Lawrence Berkeley National Laboratory

Title

Distributed energy resources customer adoption modeling with combined heat and power applications

Authors

Siddiqui, Afzal S.
Firestone, Ryan M.
Ghosh, Srijay
et al.

Publication Date

2003-07-01

LBNL-52718

ERNEST ORLANDO LAWRENCE
BERKELEY NATIONAL LABORATORY

Distributed Energy Resources with Combined Heat and Power Applications

Afzal S. Siddiqui, Ryan Firestone, Srijay Ghosh, Michael Stadler, Jennifer L. Edwards, and Chris Marnay

Ernest Orlando Lawrence Berkeley National Laboratory
University of California Berkeley
Berkeley, CA 94720

Environmental Energy Technologies Division

June 2003

http://eetd.lbl.gov/ea/EMS/EMS_pubs.html

The work described in this report was coordinated by the Consortium for Electric Reliability Technology Solutions, and was funded by the Assistant Secretary of Energy Efficiency and Renewable Energy, Distributed Energy and Electric Reliability Program of the U.S. Department of Energy under Contract No. DE-AC03-76SF00098 and the California Energy Commission, Public Interest Energy Research Program, under Work for Others Contract No. BG 99-396 (00).

LBNL-52718

Consortium for Electric Reliability Technology Solutions

Distributed Energy Resources Customer Adoption Modeling with Combined Heat and Power Applications

Prepared for the
California Energy Commission

Principal Authors

Afzal S. Siddiqui, Ryan M. Firestone, Srijay Ghosh, Michael Stadler, Jennifer L. Edwards, and Chris Marnay

Energy Analysis Department
Ernest Orlando Lawrence Berkeley National Laboratory
1 Cyclotron Road, MS 90-4000
Berkeley CA 94720-8061
C_Marnay@lbl.gov

Other DER-CAM Team Members

Owen Bailey, Emily Bartholomew, Norman Bourassa, and Kristina Hamachi LaCommare,
Ernest Orlando Lawrence Berkeley Laboratory

Tim Lipman
University of California at Berkeley

June 2003

The work described in this report was coordinated by the Consortium for Electric Reliability Technology Solutions, and was funded by the Assistant Secretary of Energy Efficiency and Renewable Energy, Distributed Energy and Electric Reliability Program of the U.S. Department of Energy under Contract No. DE-AC03-76SF00098 and the California Energy Commission, Public Interest Energy Research Program, under Work for Others Contract No. BG 99-396 (00).

Preface

It has become apparent that the energy needs of today are not necessarily best met by the traditional, centralized power system paradigm. Increased desire for efficiency, security, stability, and local control of power quality and reliability all suggest modification of the central station tradition. Concurrently, the technologies required for such a paradigm shift are becoming a reality. What this new path might look like, and how it might be shaped by technological, economic and political factors, is addressed herein.

Table of Contents

List of Figures and Tables

Glossary

CAISO	California Independent System Operator
CalPX	California Power Exchange
CEC	California Energy Commission
CERTS	Consortium for Electric Reliability Technology Solutions
CHP	combined heat and power
COP	coefficient of performance
CPUC	California Public Utilities Commission
DER	distributed energy resources
DER-CAM	Distributed Energy Resources Customer Adoption Model
DERI	distributed energy resources integration
Disco	distribution company
DOE	U.S. Department of Energy
DOE-2	building energy simulation model developed at Berkeley Lab
DRP	demand response program
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
FC	fuel cell
FCV	fuel cell vehicle
GAMS	General Algebraic Modeling System
IEM	imbalance energy market of the CAISO
MAISY	market analysis and information system
O&M	operation and maintenance
PAFC	phosphoric acid fuel cell
PEM	proton exchange membrane fuel cell
PQR	power quality and reliability
PV	photovoltaic
PX	power exchange
PURPA	Public Utilities Regulatory Policies Act
RSMEANS	R.S. Means Company annual handbook of cost estimates
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SOFC	solid oxide fuel cells
TAG	Technical Assessment Guide
TOU	time of use

Acknowledgements

The work described in this report was coordinated by the Consortium for Electric Reliability Technology Solutions, and was funded by the Assistant Secretary of Energy Efficiency and Renewable Energy, Distributed Energy and Electric Reliability Program of the U.S. Department of Energy under Contract No. DE-AC03-76SF00098 and the California Energy Commission, Public Interest Energy Research Program, under Work for Others Contract No. BG 99-396 (00). The authors would like to thank Boubekeur Ouaglal, Francisco Javier Rubio, and Cornelia Kawann who made substantial early contributions to the Berkeley Lab effort, and therefore, to this report. We would also like to express our gratitude to our program managers Mark Rawson and Laurie ten Hope of the CEC for their guidance and support of this project and to Phil Overholt, Gil Bindewald, and Pat Hoffman at DOE for prior and simultaneous project support. Our CERTS partners, Prof. Robert H. Lasseter and Giri Venkatramanan of the University of Wisconsin at Madison, Prof. Sakis Meliopoulos of the Georgia Institute of Technology and Robert Yinger of the Southern California Edison Company also provided valuable insights. The authors also recognize the advice and input of colleagues at Northern Power Systems. Finally, the authors would like to thank Prof. Alex Farrell of the Energy and Resources Group, University of California at Berkeley, for taking the time to review this work.

Executive Summary

In this report, an economic model of customer adoption of distributed energy resources (DER) is developed. It covers progress on the DER project for the California Energy Commission (CEC) at Berkeley Lab during the period July 2001 through Dec 2002 in the Consortium for Electric Reliability Technology Solutions (CERTS) Distributed Energy Resources Integration (DERI) project. CERTS has developed a specific paradigm of distributed energy deployment, the CERTS Microgrid (as described in Lasseter et al 2002). The primary goal of CERTS distributed generation research is to solve the technical problems required to make the CERTS Microgrid a viable technology, and Berkeley Lab's contribution is to direct the technical research proceeding at CERTS partner sites towards the most productive engineering problems. The work reported herein is somewhat more widely applicable, so it will be described within the context of a generic microgrid (μGrid). Current work focuses on the implementation of combined heat and power (CHP) capability. A μGrid as generically defined for this work is a semiautonomous grouping of generating sources and end-use electrical loads and heat sinks that share heat and power. Equipment is clustered and operated for the benefit of its owners. Although it can function independently of the traditional power system, or *macrogrid*, the μGrid is usually interconnected and exchanges energy and possibly ancillary services with the macrogrid. In contrast to the traditional centralized paradigm, the design, implementation, operation, and expansion of the μGrid is meant to optimize the overall energy system requirements of participating *customers* rather than the objectives and requirements of the macrogrid.

The DER customer adoption model (DER-CAM) is implemented as a mixed integer linear program (MILP) in the General Algebraic Modeling System (GAMS), a commercial software package for solving optimization problems. The most significant improvement that has been accomplished in this work is the incorporation of the CHP technology in DER-CAM. This enables the joint optimization of electricity and natural gas consumption. The current model accounts for the use of waste heat on-site, which can be used to meet some of the space/water heating loads, and also, where applicable, cooling loads using absorption chillers. Utility rates and contrasting gas prices together with emerging technology options with different cost structures and heat rates create an excellent opportunity for DER-CAM to find the minimum-cost combination of on-site generation, natural gas usage, and electricity purchases.

The addition of CHP to DER-CAM is a tremendous step towards creating a realistic customer adoption model. As is seen in industry and confirmed in results in this report, the recovered waste heat from DER is of significant value and often tips the scales in favor of DER over macrogrid dependence.

The technology data used in DER-CAM were collected from diverse sources to form a data set containing reasonable cost and performance parameters for about thirty DER options available for installation at the time of writing. The technologies include two microturbines, a commercial fuel cell (FC), small wind and photovoltaic (PV) systems, and a wide range of reciprocating engines burning both diesel and natural gas fuel. Installation costs for these technologies were estimated via standard engineering economic guidelines. Furthermore, using a combination of experience curves and literature review, costs for technologies in the year 2010 were estimated. Therefore, realistically, some of the required data are not satisfactorily reliable at this time, and results are to be treated with commensurate skepticism. Also, some arbitrary assumptions are made, for example, that fuel cells are not used for CHP. To repeat, the main purpose of this effort is to develop the CHP capability of DER-CAM and demonstrate it.

To assess DER-CAM and examine the current case for DER in California, DER-CAM was run for a cluster of businesses and residences in a San Diego neighborhood assumed to be operating as a µGrid. Various scenarios examined the effects electricity purchasing schemes and DER incentives.

Overall, under idealized assumptions, DER-CAM suggests savings of about 30% on energy bills without CHP and 40% with CHP for an example group of customers during 2000. A dramatic shift from electricity purchase to natural gas purchase is seen in order to incur these savings. In most scenarios, natural gas engines are the dominant technology, due to their relatively low capital costs and reasonable efficiency. They are a well-established technology. As would be expected, more capacity is selected when CHP is considered than when it is not. Compared to natural gas engines, microturbines are more expensive to purchase and operate, but produce more recoverable heat. When this heat is of value and/or microturbines are subsidized slightly, they are included in some solutions along with natural gas engines.

Slightly smaller installed capacity is selected when the µGrid purchases electricity directly at prices based on the last operational year of the CalPX rather than the utility. Demand charges make utility tarriffed electricity peakier in price than CalPX hourly day-ahead prices, and it is these peakier prices that encourage the installation of more capacity, even if it is not used often. In most scenarios, almost all on-site electricity demand was met by on-site capacity. This result acknowledges that electricity in San Diego was expensive enough during this time period to warrant the purchase of DER capacity, even when it would be used only during peak hours.

Absorption cooling was not selected in any of these scenarios. Where there is a direct use for recovered heat, it is more cost effective to use recovered heat for heating and electricity for cooling, even though this entails more installed capacity or incurring high daytime macrogrid prices when electric chillers would be in use.

1. Introduction

1.1 Berkeley Lab Work in Context

In this report, an economic model of customer adoption of distributed energy resources (DER) is developed. It covers progress on the DER project for the California Energy Commission (CEC) at Berkeley Lab during the period July 2001 through Dec 2002 in the Consortium for Electric Reliability Technology Solutions (CERTS) Distributed Energy Resources Integration (DERI) project. CERTS has developed a specific paradigm of distributed energy deployment, the CERTS Microgrid (as described in Lasseter et al 2002). The primary goal of CERTS distributed generation research is to solve the technical problems required to make the CERTS Microgrid a viable technology, and Berkeley Lab's contribution is to direct the technical research proceeding at CERTS partner sites towards the most productive engineering problems. The work reported herein is somewhat more widely applicable, so it will be described within the context of a generic microgrid (μGrid). Current work focuses on the implementation of combined heat and power (CHP) capability. A μGrid as generically defined for this work is a semiautonomous grouping of generating sources and end-use electrical loads and heat sinks that share heat and power. Equipment is clustered and operated for the benefit of its owners. Although it can function independently of the traditional power system, or *macrogrid*, the μGrid is usually interconnected and exchanges energy and possibly ancillary services with the macrogrid. In contrast to the traditional centralized paradigm, the design, implementation, operation, and expansion of the μGrid is meant to optimize the overall energy system requirements of participating *customers* rather than the objectives and requirements of the macrogrid.

The evolution of DER analysis began with a spreadsheet version (see Marnay *et al.* 2000). Follow-up reports used GAMS to solve the Customer Adoption Model (see Rubio *et al.* 2001) and (Marnay *et al.* 2000). The next study extended that model to account for carbon taxes (see Siddiqui *et al* .2002). CHP technologies were cursorily implemented in the next round by accounting for heating and cooling loads (see Bailey *et al.* 2002). It was found in this case that the availability of heat exchangers and absorption cooling enabled the μGrid to reduce the cost of meeting its energy needs, even further. In this study, the model is made more realistic by accounting for the intricacies of the utility tariff structure, including monthly variation in fuel prices, and most importantly by incorporating a more detailed and formal thermodynamic model of the energy flows in the system. A detailed description of the model is provided in Chapter 5.

1.2 Analysis Approach

With CERTS's wider goals in mind, Berkeley Lab has built an economic model of customer DER adoption, DER-CAM, that finds the cost-minimizing combination of on-site generation and CHP technology that a customer could install during a test year (April 1999 through March 2000 in this report). DER-CAM has been implemented in the General Algebraic Modeling System (GAMS) optimization software.

CHP technologies such as heat exchangers and absorption coolers enable the co-utilization of both the heat and electricity generated by traditional electricity generators. Waste heat can be used for air and water heating loads and can also be used to meet cooling loads via absorption coolers. All of these processes for recovered heat usage are implemented in DER-CAM. The consideration of CHP implementation to meet heating and cooling needs has been the key addition to the DER-CAM model reported here.

The inputs to DER-CAM include the μGrid's electricity, heating, and cooling uses, the operating characteristics of available DER technologies (e.g., energy conversion efficiencies, heat recovery efficiencies, costs, etc.) and economic parameters, such as the tariffs under which the μGrid can buy electricity, the prices of fuels, etc. The solutions to these analyses are not intended to be thorough financial or engineering evaluations of whether on-site generation is beneficial for this μGrid, nor are they intended to provide market assessments or forecasts of DER penetration, although DER-CAM can be used towards these ends. The objective is simply to examine economic fundamentals and determine which DER technologies may be attractive to μGrids, in what combinations they might be installed, and how they might be operated. Always, the intention is to anticipate the key technical problems that would need to be solved for this μGrid to function. The results obtained from this process are the optimal combination of on-site generation and heat recovery, an elementary operating schedule of how the equipment should be used, and summary results for each case, such as total electricity bill, electricity generation and purchases in each hour, etc.

In this study the μGrid is composed of typical southern California commercial energy customers. Historic end-use metered electrical loads for the customers have been massaged into load shapes appropriate for use in DER-CAM. Additionally estimated heating and cooling loads are obtained using DOE-2, a building energy simulation program developed at Berkeley Lab. The customers are assumed to be in the San Diego area, and so appropriate fuel and electricity costs for San Diego are applied.

1.3 Justification for the μGrid

The expectation that DER will emerge over the next decade to shape the way in which electricity is supplied stems from the following hypotheses:

1. Electricity demand will continue to grow, although more slowly than economic expansion,
2. Small-scale generating technologies, both renewable and thermal, will improve significantly,
3. Siting constraints, environmental concerns, fossil fuel scarcity, and other limits will impede continued expansion of the existing electricity supply infrastructure,
4. The potential for application of small scale CHP technologies will tilt power generation economics in favor of generation based closer to heat loads,
5. Customers' desire for control over service quality and reliability will intensify, and
6. Power electronics will enable operation of semi-autonomous systems.

The last hypothesis above is the driving force behind the CERTS Microgrid approach. This approach is built upon the fundamental concept of the μGrid, which could yield a more decentralized power system. The μGrid is connected to the macrogrid in a manner that allows it to appear to the wider grid as a *good citizen*; that is, the μGrid performs as a legitimate entity under grid rules (e.g., as what we currently consider a normal electricity *customer* or *generating* *unit*). The implications of the fourth hypothesis are examined through economic considerations in this report.

The µGrid would most likely exist on small, densely grouped contiguous geographic sites that exchange electrical energy through a low voltage (e.g., 480 V) network and heat through exchange of working fluids. In the commercial sector, heat loads may well be absorption or desiccant cooling. The generators and loads within the cluster are placed and coordinated to minimize the joint cost of serving electricity and heat demand, given prevailing market conditions, while operating safely and maintaining power balance and quality.

Traditional power system planning and operation hinges on the assumption that the selection, deployment, and financing of generating assets will be tightly coupled to changing requirements and that it will rest in the hands of a centralized authority. The Public Utilities Regulatory Policies Act (PURPA) reforms represented the first step towards reversal of this paradigm, ongoing industry restructuring represents the second, and the emergence of a decentralized power system the third. µGrids will develop their own independent operational standards and expansion plans. This will significantly affect the overall growth of the power system, but it will tend to occur in accordance with their independent incentives. In other words, the power system will be expanding according to dispersed independent goals, instead of coordinated global ones.

The emergence of the µGrid partially stratifies the current strictly hierarchical control of the power system into at least two layers. The upper layer macrogrid is the one with which current power engineers are familiar (i.e., the high voltage meshed power grid). A control center dispatches a limited set of large assets in keeping with contracts established between electricity and ancillary services buyers and sellers, while maintaining the energy balance and power quality, protecting the system, and ensuring reliability. At the same time, where they operate, the lower layer µGrid jointly locally controls some generation and load to meet end use requirements for energy and power quality and reliability (PQR).

Control of the generating and transmission assets of the macrogrid is governed by extremely precise technical standards that are uniform on regional scales, and the key parameters of the grid, such as frequency and voltage, are maintained strictly within tight tolerances. This control paradigm ensures overall stability and safety and attempts to guarantee that power and ancillary service delivery between sellers and buyers is as efficient and reliable as reasonably possible. However, it should be recognized that uniform standards of PQR are unlikely to match well with the optimal requirements of individual end uses that are highly heterogeneous (e.g., with server farms at one end of the reliability requirement spectrum and water pumps at the other). µGrids move the PQR choice closer to the end uses and permit them to match the end-use's requirements more tightly. µGrids can, therefore, improve the overall efficiency of electricity delivery at the point of end use, and, as µGrids become more prevalent, the PQR standards of the macrogrid can ultimately be matched to the purpose of bulk power delivery.

1.4 Impact of CHP Inclusion on DER adoption

The additional consideration of CHP in distributed generation greatly increases the complexity of both the modeling problem and the physical manifestation. Electricity from any source can be supplied to a customer via the existing electrical system of a building, requiring only a power electronics interface between the generators and the building wiring. On the other hand, CHP, along with increasing the equipment requirements of DER, requires that proper pumps and plumbing be installed to transfer the hot operating fluid to the thermal points of use, as well as controls to maintain the required level of thermal input. However, a key aspect of μGrid design is that generators are co-located with heat sinks whenever possible. Given that the distribution of electricity is far easier than the distribution of heat, the benefits of matching generation to heat loads are apparent. In a theoretical analysis such as DER-CAM, these issues are abstracted.

Although CHP increases the complexity of the system, the economic savings introduced can be considerable. In addition, carbon emissions are reduced because overall energy efficiency is improved; this would make CHP even more attractive if carbon taxes were introduced. Overall, DER-CAM consistently chose to implement CHP in situations where CHP was an option.

1.5 Report Outline

In Chapter 2, data on DER technology cost and performance are presented. The simplifying assumptions made regarding the technologies and thermodynamics are specified. Next, in Chapters 3 and 4, the customer and market data, respectively, are introduced. Chapter 5 describes the mathematical model used to minimize the μGrid's energy supply cost using the technology, customer, and market data as inputs. The results of the optimization are analyzed in Chapter 6. This analysis includes both an overview of the energy and financial characteristics of the μGrid's cost minimization strategy as well as detailed case studies of various regulatory scenarios. Finally, Chapter 7 summarizes the main findings of this report and offers directions for future research in this area.

2. DER Technology Cost and Performance Data

2.1 Introduction

The goal of this study is merely to demonstrate the CHP capability of DER-CAM. While DER technology data that best reflect actual operations are used wherever possible, example runs are necessarily idealized. The data were collected from various sources including manufacturer's technical specifications, phone interviews with company representatives, the open literature, and from proprietary publications such as Electric Power Research Institute's (EPRI) Technical Assessment Guide (TAG). On the other hand, many of the technologies that will be dominant in µGrids are not yet commercial, and certainly not yet mature. As a result, the collection and refinement of data is an ongoing task. However, the resources available for this study are limited and few organized data sources currently exist in the public domain. Therefore, realistically, some of the required data are not satisfactorily reliable at this time, and results are to be treated with commensurate skepticism. Also, some arbitrary assumptions are made, for example, that fuel cells are not used for CHP. To repeat, the main purpose of this effort is to develop the CHP capability of DER-CAM and demonstrate it.

2.2 About the Data

The data were organized around two scenarios: one based on current DER technology operating characteristics and costs, and the other anticipating cost and performance information to approximate conditions in the year 2010. These two data sets were used in the two scenarios to determine any differences in customer adoption behavior in 2000 compared with 2010. The 2010 scenario was performed to reflect the likelihood that some DER technologies will become more commercialized over the next decade. Lowering operating and equipment costs by increasing production volume may make emerging technologies a more viable alternative to purchasing electricity from the grid since large-scale generating technologies are mature now, and siting and congestion may raise costs in the future.

The 2010 scenario requires the forecasting of costs for some technologies whose emergence onto the market is forthcoming. For example most types of fuel cells (FCs), including the solid oxide fuel cell (SOFC), are still in development and other technologies already available in the market, like photovoltaics (PVs), are still undergoing significant improvements. Also, forecasted production volume increases over the next ten years will bring about further improvements. Therefore, the 2010 data show significant improvements to these emerging technologies, but little or no change in mature technologies.

Electricity producing technologies are represented in the DER-CAM model by a variety of input data related to the economics and performance of each technology type. These data include capital costs of equipment, operation and maintenance (O&M) costs, equipment installation costs, conversion efficiencies, and waste heat proportions. These data have been compiled from various sources and are presented in Tables 1 and 2. Generalizations regarding heat production, heat transfer, and heat utilization technologies have been made as a first attempt at CHP consideration in DER-CAM. These generalizations may be replaced with actual product specifications as this information is obtained.

This chapter presents the characteristics of the collected DER data by technology type. The electricity generation technologies incorporated in DER-CAM include microturbines, FCs, PVs, and diesel and natural gas reciprocating engines. Heat generation is through combustors and heat transfer via heat exchangers. Absorption chillers are considered in order to utilize heat for cooling while heat utilization for hot water and hot air is assumed to require no additional consideration beyond the heat exchangers and combustors.

2.3 Present Day and 2010 Scenario Data

Table 1 below illustrates the data used for the present day scenario. Included in this scenario are four microturbines, one FC, four PV systems, fourteen diesel back-up generators, and five gas-fired reciprocating engine generators. Table 1 illustrates the forecasted 2010 data. Eight additional fuel cells are considered as well as one fuel cell vehicle (FCV).

The considered parameters include the nameplate kW rating, estimated turnkey cost (turnkey costs are defined here as free on board equipment cost plus delivery cost plus installation and permitting costs), fixed and variable O&M costs, conversion efficiency or heat rate, and the heat generated per amount of electricity generated (α). Entries in the tables with a ‘PR’ label denote places where the data were available, but from a proprietary source that could not be explicitly reported.

DER generation technologies are given code names for brevity. For each code name, the first term is the type of technology:

- No prefix: a unit without recovered heat
- *CHP*: a unit with recoverable heat
- *COOL*: a unit with recoverable heat and absorption chilling capabilities
- *BOW*: Bowman microturbine
- *DE*: diesel engine
- *GA*: natural gas engine
- *MTL*: Capstone low-pressure microturbine
- *MTH*: Capstone high-pressure microturbine
- *PEM*: proton exchange membrane fuel cell
- *PAFC*: phosphoric acid fuel cell
- *PV*: photovoltaics
- *SOFC*: solid oxide fuel cell

If there is a middle term, it refers to the manufacturer of the equipment. The last term is the rated capacity (kW) of the equipment.

The technologies that were considered for CHP and absorption cooling were the natural gas engines and the Capstone microturbines.

Table 1. Present Day DER Technology Data

Name	DER Type	Source	Rated Power (kW)	Lifetime (years)	Turnkey Cost ($/kW)	OMFixed ($/kW/year)	OMVar ($/kWh)	Lev Cost (c/kWh)	Heat Rate (kJ/kWh)	Alpha (kWh/kWh)
MTL-C-30	MT	SCE	30	12.5	1333	119	0	12.14	12186	2.67
MTH-C-30	MT	SCE	30	12.5	1333	119	0	10.56	12186	2.51
PAFC-O-200	PAFC	TAG	200	12.5	PR	PR	PR	PR	PR	0.00
DE-K-15	Diesel Backup	Manufacturer	15	12.5	2257	26.5	0.000033	N/A	18288	0.00
DE-K-30	Diesel Backup	Manufacturer	30	12.5	1290	26.5	0.000033	5.57	11887	0.00
DE-K-60	Diesel Backup	Manufacturer	60	12.5	864	26.5	0.000033	6.30	11201	0.00
DE-K-105	Diesel Backup	Manufacturer	105	12.5	690	26.5	0.000033	5.48	10581	0.00
DE-K-200	Diesel Backup	Manufacturer	200	12.5	514	26.5	0.000033	5.20	11041	0.00
DE-K-350	Diesel Backup	Manufacturer	350	12.5	414	26.5	0.000033	4.61	10032	0.00
DE-K-500	Diesel Backup	Manufacturer	500	12.5	386	26.5	0.000033	4.65	10314	0.00
DE-C-7	Diesel Backup	Manufacturer	7.5	12.5	627	26.5	0.000033	N/A	10458	0.00
DE-C-20	Diesel Backup	Manufacturer	20	12.5	1188	26.5	0.000033	7.48	12783	0.00
DE-C-40	Diesel Backup	Manufacturer	40	12.5	993	26.5	0.000033	7.05	11658	0.00
DE-C-100	Diesel Backup	Manufacturer	100	12.5	599	26.5	0.000033	5.45	10287	0.00
DE-C-200	Diesel Backup	Manufacturer	200	12.5	416	26.5	0.000033	4.94	9944	0.00
DE-C-300	Diesel Backup	Manufacturer	300	12.5	357	26.5	0.000033	5.14	10287	0.00
DE-C-500	Diesel Backup	Manufacturer	500	12.5	318	26.5	0.000033	5.42	9327	0.00
GA-K-25	Gas Backup	Manufacturer	25	12.5	1730	26.5	0.000033	10.42	15596	1.72
GA-K-55	Gas Backup	Manufacturer	55	12.5	970	26.5	0.000033	7.55	12997	0.72
GA-K-100	Gas Backup	Manufacturer	100	12.5	833	26.5	0.000033	9.18	15200	1.24
GA-K-215	Gas Backup	Manufacturer	215	12.5	1185	26.5	0.000033	7.15	13157	1.22
GA-K-500	Gas Backup	Manufacturer	500	12.5	936	26.5	0.000033	7.33	12003	0.93
BOW-50	MT	Manufacturer	50	12.5	1500	5.0	0.015	N/A	11201	0.00
BOW-80	MT	Manufacturer	80	12.5	1700	7.5	0.015	N/A	10287	0.00
PV-5	PV	Jeff Oldman, Real Goods	5	20	8650	14.3	0	55.23	0	0.00
PV-20	PV	Jeff Oldman, Real Goods	20	20	7450	14.3	0	47.56	0	0.00
PV-50	PV	Jeff Oldman, Real Goods	50	20	6675	5.0	0	42.62	0	0.00
PV-100	PV	Jeff Oldman, Real Goods	100	20	6675	2.9	0	42.62	0	0.00

Table 2. 2010 DER Technology Data

Name	DER Type	Source	Rated Power *(kW)*	lifetime *(years)*	Turnkey Costs *($/kW)*	OMFixed *($/kW/year)*	OMVariable *($/kWh)*	Lev Cost *(c/kWh)*	HeatR *(kJ/kWh)*	Alpha *(kW/kW)*
MTL-C-30	MT	sce	30	10	1333.3	119		12.18	12,186	2.666667
MTH-C-30	MT	sce	30	10	1333.3	119		12.18	12,186	2.509804
PAFC-O-200	PAFC	DER-CAM team forecast	200	10	1700	0	0.0153	12.36	PR	0
PAFC-O-1200	PAFC	DER-CAM team forecast	1200	10	1800	0	0.006	9.80	PR	0
SOFC-SW-3100	SOFC-CT	DER-CAM team forecast	3100	10	670	10	0.002	6.14	PR	0
PEM-BA-250	PEM-FC	DER-CAM team forecast	250	10	750	10.8	0.002	N/A	PR	0
SOFC-C8-500	SOFC	DER-CAM team forecast	500	10	890	8.5	0.03	6.85	PR	0
PEM-10kW	PEM-FC	Ogden & Kreutz	10	10	1600	10	4.2		10,800	0
PEM-25kW	PEM-FC	Ogden & Kreutz	25	10	1000	4	3		10,800	0
PEM-50kW	PEM-FC	Ogden & Kreutz	50	10	800	2	2.6		10,800	0
DE-K-15	Diesel Backup	manufacturer	15	10	2257	26.5	0.000033	16.22	18,288	0
DE-K-30	Diesel Backup	manufacturer	30	10	1290	26.5	0.000033	10.37	11,887	0
DE-K-60	Diesel Backup	manufacturer	60	10	864	26.5	0.000033	9.50	11,201	0
DE-K-105	Diesel Backup	manufacturer	105	10	690	26.5	0.000033	8.86	10,581	0
DE-K-200	Diesel Backup	manufacturer	200	10	514	26.5	0.000033	9.16	11,041	0
DE-K-350	Diesel Backup	manufacturer	350	10	414	26.5	0.000033	8.32	10,032	0
DE-K-500	Diesel Backup	manufacturer	500	10	386	26.5	0.000033	8.57	10,314	0
DE-C-7	Diesel Backup	manufacturer	7.5	10	627	26.5	0.000033	N/A	10,458	0
DE-C-25	Diesel Backup	manufacturer	25	10	1182	26.5	0.000033	11.03	12,783	0
DE-C-40	Diesel Backup	manufacturer	40	10	993	26.5	0.000033	9.97	11,658	0
DE-C-100	Diesel Backup	manufacturer	100	10	599	26.5	0.000033	8.57	10,287	0
DE-C-200	Diesel Backup	manufacturer	200	10	416	26.5	0.000033	8.21	9,944	0
DE-C-300	Diesel Backup	manufacturer	300	10	357	26.5	0.000033	8.47	10,287	0
DE-C-500	Diesel Backup	manufacturer	500	10	318	26.5	0.000033	7.72	9,327	0
GA-K-25	Gas Backup	manufacturer	25	10	1420	26.5	0.000033	13.79	15,596	1.721519
GA-K-55	Gas Backup	manufacturer	55	10	866	26.5	0.000033	11.32	12,997	0.721831
GA-K-100	Gas Backup	manufacturer	100	10	830	26.5	0.000033	13.07	15,200	1.236736
GA-K-215	Gas Backup	manufacturer	215	10	1196	26.5	0.000033	11.59	13,157	1.218638
GA-K-500	Gas Backup	manufacturer	500	10	936	26.5	0.000033	10.63	12,003	0.928826
PV-5	PV	Jeff Oldman, Real Goods	5		5080	14.3	0	N/A		0
PV-20	PV	Jeff Oldman, Real Goods	20		4475	14.3	0	N/A		0
PV-50	PV	Jeff Oldman, Real Goods	50		4088	5	0	N/A		0
PV-100	PV	Jeff Oldman, Real Goods	100		4088	2.85	0	N/A		0
MFC-75	Mobile FC	Tim Lipman	75		0.13 $/kWh	20	10	N/A		0

2.4 DER Parameters

2.4.1 Economic Parameters

Turnkey costs were defined as the capital costs of acquiring a specific technology and the estimated installation costs. Costs are expressed in dollars per kilowatt ($/kW) of installed capacity. Operation and maintenance fixed costs (OMFixed) are the costs associated with the technology regardless of the extent to which it is used, expressed in dollars per kilowatt per year ($/kW/yr). Operation and maintenance variable costs (OMVariable) are the costs directly proportional to usage and are expressed in dollars per kilowatt hour ($/kWh). Levelized costs are estimates of the total cost of energy produced over the lifetime of the technology and are derived from the previous economic data. Levelized costs are expressed in dollars per kWh ($/kWh), thereby offering a quick comparison to tariffed electricity prices.

2.4.2 Thermodynamic Parameters

In order to calculate site fuel costs, fuel prices, and calorific contents, heat rates are required. For CHP to be considered, it is also necessary to know how much heat can be recovered from each technology, and fuel must be combusted to satisfy the balance of the heat load. The thermodynamic parameters used to determine this information are discussed below.

2.4.2.1 Heat Rate

The heat rate describes how much fuel is required to produce a unit of electric energy. Heat rate values are in kilojoules per kilowatt hour (kJ/kWh). The electric efficiency of a generation device can be determined from the heat rate by first converting to kJ/kJ (divide the heat rate by 3600 kJ/kWh) and taking the inverse of this value (to give electric energy produced per fuel energy consumed). For example, microturbine MTL-C-30 has a heat rate of 12,186 kJ/kWh. This is equivalent to 12,186/3600 = 3.385 (kJ fuel) / (kJ electricity), or 1/3.385 = 0.295 kJ electricity/ kJ fuel, which is an efficiency of 29.5%. Heat rate values are listed in Table 1 and Table 2.

2.4.2.2 Waste Heat Factor: Alpha

Alpha (α) describes how much useful heat energy is produced per electric energy produced by a given generation technology, and is a dimensionless ratio of energy terms. Only the heat in the combustion exhaust is considered in α calculations. More detail on the definition of CHP parameters is provided later.

The method for determining α is dependent on the information provided by manufacturers' specifications. For example, some manufacturers provide enough information about the exhaust (flow rate and temperature) so that calculations can be made directly: thermal energy = [flow rate]*[specific heat]*[temperature rise]. Other manufacturers provide data on how much heat energy leaves the generator via ambient heat transfer and radiator heat transfer. According to the thermodynamic principle of energy conservation, the fuel energy consumed by the generator must equal the thermal and electric energy leaving the generator: Thus, subtracting the electric energy, heat-to-ambient, and heat-to-radiator from the fuel input leaves the heat-to-exhaust as the remainder.

For example, natural gas generator GA-K-100 has an efficiency of 24.1% at the rated load of 100 kW. Thus, 415 kWh of fuel (100 kWh / .241) are consumed at rated load. The manufacturer specifies that at rated load, 153 kWh of heat are rejected to the coolant and 38 kWh to the ambient environment. The heat in the exhaust would then be the remainder of the 415 kWh of energy consumed: 415 kWh – 100 kWh (electricity) – 153 kWh (heat-to-coolant) – 38 kWh (heat-to-ambient) = 124 kWh (heat-to-exhaust). α for this example is then 124 kWh (useful heat) / 100 kWh (electricity generated) = 1.24. α values are listed in Table 1 and Table 2.[1]

2.4.2.3 Fuel to Heat Factor: Beta

Beta (β) is defined as the amount of useful heat energy produced per fuel energy burned by combustors (in kJ/kJ). Combustors would be required to provide heating when CHP does not exist or is not adequate to meet heating loads. A β value of 0.8 is assumed for heating loads. The cost of combustors is assumed to be minimal in comparison to DER electricity generation technologies and is set at zero in this study.

2.4.2.4 Recovered Heat Factor: Gamma

Gamma (γ) is defined as the fraction of recoverable waste heat from a DER technology that can be transferred to an end-use load via an operating fluid in a heat exchanger and subsequent piping to the end-use. This fractional value is assumed to be 0.8 for air or water heating, which accounts for heat exchanger performance and piping losses. For absorption cooling, γ is assumed to be 0.11, to account for the assumption that the coefficient of performance (COP) of single-effect absorption chillers is only one seventh (1/7) that of electric chillers. This is discussed further in Section 2.6.2. To date, lack of general performance data from manufacturers has prevented more specific statements of γ.

In DER-CAM, electricity generation technologies that produce exhaust (microturbines and generators) can be selected as electricity generation only, CHP for hot water and hot air supply, CHP for absorption cooling heat supply. If technologies are selected as CHP devices, their exhaust heat is available to the system for its respective uses. Ten percent is added to the costs of the particular technology to account for the cost of implementing CHP.

2.5 DER Generation Technologies

2.5.1 Microturbines

Four microturbine options were incorporated in this analysis: 30 kW Capstone low-pressure gas and high-pressure models and Bowman 50 kW and 80 kW models. α values were derived from the technical specifications provided by the manufacturer. Hourly fuel flow rates were used to calculate the heat rate of each microturbine.

---

[1] α values of zero imply that the particular technology is not CHP-enabled (at least in the DER-CAM formulation).

The Berkeley Lab received test data from John Auckland of Southern California Edison (SCE) on January 27, 2001 for the two Capstone microturbines. These data were collected at SCE's test facility located on the U.C. Irvine campus (Hamilton 1999). The equipment costs and O&M costs were added to the database to reflect this real-world test case. Both the fixed and variable O&M costs are incorporated in the fixed O&M parameter estimate in Table 1. Estimated installation costs for these test units were also provided by John Auckland and incorporated into the data set. The SCE test data replaced pre-existing data provided by the manufacturers wherever possible to represent real world operation more precisely.

No modifications were made for the 2010 scenario and the same four microturbines were considered in this forecast case. In both scenarios, only the Capstone microturbines were considered for CHP applications, whereas the Bowman MT's were only considered for electricity generation, although they are typically CHP equipped.

2.5.2 Fuel Cells

The only FC included in the present day scenario was a 200 kW phosphoric acid fuel cell (PAFC) manufactured by UTC Fuel Cells (ONSI at the time of data collection), which is the only FC widely available today. All of the data collected for this model were from the proprietary EPRI Technical Assessment Guide (EPRI 1999 November).

For the 2010 scenario, eight additional FC units were added based on the current likelihood of their emergence onto the market within the next ten years. These options include a second PAFC, four proton exchange membrane (PEM) FCs, two solid oxide fuel cells, and one FCV option, ranging in size from 10 kW-3100 kW. The heat rate conversion efficiencies range from 32-55%.

The estimated levelized cost for the ONSI 200 kW PAFC option in the present day scenario is 13.68 ¢/kWh. Over the course of the next ten years assumed improvements in the production costs of this FC model result in an approximate 26% reduction in costs to 10.15 ¢/kWh.

The FCV with a power rating of 30 kW represents a promising DER option. The levelized cost is only 7.75 ¢/kWh in 2010, largely due to the zero equipment cost assumed because the equipment is purchased for transportation reasons, with DER as a secondary use. Although the 3100 kW and 500 kW SOFC units, for which data are available, are predicted to have lower costs overall, they are too large for most DER applications within our analysis. The FCV then seems to be an attractive option with its low levelized cost in 2010. A detailed discussion of the methodology used to derive the 2010 technology cost for FCs is in Marnay *et al.* (2001).

Fuel cells were not considered for CHP in this version of DER-CAM. However, fuel cells do produce significant amounts of waste heat and future demonstrations of DER-CAM might consider this source of heat.

2.5.3 Wind

Data have been collected for two small (1 kW and 10 kW) wind turbines. However, wind was not considered a viable option for the urban setting of the current analysis and so this technology was not made available to the customers in the µGrid. With the present day turnkey costs estimated at 6,055-8,920 $/kW, the cost of such small-scale wind technology for DER applications is one of the highest of the technology options. The levelized costs for the 1 kW and 10 kW wind options are estimated to be 39.85 ¢/kWh and 27.05 ¢/kWh, respectively, far higher than those for a diesel or natural gas back-up generator or even a microturbine or FC. Because wind energy produces no waste heat, the cost differential is even greater when CHP is considered for generators, microturbines, and fuel cells. Including wind in DER-CAM would require a yearly wind profile to determine the energy provided by the wind turbines at each time step.

2.5.4 Photovoltaics

The option for customers to choose PV was permitted in the DER-CAM runs reported here. Four different PV systems, ranging in size from 5-100 kW, were included. Data were collected from Jeff Oldman of Real Goods on April 10, 2001. Cost information including the installed cost and O&M costs were provided. Hourly solar insolation profiles were stated in DER-CAM to determine how much energy could be provided by PV systems at each time step. Insolation information is discussed in Chapter 4.

The *Renewable Energy Technology Characterizations 1997* by EPRI, which summarizes and forecasts the operating and economic features of various renewable energy resources, was used to adjust the PV equipment costs for the 2010 case (EPRI 1997). Neither installation costs nor O&M costs were modified from the present day case due to uncertainty about how these costs would change over time. The projection of cost improvement is largely due to the technological improvement of crystalline-silicon PV modules expected over this period.

2.5.5 Diesel and Gas Back-up Generators

A variety of small-scale diesel- and natural gas-fueled internal combustion engines currently marketed were included as DER technology options. A total of 14 diesel options ranging in size from 15-500 kW and 5 natural gas generators from 25-500 kW constitute the internal combustion engine DER options. The data were collected and derived primarily through various manufacturers' technical specification sheets. Equipment costs were collected from the manufacturer when possible.

Current diesel fuel costs and energy content for diesel fuel #2 were used to calculate the variable and levelized cost of operating each diesel generator. This calculation assumes a 12.5-year loan term (equivalent to the expected life span of the generator) at an annual percentage rate of 9.5%. The levelized cost calculation assumes a 100% capacity factor.

The electrical costs of installing generators were roughly estimated using the RSMEANS handbook (Mossman 2000). This source estimates the electrical related costs, so estimates of the turnkey cost can also be determined. Cost information from this book was assumed to account for roughly all the electrical and mechanical costs, at least for a first approximation. Figure 1 shows the function of declining installation costs for generators with increasing kW size. Shown for both the diesel and natural gas generators, this figure clearly shows the economies of scale in generator rated capacity. Using installation cost information for selectively sized units provided from a generator manufacturer, the proportion of installation to kW rating size was used to derive an installation cost for all considered diesel and gas back-up generators in this data set.

Current restrictions on the operation hours of diesel generators would not make them a practical candidate for CHP. Therefore, DER-CAM considers diesel generators for electrical generation only and imposes usage restrictions on these generators in accordance with air quality control regulations.

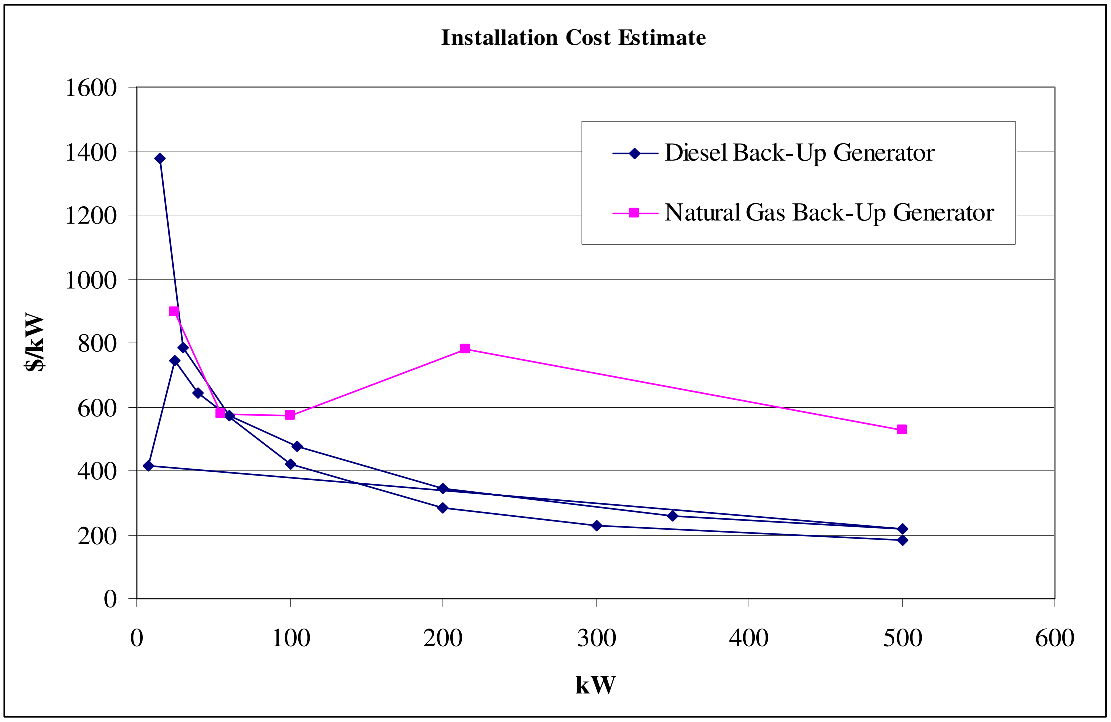


Figure 1. Installation Costs for Diesel and Gas Generators

Although mass production and marketing of reciprocating engine generators may lower their delivered costs, this technology is the most established of the DER technologies so no changes in cost or technical specification were deemed necessary for the ten-year outlook.

2.6 Waste Heat Utilization Technology

2.6.1 Heat Exchangers

Heat exchangers are designed from different materials depending upon the application. Stainless steel is expensive and not a high heat conductor, but it holds up well against the corrosive effects of condensate from exhaust gases. Heat exchangers are able to transfer about 80% of the heat from exhaust gas to an operating fluid such as water or air, thus a gamma value of 0.8 is used in the model. Hot air would be used for space heating requirement. Hot water would be used for hot water requirements or for absorption cooling (see next section).

2.6.2 Absorption Coolers

Absorption cooling is a way of using heat to drive a refrigeration cycle instead of the mechanical energy required to run a compressor. This heat can be provided either by recaptured waste heat from generators or microturbines, or by combusting natural gas when required amounts of waste heat are not available. Absorption cooling cycles take advantage of chemical processes using a refrigerant and an absorbent that combine at low pressure and low temperature to form a solution. Water-lithium bromide (H_2O-LiBr) or water-ammonia (H_2O-NH_3) are common refrigerant/absorbent combinations.

Air conditioning has a low load factor, with the largest demand concurrent with peak electricity demand. For example, in California, air conditioning is estimated to be responsible for about 29% of the costly peak electricity demand, and yet this end-use only consumes about 7% of the state's electrical energy (see Brown and Koomey, 2002). Refrigeration represents a larger share of total electricity requirements in California, about 8%, and due to the fact that it is less weather-sensitive, has a higher load factor than air conditioning. A µGrid using absorption cooling has the potential for significant electrical peak shaving by exchanging the electrical load of air conditioning for a thermal load.

The COP of a cooler is defined as the ratio of energy removed from a substance to the energy consumed. Absorption coolers capable of operating off of the relatively low-temperature heat provided by CHP (single-effect chillers) typically have a COP of 0.7 (the value used in DER-CAM). This is quite inefficient relative to electric coolers, which typically have a COP of 5 or higher. Thus, it takes more than seven times as much thermal energy as electrical energy to provide the same cooling. In light of this, absorption cooling is practical only in certain niches, such as when electricity is expensive or not available, or conversely when significant amounts of waste heat or cheap combustible fuel are available. Even with no additional equipment cost associated with absorption coolers, none of the test cases considered for this report proved favorable to this technology.

Because the data available is typically based on end use electricity demand metering, cooling loads are specified in DER-CAM as the electricity required to provide cooling. Thus, cooling loads must be multiplied by a factor of seven to get the equivalent heating load for single-effect absorption chillers. In DER-CAM, this is achieved instead by reducing the γ values for absorption cooling by a factor of 7.

Ongoing developments are being made to increase the efficiency of these cycles by capturing and using more of the rejected heat from the cycle and by using multiple cycles. Methods of increasing the efficiency of absorption cooling by adding additional generators and condensers utilizing remaining heat from the primary generation process are called double-effect and triple-effect chillers. These can have COPs of around 1.1 and 1.5 respectively, although they require higher temperature thermal input (see E Source (1997) and Wang *et al.* (2000)).

2.7 Fuel Prices and Energy Content

Fuel prices used in DER-CAM are discussed and reported in Chapter 4. The heat content of diesel is assumed to be 38,228 kJ/L (137,157 Btu/U.S. gallon) and is taken as the average of various external sources. Since natural gas prices are per unit of energy, heat content values are not required for calculations as they are already accounted for in the cost of the fuel.

2.8 Thermodynamic Approximations

Representing DER technologies as parameters in DER-CAM demands much simplification of actual behavior. These simplifications are suggested by the GAMS software, memory constraints of PC computers, time constraints of research projects, as well as the large number of technology combinations and a lack of precise technology data.

2.8.1 System Simplifications

In the current version of DER-CAM, a 10% cost increase in the generation technology for which CHP will be implemented is assumed to cover all equipment, installation, and maintenance costs. This cost increase assumes that the heat source (generation technology) is located next to the heat load (air or water heating or absorption chiller) so that there is only a minimal need for additional piping (and the costly structural modifications inherent in installing pipes) and pumping. Heat losses during operating fluid transport can then be neglected, as the piping distances will be small. Note that this is a demanding assumption equivalent to assuming a perfect mach of electrical and heat loads.

Significant consideration of the physical location of heat sources and heat loads would be required to move beyond the fixed cost calculation and negligible heat loss assumption currently in DER-CAM. Such considerations would be extremely case-specific.

2.8.2 Rated Load Approximations

Manufacturer specifications for natural gas and diesel generators are comprised mainly of performance data for generators running at rated (full) load. Heat rates are sometimes provided at specific fractions of rated load such as 50%, 75%, and 100%. However, data required to calculate the α parameter at varying loads are not provided and neither is information on how lifetime or costs are affected by varying load operation). Additional information is being collected for possible use in later versions of DER-CAM, such as carbon emissions data.

All parameters used in DER-CAM are the rated load values. While heat rate (or equivalently, efficiency) behavior at varying load is available, it would introduce a nonlinearity in the GAMS model. For example, the amount of fuel energy required by a given generator in a given hour is equal to the product of the heat rate and the power level at which the generator is being operated. With constant heat rates, this is a linear relationship ([constant heatrate] x [operation level]). However, if the heat rate varies with operation level, then calculating the amount of fuel required in a given hour is proportional to the product of two functions that depend on the operation level ([heatrate (a function of operation level)] x [operation level]). DER-CAM, however, is a mixed integer linear program and cannot handle non-linearities.

Introducing parameter variation into DER-CAM is a future objective of the project. Current DER-CAM results select technologies to operate at a rated load at most times. Thus, results calculated by DER-CAM do mostly use the correct parameter values. For microturbines and generators, heat rates tend to increase (efficiency decreases) as operation level decreases. For these technologies, as operation level decreases, the fraction of fuel that goes to electricity (highly valued energy) decreases and the fraction of fuel that goes to heat (less valued energy) would increase. This would make partial load operation more costly in most situations. This does not apply to fuel cells, which do not achieve maximum efficiency at full load. As fuel cells attain greater consideration in DER-CAM, addressing the variable parameters will be an important topic.

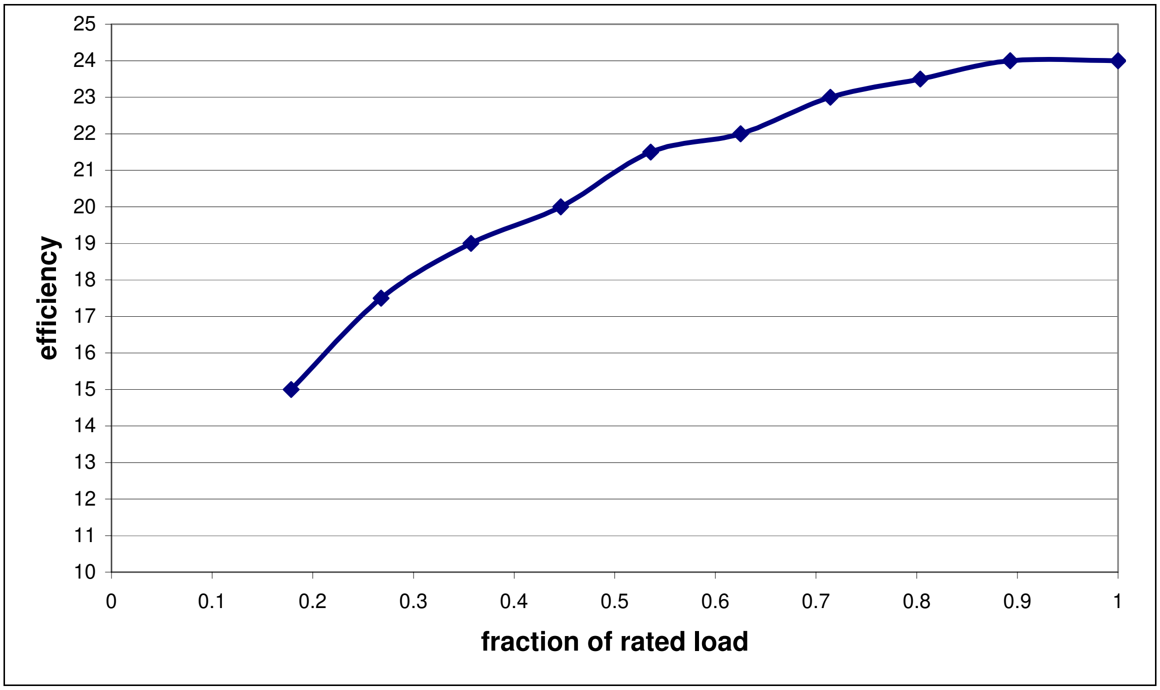


Figure 2. Efficiency of Capstone 28kW Microturbine Varying Load and Ambient Temperature of 18 C (65F) (Low Pressure Gas)

2.8.3 Variable Operation Level Assumptions

The DER-CAM model allows for any generator, microturbine, or fuel cell to be operated at any power level between 0 (off) and its rated power level at anytime. Transitions between operation levels are assumed to occur instantaneously (at each hourly operation modification) and performance of the generators is assumed to be at steady state at all times. These assumptions allow for a reasonably simple mathematical model, but are clearly unrealistic.

However, generators are not designed to be operated below a certain load level. Some microturbines are designed to operate only at rated load. No technology can maintain steady state operation while transferring from one operation level to another, nor can technologies transfer operation levels instantaneously.

Future refinement of DER-CAM data might include constraints on operation levels and transitions between operation levels. As mentioned in the previous subsection, current results show mostly technologies being operated at their rated loads. In these situations, load level and load level transition constraints become mostly irrelevant. One immediate exception to this is the start-up time required for turning on a technology, which is currently assumed to be negligible.

2.8.4 Heat Recovery

All DER technologies that process fuel to generate electricity create heat in the process. How much of this heat can be recovered and utilized is a complex question. Waste heat is transferred to an operating fluid such as steam or hot water via a heat exchanger. Certain microturbines, such as the Bowman TG80CG, are marketed as an entire CHP unit, producing electricity and hot water. Systems designed in this manner offer high overall efficiencies.

However, for generators that do not have commercial CHP options, the plug and play paradigm limits the amount of heat recovery. Many of the generators considered in DER-CAM use the forced flow of coolant through a radiator to keep the generator within its thermal constraints. DER-CAM assumes that the heat energy in this coolant is not useful, i.e., to utilize it would require reworking the coolant plumbing and careful control to prevent the coolant temperature from falling too low. Generators with coolant are generally designed to tolerate no more than a 10°C temperature drop from exit to reentrance. For this reason, only hot exhaust gas, i.e. the product of fuel combustion, is considered for heat recovery.

Exhaust gas becomes more useful and thus, more valuable as its temperature increases. A higher percentage of energy can be extracted from it, it can be converted to other energy forms more efficiently, and smaller heat exchangers are required. However, for model simplicity, only the energy content and not quality is considered. This energy content is the amount of heat it would take to raise the exhaust gas from ambient temperature to its hot temperature.

Future refinement of heat recovery might include quality considerations of the exhaust. A thermodynamic *exergy* or *availability* analysis, would measure the amount of *useful* energy contained in the exhaust gas. Consideration of the utilization of heat in coolant would also be in order.

Characterizing heat exchangers beyond the generalizations mentioned in Section 2.6.1 is a difficult proposition. Most heat exchanger manufacturers keep much of their design properties proprietary. They will work with customers to determine the right size heat exchanger for a given situation, i.e. given inlet temperatures and flow rates of the exhaust and operating fluid. However, this project attempts to examine heat exchangers from the other end. This analysis requires information on how specific heat exchangers perform under a variety of circumstances: different flow rates, different thermal loads, different generator operation levels, different exhaust temperatures, different models or DER.

Ultimately, DER-CAM might consider specific heat exchangers, rather than generalizations. Considering heat exchangers in this way would support the modular, plug and play characteristic of the proposed μGrid. Costs and performance characteristics could be made more accurate in this way. As well, such an approach would allow for optimization of heat exchanger size.

2.8.5 Future Computation

The simplifications mentioned above have been made for several reasons. Many are made for lack of detailed information. However, information is continuously being sought and collected. Certain simplifications are made for the sake of keeping DER-CAM simple enough to run on GAMS in a reasonable amount of time. It is interesting here to note that the previous version of DER-CAM (excluding CHP) took about 30 minutes for a run. Preliminary runs of the DER-CAM version described in this report (including CHP) took roughly five hours on the same computers. Upgrading to computers currently on the market reduced this time to 20 minutes. The pace at which DER-CAM model has become more detailed roughly matches the pace at which computing power can handle more complexity.

In all of this consideration, though, it is important to question the relative error introduced by simplifications. In many cases, the larger model uncertainties drowned out any refinements that more accurate parameters might enable.

3. Customer Description

This section describes the energy load shape development for the μGrid customer used to conduct this DER-CAM analysis. This project used load data from a hypothetical μGrid customer in the San Diego area that was constructed for a previous research project at Berkeley Lab (Edwards et al., 2002). The goal here is not to establish a totally realistic example, but rather to create a California relevant case study that exercises the new model capabilities developed in this work. The combination of individual customer-types that were chosen to make up the μGrid was determined from a map of a mixed commercial/ residential district in San Diego. Previous DER-CAM analyses have developed an aggregate μGrid customer by combining single customers from several representative types (e.g., one restaurant, one warehouse, one grocery store, etc.). This method improves on that assumption by combining customers that exist near each other in a typical California city plan. This section first describes the sources and development of the energy load data used for these customers. Then the individual customer types that were aggregated to form a μGrid and their individual energy characteristics are presented.

3.1 Data Description and Preparation

This analysis uses a combination of metered and simulated end-use load shape data. A set of actual customer load profiles is vital for producing credible results representing the cost-minimizing deployment of DER technology. End-use metered loads for commercial buildings are not widely available, however. Berkeley Lab had an available archived set of commercial hourly load data, collected by Southern California Edison (SCE) in 1988-1989 (SCE 1989; Akbari 1993). Even though these data were collected years ago, they are still valuable for the purposes of this study because end-use loads are unlikely to have changed significantly relative to the other uncertainties in this study. Berkeley Lab recovered these data and recreated load shapes to be used in current modeling efforts.

Unfortunately, the SCE data only include electrical loads, not natural gas loads. Nor could actual gas load data be found by any other available means. Because natural gas is the main fuel used to provide building heat and hot water, two major products of CHP technologies, finding plausible data for these loads was critical for this study. DOE-2, which is a building energy simulation program developed at Berkeley Lab, was used to simulate these heating loads for the same weather year as the SCE data.

It is critical in this study to resolve the electricity and gas loads into end uses because only some end-use loads can be provided by CHP technologies. These include refrigeration and building cooling (HVAC) for electrical loads, and hot water and building heating for gas loads. The DER-CAM model was adjusted to meet these end uses with CHP when possible.

The initial version of the SCE electricity load data consisted of a statistical analysis system data set containing hourly total load data and some end-use load data for 53 commercial premises in the SCE service territory. For confidentiality reasons, detailed information on the businesses was suppressed, but for most premises, business type, total floor area, conditioned floor area, and a corresponding set of hourly weather data were available.

These data were compiled into a database of total and end-use loads for most premises as follows (see Table 3):

- average weekday by calendar month (1 day-type x 12 months)
- average weekend by calendar month (1 day-type x 12 months)

Table 3. Number of Day-Types in Each Month

Month	Weekdays	Weekend days
January	21	10
February	20	8
March	23	8
April	20	10
May	23	8
June	22	8
July	21	10
August	23	8
September	21	9
October	22	9
November	22	8
December	21	10

Having two day-types yields a more accurate analysis of the real load profile of these customers because average California Power Exchange (CalPX) prices for those day-types can be calculated and assigned to them. Peak-day averages, which were used in a previous DER-CAM analysis that examined only total electrical loads, were not available for the electrical end-use data. The model was modified to use only week- and weekend day types. For each month of the year two sets of average hourly loads, weekday and weekend, were defined for each end use. For most buildings, electrical end uses, such as refrigeration, cooking, and HVAC, were measured separately. Not every property included data for each end use. Also, in most cases measured end use loads did not add up to the total load given for a specific property. To account for this "missing" electricity, an additional end use was calculated by taking the difference between the sum of the end uses and the total. This *residual* load accounts for electrical end uses that were not measured or for errors in data collection or recording. The end uses monitored are not consistent across all customer sites although the major end uses, such as lighting and HVAC, are always identified. The residual load also includes end uses that were measured in general but were not recorded for a given building. For this study, the Residual electrical load is considered an electricity-only load, or one that cannot be met by CHP.

Once the 10 building types analyzed in this study were selected, the DOE-2 model was run for each one to produce natural gas loads by end use. This entailed estimating the correct floor area for each building, choosing the appropriate end-use loads, such as cooking, hot water, and space heating (depending on the building type) and running the program. An output file was then produced, from which the appropriate end-use data were extracted, e.g., *Total Heating Watt* for space heating, or *DHW Heat Fuel Watt* for hot water for the Retail Store. DOE-2 is a complex simulation program, so each building type had to be treated separately. Because of the complexity of the model, the appropriate end-use parameters were not the same for each building. These data were then formatted and averaged into the same monthly format as the electrical loads. For the purposes of this analysis, it was assumed that only the hot-water and space-heat loads could be met by CHP. CHP technologies cannot reduce the gas-only load.

3.2 Additional Estimates

Some estimates and manipulations to measured data were required where there were missing data or where building types did not correspond to any available measured data. In the later instances, load shapes were constructed from measured data for applicable end uses, such as lighting and additional energy use estimates made for the likely appliance stock of that building type, such as washers and dryers for the laundromat. Additionally, for building types with unusual hours of operation, such as 24-hour markets or late-night stores, the early evening loads of measured businesses were extrapolated to include late evening hours.

3.3 Summary of Energy Data and Sources for Individual μGrid Customers

Table 4 shows the ten customer types in the commercial/residential neighborhood in San Diego. The table includes individual customer energy-use characteristics, building floor area, and data sources for electricity and heat loads. For all years considered (1999, 2000, 2010), the same load data was used.

Table 4. Energy Load Shape Data Sources

TYPE	CHARACTERISTICS	AREA[a] (m^2)	ELECTRIC	HEAT
Residential	Typical	45 Residences	SDG&E[b]	N/A[c]
Office 1	Typical 9-5 hours	1,492	SCE	DOE-2
Office 2	Medical Office (higher load)	1,010	SCE	DOE-2
Retail 1	Typical 10-6 hours	3,398	SCE	DOE-2
Retail 2	Reg. hours, higher loads	418	SCE	DOE-2
Retail 3	Open Late/ 24 hour	1,706	SCE	DOE-2
Retail 4	Reg. hours, high heat loads	741	SCE	DOE-2[d]
Restaurant	Lunch peak, open late	710	SCE	DOE-2
Hospital	24 hr. emergency	20,707	SCE + Est.[e]	DOE-2
Laundromat	50 washers, 40 dryers	444	SCE + Est.[f]	Est.[g]

a. Site area was calculated by GIS. This is the total area for all buildings classified as the corresponding customer type. This value includes all area within the property line and therefore does not account for parking or other open space that is contained within building property but does not contribute to building energy use. These values are therefore reduced by 25 percent to correct for the space that does not consume energy.
b. Publicly available data for SDG&E customers averaged over all households. Data are from 1994-1996.
c. It is assumed that the cost of CHP retrofitting individual residences is prohibitive.

d. DOE-2 requires a special input for higher heat loads of the highest hot water usage throughout one day. This value is calculated from the measured annual hot water use of a hair salon as 77.4 MMBtu.
e. Hospital measured data were not available divided into end use. Therefore, the cooling load was calculated from the total load based on the hourly percentage of total load it represented in a simulated run by DOE-2.
f. Electricity use from washers and dryers was added to lighting and plug loads from a similar business type.
g. Hot water use of washers was estimated.

The table below shows the individual energy characteristics of each of the ten customer types in the commercial/residential area. The energy characteristics of the total µGrid shown in the last row are not necessarily a sum of the characteristics of the individual customers. For example, the peak loads of the individual customers do not occur at the same times of the day or year, and will therefore not sum to the total peak load of the µGrid.

Table 5. Energy Characteristics of Individual Customers

TYPE	# OF SITES	TOTAL ANNUAL ELECTRICITY (MWh)	PEAK LOAD (kW)	PEAK HOUR	LOAD FACTOR
Residential	45	242	50	December Weekend 17:00	56%
Office	6	234	72	July Weekday 13:00	32%
Medical Office	1	242	87	July Weekday 13:00	27%
Retail 1	4	647	172	July Weekend 15:00	43%
Retail 2	2	111	26	July Weekend 15:00	48%
Retail 3	2	256	54	October Weekday 18:00	53%
Retail 4	4	141	37	July Weekend 15:00	43%
Restaurant	3	366	69	July Weekend 19:00	60%
Hospital	1	2449	406	January Weekend 8:00	69%
Laundromat	1	67	18	June Weekday 18:00	42%
Total		2516	886*	July Weekday 15:00	60%

*This is the coincident peak for the aggregation of sites and is therefore less than the sum of the sites' individual peaks because they occur at different times.

3.4 Recovered Heat

The major difference from previous reported DER-CAM work is that it is now possible to meet the heating and cooling loads by recovered heat. The model uses three different heating loads:

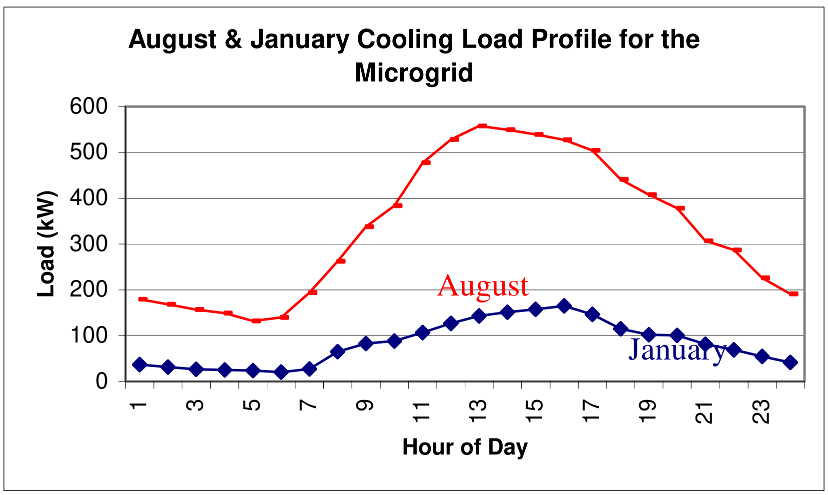
- water heating
- space heating
- natural gas only (e.g., cooking load, which cannot be met by recovered heat)

The DER-CAM model also incorporates two different electricity loads:

- cooling
- electricity only

The former can be met by recovered heat by the use of an absorption chiller as well as by electricity, but the latter requires either purchase or on-site generation of electricity. These five different load shapes are derived for each commercial customers, as described above.

The use of recovered heat improves the total energy efficiency of the DER equipment and enhances the economic benefit to the μGrid. Figure 3 shows the January and August cooling load for the μGrid for workdays, derived from the commercial customers described above.



.

Figure 3. August & January Cooling Load Profile for the μGrid

4. Market Inputs

The other key inputs to DER-CAM, as listed in Chapter 3 are:

1. Energy pricing data, namely, the San Diego Gas and Electric Company (SDG&E) tariff details and CalPX hourly day-ahead prices for 1999 (and the corresponding imbalance energy market, or IEM, prices for 2000).
2. Average natural gas and diesel prices for 1999 and 2000.
3. Solar insolation values.

4.1 SDG&E Tariff and CalPX Prices

4.1.1 1999 Data set

Customers purchasing electricity from the utility are assumed to do so at established tariffs. In this study, publicly available tariff rates for commercial customers are used (see Table 6). For the tariff, season (where summer months are May through September, inclusive), and load period (on-peak, mid-peak, and off-peak), the power charge, coincident[2] demand charge and energy charge are given as per the SDG&E rates in 1999. In addition, a fixed charge per customer per month is included (see Table 7).

Table 6. SDG&E Tariff Information for 1999

Tariff Type	Season	Load Period	Non-Coincident Demand Charge ($/kW)	Coincident Demand Charge ($/kW)	Energy Charge ($/kWh)
TOU	summer	on	5.094	13.23	0.10052
TOU	summer	mid	5.094	13.23	0.06883
TOU	summer	off	5.094	13.23	0.05562
TOU	winter	on	4.856	4.86	0.09652
TOU	winter	mid	4.856	4.86	0.06733
TOU	winter	off	4.856	4.86	0.05283

Table 7. SDG&E Fixed Customer Charges for 2000

Tariff Type	Customer Charge ($/month)	Facility Charge ($/kW)
TOU	43.50	0

Customers who install DER may have the option of selling surplus electricity back into the grid at the competitive price. For the purpose of this study, this generally refers to the day-ahead (DA) constrained, i.e., accounting for congestion, equilibrium price in the CalPX. Since California is essentially divided into two zones, north of Path 15 (NP15) and south of Path 15

[2] The coincident charge is applied to the customer residential load when the customer purchases electricity at time when the utility has the maximum system load.

(SP15), there is one market-clearing price for each zone. From the price duration curve for this market (see
Figure 4), we see a rather well-functioning market in 1999, with the *effective* price cap of $250/MWh never reached.[3]

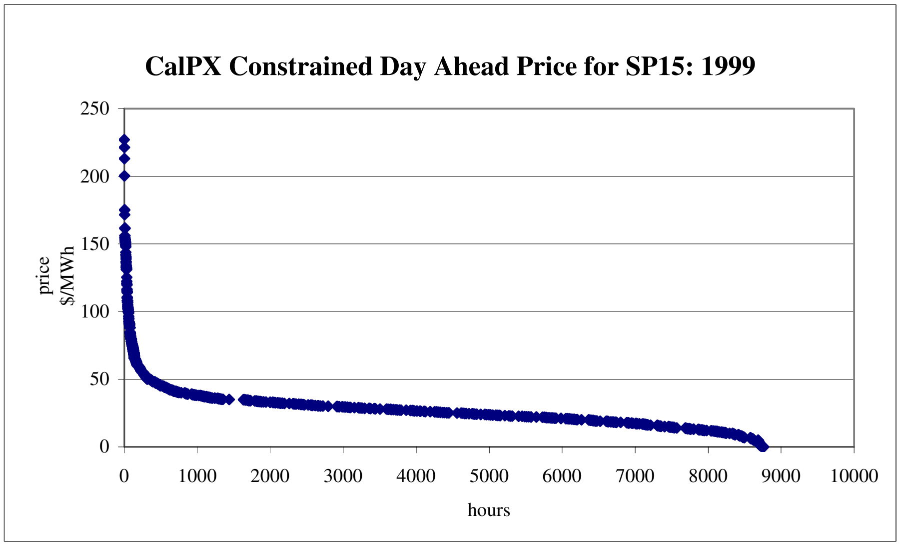


Figure 4. CalPX Day-Ahead Constrained Market Price Duration Curve for 1999 (Source: CalPX)

4.1.2 2000 Data Set

Table 8. SDG&E Tariff Information for 2000

Tariff Type	Season	Load Period	Non-Coincident Demand Charge ($/kW)	Coincident Demand Charge ($/kW)	Energy Charge ($/kWh)
TOU	summer	on	4.99	5.72	0.21162
TOU	summer	mid	4.99	5.72	0.12398
TOU	summer	off	4.99	5.72	0.07912
TOU	winter	on	5.66	3.61	0.13037
TOU	winter	mid	5.66	3.61	0.10813
TOU	winter	off	5.66	3.61	0.08127

[3] While the CalPX did not have an explicit price cap in 1999, the California ISO's imbalance energy market did have one of $250/MWh. Due to the sequential nature of the California markets, the ISO imbalance energy market clears after the CalPX day-ahead constrained market does. Consequently, the ISO's price cap becomes effective for the CalPX markets as well. Indeed, no seller would attempt to submit offers in excess of $250/MWh to the CalPX markets because buyers would simply shift their bids to the ISO's capped IEM.

Table 9. SDG&E Fixed Customer Charges for 2000

Tariff Type	Customer Charge ($/month)	Facility Charge ($/kW)
TOU	43.50	0

From the price duration curve for this market (see Figure 5), it is apparent that the IEM performed erratically in 2000, with the *effective* price cap of $250/MWh for 1999 frequently reached. Therefore, the California Independent System Operator (CAISO) Board of Governors increased the price cap to $750/MWh in 2000.

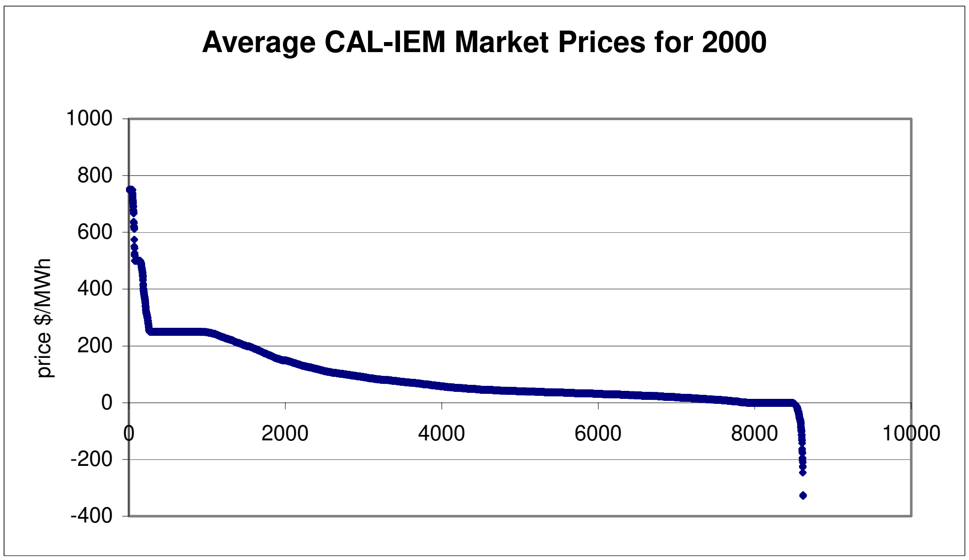


Figure 5. Average CAISO IEM Market Prices for 2000

The IEM 2000 market is characterized by high volatility. The values reach nearly $800/MWh and are often negative. A negative value means that the CAISO had too much electricity in the system and had to generators to reduce output.

4.2 Natural Gas and Diesel Prices

4.2.1 1999 Data set

The average gas prices for 1999 are very stable, with volatility[4] at a low 8.8%. The volatility of the diesel price during a year is even smaller, and therefore, the diesel prices are assumed to be constant in DER-CAM.

[4] The volatility is defined by the standard deviation about the value zero: $s = \sqrt{\frac{1}{n-1}\sum_{i=1}^{n}(\frac{x_{i+1}-x_i}{x_i})^2} * 100\%$

Table 10. Average Gas and Diesel Prices in 1999

Month	Gas Price ($/GJ)	Diesel Price ($/GJ)
January	4.89	8.46
February	4.68	8.46
March	4.63	8.46
April	4.03	8.46
May	4.45	8.46
June	4.15	8.46
July	4.10	8.46
August	4.56	8.46
September	4.76	8.46
October	4.59	8.46
November	4.97	8.46
December	5.56	8.46

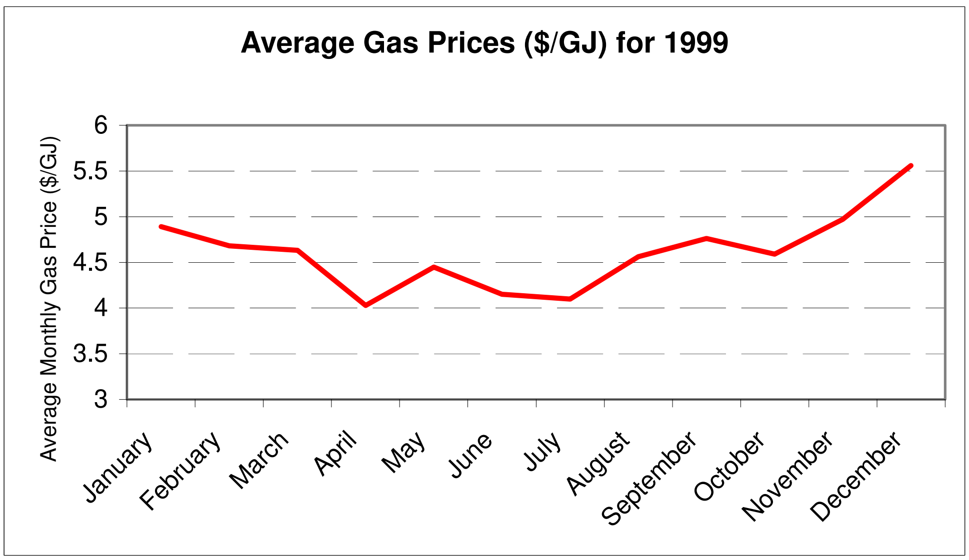


Figure 6. Average Gas Prices ($/GJ) for 1999

4.2.2 2000 Data Set

The volatility of the natural gas price on monthly basis for 2000 is 29.6%, much higher than the year before. By contrast, the diesel prices are very stable, and therefore, the diesel prices are assumed to be constant again. The natural gas prices are very high at the end of the year 2000 as the California electricity market began to collapse.

Table 11. Average Gas and Diesel Prices in 1999

Month	Gas Price ($/GJ)	Diesel Price ($/GJ)
January	4.95	8.46
February	5.78	8.46
March	5.15	8.46
April	4.94	8.46
May	5.01	8.46
June	5.02	8.46
July	6.92	8.46
August	6.36	8.46
September	7.65	8.46
October	7.31	8.46
November	7.12	8.46
December	13.13	8.46

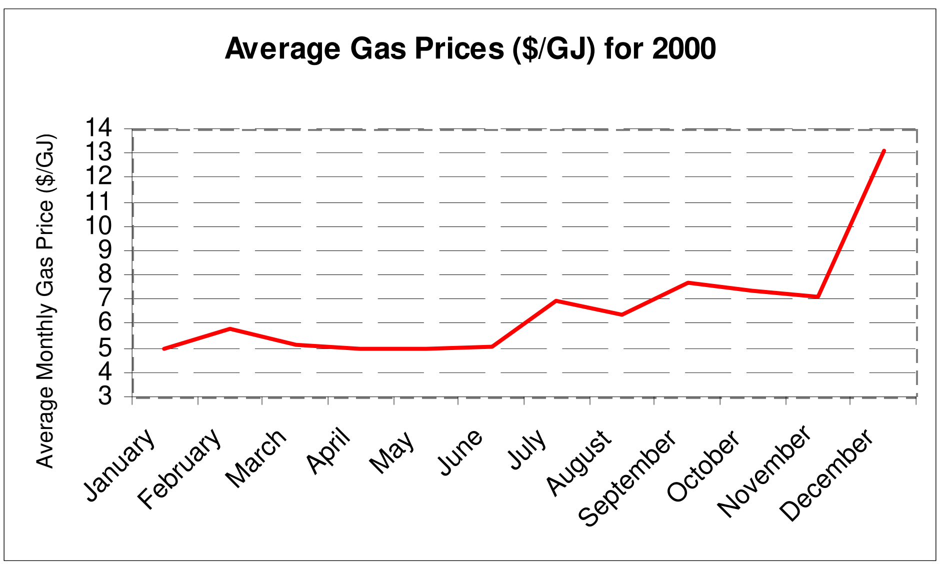


Figure 7. Average Gas Prices ($/GJ) for 2000

4.3 Solar Insolation

Figure 8 below shows monthly solar insolation values for San Diego, represented as a percent of maximum solar insolation. The total amount of direct and diffuse solar radiation in watt-hours per square meter (Wh/m^2) received on a <u>horizontal</u> surface (during the 60 minutes preceding the hour indicated) is divided by the panel rating convention insolation of 1050Wh/m^2. These data are available from the National Renewable Energy Laboratory (NREL) website at http://www.nrel.gov.

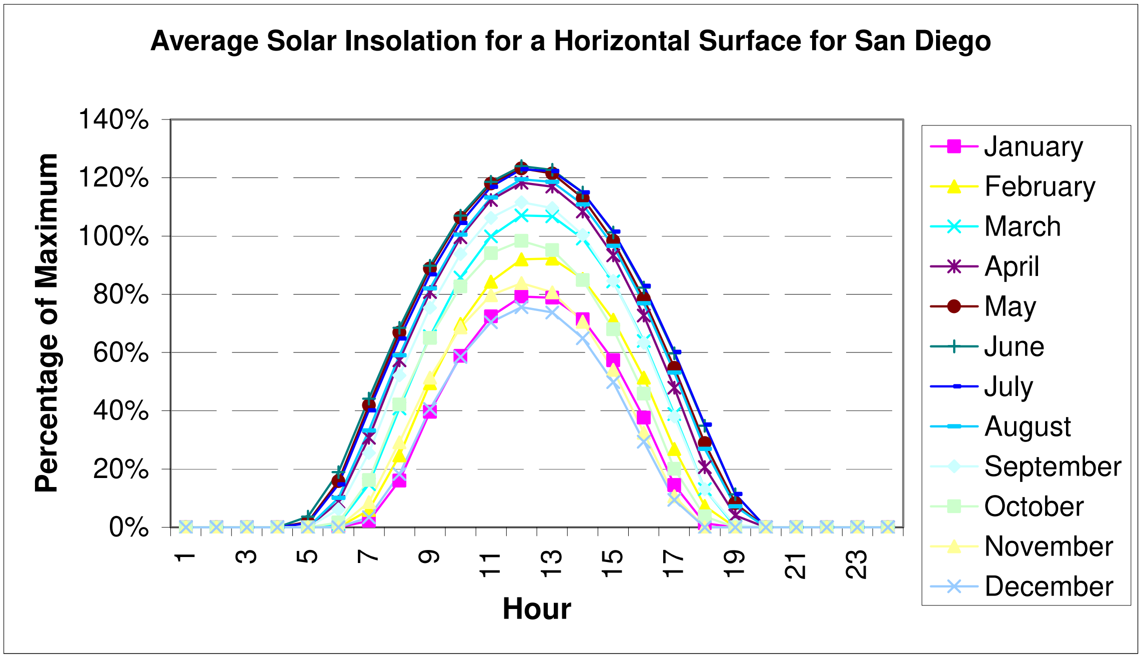


Figure 8. Average Annual Solar Insolation for a Horizontal Surface for San Diego

5. Mathematical Model

5.1 Introduction

In this section, the DER-CAM model is presented. This version of the model has been programmed in GAMS[5]. This section contains a description of GAMS and a mathematical formulation of the present version of the model. The results presented are not intended to represent a definitive analysis of the benefits of DER adoption, but rather as a demonstration of the current DER-CAM. Developing estimates of realistic customer costs and thermodynamic parameters is an important area in which improvement is both essential and possible.

5.2 Model Description

The evolution of DER analysis began with a spreadsheet version (see Marnay *et al.* 2000). Follow-up reports used GAMS to solve the Customer Adoption Model (see Rubio *et al.* 2001) and (Marnay *et al.* 2001). The next study extended that model to account for carbon taxes (see Siddiqui *et al.* 2002). CHP technologies were cursorily implemented in the next round by accounting for heating and cooling loads (see Bailey *et al.* 2002). It was found, in this case, the availability of heat exchangers and absorption cooling enabled the μGrid to reduce the cost of meeting its energy needs even further. In this study, the model is made more realistic by accounting for the intricacies of the utility tariff structure, including monthly variation in fuel prices, and most importantly by incorporating a more detailed and formal thermodynamic model of the energy flows in the system. The model's objective function, which has not essentially changed, is to minimize the cost of supplying electricity to a specific μGrid by using distributed generation to meet part or all of its electricity and heating requirement. In order to attain this objective, the following questions must be answered:

- Which distributed generation technology (or combination of technologies) should the μGrid install?
- What is the appropriate level of installed capacity of these technologies that minimizes the cost of meeting the μGrid's energy requirement?
- How should the installed capacity be operated in order to minimize the total bill for meeting the μGrid's electricity and heating loads?

It is then possible to determine the technologies that the μGrid is likely to install, to predict when the μGrid will be self-providing and/or transacting with the macrogrid, and to determine whether it is worthwhile for the μGrid to disconnect entirely from the macrogrid.

The essential inputs to DER-CAM are:

- The μGrid's electricity and heating load profiles,

[5] GAMS is a proprietary software product used for high-level modeling of mathematical programming problems. It is owned by the GAMS Development Corporation (http://www.gams.com) and is licensed to Berkeley Lab.

- Either the default electricity tariff (assumed to be from SDG&E) or the CalPX (or CAISO IEM) price at all hours of the test years (1999 and 2000), which are alternative electricity purchase options for the μGrid,
- Capital, O&M, and fuel costs of the various available DER technologies, together with the interest rate on customer investment,
- Basic physical characteristics of alternative generating technologies, and
- Thermodynamic parameters that govern the efficiency of CHP applications.

Outputs to be determined by the optimization are:

- Technology (or combination of technologies) to be installed,
- Capacity of each technology to be installed,
- When and how much of the capacity installed will be running during the test year,
- Total cost of supplying the electricity requirement, and
- Heating and cooling cost savings resulting from the application of CHP.

The important assumptions are:

- Customer decisions are taken based only on direct economic criteria. In other words, the only benefit that the μGrid can achieve is a reduction in its energy bill.
- All data are known with complete certainty, i.e., the energy loads, fuel prices, and IEM prices for the duration of the test year are all given.
- The μGrid is not allowed to generate more electricity than it consumes. On the other hand, if more electricity is consumed than generated, then the μGrid will buy from the macrogrid either at the default tariff rate or at the IEM price. No other market opportunities, such as sale of ancillary services or bilateral contracts, are considered[6].
- There is a fixed relationship between the amount of recoverable heat and electricity generated by each DER unit based on the manufacturer's technical specifications.
- Manufacturer claims for equipment price and performance are accepted without question, nor is any deterioration in output or efficiency during the lifetime of the equipment considered. Furthermore, start-up and other operating costs are not included.
- Neither reliability and power quality benefits nor economies of scale in O&M costs for multiple units of the same technology are taken into account. This underestimates the benefit of DER to many potential μGrids.

5.3 General Algebraic Modeling System (GAMS)

GAMS is a proprietary software package that solves optimization problems. The actual mathematical program is modeled via user-defined algebraic equations. GAMS then compiles them and uses standard solvers to solve the resulting problem. Since the current problem is a mixed integer program (MIP), the CPLEX solver is utilized. The foremost advantage of using GAMS is that it allows researchers to build models that can be quickly altered to address different situations or perform sensitivity analysis.

---

[6] This is not a hard constraint, but because tariffed electricity rates can deviate greatly from wholesale prices nonsensical results are possible when the μGrid can simultaneously buy and sell power.

5.4 Mathematical Formulation

This section describes intuitively the core mathematical problem solved by DER-CAM. It is structured into three main parts. First, the input parameters are listed. Second, the decision variables are defined. Third, the optimization problem is described for two possible tariff options.

5.4.1 Variables and Parameters Definition

5.4.1.1 Parameters (input information)

Time Scale Definition

Name	Definition
Day Type	Weekday or weekend
Season	Summer (May through September, inclusive) or winter (the remaining months)
Period	On-peak (hours of the day 1200 through 1800, inclusive, during summer months, and 1800 through 2000 during the winter), mid-peak (0700 through 1100 and 1900 through 2200 during the summer, and 0700 through 1700 and 2100 through 2200 during the winter), or off-peak (0100 through 0600 and 2100 through 2200 during all months)

Customer Data

Name	Description
$Cload_{m,t,h,u}$	Customer load (electricity or heating) in kW for end-use *u* during hour *h*, day type *t* and month *m* (end-uses are electric-only, cooling, space-heating, water-heating, and natural-gas-only)

Market Data[7]

Name	Description
$RTPower_{s,p}$	Regulated demand charge under the default tariff for season *s* and period *p* ($/kW)
$RTEnergy_{m,t,h,u}$	Regulated tariff for electricity purchases during hour *h*, type of day *t*, month *m*, and end-use *u* ($/kWh)
$RTCDCharge_{m}$	Regulated tariff charge for coincident demand, i.e., residual electric-only or cooling load, that occurs at the same time as the monthly system peak during month *m* ($/kW)
$RTCCharge$	Regulated tariff customer charge ($)
$IEM_{m,t,h}$	IEM or PX electricity price during month *m*, day type *t*, and hour *h*

[7] All cost data are in 1999 U.S. dollars.

Name	Description
	($/kWh)
$RTFCharge$	Regulated tariff facilities charge ($/kW)
$NGBSF_m$	Natural gas basic service fee for month m ($)
$CTax$	Tax on carbon emissions ($/kg)
$MktCRate$	Carbon emissions rate from marketplace generation (kg/kWh)
$NGCRate$	Carbon emissions rate from burning natural gas to meet heating and cooling loads (kg/kWh)
$NatGas\Pr ice_{m,t,h}$	Natural gas price during hour h, type of day t, and month m ($/kJ)

Distributed Energy Resource Technologies Information

Name	Description
$DER\max p_i$	Nameplate power rating of technology i (kW)
$DERlifetime_i$	Expected lifetime of technology i (a)
$DERcapcost_i$	Turnkey capital cost of technology i ($/kW)
$DEROMfix_i$	Fixed annual operation and maintenance costs of technology i ($/kW)
$DEROMvar_i$	Variable operation and maintenance costs of technology i ($/kWh)
$DERhours_i$	Maximum number of hours technology i is permitted to operate during the year (h)
$DERCostkWh_{i,m}$	Production cost of technology i during month m ($/kWh)
$CRate_i$	Carbon emissions rate from technology i (kg/kWh)
$DCCap$	Capacity of direct-fired natural gas absorption chiller (kW)
$DC\Pr ice$	Turnkey cost of direct-fired natural gas absorption chiller ($)
$S(i)$	Set of end-uses that can be met by technology i

Other Parameters

Name	Description
$IntRate$	Interest rate on DER investments (%)
$Solar_{m,h}$	Average fraction of maximum solar insolation received (%) during hour h and month m used to power photovoltaic (PV) cells
$DiscoER$	Disco non-commodity revenue neutrality adder[8]
$NGHR$	Natural gas heat rate (kJ/kWh)
$t(m)$	Day type in month m when system demand peaks
$h(m)$	Hour in month m when system demand peaks

[8] This value is added to the IEM price when the customer buys its power directly from the wholesale market. The *DiscoER* compensates the disco for transporting the electricity purchased from the IEM to the customer. This term is calculated such that if the µGrid's usage pattern were identical under the IEM pricing option and the regulated tariff option, then the disco would collect identical revenue from the customer.

Name	Description
α_i	The amount of heat (in kWh) that can be recovered from unit kWh of electricity that is generated using DER technology *i* (this is equal to 0 for all technologies that are not equipped with either a heat exchanger or an absorption chiller)
β_u	The amount of heat (in kWh) generated from unit kWh of natural gas purchased for end-use *u* (since the electricity-only load never uses natural gas, the corresponding β_u value equals 0)
$\gamma_{i,u}$	The amount of useful heat (in kWh) that can be allocated to end-use *u* from unit kWh of recovered heat from technology *i* (note: since the electricity-only and natural-gas-only loads never use recovered heat, the corresponding $\gamma_{i,u}$ values equal 0)

5.4.1.2 Variables

Name	Description
$InvGen_i$	Number of units of technology *i* installed by the customer
DC	Indicator variable for installation of a direct-fired natural gas absorption chiller
$GenL_{i,m,t,h,u}$	Generated power by technology *i* during hour *h*, type of day *t*, month *m* and for end-use *u* to supply the customer's load (kWh)
$GenX_{i,m,t,h}$	Generated power by technology *i* during hour *h*, type of day *t*, and month *m* to be sold into the wholesale electricity market (kWh)
$GasP_{m,t,h,u}$	Purchased natural gas during hour *h*, type of day *t*, and month *m* for end-use *u* (kWh)
$DRLoad_{m,t,h,u}$ [9]	Purchased electricity from the distribution company by the customer during hour *h*, type of day *t*, and month *m* for end-use *u* (kWh)
$\mathrm{Re}cHeat_{i,m,t,h,u}$	Amount of heat recovered from technology *i* that is used to meet end-use *u* during hour *h*, type of day *t*, and month *m* (kWh)

5.4.2 Problem Formulation

There are two slightly different problems to be solved depending on how the µGrid acquires the residual electricity that it needs beyond its self-generation:

1. by buying that power from the disco at the regulated tariff; or
2. by purchasing power at the IEM price plus an adder that would cover the non-commodity cost of delivering electricity.

5.4.2.1 Option 1: Buying at the Default Regulated Tariff

The mathematical formulation of the problem follows:

[9] The fifth variable (power purchased from the distribution company) is a derivation of other variables. However, for the sake of the model's clarity, it has been maintained.

$$\min_{\substack{InvGen_i \\ GenL_{i,m,t,h,u} \\ GenX_{i,m,t,h} \\ GasP_{m,t,h,u} \\ RecHeat_{i,m,t,h,u} \\ DC}} \sum_m RTFCharge \cdot \max\left(\sum_{u \in \{electric-only, cooling\}} DRLoad_{m,t,h,u} \right) + \sum_m RTCCharge$$

$$+ \sum_s \sum_{m \in s} \sum_p RTPower_{s,p} \cdot \max\left(\sum_{u \in \{electric-only, cooling\}} DRLoad_{m,(t,h) \in p,u} \right)$$

$$+ \sum_m \sum_{u \in \{electric-only, cooling\}} RTCDCharge_m \cdot DRLoad_{m,t(m),h(m),u} + DC\,\mathrm{Pr}\,ice \cdot DC$$

$$+ \sum_m \sum_t \sum_h \sum_u DRLoad_{m,t,h,u} \cdot \left(RTEnergy_{m,t,h} + CTax \cdot MktCRate \right)$$

$$+ \sum_i \sum_m \sum_t \sum_h \sum_u \left(GenL_{i,m,t,h,u} + GenX_{i,m,t,h} \right) \cdot DERCostkWh_i$$

$$+ \sum_i \sum_m \sum_t \sum_h \sum_u \left(GenL_{i,m,t,h,u} + GenX_{i,m,t,h} \right) \cdot DEROMvar_i$$

$$+ \sum_i \sum_m \sum_t \sum_u \sum_h \left(GenL_{i,m,t,h,u} + GenX_{i,m,t,h} \right) \cdot CTax \cdot CRate_i$$

$$+ \sum_i InvGen_i \cdot \left(DERcapcost_i \cdot AnnuityF_i + DEROMfix_i \right) + \sum_m NGBSF_m$$

$$+ \sum_m \sum_t \sum_h \sum_u GasP_{m,t,h,u} \cdot NGHR \cdot \left(NatGas\,\mathrm{Pr}\,ice_{m,t,h} + CTax \cdot NGCRate \right)$$

$$- \sum_m \sum_t \sum_h \sum_i GenX_{i,m,t,h} \cdot IEM_{m,t,h}$$

(1)

Subject to:

$$Cload_{m,t,h,u} = \sum_i GenL_{i,m,t,h,u} + DRLoad_{m,t,h,u} + \beta_u \cdot GasP_{m,t,h,u} + \sum_i \left(\gamma_{i,u} \cdot \mathrm{Re}\,cHeat_{i,m,t,h,u} \right) \forall\, m,t,h,u \tag{2}$$

$$\sum_u GenL_{i,m,t,h,u} + GenX_{i,m,t,h} \le InvGen_i \cdot DER\max p_i \quad \forall\, i,m,t,h \tag{3}$$

$$AnnuityF_i = \frac{IntRate}{\left(1 - \frac{1}{(1 + IntRate)^{DERlifetime_i}} \right)} \forall\, i \tag{4}$$

$$\sum_u GenL_{j,m,t,h,u} + GenX_{j,m,t,h} \le InvGen_j \cdot DER\max p_j \cdot Solar_{m,h} \quad \forall\, m,t,h \;\; if \;\; j \in \{PV\} \tag{5}$$

$$\sum_m \sum_t \sum_h \sum_u \left(GenL_{i,m,t,h,u} + GenX_{i,m,t,h} \right) \le InvGen_i \cdot DER\max p_i \cdot DERhours_i \;\; \forall\, i \tag{6}$$

$$\sum_{u} \mathrm{Re}\,cHeat_{i,m,t,h,u} \le \alpha_i \cdot \sum_{u} \left(GenL_{i,m,t,h,u} + GenX_{i,m,t,h} \right) \forall\, i, m, t, h \tag{7}$$

$$\mathrm{Re}\,cHeat_{i,m,t,h,u} = 0 \quad \forall\, i, m, t, h \quad if \quad u \notin S(i) \tag{8}$$

$$GenL_{i,m,t,h,u} = 0 \quad \forall\, i, m, t, h \quad if \quad u \in \{space-heating, water-heating, natural\text{-}gas\text{-}only\} \tag{9}$$

$$GasP_{m,t,h,u} \le \mathrm{DCCap} \cdot \mathrm{DC} \quad \forall\, m, t, h \quad if \quad u \in \{cooling\} \tag{10}$$

$$DRLoad_{m,t,h,u} = 0 \quad \forall\, m, t, h \quad if \quad u \in \{space-heating, water-heating, natural-gas-only\} \tag{11}$$

Equation (1) is the objective function that states that the µGrid will try to minimize total energy cost, consisting of facilities and customer charges, monthly demand charges, coincident demand charges, and disco energy charges inclusive of carbon taxation. In addition, the µGrid incurs on-site generation fuel and O&M costs, carbon taxation on on-site generation, and annualized DER investment costs. Finally, for natural gas used to meet heating and cooling loads directly, there are variable and fixed costs (inclusive of carbon taxation). Subtracted from the total cost are revenues from any self-generated electricity sold into the IEM.

The constraints to this problem are expressed in equations (2) through (10):

- Equation (2) enforces energy balance (it also indicates the means through which the load for energy end-use *u* may be satisfied).
- Equation (3) enforces the on-site generating capacity constraint.
- Equation (4) annualizes the capital cost of owning on-site generating equipment.
- Equation (5) constrains technology *j* to generate in proportion to the solar insolation if it is a PV cell.
- Equation (6) places an upper limit on how many hours each type of DER technology can generate during the year[10].
- Equation (7) limits how much heat can be recovered from each type of DER technology.
- Equation (8) prevents the use of recovered heat by end-uses that cannot be satisfied by the particular DER technology.
- Equations (9) and (11) are boundary conditions that prevent electricity from being used directly to meet heating loads.
- Equation (10) prevents direct burning of natural gas to meet the cooling load if no absorption chiller for this purpose is purchased.

5.4.2.2 Option 2: Buying from Alternative Energy Providers

The problem's mathematical formulation follows:

[10] Most of the technologies are allowed to generate during all hours of the year, but diesel generators, for example, are allowed to run for only 52 hours per year in accordance with local air quality regulation.

$$\min_{\substack{InvGen_i \\ GenL_{i,m,t,h,u} \\ GenX_{i,m,t,h} \\ GasP_{m,t,h,u} \\ \mathrm{Re}\,cHeat_{i,m,t,h,u} \\ DC}} \sum_m \sum_t \sum_h \left(\sum_u DRLoad_{m,t,h,u} \right) \cdot \left(IEM_{m,t,h} + DiscoER \right)$$

$$+ \sum_i \sum_m \sum_t \sum_h \sum_u \left(GenL_{i,m,t,h,u} + GenX_{i,m,t,h} \right) \cdot DERCostkWh_i$$

$$+ \sum_i \sum_m \sum_t \sum_h \sum_u \left(GenL_{i,m,t,h,u} + GenX_{i,m,t,h} \right) \cdot DEROMvar_i$$

$$+ \sum_i \sum_m \sum_t \sum_u \sum_h \left(GenL_{i,m,t,h,u} + GenX_{i,m,t,h} \right) \cdot CTax \cdot CRate_i$$

$$+ \sum_i InvGen_i \cdot \left(DERcapcost_i \cdot AnnuityF_i + DEROMfix_i \right) + \sum_m NGBSF_m$$

$$+ \sum_m \sum_t \sum_h \sum_u GasP_{m,t,h,u} \cdot NGHR \cdot \left(NatGas\,\mathrm{Pr}\,ice_{m,t,h} + CTax \cdot NGCRate \right)$$

$$- \sum_m \sum_t \sum_h \sum_i GenX_{i,m,t,h} \cdot IEM_{m,t,h}$$

(1a)

Subject to:

equations (2) through (11)

This formulation differs only in the objective function, equation (1a), which now charges the IEM price for each hourly time step plus the non-commodity revenue neutrality adder. Note that the same mathematical formulation can be used if the model user wants to simulate a fixed price for all customer energy purchases. In that case, all IEM hourly prices are simply set to the fixed desired value.

6. Results

This chapter discusses the various scenarios studied and the results obtained.

6.1 Scenarios and Results

The following terminology is used in describing the scenarios:

- *Tariff*: the µGrid purchases electricity under a standard utility tariff structure.
- *PX*: the µGrid purchases electricity from the PX (1999).
- *IEM*: the µGrid purchases electricity from the IEM (2000).
- *Do-nothing*: the µGrid does not invest in DER.
- *Install*: the µGrid invests in DER.
- *With CHP*: the µGrid can invest in DER including CHP.
- *Without CHP*: the µGrid can invest in DER excluding CHP.
- *Basic Analysis*: DER-CAM is run with existent technology data.
- *Subsidy*: in scenarios involving subsidies, capital costs of specified technologies are reduced by specified percentages, while all technologies not explicitly subsidized mention retain their standard costs.

Scenarios considered in this project are described in Table 12.

Table 12. Scenarios for Purchasing Electricity

2000 Data	
Basic Analysis	PX do-nothing case, PX with and without CHP tariff do-nothing case, tariff with and without CHP
1999 Data	
Basic Analysis	PX do-nothing case, PX with and without CHP tariff do-nothing case, tariff with and without CHP
Technology Subsidy	Subsidy of 50% and 75% on photo-voltaic and fuel cell technologies both with and without CHP (PX and Tariff case) Subsidy of 25%, 50%, and 75% on fuel cell technology with CHP only (tariff case only) Subsidy of 50% on photo-voltaic technology and 10% for other technologies - Analysis done with and without CHP (PX and Tariff case)

Increase in Capital Costs	Increase of 50%, 100%, 200%, and 400% in capital costs, with CHP (tariff case only)
Cover and Sales	Allow generated power from DER technologies to be sold in the wholesale market with and without CHP (PX case only)
2010 Data	
Basic Analysis	PX without CHP

In Section 6.3, five specific cases are examined from this set of scenarios. The five cases are

- CASE 1: 1999 Tariff *Do Nothing* Case
- CASE 2: 1999 Tariff Case without CHP
- CASE 3: 1999 Tariff Case with CHP
- CASE 4: 1999 Tariff Case with CHP and 75% Subsidy on Photovoltaic and Fuel Cell Technologies
- CASE 5: Tariff Case without CHP Using 2010 Technology Data

The naming conventions used for DER generation technologies are outlined in Section 2.3.

A detailed description of the scenarios considered in this project, and their results, is presented in *Appendix A: DER-CAM Scenarios and Results.* For each scenario two sets of results table are presented in the appendix, energy results and financial results. Together these tables summarize the overall operation of the µGrid. The following results are presented:

Energy Balance Results

- capacity installation (kW)
- DER technology equipment installed
- total electricity requirement (MWh)
- absorption cooling electricity reduction (MWh)
- electricity – self-generation (MWh)
- electricity sales (*if any*) (MWh)
- gas requirements (MWh)
- CHP gas reduction (MWh)
- gas consumed by power generation (MWh)
- net gas purchases (MWh)

Financial Results

- annualized net investment costs (K$)

- electricity bill for electricity purchases (K$)
- annual electricity sales revenues (*if any*) (K$)
- annual gas bill for DER (K$)
- annual gas bill for direct end uses (K$)
- annualized direct fired absorption chiller investment[11] (K$)
- annual other fuel bill[12] (K$)
- total annual energy bill (K$)
- bill savings over do-nothing case (%)

6.2 Impact of CHP

The impact of DER technologies and CHP on the annual energy bill is considerable. As shown in Figure 9, the annual energy bill using DER technologies for self-generation is 28% lower (in the tariff case with 2000 load data) than the do-nothing case. This reduction is as large as 37% when CHP is available. Figures 10 and 11 show how the μGrid self generates, purchases electricity and natural gas, and consumes fuel. Note most importantly that the DER adoption cases are quite qualitatively different from the do-nothing cases in that when DER adoption is available and adopted almost all electricity is self generated and conversely very little is purchased. The annual energy bill is greater in the do-nothing case than in case when DER is installed. Regulated tariff prices and IEM prices are higher than the costs associated with installation and operation of DER technologies. This results in a reduction of the energy bill for the *no CHP* cases, where installation of DER technologies is allowed. A further reduction in the energy bill is attainable in the *with CHP* case since CHP enables the use of waste heat to meet space and water heating (see Figure 12 and Figure 13). Absorption chillers can also enable the use of CHP for cooling loads. This use of recovered heat effectively displaces much of the natural gas purchases that were needed in the *no CHP* case. Note that DER-CAM ensures that the cost-minimizing equipment combination is chosen and installed in every scenario, given the alternatives available.

[11] Direct-fired absorption chillers were not selected in any of the scenarios; therefore this value is always $0.
[12] No other fuel usage was considered in the models; therefore this value is always $0.

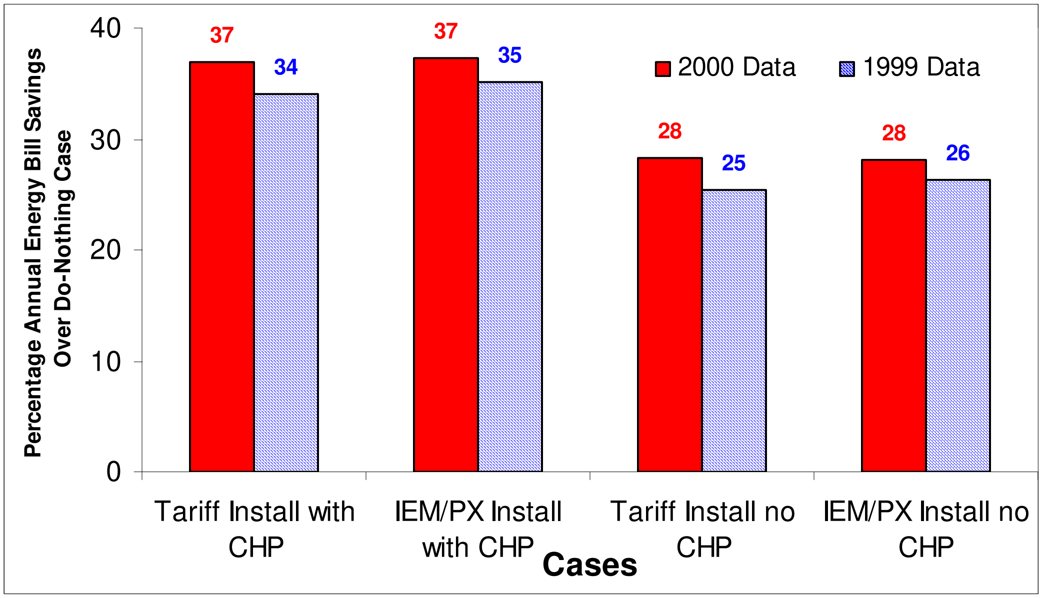


Figure 9. Percentage Annual Bill Savings

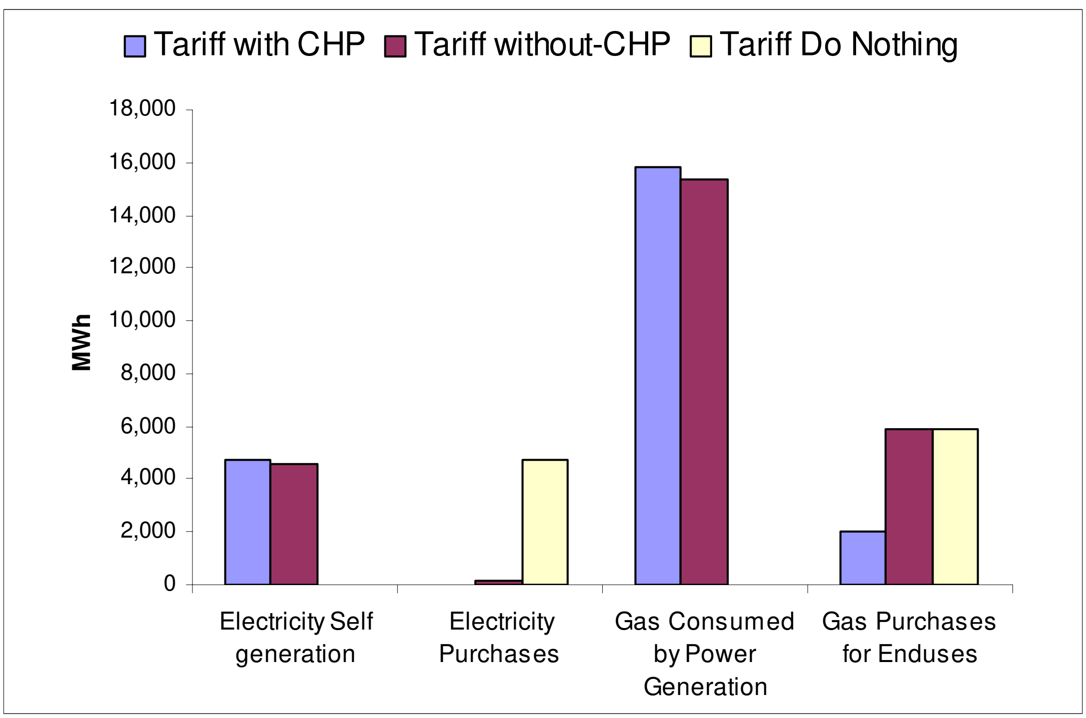


Figure 10. Energy Consumption Breakdown - 1999 (Tariff Case)

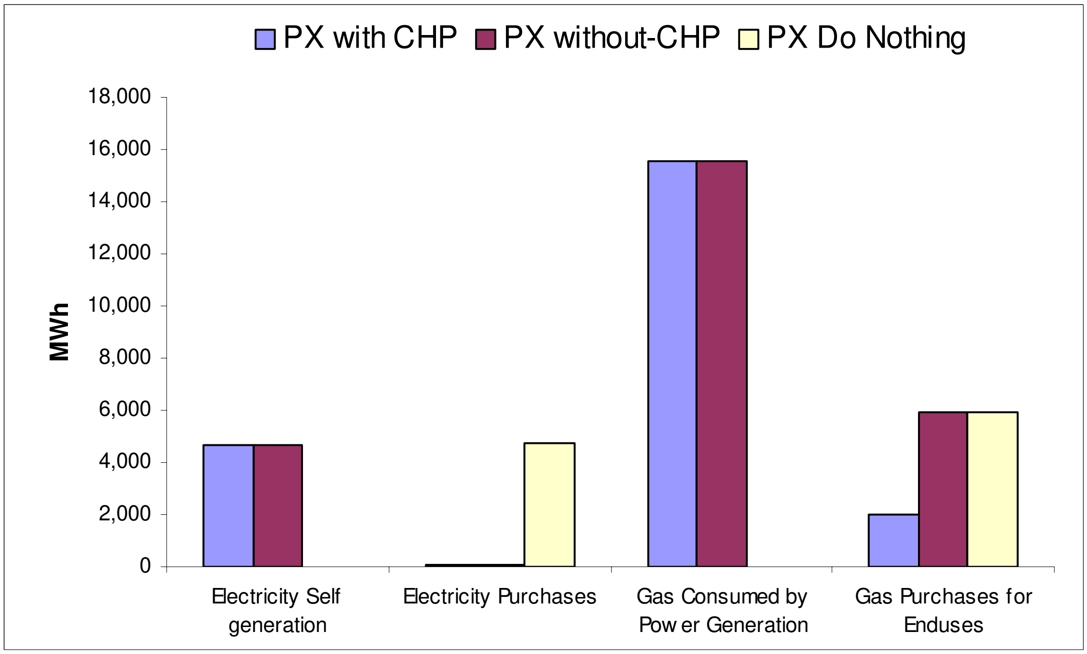


Figure 11. Energy Consumption Breakdown - 1999 (PX Case)

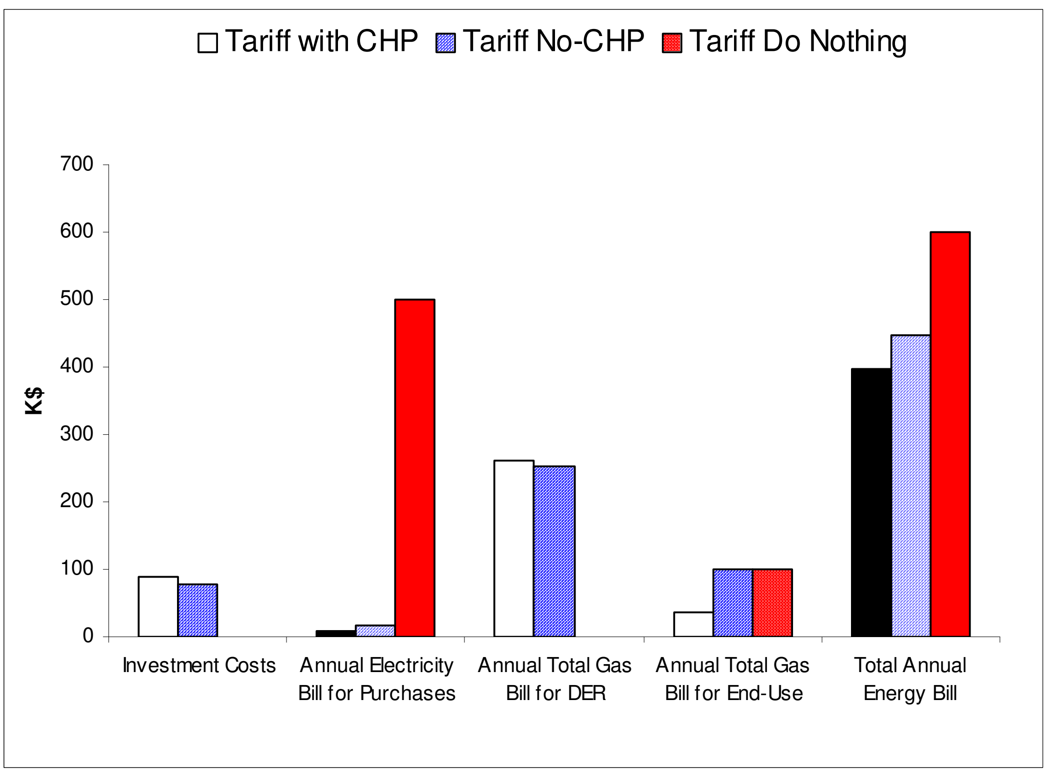


Figure 12. Net Cost Breakdown - 1999 (Tariff Case)

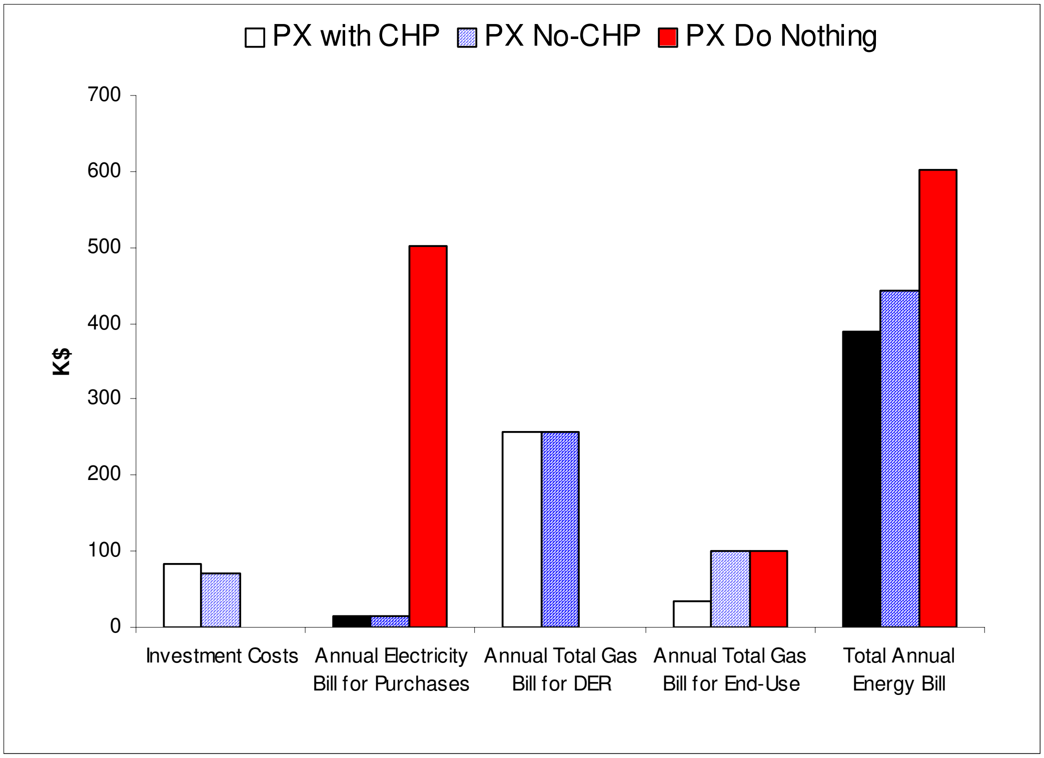


Figure 13. Net Cost Breakdown - 1999 (PX Case)

The aforementioned observations stress the ability of CHP to bring substantial cost savings, at least under the idealized assumptions applied here. Next, a few scenarios will be discussed in detail. The discussion starts with the case where no DER technologies can be installed, and the customer demand load needs to be met through macrogrid purchases. Later on, more sophisticated scenarios involving the installation of DER technologies and CHP are examined. In the latter part of this chapter, the effects of high subsidies on PVs and FCs are analyzed. Finally, results with forecasted 2010 DER technology data are presented.

6.3 Examination of Specific Cases

Of the scenarios described in Section 6.1, five particular case are examined in detail in this section.

6.3.1 CASE 1: 1999 Tariff *Do Nothing* Case

In the *do nothing* case, the electricity requirement is met by purchasing electricity from the disco. Since there is no on-site generation available, the residual demand is the same as the original electricity-only and cooling loads (see Figure 14 and Figure 15). This results in disco energy purchases even during periods when the coincident power charge applies. This charge directly affects the annual electricity bill from off-site purchases, and thus, the marginal price[13] peaks precisely when the coincident charge is active (see Figure 16 and Figure 17). For example, in

[13] This is the instantaneous price that the customer pays to acquire total energy during the relevant time period.

Figure 16, during September, the coincident charge is active during hour 16 on weekdays. As electricity is purchased from the disco during this hour, a much higher price needs to be paid to buy energy compared to other periods, thereby resulting in the peak. When the option of self-generation is available, on-site generators are partially used to meet the load demand, thereby reducing disco purchases.

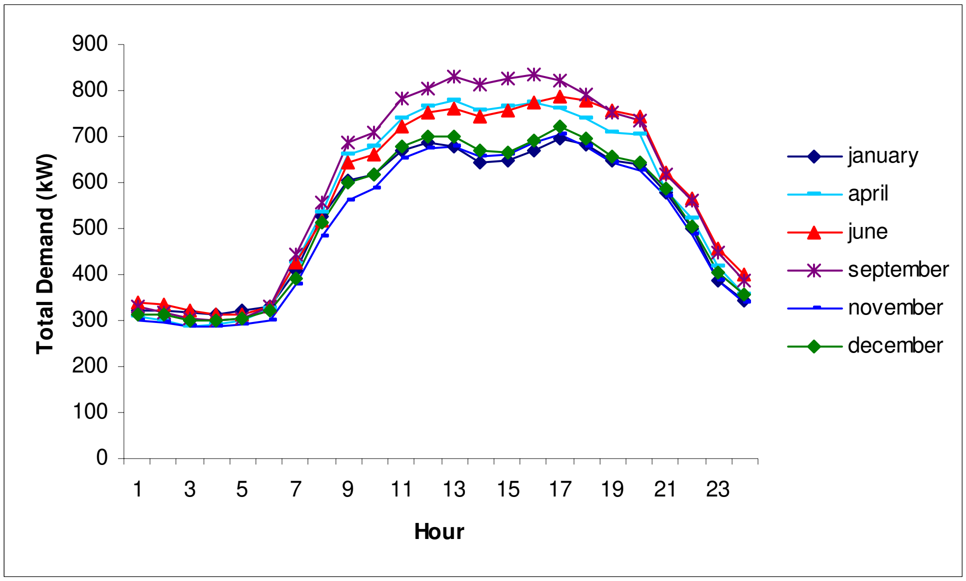


Figure 14. Electricity-Only and Cooling Demand (Week)

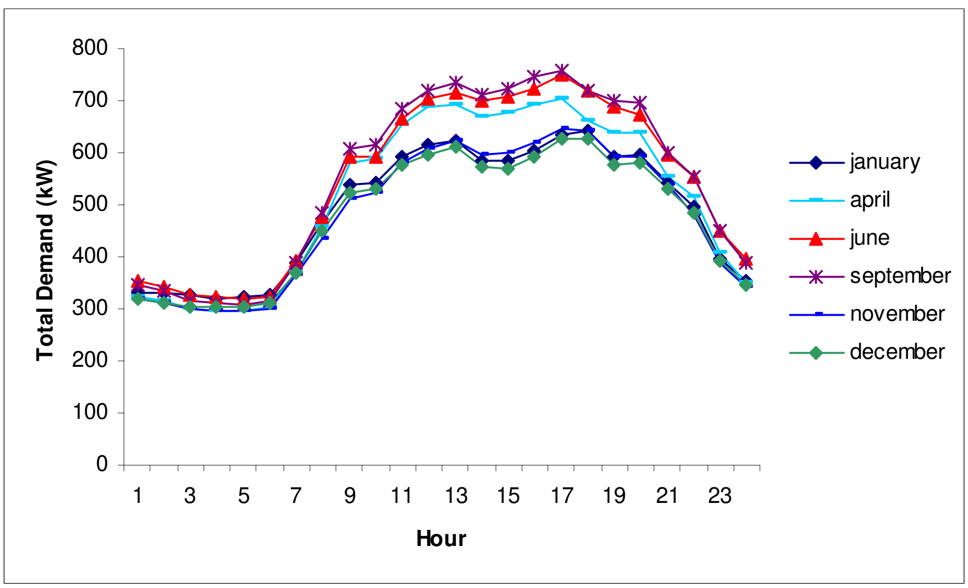


Figure 15. Electricity-Only and Cooling Demand (Weekend)

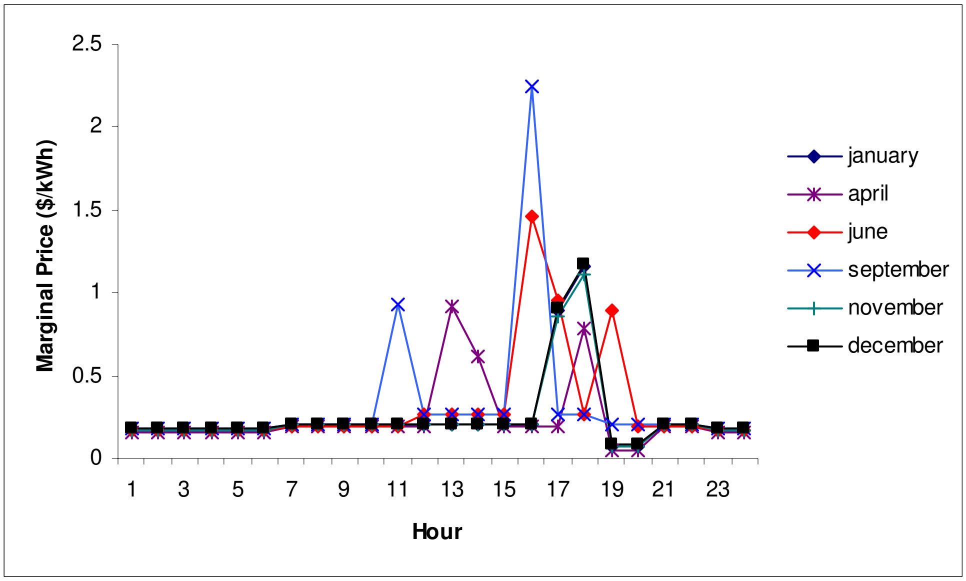


Figure 16. Marginal Price (Week)

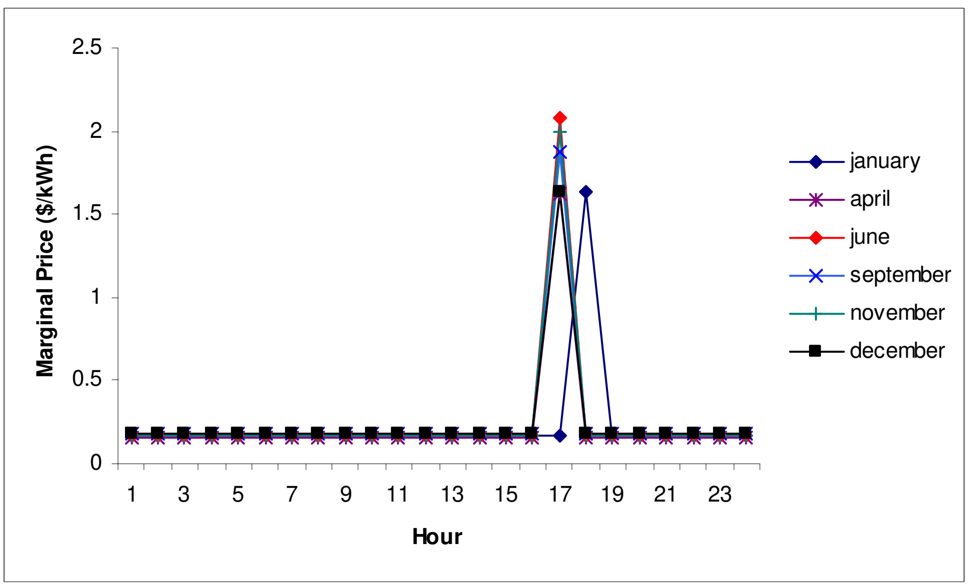


Figure 17. Marginal Price (Weekend)

6.3.2 CASE 2: 1999 Tariff Case without CHP

In this scenario, the customer is still subject to the tariff associated with purchasing electricity from the disco. However, it now has the option to install autonomous DER generation (without CHP capability). This scenario approximates the case of DER within a tariff environment.

The results indicate that the total supply cost is reduced relative to the do nothing case because of a significant reduction in the demand charge expenses (see Figure 12). DER is used in a way that reduces residual demand during the periods when the coincident charge is active. On-site generation output from DER covers much of the residual demand that was bought from the disco in Case 1 (see Figure 18 and Figure 19). Consequently, the largest decrease in cost is due to the reduction in macrogrid electricity purchases. Adding to the supply cost are natural gas purchases for DER use and DER investment costs. Meanwhile, natural gas purchases for non-DER uses remain the same.

The optimal DER equipment installation consists of five units of GA-K-55 and one unit of GA-K-500. Both of these technologies are gas-fired backup generators that have low capital costs and high heat rates, but the larger GA-K-500 units have a slightly lower levelized cost. This implies that it is economical to use the one GA-K-500 unit mainly to cover the base load while five units of the GA-K-55 are operated to cover the peak load.

There is also a significant reduction in the peak period marginal prices (see Figure 22 and Figure 23). The new marginal price curves are mostly constant at the self-generation cost, except during the peak hours, when autonomous generation is not able to cover the whole demand. However, the peaks are not at periods when the coincident charge is active. The rare peaks for marginal prices during weekends (see Figure 23), is because some generation is needed to prevent the demand charge from being applied during these hours.

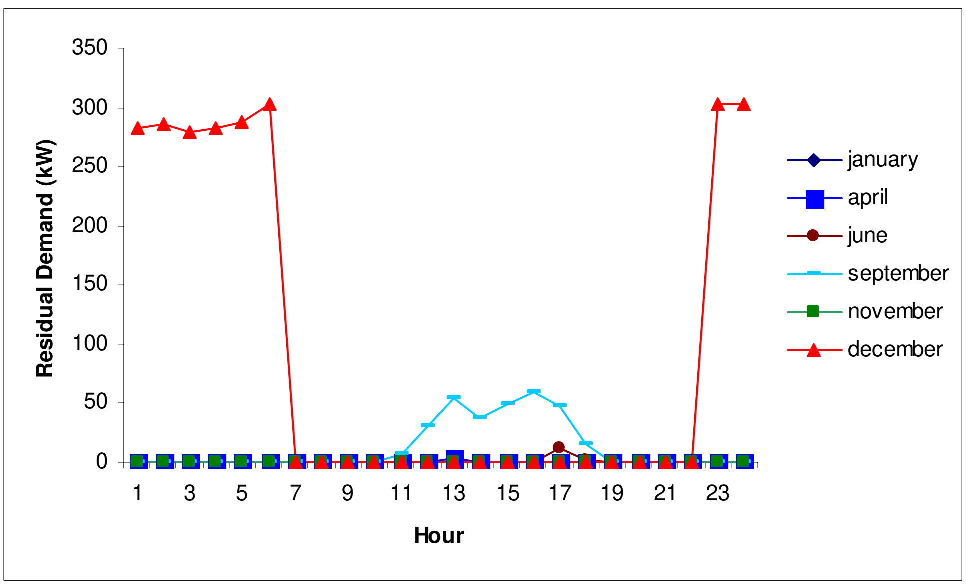


Figure 18. Electricity-Only and Cooling Residual Demand (Week)

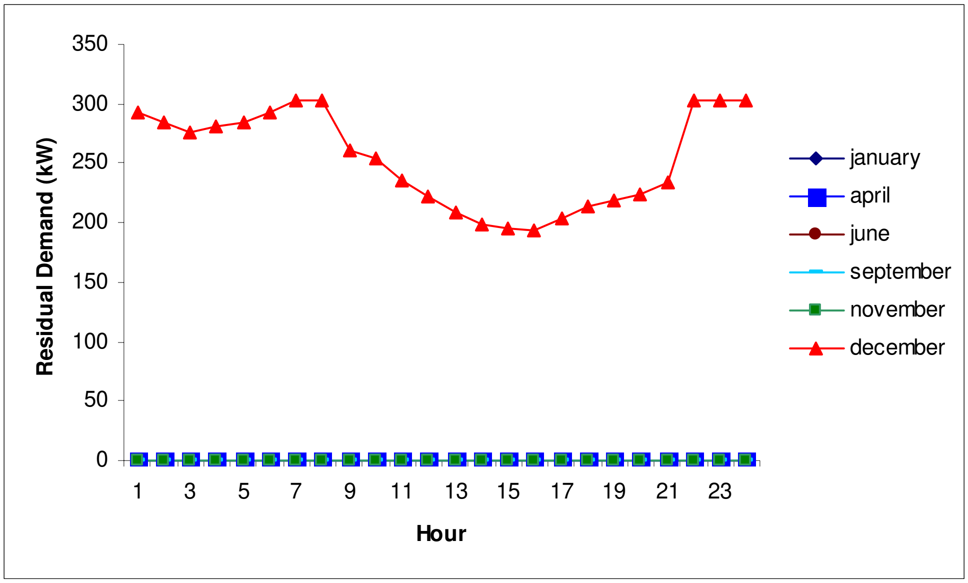


Figure 19: Electricity-Only and Cooling Residual Demand (Weekend)

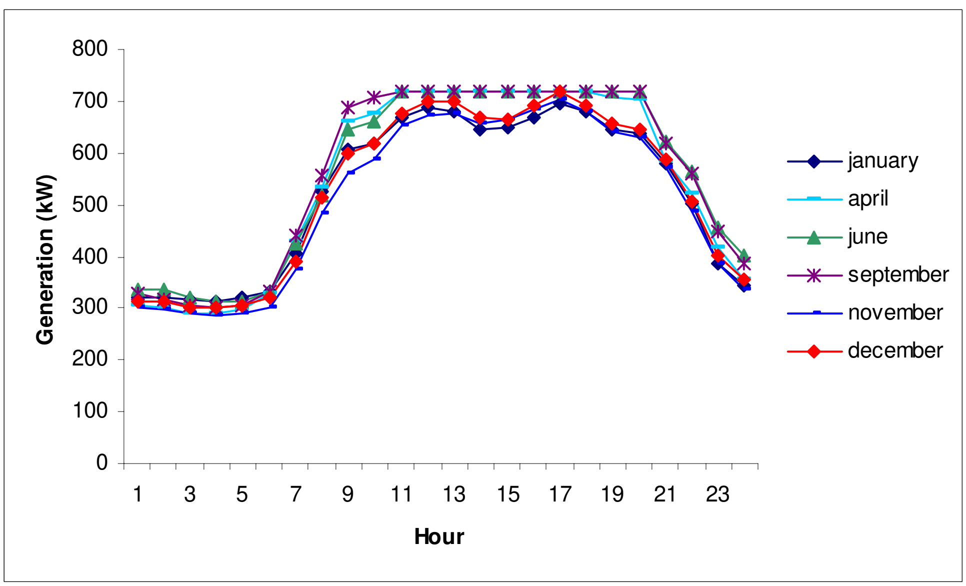


Figure 20. Electricity Generation Output for Self-Use (Week)

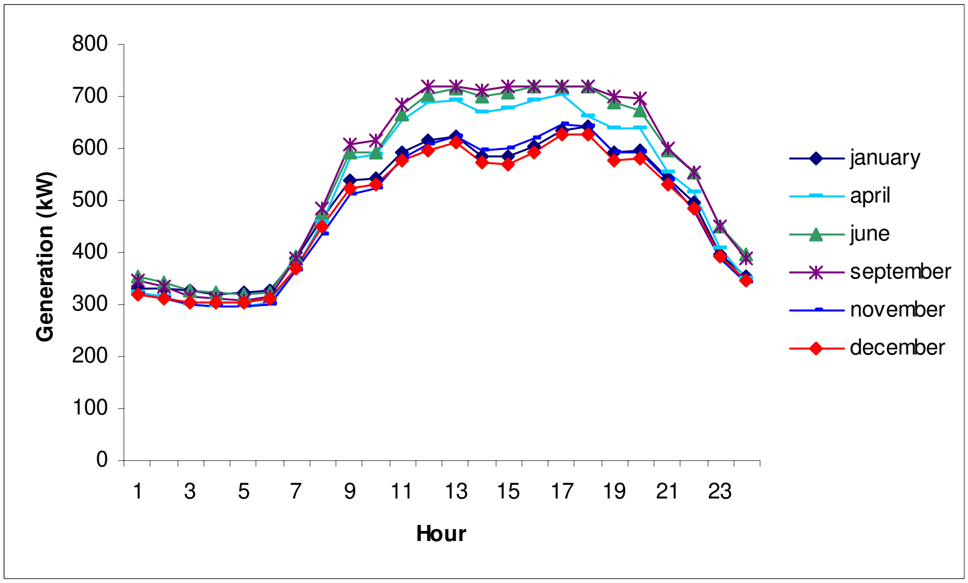


Figure 21. Electricity Generation Output for Self-Use (Weekend)

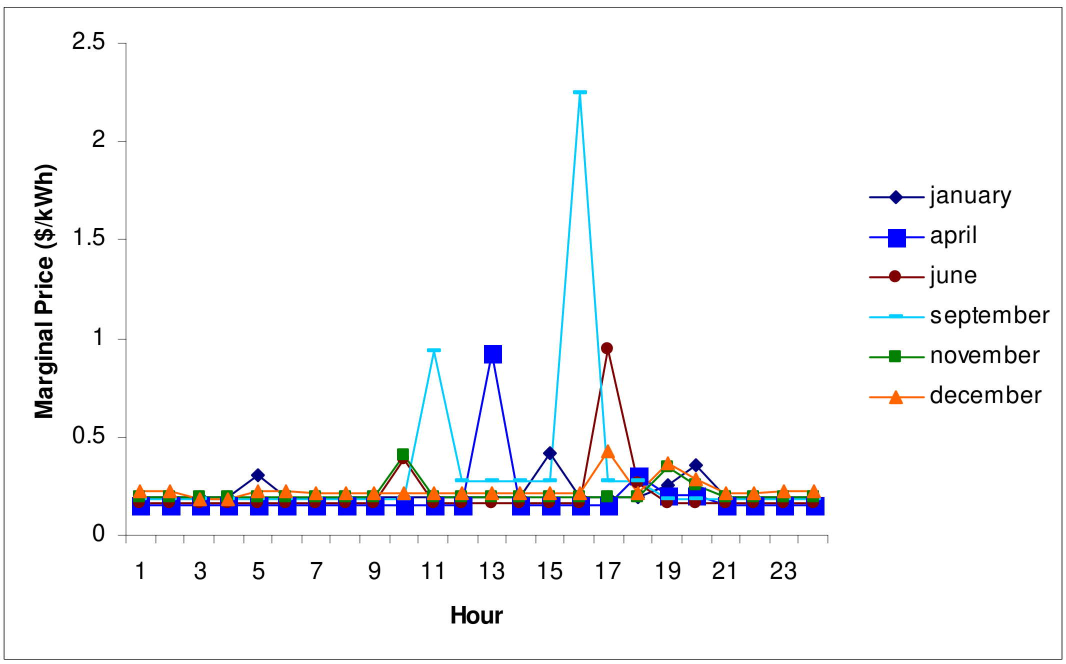


Figure 22. Marginal Price (Week)

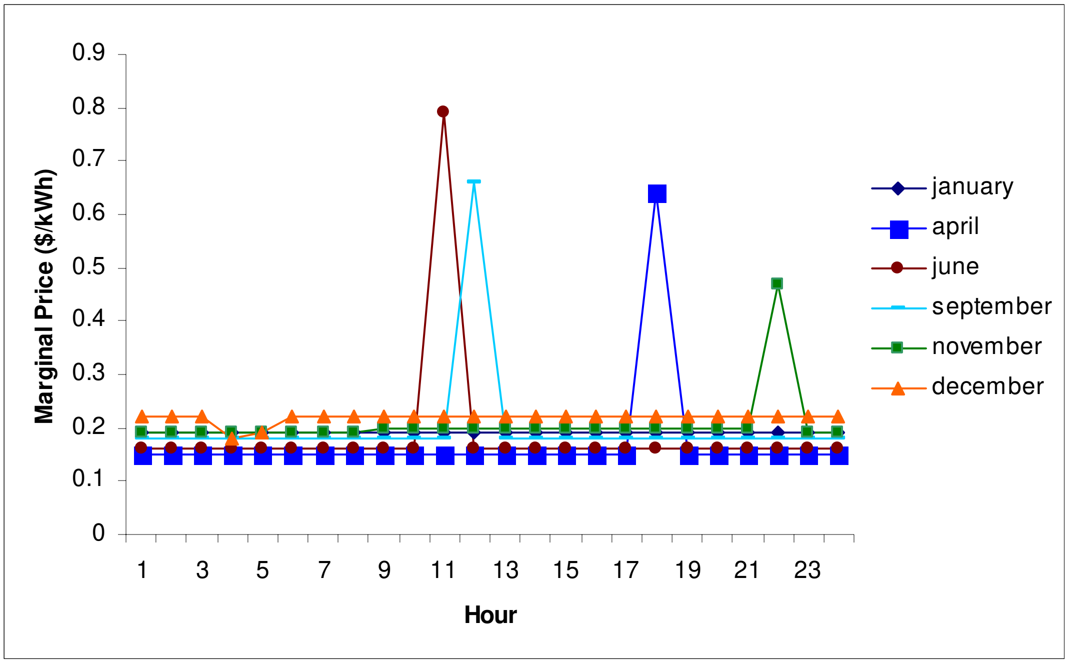


Figure 23. Marginal Price (Weekend)

6.3.3 CASE 3: 1999 Tariff Case with CHP

CHP involves the co-utilization of both the heat and electricity generated by electricity generators. CHP-enabled DER equipment using heat exchangers and absorption chillers has the capability to recover waste heat in order to meet some of the space and water heating loads as well as cooling loads. Consequently, this co-utilization displaces much of the non-DER natural gas purchases. Indeed, Figure 10 indicates a significant drop in natural gas purchases in the CHP case. This is reflected in a 73% drop in the annual non-DER natural gas bill relative to the non-CHP cases. The reason for the drop is illustrated in Figure 24 and Figure 25. In the non-CHP cases, the entire water- and space-heating load was met by purchasing natural gas. In the CHP case, however, the recovered heat obtained through CHP equipment is used to meet much of the heating loads, which displaces natural gas purchases.

The output shows installation of three units of CHPGA-K-55, one unit of CHPGA-K-500, and two units of GA-K-55. As expected, more CHP equipment is installed, which is an optimal strategy for co-utilization of electricity and heat. All of these DER technologies have relatively low capital costs and relatively high heat rates. These features make them attractive for installation where demand charge exists and for CHP applications.

The schedule of the total self-generation output and the schedules of the individual DER technologies (see Figure 30 and Figure 31) follow similar trends as in the tariff no-CHP case (i.e., increased self-generation during periods of high tariff rates). Specifically, the more economical technologies (in this case, the CHP-enabled ones) are used extensively in order to cover the base load as well as provide recovered heat to offset natural gas purchases for thermal loads. The GA-K-55 units are used only to meet the peak electrical load. Hence, the residual demand is driven almost to zero (see Figure 26 and Figure 27), and the marginal prices reflect only the fuel costs associated with DER operation (see Figure 28 and Figure 29).

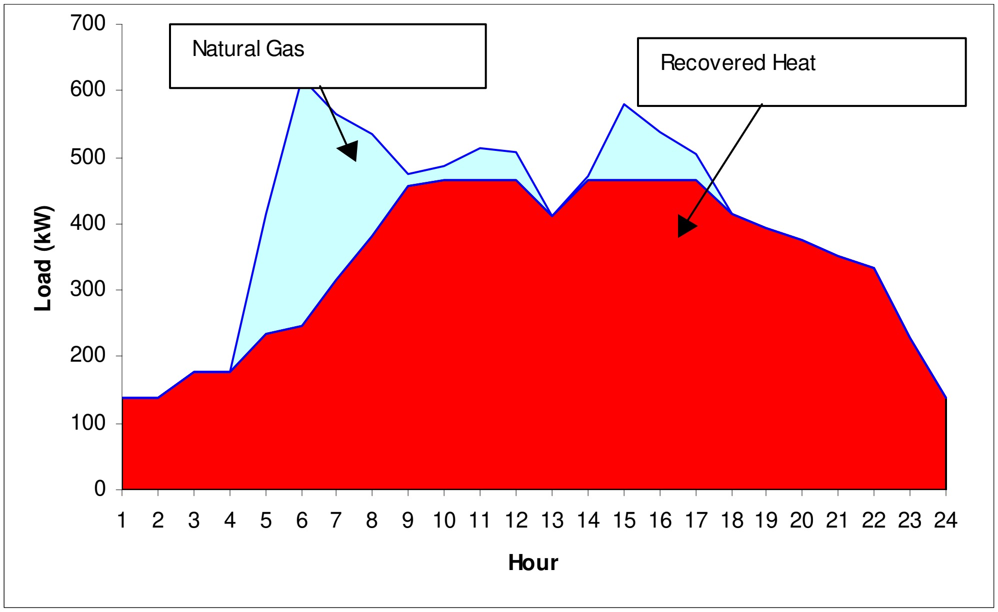


Figure 24. Water-Heating Load Met by Natural Gas and Recovered Heat (June Weekday)

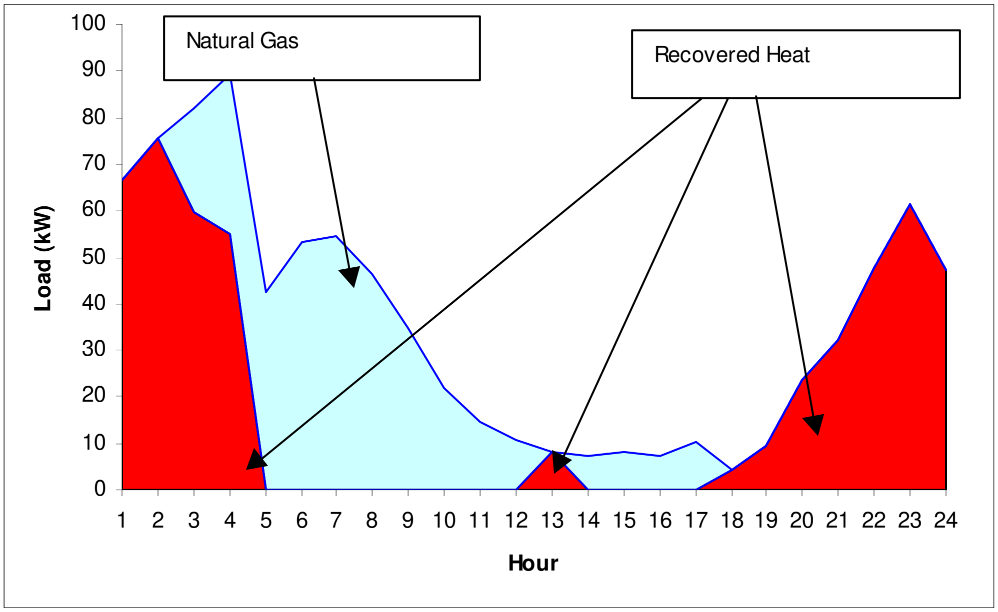


Figure 25. Space-Heating Load Met by Natural Gas and Recovered Heat (June Weekday)

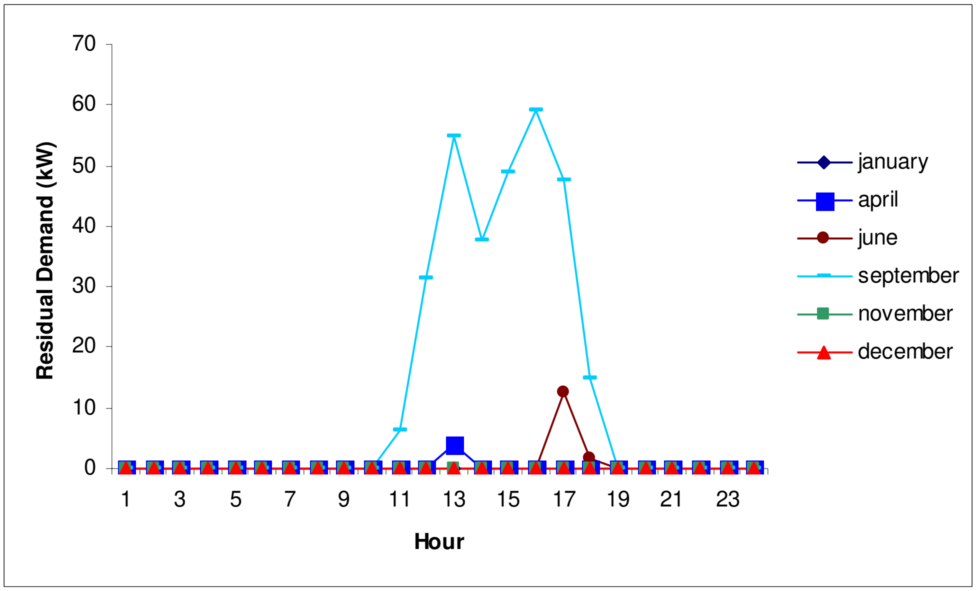


Figure 26. Electricity-Only and Cooling Residual Demand (Week)

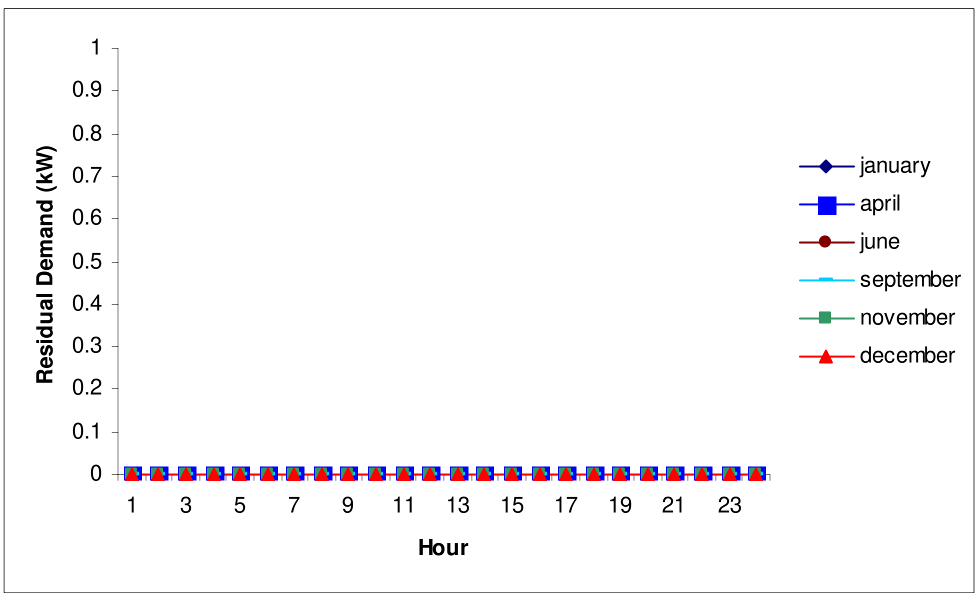


Figure 27. Electricity-Only and Cooling Residual Demand (Weekend)

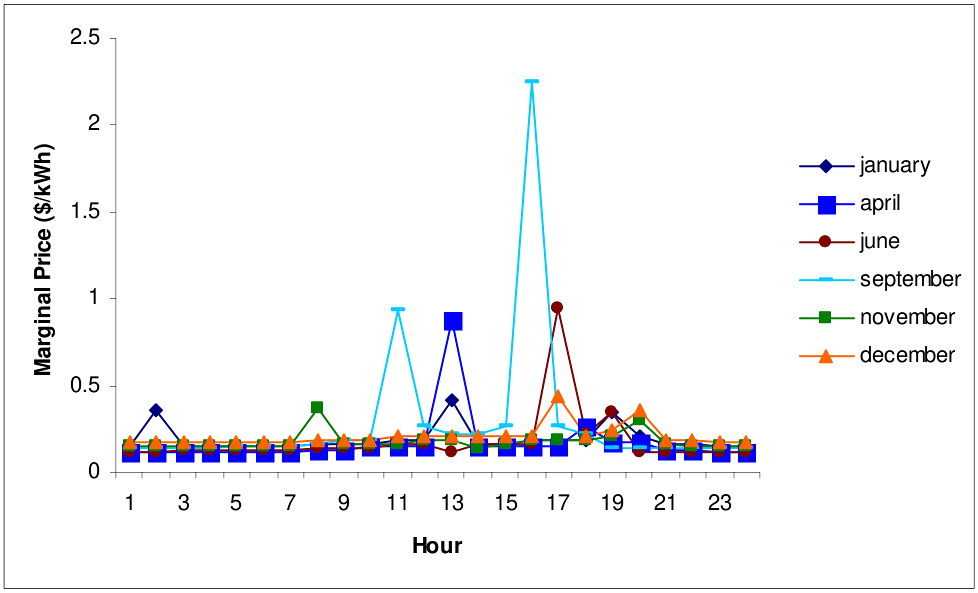


Figure 28. Marginal Price (Week)

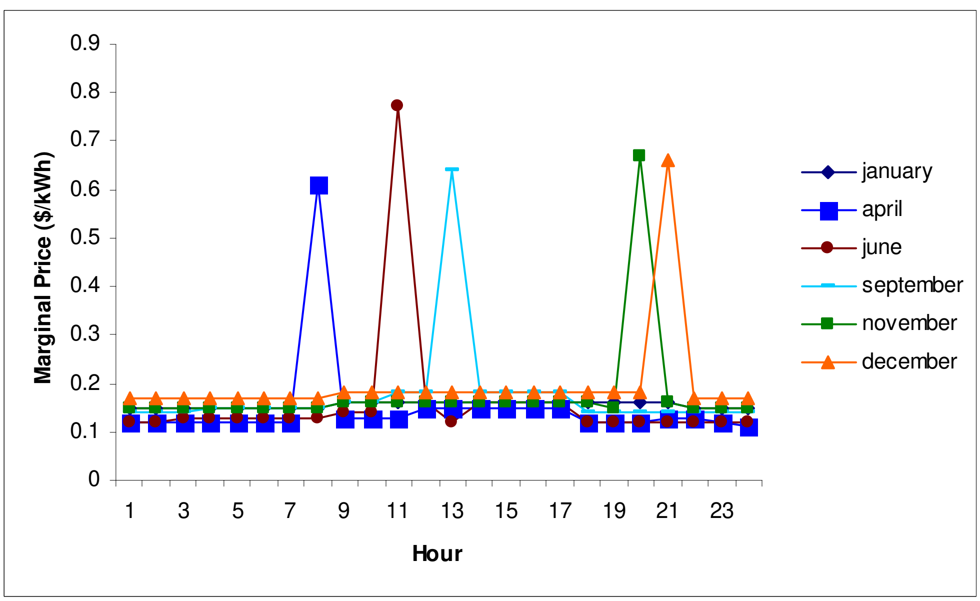


Figure 29. Marginal Price (Weekend)

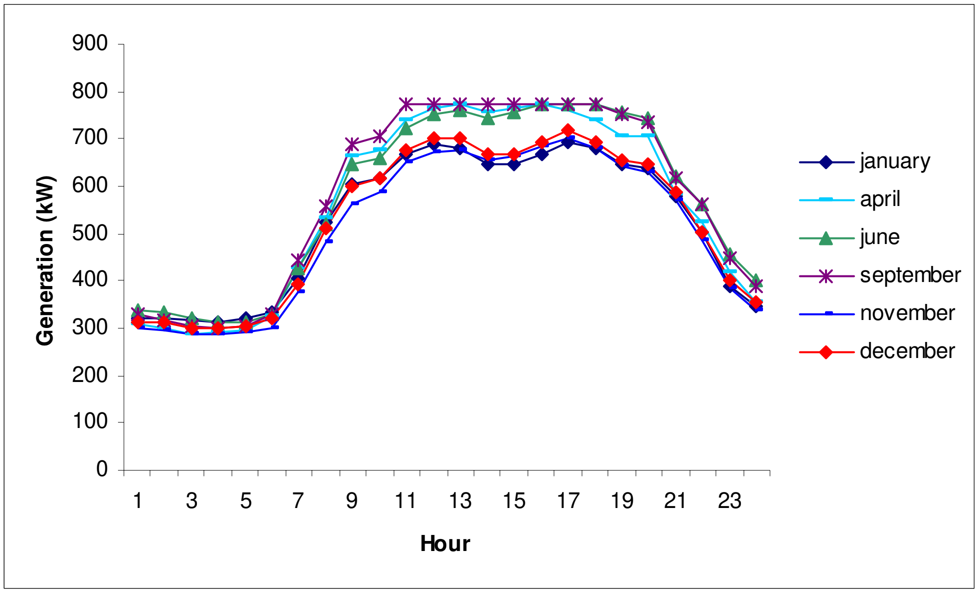


Figure 30. Electricity Generation Output for Self-Use (Week)

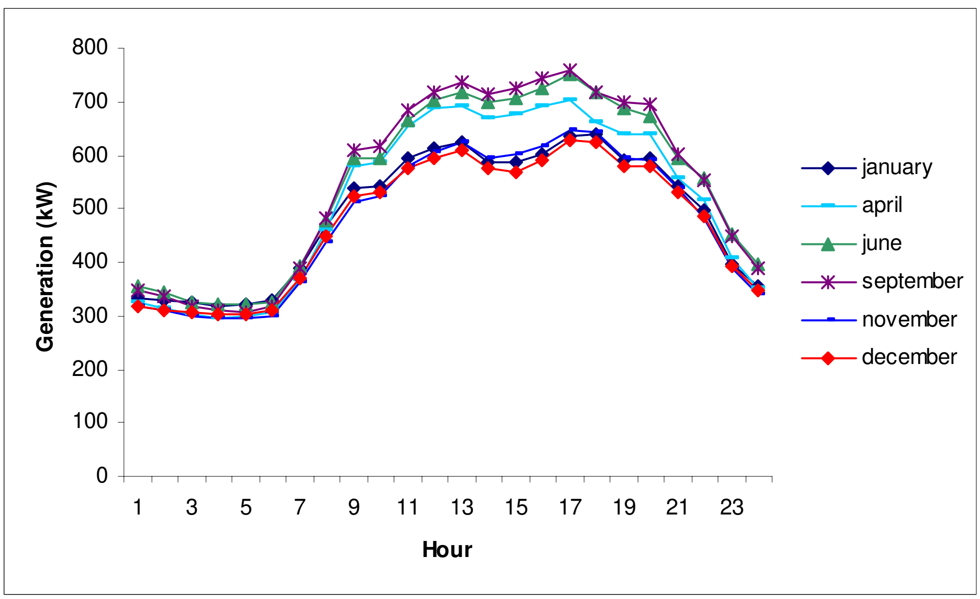


Figure 31. Electricity Generation Output for Self-Use (Weekend)

6.3.4 CASE 4: 1999 Tariff Case with CHP and 75% Subsidy on Photovoltaic and Fuel Cell Technologies

In this case, a 75 % subsidy towards the turnkey costs for PV and FC technologies is given. As is obvious, there is an increase in installed PV and FC capacity due to reduced costs (see Figure

33). Compared to the tariff with CHP case, the current scenario results in slightly higher installation and non-DER natural gas purchase costs. Alternatively, macrogrid electricity and DER natural gas costs are reduced even further. Indeed, there is a sharp reduction in electricity purchases from the disco since the residual demand is very low (see Figure 34 to Figure 36). Overall, the total energy bill is slightly lower (see Figure 32).

The generating schedules for the DER technologies are similar to those from earlier cases. The technologies installed in this case are two units of GA-K-55, one unit of CHPMTL-C-30, two units of PV-50, one unit of PV-100, one unit of CHPGA-K-55, and one unit of CHPGA-K-500. The schedules for operation of the DER technologies are shown in Figure 37 to Figure 38. PV is available to meet loads only during daylight hours while gas-fired backup generators are used to cover day and nighttime demands. Because the marginal cost of PV energy is zero, it is always used when available in preference to any other source.

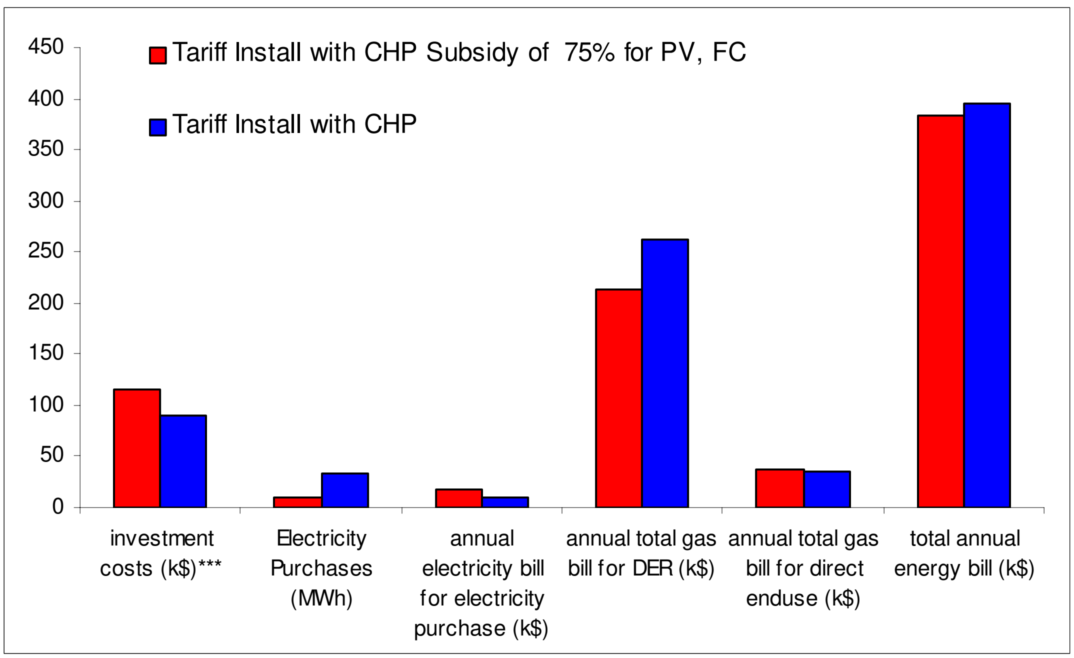


Figure 32. Cost Comparison (in k$)

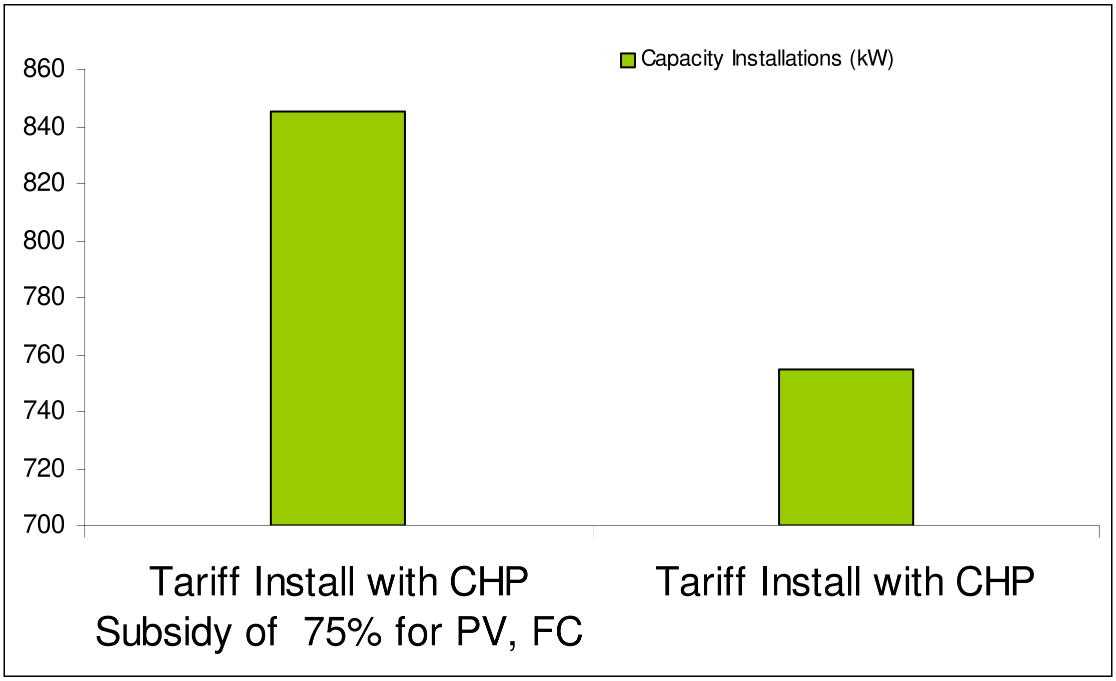


Figure 33. Comparison of Installed Capacity

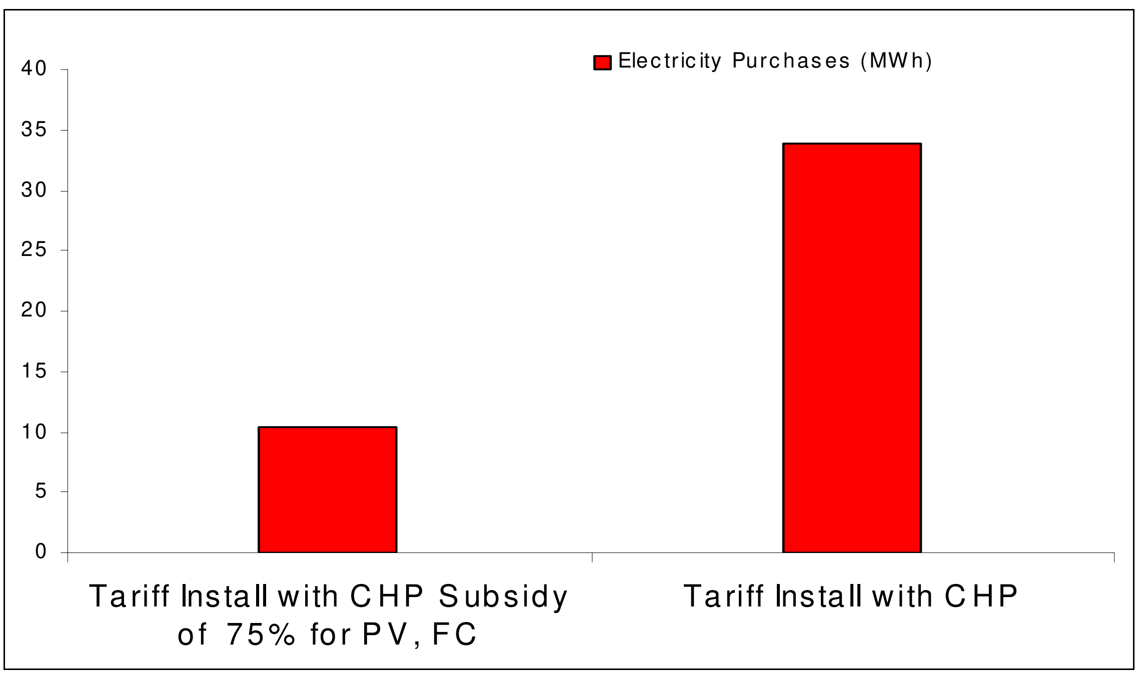


Figure 34. Comparison of Electricity Purchases

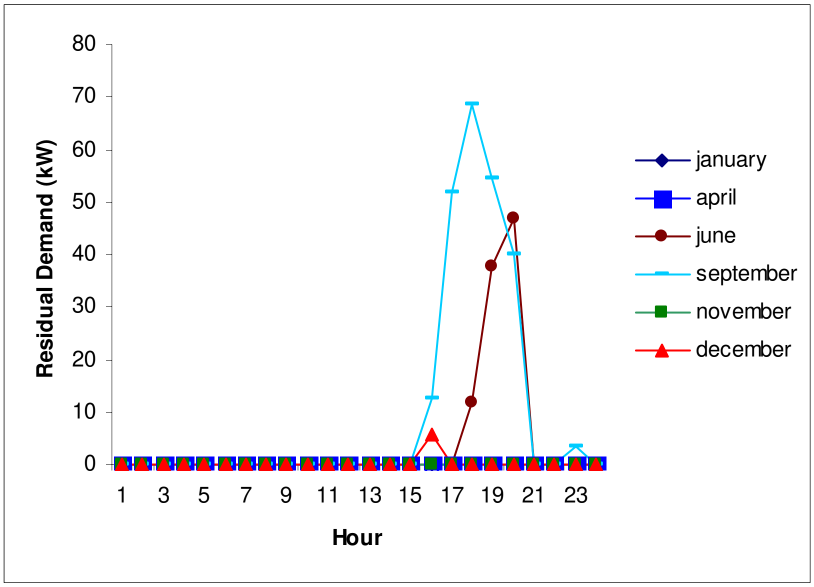


Figure 35. Electricity-Only and Cooling Residual Demand (Week)

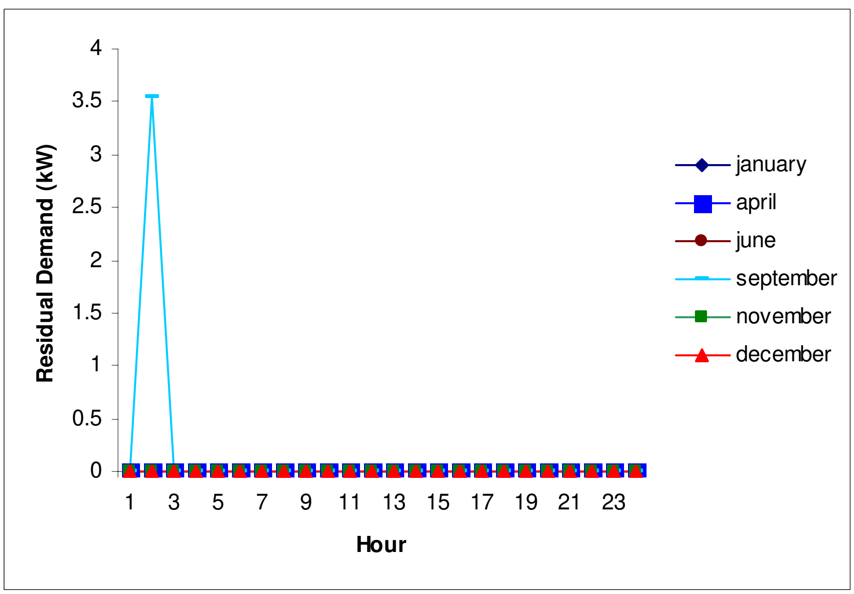


Figure 36. Electricity-Only and Cooling Residual Demand (Weekend)

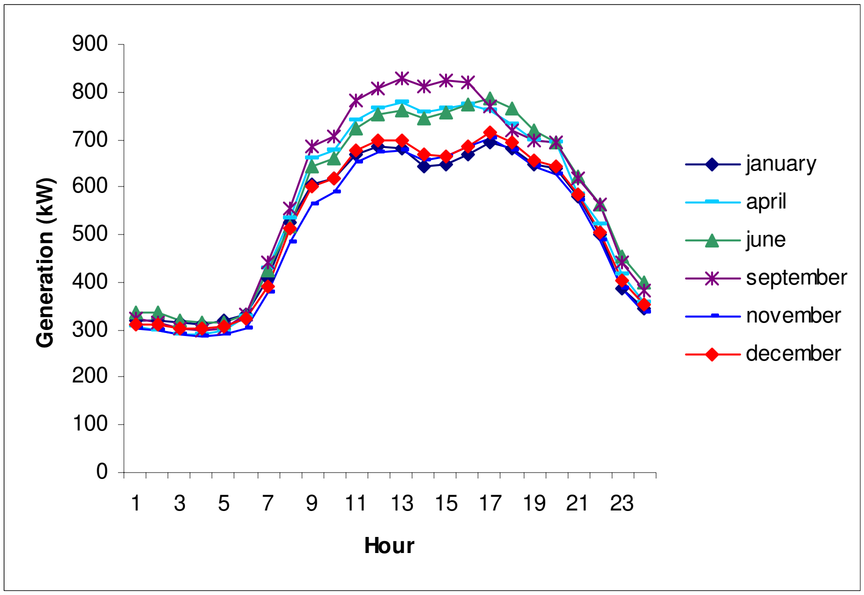


Figure 37. Electricity Generation Output for Self-Use (Week)

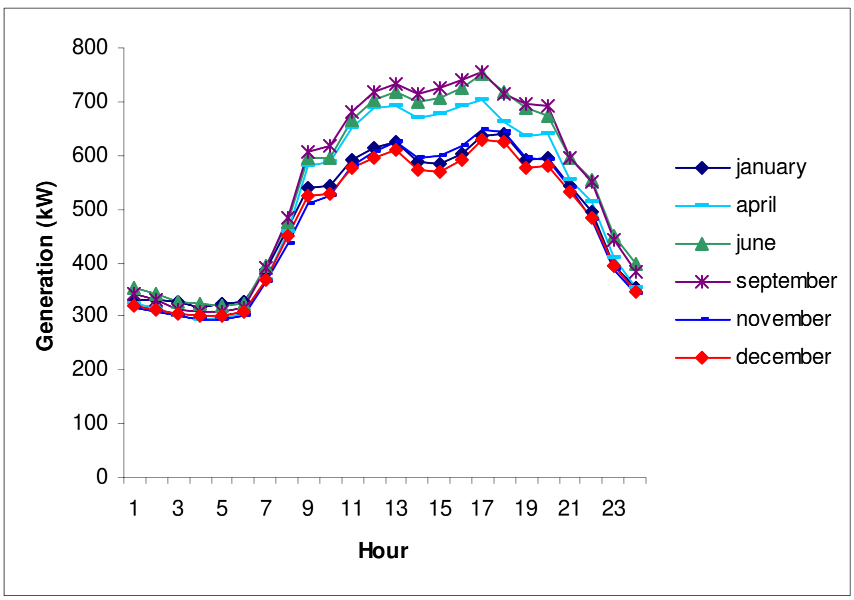


Figure 38. Electricity Generation Output for Self-Use (Weekend)

6.3.5 CASE 5: Tariff Case without CHP Using 2010 Technology Data

In this scenario, DER technology data is based on the year 2010 cost forecasts shown in Table 2. The total energy bill is reduced by 9% when compared to the 1999 tariff without CHP case and 31% when compared to the 1999 tariff do nothing case (see

Table 19 and Table 20). With the forecasted data, three units of a fuel cell, PEM-BA-250, are installed to meet the electrical load (see Table 18).

As fuel cells have much lower capital costs in this scenario, there is a higher capacity installation, three 250 kW PEM FCs. This results in reduced disco electricity and natural gas purchases as well (see Table 14 and Table 18). Accounting for the reduction in the overall energy bill.

The residual demand curves look similar to the tariff with CHP case. The coincident charge is avoided by on-site generation. The residual demands for the periods with coincident charges are usually zero (see Figure 39 and Figure 40). The marginal prices are low and are mostly constant, except during the peak hours, when on-site generation is not able to cover the whole demand. However, the peaks are usually not at periods when the coincident charge is present (see Figure 43 and Figure 44). The rare peaking of marginal prices during weekends is because some generation is needed to prevent the demand charge from being applied during these hours (see Figure 41 and Figure 42).

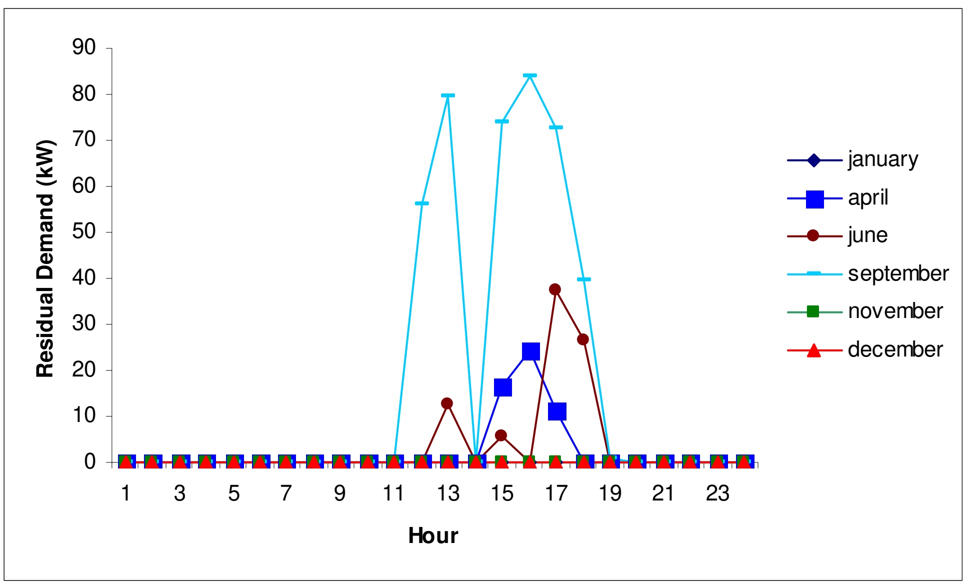


Figure 39. Electricity-Only and Cooling Residual Demand (Week)

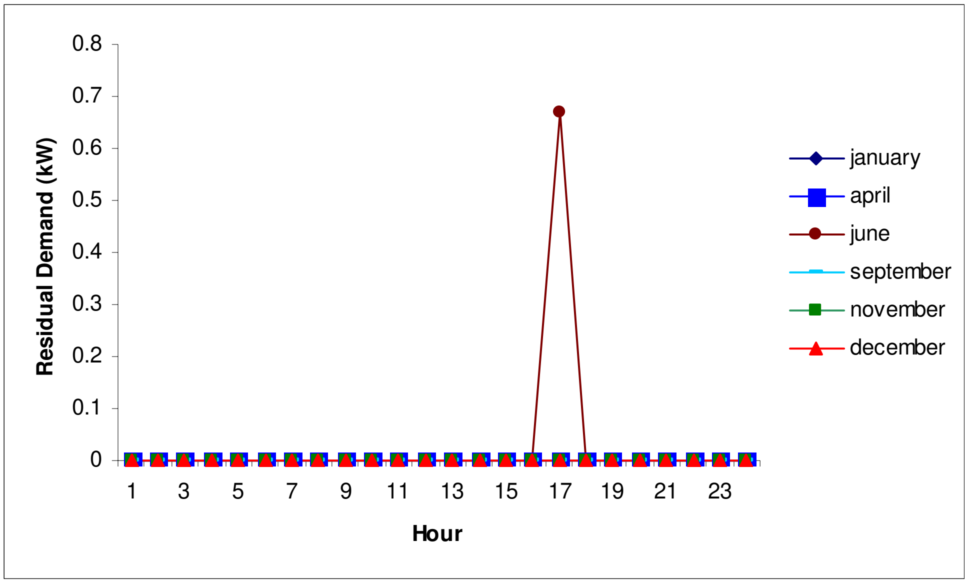


Figure 40. Electricity-Only and Cooling Residual Demand (Weekend)

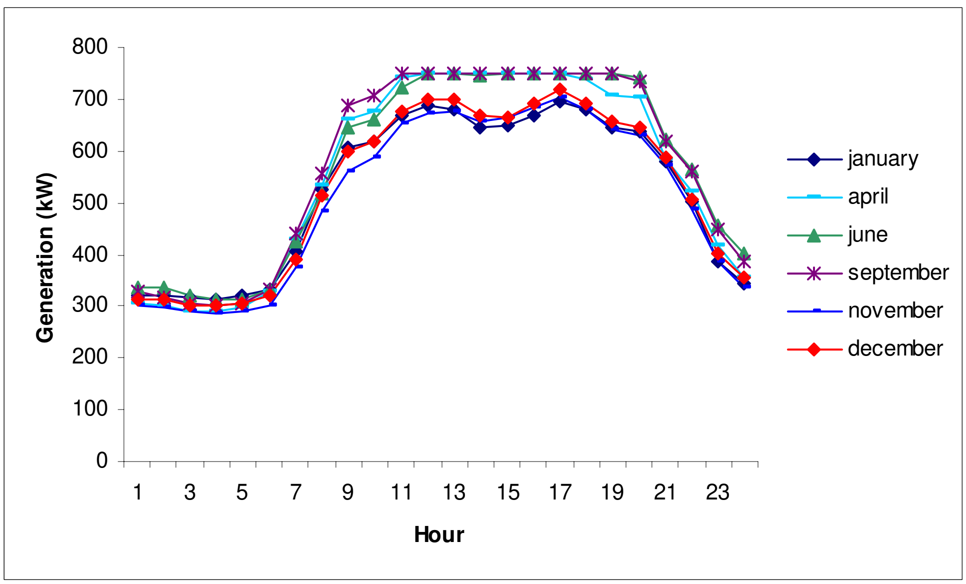


Figure 41. Electricity Generation Output for Self-Use (Week)

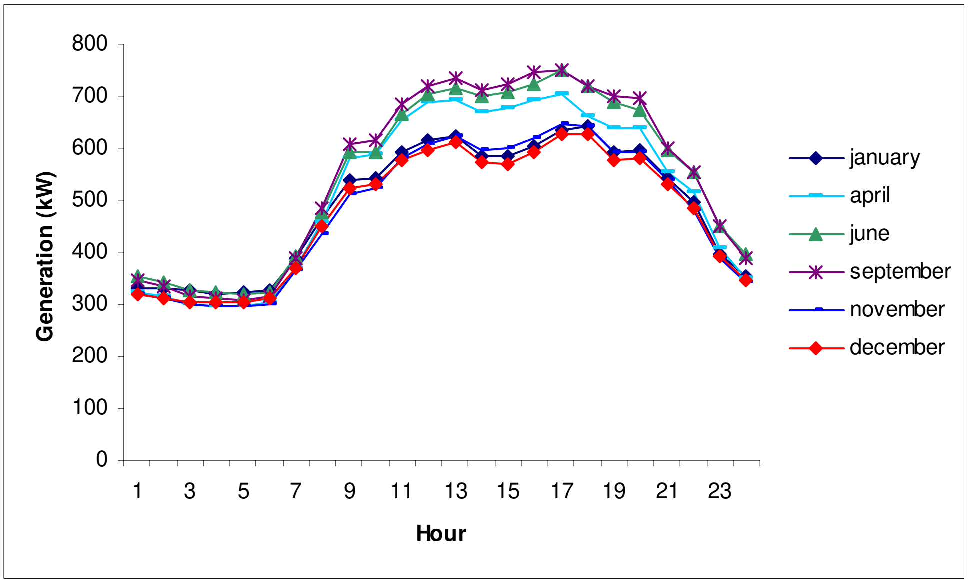


Figure 42. Electricity Generation Output for Self-Use (Weekend)

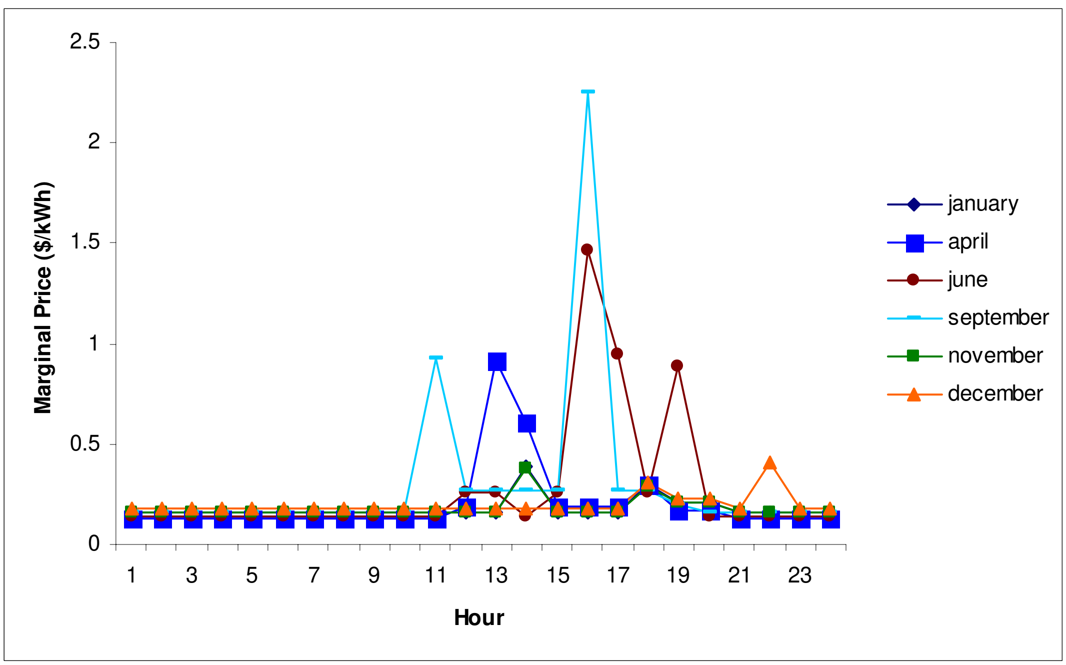


Figure 43. Marginal Price (Week)

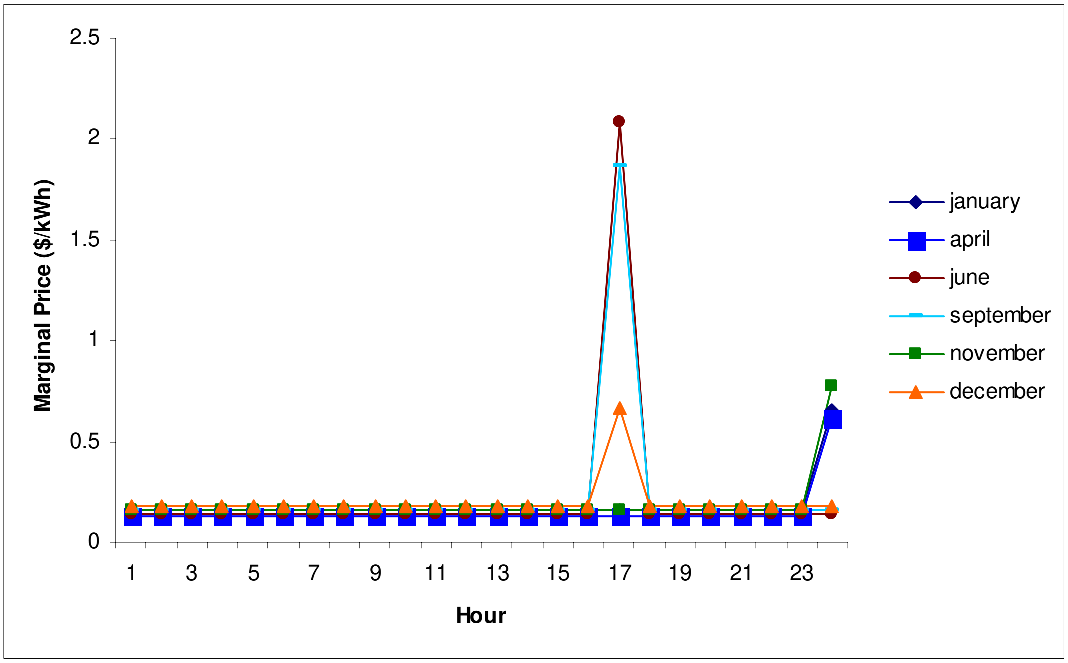


Figure 44. Marginal Price (Weekend)

6.4 Summary of the Results

This section briefly summarizes the results for the scenarios for which DER-CAM was ran.

1. **Adopted Technologies:** From the above results, installation of DER technology helps in meeting the load demand at a lower cost. In the tariff without CHP case, GA-K-55 and GA-K-500 technologies were installed because they had lower capital costs than other technologies. The tariff case with CHP resulted in increased capacity installation as CHP equipment (CHPGA-K-55 and CHPGA-K-500) was operated in order to use waste heat effectively. Such utilization of recovered heat offset some of the heating and cooling demands. Only with high (i.e., 75%) subsidies on PVs, were PV-50 and PV-100 installed. Finally, in the 2010 case, in which forecasted technology data were used, the FC PEM-BA-250 was installed.

2. **Cost Savings:** From the results, installations of DER technologies usually have marginal costs that are lower than buying electricity from the disco. Hence, in the tariff without CHP case, DER technologies are installed and purchases from the disco are reduced. Further, during certain periods on a particular day each month, the coincident charge increases the costs of buying energy from disco many fold, when compared to other periods. Hence, the generators are operated on a schedule leaves minimal residual demand during these periods of higher coincident charges bringing substantial savings. Further cost savings are achieved with the help of CHP equipment, which recycles waste heat to meet some of the heating and cooling demands, reducing gas purchases and bring further savings.

7. Conclusion

This report describes the work recently completed for the CEC at the Berkeley Lab under the CERTS DERI project. Work has focused on the continued development and application of DER-CAM, an economic model of customer adoption of DER, implemented in GAMS optimization software.

The most important improvement that has been accomplished since the last report is the incorporation of CHP technology in DER-CAM and the joint optimization of electricity and natural gas consumption. The current model accounts for the use of waste heat on-site, which can be used to meet some of the space/water heating loads and cooling loads using absorption chillers. Scenarios incorporating variability in tariff rates, IEM prices, and gas prices, and a gamut of technology options (both CHP and non-CHP enabled) with different cost structures and heat rates, create excellent opportunities to test DER-CAM's ability to find the minimal-cost combination of on-site generation and heat recovery as well as electricity and gas purchases. In general, DER-CAM chose low capital cost technologies. Logically, this would be truer when demand charges are in place, but this distinction was not clear in the results obtained here.

The addition of CHP to DER-CAM is a tremendous step towards creating a realistic customer adoption model. As is seen in industry and confirmed in the scenarios in this report, the recovered waste heat from DER is of significant value. This observation will become even more dramatic if carbon taxes are imposed, and DER-CAM now serves as a useful tool for analyzing the implications of such a tax.

With CHP and absorption chilling incorporated in DER-CAM, further improvements in DER-CAM can enhance the accuracy of the model. Such improvements include improved modeling of DER at part-load, reliability of DER equipment, and thermal and electrical storage. *Appendix C: DER-CAM Enhancements* discusses useful improvements to DER-CAM.

The current DER-CAM version was tested on a µGrid demonstration system. This required the collection of cost and performance data on DER systems, predictions as to future DER and energy costs, and the collection and interpretation of load data. This information was used to run DER-CAM for several scenarios of varying energy prices and DER incentives.

One of the first observations is that if the µGrid installs DER, it significantly lowers its total energy costs over a do-nothing scenario. DER self-generation reduces the residual demand substantially, and avoids buying electricity from the disco in periods where the coincident charge is applicable.

The introduction of CHP equipment to the model increases the installed capacity, and saves further by lowering natural gas purchases. Recovered heat can be use to meet heating and cooling loads (although no absorption chillers were selected in these scenarios). Customers save close to 30% on their 2000 electricity bills by self-generating, and save as high as 40% when they use CHP.

Absorption chilling was not chosen in any of the scenarios. The optimal solution to cooling was to include enough electrical generation capacity to operate electric chillers, which are much more efficient than absorption chillers.

When PV systems are heavily subsidized (Case 4) they become attractive too. Interestingly, because PV power is only available in daylight hours, gas engines and micro turbines are typically installed as well. This yields the result that, when PV is selected as part of a customer's DER mix, the µGrid installs more generating capacity than its own peak demand, an outcome rare elsewhere. In this case therefore, the µGrid would be able to sell power, even at the time of its own peak demand, a capability that raises overall system reliability.

References

Akbari, H., L. Rainer, K. Heinemeir, J. Huang, and E. Franconi (1993). "Measured Commercial Load Shapes and Energy-Use Intensities and Validation of the LBL End-Use Disaggregation Algorithm." Lawrence Berkeley National Laboratory Report LBNL-32193, Berkeley, CA.

Bailey, O., Boubekeur Ouaglal, Emily Bartholomew, Chris Marnay, and Norman Bourassa (2002). "An Engineering-Economic Analysis of Combined Heat and Power Technologies in a μGrid Application." Lawrence Berkeley National Laboratory Report LBNL-50023, Berkeley, CA.

Brown, R. and Jonathan G. Koomey (2002). "Electricity Use in California: Past Trends and Present Usage Patterns." Lawrence Berkeley National Laboratory Report LBNL-47992, Berkeley, CA.

Edwards, J., Chris Marnay, Emily Bartholomew, Boubekeur Ouaglal, Afzal Siddiqui, and Kristina LaCommare (2002). "Assessment of Microgrid Distributed Energy Resource Potential Using DER-CAM and GIS." Lawrence Berkeley National Laboratory Report LBNL-50132, Berkeley, CA.

EPRI. (1997). "Renewable Energy Technology Characterizations." Department of Energy, Washington, DC.

E Source (1997). "Space Cooling Technology Atlas." Report TA-SC-97, Boulder CO.

Lasseter, R., A. Akhil, C. Marnay, J. Stevens, J. Dagle, R. Guttromson, A. S. Meliopoulos, R. Yinger, and J. Eto. 2002. "White Paper on Integration of Distributed Energy Resources: The CERTS MicroGrid Concept" Berkeley, CA: Lawrence Berkeley National Laboratory Report LBNL-50829.

Marnay, C., Joseph S. Chard, Kristina S. Hamachi, Timothy Lipman, Mithra M. Moezzi, Boubekeur Ouaglal, and Afzal S. Siddiqui (2001). "Modeling of Customer Adoption of Distributed Energy Resources." Lawrence Berkeley National Laboratory Report LBNL-47772, Berkeley, CA.

Marnay, C., Raquel Blanco, Kristina S. Hamachi, Cornelia P. Kawaan, Julie G. Osborn, and F. Javier Rubio (2000). "Integrated Assessment of Dispersed Energy Resources Deployment." Lawrence Berkeley National Laboratory Report LBNL-46082, Berkeley, CA.

Mossman, M. J., ed. (2000). "RSMeans Mechanical Cost Data 23rd Annual Edition. " RSMeans Company, Inc., Kingston, MA.

Rubio, F., Afzal S. Siddiqui, Chris Marnay, and Kristina Hamachi (2001). "CERTS Customer Adoption Model." Lawrence Berkeley National Laboratory Report LBNL-47772, Berkeley, CA.

SCE, S. C. E. 1989. "End Use Metered Data for Commercial Buildings." ADM for SCE, pp. 222.

Siddiqui, Afzal S., Anibal T. de Almeida, Chris Marnay, and F. Javier Rubio (2002). "The Implications of Carbon Taxation on μGrid Adoption of Small-Scale On-Site Power Generation Using a Multi-Criteria Approach." Lawrence Berkeley National Laboratory Report LBNL-49309, Berkeley, CA.

Wang, J.F., G.C. Gao, and G.M. Chen (2000). "An improved absorption refrigeration cycle driven by unsteady thermal sources below 100°C." *International Journal of Energy Research* (24):633-640.

Appendix A: DER-CAM Scenarios and Results

The various operating cases for distributed generation technologies and the results of the analysis for the μGrid are presented in the appendix. These results are discussed in Chapter 6 Results.

Scenarios

As discussed in Section 5.4.2, there are two different optimization problems that need to be solved depending on how the customer acquires the residual electricity needed in addition to the power that is generated:

- buying power from the disco (***tariff case***)
- purchasing power from IEM (***IEM/PX case***)

The costs for the first option are the fixed and variable regulated tariff rates associated with energy purchases and in the second option, the costs are the IEM prices in addition to utility distribution company non-commodity revenue adder. Both the tariff option and the IEM/PX option were run using DER-CAM for various cases (see Table 12).

Table 13: Cases for Purchasing Electricity

2000 Data	
Basic Analysis	PX do-nothing case, PX with and without CHP tariff do-nothing case, tariff with and without CHP
1999 Data	
Basic Analysis	PX do-nothing case, PX with and without CHP tariff do-nothing case, tariff with and without CHP
Technology Subsidy	Subsidy of 50% and 75% on photo-voltaic and fuel cell technologies both with and without CHP (PX and Tariff case) Subsidy of 25%, 50%, and 75% on fuel cell technology with CHP only (tariff case only) Subsidy of 50% on photo-voltaic technology and 10% for other technologies - Analysis done with and without CHP (PX and Tariff case)
Increase in Capital Costs	Increase of 50%, 100%, 200%, and 400% in capital costs, with CHP (tariff case only)

Cover and Sales	Allow generated power from DER technologies, to be sold in the wholesale market, with and without CHP (PX case only)
2010 Data	
Basic Analysis	PX without CHP

The scenarios for which results are presented are:

Table 14. Energy Balance Results - 1999 and 2000 Basic Analysis

- *Tariff Do-Nothing*: µGrid installs no DER and purchases electricity from the utility.
- *IEM(PX) Do-Nothing*: µGrid installs no DER and purchases electricity from the IEM(2000) or PX (1999).
- *Tariff Install with CHP*: µGrid can install DER including CHP and purchases electricity from the utility.
- *IEM(PX) Install with CHP*: µGrid can install DER including CHP and purchases electricity from the IEM(2000) or PX (1999).
- *Tariff Install no CHP*: µGrid can install DER excluding CHP and purchases electricity from the utility.
- *IEM(PX) Install no CHP*: µGrid can install DER excluding CHP and purchases electricity from the IEM(2000) or PX (1999).

Table 15. Energy Balance Results - 1999 Data - Subsidies on PV and FC technologies

- *FC Only Subsidy*: The capital costs of FC's a subsidized by 25%, 50%, and 75%, while all other costs are the same as in the Basic Analysis. For these scenarios, the µGrid can install DER including CHP and purchases electricity from the utility.
- *CEC Subsidy*: The capital costs of PV are subsidized 50% and other DER equipment is subsidized 10%. Separate scenarios consider DER purchase including and excluding CHP, and purchasing electricity from the utility and from the PX.

Table 16. Energy Balance Results - 1999 Data - Sensitivity Analysis on Capital Costs for DER Technologies

- *Capital Cost Increase*: Capital costs of all DER are increased 50%, 100%, 200% and 400%. For these scenarios, the µGrid can install DER including CHP and purchases electricity from the utility.

Table 17. Energy Balance Result: Sales Case

- *Cover & Sales*: the µGrid is allowed to sell excess electrical generation back to the macrogrid. The µGrid can install DER excluding CHP in one scenario and including CHP in the other scenario. In both, µGrid purchases electricity from the PX.

Table 18. Energy Balance Result: 2010 DER Technology Data

- *NDC*: DER technology options and costs are those predicted for 2010. For this scenario, the µGrid can install DER excluding CHP and purchases electricity from the utility.

For each case, the following results are obtained:

Energy Balance Results

- capacity installation (kW)
- DER technology equipment installed
- total electricity requirement (MWh)
- absorption cooling electricity reduction (MWh)
- electricity – self-generation (MWh)
- electricity sales (*if any*) (MWh)
- gas requirements (MWh)
- CHP gas reduction (MWh)
- gas consumed by power generation (MWh)
- net gas purchases (MWh)

Financial Results

- net investment costs (K$)

- electricity bill for electricity purchases (K$)
- annual electricity sales (*if any*) (K$)
- annual gas bill for DER (K$)
- annual gas bill for direct endues (K$)
- variable operating and maintenance Costs (K$)
- total annual energy bill (K$)

The following naming conventions are used for DER generation technologies:

The first term is the type of technology:

- No prefix: a unit without recovered heat
- CHP: a unit with recoverable heat.
- COOL: a unit with recoverable heat and absorption chilling capabilities
- BOW: Bowman microturbine
- DE: diesel engine
- GA: natural gas engine
- MTL: Capstone low-pressure microturbine
- MTH: Capstone high-pressure microturbine
- PEM: proton exchange membrane fuel cell
- PAFC: phosphoric acid fuel cell
- PV: photovoltaics
- SOFC: solid oxide fuel cell

The energy balance results for the scenarios in Table 12 are displayed in Table 14 through Table 18, and the financial results are shown
Table 19 and Table 20.

Table 14. Energy Balance Results - 1999 and 2000 Basic Analysis

		A	B	BA**	C	D	E	F	FA**	G	H	I	J	K	KA	L	M	N	O
		cases	Capacity Installations (kW)	Equipment	electricity requirement (MWh)	absorption cooling electricity reduction (MWh)	net electricity consumed = C - D (MWh)	electricity self-generation (MWh)	electricity sales (MWh)	electricity purchases (MWh)	net electricity supplied = F + G* (MWh)	heat requirement (MWh)	CHP heat reduction (MWh)	net heat consumed by enduses = I - J (MWh)	natural gas directly consumed by enduses (MWh)	natural gas consumed by power generation (MWh	total natural gas purchases (MWh)	other fuel consumed by power generation (MWh)	annual other fuel purchases (MWh)
2000	Basic Analysis	Tariff Do-Nothing			4,754.702					4,754.702		4,731.200					5,914.000		
2000	Basic Analysis	IEM Do-Nothing			4,754.702					4,754.702		4,731.200					5,914.000		
2000	Basic Analysis	Tariff Install with CHP	780.000	3Us GA-K-55 & 1U CHPGA-K-500 & 2Us CHPMTL-C-30 & 1U CHPGA-K-55	4,754.702	0.000	4,754.702	4,549.942		204.761	4,754.702	4,731.200	3,433.546	1,297.654	1,622.067	15,237.451	16,859.518	0.000	0.000
2000	Basic Analysis	IEM Install with CHP	780.000	3Us GA-K-55 & 1U CHPGA-K-500 & 2Us CHPMTL-C-30 & 1U CHPGA-K-55	4,754.702	0.000	4,754.702	4551.746		202.956	4,754.702	4,731.200	3,475.686	1,255.514	1,569.392	15,244.194	16,813.586	0.000	0.000
2000	Basic Analysis	Tariff Install no CHP	775.000	5Us GA-K-55 & 1U GA-K-500	4,754.702			4,219.642		535.060	4,754.702	4,731.200		4,731.200	5,914.000	14,133.172	20,171.329	0.000	0.000
2000	Basic Analysis	IEM Install no CHP	775.000	5Us GA-K-55 & 1U GA-K-500	4,754.702			3,970.763		783.940	4,754.702	4,731.200		4,731.200	5,914.000	13,303.774	19,217.774	0.000	0.000
1999	Basic Analysis	Tariff Do-Nothing			4,754.702					4,754.702		4,731.200					5,914.000		
1999	Basic Analysis	PX Do-Nothing			4,754.702					4,754.702		4,731.200					5,914.000		
1999	Basic Analysis	Tariff Install with CHP	775.000	2Us GA-K-55 & 3Us CHPGA-K-55 & 1U CHPGA-K-500	4,754.702	0.000	4,754.702	4,718.809		35.894	4,754.702	4,731.200	3,120.242	1,610.958	2,013.698	15,804.893	17,818.591	0.000	0.000
1999	Basic Analysis	PX Install with CHP	720.000	1U GA-K-55 & 3Us CHPGA-K-55 & 1U CHPGA-K-500	4,754.702	0.000	4,754.702	4,649.510		105.192	4,754.702	4,731.200	3,120.242	1,610.958	2,013.698	15,568.180	17,581.878	0.000	0.000
1999	Basic Analysis	Tariff Install no CHP	775.000	5Us GA-K-55 & 1U GA-K-500	4,754.702			4,595.329		159.374	4,754.702	4,731.200		4,731.200	5,914.000	15,392.364	21,306.364	0.000	0.000
1999	Basic Analysis	PX Install no CHP	720.000	4Us GA-K-55 & 1U GA-K-500	4,754.702			4,649.510		105.192	4,754.702	4,731.200		4,731.200	5,914.000	15,568.180	21,482.180	0.000	0.000

Table 15. Energy Balance Results - 1999 Data - Subsidies on PV and FC technologies

		A	B	BA**	C	D	E	F	FA**	G	H	I	J	K	KA	L	M	N	O
		cases	Capacity Installations (kW)	Equipment	electricity requirement (MWh)	absorption cooling electricity reduction (MWh)	net electricity consumed = C - D (MWh)	electricity self-generation (MWh)	electricity sales (MWh)	electricity purchases (MWh)	net electricity supplied = F + G* (MWh)	heat requirement (MWh)	CHP heat reduction (MWh)	net heat consumed by enduses = I - J (MWh)	natural gas directly consumed by enduses (MWh)	natural gas consumed by power generation (MWh)	total natural gas purchases (MWh)	other fuel consumed by power generation (MWh)	annual other fuel purchases (MWh)
1999	FC Only Subsidy	Tariff Install with CHP Subsidy of 25% of FC (only FC part)	775.000	1U CHPGA-K-500 & 3Us CHPGA-K-55 & 2Us GA-K-55	4,754.702	0.000	4,754.702	4,718.809		35.894	4,754.702	4,731.200	3,120.242	1,610.958	2,013.698	15,804.893	17,818.591	0.000	0.000
		Tariff Install with CHP Subsidy of 50% of FC (only FC part)	775.000	1U CHPGA-K-500 & 3Us CHPGA-K-55 & 2Us GA-K-55	4,754.702	0.000	4,754.702	4718.809		35.894	4,754.702	4,731.200	3,120.242	1,610.958	2,013.698	15,804.893	17,818.591	0.000	0.000
		Tariff Install with CHP Subsidy of 75% of FC (only FC part)	775.000	1U CHPGA-K-500 & 3Us CHPGA-K-55 & 2Us GA-K-55	4,754.702	0.000	4,754.702	4,718.809		35.894	4,754.702	4,731.200	3,120.242	1,610.958	2,013.698	15,804.893	17,818.591	0.000	0.000
	CEC Subsidy	Tariff Install with CHP Subsidy of 50% of PV and rest with 10%	805.000	1U CHPGA-K-500 & 3Us CHPGA-K-55 & 2Us GA-K-55 & 1U CHPMTL-C-30	4,754.702	0.000	4,754.702	4,735.137		19.565	4,754.702	4,731.200	3,349.093	1,382.107	1,727.634	15,859.799	17,587.433	0.000	0.000
		Tariff Install no CHP Subsidy of 50% of PV and rest with 10%	775.000	5Us GA-K-55 & 1U GA-K-500	4,754.702			4,595.329		159.374	4,754.702	4,731.200		4,731.200	5,914.000	15,392.364	21,306.364	0.000	0.000
		PX Install no CHP Subsidy of 50% of PV and rest with 10%	720.000	4Us GA-K-55 & 1U GA-K-500	4,754.702			4,649.510		105.192	4,754.702	4,731.200		4,731.200	5,914.000	15,568.180	21,482.180	0.000	0.000
		PX Install with CHP Subsidy of 50% of PV and rest with 10%	750.000	1U CHPGA-K-500 & 2Us CHPGA-K-55 & 2Us GA-K-55 & 1U CHPMTL-C-30	4,754.702	0.000	4,754.702	4,693.810		60.893	4,754.702	4,731.200	3,349.093	1,382.107	1,727.634	15,718.632	17,446.266	0.000	0.000

Table 16. Energy Balance Results - 1999 Data - Sensitivity Analysis on Capital Costs for DER Technologies

		A	B	BA**	C	D	E	F	FA**	G	H	I	J	K	KA	L	M	N	O
		cases	Capacity Installations (kW)	Equipment	electricity requirement (MWh)	absorption cooling electricity reduction (MWh)	net electricity consumed = C - D (MWh)	electricity self-generation (MWh)	electricity sales (MWh)	electricity purchases (MWh)	net electricity supplied = F + G* (MWh)	heat requirement (MWh)	CHP heat reduction (MWh)	net heat consumed by enduses = I - J (MWh)	natural gas directly consumed by enduses (MWh)	natural gas consumed by power generation (MWh)	total natural gas purchases (MWh)	other fuel consumed by power generation (MWh)	annual other fuel purchases (MWh)
1999	Capital Cost Increase	Tariff Install with CHP and 50% Increase in capital costs	775.000	1U CHPGA-K-500 & 3Us CHPGA-K-55 & 2Us GA-K-55	4,754.702	0.000	4,754.702	4,718.809		35.894	4,754.702	4,731.200	3,120.242	1,610.958	2,013.698	15,804.893	17,818.591	0.000	0.000
1999	Capital Cost Increase	Tariff Install with CHP and 100% Increase in capital costs	765.000	1U CHPGA-K-500 & 2Us CHPGA-K-55 & 1U GA-K-55 & 1U GA-K-100	4,754.702	0.000	4,754.702	4,700.889		53.814	4,754.702	4,731.200	3,040.549	1,690.651	2,113.314	15,879.684	17,992.998	0.000	0.000
1999	Capital Cost Increase	Tariff Install with CHP and 200% Increase in capital costs	665.000	1U CHPGA-K-500 & 3Us GA-K-55	4,754.702	0.000	4,754.702	4,483.118		271.585	4,754.702	4,731.200	2,788.599	1,942.601	2,428.252	15,001.252	17,429.504	0.000	0.000
1999	Capital Cost Increase	Tariff Install with CHP and 400% Increase in capital costs	0.000	None	4,754.702	0.000	4,754.702	0.000		4,754.702	4,754.702	4,731.200	0.000	4,731.200	5,914.000	0.000	5,914.000	0.000	0.000

Table 17. Energy Balance Result: Sales Case

		A	B	BA**	C	D	E	F	FA**	G	H	I	J	K	KA	L	M	N	O
		cases	Capacity Installations (kW)	Equipment	electricity requirement (MWh)	absorption cooling electricity reduction (MWh)	net electricity consumed = C - D (MWh)	electricity self-generation (MWh)	electricity sales (MWh)	electricity purchases (MWh)	net electricity supplied = F + G* (MWh)	heat requirement (MWh)	CHP heat reduction (MWh)	net heat consumed by enduses = I - J (MWh)	natural gas directly consumed by enduses (MWh)	natural gas consumed by power generation (MWh)	total natural gas purchases (MWh)	other fuel consumed by power generation (MWh)	annual other fuel purchases (MWh)
1999	Cover & Sales	PX Install no CHP	720.000	4Us GA-K-55 & 1U GA-K-500	4,754.702	0.000	4,754.702	4,649.510	4.621	105.192	4,754.702	4,731.200		4,731.200	5,914.000	15,583.966	21,497.966	0.000	0.000
1999	Cover & Sales	PX Install with CHP	695.000	1U CHPGA-K-500 & 2Us CHPGA-K-55 & 1U CHPMTL-C-30 & 1U GA-K-55	4,754.702	0.000	4,754.702	4,603.960	2.072	150.743	4,754.702	4,731.200	3,349.093	1,382.107	1,727.634	15,418.795	17,146.429	0.000	0.000

Table 18. Energy Balance Result: 2010 DER Technology Data

		A	B	BA**	C	D	E	F	FA**	G	H	I	J	K	KA	L	M	N	O
		cases	Capacity Installations (kW)	Equipment	electricity requirement (MWh)	absorption cooling electricity reduction (MWh)	net electricity consumed = C - D (MWh)	electricity self-generation (MWh)	electricity sales (MWh)	electricity purchases (MWh)	net electricity supplied = F + G* (MWh)	heat requirement (MWh)	CHP heat reduction (MWh)	net heat consumed by enduses = I - J (MWh)	natural gas directly consumed by enduses (MWh)	natural gas consumed by power generation (MWh)	total natural gas purchases (MWh)	other fuel consumed by power generation (MWh)	annual other fuel purchases (MWh)
2010	NDC	DER 2010 data Tariff Install no CHP	750.000	3Us PEM-BA-250	4,754.702			4,693.810		60.893	4,754.702	4,731.200		4,731.200	5,914.000	11,935.316	17,849.316	0.000	0.000

Table 19. Financial Results

		cases	investment costs (k$)***	annual electricity bill for electricity purchase (k$)	electricity sales (k$)****	annual total gas bill for DER (k$)	annual total gas bill for direct enduse (k$)	direct-fired absorption chiller investment (k$)	annual other fuel bill (k$)	total annual energy bill (k$)	bill savings over do-nothing case (%)
2000	Basic Analysis	Tariff Do-Nothing	0.000	684.181		0.000	142.725	0.000		826.906	
		IEM Do-Nothing	0.000	684.181		0.000	142.725	0.000		826.906	
		Tariff Install with CHP	100.100	27.777		351.098	42.898	0.000	0.000	521.872	**-36.889**
		IEM Install with CHP	100.100	16.754		362.879	39.022	0.000	0.000	518.755	**-37.266**
		Tariff Install no CHP	77.381	66.032		306.814	142.725	0.000	0.000	592.952	**-28.293**
		IEM Install no CHP	77.381	53.867		321.052	142.725	0.000	0.000	595.025	**-28.042**
1999	Basic Analysis	Tariff Do-Nothing	0.000	501.380		0.000	99.540	0.000		600.920	
		PX Do-Nothing	0.000	501.380		0.000	99.540	0.000		600.920	
		Tariff Install with CHP	90.036	9.588		261.815	34.749	0.000	0.000	396.188	**-34.070**
		PX Install with CHP	83.865	13.506		258.085	34.749	0.000	0.000	390.206	**-35.065**
		Tariff Install no CHP	77.381	17.583		253.554	99.540	0.000	0.000	448.057	**-25.438**
		PX Install no CHP	71.209	13.506		258.085	99.540	0.000	0.000	442.341	**-26.389**
	FC and PV Subsidies	PX Install without CHP Subsidy of 50% for PV, FC	71.209	13.506		258.085	99.540	0.000	0.000	442.341	**-26.389**
		PX Install with CHP Subsidy of 50% for PV, FC	83.865	13.506		258.085	34.749	0.000	0.000	390.206	**-35.065**
		PX Install with CHP Subsidy of 75% for PV, FC	115.056	17.108		214.225	37.608	0.000	0.000	383.997	**-36.098**
		PX Install without CHP Subsidy of 75% for PV, FC	142.654	26.694		159.493	99.540	0.000	0.000	428.381	**-28.712**
		Tariff Install without CHP Subsidy of 50% for PV, FC	77.381	17.583		253.554	99.540	0.000	0.000	448.057	**-25.438**
		Tariff Install with CHP Subsidy of 50% for PV, FC	119.782	5.789		229.008	35.042	0.000	0.000	389.621	**-35.163**
		Tariff Install with CHP Subsidy of 75% for PV, FC	119.782	5.789		229.008	35.042	0.000	0.000	389.621	**-35.163**
		Tariff Install without CHP Subsidy of 75% for PV, FC	134.915	15.139		186.711	99.540	0.000	0.000	436.305	**-27.394**

Table 20. Financial Results (contd.)

		cases	investment costs (k$)***	annual electricity bill for electricity purchase (k$	electricity sales (k$)****	annual total gas bill for DER (k$)	annual total gas bill for direct enduse (k$)	direct-fired absorption chiller investment (k$)	annual other fuel bill (k$)	total annual energy bill (k$)	bill savings over do-nothing case (%)
1999	Cover & Sales	PX Install no CHP	71.209	13.506	-0.291	258.351	99.540	0.000	0.000	442.315	**-26.394**
1999	Cover & Sales	PX Install with CHP	85.811	18.910	-0.128	255.717	29.929	0.000	0.000	390.238	**-35.060**
1999	FC Only Subsidy	Tariff Install with CHP Subsidy of 25% of FC (only FC part)	90.036	9.588		261.815	34.749	0.000	0.000	396.188	**-34.070**
1999	FC Only Subsidy	Tariff Install with CHP Subsidy of 50% of FC (only FC part)	90.036	9.588		261.815	34.749	0.000	0.000	396.188	**-34.070**
1999	FC Only Subsidy	Tariff Install with CHP Subsidy of 75% of FC (only FC part)	90.036	9.588		261.815	34.749	0.000	0.000	396.188	**-34.070**
1999	CEC Subsidy	Tariff Install with CHP Subsidy of 50% of PV and rest with 10%	90.749	5.755		262.686	29.929	0.000	0.000	389.119	**-35.246**
1999	CEC Subsidy	Tariff Install no CHP Subsidy of 50% of PV and rest with 10%	71.696	17.583		253.554	99.540	0.000	0.000	442.373	**-26.384**
1999	CEC Subsidy	PX Install no CHP Subsidy of 50% of PV and rest with 10%	65.997	13.506		258.085	99.540	0.000	0.000	437.128	**-27.257**
1999	CEC Subsidy	PX Install with CHP Subsidy of 50% of PV and rest with 10%	85.049	8.134		260.446	29.929	0.000	0.000	383.557	**-36.172**
1999	Capital Cost Increase	Tariff Install with CHP and 50% Increase in capital costs	124.786	9.588		261.815	34.749	0.000	0.000	430.937	**-28.287**
1999	Capital Cost Increase	Tariff Install with CHP and 100% Increase in capital costs	152.749	12.024		263.002	36.392	0.000	0.000	464.167	**-22.757**
1999	Capital Cost Increase	Tariff Install with CHP and 200% Increase in capital costs	188.228	45.329		248.772	41.627	0.000	0.000	523.956	**-12.808**
1999	Capital Cost Increase	Tariff Install with CHP and 400% Increase in capital costs	0.000	501.380		0.000	99.540	0.000	0.000	600.920	**0.000**
2010	NDC	DER 2010 data Tariff Install no CHP	78.997	14.683		207.044	99.540	0.000	0.000	400.262	**-33.392**

Appendix B: Load, Generation, and Price Results for Specific Cases

CASE 1: 1999 Tariff *Do Nothing* Case

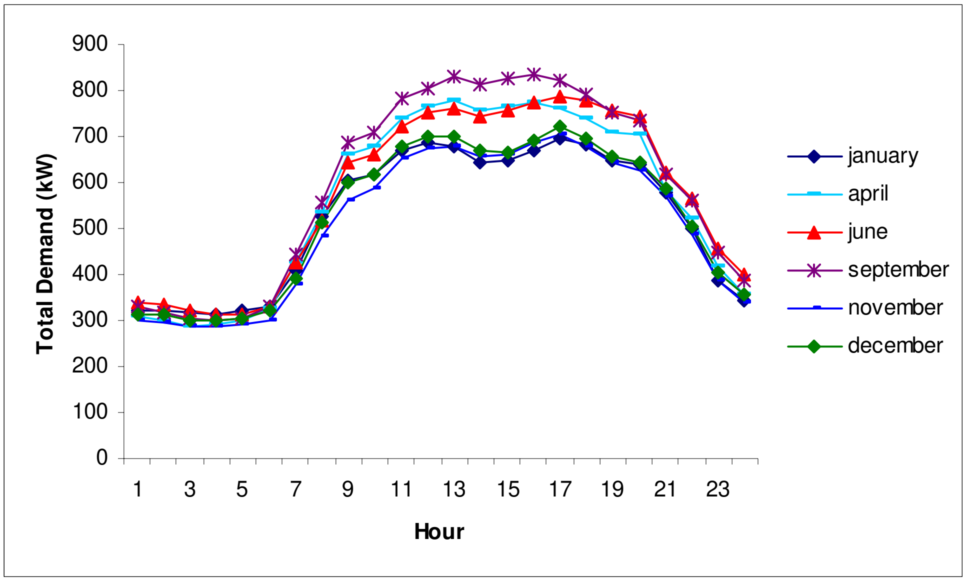


Figure 45. Electricity-Only and Cooling Demand (Week)

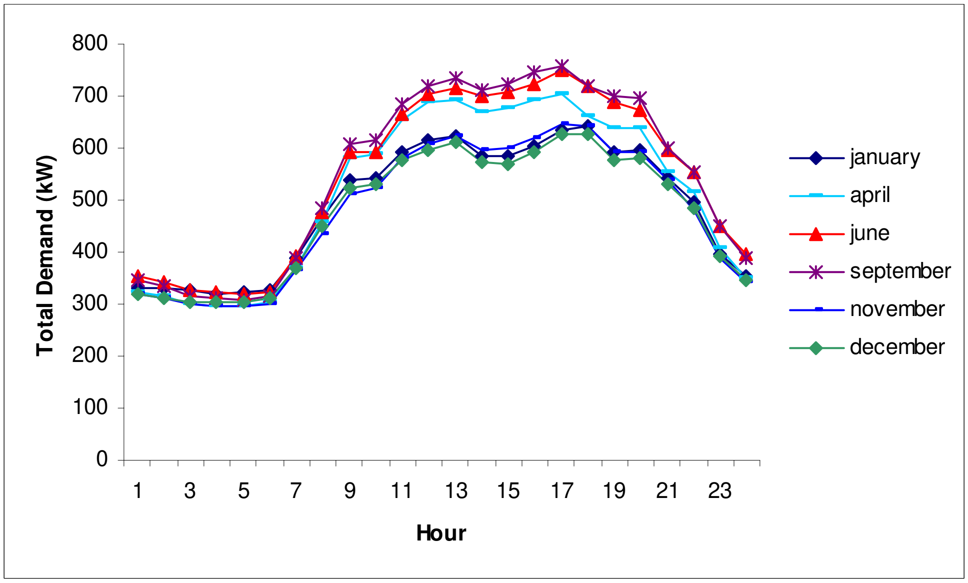


Figure 46. Electricity-Only and Cooling Demand (Weekend)

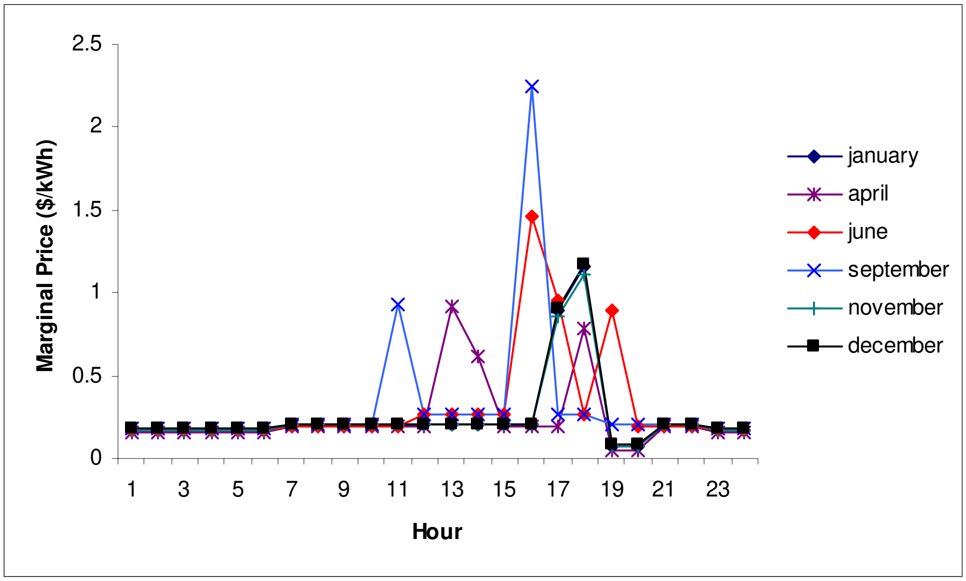


Figure 47. Marginal Price (Week)

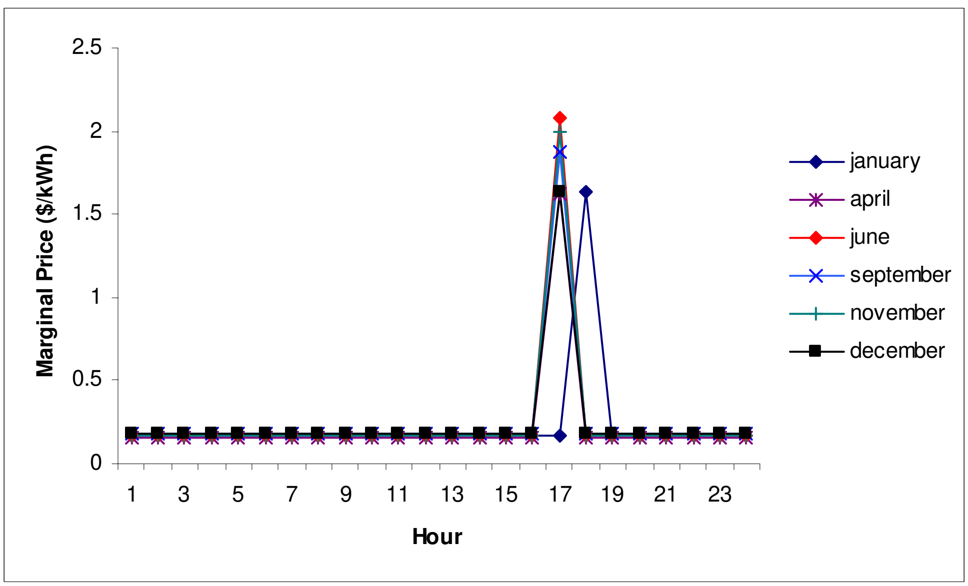


Figure 48. Marginal Price (Weekend)

CASE 2: 1999 Tariff Case without CHP

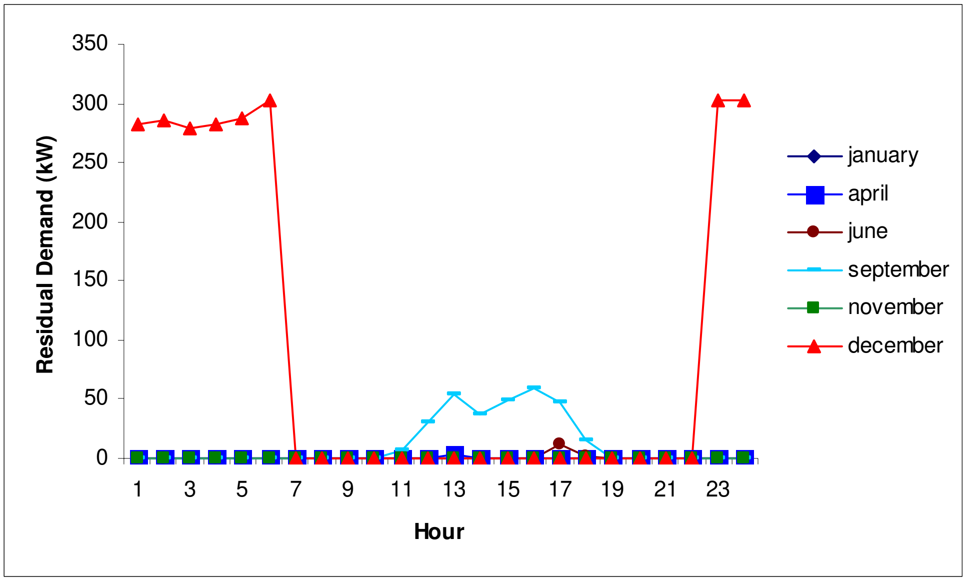


Figure 49. Electricity-Only and Cooling Residual Demand (Week)

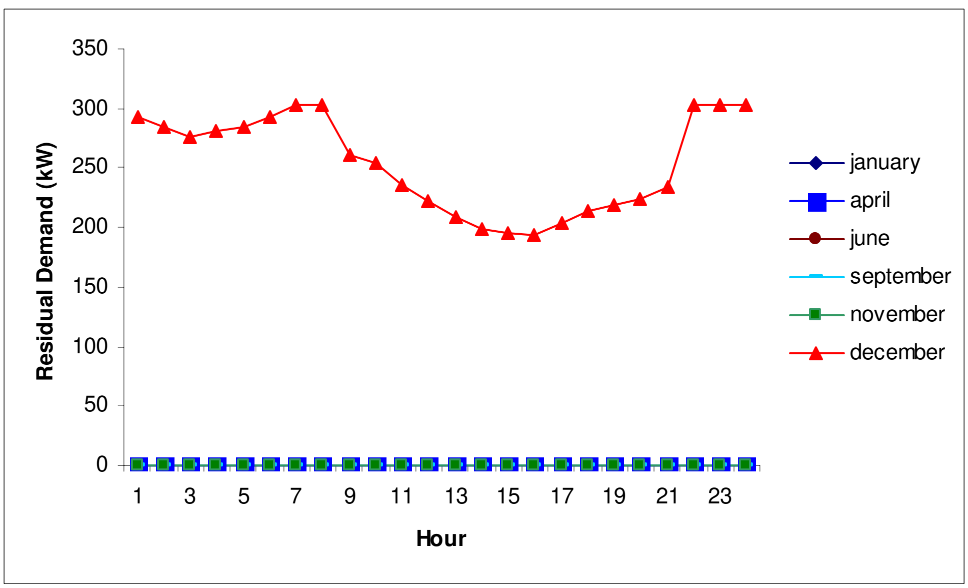


Figure 50: Electricity-Only and Cooling Residual Demand (Weekend)

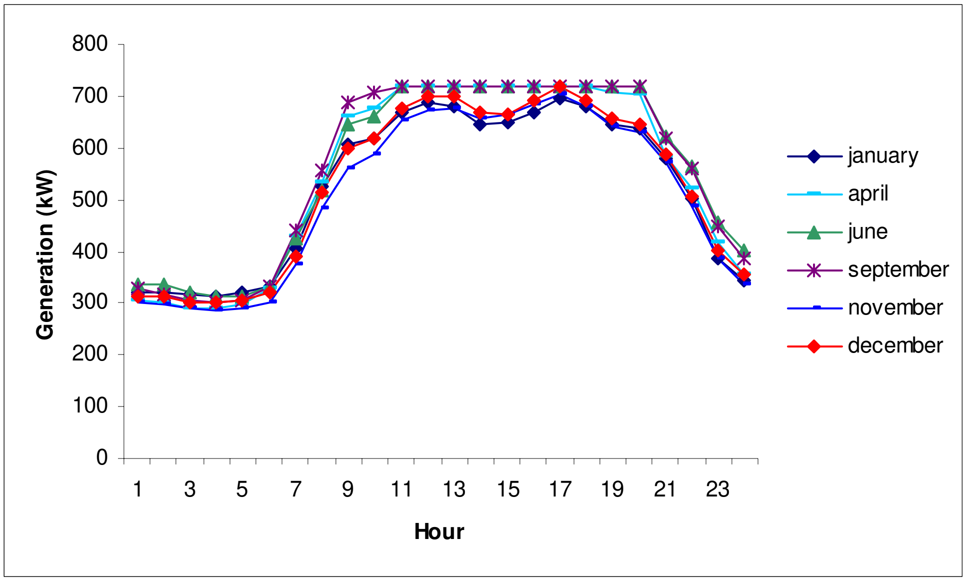


Figure 51. Electricity Generation Output for Self-Use (Week)

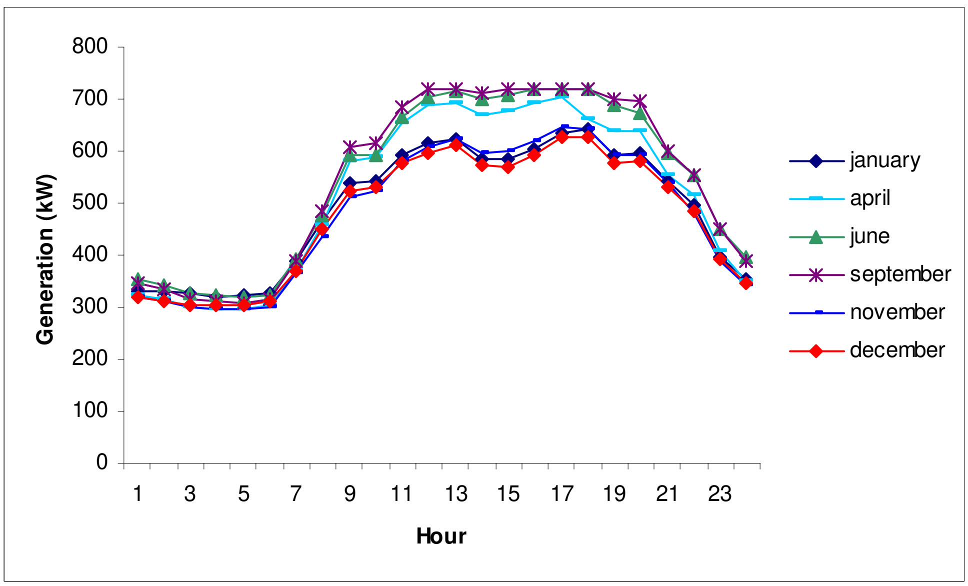


Figure 52. Electricity Generation Output for Self-Use (Weekend)

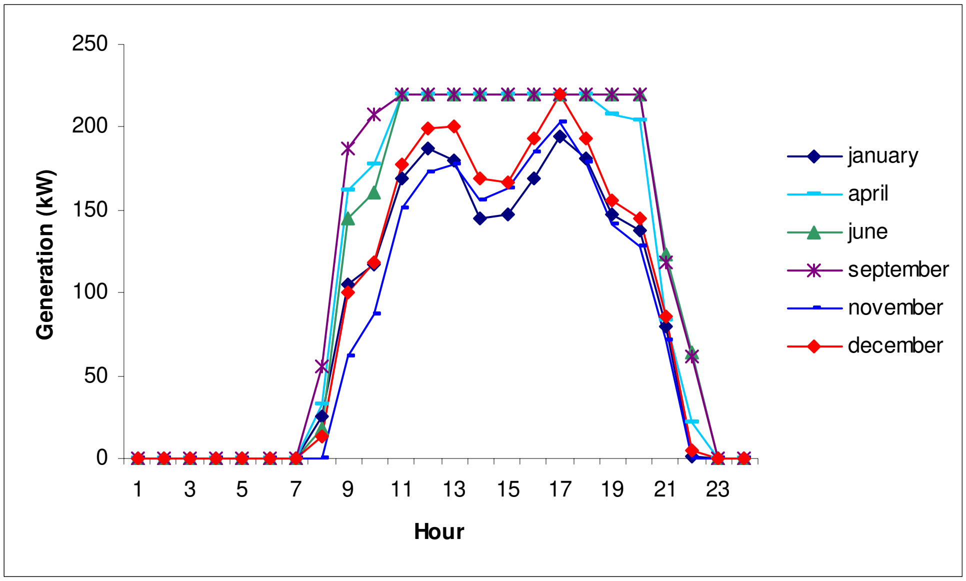


Figure 53. Electricity Generation Output from GA-K-55 (Week)

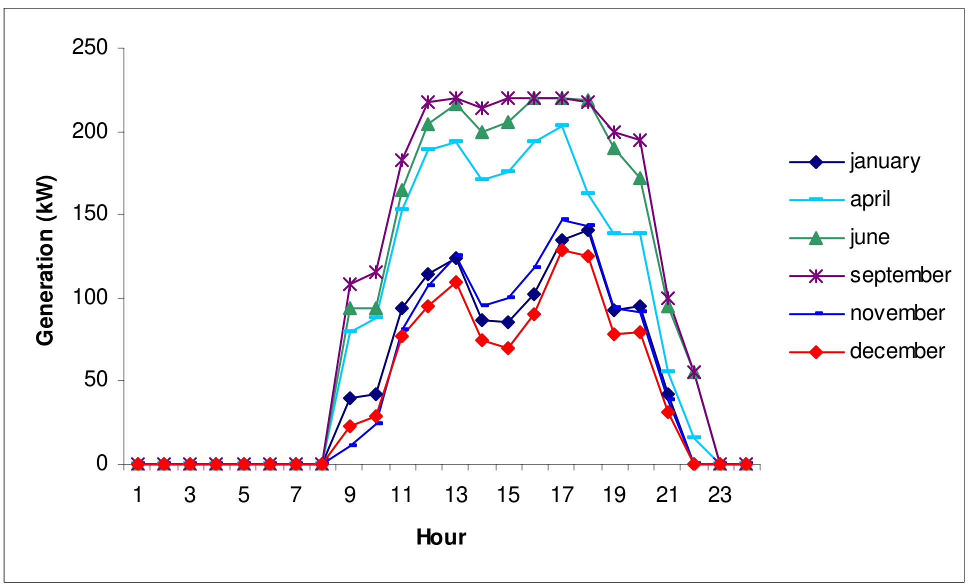


Figure 54. Electricity Generation Output from GA-K-55 (Weekend)

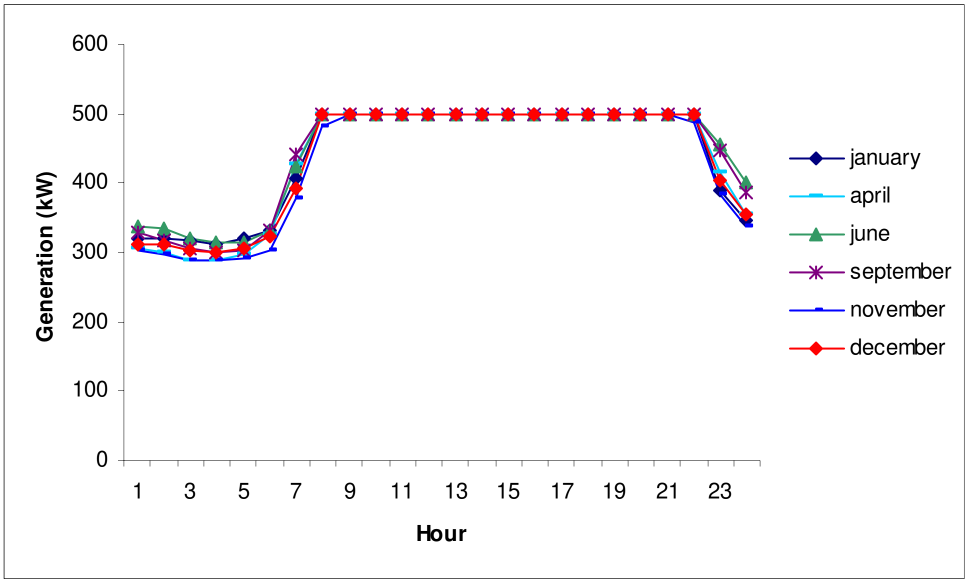


Figure 55. Electricity Generation Output from GA-K-500 (Week)

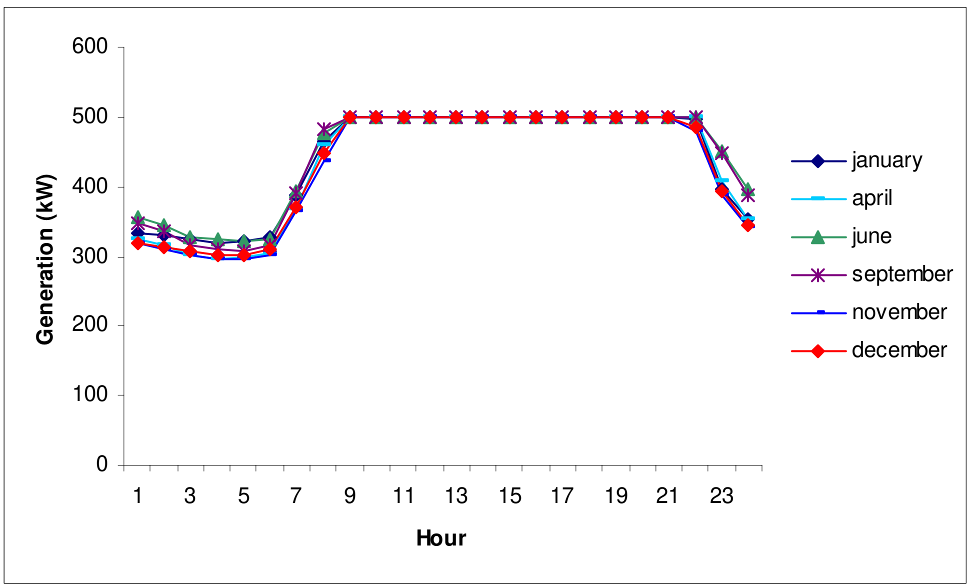


Figure 56. Electricity Generation Output from GA-K-500 (Weekend)

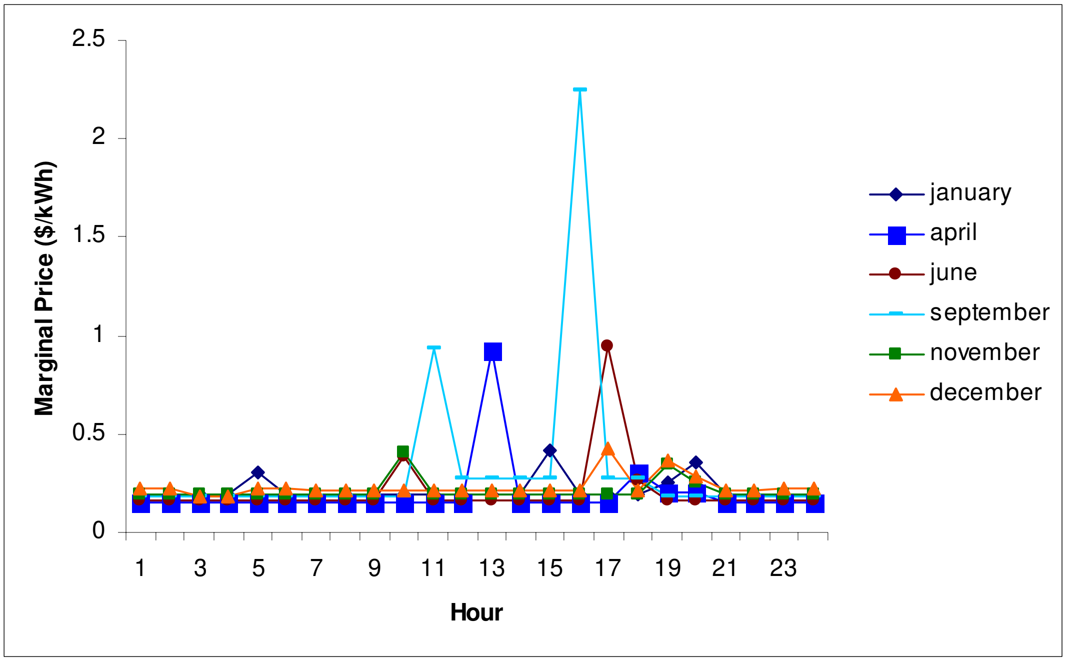


Figure 57. Marginal Price (Week)

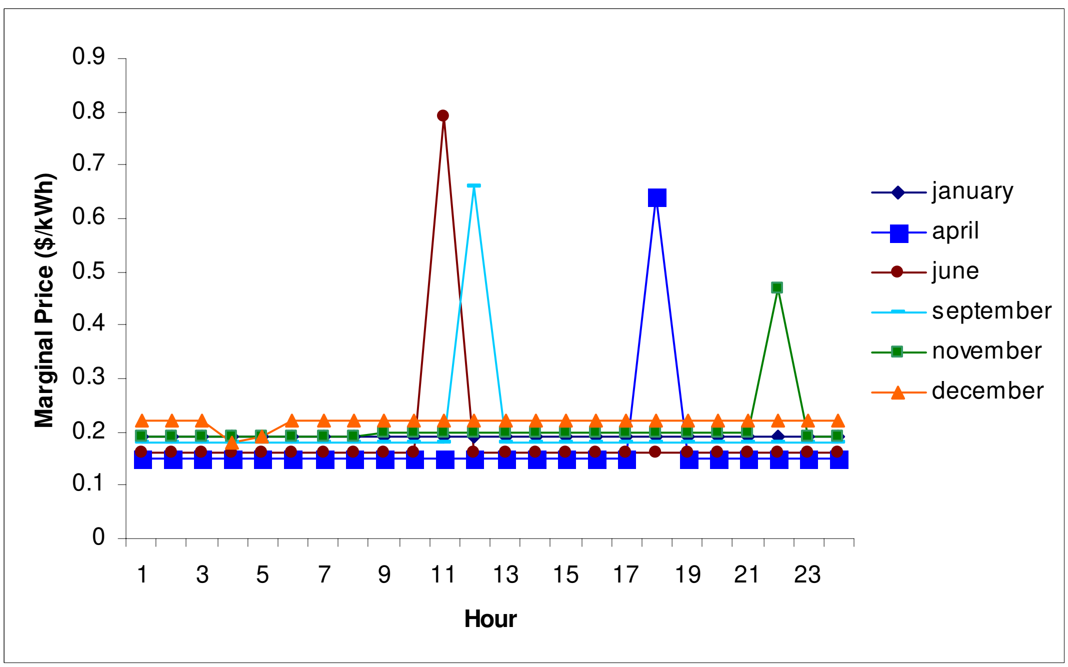


Figure 58. Marginal Price (Weekend)

CASE 3: 1999 Tariff Case with CHP

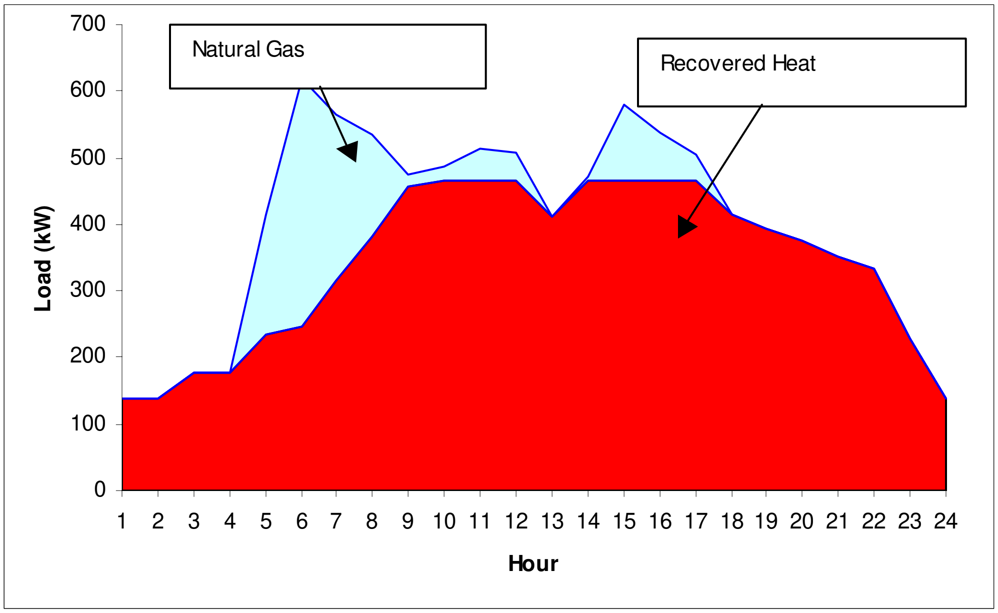


Figure 59. Water-Heating Load Met by Natural Gas and Recovered Heat (June Weekday)

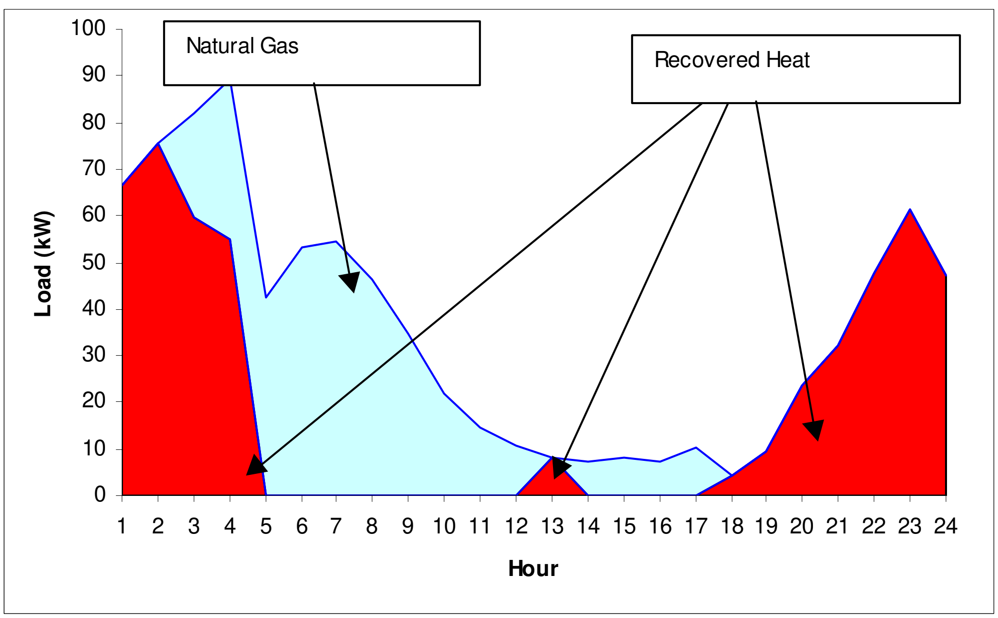


Figure 60. Space-Heating Load Met by Natural Gas and Recovered Heat (June Weekday)

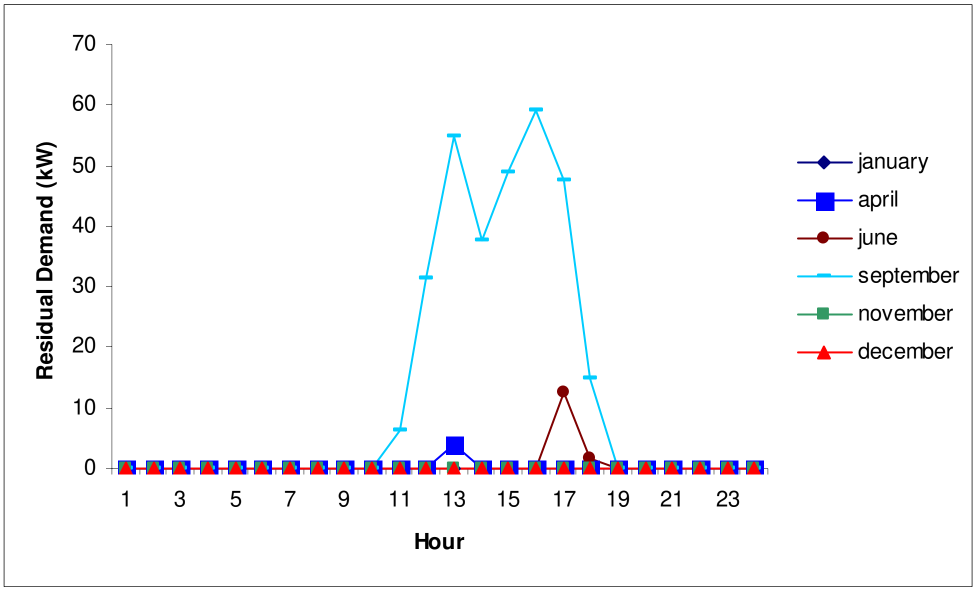


Figure 61. Electricity-Only and Cooling Residual Demand (Week)

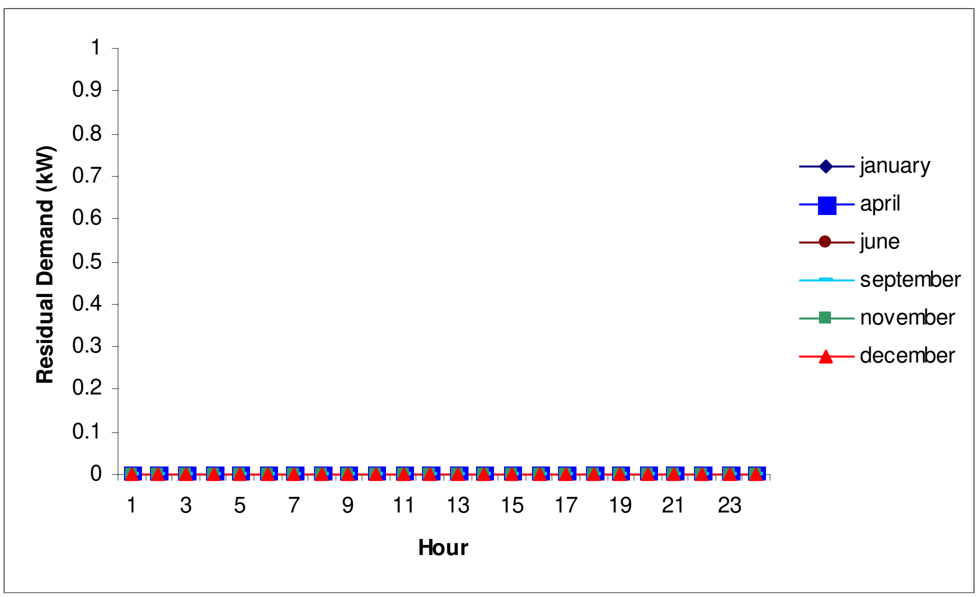


Figure 62. Electricity-Only and Cooling Residual Demand (Weekend)

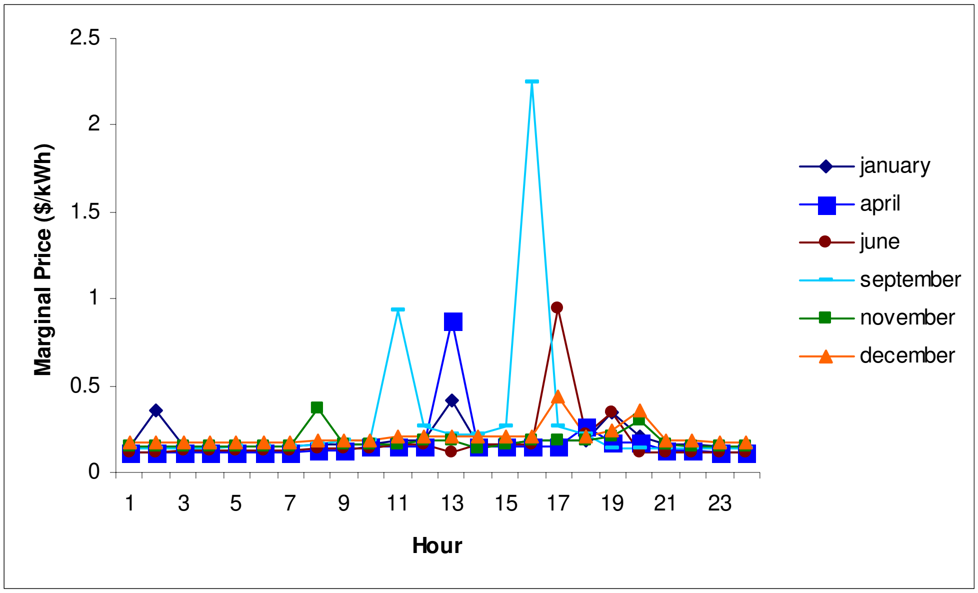


Figure 63. Marginal Price (Week)

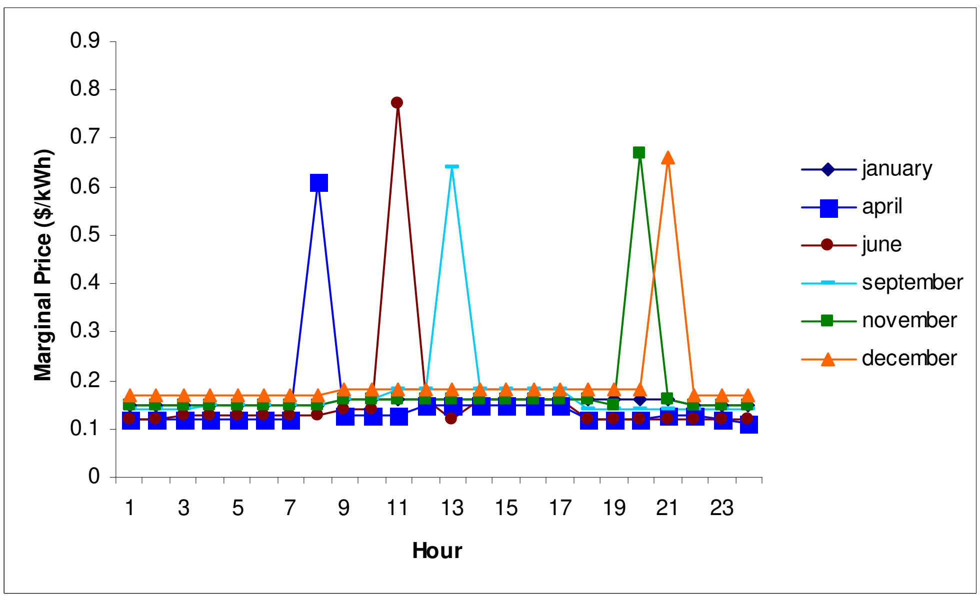


Figure 64. Marginal Price (Weekend)

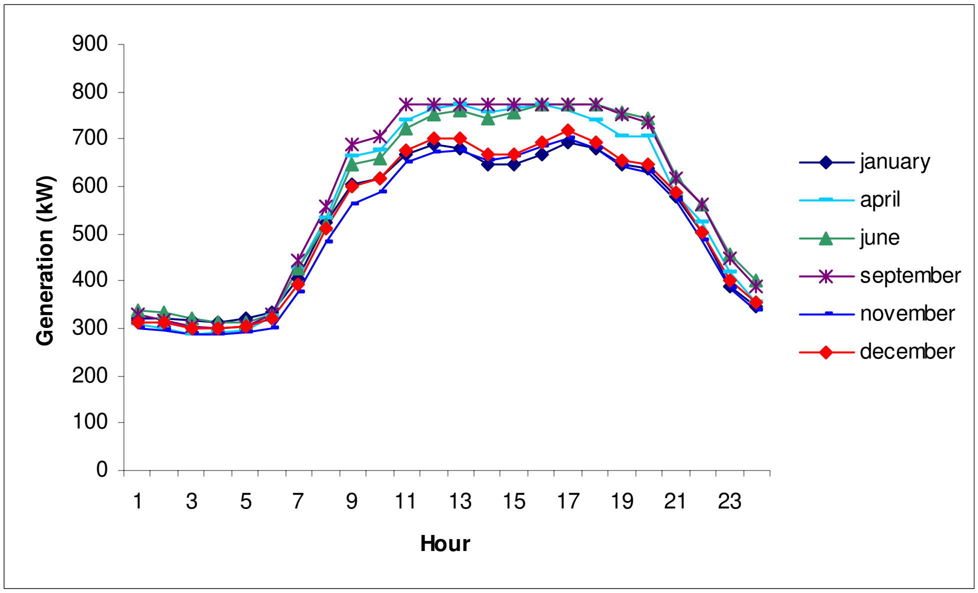


Figure 65. Electricity Generation Output for Self-Use (Week)

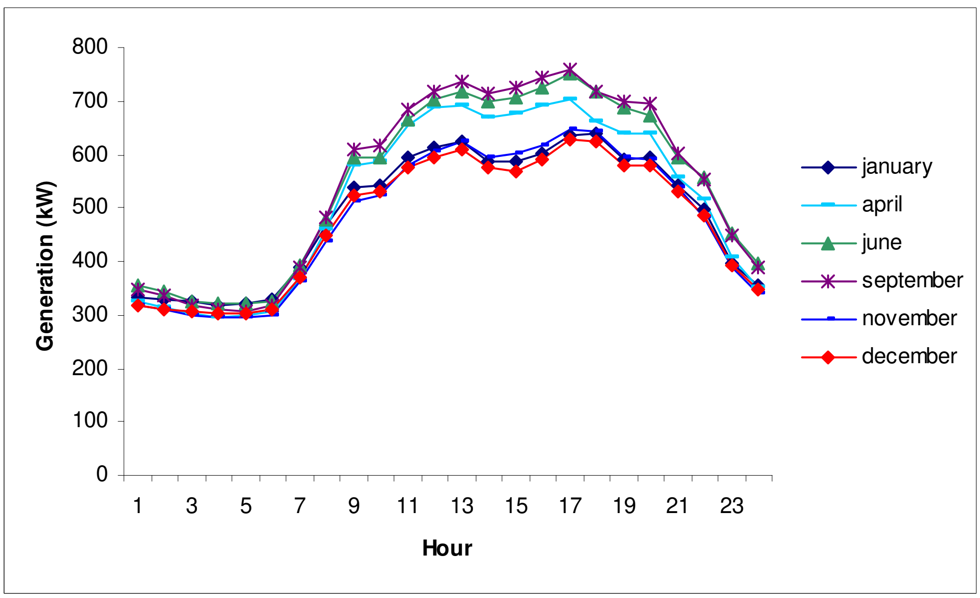


Figure 66. Electricity Generation Output for Self-Use (Weekend)

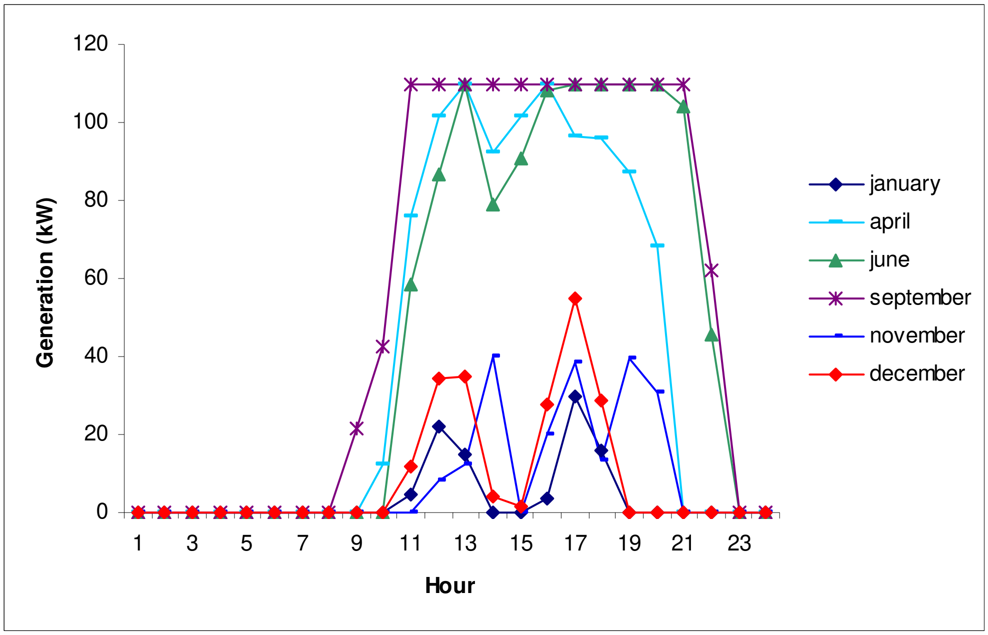


Figure 67. Electricity Generation Output from GA-K-55 (Week)

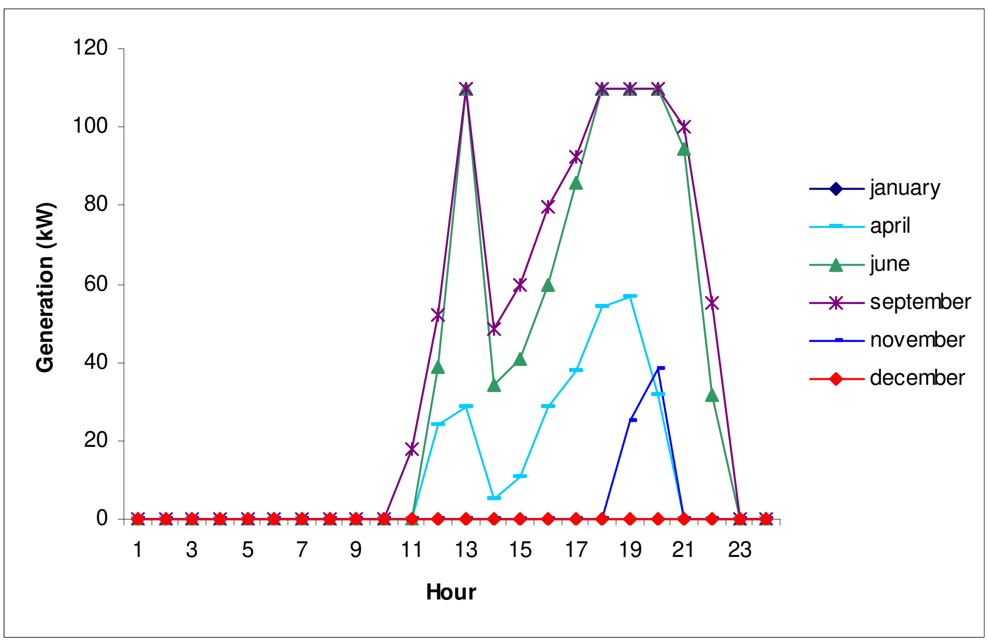


Figure 68. Electricity Generation Output from GA-K-55 (Weekend)

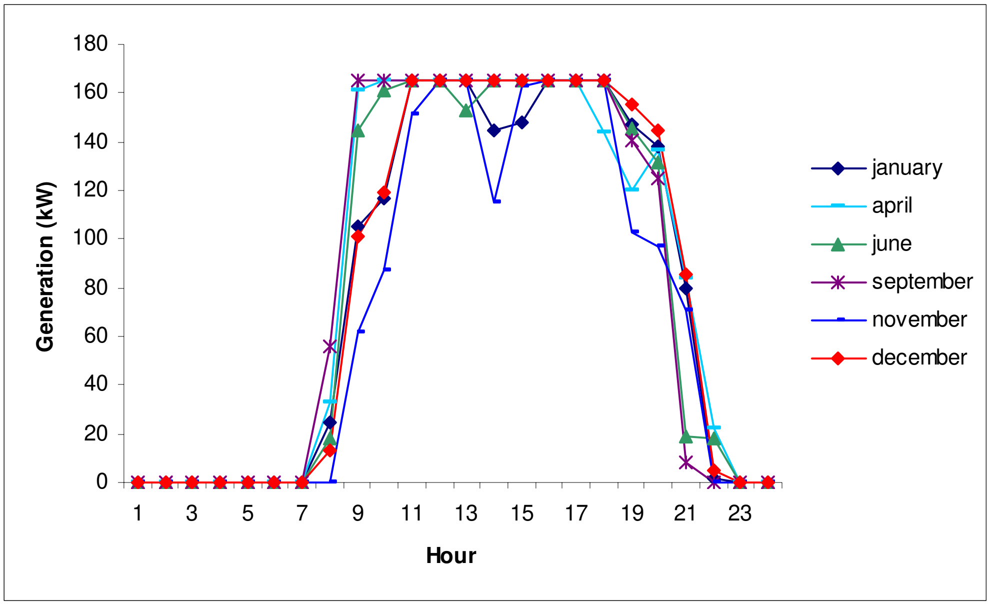


Figure 69. Electricity Generation Output from CHPGA-K-55 (Week)

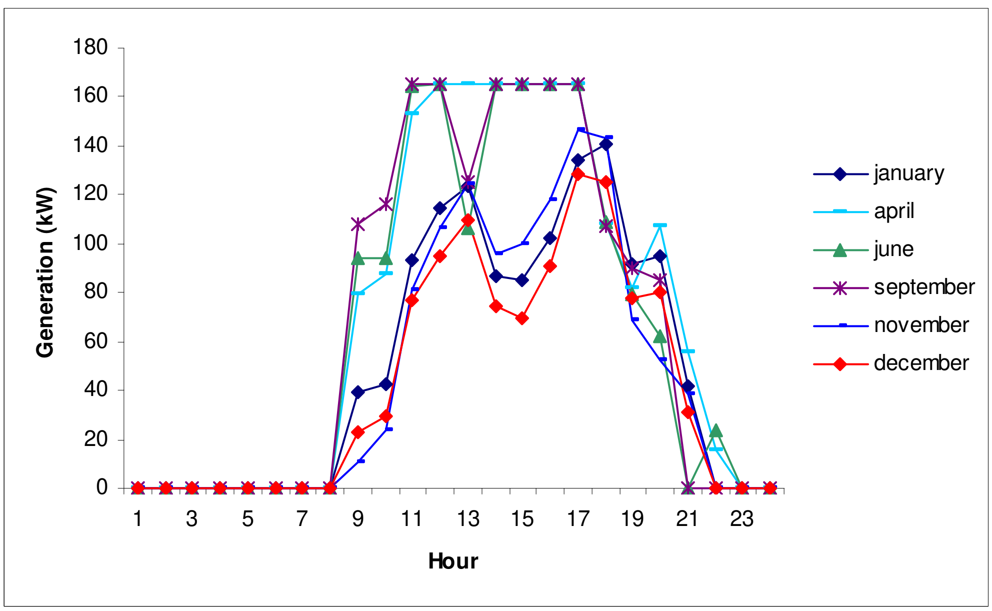


Figure 70. Electricity Generation Output from CHPGA-K-55 (Weekend)

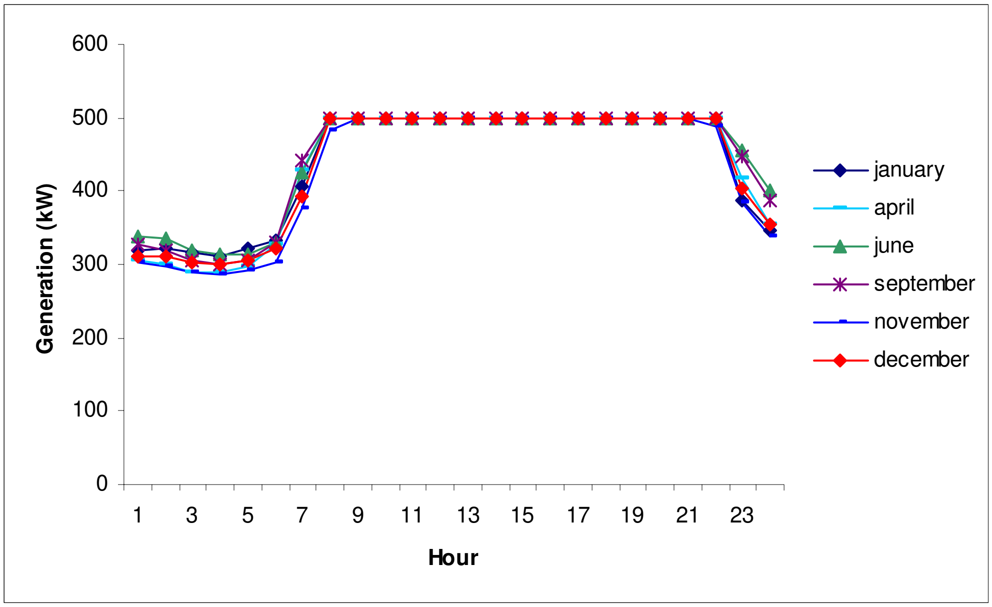


Figure 71. Electricity Generation Output from CHPGA-K-500 (Week)

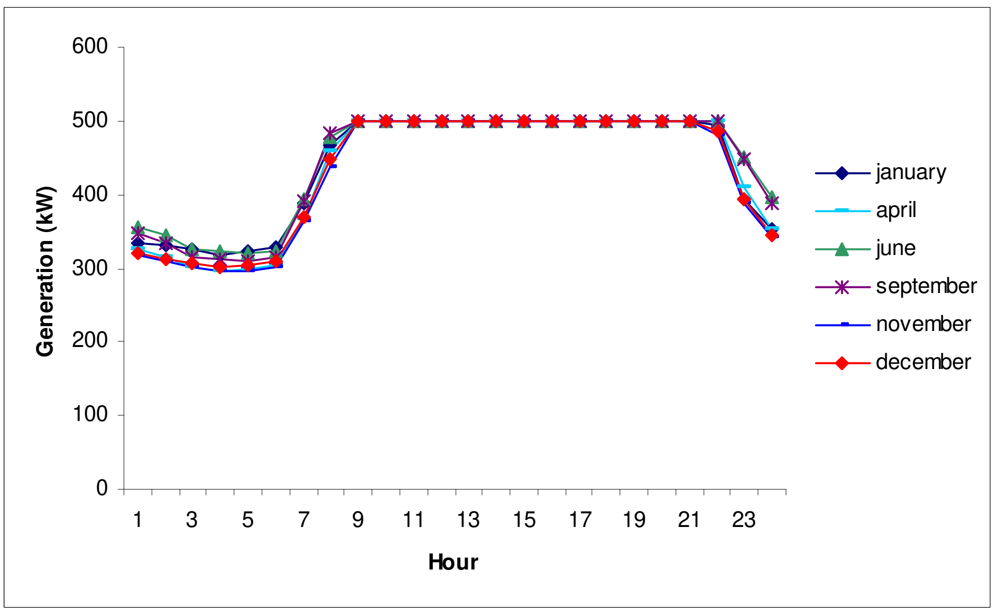


Figure 72. Electricity Generation Output from CHPGA-K-500 (Weekend)

CASE 4: 1999 Tariff Case with CHP and 75% Subsidy on Photovoltaic and Fuel Cell Technologies

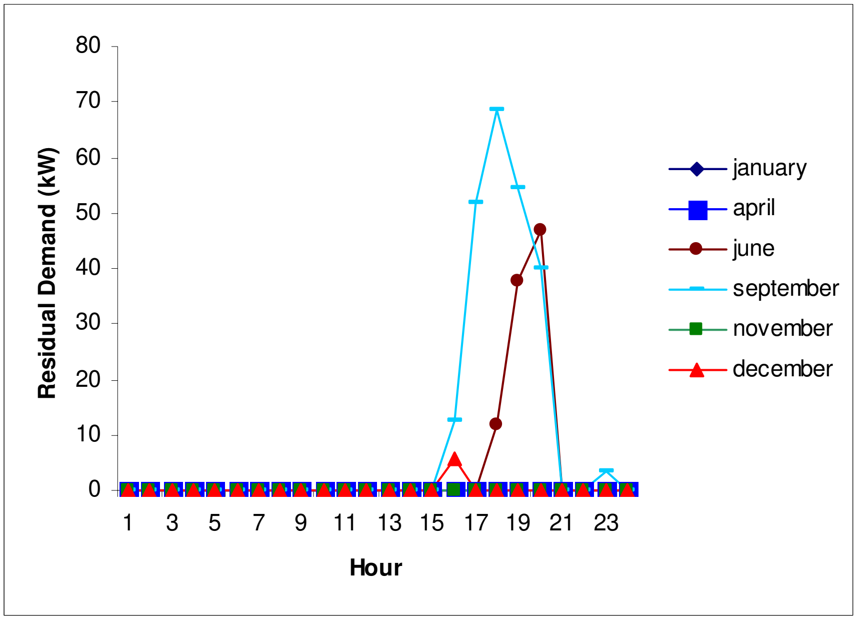


Figure 73. Electricity-Only and Cooling Residual Demand (Week)

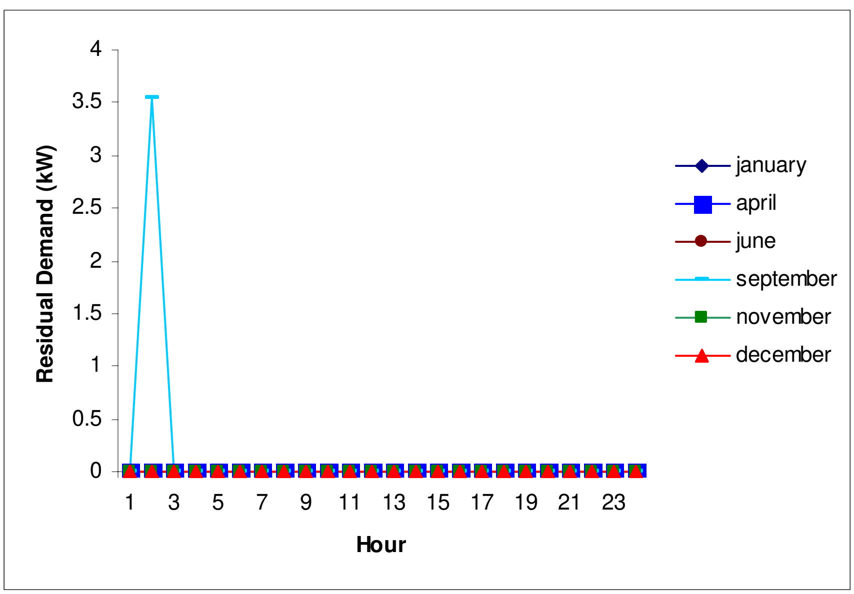


Figure 74. Electricity-Only and Cooling Residual Demand (Weekend)

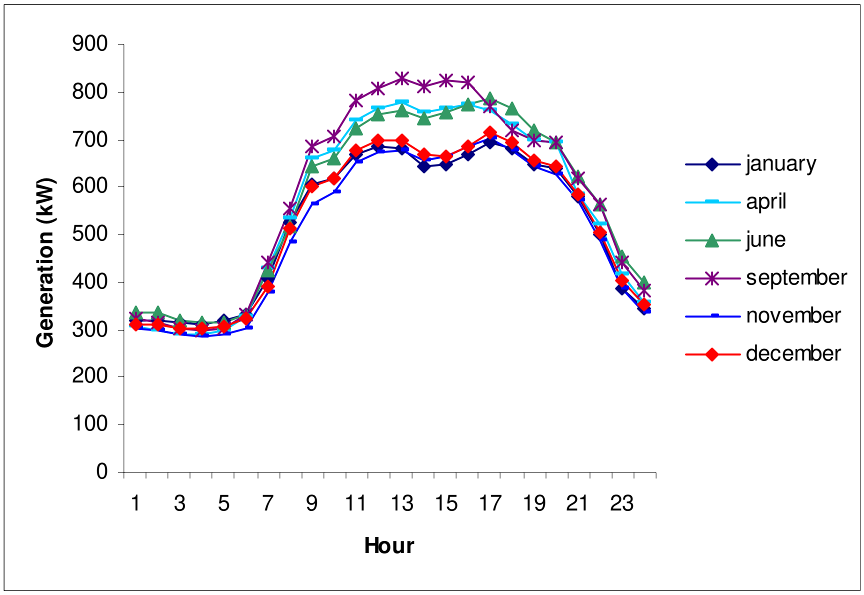


Figure 75. Electricity Generation Output for Self-Use (Week)

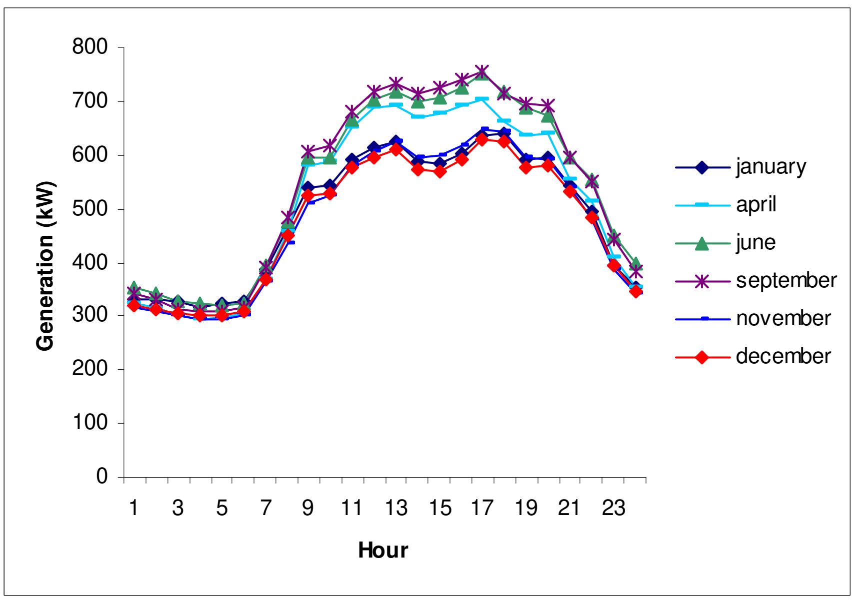


Figure 76. Electricity Generation Output for Self-Use (Weekend)

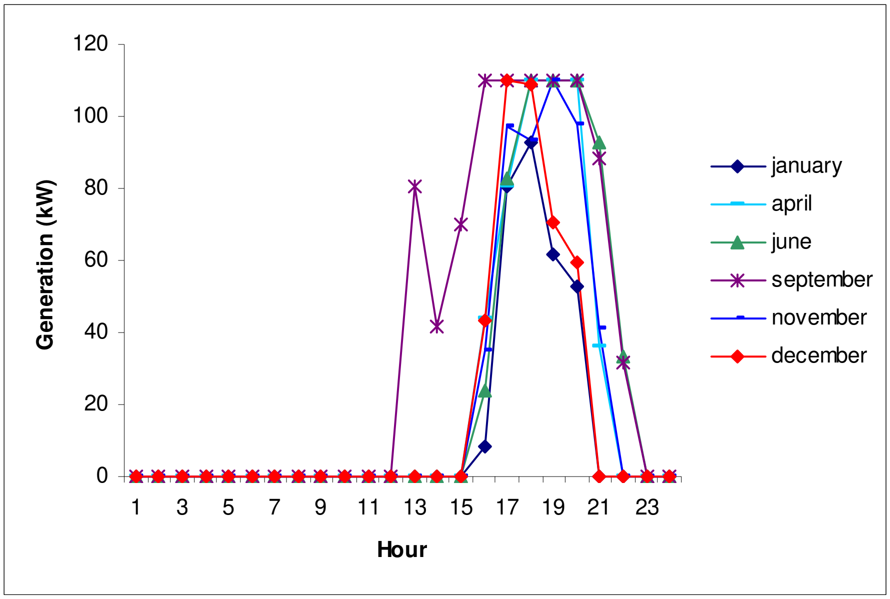


Figure 77. Electricity Generation Output from GA-K-55 (Week)

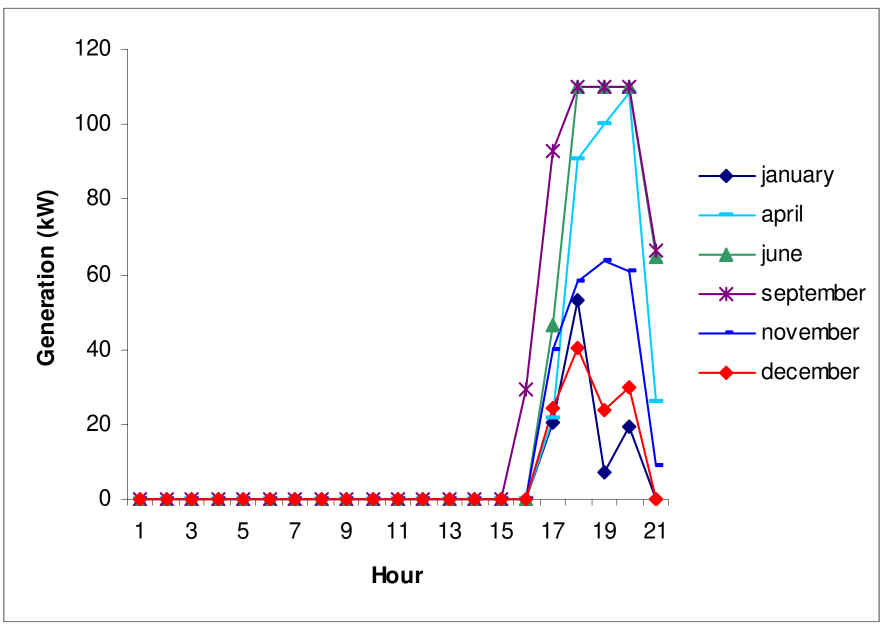


Figure 78. Electricity Generation Output from GA-K-55 (Weekend)

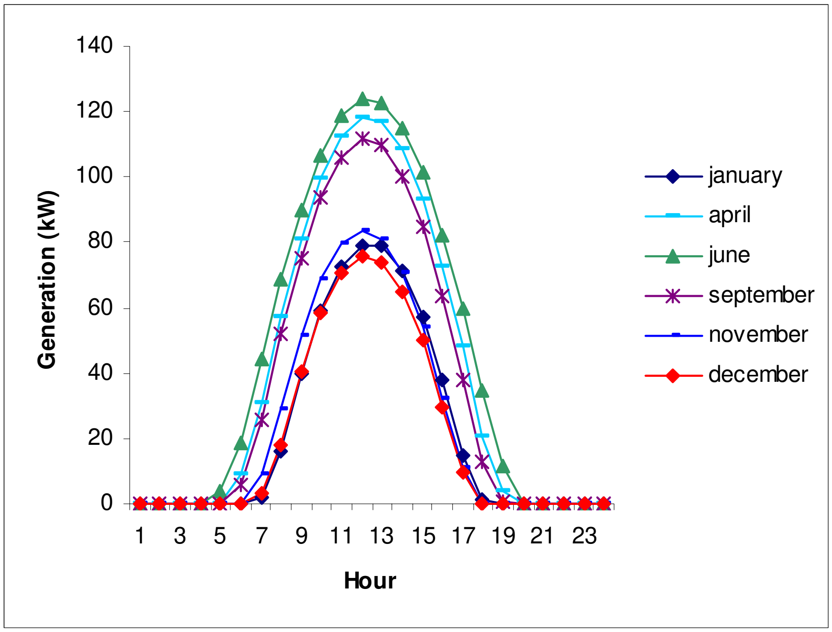


Figure 79. Electricity Generation Output from PV-50 (Week)

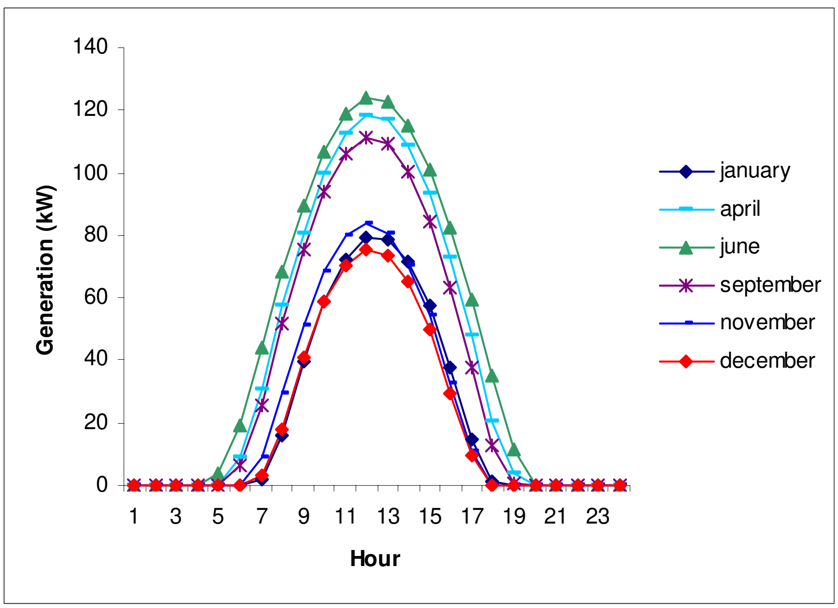


Figure 80. Electricity Generation Output from PV-50 (Weekend)

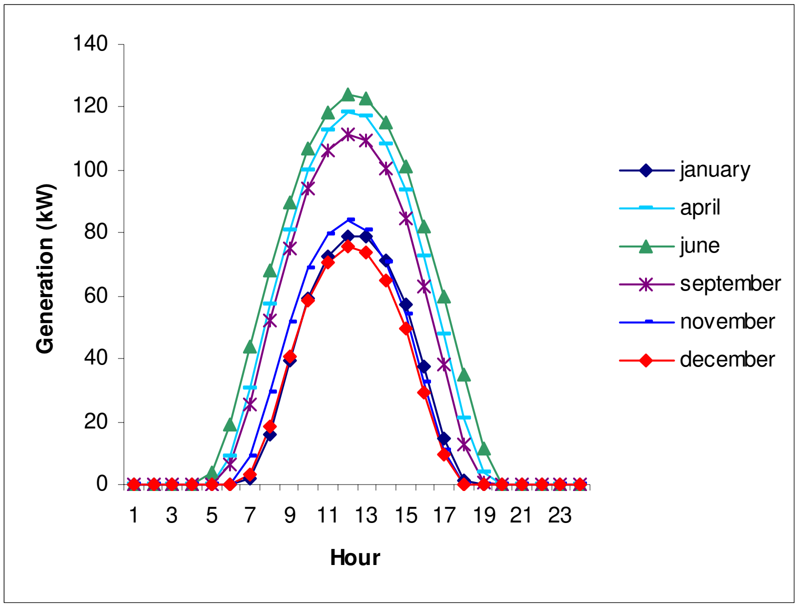


Figure 81. Electricity Generation Output from PV-100 (Week)

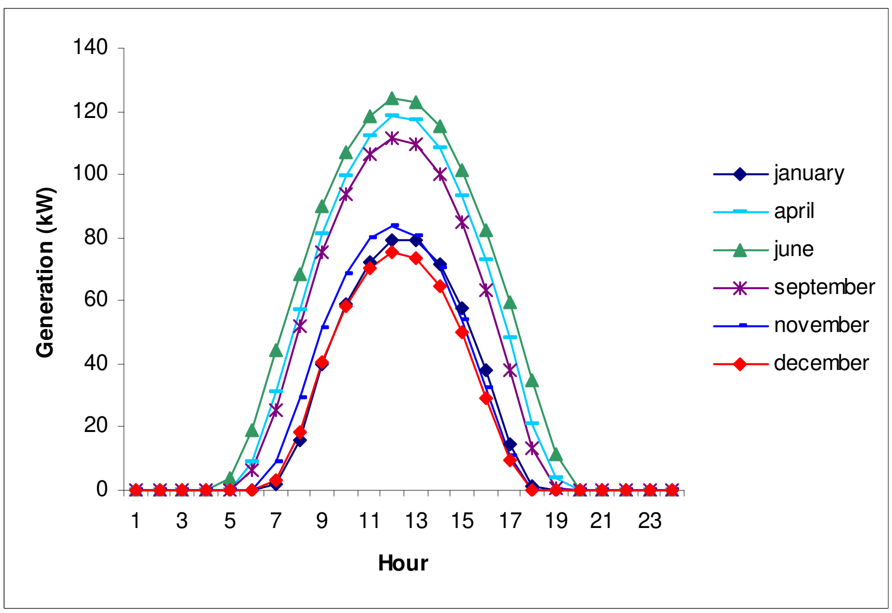


Figure 82. Electricity Generation Output from PV-100 (Weekend)

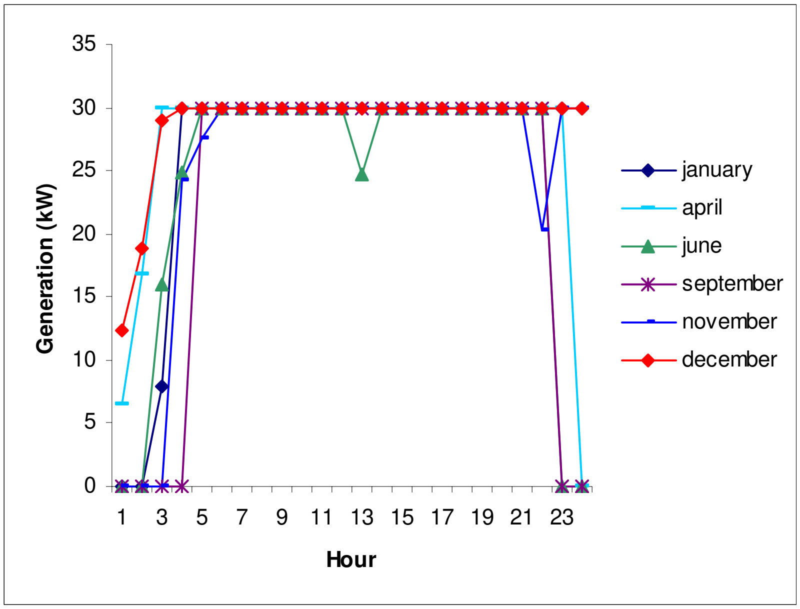


Figure 83. Electricity Generation Output from CHPMTL-C-30 (Week)

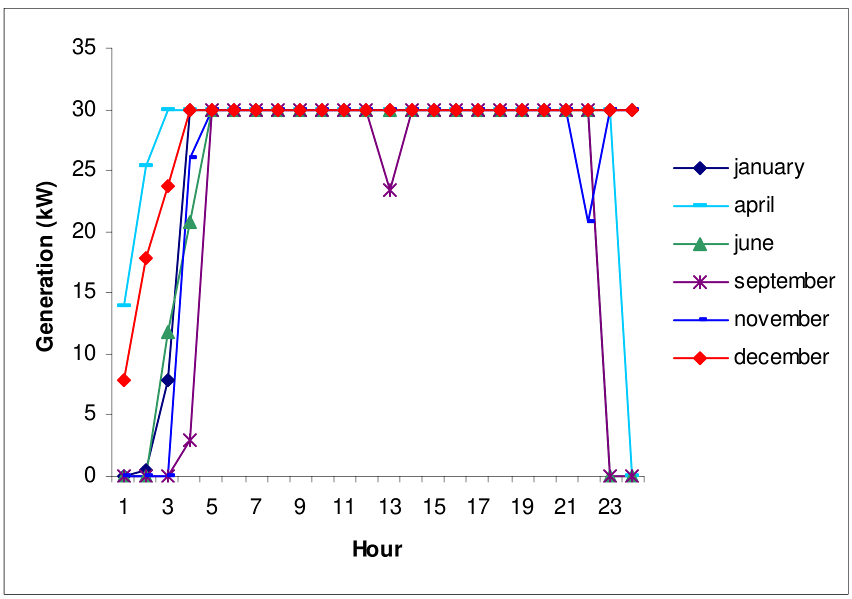


Figure 84. Electricity Generation Output from CHPMTL-C-30 (Weekend)

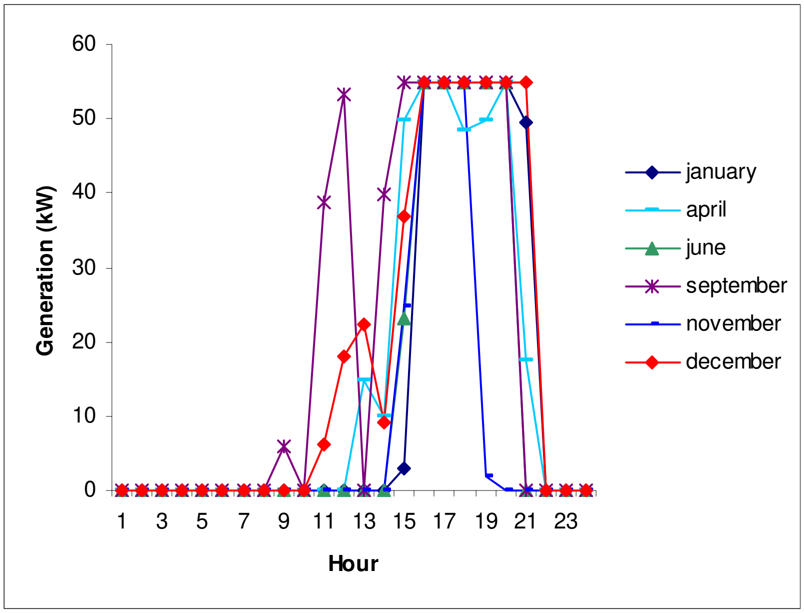


Figure 85. Electricity Generation Output from CHPGA-K-55 (Week)

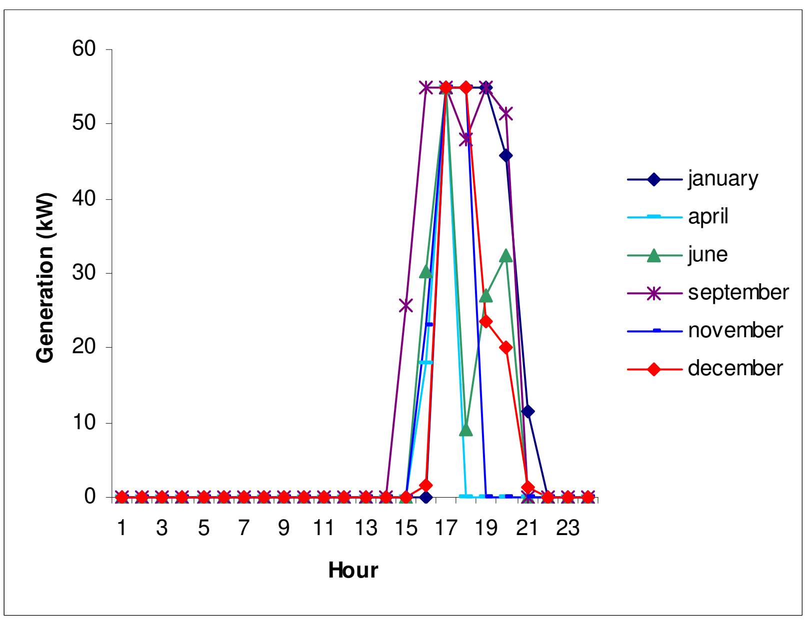


Figure 86. Electricity Generation Output from CHPGA-K-55 (Weekend)

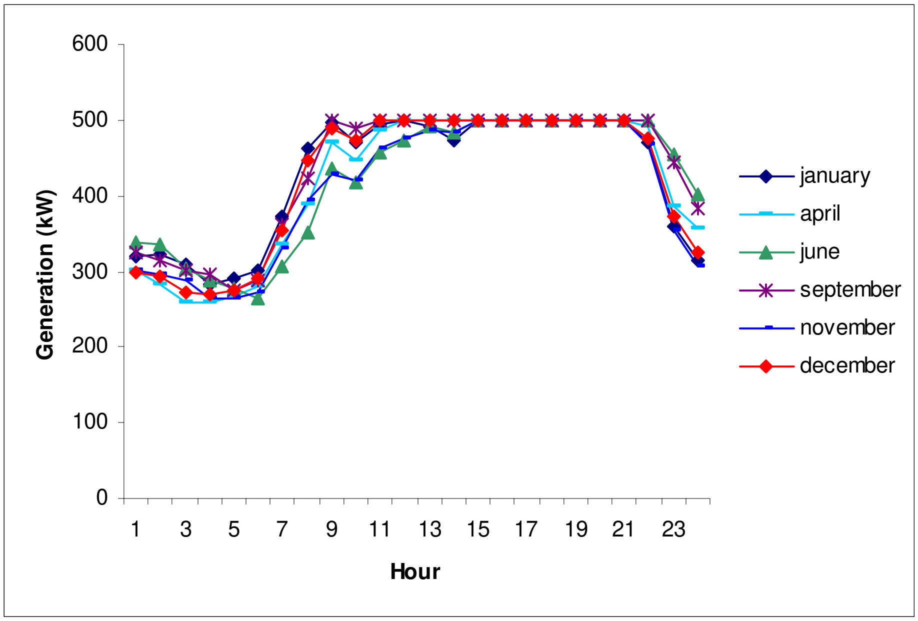


Figure 87. Electricity Generation Output from CHPGA-K-500 (Week)

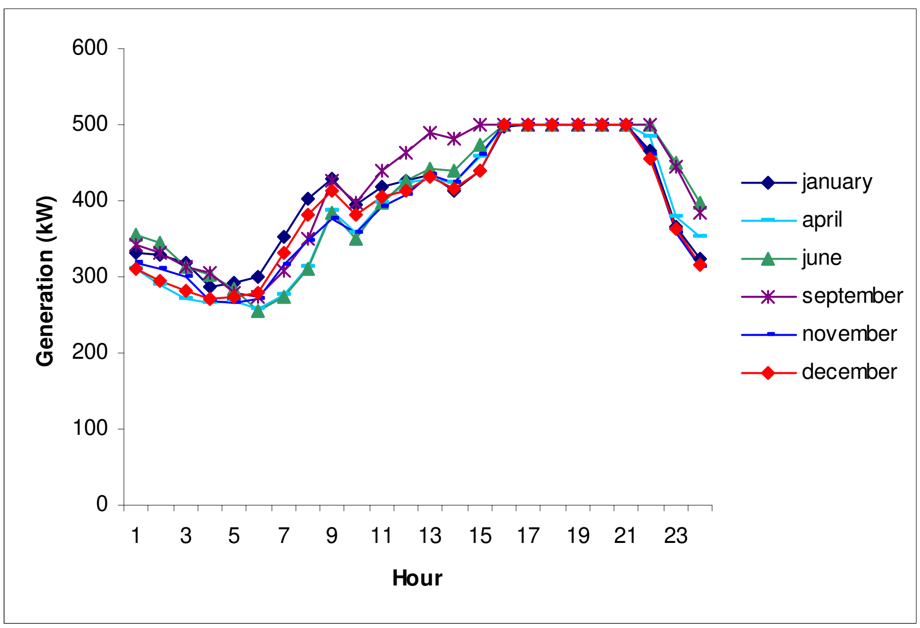


Figure 88. Electricity Generation Output from CHPGA-K-500 (Weekend)

CASE 5: Tariff Case without CHP Using 2010 Technology Data

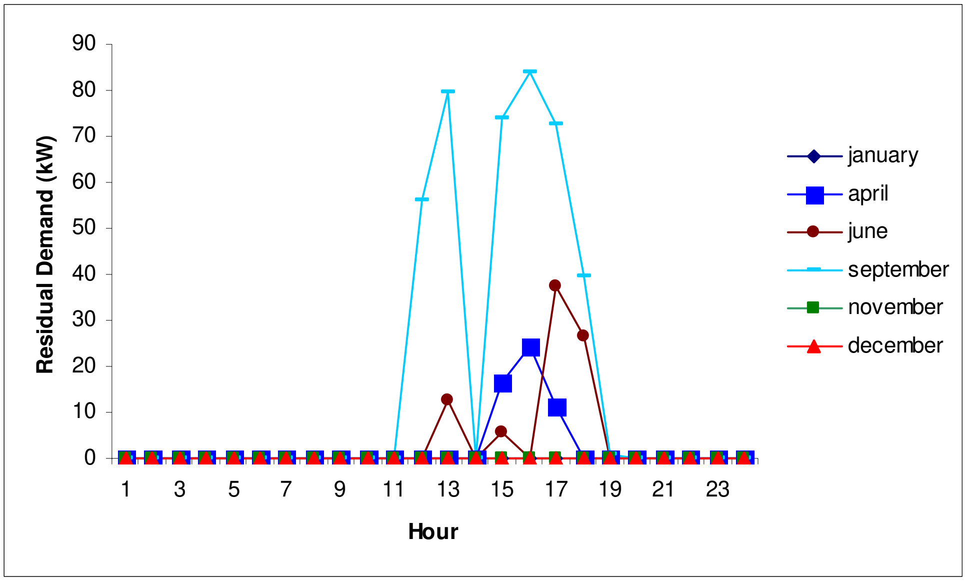


Figure 89. Electricity-Only and Cooling Residual Demand (Week)

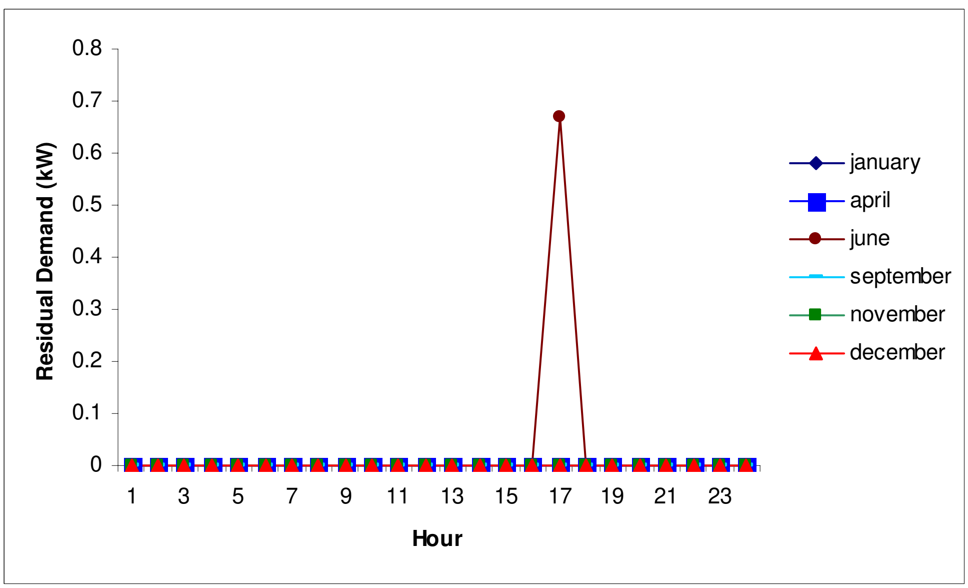


Figure 90. Electricity-Only and Cooling Residual Demand (Weekend)

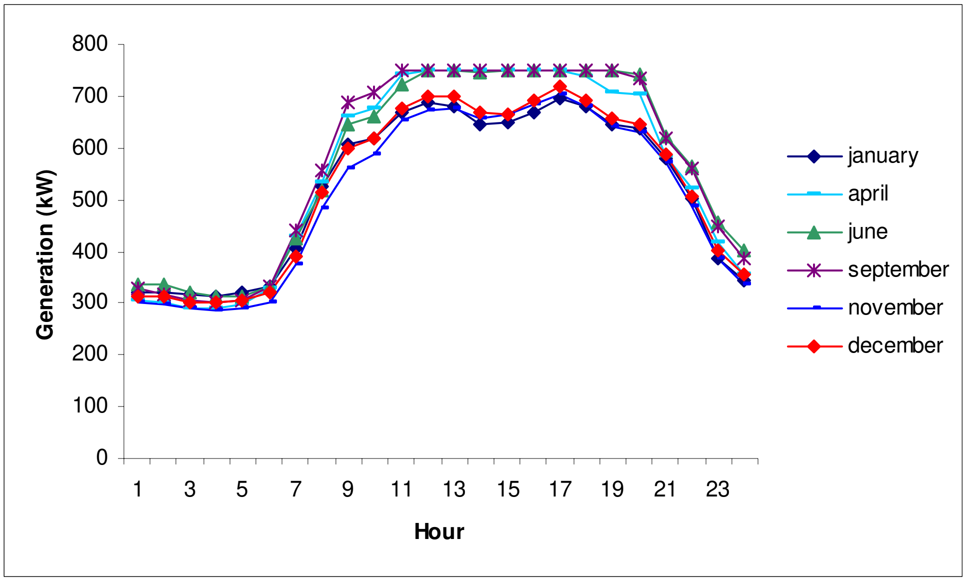


Figure 91. Electricity Generation Output for Self-Use (Week)

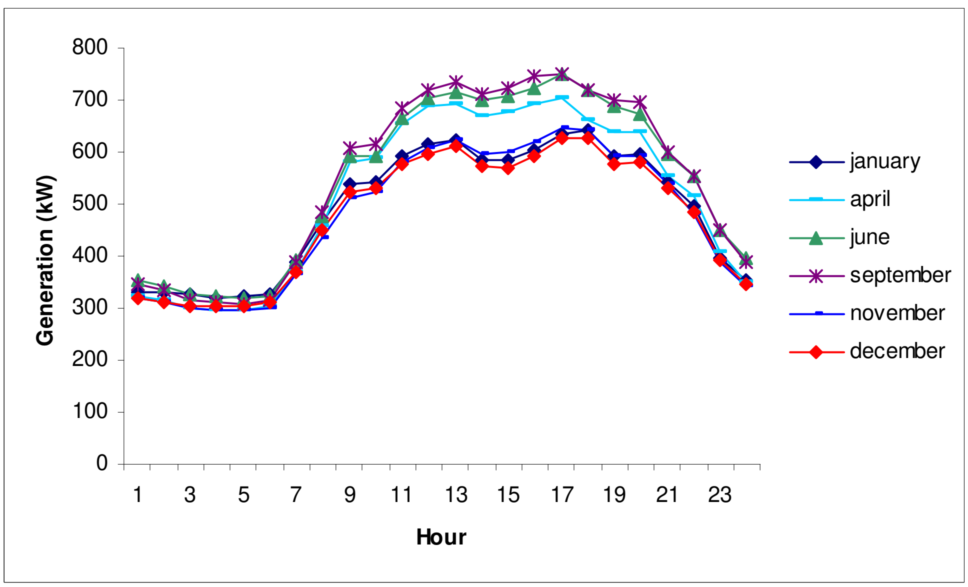


Figure 92. Electricity Generation Output for Self-Use (Weekend)

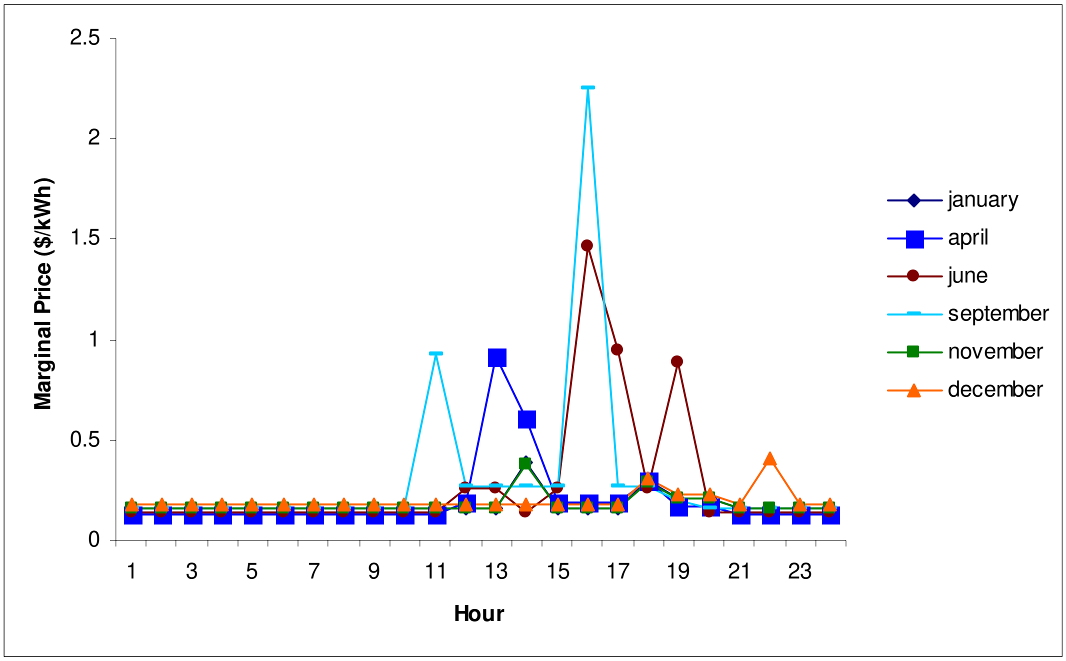


Figure 93. Marginal Price (Week)

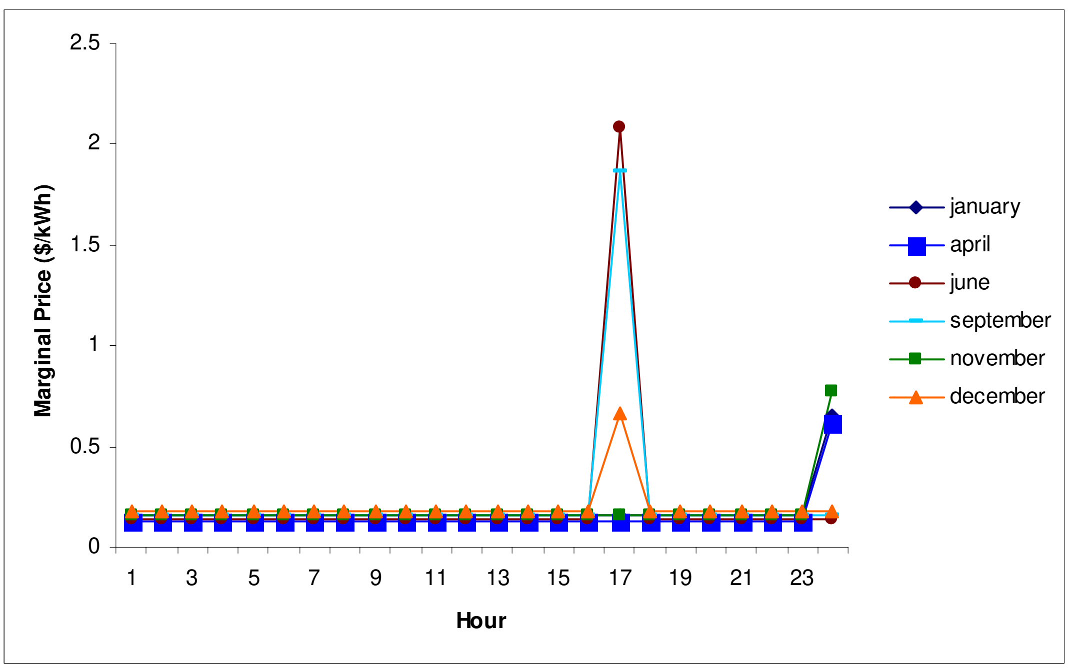


Figure 94. Marginal Price (Weekend)

Appendix C: DER-CAM Enhancements

Use of the current DER-CAM model for this project and other related projects has suggested several desirable enhancements. These enhancements are categorized as equipment, CHP representation, and load representation.

Equipment Representation:

Currently, DER-CAM assumes that DER equipment can operate anywhere between 0% and 100% of its rated capacity, that it performs equally at any capacity level, and that it can shift from one arbitrary operating level to another instantaneously. DER equipment could be more accurately modeled by including operation level constraints, part-load performance, and ramping rates for load adjustment.

Additionally, DER equipment is assumed to be 100% reliability, which is inaccurate. Reliability is a significant concern because if generators go down during a peak usage period, large demand charges are incurred for the entire month. Reliability should be represented as a stochastic process. Including this directly in DER-CAM would significantly increase the computational intensity of the model, however, as every individual day would have to be considered (rather than the current month averages), and many runs would have to be done to assess the statistical details of the results. One way around this would be a study of the costs of unreliability, the results of which could be included as cost add-on to a particular system under consideration in DER-CAM.

Additional generation technologies could also be considered. These include solar thermal technologies, direct driven natural gas chillers and CHP enabled fuel cells. Energy storage could also be addressed with the inclusion of thermal (heating and cooling) storage as well as electrical or mechanical storage.

CHP Representation:

Recoverable heat in DER-CAM is assumed to all be of equal use and therefore value. However, in reality, higher temperature heat is more useful and this could be accounted for in the model. One effect of this would be to make microturbines (MT) more attractive relative to natural gas engines because of MT's high temperature exhaust.

The cost of heat recovery could also be modeled more accurately to acknowledge the site-specific costs of piping and plumbing.

Load Representation:

Using monthly averages for load profiles, rather than daily load profiles reduces the run time of DER-CAM by an order of magnitude. In the process, however, it under estimates the demand charges that a site will incur, because these are based on maximum values, rather than averages.

This issue could be addressed by including statistical information on load variation or by including monthly maximum values in addition to the monthly average values.

Interruptible load market participation could also be included in the µGrid's economic opportunities. Another economic benefit of on-site generation stems from the opportunity it creates to offer load shedding to grid operators. In California, this would most likely be in the form of participation in a program akin to the CAISO's Demand Response Program (DRP). In this program, customers receive a fixed capacity payment during the summer months for offering to shed load in response to CAISO requests and also receive an energy payment equivalent to the IEM price for the unserved energy. A µGrid could readily participate in such a market by employing its on-site generation to displace a fraction of its load at times that it would otherwise not expect to be self-providing. Although it may seem that the times of CAISO interest in invoking the DRP are likely to also be times of high electricity prices so that the µGrid would likely already be self-providing and could not reduce load, in fact DRP has been lucrative even when capacity prices were high enough to possibly stimulate the installation of higher DER capacities. One of the keys to analyzing this problem correctly is enhancing the model to account for the random nature of calls for load shedding.