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Adaptive Nonlinear Optimization Methodology For Installed Capacity Decisions In Distributed Energy/Cooling Heat And Power Applications.

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To the Graduate Council:

I am submitting herewith a dissertation written by Carl Randolph Hudson entitled "Adaptive Nonlinear Optimization Methodology For Installed Capacity Decisions In Distributed Energy/ Cooling Heat And Power Applications.." I have examined the final electronic copy of this dissertation for form and content and recommend that it be accepted in partial fulfillment of the requirements for the degree of Doctor of Philosophy, with a major in Industrial Engineering.

Adedeji B. Badiru, Major Professor

We have read this dissertation and recommend its acceptance:

Chanaka Edirisinghe, Dukwon Kim, William Sullivan

Accepted for the Council:

Carolyn R. Hodges

Vice Provost and Dean of the Graduate School

(Original signatures are on file with official student records.)

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Adedeji B. Badiru
Major Professor

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and recommend its acceptance:

Chanaka Edirisinghe

Dukwon Kim

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Vice Chancellor and
Dean of Graduate Studies

(Original signatures are on file with official student records.)

**ADAPTIVE NONLINEAR OPTIMIZATION METHODOLOGY FOR
INSTALLED CAPACITY DECISIONS
IN DISTRIBUTED ENERGY/COOLING HEAT AND POWER
APPLICATIONS**

A Dissertation
Presented for the
Doctor of Philosophy
Degree
The University of Tennessee, Knoxville

Carl Randolph Hudson, II
December 2005

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ABSTRACT

Evaluation of potential cooling, heating and power (CHP) applications requires an assessment of the operations and economics of a particular system in meeting the electric and thermal demands of a specific end-use facility. Given the electrical and thermal load behavior of a facility, the tariff structure for grid-supplied electricity, the price of primary fuel (e.g., natural gas), the operating strategy and characteristics of the CHP system, and an assumed set of installed CHP system capacities (e.g., installed capacity of prime mover and absorption chiller), one can determine the cost of such a system as compared to reliance solely on traditional, grid-supplied electricity and on-site boilers.

It has been shown previously in the literature that net present value cost savings of CHP systems exhibit a concave behavior with respect to installed capacity, and thus, an optimum size exists for a given application. To date, current capacity selection techniques either utilize simple enumeration of candidate choices, heuristic multipliers of the base or peak demand, or apply optimization algorithms on aggregated or averaged demand data. None of these approaches are likely to result in economic optimality. This research utilizes hour-by-hour operation simulation of CHP systems to calculate life-cycle net present value (NPV) savings. Based on maximizing an NPV cost savings objective function, a nonlinear optimization algorithm is used to determine economically optimal CHP system equipment capacities. This research contributes an improved mechanism that will identify economic optimum capacities for CHP system equipment, thereby producing optimal cost benefits and potentially avoiding economic losses.

TABLE OF CONTENTS

CHAPTER 1 INTRODUCTION	1
1.1 Background.....	1
1.2 Problem Statement and Research Objective.....	3
1.3 Research Organization.....	3
CHAPTER 2 LITERATURE REVIEW	5
2.1 Modeling of CHP Systems	5
2.2 Optimization Methods	8
CHAPTER 3 METHODOLOGY	15
3.1 Overview	15
3.2 Operation Simulation.....	15
3.2.1 Escalation of Unit Prices and Loads.....	23
3.2.2 Non-CHP System Costs.....	24
3.2.3 CHP System Costs.....	26
3.3 Capacity Optimization.....	35
CHAPTER 4 MODEL DEVELOPMENT AND APPLICATION	40
4.1 Development of the Computer Model	40
4.1.1 Input Areas	42
4.1.2 Results Areas.....	51
4.2 Application of the Computer Model.....	54
4.2.1 Results During Development.....	56
4.2.2 Use of the Model in CHP Application Assessments	59
CHAPTER 5 CONCLUSIONS AND RECOMMENDATIONS	74
5.1 Conclusions	74
5.2 Recommendations for Future Work	75
LIST OF REFERENCES	78
APPENDICES	82
VITA	122

LIST OF TABLES

Table 3-1. Input Variables Used in Operation Simulation Model	18
Table 4-1. Escalation Rate Evaluation	57
Table 4-2. Optimization Benchmarking Results	60
Table 4-3. Escalation Assumptions for Example Applications	62
Table 4-4. General Data for Boston Hospital Case	64
Table 4-5. Summary Results	69

LIST OF FIGURES

Figure 3-1. Overview Flow Chart for Optimization Model.....	16
Figure 3-2. Operation Simulation Flow Chart	22
Figure 3-3. Part-Load DG Electrical Efficiency Factors	33
Figure 4-1 . Main Screen of the CHP Capacity Optimizer	41
Figure 4-2. Input Section of Main Screen.....	43
Figure 4-3. Sample Demand Data.....	44
Figure 4-4. Electric and Fuel Rate Data.....	46
Figure 4-5. Sample Escalation Input Data	47
Figure 4-6. General Data and Simulation Controls.....	49
Figure 4-7. User Defined Operating Schedule.....	50
Figure 4-8. Summary Results Area of Model.....	52
Figure 4-9. Hourly Operating Frequency.....	53
Figure 4-10. Contour Plot of Objective Function	55
Figure 4-11. Example of Objective Function Surface Features	58
Figure 4-12. Optimization Results for a Boston Hospital.....	65
Figure 4-13. Operation Frequency by Time of Day.....	66
Figure 4-14. Optimization Contour Plot for a Boston Hospital	68
Figure 4-15. Spiderplot Sensitivity Evaluation.....	71
Figure 4-16. Results of Zero CHP Capacity Optimum Solution	72
Figure 4-17. Contour Plot of Zero CHP Capacity Optimum Solution.....	73
Figure A-1. BCHP Screening Tool Hourly Load Data Switch.....	85
Figure A-2. BEA Save Hourly Data Option Screen	87
Figure A-3. Schedule E-19 Initial Page	92
Figure A-4. Maximum Demand Definition	93
Figure A-5. Further Rate Category Distinctions	95
Figure A-6. Time-of-Use Demand and Energy Rates.....	96
Figure A-7. Definition of Demand and Energy Charges	97
Figure A-8. Definition of Time Periods.....	98
Figure A-9. Standby Charge Exemption.....	99
Figure A-10. Electricity Rate Input Data Sheet	100
Figure A-11. Summary Results for Boston Hospital	112
Figure A-12. Summary Results for Boston Hotel.....	113
Figure A-13. Summary Results for Boston Nursing Home	114
Figure A-14. Summary Results for Boston Retail	115
Figure A-15. Summary Results for Boston Supermarket	116
Figure A-16. Summary Results for San Francisco Hospital.....	117
Figure A-17. Summary Results for San Francisco Hotel.....	118
Figure A-18. Summary Results for San Francisco Nursing Home.....	119
Figure A-19. Summary Results for San Francisco Retail.....	120
Figure A-20. Summary Results for San Francisco Supermarket	121

NOMENCLATURE

Symbols

C_{CHPi}	Cost of CHP system operation in hour i
C_{DGi}	Cost of operation for distributed generator in hour i
C_{esi}	Cost of supplemental grid-based electricity in hour i
C_{gb}	Annual cost of fuel for on-site boiler
C_{gbi}	Cost of fuel for on-site boiler for hour i
C_{gsi}	Cost of fuel for supplemental heating in hour i
C_{OM}	Unit operating and maintenance cost of the CHP system
C_S	Annual cost savings of CHP system relative to non-CHP system
C_U	Annual cost of non-CHP system
C_{Ui}	Cost of non-CHP system in hour i
d_{ci}	Cooling demand for hour i
d_{ei}	Electrical demand for hour i
$d_{e^o_i}$	Non-cooling related electrical demand for hour i
d_{hi}	Heating demand for hour i
d_k	Change in independent variable vector at iteration k
D_n	Depreciation tax benefit in year n
d_{pAC}	Parasitic electrical load of absorption chiller for pumps and fans
D_{Uj}	Monthly utility charge for electrical demand
E_U	Annual cost of utility-supplied electricity
F	Objective function
f_{AC}	Minimum operating fraction for absorption chiller
f_{DG}	Minimum operating fraction for distributed generator
G_{AC}	Installed cooling capacity of absorption chiller
g_{ci}	Absorption chiller cooling produced in hour i
G_{DG}	Net installed electric capacity of distributed generator
g_{ei}	CHP electrical generation in hour i
G_k	Hessian of objective function at iteration k
g_k	Gradient of objective function at iteration k
g_{Ti}	CHP thermal energy generated in hour i
h	Finite difference interval
H_k	Approximation of the inverse objective function Hessian at iteration k
I_{AC}	Installed unit capital cost for absorption chiller
I_{CHP}	Total investment (capital) cost for CHP system
I_{DG}	Installed unit capital cost for distributed generator
k_{AC}	Binary absorption chiller preference indicator
M_{ei}	Maximum CHP electrical demand for hour i
M_{Ti}	Maximum CHP thermal demand for hour i
NPV_{CHP}	Net present value of the CHP system
p_k	Newton step direction vector at iteration k
r_{djk}	Grid-based utility unit demand charge for month j and block period k
r_{ei}	Grid-based utility unit price for electric energy for hour i
r_g	Unit price for on-site fuel (e.g., natural gas)

S_{ci}	Supplemental cooling-related electricity required in hour i
S_{gi}	Supplemental gas for on-site boiler required in hour i
S_{ei}	Total supplemental grid-based electricity required in hour i
S_{hi}	Supplemental heating required in hour i
y_k	Change in gradient vector at iteration k
ϵ_{Ui}	Hourly charge for electricity by utility
η_{AC}	Efficiency (COP) for absorption chiller
η_b	Thermal efficiency of on-site boiler
η_{DG}	Electrical efficiency of distributed generator
η_{EC}	Efficiency (COP) for electric chiller
θ	Power to heat ratio of distributed generator
λ	Newton step fraction
ρ	Armijo-Goldstein coefficient

Abbreviations

AC	Absorption chiller
AG	Armijo-Goldstein
BCHP	Building cooling heating and power
BEA	Building Energy Analyzer
BFGS	Broyden-Fletcher-Goldfarb-Shanno
Btu	British thermal unit
CHP	Cooling Heating and Power
COP	Coefficient of performance
DE	Distributed energy
DER	Distributed energy resource
DG	Distributed generation
DoW	Day of the week
GRG	Generalized reduced gradient
HHV	Higher heating value
IOU	Interval of Uncertainty
IRS	Internal Revenue Service
KKT	Karush-Kuhn-Tucker
kW	Kilowatt
kWh	Kilowatt-hour
LHV	Lower heating value
MACRS	Modified Accelerated Cost Recovery System
MB	Megabyte
MMBtu	One million (10^6) Btu
NPV	Net present value
O&M	Operating and maintenance
ORNL	Oak Ridge National Laboratory
p/h	Power to heat ratio
PC	Personal computer
PURPA	Public Utility Regulatory Policy Act
PW	Present worth
RT	Refrigeration-ton = 12,000 Btu
VBA	Visual Basic for Applications

CHAPTER 1

INTRODUCTION

This document describes the research and findings in the development of a methodology and software tool that can be applied to the problem of appropriate equipment capacity selection in distributed energy cooling, heating, and power applications.

1.1 Background

Distributed energy is the provision of energy services at or near the point of use. It can take many forms, but a central element is the existence of a prime mover for generating electricity. Typical prime movers for current distributed energy applications are gas or light oil-fired turbines, fuel cells, or reciprocating engines fired with natural gas or diesel fuel. Such prime movers are only able to utilize roughly 30 percent of the input fuel energy in the production of electricity. The remaining energy can either be utilized as a thermal resource stream or must be exhausted to the atmosphere. When the waste heat is used to satisfy heating needs, the system is typically termed a cogeneration or combined heat and power system. Through the use of an absorption chiller, waste heat can also be utilized to provide useful cooling, in which case the system is considered a “cooling, heating and power” (CHP) application.

Systems such as these are not new. According to a history provided by The Center for Energy Efficiency and Renewable Energy, initial electric generation in the early twentieth century was steam powered and so inefficient that large amounts of waste steam was available for process use or building heat [CEERE (2005)]. As electric generation became more efficient and larger central station power plants were sited at greater distances from the loads, productive utilization of the waste heat decreased. In the 1980s, the Public Utility Regulatory Policy Act (PURPA) gave industrial energy users a financial incentive to adopt cogeneration by requiring

that utilities purchase electricity from qualifying facilities at the marginal cost of electricity production by the utility. Advances in technologies (e.g., introduction of microturbines and double effect absorption chillers) and the introduction of utility interconnection standards have produced new markets for CHP systems in the commercial as well as industrial sectors.

Generally, CHP systems are not the sole source of electricity and thermal resource for a facility. In most cases, these systems are merely alternatives to utility grid-supplied electricity, electric chillers, and electric or gas-fired on-site water heating. As a result, CHP systems are characteristic of the classic “make-or-buy” decision, and economic viability is relative to grid-based electricity and on-site boiler heating. An assessment of the economic viability of a particular CHP system requires an assumption regarding the installed equipment capacities of the system. As costs are a direct function of the installed capacities of these systems, the challenge is to determine the most economically optimal capacities of the equipment.

An important consideration in assessing the potential for CHP systems is recognition of the non-coincident behavior of the electric and thermal (i.e., heating and cooling) loads of a facility. That is, the load patterns for the three load streams are not perfectly correlated with each other through time. As a result, the peak of electrical demand will most likely not occur at the same point in time as either the heating or cooling demand peak. Absent a means to store electrical or thermal energy on-site, producing electricity with a distributed generator to track electrical demand (i.e., electric load following) may produce recovered thermal energy that cannot be used due to lack of thermal demand at that moment. Similarly, operating a CHP system in a thermal load following mode (i.e, tracking thermal demand), combined with limits on the sale of electricity into the grid, may also impact the degree to which the three demand streams can be satisfied by distributed energy.

1.2 Problem Statement and Research Objective

Economic evaluations of CHP systems typically utilize some analytical computational tool. These tools can vary from simple spreadsheet calculations to detailed hourly simulations of the system in its application environment (i.e., specific building type, location, and use). A review of existing tools has determined that all currently available tools have certain shortcomings that can impact the validity of their results and, potentially, the appropriateness of a project decision. Earlier research by this author [Hudson and Badiru (2004)] and others has shown that tools that utilize time-aggregated data (e.g., the averaging of electric and thermal loads) can produce an overly optimistic result, which, if taken by itself, can lead to erroneous project decisions. Thus, analytical tools that evaluate demand and supply on an hourly basis are considered necessary, but not sufficient, for determining the economic optimality/viability of CHP systems. The insufficiency of current hourly computational tools is that the model input for system installed capacity is either a heuristic input assumption or a manual enumeration of capacities provided by the user. This research will demonstrate that size selections based on specific heuristics (e.g., capacity selection as a fixed percent of electrical or thermal demands) do not necessarily produce economically optimal configurations. The research objective, therefore, is to develop and apply appropriate optimization algorithms in conjunction with detailed hourly simulation tools in order to allow for the automated determination of the most economic installed capacities for a given CHP system and application.

1.3 Research Organization

Following the present introductory chapter, a review of the literature on prior CHP system analytical tools and relevant optimization techniques is presented in Chapter 2. In Chapter 3, the detailed methodology for operation simulation and capacity optimization is presented. A computational model that incorporates these methods is presented in Chapter 4.

Results from example case studies utilizing the model and observations made during the development of the model are also presented in Chapter 4. The concluding chapter provides a summary of the research and findings and makes recommendations regarding future research.

CHAPTER 2

LITERATURE REVIEW

This chapter is divided into two sections. The first section addresses previous work in simulation and optimization modeling of CHP systems, particularly focused on determining the appropriate installed capacities of the prime mover and ancillary thermal systems. The second section reviews optimization methods that are relevant to the determination of an economically optimum CHP system.

2.1 Modeling of CHP Systems

Computer modeling of cogeneration applications (i.e., the simultaneous production of electricity and useful thermal energy) is certainly not a new concept. Schweizer and Sieck (1978) proposed the use of computer simulation modeling of cogeneration systems to provide a quantitative assessment of the potential market for industrial cogeneration equipment. Having the capability to model systems by computer simulation, the concept of seeking the most optimal size was not far behind. In an early modeling of industrial steam cogeneration, Duann (1984) stated the economic tenet that "at the optimal capacity, the marginal cost of an additional unit of cogeneration capacity is equal to the marginal value of such capacity increase". While such an optimum was shown to exist, no automated means of determining the value was offered.

An important distinction in the literature is the research related to optimization of a system's *operation* as compared to the optimization of the system's installed *capacity*. A number of early works address the optimization of the operation of a given system. Baughman, Eisner and Merrill (1989) developed a cogeneration simulation model in Microsoft Excel which sought optimal operation of industrial cogeneration systems over a 15 year planning horizon using the minimization of net present value of operating costs as the objective function. Consonni, Lozza

and Macchi (1989) developed an operations optimization simulator based on 36 separate sample day patterns to represent annual operations. Using a binary representation of equipment being either on or off, the model was a mixed integer linear program with an objective function of maximizing hourly profits from operation.

Regarding the optimization of installed system capacity, Yokoyama, Ito and Matsumoto (1991) introduced a coupled, "hierarchical" modeling concept, whereby the optimization of a system's installed capacity was an outer shell or layer serving to drive a separate inner operations optimization model based on mixed integer linear programming. Similar to Consonni, Yokoyama used 36 sample day patterns to describe annual load behavior. Utilizing the hierarchical optimization process described by Yokoyama, Asano et al. (1992) considered the impact of time-of-use rates on optimal sizing and operations of cogeneration systems. Using 14 sample day patterns to represent the load behavior, Asano evaluated three commercial applications (hotel, hospital, and office building) and calculated optimal capacities ranging from 50 to 70 percent of peak electricity demand. Contemporaneously, a set of closed form equations for calculating the optimal generation capacity of an industrial cogeneration plant with stochastic input data was developed by Wong-Kcomt (1992). Wong-Kcomt's approach relied upon single unit prices for electricity (i.e., no separate demand charges) and assumed independent Gaussian distributions to describe aggregate thermal and electrical demand. The effects of hourly non-coincidence of loads were not addressed. Wong-Kcomt showed, however, that the solution space of the objective function (cost minimization) was convex in nature.

As an extension of the hierarchical model proposed by Yokoyama in 1991, Gamou, Yokoyama and Ito (2002) investigated the impact that variation in end-use energy demands had on optimization results. Modeling demand (i.e., load) variation as a continuous random variable, probability distributions of electrical and thermal demands were developed. Dividing the problem into discrete elements, a piecewise linear programming approach was used to find the

minimum cost objective function. It was observed that the capacity deemed as optimal using average data was, in fact, suboptimal when load variations were introduced. In characterizing the variability of electrical and thermal demands, the non-coincident behavior of the electrical and thermal loads lead to the determination of a lower optimal capacity value when variability was recognized, relative to the value obtained when considering only average demands. A key finding from this work was that use of average demand data (e.g., sample day patterns) may not accurately determine the true optimal system capacity. Orlando (1996) states a similar conclusion in that “any averaging technique, even multiple load-duration curves, by definition, cannot fully model the interaction between thermal and electrical loads”.

Within the last 10 years, cogeneration technology has evolved to include systems with smaller electric generation unit capacities in uses other than large, industrial applications. Termed "distributed energy" or “distributed generation”, these systems are now being applied in commercial markets such as hospitals, hotels, schools, and retail stores. In addition, traditional cogeneration (i.e., the production of electricity and useful heat) has been expanded to include trigeneration, that is, the use of waste heat from electrical production to produce both useful heat and cooling. A number of works are focused on this recent development. Marantan (2002) developed procedures to evaluate a predefined list of candidate system capacities for an office building application, selecting the CHP system with the minimum net annual cost. Campanari, Boncompagni and Macchi (2002) used a simulation model with 21 sample day patterns and a predefined list of operating scenarios to select the least cost operating strategy for a CHP system in commercial buildings. They did a somewhat reverse-approach in investigating capacity-related optimization by varying the building size for a CHP system of fixed capacity. An important conclusion of their manual, trial and error optimization was that "due to the inherent large variability of heating, cooling, and electric demand typical of commercial buildings, the optimum size of a cogeneration plant is significantly lower than peak demand." A similar conclusion was

found by Czachorski, Ryan and Kelly (2002) while investigating the energy cost savings resulting from the use of CHP systems in hospitals, hotels, offices, retail, and educational facilities in the Chicago area. Through manual capacity enumeration, they found that, based on maximum annual energy cost savings, "the corresponding size of the power generator was between 60% and 80% of the maximum electric demand for CHP systems" in the applications considered. The study by Czachorski et al. also showed that annual energy cost savings exhibit a concave behavior with respect to generator capacity. While their work did not reflect life-cycle cost savings by including investment cost as a function of generator capacity, the inclusion of generation equipment capital cost should not eliminate the general concave behavior produced by the annual energy economics.

Additional relevant literature in this area includes work by Li et al. (2003) to evaluate a discrete, predetermined set of candidate CHP system capacities using genetic algorithms with maximization of net present value as the objective function. Czachorski, Kelly and Olsen (2003) expanded their previous study to include desiccant dehumidification equipment as well as absorption cooling for five specific building types in four different geographical locations. As in the previous study, a manual enumeration of various candidate capacities indicated the existence of an optimum installed capacity based on annual energy cost savings.

Two important distinctions between the previous works and this research are that previous efforts have used either aggregated or averaged load data with attendant loss of non-coincident behavior effects or have not provided an automated means to determine optimal installed capacities for CHP equipment.

2.2 Optimization Methods

Based on the modeling efforts described in the previous section, consideration is now given to the question of an appropriate method to apply in seeking an optimum of an economic

objective function. A discussion of relevant optimization techniques cannot be made without some knowledge of the structure of the model in which the optimization will be conducted. Therefore, rather than providing a pedagogic recitation of the wide variety of optimization methods and algorithms that exist, this section will focus on the specific methods that are applicable to the problem at hand, which will then be further developed in the following chapter. There are, however, a number of good texts on optimization methods. Two examples are Bazaraa, Sherali and Shetty (1993) and Gill, Murray and Wright (1986) .

As mentioned above, in order to determine an appropriate optimization method (i.e., to select the correct tool for the job), one must have some understanding of the system or model upon which the optimization will be applied. One approach to this selection is to consider the attributes of the system or model and proceed through somewhat of a classification process. A good initial step in the classification is to determine if the system or model is linear or nonlinear in either its objective function or in its constraints. If the objective function and all constraints are linear, then linear optimization methods (e.g., linear programming) should be applied. If either the objective function or any constraint is nonlinear, then the nonlinear class of methods may be required. A further distinction is whether the independent variables are constrained. If the feasible region is defined by constraints, constrained optimization methods generally should be applied. In addition, if one or more of the independent variables can only take on integer values, specialized integer programming methods may be required.

With respect to the economic modeling of CHP systems, life-cycle cost, or alternatively, the life-cycle savings relative to some non-CHP alternative, as a function of installed equipment capacity, has been shown to be convex and concave, respectively. [Wong-Kcomt (1992); Czachorski, Ryan and Kelly (2002)] Therefore, using either life-cycle cost or savings as the objective function necessitates a nonlinear optimization approach. Beyond this, consideration must be given as to whether the current problem has independent variables that are constrained to

certain sets of values (i.e., equality constraints) or somehow bounded (i.e., inequality constraints). In either case, constrained nonlinear optimization is generally performed by converting the problem in such a way that it can be solved using unconstrained methods (e.g., via Lagrangian multipliers or penalty methods). [Bazaraa, Sherali and Shetty (1993)] In this study, the independent variables are installed equipment capacities, which are assumed to be continuous and non-negative. Thus, the only constraints are simple bounds, defined as $x_i \geq 0$. Fletcher (1987) suggests a number of ways to handle such constraints including variable transformation (e.g., $x = y^2$) and introduction of slack variables. With slack variables, a problem of the type Maximize $F(x)$ subject to $x_i \geq 0$ can be rewritten using slack variables as Maximize $F(x)$ subject to $x_i - w_i^2 = 0$, where w_i^2 is a squared slack variable. Solution can then follow through the development of the Karush-Kuhn-Tucker (KKT) conditions and the Lagrangian function. It has been shown that for linear constraints and a concave objective function, as in this study, the global optimum will be at a point satisfying the KKT conditions [Bazaraa, Sherali and Shetty (1993); Winston (1994)].

Another method to extend equality-constraint methods to inequalities is through the use of a generalized reduced gradient (GRG) approach. The reduced gradient method seeks to reduce the number of degrees of freedom, and therefore, free variables, that a problem has by recognizing the constraints that are active (i.e., at their bounds) during each iteration. If a variable is at an active bound, it is excluded from calculations related to the determination of the incremental solution step. If no variables are at active constraints, the GRG method is very similar to the standard quasi-Newton method for unconstrained variables. A GRG interactive optimization tool is included as a bundled add-in to Microsoft Excel [Fylstra et al. (1998)]. Although applicable to the optimization requirements of this study, it was felt that development of an internal algorithm that relied on simpler, unconstrained methods with explicit checks on

bounds would be a useful element of interesting research. The Excel GRG add-in tool could then be used as a check on the accuracy and results of the unconstrained approach.

There are a number of methods available to perform unconstrained nonlinear optimization. A central distinction is whether the method relies on derivatives of the objective function. If derivatives are not available or are computationally difficult to obtain, non-derivative methods can be employed. Such methods are also needed when the objective function or gradient vector is not continuous. Methods that rely solely on function comparison are considered direct search methods [Gill, Murray et al. (1986)]. A common direct search method is the polytope or Nelder-Mead method in which prior functional evaluations are ordered such that the next iteration is a step in the direction away from the worst point in the current set of points. Another non-derivative method is the Hook and Jeeves method which performs exploratory searches along each of the coordinate directions followed by pattern searches defined by the two most recent input vectors. The main disadvantage of these direct search methods is that they can be very slow to converge.

The two direct search methods mentioned above are considered sequential methods in that new trial inputs are the product of the previous result. Another class of the direct search method is the simultaneous direct search in which the trial points are defined a priori [Bazaraa, Sherali and Shetty (1993)]. For variables in two dimensions, an example of this method would be a grid-pattern search, which will be one technique employed in this research.

If objective function derivatives are available, other, more efficient, methods can be brought to bear. One of the most fundamental procedures for optimizing a differentiable function is the method of steepest descent, also called the gradient method. In this method, the search direction is always the negative gradient, and the step size is calculated to minimize the objective function (assuming the function is convex). This is repeated until a stopping criterion, such as the gradient norm, is sufficiently small. However, it has been shown that following the direction of

steepest descent does not necessarily produce rapid convergence, particularly near a stationary point, and that other derivative methods perform better [Bazaraa, Sherali and Shetty (1993); Bartholomew-Biggs (2005)]. For large problems (i.e., those with more than 100 decision variables), the conjugate gradient method is useful as it does not require storage of large matrices [Bazaraa, Sherali and Shetty (1993)]. As this method is typically less efficient and less robust than other methods, and as the current problem concerns a small number of independent variables, the conjugate gradient method will not be considered for this application.

The remaining methods of interest are the Newton method and the related quasi-Newton method. The Newton method has been shown to be very efficient at unconstrained nonlinear optimization if the objective function has continuous first and second derivatives. If first and second derivatives are available, a Taylor-series expansion in the first three terms of the objective function yields a quadratic model of objective function that can subsequently be used to define a Newton direction for function minimization. As long as the Hessian is positive definite and the initial input values are in the neighborhood of the optimum, Newton's method converges to the optimum quadratically [Gill, Murray and Wright (1986)].

Due to the discrete form of the model in this study, analytical expressions for first and second derivatives are not available. In these situations, derivatives can be approximated using finite difference techniques. The lack of an exact expression for second derivatives means that curvature information, typically provided by calculating the Hessian matrix, is not directly available for use in a Newton method. The solution to this problem is to utilize the well-known quasi-Newton method, in which an approximation to the inverse Hessian is successively built-up during the iteration process. While typically expecting the first derivative to be analytically available in a quasi-Newton method, the additional lack of explicit first derivatives to form the gradient does not appear to be a fatal impediment. Van der Lee, Terlaky and Woudstra (2001) successfully used this approach in studying the optimization of thermodynamic efficiency in

power plant steam cycles. As Gill (1986) states, “when properly implemented, finite-difference quasi-Newton methods are extremely efficient, and display the same robustness and rapid convergence as their counterparts with exact gradients.”

With respect to the iterative update of the Hessian matrix, a number of Hessian update methods have been proposed over the years, including the Davidson-Fletcher-Powell (DFP) method, the Powell-Symmetric-Broyden (PSB) update, and the Broyden-Fletcher-Goldfarb-Shanno (BFGS) method. The literature indicates that the BFGS method is clearly accepted as the most effective update method currently available. [Gill, Murray and Wright (1986); Nocedal (1992); Zhang and Xu (2001); Bertsekas (2004); Yongyou, Hongye and Jian (2004)] Details of the BFGS algorithm will be provided in the following chapter.

A final element related to the quasi-Newton method is the use of line search methods when the full quasi-Newton step produces an objective function response that does not make satisfactory progress relative to the previous iteration, thus, possibly indicating the passing of a local optimum. In that case, a “backtracking” process along the step direction is needed. As discussed by Dennis and Schnabel (1983), the backtracking approach should conform to the Armijo and Goldstein (AG) conditions to ensure satisfactory convergence. Dennis and Schnabel provide the classic quadratic fit using three previously calculated function values to solve for the optimum quasi-Newton step multiplier, followed by the cubic spline fit, should the new quadratic step not meet AG conditions.

It should be noted that the quadratic/cubic fit method is but one method to determine an appropriate step value. While less efficient in terms of computational requirements, line search methods that do not rely on the gradient, or in this case, an approximation to the gradient, can also be used. Sequential search methods such as the Fibonacci and related Golden section methods can be utilized to determine an acceptable step multiplier [Bazaraa, Sherali and Shetty (1993)].

Other more detailed aspects of the optimization process and related literature references to these specific points will be brought out in the chapters that follow.

CHAPTER 3

METHODOLOGY

3.1 Overview

This chapter provides a detailed explanation of the simulation model as well as the approach used to determine an optimum set of equipment capacities for the CHP system. Similar to the approach used by Edirisinghe, Patterson and Saadouli (2000) and Yokoyama, Ito and Matsumoto (1991), the model consists of two nested sections: an outer, controlling optimization algorithm and an inner operation simulation routine. The overall flow of the optimization model is shown in Figure 3-1. Starting with an initial “guess” for the installed electrical generator and absorption chiller capacities, an hour-by-hour operation simulation is performed to develop a value of the objective function for the given generator and chiller capacities. Within the optimization algorithm, a stopping criterion is used to control the updating of the optimization routine and subsequent iterative looping back to the operation simulation with a new set of candidate installed capacities. The optimization algorithm seeks to maximize the net present value (NPV) savings produced by using the CHP system relative to a non-CHP scenario (where electricity is obtained solely from the grid and heating loads are met by an on-site boiler). The maximization of NPV savings (i.e., maximization of overall profitability) is an appropriate method for evaluating mutually exclusive alternatives [Sullivan, Wicks and Luxhoj (2006)].

3.2 Operation Simulation

As stated in Chapter 1, the purpose of this research is to develop an effective mechanism by which optimal sizes of CHP equipment may be determined. In recognition of the problems identified in the literature regarding the use of average or aggregated demand data [Gamou, Yokoyama and Ito (2002); Hudson and Badiru (2004)] , this approach utilizes demand data

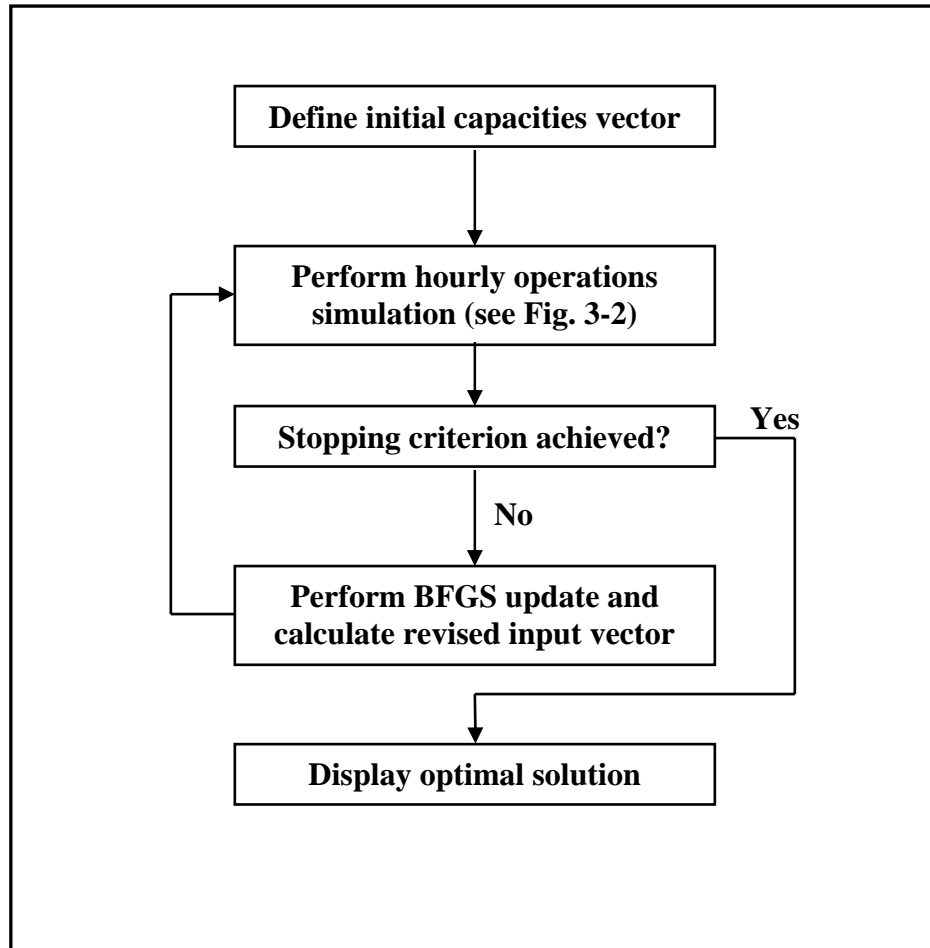


Figure 3-1. Overview Flow Chart for Optimization Model

expressed on an hourly basis, spanning a one year period. Use of hourly data has the advantage of explicitly capturing the seasonal and diurnal variations, as well as non-coincident behaviors, of electrical and thermal loads for a given application. In many cases, actual hourly demand data for an entire year may not be available for a specific site. In these situations, building energy simulation programs are available that can develop projected hourly loads for electricity, heating, and cooling on the basis of building application, size, location, and building design attributes (e.g., dimensions, insulation amounts, glazing treatments) [InterEnergy/GTI (2005); Oak Ridge National Laboratory (2005)].

The data needed to simulate the operation of a CHP system are shown in Table 3-1. The input for the hourly facility electrical demand should include all facility electrical demand *except* for cooling-related demand. As cooling may be provided by an absorption chiller under CHP operation, electrical demand related to cooling is calculated explicitly within the simulation model. For the hourly heating and cooling demands, the input values are expressed on an end-use, as-consumed thermal basis.

The prices for utility-supplied electricity typically have a price component related to the amount of energy consumed (i.e., an energy charge) as well as a component proportional to the monthly peak rate of energy consumed (i.e., a demand charge). Some utilities will price their electricity at different rates to those who self-generate a portion of their electrical needs. In addition, some electric utilities charge a monthly standby fee for the availability of power that may be called upon should the distributed generation not be available. As discussed later, utility tariff structures can have unit prices that vary both seasonally and/or diurnally. Similar to electricity rates, the unit price for on-site fuel may be different for those who operate a CHP system.

Table 3-1. Input Variables Used in Operation Simulation Model

Variable	Typical units
Facility loads	
Hourly electrical demand (non-cooling related)	kW
Hourly heating demand	Btu/hour
Hourly cooling demand	Btu/hour
Electric utility prices	
Demand charge	\$/kW-month
Energy charge	\$/kWh
Standby charge	\$/kW-month
On-site fuel price (LHV basis)	\$/MMBtu
Equipment parameters	
Boiler efficiency (LHV)	Percent
Conventional chiller COP	Without units
Absorption chiller (AC) COP	Without units
Absorption chiller (AC) capacity	RT
AC minimum output level	Percent
AC system parasitic electrical load	kW/RT
Distributed generation (DG) capacity, net	kW
DG electric efficiency (LHV) at full output	Percent
DG minimum output level	Percent
DG power/heat ratio	Without units
Operating and maintenance (O&M) cost	\$/kWh
Number of DG units	Units
DG capital cost	\$/kW installed
AC capital cost	\$/RT installed
General economic parameters	
Planning horizon	Years
Discount rate	Percent/year
Effective income tax rate	Percent

The fuel assumed for on-site distributed generation and on-site water/steam heating in this study is natural gas, expressed on a \$/MMBtu lower heating value (LHV) basis. The heating value of natural gas refers to the thermal energy content in the fuel, which can be expressed on a higher heating value (HHV) or lower heating value basis. The difference in the two heating values relates to the water formed as a product of combustion. The higher heating or gross value includes the latent heat of vaporization of the water vapor. The lower heating or net value excludes the heat that would be released if the water vapor in the combustion products was condensed to a liquid. As DG/CHP systems try to limit exhaust vapor condensation due to corrosion effects, the usable heat from natural gas is typically the LHV. In the United States, natural gas is typically priced on a HHV basis, so care should be used in entering the proper value. For natural gas, the conversion between HHV and LHV is

$$\text{heat content}_{\text{HHV}} = \text{heat content}_{\text{LHV}} \times 1.11 \text{ [Petchers (2003)]}.$$

The definitions for the equipment and economic parameters listed in Table 3-1 are as follows:

Boiler efficiency – The thermal efficiency of the assumed on-site source of thermal hot water/steam (e.g., boiler) for the baseline (non-CHP) scenario, expressed on a LHV basis.

Conventional chiller COP – The coefficient of performance for a conventional electricity-driven chiller. It is determined by dividing the useful cooling output by the electrical energy required to produce the cooling, adjusted to consistent units.

Absorption chiller COP – The coefficient of performance for the CHP system absorption chiller. It is determined by dividing the useful cooling output by the thermal energy required to produce the cooling, adjusted to consistent units. Parasitic electrical support loads (e.g., pump and fan loads) are addressed separately.

Absorption chiller capacity – The installed capacity of the absorption chiller in refrigeration tons (RT). This is an independent variable in the model.

AC minimum output level – The minimum percent operating level, relative to full output, for the absorption chiller. This is also known as the minimum turndown value.

AC system parasitic electrical load – The electrical load required to support the absorption chiller. The chiller load should include the chiller solution pump, the AC cooling water pump, and any cooling tower or induced draft fan loads related to the AC.

Distributed generation (DG) capacity - The installed capacity of the distributed electrical generator (i.e., prime mover), expressed in net kilowatts. This is an independent variable in the model.

DG electric efficiency (LHV) at full output – The electricity production efficiency of the DG prime mover at full output. This efficiency can be determined by dividing the electricity produced at full output by the fuel used on a LHV basis, adjusted to consistent units.

DG minimum output level - The minimum percent operating level, relative to full output, for the DG unit. Also known as the minimum economic turndown value.

DG power/heat ratio – The ratio of net electrical power produced to useful thermal energy available from waste heat, adjusted to consistent units.

O&M cost – The operating and maintenance cost of the total cooling, heating and power system, expressed on a \$/kWh of electricity generated basis.

Number of DG units – The number of prime mover units comprising the system. Currently, the model is limited to no more than two units, each identical in size and performance. The optimum capacity determined by the model is the total capacity of the CHP system, and for a two-unit system, that capacity is split equally between the units.

DG capital cost – The fully installed capital cost of the distributed generation system, expressed on a \$/net kW basis.

AC capital cost – The fully installed capital cost of the absorption chiller system, expressed on a \$/RT basis.

Planning horizon – The assumed economic operating life of the CHP system. The default value is 16 years to be consistent with U.S. tax depreciation schedules for 15 year property. Currently, 16 years is the maximum allowed planning horizon in the model.

Discount rate – The rate used to discount cash flows with respect to the time-value of money.

Effective income tax rate – The income tax rate used in income tax-related calculations such as depreciation and expense deductions. The effective rate reflects any relevant state income tax and its deductibility from federal taxes. More discussion on this is provided in Section 3.2.2.

The general flow of calculations within the operation simulation is shown in Figure 3-2. Once the electrical and thermal loads and general equipment/economic parameters are defined, for each iteration of the optimization routine, a trial set of distributed generator and absorption chiller capacities are provided to the operations simulator. Two separate simulations must be performed. First, the hour-by-hour costs for satisfying the thermal and electric loads solely by a traditional utility grid/on-site boiler arrangement must be calculated. This is referred to as the non-CHP or grid-only scenario. A second, separate calculation develops the hour-by-hour costs of meeting at least some part of the specified loads with a CHP system. The degree of contribution of the CHP system will be discussed in greater detail in material that follows. Two sets of annual operating costs are then determined by summing the relevant hourly costs of meeting thermal and electric demands from either the grid and on-site boiler solely (i.e., the non-CHP scenario) or from CHP operations. A differential annual operating cost (or net annual savings, if the CHP scenario is less costly than the non-CHP scenario) is determined based on the annual cost difference between the non-CHP scenario and the CHP-available scenario. A net present value is then determined by calculating the present worth of the net annual savings over the number of years defined by the planning horizon at the defined discount rate and adding the installed capital costs of the CHP system, adjusted for income tax effects (e.g., depreciation).

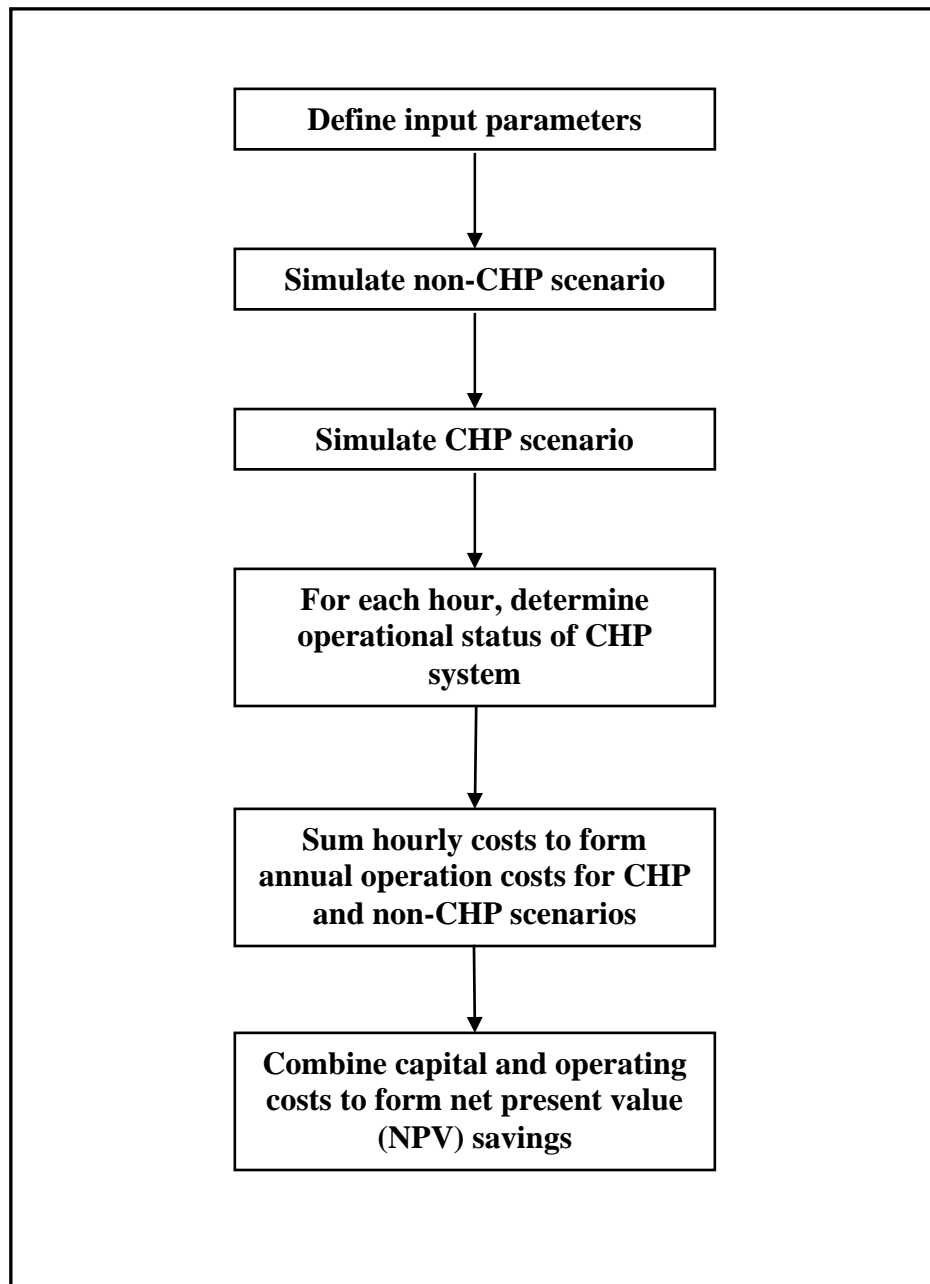


Figure 3-2. Operation Simulation Flow Chart

3.2.1 Escalation of Unit Prices and Loads

Before the detailed computations of the annual operations are discussed, the treatment of escalation must be addressed. As stated above, the planning horizon for this model can be up to 16 years. Unit prices for electricity and gas, as well as O&M unit costs, are not likely to remain constant over such a long period. Similarly, it is possible that electrical and/or thermal loads may change over such a period. As a result, the ability to reflect escalating unit prices and possible load changes is needed.

As annual operations are calculated on an hourly basis, performing an explicit calculation for every hour within a 16 year duration would require 140,160 hourly calculations. While computationally feasible using high-level programming languages (e.g., FORTRAN, C++), this research utilizes a Microsoft Excel spreadsheet platform. One of the main reasons for developing this research on a spreadsheet platform is the transparency that the spreadsheet provides for reviewing the actual calculations as opposed to a “black-box” compiled program that must be trusted by users to be computationally correct. The current version of Excel (Microsoft Office Excel 2003 SP2) is limited to 65,536 rows on a single spreadsheet, which is insufficient to perform all 16 years of hourly calculations on one sheet. Of course, one could have 16 separate worksheets, one for each year, but an additional consideration is the operational performance of the model. Based on processing times for an 8,760 hour optimization, which will be discussed in the following chapter, it was felt that explicitly performing 140,160 hourly calculations would be intractable with the current platform.

A solution to this dilemma is to express the variables that are subject to escalation as levelized values. A common method used in public utility economic analysis, a levelized value is determined by calculating the present value of the escalating annual stream and then applying an annual capital recovery factor to produce the levelized annual equivalent value [Park and Sharp-

Bette (1990)]. The levelized values are then used in the operation simulation calculations. In order to confirm that such an approach would be a viable alternative to explicit hourly calculations, an explicit 6-year hourly model was created having 52,560 hourly computational rows. The results from the explicit model were compared against the results from a 6-year levelized model for various combinations of escalation rates for unit prices and thermal and electric loads. Benchmarking of the two models using the same capacity inputs gave very good agreement (i.e., average difference in NPV savings between the two models was 0.04% in six trials). Thus, in the material that follows, unless explicitly stated, values for electricity and gas unit prices, thermal and electric loads, unit O&M costs, and the resulting annual costs should be considered annual levelized values, spanning the duration of the planning horizon.

3.2.2 Non-CHP System Costs

As mentioned above, the non-CHP scenario assumes that there is no distributed generation system, that all electrical loads are met by the grid-based utility, and that all heating loads are met by an on-site boiler. Costs related to the non-CHP system scenario for a given hour are determined on the basis of satisfying the specified non-cooling electrical demand, $d_{e^o_i}$, the heating demand, d_{hi} , and the cooling demand, d_{ci} . It is important to note that each of these demands is expressed as an end-use consumption value. As cooling in the non-CHP scenario is assumed to be provided by electricity-based chillers, the electrical consumption related to this cooling demand must be determined and added to the non-cooling electrical demand. This is done by recognizing the COP of the electric chiller, such that total non-CHP electrical demand for hour i can be expressed as

$$d_{ei} = d_{e^o_i} + d_{ci} / \eta_{EC} .$$

The pricing of electricity from the utility grid has become much more complicated since electric utilities began to be deregulated and electricity supply competition was introduced. It is

outside the scope of this work to address the regulation and economics of electric utilities and the various business and pricing arrangements that have been explored in the last decade. Despite the “unbundling” of the traditional vertically-integrated utility, in which generation, transmission, and distribution costs are now priced separately, most electric utilities in the United States still offer some form of regulated tariff pricing. The regulated tariff pricing structure will be used in this study as it remains an accessible, common form of pricing electricity to various classes of customers (e.g., industrial, commercial, residential). If interested in the underlying economic theory of costing public services such as utility rates, Bonbright, Danielsén and Kamerschen (1988) provides a detailed development of the theory and structure of public utility rates.

In the typical utility tariff, the pricing of electricity provided by a utility to an industrial or commercial customer consists of an energy charge, related to the actual amount of electrical energy consumed, and a demand charge, related to the *rate* of energy consumption (i.e., power level). The actual terms and structure of pricing tariffs vary widely from utility to utility. For some tariffs, the energy unit price, r_{ei} , may vary by hour of the day (known as a time-of-use tariff) and also by season. The demand charge rate, expressed on a \$/kW-month basis, may also vary by season and hour of the day. If there are multiple demand charge rates, varying by time of day, it is considered a block pricing arrangement. Typically, utilities will have a two- or three-block structure related to the peak and off-peak times, or the peak, shoulder, and off-peak times of day, respectively. The demand charge, assessed at the rate r_{djk} applicable for month j and block k of time, is then based on the highest power demand placed on the utility within that block interval during the course of a month. The total demand-related charge is then the sum of the demand charges incurred across all the time blocks.

Mathematically, the hourly energy charge for hour i can be expressed as

$$\mathcal{E}_{U i} = r_{ei} \cdot d_{ei}.$$

The demand charge for a given month j with n distinct demand blocks can be expressed as

$$D_{Uj} = \sum_{k=1}^n \max[d_{ei}]_{jk} \cdot r_{djk} ,$$

where $\max[d_{ei}]_{jk}$ is the maximum hourly electrical demand in the daily time period defined by block k experienced during month j . Over the period of a year, the total annual cost of utility-supplied electricity is

$$E_U = \sum_{i=1}^{8760} \varepsilon_{Ui} + \sum_{j=1}^{12} D_{Uj} .$$

In the non-CHP scenario, it is assumed that heating demands will be met by a natural-gas fired boiler. The cost of the natural gas consumed in a given hour i with a unit price for natural gas of r_g and a boiler efficiency of η_b is

$$C_{gbi} = r_g \cdot d_{hi} / \eta_b .$$

The cost of natural gas over a one year period is the sum over all i hours,

$$C_{gb} = \sum_{i=1}^{8760} C_{gbi} .$$

Finally, the total annual operating cost for the non-CHP system is

$$C_U = E_U + C_{gb} .$$

3.2.3 CHP System Costs

Relative to the non-CHP scenario, developing the annual cost for a CHP-based system is substantially more complicated. There can be utility surcharges (e.g., standby fees) which are imposed as a result of operating self-generation equipment. In addition, the unit pricing for electricity, r_{ei} and r_{djk} , may be different for customers using a CHP system than for those buying all their supply solely from the utility. The operational considerations related to the CHP system are of considerable influence as well. As an example, the fuel efficiency of electrical generation

equipment is directly proportional to relative output level. Typically, the highest efficiency (i.e., most electricity produced for the least fuel consumed) is at or near full rated output. Depending upon the type of prime mover, electrical efficiencies at low part-load can be 65 to 75 percent of full-load efficiency. As a result, there is a general lower limit on part-load operations. A typical minimum operating value is 50% of rated unit capacity. The limit becomes influential when the electrical demand is less than 50% of the rated unit capacity, requiring that electricity be purchased from the grid. Thus, there is an economic trade-off related to the size of the CHP generation capacity. A CHP system sized to meet peak electrical or thermal loads will incur higher utility standby charges and will have less ability to operate during periods of low demand. Conversely, a smaller sized system may be able to operate a larger fraction of time, but may result in a higher fraction of unmet load for the facility (resulting in higher utility purchases, typically at peak pricing). The economics are further influenced by the direct relationship of CHP electrical generation capacity and useful thermal energy available. Smaller electrical capacity means less useful thermal byproduct, which might then require additional gas-boiler or electric chiller operation.

In the detailed modeling of operations in the CHP scenario, an initial consideration is the determination of the best use of the available thermal energy. Depending on the relative prices of grid-based electricity and natural gas and the efficiencies of the various equipment items, it may be more economical to preferentially satisfy heating demands rather than cooling demands (via an absorption chiller) with the available thermal energy from the CHP prime mover. A binary variable, k_{AC} , is set to a value of 1 to indicate a preference of using the thermal energy for meeting cooling demand if 1) an absorption chiller is present in the system, 2) the cooling demand is greater than or equal to the minimum operating level for the absorption chiller, that is,

$$d_{ci} \geq f_{AC} \cdot G_{AC}$$

and 3) if the substitution cost of one unit of thermal energy displacing electric cooling is greater than the substitution cost of that unit of thermal energy displacing on-site boiler heating,

$$\eta_{AC} \cdot r_{ei} / \eta_{EC} > r_g / \eta_b.$$

If the variable k_{AC} is set to 1, then available thermal energy from the prime mover is first used to drive the absorption chiller. Any excess thermal energy available from the prime mover is used to satisfy heating demands. Conversely, if $k_{AC} = 0$, then available thermal energy from the prime mover is first used to satisfy heating demands, with any excess going to drive the absorption chiller, as long as the potential output of the chiller is greater than its minimum operating level.

Another consideration for the absorption chiller is its minimum operating duration. Absorption chillers take some time to start-up and reach equilibrium temperatures and are not designed to cycle on and off quickly. Based on discussions with technical experts on absorption chiller operations, a 4 hour minimum continuous operating duration is imposed on any absorption chiller operation [Zaltash (2005)]. For any given hour, this is accomplished in the model by evaluating the chiller operation in the previous three hours and the potential operation in the following three hours. If the current hour could accommodate chiller operation based on the minimum operating level of the chiller, and if any contiguous combination of operation during this ± 3 hour window, including the hour under consideration, yields 4 or more hours of continuous operations, operation of the chiller is allowed in the current hour. Otherwise, the absorption chiller does not operate in the current hour.

In order to determine the generation output of the DG system for a given hour, the maximum *potential* electrical demand for that hour must be determined. First, if there is no absorption chiller or if the cooling demand for the current hour is below the absorption chiller minimum operating level, the maximum electrical demand, M_{ei} , is the same as the electrical demand in the non-CHP scenario, since all cooling for that hour must come from electric chillers. Thus, from the prior section,

$$M_{ei} = d_{ei} = d_{e^{\circ}i} + d_{ci} / \eta_{EC} .$$

If an absorption chiller is available to run in a given hour and if the DG electricity production in meeting the non-cooling demand, $d_{e^{\circ}i}$, plus the parasitic electrical load of the absorption chiller, d_{pAC} , produces sufficient thermal energy to satisfy both heating and cooling demands, then

$$M_{ei} = d_{e^{\circ}i} + d_{pAC} .$$

Otherwise, M_{ei} depends on the thermal preference, k_{AC} . If $k_{AC} = 1$, indicating a preference to use the thermal energy for absorption cooling, then if

$$((d_{e^{\circ}i} + d_{pAC}) / \theta - d_{ci} / \eta_{AC}) \geq 0 \text{ and } G_{AC} \geq d_{ci} ,$$

$$\text{then } M_{ei} = d_{e^{\circ}i} + d_{pAC} .$$

Otherwise, when there is insufficient thermal energy to satisfy all the cooling demand via the absorption chiller, additional CHP system electrical demand is added to the non-cooling demand base value to supply electric chillers, such that

$$M_{ei} = d_{e^{\circ}i} + d_{pAC} + \frac{(d_{ci} - (d_{e^{\circ}i} + d_{pAC}) / \theta \cdot \eta_{AC})}{\eta_{EC}} \cdot \frac{1}{(1 + \eta_{AC} / (\theta \cdot \eta_{EC}))} .$$

The latter term is included in order to recognize that as more electricity is produced to meet the shortfall, more thermal energy is available for cooling via the absorption chiller.

If the thermal preference is to satisfy heating demand first, $k_{AC} = 0$, then if

$$(d_{ei} / \theta - d_{hi}) \leq G_{AC} \cdot f_{AC} / \eta_{AC} ,$$

such that there is insufficient thermal energy available for cooling purposes, then $M_{ei} = d_{ei}$,

which includes the additional electrical load for electric chillers to satisfy cooling demands.

However, should there be sufficient thermal energy remaining after meeting the heating demand,

$$M_{ei} = d_{e^{\circ}i} + d_{pAC} + \frac{(d_{ci} - ((d_{e^{\circ}i} + d_{pAC}) / \theta - d_{hi}) \cdot \eta_{AC})}{\eta_{EC}} \cdot \frac{1}{(1 + \eta_{AC} / (\theta \cdot \eta_{EC}))} .$$

With respect to determining the maximum potential thermal demand, for any hour i , the maximum thermal demand of the CHP system, M_{Ti} , is d_{hi} if $d_{ci} < G_{AC} \cdot f_{AC}$ or $d_{hi} + \min(d_{ci}, G_{AC}) / \eta_{AC}$ otherwise.

Once the maximum potential thermal and electric demands are calculated for each hour, the operation of the CHP system for each hour can be determined. It should be noted that calculations for CHP operations are performed for each hour of the year, irrespective of whether the CHP system will actually run in that hour. The determination of whether the CHP system runs in a given hour is dependent on the operating strategy chosen. In some cases, the operation of a CHP system may be specified explicitly by the owner/operator, irrespective of hourly costs (e.g., to coincide with daily shift schedules). In other cases, the decision to operate the CHP system may be based solely on an energy cost make-or-buy decision for a given hour (i.e., in an economic dispatch mode). Thus, the costs of potentially operating the CHP system must be known to allow for cost comparisons.

For any hour i , the potential electric generation is based on the maximum CHP electric demand, M_{ei} . If M_{ei} is less than the minimum operating level of the distributed generator, $G_{DG} \cdot f_{DG}$, then the electric generation, g_{ei} , is zero. Otherwise, $g_{ei} = \min(M_{ei}, G_{DG})$, where G_{DG} is the net electrical generating capacity of the distributed generation CHP system. The corresponding potential thermal energy available, $g_{Ti} = \min(M_{Ti}, g_{ei} / \theta)$.

To provide that all thermal and electrical demand is satisfied, any electrical, heating, or cooling demand not provided by the CHP system must be supplemented by the utility grid/on-site boiler. To determine the amount of supplemental heating needed, the heating demand, d_{hi} , is compared to the thermal energy generated, g_{Ti} , taking into account any thermal energy utilized by the absorption chiller. Mathematically,

$$s_{hi} = d_{hi} - (g_{Ti} - g_{ci} / \eta_{AC}).$$

The corresponding gas required for the on-site boiler will be $s_{gi} = s_{hi} / \eta_b$. Similarly, the amount of grid-supplied electricity needed to provide supplemental cooling (i.e., cooling beyond that provided by the CHP system) can be expressed as

$$s_{ci} = (d_{ci} - g_{ci}) / \eta_{EC} - (g_{ei} - d_{eoi} - d_{pAC}) \text{ if } g_{ei} > d_{eoi}.$$

Otherwise,

$$s_{ci} = (d_{ci} - g_{ci}) / \eta_{EC} + d_{pAC}.$$

In addition to grid electricity used for any supplemental cooling, if $G_{DG} < d_{eoi}$, the difference will also be obtained from the grid, such that

$$s_{ei} = s_{ci} + (d_{eoi} - g_{ei}).$$

Costs for the CHP system for each hour are determined as the sum of the operating costs of the distributed generation system, the cost of any fuel used in boiler firing for supplemental heating, and any grid-supplied electricity purchased to cover supplemental electrical loads. The operating costs of the DG system include natural gas fuel and system O&M costs. The hourly cost for the DG system is calculated as

$$C_{DGi} = g_{ei} / \eta_{DG} \cdot r_g + g_{ei} \cdot C_{OM}.$$

Costs for supplemental gas and electricity are $C_{gsi} = s_{gi} \cdot r_g$ and $C_{esi} = s_{ei} \cdot r_{ei}$, respectively. The total hourly cost for the CHP system can be expressed as

$$C_{CHPi} = C_{DGi} + C_{gsi} + C_{esi}.$$

It should be noted that the electrical efficiency of the distributed generator is not a constant value, but, as mentioned at the beginning of this section, is a function of the output level of the generator. Part-load efficiencies also differ by type of prime mover (e.g., gas turbine, reciprocating engine). The efficiency relationships used in the model are based on an assessment of part-load efficiency data from Fischer (2005), Goldstein et al. (2001), Orlando (1996), and

Petchers (2003). This study uses polynomial functions of the electric output fraction (i.e., part-load fraction) to generate DG part-load efficiency values. The polynomial equations and resulting part-load efficiency curves are shown in Figure 3-3 for fuel cells, reciprocating engines, and gas turbines.

As mentioned above, the determination of whether the CHP system operates in a given hour is based on the operational strategy selected. If an explicit, a priori operations schedule is not defined, hourly CHP system operation is determined on the basis of least cost when compared to the cost of the non-CHP scenario. If, for a given hour, the operation of the CHP system satisfies the electrical and thermal demands for less cost (on an energy-cost basis) than the non-CHP scenario, then the CHP system operates in that hour. Otherwise, consideration must be given to running the CHP system anyway at an energy-cost loss, so as to avoid being the hour that sets the demand charge for the month. Recall that the demand charge for a given demand block in a month is determined by the highest power demand occurring during that block of time for the entire month. Typically, the amount of economic loss related to a given hourly energy cost differential is very small compared to setting the demand charge for the month by not running the CHP system in that hour. Therefore, if $(d_{ei} - s_{ei}) \cdot r_{djk} > C_{CHPi} - C_{Ui}$, then the CHP system will be scheduled to operate in that hour. Otherwise, the CHP system will not run in that hour, and all energy will be provided by the electric grid and on-site boiler.

Once the operating decision is made, hourly costs can be summed over the entire annual period to obtain the annual operating cost for providing electricity, heating, and cooling to the facility. Recalling that two separate scenarios are determined simultaneously, the amount of annual cost savings (if any) from operating a CHP system, relative to relying on grid-based electricity and on-site boiler heating, can be defined as

$$C_S = C_U - \sum_{i=1}^{8760} C_{CHPi} ,$$

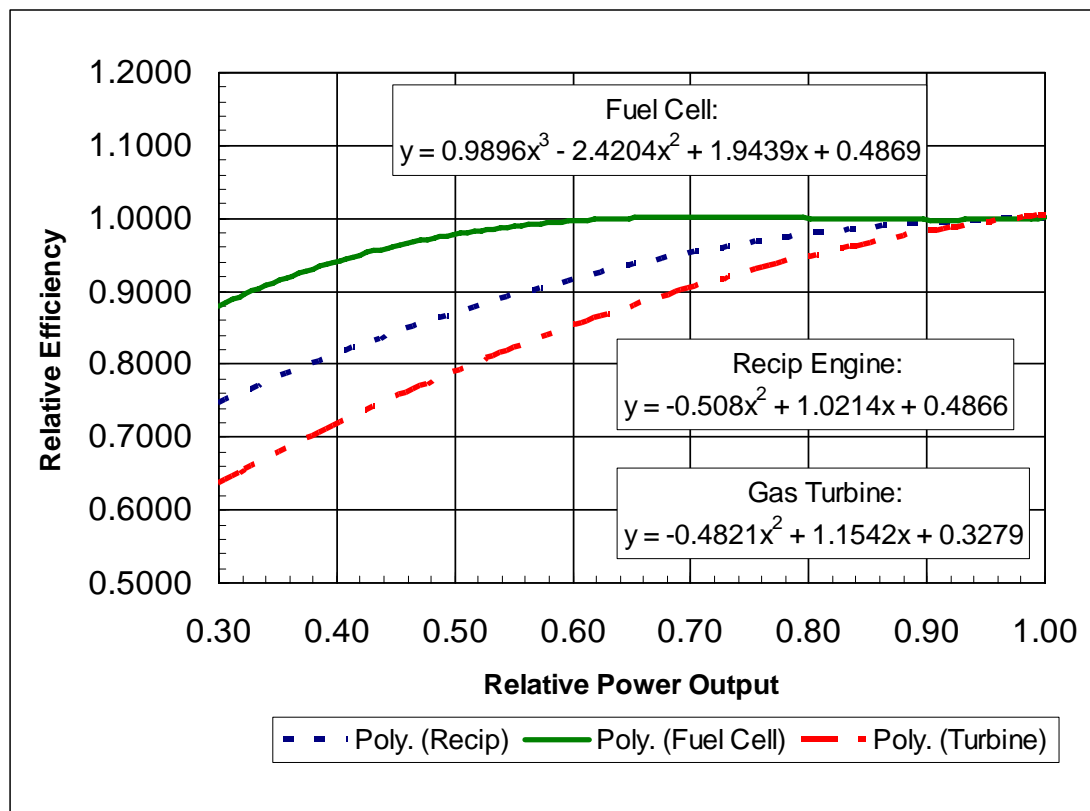


Figure 3-3. Part-Load DG Electrical Efficiency Factors

where C_U is the annual cost of the non-CHP scenario, as defined in the previous section. If C_S is positive, then the CHP system has a lower annual operating cost, and the value represents a savings relative to the non-CHP scenario.

Operating costs such as electricity and gas are considered expense items and are tax-deductible with respect to determination of income tax. Therefore, total annual operating savings C_S is multiplied by $(1 - t)$, where t is the effective income tax rate applicable to the facility under study, to determine an after-tax annual cost. If state income tax is a relevant consideration, the effective income tax rate can be determined as

$$t = \text{state rate} + \text{federal rate} \cdot (1 - \text{state rate}),$$

to reflect the deductibility of state taxes on federal taxes [Sullivan, Wicks and Luxhoj (2006)].

In order to equitably determine the economic viability of a CHP system, the capital or investment costs of the CHP system, and related income tax effects, must be included. The total capital investment cost of the CHP system is

$$I_{CHP} = G_{DG} \cdot I_{DG} + G_{AC} \cdot I_{AC}$$

and includes all equipment, labor, and materials to fully install the CHP system. As capital assets may be depreciated for income tax purposes, the income tax benefits of CHP asset depreciation are determined using a 15-year recovery period as defined by the Internal Revenue Service MACRS depreciation schedules [Internal Revenue Service (2004)].

Finally, the capital and operating cost elements are combined to create the net present value (NPV) of the cost savings of the CHP system. The cost savings NPV, which serves as the objective function for optimization, is expressed as

$$NPV_{CHP} = PW(C_S \cdot (1 - t)) - I_{CHP} + PW(D_n),$$

where PW is the present worth of a series of cash flows and D_n are the annual tax benefits resulting from depreciation of the CHP system capital investment.

3.3 Capacity Optimization

As mentioned at the outset of this chapter, the optimization goal is to maximize NPV cost savings by determining the optimum installed capacities for the electricity generation system and the absorption chiller. Given that only objective function values are directly available in this computational model (i.e., no analytical expressions for first or second derivatives), it is felt that, based on the review of the literature as noted in Chapter 2, the use of a quasi-Newton method with Broyden-Fletcher-Goldfarb-Shannon (BFGS) updates of the inverse Hessian is the most appropriate approach.

The quasi-Newton method is a variant of the Newton method and can be found in any good nonlinear optimization textbook [Gill, Murray and Wright (1986); Fletcher (1987); Bazaraa, Sherali and Shetty (1993); Bertsekas (2004); Bartholomew-Biggs (2005)]. The Newton method relies on a three term Taylor approximation of an assumed quadratic behavior of the objective function. As such, the quadratic model of the objective function, F , can be expressed as

$$F(x_k + p) \approx F_k + g_k^T p + \frac{1}{2} p^T G_k p,$$

where g , p , and G are the gradient (Jacobian) in x , step direction, and Hessian in x , respectively. As we seek to find a stationary point of the function with respect to the step direction p , the objective function can be rewritten in p as

$$F(p) = g_k^T p + \frac{1}{2} p^T G_k p.$$

A necessary condition for a stationary point is that the gradient vector vanish at that point. Thus,

$$\nabla F(p) = g_k + G_k p = 0 \text{ or } p = -G_k^{-1} g_k.$$

If G is positive definite, then conditions are sufficient to state that p can be a minimum stationary point [Gill, Murray and Wright (1986)]. In the case of maximization, G should be negative definite. The Newton method requires, however, that the Hessian of the objective function be

known or determinable. In the current problem, the Hessian can not be determined analytically. Thus, we rely on a sequential approximation to the Hessian as defined by the quasi-Newton method.

The typical quasi-Newton method assumes that the gradient of the objective function is available. As discussed in Chapter 2, the model used in this research has no analytic representation of either first or second derivatives. In this situation, a forward-difference approximation must be used to estimate the gradient vector. For the i^{th} independent variable, x_i , the gradient is estimated by

$$g_i = \frac{1}{h} (F(x_i + h) - F(x_i)),$$

where h is the finite-difference interval. For this study, a finite-difference interval of 10^{-4} was selected after evaluating choices ranging from 10^{-2} to 10^{-6} .

The general outline of the quasi-Newton method for maximization is as follows:

- Choose some x_0 as an initial estimate of the maximum of $F(x)$
- Set the initial inverse Hessian, H_0 , equal to the negative identity matrix (an arbitrary symmetric negative definite matrix)
- Repeat for $k = 0, 1, 2, \dots$
 - Determine $g_k = \nabla F(x_k)$ by forward-difference approximation
 - Set the step length scalar, λ , equal to 1
 - Calculate the full step direction $p_k = -H_k g_k$
 - Evaluate whether the full step is appropriate by comparing $F(x_k + \lambda p_k)$ to $F(x_k)$. If $F(x_k + \lambda p_k) < F(x_k) + \rho \lambda g_k^T p_k$, solve for the step length λ that produces a univariate maximum $F(\lambda)$ for $0 \leq \lambda \leq 1$.
 - Set $x_{k+1} = x_k + \lambda p_k$, $y_k = g_{k+1} - g_k$, $d_k = x_{k+1} - x_k$
 - Evaluate stopping criteria, and if not achieved,
 - Update the approximate inverse Hessian such that $H_{k+1} y_k = d_k$
 - Increment k

The stopping criteria used in this model is consistent with prior work by Edirisinghe, Patterson and Saadouli (2000) and Kao, Song and Chen (1997) in which the algorithm is

terminated when either the change (i.e., improvement) in the objective function is less than a prescribed threshold amount or when the gradients of the objective function at a particular input vector are zero. The setting of the termination threshold value is a matter of engineering judgment. If a value is chosen that requires very small changes in the objective function before termination, the algorithm can cycle for a large number of iterations with very little overall improvement in the objective function. Conversely, a more relaxed threshold value can terminate the optimization algorithm prematurely, producing a suboptimal solution. A balance must therefore be struck between long execution times and less than total maximization of the objective function. As the objective function in this study is NPV cost savings over a multiyear period, one must select a value at which iterative improvements in NPV cost savings are considered negligible. There are two approaches used in setting this termination threshold. First, on an absolute basis, if the iterative improvement of the NPV cost savings is less than \$50.00, it is considered reasonable to terminate the algorithm. In some cases, however, this absolute value can be a very small percentage of the overall savings, thus leading to long execution times with little relative gain. The second termination approach is based upon a relative measure on the objective function. If the change in NPV cost savings between iterations is greater than \$50.00, but less than 0.00001 times the objective function value, then the algorithm terminates under the assumption that a change of less than 0.001 percent is insignificant.

As will be discussed further in Chapter 4, the objective function in this study can exhibit multiple local optima of low magnitude relative to the average value within a neighborhood around the stationary point (i.e., low-level noise of the objective function). In such situations, a means to help avoid getting “trapped” in a *near* optimum response space, particularly when the response surface is relatively flat, is to require two or three consecutive iterative achievements of the stopping criterion [Kim (2005)]. For this study, two consecutive achievements of the

stopping criterion detailed in the previous paragraph were required to end the optimization process.

In some cases with multiple local optima, the model may find a local optimum rather than the global optimum. A useful technique to improve the solution is to try different starting points for the optimization [Fylstra et al. (1998)]. As discussed in Chapter 4, this alternative is available in the model.

The updating of the matrix H , representing a sequential approximation of the inverse Hessian, is done using the BFGS method. As discussed in the previous chapter, the BFGS update method is clearly considered to be the most efficient and robust approach available at this time. The BFGS formula for H_{k+1} , as presented by Zhang and Xu (2001) and Bartholomew-Biggs (2005), is:

$$H_{k+1} = H_k - \frac{H_k y_k d_k^T + d_k y_k^T H_k}{d_k^T y_k} + \left[1 + \frac{y_k^T H_k y_k}{d_k^T y_k} \right] \frac{d_k d_k^T}{d_k^T y_k}.$$

As discussed in Chapter 2, there are a number of methods that can be employed in the back-tracking search for the Newton step length λ that produces a maximum in the objective function. In this study, a quadratic and cubic spline fit was evaluated, but the method was not stable under some input conditions or required a large number of iterations before reaching the stopping criterion. This appears to be due to the lack of strict concavity of the objective function. As a result, the Golden sequential line search method was selected for its accuracy and stability. The Golden search was terminated when the Interval of Uncertainty (IOU) for the step length λ became less than 0.025. It should be noted that the step length can be unique to each variable rather than being a single scalar value. Such an approach was explored, but the additional computations did not seem to produce sufficiently improved results (i.e., faster optimization) to merit incorporating the approach in the final model.

In order to provide visual guidance regarding the surface behavior of the objective function within the overall solution space, a simultaneous uniform line search method was utilized as well. Using a 21×7 (DG x AC) grid, grid step sizes were selected to evaluate the complete range of possible CHP equipment capacities (i.e., $0 \leq \text{size} \leq \text{max load}$) for both the distributed generator and the absorption chiller. For each of the 147 cells, the DG/AC capacity combination was used as input to determine the corresponding NPV cost savings. A contour plot of the NPV cost savings was produced to graphically display the overall solution space.

As mentioned earlier, there are simple lower bound constraints that require the capacities of the distributed generator and absorption chiller to be greater than or equal to zero. In an unconstrained method, it is possible that the direction vector could propose a solution that would violate the lower bound. This model checks for this condition, and if present, sets the capacity value to zero. As an added element to improving the efficiency of the algorithm, if the capacity of the distributed generation is set to zero, the capacity of the absorption chiller is also set to zero, as DG capacity is the energy source to operate the absorption chiller. This approach does not violate the quasi-Newton method as the effect of zeroing the capacity when a negative capacity is suggested is equivalent to reducing the Newton step size for that iteration. In this situation, the new x_{k+1} point is set to zero, and gradients are calculated at the new input vector for use in the quasi-Newton algorithm. Should the economic conditions of the problem be such that the maximum objective function (given the lower bound constraints) is truly at zero capacity for the distributed generator, the next iteration will yield the same adjusted input vector (owing to a direction vector pointing into the negative capacity space) and same NPV cost savings, which will appropriately terminate the optimization on the basis of similar NPV results, as discussed above.

CHAPTER 4

MODEL DEVELOPMENT AND APPLICATION

This chapter focuses on implementation of the methodologies defined in the previous chapter onto a computational platform. The sections that follow will discuss the development of the computer model, as well as the observations and adjustments made during the development of the model. Sample case studies using the model will also be provided.

4.1 Development of the Computer Model

In order to provide useful transparency of the calculations, the methods defined in the subsequent chapter were implemented using Microsoft Excel. Excel spreadsheets allow others to view the computational formulae, which enhances understanding and confidence in the modeling approach. In addition, Microsoft Excel is a ubiquitous platform found on most personal computer (PC) systems. The model in this research, named the CHP Capacity Optimizer, was developed using Microsoft Office Excel 2003 on a PC running the Microsoft Windows XP Professional operating system (version 2002). The computer model is available upon request of the author.

One of the goals of the model was to provide a user interface that was clean and uncluttered. A main screen, shown in Figure 4-1, was designed to serve as the means to provide input to the model and to view summary results from the computations. The model makes use of Excel's Visual Basic for Applications (VBA) macro language to control movement to various sheets within the overall spreadsheet file and to initiate the optimization procedure. As shown in Figure 4-1, input to the model can be found in the upper left corner of the main sheet. As discussed previously, the data needed to run the optimizer consist of heating, cooling, and electrical hourly loads for a one year period, utility prices, various equipment efficiencies, equipment cost, and economic parameters.

4.1.1 Input Areas

In order to focus on the input navigation of the model, the input section of the main screen has been enlarged in Figure 4-2. The various input requirements will now be discussed.

Demand data

The hourly thermal and electric load data are accessed through the “Demand data” button shown in Figure 4-2. By clicking on the button, the hourly loads data sheet is shown. On that sheet hourly heating, cooling, and electric loads for the base year (i.e., the first year of operation) of the facility under consideration are stored. Although the complete demand data sheet consists of 8,760 hourly entries, Figure 4-3 provides a sample listing of the layout for the first 24 hours of the base year. It should be noted that the heating and cooling loads are expressed on an end-use, as-delivered basis. The “reported cooling electric kW” load is the corresponding electricity consumed to satisfy the cooling load if the cooling is provided by electric chillers. It is not a required input, but does serve to determine an average COP for conventional chillers. The final column of data, the “non-cooling electric load” is a required input describing all of the electrical load of the facility, exclusive of any cooling load.

The source of hourly load data can be actual hourly metering for existing facilities, if available, or the output of a building simulation program. There are at least two existing building simulation tools available to develop the hourly loads needed for input to the CHP Capacity Optimizer. One tool is the BCHP Screening Tool, available at no charge from Oak Ridge National Laboratory. The other known tool is Building Energy Analyzer offered by InterEnergy Software [InterEnergy/GTI (2005)]. Both tools utilize the DOE-2 computational engine [Birdsall et al. (1994)] to simulate any of 15 predefined structures (e.g., hospital, hotel, retail store) at any of 233 geographic locations. Both building simulation tools have an output option of saving hourly loads to a data file. The process to save the raw hourly load data and prepare it for use with the CHP Capacity Optimizer is described in Appendix A.

CHP Capacity Optimizer

Determine optimum capacity
10/12/2005 16:54

Scenario: Hospital in California

Input data

Demand data
Elec & fuel rate data
Escalation rate data

General data

On-site boiler efficiency	80.0%
Conventional chiller COP	4.00
DG electric efficiency (full output)	30.0%
DG unit minimum output	40%
Absorption chiller COP	0.70
Absorption chiller min. output	25%
Abs chiller sys elec req (kW/RT)	0.20
CHP O&M cost (\$/kWh)	0.011
DG power/heat ratio	0.65
Number of DG units	1
Type of prime mover	Recip
Discount rate	8.0%
Effective income tax rate	38.0%
DG capital cost (\$/net kW installed)	1500
AC capital cost (\$/RT installed)	1000
Planning horizon (years)	16

CHP Operations

☒ Operation based on hourly cost
☐ User defined operations

☒ Include absorption chiller
☐ Exclude absorption chiller

☒ Produce output contour plot

Figure 4-2. Input Section of Main Screen

Return to Main				Input data from raw datafile				
				Annual max:	6991660	4525781	316	634
				Annual min:	378187	0	11	387
				BTU		Rpt. Cooling	Non-cooling	
Month	Day	Hour	DoW	Heating load	Cooling load	Electric kW	Electric load	
1	1	1	7	1867479.5	136125.7	32.1	392.1	
1	1	2	7	2397348.6	126168.3	31.2	392.1	
1	1	3	7	2056502.7	124676.7	31.0	392.1	
1	1	4	7	2627097.7	121184.1	30.7	392.1	
1	1	5	7	2939225.3	110788.4	29.7	392.1	
1	1	6	7	4422894.8	274938.1	45.8	412.6	
1	1	7	7	5195368.7	282405.8	46.6	434.9	
1	1	8	7	4641695.2	300239.9	48.3	528.8	
1	1	9	7	4411973.3	345155.0	51.6	539.8	
1	1	10	7	3246873.0	373695.9	51.6	501.4	
1	1	11	7	3574033.2	485477.4	54.6	501.4	
1	1	12	7	2982991.3	867395.4	72.5	501.4	
1	1	13	7	2809368.9	934564.3	76.0	501.4	
1	1	14	7	2419090.2	993841.7	79.1	501.4	
1	1	15	7	2964515.2	1043938.2	81.7	501.4	
1	1	16	7	3284243.9	1049130.6	82.0	501.4	
1	1	17	7	2950980.5	979270.0	78.3	471.4	
1	1	18	7	2436668.1	978383.4	78.7	471.3	
1	1	19	7	1835157.9	951811.7	77.4	518.3	
1	1	20	7	2021437.6	806352.0	70.1	507.6	
1	1	21	7	1721414.7	569310.9	58.9	486.8	
1	1	22	7	1901758.0	504166.3	55.9	410.4	
1	1	23	7	2111762.9	367518.9	51.6	392.0	
1	1	24	7	1724036.9	319376.9	50.3	392.0	

Figure 4-3. Sample Demand Data

Electric and fuel rate data

Electric utility rates are defined in a separate sheet, accessed by clicking the "Elec & fuel rate data" button on the main sheet. Utility tariffs can be very complex and vary widely from utility to utility. The current input structure, shown in Figure 4-4, tries to accommodate the most common forms of tariffs, which can have different prices by time-of-day and by season. The current model is limited to two seasonal patterns. As is common in most utility tariffs, the cost of electricity consists of an energy component and a demand component. The energy cost component is the number of kilowatt-hours consumed in a given hour times the unit price charged per kilowatt-hour. As shown, the unit price can change by time-of-day. Similarly, demand charges can be divided into blocks by time-of-day. Up to three demand blocks (i.e., peak, shoulder, and off-peak) can be modeled. For each demand block, the monthly demand charge is based on the highest weekday kilowatt demand level in each month for that block multiplied by the unit demand price. A tariff used in the sample calculations is provided in Appendix B.

As some utilities require customers who self-generate to be assigned to a tariff different from those who purchase all their electricity from the utility, a second complete set of tariffs data is used for the CHP scenario. In addition, a separate capacity standby charge should be entered, if applicable. If there is no separate tariff for self-generating customers, the tariff data should simply be copied from the non-CHP section. Both tariffs must have data entries.

Unit fuel prices are also entered on this sheet. Similar to electricity, there can be different prices offered to facilities having a CHP system, so two prices (one for each scenario) must be entered. The price of natural gas is typically quoted on a HHV basis. However, it is typical that fuel usage calculations are performed on a LHV basis. For consistency, the prices entered should be on a LHV basis. (See Section 3.2 for further details.)

Finally, all unit prices should be current to the first year of operation. Escalation of prices through time will be discussed in subsequent paragraphs.

Electric rates

Non-CHP Energy

Pattern 1 Energy

\$/kWh

Pattern 2 Energy

\$/kWh

month

pattern #

hour

rate

hour

rate

1

1

1

0.07781

1

0.078

2

1

2

0.07781

2

0.078

3

1

3

0.07781

3

0.078

4

1

4

0.07781

4

0.078

5

2

5

0.07781

5

0.078

6

2

6

0.07781

6

0.078

7

2

7

0.07781

7

0.078

8

2

8

0.09653

8

0.09114

9

2

9

0.09653

9

0.09114

10

2

10

0.09653

10

0.09114

11

1

11

0.09653

11

0.09114

12

1

12

0.09653

12

0.14913

13

0.09653

13

0.14913

14

0.09653

14

0.14913

15

0.09653

15

0.14913

16

0.09653

16

0.14913

17

0.09653

17

0.14913

18

0.09653

18

0.09114

19

0.09653

19

0.09114

20

0.09653

20

0.09114

21

0.07781

21

0.078

22

0.07781

22

0.078

23

0.07781

23

0.078

24

0.07781

24

0.078

Non-CHP Demand

Pattern 1 Demand

\$/kw-mo

month

pattern #

hour

peak

shoulder

off-peak

hour

peak

shoulder

off-peak

1

1

1

1

2

1

2

2

3

1

3

3

4

1

4

4

5

2

5

5

6

2

6

6

7

2

7

7

8

2

8

6.58

8

3.64

9

2

9

6.58

9

3.64

10

2

10

6.58

10

3.64

11

1

11

6.58

11

3.64

12

1

12

6.58

12

16.12

13

6.58

13

16.12

14

6.58

14

16.12

15

6.58

15

16.12

16

6.58

16

16.12

17

6.58

17

16.12

18

6.58

18

3.64

19

6.58

19

3.64

20

6.58

20

3.64

21

21

22

22

23

23

24

24

Return to Main

NOTE: All data to be expressed in year 1 rates

Non-CHP Fuel Price
Fuel price on LHV basis
\$9.00\$/MMBtu

CHP Fuel Price
Fuel price on LHV basis
\$9.00\$/MMBtu

Electric rates

CHP Energy

Pattern 1 Energy

\$/kWh

Pattern 2 Energy

\$/kWh

month

pattern #

hour

rate

hour

rate

1

1

1

0.07781

1

0.078

2

1

2

0.07781

2

0.078

3

1

3

0.07781

3

0.078

4

1

4

0.07781

4

0.078

5

2

5

0.07781

5

0.078

6

2

6

0.07781

6

0.078

7

2

7

0.07781

7

0.078

8

2

8

0.09653

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0.09114

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0.09114

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20

0.09114

21

0.07781

21

0.078

22

0.07781

22

0.078

23

0.07781

23

0.078

24

0.07781

24

0.078

CHP Demand

Pattern 1 Demand

\$/kw-mo

month

pattern #

hour

peak

shoulder

off-peak

hour

peak

shoulder

off-peak

1

1

1

1

2

1

2

2

3

1

3

3

4

1

4

4

5

2

5

5

6

2

6

6

7

2

7

7

8

2

8

6.58

8

3.64

9

2

9

6.58

9

3.64

10

2

10

6.58

10

3.64

11

1

11

6.58

11

3.64

12

1

12

6.58

12

16.12

13

6.58

13

16.12

14

6.58

14

16.12

15

6.58

15

16.12

16

6.58

16

16.12

17

6.58

17

16.12

18

6.58

18

3.64

19

6.58

19

3.64

20

6.58

20

3.64

21

21

22

22

23

23

24

24

CHP Standby Charge

\$/kw-mo

Figure 4-4. Electric and Fuel Rate Data

Escalation rate data

As it is unlikely that prices will remain steady over the economic study period, unit prices for electricity, fuel, and operating and maintenance (O&M) can be escalated through time. In addition, heating, cooling, and electrical loads can be escalated as well to reflect changes in loads as a function of time. Escalation input is accessed via the "Escalation rate data" button on the main sheet. For each cost or load category, the annual percent change from the previous year for up to a maximum of 16 years can be entered. As shown in Figure 4-5, the escalation rate does not have to be constant during the study period, but rather can vary from year to year. Values can be positive for escalation or negative for de-escalation. As discussed in Section 3.2.1, the model levelizes the various escalation components to produce a multiplier to the base-year values. When escalation is present, the values used in the hour-by-hour calculation are levelized values, which produce equivalent results to an explicit year-by-year price/load adjustment.

Escalation data						
Expressed in percent change from previous year						
Year	Fuel price	Elec price	O&M cost	Heat load	Cool load	Elec load
2	-0.5%	0.5%	0.5%	0.0%	0.0%	0.0%
3	0.0%	1.0%	0.5%	0.0%	0.0%	0.0%
4	0.0%	1.0%	0.5%	0.0%	0.0%	0.0%
5	0.0%	1.0%	0.5%	0.0%	0.0%	0.0%
6	0.0%	1.0%	0.5%	0.0%	0.0%	0.0%
7	0.5%	0.5%	0.5%	0.0%	0.0%	0.0%
8	0.5%	0.5%	1.0%	0.0%	0.0%	0.0%
9	0.5%	0.5%	1.0%	0.0%	0.0%	0.0%
10	0.5%	0.5%	1.0%	0.0%	0.0%	0.0%
11	0.5%	0.5%	1.0%	0.0%	0.0%	0.0%
12	1.0%	1.0%	1.0%	0.0%	0.0%	0.0%
13	1.0%	1.0%	1.0%	0.0%	0.0%	0.0%
14	1.0%	1.0%	2.0%	0.0%	0.0%	0.0%
15	1.0%	1.0%	2.0%	0.0%	0.0%	0.0%
16	1.0%	1.0%	2.0%	0.0%	0.0%	0.0%
Levelized	1.010125	1.047144	1.042355	1.000000	1.000000	1.000000

Figure 4-5. Sample Escalation Input Data

General data

The remaining input data and simulation options are entered from the main sheet. As shown in Figure 4-6, data related to the existing and proposed systems must be entered. The individual items needed were defined in Section 3.2. In addition, there are three input switches available on the main sheet to allow the user to explicitly define when the CHP system operates, whether the system should include an absorption chiller, and whether a contour plot should be produced.

Although typical analyses will use hourly cost as a determinate for running the CHP system as described in Section 3.2, if it is desired to explicitly define the hours of CHP system operation (e.g., weekdays between 8 a.m. and 6 p.m.), then upon selecting "User defined operations", a new button, "Define op schedule", will appear, which takes the user to an hour-by-hour table, shown in Figure 4-7. Hours indicated with a binary value of 1 specify that the CHP system must run, irrespective of cost.

With respect to the absorption chiller option, if the user wishes to explicitly exclude consideration of an absorption chiller, for example, when the benefit of having an absorption chiller in the system is economically marginal, the user can simply click the "Exclude absorption chiller" button to force chiller exclusion.

Finally, the production of the contour plot using a simultaneous line search as described in Section 3.3 consumes slightly more than half of the computational time required for an optimization analysis. For parametric studies that evaluate various input values, it may be desirable to exclude the production of the contour plot for each scenario. A check box option is available on the main sheet to limit the production of the contour plot.

General data		CHP Operations	
On-site boiler efficiency	80.0%	<input checked="" type="radio"/> Operation based on hourly cost	
Conventional chiller COP	4.00	<input type="radio"/> User defined operations	
DG electric efficiency (full output)	30.0%		
DG unit minimum output	40%		
Absorption chiller COP	0.70		
Absorption chiller min. output	25%	<input checked="" type="radio"/> Include absorption chiller	
Abs chiller sys elec req (kW/RT)	0.20	<input type="radio"/> Exclude absorption chiller	
CHP O&M cost (\$/kWh)	0.011		
DG power/heat ratio	0.65		
Number of DG units	1		
Type of prime mover	Recip		
Discount rate	8.0%		
Effective income tax rate	38.0%		
DG capital cost (\$/net kW installed)	1500	<input checked="" type="checkbox"/> Produce output contour plot	
AC capital cost (\$/RT installed)	1000		
Planning horizon (years)	16		

Figure 4-6. General Data and Simulation Controls

Hour	Weekends	Weekdays
1	0	0
2	0	0
3	0	0
4	0	0
5	0	0
6	0	1
7	0	1
8	0	1
9	0	1
10	0	1
11	0	1
12	0	1
13	0	1
14	0	1
15	0	1
16	0	1
17	0	1
18	0	1
19	0	0
20	0	0
21	0	0
22	0	0
23	0	0
24	0	0

Figure 4-7. User Defined Operating Schedule

Determining optimum capacity

After all input has been made, the economic optimum capacity is determined by pressing the "Determine optimum capacity" button. The initiation of this optimization starts a VBA macro that contains the optimization algorithm described in Section 3.3. A listing of the algorithm is provided in Appendix C. The optimization routine is computationally intensive. Depending upon the clock speed of the PC, the optimization may take from 3 to 7 minutes.

4.1.2 Results Areas

Summary results are provided in the upper right portion of the main sheet. As shown in Figure 4-8, this area restates the electrical and thermal loads, identifies the optimum installed capacities, summarizes CHP system operation, and provides cost data related to both the non-CHP and CHP systems. As mentioned earlier in Section 3.2.1, the cost and/or load escalation is computationally handled by a levelization method, and therefore, the annual performance and cost data represent levelized values over the period of time defined by the planning horizon.

The optimum capacities are further highlighted in a green box. While this may seem redundant, it allows the user to explore other capacity values while keeping the calculated optimum in view. Specific capacity values can be entered manually using the two manual input buttons shown in Figure 4-8. All operation and cost parameters are recalculated with any manually entered capacity inputs. The results can then be compared to the calculated optimum values shown in the green inset.

Two graphs are also part of the main screen. On the lower right of the main screen, a summary of the operation of the CHP system is provided by showing the number of days per year that the system operates for each hour of the day. (See Figure 4-9.) As mentioned above, these values are levelized across the planning horizon if escalation is present.

Results							
		Demands	Electricity	Heating	Cooling		
		Annual	5,466,118 kWh	16,919 MMBtu	1,250,204 RT-hr		
		Maximum	958 kW	7.0 MMBtu/hr	377 RT		
		Minimum	387 kW	0.38 MMBtu/hr	0 RT		
			Installed DG capacity:	413.4 kW (net)	Manual DG Capacity Input		
			Installed AC capacity:	37.7 RT			
			Hours of DG operation	6,951 hours/year	Manual AC Capacity Input		
			DG generated electricity	2,871,510 kWh/year			
			DG supplied heating	13,630 MMBtu/year			
			AC supplied cooling	114,451 RT-hr/year			
		Annual costs (before tax)	With CHP	No CHP			
		CHP system	\$354,301	\$0			
		Utility elec	\$322,945	\$676,192			
		Non-CHP gas	\$40,493	\$208,294			
		Total	\$717,739	\$884,486			
			Annual operating savings (after tax):	\$103,383			
			NPV savings:	\$416,943			
			Optimum DG capacity:	413.4 kW			
			Optimum AC capacity:	37.7 RT			
			NPV savings:	\$416,943			

Figure 4-8. Summary Results Area of Model

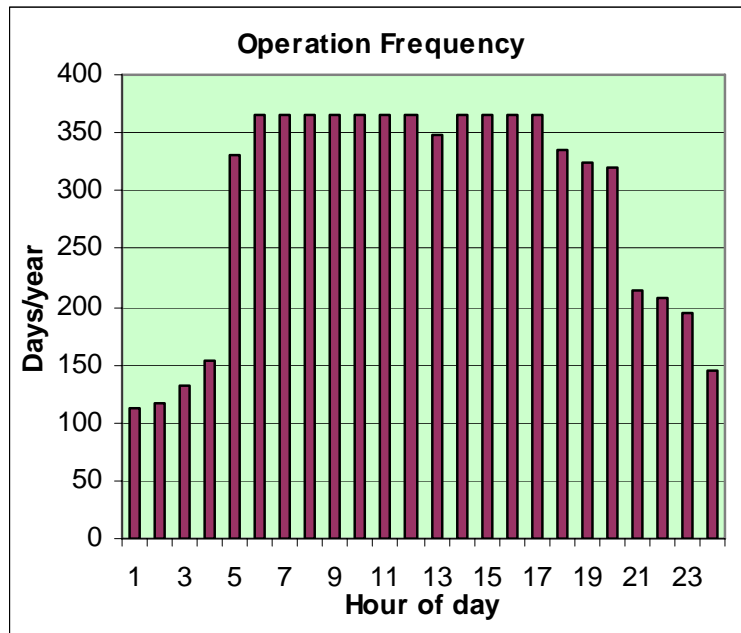


Figure 4-9. Hourly Operating Frequency

In the lower left of the main sheet, a contour plot of the entire solution space is provided in order to give the user a better insight into the economic impact of alternative (i.e., less than optimal) capacity decisions. As shown in Figure 4-10, it provides a color-coded, topographic representation of the NPV savings from the CHP system for various combinations of installed prime mover and absorption chiller capacities.

Detailed, hour-by-hour results can be reviewed by clicking on the "View detailed calcs" button, located to the left of the contour plot. The hourly computation sheet is the heart of the operation simulation. There is a row of calculations for each hour of the year. Most of the calculations described in Section 3.2 can be found in this detailed sheet. The return to the main sheet can be found at the top of column AQ.

As mentioned in Chapter 3, under certain input conditions, the model may conclude the optimization at a local optimum that is not the global optimum. If that appears to be the case (e.g., from inspection of the contour plot), there is an "Optimization Settings" button beneath the Case notes area on the main screen which allows a different optimization starting point to be tried. In some instances, several different starting point values and subsequent optimization runs may need to be tried in order to find the global optimum set of capacities. In addition, the optimization stopping criterion of \$50.00 change in NPV savings per iteration (as discussed in Section 3.3) can be modified in this area also.

4.2 Application of the Computer Model

This section addresses the results obtained from the model during two phases of the research. The first relates to results observed during the development of the model. Modifications to the optimization algorithm and explicit benchmark runs will be discussed in the first section. The second section provides the results of the completed model for a number of different cases, demonstrating the flexibility and robustness of the model under differing inputs.

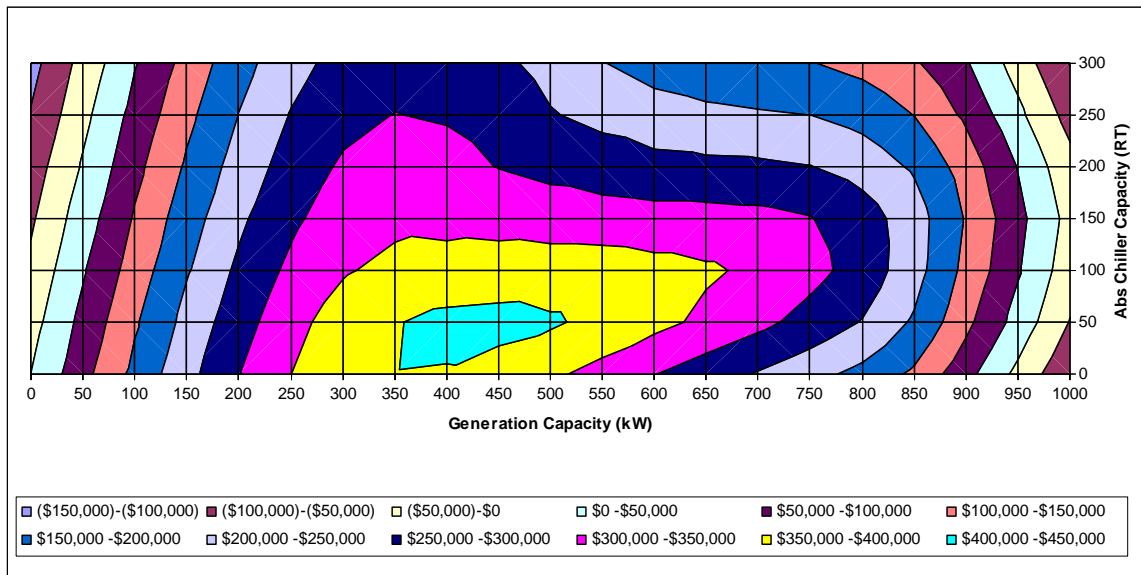


Figure 4-10. Contour Plot of Objective Function

4.2.1 Results During Development

Escalation methodology

As discussed in Section 3.2.1, escalation of unit prices and/or loads through time is addressed by the use of levelizing factors. In order to assure that this approach would yield the same results as explicit year-by-year calculations, a test model explicitly modeling every hour of a six year planning horizon was developed. This model required 52,560 rows for the hourly calculations, resulting in a 147 MB Excel file. Such a large model would not be tractable for standard use, but it is useful for benchmark comparison to the results from a levelized model. Several different escalation patterns were explored during this test. The various escalation rates and the resulting NPV savings values from the two models are provided in Table 4-1. The first case, shown in the first column of results, evaluated the models with no escalation to ensure exact agreement between the models when escalation was not a factor. The remaining columns reflect differing rates of escalation for gas and electricity unit prices as well as for thermal and electric loads. As shown, there is very little difference in the results between the two models, which led to the acceptance of a levelized modeling approach for reflecting escalation of unit prices and loads.

Objective function surface features

As mentioned in Section 3.3, there are various influences acting on the objective function which cause it to exhibit a low-magnitude “bumpiness” when moving around the solution space in very small increments. The bumpiness is due in part to single hour operating decisions in the operation simulation in which a small change in capacity during a particular iteration will cause either the prime mover or absorption chiller to hit against its minimum operating level constraint, such that the resource is not available for that hour. Such step changes in equipment availability cause slight perturbations in the objective function surface. The perturbations produce both

Table 4-1. Escalation Rate Evaluation

Case number	0	1	2	3	4	5	6
Gas unit price escalation (%)	0	2	3	3	1	1	0.5
Electricity unit price escalation (%)	0	2	2	3	2	1	1
Thermal load escalation (%)	0	1	0	0	-0.5	-1	0.5
Electrical load escalation (%)	0	1	0	2	-0.5	-2	0.5
DG capacity (kW)	421.2	654.4	487.7	633.7	658.1	532.5	533.7
AC capacity (RT)	0	89.6	25.8	67.0	75.7	42.0	38.2
Levelized model NPV savings	\$90,317	\$134,296	\$108,804	\$155,497	\$155,473	\$108,629	\$121,014
Explicit model NPV savings	\$90,317	\$134,273	\$108,824	\$155,481	\$155,587	\$108,251	\$121,039
Percent difference	0	0.02	-0.02	0.01	-0.07	0.35	-0.02

small, local optima as well as localized gradients that can be inconsistent with the overall shape of the objective function with respect to capacity changes. Figure 4-11 provides an example of the objective function surface which shows a slight rolling behavior of the maximum NPV savings in small increments of the independent variables.

To assist in avoiding the selection of a local optimum that was not the global optimum, a technique of requiring the stopping criterion to be met in successive iterations of the optimization algorithm was employed. Two or more successive iterations can be used to terminate a solution. The logic of this approach is that subsequent BFGS updates to the inverse Hessian may produce a direction vector that will step out of a small local optimum and ultimately find a better solution. In this study, two successive achievements of the stopping criterion were required to terminate the algorithm.

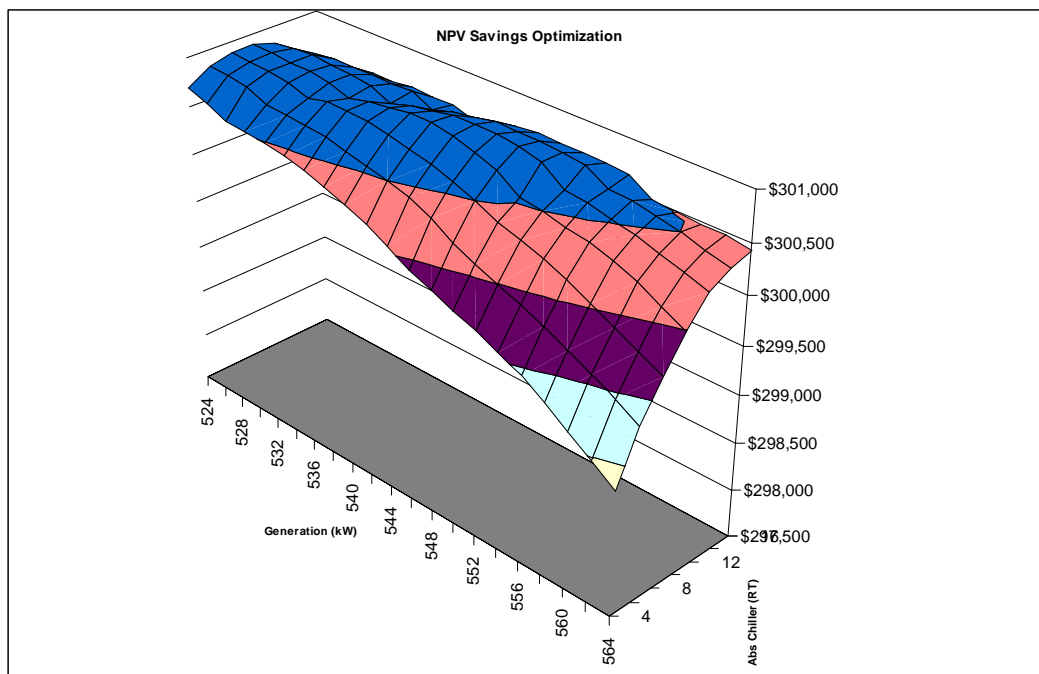


Figure 4-11. Example of Objective Function Surface Features

Optimization algorithm benchmarking

As mentioned in Section 2.2, Microsoft provides an add-in tool in Excel for solving linear and nonlinear optimization problems. The interactive tool, Solver, uses the generalized reduced gradient method in a pop-up window to help determine minimum or maximum values of an identified objective function cell. The add-in tool was used as a benchmarking check of the quasi-Newton method used in this research. As shown in Table 4-2, the results of the two optimizers are very close for the application cases that will be discussed in the next section.

4.2.2 Use of the Model in CHP Application Assessments

It is appropriate to consider whether the model substantiates a claim made at the outset of this research – that fixed heuristics (i.e., rules-of-thumb) for determining installed CHP capacity do not necessarily yield economically viable projects. To explore this question, the model will be used to determine the most economic installed equipment capacities for several different CHP systems across two dimensions: location and type of application. Two different locations will be considered, Boston and San Francisco. These locations were selected because the electric utility companies that serve those locations (Boston Edison and Pacific Gas and Electric) apply tariffs that embody most of the complex pricing structures, previously mentioned, that are found in typical utility tariffs for large urban markets (e.g., time of use pricing, separate energy and demand prices). The procedure necessary to utilize the information presented in a tariff to form the electric rate input data is provided in Appendix B, using a Pacific Gas and Electric tariff as an example. Natural gas unit price information was obtained from the Energy Information Administration website [Energy Information Administration (2005)]. The assumed price of natural gas for the assessments was \$11.00 and 9.00 per MMBtu for Boston and San Francisco, respectively.

Table 4-2. Optimization Benchmarking Results

Case	Quasi-Newton method			Excel Solver add-in		
	Optimal DG capacity (kW)	Optimal AC capacity (kW)	NPV Savings (\$)	Optimal DG capacity (kW)	Optimal AC capacity (kW)	NPV Savings (\$)
Boston Hospital	1142.0	215.4	\$954,012	1123.5	209.8	\$954,037
Boston Hotel	417.2	88.3	\$341,877	417.9	87.8	\$341,891
Boston Nursing Home	74.8	16.4	\$48,861	74.8	16.5	\$48,874
Boston Retail	118.3	35.9	\$57,945	123.1	37.4	\$58,025
Boston Supermarket	117.7	6.9	\$67,611	117.7	6.9	\$67,611
San Francisco Hospital	513.8	30.9	\$431,123	514.3	31.4	\$431,117
San Francisco Hotel	257.2	36.2	\$212,726	257.2	36.2	\$212,726
San Francisco Nursing Home	25.1	3.5	\$26,313	25.1	3.5	\$26,313
San Francisco Retail	63.9	19.1	\$15,954	62.8	18.8	\$15,990
San Francisco Supermarket	54.6	5.0	\$42,666	54.7	4.9	\$42,673

In addition to location differences, the model will be used to evaluate CHP projects across five different commercial applications: hospital, hotel, nursing home, supermarket, and retail store. These applications were selected for their differing load profiles and magnitude of absolute loads. The hourly electrical and thermal load data for all of these cases were developed using an existing building simulation program, the Building Energy Analyzer [InterEnergy/GTI (2005)]. The procedure to obtain hourly load data in the form necessary for this model is described in Appendix A. Unit electricity and natural gas prices, although varying by location, are assumed to be the same across the five applications.

Most of the data required for the model is either obtained from other models (e.g., load data), from published data (e.g., electric utility tariffs), or from values typical of the trade (e.g., equipment performance data, minimum output levels, equipment unit costs). One input element that is subject to expert judgment and, to some extent, outright guessing is the escalation behavior of unit costs over a period of time up to 16 years into the future. At the time of this writing, fossil fuel prices are highly unstable as a result of tight production capacity (due to hurricanes impacting Gulf coast production facilities) and high demand. Guessing where fossil fuel prices will be five or ten years out is very difficult. A reasonably safe assumption is that prices will not likely decrease to any large extent. As a result, the escalation values used for all cases in this section and shown in Table 4-3 represent just one possible scenario for future prices. Users of the model have the flexibility to explore alternative pricing scenarios. As shown in Table 4-3, fuel prices are assumed to only decrease slightly in the second year of operation from their current high values. Overall, demand for fossil fuel will keep prices rising slightly through time with out-years experiencing higher price escalation.

The impact of fossil fuel prices affects electric utilities as well. Owing to the regulated structure of electric utility companies, electricity prices are generally not as volatile, and it is felt that a lag exists in electricity price escalation relative to prices the utilities experience for fuel.

Table 4-3. Escalation Assumptions for Example Applications

Escalation data						
Expressed in percent change from previous year						
Year	Fuel price	Elec price	O&M cost	Heat load	Cool load	Elec load
2	-0.5%	0.5%	0.5%	0.0%	0.0%	0.0%
3	0.0%	1.0%	0.5%	0.0%	0.0%	0.0%
4	0.0%	1.0%	0.5%	0.0%	0.0%	0.0%
5	0.0%	1.0%	0.5%	0.0%	0.0%	0.0%
6	0.0%	1.0%	0.5%	0.0%	0.0%	0.0%
7	0.5%	0.5%	0.5%	0.0%	0.0%	0.0%
8	0.5%	0.5%	1.0%	0.0%	0.0%	0.0%
9	0.5%	0.5%	1.0%	0.0%	0.0%	0.0%
10	0.5%	0.5%	1.0%	0.0%	0.0%	0.0%
11	0.5%	0.5%	1.0%	0.0%	0.0%	0.0%
12	1.0%	1.0%	1.0%	0.0%	0.0%	0.0%
13	1.0%	1.0%	1.0%	0.0%	0.0%	0.0%
14	1.0%	1.0%	2.0%	0.0%	0.0%	0.0%
15	1.0%	1.0%	2.0%	0.0%	0.0%	0.0%
16	1.0%	1.0%	2.0%	0.0%	0.0%	0.0%
Levelized	1.010125	1.047144	1.042355	1.000000	1.000000	1.000000

This lag is reflected in the escalation during years 2 – 6 where electricity rates increase faster than the current high fuel prices. Beyond year 6, it is assumed that fossil and utility prices will undergo similar escalation pressures. Unit O&M costs for CHP systems are assumed to increase as the plants age, so an upward trend on unit cost seems appropriate. Finally, although loads can also be increased or decreased in the model, such changes are not being included in these sample cases. As discussed in Section 4.1.1, the equivalent levelization factor for each item is shown at the bottom of the table.

Boston hospital scenario

The remaining data needed to calculate the optimum capacity relates to equipment cost and performance and general modeling behavior (e.g., discount rate, planning horizon). The data used for the hospital in Boston is shown in Table 4-4. These values represent typical values for the parameters shown.

The numeric results of the optimization for a hospital in Boston are shown in Figure 4-12. At the top of the figure is a summary of the electric and thermal loads, as estimated by the building simulation program mentioned above. The optimal capacities for a reciprocating engine prime mover and an absorption chiller are 1142 kW and 215.4 RT, respectively. As shown, the CHP system operates for 6,712 hours each year, producing 60% of the total electricity and over 75% of the total heating required by the facility. Owing to the relative economics of gas and electricity, it is preferable that waste heat first go to satisfying heating demands before contributing to cooling demands. (Refer to Section 3.2.3.) As a result, only one third of the total cooling demand is provided by the CHP system. The levelized total annual operating cost savings from the CHP system is \$277,661/year. The resulting NPV cost savings, including capital investment, over the 16 year planning horizon is \$954,012.

A summary of the operating frequency by hour of the day is provided in Figure 4-13. It can be observed from the figure that the frequency of CHP system operation is influenced heavily

Table 4-4. General Data for Boston Hospital Case

On-site boiler efficiency	82.0%
Conventional chiller COP	3.54
DG electric efficiency (full output)	29.0%
DG unit minimum output	50%
Absorption chiller COP	0.70
Absorption chiller min. output	25%
Abs chiller sys elec req (kW/RT)	0.20
CHP O&M cost (\$/kWh)	0.011
DG power/heat ratio	0.65
Number of DG units	1
Type of prime mover	Recip
Discount rate	8.0%
Effective income tax rate	38.0%
DG capital cost (\$/net kW installed)	1500
AC capital cost (\$/RT installed)	1000
Planning horizon (years)	16

Demands	Electricity	Heating	Cooling
Annual	12,406,742 kWh	37,074 MMBtu	1,617,306 RT-hr
Maximum	2275 kW	17.0 MMBtu/hr	808 RT
Minimum	934 kW	0.51 MMBtu/hr	0 RT
Installed DG capacity:		1142.0 kW (net)	
Installed AC capacity:		215.4 RT	
Hours of DG operation		6,712 hours/year	
DG generated electricity		7,478,194 kWh/year	
DG supplied heating		27,921 MMBtu/year	
AC supplied cooling		546,886 RT-hr/year	
Annual costs (before tax)	With CHP	No CHP	
CHP system	\$1,065,024	\$0	
Utility elec	\$651,031	\$1,785,547	
Non-CHP fuel	\$124,018	\$502,367	
Total	\$1,840,073	\$2,287,913	
Annual operating savings (after tax):		\$277,661	
NPV savings:		\$954,012	
Optimum DG capacity:		1142.0 kW	
Optimum AC capacity:		215.4 RT	
NPV savings:		\$954,012	

Figure 4-12. Optimization Results for a Boston Hospital

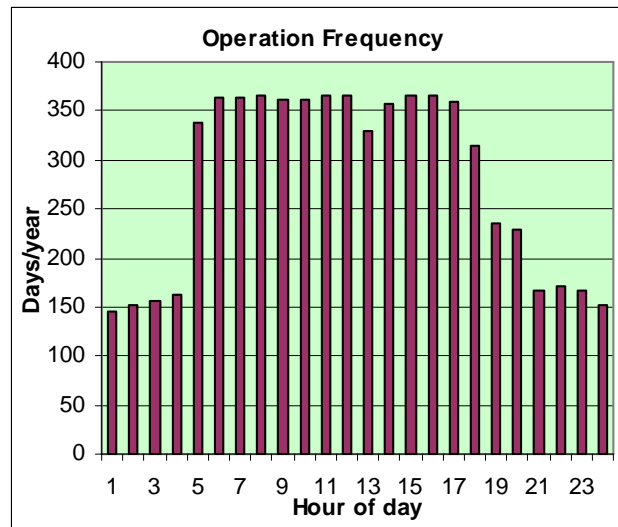


Figure 4-13. Operation Frequency by Time of Day

by the time-of-use electricity rates, which are higher during the normal workday hours. Higher grid-based electricity rates increases the likelihood that the CHP system will be the less expensive alternative, and therefore selected, during those hours.

A contour plot of the objective function surface for the hospital in Boston is shown in Figure 4-14. Each iso-savings line represents a \$50,000 increment. As shown, the surface behavior near the optimum is relatively flat. From a practical standpoint, this is a serendipitous result. Equipment capacities are offered in discrete sizes, and having a flat objective function surface in the neighborhood of the optimum gives a degree of flexibility in matching the calculated optimum set of capacities to near-values consistent with manufactured equipment sizes. As an example, vendors currently offer a reciprocating engine prime mover at 1,100 kW and an absorption chiller at 210 RT. Manually substituting these capacities into the model produces a NPV cost savings of \$951,861, which is a negligible difference relative to the value determined for the optimum capacity. Not all cases may have such a close match, but the flat gradient of the objective function near the optimum provides a reasonably wide range for matching actual equipment.

Other scenarios

Similar optimization runs were made for the hotel, nursing home, retail store, and supermarket applications in Boston as well as in San Francisco. Summary output from each of the scenarios is provided in Appendix D. It is instructive to consider the results of these ten cases together, looking in particular at the percent of peak load that the DG and AC optimum capacities represent. As shown in Table 4-5, the percent of peak load represented by the optimum capacities varies tremendously both by application and location. Clearly, a static heuristic such as 60 percent of peak load would not be appropriate guidance for any of these applications. As an example, applying the 60% rule to the San Francisco hotel case would result in a NPV loss of \$76,411 as compared to a NPV savings of \$212,726 for the optimum capacities.

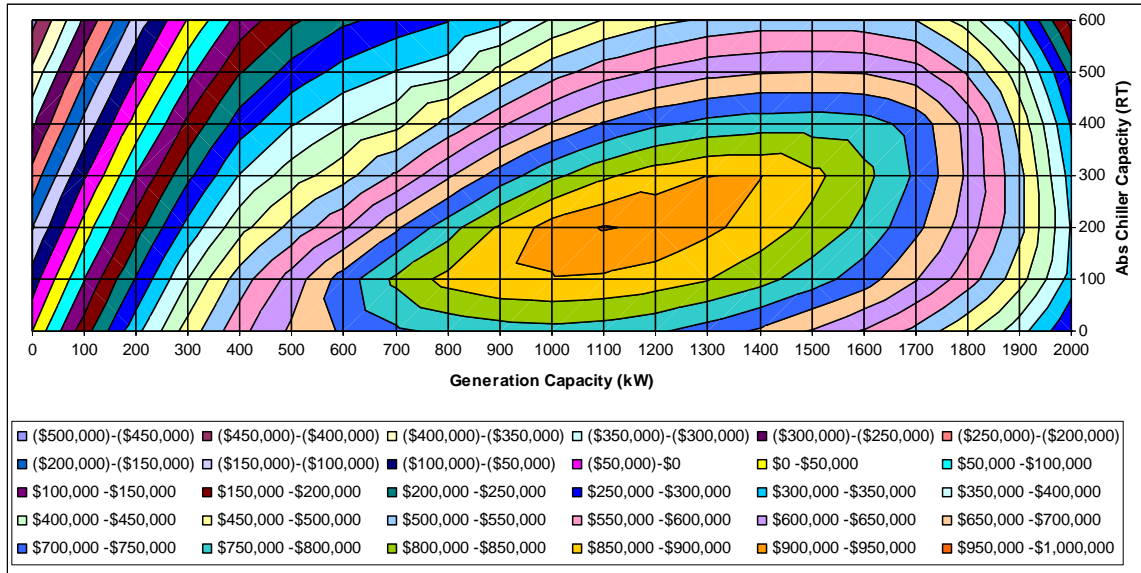


Figure 4-14. Optimization Contour Plot for a Boston Hospital

Table 4-5. Summary Results

City	Parameter	Hospital	Hotel	Nursing Home	Retail Store	Supermarket
Boston	Peak elec load (kW)	2275	1185	172	337	260
	Peak chiller load (RT)	808	492	68	147	40
	Optimal DG capacity (kW)	1142.0	417.2	74.8	118.3	117.7
	Optimal AC capacity (RT)	215.4	88.3	16.5	35.9	6.9
	NPV savings	\$954,012	\$341,877	\$48,861	\$57,945	\$67,611
	DG capacity % of peak load	50	35	43	35	45
	AC capacity % of peak load	27	18	24	24	17
San Francisco	Peak elec load (kW)	1949	1004	154	433	248
	Peak chiller load (RT)	452	334	49	131	17
	Optimal DG capacity (kW)	513.8	257.2	25.1	63.9	54.6
	Optimal AC capacity (RT)	30.9	36.2	3.5	19.1	5.0
	NPV savings	\$431,123	\$212,726	\$26,313	\$15,954	\$42,666
	DG capacity % of peak load	26	26	16	15	22
	AC capacity % of peak load	7	11	7	15	29

In trying to interpret the general trends of the results, it is noted that in this study applications within the same city are assumed to experience the same electric and fuel rates and weather conditions. Variation within a location is therefore influenced heavily by the hourly electric and thermal load behaviors (e.g., relative electric and thermal magnitudes and coincidences) for each type of application. Between cities, climate and relative prices for electricity and fuel become an influence. To understand which input parameters have a strong influence in the overall outcome, a study of the sensitivity of the figure of merit (i.e., NPV savings) to changes in individual input parameters can be performed. When several input parameters are influential, a useful technique is to develop a sensitivity graph, or spiderplot [Sullivan, Wicks and Luxhoj (2006)]. Figure 4-15 presents the impact on NPV savings for several important variables. As shown, electricity price and DG electric efficiency are the most influential directly proportional variables. Similarly, on-site fuel price is the most influential inversely proportional variable.

A final consideration is the behavior of the model when input parameters are such that the optimum capacities are zero (i.e., CHP is not economically viable). To simulate such a condition, the Boston hospital scenario was modified by reducing the DG efficiency from 29% to 26%, the discount rate was increased from 8% to 12%, and the fuel price was increased from \$11/MMBtu to \$13/MMBtu. It is of interest to note that none of these changes introduce values that are unrealistic, given current price pressures on natural gas and petroleum. The results of the optimization calculation are shown in Figures 4-16 and 4-17. Under this scenario, there is no combination of prime mover and absorption chiller capacities that produces a maximum NPV, except at the boundary conditions of zero capacity for both prime mover and absorption chiller. Figure 4-17 provides a contour plot of the scenario that clearly shows the economic losses for any non-zero set of capacities.

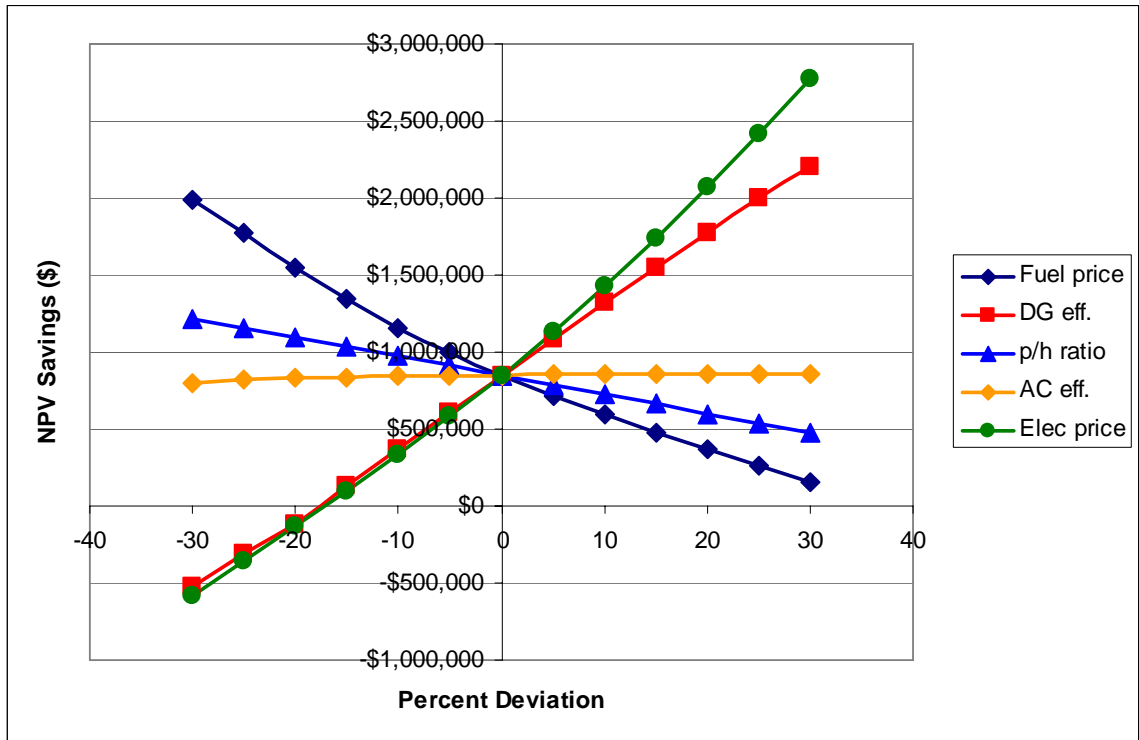


Figure 4-15. Spiderplot Sensitivity Evaluation

Results

Demands	Electricity	Heating	Cooling
Annual	12,406,742 kWh	37,074 MMBtu	1,617,306 RT-hr
Maximum	2275 kW	17.0 MMBtu/hr	808 RT
Minimum	934 kW	0.51 MMBtu/hr	0 RT
Installed DG capacity:		0.0 kW (net)	
Installed AC capacity:		0.0 RT	
Hours of DG operation		0 hours/year	
DG generated electricity		0 kWh/year	
DG supplied heating		0 MMBtu/year	
AC supplied cooling		0 RT-hr/year	
Annual costs (before tax)	With CHP	No CHP	
CHP system	\$0	\$0	
Utility elec	\$1,776,164	\$1,776,164	
Non-CHP fuel	\$592,028	\$592,028	
Total	\$2,368,191	\$2,368,191	
Annual operating savings (after tax):		\$0	
NPV savings:		\$0	
Optimum DG capacity:		0.0 kW	
Optimum AC capacity:		0.0 RT	
NPV savings:		\$0	

Figure 4-16. Results of Zero CHP Capacity Optimum Solution

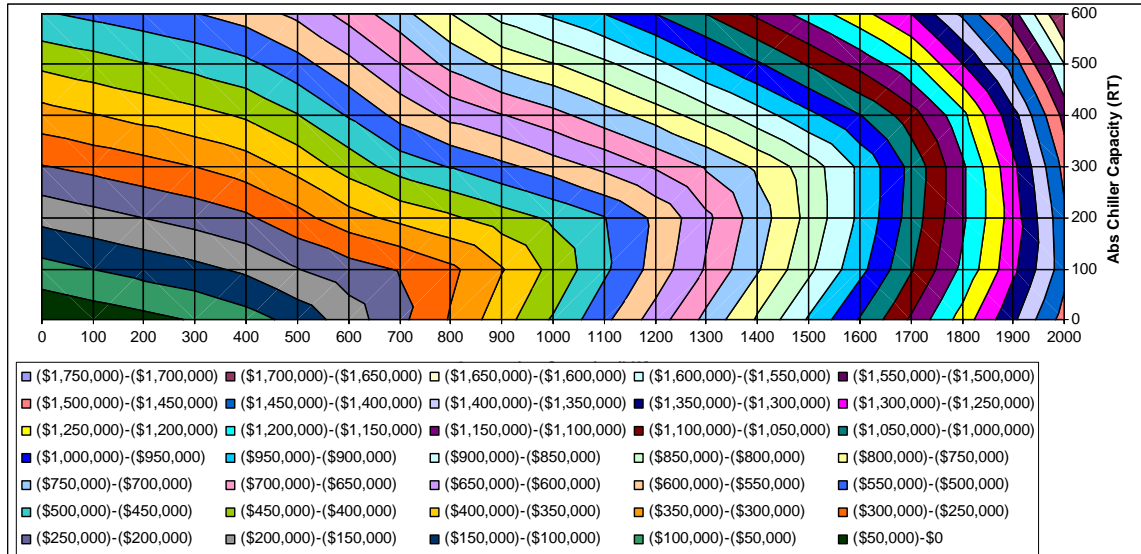


Figure 4-17. Contour Plot of Zero CHP Capacity Optimum Solution

CHAPTER 5

CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

From prior work, it has been established that accurate operation simulation of CHP systems must be performed on an hourly basis. A review of current literature and available computational tools indicated that an automated mechanism, using hourly simulation, to determine the most economically appropriate capacities for cooling, heating and power projects did not exist. This report documents the research and development of an adaptive methodology to fill that gap. Using a nested, hierarchical modeling approach, an outer optimization model controls the installed capacity values provided to an inner hourly operation simulation model. Using a quasi-Newton optimization algorithm, the optimization model iterates to produce improved estimates of the optimal installed capacities until a stopping criterion based on objective function maximization has been achieved.

The operation simulation model utilizes hourly thermal and electric load data, unit prices for electricity and fuel, and cost and performance factors for distributed energy equipment to calculate, on an hour-by-hour basis, the cost of satisfying the loads by either use of a CHP system or solely by utility-supplied electricity and on-site heating. By utilizing levelization factors to capture annual changes in unit prices and/or electric and thermal loads, the 8,760-hour simulation effectively simulates operating durations up to 16 years. With respect to the optimization algorithm, the operations model considers the installed capacity of the prime mover and the absorption chiller as independent variables. Taking the potential electrical and thermal energy available from the CHP system, while recognizing operating limitations (e.g., turn-down levels shutdown/startup frequencies), the operations model determines the operating costs for both CHP

and non-CHP scenarios. Including capital investment costs and income tax considerations, the operations model develops a single figure of merit to serve as the optimization objective function – the net present value of the savings produced by the existence of the CHP system.

The methodology and associated model have demonstrated the ability to find prime mover and absorption chiller capacities that maximize the net present value of savings produced by a CHP system, relative to the electric utility/on-site boiler arrangement traditionally used to provide electric and thermal energy to commercial facilities. In doing so, this research has shown that fixed, heuristic rules (e.g., percent of peak load) for selecting the amount of installed capacity are not economically viable methods to obtain maximum economic benefit. In contrast, this study has shown that economically optimal installed capacities vary substantially across both application and location. The model in this research has also demonstrated that sub-optimal choices of installed capacities can result in project financial losses, despite, in many cases, the opportunity for net savings at the optimal installed capacities. It is therefore critical that each potential CHP system application be evaluated on its own merits. This research has developed a tool that will assist in those evaluations.

5.2 Recommendations for Future Work

As research and model development proceed, there are always a number of improvements and expansions that are identified along the way. This effort is no exception. Some of the improvements were incorporated during the initial development phase. Comments provided by the beta version reviewers of the CHP Capacity Optimizer were invaluable to improve the model and its user interface. Other items have been determined to be more appropriate for follow-on work in this area.

The following items, not in ranked order, are subjects that should be considered for future efforts in this area:

- Thermal storage could be added to the model as an additional independent variable. Some CHP systems can benefit from storing either cold or hot thermal resources during low-demand or low-cost periods for subsequent use at peak times. Determining the proper capacity of such storage would be a logical extension of this work.
- Multiple, distinct prime movers could be modeled. Currently, the model is limited to a maximum of two identical prime mover units. Separate prime movers, even of different technologies (e.g., a combination of reciprocating engine and gas turbine units), could be modeled, the installed capacity of each as an independent variable. Consideration would need to be given as to how the waste heat would be utilized, however. For example, would the waste heat from all units flow to a common manifold? Would each unit have its own dedicated thermal utilization equipment (e.g., absorption chiller), thus, creating the possibility of additional independent variables?
- As the number of independent variables grows, it might be useful to consider other optimization methods. This would be particularly true if additional constraints beyond simple lower bounds were introduced.
- The transporting of this methodology to a high-level language platform (Visual Basic, C++, FORTRAN) may be necessary, particularly if additional model complexities are introduced. The use of the Microsoft Excel spreadsheet platform has been valuable at this stage to permit detailed inspection of the computations and enhanced understanding of the system behavior. However, the current model uses over 700,000 cells for its computations, and the resulting file size is 25 MB. Expanding the model's capability further in Excel may not be the best approach. By transporting to a high-level language platform, greater array space and input/output

storage capabilities could allow for explicit hour-by-hour modeling of multiple year operations.

- By design, this effort has not forced the independent variables to conform to a discrete set of manufacturer-available capacities. As a result, the equipment cost and operating parameters must be provided as user input. However, the inclusion of a database containing available equipment sizes as well as specific cost and operating data which could link to this model might be a useful resource to the computations.

No doubt there may be additional suggestions that other readers may have. The author would appreciate knowing of them.

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LIST OF REFERENCES

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APPENDICES

APPENDIX A

Hourly Load Data Development and Preparation

As mentioned in the body of this report, there are at least two existing building simulation tools available to develop the hourly loads needed for input to the CHP Capacity Optimizer. One such tool is the BCHP Screening Tool available at no charge from Oak Ridge National Laboratory (email: fischersk@ornl.gov). The other known tool is Building Energy Analyzer (PRO version) offered by InterEnergy Software (<http://www.interenergysoftware.com/BEA/BEA.htm>). The steps needed to obtain hourly load data from each software and to prepare the data for input to the CHP Capacity Optimizer are described in this appendix. This appendix does not, however, provide user instructions for running either of these simulation programs, as such instruction is provided by each of the software providers.

Utilizing data from BCHP Screening Tool

When preparing a simulation using the BCHP Screening Tool, there is a switch that must be set in order to produce hourly load files. The switch must be set *before* running the simulation. As shown in Figure A-1, the switch is located on the software menu bar under the File heading. Once set, when a simulation is performed, two .csv (comma separated value) files will be produced, one for case “A” (i.e., typically baseline case) and another for case “B” (i.e., CHP scenario). The CHP Capacity Optimizer needs to have input from the case “A”, traditional utility scenario (i.e., a non-CHP scenario). The baseline .csv file (initially named “untitled-A.csv”) can be opened directly by Microsoft Excel. The file contains heating, cooling, and total electrical load data by hour for an entire year in units of Btu for heating and cooling and kW for electrical load.

Because a portion of the total electrical load included in the baseline, non-CHP case is for electricity-supplied cooling, of which CHP systems will reduce, the electrical load values produced by the BCHP Screening Tool must be split into two categories: electrical load related to

Figure A-1. BCHP Screening Tool Hourly Load Data Switch

cooling and all other electrical loads (i.e., non-cooling related electrical loads). The cooling-related electrical load can be approximated by dividing each of the hourly cooling loads provided by the BCHP Screening Tool by 3412.8 to convert from Btu units to kWh units and then by dividing by an assumed coefficient of performance (COP) for the electrical chiller. Typically, electrical chillers have a COP within the range of 4 to 6. This hourly cooling-related electrical load must then be subtracted from the hourly total electrical load reported by the BCHP Screening Tool to calculate the non-cooling electrical load. In order to facilitate moving the hourly data into the CHP Capacity Optimizer, it is suggested that the column containing the total electric load in the untitled-A.csv spreadsheet be moved to the right by two columns, such that the calculated electric cooling load and non-electric cooling load columns, as described above, are adjacent to the cooling thermal column. In this manner, the data order will be consistent with the format of the CHP Capacity Optimizer, as shown in Figure 4-3.

Utilizing data from the Building Energy Analyzer

The option to save hourly data within Building Energy Analyzer PRO (BEA) is provided *after* the simulation has been performed. After the simulation, a “Save Hourly Data” button will be available as shown in Figure A-2 to save the hourly data in an .mdb (Microsoft Access) formatted file. This file must be converted to an Excel file by using the File, Export, Save As type command within Microsoft Access. Once in Excel format, the data must be combined, as discussed below, to the level needed by the CHP Capacity Optimizer. Also, only the baseline data (for the non-CHP system) is needed, so the load data provided for the alternative case can be deleted from the loads spreadsheet file (rows 8762 – 17521).

The Building Energy Analyzer segregates energy loads into heating load, cooling load, domestic hot water (DHW) load, and five different electric meter loads. As the CHP Capacity Optimizer needs only a heating load, cooling load, cooling-related electrical load, and non-cooling related electrical load, some of the raw outputs from BEA must be combined. In

BEA - Calculations Module File Name : hospBoston

File Edit Reports Charts Help

UNNAMED PROJECT

<p>Location</p> <p>Boston MA - Lat./Long. 42N/71W Summer 1% Design Dry Bulb/Mean Coincident Wet Bulb: 87/71°F (Humidity Ratio 85 gr/lb) Summer 1% Design Dew-Point/Mean-Coincident Dry Bulb: 71/79°F (Humidity Ratio 113 gr/lb)</p>	<p>Application</p> <p>Hospital; 5-story building with 3 independently controlled zone types (surgical suites, patient rooms, administration and services) and 13 ft floor height. Surgical suites area covers 5% of the building area or 25020 sf., patient rooms area covers 75% of the building area or 375300 sf. and administration and services area covers 20% of the building area or 100080 sf. Building wall glazing is 15 % and north orientation is 0 deg. Humidity control air treatment can be applied independently in each zone to cover up to 500400 sf of the entire building. Each zone has separate profiles of internal loads, ventilation and infiltration. Building construction materials are: walls; DEFAULT 4</p>
<p>Baseline Equipment Configuration</p> <p>Constant volume air handling chilled water system using three types of (water cooled) chillers: A) 1 x Elec. centr.-inlet vane control (0.68 kW/ton) sized at 40% of building ASHRAE design point cooling capacity, B) 1 x Elec. centr.-inlet vane control (0.68 kW/ton) sized at 40% of building ASHRAE design point cooling capacity, C) 1 x Elec. centr.-inlet vane control (0.68 kW/ton) sized at 40% of building ASHRAE design point cooling capacity. System configured without economizer. Cooling tower uses 1 speed fan with fixed temperature control at 85 °F. Outside air treated by gas-fired desiccant dehumidifier with 70 % effective heat exch. (downstream sensible exchange with relief air heat recovery) using no evap. cooler. Capacity of desiccant dehumidifier is autosized to 100% of outside air. Air flow face velocity is autosized. Precooling coil used. Direct cooling option is not engaged. Gas energy used for heating. Max. humidity control using desiccant dehumidifier option engaged in area 1 and 2. Gas heat source humidifier used. Cold Storage not installed. On site power generation not installed.</p>	
<p>Alternative Equipment Configuration</p> <p>Constant volume air handling chilled water system using three types of (water cooled) chillers: A) 2 x Steam fired single-effect absorp. (0.02 kW/ton and 0.7 CDP) sized at 40% of building ASHRAE design point cooling capacity, B) 1 x Elec. centr.-inlet vane control (0.68 kW/ton) sized at 40% of building ASHRAE design point cooling capacity, C) 1 x Elec. centr.-inlet vane control (0.68 kW/ton) sized at 40% of building ASHRAE design point cooling capacity. Gas Chillers Sequencing: Summer On Peak: FIRST, Summer Mid Peak: LAST, Summer Off Peak: LAST; Winter On Peak: FIRST, Winter Mid Peak: LAST, Winter Off Peak: LAST. System configured without economizer. Cooling tower uses 1 speed fan with fixed temperature control at 85 °F. Outside air treated by gas-fired desiccant dehumidifier with 70 % effective heat exch. (downstream sensible exchange with relief air heat recovery) using no evap. cooler. Capacity of desiccant dehumidifier is autosized to 100% of outside air. Air flow face velocity is</p>	

Figure A-2. BEA Save Hourly Data Option Screen
(Used with permission)

particular, the heating and DHW loads are combined to form a single heating load, expressed in Btu units. The cooling-related electrical load is given in the BEA output as Electric Meter 5. The non-cooling loads are formed as the sum of Electric Meters 1 through 4 in the BEA output. All electric loads are expressed in kWh units. As with the BCHP Screening Tool, manipulation of the columns of raw data in the spreadsheet created by Microsoft Access into a format consistent with Figure 4-3 will allow a simple cut and paste operation to import the loads data into the CHP Capacity Optimizer. To avoid file linkages between the CHP Capacity Optimizer and the raw data spreadsheet, the transfer of the load data should be done using the Paste Special, Values option within Excel.

The following macro can be helpful in automating the data manipulations of the raw data Excel spreadsheet created in MS Access when using BEA Pro.

```
Sub Datapreparation()
'
' Datapreparation Macro for creating input needed for CHP optimization
' from a raw Excel sheet created using BEA Pro
' Apply this macro to the raw data spreadsheet created by MS Access, Export operation
'
    Rows("8762:8769").Select
    Range(Selection, Selection.End(xlDown)).Select
    Selection.ClearContents
    Range("A8761").Select
    Selection.End(xlUp).Select
    Range("I1").Select
    Selection.EntireColumn.Insert
    Selection.EntireColumn.Insert
    Selection.EntireColumn.Insert
    Range("I1").Select
    Selection.NumberFormat = "General"
    ActiveCell.FormulaR1C1 = "Heat Load"
    Range("J1").Select
    Selection.NumberFormat = "General"
    ActiveCell.FormulaR1C1 = "Cool load"
    Range("K1").Select
    Selection.NumberFormat = "General"
    ActiveCell.FormulaR1C1 = "Cool elec"
    Range("L1").Select
    ActiveCell.FormulaR1C1 = "Noncool elec"
    Columns("I:L").Select
End Sub
```

```
Selection.Columns.AutoFit
Range("I2").Select
ActiveCell.FormulaR1C1 = "=RC[-3]+RC[-1]"
Range("J2").Select
ActiveCell.FormulaR1C1 = "=RC[-3]"
Range("K2").Select
ActiveCell.FormulaR1C1 = "=RC[6]"
Range("L2").Select
ActiveCell.FormulaR1C1 = "=SUM(RC[1]:RC[4])"
Range("I2:L2").Select
Selection.NumberFormat = "0"
Selection.NumberFormat = "0.0"
Selection.Copy
Range("I3:I8761").Select
ActiveSheet.Paste
Application.CutCopyMode = False
'ActiveWorkbook.Save
End Sub
```

APPENDIX B

Pacific Gas and Electric Utility Tariff T-2

(Selected pages)

Used with permission.

The electricity utility price data shown in Figure 4-4 are generally obtained from utility tariffs or other schedules that define how end-user electricity consumption will be charged. Tariffs are a ready source of utility electricity price information, as most utilities publish them on their Internet web sites. Tariffs are prepared by the utility and submitted for approval to the relevant state office with utility oversight (e.g., a public utilities commission). Unfortunately, tariffs are not necessarily easy to interpret and extract the appropriate data. There are generally several tariffs offered by a utility company. The appropriate tariff is typically determined by the type of service (e.g., residential, commercial, industrial) and by the magnitude of power consumption. Tariffs can also be voluminous and legalistic. In order to understand how to extract the relevant data from a utility tariff, the tariff for Pacific Gas and Electric medium commercial time-of-use service, Schedule E-19, will be used as an example [Pacific Gas and Electric Company (2005)]. The complete E-19 tariff is currently 29 pages in length, but not all pages are necessary to provide the input needed for CHP evaluations. Therefore, this appendix will address only the sections of the E-19 tariff that are needed to model the unit electricity pricing in the optimization model. Sections of the tariff that are highly relevant to this study are indicated with highlighting.

The first section of the tariff, as shown in Figure A-3, defines the applicability of the tariff to the particular customer. Generally, this applicability relates to a minimum or maximum power consumption (i.e., billing demand) during a period of time. Various subdivisions of rates or treatments are also defined in the initial section, as shown in Figure A-4. An important element in Figure A-4 is the definition of maximum demand. Some utilities have a demand charge that is set by the highest level of demand during a month, irrespective of what day or time the demand occurs. As the CHP Capacity Optimizer uses a demand charge avoidance strategy in deciding whether to operate the CHP system, discussed in Section 3.2.3, the maximum demand



COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE

CONTENTS:

This rate schedule is divided into the following sections:

1. Applicability	14. Common-Area Accounts	(T)
2. Territory	15. Contracts	
3. Firm Service Rates	16. Voluntary Service Provisions	
4. Metering Requirements	17. Billing	
5. Definition Of Service Voltage		
6. Definition Of Time Periods	18. Fixed Transition Amount	
7. Power Factor Adjustments	19. CARE Discount for Nonprofit	
8. Charges For Transformer and Line Losses	20. Group-Living Facilities	
9. Standard Service Facilities	20. Optional Optimal Billing Period	
10. Special Facilities	21. Service	
11. Arrangements For Visual-Display Metering	21. Electric Emergency Plan Rotating	
12. Non-Firm Service Program	22. Block Outages	
13. Non-Firm Service Rates	22. Standby Applicability	
	23. Department of Water Resources	
	Bond Charge	(T)

1. **APPLICABILITY:** **Initial Assignment:** A customer must take service under Schedule E-19 if: (1) the customer's load does not meet the Schedule E-20 requirements, but, (2) the customer's maximum billing demand (as defined below) has exceeded 499 kilowatts for at least three consecutive months during the most recent 12-month period (referred to as Schedule E-19). If 70 percent or more of the customer's energy use is for agricultural end-uses, the customer will be served under an agricultural schedule. Schedule E-19 is not applicable to customers for whom residential service would apply, (see except for single-phase and polyphase service in common areas in a multifamily complex (see Common-Area Accounts section).

Customer accounts which fail to qualify under these requirements will be evaluated for transfer to service under a different applicable rate schedule.

(D)

The provisions of Schedule S—Standby Service Special Conditions 1 through 6 shall also apply to customers whose premises are regularly supplied in part (but not in whole) by electric energy from a nonutility source of supply. These customers will pay monthly reservation charges as specified under Section 1 of Schedule S, in addition to all applicable Schedule E-19 charges. Exemptions to standby charges are outlined in the Standby Applicability Section of this rate schedule.

Voluntary E-19 Service: This schedule is available on a voluntary basis for customers with maximum billing demands less than 500 kW. Customers voluntarily taking service on this schedule are subject to all the terms and conditions below, unless otherwise specified in Section 16.

(T)

(Continued)

Advice Letter No. 2623-E

Decision No. 05-01-056

53911

Issued by
Karen A. Tomcala
Vice President
Regulatory Relations

Date Filed February 7, 2005

Effective March 19, 2005

Resolution No.

Figure A-3. Schedule E-19 Initial Page



COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

1. **APPLICABILITY:** Depending upon whether or not an Installation or Processing Charge applies, the customer will be served under one of these rates under Schedule E-19:
(Cont'd.)

Rate V: Applies to customers who qualify for the voluntary provisions of this tariff and at least one of the following: (1) to customers who are served under Schedule E-19 Voluntary prior to January 1, 1996, and have not changed rate schedules since that time; or (2) to customers whose service has an existing and appropriate time-of-use meter installed and initiated service on this schedule during 1996; or (3) to customers who signed an "Incentive Program Prescriptive Performance Off-Peak Cooling Application" with PG&E prior to January 1, 1996, in order to install a thermal energy storage system and now are about to operate that system. (N)

Rate W: Applies to customers whose maximum demand is less than 200 kW and whose account does not have an appropriate time-of-use meter. The customer must pay a "Time-Of-Use Installation Charge" prior to taking service under this schedule. (T)

Rate X: Applies to customers whose account has an appropriate time-of-use meter, but is not currently being served under this schedule. The customer will be required to pay a "Time-Of-Use Processing Charge" prior to taking service under this schedule. The Time-Of-Use Processing Charge will be waived for those customers who are initially required to be placed on a time-of-use schedule when their maximum demand is 200 kW or greater for three consecutive months and selects this schedule. (D)
(N)
(N)

Transfers Off of Schedule E-19: If a customer's maximum demand has failed to exceed 499 kilowatts for 12 consecutive months, PG&E will transfer that customer's account to voluntary E-19 service or to a different applicable rate schedule. After being placed on this schedule due to the 200 kW or greater provisions of this schedule, customers who fail to exceed 199 kilowatts for 12 consecutive months may elect to stay on the time-of-use provisions of this schedule or elect an applicable non-time-of-use rate schedule. (N)
(N)

Assignment of New Customers: If a customer is new and PG&E believes that the customer's maximum demand will be 500 through 999 kilowatts and that the customer should not be served under a time-of-use agricultural schedule, PG&E will serve the customer's account under Schedule E-19.

Definition of Maximum Demand: Demand will be averaged over 30-minute intervals for customers whose maximum demand exceeds 499 kW. "Maximum demand" will be the highest of all the 30-minute averages for the billing month. If the customer's use of electricity is intermittent or subject to violent fluctuations, a 5-minute or 15-minute interval may be used instead of the 30-minute interval. If the customer has any welding machines, the diversified resistance welder load, calculated in accordance with Section J of Rule 2, will be considered the maximum demand if it exceeds the maximum demand that results from averaging the demand over 30-minute intervals. The customer's maximum-peak-period demand will be the highest of all the 30-minute averages for the peak period during the billing month. (See Section 6 for a definition of "Peak-Period.") See Section 16 for the definition of maximum demand for customers voluntarily selecting E-19.

(Continued)

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Figure A-4. Maximum Demand Definition

charge rate should be included with (i.e., added to) the demand charge block with the highest time-of-use demand charge (e.g., added to the peak block demand charge). While the absolute monthly peak load could occur at an off-peak time of day, the discrepancy introduced is considered minimal.

Further categorization of the applicable rate is shown in Figure A-5, where pre-existing conditions define a rate structure. Once the applicable rate structure is identified using information on the previous figures, the appropriate quantitative unit prices can be found. As shown in Figure A-6, the rates used in this study are the demand and energy rates under the assumption of delivery at secondary voltage. As customer/meter charges are flat rates which will be incurred with or without a CHP system, they are not needed as input to the CHP Capacity Optimizer. The section below the total rate table, unbundling of total rates, is merely a restatement of the above rate, subdivided by each contributing cost element. It is interesting information, but not needed for the model. Figure A-7 provides the definitions of the demand charge and the energy charge. The treatment of time-of-use rates is clarified in this section. The actual times that constitute the time-of-use periods are defined in Figure A-8. It is noted that the time boundaries for partial-peak and off-peak are defined on the half hour. As the minimum time division for the optimizer model is hourly, the rates in the model are applied to the beginning of the hour with equivalent total duration. It should also be noted that, as is typical of most utilities, weekends and holidays are considered off-peak times.

An important exemption for distributed energy resources is shown in Figure A-9. As mentioned in Section 3.2, electric utilities can charge a fee for having power *available* if the CHP system can not operate. In this particular tariff, the utility waives the standby fee, subject to the requirement of participating in real-time pricing, when it is offered by the utility in the future.

The resulting combination of all these elements into the data necessary for the CHP Capacity Optimizer is shown in Figure A-10.



Pacific Gas and Electric Company
San Francisco, California

Cancelling

Revised
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21359-E

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

1. APPLICABILITY: (Cont'd.) **Standby Demand:** For customers for whom Schedule S—Standby Service Special Conditions 1 through 6 apply, standby demand is the portion of a customer's maximum demand in any month caused by nonoperation of the customer's alternate source of power, and for which a demand charge is paid under the regular service schedule.
- If the customer imposes standby demand in any month, then the regular service maximum demand charge will be reduced by the applicable reservation capacity charge (see Schedule S Special Condition 1).
- To qualify for the above reduction in the maximum demand charge, the customer must, within 30 days of the regular meter-read date, demonstrate to the satisfaction of PG&E the amount of standby demand in any month. This may be done by submitting to PG&E a completed Electric Standby Service Log Sheet (Form 79-726).
2. TERRITORY: This rate schedule applies everywhere PG&E provides electricity service.
3. FIRM SERVICE RATES: Total bundled service charges are calculated using the total rates shown below. Direct Access (DA) and Community Choice Aggregation (CCA) charges shall be calculated in accordance with the paragraph in this rate schedule titled Billing. (T)
- Customers that received the benefit of the 10 percent rate reduction prior to January 1, 2004, and who pay the Fixed Transition Amount (FTA), shall be subject to the rates set forth in Table A, which include the FTA charge and the Rate Reduction Bond Memorandum Account (RRBMA) credit. All other firm service customers taking service under this rate schedule shall be subject to the rates set forth in Table B.

(Continued)

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Figure A-5. Further Rate Category Distinctions



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COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

3. FIRM SERVICE RATES: (Cont'd.)

Table B (Non-FTA Rates)

Total Customer/Meter Charge Rates	TOTAL RATES		
	Secondary Voltage	Primary Voltage	Transmission Voltage
Customer Charge Mandatory E-19 (\$ per meter per day)	\$5.74949	\$4.59959	\$20.04107
Customer Charge Rate V (\$ per meter per day)	\$2.66119	\$2.66119	\$2.66119
Customer Charge Rate W (\$ per meter per day)	\$2.50349	\$2.50349	\$2.50349
Customer Charge Rate X (\$ per meter per day)	\$2.66119	\$2.66119	\$2.66119
One-time TOU Installation Charge (\$ per meter)	\$443.00	\$443.00	\$443.00
One-time TOU Processing Charge (\$ per meter)	\$87.00	\$87.00	\$87.00
Optional Optimal Billing Period Service (\$ per meter per month)	\$130.00	\$130.00	—
Optional Meter Data Access Charge (\$ per meter per day)	\$0.98563	\$0.98563	\$0.98563
Total Demand Rates (\$ per kW)			
Maximum Peak Demand Summer	\$13.12 (R)	\$11.28 (R)	\$6.85 (R)
Maximum Part-Peak Demand Summer	\$3.64	\$2.54	\$0.55
Maximum Demand Summer	\$3.00	\$3.01	\$0.67
Maximum Part-Peak Demand Winter	\$3.58	\$2.54	\$0.69
Maximum Demand Winter	\$3.00 (R)	\$3.01 (R)	\$0.67 (R)
Total Energy Rates (\$ per kWh)			
Peak Summer	\$0.14913 (R)	\$0.12418 (R)	\$0.13585 (R)
Part-Peak Summer	\$0.09114	\$0.08099	\$0.09315
Off-Peak Summer	\$0.07800	\$0.07331	\$0.08452
Part-Peak Winter	\$0.09653	\$0.08861	\$0.10742
Off-Peak Winter	\$0.07781 (R)	\$0.07422 (R)	\$0.08916 (R)
Average Rate Limiter (\$/kWh in summer months)	\$0.14043	\$0.14043	—
Peak Period Rate Limiter (\$/kWh in summer months)	\$0.97773	\$0.84937	\$0.58676

Total bundled service charges shown on customers' bills are unbundled according to the component rates shown below.

UNBUNDLING OF TOTAL RATES

Customer/Meter Charge Rates: Customer and meter charge rates provided in the Total Rate section above are assigned entirely to the unbundled distribution component.

Demand Rates by Component (\$ per kW)

Generation:			
Maximum Peak Demand Summer	\$6.33 (R)	\$7.39 (R)	\$6.85 (R)
Maximum Part-Peak Demand Summer	\$1.75	\$1.67	\$0.55
Maximum Demand Summer	(\$3.28)	(\$2.47)	(\$3.75)
Maximum Part-Peak Demand Winter	\$1.73	\$1.67	\$0.69
Maximum Demand Winter	(\$3.28) (R)	(\$2.47) (R)	(\$3.75) (R)
Distribution:			
Maximum Peak Demand Summer	\$6.79	\$3.89	\$0.00
Maximum Part-Peak Demand Summer	\$1.89	\$0.87	\$0.00
Maximum Demand Summer	\$1.94	\$1.14	\$0.08
Maximum Part-Peak Demand Winter	\$1.85	\$0.87	\$0.00
Maximum Demand Winter	\$1.94	\$1.14	\$0.08
Transmission Maximum Demand*	\$2.32	\$2.32	\$2.32
Reliability Services Maximum Demand*	\$2.02	\$2.02	\$2.02

* Transmission, Transmission Rate Adjustments, and Reliability Service charges are combined for presentation on customer bills.

(Continued)

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Figure A-6. Time-of-Use Demand and Energy Rates



COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

3. FIRM
SERVICE
RATES:
(Cont'd.)

a. TYPES OF CHARGES: The customer's monthly charge for service under Schedule E-19 is the sum of a customer charge, demand charges, and energy charges:

- The **customer charge** is a flat monthly fee.
- This schedule has three **demand charges**, a maximum-peak-period-demand charge, a maximum part-peak-period and a maximum-demand charge. The maximum-peak-period-demand charge per kilowatt applies to the maximum demand during the month's peak hours, the maximum part-peak-period demand charge applies to the maximum demand during the month's part-peak hours, and the maximum demand charge per kilowatt applies to the maximum demand at any time during the month. The bill will include all of these demand charges. (Time periods are defined in Section 6.) (T)
- The **energy charge** is the sum of the energy charges from the peak, partial-peak, and off-peak periods. The customer pays for energy by the kilowatt-hour (kWh), and rates are differentiated according to time of day and time of year. (T)
- If applicable, all **TOU Installation** or **TOU Processing Charges** must be paid in one lump sum before the customer can take service under this rate schedule. Payments for these charges are not transferable to another service or refundable, in whole or part. PG&E will place the account on this schedule within four weeks of receiving payment from the customer. The meters required for this schedule may become obsolete as a result of electric industry restructuring or other action by the California Public Utilities Commission. Therefore, any and all risks of paying the required charges and not receiving commensurate benefit are entirely that of the customer. (T)
- The monthly charges may be increased or decreased based upon the power factor. (See Section 7.) (T)
- As shown on the rate chart, which set of customer, demand, and energy charges is paid depends on the level of the customers maximum demand and the voltage at which service is taken. Service voltages are defined in Section 5 below. (T)
- Please note that the rates in the table above apply only to firm service. Rates for non-firm service can be found in Section 12 of this rate schedule. (T)

(Continued)

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Figure A-7. Definition of Demand and Energy Charges



COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

6. DEFINITION OF TIME PERIODS:	Times of the year and times of the day are defined as follows:		(T)	(L)	
	SUMMER	Period A (Service from May 1 through October 31):			
	Peak:	12:00 noon. to 6:00 p.m.	Monday through Friday (except holidays).		
	Partial-peak:	8:30 a.m. to 12:00 noon AND 6:00 p.m. to 9:30 p.m. Monday through Friday (except holidays).			
	Off-peak:	9:30 p.m. to 8:30 a.m.	Monday through Friday		
		All day		Saturday, Sunday, and holidays	(L)
	WINTER	Period B (service from November 1 through April 30):			
	Partial-Peak:	8:30 a.m. to 9:30 p.m.	Monday through Friday (except holidays).		
	Off-Peak:	9:30 p.m. to 8:30 a.m.	Monday through Friday (except holidays).		
		All day		Saturday, Sunday, and holidays	
HOLIDAYS: "Holidays" for the purposes of this rate schedule are New Year's Day, President's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. The dates will be those on which the holidays are legally observed.					
CHANGE FROM SUMMER TO WINTER OR WINTER TO SUMMER: When a billing month includes both summer and winter days, PG&E will calculate demand charges as follows. It will consider the applicable maximum demands for the summer and winter portions of the billing month separately, calculate a demand charge for each, and then apply the two according to the number of billing days each represents.					
7. POWER FACTOR ADJUSTMENTS:	Bills will be adjusted based on the power factor for all customers except those selecting voluntary E-19 service. The power factor is computed from the ratio of lagging reactive kilovolt-ampere-hours to the kilowatt-hours consumed in the month. Power factors are rounded to the nearest whole percent.			(T)	
	The rates in this rate schedule are based on a power factor of 85 percent. If the average power factor is greater than 85 percent, the total monthly bill will be reduced by 0.06 percent of the bundled service bill less any taxes and the ERA amount calculated using applicable rates provided in Schedule E-ERA for each percentage point above 85 percent. If the average power factor is below 85 percent, the total monthly bill of the bundled service bill less any taxes and the ERA amount calculated using applicable rates provided in Schedule E-ERA will be increased by 0.06 percent for each percentage point below 85 percent.				
Power factor adjustments will be assigned to distribution for billing purposes.					
8. CHARGES FOR TRANSFORMER AND LINE LOSSES:	The demand and energy meter readings used in determining the charges will be adjusted to correct for transformation and line losses in accordance with Section B.4 of Rule 2.			(T)	

(Continued)

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Figure A-8. Definition of Time Periods



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21371,21383-E

COMMERCIAL/INDUSTRIAL/GENERAL
SCHEDULE E-19—MEDIUM GENERAL DEMAND-METERED TIME-OF-USE SERVICE
(Continued)

22. STANDBY APPLICABILITY: SOLAR GENERATION FACILITIES EXEMPTION: Customers who utilize solar generating facilities which are less than or equal to one megawatt to serve load and who do not sell power or make more than incidental export of power into PG&E's power grid and who have not elected service under Schedule E-NEM, will be exempt from paying the otherwise applicable standby reservation charges. (T)
- DISTRIBUTED ENERGY RESOURCES EXEMPTION:** Any customer under a time-of-use rate schedule using electric generation technology that meets the criteria as defined in Electric Rule 1 for Distributed Energy Resources is exempt from the otherwise applicable standby reservation charges. Customers qualifying for this exemption shall be subject to the following requirements. Customers qualifying for an exemption from standby charges under Public Utilities (PU) Code Sections 353.1 and 353.3, as described above, must take service on a time-of-use (TOU) schedule in order to receive this exemption until a real-time pricing program, as described in PU Code 353.3, is made available. Once available, customers qualifying for the standby charge exemption must participate in the real-time program referred to above. Qualification for and receipt of this distributed energy resources exemption does not exempt the customer from metering charges applicable to time-of-use (TOU) and real-time pricing, or exempt the customer from reasonable interconnection charges, non-bypassable charges as required in Preliminary Statement BB - *Competition Transition Charge Responsibility for All Customers and CTC Procurement*, or obligations determined by the Commission to result from participation in the purchase of power through the California Department of Water Resources, as provided in PU Code Section 353.7.
23. DWR BOND CHARGE: The Department of Water Resources (DWR) Bond Charge was imposed by California Public Utilities Commission Decision 02-10-063, as modified by Decision 02-12-082, and is property of DWR for all purposes under California law. The Bond Charge applies to all retail sales, excluding CARE and Medical Baseline sales. The DWR Bond Charge (where applicable) is included in customers' total billed amounts. (T)

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Figure A-9. Standby Charge Exemption

Electric rates						Non-CHP					
Non-CHP Energy						Demand					
		Pattern 1		Pattern 2				Pattern 1		Pattern 2	
		Energy		Energy				Demand		Demand	
		\$/kWh		\$/kWh				\$/kw-mo		\$/kw-mo	
month	pattern #	hour	rate	hour	rate	month	pattern #	hour	peak	shoulder	off-peak
1	1	1	0.07781	1	0.078	1	1	1			
2	1	2	0.07781	2	0.078	2	1	2			
3	1	3	0.07781	3	0.078	3	1	3			
4	1	4	0.07781	4	0.078	4	1	4			
5	2	5	0.07781	5	0.078	5	2	5			
6	2	6	0.07781	6	0.078	6	2	6			
7	2	7	0.07781	7	0.078	7	2	7			
8	2	8	0.09653	8	0.09114	8	2	8	6.58		3.64
9	2	9	0.09653	9	0.09114	9	2	9	6.58		3.64
10	2	10	0.09653	10	0.09114	10	2	10	6.58		3.64
11	1	11	0.09653	11	0.09114	11	1	11	6.58		3.64
12	1	12	0.09653	12	0.14913	12	1	12	6.58	16.12	
		13	0.09653	13	0.14913			13	6.58	16.12	
		14	0.09653	14	0.14913			14	6.58	16.12	
		15	0.09653	15	0.14913			15	6.58	16.12	
		16	0.09653	16	0.14913			16	6.58	16.12	
		17	0.09653	17	0.14913			17	6.58	16.12	
		18	0.09653	18	0.09114			18	6.58		3.64
		19	0.09653	19	0.09114			19	6.58		3.64
		20	0.09653	20	0.09114			20	6.58		3.64
		21	0.07781	21	0.078			21			
		22	0.07781	22	0.078			22			
		23	0.07781	23	0.078			23			
		24	0.07781	24	0.078			24			

Electric rates						CHP					
CHP Energy						Demand					
		Pattern 1		Pattern 2				Pattern 1		Pattern 2	
		Energy		Energy				Demand		Demand	
		\$/kWh		\$/kWh				\$/kw-mo		\$/kw-mo	
month	pattern #	hour	rate	hour	rate	month	pattern #	hour	peak	shoulder	off-peak
1	1	1	0.07781	1	0.078	1	1	1			
2	1	2	0.07781	2	0.078	2	1	2			
3	1	3	0.07781	3	0.078	3	1	3			
4	1	4	0.07781	4	0.078	4	1	4			
5	2	5	0.07781	5	0.078	5	2	5			
6	2	6	0.07781	6	0.078	6	2	6			
7	2	7	0.07781	7	0.078	7	2	7			
8	2	8	0.09653	8	0.09114	8	2	8	6.58		3.64
9	2	9	0.09653	9	0.09114	9	2	9	6.58		3.64
10	2	10	0.09653	10	0.09114	10	2	10	6.58		3.64
11	1	11	0.09653	11	0.09114	11	1	11	6.58		3.64
12	1	12	0.09653	12	0.14913	12	1	12	6.58	16.12	
		13	0.09653	13	0.14913			13	6.58	16.12	
		14	0.09653	14	0.14913			14	6.58	16.12	
		15	0.09653	15	0.14913			15	6.58	16.12	
		16	0.09653	16	0.14913			16	6.58	16.12	
		17	0.09653	17	0.14913			17	6.58	16.12	
		18	0.09653	18	0.09114			18	6.58		3.64
		19	0.09653	19	0.09114			19	6.58		3.64
		20	0.09653	20	0.09114			20	6.58		3.64
		21	0.07781	21	0.078			21			
		22	0.07781	22	0.078			22			
		23	0.07781	23	0.078			23			
		24	0.07781	24	0.078			24			

CHP Standby Charge											
0 \$/kw-mo											

Figure A-10. Electricity Rate Input Data Sheet

APPENDIX C

Optimization Algorithm

```

Private Sub btnOptimize_Click()
    ' this performs a multivariate optimization using the quasi-Newton method
    ,
    Dim H(1 To 2, 1 To 2) As Double
    Dim B(1 To 2, 1 To 2) As Double
    Dim C(1 To 2, 1 To 2) As Double
    Dim C2(1 To 2, 1 To 2) As Double
    Dim C3(1 To 2, 1 To 2) As Double
    Dim C4(1 To 2, 1 To 2) As Double
    Dim g(1 To 2) As Double
    Dim gnew(1 To 2) As Double
    Dim p(1 To 2) As Double
    Dim s(1 To 2) As Double
    Dim y(1 To 2) As Double
    Dim x(1 To 2) As Double
    Dim xnew(1 To 2) As Double
    Dim F(26) As Double
    Dim t1 As Double
    Dim t2 As Double
    Dim denom As Double
    Dim A As Double

    Worksheets("main").Range("c4").Value = "Updating! Requires 2 - 6 minutes. "
    Application.ScreenUpdating = False
    Worksheets("optimum").Activate
    Call cleancontour
    Call cleanoptrack
    Worksheets("main").Activate
    Application.ScreenUpdating = True
    Application.ScreenUpdating = False

    ' first set the starting point at mid-way in the possible size range
    ' force xmax to be largest by assuming no abs chiller
    x(2) = 0
    Worksheets("optimum").Activate
    Worksheets("baseloads").Range("a12").Value = x(2)
    x(1) = Worksheets("baseloads").Range("a11").Value
    xmax = x(1)
    phratio = Worksheets("baseloads").Range("a14").Value
    accop = Worksheets("baseloads").Range("a13").Value
    startfrac = Worksheets("OptiSet").Range("b5").Value
    absstop = Worksheets("OptiSet").Range("b6").Value
    x(1) = x(1) * startfrac
    x(2) = x(1) / phratio * accop
    RTconv = 3412.8 / 12000
    ymax = xmax / phratio * accop * RTconv
    ' initial Hessian matrix
    H(1, 1) = -1: H(1, 2) = 0: H(2, 1) = 0: H(2, 2) = -1
    p(1) = 0: p(2) = 0

```

```

'get initial obj function
Worksheets("baseloads").Range("a12").Value = x(2) * RTconv
Worksheets("baseloads").Range("ai1").Value = x(1)
F(0) = Worksheets("baseloads").Range("ap8777").Value
Fsav = F(0)
dgbest = x(1)
acbest = x(2) * RTconv
difstop = 0.00001
gradstep = 0.0001
GScnt = 0
'find initial gradient vector
x1tmp = x(1) + gradstep
x2tmp = x(2) + gradstep
Worksheets("baseloads").Range("a12").Value = x(2) * RTconv
Worksheets("baseloads").Range("ai1").Value = x1tmp
g(1) = (Worksheets("baseloads").Range("ap8777").Value - F(0)) / gradstep
Worksheets("baseloads").Range("a12").Value = x2tmp * RTconv
Worksheets("baseloads").Range("ai1").Value = x(1)
g(2) = (Worksheets("baseloads").Range("ap8777").Value - F(0)) / gradstep
' write interim data values
Worksheets("optimum").Range("a96").Activate
ActiveCell.Offset(0, 0) = 0
ActiveCell.Offset(0, 1) = x(1)
ActiveCell.Offset(0, 2) = x(2)
ActiveCell.Offset(0, 3) = g(1)
ActiveCell.Offset(0, 4) = g(2)
ActiveCell.Offset(0, 5) = H(1, 1)
ActiveCell.Offset(0, 6) = H(1, 2)
ActiveCell.Offset(0, 7) = H(2, 1)
ActiveCell.Offset(0, 8) = H(2, 2)
ActiveCell.Offset(0, 11) = F(0)
' =====
' start major iterative loop
' failsafe quit after 25 iterations
For k = 1 To 25
step = 1
'MsgBox "top of loop"
'find direction
For i = 1 To 2
p(i) = 0
For j = 1 To 2
p(i) = H(i, j) * g(j) + p(i)
Next j
p(i) = -p(i)
Next i
Worksheets("optimum").Range("a96").Activate
ActiveCell.Offset(k - 1, 9) = p(1)
ActiveCell.Offset(k - 1, 10) = p(2)

```

```

' start with full step
For i = 1 To 2
xnew(i) = x(i) + p(i)
If xnew(i) <= 0 Then
xnew(i) = 0#
p(i) = xnew(i) - x(i)
End If
Next i
If xnew(1) <= 0 Then
xnew(2) = 0
p(2) = xnew(2) - x(2)
End If
Worksheets("baseloads").Range("a12").Value = xnew(2) * RTconv
Worksheets("baseloads").Range("a11").Value = xnew(1)
F(k) = Worksheets("baseloads").Range("ap8777").Value
' check for progress
If F(k) < F(k - 1) Then
' =====
' reduce step size by Golden search
GScnt = GScnt + 1
Worksheets("optimum").Range("f61").Value = x(1)
Worksheets("optimum").Range("g61").Value = x(2)
Worksheets("optimum").Range("f62").Value = p(1)
Worksheets("optimum").Range("g62").Value = p(2)
Call cmdGoldStep_Click
' pick best step fraction
v1 = Worksheets("optimum").Range("d65").Value
v2 = Worksheets("optimum").Range("d66").Value
If v1 > v2 Then
step = Worksheets("optimum").Range("c65").Value
Else
step = Worksheets("optimum").Range("c66").Value
End If

For i = 1 To 2
xnew(i) = x(i) + step * p(i)
If xnew(i) <= 0 Then xnew(i) = 0
Next i
If xnew(1) <= 0 Then xnew(2) = 0
Worksheets("baseloads").Range("a12").Value = xnew(2) * RTconv
Worksheets("baseloads").Range("a11").Value = xnew(1)
F(k) = Worksheets("baseloads").Range("ap8777").Value
' exit Golden search area
MsgBox "finished golden search"
End If
' acceptable to proceed
For i = 1 To 2
s(i) = xnew(i) - x(i)

```

```

x(i) = xnew(i)
Next i
Fsav = F(k)
dgbest = x(1)
acbest = x(2) * RTconv
' test for optimization termination on function value change
stopcrit = absstop
If difstop * Abs(Fsav) > stopcrit Then stopcrit = difstop * Abs(Fsav)
'MsgBox "check stop criteria"
'the following three lines represent a 2-sequential achievement requirement
If k > 1 Then
If Abs(Fsav - F(k - 1)) <= stopcrit And Abs(F(k - 1) - F(k - 2)) <= stopcrit Then Exit For
End If
'the next line is for a single achievement requirement
'If Abs(Fsav - F(k - 1)) <= stopcrit Then Exit For

' don't stop yet, so find new gradient vector
x1tmp = x(1) + gradstep
x2tmp = x(2) + gradstep
Worksheets("baseloads").Range("al2").Value = x(2) * RTconv
Worksheets("baseloads").Range("ai1").Value = x1tmp
gnew(1) = (Worksheets("baseloads").Range("ap8777").Value - F(k)) / gradstep
Worksheets("baseloads").Range("al2").Value = x2tmp * RTconv
Worksheets("baseloads").Range("ai1").Value = x(1)
gnew(2) = (Worksheets("baseloads").Range("ap8777").Value - F(k)) / gradstep
For i = 1 To 2
y(i) = gnew(i) - g(i)
g(i) = gnew(i)
Next i
' test whether both gradient changes are zero
' if so, skip Hessian update
ztst = 0
If y(1) = 0 And y(2) = 0 Then ztst = 1
If ztst < 1 Then
' update Hessian via BFGS method
denom = s(1) * y(1) + s(2) * y(2)
t1 = y(1) * H(1, 1) + y(2) * H(2, 1)
t2 = y(1) * H(1, 2) + y(2) * H(2, 2)
A = t1 * y(1) + t2 * y(2)
A = A / denom + 1
For i = 1 To 2
For j = 1 To 2
B(i, j) = s(i) * s(j) / denom * A
C(i, j) = s(i) * y(j)
C2(i, j) = y(i) * s(j)
Next j
Next i
For i = 1 To 2
For j = 1 To 2

```

```

C3(i, j) = 0
C4(i, j) = 0
For m = 1 To 2
C3(i, j) = C3(i, j) + C(i, m) * H(m, j)
C4(i, j) = C4(i, j) + H(i, m) * C2(m, j)
Next m
Next j
Next i
For i = 1 To 2
For j = 1 To 2
C(i, j) = (C3(i, j) + C4(i, j)) / denom
H(i, j) = H(i, j) + B(i, j) - C(i, j)
Next j
Next i
' next end if for when gradients are the same and the Hessian is not updated
End If
' write interim data values
Worksheets("optimum").Range("g70").Value = GScnt
Worksheets("optimum").Range("g71").Value = k
Worksheets("optimum").Range("a96").Activate
ActiveCell.Offset(k, 0) = k
ActiveCell.Offset(k, 1) = x(1)
ActiveCell.Offset(k, 2) = x(2)
ActiveCell.Offset(k, 3) = g(1)
ActiveCell.Offset(k, 4) = g(2)
ActiveCell.Offset(k, 5) = H(1, 1)
ActiveCell.Offset(k, 6) = H(1, 2)
ActiveCell.Offset(k, 7) = H(2, 1)
ActiveCell.Offset(k, 8) = H(2, 2)
ActiveCell.Offset(k, 11) = F(k)
ActiveCell.Offset(k - 1, 12) = step

Next k
' write interim data values
Worksheets("optimum").Range("g70").Value = GScnt
Worksheets("optimum").Range("g71").Value = k
Worksheets("optimum").Range("a96").Activate
ActiveCell.Offset(k, 0) = k
ActiveCell.Offset(k, 1) = x(1)
ActiveCell.Offset(k, 2) = x(2)
ActiveCell.Offset(k, 3) = g(1)
ActiveCell.Offset(k, 4) = g(2)
ActiveCell.Offset(k, 5) = H(1, 1)
ActiveCell.Offset(k, 6) = H(1, 2)
ActiveCell.Offset(k, 7) = H(2, 1)
ActiveCell.Offset(k, 8) = H(2, 2)
ActiveCell.Offset(k, 11) = F(k)
ActiveCell.Offset(k - 1, 12) = step
' check for exit reason

```

```

If k > 25 Then
    z = MsgBox("No optimal solution to termination specs was found within 25 iterations. Best
solution shown.", vbExclamation + vbOKOnly, "Termination Notice!")
Else
    MsgBox "Finished"
End If
' =====
' start contour plot routine
dgbest = Worksheets("optimum").Range("l124").Value
acbest = Worksheets("optimum").Range("l125").Value
Worksheets("baseloads").Range("ai1").Value = dgbest
Worksheets("baseloads").Range("al2").Value = acbest * RTconv
Worksheets("main").Activate
Application.ScreenUpdating = True
Worksheets("main").Range("b27").Value = "Optimum found! Creating contour plot"
Application.ScreenUpdating = False
Worksheets("optimum").Activate
' option for producing contour plot
'z = MsgBox("Update Contour Plot?", vbQuestion + vbYesNo, "Chart Update")
z = 0
If Worksheets("main").checkboxContour.Value = True Then z = 6

If z = 6 Then
    ' set DG cap range
    scfac = 0
    mf = 0
    delta = xmax / 20
    Call bestscale(delta, mf, scfac)
    xmin = 0.5
    Worksheets("optimum").Range("m29").Activate
    Worksheets("optimum").Range("m29").Value = xmin
    xmin = 0
    delta = scfac * 10 ^ mf
    For i = 1 To 20
        xnext = xmin + i * delta
        ActiveCell.Offset(i, 0) = xnext
    Next i
    ' set AC cap range
    scfac = 0
    mf = 0
    delta = ymax / 6
    Call bestscale(delta, mf, scfac)
    ymin = 0.5
    Worksheets("optimum").Range("n27").Activate
    Worksheets("optimum").Range("n27").Value = ymin
    ymin = 0
    delta = scfac * 10 ^ mf
    For i = 1 To 6
        ynext = ymin + i * delta

```



```

ActiveCell.Offset(0, i) = ynext
Next i

' start calculation pass
'get initial capacity value
Worksheets("optimum").Range("n27").Activate
acap = ActiveCell.Value
Worksheets("baseloads").Range("a12").Value = acap
T = 1
Worksheets("optimum").Range("m29").Activate

' start outer loop of AC capacities
Do While acap > 0
cap = ActiveCell.Value
R = 0
' go through DG capacities
Do While cap > 0
Worksheets("baseloads").Range("ai1").Value = cap
crntval = Worksheets("baseloads").Range("ap8777").Value
ActiveCell.Offset(R, T) = crntval
R = R + 1
cap = ActiveCell.Offset(R, 0).Value
Loop
T = T + 1
acap = ActiveCell.Offset(-2, T).Value
Worksheets("baseloads").Range("a12").Value = acap

Loop

' end of contour plotting
End If
Worksheets("optimum").Range("m29").Value = xmin
Worksheets("optimum").Range("n27").Value = ymin
' recall best obj function
Worksheets("baseloads").Range("ai1").Value = dgbest
Worksheets("baseloads").Range("a12").Value = acbest * RTconv

'end calculations
Worksheets("Main").Activate
Application.ScreenUpdating = True
Worksheets("main").Range("c4").Value = " "
Worksheets("main").Range("b27").Value = " "
'MsgBox "finished"

End Sub

```

```

Private Sub cmdGoldStep_Click()
' this performs Golden Search for the step
' that produces the max savings
' set initial range values
IOUstop = 0.025
cntr = 0
xlow = 0
xhigh = 1
Worksheets("optimum").Activate
Worksheets("optimum").Range("c61").Activate
Worksheets("optimum").Range("c61").Value = cntr
Worksheets("optimum").Range("c62").Value = xlow
Worksheets("optimum").Range("c63").Value = xhigh

' start iteration loop, stopping when IOU <= IOU stop
c1 = Worksheets("optimum").Range("f61").Value
C2 = Worksheets("optimum").Range("g61").Value
p1 = Worksheets("optimum").Range("f62").Value
p2 = Worksheets("optimum").Range("g62").Value
IOU = Worksheets("optimum").Range("c64").Value
Do While IOU >= IOUstop
cntr = cntr + 1
Worksheets("optimum").Range("c61").Value = cntr
Worksheets("optimum").Range("c65").Activate
' select low end step and calc inputs
s = ActiveCell.Value
R = 0

' two-step calc loop
Do While s > 0
' enter capacities into baseload spreadsheet
cap = c1 + s * p1
acap = (C2 + s * p2) * 3412.8 / 12000
Worksheets("baseloads").Range("ai1").Value = cap
Worksheets("baseloads").Range("al2").Value = acap
ActiveCell.Offset(R, 1) = Worksheets("baseloads").Range("ap8777").Value
R = R + 1
s = ActiveCell.Offset(R, 0).Value
Loop

' next step logic
x1 = Worksheets("optimum").Range("c65").Value
x2 = Worksheets("optimum").Range("c66").Value
y1 = Worksheets("optimum").Range("d65").Value
y2 = Worksheets("optimum").Range("d66").Value
If y1 < y2 Then
Worksheets("optimum").Range("c62").Value = x1
Else
Worksheets("optimum").Range("c63").Value = x2

```

```
End If
IOU = Worksheets("optimum").Range("c64").Value

Loop
'MsgBox "finished"

End Sub
```

APPENDIX D

Results from Application Scenarios

Results

Demands	Electricity	Heating	Cooling
Annual	12,406,742 kWh	37,074 MMBtu	1,617,306 RT-hr
Maximum	2275 kW	17.0 MMBtu/hr	808 RT
Minimum	934 kW	0.51 MMBtu/hr	0 RT

Installed DG capacity: 1142.0 kW (net)
 Installed AC capacity: 215.4 RT

Hours of DG operation: 6,712 hours/year
 DG generated electricity: 7,478,194 kWh/year
 DG supplied heating: 27,921 MMBtu/year
 AC supplied cooling: 546,886 RT-hr/year

Annual costs (before tax)	With CHP	No CHP
CHP system	\$1,065,024	\$0
Utility elec	\$651,031	\$1,785,547
Non-CHP fuel	\$124,018	\$502,367
Total	\$1,840,073	\$2,287,913

Annual operating savings (after tax): \$277,661
 NPV savings: \$954,012

Optimum DG capacity: 1142.0 kW
 Optimum AC capacity: 215.4 RT
 NPV savings: \$954,012

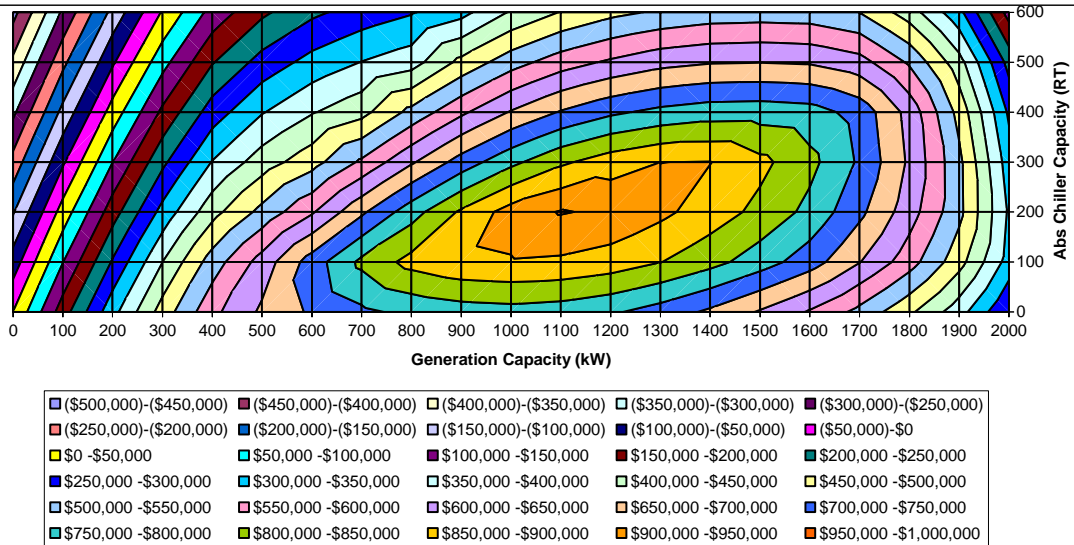


Figure A-11. Summary Results for Boston Hospital

Results

Demands	Electricity	Heating	Cooling
Annual	4,778,146 kWh	15,645 MMBtu	799,048 RT-hr
Maximum	1185 kW	7.1 MMBtu/hr	492 RT
Minimum	254 kW	0.12 MMBtu/hr	0 RT

Installed DG capacity: 417.2 kW (net)
 Installed AC capacity: 88.3 RT

Hours of DG operation: 6,695 hours/year
 DG generated electricity: 2,683,205 kWh/year
 DG supplied heating: 10,544 MMBtu/year
 AC supplied cooling: 171,531 RT-hr/year

Annual costs (before tax)	With CHP	No CHP
CHP system	\$382,962	\$0
Utility elec	\$312,031	\$715,878
Non-CHP fuel	\$69,114	\$211,994
Total	\$764,107	\$927,872

Annual operating savings (after tax): \$101,534
 NPV savings: \$341,877

Optimum DG capacity: 417.2 kW
 Optimum AC capacity: 88.3 RT
 NPV savings: \$341,877

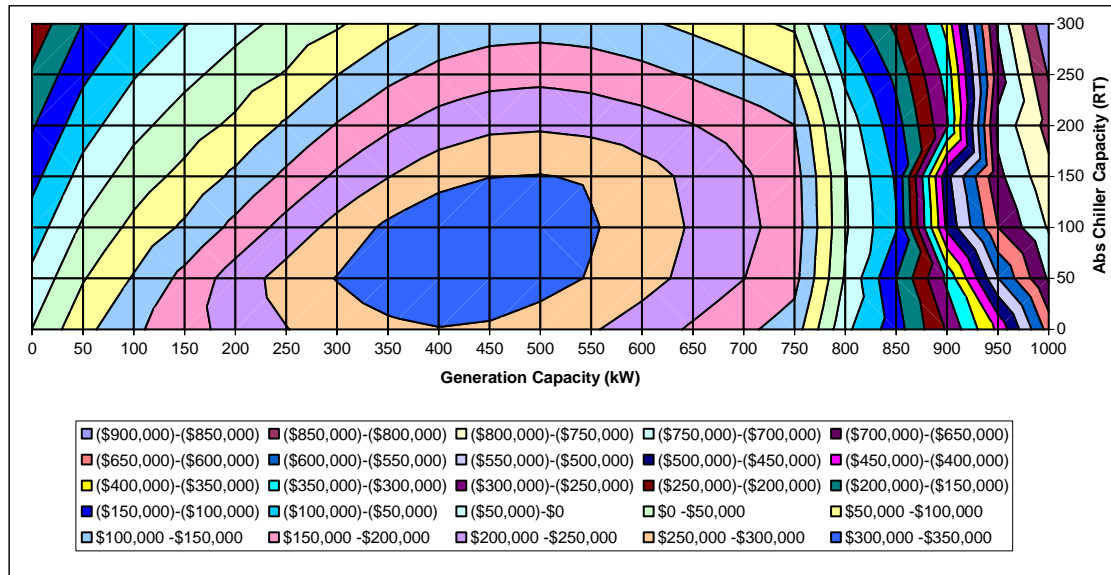


Figure A-12. Summary Results for Boston Hotel

Results

Demands	Electricity	Heating	Cooling
Annual	601,572 kWh	2,662 MMBtu	87,007 RT-hr
Maximum	172 kW	1.4 MMBtu/hr	68 RT
Minimum	16 kW	0.00 MMBtu/hr	0 RT

Installed DG capacity: 74.8 kW (net)
 Installed AC capacity: 16.4 RT

Hours of DG operation: 5,067 hours/year
 DG generated electricity: 378,124 kWh/year
 DG supplied heating: 1,240 MMBtu/year
 AC supplied cooling: 33,631 RT-hr/year

Annual costs (before tax)	With CHP	No CHP
CHP system	\$53,786	\$0
Utility elec	\$31,445	\$95,603
Non-CHP fuel	\$19,267	\$36,068
Total	\$104,498	\$131,671

Annual operating savings (after tax): \$16,847
 NPV savings: \$48,861

Optimum DG capacity: 74.8 kW
 Optimum AC capacity: 16.4 RT
 NPV savings: \$48,861

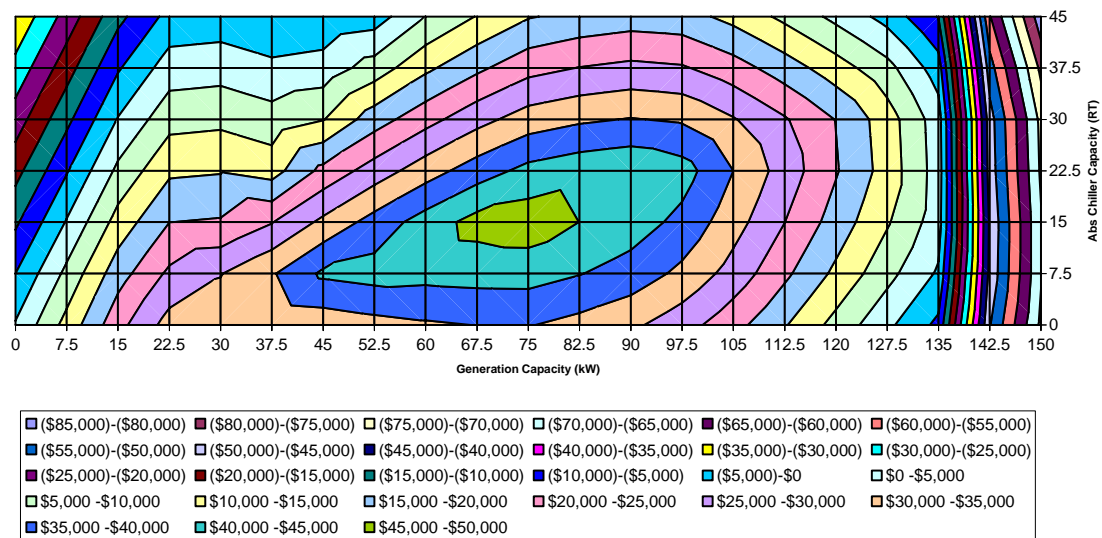


Figure A-13. Summary Results for Boston Nursing Home

Results

Demands	Electricity	Heating	Cooling
Annual	1,228,619 kWh	2,924 MMBtu	147,391 RT-hr
Maximum	337 kW	2.7 MMBtu/hr	147 RT
Minimum	0 kW	0.00 MMBtu/hr	0 RT

Installed DG capacity: 118.3 kW (net)
 Installed AC capacity: 35.9 RT

Hours of DG operation: 4,641 hours/year
 DG generated electricity: 526,416 kWh/year
 DG supplied heating: 1,665 MMBtu/year
 AC supplied cooling: 35,673 RT-hr/year

Annual costs (before tax)	With CHP	No CHP
CHP system	\$75,258	\$0
Utility elec	\$100,280	\$193,285
Non-CHP fuel	\$17,491	\$40,618
Total	\$193,029	\$233,903

Annual operating savings (after tax): \$25,342
 NPV savings: \$57,945

Optimum DG capacity: 118.3 kW
 Optimum AC capacity: 35.9 RT
 NPV savings: \$57,945

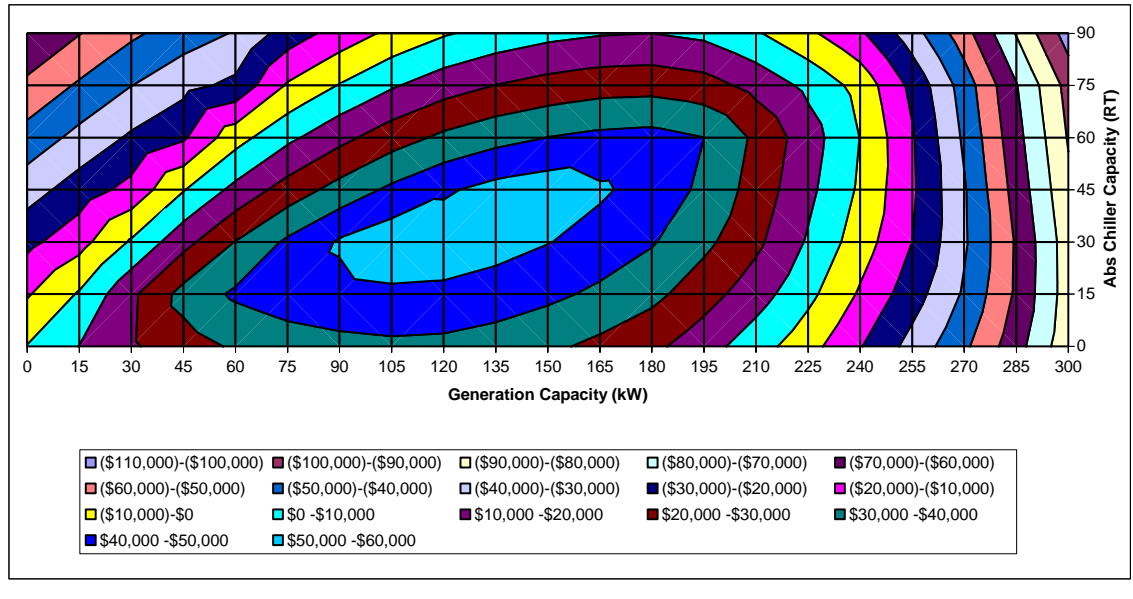


Figure A-14. Summary Results for Boston Retail

Results

Demands	Electricity	Heating	Cooling
Annual	1,625,584 kWh	3,640 MMBtu	27,517 RT-hr
Maximum	260 kW	2.1 MMBtu/hr	40 RT
Minimum	158 kW	0.00 MMBtu/hr	0 RT

Installed DG capacity: 117.7 kW (net)
 Installed AC capacity: 6.9 RT

Hours of DG operation: 6,037 hours/year
 DG generated electricity: 710,551 kWh/year
 DG supplied heating: 2,613 MMBtu/year
 AC supplied cooling: 5,101 RT-hr/year

Annual costs (before tax)	With CHP	No CHP
CHP system	\$101,060	\$0
Utility elec	\$119,757	\$223,794
Non-CHP fuel	\$13,915	\$49,319
Total	\$234,732	\$273,113

Annual operating savings (after tax): \$23,796
 NPV savings: \$67,611

Optimum DG capacity: 117.7 kW
 Optimum AC capacity: 6.9 RT
 NPV savings: \$67,611

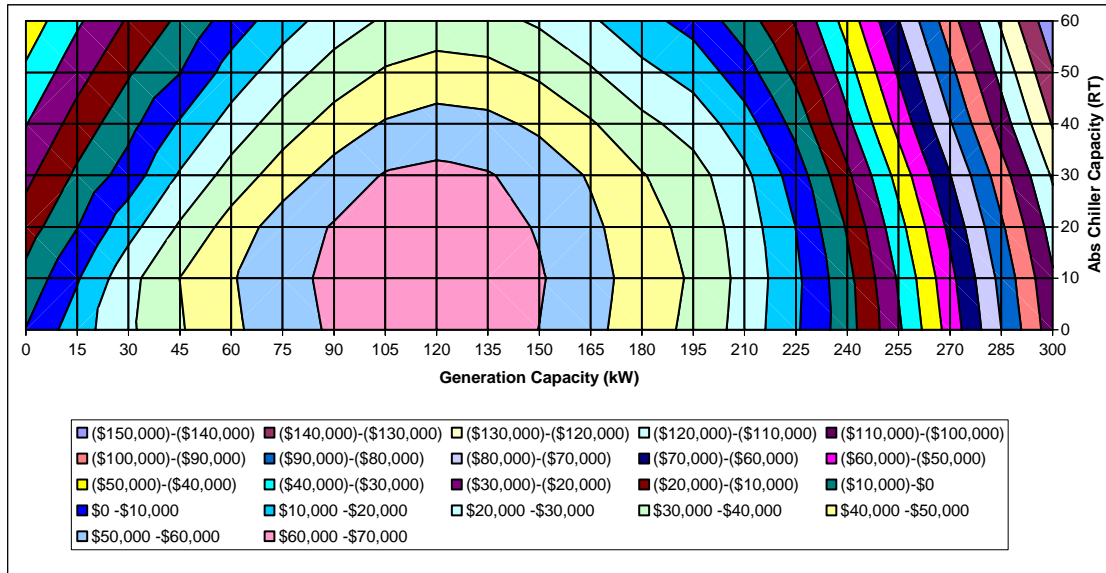


Figure A-15. Summary Results for Boston Supermarket

Results

Demands	Electricity	Heating	Cooling
Annual	11,812,862 kWh	18,760 MMBtu	1,403,216 RT-hr
Maximum	1949 kW	7.5 MMBtu/hr	452 RT
Minimum	943 kW	0.53 MMBtu/hr	8 RT

Installed DG capacity:	513.8 kW (net)
Installed AC capacity:	30.9 RT
Hours of DG operation	6,521 hours/year
DG generated electricity	3,350,640 kWh/year
DG supplied heating	14,922 MMBtu/year
AC supplied cooling	103,406 RT-hr/year

Annual costs (before tax)	With CHP	No CHP
CHP system	\$396,892	\$0
Utility elec	\$1,021,074	\$1,440,860
Non-CHP fuel	\$43,619	\$213,185
Total	\$1,461,585	\$1,654,045

Annual operating savings (after tax):	\$119,326
NPV savings:	\$431,123

Optimum DG capacity:	513.8 kW
Optimum AC capacity:	30.9 RT
NPV savings:	\$431,123

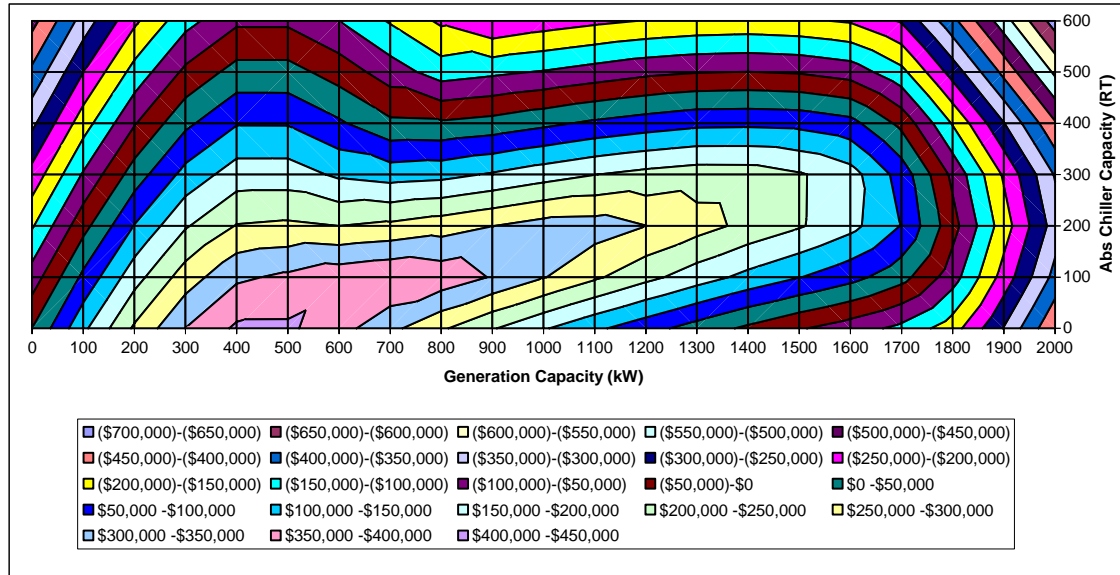


Figure A-16. Summary Results for San Francisco Hospital

Results

Demands	Electricity	Heating	Cooling
Annual	4,522,398 kWh	9,992 MMBtu	680,125 RT-hr
Maximum	1004 kW	3.4 MMBtu/hr	334 RT
Minimum	249 kW	0.12 MMBtu/hr	0 RT

Installed DG capacity:	257.2 kW (net)
Installed AC capacity:	36.2 RT
Hours of DG operation	7,987 hours/year
DG generated electricity	2,054,605 kWh/year
DG supplied heating	8,465 MMBtu/year
AC supplied cooling	110,024 RT-hr/year

Annual costs (before tax)	With CHP	No CHP
CHP system	\$243,374	\$0
Utility elec	\$295,930	\$541,841
Non-CHP fuel	\$17,357	\$113,550
Total	\$556,660	\$655,391

Annual operating savings (after tax):	\$61,213
NPV savings:	\$212,726

Optimum DG capacity:	257.2 kW
Optimum AC capacity:	36.2 RT
NPV savings:	\$212,726

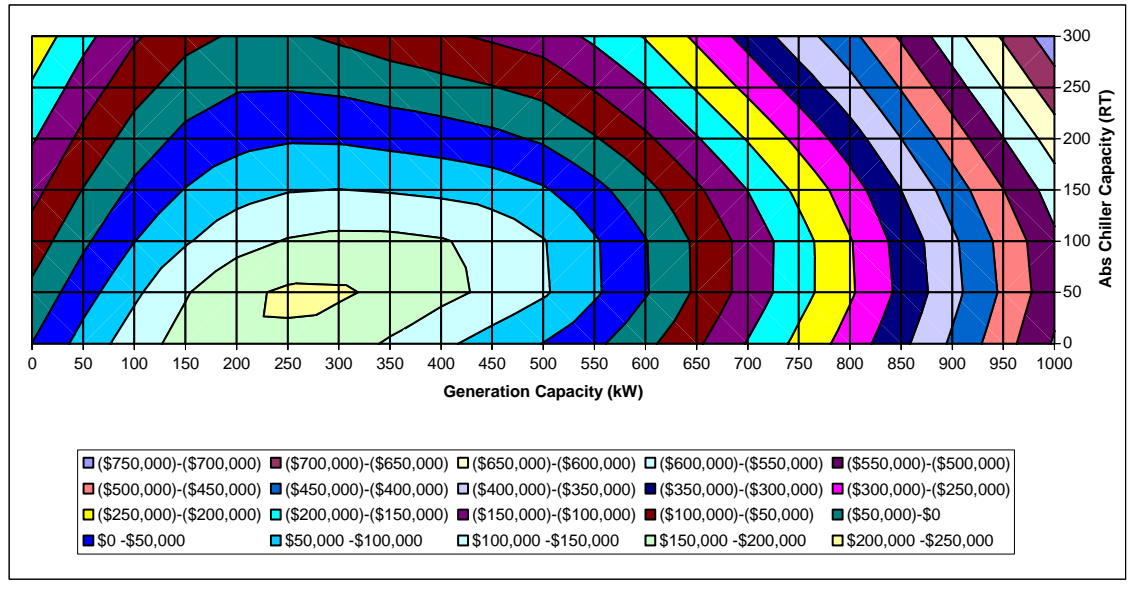


Figure A-17. Summary Results for San Francisco Hotel

Results

Demands	Electricity	Heating	Cooling
Annual	555,117 kWh	1,284 MMBtu	52,632 RT-hr
Maximum	154 kW	0.6 MMBtu/hr	49 RT
Minimum	15 kW	0.00 MMBtu/hr	0 RT

Installed DG capacity:	25.1 kW (net)
Installed AC capacity:	3.5 RT
Hours of DG operation	7,611 hours/year
DG generated electricity	174,829 kWh/year
DG supplied heating	985 MMBtu/year
AC supplied cooling	11,617 RT-hr/year

Annual costs (before tax)	With CHP	No CHP
CHP system	\$23,386	\$0
Utility elec	\$52,898	\$75,742
Non-CHP fuel	\$3,399	\$14,588
Total	\$79,683	\$90,330

Annual operating savings (after tax):	\$6,601
NPV savings:	\$26,313

Optimum DG capacity:	25.1 kW
Optimum AC capacity:	3.5 RT
NPV savings:	\$26,313

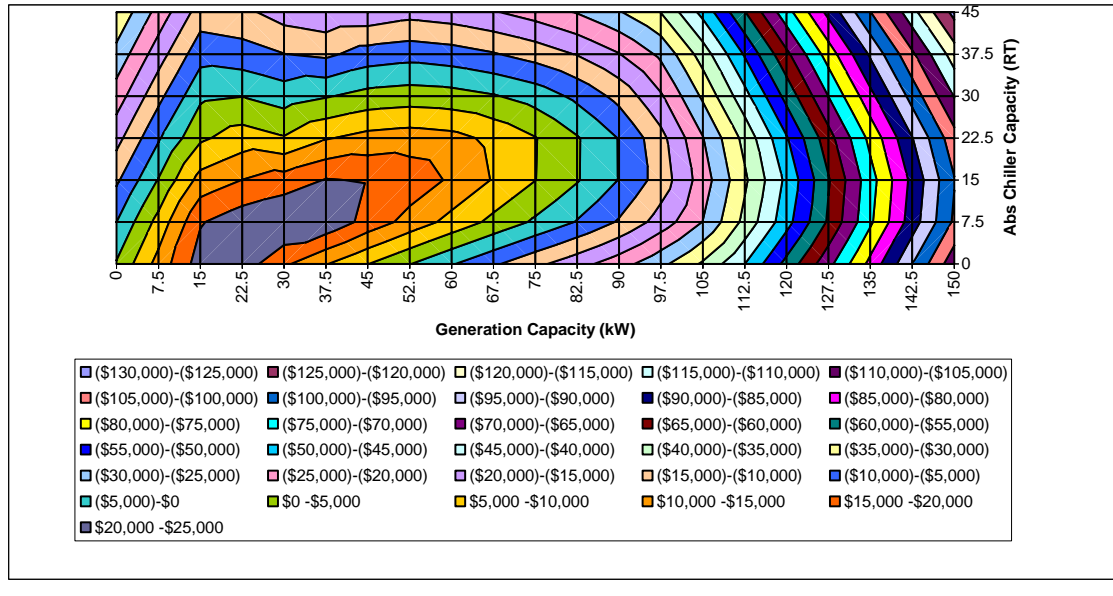


Figure A-18. Summary Results for San Francisco Nursing Home

Results

Demands	Electricity	Heating	Cooling
Annual	1,791,947 kWh	1,038 MMBtu	90,878 RT-hr
Maximum	433 kW	1.8 MMBtu/hr	131 RT
Minimum	0 kW	0.00 MMBtu/hr	0 RT

Installed DG capacity: 63.9 kW (net)
 Installed AC capacity: 19.1 RT

Hours of DG operation: 4,538 hours/year
 DG generated electricity: 286,371 kWh/year
 DG supplied heating: 560 MMBtu/year
 AC supplied cooling: 29,802 RT-hr/year

Annual costs (before tax)	With CHP	No CHP
CHP system	\$33,959	\$0
Utility elec	\$194,112	\$241,086
Non-CHP fuel	\$5,296	\$11,510
Total	\$233,368	\$252,596

Annual operating savings (after tax): \$11,922
 NPV savings: \$15,954

Optimum DG capacity: 63.9 kW
 Optimum AC capacity: 19.1 RT
 NPV savings: \$15,954

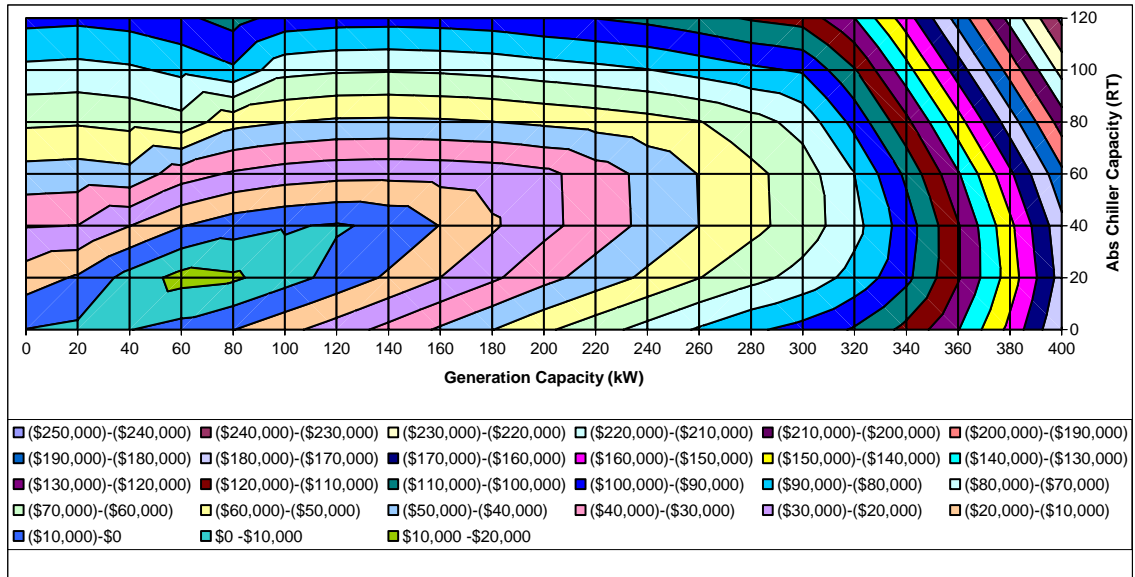


Figure A-19. Summary Results for San Francisco Retail

Results

Demands	Electricity	Heating	Cooling
Annual	1,615,892 kWh	2,282 MMBtu	4,283 RT-hr
Maximum	248 kW	0.7 MMBtu/hr	17 RT
Minimum	163 kW	0.00 MMBtu/hr	0 RT

Installed DG capacity:	54.6 kW (net)
Installed AC capacity:	5.0 RT
Hours of DG operation	7,663 hours/year
DG generated electricity	418,245 kWh/year
DG supplied heating	1,741 MMBtu/year
AC supplied cooling	1,415 RT-hr/year

Annual costs (before tax)	With CHP	No CHP
CHP system	\$49,542	\$0
Utility elec	\$136,702	\$186,582
Non-CHP fuel	\$6,153	\$25,937
Total	\$192,397	\$212,519

Annual operating savings (after tax):	\$12,476
NPV savings:	\$42,666

Optimum DG capacity:	54.6 kW
Optimum AC capacity:	5.0 RT
NPV savings:	\$42,666

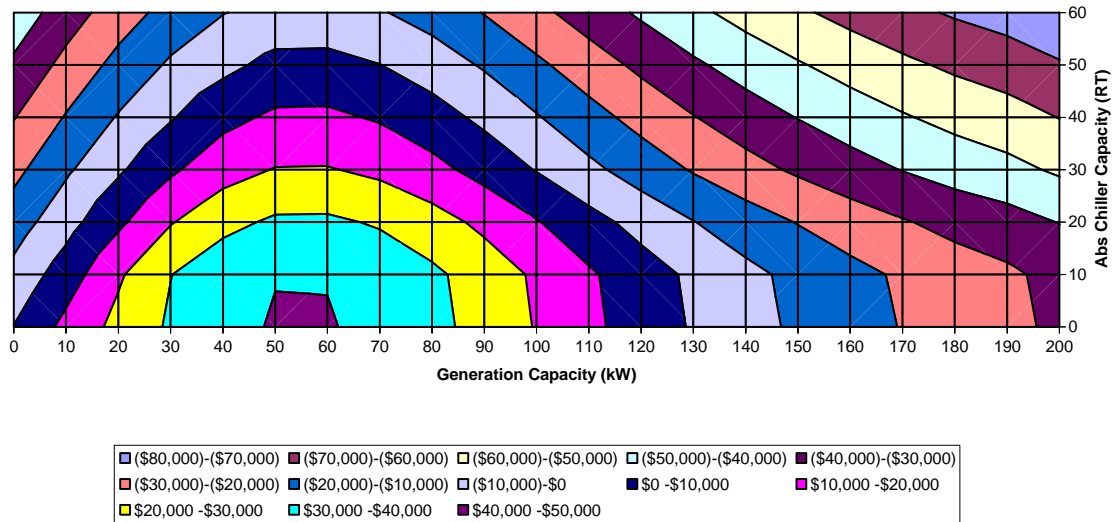


Figure A-20. Summary Results for San Francisco Supermarket

VITA

Carl R. Hudson, II, a native of Knoxville, Tennessee, obtained his Bachelor of Science degree in Nuclear Engineering from The University of Tennessee, Knoxville in 1976. He also began work at Oak Ridge National Laboratory (ORNL) in 1976. He received a Masters in Business Administration degree with a concentration in Industrial Management from The University of Tennessee, Knoxville in 1980. To continue the life-long pursuit of knowledge, he undertook the challenge of the doctoral degree in Industrial Engineering at The University of Tennessee, Knoxville in 2002 while continuing his work at ORNL on electric and thermal energy systems. He is, at this writing, a doctoral candidate and full-time employee at ORNL.