CONTINUING CHALLENGES FACED BY ADOPTERS OF DISTRIBUTED GENERATION TECHNOLOGIES: RESULTS OF TARGETED STAKEHOLDER INTERVIEWS FOR THE CALIFORNIA SELF-GENERATION INCENTIVE PROGRAM

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Abstract

This paper summarizes the key results of targeted stakeholder interviews in a statewide distributed generation (DG) incentive program. End-users and developers/installers of rebated DG systems known to have experienced equipment reliability problems were interviewed to obtain insights on the causes of DG equipment or monitoring system failure, and operations and maintenance costs incurred. This paper summarizes the most common equipment reliability problems cited by DG end-users and developers/installers in the California market as of the third quarter of 2004, and compares the performance of rebated DG systems by technology.

Introduction

Assembly Bill 970, enacted on September 3, 2000, mandated that the California Public Utilities Commission (CPUC) initiate certain load control and distributed generation activities. Consequently, the CPUC issued Decision 01-03-073 (D.01-03-073) on March 27, 2001, which required California's investor-owned utilities (IOUs) to implement a statewide distributed generation (DG) incentive program. Thus, the Self-Generation Incentive Program (SGIP) was originally designed to provide financial incentives to qualifying IOU customers who installed up to 1.5 MW of new, qualifying DG equipment to meet all or a portion of their facility's needs.[A]

At the end of 2004, the SGIP had supported the installation of approximately 120 MW of operational DG capacity statewide, with nearly 300 MW in various stages of development, representing just over $1 billion in private and ratepayer supported investment. The SGIP is administered by Southern California Edison (SCE), Pacific Gas & Electric Company (PG&E), and Southern California Gas Company (SoCalGas) within their respective service territories. Within the San Diego Gas & Electric Company (SDG&E) service territory, the SGIP is administered by the San Diego Regional Energy Office (SDREO).

In order to measure the SGIP's effectiveness in reducing peak demand to the grid, available metered data was collected from rebated, operational systems to assess system performance. Where utility data was unavailable, interval metered data was collected from end-users or third-party developers/installers of rebated DG systems. In cases where valid interval metered data was unavailable from both the utility

[A] Under CPUC Decision 04-12-045, issued December 16, 2004, maximum SGIP project size was increased to 5 MW, although SGIP incentive payments remain capped at 1.0 MW.

or program participants, and the site was deemed important to the M&E sample, interval meters were installed, at no additional cost to the end-user, using Program evaluation funds. For the remainder of the operational projects, energy and demand impacts were estimated based on results from available metered data.

Additionally, numerous in-depth interviews were conducted with developers/installers and end-users of rebated DG equipment to assess project operating experience, program effectiveness and participant satisfaction. In the 2004 targeted process assessment, participants known to have experienced DG equipment reliability issues were surveyed to determine whether problems stemmed from the nature of the project, a third-party equipment supplier or project implementer, the utility, or the program itself.

Time-series performance data from the 2004 program impact evaluation and qualitative interview data from the program process evaluation thus provide an in-depth exploration of performance issues by technology for a cross-section of rebated DG systems. This paper summarizes and compares reliability issues cited by program participants, seeking to illuminate the continuing challenges faced by adopters of these emerging technologies as the DG market continues to progress toward self-sustainability.

Overview of the Self-Generation Incentive Program

The SGIP was designed to complement the California Energy Commission's (CEC's) Emerging Renewables Program (ERP). In contrast to the ERP, the SGIP provides incentive funding to larger and non-renewable DG up to the first MW of rebated capacity. Additionally, the SGIP focuses on providing funding primarily to the non-residential market sectors (commercial, industrial, and agricultural).[B] A summary of current program eligibility requirements and incentives is presented in Table 1.

Table 1: Summary of Current SGIP Incentives (January 1, 2005)

Program Incentive Level	Minimum Size (kW)	Maximum Size (kW)[C]	Qualifying Technologies [D, E]	Incentives Offered ($/Watt)
Level 1	30 kW	5 MW	Renewable Fuel Cells	$4.50/Watt
			Photovoltaics (PV)	$3.50/Watt, decreasing to $3.00/Watt on 1/1/2006
			Wind Turbines	$1.50/Watt
Level 2	None	5 MW	Non-Renewable Fuel Cells	$2.50/Watt
Level 3-R	None	5 MW	Renewable Fueled Microturbines	$1.30/Watt
			Renewable Fueled Internal Combustion Engines and Large Gas Turbines	$1.00/Watt
Level 3-N	None	5 MW	Non-Renewable and Waste Gas Fueled Microturbines	$0.80/Watt
			Non-Renewable and Waste Gas Fueled Internal Combustion Engines and Large Gas Turbines	$0.60/Watt

[B] While residential customers are also eligible for funding under the SGIP, the vast majority of residential customers do not maintain on-site load sufficient to sustain a PV system of 30 kW or greater.

[C] While qualifying DG technologies may now be sized up to 5 MW, CPUC Rulings have capped the maximum incentive basis at 1.0 MW.

[D] "Hybrid" systems which contain more than one qualifying technology are also eligible for incentives under the SGIP, provided they meet all eligibility requirements for each technology.

[E] Large gas turbines are greater than or equal to 1 MW in capacity. Microturbines are <1 MW in capacity.

Assembly Bill 1685 (AB1685) extended funding for the SGIP through December 31, 2007, or until allocated funds are exhausted. AB1685 also mandated a new NOx emissions standard commencing January 1, 2005, and introduced a NOx emissions credit for combined heat and power (CHP) units. However, waste gas fueled Level 3-N systems were exempted from meeting emissions standards if certain requirements were met.

Under the SGIP, Level 2 and 3-N systems are also required to achieve minimum system efficiencies on an annual basis, as mandated by Section 218.5 of the Public Utilities Code. PUC 218.5(a) requires that cogeneration systems produce useful thermal energy equivalent to at least 5% of total facility energy output, while PUC 218.5(b) requires that systems achieve a minimum annual system efficiency of 42.5%. Annual system efficiency for PUC 218.5(b) is calculated as the sum of electric net generator output plus one-half of the useful thermal energy, divided by the natural gas fuel input.[F]

System Performance Results from the 2004 Impacts Analysis

The results of the 2004 impacts analysis completed in April 2005 indicate that SGIP DG normalized electric output during the hour of the 2004 California ISO electric system peak (September 8, from 3:00 to 4:00 P.M.) was equal to approximately 0.53 kW per kW of rebated system capacity. As shown in Table 2, the weighted average contribution of SGIP PV to demand impacts during the hour of California ISO system peak was 0.39 kW per kW of system capacity, based on rebated size. This value may be lower than expected for PV systems, due largely in part to known factors influencing actual PV system power output as compared to rated system sizes for calculating incentives.

For cogeneration systems, the weighted average contribution to demand impacts during the hour of the California ISO system peak was 0.58 kW per kW of system capacity, based on rebated size. These results are due in part to substantial variability observed in cogeneration system output, including a number of units known to have been non-operational at the time of system peak.

Table 2: SGIP DG System Electric Impact Coincident with 2004 CAISO Peak Load

Incentive Level / Basis	On-Line Systems (n)	On-Line Capacity (kW)	Peak Demand Impact (kW_P)	Unit Demand Impact (kW_P)
Level 1 PV	235	25,365	9,938	0.39
Level 1 Wind	1	950	0	0.00
Level 2 Fuel Cell	2	800	744	0.93
Level 3/3-N/3-R Engine/Turbine	150	75,930	44,115	0.58
Total	**388**	**103,045**	**54,797**	**0.53**

Moreover, as shown in Table 3, overall, SGIP DG systems maintained an average 218.5(b) efficiency of 37% in 2004.[G] Available metered data suggested that only 9 of the 31 monitored Level 3/3-N systems achieved the 218.5(b) overall system efficiency target of 42.5%.

[F] For the purposes of PUC 218.5 calculations, system efficiency is defined as the sum of electric energy production plus one half of the useful thermal energy output, divided by fuel input.

[G] This factor represents the ratio of actual metered energy production to total energy that would have been produced has the system operated continuously at the rebated power output level.

Table 3: Observed Level 3/3-N SGIP Cogeneration System Efficiencies (n = 31)

Summary Statistic	218.5 (a) proportion	218.5 (b) Efficiency	Overall Plant Efficiency
Min	5%	19%	22%
Max	71%	54%	82%
Median	46%	36%	46%
Mean	44%	37%	49%
Std Dev	17%	7%	14%
Coefficient of Variation	0.4	0.2	0.3

Generator electric energy production data for both 2003 and 2004 were available for some of the operational Level 3/3-N/3-R projects. For the 43 projects with at least six months of data within each year, capacity factors were calculated for 2003 and 2004. As shown in Figure 1, average cogeneration system capacity factor declined and inter-site variability rose between 2003 and 2004.

Possible reasons considered for the lower than expected and decreasing average capacity factors for cogeneration systems included: 1) mechanical equipment failure, 2) staff turnover or changes in ownership, 3) increases in operating costs due to natural gas prices, and 4) relationships between cogeneration size and facility electric load or timing. To provide additional information on observed characteristics of metered data, Itron interviewed end-users of a sample of these systems.

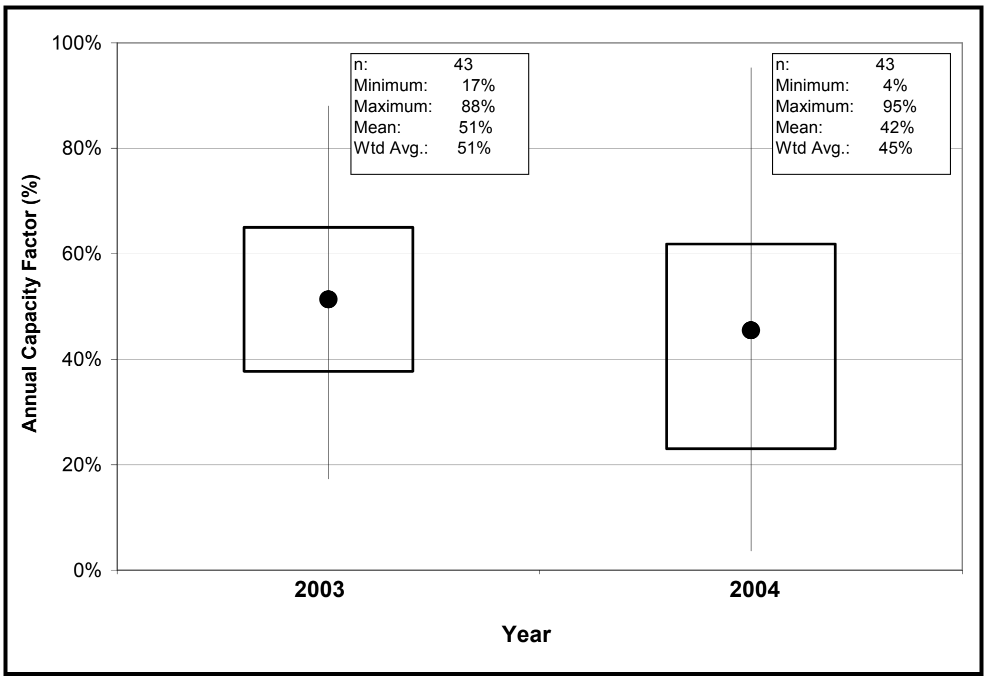

Figure 1: Incentive Level 3/3-N/3-R Capacity Factor Trend

Initially, Itron identified end-users of DG systems with substantial operating history and available metered data for 2004. Random samples were drawn from these groups. 45 PV end-user interviews were completed, representing 52 systems. Additionally, 47 Level 3/3-N/3-R end-user interviews were also completed. Results of the PV end-user interviews are presented in Table 4, and results of the cogeneration system end-user interviews are presented in Table 5.

Table 4: Performance Characteristics of Sampled PV Systems (n = 52)

Item	Value
Program total funded capacity 2003-2004 (kW)*	31,820

Sample capacity (kW)	7,090
Program average system size (kW)*	111
Sampled average system size (kW)	136
Actual capacity factor for sample	17 %
Number of days with no 2004 energy production in sample	1.4

* Note: These statistics were calculated for the 286 PV systems that received SGIP funding in 2003 and 2004.

Table 5: Performance Characteristics of Sampled Cogeneration Systems (n = 47)

Characteristic	Mean IC Engine Nonren. Fuel	Mean Microturbine Nonren. Fuel	Mean Microturbine Ren. Fuel
Program total funded capacity 2003-2004 (kW)	30,103	7,255	1,150
Sample capacity (kW)	14,873	1,550	870
Program average system size (kW)	301	154	230
Sampled average system size (kW)	531	134	290
Average actual capacity factor (%)	54 %	47 %	37 %
Average planned generation capacity factor (%)	68 %	70 %	Not Available
Average actual heat recovery rate (kBtu/kWh)	1.9	4.0	Not Applicable
Average planned heat recovery rate (kBtu/kWh)	3.8	5.9	Not Applicable
No. of days with no 2004 energy production in sample	40	54	Not Available

Within the PV sample, the capacity factor looks to be on target (a typical system has a 16%-20% annual capacity factor). However, within the cogeneration sample, capacity factor to date was found to be considerably lower than planned, though end-users were optimistic that capacity factors would improve over time. Further investigations suggest that one reason for the lower-than-expected energy production (as measured by annual capacity factor) was due to the significant number of days when the systems were not operating.

Objectives of the SGIP Targeted Process Assessment

The targeted process assessment of the SGIP was conducted to further investigate the poor performance results reported in the Program Year 2004 impacts evaluation. Specifically, the targeted process assessment sought to obtain insights upon causes of DG equipment failure. Additionally, the process assessment sought to investigate the possibility that some attribution of the poor observed DG system performance was actually caused by monitoring system failure, as opposed to poor generating equipment performance. The process assessment also included questions regarding incurred operations and maintenance costs. Table 6 summarizes the final distribution of the end-user sample.

Table 6: End-User Sample by DG Technology

Incentive Level/Technology	End-Users (n)
Level 1 – PV	11
Level 3R – Microturbines, Renewable Fuels	2
Level 3N – IC Engines, Nonrenewable Fuels	11
Level 3N – Microturbines, Nonrenewable Fuels	8
Total (all Levels/Technologies):	32

As shown, 32 surveys were conducted with end-users of DG systems known to have experienced equipment reliability problems. Additionally, 29 surveys were conducted with developer/installers representing 165 operational DG projects (54% of total SGIP operational projects). Table 7 summarizes the final distribution of the developer/installer sample.

Table 7: Developer/Installer Sample by DG Technology

	PV	FC - Nonren. Fuel	IC - Nonren. Fuel	MT - Nonren . Fuel	MT - Ren. Fuel	All Technologies
Sampled						
# of Suppliers	16	2	9	3	0	29
# of Operating Projects	118	3	39	5	0	165
Population						
# of Suppliers	67	2	22	9	0	101
# of Operating Projects	210	3	73	19	1	306
Percent of Projects Sampled	56%	100%	53%	26%	0%	54%
Capacity Sampled (kW)	16,914	1,000	31,035	896	0	49,845
Population Capacity (kW)	23,867	1,000	46,426	2,396	90	73,690
Percent of Capacity Sampled	71%	100%	67%	37%	0%	68%
Mean Capacity Sample (kW)	171	333	1,633	90	n/a	302
Mean Capacity Population (kW)	114	333	636	126	90	242

Note: The number of projects in the table exceeds the number of surveys completed since many of the surveys represented suppliers with multiple projects and/or multiple technologies.

End-users and developers/installers who provided interval metered data to Itron for the 2004 impacts analysis were additionally asked a series of questions to assess challenges faced in the data collection and transmittal processes. A total of 17 respondents elaborated upon monitoring equipment hardware or software problems encountered during these processes.

All surveys were completed by Itron staff via telephone, with the exception of one developer/installer interview that was conducted in-person. Results of the developer/installer, end-user, and data provider interviews are summarized in the sections that follow.

Developer/Installer Perspective

Equipment Reliability

Over 60% of DG system developers/installers surveyed reported having encountered "rare" equipment reliability problems, including:

- Start-up problems caused by installation faults or faulty electrical equipment,
- Inverter failure or malfunction,
- Internal combustion engine problems, and
- Heat recovery equipment problems.

Less than 10% of developers/installers surveyed reported "severe" reliability problems, including problems associated with heat recovery equipment, inverter failures, and faulty engine generator design.

Actual DG System Performance versus Rated DG System Performance
Nearly all developers/installers surveyed reported *average* to *above-average* overall system performance. The single respondent who reported disappointing overall system performance cited problems with ambient temperatures for microturbine heat recuperators that resulted in diurnal de-rating.

Additionally, nearly all of the developers/installers surveyed reported having met their revenue goals for SGIP DG system installations. The two respondents who disagreed cited equipment failure[H] and unexpected changes in gas tariffs subsequent to DG system installation.

In general, the majority of developers/installers reported DG systems electric energy production at or above their initial expectations. Less than 10% of respondents reported production below expectations. Developers/installers reporting low energy production relative to expectations were nearly evenly distributed among technology types (PV, microturbines, and internal combustion engines).

Actual Versus Expected Useful Heat Recovery
Developers/installers of cogeneration equipment were also asked whether they felt their systems' heat recovery for useful purposes had met, exceeded, or failed to meet, their initial expectations. The majority of respondents (80%) indicated that their systems met initial heat recovery expectations. Additionally, 13% of the respondents indicated that their systems exceeded initial expectations. Only 7% of respondents indicated that systems failed to meet initial expectations. In these cases, failures were linked to problems with heat recuperators on microturbine units.

Problems with Meter Installation, Monitoring, or Data Collection
Developers/installers were additionally asked to describe any problems encountered in meter installation, monitoring, or data collection. Approximately one-third of respondents reported no problems or only minor start-up problems, including brief interruptions in data communications and unexpected requirements to install multiple PV system meters to record net usage and system output.

Overall Satisfaction
Finally, developers/installers were asked to rate their level of satisfaction with a number of aspects of the SGIP, including system reliability and performance. Ratings were based on a 1 to 5 scale, with a 1 indicating that the respondent was "very dissatisfied" and a 5 indicating that the respondent was "very satisfied". Table 8 presents the satisfaction results by technology.

Table 8: Reported Levels of Satisfaction with DG Equipment Reliability/Performance

Technology	Satisfaction Rating	Respondents
PV	4.4	16
Fuel Cell – Nonrenewable Fuel	4.5	1
IC Engine – Nonrenewable Fuel	4.5	8
Microturbine – Nonrenewable Fuel	2.5	2
All Technologies	**4.4**	**27**

As shown, the majority of respondents reported relatively high levels of satisfaction with DG equipment reliability/performance, averaging 4.4 on a scale of 1 to 5. However, system reliability appears to be a problem for microturbine projects, which reported an average score of only 2.5 on a scale of 1 to 5. This result is due at least in part to the relative immaturity of this technology (and perhaps to the low number

[H] However, all later installations and replacement units for these internal combustion engines were reported to have achieved satisfactory revenues.

of respondents, although our “gut feeling” is that a larger sampling would have borne out these numbers.).

End-User Perspective

Equipment Reliability

Overall, end-users of rebated DG systems reported a higher incidence of equipment reliability problems than developers/installers. Additionally, equipment performance problems cited by end-users were fairly consistent within DG system technology groups.

As expected, PV end-users reported few equipment reliability problems. None of the PV end-users surveyed indicated that their systems had been offline for any extended period of time since installation. PV end-users further indicated that while selected inverters occasionally failed, those failures did not cause a significant loss of generation capacity. Such problems were typically identified quickly and resolved within a matter of a few days.

Similarly, neither of the end-users of renewable fueled microturbines indicated that their systems were offline for any extended period of time since installation for any reason.

However, end-users of Level 3/3-N microturbines and internal combustion engines reported higher incidences of problems. Approximately 50% of end-users of nonrenewable fueled internal combustion engines and 75% of end-users of nonrenewable fueled microturbines reported significant lengths of equipment downtime due to equipment problems since installation.[1] Continuous lengths of time off-line cited ranged from two weeks to five months. Case studies for the end-users reporting significant lengths of time off-line are summarized below.

IC Engine Case Studies

Case 1: Generator Motor Defects Requiring Replacement. One end-user’s system went offline for five months after only three months of continuous operation. System failure was attributed to problems with generator motors, transfer errors and switch gears. The end-user was forced to replace the generator motors. While the respondent’s equipment manufacturer offered to replace the defective units at no additional charge, the manufacturer failed to actually install the new units. The developer/installer then graciously installed the new motors at no additional charge to the end-user. The DG system functioned after the motor replacement, but minor problems persisted.

Case 2: Recurring Catastrophic Engine Failures. A second end-user reported several outages due to major engine failure. On one occasion, the system was offline for three months straight. The end-user’s system had commenced operations only seven months prior to the interview.

Case 3: Engine De-Rating Issues Requiring System Upgrade. A third end-user reported three weeks of downtime while upgrades were performed on the DG system. This end-user, whose facility was located in an area where temperatures frequently reach extreme highs, stated that the engines were de-rating when outside temperatures exceeded a certain level. Accordingly, the engines were upgraded to maintain peak performance during extreme conditions. This end-user reported that the engines successfully withstood much higher temperatures after the upgrade.

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[1] One additional end-user reported that significant lengths of time offline were required to maintain a level of system efficiency sufficient to meet the CPUC-mandated efficiency goal. In order to meet this efficiency target, it was necessary to ensure that the site possessed a sufficient thermal load to operate the turbines.

Case 4: Engine Failures and Non-Catastrophic Catalytic Converter Issues. A fourth end-user reported having installed rebated internal combustion engine systems at three different sites. This end-user stated that units at just one of the three sites had been offline for two weeks due to engine failures. This unit had commenced operations approximately seventeen months prior to the interview. While the unit at a second site also experienced problems with catalytic converters overheating, the equipment manufacturer bore the costs of replacement equipment while the problem was diagnosed and resolved. Thus, no significant downtime was reported at the second site despite equipment reliability problems.

Case 5: Ongoing, Recurring Engine Problems. The final end-user, whose system commenced operations approximately 15 months prior to the interview, also reported recurring extended periods of time offline due to engine problems. This problem was ongoing as of the time of the interview.

Microturbine Case Studies

Case 1: Catastrophic Fan, Control Module, Oil Cooler and Compressor Motor Problems. One end-user, who installed two microturbines roughly 19 months prior to the interview, stated that one unit went offline for three months shortly after installation, due to problems with fans and control modules. The second unit operated continuously for nearly 19 months after installation before failing due to a leak in the oil cooler. Subsequently, the gas compressor motor failed. As of the time of the interview, the second unit had been offline for approximately two weeks and was awaiting compressor motor replacement. The end-user reported having experienced roughly 25 break-downs since both units were installed.

Case 2: One-Time Inverter Failures. A second end-user, whose system commenced operations approximately 11 months prior to the interview, reported one-time inverter failures. While the inverters were offline, the turbine continued to generate thermal energy to heat facility's pool. The inverters were replaced within two weeks of failure.

Case 3: Recurring Natural Gas Compressor Failures. A third end-user reported two to four weeks of continuous system downtime to date due to natural gas compressor failure. Over the past two and a half years of operation, the compressor had experienced recurring failures. As of the time of the interview, the end-user was planning to replace the compressor.

Case 4: Heat Exchanger Problems. A fourth respondent, whose microturbines were operational for less than a year, indicated that all units had been going offline sporadically since they became operational. The units were normally offline for up to a month at a time. At the time of the interview, half of the turbines were offline due to heat exchanger problems. These problems precluded turbine operation since the turbine manufacturer's operating instructions discouraged turbine operation while the heat exchanger was offline.

Case 5: Gas Drying System or Compressor Problems. A fifth end-user reported six weeks of downtime and counting due to a problem with the system's gas drying system or the compressor. The end-user was unsure of the true nature of the problem. Desiccant was reentering the cylinder heads, causing them to overheat and clang. The problem had not been resolved as of the time of the interview.

Case 6: Injector and Fuel Supply Nozzle Problems. Finally, a sixth end-user, whose microturbines had been operational for nearly two years, stated that the units went offline for a period of two to three months after 18 months of continuous operation. Problems with injectors and fuel supply nozzles caused filters to clog. At that point, the media used to control the siloxane should have been replaced. Since they were not, it was necessary to shut the microturbines down for two to three months while clean-up efforts were undertaken.

Thus, a host of equipment reliability problems were reported, including major engine failures for end-users of nonrenewable-fueled internal combustion engines and heat recovery and gas compressor problems for end-users of nonrenewable-fueled microturbines.

Operations and Maintenance Costs

DG end-users were also asked to describe the nature of unexpected operations and maintenance (O&M) costs incurred. Before launching a discussion of unexpected O&M costs, however, it is important to understand the "routine" O&M costs expected to be incurred by DG end-users, and the unplanned O&M costs previously reported in the 2004 impacts analysis. Thus, a brief description of O&M costs as gathered in the impacts analysis follows.

Routine O&M Costs

During the course of the 2004 impacts evaluation, DG end-users were initially surveyed regarding O&M costs. Of the 45 PV system end-users surveyed, 30 reported O&M costs associated with panel cleaning averaging 0.44 cents per kWh. Of the cogeneration system end-users surveyed, all but two reported routine maintenance costs covered under fixed annual contracts. In most cases, these contracts also included unplanned maintenance costs, including the cost of absorption chillers.

Almost all end-users who provided O&M costs in the impacts analysis indicated that costs were at or above the "rule of thumb" estimates of 1.5 cents/kWh for nonrenewable-fueled internal combustion engines and 2.0 cents/kWh for nonrenewable-fueled microturbines. The average maintenance cost reported for nonrenewable-fueled internal combustion engines was 2.0 cents/kWh, while the average cost reported for nonrenewable-fueled microturbines averaged 2.6 cents per kWh. Microturbines utilizing landfill or digester gas possessed the highest maintenance costs, at 3.1 cents per kWh on average. These results are summarized in Table 9.

Table 9: O&M Costs Reported by End-Users in the 2004 Impacts Analysis

O & M Cost Item	**IC Engine** Nonren. Fuel	**Microturbine** Nonren. Fuel	**Microturbine** Ren. Fuel	**All Technologies**
Average annual maintenance cost (cents per kWh)	2.0 (n = 18)	2.6 (n = 14)	3.1 (n = 3)	2.2 (n = 35)
Average out-of-pocket cost for unplanned maintenance/repairs ($/ yr)	$14,682 (n = 22)	$5,063 (n = 15)	$1,333 (n = 3)	9,583 (n = 42)
Average unplanned maintenance cost for systems with costs>0	$64,600 (n = 5)	$24,500 (n = 3)	$4,000 (n = 1)	$10,344 (n = 9)
Average third party fuel cost ($/MMBtu)	N/A	N/A	N/A	6.60 (n = 11)

As shown, the average cost reported for unplanned O&M was significant, ranging from $4,000 to over $64,000 per year. This translated to an average out-of-pocket O&M cost ranging from just over $1,000 to over $14,000 per year.

Unexpected O&M Costs

In the targeted process assessment, end-users were asked to describe the nature of unexpected O&M costs incurred. Nearly one-fifth of these end-users cited costs arising from the purchase of replacement equipment, which were not covered under warranty. These results are summarized in Table 10.

Table 10: Unexpected Costs Incurred by End-Users to Replace Failed Equipment

Failed Equipment	Number of Respondents
Natural gas compressor	2
Digester gas compressor	1
Injectors and fuel supply nozzles for digester gas	1
Heat exchanger and microturbine circuit boards	1
Piping and exhaust system for internal combustion engine	1

Other unexpected system operation/maintenance costs cited by end-users in the process assessment included:

- Unexpected increases in gas transmission prices (3 respondents),
- Unexpected changes in rate tariffs (2 respondents),
- Unanticipated departing load charges (2 respondents),
- Peak demand charges incurred when the system was offline (1 respondent),
- Unexpected costs related to the purchase of additional monitoring equipment (1 respondent),
- Unexpected costs related to the purchase of additional sensor relays and battery backup panel for interconnection (1 respondent),
- Parasitic load costs incurred in cooling intercoolers for generators (1 respondent),
- Increased gas consumption costs incurred when the system was offline (1 respondent), and
- General mechanical costs incurred in exhaust system maintenance (1 respondent).

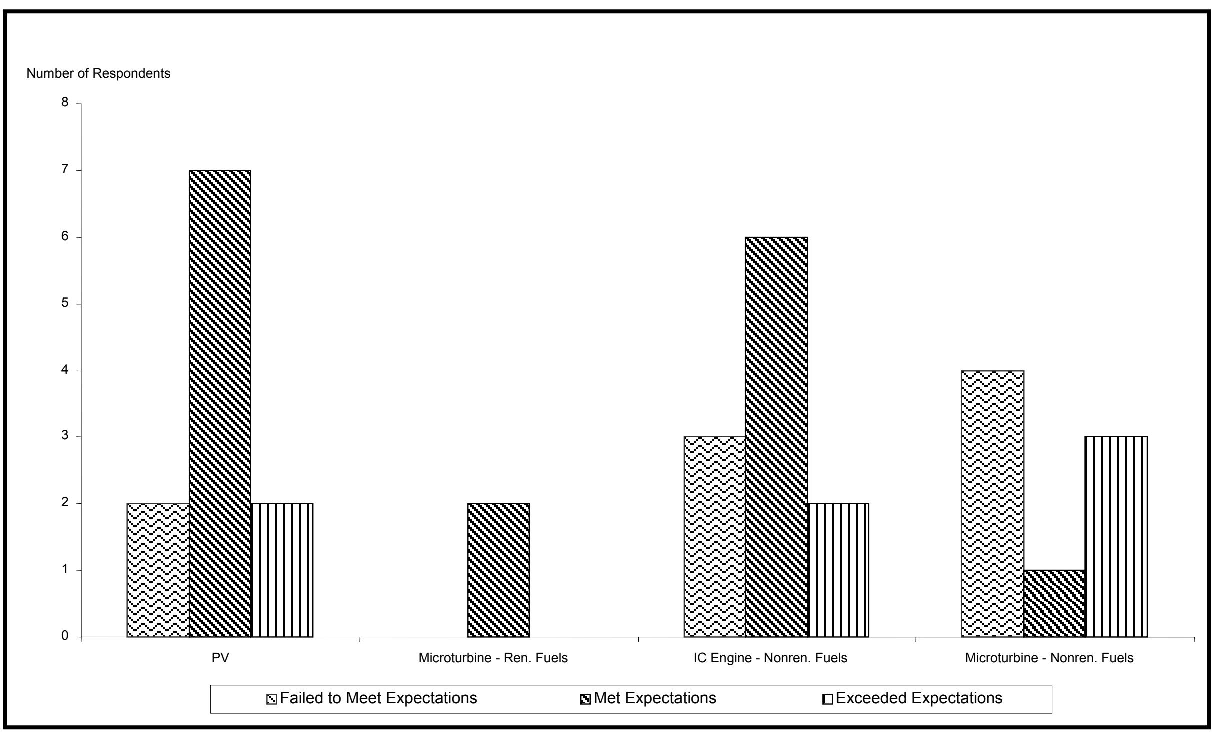

Figure 2: End-Users' Reported Expectations vs. Actual Energy Production

Actual Versus Expected Electric Energy Production

End-users were also asked whether they felt that their system's electric energy production had exceeded, met, or failed to meet their initial expectations. The majority of respondents surveyed indicated that their system's electric energy production met their initial expectations. The remainder of respondents were nearly evenly split as to whether their system's electric energy production exceeded or failed to meet their initial expectations. Figure 2 summarizes the results by technology.

As shown, the majority of end-users felt that their DG systems' electric energy production met their initial expectation, with the exception of end-users of nonrenewable-fueled microturbines. This result was hardly surprising given the high incidence of equipment problems cited by end-users who installed microturbines using nonrenewable fuels.

Actual Versus Expected Useful Heat Recovery

Respondents who had installed cogeneration systems were additionally asked whether they felt that their system's heat recovery for useful purposes had failed to meet, met, or exceeded their initial expectations. As shown in Figure 3, the majority of end-users reported that their systems' heat recovery met their initial expectations. The proportion of respondents who reported that their systems' heat recovery failed to meet their expectations slightly exceeded the proportion of respondents who reported that their systems' heat recovery exceeded their initial expectations.

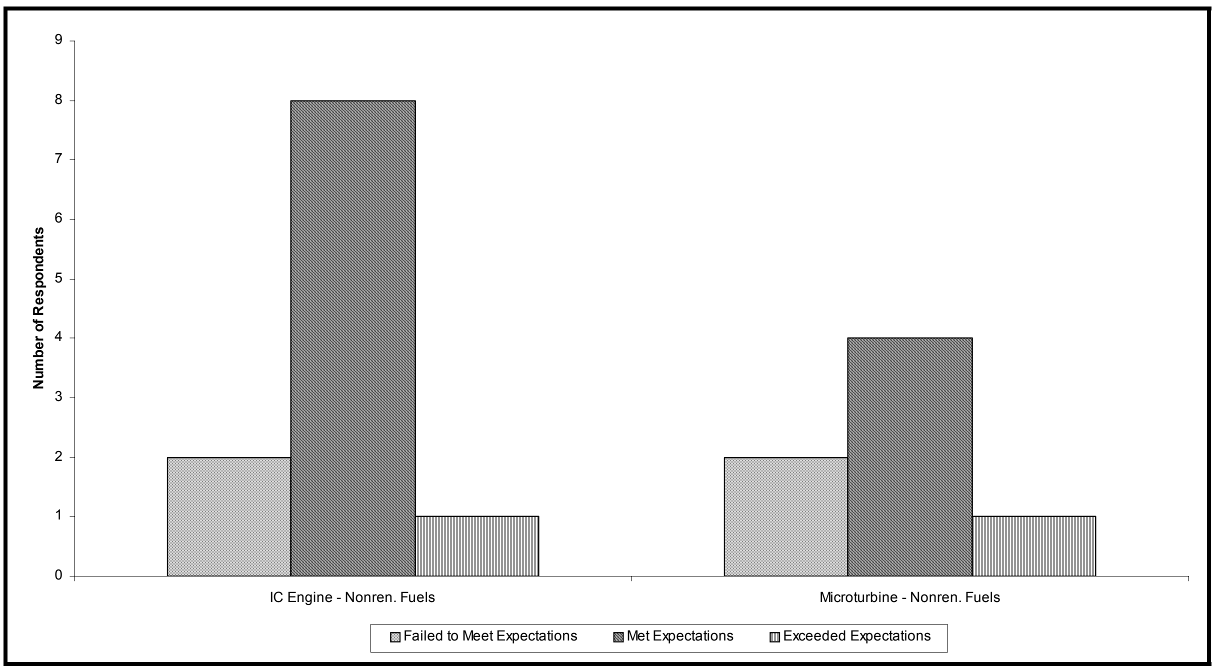

Figure 3: End-User Actual vs. Expected Useful Heat Recovery

General Program Satisfaction

Finally, end-users were asked to rate their level of satisfaction with a number of aspects of the SGIP, including system reliability and performance. Ratings were based on a 1 to 5 scale, with a 1 indicating that the end-user was "very dissatisfied" and a 5 indicating that the end-user was "very satisfied". Table 11 presents the satisfaction results for equipment reliability and performance by DG system technology.

Table 11: Reported Levels of End-User Satisfaction with DG Equipment Reliability/Performance

Technology	Satisfaction Rating	Respondents
PV	4.6	11
Microturbine – Renewable Fuel	4.5	2
IC Engine – Nonrenewable Fuel	3.3	11
Microturbine – Nonrenewable Fuel	3.3	8
All Technologies	**3.8**	**32**

As shown, PV end-users reported the highest average level of satisfaction with system reliability and performance, at 4.6 on a scale of 1 to 5. These results are not surprising in light of the low incidence of equipment reliability problems reported by the PV end-users. End-users of renewable-fueled microturbines reported the second highest level of satisfaction with equipment reliability and performance, at 4.5. Finally, end-users of nonrenewable-fueled internal combustion engines and microturbines reported identical levels of satisfaction with equipment reliability and performance, at 3.3. These results are also not surprising given the high incidence of equipment reliability problems cited by these end-users. Overall, however, SGIP DG end-users were fairly satisfied with system performance, displaying an average satisfaction level of 3.8 on a scale of 1 to 5.

Data Provider Perspective

Finally, four end-users and 17 developers/installers who provided interval metered data for the recent impacts evaluation were interviewed to obtain insights on possible monitoring equipment or data collection/data transfer problems. This information was used to develop recommendations for improving the metered data collection and transmittal processes.

Almost none of the data providers who supplied Web data download access reported delays or problems in data transmittal. However, those data providers who supplied data files via email cited a number of problems. One-third of the data providers surveyed reported the following hardware/software glitches:

- Three data providers reported monitoring equipment failures during start-up due to software or communication equipment failures.
- Two data providers reported recurring problems with data loggers generating nonexistent values or zeroing out values that should be recorded.
- One data provider reported connectivity problems due to a disconnected phone line preventing data transmittal from the end-user's site.
- One data provider reported that approximately three months of data was lost during the process of switching over data during an energy management system upgrade.

Thus, most of the hardware/software problems reported were technology-independent, and were likely to have been resolved during the monitoring system commissioning process. The majority of these issues were not expected to result in systematic loss of metered data. None of these issues were expected to affect the performance of the generating equipment itself in any way.

Conclusion

The 2004 impacts analysis revealed relatively low average annual capacity factors for both PV and cogeneration systems rebated by the SGIP. The weighted average contribution of PV to normalized demand impacts during the hour of the 2004 California ISO system peak was estimated to be 0.39 kW per kW of system capacity, based on rebated size. This relatively low value reflects the timing of the system peak within the year (early September during Hour 15) and known factors influencing actual PV system power output with regard to rated system sizes for calculating incentives.

For cogeneration systems, the weighted average contribution to demand impacts during the hour of the 2004 California ISO system peak was 0.58 kW per kW of system capacity, based on rebated size. Observed average capacity factors for cogeneration systems fell between 2003 and 2004, and inter-site capacity factor variability rose between 2003 and 2004. Only 9 of the 31 cogeneration systems met 218.5(b) efficiency requirements.

The targeted process assessment was conducted to shed further light on the performance results reported in the 2004 impacts analysis. End-users and developers/installers of DG systems were surveyed regarding their DG system and monitoring equipment performance.

Performance issues related to the data collection and monitoring systems were generally due to hardware or software problems. The majority of these problems were likely to be resolved after initial glitches were worked out of the data acquisition systems, or after the upgrade process had been completed. Thus, monitoring system failures were not expected to cause systematic, recurring performance problems.

(Is there a way to estimate possible savings if the units had been operational? That is, what we are losing from not solving this problem? This is very difficult to do for the economic savings. Our cost effectiveness analyses in fact showed that with increasing "spark gap," an increased capacity factor would only make the economics worse — i.e., longer operation at a loss drives the overall economics down even further.)

In general, developers/installers had a more positive outlook regarding DG system performance and reliability than end-users, generally reporting that their DG systems' electric energy production and useful heat recovery met their initial expectations. Developers/installers additionally indicated that they were generally satisfied with actual DG system performance vis-à-vis manufacturer rated performance.

In contrast, more than half of the end-users of cogeneration systems reported significant downtime due to component failures. A number of cogeneration system end-users additionally reported unexpected costs incurred due to unforeseen increases in fuel prices, and heat recovery equipment and engine malfunction. In general, end-users of nonrenewable-fueled microturbines and internal combustion engines installed in the first two years of the inception of the SGIP reported poor equipment performance. Despite this anecdotal evidence of poor cogeneration system performance, however, end-users of nonrenewable-fueled internal combustion engines and microturbines assigned a moderate level of satisfaction to system reliability and performance, at 3.3 on a scale of 1 to 5.

End-users of PV systems, in contrast, reported high levels of satisfaction with system reliability and no significant downtime since installation. PV end-users only reported infrequent inverter failures, which resulted in insignificant losses of generation capacity.

Overall, adopters of nonrenewable fueled technologies continue to face challenges in maintaining acceptable levels of operations and system efficiency in light of equipment component failures and rising fuel prices. Additionally, the moderate equipment performance satisfaction rating reported by cogeneration system end-users, even in light of anecdotal evidence of very poor DG performance, implies that low end-user expectations remain a significant barrier to DG market development. Pervasive pessimism regarding DG system performance will not promote the maturation of these technologies if end-users and developers/installers do not exert sufficient pressure upon equipment suppliers and manufacturers to provide high-quality products.

Finally, it is important to note that while significant challenges remain, substantial progress has been made in the market for on-site generation. Many of the initial hardware and software glitches associated with either DG or monitoring system commissioning are identified and resolved as end-users and developers/installers acquire increased experience with O&M practices for their DG systems. Since substantial room for maturation of DG technology remains, particularly in the case of nonrenewable-fueled microturbines, the contribution to the DG system development process made by these early adopters of the technologies is irrefutable.

References

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