California's Statewide Self-Generation Incentive Program – What Has Been Consumer Response To Date And Is It Cost-Effective?

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ABSTRACT

California has initiated over the last several years' two major programs funded by electric ratepayers that are designed to promote the distributed generation market, while simultaneously expanding the market for commercialized renewable technologies. These programs include, the $100+ million Emerging Renewable Buydown Program administered by the California Energy Commission since 1998, and the recently implemented $500 million Self-Generation Incentive Program, sponsored at the direction of the California legislature (AB 970) and the Public Utilities Commission. This paper presents key findings from the second-year process and impact evaluations of the Self-Generation Incentive Program targeted at the nonresidential market segments.

While this paper provides an overview of the four-year $500,000,000 incentive Program's accomplishments through the end of its second year, it also addresses the key experiences of participating host customers and the third-party providers of solar photovoltaic (PV), fuel cell, microturbine and internal combustion engine cogeneration systems. The results discussed will help guide electric consumers, supply channel stakeholders, distributed generation program administrators and utility and state policy decision makers regarding needed improvements to the program design and the implementation process. We also provide a brief review of the Program's average incentive costs that have been (or are expected to be) paid out to the applicants associated with the 72 operational projects as of December 31, 2002.

INTRODUCTION

Distributed generation resources are small-scale power generation technologies, typically in the range of 1 kW to 10,000 kW, located where electricity is used (e.g., within a business or residence) to provide an alternative to (or an enhancement of) the traditional utility electric power system. Under the requirements of the California Self-Generation Incentive Program, projects are restricted to the middle of this range: 30 kW to 1,500 kW.

The program was adopted on March 27, 2001 by the CPUC under Decision 01-03-073.[1] Under the direction of this California Public Utilities Commission (CPUC) Decision, the Self-Generation Incentive Program is offered and administered on a regional joint-delivery basis through three investor-owned utilities; Southern California Edison (SCE), Pacific Gas & Electric (PG&E), Southern California Gas Company (SoCalGas)—and one non-utility administrator entity, the San Diego Regional Energy Office (SDREO).[2] The program has been available to provide financial incentives for the installation of new qualifying electric generation equipment since June 29, 2001 and will continue to accept applications through December 31, 2004, subject to availability of the regional Administrator program funds for their respective geographic areas and funded Incentives Levels. The $100 million total Program annual incentive budget is initially equally allocated each year amongst Program Incentive Level 1 (photovoltaics, fuel cells operating on renewable fuel, and wind turbines), Level 2 (fuel cells operating on nonrenewable fuel), Level 3R (microturbines and internal combustion (IC) engines both operating on renewable fuel), and Level 3N (microturbines and IC engines both operating on nonrenewable fuel).[3] As required according to market demand, the Program Administrators may reallocate these annual Program incentive budgets, with certain exceptions regarding transfer to Level 3-N (nonrenewable) technologies. As a result of a subsequent CPUC regulatory approval, the administrators can also "borrow-forward" into future program year incentive budgets upon request, given the approval from the Energy Division.

The remainder of this paper presents an overview of the 2002 year-end program status, discusses data used for the evaluation, and reviews system impacts, operational characteristics, compliance with useful thermal energy and system efficiency criteria, renewable fuel cleanup equipment costs, process assessment results, and key findings.

Although this paper originally was also intended to review evaluation results addressing Program cost-effectiveness and the primary strengths and weaknesses of Utility and NonUtility Program Administrators, the cost-effectiveness assessment is dependent upon the development of a methodology for all AB970 load removal programs by the CPUC Energy Division and, unfortunately, this effort and the administrator comparative review will not be completed until prior to August 2003.

PROGRAM STATUS OVERVIEW

The Program Administrators have been accepting applications since late June 2001. Table 1 presents the status of the 340 PY2001 and PY2002 projects that were active at the end of January 2003. Table 2 summarizes the generation capacity characteristics of all completed projects as of the end of January 2003.

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1 CPUC Decision 01-03-073 (Rulemaking 98-07-037). Interim Opinion: Implementation of Public Utilities Code Section 399.15(b), Paragraphs 4-7; Load Control and Distributed Generation Initiatives. March 27, 2001.

2 SDREO is the Program Administrator for San Diego Gas & Electric customers.

3 The creation of discrete incentive levels for renewable and nonrenewable fueled technologies in level 3 was made in the second year of the program.

Table 1: Summary of Active Projects -- PY2001 and PY2002

	PY2001 Total Active			PY2002 Total Active		
	Projects	kW	Incentives ($)	Projects	kW	Incentives ($)
Level 1	12	2,291	$7,979,166	157	26,875	$ 87,158,828
Level 2	1	200	$ 367,632	1	600	$ 1,500,000
Level 3N	43	15,452	$ 9,906,503	118	57,625	$ 33,680,452
Level 3R	0	0	$ 0	8	1,585	$ 1,462,433
Total	**56**	**17,943**	**$ 18,253,301**	**284**	**86,685**	**$123,801,714**

Table 2: Installed Capacities of Completed/Paid Projects

Incentive Level	Technology	System Size (kW)				
		N	Mean	Minimum	Median	Maximum
Level 1	Photovoltaic	21	110	30	46	521
Level 2	Fuel Cell, Nonrenewable Fuel	1	200	200	200	200
Level 3N	IC Engine, Nonrenewable Fuel	7	716	150	1,000	1,063
	Microturbine, Nonrenewable Fuel	5	89	60	84	120

Evaluation Objectives

This second year evaluation of the Self-Generation Incentive Program was performed to fulfill specific requirements identified in CPUC Decision 01-03-073 (Interim Opinion: Implementation of Public Utilities Code Section 399.15(b); Load Control and Distributed Generation Initiatives, March 27, 2001). This Process evaluation addressed a number of topics, including: program awareness, Program Administrator marketing, ease of application implementation and efficiency, and to the degree they can be addressed given available data, related program design issues. The evaluation goals and their rationale are described in Decision 01-03-073. Evaluation criteria were then developed for meeting each goal and incorporated into the process and impacts evaluations and these were approved in the presiding ALJ's subsequent Ruling of April 2002.

The objectives of the second year impact study are to compile and summarize electrical energy production and demand reduction by specific time periods and technology-specific factors, determine operating and reliability statistics, determine compliance with thermal energy utilization and system efficiency program requirements, compliance with program reliability criteria, determine compliance of Incentive Level 1 systems with the renewable fuel usage requirements, and review/compare renewable fuel clean-up equipment costs for renewable-fueled self-generation systems.

Data Collection

Data for the second-year process and impact evaluation of the Self-Generation Incentive Program was collected from a number of different sources, including the following: 1) the four Administrator's program tracking databases, 2) participant end-user and nonparticipant survey data, 3) investor-owned utility (IOU)/energy service provider electric metering data of net generator output, and 4) other required operational data (i.e., recovered useful thermal energy, natural gas consumption for Level 2 & 3 projects).

Assessment of the impact evaluation performance metrics is ongoing and requires that electric, thermal energy, and gaseous fuel metering be performed to provide the needed data to meet the various objectives of this assessment. Table 3 provides an overview of the major impacts evaluation related measurement activities and objectives as they apply to the technologies included under each Program incentive level. These measurement activities include: 1) System On-Peak Energy Production, 2) Annual Renewable Energy Production, 3) FERC 218.5 Efficiency and useful thermal energy requirements, and 4) Annual Renewable Fuel Usage compliance.

Table 3: Overview of Impacts Evaluation Measurement Objectives

Measurement	Objective	L-1	L-2	L-3R	L-3N
1.On-Peak Energy Production (kW)	Compare actual on-peak kW contribution of systems versus rated kW	X	X	X	X
2. Renewable Energy Production (kWh)	Assess total renewable energy kWh contribution of systems for calendar year	X		X	
3. Efficiency/Cogeneration ▪ 5% (Useful Thermal) ▪ 42.5% (Overall)	Determine compliance with FERC 218.5 program requirements		X		X
4. Renewable Fuel Usage ▪ >75% Annual Renewable Fuel Use	Determine compliance with program renewable fuel usage requirement per D.02-09-051	X (FC)		X	

It is also important to note that metering and monitoring activities by design are not restricted to the Itron/RER team of program evaluation contractors. In some cases, program administrators and/or local utilities as well as program applicants and/or host customers may be undertaking metering and monitoring activities for their own purposes. In these instances, the metering and monitoring team is pursuing opportunities available for utilizing existing metering and monitoring capabilities, thereby minimizing overall data collection cost and host customer inconvenience, while still ensuring availability of metered data that is suitable for program evaluation purposes.

System Impacts and Operational Characteristics

Electrical system demand and energy impacts were estimated for projects that had begun normal operations prior to December 31, 2002 using available metered data and other system characteristics information from the program tracking systems maintained by the Program Administrators. For a subset of operational projects that did not provide metered data for the study, impacts on the system peak were estimated based upon their generation capacity and the available operational characteristics of their "metered counterpart projects" for the technology. Furthermore, electric net generator output (E-NGO) metered data were not collected from all projects during program operational years one and two. Consequently, this initial assessment of demand and energy impacts on the electrical system is based on a combination of metered data and engineering estimates.

Overall estimated program demand impacts on 2002 ISO system peak load are summarized in Table 4 below. During 2002, the California ISO system peak reached a maximum value of 42,352 MW on July 10th. There were 30 known operational program projects when the ISO experienced this summer peak demand, however interval-metered data were available for only 9 of these 30 projects. While the total on-line nameplate generation capacity of the 30 operational projects was 8.3 MW, the total impact of the Program on the ISO peak demand is estimated at 6.7 MW. Program incentive Level 3 systems (IC engines and microturbines) account for 82% of this total 2002 system peak impact.

Table 4: Overall Program 2002 ISO System Peak Demand Impacts

Incentive Level & Technology	On-Line Systems (n)	On-Line Capacity (kW)	Peak Demand Impact (kW_P)
Level 1 PV	11	1,130	790
Level 2 Fuel Cell	2	400	400
Level 3 IC Engines / Microturbines	17	6,752	5,472
Total Estimated Impact	**30**	**8,282**	**6,662**

Figure 1 below presents the demand impacts by program incentive level. As shown, the impacts are greatest for Level 3 combustion technologies.

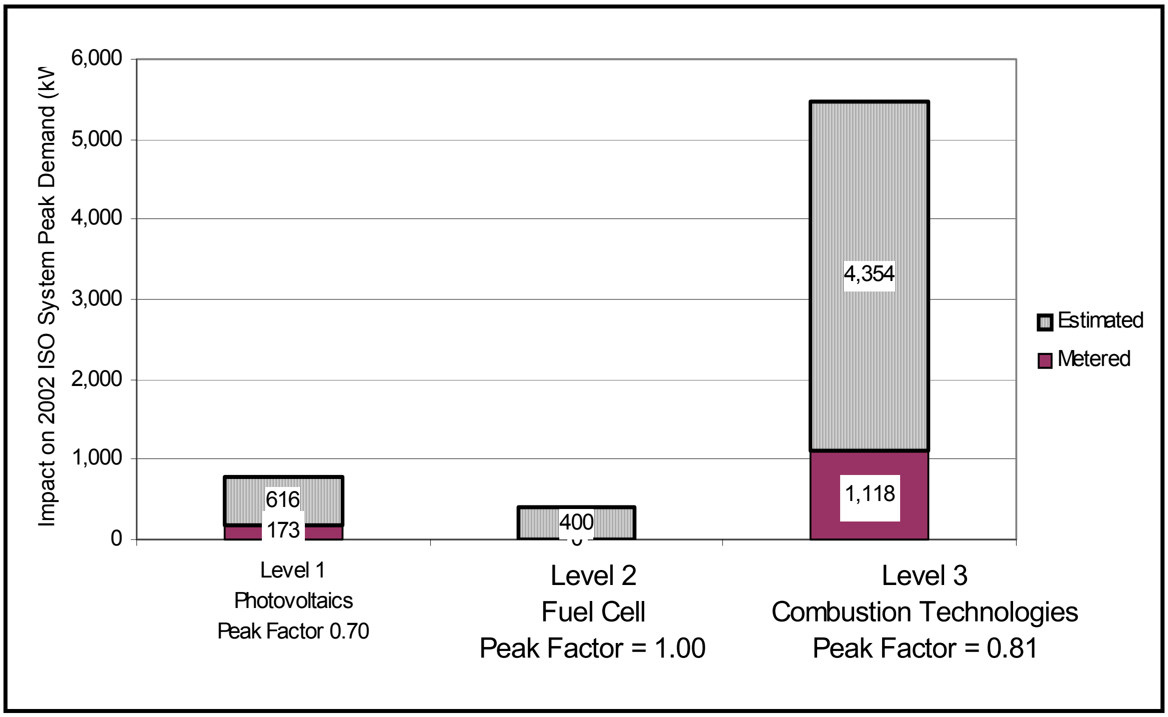

Figure 1: 2002 ISO System Peak Demand Impacts by Incentive Level

Overall Program electrical energy impacts are summarized in Table 5. While Level 3 internal combustion engines and microturbines account for 82% of peak demand impacts, they represent 86% of total energy impacts. This difference is due to the fact that the average capacity factor of Level 3 technologies is greater than that for Level 1 solar photovoltaics.

Table 5: Overall Energy Impacts in 2002 by Quarter (kWh)

Incentive Level & Technology	Q1-2002	Q2-2002	Q3-2002	Q4-2002	Total kWh
Level 1 PV	59,899	461,814	679,860	646,822	1,848,394
Level 2 Fuel Cell	410,400	528,580	839,040	839,420	2,617,440
Level 3 IC Engines /Micro-turbines	2,476,239	4,795,801	7,402,374	13,002,985	27,677,399
Total	**2,946,538**	**5,786,195**	**8,921,274**	**14,489,227**	**32,143,233**

Useful Thermal Energy And System Efficiency Review

Available metered thermal data collected from the on-line Level 3-N projects were used to calculate overall system efficiency incorporating both electricity produced and useful heat recovered.[4] An average of 18.2% of the facilities' total annual energy output is in the form of useful thermal energy delivered to the absorption chillers, which considerably exceeds the Public Utilities Code 218.5 (a) requirement of 5%. The average overall system efficiency of approximately 43.5% is slightly above the required 42.5% efficiency stipulated in Public Utilities Code 218.5 (b). Project-specific system efficiencies for both projects on an individual basis exceeded minimum requirements prescribed by Public Utilities Code 218.5 (b).

Review of Renewable Fuel Cleanup Equipment Costs

One of the added requirements of the second year impacts evaluation by the CPUC included a review and comparison of renewable fuel clean-up equipment costs for renewable-fueled self-generation systems. Two types of data were reviewed to estimate the cost of renewable fuel cleanup equipment. Purchase orders from microturbine and internal combustion engine projects and estimated costs from program tracking data were used.

Renewable fuel cleanup equipment cost data from program project purchase orders were available for six microturbine projects and one internal combustion engine project utilizing renewable fuel. An analysis of these data revealed that the incremental cost for fuel cleanup was negligible for internal combustion engines. For microturbines, the capacity-weighted average, which provides an overall summary of renewable fuel cleanup equipment costs at the program level, was found to be $0.59/Watt.

Total project cost data entered into the program-tracking database were also reviewed to infer an estimate of the incremental cost of renewable fuel clean-up equipment. From this review, it was found that the size-weighted average natural gas microturbine total system cost is about $2.70/Watt. In addition, the size-weighted average result for incremental cleanup costs is $0.89/Watt.

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4 However, thermal data for only two Level 3 projects were obtained for this analysis due to a lack of understanding and/or cooperation from third parties who would not agree to provide their operational data before receiving their incentive payments.

Combining these results for total natural gas system cost ($2.70/Watt) and incremental cleanup costs (either $0.59/Watt or $0.89/Watt) yields an estimated range of total renewable microturbine system cost from $3.28/Watt to $3.58/Watt. However, the existing $1.50/Watt incentive offered by the program for Level 3-R projects is reportedly based on an assumed project cost of $3.74/Watt for microturbine projects utilizing renewable fuel, an amount that exceeds both the $3.28/Watt and the $3.58/Watt system cost estimates described above. This result is not sufficient, however, to develop any definitive/general conclusions about the appropriateness of the $3.74/Watt project cost assumption or the $1.50/Watt incentive due to the small sample sizes and the substantial variability of project cost data.

Review of Incentives – Operational Projects

The Program currently has established maximum incentive levels for select technologies, ranging from $1.00 per watt (Level 3-N, nonrenewable fueled engines and turbines) to $4.50 per watt (Level 1, PV, wind, and renewable based fuel cells). In addition, there are currently incentive caps on the maximum percentage of *eligible project installed costs* that may be paid by the Program. These are set at 50% for Level 1, 40% for Level 2 and 3-R, and 30% for Level 3 technologies. Due to this dual incentive determination approach, the resulting eligible incentives that are paid out to participants can be quite different (e.g., lower) than those incentive levels established for the Program. In this paper we review the weighted average incentives paid to the operational projects ($/Watt) for each incentive level at the end of the second program year. In addition, we present a refined estimate of the program incentives unit cost for this same group of operational projects, this time based on the projects contribution to the California ISO system peak from the impacts analysis contained in Table 4 above ($\$/W_P$). This incentive cost per peak kW removed from the grid provides a more meaningful basis for considering distributed generation program costs. Note that administration costs are not included in these initial results presented in Table 6, but will be considered in both the cost-effectiveness methodology and the administrator comparative assessment.

Table 6: Incentives of Operational SGIP Projects

Incentive Level	$/W	$/Wp
1 (PV)	3.83	5.47
2 (FC)	2.20	2.20
3 (Non-Renewable)	0.56	0.69

Clearly, the average incentive costs associated with the renewable-fueled Level 1 solar PV projects are significantly greater than the nonrenewable Level 3 projects – but so are their installed costs and non-electric benefits. It is also worth noting the average incentives paid for all three Levels to date ranges from 12% (i.e., Level 2) to 44% (i.e., Level 3) *below* the established incentive maximum levels that are allowed under the Program. The incentive costs per peak watt removed from the grid for these operational projects, based upon the ISO peak day in 2002 provides another perspective on the Program's incentive costs. Level 1 PV is by far the most costly program incentive, based on its contribution to the grid at the peak hour (Hr=15) at nearly eight times the incentive cost of Level 3 projects contribution to system peak. By comparison, Level 2 fuel cell incentives are just over three times greater than the Level 3-N incentives, per system peak watt contributed to the electric grid during the ISO summer peak day.

Process Assessment Results

Data collection for the process evaluation included in-depth interviews with 108 host customer participants and 62 third-party suppliers.[5] Host customer respondents were asked questions about how they heard about the program, why they chose to install distributed generation equipment, difficulty of the various stages of project development, experience with and opinions of program requirements, general business characteristics as well as characteristics about their self generation systems, and overall satisfaction with the program. Suppliers were questioned about their level of involvement in the program, their opinions on the application process and requirements of the program, barriers to program participation, impact of the program on the industry, distribution channels and lead times, general business characteristics, and overall satisfaction with the program.

Results for the following areas are presented in this section: participant overall satisfaction with the program, perceptions relating to the program application requirements, marketing strategies that impacted participating customers, and perceptions of third-party system integrators and equipment manufacturers.

Overall Satisfaction With The Program

Overall Satisfaction with the Program was reportedly high with both groups. On a scale of 1 to 5, with 1 meaning very dissatisfied and 5 meaning very satisfied, host customers on average ranked their overall satisfaction with the program 4.3. Many respondents indicated that they understood problems would occur since the program was new, and thus there would be a learning curve on their part and on the part of the Program Administrators. It was surprising how many respondents thought they were one of the first host customers to go through the Program. One respondent remarked, "We were one of the first customers into the Program and we encountered all kinds of problems for that reason." Host customers who felt that their systems were pioneer projects were more likely to be understanding of delays associated with the learning process. Regardless of the difficulties associated with the application and/or project development process, host customers were reportedly appreciative of the existence of the incentive. The high level of overall satisfaction from all respondents may indicate that many host customers feel the incentive is worth the effort of meeting program requirements. Although limited information was gathered on self-reported free-ridership, it was fairly clear that free-ridership was very low for the incentive level 1 Photovoltaics and level 2 Fuel Cell projects. Free-ridership levels are no doubt somewhat higher (and maybe less clear) for the incentive level 3 internal combustion engine projects.

Suppliers ranked their overall satisfaction with the program 4.1. Almost without exception, third-party microturbine and photovoltaic vendors reported they appreciated the existence of the Program and thought it was helpful in developing the distributed generation market. This was especially true for photovoltaic suppliers during the last quarter of 2002 and the first quarter of 2003 when the CEC

5 Nonparticipants, Program Administrators, and verification contractors were also surveyed as part of the evaluation.

rebate program's funding had been exhausted, leaving the Self-Generation Incentive Program as the only option. Microturbine vendors were also appreciative of the Self-Generation Incentive Program as it is the only source of incentives for that technology, and the incentive amount was sufficient to make some otherwise infeasible projects economically viable. Where dissatisfaction was expressed, the focus was primarily on three issues: delay in receiving the incentive payment, problems with connecting the new system to the grid, and difficulty in meeting all of the program's documentation requirements.

Perceptions Of Application Requirements

The majority of host customers reported they found the program application materials clear; however, a significant portion reported the materials were excessively complex, lengthy, and confusing. Some stated that a third-party interpreter was necessary. Furthermore, those customers who relied on a third-party installer or ESCO to direct the process for them seemed relieved to not be directly involved with it.

The majority of suppliers, on the other hand, reported the materials were clear but did not completely describe all the documentation that would eventually be required to obtain the rebate. For this reason, third parties who had been through the process more than once had a much easier time with the application process than did those who experienced it for the first time. In addition, some suppliers who had submitted applications to more than one Program Administrator reported that there were inconsistencies in the way some processes were handled in different areas of the state.

In addition to the clarity of the materials, customers were asked about difficulties in meeting program requirements including obtaining permits and providing documentation. Areas identified as difficult included the process of interconnecting to the grid, the process of having a net generation output meter installed, and the process of obtaining an air emissions permit.

Suppliers also reported difficulties with the interconnection process and with obtaining air emissions and building permits. In addition, it was reported that the one-year deadline was insufficient for projects involving new construction and for installations in institutional buildings as these installations required additional time to obtain project approval from the Office of Statewide Health Planning and Development.

The Statewide Working Group has allowed for a formal extension of the one-year deadline to 18 months where a need is identified. Interconnection difficulties will take more time to adequately address the full extent of the many issues that complicate and often delay the final operation of the self-generation projects.

Marketing Strategies

Marketing efforts for the Self-Generation Incentive Program have targeted third parties rather than customers. These efforts included workshops, some of which focused on particular technologies (e.g. photovoltaics) or technical topics (e.g. cogeneration), promotional materials, website information, presentations to specific groups or businesses, direct mail (including email), and print and radio advertisements.

The strategy of targeting third parties appears to be working well for the program. Most participant customers reported hearing about the program from a third party. In contrast, most nonparticipants reported hearing about the program from news articles, utility representatives and Internet searches. This suggests that third parties are much more influential than utility representatives or other sources of information in getting customers to participate in the program, since education by third parties leads to participation much more often than does education by utility representatives or media sources.

Perceptions Of Third-Party Suppliers

Participant ESCOs reported that the program had helped develop the market for energy services. This was especially true for the photovoltaic industry. In particular, the program helps reduce the barrier of the high capital cost of the equipment and installation in two ways. First, it directly reduces the installation cost via the rebate. Second, by thus increasing consumer demand for the technology, it stimulates economies of scale in manufacturing and installation as third-party vendors and suppliers become more efficient at designing and installing the systems. Furthermore, most respondents felt that the program had helped to promote awareness of self-generation opportunities among consumers. However, suppliers in general reported that lack of customer awareness of the benefits of distributed generation is still low and remains the primary barrier to program participation.

SUMMARY OF KEY FINDINGS

The peak demand impact estimated for 2002 operational program projects is 6.7 MW. Moreover, 2002 operational program projects produced over 32,000 MWh of energy. Internal combustion engine and microtubine systems accounted for roughly 82% of the reduction in demand and 86% of the energy impacts. For the two cogeneration systems for which complete-year datasets were available, roughly 18% of the facilities' total annual energy output was in the form of useful thermal energy delivered to absorption chillers. Furthermore, overall system efficiency exceeded the prescribed minimum requirements. The average incentives to be paid for operational projects to date ranges from 12% (Level 2) to 44% (Level 3) *below* the established incentive maximum levels that are allowed under the Program.

On the process side, the program is reportedly having a significant effect on the development of the third party market, especially for photovoltaic suppliers. ESCOs who were interviewed felt that "the energy services industry in California would not exist without the program." In addition, most customers surveyed reported learning of the program and of self-generation opportunities from their third party vendors. Furthermore, many suppliers interviewed reported that they did not think the program marketed effectively to customers; some were surprised that it did so at all. These results suggest that the program is, in fact, targeting third parties and ESCOs. Furthermore, customers who reported working with third parties offering turnkey projects were the most satisfied with their experience.

Interconnection, air emissions permitting, and net generation output metering continue to present problems. While the Program Administrators expended considerable effort in PY2002 attempting to smooth the interconnection process, suppliers and host customers reported that the process remains problematic. In addition, net-metered customers often stated that meters were not installed in a timely fashion or that they did not understand the billing process associated with their contributions to the grid. Numerous host customers also indicated problems obtaining air emissions permits within the required time frame. Regardless of the numerous complaints cited regarding these processes, however, overall satisfaction with the program remained high among all participants. Thus, while these processes should be improved, they do not appear to be preventing host customers from completing their projects.

Awareness of the Program and self-generation opportunities among customers remains relatively low. Suppliers reported that marketing efforts made by the utilities were not reaching the customers. Further, the supplier and host customer interviews confirmed that third party suppliers continue to be the dominant source of information on the program for participant host customers. However, nonparticipants reported that they were just as likely to hear about the program from utility representatives or Internet searches as they were from third party suppliers. In fact, the dominant source of program information identified by nonparticipants was newspaper or magazine articles. This finding suggests that third parties are much more influential in the decision to participate than utility representatives or other sources of information.

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