EVALUATION OF PUBLIC SERVICE ELECTRIC & GAS COMPANY'S STANDARD OFFER PROGRAM

Charles A. Goldman, Lawrence Berkeley Laboratory, Berkeley, CA
M. Suzie Kito, Lawrence Berkeley Laboratory, Berkeley, CA
Mithra M. Moezzi, Lawrence Berkeley Laboratory, Berkeley, CA

Abstract

This paper discusses results from a process and impact evaluation of the Public Service Electric and Gas Company (PSE&G) Standard Offer program. During the first 18 months of the pilot program, about 40 MW of summer prime period average demand savings are in various stages of development with about nine MW in commercial operation. Sixteen energy service companies (ESCOs) and nineteen large customers have sponsored projects. However, a single ESCO affiliated with PSE&G accounts for about 43 percent of the program savings and has also financed many projects sponsored by other ESCOs and customers, which in conjunction with its own projects, represent about 60-70 percent of the program's savings. Lighting and fuel switching measures account for about 65 percent and 17 percent of the summer prime period average demand savings, respectively. Total program costs, including both utility payments and costs borne by customers, average about 6.8 ¢/kWh levelized over the term of the contracts (usually 10 years).

Introduction

In May 1993, PSE&G initiated its Standard Offer program, a large-scale pilot approved by the New Jersey Board of Public Utilities (NJBPU) based on a settlement agreement negotiated among the major stakeholders. The program's design is innovative in that the utility offers long-term contracts with standard terms and conditions to project sponsors, either customers or third-party energy service companies (ESCOs) on a first-come, first-served basis. The design includes posted, time-differentiated prices which are paid for energy savings that are verified over the contract term based on a statewide measurement and verification (M&V) protocol. The program's scope is also quite broad and includes new construction and retrofits in existing commercial, industrial, and residential buildings. However, the Standard Offer is PSE&G's primary DSM program for large commercial and industrial (C/I) customers. From a policy perspective, the program is interesting for several reasons: (1) its potential size is significantly larger than any current utility program that relies mainly on third-party energy service providers to market and deliver a performance-based program (e.g., DSM bidding), and (2) participation in the Standard Offer by PSE&G's for-profit subsidiary, the Public Service Conservation Resources Corporation (PSCRC), represents a practical test of the DSM incentive regulations adopted by the NJBPU.[1] PSCRC's direct participation also raises important competitive issues with respect to PSE&G's role in the development of the energy services market.

This paper summarizes results from a LBL process and impact evaluation of the Standard Offer program that was co-funded by PSE&G and the Department of Energy.[2,a] We focus on six major topics: (1) market response, (2) program costs and cost-effectiveness, (3) potential lost opportunities and partial

---

a As part of the Stipulation of Settlement (1992)[3] that approved the pilot, the NJBPU asked PSE&G to conduct an independent evaluation.

retrofit treatments, (4) the utility's effectiveness in implementing the program and the effect that PSCRC's involvement has had on the energy services industry in New Jersey, (5) customer satisfaction, and (6) key lessons learned from this pilot and transferability of the Standard Offer concept, particularly in light of the competitive pressures currently facing electric utilities. In the next sections, we briefly describe our research approach, review key program features, and then present major findings on the six topics.

Approach

We reviewed all program materials, regulatory filings, and a sample of proposals submitted by project sponsors, made site visits to several facilities in various stages of development, and interviewed key program participants. These included in-person interviews with utility and regulatory staff and telephone surveys with project sponsors (both customers and ESCOs), host customers that used ESCOs as project sponsors, and ESCOs that are not active in the program. We attempted to interview all project sponsors and a sample of host customers that had worked with each participating ESCO; each respondent was contacted several times with varying degrees of success. Response rates were highest for ESCOs active in the program (75%), followed by customer sponsors and ESCOs not active in the program (55-60%), and then host customers (<50%). Respondents were asked a mix of open-ended and close-ended questions and were interviewed between September 1994 and February 1995.

We also reviewed PSE&G's program tracking database to analyze program impacts for the first 18 months of field operation (June 1993-December 1994). The tracking database includes descriptive information on each facility (floor space, SIC code), a detailed inventory of individual measures installed, baseline and proposed equipment efficiencies, estimated hours of operation and savings by time period, actual savings based on end-use and equipment metering and monitoring of hours of operation, and various types of program costs. In analyzing market response, we distinguish between committed projects and projects on-line. Committed projects include all projects submitted by sponsors to PSE&G, which are in various stages of development (i.e., pre-implementation audit, under construction, commercial operation). Projects that are in commercial operation represent a subset of committed projects that are providing verified savings to the utility. Unless otherwise noted, summary statistics reflect summer prime period average demand reductions (SPPADR) for committed projects.[b]

Key Program Features

PSE&G offers a standard contract that includes time-differentiated payments for electricity savings, which are directly tied to their value to the utility. For example, for a 10-year project coming on-line in 1994, levelized payments would be about 17.9 ¢/kWh during the summer prime period, 4.8-5.4 ¢/kWh during the on-peak periods of each season, and 2.9-3.5 ¢/kWh during the off-peak periods of each season. Contract terms are five, ten, or 15 years, depending on measure life. The program has as an explicit design objective that DSM resources should be as reliable as supply-side resources to the extent feasible. Thus, there are standardized verification protocols for monitoring various types of retrofit applications. For example, one

---

b Summer Prime Period Average Demand Reduction is defined as the total kWh saved during the Summer Prime Period divided by the total number of hours in that period (430). The Summer Prime Period includes weekday hours from 12 noon - 5 p.m., between June 1 and Sept. 30, except holidays.

protocol covers constant load, constant operating hours, non-weather sensitive end uses such as lighting system conversions and constant-load motors and typically involves continuous metering of hours of operation. Savings verification agreements at individual facilities for certain types of measures with approved protocols and new retrofit applications for which there are no protocols must be approved by staffs of the NJBPU and Division of Ratepayer Advocate. Minimum size requirements for projects are 100 and 50 kW of demand reductions during the summer prime period for existing and new buildings respectively. Thus, only large C/I customers have the option of directly sponsoring projects, while smaller C/I and residential customers must work with a third-party sponsor who aggregates jobs from individual facilities. Given the transaction costs and performance risks, some large customers prefer to have ESCOs assume the responsibilities of project sponsorship. Project sponsors assume significant performance risks and are liable for penalties for non-delivery of energy savings by the agreed-upon installation date and under-performance (i.e., for not maintaining 80 percent of the forecast demand reductions expected to occur in the summer prime period).

Utility program staff review proposals submitted by project sponsors, perform an initial cost-effectiveness analysis to ensure that projects pass the Total Resource Cost test, negotiate savings verification agreements based on the standard protocols, verify key factors that influence estimates of energy savings by conducting pre- and post-implementation audits (e.g., verify fixture count, check baseline and post-retrofit equipment efficiency, test for changes in lighting levels), and approve payments for delivered savings.

Program Evolution

Table 1 provides an overview of the evolution of the Standard Offer from design through various phases of implementation (based on our analysis of significant events/milestones) in three areas - regulatory, utility, and market activities.

- The program design and rules were the product of a consensus settlement involving major stakeholders, which was approved by the NJBPU and which of necessity involved compromises among the parties on key issues (e.g., the role of the utility's energy services subsidiary, M&V protocols, and the scope of utility program marketing).
- Throughout much of the implementation period, several winning ESCOs from PSE&G's earlier competitive bidding solicitation (held in 1989) were marketing that program as well as the Standard Offer. About 8.5 MW of DSM projects from the bidding program came on-line in 1994. The competing offers created some confusion among large C/I customers, which adversely affected market response to the Standard Offer.
- During the first 8-9 months of program operation (June 1993-March 1994), PSE&G program staff consciously limited their program marketing activities because of concern over influencing customer's access to and selection among competing ESCOs. Meanwhile, PSCRC, the ESCO subsidiary of PSE&G, aggressively entered the energy services market. PSCRC provided financing for projects sponsored by other ESCOs or host customers and organized an Energy Services Network (ESN) in which it acted as a project facilitator attempting to guide customers towards other qualified third party firms that were members of the ESN. Major problems arose in implementing the ESN and the concept has not worked particularly well given the conditions in New Jersey.
- In response to the market's initial slow response and confusion among customers, PSE&G made significant mid-course corrections in April 1994 which involved PSE&G specialists in regional offices providing assistance to customers on specific program issues and more aggressive marketing

Table 1. Program Chronology

	Regulatory	Utility	Market
(1) Program Design/Approval: (1992 - Early 1993)	• Negotiated settlement among parties approved by BRC (12/92) • Work on M&V protocols	• Utility forms PSCRC (1992) • Informational meetings for customers (early 1993)	• ESCOs that won 1989 RFP marketing to large C/I customers • PSCRC promotes Energy Service Network (ESN)
(2) Initial Program Implementation: (June 1993 - March 1994)	• BRC provides list of ESCOs to interested customers	• Utility program managers provide only general information ("hands off" attitude)	• Several ESCOs marketing Standard Offer and '89 Bid • PSCRC as facilitator and financier
(3) Program Implementation: (April 1994 - December 1994)	• Minor program changes and clarifications approved by BRC • Pilot program extended	• Establish program specialists in 6 field offices • Provide customers with more specific assistance	• Energy Service Network problems cause several ESCOs to leave • PSCRC offers "Bright Investment" program for small C/I customers (5/94)
(4) Program Implementation: (January 1995 -)	• "Stay the course on DSM" while considering industry restructuring	• Utility re-organization and departure of key program staff • Planning for Standard Offer II; "re-engineering" of administrative processes	• Increasing momentum and customer acceptance

of the Standard Offer program by PSE&G representatives.

- In late 1994, the NJBPU extended the pilot program to December 1995 while it considers broader issues related to industry restructuring. At the time of this writing, it appears that customer and market acceptance is increasing. PSE&G completed an internal re-organization in early 1995, during which several key program staff left the utility. As part of its planning for Standard Offer II, PSE&G is reviewing and "re-engineering" its administrative processes.

Market Response

Through December 31, 1994, PSE&G has received commitments from 35 project sponsors (16 ESCOs and 19 customer sponsors) for about 40 MW of SPPADR in over 1,050 facilities; about 9 MW are operational (Table 2). The market response is significantly less than the original program target of 150 MW by mid-1995, particularly in light of the long project development times. However, based on the experience of other utility programs that require customers to sign long-term, performance-based contracts (e.g., DSM bidding programs), the original target was probably unrealistic. The market response to the Standard Offer compares favorably with most DSM bidding programs over a similar time period, assuming that almost all submitted projects proceed and become operational.[3] Direct comparisons are difficult because, in bidding programs, the utility selects a limited number of ESCOs who then must meet individual contract demand reduction goals. In contrast, the number of potential competing firms is limited only by the market in the Standard Offer, while the quantity constraint is program-wide.

Table 2. Distribution of Projects by Sponsor Type

Sponsor Type	Number of Facilities	Committed Projects: Connected Load Savings (MW)	Committed Projects: Summer Prime Period Demand Savings (MW)	Commercial Operation: Summer Prime Period Demand Savings (MW)
ESCOs (excluding PSCRC) (14)	94	24.5	15.1	1.8
PSCRC	146	16.2	10.7	4.9
PSCRC -- Bright Investments	782	7.1	7.1	2.4
Customer Sponsors (19)	34	12.4	7.2	0.2
TOTAL	1,056	60.2	40.1	9.3

By almost any measure, PSCRC has a very significant role in the market. As a project sponsor, PSCRC accounts for about 43 percent of the SPPADR from committed projects, with almost 80 percent of the savings from projects that are in commercial operation. PSCRC has been active in both the large and small C/I markets, where its Bright Investment program promotes lighting efficiency options to customers with projects that save less than 50 kW. PSCRC has also provided construction and permanent financing to many of the other ESCOs and several customer sponsors. While it is not possible to give a precise answer, based on our interviews with ESCOs and customers, it appears that PSCRC is providing some type of financing (direct and indirect) for projects representing about 60-70 percent of the savings in the program.

Thus far, about 98 percent of the committed savings involve equipment replacements and retrofits in existing commercial/industrial facilities with about two percent of the activity in new construction. PSE&G staff claim that there has been little new construction occurring in the service territory but were unable to provide estimates of the amount of new floor space added in 1993 and 1994, so market penetration rates could not be estimated. M&V issues have also proven quite thorny in new construction, given the difficulty of establishing the appropriate "baseline" energy consumption in new buildings. The lack of activity in the residential sector is not too surprising given the transaction costs and risks involved for third parties (e.g., getting commitments from thousands of individual customers in advance) and the existence of many PSE&G "core" programs that are already targeting this market.[c]

In Figure 1, we show the SPPADR for projects in thirteen target market sectors.[d] By far, the largest categories are "out of scope" and "industrial" accounting for about 28 and 27 percent, respectively, of the total SPPADR. "Out of scope" is a catchall category that includes SIC codes for which commercial building types are not defined, including research/testing labs, transportation and trucking businesses, and sanitary facilities. "Industrial" includes facilities of various types of manufacturing firms. For lighting measures installed by these firms (which account for roughly two-thirds of the savings from this sector), a facility-by-facility analysis would be required to determine whether retrofits are occurring at corporate headquarter offices or at manufacturing plants.[e] Warehouses, health care and retail facilities have each accounted for about 3-4 MW of savings (8-9% each). The market penetration in large office buildings is quite low at 2.2 MW (6% of total program savings), which is surprising given the significant DSM potential in that sector,[4] but apparently reflects barriers associated with the Standard Offer design.[f] Various types of lighting measures (66%) and electric-to-gas fuel conversions of space and water heating equipment and industrial processes (17%) account for most of the savings, along with HVAC measures (7%) and industrial process improvements (5%) (see Figure 2). One of the interesting findings is that, thus far, lighting measures account for about 75 percent of the savings from projects sponsored by ESCOs, while non-lighting measures represent 75 percent of the savings from projects sponsored by customers. Possible explanations for this phenomenon include the fact that: (1) a number of ESCOs focus only on measures for which there are approved M&V protocols, (2) because they receive the entire Standard Offer payment, customer sponsors may be more willing to invest the resources (both money and time) to get M&V protocols approved for site-specific process and equipment retrofits, and (3) non-lighting projects tend to take longer for ESCOs to develop because they are more complex.

---

c In April 1995, PSE&G approved its first residential contract under the Standard Offer, although no savings have been delivered.

d LBL mapped the SIC codes reported by each project sponsor into 13 market segments based on building types used in the commercial/industrial forecasting model (COMMEND) developed by EPRI.

e In this group, roughly two-thirds of savings come from lighting measures, and one-third from other measures.

f See Xenergy (1994).[4] Owners of tenant-occupied buildings are wary of the long contract terms, which typically exceed tenant leases, and penalty provisions that may be invoked if existing tenants leave and savings do not persist.

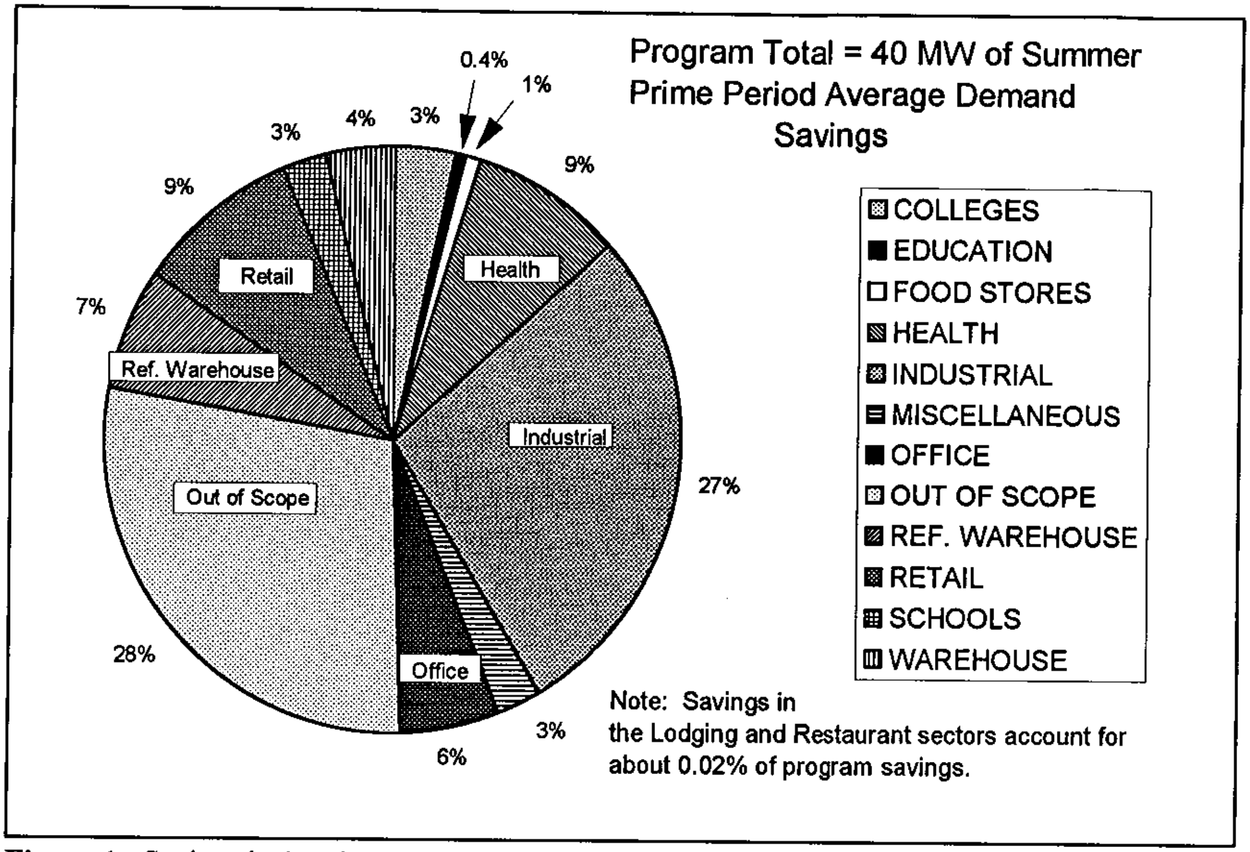

Figure 1. Savings by Market Sector

Program Costs and Cost-Effectiveness

We obtained information from PSE&G's tracking database on various types of program costs, annual estimates of energy savings in each of seven time periods, avoided supply benefits, and contract lifetimes in order to analyze the costs and cost-effectiveness of the Standard Offer program. We present program costs in terms of levelized total resource costs (TRC) per kWh in nominal dollars. We use the utility's discount rate of 11.2 percent and the contract terms (typically 10 years) as a conservative proxy for the economic lifetime of the measures installed in calculating levelized costs.[g] Annual energy savings are typically based on estimates from pre-implementation audits, although PSE&G payments depend upon delivered energy savings by time period. Thus, if the distribution of actual savings by time period changes compared to the engineering estimate, our estimates of levelized program costs per kWh will change somewhat. However, this should not affect the overall cost-effectiveness of the projects because PSE&G payments are set at a level which is proportional to the avoided cost benefits in any time period. Costs to the utility include only PSE&G payments to the project sponsors. Project sponsors are billed for the utility's costs to administer the program, which the sponsor must then internalize in estimating overall project cost.

[g] Levelized TRC would be about 15 percent lower if the measures produced savings for an additional five years after the contract term expired.

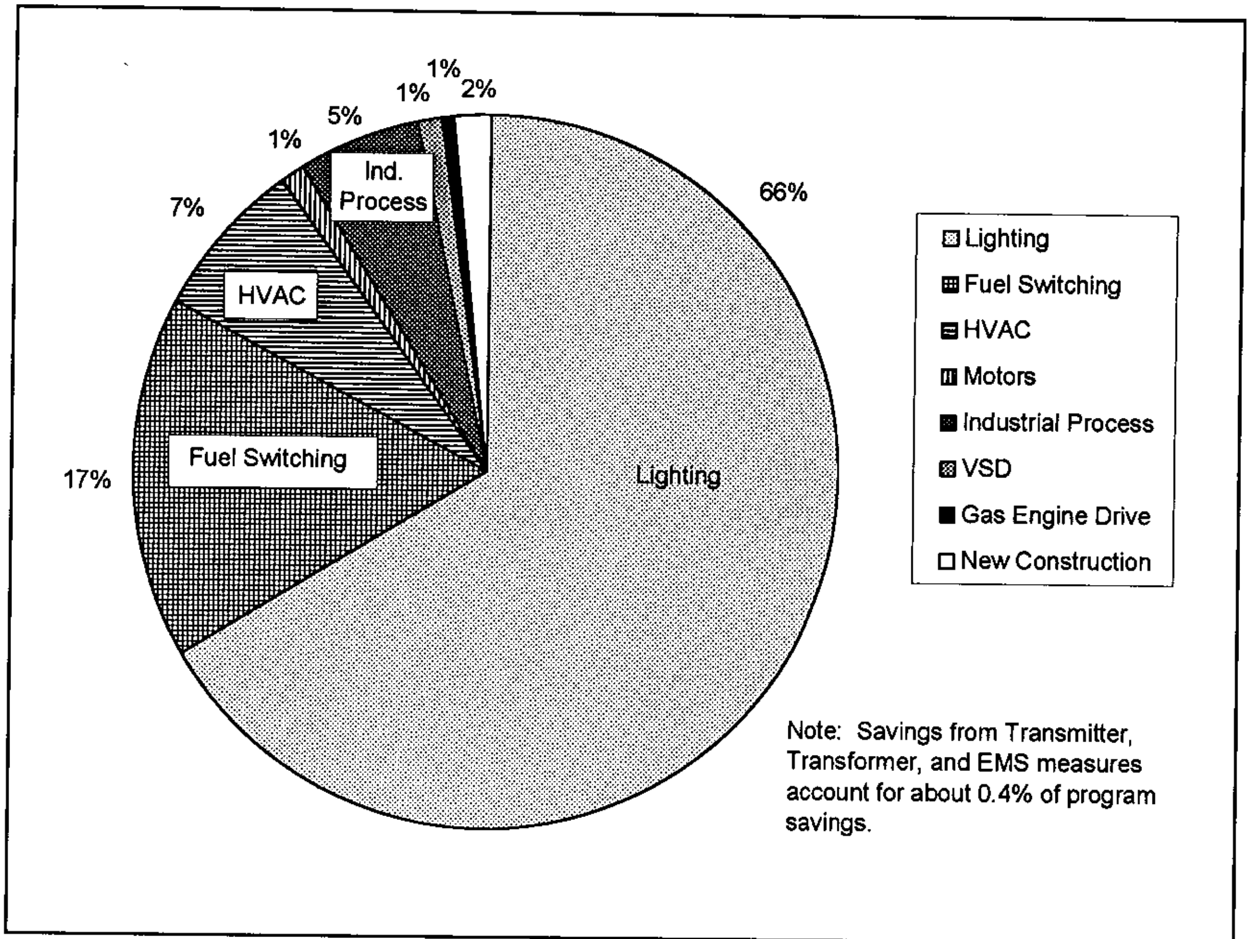

Figure 2. Savings by Measure Type

For projects sponsored by ESCOs, the levelized TRC is defined as follows:

$$TRC = (PP+O\&M+HFP+IEC)x[(I(1+I)^n)/((1+I)^n - 1)]/ kWh$$

where:

PP	=	PSE&G Payment
O&M	=	Incremental O&M Savings (or additional costs)
HFP	=	Host Facility Payment
IEC	=	Incidental Energy Costs (for fuel switching projects)
I	=	Discount Rate, 11.2 percent
n	=	Contract Term
kWh	=	Energy Savings

Host facility payments include any payments from the host customer to the ESCO and can include a share of the bill savings, contributions toward equipment purchases, etc.

For projects sponsored by customers, PSE&G uses an alternative definition of Total Resource Costs, which substitutes customer-reported capital costs and M&V costs for PSE&G and host facility payments:

$$TRC = (CC+O\&M+M\&V+IEC)x[(I(1+I)^n)/((1+I)^n - 1)]/ kWh$$

where:

CC	=	Total capital cost of the installed measure
O&M	=	Incremental O&M Savings (or additional costs)
M&V	=	Measurement & Verification Costs

Total resource costs, levelized over the contract term of each facility (typically 10 years), average 6.8 ¢/kWh for the program overall, which is about 74 percent of the utility's avoided supply costs. Costs incurred by the utility average about 6.1 ¢/kWh, which consist entirely of the Standard Offer payment. TRC values range from about 6.6 ¢/kWh for large C/I projects sponsored by ESCOs and customer-sponsored projects to about 8 ¢/kWh for PSCRC's Bright Investment program, which is targeted at smaller C/I customers. Figure 3 provides a breakdown of the various cost components for each type of project sponsor. Net total resource costs are shown by an arrow for each type of sponsor; note that incremental O&M costs are negative because high efficiency lighting retrofits are assumed to yield O&M savings. On average, host customers contribute about 0.5 ¢/kWh in projects sponsored by ESCOs and 2.1 ¢/kWh in Bright Investment projects. For customer-sponsored projects, capital costs of the measures account for about 42 percent of the total costs. Incidental energy costs are also a significant cost component in customer-sponsored projects (3.5 ¢/kWh) which reflects the prevalence of fuel switching projects.

In the large C/I market, total resource costs average about 5.9 ¢/kWh for the 217 projects that installed

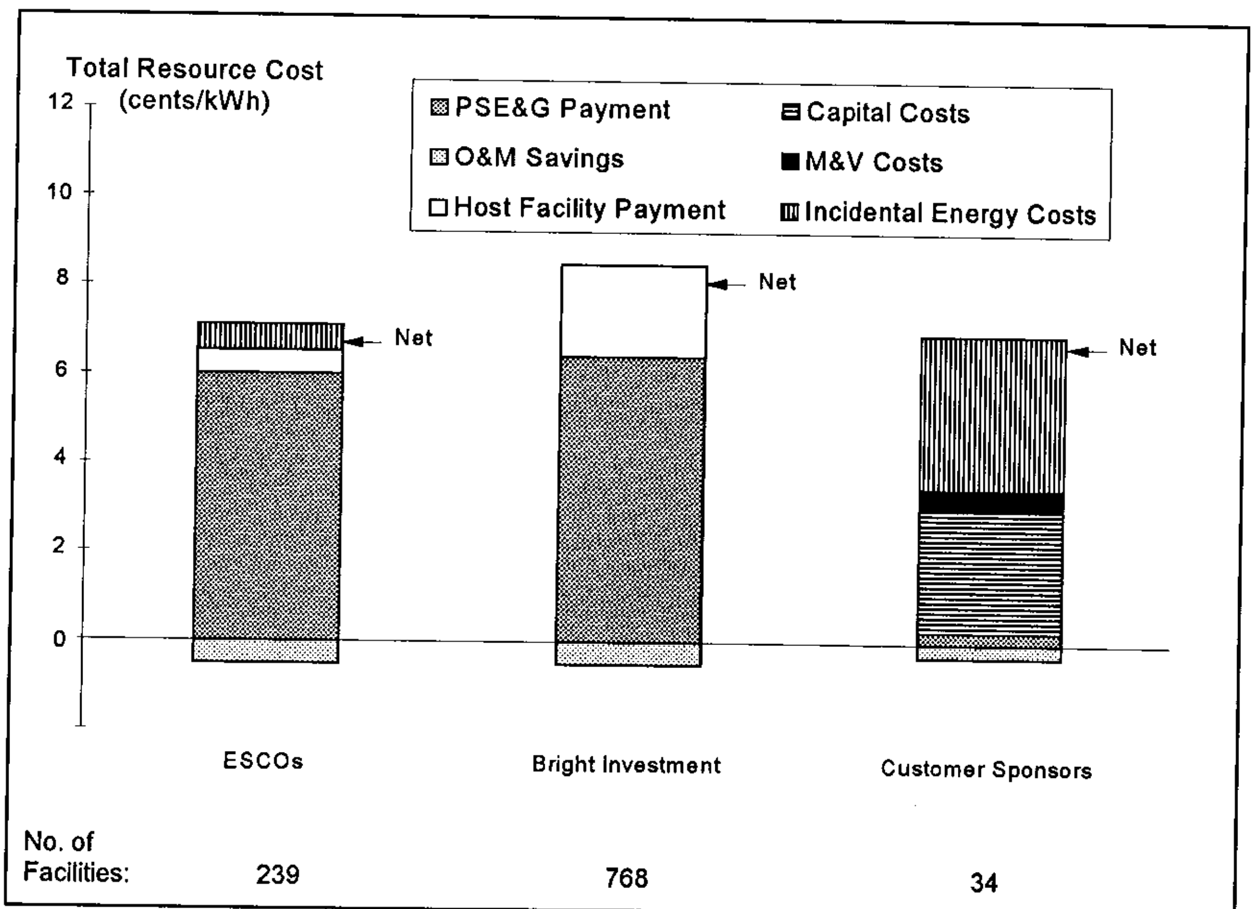

Figure 3. Total Resource Costs

only lighting measures. Levelized TRC is about 7.8 ¢/kWh for the seven projects that involved lighting plus non-lighting measures, and 7.3 ¢/kWh for the 27 facilities that are implementing fuel switching projects.

We also compared the costs of the Standard Offer program with a sample of eight DSM bidding programs taken from a recent LBL study[3] to provide policy makers with insights on the range in current practice.[h] The total resource costs of the Standard Offer program (6.8 ¢/kWh) are in the mid-range compared to these other utilities that have implemented DSM bidding programs (3.4 - 8 ¢/kWh) and are slightly lower than PSE&G's 1989 DSM bids (7.1 vs. 6.8 ¢/kWh).

Concerns Regarding Potential "Lost Opportunities" and Partial Retrofit Treatments

Several key design features of the Standard Offer make it difficult for the program to capture certain potential "lost opportunities" for energy efficiency.[5] For example, the program is unlikely to capture conservation opportunities that arise when equipment fails and must be replaced quickly because of the M&V requirements, approval process for measures, and size threshold.[i] Potential "lost opportunities" may also be created if a program design encourages partial or selective treatment of facilities, which then make it impractical or uneconomic for providers of energy services to capture the remaining efficiency options cost-effectively. Gordon et al. (1994)[5] are particularly concerned about non-lighting measures where the cost/kW saved is extremely variable among measures and between sites. In this situation, they argue that ESCOs are naturally driven to look for the least expensive savings and less complex projects because of the performance risks associated with the M&V requirements. Moreover, because the incentive is based on savings and not cost, the higher costs/kWh of many non-lighting measures and comprehensive services will put those ESCOs that target these market niches at a competitive disadvantage compared to lighting service contractors. Based on analysis of the program tracking database and interviews with ESCOs and customers, we would offer the following comments on this issue.

There appears to be little evidence of selective and partial lighting treatments completed under the Standard Offer program, with the exception of lighting controls, which are not covered by the M&V protocols. For the program overall, sponsors expect to reduce prime period kW demand for lighting fixtures being replaced by about 50 percent. Based on their pre-implementation audits, utility program staff believe that sponsors are capturing about 90-95 percent of the potential lighting improvements. If correct, this means that lighting savings are about 45 percent of baseline lighting energy usage.

It appears that the program's stringent and time-consuming requirements for developing M&V plans do contribute to the relatively low market penetration of HVAC equipment, refrigeration, and industrial process application retrofits. Several ESCOs reported that they have installed energy management control systems and lighting controls measures in customer facilities outside of the program because there are no acceptable M&V protocols. The marketing strategies of some ESCOs as well as customer decision-making processes and financial performance requirements also appear to limit comprehensive retrofits in certain market segments. A comprehensive package of measures involves a tougher and longer sell compared to a

---

h The bidding programs were selected based on their similarities with the Standard Offer in terms of performance risks borne by developers.

i At the time of failure (or planned replacement), the societal cost of acquiring the higher-efficiency equipment is only the incremental cost compared to the "typical" alternative, but this opportunity for higher end-use efficiency occurs in a very limited time frame.

lighting project for many customers. Thus, several ESCOs claim that they are pursuing a staged approach, in which lighting projects are followed by marketing of other applications such as variable speed drives, motors, and chillers. These ESCOs claim that 25-50 percent of the customers will ultimately agree to additional efficiency improvements if they are satisfied with the ESCOs initial performance. Other ESCOs also noted that they encourage customers to install all cost-effective measures in their facility, but that HVAC equipment replacement and fuel substitution projects often fail to pass a TRC test. These measures would be attractive to customers, but are ineligible under the program. This issue of projects failing the TRC test will become more prominent in the future because the utility's current projections of avoided costs are expected to be significantly lower than those used in the initial Standard Offer pilot.

The issue of partial treatment of facilities is of greater concern in the small C/I market because PSCRC's Bright Investment program markets lighting measures only and because there have been few other ESCOs actively targeting these customers. Although PSE&G's pilot small C/I program offers rebates for certain lighting and non-lighting measures, that program has apparently not established a strong market presence. When asked why they chose the Bright Investment program rather than PSE&G's rebate program, most respondents indicated that they were unaware that the utility had a rebate program. We found that only one of the 25 Bright Investment customers we interviewed was aware that the rebate program existed, because this customer had previously participated.

Program Marketing

Based on our interviews, we would characterize the market environment as follows:

- Overall, many ESCOs stress that the program has been a "harder sell" than anticipated and they report low proposal to closing ratios.[j] Four of ten firms responding estimated that their proposal to closing ratios were between 8 and 15 percent. A few firms that target their marketing efforts very selectively report higher values (e.g., 40-70 percent of customers that are pre-qualified by the ESCO). Almost all large customers have been contacted by more than one ESCO and it appears that there has been intense competition among firms for projects involving these large customers. For example, the number of proposals received ranged from one to 12 among the seventeen host customers interviewed, with a median of four proposals per large customer. However, among the 25 small C/I customers that participated in the Bright Investments program, we found that it was not uncommon for customers to have been approached by only one firm.
- ESCOs listed the following factors as adversely affecting customer participation: (1) general uncertainty in the economy which makes many companies hesitant to sign long-term contracts, (2) unacceptable contract provisions (e.g., penalties for non-performance, termination values) and term, (3) customer perception that the program is too complex and risky and has high transaction costs, particularly in terms of the time and cost involved in developing M&V protocols for certain non-lighting measures, and (4) substantial confusion initially in the marketplace. This confusion occurred because some ESCOs were marketing both the 1989 bid program and the Standard Offer to customers, because utility field staff in regional offices had difficulty explaining the Standard Offer program, and because of ill-defined relationships between PSCRC and some members of its Energy Service Network, which

---

j Proposal to closing ratio refers to the number of proposals made to customers compared to number of accepted proposals that produce a project.

resulted in many large customers being inundated with proposals.

- In terms of customer perception, we found that many customers do not distinguish between PSE&G and its affiliate, PSCRC, and many view them as one entity. Some ESCOs complain that PSCRC has not done enough to dissuade customers of that notion, which they claim gives PSCRC a distinct marketing advantage.

Program Delivery and Administration

Respondents provided some important feedback on the utility's implementation of the program as well as suggestions for improvement:

- About two-thirds of the ESCOs and customer sponsors indicated that PSE&G program managers were very responsive and helpful. In most cases, PSE&G had reviewed and approved their proposals in a timely fashion (2-4 weeks) and were technically competent and knowledgeable in negotiating appropriate M&V plans. There is a fairly widespread perception among project sponsors that the program was understaffed.
- Almost all customer sponsors and most ESCOs believe that PSE&G program staff have implemented the program fairly. However, about half of the ESCOs made a sharp distinction between program staff (who they regarded as generally fair) and PSE&G field representatives, who they felt have steered customers towards PSCRC. Comments such as "PSE&G people have done an outstanding job but the reps have been pitching PSCRC" were typical. However, it should be noted that no ESCO has filed a formal complaint with the NJBPU.
- Project sponsors, both ESCOs and customers, gave very mixed reviews to PSE&G's program materials and the Automated Entry/Standard Offer Program (AESOP) software used to prepare project proposals. ESCOs that had participated in the 1989 bidding program generally gave high ratings to the written program material (an average of 4 out of 5). However, ESCOs that did not have prior experience in the 1989 bid program and many customer sponsors were quite critical of the program materials and the project proposal software. For example, on a scale of 1 to 5 (1=poor and 5=excellent), five ESCOs rated the clarity and usefulness of the written material at a 1 to 2. Only 10 percent of the customer sponsors said that the instructions for preparing project proposals on the required software was "very clear," while 50 percent said it was either "not at all clear," or "not too clear."

Role of PSCRC

In the Stipulation of Settlement approving the pilot program, PSCRC anticipated that it would provide capital investment services for projects developed, constructed, and managed by ESCOs and customers and offer project facilitation services to the DSM industry and customers. PSCRC formed the Energy Services Network, which included various types of providers (engineering/construction/procurement firms, energy service companies, lighting service contractors), as the primary vehicle to implement this latter objective.

Most ESCOs stated that PSCRC has played a positive role in stimulating the energy services infrastructure in New Jersey by providing capital investment services to other ESCOs and customers. ESCOs expressed sharply divergent views regarding PSCRC's role as a project facilitator. A number of companies that were still actively working with PSCRC maintained that it has played a positive role in the market. Other ESCOs were quite critical and argued that PSCRC has become a "full-fledged project developer," rather than a project facilitator. Comments such as, "PSCRC has a natural monopoly on project sponsorship," and "PSCRC is an 800-pound gorilla in the marketplace" reflect the intensity of some of these views.

Many of the original ESCO members dropped out of the Energy Service Network after disagreements with PSCRC and a shake-out has occurred in the energy services market in PSE&G's service area. For example, a few ESCOs have significantly downsized their marketing efforts in PSE&G's service territory and are concentrating in other areas where opportunities are perceived to be greater and they don't face a well-capitalized ESCO that is affiliated with the host utility. Other "full-service" ESCOs have adapted to PSCRC's presence in the market by consciously focusing on market segments and niches where PSCRC and its trade allies are less active. Meanwhile, PSCRC has formed alliances with several lighting service contractors and engineering/construction firms that develop projects for PSCRC to sponsor. Overall, PSCRC appears to have de-emphasized the ESN concept somewhat because it was not efficient or effective given the level of competition in the marketplace and the overlap in services offered by members with divergent roles in the ESN. This situation made it difficult for PSCRC to "manage" the market.

Looking to the future, given PSCRC's major role (and financial stake) in the program, we would argue that PSE&G continues to have some responsibility for ensuring the development of a healthy, competitive energy services industry in New Jersey. At least in PSE&G's service territory, PSCRC is not just another ESCO and shouldn't be treated as such by the regulators. Thus, we believe that a significant regulatory oversight and monitoring role is required to ensure the development of a robust and competitive energy services market and to ensure that ratepayer investments in DSM continue to be prudently managed by PSE&G. We believe that this is one of the "transaction costs" that regulators and utilities must bear if they decide that public policy is best served by allowing a utility to purchase from an affiliated company in its own service territory.

Customer Satisfaction

- We found that the group of 11 customer sponsors had very strong reactions to the program with about 65 percent stating that they were very satisfied, while the two dissatisfied customer sponsors complained about the program's complexity and problems with the M&V plans. One observed that the program involves "kindergarten engineering, but PhD paperwork."
- Among the 17 host customers surveyed that worked with ESCOs, customer satisfaction appears to be quite high (35 percent indicating that they were very satisfied) with only one dissatisfied customer. Host customers gave slightly higher ratings to their project sponsors (i.e., ESCOs), with 47 percent indicating that they were "very satisfied" with the ESCOs performance.
- Among participants in PSCRC's Bright Investment program, we found that 16 of 25 customers were "very satisfied." The one customer who indicated that he was "very dissatisfied," complained that he's "not saving money" as promised.

Lessons Learned and Transferability of the Standard Offer Concept

In our opinion, it is important to distinguish between the Standard Offer concept and the PSE&G program because the pilot has been shaped to a great extent by the policy and design choices made by PSE&G, the NJBPU, and interested parties. For example, the policy decision to allow the utility's subsidiary to participate actively in the program and the design philosophy of "making DSM look like supply" were particularly critical. Direct participation by an ESCO that was affiliated with the host utility created additional program implementation and monitoring challenges for the utility and regulator. For example, the requirement that all site-specific M&V plans be approved by non-utility parties (i.e., regulatory and ratepayer advocate staff) for many types of measures covered by the M&V protocol was due in part to concerns regarding conflict of interest. The stringent limitations on utility involvement in program marketing also proved ineffective (both because of the slow initial market response and perception that field representatives were steering customers anyway). PSE&G, to its credit, made some mid-course corrections to program marketing support.

We would suggest modifying the Standard Offer in the following areas in order to more effectively transfer the program concept to other utilities:

- The design goal of "performance-based" DSM (e.g., payments for energy savings linked to long-term performance) is laudable, but can best be achieved by recognizing the distinctive characteristics of DSM resources. Despite the fact that PSE&G is offering very attractive financial incentives to project sponsors for verified savings (about 5.5-6.0 ¢/kWh), certain program design features appear to create significant obstacles to participation in various market segments. Thus, we would place additional emphasis on developing contracts whose terms and conditions are adapted to the distinctive characteristics of DSM resources and whose length and scope are attractive to more customers.[k] This could potentially reduce transaction and marketing costs and ultimately lead to a more efficient allocation of performance and development risks among ratepayers, utility shareholders, participating customers, and project sponsors (e.g., ESCOs).
- The initial results in New Jersey suggest that the "one size fits all" approach implied by the Standard Offer is not appropriate for all customer classes. The Standard Offer concept appears to work best in commercial/industrial markets in either retrofit or planned replacement situations. At PSE&G, through December 31, 1994, no ESCO had filed project proposals in the residential sector and there has been a limited response in C/I new construction markets. We and others[5] would argue that the M&V protocols don't appear to be particularly amenable to capturing many of the technical opportunities in commercial new construction or in situations where there are very limited windows of opportunity to influence investment decisions (e.g., emergency replacement or failed equipment situations). We would recommend alternative program delivery strategies and M&V approaches for new construction and many types of "lost opportunity" situations.
- Incentive mechanisms will also affect the utility's role and interest in a Standard Offer type program. The combination of cost recovery through expensing, the opportunity to recover net lost revenues and profit through PSCRC's activities has provided strong motivation for PSE&G to pursue DSM resources. PSCRC's presence has facilitated the development of the energy services industry in New Jersey in the short-term, particularly its willingness to provide various types of financing to small, relatively new firms or customers. However, over the long term, incentive mechanisms that place the utility on both sides of the transaction (i.e., buyer and seller) necessitate additional regulatory scrutiny to minimize problems that inevitably arise from perceived or actual conflicts of interest. If other states adopt the Standard Offer concept, regulators should consider alternative shareholder incentive mechanisms (e.g., shared savings), having the program administered by an independent agency if the host utility's energy services affiliate participates directly, or establishing additional conditions that encourage market facilitation and limit market power (e.g., limit on the potential market share of the utility's energy services subsidiary).
- Other jurisdictions and utilities need not necessarily adopt the formula used in New Jersey to

[k] This would involve changes in the contract between the utility and project sponsor as well as the Energy Service Agreements between a third-party project sponsor and a customer.

establish the Standard Offer price. Payments could be set low initially to maximize contributions by participants and ratcheted up over time if necessary. Some experimentation will be required to develop a realistic assessment of the price-quantity relationship in various market sectors. Experience at PSE&G also suggests that other elements of program design (e.g., contract term and conditions, measures without acceptable M&V protocols) create their own barriers that discourage participation.

- One way to assess the relative merits of the Standard Offer concept is to compare it with alternative program designs that are often targeted at large C/I customers, such as customized rebate and DSM bidding programs (see Table 3). The Standard Offer concept combines elements of these two other approaches. In both customized rebate and Standard Offer programs, eligible customers participate on a "first come, first serve" basis, subject either to a program budget constraint or limit on resource block size, based on standard contract terms and conditions. However, in a customized rebate program, the agreement between a utility and customer is typically quite short (1-2 pages) with limited performance requirements compared to the Standard Offer. In a customized rebate program, customers typically propose one or more measures at their facility based on an audit. The utility must approve the project and customers receive a one-time incentive payment (which is often capped at a percent of project costs or a ¢/kWh limit) upon verification of installation. The Standard Offer extends incentive

Table 3. Comparison of "Typical" Programs

Feature	Customized Rebate	Standard Offer	DSM Bidding
Resource Need	Defined implicitly by program budget cap	Limit on resource block size	Resource block size range
Eligible Participants	Large customers	Large customers & third parties	Third parties & large customers
Program Selection Criteria	First-come, first-serve; some target marketing by utility field reps & vendors	"First-come, first-serve"	Utility selects winning bids, based on bid evaluation criteria; customers targeted by winning bidders
Financial Incentive	One-time, up-front rebate (paid after installation); often capped at % of project cost, or ¢/kWh, or payback criterion	Fixed payments over contract term (time-differentiated based on value of savings to utility)	Based on bidder's price
Terms & Conditions (Scope)	Standard (Limited)	Standard (Comprehensive)	Negotiated, based on sample contract (Comprehensive)
Performance Requirements	Maintain equipment to provide energy-related benefits for specified period (e.g., 5 years)	Sponsor must verify savings over contract term; penalties for non-performance	Bidder typically verifies savings; penalties for non-performance negotiated in contract
Performance Monitoring	Impact evaluation	Standardized protocol	Utility M&V guidelines; bidder M&V plan approved utility

payments over the economic lifetime of the measures with payments linked to verified savings. DSM bidding and Standard Offer programs are similar in that they have comparable performance requirements and scope of contract terms and conditions. However, in DSM bidding, financial incentives are not pre-specified and the utility screens and selects third-party providers, who, in turn, target customers as they see fit.

- For us, the major implications are as follows: (1) the utility has relatively more influence in determining preferred providers in DSM bidding compared to either the Standard Offer or customized rebate programs where customers have sole responsibility for judging the technical competence, experience, and track record of service providers; (2) both Standard Offer and DSM bidding programs effectively shift performance risk to DSM developers and away from ratepayers, but the cost premium can be significant compared to customized rebate programs (~1.0-2.5 ¢/kWh); (3) compared to DSM bidding, the Standard Offer concept is more attractive to many ESCOs and large customers because development risks are lower because potential bidders may not recover their initial up-front project development and marketing costs if their bid is not accepted by the utility; and (4) with comparable financial incentives, customized rebate programs are likely to achieve greater market penetration than the other two approaches although persistence of savings is more uncertain.
- The Standard Offer concept may be more attractive than some other DSM program designs during a transition period to a more competitive electricity industry in which utilities may not be uniquely positioned to foster increased energy efficiency. For example, the Standard Offer is quite amenable to being managed by a "public goods" agency or consortium that is empowered to acquire various types of DSM resources in pursuit of societal objectives.. Thus, one approach would be to have this consortium define standard terms and conditions for entities that wish to provide energy savings. Obviously, this assumes that there is a suitable funding mechanism and some type of consensus regarding continuation of public policy objectives that electric utilities currently perform. The Standard Offer concept is also compatible with notions of "customer choice" because it maximizes a customer's choice of service providers and theoretically places fewer constraints on their choice of acceptable end use efficient technologies.

References

1. New Jersey Administrative Code 1991. "Demand Side Management Resource Plan." State of New Jersey, 14:12. October.

2. Goldman, C.A. and M.S. Kito 1995. "Evaluation of Public Service Electric and Gas Company's Standard Offer Program." Lawrence Berkeley Laboratory. LBL-37157. June.

3. New Jersey Board of Public Utilities 1992. Docket No. #92020105. Stipulation of Settlement. October.

4. Goldman, C.A. and M.S. Kito 1994. "Review of Demand-Side Bidding Programs: Impacts, Costs, and Cost-Effectiveness." Lawrence Berkeley Laboratory. LBL-35021. May.

5. Xenergy, Inc. 1994. "Electric, Gas, and Fuel Switching DSM Potential Assessment." October.

6. Gordon, F., L. Tumidaj, G. Smith, J. Stein, and S. Coakley 1994. "Lost Opportunities Study: PSE&G's Programs and Relationship to Lost Opportunities." May.