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Ernest Orlando Lawrence Berkeley National Laboratory

The Effects of Electricity Tariff Structure on Distributed Generation Adoption in New York State

Prepared for the
Distributed Energy Program

Principal Authors
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Environmental Energy
Technologies Division
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Disclaimer

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Preface

New ideas must not only prove their merit but also make a place for themselves within traditional systems. Distributed generation has become a player within the centralized power paradigm.

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Acronyms and Abbreviations

CPUC	California Public Utilities Commission
CHP	combined heat and power
ConEd	Consolidated Edison
DER-CAM	Distributed Energy Resources Customer Adoption Model
DG	distributed generation
FEMP	Federal Energy Management Program (U.S.)
ICE	internal combustion engine
IOU	investor owned utility
LBNL	Ernest Orlando Lawrence Berkeley National Laboratory
NG	natural gas
NGSC	natural gas service classification
NiMo	Niagara Mohawk Power Corporation
NYISO	New York Independent System Operator
NYSERDA	New York State Energy Research and Development Authority
NYSPSC	New York State Public Service Commission
O&R	Orange and Rockland Utilities, Inc.
PV	photovoltaic
RTP	real time pricing
SC	service classification
TOU	time of use
U.S. EPA	United States Environmental Protection Agency

Executive Summary

Introduction

As in other U.S. states with relatively high electricity prices, New York State has offered economic incentives for certain consumers that generate their own electricity on-site, a practice known as distributed generation (DG). DG can be particularly attractive when the waste heat from thermal generating equipment, such as gas turbines and internal combustion engines (ICEs), can be used to offset fuel purchases for water and space heating, cooling, or steam production. This practice is known as combined heating and power (CHP) or cogeneration. Typically, DG is most economical when utility electricity is used to cover peak consumption or during DG equipment outages. Utility service under this paradigm is termed standby service.

Aside from lower energy bills, DG systems can offer additional benefits to adopters, other electric utility customers, and society in general. DG adopters gain improved reliability if their systems are capable of operating in isolation from the grid. DG can offset or delay the need for building more central power plants or increasing transmission and distribution infrastructure, and can also reduce grid congestion, translating into lower electricity rates for all utility customers. Societal benefits can include reduced carbon and other pollutant emissions.

However, DG is not necessarily a win-win-win proposition. Utilities may see DG customers as "peakier," or having more variations in their consumption patterns than non-DG participants. This requires the site to have the same service capacity as before DG installation while the customer is buying less energy. Depending on the operating scheme and relative performance of the DG system and the power plants supplying the grid, fuel consumption, carbon and other pollutant emissions, and noise pollution can all increase with DG adoption. For these reasons, DG policy needs to encourage applications with greater public benefit, while discouraging those from which the public incurs a net cost. Inherent in this is the need to analyze DG costs and benefits and the influence public policy has on DG adoption and operation.

In 2002, NYSERDA (New York State Energy Research and Development Authority) published a report on the market potential for CHP in New York State (Hedman, 2002). The report found DG CHP systems account for five GW of total electrical capacity distributed among 210 sites, mostly at large industrial complexes, each with an average capacity of 25 MW. Hedman estimates the potential for an additional 8.5 GW of electrical capacity for CHP, distributed among 26,000 sites, each generating about 330 kW. Seventy-four percent of these new installations, mostly commercial and institutional facilities, would require less than five MW of electrical capacity.

DG prevalence in New York has been increasing, and is now economically feasible at smaller scales. Recently, electric utilities began to question the equity of electricity pricing for standby service. In particular, the utilities did not feel that DG customers were paying their fair share of delivery (transmission and distribution) costs under existing tariff structures. In response, the New York State Public Service Commission (NYSPSC) opened regulatory hearings and ultimately approved a tariff structure for standby service.

Electricity tariff structure

Utilities and their regulators design tariffs based on fixed and variable costs. The main structural elements of an electricity tariff are typically fixed, volumetric, and demand charges.

- ***Fixed*** charges are invariant, $/month fees. They are considered infrastructure supply and delivery costs required by the customer regardless of their monthly energy consumption.
- ***Volumetric*** charges, expressed in $/kWh, are in proportion to energy consumed. They fluctuate by time of day within the month and cover the variable costs of producing electricity, such as fuel charges and variable maintenance expenses.
- ***Demand*** charges, expressed in $/kW, are levied on the maximum power used during a specified time range, such as on-peak hours of a month, regardless of the duration or frequency of that level of consumption. Demand charges are intended to collect the fixed costs of infrastructure shared with other customers in proportion to the capacity each requires.

The two major components of customer electricity bills are variable electricity supply costs and delivery charges covering infrastructure and service. Historically, although fixed in nature, some delivery costs have been collected by adding them to the volumetric prices for supply. When a class of customers has similar, regular consumption patterns, volumetric delivery prices equitably recover costs and generate some profit from the delivery of electricity. However, if there are significant differences in the use patterns within a class, volumetric delivery pricing may no longer be fair.

Electric utilities have argued that their delivery costs do not vary according to installed DG capacity because the same amount of infrastructure is required to meet a site's full demand during DG outages. With volumetric delivery pricing, utilities collect revenue on the lower standby power delivered, but not for the infrastructure maintained, leaving some costs unpaid. This is particularly true when the DG site is located a short distance from the power plant and has transformers and power lines dedicated to it. In this case, the localized infrastructure is not shared among several customers.

In 2000, the NYSPSC began hearings on DG tariffs involving the key stakeholders: investor-owned electric utilities (IOUs) and DG adopters, manufacturers, suppliers, and installers. Their objective was to develop standby tariffs that equitably address delivery costs. In 2001, the NYSPSC filed the "Opinion and Order Approving Guidelines for the Design of Standby Service Rates" (NYSPSC, 2001). Key points from this filing were:

- Supply charges should remain the same for all customers.
- Standby customers' delivery charges should reflect the different nature of service provided.
- Standby delivery charges should have three components:
  - ***Contract*** (fixed) ***demand*** fees to recover localized delivery costs.
  - ***Daily demand*** charges to cover delivery costs further from the site. The daily demand structure should allow assigning costs according to the proportion of infrastructure each

customers requires, so standby customers with frequent DG outages will incur higher daily demand charges.
  - ***Monthly customer*** charges to recover administrative and service costs, regardless of the customer's peak demand or total consumption.

- Delivery charges should be revenue neutral across classes of customers; the total delivery revenue collected under standby rates should be the same as it was before the rates went into effect, even though some customers will be paying more and others less.
- Standby delivery charges should be based on actual costs and should not be used as part of any incentive program to promote DG as a public policy or to benefit the utility. Such inducements can be addressed through other billing mechanisms.

The utility-proposed standby rates came into effect in 2004. Their impact on DG economics and consequently, on adoption patterns will determine net benefits and costs to customers, utilities, and the public. This study will analyze the effects of these new rates.

Each of the New York State IOUs filed an analysis of their revenues under parent and standby tariffs for five prototypical customers. The disaggregated costs of service reported in these filings demonstrate the impact of tariff structure change (Figure 1). Under the standby tariff, the fixed cost of monthly charges and contract demand increases to a significant portion of the electricity bill and demand charges become less significant. Overall, this shows that standby charges increase fixed electricity costs and reduce the marginal cost of purchasing energy. It will be shown in this report that these changes tend to discourage DG capacity.

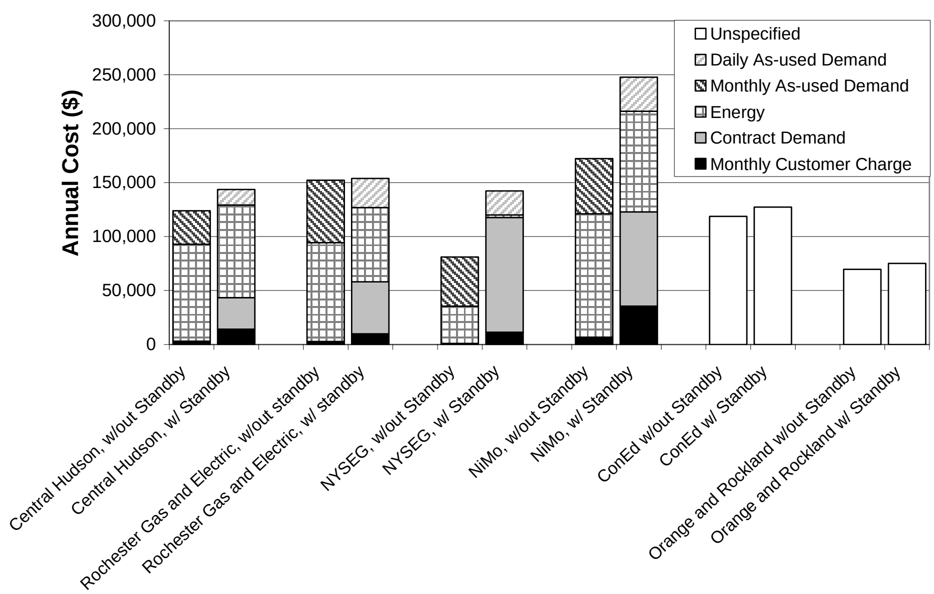

Figure ES 1: Disaggregated electricity costs for commercial customers reported by the New York IOUs

California, another state with relatively high electricity prices, has also dealt with the issue of equitable pricing of standby service. There, utilities charge standby customers under their parent tariff, and include an additional fixed monthly charge for each kW of backup standby capacity provided. Standby customers pay a monthly charge per kW of installed DG capacity. However, recognizing the public benefit of DG in certain circumstances, utilities exempt standby customers if they provide some public advantage, either to the utility or to the environment.

Relative to parent tariffs, New York standby rates reduce the marginal costs of purchasing utility electricity, whereas California's leave marginal costs unchanged. The New York standby tariff eliminates the volumetric delivery rate, reducing the net $/kWh rate from the parent tariff, while the California standby tariff does not. Reducing the marginal cost of purchasing electricity discourages generating it on-site.

The key structural difference between New York and California standby tariffs is in assessing fixed charges. In New York, standby customers pay a fixed delivery charge based on the *total* load the utility would incur during a DG outage (the peak electricity load of the site), while California standby customers are billed based only on the *additional* load incurred during an outage (the peak capacity of the DG system). From the customer perspective, the New York fixed $/kW rate is a fixed disincentive to DG adoption (independent of system size), while the California charge is a variable disincentive (increasing with system size increases).

Distributed Energy Resources Customer Adoption Model (DER-CAM)

This study used specially designed software to examine the effects of electricity tariff structure on DG adoption by determining economically optimal DG investment decisions under various tariff structures. This program generates the best solution to the very complex problem of finding the most efficient generating system for the least cost. It works on the economic principle of cost minimization, which is widely used in industry decision-making.

DER-CAM (Distributed Energy Resources-Customer Adoption Model) is software developed at LBNL (Lawrence Berkeley National Laboratory) that determines the economically optimal DG investment decision for a given site. DER-CAM also provides the equipment's economically optimal operating schedule, so that energy costs, utility electricity consumption, and carbon emissions can be estimated. DER-CAM's input includes the site's hourly end-use energy demand, electricity and natural gas supply costs, and DG technology adoption options[1]. In this research, DER-CAM examined the potential for DG in New York State under parent[2] and standby tariffs, and determined the effects of the new tariff structure on DG adoption. Figure ES 2 shows a high-level schematic of DER-CAM.

[1] Technology options typically considered in DER-CAM are internal combustion engines, microturbines, turbines, fuel cells, and photovoltaics. All natural gas fired equipment are considered with and without heat recovery for heating and absorption cooling.

[2] The term *parent tariff* herein refers to the tariff which the site would be subject to if they were not subject to a standby tariff. In the New York State IOU tariff documents, parent tariffs are refered to as the *Otherwise Applicable Rate* and the *Otherwise Applicable Service Classification*.

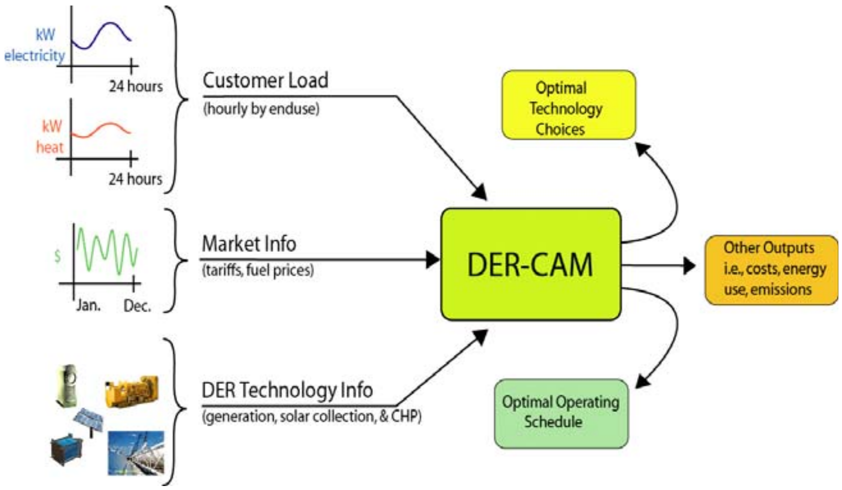

Figure ES 2: DER-CAM schematic

Prototype Building

DER-CAM needed detailed information about a typical candidate for DG adoption, a small facility with a peak electric load near one MW and similar sized heating and electrical loads. The chosen prototype was a 90-bed hospital, with peak electrical loads of 1200 kW in the summer, and heating loads roughly equal to electrical loads. DER-CAM was then used to find the economically optimal DG system and operation.

Examination of Current New York Tariffs

The first part of this study examined DER-CAM results under actual parent and standby tariffs in three distinct regions of New York. Electricity and natural gas tariffs from one IOU (investor owned utility) in each region were collected and used in this project. The regions were classified:

- **High Congestion**, New York City: Consolidated Edison Company of New York, Inc. (ConEd),
- **Moderate Congestion**, Hudson Valley: Orange and Rockland Utilities, Inc. (O&R), and
- **Low Congestion**, Western New York: Niagara Mohawk Power Corporation (NiMo).

DER-CAM determined the economically optimal DG investment under several parent and standby tariffs offered by each IOU. Figure ES 3 shows these results. Figure ES 4 shows the annual energy costs in each of these cases. The graphs use the following notation:

- **FLT** – flat rate tariff: a constant volumetric price,
- **TOU** – time of use tariff: volumetric price varies by time of day, typically divided into peak and off peak periods,
- **RTP** – real time pricing: volumetric price varies at each hour of each day, and is set on the previous day,
- **no inv. –** without investment in DG,

- **inv**. **–** DG investment under the parent tariff, and
- **standby –** DG investment under the standby tariff.

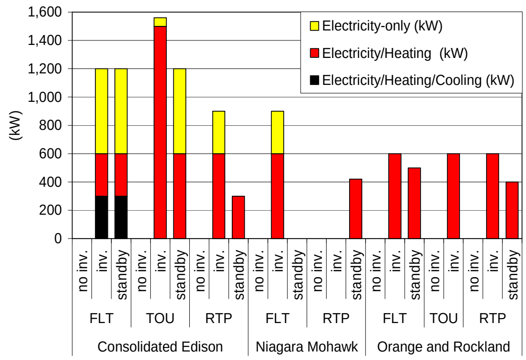

Figure ES 3: Economically optimal DG installation

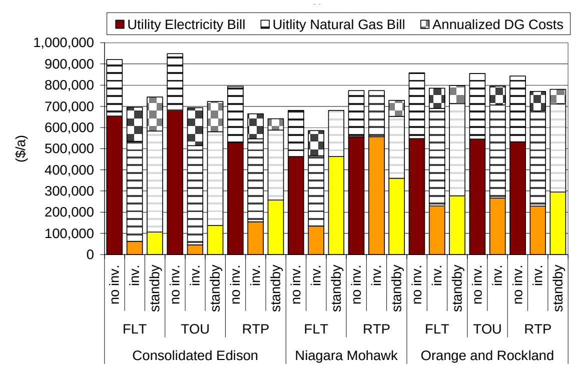

Figure ES 4: Annual energy costs under economically optimal DG investment

Figure ES 3 shows that investing in DG becomes more attractive with increasing electricity rates: NiMo shows the least investment incentive and ConEd the greatest. Standby tariffs tend to encourage installing smaller DG systems than parent tariffs. The comparison of various options under different volumetric pricing schemes (flat rate, time of use, and real time pricing) shows inconclusive results.

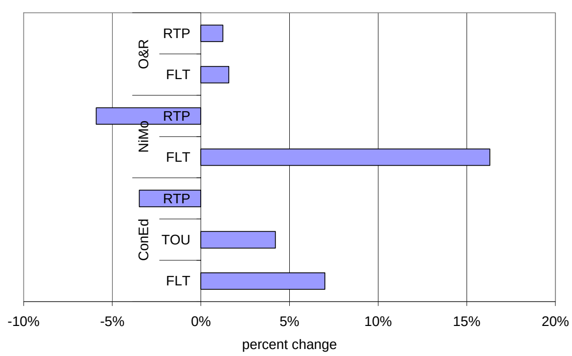

Figure ES 5: Increase in annual energy bill to dg investors from parent to standby tariffs

In five of the seven cases, standby tariffs encourage less DG investment than parent tariffs because they increase the fixed costs of utility electricity while reducing the variable costs: fixed costs increase by including a contract demand charge and larger monthly fees, variable costs decrease by reducing volumetric rates and as-used demand charges. The increased fixed costs guarantee the utility will collect at least the same (and in most cases, more) revenue from DG customers as it did under the parent tariff, thus removing any economic incentive to install a system. The reduced incentive to install DG is illustrated in Figure ES 5, which shows that standby tariffs increase the annual energy costs of DG investors in five of the seven cases, including all TOU and flat rate tariffs. However, in only one case does a switch from parent to standby tariff make DG uneconomic (Figure ES 3).

Sensitivities to Energy Cost Components

The second part of this study consists of sensitivity analyses on three energy cost components: volumetric electricity rates, volumetric natural gas rates, and as-used demand charges. For these analyses, the actual rates for the moderately congested region – O&R – became the basis for a generic set of New York State electricity and natural gas rates. DER_CAM found optimal DG investment under parent tariffs, standby tariffs, and a generalized California style standby tariff. Figure ES 6 through Figure ES 8 show the results.

In these graphs, the nine structures are referred to and shown as follows:

Structure	Reference name in figures	Line	Marker
Flat-Parent	FLAT	thin, dotted	+
Flat-Standby	FLAT_NY	medium, dotted	+
Flat-Standby-CA	FLAT_CA	thick, dotted	+
TOU-Parent	TOU	thin, solid	Δ
TOU-Standby	TOU_NY	medium, solid	Δ
TOU-Standby-CA	TOU_CA	thick, solid	Δ
RTP-Parent	RTP	thin, dashed	o
RTP-Standby	RTP_NY	medium, dashed	o
RTP-Standby-CA	RTP_CA	thick, dashed	o

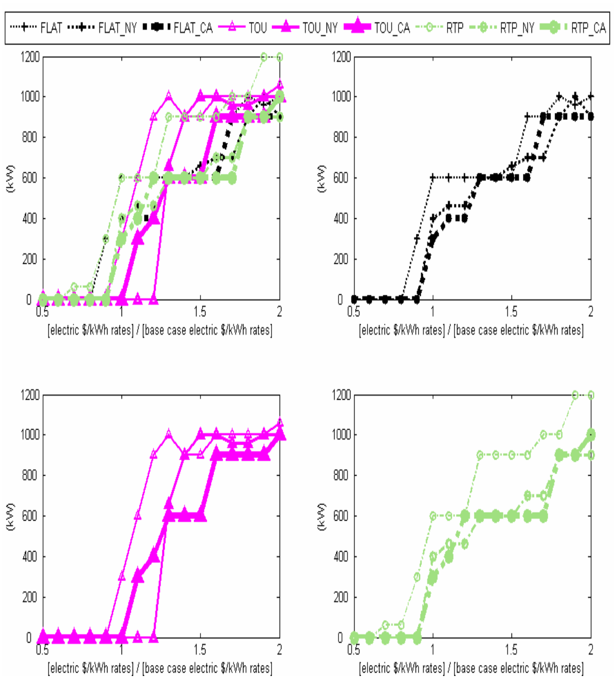

Figure ES 6: Installed DG capacity for volumetric electricity rate sensitivity

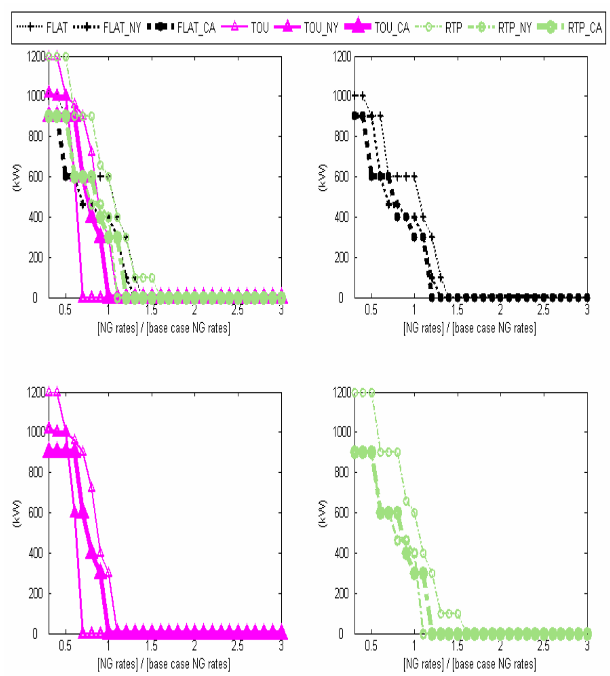

Figure ES 7: Installed DG capacity for volumetric natural gas rate sensitivity

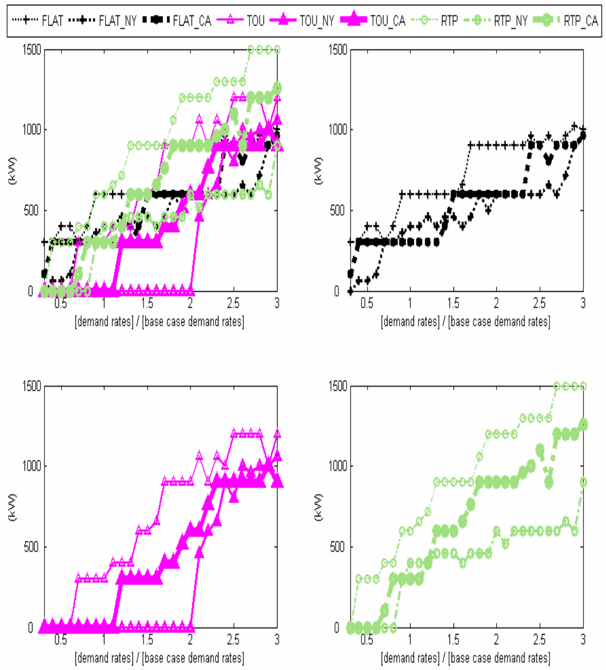

Figure ES 8: Installed DG capacity for as-used demand rate sensitivity

Figure ES 6 shows the intuitive result that DG economic feasibility is quite sensitive to electricity prices, and in the New York cases, almost no DG investment is economical for volumetric electricity prices below 80% of current prices. As prices rise, DG capacity increases, initially for CHP units and then for electricity-only units. The optimal DG capacity increases as electricity prices rise from 80% to 160% of current prices, but prices above 160% do not encourage more growth in the optimal capacity.

The natural gas price sensitivity (Figure ES 7) shows similar results. With lower than current natural gas costs, large DG systems covering most of the hospital's loads are cost-effective. As natural gas prices increase, only smaller systems with higher load factors remain economical. When natural gas prices exceed 125% of current prices, DG is no longer a good investment.

The as-used demand charge sensitivity results (Figure ES 8) show that demand charges are an effective way to influence the level of DG installation. The TOU New York standby (TOU_NY) tariff encourages very little DG installation, although when a threshold of 200% of base case as-used daily demand charges is surpassed, installed capacities increase and become comparable to for the other two tariff structures.

Discussion and Conclusions

Standby customers consume utility electricity differently than if they purchased all of their power from the utility. The IOUs of New York State have successfully argued that because of this difference, standby customers should be charged differently than standard customers.

As shown in this report, altering electricity tariff structure affects the economic incentives to invest in DG. Understanding how these incentives change, and the resulting implications to customers, utilities, the public, and the environment is key to developing an effective DG policy.

Because standby tariffs simultaneously increase fixed utility electricity charges and decrease marginal utility costs, they are disincentives to DG investment. Standby rates encourage base-loaded units (ones that are generating power most of the time), which make load factors from DG customers lower than from their non-DG counterparts, so that DG customers appear "peakier." Load factor is the ratio of average to peak utility electricity consumed. A "peaky" customer buys a lot of electricity occasionally, but relatively little most of the time.

To counter running larger units part time to evade high demand charges, however, standby customers with less than 1 MW of electrical capacity can avoid standby tariffs by operating DG systems at combined efficiencies of 60% or greater. Because parent tariffs are more favorable to customers, this discourages installing DG capacity larger than the heat loads. For the prototypical hospital, standby tariffs encourage DG systems sized smaller than the heat loads, which means that some fuel and carbon savings from using recovered heat are lost.

From the customer perspective, exemption for standby tariffs is desirable in most cases; for systems under 1 MW, maintaining an overall system efficiency of 60% or greater would qualify customers for exemption. Also exempt are customers with fuel cells or DG systems fueled by renewable resources, sustainably-managed biomass, or methane waste. For larger customers, systems with high capital costs and low marginal energy costs may be more desirable under standby tariffs than under parent tariffs.

The sensitivity analyses demonstrate that as-used demand charges are proportionally more significant under typical parent tariffs (monthly demand) than under standby tariffs (daily demand). Parent tariffs' high cost of daytime demand encourages peak shaving (installing larger systems to operate only at peak demand hours), while the more reasonable standby tariff charges do not.

However, for the tariffs considered, the price of electricity has a greater effect on DG system size than do the actual rate structures. The volumetric rate structure does not appear to be significant, while the standby structure does tend to reduce the capacity of DG systems.

Given that standby tariffs imposed by the utilities will be based on cost, this study can be used to suggest countermeasures that public agencies can take to encourage desired levels of DG capacity installation. Adjusting the marginal cost differential between DG electricity production and utility purchase can effectively do this. One way to achieve this would be to subsidize natural gas costs for DG. The level of subsidy would depend on the public objective; encouraging peak-shaving DG systems requires a higher level of subsidy than encouraging optimally efficient CHP systems.

1. Introduction: Distributed Generation in New York State

1.1 Benefits and Costs of Distributed Generation

As in several U.S. locations with relatively high electricity prices, New York State has offered economic incentives for certain electricity consumers that generate their own electricity on-site, a practice known as *distributed generation* (DG). DG can be particularly attractive when the waste heat from thermal generation equipment, such as gas turbines and internal combustion engines (ICEs), can be used to offset fuel purchases for on-site steam production, hot water, or space heating and/or cooling.[3] This practice is known as *combined heating and power* (CHP) or *cogeneration*. Aside from the direct economic benefit of reduced energy bills, DG systems can offer improved electric reliability if they can operate during grid blackouts. Other potentially valuable forms of DG include fuel cells and renewable energy devices such as photovoltaics (PV), solar heating, and wind turbines. Typically, DG is most economical when utility electricity is only used during DG equipment outages and to cover peak consumption. Utility service under this paradigm is termed *standby service*.

DG adopters are not the only ones to benefit. DG can lessen the electrical loads the utilities are obligated to provide. Their use can reduce grid congestion and may offset or delay the need for building other central power plants or increasing transmission and distribution infrastructure. Electricity utility ratepayers benefit three ways: by avoiding price spikes during congested times, by delaying rate hikes to finance infrastructure expansion, and from reduced outages caused by grid overloads. Other societal benefits can include reduced carbon and other pollutant emissions.

However, DG is not necessarily a win-win-win proposition. Utilities may see DG customers as "peakier," or having more variations in their consumption patterns, than their non-DG counterparts. To cover outages, the DG site requires the same service capacity as before installation while the customer is buying less energy. Fuel consumption and its subsequent greenhouse gas emissions can increase if DG systems are less efficient than the macrogrid. DG ICEs are often more polluting than large natural gas power plants with modern emissions control technologies.[4] DG can create noise pollution, and can be a threat to the health of the macrogrid if proper interconnection devices and procedures are not used.

Stakeholders have different costs and benefits under various scenarios, and it is beyond the scope of this report to discuss them all. Detailed studies of DG benefits are provided by LBNL (the Ernest Orlando Lawrence Berkeley National Laboratory) (Gumerman, 2003) and the Rocky Mountain Institute (Lovins, 2002). Distributed Utility Associates (Iannucci, 2003) provides a summary of 30 quantitative studies of DG's values and benefits.

[3] Heat can be used for cooling with absorption chillers, which use heat to produce chilled water, and by desiccant dehumidifiers, which remove moisture from air, thus reducing the electrical load required for space conditioning.

[4] In 2001, natural gas fired power plants in New York State whose primary NOx controllers were selective catalytic reduction (SCR) devices had emissions of approximately 0.05 to 0.2 kg/MWh. Lean burn reciprocating engines without SCR have NOx emissions of approximately 0.7 to 1.4 kg/MWh. Data sources: U.S. EPA (2001) and Goldstein (2003).

DG policy must encourage implementations that benefit the public while discouraging those which are detrimental. Inherent in this is the need for quantitative analysis of DG costs and benefits as well as the influence of policy on DG adoption and operation.

1.2 DG Potential in New York

In 2002, NYSERDA (New York State Energy Research and Development Authority) published a study on CHP's market potential in the state (Hedman, 2002). The report found DG CHP systems account for five GW of existing electrical capacity distributed among 210 sites, mostly large industrial complexes, each with an average capacity of 25 MW. Hedman estimates the technical potential for an additional 8.5 GW of electrical capacity, distributed among 26,000 sites, each generating an average of 330 kW. Of the potential sites, 74% – mostly commercial and institutional facilities – require less than five MW of electrical capacity.

1.3 Standby Tariffs in New York

DG installation in New York has been increasing, and is now economically feasible at smaller scales. In recent years, utilities began to question the equity of electricity pricing for standby service. In particular, they did not feel that DG customers were paying their fair share of delivery (transmission and distribution) costs under existing tariff structures. In response, the State of New York Public Service Commission (NYSPSC) initiated regulatory hearings and ultimately approved a tariff structure for standby service.

1.4 Structure of This Report

This is a report of research to examine the effects of electricity tariff structure on DG economics using New York State as a test case, and to estimate the resulting implications for the utility, other electricity customers, and society.

The report begins with a description of electricity pricing structures and a brief history of the development of electricity tariffs for standby service in New York State (Section 1). Next DG economics under various electricity tariff structures are examined by finding economically optimal DG system investments for a specific prototypical site under the various tariff structures, and then determining the resulting costs and implications of installing the optimal system. Section 3 describes the software used to determine the economically optimal DG system. Section 4 details the input data used and Section 5 discusses the scenarios considered. The results of this analysis are provided in Section 6, and finally, Section 7 presents the conclusions.

2. Electricity Tariff Structures and Standby Tariffs in New York

This section describes typical New York electricity tariff components and then gives a brief history of the development of the state's rates and structures for standby service. Finally, it compares them to standby tariffs in California.

2.1 Typical Electricity Pricing

Utilities incur both variable and fixed costs for providing electricity to customers. Variable costs come from producing electricity, among them buying fuel and operating power plants. They may be incurred directly if the plants are self-owned, indirectly through electricity purchase prices contracted with suppliers, or at market clearing prices. Infrastructure costs, including delivery, are largely fixed and depend on the size of system, but not actual electricity consumption. Some infrastructure costs are localized to individual customers (power lines and substations directly feeding a site); others, like power plants or administration, serve the entire customer base; while many lie between these two extremes, for example, shared distribution lines and substations.

Based on these variable and fixed expenses, utilities and their regulators typically design tariffs to cover three kinds of costs:

- F*ixed charges* are invariant, $/month. These are infrastructure costs of supply and delivery required by the customer regardless of their energy consumption for that month.
- V*olumetric charges* are proportional to the amount of energy consumed. They are expressed in $/kWh and may vary by time of day within a month. Volumetric rates are intended to cover the variable costs of producing electricity, such as fuel and some maintenance.
- D*emand charges* are expressed in $/kW and levied on the maximum power consumption during a specified time range (such as the on-peak hours of the month), regardless of the duration or frequency of that level of power consumption. Demand charges are intended to collect the fixed costs of infrastructure shared with other customers by raising revenue in proportion to the amount of power required by the individual.

Volumetric and demand charges may have a *block* structure, in which there are different prices for different quantities of consumption. For example, customers incur a volumetric charge of $0.10/kWh for their first 1000 kWh of power each month, $0.08 cents for their next 2000 kWh, and $0.07/kWh for all consumption in excess of 3000 kWh.

The two major components of customer electricity bills are variable electricity, or *supply*, costs and infrastructure and service, or *delivery*, costs. Historically, although fixed in nature, some delivery costs have been collected through volumetric pricing ($/kWh) by adding them to the charges for supply. When a class of customers has similar, regular consumption patterns, volumetric delivery prices can equitably recover cost and generate some profit. However, if there are significant differences in customer usage patterns, volumetric delivery pricing may no longer be fair.

2.2 Utilities' Case for Reform of Delivery Service Pricing for DG Customers[5]

Electric utilities have argued that their delivery costs do not vary regardless of DG capacity installed on a site because the same amount of infrastructure is required to meet full demand during DG outages. This is particularly true for localized distribution lines and substations not shared with or partly paid for by other customers. However, volumetric pricing does not allow the utilities to collect as much delivery revenue from standby customers as from their non-DG counterparts, because the standby customers generate some of their own electricity.

In 2000, the NYSPSC began regulatory proceedings on DG tariffs. Key stakeholders included investor owned electric utilities (IOUs) and DG adopters, manufacturers, suppliers, and installers. The objective was to develop standby tariffs that equitably address delivery costs. DG owners and advocates called for continued volumetric delivery pricing, arguing that DG benefits the utility system by relieving congestion, and therefore, should be compensated with reduced delivery charges. Utilities argued for fixed delivery charges based on the site's maximum possible demand, or *contract demand*, because they have the same infrastructure obligations, regardless of on-site DG capacity.

The NYSPSC felt neither camp was completely correct. While delivery charges should not be volumetric, they should not be entirely fixed either. Infrastructure costs are not shared equally among DG customers; they are greater when the DG site is closer to the power plant or if power lines or substations are dedicated to covering its outages. Since DG customers have outages at random times, infrastructure for standby customers must only meet the expected level of DG outages, rather than additive peak demand if all DG owners had outages at the same time.

In 2001, the NYSPSC filed the "Opinion and Order Approving Guidelines for the Design of Standby Service Rates" (NYSPSC, 2001). Key points from this filing were:

- Supply charges should remain the same: volumetric pricing of electricity supply is rational for both traditional and standby customers, who continue to have the option of obtaining supply service from a third party and only delivery service from the utility.[6]
- Delivery charges for standby customers should reflect the different nature of service provided to them.
- Delivery charges for standby customers should be comprised of three components:

[5] Historical information in this section is from the NYSPSC 2001 report.

[6] Although not addressed in this filing, it is not necessarily true that supply costs are unaffected by on-site generation patterns. If supply costs are based on actual hourly, market supply costs, then they are derived from a weighted average of supply costs throughout the month, the weighting of which comes from typical class load profiles. However, standby customers do not consume utility electricity in the same patterns as typical class load profiles. If they are base-loading DG that run throughout the day, then the ratio of peak time purchase to off-peak time purchase of electricity is greater for standby customers. If they are peak-loading plants used to avoid (in part) on-peak demand charges, then the peak to off-peak ratio is lower than for traditional customers.

  - **Contract (fixed) demand charges** to recover dedicated, localized delivery costs. The default contract demand is the maximum possible load drawn from the utility, as determined by the customer or the utility[7].
  - **Daily demand charges** to cover delivery costs further from the site. The daily demand structure assigns costs in proportion to each customer's share of the required infrastructure so standby customers with frequent DG outages incur higher daily demand charges.
  - **Monthly customer charges** to recover administrative and service costs regardless of peak demand or total consumption.
- Delivery charges should be revenue neutral across classes of customers. The total delivery revenue collected from a class of standby customers should remain the same, though some customers will be paying more, and others less, than before tariff changes.
- Standby delivery charges should be based on actual costs and should not be part of any incentive program to promote DG installation as a public policy or for benefits to the utility. Such inducements can be addressed through other billing mechanisms.

2.3 IOU Standby Rate Filings

The IOUs filed standby rates and the NYSPSC ordered them to estimate bills for five proto-typical standby customers[8] (NYSPSC Case 03-E-0640, 2003). For each customer type, the bills were to be calculated under three scenarios: its parent tariff, prior to DG installation; its parent tariff, after DG installation; and using the proposed standby tariff, after DG installation.

The disaggregated costs of service reported in the IOU filings demonstrate the impact of tariff structure change (Figure 1). Under the standby tariff, the fixed cost of monthly charges and contract demand increase to a significant portion of the electricity bill and demand charges become less significant. Overall, this shows that standby charges increase fixed electricity costs and reduce the marginal cost of purchasing energy.

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[7] Customers may contract for a lower demand than this and use load-shedding techniques to keep their electric load below their contract demand during a DG outage. However, stiff penalties are applied if this contract demand is exceeded: For demand between 110% and 120% of contract demand, a surcharge of 12 times the monthly contract demand charge for the excess demand is applied. For demand greater than 120% of contract demand, a surcharge of 24 times the monthly contract demand charge for the excess demand is applied.

[8] The five customer types were commercial buildings, hospitals, industrial facilities, nursing homes, and schools.

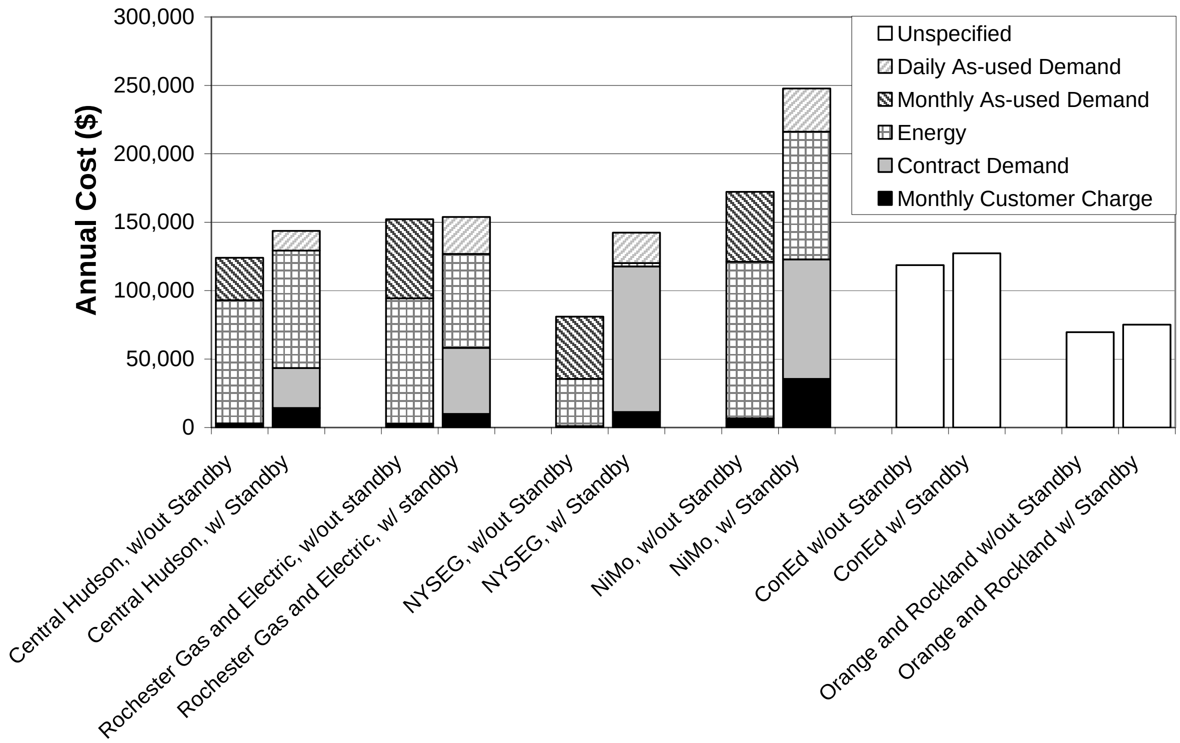


Figure 1: Disaggregated electricity costs for commercial customers reported by the New York IOUs

Figure 2 compares utility revenues from standby customers under parent tariffs with revenues from standby tariffs for all building types.[9] Upon examination of these filings, the NYSPSC approved the proposed standby rates of the six IOUs. Figure 2 brings the revenue neutrality of the proposed standby rates into question. In almost all cases, the utility's revenue increased under the standby tariffs. It can be argued that these prototypes do not represent their entire classes, and it would be expected that some customers would fare better under standby tariffs, while others would not. No proof of rate neutrality has been made publicly available.

[9] The IOU filings are posted at http://www.dps.state.ny.us/99E1470.htm (last accessed February, 2005).

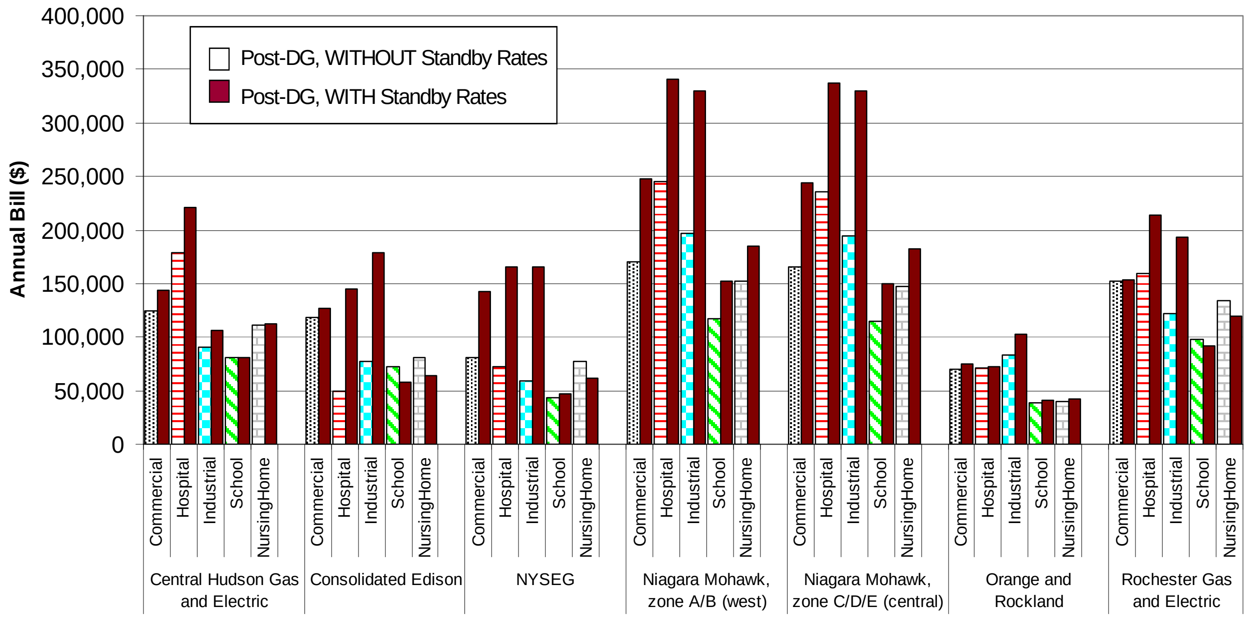


Figure 2: IOU reporting of revenues from standby customers

This observation does not question the *equity* of the standby tariffs, but rather whether the *rate neutrality* objective has been achieved. If it was argued that current tariff structures do not equitably charge standby customers (versus traditional customers) for delivery service, then standby customers *should* be paying more for delivery service than previously.

While the debate continues, the utility-proposed standby rates came into effect in 2004.[10] It is important to analyze the impact of these tariff structures on DG economic feasibility and, consequently, on the DG adoption patterns that will determine net benefits and costs to customers, utilities, and the public.

2.4 An Alternate Standby Service Tariff: California

California, another state with relatively high electricity prices, has also dealt with equitable pricing of standby service. In 2001, the California Public Utilities Commission California (CPUC) ruled that standby service should incur fixed costs for backup capacity from the utilities, in addition to standard costs for service (CPUC, 2001). Utilities have implemented this by charging standby customers under their parent tariff, and including an additional fixed monthly charge for each kW of standby capacity provided. However, if the DG users provide some benefit to the public, the utility or the environment, they can be exempt.

The key difference between New York and California standby rate structures is that, while New York charges standby customers a fixed delivery fee based on the *total* load the utility would incur during a DG outage, California charges are based only on the *additional* load from an

[10] Central Hudson's standby tariffs went into effect on July 1, 2004. Standby tariffs for the five other IOUs in New York State went into effect in January and February 2004.

outage. From the customer perspective, the New York fixed $/kW rate is a *fixed* disincentive to DG adoption, while the California charge is a *variable* disincentive (increasing with DG system size). However, the New York standby tariff eliminates volumetric delivery rates, thus reducing the net $/kWh rate, while the California tariff maintains the volumetric delivery rates and the net $/kWh rate to standby customers remains the same. Relative to parent tariffs, New York standby tariffs reduce the marginal costs of purchasing utility electricity and increase the fixed costs, whereas California standby tariffs increase the fixed costs but do not change the marginal costs.

3. Distributed Energy Resources Customer Adoption Model (DER-CAM)

This study used DER-CAM to examine the economic potential for DG in New York State under parent and standby tariffs, and to determine the effects of tariff structure on DG adoption. DER-CAM determines the best solution through the economic principle of cost minimization.

Developed at LBNL, DER-CAM is software designed to factor many variables into determining the most economical DG investment decision for a given site. The DER-CAM solution provides both the generating equipment and the optimal operating schedule so that energy costs, utility electricity consumption, and carbon emissions can be estimated. Input to DER-CAM includes the site's hourly end-use energy demand, electricity and natural gas supply costs, and DG technology adoption options.

DG generation technology options include PV, natural gas fueled ICEs, microturbines, gas turbines, and fuel cells. By matching thermal and fuel cell generation to heat exchangers and absorption chillers, heat recovered from natural gas driven generators can be used to offset heating and cooling loads.

Natural gas fired technologies, the most common solution, can be purchased as:

- **generator**: for electricity only,
- **generator and heat exchanger**: for electricity and heat recovery for water or space heating,
- **generator, heat exchanger, and absorption chiller**: for electricity and heat to serve water and space heating and cooling loads.

DER-CAM output includes the optimal DG system and an hourly operating schedule, as well as the resulting costs, fuel consumptions, and carbon emissions. Figure 3 shows a high-level schematic of DER-CAM. References to detailed descriptions of DER-CAM, and a list of input modifications made for this effort, are provided in Appendix D.

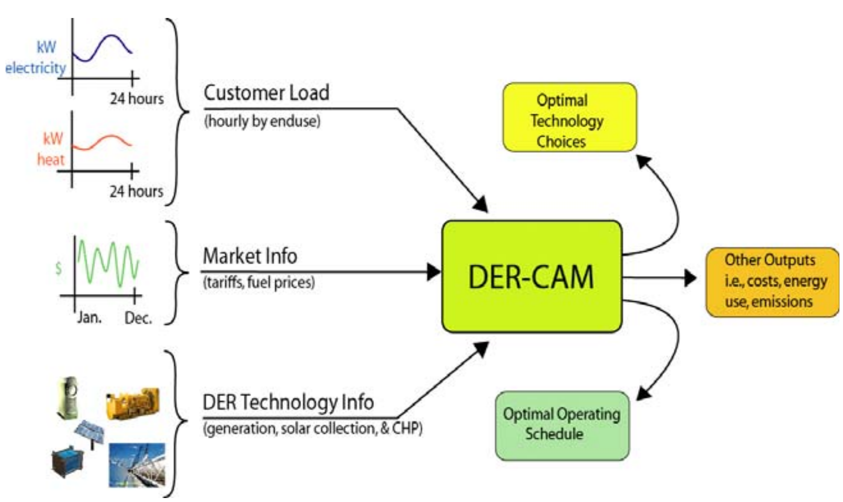


Figure 3: DER-CAM schematic

4. Data Collection

The objective of this research was to examine the effects of tariff structure in New York State on DG economic feasibility and adoption, and the resulting effects on utilities and the public. Two approaches were taken. The first considers a prototype customer well suited to CHP under the actual tariff options of several representative New York IOUs. The second examines sensitivities to utility price and subsidy variations for this same customer, using generalized tariffs representative of New York IOUs.

This section describes the selection of building type, load data, and electricity and natural gas tariffs. Additional input data to DER-CAM, such as DG technology cost and performance characteristics, macrogrid performance, and economic data are described in Appendix E.

4.1 Prototype DG Adopter: Small Hospital

This research required detailed information on a typical building type for DER-CAM input. The site was chosen because it fit the NYSERDA (2002) finding that the majority of CHP potential is found at facilities with peak loads less than five MW, and because DG adoption is typically driven by a compelling use for recovered heat. A site with well-balanced electricity and heat loads met that condition. Given LBNL's focus on smaller (under one MW) DG systems, a prototype building with peak loads near one MW was ideal.

Three criteria influenced the choice of a hospital as the prototype building. Small hospitals have year-round heating requirements that are roughly equal to their electricity needs, promising high waste heat utilization. Second, they have high electrical load factors (average consumption/peak consumption) because of their year-round, full-time operation. These load factors requires a DG system that can meet a large portion of their peak demand and total consumption with little excess capacity. Finally and fortunately, data for a suitable hospital was readily obtainable.

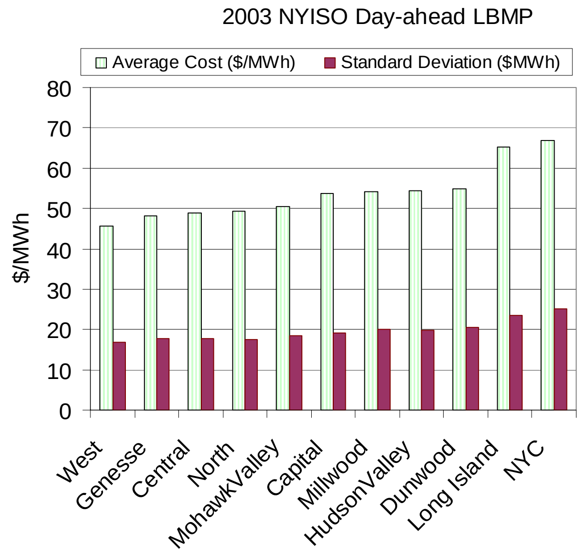
Hourly end-use load profiles for the 90-bed Wyoming County Hospital in Warsaw, NY were available from a prior LBNL case-study (Bailey, 2003)[11] and are presented in Appendix A. All end-use loads are modeled as time-specific, perfectly inelastic demands.

4.2 Regions

Chief factors in DG economic feasibility are current utility electricity and natural gas prices, which vary by location within the state. New York can be divided into regions based on the relative congestion of their power grids. Here, three regions are considered: highly congested, represented by New York City; moderately congested, the Hudson Valley; and un-congested, western and far northern New York State. Increased congestion correlates with greater daily fluctuations in electricity costs and increased average commodity prices, as illustrated in Figure 4. An examination of these in relation to the NYISO (New York Independent System Operator) load zone map

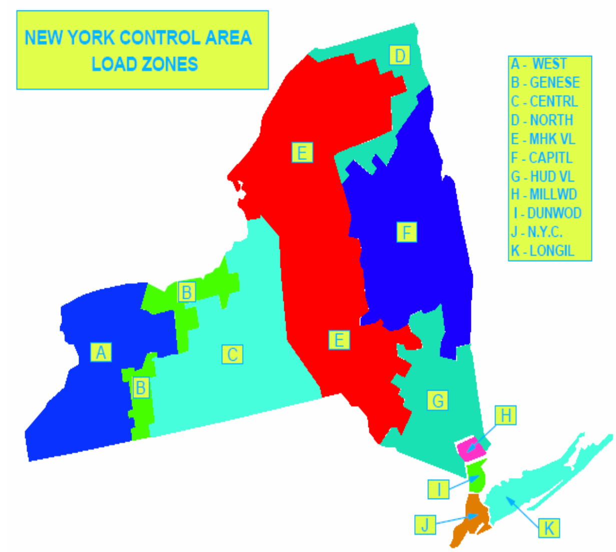
[11] Although the Wyoming County Hospital was not selected for a detailed case study, LBNL researcher Owen Bailey visited the site, collected data, and generated the load profiles required for DER-CAM.

Figure 5) shows a clear correlation between electricity price and location relative to New York City.



(Source: LBNL, http:/electricitymarketdata.lbl.gov)

Figure 4: NYISO 2003 Day Ahead Electricity Costs, by Zone



(Source: NYISO)

Figure 5: NYISO Load Zones

Electricity and natural gas tariffs were gathered from IOUs in each the three regions. They are:

- **High Congestion**, New York City: Consolidated Edison Company of New York, Inc. (ConEd)
- **Moderate Congestion**, Hudson Valley: Orange and Rockland Utilities, Inc. (O&R)
- **Low Congestion**, Western New York: Niagara Mohawk Power Corporation (NiMo)

Electricity and natural gas rates for each of these utilities are described in Section 4.4. Rates for 2003 are reported in Appendix B, along with the DER-CAM representations of these rates.

4.3 Tariff Structure

Non-standby electricity tariffs from the utilities listed above generally include fixed monthly ($/month), volumetric ($/kWh), and monthly demand ($/kW peak demand) charges. The most significant structural difference among them is the time dependence of energy consumption charges. Three major variations exist:

- **Flat Rates**: Customers pay the same $/kWh price at all hours of the day. Flat rates tend to be the default for smaller customers (typically without interval metering which reports the time of day when electricity was consumed).

- **Time of Use (TOU) Rates**: Customers pay a higher $/kWh price during on-peak hours (daytime) and a lower price during off-peak hours (morning, night, weekend, holiday). TOU rates tend to be the default for larger customers and are often optional for smaller customers.
- **Day-Ahead Hourly Rates**: Customers pay the day-ahead hourly $/kWh price for their region as set by NYISO-operated markets. Day-ahead hourly rates are usually optional, although they are mandatory for NiMo customers with maximum demand greater than two MW. These rates are referred to as *real time pricing* (RTP) in this report.

For flat and TOU rates, the supply cost is based on a weighted average of actual supply costs incurred by the utility during each month. Weighting is determined by typical load profiles for each customer class.

For standby customers, delivery costs in the non-standby tariffs are removed and replaced by the monthly charge/contract demand/daily demand tariff structure described in Section 2.2.

Natural gas tariffs are similar to electricity tariffs, but typically exclude demand charges.

4.4 Tariff Descriptions

For each utility, information on tariffs was collected for the test year, 2003. These tariffs are described below and listed in Appendix B, along with their corresponding DER-CAM representations.

4.4.1 High Congestion: New York City

ConEd serves the New York City area. For customers with demand greater than 10 kW, ConEd's SC-9 (Service Classification 9) defines three electricity rates. For each rate, separate standby charges are stated in SC-14RA. Under the SC14-RA, customers pay the supply charges of SC-9, but not the delivery (transmission and distribution) fees. Additionally, standby customers pay fixed monthly ($/month), contract demand ($/kW maximum potential load), and daily demand ($/kW maximum daily consumption) charges. All ConEd rates used in this report are for customers in New York City.

Standby rates went into effect in February 2004 and were available for this research through October 2004. For this research, 2003 was the test year and 2004 standby delivery rates were applied to the 2003 parent tariff. February values were used for December and January and October values applied for November, thus estimating a full year's data.

4.4.1.1 Rate 1

Rate 1 has flat rate volumetric charges that include maximum monthly ($/kW) demand and volumetric ($/kWh) consumption charges, and fixed monthly fees.

4.4.1.2 Rate 2

Rate 2 lists charges for maximum monthly demand during on-peak hours, separate energy charges for on- and off-peak consumption, and fixed monthly fees. Rate 2 has TOU volumetric charges and is mandatory for customers with peak annual loads above 1500 kW, or above 900 kW under certain conditions.

4.4.1.3 Rate 3

Rate 3 is similar to Rate 2, although the rates are higher. Rate 3 is optional for customers not required to be on Rate 2 and allows those with less than typical on-peak consumption to choose a rate with lower off-peak costs.

4.4.1.4 Voluntary Real Time Pricing

Under ConEd's Rider M, SC-9 customers may also choose to pay NYISO's location based day-ahead hourly prices. Day-ahead prices are set and reported to customers by 4 p.m. the day before they will be effective. Under Rider M, customers pay the NYISO charges for energy supply in addition to the delivery rates of their parent tariff. This tariff structure is termed real-time pricing (RTP).[12]

4.4.1.5 Natural Gas Rates

Rate 2, General Firm Sales is the ConEd natural gas rate that would apply to the prototype hospital. It lists fixed monthly fees and block energy ($/therm) charges with an initial monthly volume priced at one rate, and subsequent blocks priced lower. This structure accounts for fixed delivery (infrastructure) costs by attaching them only to the first block of consumption. There are reduced rates for natural gas consumption for air conditioning (direct- or indirect-fired absorption chillers) and for DG, although separate meters are required for each service.

4.4.2 Moderate Congestion: Hudson Valley

O&R, whose rates were used in this study, is one of the utilities serving the Hudson Valley. This part of the state has medium range electricity prices and variation (see Figure 4). SC-2 is the general electricity tariff for lower voltage customers. SC-20 is an optional TOU rate for secondary customers with demand exceeding 5 kW for at least two consecutive months per year. Rider M allows customers under SC-2 and SC-20 to purchase their electricity supply at day-ahead hourly rates. SC-25 is the new standby service tariff.

Again, O&R standby rates went into effect in February 2004 and were available for this research through October 2004. For this research, 2003 was the test year and 2004 standby delivery rates were applied to the 2003 parent tariff. February values were used for December and January and October values applied for November, thus estimating a full year's data.

[12] RTP may also refer to energy supply costs determined during the hour prior to the hour of use. This is known as *day-of* hourly pricing. In this report, RTP will always refer to day-ahead hourly pricing.

4.4.2.1 SC-2: General Secondary Service

SC-2 calls for fixed monthly ($) fees and delivery charges in the form of monthly demand ($/kW) charges. It also has block structure volumetric ($/kWh) and flat rate volumetric ($/kWh) supply charges. Delivery components have summer (June through September) and non-summer values.

4.4.2.2 SC-20: Option TOU Secondary Service

SC-20 is an optional rate for SC-2 customers with peak demand greater than five kW for any two consecutive months each year. SC-22 contains a fixed monthly ($) fee, delivery charges in the form of monthly TOU demand ($/kW) charges, as well as TOU volumetric ($/kWh) and volumetric ($/kWh) supply charges. There are two times of use: on-peak and off-peak, with on-peak hours defined differently for summer and winter months.

4.4.2.3 SC-25: Standby Service

SC-25 lists the electricity rates for standby customers of all service classification. For SC-2 and SC-20 customers, SC-25 calls for fixed monthly ($), fixed contract demand ($/kW contracted), daily demand ($/kW), and volumetric ($/kWh) supply charges. The supply charges are the same as those of the parent tariffs.

4.4.2.4 Rider M

Rider M allows customers under SC-2, SC-20, and SC-25, along with several other service classifications, to opt for the NYISO day-ahead hourly RTP rates for the Hudson Valley load zone, instead of the flat market supply charges in the applicable tariff.[13]

4.4.2.5 Natural Gas SC-2

A separate tariff, SC-2 for natural gas service, contains fixed ($) monthly and volumetric ($/cubic foot[14]) delivery and supply charges.

4.4.3 Low Congestion: Western New York

NiMo serves many of the low congestion regions of New York State. This research used the rates for western New York, including Buffalo and Niagara Falls. SC-3 describes the electricity rates for large general service with peak consumption between 100 kW and 2000 kW. A day-ahead RTP tariff, SC-3A, is mandatory for customers with peak demand larger than 2000 kW. Although the buildings studied in this research do not use it, it is included for illustrative purposes. Standby service rates are defined in SC-7, which went into effect in January 2004 and were available for this research through October 2004. For this research, 2003 was the test year

[13] Customers must still pay the non-energy components of the flat supply rate, which include the cost of capacity and ancillary services and amount to approximately $0.01/kWh to $0.02/kWh.
[14] One cubic foot of natural gas contains approximately 0.001 therms.

and 2004 standby delivery rates were applied to the 2003 parent tariff. As before, February values were used for December and January and October values applied for November, thus estimating a full year's data.

4.4.3.1 SC-3: Large General Service

SC-3 contains fixed monthly ($) fees; delivery charges in the form of monthly block rate demand ($/kW) charges, and block rate volumetric ($/kWh) and volumetric ($/kWh) supply charges. Supply charges are updated monthly.

4.4.3.2 SC-3A: Large General TOU Service

SC-3A is mandatory for customers with peak demand over 2000 kW. Although the building type considered in this report would not use it, it is included for completeness. The structure is similar to SC-3, although the volumetric delivery charges are different for on-peak and off-peak hours.

4.4.3.3 SC-7: Standby Service

Standby service replaces the delivery portion of parent tariffs with the mandated structure of fixed ($), contract demand ($/kW), and daily demand ($/kW) charges. The volumetric supply rates are the same as in the parent tariffs.

4.4.3.4 Natural Gas Rates: NSC-3 and NSC-12

NGSC-3 describes the natural gas rates for large customers. There is a fixed ($/month) charge for consumption up to three therms, and volumetric ($/therm) charges for consumption above that.

NGSC-12 lists natural gas rates for DG customers. The structure is the same as NGSC-3, with a fixed ($/month) charge for the first three therms and volumetric charges for consumption beyond that. NGSC-12 has special rates for customers with different total annual consumptions. The volumetric charges for NGSC-12 are less than those listed in NCSC-3. However, customers must maintain a load factor[15] greater than 50% to be eligible for NGSC-12.

[15] Load factor is defined as [Annual Usage] / [365*(Winter Peak Day Consumption)].

5. Studies

DER-CAM was used for three sets of studies to determine economically optimal DG investment and operation under different rates. DER-CAM tested current tariffs for each of the congestion regions and rate structures. Next, it analyzed sensitivities with mid-range generic tariffs to find the significant factors fostering or deterring DG use. Last, it ran sensitivities adding subsidies for other DG technologies. The purpose was to examine how tariff structure affects DG economic feasibility, and subsequent energy consumption and emissions implications.

5.1 Current Rates

Energy rates were varied to represent the three congestion regions of New York State, and then the three volumetric pricing structures (flat, TOU, and RTP) within the three tariff structures (parent tariff, New York style standby, and California style standby). As described in Chapter 4, rates for 2003 were collected from the utilities serving the congestion regions and translated into DER-CAM tariff input. These rates are listed in Appendix B.

5.2 Sensitivities

Because electricity rates and structures are complex, the regional studies did not produce results from which a tariff's structural effects on DG economic feasibility could clearly be determined. Therefore, generic rates were developed and sensitivity analyses performed by varying one parameter (volumetric electricity rates, volumetric natural gas rates, or electricity demand rates) per analysis. The generic rates are described and shown in Appendix C.

5.3 Sensitivities with Subsidy

Finally, to examine the combined effects of tariff structure and public benefit incentives, sensitivities were repeated adding subsidies for using PV, fuel cells, and microturbines instead of natural gas ICEs. The results of these sensitivities are presented in Appendix F.

6. Results and Analysis

This section presents and discusses the results of the rate and sensitivity analyses described in Section 5. They provide insight into the effects of tariff structure on DG future adoption. The subsidy sensitivities described in Subsection 5.3 are presented in Appendix F.

6.1 Current Utility Tariff Results

DER-CAM first assessed economically optimal investment decisions for the prototype hospital under the various tariffs, abbreviated in this section's graphics as:

- **FLT:** flat volumetric ($/kWh) charges,
- **TOU:** time of use volumetric charges for peak and off-peak hours,
- **RTP:** day-ahead hourly volumetric charges,
- **No inv:** scenarios in which DG investments were not allowed,
- **Inv:** scenarios in which DG investments were allowed and the parent tariff was applied,
- **Standby:** scenarios in which DG investments were allowed and the appropriate standby tariff was applied.

Figure 6 shows the optimal DG system solution for each tariff. In all cases, DER-CAM selected only natural gas engines, although PV, natural gas fired microturbines, and fuel cells were also available. Natural gas fired technologies can be purchased as:

- **generator**: for electricity only,
- **generator and heat exchanger**: for electricity and heat recovery for heating
- **generator, heat exchanger, and absorption chiller**: for electricity and heat recovery for heating and cooling

The installed capacities displayed in Figure 6 predict the peak load offset DG investment could bring. Figure 7 shows the source of consumed electricity under each of these scenarios. Note that the installation of absorption chillers in the ConEd flat rate cases slightly reduces the total amount of electricity required. Figure 8 shows the resulting annual energy bills under each tariff, broken down into utility electricity bills, utility natural gas bills, and DG costs (amortized capital costs plus maintenance costs).

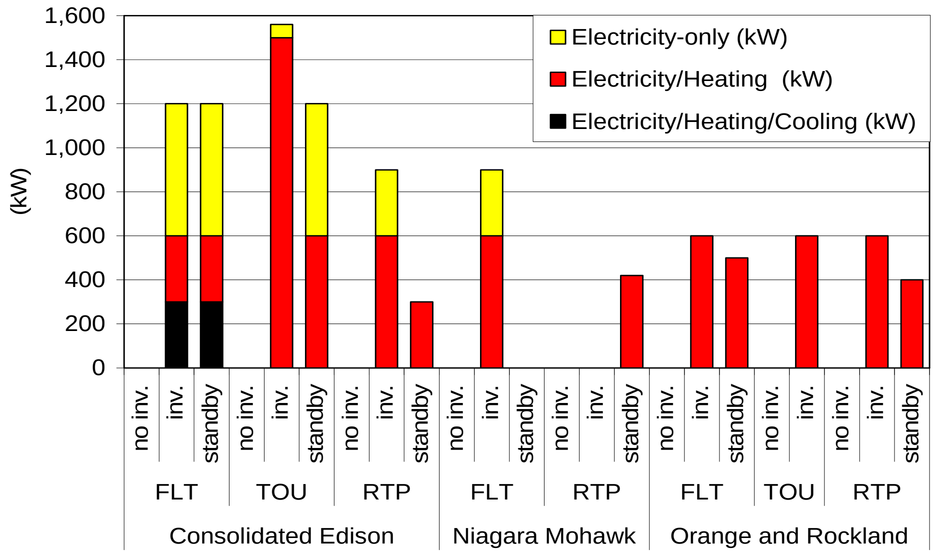


Figure 6: Economically optimal natural gas DG system installation under various tariffs

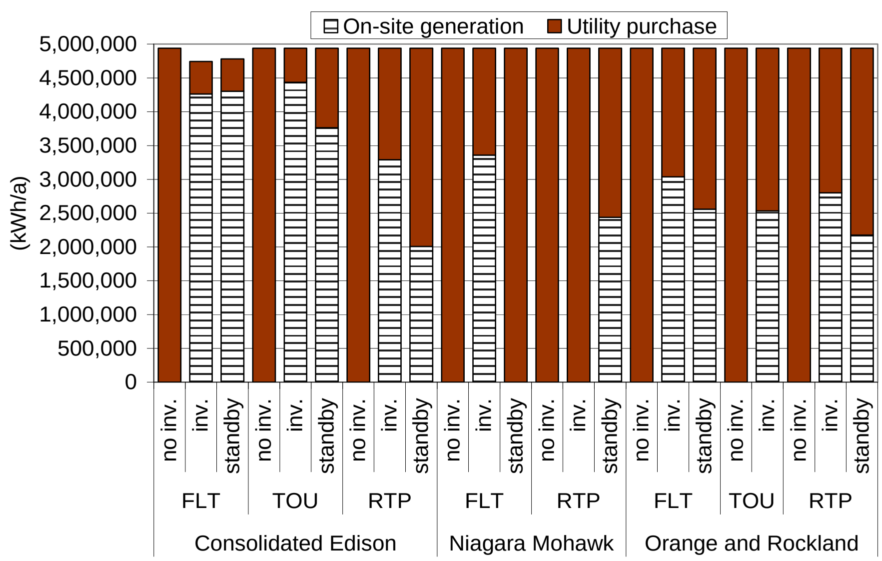


Figure 7: Electricity consumption sources under various tariffs

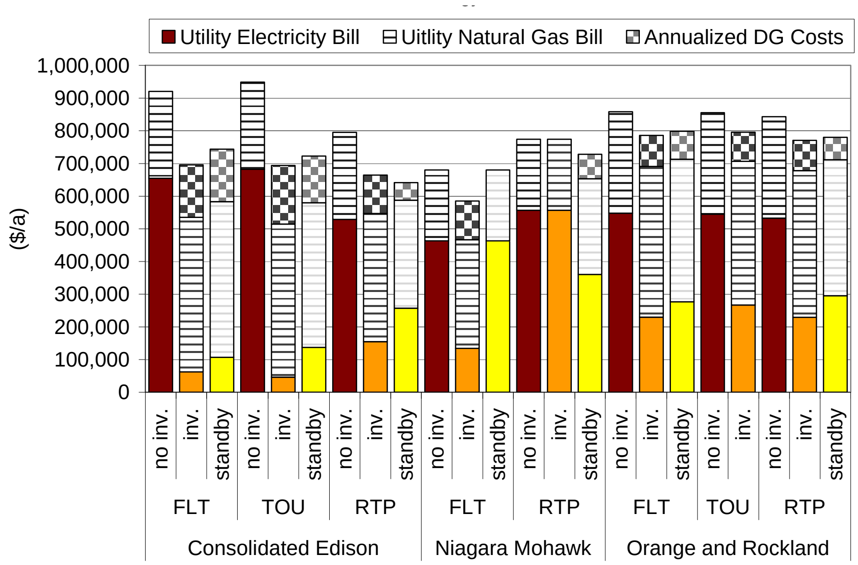


Figure 8: Total annual energy cost under various tariffs

Figure 9 shows the amount and percentage of carbon equivalent[16] reductions compared to the no-investment case.[17] In all cases where DG systems were installed, carbon emissions were reduced between 1% and 8.5%, or 10 to 80 metric tons carbon equivalent.

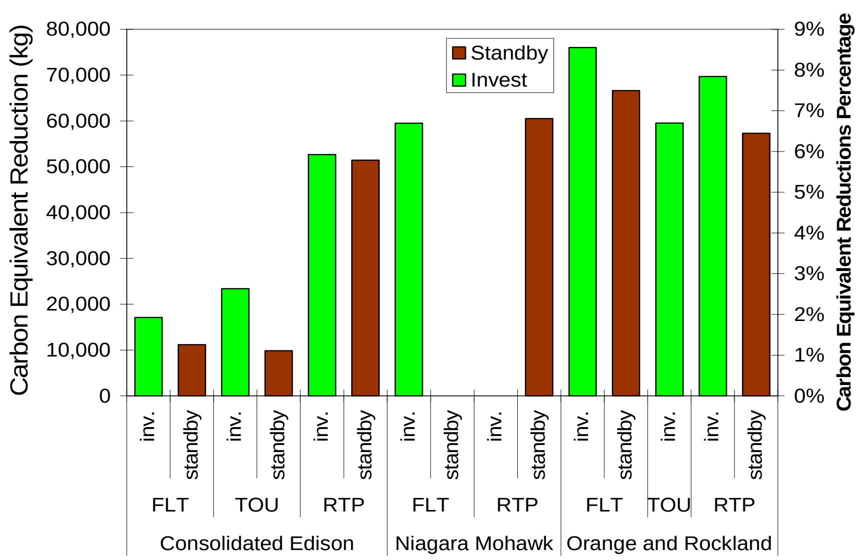


Figure 9: Carbon equivalent reductions after optimal DG installation under various tariffs.

[16] Carbon dioxide (CO_2) is the only greenhouse gas considered in this analysis. One kg of CO_2 contains 0.273 kg of carbon, and has a carbon equivalent value of 0.273 kg.
[17] The average carbon equivalent emissions rate for New York State power plants (0.13 kg/kWh) was derived from data reported in NYSERDA (2002).

6.2 Current Utility Tariff Analysis

Under the utility rates scales examined, standby tariffs discourage DG capacity in five of the seven cases where parent and standby tariffs exist, and only encourage DG capacity in one of them. The higher fixed and lower volumetric costs under standby rates reduce the marginal cost of utility electricity and, therefore, DG offsets to utility purchase are less economically attractive. To pay off under standby rates, DG must be efficiently utilized. This encourages smaller DG systems with higher load factors. It also encourages DG systems sized to meet heating loads rather than electrical loads.

Although standby rates discourage DG adoption, higher energy prices in more congested areas encourage it. Figure 6 shows this; in low-congestion, low-priced western New York State, NiMo tariffs encourage the least DG capacity, while in high-congestion, high-priced New York City, ConEd rates encourage the highest, much of it generating electricity only.

Across all tariffs and structures, ICEs are the dominant technology. Heat recovery for heating is always economical, and in cases with high marginal electricity costs, some DG without heat recovery is also profitable. ConEd tariffs encourage the largest DG systems, many of which do not use recovered heat. However, while DG without heat recovery is profitable there, it is also less energy and carbon efficient than purchasing electricity from the utility. Figure 9 illustrates this, showing that the ConEd cases reduce carbon emissions the least. For NiMo and O&R, DG is economical only when both the electricity *and* the heat are used; they are the most carbon efficient systems.

A comparison of Figure 8 to Figure 6 shows that the volumetric pricing structure has less effect on DG economics than the actual price of electricity: for O&R, annual electricity costs are comparable for all three structures (flat, TOU, and RTP) and DG capacity is the same. For ConEd, annual electricity costs are greatest under the TOU structure and least under the RTP structure – installed capacity is correspondingly greatest under the TOU structure and least under the RTP structure.

6.3 Sensitivities

While assessing DG adoption under actual New York tariffs offers some insights, the number and complexity of the variables in each scenario make the effects of each variable difficult to identify. Therefore, generic tariffs of varying structures were developed and single-variable sensitivities performed on each generic tariff.

There are two types of tariff structures: volumetric electricity pricing and standby rate. Electricity pricing structure was categorized as:

- **Flat**: constant rates for every hour of the month,
- **TOU**: “time of use” – two rates for each month: one for on-peak and one for off-peak consumption,
- **RTP**: “real time pricing” – hourly rates announced each day for the following day.

Standby rate structure was categorized as:

- **Parent**: standby service provided at parent tariff rates,
- **Standby**: standby service provided at typical New York standby rates, including fixed contract demand and monthly charges, and daily demand charges,
- **Standby-CA**: California style standby rates, consisting of a standby charge on the installed capacity of the DG system. The parent tariff determines the charge (see Section 2.4).

From these two structures, there were nine possible combinations to consider for each single-variable sensitivity. For the technology subsidy sensitivities, only the most common tariffs, TOU-Parent and TOU-Standby, were used.

Because O&R rates are close to the median for New York State (see Section 4.2), they became the basis for the generic tariffs. As described earlier in Subsection 4.4.2, O&R offers flat, TOU, and RTP rates, with a standby rate for the flat and RTP ones. That same standby rate was used to make the generic TOU rate. Additionally, Standby-CA rates came from adding a standby charge of $3.34/kW of installed capacity to the parent tariffs. It is the average of the standby rates for the three IOUs in California.[18] Appendix C lists these nine rates as expressed in DER-CAM, which are referred to as the *base cases*.

DER-CAM conducted sensitivity tests on three energy cost components for the nine different rates: volumetric electricity ($/kWh) and volumetric natural gas ($/kJ) rates, and demand charges. In each test, one parameter was varied as a percentage of the base case value. For example, for the volumetric electricity sensitivity, each base case was tested with rates varying from 50% to 200% at 10% intervals. DER-CAM performed 144 runs, 16 runs for each of the nine tariff structures.

In all sensitivity cases, DER-CAM selected natural gas engines as the technology for DG optimal investment. However, alternative DG types can provide public benefits and, therefore, public subsidies for these technologies were considered. The three sensitivities above (volumetric electricity, volumetric natural gas, and demand rates) were repeated for various levels of subsidy for PV, microturbines, and fuel cells. For each technology, three different subsidy levels were considered. Only TOU-Parent and TOU-Standby structures were considered because they are most common. These results are presented in Appendix F.

For all graphs in this section, the nine structures are referred to and shown as follows:

Structure	Reference name in figures	Line	Marker
Flat-Parent	FLAT	thin, dotted	+
Flat-Standby	FLAT_NY	medium, dotted	+
Flat-Standby-CA	FLAT_CA	thick, dotted	+

[18] Current (July 2004) standby rates from major investor-owned utilities in California are $2.40 from Pacific Gas and Electric, $3.35 from San Diego Gas and Electric, and $4.26/kW from Southern California Edison.

TOU-Parent	TOU	thin, solid	Δ
TOU-Standby	TOU_NY	medium, solid	Δ
TOU-Standby-CA	TOU_CA	thick, solid	Δ
RTP-Parent	RTP	thin, dashed	o
RTP-Standby	RTP_NY	medium, dashed	o
RTP-Standby-CA	RTP_CA	thick, dashed	o

In standby tariff cases where DER-CAM selected no DG, results are reported as if the parent tariff were imposed, not the standby tariff.

6.3.1 Volumetric Electricity Rates

For each of the nine rate structures, DER-CAM tested volumetric electricity rates from 50% to 200% of the base case values in increments of 10%. The results are presented graphically below. For each figure, the top left graph shows the results for all rate structures and all sensitivity points. For ease of comprehension, the other three graphs in each figure separate these results into flat (FLT), TOU, and RTP cases.

Figure 10 displays the installed capacity for each scenario in the volumetric electricity rate sensitivity. As expected, volumetric rates can make or break DG adoption. If they decrease below 80% of their current values, almost no DG adoption is seen. However, if rates increase to 160% of their current values, significant DG adoption occurs under all tariff structures. Two important phenomena are noticed:

- For the Flat and RTP structures, DG adoption capacity increases gradually from zero to 1000 kW as volumetric rates increase from 80% to 160%. However, this increase is much sharper under TOU structures, and starts approximately at the base case rates.
- As expected, the parent tariffs encourage larger DG installations than the respective standby tariffs. For the TOU structures, the shift from parent tariff to New York style standby shifts the threshold price for installation from 90% to 120% of base case volumetric electricity rates.

Figure 11 shows the total annual energy cost for each scenario, including all utility electricity and natural gas purchases, as well as annualized capital and maintenance costs for the DG system selected. As volumetric prices increase, DG systems are used to insulate customers from increased energy costs. For the TOU New York standby structure (TOU_NY), the spike in energy costs at 120% of base case volumetric rates is due to the payback period constraint[19] in DER-CAM. While lower annual energy bills could be achieved by larger DG investment at this point, the payback period would be too long. However, when volumetric rates increase further, the payback period on DG systems is reduced, and larger systems are installed, thus reducing energy costs, even with increasing energy prices.

Figure 12 and Figure 13 display the heating and cooling load offsets from recovered heat. Absorption chillers recover waste heat to provide air-cooling load offsets. For heating offset

[19] The DER-CAM payback period constraint is six years.

(Figure 12), the transition from no offset to maximum (approximately 5.5 GWh of heating annually) is rapid and clustered around the base case rates. The transition is slightly more gradual for the RTP rates than for the flat and TOU rates. This is intuitive, as DG system operation under RTP rates may be responding to fluctuating volumetric prices exceeding a threshold, whereas under flat and TOU rates, the monthly rate is either above or below the threshold. Cooling offset (Figure 13) from investing in absorption chillers becomes economical when volumetric electricity prices exceed 120% of current values.

When volumetric electricity rates surpass a threshold, DG systems begin to become economical. Initially, systems are sized to match the heating load. As Figure 12 shows, no additional heating offset is achieved as installed capacity increases (Figure 10). As it increases, the excess recovered heat is used for absorption chilling (Figure 13). While absorption chillers reduce the electrical load, DG systems that run year-round but only cool with recovered heat when cooling loads are present are less carbon efficient than using utility electricity for all electricity and cooling loads. This point is illustrated by comparing Figure 13 to Figure 14, which show the total carbon equivalent emissions from utility electricity consumption and from on-site natural gas consumption. Carbon emissions reach a minimum where heating load offsets saturate (120% of base case volumetric rates) and then increase as DG installed capacity increases.

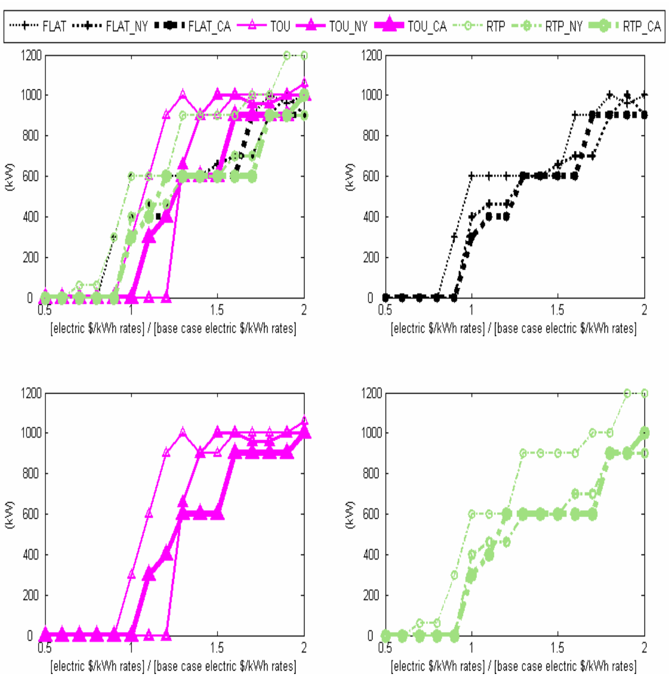


Figure 10: Installed DG capacity for volumetric electricity rate sensitivity

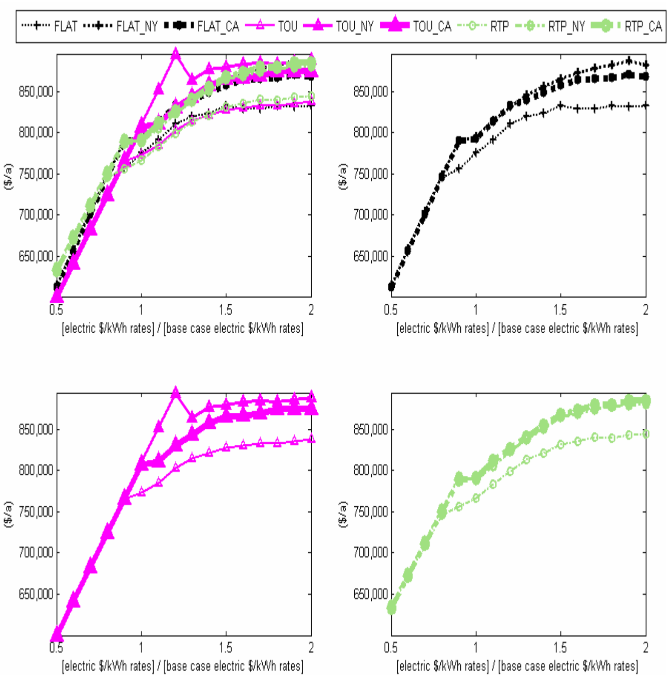


Figure 11: Total annual energy cost for volumetric electricity rate sensitivity

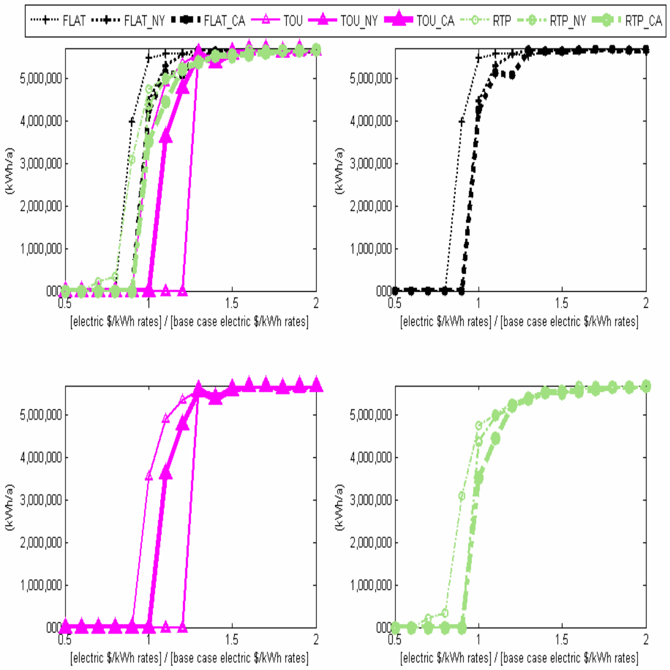


Figure 12: Heating load offset by recovered heat for volumetric electricity rate sensitivity

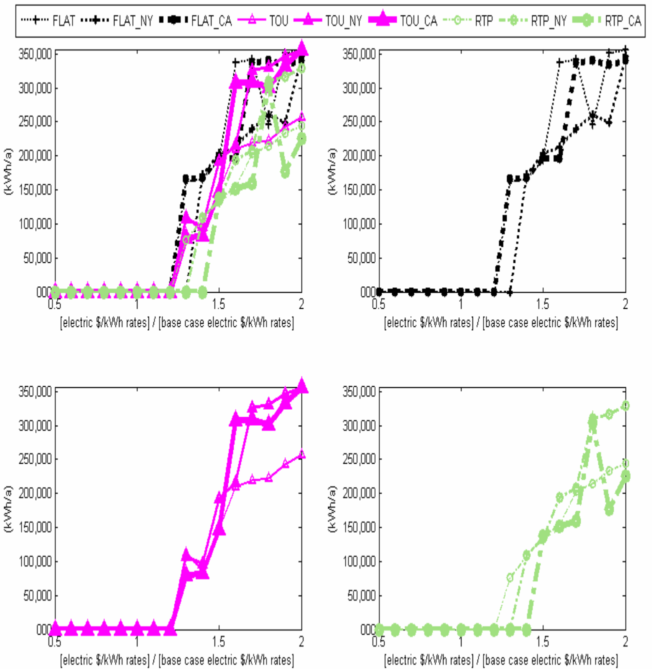


Figure 13: Cooling load offset by recovered heat for volumetric electricity rate sensitivity

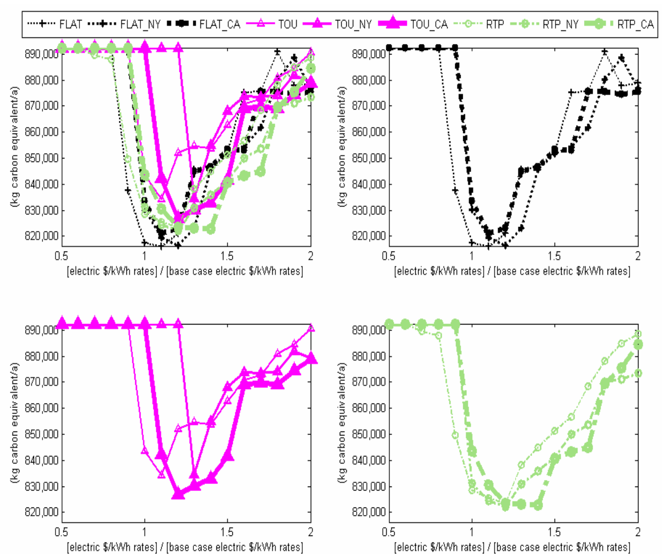


Figure 14: Total carbon equivalent emissions for volumetric electricity rate sensitivity

6.3.2 Volumetric Natural Gas Rates

A sensitivity analysis of volumetric natural gas rates was also conducted. For each of the nine structures, DER-CAM varied volumetric natural gas rates from 30% to 300% of the base case values in increments of 10%. The results are presented graphically below.

Figure 15 shows the total installed electrical capacity of DG in the volumetric natural gas rate sensitivity. The price of natural gas effectively determines DG feasibility. If volumetric rates are increases to 150% of base case, no DG installation is economical. Although DG can improve energy efficiency at a site, it cannot shield against increases in natural gas costs (Figure 16). As in the volumetric electricity rate sensitivity, carbon emissions (Figure 19) are minimized when DG systems are sized to meet heating load (Figure 17) rather than heating and absorption cooling loads (Figure 18).

DG's pattern of sensitivity to natural gas prices is consistent across tariff structures, although DG investment under the New York style standby tariff with TOU volumetric electricity pricing becomes uneconomical at lower natural gas prices (70% of base case) than do the other structures (100% to 140% of base case).

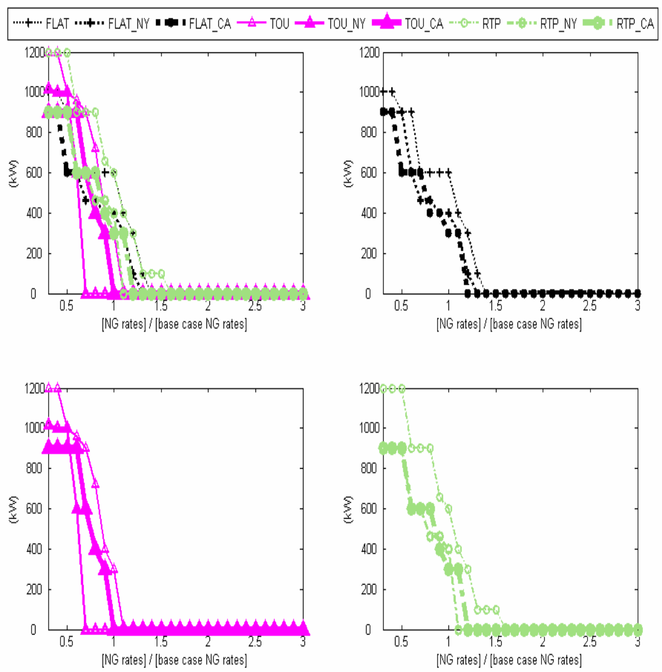


Figure 15: Installed DG capacity for volumetric natural gas rate sensitivity

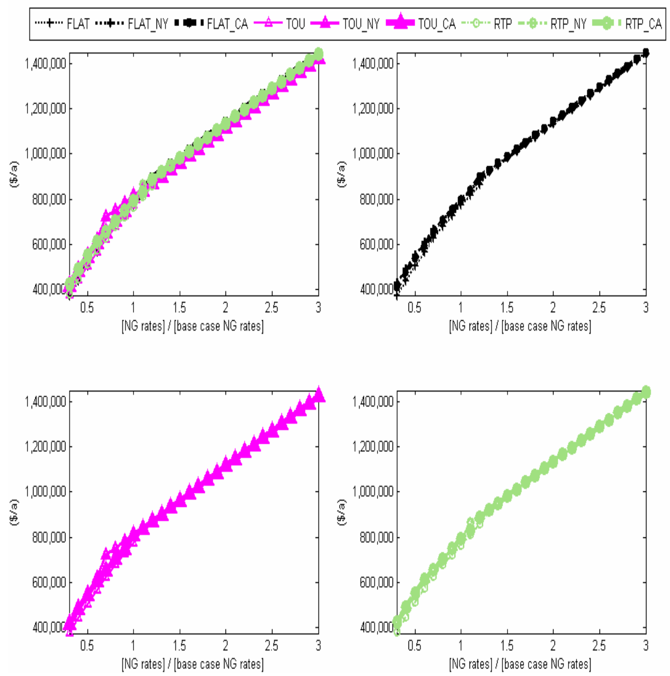


Figure 16: Total annual energy cost for volumetric natural gas rate sensitivity

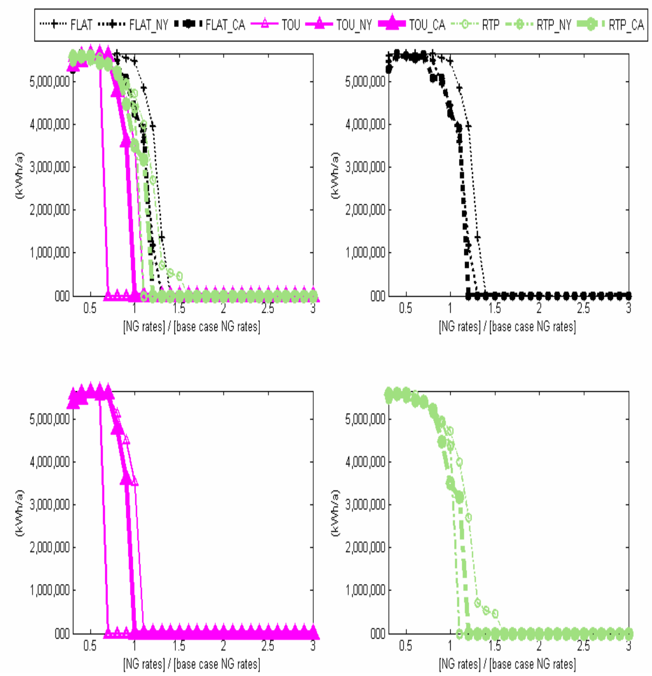


Figure 17: Heating load offset by recovered heat for volumetric natural gas rate sensitivity

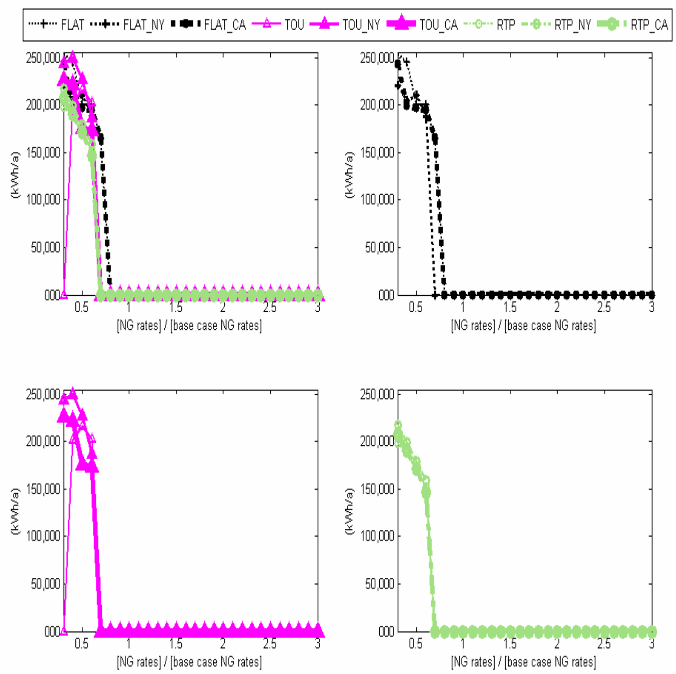


Figure 18: Cooling load offset by recovered heat for volumetric natural gas rate sensitivity

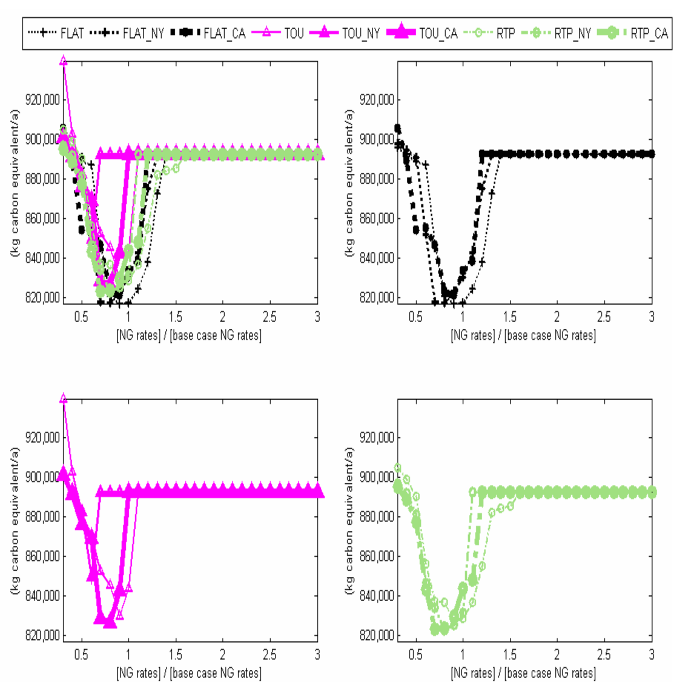


Figure 19: Total carbon equivalent emissions for volumetric natural gas rate sensitivity

6.3.3 As-used Demand Rates

The third sensitivity analysis tested electricity as-used demand rates. These are the as-used monthly demand rates under parent tariff and California standby tariff structures, and the as-used daily demand rates under New York standby tariff structures. Fixed charges such as contract demand (New York standby) and capacity demand (California standby) were not varied. For each of the nine structures, DER-CAM varied as-used demand rates from 30% to 300% of the base case values in increments of 10%.

In all cases, parent tariffs encourage significantly more DG installation than standby tariffs (Figure 20). Clearly, demand charges are an effective way to influence the level of DG installation. The TOU New York standby (TOU_NY) tariff particularly discourages on-site generation, although after as-used daily demand charges surpass 200%, DG installation quickly catches up to the levels other rate structures encourage. Note here that an annual energy cost spike (Figure 21) is present, as in the volumetric natural gas rate sensitivity, again from the imposed payback period constraint.

The demand sensitivity emphasizes that the TOU New York and California (TOU_NY and TOU_CA) standby rates are the least favorable for heat load offset (Figure 22). Cooling loads (Figure 23) for the RTP tariffs are economically offset by absorption cooling for much lower demand charges (200% of base case) for the parent tariff structure (RTP) and the California standby (RTP_CA) than for the New York standby (RTP_NY).

There is no tradeoff between using recovered heat for heating versus cooling; instead, as demand rates increase, DG systems are first installed to meet heating loads, then enlarged and the remaining recovered heat is used to offset cooling loads (Figure 22 and Figure 23). This implies that demand charges are not large enough to make absorption cooling the best option for recovered heat. Installed system capacity increases beyond the size for meeting heating load more gradually in this sensitivity than in the others; therefore, the carbon emissions do not show the same well defined minimum seen earlier.

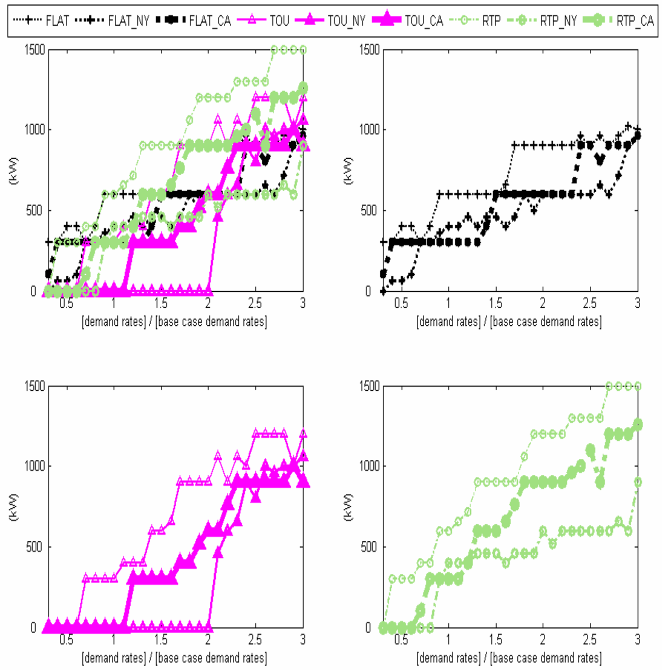


Figure 20: Installed DG capacity for as-used demand rate sensitivity

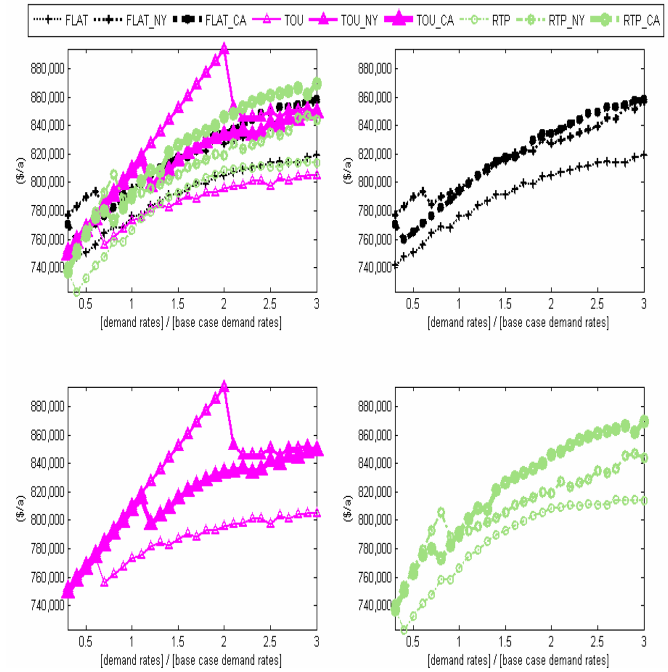


Figure 21: Total annual energy cost for as-used demand rate sensitivity

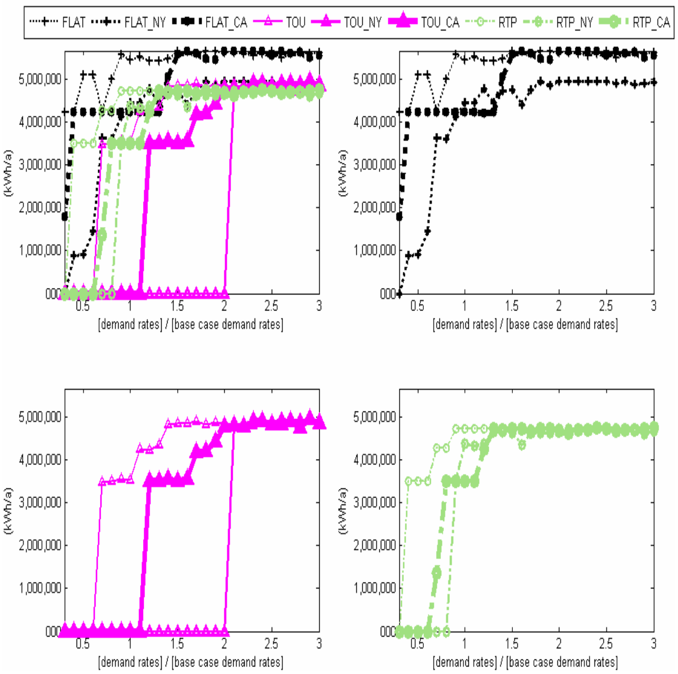


Figure 22: Heating load offset by recovered heat for as-used demand rate sensitivity

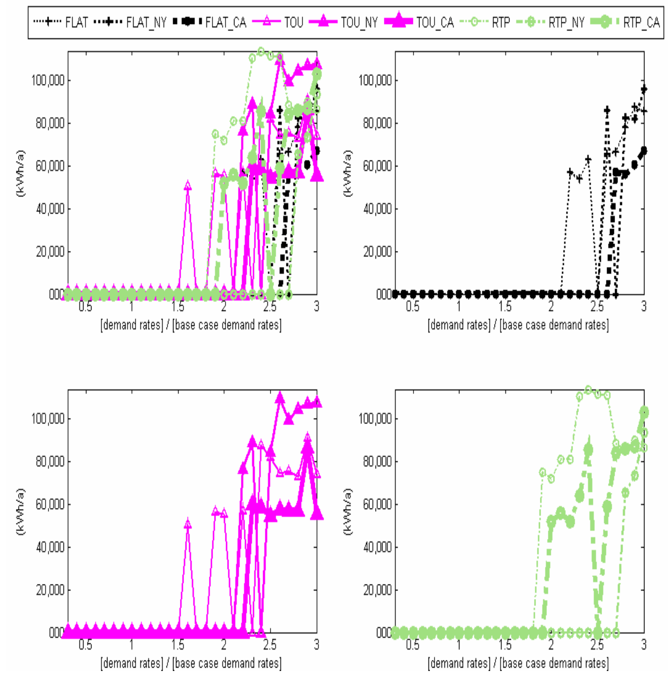


Figure 23: Cooling load offset by recovered heat for as-used demand rate sensitivity

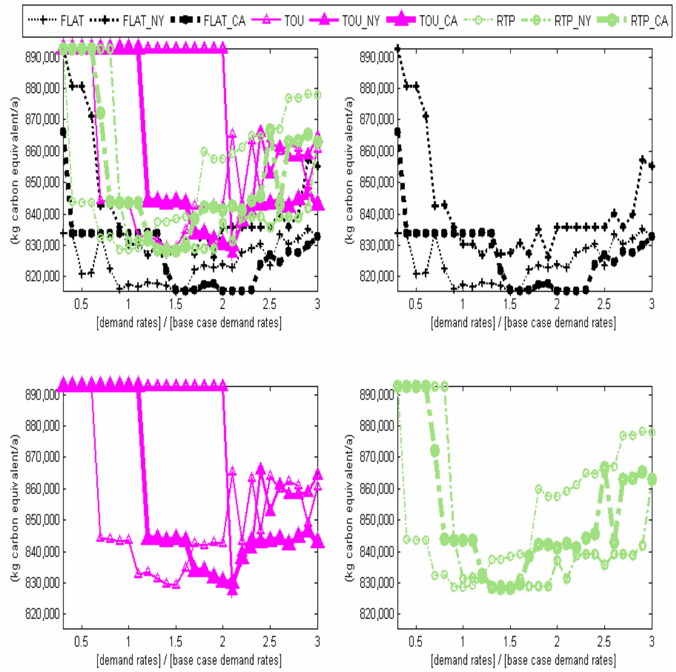


Figure 24: Total carbon equivalent emissions for volumetric natural gas rate sensitivity

6.4 Encouraging Alternative Technologies

In all the sensitivities, DER-CAM selected only natural gas engines, the dominant DG technology. However, other technologies may offer societal benefits and earn subsidies through the NYSERDA program described in Appendix subsection G.1. The three sensitivities (volumetric electric, volumetric natural gas, and as-used demand charges) were repeated with capital cost subsidies for the alternatives, fuel cells, microturbines, and PV. Only the TOU parent (TOU) and New York style standby (TOU_NY) were considered for these studies, again because those rates are the most common. The subsidy parameter was varied from 50% to 200% of base case prices in increments of 25%. Because carbon dioxide is the only emission in DER-CAM, it is the primary focus of these sensitivities, although alternate technologies would also reduce emissions of NO_2, SO_2, and particulate matter. Key results are discussed here and detailed findings are presented in Appendix F.

For all sensitivities, alternative technologies require significant subsidies before they are selected instead of, or in addition to, natural gas engines. Fuel cells and PV need 90% subsidies, and microturbines 75%. Natural gas engines are particularly well suited to sites where electric and heating loads are about equal. PV and fuel cells are more economically attractive to sites with lower heat loads.

As in the earlier sensitivities, standby rates encourage lower DG investment levels than parent tariffs. As-used daily demand charges under standby tariffs contribute to lower marginal costs of electricity than monthly demand charges under parent tariffs. Standby rates, however, recoup this difference in marginal revenue by assessing fixed contract demand charges. The result lessens the economic incentive to install or operate DG systems.

Marginal costs of operation are significant factors in selecting DG options. In the technology subsidy sensitivities, subsidized capacity reaches 1200 kW for PV systems, ranges from 400 to 800 kW for fuel cells, and is near 200 kW for microturbines. This coincides with the ordering of marginal energy costs: PV with no marginal cost, fuel cells with high electrical efficiency and thus low marginal costs, and microturbines, with relatively low electrical efficiency and thus high marginal costs.

7. Discussion and Conclusions

Standby customers consume utility electricity differently than if they purchased all of their power from the utility. The IOUs of New York State have successfully argued that because of this difference, standby customers should be charged differently than standard customers for electricity.

As shown in this report, altering tariff structures changes the economic incentives to invest in DG. Understanding these changes and the resulting implications to customers, utilities, the public, and the environment is key to developing effective DG policy.

New York standby tariffs simultaneously increase fixed utility electricity costs and decrease marginal utility electricity costs. Both of these discourage DG investment. Standby rates encourage base-loaded units, which make load factors of DG customers lower than those of their non-DG counterparts. Utilities may then see DG customers as “peakier,” or having more variations in their use patterns than their full-service counterparts. Further, for the prototypical hospital, standby tariffs encourage DG systems sized *smaller* than the heat loads. This means that fuel and carbon savings from using recovered heat are not maximized.

To counter this, however, customers generating less than 1 MW of electrical capacity, can avoid standby tariffs by operating their DG systems at combined efficiencies of 60% or greater. Because parent tariffs are more favorable to customers, this discourages installing DG capacity *larger* than the heat loads.

The sensitivities described in Chapter 6 demonstrate that as-used demand charges are proportionally higher under typical parent tariffs (monthly demand) than under standby tariffs (daily demand). This further illustrates the discouraging effect that standby tariffs create for peak-shaving DG systems, as peak-shaving is motivated by high marginal costs of daytime electricity, such as those caused by demand charges. Peak-shaving is using any strategy that will lower peak usage.

However, the observations of subsection 6.2 suggest that the effect of tariff structure is less important than the magnitude of the rates. The *volumetric rate structure* does not appear to be significant, while the *standby structure* does tend to reduce the capacity of DG systems.

The subsidized technology sensitivities emphasize the importance of the marginal electricity cost in determining DG investments. PV systems have no marginal cost, fuel cells have lower marginal costs than ICEs, and microturbines have higher marginal costs than ICEs. Their levels of installation (at favorable subsidy) reflect this: PV capacity reaches 1200 kW, fuel cell capacity ranges from 400 to 800 kW, and microturbine capacity is near 200 kW. In addition, both installed capacities of alternative technologies and marginal energy cost differentials tend to be greater under parent tariffs than standby tariffs.

Given that standby tariffs imposed by the utilities are to be cost based, this study can be used to suggest countermeasures that public agencies can take to encourage desired levels of DG capacity installation. This can effectively be done by adjusting the marginal cost differential between DG electricity production and utility purchase. One way to achieve this would be to subsidize natural gas costs for DG. The level of subsidy would depend on the objective – encouraging optimally efficient CHP systems would require changing one level of marginal cost differential, while encouraging peak-shaving DG systems would require a higher one.

From the customer perspective, exemption for standby tariffs is desirable in most cases; for systems under 1 MW, maintaining an overall system efficiency of 60% or greater would qualify customers for exemption. Also exempt are customers with fuel cells or DG systems fueled by renewable resources, sustainably-managed biomass, and methane waste. For larger customers, systems with high capital costs and low marginal energy costs may be more desirable under standby tariffs than under parent tariffs.

This report illustrates the effect of tariff structure on DG economics for a site with well-balanced electrical and heating loads. Further research is required to determine how tariff structures affect sites with less balanced loads, as well as sites with larger and smaller end-use loads than the small prototypical hospital considered here. Additionally, the effects of thermal storage and end-use demand elasticity – through rescheduling or limiting the load – should be considered to construct more accurate models on which potential DG adopters can base their decisions.

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Appendix A. Hourly End-use Load Profiles

Annual hourly end-use loads from the Wyoming County Hospital, in Warsaw, NY were used as prototypical New York State hospital loads. These data were compiled as part of a DG case study[20] conducted by LBNL (Bailey, 2003). Load profiles were developed for three day-types in each month: typical weekdays, peak weekdays, and weekend days. **Typical weekday** ("week" in the graph below) is the average of all but the three highest consumption weekdays of the month. **Peak weekday** ("peak") is the average of the three highest consumption weekdays of the month. **Weekend day** ("weekend") is the average of the weekend days and holidays of the month. End-uses in this research are electricity only, cooling, space heating, water heating, and natural gas only, each of which is described below. The graphs in this appendix show the end-use loads for four representative months: January, April, July, and October, although DER-CAM uses hourly data for all twelve months.

Electricity-only refers to loads that can only be met by electricity. This includes all electricity loads except space cooling, which could also be met by heat via an absorption chiller.
Figure A- 1 displays electricity only loads.

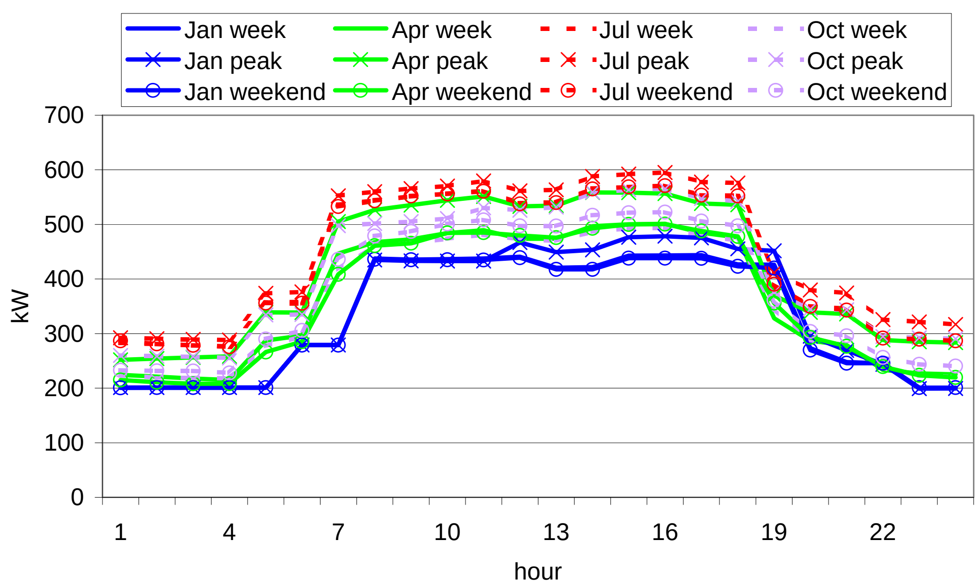

Figure A- 1: Electricity-only loads

[20] Although the Wyoming County Hospital was not selected as one of the five case studies pursued in detail, LBNL researcher Owen Bailey visited the site, collected data, and generated the load profiles required for DER-CAM.

Cooling refers to electricity required to provide space cooling. In DER-CAM, when an absorption chiller provides space cooling, the recovered generator heat used is translated into an offset of the cooling electricity load. Figure A- 2 displays cooling loads.

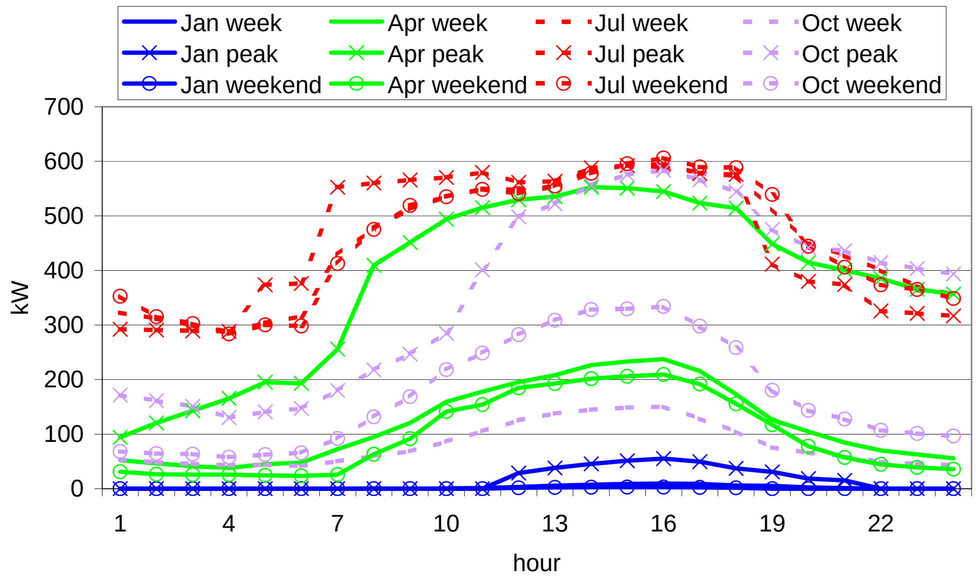

Figure A- 2: Cooling loads

Space heating refers to the space-heating load, shown in Figure A- 3. The amount of heat (from natural gas combustion or recovered generator heat) required to meet this load is greater than the load itself because of imperfect heat transfer in boilers and heat exchangers.

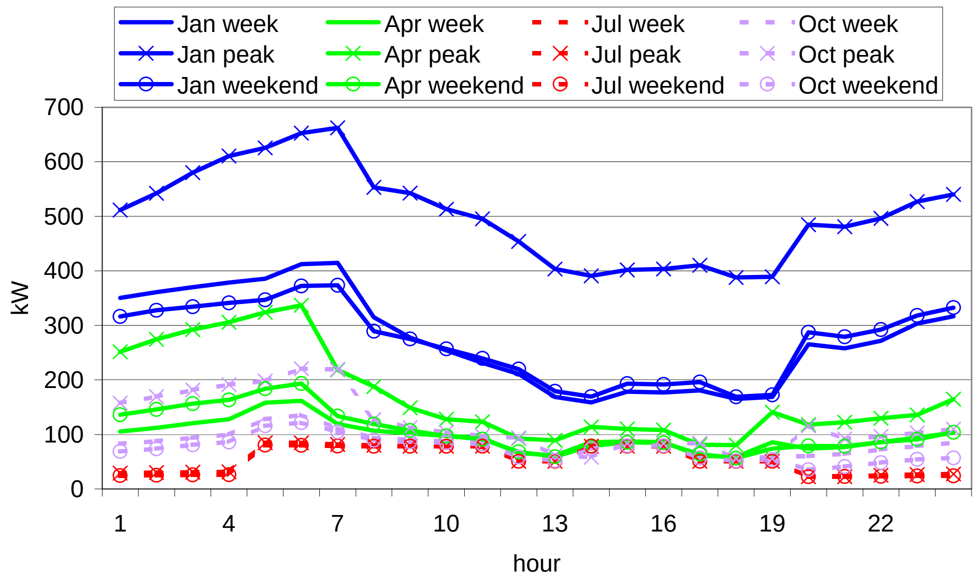

Figure A- 3: Space heating loads

Water heating refers to the water-heating load, again shown in Figure A- 4. The amount of heat (from natural gas combustion or recovered generator heat) required to meet this load is greater than the load because of boiler and heat exchanger inefficiencies in heat transfer.

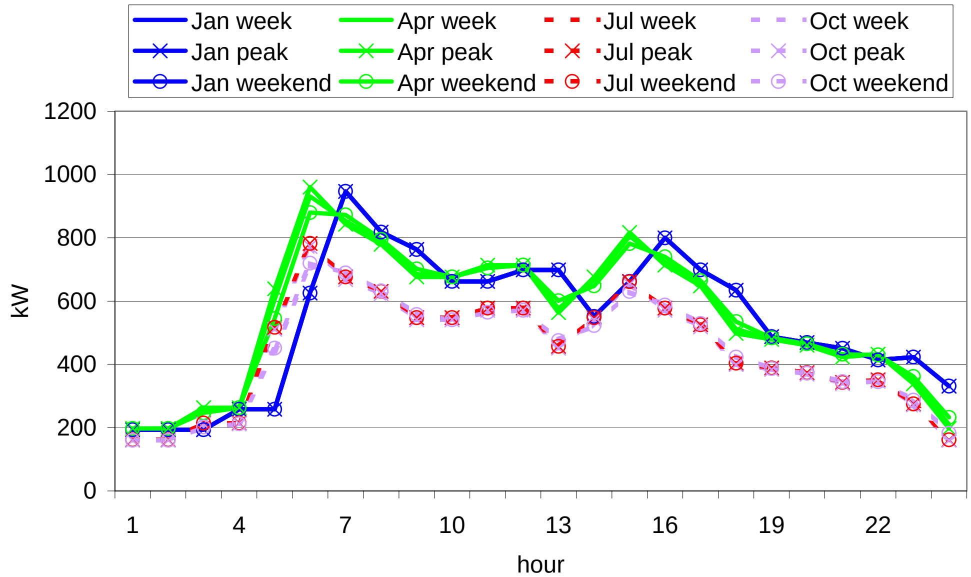

Figure A- 4: Water heating loads

Natural Gas Only refers to loads that can only be met by natural gas. These include distributed heating loads that would not be connected to a centralized cogeneration system and some cooking loads. Figure A- 5 displays natural gas only loads.

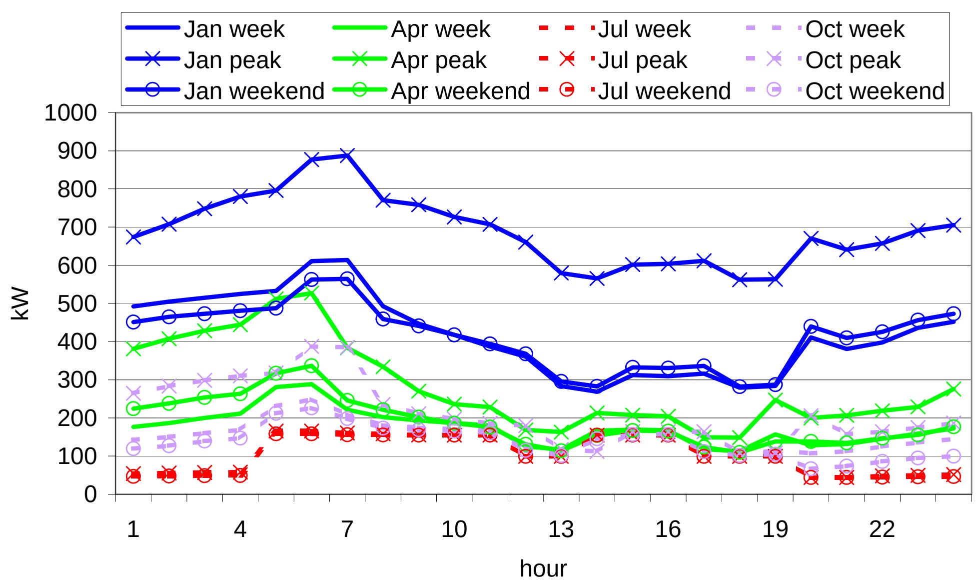

Figure A- 5: Natural Gas Only loads

Appendix B. Utility Electricity and Natural Gas Tariffs and Corresponding DER-CAM Representations

This appendix describes the utility tariffs used in this research, and their DER-CAM representations. Certain assumptions were made in creating the DER-CAM tariff input, mostly regarding block structures, which cannot be represented in DER-CAM. Conveniently, for the cases considered, total demand and consumption values are consistently in the same block, so that final block rates can be used, with the expenses above this marginal price being attributed to fixed monthly costs. To illustrate this, consider a tariff where the volumetric supply price of electricity is $0.10/kWh for the first 1000 kWh (Block 1) and $0.05/kWh for all additional consumption (Block 2), and monthly consumption is always greater than 1000 kWh. Then, the Block 2 price ($0.05/kWh) will be the volumetric electricity rate for all consumption. To account for the additional cost of the Block 1 electricity, a fixed monthly charge of $50 ([$0.10/kWh - $0.05/kWh] x [1000 kWh]) is added to the DER-CAM rates.

B.1 Consolidated Edison

ConEd provides utility electricity and natural gas service to most of New York City and Westchester County. This research used only New York City electricity purchases, which are listed here.

For customers with electrical demand greater than 10 kW, ConEd's SC-9 defines three electricity rates. For each, separate standby charges are stated in SC-14RA, under which customers pay the supply charges of SC-9, but not the delivery (transmission and distribution) costs. Additionally, standby customers pay fixed monthly ($/month), contract demand ($/kW maximum potential load), and daily demand ($/kW maximum daily consumption) charges.

Standby rates went into effect in February 2004 and were available through October 2004 at the time of this research. For this study, 2003 was used as the test year. Therefore, the 2004 standby delivery rates were applied to the 2003 parent tariff. February values were also used for January and December, and October values substituted for November, thus providing estimates for a full year of data. Table A- 1 and Table A- 2 give these electricity rates for 2003 and their DER-CAM representations.

Natural Gas Rate 2 is applicable the buildings in this research. Reduced rates are offered during summer months for natural gas used for air conditioning and for DG. Table A- 3 states these natural gas rates for 2003 and their DER-CAM representations.

SC-9 Rate 1

Rate 1 concerns demand ($/kW) charges for maximum monthly demand, energy charges for volumetric consumption ($/kWh), and fixed monthly fees. It is a flat rate with cost per kWh constant, regardless of time of day.

SC-9 Rate 2

Rate 2 lists demand charges for maximum monthly demand during on-peak hours, separate energy charges for on-peak and off-peak consumption, and fixed monthly fees. It is a *time of use* (TOU) rate; the cost per kWh depends on the time of day. Rate 2 is mandatory for customers with peak annual loads above 1500 kW, or above 900 kW under some conditions.

SC-9 Rate 3

Rate 3 has the same structure as Rate 2, although the charges are higher. It is optional for customers not required to be on Rate 2. Rate 3 allows customers with proportionally less on-peak consumption than the typical customer to choose a rate with lower off-peak costs.

Voluntary Real Time Pricing

Under ConEd's Rider M, SC-9 customers may also choose to pay the location based day-ahead hourly prices set by the NYISO. Day-ahead prices are set and reported to customers by 4 p.m. on the day before the rates will be effective. Under Rider M, customers pay the NYISO charges for energy supply in addition to the delivery rates of their parent tariff. This tariff structure is called *real-time pricing* (RTP).[21]

Natural Gas Rates

Natural Gas Rate 2, General Firm Sales has a fixed monthly fee and an energy charge ($/therm). The energy fee is in a block structure, with an initial monthly volume (block) priced at one rate, and subsequent blocks at lower rates. This structure accounts for fixed infrastructure (delivery) costs by attaching them only to the first block of consumption. There are reduced rates for natural gas consumption for air conditioning (direct or indirect-fired absorption chillers) and for DG.

B.2 Orange and Rockland Utilities, Inc.

O&R provides electricity and natural gas to many suburban communities near New York City, not only in New York State, but also in northern New Jersey and northeastern Pennsylvania. Their service area includes the Hudson Valley load zone, described in this report.

SC-2 is the general electricity tariff for customers at secondary voltage levels. SC-20 is an optional TOU tariff for secondary customers with demand in excess of five kW for at least two consecutive months per year. Rider M allows customers under SC-2 and SC-20 to purchase their electricity at the day-ahead hourly rates. SC-25 is the standby service tariff.

[21] RTP may also refer to energy supply costs determined during the hour prior the hour to be priced. This is known as *day-of* hourly pricing. In this report, RTP always refers to day-ahead hourly pricing.

Standby rates went into effect in February 2004 and were available through October 2004 at the time of this study. For this research, 2003 was used as the test year. Therefore, the 2004 standby delivery rates were applied to the 2003 parent tariff. February values were also used for December and January, and October values were used for November, thus providing estimates for a full year of data. Table A- 4 shows these rates and their DER-CAM representations for 2003.

Natural Gas Service Classification 2 (NGSC-2) provides the applicable natural gas rates for the hypothetical building in the study. Table A- 5 shows these rates and their DER-CAM representations.

SC-2: General Secondary Service

SC-2 gives a fixed monthly ($) fee, delivery charges in the form of monthly demand ($/kW) charges, and block volumetric ($/kWh) and volumetric ($/kWh) flat rate supply charges. Delivery components have summer (June through September) and non-summer values.

SC-20: Option TOU Secondary Service

SC-20 is optional for SC-2 customers with peak demand greater than five kW for any two consecutive months each year. SC-20 contains a fixed monthly ($) charge, delivery charges in the form of monthly TOU demand ($/kW) charges, and TOU volumetric ($/kWh) and volumetric ($/kWh) supply charges. The periods for TOU delivery components are:

- Period 1: 1 pm - 7 pm, Monday – Friday, except holidays, June – September
- Period 2: 10 a.m. - 9 p.m., Monday – Friday, except holidays, October – May
- Period 3: all other hours

SC-25: Standby Service

SC-25 covers electricity rates for all standby customers. For SC-2 and SC-20 customers, SC-25 imposes fixed ($) monthly, fixed contract demand ($/kW contracted), daily demand ($/kW), and volumetric ($/kWh) supply charges. The supply charges are the same as those of the parent tariffs.

Rider M

Rider M allows customers under SC-2, SC-20, and SC-25 (along with several other service classifications) to opt to pay the NYISO day-ahead hourly RTP rates for the Hudson Valley load zone, instead of the flat market supply charges specified in the applicable tariff.[22]

[22] Customers must still pay the non-energy components of the flat supply rate. These include the cost of capacity and ancillary services of approximately $0.01/kWh to $0.02/kWh.

NGSC-2

NGSC-2, a separate tariff for natural gas service, contains fixed ($) monthly and volumetric ($/cubic foot) delivery and supply charges.[23]

B.3 Niagara Mohawk

The NiMo Power Corporation serves many of the low congestion regions of upstate New York. For this research, rates for western New York, including Buffalo and Niagara Falls were used. SC-3 describes the electricity rates for large general service with peak consumption between 100 kW and 2000 kW. A day-ahead RTP tariff, SC-3A is mandatory for customers with peak demand above 2000 kW. Although the buildings studied in this research do not use it, it is included for illustrative purposes. Standby service rates are defined in SC-7.

Standby rates went into effect in January 2004 and were available through October 2004 at the time of this research. For this study, 2003 was used as the test year. Therefore, the 2004 standby delivery rates were applied to the 2003 parent tariff. February values were also used for December and January, and October values were used for November, thus providing estimates for a full year of data. Table A- 6 shows these rates for 2003.

NGSC-3 deals with natural gas rates for large customers. NGSC-12 is a separate rate for natural gas used for DG. Table A- 7 shows these rates for 2003.

SC-3: Large General Service

SC-3 contains fixed monthly ($) fees, monthly block demand ($/kW) delivery charges, and block volumetric ($/kWh) and flat volumetric ($/kWh) supply charges. Supply charges are updated monthly.

SC-3A: Large General TOU Service

SC-3A is mandatory for customers with peak demand over 2000 kW. Again, although the building type considered in this report would not use it, it is included for completeness. The structure is similar to SC-3, although the volumetric delivery charges are different for on-peak and off-peak hours.[24] Supply charges are the RTP rates for the Frontier load region.

SC-7: Standby Service

Standby service replaces the delivery portion of parent tariffs with mandated fixed, contract demand, and daily demand charges. The volumetric supply rates of the parent tariffs remain unchanged.

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[23] For comparison to other natural gas rates, note that 1 cubic foot of natural gas contains approximately 0.001 therms.

[24] On-peak hours are defined as 8 a.m. to 10 p.m., Monday – Friday, except holidays. All other hours are off-peak.

NGSC-3 and NGSC-12

NGSC-3 describes the natural gas rates for large customers. There is a fixed monthly ($) charge for the first 5,000 therms, and volumetric ($/therm) charges for consumption beyond that.

NGSC-12 describes natural gas rates for DG customers. The structure is the same as NGSC-3, with a fixed ($/month) fee for consumption up to three therms and volumetric charges for consumption above that. NGSC-12 provides different rates for customers with different total annual consumption. NGSC-12 volumetric charges are less than those in NCSC-3. However, customers must maintain a load factor[25] above 50% to be eligible for NGSC-12.

[25] Load factor is defined as [Annual Usage] / [365*(Winter Peak Day Consumption)].

B.4 Tables of 2003 Tariffs

Table A- 1: ConEd electricity rates

Rate I - less than 1500kW, or less than 900 kW under certain Riders

parent tariff

		Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Energy ($/kWh)	first 15,000 kWh	0.07	0.07	0.07	0.07	0.08	0.09	0.10	0.10	0.09	0.08	0.08	0.09
	over 15,000 kWh	0.07	0.07	0.07	0.07	0.08	0.09	0.10	0.10	0.09	0.08	0.08	0.09
Monthly Demand ($/kW)	first 5 kW or less ($)	79.85	80.10	81.90	81.15	89.15	103.70	98.85	99.05	103.00	88.95	82.90	83.00
	next 895 kW	15.97	16.02	16.38	16.23	17.83	20.74	19.77	19.81	20.60	17.79	16.58	16.60
	over 900 kW	14.75	14.80	15.16	15.01	16.61	19.52	18.55	18.59	19.38	16.57	15.36	15.38

DERCAM Representation: parent tariff

	Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Energy ($/kWh)	0.07	0.07	0.07	0.07	0.08	0.09	0.10	0.10	0.09	0.08	0.08	0.09
Monthly Demand ($/kW)	15.97	16.02	16.38	16.23	17.83	20.74	19.77	19.81	20.60	17.79	16.58	16.60

note that the energy prices are the same for both blocks
note that the first 5 kW of demand is priced at the same rate as the next 895 kW
assume that demand is always greater than 5 kW
assume that all demand is priced at the rate for the first 900 kW

standby tariff

			Feb 04	Mar 04	Apr 04	May 04	Jun 04	Jul 04	Aug 04	Sep 04	Oct 04
Monthly Charge ($)			63.20	66.72	66.75	68.94	74.67	60.95	65.66	67.48	66.36
Contract Demand ($/kW contract)			3.91	4.13	4.13	4.27	4.62	3.78	4.07	4.19	4.11
As-used Daily Demand ($/kW)			0.34	0.36	0.36	0.37	1.02	0.83	0.89	0.92	0.36

parent tariff without transmission and distribution

		Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Energy ($/kWh)	first 15,000 kWh	0.06	0.06	0.06	0.06	0.07	0.08	0.09	0.09	0.07	0.07	0.07	0.07
	over 15,000 kWh	0.06	0.06	0.06	0.06	0.07	0.08	0.09	0.09	0.07	0.07	0.07	0.07
Monthly Demand ($/kW)	first 5 kW or less ($)	29.90	30.15	31.95	31.20	39.20	41.20	36.35	36.55	40.50	39.00	32.95	33.05
	next 895 kW	5.98	6.03	6.39	6.24	7.84	8.24	7.27	7.31	8.10	7.80	6.59	6.61
	over 900 kW	5.98	6.03	6.39	6.24	7.84	8.24	7.27	7.31	8.10	7.80	6.59	6.61

standby tariff estimate for 2003

		Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Standby	Monthly Charge ($)	63.20	63.20	66.72	66.75	68.94	74.67	60.95	65.66	67.48	66.36	66.36	63.20
	Contract Demand ($/kW contract)	3.91	3.91	4.13	4.13	4.27	4.62	3.78	4.07	4.19	4.11	4.11	3.91
	As-used Daily Demand ($/kW)	0.34	0.34	0.36	0.36	0.37	1.02	0.83	0.89	0.92	0.36	0.36	0.34
Energy ($/kWh)	first 15,000 kWh	0.06	0.06	0.06	0.06	0.07	0.08	0.09	0.09	0.07	0.07	0.07	0.07
	over 15,000 kWh	0.06	0.06	0.06	0.06	0.07	0.08	0.09	0.09	0.07	0.07	0.07	0.07
Monthly Demand ($/kW)	first 5 kW or less ($)	29.90	30.15	31.95	31.20	39.20	41.20	36.35	36.55	40.50	39.00	32.95	33.05
	next 895 kW	5.98	6.03	6.39	6.24	7.84	8.24	7.27	7.31	8.10	7.80	6.59	6.61
	over 900 kW	5.98	6.03	6.39	6.24	7.84	8.24	7.27	7.31	8.10	7.80	6.59	6.61

DERCAM representation: standby tariff estimate for 2003

		Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Standby	Monthly Charge ($)	63.20	63.20	66.72	66.75	68.94	74.67	60.95	65.66	67.48	66.36	66.36	63.20
	Contract Demand ($/kW contract)	3.91	3.91	4.13	4.13	4.27	4.62	3.78	4.07	4.19	4.11	4.11	3.91
	As-used Daily Demand ($/kW)	0.34	0.34	0.36	0.36	0.37	1.02	0.83	0.89	0.92	0.36	0.36	0.34
Energy ($/kWh)		0.06	0.06	0.06	0.06	0.07	0.08	0.09	0.09	0.07	0.07	0.07	0.07
Monthly Demand ($/kW)		5.98	6.03	6.39	6.24	7.84	8.24	7.27	7.31	8.10	7.80	6.59	6.61

note that the energy prices are the same for both blocks
note that the first 5 kW of demand is priced at the same rate as the next 895 kW
standby components from 2004 used in conjunction with energy and monthly demand components from 2003
assume that demand is always greater than 5 kW
assume that all demand is priced at the rate for the first 900 kW

Rate 3 - Large- Voluntary Time of Day : Customers not subject ot Rate II who opt for a time of day rate

parent tariff

		Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Energy ($/kWh)	On peak	0.08	0.08	0.07	0.07	0.09	0.10	0.12	0.12	0.09	0.08	0.09	0.09
	Off peak	0.05	0.05	0.05	0.05	0.06	0.07	0.07	0.07	0.06	0.06	0.07	0.07
Monthly Demand ($/kW)	On peak	14.02	14.07	14.61	14.33	15.68	24.07	22.77	22.80	24.00	15.69	14.62	14.75
	All hours	3.17	3.17	3.17	3.17	3.17	9.79	9.79	9.79	9.79	3.17	3.17	3.17

on peak hours: 8 a.m to 10 p.m., Monday-Friday
off peak hours: all other hours

DERCAM representation: parent tariff

		Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Energy ($/kWh)	On peak	0.08	0.08	0.07	0.07	0.09	0.10	0.12	0.12	0.09	0.08	0.09	0.09
	Off peak	0.05	0.05	0.05	0.05	0.06	0.07	0.07	0.07	0.06	0.06	0.07	0.07
Monthly Demand ($/kW)	On peak	14.02	14.07	14.61	14.33	15.68	24.07	22.77	22.80	24.00	15.69	14.62	14.75
	All hours	3.17	3.17	3.17	3.17	3.17	9.79	9.79	9.79	9.79	3.17	3.17	3.17

on peak hours: 8 a.m to 10 p.m., Monday-Friday
off peak hours: all other hours

standby tariff

		Feb 04	Mar 04	Apr 04	May 04	Jun 04	Jul 04	Aug 04	Sep 04	Oct 04
Monthly Charge ($)		63.20	66.72	66.75	68.94	74.67	60.95	65.66	67.48	66.36
Contract Demand ($/kW contract)		3.91	4.13	4.13	4.27	4.62	3.78	4.07	4.19	4.11
As-used Daily Demand ($/kW)		0.34	0.36	0.36	0.37	1.02	0.83	0.89	0.92	0.36

Table A- 2: ConEd electricity rates (continued)

parent tariff without transmission and distribution

		Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Energy ($/kWh)	**On peak**	0.07	0.07	0.07	0.07	0.08	0.10	0.11	0.11	0.09	0.08	0.08	0.08
	Off peak	0.04	0.04	0.05	0.05	0.06	0.06	0.07	0.06	0.06	0.05	0.06	0.06
Monthly Demand ($/kW)	**On peak**	6.37	6.42	6.96	6.68	8.03	8.52	7.22	7.25	8.45	8.04	6.97	7.10
	All hours	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

standby tariff estimate for 2003

		Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Standby	**Monthly Charge ($)**	63.20	63.20	66.72	66.75	68.94	74.67	60.95	65.66	67.48	66.36	66.36	63.20
	Contract Demand ($/kW contract)	3.91	3.91	4.13	4.13	4.27	4.62	3.78	4.07	4.19	4.11	4.11	3.91
	As-used Daily Demand ($/kW)	0.34	0.34	0.36	0.36	0.37	1.02	0.83	0.89	0.92	0.36	0.36	0.34
Energy ($/kWh)	**On peak**	0.07	0.07	0.07	0.07	0.08	0.10	0.11	0.11	0.09	0.08	0.08	0.08
	Off peak	0.04	0.04	0.05	0.05	0.06	0.06	0.07	0.06	0.06	0.05	0.06	0.06
Monthly Demand ($/kW)	**On peak**	6.37	6.42	6.96	6.68	8.03	8.52	7.22	7.25	8.45	8.04	6.97	7.10
	All hours	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

DERCAM representation: standby tariff estimate for 2003

		Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Standby	**Monthly Charge ($)**	63.20	63.20	66.72	66.75	68.94	74.67	60.95	65.66	67.48	66.36	66.36	63.20
	Contract Demand ($/kW contract)	3.91	3.91	4.13	4.13	4.27	4.62	3.78	4.07	4.19	4.11	4.11	3.91
	As-used Daily Demand ($/kW)	0.34	0.34	0.36	0.36	0.37	1.02	0.83	0.89	0.92	0.36	0.36	0.34
Energy ($/kWh)	**On peak**	0.07	0.07	0.07	0.07	0.08	0.10	0.11	0.11	0.09	0.08	0.08	0.08
	Off peak	0.04	0.04	0.05	0.05	0.06	0.06	0.07	0.06	0.06	0.05	0.06	0.06
Monthly Demand ($/kW)	**On peak**	6.37	6.42	6.96	6.68	8.03	8.52	7.22	7.25	8.45	8.04	6.97	7.10
	All hours	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

standby components from 2004 used in conjunction with energy and monthly demand components from 2003
on peak hours: 8 a.m to 10 p.m., Monday-Friday
off peak hours: all other hours

Voluntary Real Time Pricing
Customer pays T&D on parent tariff plus NYISO day ahead commodity price

parent tariff: Rate 1 without T&D

		Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Energy ($/kWh)	**first 15,000 kWh**	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	over 15,000 kWh	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Monthly Demand ($/kW)	**first 5 kW or less ($)**	49.95	49.95	49.95	49.95	49.95	62.50	62.50	62.50	62.50	49.95	49.95	49.95
	next 895 kW	9.99	9.99	9.99	9.99	9.99	12.50	12.50	12.50	12.50	9.99	9.99	9.99
	over 900 kW	8.77	8.77	8.77	8.77	8.77	11.28	11.28	11.28	11.28	8.77	8.77	8.77

Customer also pays day-ahead hourly LBMP for the New York City NYISO load zone

DERCAM representation: parent tariff, Rate 1

	Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Energy ($/kWh)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Monthly Demand ($/kW)	9.99	9.99	9.99	9.99	9.99	12.50	12.50	12.50	12.50	9.99	9.99	9.99

Customer also pays day-ahead hourly LBMP for the New York City NYISO load zone
note that the energy prices are the same for both blocks
note that the first 5 kW of demand is priced at the same rate as the next 895 kW
assume that demand is always greater than 5 kW
assume that all demand is priced at the rate for the first 900 kW

standby tariff

			Feb 04	Mar 04	Apr 04	May 04	Jun 04	Jul 04	Aug 04	Sep 04	Oct 04
Monthly Charge ($)			63.20	66.72	66.75	68.94	74.67	60.95	65.66	67.48	66.36
Contract Demand ($/kW contract)			3.91	4.13	4.13	4.27	4.62	3.78	4.07	4.19	4.11
As-used Daily Demand ($/kW)			0.34	0.36	0.36	0.37	1.02	0.83	0.89	0.92	0.36

parent tariff without T$D (only the NYISO commodity rate)

standby tariff estimate for 2003

		Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Standby	**Monthly Charge ($)**	63.20	63.20	66.72	66.75	68.94	74.67	60.95	65.66	67.48	66.36	66.36	63.20
	Contract Demand ($/kW contract)	3.91	3.91	4.13	4.13	4.27	4.62	3.78	4.07	4.19	4.11	4.11	3.91
	As-used Daily Demand ($/kW)	0.34	0.34	0.36	0.36	0.37	1.02	0.83	0.89	0.92	0.36	0.36	0.34
Energy ($/kWh)	**first 15,000 kWh**	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	over 15,000 kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Monthly Demand ($/kW)	**first 5 kW or less ($)**	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	next 895 kW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	over 900 kW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

DERCAM representation: standby tariff estimate for 2003

		Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Standby	**Monthly Charge ($)**	63.20	63.20	66.72	66.75	68.94	74.67	60.95	65.66	67.48	66.36	66.36	63.20
	Contract Demand ($/kW contract)	3.91	3.91	4.13	4.13	4.27	4.62	3.78	4.07	4.19	4.11	4.11	3.91
	As-used Daily Demand ($/kW)	0.34	0.34	0.36	0.36	0.37	1.02	0.83	0.89	0.92	0.36	0.36	0.34
Energy ($/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Customer also pays day-ahead hourly LBMP for the New York City NYISO load zone
note that the energy prices are the same for both blocks
note that the first 5 kW of demand is priced at the same rate as the next 895 kW
standby components from 2004 used in conjunction with energy and monthly demand components from 2003
assume that demand is always greater than 5 kW
assume that all demand is priced at the rate for the first 900 kW

Table A- 3: ConEd natural gas rates

Rate II (to include NG consumption for heating)

	Jan 03	*Feb 03*	*Mar 03*	*Apr 03*	*May 03*	*Jun 03*	*Jul 03*	*Aug 03*	*Sep 03*	*Oct 03*	*Nov 03*	*Dec 03*
First 3 therms or less ($)	11.08	11.08	11.08	11.08	11.08	11.08	11.08	11.08	11.08	11.08	11.08	11.08
Next 87 therms ($/therm)	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44
Next 2910 therms ($/therm)	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34
Excess over 3000 therms ($/therm)	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Gas Cost Factor ($/therm)	0.58	0.62	0.71	0.71	0.68	0.76	0.75	0.71	0.73	0.65	0.69	0.69
Monthly Rate Adjustment ($/therm)	-0.04	-0.04	-0.03	-0.03	-0.03	-0.03	-0.03	-0.03	-0.03	-0.03	-0.03	-0.03

DER-CAM representation

	Jan 03	*Feb 03*	*Mar 03*	*Apr 03*	*May 03*	*Jun 03*	*Jul 03*	*Aug 03*	*Sep 03*	*Oct 03*	*Nov 03*	*Dec 03*
Monthly Rate ($)	361.23	361.23	361.23	361.23	361.23	361.23	361.23	361.23	361.23	361.23	361.23	361.23
Energy Cost ($/therm)	0.76	0.81	0.91	0.90	0.88	0.96	0.94	0.91	0.93	0.85	0.88	0.89
Energy Cost ($/kJ)	7.228E-06	7.642E-06	8.600E-06	8.570E-06	8.383E-06	9.134E-06	8.947E-06	8.595E-06	8.789E-06	8.029E-06	8.349E-06	8.416E-06

assume at least 3000 therms are consumed per month
*then, [monthly rate ($)] = [block 1 cost ($)] - [87 (therms)*block 2 cost($/therm)] - [2910 (therms)*block 3 cost($/therm)]*

air conditioning rate
(rate for June 14-Oct 14)

						Jun 03	*Jul 03*	*Aug 03*	*Sep 03*	*Oct 03*
First 1200 therms ($/therm)						0.18	0.18	0.18	0.18	0.18
Excess over 1200 therms ($/therm)						0.15	0.15	0.15	0.15	0.15

plus Gas Cost Factor and Monthly Rate Adjustment

DER-CAM representation

	Jan 03	*Feb 03*	*Mar 03*	*Apr 03*	*May 03*	*Jun 03*	*Jul 03*	*Aug 03*	*Sep 03*	*Oct 03*	*Nov 03*	*Dec 03*
Monthly Rate ($)	no additional cost for this service											
Energy Cost ($/therm)	0.76	0.81	0.91	0.90	0.88	0.90	0.88	0.84	0.86	0.85	0.88	0.89
Energy Cost ($/kJ)	7.228E-06	7.642E-06	8.600E-06	8.570E-06	8.383E-06	9.134E-06	8.947E-06	8.595E-06	8.789E-06	8.029E-06	8.349E-06	8.416E-06

Special air conditioning rate is applied in June through September. All other months use standard Rate II prices.
assume all air conditioning NG consumption is billed at the block 2 price

Rider H- Distributed Generation
Rate I - Less than 5 MW
Summer: April 1 - October 31, Winter: November 1 - March 31

	up to 0.25 MW	**0.25 to 1.00 MW**	**1 MW - 3 MW**	**3 MW - 5 MW**
First 3 therms or less ($)	104.00	142.00	283.00	377.00
Excess over 3 therms ($/therm), Summer	0.13	0.13	0.13	0.13
Excess over 3 therms ($/therm), Winter	0.16	0.16	0.16	0.16

plus Gas Cost Factor and Monthly Rate Adjustment

DER-CAM representation

	Jan 03	*Feb 03*	*Mar 03*	*Apr 03*	*May 03*	*Jun 03*	*Jul 03*	*Aug 03*	*Sep 03*	*Oct 03*	*Nov 03*	*Dec 03*
Monthly Rate ($), up to 0.25 MW DG system	103.58	103.58	103.58	103.58	103.58	103.58	103.58	103.58	103.58	103.58	103.58	103.58
Monthly Rate ($), 0.25 MW to 1.00 MW DG system	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58	141.58
Monthly Rate ($), 1.00 MW to 3.00 MW DG system	282.58	282.58	282.58	282.58	282.58	282.58	282.58	282.58	282.58	282.58	282.58	282.58
Monthly Rate ($), 3.00 MW to 5.00 MW DG system	376.58	376.58	376.58	376.58	376.58	376.58	376.58	376.58	376.58	376.58	376.58	376.58
Energy Cost ($/therm)	0.69	0.74	0.84	0.80	0.78	0.86	0.84	0.81	0.83	0.75	0.81	0.82
Energy Cost ($/kJ)	6.562E-06	6.976E-06	7.935E-06	7.606E-06	7.420E-06	8.171E-06	7.984E-06	7.632E-06	7.826E-06	7.065E-06	7.684E-06	7.751E-06

Table A- 4: O&R electricity rates

SC-2

DER-CAM Representation

	Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Monthly Charge ($)	21.75125	21.75125	21.75125	21.75125	21.75125	20.25125	20.25125	20.25125	20.25125	21.75125	21.75125	21.75125
Demand Charge ($/kW)	6.29	6.29	6.29	6.29	6.29	10.76	10.76	10.76	10.76	6.29	6.29	6.29
Energy Charge ($/kWh)	0.078465	0.067195	0.090535	0.102535	0.107429	0.098979	0.092049	0.096709	0.074729	0.087799	0.066829	0.083629

30,000 kWh / 300 hours = 100 kW.
assume usage always exceeds 300 hrs x peak load and that this is always greater than 30,000 kWh
assume that usage price is average of 2nd and 3rd blocks

DER-CAM Representation

		Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Standby	**Monthly Charge ($)**	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49
	Contract Demand ($/kW contract)	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94
	As-used Daily Demand ($/kW)	0.2801	0.2801	0.2801	0.2801	0.2801	0.3913	0.3913	0.3913	0.3913	0.2801	0.2801	0.2801
Energy ($/kWh)		0.06619	0.05492	0.07826	0.09026	0.095154	0.086704	0.079774	0.084434	0.062454	0.075524	0.054554	0.071354

2004 standby rates used in conjunction with 2003 energy rates

SC-20: Optional Time Of Use

DER-CAM Representation

		Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Monthly Charge ($)		21.45	21.45	21.45	21.45	21.45	21.45	21.45	21.45	21.45	21.45	21.45	21.45
Demand Charge ($/kW), On-peak hours		6.56	6.56	6.56	6.56	6.56	15.47	15.47	15.47	15.47	6.56	6.56	6.56
Energy Charge ($/kWh)	***on peak***	0.07216	0.06241	0.08258	0.09297	0.096884	0.135204	0.129214	0.133244	0.114234	0.080094	0.061784	0.076314
	off peak	0.05965	0.0499	0.07007	0.08046	0.084374	0.077074	0.071084	0.075114	0.056104	0.067584	0.049274	0.063804

on peak hours: 1p.m. to 7p.m., Monday-Friday, June through September and 10 a.m. to 9 p.m., Monday-Friday, October-May, except holidays
off peak hours: all other hours

Standby (SC 25)
DER-CAM Representation

		Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Standby	**Monthly Charge ($)**	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49
	Contract Demand ($/kW contract)	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94
	As-used Daily Demand ($/kW)	0.2801	0.2801	0.2801	0.2801	0.2801	0.3913	0.3913	0.3913	0.3913	0.2801	0.2801	0.2801
Energy ($/kWh)		0.06619	0.05492	0.07826	0.09026	0.095154	0.086704	0.079774	0.084434	0.062454	0.075524	0.054554	0.071354

2004 standby rates used in conjunction with 2003 energy rates
same as standby service for SC 2

Real Time Pricing
SC 2:
DER-CAM Representation

	Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Monthly Charge ($)	21.75125	21.75125	21.75125	21.75125	21.75125	20.25125	20.25125	20.25125	20.25125	21.75125	21.75125	21.75125
Demand Charge ($/kW)	6.29	6.29	6.29	6.29	6.29	10.76	10.76	10.76	10.76	6.29	6.29	6.29
Energy Charge ($/kWh)	0.035975	0.035975	0.035975	0.035975	0.033709	0.033709	0.033709	0.033709	0.033709	0.033709	0.033709	0.033709

customer also pays NYISO Hudson Valley day-ahead hourly LBMP rates
non-energy components of the forecast component of the market supply charge are included in the DER-CAM energy charge
30,000 kWh / 300 hours = 100 kW.
assume usage always exceeds 300 hrs x peak load and that this is always greater than 30,000 kWh
assume that usage price is average of 2nd and 3rd blocks

Standby (SC 25)
DER-CAM Representation

		Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Standby	**Monthly Charge ($)**	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49
	Contract Demand ($/kW contract)	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94
	As-used Daily Demand ($/kW)	0.2801	0.2801	0.2801	0.2801	0.2801	0.3913	0.3913	0.3913	0.3913	0.2801	0.2801	0.2801
Energy ($/kWh)		0.0237	0.0237	0.0237	0.0237	0.021434	0.021434	0.021434	0.021434	0.021434	0.021434	0.021434	0.021434

customer also pays NYISO Hudson Valley day-ahead hourly LBMP rates
2004 standby rates used in conjunction with 2003 energy rates

Table A- 5: O&R natural gas rates

NGSC-2: General Service

	Jan 03	*Feb 03*	*Mar 03*	*Apr 03*	*May 03*	*Jun 03*	*Jul 03*	*Aug 03*	*Sep 03*	*Oct 03*	*Nov 03*	*Dec 03*
Delivery Charge												
first 3 Ccf or less ($)	7.74	7.74	7.74	7.74	7.74	7.74	7.74	7.74	7.74	7.74	7.74	7.74
next 47 Ccf ($/Ccf)	0.26663	0.26663	0.26663	0.26663	0.26663	0.26663	0.26663	0.26663	0.26663	0.26663	0.26663	0.26663
next 4950 Ccf ($/Ccf)	0.25375	0.25375	0.25375	0.25375	0.25375	0.25375	0.25375	0.25375	0.25375	0.25375	0.25375	0.25375
excess of 5000 Ccf ($/Ccf)	0.2179	0.2179	0.2179	0.2179	0.2179	0.2179	0.2179	0.2179	0.2179	0.2179	0.2179	0.2179
Gas Supply Charge ($/Ccf)	0.72247	0.73854	0.81771	0.86192	0.83721	0.90654	0.91309	0.864	0.85557	0.79674	0.83644	0.83988
Monthly Gas Adjustment ($/Ccf)	-0.00866	-0.00355	-0.00324	-0.00291	-0.00291	-0.00317	-0.00356	-0.00406	-0.00419	-0.00367	-0.00145	0.00153

conversions:
Ccf = 100 ft^3
100 Ccf NG = approx. 0.103 Therms = 1.08 x 10^6 kJ

DER-CAM representation

	Jan 03	*Feb 03*	*Mar 03*	*Apr 03*	*May 03*	*Jun 03*	*Jul 03*	*Aug 03*	*Sep 03*	*Oct 03*	*Nov 03*	*Dec 03*
Monthly Rate ($)	186.83	186.83	186.83	186.83	186.83	186.83	186.83	186.83	186.83	186.83	186.83	186.83
Energy Rate ($/Ccf)	0.9317	0.9529	1.0324	1.0769	1.0522	1.1213	1.1274	1.0778	1.0693	1.0110	1.0529	1.0593
Energy Rate ($/Therm)	0.0907	0.0928	0.1005	0.1049	0.1025	0.1092	0.1098	0.1050	0.1041	0.0984	0.1025	0.1031
Energy Rate ($/kJ)	8.833E-06	9.034E-06	9.787E-06	1.021E-05	9.975E-06	1.063E-05	1.069E-05	1.022E-05	1.014E-05	9.584E-06	9.982E-06	1.004E-05

assume at least 5,000 Ccf are consumed per month

Table A- 6: NiMo electricity rates

SC 3: Large General Service (demand 100kW - 2000 kW)

parent tariff

	Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Customer Charges ($)	260.15	260.15	260.15	260.15	260.15	260.15	260.15	260.15	260.15	260.15	260.15	260.15
Delivery (demand) Charge ($/kW)												
first 40 kW ($)	598.8	598.8	598.8	598.8	598.8	598.8	598.8	598.8	598.8	598.8	598.8	598.8
over 40 kW ($/kW)	14.97	14.97	14.97	14.97	14.97	14.97	14.97	14.97	14.97	14.97	14.97	14.97
Delvery (energy) Charge ($/kWh)												
first 450 hours of max kWh usage	0.02187	0.02187	0.02187	0.02187	0.02187	0.02187	0.02187	0.02187	0.02187	0.02187	0.02187	0.02187
over 450 hours of max kWh usage	0.00988	0.00988	0.00988	0.00988	0.00988	0.00988	0.00988	0.00988	0.00988	0.00988	0.00988	0.00988
RKVA Charge	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Delivery Charge Adjustment	included in ESC											
Systems Benefit Charge (varies annually)	0.001476	0.001476	0.001476	0.001476	0.001476	0.001476	0.001476	0.001476	0.001476	0.001476	0.001476	0.001476
Transmission Revenue Adjustment ($/kWh)	0.00127	0.0016	0.00211	0.00171	0.00148	0.00155	0.00147	0.00108	0.00103	0.001	0.00111	0.00116
Electricity Supply Charge ($/kWh)	0.04756853	0.05593205	0.06566009	0.0526548	0.04995962	0.04941651	0.05294385	0.05321777	0.05241733	0.05033484	0.04937785	0.04852926

DER-CAM representation: parent tariff

	Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Monthly Charge ($)	260.15	260.15	260.15	260.15	260.15	260.15	260.15	260.15	260.15	260.15	260.15	260.15
Demand Charge ($/kW)	14.97	14.97	14.97	14.97	14.97	14.97	14.97	14.97	14.97	14.97	14.97	14.97
Energy Charge ($/kWh)	0.0503	0.0590	0.0692	0.0558	0.0529	0.0524	0.0559	0.0558	0.0549	0.0528	0.0520	0.0512

assume monthly demand is always greater than 40 kW
*assume that monthly kWh usage is always less than PeakDemand*450 hours (always in block 1)*
assume the RkVA charges are not significant

standby tariff

	Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Customer Charge ($)												
Distribution Delivery	260.15	260.15	260.15	260.15	260.15	260.15	260.15	260.15	260.15	260.15	260.15	260.15
Competitive Transition	401.39	401.39	401.39	401.39	401.39	401.39	401.39	401.39	401.39	401.39	401.39	401.39
Contract Demand Charge ($/kW Contract)												
Distribution Delivery	3.84	3.84	3.84	3.84	3.84	3.84	3.84	3.84	3.84	3.84	3.84	3.84
Competitive Transition	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93	5.93
On Peak Daily Demand ($/kW)												
Distribution Delivery	0.2127	0.2127	0.2127	0.2127	0.2127	0.2127	0.2127	0.2127	0.2127	0.2127	0.2127	0.2127
Competitive Transition	0.3282	0.3282	0.3282	0.3282	0.3282	0.3282	0.3282	0.3282	0.3282	0.3282	0.3282	0.3282
Reactive Demand ($/RKVA)	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Energy Charges ($/kWh):												
Electricity Supply Service	0.04756853	0.05593205	0.06566009	0.0526548	0.04995962	0.04941651	0.05294385	0.05321777	0.05241733	0.05033484	0.04937785	0.04852926
Systems Benefit	0.001476	0.001476	0.001476	0.001476	0.001476	0.001476	0.001476	0.001476	0.001476	0.001476	0.001476	0.001476
Delivery Charge Adjustment	included in ESC											
Transmission Revenue Adjustment	0.00127	0.0016	0.00211	0.00171	0.00148	0.00155	0.00147	0.00108	0.00103	0.001	0.00111	0.00116

DER-CAM representation: standby tariff

		Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Standby	Monthly Charge ($)	661.54	661.54	661.54	661.54	661.54	661.54	661.54	661.54	661.54	661.54	661.54	661.54
	Contract Demand ($/kW contract)	9.77	9.77	9.77	9.77	9.77	9.77	9.77	9.77	9.77	9.77	9.77	9.77
	As-used Daily Demand ($/kW)	0.5409	0.5409	0.5409	0.5409	0.5409	0.5409	0.5409	0.5409	0.5409	0.5409	0.5409	0.5409
Energy ($/kWh)		0.0503	0.0590	0.0692	0.0558	0.0529	0.0524	0.0559	0.0558	0.0549	0.0528	0.0520	0.0512

standby rates from 2004 used in conjuction with energy rates from 2003

SC-3A, Large General Service, Time of Use Rates

parent tariff

		Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Customer Charges ($)		902	902	902	902	902	902	902	902	902	902	902	902
Demand Charges ($/kW)													
Distribution Delivery		6.34	6.34	6.34	6.34	6.34	6.34	6.34	6.34	6.34	6.34	6.34	6.34
Competitive Transition		4.06	4.06	4.06	4.06	4.06	4.06	4.06	4.06	4.06	4.06	4.06	4.06
RkVA charges (per kW)		1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Systems Benefits Charge		0.001476	0.001476	0.001476	0.001476	0.001476	0.001476	0.001476	0.001476	0.001476	0.001476	0.001476	0.001476
Energy Charges ($/kWh)		Day ahead hourly rates											
Competitive Transition Charge ($/kWh)													
*first 250 hours of use	on peak	0.02181	0.02181	0.02181	0.02181	0.02181	0.02181	0.02181	0.02181	0.02181	0.02181	0.02181	0.02181
	off peak	0.01614	0.01614	0.01614	0.01614	0.01614	0.01614	0.01614	0.01614	0.01614	0.01614	0.01614	0.01614
*remaining	on peak	0	0	0	0	0	0	0	0	0	0	0	0
	off peak	0	0	0	0	0	0	0	0	0	0	0	0
Transmission Revenue Adjustment		0.00105	0.00143	0.00218	0.00188	0.00147	0.00155	0.00131	0.00107	0.00103	0.00098	0.00126	0.00123

DER-CAM representation: parent tariff

		Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Monthly Charge ($)		902	902	902	902	902	902	902	902	902	902	902	902
Demand Charge ($/kW)		10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
Energy Charge ($/kWh)	*on peak*	0.0243	0.0247	0.0255	0.0252	0.0248	0.0248	0.0246	0.0244	0.0243	0.0243	0.0245	0.0245
	off peak	0.0187	0.0190	0.0198	0.0195	0.0191	0.0192	0.0189	0.0187	0.0186	0.0186	0.0189	0.0188

on peak hours: 8 a.m. - 10 p.m., Monday-Friday, except holidays
off peak hours: all other hours
customer also pays the day-ahead hourly LBMP for the the NYISO Frontier Load Zone
assume that all competitive transition energy charges are prices as if for the first 250 hours of peak demand

standby tariff

	Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Customer Charge ($)												
Distribution Delivery	902	902	902	902	902	902	902	902	902	902	902	902
Competitive Transition	1235.63	1235.63	1235.63	1235.63	1235.63	1235.63	1235.63	1235.63	1235.63	1235.63	1235.63	1235.63
Contract Demand Charge ($/kW Contract)												
Distribution Delivery	2.91	2.91	2.91	2.91	2.91	2.91	2.91	2.91	2.91	2.91	2.91	2.91
Competitive Transition	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99
On Peak Daily Demand ($/kW)												
Distribution Delivery	0.1591	0.1591	0.1591	0.1591	0.1591	0.1591	0.1591	0.1591	0.1591	0.1591	0.1591	0.1591
Competitive Transition	0.218	0.218	0.218	0.218	0.218	0.218	0.218	0.218	0.218	0.218	0.218	0.218
Reactive Demand ($/RKVA)	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02
Energy Charges ($/kWh):												
Electricity Supply Service	Day ahead hourly rates											
Systems Benefit	0.001476	0.001476	0.001476	0.001476	0.001476	0.001476	0.001476	0.001476	0.001476	0.001476	0.001476	0.001476
Delivery Charge Adjustment	included in ESC											
Transmission Revenue Adjustment	0.00105	0.00143	0.00218	0.00188	0.00147	0.00155	0.00131	0.00107	0.00103	0.00098	0.00126	0.00123

DER-CAM representation: standby tariff

		Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Standby	Monthly Charge ($)	2137.63	2137.63	2137.63	2137.63	2137.63	2137.63	2137.63	2137.63	2137.63	2137.63	2137.63	2137.63
	Contract Demand ($/kW contract)	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9
	As-used Daily Demand ($/kW)	0.3771	0.3771	0.3771	0.3771	0.3771	0.3771	0.3771	0.3771	0.3771	0.3771	0.3771	0.3771
Energy ($/kWh) (excluding hourly day-ahead rate)		0.0025	0.0029	0.0037	0.0034	0.0029	0.0030	0.0028	0.0025	0.0025	0.0025	0.0027	0.0027

standby rates from 2004 used in conjuction with energy rates from 2003
customer also pays the day-ahead hourly LBMP for the the NYISO Frontier Load Zone

Table A- 7: NiMo natural gas rates

Service Classification 3: Large General

	Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
first 5,000 therms ($)	782.11	782.11	782.11	782.11	782.11	782.11	782.11	782.11	782.11	782.11	782.11	782.11
Over 5,000 therms ($/therm)	0.04627	0.04627	0.04627	0.04627	0.04627	0.04627	0.04627	0.04627	0.04627	0.04627	0.04627	0.04627
Gas Supply ($/therm)	0.55207	0.60457	0.89256	0.75659	0.78318	0.72308	0.62031	0.50993	0.6269	0.62149	0.60073	0.6152

DER-CAM representation

	Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Monthly Rate ($)	550.76	550.76	550.76	550.76	550.76	550.76	550.76	550.76	550.76	550.76	550.76	550.76
Energy Rate ($/therm)	0.59834	0.65084	0.93883	0.80286	0.82945	0.76935	0.66658	0.5562	0.67317	0.66776	0.647	0.66147
Energy Rate ($/kJ)	5.6725E-06	6.1703E-06	8.9005E-06	7.6115E-06	7.8636E-06	7.2938E-06	6.3195E-06	5.273E-06	6.382E-06	6.3307E-06	6.1339E-06	6.271E-06

assume at least 5,000 therms are consumed per month
*then, [monthly rate ($)] = [block 1 cost ($)] - [5000 (therms)*block 2 cost($/therm)]*

Service Classification 12: Distributed Generation

annual consumption less than 250,000 therms

	Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
first 3 therms ($)	100	100	100	100	100	100	100	100	100	100	100	100
over 3 therms ($/therm)	0.05256	0.05256	0.05256	0.04149	0.04149	0.04149	0.04149	0.04149	0.04149	0.04149	0.05256	0.05256
Mechant Function Charge ($/therm)	0.0199	0.0199	0.0199	0.0199	0.0199	0.0199	0.0199	0.0199	0.0199	0.0199	0.0199	0.0199
Monthly Cost of Gas Supply ($/therm)	0.50207	0.55457	0.84256	0.70659	0.73318	0.67308	0.57031	0.45993	0.5769	0.57149	0.55073	0.5652

DER-CAM representation: Annual consumption less than 250,000 therms

	Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Monthly Rate ($)	99.84232	99.84232	99.84232	99.87553	99.87553	99.87553	99.87553	99.87553	99.87553	99.87553	99.84232	99.84232
Energy Rate ($/therm)	0.57453	0.62703	0.91502	0.76798	0.79457	0.73447	0.6317	0.52132	0.63829	0.63288	0.62319	0.63766
Energy Rate ($/kJ)	5.4468E-06	5.9445E-06	8.6748E-06	7.2808E-06	7.5329E-06	6.9631E-06	5.9888E-06	4.9424E-06	6.0513E-06	0.000006	5.9081E-06	6.0453E-06

assume at least 3 therms are consumed per month
*then, [monthly rate ($)] = [block 1 cost ($)] - [3 (therms)*block 2 cost($/therm)]*

annual consumption 250,000 - 1,000,000 therms

	Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
first 3 therms ($)	353.85	353.85	353.85	353.85	353.85	353.85	353.85	353.85	353.85	353.85	353.85	353.85
over 3 therms ($/therm)	0.04683	0.04683	0.04683	0.03697	0.03697	0.03697	0.03697	0.03697	0.03697	0.03697	0.04683	0.04683
Mechant Function Charge ($/therm)	0.0199	0.0199	0.0199	0.0199	0.0199	0.0199	0.0199	0.0199	0.0199	0.0199	0.0199	0.0199
Monthly Cost of Gas Supply ($/therm)	0.50207	0.55457	0.84256	0.70659	0.73318	0.67308	0.57031	0.45993	0.5769	0.57149	0.55073	0.5652

DERCAM representation: Annual consumption 250,000 - 1,000,000 therms

	Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Monthly Rate ($)	353.70951	353.70951	353.70951	353.73909	353.73909	353.73909	353.73909	353.73909	353.73909	353.73909	353.70951	353.70951
Energy Rate ($/therm)	0.5688	0.6213	0.90929	0.76346	0.79005	0.72995	0.62718	0.5168	0.63377	0.62836	0.61746	0.63193
Energy Rate ($/kJ)	5.3925E-06	5.8902E-06	8.6205E-06	7.238E-06	7.49E-06	6.9203E-06	5.946E-06	4.8995E-06	6.0084E-06	5.9571E-06	5.8538E-06	5.991E-06

1,000,000 therms of NG would produces approximately 1000 kW of electricity continuously for one year. Current site studies don't exceed this.
Monthly Cost of Gas Supply (MCGS) rates for SC-12 are only available for 2004. However, they are consistently approximately $0.05 less than SC3 rates
therefore, assume [SC-12 MCGS rates for 2003 ($/therm)] = [SC-3 MCGS rates ($/therm) - $0.05/therm]
assume at least 3 therms are purchased every month
*then, [monthly rate ($)] = [block 1 cost ($)] - [3 (therms)*block 2 cost($/therm)]*

Appendix C. Generic Electricity and Natural Gas Tariffs Developed for Sensitivities

While an assessment of DG adoption potential under actual New York tariffs is useful, the many variables in each scenario make the effects of individual factors difficult to identify. Therefore, generic tariffs of varying structures were developed and single-variable sensitivities performed for each.

There are two types of tariff structures: volumetric electricity pricing and standby rate. Volumetric electricity pricing categories are:

- **Flat**: constant volumetric rates for every hour of the month
- **TOU**: “time of use” – two volumetric rates per month: for on-peak and off-peak consumption.
- **RTP**: “real time pricing” – hourly rates announced each day for the following day.

Standby rate structure categories are:

- **Parent**: standby service provided at parent tariff rates
- **Standby**: standby service provided at typical New York standby rates, including monthly, fixed contract demand, and daily demand charges.
- **Standby-CA**: California style standby rates – a standby charge on the installed capacity of the DG system, which is added to the bill as determined by the parent tariff.

The generic tariffs were based on O&R intermediate rates. As described in Appendix B, O&R offers flat, TOU, and RTP rates, with standby charges to go along with the flat and day-ahead hourly rates. The same standby rates used with flat and RTP charges became the generic TOU rate. Additionally, Standby-CA rates were developed by adding a standby charge of $3.34/kW of installed capacity to the parent tariffs. This is the average for the three IOUs in California.[26] Table A- 8 shows the generic flat, TOU, and RTP rates for the parent and standby tariffs.

The actual O&R natural gas rates listed in Appendix B were used for all generic tariffs.

[26] Current standby rates from IOUs in California are $2.40 from Pacific Gas and Electric, $3.35 from San Diego Gas and Electric, and $4.26/kW from Southern California Edison.

Table A- 8: Generic electricity rates used for sensitivity analyses

Flat Commodity Rate

Without Standby

	Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Monthly Charge ($)	21.75125	21.75125	21.75125	21.75125	21.75125	20.25125	20.25125	20.25125	20.25125	21.75125	21.75125	21.75125
Demand Charge ($/kW)	6.29	6.29	6.29	6.29	6.29	10.76	10.76	10.76	10.76	6.29	6.29	6.29
Energy Charge ($/kWh)	0.078465	0.067195	0.090535	0.102535	0.107429	0.098979	0.092049	0.096709	0.074729	0.087799	0.066829	0.083629

With Standby

		Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Standby	Monthly Charge ($)	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49
	Contract Demand ($/kW contract)	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94
	As-used Daily Demand ($/kW)	0.2801	0.2801	0.2801	0.2801	0.2801	0.3913	0.3913	0.3913	0.3913	0.2801	0.2801	0.2801
Energy ($/kWh)		0.06619	0.05492	0.07826	0.09026	0.095154	0.086704	0.079774	0.084434	0.062454	0.075524	0.054554	0.071354

Time of Use Rate

Without Standby

		Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Monthly Charge ($)		21.45	21.45	21.45	21.45	21.45	21.45	21.45	21.45	21.45	21.45	21.45	21.45
Demand Charge ($/kW), On-peak hours		6.56	6.56	6.56	6.56	6.56	15.47	15.47	15.47	15.47	6.56	6.56	6.56
Energy Charge ($/kWh)	*on peak*	0.07216	0.06241	0.08258	0.09297	0.096884	0.135204	0.129214	0.133244	0.114234	0.080094	0.061784	0.076314
	off peak	0.05965	0.0499	0.07007	0.08046	0.084374	0.077074	0.071084	0.075114	0.056104	0.067584	0.049274	0.063804

With Standby

		Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Standby	Monthly Charge ($)	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49
	Contract Demand ($/kW contract)	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94
	As-used Daily Demand ($/kW)	0.2801	0.2801	0.2801	0.2801	0.2801	0.3913	0.3913	0.3913	0.3913	0.2801	0.2801	0.2801
Energy Charge ($/kWh)	*on peak*	0.07216	0.06241	0.08258	0.09297	0.096884	0.135204	0.129214	0.133244	0.114234	0.080094	0.061784	0.076314
	off peak	0.05965	0.0499	0.07007	0.08046	0.084374	0.077074	0.071084	0.075114	0.056104	0.067584	0.049274	0.063804

notes

Period 1 1p.m. to 7p.m. Mon-Fri, except holidays, June through Sept
Period 2 10 a.m. to 9 p.m. Mon-Fri, except holidays, Oct-May
Period 3 all other hours

Day Ahead Real Time Price

Without Standby

	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49
Monthly Charge ($)	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94
Demand Charge ($/kW), On-peak hours	0.2801	0.2801	0.2801	0.2801	0.2801	0.3913	0.3913	0.3913	0.3913	0.2801	0.2801	0.2801
Energy Charge ($/kWh)	NYISO Day-Ahead Market hourly commodity cost for Hudson Valley region + $0.0212/kWh											

With Standby

		Jan 03	Feb 03	Mar 03	Apr 03	May 03	Jun 03	Jul 03	Aug 03	Sep 03	Oct 03	Nov 03	Dec 03
Standby	Monthly Charge ($)	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49	37.49
	Contract Demand ($/kW contract)	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94
	As-used Daily Demand ($/kW)	0.2801	0.2801	0.2801	0.2801	0.2801	0.3913	0.3913	0.3913	0.3913	0.2801	0.2801	0.2801
Energy Charge ($/kWh)		NYISO Day-Ahead Market hourly commodity cost for Hudson Valley region + $0.0212/kWh											

Appendix D. Recent Modifications to DER-CAM

DER-CAM, described in detail in Siddiqui (2003), was used for a case study to see how computer simulated modeling and decision-making compared to that of actual DG adopters (Bailey, 2003). Based on findings from several case studies and details particular to New York State, the following modifications were made to DER-CAM:

- **Minimum load constraints**: all electricity generation equipment except PV was constrained to operate between minimum and full load, or not at all, during any hourly timestep.
- **Effect of DG reliability on demand charges**: demand charges were based on the statistically expected charge for each month or day (monthly or daily demand), rather than on the assumption of 100% reliability. The expected maximum demand depends on the number, capacity, and reliability of generators installed.
- **Payback period**: a maximum payback period constraint was included on all investments. In practice, most economically motivated adopters would not consider solutions with long payback periods, even if savings were maximized.
- **Contract demand**: a contract demand charge based on maximum potential electricity load was added. DER-CAM assumes the maximum potential electricity load is the actual annual peak electricity demand. In reality, customers may report a lower contract demand, and either pay a large fine for any over-demand or use on-site peak-shaving procedures to limit the site's demand in the event of a generator outage.
- **Daily demand**: a daily demand charge was added.
- **Monthly pricing**: electricity pricing was changed from seasonal to monthly to represent New York State energy rates more accurately.
- **Multiple natural gas rates**: natural gas rates were changed from a single monthly rate (fixed and volumetric components) to three separate rates for typical, air-conditioning, and DG, because some New York utilities offer different rates for different end uses.

Appendix E. DATA used in DER-CAM

This appendix describes data input common to all DER-CAM runs in this study. End-use load profiles are described in Appendix A. Electricity and natural gas tariffs are described in Appendix B and Appendix C.

E.1 Distributed Generation Technology

DG technology data is described in Firestone (2004).[27] The technologies considered in this research were:

- microturbines: 60 kW,
- natural gas engines: 60 kW, 100 kW, 300 kW, and 1000 kW,
- fuel cells: 200 kW, and
- PV: 50 kW.

All equipment except the PV were available in DER-CAM as:

- electricity only,
- electricity and heat recovery for heating, and
- electricity and heat recovery for heating and absorption cooling.

All generation technologies except PV were subject to a 50% minimum load constraint; at any timestep, purchased technologies could either be off, or on at 50% to 100% of rated electrical capacity. This limitation does not apply to PV.

E.2 Economics

The maximum payback period constraint was set to six years and the discount rate at five percent.

E.3 Macrogrid Efficiency and Carbon Emissions

Data in NYSERDA (2002) was used to estimate New York State macrogrid efficiency (33%) and carbon emissions (0.0935 kg carbon equivalent per kWh electricity), based on data provided for 2002.

[27] This report is available at http://der.lbl.gov/data/DERCAMTechDataOnline.pdf (last accessed September, 2005). The technology data is based mostly on Goldstein (2003), available at http://www.eea-inc.com/dgchp_reports/TechCharNREL.pdf (last accessed February, 2005).

E.4 Insolation

Statistics for solar insolation, the amount of incoming solar radiation received by an exposed surface, for New York were collected from NASA's (National Aeronautics and Space Administration) Atmospheric Sciences Data Center.[28] This included monthly values of time of solar noon, day length, total daily insolation, and peak daily insolation. A normal distribution of insolation centered at solar noon was assumed for each month, with standard deviations adjusted so that insolation patterns matched the day length data. These patterns were then scaled by the total daily insolation to generate the hourly data required for DER-CAM. Figure A- 6 displays the values used in this research.

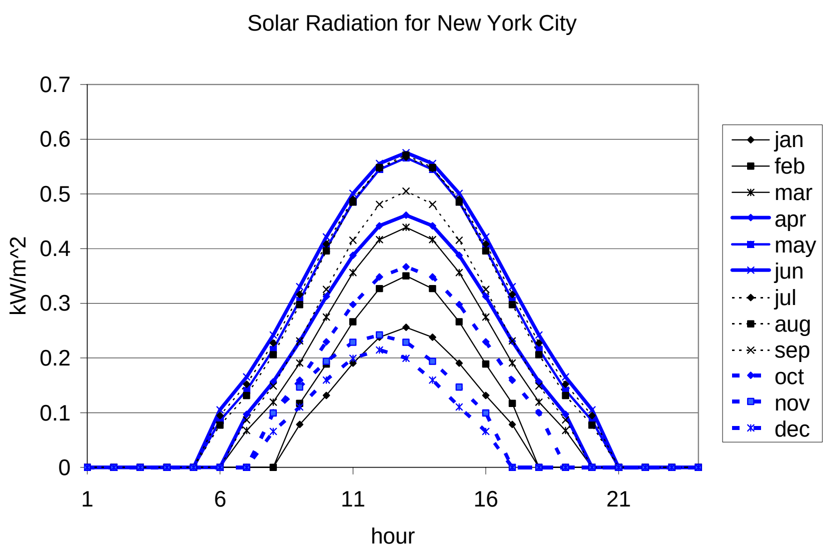

Figure A- 6: Insolation data for New York State

[28] http://eosweb.larc.nasa.gov (last accessed September, 2005).

Appendix F. Results of DER-CAM Sensitivities with Technology Subsidy

In all of the sensitivity analyses in Section 6, DER-CAM selected only natural gas engines, the dominant DG device, for optimal solutions. However, alternate technologies may offer societal benefits and receive public subsidies, such as those described in NYSERDA's program (see Appendix G.1). The three sensitivities (volumetric electric, volumetric natural gas, and as-used demand charges) were repeated while allotting capital cost subsidies to alternative DG technologies. Only the TOU parent (TOU) and New York style standby (TOU_NY) were considered for these studies. Separate studies were conducted to examine the effects of subsidies on fuel cells, microturbines, and PV. The sensitivity parameter was varied from 50% to 200% of base case prices in increments of 25%. Carbon dioxide is the only emission accounted for in DER-CAM and reported in this appendix. Alternate technologies also offer reduced emissions of NO_2, SO_2, and particulate matter, which are not considered here.

F.1 Fuel Cell Subsidies

Compared to natural gas ICEs, fuel cells offer higher electrical efficiencies and lower emissions while promising higher reliability. The high price of this emerging technology, however, is a barrier to adoption. Fuel cell subsidies of 50%, 70% and 90% were tested here for each of the three sensitivities. Only subsidies of 90% were effective in stimulating fuel cell adoption.

Volumetric Electricity Rate Sensitivity

Figure A- 7 and Figure A- 8 show the installed electrical capacity of fuel cells and natural gas engines. Fuel cells are selected only when 90% subsidies are offered. In most cases, fuel cell capacity directly replaces natural gas engine capacity. Under the parent tariff, 400 kW of fuel cell capacity is the optimal solution over a large range of volumetric electricity rates with a 90% fuel cell subsidy. The standby tariff encourages even more fuel cell capacity for volumetric electricity prices between 125% and 200% of base case rates, but this increase disappears at higher electricity prices. Primary fuel consumption can be lowered up to 2.5% (Figure A- 9) but these fuel benefits drop off as electricity becomes more expensive.

Correspondingly, carbon equivalent emissions can be reduced by similar amounts (Figure A- 10). However, the public cost to achieve the additional carbon savings by getting DG adopters to choose fuel cells over natural gas engines is high (Figure A- 11), in the order of $10,000 to $30,000 per ton of carbon equivalent emissions reduction. Because the prototypical hospital has ample use for recovered heat, subsidizing higher electrical efficiency is not an effective way to reduce primary fuel consumption or carbon emissions.

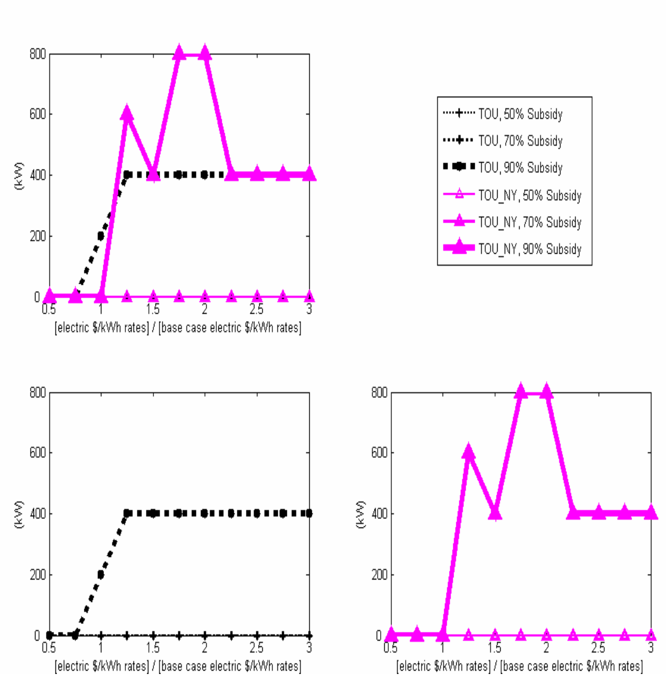

Figure A- 7: Installed electrical capacity of fuel cells for volumetric electricity rate variation and fuel cell subsidies

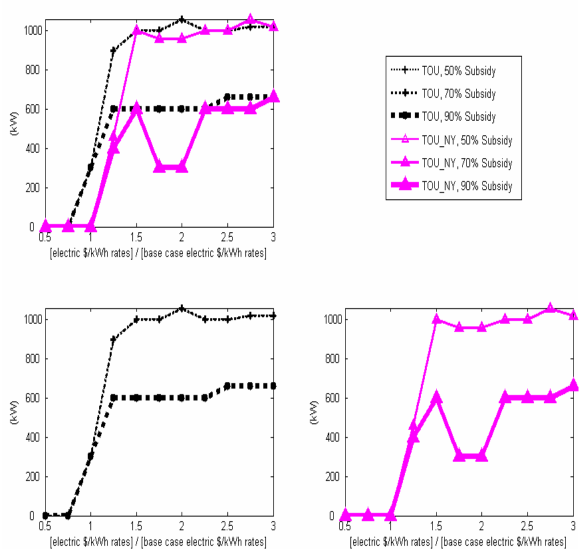

Figure A- 8: Installed electrical capacity of natural gas engines for volumetric electricity rate variation and fuel cell subsidies

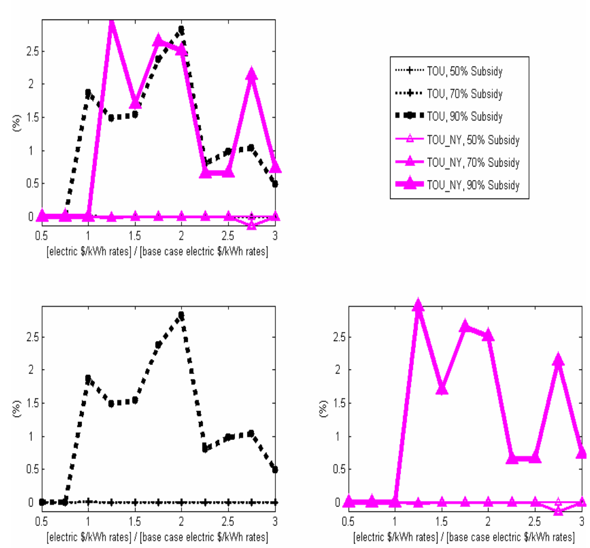

Figure A- 9: Primary fuel reduction for volumetric electricity rate variation and fuel cell subsidies

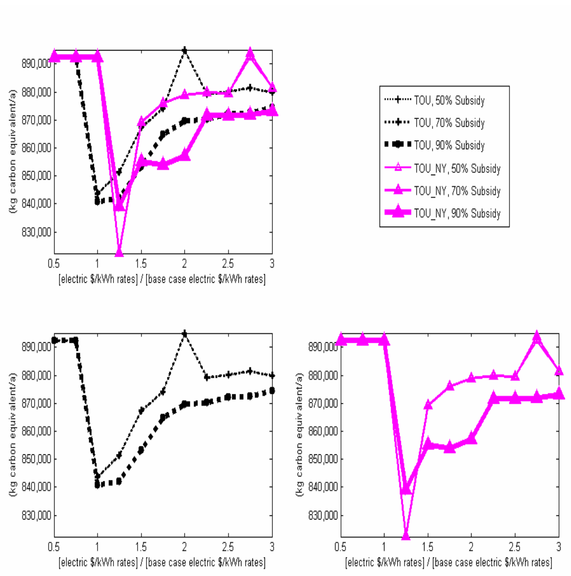

Figure A- 10: Carbon equivalent emissions for volumetric electricity rate variation and fuel cell subsidies

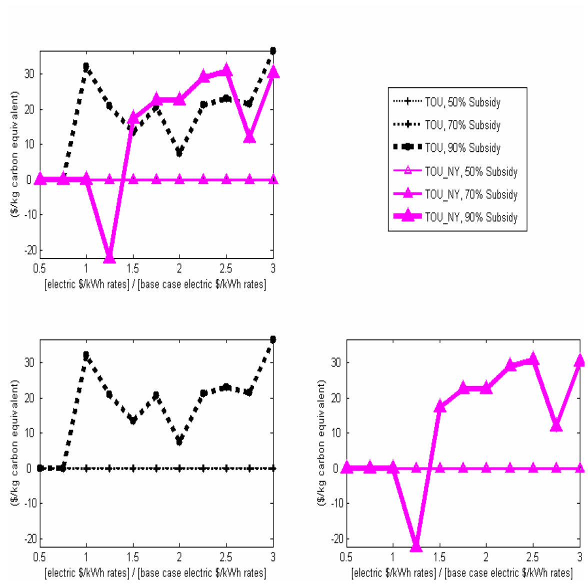

Figure A- 11: Annualized subsidy cost of carbon equivalent savings for volumetric electricity rate variation and fuel cell subsidies

Volumetric Natural Gas Sensitivity

Natural gas cost increases above 120% of base case prices under the parent tariff (TOU), or above 150% of base case prices under the standby tariff (TOU_NY), make any DG installation uneconomical (Figure A- 12 and Figure A- 13). While some 90% subsidized fuel cells are installed, carbon emissions stay about the same as they are under the parent tariff (TOU) without a subsidy. The only exception to this is for the standby tariff (TOU_NY) at 50% and 75% of base case volumetric natural gas rates, where installed fuel cells replace utility electricity purchase, not natural gas ICEs, in which case the fuel cells subsidy does reduce carbon emissions by 2% and 6% respectively.

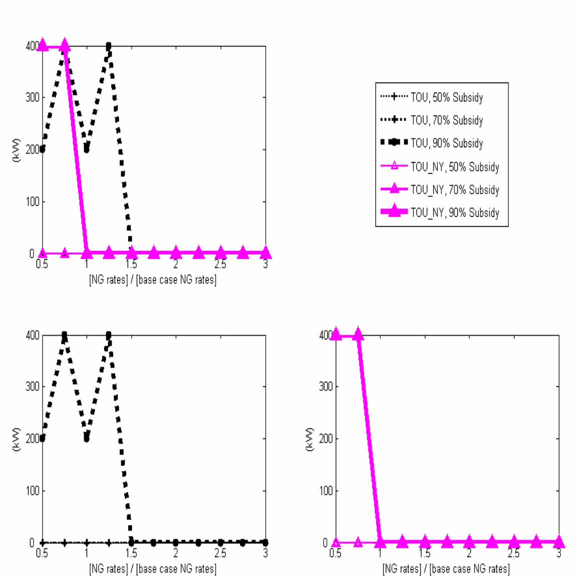

Figure A- 12: Installed electrical capacity of fuel cells for volumetric natural gas rate variation and fuel cell subsidies

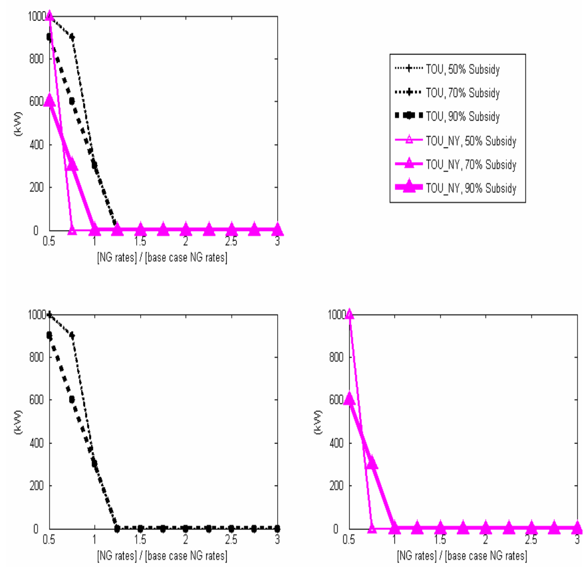

Figure A- 13: Installed electrical capacity of natural gas engines for volumetric natural gas rate variation and fuel cell subsidies

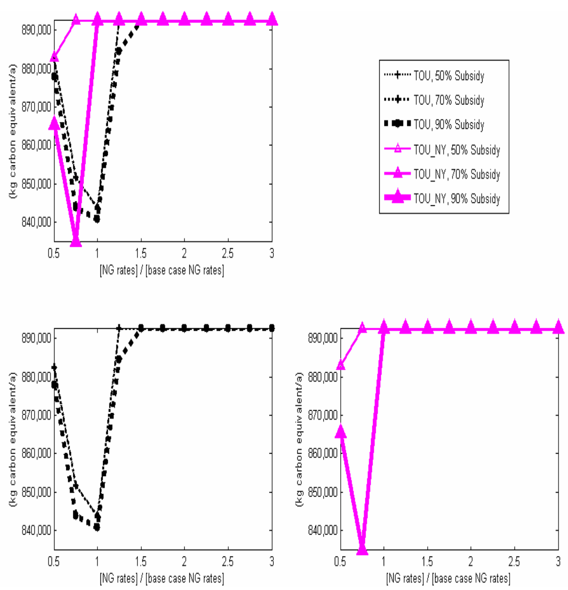

Figure A- 14: Carbon equivalent emissions for volumetric natural gas rate variation and fuel cell subsidies

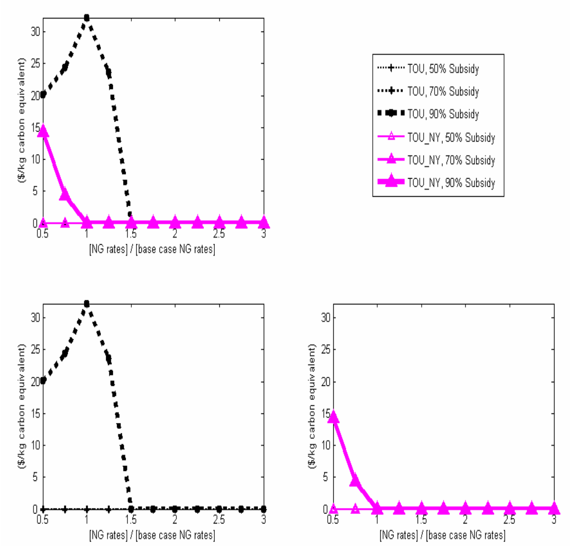

Figure A- 15: Annualized subsidy cost of carbon emissions for volumetric natural gas rate variation and fuel cell subsidies

As-Used Demand Sensitivity

Demand sensitivities show that DG investment is motivated more by TOU parent tariff rates than by TOU_NY standby demand charges because as-used monthly demand charges are a larger portion of the bill than as-used daily demand charges. This is seen in Figure A- 16 and Figure A-17. This demand sensitivity shows that fuel cells are not adopted unless they are subsidized at 90%. For this subsidy level, fuel cells mainly replace natural gas engine electrical capacity.

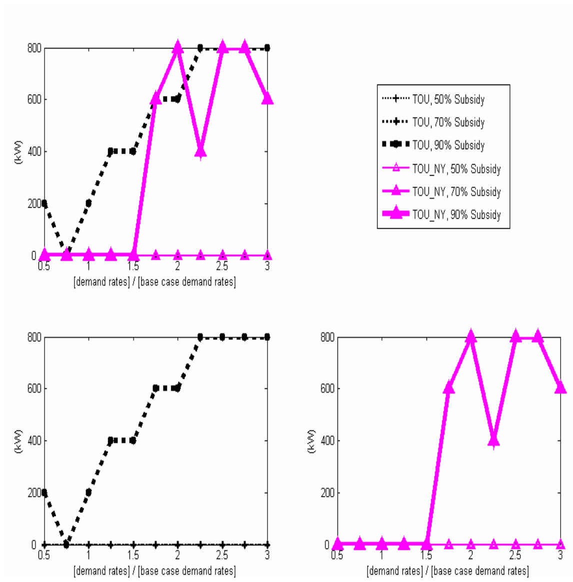

Figure A- 16: Installed electrical capacity of fuel cells for as-used demand rate variation and fuel cell subsidies

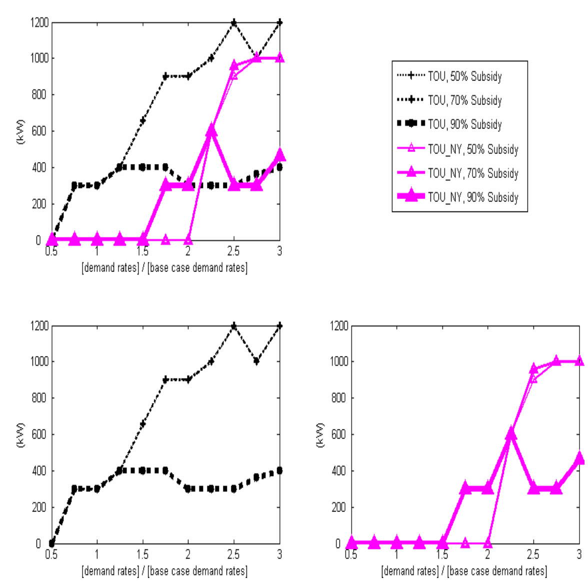

Figure A- 17: Installed electrical capacity of natural gas engines for as-used demand rate variation and fuel cell subsidies

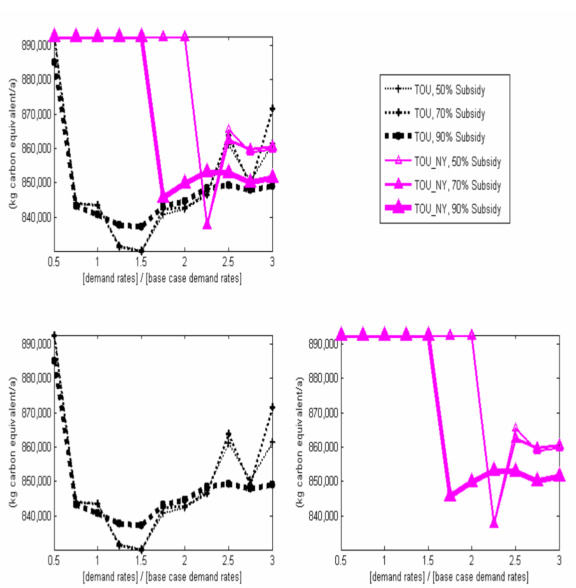

Figure A- 18: Carbon equivalent emissions for as-used demand rate variation and fuel cell subsidies

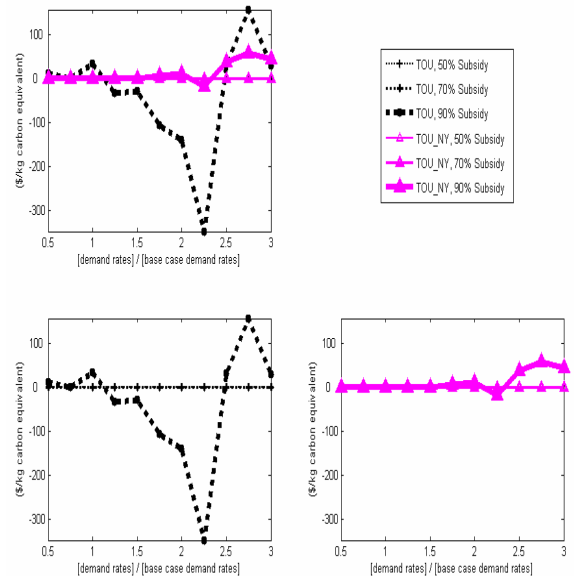

Figure A- 19: Annualized subsidy cost of carbon emissions for as-used demand rate variation and fuel cell subsidies

F.2 Microturbine Subsidies

While microturbines offer lower electrical efficiency than natural gas engines, they produce higher quality recoverable heat and have lower emissions rates. Microturbine subsidies of 25%, 50% and 75% were considered for each of the three energy price sensitivities. Only subsidies of 75% encouraged microturbine adoption.

Volumetric Electricity Rate Sensitivity

For the volumetric electricity rate sensitivity, microturbine subsidies of 75% make them an economical option, particularly when DG systems smaller than the site's peak demand are selected. Figure A- 20 shows the microturbine's attractiveness when DG capacity is small (Figure A- 21). However, as the overall size of DG systems gets larger, the amount of generating capacity from mircoturbines reduces to 120 kW and remains constant since the optimal capacity of DG systems will not be above 1000 kW. Microturbines subsidies would not reduce carbon emissions for the hospital below those of natural gas engines (Figure A- 22).

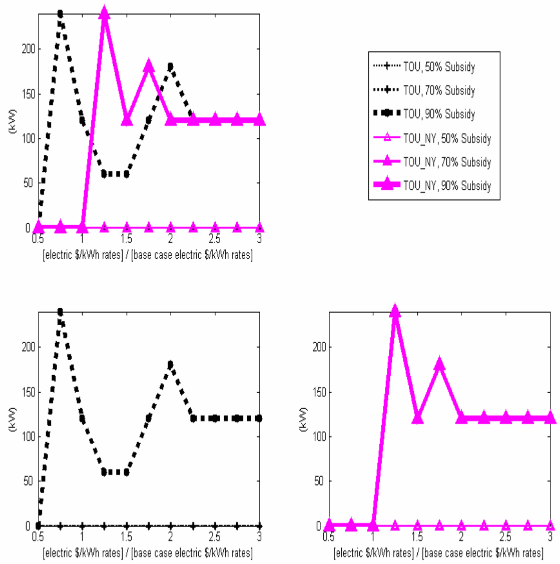

Figure A- 20: Installed electrical capacity of microturbines for volumetric electricity rate variation and microturbine subsidies

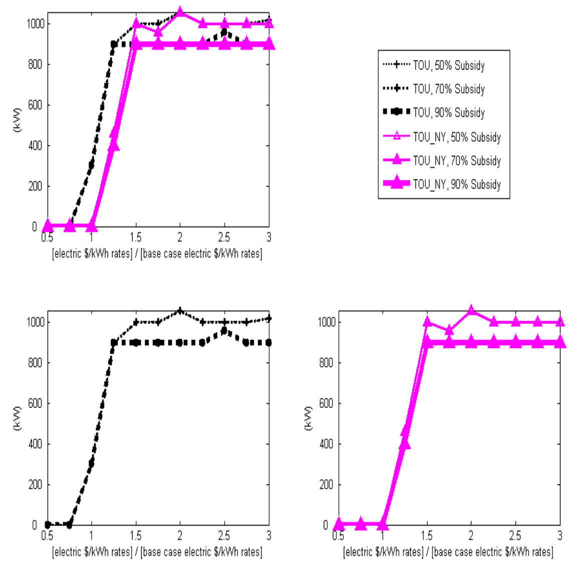

Figure A- 21: Installed electrical capacity of natural gas engines for volumetric electricity rate variation and microturbine subsidies

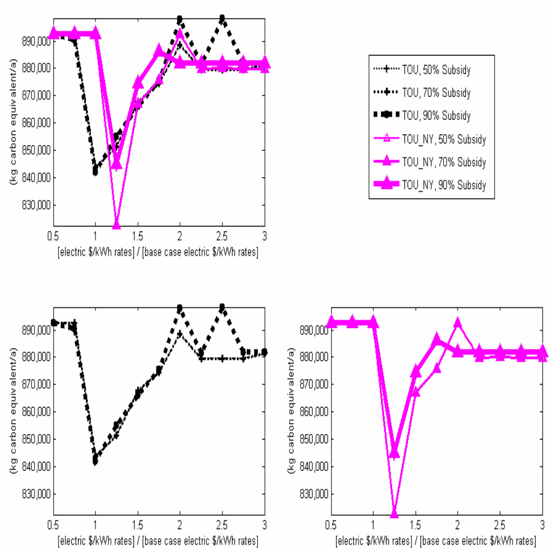

Figure A- 22: Carbon equivalent emissions for volumetric electricity rate variation and microturbine subsidies

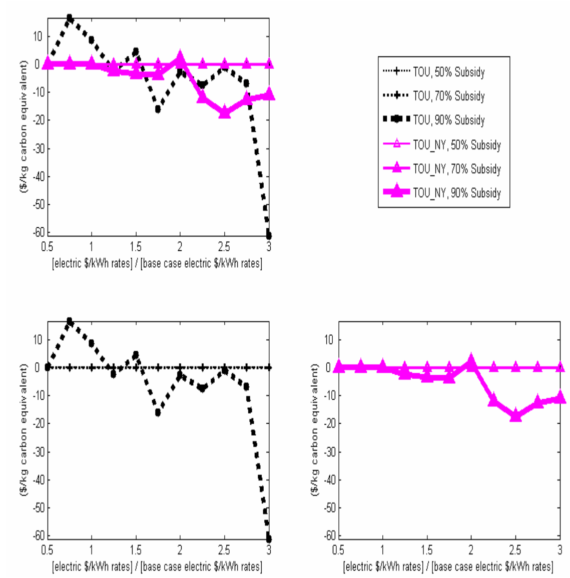

Figure A- 23: Annualized subsidy cost of carbon equivalent savings for volumetric electricity rate variation and microturbine subsidies

Volumetric Natural Gas Sensitivity

As in the previous sensitivity, microturbines with 75% subsidy can be economical (Figure A-24), particularly for overall DG systems smaller than the site's peak load are installed. For the parent tariff (TOU), DG is economical for most of the range of natural gas prices (50% to 300% of base case volumetric natural gas rates). However, for the standby tariff (TOU_NY), DG is not economical beyond 125% of base case volumetric natural gas prices.

As in the previous sensitivity, a microturbine subsidy would not reduce carbon emissions below those of natural gas engines (Figure A- 26): all subsidy levels result in the same pattern of carbon emissions, even though investment occurs only at the 75% subsidy level.

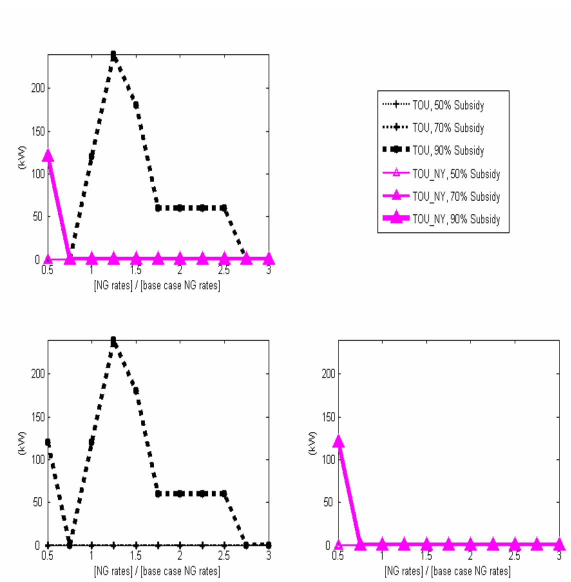

Figure A- 24: Installed electrical capacity of microturbines for volumetric natural gas rate variation and microturbine subsidies

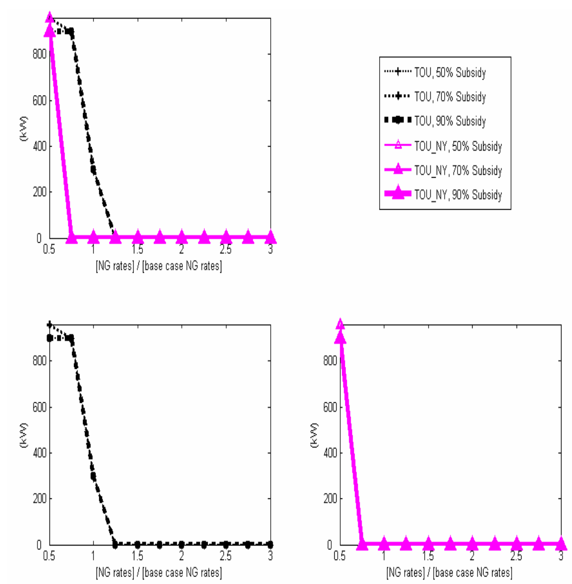

Figure A- 25: Installed electrical capacity of natural gas engines for volumetric natural gas rate variation and microturbine subsidies

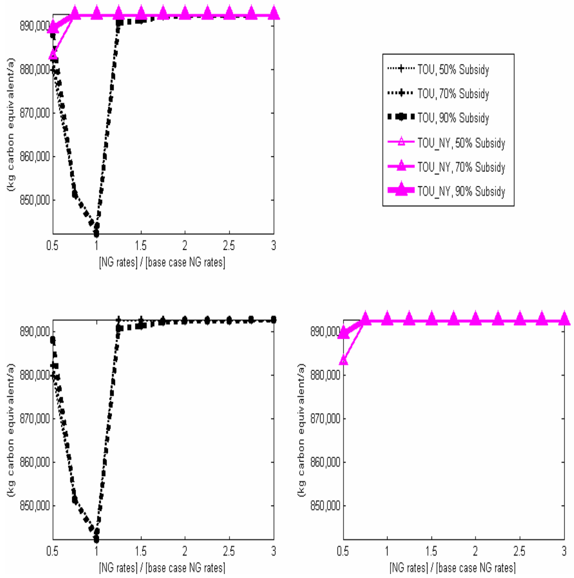

Figure A- 26: Carbon equivalent emissions for volumetric natural gas rate variation and microturbine subsidies

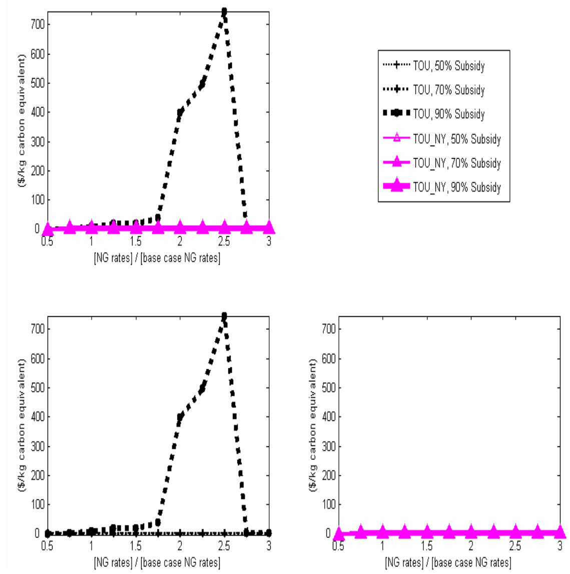

Figure A- 27: Annualized subsidy cost of carbon emissions for volumetric natural gas rate variation and microturbine subsidies

As-Used Demand Sensitivity

For the as-used demand sensitivity, under the parent tariff (TOU), microturbines are selected across the range of as-used demand prices (50% to 300% of base case as-used demand) (Figure A- 28). However, under the standby tariff (TOU_NY), demand charges must rise above 150% of the base case before DG systems are installed (Figure A- 28 and Figure A- 29). Again, this emphasizes the decreased significance of daily demand charges, compared to monthly demand charges, on the overall electricity bill.

Under the standby tariff (TOU_NY), microturbine subsidies encourage DG installation when demand charges are at 150% to 200% of base case. This is lower than without the subsidy, and is the only case that leads to carbon emissions reductions. Other than this range, though, microturbine subsidies have little effect on carbon emissions in this sensitivity (Figure A- 30).

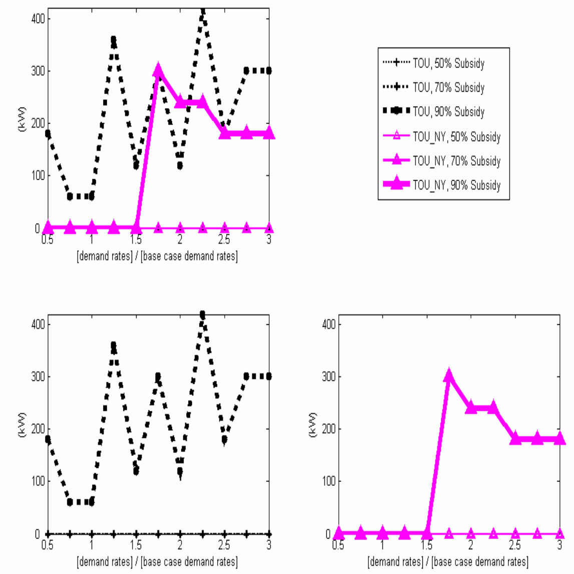

Figure A- 28: Installed electrical capacity of microturbines for as-used demand rate variation and microturbine subsidies

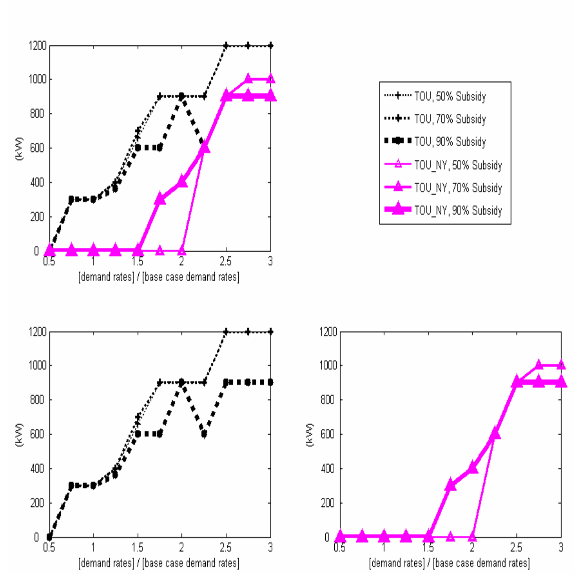

Figure A- 29: Installed electrical capacity of natural gas engines for as-used demand rate variation and microturbine subsidies

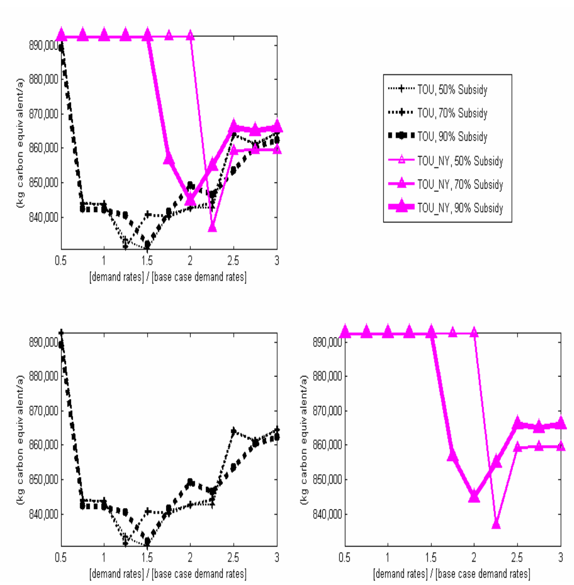

Figure A- 30: Carbon equivalent emissions for as-used demand rate variation and microturbine subsidies

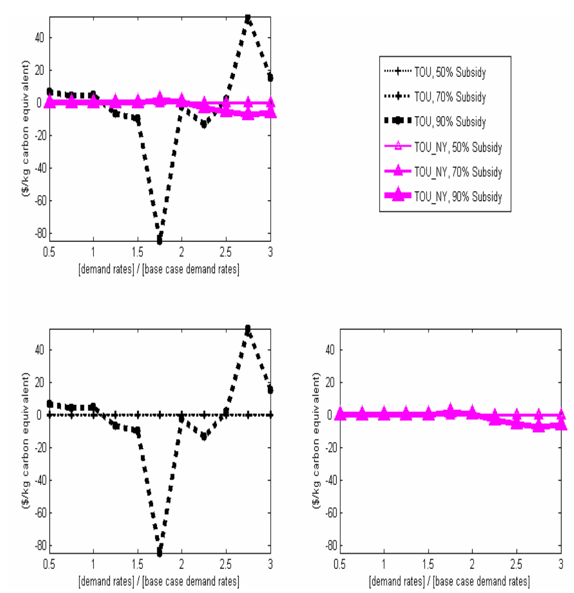

Figure A- 31: Annualized subsidy cost of carbon emissions for as-used demand rate variation and microturbine subsidies

F.3 Photovoltaic Subsidies

PV systems have many appealing characteristics, including zero carbon emissions, low maintenance, long lifetime, and power production coinciding with peak daytime demand hours. However, PV's high cost is a barrier to their adoption. This set of sensitivities examines PV subsidies of 50%, 70%, and 90%. Significant adoption occurs only for subsidies of 90%. As will be shown, PV battery subsidies can reduce carbon emissions, although at a cost near $3000 per metric ton of carbon equivalent reductions.

Note that PV capacity is reported in the system's peak output under average monthly insolation data for New York State,[29] which is 600 W/m^2. PV systems are rated for insolation of 1000 W/m^2. Therefore, in New York, a system with a nameplate capacity of 100 kW only provides 60 kW of peak electrical capacity, and is reported as a 60 kW system.

PV are exempt from standby tariffs under certain conditions, which vary by IOU. For ConEd customers, PV systems are exempt if they are used alone or only in conjunction with other environmentally favorable technologies, such as fuel cells, wind energy, or biomass. O&R only exempts residential PV systems under 10 kW. NiMo exempts PV systems under 50 kW.

Volumetric Electricity Rate Sensitivity

For the volumetric electricity rate sensitivity, significant investment in PV with 90% subsidy begins at 100% of base case rates for the parent tariff (TOU) and 125% for the standby tariff (TOU_NY). For both rate structures, optimal investment will not be higher than 1100 kW of PV electrical capacity (Figure A- 32), while 400 kW to 600 kW of natural gas engine electrical capacity is selected to provide electricity and heat when insolation is not available (Figure A- 33).

For both tariffs, PV subsidies can bring about a 200-ton reduction in carbon equivalent emissions when volumetric electricity rates increase to 125% or greater of base case rates (Figure A- 34). In cases where significant PV capacity is installed (90% subsidy), the annualized subsidy cost is approximately $3000 per ton of carbon equivalent emissions reduction under the parent tariff (TOU) and $4000 per ton under the standby tariff (Figure A- 35).

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[29] Insolation data was collected from NASA's Atmospheric Sciences Data Center http://eosweb.larc.nasa.gov (last accessed February, 2005).

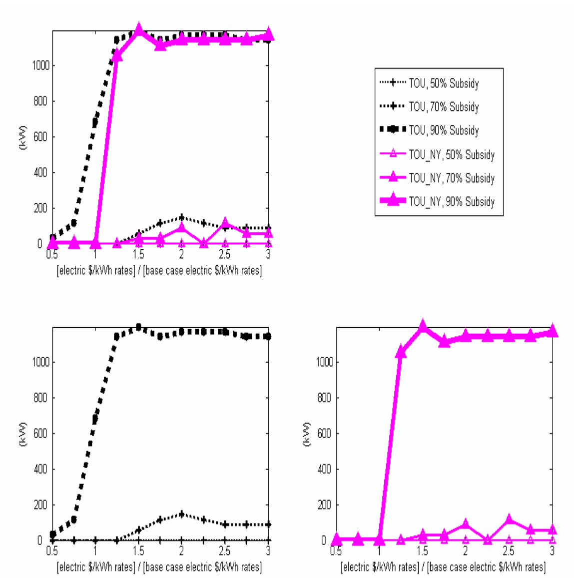

Figure A- 32: Installed electrical capacity of PV for volumetric electricity rate variation and PV subsidies

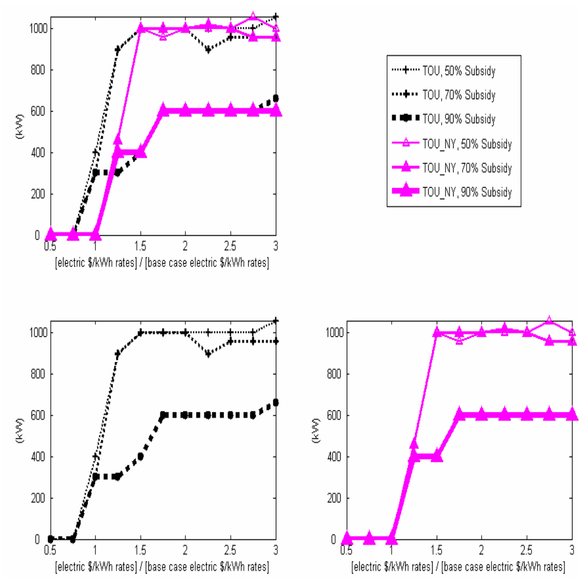

Figure A- 33: Installed electrical capacity of natural gas engines for volumetric electricity rate variation and PV subsidies

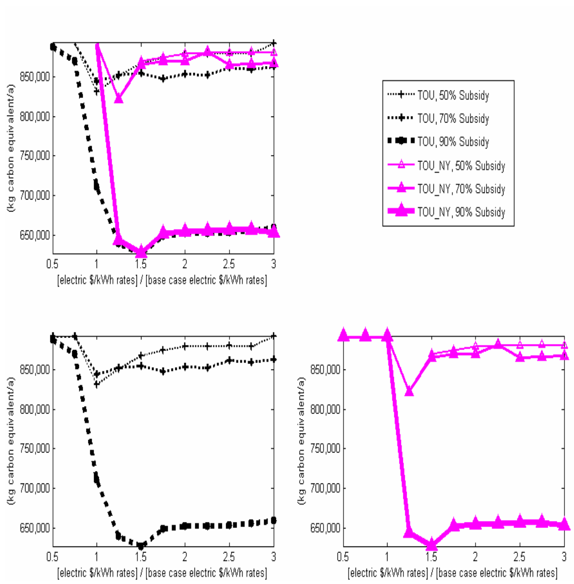

Figure A- 34: Carbon equivalent emissions for volumetric electricity rate variation and PV subsidies

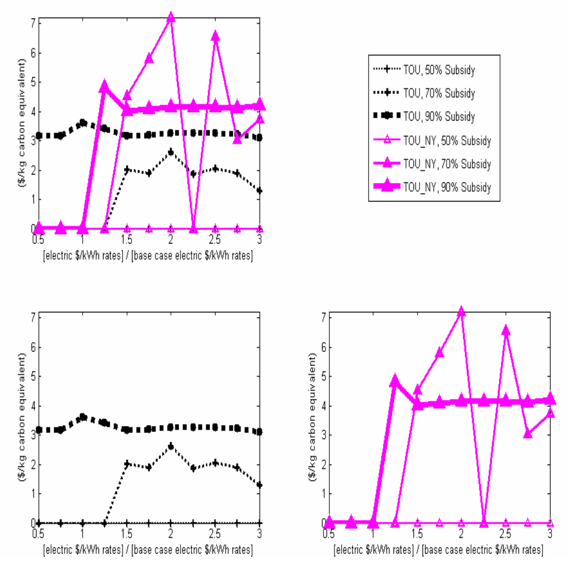

Figure A- 35: Annualized subsidy cost of carbon equivalent savings for volumetric electricity rate variation and PV subsidies

Volumetric Natural Gas Sensitivity

For the volumetric natural gas sensitivity, significant installation of PV occurs with a 90% subsidy, but only under the parent tariff (TOU), not the standby tariff (TOU_NY) (Figure A- 36). Under both tariffs, PV compliment natural gas ICE DG systems, which explains their highest level of adoption at the lowest natural gas prices (largest ICE DG system capacity). Under the parent tariff, PV is still economical on its own at higher natural gas prices. However, under the standby tariff, it is more economical to revert to the parent tariff than to install PV and incur the standby tariff.

PV is useful for reducing peak demand, which explains why they are installed under the parent tariff, where as-used monthly demand charges are larger than as-used daily demand charge. There are two reasons for the discrepancy in charges. First, parent tariff demand rates are greater than the number of weekdays per month times the daily demand rates. Second, monthly demand charges are based on the peak day demand, whereas daily demand is based only on the peak demand for the top three peak days each month. For all other weekdays in the month, the daily demand is based on the typical weekday demand. In other words, PV's demand offsets are more valuable under parent tariffs (monthly as-used demand) than under standby tariffs (daily as-used demand).

PV subsidies of 90% can lead to lower carbon equivalent emissions of approximately 150 tons per year, at a cost of $3000 per ton (Figure A- 38 and Figure A- 39). These savings are possible for all natural gas volumetric rates examined (50% to 300% of base case rates) under the parent tariff, but are not possible under the standby tariff.

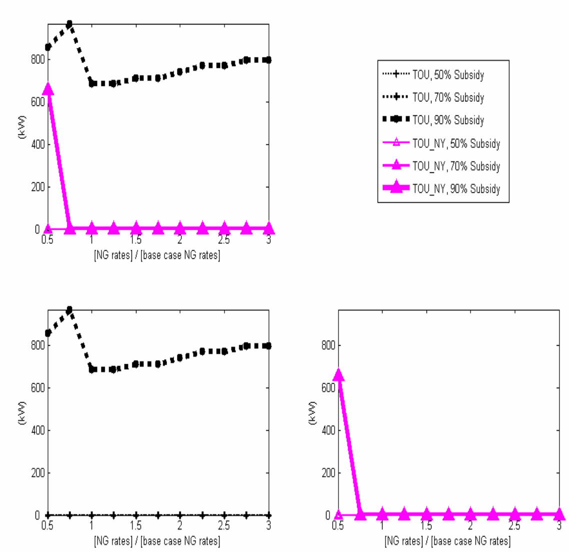

Figure A- 36: Installed electrical capacity of PV for volumetric natural gas rate variation and PV subsidies

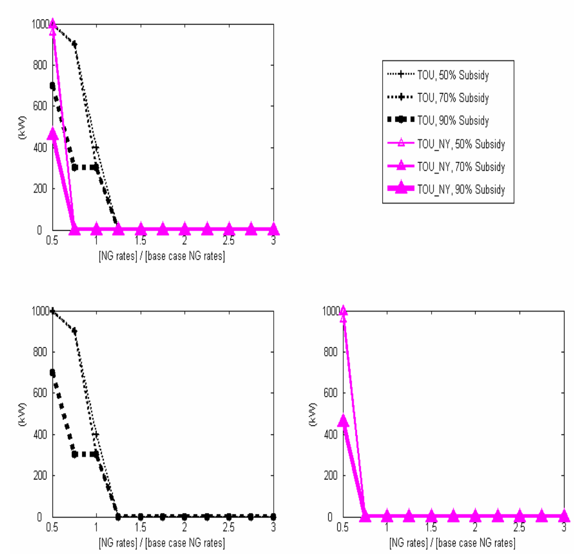

Figure A- 37: Installed electrical capacity of natural gas engines for volumetric natural gas rate variation and PV subsidies

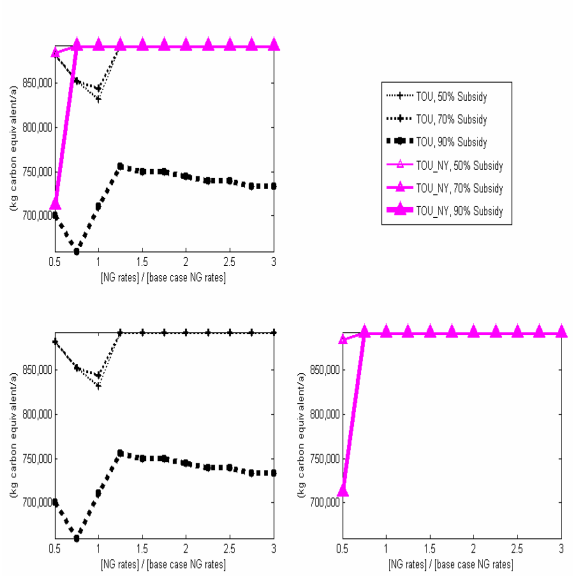

Figure A- 38: Carbon equivalent emissions for volumetric natural gas rate variation and PV subsidies

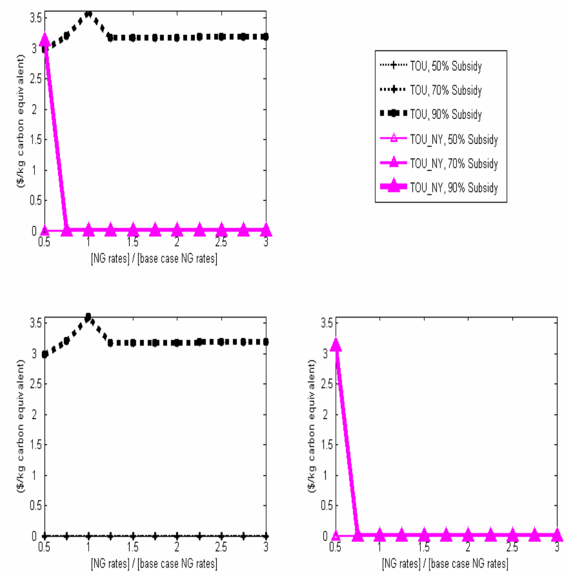

Figure A- 39: Annualized subsidy cost of carbon emissions for volumetric natural gas rate variation and PV subsidies

As-Used Demand Sensitivity

As-used demand sensitivity performed with PV subsidies again emphasizes the greater impact of as-used *monthly* demand charges (under the TOU parent tariff) compared to as-used *daily* demand charges. Under the parent tariff (TOU), 90% subsidized PV and natural gas engine installation gradually increase as demand charges increase, with installation across the entire range of demand charges considered (50% to 300% of base case as-used demand charges). However, no DG installation occurs under the standby tariff (TOU_NY) until demand charges are 175% of base case rates, at which point installation of both PV and natural gas engines quickly reaches the same installation capacity as under parent tariffs (Figure A- 40 and Figure A- 41).

Where significant PV installation is selected, carbon equivalent emissions reductions up to 200 tons per year under parent tariffs are possible for most demand rates considered, and under standby tariffs for demand rates greater than 200% of base case rates (Figure A- 42). The annualized subsidy cost of these reductions is \$3000 per ton under parent tariffs and \$4000 per ton under standby tariffs (Figure A- 43).

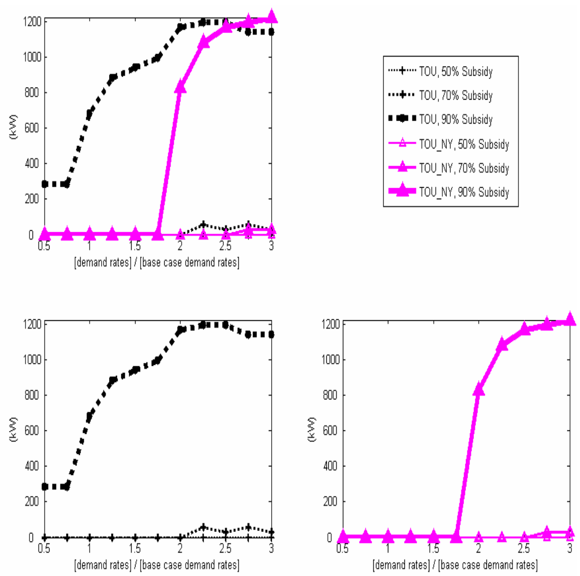

Figure A- 40: Installed electrical capacity of PV for as-used demand rate variation and PV subsidies

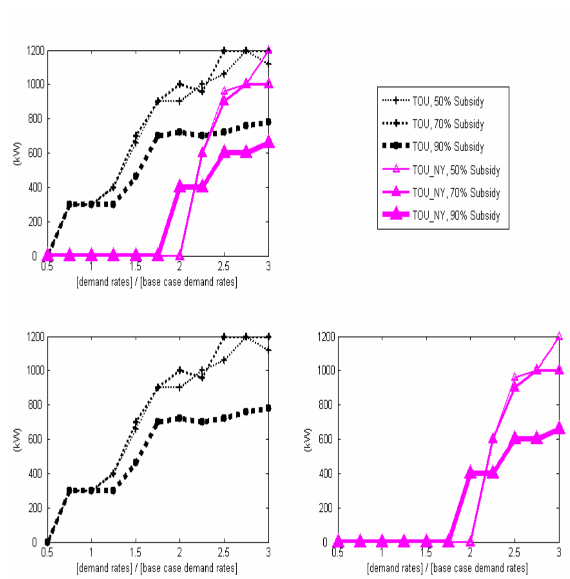

Figure A- 41: Installed electrical capacity of natural gas engines for as-used demand rate variation and PV subsidies

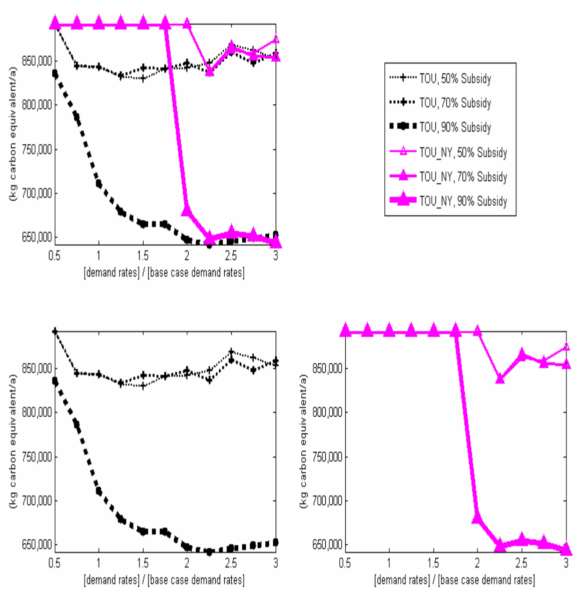

Figure A- 42: Carbon equivalent emissions for as-used demand rate variation and PV subsidies

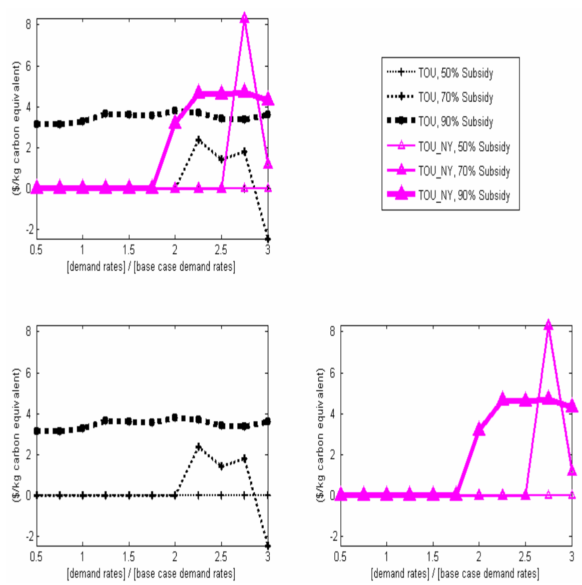

Figure A- 43: Annualized subsidy cost of carbon emissions for as-used demand rate variation and PV subsidies

Appendix G. Public Incentives for Self-generation

G.1 State Incentives

Acknowledging the public benefits of certain DG systems, NYSERDA offers subsidies and technical assistance for DG adopters. For the past four years, the state has operated the Distributed Generation and Combined Heat and Power Program[30] described below.

Purpose of Program

The Distributed Generation and Combined Heat & Power (DG-CHP) Program is funded at a level of $15 million per year. This Program supports the development and demonstration of distributed generation (DG) systems, components and related power systems technologies, and combined heat and power (CHP) application in industrial, municipal, commercial and residential sectors.

Eligibility

NYSERDA will support three types of projects with a maximum NYSERDA funding commitment of:
(1) $100,000 for feasibility studies,
(2) $500,000 for product development, and
(3) $1,000,000 for demonstrations.

All proposals must be cost-shared, preferably at or above 50% (cash and in-kind), with preference given to proposals with higher contribution levels and higher cash portion of the contribution.[31]

For demonstration projects, the funding is the lesser of $1,000,000 or a percentage of total project cost as determined below:

Established technologies (ICEs and steam engines):	30%
Established technologies with renewable fuels:	40%
Intermediate technologies (e.g. microturbines)	40%
Intermediate technologies with renewable fuel	50%
Emerging technologies (e.g. fuel cells)	50%
Emerging technologies with renewable fuel	60%

Additionally, projects that replicate successful past projects are eligible for subsidies of 15% of the project cost, or 25% if the project uses renewable fuels.

[30]As of March 2004, NYSERDA had received approximately 400 proposals for subsidy and accepted 120. Twenty have been completed, 60 are ongoing, and 40 backed out after acceptance. Data gathered from conversation with Dana Levy of NYSERDA on 8 March, 2004.
[31] Description provided by NYSERDA at http://www.nyserda.org/dgchp.html (last accessed July 2004, unavailable in February 2005 and in September 2005).

G.2 Utility Rate Incentives

Utility rates may also include incentives for DG. Natural gas delivery rates for DG systems are sometimes lower than for other customers because of DG users' higher load factors. Standby customers can choose between their parent and standby tariffs if they meet certain maximum size and minimum efficiency standards.[32] Net metering is available to residential PV systems with less than 10 kW of electrical capacity and farm waste electric generating equipment[33] with less than 400 kW of electrical capacity.

G.3 Regional Incentives

Regional organizations, such as the New York City Economic Development Corporation, also offer incentives for DG use.[34]

G.4 Incentives to Federal Institutions

U.S. Executive Order 12902 (Clinton, 1994) calls on federal facilities to reduce their energy and water consumption. This order includes using renewable technologies and CHP to meet this goal and calls for federal provisions to aid implementation. FEMP (Federal Energy Management Program) provides federal building managers throughout the U.S. with technical assistance for data collection, feasibility studies, system selection and sizing assistance, and project facilitation.[35] Additional resources and incentives may be available to federal facilities through their respective government agencies.

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[32] In all New York IOUs, DG customers with electrical capacities less than 1 MW and CHP efficiencies greater than 60% can choose between standby and parent tariffs. Customers of all of the IOUs are exempt from standby rates if the electrical capacity of their DG system is less than 15% of their peak load.

[33] Farm waste systems use digesters to generate methane from manure. This methane then replaces natural gas in equipment such as ICEs and microturbines.

[34] The New York City Economic Development Corporation's Energy Cost Savings Program offers incentives for DG users including reductions in natural gas rates, and in natural gas and electricity delivery rates.
http://www.newyorkbiz.com/Business_Incentives/Energy/ECSPProgram.pdf (last accessed February 2005).

[35] An overview of the FEMP CHP Program can be found at
http://www.eere.energy.gov/femp/pdfs/chp_prog_overvw.pdf (last accessed February 2005).