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CPUC Self-Generation Incentive Program Seventh-Year Impact Evaluation

Final Report

Submitted to:

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

Prepared by:

Itron, Inc.
601 Officers Row
Vancouver, WA 98661

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CPUC Self-Generation Incentive Program (SGIP) Seventh-Year Impact Evaluation Highlights

This report summarizes an evaluation of impacts resulting from distributed generation (DG) technologies under the seventh Program Year (PY07) of the SGIP.

Program Overview:

- SGIP established in 2001 as response to peak demand problems facing California
- DG technologies eligible under the SGIP have included solar PV; wind energy; and fossil and renewable-fueled internal combustion engines (ICE), fuel cells (FC), microturbines (MT) and small gas turbines (GT). As of 01/01/08, only wind and fuel cell technologies remained eligible.
- SGIP as of 12/31/07:
  - Over 1,200 on-line SGIP projects (1,111 Complete & 98 "On-Line" Active)
  - Over 300 MW of rebated generating capacity
  - $488 million incentives paid to Complete projects, $283 million reserved for Active projects
  - Matched by private and public funds at a ratio of over 1.6 to 1
  - Total eligible project funds almost $1.3 billion, corresponding to Complete projects
- Rebated Capacity:
  - PV technologies: nearly 105 MW (close to 40% SGIP total capacity)
  - ICEs, GTs, and MTs powered by non-renewable fuels: over 145 MW (approx. 50% SGIP total capacity)
- Incentives Paid:
  - PV technologies: over $370 million (approx. 75% SGIP total incentives paid)
  - ICEs (renewable and non-renewable fueled): close to $75 million (approx. 15% SGIP total incentives paid)

Program Impacts:

- Energy: By the end of 2007, SGIP facilities were delivering over 720,000 MWh of electricity to California's electricity system; enough electricity to power over 60,000 homes for one year
  - Cogeneration facilities supplied over 70% of that total
  - PV systems provided nearly 23%; up 6% from PY06
  - PG&E largest PA contributor, providing 42% of total delivered electricity

- <u>Peak Demand</u>: 1,147 SGIP projects on-line during CAISO 2007 peak, providing nearly 140 MW of generating capacity; representing an aggregated capacity factor of 0.49 MW of peak SGIP capacity per MW of rebated capacity
  - Fuel cells: highest peak capacity factor at 0.76 kWhr of peak capacity per kWhr of rebated capacity.
  - PV: aggregate CAISO peak capacity factor of 0.60 kWhr per kWhr.
  - PV: 47% of peak capacity from SGIP facilities during CAISO 2007 peak
- <u>Greenhouse Gas (GHG) Emissions</u>: SGIP provided net GHG emission reductions of over 120,000 tons of CO_2 equivalent in 2007; making a total cumulative GHG reductions from SGIP since 2005 of over 323,000 tons of CO_2 equivalent. For PY07:
  - PV provided approx 80% of total reduction; up from 56% in PY06
  - Biogas-fueled DG facilities reduced over 38,000 tons of CO_2 equivalent
  - % of total by PA: PG&E: approx 61%; SCE: approx 22%; CCSE: approx 11%; SCG: approx 6%
- <u>Efficiency and Waste Heat Utilization</u>: Cogeneration facilities made up close to 60% of the SGIP PY07 capacity and provide not only electricity to customers but also recover waste heat and harness it for on-site heating and cooling needs. These facilities are required to achieve efficiency and wast heat requirements set by Public Utility Code (PUC).
  - All SGIP cogeneration technologies achieved and exceeded PUC 216.6(a)
  - FCs and GTs able to meet and exceed PUC 216.6(b), but ICEs and MTs fell short of requirements, due in part to lower than anticipated electricity generation efficiencies and lack of a significant coincident thermal load
  - Good match of electrical and thermal loads can play significant role in contribution of DG cogeneration facilities to offset peak demand and reduce GHG emissions during peak

Additional Observations:

- The SGIP provides significant value as a unique test bed for examining the actual performance of a mix of DG technologies operating in a commercial setting within California's utility and regulatory framework.
  - Multiple year trend analyses have provided important information on the impact of aging and deterioration on DG performance.
  - Performance evaluations have also shown short-comings of DG facilities that must be addressed as California begins to embark on a plan to expand growth of DG technologies.

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Executive Summary

Abstract

This report provides an evaluation of the impacts of the SGIP in its seventh year of operation. By the end of 2007, the SGIP was one of the single largest distributed generation (DG) incentive programs in the United States. Nearly $490 million in incentives had been provided to SGIP facilities, matched by approximately $800 million in other public and private funds, bringing total project investment to over $1.3 billion. By the end of the 2007 Program Year (PY07), over 1,200 SGIP facilities were operational, representing 305 MW of electricity generating capacity. During PY07, SGIP facilities provided over 720,000 MWh of electricity to California's grid; enough electricity to meet the needs of 60,000 homes for one year. SGIP facilities also supplied over 140 MW of needed generating capacity to the grid during the height of California's summer 2007 peak demand. SGIP facilities also offset over 120,000 tons of CO_2 equivalent GHG emissions during 2007. Additionally, SGIP cogeneration facilities recovered waste heat from the cogeneration process and used it to meet customer heating and cooling needs. While all SGIP cogeneration technologies achieved PUC 216.6(a) requirements, ICEs and MTs were not able to meet those of PUC 216.6(b). As in-depth measured performance data has continued to be collected, the SGIP has become more than a means of contributing capacity to California's electricity system. The SGIP represents a unique test bed for examining the actual performance of a mix of DG technologies operating in a commercial setting within California's utility and regulatory framework. Due to the wealth of data represented by over seven years of DG operational history, the SGIP can provide valuable lessons for planning and implementing future DG programs.

Some Words on the Executive Summary Format

Based on a request from the PG&E Project Manager, this report presents a new format for its Executive Summary which attempts to balance brevity with depth of information by using hyperlinks. In an acknowledgment of the fact that not every reader will be equally interested in every topic – nor have the time to read through an entire report to find detail on those findings that are of interest, this Executive Summary is, in essence, a deck of one-page snapshots of key report topics. Each page includes one or two graphics followed by a limited number of key "Take-Away" bullet points. Hyperlinks, indicated by blue underlined text, are used for ease of finding related sections in the body of the report or to related Web sites for such items as legislation and regulatory proceedings. For those reading a print copy, a "hard-copy link" to the main related report section is included immediately after the page heading, indicating the relevant section and page number (e.g., *Refer To Section 3.2, page 3-1*). While it is our intent that the Executive Summary provide a solid overview of evaluation findings, we strongly encourage reading the detail behind the graphics and "Take-Aways" to ensure they are not taken or used out of context. For further ease of use, tables of Key Terms related to the Executive Summary are included on the following page and a table of Useful Links follows the Conclusions & Recommendation section.

Table 1-1: Executive Summary Topic Directory

Executive Summary Topics	
1.1 Introduction & Background	1.7 Trends: Coincident Peak Demand
1.2 Program-Wide Findings	1.8 Trends: Aging and Performance Degradation: PV
1.3 Impacts: Energy	1.9 Trends: Aging and Performance Degradation: CHP
1.4 Impacts: Peak Demand	1.10 Trends: SGIP Portfolio
1.5 Efficiency & Waste Heat Utilization	1.11 Conclusions & Recommendations
1.6 Greenhouse Gas Emission Reduction Impacts	1.12 Useful Links

Table 1-2: Key Terms

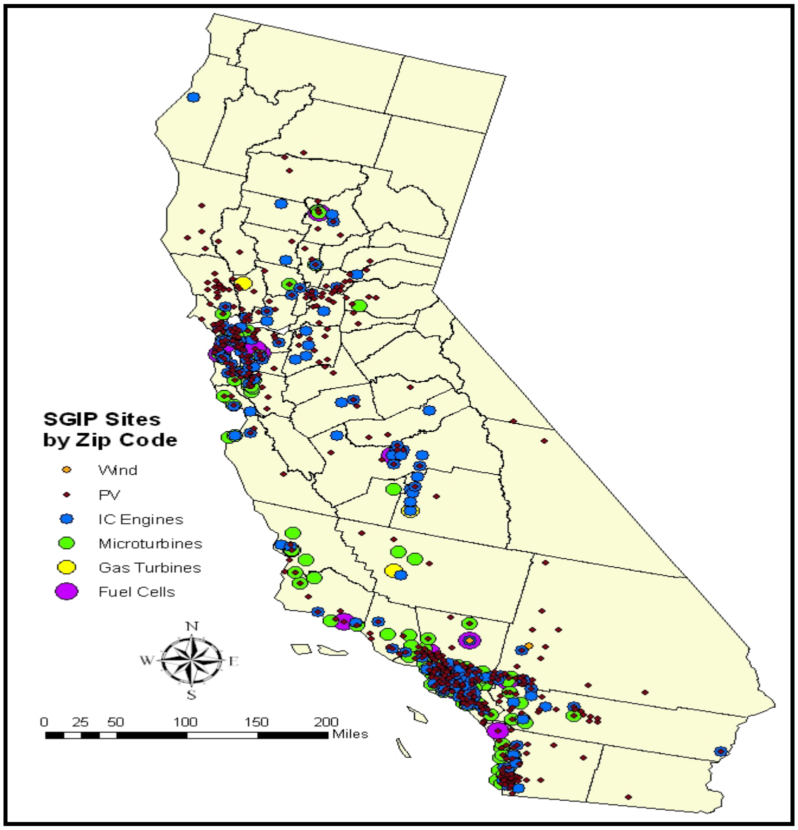
SGIP Project Categories	
Active	Have not been withdrawn, rejected, completed, or placed on a wait list. Active projects will eventually migrate either to the Complete or Inactive category.
Complete	Generation system has been installed, verified through on-site inspections, and an incentive check has been issued. All Complete projects are considered as "on-line" projects for impact evaluation purposes.
Inactive	No longer progressing in SGIP implementation process because they have been withdrawn by applicant or rejected by PA
On-line	Have entered normal operations (i.e., projects are through the shakedown or testing phase and are expected to provide energy on a relatively consistent basis.)
Rebated Capacity	The capacity rating associated with the rebate (incentive) provided to the applicant. The rebate capacity may be lower than the typical "nameplate" rating of a generator.
Technologies	
CHP	Combined Heat and Power (used interchangeably with "cogeneration")
DG	Distributed Generation
FC-N	Fuel Cells (Non-renewable)
FC-R	Fuel Cells (Renewable)
GT-N	Gas Turbines (Nonrenewable-fueled)
GT-R	Gas Turbines (Renewable-fueled)
ICE-N	Internal Combustion Engines (Non-renewable-fueled)
ICE-R	Internal Combustion Engines (Renewable-fueled)
MT-N	Microturbines (Non-renewable-fueled)
MT-R	Microturbines (Renewable-fueled)
PV	Photovoltaics
WD	Wind Turbines
Misc. Defined Terms	
CCSE	California Center for Sustainable Energy
CEC	California Energy Commission
CPUC	California Public Utilities Commission
CSI	California Solar Intitiave
IOU	Invester-owned Utility
PA	Program Administrator
PG&E	Pacific Gas and Electric Company
PY	Program Year
SCG	Southern California Gas Company
SDG&E	San Diego Gas and Electric Company
SCE	Southern California Edison
SGIP	Self-Generation Incentive Program

1.1 Introduction & Background (*Refer to Section 2, page 2-1*)

Table 1-3: SGIP Eligible Technologies

SGIP Generation Technologies and Applicable Program Years
Photovoltaics (PV): PY01- PY06
Wind Turbines (WD): PY01 - present
Non-renewable fuel cells (FC-N): PY01- present
Renewable fuel cells (FC-R): PY01 - present
Non-renewable-fueled internal combustion engines (IC engines-N): PY01 – PY06
Renewable-fueled internal combustion engines (IC engines-R): PY01 – PY06
Non-renewable-fueled microturbines (MT-N): PY01 – PY06
Renewable-fueled microturbines (MT-R): PY01 - present
Non-renewable-fueled gas turbines (GT-N): PY01 – PY06
Renewable-fueled gas turbines (GT-R): PY01 – PY06

Figure 1-1: Distribution of SGIP Facilities as of 12/31/07



Take-Aways:

- Per AB 970, CPUC D.01-03-073 (3/27/01) outlined provisions of DG incentive program, which became the SGIP
- SGIP operates in service areas of PG&E, SCE, SCG, and SDG&E (some projects in municipal electric utility service areas)
- Administered by PG&E, SCE, and SCG, in respective territories, and by CCSE (formerly SDREO) in SDG&E's territory
- July 2001: 1st SGIP application accepted. December 31, 2007: SGIP one of the single largest DG incentive programs in country
- Financial incentives for diverse family of technologies, including systems employing solar PV, wind energy, fuel cells, microturbines, small gas turbines and international combustion engines
- SGIP M&E per D.01-03-073. This impact evaluation of SGIP 7th program year covers all SGIP projects coming on-line prior to January 1, 2008
- Examines impacts or requirements associated with energy delivery, peak demand, efficiency and waste heat utilization, and GHG emission reductions

1.2 Program-Wide Findings *(Refer to Section 3, page 3-1)*

Table 1-4: SGIP Projects and Rebated Capacity by PAs as of 12/31/07

PA	No. of Projects	Capacity (MW)	% of Total Capacity
PG&E	616	143	47%
SCE	275	60	20%
SCG	176	69	23%
CCSE	142	33	11%
Totals	**1,209**	**305**	**100%**

Figure 1-2: SGIP Capacity (MW) by Technology and Fuel Type as of 12/31/07 (Complete Projects)

Total Capacity = 270.6 MW

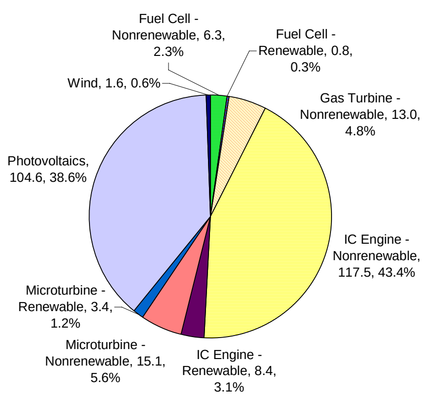
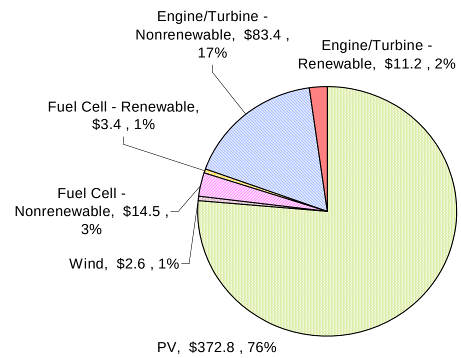


Figure 1-3: SGIP Incentive Payments by Technology and Fuel Type as of 12/31/07 (Complete Projects)

Total Payments = $488 million



Take-Aways:

- SGIP as of 12/31/07:
  - Over 1,200 on-line SGIP projects (1,111 Complete & 98 "On-Line" Active)
  - Over 300 MW of rebated generating capacity
  - $488 million incentives paid to Complete projects, $283 million reserved for Active projects
  - Matched by private and public funds at a ratio of over 1.6 to 1
  - Total eligible project costs almost $1.3 billion, corresponding to Complete projects
  - PG&E: most SGIP projects and largest aggregated capacity, nearly 50% SGIP total capacity
- Rebated Capacity:
  - PV technologies: nearly 105 MW (close to 40% SGIP total capacity)
  - FCs, ICEs, GTs, and MTs powered by non-renewable fuels: over 150 MW (approx. 56% of SGIP total capacity)
- Incentives Paid:
  - PV technologies: over $370 million (approx. 75% SGIP total incentives paid)
  - ICEs (renewable and non-renewable fueled): close to $75 million (approx. 15% SGIP total incentives paid)

1.3 Impacts – Energy (*Refer to Section 5.1, page 5-1*)

Table 1-5: Statewide Energy Impact in 2007 by Quarter (MWh)

Technology	Fuel	Q1-2007 (MWh)	Q2-2007 (MWh)	Q3-2007 (MWh)	Q4-2007 (MWh)	Total* (MWh)
FC	N	11,734	12,410	12,947	12,508	49,599
FC	R	717	551	679	594	2,540
GT	N	19,865	22,068	17,964	22,297	82,193 †
IC ENGINES	N	78,647	74,066	84,816	79,220	316,748 †
IC ENGINES	R	9,394	9,024	8,696	9,191	36,304 †
MT	N	13,069	16,203	15,083	17,554	61,910 †
MT	R	2,257	1,966	1,680	1,864	7,767 †
PV		28,394	52,898	50,965	29,514	161,770
WD		502	784	571	569	2,426 [a]
	TOTAL	**164,578**	**189,970**	**193,400**	**173,309**	**721,257**

Table 1-6: Annual Energy Impacts by PA (MWh)

Technology	PG&E (MWh)	SCE (MWh)	SCG (MWh)	CCSE (MWh)	Total (MWh)
FC	24,344	3,908 †	11,244 †	12,642	52,139
GT	22,689 [a]		29,876 [a]	29,629	82,193 †
IC ENGINES	136,071 †	73,520 †	116,238 †	27,223	353,052
MT	27,647 †	17,395 †	21,255 †	3,379	69,677 †
PV	92,849	31,360	16,894	20,667	161,770
WD		2,426 [a]			2,426 [a]
Total	**303,601**	**128,609**	**195,508**	**93,540**	**721,257**

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

Take-Aways:

- During PY07, SGIP projects delivered over 720,000 MWh of electricity to California's grid - enough to meet electricity requirements of 60,000 homes for a year – that did not have to be generated by central station power plants or delivered by T&D system
- Cogeneration systems (fuel cells, engines, and turbines): over 77% (557,061 MWh) of electricity delivered by SGIP during 2007; 15% decline from 2006
- PV: approx 22% (161,770 MWh) of electricity delivered by SGIP in 2007; 5% increase from 2006
- Natural gas-fueled ICEs: 44% (316,748 MWh); largest share by single technology in 2007; 14% decline from PY06
- PG&E: largest PA contributor, approx. 42% (303,601 MWh) of total electricity delivered by SGIP during 2007; down 2% from PY06 at 44%
- SCG: approx 27% (195,508 MWh); down 5% from PY06 at 32%
- SCE: approx 18% (128,609 MWh); up 4% from PY06 at 14%
- CCSE: approx 13% (93, 540 MWh); up 4% from PY06 at 9%

1.4 Impacts – Peak Demand (*Refer to Section 5.2, page 5-9*)

Figure 1-4: SGIP Impact on CAISO 2007 Peak Day

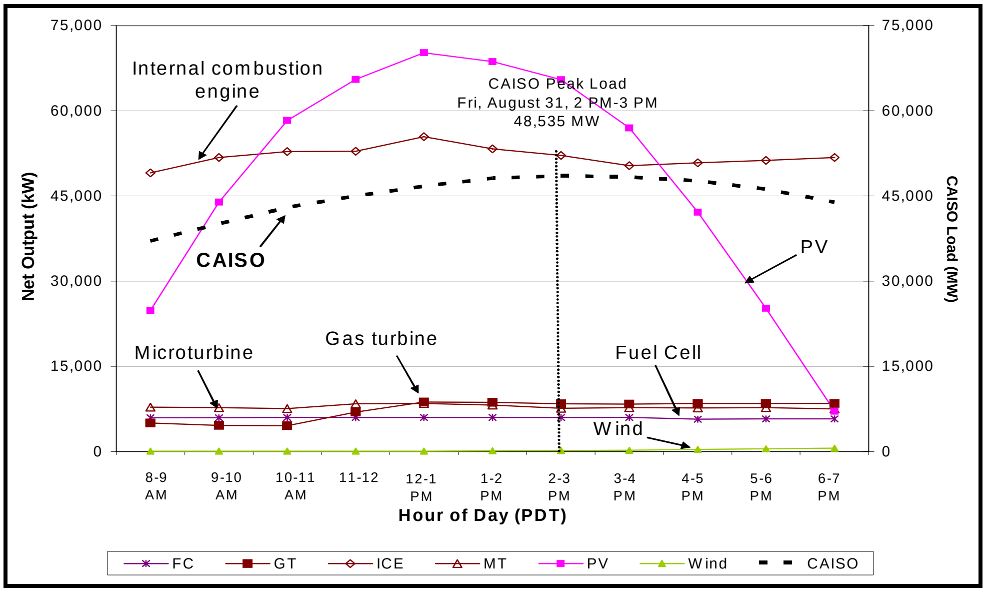


Table 1-7: Demand Impact Coincident with 2007 CAISO System Peak Load

		On-Line Systems	Operational	Impact	Hourly Capacity Factor*
Technology		**(n)**	**(kW)**	**(kW)**	**(kWh/kWh)**
FC		14	8,000	5,982	0.748
GT		5	13,043	8,386	0.643 †
IC ENGINES		214	133,411	52,110	0.391
MT		121	19,274	7,619	0.395 †
PV		791	109,052	65,490	0.601
WD		2	1,649	156	0.095 [a]
	TOTAL	**1,147**	**284,429**	**139,743**	

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

Take-Aways:

- 1,147 SGIP projects on-line during CAISO 2007 summer peak (August 31, 2:00 PM to 3:00 PM (PDT), reached max value of 48,835 MW)
- Total rebated capacity of these on-line projects exceeded 284 MW
- Total impact of SGIP projects coincident with CAISO peak load est. slightly below 140 MW
- Collective peak hour impact of SGIP projects on CAISO 2007 peak approx 0.49 kWh per kWh
- PV: approx 47% of total SGIP peak impact in PY07
- IC engines: approx 37% of total SGIP peak impact in PY07
- Reversal from PY06, wherein PV systems contributed approx 37% and IC engines approx 48%
- Relatively high hourly capacity factor of 0.6 for PV result of early afternoon timing of CAISO system peak

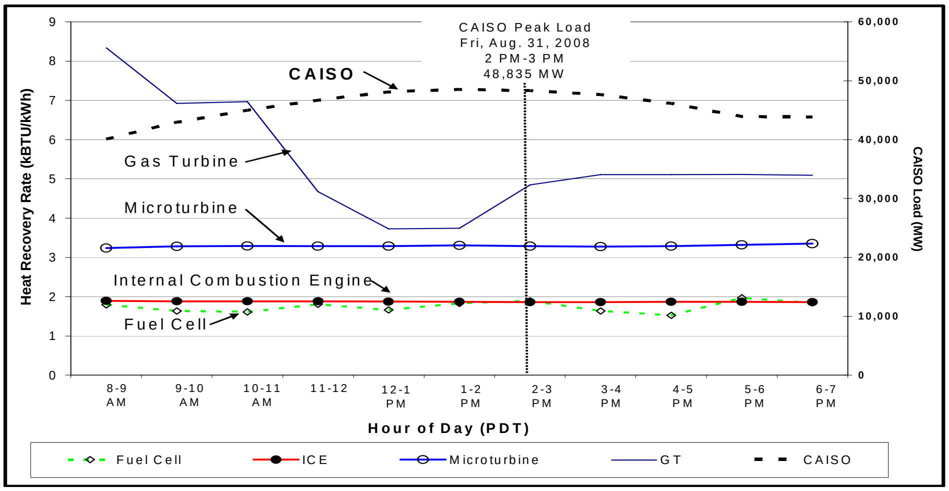
1.5 Efficiency and Waste Heat Utilization *(Refer to Section 5.3, page 5-21)*

Table 1-8: PUC 216.6 Cogeneration System Performance by Technology

Technology	Number of projects (n)	216.6 (a) Proportion as Useful Heat (%)*	216.6 (b) Avg. Efficiency Level Achieved (%, LHV)*
FC	14	37†	54
GT	5	62†	53†
IC Engines	206	36	38
MT	110	50†	30

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

Figure 1-5: Heat Recovery Rate during CAISO Peak Day



Take -Aways:

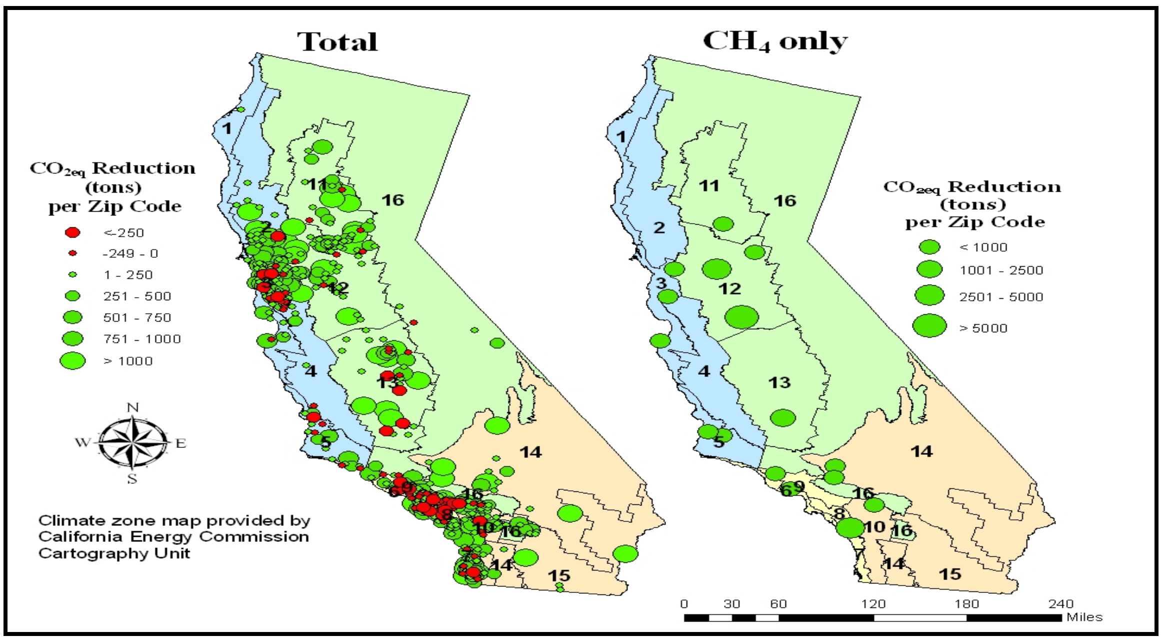
- PUC 216.6(a) requires recovered useful waste heat from cogeneration system exceed 5% of combined recovered waste heat plus the electrical energy output of system.
  - All SGIP cogeneration technologies achieved and exceeded PUC 216.6(a) requirement
  - Recovered total output energy as useful heat: FC: 37%; ICE: 36%; GT: 62%; MT: 50%
- PUC 216.6(b) requires sum of electric generation and half of heat recovery of the system exceed 42.5% of energy entering system as fuel.
  - FCs and GTs able to meet and exceed PUC 216.6(b) requirement
  - ICEs and MTs fell short of requirements, due in part to lower than anticipated electricity generation efficiencies and lack of a significant thermal load coincident with electricity generation
- Good match of electrical and thermal loads can play significant role in contribution of DG cogeneration facilities to offset peak demand and reduce GHG emissions during peak
- Particularly true when recovered waste heat used to drive absorption chillers that offset air conditioning loads
- Average thermal energy recovery by SGIP cogeneration facilities does not appear to have been influenced by peak hour electrical demands. *This should be an important consideration for expansion of cogeneration facilities in California's electricity market.*

1.6 Greenhouse Gas Emission Reduction Impacts *(Refer to Section 5.4, page 5-26)*

Table 1-9: Net Reduction of GHG Emissions from SGIP Systems in PY07 by Fuel and Technology

Technology	Tons of CO_2 eq. Emissions	Annual Energy Impact (in MWh)	CO_2 eq. Factor (Tons/MWh)
Photovoltaics	-96,621	161,770	-0.6
Wind turbines	-1,454	2,426	-0.6
Non-renewable fuel cells	-11,098	49,599	-0.22
Non-renewable MT	13,956	61,910	0.23
Non-renewable-fueled IC engines	-1,229	316,748	0.00
Non-renewable- and waste gas-fueled small gas turbines	13,765	82,194	0.17
Renewable-fueled fuel cells	-602	2,540	-0.24
Renewable-fueled MT	-4,881	7,767	-0.63
Renewable-fueled-IC engines	-33,246	36,304	-0.92
TOTAL	**-121,410**	**721,257**	**-0.17**

Figure 1-6: PY07 Distribution of GHG Emission Reductions Among SGIP Facilities

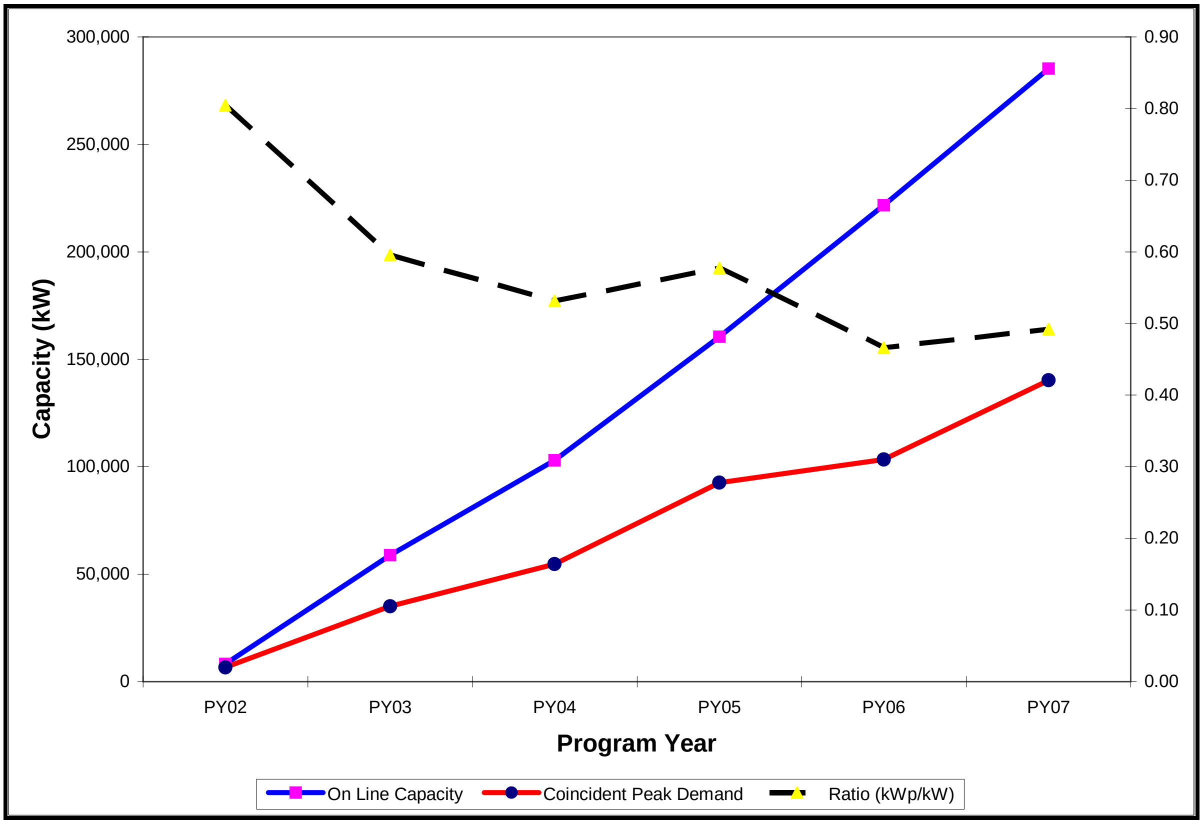


Take-Aways:

- Net GHG emissions from SGIP projects developed relative to baseline GHG emissions from "grid electricity"
- GHG emission reduction analysis focus remains primarily on CO_2 and CH_4 as main contributors of GHG from SGIP facilities
- PY07 SGIP Net GHG emission reductions:
  - PV systems: 80% of total; up significantly from 56% in PY06, due to growth in PV capacity
  - Renewable-fueled SGIP facilities: over 26% of total, due to capture of methane in "biogas"
  - % of Total by PA: PG&E: 61%; SCE: 22%; CCSE: 11%; SCG: 6%

1.7 Trends: Coincident Peak Demand (*Refer to Section 3.4 page 3-21*)

Figure 1-7: Trend on Coincident Peak Demand from PY02 to PY07

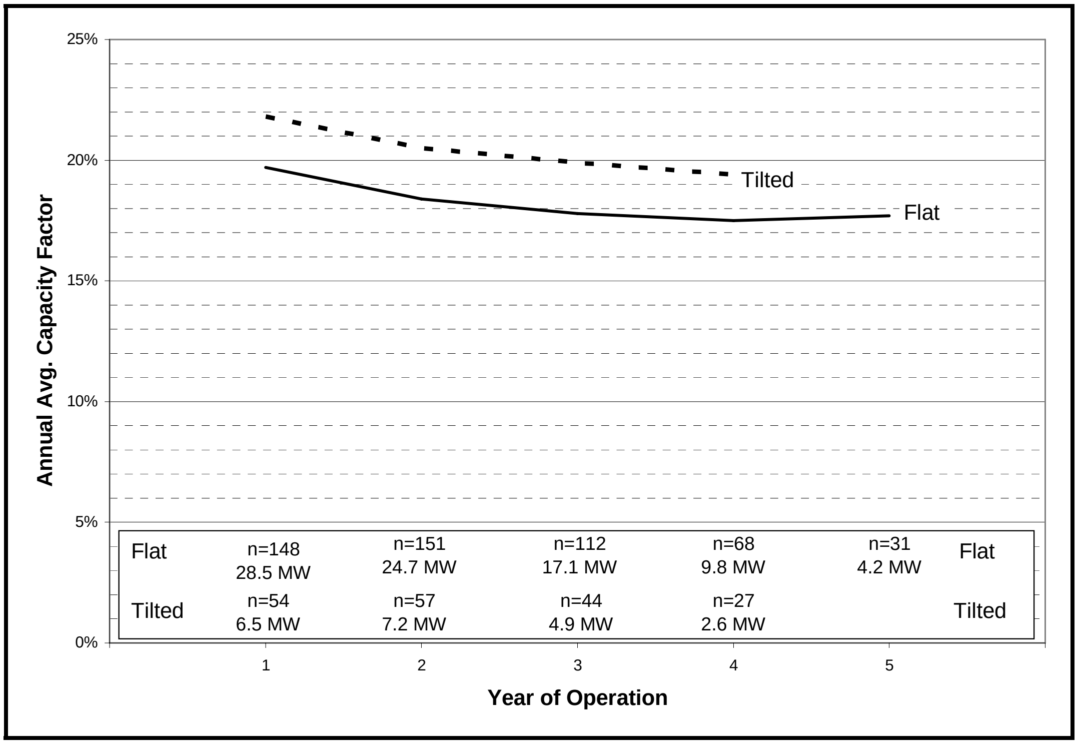


Take-Aways:

- Ratio of peak capacity to online capacity (kWp/kW) reflects amount of capacity actually observed to be available during CAISO peak demand
- Relatively high kWp/kW ratio observed in PY02 should not be considered indicative of DG technologies, as it may be due to the low number of systems monitored during that program year
- kWp/kW ratio from PY04 on has generally ranged between 0.5 and 0.6. *Note that since this ratio resulted without any pre-specified plans by the CPUC or the utilities, it reflects the level of impact on coincident peak demand that could be expected from an unplanned expansion of DG technologies.*
- Based on a ratio of 0.6 and using CEC forecasts for peak electricity demand, we can estimate the amount of DG capacity that would be needed for DG technologies to provide 25% of California's peak electricity by 2020: 25,000 MW
- A lower contribution from DG technologies could possibly be achieved at lower costs by improved matching of coincident peak contributions of DG mix

1.8 Trends: Aging & Performance Degradation: PV *(Refer to Section 3.4, page 3-23)*

Figure 1-8: PV Annual Capacity Factor versus Year of Operation

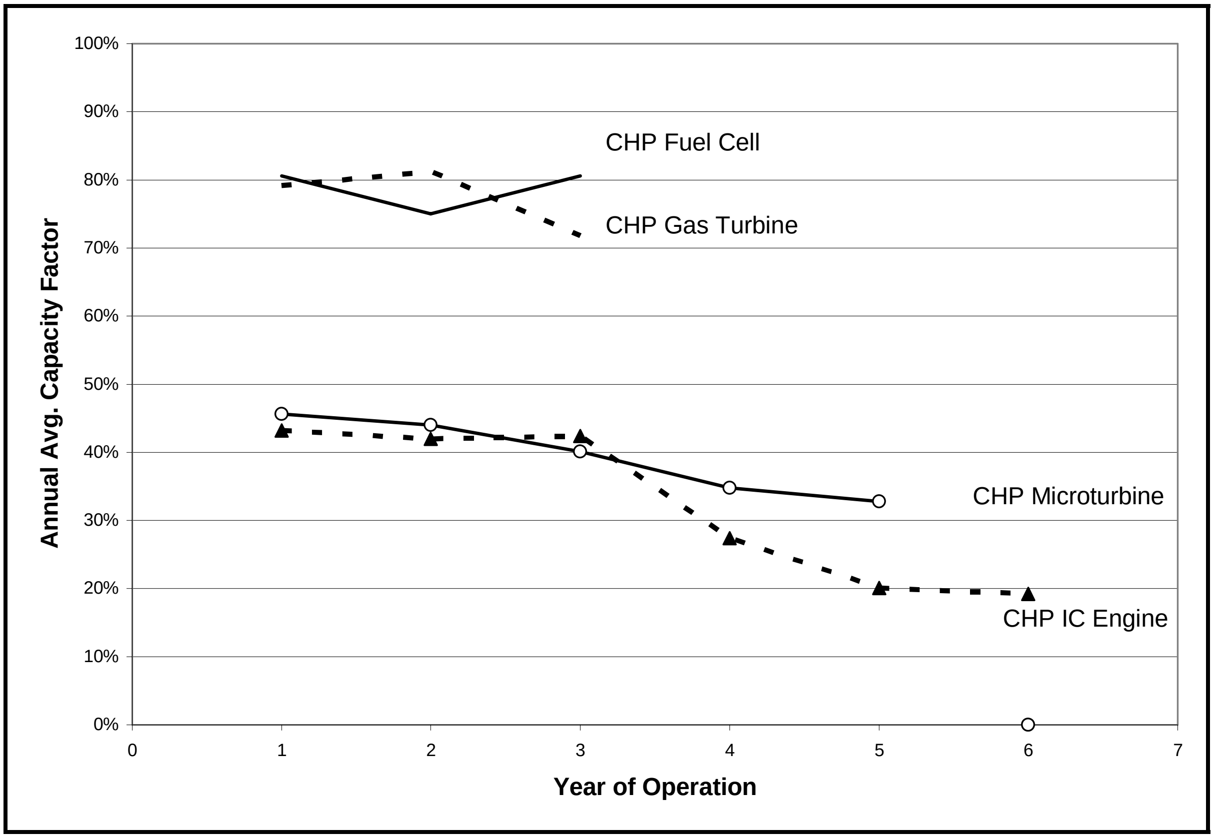


Take-Aways:

- Year-to-year variability in average annual capacity factor of fixed and tilted PV systems is due to a range of factors including weather, maintenance/reliability issues, and location of projects
- Observed annual capacity factors for both tilted and flat PV systems have declined with age
- Decline in annual capacity factor of PV systems over 4 program years:
  - Flat PV systems: declined approximately two percentage points after four years of operation; flattening out and slightly increasing by year 5
  - Tilted PV systems: also decline two percentage points over four years but with a higher initial rate of decline than flat systems and with a consistent downward trend
  - Understanding reasons for the differences requires additional process evaluation information
- Important as it allows policy makers and CSI PAs to recognize the extent to which PV capacity factors may possibly be expected to decline over the life of the CSI

1.9 Trends: Aging & Performance Degradation: CHP *(Refer to Section 3.4, page 3-25)*

Figure 1-9: CHP Annual Capacity Factor versus Year of Operation

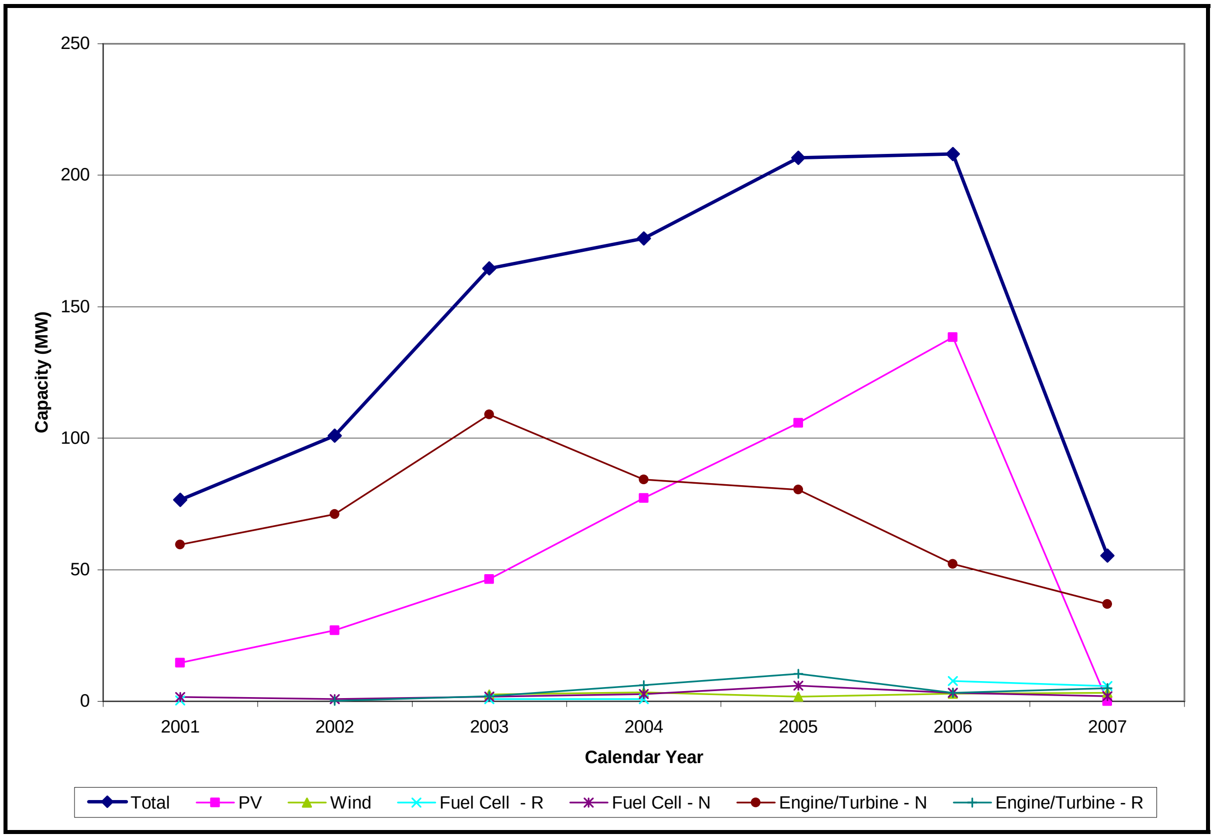


Take-Aways:

- Year-to-year variability in average annual capacity factor of CHP systems is due to a range of factors including equipment maintenance/reliability issues, staff turnover, and interruption in fuel or service provider contracts, fuel prices, and occupancy/operations schedules of metered CHP systems
- Annual capacity factor trends for ICEs and MTs exhibit noticeable downward trend over life of program:
  - IC engines: decline of nearly 20 percentage points in annual capacity factors from program year 1 through program year 7, with very rapid decline between program years 3 and 5 accounting for nearly all of loss of annual capacity factor.
  - Microturbines: decline of nearly 10 percentage points in annual capacity factor over 5 program years. As with ICEs, a significant amount of decline occurred during middle years
- There is limited data on fuel cells and gas turbines due to the limited number of systems operating in the SGIP. No trends are apparent and increases or decreases in later years may be due to the limited data.
- Understanding reasons for changes requires additional process evaluation information

1.10 Trends: SGIP Portfolio (*Refer to Section 3.4, page 3-26*)

Figure 1-10: Capacity of Active SGIP Projects PY01 to PY07



Take-Aways:

- Changes in eligibility of SGIP technologies have changed SGIP portfolio
- From PY01 through PY05, there was a steady increase in all Active projects
- PV:
  - Steady growth in capacity of PV projects through end of PY06
  - With CSI, PV technologies no longer were eligible to receive incentives under SGIP. As of January 1, 2007, rapid decline in Active SGIP PV projects, with only legacy projects moving forward in PY07
- IC engines and turbine technologies: Steady decline in capacity of IC engines and turbine technologies since PY03
- Passage of AB 2778 (September 2006) limits eligibility of cogeneration projects within the SGIP to "ultra-clean and low emission distributed generation" technologies, defined as fuel cells and wind DG technologies that meet or exceed emissions standards required under the DG certification program adopted by the California Air Resources Board
- Fuel Cells & Wind Technologies: Little growth of fuel cell and wind technologies under the SGIP over the past several years
- Changes in capacity additions from PV and cogeneration technologies will substantially affect SGIP portfolio beyond PY07
- Changes in SGIP portfolio will influence impacts by technologies as well as observations on the impacts of those technologies within electricity system

1.11 Conclusions & Recommendations

The SGIP continues to present tremendous learning 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. The successfulness of that growth will require a thoughtful approach to the manner in which DG technologies can meet the sometimes competing needs for increased electricity system performance, environmental improvements and lower costs to rate payers. The extensive performance data collected from a diverse group of DG technologies deployed under the SGIP can continue to provide important information to help plan and deploy future DG programs. To help enhance the information available under the SGIP, we recommend the following work be considered by the CPUC and PAs:

- There has been a steady decline in the application of cogeneration projects to the SGIP as well as an increase in attrition of cogeneration projects. **Process evaluations should be conducted to examine the reasons for the decline in the numbers of cogeneration projects.**
- There has been a decline in the performance of SGIP technologies as demonstrated by the average annual capacity factors for PV and CHP technologies. **Process evaluations that are complemented by individual project performance information should be conducted to better identify the reasons for the performance declines**.
- The ability of cogeneration technologies to achieve high electrical efficiencies and have matched thermal and electrical loads will be important in pursuing improved system efficiency and decreased net GHG emissions. **Evaluations should be conducted to assess the degree to which DG technology installers are complying with the new Waste Heat Utilization Worksheet requirements established in 2006 by the PAs**.
- There is likely to be increased emphasis on the use of renewable fuel use facilities in the future. In addition, PAs may want to consider use of mixed incentive payments for facilities that use mixes of renewable and non-renewable fuels. However, due to the current approach to renewable fuel use requirements and the cost of monitoring biogas fuel use, there has been limited information collected on actual biogas fuel consumption at renewable fuel use facilities. **Actual biogas fuel use monitoring should be conducted to better understand the performance of new technologies (e.g., fuel cells) using biogas and the ability and costs of using renewable and non-renewable fuel mixes**.
- There were no new wind energy projects submitted to the SGIP in PY05 – PY07. However, wind energy DG projects are eligible for the program and may play an important role in helping California achieve its DG targets. **Evaluations should be conducted to determine the reasons for the low application of wind energy technologies to the SGIP, the potential benefits of having additional wind energy projects and the steps needed to encourage applications of wind DG projects to the SGIP**.

1.12 Useful Links

Table 1-10: Useful Links

Legislation & Regulation	
Assembly Bill 970 (Ducheny, September 7, 2000)	http://www.leginfo.ca.gov/pub/99-00/bill/asm/ab_0951-1000/ab_970_bill_20000907_chaptered.html
Assembly Bill 1685 (Leno, October 12, 2003)	http://www.leginfo.ca.gov/pub/03-04/bill/asm/ab_1651-1700/ab_1685_bill_20031012_chaptered.html
Assembly Bill 2778 (Lieber, September 29, 2006)	http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_2751-2800/ab_2778_bill_20060929_chaptered.html
CPUC Proceeding R0403017	http://docs.cpuc.ca.gov/published/proceedings/R0403017.htm
CPUC Decision 04-12-045 (D. 04-12-045, December 16, 2004)	http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/42455.htm
CPUC Proceeding R9807037	http://docs.cpuc.ca.gov/published/proceedings/R9807037.htm
CPUC Decision 01-03-073 (D.01-03-073, March 27, 2001)	http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/6083.htm
Public Utilities Code 216.6 (prev. Public Utilities Code 218.5)	http://www.leginfo.ca.gov/cgi-bin/displaycode?section=puc&group=00001-01000&file=201-248
SGIP Study Reports	
SGIP Data & Reports	http://www.energycenter.org/ContentPage.asp?ContentID=279&SectionID=276&SectionTarget=35
PA SGIP Sites	
CCSE (in SDG&E territory)	http://www.sgip.energycenter.org
SCE	http://www.sce.com/sgip
SCG	http://www.socalgas.com/business/selfGen/
PG&E	http://www.pge.com/selfgen/

2

Introduction

2.1 Program Background

During the summer of 2000, California experienced a series of rolling blackouts leaving thousands electricity customers in Northern California without power and shutting down hundreds of businesses. In hindsight, the blackouts of 2000 were considered by many electricity market analysts as the first manifestations of California's electricity crisis.[1] While manipulation of California's electricity market played a key role in the ensuing electricity crises, it was also apparent that the state faced severe peak electricity demand problems.[2] Passed in response to California's peak electricity demand problems, Assembly Bill (AB) 970 directed the California Public Utilities Commission (CPUC) in consultation with the California Independent System Operator (CAISO), and the California Energy Commission (CEC) to "adopt energy conservation, demand-side management and other initiatives in order to reduce demand for electricity and reduce load during peak demand periods." The same legislation required the CPUC to consider establishment of incentives for load control and distributed generation that enhance reliability with "differential incentives for renewable or super clean distributed generation resources." The CPUC issued Decision 01-03-073 (D.01-03-073)[3] on March 27, 2001 outlining the provisions of a distributed generation (DG) incentive program, which became known as the Self-Generation Incentive Program (SGIP). The 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 (PV) systems, fossil- and renewable-fueled reciprocating engines, fuel cells, microturbines, small-scale gas turbines, and wind energy systems. The first SGIP application was accepted in July 2001. The SGIP grew steadily from 2001 onward.

1 PBS, "The California Energy Crisis Timeline" http://www.pbs.org/wgbh/pages/frontline/shows/blackout/california/timeline.html

2 California State Auditor/Bureau of State Audits, Summary of Report 2000-134.2 - May 2001 http://www.bsa.ca.gov/reports/summary.php?id=325

3 CPUC Decision 01-03-073 (D.01-03-073, March 27, 2001) http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/6083.htm

In October of 2003, AB 1685[4] extended the SGIP beyond 2004 through 2007 in largely the same form that existed on January 1, 2004. This legislation notwithstanding, a number of program modifications were made in 2004 and 2007. In particular, with enactment of the California Solar Initiative (CSI), incentive funding for PV moved outside of the SGIP. Consequently, effective January 1, 2007, the SGIP no longer offered incentives to PV systems. Similarly, AB 2778[5] (approved in September 2006) extended the SGIP through 2012 but limited project eligibility to "ultra-clean and low emission distributed generation" technologies. These technologies were defined as fuel cells and wind DG technologies that met or exceeded emissions standards required under the DG certification program adopted by the California Air Resources Board. AB 2778 also set minimum system efficiency eligibility for SGIP projects based on electrical and process heat efficiencies and taking into account oxides of nitrogen (NOx) emissions.

The SGIP has been operational since July 2001 and as of the end of 2007, represented one of the single largest DG incentive programs in the country. As of December 31, 2007, nearly $488 million in incentives had been paid out through the SGIP, resulting in the installation of over 1,550 DG "Complete" and "Active" projects representing just under 470 megawatts (MW) of rebated capacity.

2.2 Impact Evaluation Requirements

Due to the magnitude of the SGIP, the CPUC felt evaluation was an essential element of the program. In its March 2001 decision, the CPUC authorized the SGIP Program Administrators "to outsource to independent consultants or contractors all program evaluation activities…." Impact evaluations were among the evaluation activities outsourced to independent consultants. The Decision also directed the assigned Administrative Law Judge (ALJ), 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 2008.

4 Assembly Bill 1685 (Leno, October 12, 2003) (http://www.leginfo.ca.gov/pub/03-04/bill/asm/ab_1651-1700/ab_1685_bill_20031012_chaptered.html)

5 Assembly Bill 2778 (Lieber, September 29,2006) (http://www.leginfo.ca.gov/pub/05-06/bill/asm/ab_2751-2800/ab_2778_bill_20060929_chaptered.html)

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

Program Year (PY) Covered	Date of Report
2001[6]	June 28, 2002
2002[7]	April 17, 2003
2003[8]	October 29, 2004
2004[9]	April 15, 2005
2005[10]	March 1, 2007
2006[11]	August 30, 2007

In accordance with a May 18, 2006 Rulemaking, the 2007 Impact Evaluation Report was to be filed with the CPUC by June 16, 2008. On May 28, 2008, PG&E filed a motion with the CPUC on behalf of the PAs requesting approval of an extension for submittal of the 2007 Impact Evaluation Report. The ALJ approved an extension to October 1, 2008. Table 2-2 identifies the schedule for filing of the 2007 and 2008 impact evaluation reports.

Table 2-2: Post-PY2006 SGIP Impact Evaluation Reports

Program Year (PY) Covered	Date of Report Filing to the CPUC
2007	October 1, 2008
2008	June 15, 2009

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6 *California Self-Generation Incentive Program: First Year Impact Evaluation Report.* Submitted to Southern California Edison. Prepared by Regional Economic Research (RER), June 28, 2002. http://www.energycenter.org/uploads/Selfgen%20First%20Year%20Process%20Report.pdf

7 *California Self-Generation Incentive Program: Second Year Impact Evaluation Report.* Submitted to Southern California Edison. Prepared by Itron, Inc., April 17, 2003. http://www.energycenter.org/uploads/SelfGen%20Second%20Year%20Impacts%20Report.pdf

8 *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. http://www.energycenter.org/uploads/Selfgen%20Third%20Year%20Impacts%20Report.pdf

9 *California Self-Generation Incentive Program: Fourth Year Impact Evaluation Report.* Submitted to Southern California Edison. Prepared by Itron, Inc., April 15, 2005. http://www.energycenter.org/uploads/SelfGen%202004%20Fourth%20Year%20Impacts.PDF

10 *California Self-Generation Incentive Program: Fifth Year Impact Evaluation Report.* Submitted to Pacific Gas & Electric. Prepared by Itron, Inc., March 1, 2007. http://www.energycenter.org/uploads/SelfGen_Fifth_Year_Impact_Report.pdf

11 *California Self-Generation Incentive Program: Sixth Year Impact Evaluation Final Report.* Submitted to Pacific Gas & Electric. Prepared by Itron, Inc., August 30, 2007. http://www.energycenter.org/uploads/SGIP_M&E_Sixth_Year_Impact_Evaluation_Final_Report_August_30_2007.pdf

This report provides the findings of an impact evaluation covering the 2007 program year (PY07) of the SGIP.

In addition to being one of the largest DG incentive programs in the country, the SGIP also represents a program with an extremely diverse family of technologies. DG technologies that have received rebates under the SGIP include systems employing solar photovoltaic (PV), wind energy, fuel cells, microturbines, small gas turbines and international combustion engines (IC engines). DG technologies deployed under the SGIP receive incentives in accordance with their associated "incentive level." Because incentive levels and the groupings of technologies that fall within them have changed over time, we summarize impact results in this report by technology and fuel type instead of incentive level[12]. Table 2-3 summarizes the SGIP technology groups used in this report.

Table 2-3: SGIP Technologies[13]

SGIP Generation Technologies and Applicable Program Years
Photovoltaics (PV): PY01- PY06
Wind Turbines (WD): PY01 - present
Non-renewable fuel cells (FC-N): PY01- present
Renewable fuel cells (FC-R): PY01 - present
Non-renewable-fueled internal combustion engines (IC engines-N): PY01 – PY06
Renewable-fueled internal combustion engines (IC engines-R): PY01 – PY06
Non-renewable-fueled microturbines (MT-N): PY01 – PY06
Renewable-fueled microturbines (MT-R): PY01 - present
Non-renewable-fueled gas turbines (GT-N): PY01 – PY06
Renewable-fueled gas turbines (GT-R): PY01 – PY06

2.3 Scope of the Report

The 2007 Impact Evaluation Report represents the seventh impact evaluation 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 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 2007 report examines the effects of

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[12] The use of technology and fuel type in lieu of incentive level was initiated with the Sixth Year Impact Report

[13] This table lists technologies that have been eligible at some time during the SGIP to receive incentives. Effective January 1, 2007, new PV projects could no longer receive incentives under the SGIP. In addition, eligibility of other DG technologies was restricted to wind and fuel cells.

SGIP technologies on electricity production and demand reduction; on system reliability and operation; and on compliance with renewable fuel use and thermal energy efficiency requirements. In addition, the 2007 report also examines greenhouse gas (GHG) emission reductions associated with each SGIP technology category. Transmission and distribution (T&D) system operation and reliability impacts are not addressed in the 2007 Impact Evaluation Report due to lack of SGIP project-specific load data but will be treated in the 2008 Impact Evaluation Report.

Impact Evaluation Objectives

Below is a summary of the impact evaluation objectives contained in the 2007 report.

- Electricity energy production and demand reduction
  - Annual production and production at peak periods during summer (both at CAISO system and at individual IOU-specific summer peaks)
  - Peak demand impacts (both at CAISO 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 are assessed against PUC 216.6[14] requirements
  - PUC 216.6 (a): useful recovered waste heat requirements
  - PUC 216.6 (b): system efficiency requirements
- GHG emission reductions are estimated 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 through 2007

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 seventh-year impact evaluation of the SGIP through the end of 2007.
- **Section 2** is this introduction.
- **Section 3** presents a summary of the program status of the SGIP through the end of 2007.

[14] Public Utilities Code 216.6 was previously Public Utilities Code 218.5. The requirements have not changed. http://www.leginfo.ca.gov/cgi-bin/displaycode?section=puc&group=00001-01000&file=201-248

- **Section 4** describes the sources of data used in this report for the different technologies.
- **Section 5** discusses the 2007 impacts associated with SGIP projects at the program level. The section provides a summary discussion as well as specific information on impacts associated with energy delivery; peak demand reduction; efficiency and waste heat utilization requirements; and GHG 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** describes the methodology used for developing estimates of SGIP GHG impacts.
- **Appendix C** 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 D** gives an overview of the metering systems employed under the SGIP for metering electric generation, fuel consumption, and heat recovery.
- **Appendix E** provides a listing of the various metering equipment installed by Itron for the purposes of this evaluation and associated specification sheets.
- **Appendix F** provides copies of legislation and CPUC rulings relevant to the SGIP and referred to in this report.

3

Program Status

3.1 Introduction

This section provides information on the status of the Self-Generation Incentive Program (SGIP) as of the end of December 31, 2007. The status is based on project data provided by the Program Administrators (PAs) relative to all applications extending from Program Year 2001 (PY01) through the end of Program Year 2007 (PY07). Information in this section includes the geographical distribution of SGIP projects; the status of projects in the SGIP; the associated amount of rebated capacity deployed under the SGIP; incentives paid or reserved; and project costs.

3.2 Overview

Table 3-1 provides a summary of the number and rebated capacity[1] of SGIP projects among the various PAs as of the end of PY07.

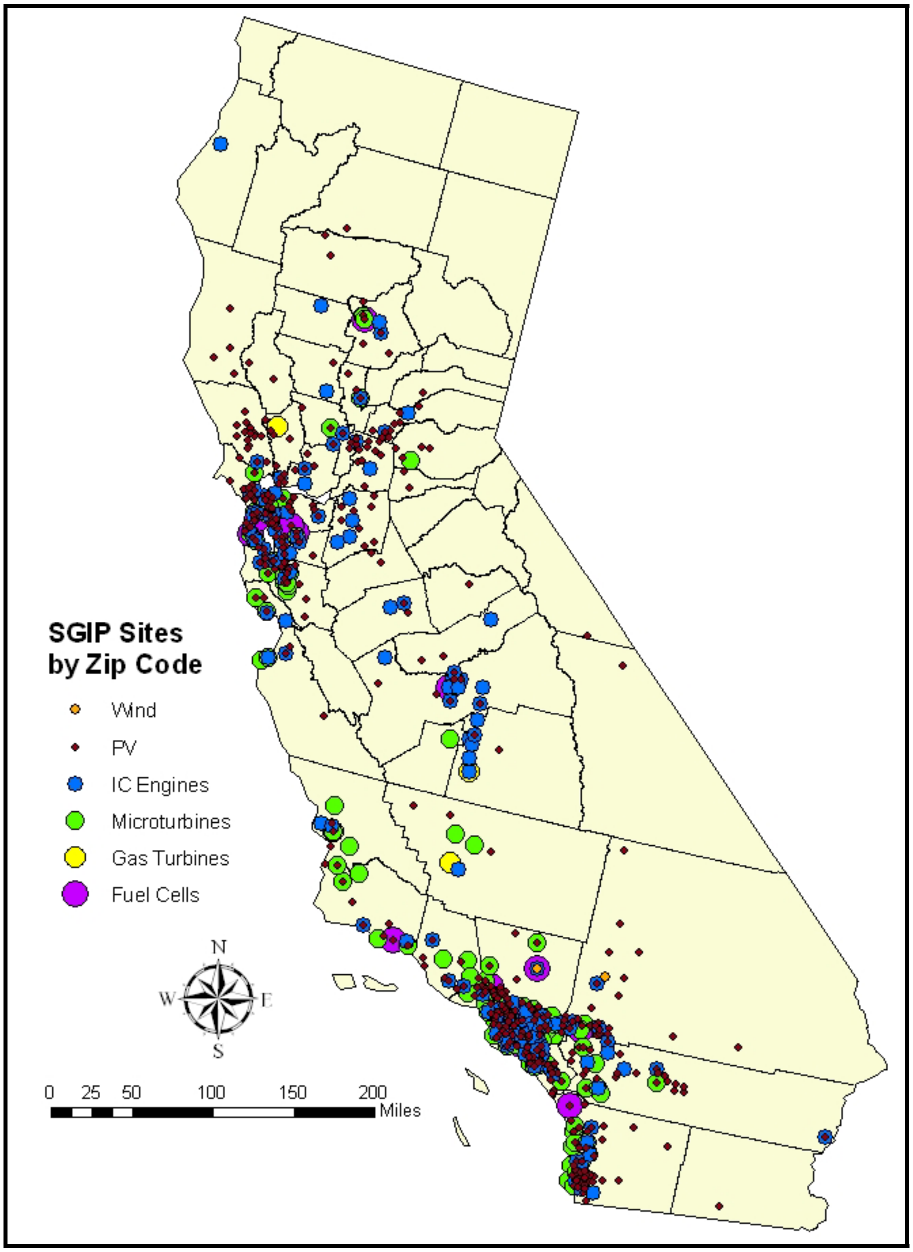
Table 3-1: SGIP Projects and Rebated Capacity by PAs as of 12/31/07

PA	No. of Projects	Capacity (MW)	% of Total Capacity
PG&E	616	143	47%
SCE	275	60	20%
SCG	176	69	23%
CCSE	142	33	11%
Totals	**1,209**	**305**	**100%**

Geographically, projects deployed under the SGIP are located throughout the service territories of the three major investor-owned utilities (IOUs) in California as well as throughout a number of municipal electric utilities. Figure 3-1 shows the distribution of SGIP facilities across California by technology type. As may be expected, SGIP facilities tend to be concentrated in the urban centers of California. In addition, the map shows the predominance of PV facilities within the SGIP as of the end of PY07.

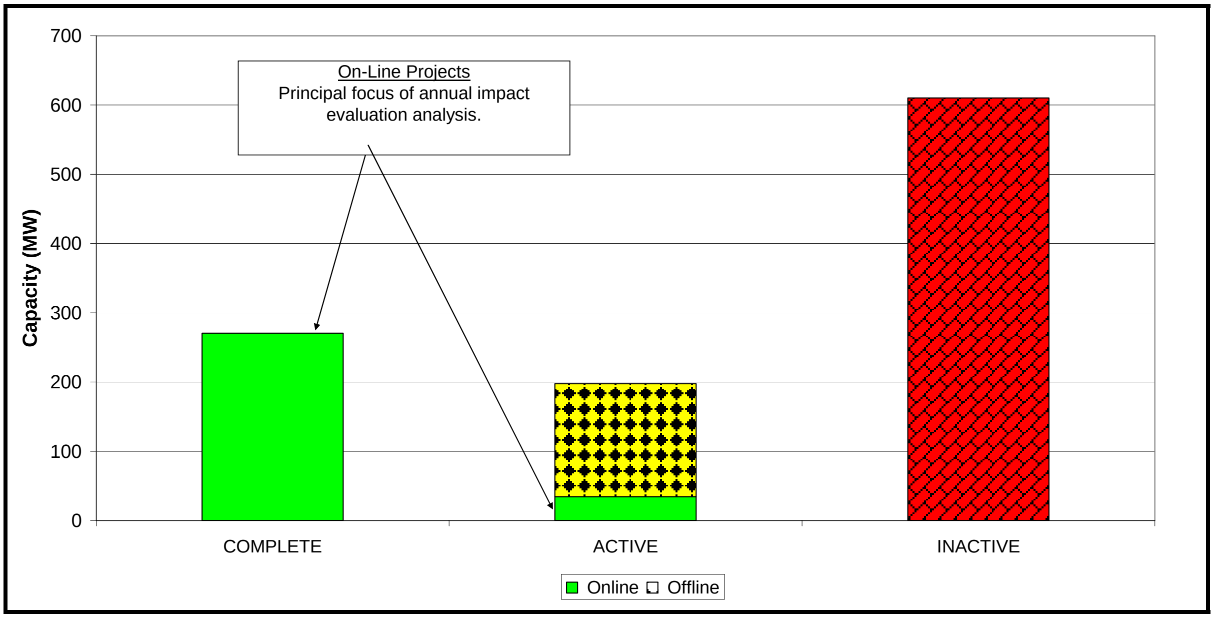
[1] The rebated capacity is the rating associated with the rebate (incentive) provided to the applicant. The rebate capacity may be lower than the typical "nameplate" rating of a generator.

Figure 3-1: Distribution of SGIP Facilities as of 12/31/07



Once SGIP applications are received within the program, the associated projects follow a pathway of either eventually becoming "Complete" or "Inactive" projects. Figure 3-2 summarizes the status of SGIP projects at a very high level. It shows the status of all SGIP projects by their stage of progress within the SGIP implementation process and their "on-line" status, as of the end of 2007. "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 provide energy on a relatively consistent basis).[2]

Figure 3-2: Summary of PY01–PY07 SGIP Project Status as of 12/31/2007



Key stages in the SGIP implementation process include:

- ***Complete Projects:*** These represent SGIP projects for which the generation system has been installed, verified through on-site inspections, and an incentive check has been issued. We consider all Complete projects as "on-line" projects for impact evaluation purposes.
- ***Active Projects:*** These represent SGIP projects that have not been withdrawn, rejected, completed, or placed on a wait list.[3] As time goes on, the Active projects will migrate either to the Complete or to the Inactive category. Some of these projects entered normal operations as of the end of 2007. However, because an incentive check had not been issued, we do not consider these projects Complete projects. Note that we treat Active projects as "on-line" if they have entered normal operation, even if they have not received an incentive check.[4]

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2 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.

3 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. (http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/42455.htm). Over time, projects that are withdrawn or rejected are replaced by projects from the wait list.

4 "Off-line" projects are those projects that active applications but are not yet operational.

- ***Inactive Projects:*** These represent SGIP projects that are no longer progressing in the SGIP implementation process because they have been withdrawn by the applicants or rejected by the PAs.

Complete and Active SGIP Projects

The status of Complete and Active projects within the SGIP is important because these projects represent technologies that can potentially impact the electricity system. Table 3-2 provides a breakdown by technology and fuel type of the Complete and Active projects depicted graphically in Figure 3-2. The “(n)” in the table represents the number of Complete, Active, or total projects. The “(MW)” refers to the total rebated capacity in megawatts (MW) for those “n” projects.

Table 3-2: Quantity and Capacity of Complete and Active Projects

Technology & Fuel	Complete		Active (All)		Total		
	(n)	(MW)	(n)	(MW)	(n)	(MW)	Avg. Size (kW)
Photovoltaic	768	104.6	253	66.9	1021	171.5	168
Wind	2	1.6	6	3.9	8	5.5	688
Fuel Cell – Non-renewable	11	6.3	10	4.7	21	11.0	521
Fuel Cell - Renewable	2	0.8	13	11.7	15	12.4	828
Engine/Turbine – Non-renewable	295	145.6	138	98.8	433	244.4	564
Engine/Turbine - Renewable	33	11.8	23	11.6	56	23.4	418
All	**1111**	**270.6**	**443**	**197.5**	**1554**	**468.1**	**301**

There were over 1550 Complete and Active projects, representing just under 470 MW of capacity in the SGIP by December 31, 2007. Over 160 projects were completed in 2007, increasing the capacity of Complete projects to over 270 MW.[5] However, the number of Active projects decreased between 2006 and 2007. The combined effect of the increase in Complete projects and decrease in Active projects resulted in a total project capacity of about 470 MW; which is roughly equivalent to the total project capacity seen at the end of 2006. With enactment of the California Solar Initiative (CSI), photovoltaic (PV) projects were no longer eligible to receive incentives under the SGIP effective January 1, 2007. As PV projects were the largest contributors to new SGIP projects, loss of new PV projects was the primary reason for the decrease in Active projects.[6]

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5 There were 948 Complete projects by the end of 2006, representing slightly more than 233 MW of rebated capacity.

6 At the end of 2006, there were over 600 Active PV projects, whereas at the end of 2007 there were only 253 projects awaiting completion. Approximately 130 of the PV projects Active at the end of 2006 were completed in 2007. Of the remaining 400 PV projects, 253 remained Active, while the rest either were rejected or withdrew from the program.

SGIP On-Line Projects

While Complete and Active project represent SGIP projects with potential impacts, "on-line" projects represent those projects that have actual impacts as they are grid-connected and operational. Consequently, the principal focus of the 2007 impact evaluation is the subset of projects that were "on-line" by December 31, 2007. Table 3-3 provides information on the number and capacity of "on-line" projects. The information is broken down by technology and fuel type as well as identification of whether the project is Complete or Active "on-line." By the end of 2007, "on-line" projects represented over 1,200 projects and 305 MW of rebated capacity.

Table 3-3: Quantity and Capacity of Projects On-Line as of 12/31/2007

Technology & Fuel	Complete		Active (On-Line)		Total On-Line Projects		
	(n)	(MW)	(n)	(MW)	(n)	(MW)	Avg. Size (kW)
PV	768	104.6	71	17.9	839	122.5	146
Wind	2	1.6	0	0.0	2	1.6	824
Fuel Cell – Non-renewable	11	6.3	3	2.0	14	8.2	586
Fuel Cell - Renewable	2	0.8	0	0.0	2	0.8	375
Engine/Turbine – Non-renewable	295	145.6	22	12.5	317	158.1	499
Engine/Turbine - Renewable	33	11.8	2	2.1	35	13.9	398
All	**1111**	**270.6**	**98**	**34.5**	**1209**	**305.1**	**252**

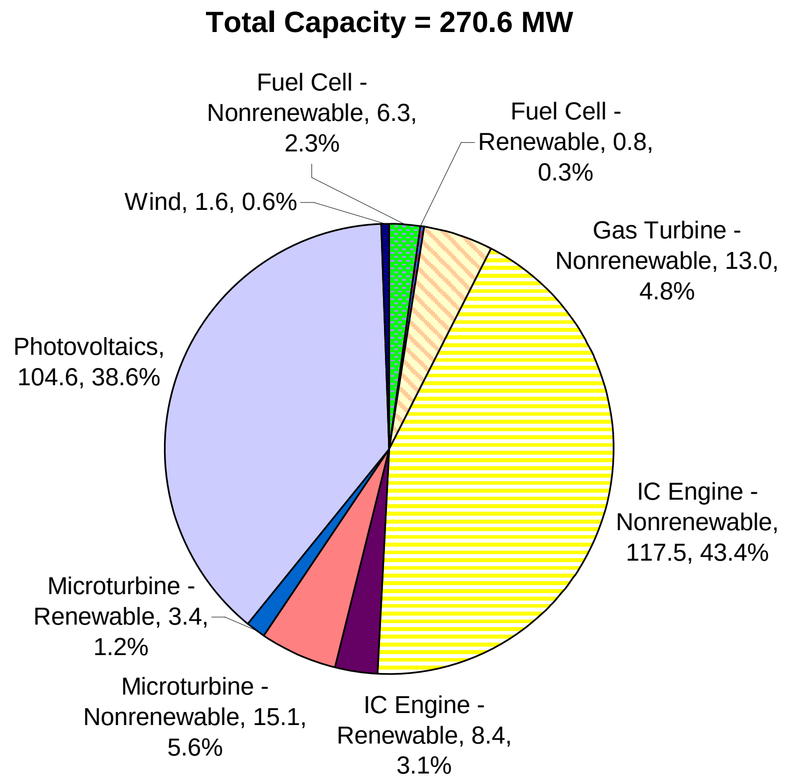
Complete SGIP Projects

Statistics on Complete projects serve as a benchmark in evaluating changes in the SGIP with respect to capacity, paid incentives and costs.

Figure 3-3 shows a breakout of the SGIP generating capacity for all Complete projects by technology and fuel type at the end of 2007.[7] IC engines, gas turbines, and microturbines powered by non-renewable fuels contributed over 145 MW of rebated capacity or more than half the total capacity of the SGIP. PV technologies by themselves contributed nearly 105 MW of rebated capacity; close to 40 percent of the total SGIP capacity.

[7] We refer here only to Complete projects and do not include on-line Active projects. On-line Active projects had not received incentive checks and as such were not included in the formal count of projects until they receive their incentive check.

Figure 3-3: SGIP Complete Project Capacity (MW) by Technology and Fuel Type as of 12/31/07

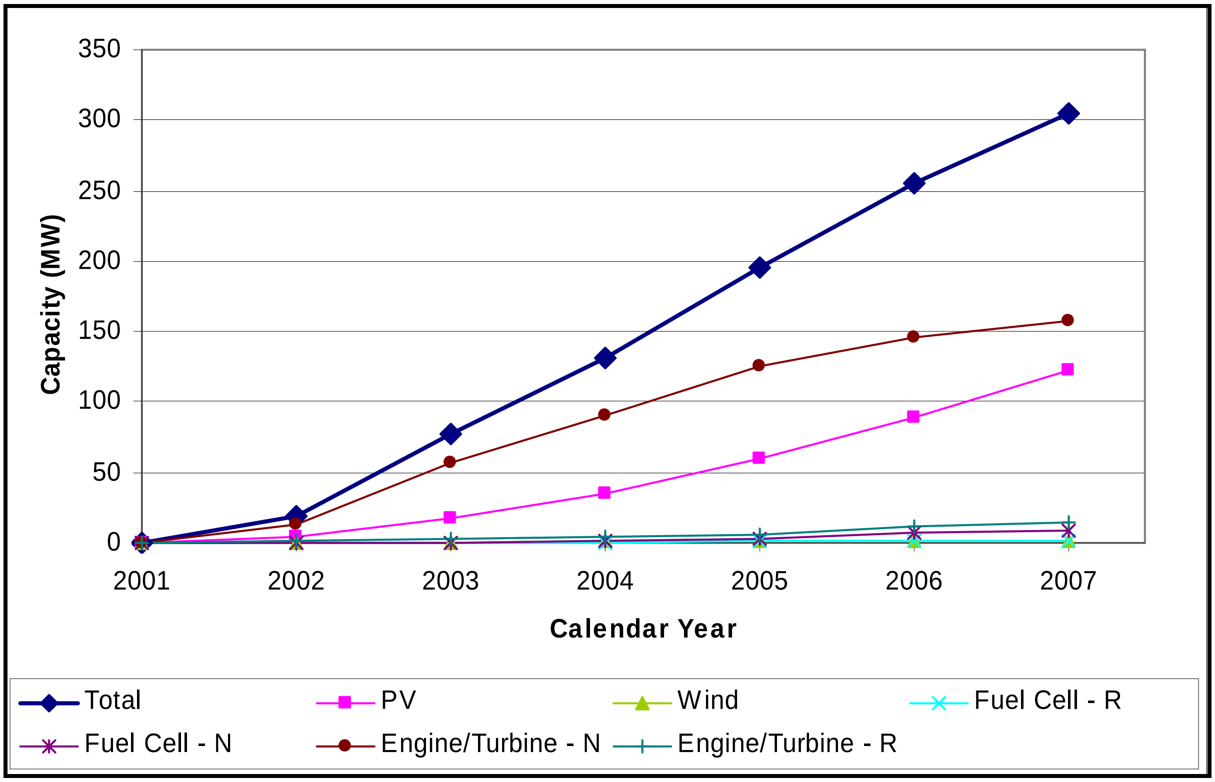


Capacity Trends of SGIP Projects

Figure 3-4 shows the increase in rebated capacity of on-line (Complete and Active) projects extending from 2001 through the end of 2007 by technology and fuel type. The capacity of Complete projects increased 20 percent (50 MW) from 2006 to 2007. PV systems installed between 2006 to 2007 represent almost 35 MW of capacity; contributing over half of the growth of the SGIP during this period. Slightly more than 17 MW of the remaining growth in capacity came from microturbines, IC engines, and gas turbines using non-renewable fuel. With the passage of AB 2778, project eligibility under the SGIP was restricted to wind energy and fuel cell technologies. Fuel cells powered by non-renewable sources contributed a little more than one MW of new capacity during 2007. Similarly, renewable-fueled microturbines and IC engines contributed about three MW of increased capacity during 2007.[8]

[8] There have been no new wind projects or renewable-fueled fuel cell projects completed in the SGIP since 2005.

Figure 3-4: Growth in On-Line Project Capacity from 2001-2007



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.[9]

Table 3-4 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 2007, approximately 10 percent of the rebated PV capacity in the SGIP represented systems installed at sites of IOU customers who were also customers of municipal utilities. Approximately three percent of cogeneration (Engine/Turbine – Non-renewable) capacity was attributable to dual-utility customers. Sixty-nine of the 94 PV projects involving municipal utility customers correspond to SCG SGIP projects. Most of these projects received support from both the SGIP and a solar PV program offered by the municipal utility.

9 Situations where IOU customers can also be customers of municipal utilities occur when there is a geographical division of energy services. For example, due to their geographical location, a customer in Southern California may receive electricity service from a municipal utility such as Los Angeles Department of Water and Power and receive natural gas service from Southern California Gas (SCG) Company. As SCG participates in the SGIP, that electricity customer was eligible to apply to the SGIP.

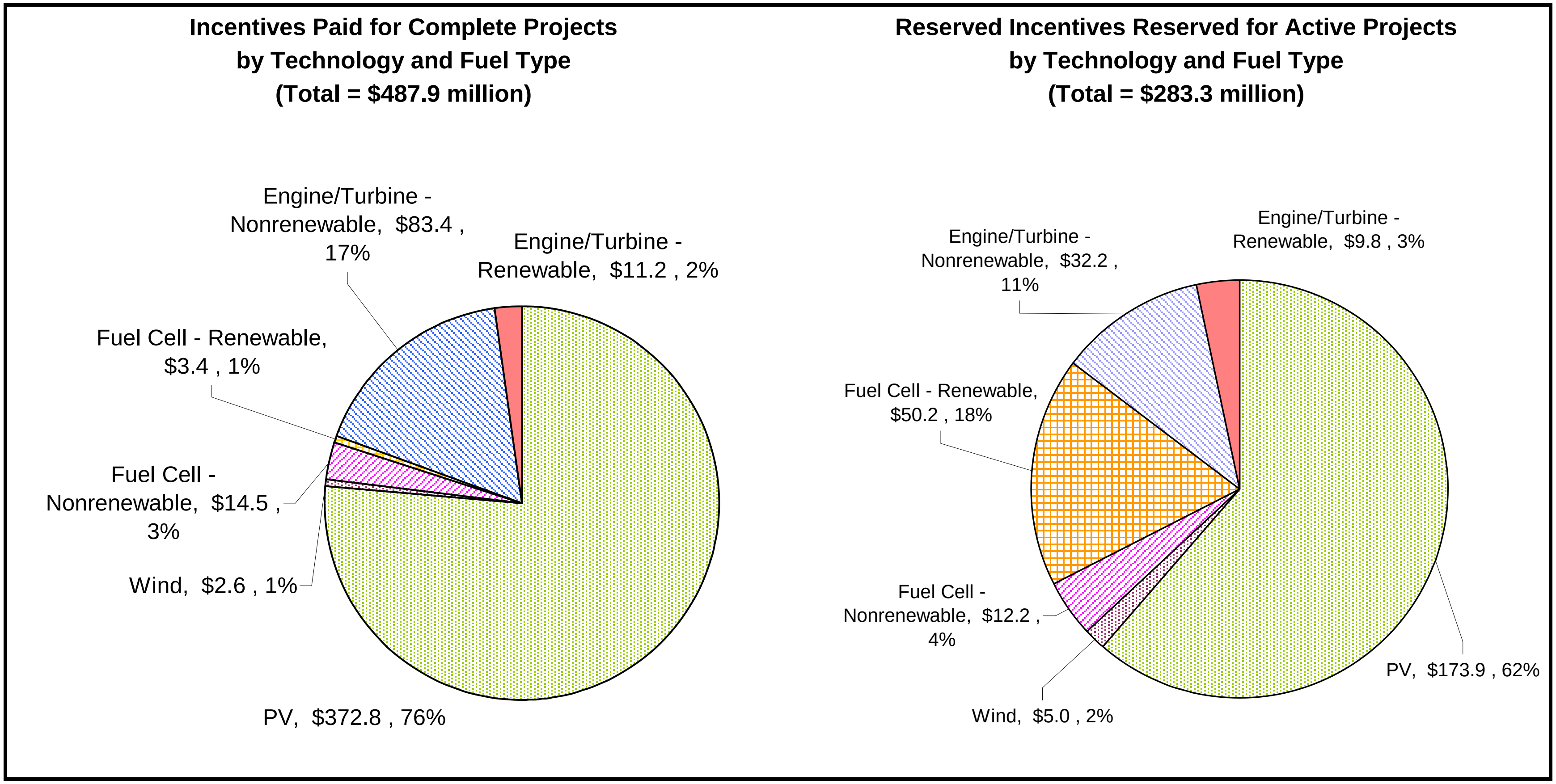
Table 3-4: Electric Utility Type for On-Line Projects as of 12/31/2007

Technology & Fuel	IOU		Municipal		Total On-Line	
	(n)	(MW)	(n)	(MW)	(n)	(MW)
Photovoltaics	745	110.6	94	11.9	839	122.5
Wind	2	1.6	0	0.0	2	1.6
Fuel Cell – Non-renewable	13	7.2	1	1.0	14	8.2
Fuel Cell - Renewable	2	0.8	0	0.0	2	0.8
Engine/Turbine – Non-renewable	302	153.5	15	4.6	317	158.1
Engine/Turbine - Renewable	35	13.9	0	0.0	35	13.9
All	**1099**	**287.6**	**110**	**17.6**	**1209**	**305.1**

Another way to identify project status within the SGIP is by the stage of incentive payment. Incentives are only paid for Complete projects. In comparison, incentives are reserved for Active projects and are not paid until the project reaches the Complete stage. PAs can use incentive payment status to examine the funding backlog of SGIP projects by technology and fuel type. Figure 3-5 summarizes SGIP incentives paid or reserved as of December 31, 2007. By the end of PY07, almost $488 million in incentive payments had been paid to Complete projects. The reserved backlog totaled slightly over $283 million. This is a significant reduction compared with the prior year, which had a backlog of $487 million. The reduction in backlog is most likely due to PV projects no longer being eligible under the program.[10] Incentive reservations for renewable-fueled fuel cell projects increased from about $35 million at the end of 2006 to $50 million at the end of 2007.

[10] At the end of 2006, there was a total of $411 million reserved for PV projects, whereas at the end of 2007 there was roughly $174 million reserved for PV projects.

Figure 3-5: 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 3-5 summarizes the system capacity characteristics of all Complete projects by technology and fuel type. Generally, gas turbines deployed under the SGIP tend to have the largest project capacities, followed by IC engines. Maximum capacities for IC engines and gas turbines using non-renewable fuel exceeded four MW, with average sizes of approximately 625 kW and 2.6 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, non-renewable-fueled microturbines deployed by the end of PY07 under the SGIP tended to be less than 150 kW in capacity, while renewable-fueled microturbines tended to be slightly larger with an average of just less than 180 kW in capacity. The few wind and fuel cell systems deployed under the SGIP by the end of PY07 were medium-sized facilities with capacities of less than one MW.

Table 3-5: Installed Capacities of PY01–PY07 Projects Completed by 12/31/2007

Technology & Fuel	System Size (kW)				
	n	Mean	Minimum	Median	Maximum
Photovoltaic	768	136	28[11]	69	1,050
Wind Turbine	2	824	699	824	950
Fuel Cell – Non-renewable	11	568	200	500	1,000
Fuel Cell - Renewable	2	375	250	375	500
Internal Combustion Engine – Non-renewable	188	625	60	449	4,110
Internal Combustion Engine – Renewable	14	603	80	602	1,030
Gas Turbine – Non-renewable	5	2,609	1,210	1,423	4,527
Microturbine – Non-renewable	102	148	28	106	928
Microturbine - Renewable	19	177	30	120	420

System capacities of Active projects may indicate incipient changes in SGIP project capacities. If a large number of Active projects have smaller capacities than their Complete project technology counterparts, migration of these Active projects into the Complete project category will act to decrease the average installed capacity. This is important because in

[11] This PV system minimum is an anomaly. In accordance with SGIP requirements, the minimum eligible size is 30 kW or greater.

some cases impacts from technologies can be more affected by project capacity rather than the number of projects. With the exception of PV systems, SGIP technologies saw a decrease in mean capacity. The mean system size of PV systems increased in 2007 from 127 to 136 kW, while the mean size of gas turbines decreased from 2,905 kW to 2,609 kW, and the mean size of renewable-fueled microturbines and renewable-fueled IC engines both decreased by about 10 kW of capacity.

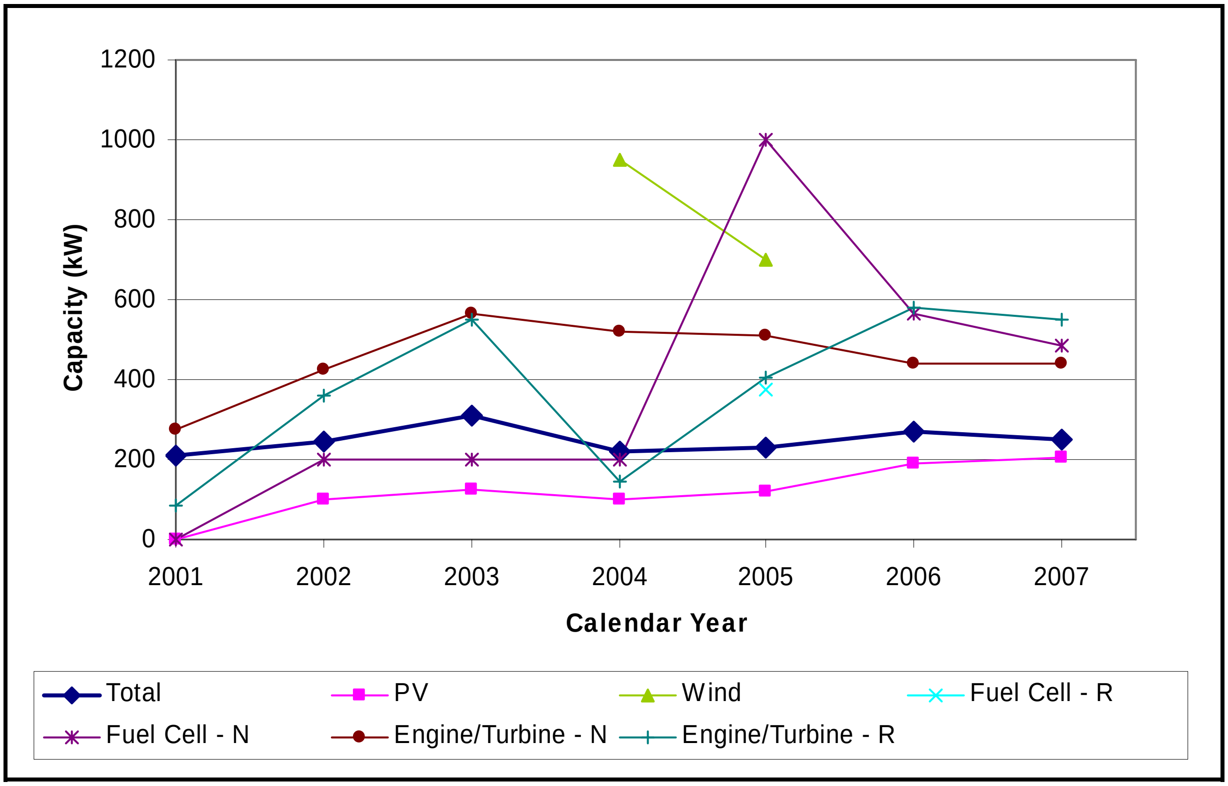
Table 3-6 summarizes the system capacity characteristics of Active projects by technology and fuel type. With the exception of wind and non-renewable fuel cells, the rated capacities of Active projects tended to be greater than their Complete project technology counterparts. As a result, the capacity of SGIP projects overall can be expected to increase in 2008 as these larger, Active projects migrate to the Complete status. The same prediction was made for 2007 when Active project sizes were compared to Complete project sizes. However, many of the larger Active projects at the end of 2006 were not completed in 2007. The result was consistent average sizes per technology of Complete projects from the end of 2006 to the end of 2007. If the larger Active projects are completed in 2008, this will increase the average size per technology at the end of 2008 compared to the average size seen at the end of 2007.

Table 3-6: Rated Capacities of PY01-PY07 Projects Active as of 12/31/2007

Technology & Fuel	System Size (kW)				
	n	Mean	Minimum	Median	Maximum
Photovoltaic	253	264	30	162	1,004
Wind Turbine	6	643	30	550	1,500
Fuel Cell – Non-renewable	10	470	200	400	1,000
Fuel Cell - Renewable	13	898	300	1,000	1,200
Internal Combustion Engine – Non-renewable	103	651	50	370	5,000
Internal Combustion Engine – Renewable	14	654	56	410	1,696
Gas Turbine – Non-renewable	5	3,824	1,000	4,500	5,000
Gas Turbine – Renewable	2	425	100	425	750
Microturbine – Non-renewable	30	422	30	240	2,253
Microturbine - Renewable	7	227	52	210	585

Figure 3-6 shows the trend of capacity for Complete projects from 2001 through the end of 2007. Overall, PV was the only technology showing an increase in installed capacity from 2006, where 3 MW more of capacity was installed in 2007 than in 2006. All other technologies saw a decrease in the installed capacity compared to 2006. There were no new wind projects or renewable fuel cell projects in 2007. Non-renewable-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 and in 2007 increased to over 200 kW. The net result has been that the average overall capacity of SGIP projects increased slightly from 2002 to 2003, decreased in 2004 and 2005, increased in 2006, but decreased again in 2007. The average capacity of all Complete projects through the end of 2007 was 250 kW.

Figure 3-6: Trend of Capacity of Complete Projects from PY01–PY07



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 3-7 provides total and average project cost data for Complete and Active projects from PY01 through PY07. Average per-Watt eligible project costs represent capacity-weighted averages.

Table 3-7: Total Eligible Project Costs of PY01–PY07 Projects

Technology & Fuel	Complete			Active		
	Total (MW)	Wt.Avg. ($/W)	Total ($ MM)	Total (MW)	Wt.Avg. ($/W)	Total ($ MM)
Photovoltaic	104.6	$8.24	$861	66.9	$9.75	$652
Wind Turbine	1.6	$3.26	$5	3.9	$3.86	$15
Fuel Cell – Non-renewable	6.3	$7.40	$46	4.7	$7.33	$34
Fuel Cell - Renewable	0.8	$9.70	$7	11.7	$6.90	$81
Internal Combustion Engine – Non-renewable	117.5	$2.21	$259	67.0	$2.50	$167
Internal Combustion Engine – Renewable	8.4	$2.53	$21	9.2	$2.60	$24
Gas Turbine – Non-renewable	13.0	$2.22	$29	19.1	$1.28	$24
Gas Turbine – Renewable	.	.	.	0.9	$2.01	$2
Microturbine – Non-renewable	15.1	$3.14	$47	12.7	$2.86	$36
Microturbine - Renewable	3.4	$3.50	$12	1.6	$4.66	$7
Total	**270.6**	**$4.76**	**$1,289**	**197.5**	**$5.28**	**$1,043**

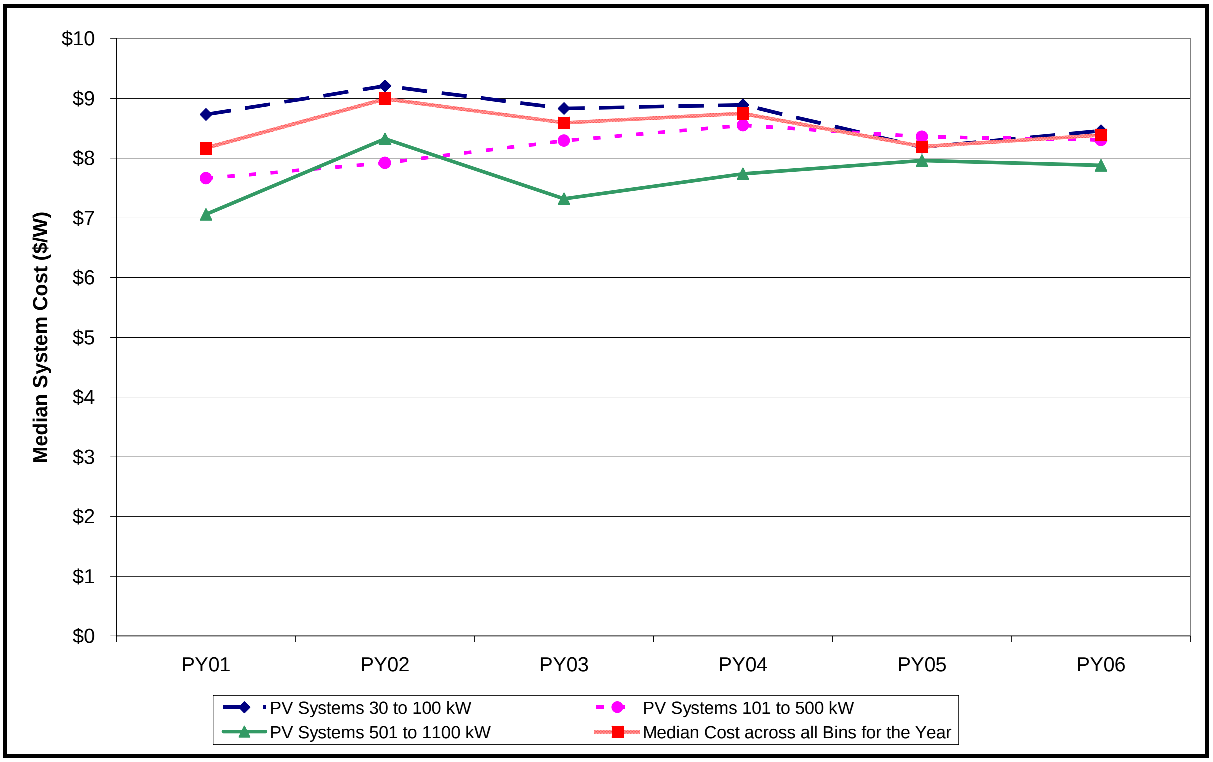
By the end of PY07, total eligible project costs (private investment plus the potential SGIP incentive) corresponding to Complete projects was almost $1.3 billion. PV projects accounted for the vast majority (66 percent) of total eligible Complete project costs. Similarly, PV projects represent the single largest project cost category in either the Complete or Active project categories. From a system capacity perspective, PV projects made up approximately 39 percent of the total Complete project capacity installed through PY07. The combined costs of renewable- and non-renewable-fueled engines and turbines accounted for the second highest total Complete project costs at $368 million (approximately 29 percent of the total eligible project costs), and corresponded to 58 percent of the total Complete project installed capacity.

On an average cost-per-installed-Watt ($/W)-basis, fuel cell and PV projects deployed under the SGIP have been 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).[12]

PV Cost Trends

Cost trends for Complete PV projects between PY01 through PY06 are shown in Figure 3-7.

Figure 3-7: Cost Trend of Complete PV Projects



Starting on January 1, 2007, PV systems were no longer eligible under the SGIP. Consequently, there were no new applications for PV projects in 2007 from which cost trends could be drawn. The shown cost trends are reported 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 and $9 per Watt from PY01 through PY06. While the smallest PV systems showed the highest median cost per Watt, the cost decreased in PY05, then increased slightly in PY06, but was still lower than the original median cost per Watt in PY01. The largest PV systems (i.e., those between 500 and 1100 kW) had the lowest installed costs (at $7.88 per Watt); however this was an increase from the cost in PY01 ($7.06 per Watt). Of interest is the decrease in the difference of median cost per Watt between the smaller and larger size PV projects. In PY01, the difference in median cost per

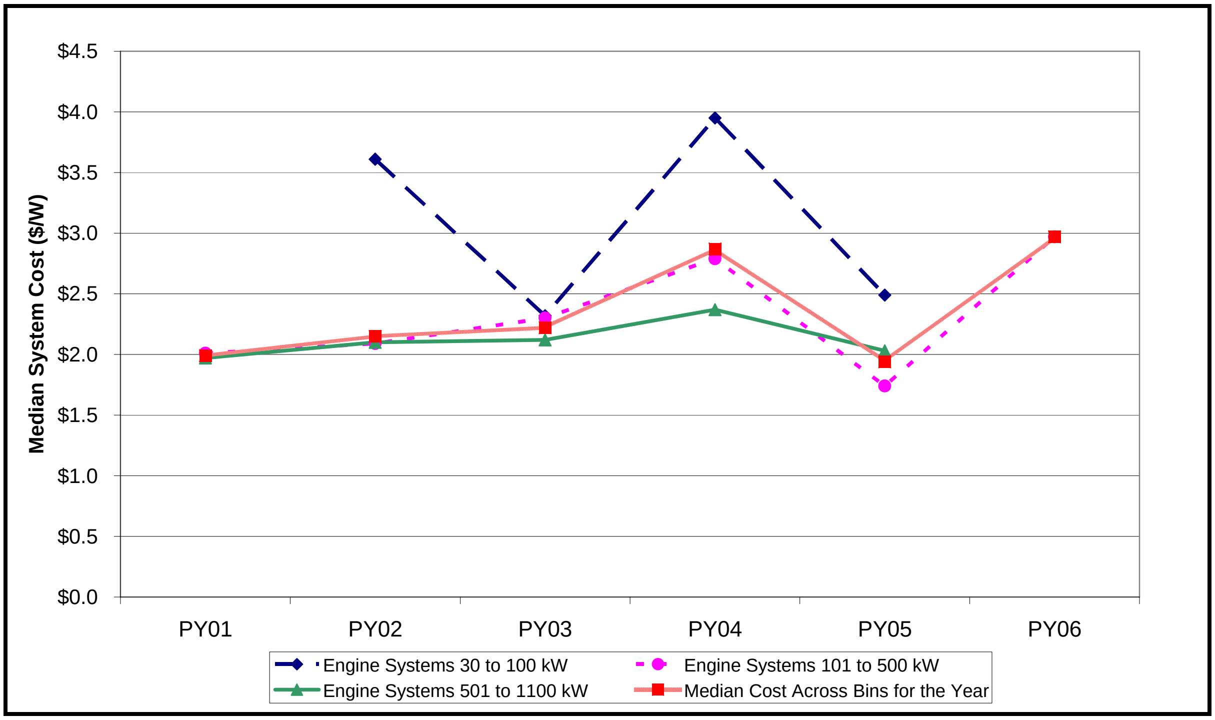
12 Note that fuel cells powered by renewable resources, such as biogas, require preconditioning equipment to clean the fuel before it is charged to the fuel cell and, as such, have additional capital costs.

Watt between the smallest PV systems (i.e., those between 30 and 100kW) and the largest PV systems (i.e., those between 500 and 1100 kW) was $1.67 per Watt. This difference decreased to $0.58 per Watt in PY06, which reflects the decrease in median cost per Watt for small systems and an increase in median cost per Watt for large systems. Additionally, there appears to be very little difference in the median cost per Watt between 30 to 100 kW systems and 101 to 500 kW systems.

Cogeneration Technology Cost Trends

Cost trends for Complete natural gas-fired IC engines are shown in Figure 3-8.

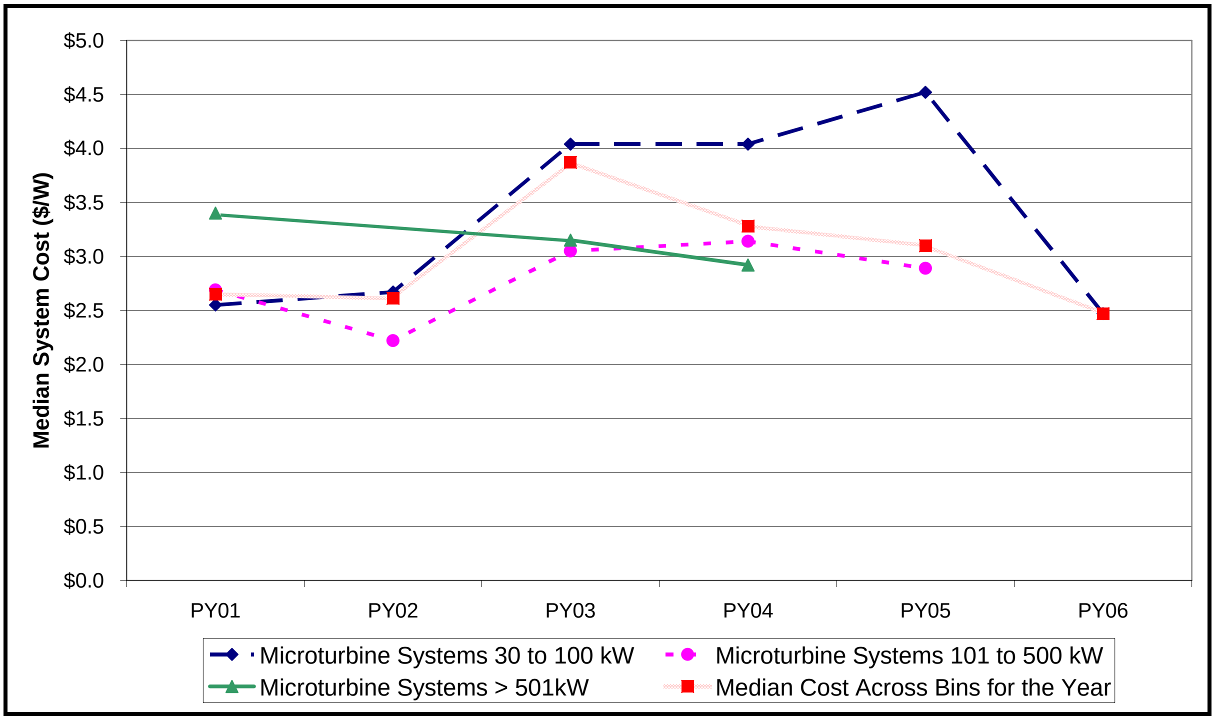
Figure 3-8: Cost Trend of Complete Natural Gas Engine Projects



Median project costs for small engines have varied widely from PY01 to PY05. The dip and rise in costs for the smaller IC engines can possibly be attributed to learning curves associated with the emergence of new systems in the marketplace. The first engines to emerge generally represented prototypes equipped with significant monitoring or other extra features that tended to drive up the capital costs. The prototypes were replaced by lower cost, more "commercial" systems. However, as the technologies were still new, costs increased to resolve operational issues as they were discovered. Median project costs for medium- to larger-sized engines (i.e., those from 101 kW to over one MW) showed relatively slow increases from PY01 through PY04, then the medium-sized engines median cost decreased by almost $1.05 per Watt in 2005 to $1.74 per Watt. However, the mean cost per Watt was $3.12. So far, only one non-renewable-fueled IC engine project that applied to the program in PY06 had been completed. This project cost was $2.97 per Watt, which was higher than the median cost per Watt for all sized systems in PY05 and all but the smallest engines in PY01 through PY04. This project may not be representative of other PY06 applications. However, it is also possible that this increase in cost per Watt was a result of the addition of NOx control technologies required to meet the NOx standard of 0.07 lbs/MWh for distributed generation, which began in 2007.

Figure 3-9 illustrates a cost trend for Complete natural gas-fired microturbines. Generally, small to medium-sized microturbines demonstrated moderate increases in median costs from PY02 through PY05, with the costs of the smaller systems (i.e., 30 to 100 kW) rising more substantially than those of the medium-sized ones (i.e., 101 kW to 500 kW).

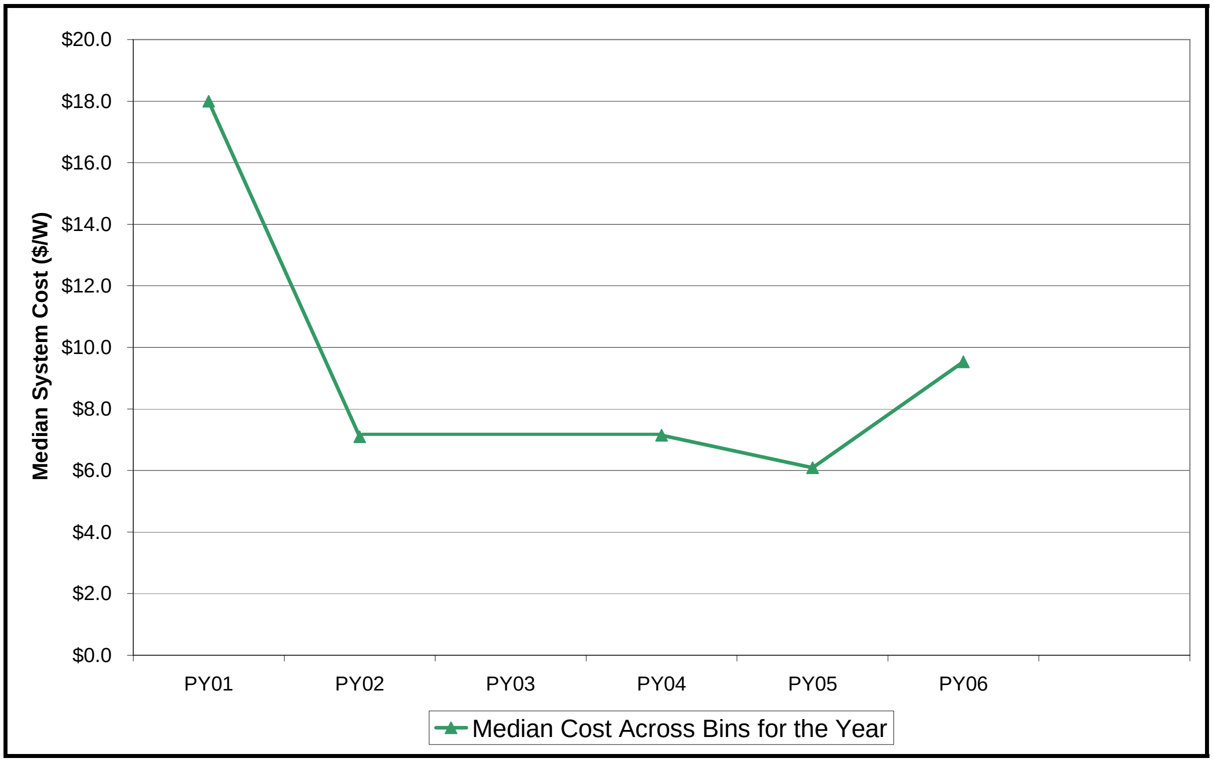
Figure 3-9: Cost Trend for Complete Natural Gas Microturbine Projects



The median cost per Watt of smaller microturbines (less than 101 kW) increased by nearly $2 per Watt from PY01 to PY05, but then dropped in PY06 back to the PY01 $2 per Watt cost. However, the PY06 median cost-per-Watt value was based on only three projects. Consequently, the median cost may not be representative of other projects that applied in PY06. Medium-sized projects saw a decreased cost per Watt in PY05 back to the PY03 cost per Watt. No large projects have been completed since PY04, and no medium-sized projects have been completed since PY05. As a result, cost trends are not available for these size groups during these program years. Additionally, none of the projects that applied in PY07 was completed in 2007. The cost trend, therefore, cannot yet be extended through PY07.

Figure 3-10 shows the cost trend for Complete natural gas fuel cell projects in the SGIP. Because there were only 11 Complete fuel cell projects, all sizes of fuel cells have been grouped together. Fuel cell costs reported for PY01 may not be representative of that year as there was only one fuel cell project completed in 2001. Costs remained level from PY02 through PY04, decreased by about $1 per Watt in PY05, and increased by about $3 per Watt in PY06. As with the PY01 fuel costs, the PY06 fuel cells costs may not be representative as there was only one Complete fuel cell project in 2006.

Figure 3-10: Cost Trend for Complete Natural Gas Fuel Cell Projects



Incentives Paid and Reserved

Information on the amount of incentives paid and reserved is presented in Table 3-8.[13] PV projects account for approximately 76 percent of the incentives paid for Complete projects and 60 percent of the incentives reserved for Active projects. At the end of 2006, there was a total of $411 million reserved for PV projects, whereas at the end of 2007 there was roughly $174 million reserved for PV projects. The decrease in reserved incentives for PV was due to PV projects no longer being eligible under the SGIP effective January 1, 2007. For this same reason, there were no new Active PV projects. The only Active PV projects remaining at the end of 2007 represent projects for which applications were received during or prior to PY06. The second largest category of reserved incentives was tied to fuel cell projects. Reserved incentives for renewable- and non-renewable-powered fuel cells were approximately $62 million at the end of PY07. Note that reserved incentives for renewable-fueled fuel cell projects increased from about $35 million at the end of 2006 (accounting for seven percent of the total reserved incentives) to $50 million at the end of 2007 (18 percent of the total reserved incentives).

Table 3-8: 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	104.6	$3.57	$373	66.9	$2.60	$174
Wind Turbine	1.6	$1.60	$3	3.9	$1.29	$5
Fuel Cell – Non-renewable	6.3	$2.32	$14	4.7	$2.59	$12
Fuel Cell - Renewable	0.8	$4.50	$3	11.7	$4.31	$50
Internal Combustion Engine – Non-renewable	117.5	$0.57	$67	67.0	$0.43	$29
Internal Combustion Engine – Renewable	8.4	$0.87	$7	9.2	$0.86	$8
Gas Turbine – Non-renewable	13.0	$0.30	$4	19.1	$0.18	$3
Gas Turbine – Renewable	.	.	.	0.9	$0.78	$1
Microturbine – Non-renewable	15.1	$0.83	$12	12.7	$0.63	$8
Microturbine - Renewable	3.4	$1.13	$4	1.6	$1.26	$2
Total	**270.6**	**$1.80**	**$488**	**197.5**	**$1.48**	**$292**

13 The maximum possible incentive payment for each system is the system size (up to one MW) multiplied by the applicable dollar-per-kW incentive rate.

Participants' Out-of-Pocket Costs After SGIP Incentive

Participants' out-of-pocket costs (total eligible project cost less the SGIP incentive) are summarized in Table 3-9[14]. Insights regarding costs differences between the technologies are speculative, but take into account a combination of assumed project costs, information on additional monies obtained from other incentive programs (when available), and professional judgment.

On a cost-per-Watt basis[15], renewable- and non-renewable-fueled fuel cells had the highest cost, followed by PV. The higher first cost of fuel cells was offset to some degree by their higher efficiency (reduced fuel purchases) and to a lesser degree by reduced cost for air pollution control equipment and purchased emission offsets. Higher costs for the renewable-fueled fuel cells likely include the cost of biogas[16] cleanup equipment. In certain instances, fuel cells also provide additional power reliability benefits that may have driven project economics. PV was the next highest capital cost technology, followed by renewable-fueled microturbines and non-renewable-fueled microturbines, respectively.

Table 3-9: 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	104.6	$4.30	$449	66.9	$7.08	$473
Wind Turbine	1.6	$1.63	$3	3.9	$2.57	$10
Fuel Cell – Non-renewable	6.3	$4.69	$29	4.7	$4.63	$22
Fuel Cell - Renewable	0.8	$5.20	$4	11.7	$2.56	$30
Internal Combustion Engine – Non-renewable	117.5	$1.63	$191	67.0	$2.07	$139
Internal Combustion Engine – Renewable	8.4	$1.60	$14	9.2	$1.75	$16
Gas Turbine – Non-renewable	13.0	$1.92	$25	19.1	$1.10	$21
Gas Turbine – Renewable	.		$0	0.9	$1.23	$1
Microturbine – Non-renewable	15.1	$2.24	$34	12.7	$2.24	$28
Microturbine - Renewable	3.4	$2.30	$8	1.6	$3.40	$5
Total	**270.6**	**$2.80**	**$757**	**197.5**	**$3.77**	**$745**

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14 Out-of-pocket cost estimates provided in this table are adjusted for both SGIP incentives and incentives from other programs (where information was available as supplied by PAs) but do not adjust for federal investment tax credits

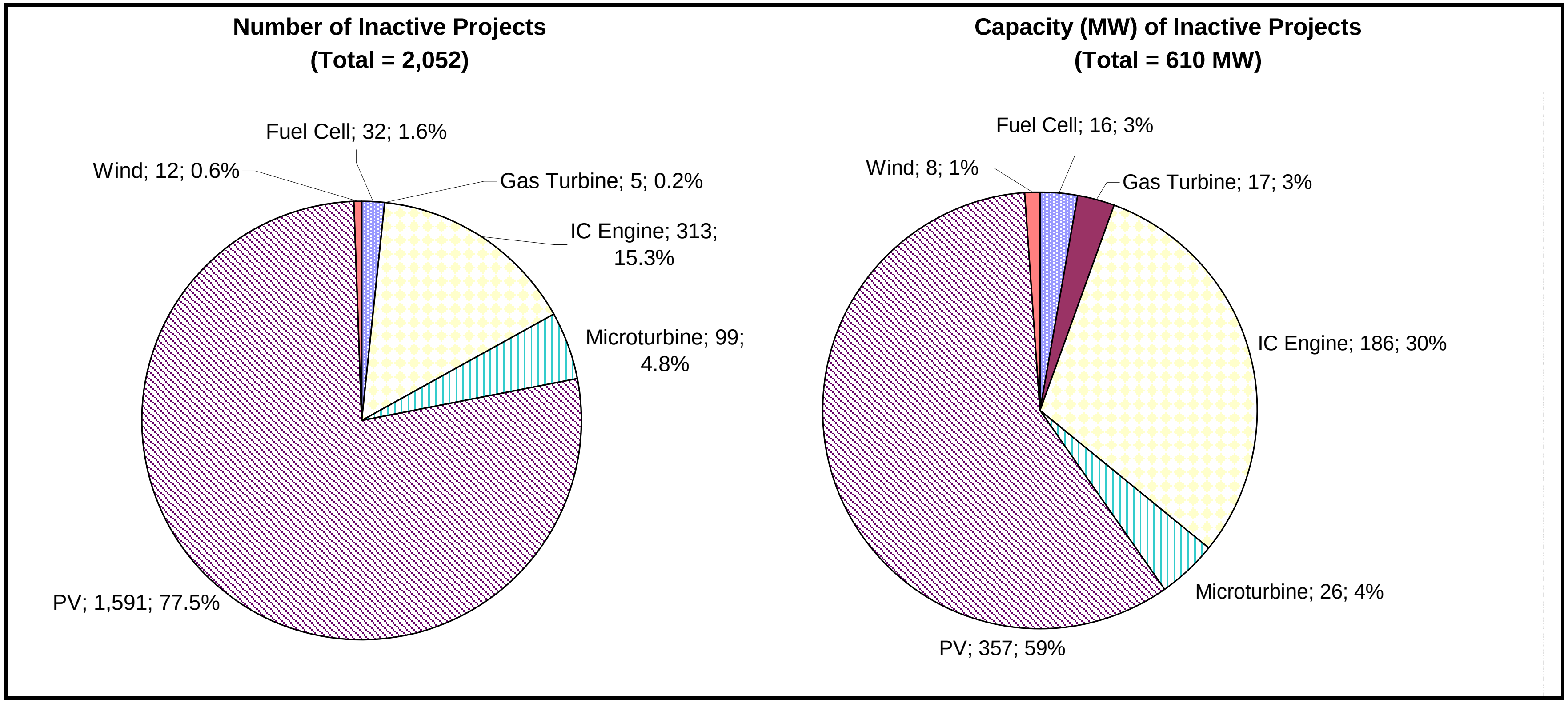
15 This is a rated capacity basis

16 For the purposes of this report, biogas is considered to be gas derived from anaerobic decomposition occurring from landfills, wastewater treatment facilities, or dairy digesters.

3.4 Characteristics of Inactive Projects

As of December 31, 2007, there were 2,052 Inactive projects (those projects that were either withdrawn or rejected), representing 610 MW of generating capacity. Figure 3-11 presents the technology distribution of these Inactive projects.

Figure 3-11: Number and Capacity (MW) of Inactive Projects



It is interesting to note the following from Figure 3-11:

- PV projects constituted the largest share of number of Inactive projects (1,591 projects or 77.5 percent) and the largest share of total Inactive capacity (357 MW or 59 percent).
- IC engines (fueled by either non-renewable or renewable fuel) accounted for the second largest share of number of Inactive projects (313 projects or 15 percent) and the second largest share of total Inactive capacity (186 MW or 30 percent).
- The 99 Inactive microturbine (fueled by either non-renewable or renewable fuel) projects accounted for 26 MW of total Inactive capacity (four percent).
- Five Inactive gas turbine projects accounted for 17 MW of total Inactive capacity (three percent).
- Twelve Inactive wind projects accounted for eight MW of total Inactive capacity (1 percent) and 32 Inactive fuel cell (fueled by either non-renewable or renewable fuel) projects represented 16 MW of total Inactive capacity (three percent).

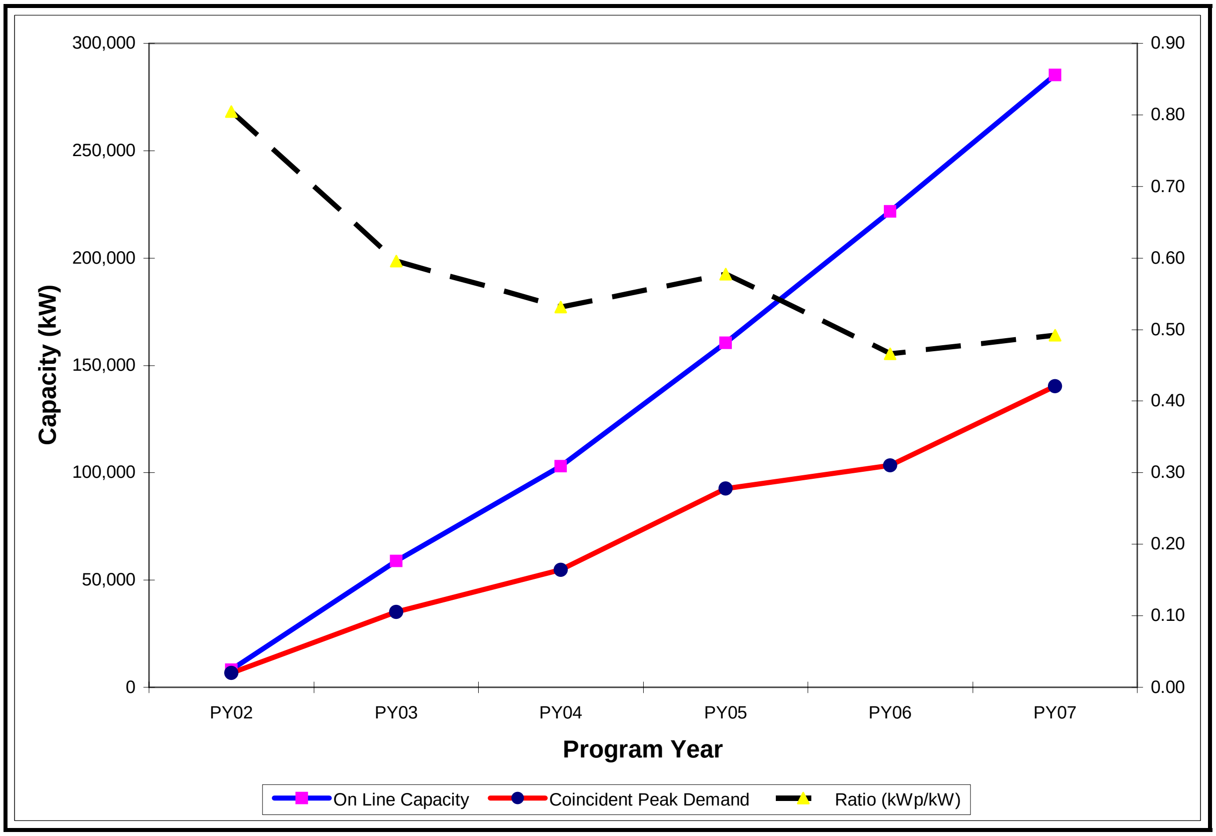
3.5 Trends on Program Impacts

When the SGIP was created in 2001 by AB 970, it was established largely in response to concerns over peak electricity demand. However, as the number and diversity of technologies deployed under the SGIP has increased and in-depth measured performance data has continued to be collected, the SGIP has become more than a means of contributing capacity to California's electricity system. The SGIP represents a unique test bed for examining the measured performance of a mix of DG technologies operating in a commercial setting within California's unique utility and regulatory framework. California is actively looking towards expansion of DG technologies to help meet future electricity demands. However, future DG technologies must provide electricity capacity within a complex landscape that includes interwoven needs for additional peak capacity, enhanced reliability of the state's transmission and distribution system, expansion of renewable energy resources, improved air quality and net reduction in GHG emissions. Due to the wealth of performance data and experiences gained under the SGIP on a diversity of DG technologies, it provides an invaluable springboard for developing future DG programs and technologies.

Coincident Peak Demand

Figure 3-12 shows the change in coincident peak demand that has occurred from PY02 through the end of PY07. 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.[17] In general, the kWp/kW ratio for the mix of SGIP technologies from PY04 on has generally ranged between 0.5 and 0.6. Note that this ratio resulted without any pre-specified plans by the CPUC or the utilities on how DG should be deployed to address peak demand. As such, the ratio reflects the level of impact on coincident peak demand that could be expected from an unplanned expansion of DG technologies. Based on a kWp/kW ratio of 0.6 and using Energy Commission forecasts for peak electricity demand, we can estimate the amount of DG capacity that would be needed for DG technologies to provide 25 percent of California's peak electricity by 2020.[18,19] Under an unplanned expansion similar to that observed in the SGIP, California would require an estimated 25,000 MW of DG capacity to meet the 25 percent target. A lower contribution from DG technologies could possibly be achieved at reduced costs by improved matching of the coincident peak contributions from the DG mix.

Figure 3-12: Trend on Coincident Peak Demand from PY02 to PY07



[17] The relatively high kWp/kW ratio observed in PY02 should not be considered indicative of DG technologies as it may be due to the low number of systems monitored during that program year.

18 Rawson, M. and Sugar, J. March 2007. Distributed Generation and Cogeneration Policy Roadmap for California, CEC-500-2007-021, California Energy Commission

[19] California Energy Demand 2008-2018 Staff Revised Forecast, CEC-200-2007-015-SF2, November 2007. We used a non-coincident peak demand forecast of 75,000 MW from the report.

System Efficiency of Cogeneration Systems

Part of the attractiveness of cogeneration technologies has been their implied ability to improve system efficiency by achieving higher levels of efficiencies than would otherwise be provided from central station simple cycle power plants. However, IC engines and microturbines have demonstrated lower than expected electrical efficiencies. In addition, both of these technologies have shown poor compliance with the overall energy efficiency levels required under PUC 216.6(b). Comparison between the PUC 216.6(b) results of PY06 and PY07 show little improvement for IC engines or microturbines. Higher efficiencies and better matching of thermal and electrical load are needed for gas-fired IC engines and microturbines to improve their electricity system efficiencies and help reduce net GHG emissions.

In spite of these shortcomings, IC engines and microturbines have other attractive features. Both technologies provide generating capacities in size ranges small enough to meet the thermal and electrical loads of typical commercial customers. The IC engine industry has a well developed infrastructure for parts and service. Microturbines have shown the ability to meet very low NO_x requirements. However, if IC engines and microturbines are to play a valuable role in future DG expansion, they must demonstrate higher efficiencies and better matching of thermal and electrical loads. In 2006, Itron recommended changes to the waste heat utilization (WHU) worksheet used by the PAs in determining eligibility of cogeneration[20] facilities to the SGIP. The recommended changes to the WHU worksheet were meant to ensure a more accurate basis for the electrical generating efficiencies used by applicants and to improve the match between electrical and thermal loads. It is possible that the increase in cogeneration facilities subject to the new requirements was too small to show a significant impact on the PUC 216.6(b) results. However, it was outside the scope of this report to investigate the extent to which changes in the WHU worksheet have been adopted.

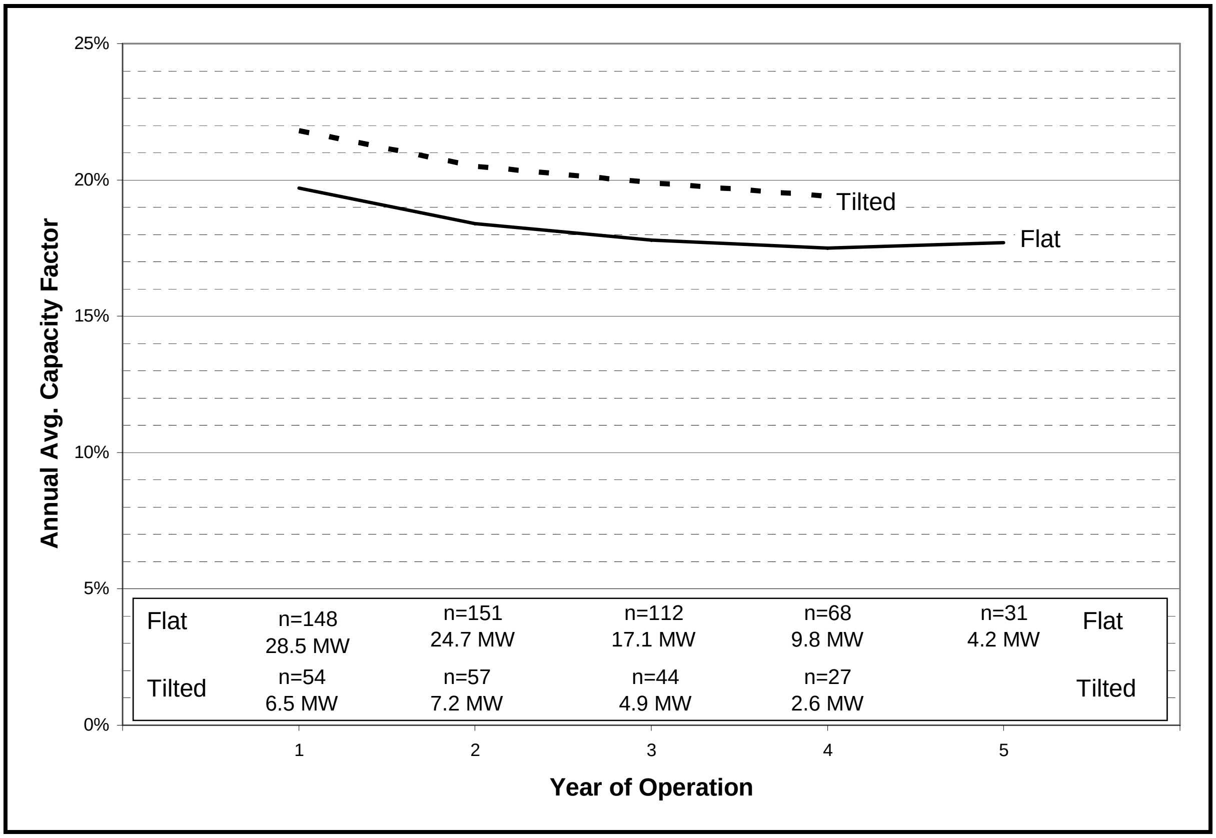
Aging and Performance Degradation of SGIP Technologies

Given the duration and variety of technologies deployed under the SGIP, the program also provides valuable information on the extent to which aging affects performance of DG technologies. Figure 3-13 summarizes the average annual capacity factor of fixed and tilted PV systems over the past six years of the SGIP. Year-to-year variability is due to a range of factors including weather, maintenance/reliability issues, and location of projects. Two interesting observations can be made from the PV capacity factor trend lines. First, the observed annual capacity factors for both tilted and flat PV systems have declined with age. For flat PV systems, the annual capacity factor declined by approximately two percentage point over the course of four years of operation. For tilted PV systems, the annual capacity

[20] Cogeneration facilities are also known as combined heat and power (CHP) facilities and these terms are used interchangeably in this report.

factor declined by just over two percentage points over the same period of time. Second, for flat PV systems it is interesting that the rate of performance diminution was relatively high during the first several years of operation before reaching a plateau. Between year four and year five of operation the average capacity factor actually increased very slightly. It is surprising that tilted PV systems show a more rapid decline in annual capacity factor than flat PV systems. Intuitively, flat PV systems would seem to be more susceptible to soiling and less easy to keep clean. Without additional process evaluation information, we cannot state the reasons for the differences in decline of capacity factor between fixed and tilted PV systems. Nonetheless, it is important for policy makers and the CSI PAs to recognize the extent to which PV capacity factors may possibly be expected to decline over the life of the CSI.

Figure 3-13: PV Annual Capacity Factor versus Year of Operation

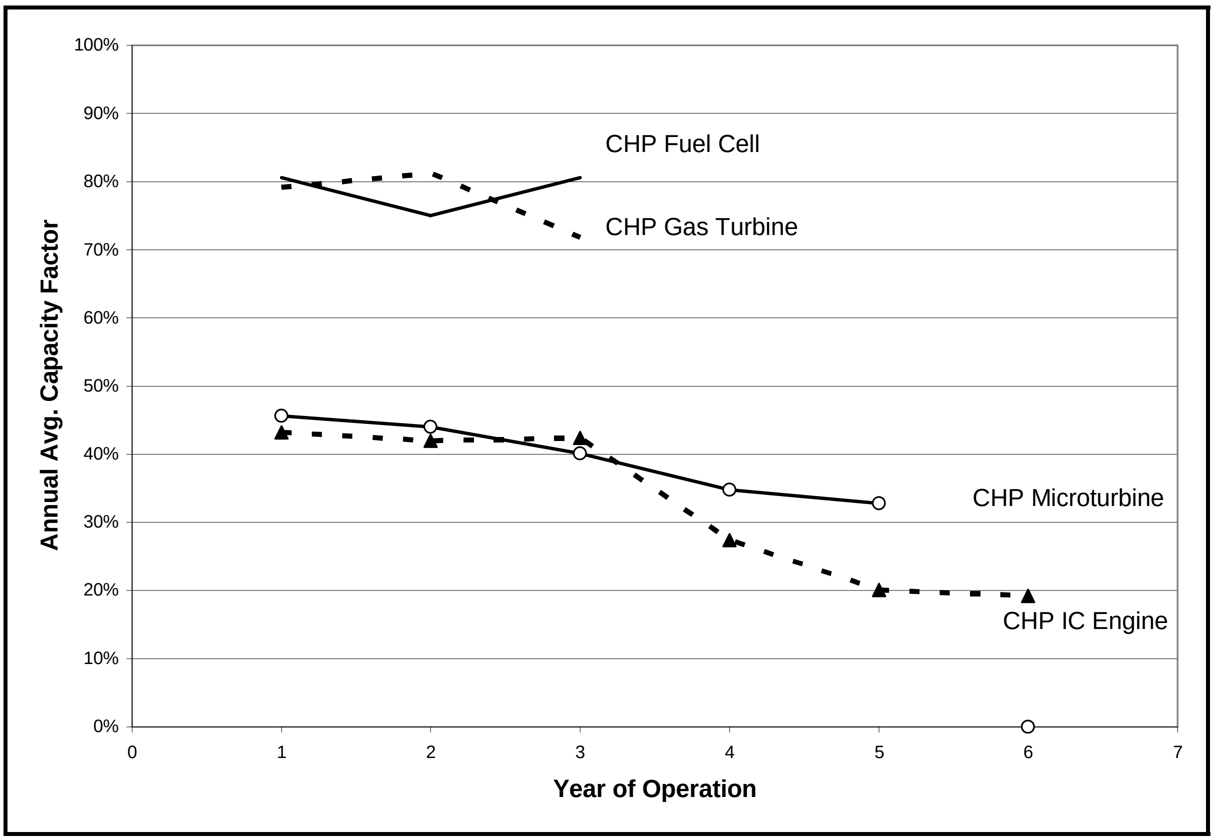


Year to year changes in the average annual capacity factor for combined heat and power (CHP) systems deployed under the SGIP are presented in Figure 3-14. Results are presented separately for each of the four types of prime movers covered by the SGIP. The annual capacity factors (CF) for microturbines and IC engines exhibit a noticeable downward trend over the life of the program. Annual capacity factors for IC engines show a disturbing decline of nearly 20 percentage points from program year one through program year seven.

There is a very rapid decline between program years three and five that account for nearly the entire decline in annual capacity factor. Microturbines show a lesser overall decline, but still show an observed decline in annual capacity factor of nearly ten percentage points over five program years. As with IC engines, a significant amount of the decline in annual capacity factor occurred during the middle years of operation.

Without additional information, it is difficult to identify the reasons for the decline in annual capacity factors observed for IC engines and microturbines. Year-to-year variability can be due to a variety of factors including equipment maintenance/reliability issues, staff turnover, and interruption in fuel or service provider contracts, fuel prices, and occupancy/operations schedules of metered CHP systems. Nonetheless, the identification that capacity factor has declined over time for CHP systems and the extent of that decline is valuable information as California begins considering programs to expand the use of DG technologies to help address peak electricity demand.

Figure 3-14: CHP Annual Capacity Factor versus Year of Operation



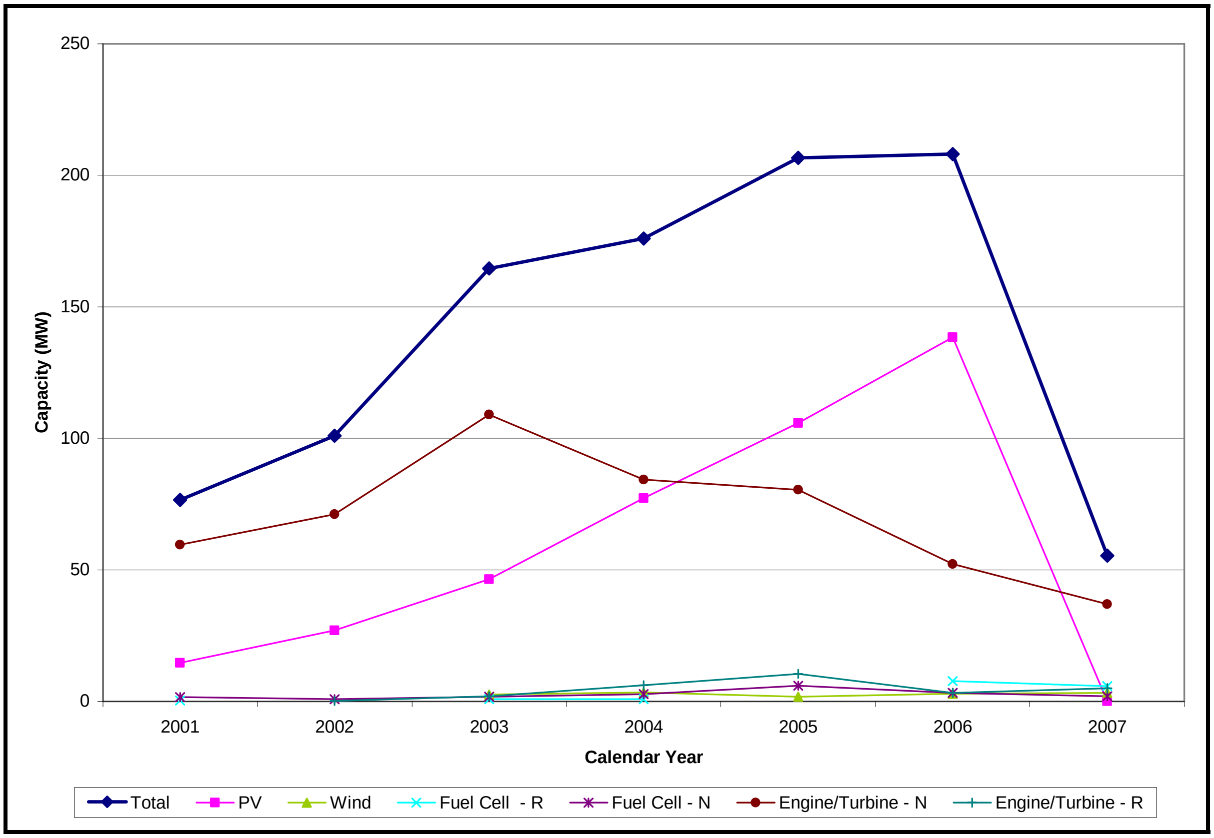
The SGIP Portfolio of DG Projects

As noted earlier, one of the most valuable aspects of the SGIP has been its use as a living laboratory for DG technologies operating in a commercial setting and within a utility and regulatory framework unique to California. However, changes in the eligibility of SGIP technologies have changed the portfolio of DG technologies that make up the SGIP.

Figure 3-15 shows the capacity of Active SGIP projects by technology from PY01 through PY07. From PY01 through PY05, there was a steady increase in all Active projects. The capacity of PV projects continued to grow steadily beyond PY05 to the end of PY06. With enactment of the CSI, PV technologies have no longer been eligible to receive incentives under the SGIP. Consequently, effective January 1, 2007, there was a rapid decline in Active PV projects, with only those legacy projects that had applied earlier than PY07 moving forward in PY07. Since PY03, there has also been a steady decline in the capacity of IC engines and turbine technologies under the SGIP. Passage of AB 2778 limits eligibility of cogeneration projects within the SGIP to "ultra-clean and low emission distributed generation" technologies. These technologies are defined as fuel cells and wind DG technologies that meet or exceed the emissions standards required under the DG certification program adopted by the California Air Resources Board. We have seen little growth of fuel cell and wind technologies under the SGIP over the past several years. Consequently, with few new fuel cell projects and with the decline in Active IC engine and turbine technology projects, this will produce significant changes in the make up of cogeneration technologies in the SGIP.

The changes in capacity additions from PV and cogeneration technologies will substantially affect the makeup of the SGIP portfolio going forward beyond PY07. Changes in the portfolio will influence impacts by the technologies as well as observations on the impacts of those technologies within the electricity system.

Figure 3-15: Capacity of Active SGIP Projects PY01 to PY07



3.6 Conclusions and Recommendations

The SGIP continues to present tremendous learning 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. Like many other states, California is poised to move forward into an era of potentially rapid growth in DG. The successfulness of that growth will require a thoughtful approach to the manner in which DG technologies can meet the sometimes competing needs for increased electricity system performance, environmental improvements and lower costs to rate payers. Due to the extensiveness of performance data collected from a diverse group of DG technologies deployed under the SGIP, it can continue to provide important information to help plan and deploy future DG programs. To help enhance the information available under the SGIP, we recommend the following work be considered by the CPUC and PAs:

1. There has been a steady decline in the application of cogeneration projects to the SGIP as well as an increase in attrition of cogeneration projects. Process evaluations should be conducted to examine the reasons for the decline in the numbers of cogeneration projects.

2. There has been a decline in the performance of SGIP technologies as demonstrated by the average annual capacity factors for PV and CHP technologies. Process evaluations that are complemented by individual project performance information should be conducted to better identify the reasons for the performance declines.
3. The ability of cogeneration technologies to achieve high electrical efficiencies and have matched thermal and electrical loads will be important in pursuing improved system efficiency and decreased net GHG emissions. Evaluations should be conducted to assess the degree to which DG technology installers are complying with the new Waste Heat Utilization Worksheet requirements established in 2006 by the PAs.
4. There is likely to be increased emphasis on the use of renewable fuel use facilities in the future. In addition, PAs may want to consider use of mixed incentive payments for facilities that use mixes of renewable and non-renewable fuels. However, due to the current approach to renewable fuel use requirements and the cost of monitoring biogas fuel use, there has been limited information collected on actual biogas fuel consumption at renewable fuel use facilities. Actual biogas fuel use monitoring should be conducted to better understand the performance of new technologies (e.g., fuel cells) using biogas and the ability and costs of using renewable and non-renewable fuel mixes.
5. There were no new wind energy projects submitted to the SGIP in PY05–PY07. However, wind energy DG projects are eligible for the program and may play an important role in helping California achieve its DG targets. Evaluations should be conducted to determine the reasons for the low application of wind energy technologies to the SGIP, the potential benefits of having additional wind energy projects and the steps needed to encourage applications of wind DG projects to the SGIP.

4

Sources of Data for the Impact Evaluation

This section describes sources of data used in conducting the seventh-year impact evaluation. Several key types of data sources are presented first. 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

SGIP Program Administrators (PAs) maintain project tracking database files containing information essential for designing and conducting SGIP impact evaluation activities. The PAs provided Itron with regular updates of their program tracking database files; usually on a monthly basis. Information of particular importance includes basic project characteristics (e.g., technology type, rebated capacity of the project, and fuel type) and key participant characteristics (e.g., Host and Applicant names[1], addresses, and phone numbers). The project's technology type, program year, and project location (by PA area) were also used in developing a sample design to ensure collection of statistically significant data. Updated SGIP handbooks were used for planning and reference purposes.[2]

Reports from Monitoring Planning and Installation Verification Site Visits

Information contained in the PA project database files is updated through site visits to the SGIP projects. Project site visits are conducted by independent consultants hired by the PAs to perform verification of SGIP installations. Project-specific information is reported in Inspection Reports produced by these independent consultants. The PAs regularly provided copies of the Inspection Reports. In addition, site visits are conducted by Itron engineers in preparing monitoring plans for on-site data collection activities. Among the types of

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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 PA for incentive funding. Third parties (e.g., a party other than the PA 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 PA websites.

information collected during site inspections or in preparation of monitoring plans include meter nameplate rating and the date the system entered normal operation.

Metered Performance Data

In addition to information collected from the PA project database and from project site visits, metered data were also used when available. The metered data collected and used for evaluation purposes include electric net generator output (ENGO) data, useful thermal energy data, and fuel use data.

Electric Net Generator Output (ENGO) Data

ENGO data provide information on the amount of electricity generated by the metered SGIP project. This information is needed to assess annual and peak electricity contributions from SGIP projects. ENGO data were collected from a variety of sources, including meters Itron installed on SGIP projects under the direction of the PAs, and meters installed by project Hosts, Applicants, electric utilities, and third parties. Some electric utilities may install different types of ENGO metering depending on project type. In some cases, this impeded Itron's ability to assess peak demand impacts. For example, some of the installed meters did not record electricity generation data in sub-hour intervals. These types of meters were encountered with some cogeneration systems installed in schools, as well as with some renewable-fueled engine/turbine projects eligible for net metering. As a result, peak demand impacts could not be determined for these projects. We have been working with the affected PAs and electric utility companies on a plan to have all SGIP projects equipped with interval recording electric metering in the future.

Useful Thermal Energy (HEAT) Data

Useful thermal energy (also referred to as HEAT) data are used to assess compliance of SGIP cogeneration facilities with required levels of efficiency and useful waste heat recovery. In addition, useful thermal energy data enable us to estimate electricity or natural gas displaced by SGIP facilities that would have otherwise been provided by the utility companies. This information is used to assess energy efficiency impacts as well as determine net GHG emission impacts. HEAT data are collected from metering systems installed by Itron as well as metering systems installed by applicants, Hosts, or third parties.

Over the course of the SGIP, the approach for collecting HEAT data has changed. Collecting HEAT data has historically involved installation of invasive monitoring equipment (i.e., insertion type flow meters and temperature sensors). Many third parties or Hosts had this type of HEAT metering equipment installed at the time the SGIP project was commissioned, either as part of their contractual agreement with a third party vendor or as part of an internal process/energy monitoring plan. In numerous cases, Itron was able to obtain the relevant data being collected by these Hosts and third parties. Itron initially adopted an approach of obtaining HEAT data from others in an effort to minimize both the cost- and disruption-related aspects of installing HEAT monitoring equipment. The majority of useful thermal energy data for 2003-2004 were obtained in this manner.

Itron began installing HEAT meter systems in the summer of 2003 for SGIP projects that were included in the sample design but for which data from existing HEAT metering were not available. As the HEAT data collection effort grew, it became clear that Itron 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 were labor intensive and required examination of the collected data by more expert staff, thereby increasing costs. In addition, reliance on HEAT data collected by SGIP Host customers and third-parties created evaluation schedule impacts and other risks that more than outweighed the benefits of lower metering installation costs.

In mid-2006, Itron responded to the HEAT data issues by changing the approach to collection of HEAT data. Itron continued to collect HEAT data from others in those instances where the data could be obtained easily and reliably. In all other instances, an approach has been adopted of installing HEAT metering systems for those projects in the sample design. Itron adopted the installation of non-invasive metering equipment such as ultrasonic flow meters, clamp-on temperature sensors, and wireless, cellular-based communications to reduce the time and invasiveness of the installations and increase data communication reliability. The increase in equipment costs was offset by the decrease in installation time and a decrease in maintenance problems. This approach has been used to obtaining HEAT data and using non-invasive systems throughout 2007. Appendix E provides detailed information on the non-invasive metering equipment that has been installed.

Fuel Usage (FUEL) Data

Fuel usage (also called FUEL) data are used in the impact evaluation to determine overall system efficiencies of SGIP cogeneration facilities, to determine compliance of renewable fuel use facilities with renewable fuel use requirements, and to estimate net GHG emission impacts. To date, fuel use data collection activities have focused exclusively on monitoring consumption of natural gas by SGIP generators. In the future it may also be necessary to monitor consumption of gaseous renewable fuel (i.e., biogas) to more accurately assess compliance of SGIP projects using blends of renewable and non-renewable fuels with renewable fuel use requirements.

FUEL data used in the seventh-year impact evaluation were obtained from meters installed by Itron, but mostly from FUEL metering systems installed at SGIP projects by natural gas utilities, SGIP participants, or by third parties. Itron reviewed FUEL data obtained from others and their bases were documented prior to processing the FUEL data 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 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 impact analysis. It was also found that much of the FUEL data being obtained from others are collected and reported on time intervals much greater than one hour (e.g., daily or monthly). In the past, hourly FUEL consumption was estimated based on the associated ENGO readings. However, this approach did not work in a number of instances. For example, it failed in those instances where there were multiple generators, but the electricity production was metered for only a portion of the generators and FUEL data were collected for all generators. In those cases, estimates of FUEL consumption based on ENGO readings would provide inaccurate FUEL data. In addition, there were instances where it is important to know the FUEL data for a particular hour (e.g., to better understand what was happening to cogeneration system efficiency during peak electricity demand). In those situations, hourly FUEL data were required. In order to address these issues, Itron has recommended to the PAs installation of separate FUEL metering in special situations as well as the use of pulse recorders on existing gas meters to enable collection of hourly FUEL data.

4.2 Metered Performance Data Collection Status Summary

As of the end of 2007, over 1,200 SGIP projects were determined to be on-line. These projects corresponded to approximately 300 MW of rebated SGIP project capacity. It was 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 through the end of December 2007. Data collection status by PA is discussed in Appendix C.

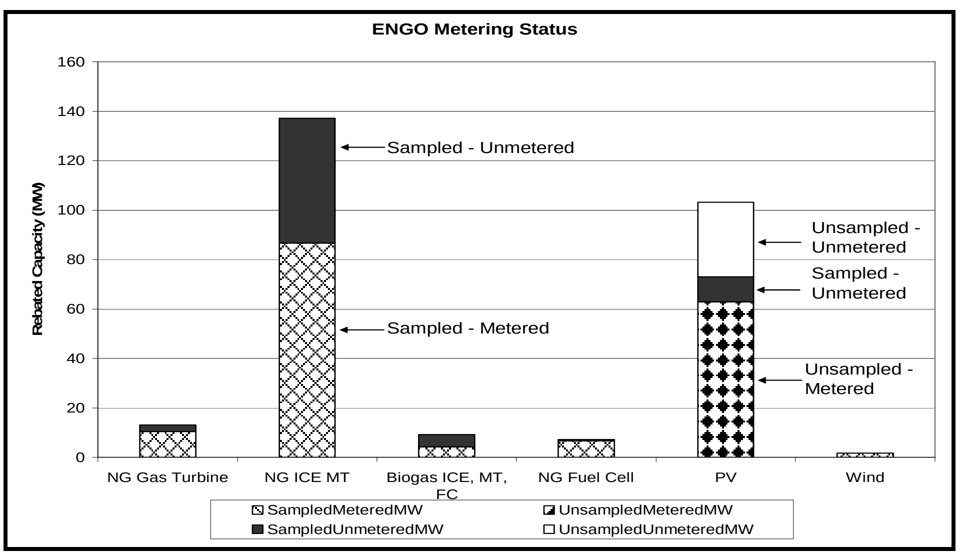
The status of ENGO data collection is summarized in Figure 4-1. Note that the population of projects for data collection includes Complete projects as well as all Active projects.[3] Data collection efforts have been classified into four general categories. “Sampled-Unmetered” projects refer to projects that fall within the sample design and should be metered but have

[3] All Active projects are included rather than just on-line Active projects because it is impossible to know which projects will move forward to become Complete projects. Consequently, the population is based inclusive to all projects to ensure the sample design has not been underestimated.

not yet been metered. For example, this includes projects that have not yet received incentive checks. In those instances, metering is placed on hold until the incentive check has been issued and the project moves into the Complete category. “Unsampled-Unmetered” represent those projects that fall outside the sample design and, consequently, are not intended for metering. “Sampled-Metered” refers to projects that are contained in the sample design and are metered as of the date of the evaluation. “Unsampled-Metered” are projects that are outside the sample design but for which metering is already being conducted. An example would be a project for which there is currently sufficient data to meet the 90/10 confidence level target of the sample design, but ENGO data is being collected by someone else (e.g., Host, applicant or third party). While additional ENGO data collection activity would not be pursued in this situation, the data would still be used for impact evaluation purposes, if provided.

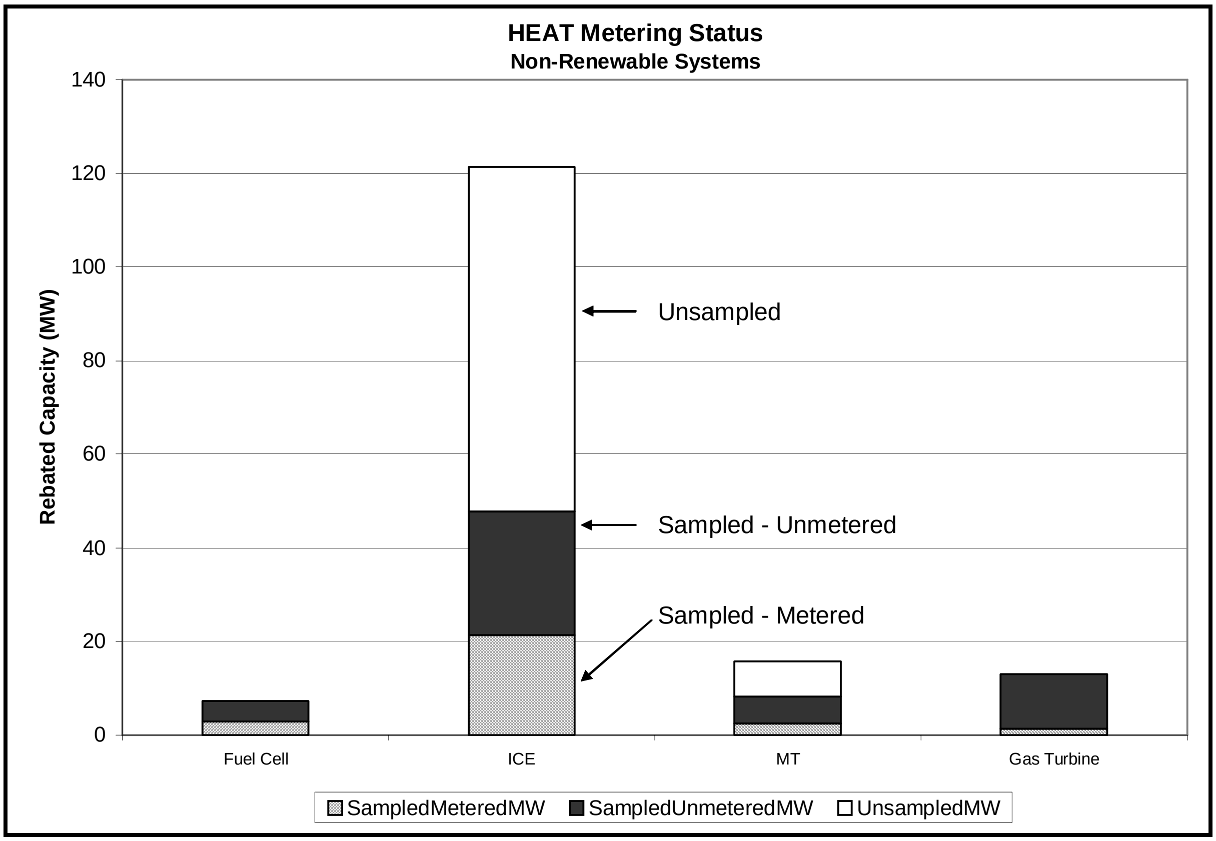
A substantial quantity of ENGO metering installation activity remains to be completed. In particular, because of the importance of having ENGO data for cogeneration facilities, Itron was directed by the PAs beginning in late 2006 to initiate a census approach to have ENGO metering on all cogeneration facilities. Similarly, prior to 2006, the PAs were to be responsible for providing ENGO data for all PV projects greater than 300 kW in rebated capacity. Itron was responsible for installing ENGO meters on PV projects smaller than 300 kW based on a statistical sample design approach. In late 2006, Itron was directed by the PAs to employ a statistical sample design approach to collecting PV ENGO data, regardless of rebated capacity. This activity is ongoing and is being carried out in consultation and collaboration with the PAs. Moving through PY2008, the highest priority is installation of additional ENGO metering for non-renewable-fueled gas turbines and renewable-fueled engines/turbines.

Figure 4-1: ENGO Data Collection as of 12/31/2007



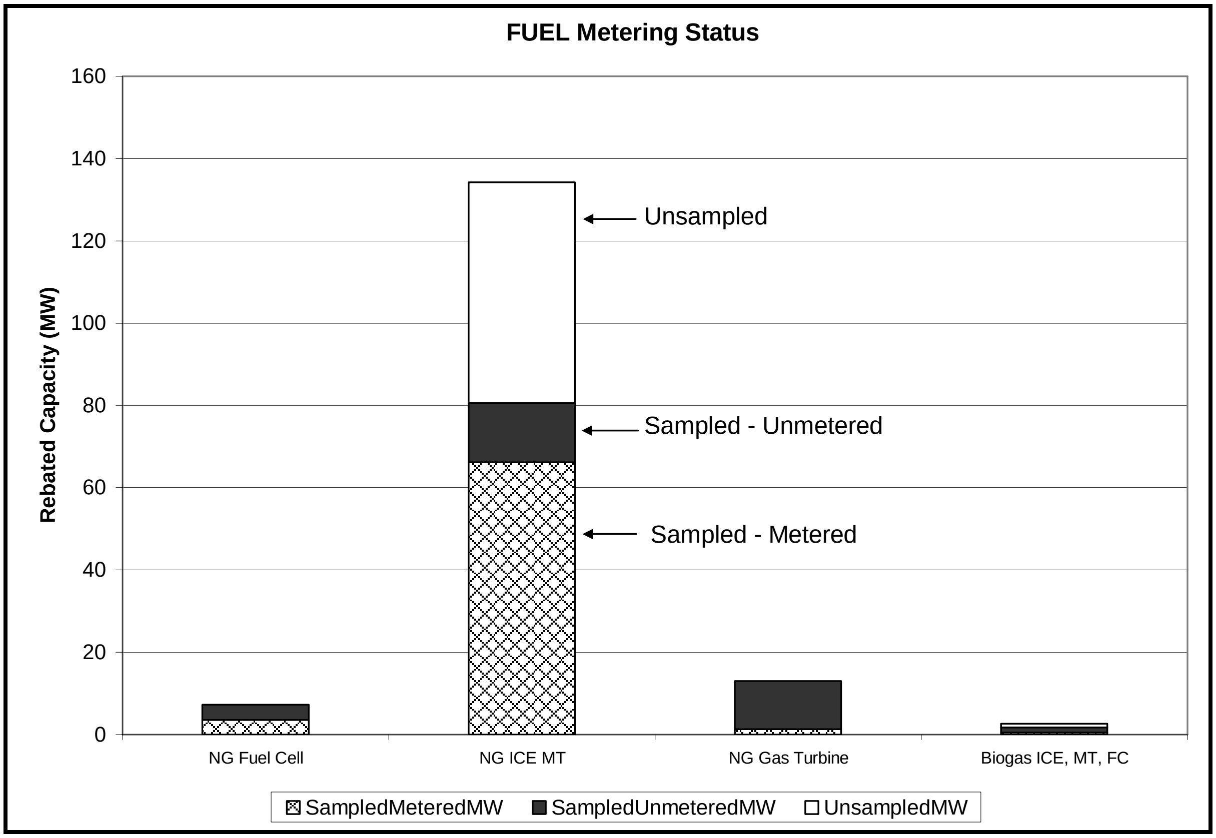
The status of HEAT data collection is summarized in Figure 4-2. Overall, significantly more HEAT metering is needed for all technologies. However, the most important area for improvement in 2008 is non-renewable-fueled gas turbines. These systems are relatively larger capacity and it is more likely that HEAT metering will be available from the Applicant. While the focus will be on obtaining HEAT data from others, HEAT metering will be installed in situations where data are unavailable or of insufficient quality for the purposes of the impact evaluations.

Figure 4-2: HEAT Data Collection as of 12/31/2007



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. As indicated in the figure, there is a significant amount of FUEL metering needed for SGIP cogeneration facilities and particularly for renewable fuel use projects using blends of renewable and non-renewable fuels.

Figure 4-3: FUEL Data Collection as of 12/31/2007



5

Program Impacts

This section presents impacts from SGIP projects that were on-line through the end of PY07. Impacts examined include effects on energy delivery; peak demand; waste heat utilization and efficiency requirements; and GHG emission reductions. 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, 2007. 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 which are installed and operational, but for which incentives have not yet been disbursed). 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 C. Data availability and corresponding analytic methodologies vary by program level and technology.

This section is composed of the following four subsections:

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

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, 2007. Impacts were estimated using available metered data for 2007 and system characteristics information from program tracking systems maintained by the PAs, and were augmented with information obtained over time by Itron.

By the end of 2007, 1209 SGIP facilities were on-line, representing over 305 MW of electricity generating capacity. Some of these facilities (e.g., PV and wind) provided their host sites with only electricity, while cogeneration[1] 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 2007. Energy delivery is described by technology and fuel.

Table 5-1: Statewide Energy Impact in 2007 by Quarter (MWh)

Technology	Fuel	Q1-2007 (MWh)	Q2-2007 (MWh)	Q3-2007 (MWh)	Q4-2007 (MWh)	Total* (MWh)
FC	**N**	11,734	12,410	12,947	12,508	49,599
FC	**R**	717	551	679	594	2,540
GT	**N**	19,865	22,068	17,964	22,297	82,193 †
IC ENGINES	**N**	78,647	74,066	84,816	79,220	316,748 †
IC ENGINES	**R**	9,394	9,024	8,696	9,191	36,304 †
MT	**N**	13,069	16,203	15,083	17,554	61,910 †
MT	**R**	2,257	1,966	1,680	1,864	7,767 †
PV		28,394	52,898	50,965	29,514	161,770
WD		502	784	571	569	2,426 [a]
	TOTAL	**164,578**	**189,970**	**193,400**	**173,309**	**721,257**

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

During PY07, SGIP projects delivered over 720,000 MegaWatt-hours (MWh) of electricity to California's grid; enough electricity to meet the electricity requirements of 60,000 homes for a year[2]. SGIP projects are located at customer sites of the IOUs[3] to help meet on-site demand. Consequently, the 720,000 MWh of electricity provided by SGIP facilities represented electricity that did not have to be generated by central station power plants or delivered by the transmission and distribution system.

Natural gas-fueled technologies provided 71 percent of the electricity generated by SGIP systems during 2007. This is a six percent decline from the 78 percent of 2006. One

[1] Cogeneration facilities are also known as combined heat and power (CHP) facilities and these terms are used interchangeably in this report.

[2] Assuming the typical home consumes approximately 12,000 kWh of electricity per year

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

explanation for this decline is the five percent growth in PV's contribution, from 17 percent in 2006 to 22 percent in 2007. Natural gas-fueled IC engines, a technology composing 42 percent of the total program generating capacity, contributed the largest share of the total annual delivered energy, 44 percent.

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 technology.

Table 5-2: Annual Capacity Factors by Technology

Technology		Annual Capacity Factor* (kWyear/kWyear)
FC		0.746
GT		0.719 †
IC Engines		0.306
MT		0.411 †
PV		0.177
WD		0.168 [a]

* [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

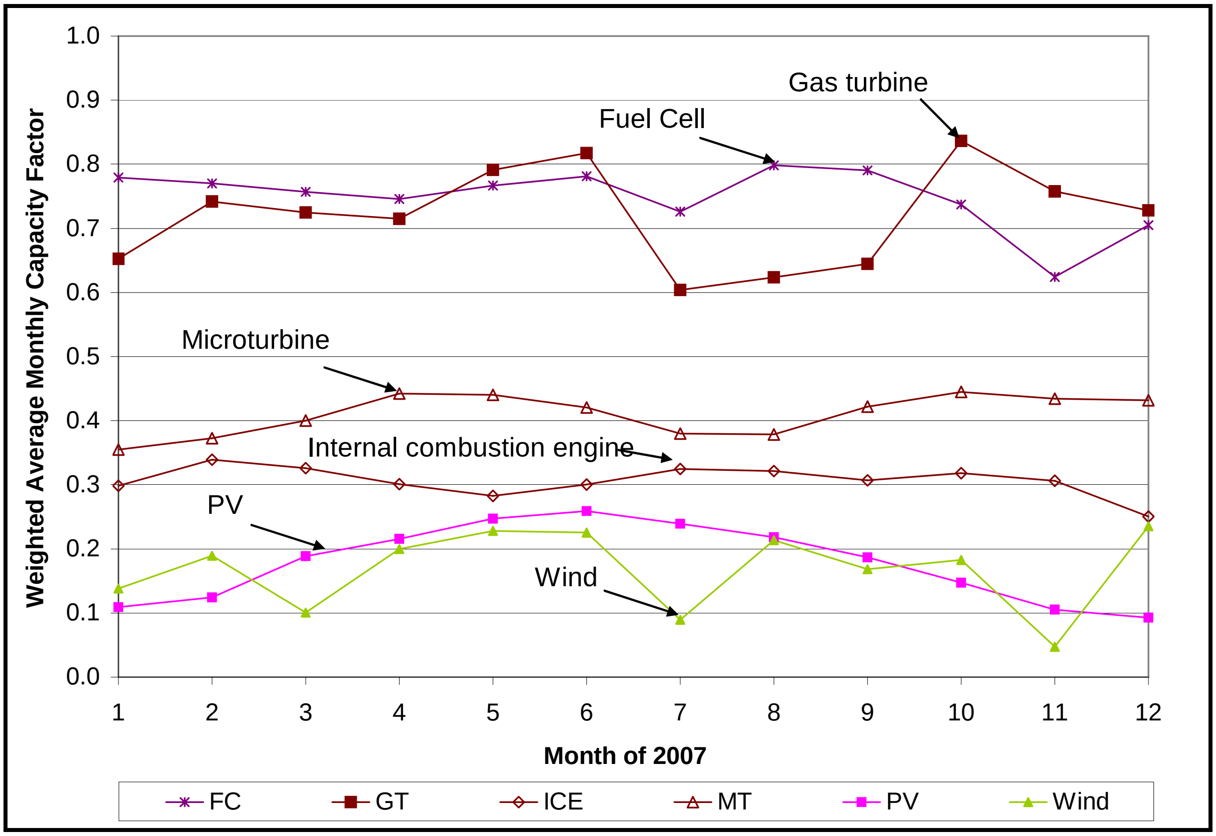
	Annual Capacity Factor* (kWyear/kWyear)	
Technology	**Natural Gas**	**Renewable Fuel**
FC	0.784	0.387
GT	0.719 †	
IC Engines	0.294 †	0.464 †
MT	0.441 †	0.265 †

* 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 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 biogas use in fuel cells is reflected in its significantly lower capacity factor, when compared to its natural gas-fueled counterpart. From 2006 to 2007 there was very little change in annual capacity factor for fuel cells of either fuel type.

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 2007. As expected, natural gas turbines in the program maintained the highest monthly capacity factors throughout the year, falling below 0.7 for just four months. Fuel cell monthly capacity factors fell below 0.7 for only one month. The monthly capacity factors shown in Figure 5-1 for fuel cells represent 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 encountered additional operational issues that reduced their capacity factors. Monthly capacity factors for natural gas-powered fuel cells were significantly higher than the combined natural gas/biogas capacity factors shown here for fuel cells overall. Appendix A provides similar capacity factor charts that distinguish technologies by fuel type. Figure 5-1 also shows that microturbines had monthly capacity factors that tended to run consistently above 0.35 throughout the year. IC engines meanwhile did not exceed 0.35 but were fairly consistent from month to month.

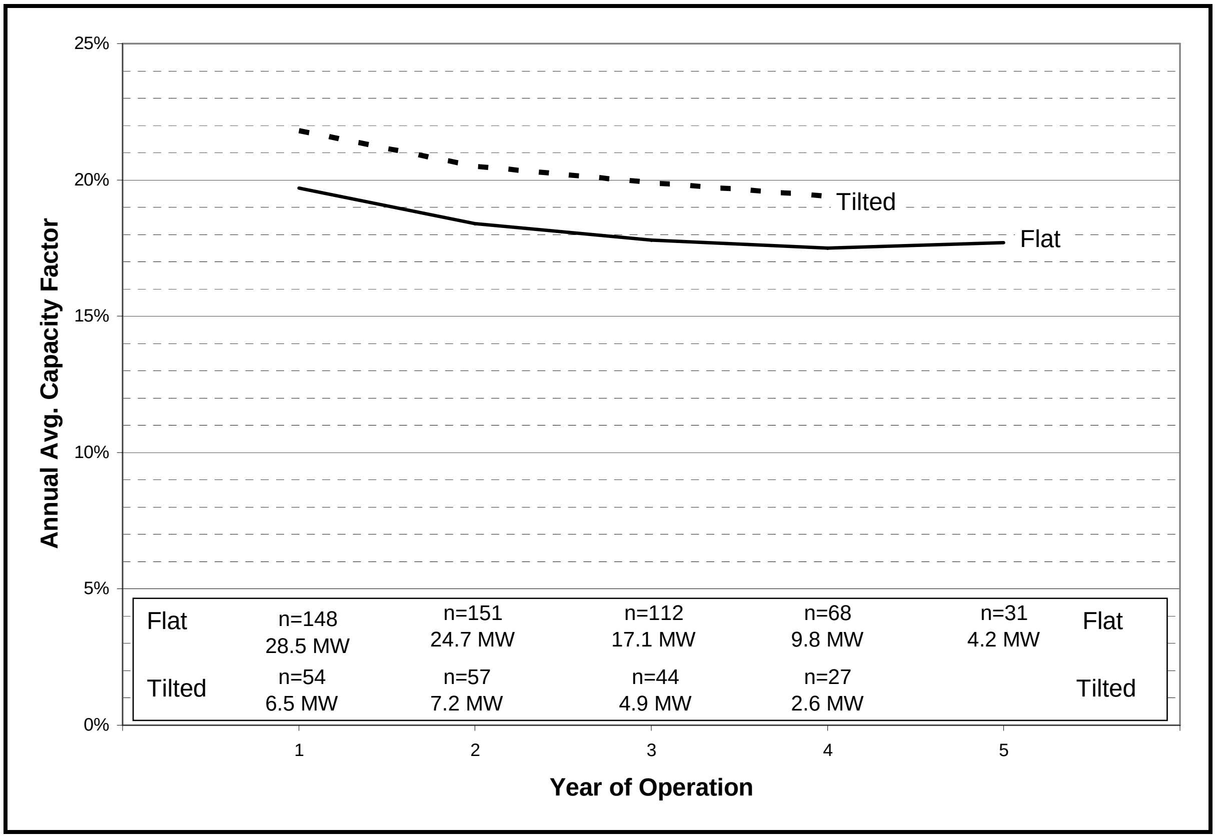
Figure 5-1: Weighted Average Capacity Factor by Technology and Month



Some SGIP systems have now been operating for several years. The possibility that annual average capacity factors change as systems age was explored by graphing annual average capacity factors versus year of operation. The scope of this analysis was limited to only those projects for which metered data were available. Results of this analysis are presented in Figure 5-2 and Figure 5-3.

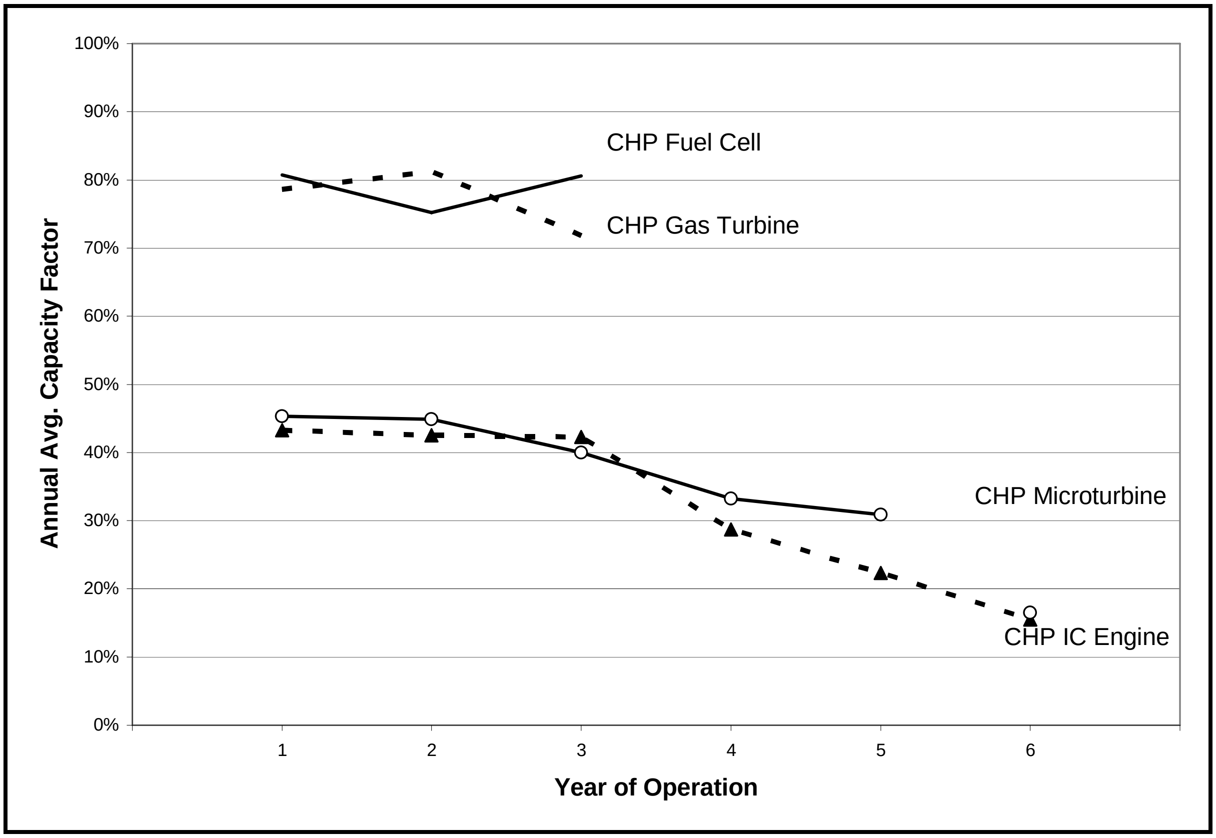
Results for PV systems are presented in Figure 5-2. Results are presented separately for tilted and flat PV systems. For purposes of this analysis all PV systems sloped less than 20 degrees were treated as having a flat configuration. The chart is annotated with information about the quantity and capacity of PV systems for each year of operation. Year-to-year variability is due to a range of factors including weather, maintenance/reliability issues, and location of projects. Two interesting observations can be made from the PV capacity factor trend lines. First, the observed annual capacity factors for both tilted and flat PV systems have declined with age. For flat PV systems, the annual capacity factor declined by approximately two percentage point over the course of four years of operation. For tilted PV systems, the annual capacity factor declined by just over two percentage points over the same period of time. Second, for flat PV systems it is interesting that the rate of performance diminution was relatively high during the first several years of operation before reaching a plateau. Between year four and year 5 of operation the average capacity factor actually increased very slightly. It is surprising that tilted PV systems show a more rapid decline in annual capacity factor than flat PV systems. Intuitively, flat PV systems would seem to be more susceptible to soiling and less easy to keep clean. However, without additional information, the reasons for the more rapid decline in annual capacity factor for tilted PV systems cannot be determined.

Figure 5-2: PV Annual Capacity Factor versus Year of Operation



Results for combined heat and power (CHP) systems are presented in Figure 5-3. Results are presented separately for each of the four types of prime movers covered by the SGIP. The annual capacity factor trends for microturbines and IC engines exhibit a noticeable downward trend over the life of the program. Annual capacity factors for IC engines show a disturbing decline of nearly 20 percentage points from program year one through program year seven. There is a very rapid decline between program years three and five that account for nearly all of the loss of annual capacity factor. Microturbines show a lesser overall decline, but still show an observed decline in annual capacity factor of nearly ten percentage points over five program years. As with IC engines, a significant amount of the decline in annual capacity factor occurred during the middle years of operation. Without additional information, it is difficult to identify the reasons for the decline in annual capacity factor observed for IC engines and microturbines. Year-to-year variability can be due to a variety of factors including equipment maintenance/reliability issues, staff turnover, and interruption in fuel or service provider contracts, fuel prices, and occupancy/operations schedules of metered CHP systems. Note that there were far fewer gas turbine and fuel cell projects for which metered data were available, and most of these projects were completed only relatively recently. In addition, limited metering data prevented estimation of annual capacity factor information for gas turbines and fuel cells in later program years. Nonetheless, data for gas turbines and fuel cells are presented to illustrate general differences among the four different technologies. Data for additional years of operation are needed before general conclusions about trends can be drawn for gas turbines and fuel cells.

Figure 5-3: CHP Annual Capacity Factor versus Year of Operation



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: Annual Energy Impacts by PA (MWh)

Technology		PG&E (MWh)	SCE (MWh)	SCG (MWh)	CCSE (MWh)	Total (MWh)
FC		24,344	3,908 †	11,244 †	12,642	52,139
GT		22,689 [a]	HIDDEN TO MAINTAIN CONFIDENTIALITY			82,193 †
IC ENGINES		136,071 †	73,520 †	116,238 †	27,223	353,052
MT		27,647 †	17,395 †	21,255 †	3,379	69,677 †
PV		92,849	HIDDEN TO MAINTAIN CONFIDENTIALITY			161,770
WD			2,426 [a]			2,426 [a]
	Total	**303,601**	**128,609**	**195,508**	**93,540**	**721,257**

* Except for bottom row, [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 in 2006, over 40 percent of the total electricity delivered by the program in 2007 came from SGIP systems operating in PG&E's service territory. The contribution from PG&E's IC engines was 45 percent, down from 57 percent in 2006. A similar association is seen with SGIP systems in SCG's service territory. SGIP projects in SCG's service territory delivered 27 percent of the total electricity delivered by the program. Almost 60 percent came from SCG's IC engines, down from 68 percent in 2006. Within each PA territory but SCG, PV contributed at least 22 percent of the annual electricity delivery.[4] Overall, PV system contributions to program total annual electricity delivery grew from 17 to 22 percent from 2006 to 2007.

[4] PV systems in SCG service territory contributed approximately nine percent of the annual electricity delivery.

Table 5-5 presents annual weighted average capacity factors for each technology and PA for the year 2007. 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

	PG&E	SCE	SCG	CCSE
	Annual Capacity Factor*			
Technology	(kWyear/kWyear)			
FC	0.749	0.470 †	HIDDEN TO MAINTAIN CONFIDENTIALITY	
GT	0.645 [a]		0.758 [a]	0.747
IC ENGINES	0.290 †	0.324 †	0.317 †	0.297
MT	0.396 †	0.425 †	0.482 †	0.229
PV	0.182	0.163	0.179	0.176
WD		0.168 [a]		

* [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 0.47 capacity factor for fuel cells in SCE territory reflects the influence of biogas-fueled units. As noted earlier, additional operational issues are encountered when using biogas in fuel cells, which can significantly impact rating and overall availability. SCE continues to be the only territory with 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 at the customer site during times of peak electricity demand represents a critical impact. By providing electricity directly at the customer site during peak hours, SGIP facilities reduce the need for utilities to power up peaking units to supply electricity to these customers. As a result, SGIP provide grid benefits 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 PY07 were estimated by looking at SGIP contributions coincident with the California Independent System Operator (CAISO) 2007 system peak load.

Table 5-6 summarizes the overall SGIP program impact on electricity demand coincident with the 2007 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 peak hour average capacity factor.

Table 5-6: Demand Impact Coincident with 2007 CAISO System Peak Load

Technology		On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor* (kWh/kWh)
FC		14	8,000	5,982	0.748
GT		5	13,043	8,386	0.643 †
IC ENGINES		214	133,411	52,110	0.391
MT		121	19,274	7,619	0.395 †
PV		791	109,052	65,490	0.601
WD		2	1,649	156	0.095 [a]
	TOTAL	**1,147**	**284,429**	**139,743**	

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

In 2007, the CAISO system peak reached a maximum value of 48,835 MW on August 31 during the hour from 2:00 to 3:00 P.M. (PDT). This was 1,363 MW less than the peak load of 50,198 MW that occurred one hour later in the day on July 24 of 2006. There were 1,147 SGIP projects known to be on-line when the CAISO experienced the 2007 summer peak. Generator electric interval-metered data were available for 374 of these on-line projects. Based on the interval-metered data, we were able to estimate the impact of the SGIP on-line project coincident with the peak demand. While the total rebated capacity of these on-line projects exceeded 284 MW, the total impact of the SGIP projects coincident with the CAISO peak load was estimated at slightly below 140 MW. In essence, the collective peak hour impact of the SGIP projects on the CAISO 2007 peak was approximately 0.49 kWh at peak per kWh of rebated capacity. It is important to recognize that the individual and collective peak hour impacts of the SGIP projects can be used as a proxy for the peak hour impact that may be expected from a much larger penetration of DG technologies in California's electricity system under certain assumptions. Because the peak hour capacity factors for SGIP technologies represent observed values, use of these factors as proxies can be especially useful in estimating the influence of different mixes of DG technologies on peak demand. Tables in Appendix A differentiate peak demand impacts by technology and fuel.

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 average 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 2007, fuel cells operating in the SGIP demonstrated the highest peak hour average capacity factor; just below 0.75. Gas turbines followed with an average peak hour capacity factor just under 0.65. Microturbines and IC engines had much lower average peak hour capacity factors; both just below 0.4. Under the 2007 summer peak conditions, occurring in the second hour after the sun reached its apex, PV systems demonstrated a peak hour average capacity factor of 0.6. The peak hour average capacity factor for wind was very low; under 0.1. Since there continued to be only two wind systems operating in the SGIP during 2007, this peak hour average capacity factor should not be considered representative of wind performance in general.[5]

For intermittent technologies such as wind and solar, the timing of peak demand is a crucial factor in contributing to peak capacity. Figure 5-4 profiles the hourly weighted average capacity factor for each technology from morning to early evening during the 2007 peak day. The chart also indicates the hour and magnitude of the CAISO peak load. The influence of timing of peak demand is readily apparent with PV. If the CAISO peak hour had occurred two hours earlier, the peak hour average capacity factor for PV would have been almost 10 percent greater.

[5] 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)

Figure 5-4: CAISO Peak Day Capacity Factors by Technology

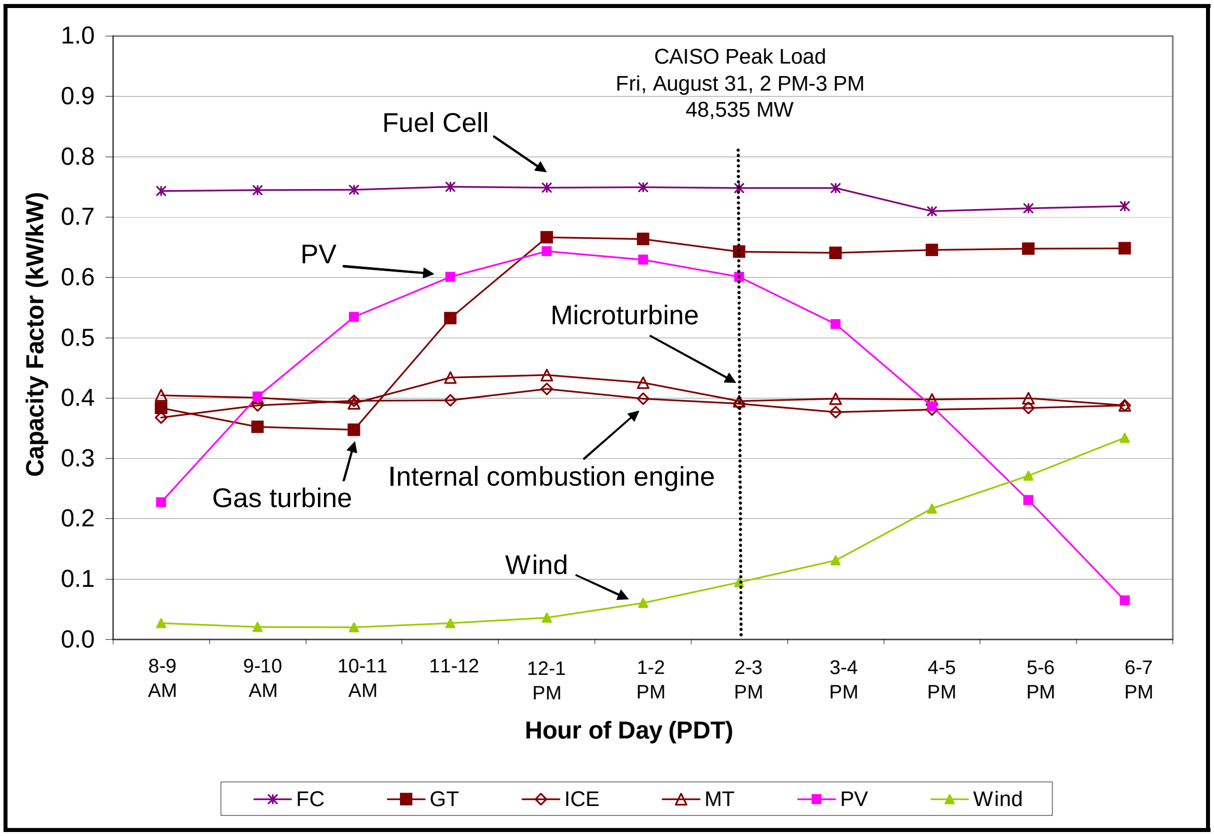
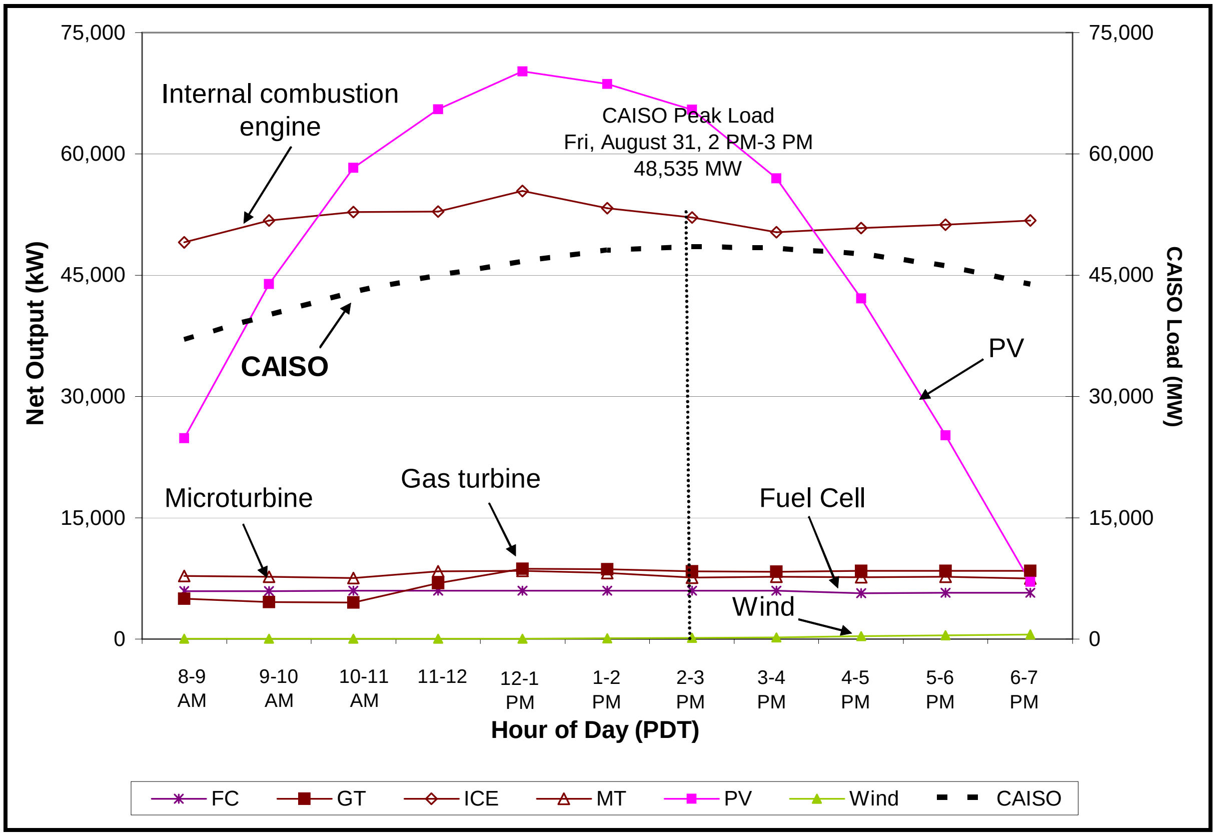


Figure 5-5 plots the hourly total net electrical contribution for each SGIP technology from morning to early evening during the 2007 peak day. This figure is useful in assessing the potential impact of increasing amounts of a particular SGIP technology on meeting peak hour energy delivery. For example, SGIP's 791 PV systems provided approximately 66 MW to the grid during the peak hour. These PV systems represented approximately 110 MW of operational PV capacity. In comparison to the CAISO peak hourly demand of nearly 49,000 MW, SGIP's PV contribution represented only 0.13 percent of the total. However, in scaling up PV capacity to 3000 MW as targeted in the California Solar Initiative, PV potentially could have contributed over 1,800 MW of electricity during the peak hour; or over 3.5 percent of the 2007 peak demand. In addition, because PV's contribution occurs primarily at the distribution system level, this percentage 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.[6] 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 5-5 represent PV systems with predominately a southern exposure. PV

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

systems with a southwestern orientation would have a significantly higher contribution to peak.[7]

Figure 5-5: SGIP Impact on CAISO 2007 Peak Day



PA-Specific Peak Demand Impacts

Table 5-7 through Table 5-9 present the total net electrical output during the respective peak hours of California's three large IOUs. 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 utilities 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

[7] 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

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)
PGE	**21,364**	**29-Aug-07**	**6 PM**

Technology		On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC		6	3,550	1,795	0.506
GT		3	4,016	2,643	0.658
IC ENGINES		96	54,992	17,251	0.314
MT		51	8,218	3,566	0.434
PV		391	57,717	5,397	0.094
WD		0	0	0	
	TOTAL	**547**	**128,493**	**30,652**	**0.239**

PG&E's 2007 peak demand occurred at 6:00 P.M. on August 29. Gas turbines that were operating under the SGIP at that time reflected a peak hour average capacity factor of over 0.65. Fuel cells, microturbines, and IC engines had peak hour capacity factors somewhat lower. Fuel cells had a peak hour average capacity factor just above 0.5. Microturbines and IC engines both had peak hour capacity factors well under 0.5. PV systems, due to the limited amount of insolation available at 6.00 P.M., had a peak hour average capacity factor under 0.1. The combined SGIP contribution to peak hour generation was an overall peak hour capacity factor of 0.24. Note also that the electricity contribution from the combined SGIP facilities operating in PG&E's service territory during the 2007 summer peak provided 0.15 percent of the required demand.

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

Elec PA	Peak (MW)	Date	Hour (PDT)
SCE	**23,516**	**31-Aug-07**	**3 PM**

Technology		On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC		4	1,450	799	0.551
GT		1	4,500	1,948	0.433
IC ENGINES		93	63,483	23,576	0.371
MT		47	8,162	3,136	0.384
PV		199	25,623	11,491	0.448
WD		2	1,649	216	0.131
	TOTAL	**346**	**104,867**	**41,165**	**0.393**

SCE's 2007 peak demand occurred at 3:00 P.M. on August 31, essentially the same date and time as the CAISO peak. The single gas turbine operating under the SGIP showed a peak hour capacity factor less than that of the average shown for gas turbines operating in PG&E's territory. The SGIP fuel cells operating in SCE's service territory demonstrated a slightly higher peak hour average capacity factor than those in PG&E's territory. This occurred despite there being one fuel cell in the SCE territory powered with biogas which generally yields an overall lower capacity factor. IC engines operating under the SGIP for SCE showed a higher peak hour average capacity factor than they did for PG&E. Microturbines for SCE, on the other hand, showed a lower peak hour average capacity factor. The SCE peak hour occurred in the afternoon three hours earlier than PG&E's peak. This contributed to SGIP PV facilities in SCE having a peak hour average capacity about five times greater than that for PV in PG&E. The wind peak hour average capacity factor for SCE was close to 0.13, but should be recognized as representing only two wind systems. The electricity contribution from the combined SGIP facilities operating in SCE's service territory during the 2007 summer peak provided 0.17 percent of the required demand.

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

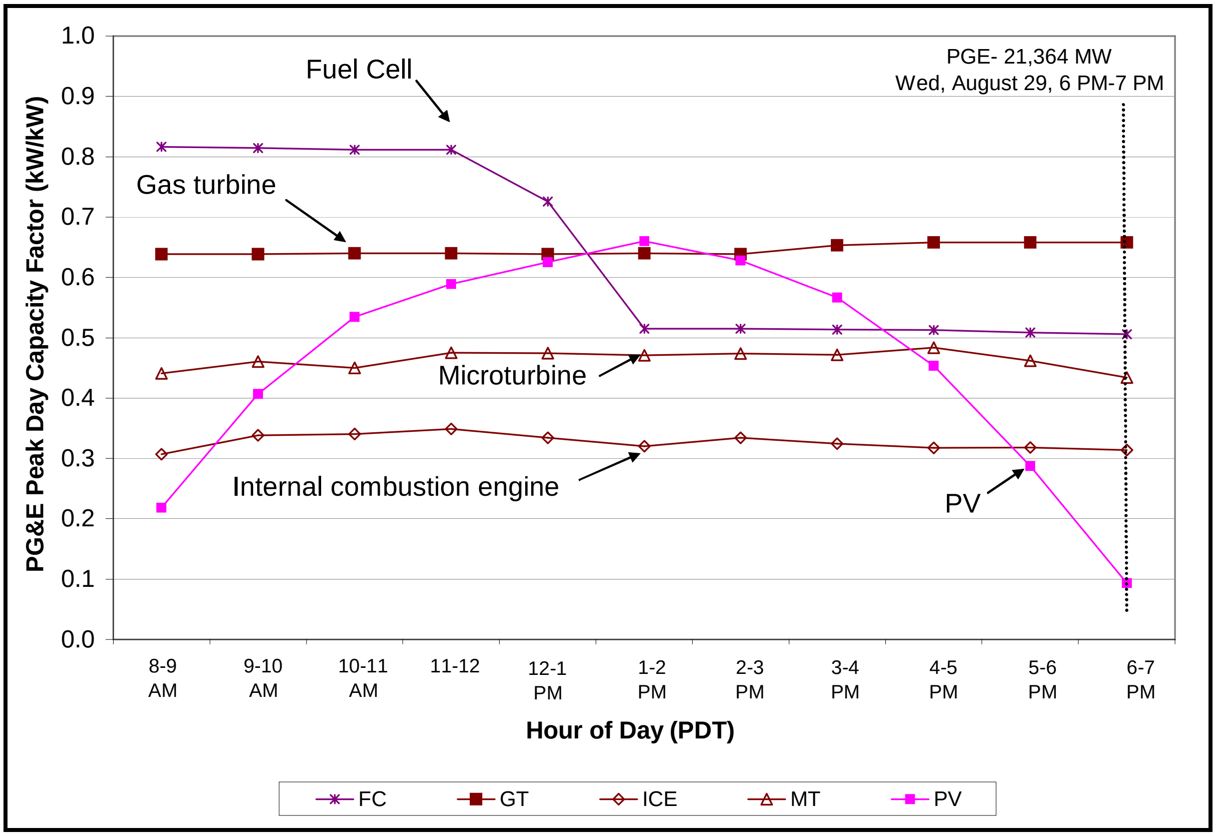
Elec PA	Peak (MW)	Date	Hour (PDT)
SDGE	**4,636**	**3-Sep-07**	**3 PM**

Technology		On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC		3	2,000	834	0.417
GT		1	4,527	3,612	0.798
IC ENGINES		19	11,995	4,960	0.413
MT		16	1,692	314	0.185
PV		104	13,998	5,746	0.411
WD		0	0	0	
	TOTAL	**143**	**34,212**	**15,465**	**0.452**

SDG&E's 2007 peak hour occurred at 3:00 P.M. on Monday, September 3. Recall that the 2006 peak hour had occurred on a Saturday at 2:00 P.M. which was thought to have contributed to low peak hour average capacity factors for the natural gas-fired cogeneration facilities. The peak hour average capacity factor for fuel cells operating in SDG&E territory during its peak was just under 0.42, substantially lower than that observed for both PG&E and SCE. IC engines, however, showed significantly higher peak hour average capacity factors than their counterparts in PG&E and SCE service territories, exceeding 0.4. SDG&E's PV peak hour average capacity factor was just above 0.4, somewhat lower than that observed for SCE during the same hour of day. The electricity contribution from the combined SGIP facilities operating in SDG&E's service territory during the 2007 summer peak provided 0.35 percent of the required demand. This was a large improvement over the 0.20 percent figure for 2006 on a Saturday one hour earlier in the day.

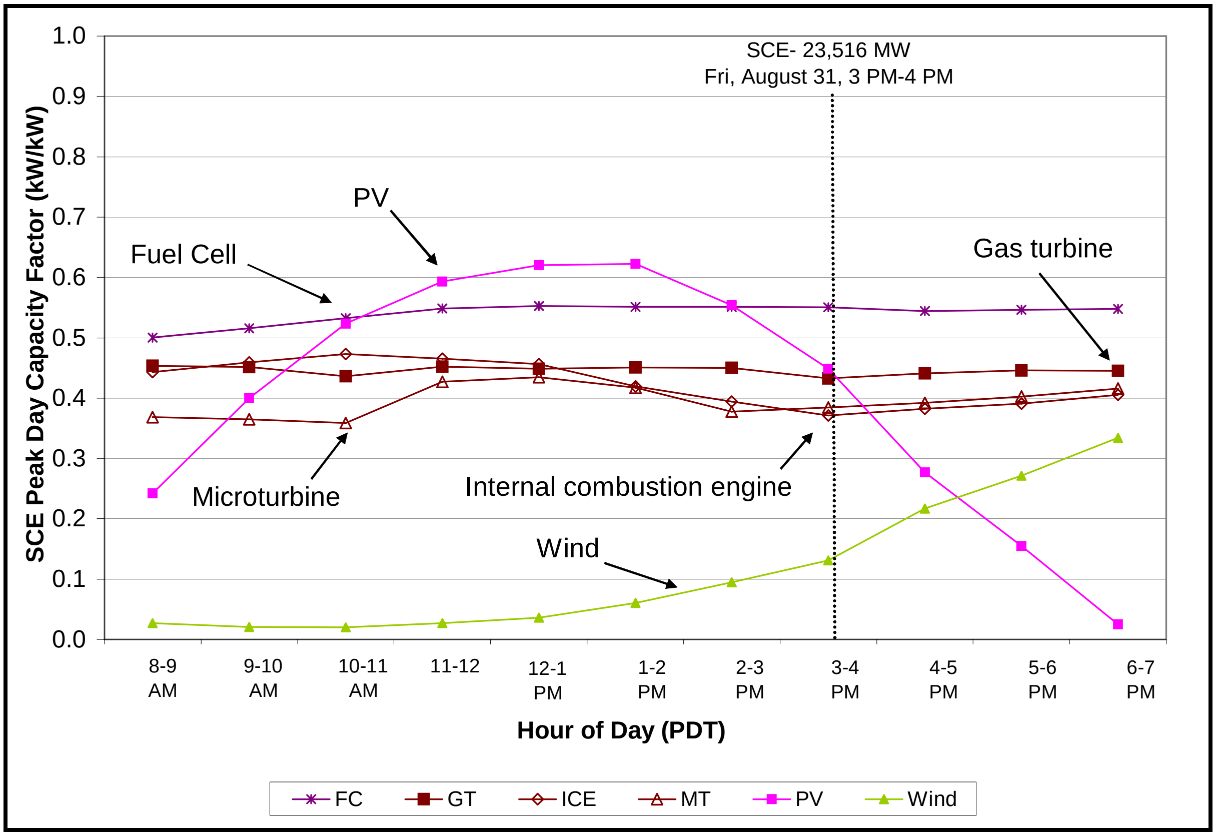
Figure 5-6 through Figure 5-8 plot profiles of hourly weighted average capacity factors by technology for the SGIP systems directly feeding the utilities on the dates of their respective peak demand. The plots also indicate the date, hour, and value of the peak load for the electric utility. Note that 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 utilities 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 5-6: Electric Utility Peak Day Capacity Factors by Technology – PG&E



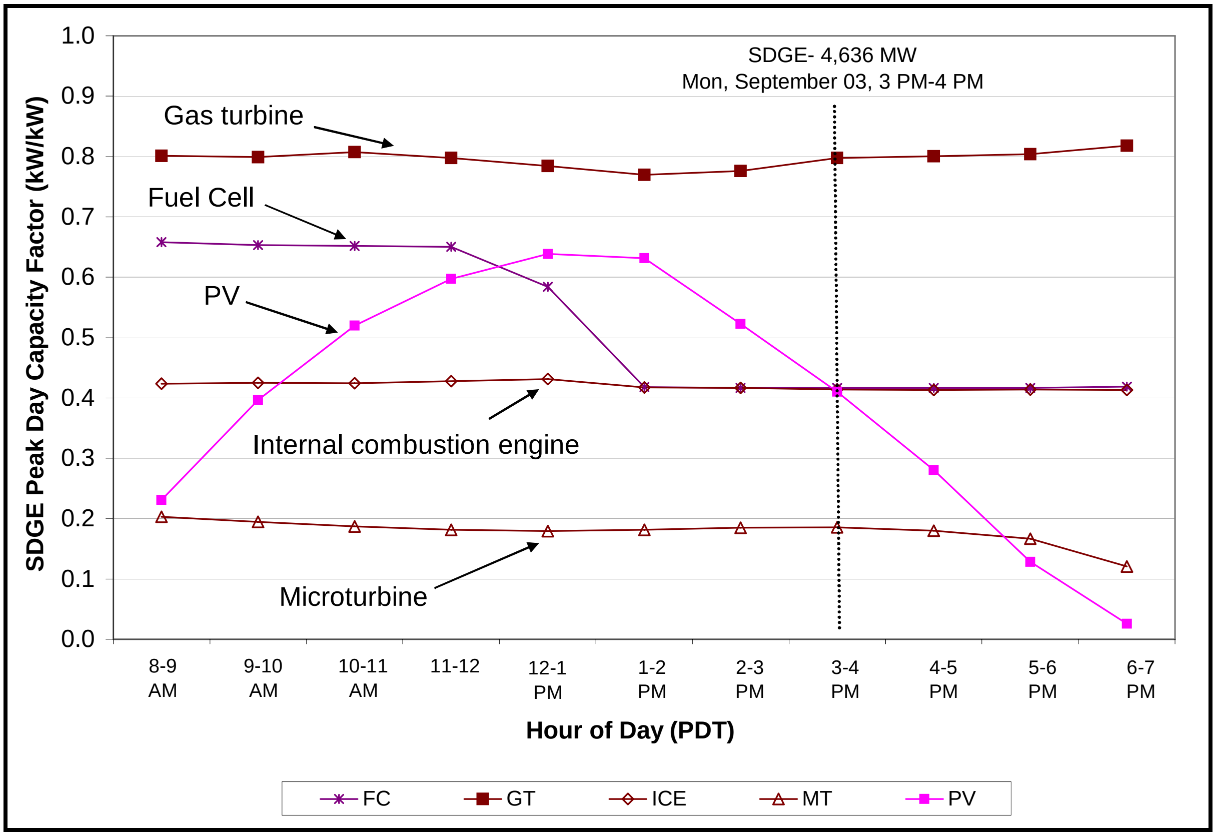
Except for fuel cells, the hour-by-hour peak day capacity factor plot for PG&E reflects the almost flat generation profiles exhibited on average from natural gas-fired cogeneration facilities operating under the SGIP. For PG&E fuel cells, the capacity factor declined before noon as a result of one of the five fuel cells for which metered data were available happening to go offline at that time. The same fuel cell, however, was operating near full capacity two days later on the day of the CAISO peak hour. Meanwhile gas turbines had a fairly constant but somewhat low average capacity factor throughout the day, never exceeding 0.7. Microturbines and IC engines likewise had fairly constant but low average capacity factors. Microturbines reached 0.48 while IC engines never surpassed 0.35. 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 5-7: Electric Utility Peak Day Capacity Factors by Technology – SCE



For most of the natural gas-fired cogeneration facilities, the hour-by-hour peak day capacity factor plot for SCE shows the almost flat profiles similar to those seen for PG&E. For SCE's peak day, however, all of those technologies but IC engines showed lower capacity factors. In particular, SCE fuel cells operated over the day near that lower level exhibited by PG&E's fuel cells during the afternoon if its peak day. Likewise gas turbines did not exceed capacity factors of 0.5. The wind capacity factor picks up from essentially zero at 11:00 A.M. to nearly 0.15 by the peak hour, 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 5-8: Electric Utility Peak Day Capacity Factors by Technology – SDG&E/CCSE

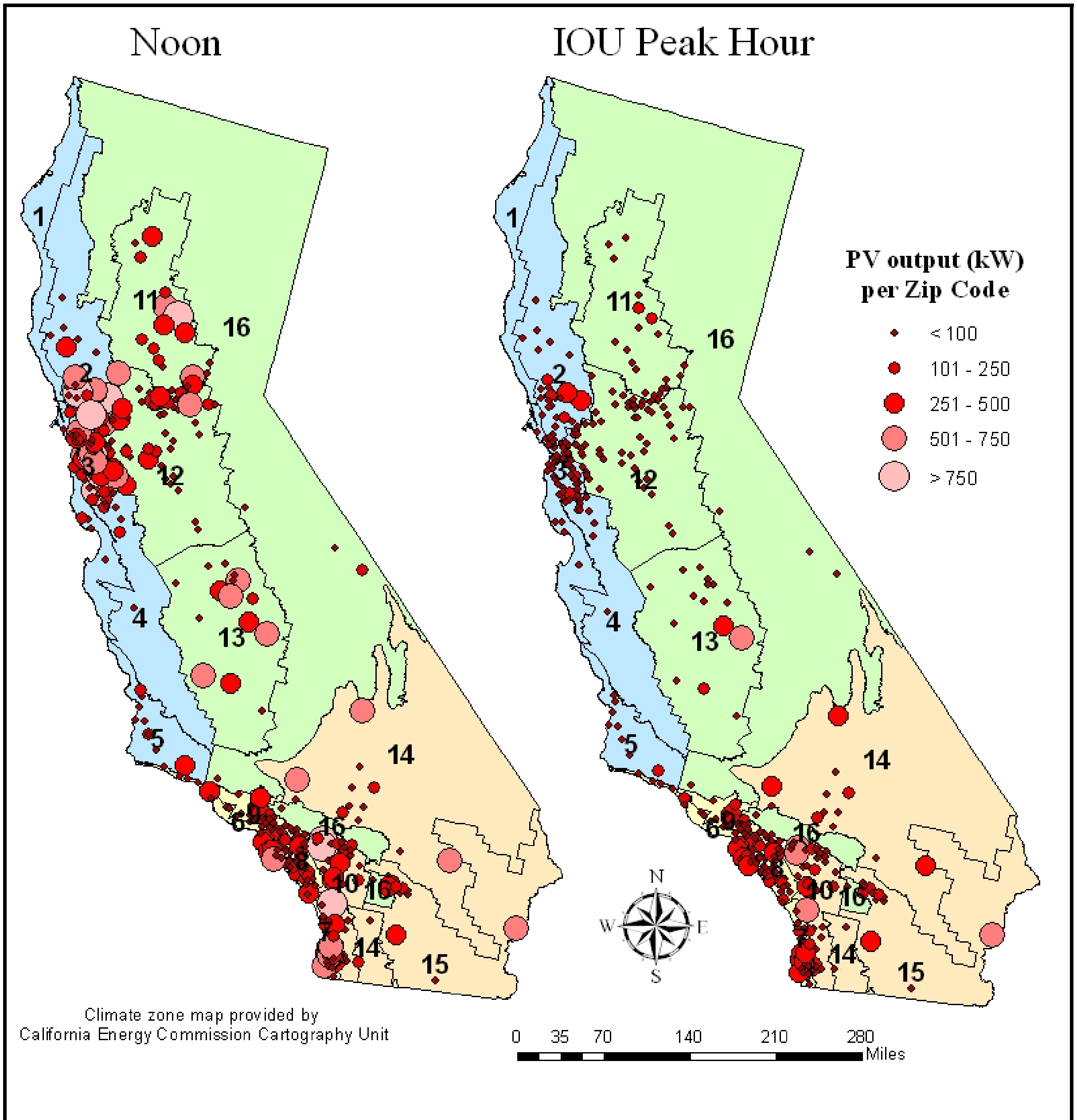


SDG&E shows peak day profiles similar to PG&E where, except for fuel cells, the hour-by-hour peak day capacity factor plot reflects the almost flat generation profiles exhibited on average from natural gas-fired cogeneration facilities operating under the SGIP. Like PG&E, the decline in the fuel cell average capacity factor was a result of one of the three SDG&E fuel cells going offline just before noon on the peak day. Gas turbine average capacity factors stayed close to 0.8 throughout the day. The microturbine average capacity factor never exceeded 0.2, while the IC engine average capacity factor stayed above 0.4 throughout the day.

The influence of timing of the CAISO peak hour on the ability of intermittent resources to contribute to peak electricity delivery was discussed earlier. The importance of peak hour delivery at the IOU-level is readily seen by examining the impact of peak hour on PV system contribution. More than half the growth in capacity in the SGIP in PY07 came from PV systems. The capacity factor for PV is strongly influenced by the amount of available solar resource. PV output increases over the course of the morning, peaking 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 5-9 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 2007 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 2007 system peak at 3 pm.

Figure 5-9: Impact of Peak Demand Time of Day on PV Capacity*



* Note: PG&E's peak was at 6.00 P.M. on August 29, 2007. SCE's peak was at 3.00 P.M. on August 31, 2007. SDG&E's peak occurred at 3.00 P.M. on September 3, 2007.

5.3 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 effectively and realize high overall system and electricity efficiencies, Public Utility Code (PUC) 216.6[8] requires that participating non-renewable-fueled fuel cells and engines/turbines meet minimum levels of thermal energy utilization and overall system efficiency.[9]

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. A summary of these requirements is presented in Table 5-10.

Table 5-10: Required Minimum PUC 216.6 Levels of 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 percent credit for useful heat, LHV)	42.5

SGIP facilities use a variety of means to recover heat from cogeneration systems, 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 5-11, which includes all projects subject to heat recovery requirements and on-line through December 2007.

Table 5-11: End-Uses Served by Recovered Useful Thermal Energy (Total n and kW as of 12/31/2007)

End Use Application	On-Line Systems (n)	On-Line Capacity (kW)
Heating Only	213	87,537
Heating & Cooling	68	46,311
Cooling Only	35	25,421
To Be Determined	19	8,603
Total	**335**	**167,873**

[8] PUC 216.6 has replaced PUC 218.5; however the requirements remain the same.

[9] Several renewable-fueled projects entering the program during its first years were also subject to heat recovery requirements are included in the analysis covered in this section.

PY07 PUC 216.6 Compliance

Available metered data collected from on-line cogeneration projects were used to estimate performance of unmetered projects. Resulting performance data for both metered and unmetered projects were used to calculate PUC 216.6 performance metrics at the technology level. Results summarized in Table 5-12 represent capacity weighted averages for each technology type. These results can be thought of as representing the overall performance of a single, very large system if all of the systems were combined. This basis is intended to yield results that can be compared directly with other pertinent reference points (e.g., performance of large, centralized power plants).

Table 5-12: PUC 216.6 Cogeneration System Performance by Technology

Technology	Number of projects (n)	216.6 (a) Proportion as Useful Heat (%)*	216.6 (b) Avg. Efficiency Level Achieved (%, LHV)*
FC	14	37†	54
GT	5	62†	53†
IC Engines	206	36	38
MT	110	50†	30

* ª indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates accuracy is at least 90/10.

The cogeneration system performance results in Table 5-12 are based on electric output, fuel input, and heat recovery data. Availability of these data varied from site to site, and from month to month for some sites. The impact of data availability on accuracy of impacts estimates was examined in the uncertainty analysis described in Appendix C.

Within Table 5-12, the PUC 216.6(a) results are expressed as the proportion of the total output energy from the facility recovered as useful heat. For example, fuel cells in the SGIP recovered on average 37 percent of their total output energy as useful heat, whereas IC engines recovered on average 36 percent of their total output energy as useful heat. All of the cogeneration technologies in the SGIP achieved and exceeded the PUC 216.6(a) requirement of providing at least five percent of the output energy as useful heat.

The PUC 216.6(b) results in Table 5-12 are expressed as the average overall PUC 216.6(b) system efficiency achieved by the technology.[10] For example, fuel cells on average achieved an overall PUC 216.6(b) system efficiency of 54 percent, whereas IC engines on average

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[10] Please note that system efficiency typically includes the sum of all useful work (electricity plus thermal energy) divided by the amount of energy going into the system; whereas PUC 216.6(b) uses only one-half the recovered thermal energy

achieved an overall system efficiency of 38 percent. The fuel cell and gas turbine 216.6(b) results exceeded the 42.5 percent threshold by a substantial margin. Factors influencing this outcome include the high electric conversion efficiency of fuel cells, and the high degree of heat recovery exhibited by this group of gas turbine systems during 2007. The IC engine and microturbine 216.6(b) results from Table 5-12 both fall short of the 42.5 percent threshold. The relative magnitude of the shortfall is due in part to a difference in electrical conversion efficiency, which is higher for IC engines than for microturbines.

The shortfall of SGIP microturbine and IC engine technologies in meeting the PUC 216.6(b) requirements is due in part to lower than anticipated electricity generation efficiencies. In the 2006 Impact Evaluation Report, we noted that electrical conversion efficiencies of IC engines averaged 29 percent while microturbines averaged 19 percent; both well below the average electrical conversion efficiencies seen for gas turbines and fuel cells in the SGIP. [11] Another reason IC engines and microturbines failed to meet PUC 216.6(b) requirement is due to the lack of a significant coincident thermal load. In other words, many facilities do not have a need for the waste heat provided by the generator. Because PUC 216.6(b) requires that half of the energy efficiency contribution comes from recovered waste heat, lack of thermal load impacts the overall efficiency.

In addition, good match between electrical and thermal loads can play a significant role in the contribution of DG cogeneration facilities to help offset peak demand and reduce GHG emissions during peak.[12] This is particularly true for cogeneration systems wherein recovered waste heat is used to drive absorption chillers that offset air conditioning loads. The lack of a good match between thermal and electrical loads for SGIP cogeneration projects was explored in a special report conducted by Itron for the CPUC in later 2006.[13] Figure 5-10 shows hourly heat recovery rates during the 2007 CAISO system peak day. As shown, average thermal energy recovery by cogeneration facilities within the SGIP does not appear to have been influenced by peak hour electrical demands. This should be an important consideration for expansion of cogeneration facilities going forward in California's electricity market.

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. Figure 5-10 provides normalized heat recovery results by technology during the CAISO peak day. Results summarized in Figure 5-10 represent capacity weighted averages for each technology type.

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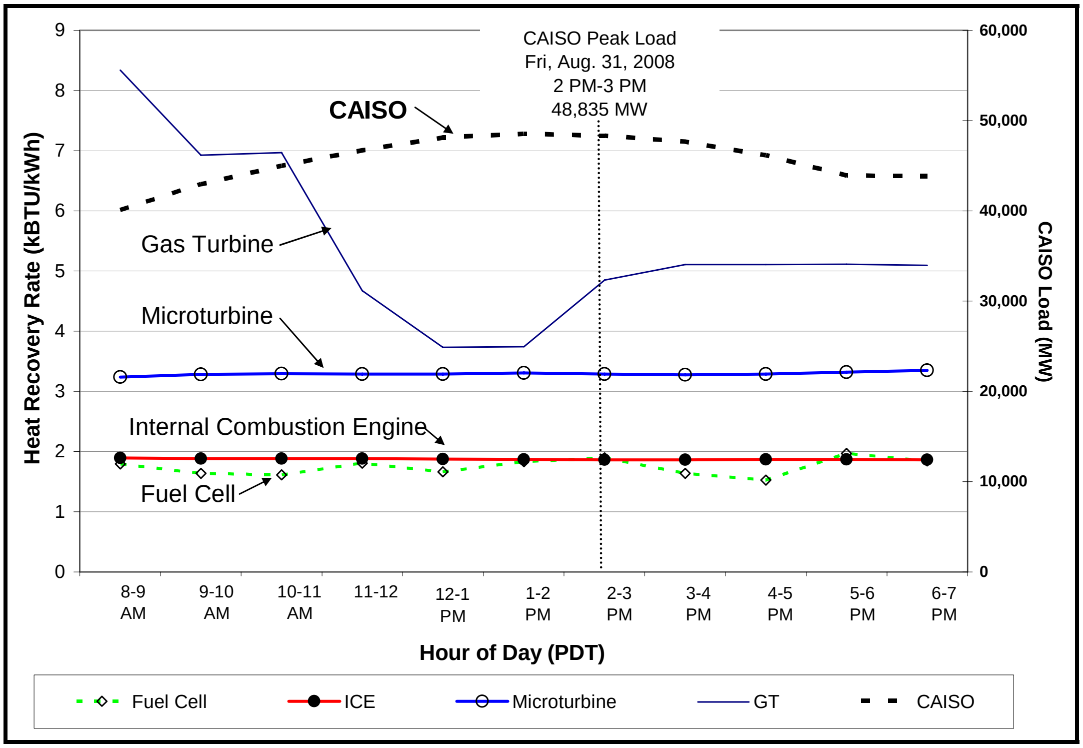
[11] *California Self-Generation Incentive Program: Sixth Year Impact Evaluation Final Report.* Submitted to Pacific Gas & Electric. Prepared by Itron, Inc., August 30, 2007.

[12] Peak electricity demand in California is met in part using older peaking units that have higher CO_2 emissions than newer cogeneration technologies

[13] Itron for the CPUC, "In-Depth Analysis of Useful Waste Heat Recovery and Performance of Level 3/3N Systems," February 2007.

Figure 5-10: Heat Recovery Rate during CAISO Peak Day



Observations of interest from the above figure include:

- Microturbines recovered more heat than fuel cells and IC engines. This is explained in part by the relatively lower electrical efficiency of microturbines. Lower electrical efficiency leaves more potential heat available for recovery.[14]
- Gas turbines are the only technology type exhibiting substantial variability throughout the day. This variability is explained in part by the fact that metered HEAT data were available for only one of the five on-line gas turbine systems on this day.

AB 1685 (60 percent) Efficiency Status

Assembly Bill 1685 (Leno, October 12, 2003)[15] required that all SGIP combustion-based technologies operating in a combined heat and power application achieve a 60 percent system efficiency on a higher heating basis.[16] System efficiencies were calculated for each non-renewable-fueled cogeneration technology on-line in 2007.

[14] Itron for the CPUC, "In-Depth Analysis of Useful Waste Heat Recovery and Performance of Level 3/3N Systems," February 2007. http://www.sdenergy.org/uploads/Selfgen_ThermalAnalysisReport.pdf

[15] AB1685 (Leno, October 12, 2003) http://www.leginfo.ca.gov/pub/03-04/bill/asm/ab_1651-1700/ab_1685_bill_20031012_chaptered.html

[16] It should be noted that this requirement is different from the PUC 216.6(b) efficiency requirement, which includes only one-half of the recovered thermal energy in estimating overall system efficiency.

Table 5-13 provides technology-specific summary statistics for overall system efficiency.

Table 5-13: Cogeneration System Overall System Efficiency by Technology

Technology	Number of projects (n)	Overall System Efficiency (%, HHV)*
FC	14	60
GT	5	69†
IC ENGINES	206	42
MT	110	36†

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

California Air Resources Board (CARB) NOx Compliance

Beginning in 2005, in addition to meeting the waste heat utilization requirement, non-renewable-fueled engine/turbine projects submitting applications to the SGIP were required to meet the 2005 CARB NO_x emission standard of 0.14 pounds of NO_x emitted per Megawatt-hour of generated electricity (lbs/MWh). This standard could be met by using a fossil fuel combustion emission credit for waste heat utilization so long as the system achieved the 60 percent minimum efficiency standard. The following formula was 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 was 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 was 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 represents a NO_x emission rate (lbs per MWh) which utilizes the thermal credit. If this rate was less than 0.14 lbs per MWh then the system qualified.

Effective January 1, 2007, cogeneration facilities receiving incentives under the SGIP were required to meet a CARB NO_x emission limit of 0.07 lbs/MWh. However, there were no SGIP cogeneration facilities that applied by January 1, 2007 and were on-line by December 31, 2007. As of December 31, 2007, 29 non-renewable-fueled engines/turbines had come online under this new program requirement.[17] Of the 29 systems, seven were microturbines, three were gas turbines, and 19 were internal combustion engines. With the addition of the NO_x requirement it appears that fewer IC engine projects are being completed due to the additional cost of installing NO_x controls. Conversely, more microturbine projects are being completed because microturbines have low NO_x emissions without use of additional NO_x controls. All 29 systems had gone through NO_x emission tests and theoretically would meet the CARB NO_x requirement. However it cannot be determined if these systems would actually meet the standard under normal operating conditions because HEAT data were not available.

5.4 Greenhouse Gas Emission Reductions

Greenhouse gas (GHG) emission reductions from SGIP facilities were investigated for the first time in the 2005 Impact Evaluation Report and subsequently reported in the 2006 Impact Evaluation Report.[18] Due to the continued interest and concern over the release of energy-related GHG emissions, net GHG emissions for SGIP facilities during PY07 were examined.

The approach used for calculating GHG reductions for PY07 remains essentially the same as PY06 with two differences. First, we use technology-specific waste heat recovery rates based upon actual and estimated waste heat recovery data in this report whereas we used a

[17] These 29 cogeneration facilities had applied in earlier program years and as such were not subject to the CARB 2007 requirements but to the earlier CARB requirements.

[18] Itron, Inc. CPUC Self-Generation Incentive Program Sixth Year Impact Evaluation: Final Report. Submitted to Pacific Gas and Electric Company and the Self-Generation Incentive Program Working Group. August 30, 2007.

single waste heat recovery rate in the 2006 estimates. Second, we have changed our assumptions regarding flaring of biogas under baseline conditions for renewable fuel use facilities. Net GHG emission impacts are presented by technology and fuel group (e.g., renewable-fueled microturbines, non-renewable-fueled gas turbines, and renewable-fueled fuel cells). This allows the examination of possible relationships between net changes in CO_2- and CH_4-specific GHG reductions with cogeneration technology and fuel type. Note that as in the 2006 Impact Evaluation Report, the focus on GHG emission reduction in the impact 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.

GHG Analysis Approach

As in 2006, the net change in GHG emissions due to the operation of SGIP systems on-line during PY07 was based on metered electricity data. GHG emission reduction estimates were derived from four 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 differences in CO2 emissions resulting from displacement of natural gas that would have been combusted at the project site to provide process heating but was instead supplied via waste heat recovered from the customer SGIP cogeneration system;
3. 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
4. Methane captured and used by biogas-fired SGIP facilities.

As mentioned above, the approach to estimating GHG emissions in this report differs from the Sixth-Year Impact Evaluation Report in two critical ways. First, technology-specific waste heat recovery rates based upon actual and estimated SGIP data in this report were used, whereas a single waste heat recovery rate was used in the 2006 estimates. Second, assumptions regarding flaring of biogas under baseline conditions for renewable fuel use facilities have changed. In 2006, it was assumed that biogas from landfills, wastewater treatment facilities and dairy digesters less than 400 kW in size would have been vented directly to the atmosphere under baseline conditions.[19] Due to changes in regulations,

[19] In this situation, the baseline condition refers to the normal operation of the facility if the SGIP technology had not been used at the site. For example, dairies typically collect and treat dairy manure in open lagoons. Methane gas is created naturally due to decomposition of the organic material in the manure and is released to the atmosphere. As most dairies do not capture or flare the methane, the baseline condition is venting of methane to the atmosphere.

baseline conditions in this report have been changed. All methane generated from landfill gas recovery operations is assumed to be flared as opposed to vented directly to the atmosphere. Similarly, it is assumed that methane from wastewater treatment facilities is flared unless the amount of potential methane generated from the facility is smaller than 150 kW in equivalent size, in which case it was assumed to be vented.

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 was 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 were based on the amount of CO_2 that would have been generated by the mix of utility electricity generation sources. Table 5-14 shows the reduction of CO_2-specific GHG emissions for PV and wind turbine projects. PV projects within the SGIP have greater GHG reductions relative to SGIP wind turbines (96,621 tons compared to just over 1,400 tons), because the SGIP PV projects generated a much larger quantity of energy in comparison to the wind turbine projects (161,770 MWh versus 2,426 MWh).

Table 5-14: Reduction of CO_2 Emissions from PV and Wind Projects in 2007 (Tons of CO_2)

Technology	Tons of CO_2 Emissions	Annual Energy Impact (MWh)	CO_2 Factor (Tons/MWh)
Photovoltaics	-96,621	161,770	-0.60
Wind Turbines	-1,454	2,426	-0.60
Total	**-98,075**	**164,196**	**-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 cogeneration 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 5-15 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.

In the table below, the cogeneration emissions released represent the amount of CO_2 each group of facilities would release if there was no indirect displacement either through boilers or absorption chillers. The net cogeneration emissions released represents the amount of CO_2 each group of facilities does release into the atmosphere; however, these facilities also displace generation from the overall grid. The amount emitted by each group is compared to the direct displacement. The difference of the two values represents the net CO_2 emissions attributable to each group.

For example, the generation from internal combustion engines displaces 177,322 tons of CO_2, which is represented as a negative value as it decreases that amount of CO_2 emissions. Internal combustion engines also release 176,093 tons of CO_2 when they generate electricity. The net effect of internal combustion engines is -1,229 tons of CO_2, reducing GHG emissions. If this group of internal combustion engines did not generate electricity in 2007, the amount of GHG emissions would have been higher by 1,229 tons.

The net effect of all non-renewable cogeneration technology types was an increase in CO_2 emissions, as shown by the total net 15,394 tons of CO_2.

Table 5-15: Reduction of CO_2 Emissions from Non-renewable Cogeneration Projects in 2007 Categorized by Direct/Indirect Displacement (Tons of CO_2)

Technology	Cogeneration Emissions Released	Indirect Displacement through Waste Heat Recovery	Indirect Displacement from Absorption Chillers	Net Cogeneration Emissions Released	Direct Displacement from Grid (Reduces Emissions)	Net CO_2 Emission
Fuel Cells	22,268	-6,255	-83	15,930	-27,029	-11,098
Microturbines	55,873	-7,000	-913	47,960	-34,005	13,956
IC Engines	206,856	-25,860	-4,903	176,093	-177,322	-1,229
Gas Turbines	74,180	-14,051	-1,281	58,847	-45,082	13,765
Total	**359,177**	**-53,166**	**-7,180**	**298,830**	**-283,438**	**15,394**

It is beneficial to have a net CO_2 reduction factor when assessing the overall GHG implications associated with SGIP DG facilities and making comparisons between DG technologies. Table 5-16 is a listing of net CO_2 factors (in tons of CO_2 reduced per MWh of electricity generated) for non-renewable cogeneration technologies. Positive 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 0.23 tons per MWh for microturbines to a low of -0.22 tons per MWh for fuel cells. 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 5-16: Reduction of CO_2 Emissions from Non-renewable Cogeneration Projects in 2007 (Tons of CO_2)

Technology	Tons of CO_2 Emissions	Annual Energy Impact (MWh)	CO_2 Factor (Tons/MWh)
Fuel Cells	-11,098	49,599	-0.22
Microturbines	13,956	61,910	0.23
IC Engines	-1,229	316,748	0.00
Gas Turbines	13,765	82,194	0.17
Total	**15,394**	**510,451**	**0.03**

<u>GHG Reductions from Renewable (Biogas) Projects</u>

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 others are cogeneration facilities that use waste heat recovery to produce process heating or cooling. Consequently, biogas-powered cogeneration facilities can directly 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 5-17 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. The net CO_2 reduction factors for renewable fuel technologies are presented in Table 5-18. These results show that renewable IC engines and fuel cells have similar CO_2 reduction factors while renewable microturbines lead to increases in carbon dioxide in a similar manner to its non-renewable fuel counterpart.

Table 5-17: Reduction of CO_2 Emissions from Renewable Cogeneration Projects in 2007 Categorized by Direct and Indirect Displacement (Tons of CO_2)

Technology	Cogeneration Emissions Released	Indirect Displacement through Waste Heat Recovery	Indirect Displacement from Absorption Chillers	Net Cogeneration Emissions Released	Direct Displacement from Grid (Reduces Emissions)	Net CO_2 Emission
Fuel Cells	1,140	-334	0	806	-1,408	-602
Microturbines	7,010	-512	-228	6,270	-4,210	2,060
IC Engines	23,709	-4,329	-138	19,242	-19,636	-395
Total	**31,859**	**-5,175**	**-366**	**26,318**	**-25,254**	**1,063**

Table 5-18: Reduction of CO_2 Emissions from Renewable Cogeneration Projects in 2007 (Tons of CO_2)

Technology	Tons of CO_2 Emissions	Annual Energy Impact (MWh)	CO_2 Factor (Tons/MWh)
Fuel Cells	-602	2,540	-0.24
Microturbines	2,060	7,767	0.27
IC Engines	-395	36,304	-0.01
Total	**1,062**	**46,611**	**0.03**

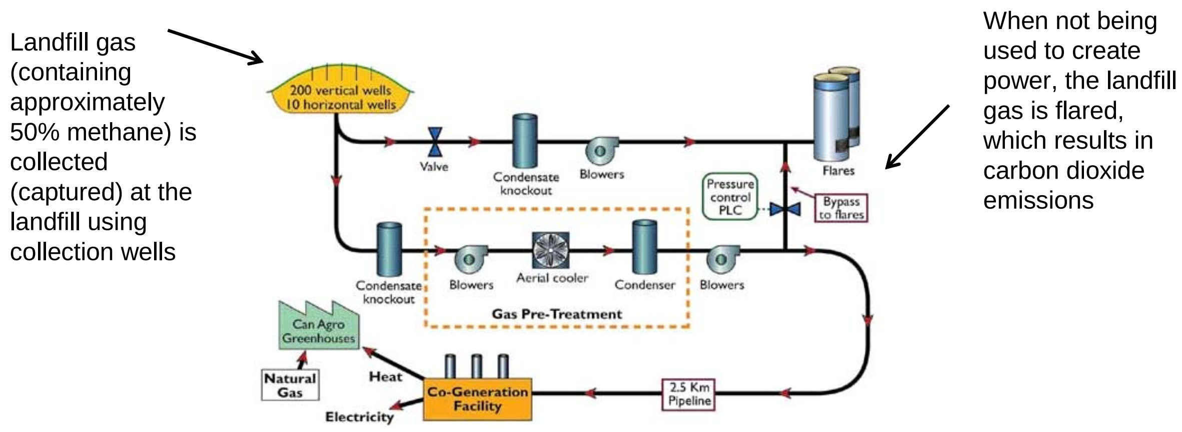
As indicated earlier, biogas-powered SGIP facilities not only realize GHG reductions due to CO_2 reductions, but also due to captured methane. In particular, this is methane that would have otherwise been emitted to the atmosphere if vented. When reporting GHG emission reductions from different types of greenhouse gases, the convention is to report the GHG reductions in terms of tons of CO_2 equivalent. Methane has a GHG equivalence 21 times that of CO_2. Consequently, 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 39 facilities that relied upon renewable biogas fuels during 2007. Of the 39 facilities, 25 were digesters and 14 were landfill gas. In the SGIP Sixth-Year Impact Evaluation Report[20], the assumption was made that small facilities of all types vented their methane. For this report, all landfill gas facilities were assumed to have captured and flared the methane, all dairies were assumed to have vented the methane and wastewater treatment plants were assumed to have vented digester gas if

[20] *California Self-Generation Incentive Program: Sixth Year Impact Evaluation Final Report.* Submitted to Pacific Gas & Electric. Prepared by Itron, Inc., August 30, 2007, Appendix C, pages C1-C3 http://www.energycenter.org/uploads/SGIP_M&E_Sixth_Year_Impact_Evaluation_Final_Report_August_30_2007.pdf

under 150 kW of rebated capacity and flared otherwise. Figure 5-11 provides a pictorial depiction of the capturing and flaring of methane.

Figure 5-11 Landfill Gas with Methane Capture Diagram



Methane is naturally created at landfill gas facilities, wastewater treatment plants and dairies. If not captured, the methane escapes into the atmosphere contributing to greenhouse gas (GHG) emissions. Capturing the methane provides an opportunity to use it as fuel. When the methane is not used to create energy, it is burned in a flare. Because the resulting CO_2 has much less GHG potency than methane, the use of the flare reduces the CO_2 equivalent emissions. Distributed generation, such as SGIP projects, deliver additional economic and environmental benefits by reducing the need to generate electricity at central station power plants.

The total electricity generated from these sites was multiplied by technology-specific emission factors for CH_4 to calculate the total CH_4 emissions avoided by relying upon methane to generate power from these SGIP facilities.[21] Table 5-19 presents the tons of CH_4 emissions avoided and tons of CO_2 equivalent[22] by renewable fuel technology type. In the SGIP Sixth-Year Impact Evaluation Report, the largest reduction of methane-specific GHG emissions came from renewable-fueled microturbines, which were responsible for almost 75 percent of the total methane emission reduction[23]. This year, due to the above-described

[21] See Appendix B for the derivation of renewable fuel technology-specific CH_4 emission factors. They are equal to 246 grams per kWh for IC engines, 313 grams per kWh for microturbines, and 143 grams per kWh for fuel cells.

[22] 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

[23] *California Self-Generation Incentive Program: Sixth Year Impact Evaluation Final Report.* Submitted to Pacific Gas & Electric. Prepared by Itron, Inc., August 30, 2007, page 1-22

changes in the assumptions regarding the baseline, internal combustion engines accounted for almost 80 percent of the total methane emission reduction. This difference stems from the number of facilities using each type of technology which were included in the baseline. Of the cogeneration systems that rely upon renewable fuel sources that were assumed to have vented methane prior to participation in the SGIP, seven were microturbines and five were internal combustion engine facilities. There were no such fuel cell facilities during PY07.

Table 5-19: Reduction of CH_4 Emissions from Renewable Cogeneration Projects in 2007 (in Tons of CH_4 and Tons of CO_2 equivalent)

Technology	Tons of CH_4 Emissions	Tons of CO_2 eq. Emissions
Fuel Cells	NA[1]	NA[1]
Internal Combustion Engines	-1,564	-32,851
Microturbines	-330[2]	-6,941[2]
Total	**-1,894**	**-39,792**

[1] Fuel cells did not contribute to the reductions of CH_4 emissions from renewable cogeneration projects in 2007 due to the changes in the assumptions regarding the baseline. The two SGIP fuel cell projects were both wastewater treatment plants with a rebated capacity greater than 150 kW.

[2] The decrease in tons of methane reduced for microturbines is also due to the change in assumptions regarding the baseline. In particular, a number of microturbine projects used landfill gas and digester gas from wastewater treatment facilities. In the 2006 Impact Evaluation Report, methane from these applications was assumed to be vented to the atmosphere. In this report, the methane was assumed to be flared. The result was a decrease in methane reduction from these facilities.

Total Net Change in GHG Emissions

To determine the total net GHG impact of SGIP facilities during 2007, the net GHG reductions must be reported in units of CO_2 equivalent to allow a basis of comparison. Table 5-20 shows the tons of GHG emissions reduced in tons of CO_2 equivalent, broken down by the different SGIP fuel and technology combinations. [24] The total reduction of GHG emissions measured in CO_2 equivalent units is approximately 121,410 tons with the largest portions of this reduction coming from PV projects, followed by renewable-fueled IC engines. During the 2006 program year, the total GHG emission reduction calculated for the SGIP projects was 100,630 tons of CO_2 equivalent. Most of these reductions also came from PV projects as well. The fuel/technology cogeneration group contributing the largest energy impact is non-renewable-fueled IC engines.

http://www.energycenter.org/uploads/SGIP_M&E_Sixth_Year_Impact_Evaluation_Final_Report_August_30_2007.pdf

[24] Note that the results in Table 5-25 can be developed by adding the equivalent CO_2 values in Table 5-22 to the direct CO_2 values in Table 5-17, Table 5-19, and Table 5-21 (note: due to rounding, this sum is approximately equal to the sum of total GHG emissions reduced presented in Table 5-23)..

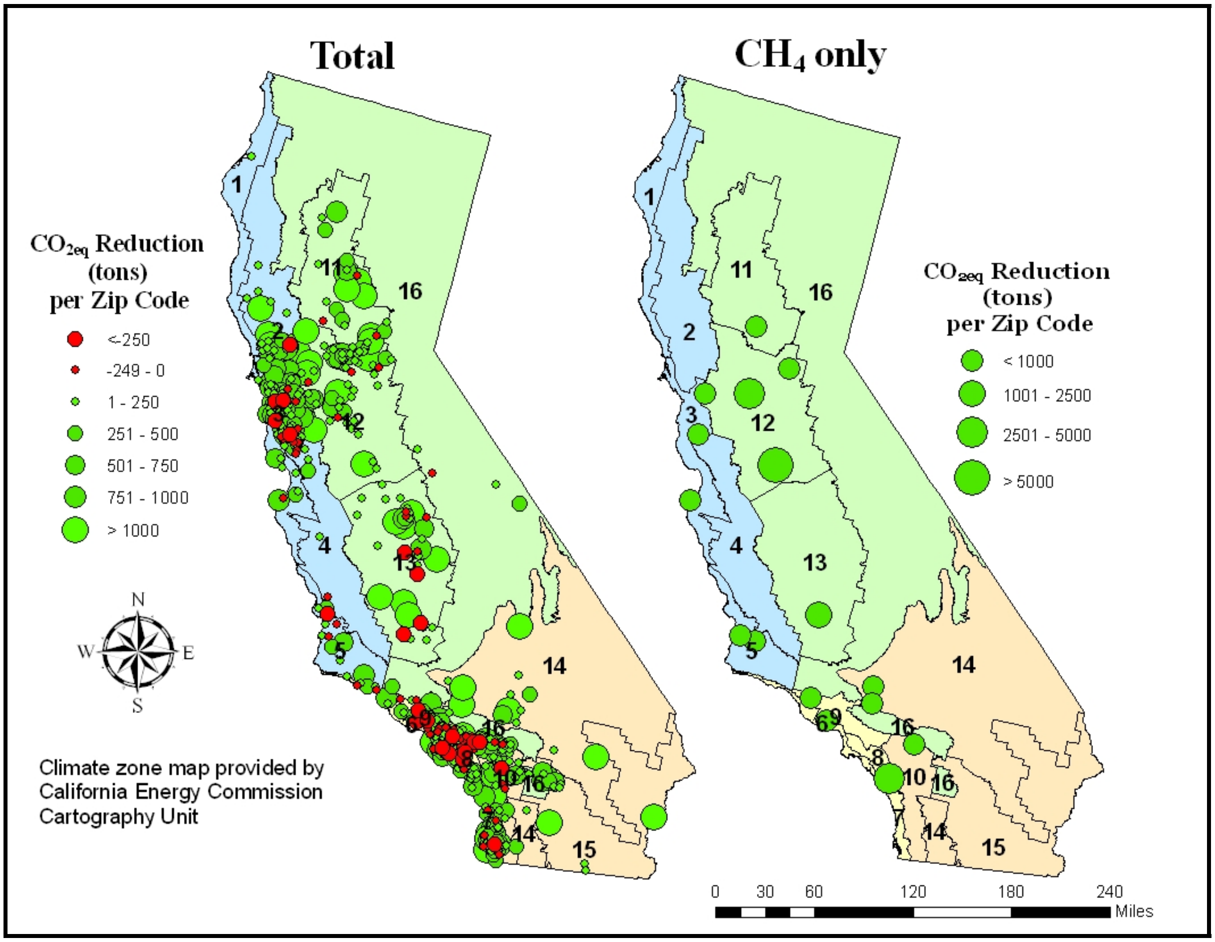
The last column in Table 5-20 presents ratios of the tons of GHG emissions reduced per MWh generated by each fuel and technology category for the 2007 program year. Renewable fuel technologies have the most negative ratios (mostly due to the potent CH_4 emission reductions), while non-renewable microturbines have the highest and are positive. The CO_2 factors range from the lowest value of -0.92 for renewable fuel IC engines to a high of 0.23 for non-renewable-fueled microturbines. It is interesting to note that the ratio of tons of CO_2 equivalent reduced per MWh is now negative for renewable-fueled microturbines, representing a net reduction in CO_2 equivalent emissions due to the methane reductions from this group of projects as shown in the table below. When only CO_2 emissions are considered, this project group emits more emissions than it reduces.

Table 5-20: Net Reduction of GHG Emissions from SGIP Systems Operating in Program Year 2007 (Tons of CO_2 eq.) by Fuel and Technology and Ratios of Tons of GHG Reductions per MWh

Technology	Tons of CO_2 eq. Emissions	Annual Energy Impact (in MWh)	CO_2 eq. Factor (Tons/MWh)
Photovoltaics	-96,621	161,770	-0.6
Wind turbines	-1,454	2,426	-0.6
Non-renewable fuel cells	-11,098	49,599	-0.22
Non-renewable MT	13,956	61,910	0.23
Non-renewable-fueled IC engines	-1,229	316,748	0.00
Non-renewable- and waste gas-fueled small gas turbines	13,765	82,194	0.17
Renewable-fueled fuel cells	-602	2,540	-0.24
Renewable-fueled MT	-4,881	7,767	-0.63
Renewable-fueled-IC engines	-33,246	36,304	-0.92
TOTAL	**-121,410**	**721,257**	**-0.17**

Due to the increasing role of GHG emission reductions, it is also important to identify the distribution of GHG reductions within the SGIP. Figure 5-12 shows the distribution of GHG emission reductions from SGIP facilities located 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. It is interesting to note that while overall GHG reductions occur across a large number of SGIP facilities, the relatively large GHG emission reductions due to methane capture occur from only a handful of projects, scattered throughout the state.

Figure 5-12: PY07 Distribution of GHG Emission Reductions Among SGIP Facilities



Net Change in GHG Emissions by Program Administrator

Table 5-21 through Table 5-24 present the reduction of CO_2 emissions in 2007 by PA and fuel/technology group. These tables also include the annual energy impact and the CO_2 factor for each group. A comparison of these tables show that the PA responsible for the largest reduction of CO_2 emissions is PG&E (-49,120 tons) followed by SCE (-18,400 tons), CCSE (-9,499 tons), and SCG (-4,604 tons). In fact, PG&E projects reduce almost three times the amount of emissions as SCE's. PG&E's projects generate the most energy impacts overall (303,601 MWh), followed by SCG (195,508 MWh), SCE (128,609 MWh), and CCSE (93,540 MWh).

Table 5-21: Technology-Specific CO2 Reductions for PG&E

Technology	Tons of CO_2 Emissions	Energy Impact in MWh	CO_2 Factor (Tons/MWh)
Photovoltaics	-54,386	92,849	-0.59
Wind turbines	-	-	-
Non-renewable fuel cells	-5,109	24,344	-0.21
Non-renewable MT	5,140	23,829	0.22
Non-renewable-fueled IC engines	238	119,088	0.00
Non-renewable- and waste gas-fueled small gas turbines	3,952	22,689	0.17
Renewable-fueled fuel cells	-	-	-
Renewable-fueled MT	1,013	3,818	0.27
Renewable-fueled IC engines	32	16,983	0.00
TOTAL	**-49,120**	**303,601**	**-0.16**

Table 5-22: Technology-Specific CO_2 Reductions for SCE

Technology	Tons of CO_2 Emissions	Energy Impact in MWh	CO_2 Factor (Tons/MWh)
Photovoltaics	-19,275	31,360	-0.62
Wind turbines	-1,454	2,426	-0.60
Non-renewable fuel cells	-328	1,369	-0.24
Non-renewable MT	3,265	13,903	0.23
Non-renewable-fueled IC engines	-473	56,921	-0.01
Non-renewable- and waste gas-fueled small gas turbines	-	-	-
Renewable-fueled fuel cells	-602	2,540	-0.24
Renewable-fueled MT	963	3,492	0.28
Renewable-fueled IC Engines	-496	16,599	-0.03
TOTAL	**-18,400**	**128,609**	**-0.14**

Table 5-23: Technology-Specific CO_2 Reductions for SCG

Technology	Tons of CO_2 Emissions	Energy Impact in MWh	CO_2 Factor (Tons/MWh)
Photovoltaics	-10,279	16,894	-0.61
Wind turbines	-	-	-
Non-renewable fuel cells	-2,640	11,244	-0.23
Non-renewable MT	4,972	21,255	0.23
Non-renewable-fueled IC engines	-687	113,516	-0.01
Non-renewable and waste gas-fueled small gas turbines	3,960	29,876	0.13
Renewable-fueled fuel cells	-	-	-
Renewable-fueled MT	-	-	-
Renewable-fueled IC Engines	70	2,722	0.03
TOTAL	**-4,604**	**195,508**	**-0.02**

Table 5-24: Technology-Specific CO_2 Reductions for CCSE

Technology	Tons of CO_2 Emissions	Energy Impact in MWh	CO_2 Factor (Tons/MWh)
Photovoltaics	-12,681	20,667	-0.61
Wind turbines	-	-	-
Non-renewable fuel cells	-3,025	12,642	-0.24
Non-renewable MT	578	2,922	0.20
Non-renewable-fueled IC engines	-307	27,223	-0.01
Non-renewable and waste gas-fueled small gas turbines	5,853	29,629	0.20
Renewable-fueled fuel cells	-	-	-
Renewable-fueled MT	83	457	0.18
Renewable-fueled IC Engines	-	-	-
TOTAL	**-9,499**	**93,540**	**-0.1**

The overall CO_2 factor is shown for each PA and is calculated by dividing the total CO_2 emissions reduced by the total annual energy impact. A comparison of these factors show that PG&E has the lowest ratio (-0.16), followed by SCE and CCSE (with ratios of -0.14 and -0.10 respectively). A more detailed examination of the CO_2 factors shows that the PA-specific ratios are lowest for PV projects and tend to be highest for renewable and non-renewable-fueled microturbines.

The next three tables, Table 5-25 through Table 5-27, 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). Again, PG&E reduces the largest quantity of emissions (1,207 tons). The renewable fuel projects under SCG and CCSE are responsible for a much smaller fraction of CH_4 reductions at just under 545 tons and 143 tons respectively. This is due to the fact that CCSE oversees only 2 microturbine projects that were included in the baseline, while PG&E oversees 5 microturbine projects and 4 internal combustion engines. SCG oversees only one internal combustion engine. SCE did not oversee any renewable fuel projects which met the new assumptions for the baseline.

Table 5-25: Technology-Specific CH_4 Reductions for PG&E (in tons of CH_4 and tons of CO_2 eq.)

Technology	Tons of CH_4 Emissions	Tons of CO_2 eq. Emissions
Fuel Cells	-	-
Microturbines	-188	-3,938
IC Engines	-1,019	-21,409
TOTAL	**-1,207**	**-25,347**

Table 5-26: Technology-Specific CH_4 Reductions for SCG (in tons of CH_4 and tons of CO_2 eq.)

Technology	Tons of CH_4 Emissions	Tons of CO_2 eq. Emissions
Fuel Cells	-	-
Microturbines	-	-
IC Engines	-545	-11,442
TOTAL	**-545**	**-11.442**

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

Technology	Tons of CH_4 Emissions	Tons of CO_2 eq. Emissions
Fuel Cells	-	-
Microturbines	-143	-3,003
IC Engines	-	-
TOTAL	**-143**	**-3,003**

The last set of tables presents the total GHG emission reduction impact by PA. The total GHG emission reduction represents the sum of methane emission reductions as converted to CO_2 equivalent and with the non-methane CO_2 reductions. Table 5-28 through Table 5-30 present the CO_2 equivalent factors by PA and technology. Note that no methane-specific GHG emission reductions stemmed from projects administrated by SCE due to the change in the assumptions related to the baseline for calculating methane emissions. For this reason, their results remain the same as those presented in Table5-22.

Table 5-28: Technology-Specific GHG Emission Reductions and CO_2 eq. Factors for PG&E (in tons of CO_2 eq.)

Technology	Tons of CO_2 eq. Emissions	Annual Energy Impact (in MWh)	CO_2 eq. Factor (Tons/MWh)
Photovoltaics	-54,386	92,849	-0.59
Wind turbines	-	-	-
Non-renewable fuel cells	-5,109	24,344	-0.21
Non-renewable MT	5,140	23,829	0.22
Non-renewable-fueled IC engines	238	119,088	0.00
Non-renewable and waste gas-fueled small gas turbines	3,952	22,689	0.17
Renewable-fueled fuel cells	-	-	-
Renewable-fueled MT	-2,925	3,818	-0.76
Renewable-fueled IC Engines	-21,377	16,983	-1.26
TOTAL	**-74,467**	**303,601**	**-0.25**

Table 5-29: Technology-Specific GHG Emission Reductions and CO_2 eq. Factors for SCG (in tons of CO_2 eq.)

Technology	Tons of CO_2 eq. Emissions	Annual Energy Impact (in MWh)	CO_2 eq. Factor (Tons/MWh)
Photovoltaics	-10,279	16,894	-0.61
Wind turbines	-	-	-
Non-renewable fuel cells	-2,640	11,244	-0.23
Non-renewable MT	4,972	21,255	0.23
Non-renewable-fueled IC engines	-604	113,516	-0.01
Non-renewable and waste gas-fueled small gas turbines	3,960	29,876	0.13
Renewable-fueled fuel cells	-	-	-
Renewable-fueled MT	-	-	-
Renewable-fueled IC Engines	-11,372	2,722	-4.18
TOTAL	**-15,963**	**195,508**	**-0.08**

Table 5-30: Technology-Specific GHG Emission Reductions and CO_2 eq. Factors for CCSE (in tons of CO_2 eq.)

Technology	Tons of CO_2 eq. Emissions	Annual Energy Impact (in MWh)	CO_2 eq. Factor (Tons/MWh)
Photovoltaics	-12,681	20,667	-0.61
Wind turbines	-	-	-
Non-renewable fuel cells	-3,025	12,642	-0.24
Non-renewable MT	578	2,922	0.20
Non-renewable-fueled IC engines	-307	27,223	-0.01
Non-renewable and waste gas-fueled small gas turbines	5,853	29,629	0.20
Renewable-fueled fuel cells	-	-	-
Renewable-fueled MT	-2,920	457	-6.39
Renewable-fueled IC Engines	-	-	-
TOTAL	**-12,502**	**93,540**	**-0.13**

Appendix A

System Costs and Energy and Demand Impacts

A.1 Overview

This appendix summarizes system costs, energy and demand impacts, and relative performance (described in terms of capacity factors for specific time periods) of the seventh-year impact evaluation. It describes demand impacts and capacity factors for the CAISO peak day as well as for the individual electric utility peak days. This appendix is divided into three sections. The first section presents results for the program overall. The second and third sections present results for renewable and non-renewable technologies, respectively. The sequence of each section is as follows:

1. Costs
   Eligible Costs
   Incentives
   Other Incentives
   Total Incentives

2. Annual Energy
   Annual Electric Energy Totals by PA
   Quarterly Electric Energy Totals

3. Peak Demand
   CAISO Peak Hour Demand Impacts
   Electric Utility Peak Hours Demand Impacts

4. Capacity Factors
   Annual Capacity Factors
   Annual Capacity Factors by Technology
   Annual Capacity Factors by Technology and PA
   Monthly Capacity Factors by Technology
   CAISO Peak Day Capacity Factors by Technology
   Electric Utility Peak Day Capacity Factors by Technology

Reporting of overall program results and of annual energy by technologies includes a distinction between metered and estimated values. Metered values have very little uncertainty, most meters having accuracies within one percent. The uncertainty of estimated values is greater and is the primary determinant of the margin of error of results.

Results presented for the peak days of the three individual electric utilities 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.

This appendix summarizes relative performance of groups of systems in terms of their weighted average capacity factors for specific time periods. These measures describe electric net generation output relative to a unit of system rebated capacity. For example, an hourly capacity factor of 0.7 during the CAISO system peak hour indicates that 0.7 kW of net electrical output was produced for every kW of related system rebated capacity.

A.2 Program Totals

Costs

Table A-1 on the following pages lists total eligible costs, SGIP incentives, and other incentives by system type and fuel.

Table A-1: Complete and Active System Costs by Technology and Fuel

Technology*	Fuel†	Cost Component	Complete Projects (M$)	Active Projects (M$)
FC	**N**	Eligible Cost	$46.26	$34.43
		Incentive	$14.47	$12.16
		Other Incentive	$2.45	$0.50
		Total Incentive	$16.92	$12.66
FC	**R**	Eligible Cost	$7.28	$80.57
		Incentive	$3.38	$50.24
		Other Incentive	$0.00	$0.50
		Total Incentive	$3.38	$50.74
GT	**N**	Eligible Cost	$28.90	$24.48
		Incentive	$3.86	$3.40
		Other Incentive	$0.00	$0.00
		Total Incentive	$3.86	$3.40
GT	**R**	Eligible Cost	.	$1.71
		Incentive	.	$0.66
		Other Incentive	$0.00	$0.00
		Total Incentive	$0.00	$0.66
ICE	**N**	Eligible Cost	$259.29	$167.42
		Incentive	$67.07	$28.80
		Other Incentive	$0.86	$0.05
		Total Incentive	$67.93	$28.85
ICE	**R**	Eligible Cost	$21.37	$23.81
		Incentive	$7.36	$7.83
		Other Incentive	$0.48	$0.00
		Total Incentive	$7.84	$7.83
MT	**N**	Eligible Cost	$47.22	$36.28
		Incentive	$12.47	$7.95
		Other Incentive	$1.06	$0.00
		Total Incentive	$13.53	$7.95
MT	**R**	Eligible Cost	$11.76	$7.42
		Incentive	$3.81	$2.01
		Other Incentive	$0.19	$0.00
		Total Incentive	$4.01	$2.01
PV		Eligible Cost	$861.45	$652.27
		Incentive	$372.82	$173.87
		Other Incentive	$39.39	$4.93
		Total Incentive	$412.20	$178.81

* FC = Fuel Cell; GT = Gas Turbine; ICE = Internal Combustion Engine; MT = Microturbine; PV = Photovoltaic; WD = Wind

† N = Non-renewable; R = Renewable

Table A-1: Complete and Active System Costs by Technology and Fuel (continued)

			Complete Projects	Active Projects
Technology*	**Fuel†**	**Cost Component**	**(M$)**	**(M$)**
WD		Eligible Cost	$5.38	$14.88
		Incentive	$2.63	$4.99
		Other Incentive	$0.06	$0.00
		Total Incentive	$2.69	$4.99
		Total Eligible Cost	$1,288.90	$1,043.27
		Total Incentive	$487.87	$291.90
		Total Other Incentive	$44.50	$5.98
		Total All Incentives	$532.37	$297.89

* FC = Fuel Cell; GT = Gas Turbine; ICE = Internal Combustion Engine; MT = Microturbine; PV = Photovoltaic; WD = Wind

† N = Non-renewable; R = Renewable

Annual Energy

Table A-2 on the following page presents annual total net electrical output in MWh for the program and for each PA. It also shows subtotals for each PA and technology. Later tables in this appendix differentiate by natural gas versus renewable methane fuel. This table also shows subtotals by basis (metered, and estimated), indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-2: Annual Electric Energy Totals by Technology and PA

		PG&E	SCE	SCG	CCSE	Total
Technology	**Basis**	**(MWh)**	**(MWh)**	**(MWh)**	**(MWh)**	**(MWh)**
FC	**Total***	**24,344**	**3,908 †**	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY		**52,139**
	M*	17,027	3,186			36,173
	E*	7,317 †	0,722 [a]			15,966 †
GT	**Total***	**22,689 [a]**				**82,193 †**
	M*	7,726				59,927
	E*	14,963 [a]				22,266 [a]
ICE	**Total***	**136,071 †**	**73,520 †**	**116,238 †**	**27,223**	**353,052**
	M*	26,732	39,393	63,935	27,094	157,154
	E*	109,340 †	34,127 †	52,303 †	0,128 [a]	195,898 †
MT	**Total***	**27,647 †**	**17,395 †**	**21,255 †**	**3,379**	**69,677 †**
	M*	2,496	10,642	9,802	3,367	26,307
	E*	25,152 †	6,752 †	11,453 †	0,013	43,370 †
PV	**Total***	**92,849**	**31,360**	**16,894**	**20,667**	**161,770**
	M*	40,376	3,309	6,880	18,717	69,281
	E*	52,473	28,051	10,014	1,950 †	92,489
WD	**Total***		INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY			**2,426 [a]**
	M*					1,636
	E*					0,790 [a]
	Total	**303,601**	**128,609**	**195,508**	**93,540**	**721,257**

*For all but last row, [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Table A-3 presents quarterly total net electrical output in MWh for the program. It also shows subtotals for each technology and fuel, natural gas versus renewable methane. Additionally, it shows subtotals by basis (metered and estimated), indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-3: Quarterly Electric Energy Totals

Technology	Fuel	Basis	Q1-2007 (MWh)	Q2-2007 (MWh)	Q3-2007 (MWh)	Q4-2007 (MWh)	Total* (MWh)
FC	**N**	**Total**	**11,734**	**12,410**	**12,947**	**12,508**	**49,599**
		M	7,300	8,412	9,386	8,535	33,633
		E	4,434	3,998	3,561	3,972	15,966 †
	R	**Total**	**717**	**551**	**679**	**594**	**2,540**
		M	717	551	679	594	2,540
		E	0	0	0	0	0
GT	**N**	**Total**	**19,865**	**22,068**	**17,964**	**22,297**	**82,193 †**
		M	9,056	18,141	13,944	18,786	59,927
		E	10,809	3,927	4,020	3,511	22,266 [a]
ICE	**N**	**Total**	**78,647**	**74,066**	**84,816**	**79,220**	**316,748 †**
		M	35,070	34,501	41,026	33,063	143,661
		E	43,577	39,565	43,789	46,157	173,088 †
	R	**Total**	**9,394**	**9,024**	**8,696**	**9,191**	**36,304 †**
		M	3,261	3,795	3,331	3,106	13,493
		E	6,132	5,229	5,365	6,084	22,810 †
MT	**N**	**Total**	**13,069**	**16,203**	**15,083**	**17,554**	**61,910 †**
		M	3,759	6,908	6,457	7,188	24,314
		E	9,310	9,295	8,626	10,366	37,596 †
	R	**Total**	**2,257**	**1,966**	**1,680**	**1,864**	**7,767 †**
		M	602	532	406	453	1,993
		E	1,655	1,434	1,273	1,411	5,773 †
PV		**Total**	**28,394**	**52,898**	**50,965**	**29,514**	**161,770**
		M	12,127	23,101	22,044	12,010	69,281
		E	16,267	29,797	28,921	17,504	92,489
WD		**Total**	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY				**2,426 [a]**
		M					1,636
		E					790 [a]
		TOTAL	**164,578**	**189,970**	**193,400**	**173,309**	**721,257**

*In rightmost column only and except for last row, [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Peak Demand

Table A-4 presents total net electrical output in kW for the program during the peak hour of 2:00 to 3:00 P.M. (PDT) on August 31, 2007. The table also shows for each technology and basis the subtotals of output, counts of systems, and total operational system capacity in kW. The two bases, metered and estimated, indicate respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available. Later tables in this appendix differentiate peak demand impacts by natural gas versus renewable methane fuel.

Table A-4: CAISO Peak Hour Demand Impacts

CAISO Peak	Date	Hour
(MW)		(PDT)
48,535	31-Aug-07	2 PM

		On-Line Systems	Operational	Impact	Hourly Capacity Factor*
Technology	Basis	(n)	(kW)	(kW)	(kWh/kWh)
FC	**Total**	**14**	**8,000**	**5,982**	0.748
	M	9	5,750	4,102	0.713
	E	5	2,250	1,880	0.836 †
GT	**Total**	**5**	**13,043**	**8,386**	0.643 †
	M	3	10,410	6,744	0.648
	E	2	2,633	1,642	0.624 [a]
ICE	**Total**	**214**	**133,411**	**52,110**	0.391
	M	89	57,016	23,750	0.417
	E	125	76,395	28,360	0.371 †
MT	**Total**	**121**	**19,274**	**7,619**	0.395 †
	M	51	8,440	3,307	0.392
	E	70	10,834	4,312	0.398 †
PV	**Total**	**791**	**109,052**	**65,490**	0.601
	M	221	45,684	27,981	0.612
	E	570	63,369	37,509	0.592
WD	**Total**	**2**	**1,649**	**156**	0.095 [a]
	M	1	950	-3	-0.003
	E	1	699	159	
	TOTAL	**1,147**	**284,429**	**139,743**	

*In column with hourly capacity factor 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.

Figure A-1 plots profiles of hourly total net electrical output in kW for each technology from morning to early evening during the day of the annual peak hour, August 31, 2007. The chart also shows the profile of the hourly CAISO loads in MW using the vertical axis on the right side of the chart. The preceding table shows the values of net output for each technology during the peak hour. Again, later tables and charts in this appendix differentiate by natural gas versus renewable methane fuel.

Figure A-1: CAISO Peak Day Output by Technology

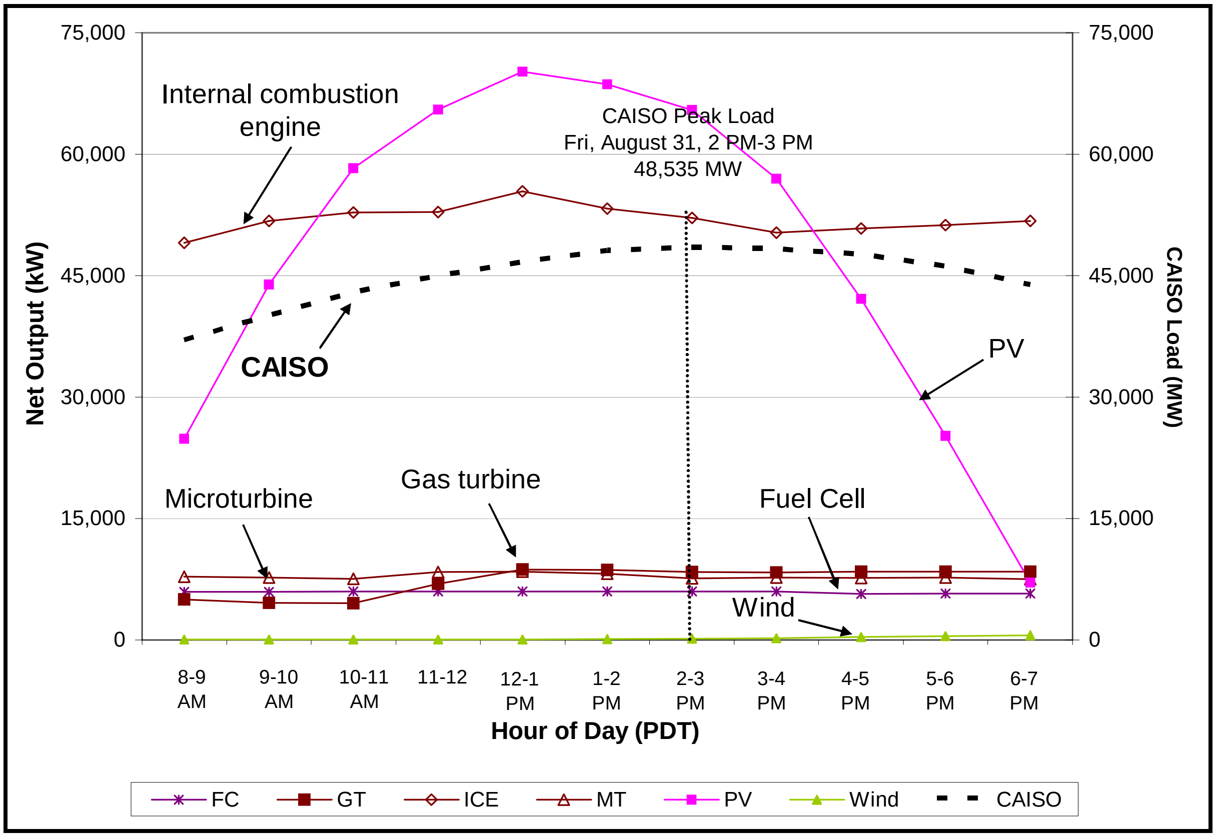


Table A-5, Table A-6, and Table A-7 list for each electric utility the hourly total net electrical output in kW during the annual peak hour from 2:00 to 3:00 P.M., August 31, 2007. The tables also list the number of systems on-line, their combined capacities, and their hourly capacity factors. The last three rows of each table summarize the results across all technologies and fuels. Results presented for the three individual electric utilities for the CAISO peak hour 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 A-5: CAISO Peak Hour Output by Technology, Fuel, Basis and Electric Utility—PG&E

Technology	Fuel	Basis	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC	**N**	**Total**	**6**	**3,550**	**2,974**	0.838
		M	3	2,500	2,152	0.861
		E	3	1,050	822	0.783 †
FC	**R**	**Total**	**0**	**0**	**0**	
		M	0	0	0	
		E	0	0	0	
GT	**N**	**Total**	**3**	**4,016**	**2,566**	0.639 [a]
		M	1	1,383	924	0.668
		E	2	2,633	1,642	0.624 [a]
ICE	**N**	**Total**	**89**	**51,062**	**17,527**	0.343 †
		M	18	9,763	3,433	0.352
		E	71	41,299	14,094	0.341 †
ICE	**R**	**Total**	**7**	**3,930**	**1,461**	0.372 [a]
		M	0	0	0	
		E	7	3,930	1,461	0.372 [a]
MT	**N**	**Total**	**39**	**6,458**	**3,277**	0.507 †
		M	4	960	682	0.711
		E	35	5,498	2,594	0.472 †
MT	**R**	**Total**	**12**	**1,760**	**339**	0.192 [a]
		M	0	0	0	
		E	12	1,760	339	0.192 [a]
PV		**Total**	**397**	**58,038**	**37,650**	0.649
		M	93	25,038	16,260	0.649
		E	304	33,000	21,390	0.648
WD		**Total**	**0**	**0**	**0**	
		M	0	0	0	
		E	0	0	0	
		TOTAL	**553**	**128,814**	**65,792**	0.511
		M	119	39,644	23,451	0.592
		E	434	89,170	42,342	0.475

*In column with hourly capacity factor only, excluding grand total rows at bottom, [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Table A-6: CAISO Peak Hour Output by Technology, Fuel, Basis and Electric Utility—SCE

Technology	Fuel	Basis	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC	**N**	**Total**	**2**	**700**	**613**	0.875 [a]
		M	1	500	456	0.912
		E	1	200	157	0.783 [a]
FC	**R**	**Total**	**2**	**750**	**187**	0.249
		M	2	750	187	0.249
		E	0	0	0	
GT	**N**	**Total**	**1**	**4,500**	**2,024**	0.450
		M	1	4,500	2,024	0.450
		E	0	0	0	
ICE	**N**	**Total**	**86**	**57,974**	**23,771**	0.410 †
		M	48	31,829	12,869	0.404
		E	38	26,145	10,902	0.417 †
ICE	**R**	**Total**	**7**	**5,509**	**1,237**	0.225 †
		M	4	3,429	619	0.181
		E	3	2,080	618	0.297 [a]
MT	**N**	**Total**	**43**	**7,122**	**2,879**	0.404 †
		M	29	5,298	2,139	0.404
		E	14	1,824	740	0.405 [a]
MT	**R**	**Total**	**4**	**1,040**	**203**	0.195 [a]
		M	2	490	82	0.168
		E	2	550	121	0.219 [a]
PV		**Total**	**199**	**25,623**	**14,200**	0.554
		M	21	3,979	2,684	0.674
		E	178	21,644	11,516	0.532
WD		**Total**	**2**	**1,649**	**156**	0.095 [a]
		M	1	950	-3	-0.003
		E	1	699	159	0.228 [a]
		TOTAL	**346**	**104,867**	**45,269**	0.432
		M	109	51,725	21,058	0.407
		E	237	53,142	24,211	0.456

*In column with hourly capacity factor only, excluding grand total rows at bottom, [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Table A-7: CAISO Peak Hour Output by Technology, Fuel, Basis and Electric Utility—SDG&E

Technology	Fuel	Basis	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC	**N**	**Total**	**3**	**2,000**	**1,308**	0.654
		M	3	2,000	1,308	0.654
		E	0	0	0	
FC	**R**	**Total**	**0**	**0**	**0**	
		M	0	0	0	
		E	0	0	0	
GT	**N**	**Total**	**1**	**4,527**	**3,796**	0.839
		M	1	4,527	3,796	0.839
		E	0	0	0	
ICE	**N**	**Total**	**19**	**11,995**	**6,829**	0.569
		M	19	11,995	6,829	0.569
		E	0	0	0	
ICE	**R**	**Total**	**0**	**0**	**0**	
		M	0	0	0	
		E	0	0	0	
MT	**N**	**Total**	**13**	**1,128**	**372**	0.330
		M	13	1,128	372	0.330
		E	0	0	0	
MT	**R**	**Total**	**3**	**564**	**31**	0.056
		M	3	564	31	0.056
		E	0	0	0	
PV		**Total**	**104**	**13,998**	**7,655**	0.547
		M	95	13,355	7,300	0.547
		E	9	643	355	0.552 †
WD		**Total**	**0**	**0**	**0**	
		M	0	0	0	
		E	0	0	0	
		TOTAL	**143**	**34,212**	**19,991**	0.584
		M	134	33,569	19,636	0.585
		E	9	643	355	0.552

*In column with hourly capacity factor only, excluding grand total rows at bottom, [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Figure A-2, Figure A-3, and Figure A-4 plot for each electric utility profiles of hourly total net electrical output in kW for each technology from morning to early evening during the day of the annual peak hour, August 31, 2007. The charts also show the profile of the hourly CAISO loads in MW using the vertical axis on the right side of the chart. The preceding tables list the values associated with these charts for the peak hour. Results presented for the three individual electric utilities on the CAISO peak day 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.

Figure A-2: CAISO Peak Day Output by Technology, Fuel, and Electric Utility —PG&E

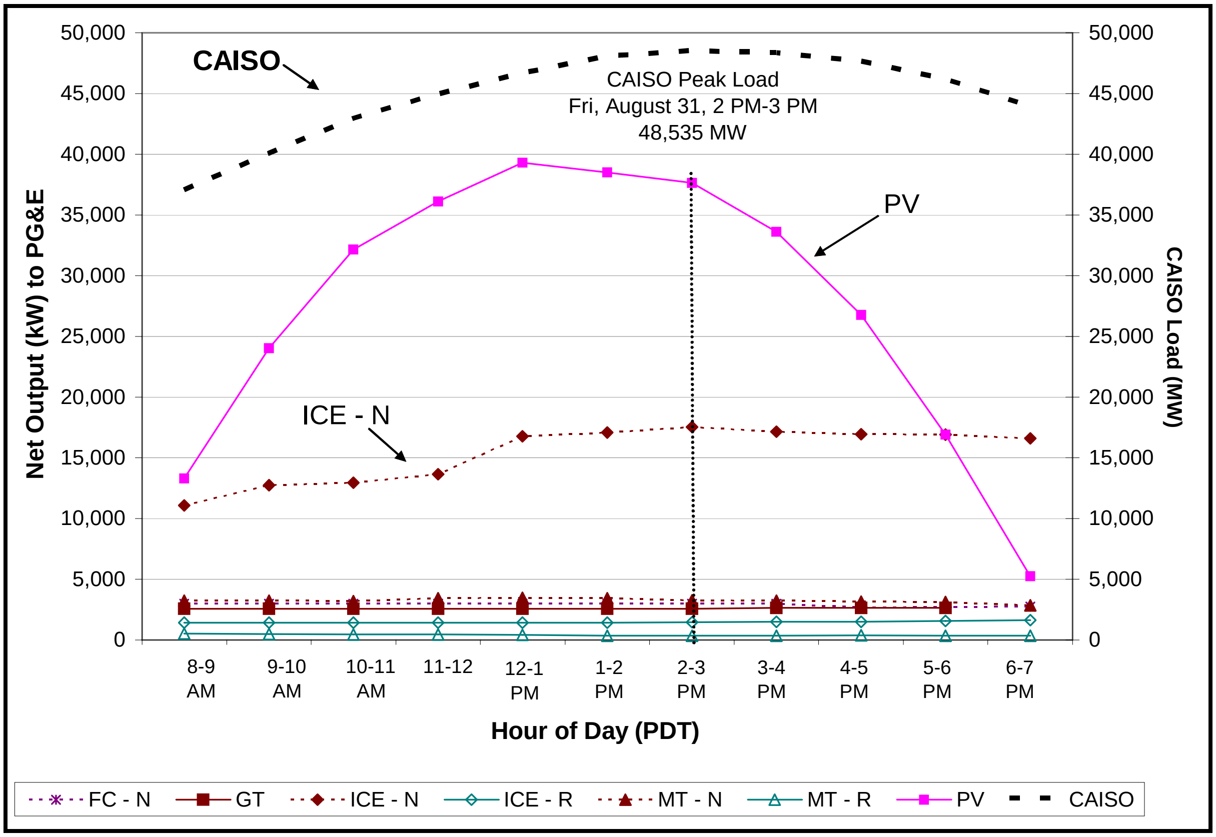


Figure A-3: CAISO Peak Day Output by Technology, Fuel, and Electric Utility —SCE

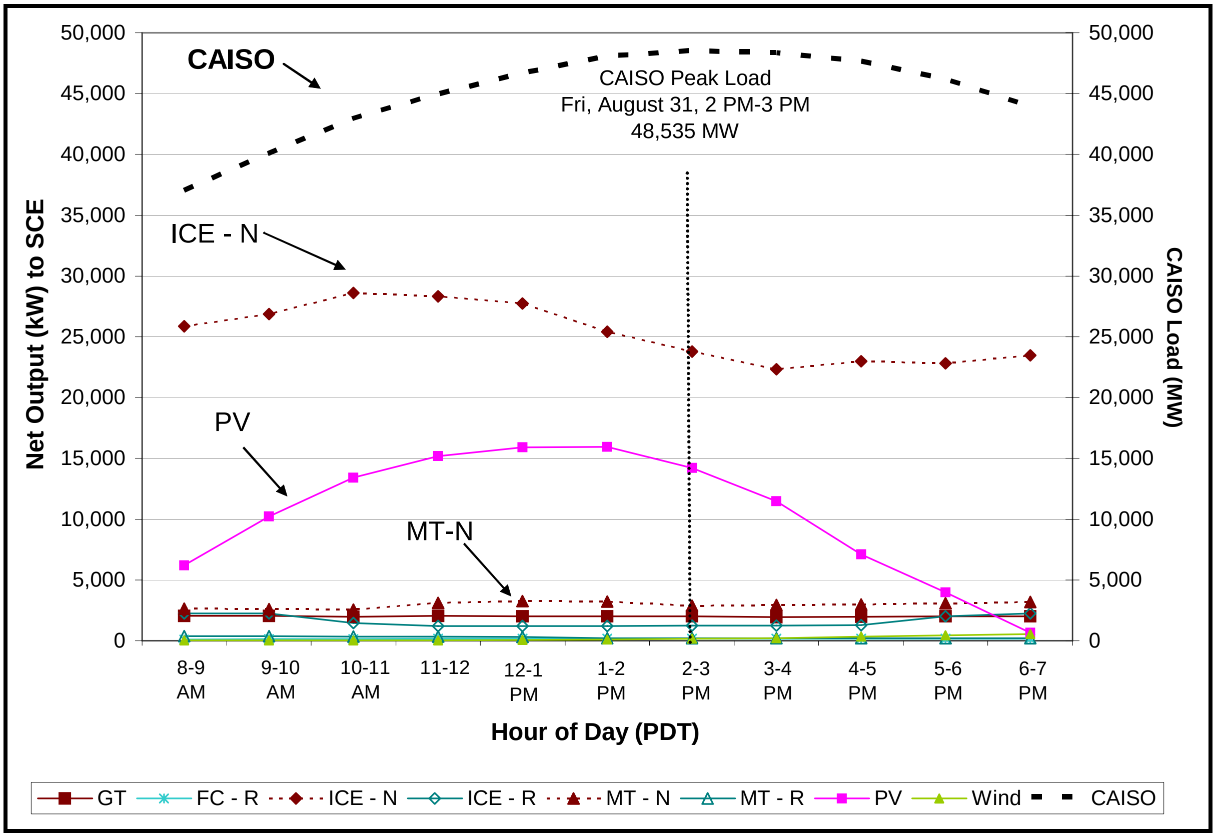


Figure A-4: CAISO Peak Day Output by Technology, Fuel, and Electric Utility—SDG&E

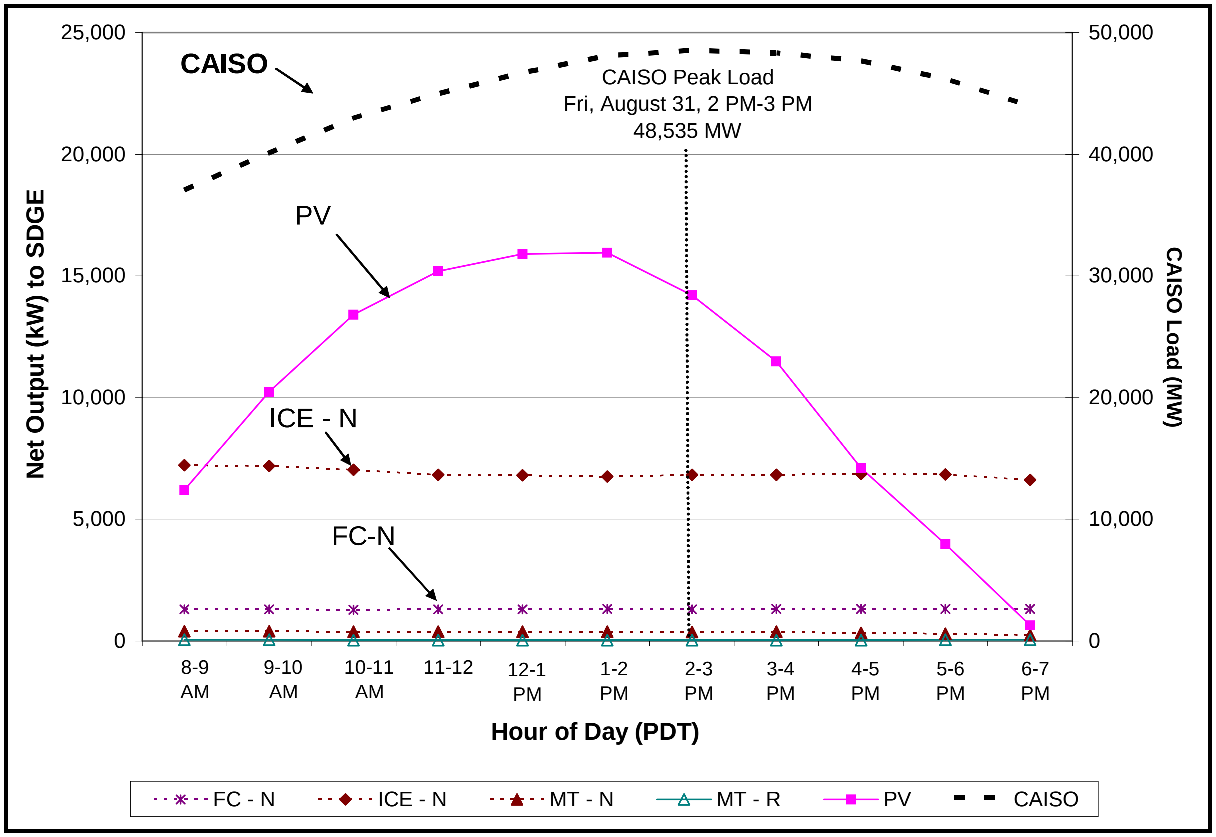


Table A-8, Table A-9, and Table A-10 present the total net electrical output in kW during the respective peak hours of the three large, investor-owned electric utilities. Preceding each of these are small tables listing the date, hour, and load of the utility's peak hour day. The tables also show for each technology and basis the subtotals of output, counts of systems, and total operational system capacity in kW. The two bases, metered and estimated, indicate respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available. Later tables in this appendix differentiate electric utility peak demand impacts by natural gas versus renewable methane fuel.

Results presented for the peak days of the three individual electric utilities 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 A-8: Electric Utility Peak Hours Demand Impacts—PG&E

Elec PA	Peak (MW)	Date	Hour (PDT)
PG&E	**21,364**	**29-Aug-07**	**6 PM**

Technology	Basis	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC	**Total**	**6**	**3,550**	**1,795**	**0.506**
	M	4	2,750	1,296	0.471
	E	2	800	499	0.624
GT	**Total**	**3**	**4,016**	**2,643**	**0.658**
	M	1	1,383	926	0.669
	E	2	2,633	1,717	0.652
ICE	**Total**	**96**	**54,992**	**17,251**	**0.314**
	M	20	10,698	3,356	0.314
	E	76	44,294	13,895	0.314
MT	**Total**	**51**	**8,218**	**3,566**	**0.434**
	M	4	960	460	0.479
	E	47	7,258	3,107	0.428
PV	**Total**	**391**	**57,717**	**5,397**	**0.094**
	M	93	25,038	2,607	0.104
	E	298	32,679	2,790	0.085
WD	**Total**	**0**	**0**	**0**	**0.000**
	M	0	0	0	0.000
	E	0	0	0	0.000
	TOTAL	**547**	**128,493**	**30,652**	**0.239**

Table A-9: Electric Utility Peak Hours Demand Impacts—SCE

Elec PA	Peak (MW)	Date	Hour (PDT)
SCE	**23,516**	**31-Aug-07**	**3 PM**

Technology	Basis	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC	**Total**	**4**	**1,450**	**799**	**0.551**
	M	3	1,250	642	0.514
	E	1	200	157	0.783
GT	**Total**	**1**	**4,500**	**1,948**	**0.433**
	M	1	4,500	1,948	0.433
	E	0	0	0	0.000
ICE	**Total**	**93**	**63,483**	**23,576**	**0.371**
	M	52	35,258	12,810	0.363
	E	41	28,225	10,766	0.381
MT	**Total**	**47**	**8,162**	**3,136**	**0.384**
	M	31	5,788	2,260	0.390
	E	16	2,374	876	0.369
PV	**Total**	**199**	**25,623**	**11,491**	**0.448**
	M	21	3,979	2,080	0.523
	E	178	21,644	9,411	0.435
WD	**Total**	**2**	**1,649**	**216**	**0.131**
	M	1	950	-3	-0.003
	E	1	699	219	0.313
	TOTAL	**346**	**104,867**	**41,165**	**0.393**

Table A-10: Electric Utility Peak Hours Demand Impacts—SDG&E

Elec PA	Peak (MW)	Date	Hour (PDT)
SDGE	**4,636**	**3-Sep-07**	**3 PM**

Technology	Basis	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor (kWh/kWh)
FC	**Total**	**3**	**2,000**	**834**	**0.417**
	M	3	2,000	834	0.417
	E	0	0	0	0.000
GT	**Total**	**1**	**4,527**	**3,612**	**0.798**
	M	1	4,527	3,612	0.798
	E	0	0	0	0.000
ICE	**Total**	**19**	**11,995**	**4,960**	**0.413**
	M	19	11,995	4,960	0.413
	E	0	0	0	0.000
MT	**Total**	**16**	**1,692**	**314**	**0.185**
	M	16	1,692	314	0.185
	E	0	0	0	0.000
PV	**Total**	**104**	**13,998**	**5,746**	**0.411**
	M	95	13,355	5,493	0.411
	E	9	643	253	0.394
WD	**Total**	**0**	**0**	**0**	**0.000**
	M	0	0	0	0.000
	E	0	0	0	0.000
	TOTAL	**143**	**34,212**	**15,465**	**0.452**

Capacity Factors

This section describes weighted average capacity factors that indicate system performance relative to system rebated kilowatt for specific time periods. For example, an hourly weighted average capacity factor of 0.7 during the CAISO system peak hour indicates that 0.7 kW of net electrical output was produced for every kW of related system rebated capacity.

Table A-11 presents annual weighted average capacity factors for each technology for the year 2007. The table shows the annual weighted average capacity factors for each technology using all metered and estimated values, and by bases of metered and of estimated. The two bases, metered and estimated, indicate respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available. The distinction by basis indicates simply that different sets of observations were used in the calculations, not that estimated capacity factors were systematically lower or higher than metered capacity factors. Again, later tables in this appendix differentiate capacity factors by natural gas versus renewable methane fuel.

Table A-11: Annual Capacity Factors

Technology	Basis	Annual Capacity Factor* (kWyear/kWyear)
FC	**Total**	0.746
	M	0.723
	E	0.805 †
GT	**Total**	0.719 †
	M	0.739
	E	0.671 [a]
ICE	**Total**	0.306
	M	0.307
	E	0.304 †
MT	**Total**	0.411 †
	M	0.390
	E	0.425 †
PV	**Total**	0.177
	M	0.212
	E	0.157
WD	**Total**	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY
	M	
	E	

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

Table A-12 presents annual weighted average capacity factors for each technology and PA for the year 2007. These values arise from the combination of all metered and estimated values. Where entries are blank the PA had no operational systems of the technology type. Later tables in this appendix differentiate capacity factors by natural gas versus renewable methane fuel.

Table A-12: Annual Capacity Factors by Technology and PA

	PG&E	SCE	SCG	CCSE
	Annual Capacity Factor*			
Technology	(kWyear/kWyear)			
FC	0.749	0.470 †	0.856 †	0.794
GT	0.645 [a]			
ICE	0.290 †	0.324 †	0.317 †	0.297
MT	0.396 †	0.425 †	0.482 †	0.229
PV	0.182	0.163	0.179	0.176
WD				

INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY

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

Table A-13 presents annual weighted average capacity factors for the technologies that can be fueled with either natural gas or renewable methane gas. Where entries are blank the PA had no operational systems of the technology type. This table allows easy comparison of these technologies by fuel type.

Table A-13: Annual Capacity Factors by Technology and Fuel

	Annual Capacity Factor* (kWyear/kWyear)	
Technology	Natural Gas	Renewable Fuel
FC	0.784	0.387
GT	0.719 †	
ICE	0.294 †	0.464 †
MT	0.441 †	0.265 †

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

Figure A-5 plots profiles of monthly weighted average capacity factors for each technology. Again, later charts in this appendix differentiate capacity factors by natural gas versus renewable methane fuel

Figure A-5: Monthly Capacity Factors by Technology

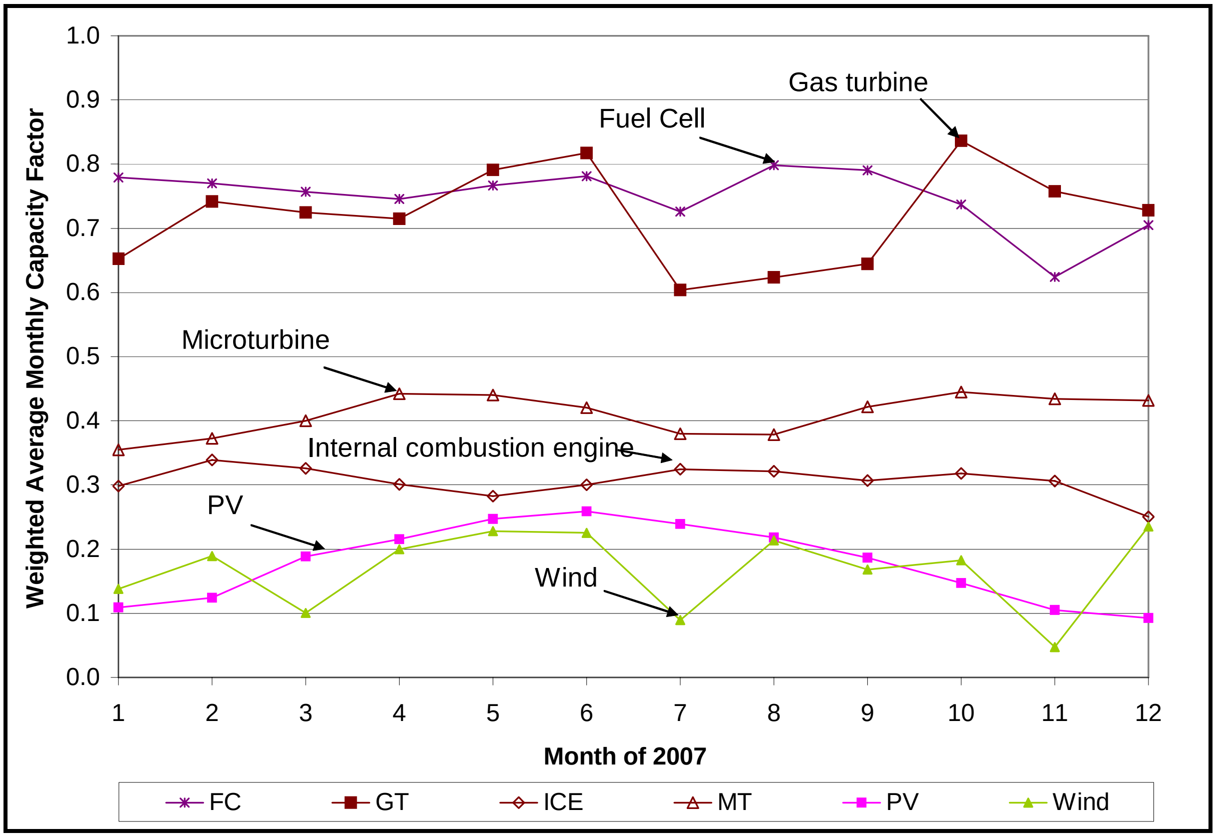


Figure A-6 plots profiles of hourly weighted average capacity factor for each technology from morning to early evening during the day of the annual peak hour, August 31, 2007. The plot also indicates the hour and value of the CAISO peak load. Again, later charts in this appendix differentiate by natural gas versus renewable methane fuel.

Figure A-6: CAISO Peak Day Capacity Factors by Technology

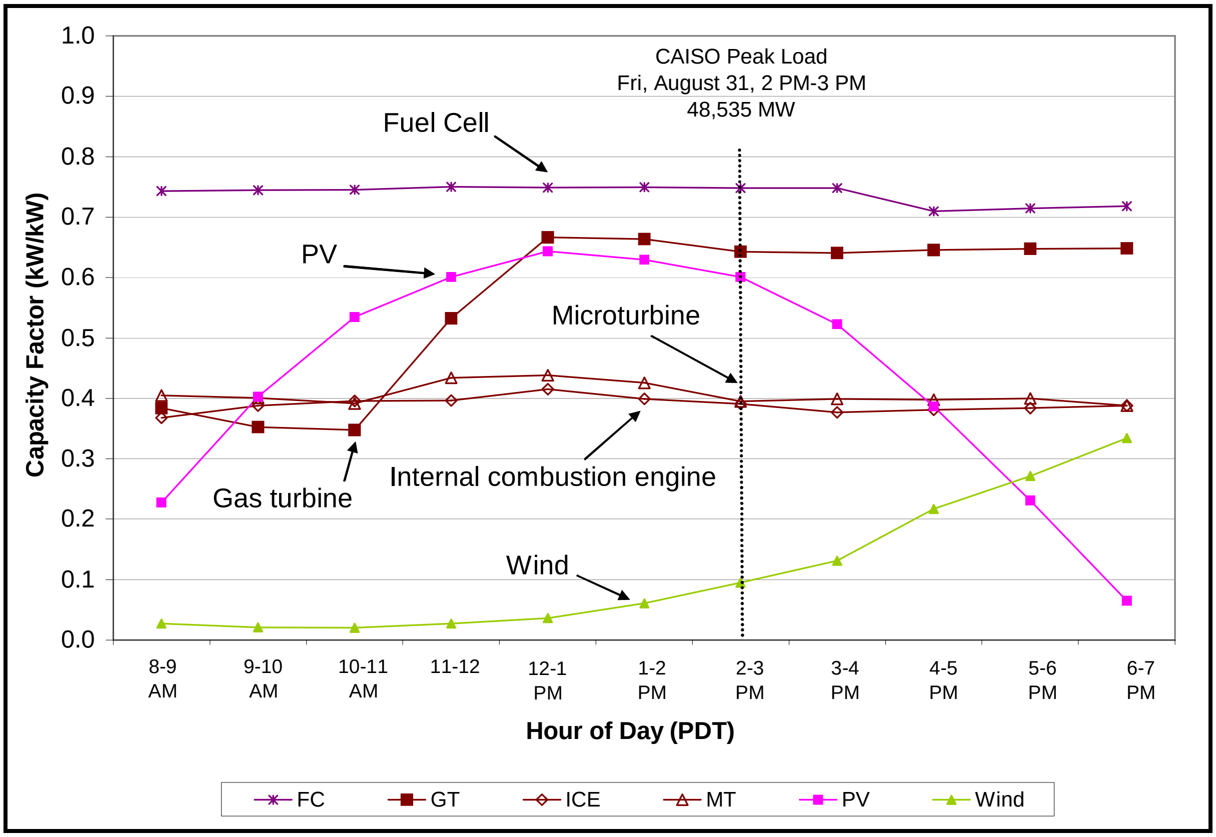


Figure A-7, Figure A-8, and Figure A-9 plot profiles of hourly weighted average capacity factors by technology for the systems directly feeding the utilities on the dates of their respective annual peak hours. The plots also indicate the date, hour, and value of the peak load for the electric utility. The plots include only those technologies that were operational for the electric utility, so not all technologies appear for all electric utilities. In later sections, this appendix describes separately those technologies that can use natural gas versus renewable fuel.

Results presented for the peak days of the three individual electric utilities do not strictly include all systems or only systems administered by the PA associated with the electric utility. About half of all 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.

Figure A-7: Electric Utility Peak Day Capacity Factors by Technology—PG&E

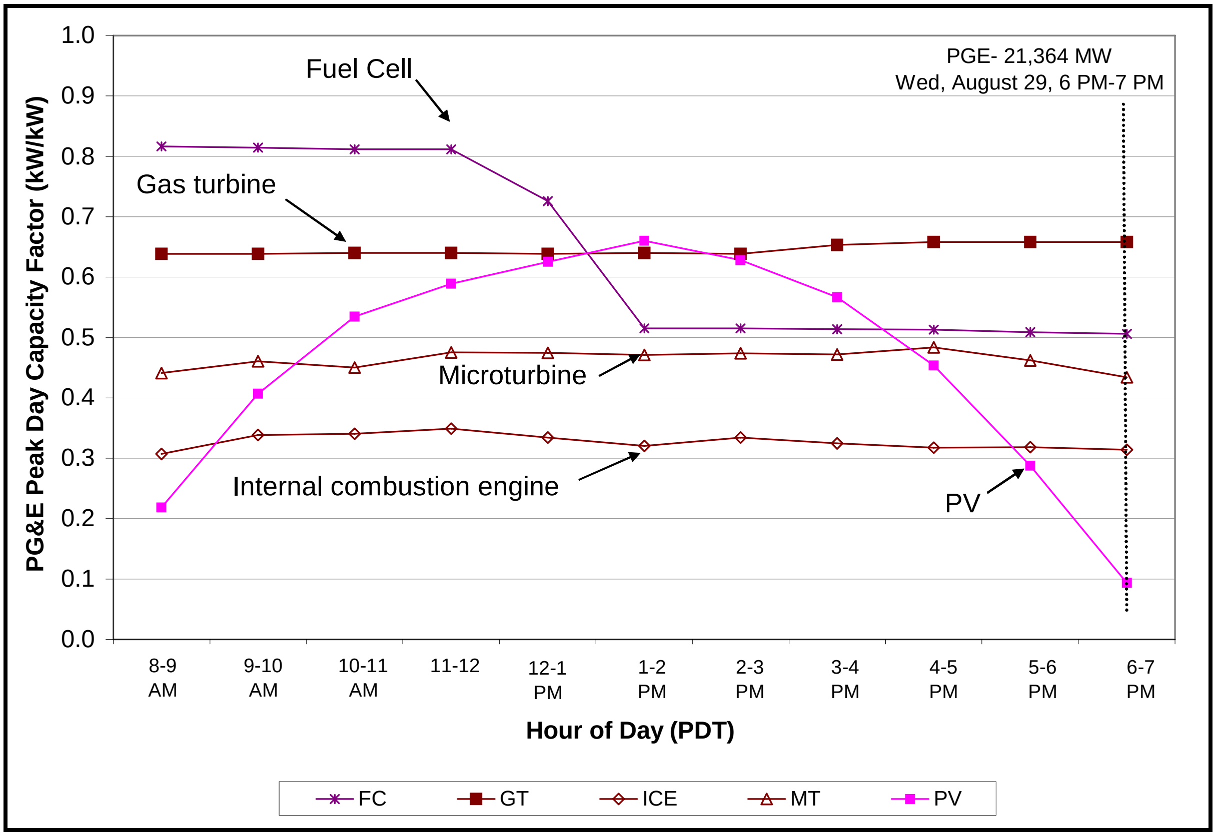


Figure A-8: Electric Utility Peak Day Capacity Factors by Technology—SCE

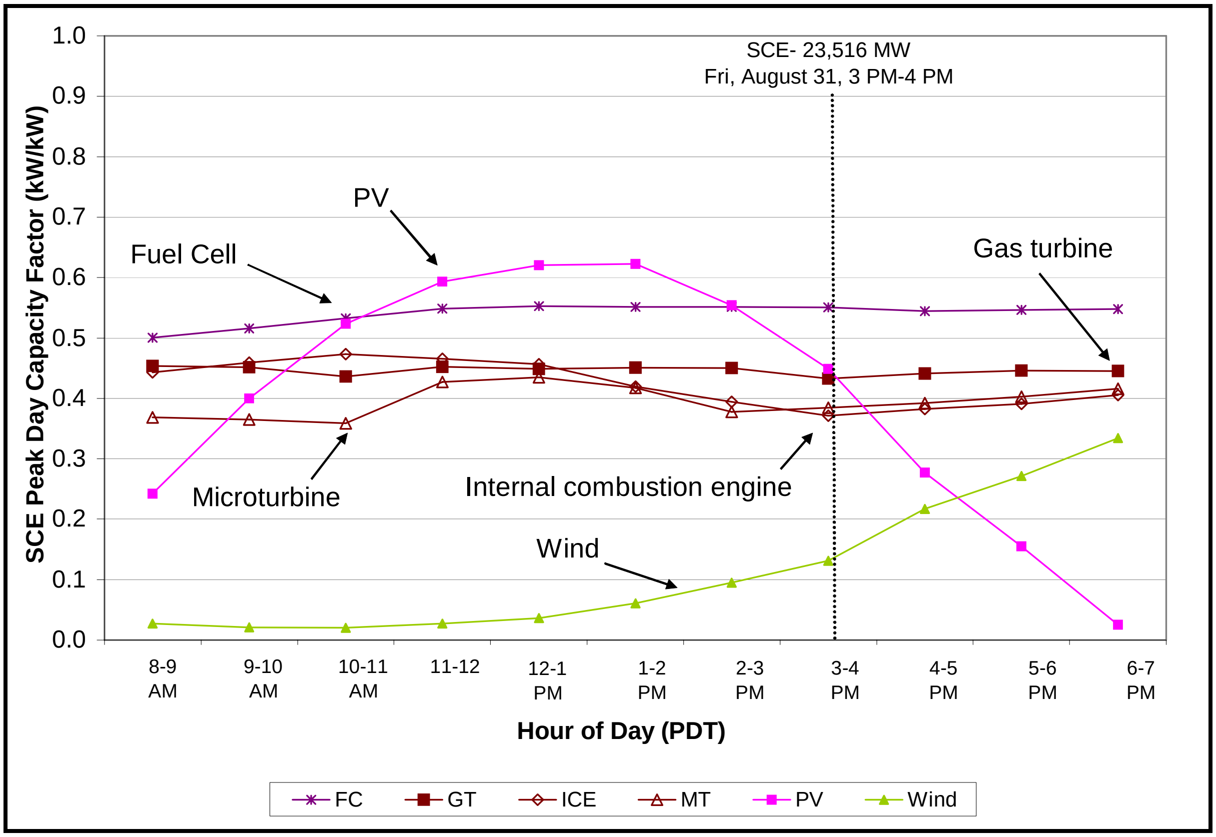
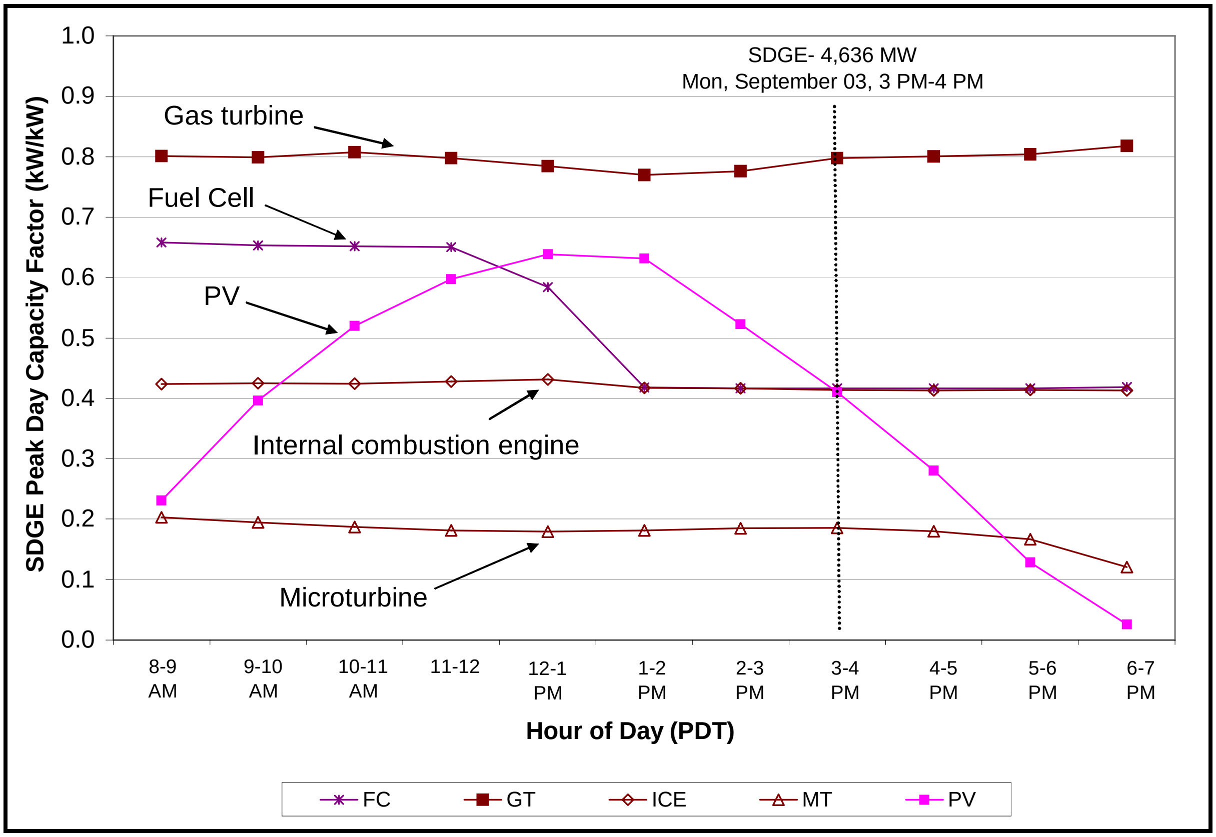


Figure A-9: Electric Utility Peak Day Capacity Factors by Technology—SDG&E



A.3 Renewable Power Systems

This section describes impacts of renewable power systems. It begins with PV, followed by wind, renewable fuel cells, renewable internal combustion (IC) engines, and renewable microturbines. There are no renewable gas turbines in the program. The next section describes non-renewable power systems.

Solar Photovoltaic

Costs

Table A-14 lists total eligible costs, SGIP incentives, and other incentives for PV systems.

Table A-14: Complete and Active System Costs

		Complete Projects	Active Projects
Technology	**Cost Component**	**(M$)**	**(M$)**
PV	Eligible Cost	$861.45	$652.27
	Incentive	$372.82	$173.87
	Other Incentive	$39.39	$4.93
	Total Incentive	$412.20	$178.81

Annual Energy

Table A-15 presents annual total net electrical output in MWh from PV for the program and for each PA. This table also shows subtotals by basis (metered, and estimated), indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-15: Annual Electric Energy Totals* by PA

		PG&E	SCE	SCG	CCSE	Total
Technology	**Basis**	**(MWh)**	**(MWh)**	**(MWh)**	**(MWh)**	**(MWh)**
PV	**Total***	**92,849**	**31,360**	**16,894**	**20,667**	**161,770**
	M*	40,376	3,309	6,880	18,717	69,281
	E*	52,473	28,051	10,014	1,950 †	92,489

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

Table A-16 presents quarterly total net electrical output in MWh for PV. This table also shows subtotals by basis (metered, and estimated), indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-16: Quarterly Electric Energy Totals

Technology	Basis	Q1-2007 (MWh)	Q2-2007 (MWh)	Q3-2007 (MWh)	Q4-2007 (MWh)	Total* (MWh)
PV	**Total**	**28,394**	**52,898**	**50,965**	**29,514**	**161,770**
	M	12,127	23,101	22,044	12,010	69,281
	E	16,267	29,797	28,921	17,504	92,489

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

Peak Demand

Table A-17 presents total net electrical output in kW for PV during the peak hour of 2:00 to 3:00 P.M. (PDT) on August 31, 2007. The table also shows counts of systems and total operational system capacity in kW.

Table A-17: CAISO Peak Hour Demand Impacts

Technology	Basis	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor* (kWh/kWh)
PV	**Total**	**791**	**109,052**	**65,490**	**0.601**

*In column with hourly capacity factor 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.

Table A-18 presents the total net electrical output in kW for PV during the respective peak hours of the three large, investor-owned electric utilities. The table also shows counts of systems and total operational system capacity in kW. The table also lists the dates, hours, and loads of the utility's peak hour day. These results for the three individual electric utilities do not strictly include all systems or only systems administered by the PA associated with the electric utility. The results include only those systems whose output feeds directly into the electric utility's distribution system.

Table A-18: Electric Utility Peak Hours Demand Impacts

PA	Peak (MW)	Date	Hour (PDT)	Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)
PGE	21,364	8/29/2007	18	**PV**	391	57,717	5,397
SCE	23,516	8/31/2007	15	**PV**	199	25,623	11,491
SDGE	4,636	9/3/2007	15	**PV**	104	13,998	5,746

Capacity Factors

Weighted average capacity factors indicate PV performance relative to a system rebated kilowatt for specific time periods. Capacity factors for PV for time periods of a whole day or more are typically less than 0.3 as there generally is no net output between sunset and dawn. Table A-19 presents annual weighted average capacity factors for PV for the year 2007.

Table A-19: Annual Capacity Factors

Technology	Annual Capacity Factor* (kWyear/kWyear)
PV	0.177

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

Table A-20 presents annual weighted average capacity factors for PV for each PA for the year 2007.

Table A-20: Annual Capacity Factors by PA

	PG&E	SCE	SCG	CCSE
	Annual Capacity Factor*			
Technology	(kWyear/kWyear)			
PV	0.182	0.163	0.179	0.176

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

Figure A-10 plots profiles of monthly weighted average capacity factors for PV for each PA. This particular plot uses a reduced height for the vertical axis, with a maximum of 0.30 to allow easier differentiation of capacity factor variations by month.

Figure A-10: Monthly Capacity Factors by PA

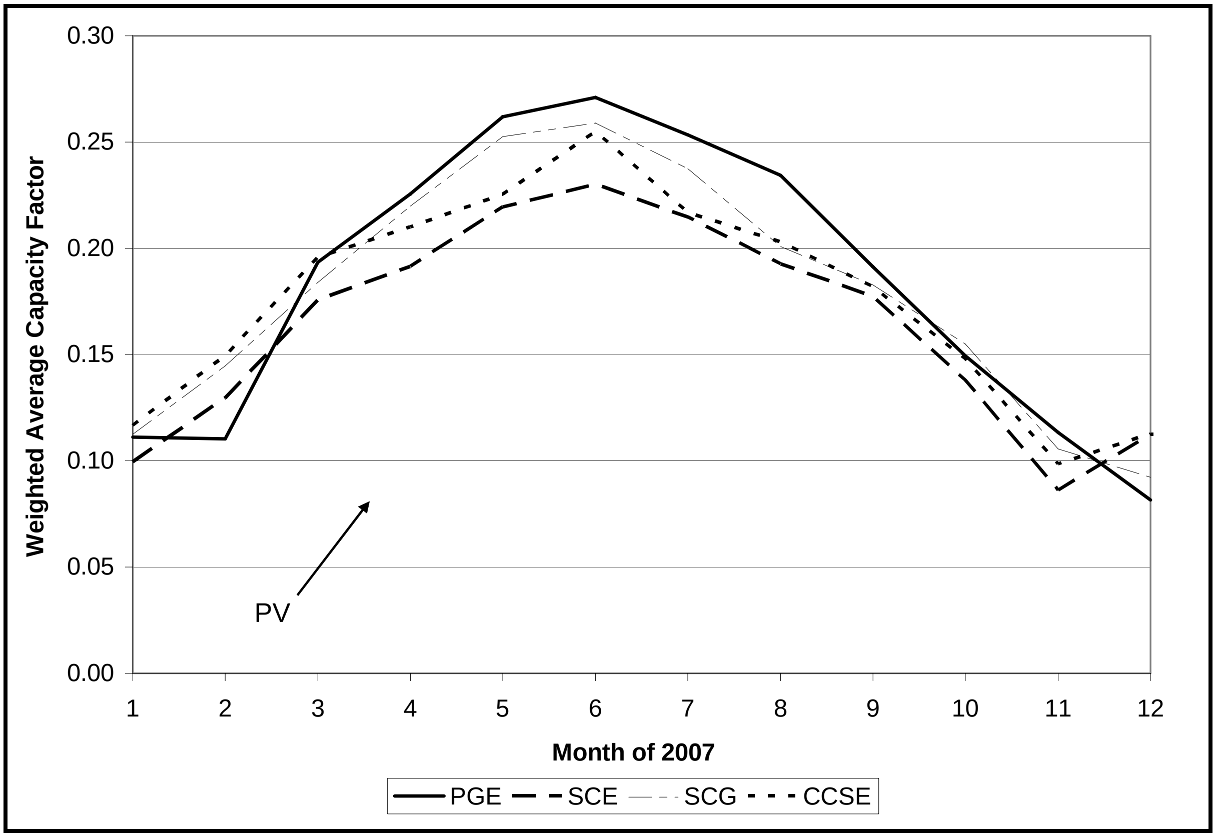


Figure A-11 plots the profiles of hourly weighted average capacity factor for PV for each PA from the morning to early evening during the day of the annual peak hour, August 31, 2007. The chart also shows the profile of the hourly CAISO loads in MW using the vertical axis on the right side of the chart.

Figure A-11: CAISO Peak Day Capacity Factors by PA

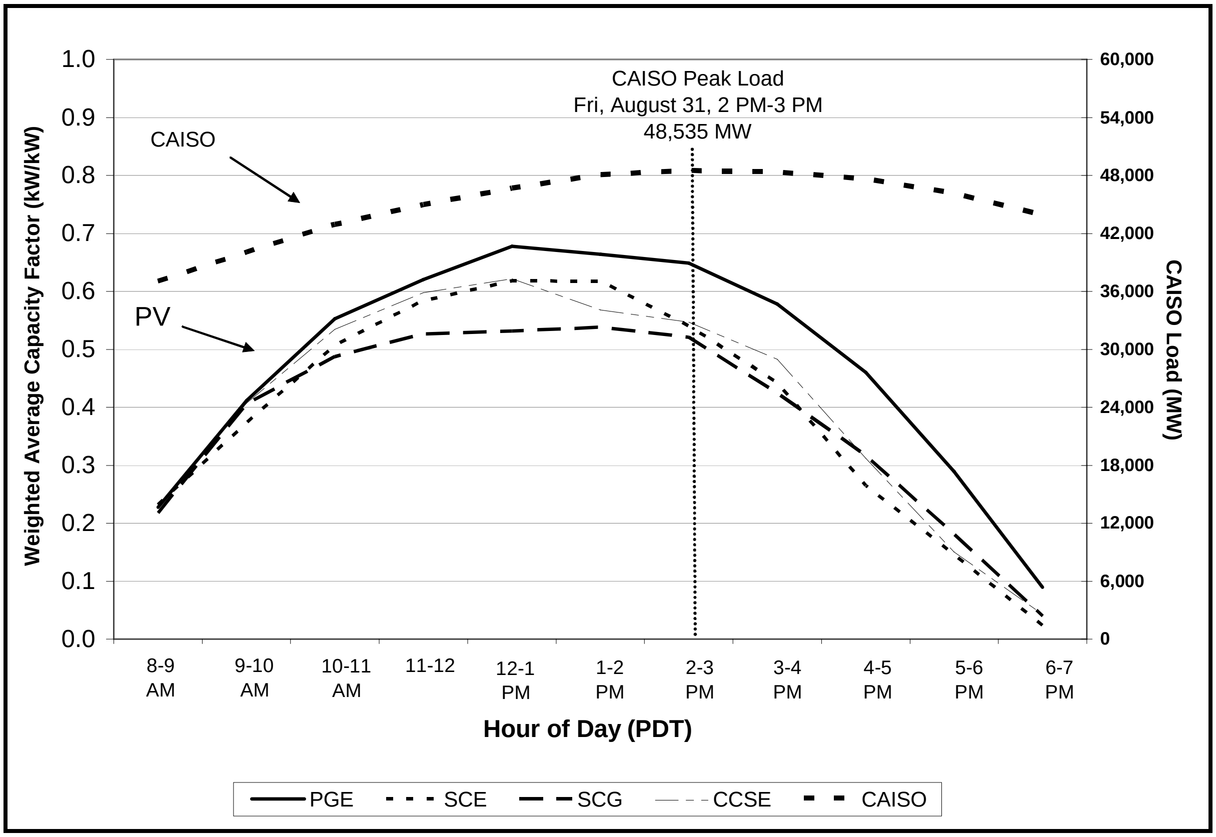


Figure A-12, Figure A-13, and Figure A-14 plot profiles of hourly weighted average capacity factors for PV systems directly feeding the electric utilities on the dates of their respective annual peak hours. Systems administered by the PA associated with the electric utility but not feeding directly into its distribution system are not included in these results. The plots also indicate the date and hour and value of the peak load for the electric utility.

Figure A-12: Electric Utility Peak Day Capacity Factors—PG&E

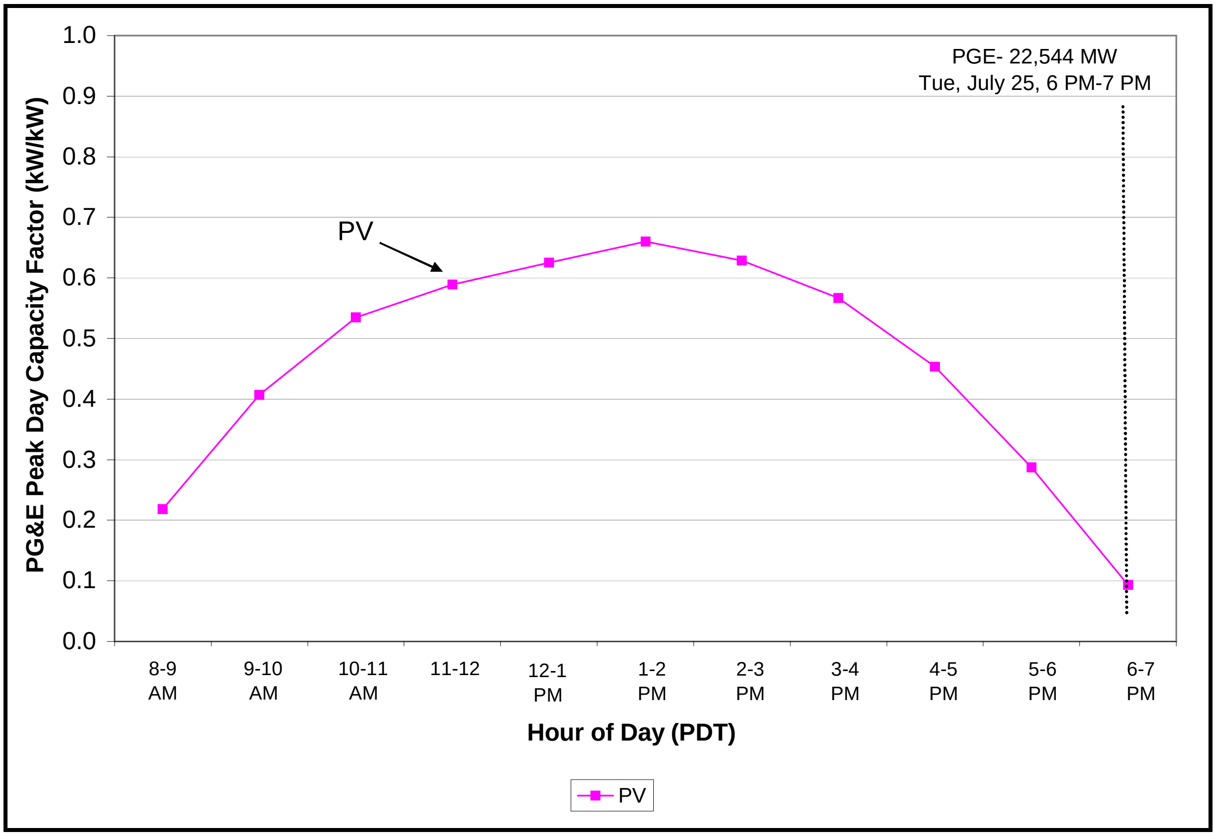


Figure A-13: Electric Utility Peak Day Capacity Factors—SCE

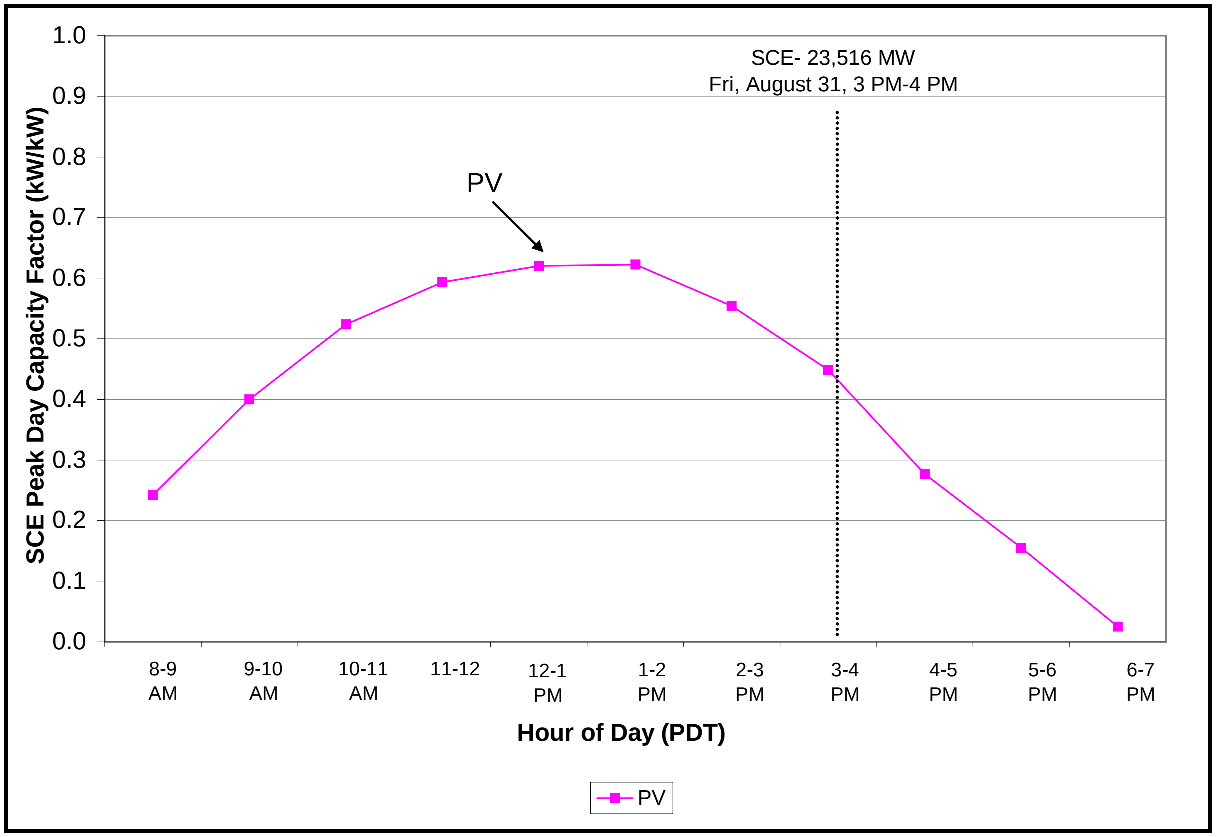
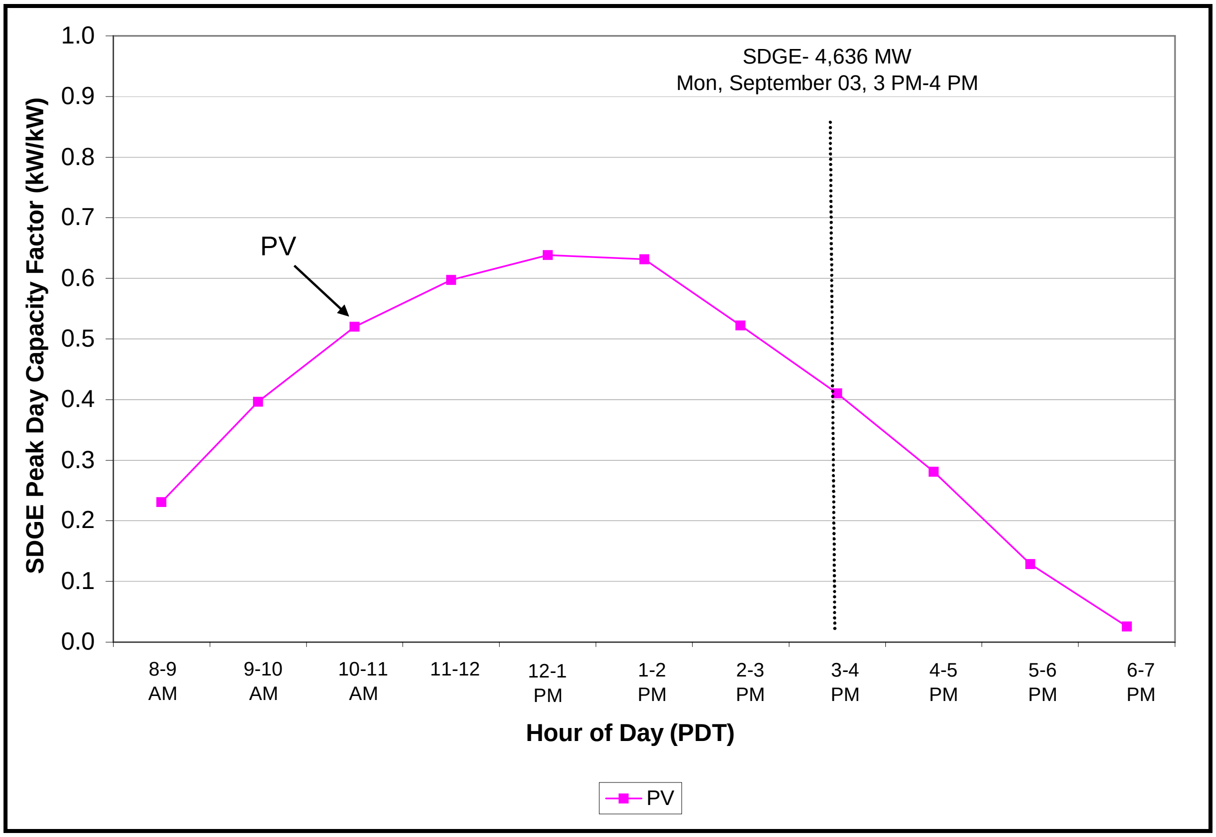


Figure A-14: Electric Utility Peak Day Capacity Factors—SDG&E



Wind

Costs

Table A-21 lists total eligible costs, SGIP incentives, and other incentives for wind systems.

Table A-21: Complete and Active System Costs

Technology	Cost Component	Complete Projects (M$)	Active Projects (M$)
WD	Eligible Cost	$5.38	$14.88
	Incentive	$2.63	$4.99
	Other Incentive	$0.06	$0.00
	Total Incentive	$2.69	$4.99

Annual Energy

Table A-22 presents annual total net electrical output in MWh from Wind for the program and for each PA. This table also shows subtotals by basis (metered, and estimated), indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-22: Annual Electric Energy Totals by PA

Technology	Basis	PG&E (MWh)	SCE (MWh)	SCG (MWh)	CCSE (MWh)	Total (MWh)
WD	**Total***	**0**	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY			
	M	0				
	E	0				

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

Table A-23 presents quarterly total net electrical output in MWh for wind. This table also shows subtotals by basis (metered, and estimated), indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-23: Quarterly Electric Energy Totals

Technology	Basis	Q1-2007 (MWh)	Q2-2007 (MWh)	Q3-2007 (MWh)	Q4-2007 (MWh)	Total* (MWh)
WD	**Total**	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY				
	M					
	E					

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

Peak Demand

Table A-24 presents total net electrical output in kW for wind during the peak hour of 2:00 to 3:00 P.M. (PDT) on August 31, 2007. The table also shows counts of systems and total operational system capacity in kW.

Table A-24: CAISO Peak Hour Demand Impacts

Technology	Basis	On-Line Systems (n)	Operational (kW)	Impact (kW)	Hourly Capacity Factor* (kWh/kWh)
WD	**Total**	**2**	**1,649**	**156**	**0.095** [a]

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

Table A-25 presents the total net electrical output in kW for wind during the respective peak hours of the three large, investor-owned electric utilities. The table also shows counts of systems and total operational system capacity in kW. Additionally, the table lists the dates, hours, and loads of the utility's peak hour day. These results for the three individual electric utilities do not strictly include all systems or only systems administered by the PA associated with the electric utility. The results include only those systems whose output feeds directly into the electric utility's distribution system.

Table A-25: Electric Utility Peak Hours Demand Impacts

Elec PA	Peak (MW)	Date	Hour (PDT)	Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)
PGE	21,364	8/29/2007	18	**WD**	0	0	0
SCE	23,516	8/31/2007	15	**WD**	2	1,649	216
SDGE	4,636	9/3/2007	15	**WD**	0	0	0

Capacity Factors

Weighted average capacity factors indicate wind performance relative to a system-rebated kW for specific time periods. Capacity factors for wind for time periods extending over many days or more here have been observed to be typically less than 0.3. Table A-26 presents annual weighted average capacity factors for wind for the year 2007.

Table A-26: Annual Capacity Factors

Technology	Annual Capacity Factor* (kWyear/kWyear)
WD	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY

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

Table A-27 presents annual weighted average capacity factors for wind for each PA for the year 2007.

Table A-27: Annual Capacity Factors by PA

	PG&E	SCE	SCG	CCSE
	Annual Capacity Factor*			
Technology	(kWyear/kWyear)			
WD	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY			

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

Figure A-15 plots profiles of monthly weighted average capacity factors for wind for each PA. This particular plot uses a reduced height for the vertical axis, with a maximum of 0.3 to allow easier differentiation of capacity factor variations by month. Only SCE appears in the charts as it is the only PA with wind systems.

Figure A-15: Monthly Capacity Factors by PA

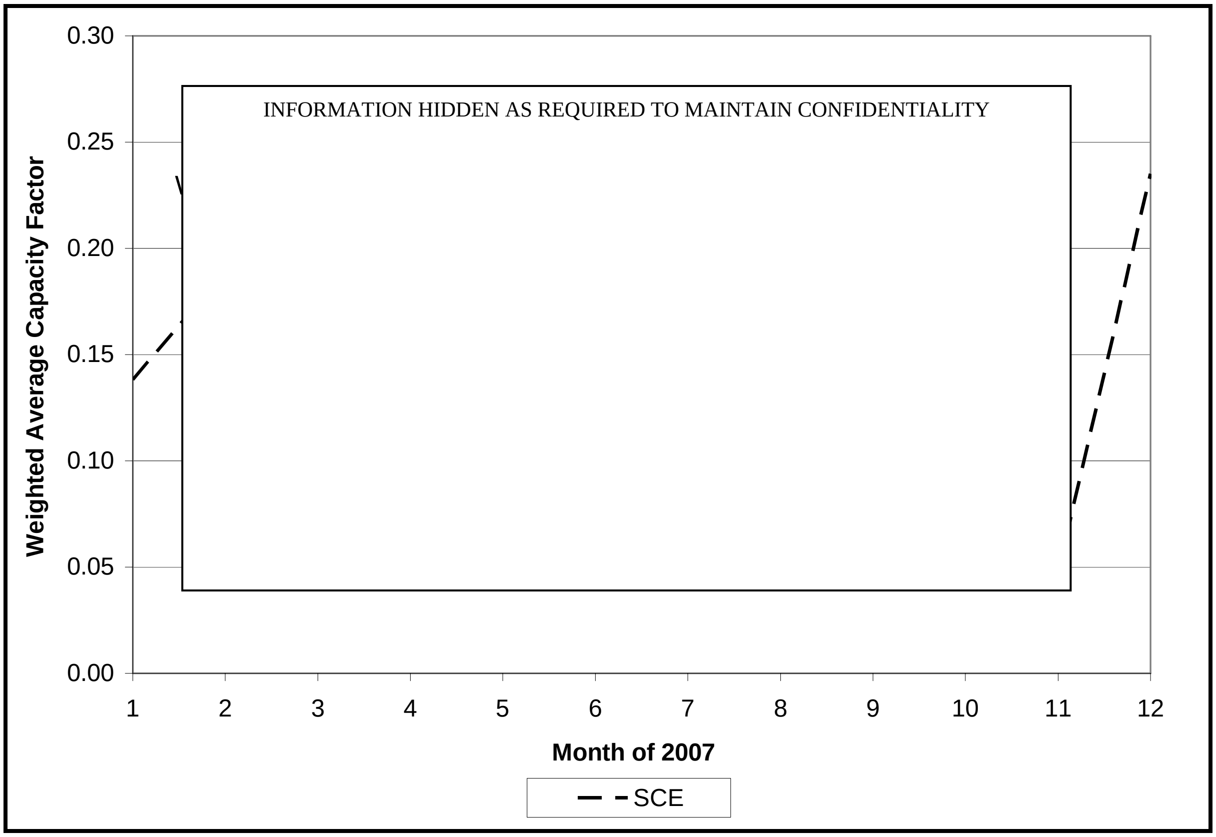


Figure A-16 plots the profiles of hourly weighted average capacity factor for wind for each PA from the morning to early evening during the day of the annual peak hour, August 31, 2007. The chart also shows the profile of the hourly CAISO loads in MW using the vertical axis on the right side of the chart. SCE is the sole PA with wind systems, so no other PAs appear in the chart.

Figure A-16: CAISO Peak Day Capacity Factors by PA

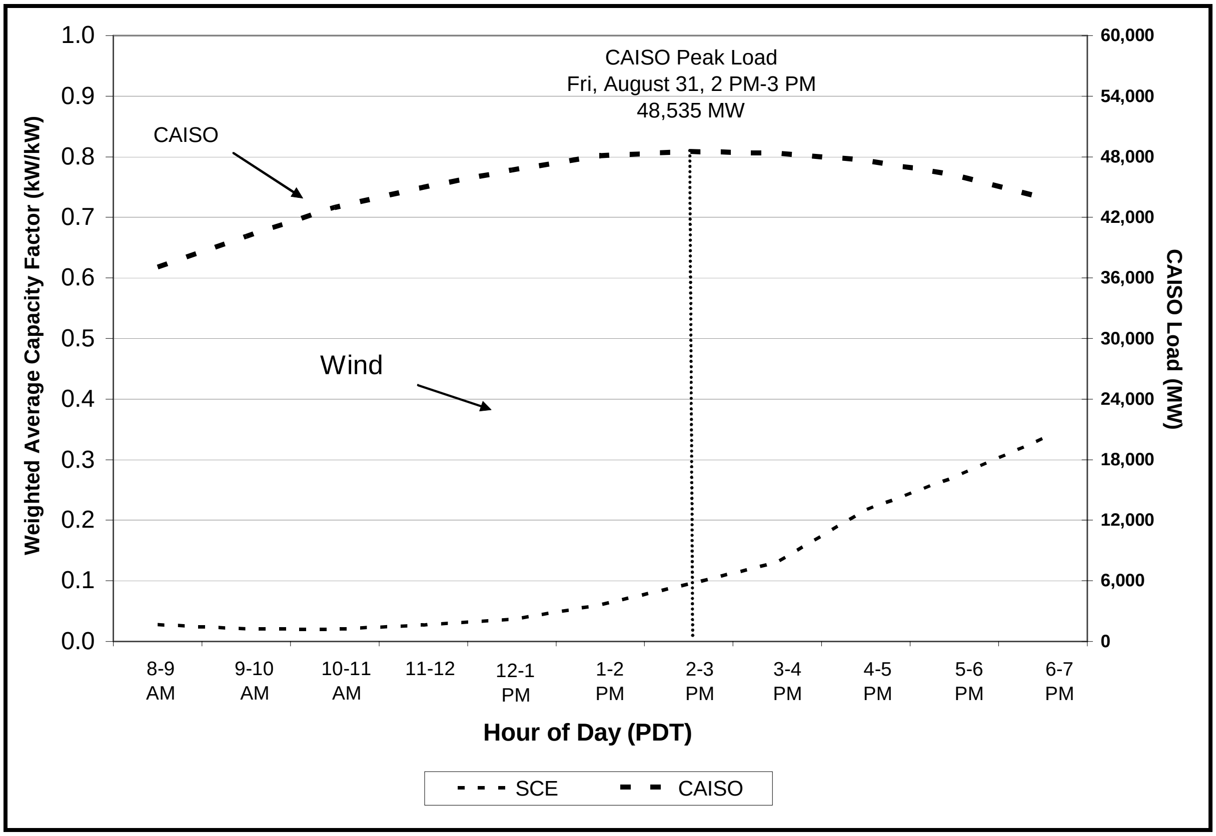
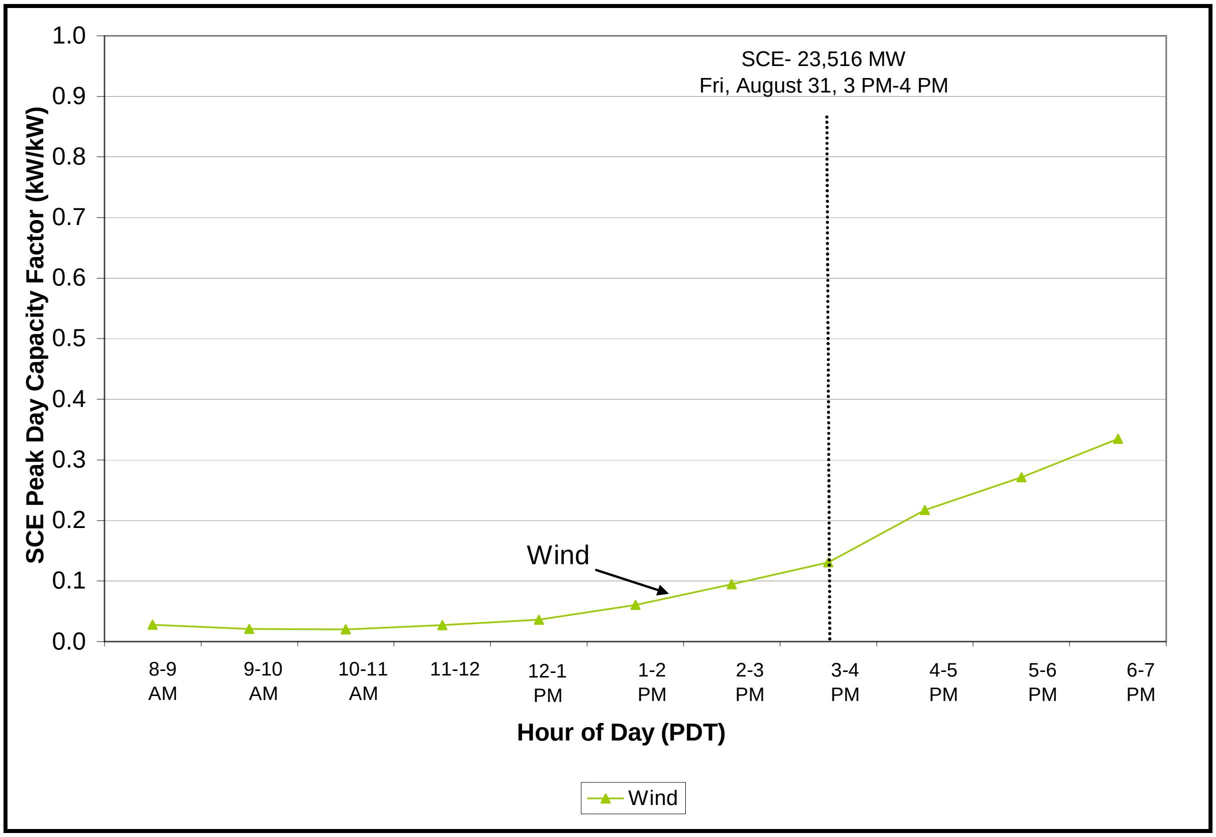


Figure A-17 plot profiles of hourly weighted average capacity factors for wind systems directly feeding the electric utilities on the dates of their respective annual peak hours. Systems administered by the PA associated with the electric utility but not feeding directly into its distribution system are not included in these results. The plots also indicate the date and hour and value of the peak load for the electric utility. SCE is the only PA with wind systems, so no charts are shown for peak days for PG&E or SDG&E.

Figure A-17: Electric Utility Peak Day Capacity Factors—SCE



Renewable Fuel Cells

Costs

Table A-28 lists total eligible costs, SGIP incentives, and other incentives for renewable fuel cell systems.

Table A-28: Complete and Active System Costs

			Complete Projects	Active Projects
Technology	**Fuel**	**Cost Component**	**(M$)**	**(M$)**
FC	**R**	Eligible Cost	$7.28	$80.57
		Incentive	$3.38	$50.24
		Other Incentive	$0.00	$0.50
		Total Incentive	$3.38	$50.74

Annual Energy

Table A-29 presents annual total net electrical output in MWh from renewable fuel cells for the program and for each PA. This table also shows subtotals by basis (metered and estimated), indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-29: Annual Electric Energy Totals by PA

		PG&E	SCE	SCG	CCSE	Total
Technology	**Basis**	**(MWh)**	**(MWh)**	**(MWh)**	**(MWh)**	**(MWh)**
FC	**Total***	**0**	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY			
	M	0				
	E	0	0	0	0	0

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

Table A-30 presents quarterly total net electrical output in MWh for renewable fuel cells. This table also shows subtotals by basis (metered and estimated), indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-30: Quarterly Electric Energy Totals

			Q1-2007	Q2-2007	Q3-2007	Q4-2007	Total*
Technology	**Fuel**	**Basis**	**(MWh)**	**(MWh)**	**(MWh)**	**(MWh)**	**(MWh)**
FC	**R**	**Total**	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY				**0**
		M					0
		E					0

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

Peak Demand

Table A-31 presents total net electrical output in kW for renewable fuel cells during the peak hour of 2:00 to 3:00 P.M. (PDT) on August 31, 2007. The table also shows counts of systems and total operational system capacity in kW.

Table A-31: CAISO Peak Hour Demand Impacts

	On-Line Systems	Operational	Impact*
Technology	**(n)**	**(kW)**	**(kW)**
FC	2	750	187

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

Table A-32 presents the total net electrical output in kW for renewable fuel cells during the respective peak hours of the three large, investor-owned electric utilities. The table also shows counts of systems and total operational system capacity in kW. The table also lists the dates, hours, and loads of the utility's peak hour day. These results for the three individual electric utilities do not strictly include all systems or only systems administered by the PA associated with the electric utility. The results include only those systems whose output feeds directly into the electric utility's distribution system.

Table A-32: Electric Utility Peak Hours Demand Impacts

Elec PA	Peak (MW)	Date	Hour (PDT)	Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)
PGE	21,364	8/29/2007	18	**FC**	0	0	0
SCE	23,516	8/31/2007	15	**FC**	2	750	187
SDGE	4,636	9/3/2007	15	**FC**	0	0	0

Capacity Factors

Weighted average capacity factors indicate renewable fuel cell performance relative to a system-rebated kW for specific time periods. Table A-33 presents annual weighted average capacity factors for renewable fuel cells for the year 2007.

Table A-33: Annual Capacity Factors

Technology	Annual Capacity Factor* (kWyear/kWyear)
FC	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY

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

Table A-34 presents annual weighted average capacity factors for renewable fuel cells for each PA for the year 2007.

Table A-34: Annual Capacity Factors by PA

Technology	PG&E	SCE	SCG	CCSE
	Annual Capacity Factor* (kWyear/kWyear)			
FC	0.000	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY		

Figure A-18 plots profiles of monthly weighted average capacity factors for renewable fuel cells for each PA. Only SCE appears in the charts as it is the only PA with renewable fuel cells.

Figure A-18: Monthly Capacity Factors by PA

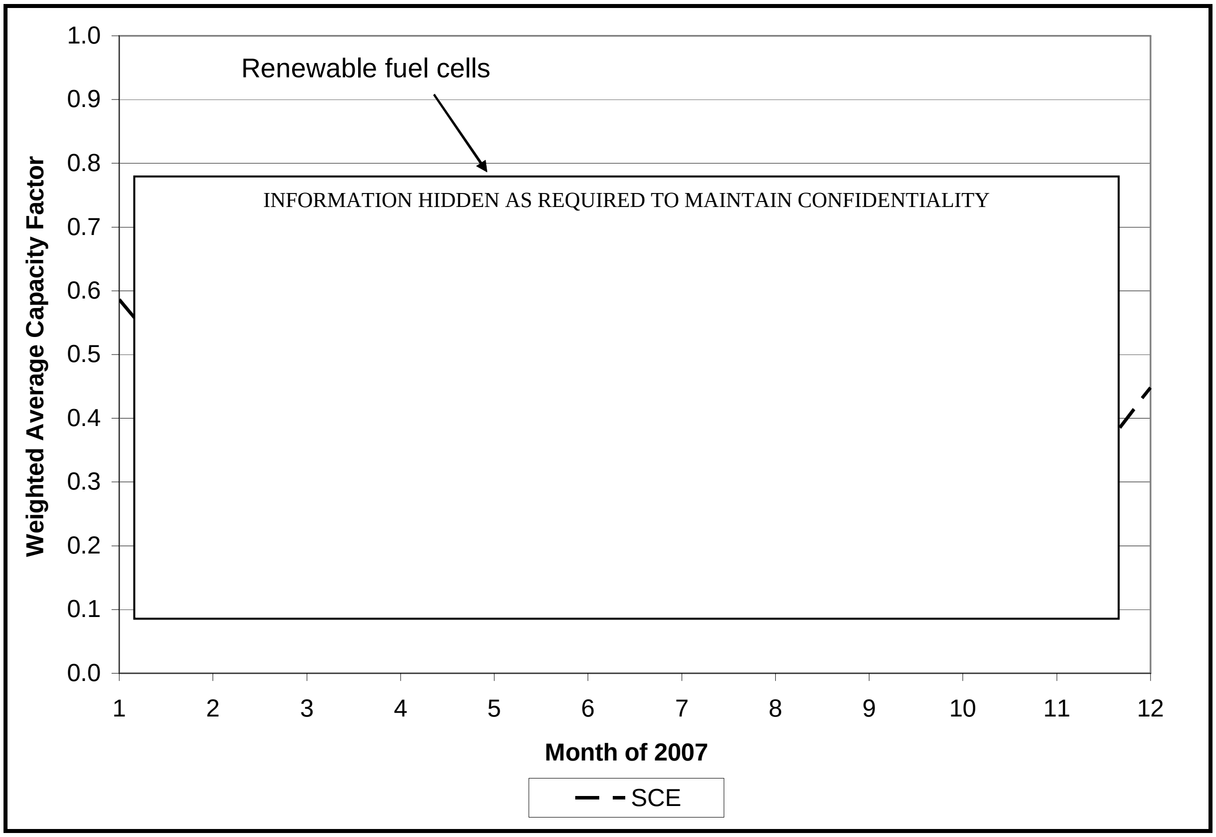


Figure A-19 plots the profiles of hourly weighted average capacity factor for renewable fuel cells for each PA from the morning to early evening during the day of the annual peak hour, August 31, 2007. The chart also shows the profile of the hourly CAISO loads in MW using the vertical axis on the right side of the chart. SCE is the sole PA with renewable fuel cells, so no other PAs appear in the chart.

Figure A-19: CAISO Peak Day Capacity Factors by PA

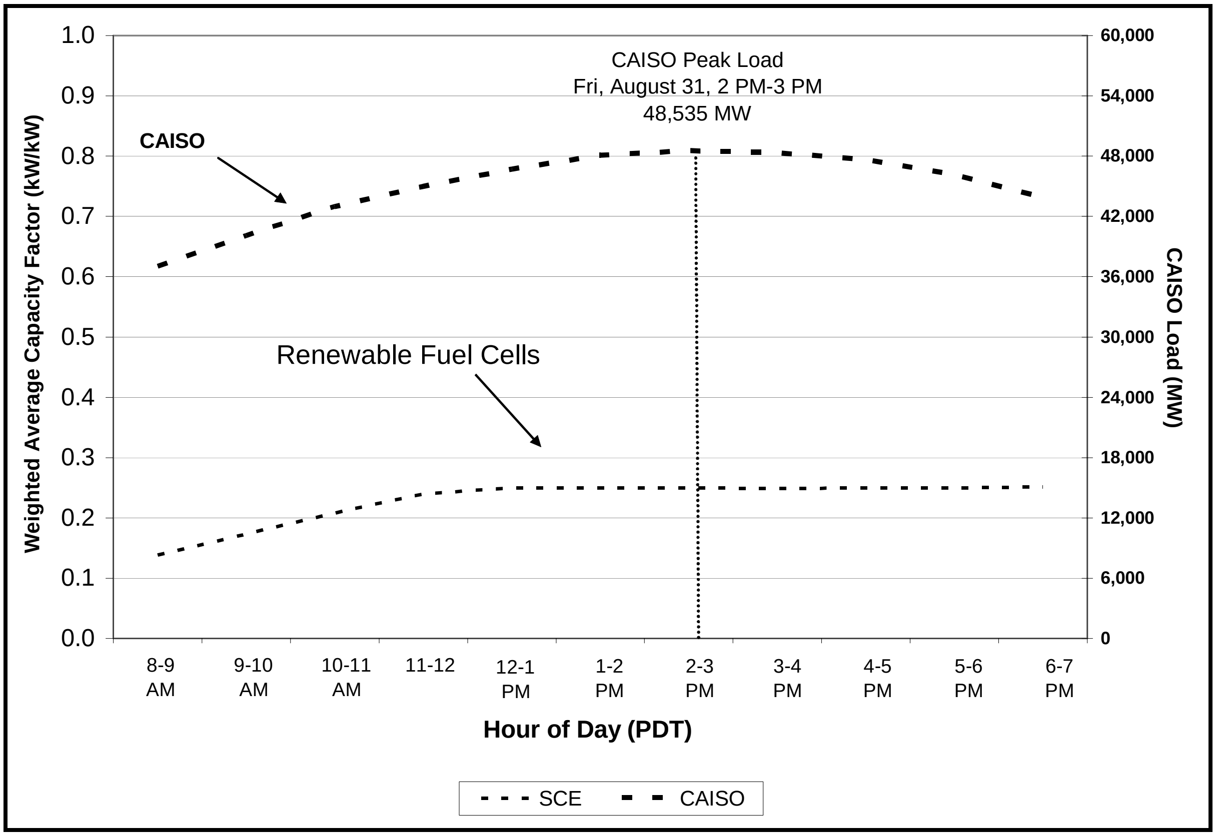
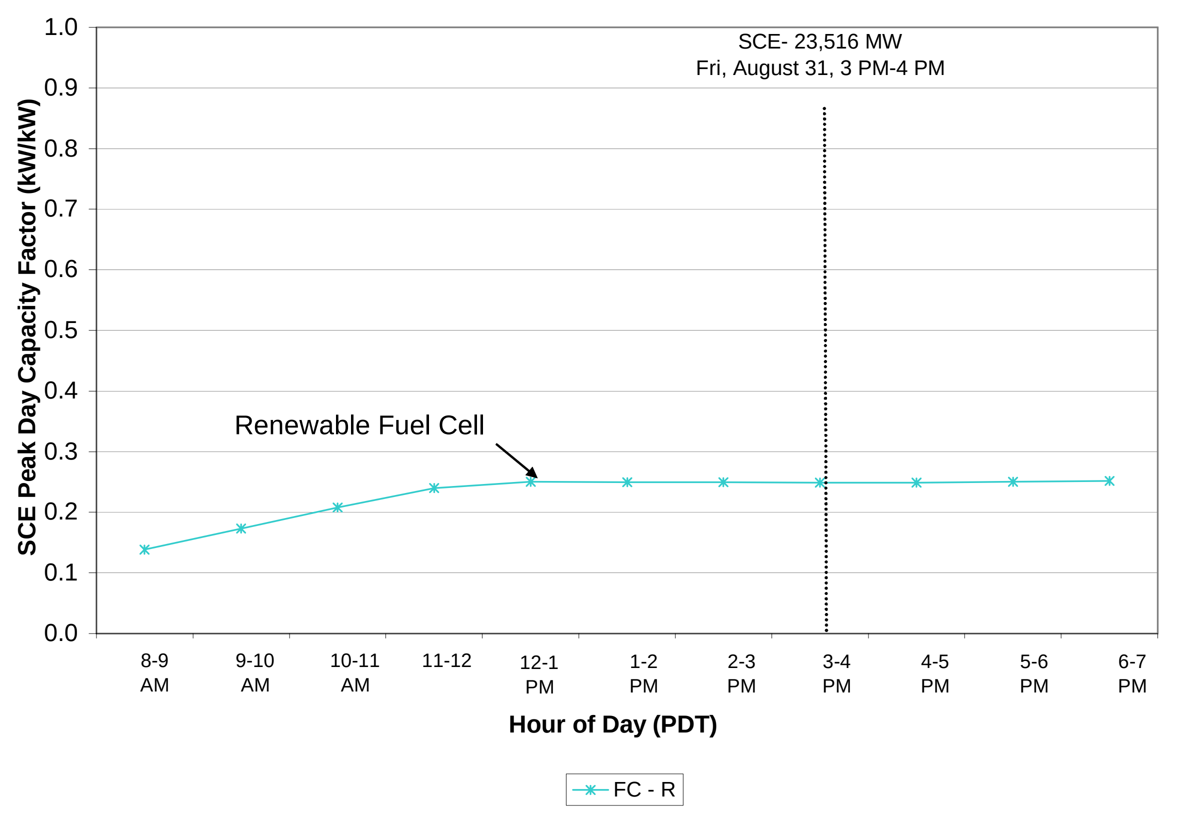


Figure A-20 plot profiles of hourly weighted average capacity factors for renewable fuel cells directly feeding the electric utilities on the dates of their respective annual peak hours. Systems administered by the PA associated with the electric utility but not feeding directly into its distribution system are not included in these results. The plots also indicate the date and hour and value of the peak load for the electric utility. SCE is the only PA with renewable fuel cells, so no charts are shown for peak days for PG&E or SDG&E.

Figure A-20: Electric Utility Peak Day Capacity Factors—SCE



Renewable Internal Combustion Engines and Microturbines

Costs

Table A-35 lists total eligible costs, SGIP incentives, and other incentives for renewable IC engine and microturbine systems.

Table A-35: Complete and Active System Costs by Technology

Technology	Fuel	Cost Component	Complete Projects (M$)	Active Projects (M$)
ICE	**R**	Eligible Cost	$21.37	$23.81
		Incentive	$7.36	$7.83
		Other Incentive	$0.48	$0.00
		Total Incentive	$7.84	$7.83
MT	**R**	Eligible Cost	$11.76	$7.42
		Incentive	$3.81	$2.01
		Other Incentive	$0.19	$0.00
		Total Incentive	$4.01	$2.01

Annual Energy

Table A-36 presents annual total net electrical output in MWh from renewable IC engines and microturbines for the program and for each PA. This table also shows subtotals by basis (metered, and estimated), indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-36: Annual Electric Energy Totals by Technology and PA

Technology	Basis	PG&E (MWh)	SCE (MWh)	SCG (MWh)	CCSE (MWh)	Total (MWh)
ICE	**Total***	**16,983 †**	**16,599**	**2,722 [a]**	**0**	**36,304 †**
	M	0	13,493	0	0	13,493
	E	16,983	3,105	2,722	0	22,810

Technology	Basis	PG&E (MWh)	SCE (MWh)	SCG (MWh)	CCSE (MWh)	Total (MWh)
MT	**Total***	**3,818 †**	**3,492 †**	**0**	**457**	**7,767 †**
	M	0	1,536	0	457	1,993
	E	3,818	1,955	0	0	5,773

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

Table A-37 presents quarterly total net electrical output in MWh for renewable IC engines and microturbines. These tables also show subtotals by basis (metered, and estimated), indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-37: Quarterly Electric Energy Totals by Technology

Technology	Fuel	Basis	Q1-2007 (MWh)	Q2-2007 (MWh)	Q3-2007 (MWh)	Q4-2007 (MWh)	Total* (MWh)
ICE	**R**	**Total**	**9,394**	**9,024**	**8,696**	**9,191**	**36,304 †**
		M	3,261	3,795	3,331	3,106	13,493
		E	6,132	5,229	5,365	6,084	22,810 †
MT	**R**	**Total**	**2,257**	**1,966**	**1,680**	**1,864**	**7,767 †**
		M	602	532	406	453	1,993
		E	1,655	1,434	1,273	1,411	5,773 †

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

Peak Demand

Table A-38 presents total net electrical output in kW for renewable IC engines and microturbines during the peak hour of 2:00 to 3:00 P.M. (PDT) on August 31, 2007. The table also shows counts of systems and total operational system capacity in kW.

Table A-38: CAISO Peak Hour Demand Impacts by Technology

Technology	On-Line Systems (n)	Operational (kW)	Impact* (kW)
ICE	14	9,439	2,698 †
MT	19	3,364	573 †

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

Table A-39 presents the total net electrical output in kW for renewable IC engines and microturbines during the respective peak hours of the three large, investor-owned electric utilities. The table also shows counts of systems and total operational system capacity in kW. The table also lists the dates, hours, and loads of the utility's peak hour day. These results for the three individual electric utilities do not strictly include all systems or only systems administered by the PA associated with the electric utility. The results include only those systems whose output feeds directly into the electric utility's distribution system.

Table A-39: Electric Utility Peak Hours Demand Impacts by Technology

Elec PA	Peak (MW)	Date	Hour (PDT)	Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)
PGE	21,364	8/29/2007	18	**ICE**	7	3,930	1,610
SCE	23,516	8/31/2007	15	**ICE**	7	5,509	1,241
SDGE	4,636	9/3/2007	15	**ICE**	0	0	0
Elec PA	**Peak (MW)**	**Date**	**Hour (PDT)**	**Technology**	**On-Line Systems (n)**	**Operational (kW)**	**Impact (kW)**
PGE	21,364	8/29/2007	18	**MT**	12	1,760	586
SCE	23,516	8/31/2007	15	**MT**	4	1,040	203
SDGE	4,636	9/3/2007	15	**MT**	3	564	45

Capacity Factors

Weighted average capacity factors indicate renewable IC engines and microturbines performances relative to a system-rebated kW for specific time periods. Table A-40 presents annual weighted average capacity factors for renewable IC engines and microturbines for the year 2007.

Table A-40: Annual Capacity Factors by Technology

Technology	Annual Capacity Factor* (kWyear/kWyear)
ICE	0.464 †
MT	0.265 †

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

Table A-41 presents annual weighted average capacity factors for renewable IC engines and microturbines for each PA for the year 2007.

Table A-41: Annual Capacity Factors by Technology and PA

	PG&E	SCE	SCG	CCSE
	Annual Capacity Factor*			
Technology	(kWyear/kWyear)			
ICE	0.491 †	0.445	0.429 [a]	0.000
MT	0.250 †	0.383 †	0.000	0.093

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

Figure A-21 and Figure A-22 plot profiles of monthly weighted average capacity factors for renewable IC engines and microturbines for each PA.

Figure A-21: Monthly Capacity Factors by PA—Renewable IC Engine

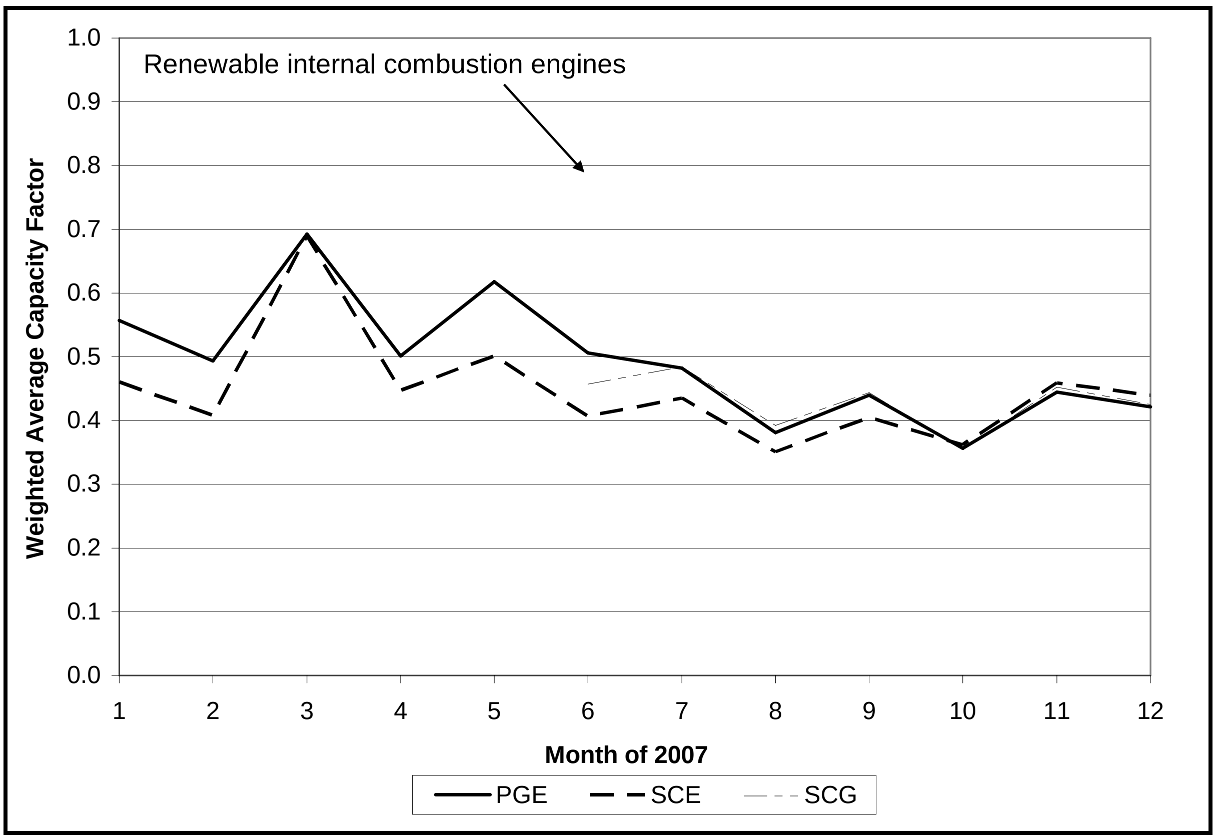


Figure A-22: Monthly Capacity Factors by PA—Renewable MT

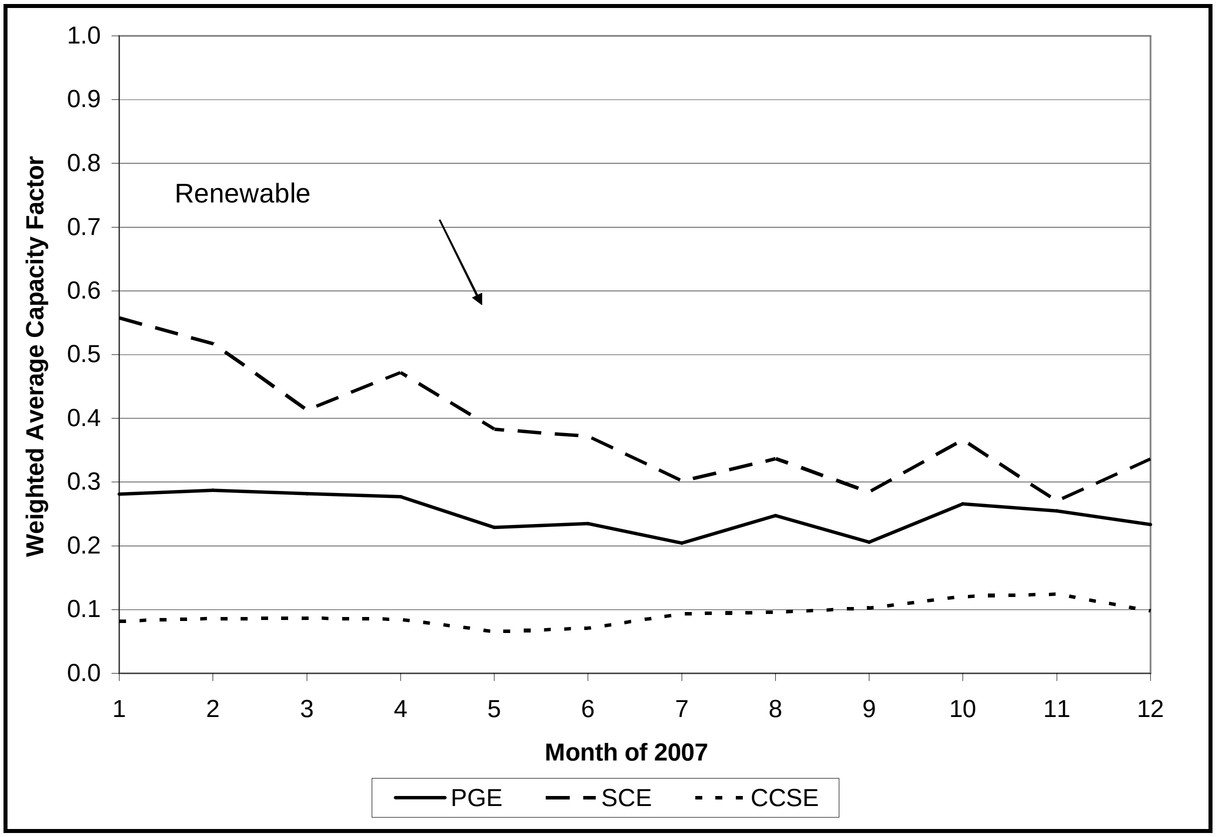


Figure A-23 and Figure A-24 plot the profiles of hourly weighted average capacity factor for renewable IC engines and microturbines for each PA from the morning to early evening during the day of the annual peak hour, August 31, 2007. The charts also show the profile of the hourly CAISO loads in MW using the vertical axis on the right side of the charts.

Figure A-23: CAISO Peak Day Capacity Factors by PA—Renewable IC Engine

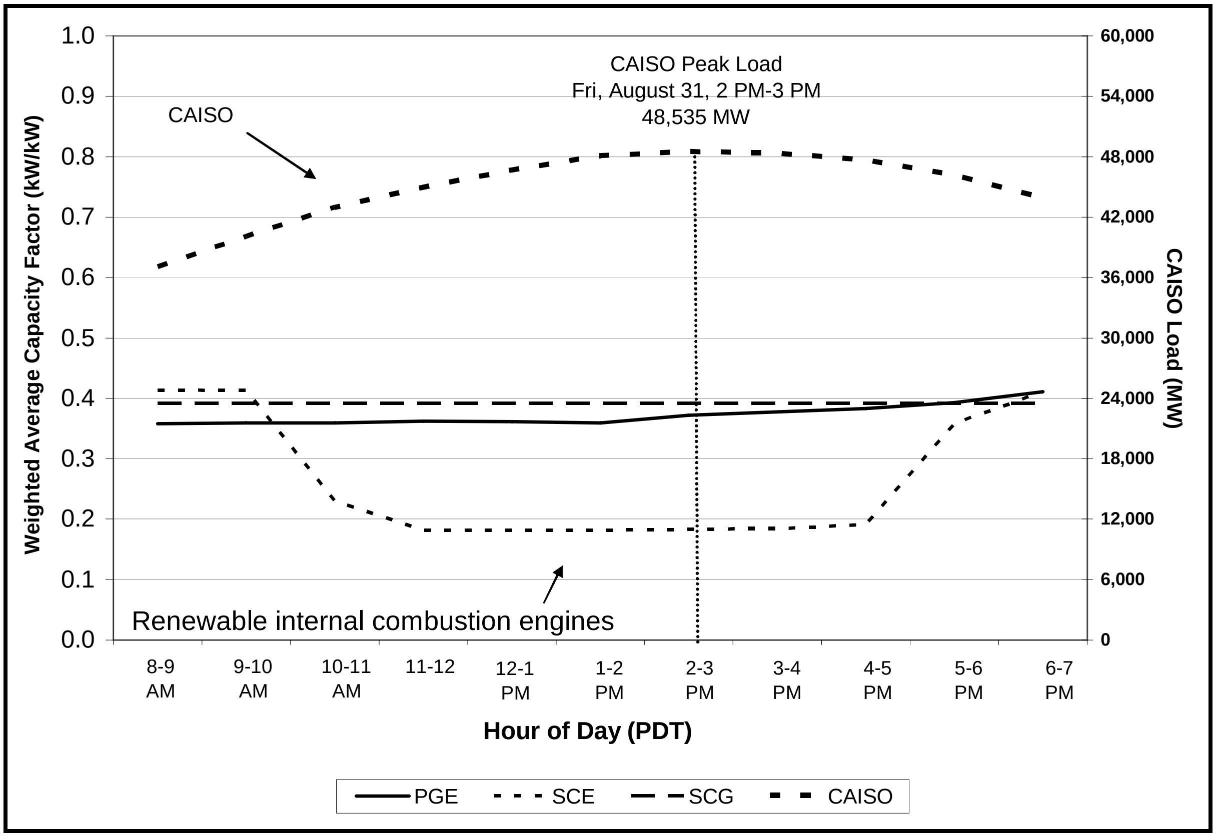


Figure A-24: CAISO Peak Day Capacity Factors by PA—Renewable Microturbine

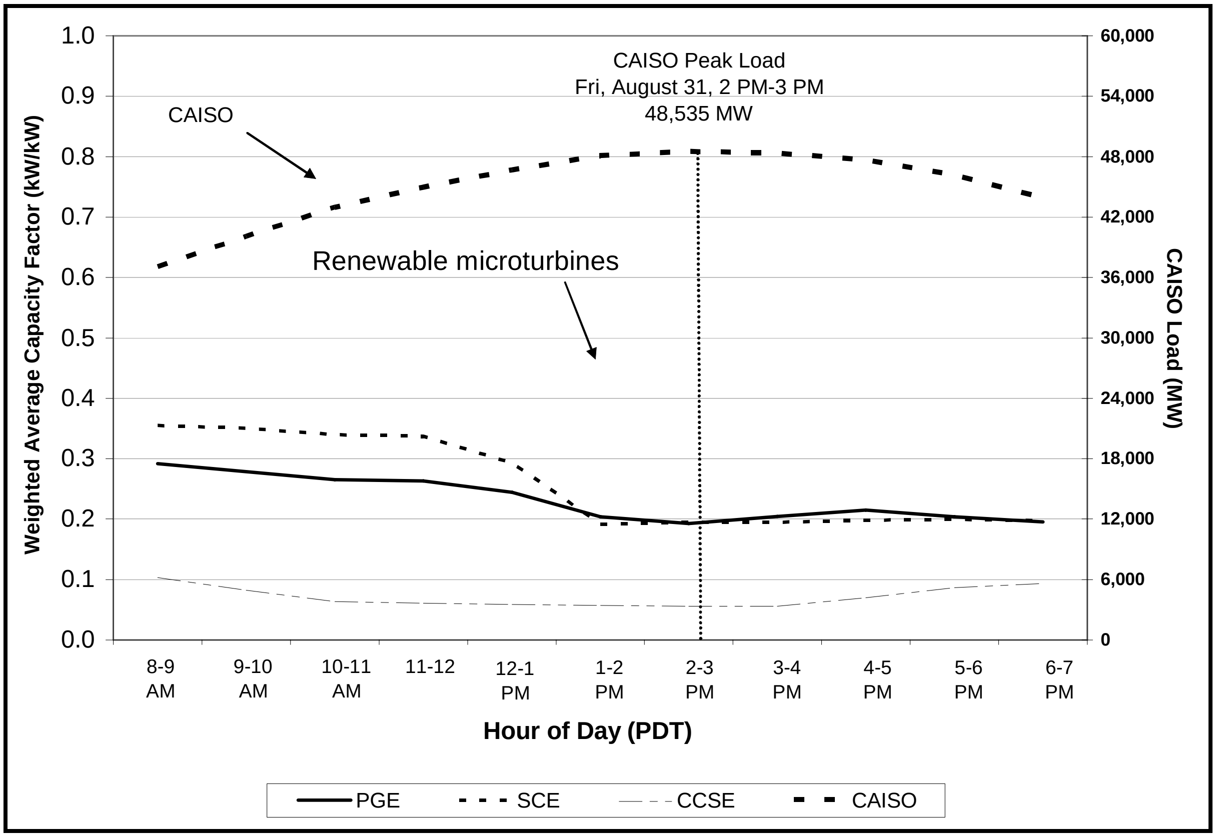


Figure A-25, Figure A-26, and Figure A-27 plot profiles of hourly weighted average capacity factors for renewable IC engines and microturbines directly feeding the electric utilities on the dates of their respective annual peak hours. Systems administered by the PA associated with the electric utility but not feeding directly into its distribution system are not included in these results. The plots also indicate the date and hour and value of the peak load for the electric utility. SDG&E is the only electric utility without renewable IC engines, so no curve appears for that technology on its peak day.

Figure A-25: Electric Utility Peak Day Capacity Factors by Technology—PG&E

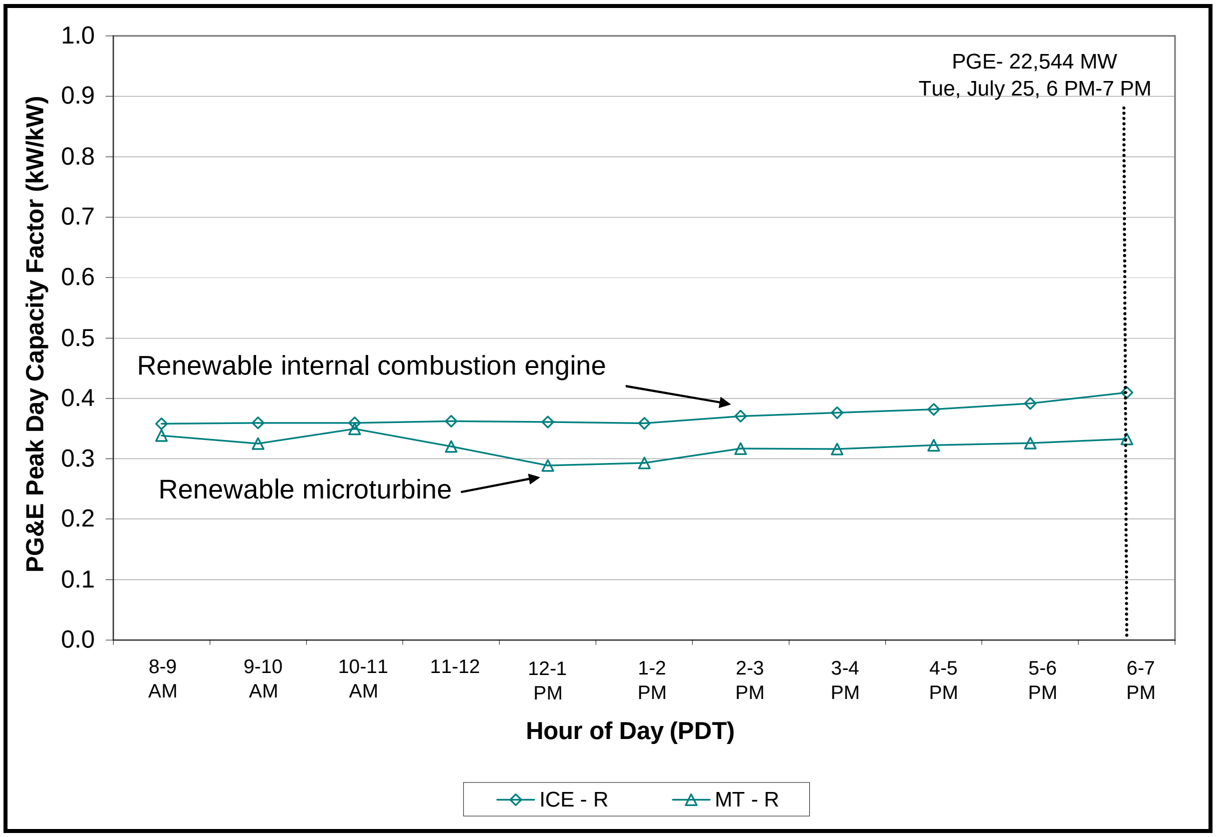


Figure A-26: Electric Utility Peak Day Capacity Factors by Technology—SCE

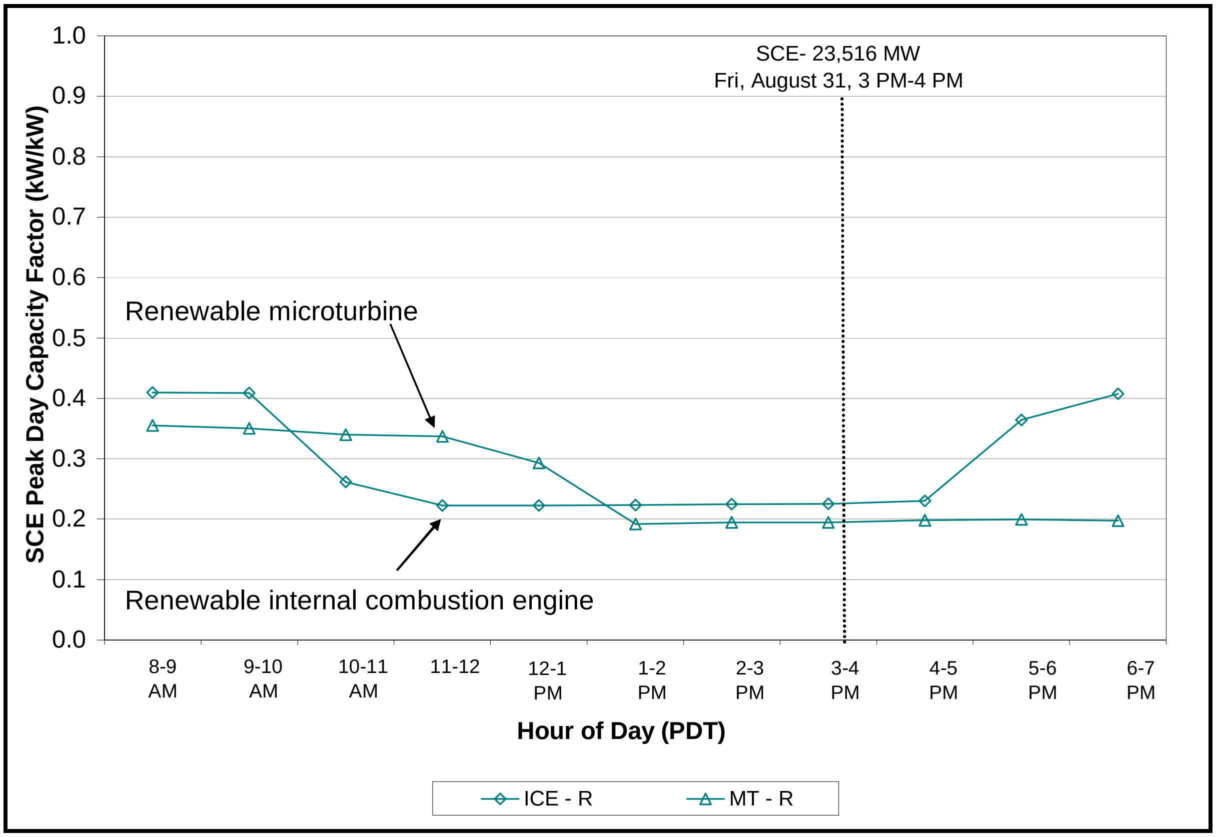
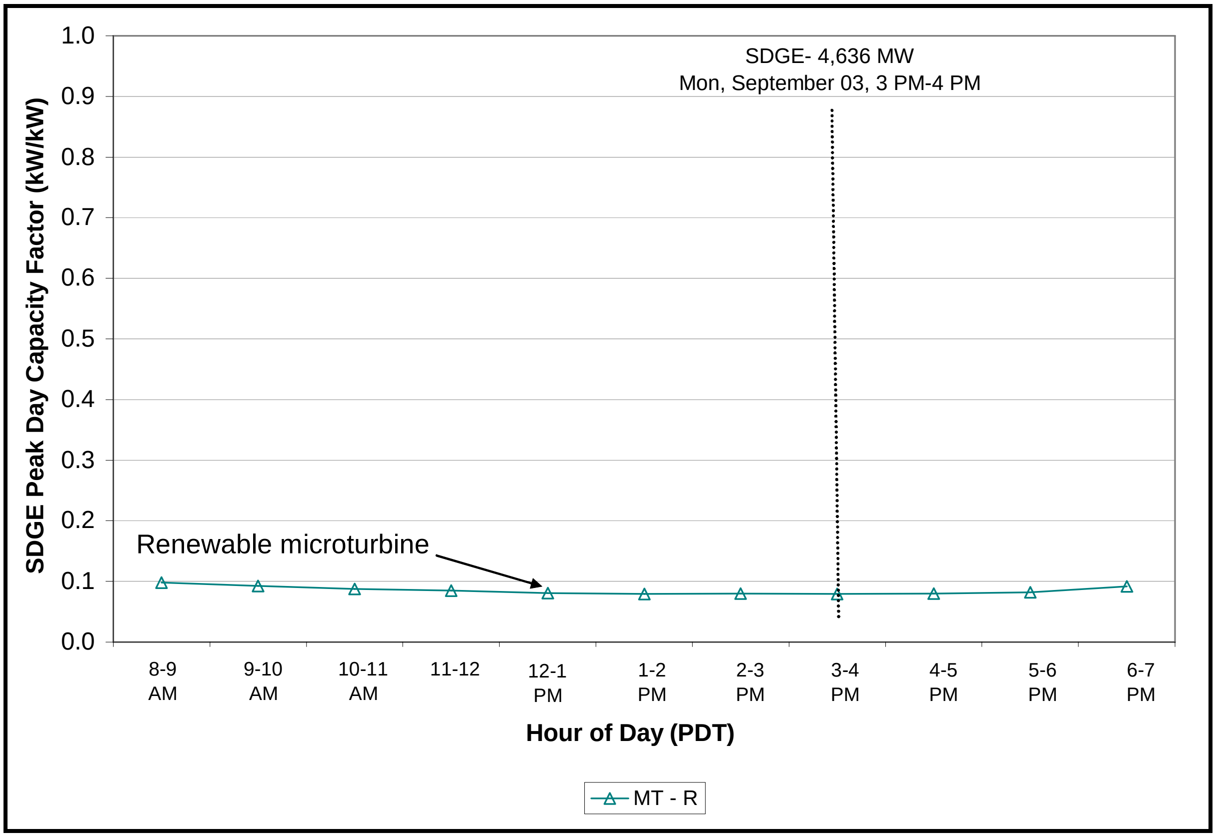


Figure A-27: Electric Utility Peak Day Capacity Factors by Technology—SDG&E



A.4 Non-Renewable Power Systems

This section describes impacts of non-renewable power systems. It begins with fuel cells and proceeds to gas turbines, IC engines, and microturbines.

Natural Gas Fuel Cells

Costs

Table A-42 lists total eligible costs, SGIP incentives, and other incentives for natural gas fuel cells.

Table A-42: Complete and Active System Costs

			Complete Projects	Active Projects
Technology	**Fuel**	**Cost Component**	**(M$)**	**(M$)**
FC	**N**	Eligible Cost	$46.26	$34.43
		Incentive	$14.47	$12.16
		Other Incentive	$2.45	$0.50
		Total Incentive	$16.92	$12.66

Annual Energy

Table A-43 presents annual total net electrical output in MWh from natural gas fuel cells for the program and for each PA. This table also shows subtotals by basis (metered, and estimated), indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-43: Annual Electric Energy Totals by PA

		PG&E	SCE	SCG	CCSE	Total
Technology	**Basis**	**(MWh)**	**(MWh)**	**(MWh)**	**(MWh)**	**(MWh)**
FC	**Total***	**24,344**	INFORMATION HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY		**12,642**	**49,599**
	M	17,027			12,193	33,633
	E	7,317			449	15,966

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

Table A-44 presents quarterly total net electrical output in MWh for natural gas fuel cells. This table also shows subtotals by basis (metered, and estimated), indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-44: Quarterly Electric Energy Totals

Technology	Fuel	Basis	Q1-2007 (MWh)	Q2-2007 (MWh)	Q3-2007 (MWh)	Q4-2007 (MWh)	Total* (MWh)
FC	**N**	**Total**	**11,734**	**12,410**	**12,947**	**12,508**	**49,599**
		M	7,300	8,412	9,386	8,535	33,633
		E	4,434	3,998	3,561	3,972	15,966 †

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

Peak Demand

Table A-45 presents total net electrical output in kW for natural gas fuel cells during the peak hour of 2:00 to 3:00 P.M. (PDT) on August 31, 2007. The table also shows counts of systems and total operational system capacity in kW.

Table A-45: CAISO Peak Hour Demand Impacts

Technology	On-Line Systems (n)	Operational (kW)	Impact* (kW)
FC	12	7,250	5,795

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

Table A-46 presents the total net electrical output in kW for natural gas fuel cells during the respective peak hours of the three large, investor-owned electric utilities. The table also shows counts of systems and total operational system capacity in kW. The table also lists the dates, hours, and loads of the utility's peak hour day. These results for the three individual electric utilities do not strictly include all systems or only systems administered by the PA associated with the electric utility. The results include only those systems whose output feeds directly into the electric utility's distribution system.

Table A-46: Electric Utility Peak Hours Demand Impacts

Elec PA	Peak (MW)	Date	Hour (PDT)	Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)
PGE	21,364	8/29/2007	18	**FC**	6	3,550	1,795
SCE	23,516	8/31/2007	15	**FC**	2	700	612
SDGE	4,636	9/3/2007	15	**FC**	3	2,000	834

Capacity Factors

Weighted average capacity factors indicate natural gas fuel cell performance relative to a system rebated kilowatt for specific time periods. Table A-47 presents annual weighted average capacity factors for natural gas fuel cells for the year 2007.

Table A-47: Annual Capacity Factors

Technology	Annual Capacity Factor* (kWyear/kWyear)
FC	0.784

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

Table A-48 presents annual weighted average capacity factors for natural gas fuel cells for each PA for the year 2007.

Table A-48: Annual Capacity Factors by PA

	PG&E	SCE	SCG	CCSE
Technology	Annual Capacity Factor (kWyear/kWyear)			
FC	0.749			0.794

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

Figure A-28 plots profiles of monthly weighted average capacity factors for natural gas fuel cells for each PA. Monthly capacity factors for SCG and SCE natural gas fuel cells directly overlap those of CCSE from early August and September respectively. This overlap is a result of the metered data for CCSE systems being used to estimate output for the SCG and SCE systems.

Figure A-28: Monthly Capacity Factors by Technology and PA

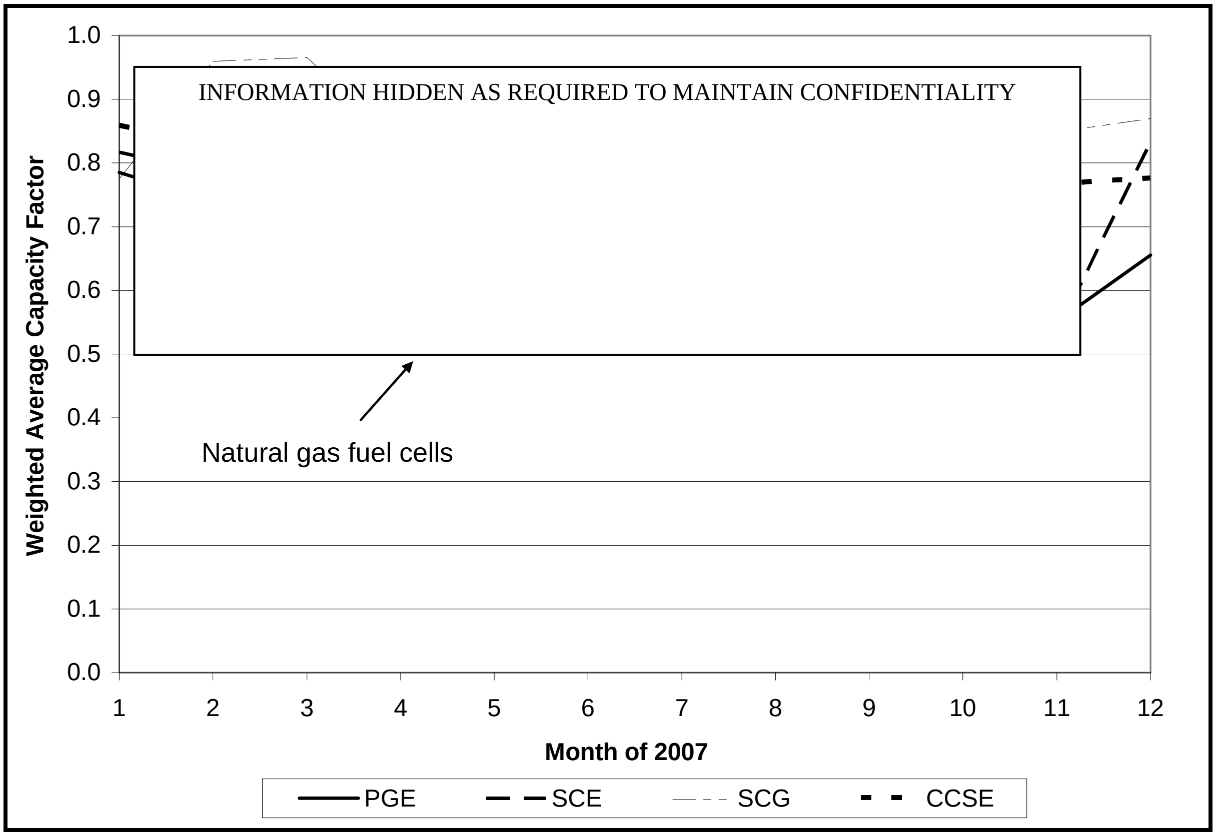


Figure A-29 plots the profiles of hourly weighted average capacity factor for natural gas fuel cells for each PA from the morning to early evening during the day of the annual peak hour, August 31, 2007. The chart also shows the profile of the hourly CAISO loads in MW using the vertical axis on the right side of the chart.

Figure A-29: CAISO Peak Day Capacity Factors by PA

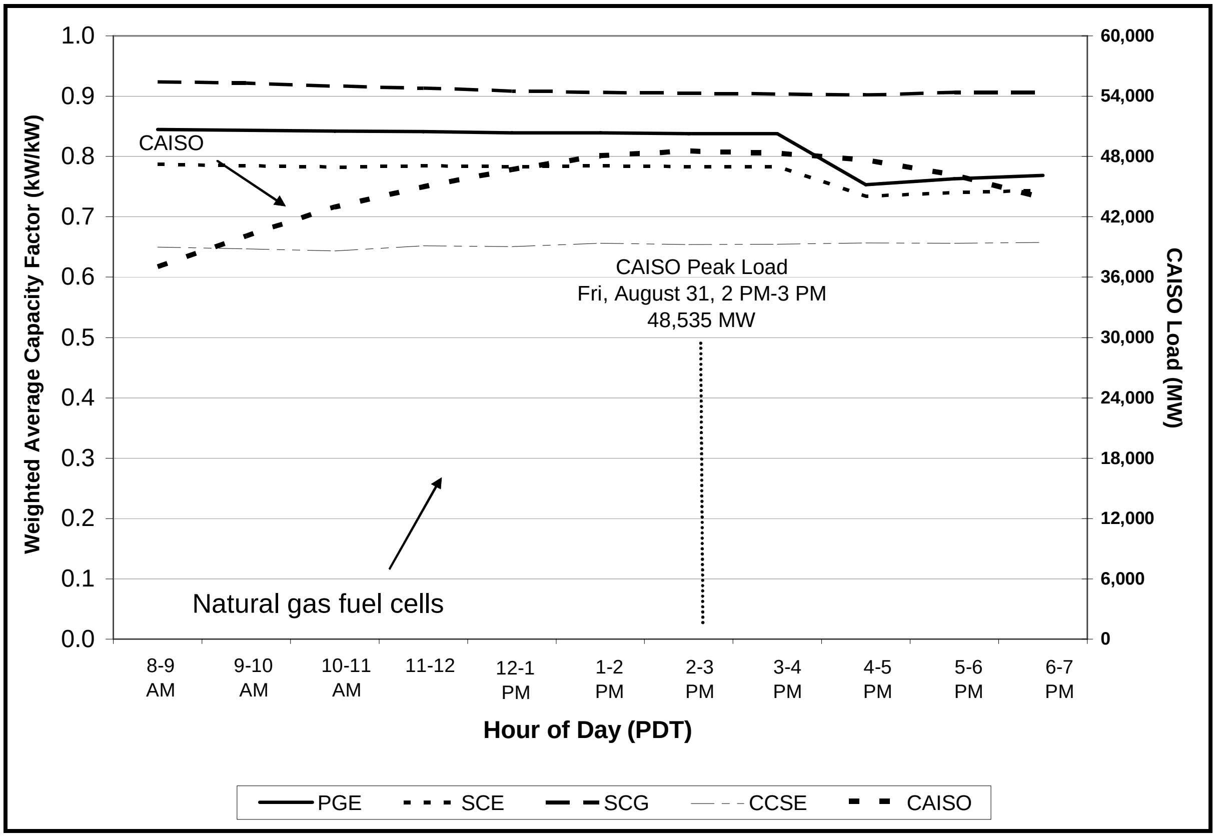


Figure A-30 and Figure A-32 plot profiles of hourly weighted average capacity factors for natural gas fuel cells directly feeding the electric utilities on the dates of their respective annual peak hours. Systems administered by the PA associated with the electric utility but not feeding directly into its distribution system are not included in these results. SCE and SCG both administer natural gas fuel cell systems, but no chart appears for SCE because none of these systems fed directly into SCE's distribution system on SCE's peak day. The plots also indicate the date and hour and value of the peak load for the electric utility.

Figure A-30: Electric Utility Peak Day Capacity Factors—PG&E

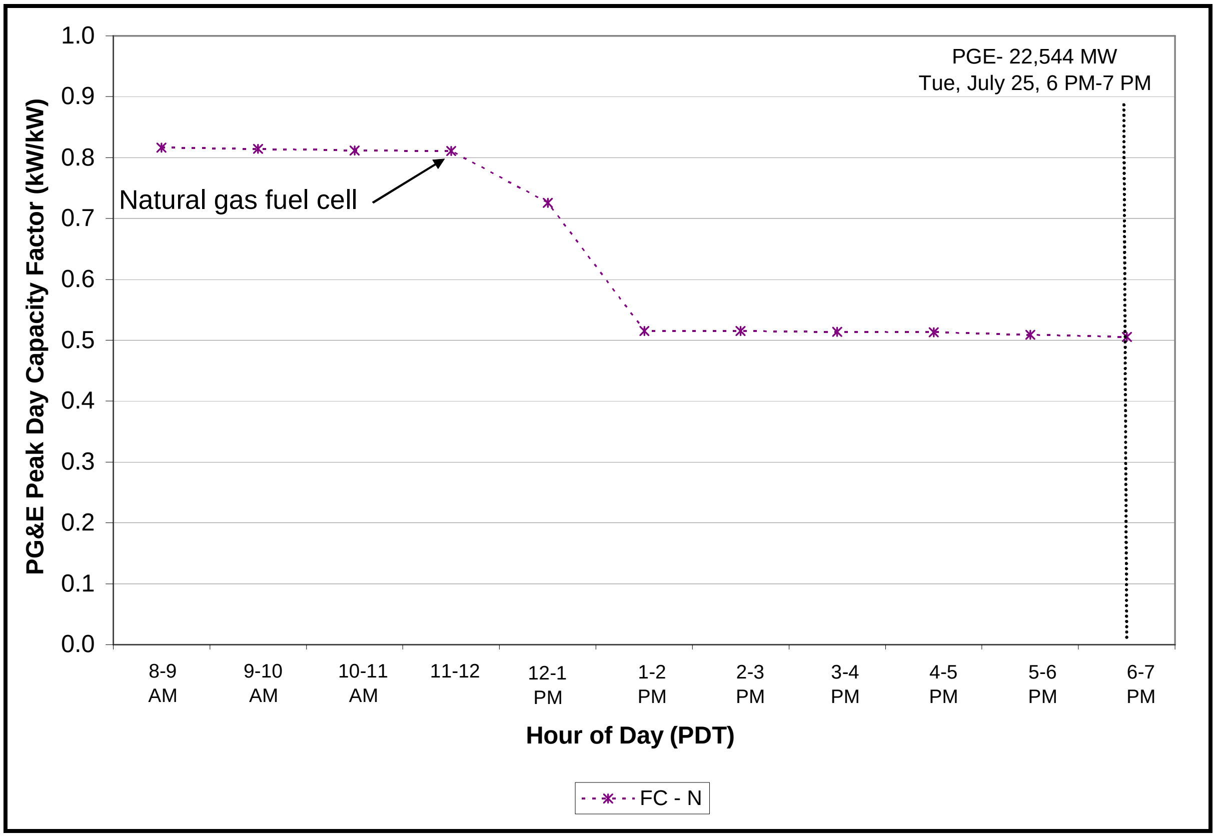


Figure A-31: Electric Utility Peak Day Capacity Factors—SDG&E

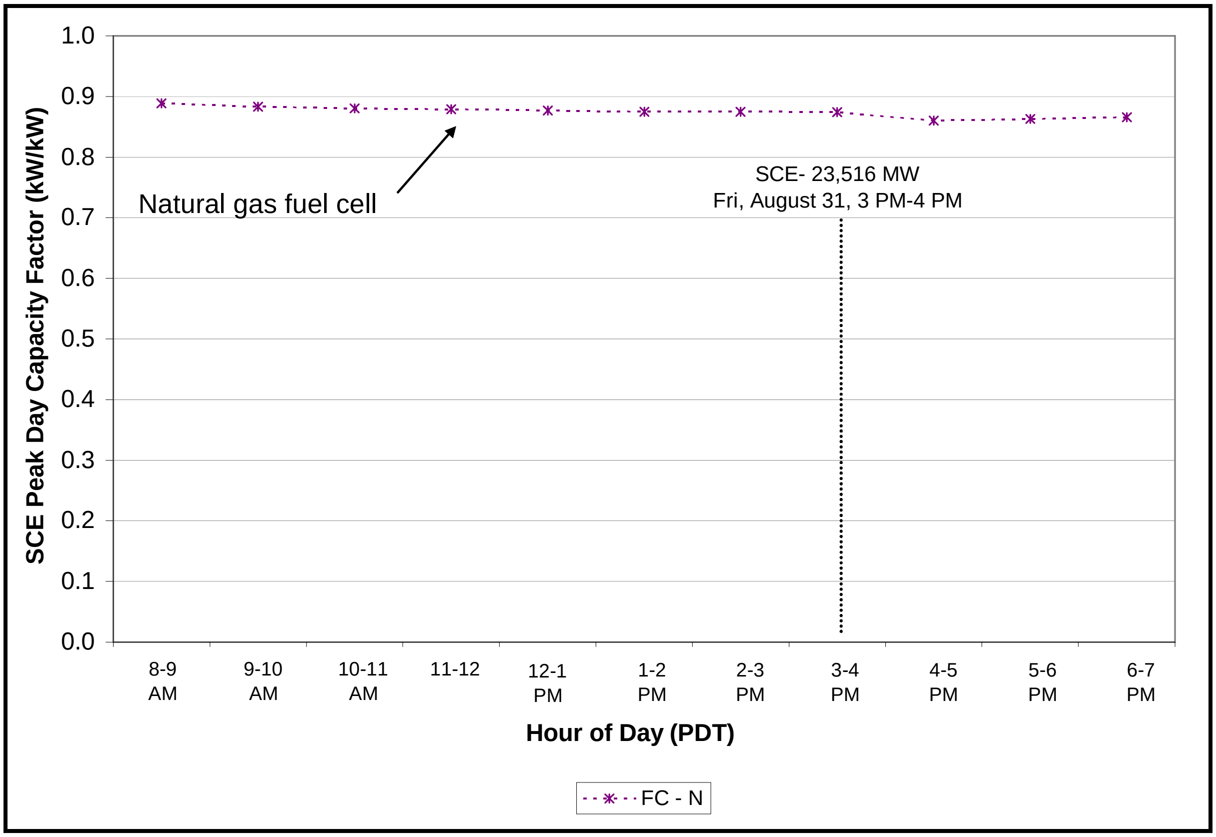
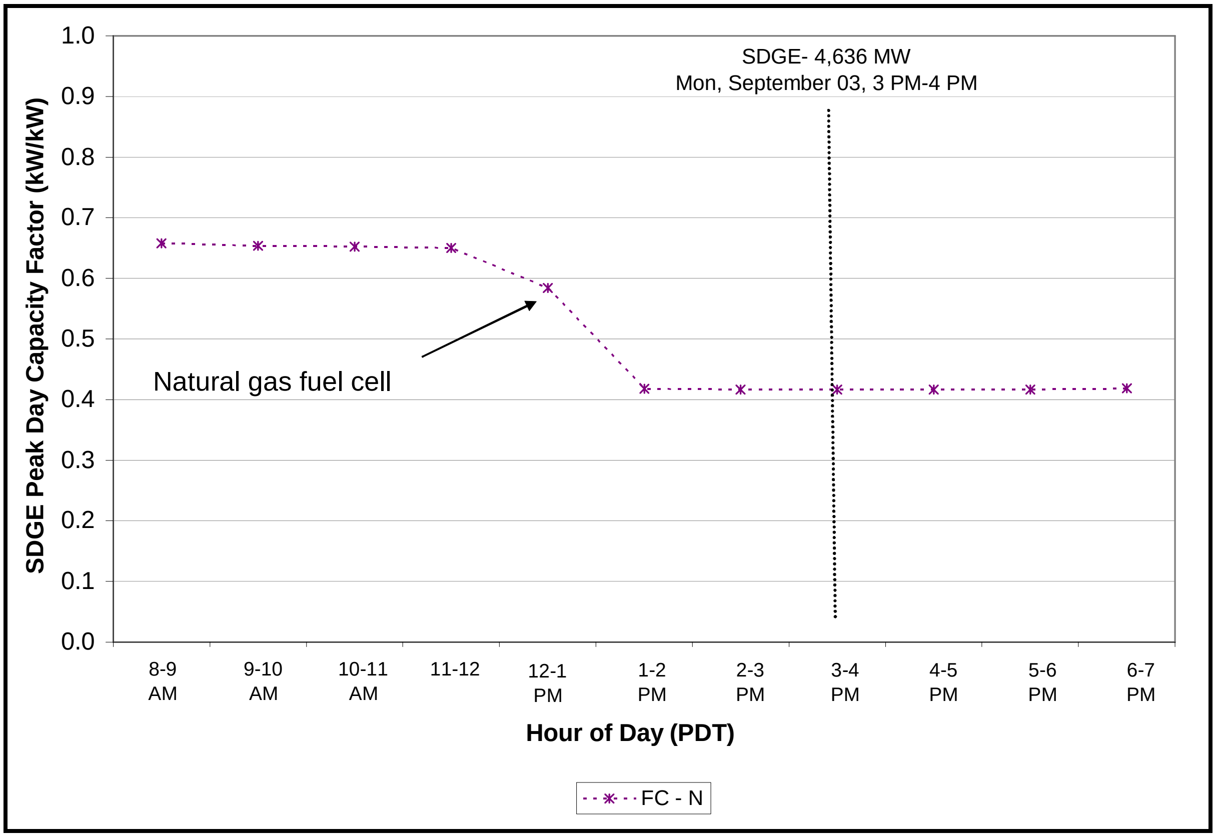


Figure A-32: Electric Utility Peak Day Capacity Factors—SDG&E



Natural Gas Turbines, Internal Combustion Engines, and Microturbines

Costs

Table A-49 lists total eligible costs, SGIP incentives, and other incentives for natural gas turbine, IC engine, and microturbine systems.

Table A-49: Complete and Active System Costs by Technology

Technology	Fuel	Cost Component	Complete Projects (M$)	Active Projects (M$)
GT	**N**	Eligible Cost	$28.90	$24.48
		Incentive	$3.86	$3.40
		Other Incentive	$0.00	$0.00
		Total Incentive	$3.86	$3.40
ICE	**N**	Eligible Cost	$259.29	$167.42
		Incentive	$67.07	$28.80
		Other Incentive	$0.86	$0.05
		Total Incentive	$67.93	$28.85
MT	**N**	Eligible Cost	$47.22	$36.28
		Incentive	$12.47	$7.95
		Other Incentive	$1.06	$0.00
		Total Incentive	$13.53	$7.95

Annual Energy

Table A-50 presents annual total net electrical output in MWh from natural gas turbine, IC engine, and microturbine systems for the program and for each PA. This table also shows subtotals by basis (metered, and estimated), indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-50: Annual Electric Energy Totals by PA

Technology	Basis	PG&E (MWh)	SCE (MWh)	SCG (MWh)	CCSE (MWh)	Total (MWh)
GT	**Total***	**22,689 [a]**	**0**	HIDDEN AS REQUIRED TO MAINTAIN CONFIDENTIALITY		**82,193 †**
	M	7,726				59,927
	E	14,963				22,266
ICE	**Total***	**119,088 †**	**56,921 †**	**113,516 †**	**27,223**	**316,748 †**
	M	26,732	25,899	63,935	27,094	143,661
	E	92,357	31,022	49,581	128	173,088
MT	**Total***	**23,829 †**	**13,903 †**	**21,255 †**	**2,922**	**61,910 †**
	M	2,496	9,106	9,802	2,909	24,314
	E	21,334	4,797	11,453	13	37,596
	Total	**165,607**	**70,824**	**164,647**	**59,774**	**460,852**

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

Table A-51 present quarterly total net electrical output in MWh for natural gas turbine, IC engine, and microturbine systems. These tables also show subtotals by basis (metered, and estimated), indicating respectively the subtotal physically metered at the many SGIP sites and the subtotal estimated where metered electrical energy data were not available.

Table A-51: Quarterly Electric Energy Totals

Technology	Fuel	Basis	Q1-2007 (MWh)	Q2-2007 (MWh)	Q3-2007 (MWh)	Q4-2007 (MWh)	Total* (MWh)
GT	**N**	**Total**	**19,865**	**22,068**	**17,964**	**22,297**	**82,193 †**
		M	9,056	18,141	13,944	18,786	59,927
		E	10,809	3,927	4,020	3,511	22,266 [a]
ICE	**N**	**Total**	**78,647**	**74,066**	**84,816**	**79,220**	**316,748 †**
		M	35,070	34,501	41,026	33,063	143,661
		E	43,577	39,565	43,789	46,157	173,088 †
MT	**N**	**Total**	**13,069**	**16,203**	**15,083**	**17,554**	**61,910 †**
		M	3,759	6,908	6,457	7,188	24,314
		E	9,310	9,295	8,626	10,366	37,596 †

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

Peak Demand

Table A-52 presents total net electrical output in kW for natural gas turbine, IC engine, and microturbine systems during the peak hour of 2:00 to 3:00 P.M. (PDT) on August 31, 2007. The table also shows counts of systems and total operational system capacity in kW.

Table A-52: CAISO Peak Hour Demand Impacts

Technology	On-Line Systems (n)	Operational (kW)	Impact* (kW)
GT	5	13,043	8,386 †
ICE	200	123,972	49,412
MT	102	15,910	7,046 †
Total	307	152,925	64,844

*Except for the total, [a] indicates confidence is less than 70/30. † indicates confidence is better than 70/30. No symbol indicates confidence is better than 90/10.

Table A-53 presents the total net electrical output in kW for natural gas turbine, IC engine, and microturbine systems during the respective peak hours of the three large, investor-owned electric utilities. The table also shows counts of systems and total operational system capacity in kW. The table also lists the dates, hours, and loads of the utility's peak hour day. These results for the three individual electric utilities do not strictly include all systems or only systems administered by the PA associated with the electric utility. The results include only those systems whose output feeds directly into the electric utility's distribution system.

Table A-53: Electric Utility Peak Hours Demand Impacts

Elec PA	Peak (MW)	Date	Hour (PDT)	Technology	On-Line Systems (n)	Operational (kW)	Impact (kW)
PGE	21,364	8/29/2007	18	**GT**	3	4,016	2,643
				ICE	89	51,062	15,640
				MT	39	6,458	2,980
				Total	131	61,536	21,264
SCE	23,516	8/31/2007	15	**GT**	1	4,500	1,948
				ICE	86	57,974	22,335
				MT	43	7,122	2,933
				Total	130	69,596	27,216
SDGE	4,636	9/3/2007	15	**GT**	1	4,527	3,612
				ICE	19	11,995	4,960
				MT	13	1,128	269
				Total	33	17,650	8,841

Capacity Factors

Weighted average capacity factors indicate natural gas turbine, IC engine, and microturbine systems performance relative to a system rebated kilowatt for specific time periods. Table A-54 presents annual weighted average capacity factors for natural gas turbine, IC engine, and microturbine systems for the year 2007.

Table A-54: Annual Capacity Factors

Technology	Annual Capacity Factor* (kWyear/kWyear)
GT	0.719 †
ICE	0.294 †
MT	0.441 †

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

Table A-55 presents annual weighted average capacity factors for natural gas turbine, IC engine, and microturbine systems for each PA for the year 2007.

Table A-55: Annual Capacity Factors by Technology and PA

	PG&E	SCE	SCG	CCSE
	Annual Capacity Factor*			
Technology	(kWyear/kWyear)			
FC	0.749		†	0.794
GT	0.645 [a]			
ICE	0.274 †	0.300 †	0.315 †	0.297
MT	0.437 †	0.437 †	0.482 †	0.297

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

Figure A-33, Figure A-34, and Figure A-35 plot profiles of monthly weighted average capacity factors for natural gas turbine, IC engine, and microturbine systems for each PA.

Figure A-33: Monthly Capacity Factors by Technology—Natural Gas Turbine

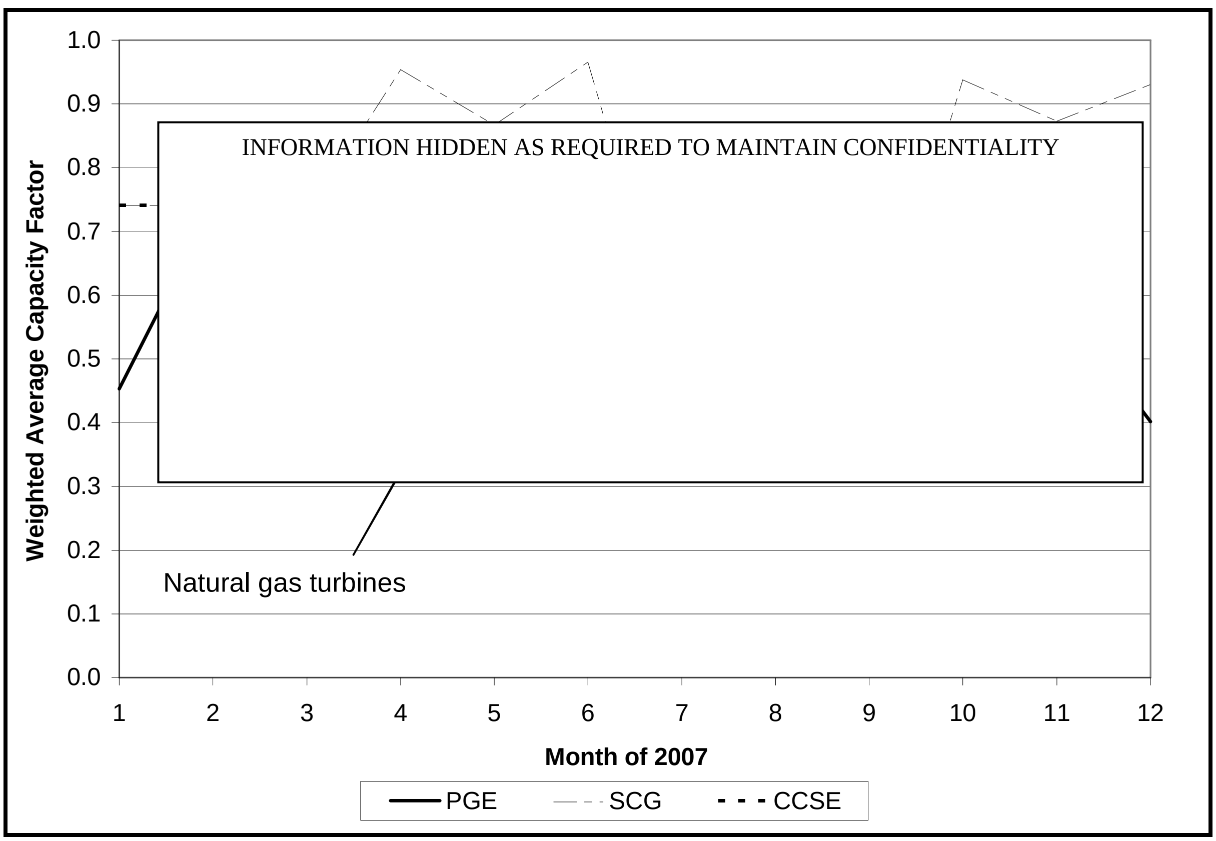


Figure A-34: Monthly Capacity Factors by Technology—Natural Gas IC Engine

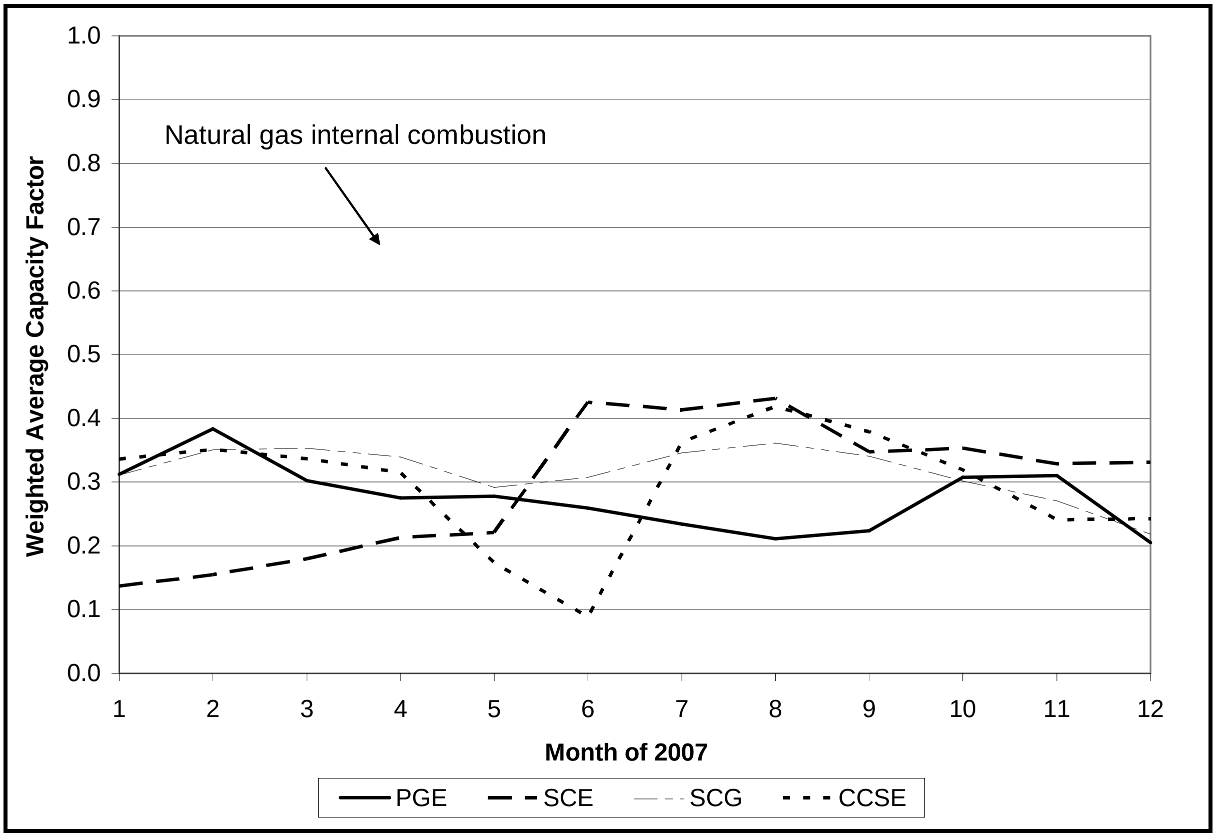


Figure A-35: Monthly Capacity Factors by Technology—Natural Gas Microturbine

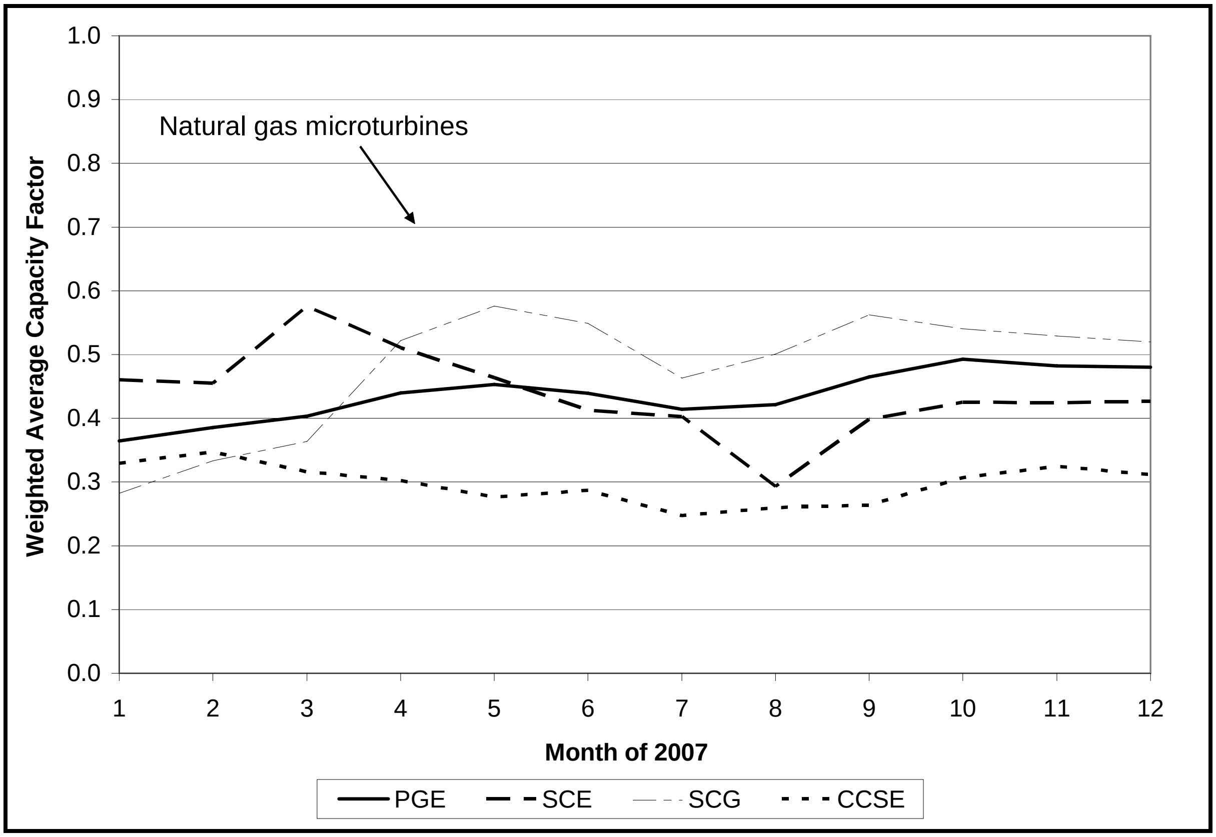


Figure A-36 plots the profiles of hourly weighted average capacity factor for natural gas turbine, IC engine, and microturbine systems from the morning to early evening during the day of the annual peak hour, August 31, 2007. The charts also show the profile of the hourly CAISO loads in MW using the vertical axis on the right side of the chart.

Figure A-36: CAISO Peak Day Capacity Factors by Technology

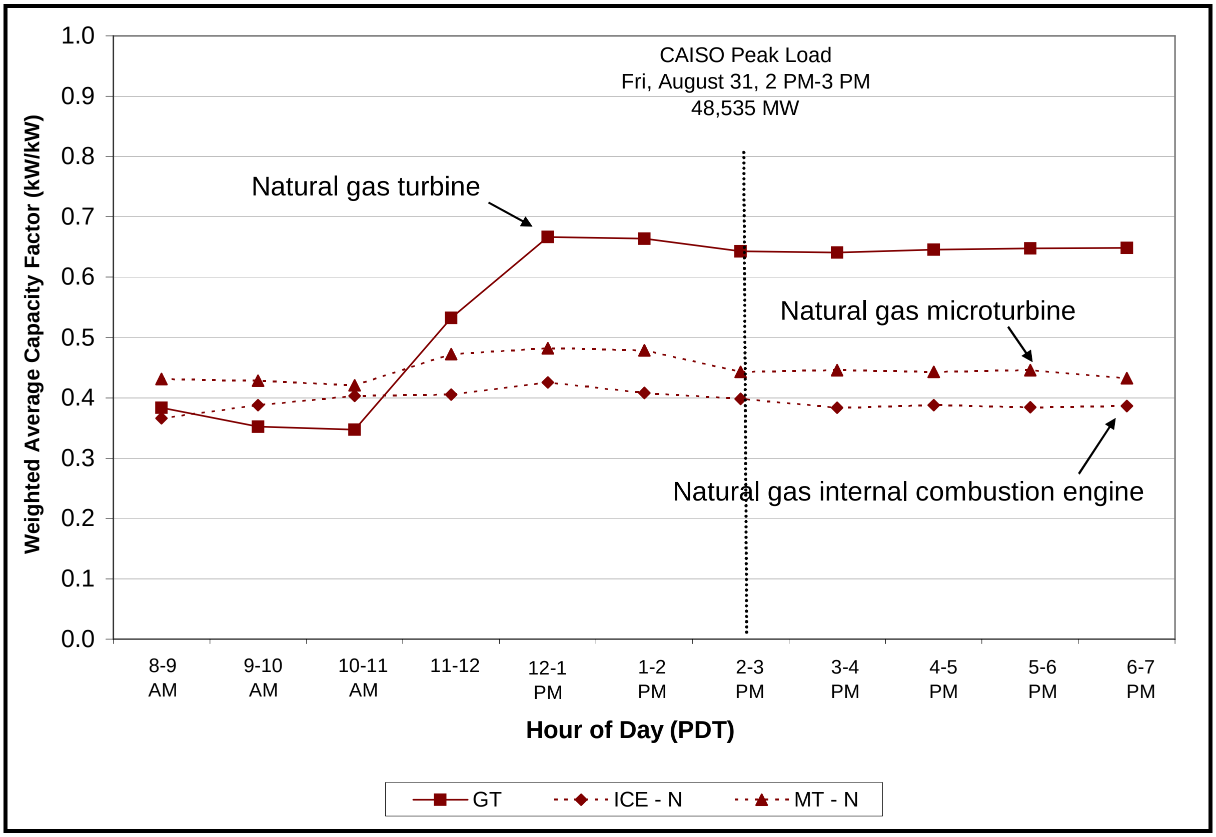


Figure A-37, Figure A-38, and Figure A-39 plot the profiles of hourly weighted average capacity factor for natural gas turbine, IC engine, and microturbine systems for each PA from the morning to early evening during the day of the annual peak hour, August 31, 2007. The charts also show the profile of the hourly CAISO loads in MW using the vertical axis on the right side of the chart.

Figure A-37: CAISO Peak Day Capacity Factors by Technology and PA—Natural Gas Turbine

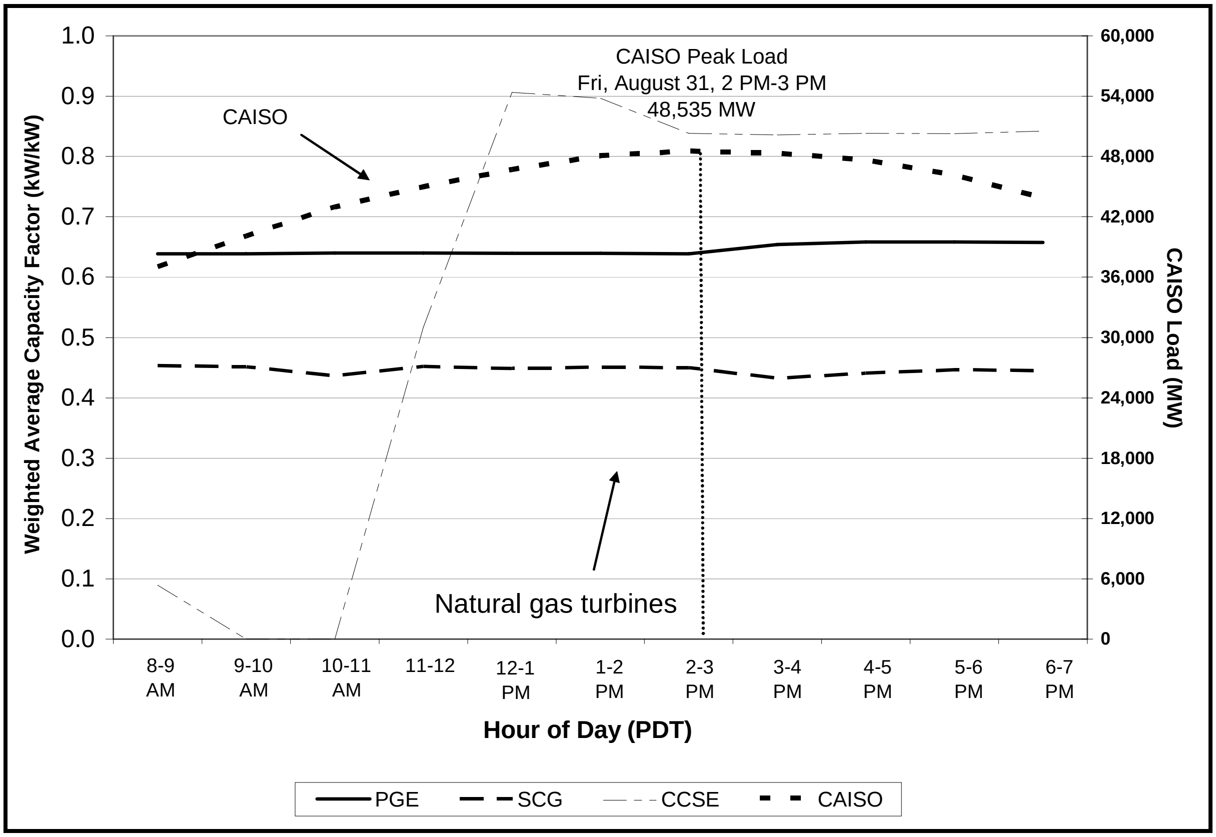


Figure A-38: CAISO Peak Day Capacity Factors by Technology and PA—Natural Gas IC Engine

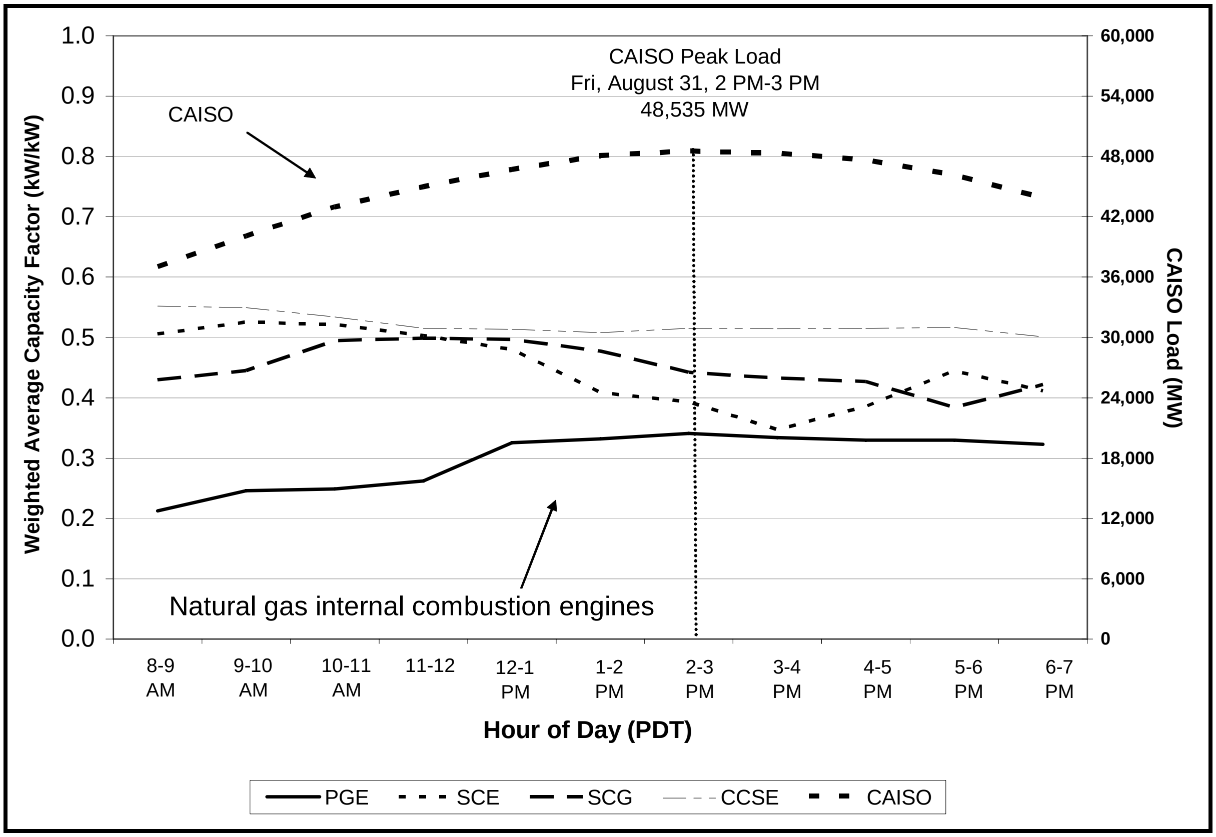


Figure A-39: CAISO Peak Day Capacity Factors by Technology and PA— Natural Gas Microturbine

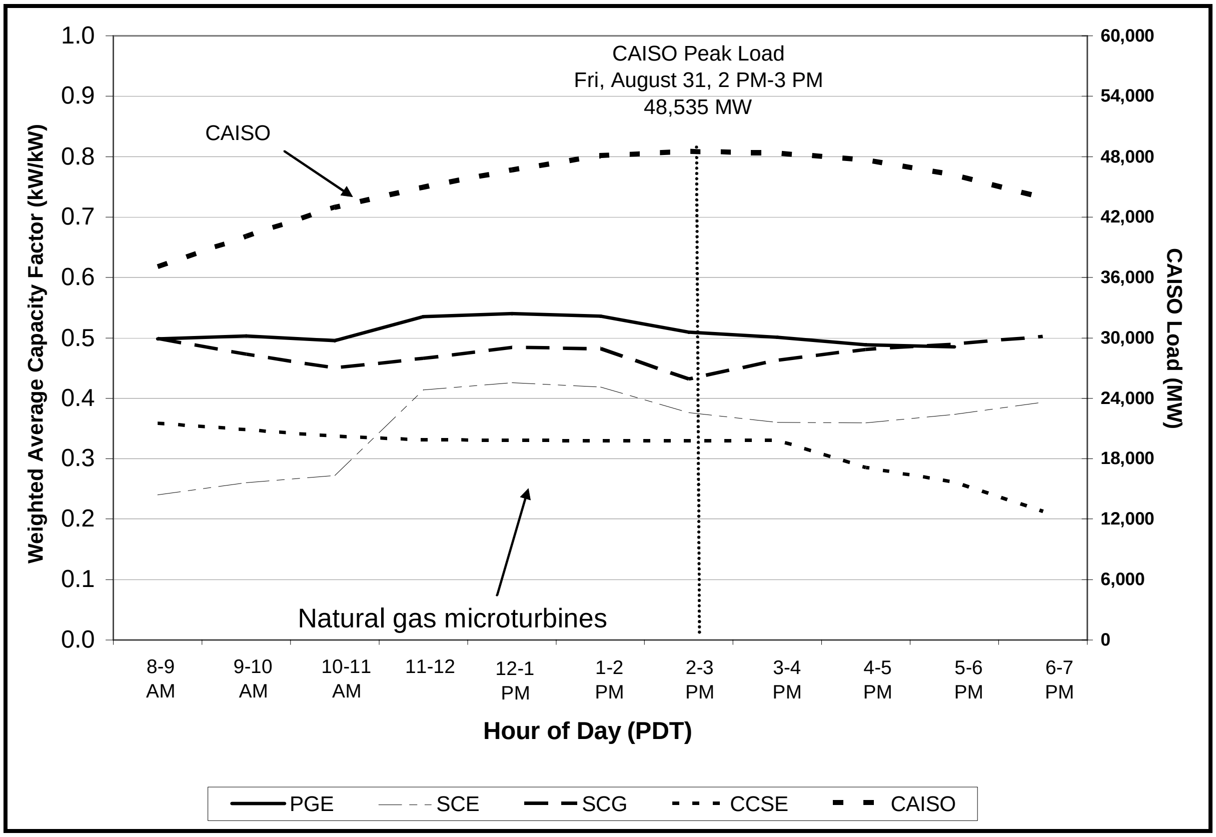


Figure A-40, Figure A-41, and Figure A-42 plot profiles of hourly weighted average capacity factors for natural gas turbine, IC engine, and microturbine systems directly feeding the electric utilities on the dates of their respective annual peak hours. Systems administered by the PA associated with the electric utility but not feeding directly into its distribution system are not included in these results. The plots also indicate the date and hour and value of the peak load for the electric utility.

Figure A-40: Electric Utility Peak Day Capacity Factors by Technology—PG&E

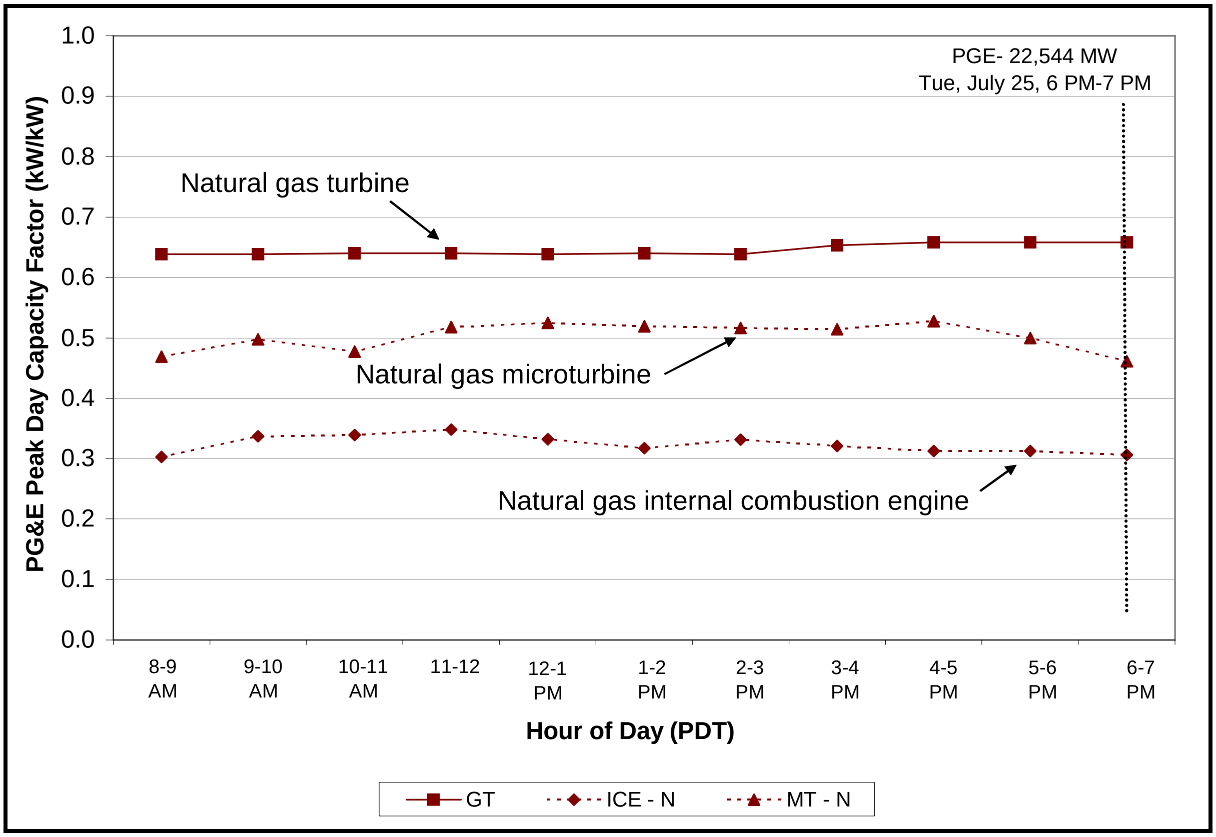


Figure A-41: Electric Utility Peak Day Capacity Factors by Technology—SCE

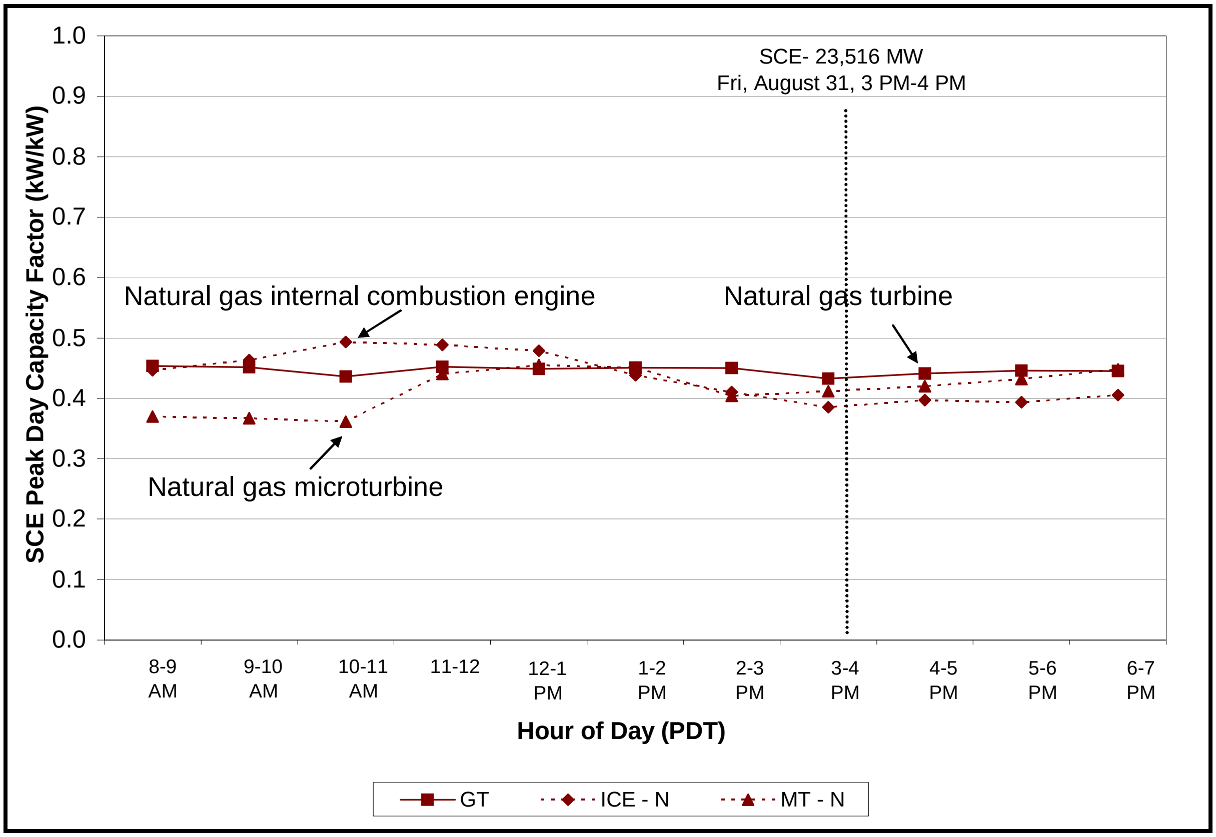
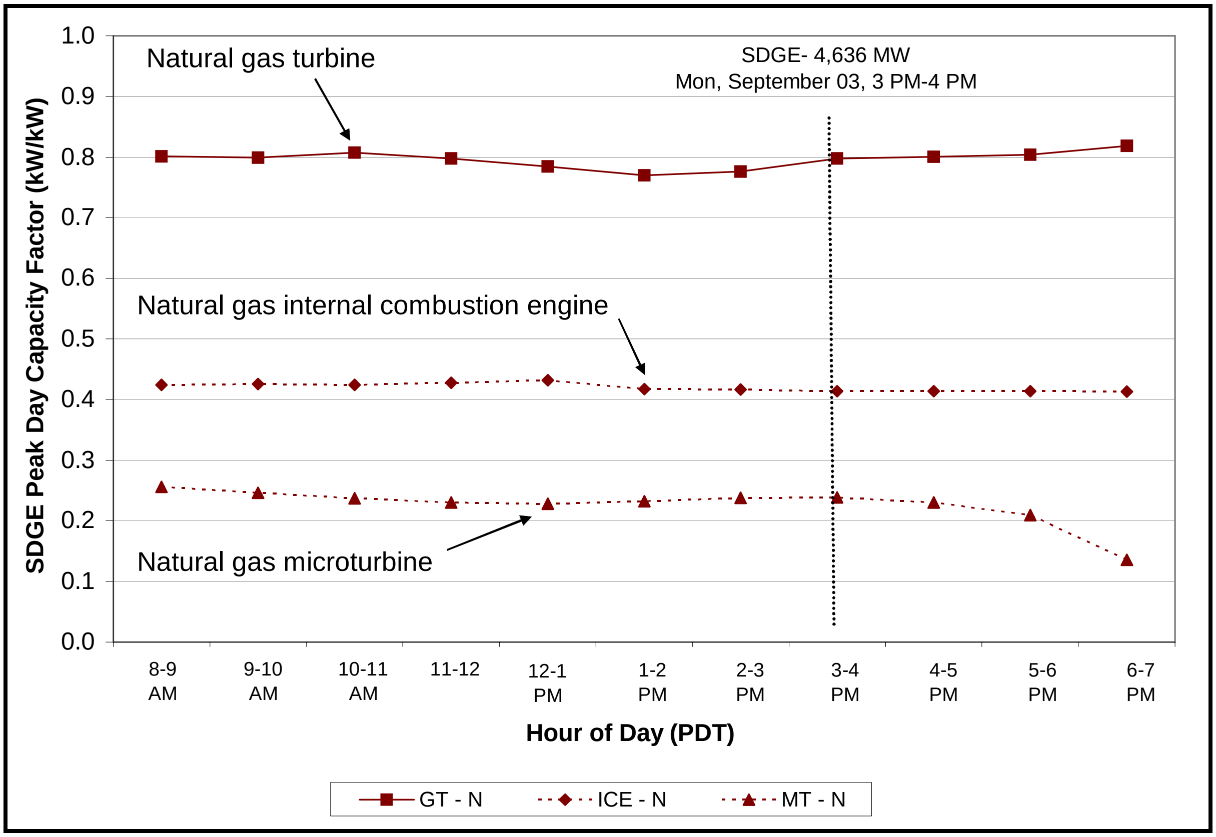


Figure A-42: Electric Utility Peak Day Capacity Factors by Technology—SDG&E



Appendix B

Greenhouse Gas Emissions Reduction Methodology

This appendix provides information regarding the methodology used to estimate the net reduction in specific greenhouse gas (GHG) emissions from the operation of SGIP systems on-line during PY07. The GHG emissions considered in this analysis are carbon dioxide (CO_2) and methane (CH_4), as these are the two primary pollutants whose emissions are potentially affected by the operation of SGIP systems. Specifically, the operation of photovoltaic projects, wind turbines, and non-renewable microturbines, gas turbines, and internal combustion engines directly affect CO_2 emissions, while renewable microturbines, gas turbines, and internal combustion engines directly affect both CH_4 and CO_2 emissions.

B.1 Net GHG Emission Reductions

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

- When in operation, power generated by SGIP systems directly displaces grid electricity that would have been generated from central station power plants.[1] As a result, SGIP projects displace the accompanying CO_2 emissions that these central station power plants would have released to the atmosphere. The CO_2 emissions from these conventional power plants are estimated on an hour-by-hour basis over all 8,760 hours of the 2007 year[2]. The CO_2 estimates are based on a methodology developed by Energy and Environmental Economics, Inc. (E3) and made publicly available on its website as part of its avoided cost calculator.[3]

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

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

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

- The operation of specific renewable and non-renewable-fueled cogeneration systems such as microturbines, fuel cells, gas turbines, and reciprocating internal combustion (IC) engines emit CO_2. While CO_2 emissions from central power plants are avoided when SGIP systems are in operation, the SGIP cogeneration plants emit CO_2 as well. Emissions of CO_2 from SGIP facilities are estimated based on the hour-by-hour electricity generated from SGIP facilities over all 8,760 hours of the 2007 year.
- Waste heat recovered from the operation of cogeneration systems displaces natural gas that would have been used to fuel boilers responsible for producing process heating at the customer host site. This displaces accompanying CO_2 emissions from the boilers, which are taken into account by calculating the CO_2 emissions avoided from using natural gas to fuel boilers. Since virtually all fuel carbon in natural gas is converted to CO_2 during combustion, the amount of CH_4 released from incomplete combustion is considered insignificant and is not included in the estimated reduction in GHG from SGIP systems.
- For those facilities that contain both absorption and electric chillers, recovered waste heat can also displace electricity (and its accompanying CO_2 emissions) that would have been used to operate electric chillers. In this case, electricity is displaced only when recovered waste heat is used as a heat source for the absorption chiller and it is used instead of the electric chiller. Estimates of avoided CO_2 emissions are based on the hour-by-hour electricity savings from reduced reliance on central station facilities.
- In the SGIP Sixth-Year Impact Evaluation Final Report[4], the assumption was made that renewable fuel use facilities with a rebated capacity less than 400 kW, such as dairies, small landfill sites, and wastewater treatment plants, were assumed to capture CH_4 that typically would have been vented and instead used it for energy purposes. This assumption has been changed for this Impact Report. Based on inspection reports, as well as information from industry articles, the baseline was modified and recalculated by differentiating between wastewater treatment plants, dairies, and landfill gas facilities. All dairies are assumed to have previously vented the methane. All landfill gas facilities are assumed to have previously captured and flared the methane. For wastewater treatment plants, the threshold of 150 kW was chosen as the cut-off point between venting and flaring methane. Smaller wastewater treatment plants are assumed to vent the methane. The avoided CH_4 emissions represent a direct reduction of greenhouse gases. Flaring was assumed to have essentially the same degree of combustion completion as SGIP renewable fuel use facilities. Consequently, for wastewater treatment plants equal to or larger than 150 kW, and all landfill gas facilities, there is no net CH_4 benefit.

[4] Itron, Inc. CPUC Self-Generation Incentive Program Sixth Year Impact Evaluation: Final Report. Submitted to Pacific Gas and Electric Company and the Self-Generation Incentive Program Working Group. August 30, 2007.

Section B.2 presents an overview of the estimation technique used to calculate reductions in CH_4 emissions from renewable fuel use facilities and, therefore, focuses on quantifying the avoided CH_4 emissions from all dairies and wastewater treatment facilities with a rebated capacity less than 150 kW. Section B.3 presents the methodology for the estimation of net reductions in CO_2 emissions. Since SGIP systems emit CO_2 while generating electricity, the release of these emissions must be accounted for in addition to the reduction in CO_2 resulting from the reliance on recovered waste heat and reduced use of electricity generated by conventional power plants.

B.2 Methodology for the Calculation of Methane Emission Reductions

Calculation of CH_4 emission reductions from cogeneration facilities was carried out for the subset of 39 renewable fuel use facilities in the SGIP system. These facilities used exclusively or predominately biogas as the generation fuel source. These included the following facility types:

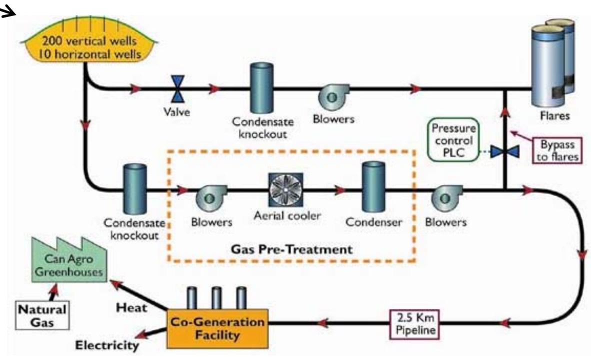
- Renewable-Powered Fuel Cells,
- Renewable-Fueled Microturbines,
- Renewable-Fueled Internal Combustion Engines, and
- Renewable-Fueled Small Gas Turbines.

The baseline treatment of biogas is important for assessing the methane emission impacts of renewable fuel facilities. Baseline treatment refers to the typical fate of the biogas in lieu of being used for energy purposes (e.g., the biogas could be vented directly to the atmosphere or flared). The calculation of methane emission reductions does not include methane that would have been flared as part of the baseline as there was no resulting release of methane.

Figure B-1 provides a depiction of a biogas facility that captures and flares methane. The methane is assumed to be captured by the facility and then flared, destroying the methane but still resulting in the release of carbon dioxide. A facility that vents the methane will have lower direct carbon dioxide emissions than a facility that flares the methane. However, the carbon dioxide equivalent value of methane emissions is significantly greater when the methane is vented rather than flared, as one ton of emitted methane is equivalent to 21 tons of emitted carbon dioxide. Changing the methane emission disposition baseline assumption does not require any accompanying change to the direct carbon dioxide emission reduction calculations involving the baseline power plant or the treatment distributed generation system.

Figure B-1: Landfill Gas with Methane Capture Diagram

Landfill gas (containing approximately 50% methane) is collected (captured) at the landfill using collection wells



When not being used to create power, the landfill gas is flared, which results in carbon dioxide emissions

Methane is naturally created at landfill gas facilities, wastewater treatment plants and dairies. If not captured, the methane escapes into the atmosphere contributing to greenhouse gas (GHG) emissions. Capturing the methane provides an opportunity to use it as fuel. When the methane is not used to create energy, it is burned in a flare. Because the resulting CO_2 has much less GHG potency than methane, the use of the flare reduces the CO_2 equivalent emissions. Distributed generation, such as SGIP projects, deliver additional economic and environmental benefits by reducing the need to generate electricity at central station power plants.

There are three common sources of biogas: landfills, wastewater treatment facilities, and dairies. For dairy digesters, the baseline is usually to vent any generated biogas to the atmosphere. Of the approximately 2000 dairies in California, conventional manure management practice for flush dairies[5] has been to pump the mixture of manure and water to an uncovered lagoon. Naturally occurring anaerobic digestion processes convert carbon present in the waste into carbon dioxide and water. Because these lagoons are typically uncovered, all of the methane generated in the lagoon escapes into the atmosphere. Currently, there are no requirements that dairies capture and flare the biogas, although some air pollution control districts are considering anaerobic digesters as a possible Best Available Control Technology (BACT) for control of volatile organic compounds. Consequently, the baseline used in this report for dairy digesters is venting of the methane to the atmosphere for all dairies.

For wastewater treatment facilities, the baseline is not as straightforward. There are approximately 250 wastewater treatment plants (WWTPs) in California and fewer than 30 of those conduct energy recovery. The larger facilities (i.e., those that could generate one MW or more of electricity) tend to install energy recovery systems. However, the vast majority of the remaining WWTPs do not recover energy, and most flare the gas on an infrequent basis.

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

Consequently, for smaller facilities (i.e., those with capacity less than 150 kW), venting of the biogas (methane) is used as the baseline.

Landfill gas recovery operations present the biggest challenge in defining the methane treatment baseline. A study conducted by the California Energy Commission in 2002[6] showed that landfills with biogas capacities less than 500 kW would tend to vent rather than flare the generated landfill gas by a margin of more than three to one. However, evidence also supports a lower threshold value, as landfills with over 2.5 million metric tons of waste are required to collect and either flare or utilize their gas. Additionally, inspection reports provided verification that those facilities participating in SGIP would have flared their methane. Consequently, for this impact evaluation, the threshold value was eliminated for landfill gas facilities. The baseline is to flare the methane. In situations where flaring occurs, the net methane impact is zero. In essence, combustion of methane in a flare or in a SGIP facility results in zero emissions of methane to the atmosphere.

Methane captured and used at renewable fuel use facilities where the baseline is venting represents CH_4 emissions that are no longer emitted to the atmosphere. Biogas consumption is not metered at SGIP facilities. In 2007, over 90 percent of the SGIP facilities that used a renewable fuel (other than wind or PV) in 2007 used IC engines or microturbines as the prime mover. Methane emission factors were calculated for each renewable fuel technology type by assuming electrical efficiencies for each technology:

IC Engine equation: uses electrical efficiency of 28 percent.

$$CH_4 \cong \left(\frac{3412\ Btu}{kWhr}\right)\left(\frac{1}{.28}\right)\left(\frac{ft^3 of\ CH_4}{1000\ Btu}\right)\left(\frac{lbmole\ of\ CH_4}{360\ ft^3}\right)\left(\frac{16\ lb_m\ of\ CH_4}{lbmole\ of\ CH_4}\right)\left(\frac{454\ grams}{lb_m}\right)$$

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

Microturbine Engine equation: uses electrical efficiency of 22 percent.

$$CH_4 \cong \left(\frac{3412\ Btu}{kWhr}\right)\left(\frac{1}{.22}\right)\left(\frac{ft^3 of\ CH_4}{1000\ Btu}\right)\left(\frac{lbmole\ of\ CH_4}{360\ ft^3}\right)\left(\frac{16\ lb_m\ of\ CH_4}{lbmole\ of\ CH_4}\right)\left(\frac{454\ grams}{lb_m}\right)$$

$$\cong 313\ \frac{grams}{kWhr}$$

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

Fuel Cell equation: uses electrical efficiency of 42 percent.

$$CH_4 \cong \left(\frac{3412\ Btu}{kWhr}\right)\left(\frac{1}{.48}\right)\left(\frac{ft^3 of\ CH_4}{1000\ Btu}\right)\left(\frac{lbmole\ of\ CH_4}{360\ ft^3}\right)\left(\frac{16\ lb_m\ of\ CH_4}{lbmole\ of\ CH_4}\right)\left(\frac{454\ grams}{lb_m}\right)$$

$$\cong 143\,\frac{grams}{kWhr}$$

The derived methane emission factors (*CH_4EF*) are multiplied by the total electricity generated from the SGIP renewable fuel use sites (depending upon technology) to estimate the annual avoided CH_4 emissions. Since GHG emissions are often reported in terms of tons of CO_2 equivalent[7], each facility's avoided CH_4 emissions were converted first from grams to pounds and then pounds to metric tons. The equation used to calculate the reduction in CH_4 emissions for site *j*, is equal to:

$$Avoided\ CH_4\ emissions \quad = \quad \left(\frac{CH_4EF_j\,grams}{kWh}\right)\left(electricity_j\right)\left(\frac{0.002204 lbs}{grams}\right)$$

*CH_4EF_j grams/kWh * electricity generated in 2007 by site j*
*in 2007 by site j (in tons * 0.002204 lbs/grams ÷ 2,205 lbs/metric ton*
of CH_4 reduced)

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

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

This section describes the methodology used to calculate the net reduction of carbon dioxide emissions from SGIP facilities during PY07. The methodological approach used for this analysis relies upon the multiplication of emission factors (in pounds of CO_2 per kWh of electricity generated) that are technology, location, and hour-specific by the total kWh generated by SGIP cogeneration sites during 2007. The different fuel/technology combinations that are accounted for include renewable and non-renewable; fuel cells, internal

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

combustion engines, microturbines, and gas turbines. The location or service territory of a cogeneration site is also considered in the development of emission factors by accounting for whether the facility is located in PG&E's territory (northern California) or in SCE/SDG&E's territory (southern California). The geographic location naturally has an effect on the demand and use of electricity due to differences in climate and electricity market conditions. This in turn affects the emission factors used to estimate the avoided CO_2 released by conventional power plants. Lastly, the date and time that electricity is generated affects the emission factors because the mix of high and low efficiency plants used differ throughout the day. The larger the proportion of low efficiency plants that would have been used to generate electricity, the greater the avoided CO_2 emissions.

Underlying Assumption of CO_2 Emissions Factors

As described above, there are a number of elements that can affect the emission factors used to calculate the overall net emission reductions of CO_2 for SGIP facilities. The basic methodology used to formulate emission factors for this analysis relies upon certain assumptions made by E3 in their emission factor development and avoided cost calculation workbook.[8] These are as follows:

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

Hourly carbon dioxide emission factors used in this study were based upon a methodology initially developed by E3. E3 provided CO_2 emission factors and the basis for those factors in a workbook available for download on their website. The premise for hourly CO_2 emission factors calculated in E3's workbook is that the marginal power plant relies on natural gas to generate electricity. Variations in the price of natural gas reflect the market demand conditions for electricity; as demand for electricity increases, all else equal, the price of natural gas will rise. To meet the higher demand for natural gas, utilities will have to rely more heavily on less efficient power plants once production capacity is reached at their relatively efficient plants. This means that during periods of higher electricity demand, there is increased reliance on lower efficiency plants, which in turn leads to a higher emission factor for CO_2. In other words, one can expect an emission factor representing the release of CO_2 from the central grid to be higher during peak hours than during off-peak hours. The avoided cost methodology initially developed by E3 is under review and may be modified in the future. There is some question regarding the proxy that is used as demand response and energy efficiency currently use the same E3 avoided cost methodology.

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

The E3 workbook mentioned previously includes the price of natural gas for each hour over the year 1999 presented as the percentage of the annual average price of natural gas for 1999. Two streams of hourly natural gas prices exist: one for northern California and another for southern California. These “price shape” data streams dictate the mix of high and low efficiency power plants used by the conventional power grid to meet demand. During the hours where the price of natural gas is high (e.g., weekday, on-peak versus weekend or holiday, off-peak), the demand for electricity is met using high efficiency as well as low efficiency peaking power plants (“peakers”). The price of natural gas is used to calculate an implied heat rate, which is dependent on the mix of low and high efficiency power plants. This implied heat rate is used to calculate the tons of CO_2 per kWh emission factors for each hour of the year. The greater the demand during these times (as indicated by a higher hourly price for natural gas), the higher the percentage of electricity generated by peakers and the greater the benefit of relying upon SGIP systems.

Base CO_2 Emission Factors

Two streams of 8,760 hourly emission factors for 1999 are included in the E3 workbook: one is for PG&E (hereafter these factors will be referred to as the northern California CO_2 emission factors), and the other is for SCE and SDG&E (hereafter referred to as the southern California CO_2 emission factors). Inputs to develop the hourly emission factors are geographically dependent due to different weather conditions, different central station plant heat rates, and different natural gas market conditions.

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

$$\begin{aligned}BaseCO_2\ EF_{it} = {} & high\ efficiency\ plant\ CO_2\ EF + (implied\ heat\ rate_{it} - high\ efficiency \\ & plant\ heat\ rate)*[(\ low\ efficiency\ plant\ CO_2\ EF - high\ efficiency\ plant \\ & CO_2\ EF)/(low\ efficiency\ plant\ heat\ rate - high\ efficiency\ plant\ heat\ rate)]\end{aligned}$$

where i =*NCal for northern California and SCal for southern California*
t = *hour, 1 to 8760 in year 1999*

This equation shows that for a given hour *t*, the emission factor is dependent upon how the implied heat rate of the average power plant differs from the average heat rate of a high efficiency power plant. The higher the heat rate (which indicates a heavier reliance on lower efficiency plants such as during times of high electricity demand), the greater the emission factor. To calculate the base hourly emission factor values, Itron relies upon the parameters and “price shape” data or percentage mix representing low and high efficiency plants in operation that E3 presents in its workbook.

These are as follows:

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

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

high efficiency plant heat rate = 6,240 Btus/kWh

low efficiency plant heat rate = 14,000 Btus/kWh

implied heat $rate_{it}$ = current price of natural gas_{it}/annual average price of natural gas_{it} * avg heat $rate_i$

where i = NCal, SCal
t = hours 1 to 8760 in year 1999

avg heat $rate_{NC}$ =9,160 Btus/kWh for NCal
avg heat $rate_{SC}$ = 9,590 Btus/kWh for SCal

If implied heat $rate_t$ < 6,240, then implied heat $rate_t$ assumed to be 6,240

If implied heat $rate_t$ > 14,000 then implied heat $rate_t$ assumed to be 14,000
(implied heat rate is bounded by low and high efficiency plant heat rates)

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

Since CO_2 emissions avoided for every hour of the year 2007 were required to be able to calculate the net emission reductions of this primary component of greenhouse gases, simply lining up the hourly emission factors from 1999 to the hourly totals of electricity generated from power plants in 2007 would not work due to the possible differences in days of the week. Upon examination of these two years, it was determined that January 1, 1999, fell on a Friday while January 1, 2007, fell on a Monday. To properly align the emission factors for the correct day type, the emission factor values for 1/1/1999, 1/2/1999, and 1/3/1999 were removed from both the northern and southern California price streams and moved up. This adjustment was made so that the emission factor value calculated for Monday, January 4, 1999, could be multiplied by the electricity supplied by the conventional grid on Monday, January 1, 2007. This realignment allowed Itron to maintain the proper days of the week over the year for the emissions factor values. However, this adjustment left three missing days at the end of the year, a Saturday, Sunday, and Monday. To correct this adjustment, the emission factor values for the last non-holiday Saturday, Sunday, and Monday of the month of December, 12/18/1999, 12/19/1999, and 12/20/1999 were used for the last three days of 2007.

Technology-Specific Adjustments to CO_2 Emission Factors

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

SGIPCO_2 EF_a (in lbs. per kWh)	=	1.90 when a = Gas Turbine
	=	1.90 when a = Microturbine
	=	1.49 when a = IC Engine
	=	0.87 when a = Fuel Cell

The equation used to derive the carbon dioxide emission factors for each technology type is as follows:

Microturbine and Gas Turbine equation: uses electrical efficiency of 22 percent.

$$(CO_2)_{MT} \cong \left(\frac{3412\ Btu}{kWhr}\right)\left(\frac{1}{.22}\right)\left(\frac{ft^3 of\ CH_4}{1000\ Btu}\right)\left(\frac{lbmole\ of\ CH_4}{360\ ft^3}\right)\left(\frac{lbmole\ of\ CO_2}{lbmole\ of\ CH_4}\right)\left(\frac{44\ lbs\ of\ CO_2}{lbmole\ of\ CO2}\right)$$

$$\cong \frac{1.90\ lbs\ of\ CO_2}{kWhr}$$

IC Engine equation: uses electrical efficiency of 28 percent.

$$(CO_2)_{ICE} \cong \left(\frac{3412\ Btu}{kWhr}\right)\left(\frac{1}{.28}\right)\left(\frac{ft^3 of\ CH_4}{1000\ Btu}\right)\left(\frac{lbmole\ of\ CH_4}{360\ ft^3}\right)\left(\frac{lbmole\ of\ CO_2}{lbmole\ of\ CH_4}\right)\left(\frac{44\ lbs\ of\ CO_2}{lbmole\ of\ CO2}\right)$$

$$\cong \frac{1.49\ lbs\ of\ CO_2}{kWhr}$$

Fuel Cell equation: uses electrical efficiency of 48 percent

$$(CO_2)_{FC} \cong \left(\frac{3412\ Btu}{kWhr}\right)\left(\frac{1}{.48}\right)\left(\frac{ft^3 of\ CH_4}{1000\ Btu}\right)\left(\frac{lbmole\ of\ CH_4}{360\ ft^3}\right)\left(\frac{lbmole\ of\ CO_2}{lbmole\ of\ CH_4}\right)\left(\frac{44\ lbs\ of\ CO_2}{lbmole\ of\ CO2}\right)$$

$$\cong \frac{0.87\ lbs\ of\ CO_2}{kWhr}$$

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

Waste Heat Recovery for Boiler Fuel Adjustment to CO_2 Emission Factors

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

The emission factor adjustment made to account for the recovery of waste heat is technology dependent. Hourly heat recovery boiler fuel factors (HRBFs) were applied for those facilities that are able to recover waste heat for use in boilers.

$$
\begin{aligned}
HRBF_a \text{ (in lbs. per kWh)} &= 0.49 \text{ when a = Gas Turbine} \\
&= 0.35 \text{ when a = Microturbine} \\
&= 0.29 \text{ when a = IC Engine} \\
&= 0.29 \text{ when a = Fuel Cell}
\end{aligned}
$$

These HRBFs were calculated based upon hourly heat recovery rates from the SGIP projects active in 2007. For this impacts report, Itron was able to use both metered and estimated data to calculate the hourly heat recovery rates for each facility.

The equation used to derive the components of the emission factors is as follows:

$$
\left(CO_2EF\right) \cong \left(\frac{kBtu}{kWh}\right)\left(\frac{ft^3 of\ CH_4}{1000\ Btu}\right)\left(\frac{lbmole\ of\ CO_2}{360\ ft^3}\right)\left(\frac{44\ lbs\ of\ CO_2}{lbmole\ of\ CO2}\right)
$$

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

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

Absorption Chiller Adjustment to CO_2 Emission Factors

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

Actual heat recovery rates and typical absorption and centrifugal chiller efficiencies were incorporated into an algorithm to estimate the avoided electricity that would have been serving the centrifugal chiller in the absence of the cogeneration system. This component of the emission factors is also technology-specific. The following Heat Recovery Chiller Factors (HRCF) were applied for those facilities that are able to use waste heat for operating chillers:

$$
\begin{aligned}
HRCF_a \text{ (in lbs. per kWh)} &= 0.15 \text{ when a = Gas Turbine} \\
&= 0.11 \text{ when a = Microturbine} \\
&= 0.09 \text{ when a = IC Engine} \\
&= 0.09 \text{ when a = Fuel Cell}
\end{aligned}
$$

Just as was the case with HRBFs, the HRCFs were calculated based upon hourly heat recovery rates calculated from data collected from SGIP projects active in 2007.

The equation used to derive this component of the emission factors is as follows:

$$
\begin{aligned}
\left(CO_2 EF\right) &\cong \left(\frac{kBtu}{kWh_{ENGO}}\right)\left(\frac{0.7\,Btu_{in}}{Btu_{out}}\right)\left(\frac{0.634\,kWh_{ENGO}}{ton\ of\ cooling}\right)\left(\frac{ton\ of\ cooling}{12\,kBtu}\right)\left(\frac{lb\ of\ CO_2}{kWh_{elecin}}\right) \\
&\cong \frac{0.15\,lbs\ of\ CO_2}{kWh_{electin}}
\end{aligned}
$$

Fully Adjusted CO_2 Emission Factors

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

$$\textit{Fully adjusted } CO_2\ EF_{ijt} = (BaseCO_2\ EF_{it} - SGIPCO_2\ EF_{ijt} + HRBF_{ijt} + HRCF_{ijt})*electricity_{jit}$$

where:

i = NCal or SCal
t = hour
j = facility

Appendix C

Data Analysis

The data sources for the evaluation impact report were described in Section 4. Program impact estimates and the uncertainty in those estimates were presented in Section 5. This appendix discusses data availability by Program Administrator (PA) and the data analysis methodology, including the bases of the impact estimates uncertainty characterizations.

C.1 Data Processing Methods

This section discusses the ENGO, HEAT, and FUEL data processing and validation methodology for photovoltaic (PV), fuel cells, and engines/turbines operating on non-renewable or renewable fuel.

ENGO Data Processing

PV data is processed differently from the fuel cell, engine and turbine data. For PV, a code template has been developed which reads, processes and validates data, and outputs suspect data. When necessary, the code adjusts for daylight savings time, accounts for inverter losses, corrects a data stream which contains more than one site, as well as many other site-specific and data-provider specific issues. Validation of PV data utilizes irradiance, temperature, and rainfall data downloaded from the California Irrigation Management Information System (CIMIS). Each PV site is assigned a nearby CIMIS site. Data is flagged as suspect when there is low daily output, low hourly output, high daily output, or high hourly output compared to the available irradiation. The suspect data is reviewed internally and either validated or invalidated. An example of a suspect case that can be validated internally is a bad weather event which results in low daily output. An example of a suspect case that can be invalidated internally is consistently high daily output which greatly exceeds the system capacity. When the data validity cannot be determined internally the data provider is contacted. Data providers are most often contacted if a site has an outage for more than two days in order to determine if the outage was a PV system failure (indicates valid data) or a data acquisition system failure (indicates invalid data). Invalid data is excluded from the analysis.

For fuel cells, engines and turbines, ENGO data refers to a measure of system output that excludes electric parasitic loads (e.g., onsite controls, pumps, fans, compressors, generators and heat recovery systems.) In some cases it is not possible to measure ENGO directly with a single meter. In those cases ENGO is calculated by subtracting the electrical parasitic loads from the gross generator output. Due to wide variety of formats in which raw data is received, conversion of raw data to a common format is essential in order to ensure that all data received are treated consistently. After converting the data to a common format, all data files are reviewed to identify suspicious data (low or high capacity factors). Data providers are contacted when data validity cannot be determined internally. In cases where anomalous behavior cannot be explained, the metered data are excluded from the analysis.

HEAT Data Processing

Thermal data is stored in 15-minute intervals, in units of kBtu, in permanent SAS datasets. Main source of thermal data are applicants and Itron installed heat meters. If the data comes from Itron data loggers, processing time is minimal because the raw data is already stored in 15-minute intervals. However, if the raw data comes from applicants, then the data should be converted to the standard format. When data are received from an applicant, host, or some other party, certain validation steps must be passed before the data are incorporated into the analysis. These steps include calculation of a valid range of heat recovery rates based on system type and size and comparing waste heat recovered with net generator output for the 15-minute interval.

FUEL Data Processing

Two main sources of fuel data for non-renewable projects are natural gas utilities and Itron metering. If the data comes from Itron data loggers, processing time is minimal because the raw data is already stored in 15-minute intervals. However, if the raw data comes from gas utility, data is typically reported in monthly or billing cycle intervals. Monthly electrical conversion efficiencies are calculated to validate the monthly fuel data. Validated monthly data is transformed into 15-minute data based on the monthly electrical efficiencies and 15-minute ENGO data. In this case the fuel data are a ratio using other metered data (ENGO), so a flag in the permanent dataset is set to "R".

C.2 Estimating Impacts of Unmetered Systems

Data from metered systems were used to estimate impacts for unmetered systems of the same technology and fuel. In most cases, the metered data were for the exact same hour of the year and from systems of same technology, fuel, and PA. For PV systems, the metered data were further limited to systems with additional similarities to those of the unmetered systems.

By limiting the metered data used to those with the same PA, factors that can influence operational performance were better matched between the metered and unmetered systems. These PA-related factors include local economic climate, available tariffs, and to some degree the local meteorological climate. Likewise in the case of PV, additional system similarities included technology details that can influence power output. These PV details included an output capacity class of large versus small (small defined as less than 300 kW), a locale category (coastal or inland), and a module configuration category (flat, tilted, tracking, or mixed).

All estimated hourly impacts were based on no fewer than five metered observations of the same technology and fuel type. For some unmetered systems there were hours with fewer than five metered observations with like technology, fuel, and PA. To estimate impacts for these metered data from one or more of the other PAs was included until there were at least five metered observations for the same hour. For example, metered data from SCE could be used to estimate impacts for similar systems at the same hour for SCG unmetered systems when too few metered observations existed from SCG systems alone. If there still were fewer than five metered observations, then data from CCSE were allowed to be used. If inclusion of CCSE did not provide enough metered observations, then data from PG&E were allowed.

The inclusion of metered data from other PAs did not always satisfy the minimum requirement of five metered observations for the same hour of the year and same technology and fuel. In these cases the metered data were restricted again to the same PA but the time component of the metered data was allowed to include same hours of the day from like weekday types (weekday or weekend) from the same month. For example, an hourly estimate for 3:00 to 4:00 P.M. on Monday, July 24, for a renewable IC engine system administered by SCE might be based on metered observations from renewable IC engine systems administered by SCE from all July weekday hours of 3:00 to 4:00 P.M.

In fewer than three percent of the system hours needing to be estimated the relaxation of the metered data time component did not satisfy the minimum requirement of five metered observations. Estimates for these system hours thus were allowed to be based on metered observations during like weekday hours of the same month and from other PAs.

A ratio representing average power output per unit of rebated system capacity was calculated using at least five metered observations for each system hour needing an impact estimate. The product of this ratio and the system's rebated capacity was the system's estimated hourly average power output. Estimates of power output were calculated as:

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

Where:

$EN\hat{G}O_{psdh}$ = Predicted net generator output for project *p* in strata[1] *s* on date *d* during hour *h*

Units: kWh
Source: Calculated

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

Units: kW
Source: SGIP Tracking Database

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

Units: kWh
Source: Net Generator Output Meters

C.3 Assessing Uncertainty of Impacts Estimates

Program impacts covered in Section 5 include those on electricity and fuel, as well as those on greenhouse gas (GHG) emissions. The principal factors contributing to uncertainty in those reported results are quite different for these two types of program impacts. The treatment of those factors is described below for each of the two types of impacts.

Electricity and Fuel Impacts

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

Sampling error refers to differences between actual values and values estimated for unmetered systems. The estimated impacts calculated for unmetered systems are based on the assumption that performance of unmetered systems is identical to the average

[1] Strata are always defined by like technology and fuel and like hour of like weekday in like month. As described in text, however, strata may be more specific by additional like technology details, like PA or like group of PAs, and by exact hour of the year.

performance exhibited by groups of similar metered projects. Very generally, the *central tendency* (i.e., an average) of metered systems is used as a proxy for the central tendency of unmetered systems.

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

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

For this impact evaluation an empirical approach known as Monte Carlo Simulation (MCS) analysis was used to quantify impact estimates uncertainty. The term MCS refers to "the use of random sampling techniques and often the use of computer simulation to obtain approximate solutions to mathematical or physical problems especially in terms of a range of values each of which has a calculated probability of being the solution."[2]

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

GHG Emission Impacts

Electricity and fuel impact estimates represent the starting point for the analysis of GHG emission impacts. Uncertainty in those electricity and fuel impact estimates therefore flows down to the GHG emissions impact estimates. However, additional sources of uncertainty are introduced in the course of the GHG emissions impacts analysis. GHG emissions impact estimates are therefore subject to greater levels of uncertainty than are electricity and fuel

[2] Webster's dictionary

impact estimates. The two most important additional sources of uncertainty in GHG emissions impacts are summarized below.

Baseline Central Station Power plant GHG Emissions. Estimation of net GHG emissions impacts of each SGIP system involves comparing emissions of the SGIP system with emissions that would have occurred in the absence of the program. The latter quantity depends on the central station power plant generation technology (e.g., natural gas combined cycle, natural gas turbine) that would have met the participant's electric load if the SGIP system had not been installed. Data concerning marginal baseline generation technologies and their efficiencies (and hence GHG emissions factors) were obtained from E3. Quantitative assessment of uncertainty in E3's avoided GHG emissions database is outside the scope of this SGIP impacts evaluation.

Baseline Biogas Project GHG Emissions. Biomass material (e.g., trash in landfills, manure at dairies) would typically have existed and decomposed (releasing methane) even in the absence of the program. While the program does not influence the existence or decomposition of the biomass material, it may impact whether or not the methane is released directly into the atmosphere or not. This is critical because methane is a much more active GHG than are the products of its combustion (e.g., CO_2).

For this GHG impacts evaluation Itron used the methane disposition baseline assumptions summarized in Table C-1. Due to the influential nature of this factor, and given the current relatively high level of uncertainty surrounding assumed baselines, Itron will continue collecting additional site-specific information about methane disposition and incorporating them into the analysis. Modification of installation verification inspection forms will be recommended, and information available from air permitting and other information sources will be compiled.

Table C-1: Methane Disposition Baseline Assumptions for Biogas Projects

Renewable Fuel Facility Type	SGIP System Size (Rebated kW)	Methane Disposition Baseline Assumption
Dairy Digester	Any size	Venting
Waste Water Treatment	≥150 kW	Flaring; otherwise Venting
Landfill Gas Recovery	Any size	Flaring

Data Sources

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

SGIP Project Information

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

Metered Data for SGIP DG Systems

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

1. Metered data are used to estimate the actual performance of metered systems. The metered data are not used directly for this purpose. Rather, information about measurement error is applied to metered values to estimate actual values.
2. The central tendencies of groups of metered data are used to estimate the actual performance of unmetered systems.
3. The variability characteristics exhibited by groups of metered data contribute to development of distributions used in the MCS study to explore the likelihood that actual performance of unmetered systems deviates by certain amounts from estimates of their performance.

Manufacturer's Technical Specifications

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

Analytic Methodology

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

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

Ask Question

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

- Program Total Annual Electrical Energy Impacts
- Program Total Coincident Peak Electrical Demand Impacts
- Program Total PUC216.6 (b) Cogeneration System Efficiency

Design Study

The MCS study's design determines requirements for generation of sample data. The process of specifying study design includes making tradeoffs between flexibility and accuracy, and cost. This MCS study's tradeoffs pertain to treatment of the dynamic nature of the SGIP and to treatment of the variable nature of data availability. Some of the systems came on-line during 2006 and therefore contributed to energy impacts for only a portion of the year. Some of the systems for which metered data are available have gaps in the metered data archive that required estimation of impacts for a portion of hours during 2006. These issues are discussed below.

Sample data for each month of the year could be simulated, and then annual electrical energy impacts could be calculated as the sum of monthly impacts. Alternatively, sample energy production data for entire years could be generated. An advantage of the monthly approach is that it accommodates systems that came on-line during 2006 and therefore contributed to energy impacts for only a portion of the year. The disadvantage of using monthly simulations is that this approach is 12 times more labor- and processor-intensive than an annual simulation approach.

A central element of the MCS study involves generation of actual performance values (i.e., sample data) for each simulation run. The method used to generate these values depends on whether or not the system is metered or not. However, for many of the SGIP systems metered data are available for a portion—but not all—of 2006. This complicates any analysis that requires classification of systems as either "metered" or "not metered".

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

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

<u>Generate Sample Data</u>

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

Metered Data Available—Generating Sample Data that Include Measurement Error

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

Table C-2: Summary of Random Measurement-Error Variables

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

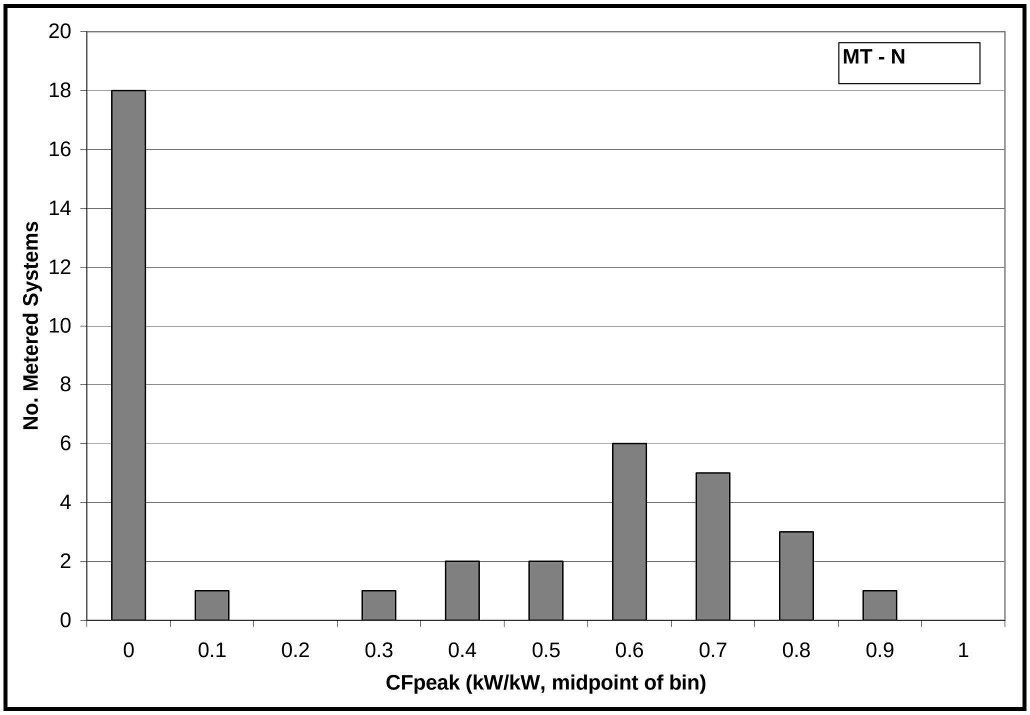
Metered Data Unavailable—Generating Sample Data from Performance Distributions

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

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

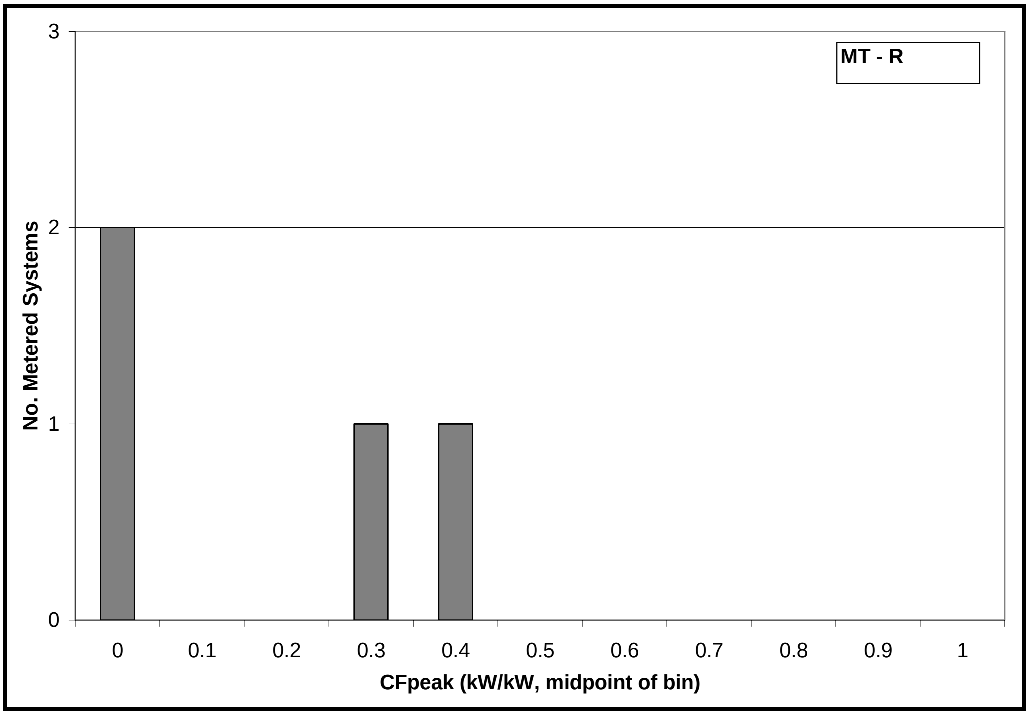
The assessment of the suitability of available metered data for use in MCS performance distributions is illustrated below with an example using 2006 data. The output of a group of non-renewable-fueled microturbines during the hour when CAISO system load reached its annual peak value is illustrated in Figure C-1. In this figure microturbine system output is expressed as metered power output per unit of system rebated capacity (CFpeak). Metered data were available for 39 systems. There were 50 systems for which metered data were not available for this hour. For each MCS run the actual performance of each of these systems must be assigned from an MCS performance distribution. The metered data available for this group of systems appear to provide a good general indication of the distribution of values likely for unmetered systems.

Figure C-1: Non-Renewable-Fueled Microturbine Measured Coincident Peak Output



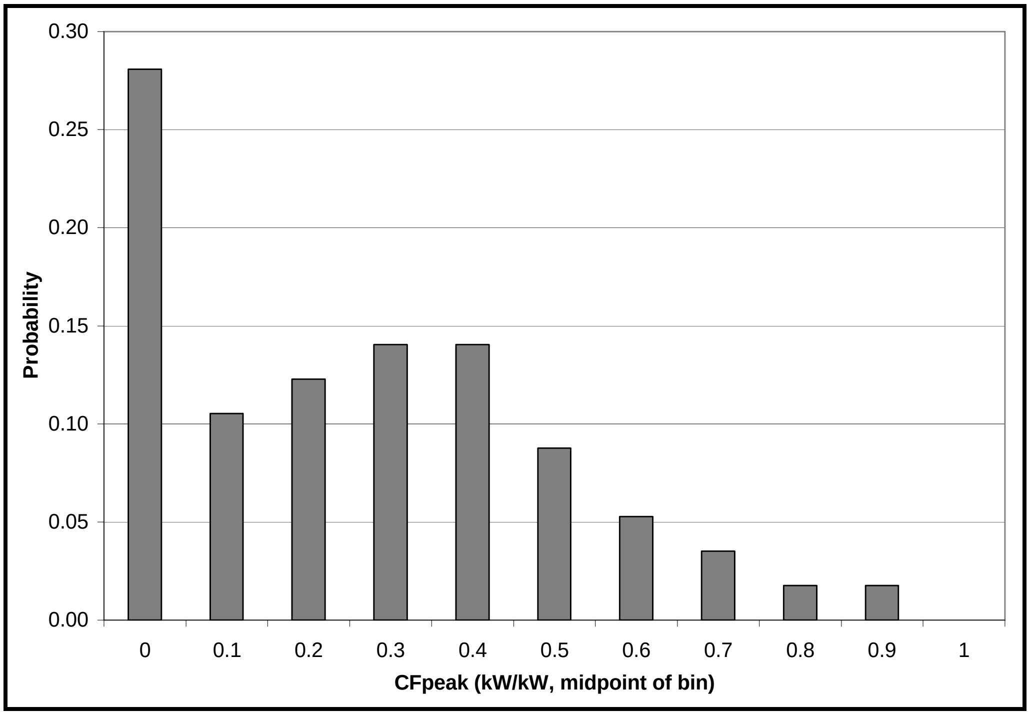
There are other sample design strata for which the quantity of metered data available is insufficient to provide a good indication of the distribution of values likely for unmetered projects. For example, there were only four metered renewable-fueled microturbines during the CAISO peak hour in 2006. The measured performance of these four systems is summarized in Figure C-2.

Figure C-2: Renewable-Fueled Microturbine Measured Coincident Peak Output



If 10, 24, or 31 systems were metered it is unlikely that all of them would fall in this exact same distribution. Instead you would expect to see some systems have a CF of 0.1 and 0.2, and other systems could have been running at full capacity (CF = 1). The metered data available for this group of systems do not appear to provide a good general indication of the distribution of values likely for unmetered systems. Figure C-3 shows the distribution used in the MCS for renewable-fueled microturbines at the CAISO peak hour.

Figure C-3: CFpeak Distribution used in MCS for Renewable-Fueled Microturbines



Use of a simplified distribution shown in Figure C-3 emphasizes the fact that the performance of the unmetered systems is not known, and that in the MCS the assumed distribution of CFpeak values is based on judgment. Lastly, the modification introduces a small measure of additional conservatism into MCS results.

Review of metered data availability for all technology and fuel sample design strata revealed numerous instances such as that described above. Consequently, in some instances simplifying assumptions were made. Fuel cell, engine and turbine technologies were not separated by PA and renewable-fueled systems were assumed to follow a similar distribution to non-renewable-fueled systems within the same technology group. Engineering judgment was used for the wind turbine distribution to determine the maximum output possible for the wind speed at that day and hour. For PV, SCE and SCG systems were grouped together and PV groups were further broken down by configuration and location (coastal or inland).

Lastly, the heat recovery distribution from 2005 for non-renewable engines/turbines was used for the 2007 analysis because there was more heat data available in 2005 than in 2007.

Table C-3 shows the groups used to estimate the uncertainty in the CAISO peak hour impact.

Table C-3: Technology and Fuel Groupings for the CAISO peak hour MCS Analysis

Technology	Fuel	PA[3]	PV Configuration	Coastal/Inland
PV	n/a	PGE, CCSE, SCE & SCG	Near Flat, Other[4], Tracking[5]	Coastal, Inland
Wind	n/a	SCE[6]	n/a	n/a
IC Engine	Non-renewable, Renewable	All	n/a	n/a
Microturbine	Non-renewable, Renewable	All	n/a	n/a
Gas Turbine	Non-renewable[7]	All	n/a	n/a
Fuel Cell	Non-renewable, Renewable	All	n/a	n/a

[3] PV projects are grouped by PA while engines are not because PV output is dependent on location.

[4] Near Flat systems are those systems with a tilt of 20^{o} or less. Other systems are those systems with a tilt greater than 20^{o}.

[5] Tracking systems are those systems with automatically adjusting tilts which allow the PV system to follow the sun. All tracking systems in SGIP are one-axis tracking systems. Tracking systems were not broken out by coastal/inland.

[6] As of December 31, 2007 there are two Complete wind turbine projects in the SGIP and both are within SCE's service territory.

[7] There are no renewable-fueled gas turbines in the program as of December 31, 2007.

Table C-4 shows the groups used to estimate the uncertainty in the yearly energy production. Yearly capacity factors for PV throughout California are less variable than for the CAISO peak hour, therefore all fixed (near flat and other) PV systems are grouped together for the uncertainty analysis of the annual energy production, Tracking systems are kept separate because these systems are designed to have higher daily output than a fixed system. Internal combustion engines, gas turbines, and microturbines are grouped together for the uncertainty analysis of the annual energy production because of the small number of systems within each technology group for which data was available for 75 percent of the year and because a significant difference was not seen between the annual capacity factors of these systems.

Table C-4: Technology and Fuel Groupings for the 2007 Annual Energy Production MCS Analysis

Technology	Fuel	PV Configuration
PV	n/a	Fixed, Tracking
Wind	n/a	n/a
Engine/Turbine	Non-renewable, Renewable	n/a
Fuel Cell	All	n/a

Performance distributions were developed for each of the groups in the tables based on metered data and engineering judgment. In the MCS, a capacity factor is randomly assigned from the performance distribution and sample values are calculated as the product of CFpeak and system size. All of these performance distributions are shown in Figure C-4 through Figure C-61.

Performance Distributions for Coincident Peak Demand Impacts

Figure C-4: PG&E PV Measured Coincident Peak Output (Coastal, Near Flat)

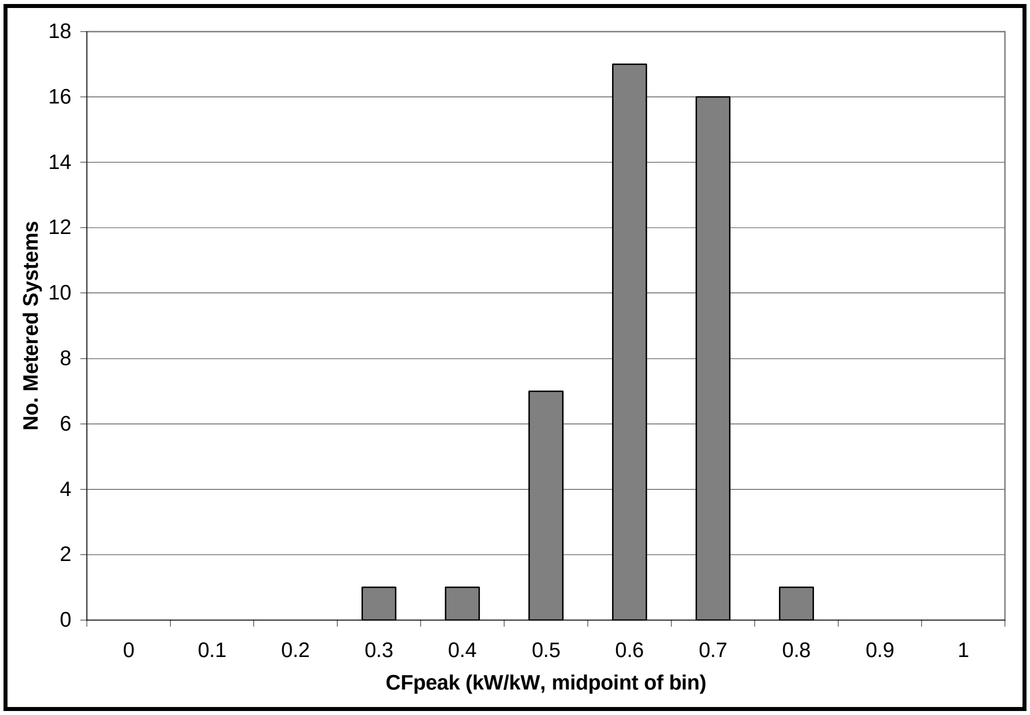


Figure C-5: MCS Distribution—PG&E PV Coincident Peak Output (Coastal, Near Flat)

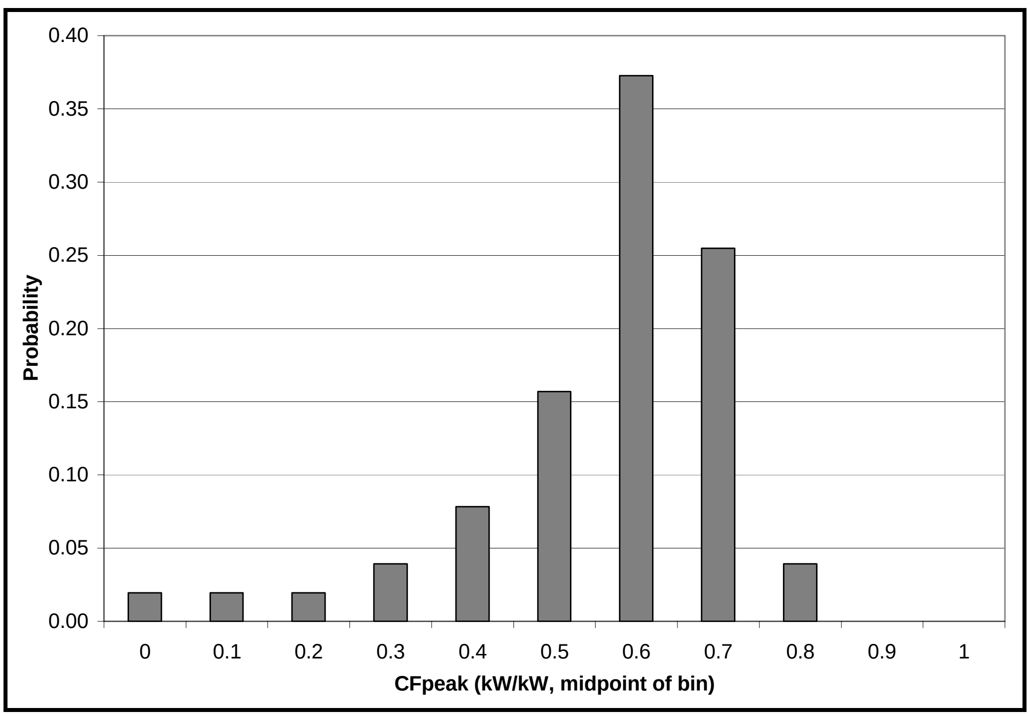


Figure C-6: PG&E PV Measured Coincident Peak Output (Coastal, Other)

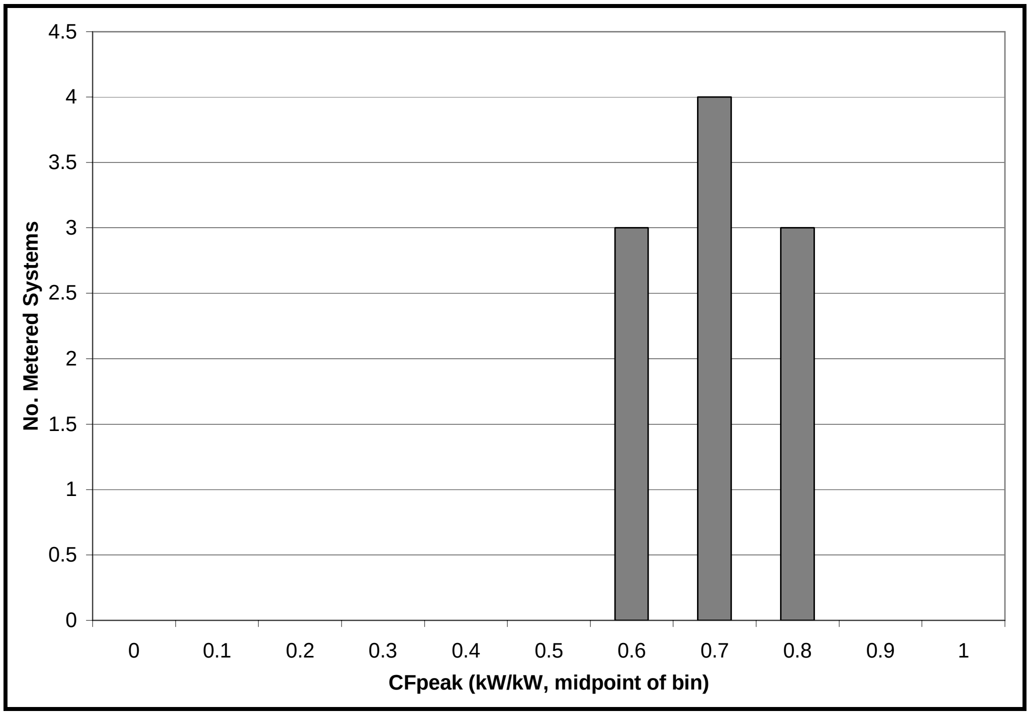


Figure C-7: MCS Distribution—PG&E PV Coincident Peak Output (Coastal, Other)

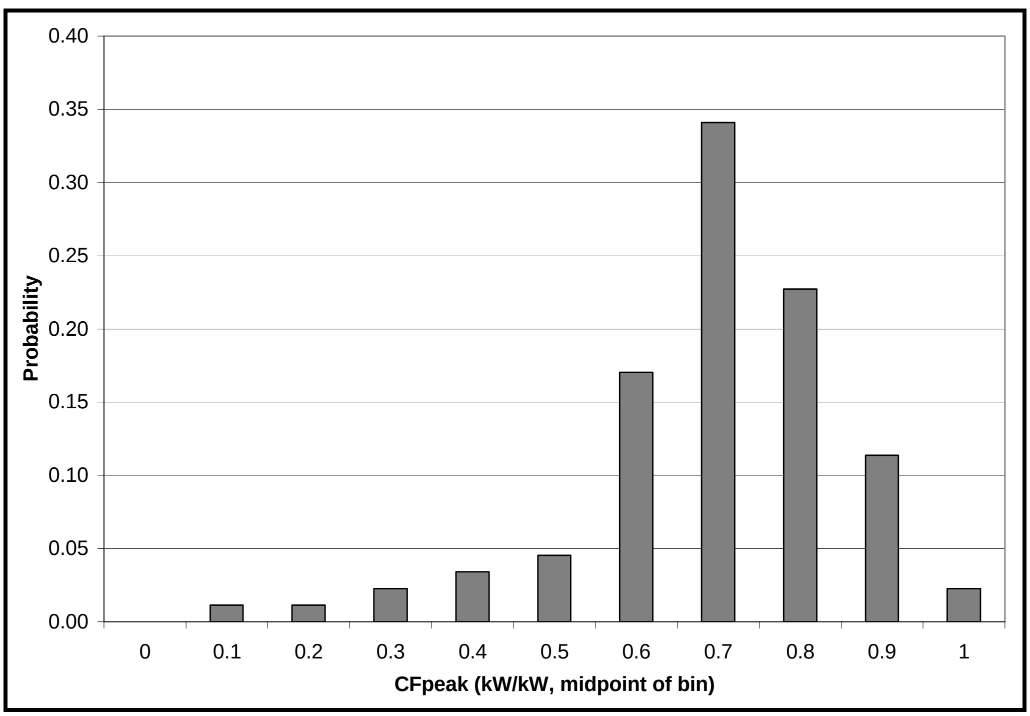


Figure C-8: PG&E PV Measured Coincident Peak Output (Inland, Near Flat)

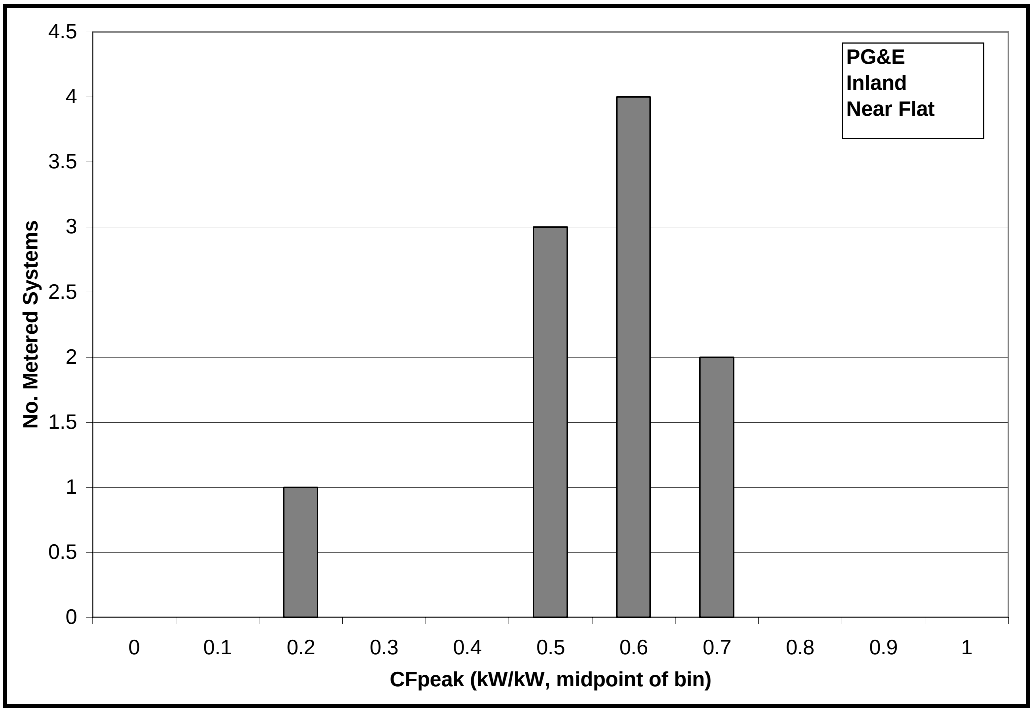


Figure C-9: MCS Distribution—PG&E PV Coincident Peak Output (Inland, Near Flat)

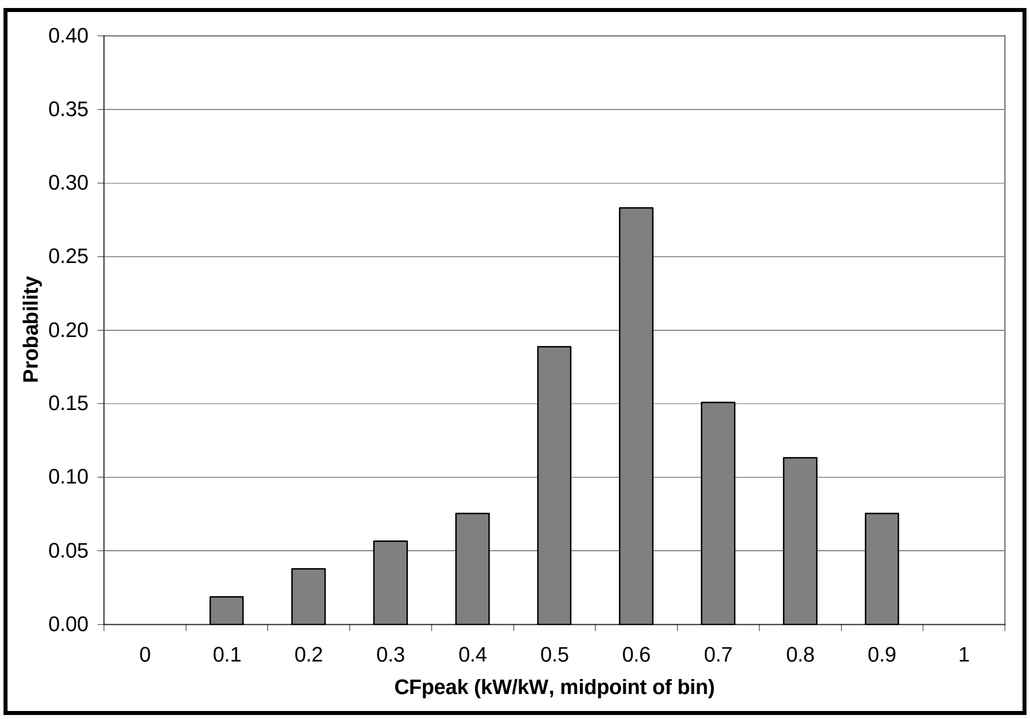


Figure C-10: PG&E PV Measured Coincident Peak Output (Inland, Other)

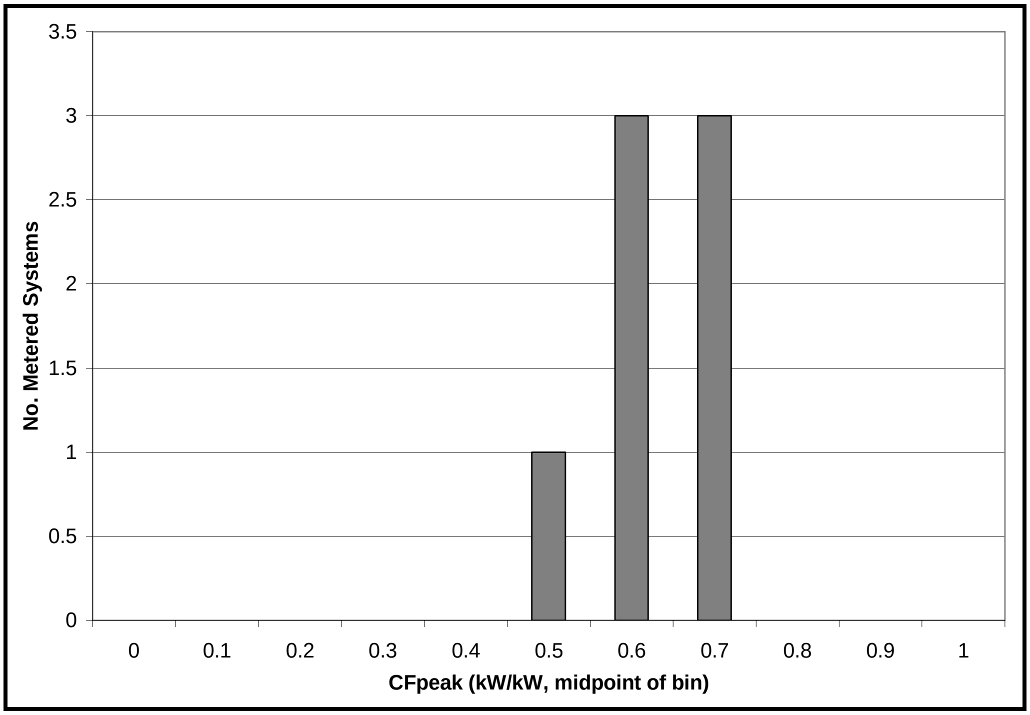


Figure C-11: MCS Distribution—PG&E PV Coincident Peak Output (Inland, Other)

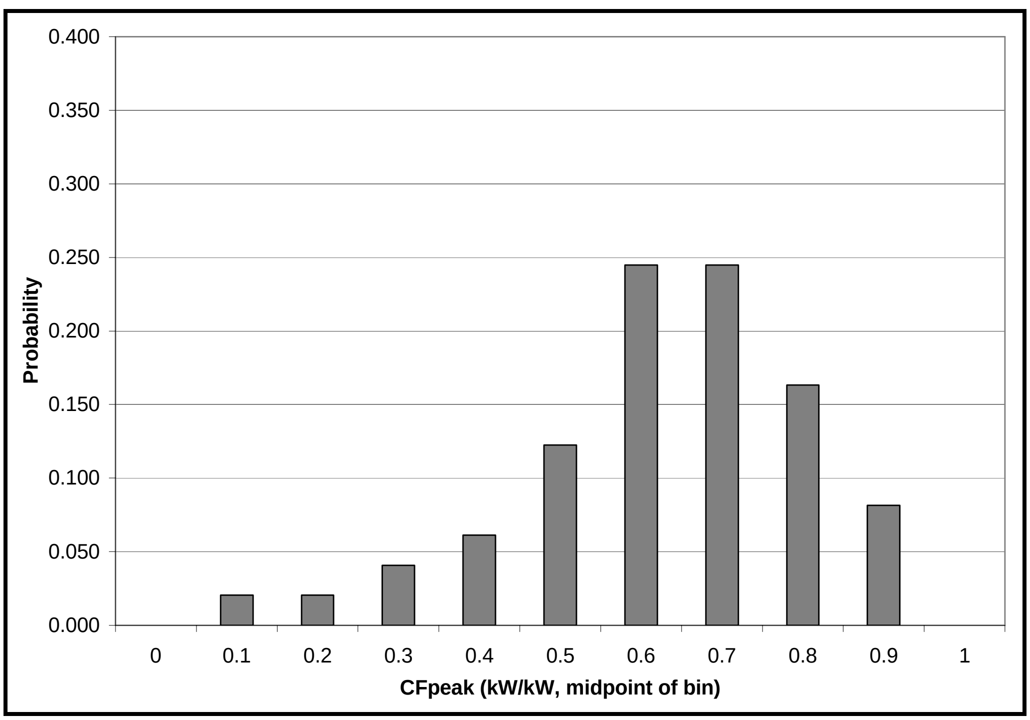


Figure C-12: PG&E PV Measured Coincident Peak Output (Tracking)

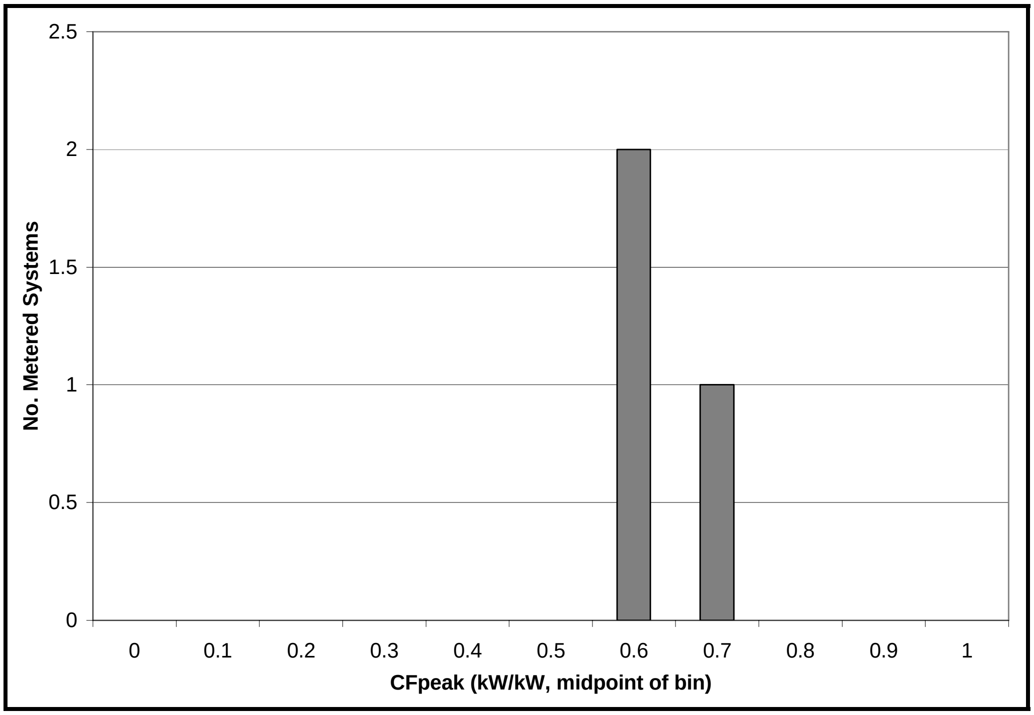


Figure C-13: MCS Distribution—PG&E PV Coincident Peak Output (Tracking)

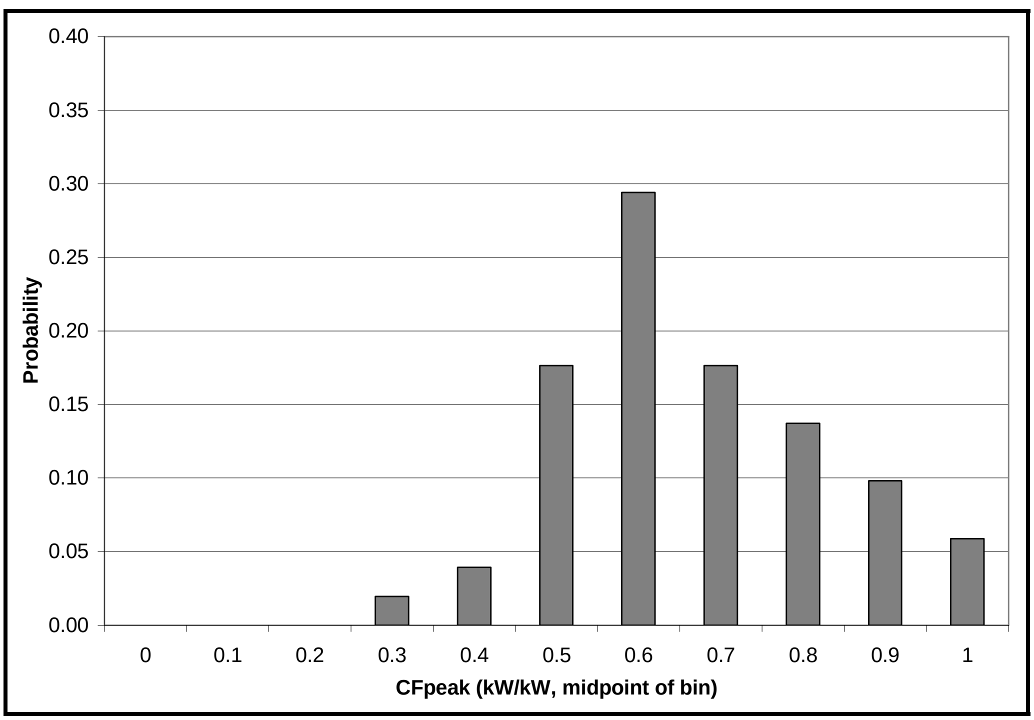


Figure C-14: LA (SCE & SCG) PV Measured Coincident Peak Output (Coastal, Near Flat)

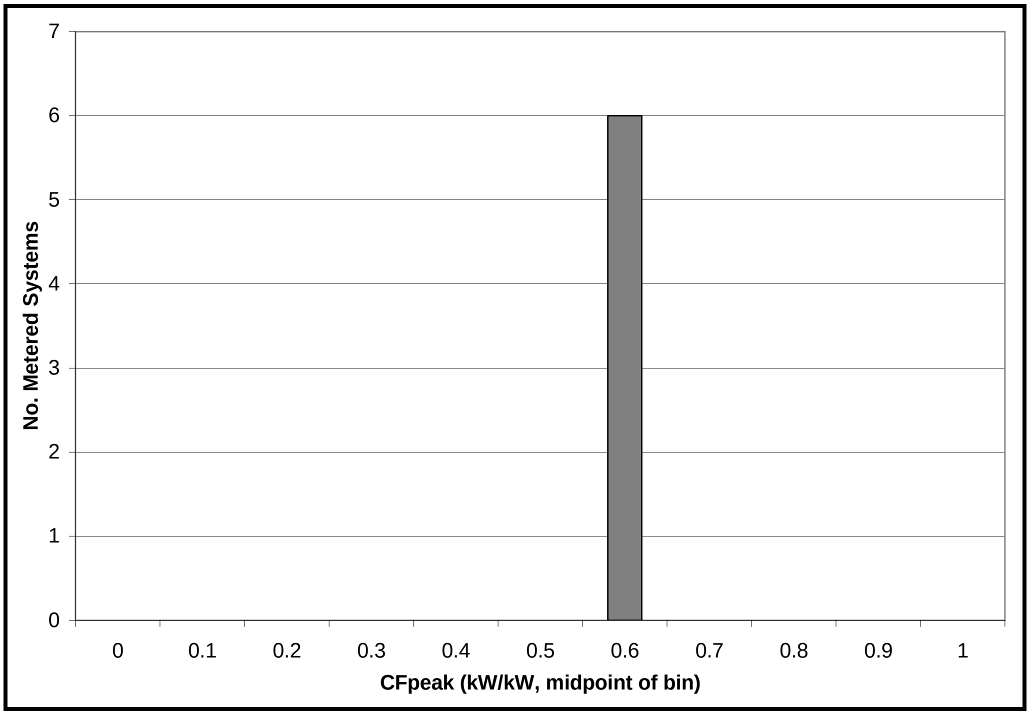


Figure C-15: MCS Distribution—LA (SCE & SCG) PV Coincident Peak Output (Coastal, Near Flat)

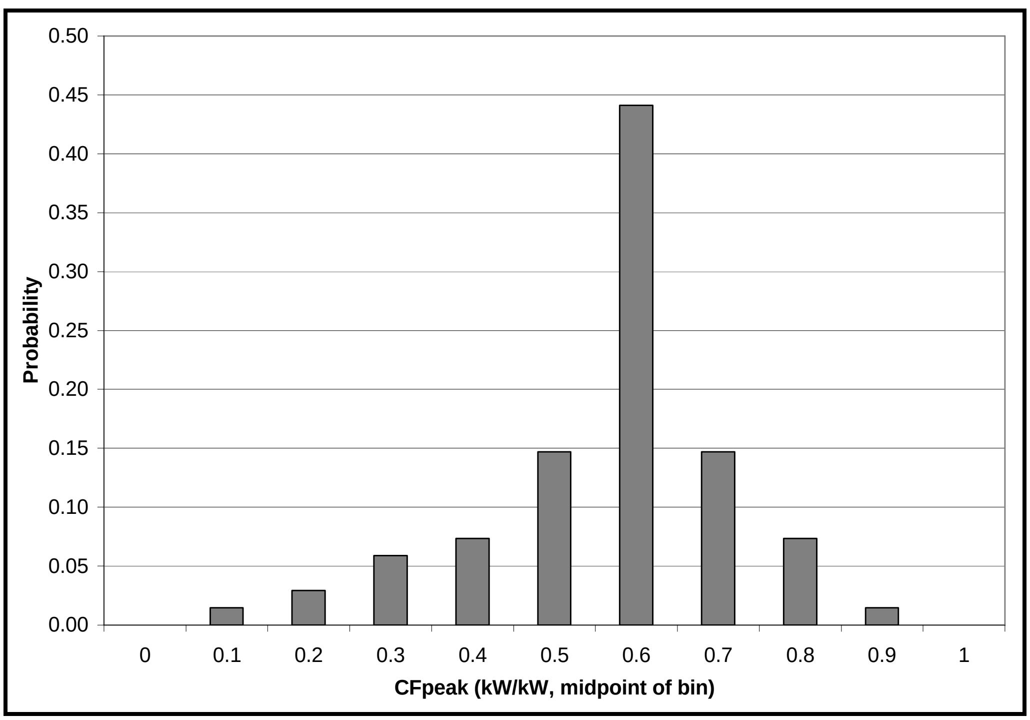


Figure C-16: LA (SCE & SCG) PV Measured Coincident Peak Output (Coastal, Other)

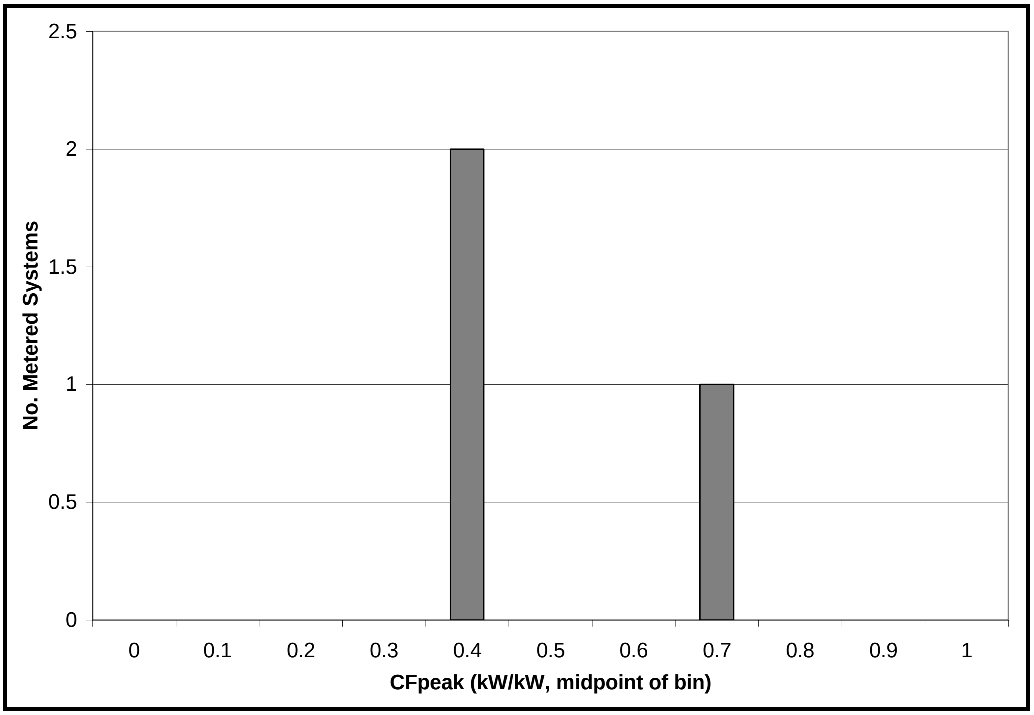


Figure C-17: MCS Distribution—LA (SCE & SCG) PV Coincident Peak Output (Coastal, Other)

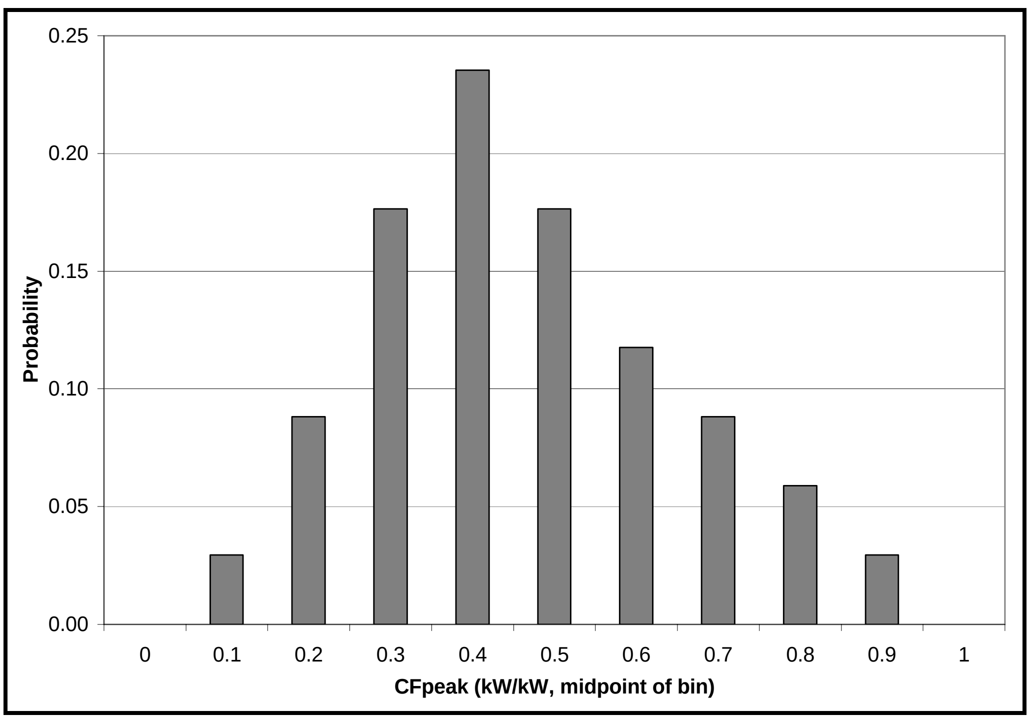


Figure C-18: LA (SCE & SCG) PV Measured Coincident Peak Output (Inland, Near Flat)

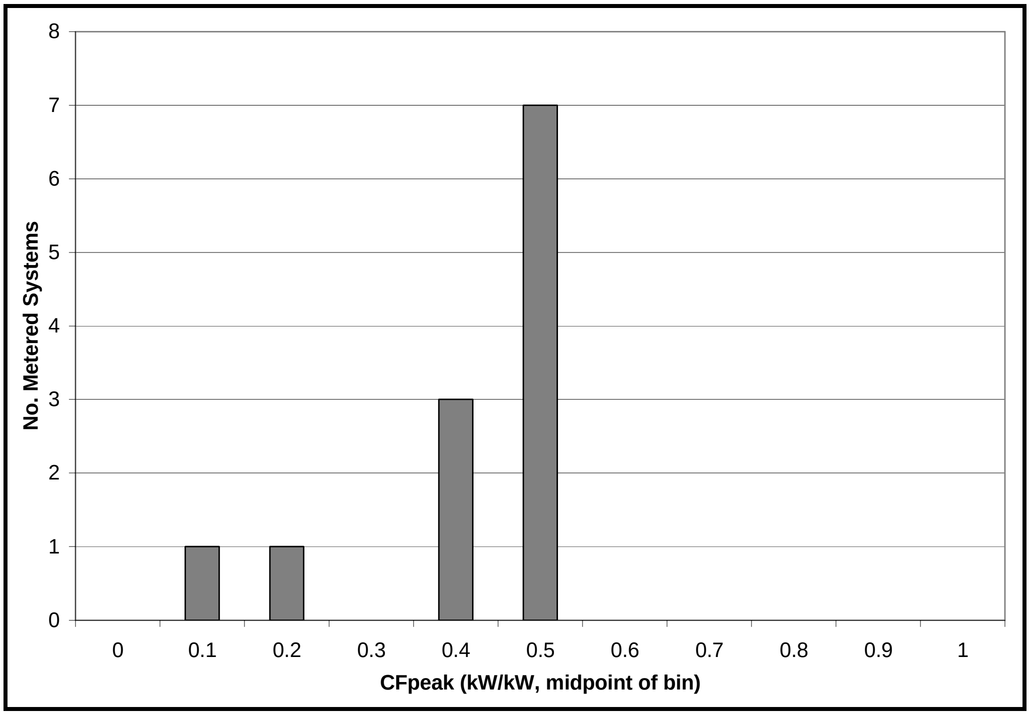


Figure C-19: MCS Distribution—LA (SCE & SCG) PV Coincident Peak Output (Inland, Near Flat)

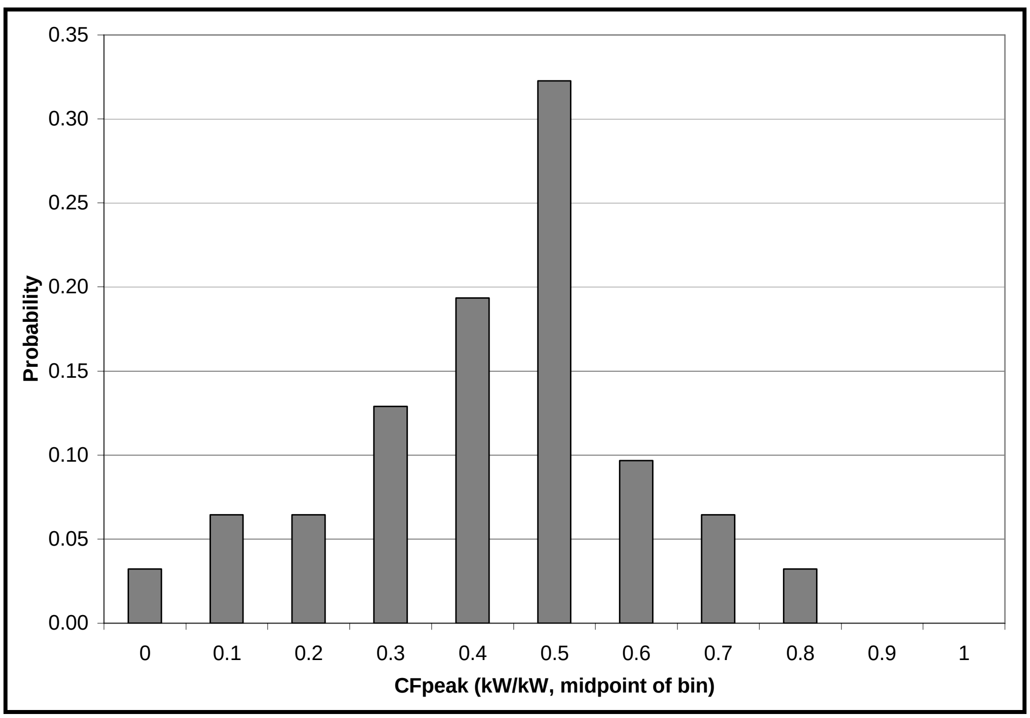


Figure C-20: LA (SCE & SCG) PV Measured Coincident Peak Output (Inland, Other)

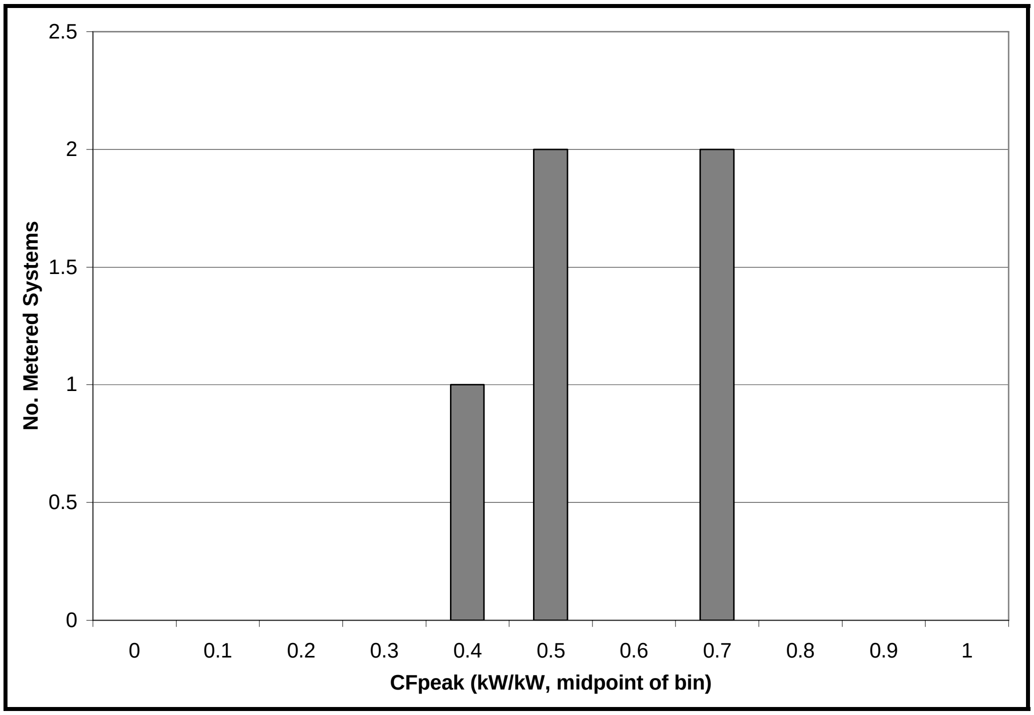


Figure C-21: MCS Distribution—LA (SCE & SCG) PV Coincident Peak Output (Inland, Other)

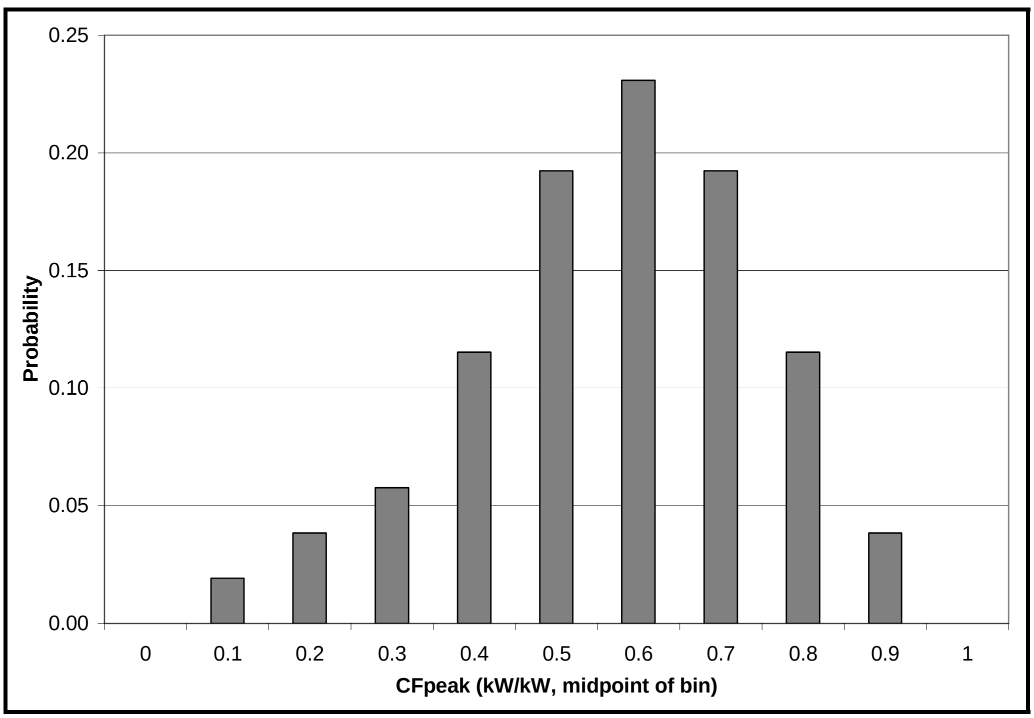


Figure C-22: LA (SCE & SCG) PV Measured Coincident Peak Output (Tracking)

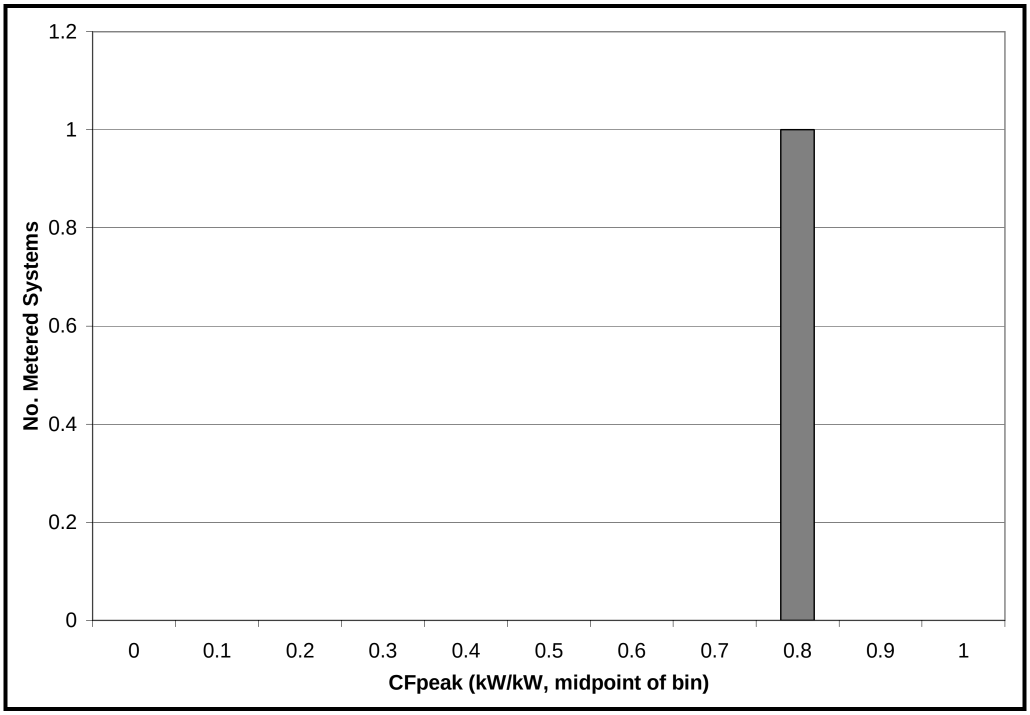


Figure C-23: MCS Distribution—LA (SCE & SCG) PV Coincident Peak Output (Tracking)

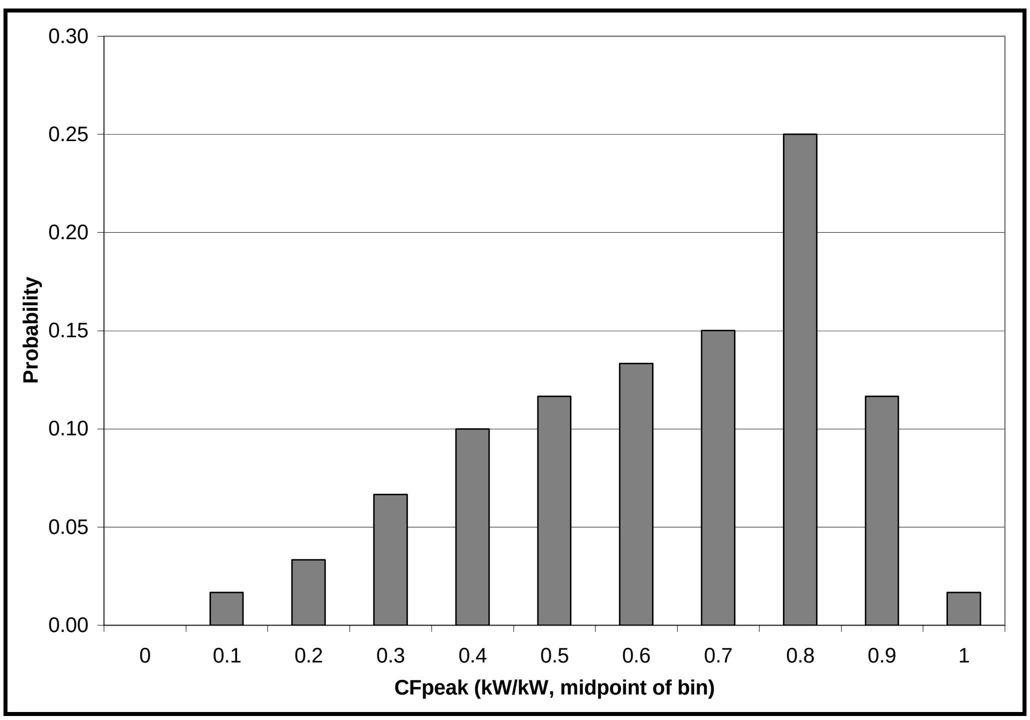


Figure C-24: CCSE PV Measured Coincident Peak Output (Coastal, Near Flat)

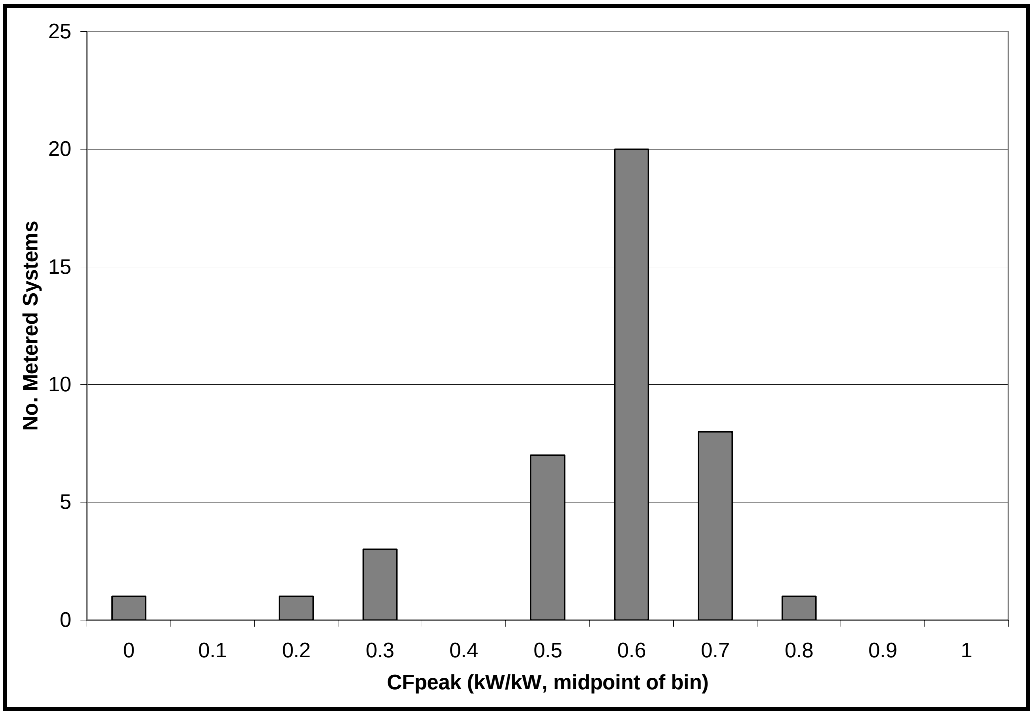


Figure C-25: MCS Distribution—CCSE PV Coincident Peak Output (Coastal, Near Flat)

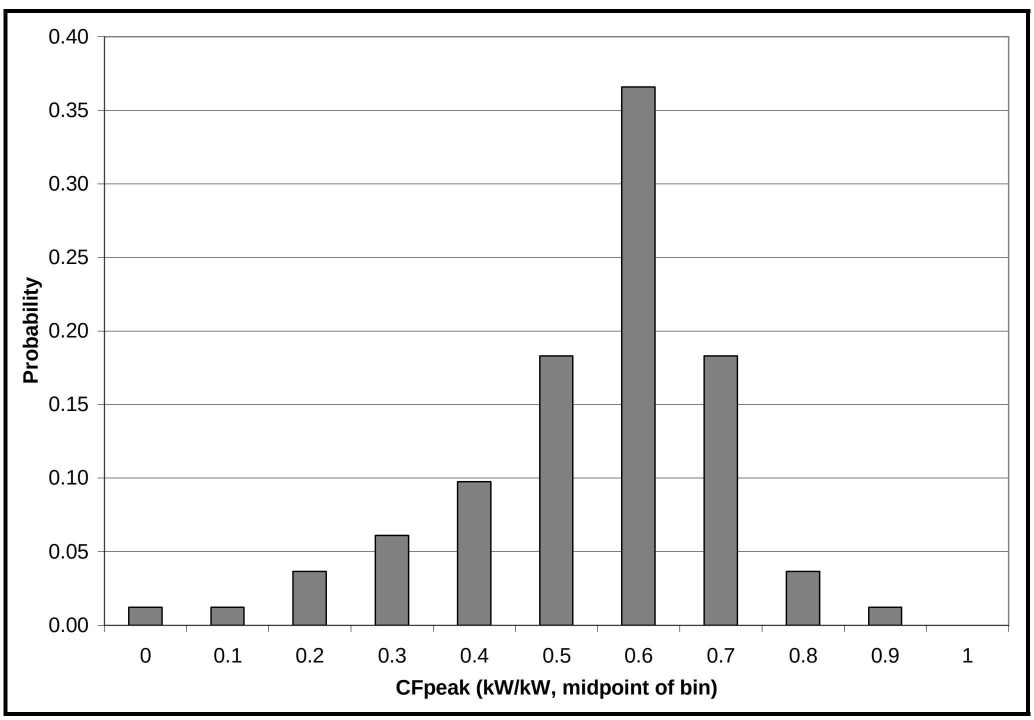


Figure C-26: CCSE PV Measured Coincident Peak Output (Coastal, Other)

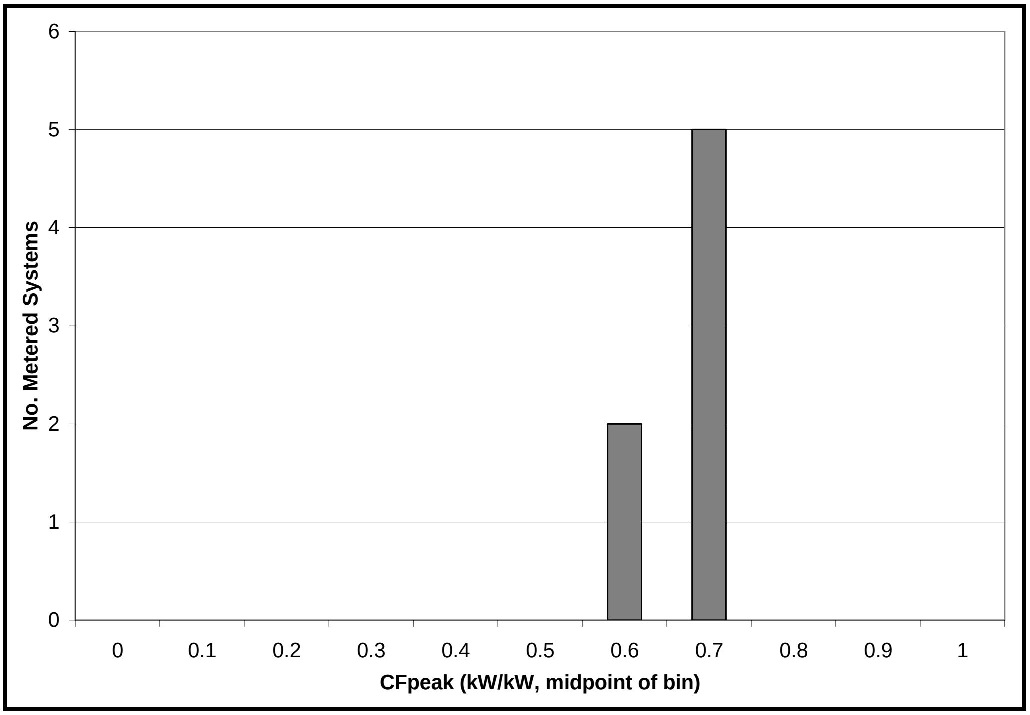


Figure C-27: MCS Distribution—CCSE PV Coincident Peak Output (Coastal, Other)

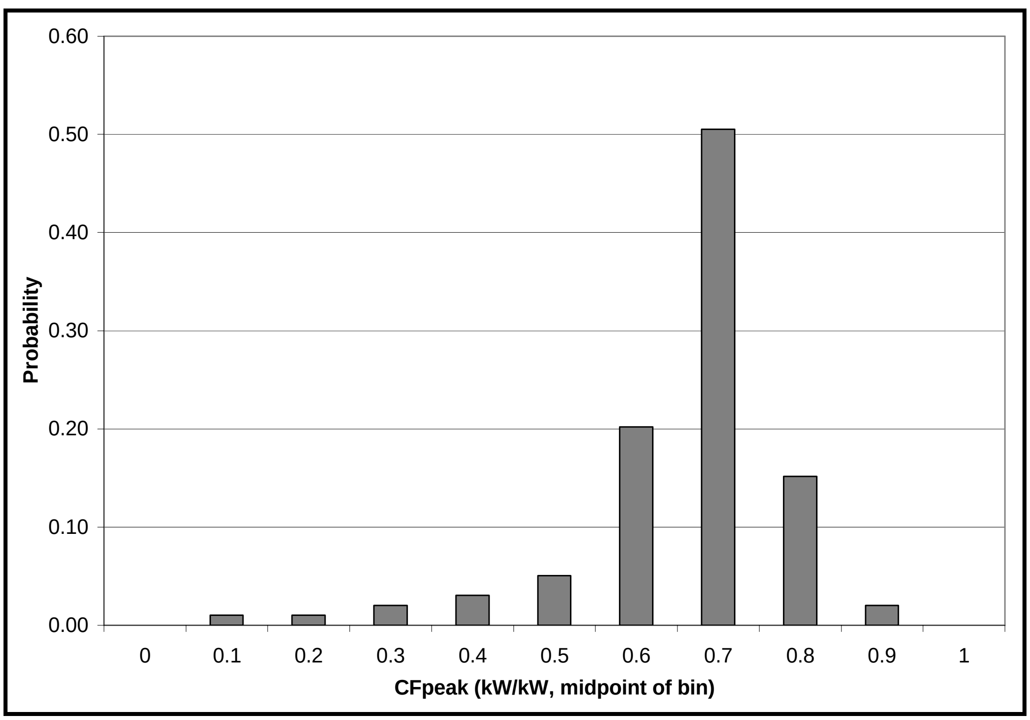


Figure C-28: CCSE PV Measured Coincident Peak Output (Inland, Near Flat)

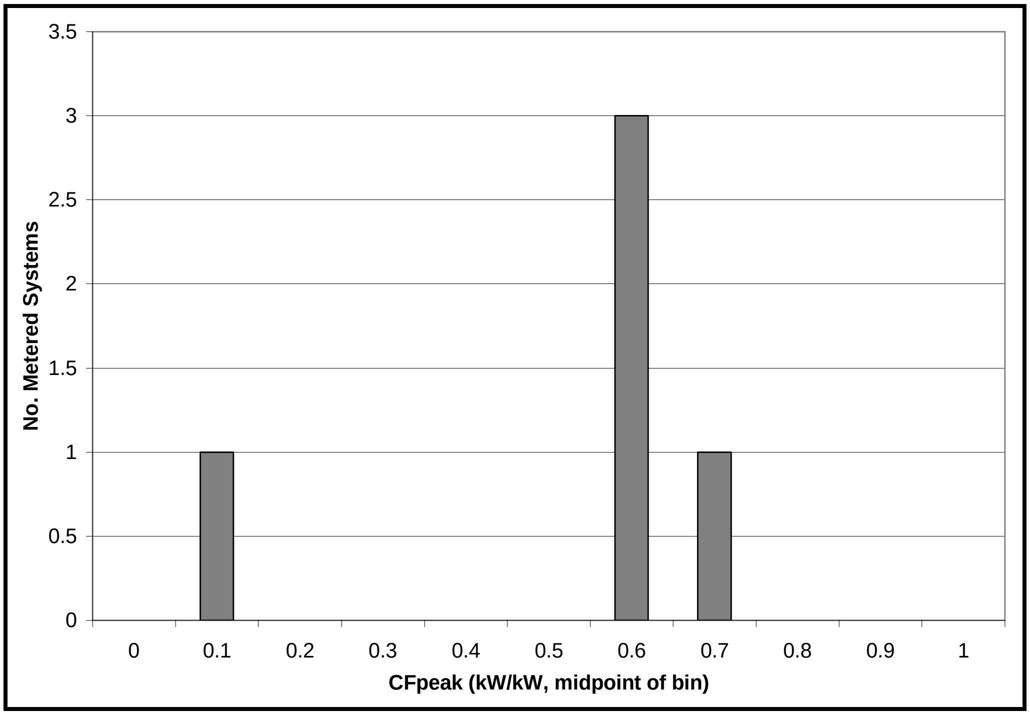


Figure C-29: MCS Distribution—CCSE PV Coincident Peak Output (Inland, Near Flat)

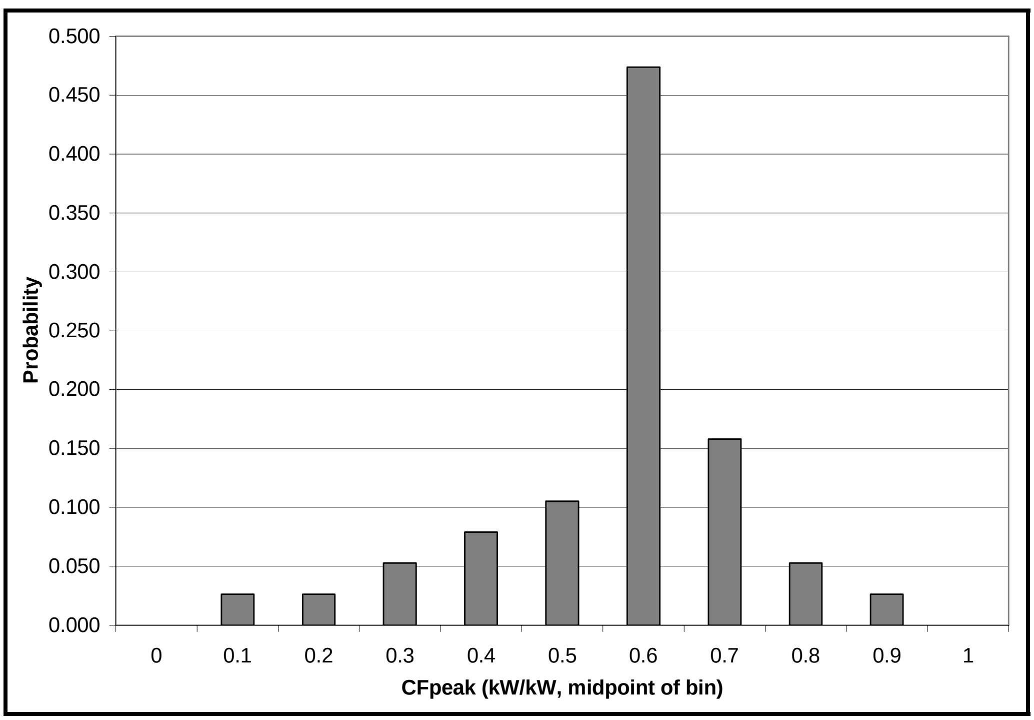


Figure C-30: CCSE PV Measured Coincident Peak Output (Inland, Other)

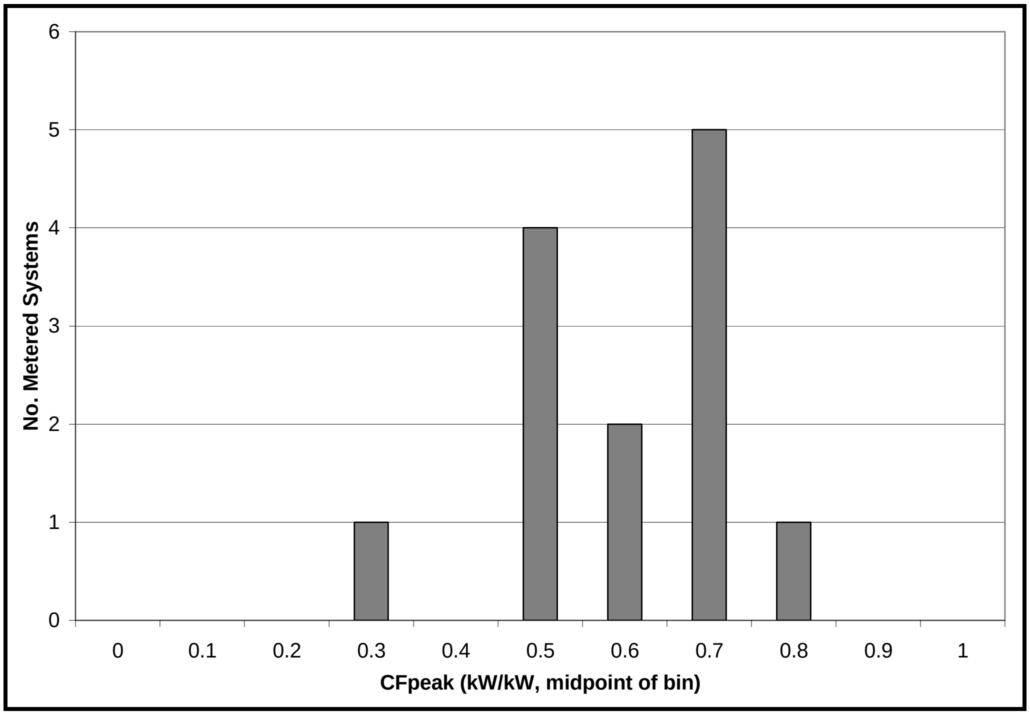


Figure C-31: MCS Distribution—CCSE PV Coincident Peak Output (Inland, Other)

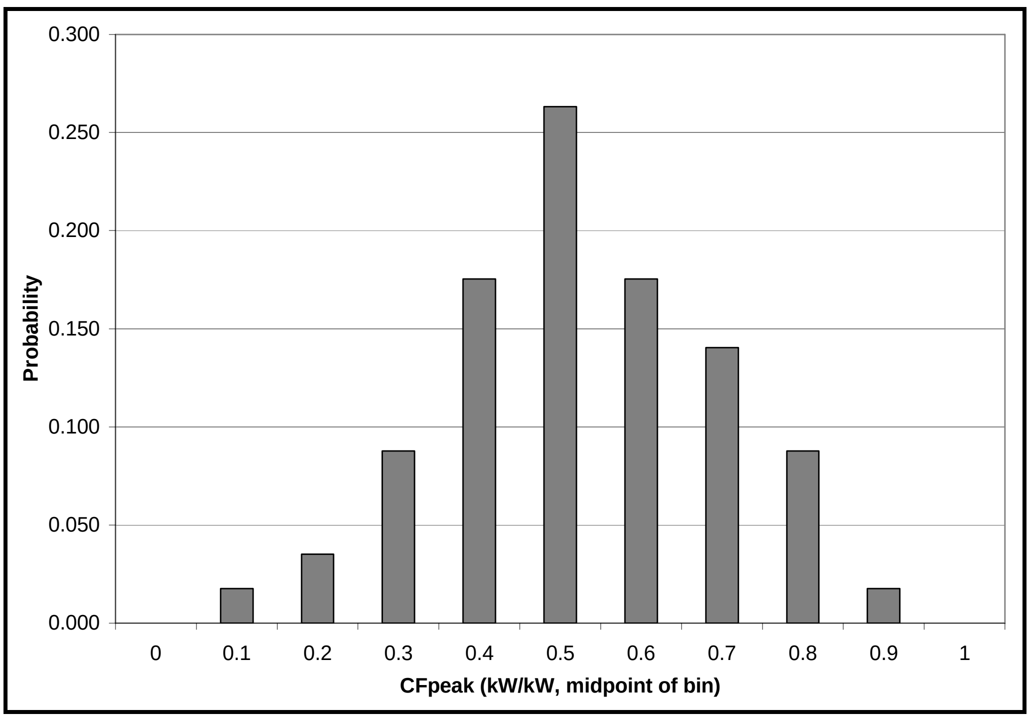


Figure C-32: Fuel Cell Measured Coincident Peak Output (Non-Renewable Fuel)

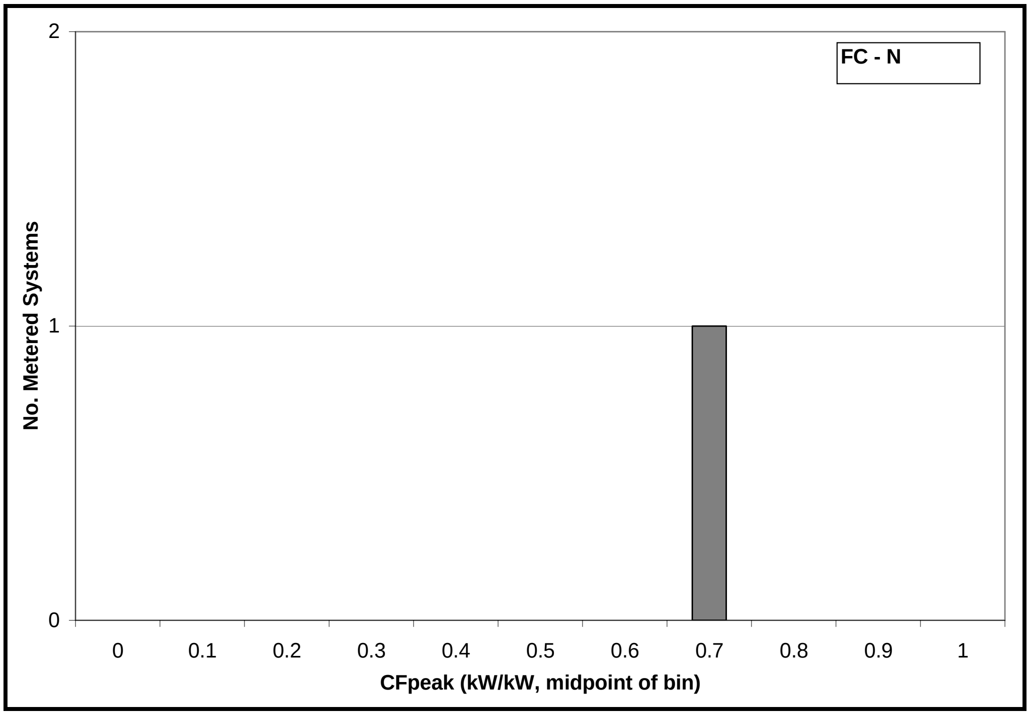


Figure C-33: MCS Distribution –Fuel Cell Coincident Peak Output (Non-Renewable Fuel)

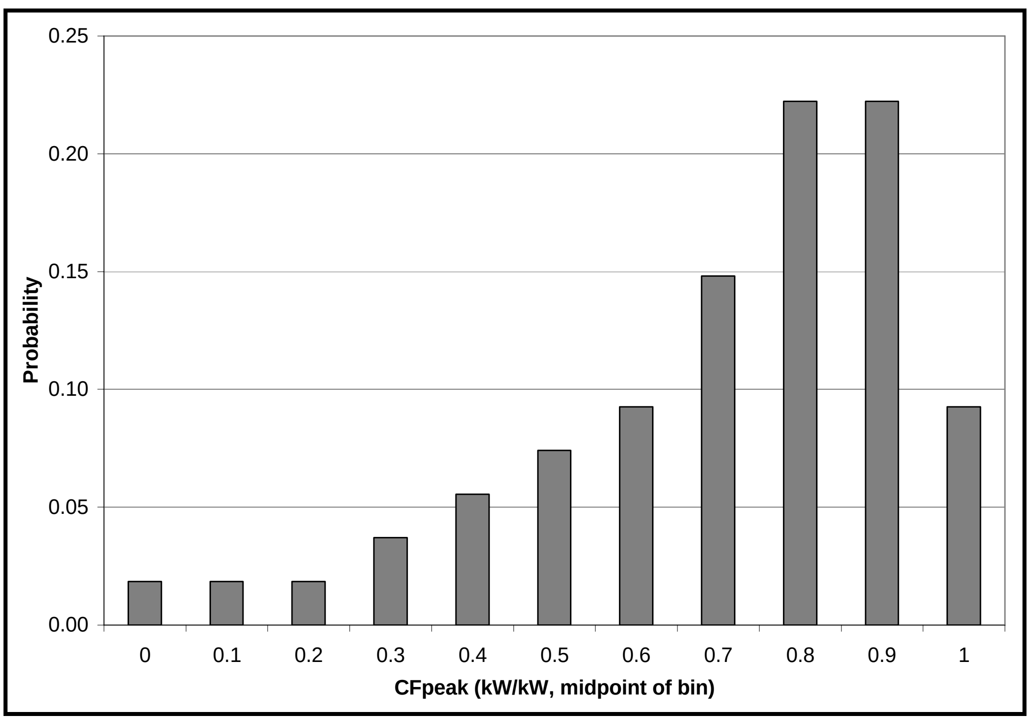


Figure C-34: Fuel Cell Measured Coincident Peak Output (Renewable Fuel)

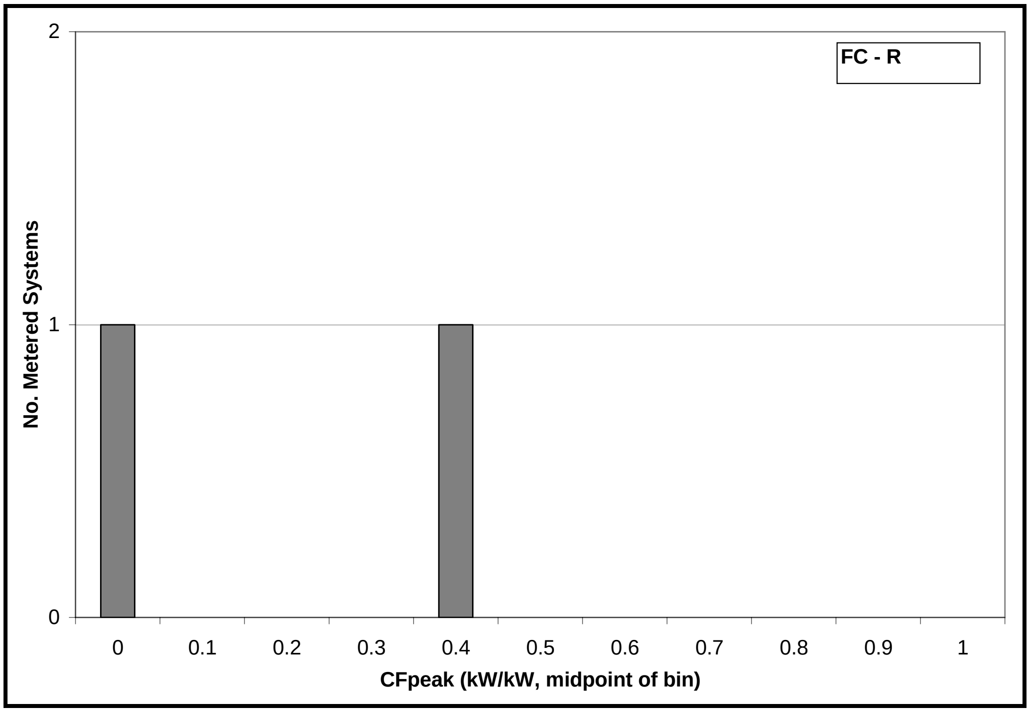


Figure C-35: MCS Distribution –Fuel Cell Coincident Peak Output (Renewable Fuel)

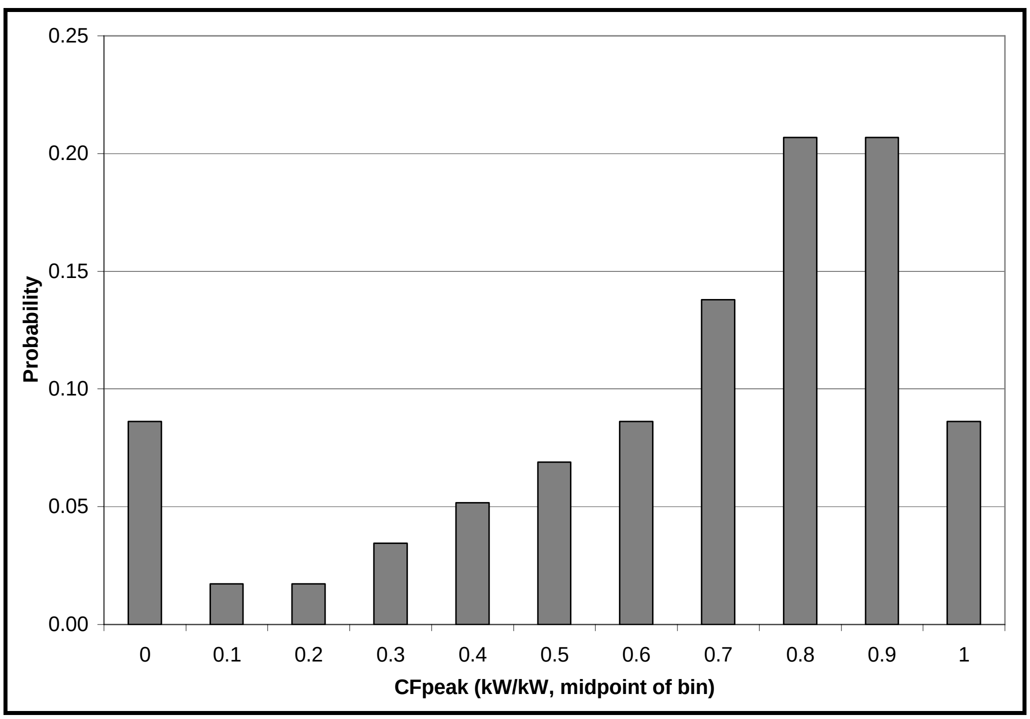


Figure C-36: IC Engine Measured Coincident Peak Output (Non-Renewable Fuel)

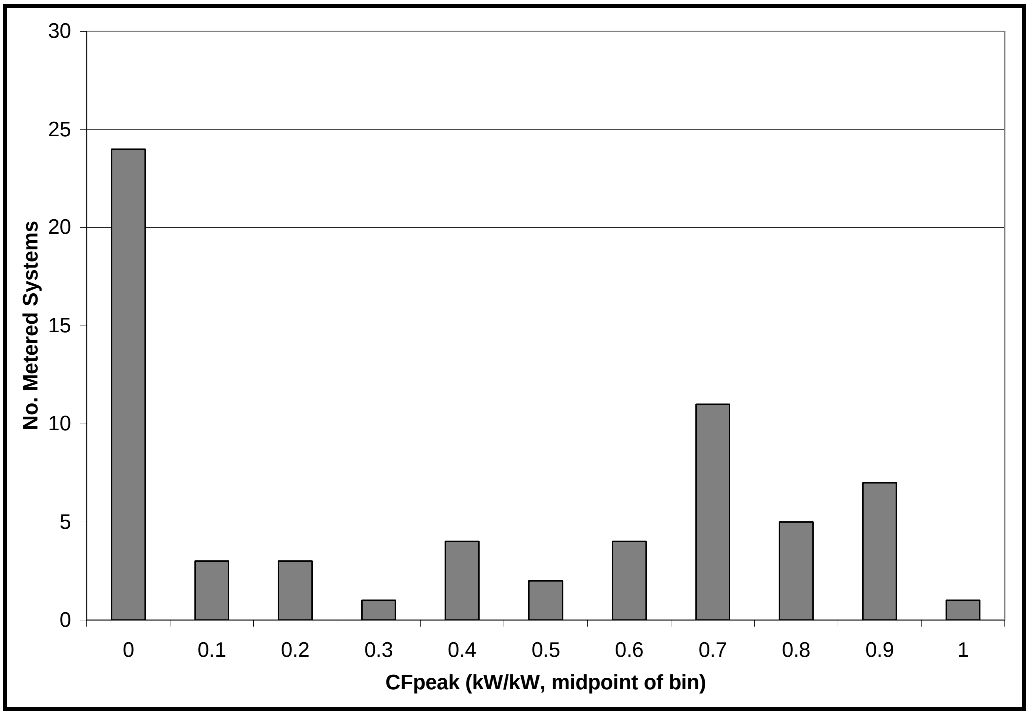


Figure C-37: MCS Distribution—IC Engine Coincident Peak Output (Non-Renewable Fuel)

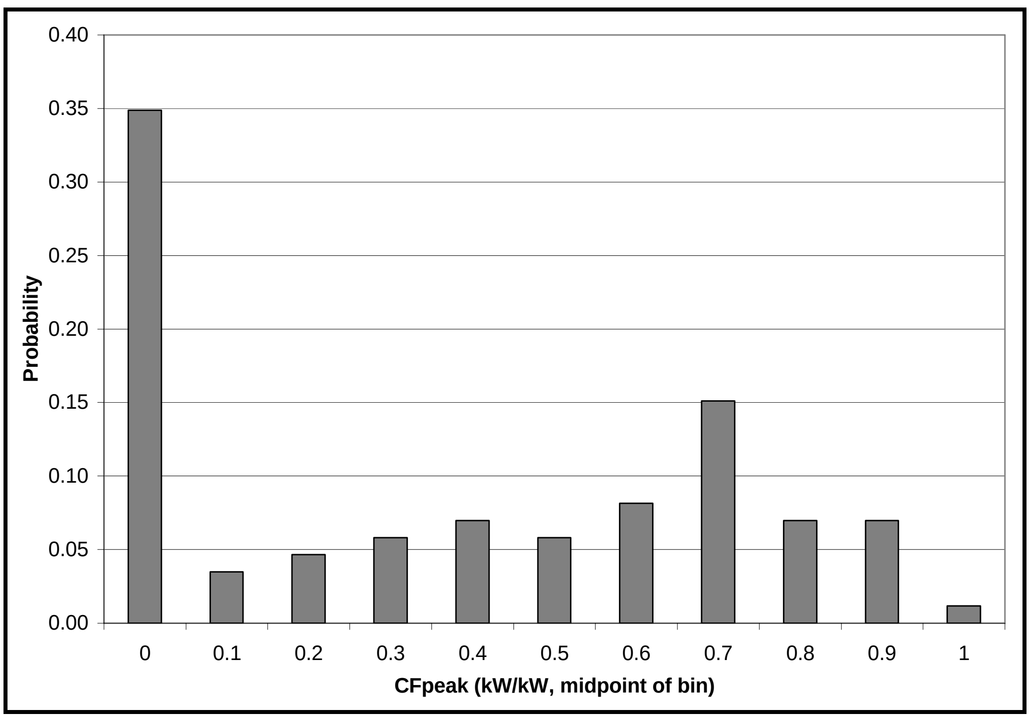


Figure C-38: IC Engine Measured Coincident Peak Output (Renewable Fuel)

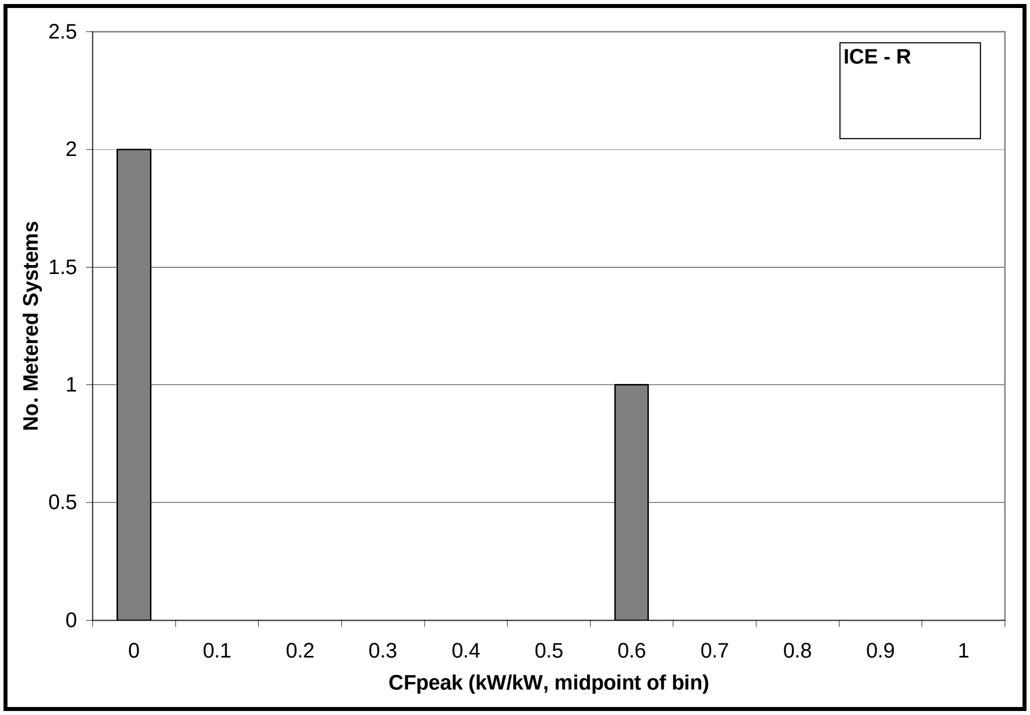


Figure C-39: MCS Distribution—IC Engine Coincident Peak Output (Renewable Fuel)

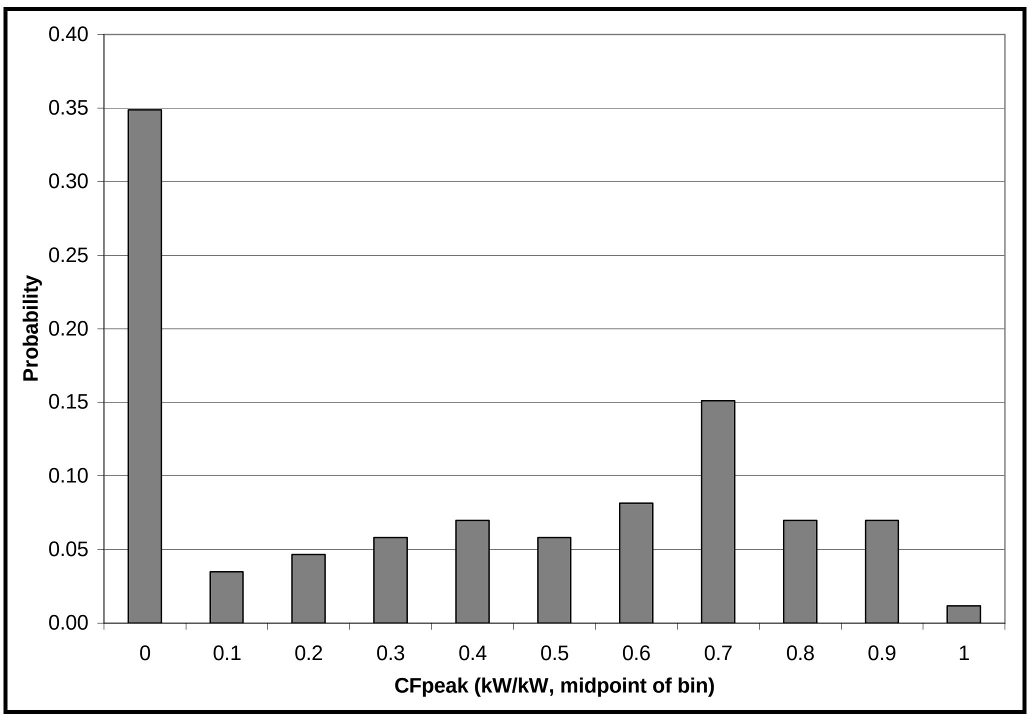


Figure C-40: Gas Turbine Measured Coincident Peak Output (Non-Renewable Fuel)

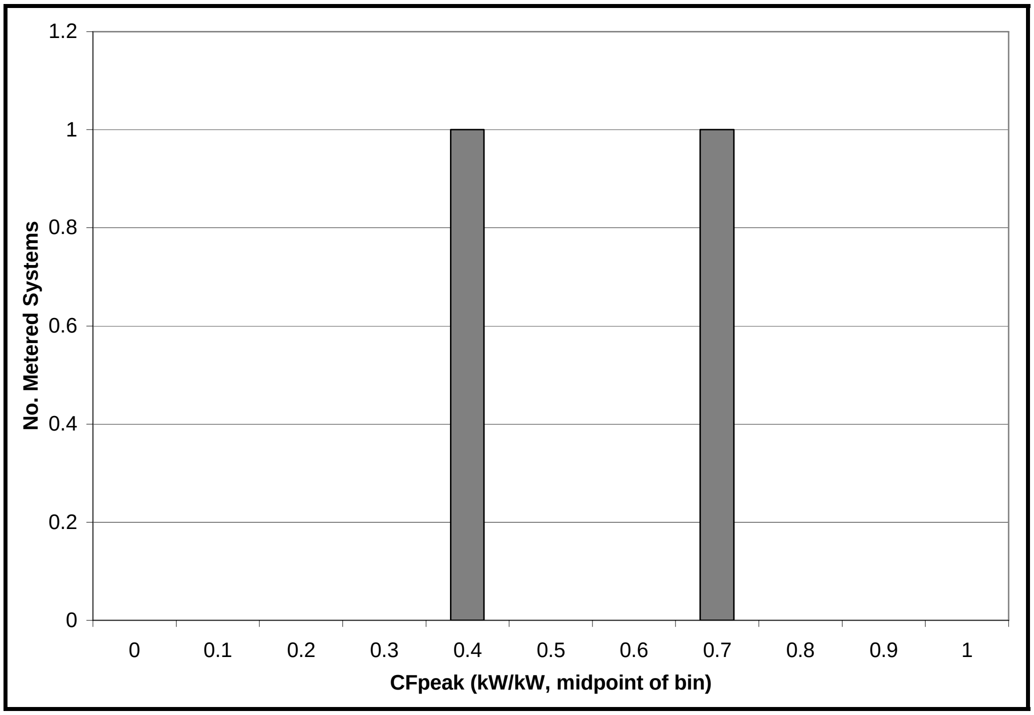


Figure C-41: MCS Distribution—Gas Turbine Coincident Peak Output (Non-Renewable Fuel)

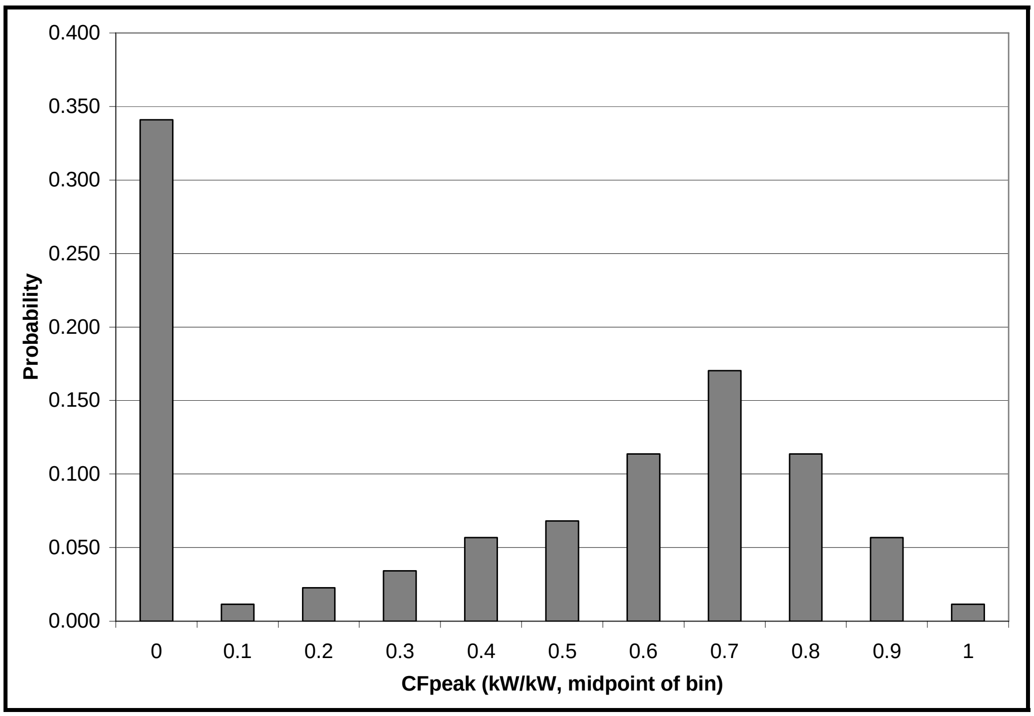


Figure C-42: Microturbine Measured Coincident Peak Output (Non-Renewable Fuel)

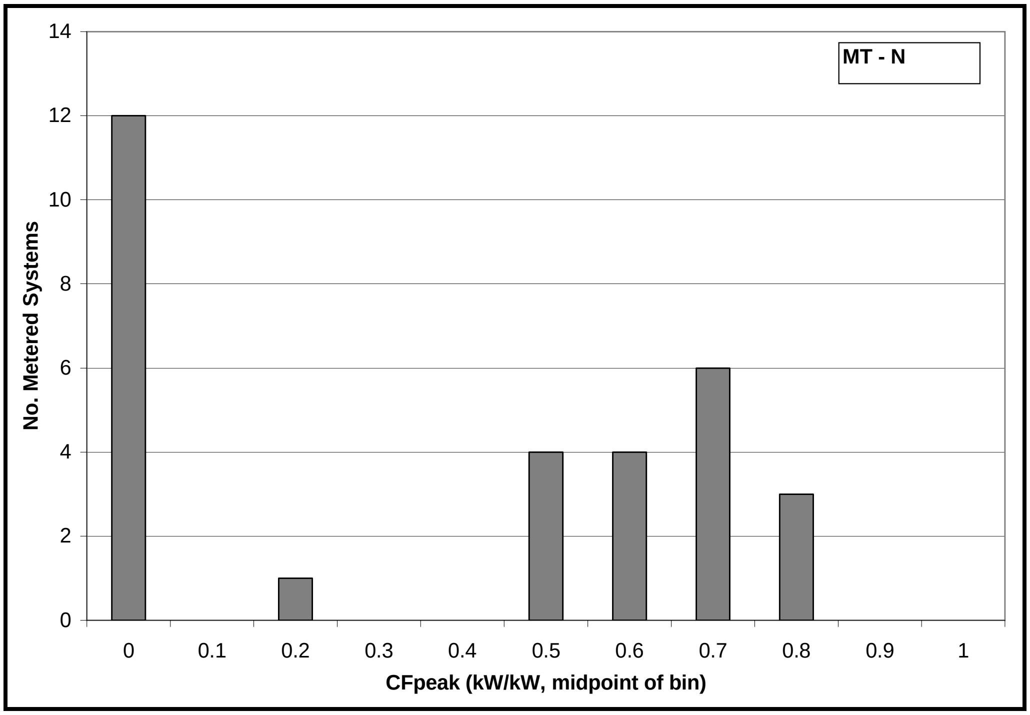


Figure C-43: MCS Distribution—Microturbine Coincident Peak Output (Non-Renewable Fuel)

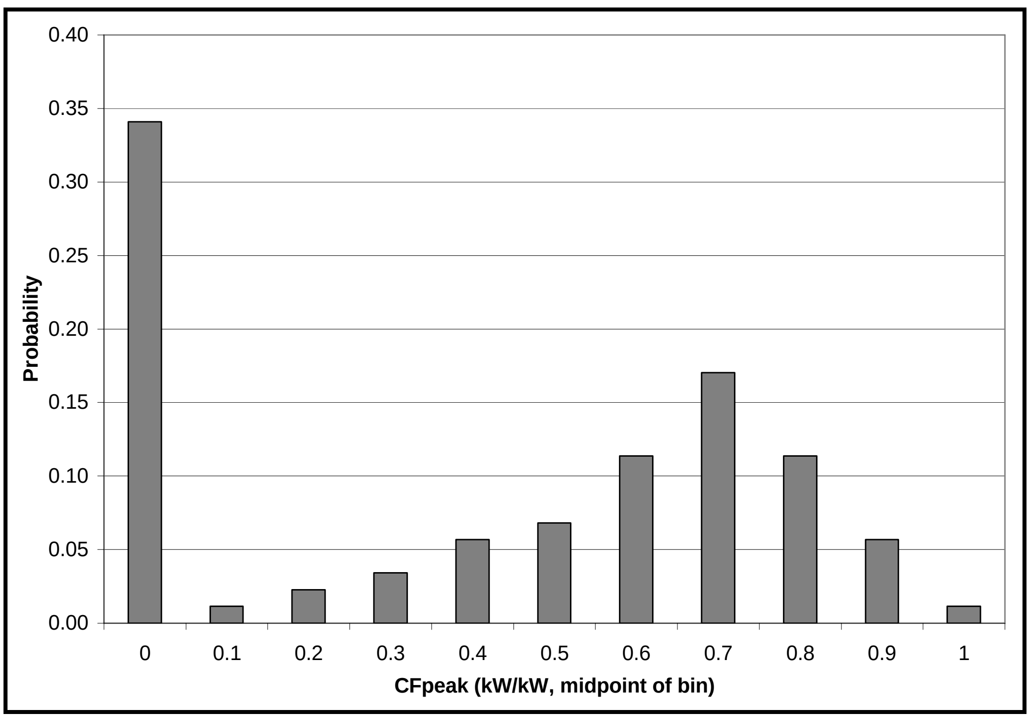


Figure C-44: Microturbine Measured Coincident Peak Output (Renewable Fuel)

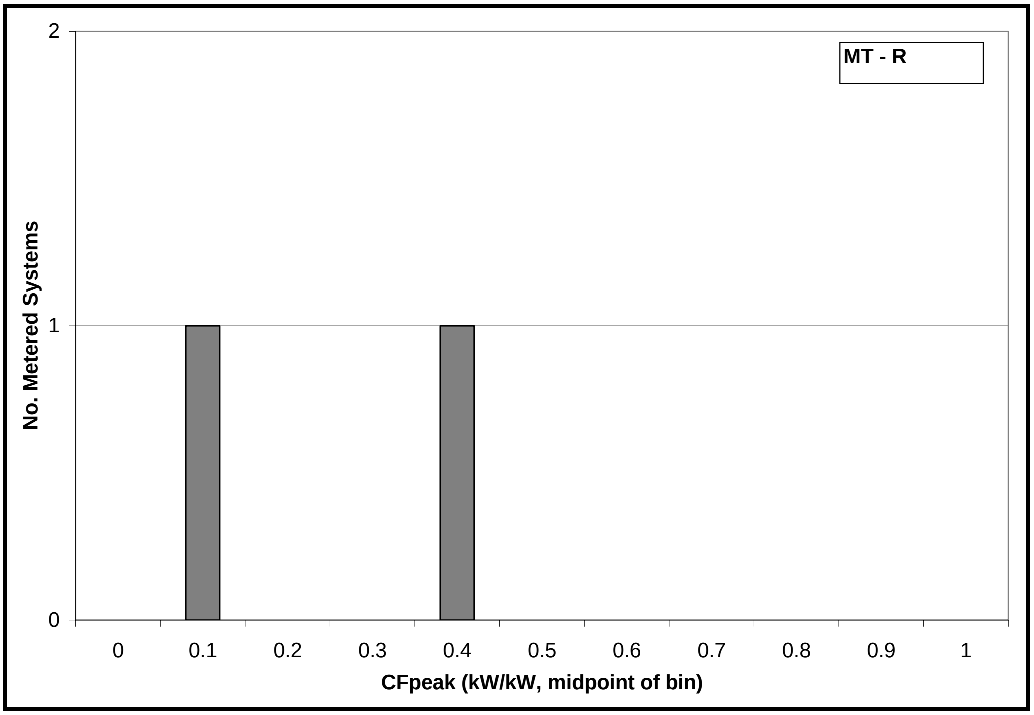
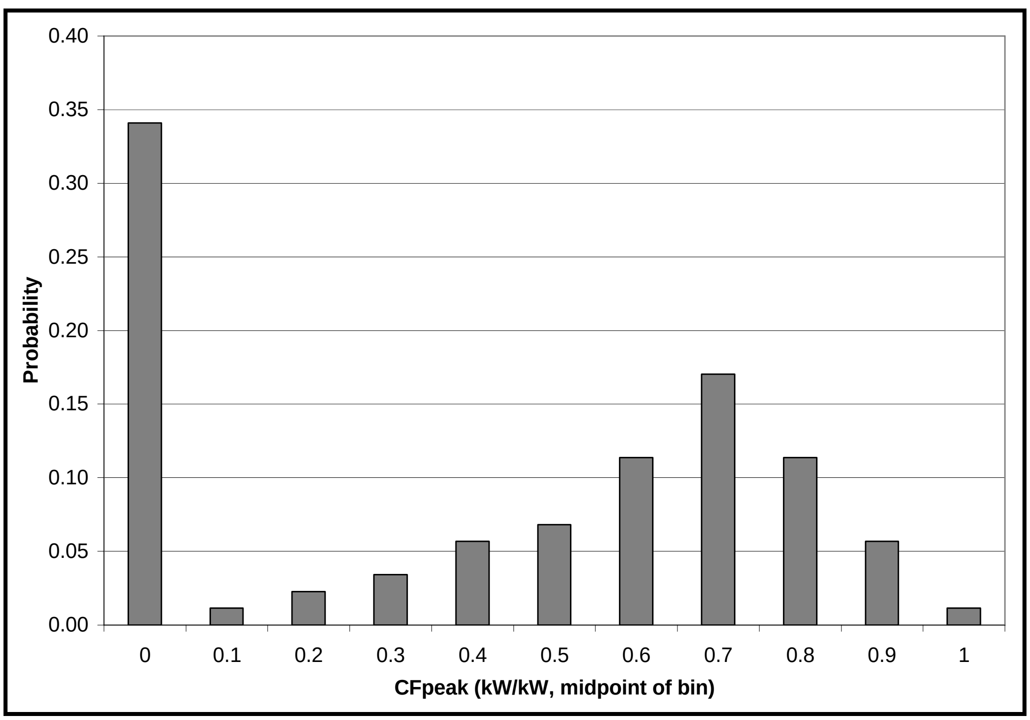


Figure C-45: MCS Distribution—Microturbine Coincident Peak Output (Renewable Fuel)



Performance Distributions for Energy Impacts

Figure C-46: PV (Non-tracking) Measured Energy Production (Capacity Factor)

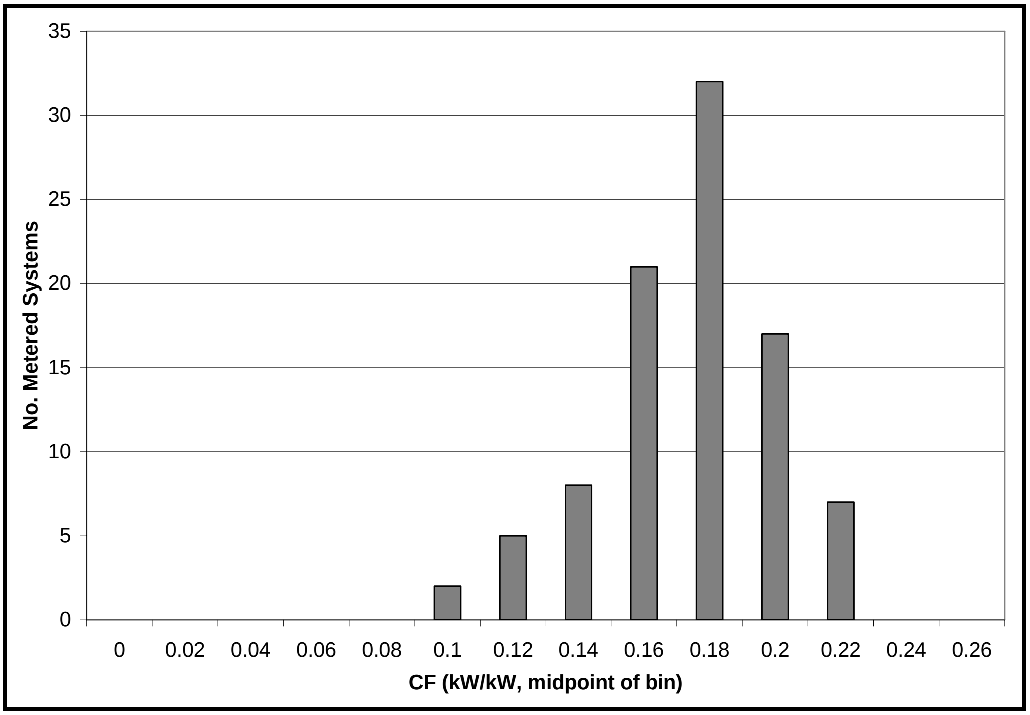


Figure C-47: MCS Distribution—PV (Non-tracking) Energy Production (Capacity Factor)

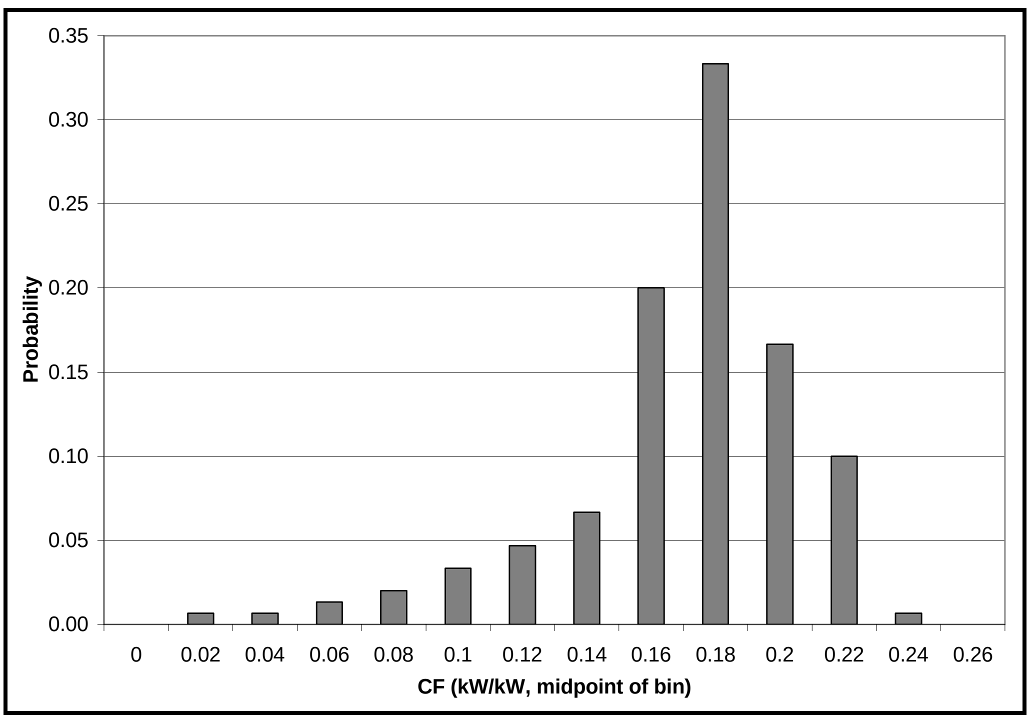


Figure C-48: PV (Tracking) Measured Energy Production (Capacity Factor)

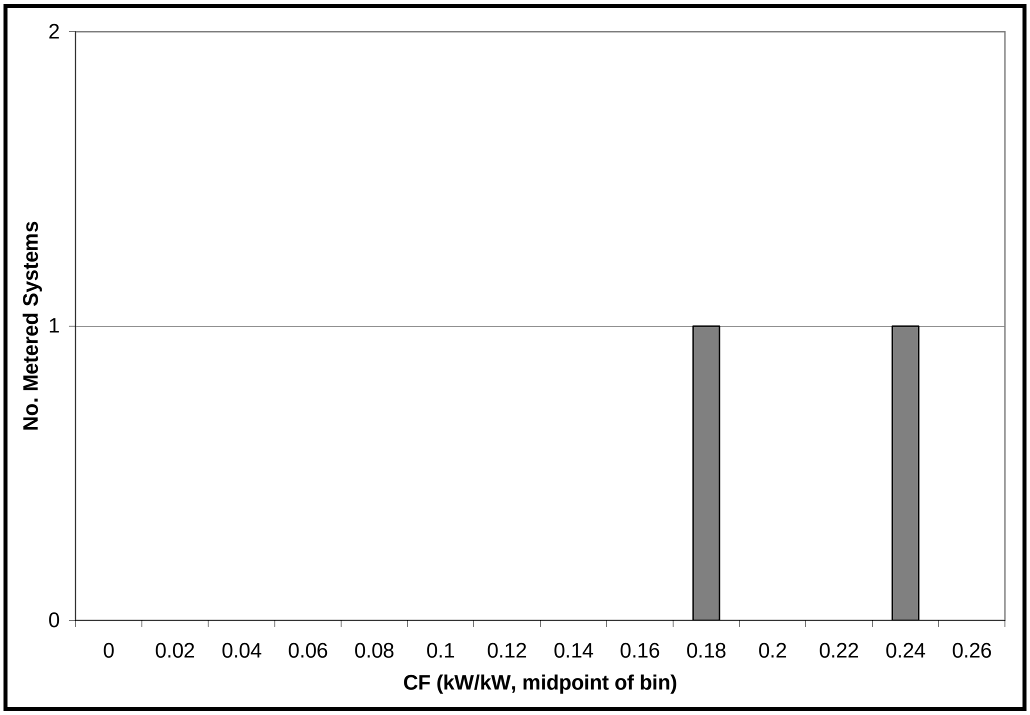


Figure C-49: MCS Distribution—PV (Tracking) Energy Production (Capacity Factor)

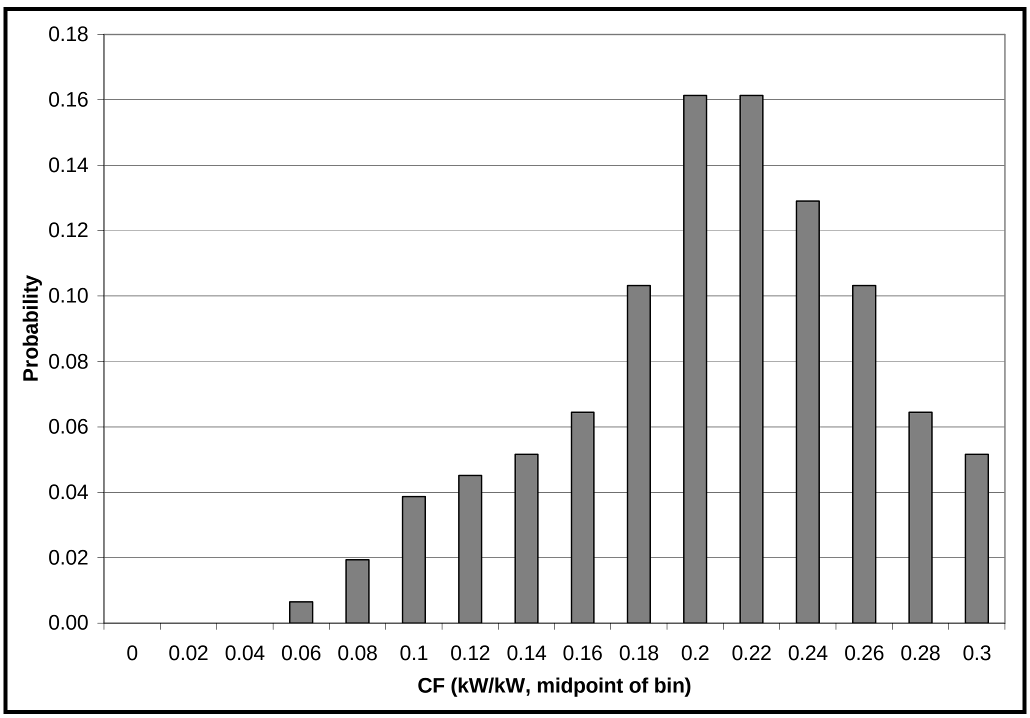


Figure C-50: Wind Turbine Measured Energy Production (Capacity Factor)

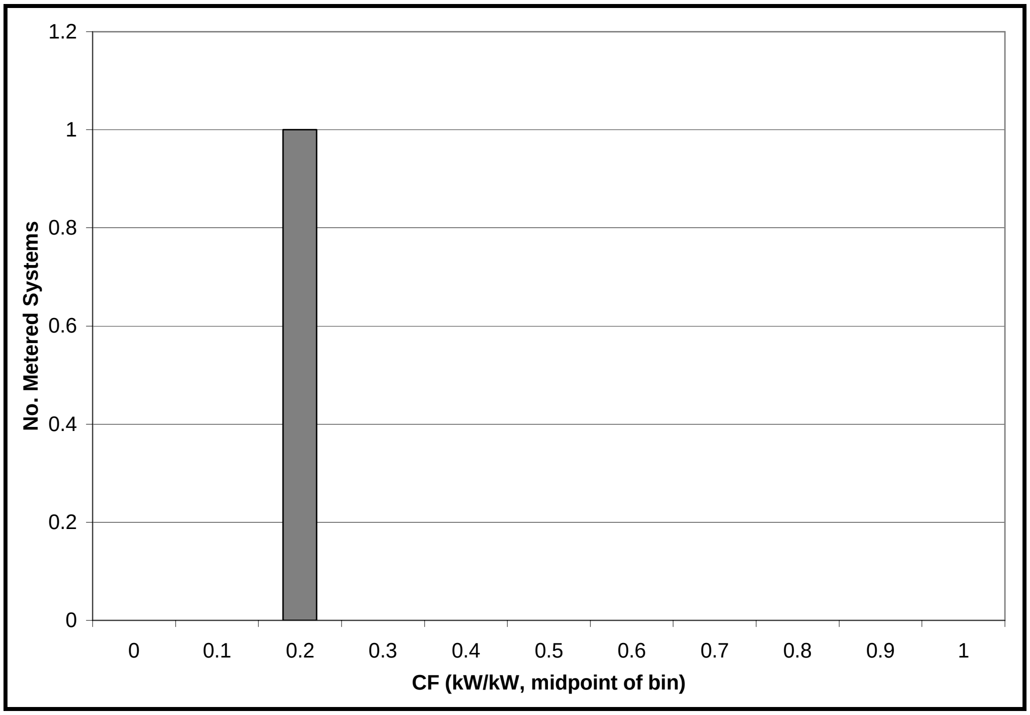


Figure C-51: MCS Distribution—Wind Turbine Energy Production (Capacity Factor)

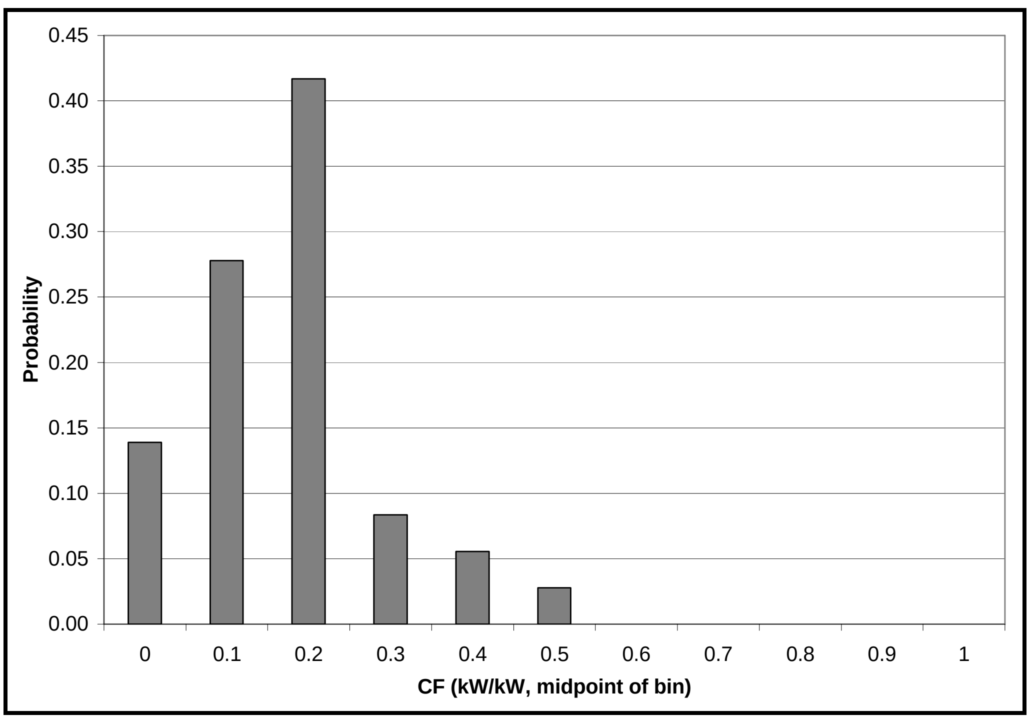


Figure C-52: Fuel Cell Measured Energy Production (Capacity Factor)

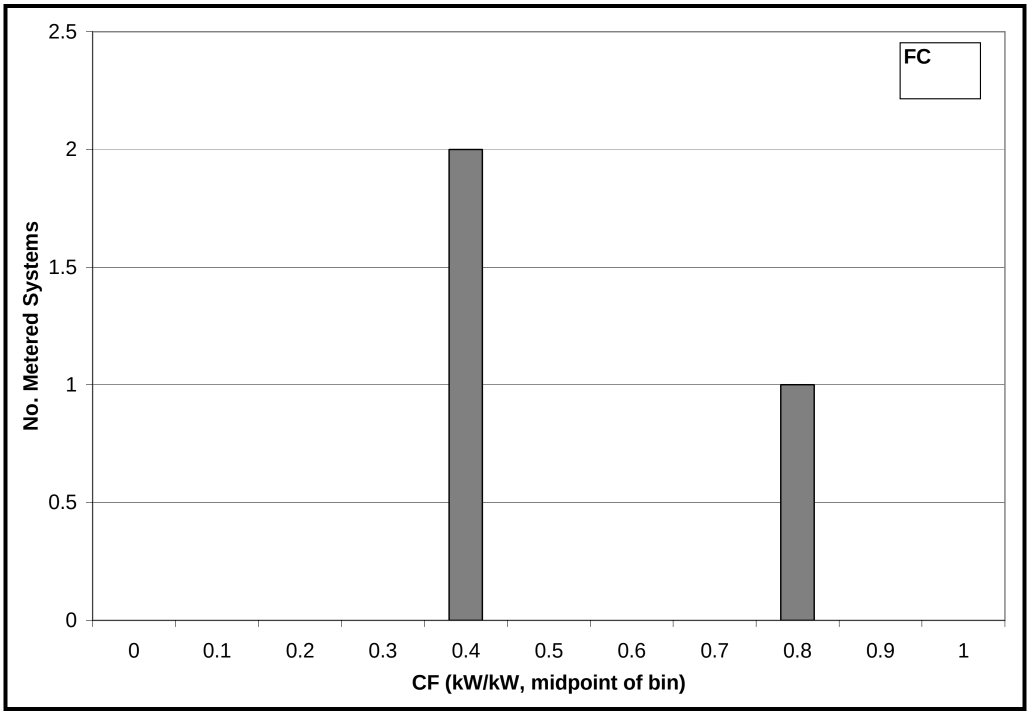


Figure C-53: MCS Distribution—Fuel Cell Energy Production (Capacity Factor)

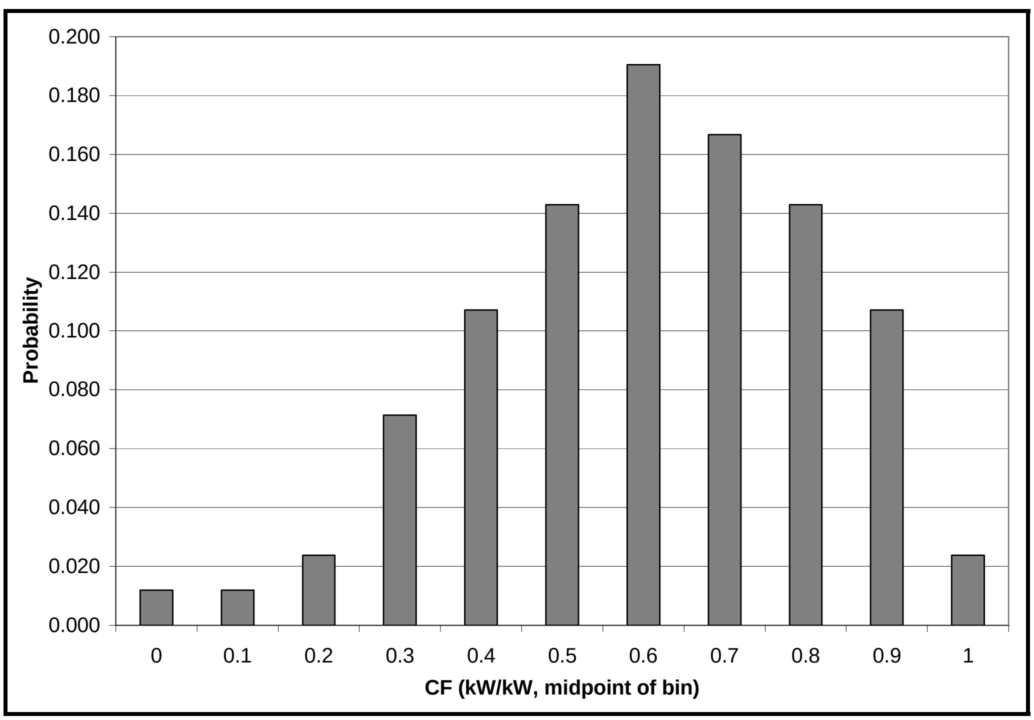


Figure C-54: Engine/Turbine (Non-Renewable) Measured Electricity Production (Capacity Factor)

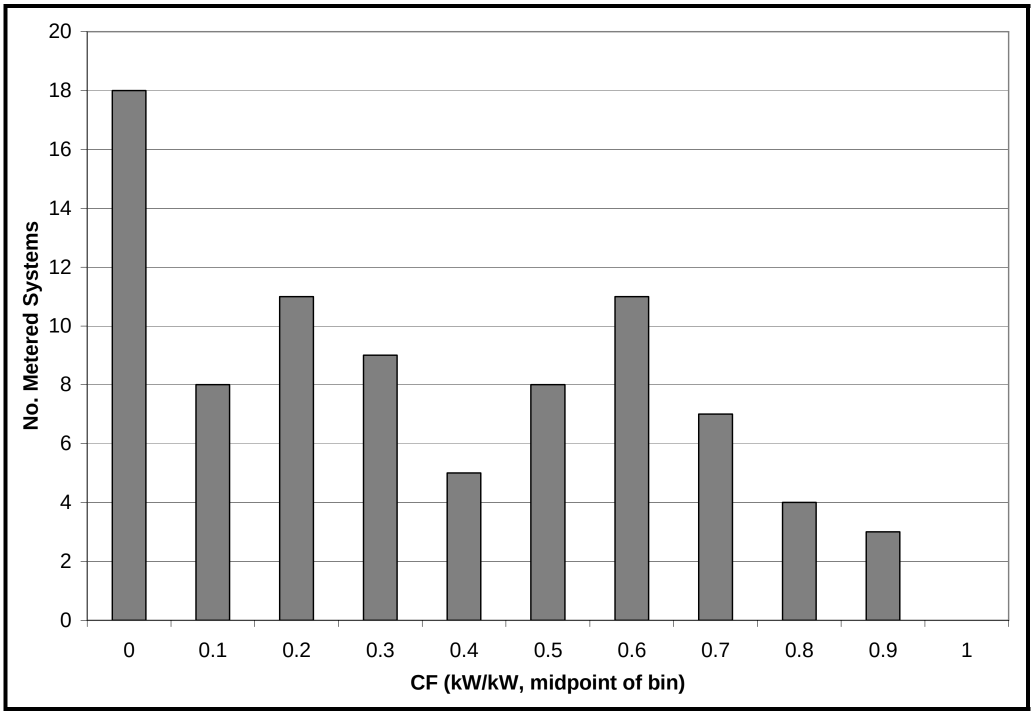


Figure C-55: MCS Distribution—Engine/Turbine (Non-Renewable) Electricity Production (Capacity Factor)

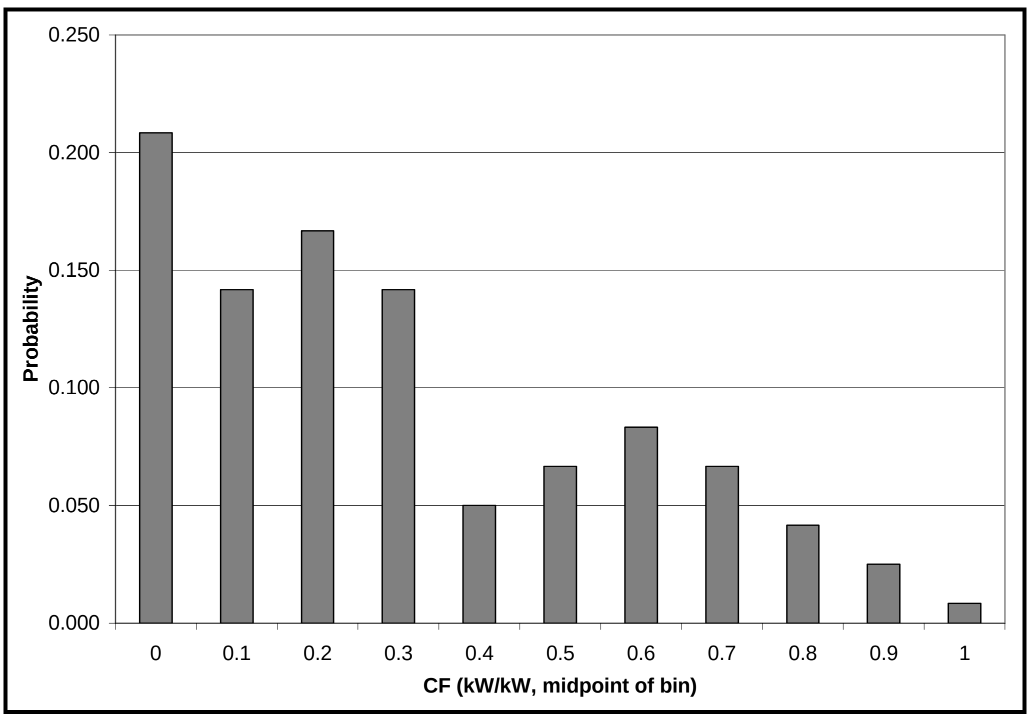


Figure C-56: Engine/Turbine (Renewable) Measured Electricity Production (Capacity Factor)

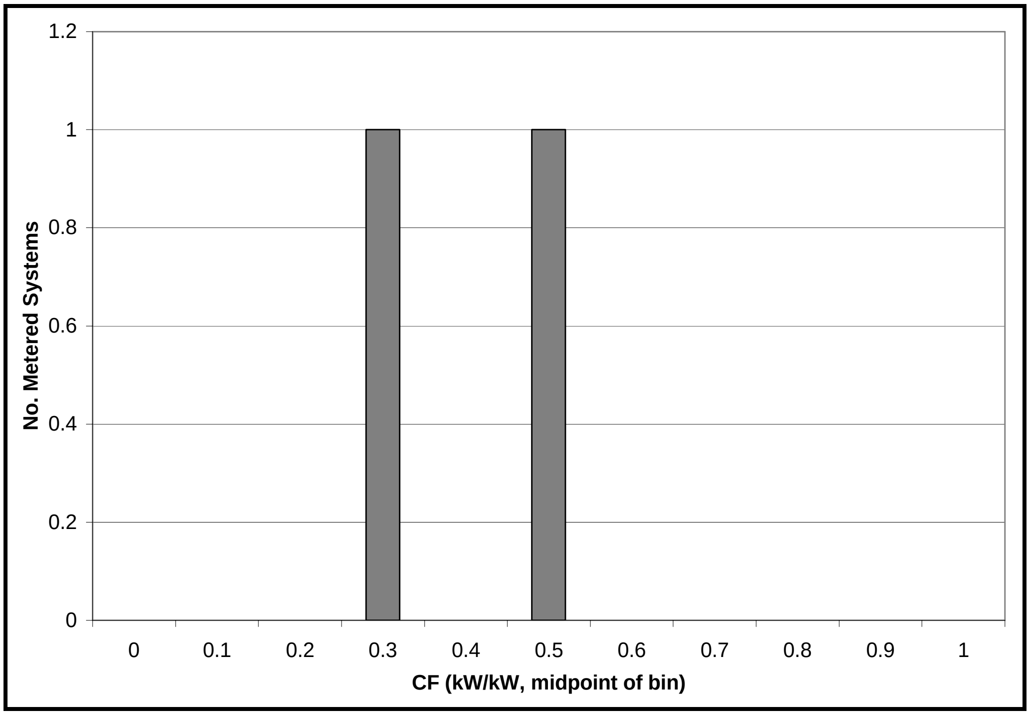


Figure C-57: MCS Distribution—Engine/Turbine (Renewable) Electricity Production (Capacity Factor)

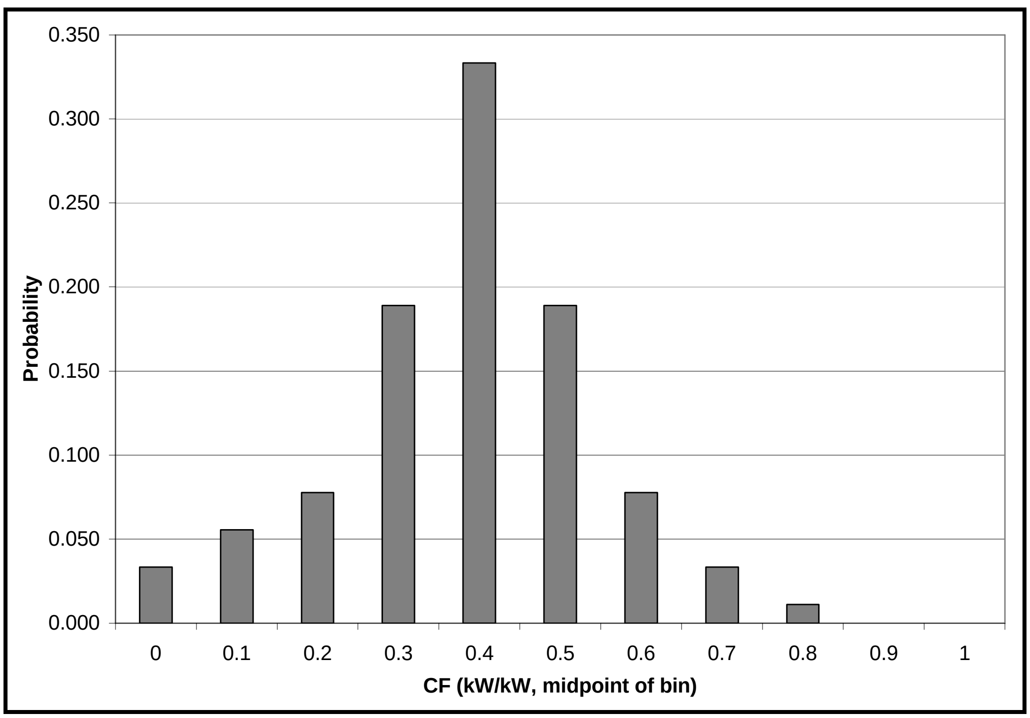


Figure C-58: Fuel Cell (Non-Renewable) Measured Heat Recovery Rate in 2006

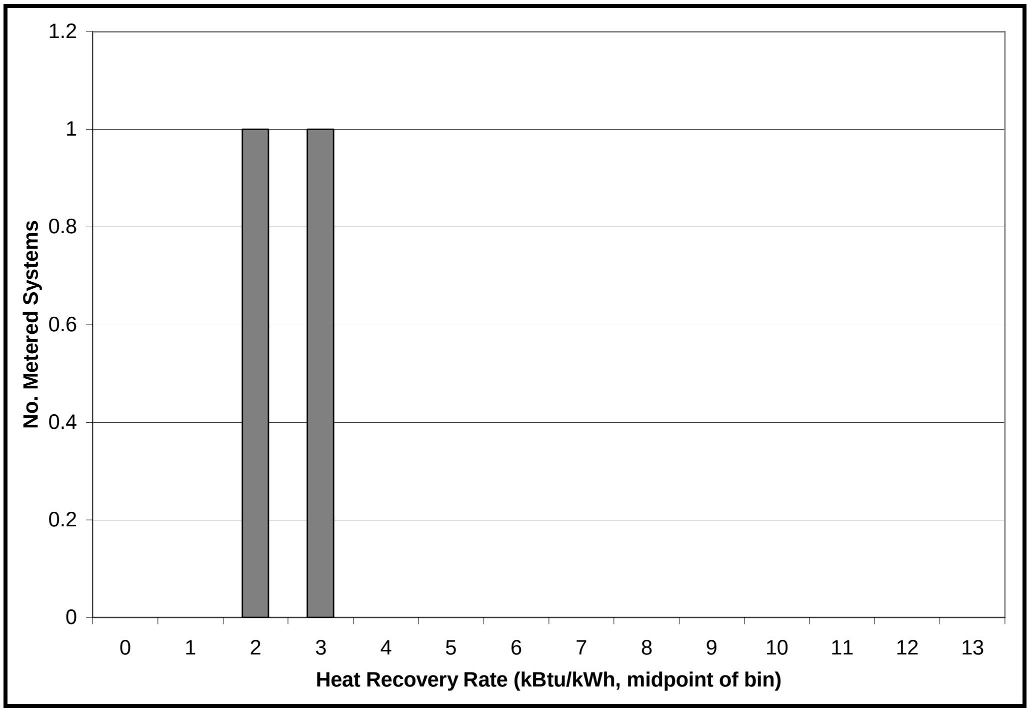


Figure C-59: 2007 MCS Distribution—Fuel Cell (Non-Renewable) Heat Recovery Rate

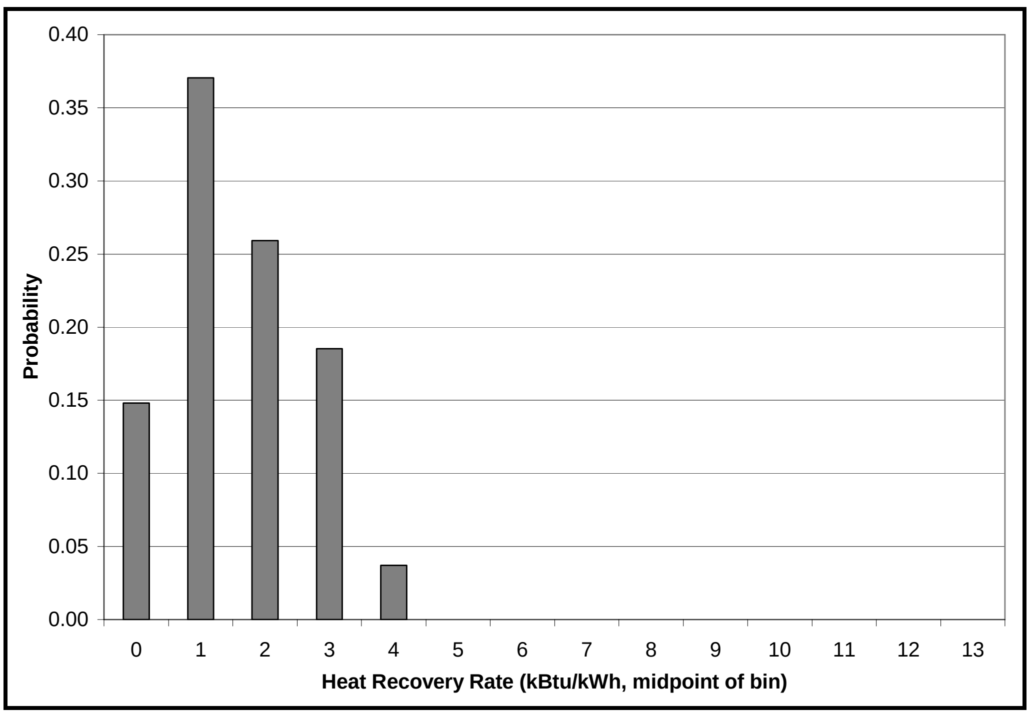


Figure C-60: Engine/Turbine Measured Heat Recovery Rate in 2006

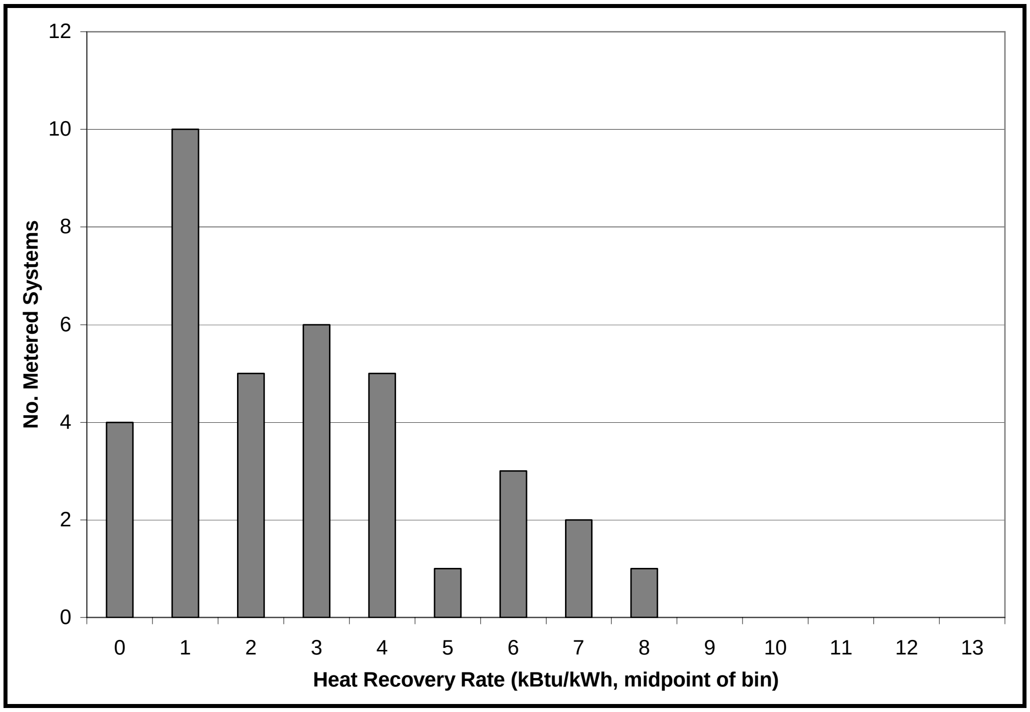
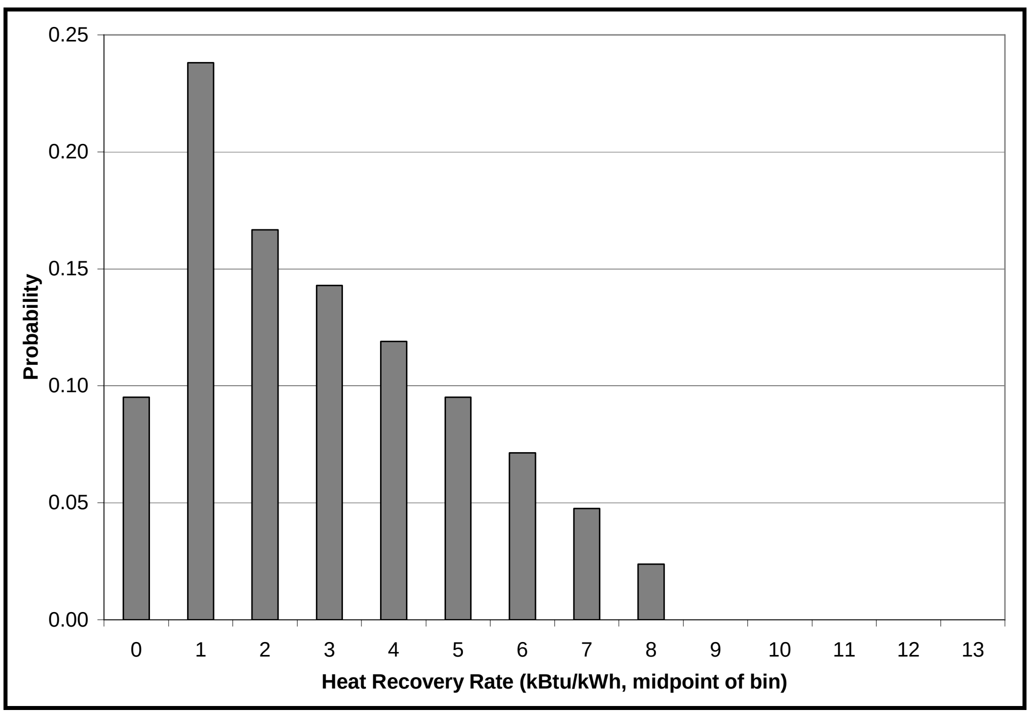


Figure C-61: 2007 MCS Distribution—Engine/Turbine Heat Recovery Rate



<u>*Bias*</u>

Performance data collected from metered sites were used to estimate program impacts attributable to unmetered sites. If the metered sites are not representative of the unmetered sites then those estimates will include systematic error called bias. Potential sources of bias of principle concern for this study include:

<u>Planned data collection disproportionally favors dissimilar groups</u>. For example, a limited number of new HEAT metering has been installed in the last 12 months. During this period 48 new projects have been completed and have entered commercial operations. If the actual heat recovery performance of the newer systems differs systematically from the older, metered systems then estimates calculated for the newer systems will be biased. A similar situation can occur when actual performance differs substantially from performance assumptions underlying data collection plans.

<u>Actual data collection allocations deviate from planned data collection allocations</u>. In program impacts evaluation studies actual data collection almost invariably deviates somewhat from planned data collection. If the deviation is systematic rather than random then estimates calculated for unmetered systems may be biased. For example, a limited number of ENGO meters for PV systems has been installed by Itron in the last 18 months. In some areas the result is a metered dataset containing a disproportionate quantity of data received from program participants who operate their own metering. This metered dataset is used to calculate impacts for unmetered sites. If the actual performance of the unmetered systems differs systematically from that of the systems metered by participants then estimates calculated for the unmetered systems will be biased. One example of this is if a participant metered system's output decreases unexpectedly the participant will know almost immediately and steps can be taken to get the system running normally again. However, a similar situation with an unmetered system could go unnoticed for months.

<u>Actual data collection quantities deviate from planned data collection quantities</u>. For example, plans called for collection of ENGO data from all RFU systems; however data actually were collected only from a small proportion of completed RFU systems.

In the MCS analysis bias is accounted for during development of performance distributions assumed for unmetered systems. If the metered sample is thought to be biased then engineering judgment dictates specification of a relatively 'more spread out' performance distribution. Bias is accounted for, but the accounting does not involve adjustment of point estimates of program impacts. If engineering judgment dictates an accounting for bias then the performance distribution assumed for the MCS analysis has a higher standard deviation. The result is a larger confidence interval about the reported point estimate. If there is good reason to believe that bias could be substantial then the confidence interval reported for the point estimate will be larger than it otherwise would be.

To this point the discussion of bias has been limited to sampling bias. More generally, bias can also be the result of instrumentation yielding measurements that are not representative of the actual parameters being monitored. Due to the wide variety of instrumentation types and data providers involved with this project it is not possible to say one way or the other whether or not instrumentation bias contributes to error in impacts reported for either metered or unmetered sites. Due to the relative magnitudes involved, instrumentation error—if it exists—accounts for an insignificant portion or total bias contained in point estimates.

It is important to note that possible sampling bias affects only impacts estimates calculated for unmetered sites. The relative importance of this varies with metering rate. For example, where the metering rate is 90 percent, a 20 percent sampling bias will yield an error of only two percent in total (metered + unmetered) program impacts. All else equal, higher metering rates reduce the impact of sampling bias on estimates of total program impacts.

Calculate the Quantities of Interest for Each Sample

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

- Program Total Annual Electrical Energy Impacts
- Program Total Coincident Peak Electrical Demand Impacts
- Program Total PUC216.6 (b) Cogeneration System Efficiency

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

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

Where:

PUC216.6b$_r$ is program total PUC216.6 (b) cogeneration system efficiency for run *r*
Units: %

ELEC$_{rs}$ is total electricity production for run *r* and system *s*
Units: kWh

KWH2KBTU is a conversion factor
Value: 0.2931 (i.e., 1/3.412)
Units: kWh/kBtu

C1 is a constant
Value: 0.5
Units: none
Basis: Cogeneration system efficiency definition of CPUC

HEAT$_{rs}$ is total useful waste heat recovery for run *r* and system *s*
Units: kBtu

FUEL$_{rs}$ is total fuel consumption for run *r* and system *s*
Units: kBtu
Basis: Lower Heating Value of fuel

Analyze Accumulated Quantities of Interest

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

Results

The confidence levels in the energy impacts, demand impacts, and PUC 216.6 compliance results have been presented along with those results. This section will present the precision and confidence intervals associated with those confidence levels in more detail. Three bins were used for Confidence Levels: 90/10 or better, 70/30 or better (but worse than 90/10), and worse than 70/30.

Table C-5: Uncertainty Analysis Results for Annual Energy Impact Results by Technology and Basis

Technology / Basis	Confidence Level	Precision*	Confidence Interval*
Fuel Cell	90%	7.42%	0.643 to 0.746
Metered	90%	0.17%	0.726 to 0.729
Estimated	70%	22.3%	0.470 to 0.740
Gas Turbine	70%	21.6%	0.393 to 0.608
Metered	90%	0.37%	0.720 to 0.726
Estimated	< 70%	62.5%	0.119 to 0.514
IC Engine	90%	9.50%	0.283 to 0.343
Metered	90%	0.09%	0.315 to 0.316
Estimated	70%	10.2%	0.279 to 0.342
Microturbine	70%	7.2%	0.323 to 0.373
Metered	90%	0.12%	0.384 to 0.385
Estimated	70%	13.6%	0.277 to 0.365
Photovoltaics	90%	1.34%	0.197 to 0.202
Metered	90%	0.05%	0.183 to 0.183
Estimated	90%	2.13%	0.207 to 0.216
Wind	< 70%	30.9%	0.141 to 0.268
Metered	90%	0.45%	0.171 to 0.173
Estimated	< 70%	60.0%	0.100 to 0.400

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-6: Uncertainty Analysis Results for Annual Energy Impact Results by Technology, Fuel, and Basis

Technology & Fuel/ Basis	Confidence Level	Precision*	Confidence Interval*
Fuel Cell - Non-renewable	90%	7.83%	0.670 to 0.783
Metered	90%	0.18%	0.775 to 0.778
Estimated	70%	22.3%	0.470 to 0.740
Fuel Cell - Renewable	90%	0.35%	0.385 to 0.388
Metered			
Estimated	90%	0.35%	0.385 to 0.388
Gas Turbine - Non-renewable	70%	21.6%	0.393 to 0.608
Metered	90%	0.37%	0.720 to 0.726
Estimated	< 70%	62.5%	0.119 to 0.514
IC Engine – Non-renewable	70%	6.5%	0.284 to 0.324
Metered	90%	0.09%	0.304 to 0.305
Estimated	70%	11.2%	0.270 to 0.338
IC Engine – Renewable	70%	8.9%	0.381 to 0.456
Metered	90%	0.29%	0.476 to 0.479
Estimated	70%	15.2%	0.326 to 0.443
Microturbine – Non-renewable	70%	8.5%	0.320 to 0.379
Metered	90%	0.12%	0.405 to 0.406
Estimated	70%	17.6%	0.250 to 0.358
Microturbine – Renewable	70%	10.4%	0.305 to 0.375
Metered	90%	0.34%	0.242 to 0.244
Estimated	70%	13.4%	0.333 to 0.436

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-7: Uncertainty Analysis Results for PG&E Annual Energy Impact

Technology / Basis	Confidence Level	Precision*	Confidence Interval*
Fuel Cell	90%	8.5%	0.651 to 0.772
Estimated	70%	29.2%	0.425 to 0.775
Metered	90%	0.3%	0.746 to 0.750
Gas Turbine	< 70%	31.4%	0.288 to 0.551
Estimated	< 70%	66.7%	0.100 to 0.500
Metered	90%	0.5%	0.642 to 0.648
IC Engine	70%	11.7%	0.268 to 0.339
Estimated	70%	14.1%	0.267 to 0.355
Metered	90%	0.1%	0.273 to 0.273
Microturbine	70%	16.0%	0.270 to 0.373
Estimated	70%	18.0%	0.267 to 0.384
Metered	90%	0.3%	0.296 to 0.298
Photovoltaics	90%	1.8%	0.198 to 0.205
Estimated	90%	2.8%	0.205 to 0.217
Metered	90%	0.1%	0.186 to 0.186

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-8: Uncertainty Analysis Results for SCE Annual Energy Impact

Technology / Basis	Confidence Level	Precision*	Confidence Interval*
Fuel Cell	70%	9.9%	0.389 to 0.474
Estimated	< 70%	33.3%	0.400 to 0.800
Metered	90%	0.4%	0.385 to 0.388
IC Engine	70%	11.8%	0.289 to 0.366
Estimated	70%	21.6%	0.242 to 0.376
Metered	90%	0.2%	0.352 to 0.353
Microturbine	70%	7.8%	0.373 to 0.436
Estimated	70%	29.2%	0.237 to 0.433
Metered	90%	0.2%	0.436 to 0.438
Photovoltaics	90%	3.7%	0.199 to 0.215
Estimated	90%	4.0%	0.202 to 0.219
Metered	90%	0.2%	0.173 to 0.173
Wind	< 70%	30.9%	0.141 to 0.268
Estimated	< 70%	60.0%	0.100 to 0.400
Metered	90%	0.4%	0.171 to 0.173

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-9: Uncertainty Analysis Results for SCG Annual Energy Impact

Technology / Basis	Confidence Level	Precision*	Confidence Interval*
Fuel Cell	70%	19.5%	0.553 to 0.821
Estimated	< 70%	33.3%	0.400 to 0.800
Metered	90%	0.4%	0.856 to 0.864
Gas Turbine			
Estimated			
Metered			
IC Engine	70%	8.9%	0.290 to 0.347
Estimated	70%	20.0%	0.247 to 0.370
Metered	90%	0.1%	0.326 to 0.327
Microturbine	70%	11.1%	0.339 to 0.423
Estimated	70%	26.8%	0.223 to 0.386
Metered	90%	0.2%	0.462 to 0.464
Photovoltaics	90%	3.0%	0.200 to 0.212
Estimated	90%	4.9%	0.200 to 0.220
Metered	90%	0.2%	0.199 to 0.200

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-10: Uncertainty Analysis Results for CCSE Annual Energy Impact

Technology / Basis	Confidence Level	Precision*	Confidence Interval*
Fuel Cell	90%	0.3%	0.792 to 0.797
Estimated			
Metered	90%	0.3%	0.792 to 0.797
Gas Turbine	90%	0.5%	0.744 to 0.750
Estimated			
Metered	90%	0.5%	0.744 to 0.750
IC Engine	90%	2.3%	0.289 to 0.303
Estimated	< 70%	100.0%	0.000 to 0.600
Metered	90%	0.2%	0.294 to 0.295
Microturbine	90%	0.2%	0.228 to 0.229
Estimated			
Metered	90%	0.2%	0.228 to 0.229
Photovoltaics	90%	2.7%	0.172 to 0.181
Estimated	70%	9.1%	0.193 to 0.232
Metered	90%	0.1%	0.172 to 0.172

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-11: Uncertainty Analysis Results for Peak Demand Impact

Technology / Basis	Confidence Level	Precision*	Confidence Interval*
Fuel Cell	90%	8.46%	0.641 to 0.759
Metered	90%	0.18%	0.712 to 0.715
Estimated	70%	19.2%	0.562 to 0.829
Gas Turbine	70%	9.3%	0.546 to 0.658
Metered	90%	0.31%	0.646 to 0.650
Estimated	< 70%	67.1%	0.138 to 0.700
IC Engine	90%	9.27%	0.355 to 0.428
Metered	90%	0.09%	0.416 to 0.417
Estimated	70%	11.0%	0.331 to 0.413
Microturbine	70%	8.1%	0.371 to 0.437
Metered	90%	0.12%	0.391 to 0.392
Estimated	70%	14.2%	0.355 to 0.473
Photovoltaics	90%	2.04%	0.560 to 0.583
Metered	90%	0.05%	0.612 to 0.612
Estimated	90%	3.90%	0.518 to 0.560
Wind	< 70%	72.2%	0.041 to 0.253
Metered	90%	-0.45%	-0.003 to -0.003
Estimated	< 70%	71.4%	0.100 to 0.600

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-12: Uncertainty Analysis Results for Peak Energy Impact Results by Technology, Fuel, and Basis for PG&E

Technology & Fuel/ Basis	Confidence Level	Precision*	Confidence Interval*
Fuel Cell - Non-renewable	90%	9.4%	0.723 to 0.873
Estimated	70%	22.3%	0.538 to 0.848
Metered	90%	0.3%	0.858 to 0.863
Fuel Cell - Renewable			
Estimated			
Metered			
Gas Turbine - Non-renewable	< 70%	36.4%	0.321 to 0.689
Estimated	< 70%	67.1%	0.138 to 0.700
Metered	90%	0.4%	0.665 to 0.671
IC Engine – Non-renewable	70%	13.2%	0.320 to 0.417
Estimated	70%	16.2%	0.312 to 0.433
Metered	90%	0.2%	0.351 to 0.352
IC Engine – Renewable	< 70%	43.2%	0.211 to 0.531
Estimated	< 70%	43.2%	0.211 to 0.531
Metered			
Microturbine – Non-renewable	70%	18.0%	0.377 to 0.542
Estimated	70%	23.7%	0.316 to 0.512
Metered	90%	0.3%	0.709 to 0.713
Microturbine – Renewable	< 70%	30.1%	0.289 to 0.537
Estimated	< 70%	30.1%	0.289 to 0.537
Metered			
Photovoltaics	90%	2.4%	0.606 to 0.635
Estimated	90%	4.5%	0.570 to 0.625
Metered	90%	0.1%	0.648 to 0.649

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-13: Uncertainty Analysis Results for Peak Energy Impact Results by Technology, Fuel, and Basis for SCE

Technology & Fuel/ Basis	Confidence Level	Precision*	Confidence Interval*
Fuel Cell - Non-renewable	< 70%	38.5%	0.400 to 0.900
Estimated	< 70%	38.5%	0.400 to 0.900
Metered			
Fuel Cell - Renewable	90%	0.4%	0.248 to 0.251
Estimated			
Metered	90%	0.4%	0.248 to 0.251
Gas Turbine - Non-renewable			
Estimated			
Metered			
IC Engine – Non-renewable	70%	14.7%	0.325 to 0.437
Estimated	70%	26.5%	0.273 to 0.470
Metered	90%	0.2%	0.393 to 0.394
IC Engine – Renewable	70%	27.8%	0.162 to 0.287
Estimated	< 70%	73.3%	0.100 to 0.650
Metered	90%	0.4%	0.180 to 0.181
Microturbine – Non-renewable	70%	12.5%	0.338 to 0.434
Estimated	< 70%	47.4%	0.219 to 0.613
Metered	90%	0.2%	0.376 to 0.377
Microturbine – Renewable	< 70%	46.2%	0.165 to 0.449
Estimated	< 70%	62.1%	0.164 to 0.700
Metered	90%	0.3%	0.167 to 0.168
Photovoltaics	90%	7.8%	0.436 to 0.510
Estimated	90%	8.9%	0.419 to 0.501
Metered	90%	0.2%	0.591 to 0.593
Wind	< 70%	72.2%	0.041 to 0.253
Estimated	< 70%	71.4%	0.100 to 0.600
Metered	90%	-0.4%	-0.003 to -0.003

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-14: Uncertainty Analysis Results for Peak Energy Impact Results by Technology, Fuel, and Basis for SCG

Technology & Fuel/ Basis	Confidence Level	Precision*	Confidence Interval*
Fuel Cell - Non-renewable	70%	22.6%	0.572 to 0.905
Estimated	< 70%	22.6%	0.572 to 0.905
Metered	90%	37.88%	0.437 to 0.970
Fuel Cell - Renewable			
Estimated			
Metered			
Gas Turbine - Non-renewable	90%	0.4%	0.448 to 0.452
Estimated			
Metered	90%	0.45%	0.448 to 0.452
IC Engine – Non-renewable	70%	8.3%	0.379 to 0.448
Estimated	70%	23.0%	0.286 to 0.457
Metered	90%	0.1%	0.442 to 0.443
IC Engine – Renewable	< 70%	100.0%	0.000 to 0.800
Estimated	< 70%	100.0%	0.000 to 0.800
Metered			
Microturbine – Non-renewable	70%	12.3%	0.371 to 0.475
Estimated	70%	27.0%	0.302 to 0.525
Metered	90%	0.2%	0.431 to 0.433
Microturbine – Renewable			
Estimated			
Metered			
Photovoltaics	90%	5.6%	0.491 to 0.549
Estimated	70%	6.5%	0.439 to 0.500
Metered	90%	0.2%	0.597 to 0.600

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-15: Uncertainty Analysis Results for Peak Energy Impact Results by Technology, Fuel, and Basis for CCSE

Technology & Fuel/ Basis	Confidence Level	Precision*	Confidence Interval*
Fuel Cell - Non-renewable	90%	0.3%	0.652 to 0.656
Estimated			
Metered	90%	0.3%	0.652 to 0.656
Fuel Cell - Renewable			
Estimated			
Metered			
Gas Turbine - Non-renewable	90%	0.4%	0.835 to 0.842
Estimated			
Metered	90%	0.4%	0.835 to 0.842
IC Engine – Non-renewable	90%	0.2%	0.514 to 0.516
Estimated			
Metered	90%	0.2%	0.514 to 0.516
IC Engine – Renewable			
Estimated			
Metered			
Microturbine – Non-renewable	90%	0.2%	0.329 to 0.330
Estimated			
Metered	90%	0.2%	0.329 to 0.330
Microturbine – Renewable	90%	0.4%	0.056 to 0.056
Estimated			
Metered	90%	0.4%	0.056 to 0.056
Photovoltaics	90%	0.5%	0.540 to 0.545
Estimated	70%	13.0%	0.379 to 0.493
Metered	90%	0.1%	0.545 to 0.546

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Table C-16: Uncertainty Analysis Results for Annual PUC 216.6(b)

Technology / Basis	Confidence Level	Precision*	Confidence Interval*
Fuel Cell	90%	4.7%	53.0 to 58.1
Metered	90%	1.8%	43.5 to 45.1
Estimated	90%	5.0%	53.7 to 59.4
Gas Turbine	70%	13.0%	40.4 to 52.4
Metered	90%	3.3%	44.9 to 47.9
Estimated	70%	16.3%	38.9 to 54.1
IC Engine	90%	4.5%	39.7 to 43.4
Metered	90%	1.9%	23.8 to 24.7
Estimated	90%	4.5%	39.7 to 43.5
Microturbine	90%	10.0%	26.8 to 32.8
Metered	90%	1.9%	22.3 to 23.2
Estimated	70%	6.2%	28.0 to 31.8

* Both precision and confidence interval are given according to the corresponding confidence level. Results with less than 70% confidence also use the 70% confidence level values.

Appendix D

Metering Systems

As a part of the Measurement & Evaluation (M&E) of the SGIP, Itron installs metering equipment at Host facilities. The exact metering required varies by incentive level but may include electric, fuel, and/or heat metering. Many considerations inform the metering decision process, including the presence of existing metering equipment, the quality or quantity of data from existing metering sources, and the relative difficulty, and therefore expense, of installing new metering equipment.

D.1 Electric Generation Metering Equipment

Metering equipment installed by Itron for the purpose of obtaining electric net generation output (ENGO) falls under two distinct categories: systems where ENGO is the only metering required, such as PV and cogeneration systems with HEAT metering in addition to ENGO metering. Each of these two systems seeks to achieve the same goal through slightly different approaches.

Systems without HEAT Metering

Metering of these systems for ENGO involves the installation of current transducers (CTs), a meter, a socket, a panel, communications equipment, and associated wire and conduit. The exact equipment required varies based upon the equipment found on-site. For example, a panel may be installed that has ample room for the M&E meter. For the purposes of this description the assumption is made that there is no existing empty panel socket that facilitates ENGO meter installation.

Itron's installation subcontractors install an electrical panel to house the wiring and meter. All wiring is run through conduit at least at the protective level as found on-site. Typical installation practices involve rigid conduit (EMT) but may involve flexible conduit if necessary or appropriate. A meter socket is installed on this panel that varies depending upon the electrical characteristics of the system such as 1-phase versus 3-phase and maximum amperage. CTs are installed on each phase of power and wired to the electrical meter. The meter used is a revenue-grade electrical meter equipped with a land-based modem for communications. A telephone line is activated at the property and a telephone line is installed from the Minimum Point of Entry to the meter.

Systems with HEAT Metering

ENGO metering of cogeneration systems varies from the above description in order to minimize the expense of installing metering equipment. Because a data logger is installed for HEAT metering, the ENGO can be stored on the data logger as well. In these cases, power transducers with a pulse output are installed on each phase of power and wired to the data logger's pulse input channel. Similar to the ENGO-only description, all wire is run through conduit at least to the level found at the facility.

D.2 Fuel Consumption Metering Equipment

Fuel meters are installed in very few cases for M&E purposes. These include renewable-fueled systems that are piped to also use utility-supplied natural gas and in some fossil-fueled cogeneration systems lacking a dedicated fuel meter. Fuel meters are invasive and require a licensed contractor to complete the work and typically require the plant operator to shut down the cogeneration system. Gas meter technology varies based on the operating pressure of the system. Low pressure and low capacity systems use diaphragm meters while higher pressure or capacity systems will use rotary or turbine meters. Table D-1 below provides some guidelines that are used for meter selection.

Table D-1: Gas Meter Selection Criteria

Gas Meter Type	Maximum Pressure (psig)	Maximum Flow (SCFH)
Diaphragm	100	1,000
Rotary	175	141,000
Turbine	1,440	18,000,000

Electronic volume correctors may also be specified to correct for ambient conditions. Finally, gas meters are specified with a pulse output that is stored in a data logger. Data logger characteristics, including power and transmission of data to the evaluation contractor, use the method described on the following page for metering of heat recovery.

D.3 Heat Recovery Metering Equipment

Heat recovery applies to non-renewable-fueled cogeneration systems. 2006 represents a transitional year as early systems utilized invasive equipment and later systems utilized noninvasive equipment. This discussion will focus on the latter. Conceptually, measurement of heat typically involves measurement of a fluid flow and the temperature of that fluid on both sides of a heat exchanger[1]. The fluid may be liquid (water, glycol mixture, oil, etc.) or gas (steam or exhaust air) and temperatures range from 32°F to 500°F. The heat exchanger may be a simple plate-and-frame heat exchanger or as complex as an absorption chiller.

Flow is measured using an ultrasonic flow meter with clamp-on transducers. Itron researched all commercially available products and chose a product that is highly calibrated and has a much better low flow reading capability than other ultrasonic flow meters. Accuracy and precision are similar to that of insertion flow meters used in the past.

Temperature is measured using clamp-on thermocouples. These thermocouples are accurate and precise but suffer from a delay in temperature changes as it takes some time for the fluid temperature to migrate to the pipe surface. This delay is partially offset by utilizing a differential temperature, where the delay is seen on both measurements and is assumed to cancel out. As these temperature sensors are relatively inexpensive and not as accurate as desired, redundant sensors are used (two on the hot side and two on the cold side). This allows for the average of each of the two sensors to be used in the differential temperature calculations as long as they are within a certain range. Should one sensor fall out of range the calculation of heat may still be completed without requiring a service call.

Data are stored in a data logger capable of reading digital and analog inputs. Memory is sufficient to store data for at least one month should communications fail. Proprietary software is used to program the data logger and to communicate with the data logger in a server/client configuration for downloading data.

Communications are handled by a cellular-based modem using an IP connection. Static IP addresses are currently used, and the capability of using dynamic IP addresses is being explored. Data are downloaded daily and copied to a web-accessible server.

Power is supplied to the data logger, flow meter, and modem via an external battery. This battery is connected to facility power and, in the event of a power outage, is capable of operating the metering equipment for approximately two days.

[1] There are some instances where exhaust air is used directly in a process without the use of a heat exchanger. As these systems do not represent a significant portion of the metering effort they will not be specifically discussed here. However, they are conceptually similar to heat exchanger based systems.

All equipment is housed in a NEMA weatherproof enclosure, which is mounted to a wall near the thermal metering location. NEMA specification is typically 4x but varies based on conditions found at the facility.

Appendix E

Metering Equipment Specification Sheets

Appendix E contains the specification sheets for the major metering equipment installed so far under the Self-Generation Incentive Program. Below is a list of the specification sheets provided in this appendix for each type of metering system:

ENGO Equipment

- Sentinel Electric Meter
- Hawkeye Transducers
- Alpha Plus Meter (legacy ENGO meter installs). The Alpha Plus meter is representative of ENGO meters installed prior to 2006.

FUEL Equipment

No FUEL meter equipment has been installed post-2006 yet. However, several rotary type fuel meters were installed prior to 2006. Consequently, the appendix contains specification sheets for representative legacy rotary fuel meters as well as the ancillary data loggers and cell modems that would be required for new installs.

- American Meters Rotary Flow Meter
- Campbell Data Logger
- Airlink Modem

HEAT Equipment

HEAT metering equipment installed under the SGIP consists of legacy equipment installed prior to 2007 and new (post-2006) systems.

New (post-2006) HEAT metering systems consist of the following equipment:

- Flexim Flow Meter
- Flexim Clamp-on Transducers
- Newport Thermocouple
- Omega Thermocouple Extension Wire
- Campbell Data Logger
- Airlink Modem

Legacy (pre-2006) HEAT metering systems consisted of the following equipment:

- Onicon Btu Meter
- DENT Data Logger
- Onicon Insertion Dual Flow Meter (with temperature sensors)

ENGO Equipment Specification Sheets

Knowledge to Shape Your Future

CellReader® Meter
SENTINEL®

introduction

Itron SENTINEL® Meter with Trilliant CellReader®

The Itron SENTINEL solid-state electricity meter now provides utilities the industry's leading wireless communication solutions for commercial and industrial applications. The SENTINEL Meter with Trilliant CellReader technology offers utilities RF communications capabilities, superior data acquisition and on-site monitoring. Complex meter information is available any time, from anywhere, via this under-the-cover solution. The SENTINEL CellReader meter is ideal for remote interval and time-of-use (TOU) data collection, including all necessary register, load profile and meter diagnostic data. Using today's digital cellular technology, SENTINEL meters can provide public network radio frequency (RF) communications with the best available wireless network coverage at the best available cost.

features

Key Features & Benefits

- Cost-effective meter communications for all load profile, register and diagnostic data
- Internal card for commercial and industrial solid-state Itron SENTINEL Meter
- Saves time and money – no telephone line connections, easy to install, near-zero operating costs
- Under-the-cover mounting
- Easy to retrofit and secure
- Tamper-resistant operation
- No external power supply
- No batteries
- Secure communications and data transfers
- Affordable on-demand, two-way communications for data retrieval or programming
- Configurable, programmable, and readable through public networks and even the Private iDEN™ network
- GSM, iDEN and CDMA public networks offer packet-switched mode
- GSM and CDMA Networks offer circuit-switched mode for dial-up access

features

Network Communications Options

A SENTINEL meter equipped with Trilliant CellReaders iDEN, CDMA, or GPRS communications is effectively always on and always connected.

> **iDEN Networks**
> SENTINEL meters equipped with Trilliant CellReaders operate on any iDEN wireless network in North America. The iDEN is a dedicated data-only network based on cellular technology that uses packet switching for maximum efficiency. This means the network is always and instantly accessible. The Private iDEN system enables backhaul communications at practically zero-variable cost.

> **CDMA Networks**
> Trilliant CellReaders enable SENTINEL meters to communicate meter data via any public CDMA network, such as Verizon Wireless, Bell Mobility, Telus Mobility and Spring Nextel. Packet data mode works on the latest generation of CDMA technology known as 1xRTT or CDMA2000.

> **GSM Networks**
> Utilizing Trilliant CellReader, SENTINEL meters operate on any public GSM network, such as those operated by Rogers Wireless, T-Mobile, and AT&T/Cingular Wireless. Packet data mode is available on GSM networks with recent upgrades to include GPRS data services.

specifications

Supply

- Uses meter's internal power supply

Local Port

- Supports meter ANSI Type 2 optical port
- Communications protocol: ANSI C12.18

Environmental

- Operating temperature: -30° C to 60° C (iDEN is -25° C)
- Humidity range: 0-95% (non-condensing)

Mechanical

- Enclosure: Fits inside meter
- Weight: 5 oz. (0.142 kg)

AMR Features

- Fully transparent gateway
- Total meter data accessibility
- Data traffic reduction and optimization
- ANSI C12.19

Systems Supported

- Itron MV-90 xi and data acquisition systems
- Itron PC-PRO+® Advanced
- Trilliant SerViewCom™ Communications Server Software
- Trilliant Table TestBench programming software

Antenna

- Internal 3db patch antenna
- V.S.W.R.: 1.5:1 or less
- Impedance: 50 ohms
- Cable: RG-174A/U
- Standard termination: SMA male

Optional Antenna

- External 4.9db omnidirectional whip antenna

communications

CDMA

- Power consumption:
  - 1.8 max.
  - (Average: <0.4W)
  - (Maximum: <2W)
- CDMA/1xRTT communications:
  - Circuit switched data mode: Up to 14.4 kbps
  - Packet switched data mode: Up to 153 kbps
- Reception sensitivity: -104 dBm
- Security: DES encryption
- Approvals:
  - FCC:09EQ2438
  - IC: 3651C-Q2438

iDEN

- Operating voltage: 5V DC
- Operating current: 75 ma
- Communications protocol:
  - TCP/IP over wireless packet data
  - Communications data rate: 19.2 kbps
  - Transmission power: 0.6 watts nominal
  - Reception sensitivity: <-111 dBm
- iDEN wireless packet data networks
  - Receiver Tx: 806-821 Mhz
  - Receiver Rx: 851-866 Mhz
- Approvals:
  - Contains a type-accepted transmitter approved under FCC ID#: AZ492FT5826
  - IC: 109U-92FT5826

GSM

- GSM/GPRS communications:
  - Circuit switched data mode: Up to 14.4 kbps
  - Packet switched data mode: Up to 115 kbps
- Reception sensitivity: -104 dBm
- Approvals:
  - Contains a type-accepted transmitter approved under FCC ID#: 09EQ2426-5K

profile

Itron Inc.

Itron is a leading technology provider and critical source of knowledge to the global energy and water industries. Nearly 3,000 utilities worldwide rely on Itron technology to deliver the knowledge they require to optimize the delivery and use of energy and water. Itron delivers value to its clients by providing industry-leading solutions for electricity metering; meter data collection; energy information management; demand response; load forecasting, analysis and consulting services; distribution system design and optimization; web-based workforce automation; and enterprise and residential energy management.

To know more, start here: www.itron.com

Corporate Headquarters
2111 North Molter Road
Liberty Lake, Washington 99019
U.S.A.
Tel.: 1.800.635.5461
Fax: 1.509.891.3355

Itron Inc.
Oconee Electricity Metering
313-B North Highway 11
West Union, SC 29696
U.S.A.
Tel.: 1.864.638.8300
Fax: 1.864.638.4950

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Publication 100795SP-01
04/07

The solution for local or remote electrical metering and submetering in commercial buildings!

Installation Instructions

Hawkeye 8051/8053

PULSE OUTPUT kWH TRANSDUCERS

VERIS INDUSTRIES

10831 S.W. CASCADE BLVD.
PORTLAND, OREGON 97223
(503) 598-4564 FAX (503) 598-4664
1-800-354-8556
http://www.veris.com email:sales@veris.com
®

Applications

- Tenant submetering for commercial tenants
- Energy management & performance contracting
- Departmental costing in manufacturing facilities
- Cooling plant optimization

Easy cost-effective installation

- Precision transducer electronics and high accuracy instrument grade CT's in a single easy to install package...reduces the number of installed components
- Unique split-core design eliminates the need to remove conductors
- Fits easily into distribution panels...lowest total installed cost
- Automatically detects phase reversal...eliminates the need to be concerned with CT load orientation
- Economical single-CT version available for balanced loads (H8051)

High accuracy and resolution

- ± 1% accuracy conforms to ANSI C12.1 metering standards (H8053)
- 0.1 to 1.0 kWH/pulse selectable

OPERATION

The H-8000 Series combines a microprocessor based kWh transducer and high accuracy split-core instrument grade current transformers (CTs) in a single unit. Because the electronics are integral to the CT(s), hardware and installation costs are greatly reduced. Split-core design eliminates the need to remove conductors.

WARNING--REFER SERVICING TO QUALIFIED PERSONNEL ONLY!

• *This product is not intended for life or safety applications*

• Potential electrocution hazard exists. Installing sensors in an energized electrical enclosure or on any energized conductor can be hazardous.

• Read instructions thoroughly prior to install

Severe injury or death can result from electrical shock during contact with high voltage conductors or related equipment. Disconnect and lock-out all power sources during installation and service. Applications shown are suggested means of installing sensors, but it is the responsibility of the installer to ensure that the installation is in compliance with all national and local codes. Installation should be attempted only by individuals familiar with codes, standards, and proper safety procedures for high-voltage installations.

PRODUCT DIAGRAM

A VOLTAGE LEADS

Connect the leads to the three-phase source to be monitored. Input range is 208 to 480VAC.

B MANDATORY FUSE PER NEC

Maximum current draw is 60 mA. Fuses provided by factory are rated 1/2A, 600 VAC, 200 KAIC.

C PULSE OUTPUT CONNECTOR

Please refer to wiring diagram on page 4.

D STATUS LED

The LED blinks green when the product is functioning normally. It will blink slowly, approximately one second on, then one second off.

If the LED is red and blinking slowly, it may indicate incorrect wiring or a power factor that is less than 0.5. If the LED is red and blinking fast the CT's maximum current rating has been exceeded or the pulse rate switches are incorrectly set.

E PULSE RATE SWITCHES

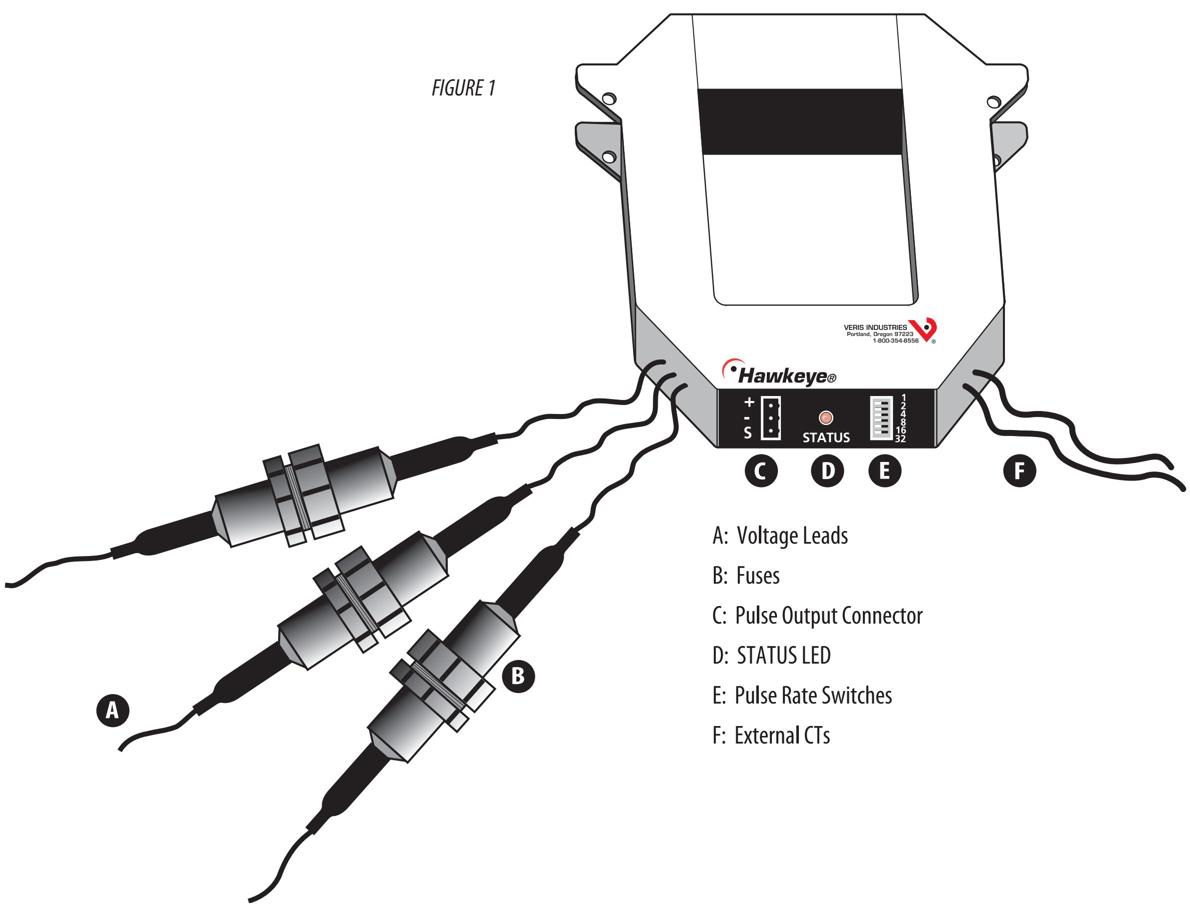
These switches set the pulse output rate. Please refer to Figure 4 for settings.

F EXTERNAL CTs (3 phase versions only)

These external CTs are permanently attached and must not be disconnected or used with other power meters.

Color match CTs and voltage leads! *Example: Clamp the red label CT around the power conductor connected to the red voltage wire.*

FIGURE 1



A: Voltage Leads

B: Fuses

C: Pulse Output Connector

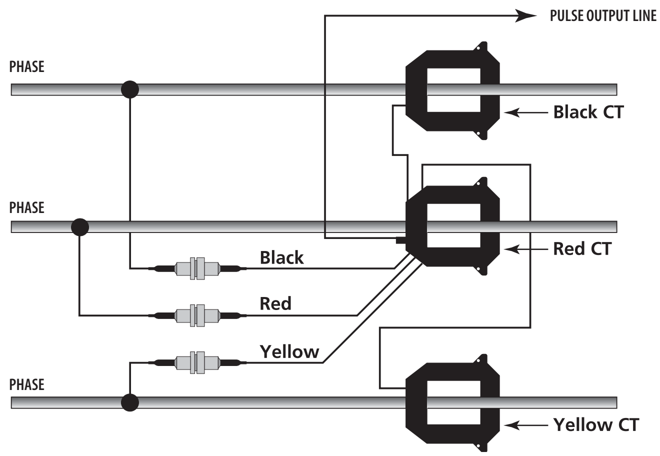
D: STATUS LED

E: Pulse Rate Switches

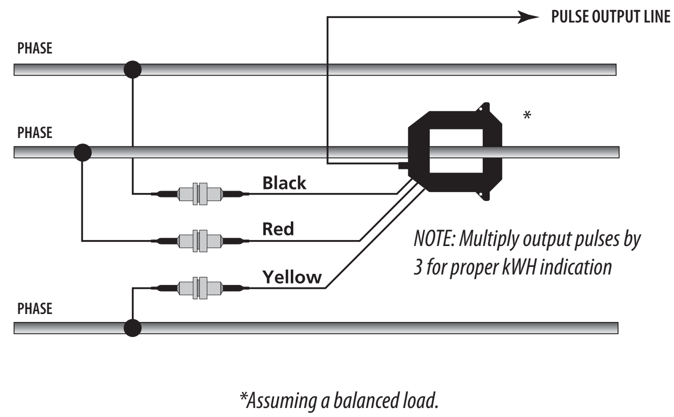
F: External CTs

WIRING DIAGRAMS

TYPICAL 208/480 VAC 3Ø, 3,4 WIRE INSTALLATION

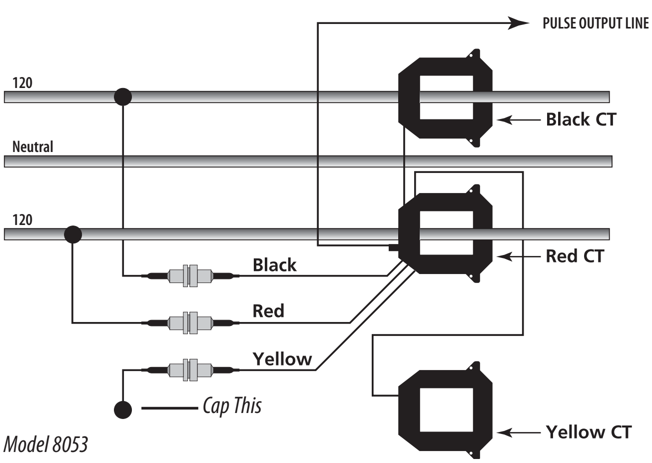


Model 8053

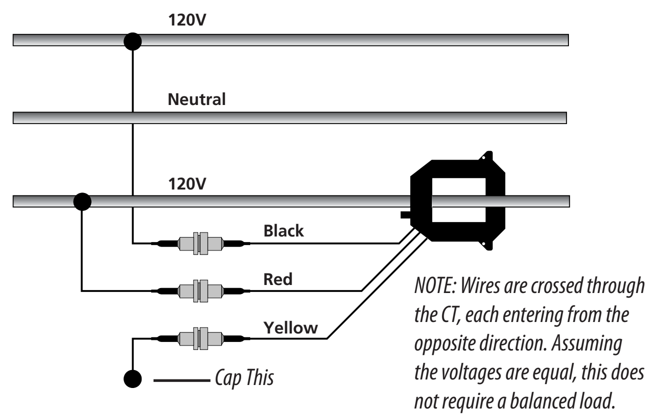


Model 8051

TYPICAL 240/120 VAC 1Ø, 3-WIRE INSTALLATION

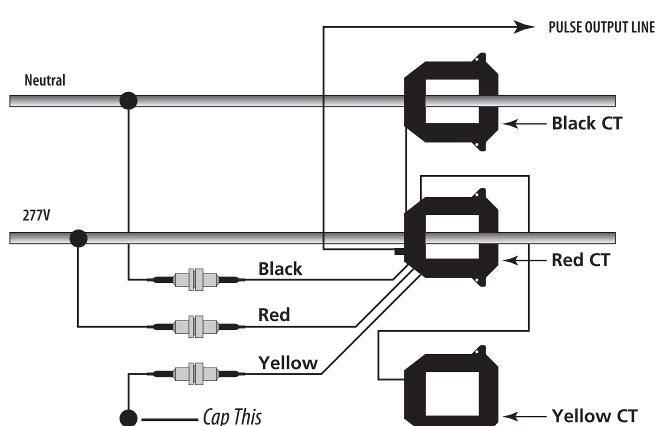


Model 8053

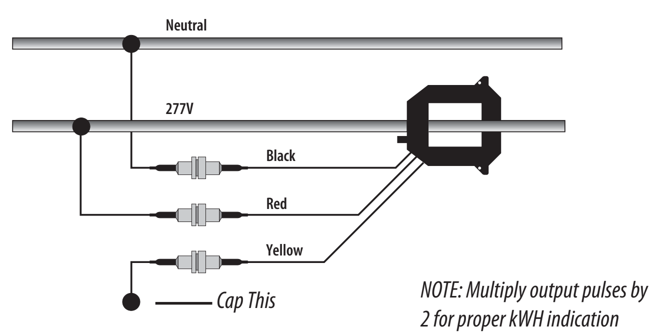


Model 8051

TYPICAL 277 VAC 1Ø, 2-WIRE INSTALLATION



Model 8053



Model 8051

FIGURE 2

The H8000 series is NOT intended to be connected to the load side of variable frequency drives. Damage to the unit will result from such a connection.

1 Set the switches for the desired pulse-rate as shown in Figure 4. Note that some settings are not allowed.

2 Disconnect power and lock-out all power sources during installation. DO NOT CONNECT VOLTAGE INPUTS LIVE!

3 Connect the voltage leads to the 3-phase conductors, as shown in Figure 2. Becaue the meter requires voltage to communicate, connect the leads to a location which is not normally switched off. Connect the red lead to the conductor most convieniently located to physically mount the CT with pulse output connector. After selecting the conductor for the red lead, the black and yellow leads may be attached to the other two conductors in any order.

4 Attach CTs to conductors. Each CT must be attached to the same conductor as the correspondingly colored voltage lead. (See wiring diagram above) The unit will automatically detect phase reversal, so it is not important to orient a particular side of each CT towards the load.

5 Remove the terminal block and attach the pulse output wires. Positive, negative and Shield wires must be connected as shown in Figure 3.

If necessary, insulate any exposed wiring. Ensure that insulation complies with local and national electrical codes.

Approximate check of output:

6 1. Check actual current with Amp clamp.
Expected power is:

kW = Volts x Amps x 1.732 x PF ÷ 1000

kW = Horsepower x .746

2. Calculate approximate seconds per pulse:

$$S = \frac{kWh}{\text{Pulse Setting}}$$

$$\text{seconds/pulse} = \frac{3600 \times S}{kW}$$

Note: Since these calculations are approximate, there may be some variation.

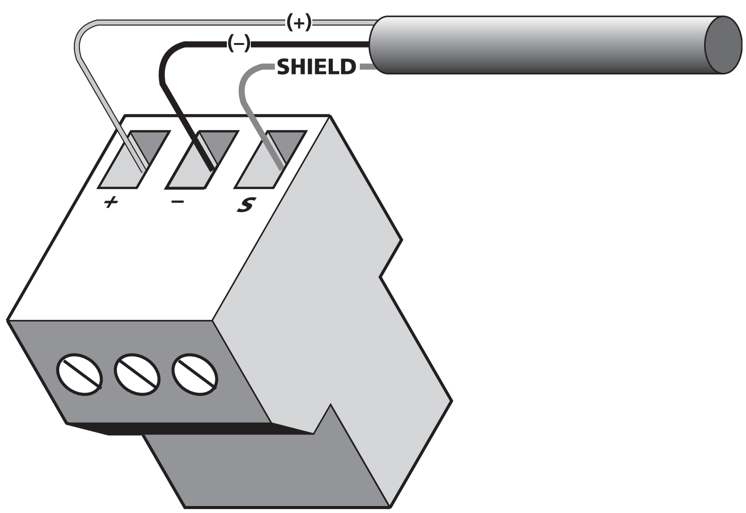


FIGURE 3

NOTES

1. DO NOT GROUND THE SHIELD INSIDE THE ELECTRICAL PANEL.
   All wires, including the shield should be insulated to prevent accidental contact to high voltage conductors.
2. The cable should be mechanically secured where it enters the electrical panel.
3. The cable should be shielded twisted pair wire BELDEN 1120A or similar

WARNING: After wiring the cable, remove all scraps of wire or foil shield from the electrical panel. This could be DANGEROUS if wire scraps come into contact with high voltage wires!

PULSE-RATE SELECTION SWITCHES

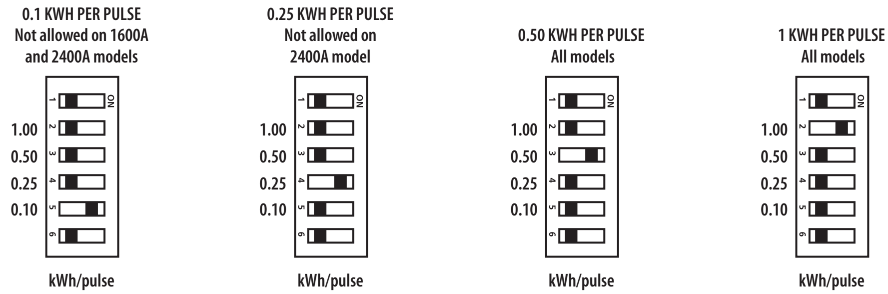


FIGURE 4

TROUBLESHOOTING

Problem: STATUS LED does not blink.

Solution: Check fuses and voltage connections. STATUS LED should blink regardless of CTs, pulse output connections and DIP switch setting.

Problem: Readings seem highly inaccurate.

Solution:

- Check that each CT is installed on the conductor with the corresponding color voltage input lead attached. In most cases, incorrect wiring will cause the STATUS LED to blink RED (slowly). However, a Power Factor lower than 0.5 could cause the LED to blink this way, even if the unit is installed properly.
- It does not matter which side of the CTs face towards the load.
- If current is below 7% of full scale maximum for the CT, a smaller CT should be used for very low currents. An alternative is to wrap each wire through each CT multiple times and divide the output reading by the number of turns through the CT window.
- If using a single-phase CT model 8051, ensure that all 3 phases are passing approximately the same current by testing each phase with an amp-clamp. If phases are unbalanced, you should use the model 8053.

Problem: Meter off-line when load is switched off.

Solution: Voltage leads must be connected on the Line side of the conductor. The power meter cannot communicate without voltage.

Problem: STATUS LED blinks red.

Solution:

- If the LED blinks quickly, approximately 5 blinks in 2 seconds, either the pulse-rate switch settings are incorrect OR the CT used is too small. First check the switch settings. Ensure that an incorrect setting has not been selected by comparison to Figure 4. Note that some settings are not available on some models. If switch settings are OK, then the CT used is too small. A CT with a larger current rating is required.
- If the LED blinks slowly, approximately. 1 blink in two seconds, the CTs are not installed on the correct conductors, or the loads Power Factor is less than 0.5. The meter can accurately measure these low PFs, but few loads operate normally at such a low power factor.

SPECIFICATIONS

Input primary voltage	208 to 480 V AC
Input frequency	47-70 Hz.
Number of phases monitored	One or Three
Frequency	50/60 Hz
Maximum primary current	2400 amps cont. per phase*
Internal isolation	2000 VAC rms
Case insulation	600 VAC
Temperature range	0 to 60o C
Humidity range	0 - 95 % non-condensing
Accuracy	±1.0 % (H8053-ANSI C12.1)†
Current transformer	Split core, 100 to 2400 amps
Pulse output type	Normally open Opto-Fet
Maximum output current	100mA@24VAC/DC
Pulse width	200msec

** Larger sizes available, consult factory*

† Meter accuracy specified with conductors centered in CT window

ALPHA Plus® Meter

ALPHA Plus Means Powerful Metering

Elster Electricity's ALPHA Plus meter is a powerful meter that builds on the patented ALPHA® metering technology. The ALPHA Plus meter can be a single phase, 240 volt, one-rate demand meter or a polyphase, wide voltage supply, multi-rate, real/reactive meter that validates meter service connections automatically, performs power quality monitoring, and provides load profile reading with remote communications.

Load Profile and Event Logs

The main circuit board has 28 KB of memory available to record load profile and data logs. The following table shows an example of the quantity of load profile data the meter can store with a 15-minute demand interval.

Number of channels	Maximum days stored
1 channel	141 days*
4 channels	36 days*

*Number of days may be fewer depending on the number of event log entries.

The integrity of load profile data does not depend on the meter battery because load profile memory is stored in nonvolatile EEPROM. When enabled with the load profile capability, the ALPHA Plus meter records date and time stamps for the following events:

- power failure
- test mode
- time change
- demand reset

With power quality monitoring enabled, the meter also includes date and time stamps of PQM events, including voltage sags.

Power Quality Monitoring

When this feature is enabled, the ALPHA Plus meter searches for exceptions to user-defined thresholds for items such as voltage, current, power factor, and total harmonic distortion. The meter performs various tests that measure and collect power quality data 24 hours a day.

System Service Tests

System service tests are performed to check the validity of the electrical service as wired to the meter. The ALPHA Plus meter verifies the service type, phase rotation, and validity of phase voltages. The ALPHA Plus meter also determines if phase currents are within a user-defined threshold.

Instrumentation

Instrumentation values provide near instantaneous analysis of the electrical service. All quantities can be programmed to display on the LCD in the normal or alternate display sequence:

- per phase voltage and per phase current
- per phase voltage and per phase current phase angles (as measured to phase A voltage)
- per phase current phase angle as measured to same-phase voltage
- per phase power factor and power factor angle
- per phase kW, kVAR, and kVA
- per phase total harmonic distortion for both voltage and current
- system frequency
- system kW, kVAR, kVA, power factor, and power factor angle

Revenue Metering

A1K+ and A1R+ meters measure, store, and display a full set of energy and demand values for both real/apparent and real/reactive quantities, respectively. These meters provide two complete blocks of time-of-use data. Each TOU rate is supported by separate fractional energy registers.

The A1R+ meter offers vectorial kVA values as a metered quantity choice. Average PF can be displayed when kW and kVA are selected as metered quantities.

Technology to Empower Utilities

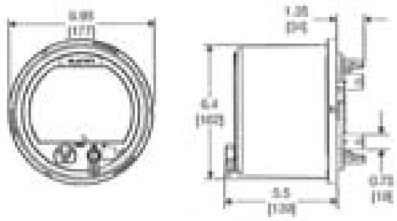
ELSTER

Communications

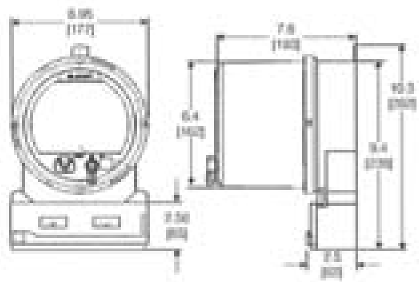
Data can always be retrieved using the standard optical port. By adding an option board, additional communications interfaces are available for the ALPHA Plus meter, including the following:

- 2400 bps internal telephone modem with outage callback
- RS-232 serial interface
- RS-485 serial interface
- 20 mA current loop
- external serial interface

S-base Dimensions



A-base Dimensions



Dimensions in inches [millimeters]. For reference only. Do not use in construction.

Specifications and Technical Data

Absolute Maximums		
Voltage	Continuous at maximum of operating range	
Surge voltage withstand	*ANSI C37.90.1 oscillatory*	2.5 kV, 2500 strikes
	ANSI C37.90.1 fast transient	5 kV, 2500 strikes
	ANSI C62.41	6 kV at 1.2/50 μs, 10 strikes
	IEC 61000-4-4	4 kV, 2.5 kHz repetitive burst for 1 minute
	ANSI C12.1 insulation	2.5 kV, 60 Hz for 1 minute
Current	Continuous at Class amperes Temporary (1 second) at 200 % of meter max. current	
Operating Ranges		
Voltage	*Nameplate nominal range* 120 V to 480 V	*Operating range* 96 V to 528 V
	63 V to 240 V*	54 V to 264 V*
	Dedicated 240 V	192 V to 264 V
Current	0 to Class amperes	
Frequency	Nominal 50 Hz or 60 Hz ±5 %	
Temperature range	-40 °C to +85 °C inside meter cover	
Humidity range	0 % to 100 % noncondensing	
Operating Characteristics		
Power supply burden (Phase A)	Less than 3 W	
Per phase current burden	0.1 milliohms typical at 25 °C	
Per phase voltage burden	*120 V*	0.008 W
	240 V	0.03 W
	480 V	0.04 W
Accuracy	*Power supply* 120 V to 480 V 120 V to 240 V Dedicated 240 V	*ANSI C12.20 accuracy* Meets accuracy Class 0.2 %
	63 V to 240 V*	Meets accuracy Class 0.5 %
General Performance Characteristics		
Starting current	*Form 1S & Form 3S*	10 mA for Class 20 100 mA for Class 200 160 mA for Class 320
	All other forms	5 mA for Class 20 50 mA for Class 200 80 mA for Class 320
Startup delay	Less than 3 seconds from power application to pulse accumulation	
Creep 0.000A (no current)	No more than one pulse measured per quantity, conforming to ANSI C12.1 requirements	
Primary time base	Power line frequency (50 Hz or 60Hz), with selectable crystal oscillator	
Secondary time base	Meets the ANSI limit of 0.02 % using the 32.768 kHz crystal. Initial performance is expected to be equal to or better than ±55 seconds per month at room temperature	
Outage carryover capacity	6 hours at 25 °C. Supercapacitor rated at 0.1 Farads, 5.5 V	
Battery (optional)	$LiSOCl_2$ battery rated 1000 mAhr, 3.6 V and shelf life of 20+ years. 5 years continuous duty at 25 °C	
Communications rate	*Optical port* *Remote port*	9600 bps (nominal) 1200 to 19,200 bps
Shipping Weights *All values are approximate*		
S-base	*Single* *4-pack*	5.5 lbs [2.49 kg] 15.5 lbs [7.03 kg]
A-base	*Single* *4-pack*	7.5 lbs [3.4 kg] 26 lbs [11.8 kg]

*Not available on meters with the CPS power supply.

ELSTER

Elster Electricity, LLC
Raleigh, North Carolina, USA
+1 800 338 5251 (US Toll Free)
+1 905 634 4895 (Canada)
support@us.elster.com
www.elsterelectricity.com

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FUEL Equipment Specification Sheets

SB 5500.4

RPM® SERIES Rotary Gas Meters

AMERICAN METER COMPANY

RPM® SERIES

Rotary Gas Meters –
accurate, versatile, tough

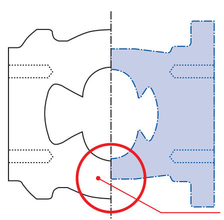
Accurate

American Meter Company offers a complete line of RPM® Series Rotary Gas Meters designed for commercial, industrial and pipeline applications. These meters are precision engineered to ANSI B109.3 National Standards to accurately measure natural gas flow at all standard line conditions.

Versatile

The meters are also suitable for propane and butane gases, as well as other inert gases. The meters are badge rated as standard to 175 (12 bar) MAOP and can be rated to ***285 (20 bar) MAOP at no extra charge*** for high-pressure applications.

All models can be modified to fit a variety of "meter read" formats including Mercury Mini-Max T Fixed Factor and Temperature Compensation, Mercury Full Pressure and Temperature Mini-Max or Mini AT Correction, Continuous Mechanical Temperature Compensation, Automated Meter Reading with ERTransponders and Low Frequency Pulser options; all to provide flexibility in meeting specific gas measurement needs.



Tough

These rotary meters provide outstanding performance in the most adverse of applications. The RPM Series meter housing provides greater strength and higher pressure ratings than other manufacturers of equal capacity. Their rugged construction and superior strength at the bending moment of the housing ensures this meter ***will not "lock up"*** even under the most unstable pipe stress conditions that can occur on new meter pipe sets.

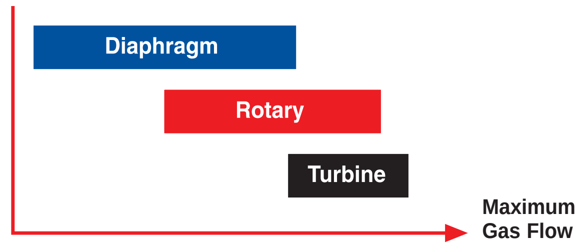
Meter Selection and Operating Principles

The Rotary Gas Meter complements American Meter's existing line of traditional diaphragm and turbine meters. A rotary gas meter, like a diaphragm meter, operates on the positive displacement theory of measurement by creating a fixed-volume measuring compartment. In the rotary's case, the positive displacement occurs between the meter's internal housing cavity and its rotating impellers.

Deciding whether a rotary, diaphragm, or turbine meter is the best choice for your particular application should depend on the following:

- pressure of the gas being measured
- maximum flow rate to be measured
- minimum flow rate to be measured
- desired rangeability

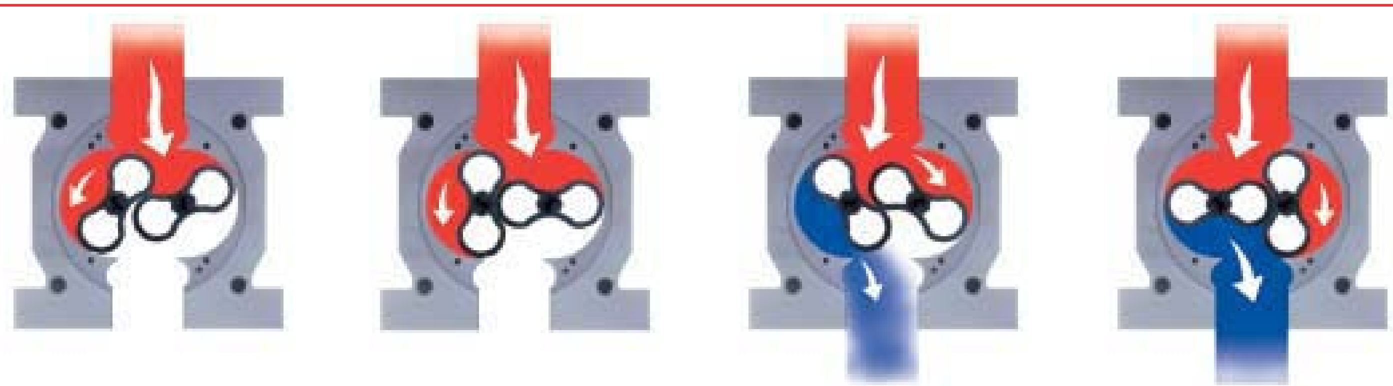
American Meter can offer you all three types.



Rotary Operating Principles

As downstream demand initiates the flow of gas, a pressure drop develops between the meter's inlet and outlet. This creates an internal force on a pair of hour-glass shaped impellers that begin to rotate allowing the flow of gas to start. As the impellers rotate, gas alternately flows into two fixed-volume chambers created between the impellers and the internal cavity of the meter's housing. While cycling, these chambers measure a fixed-volume of gas and then discharge that gas downstream, filling the demand.

These impellers rotate by way of highly synchronized precision gears and will cycle four times during each revolution of the impeller shaft. During operation, there is no metal-to-metal contact between the meter's housing and impellers.



Demand initiates gas flow through the meter. **Impeller captures a fixed volume of gas.** **Measuring cavity opens releasing gas downstream.** **The meter cycles four times completing one revolution.**

RPM Series Rotary Accessory Options

All RPM Series meters mount in either a horizontal or vertical position, depending on available space and convenience. Once installed, all standard and optional accessories can be easily positioned for convenient reading and quick service. All models have extremely good rangeability and are available in various pipe sizes to meet a variety of applications. For example, our 5.5M meter comes in 2" and 3" pipe inlet variations allowing you to increase capacity of a 3M meter 2" pipe installation without changing out the pipe set.

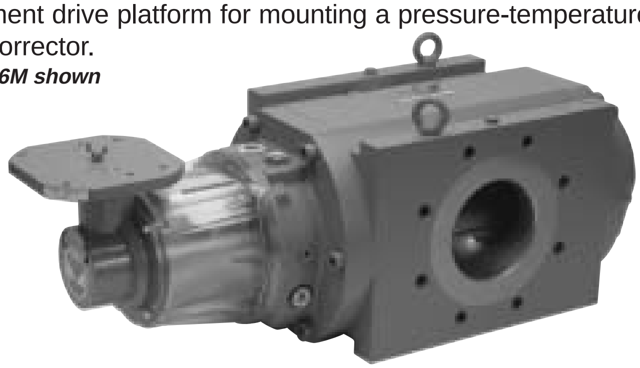
RPM Series meters are available in the following configurations:

RPM-STD

STANDARD meter with uncorrected mechanical register.
3.5M shown

RPM-ID

Meter with uncorrected mechanical register and instrument drive platform for mounting a pressure-temperature corrector.
16M shown



RPM-CMTC

Meter with Continuous Mechanical Temperature Compensator.
1.5M shown

RPM-CMTC-ID

Meter with Continuous Mechanical Temperature Compensator and instrument drive for mounting a pressure-compensating index or pressure corrector.
5.5M shown

RPM-CMTC with Direct-Mount TRACE® or ITRON® ERT

Meter with Continuous Mechanical Temperature Compensation. No more instrument drive accessory and sandwich pulsers are needed. The ERT can be programmed at our factory, in your meter shop, or in the field. Four optional kits are available.
7M shown with ITRON 40G ERT

RPM-CMTC or STANDARD Meter with Low-Frequency Pulser Options

Military and standard connections are available.
5.5M shown

American Meter

RPM® SERIES

Rotary Meter with Mercury Instrumentation

Integral On Top
5.5M Shown

New Horizons in Measurement and Instrumentation

A new generation of Mercury Mini-Max® and Mini-AT® Correctors now mount three different ways: integrally on top, direct on the end, or on a standard instrument drive plate to American Meter's RPM® Series Rotary Meters.

The integral or direct-mount combination eliminates the need for the mechanical register and base plate of the corrector, as well as the instrument-mounting plate and mechanical-drive mechanism from the meter.

Cost savings are achieved on both integral and direct-mount units making for an attractive lower-price combination over standard Instrument Drive (ID) mountings.

These new Mercury correctors can be mounted to the AMCO rotary meter directly at American Meter's factory or installed in the field or meter shop.

Direct Side Mount
1.5M Shown

Capabilities

- Unless the meter installation possesses an unusual obstruction, the corrector can rotate 360° and clear adjacent pipe, fittings, and bolts in 90°/180° intervals.
- The Mercury correctors work with both horizontal and vertical meter pipe set mountings.
- There is no need to open the corrector in order to mount or remove from the meter.
- The Instrument Drive (ID) assembly functions with other Mercury ID correctors or other brands. Available rotation of the larger correctors may be limited.

Instrument Drive (ID)
16M Shown

Contact your Mercury/AMCO sales representative for more information.

Mercury Instruments, Inc.

3940 Virginia Avenue, Cincinnati, Ohio 45227 USA
Phone: 513/272-1111 • Fax 513/272-0211
web: www.mercuryinstruments.com
e-mail: info@mercuryinstruments.com

Mercury Mini-Max® Specifications

Input Volume

- Dual dry-reed switches – one pulse per each meter revolution
- Uncorrected volume totalized on the mechanical index and displayed on LCD
- Uncorrected volume-pulse counting continues for 30 minutes with main battery removed

Input Pressure

Mini-Max Electronic Temperature Corrector (ETC) is Fixed-Factor only.
Mini-Max Pressure and Temperature (P&T) Corrector is as follows:

- Precision strain-gauge pressure transducer compensated to minimize ambient temperature effects
- Live LCD display of input pressure
- Standard transducer ranges (accuracy +/- .4% F.S.):

Pressure Ranges

(PSI)	*(BAR)*	*Transducer Type*
0-1	0.07	Gauge only
0-3	0.20	Gauge only
0-6	0.40	Gauge only
0-15	1.00	Gauge only
0-30	2.00	Gauge or Absolute
0-60	4.00	Gauge or Absolute
0-100	7.00	Gauge or Absolute
0-300	20.00	Gauge or Absolute
0-600	41.00	Gauge or Absolute
0-1000	70.00	Gauge or Absolute

Input Temperature

- Highly stable solid-state temperature sensor in a sealed 1/4-inch diameter, 6-inch long, stainless-steel probe with 6-foot shielded conductor and 1/2-inch NPT slip-along fitting to match thermowell
- Range: -40 to 150°F (-40 to 65.5°C)
- Live LCD display of input temperature

Corrected Volume

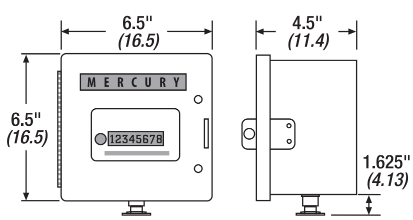
- Corrected to desired base pressure and base temperature within +/- .3% accuracy
- Corrected for supercompressibility (NX-19 or AGA-8)
- Selectable (metric and imperial) volume units
- Displayed continuously on 8-character x 1/2-inch LCD

Certifications

- Designed for Class I, Divisions 1 and 2, Group D (certifications pending)

Warranty

- Corrector 4 years



Mercury Mini-AT® Specifications

Input Volume

- Dual dry-reed switches – one pulse per each meter revolution
- Uncorrected volume totalized on the mechanical index and displayed on LCD

Input Pressure

- Precision strain-gauge pressure transducer compensated to minimize ambient temperature effects
- Live LCD display of input pressure
- Standard transducer ranges (accuracy +/- .25% F.S.):

Pressure Ranges

(PSI)	*(BAR)*	*Transducer Type*
0-1	0.07	Gauge only
0-3	0.20	Gauge only
0-6	0.40	Gauge only
0-15	1.00	Gauge only
0-30	2.00	Gauge or Absolute
0-60	4.00	Gauge or Absolute
0-100	7.00	Gauge or Absolute
0-300	20.00	Gauge or Absolute
0-600	41.00	Gauge or Absolute
0-1000	70.00	Gauge or Absolute
0-1500	100.00	Gauge or Absolute

Input Temperature

- Highly stable solid-state temperature sensor in a sealed 1/4-inch diameter, 9-inch long, stainless-steel probe with 6-foot armored conductor and 1/2-inch NPT slip-along fitting to match thermowell
- Range: -40 to 170°F (-40 to 76.6°C)
- Live LCD display of input temperature

Corrected Volume

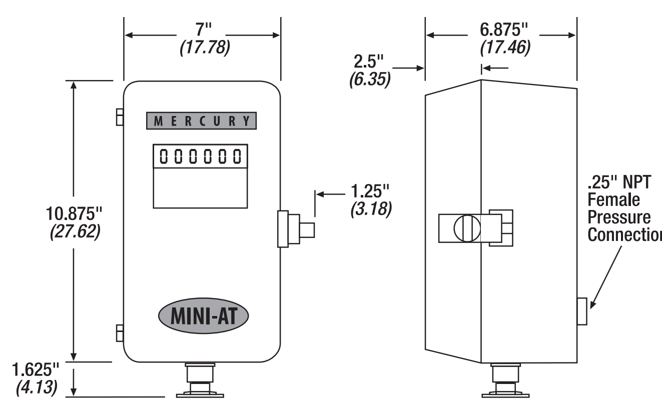
- Corrected to desired base pressure and base temperature within +/- .1% accuracy
- Corrected for supercompressibility (NX-19 or AGA-8)
- Selectable (metric and imperial) volume units
- Displayed continuously on 8-digit x 1/2-inch LCD

Certifications

- Designed for Class I, Divisions 1 and 2, Group D (certifications pending)

Warranty

- Corrector 4 years



Technical Data

Description	Units	Meter Size 8C –	9C G16	11C –	1.5M G25	2M G40	3.5M G65	5.5M G100	7M –	11M –	16M G250
Rated capacity @ 0.25 psig *(17 mBarg)*	scfh *(Sm³/h)*	800 *(22.4)*	900 *(25.2)*	1100 *(30.8)*	1500 *(42.0)*	2000 *(56.0)*	3500 *(98.0)*	5500 *(154.0)*	7000 *(196.0)*	11000 *(308.0)*	16000 *(448.0)*
Max. allowable pressure (MAOP) 285 optional	psig	175/285	175/285	175/285	175/285	175/285	175/285	175/285	175/285	175/285	175/285
Rangeability ±1%*		>30:1	>30:1	>40:1	>40:1	>75:1	>75:1	>120:1	>70:1	>120:1	>100:1
Rangeability ±2%*		>60:1	>60:1	>75:1	>75:1	>140:1	>140:1	>210:1	>115:1	>225:1	>150:1
Start rate	cfh	<3.0	<3.0	<3.0	<3.0	<4.0	<4.0	<4.4	<5.5	<5.5	<7.0
Drive register/I.D. CW/CCW	cf/rev	10	10	10	10	10	10	10/100	10/100	10/100	1000
Max. operating speed	rpm	2043	2043	2358	2358	2950	2950	2425	2098	2414	2976
Flange/flange dimension	in.	6.75	6.75	6.75	6.75	6.75	6.75	6.75	9.50	9.50	9.50
Nominal pipe size	in.	1.5/2	1.5/2	1.5/2	1.5/2	2	2	2/3	3	4	4

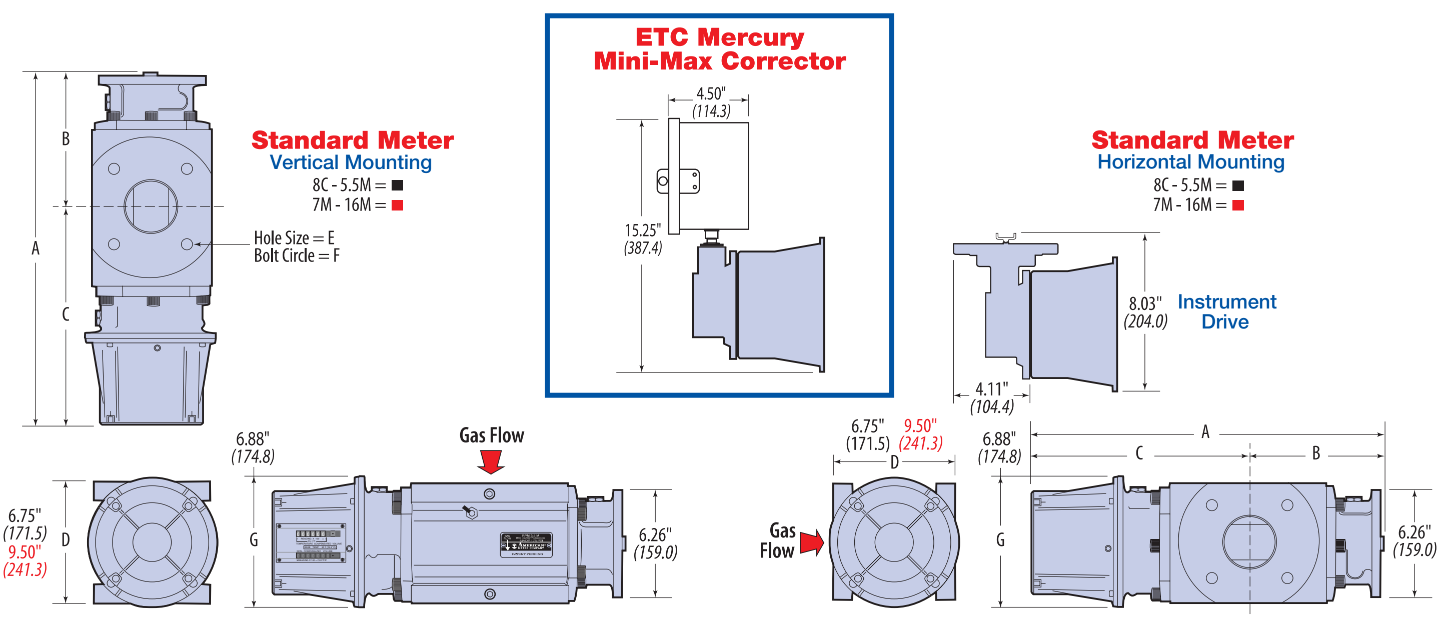
** Data represents averages taken from base model meters tested on Bell provers.*

Dimensions inches *(metric)*

Standard meter with mechanical temperature compensator Horizontal and vertical mounting

Meter Size	8C –	9C G16	11C –	1.5M G25	2M G40	3.5M G65	5.5M (2") G100	5.5M (3") G100	7M –	11M –	16M G250
A	16.080 *(408.43)*	16.080 *(408.43)*	17.580 *(446.53)*	17.580 *(446.53)*	15.580 *(395.73)*	15.580 *(395.73)*	19.520 *(495.81)*	19.520 *(495.81)*	18.650 *(473.71)*	20.410 *(518.41)*	22.822 *(579.68)*
B	5.810 *(147.60)*	5.810 *(147.60)*	6.390 *(162.30)*	6.390 *(162.30)*	5.390 *(136.90)*	5.390 *(136.90)*	7.360 *(186.90)*	7.360 *(186.90)*	6.970 *(177.40)*	7.980 *(202.70)*	9.056 *(230.02)*
C	10.280 *(261.11)*	10.280 *(261.11)*	11.200 *(284.48)*	11.200 *(284.48)*	10.190 *(258.83)*	10.190 *(258.83)*	12.160 *(308.86)*	12.160 *(308.86)*	11.420 *(290.07)*	12.370 *(314.20)*	13.506 *(343.05)*
D	6.75 *(171.5)*	6.75 *(171.5)*	6.75 *(171.5)*	6.75 *(171.5)*	6.75 *(171.5)*	6.75 *(171.5)*	6.75 *(171.5)*	6.75 *(171.5)*	9.50 *(241.3)*	9.50 *(241.3)*	9.50 *(241.3)*
E (ANSI)	5/8-11	5/8-11	5/8-11	5/8-11	5/8-11	5/8-11	5/8-11	5/8-11	5/8-11	5/8-11	5/8-11
E *(metric)*	M16X2	M16X2	M16X2	M16X2	M16X2	M16X2	M16X2	M16X2	M16X2	M16X2	M16X2
F (ANSI)	4.750 *(120.65)*	4.750 *(120.65)*	4.750 *(120.65)*	4.750 *(120.65)*	4.750 *(120.65)*	4.750 *(120.65)*	4.750 *(120.65)*	6.000 *(152.40)*	6.000 *(152.40)*	7.500 *(190.50)*	7.500 *(190.50)*
F *(metric)*	4.924 *(125.00)*	4.924 *(125.00)*	4.924 *(125.00)*	4.924 *(125.00)*	4.924 *(125.00)*	4.924 *(125.00)*	4.924 *(125.00)*	6.299 *(160.00)*	6.299 *(160.00)*	7.087 *(180.00)*	7.087 *(180.00)*
G	6.88 *(174.8)*	6.88 *(174.8)*	6.88 *(174.8)*	6.88 *(174.8)*	6.88 *(174.8)*	6.88 *(174.8)*	6.88 *(174.8)*	6.88 *(174.8)*	6.88 *(174.8)*	6.88 *(174.8)*	6.88 *(174.8)*
Weight lbs. *(kg.)*	22.0 *(10.00)*	22.0 *(10.00)*	26.0 *(11.80)*	26.0 *(11.80)*	26.0 *(11.80)*	26.0 *(11.80)*	38.0 *(17.24)*	36.0 *(16.33)*	60.0 *(27.22)*	74.0 *(33.57)*	90.0 *(40.83)*

Warranty — Five-year limited warranty with conditions. See IM 5700 for details.



RPM® SERIES

Sizing and Ordering Specifications

RPM Series Rotary Meter Capacities * – scfh *(Sm³/h)*

Local Atm Pressure - (psia) 14.37
Sea Level Atm Pressure - (psia) 14.73

Line Pressure	Meter Size 8C	9C	11C	1.5M	2M	3.5M	5.5M	7M	11M	16M
0.25 psig *(17 mBarg)*	800 *(22.4)*	900 *(25.2)*	1,100 *(30.8)*	1,500 *(42.0)*	2,000 *(56.0)*	3,500 *(98.0)*	5,500 *(154.0)*	7,000 *(196.0)*	11,000 *(308.0)*	16,000 *(448.0)*
2 psig *(1.4 mBarg)*	891 *(24.9)*	1,002 *(28.1)*	1,225 *(34.3)*	1,670 *(46.8)*	2,227 *(62.3)*	3,897 *(109.1)*	6,124 *(171.5)*	7,794 *(218.2)*	12,247 *(342.9)*	17,814 *(498.8)*
5 psig *(345 mBarg)*	1,054 *(29.5)*	1,185 *(33.2)*	1,449 *(40.6)*	1,976 *(55.3)*	2,634 *(73.8)*	4,610 *(129.1)*	7,244 *(202.8)*	9,219 *(258.1)*	14,487 *(405.6)*	21,073 *(590.0)*
10 psig *(690 mBarg)*	1,325 *(37.1)*	1,491 *(41.7)*	1,822 *(51.0)*	2,485 *(69.6)*	3,313 *(92.8)*	5,798 *(162.3)*	9,111 *(255.1)*	11,595 *(324.7)*	18,221 *(510.2)*	26,504 *(742.1)*
25 psig *(1.7 Barg)*	2,140 *(59.9)*	2,407 *(67.4)*	2,942 *(82.4)*	4,012 *(112.3)*	5,350 *(149.8)*	9,362 *(262.1)*	14,711 *(411.9)*	18,724 *(524.3)*	29,423 *(823.8)*	42,797 *(1,198.3)*
50 psig *(3.4 Barg)*	3,498 *(97.9)*	3,935 *(110.2)*	4,809 *(134.7)*	6,558 *(183.6)*	8,744 *(244.8)*	15,302 *(428.5)*	24,046 *(673.3)*	30,604 *(856.9)*	48,092 *(1,346.6)*	69,952 *(1,958.7)*
75 psig *(5.2 Barg)*	4,855 *(136.0)*	5,462 *(152.9)*	6,676 *(186.9)*	9,104 *(254.9)*	12,138 *(339.9)*	21,242 *(594.8)*	33,381 *(934.7)*	42,485 *(1,189.6)*	66,762 *(1,869.3)*	97,108 *(2,719.0)*
100 psig *(6.9 Barg)*	6,213 *(174.0)*	6,990 *(195.7)*	8,543 *(239.2)*	11,650 *(326.2)*	15,533 *(434.9)*	27,183 *(761.1)*	42,716 *(1,196.0)*	54,365 *(1,522.2)*	85,431 *(2,392.1)*	124,263 *(3,479.4)*
150 psig *(10.3 Barg)*	8,929 *(250.0)*	10,045 *(281.3)*	12,277 *(343.8)*	16,741 *(468.8)*	22,322 *(625.0)*	39,063 *(1,093.8)*	61,385 *(1,718.8)*	78,126 *(2,187.5)*	122,770 *(3,437.6)*	178,574 *(5,000.1)*
175 psig *(12.1 Barg)*	10,286 *(288.0)*	11,572 *(324.0)*	14,144 *(396.0)*	19,287 *(540.0)*	25,716 *(720.1)*	45,003 *(1,260.1)*	70,720 *(1,980.1)*	90,007 *(2,520.2)*	141,439 *(3,960.3)*	205,730 *(5,760.4)*
200 psig *(13.8 Barg)*	11,644 *(326.0)*	14,585 *(408.4)*	17,826 *(499.1)*	24,308 *(680.6)*	32,411 *(907.5)*	56,719 *(1,588.1)*	89,130 *(2,495.7)*	113,439 *(3,176.3)*	178,261 *(4,991.3)*	259,288 *(7,260.1)*
250 psig *(17.2 Barg)*	14,360 *(402.1)*	16,155 *(452.3)*	19,745 *(552.9)*	26,925 *(753.9)*	35,900 *(1,005.2)*	62,824 *(1,759.1)*	98,724 *(2,764.3)*	125,648 *(3,518.2)*	197,447 *(5,528.5)*	287,196 *(8,041.5)*
285 psig** *(19.6 Barg)*	16,261 *(455.3)*	18,293 *(512.2)*	22,358 *(626.0)*	30,489 *(853.7)*	40,652 *(1,138.2)*	71,141 *(1,991.9)*	111,792 *(3,130.2)*	142,281 *(3,983.9)*	223,585 *(6,260.4)*	325,214 *(9,106.0)*

Using the chart above:

Select the appropriate size rotary meter based on maximum instantaneous flow rate and minimum pressure.

- Size is determined by finding the maximum hourly flow rate in cubic feet per hour (scfh) and the corresponding pressure at that flow rate.

Note: 1000 BTU's/hr of natural gas approximately equals 1 CFH. (BTU input rating can be found on the equipment/burner name plate.)

- Find a value larger than the required maximum instantaneous hourly flow rate in the row representative to the specific minimum operating pressure. The proper rotary meter model heads the column. For example, maximum load of 25,000 scfh at 100 PSIG requires a 3.5M meter.

* Capacity data based upon natural gas with specific gravity of 0.60.

*** 285 MAOP optional at no charge.*

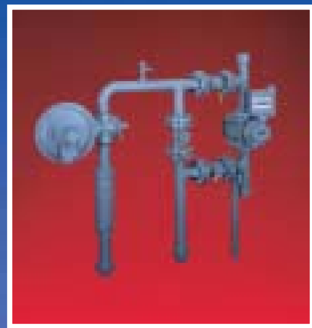
Ordering Information

Options	Meter Size 8C and 9C – G16	11C and 1.5M – G25	2M and 3.5M G40 G65	5.5M G100	7M –	11M –	16M G250
Type	← english or metric →						
Connections	NPT/flanged	NPT/flanged	flanged	flanged	flanged	flanged	flanged
Pipe size	1.5"/2"	1.5"/2"	2"	2" or 3"	3"	4"	4"
Mounting	← vertical or horizontal →						
Counter	← 4, 5 or 6 digit →						
Output drive	← STANDARD, ETC, CMTC or Instrument Drive →						
Multiplier	← 10, 100 →						1000
Carton size	← 16"H x 12"W x 21.5"L →				← 16"H x 13"W x 24"L →		
Shipping wgt. lbs. *(kg.)*	26 *(11.79)*	33 *(14.97)*	30 *(13.61)*	42 *(19.05)*	65 *(29.48)*	75 *(34.02)*	90 *(40.82)*

A Complete Family of Gas Measurement, Pressure Regulation, and Testing Systems

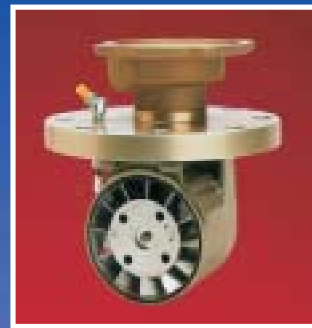
AL800/AL1000 Diaphragm Meter

American Meter is the industry's leading supplier of diaphragm meters with models for applications from domestic service to large industrial users. See bulletin SB 3500 for more information.



Rotary Meter with Prefabricated Sets

Prefabricated new or replacement meter sets to customer specifications are available.



Pre-Calibrated Replacement Cartridges

Tested at atmospheric or actual operating pressure, pre-calibrated measurement cartridges are available for field service changes. Cartridges returned to the factory for re-certification and/or service are tested at five flow rates and at specified pressure.

1800 PFM Series

1800 PFM industrial regulators are designed for applications requiring medium-to-high capacity, extremely precise outlet-pressure control, and fast response to changing loads. See bulletin SB 8551 for more information.

Turbine Gas Meters

High-performance meters provide accurate measurement of high-volume gas flow. Turbines are available from 3" to 12" line sizes and line pressures up to 1440 PSIG. See bulletin SB 4510 for more information.

ISO 9001: 2000

QMI REGISTERED

Certificate No. 006697

Contact your AMCO/CMCO sales representative for more information.

Filters

Filtration down to 10 microns. Protects meter and regulator stations from dirt and pipe scale damage. See bulletin SB 12521 for more information.

AMERICAN METER COMPANY
Measurement Engineers Since 1836
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Fax 215/830-1890
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Fax 519/650-1917
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American Meter Company has a program of continuous product development and improvement; and, therefore, the information in this bulletin is subject to change or modification without notice.

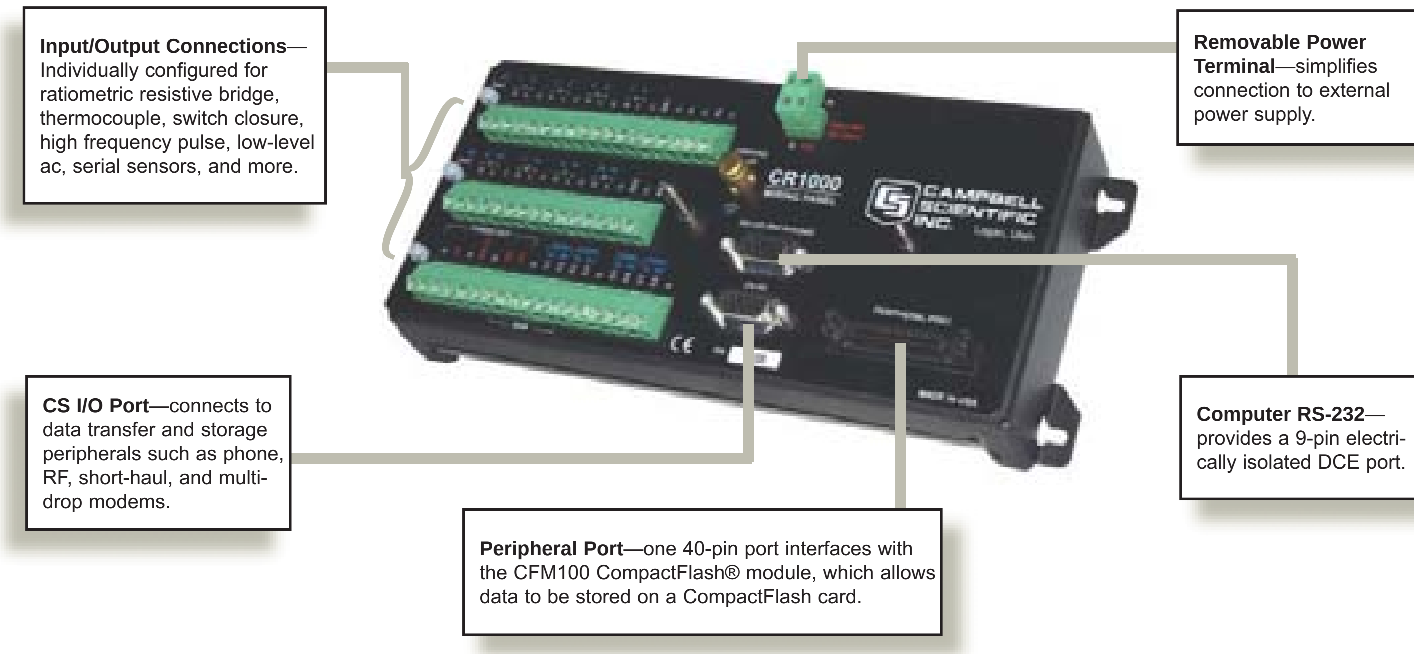
CR1000 *Measurement & Control System*

A Rugged Instrument with Research-Grade Performance

CAMPBELL SCIENTIFIC, INC.
815 W. 1800 N. • Logan, Utah 84321-1784 • (435) 753-2342 • FAX (435) 750-9540 • www.campbellsci.com

CR1000 Measurement and Control System

The CR1000 provides precision measurement capabilities in a rugged, battery-operated package. It consists of a measurement and control module and a wiring panel. Standard operating range is -25° to +50°C; an optional extended range of -55° to +85°C is available.



Features

- 2 Mbytes standard memory; 4 Mbytes optional memory
- Program execution rate of up to 100 Hz
- CS I/O and RS-232 serial ports
- 13-bit analog to digital conversions
- 16-bit H8S Hitachi Microcontroller with 32-bit internal CPU architecture
- Temperature compensated real-time clock
- Background system calibration for accurate measurements over time and temperature changes
- Single DAC used for excitation and measurements to give ratio metric measurements
- Gas Discharge Tube (GDT) protected inputs
- Data values stored in tables with a time stamp and record number
- Battery-backed SRAM memory and clock ensuring data, programs, and accurate time are maintained while the CR1000 is disconnected from its main power source
- Measures intelligent serial sensors without using an SDM-SIO4

Measurement and Control Module

The module measures sensors, drives direct communications and telecommunications, reduces data, controls external devices, and stores data and programs in on-board, non-volatile storage. The electronics are RF shielded and glitch protected by the sealed, stainless steel canister. A battery-backed clock assures accurate timekeeping. The module can simultaneously provide measurement and communication functions. The on-board, BASIC-like programming language supports data processing and analysis routines.

Wiring Panel

The CR1000WP is a black, anodized aluminum wiring panel that is compatible with all CR1000 and CR1000-4M modules. The wiring panel includes switchable 12 V, redistributed analog grounds (dispersed among analog channels rather than grouped), unpluggable terminal block for 12 V connections, gas-tube spark gaps, and 12 V supply on pin 8 to power our COM-series phone modems and other peripherals. The control module easily disconnects from the wiring panel allowing field replacement without rewiring the sensors. A description of the wiring panel's input/output channels follows.

Analog Inputs

Eight differential (16 single-ended) channels measure voltage levels. Resolution on the most sensitive range is 0.67 µV.

Pulse Counters

Two pulse channels can count pulses from high level (5 V square wave), switch closure, or low level ac signals.

Switched Voltage Excitations

Three outputs provide precision excitation voltages for resistive bridge measurements.

Digital I/O Ports

Eight ports are provided for frequency measurements, digital control, and triggering. Three of these ports can also be used to measure SDM devices.

RS-232 Port

A PC or laptop can be connected to this 9-pin port via an RS-232 cable.

CS I/O port

Data transfer peripherals that require power from the datalogger can be connected to this port via an SC12 cable. This port is also used for connecting the datalogger to a PC via an SC32B or SC-USB interface when optical isolation is required.

Peripheral Port

One 40-pin port interfaces with the CFM100 CompactFlash® Module or the NL115 Ethernet Interface and CompactFlash Module.

Switched 12 Volt

This terminal provides unregulated 12 V that can be switched on and off under program control.

Storage Capacity

The CR1000 has 2 Mbyte of FLASH memory for the Operating System. The standard CR1000 provides 2 Mbytes battery-backed SRAM for CPU usage, program storage, and data storage; an optional version provides 4 Mbytes of SRAM. Data is stored in a table format. The storage capacity of the CR1000 can be increased by using a CompactFlash® card.

Communication Protocols

The CR1000 supports the PakBus® communication protocol. PakBus networks have the distributed routing intelligence to continually evaluate links. Continually evaluating links optimizes delivery times and, in the case of delivery failure, allows automatic switch over to a configured backup route.

The CR1000 also supports Modbus RTU protocol—both floating point and long formats. The datalogger can act as a slave, master, or both.

Enclosure/Stack Bracket

A CR1000 housed in a weather-resistant enclosure can collect data under extremely harsh conditions. The enclosure protects the CR1000 from dust, water, sunlight, or pollutants. An internal mounting plate is prepunched for easy system configuration and exchange of equipment in the field.

A stack bracket kit is available that allows you to attach the CR1000 to the backplate of an ENC10/12 enclosure in a "horizontal" orientation (i.e., the long axis of the CR1000 spanning the short axis of the ENC10/12 enclosure). This stack bracket also allows you to place a small peripheral under the mounting bracket and secure it with Velcro®, thus conserving space, and place the wiring panel terminals at about the same height as the terminals in one of our power supplies.

The stack bracket as viewed from the side with a CR1000 attached.

Power Supplies

Any 12 Vdc source can power the CR1000; a PS100 or BPALK is typically used. The PS100 includes one 7 Ahr rechargeable battery, charged with ac power (requires a wall charger) or a solar panel. The BPALK consists of eight non-rechargeable D-cell alkaline batteries with a 7.5 Ahr rating at 20°C. An external AA-cell battery pack supplies power while the D-cells are replaced.

Also available are the BP12 and BP24 battery packs, which provide nominal ratings of 12 and 24 Ahrs, respectively. These batteries should be connected to a charging regulator and a charging source. For information about analyzing your system's power requirements, see our Power Supply product literature or Application Note 5-F. Both can be obtained from: www. campbellsci.com

Its low-power design allows the CR1000 to operate for up to one year on the PS100 power supply, depending on scan rate, number of sensors, data retrieval method, and external temperature.

Data Storage and Retrieval Options

To determine the best option for your application, consider the accessibility of your site, availability of services (e.g., cellular phone or satellite coverage), quantity of data to collect, and desired time between data-collection sessions. Some communication options can be combined—increasing the flexibility, convenience, and reliability of your communications.

Radios

Radio frequency (RF) communications are supported via narrow-band UHF, narrow-band VHF, spread spectrum, or meteor burst radios. Line-of-sight is required for all of our RF options.

Meteorological conditions measured at Lake Louise, Alberta, Canada are telemetered via phone-to-RF link to a base station.

Telephone Networks

The CR1000 can communicate with a PC using landlines, cellular CDMA, or cellular GPRS transceivers. A voice synthesized modem enables anyone to call the CR1000 via phone and receive a verbal report of realtime site conditions.

Satellite Transmitters

Our NESDIS-certified GOES satellite transmitter provides one-way communications from a Data Collection Platform (DCP) to a receiving station. The transmitter complies with the High Data Rate (HDR) specifications. We also offer an Argos transmitter that is ideal for high-altitude and polar applications.

This station for the National Estuarine Research Reserve (NERR) in Virginia transmits data via our GOES satellite transmitter.

Multidrop Interface

The MD485 intelligent RS-485 interface permits a PC to address and communicate with one or more dataloggers over a single two-twisted-pair cable. Distances up to 4000 ft are supported.

Short Haul Modems

The SRM-5A RAD Short Haul Modem supports communications between the CR1000 and a computer via a four-wire unconditioned line (two twisted pairs).

Direct Links

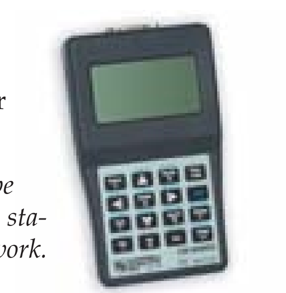
A desktop or laptop PC connects directly to the CR1000's RS-232 port. If optical isolation is required, the PC is connected to the datalogger's CS I/O port via an SC32B or SC-USB interface.

PDAs

User-supplied PDAs can be used to set the CR1000's clock, monitor real-time data, retrieve data, graph data, and transfer CR1000 programs. PConnect software (purchased separately) is required for PDAs with a Palm™ OS, and PConnectCE software (purchased separately) is required for PDAs with a Windows® CE OS.

Keyboard Display

With the CR1000KD, you can program the CR1000, manually initiate data transfer, and display data. The CR1000KD displays 8 lines x 21 characters (64 x 128 pixels) and has a 16-character keyboard. Custom menus are supported allowing you to set up choices within the datalogger program that can be initiated by a simple "toggle" or "pick list".



One CR1000KD can be carried from station to station in a CR1000 network.

Ethernet

Use of an NL100 or NL115 interface enables the CR1000 to communicate over a local network or a dedicated internet connection via TCP/IP. The NL115 also supports data storage on CompactFlash cards.

CompactFlash®

The CR1000's data can be stored on a CompactFlash card using either a CFM100 or NL115 module. On the computer side, the CompactFlash cards are read by the computer's PCMCIA slot fitted with a CF1 CompactFlash adapter or by a USB port fitted with the ImageMate USB CompactFlash Reader/Writer.

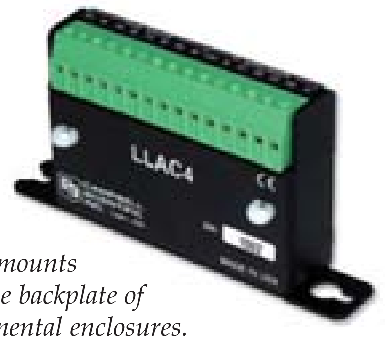
DSP4 Heads Up Display

Primarily intended for vehicle test applications, the DSP4 permits dashboard mounting in a variety of vehicles without obstructing the view of the driver.

Channel Expansion

4-Channel Low Level AC Module

The LLAC4 is a small peripheral device that allows you to increase the number of available low-level ac inputs by using control ports. This module is often used to measure up to four anemometers, and is especially useful for wind profiling applications.



The LLAC4 mounts directly to the backplate of our environmental enclosures.

Synchronous Devices for Measurement (SDMs)

SDMs are addressable peripherals that expand the CR1000's measurement and control capabilities. For example, SDMs are available to add control ports, analog outputs, pulse count channels, interval timers, or even a CANbus interface to your system. Multiple SDMs, in any combination, can be connected to one CR1000 datalogger.

Multiplexers

Multiplexers increase the number of sensors that can be measured by a CR1000 by sequentially connecting each sensor to the datalogger. Several multiplexers can be controlled by a single CR1000. The CR1000 is compatible with the AM16/32 and AM25T.

Software

Starter Software

Campbell Scientific offers easy-to-use starter software intended for first time users or applications that don't require sophisticated communications or datalogger program editing. These software products provide different functions and can be used in conjunction with each other. Starter software can be downloaded at no charge from www.campbellsci.com/resource.html. Our Resource CD also provides this software as well as PDF versions of our literature and manuals.

Our SCWin Short Cut for Windows® generates straightforward CR1000 programs in four easy steps. Short Cut supports programming for our multiplexers, ET106 stations, MetData1 stations, and virtually any sensor that our CR1000 can measure.

Our PC200W Starter Software allows you to transfer a program to, or retrieve data from, a CR1000 via a direct communications link.

Datalogger Support Software

Our general purpose datalogger support software packages provide more capabilities than our starter software. Each of these software packages contains program editing, communications, and display tools that can support an entire datalogger network.

PC400, our mid-level software, supports a variety of telemetry options, manual data collection, and data display. For programming, it includes both Short Cut and the CRBasic program editor. PC400 does not support combined communication options (e.g., phone-to-RF), PakBus® routing, or scheduled data collection; LoggerNet software is recommended for those applications.

Campbell Scientific offers the following three LoggerNet Software Packages:

- **LoggerNet**, the standard package, is recommended for those who have datalogger networks that do not require the more advanced features offered in LoggerNet Admin. It consists of a server application and several client applications integrated into a single product. This software provides all of PC400's capabilities as well as support for combined communication options (e.g., phone-to-RF), PakBus® routing, and scheduled data collection

- **LoggerNet Admin** is intended for customers who have large networks. Besides providing better tools for managing large networks, LoggerNet Admin allows you to remotely manage a datalogger network over TCP/IP, and to remotely and automatically distribute data to other computers.

- **LoggerNetRemote** includes LoggerNet Admin clients to administer a running LoggerNet Admin server via TCP/IP from a remote PC. This software does not include the LoggerNet server.

LoggerNet provides a way to accomplish almost all the tasks you'll need to complete when using a datalogger.

Applications

The measurement precision, flexibility, long-term reliability, and economical price of the CR1000 make it ideal for scientific, commercial, and industrial applications.

Meteorology

The CR1000 is used in long-term climatological monitoring, meteorological research, and routine weather measurement applications.

Our rugged, reliable weather station measures meteorological conditions at St. Mary's Lake, Glacier National Park, MT.

Sensors the CR1000 can measure include:

- cup, propeller, and sonic anemometers
- tipping bucket rain gages
- wind vanes
- pyranometers
- ultrasonic distance sensors
- thermistors, RTDs, and thermocouples
- barometric pressure sensors
- RH sensors
- cooled mirror hygrometers

Data is output in your choice of units (e.g., wind speed in miles per hour, meters per second, or knots). Standard CR1000 outputs include wind vector averaging, sigma, theta, histograms, saturation vapor pressure, and vapor pressure from wet/dry bulb temperatures.

Agriculture and Agricultural Research

The versatility of the CR1000 allows measurement of agricultural processes and equipment in applications such as:

- plant water research
- canopy energy balance
- machinery performance
- plant pathology
- crop management decisions
- food processing/storage
- frost prediction
- irrigation scheduling
- integrated pest management

This vitaculture site in Australia integrates meteorological, soil, and crop measurements.

Wind Profiling

Our data acquisition systems can monitor conditions at wind assessment sites, at producing wind farms, and along transmission lines. The reliability of these systems ensures data collection, even under adverse conditions. Wide operating temperature ranges and weatherproof enclosures allow our systems to operate reliably in harsh environments.

The CR1000 makes and records measurements, controls electrical devices, and can function as PLCs or RTUs. Because the datalogger has its own power supply (batteries, solar panels), it can continue to measure and store data and perform control during power outages.

Typical sensors for wind assessment applications include, but are not limited to:

- sonic anemometers
- three-cup and propeller anemometers (up to 10 anemometers can be measured by using two LLAC4 peripherals)
- wind vanes
- temperature sensors (air, water, and equipment)
- barometric pressure
- wetness
- solar radiation

Photo courtesy npower renewables

A Campbell Scientific system monitors an offshore wind farm in North Wales.

For turbine performance applications, the CR1000 can monitor electrical current, voltage, wattage, stress, and torque.

Soil Moisture

The CR1000 is compatible with the following soil moisture measurement technologies:

- **Soil moisture blocks** are inexpensive sensors that estimate soil water potential.
- **Matric water potential sensors** also estimate soil water potential but are more durable than soil moisture blocks.
- **Time-Domain Reflectometry Systems (TDR)** use a reflectometer controlled by a CR1000 to accurately measure soil water content. Multiplexers allow sequential measurement of a large number of probes by one reflectometer, reducing cost per measurement.
- **Self-contained water content reflectometers** are sensors that emit and measure a TDR pulse.
- **Tensiometers** measure the soil pore pressure of irrigated soils and calculate soil moisture.

Air Quality

The CR1000 can monitor and control gas analyzers, particle samplers, and visibility sensors. It can also automatically control calibration sequences and compute conditional averages that exclude invalid data (e.g., data recorded during power failures or calibration intervals).

Road Weather/RWIS

Our fully NTCIP-compliant Environmental Sensor Stations (ESS) are robust, reliable weather stations used for road weather/RWIS applications. A typical ESS includes a tower, CR1000, two road sensors, remote communication hardware, and sensors that measure wind speed and direction, air temperature, humidity, barometric pressure, solar radiation, and precipitation. The CR1000 can also measure soil moisture and temperature sensors, monitor bridge vibrations, and control external devices.

Water Resources/Aquaculture

Our CR1000 is well-suited to remote, unattended monitoring of hydrologic conditions. Most hydrologic sensors, including SDI-12 probes, interface directly to the CR1000. Typical hydrologic measurements:

- **Water level** is monitored with incremental shaft encoders, double bubblers, ultrasonic level transducers, resistance tapes, or strain gage or vibrating wire pressure transducers. Some shaft encoders require a QD1 Interface. Vibrating wire transducers require an AVW1, AVW4, or AVW100 Interface.
- **Well draw-down tests** use a pressure transducer measured at logarithmic intervals or at a rate based on incremental changes in water level.
- **Ionic conductivity measurements** use one of the switched excitation ports from the CR1000.
- **Samplers** are controlled by the CR1000 as a function of time, water quality, or water level.
- **Alarm and pump actuation** are controlled through digital I/O ports that operate external relay drivers.

A turbidity sensor was installed in a tributary of the Cedar River watershed to monitor water quality conditions for the city of Seattle, Washington.

Vehical Testing

This versatile, rugged datalogger is ideally suited for testing cold and hot temperature, high altitude, off-highway, and cross-country performance. The CR1000 is compatible with our SDM-CAN interface, GPS16-HVS receiver, and DSP4 Heads Up Display.

Vehicle monitoring includes not only passenger cars, but locomotives, airplanes, helicopters, tractors, buses, heavy trucks, drilling rigs, race cars, and motorcycles.

The CR1000 can measure:

- **Suspension**—strut pressure, spring force, travel, mounting point stress, deflection, ride
- **Fuel system**—line and tank pressure, flow, temperature, injection timing
- **Comfort control**—ambient and supply air temperature, solar radiation, fan speed, ac on and off, refrigerant pressures, time-to-comfort, blower current
- **Brakes**—line pressure, pedal pressure and travel, ABS, line and pad temperature
- **Engine**—pressure, temperature, crank position, RPM, time-to-start, oil pump cavitation
- **General vehicle**—chassis monitoring, road noise, vehicle position and speed, steering, air bag, hot/cold soaks, wind tunnels, traction, CANbus, wiper speed and current, vehicle electrical loads

Other Applications

- Eddy covariance systems
- Wireless sensor/datalogger networks
- Mesonet systems
- Avalanche forecasting, snow science, polar, high altitude
- Fire weather
- Geotechnical
- Historic preservation

CR1000 Specifications

Electrical specifications are valid over a -25° to +50°C range unless otherwise specified; non-condensing environment required. To maintain electrical specifications, Campbell Scientific recommends recalibrating dataloggers every two years.

PROGRAM EXECUTION RATE

10 ms to 30 min. @ 10 ms increments

ANALOG INPUTS

8 differential (DF) or 16 single-ended (SE) individually configured. Channel expansion provided by AM16/32 and AM25T multiplexers.

RANGES, RESOLUTION AND TYPICAL INPUT NOISE: Basic resolution (Basic Res) is the A/D resolution of a single conversion. **Resolution of DF measurements with input reversal is half the Basic Res.** Noise values are for DF measurements with input reversal; noise is greater with SE measurements.

Input Range (mV)	Basic Res (µV)	Input Referred Noise Voltage 250 µs Int. (µV RMS)	50/60 Hz Int. (µV RMS)
±5000	1330	385	192
±2500	667	192	95.9
±250	66.7	19.2	19.2
±25	6.7	2.3	1.9
±7.5	2	0.62	0.58
±2.5	0.67	0.34	0.19

ACCURACY[1]:
±(0.06% of reading + offset), 0° to 40°C
±(0.12% of reading + offset), -25° to 50°C
±(0.18% of reading + offset), -55° to 85°C (-XT only)

[1]The sensor and measurement noise are not included and the offsets are the following:

Offset for DF w/input reversal = 1.5·Basic Res + 1.0 µV
Offset for DF w/o input reversal = 3·Basic Res + 2.0 µV
Offset for SE = 3·Basic Res + 3.0 µV

MINIMUM TIME BETWEEN VOLTAGE MEASUREMENTS: Includes the measurement time and conversion to engineering units. For voltage measurements, the CR1000 integrates the input signal for 0.25 ms or a full 16.66 ms or 20 ms line cycle for 50/60 Hz noise rejection. DF measurements with input reversal incorporate two integrations with reversed input polarities to reduce thermal offset and common mode errors and therefore take twice as long.

250 µs Analog Integration:	~1 ms SE
1/60 Hz Analog Integration:	~20 ms SE
1/50 Hz Analog Integration:	~25 ms SE

COMMON MODE RANGE: ±5 V

DC COMMON MODE REJECTION: >100 dB

NORMAL MODE REJECTION: 70 dB @ 60 Hz when using 60 Hz rejection

SUSTAINED INPUT VOLTAGE W/O DAMAGE: ±16 Vdc max.

INPUT CURRENT: ±1 nA typical, ±6 nA max. @ 50°C; ±90 nA @ 85°C

INPUT RESISTANCE: 20 Gohms typical

ACCURACY OF BUILT-IN REFERENCE JUNCTION THERMISTOR (for thermocouple measurements):
±0.3°C, -25° to 50°C
±0.8°C, -55° to 85°C (-XT only)

ANALOG OUTPUTS

3 switched voltage, active only during measurement, one at a time.

RANGE AND RESOLUTION: Voltage outputs programmable between ±2.5 V with 0.67 mV resolution.

ACCURACY: ±(0.06% of setting + 0.8 mV), 0° to 40°C
±(0.12% of setting + 0.8 mV), -25° to 50°C
±(0.18% of setting + 0.8 mV), -55° to 85°C (-XT only)

CURRENT SOURCING/SINKING: ±25 mA

RESISTANCE MEASUREMENTS

MEASUREMENT TYPES: The CR1000 provides ratiometric measurements of 4- and 6-wire full bridges, and 2-, 3-, and 4-wire half bridges. Precise, dual polarity excitation using any of the 3 switched voltage excitations eliminates dc errors.

RATIO ACCURACY[1]: Assuming excitation voltage of at least 1000 mV, not including bridge resistor error.

$$\pm(0.04\% \text{ of reading + offset})/V_{ex}$$

[1]The sensor and measurement noise are not included and the offsets are the following:

Offset for DF w/input reversal = 1.5·Basic Res + 1.0 µV
Offset for DF w/o input reversal = 3·Basic Res + 2.0 µV
Offset for SE = 3·Basic Res + 3.0 µV

Offset values are reduced by a factor of 2 when excitation reversal is used.

PERIOD AVERAGING MEASUREMENTS

The average period for a single cycle is determined by measuring the average duration of a specified number of cycles. The period resolution is 192 ns divided by the specified number of cycles to be measured; the period accuracy is ±(0.01% of reading + resolution). Any of the 16 SE analog inputs can be used for period averaging. Signal limiting are typically required for the SE analog channel.

INPUT FREQUENCY RANGE:

Input Range	Signal (peak to peak)[2] Min	Max	Min. Pulse W.	Max[3] Freq.
±2500 mV	500 mV	10 V	2.5 µs	200 kHz
±250 mV	10 mV	2 V	10 µs	50 kHz
±25 mV	5 mV	2 V	62 µs	8 kHz
±2.5 mV	2 mV	2 V	100 µs	5 kHz

[2]The signal is centered at the datalogger ground.

[3]The maximum frequency = 1/(Twice Minimum Pulse Width) for 50% of duty cycle signals.

PULSE COUNTERS

Two 24-bit inputs selectable for switch closure, high frequency pulse, or low-level ac.

MAXIMUM COUNTS PER SCAN: 16.7×10^6

SWITCH CLOSURE MODE:
Minimum Switch Closed Time: 5 ms
Minimum Switch Open Time: 6 ms
Max. Bounce Time: 1 ms open w/o being counted

HIGH FREQUENCY PULSE MODE:
Maximum Input Frequency: 250 kHz
Maximum Input Voltage: ±20 V
Voltage Thresholds: Count upon transition from below 0.9 V to above 2.2 V after input filter with 1.2 µs time constant.

LOW LEVEL AC MODE: Internal ac coupling removes dc offsets up to ±0.5 V.

Input Hysteresis: 16 mV @ 1 Hz
Maximum ac Input Voltage: ±20 V
Minimum ac Input Voltage:

Sine wave (mV RMS)	Range (Hz)
20	1.0 to 20
200	0.5 to 200
2000	0.3 to 10,000
5000	0.3 to 20,000

DIGITAL I/O PORTS

8 ports software selectable, as binary inputs or control outputs. C1-C8 also provide edge timing, subroutine interrupts/wake up, switch closure pulse counting, high frequency pulse counting, asynchronous communications (UART), SDI-12 communications, and SDM communications.

HIGH FREQUENCY MAX: 400 kHz

SWITCH CLOSURE FREQUENCY MAX: 150 Hz

OUTPUT VOLTAGES (no load): high 5.0 V ±0.1 V; low <0.1

OUTPUT RESISTANCE: 330 ohms

INPUT STATE: high 3.8 to 5.3 V; low -0.3 to 1.2 V

INPUT HYSTERISIS: 1.4 V

INPUT RESISTANCE: 100 kohms

SWITCHED 12 V

One independent 12 V unregulated sources switched on and off under program control. Thermal fuse hold current = 900 mA @ 20°C, 650 mA @ 50°C, 360 mA @ 85°C.

SDI-12 INTERFACE SUPPORT

Control ports 1, 3, 5, and 7 may be configured for SDI-12 asynchronous communications. Up to ten SDI-12 sensors are supported per port. It meets SDI-12 Standard version 1.3 for datalogger mode.

CE COMPLIANCE

STANDARD(S) TO WHICH CONFORMITY IS DECLARED: IEC61326:2002

CPU AND INTERFACE

PROCESSOR: Hitachi H8S 2322 (16-bit CPU with 32-bit internal core)

MEMORY: 2 Mbytes of Flash for operating system; 2 Mbytes of battery-backed SRAM for CPU usage, program storage and data storage; 4 Mbytes optional

SERIAL INTERFACES: CS I/O port is used to interface with Campbell Scientific peripherals; RS-232 port is for computer or non-CSI modem connection.

PARALLEL INTERFACE: 40-pin interface for attaching data storage or communication peripherals such as the CFM100 module

BAUD RATES: Selectable from 300 bps to 115.2 kbps. ASCII protocol is one start bit, one stop bit, eight data bits, and no parity.

CLOCK ACCURACY: ±3 min. per year

SYSTEM POWER REQUIREMENTS

VOLTAGE: 9.6 to 16 Vdc

TYPICAL CURRENT DRAIN:
Sleep Mode: ~0.6 mA
1 Hz Scan (8 diff. meas., 60 Hz rej., 2 pulse meas.)
w/RS-232 communication: 19 mA
w/o RS-232 communication: 4.2 mA
1 Hz Scan (8 diff. meas., 250 µs integ., 2 pulse meas.)
w/RS-232 communication: 16.7 mA
w/o RS-232 communication: 1 mA
100 Hz Scan (4 diff. meas., 250 µs integ.)
w/RS-232 communication: 27.6 mA
w/o RS-232 communication: 16.2 mA

EXTERNAL BATTERIES: 12 Vdc nominal; reverse polarity protected.

PHYSICAL SPECIFICATIONS

MEASUREMENT & CONTROL MODULE SIZE: 8.5" x 3.9" x 0.85" (21.6 x 9.9 x 2.2 cm)

CR1000WP WIRING PANEL SIZE: 9.4" x 4" x 2.4" (23.9 x 10.2 x 6.1 cm); additional clearance required for serial cable and sensor leads.

WEIGHT: 2.1 lbs (1 kg)

WARRANTY

Three years against defects in materials and workmanship.

CAMPBELL SCIENTIFIC, INC.
815 West 1800 North • Logan, Utah 84321-1784 • (435) 753-2342 • Fax (435) 750-9540
Offices also located in: Australia • Brazil • Canada • England • France • Germany • South Africa • Spain

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AirLink
COMMUNICATIONS

RAVEN

CDMA

> APPLICATIONS

UTILITIES
- Natural Gas Wellhead Monitoring
- C&I Meters
- Transmission Line Flow Meters
- Energy Management Systems

TRANSPORTATION
- Traffic Measurement
- Traffic Control
- Variable Message Signs

ATMOSPHERIC/ENVIRONMENTAL
- Weather Monitoring
- Irrigation Control
- Seismic Monitoring
- Water Level Monitoring

PRIMARY/REDUNDANT CONNECTIVITY
- Automated Teller Machines
- Routers
- Enterprise Servers

> APPLICATION INTERFACES

Standard interfaces include:
- AT command set.
- Host TCP/IP stack communicates with Raven via PPP.
- Windows 95/98/2000/NT/XP Dial Up Networking communicates with Raven using PPP.

> SPECIAL FEATURES

- Class I Div 2 certified
- High speed data transfer rate
- Full duplex transceiver
- Low power consumption
- Proven technology
- Compact size
- Rugged aluminum case
- LEDs show status of network operation
- Optional mounting brackets

The AirLink Raven CDMA is a rugged, intelligent wireless data platform designed to enable real-time, two-way communications with remote assets.

THE ALEOS PLATFORM

The AirLink Embedded Operating System (ALEOS) is the power inside the Raven. ALEOS has its own embedded TCP/IP stack which enables transmission of date from non-IP devices. ALEOS enables several functions including remote configuration and diagnostics, packet assembly and dis-assembly for UDP and TCP, and dynamic IP management. The unique intelligence within ALEOS enables virtually any type of remote device to connect via the public wireless data network.

ALEOS
AirLink Embedded Operating System

FEATURES
- Integrated IP stack
- Standard AT commands
- Remote configuration, downloads, troubleshooting
- Telemetry protocols
- Encryption and security
- Dynamic DNS
- Network Address Translation
- Simple firewall to filter unauthorized IP adresses

BENEFITS
- Common ALEOS code used across all AirLink intelligent devices
- Provides a common experience to customers regardless of the network technology
- Allows customers to migrate to next generation networks with no change to their applications
- Over-the-air updates

WE MAKE WIRELESS DATA WORK

HEAT Equipment Specification Sheets—New

The Multitalented

FLUXUS® ADM 7407 is an ultrasonic flowmeter for permanent installation. The instrument works according to the transit-time principle which makes use of the fact that the speed of propagation of an ultrasonic signal in a flowing medium depends on the flow velocity.

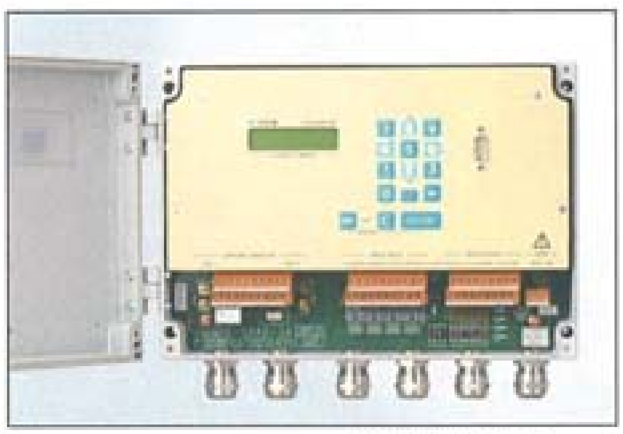
Since the transducers are mounted on the pipe, they are not subject to wear and tear and can be installed rapidly, without cutting into the pipe and without process interruption. The measurement causes no pressure loss. Chemically aggressive media are not a problem; there is no need for expensive materials.

Thanks to its exceptional dual-uP technology, high number of measuring cycles per second and adaptive signal processing, FLUXUS® ADM 7407 produces stable and reliable measuring results even under difficult conditions.

The operation of the flowmeter is especially easy thanks to the clearly structured user dialogue. A status display allows the user to assess application conditions while measuring flow. With the optional software FluxData, you can transfer your measuring data from the flowmeter to a PC, analyse and visualise the measuring results and manage the data files. All this can be done fast and easily thanks to the user-friendly graphical interface.

FLUXUS® ADM 7407 can be equipped with up to 4 process inputs. The input quantities (e.g. temperature or pressure) can be used by FLUXUS together with the measured flow for the calculation of further quantities: heat flow, mass flow, etc.

FLUXUS® ADM 7407



FLUXUS® ADM 7407, opened

Features

- non-invasive flow measurement for permanent installation
- 1 or 2 flow channels
- unique signal processing
- flexible configuration of inputs and outputs
- enhanced status information
- integrated energy calculator and flow calculator

Technical Data

Measurement

Measuring principle:	transit time difference correlation principle
Flow velocity:	(0.01 to 25) m/s
Resolution:	0.025 cm/s
Repeatability:	0.15% of reading ± 0.01 m/s
Accuracy	(for fully developed, rotationally symmetrical flow profile)
- Volume flow:	± 1% to 3% of read. ± 0.01 m/s depending on application ± 0.5% of reading ± 0.01 m/s with process calibration
- Path velocity:	± 0.5% of reading ± 0.01 m/s
Measurable fluids:	all acoustically conductive fluids with < 10% gaseous or solid content in volume

All FLEXIM transducers can be connected to the transmitter. Clamp-on flow transducers are available for a wide diameter range (DN 6 to DN 6500) and for temperatures ranging from -30°C to 400°C (also in explosive atmosphere). The transducers have a degree of protection of IP65 (consult factory for IP68). You will find more information about the transducers in the corresponding specification sheets.

Transmitter

Housing	
- Weight:	approx. 2.8kg
- Deg. of protection:	IP65 acc. to. EN60529
- Material:	Aluminium, powder coated
- Dimensions:	(280 x 200 x 70) mm (WxHxD) without hinges
Flow channels:	1 or 2
Explosion protection in:	zone 2
Power supply:	(100 to 240) VAC (18 to 36) VDC
Display:	2 x 16 characters, dot matrix, backlit
Operating temperature:	-10°C to 60°C
Power consumption:	< 15W
Signal damping:	(0 to 100) s, adjustable
Measuring cycle:	(100 to 1000) Hz (1 channel)
Response time:	1 s (1 channel), 70 ms opt.

Measuring functions

Quantities of measurement:	Volume and mass flow rate, flow velocity, heat flow rate (only if temperature inputs are installed)
Totalizers:	Volume, mass, heat (opt.)
Calculation functions:	Average, difference, sum
Operating languages:	Czech, Danish, Dutch, English, French, German, Norwegian, Polish, Spanish

Data logger

Loggable values:	All measured quantities and totalized values
Capacity:	>100000 meas. values

Communication

Interface:	RS232, RS485 optional
Data:	actual meas. value, logged data, parameter records

Software FluxData (optional)

Function:	Downloading meas. data/parameter records, graphical presentation, conversion to other formats
Operating systems:	All Windows™ versions

Process outputs (optional)

- The outputs are galvanically isolated from the main device.
- The number of outputs that can be installed depends on the output type. Consult FLEXIM for more information.

Current	
- Range:	(0/4 to 20) mA
- Accuracy:	0.1% of reading ± 15µA
- Active output:	R_{ext} < 500 Ω
- Passive output:	U_{ext} < 24V, R_{ext} < 1kΩ
Voltage	
- Range:	(0 to 1) V or (0 to 10) V
- Accuracy:	0 to 1V: 0.1% of reading ± 1 mV 0 to 10V: 0.1% of reading ± 10 mV
- Intr. resistance:	R_i = 500 Ω
Frequency	
- Range:	0 to 1kHz or 0 to 10kHz
- Open collector:	24 V/4 mA
Binary	
- Open collector:	24 V/4 mA
- Reed relay:	48 V/0.1 A
- Function as state output:	limit, sign change or error
- Properties of the pulse output:	Value: (0.01 to 1000) units Width: (1 to 1000) ms

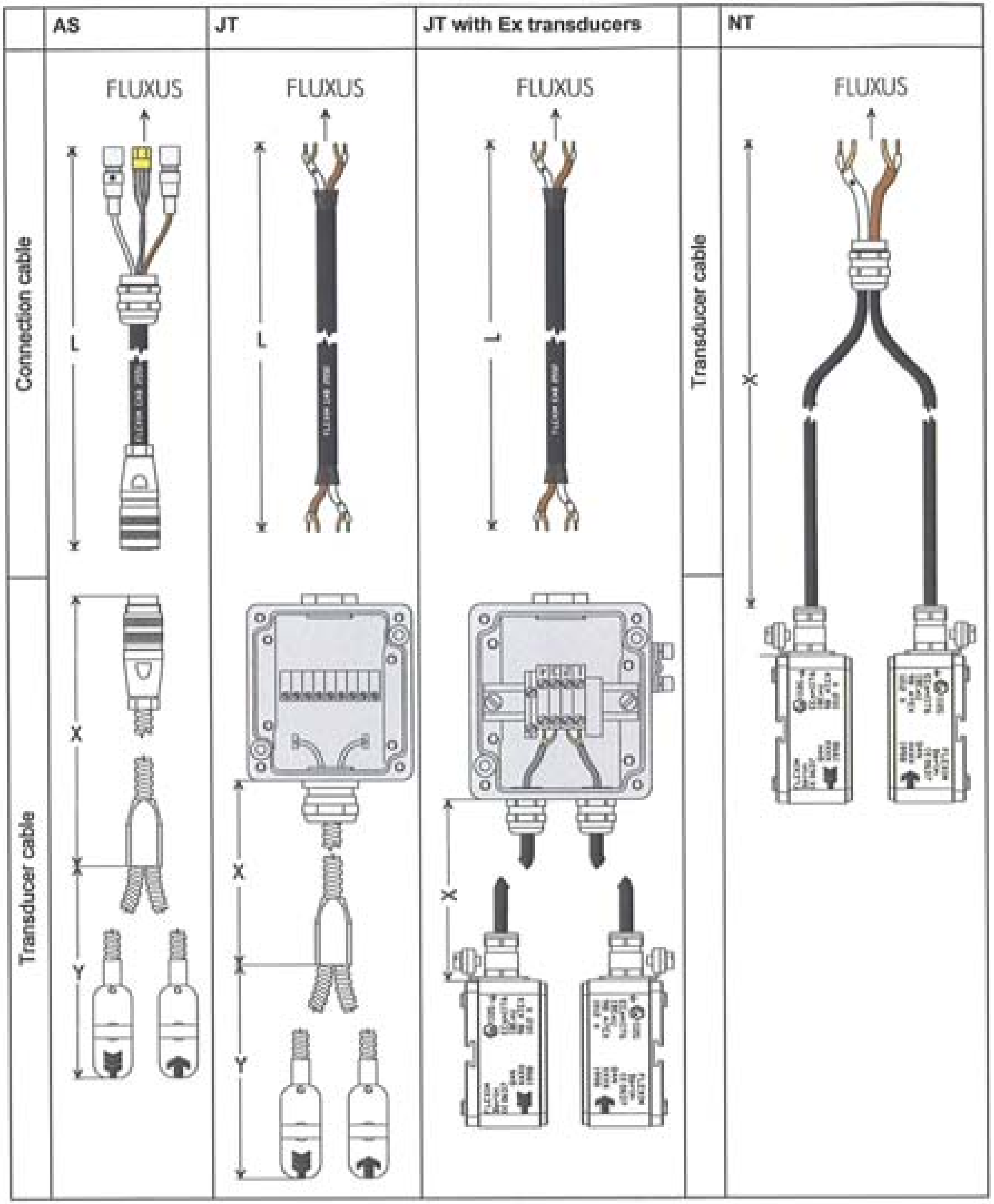
Process inputs (optional)

- The inputs are galvanically isolated from the main device.
- A maximum of 4 inputs can be installed.

Temperature	
- Type:	Pt100 four-wire circuit
- Range:	-50°C to 400°C
- Resolution:	0.1 K
- Accuracy:	± (0.02K + 0.1% of reading)
Current	
- Range:	active: (0 to 20) mA passive input: (-20 to 20) mA
- Accuracy:	0.1% of reading ± 10µA
- Active input:	R_i = 50Ω
- Passive input:	U_{ext} < 24V, R_{ext} < 1kΩ
Voltage	
- Range:	(0 to 1) V or (0 to 10) V
- Accuracy:	0 to 1V: 0.1% of reading ± 1 mV 0 to 10V: 0.1% of reading ± 10 mV
- Intr. resistance:	R_i= 1MΩ

Subject to change without notification.

Connection Types

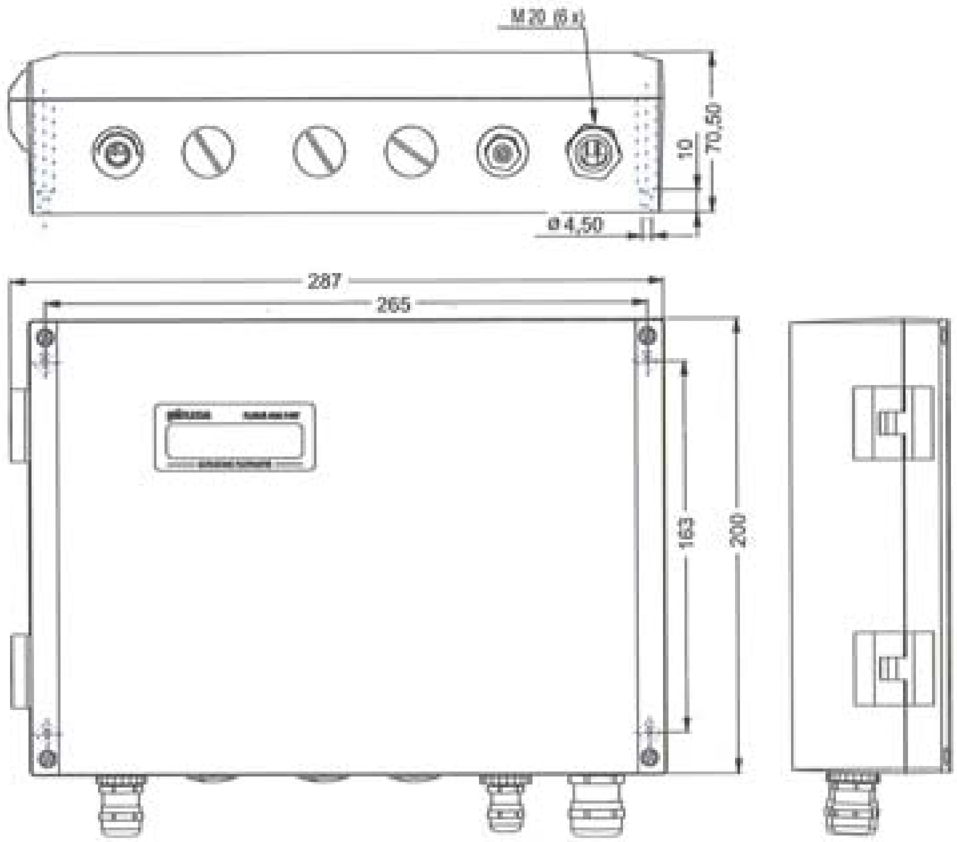


Cable Length

Lengths X and Y of the transducer cable and maximal length of the connection cable as indicated above. All lengths are given in meters.

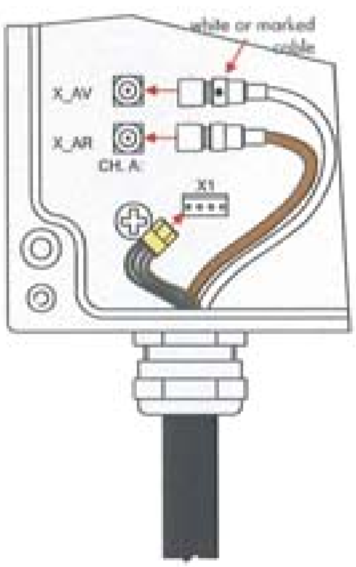
	Connection type AS	Connection type JT
K2	X=2m; Y=2.5m, L=100m (cable type 2551)	X=2 m; Y=2,5m, L=300m (cable type 2552)
K4	X=5 m; Y=7m, L=100m (cable type 2551)	X=5m; Y=7m, L=300m (cable type 2552)
M2	X=2m; Y=2.5m, L=100m (cable type 2551)	X=2m; Y=2.5m, L=300m (cable type 2552)
M3	X=5m; Y=7m, L=100m (cable type 2551)	X=5m; Y=7m, L=300m (cable type 2552)
M4	--	Y=5 m, L=300m (cable type 2552)
Q3	X=2m; Y=1m, L=50m (cable type 2551)	X=2m; Y=1m, L=90m (cable type 2552)
Q4	--	Y=5 m, L=90m (cable type 2552)
S2	X=1m; Y=1m, L=2m (cable type 2551)	X=1 m; Y=1m, L=40m (cable type 2552)

Dimensions of the Housing (in mm)

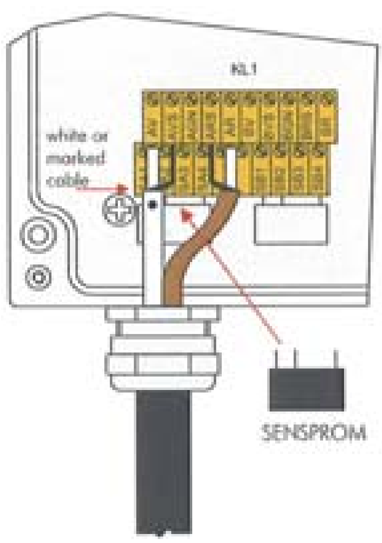


Connection of the Transducers

Connection type AS



Connection type JT



internet: www.flexim.com
e-mail: flexim@flexim.com

FLEXIM GmbH
Wolfener Str. 36
12681 Berlin, Germany
Tel.:+49 (30) 93 66 76 60
Fax:+49 (30) 93 66 76 80

Non-invasive Ultrasonic Flow Measurement with FLUXUS® ADM

Flow transducers of the clamp-on type are mounted onto the pipe instead of inserted into it. They are not in contact with the medium and are therefore ideal for measurement on chemically aggressive, corrosive or ultra-pure media. With the clamp-on technology, retrofitting on existing installation is very easy and can be made without cutting into the pipe and without process interruption.

Q3N transducers, mounted with chains

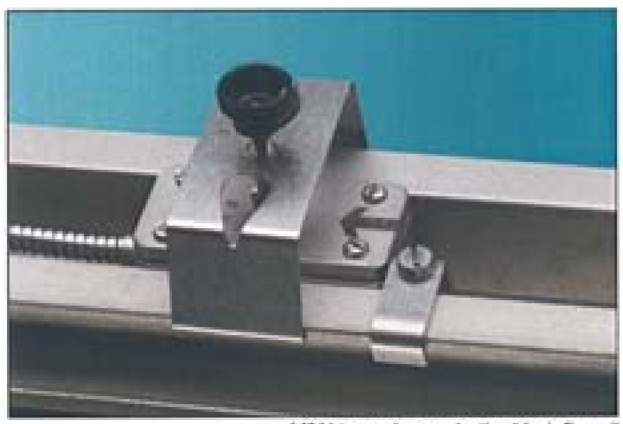
Operating Conditions

Together, the various transducers cover a pipe diameter range from 6 mm to 6500 mm and a temperature range from -30°C to 400°C. The standard versions have a degree of protection IP65. Different types of explosion-proof transducers are also available.

All FLEXIM clamp-on transducers are watertight and suitable for use in harsh industrial environment. With the exception of the explosion-proof transducers, the transducer housings or caps and the transducer cable conduits are made of stainless steel. The robust integrated transducer cables guarantee good measurement results over long periods of extensive use.

Pair Calibrated Transducers

All transducer pairs delivered with the instrument have been wet-flow calibrated at the factory. The calibration, zero offset and other transducer parameters are stored in a transducer-resident non-volatile memory. These intelligent transducers automatically send their data to the instrument upon connection to optimize operation. Parameterisation errors are thus avoided and a zero adjustment is not necessary.



M2N transducers in the Variofix rail

S2N Transducers for Small Pipes

The S2N transducers have been specially designed for flow measurement on pipes of small diameter. They are typically used in hydraulic systems, enamelling lines as well as in ultra-clean water systems.

Features

- wet-flow calibrated transducers
- automatic transducer detection
- watertight stainless steel construction
- no contact with the medium, no risk of corrosion, hygienic measurement, suitable for ultra clean liquids
- low storekeeping costs since only 2 types of transducers are needed to cover the most common pipe sizes
- measurement is independent of fluid conductivity and pressure
- no pressure loss, no risk of leakage

Technical Data

Clamp-On Transducers Type M2N, M2E, M3N

Rated (possible) diameter range*:	M2N, M2E: (50) 100 to 2500mm M3N: (50) 100 to 6500mm
Dimensions:	(60 x 30 x 33.5)mm
Material:	Housing: stainless steel Contact surface: PEEK (M2N) or Polyimide (M2E)
Deg. of protection:	IP65 acc. to EN60529 M2N, M3N: consult factory for IP68
Use in explosive atmosphere	
- Hazard zone:	zone 2
- Marking, M2N:	Ex II3G T6...T4 T_a -30°C...130°C
- Marking, M3N:	Ex II3G T6...T4 T_a -30°C...130°C
- Marking, M2E:	Ex II3G T6...T3 T_a -30°C...200°C

Clamp-On Transducers Type K2N

Rated (possible) diameter range*:	in liquids: (100) 200 to 6500mm
Dimensions:	(126.5 x 50 x 53.5)mm
Material:	PEEK with stainless steel cap
Deg. of protection:	IP65 acc. to EN60529
Use in explosive atmosphere	
- Hazard zone:	zone 2
- Marking:	Ex II3G T6...T4 T_a -30°C...130°C

Clamp-On Transducers Type S2N

Rated (possible) diameter range*:	(6) 10 to 70mm
Dimensions:	(26 x 13 x 15)mm
Material:	Housing: stainless steel Contact surface: Polyetherimide
Deg. of protection:	IP65 acc. to EN60529
Use in explosive atmosphere	
- Hazard zone:	zone 2
- Marking:	Ex II3G T6...T4 T_a -30°C...130°C

Clamp-On Transducers Type Q3N, Q3E

Rated (possible) diameter range*:	(10) 25 to 400mm
Dimensions:	(42.5 x 18 x 21.5)mm
Material:	Housing: stainless steel Contact surface: PEEK (Q3N) or Polyimide (Q3E)
Deg. of protection:	IP65 acc. to EN60529 Q3N: consult factory for IP68
Use in explosive atmosphere	
- Hazard zone:	zone 2
- Marking Q3N:	Ex II3G T6...T4 T_a -30°C...130°C
- Marking Q3E:	Ex II3G T6...T3 T_a -30°C...200°C

Clamp-On Transducers Type M4N, Q4N

Rated (possible) diameter range*:	M4N: (50) 100 to 3000mm Q4N: (10) 25 to 400mm
Dimensions:	(60 x 30 x 33.5)mm
Material:	Housing: stainless steel Contact surface: PEEK
Deg. of protection:	IP65 acc. to EN60529
Use in explosive atmosphere	
- Hazard zone:	zone 1 and 2
- Marking:	CE 0044; Ex II2G EEx m II T6...T4 T_a -20°C...120°C
- Certification:	IBExU 98 ATEX 1012 X
- Type of protection:	Encapsulation

Clamp-On Transducers Type K4N Ex-A, K4N Ex-Z**

Rated (possible) diameter range*:	in liquids: (100) 200 to 6500mm
Dimensions:	K4N Ex-A: (126.5 x 50 x 53.5)mm K4N Ex-Z: (126.5 x 47 x 53.5)mm
Material:	PEEK with stainless steel cap
Deg. of protection:	IP65 acc. to EN60529
Use in explosive atmosphere	
- Hazard zone:	zone 1 and 2
- Marking:	CE 0044; Ex II2G EEx q II T6...T3 T_a -30°C...180°C
- Certification:	IBExU 04 ATEX 1011 X
- Type of protection:	Powder filling

*: The range specified in parenthesis is the range in which measurement might be possible under good conditions, but for which FLEXIM gives no specification.

**: The transducers K4N Ex-Z must always be used in the mounting fixture with which they were delivered in order to protect them against mechanical stress.

Subject to change without notification.

Operating Temperature and Explosion Protection Temperature of the Transducers

Operating temperature					
	M2N, M3N, Q3N, S2N	M2E, Q3E	K2N	Q4N, M4N, P4N	K4N
Process:	-30°C ... 130°C	-30°C ... 200°C, for short periods 300°C	-30°C ... 130°C	-30°C ... 130°C	-30°C ... 130°C
Ambient:	-30°C ... 130°C	-30°C ... 200°C, for short periods 300°C	-30°C ... 130°C	-30°C ... 130°C	-30°C ... 130°C

Explosion protection temperature					
	M2N, M3N, Q3N, S2N	M2E, Q3E	K2N	Q4N, M4N, P4N	K4N
Explosion protection in:	zone 2	zone 2	zone 2	zone 2 and 1	zone 2 and 1
Temperature class T3	--	-30°C ... 190°C	--	--	-30°C ... 180°C
Temperature class T4	-30°C ... 120°C	-30°C ... 125°C	-30°C ... 120°C	-20°C ... 120°C	-30°C ... 125°C
Temperature class T5	-30°C ... 90°C	-30°C ... 90°C	-30°C ... 90°C	-20°C ... 90°C	-30°C ... 90°C
Temperature class T6	-30°C ... 75°C	-30°C ... 75°C	-30°C ... 75°C	-20°C ... 75°C	-30°C ... 75°C

Note: With the WaveInjector®, the temperature range of nearly every transducer can be extended up to 400°C. You will find more information about the WaveInjector in the corresponding specification sheet.

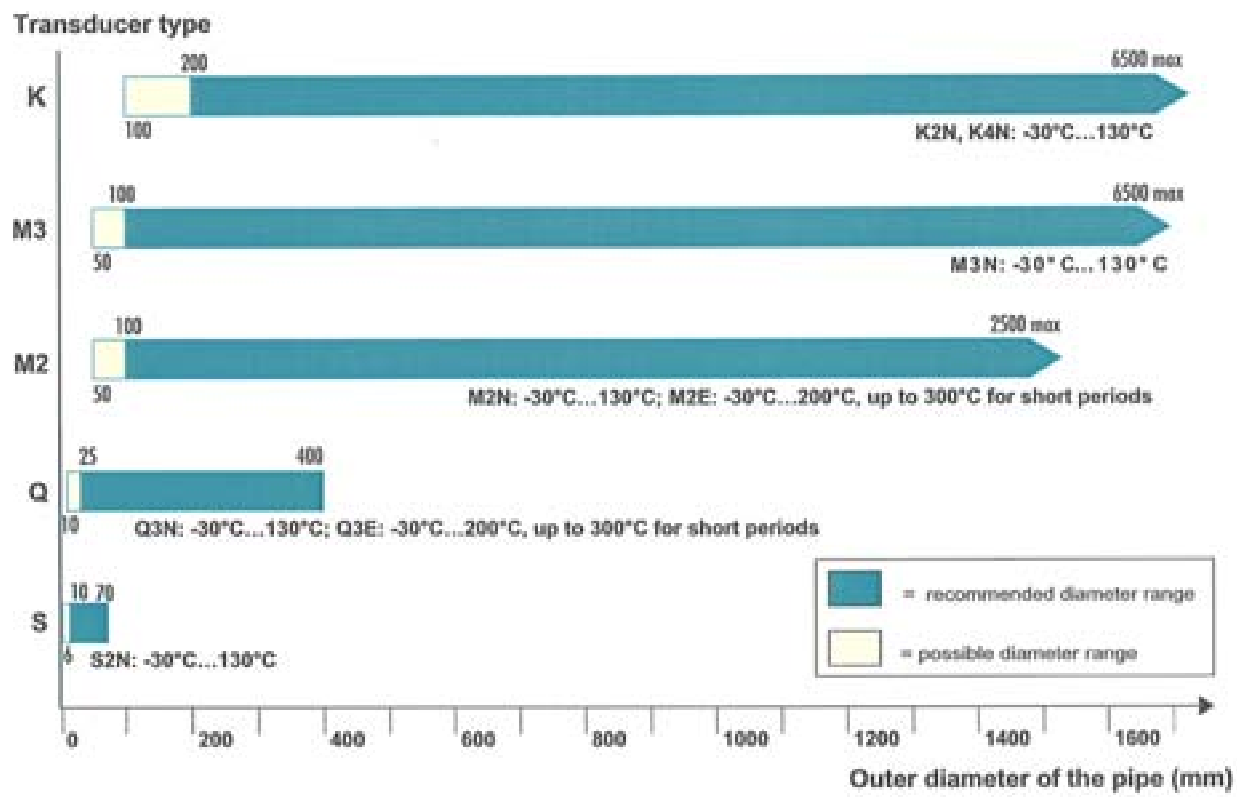
Diameter Range and Operating Temperature Range of the Transducers

The **recommended diameter range** is the diameter range covered by a transducer under normal measuring conditions (signal damping mainly through fluid, no gas or solid in the fluid).

The **possible diameter range** is the diameter range covered by a transducer under good measuring conditions.

The specified temperature range is the **range of possible process temperatures** at which the transducers can be operated. The range of possible ambient temperatures is identical.

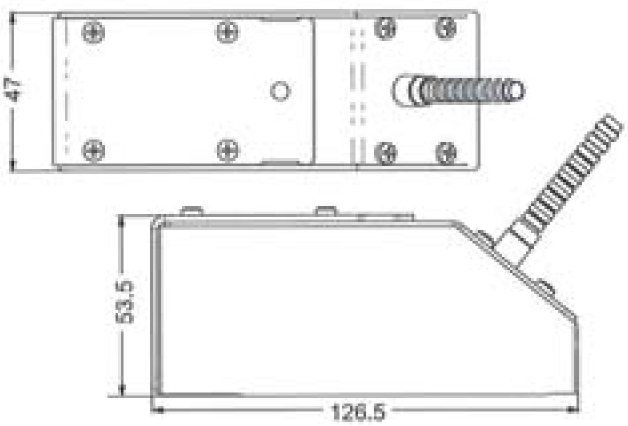
Note: With the WaveInjector®, the temperature range of nearly every transducer can be extended up to 400°C. You will find more information about the WaveInjector in the corresponding specification sheet.



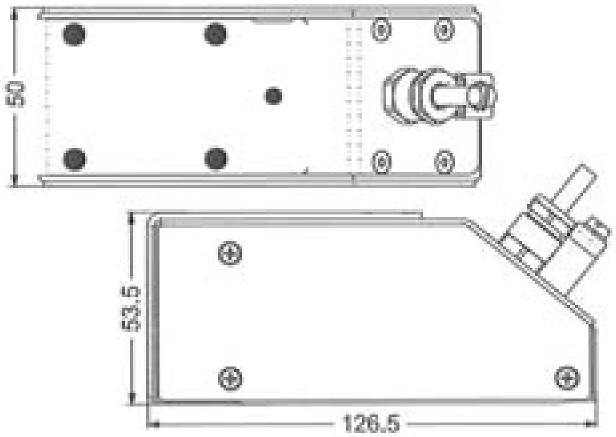
Subject to change without notification.

Dimensions (in mm)

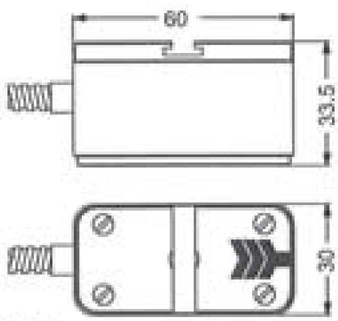
K2N



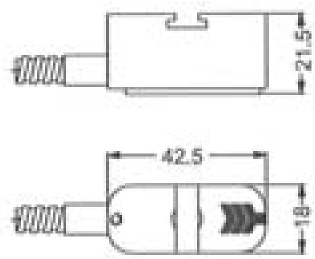
K4N Ex-A



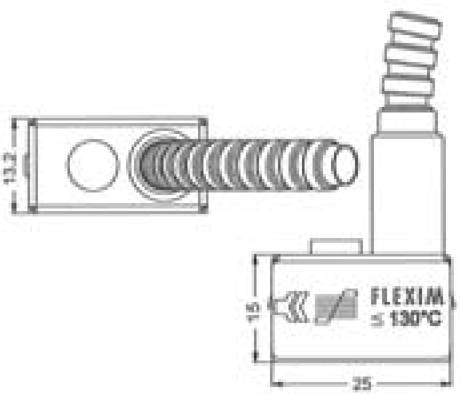
M2N, M2E, M3N



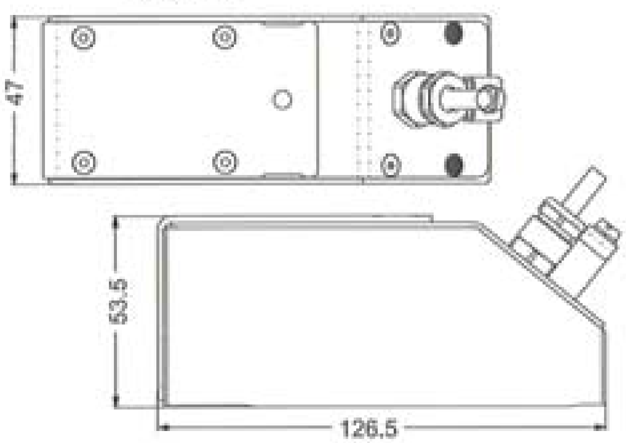
Q3N, Q3E



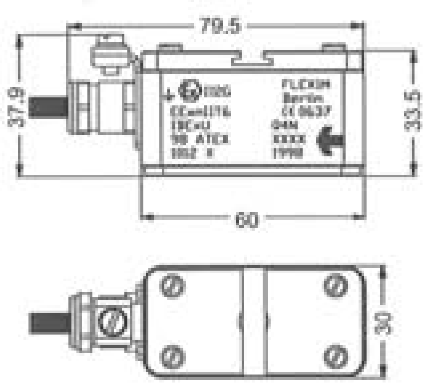
S2N



K4N Ex-Z



Q4N Ex, M4N Ex



internet: www.flexim.com
e-mail: flexim@flexim.com

FLEXIM GmbH
Wolfener Str. 36
12681 Berlin, Germany
Tel.:+49 (30) 93 66 76 60
Fax:+49 (30) 93 66 76 80

"Bolt-On" Washer Thermocouple Assemblies
WT

Features

- **New Rugged Design**
- **For #6, #8, #10 and 1⁄4" Screw Sizes**
- **Made from 20 AWG Glass-On-Glass or Teflon® Insulated Special Limits of Error Wire**
- **Stocked in 12, 24, 36 and 60" Lengths with Stripped End Leads**
- **Rated to 480°C (900°F)**

Washer Dimensions
#6 and #8 screw size: 0.875" L x 0.250" W
#10 and 1/4" screw size: 1" L x 0.360" W

To Order (Specify Model No.) *Prices Shown in U.S. Dollars*

Model No. 12" L $8.00 each	Model No. 24" L $9.00 each	Model No. 36" L $10.00 each	Model No. 60" L $12.00 each	Washer Hole Diameter	Nominal Screw Size	
					American	Metric
WT(*)-6-12	WT(*)-6-24	WT(*)-6-36	WT(*)-6-60	0.145"	#6	M3.5
WT(*)-8-12	WT(*)-8-24	WT(*)-8-36	WT(*)-8-60	0.170"	#8	M4
WT(*)-10-12	WT(*)-10-24	WT(*)-10-36	WT(*)-10-60	0.195"	#10	M4.5
WT(*)-14-12	WT(*)-14-24	WT(*)-14-36	WT(*)-14-60	0.260"	1/4"	M6

***Specify calibration:** J, K, T or E. Stripped leads are standard.
To order other terminations, add suffix "**L**" for #10 spade lugs ($4 add'l), "**M**" for OST male connector ($4 add'l), or "F" for OST female connector ($5 add'l). To order with lead lengths over 60", change "60" in model number to desired length in inches, and add $1 per add'l. foot to the 60" price.
To order with Teflon insulated lead wires, add suffix "**-TT**" to model no. No additional cost.
Example: WTK-14-12-TT, 1/4" washer probe, type K, 12" length, stripped leads, Teflon insulated wire, $8.
Ordering Example: WTK-6-12, washer thermocouple, type K, #6 screw, 12" length. glass braid insulated wire, **$8**

Heavy-Duty Armored Style - WT

Features

- **6 ft. 304 Stainless Steel Armor Cable**
- **Available with Stripped Leads or OSTW Connector**
- **0.275" Flexible Cable O.D. U 0.260" Washer I.D.**

Rugged thermocouple, for surface mount applications, has a washer mounting surface and an overall dimension of 0.680" O.D., with a 0.260" mounting hole of 304 SS material. Attached to the mounting surface: 6' of 304 SS flexible armor cable with stripped wire ends. Armor cable has 0.275" O.D., with 0.070" washer thickness. Standard male connectors are available for cold-end termination. Rated to

480°C (900°F).

Calibrations			
J =	**K =**	**T =**	**E =**
Iron-Constantan	**CHROMEGA®-ALOMEGA®**	**Copper Constantan**	**CHROMEGA®-Constantan**

Model No.	Termination	Price
WT(*)-HD-72-S	Stripped leads	**$23**
WT(*)-HD-72-OSTW-M	OSTW connector	**$29**

***Specify calibration:** J, K, T or E.
Ordering Example: **WTK-HD-72-S,** heavy duty washer thermocouple, type K, 72" cable, with stripped leads, **$23**

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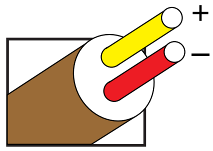
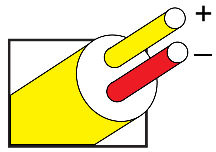
MAXIMUM TEMPERATURE RANGE
Thermocouple Grade
– 328 to 2282°F
– 200 to 1250°C
Extension Grade
32 to 392°F
0 to 200°C
LIMITS OF ERROR
(whichever is greater)
Standard: 2.2°C or 0.75% Above 0°C
2.2°C or 2.0% Below 0°C
Special: 1.1°C or 0.4%
COMMENTS, BARE WIRE ENVIRONMENT:
Clean Oxidizing and Inert; Limited Use in Vacuum or Reducing; Wide Temperature Range; Most Popular Calibration
TEMPERATURE IN DEGREES °F
REFERENCE JUNCTION AT 32°F



Thermocouple Grade

Nickel-Chromium vs. Nickel-Aluminum



Extension Grade

Revised Thermocouple Reference Tables

TYPE K

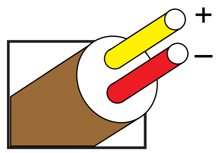
Reference Tables N.I.S.T. Monograph 175 Revised to ITS-90

Thermoelectric Voltage in Millivolts

°F	-10	-9	-8	-7	-6	-5	-4	-3	-2	-1	0	°F
-450							-6.458	-6.457	-6.457	-6.456	-6.456	-450
-440	-6.456	-6.455	-6.454	-6.454	-6.453	-6.452	-6.451	-6.450	-6.449	-6.448	-6.446	-440
-430	-6.446	-6.445	-6.444	-6.443	-6.441	-6.440	-6.438	-6.436	-6.435	-6.433	-6.431	-430
-420	-6.431	-6.429	-6.427	-6.425	-6.423	-6.421	-6.419	-6.416	-6.414	-6.411	-6.409	-420
-410	-6.409	-6.406	-6.404	-6.401	-6.398	-6.395	-6.392	-6.389	-6.386	-6.383	-6.380	-410
-400	-6.380	-6.377	-6.373	-6.370	-6.366	-6.363	-6.359	-6.355	-6.352	-6.348	-6.344	-400
-390	-6.344	-6.340	-6.336	-6.332	-6.328	-6.323	-6.319	-6.315	-6.310	-6.306	-6.301	-390
-380	-6.301	-6.296	-6.292	-6.287	-6.282	-6.277	-6.272	-6.267	-6.262	-6.257	-6.251	-380
-370	-6.251	-6.246	-6.241	-6.235	-6.230	-6.224	-6.218	-6.213	-6.207	-6.201	-6.195	-370
-360	-6.195	-6.189	-6.183	-6.177	-6.171	-6.165	-6.158	-6.152	-6.146	-6.139	-6.133	-360
-350	-6.133	-6.126	-6.119	-6.113	-6.106	-6.099	-6.092	-6.085	-6.078	-6.071	-6.064	-350
-340	-6.064	-6.057	-6.049	-6.042	-6.035	-6.027	-6.020	-6.012	-6.004	-5.997	-5.989	-340
-330	-5.989	-5.981	-5.973	-5.965	-5.957	-5.949	-5.941	-5.933	-5.925	-5.917	-5.908	-330
-320	-5.908	-5.900	-5.891	-5.883	-5.874	-5.866	-5.857	-5.848	-5.840	-5.831	-5.822	-320
-310	-5.822	-5.813	-5.804	-5.795	-5.786	-5.776	-5.767	-5.758	-5.749	-5.739	-5.730	-310
-300	-5.730	-5.720	-5.711	-5.701	-5.691	-5.682	-5.672	-5.662	-5.652	-5.642	-5.632	-300
-290	-5.632	-5.622	-5.612	-5.602	-5.592	-5.581	-5.571	-5.561	-5.550	-5.540	-5.529	-290
-280	-5.529	-5.519	-5.508	-5.497	-5.487	-5.476	-5.465	-5.454	-5.443	-5.432	-5.421	-280
-270	-5.421	-5.410	-5.399	-5.388	-5.377	-5.365	-5.354	-5.343	-5.331	-5.320	-5.308	-270
-260	-5.308	-5.296	-5.285	-5.273	-5.261	-5.250	-5.238	-5.226	-5.214	-5.202	-5.190	-260
-250	-5.190	-5.178	-5.166	-5.153	-5.141	-5.129	-5.117	-5.104	-5.092	-5.079	-5.067	-250
-240	-5.067	-5.054	-5.042	-5.029	-5.016	-5.003	-4.991	-4.978	-4.965	-4.952	-4.939	-240
-230	-4.939	-4.926	-4.913	-4.900	-4.886	-4.873	-4.860	-4.847	-4.833	-4.820	-4.806	-230
-220	-4.806	-4.793	-4.779	-4.766	-4.752	-4.738	-4.724	-4.711	-4.697	-4.683	-4.669	-220
-210	-4.669	-4.655	-4.641	-4.627	-4.613	-4.599	-4.584	-4.570	-4.556	-4.542	-4.527	-210
-200	-4.527	-4.513	-4.498	-4.484	-4.469	-4.455	-4.440	-4.425	-4.411	-4.396	-4.381	-200
-190	-4.381	-4.366	-4.351	-4.336	-4.321	-4.306	-4.291	-4.276	-4.261	-4.246	-4.231	-190
-180	-4.231	-4.215	-4.200	-4.185	-4.169	-4.154	-4.138	-4.123	-4.107	-4.091	-4.076	-180
-170	-4.076	-4.060	-4.044	-4.029	-4.013	-3.997	-3.981	-3.965	-3.949	-3.933	-3.917	-170
-160	-3.917	-3.901	-3.885	-3.869	-3.852	-3.836	-3.820	-3.803	-3.787	-3.771	-3.754	-160
-150	-3.754	-3.738	-3.721	-3.705	-3.688	-3.671	-3.655	-3.638	-3.621	-3.604	-3.587	-150
-140	-3.587	-3.571	-3.554	-3.537	-3.520	-3.503	-3.486	-3.468	-3.451	-3.434	-3.417	-140
-130	-3.417	-3.400	-3.382	-3.365	-3.348	-3.330	-3.313	-3.295	-3.278	-3.260	-3.243	-130
-120	-3.243	-3.225	-3.207	-3.190	-3.172	-3.154	-3.136	-3.119	-3.101	-3.083	-3.065	-120
-110	-3.065	-3.047	-3.029	-3.011	-2.993	-2.975	-2.957	-2.938	-2.920	-2.902	-2.884	-110
-100	-2.884	-2.865	-2.847	-2.829	-2.810	-2.792	-2.773	-2.755	-2.736	-2.718	-2.699	-100
-90	-2.699	-2.680	-2.662	-2.643	-2.624	-2.605	-2.587	-2.568	-2.549	-2.530	-2.511	-90
-80	-2.511	-2.492	-2.473	-2.454	-2.435	-2.416	-2.397	-2.378	-2.359	-2.339	-2.320	-80
-70	-2.320	-2.301	-2.282	-2.262	-2.243	-2.223	-2.204	-2.185	-2.165	-2.146	-2.126	-70
-60	-2.126	-2.106	-2.087	-2.067	-2.048	-2.028	-2.008	-1.988	-1.969	-1.949	-1.929	-60
-50	-1.929	-1.909	-1.889	-1.869	-1.850	-1.830	-1.810	-1.790	-1.770	-1.749	-1.729	-50
-40	-1.729	-1.709	-1.689	-1.669	-1.649	-1.628	-1.608	-1.588	-1.568	-1.547	-1.527	-40
-30	-1.527	-1.507	-1.486	-1.466	-1.445	-1.425	-1.404	-1.384	-1.363	-1.343	-1.322	-30
-20	-1.322	-1.301	-1.281	-1.260	-1.239	-1.218	-1.198	-1.177	-1.156	-1.135	-1.114	-20
-10	-1.114	-1.094	-1.073	-1.052	-1.031	-1.010	-0.989	-0.968	-0.947	-0.926	-0.905	-10
0	-0.905	-0.883	-0.862	-0.841	-0.820	-0.799	-0.778	-0.756	-0.735	-0.714	-0.692	0
0	-0.692	-0.671	-0.650	-0.628	-0.607	-0.586	-0.564	-0.543	-0.521	-0.500	-0.478	0
10	-0.478	-0.457	-0.435	-0.413	-0.392	-0.370	-0.349	-0.327	-0.305	-0.284	-0.262	10
20	-0.262	-0.240	-0.218	-0.197	-0.175	-0.153	-0.131	-0.109	-0.088	-0.066	-0.044	20
30	-0.044	-0.022	0.000	0.022	0.044	0.066	0.088	0.110	0.132	0.154	0.176	30
40	0.176	0.198	0.220	0.242	0.264	0.286	0.308	0.330	0.353	0.375	0.397	40
50	0.397	0.419	0.441	0.463	0.486	0.508	0.530	0.552	0.575	0.597	0.619	50
60	0.619	0.642	0.664	0.686	0.709	0.731	0.753	0.776	0.798	0.821	0.843	60
70	0.843	0.865	0.888	0.910	0.933	0.955	0.978	1.000	1.023	1.045	1.068	70
80	1.068	1.090	1.113	1.136	1.158	1.181	1.203	1.226	1.249	1.271	1.294	80
90	1.294	1.316	1.339	1.362	1.384	1.407	1.430	1.453	1.475	1.498	1.521	90
°F	0	1	2	3	4	5	6	7	8	9	10	°F

°F	0	1	2	3	4	5	6	7	8	9	10	°F
100	1.521	1.543	1.566	1.589	1.612	1.635	1.657	1.680	1.703	1.726	1.749	100
110	1.749	1.771	1.794	1.817	1.840	1.863	1.886	1.909	1.931	1.954	1.977	110
120	1.977	2.000	2.023	2.046	2.069	2.092	2.115	2.138	2.161	2.184	2.207	120
130	2.207	2.230	2.253	2.276	2.298	2.321	2.344	2.367	2.390	2.413	2.436	130
140	2.436	2.459	2.483	2.506	2.529	2.552	2.575	2.598	2.621	2.644	2.667	140
150	2.667	2.690	2.713	2.736	2.759	2.782	2.805	2.828	2.851	2.874	2.897	150
160	2.897	2.920	2.944	2.967	2.990	3.013	3.036	3.059	3.082	3.105	3.128	160
170	3.128	3.151	3.174	3.197	3.220	3.244	3.267	3.290	3.313	3.336	3.359	170
180	3.359	3.382	3.405	3.428	3.451	3.474	3.497	3.520	3.544	3.567	3.590	180
190	3.590	3.613	3.636	3.659	3.682	3.705	3.728	3.751	3.774	3.797	3.820	190
200	3.820	3.843	3.866	3.889	3.912	3.935	3.958	3.981	4.004	4.027	4.050	200
210	4.050	4.073	4.096	4.119	4.142	4.165	4.188	4.211	4.234	4.257	4.280	210
220	4.280	4.303	4.326	4.349	4.372	4.395	4.417	4.440	4.463	4.486	4.509	220
230	4.509	4.532	4.555	4.578	4.601	4.623	4.646	4.669	4.692	4.715	4.738	230
240	4.738	4.760	4.783	4.806	4.829	4.852	4.874	4.897	4.920	4.943	4.965	240
250	4.965	4.988	5.011	5.034	5.056	5.079	5.102	5.124	5.147	5.170	5.192	250
260	5.192	5.215	5.238	5.260	5.283	5.306	5.328	5.351	5.374	5.396	5.419	260
270	5.419	5.441	5.464	5.487	5.509	5.532	5.554	5.577	5.599	5.622	5.644	270
280	5.644	5.667	5.690	5.712	5.735	5.757	5.779	5.802	5.824	5.847	5.869	280
290	5.869	5.892	5.914	5.937	5.959	5.982	6.004	6.026	6.049	6.071	6.094	290
300	6.094	6.116	6.138	6.161	6.183	6.205	6.228	6.250	6.272	6.295	6.317	300
310	6.317	6.339	6.362	6.384	6.406	6.429	6.451	6.473	6.496	6.518	6.540	310
320	6.540	6.562	6.585	6.607	6.629	6.652	6.674	6.696	6.718	6.741	6.763	320
330	6.763	6.785	6.807	6.829	6.852	6.874	6.896	6.918	6.941	6.963	6.985	330
340	6.985	7.007	7.029	7.052	7.074	7.096	7.118	7.140	7.163	7.185	7.207	340
350	7.207	7.229	7.251	7.273	7.296	7.318	7.340	7.362	7.384	7.407	7.429	350
360	7.429	7.451	7.473	7.495	7.517	7.540	7.562	7.584	7.606	7.628	7.650	360
370	7.650	7.673	7.695	7.717	7.739	7.761	7.783	7.806	7.828	7.850	7.872	370
380	7.872	7.894	7.917	7.939	7.961	7.983	8.005	8.027	8.050	8.072	8.094	380
390	8.094	8.116	8.138	8.161	8.183	8.205	8.227	8.250	8.272	8.294	8.316	390
400	8.316	8.338	8.361	8.383	8.405	8.427	8.450	8.472	8.494	8.516	8.539	400
410	8.539	8.561	8.583	8.605	8.628	8.650	8.672	8.694	8.717	8.739	8.761	410
420	8.761	8.784	8.806	8.828	8.851	8.873	8.895	8.918	8.940	8.962	8.985	420
430	8.985	9.007	9.029	9.052	9.074	9.096	9.119	9.141	9.163	9.186	9.208	430
440	9.208	9.231	9.253	9.275	9.298	9.320	9.343	9.365	9.388	9.410	9.432	440
450	9.432	9.455	9.477	9.500	9.522	9.545	9.567	9.590	9.612	9.635	9.657	450
460	9.657	9.680	9.702	9.725	9.747	9.770	9.792	9.815	9.837	9.860	9.882	460
470	9.882	9.905	9.927	9.950	9.973	9.995	10.018	10.040	10.063	10.086	10.108	470
480	10.108	10.131	10.153	10.176	10.199	10.221	10.244	10.267	10.289	10.312	10.334	480
490	10.334	10.357	10.380	10.402	10.425	10.448	10.471	10.493	10.516	10.539	10.561	490
500	10.561	10.584	10.607	10.629	10.652	10.675	10.698	10.720	10.743	10.766	10.789	500
510	10.789	10.811	10.834	10.857	10.880	10.903	10.925	10.948	10.971	10.994	11.017	510
520	11.017	11.039	11.062	11.085	11.108	11.131	11.154	11.176	11.199	11.222	11.245	520
530	11.245	11.268	11.291	11.313	11.336	11.359	11.382	11.405	11.428	11.451	11.474	530
540	11.474	11.497	11.519	11.542	11.565	11.588	11.611	11.634	11.657	11.680	11.703	540
550	11.703	11.726	11.749	11.772	11.795	11.818	11.841	11.864	11.887	11.910	11.933	550
560	11.933	11.956	11.978	12.001	12.024	12.047	12.070	12.093	12.116	12.140	12.163	560
570	12.163	12.186	12.209	12.232	12.255	12.278	12.301	12.324	12.347	12.370	12.393	570
580	12.393	12.416	12.439	12.462	12.485	12.508	12.531	12.554	12.577	12.600	12.624	580
590	12.624	12.647	12.670	12.693	12.716	12.739	12.762	12.785	12.808	12.831	12.855	590
600	12.855	12.878	12.901	12.924	12.947	12.970	12.993	13.016	13.040	13.063	13.086	600
610	13.086	13.109	13.132	13.155	13.179	13.202	13.225	13.248	13.271	13.294	13.318	610
620	13.318	13.341	13.364	13.387	13.410	13.433	13.457	13.480	13.503	13.526	13.549	620
630	13.549	13.573	13.596	13.619	13.642	13.665	13.689	13.712	13.735	13.758	13.782	630
640	13.782	13.805	13.828	13.851	13.874	13.898	13.921	13.944	13.967	13.991	14.014	640
650	14.014	14.037	14.060	14.084	14.107	14.130	14.154	14.177	14.200	14.223	14.247	650
660	14.247	14.270	14.293	14.316	14.340	14.363	14.386	14.410	14.433	14.456	14.479	660
670	14.479	14.503	14.526	14.549	14.573	14.596	14.619	14.643	14.666	14.689	14.713	670
680	14.713	14.736	14.759	14.783	14.806	14.829	14.853	14.876	14.899	14.923	14.946	680
690	14.946	14.969	14.993	15.016	15.039	15.063	15.086	15.109	15.133	15.156	15.179	690
°F	0	1	2	3	4	5	6	7	8	9	10	°F

Revised Thermocouple Reference Tables

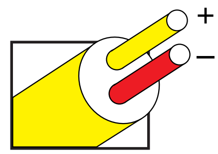


Thermocouple Grade

TYPE K

Reference Tables N.I.S.T. Monograph 175 Revised to ITS-90

Nickel-Chromium vs. Nickel-Aluminum



Extension Grade

MAXIMUM TEMPERATURE RANGE

Thermocouple Grade
– 328 to 2282°F
– 200 to 1250°C

Extension Grade
32 to 392°F
0 to 200°C

LIMITS OF ERROR
(whichever is greater)
Standard: 2.2°C or 0.75% Above 0°C
2.2°C or 2.0% Below 0°C
Special: 1.1°C or 0.4%

COMMENTS, BARE WIRE ENVIRONMENT:
Clean Oxidizing and Inert; Limited Use in Vacuum or Reducing; Wide Temperature Range; Most Popular Calibration

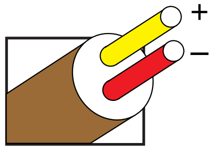
TEMPERATURE IN DEGREES °F
REFERENCE JUNCTION AT 32°F

Thermoelectric Voltage in Millivolts

°F	0	1	2	3	4	5	6	7	8	9	10	°F
700	15.179	15.203	15.226	15.250	15.273	15.296	15.320	15.343	15.366	15.390	15.413	700
710	15.413	15.437	15.460	15.483	15.507	15.530	15.554	15.577	15.600	15.624	15.647	710
720	15.647	15.671	15.694	15.717	15.741	15.764	15.788	15.811	15.834	15.858	15.881	720
730	15.881	15.905	15.928	15.952	15.975	15.998	16.022	16.045	16.069	16.092	16.116	730
740	16.116	16.139	16.163	16.186	16.209	16.233	16.256	16.280	16.303	16.327	16.350	740
750	16.350	16.374	16.397	16.421	16.444	16.468	16.491	16.514	16.538	16.561	16.585	750
760	16.585	16.608	16.632	16.655	16.679	16.702	16.726	16.749	16.773	16.796	16.820	760
770	16.820	16.843	16.867	16.890	16.914	16.937	16.961	16.984	17.008	17.031	17.055	770
780	17.055	17.078	17.102	17.125	17.149	17.173	17.196	17.220	17.243	17.267	17.290	780
790	17.290	17.314	17.337	17.361	17.384	17.408	17.431	17.455	17.478	17.502	17.526	790
800	17.526	17.549	17.573	17.596	17.620	17.643	17.667	17.690	17.714	17.738	17.761	800
810	17.761	17.785	17.808	17.832	17.855	17.879	17.902	17.926	17.950	17.973	17.997	810
820	17.997	18.020	18.044	18.068	18.091	18.115	18.138	18.162	18.185	18.209	18.233	820
830	18.233	18.256	18.280	18.303	18.327	18.351	18.374	18.398	18.421	18.445	18.469	830
840	18.469	18.492	18.516	18.539	18.563	18.587	18.610	18.634	18.657	18.681	18.705	840
850	18.705	18.728	18.752	18.776	18.799	18.823	18.846	18.870	18.894	18.917	18.941	850
860	18.941	18.965	18.988	19.012	19.035	19.059	19.083	19.106	19.130	19.154	19.177	860
870	19.177	19.201	19.224	19.248	19.272	19.295	19.319	19.343	19.366	19.390	19.414	870
880	19.414	19.437	19.461	19.485	19.508	19.532	19.556	19.579	19.603	19.626	19.650	880
890	19.650	19.674	19.697	19.721	19.745	19.768	19.792	19.816	19.839	19.863	19.887	890
900	19.887	19.910	19.934	19.958	19.981	20.005	20.029	20.052	20.076	20.100	20.123	900
910	20.123	20.147	20.171	20.194	20.218	20.242	20.265	20.289	20.313	20.336	20.360	910
920	20.360	20.384	20.407	20.431	20.455	20.479	20.502	20.526	20.550	20.573	20.597	920
930	20.597	20.621	20.644	20.668	20.692	20.715	20.739	20.763	20.786	20.810	20.834	930
940	20.834	20.857	20.881	20.905	20.929	20.952	20.976	21.000	21.023	21.047	21.071	940
950	21.071	21.094	21.118	21.142	21.165	21.189	21.213	21.236	21.260	21.284	21.308	950
960	21.308	21.331	21.355	21.379	21.402	21.426	21.450	21.473	21.497	21.521	21.544	960
970	21.544	21.568	21.592	21.616	21.639	21.663	21.687	21.710	21.734	21.758	21.781	970
980	21.781	21.805	21.829	21.852	21.876	21.900	21.924	21.947	21.971	21.995	22.018	980
990	22.018	22.042	22.066	22.089	22.113	22.137	22.160	22.184	22.208	22.232	22.255	990
1000	22.255	22.279	22.303	22.326	22.350	22.374	22.397	22.421	22.445	22.468	22.492	1000
1010	22.492	22.516	22.540	22.563	22.587	22.611	22.634	22.658	22.682	22.705	22.729	1010
1020	22.729	22.753	22.776	22.800	22.824	22.847	22.871	22.895	22.919	22.942	22.966	1020
1030	22.966	22.990	23.013	23.037	23.061	23.084	23.108	23.132	23.155	23.179	23.203	1030
1040	23.203	23.226	23.250	23.274	23.297	23.321	23.345	23.368	23.392	23.416	23.439	1040
1050	23.439	23.463	23.487	23.510	23.534	23.558	23.581	23.605	23.629	23.652	23.676	1050
1060	23.676	23.700	23.723	23.747	23.771	23.794	23.818	23.842	23.865	23.889	23.913	1060
1070	23.913	23.936	23.960	23.984	24.007	24.031	24.055	24.078	24.102	24.126	24.149	1070
1080	24.149	24.173	24.197	24.220	24.244	24.267	24.291	24.315	24.338	24.362	24.386	1080
1090	24.386	24.409	24.433	24.457	24.480	24.504	24.527	24.551	24.575	24.598	24.622	1090
1100	24.622	24.646	24.669	24.693	24.717	24.740	24.764	24.787	24.811	24.835	24.858	1100
1110	24.858	24.882	24.905	24.929	24.953	24.976	25.000	25.024	25.047	25.071	25.094	1110
1120	25.094	25.118	25.142	25.165	25.189	25.212	25.236	25.260	25.283	25.307	25.330	1120
1130	25.330	25.354	25.377	25.401	25.425	25.448	25.472	25.495	25.519	25.543	25.566	1130
1140	25.566	25.590	25.613	25.637	25.660	25.684	25.708	25.731	25.755	25.778	25.802	1140
1150	25.802	25.825	25.849	25.873	25.896	25.920	25.943	25.967	25.990	26.014	26.037	1150
1160	26.037	26.061	26.084	26.108	26.132	26.155	26.179	26.202	26.226	26.249	26.273	1160
1170	26.273	26.296	26.320	26.343	26.367	26.390	26.414	26.437	26.461	26.484	26.508	1170
1180	26.508	26.532	26.555	26.579	26.602	26.626	26.649	26.673	26.696	26.720	26.743	1180
1190	26.743	26.767	26.790	26.814	26.837	26.861	26.884	26.907	26.931	26.954	26.978	1190
1200	26.978	27.001	27.025	27.048	27.072	27.095	27.119	27.142	27.166	27.189	27.213	1200
1210	27.213	27.236	27.259	27.283	27.306	27.330	27.353	27.377	27.400	27.424	27.447	1210
1220	27.447	27.471	27.494	27.517	27.541	27.564	27.588	27.611	27.635	27.658	27.681	1220
1230	27.681	27.705	27.728	27.752	27.775	27.798	27.822	27.845	27.869	27.892	27.915	1230
1240	27.915	27.939	27.962	27.986	28.009	28.032	28.056	28.079	28.103	28.126	28.149	1240
1250	28.149	28.173	28.196	28.219	28.243	28.266	28.289	28.313	28.336	28.360	28.383	1250
1260	28.383	28.406	28.430	28.453	28.476	28.500	28.523	28.546	28.570	28.593	28.616	1260
1270	28.616	28.640	28.663	28.686	28.710	28.733	28.756	28.780	28.803	28.826	28.849	1270
1280	28.849	28.873	28.896	28.919	28.943	28.966	28.989	29.013	29.036	29.059	29.082	1280
1290	29.082	29.106	29.129	29.152	29.176	29.199	29.222	29.245	29.269	29.292	29.315	1290
°F	0	1	2	3	4	5	6	7	8	9	10	°F

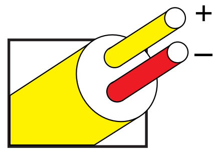
°F	0	1	2	3	4	5	6	7	8	9	10	°F
1300	29.315	29.338	29.362	29.385	29.408	29.431	29.455	29.478	29.501	29.524	29.548	1300
1310	29.548	29.571	29.594	29.617	29.640	29.664	29.687	29.710	29.733	29.757	29.780	1310
1320	29.780	29.803	29.826	29.849	29.873	29.896	29.919	29.942	29.965	29.989	30.012	1320
1330	30.012	30.035	30.058	30.081	30.104	30.128	30.151	30.174	30.197	30.220	30.243	1330
1340	30.243	30.267	30.290	30.313	30.336	30.359	30.382	30.405	30.429	30.452	30.475	1340
1350	30.475	30.498	30.521	30.544	30.567	30.590	30.613	30.637	30.660	30.683	30.706	1350
1360	30.706	30.729	30.752	30.775	30.798	30.821	30.844	30.868	30.891	30.914	30.937	1360
1370	30.937	30.960	30.983	31.006	31.029	31.052	31.075	31.098	31.121	31.144	31.167	1370
1380	31.167	31.190	31.213	31.236	31.260	31.283	31.306	31.329	31.352	31.375	31.398	1380
1390	31.398	31.421	31.444	31.467	31.490	31.513	31.536	31.559	31.582	31.605	31.628	1390
1400	31.628	31.651	31.674	31.697	31.720	31.743	31.766	31.789	31.812	31.834	31.857	1400
1410	31.857	31.880	31.903	31.926	31.949	31.972	31.995	32.018	32.041	32.064	32.087	1410
1420	32.087	32.110	32.133	32.156	32.179	32.202	32.224	32.247	32.270	32.293	32.316	1420
1430	32.316	32.339	32.362	32.385	32.408	32.431	32.453	32.476	32.499	32.522	32.545	1430
1440	32.545	32.568	32.591	32.614	32.636	32.659	32.682	32.705	32.728	32.751	32.774	1440
1450	32.774	32.796	32.819	32.842	32.865	32.888	32.911	32.933	32.956	32.979	33.002	1450
1460	33.002	33.025	33.047	33.070	33.093	33.116	33.139	33.161	33.184	33.207	33.230	1460
1470	33.230	33.253	33.275	33.298	33.321	33.344	33.366	33.389	33.412	33.435	33.458	1470
1480	33.458	33.480	33.503	33.526	33.548	33.571	33.594	33.617	33.639	33.662	33.685	1480
1490	33.685	33.708	33.730	33.753	33.776	33.798	33.821	33.844	33.867	33.889	33.912	1490
1500	33.912	33.935	33.957	33.980	34.003	34.025	34.048	34.071	34.093	34.116	34.139	1500
1510	34.139	34.161	34.184	34.207	34.229	34.252	34.275	34.297	34.320	34.343	34.365	1510
1520	34.365	34.388	34.410	34.433	34.456	34.478	34.501	34.524	34.546	34.569	34.591	1520
1530	34.591	34.614	34.637	34.659	34.682	34.704	34.727	34.750	34.772	34.795	34.817	1530
1540	34.817	34.840	34.862	34.885	34.908	34.930	34.953	34.975	34.998	35.020	35.043	1540
1550	35.043	35.065	35.088	35.110	35.133	35.156	35.178	35.201	35.223	35.246	35.268	1550
1560	35.268	35.291	35.313	35.336	35.358	35.381	35.403	35.426	35.448	35.471	35.493	1560
1570	35.493	35.516	35.538	35.560	35.583	35.605	35.628	35.650	35.673	35.695	35.718	1570
1580	35.718	35.740	35.763	35.785	35.807	35.830	35.852	35.875	35.897	35.920	35.942	1580
1590	35.942	35.964	35.987	36.009	36.032	36.054	36.076	36.099	36.121	36.144	36.166	1590
1600	36.166	36.188	36.211	36.233	36.256	36.278	36.300	36.323	36.345	36.367	36.390	1600
1610	36.390	36.412	36.434	36.457	36.479	36.501	36.524	36.546	36.568	36.591	36.613	1610
1620	36.613	36.635	36.658	36.680	36.702	36.725	36.747	36.769	36.792	36.814	36.836	1620
1630	36.836	36.859	36.881	36.903	36.925	36.948	36.970	36.992	37.014	37.037	37.059	1630
1640	37.059	37.081	37.104	37.126	37.148	37.170	37.193	37.215	37.237	37.259	37.281	1640
1650	37.281	37.304	37.326	37.348	37.370	37.393	37.415	37.437	37.459	37.481	37.504	1650
1660	37.504	37.526	37.548	37.570	37.592	37.615	37.637	37.659	37.681	37.703	37.725	1660
1670	37.725	37.748	37.770	37.792	37.814	37.836	37.858	37.881	37.903	37.925	37.947	1670
1680	37.947	37.969	37.991	38.013	38.036	38.058	38.080	38.102	38.124	38.146	38.168	1680
1690	38.168	38.190	38.212	38.235	38.257	38.279	38.301	38.323	38.345	38.367	38.389	1690
1700	38.389	38.411	38.433	38.455	38.477	38.499	38.522	38.544	38.566	38.588	38.610	1700
1710	38.610	38.632	38.654	38.676	38.698	38.720	38.742	38.764	38.786	38.808	38.830	1710
1720	38.830	38.852	38.874	38.896	38.918	38.940	38.962	38.984	39.006	39.028	39.050	1720
1730	39.050	39.072	39.094	39.116	39.138	39.160	39.182	39.204	39.226	39.248	39.270	1730
1740	39.270	39.292	39.314	39.335	39.357	39.379	39.401	39.423	39.445	39.467	39.489	1740
1750	39.489	39.511	39.533	39.555	39.577	39.599	39.620	39.642	39.664	39.686	39.708	1750
1760	39.708	39.730	39.752	39.774	39.796	39.817	39.839	39.861	39.883	39.905	39.927	1760
1770	39.927	39.949	39.970	39.992	40.014	40.036	40.058	40.080	40.101	40.123	40.145	1770
1780	40.145	40.167	40.189	40.211	40.232	40.254	40.276	40.298	40.320	40.341	40.363	1780
1790	40.363	40.385	40.407	40.429	40.450	40.472	40.494	40.516	40.537	40.559	40.581	1790
1800	40.581	40.603	40.624	40.646	40.668	40.690	40.711	40.733	40.755	40.777	40.798	1800
1810	40.798	40.820	40.842	40.864	40.885	40.907	40.929	40.950	40.972	40.994	41.015	1810
1820	41.015	41.037	41.059	41.081	41.102	41.124	41.146	41.167	41.189	41.211	41.232	1820
1830	41.232	41.254	41.276	41.297	41.319	41.341	41.362	41.384	41.405	41.427	41.449	1830
1840	41.449	41.470	41.492	41.514	41.535	41.557	41.578	41.600	41.622	41.643	41.665	1840
1850	41.665	41.686	41.708	41.730	41.751	41.773	41.794	41.816	41.838	41.859	41.881	1850
1860	41.881	41.902	41.924	41.945	41.967	41.988	42.010	42.032	42.053	42.075	42.096	1860
1870	42.096	42.118	42.139	42.161	42.182	42.204	42.225	42.247	42.268	42.290	42.311	1870
1880	42.311	42.333	42.354	42.376	42.397	42.419	42.440	42.462	42.483	42.505	42.526	1880
1890	42.526	42.548	42.569	42.591	42.612	42.633	42.655	42.676	42.698	42.719	42.741	1890
°F	0	1	2	3	4	5	6	7	8	9	10	°F

MAXIMUM TEMPERATURE RANGE
Thermocouple Grade
– 328 to 2282°F
– 200 to 1250°C
Extension Grade
32 to 392°F
0 to 200°C
LIMITS OF ERROR
(whichever is greater)
Standard: 2.2°C or 0.75% Above 0°C
2.2°C or 2.0% Below 0°C
Special: 1.1°C or 0.4%
COMMENTS, BARE WIRE ENVIRONMENT:
Clean Oxidizing and Inert; Limited Use in Vacuum or Reducing; Wide Temperature Range; Most Popular Calibration
TEMPERATURE IN DEGREES °F
REFERENCE JUNCTION AT 32°F



Thermocouple Grade

Nickel-Chromium vs. Nickel-Aluminum



Extension Grade

Revised Thermocouple Reference Tables

TYPE K

Reference Tables
N.I.S.T. Monograph 175
Revised to ITS-90

Z

Thermoelectric Voltage in Millivolts

°F	0	1	2	3	4	5	6	7	8	9	10	°F
1900	42.741	42.762	42.783	42.805	42.826	42.848	42.869	42.891	42.912	42.933	42.955	1900
1910	42.955	42.976	42.998	43.019	43.040	43.062	43.083	43.104	43.126	43.147	43.169	1910
1920	43.169	43.190	43.211	43.233	43.254	43.275	43.297	43.318	43.339	43.361	43.382	1920
1930	43.382	43.403	43.425	43.446	43.467	43.489	43.510	43.531	43.552	43.574	43.595	1930
1940	43.595	43.616	43.638	43.659	43.680	43.701	43.723	43.744	43.765	43.787	43.808	1940
1950	43.808	43.829	43.850	43.872	43.893	43.914	43.935	43.957	43.978	43.999	44.020	1950
1960	44.020	44.041	44.063	44.084	44.105	44.126	44.147	44.169	44.190	44.211	44.232	1960
1970	44.232	44.253	44.275	44.296	44.317	44.338	44.359	44.380	44.402	44.423	44.444	1970
1980	44.444	44.465	44.486	44.507	44.528	44.550	44.571	44.592	44.613	44.634	44.655	1980
1990	44.655	44.676	44.697	44.719	44.740	44.761	44.782	44.803	44.824	44.845	44.866	1990
2000	44.866	44.887	44.908	44.929	44.950	44.971	44.992	45.014	45.035	45.056	45.077	2000
2010	45.077	45.098	45.119	45.140	45.161	45.182	45.203	45.224	45.245	45.266	45.287	2010
2020	45.287	45.308	45.329	45.350	45.371	45.392	45.413	45.434	45.455	45.476	45.497	2020
2030	45.497	45.518	45.539	45.560	45.580	45.601	45.622	45.643	45.664	45.685	45.706	2030
2040	45.706	45.727	45.748	45.769	45.790	45.811	45.832	45.852	45.873	45.894	45.915	2040
2050	45.915	45.936	45.957	45.978	45.999	46.019	46.040	46.061	46.082	46.103	46.124	2050
2060	46.124	46.145	46.165	46.186	46.207	46.228	46.249	46.269	46.290	46.311	46.332	2060
2070	46.332	46.353	46.373	46.394	46.415	46.436	46.457	46.477	46.498	46.519	46.540	2070
2080	46.540	46.560	46.581	46.602	46.623	46.643	46.664	46.685	46.706	46.726	46.747	2080
2090	46.747	46.768	46.789	46.809	46.830	46.851	46.871	46.892	46.913	46.933	46.954	2090
2100	46.954	46.975	46.995	47.016	47.037	47.057	47.078	47.099	47.119	47.140	47.161	2100
2110	47.161	47.181	47.202	47.223	47.243	47.264	47.284	47.305	47.326	47.346	47.367	2110
2120	47.367	47.387	47.408	47.429	47.449	47.470	47.490	47.511	47.531	47.552	47.573	2120
2130	47.573	47.593	47.614	47.634	47.655	47.675	47.696	47.716	47.737	47.757	47.778	2130
2140	47.778	47.798	47.819	47.839	47.860	47.880	47.901	47.921	47.942	47.962	47.983	2140
2150	47.983	48.003	48.024	48.044	48.065	48.085	48.105	48.126	48.146	48.167	48.187	2150
2160	48.187	48.208	48.228	48.248	48.269	48.289	48.310	48.330	48.350	48.371	48.391	2160
2170	48.391	48.411	48.432	48.452	48.473	48.493	48.513	48.534	48.554	48.574	48.595	2170
2180	48.595	48.615	48.635	48.656	48.676	48.696	48.717	48.737	48.757	48.777	48.798	2180
2190	48.798	48.818	48.838	48.859	48.879	48.899	48.919	48.940	48.960	48.980	49.000	2190
2200	49.000	49.021	49.041	49.061	49.081	49.101	49.122	49.142	49.162	49.182	49.202	2200
2210	49.202	49.223	49.243	49.263	49.283	49.303	49.323	49.344	49.364	49.384	49.404	2210
2220	49.404	49.424	49.444	49.465	49.485	49.505	49.525	49.545	49.565	49.585	49.605	2220
2230	49.605	49.625	49.645	49.666	49.686	49.706	49.726	49.746	49.766	49.786	49.806	2230
2240	49.806	49.826	49.846	49.866	49.886	49.906	49.926	49.946	49.966	49.986	50.006	2240
°F	0	1	2	3	4	5	6	7	8	9	10	°F

°F	0	1	2	3	4	5	6	7	8	9	10	°F
2250	50.006	50.026	50.046	50.066	50.086	50.106	50.126	50.146	50.166	50.186	50.206	2250
2260	50.206	50.226	50.246	50.266	50.286	50.306	50.326	50.346	50.366	50.385	50.405	2260
2270	50.405	50.425	50.445	50.465	50.485	50.505	50.525	50.545	50.564	50.584	50.604	2270
2280	50.604	50.624	50.644	50.664	50.684	50.703	50.723	50.743	50.763	50.783	50.802	2280
2290	50.802	50.822	50.842	50.862	50.882	50.901	50.921	50.941	50.961	50.981	51.000	2290
2300	51.000	51.020	51.040	51.060	51.079	51.099	51.119	51.139	51.158	51.178	51.198	2300
2310	51.198	51.217	51.237	51.257	51.276	51.296	51.316	51.336	51.355	51.375	51.395	2310
2320	51.395	51.414	51.434	51.453	51.473	51.493	51.512	51.532	51.552	51.571	51.591	2320
2330	51.591	51.611	51.630	51.650	51.669	51.689	51.708	51.728	51.748	51.767	51.787	2330
2340	51.787	51.806	51.826	51.845	51.865	51.885	51.904	51.924	51.943	51.963	51.982	2340
2350	51.982	52.002	52.021	52.041	52.060	52.080	52.099	52.119	52.138	52.158	52.177	2350
2360	52.177	52.197	52.216	52.235	52.255	52.274	52.294	52.313	52.333	52.352	52.371	2360
2370	52.371	52.391	52.410	52.430	52.449	52.468	52.488	52.507	52.527	52.546	52.565	2370
2380	52.565	52.585	52.604	52.623	52.643	52.662	52.681	52.701	52.720	52.739	52.759	2380
2390	52.759	52.778	52.797	52.817	52.836	52.855	52.875	52.894	52.913	52.932	52.952	2390
2400	52.952	52.971	52.990	53.010	53.029	53.048	53.067	53.087	53.106	53.125	53.144	2400
2410	53.144	53.163	53.183	53.202	53.221	53.240	53.260	53.279	53.298	53.317	53.336	2410
2420	53.336	53.355	53.375	53.394	53.413	53.432	53.451	53.470	53.490	53.509	53.528	2420
2430	53.528	53.547	53.566	53.585	53.604	53.623	53.643	53.662	53.681	53.700	53.719	2430
2440	53.719	53.738	53.757	53.776	53.795	53.814	53.833	53.852	53.871	53.890	53.910	2440
2450	53.910	53.929	53.948	53.967	53.986	54.005	54.024	54.043	54.062	54.081	54.100	2450
2460	54.100	54.119	54.138	54.157	54.176	54.195	54.214	54.233	54.252	54.271	54.289	2460
2470	54.289	54.308	54.327	54.346	54.365	54.384	54.403	54.422	54.441	54.460	54.479	2470
2480	54.479	54.498	54.517	54.536	54.554	54.573	54.592	54.611	54.630	54.649	54.668	2480
2490	54.668	54.687	54.705	54.724	54.743	54.762	54.781	54.800	54.819	54.837	54.856	2490
2500	54.856	54.875	54.894									2500
°F	0	1	2	3	4	5	6	7	8	9	10	°F

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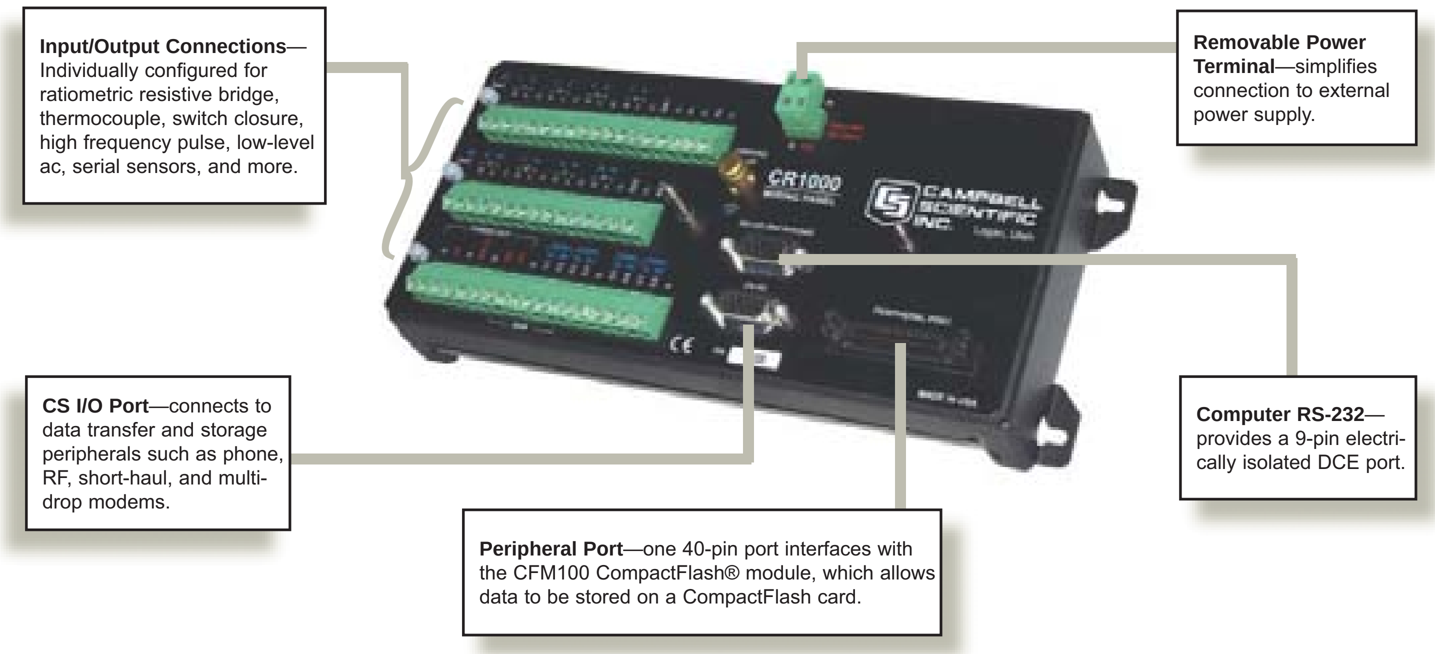
CR1000 Measurement and Control System

The CR1000 provides precision measurement capabilities in a rugged, battery-operated package. It consists of a measurement and control module and a wiring panel. Standard operating range is -25° to +50°C; an optional extended range of -55° to +85°C is available.



Features

- 2 Mbytes standard memory; 4 Mbytes optional memory
- Program execution rate of up to 100 Hz
- CS I/O and RS-232 serial ports
- 13-bit analog to digital conversions
- 16-bit H8S Hitachi Microcontroller with 32-bit internal CPU architecture
- Temperature compensated real-time clock
- Background system calibration for accurate measurements over time and temperature changes
- Single DAC used for excitation and measurements to give ratio metric measurements
- Gas Discharge Tube (GDT) protected inputs
- Data values stored in tables with a time stamp and record number
- Battery-backed SRAM memory and clock ensuring data, programs, and accurate time are maintained while the CR1000 is disconnected from its main power source
- Measures intelligent serial sensors without using an SDM-SIO4

Measurement and Control Module

The module measures sensors, drives direct communications and telecommunications, reduces data, controls external devices, and stores data and programs in on-board, non-volatile storage. The electronics are RF shielded and glitch protected by the sealed, stainless steel canister. A battery-backed clock assures accurate timekeeping. The module can simultaneously provide measurement and communication functions. The on-board, BASIC-like programming language supports data processing and analysis routines.

Wiring Panel

The CR1000WP is a black, anodized aluminum wiring panel that is compatible with all CR1000 and CR1000-4M modules. The wiring panel includes switchable 12 V, redistributed analog grounds (dispersed among analog channels rather than grouped), unpluggable terminal block for 12 V connections, gas-tube spark gaps, and 12 V supply on pin 8 to power our COM-series phone modems and other peripherals. The control module easily disconnects from the wiring panel allowing field replacement without rewiring the sensors. A description of the wiring panel's input/output channels follows.

Analog Inputs

Eight differential (16 single-ended) channels measure voltage levels. Resolution on the most sensitive range is 0.67 µV.

Pulse Counters

Two pulse channels can count pulses from high level (5 V square wave), switch closure, or low level ac signals.

Switched Voltage Excitations

Three outputs provide precision excitation voltages for resistive bridge measurements.

Digital I/O Ports

Eight ports are provided for frequency measurements, digital control, and triggering. Three of these ports can also be used to measure SDM devices.

RS-232 Port

A PC or laptop can be connected to this 9-pin port via an RS-232 cable.

CS I/O port

Data transfer peripherals that require power from the datalogger can be connected to this port via an SC12 cable. This port is also used for connecting the datalogger to a PC via an SC32B or SC-USB interface when optical isolation is required.

Peripheral Port

One 40-pin port interfaces with the CFM100 CompactFlash® Module or the NL115 Ethernet Interface and CompactFlash Module.

Switched 12 Volt

This terminal provides unregulated 12 V that can be switched on and off under program control.

Storage Capacity

The CR1000 has 2 Mbyte of FLASH memory for the Operating System. The standard CR1000 provides 2 Mbytes battery-backed SRAM for CPU usage, program storage, and data storage; an optional version provides 4 Mbytes of SRAM. Data is stored in a table format. The storage capacity of the CR1000 can be increased by using a CompactFlash® card.

Communication Protocols

The CR1000 supports the PAKBUS® communication protocol. PAKBUS networks have the distributed routing intelligence to continually evaluate links. Continually evaluating links optimizes delivery times and, in the case of delivery failure, allows automatic switch over to a configured backup route.

The CR1000 also supports Modbus RTU protocol—both floating point and long formats. The datalogger can act as a slave, master, or both.

Enclosure/Stack Bracket

A CR1000 housed in a weather-resistant enclosure can collect data under extremely harsh conditions. The enclosure protects the CR1000 from dust, water, sunlight, or pollutants. An internal mounting plate is prepunched for easy system configuration and exchange of equipment in the field.

A stack bracket kit is available that allows you to attach the CR1000 to the backplate of an ENC10/12 enclosure in a "horizontal" orientation (i.e., the long axis of the CR1000 spanning the short axis of the ENC10/12 enclosure). This stack bracket also allows you to place a small peripheral under the mounting bracket and secure it with Velcro®, thus conserving space, and place the wiring panel terminals at about the same height as the terminals in one of our power supplies.

The stack bracket as viewed from the side with a CR1000 attached.

Power Supplies

Any 12 Vdc source can power the CR1000; a PS100 or BPALK is typically used. The PS100 includes one 7 Ahr rechargeable battery, charged with ac power (requires a wall charger) or a solar panel. The BPALK consists of eight non-rechargeable D-cell alkaline batteries with a 7.5 Ahr rating at 20°C. An external AA-cell battery pack supplies power while the D-cells are replaced.

Also available are the BP12 and BP24 battery packs, which provide nominal ratings of 12 and 24 Ahrs, respectively. These batteries should be connected to a charging regulator and a charging source. For information about analyzing your system's power requirements, see our Power Supply product literature or Application Note 5-F. Both can be obtained from: www. campbellsci.com

Its low-power design allows the CR1000 to operate for up to one year on the PS100 power supply, depending on scan rate, number of sensors, data retrieval method, and external temperature.

Data Storage and Retrieval Options

To determine the best option for your application, consider the accessibility of your site, availability of services (e.g., cellular phone or satellite coverage), quantity of data to collect, and desired time between data-collection sessions. Some communication options can be combined—increasing the flexibility, convenience, and reliability of your communications.

Radios

Radio frequency (RF) communications are supported via narrow-band UHF, narrow-band VHF, spread spectrum, or meteor burst radios. Line-of-sight is required for all of our RF options.

Meteorological conditions measured at Lake Louise, Alberta, Canada are telemetered via phone-to-RF link to a base station.

Telephone Networks

The CR1000 can communicate with a PC using landlines, cellular CDMA, or cellular GPRS transceivers. A voice synthesized modem enables anyone to call the CR1000 via phone and receive a verbal report of realtime site conditions.

Satellite Transmitters

Our NESDIS-certified GOES satellite transmitter provides one-way communications from a Data Collection Platform (DCP) to a receiving station. The transmitter complies with the High Data Rate (HDR) specifications. We also offer an Argos transmitter that is ideal for high-altitude and polar applications.

This station for the National Estuarine Research Reserve (NERR) in Virginia transmits data via our GOES satellite transmitter.

Multidrop Interface

The MD485 intelligent RS-485 interface permits a PC to address and communicate with one or more dataloggers over a single two-twisted-pair cable. Distances up to 4000 ft are supported.

Short Haul Modems

The SRM-5A RAD Short Haul Modem supports communications between the CR1000 and a computer via a four-wire unconditioned line (two twisted pairs).

Direct Links

A desktop or laptop PC connects directly to the CR1000's RS-232 port. If optical isolation is required, the PC is connected to the datalogger's CS I/O port via an SC32B or SC-USB interface.

PDAs

User-supplied PDAs can be used to set the CR1000’s clock, monitor real-time data, retrieve data, graph data, and transfer CR1000 programs. PConnect software (purchased separately) is required for PDAs with a Palm™ OS, and PConnectCE software (purchased separately) is required for PDAs with a Windows® CE OS.

Keyboard Display

With the CR1000KD, you can program the CR1000, manually initiate data transfer, and display data. The CR1000KD displays 8 lines x 21 characters (64 x 128 pixels) and has a 16-character keyboard. Custom menus are supported allowing you to set up choices within the datalogger program that can be initiated by a simple “toggle” or “pick list”.

One CR1000KD can be carried from station to station in a CR1000 network.

Ethernet

Use of an NL100 or NL115 interface enables the CR1000 to communicate over a local network or a dedicated internet connection via TCP/IP. The NL115 also supports data storage on CompactFlash cards.

CompactFlash®

The CR1000's data can be stored on a CompactFlash card using either a CFM100 or NL115 module. On the computer side, the CompactFlash cards are read by the computer’s PCMCIA slot fitted with a CF1 CompactFlash adapter or by a USB port fitted with the ImageMate USB CompactFlash Reader/Writer.

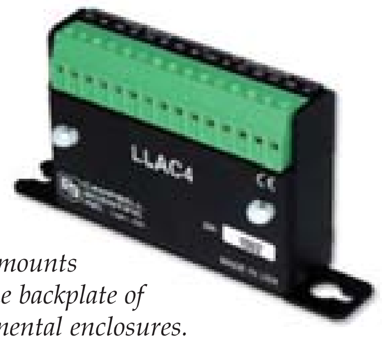
DSP4 Heads Up Display

Primarily intended for vehicle test applications, the DSP4 permits dashboard mounting in a variety of vehicles without obstructing the view of the driver.

Channel Expansion

4-Channel Low Level AC Module

The LLAC4 is a small peripheral device that allows you to increase the number of available low-level ac inputs by using control ports. This module is often used to measure up to four anemometers, and is especially useful for wind profiling applications.



The LLAC4 mounts directly to the backplate of our environmental enclosures.

Synchronous Devices for Measurement (SDMs)

SDMs are addressable peripherals that expand the CR1000's measurement and control capabilities. For example, SDMs are available to add control ports, analog outputs, pulse count channels, interval timers, or even a CANbus interface to your system. Multiple SDMs, in any combination, can be connected to one CR1000 datalogger.

Multiplexers

Multiplexers increase the number of sensors that can be measured by a CR1000 by sequentially connecting each sensor to the datalogger. Several multiplexers can be controlled by a single CR1000. The CR1000 is compatible with the AM16/32 and AM25T.

Software

Starter Software

Campbell Scientific offers easy-to-use starter software intended for first time users or applications that don't require sophisticated communications or datalogger program editing. These software products provide different functions and can be used in conjunction with each other. Starter software can be downloaded at no charge from www.campbellsci.com/resource.html. Our Resource CD also provides this software as well as PDF versions of our literature and manuals.

Our SCWin Short Cut for Windows® generates straightforward CR1000 programs in four easy steps. Short Cut supports programming for our multiplexers, ET106 stations, MetData1 stations, and virtually any sensor that our CR1000 can measure.

Our PC200W Starter Software allows you to transfer a program to, or retrieve data from, a CR1000 via a direct communications link.

Datalogger Support Software

Our general purpose datalogger support software packages provide more capabilities than our starter software. Each of these software packages contains program editing, communications, and display tools that can support an entire datalogger network.

PC400, our mid-level software, supports a variety of telemetry options, manual data collection, and data display. For programming, it includes both Short Cut and the CRBasic program editor. PC400 does not support combined communication options (e.g., phone-to-RF), PAKBUS® routing, or scheduled data collection; LoggerNet software is recommended for those applications.

Campbell Scientific offers the following three LoggerNet Software Packages:

- **LoggerNet**, the standard package, is recommended for those who have datalogger networks that do not require the more advanced features offered in LoggerNet Admin. It consists of a server application and several client applications integrated into a single product. This software provides all of PC400's capabilities as well as support for combined communication options (e.g., phone-to-RF), PAKBUS® routing, and scheduled data collection

- **LoggerNet Admin** is intended for customers who have large networks. Besides providing better tools for managing large networks, LoggerNet Admin allows you to remotely manage a datalogger network over TCP/IP, and to remotely and automatically distribute data to other computers.

- **LoggerNetRemote** includes LoggerNet Admin clients to administer a running LoggerNet Admin server via TCP/IP from a remote PC. This software does not include the LoggerNet server.

LoggerNet provides a way to accomplish almost all the tasks you'll need to complete when using a datalogger.

Applications

The measurement precision, flexibility, long-term reliability, and economical price of the CR1000 make it ideal for scientific, commercial, and industrial applications.

Meteorology

The CR1000 is used in long-term climatological monitoring, meteorological research, and routine weather measurement applications.

Our rugged, reliable weather station measures meteorological conditions at St. Mary's Lake, Glacier National Park, MT.

Sensors the CR1000 can measure include:

- cup, propeller, and sonic anemometers
- tipping bucket rain gages
- wind vanes
- pyranometers
- ultrasonic distance sensors
- thermistors, RTDs, and thermocouples
- barometric pressure sensors
- RH sensors
- cooled mirror hygrometers

Data is output in your choice of units (e.g., wind speed in miles per hour, meters per second, or knots). Standard CR1000 outputs include wind vector averaging, sigma, theta, histograms, saturation vapor pressure, and vapor pressure from wet/dry bulb temperatures.

Agriculture and Agricultural Research

The versatility of the CR1000 allows measurement of agricultural processes and equipment in applications such as:

- plant water research
- canopy energy balance
- machinery performance
- plant pathology
- crop management decisions
- food processing/storage
- frost prediction
- irrigation scheduling
- integrated pest management

This vitaculture site in Australia integrates meteorological, soil, and crop measurements.

Wind Profiling

Our data acquisition systems can monitor conditions at wind assessment sites, at producing wind farms, and along transmission lines. The reliability of these systems ensures data collection, even under adverse conditions. Wide operating temperature ranges and weatherproof enclosures allow our systems to operate reliably in harsh environments.

The CR1000 makes and records measurements, controls electrical devices, and can function as PLCs or RTUs. Because the datalogger has its own power supply (batteries, solar panels), it can continue to measure and store data and perform control during power outages.

Typical sensors for wind assessment applications include, but are not limited to:

- sonic anemometers
- three-cup and propeller anemometers (up to 10 anemometers can be measured by using two LLAC4 peripherals)
- wind vanes
- temperature sensors (air, water, and equipment)
- barometric pressure
- wetness
- solar radiation

Photo courtesy npower renewables

A Campbell Scientific system monitors an offshore wind farm in North Wales.

For turbine performance applications, the CR1000 can monitor electrical current, voltage, wattage, stress, and torque.

Soil Moisture

The CR1000 is compatible with the following soil moisture measurement technologies:

- **Soil moisture blocks** are inexpensive sensors that estimate soil water potential.
- **Matric water potential sensors** also estimate soil water potential but are more durable than soil moisture blocks.
- **Time-Domain Reflectometry Systems (TDR)** use a reflectometer controlled by a CR1000 to accurately measure soil water content. Multiplexers allow sequential measurement of a large number of probes by one reflectometer, reducing cost per measurement.
- **Self-contained water content reflectometers** are sensors that emit and measure a TDR pulse.
- **Tensiometers** measure the soil pore pressure of irrigated soils and calculate soil moisture.

Air Quality

The CR1000 can monitor and control gas analyzers, particle samplers, and visibility sensors. It can also automatically control calibration sequences and compute conditional averages that exclude invalid data (e.g., data recorded during power failures or calibration intervals).

Road Weather/RWIS

Our fully NTCIP-compliant Environmental Sensor Stations (ESS) are robust, reliable weather stations used for road weather/RWIS applications. A typical ESS includes a tower, CR1000, two road sensors, remote communication hardware, and sensors that measure wind speed and direction, air temperature, humidity, barometric pressure, solar radiation, and precipitation. The CR1000 can also measure soil moisture and temperature sensors, monitor bridge vibrations, and control external devices.

Water Resources/Aquaculture

Our CR1000 is well-suited to remote, unattended monitoring of hydrologic conditions. Most hydrologic sensors, including SDI-12 probes, interface directly to the CR1000. Typical hydrologic measurements:

- **Water level** is monitored with incremental shaft encoders, double bubblers, ultrasonic level transducers, resistance tapes, or strain gage or vibrating wire pressure transducers. Some shaft encoders require a QD1 Interface. Vibrating wire transducers require an AVW1, AVW4, or AVW100 Interface.
- **Well draw-down tests** use a pressure transducer measured at logarithmic intervals or at a rate based on incremental changes in water level.
- **Ionic conductivity measurements** use one of the switched excitation ports from the CR1000.
- **Samplers** are controlled by the CR1000 as a function of time, water quality, or water level.
- **Alarm and pump actuation** are controlled through digital I/O ports that operate external relay drivers.

A turbidity sensor was installed in a tributary of the Cedar River watershed to monitor water quality conditions for the city of Seattle, Washington.

Vehical Testing

This versatile, rugged datalogger is ideally suited for testing cold and hot temperature, high altitude, off-highway, and cross-country performance. The CR1000 is compatible with our SDM-CAN interface, GPS16-HVS receiver, and DSP4 Heads Up Display.

Vehicle monitoring includes not only passenger cars, but locomotives, airplanes, helicopters, tractors, buses, heavy trucks, drilling rigs, race cars, and motorcycles.

The CR1000 can measure:

- **Suspension—**strut pressure, spring force, travel, mounting point stress, deflection, ride
- **Fuel system—**line and tank pressure, flow, temperature, injection timing
- **Comfort control—**ambient and supply air temperature, solar radiation, fan speed, ac on and off, refrigerant pressures, time-to-comfort, blower current
- **Brakes—**line pressure, pedal pressure and travel, ABS, line and pad temperature
- **Engine—**pressure, temperature, crank position, RPM, time-to-start, oil pump cavitation
- **General vehicle—**chassis monitoring, road noise, vehicle position and speed, steering, air bag, hot/cold soaks, wind tunnels, traction, CANbus, wiper speed and current, vehicle electrical loads

Other Applications

- Eddy covariance systems
- Wireless sensor/datalogger networks
- Mesonet systems
- Avalanche forecasting, snow science, polar, high altitude
- Fire weather
- Geotechnical
- Historic preservation

CR1000 Specifications

Electrical specifications are valid over a -25° to +50°C range unless otherwise specified; non-condensing environment required. To maintain electrical specifications, Campbell Scientific recommends recalibrating dataloggers every two years.

PROGRAM EXECUTION RATE

10 ms to 30 min. @ 10 ms increments

ANALOG INPUTS

8 differential (DF) or 16 single-ended (SE) individually configured. Channel expansion provided by AM16/32 and AM25T multiplexers.

RANGES, RESOLUTION AND TYPICAL INPUT NOISE: Basic resolution (Basic Res) is the A/D resolution of a single conversion. **Resolution of DF measurements with input reversal is half the Basic Res.** Noise values are for DF measurements with input reversal; noise is greater with SE measurements.

Input Range (mV)	*Basic Res (µV)*	*Input Referred Noise Voltage 250 µs Int. (µV RMS)*	*50/60 Hz Int. (µV RMS)*
±5000	1330	385	192
±2500	667	192	95.9
±250	66.7	19.2	19.2
±25	6.7	2.3	1.9
±7.5	2	0.62	0.58
±2.5	0.67	0.34	0.19

ACCURACY[1]:
±(0.06% of reading + offset), 0° to 40°C
±(0.12% of reading + offset), -25° to 50°C
±(0.18% of reading + offset), -55° to 85°C (-XT only)

[1]The sensor and measurement noise are not included and the offsets are the following:

Offset for DF w/input reversal = 1.5·Basic Res + 1.0 µV
Offset for DF w/o input reversal = 3·Basic Res + 2.0 µV
Offset for SE = 3·Basic Res + 3.0 µV

MINIMUM TIME BETWEEN VOLTAGE MEASUREMENTS: Includes the measurement time and conversion to engineering units. For voltage measurements, the CR1000 integrates the input signal for 0.25 ms or a full 16.66 ms or 20 ms line cycle for 50/60 Hz noise rejection. DF measurements with input reversal incorporate two integrations with reversed input polarities to reduce thermal offset and common mode errors and therefore take twice as long.

250 µs Analog Integration:	~1 ms SE
1/60 Hz Analog Integration:	~20 ms SE
1/50 Hz Analog Integration:	~25 ms SE

COMMON MODE RANGE: ±5 V

DC COMMON MODE REJECTION: >100 dB

NORMAL MODE REJECTION: 70 dB @ 60 Hz when using 60 Hz rejection

SUSTAINED INPUT VOLTAGE W/O DAMAGE: ±16 Vdc max.

INPUT CURRENT: ±1 nA typical, ±6 nA max. @ 50°C; ±90 nA @ 85°C

INPUT RESISTANCE: 20 Gohms typical

ACCURACY OF BUILT-IN REFERENCE JUNCTION THERMISTOR (for thermocouple measurements):
±0.3°C, -25° to 50°C
±0.8°C, -55° to 85°C (-XT only)

ANALOG OUTPUTS

3 switched voltage, active only during measurement, one at a time.

RANGE AND RESOLUTION: Voltage outputs programmable between ±2.5 V with 0.67 mV resolution.

ACCURACY: ±(0.06% of setting + 0.8 mV), 0° to 40°C
±(0.12% of setting + 0.8 mV), -25° to 50°C
±(0.18% of setting + 0.8 mV), -55° to 85°C (-XT only)

CURRENT SOURCING/SINKING: ±25 mA

RESISTANCE MEASUREMENTS

MEASUREMENT TYPES: The CR1000 provides ratiometric measurements of 4- and 6-wire full bridges, and 2-, 3-, and 4-wire half bridges. Precise, dual polarity excitation using any of the 3 switched voltage excitations eliminates dc errors.

RATIO ACCURACY[1]: Assuming excitation voltage of at least 1000 mV, not including bridge resistor error.

$\pm(0.04\%$ of reading + offset$)/V_{ex}$

[1]The sensor and measurement noise are not included and the offsets are the following:

Offset for DF w/input reversal = 1.5·Basic Res + 1.0 µV
Offset for DF w/o input reversal = 3·Basic Res + 2.0 µV
Offset for SE = 3·Basic Res + 3.0 µV

Offset values are reduced by a factor of 2 when excitation reversal is used.

PERIOD AVERAGING MEASUREMENTS

The average period for a single cycle is determined by measuring the average duration of a specified number of cycles. The period resolution is 192 ns divided by the specified number of cycles to be measured; the period accuracy is ±(0.01% of reading + resolution). Any of the 16 SE analog inputs can be used for period averaging. Signal limiting are typically required for the SE analog channel.

INPUT FREQUENCY RANGE:

Input Range	*Signal (peak to peak)[2] Min*	*Max*	*Min. Pulse W.*	*Max[3] Freq.*
±2500 mV	500 mV	10 V	2.5 µs	200 kHz
±250 mV	10 mV	2 V	10 µs	50 kHz
±25 mV	5 mV	2 V	62 µs	8 kHz
±2.5 mV	2 mV	2 V	100 µs	5 kHz

[2]The signal is centered at the datalogger ground.

[3]The maximum frequency = 1/(Twice Minimum Pulse Width) for 50% of duty cycle signals.

PULSE COUNTERS

Two 24-bit inputs selectable for switch closure, high frequency pulse, or low-level ac.

MAXIMUM COUNTS PER SCAN: $16.7\text{x}10^6$

SWITCH CLOSURE MODE:
Minimum Switch Closed Time: 5 ms
Minimum Switch Open Time: 6 ms
Max. Bounce Time: 1 ms open w/o being counted

HIGH FREQUENCY PULSE MODE:
Maximum Input Frequency: 250 kHz
Maximum Input Voltage: ±20 V
Voltage Thresholds: Count upon transition from below 0.9 V to above 2.2 V after input filter with 1.2 µs time constant.

LOW LEVEL AC MODE: Internal ac coupling removes dc offsets up to ±0.5 V.

Input Hysteresis: 16 mV @ 1 Hz
Maximum ac Input Voltage: ±20 V
Minimum ac Input Voltage:

Sine wave (mV RMS)	*Range (Hz)*
20	1.0 to 20
200	0.5 to 200
2000	0.3 to 10,000
5000	0.3 to 20,000

DIGITAL I/O PORTS

8 ports software selectable, as binary inputs or control outputs. C1-C8 also provide edge timing, subroutine interrupts/wake up, switch closure pulse counting, high frequency pulse counting, asynchronous communications (UART), SDI-12 communications, and SDM communications.

HIGH FREQUENCY MAX: 400 kHz

SWITCH CLOSURE FREQUENCY MAX: 150 Hz

OUTPUT VOLTAGES (no load): high 5.0 V ±0.1 V; low <0.1

OUTPUT RESISTANCE: 330 ohms

INPUT STATE: high 3.8 to 5.3 V; low -0.3 to 1.2 V

INPUT HYSTERISIS: 1.4 V

INPUT RESISTANCE: 100 kohms

SWITCHED 12 V

One independent 12 V unregulated sources switched on and off under program control. Thermal fuse hold current = 900 mA @ 20°C, 650 mA @ 50°C, 360 mA @ 85°C.

SDI-12 INTERFACE SUPPORT

Control ports 1, 3, 5, and 7 may be configured for SDI-12 asynchronous communications. Up to ten SDI-12 sensors are supported per port. It meets SDI-12 Standard version 1.3 for datalogger mode.

CE COMPLIANCE

STANDARD(S) TO WHICH CONFORMITY IS DECLARED: IEC61326:2002

CPU AND INTERFACE

PROCESSOR: Hitachi H8S 2322 (16-bit CPU with 32-bit internal core)

MEMORY: 2 Mbytes of Flash for operating system; 2 Mbytes of battery-backed SRAM for CPU usage, program storage and data storage; 4 Mbytes optional

SERIAL INTERFACES: CS I/O port is used to interface with Campbell Scientific peripherals; RS-232 port is for computer or non-CSI modem connection.

PARALLEL INTERFACE: 40-pin interface for attaching data storage or communication peripherals such as the CFM100 module

BAUD RATES: Selectable from 300 bps to 115.2 kbps. ASCII protocol is one start bit, one stop bit, eight data bits, and no parity.

CLOCK ACCURACY: ±3 min. per year

SYSTEM POWER REQUIREMENTS

VOLTAGE: 9.6 to 16 Vdc

TYPICAL CURRENT DRAIN:
Sleep Mode: ~0.6 mA
1 Hz Scan (8 diff. meas., 60 Hz rej., 2 pulse meas.)
w/RS-232 communication: 19 mA
w/o RS-232 communication: 4.2 mA
1 Hz Scan (8 diff. meas., 250 µs integ., 2 pulse meas.)
w/RS-232 communication: 16.7 mA
w/o RS-232 communication: 1 mA
100 Hz Scan (4 diff. meas., 250 µs integ.)
w/RS-232 communication: 27.6 mA
w/o RS-232 communication: 16.2 mA

EXTERNAL BATTERIES: 12 Vdc nominal; reverse polarity protected.

PHYSICAL SPECIFICATIONS

MEASUREMENT & CONTROL MODULE SIZE: 8.5" x 3.9" x 0.85" (21.6 x 9.9 x 2.2 cm)

CR1000WP WIRING PANEL SIZE: 9.4" x 4" x 2.4" (23.9 x 10.2 x 6.1 cm); additional clearance required for serial cable and sensor leads.

WEIGHT: 2.1 lbs (1 kg)

WARRANTY

Three years against defects in materials and workmanship.

CAMPBELL SCIENTIFIC, INC.
815 West 1800 North • Logan, Utah 84321-1784 • (435) 753-2342 • Fax (435) 750-9540
Offices also located in: Australia • Brazil • Canada • England • France • Germany • South Africa • Spain

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AirLink
COMMUNICATIONS

RAVEN

CDMA

> APPLICATIONS

UTILITIES
- Natural Gas Wellhead Monitoring
- C&I Meters
- Transmission Line Flow Meters
- Energy Management Systems

TRANSPORTATION
- Traffic Measurement
- Traffic Control
- Variable Message Signs

ATMOSPHERIC/ENVIRONMENTAL
- Weather Monitoring
- Irrigation Control
- Seismic Monitoring
- Water Level Monitoring

PRIMARY/REDUNDANT CONNECTIVITY
- Automated Teller Machines
- Routers
- Enterprise Servers

> APPLICATION INTERFACES

Standard interfaces include:
- AT command set.
- Host TCP/IP stack communicates with Raven via PPP.
- Windows 95/98/2000/NT/XP Dial Up Networking communicates with Raven using PPP.

> SPECIAL FEATURES

- Class I Div 2 certified
- High speed data transfer rate
- Full duplex transceiver
- Low power consumption
- Proven technology
- Compact size
- Rugged aluminum case
- LEDs show status of network operation
- Optional mounting brackets

The AirLink Raven CDMA is a rugged, intelligent wireless data platform designed to enable real-time, two-way communications with remote assets.

THE ALEOS PLATFORM

The AirLink Embedded Operating System (ALEOS) is the power inside the Raven. ALEOS has its own embedded TCP/IP stack which enables transmission of date from non-IP devices. ALEOS enables several functions including remote configuration and diagnostics, packet assembly and dis-assembly for UDP and TCP, and dynamic IP management. The unique intelligence within ALEOS enables virtually any type of remote device to connect via the public wireless data network.

ALEOS
AirLink Embedded Operating System

FEATURES
- Integrated IP stack
- Standard AT commands
- Remote configuration, downloads, troubleshooting
- Telemetry protocols
- Encryption and security
- Dynamic DNS
- Network Address Translation
- Simple firewall to filter unauthorized IP adresses

BENEFITS
- Common ALEOS code used across all AirLink intelligent devices
- Provides a common experience to customers regardless of the network technology
- Allows customers to migrate to next generation networks with no change to their applications
- Over-the-air updates

WE MAKE WIRELESS DATA WORK

HEAT Equipment Specification Sheets—Legacy

• SYSTEM-10-BAC-IP BTU METER •
BACnet/IP COMPATIBLE

ONICON INCORPORATED

DESCRIPTION

The System-10 BTU Meter provides highly accurate thermal energy measurement in chilled water, hot water and condenser water systems based on signal inputs from two matched temperature sensors (included) and any of ONICON's insertion or in-line flow meters (ordered separately). The System-10-BAC-IP provides energy flow and temperature data on a local alphanumeric display and to the BACnet/IP network via the BACnet/IP communications driver. An optional auxiliary input is also available to totalize pulses from another device and communicates the total directly to the BACnet/IP network.

APPLICATIONS

Chilled water, hot water and condenser water systems for:

- Commercial office tenant billing
- Central plant monitoring
- University campus monitoring
- Institutional energy cost allocation
- Performance/efficiency evaluations
- Performance contracting energy monitoring

FEATURES

BACnet Compatible Serial Communications - Provides complete energy, flow and temperature data to the control system through a single BACnet/IP network connection, reducing installation costs.

Simple Installation and Commissioning - Factory programmed and ready for use upon delivery. All process data and programming functions are accessible via front panel display and keypad.

Single Source Responsibility - One manufacturer is responsible for every aspect of the energy measurement process, ensuring component compatibility and overall system accuracy.

N.I.S.T. Traceable Calibration with Certification - Each Btu measurement system is individually calibrated using application specific flow and temperature data and is provided with calibration certifications.

Precision Solid State Temperature Sensors - Custom calibrated and matched to an accuracy better than ±0.15° F over calibrated range.

A Variety of Accurate Flow Meters - ONICON has flow meters for every application. In the most demanding applications, the F-3000 series in-line electromagnetic meters offer accuracies of ± 0.2% of reading in limited straight pipe runs. Insertion turbine meters offer outstanding value with ± 1.0% of reading accuracy and are priced independent of pipe size. F-2000 series in-line vortex meters offer ± 1.0% of reading accuracy for very high temperature applications.

Complete Installation Package - All mechanical installation hardware, color coded interconnecting cabling and installation instructions are provided to ensure error-free installation and accurate system performance.

ORDERING INFORMATION

The System-10 BTU Meter is sold complete with temperature sensors and standard thermowells. Flow Meters are purchased separately.

ITEM #	DESCRIPTION
SYSTEM-10-BAC-IP	System-10 BTU Meter BACnet/IP compatible
SYSTEM-10-OPT1	Add for 6" and larger pipes
SYSTEM-10-OPT2	Add for 2.5" - 3" copper tube
SYSTEM-10-OPT3	Add for 4" copper tube
SYSTEM-10-OPT4	Upgrade to outdoor thermowells (pair)
SYSTEM-10-OPT5	Upgrade to hot tap thermowells (pair)
SYSTEM-10-OPT8	High temperature sensors (over 200° F)
SYSTEM-10-OPT9	Add one analog output
SYSTEM-10-OPT10	Add four analog outputs
SYSTEM-10-OPT11	Auxiliary pulse input
Choose from the following flow meters:	
F-1100/F-1200	Insertion Turbine Flow Meter (1¼"-72")
F-1300	Inline Turbine Flow Meter (¾" - 1")
F-2000 Series	Full Bore Vortex Flow Meter
F-3000 Series	Full Bore Electromagnetic Flow Meter
Refer to catalog for flow meter installation kits. Consult with ONICON for additional flow meter types.	

UL LISTED
PROCESS CONTROL EQUIPMENT
3GF5

1500 North Belcher Road, Clearwater, Florida 33765 Tel (727) 447-6140 Fax (727) 442-5699
www.onicon.com E-mail: sales@onicon.com

SYSTEM-10-BAC-IP BTU METER SPECIFICATIONS

ONICON INCORPORATED

CALIBRATION

Flow meter and temperature sensors are individually calibrated, followed by a complete system calibration.
Field commissioning is also available.

ACCURACY

Differential temperature accuracy ±0.15° F over calibrated range
Computing nonlinearity within ±0.05%

PROGRAMMING

Factory programmed for specific application
Field programmable via front panel interface

MEMORY

Non-volatile EEPROM memory retains all program parameters and totalized values in the event of power loss.

DISPLAY

Alphanumeric LCD displays total energy, total flow, energy rate, flow rate, supply temperature and return temperature
Alpha: 16 character, 0.2" high; Numeric: 6 digit, 0.4" high

OUTPUT SIGNALS

BACnet/IP Points List (Complies with Annex J)

Name	BACnet Object Type	Units
Total Energy	Analog Value	Btu, kW-hrs or ton-hrs
Energy Rate	Analog Input	Btu/hr, kW or tons
Total Flow	Analog Value	gallons, liters or meters³
Flow Rate	Analog Input	gpm, gph, mgd, l/s, l/m, l/hr or m³/hr
Supply Temperature	Analog Input	°F or °C
Return Temperature	Analog Input	°F or °C
Delta T	Analog Input	°F or °C
Energy Total Reset	Binary Value	Not applicable
Flow Total Reset	Binary Value	Not applicable
Auxiliary Input Total	Analog Value	Pulse Accumulator
Auxiliary Input Reset	Binary Value	Not applicable

Network Connection: 10BaseT, 10Mbps, RJ45 connection
Isolated solid state dry contact for energy total
Contact rating: 100 mA, 50V
Contact duration: 0.5, 1, 2, or 6 sec
Optional Analog Output(s) (4-20 mA, 0-10 V or 0-5 V):
One or four analog output(s) available for flow rate, energy rate, supply/return temps, or delta-T.

LIQUID FLOW SIGNAL INPUT

0-15 V pulse output from any ONICON flow meter.

TEMPERATURE SENSORS

Solid state sensors are custom calibrated using N.I.S.T. traceable temperature standards.
Current based signal (mA) is unaffected by wire length.

TEMPERATURE RANGE

Liquid temperature range:	32° to 200° F
Optional liquid temperature range:	122° to 302° F
Ambient temperature range:	40° to 120° F

MECHANICAL

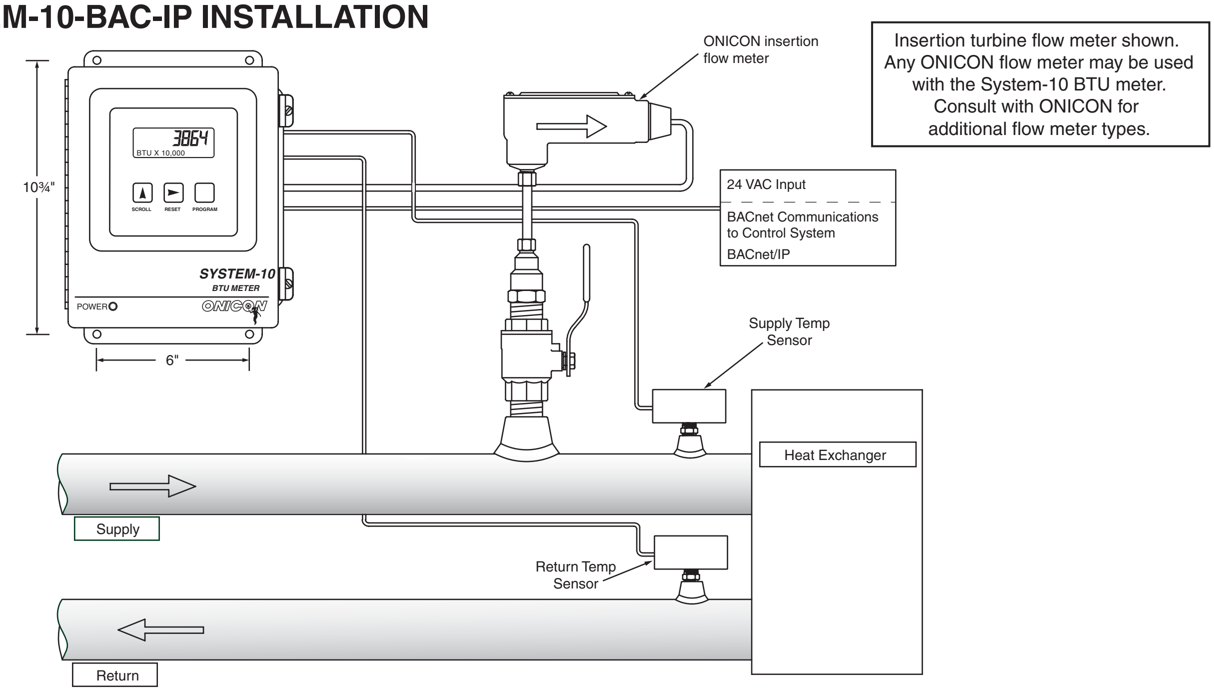
ELECTRONICS ENCLOSURE:
Standard: Steel NEMA 13, wall mount, 8"x10"x4"
Optional: NEMA 4 (Not UL listed)
Approximate weight: 12 lbs.
TEMPERATURE THERMOWELLS:
Standard: ½" NPT brass thermowells (length varies with pipe size) with junction box
Note: 6" pipes and larger require SS thermowell option
Optional:
- ½" NPT stainless steel thermowells
- Outdoor junction box with thermal isolation
- Hot tap thermowells with isolation valves are available in plated brass or stainless steel

ELECTRICAL

INPUT POWER*:
Standard: 24 VAC 50/60 Hz, 300 mA
Optional: 120 VAC 50/60 Hz, 200 mA
230 VAC, 50 Hz, 150 mA
*Based on Btu meters configured for network connection without the optional analog outputs
INTERNAL SUPPLY:
Provides 24 VDC at 200 mA to electronics and flow meter
WIRING:
Temperature signals: Use 18 - 22 ga twisted shielded pair
Flow signals: Use 18 - 22 ga shielded - see flow meter specification sheet for number of conductors

NOTE: Specifications are subject to change without notice.

TYPICAL SYSTEM-10-BAC-IP INSTALLATION



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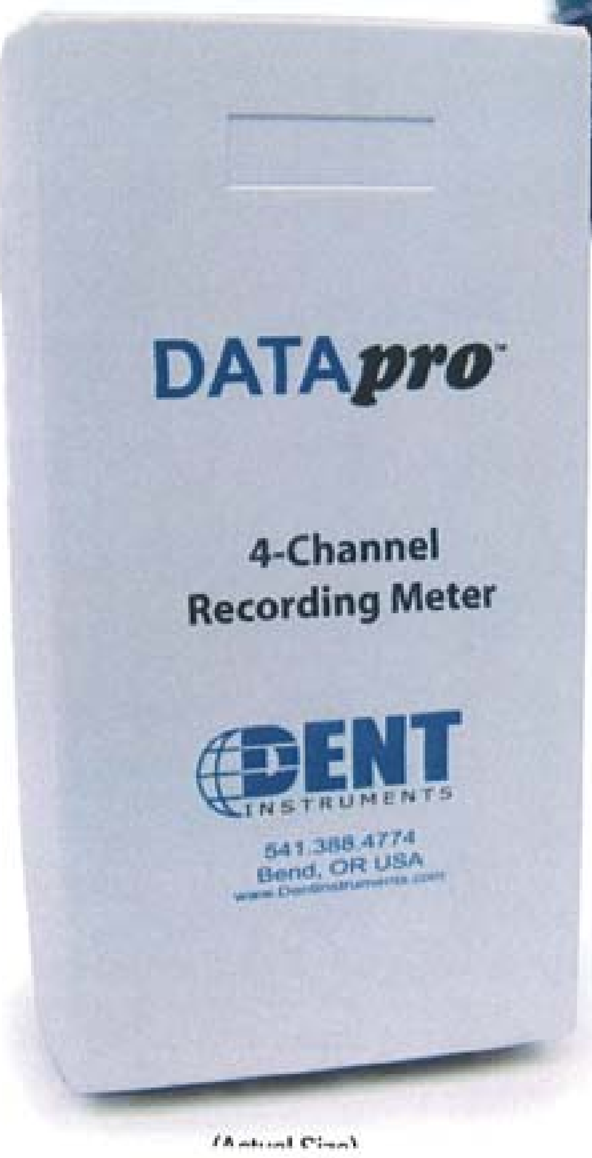
Measure, log and analyze almost anything!

Count pulses, or measure tempera-ture, control & process signals, AC current and much more.



(Actual Size)

One DATA*pro*™ is right for you

Who can use the DATA*pro*? Virtually anyone with a measuring problem. The DATA*pro* series can monitor, store and analyze data from a variety of common sensors, allowing you to make the right decision for your application. Production managers, security supervisors, facilities managers, architects, building owners, meteorologists, researchers, waste management supervisors, and engineers of all types are discovering new applications every day that one of the DATA*pro* Recording Meters can address. It's that versatile!

Applications

A growing family of DATA*pro* models is available to meet almost any measuring need. Virtually any utility – gas, water, electric, steam, HVAC, compressed air, solid or liquid waste – can be recorded. One DATA*pro* model will correlate utility consumption with inside or outside temperature, while others can measure and record data from manufacturing processes or environmental changes. With the ability to accept pulses and inputs such as 4-20mA, 0-10VDC, temperature, or AC current, one DATA*pro* model is right for you.

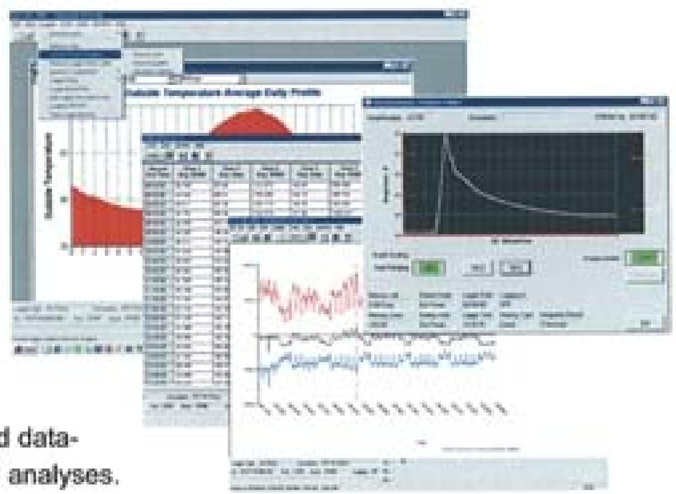
DENT
INSTRUMENTS
www.DentInstruments.com

Easy Installation

Installation and connection are both a breeze. Magnetic strips on the housing facilitate mounting on metal cabinets, and a simple 8-position port connects all external inputs. You supply the sensor; we supply the Recorder.

State of the Art Software

The ELOG software is used to program the meter, display metered values, retrieve and analyze the data. The Windows™ software graphically displays recorded data, performs analyses and allows automatic, remote data collection. Data is also easily exported to popular spreadsheets and databases for special analyses.



Versatile Options

A variety of options will suit your situation:

Modem - For long-term monitoring applications an internal modem is available. The modem can be programmed to automatically download data or used to read real-time values.

Weatherproof - A custom housing is dust and liquid resistant, allowing the unit to operate in harsh, wet and outdoor environments.

High Memory - This is the option you want when recording lots of data. Capacity is quadrupled to store up to 100,000 records between downloads.

4 Channel DATA*pro* Models

4V - 4 Voltage channels (0-10 Vdc)

4C - 4 Current channels

4P - 4 Pulse channels

4T - 4 Temperature channels

1T/3P - 1 Temperature, 3 pulse

2T/2P - 2 Temperature, 2 pulse

4M - 4 Milliamp (4-20mA or 0-25mA)

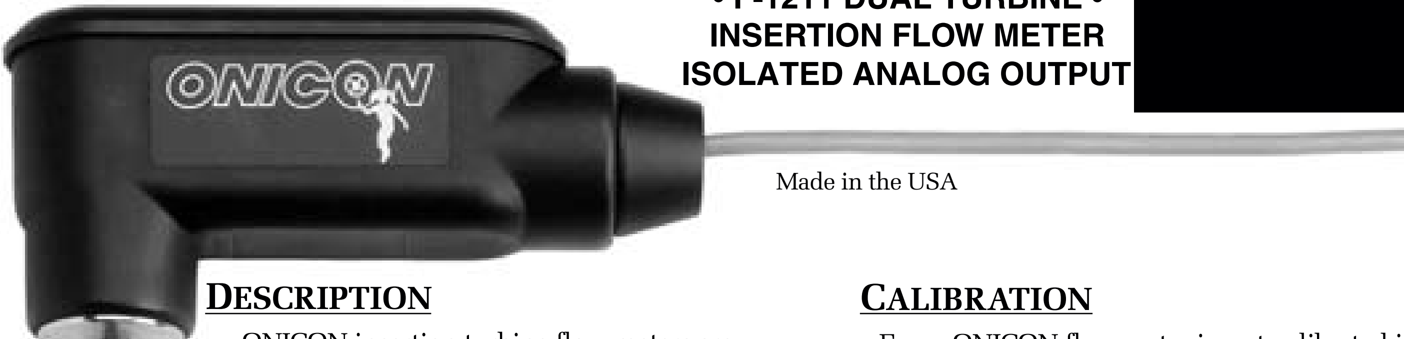
There's a DATApro model for every application

Specifications

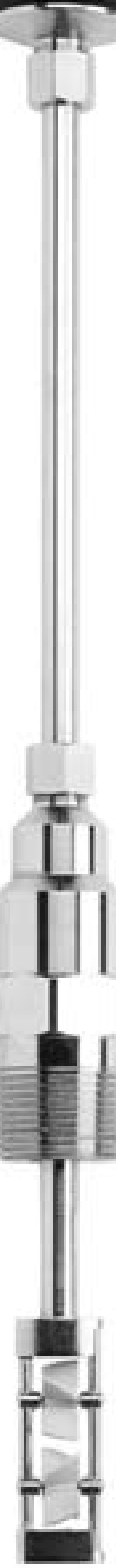
Inputs	4 channels of AC current, DC voltage, DC milliamps, pulse count, or temperature
Measurements	Min, Max, Average, Total
Frequency	10 Hz (pulse) and 50 or 60 Hz (current)
Accuracy	<1% of reading, exclusive of sensor accuracy
Baud Rate	Up to 57,600 (direct) or 14,400 (modem)
Resolution	Better than .1% FS for all parameters; 12 bit A/D (1 part in 4,096)
Memory	128kB (25,000 readings) or 512kB (100,000 readings)
Sampling Frequency	7.68 kHz (128 points per current waveform) or 10 Hz, interrupt driven
Recording Intervals	3, 15, 30 seconds; 1, 2, 5, 10, 15, 20, 30 minutes and 1, 12, 24 hrs.
Real Time Clock	Crystal controlled, true calendar, 20 ppm accuracy (<1 min/month)
Battery Life	3 years @ 1 min. sampling, LED indicator of low battery
Operating Temp.	-7 to 60 °C (20 to 140 °F)
Operating Humidity	5% to 95% non-condensing
Dimensions	8 x 15 x 6 cm (3.2" x 5.9" x 2.4")
Weight	340 gm (12 ounces)

DENT INSTRUMENTS
64 NW Franklin Ave. • Bend, OR 97701-2906 USA • Phone: 541.388.4774 • Fax: 541.385.9333

• F-1211 DUAL TURBINE •
INSERTION FLOW METER
ISOLATED ANALOG OUTPUT



Made in the USA



DESCRIPTION

ONICON insertion turbine flow meters are suitable for measuring electrically conductive water-based liquids. The F-1211 model provides isolated 4-20 mA and 0-10 V analog output signals that are linear with the flow rate.

APPLICATIONS

- Chilled water, hot water, condenser water, and water/glycol/brine for HVAC
- Process water and water mixtures
- Domestic water

GENERAL SPECIFICATIONS

ACCURACY
± 0.5% OF READING at calibrated velocity
± 1% OF READING from 3 to 30 ft/s (10:1 range)
± 2% OF READING from 0.4 to 20 ft/s (50:1 range)

SENSING METHOD
Electronic impedance sensing
(non-magnetic and non-photoelectric)

PIPE SIZE RANGE
2½" through 72" nominal

SUPPLY VOLTAGE
24±4 V AC/DC at 100 mA

LIQUID TEMPERATURE RANGE
Standard: 180° F continuous, 200° F peak
High Temp: 280° F continuous, 300° F peak
Meters operating above 250° F require
316 stainless steel construction option

AMBIENT TEMPERATURE RANGE
-5 to 160° F (-20 to 70° C)

OPERATING PRESSURE
400 PSI maximum

PRESSURE DROP
Less than 1 PSI at 20 ft/s in 2½" pipe,
decreasing in larger pipes and lower velocities

OUTPUT SIGNALS PROVIDED:

ANALOG OUTPUT (ISOLATED)
Voltage output: 0-10 V (0-5 V available)
Current output: 4-20 mA

FREQUENCY OUTPUT
0-15 V peak pulse, typically less than 300 Hz

(continued on back)

CALIBRATION

Every ONICON flow meter is wet-calibrated in our flow laboratory against primary volumetric standards directly traceable to NIST. Certification of calibration is included with every meter.

FEATURES

Unmatched Price vs. Performance - Custom calibrated, highly accurate instrumentation at very competitive prices.

Excellent Long-term Reliability - Patented electronic sensing is resistant to scale and particulate matter. Low mass turbines with engineered jewel bearing systems provide a mechanical system that virtually does not wear.

Industry Leading Two-year "No-fault" Warranty - Reduces start-up costs with extended coverage to include accidental installation damage (miswiring, etc.). Certain exclusions apply; see our complete warranty statement for details.

Installation Flexibility - Patented dual turbine models deliver outstanding accuracy in short pipe runs.

Simplified Hot Tap Insertion Design - Standard on every insertion flow meter. Allows for insertion and removal by hand without system shutdown.

OPERATING RANGE FOR
COMMON PIPE SIZES
0.17 TO 20 ft/s
± 2% accuracy begins at 0.4 ft/s

Pipe Size (Inches)	Flow Rate (GPM)
2½	2.5 - 230
3	4 - 460
4	8 - 800
6	15 - 1800
8	26 - 3100
10	42 - 4900
12	60 - 7050
14	72 - 8600
16	98 - 11,400
18	120 - 14,600
20	150 - 18,100
24	230 - 26,500
30	360 - 41,900
36	510 - 60,900

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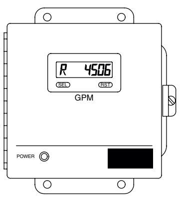
F-1211 SPECIFICATIONS cont.

MATERIAL
Wetted metal components
Standard: Electroless nickel plated brass
Optional: 316 stainless steel

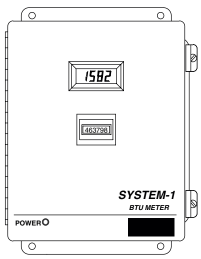
ELECTRONICS ENCLOSURE
Standard: Weathertight aluminum enclosure
Optional: Submersible enclosure

ELECTRICAL CONNECTIONS
4-wire minimum for 4-20 mA or 0-10 V output
Second analog output and/or frequency output requires additional wires
Standard: 10' of cable with ½" NPT conduit connection
Optional: Indoor DIN connector with 10' of plenum rated cable

ALSO AVAILABLE



Display Modules



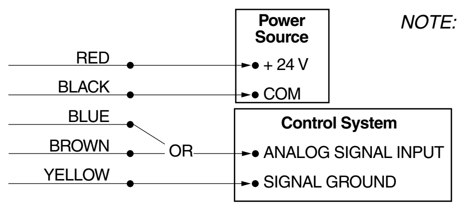
BTU Measurement Systems

F-1211 Wiring Information

WIRE COLOR CODE		NOTES
RED	(+) 24 V AC/DC supply voltage, 100 mA	Connect to power supply positive
BLACK	(–) Common ground (Common with pipe ground)	Connect to power supply negative
GREEN	(+) Frequency output signal: 0-15 V peak pulse	Required when meter is connected to local display or BTU meter
BLUE	(+) Analog signal: 4-20 mA (isolated)	Use yellow wire as (–) for these signals. Both signals may be used independently.
BROWN	(+) Analog signal: 0-10 V (isolated)	
YELLOW	(–) Isolated ground	Use for analog signals only
DIAGNOSTIC SIGNALS		
ORANGE	Bottom turbine frequency	These signals are for diagnostic purposes - connect to local display or BTU Meter
WHITE	Top turbine frequency	

F-1211 Wiring Diagram

Flow Meter into Control System (No Display or BTU Meter)

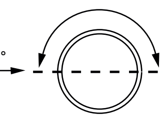


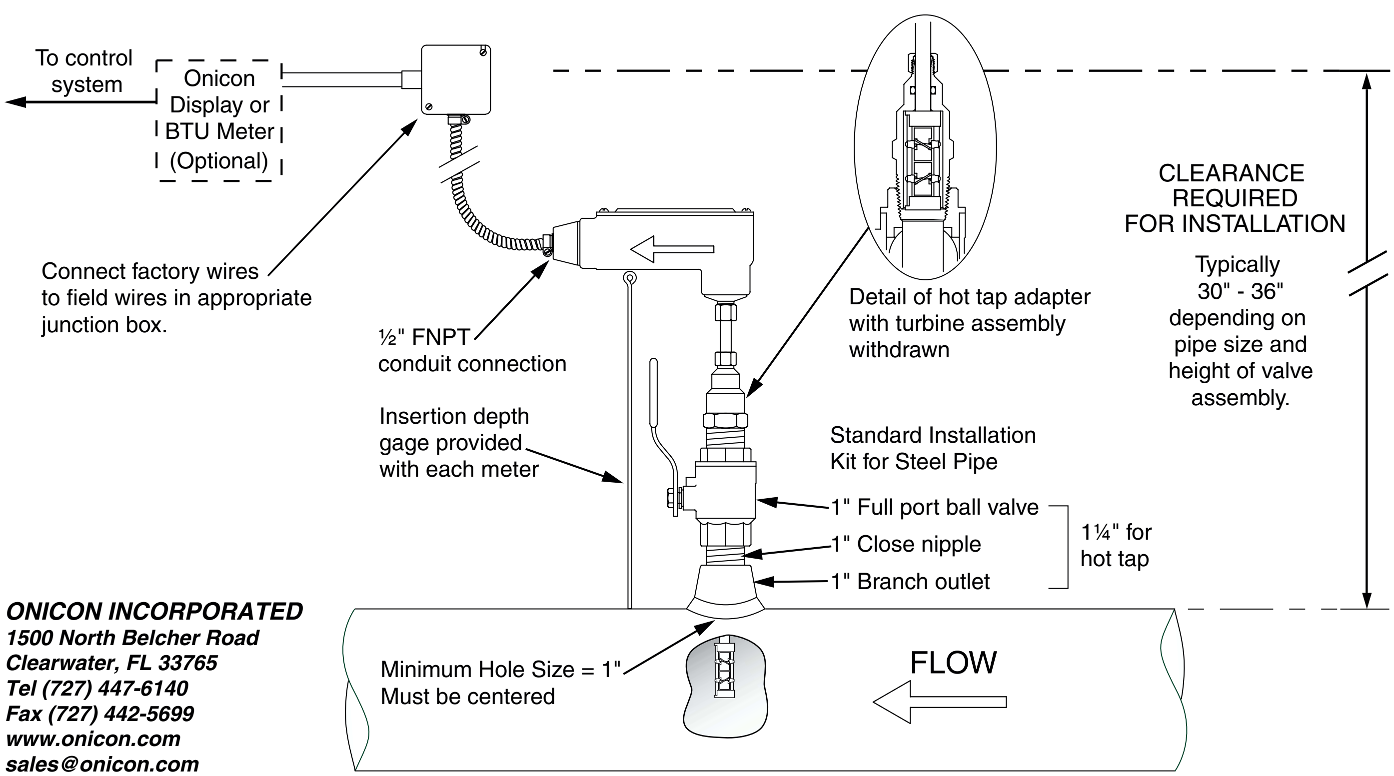
NOTE: 1. Black wire is common with the pipe ground (typically earth ground).
2. Frequency output required for ONICON display module or BTU meter, refer to wiring diagram for peripheral device.

Typical Meter Installation

(New construction or scheduled shutdown)

- Acceptable to install in vertical pipe
- Position meter anywhere in upper 180˚ for horizontal pipe





ONICON INCORPORATED
1500 North Belcher Road
Clearwater, FL 33765
Tel (727) 447-6140
Fax (727) 442-5699
www.onicon.com
sales@onicon.com

Note: Installation kits vary based on pipe material and application. For installations in pressurized (live) systems, use "Hot tap" 1¼ inch installation kit and drill hole using a 1 inch wet tap drill.

Appendix F

Legislation and Regulation

Assembly Bill 970

Assembly Bill No. 970

CHAPTER 329

An act to add and repeal Section 12078 of the Government Code, to add and repeal Section 42301.14 of the Health and Safety Code, to add Chapter 6.5 (commencing with Section 25550) to Division 15 of, and to repeal Sections 25550, 25552, and 25555 of, the Public Resources Code, and to amend Section 372 of, and to add Section 399.15 to, the Public Utilities Code, relating to energy resources, making an appropriation therefor, and declaring the urgency thereof, to take effect immediately.

[Approved by Governor September 6, 2000. Filed with Secretary of State September 7, 2000.]

LEGISLATIVE COUNSEL'S DIGEST

AB 970, Ducheny. Electrical energy: thermal powerplants: permits.

Existing law provides for the restructuring of California's electric power industry so that the price for the generation of electricity is determined by a competitive market.

Under existing law, air pollution control districts, air quality management districts, and the State Energy Resources Conservation and Development Commission issue permits for the operation of powerplants.

This bill would authorize those districts to issue a temporary, expedited, consolidated permit for a thermal powerplant if specified conditions are met, and would require the commission to establish a process for the expedited review of applications to construct and operate powerplants and thermal powerplants and related facilities.

This bill would require the Public Utilities Commission to identify and undertake certain actions to reduce or remove constraints on the electrical transmission and distribution system, and adopt specified energy conservation initiatives and undertake efforts to revise, mitigate, or eliminate specified policies or actions of the Independent System Operator for which the Public Utilities Commission or Electricity Oversight Board make a specified finding.

The bill would appropriate $57,500,000 from the General Fund for purposes of the bill. Of that amount, $5,200,000 would be allocated to fund specified staff resources to implement specified programs at the commission, the agencies, boards, and departments within the California Environmental Protection Agency, and the Resources Agency; $2,300,000 would be allocated to the Public Utilities Commission to fund specified staff resources, and $50,000,000 would be allocated to the commission to implement energy conservation and demand-side energy programs.

The bill would declare that it is to take effect immediately as an urgency statute.

Appropriation: yes.

The people of the State of California do enact as follows:

SECTION 1. This act shall be known, and may be cited, as the California Energy Security and Reliability Act of 2000.

SEC. 2. The Legislature finds and declares as follows:

(a) In recent years there has been significant growth in the demand for electricity in the state due to factors such as growth in population and economic activities that rely on electrical generation.

(b) In the past decade, efforts to construct and operate new, environmentally superior and efficient generation facilities and to promote cost-effective energy conservation and demand-side management have seriously lagged.

(c) As a result, California faces potentially serious electricity shortages over the next two years, which necessitates immediate action by the state.

(d) The purpose of this act is to provide a balanced response to the electricity problems facing the state that will result in significant new investments in new, environmentally superior electricity generation, while also making significant new investments in conservation and demand-side management programs in order to meet the energy needs of the state for the next several years.

(e) It is further the intent of this act to provide assistance to persons proposing to construct electrical generation facilities without in any manner compromising environmental protection.

SEC. 3. Section 12078 is added to the Government Code, to read:

12078. (a) There is hereby established the Governor's Clean Energy GREEN TEAM, which shall consist of a chairperson and not more than 15 members as follows:

(1) The Chair of the Electricity Oversight Board.

(2) The President of the California Public Utilities Commission.

(3) The Chair of the Energy Resources Conservation and Development Commission.

(4) The Secretary for Environmental Protection.

(5) The Secretary of the Resources Agency.

(6) The Secretary of the Trade and Commerce Agency.

(7) The director of the Governor's Office of Planning and Research.

(8) Representatives from the United States Environmental Protection Agency, the United States Fish and Wildlife Service, and other affected federal agencies appointed by the Governor.

(9) Representatives of local and regional agencies, including, but not limited to, air pollution control districts and air quality management districts appointed by the Governor.

(b) Within 90 days of the effective date of this section, the GREEN TEAM shall do all of the following:

(1) Compile and, upon request, make available to persons proposing to construct powerplants, all available guidance documents and other information on the environmental effects associated with powerplants proposed to be certified pursuant to Division 15 (commencing with Section 25000) of the Public Resources Code, and including state-of-the-art and best available control technologies and air emissions offsets that could be used to mitigate those environmental effects.

(2) Upon request, provide assistance to persons proposing to construct powerplants in obtaining essential inputs, including, but not limited to, natural gas supply, emission offsets, and necessary water supply.

(3) Upon request, provide assistance to persons proposing to construct powerplants pursuant to Chapter 6 (commencing with Section 25500) of Division 15 of the Public Resources Code in identifying the environmental effects of such powerplants and any actions the person may take to mitigate those effects.

(4) Upon request, provide assistance to persons proposing to construct powerplants in working with local governments in ensuring that local permits, land use authorizations, and other approvals made at the local level are undertaken in the most expeditious manner feasible without compromising public participation or environmental protection.

(5) Develop recommendations for low- or zero-interest financing programs for renewable energy, including distributed renewable energy for state and nonprofit corporations.

(c) This section shall remain in effect only until January 1, 2004, and as of that date is repealed, unless a later enacted statute, that is enacted before January 1, 2004, deletes or extends that date.

SEC. 4. Section 42301.14 is added to the Health and Safety Code, to read:

42301.14. (a) To the extent permitted by the federal Clean Air Act (42 U.S.C. Sec. 7401 et seq.), and notwithstanding Section 65950 of the Government Code, a district may issue a temporary, expedited, consolidated permit, as provided by Sections 42300.1 and 42301.3, for a powerplant within 60 days after the date of certification of an environmental impact report, within 30 days after the adoption of a negative declaration, or within 30 days after the date of a determination that the project is exempt from Division 13 (commencing with Section 21000) of the Public Resources Code, if all of the following conditions are met:

(1) The powerplant will emit less than 5 parts per million of oxides of nitrogen averaged over a three-hour period.

(2) The powerplant will operate exclusively under the terms of a contract entered into with the Independent System Operator and approved by the Electricity Oversight Board established pursuant to Article 2 (commencing with Section 334) of Chapter 2.3 of Part 1 of Division 1 of the Public Utilities Code.

(3) The owner or operator of the powerplant shall demonstrate that the powerplant, on average, will displace electrical generation that produces greater air emissions in the same air basin or in a basin that causes air pollution transport into that basin.

(4) The powerplant will be interconnected to the grid in a manner that the Public Utilities Commission, in consultation with the Electricity Oversight Board, has determined will allow the powerplant to provide service to a geographical area of the state that is urgently in need of generation in order to provide reliable electric service. However, nothing in this paragraph affects the authority of the Energy Resources Conservation and Development Commission over powerplants pursuant to Chapter 6 (commencing with Section 25500) of Division 15 of the Public Resources Code.

(5) The powerplant will be operated at a location that has the necessary fueling and electrical transmission and distribution infrastructure for its operation.

(6) The owner or operator of the powerplant enters into a binding and enforceable agreement with the district, and where applicable, with the Energy Resources Conservation and Development Commission, which demonstrates either of the following:

(A) That the powerplant will cease to operate and the permit will terminate within three years.

(B) That the powerplant will be modified, replaced, or removed within a period of three years with a combined-cycle powerplant that uses best available control technology and offsets, as determined at the time the combined-cycle plant is constructed, and that complies with all other applicable laws and regulations.

(7) Where applicable, the owner or operator of the powerplant will obtain offsets or, where offsets are unavailable, pay an air emissions mitigation fee to the district based upon the actual emissions from the powerplant, to the district for expenditure by the district pursuant to Chapter 9 (commencing with Section 44275) of Part 5, to mitigate the emissions from the plant.

(8) It is the intent of the Legislature in this section to encourage the expedited siting of cleaner generating units to address peaking power needs. It is further the intent of the Legislature to require local air quality management districts and air pollution control districts to recognize the critical need for these facilities and the short life span of these facilities in exercising their discretionary authority to apply

more restrictive air quality regulations than would otherwise be required by law.

(b) This section may be utilized for the purpose of expediting the siting of electrical generating facilities pursuant to Chapter 6 (commencing with Section 25500) of Division 15 of the Public Resources Code.

(c) This section shall remain in effect only until January 1, 2004, and as of that date is repealed, unless a later enacted statute, that is enacted before January 1, 2004, deletes or extends that date.

SEC. 5. Chapter 6.5 (commencing with Section 25550) is added to Division 15 of the Public Resources Code, to read:

CHAPTER 6.5. EXPEDITED SITING OF ELECTRICAL GENERATION

25550. (a) Notwithstanding subdivision (a) of Section 25522, and Section 25540.6 the commission shall establish a process to issue its final certification for any thermal powerplant and related facilities within six months after the filing of the application for certification that, on the basis of an initial review, shows that there is substantial evidence that the project will not cause a significant adverse impact on the environment or electrical system and will comply with all applicable standards, ordinances, or laws. For purposes of this section, filing has the same meaning as in Section 25522.

(b) Thermal powerplants and related facilities reviewed under this process shall satisfy the requirements of Section 25520 and other necessary information required by the commission, by regulation, including the information required for permitting by each local, state, and regional agency that would have jurisdiction over the proposed thermal powerplant and related facilities but for the exclusive jurisdiction of the commission and the information required for permitting by each federal agency that has jurisdiction over the proposed thermal powerplant and related facilities.

(c) After acceptance of an application under this section, the commission shall not be required to issue a six-month final decision on the application if it determines there is substantial evidence in the record that the thermal powerplant and related facilities may result in a significant adverse impact on the environment or electrical system or does not comply with an applicable standard, ordinance, or law. Under this circumstance, the commission shall make its decision in accordance with subdivision (a) of Section 25522 and Section 25540.6, and a new application shall not be required.

(d) For an application that the commission accepts under this section, all local, regional, and state agencies that would have had jurisdiction over the proposed thermal powerplant and related facilities, but for the exclusive jurisdiction of the commission, shall provide their final comments, determinations, or opinions within 100 days after the filing of the application. The regional water quality control boards, as established pursuant to Chapter 4 (commencing with Section 13200) of Division 7 of the Water Code, shall retain jurisdiction over any applicable water quality standard that is incorporated into any final certification issued pursuant to this chapter.

(e) Thermal powerplants and related facilities that demonstrate superior environmental or efficiency performance shall receive priority in review.

(f) With respect to a thermal powerplant and related facilities reviewed under the process established by this chapter, it shall be shown that the applicant has a contract with a general contractor and has contracted for an adequate supply of skilled labor to construct, operate, and maintain the plant.

(g) With respect to a thermal powerplant and related facilities reviewed under the process established by this chapter, it shall be shown that the thermal powerplant and related facilities complies with all regulations adopted by the commission that ensure that an application addresses disproportionate impacts in a manner consistent with Section 65040.12 of the Government Code.

(h) This section shall not apply to an application filed with the commission on or before August 1, 1999.

(i) To implement this section, the commission may adopt emergency regulations in accordance with Chapter 3.5 (commencing with Section 11340) of Part 2 of Division 3 of Title 2 of the Government Code. For purposes of that chapter, including without limitation, Section 11349.6 of the Government Code, the adoption of the regulations shall be considered by the Office of Administrative Law to be necessary for the immediate preservation of the public peace, health, safety, and general welfare.

(j) This section shall remain in effect until January 1, 2004, and as of that date is repealed unless a later enacted statute, that is enacted before January 1, 2004, deletes or extends that date.

25552. (a) The commission shall implement a procedure, consistent with Division 13 (commencing with Section 21000) and with the federal Clean Air Act (42 U.S.C.A. Sec. 7401 et seq.), for an expedited decision on simple cycle thermal powerplants and related facilities that can be put into service on or before August 1, 2001, including a procedure for considering amendments to a pending application if the amendments specify a change from a combined cycle thermal powerplant and related facilities to a simple cycle thermal powerplant and related facilities.

(b) The procedure shall include all of the following:

(1) A requirement that, within 15 days of receiving the application or amendment to a pending application, the commission shall determine whether the application is complete.

(2) A requirement that, within 25 days of determining that an application is complete, the commission shall determine whether the

application qualifies for an expedited decision pursuant to this section. If an application qualifies for an expedited decision pursuant to this section, the commission shall provide the notice required by Section 21092.

(c) The commission shall issue its final decision on an application, including an amendment to a pending application, within four months from the date on which it deems the application or amendment complete, or at any later time mutually agreed upon by the commission and the applicant, provided that the thermal powerplant and related facilities remain likely to be in service before or during August 2001.

(d) The commission shall issue a decision granting a license to a simple cycle thermal powerplant and related facilities pursuant to this section if the commission finds all of the following:

(1) The thermal powerplant is not a major stationary source or a modification to a major stationary source, as defined by the federal Clean Air Act, and will be equipped with best available control technology, in consultation with the appropriate air pollution control district or air quality management district and the State Air Resources Board.

(2) The thermal powerplant and related facilities will not have a significant adverse effect on the environment as a result of construction or operation.

(3) With respect to a project for a thermal powerplant and related facilities reviewed under the process established by this section, the applicant has a contract with a general contractor and has contracted for an adequate supply of skilled labor to construct, operate, and maintain the thermal powerplant.

(e) In order to qualify for the procedure established by this section, an application or an amendment to a pending application shall be complete by October 31, 2000, satisfy the requirements of Section 25523, and include a description of the proposed conditions of certification that will do all of the following:

(1) Assure that the thermal powerplant and related facilities will not have a significant adverse effect on the environment as a result of construction or operation.

(2) Assure protection of public health and safety.

(3) Result in compliance with all applicable federal, state, and local laws, ordinances, and standards.

(4) A reasonable demonstration that the thermal powerplant and related facilities, if licensed on the expedited schedule provided by this section, will be in service before August 1, 2001.

(5) A binding and enforceable agreement with the commission, that demonstrates either of the following:

(A) That the thermal powerplant will cease to operate and the permit will terminate within three years.

(B) That the thermal powerplant will be modified, replaced, or removed within a period of three years with a combined-cycle thermal powerplant that uses best available control technology and obtains necessary offsets, as determined at the time the combined-cycle thermal powerplant is constructed, and that complies with all other applicable laws, ordinances, and standards.

(6) Where applicable, that the thermal powerplant will obtain offsets or, where offsets are unavailable, pay an air emissions mitigation fee to the air pollution control district or air quality management district based upon the actual emissions from the thermal powerplant, to the district for expenditure by the district pursuant to Chapter 9 (commencing with Section 44275) of Part 5 of Division 26 of the Health and Safety Code, to mitigate the emissions from the plant. To the extent consistent with federal law and regulation, any offsets required pursuant to this paragraph shall be based upon a 1:1 ratio, unless, after consultation with the applicable air pollution control district or air quality management district, the commission finds that a different ratio should be required.

(7) Nothing in this section shall affect the ability of an applicant that receives approval to install simple cycle thermal powerplants and related facilities as an amendment to a pending application to proceed with the original application for a combined cycle thermal powerplant or related facilities.

(f) This section shall remain in effect only until January 1, 2003, and as of that date is repealed, unless a later enacted statute, that is enacted before January 1, 2003, deletes or extends that date except that the binding commitments in paragraph (5) of subdivision (e) shall remain in effect after that date.

25553. Notwithstanding any other provision of law, on or before 120 days after the effective date of this section or on the earliest feasible date thereafter, the commission shall take both of the following actions:

(a) Update its assessment in trends in energy consumption pursuant to Section 25216 in order to provide the Governor, the Legislature, and the public with accurate information on the status of electricity supply, demand, and conservation in the state and to recommend measures that could be undertaken to ensure adequate supply and energy conservation in the state.

(b) Adopt and implement updated and cost-effective standards pursuant to Section 25402 to ensure the maximum feasible reductions in wasteful, uneconomic, inefficient, or unnecessary consumption of electricity.

25555. (a) In consultation with the Public Utilities Commission, the commission shall implement the peak electricity demand reduction grant programs listed in paragraphs (1), (2), and (3). The commission's implementation of these programs shall be consistent with guidelines established pursuant to subdivision (b). The award of a grant pursuant to this section is subject to appeal to the commission upon a showing that factors other than those adopted by the commission were applied in making the award. Any action taken by an applicant to apply for, or to become or remain eligible to receive, a grant award, including satisfying conditions specified by the commission, does not constitute the rendering of goods, services, or a direct benefit to the commission. Awards made pursuant to this section are not subject to any repayment requirements of Chapter 7.4 (commencing with Section 25645). The peak electricity demand programs the commission shall implement pursuant to this section shall include, but not be limited to, the following:

(1) For San Francisco Bay Area and San Diego region electricity customers, the peak electricity demand program shall include both of the following:

(A) Incentives for price responsive heating, ventilation, air conditioning, and lighting systems.

(B) Incentives for cool communities.

(2) For statewide electricity customers, the peak electricity demand program shall include all of the following:

(A) Incentives for price responsive heating, ventilation, air conditioning, and lighting systems.

(B) Incentives for cool communities.

(C) Incentives for energy efficiency improvements for public universities and other state facilities.

(D) Funding for state building peak reduction measures.

(E) Incentives for light-emitting diode traffic signals.

(F) Incentives for water and wastewater treatment pump and related equipment retrofits.

(3) Renewable energy development, except hydroelectric development, for both onsite distributed energy development and for commercial scale projects through which awards may be made by the commission to reduce the cost of financing those projects.

(b) In consultation with the Public Utilities Commission, the commission shall establish guidelines for the administration of this section. The guidelines shall enable the commission to allocate funds between the programs as it determines necessary to lower electricity system peak demand. The guidelines adopted pursuant to this subdivision are not regulations subject to the requirements of Chapter 3.5 (commencing with Section 11340) of Part 1 of Division 3 of Title 2 of the Government Code.

(c) The commission may choose from among one or more business entities capable of supplying or providing goods or services that meet a specified need of the commission in carrying out the responsibilities for programs included in this section. The commission may select an entity on a sole source basis if the cost to the state will be reasonable and the commission determines that it is in the state's best interest.

(d) The commission shall contract with one or more business entities for evaluation of the effectiveness of the programs implemented pursuant to subdivision (a). The contracting provisions specified in subdivision (c) shall apply to these contracts.

(e) For purposes of this section, the following definitions shall apply:

(1) ‘‘Low-rise buildings’’ means one and two story buildings.

(2) ‘‘Price responsive heating, ventilation, air conditioning, and lighting systems’’ means a program that provides incentives for the installation of equipment that will automatically lower the electricity consumption of these systems when the price of electricity reaches specific thresholds.

(3) ‘‘Light-emitting diode traffic signals’’ means a program to provide incentives to encourage the replacement of incandescent traffic signal lamps with light-emitting diodes.

(4) ‘‘Cool communities’’ means a program to reduce ‘‘heat island’’ effects in urban areas and thereby conserve energy and reduce peak demand.

(5) ‘‘Water and wastewater treatment pump retrofit’’ means a program to provide incentives to encourage the retrofit and replacement of water and wastewater treatment pumps and equipment and installation of energy control systems in order to reduce their electricity consumption during periods of peak electricity system demand.

(f) The commission may expend no more than 3 percent of the amount appropriated to implement this section, for purposes of administering this section.

(g) This section shall remain in effect only until January 1, 2004, and as of that date is repealed, unless a later enacted statute, which is enacted before January 1, 2004, deletes or extends that date.

SEC. 6. Section 372 of the Public Utilities Code is amended to read:

372. (a) It is the policy of the state to encourage and support the development of cogeneration as an efficient, environmentally beneficial, competitive energy resource that will enhance the reliability of local generation supply, and promote local business growth. Subject to the specific conditions provided in this section, the commission shall determine the applicability to customers of uneconomic costs as specified in Sections 367, 368, 375, and 376. Consistent with this state policy, the commission shall provide that these costs shall not apply to any of the following:

(1) To load served onsite or under an over the fence arrangement by a nonmobile self-cogeneration or cogeneration facility that was operational on or before December 20, 1995, or by increases in the capacity of such a facility to the extent that such increased capacity was constructed by an entity holding an ownership interest in or operating the facility and does not exceed 120 percent of the installed

capacity as of December 20, 1995, provided that prior to June 30, 2000, the costs shall apply to over the fence arrangements entered into after December 20, 1995, between unaffiliated parties. For the purposes of this subdivision, ‘‘affiliated’’ means any person or entity that directly, or indirectly through one or more intermediaries, controls, is controlled by, or is under common on control with another specified entity. ‘‘Control’’ means either of the following:

(A) The possession, directly or indirectly, of the power to direct or to cause the direction of the management or policies of a person or entity, whether through an ownership, beneficial, contractual, or equitable interest.

(B) Direct or indirect ownership of at least 25 percent of an entity, whether through an ownership, beneficial or equitable interest.

(2) To load served by onsite or under an over the fence arrangement by a nonmobile self-cogeneration or cogeneration facility for which the customer was committed to construction as of December 20, 1995, provided that the facility was substantially operational on or before January 1, 1998, or by increases in the capacity of such a facility to the extent that the increased capacity was constructed by an entity holding an ownership interest in or operating the facility and does not exceed 120 percent of the installed capacity as of January 1, 1998, provided that prior to June 30, 2000, the costs shall apply to over the fence arrangements entered into after December 20, 1995, between unaffiliated parties.

(3) To load served by existing, new, or portable emergency generation equipment used to serve the customer’s load requirements during periods when utility service is unavailable, provided such emergency generation is not operated in parallel with the integrated electric grid, except on a momentary parallel basis.

(4) After June 30, 2000, to any load served onsite or under an over the fence arrangement by any nonmobile self-cogeneration or cogeneration facility.

(b) Further, consistent with state policy, with respect to self-cogeneration or cogeneration deferral agreements, the commission shall do the following:

(1) Provide that a utility shall execute a final self-cogeneration or cogeneration deferral agreement with any customer that, on or before December 20, 1995, had executed a letter of intent (or similar documentation) to enter into the agreement with the utility, provided that the final agreement shall be consistent with the terms and conditions set forth in the letter of intent and the commission shall review and approve the final agreement.

(2) Provide that a customer that holds a self-cogeneration or cogeneration deferral agreement that was in place on or before December 20, 1995, or that was executed pursuant to paragraph (1) in the event the agreement expires, or is terminated, may do any of the following:

(A) Continue through December 31, 2001, to receive utility service at the rate and under terms and conditions applicable to the customer under the deferral agreement that, as executed, includes an allocation of uneconomic costs consistent with subdivision (e) of Section 367.

(B) Engage in a direct transaction for the purchase of electricity and pay uneconomic costs consistent with Sections 367, 368, 375, and 376.

(C) Construct a self-cogeneration or cogeneration facility of approximately the same capacity as the facility previously deferred, provided that the costs provided in Sections 367, 368, 375, and 376 shall apply consistent with subdivision (e) of Section 367, unless otherwise authorized by the commission pursuant to subdivision (c).

(3) Subject to the fire wall described in subdivision (e) of Section 367 provide that the ratemaking treatment for self-cogeneration or cogeneration deferral agreements executed prior to December 20, 1995, or executed pursuant to paragraph (1) shall be consistent with the ratemaking treatment for the contracts approved before January 1995.

(c) The commission shall authorize, within 60 days of the receipt of a joint application from the serving utility and one or more interested parties, applicability conditions as follows:

(1) The costs identified in Sections 367, 368, 375, and 376 shall not, prior to June 30, 2000, apply to load served onsite by a nonmobile self-cogeneration or cogeneration facility that became operational on or after December 20, 1995.

(2) The costs identified in Sections 367, 368, 375, and 376 shall not, prior to June 30, 2000, apply to any load served under over the fence arrangements entered into after December 20, 1995, between unaffiliated entities.

(d) For the purposes of this subdivision, all onsite or over the fence arrangements shall be consistent with Section 218 as it existed on December 20, 1995.

(e) To facilitate the development of new microcogeneration applications, electrical corporations may apply to the commission for a financing order to finance the transition costs to be recovered from customers employing the applications.

(f) To encourage the continued development, installation, and interconnection of clean and efficient self-generation and cogeneration resources, to improve system reliability for consumers by retaining existing generation and encouraging new generation to connect to the electric grid, and to increase self-sufficiency of consumers of electricity through the deployment of self-generation and cogeneration, both of the following shall occur:

(1) The commission and the Electricity Oversight Board shall determine if any policy or action undertaken by the Independent System Operator, directly or indirectly, unreasonably discourages

the connection of existing self-generation or cogeneration or new self-generation or cogeneration to the grid.

(2) If the commission and the Electricity Oversight Board find that any policy or action of the Independent System Operator unreasonably discourages, the connection of existing self-generationor cogeneration or new self-generation or cogeneration to the grid, the commission and the Electricity Oversight Board shall undertake all necessary efforts to revise, mitigate, or eliminate that policy or action of the Independent System Operator.

SEC. 7. Section 399.15 is added to the Public Utilities Code, to read:

399.15. Notwithstanding any other provision of law, within 180 days of the effective date of this section, the commission, in consultation with the Independent System Operator, shall take all of the following actions, and shall include the reasonable costs involved in taking those actions in the distribution revenue requirements of utilities regulated by the commission, as appropriate:

(a) (1) Identify and undertake those actions necessary to reduce or remove constraints on the state's existing electrical transmission and distribution system, including, but not limited to, reconductoring of transmission lines, the addition of capacitors to increase voltage, the reinforcement of existing transmission capacity, and the installation of new transformer banks. The commission shall, in consultation with the Independent System Operator, give first priority to those geographical regions where congestion reduces or impedes electrical transmission and supply.

(2) Consistent with the existing statutory authority of the commission, the commission shall afford electrical corporations a reasonable opportunity to fully recover costs it determines are reasonable and prudent to plan, finance, construct, operate, and maintain any facilities under its jurisdiction required by this section.

(b) In consultation with the State Energy Resources Conservation and Development Commission, adopt energy conservation demand-side management and other initiatives in order to reduce demand for electricity and reduce load during peak demand periods. Those initiatives shall include, but not be limited to, all of the following:

(1) Expansion and acceleration of residential and commercial weatherization programs.

(2) Expansion and acceleration of programs to inspect and improve the operating efficiency of heating, ventilation, and air-conditioning equipment in new and existing buildings, to ensure that these systems achieve the maximum feasible cost-effective energy efficiency.

(3) Expansion and acceleration of programs to improve energy efficiency in new buildings, in order to achieve the maximum feasible reductions in uneconomic energy and peak electricity consumption.

(4) Incentives to equip commercial buildings with the capacity to automatically shut down or dim nonessential lighting and incrementally raise thermostats during peak electricity demand period.

(5) Evaluation of installing local infrastructure to link temperature setback thermostats to real-time price signals.

(6) Incentives for load control and distributed generation to be paid for enhancing reliability.

(7) Differential incentives for renewable or super clean distributed generation resources.

(8) Reevaluation of all efficiency cost-effectiveness tests in light of increases in wholesale electricity costs and of natural gas costs to explicitly include the system value of reduced load on reducing market clearing prices and volatility.

(c) In consultation with the Energy Resources Conservation and Development Commission, adopt and implement a residential, commercial, and industrial peak reduction program that encourages electric customers to reduce electricity consumption during peak power periods.

SEC. 8. The sum of fifty seven million five hundred thousand dollars ($57,500,000) is hereby appropriated from the General Fund to the State Controller for the following purposes:

(a) Five million two hundred thousand dollars ($5,200,000) to fund temporary staff resources, including, but not limited to, limited term positions, not to exceed four years, at the Energy Resources Conservation and Development Commission, the agencies, boards, and departments within the California Environmental Protection Agency, and the Resources Agency, with jurisdiction over electrical powerplant siting and conservation and demand side management programs, for the exclusive purpose of implementing programs pursuant to this act.

(1) Prior to the expenditure of funds pursuant to this subdivision, the commission shall prepare and submit an expenditure plan to the Governor and the Legislature that specifies those agencies and positions for which those funds will be expended.

(2) It is the intent of the Legislature that these funds for staff resources be expended exclusively to implement programs that achieve the maximum feasible cost-effective energy conservation and efficiency while providing the necessary staff resources to expedite siting of electrical powerplants that meet the criteria established pursuant to the act adding this section.

(b) Two million three hundred thousand dollars ($2,300,000) to the Public Utilities Commission, to fund temporary staff resources, including limited term positions not to exceed four years, and to implement the programs established pursuant to this act.

(c) Fifty million dollars ($50,000,000) to the Energy Resources Conservation and Development Commission, to implement cost-effective energy conservation and demand-side management programs established pursuant to Section 25555 of the Public Resources Code, as enacted by this act. The commission shall prioritize conservation and demand-side management programs funded pursuant to this subdivision to ensure that those programs that achieve the most immediate and cost-effective energy savings are undertaken as a first priority.

SEC. 9. Nothing in this act shall, in any way, apply to a pending application for the certification of the Metcalf Energy Center, which was filed with the State Energy Resources Conservation and Development Commission by Calpine and Bechtel under Docket No. (99-AFC-3).

SEC. 10. This act is an urgency statute necessary for the immediate preservation of the public peace, health, or safety within the meaning of Article IV of the Constitution and shall go into immediate effect. The facts constituting the necessity are:

Due to the shortage of electric generation capacity to meet the needs of the people of this state and in order to limit further impacts of this shortage on the public health, safety, and welfare, it is necessary that this act take effect immediately.

O

Assembly Bill 1685

Assembly Bill No. 1685

CHAPTER 894

An act to amend Sections 353.2 and 379.5 of, and to add Section 379.6 to, the Public Utilities Code, relating to energy.

[Approved by Governor October 12, 2003. Filed with Secretary of State October 12, 2003.]

LEGISLATIVE COUNSEL'S DIGEST

AB 1685, Leno. Energy: self-generation incentive program: peak reduction.

Existing law requires the Public Utilities Commission on or before March 7, 2001, and in consultation with the Independent System Operator, to take certain actions, including, in consultation with the State Energy Resources Conservation and Development Commission (Energy Commission), adopting energy conservation demand-side management and other initiatives in order to reduce demand for electricity and reduce load during peak demand periods, including, but not limited to, differential incentives for renewable or superclean distributed generation resources. Pursuant to this requirement, the commission has developed a Self Generation Incentive Program to encourage customers of electrical corporations to install distributed generation that operates on renewable fuel or contributes to system reliability. Existing law defines ''ultra-clean and low-emission distributed generation'' as an electric generation technology that produces zero emissions during operation or that produces emissions that are equal to or less than limits established by the State Air Resources Board, if the electric generation technology commences operation between January 1, 2003, and December 31, 2005.

This bill would require the commission, in consultation with the Energy Commission, to administer, until January 1, 2008, a self-generation incentive program for distributed generation resources in the same form that exists on January 1, 2004, but would require that combustion-operated distributed generation projects using fossil fuels commencing January 1, 2005, meet a NO_x emission standard, and commencing January 1, 2007, meet a more stringent NOx emission standard and a minimum efficiency standard, to be eligible for incentive rebates under the program. The bill would establish a credit for combined heat and power units that meet a certain efficiency standard.

The bill would revise the definition of an ultra-clean and low-emission distributed generation to include electric generation technologies that commence operation prior to December 31, 2008.

The people of the State of California do enact as follows:

SECTION 1. The Legislature finds and declares each of the following:

(a) Increasing California's reliance on renewable energy resources, particularly solar, ''ultra-clean,'' and ''low-emission'' electricity generation, promotes stable electricity prices, protects public health, improves environmental quality, stimulates sustainable economic development, creates new employment opportunities, and reduces reliance on imported fuels.

(b) The development of renewable energy resources, particularly nonpolluting solar electricity generation, ameliorates air quality problems throughout the state and improves public health by reducing the burning of fossil fuels and the associated environmental impacts.

(c) The Self Generation Incentive Program administered by the Public Utilities Commission and established pursuant to Section 379.5 (Decision 01-03- 073, March 27, 2001), has been a critically important subsidy for the growth of solar electricity generation in California, but is set to expire at the end of 2004.

(d) The Legislature intends that the commission continue the Self Generation Incentive Program in order to subsidize solar electricity generation.

SEC. 2. Section 353.2 of the Public Utilities Code is amended to read:

353.2. (a) As used in this article, ''ultra clean and low emission distributed generation'' means any electric generation technology that meets both of the following criteria:

(1) Commences initial operation between January 1, 2003, and December 31, 2008.

(2) Produces zero emissions during its operation or produces emissions during its operation that are equal to or less than the 2007 State Air Resources Board emission limits for distributed generation, except that technologies operating by combustion must operate in a combined heat and power application with a 60-percent system efficiency on a higher heating value.

(b) In establishing rates and fees, the commission may consider energy efficiency and emissions performance to encourage early compliance with air quality standards established by the State Air Resources Board for ultra clean and low emission distributed generation.

SEC. 3. Section 379.5 of the Public Utilities Code is amended to read:

379.5. Notwithstanding any other provision of law, on or before March 7, 2001, the commission, in consultation with the Independent System Operator, shall take all of the following actions, and shall include the reasonable costs involved in taking those actions in the distribution revenue requirements of utilities regulated by the commission, as appropriate:

(a) (1) Identify and undertake those actions necessary to reduce or remove constraints on the state's existing electrical transmission and distribution system, including, but not limited to, reconductoring of transmission lines, the addition of capacitors to increase voltage, the reinforcement of existing transmission capacity, and the installation of new transformer banks. The commission shall, in consultation with the Independent System Operator, give first priority to those geographical regions where congestion reduces or impedes electrical transmission and supply.

(2) Consistent with the existing statutory authority of the commission, afford electrical corporations a reasonable opportunity to fully recover costs it determines are reasonable and prudent to plan, finance, construct, operate, and maintain any facilities under its jurisdiction required by this section.

(b) In consultation with the State Energy Resources Conservation and Development Commission, adopt energy conservation demand-side management and other initiatives in order to reduce demand for electricity and reduce load during peak demand periods. Those initiatives shall include, but not be limited to, all of the following:

(1) Expansion and acceleration of residential and commercial weatherization programs.

(2) Expansion and acceleration of programs to inspect and improve the operating efficiency of heating, ventilation, and air-conditioning equipment in new and existing buildings, to ensure that these systems achieve the maximum feasible cost-effective energy efficiency.

(3) Expansion and acceleration of programs to improve energy efficiency in new buildings, in order to achieve the maximum feasible reductions in uneconomic energy and peak electricity consumption.

(4) Incentives to equip commercial buildings with the capacity to automatically shut down or dim nonessential lighting and incrementally raise thermostats during a peak electricity demand period.

(5) Evaluation of installing local infrastructure to link temperature setback thermostats to real-time price signals.

(6) Incentives for load control and distributed generation to be paid for enhancing reliability.

(7) Differential incentives for renewable or super clean distributed generation resources pursuant to Section 379.6.

(8) Reevaluation of all efficiency cost-effectiveness tests in light of increases in wholesale electricity costs and of natural gas costs to explicitly include the system value of reduced load on reducing market clearing prices and volatility.

(c) In consultation with the Energy Resources Conservation and Development Commission, adopt and implement a residential, commercial, and industrial peak reduction program that encourages electric customers to reduce electricity consumption during peak power periods.

SEC. 4. Section 379.6 is added to the Public Utilities Code, to read:

379.6. (a) The commission, in consultation with the State Energy Resources Conservation and Development Commission, shall until January 1, 2008, administer a self-generation incentive program for distributed generation resources, in the same form as exists on January 1, 2004.

(b) Notwithstanding subdivision (a), the self-generation incentive program shall do all of the following:

(1) Commencing January 1, 2005, require all combustion-operated distributed generation projects using fossil fuels to meet an oxides of nitrogen (NO_x) emissions rate standard of 0.14 pounds per megawatthour to be eligible for self-generation rebates.

(2) Commencing January 1, 2007, require all combustion-operated distributed generation projects using fossil fuels to meet an oxides of nitrogen (NOx) emissions rate standard of 0.07 pounds per megawatthour and a minimum efficiency of 60 percent, to be eligible for self-generation rebates. A minimum efficiency of 60 percent shall be measured as useful energy output divided by fuel input. The efficiency determination shall be based on 100 percent load.

(3) Combined heat and power units that meet the 60 percent efficiency standard may take a credit to meet the applicable oxides of nitrogren (NOx) emission standard of 0.14 pounds per megawatthour or 0.07 pounds per megawatthour. Credit shall be at the rate of one megawatthour for each 3.4 million British Thermal Units (BTUs) of heat recovered.

(4) Provide the commission with flexibility in administering the self-generation incentive program, including, but not limited to, flexibility with regard to the amount of rebates, inclusion of other ultra clean and low emission distributed generation technologies, and

evaluation of other public policy interests, including, but not limited to, ratepayers, and energy efficiency and environmental interests.

O

Assembly Bill 2778

Assembly Bill No. 2778

CHAPTER 617

An act to amend Section 379.6 of the Public Utilities Code, relating to electricity.

[Approved by Governor September 29, 2006. Filed with Secretary of State September 29, 2006.]

LEGISLATIVE COUNSEL'S DIGEST

AB 2778, Lieber. Electricity: self-generation incentive program.

Under existing law, the Public Utilities Commission (PUC) has regulatory authority over public utilities, including electrical corporations. Existing law requires the commission, in consultation with the State Energy Resources Conservation and Development Commission (Energy Commission), to administer, until January 1, 2008, a self-generation incentive program for distributed generation resources in the same form that exists on January 1, 2004, subject to certain air emissions and efficiency standards. In a decision, the PUC adopted the California Solar Initiative, which modified the self-generation incentive program for distributed generation resources and provides incentives to customer-side photovoltaics and solar thermal electric projects under one megawatt.

This bill would require the commission, in consultation with the Energy Commission, to administer, until January 1, 2012, a self-generation incentive program for distributed generation resources. The program in its currently existing form, would be applicable to all eligible technologies, as determined by the commission, until January 1, 2008, except for solar technologies, which the commission would be required to administer separately, after January 1, 2007, pursuant to the California Solar Initiative. The bill, commencing January 1, 2008, until January 1, 2012, would limit eligibility for nonsolar technologies to fuel cells and wind distributed generation technologies that meet or exceed the emissions standards required under the distributed generation certification program adopted by the State Air Resources Board. The bill would require the Energy Commission, on or before November 1, 2008, in consultation with the commission and the board, to evaluate the costs and benefits of providing ratepayer subsidies for renewable and fossil fuel "ultraclean and low-emission distributed generation," as defined, as part of the Energy Commission's integrated energy policy report.

The people of the State of California do enact as follows:

SECTION 1. Section 379.6 of the Public Utilities Code is amended to read:

379.6. (a) (1) The commission, in consultation with the State Energy Resources Conservation and Development Commission, shall administer, until January 1, 2012, the self-generation incentive program for distributed generation resources originally established pursuant to Chapter 329 of the Statutes of 2000.

(2) Except as provided in paragraph (3), the extension of the program pursuant to Chapter 894 of the Statutes of 2003, as amended by Chapter 675 of the Statutes of 2004 and Chapter 22 of the Statutes of 2005, shall apply to all eligible technologies, as determined by the commission, until January 1, 2008.

(3) The commission shall administer solar technologies separately, after January 1, 2007, pursuant to the California Solar Initiative adopted by the commission in Decision 06-01-024.

(b) Commencing January 1, 2008, until January 1, 2012, eligibility for the program pursuant to paragraphs (1) and (2) of subdivision (a) shall be limited to fuel cells and wind distributed generation technologies that meet or exceed the emissions standards required under the distributed generation certification program requirements of Article 3 (commencing with Section 94200) of Subchapter 8 of Chapter 1 of Division 3 of Title 17 of the California Code of Regulations.

(c) Eligibility for the self-generation incentive program's level 3 incentive category shall be subject to the following conditions:

(1) Commencing January 1, 2007, all combustion-operated distributed generation projects using fossil fuel shall meet an oxides of nitrogen (NO_x) emissions rate standard of 0.07 pounds per megawatthour and a minimum efficiency of 60 percent. A minimum efficiency of 60 percent shall be measured as useful energy output divided by fuel input. The efficiency determination shall be based on 100 percent load.

(2) Combined heat and power units that meet the 60-percent efficiency standard may take a credit to meet the applicable NO_x emissions standard of 0.07 pounds per megawatthour. Credit shall be at the rate of one megawatthour for each 3.4 million British thermal units (Btus) of heat recovered.

(3) Notwithstanding paragraph (1), a project that does not meet the applicable NO_x emissions standard is eligible if it meets both of the following requirements:

(A) The project operates solely on waste gas. The commission shall require a customer that applies for an incentive pursuant to this paragraph to provide an affidavit or other form of proof, that specifies that the project shall be operated solely on waste gas. Incentives awarded pursuant to this paragraph shall be subject to refund and shall be refunded by the recipient to the extent the project does not operate on waste gas. As used in this paragraph, "waste gas" means natural gas that is generated as a byproduct of petroleum production operations and is not eligible for delivery to the utility pipeline system.

(B) The air quality management district or air pollution control district, in issuing a permit to operate the project, determines that operation of the project will produce an onsite net air emissions benefit, compared to permitted onsite emissions if the project does not operate. The commission shall require the customer to secure the permit prior to receiving incentives.

(d) In determining the eligibility for the self-generation incentive program, minimum system efficiency shall be determined either by calculating electrical and process heat efficiency as set forth in Section 218.5, or by calculating overall electrical efficiency.

(e) In administering the self-generation incentive program, the commission may adjust the amount of rebates, include other ultraclean and low-emission distributed generation technologies, as defined in Section 353.2, and evaluate other public policy interests, including, but not limited to, ratepayers, and energy efficiency and environmental interests.

(f) On or before November 1, 2008, the State Energy Resources Conservation and Development Commission, in consultation with the commission and the State Air Resources Board, shall evaluate the costs and benefits, including air pollution, efficiency, and transmission and distribution system improvements, of providing ratepayer subsidies for renewable and fossil fuel “ultraclean and low-emission distributed generation,” as defined in Section 353.2, as part of the integrated energy policy report adopted pursuant to Chapter 4 (commencing with Section 25300) of Division 15 of the Public Resources Code. The State Energy Resources Conservation and Development Commission shall include recommendations for changes in the eligibility of technologies and fuels under the program, and whether the level of subsidy should be adjusted, after considering its conclusions on costs and benefits pursuant to this subdivision.

O

CPUC Decision 04-12-045

Date of Issuance 4/25/2008

Decision 08-04-049 April 24, 2008

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues.	Rulemaking 08-03-008 (Filed March 13, 2008)

OPINION GRANTING IN PART PETITION BY FUELCELL ENERGY TO MODIFY DECISION 04-12-045

1. Summary

In Rulemaking (R.) 08-03-008, the Commission transferred the petition of FuelCell Energy (FCE) to modify Decision (D.) 04-12-045 to the Commission's new distributed generation rulemaking to be handled in the above-captioned proceeding.

This decision grants in part the petition by FCE to raise the cap on incentives to individual projects that apply for incentives through the Commission Self-Generation Incentive Program (SGIP). During 2008 and 2009 only, this decision allows program administrators of SGIP to use any carryover funds from prior budget years to pay incentives up to 3 megawatts (MW) for qualifying fuel cell or wind distributed generation (DG) projects. Incentives over 1 MW will be paid at a lower rate.

2. Background

In D.01-03-073, the Commission authorized the SGIP to encourage the development and commercialization of new DG technologies.[1] Under the SGIP, certain entities qualify for financial incentives to install DG to serve some portion of a customer's onsite load. In subsequent orders, the Commission refined the program, taking actions such as adopting a reliability requirement, developing renewable fuel criteria, and increasing the maximum project size eligible for incentives.

With regard to project size, the Commission initially limited both the size of eligible projects and incentives to 1 MW, reasoning that the size limit "represents a fairly large installation for a single customer site and, at the same time, will not use up an unreasonable amount of program funding." (D.01-03-073, at 29.) In a subsequent order, the Commission increased the project size eligible to participate up to 5 MW to "allow developers, customers, utilities and ratepayers to receive cost savings achieved by larger projects." (D.04-12-045 at 9.) Despite raising this maximum project size, the Commission retained the cap on incentives at 1 MW due to concerns about depleting limited SGIP budgets. (*Id.*)

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[1] "Self-generation" refers to distributed generation technologies (microturbines, small gas turbines, wind turbines, photovoltaics, fuel cells and internal combustion engines) installed on the customer's side of the utility meter that provide electricity for a portion or all of that customer's electric load. In D.06-01-024, the Commission directed that starting in 2007, photovoltaic self-generation projects would be separately funded through the California Solar Initiative, rather than the SGIP.

For 2008, the SGIP budget is $ 83 million, as set forth by the Commission in D.08-01-029. In addition, the SGIP is limited by Pub. Util. Code § 379.6 to funding only wind and fuel cell DG projects, effective January 1, 2008.

3. Petition for Modification

On July 25, 2007, FCE filed its petition requesting the Commission modify D.04-12-045 to increase the limit of incentive payments available under the SGIP program from the current cap of 1 MW to 3 MW.[2] Although projects up to 5 MW are eligible for participation in SGIP, incentives are limited to 1 MW. FCE contends this has suppressed participation by larger fuel cell projects in the program. FCE argues an increase in the incentive cap to 3 MW is needed to stimulate the much needed market transformation for affordable fuel cell technology and other renewable distributed generation applications that are only economic at a larger scale. FCE also maintains that the modification would result in new projects that would deliver substantial reductions in greenhouse gases.

In its petition, FCE contends the market for fuel cells in California is significantly constrained, particularly in the waste treatment market, by the 1 MW limit. Based on feedback from operators of industrial facilities and wastewater treatment plants, FCE reasons the modification will result in significant deployments of new fuel cell power plants at these sites. The most

[2] FCE's petition was filed in R.04-03-017, the docket in which D.04-12-045 was issued, and also served on parties to R.06-03-004. Service to both lists was completed on July 31, 2007, which extended the filing date for comments on the petition to August 30, 2007. The two dockets, R.04-03-017 and R.06-03-004, were consolidated for purposes of resolving this petition. The petition was transferred to this docket by R.08-03-008 and is resolved herein.

prominent emerging market sector is municipal wastewater treatment. Specifically, FCE contends that fuel cells' high electrical efficiency enables them to deliver almost twice the electrical output for each unit of gas consumed. In a declaration filed with its petition, FCE's witness states that wastewater treatment plant operators have expressed an interest in fuel cell technology as an alternative to combustion technologies. Further, the witness states that he has had conversations with wastewater treatment plant owners who have tried but failed to cost-justify installation of fuel cells at larger facilities without incentives.

FCE further justifies its modification request with the reasoning that raising the incentive cap will result in new projects that would deliver substantial greenhouse gas (GHG) reductions in addition to peak electricity demand reductions. According to FCE, renewable fuel cells can provide high GHG reduction by capturing and using biogas in lieu of its use in either flares or combustion. Thus, FCE argues, larger fuel cell projects, particularly at municipal wastewater plants, could benefit ratepayers by maximizing returns on local tax dollars and increasing the reduction in combustion emissions, with associated environmental benefits. Moreover, FCE contends that increasing the cap on SGIP incentives from 1 to 3 MW could lead to reduced product costs via larger production volumes, thus enabling market transformation for fuel cells.

FCE maintains the only down side to its request is the potential that program funds could be depleted more rapidly than they would otherwise. To offset this concern, FCE suggests the Commission authorize additional SGIP funding to support more projects, or consider other measures to ensure participation by small projects.

According to Rule 16.4(d) of the Commission's Rules of Practice and Procedure, petitions for modification must be filed within one year of a

Commission decision. FCE states that its petition, filed more than two years after issuance of D.04-12-045, is based on experience gained, particularly with larger customers, over the six-year history of SGIP, and therefore could not have been filed earlier. UTC Power Corporation (UTC) objects to FCE's late-filed petition to modify, asserting that FCE has not adequately justified its late submission because potential customers of every size have existed since SGIP's inception. We find that FCE has adequately justified the late filing of its petition because information pertaining to larger customers and the market demand for fuel cells is newly available. Thus, we will address FCE's petition on its merits.

4. Comments on Petition

Responses to the petition were filed by California Center for Sustainable Energy (CCSE), Center for Energy Efficiency and Renewable Technologies (CEERT), Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and UTC. In addition, responses were filed by Alliance Power Inc., ApolloPower Inc., California State University Northridge, Carollo Engineers P.C., Chevron Energy Solutions Company (CES), Gills Onions Rio Farms, HydroGen Corporation, Manuel Bros., Inc., Marubeni Corporation, MISCO, National Fuel Cell Research Center, Powerhouse Energy LLC, Silverwood Energy Inc., and Starwood Hotels and Resorts Worldwide Inc. We refer to this latter group collectively as the "fuel cell supporters" because though the comments were filed individually, they were strikingly similar, and in some cases identical to each other.

The fuel cell supporters state strong support for the petition, contending the increase in project size eligible for incentives is needed to cost-effectively develop the biogas market for fuel cell technology at waste treatment plants, landfills, and other host facilities that need larger scale projects. They allege that raising the incentive cap for both natural gas and renewable biogas supplied fuel cell technologies will allow larger users of electric and thermal energy to implement more efficient technologies which utilize less fuel. They contend there is an increasing market demand for DG between 1 and 3 MW to meet the requirements of end user customers. According to the fuel cell supporters, if the Commission raised the incentive cap to 3 MW, this would help encourage innovation and expansion of DG applications at a time when the state needs renewable DG and efficient use of fuel stocks. These parties claim the current 1 MW cap on incentives deters larger installations because they are uneconomic and too risky to develop.

Moreover, these parties contend that large fuel cell projects provide benefits to utility systems in California such as decreasing GHG emissions per megawatt hour of baseload electricity and thermal load supplied, reducing transmission and distribution grid constraints, reducing the need for new generation capacity, and eliminating emissions from combustion-fired power generation that would otherwise be used if renewable biogas or natural gas supplied fuel cell projects are not implemented. The fuel cell supporters further contend that if the Commission is concerned that raising the incentive cap will negatively affect SGIP participation by smaller DG projects, the Commission can monitor this, allocate money between large and small projects, or increase the SGIP budget.

UTC opposes FCE's petition, arguing that the Commission has denied past requests to raise the 1 MW cap on the basis that an increase might cause large projects to deplete the SGIP budget. UTC contends the 1 MW cap should be maintained to ensure the broad distribution of SGIP funds. According to UTC, increasing the cap beyond 1 MW would minimize the overall number of projects funded by SGIP, in opposition to the Commission's earlier stated goal of making SGIP funds available to a broad range of projects and customers.

Moreover, UTC contends the SGIP is successful at current incentive levels, with program data provided by FCE in its petition indicating that 2006 saw the highest level of fuel cell participation in SGIP to date.[3] Thus, UTC concludes that maintaining current incentive levels will support more projects and increase fuel cell market penetration. UTC argues that the overall number of fuel cells manufactured promotes economies of scale that lead to price reductions. Thus, a higher number of smaller projects promote competition and innovation in clean energy more than incentives limited to a few large projects.

CEERT supports the petition as it relates to renewable fuel cells, and supports the recommendation for increased SGIP funding. CEERT also proposes that to ensure smaller installations receive incentives, the Commission could require installations over 1 MW to wait until the close of the fiscal year to receive incentives for the portion of their project over 1 MW. In reply, FCE opposes this request as creating too much uncertainty for fuel cell developers and undermining the ability to obtain project financing.

CCSE, PG&E and SCE support the petition, but only with respect to fuel cells operating on renewable fuel. SCE contends that raising the incentive cap for non-renewable technologies risks depleting program funds. PG&E suggests a lower incentive level of $2.50/watt for incentives over the first MW to extend the SGIP budget, and it also recommends permitting the increased incentive cap

[3] UTC cites statistics provided by FCE on p. 4 of its July 25, 2007 petition.

on a two-year pilot basis. CCSE also supports a tiered incentive approach to prevent a small group of large customers from monopolizing program funds.

In response to UTC, FCE states that the current 1 MW cap inhibits development of the market for larger installations. FCE proposes consideration of conditions to ensure funds are fairly allocated to large and small DG, such as budget allocations between large and small customer classes with corresponding discretion to shift funds, or scaled incentives as suggested by PG&E and CCSE. FCE supports the suggestion that any increase in the incentive cap should apply to renewable projects only.

5. Amended Petition

On February 8, 2008, FCE filed an amended petition containing further information in support of its petition and amending its initial request. FCE now asks that the Commission raise the 1 MW incentive cap solely for renewable fuel projects, establish tiered incentives for capacity over 1 MW, and approve the increased incentives on a two-year pilot basis, with extension only upon Commission review.

The amended petition includes two additional declarations containing financial information and analysis on the need for incentives to encourage development of larger fuel cell projects, the efficiencies and economies of scale of fuel cell projects larger than 1 MW, GHG emissions benefits, and financial impacts of tiered incentives. In its amended petition, FCE provides information on two potential projects larger than 1 MW it is working to develop, and it claims incentives are required up to 3 MW to make the payback period for these projects acceptable to potential customers. FCE contends larger projects are better able to deliver cost-effective solutions for wastewater treatment operators because the cost of the fuel treatment system and other external costs of the fuel cell, including mechanical and electric systems and installation, become less significant as project size increases. (FCE Amended Petition, 2/8/08, Declaration of Jeff Cox.) The amended petition also includes data from the SGIP Sixth Year Impact Evaluation, dated August 2007, to support FCE's contention that renewable fuel cells attain the highest net GHG reductions of any participating SGIP technology. (*Id.*, p. 13.)

The following parties filed comments on the amended petition: Californians for Renewable Energy (CARE), CCSE, Debenham Energy LLC (Debenham), SCE, TechNet,[4] and UTC. SCE and CCSE support FCE's amended petition, although SCE suggests the Commission dedicate a percentage of SGIP funds to projects below 1 MW.

CARE, TechNet and UTC oppose the amended petition. UTC comments that the benefits claimed by FCE in its amended petition are inaccurate. UTC disputes FCE's claim that increased funding to large projects will result in market transformation for fuel cell technology. In addition, UTC maintains the mechanisms suggested in the amended petition to preserve funds do not mitigate UTC's concern about budget depletion and lack of funding for small DG projects. CARE echoes this concern that raising the incentive cap to 3 MW will deplete SGIP funds more quickly and benefit a few large companies rather than encourage development of the industry as a whole. TechNet contends that retaining the 1 MW cap on incentives will allow more Californians to benefit from the program, fostering greater competition, innovation, and cost reduction. TechNet urges the Commission to promote fuel cell competition in a technology

4 TechNet is a bipartisan political network of chief executive officers and senior executives that promote the growth of technology and innovation in the economy.

neutral fashion rather than allowing a vast portion of the SGIP budget to benefit only a few large projects.

In a ruling dated February 14, 2008, the Administrative Law Judge (ALJ) asked for comment on whether the Commission should consider increasing the cap on incentives for eligible wind DG projects as well as renewable fuel cells, as requested in the amended petition. SCE opposes increasing the incentive cap for wind projects without additional information. Debenham, a renewable energy consulting firm, supports the idea, arguing that wind projects need a higher incentive cap for technology-specific reasons. Specifically, Debenham contends the intermittent nature of wind technology is constrained by the 1 MW incentive cap designed to favor to photovoltaics, and this has put a damper on wind participation in SGIP. Further, Debenham supports an incentive cap increase so that fuel cells and wind can share equally in SGIP benefits. CCSE echoes the comments of Debenham that wind projects have experienced difficulty in the below 1 MW sizing range and raising the incentive cap could stimulate projects greater than 1 MW.

6. Discussion

The key issue raised by FCE's petition is whether the Commission should deviate from prior decisions that created and retained a 1 MW cap on incentives to any one project. If we raise the incentive limit beyond 1 MW, as FCE requests, this could allow a large portion of each utility's SGIP budget to go towards a single project, or at most, a few large projects. On the other hand, parties suggest mechanisms to preserve program funds, such as raising the incentive cap for only renewable fuel cell projects, reducing incentives for projects over 1 MW, and lifting the 1 MW cap on a pilot basis.

FCE and CCSE, point out that the SGIP currently has $96 million in unused funds from prior years.[5] CCSE contends that unused funds indicate potential shortcomings in the eligible technology market, the incentive rates, and/or program execution. PG&E and CCSE note that fuel cell participation in SGIP has not been high. CCSE states it has funded only $21.1 of $506.7 million in incentives to wind and fuel cell projects, or just 4%, and only 8.9 MW of 278.1 MW, or 3.2% of installed capacity. PG&E claims the renewable fuel cell market needs stimulation because no renewable fuel cell projects have been completed in its service territory, although five such projects (representing 4.7 MW in capacity) are currently pending. Our Energy Division reviewed SGIP data and found that although SGIP funded a total of 233.8 MW in 2005 through 2007, there were only 32 fuel cell project applications in SGIP in those years. Nine of the 32 projects have been completed, with a capacity of 5.7 MW. Three of the 32 applications pertained to renewable fuel cells, for a total capacity of 2.62 MW. There were five wind turbine project applications over the same period, for 3.8 MW in capacity, and none have been completed. Moreover, only six fuel cell and wind SGIP applications during that period were for projects over 1 MW, with a maximum size of 1.5 MW, and none have been completed. The fact that SGIP has not funded a completed wind or fuel cell project greater than 1 MW from 2005 to the present is consistent with the notion that the existing incentive cap is effectively functioning as a cap on wind and fuel cell project size, despite the fact that projects up to 5 MW are eligible to participate in SGIP.

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[5] FCE and CCSE cite the SGIP administrators' website as the source of this figure. The Commission's Energy Division has corroborated this figure.

CCSE maintains that providing incentives to larger installations, coupled with a tiered incentive structure that pays less than the full incentive over 1 MW, can provide for the installation of more MW of renewable fuel cell DG projects for fewer incentive dollars. In their example, the current 1 MW cap for CCSE allows them to fund 5.4 MW of renewable fuel projects. If the incentive cap were raised to 3 MW, coupled with tiered incentives, CCSE's budget could fund 8.6 MW with the same budget of $23.4 million.

In support of its petition, FCE argues the market for fuel cells is constrained by the 1 MW limit and that "larger projects are better able to deliver cost-effective solutions to the wastewater operator." (FCE Petition, 7/25/07, p. 6.) FCE also suggests that increasing the incentive cap will allow fuel cell manufacturers to reduce product costs via larger production volumes as they realize economies of scale in raw material procurement and production labor when a higher volume of fuel cells are manufactured and sold. (*Id.*, p. 8.) FCE's amended petition attempts to bolster these assertions with additional data about fuel cell project costs and production efficiencies. UTC disputes FCE's assertions regarding production efficiencies and economies of scale.

Without relying on the disputed claims of production efficiencies and economies of scale, we find the argument by CCSE compelling that unspent funds and the low participation rates for fuel cell and wind projects suggests modifications to the current SGIP structure may be warranted. If we increase the incentive cap for both wind and fuel cell DG projects, coupled with decreased incentives for installations over 1 MW, we can attempt to install more MW with the same budget. Moreover, the existence of $96 million in unspent funds allows us to test FCE's assertions on a pilot basis. The possibility that the 1 MW incentive cap is inhibiting larger scale wind and fuel cell project development, coupled with significant unspent SGIP funds, provides sufficient reason to raise the incentive cap on a trial basis for 2008 and 2009 using carryover funds. As noted above, the original reason for the incentive cap was to prevent a few large projects from depleting SGIP funds, thus excluding broad program participation. At this juncture, given the magnitude of unsubscribed funds, it is reasonable to allow carryover funds to be used to fund larger projects.

Moreover, to the extent there is latent demand that may have been suppressed due to a lack of incentives above 1 MW, we believe it is reasonable to raise the incentive cap for all SGIP-qualifying technologies. Although FCE requests increasing the cap for renewable technologies only, we see no reason not to extend this proposal to all technologies currently supported by SGIP. Policy preferences for a given technology, as well as differences in the underlying economics, are currently reflected in SGIP through the incentive levels and Commission rules on allocation of funds between renewable and non-renewable projects. (See D.01-03-073.) We will allow all SGIP eligible technologies to apply for carryover funds, and prior Commission orders regarding allocation of funds between renewable and non-renewable (i.e., Level 2 and Level 3) incentive categories are unchanged and apply equally to carryover funds.

Thus, we will grant FCE's petition in part and allow the SGIP administrators to use carryover funds from prior budget years to provide incentives up to 3 MW to qualifying projects up to 5 MW during 2008 and 2009. We will not grant a permanent change to SGIP rules, and we will only allow projects to receive incentives over 1 MW to the extent carryover funding is available. Program administrators should adhere to all prior Commission orders regarding allocation of funds between renewable and non-renewable incentive levels. Projects applying for incentives up to a maximum of 1 MW will be funded according to standard SGIP rules from each program administrator's annual budget allocation.[6] Projects applying for incentives greater than 1 MW, if approved, will receive all of their funding from carryover funds, as available. This preserves the current year's SGIP budget of $83 million for projects receiving incentives up to 1 MW. Any incentives paid over 1 MW will decline in tiers, as suggested in the amended petition. We will adopt CCSE's proposed tiering structure, because it is most conservative and will maximize the use of the carryover funds. Plus, CCSE's proposal is easily applicable to all current SGIP incentives, which vary by technology, as the tiers are based on a percentage of the current incentive. We adopt incentive levels for projects that receive incentives up to 3 MW as follows:

Table 1: Tiered Incentive Rates[7]

Capacity	Incentive Rate
0-1 MW	100%
1 MW – 2 MW	50%
2 MW – 3 MW	25%

In addition, we will allow eligible projects under review larger than 1 MW to be deemed eligible to apply for carryover incentive funding as set forth in this

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[6] If the annual budget is fully subscribed with applications meeting standard program rules, the SGIP program administrators may use carryover funds to support these projects as well.

[7] Current SGIP incentive levels were set by Commission order and are $1.50/watt for Level 2 renewable wind projects, $4.50/watt for Level 2 renewable fuel cell projects, and $2.50/watt for Level 3 non-renewable fuel cell projects.

order, up to 3 MW, without the need to reapply. The program administrators should notify all such applicants to whom this might apply to determine if they wish to be considered for additional incentives. Completed projects that seek additional funding for an expansion will need to reapply.

Although we initially issued a proposed decision to deny FCE's petition, the new information regarding unspent SGIP funds and low participation rates for fuel cells and wind convinces us that we should consider testing program modifications. Therefore, we will grant FCE's amended petition in part, for all qualifying wind and fuel cell DG projects, with tiered incentives as set forth in Table 1. The increase in the incentive cap to 3 MW and tiered incentives shall apply on a pilot basis for two years, i.e., SGIP program years 2008 and 2009, and projects that apply for incentives over 1 MW, if approved, will be funded entirely from SGIP carryover funds, as available. The increased incentive cap may continue past 2009 only upon further order of this Commission, which we expect would follow a review of program participation and budgets.

Some parties suggest raising the SGIP total budget. We will not consider an increase in the annual SGIP budget at this time, in light of recent legislative restrictions that limit us to funding only wind and fuel cell DG projects through SGIP. Rather, we will use SGIP carryover funds to allow expanded program eligibility.

7. Motion for Confidentiality

Along with its Amended Petition, FCE filed a motion requesting confidential treatment of Appendix C, Attachment 1 to its filing. According to FCE, this document contains commercially sensitive production cost data and cost projections associated with FCE's products, that qualify as "trade secrets" under Government Code Section 6254.7(d). This information involves production data known only to certain individuals and which gives its user an opportunity to obtain a business advantage over its competitors, as discussed in the Government Code defining trade secrets. If revealed, this information would subject FCE to competitive disadvantage with respect to other fuel cell manufacturers. FCE contends the competitive retail environment in which FCE competes necessitates confidential treatment of this information. Debenham opposes the motion for confidentiality, arguing FCE has failed to state any valid legal reason for granting the motion.

We disagree with Debenham and find FCE has stated a valid legal reason to grant confidentiality. FCE's production cost data and cost projections in its filing are commercially sensitive trade secrets under Government Code Section 6254.7(d) and would place FCE at a disadvantage if revealed to competitors. We have granted similar requests for confidential treatment of commercially sensitive business data, and will do so here as well.

8. Comments on Proposed Decision

The proposed decision of Commissioner Michael R. Peevey in this matter was initially mailed to the parties on January 15, 2008, in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed by FCE, PG&E, SCE, and UTC. Reply comments were filed by CCSE, SCE, and UTC. The proposed decision was subsequently withdrawn from the Commission's agenda following the filing of FCE's amended petition.

The proposed decision was mailed for comment a second time, following the filing of FCE's amended petition on February 8, 2008. Comments were filed by CCSE, Debenham, FCE, PG&E, SCE, jointly by San Diego Gas & Electric Company and Southern California Gas Company (SDG&E/SoCalGas), and UTC.

Reply comments were filed by CCSE, Debenham, FCE, SCE, and UTC. The comments generally support the proposed decision, and minor modifications as suggested by the comments have been incorporated into the decision. Specifically, PG&E and CCSE request that the Commission clarify that eligible projects larger than 1 MW that are currently under review should not have to cancel their application and reapply to be considered for additional incentives. This clarification has been added to the order.

UTC requests that the augmented incentives be limited to the current $96 million in carryover funds. We decline this suggestion, preferring to allow any additional SGIP carryover funds that may become available over the course of 2008 and 2009 to be used as described in this order. SDG&E/SoCalGas ask for several clarifications on administration of carryover funding, such as how to handle add-ons to existing projects, roll-over of the budget if insufficient to fund a project greater than 1 MW, guidelines for budget transfers, a cap on the amount of carryover funds spent in one year, and wording to allow all eligible technologies to receive augmented incentives. We specifically decline to limit the amount of carryover funding spent in one year, and we decline the wording change to refer to "all eligible technologies." If legislation changes the SGIP eligibility, we can address extension of this program at that time. With regard to the other proposals, we will not address this level of administrative detail in the order, preferring to let our Energy Division work with the SGIP program administrators on appropriate resolution of issues such as these, as they arise, in keeping with the overall guidance set forth in this order.

9. Assignment of Proceeding

President Michael R. Peevey is the assigned Commissioner and Dorothy J. Duda is the assigned ALJ for this portion of this proceeding.

Findings of Fact

1. Under the SGIP, projects up to 5 MW in size can apply for incentives, but incentives will be given only up to 1 MW.

2. The Commission has denied requests to increase the 1 MW incentive limit on the basis that this could deplete the SGIP budget.

3. There are $96 million in unspent SGIP funds from prior program years.

4. There has been low participation by fuel cells and wind projects in the SGIP.

Conclusions of Law

1. Increasing the SGIP 1 MW incentive limit without restriction would decrease the number of projects funded by SGIP.

2. Raising the incentive cap to 3 MW for qualifying SGIP wind and fuel cell projects, coupled with tiered incentives over 1 MW, will allow more MW of DG to be installed for the same dollars.

3. Given the large amount of unspent SGIP funds from prior years, the Commission should raise the cap for incentives to 3 MW for qualifying wind and fuel cell projects. Projects applying for incentives up to a maximum of 1 MW will be funded from the annual SGIP budget. Projects applying for incentives greater than 1 MW, if approved, will be funded entirely from SGIP carryover funds, as available.

4. Incentives paid beyond 1 MW should be reduced according to Table 1 and available only for 2008 and 2009.

5. Production cost data and cost projections in Appendix C, Attachment 1 to FCE's filing should be granted confidentiality as trade secrets under Government Code Section 6254.7(d).

O R D E R

IT IS ORDERED that:

1. The petition to modify Decision (D.) 04-12-045 filed by FuelCell Energy (FCE) on July 25, 2007, and amended on February 8, 2008 is granted in part as set forth herein.

2. D.04-12-045 is modified to allow Self-Generation Incentive Program administrators to pay qualifying distributed generation projects incentives up to 3 megawatts (MW) from prior years' carryover funds, with incentives over 1 MW reduced as set forth in Table 1, and with all prior Commission orders regarding allocation of funds to renewable and non-renewable incentive categories applying to the use of carryover funds.

3. This modification shall apply for the SGIP in 2008 and 2009 only, unless modified by further order of this Commission.

4. The motion for confidentiality filed by FCE on February 8, 2008 is granted for two years from the date of this order. During that period, the information shall not be made accessible or disclosed to anyone other than Commission staff, except upon execution of an appropriate non-disclosure agreement with FCE, or on the further order or ruling of the Commission, the assigned Commissioner, the assigned Administrative Law Judge (ALJ), or the ALJ then designated as Law and Motion Judge.

5. If FCE believes that further protection of the information filed under seal is needed, it may file a motion stating the justification for further withholding of the information from public inspection, or for such other relief as the Commission rules may then provide. This motion shall be filed no later than one month before the expiration date of today's order.

6. This decision shall be served on the service list for Rulemaking (R.) 04-03-017 and R.06-03-004.

7. This order is effective today.

Dated April 24, 2008, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
RACHELLE B. CHONG
TIMOTHY ALAN SIMON
Commissioners

CPUC Decision 01-03-073

Decision 01-03-073 March 27, 2001

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's Proposed Policies and Programs Governing Energy Efficiency, Low-Income Assistance, Renewable Energy and Research Development and Demonstration.	Rulemaking 98-07-037 (Filed July 23, 1998)

INTERIM OPINION: IMPLEMENTATION OF PUBLIC UTILITIES CODE SECTION 399.15(b), PARAGRAPHS 4-7; LOAD CONTROL AND DISTRIBUTED GENERATION INITIATIVES

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INTERIM OPINION: IMPLEMENTATION OF PUBLIC UTILITIES CODE SECTION 399.15(b), PARAGRAPHS 4-7; LOAD CONTROL AND DISTRIBUTED GENERATION INITIATIVES

1. Summary

By today's decision, we adopt the Energy Division's program proposals for load control and distributed generation initiatives, pursuant to Pub. Util. Code § 399.15(b), with certain modifications and clarifications. We authorize a total of $137.8 million in funding for these programs, on an annual basis through December 31, 2004.

As discussed in this decision, we cannot raise electric utility rates until the Commission has determined that the rate freeze is over, or unless the Legislature specifically authorizes us to impose an additional charge during the freeze to recover these program costs. Nor can we ignore the Legislature's clear direction to include the cost of these programs in distribution revenue requirements. We recognize that SDG&E's rate freeze is over, although there is a rate cap on SDG&E's generation-related rate component. However, SDG&E is also subject to performance-based ratemaking (PBR) for its distribution revenue requirements. It would be inconsistent with the PBR framework to address the level of SDG&E's distribution revenue requirements and rates on a piecemeal basis. Instead, SDG&E should address the costs of these programs within the context of the PBR mechanism in its next PBR and cost-of-service proceeding. For PG&E and SCE, where the rate freeze is still in effect, we direct them to increase their distribution revenue requirements, without modifying current rates, to reflect today's authorized budgets.

Within 15 days, PG&E and SCE shall file Advice Letters increasing their electric distribution revenue requirements, without modifying current rates, for

this purpose. SDG&E shall address the funding of these programs in its next PBR and cost-of-service proceeding. On the gas side, PG&E, SDG&E and Southern California Gas Company (SoCal) should include the costs of these programs in their next gas rate recovery proceeding, e.g., the Biennial Cost Adjustment Proceeding. In the interim, all program costs should be tracked in memorandum accounts, and the utilities should establish such accounts for this purpose.

By directing this Commission to adopt new utility programs to reduce demand for electricity within six months of the passage of AB 970, the Legislature clearly stated its intent to proceed expeditiously with the deployment of these initiatives. Accordingly, PG&E, SDG&E, SCE and SoCal, collectively referred to as “the utilities,” are directed to implement these programs without delay.

Under the adopted programs, SDG&E will administer a demand-responsiveness pilot program, targeted to reach 5,000 residential customers in its service territory. SCE will administer a similar pilot program, targeted to 5,000 small commercial customers. SDG&E and SCE will provide financial incentives to customers who agree to set their thermostats at pre-specified levels. Through an internet interface, the utility will monitor and verify actual interruption of loads at the customer site and provide interactive information to customers about their electric usage, in order to encourage peak demand reduction. Within certain parameters, customers will have the flexibility to override the thermostat settings, subject to pre-specified penalties.

We also authorize a pilot program to provide interactive consumption and cost information to small customers, such as historical energy bill information, representative energy usage and cost information for common appliances, and tariff options. PG&E will contract with an independent web designer to develop a website that provides customer online access to this information. Our goal is to reach 10,000 to 15,000 customers in PG&E's service territory. The program will be targeted to residential customers with relatively high monthly energy consumption, residential customers with swimming pools, homes and small businesses in the San Francisco peninsula or in Silicon Valley, and / or rural residences and small businesses.

We also authorize today a self-generation program across all the utility service territories. "Self-generation" refers to distributed generation technologies (microturbines, small gas turbines, wind turbines, photovoltaics, fuel cells and internal combustion engines) installed on the customer's side of the utility meter that provide electricity for a portion or all of that customer's electric load. Under the program, financial incentives will be provided to distributed generation technologies as follows:

Incentive category	Incentive offered	Maximum percentage of project cost	Minimum system size	Maximum system size	Eligible Technologies
Level 1	$4.50 / W	50%	30 kW	1 MW	▪ Photovoltaics ▪ Fuel cells operating on renewable fuel ▪ Wind turbines
Level 2	$2.50 / W	40%	None	1 MW	▪ Fuel cells operating on non-renewable fuel and utilizing sufficient waste heat recovery
Level 3	$1.00 / W	30%	None	1 MW	▪ Microturbines utilizing sufficient

					waste heat recovery and meeting reliability criteria ▪ Internal combustion engines and small gas turbines, both utilizing sufficient waste heat recovery and meeting reliability criteria

For SDG&E's service territory, the program will be administered (via contractual arrangement) through the San Diego Regional Energy Office. PG&E, SCE and SoCal will administer programs in their service territories.

All program administrators are required to outsource to independent consultants or contractors all program evaluation activities, and are encouraged to outsource as many other aspects of program implementation as possible. Independent contractors, and not program administrators[1], will perform all installation of technologies (hardware and software) at customer sites. We encourage the program administrators to coordinate and work closely with local governments, community-based organizations and business associations to recruit and contact interested customers.

[1] SDG&E would not be precluded from bidding to perform installations, since it will not be serving as program administrator.

Attachment 1 describes the authorized programs and funding levels in greater detail.

2. Background

AB 970, signed by the Governor on September 6, 2000, requires the Commission to initiate certain load control and distributed generation activities within 180 days. By ruling dated October 17, 2000, we assigned the implementation of Pub. Util. Code § 399.15(b) (codifying AB 970), paragraphs 4 through 7 to this proceeding. The relevant excerpts from the statute are as follows:

4. Incentives to equip commercial buildings with the capacity to automatically shut down or dim nonessential lighting and incrementally raise thermostats during peak electricity demand period.

5. Evaluation of installing local infrastructure to link temperature setback thermostats to real-time price signals.

6. Incentives for load control and distributed generation to be paid for enhancing reliability.

7. Differential incentives for renewable or super clean distributed generation resources.

In the same October 17, 2000 ruling, we directed the Energy Division to "develop specific program plans for implementing load control and distributed generation initiatives per § 399.15(b) for our consideration." We also consulted with the California Energy Commission (CEC) during the development of these programs.

The Energy Division report on recommended programs was issued for comment on January 31, 2001. The following organizations responded: Cannon Technologies, Capstone Turbine Corporation (Capstone), CEC, California Independent System Operator (ISO), California Retailers Association, Natural

Resources Defense Council (NRDC), Office of Ratepayer Advocates (ORA), PG&E, SDG&E / SoCal (jointly), SCE, Solar Development Corporation, The Utility Reform Network (TURN) and Xenergy, Inc. (Xenergy).

3. Energy Division's Program Recommendations

Below, we briefly summarize Energy Division's January 31, 2001 program proposals. For all programs, Energy Division recommends extensive outsourcing of installation, outreach, and as many aspects of program administration as possible. Energy Division also recommends that all program evaluation activities be outsourced to independent consultants or contractors.

For each program type and utility distribution company, the table below presents Energy Division's recommended annual collections and budgets through the end of 2004, which is the sunset period of AB 970.[2]

Utility	**Demand Responsiveness Budget ($ million)**	**Self Generation Budget ($ million)**	**Total Annual Budget ($ million)**
PG&E	$3.0	$60.0	$63.0
SCE	$5.9	$32.5	$38.4
SDG&E	$3.9	$15.5	$19.4
SoCal	NA	$17.0	$17.0
Total	**$12.8**	**$125.0**	**$137.8**

[2] The comments appear to reflect some confusion on this point. We clarify that the program designs, budgets and annual funding levels are authorized through the end of 2004, consistent with the sunset period of AB 970, unless further modified by subsequent Commission decision.

3.1 Demand-Responsiveness Programs

Energy Division proposes three pilot programs to implement demand-responsiveness initiatives pursuant to AB 970. SDG&E is designated to administer the residential sector pilot, SCE to administer a small commercial sector pilot, and PG&E to implement an internet information test pilot reaching both residential and small commercial customers.

3.1.1 Residential Demand-Responsiveness Pilot Program

The residential pilot program proposed in the Energy Division report calls for installing remotely controlled thermostats using an internet-based communication link. This approach differs from existing "direct control" air-conditioning (A / C) cycling programs in that it uses internet technology as the means to communicate and monitor customer demand responsiveness. It also allows participants to maintain control over their equipment and even override the remote signal, if so desired, via the internet connection.

Energy Division recommends that the program be designed for a pool of 5,000 customers in SDG&E's service territory. Program participants would receive the equipment and installation free of charge from the utility. In addition, Energy Division recommends that the customer receive an incentive of $100 at the end of each year of program participation.[3] The incentive would be reduced by $2 each time the default thermostat setting is overridden, although it would never be less than $0.

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[3] Several parties interpret Energy Division's recommendations to mean that only a one-time incentive would be offered at the end of the first year. This was not the intent, and Attachment 1 clarifies that incentives would be available for the entire duration of the pilot period, i.e., through the end of 2004.

Under Energy Division's proposal, SDG&E would target three distinct customer groups: 1) residential customers whose average monthly electricity consumption is greater than 250 kWh; 2) residential customers residing in geographical areas in SDG&E's service territory known to have high electric consumption due to climate; and 3) customers residing in known limited- to moderate-income areas. Energy Division's preliminary estimates indicate that the program will save approximately $6.6 million over ten years (1.68 benefit-cost ratio).

3.1.2 Small Commercial Demand-Responsiveness Pilot Program

Energy Division recommends that 5,000 small commercial customers in SCE's service territory receive the same demand-responsiveness technology described above. These customers would be paid $250 at the end of each year of program participation. The incentive would be reduced by $5 each time the default thermostat setting is overridden.

SCE would administer the pilot and target commercial customers 1) with high average consumption in the summer, 2) with high consumption due to climate, and / or 3) located in small cities or rural areas. Energy Division estimates that the program will produce $13.1 million in savings over ten years (2.22 benefit-cost ratio).

3.1.3 Interactive Consumption and Cost Information For Small Customers Pilot Program

Energy Division recommends that PG&E contract with an independent web designer to develop a website that provides customer online access to historical energy bill information and presents information on tariff options, representative energy usage and cost information for common appliances, and other information to better support the needs of small customers. Energy Division proposes to reach 10,000 to 15,000 customers under this pilot, targeted to: 1) residential customers with monthly consumption of more than 250 kWh, 2) residential customers known to have swimming pools, 3) homes and small businesses in the San Francisco peninsula or in Silicon Valley, and / or 4) rural residences and small businesses.

Energy Division recommends that PG&E provide an incentive to a customer for actually logging onto the web site and accessing their own energy profile. The incentive could be in the form of a gift certificate of approximately $20 for a home improvement center, appliance store, or a particular product, such as a compact fluorescent lamp. Energy Division does not present a projection of expected energy savings in its report, due to the difficulty in generating such an estimate at this time.

3.2 Self-Generation Program

In its report, Energy Division defines “self-generation” as “distributed generation (DG) installed on the customer’s side of the utility meter, which provides electricity for a portion or all of that customer’s electric load.” (Report, p. 5.) DG units sited on the utility-side of the customer’s meter or owned by the distribution utility or a publicly-owned utility would not be eligible for incentives under Energy Division’s proposal.

For the purpose of this program, Energy Division defines DG technologies as internal combustion engines, microturbines, small gas turbines, wind turbines, photovoltaics, fuel cells, and combined heat and power or cogeneration. A subset of these technologies is considered renewable and eligible for differential incentives, as required by § 399.15(b) paragraph (7), including wind turbines, photovoltaics and fuel cells. Diesel-fired DG resources and emergency or backup systems would not be eligible under the program.

Energy Division proposes to limit the AB970 initiatives to renewable self-generation technologies that are 30 kW or greater in capacity. The proposed program offers incentives of $4.50 per watt of installed on-site renewable generation capacity, up to a maximum of 50% of total installation costs. Non-renewable self-generation (of any capacity) would also be eligible under the program, but with a lower incentive: $1.00 per watt of on-site generation, up to 30% of total costs.

In addition, Energy Division recommends that the utilities be required to waive interconnection and standby fees for any self-generation units installed through this program, as well as through the CEC renewables buy-down program.

Energy Division estimates program costs at $125 million, and projects benefits of $1.12 billion over the life of the units (benefit-cost ratio of 9.98).

4. Discussion

The comments we received on Energy Division’s proposals were extensive and generally very constructive. In the following sections, we concentrate on the chief points of contention, and do not try to summarize every nuance in the comments.

4.1 Cost Recovery and Ratemaking

Pub. Util. Code § 399.15 specifies that the Commission shall “include the reasonable costs involved…in the distribution revenue requirements of utilities regulated by the commission, as appropriate.”

To implement this provision, Energy Division recommends that funding for the proposed programs be collected from ratepayers through a non-bypassable usage-based charge, similar to the public goods charge. Energy Division assigns some of the program costs for self-generation to gas ratepayers; however, the majority of program costs are allocated to electric ratepayers. Energy Division recommends that program expenditures be tracked in a balancing account until ratemaking can be formally addressed in each electric utility's next cost of service / performance-based ratemaking proceeding, and SoCal's next biennial cost adjustment proceeding.

The utilities strongly object to Energy Division's recommendations to track costs until future rate recovery proceedings, arguing that such an approach would further jeopardize their already fragile financial position. SDG&E and SoCal take the positions that the entire public, and not just utility ratepayers, should be responsible for funding these programs.

TURN contends that most of the private benefits of the self-generation program accrue to non-residential program participants, and argues that residential customers should probably not subsidize these program costs at all. TURN requests that we track all program costs and benefits by customer class before adopting a specific cost allocation.

Until we have determined that the electric rate freeze is over for PG&E and SCE,[4] or until there is specific Legislative authority to impose an additional charge to recover these costs, we cannot consider granting the rate relief requested by the utilities, particularly not in this rulemaking proceeding. Nor can we ignore the Legislature's clear direction to include the cost of these programs in distribution revenue requirements. We recognize that SDG&E's rate freeze is over, although there is a rate cap on SDG&E's generation-related rate component. However, SDG&E is also subject to PBR for its distribution revenue requirements. It would be inconsistent with the PBR framework to address the level of SDG&E's distribution revenue requirements and rates on a piecemeal basis. Instead, SDG&E should address the costs of these programs within the

[4] We are examining this issue in A.00-11-038 et al.

context of the PBR mechanism in its next PBR and cost-of-service proceeding. For PG&E and SCE, where the rate freeze is still in effect, we direct them to increase their distribution revenue requirements, without modifying current rates, to reflect today's authorized budgets.

Should general fund appropriations be made available for demand-responsiveness and self-generation programs through subsequent Legislative action, we will consider augmenting today's approved programs. As described further below, the Energy Division's proposed programs consist of a focused set of pilots that can be broadened to encompass additional market sectors, technologies and system sizes, if and when appropriate.

Within 15 days, PG&E and SCE shall file Advice Letters increasing their electric distribution revenue requirements, without modifying current rates, for this purpose. SDG&E shall address the funding of these programs in its next PBR and cost-of-service proceeding. On the gas side, PG&E, SDG&E and Southern California Gas Company (SoCal) should include the costs of these programs in their next gas rate recovery proceeding, e.g., the Biennial Cost Adjustment Proceeding. In the interim, all program costs should be tracked in memorandum accounts, and the utilities should establish such accounts for this purpose. We will address specific cost allocation issues, including the one raised by TURN, when we address the rate recovery for these programs. In the meantime, the utilities should track all program costs and benefits by customer class, as TURN recommends.

Several parties request clarification regarding the allocation of costs for the self-generation program between electric and gas customers of the combined utilities. As discussed in the Energy Division report, some of the program costs for self-generation are assigned to gas ratepayers, as well as electric ratepayers, to reflect the public benefits (e.g., environmental) that will accrue to gas ratepayers as well. (Report, p. 7.) To establish the budget for each individual utility, Energy Division allocated the total costs for the self-generation program (developed on a statewide basis) to each service territory based on the relative proportion of costs currently allocated to each utility for energy efficiency programs. In our opinion, this represents a reasonable proxy for the allocation of benefits between gas and electric customers that we can expect from the self-generation program. In the Advice Letter filings described above, PG&E and SDG&E should present the specific factors they use to allocate costs between their electric and gas customers, for the purpose of increasing their electric distribution revenue requirements.

4.2 Size and Scope of AB 970 Initiatives

The comments reflect divergent opinions concerning the appropriate size and scope of the AB 970 demand-responsiveness and self-generation initiatives. ORA, for example, recommends a much larger overall program funded at $300 million per year, whereas other parties, such as PG&E, express concerns that the level of ratepayer funding proposed by the Energy Division may be too ambitious at the proposed $138 million annual level.

Parties also differ with respect to the scope of technologies and applications that should be eligible under the proposed programs. Whereas the Energy Division recommends that all customer sectors be eligible under the self-generation initiatives, ORA recommends limiting the incentives to non-public sector retrofit applications for residential and small/medium businesses. CEC recommends expanding eligibility to cover installations of DG systems on either side of the customer's meter, rather than only on the customer side, as recommended by Energy Division. Capstone recommends that the eligibility of renewable technologies be expanded by lowering the proposed size minimum of

30kW to 10kW**,** while PG&E and SDG&E recommend that self-generation units be subject to specific size limits.

With respect to the demand-responsiveness pilots, several parties propose significant expansions in scope to include additional options and technologies. For example, CEC recommends that the demand-responsiveness pilots include load curtailment options that address lighting (e.g., dimmable ballasts), metering technologies and market-based rate designs. CEC also recommends that the internet information test pilot be expanded to encompass full-scale deployment of metering systems that provide real-time usage data feedback through internet-based systems to customers. Cannon Technologies recommends that the pilots be expanded to include additional peak reduction technologies that allow the utilities to interrupt load on a one-way basis. Along these lines, TURN recommends that the Commission authorize expansions in the utilities' existing direct load control air-conditioning cycling programs as part of the AB 970 initiatives.

It is clear from the comments that the AB 970 initiatives could be expanded to greatly exceed the $138 million annual budget developed by Energy Division, by including a wider array of technologies, system sizes and applications. However, we are not persuaded that such expansion is in the public interest at this time. Instead, we concur with Energy Division that the § 399.15(b) initiatives should encompass a specific set of programs that can be tested on a pilot basis, without risking major investment of ratepayer funding on a full-scale statewide rollout. In this way, we will complement, rather than duplicate, initiatives for peak-demand reductions that are being explored in the Commission's rulemaking into the operation of interruptible programs (Rulemaking (R.) 00-10-002), proceeding on real-time pricing (Application

(A.) 00-07-055), as well as programs being implemented under the CEC's AB 970 demand-responsiveness grant programs and renewables programs.

We believe that Energy Division's proposal for overall program size and scope best accomplishes this goal. Although several parties critique various aspects of the Energy Division's preliminary cost-benefit analysis, no party presents convincing argument or analysis to indicate that the level of proposed funding represents an unreasonable investment in demand-responsiveness and self-generation, relative to expected benefits.[5] We find that Energy Division's proposed annual funding level of $137.8 million for the § 399.15(b) demand-responsiveness and self-generation initiatives to be reasonable. Should additional funding become available via legislative action, we may consider expanding today's adopted demand-responsiveness and self-generation initiatives in a subsequent decision. We may also consider future funding increases for these programs via distribution rates, in this rulemaking, as we gain further experience with the programs adopted today.

SCE requests that we clarify the relationship between the programs adopted in this rulemaking and those being considered in the interruptible rulemaking, R.00-10-002. Nothing in this decision is intended to preclude or prejudge the Commission's consideration of additional initiatives involving interruptible programs (for all customer groups including the residential and small commercial sector) in that proceeding.

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[5] ORA presents an analysis of program cost-effectiveness that produces a benefit cost ratio for self-generation of 2:1, which is significantly less than Energy Division's preliminary analysis, but still comparable to the energy efficiency portfolios of the combined utilities. See ORA's comments, p. 5.

Although we generally concur with the Energy Division's proposed size and general scope of program initiatives, we do lower the minimum size requirement for receiving renewables incentives and make specific improvements to design and implementation parameters, in response to parties' comments. These modifications are discussed below, by general category and specific program initiative.

4.3 Program Administration

In its report, Energy Division assumes that the utilities will administer these programs "for the purposes of expediency," at least for 2001. (Report, p. 6.) SDG&E, SCE and SoCal concur with this approach, and recommend that the Commission affirmatively state now that the utilities will serve as the administrators through at least 2004. PG&E suggests that the Commission consider alternatives to utility administration, particularly if the expectation is to have utilities gear up for only a one-year assignment of program administration.

Although TURN does not propose a specific alternative to utility administration, it recommends that the Commission "find any other entity, private, non-profit or government, whose interest is more aligned with program success" to administer the self-generation program. In TURN's view, the utilities have presented positions in the distributed generation rulemaking (R.99-10-025) that reflect their perception that self-generation will reduce distribution revenues.

ORA expresses similar concerns, and recommends that SDG&E contract with the San Diego Regional Energy Office to provide administrative services for the self-generation programs in SDG&E's service territory. For the longer-term, ORA urges the Commission to establish a statewide network of Commission- certified regional energy offices to become administrators of both energy efficiency public purpose programs and self-generation programs.

ORA's proposal to designate the San Diego Regional Energy Office as program administrator for self-generation in SDG&E's service territory provides us with an opportunity to explore non-utility administration on a limited basis. We believe that such exploration will be valuable, given the concerns raised by parties regarding utility administration in this proceeding. The independent evaluation of the self-generation program should include an examination of the relative effectiveness of the two administrative approaches we adopt today.

Today's decision is not the appropriate forum for addressing the administrative structure of energy efficiency and self-generation programs for the longer-term, as proposed by ORA, and we will not adopt ORA's recommendation to establish regional energy offices for this purpose. However, nothing in today's decision precludes the Commission from considering alternatives to utility administration for future demand-responsiveness or self-generation program initiatives, based on our evaluation of the § 399.15(b) pilot results or other relevant information.

We direct the utilities to administer today's adopted pilot programs through the funding period, i.e., through December 31, 2004, with the exception of the self-generation program in SDG&E's service territory. For this program, SDG&E shall contract with the San Diego Regional Energy Office at the full budget amount specified herein ($15.5 million) to provide administrative services.

Energy Division recommends that the self-generation program be administered through the utility's existing standard performance contract (SPC) program. The SPC programs rely on third parties such as energy service companies to install equipment at customer facilities. Contractors then follow an established program procedure to install the equipment, measure and verify the equipment's impact on on-site consumption, and collect payment from the utility.

SDG&E / SoCal point out in their joint comments that SoCal does not currently administer an SPC program for energy efficiency. Therefore, SoCal requests flexibility to utilize other approaches for implementing the self-generation program. Xenergy also comments that their knowledge from conducting the statewide SPC program evaluations suggests that there may be other equally viable, and potentially less burdensome, program delivery choices. Like SoCal, the San Diego Regional Energy Office also does not have an existing SPC program. Given this, we will grant the program administrators flexibility in program delivery mechanisms, as long as they meet the following basic requirements:

- Available incentive funding (dollars per watt or percentage of system cost) is fixed on a statewide basis at the levels described below. (See table in Section 4.6.1.)
- Inspections are conducted to verify that the funded self-generation systems are actually installed and operating.
- The measurement and verification protocols established by the administrators include some sampling of actual energy production by the funded self-generation unit over a statistically relevant period. (See also Section 4.6.2 below.)
- As discussed below, the target expenditures for program administration be limited to 5% of program funding, with the exception of measurement and verification activities.

Finally, we clarify our expectations regarding outsourcing by program administrators. While we afford administrators the flexibility to select the manner of outsourcing (e.g., competitive bidding, sole source contracting) for these pilot programs, we do require program administrators to outsource to independent consultants or contractors all program evaluation activities. This requirement, coupled with the role of Energy Division in the evaluation process (see Section 4.8 below), will ensure that the programs are independently evaluated. In addition, all installation of technologies (hardware and software) at customer sites shall be performed by independent contractors and not utility personnel (for those utilities that will administer their own programs), or agency personnel (in the case of the San Diego Regional Energy Office). This requirement will ensure that market actors other than the program administrators are involved in program delivery, consistent with the manner in which we implement energy efficiency and low-income assistance programs.

Program administrators should also outsource other aspects of program administration and implementation, to the extent feasible. In particular, the majority of program marketing and outreach activities should be outsourced, to the extent feasible, although the program administrator should actively participate and assist contractor efforts for this purpose. We also encourage the program administrators to coordinate and work closely with local governments, community-based organizations, business associations and other entities to recruit and contact interested customers.

4.4 Budget Allocations and Fund Shifting Flexibility

In its January 31, 2001 report, Energy Division recommends that administrative expenses be limited to 5% of total program funding, for each program, and estimates a 3% budget allocation for certain evaluation activities in developing the overall funding levels.[6] Based on the comments of Xenergy and others, we believe that the administrators should be afforded some flexibility in

[6] See Energy Division Report, p. 6 and program budgets on pp. 15 and 21.

allocating the authorized budget for each program (e.g., $3.9 million for the residential demand-responsiveness pilot) among the various cost categories (administration, program evaluation, installation, service and operation costs, customer incentives). We agree with Energy Division that contract administration, marketing and regulatory reporting should be undertaken as cost-efficiently as possible by program administrators, so that proportionately more funds are available for hardware installations and customer incentives. However, we also recognize that it is difficult to estimate at the outset precisely what the appropriate allocation across cost categories should be for these programs. For this reason, we are establishing are target of administering these programs at a cost no greater than 5% of program funds, with the exception of measurement and evaluation activities. In any event, the actual cost of administration must be reasonable.

We will provide some flexibility, enabling the utilities to shift funds across cost categories within the overall budgeted amounts for each of the four programs (i.e., residential demand-responsiveness, small commercial demand-responsiveness, interactive information for small customers and self-generation programs), with the following exceptions. First, utilities may not shift any funds between the demand-responsiveness and self-generation programs that they administer without first obtaining Commission authorization. Second, one-third of the self-generation incentive funds is initially allocated to each of the self-generation categories. Although the utilities may exercise full discretion in moving funds from non-renewable self-generation categories to the renewable category, a utility must seek approval through advice letter prior to shifting additional funds into either of the non-renewable categories. The utilities shall not unreasonably withhold funds that could be used to deploy a greater amount of renewable self-generation. Finally, with the exception of measurement and evaluation activities, administrators must obtain Commission authorization to allocate more than 5% of program funds to “administrator costs” (i.e., contract administration, marketing, and regulatory reporting) within each program budget, for either demand-responsiveness or self-generation programs. Such authorization may be requested via Advice Letter. The funds authorized today are designated exclusively for approved § 399.15(b) demand-responsiveness and self-generation activities, and shall not be used for other purposes.

4.5 Design Parameters For Demand-Responsiveness Pilot Programs

As discussed above, Energy Division proposed a specific set of customer incentive levels and selected a particular load control technology to test under the residential and small commercial demand-responsiveness pilot programs. Several parties argue that the effectiveness of these programs, which are intended to induce customer behavioral changes, will best be achieved by allowing some flexibility and experimentation in the design of customer incentives, marketing approaches, technology type and other design parameters.

We agree that the effectiveness of these pilot programs will be enhanced by allowing some flexibility in their implementation. In particular, within the overall program funding levels authorized for each pilot, we will allow the utilities to experiment with alternative incentive designs. This may involve higher annual customer incentives and override penalties, or other signals that will differentiate usage of air conditioning during peak periods, as some parties suggest. Similarly, for the interactive consumption and cost information pilot, PG&E should have the flexibility to select the design and amount of the incentive, as suggested in its comments. (PG&E Comments, p. 4.)

We also will allow some flexibility in the overall number of pilot participants, as recommended by Xenergy and others. The utility administrators should consider the 5,000 participant level (for the residential and small commercial) and 10,000-15,000 participant level (for the small customer information pilot) as general targets, rather than strict requirements. In this way, the utility administers will be able to make reasonable modifications to other program design parameters (e.g., incentive levels) and also accommodate within the authorized program budgets any additional costs (e.g., equipment) that exceed the Energy Division's preliminary estimates.

SDG&E and others comment that the 250 kWh threshold for residential customers, as suggested in the Energy Division report, may not be an appropriate level for targeting higher electric load residences. We will afford SDG&E and SCE flexibility in establishing monthly consumption threshold levels in order to define a target group of participants with high average consumption.

However, we will not retreat from Energy Division's recommendation that the residential pilot also target limited- to moderate-income areas. In its comments, SDG&E argues that these customers are unlikely to use central air conditioning, an assertion that appears nonsensical given the high summer temperature climate zones within SDG&E's service territory. SDG&E and TURN also suggest in their comments that many limited- to moderate-income customers do not use personal computers (with internet access), and therefore cannot effectively participate in the residential pilot program. This reflects a basic misunderstanding of the "internet connectivity" referred to in Energy Division's report. Customers are not required to have internet capability via a personal computer, although this is one technology option. Rather, at a minimum, the thermostat equipment itself needs to be capable of internet interface, an option that does not require the customer to own or operate a personal computer. As discussed below, the utilities may elect to employ more than one technology in implementing the pilots, and we expect them to take into consideration the targeted market in making such choices.

Finally, we clarify our intent to allow some flexibility with respect to the specific technologies employed in the residential and small commercial demand-responsiveness pilot programs, and encourage the utilities to solicit multiple bids for this purpose. However, such flexibility is not intended to alter the focus of the pilot program recommended by Energy Division in its January 31, 2001 report. Consistent with those recommendations, we will not test technologies that simply allow the utility to interrupt load on a one-way basis. More specifically, any technology installed for the demand-responsiveness pilot programs must include the following features:

(1) Allow each customer some level of control over its own HVAC equipment (over-ride, etc.),

(2) Provide interactive information for consumers to make consumption decisions (e.g., via the thermostat or a computer internet connection), and

(3) Allow the administrator to verify actual interruption of the individual device at the customer site, including duration and level of kW demand reduction.

With respect to the interactive consumption and cost information pilot, Xenergy seeks to ensure that PG&E pursues other methods of providing customers with information on their energy usage profile and the benefits of various rate options, including mail out audits, telephone approaches and other alternatives. We do not intend this pilot to replace or diminish other effective methods that PG&E might also employ to provide energy information to smaller customers. However, we are not persuaded that including several, very different information dissemination approaches in a single pilot program, as suggested by Xenergy, would enhance the effort. We therefore retain the focus of the pilot, which is to implement and test the website approach proposed by the Energy Division.

4.6 Design Parameters For Self-Generation Program

Parties provided extensive comments on the various aspects of this proposed program, including incentive design, warranty requirements and the waiver of interconnection fees and standby charges. We summarize the main areas of contention in the following sections, and describe the modifications we adopt to Energy Division's proposal.

4.6.1 Technology Categories, Incentive Levels and Size Limits

Energy Division proposed two categories of self-generation technologies and associated incentives, based on a consideration of various system dimensions, including air emissions characteristics, fuel type, and system cost. After considering parties' comments, we modify certain aspects of Energy Division's proposal, as discussed below.

Several parties argue that incentives are not required or warranted for non-renewable self-generation systems. They argue against funding these systems because they are less efficient and more polluting than combined cycle technologies without waste heat recovery. We find merit in these concerns. Section 399.15(b) requires the Commission to establish both "incentives for… distributed generation to be paid for enhancing reliability" as well as "differential incentives for renewable and super clean distributed generation resources." We agree with PG&E that many fossil fuel applications would fail to satisfy any of these criteria.

As NRDC and TURN have pointed out, some micro-turbines operating on natural gas may be cleaner than large central station fossil generators, but combustion turbines and other small natural gas generators may actually be more polluting than modern central station facilities. While we have not created an exhaustive record in this proceeding from which to reach a firm conclusion, there is nothing to suggest that these technologies offer "super clean" generation, and when run on natural gas, certainly are not renewable.[7] Thus, to qualify for incentives, a fossil facility must serve to enhance system reliability.

Since all new generation could arguably add incrementally to the reliability of available generation, the language of § 399.15(b) suggests that the Legislature had in mind some other contribution to system reliability. In order to qualify for incentives, a fossil-fired facility must make a demonstrable contribution to the reliability of the transmission or distribution system. We

[7] We note that neither the Energy Division report nor the applicable statute provide a definition for "super clean" generation and find that the information before us does not provide a basis for declaring that any particular fuel-burning technology fits in such a category.

expect the utilities to work with those customers seeking incentives for fossil-fueled facilities to determine whether a proposed facility will enhance transmission or distribution reliability and document those benefits prior to approving an incentive payment.

We note Capstone's suggestion that micro-turbines be allowed to qualify for renewable incentive levels if they utilize renewable fuels. While it is logical to consider such facilities as providing renewable power, the incentives, that we are offering here, relate to capital cost. Capstone has not suggested that micro-turbines using renewable fuels would be appreciably more expensive to install a unit using renewable fuel than it would to install one using fossil fuels. However, it would be appropriate to enable such a facility to qualify for a normal micro-turbine incentive payment without meeting a "system reliability" test. We will consider expanding the program to include renewable-fuel micro-turbines once we determine what comprises a renewable fuel and are persuaded that a facility that once qualifies for a "renewable fuel" incentive would not later switch to fossil fuel. We seek the Energy Division's assistance in answering these questions and ask the staff to report back to us.

In addition, we will modify Energy Division's proposal, as recommended by TURN and ORA, to require that non-renewable technologies utilize waste heat recovery at the customer site. This further mitigates concerns over providing incentives to nonrenewable technologies. Accordingly, we modify the technology categories to require that fuel cells utilizing non-renewable fuels, microturbines, and internal combustion engines, be installed in combined heat and power applications, in order to be eligible for incentives under the self-generation program.[8] However, this requirement only becomes meaningful if the opportunity for heat recovery and reuse is meaningful. We ask the Energy Division to work with interested parties to develop heat recovery standards and to submit those standards to us for subsequent consideration.

Further the CEC recommends creation of an additional category for fuel cells operating on a non-renewable fuel source, stating that these systems do not yield the same benefits as fuel cells operating on renewable fuels. We agree that this distinction is warranted, and establish a $2.50 per watt incentive for this category, up to a maximum of 40% of project cost.

NRDC points out that a small number of very large units could easily use up most or all of the available funding, and suggests that the Commission consider adopting a size limit. PG&E specifically recommends limiting the size of units eligible for funding to 10 MW or less, because PG&E generally does not interconnect any project larger than 10 MW to its distribution system.

We believe that a size limitation is reasonable in order to provide options to assist in the installation of self-generation systems for as many California customers as possible. We prefer adopting a size limit to specifying a maximum percentage of available budget that can be paid to a single customer or system, which is an approach often used in program design. Use of such a mechanism in this case, however, would result in widely varying system size

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8 This modification also makes moot Energy Division’s proposal to pay additional incentives for energy savings from the installation of combined heat and power systems.

limitations across service territories, because of differing budget allocations for the various administrators.

In our judgment, a system size limit of 1 MW will effectively address the concerns raised by NRDC and others. This size represents a fairly large installation for a single customer site and, at the same time, will not use up an unreasonable amount of program funding. We note that one system of this maximum size would only receive about one-third of the available funding in SDG&E's service territory, which is the smallest budgeted program. Individual customers may apply for incentives for more than one system, as long as the combined size does not exceed 1 MW.

In addition, we will preserve the funds available for use in this program by adjusting incentive payments to complement those offered by the CEC, rather than to compete with them. We discuss this change in Section 4.9, below.

Finally, CEC and NRDC express concern over potential overlap between Energy Division's proposed self-generation program and CEC's renewables buy-down program, even with the 30 kW minimum size requirement. We note that only seven systems above 30 kW have been installed under CEC's renewables buy-down program (from a total of 332 systems installed, or 2%) since its inception. Out of 176 additional systems that CEC has approved, but are not yet installed, only nine (5%) represent systems greater than 30 kW.[9] With the higher incentive level offered under today's adopted program,

[9] Source: From "Appendix C: Emerging Renewable Resources Account" in "Renewable Energy Program: Annual Project Activity Report to the Legislature", CEC publication nos. P500-00-004 (March 2000) and P500-00-021 (December 2000). Available online at

Footnote continued on next page

we believe that this market can be effectively reached, and will allow customers to participate in both programs, subject to the requirements set forth below.

With the modifications described above, we adopt the following incentive structure for the self-generation program:

Incentive category	**Incentive offered**	**Maximum percentage of project cost**	**Minimum system size**	**Maximum system size**	**Eligible Technologies**
Level 1	$4.50/W	50%	30 kW	1 MW	Photovoltaics Fuel cells operating on renewable fuel Wind turbines
Level 2	$2.50/W	40%	None	1 MW	▪ Fuel cells operating on non-renewable fuel and utilizing waste heat recovery
Level 3	$1.00/W	30%	None	1 MW	▪ Microturbines utilizing waste heat recovery and meeting reliability criteria ▪ Internal combustion engines and small gas turbines, both utilizing waste

http://www.energy.ca.gov/reports/2000-12-04_500-00-004.PDF and http://www.energy.ca.gov/reports/2000-12-04_500-00-021.PDF.

					heat recovery and meeting reliability criteria

Based on California Retailers Association's comments, we clarify that hybrid DG systems that incorporate technologies from different incentive categories will receive payments based on the appropriate category. For example, a 100 kW system that utilizes 60 kW of microturbines and 40 kW of photovoltaics may receive $1.00/W for the 60 kW microturbine system and $4.50/W for the photovoltaic system. The program administrators shall provide for multiple technologies to be included in the customer's program application.

We require that program administrators keep the incentive levels fixed on a statewide basis throughout the program period. This requirement differs from the flexibility afforded to the administrators in the demand responsiveness programs for several reasons. First, the self-generation program is not designed to induce or monitor changes in consumer behavior, but rather to encourage the purchase of equipment. We believe that considerable flexibility in designing incentive levels is warranted in the former instance, but not necessarily in the latter. Moreover, a program design that varies the incentive payment levels may confuse consumers, or cause them to wait for the possibility of higher incentives before installing self-generation systems. In addition, we believe that the incentive payment for this program should be uniform statewide, as the market for self-generation technologies is not limited to or differentiated by a particular region or utility territory.

4.6.2 Monitoring Peak Demand Reductions

Energy Division's proposal for the self-generation program does not impose operating requirements or establish differential incentives related to on-peak operation. As a result, SDG&E / SoCal argue that the proposed program design does not ensure that generation units will contribute to peak demand reduction. PG&E also requests that we clarify whether units are required to operate during peak.

We are not persuaded that it is necessary or reasonable to impose operating requirements or incentives related to on-peak operation for this program. We believe that customers willing to invest in self-generation already have sufficient economic incentive from energy prices to employ time-of-use meters to measure their usage and to operate their self-generation systems during peak periods. Moreover, the system output for solar technologies is generally coincident with afternoon system peak without any operating requirements. In addition, a per-watt or percentage of system cost up-front payment is already employed through the CEC's Emerging Renewables Buy-Down Program ("renewables buy-down program"). Maintaining that approach should help minimize market confusion and disruption.

However, for program evaluation purposes, we will require program administrators to monitor the extent to which self-generation units installed under this program operate during peak periods. Program administrators should direct their independent evaluation consultants or contractors to develop a process for monitoring and collecting this data from program participants. At the end of the first program year, administrators should report to the Commission on peak operation from the program, and continue this reporting in subsequent years. By the end of the second program year, the consultants or contractors should present recommendations on incentive or program designs that could improve on-peak load reduction from self-generation.

It is not the intent of this evaluation process to penalize customers for not running their self-generation during peak periods. Nor may the program administrators use the collected information in any way to penalize or restrict the ability of customers to run their self-generation systems. Rather, the purpose of this information is to assist us in identifying potential improvements in program design and incentive mechanisms for self-generation programs in the future.

We offer an example of how this operational data might be obtained for evaluation and ongoing program design purposes. If the self-generation unit does not already have built-in logging capability for this purpose, then the unit could be outfitted with a low-cost single-channel datalogger and sensor (such as a relay switch) which would at least enable the utility to determine when the unit is operating and producing electrical output. Program administrators should develop and disseminate the specific requirements for system installations and monitoring capabilities required for program evaluation. The costs of the required monitoring equipment should be paid from program funds.

4.6.3 Warranty Requirements

Under Energy Division's proposal, self-generation systems must be covered by a warranty of not less than three years. CEC recommends a warranty period of five years for eligible systems, consistent with the requirements under CEC's renewables buy-down program and industry practices. We concur with the CEC's recommendation, and adopt a five-year warranty requirement for technologies in Levels 1 and 2 above.

For Level 3 technologies, however, we adopt a different requirement, based on SDG&E's observation that equipment manufacturers for these technologies typically offer warranties of only three to 12 months. In our opinion, a three-year warranty period is sufficient to ensure the continued operation and reliability of these systems and will encourage manufacturers and vendors to offer high quality products. We will adopt SDG&E's recommendation that the customer installing these self-generation systems purchase a three-year (minimum) maintenance contract from the manufacturer or vendor in order to comply with this requirement, if the system does not already include the required warranty. The customer may include the cost of this warranty in the system cost, for purposes of calculating their program incentive, up to the maximum percentage levels specified.

4.6.4 Waiver of Interconnection Fees and Standby Charges

The utilities strongly object to Energy Division's recommendation that interconnection fees and standby charges be waived for any self-generation units installed through the program. They argue that this recommendation is not justified and would ignore the Commission's recent decision on interconnection standards (Decision (D). 00-12-037) as well as the record developed in R.99-10-025 on standby charges. California Retailers Association, on the other hand, supports this recommendation and urges the Commission to adopt it.

We conclude that the appropriate forum for addressing interconnection fees and standby charges for distributed generation is R.99-10-025. We will not prejudge the issues still being considered in that proceeding, or modify prior Commission decisions regarding interconnection fees in designing the § 399.15(b) programs we adopt today. However, we do clarify that the interconnection fees (as defined in D.00-12-037) should be included in total installation costs for the purpose of determining the maximum size of the self-generation incentive. In this way, program dollars can be used to defray a portion of those costs.

4.7 Cost-Effectiveness

AB 970 directs the Commission to reexamine the methodologies used for cost-effectiveness, and revise them in "in light of increases in wholesale electricity costs and of natural gas costs to explicitly include the system value of reduced load on reducing market clearing prices and volatility." (§ 399.15(b)(8).) In its January 31, 2001 report, Energy Division proposes refinements to existing cost-effectiveness testing for this purpose, on a preliminary basis. Energy Division applied this new methodology to estimate the benefits and costs of the proposed self-generation and demand-responsiveness programs.

In their comments, the utilities and CEC contend that Energy Division's estimates for certain cost-effectiveness parameters (e.g., avoided transmission and distribution costs, reliability benefits) are overstated, and that the analysis does not take into account all of the costs associated with DG. ORA presents its own cost-effectiveness test results that it contends is more consistent with the approach (and inputs) used by the Commission to evaluate demand-side management programs.

Despite criticisms of certain aspects of Energy Division's analysis, none of the parties present convincing argument or facts to indicate that Energy Division's recommended programs will not produce sizeable public benefits.[10] They do recommend, however, that we continue to refine our cost-effectiveness methods for the future. We concur with this recommendation, and clarify that

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[10] ORA presents an analysis of program cost-effectiveness that produces a benefit cost ratio for self-generation of 2:1, which is significantly less than Energy Division's preliminary analysis, but still comparable to the energy efficiency portfolios of the combined utilities. See ORA's comments, p. 5.

the cost-effectiveness inputs and methods applied to the Energy Division proposals are limited only to these pilots.

An appropriate cost-effectiveness method for future, longer-term programs still needs to be developed. Energy Division's proposal to hire an independent consultant to perform such a task, utilizing funds appropriated for implementation of AB 970, is a reasonable approach. The scope of work should encompass the development of methodologies, input assumptions and forecasts for addressing § 399.15(b)(8) and other cost-effectiveness issues. In particular, we seek to develop a cost-effectiveness methodology that can be used on a common basis to evaluate all programs that will remove electric load from the centralized grid, including energy efficiency, load control / demand-responsiveness programs and self-generation.

Energy Division should submit the final consultant report no later than December 31, 2002, and serve a notice of its availability to all appearances and the state service list in this proceeding (or its successor). Energy Division may hold public workshops with the consultant and interested parties during the development of this methodology, as it deems appropriate. The schedule for comments on the final report will be established by Assigned Commissioner or Administrative Law Judge ruling.

4.8 Program Evaluation

The programs adopted today will be evaluated during and after the program period, consistent with Energy Division's recommendations. For the residential and small commercial demand-responsiveness pilot programs, SDG&E and SCE will each conduct a process evaluation during 2001 and an energy savings and peak demand savings impact study at the end of 2002. For the interactive and cost information pilot program, PG&E or its evaluation contractor will contact site users and non-users to discuss their satisfaction with the information on the site and suggest potential improvements. Program administrators for the self-generation program are required to perform program evaluations and load impact studies to verify energy production and system peak demand reductions, as described in greater detail in Section 4.6.2. They are also required to conduct an independent analysis of the relative effectiveness of the utility and non-utility administrative approaches we adopt today. (See Section 4.3.)

As discussed above, program administrators are required to outsource to independent consultants or contractors these evaluation activities. Energy Division shall assist program administrators in the development of the scope of work, selection criteria and the evaluation of submitted proposals to perform these program evaluations. The assigned Administrative Law Judge, in consultation with Energy Division and the program administrators, shall establish a schedule for filing the required evaluation reports. Energy Division should hold a workshop with program administrators as soon as practicable to develop scheduling proposals for this purpose.

4.9 Coordination and Eligibility Issues

Several parties commented on coordination and eligibility issues, particularly with respect to the CEC's programs. In particular, CEC and NRDC express concern over potential overlap between Energy Division's proposed self-generation program and CEC's renewables buy-down program. As the CEC points out, the CEC's program currently offers payments to renewable self-generators at a level lower than that approved in this order. The CEC argues that rather than add to the over-all deployment of renewable resources, a parallel program, offering larger incentives, would drive participants away from CEC program altogether. This would not be a sensible result.

We encourage the CEC to consider adopting a rebate level equal to that adopted in this order. However, as long as the CEC does not reduce its "buy-down" levels, it is appropriate for those receiving CEC incentives to also receive incremental payments from the utilities, bringing the total incentive payments up to the level approved in this order. Of course, this process must be carefully monitored to ensure that no customer can play one program off against another, to achieve exorbitant incentive payments.

It is unlikely that these programs can be successfully coordinated unless there is a common application process for involvement in either program. Thus, we direct the utilities and the Energy Commission to work with the CEC to develop a one-step application process, for use by all customers seeking a CEC renewables "buy-down" or utility renewable self-generation incentive payment.

Energy Division's program proposals for both demand-responsiveness and self-generation state that customers receiving incentives from these programs cannot also participate in any other interruptible or curtailable rate programs. Some parties, including TURN, argue that this prohibition should be eliminated. We agree with the Energy Division that participation in multiple programs could potentially allow an individual customer to receive multiple incentive payments for taking a single action. For example, a commercial customer could be receiving an interruptible rate discount, while at the same time utilizing incentives from the self-generation program to assist in the purchase of on-site generation for use during interruption periods. However, we do not find it necessary to prohibit customers from participating in an interruptible program with load that is not displaced by self-generation receiving incentives through this program.

In its comments, the CEC refers to the guidelines already in place for CEC's renewables buy-down program. Although we do not specifically adopt the CEC guidelines today, we do agree with the CEC that the administrators of these new self-generation programs should take advantage of the work already done by the CEC in developing appropriate program details to encourage self-generation. Those program parameters are available at http://www.energy.ca.us/greengrid/. In order to ensure that the new self-generation program is available as consistently as possible on a statewide basis, we direct SoCal to take the lead in convening a working group including PG&E, SCE, SDG&E, and the San Diego Regional Energy Office to select final program details for statewide implementation. These details may include eligibility criteria for heat recovery levels or system efficiency.

We note that SoCal and SCE generally serve the same service territory and customers. Accordingly, SCE and SoCal must coordinate their marketing and tracking of program incentives very carefully in order to ensure that customers do not receive incentives for the same self-generation equipment from both utilities. In the alternative, as ORA proposes, SoCal may administer the self-generation program for the combined geographic region, if SCE and SoCal so agree.

We recognize that additional incentives for self-generation and demand-responsiveness programs may be authorized by the Legislature in the coming months. As several parties point out, additional issues regarding eligibility and coordination may need to be addressed at that time. We delegate to the Assigned Commissioner the task of clarifying these and other implementation issues by ruling, if and when such a need arises.

5. Comments on Draft Decision

The draft decision of Commissioner Lynch and Administrative Law Judge Gottstein in this matter was mailed to the parties in accordance with Section 311(g)(3) of the Public Utilities Code and Rule 77.7(f)(9) of the Rules of Practice and Procedure. AB 970 requires that these programs be implemented in March 2001. In order to meet this goal, we must reduce the 30-day period for public review and comment. As defined in Rule 77.7(f)(9), the public necessity of adopting this order outweighs the public interest in having the full 30-day period for review and comment. We therefore shorten the comment period to seven days. Comments were filed on March 9, 2001 by SCE, SDG&E / SoCal, PG&E, ORA, NRDC, TURN, and Caterpillar, Inc. In response to the comments, we make minor corrections and clarifications to the draft decision and attached report, but do not make substantive changes to the program or ratemaking directives contained therein.

Findings of Fact

1. Energy Division's proposed programs to comply with Pub. Util. Code § 399.15(b), as modified by this decision, are expected to produce sizeable public benefits in the form of electric peak-demand reductions, environmental and other benefits, relative to their cost. Some of these benefits (e.g., environmental) are expected to accrue to gas, as well as electric, ratepayers.

2. The Commission has not yet determined that the electric rate freeze has ended for SCE and PG&E. The electric rate freeze is over for SDG&E, although there is a rate cap on SDG&E's generation-related rate component and SDG&E is also subject to PBR for its distribution revenue requirements.

3. The self-generation programs adopted today will produce significant public (e.g., environmental) benefits for all ratepayers, including gas ratepayers.

4. The Legislature has not authorized an additional charge, above current electric rate freeze levels, to recover the costs of § 399.15(b) programs. The current allocation of energy efficiency funding between gas and electric customers, on a percentage basis, is a reasonable proxy for the allocation of

benefits between these customers that we can expect from the self-generation program.

5. Energy Division's proposed programs, as modified by this decision, encompass a specific set of initiatives that can be tested on a pilot basis, without risking major investment of ratepayer funding on a full-scale rollout. The proposed programs complement, rather than duplicate, initiatives for peak-demand reductions that are being explored in other Commission proceedings, as well as programs being implemented by the CEC.

6. ORA's proposal to designate the San Diego Regional Energy Office as program administrator for the self-generation program in SDG&E's service territory provides us with an opportunity to explore non-utility administration on a limited, pilot basis.

7. ORA's proposal to establish non-utility administrators for energy-efficiency and self-generation programs for the longer-term is beyond the scope of the issues related to § 399.15(b) implementation and Energy Division's report.

8. Energy Division's requirement that the self-generation program be administered through the utility's existing SPC program for energy efficiency poses implementation problems because SoCal and the San Diego Regional Energy Office do not currently administer such a program. There may also be equally viable, and potentially less burdensome, program delivery choices.

9. Requiring administrators to outsource program evaluation, and involving Energy Division in the process, will ensure that the programs authorized today are independently evaluated. Requiring that the installation of technologies at customer sites be performed by independent contractors ensures that market actors other than the program administrators are involved in the programs. These requirements are consistent with the manner in which Commission-

authorized energy efficiency and low-income assistance programs are implemented.

10. Because the programs we authorize today are new, it is difficult at this time to establish budget allocations across individual cost categories (e.g., administration, evaluation) that will not be unduly restrictive to program administrators. At the same time, affording program administrators unlimited flexibility in allocating the program budgets will not ensure that an appropriate level of funding is available for hardware installations and customer incentives.

11. The effectiveness of Energy Division's proposed demand-responsiveness programs will be enhanced by allowing some flexibility and experimentation in the design of customer incentives, marketing approaches, technology selections and other design parameters, within the guidelines described in this decision.

12. There is no evidence to support SDG&E's contention that limited- to moderate-income residential customers in its service territory are unlikely to use central air conditioning.

13. The residential and commercial demand-responsiveness programs require only that the thermostat itself is capable of internet interface, an option that does not require the customer to own or operate a personal computer.

14. Including several, very different information dissemination approaches in the interactive consumption and cost information pilot would detract from the focus of the pilot, i.e., to test a specific website approach, and would not enhance the effort.

15. Categorically excluding non-renewable technologies from the self-generation program adopted today would not be consistent with the legislative intent reflected in Pub. Util. Code § 399.15 (b), which also allows technologies to qualify if they enhance system reliability.

16. Without waste heat recovery, certain non-renewable self-generation technologies may be less efficient and more polluting than combined cycle technologies. Requiring that these technologies utilize waste heat recovery at the customer site mitigates these concerns and is consistent with our goal of improving the overall efficiency of the electrical generation system.

17. Creating an additional category under the self-generation program for fuel cells operating on a non-renewable fuel source recognizes that these systems do not yield the same benefits as those that operate on renewable fuels.

18. Without some form of size or funding limitation, a small number of very large self-generation units could easily use up most or all of the available program budget. This problem can be addressed by 1) establishing a unit size limit or 2) specifying a maximum percentage of funding that can be paid to a single customer or system. The latter approach, however, would result in widely varying system size limitations across service territories because of differing budget allocations.

19. A system size limit of 1 MW for self-generation projects represents a fairly large installation for a single customer site and, at the same time, will not use up an unreasonable amount of program funding.

20. Affording program administrators flexibility to design the self-generation incentive levels for their individual programs may confuse consumers, or cause them to wait for the possibility of higher incentives before installing self-generation systems. In addition, a uniform, statewide incentive for this program recognizes that the market for self-generation technologies is not limited to or differentiated by a particular region or utility service territory.

21. Establishing on-peak/off-peak operating requirements or differential financial incentives for self-generation systems may not be necessary or reasonable because:

1) It is likely that customers willing to invest in self-generation already have sufficient economic incentive from energy prices to operate their systems during peak periods,

2) The system output for solar technologies is already generally coincident with afternoon system peak, without any further requirements, and

3) The incentive approach (dollars per watt installed) proposed by Energy Division is consistent with the CEC's renewables buy-down program and maintaining that approach should help minimize market confusion and disruption.

22. Monitoring the extent to which self-generation units installed under the program operate during peak periods will assist us in improving program design and incentive mechanisms for self-generation programs in the future.

23. Requiring a five-year manufacturer's warranty for technologies eligible under CEC's renewables buy-down program is consistent with CEC's program requirements and industry practice for those technologies.

24. Manufacturers of other distributed generation equipment (e.g., microturbines) typically offer warranties of only three to 12 months. Requiring a three-year warranty, either from the equipment manufacturer or through a maintenance contract, is sufficient to ensure continued operation and reliability of the system, and will encourage manufacturers and vendors to offer high quality products.

25. Any determinations in this decision regarding the waiver of interconnection fees or standby charges could prejudge the issues being considered and addressed in R.99-10-025.

26. The cost-effectiveness methods and inputs applied to Energy Division's proposals are preliminary and limited only to these pilot programs. An appropriate cost-effectiveness method for future, longer-term programs still needs to be developed.

27. Participation in multiple load control and self-generation programs would potentially allow an individual customer to receive multiple incentive payments for taking a single action. For example, a commercial customer could be receiving an interruptible rate discount, while at the same time utilizing incentives from the self-generation program to assist in the purchase of on-site generation for use during interruption periods.

28. Careful coordination is required to ensure that consumers are not "double dipping" and inappropriately receiving incentives from more than one program, whether sponsored by this Commission, CEC, the ISO or other state agencies. Coordination is particularly needed between SoCal and SCE in implementing the self-generation program, since they generally serve the same service territory and customers.

Conclusions of Law

1. Energy Division's proposed programs and annual funding levels for the implementation of Pub. Util. Code § 399.15(b), as modified by this decision and described in Attachment 1, are reasonable and should be adopted.

2. Until the Commission determines that the electric rate freeze has ended for SCE and PG&E, or until there is specific Legislative authority to impose an additional charge to recover the costs of § 399.15(b) programs, we cannot grant the rate relief requested by the utilities. Although the rate freeze has ended for SDG&E, it would be inconsistent with the PBR framework to address the level of SDG&E's distribution revenue requirements and rates on a piecemeal basis, rather than within the PBR context in its next PBR / cost-of-service proceeding.

3. The utilities should proceed with today's authorized programs without further delay and establish memorandum accounts to track all program costs. As discussed in this decision, the utilities should also track all program costs and benefits by customer class.

4. It is reasonable that program administrators for the demand-responsiveness programs should have flexibility to design the customer incentive and pilot program according to the guidelines established in this decision and within the adopted program funding levels.

5. The residential demand-responsiveness pilot program should also target limited to moderate-income areas, as recommended by Energy Division.

6. The interactive consumption and cost information pilot should implement and test the website approach recommended by Energy Division, and not be expanded to include other information dissemination approaches. However, nothing in today's decision is intended to diminish or replace other effective methods that PG&E might also employ to provide energy information to smaller customers.

7. Given the concerns raised by parties regarding utility administration of self-generation programs, it is reasonable to explore a non-utility administrative option, on a limited basis, during the implementation of today's adopted programs. For this purpose, ORA's proposal to designate the San Diego Regional Energy Office as program administrator for SDG&E's self-generation program is a reasonable approach and should be adopted.

8. Program administrators should have flexibility in selecting program delivery mechanisms for the self-generation program, as long as they meet the basic requirements described herein.

9. In implementing today's adopted pilot programs, program administrators should outsource program implementation and administrative activities according to the guidelines established in this decision.

10. It is reasonable to establish fund-shifting rules that provide program administrators with sufficient flexibility to manage program costs, while

ensuring that an appropriate proportion of funding goes to hardware installations and customer incentives.

11. It is reasonable to require that certain distributed generation technologies also employ waste heat recovery, as a prerequisite for funding under the self-generation program.

12. It is reasonable to establish a third category of technology and incentive level under the self-generation program for fuel cells operating on non-renewable fuel.

13. The incentive structure described in this decision for the self-generation program is reasonable and should be adopted.

14. Hybrid self-generation systems that incorporate technologies from different incentive categories should receive payments based on the appropriate category, as described in this decision.

15. The self-generation incentive levels we adopt today should be fixed and applied uniformly on a statewide basis throughout the program period, unless modified by subsequent Commission decision.

16. It is reasonable to require a warranty period of five-years for Level 1 and 2 technologies. For Level 3 technologies, it is reasonable to require a warranty period of three years. The customer installing the self-generation system should purchase a minimum of a three-year warranty from the manufacturer or a vendor in order to comply with this requirement, if the system does not already include the required warranty. The customer may include the cost of this warranty in the system cost, for purposes of calculating their program incentive, up to the maximum percentage levels specified.

17. The appropriate forum for considering Energy Division's proposal to waive interconnection fees and standby charges is R.99-10-025, and not this

proceeding. However, it is reasonable to use program funds to defray a portion of a project's interconnection fees (as defined in D.00-12-037) by including these fees in the total installation costs when determining the maximum size of the self-generation incentive.

18. As described in this decision, Energy Division should hire an independent consultant to develop a cost-effectiveness method that can be used on a common basis to evaluate all programs that will remove electric load from the centralized grid, including energy efficiency, load control/demand-responsiveness programs and self-generation.

19. The programs authorized today should be evaluated during and after the program period, as described in this decision.

20. Customers installing self-generation systems eligible for the CEC buy-down program should be allowed to augment the funding received from that program with funding available from today's adopted self-generation program, up to the maximum incentive limits.

21. It is reasonable that administrators of today's adopted self-generation programs should take advantage of the work already done by the CEC in developing appropriate program details to encourage self-generation.

22. SCE and SoCal should carefully coordinate their marketing and tracking of program incentives very carefully in order to ensure that customers do not receive incentives for the same self-generation equipment from both utilities. In the alternative, SoCal may administer the self-generation program for the combined geographic region, if SCE and SoCal so agree.

23. As discussed in this decision, the Assigned Commissioner may further clarify eligibility and other implementation issues by ruling, if and when such a need arises.

24. Public necessity, as defined in Rule 77.7(f)(9) requires that the usual 30-day review and comment period on the draft decision be shortened to seven days.

25. In order to implement today's adopted programs as expeditiously as possible, this order should be effective today.

INTERIM ORDER

1. The programs and annual budgets described in Attachment 1 are approved through December 31, 2004. Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCal), collectively referred to as "the utilities," shall implement these programs without delay, consistent with today's decision.

2. The annual program budgets approved today are as follows:

Utility	Demand Responsiveness Budget	Self Generation Budget ($ million)	Total Annual Budget ($ million)
PG&E	$3,000,000	$60,000,000	$63,000,000
SCE	$5,940,000	$32,500,000	$38,440,000
SDG&E	$3,930,000	$15,500,000	$19,430,000
SoCal	NA	$17,000,000	$17,000,000
Total	**$12,870,000**	**$125,000,000**	**$137,870,000**

Within 15 days of the effective date of this decision, PG&E and SCE shall file Advice Letters increasing their electric distribution revenue requirements, without modifying current rates, to include today's authorized program budgets. SDG&E shall address the funding of these programs in its next PBR and cost-of-service proceeding. PG&E, SDG&E and SoCal shall include the costs of the programs allocated to gas customers in their next gas rate recovery proceeding, e.g., the Biennial Cost Adjustment Proceeding. In these filings, PG&E and SDG&E shall present the specific factors they use to allocate self-generation program budgets between their electric and gas customers. These factors shall reflect the current allocation of energy efficiency programs between these customers, as discussed in this decision. The utilities shall establish memorandum accounts to track program costs, and shall also track all program costs and benefits by customer class.

3. The utilities shall be the program administrators for the demand-responsiveness programs described in Attachment 1. For the self-generation program authorized in SDG&E's service territory, SDG&E shall contract with the San Diego Regional Energy Office to provide administrative services at the full budgeted amount for that program ($15.5 million). PG&E, SCE and SoCal shall administer the self-generation programs in their service territories. However, as discussed in this decision, SoCal and SCE may assign to SoCal the administration of self-generation programs for their combined service territories.

4. In implementing today's adopted programs, program administrators shall outsource program implementation and administrative activities as directed below:

- Program administrators shall outsource to independent consultants or contractors all program evaluation activities.
- All installation of technologies (hardware and software) at customer sites shall be done by independent contractors and not utility personnel (or agency personnel, in the case of the San Diego Regional Energy Office).
- Program administrators shall also outsource as many other aspects of program administration and implementation as feasible. In particular,

the majority of program marketing and outreach activities should be outsourced, to the extent feasible, although the program administrator shall actively participate and assist contractor efforts for this purpose.

- Program administrators shall have the flexibility to select the manner of outsourcing (e.g., competitive bidding, sole source contracting) for the programs adopted today.

5. Under the self-generation program authorized today, program administrators shall offer the following incentives on a uniform, statewide basis:

Incentive category	**Incentive offered**	**Maximum percentage of project cost**	**Minimum system size**	**Maximum system size**	**Eligible Technologies**
Level 1	$4.50 / watt (W)	50%	30 kilowatt (kW)	1 megawatt (MW)	▪ Photovoltaics ▪ Fuel cells operating on renewable fuel ▪ Wind turbines
Level 2	$2.50 / W	40%	None	1 MW	▪ Fuel cells operating on non-renewable fuel and utilizing waste heat recovery
Level 3	$1.00 / W	30%	None	1 MW	▪ Microturbines utilizing waste heat recovery and meeting reliability criteria ▪ Internal combustion engines and small gas turbines, both utilizing waste heat recovery and meeting reliability criteria

6. As described in this decision, hybrid self-generation systems that incorporate multiple technologies shall be eligible for payments based on the appropriate incentive category, and the program applications should provide for these systems.

7. Interconnection fees for systems funded under the self-generation program shall be included in the total installation costs when determining the maximum size of the self-generation incentive. Today's decision does not address or adopt policies regarding the waiver of these fees or of standby charges for distributed generation technologies.

8. Level 1 and 2 technologies installed under the self-generation program shall be covered by a warranty of not less than five years, consistent with the requirements of the California Energy Commission's (CEC) Emerging Renewables Buy-Down Program. Level 3 technologies shall be covered by a warranty period of not less than three years. The customer installing the Level 3 system shall purchase a minimum of a three-year maintenance contract from the manufacturer or a vendor in order to comply with this requirement, if the system does not already include the required warranty. The customer may include the cost of this warranty in the system cost, for purposes of calculating the program incentive, up to the maximum percentage levels allowed.

9. As described in this decision, program administrators shall have flexibility in selecting program delivery mechanisms for the self-generation program, subject to the following requirements:

- Available incentive funding (dollars per watt or percentage of system cost) is fixed on a statewide basis at the levels authorized in today's decision.
- Inspections are conducted to verify that the funded self-generation systems are actually installed and operating.

- The measurement and verification protocols established by the administrators include some sampling of actual energy production by the funded self-generation unit over a statistically relevant period.

10. Program administrators shall have flexibility to reallocate and shift funds within the authorized program budgets as described in this decision.

11. As described in this decision, program administrators for the demand-responsiveness programs shall have flexibility within the adopted program funding levels to 1) select the design and level of customer incentive, 2) establish monthly consumption threshold levels for defining the high consumption target groups, and 3) select the specific technologies employed in the residential and small commercial demand-responsiveness programs. However, any technology installed for these programs must include the following features:

- Provide customers some level of control (e.g., thermostat setting override) over their own heating, ventilation and air-conditioning equipment.
- Provide interactive information for consumers to make consumption decisions (e.g., via the thermostat or a computer internet connection), and
- Allow the administrator to verify actual interruption of the individual device at the customer site, including duration and level of kW demand reduction.

12. The programs authorized today shall be evaluated during and after the program period, as follows:

- For the residential and small commercial demand-responsiveness pilot programs, SDG&E and SCE shall each conduct a process evaluation during 2001 and an energy savings and peak demand savings impact study at the end of 2002.

- For the interactive and cost information pilot program, PG&E shall contact site users and non-users to discuss their satisfaction with the information on the site and suggest potential improvements.

- Program administrators for the self-generation program shall perform program evaluations and load impact studies to verify energy production and system peak demand reductions. In particular, program administrators shall monitor the extent to which self-generation units installed under this program operate during peak periods. The costs of monitoring equipment installed for this purpose shall be paid from program funds. Program administrators shall direct their independent evaluation consultants or contractors to develop a process for monitoring and collecting this data from program participants. At the end of the first program year, administrators shall report to the Commission on peak operation from the program, and continue this reporting in subsequent years. By the end of the second program year, the consultants or contractors shall present recommendations on incentive or program designs that could improve on-peak load reduction from self-generation.

- Program administrators for the self-generation program shall also conduct an independent analysis of the relative effectiveness of the utility and non-utility administrative approaches we adopt today.

13. Program administrators shall outsource to independent consultants or contractors all program evaluation activities. Energy Division shall assist program administrators in the development of the scope of work, selection criteria and the evaluation of submitted proposals to perform these program evaluations. The assigned Administrative Law Judge, in consultation with Energy Division and the program administrators, shall establish a schedule for filing the required evaluation reports. Energy Division shall hold a workshop with program administrators as soon as practicable to develop scheduling proposals for this purpose.

14. As described in this decision, Energy Division shall hire an independent consultant to develop a cost-effectiveness method that can be used on a common

basis to evaluate all programs that will remove electric load from the centralized grid, including energy efficiency, load control / demand-responsiveness programs and self-generation. Energy Division shall utilize funds appropriated for the implementation of AB 970 for this purpose.

The scope of work shall encompass the development of methodologies, input assumptions and forecasts for addressing § 399.15(b)(8) and other cost-effectiveness issues. Energy Division shall submit the final consultant report no later than December 31, 2002, and serve a notice of its availability to all appearances and the state service list in this proceeding (or its successor) . Energy Division may hold public workshops with the consultant and interested parties during the development of this methodology, as it deems appropriate. The Assigned Commissioner or Administrative Law Judge shall establish a schedule for comments on the final report.

15. Customers installing self-generation systems eligible for the CEC Emerging Renewables Buy-Down Program may augment the funding received from that program with funding available from today's adopted self-generation program, up to the maximum incentive limits. Program administrators shall work with the CEC to ensure the appropriate tracking and accounting of who receives funding, so that an applicant can be easily crosschecked to make sure that there is no duplication.

16. Program administrators should take advantage of the work already done by the CEC in developing appropriate program details to encourage self-generation, and SoCal shall convene a working group including PG&E, SCE, SDG&E, and the San Diego Regional Energy Office to select final program details for statewide implementation, as soon as practicable.

17. SCE and SoCal shall coordinate their marketing and tracking of program incentives very carefully in order to ensure that customers do not receive incentives for the same self-generation equipment from both utilities. In the alternative, SoCal may administer the self-generation program for the combined geographic region, if SCE and SoCal so agree.

18. The Energy Division shall work with the respondent utilities and the California Energy Commission (CEC) to develop reliability criteria for fossil generators participating in the self-generation program and to ensure coordination with CEC programs as discussed in this decision.

This order is effective today.

Dated March 27, 2001, at San Francisco, California.

LORETTA M. LYNCH
President
CARL W. WOOD
GEOFFREY F. BROWN
Commissioners

I dissent.

/s/ HENRY M. DUQUE
Commissioner

I dissent.

/s/ RICHARD A. BILAS
Commissioner

Attachment 1

Adopted Programs to Fulfill AB970 Load Control and Distributed Generation Requirements

(Public Utilities Code Section 399.15(b))

(Paragraphs 4 through 7)

March 26, 2001

Table of Contents

DEMAND - RESPONSIVENESS PROGRAMS

Residential Demand-Responsiveness Pilot Program

Overview

Brief description

This pilot program is designed to test the viability of a new approach to residential load control and demand-responsiveness through the use of internet technology and thermostats to affect HVAC energy use. This program is designed to include approximately 5,000 residential customers in the San Diego Gas & Electric service territory, representing an estimated 4 MW in peak demand reduction, to produce savings before the end of 2002. Consumers will be provided with the necessary technology installation and a small incentive for program participation.

Rationale

We prefer this program to other residential load control program options for the following reasons:

- Potential for peak demand reduction through control of residential and small commercial HVAC appliances
- Probability of customer acceptance
- Utilization of internet platform, which ensures likelihood of forward compatibility of technology
- Data collection ability for measurement and evaluation purposes
- Ability to test residential customer response to energy market demand and price fluctuations.

SDG&E will be the administrator of this pilot program.

Objectives

The main objective of this program is to fulfill the statutory requirement of AB970 contained in PU Code 399.15(b) paragraph 5. This paragraph requires the PUC to undertake the following activity: “Evaluation of installing local infrastructure to link temperature setback thermostats to real-time price signals.”

This pilot program will accomplish this directive, while simultaneously testing other assumptions of interest to the PUC including:

- Consumer participation and behavior patterns in the program
- Consumer satisfaction with newer interactive load control technologies
- Responsiveness of residential customer load to price or system demand signals
- Ability of such programs to deliver reliable and verifiable energy and demand savings.

Administrative responsibility

Commission role

For this pilot program, the Commission will perform traditional oversight of program design, roll out, and implementation. In addition, the Commission will post program information on its web site, so that consumers and other interested parties may learn about the program.

Utility role

SDG&E's functions for this pilot program include:

- Collecting and accounting for program funding from electric distribution customers
- Fine tuning program design and implementation
- Contracting with a third party for program services and equipment
- Acting as a contract administrator for program delivery
- Conducting customer recruiting for program participation, including posting information on utility web site
- Providing marketing assistance and facilitation to contractor(s) providing program delivery
- Performing regulatory reporting functions for the program
- Contracting with independent evaluator(s) to conduct a process evaluation beginning in 2001 and a load impact evaluation after 2002 and at the end of the pilot period (or another schedule established by the Commission).

Third party role

The third party (or parties) for this program will be equipment and service providers. These third parties will provide:

- Connected HVAC programmable thermostats for residential customers
- Data services and software
- Installation services
- System administration
- Communications services
- Settlements and / or reporting of program activity.

The utility will also be required to hire an independent contractor to perform the program evaluations and load impact studies to verify energy savings and peak demand reductions produced by this pilot program.

Eligibility

Participant

For purposes of this pilot program, SDG&E will target three distinct residential customer groups to test program concept viability for each. These include: 1) residential customers whose average monthly electricity consumption is greater than average for their customer class, with the exact specified consumption level to be determined by SDG&E; 2) residential customers residing in geographical areas in SDG&E service territory known to have high electricity consumption due to climate; and 3) customers residing in known limited- to moderate-income areas.

Technology

SDG&E has flexibility to select the exact nature of the technology utilized for this program, based on bids received from technology suppliers. The preferred technologies eligible to be included in this program should be programmable HVAC (connected) thermostats with two-way internet connectivity. SDG&E should not consider technologies that simply allow the utility to interrupt load on a one-way basis. At a minimum, the technology selected must have the following characteristics:

- Allow each customer some level control over its own HVAC equipment (override, etc.)
- Provide interactive information for consumers to make consumption decisions (e.g. via the thermostat or a computer internet connection), and
- Allow the administrator to verify actual interruption of the individual device at the customer site, including duration and level of kW demand reduction.

Program Expenditures

Budget

The table below includes initial estimates of annual program costs. These will be further refined once the utility issues a request for proposal and receives bids from contractors for exact costs.

Item and assumptions	Estimated Cost
Administrative Costs	
Contract administration, marketing, and regulatory reporting, and program evaluation (admin. and marketing may not exceed 5% of total budget)	$786,000
Installation, service, and operation costs	
Includes hardware, software, installation costs, communications costs, and customer incentives	$3,144,000
Total Annual Program Budget	**$3,930,000**

Incentive Structure

All program participants will receive the equipment and installation free of charge from the utility. In addition, the customer should receive an incentive at the end of each year of program participation. The program administrator shall set a program incentive, which may include an annual program incentive, override penalties, and/or on-peak interruption bonuses.

Verification

Purpose

The purpose of verification in the context of this program is to ensure that the technologies installed in residential homes through the program are installed and operating properly, and have the potential to deliver energy and peak demand savings. Verification should also produce the information necessary to estimate the energy and peak demand savings delivered at each customer site. Evaluation of the aggregate energy and demand savings achieved by the program should be the responsibility of the independent evaluator hired by the utility.

Responsibility

Responsibility for verification of installation of technologies and program operation should be retained by the utility. The utility should verify that the third party hired to deliver the program to consumers has installed operating equipment at residential customer sites. Site inspections should be done on a random sample of at least 10% of homes participating in the program. The utility or its agents should be responsible for these verification inspections.

Procedures or protocols

The hardware and software offered by the delivery contractor for this program should have the capability for periodic reporting of thermostat settings and consumer behavior, for payment settlement purposes. This information should also be made available to the program evaluator hired by the utility in order to estimate aggregate energy savings and peak demand reduction impacts of the pilot program.

Program process

The first step in the program process for this residential pilot is for the utility to issue an RFP and select a contractor or team of contractors to handle technology installation at customer sites, as well as software setup at the utility site. The contractor or contractors should be competitively selected through an open solicitation process. Once this contractor is selected, the utility and contractor can jointly begin to recruit residential customers for program participation.

Application

No application from individual customers should be required for this program, except a signed affidavit from the customer agreeing to have the equipment installed at their home and that they understand the terms and conditions of the pilot program. The contractor should have the authority to interact with the customer to make sure the necessary paperwork and program understanding is accomplished with each and every participating residential customer.

Installation

The contractor should also coordinate with individual consumers to arrange installation and setup of equipment. The utility may either manage this process or ask that the contractor handle the scheduling and coordination of equipment installations.

Operation

Once equipment has been installed at the customer's home, the program can be operated by setting a customer's thermostat to a preset default, the exact nature of which should be determined at the outset of the program by SDG&E. SDG&E should define what will be considered an "event." A maximum number of events during an annual program period should be set. A customer should have the ability to override the thermostat setting at any time during an event, with some loss of incentive. The program operators may wish to vary the thermostat settings and/or the numbers of hours over which each event occurs to test consumer tolerance and reactions to different operating procedures or schedules.

Payment

Customers should receive free equipment and installation at the beginning of program participation. At the end of each year of participation, the customer should receive from the utility for the amount set by the applicable incentive program.

Evaluation

The utility should contract with a third party consultant to conduct both a process evaluation during 2001 and an energy savings and peak demand savings impact study at the end of 2002, and thereafter on a schedule to be set by the Commission.

Marketing and Promotion

At a minimum, information about the program should be made available to target households through the utility web site and bill inserts. Community-based organizations should also be involved in program marketing and outreach, to the extent feasible. In addition, utility representatives should work with the program delivery contractor to contact and recruit interested customers.

The CPUC will also include information about the program on its web site, and include links or contact information at the utility where consumers can request more information.

Small Commercial Demand-Responsiveness Pilot Program

Overview

Brief description

This pilot program is designed to test the viability of a new approach to small commercial load control and demand-responsiveness through the use of internet technology and thermostats to affect HVAC energy use. This program is designed to include approximately 5,000 small commercial customers in the Southern California Edison service territory, representing an estimated 4 MW in peak demand reduction, to produce savings before the end of 2002. Consumers will be provided with the necessary technology installation and a small incentive for program participation.

Rationale

We chose this program over other small commercial load control program options for the following reasons:

- Potential for peak demand reduction through control of small commercial HVAC appliances
- Probability of customer acceptance
- Utilization of internet platform, which ensures likelihood of forward compatibility of technology
- Data collection ability for measurement and evaluation purposes
- Ability to test customer response to energy market demand and price fluctuations.

We direct that SCE implement this pilot program.

Objectives

The main objective of this program is to fulfill the statutory requirement of AB970 contained in PU Code 399.15(b) paragraphs 4, 5, and 6 to "equip commercial buildings with the capacity to automatically control thermostats…", "evaluate installation of local infrastructure," and provide "incentives for load control." This pilot program will accomplish these directives, while simultaneously testing other assumptions of interest to the PUC including:

- Consumer participation and behavior patterns in the program

- Consumer satisfaction with newer interactive load control technologies
- Responsiveness of small commercial customer load to price or system demand signals
- Ability of such programs to deliver reliable and verifiable energy and demand savings

Administrative responsibility

Commission role

For this pilot program, the Commission will perform traditional oversight of program design, roll out, and implementation. In addition, the Commission will post program information on its web site, so that consumers and other interested parties may learn about the program.

Utility role

SCE's functions for this pilot program include:

- Collecting and accounting for program funding from electric distribution customers
- Fine tuning program design and implementation
- Contracting with a third party for program services and equipment
- Acting as a contract administrator for program delivery
- Conducting customer recruiting for program participation, including posting information on utility web site
- Providing marketing assistance and facilitation to contractor(s) providing program delivery
- Performing regulatory reporting functions for the program
- Contracting with independent evaluator(s) to conduct a process evaluation in 2001 and a load impact evaluation after 2002, and annually thereafter (exact schedule to be determined).

Third party role

The third party (or parties) for this program will be equipment and service providers. These third parties will provide:

- Connected HVAC programmable thermostats for small commercial customers
- Data services and software
- Installation services
- System administration
- Communications services

- Settlements and / or reporting of program activity.

The utility will also be required to hire an independent contractor to perform the program evaluations and load impact studies to verify energy savings and peak demand reductions produced by this pilot program.

Eligibility

Participant

For purposes of this pilot program, we recommend targeting three distinct small commercial customer groups, to test program concept viability for each: 1) small commercial customers with high average monthly consumption in the summer; 2) small commercial customers in geographical areas in SCE service territory known to have high electricity consumption due to climate; and 3) customers located in small cities or rural areas. Small commercial customers are precluded from participating in both the §399.15(b) demand responsiveness programs and other demand responsiveness programs offered by other state agencies or the interruptible programs being considered in R.00-10-002.

Technology

SCE has flexibility to select the exact nature of the technology utilized for this program, based on bids received from technology suppliers. The preferred technologies eligible to be included in this program should be programmable HVAC (connected) thermostats with two-way internet connectivity. SCE should not consider technologies that simply allow the utility to interrupt load on a one-way basis. At a minimum, the technology selected must have the following characteristics:

- Allow each customer some level control over its own HVAC equipment (override, etc.)
- Provide interactive information for consumers to make consumption decisions (e.g. via the thermostat or a computer internet connection), and
- Allow the administrator to verify actual interruption of the individual device at the customer site, including duration and level of kW demand reduction.

Program Expenditures

Budget

The table below shows initial estimates of annual program costs. These will be further refined once the utility issues a request for proposal and receives bids from contractors for exact costs.

Item and assumptions	Estimated Cost
Administrator Costs	
Contract administration, marketing, and regulatory reporting, and program evaluation (admin and marketing limited to a maximum of 5% of budget)	$1,188,000
Installation, service, and operation costs	
Includes hardware, software, installation costs, communications, and customer incentives	$4,752,000
Total Annual Program Budget	$5,940,000

Incentive Structure

All customers participating in the program should receive the equipment and installation free of charge from the utility. In addition, the customer should receive a one-time incentive payment at the end of each year of program participation. The program administrator shall set a program incentive, which may include an annual program incentive, override penalties, and / or on-peak interruption bonuses.

Verification

Purpose

The purpose of program verification is to ensure that the technologies installed at small commercial sites through the program are installed and operating properly, and have the potential to deliver energy and peak demand savings. Verification should also produce the information necessary to estimate the energy and peak demand savings delivered at each customer site. Evaluation of the aggregate energy and demand savings achieved by the program should be the responsibility of the independent evaluator hired by the utility.

Responsibility

The utility will have responsibility for verification of technology installation and program operation. The utility should verify that the third party hired to deliver the program to consumers has installed operating equipment at small commercial customer sites. Site inspections should be conducted on a random sample of at least 10% of small businesses participating in the program. The utility or its agents will be responsible for these verification inspections.

Procedures or protocols

The hardware and software offered by the delivery contractor for this program should have the capability for periodic reporting of thermostat settings and consumer behavior, for payment settlement purposes. This information should also be made available to the program evaluator hired by the utility in order to estimate aggregate energy savings and peak demand reduction impacts of the pilot program.

Program process

The first step in the residential pilot program process is for the utility to issue an RFP and select a contractor or team of contractors to handle technology installation at customer sites, as well as software setup at the utility site. The contractor or contractors should be competitively selected through an open solicitation process. Once this contractor is selected, the utility and contractor can jointly begin to recruit small commercial customers for program participation.

Application

No application from individual customers should be required for this program, except a signed affidavit from the customer agreeing to have the equipment installed at their site and that they understand the terms and conditions of the pilot program. The contractor should have the authority to interact with the customer to make sure the necessary paperwork and program understanding is accomplished with each and every participating small commercial customer.

Installation

The contractor should also coordinate with individual consumers to arrange installation and setup of equipment. The utility may either manage this process or ask that the contractor handle the scheduling and coordination of equipment installations.

Operation

Once equipment has been installed at the customer’s site, the program can be activated by setting a customer’s thermostat to a preset default for a maximum time period to be determined at the outset of the program. Each interruption period will be considered an “event.” A maximum number of events during an annual program period should also be determined at the beginning of the program and communicated to the customer. A customer should have the ability to override the thermostat setting at any time during an event. The program operators may also wish to vary the thermostat settings and / or the numbers of hours over which each event occurs to test consumer tolerance and reactions to different operating procedures or schedules.

Payment

Customers will receive free equipment and installation at the beginning of program participation. At the end of each year of participation, the utility should pay the applicable program incentive to the customer.

Evaluation

The utility must contract with a third party consultant to conduct both a process evaluation during 2001 and an energy savings and peak demand savings impact study at the end of 2002. Other evaluation schedules will be set by the Commission.

Marketing and Promotion

At a minimum, information about the program should be made available to target small commercial customers through the utility web site and bill inserts. Community-based organizations and small business associations should also be involved in program marketing and outreach, to the extent feasible. In addition, utility representatives should work with the program delivery contractor to contact and recruit interested customers.

The CPUC will also include information about the program on its web site, and include links or contact information at the utility where consumers can request more information.

Interactive Consumption and Cost Information for Small Customers

Overview

Description

The purpose of this program is to provide small, less sophisticated electric customers with access to high-quality information about the changing electricity market. This program requires PG&E to hire a web-site designer to develop a pilot site to test internet support for the needs of small customers. In addition to market information, including prices and costs, customers should be able to access their demand and consumption profiles, to help them understand better how their electric bills are (or will be) influenced by their load profiles.

Rationale

In this rapidly changing electricity market, many consumers, especially small ones, require access to dependable and straightforward information about electricity prices and costs. Missing from many press and public agency accounts of the crisis is the link between activities of the FERC, ISO, PUC, Legislature, Governor, or utility and the customer’s own energy profile. This pilot program will explore how provision of this type of information to smaller consumers can be tailored to help close the information gap.

Objectives

The program objectives are:

- Link market information with customer consumption information
- Test costs and benefits of this approach to consumer outreach (in addition to more traditional audit programs PG&E already offers)
- Link information contained on this site to customer solutions, including equipment and appliance manufacturers that provide high-efficiency products and services
- Explore the nexus of utility and third party services to consumers.

Administrative Responsibility

Commission role

The Commission will oversee program design and implementation. The Commission will also post announcements of this pilot on its web site.

Utility role

We nominate PG&E to administer this program, because we find their current online customer services already more advanced than those of the other utilities. We do not, however, recommend that PG&E develop this web site in-house. Instead, we recommend that PG&E take on the role of marketing the new site to a select group of customers. PG&E should also hire an independent web design consultant to develop the site. PG&E should hire an independent evaluation contractor to study customer reaction to the site and recommend changes and improvements before more widespread deployment of the strategy. We understand that several similar efforts have been ordered in various Commission decisions and that the utilities are already working on a joint statewide website. This effort is intended to be more robust and go beyond those activities.

Third party role

As discussed above, an independent web design contractor should develop and host the site linked from the PG&E main web site. Since the site will contain individual customer data, the web developer will likely be required to sign a confidentiality agreement to protect consumer usage data.

PG&E should hire a separate contractor to evaluate the program concept and customer reaction.

Eligibility

Participant

We recommend targeting this program at approximately 10,000-15,000 selected residential and small commercial customers in PG&E's service territory. Targeted customers could be any or all of the following:

- Residential customers with higher than average monthly consumption for their customer class (the exact specified amount is to be determined by PG&E)
- Residential customers known to have swimming pools
- Homes and small businesses on the San Francisco peninsula or in Silicon Valley
- Rural residences and small businesses

Technology

The site developed should be located on the web, hosted by an independent web site developer, and contain the following information, at a minimum:

- Up-to-date information about the structure of the California electricity market and how it affects small customers
- Information about how electricity is priced
- Rate tariff options for residential customers, explained in simple terms (not simply copies of tariff schedules)
- Customer online access to their own historical energy bill information
- Representative energy usage and cost information for common appliances, including refrigerators, ovens, dishwashers, clothes washers, dryers, televisions, and computers
- Links to manufacturers or retailers of high-efficiency appliances, tailored to the appliance or equipment needs of the individual
- Information about low-cost efficiency options and how much energy and bill savings they could produce, tailored to customer's geographic area
- Information about renewable self-generation options, costs, and benefits
- Links to manufacturers or retailers of self-generation equipment.

Program Expenditures

Budget

The table below gives preliminary annual budget information for planning purposes. Actual expenditures will likely vary, depending on the bids received by PG&E for web development and hosting services, as well as for program evaluation.

Item and assumptions	**Estimated Cost**
Administrator Costs	
Contract administration, marketing, and regulatory reporting, and program evaluation (admin. & marketing limited to 5% of total budget)	$600,000
Service and Operation Costs	
Includes web development and hosting, including secure access to customer confidential historical billing data, plus incentives for consumers	$2,400,000
Total Annual Program Budget	**$3,000,000**

Incentives

We recommend that PG&E provide a small incentive to a customer for actually logging onto the web site and accessing their own energy profile. This incentive could be in the form of a gift certificate of approximately $20 for a home improvement center, appliance store, or a particular product, such as a compact fluorescent lamp. This small bonus is intended to produce initial interest in viewing the site. Our intention is to provide customers with useful information on the site so that they will return to the site to further increase their energy consumption knowledge.

Verification

Purpose

In the case of this program, the purpose of verification is to determine how many customers access the web site, what kinds of information they look at once there, and if they make repeat visits. “Click-through” rates to sites of appliance manufacturers or retailers should also be tracked.

Responsibility

The web development consultant and hosting contractor will be responsible for verification. Verification information should be reported by PG&E in its periodic reporting to the Commission.

Program Process

Development

The first step is for PG&E to issue an RFP to hire a web development consultant to develop the web site. Development of the information aspects of the site should proceed first so all utility customers can use it. Customer-specific data, including secure access over the web, should be developed second.

Monitoring

The web-hosting contractor should perform periodic statistical analysis of site usage. The contractor should also provide PG&E with information about which customers have accessed the site. This will allow PG&E to send that customer their incentive coupon or gift certificate.

Payment

When the web site contractor notifies PG&E that a customer has access their own energy profile on-line, PG&E should process the incentive / gift and send it directly to the customer.

Evaluation

PG&E should hire an independent evaluation contractor to contact site users and non-users to discuss their satisfaction with the information on the site and suggest potential improvements.

Marketing and Promotion

While the site is under development, PG&E should select customers for receipt of program marketing materials encouraging testing of the site. Bill inserts should be sent to those eligible customers explaining the features of the site and offering the incentive gift certificate or coupon.

SELF - GENERATION PROGRAM

Self-Generation Program

Overview

Description

This program is intended to encourage installation of several types of self-generation technologies, both renewable and non-renewable, as detailed below. The installations may occur at any type of customer site in California. This proposal is designed to complement the current CEC buy-down program, which tends to fund smaller renewable units, while capturing the significant benefits of larger distributed generation units. Such benefits include: greater reduction of grid-supplied electricity, lower installation cost per kW, and, in the case of renewable installations, greater environmental benefits for all Californians.

This program targets photovoltaic, wind, and renewable fuel cell installations of 10 kW or greater. Customers installing units beginning January 1, 2001 should be eligible for program incentives regardless of when they become available.

This program offers differential incentives for self-generation technologies, differentiated by their fuel type, air emissions characteristics, and system costs. Photovoltaics, wind turbines, and fuel cells using renewable fuels are eligible for $4.50 per watt of installed on-site renewable generation capacity, up to a maximum of 50% of total installation costs. Nonrenewable fuel cells utilizing waste heat recovery and meeting reliability criteria may receive $2.50 per watt, up to a maximum of 40% of system cost. Any type of microturbine or internal combustion engine utilizing waste heat recovery may qualify for $1.00 per watt of on-site generation, up to 30% of total project costs. Administrators will administer this program through their existing energy efficiency standard performance contract (SPC) programs and / or similar program approaches. Contractors and energy service companies participating in this program will also be eligible to receive incentives on behalf of customers.

Rationale

In AB 970, the California legislature demonstrated that renewable technologies and self-generation are a policy priority. Self-generation and the use of renewables can provide significant benefits to Californians by improving the quality and reliability of the state's electricity distribution network, which is critical to the state's economic vitality, while protecting the environment and developing “green” technologies. The statute directs the Commission to adopt incentives for distributed generation to be paid for enhancing reliability, and differential incentives for “renewable or super-clean distributed generation resources.”[11]

The self-generation incentives provided through this programs are intended to:

- encourage the deployment of distributed generation in California to reduce the peak electric demand;[12]
- give preference to new renewable energy capacity; and
- ensure deployment of clean self-generation technologies having low and zero operational emissions.

Given the high prices experienced over the last year, the transmission constraints that will persist in California for the near future, air quality considerations, California's residents and businesses are more receptive than ever to thinking about alternative generation resources. The biggest drawback is cost. It is in the best interest of all Californians to reduce the strains on infrastructure, economy, and environment, by actively promoting renewable and super-clean technologies.

Objectives

The main objectives of this program are to fulfill the requirements of PU Code §399.15 (b) paragraph 6 and 7, which call for “incentives for distributed generation to be paid for enhancing reliability” and “differential incentives for renewable or super clean distributed generation resources.” This program also meets the following additional objectives:

- Utilize an existing network of service providers and customers to provide access to self-generation technologies quickly
- Provide access at subsidized costs that reflect the value to the electricity system as a whole, and not just individual consumers
- Help support continuing market development of the energy services industry
- Provide access through existing infrastructure, administered by the entities with direct connections to and trust of small consumers

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[11] AB970 contained in PU Code 399.15(b) paragraphs 6 and 7.

[12] For this reason, self-generators installed primarily as backup or emergency power are not eligible for the program.

- Take advantage of customers' heightened awareness of electricity reliability and cost.

Administrative Responsibility

Commission role

The Commission will oversee program design, roll out, and program implementation. In addition, the Commission will post program information on its web site, so that consumers and other interested parties may learn about the program.

Administrator role

PG&E, SCE and SoCalGas will administer the program in their own service territories, while SDG&E should contract with the San Diego Regional Energy Office (SDREO) to implement the program in its territory. We ask SoCalGas to lead a working group of all five entities to refine program design and ensure statewide consistency in program delivery. The utilities will be responsible for collecting and accounting for funding collected from their distribution customers. All administrators (including SDREO) will be responsible for the following:

- Fine tuning program design and implementation
- Modifying program forms and administrative procedures
- Verifying, or hiring a contractor to verify, installation of systems at customer sites
- Dispersing payment for installed systems after verification of installation
- Working with contractors and energy service companies participating in other energy efficiency programs to conduct customer recruiting for program participation
- Posting program information, including application form, on the internet
- Performing regulatory reporting functions for the program
- Contracting with independent evaluator(s).

Third party role

The third party (or parties) may be energy service companies or general contractors who install self-generation systems at eligible customer sites. The administrator will be required to hire an independent contractor to perform the program evaluations and load impact studies to verify energy production and system peak demand reductions produced by this program.

Eligibility

Participant

Any customer of an investor-owned distribution company in California is eligible to receive incentives from this program. In addition, contractors or energy service companies who install self-generation units at these customers' sites are also eligible to receive program incentives in lieu of customer receipt of the incentives, as long as the customer agrees.

The following entities are not eligible for incentives under this program:

- Customers who have entered into contracts for DG services (e.g. DG installed as a distribution upgrade or replacement deferral) and who are receiving payment for those services; (this does not include power purchase agreements, which are allowed)
- Customers who are participating in utility interruptible or curtailable rate schedules or programs
- Customers who are participating in any other state agency-sponsored interruptible, curtailable, or demand-responsiveness program
- Utility distribution companies themselves or their facilities.

Technology Eligibility and Incentive Structure

For purposes of this program, renewable and non-renewable self-generation technologies will be eligible for incentives according to the following structure:

Incentive category	**Incentive offered**	**Maximum percentage of project cost**	**Minimum system size**	**Maximum system size**	**Eligible Technologies**
Level 1	$4.50/W	50%	30 kW	1 MW	▪ Photovoltaics ▪ Fuel cells operating on renewable fuel ▪ Wind turbines
Level 2	$2.50/W	40%	None	1 MW	▪ Fuel cells operating on non-renewable fuel and utilizing waste heat recovery
Level 3	$1.00/W	30%	None	1 MW	▪ Microturbines utilizing waste heat recovery and meeting reliability criteria ▪ Internal combustion engines and small gas turbines, both utilizing waste heat recovery and meeting reliability criteria

Systems installed under Levels 1 and 2 must be covered by a warranty of not less than five years. Systems installed under Level 3 must be covered by a warranty of not less than three years. Where those Level 3 systems are not warrantied by the manufacturer for at least three years, customers should purchase a minimum of a three-year service contract from the manufacturer or a vendor in order to comply with this requirement. The customer may include the cost of this warranty in the system cost, for purposes of calculating their program incentive, up to the maximum percentage levels specified.

"Hybrid" self-generation systems that incorporate technologies from different incentive categories will receive payments based on the appropriate category. Diesel-fired systems are ineligible for participation in this program.

In addition, applicants to the program will be allow to consider interconnection fees charged by the utilities as part of the cost of the system, for purposes of calculating the incentive.

Program Expenditures

Budget

The table below gives annual estimates of program costs for each administrator.

Item and Assumptions	PG&E	SCE	SoCalGas	SDREO
Administrator Costs				
Incremental design, contract administration, marketing, regulatory reporting, and program evaluation (admin. and marketing not to exceed 5%)	$12,000,000	$6,500,000	$3,400,000	$3,100,000
Incentives				
Maximum available for all types of systems	$48,000,000	$26,000,000	$13,600,000	$12,400,000
Total Program Budget	**$60,000,000**	**$32,500,000**	**$17,000,000**	**$15,500,000**

Verification

Purpose

The purpose of program verification is to ensure that the self-generation units installed at customer sites are installed and operating properly, and have the potential to deliver electric generation. Safety of electrical connections and interconnection (if applicable) should be an important priority of the verification process.

Responsibility

As with the current SPC programs, the responsibility for measurement and verification of energy savings rests with the applicant to the program. The administrator or its independent contractors should be responsible for inspection of installations, but not verification of energy production from self-generation systems.

Procedures or protocols

The existing SPC programs have protocols and procedures designed to measure energy savings from energy efficiency measures. These protocols should be modified and updated to include measurement and verification of energy production from self-generation and cogeneration units, as well as any associated gas or electric efficiency gains. Although the administrator has discretion to utilize other non-SPC program delivery, any program design must include a protocol for estimating the energy production of the self-generation units through a consistent and accepted methodology (using monitoring, statistical sampling techniques, etc.). The administrators are responsible for designing, or hiring a contractor to design, the exact protocols required by the self-generation programs.

Program process

The preferred approach is to operate the self-generation program through existing SPC program rules and procedures, where possible. The administrators, through the working group led by SoCalGas, should finalize all program details prior to program launch in each service territory. Additional requirements related to self-generation installations are included below.

Application

The applicant must provide copies of the following information as proof of installation and parallel operation with the utility distribution grid:

- the final purchase invoice of the self-generation system;
- affidavit signed by the installer of the system and customer stating that the system has been purchased and installed, and that an administrator representative or contractor will be allowed to inspect or monitor the system;
- the building permit showing final inspection signoff;
- an interconnection agreement executed with the utility for the system (if applicable).

Marketing and Promotion

Program marketing should be conducted through existing networks of SPC program service providers. Administrators are also required to provide information about this program to professional organizations representing distributed generation manufacturers, vendors, potential customers, and other interests. Examples of such organizations are the Distributed Power Coalition of America (DPCA) and the California Alliance for Distributed Energy Resources (CADER). Promotion should also be conducted through bill inserts, Internet (e.g. PUC, utility, and industry additional web sites), and other media.

Public Utilities Code 216.6

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PUBLIC UTILITIES CODE
SECTIONS 216-218

216. (a) "Public utility" includes every common carrier, toll bridge corporation, pipeline corporation, gas corporation, electrical corporation, telephone corporation, telegraph corporation, water corporation, sewer system corporation, and heat corporation, where the service is performed for, or the commodity is delivered to, the public or any portion thereof.

(b) Whenever any common carrier, toll bridge corporation, pipeline corporation, gas corporation, electrical corporation, telephone corporation, telegraph corporation, water corporation, sewer system corporation, or heat corporation performs a service for, or delivers a commodity to, the public or any portion thereof for which any compensation or payment whatsoever is received, that common carrier, toll bridge corporation, pipeline corporation, gas corporation, electrical corporation, telephone corporation, telegraph corporation, water corporation, sewer system corporation, or heat corporation, is a public utility subject to the jurisdiction, control, and regulation of the commission and the provisions of this part.

(c) When any person or corporation performs any service for, or delivers any commodity to, any person, private corporation, municipality, or other political subdivision of the state, that in turn either directly or indirectly, mediately or immediately, performs that service for, or delivers that commodity to, the public or any portion thereof, that person or corporation is a public utility subject to the jurisdiction, control, and regulation of the commission and the provisions of this part.

(d) Ownership or operation of a facility that employs cogeneration technology or produces power from other than a conventional power source or the ownership or operation of a facility which employs landfill gas technology does not make a corporation or person a public utility within the meaning of this section solely because of the ownership or operation of that facility.

(e) Any corporation or person engaged directly or indirectly in developing, producing, transmitting, distributing, delivering, or selling any form of heat derived from geothermal or solar resources or from cogeneration technology to any privately owned or publicly owned public utility, or to the public or any portion thereof, is not a public utility within the meaning of this section solely by reason of engaging in any of those activities.

(f) The ownership or operation of a facility that sells compressed natural gas at retail to the public for use only as a motor vehicle fuel, and the selling of compressed natural gas at retail from that facility to the public for use only as a motor vehicle fuel, does not make the corporation or person a public utility within the meaning of this section solely because of that ownership, operation, or sale.

(g) Ownership or operation of a facility that has been certified by the Federal Energy Regulatory Commission as an exempt wholesale generator pursuant to Section 32 of the Public Utility Holding Company Act of 1935 (Chapter 2C (commencing with Section 79) of Title 15 of the United States Code) does not make a corporation or person a public utility within the meaning of this section, solely due to the ownership or operation of that facility.

(h) The ownership, control, operation, or management of an electric plant used for direct transactions or participation directly or indirectly in direct transactions, as permitted by subdivision (b) of Section 365, sales into the Power Exchange referred to in Section 365, or the use or sale as permitted under subdivisions (b) to (d), inclusive, of Section 218, shall not make a corporation or person a public utility within the meaning of this section solely because of that ownership, participation, or sale.

216.2. Notwithstanding Section 216, "public utility" does not include a motor carrier of property.

216.4. "Cable television corporation" shall mean any corporation or firm which transmits television programs by cable to subscribers for a fee.

216.6. "Cogeneration" means the sequential use of energy for the production of electrical and useful thermal energy. The sequence can be thermal use followed by power production or the reverse, subject to the following standards:

(a) At least 5 percent of the facility's total annual energy output shall be in the form of useful thermal energy.

(b) Where useful thermal energy follows power production, the useful annual power output plus one-half the useful annual thermal energy output equals not less than 42.5 percent of any natural gas and oil energy input.

216.8. "Commercial mobile radio service" means "commercial mobile service," as defined in subsection (d) of Section 332 of Title 47 of the United States Code and as further specified by the Federal Communications Commission in Parts 20, 22, 24, and 25 of Title 47 of the Code of Federal Regulations, and includes "mobile data service," "mobile paging service," "mobile satellite telephone service," and "mobile telephony service," as those terms are defined in Section 224.4.

217. "Electric plant" includes all real estate, fixtures and personal property owned, controlled, operated, or managed in connection with or to facilitate the production, generation, transmission, delivery, or furnishing of electricity for light, heat, or power, and all conduits, ducts, or other devices, materials, apparatus, or property for containing, holding, or carrying conductors used or to be used for the transmission of electricity for light, heat, or power.

218. (a) "Electrical corporation" includes every corporation or person owning, controlling, operating, or managing any electric plant for compensation within this state, except where electricity is

generated on or distributed by the producer through private property solely for its own use or the use of its tenants and not for sale or transmission to others.

(b) "Electrical corporation" does not include a corporation or person employing cogeneration technology or producing power from other than a conventional power source for the generation of electricity solely for any one or more of the following purposes:

(1) Its own use or the use of its tenants.

(2) The use of or sale to not more than two other corporations or persons solely for use on the real property on which the electricity is generated or on real property immediately adjacent thereto, unless there is an intervening public street constituting the boundary between the real property on which the electricity is generated and the immediately adjacent property and one or more of the following applies:

(A) The real property on which the electricity is generated and the immediately adjacent real property is not under common ownership or control, or that common ownership or control was gained solely for purposes of sale of the electricity so generated and not for other business purposes.

(B) The useful thermal output of the facility generating the electricity is not used on the immediately adjacent property for petroleum production or refining.

(C) The electricity furnished to the immediately adjacent property is not utilized by a subsidiary or affiliate of the corporation or person generating the electricity.

(3) Sale or transmission to an electrical corporation or state or local public agency, but not for sale or transmission to others, unless the corporation or person is otherwise an electrical corporation.

(c) "Electrical corporation" does not include a corporation or person employing landfill gas technology for the generation of electricity for any one or more of the following purposes:

(1) Its own use or the use of not more than two of its tenants located on the real property on which the electricity is generated.

(2) The use of or sale to not more than two other corporations or persons solely for use on the real property on which the electricity is generated.

(3) Sale or transmission to an electrical corporation or state or local public agency.

(d) "Electrical corporation" does not include a corporation or person employing digester gas technology for the generation of electricity for any one or more of the following purposes:

(1) Its own use or the use of not more than two of its tenants located on the real property on which the electricity is generated.

(2) The use of or sale to not more than two other corporations or persons solely for use on the real property on which the electricity is generated.

(3) Sale or transmission to an electrical corporation or state or local public agency, provided, however, that the sale or transmission of the electricity service to a retail customer shall only be provided through the transmission system of the existing local publicly owned electric utility or electrical corporation of that retail customer.

(e) The amendments made to this section at the 1987 portion of the 1987-88 Regular Session of the Legislature do not apply to any corporation or person employing cogeneration technology or producing power from other than a conventional power source for the generation of electricity that physically produced electricity prior to January 1, 1989, and furnished that electricity to immediately adjacent real property for use thereon prior to January 1, 1989.

218.3. "Electric service provider" means an entity that offers electrical service to customers within the service territory of an electrical corporation, as defined in Section 218, but does not include an entity that offers electrical service solely to service customer load consistent with subdivision (b) of Section 218, and does not include an electrical corporation, as defined in Section 218, or a public agency that offers electrical service to residential and small commercial customers within its jurisdiction, or within the service territory of a local publicly owned electric utility. "Electric service provider" includes the unregulated affiliates and subsidiaries of an electrical corporation, as defined in Section 218.