SOCIAL COSTS AND BENEFITS OF COGENERATION SYSTEMS IN CALIFORNIA

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ABSTRACT

This paper presents the results of a study that Itron conducted for the California Public Utilities Commission (PUC) to evaluate the costs and benefits of commercial and industrial cogeneration systems receiving incentives from the Self-Generation Incentive Program (SGIP)[A]. Part of this study included evaluation of the cost-effectiveness of the program and technologies making up the program from the societal perspective. Using detailed performance data obtained through a monitoring and evaluation program, Itron compared the hourly costs and benefits of cogeneration systems installed at sites participating in the SGIP to electricity and energy purchased by the sites from conventional utility grid/boiler systems. This analysis included both hourly-based avoided costs of grid generation, hourly environmental externality differences, and reported installed capital/estimated operating and maintenance costs over the life cycle of cogeneration systems. Because the performance data was logged on a real-time basis, the effects of cogeneration systems in the SGIP could be evaluated taking into account the differences between peak and off-peak costs and benefits.

Objective: Identify all cost and benefits of cogeneration in the California market, including environmental externalities associated with air pollution

Introduction

California has long held a policy of encouraging industrial cogeneration. More recently programs, notably the Self-Generation Incentive Program (SGIP), have been implemented to encourage commercial as well as industrial cogeneration. The basis for the policy of encouraging cogeneration is that this practice was thought to increase energy efficiency as well as producing other societal benefits. These societal benefits include the following.

- Reduction in market energy prices.
- Reduction in the net production of air pollutants.
- Increased electrical reliability.
- Reduced costs for transmission and distribution.
- Voltage and frequency stabilization of the electrical grid.

Although these effects can be reasonably presumed to result from cogeneration, quantitative evidence for them, and the balance between the cost of the incentives and the resultant benefits, have not been previously studied at a programmatic level.

[A] CPUC Self-Generation Incentive Program Preliminary Cost-Effectiveness **Evaluation Report Final Report** Submitted to Southern California Edison and The Self-Generation Incentive Program Working Group. Prepared By Itron, Inc., 1104 Main Street, Suite 630 Vancouver, WA 98660, September 2005.

As part of Itron's multi-year evaluation of the SGIP, we were asked to assess the costs and benefits of the overall Program and the technologies employed within the program to develop benefit-to-cost ratios. This required detailed analysis of the output of cogeneration systems in the SGIP program compared with conventional practices—purchase of electric power and natural gas for HVAC and process heating needs. The study, completed by Itron in September of 2005, looked at the effects of the SGIP from several perspectives: Program Participants, utility Ratepayers (effects on utility customers who are not using the SGIP Program), as well as the Societal perspective. Together, these three perspectives comprise a more expansive definition of "Societal interests" as addressed in this paper. Through analysis of the detailed data, we were able to draw some original conclusions regarding the benefits of cogeneration systems operating in the SGIP from a broad social viewpoint. Although the SGIP provides incentives for photovoltaic and wind systems in addition to cogeneration systems, this paper focused solely on cogeneration and biofuel generation impacts[B].

Data Sources

As benefit-cost analysis required that the economics of cogeneration systems be evaluated over their entire life cycles, it was necessary to project costs and benefit over the estimated 20-year life of the systems. Three general sources of data were required—project-specific cost and performance data, avoided cost data, and retail cost data. The sources for each of these three data types are described below.

Project Cost and Performance Data

SGIP cogenerators are required to monitor their electrical power output and heat recovery rates. Many of the systems in the Program collect and record this data at 15 or 30-minute intervals. By collecting and reducing this data, Itron was able to obtain fairly comprehensive generation and energy use profiles for each monitored self-generation system. These time-dependent profiles could then be compared to the electrical or natural gas use profiles that that would otherwise have been associated with the host sites obtaining electricity and process heat or cooling from utilities. The fuel utilization data was also available on a detailed time-dependent basis. In addition, data was obtained through program applications and site inspections. These data include system type, system size, technology type, fuel type, eligible system installed cost, SGIP incentive magnitude, and startup date.

Models developed by Energy and Environmental Economics, Inc. (E3) were used to estimate utility avoided costs for electricity and natural gas. The electricity model estimates avoided cost for each hour of a typical year by simulating the dispatch order and operating costs of representative generation resources. The avoided costs were estimated for each hour of the year for each major investor-owned utility. Natural gas costs were estimated for each month by another E3 model.

The sampling of cogeneration systems used in this analysis was necessarily limited to those systems that had at least several months of performance data. The sampling approach was based on a 90 percent confidence level with 10 percent precision.. The metered data includes electric net generator output, fuel consumption, and useful recovered thermal energy (heat).

Table 1 presents some of the typical operational characteristics of the cogeneration systems.

[B] Although strictly speaking, "cogeneration" refers only to combined heat and electricity generation, in this paper biofuel generation is included, whether or not the waste heat is recovered.

Table 1

Technology	Abbreviation	Sample #	Total Rated Capacity MW	Average Capacity kW	Total Eligible System Cost Million 2005 $	Calculated Average Cost 2005 $/Watt
Microturbine-biofuel	MTR	6	1.374	229.0	$4.3	$3.13
Microturbine-natural gas	MTN	41	5.9702	145.6	$17.1	$2.86
IC engine--biofuel	ICR	2	1.87	935.0	$4.8	$2.56
IC engine-natural gas	ICN	90	61.385	682.1	$125.6	$2.05
Total		**139**	**70.5992**	**507.9**	**$151.8**	**$2.15**

The annualized capacity factors and heat recovery data, based on the short initial operating period for which we have data, averaged 47% and 3.3 MBtu/kWh, respectively. These low values are probably representative of the emerging nature of the technologies and the learning curves associated with debugging of new installations. Consequently, an optimistic case was also evaluated. The optimistic case was based on the three months exhibiting the best performance for each sampled system. System capacity-weighted average results are summarized in Table 2.

Table 2

Performance Criteria	Base Case	Optimistic Case
Capacity Factor	47%	54%
Heat Recovery Factor (MBtu/kWh)	3.3	3.9

In most cases heat recovered from cogeneration systems reduced fuel consumption of natural gas boilers. Estimates of natural gas savings resulting from utilization of recovered heat were calculated based on available metered heat recovery rates. In cases where metered heat recovery data were not available, the heat recovery rate was estimated using typical heat recovery rates indicated for that technology and thermal use application based on the available metered data.

Key DG system eligible initial costs and performance information is available at the site-specific level. However, this life-cycle analysis requires incorporation of additional cost and performance data from secondary sources. For example, cogeneration system prime movers require a major overhaul periodically, which represents additional costs to project owners that are generally not provided in the initial capital or warranty-period contract cost estimates. Values assumed for these types of data elements are based on in-depth interviews from the SGIP Fourth-year impacts analysis or secondary sources.

Projecting Utility Avoided Costs

Electricity Avoided Cost: When program Participants generate their own power, their utility companies avoid costs that would have otherwise been incurred to procure and deliver that electric power using existing utility system supply options. The avoided electric cost values for each electric utility vary from hour to hour during the year and are a function of many factors. Substitution of self-generation in place of conventional central station generation technologies also results in changes in air pollutant emission rates, which may have economic consequences. Avoided electric and environmental cost forecasts and associated models developed by Energy and Environmental Economics, Inc. (E^3)[C] and approved by the CPUC in D.05-04-024 are used in this assessment for both the Ratepayer and Societal Tests.

The E3 model computes avoided costs by year and hour of year for each of the three participating investor-owned SGIP electric utilities. For each hour a marginal generator type and vintage is determined based on system load factors and on the mix of generation equipment likely to be used at that time. *Off-peak hours* are typically served by more efficient, cleaner, base-loaded generation units. During system *peak hours* less efficient and more polluting units also used in order to meet the higher system demand and maintain minimum spinning generator reserves.

The E3 model includes both the energy costs and the transmission and distribution (T&D) costs for each hour for years 2006 through 2023. The T&D costs are all loaded only to the hours when the utility is at or close to its peak capacity. As such, these costs are very sensitive to the time of generation and are highly variable. T&D avoided costs are relevant for the Ratepayer and Societal but not the Participant perspectives. The E3 Model also integrates factors for line loss, system reliability, and a small adder for price effects of reduced grid demand.

The E3 model also estimates the social cost of environmental pollution, based on the assumed grid resources employed during each hour of a typical year. Carbon emissions were found to be significantly different when comparing cogeneration to the conventional alternatives. Other air emissions costs (nitrogen oxides, sulfur, and particulate) did not differ significantly and were thus not included in the analysis. These costs, in addition to the normal emission control operation costs, were estimated based on the cost of purchased emissions offsets. They are relevant from the Societal, but not the Participant or Ratepayer perspectives[D].

The avoided cost components, projected through the year 2024 are illustrated in Figure 1. Note that the costs are projected to decline, then increase slightly, but revert to essentially 2004 levels by 2024. Also note that the carbon dioxide environmental component, though small relative to the market component, increases over time.

[C] Energy and Environmental Economics, Inc., *Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs*, prepared for the California Public Utilities Commission, October 25, 2004. Available at www.ethree.com/cpuc_avoidedcosts.html.

[D] It should be noted that at present carbon emissions controls are not regulated. Nevertheless, the societal costs associated for carbon emissions are included in the analysis because it is expected that these emissions impose societal costs.

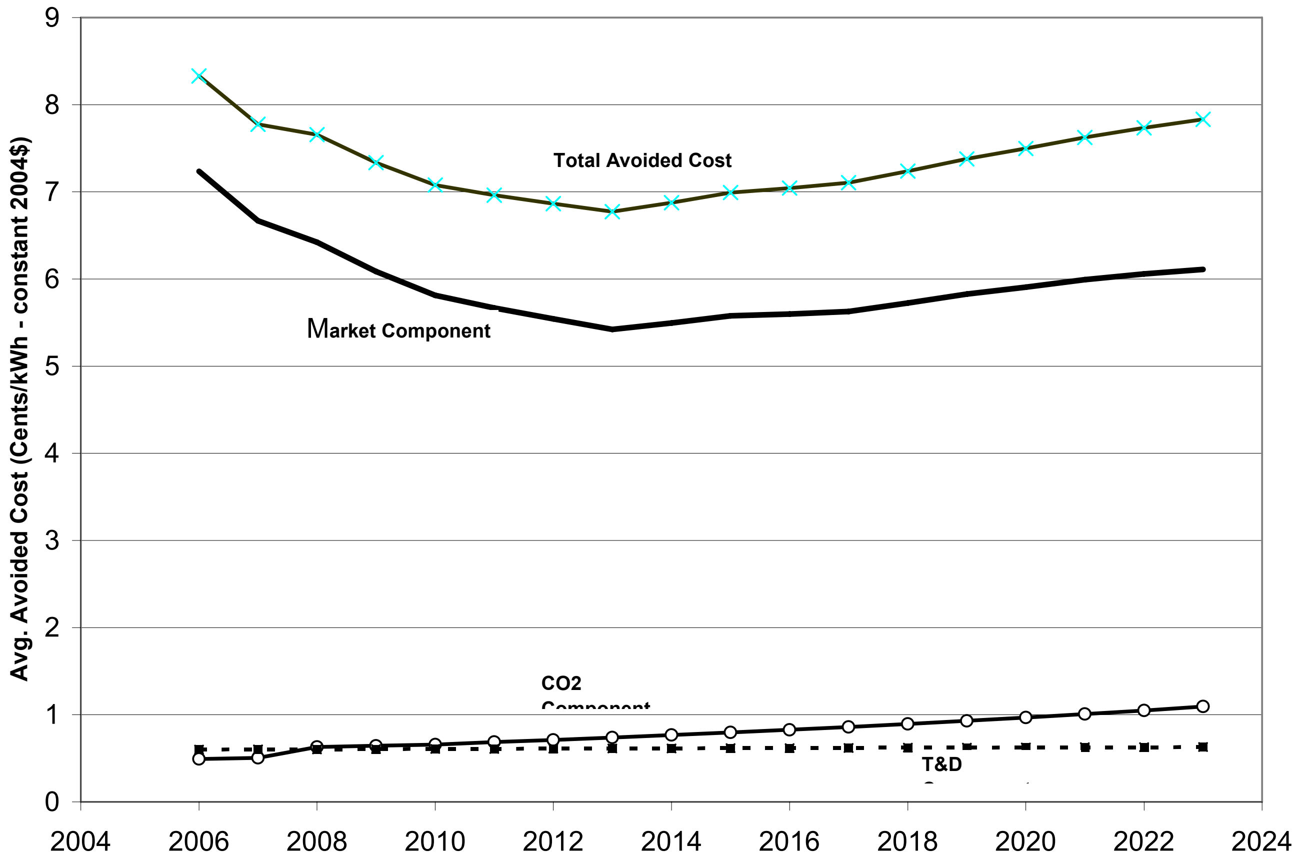

Figure 1

Gas Avoided Cost: The E3 model also projects the avoided costs for natural gas throughout much of the analysis period. These projected fuel costs are applied to the cost of utility electric generation (of which it is a major component) and to the consumer purchased fuel.

Projecting Retail Cost

Retail Electricity Cost: The revenue requirement forecasts submitted by the electric utilities to the CEC in connection with the 2005 Integrated Energy Policy Report (IEPR) proceeding were used as the basis for projecting future retail electricity prices. The revenue requirement forecasts were transformed into escalation factors that were then applied to the January 2004 rates corresponding to the current electricity tariffs. Because the utilities' revenue requirement forecasts only extend through 2016, the remaining years were assumed to have zero additional escalation in real terms.

Retail Natural Gas Cost: Except for biofuel generators, variable cogeneration costs are largely driven by the cost of purchased natural gas fuel. From the Participant perspective the cost of this fuel is somewhat offset by their reduced purchases of process heating fuel by recovered waste heat. Because cogenerators arrange for their own commodity purchase of natural gas, only the gas T&D component is paid to the utility. The projected commodity gas is assumed to be the same as that used in the E3 avoided cost modeling. The T&D component was assumed to remain flat in real terms.

Figure 2 illustrates the projected trends of retail electricity and natural gas prices though 2024, in real (constant 2004) dollars. Note that retail rates are generally expected to decline in real terms, with the exception of a near turn increase in SCE electricity rates. Natural gas rates are projected to decline fairly sharply relative to the present and also in relation to the electricity prices. As we note in the performance section, this has a dramatic effect on system economic performance, especially from the Participant Perspective.

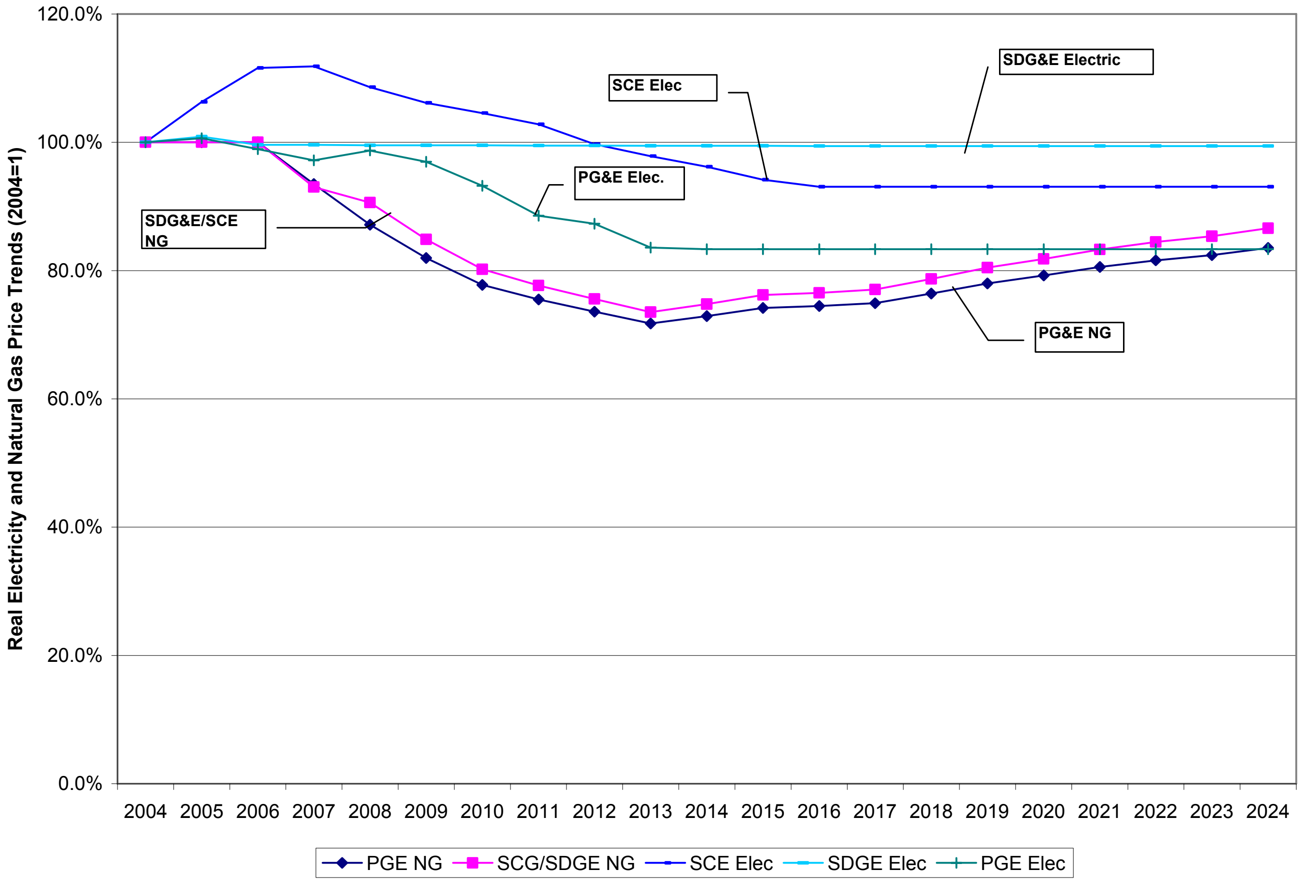

Figure 2

Other Benefits Considered

Other Possible economic impacts relevant to the Societal and Ratepayer perspectives include national security impacts, and power quality impacts of distributed generation. In addition, on-site generation adds a reliability value for Participants that are able to run their cogeneration systems under blackout conditions. None of these potential values were included in the Cost-Effectiveness analysis.

Other Modeling Assumptions

Other influential assumptions are embedded in many of the data elements identified above. Other assumptions having a direct bearing on the cost-effectiveness evaluation results include those related to such factors as inflation rates, debt service (loan) interest rates, private and social discount rates, and treatment of tax rates, credits and depreciation.

The assumption regarding general inflation rates, cost escalation rates, social and private discount rates and loan rates are all assumed to be interrelated. An inflation rate equal to 2% is assumed. Assuming this inflation and a real social discount rate of 3% yields a nominal social discount rate of 5.1%.[E] The real discount rate applicable to the other three perspectives is assumed to be 6% in real terms. Discount rates are assumed to be 8.1 % from the Participant and Ratepayer perspectives and 5.1% from the Societal Perspective.

Economic Performance of SGIP Cogeneration Systems

In this section the basis for calculating the costs and benefits and the results of the modeling are discussed for each of the three perspectives. The *Base Case* and *Optimistic Case* results are presented for all perspectives. The Base Case results reflect the economic performance using the projection methods discussed above, together with the actual observed system performance with respect to operating conditions and capacity factors. The Optimistic Case results reflect performance assuming that the systems are able to regularly achieve capacity factors observed for the best three months of the first year of operation and are the operating conditions more representative of fully operational systems.

Participant Perspective

The incentive payments received from the SGIP Program by the Participants provide the incentive for heat and power users to adopt the emerging small-scale cogeneration technologies. Increased risk and uncertainty associated with "getting into the power business" versus focusing on their primary product is a factor that is not included in the cost-benefit modeling. Also excluded in the modeling are the benefits associated with reduced loss of load probability for cogenerators whose systems have cold-start capabilities. For food processors, data processors and certain assembly line applications these values can be quite significant.

Benefit-Cost Framework

The benefits included in the framework for the Participant Test are listed below.

- Lower cost of electricity.
- Combined heat and power.
- Other incentives.
- Tax credits and other tax effects.
- Depreciation benefits.

To recognize variations in participant benefits across technologies, the analysis is conducted at the technology level, and then aggregated to the program level. That is, program-level participant benefits and cost can be expressed as:[F]

$$ParticipantBenefits = \sum_{i=1}^{N} \mathrm{Re}\, dElecBills_i + ValDispFuels_i + Inc_i + IncO_i + TC_i$$

where Inc_i represents SGIP incentives, $IncO_i$ reflects other incentives, and TC_i indicates tax credits and depreciation benefits. Reductions in electric bills are computed as the sum of reductions in energy

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E The nominal discount rate is calculated as (1+inflation rate) x (1+real discount rate) – 1.

F Note here that the Participant Test is based on gross, rather than net, benefits and costs. This is consistent with the SPM, which indicates that "Load impacts form Participants should be based on gross, whereas for all other tests the use of net is appropriate." (p. 27) charges (*RedEnChg*) and reductions in demand charges (*RedDemChg*). These reductions take into account the specific treatments of net metering under the SGIP, which differ across DG technologies. Note that these reductions are net of any possible charges associated with the use of DG (e.g., non-bypassable charges for cogeneration systems).

Participant Costs include the following elements for the DG system.

- Gross Equipment Costs.
- O&M Costs including Fuel Costs.
- Participant Environmental Costs.

The participant costs can be expressed as:

$$ParticipantCosts = \sum_{i=1}^{N} (InstCost_i + O\&MCosts_i)$$

where $InstCost_i$ is the gross installed cost of equipment and offsets and $O\&MCosts_i$ reflects O&M costs. Installed costs are assumed to be incurred in the first period, and incentives are assumed to be paid in that period as well.

Participant Test Results

The results of the modeling are presented in Table 3. The results are expressed as the NPV per kW of installed capacity, summed over the projected 20-year life-cycle of the systems (constant 2005 $). Not surprisingly the benefit elements are dominated by reduced electricity purchase costs. Much smaller benefits are calculated for tax benefits and reduced heating fuel purchases. Of the cost elements fuel purchase costs of operating the cogeneration systems dominate for natural gas powered systems (ICN and MTN). System purchase costs dominate the biogas system cost categories and are roughly one-third of the fuel costs of the natural gas-fueled systems.

For the Base Case net benefits (total benefits less total costs) are quite positive for all but the nonrenewable microturbine (MTN) systems. These systems show a NPV loss of over $1,100 per installed kW in the Base Case and their costs are dominated by natural gas fuel purchases. The high benefit-cost ratios for the renewable-fueled systems (MTR and ICR) are due, in large measure, to the fuel cost savings achieved by utilizing no-cost fuels.

Under the Optimistic Case performance assumptions, the NPV for these MTN systems becomes slightly positive. The economic performance of the other types of cogeneration systems becomes more robustly beneficial from the Participants' perspective. The relatively poor economic performance of the natural gas fired cogeneration systems should be understood in light of the high natural gas versus electricity price trends previously discussed. Coupled with the relatively lower electrical conversion efficiencies of MTN systems, these high fuel costs swamp the electricity cost savings that would result from historically normal natural gas-to-electricity price spreads.

Table 3

Benefit Elements-Base Case	$/kW Rebated Basis			
	ICN	MTN	ICR	MTR
Avoided Electricity Costs	$3,303	$3,464	$2,879	$2,473
Tax Credits	$0	$0	$0	$0
Tax Deductions	$503	$676	$661	$751
Avoided Fuel Costs	$454	$699	$620	$170
Salvage	$0	$0	$0	$0
Total Benefit	**$4,260**	**$4,839**	**$4,160**	**$3,394**
Cost Element-Base Case				
System costs	$1,095	$1,475	$1,450	$1,526
Maintenance Costs - Annual	$559	$831	$504	$578
Maintenance Costs - Periodic	$0	$545	$0	$642
Nonbypassable Charges	$215	$174	$136	$129
DG Fuel Costs	$2,065	$2,953	$0	$0
Total Cost	**$3,933**	**$5,978**	**$2,090**	**$2,874**
Net Benefit-Base Case	**$327**	**-$1,139**	**$2,070**	**$520**
Benefit/Cost Ratio	**108%**	**81%**	**199%**	**118%**
Benefit Elements-Optimistic Case	**ICN**	**MTN**	**ICR**	**MTR**
Avoided Electricity Costs	$3,555	$3,653	$3,113	$2,626
Tax Credits	$0	$0	$0	$0
Tax Deductions	$503	$676	$661	$751
Avoided Fuel Costs	$731	$1,109	$1,025	$287
Salvage	$0	$0	$0	$0
Total Benefit	**$4,789**	**$5,438**	**$4,798**	**$3,664**
Cost Elements-Optimistic Case				
System costs	$1,189	$1,602	$1,575	$1,657
Maintenance Costs - Annual	$297	$201	$274	$143
Maintenance Costs - Periodic	$0	$273	$0	$321
Nonbypassable Charges	$228	$183	$147	$138
DG Fuel Costs	$2,194	$3,075	$0	$0
Total Cost	**$3,908**	**$5,333**	**$1,996**	**$2,259**
Net Benefit-Optimistic Case	**$881**	**$105**	**$2,802**	**$1,405**
Benefit/Cost Ratio	**1.23**	**1.02**	**2.40**	**1.62**

Ratepayer Perspective Benefits and Costs

The Ratepayer perspective evaluates the SGIP costs and benefit from the standpoint of utility ratepayers in utilities that participate in the SGIP Program who do not directly participate in the Program. As might be expected, this perspective differs markedly from that of the Participants. Because both gas and electricity utilities participate in the SGIP, their ratepayers' costs and benefits need to be tallied separately.

Benefit-Cost Framework

Benefits to electric utility Ratepayers include the following.

- Avoided generation costs.
- Avoided transmission and distribution capital costs.
- Reliability net benefits.
- Reduced line losses.
- Price effects.

The overall benefits accruing to electric ratepayers include the reductions in system costs associated with the replacement of conventional generation with DG. As with the other tests discussed above, electric ratepayer benefits are derived at the technology level, and then aggregated to the program level. That is:

$$(1)\ \ ElecRatePBen = \sum_{i=1}^{N} NTG_i \times AvNPEleCosts_i$$

where NTG_i is the net-to-gross ratio associated with technology i and $AvNPEleCosts_i$ is gross avoided costs from the electric ratepayer perspective. Note that the net-to-gross ratio is required by the SPM for use in ratepayer tests.

Costs to electric utility customers include the following.

- SGIP Program costs.
- Decreased revenue from sale of electricity to participants.

Benefits to gas utility ratepayers include the following.

- Increased revenue from transportation of fuel for gas-fired SGIP systems.
- Decreased costs for transportation of fuel for boilers.

From the perspective of gas customers, benefits (call these *GasNPBenefits*) consist of avoided fuel transportation costs associated with the use of waste heat by CHP projects (*WasteHeatBenefits*), plus increased revenues from the transportation of natural gas for gas-fired DG (*IncrGasRev*). These benefits are computed at the technology level and then summed to the program level, as given by:

$$GasNPBenefits = \sum_{i=1}^{N} NTG_i \times (WasteHeatBenefits_i + IncrGas\mathrm{Re}v_i)$$

Cost components applicable to electric utility ratepayers include the following.

- Incentives paid to cogenerators.
- Administrative costs due to the SGIP Program.
- Costs for interconnection not paid for by Program participants.

The electricity ratepayer costs can be represented as:

$$ElecRatePCosts = \sum (NTG_i\ \mathrm{Re}\,dElecBills_i + IntCosts_i + IncCostE_i) + Ad\min CostE$$

where $IncCostE_i$ indicates electric incentives provided to technology I, *AdminCostE* depicts admin costs funded by electric ratepayers, and $IntCosts_i$ includes any utility interconnection costs not paid for by participants.

Costs components applicable to gas utility ratepayers include the following.

- SGIP Program costs.
- Decreased revenue from transportation of fuel for boilers.
- Increased utility costs for transportation of fuel for gas-fired SGIP systems.

The gas ratepayer costs can be expressed as:

$$GasRatePCosts = \sum_{i=1}^{N} (NTG_i ValDispFuels_i + IncCostG_i) + Ad\min CostG$$

where $IncCostG_i$ and *AdminCostG* are the costs of SGIP incentives and Program costs funded by gas ratepayers.

Ratepayer Results

From the perspectives of both the electricity and the gas utility ratepayer not in the Program, the benefit/cost ratios are less than 1.0. None of the technologies appears to offer net benefits to either ratepayer group. Using the Optimistic Case assumptions does not change this picture; in fact the net benefits are even lower from the Ratepayer perspective as the increased capacity factor assumption with the increasing disparity between natural gas prices and electricity prices drives up the ratepayer costs.

Electricity Ratepayer Results

Table 4 displays the results from the electric Ratepayer perspective, again in terms of the life-cycle NPV on a per installed kW basis. The benefits from avoided having to provide electricity to cogenerators is more than is more than offset by the lost revenues the cogenerators would have paid. The avoided T&D costs are roughly offset by the cost of incentives and administering the program. The net result is that each kW of installed capacity cost electric ratepayers in excess of $2,000 per installed kW over the life of the systems.

Table 4

Base Case Electric Ratepayer Benefits	ICN	MTN	ICR	MTR
Avoided Electricity Costs	$3,403	$3,545	$1,507	$1,800
Avoided T&D Costs	$335	$304	$165	$156
Total (Excl. T&D)	$3,403	$3,545	$1,507	$1,800
Total (Incl. T&D)	$3,739	$3,849	$1,672	$1,955
Base Case Electric Ratepayer Costs				
Reduced Electricity Revenues	$5,441	$5,705	$4,742	$4,072
Incentives	$304	$417	$605	$825
Program Administration	$25	$27	$45	$43
Total	**$5,770**	**$6,148**	**$5,392**	**$4,941**
Net Benefit (Incl. T&D)	**-$2,031**	**-$2,299**	**-$3,720**	**-$2,985**
Benefit/Cost Ratio	**0.59**	**0.58**	**0.28**	**0.36**
Optimistic Case Electric Ratepayer Benefits	**ICN**	**MTN**	**ICR**	**MTR**
Avoided Electricity Costs	$3,659	$3,731	$1,598	$1,889
Avoided T&D Costs	$356	$319	$170	$164
Total (Excl. T&D)	$3,659	$3,731	$1,598	$1,889
Total (Incl. T&D)	$4,015	$4,050	$1,768	$2,052
Optimistic Case Electric Ratepayer Costs				
Reduced Electricity Revenues	$5,855	$6,016	$5,127	$4,325
Incentives	$304	$417	$605	$825
Program Administration	$25	$27	$45	$43
Total	**$6,184**	**$6,459**	**$5,777**	**$5,194**
Net Benefit (Incl. T&D)	**-$2,169**	**-$2,409**	**-$4,009**	**-$3,141**
Benefit/Cost Ratio	**0.65**	**0.63**	**0.31**	**0.40**

Gas Ratepayer Results

As seen from Table 5, natural gas ratepayers see negative net benefits from the Program as well. For natural gas-fuel technologies, the cost of supplying the incremental gas to cogenerators is greater than the increased revenues. In addition we include the cost for incentive payments and Program administration borne by the gas utilities. The net result is negative net benefits to gas utilities of nearly $500 per install kW of ICN and more than $700 per kW for MTN. Biofuel systems impose far lower, but still slightly negative net benefits for gas ratepayers.

The Optimistic Case results are slightly better for gas ratepayers. The more efficient conversion rate for the systems result in less net gas consumption and thus lower net subsidies for gas deliveries to project owners for all technologies.

Table 5

Base Case Gas Ratepayer Benefits	ICN	MTN	ICR	MTR
Increased Gas Delivery Revenues - DG	$208.50	$269.52	$0.00	$0.00
Avoided Gas Delivery Costs - Displaced	$114.03	$190.59	$162.28	$46.69
Total	**$322.52**	**$460.11**	**$162.28**	**$46.69**
Base Case Gas Ratepayer Costs				
Increased Gas Delivery Costs - DG	$504.33	$798.19	$0.00	$0.00
Decreased Gas Delivery Revenue - Displaced	$44.40	$63.23	$58.55	$15.89
Incentives	$252.40	$287.23	$51.15	$84.60
Program Administration	$22.49	$21.15	$2.53	$4.46
Total	**$823.62**	**$1,169.81**	**$112.22**	**$104.95**
Net Benefit (Incl. T&D)	**($501.10)**	**($709.71)**	**$50.05**	**($58.26)**
Benefit/Cost Ratio	**0.39**	**0.39**	**1.45**	**0.44**
"Optimistic" Case Gas Ratepayer Benefits	**ICN**	**MTN**	**ICR**	**MTR**
Increased Gas Delivery Revenues - DG	$220.90	$282.48	$0.00	$0.00
Avoided Gas Delivery Costs - Displaced	$184.10	$300.24	$265.21	$78.19
Total	$405.00	$582.72	$265.21	$78.19
Optimistic Case Gas Ratepayer Costs				
Increased Gas Delivery Costs - DG	$535.02	$825.20	$0.00	$0.00
Decreased Gas Delivery Revenue - Displaced	$71.23	$100.96	$96.84	$27.07
Incentives	$252.40	$287.23	$51.15	$84.60
Program Administration	$22.49	$21.15	$2.53	$4.46
Total	**$881.15**	**$1,234.54**	**$150.52**	**$116.12**
Net Benefit (Incl. T&D)	**($476.14)**	**($651.82)**	**$114.69**	**($37.94)**
Benefit/Cost Ratio	**0.46**	**0.47**	**1.76**	**0.67**

Societal Perspective Benefits and Costs

The societal test evaluates the costs and benefits of the SGIP from the perspective of all members of society. A distinguishing characteristic of the societal test is its inclusion of economic impacts of air pollutant emissions that are not tied directly to the delivery or purchase of energy.[G] Environmental externalities covered by this analysis include oxides of nitrogen (NOx) and carbon dioxide (CO_2). The societal test also includes consideration of adders for reliability, marginal transmission and distribution effects and other social externalities.

Benefit-Cost Framework

The benefits included in the societal test are listed below:

- Avoided generation costs,
- Avoided transmission and distribution capital,
- Reliability net benefits,
- Reduced line losses,

[G] The Societal Test is a variant of the Total Resource Cost (TRC) Test. It is more comprehensive than the TRC Test.

- External environmental benefits,
- Price effects, and
- Waste heat use benefits of combined heat and power applications.

External environmental benefits refer to reductions in pollution-related costs that are excluded from transactions between utility companies and utility customers.[H] Operation of SGIP systems results in decreased use of conventional fuels and energy technologies to deliver heating, cooling, and electric end-use[I] energy services. These energy services, the conventional fuels and technologies, and resulting external environmental costs are depicted graphically in Figure 3. Avoidance of these external environmental costs attributable to operation of SGIP systems represents an economic benefit from the perspective of society.

As represented in Figure 3, both cogeneration and grid electricity production result in air emissions. Combustion in boilers also produces emissions. If the external cost from cogeneration systems are lower than costs from the combination of foregone emissions from the grid and boilers replaced by cogeneration, positive net benefits accrue to society.

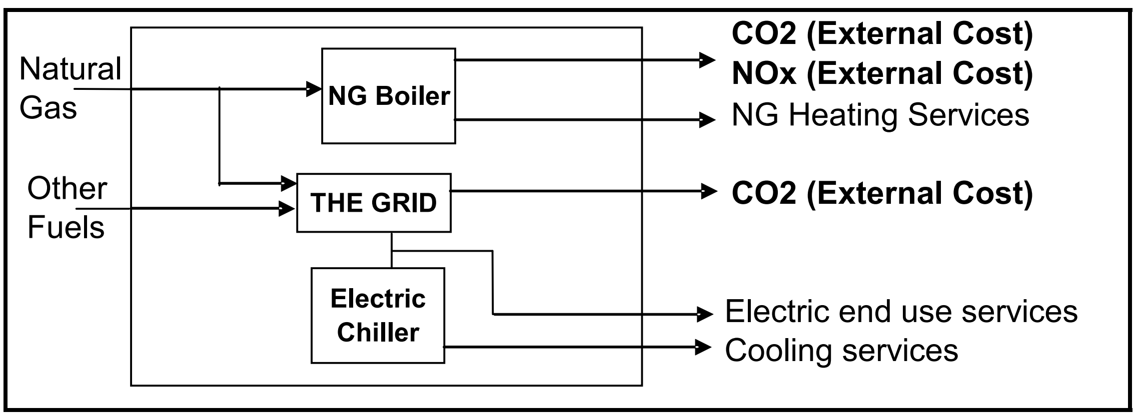

Figure 3

The external costs included in the modeling include the costs of pollution from carbon and NOx emissions. PM10 and SOx emissions from natural gas-fired systems are fairly low and are considered negligible. The assumed emission rates for cogeneration systems are shown in Table 6. The emission rates for grid generation are estimated within the E3 model by utility area for each hour of a typical year. The social cost is also estimated in the E3 model for each year. These costs are based on the estimated cost to purchase offsets.

Table 6

Pollutant	Unit-Electricity Emission Rate (Pound/MWh)		Unit-Weight Value	Unit-Electricity Value ($/MWh)	
	MT	ICE	($/lb)	MT	ICE
NO_x	0.5	3	3.500	1.75	10.5
CO_2	1600	1300	0.004	6.4	5.2

[H] External costs stand in contrast to internal environmental costs that are accounted for in costs incurred by conventional generators and prices paid for grid-supplied power. Internal environmental costs are included in the market component of E^3's avoided electric cost model, as described in Section 3.

[I] Including electric resistance heating.

Other benefits counted within the Societal Framework include the price effects from reduced electrical demand, reduced line losses and avoided need to expend capital on T&D expansion.

The cost components in the societal test are listed below:

- External environmental costs from cogeneration system operations (see discussion above),
- System purchase, operation, and maintenance, and
- SGIP Program costs.

The societal cost components can be expressed as:

$$SocietalCosts = \sum_{i=1}^{N} NTG_i \times (InstCost_i + OMCost_i + EnvCost_i) + AdminCost_i$$

Note that neither lost revenues to utilities nor reduced cost of purchased electricity by cogenerators is included in the Societal Perspective. Incentive costs and tax benefits are likewise excluded. These are considered to be transfers and thus neutral from a Societal perspective.

Societal Results

The results from the Societal perspective are shown in Table7. Only ICR systems appear to offer net benefits from the Societal Perspective. For Base Case MTN systems, the cost of gas purchased for cogeneration exceeds the avoided electricity generation benefit. For ICN systems fuel versus avoided electricity cost is net positive, but adding in the maintenance cost reverses the operating cost advantage. For MTN, the high maintenance costs results in greatly higher cost of cogeneration versus grid generation. When the added capital costs for the cogeneration systems plus Program administrative costs are added in, the net Societal benefits become overwhelmingly negative. The positive contribution from reduced T&D costs and net environmental externality costs are not large enough to overcome these costs.

ICR systems do offer positive net benefits. Despite their high purchase and maintenance costs, their lack of fuel cost and absence of offsetting environmental externality costs, these systems offer positive net benefits from the Societal perspective.

In all cases the environmental benefits exceed their environmental costs. The cost of additional pollution from cogeneration operations is more than offset by the reduced pollution costs from avoided grid generation plus avoided boiler operation.

Table 7

Benefit Elements-Base Case	**ICN**	**MTN**	**ICR**	**MTR**
Avoided Electricity Costs	$4,382.3	$4,565.8	$1,941.0	$2,317.8
Avoided T&D Costs	$437.5	$395.0	$213.1	$202.7
Avoided CO2 Costs	$460.9	$482.7	$202.4	$248.9
Waste Heat Benefits NOx	$5.0	$7.2	$3.5	$1.7
Waste Heat Benefits CO2	$99.4	$142.8	$69.8	$33.8
Avoided Fuel Costs	$953.9	$1,469.9	$1,303.5	$358.4
Salvage	$0.0	$0.0	$0.0	$0.0
Total (Excl. T&D)	**$5,901.5**	**$6,668.4**	**$3,520.3**	**$2,960.6**
Total (Incl. T&D)	**$6,339.0**	**$7,063.4**	**$3,733.4**	**$3,163.3**
Cost Element-Base Case				
System costs	$1,930.8	$2,553.9	$2,461.5	$3,008.4
Maintenance Costs - Annual	$1,193.3	$1,775.7	$1,077.6	$1,234.4
Maintenance Costs - Periodic	$0.0	$1,132.8	$0.0	$1,334.3
DG NOx Costs	$0.5	$0.1	$0.0	$0.0
DG CO2 Costs	$388.5	$557.8	$0.0	$0.0
DG Fuel Costs	$4,343.1	$6,208.6	$0.0	$0.0
Program Administration	$47.8	$47.8	$47.8	$47.8
Total	**$7,904.0**	**$12,276.6**	**$3,586.9**	**$5,624.9**
Net Benefit (Incl. T&D)	**($1,565.0)**	**($5,213.2)**	**$146.6**	**($2,461.6)**
Net Environmental Benefit	$176.28	$74.85	$275.77	$284.37
Benefit/Cost Ratio	**0.80**	**0.58**	**1.04**	**0.56**
Benefit Elements-Optimistic Case	**ICN**	**MTN**	**ICR**	**MTR**
Avoided Electricity Costs	$4,711.9	$4,805.1	$2,057.7	$2,432.6
Avoided T&D Costs	$464.1	$414.4	$220.6	$213.5
Avoided CO2 Costs	$496.4	$508.4	$215.0	$261.4
Waste Heat Benefits NOx	$8.1	$11.5	$5.7	$2.8
Waste Heat Benefits CO2	$160.0	$226.8	$113.0	$54.4
Avoided Fuel Costs	$1,537.8	$2,332.6	$2,154.4	$603.0
Salvage	$0.0	$0.0	$0.0	$0.0
Total (Excl. T&D)	**$6,914.2**	**$7,884.4**	**$4,545.8**	**$3,354.2**
Total (Incl. T&D)	**$7,378.2**	**$8,298.8**	**$4,766.4**	**$3,567.7**
Cost Elements-Optimistic Case				
System costs	$2,011.2	$2,660.4	$2,564.1	$3,133.8
Maintenance Costs - Annual	$633.8	$428.8	$584.7	$305.0
Maintenance Costs - Periodic	$0.0	$566.4	$0.0	$667.2
DG NOx Costs	$0.6	$0.1	$0.0	$0.0
DG CO2 Costs	$413.0	$584.6	$0.0	$0.0
DG Fuel Costs	$4,614.5	$6,466.4	$0.0	$0.0
Program Administration	$47.8	$47.8	$47.8	$47.8
Total	**$7,720.8**	**$10,754.4**	**$3,196.5**	**$4,153.7**
Net Benefit (Incl. T&D)	**($342.6)**	**($2,455.6)**	**$1,569.8**	**($586.0)**
Net Environmental Benefit	$250.93	$161.94	$333.67	$318.59
Benefit/Cost Ratio	**0.96**	**0.77**	**1.49**	**0.86**

Under the Optimistic Case assumptions, all of the technologies improve from a Societal net benefit perspective. Costs are slightly lower and benefits are considerably higher under this case. However, the

ICR systems remain the only technology to offer positive net Societal benefits of $334/kW. MTR and ICN systems come fairly close to offering positive net benefits, with benefit-cost ratios of 0.86 and 0.96, respectively.

Summary of Benefit-Cost Economic Results

Table 8 summarizes the calculated benefit/cost ratios for all four cogeneration technology-fuel types and from all three perspectives. The top half of the table shows the results under the Base Case assumptions. The bottom half of the table provides results under the Optimistic assumptions.

Table 8

Base Case				
Technology	**Society**	**Gas Ratepayer**	**Electric Ratepayer**	**Participant**
Microturbine-biofuel	0.56	0.44	0.36	1.18
Microturbine---natural gas	0.80	0.39	0.58	0.81
IC engine--biofuel	1.04	1.45	0.28	1.99
IC engine-natural gas	0.58	0.39	0.59	1.08
Capacity Wtd.Avg,	**0.61**	**0.42**	**0.58**	**1.08**
Optimistic Case				
Technology	**Society**	**Gas Ratepayer**	**Electric Ratepayer**	**Participant**
Microturbine-biofuel	0.86	0.67	0.40	1.62
Microturbine---natural gas	0.96	0.47	0.63	1.02
IC engine--biofuel	1.49	1.76	0.31	2.40
IC engine-natural gas	0.77	0.46	0.65	1.23
Total (Wtd. Avg.)	**0.81**	**0.50**	**0.63**	**1.25**

From Table 8, based on a strictly economic criterion, the portfolio of modeled systems is cost effective from the Participants' perspective, under both the Base Case and the Optimistic Case scenarios. When considered from the Societal perspective, the portfolio of SGIP systems is not cost-effective under either the Base Case or the Optimistic Case scenarios. Only bio-fueled IC engines are cost-effective from the Societal perspective. In addition, based on the quantified benefits to the utilities, neither gas nor electricity ratepayers who are not participating in the program appear to benefit from it.

Are Cogeneration Systems Beneficial to Society?

The model results presented in Table 8 offer a detailed and quantitative look at the benefits and costs of SGIP cogeneration systems. However, despite their quantitative precision, these quantitative assessments offer only a limited viewpoint on the benefits of the cogeneration systems and the SGIP Program.

A critical policy question to with regard to promoting cogeneration systems is whether or not they are beneficial to society as a whole. The results presented in the previous section go only part of the way in answering this question. Other critical quantitative and qualitative factors still need to be addressed before a conclusion can be reached.

Some of these quantitative questions include the following.

- How representative are the systems in the sample?
- How representative was the observation period?
- How valid and robust are the modeling assumptions?
- How might omitted variable have influence the quantitative result?

Some qualitative questions are as follows.

- Which components have been omitted from the analysis?
- How might technological change affect the net benefits of cogeneration systems?

These remaining quantitative and qualitative questions are addressed below.

Remaining Quantitative Questions

Representiveness of the Sample/Sampling Period

The sample of systems from which these results were drawn reflects only a minority of cogeneration systems in California. While the collected data represents the most comprehensive set of real-time performance data obtained to date on a program the size of the SGIP, the data collection period was less than two years in all cases and less than one year in the large majority of cases. The collected data thus includes system performance during the start-up and debugging period. In interviews conducted by Itron in connection with the Fourth Year Impacts Evaluation, a large majority of cogeneration operators noted that they expected either some or considerable improvement in system performance and/or capacity factor once the initial operating problems were resolved.

Further complicating interpretation of results are the economic conditions prevailing during the sample period. The 2004 performance monitoring took place during a period of extraordinarily high natural gas prices. In some cases these high fuel prices resulted in voluntary reduction in cogeneration operations because the spread between the gas and electricity prices was far higher that that projected by the modeling. Reduction in operating hours resulted in lower than normal capacity factors for these impacted systems, which imposed a pessimistic bias to the results – unless gas prices continue to remain at their historic high levels into the future. The Optimistic Case assumptions, using only the three highest capacity factor months is only a partial correction for this influence. This Case, rather than the Base Case is arguably a better basis on which to evaluate the social benefits of cogeneration.

Robustness of Modeling Assumptions and Projections

Assumptions regarding system performance, future price trends and economic variables are important drivers in the modeling results. Most of these factors have wide uncertainty ranges. The performance sampling variables discussed above are layered on top of the difficulty of projecting the performance of these installed cogeneration systems over a 20-year period. It is however very likely that most of these technologies will further mature in these smaller applications and performance will improve over time.

Projecting energy prices over a 20-year period is obviously a major uncertainty factor. The volatility of natural gas prices in the past five years (and even the past two years) is an indication of the degree of forecast difficulty. As noted above, the projected relative retail price trends of electricity and natural gas bias the economic results against natural gas-fueled cogeneration. If electricity prices are higher than project, the economic viability of cogeneration would improve. Conversely, higher gas prices, such as those we are currently experience will greatly reduce the viability of all but he most favorable cogeneration system applications.

Economic variables such as inflation and discount rates are also a source of uncertainty. If inflation proves to be higher than the 2 percent per year rate assumed, the economic viability of the system already in place will look better from both the Participant and Societal perspectives.

Influence of Omitted Variables

In general, it is easier to quantify costs than benefits, especially benefits that accrue broadly to society but are not easily assigned a price. The omitted variables discussed further below fall entirely into the social benefit category. Their omission might impart a negative bias to the quantification of the social benefits.

Remaining Qualitative Questions

In addition to the quantitative limitations and uncertainties discussed above, the effects of qualitative factors also influence evaluation of the societal benefits of cogeneration. A few of these issues are discussed briefly below.

Demonstration Effects and Technical Maturity

The "demonstration benefits" from fielding these energy technologies were not included in the quantitative modeling. These benefits are important but very difficult to quantify. There are peer effects from having these systems in place so others can see and emulate them. Market development and technical maturation benefits are similarly important but again difficult to quantify. As more emerging technology systems such as the microturbine and fuel cells are placed into operation markets begin to develop and infrastructure for support improves. Vendor and manufacturers improve their products and will eventually lower their unit prices. Qualified installers and knowledgeable sales forces expand. The experience of e utility Program Administrators and other utility personnel involved with interconnection and ongoing operation improves with hands-on experience with these cogeneration systems.

The real-world experience gained from pioneering cogeneration application helps to identify the applications that are more or less favorable. For example, as more cogeneration systems are installed due to the SGIP it has become apparent applications where waste heat can be used to supplant electric chiller are very advantageous. Similarly, it has become more apparent that microturbines experience higher operating and maintenance cost if they are used in load-following or diurnal cycling applications.

All of these factors would work toward creating a more robust cogeneration industry. Their omission might well impart a negative bias to the overall estimates of true "societal benefits".

Other social benefits not quantified include the benefits to energy security, local grid stability support resulting from distributed generation and a price effects beyond 2008. From the Participant perspective, the omission of power reliability benefits may also impart a negative bias.

Focusing on biofuel systems, one important omitted variable is the disposition of the gas in the absence of the microturbine or IC-engine generation systems. If the biofuel gases are otherwise directly emitted into the atmosphere the pollution externalities would be much higher than those included in the analysis. If they are collected and flared, there are combustion-related air emissions that were not included in the analysis. If quantified these effects could greatly increase the reported societal benefits from these biofuel systems.

Societal Benefit Conclusions

The uncertainty and omitted factors discussed above tend to suggest that the qualitative analysis systematically underestimates benefits, especially societal benefits of cogeneration. If this is accepted, then the quantitative benefit cost evaluation should weight the Optimistic Case more heavily. Based on the Optimistic Case results, natural gas-fueled ICN are nearly beneficial while microturbine systems do not appear beneficial. Biofuel MTR systems are clearly beneficial. Biofuel MTR systems would only be considered beneficial if the omitted variable of reduced emissions in the absence of these systems were quantified. This suggests a fruitful topic for further research.

From the Participant perspective, the systems are all beneficial under the Optimistic Case, but microturbines are somewhat questionable, especially under the Base Case. The reasons for low performance for microturbines are not well understood, and may constitute an area of further study.

From the Ratepayer perspective, the SGIP as currently formulated and with cogeneration systems operating as observed (and with the disparity in natural gas and electricity prices), the program provides a low benefit to cost ratio. Adding in local benefits from grid support (not presently estimated in the model) would add to the benefits from this perspective, but it is unlikely to change the overall result. However, significant increases in the number of cogeneration systems, along with increased cogeneration efficiencies could possibly impact the overall B/C ratios.

The quantitative uncertainties imposed by the small sample of sites monitored for useful recovered heat and the short observation period can be reduced with further data collection. This ongoing data collection process is already in place as part of the SGIP Program measurement and evaluation effort. More thermal and electric output data will improve our ability to evaluate the benefits and cost of this initial group of cogeneration facilities funded by the SGIP.

It should be recognized that the cost effectiveness results in this study are based on SGIP-specific projects and incentive structures. As such, the results may not be reflective of the performance or costs of DG technologies employed in other settings. Similarly, care should be taken in trying to gauge the performance or cost effectiveness of DG technologies in general from these results. Moreover, it is important to recognize that the current results represent only a snapshot in time. Given the substantive changes likely to occur with future SGIP systems (e.g., increased efficiency of microturbines, better air pollution control for IC engines, etc.) the level of program cost-effectiveness may change significantly.