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Authors
Siddiqui, Afzal S.
Marnay, Chris
Firestone, Ryan M.
et al.

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Ernest Orlando Lawrence
Berkeley National Laboratory

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Disclaimer

Distributed Generation with Heat Recovery and Storage

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Afzal S. Siddiqui[1], *Chris Marnay*[2], *Ryan M. Firestone*[3], *and Nan Zhou*[4]

Abstract

Electricity produced by distributed energy resources (DER) located close to end-use loads has the potential to meet consumer requirements more efficiently than the existing centralized grid. Installation of DER allows consumers to circumvent the costs associated with transmission congestion and other non-energy costs of electricity delivery and potentially to take advantage of market opportunities to purchase energy when attractive. On-site, single-cycle thermal power generation is typically less efficient than central station generation, but by avoiding non-fuel costs of grid power and by utilizing combined heat and power (CHP) applications, i.e., recovering heat from small-scale on-site thermal generation to displace fuel purchases, DER can become attractive to a strictly cost-minimizing consumer. In previous efforts, the decisions facing typical commercial consumers have been addressed using a mixed-integer linear program, the DER Customer Adoption Model (DER-CAM). Given the site's energy loads, utility tariff structure, and information (both technical and financial) on candidate DER technologies, DER-CAM minimizes the overall energy cost for a test year by selecting the units to install and determining

[1] Lecturer, Department of Statistical Science, University College London, London WC1E 6BT, United Kingdom, tel: +44 (0)20 7679 1871, e-mail: afzal@stats.ucl.ac.uk. Most of this work was completed while the lead author was College Lecturer, Department of Banking and Finance, Michael Smurfit Graduate School of Business, University College Dublin, Blackrock, Co. Dublin, Republic of Ireland.
[2] Staff Scientist, Environmental Energy Technologies Division, Ernest Orlando Lawrence Berkeley National Laboratory, Berkeley, CA 94720, USA, tel: +1 510 486 7028, fax: +1 510 486 7976, e-mail: C_Marnay@lbl.gov.
[3] Graduate Student Research Assistant, Environmental Energy Technologies Division, Ernest Orlando Lawrence Berkeley National Laboratory, Berkeley, CA 94720, USA, tel: +1 510 495 2604, fax: +1 510 486 7976, e-mail: RMFirestone@lbl.gov.
[4] Post-Doctoral Fellow, Environmental Energy Technologies Division, Ernest Orlando Lawrence Berkeley National Laboratory, Berkeley, CA 94720, USA, tel: +1 510 486 5534, fax: +1 510 486 7976, e-mail: NZhou@lbl.gov.

their hourly operating schedules. In this paper, the capabilities of DER-CAM are enhanced by the inclusion of the option to store recovered low-grade heat. By being able to keep an inventory of heat for use in subsequent periods, sites are able to lower costs even further by reducing lucrative peak-shaving generation while relying on storage to meet heat loads. This and other effects of storage are demonstrated by analysis of five typical commercial buildings in San Francisco, California, USA, and an estimate of the cost per unit capacity of heat storage is calculated.

CE Database subject headings: California; Energy; Grid systems; Optimization; Heat flow; Financial management, investments; Utilities; Buildings, non-residential.

Introduction

There have been many claimed potential benefits from a move from our current highly centralized power generation and delivery system towards a more distributed paradigm (see Lovins *et al.* 2002 and Gumerman *et al.* 2003). Decentralized visions and concepts go by many poorly defined names including distributed energy resources (DER), distributed generation (DG), and microgrids. However, common to virtually all arguments in favor of decentralization is the clear need in the post-industrial economies to lower the prevalence of fossil fuel sources of waste heat and other losses associated with energy conversion to electricity and its subsequent long-distance delivery to serve end-use loads, e.g., these two sources of energy loss in the United States (US) together accounted for fully 18% of all US 2003 total primary energy consumption (see EIA 2005a). Note, however, that this is only the waste heat from fossil generation, excluding nuclear or other renewable sources. Furthermore, losses tend to increase over time both because electricity provides a growing share of end-use energy consumption in developed economies and because fossil-fired generation tends to provide a growing share of the total fuel mix. This combination of effects is particularly powerful in the case of the US, as can be seen in Figure 1. Note that electricity generation from most sources, except oil, is growing to meet the growing demand and that fossil fuels as a group are growing faster than the total. Based on estimates for historic changes in conversion and delivery efficiency, an estimate of the total waste heat from fossil generation is shown in Figure 1. There has been fairly clear and consistent growth in waste heat production over this forty-year historical window. Indeed, these losses offer an obvious and attractive target in the effort to increase efficiency and, equivalently, to lower carbon emissions. In order to achieve this, many have recognized the importance of the opportunity offered for waste reduction by application of combined heat and power (CHP) technology (see, for example, Blair 2004). Because compared to electricity transmission, transporting low-grade recovered heat is prohibitively expensive relative to its net economic value, generating electricity close to potential uses for waste heat, rather than in large remote stations, has a compelling attraction. While considerable attention has been paid historically to application of CHP for provision of process heat, mostly on relatively large scales, significant penetration of CHP technology will require its application in the commercial (or even residential) sectors, posing some major research challenges. Significant among these is the need to match heat delivery to highly variable building requirements, driven by work hours, weather, and fuel prices. In fact, the scheduling and controls requirements for effectively using CHP in typical commercial buildings are daunting and are one of the main motivations for this research path.

Self-provision of electricity can be attractive simply because on-site generation avoids many of the costs associated with electricity delivery, which typically account for one half or more of the retail price. Also, for most commercial buildings, electricity costs far exceed heat energy costs, and electricity production will provide the majority of overall customer energy bill savings from CHP; however, electricity generation on building or neighborhood scales will usually be inefficient compared to modern central-station generation, implying both that potentially more heat will be available than at central stations and that effective use of waste heat will play a key role in the economics of DER. When seeking methods for achieving the efficient operation of DER, a long analytic tradition is available on finding efficient technology choice and operation for central-station power generation without CHP, and some useful knowledge on operation of larger scale CHP systems, such as district heating systems. However, available methods for optimizing operation of small-scale CHP are extremely limited, especially under variable fuel prices, and with the burden of small-scale diseconomies.

The concept of CHP is hardly new and is widely applied in industry. However, it is much less common in the commercial sector. Nonetheless, Thomas Edison had a plan to pipe heat to investors' offices from his first-ever central-station power plant at Pearl Street, New York (see Munson 2005, p.17). More recently, the interest in distributed generation and decentralized systems has rekindled interest in commercial CHP, although the implementation problems are well recognized (see USCHP 2001). Pre-eminent among the problems is the variable loads that characterize energy consumption in the commercial sector. Seasonal changes, daily occupancy patterns, weather sensitivity of energy requirements, and many other complications mean that the steady-state production of power and heat in favorable proportions that can guarantee high overall efficiency rarely obtains. Notably, inconsistency between building electrical loads and heat loads make inclusion of thermal storage in building

CHP systems key to their viability, and development of analysis tools for CHP systems incorporating storage is a critical challenge. Currently in San Francisco, California, USA, the Energy and Environmental Analysis, Inc. (EEA) Combined Heat and Power Installation Database reports 64 MW of installed CHP, including 8 MW of systems with an electrical capacity less than 2 MW (see EEA 2006).

Focusing strictly on the customer economic perspective, past work has developed methods for jointly optimizing heat and electricity production and use within a strict cost-minimizing framework, but this has been achieved under the assumption that meeting heat and electricity loads are hard constraints. While in the time steps typically used, i.e., hourly, meeting electricity loads can be reasonably considered a hard requirement, heat loads pose a more complex challenge because:

1. Active storage of low-grade heat will likely be economic under some circumstances and is already widely used (see, for example, Brown 2000).
2. Over short periods, heat delivery can deviate significantly from the optimal level needed to maintain preferred indoor ambient and domestic hot water temperatures. This effect derives from both occupant tolerance for short-lived deviations from desired comfort levels and from the natural thermal storage capability of buildings and water tanks, which can create a considerable lag between deviations in heat production and unacceptable ambient conditions. In fact, the thermal properties of buildings can also be adjusted to enhance their heat lag performance (see, for example, Kedl 1991 and Hittle 2002)
3. De-synchronizing electricity and heat production may have a significant effect on the benefits of on-site electricity generation.

This paper addresses the first and third issues by expanding on past models to permit active storage of heat between time periods. A simple model of thermal energy storage is developed as a first step towards eventual full de-synchronization of heat and electricity production within the complex economic and physical constraints implicit in points 1-3 above.

The approach taken in this paper and prior work by Berkeley Lab is well demonstrated by Figure 2. In this Sankey diagram, energy inflows to the building are shown on the left, and in this study, they are only utility-purchased natural gas and electricity. On the right side, useful energy flows in the building are shown. Some end uses can be served only by electricity and others only by natural gas, shown at the top and bottom. Space-heating and domestic water-heating are the traditional CHP opportunities that can be served either by direct fire of natural gas or heat recovered from the energy conversion of natural gas fuel to electricity. Finally, cooling and refrigeration are by far the most important, interesting, and challenging loads for three reasons:

1. They can be met in four ways: by electricity using the familiar direct expansion (DX) air conditioning equipment, by direct mechanically driven DX, by direct fire of natural gas in absorption cycles, or by waste heat driven absorption cycles.
2. Since these loads are, in warm climates, coincident with peak electricity requirements, under time-of-use rates and/or with demand (or power) charges imposed, they are more expensive to serve than other end uses. Conversely, cooling with waste heat reinforces the already powerful economic return on peak shaving.

3. And finally, sizing equipment to meet these requirements is particularly complex because cooling equipment is relatively expensive, and if DX cooling is involved, supplemental absorption cooling allows downsizing of electrical systems.

Consequently, building cooling is the most interesting load and the focus of research at Berkeley Lab. The approach used here and in other work is that equipment choice and operation are solved for the system shown in Figure 2 in one simultaneous problem. The sizing and operation of all equipment is, therefore, properly traded off against other alternatives. In prior work, the solution included optimum equipment choices and operating schedules for on-site generators, shown at “1” in Figure 2, for traditional CHP equipment for space and water heating, shown at “2” in Figure 2, and the most interesting choice of cooling and refrigeration at “3.” The innovation reported in this paper is that constraints on the timing of use of waste heat have been relaxed by the addition of storage as shown in Figure 2 at “4.” In particular, heat recovered from the generation of electricity can be stored by a storage device as shown in the figure. It can then be freely charged and discharged, with a small thermal loss being the only penalty. Once heat is recovered from storage, it can be used as in prior versions of this model. Note that the addition of storage allows heat to be passed from one period to a subsequent one, but more importantly, it frees the electricity generating schedule to take increased advantage of the time-varying opportunities for cost savings.

The structure of this paper is as follows:

- the input parameters and decision variables are defined, and the mathematical model is formulated
- the customer load data, along with utility tariff details, DER technology cost and performance criteria, and thermodynamic parameters, are indicated
- the main results for a variety of customer sites are presented and discussed
- the findings are summarized and directions offered for future research

Mathematical Model

In this section, the DER Customer Adoption Model (DER-CAM) is presented, including an overview of the present version of the model's mathematical formulation. While this model has been used extensively by Berkeley Lab researchers and results have been previously reported (see Marnay *et al.* 2001 and Rubio *et al.* 2001), the current version additionally incorporates CHP-enabled technologies and carbon taxation (see Siddiqui *et al.* 2005a and Siddiqui *et al.* 2005b). All versions of the model have been programmed in the commercial optimization software, GAMS (General Algebraic Modeling System). The results presented are not intended to represent a definitive analysis of the benefits of DER adoption, but rather as a demonstration of the current DER-CAM. Developing estimates of realistic customer costs is an important area in which improvement is both essential and possible, and is being actively pursued by the authors in other work. In particular, the current approach via a mixed-integer linear program captures the diseconomies of small-scale investment.

Model Description

In its current formulation, the model purchases two fuels, electricity and natural gas, and supplies four types of end uses: electricity only (e.g., lighting), cooling, space heating, and water heating. The model's objective function is to minimize the cost of supplying the four end uses to a specific site during a given year by optimizing the distributed generation of part or all of its electricity requirement. In order to attain this objective, the following questions must be answered:

1. Which distributed generation and CHP technology (or combination of technologies) should the site install?
2. What is the appropriate level of installed capacity of these technologies that minimizes the cost of meeting the site's requirements for energy?
3. How should the installed capacity be operated in order to minimize the total bill for meeting the site's four end-use requirements?

The essential inputs to DER-CAM are:

- the site's four load profiles (although natural gas only is depicted as an end use in Figure 2, we do not consider it here in order to focus on heat recovery and storage)
- utility electricity and natural gas tariffs
- capital, operating and maintenance (O&M), and fuel costs of the various available DER technologies, together with the interest rate on customer investment
- rate of carbon emissions from the macrogrid and from the burning of natural gas for on-site power generation and direct combustion to meet thermal loads
- carbon tax rates

- thermodynamic parameters governing the use of CHP-enabled DER technologies and heat storage

Outputs to be determined by the optimization are the cost minimizing:

- combination of technologies installed and their respective capacities
- hourly operating schedules for installed equipment (although electricity markets typically clear on a 15-minute basis, since reporting of market data is done on a hourly basis and due to computational constraints, we proceed with our analysis similarly)
- total cost and carbon emissions of supplying the total energy requirement through either DER or macrogrid generation, or typically, a combination of the two

Of the important assumptions that follow, the first three tend to understate the benefit of DER, while the fourth overstates it:

1. Customer decisions are taken based only on direct economic criteria, i.e., the only benefit that the site can achieve is a reduction in its energy bill.
2. The site is not allowed to generate more electricity than it consumes. On the other hand, if more electricity is consumed than generated, then the site will buy from the utility at the default tariff rate. No other market opportunities, such as sale of ancillary services and load interrupts, are considered.
3. Reliability and power quality benefits, and economies of scale in O&M costs for multiple units of the same technology are not taken into account.
4. Manufacturer claims for equipment price and performance are accepted without question. Some of the permitting and other costs are not considered in

the capital cost of equipment, nor are start-up losses and some other operating costs.

Mathematical Formulation

This section describes intuitively the core mathematical problem solved by DER-CAM. First, the input parameters are listed, and the decision variables are defined. Note that although power units, i.e., kW, are used to measure heat flow over the course of one hour, the actual heat used in that hour is measured in units of energy, i.e., kWh. Therefore, we discuss heat flows measured in kW to enable comparison with power. Next, the optimization problem is described.

Input Parameters

Indices

Name	**Definition**
h	Hour {1,2,…,24}
i	Technology {the set of technologies selected}
m	Month {1,2,…,12}
p	Period {on-peak, mid-peak, off-peak} On-peak (hours of the day 12 through 18, inclusive, during summer months, and 18 through 20 during the winter), mid-peak (07 through 11 and 19 through 22 during the summer, and 07 through 17 and 21 through 22 during the winter), or off-peak (01 through 06 and 23 through 24 during all months)
s	Season {summer, winter}: summer (June through September, inclusive) or winter (the remaining months)
t	Day type {weekday, peak, weekend}
u	End use {electricity only, cooling, space heating, water heating }

Customer Data

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

Market Data

Name	Description
$RTPower_{s,p}$	Regulated non-coincident demand charge under the default tariff for season *s* and period *p* (US$/kW)
$RTEnergy_{m,t,h,u}$	Regulated tariff for electricity purchases during hour *h*, type of day *t*, month *m*, and end use *u* (US$/kWh)
$RTCDCharge_m$	Regulated tariff charge for coincident demand, i.e., that occurs at the same time as the monthly system peak during month *m* (US$/kW)
$RTCCharge$	Regulated tariff customer charge (US$)
$RTFCharge$	Regulated tariff facilities charge (US$/kW)
$NGBSF_m$	Natural gas basic service fee for month *m* (US$)
$CTax$	Tax on carbon emissions (US$/kg-carbon)
$MktCRate$	Carbon emissions rate from marketplace generation (kg-carbon/kWh)
$NGCRate$	Carbon emissions rate from burning natural gas to meet heating and cooling loads (kg-carbon/kWh)
$NatGasPrice_{m,t,h}$	Natural gas price during hour *h*, type of day *t*, and month *m* (US$/kJ)

Distributed Energy Resource Technologies Information

Name	Description
$DERmaxp_i$	Nameplate power rating of technology *i* (kW)
$DERlifetime_i$	Expected lifetime of technology *i* (a)
$DERcapcost_i$	Turnkey capital cost of technology *i* (US$/kW)
$DEROMfix_i$	Fixed annual operation and maintenance costs of technology *i* (US$/kW)

$DEROMvar_i$	Variable operation and maintenance costs of technology *i* (US$/kWh)
$DERhours_i$	Maximum number of hours technology *i* is permitted to operate during the year (h)
$DERCostkWh_{i,m}$	Production cost of technology *i* during month *m* (US$/kWh)
$AnnuityF_i$	Annuity factor for DER technology *i*, where $AnnuityF_i = \frac{IntRate}{\left(1 - \frac{1}{(1+IntRate)^{DERlifetime_i}}\right)} \forall i$
$CRate_i$	Carbon emissions rate from technology *i* (kg-carbon/kWh)
$DCCap$	Capacity of direct-fired natural gas absorption chiller (kW)
$DCPrice$	Turnkey cost of direct-fired natural gas absorption chiller (US$)
$AnnDCPrice$	Annualized cost of direct-fired natural gas absorption chiller (US$), where $AnnDCPrice = \frac{IntRate}{\left(1 - \frac{1}{(1+IntRate)^{DCLifetime}}\right)} \cdot DCPrice$
$DCLifetime$	Expected lifetime of direct-fired natural gas absorption chiller (a)
$SHCap$	Capacity of heat storage unit (kWh), which is maximum amount of stored heat that could be used (for space and water heating and for absorption cooling) in a day
$SHPrice$	Turnkey cost of heat storage unit (US$)
$AnnSHPrice$	Annualized cost of heat storage unit (US$), where $AnnSHPrice = \frac{IntRate}{\left(1 - \frac{1}{(1+IntRate)^{SHLifetime}}\right)} \cdot SHPrice$
$SHLifetime$	Expected lifetime of heat storage unit (a)
$S(i)$	Set of end uses that can be met by technology *i*

Other Parameters

Name	**Description**

$IntRate$	Interest rate on DER investments (%), which we assume to be 7.5% per annum
$NGHR$	Natural gas higher heating value (HHV) rate (kJ/kWh)
$t(m)$	Day type in month *m* when system demand peaks
$h(m)$	Hour in month *m* when system demand peaks
α_i	The heat flow (in kW) that can be recovered from unit kW of electricity that is generated using DER technology *i* (this is equal to 0 for all technologies that are not equipped with either a heat exchanger (HX) or an absorption chiller)
β_u	The heat flow (in kW) generated from unit kW of natural gas purchased for end use u (since the electricity-only load never uses natural gas, the corresponding β_u value equals 0)
$\gamma_{i,u}$	The useful heat flow (in kW) that can be allocated to end use *u* from unit kW of recovered heat flow from technology *i* (note: since the electricity-only load never uses recovered heat, the corresponding $\gamma_{i,u}$ values equal 0)
δ_u	The heat flow (in kW) that can be allocated to end use *u* from unit kW of stored heat flow that is released (note: since the electricity-only load never uses recovered heat, the corresponding δ_u value equal 0)
ε	The heat flow (in kW) that is not lost due to dissipation during one hour from unit kW of stored heat

Decision Variables

Name	Description
$InvGen_i$	Number of units of technology *i* installed by the customer
DC	Indicator variable for installation of a direct-fired natural gas absorption chiller
SH	Indicator variable for installation of a heat storage unit
$GenL_{i,m,t,h,u}$	Generated power by technology *i* during hour *h*, type of day *t*, month *m* and

	for end use u to supply the customer's load (kW)
$GasP_{m,t,h,u}$	Purchased natural gas during hour h, type of day t, and month m for end use u (kW)
$DRLoad_{m,t,h,u}$	Purchased electricity from the distribution company by the customer during hour h, type of day t, and month m for end use u (kW) (this variable is derived from other variables, but listed here for clarity)
$RecHeat_{i,m,t,h,u}$	Amount of heat flow recovered from technology i that is used to meet end use u during hour h, type of day t, and month m (kW)
$StoHeat_{m,t,h}$	Amount of stored heat available at the beginning of hour h, type of day t, and month m (kWh)
$InHeat_{i,m,t,h}$	Amount of heat flow from technology i that is diverted towards the heat storage unit during hour h, type of day t, and month m (kW)
$OutHeat_{m,t,h,u}$	Amount of stored heat flow that is released to meet the load of end use u during hour h, type of day t, and month m (kW)

Problem Formulation

It is assumed that the site acquires the residual electricity that it needs beyond its self-generation from the utility at the regulated tariff. The mathematical formulation of the problem follows:

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

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

$$+\sum_{m}\sum_{u\in\{electricity-only,cooling\}} RTCDCharge_{m}\cdot DRLoad_{m,t(m),h(m),u} + AnnDCPrice\cdot DC$$
$$+ AnnSHPrice\cdot SH$$

$$+\sum_{m}\sum_{t}\sum_{h}\sum_{u} DRLoad_{m,t,h,u}\cdot\left(RTEnergy_{m,t,h} + CTax\cdot MktCRate\right)$$

$$+\sum_{i}\sum_{m}\sum_{t}\sum_{h}\sum_{u} GenL_{i,m,t,h,u}\cdot DERCostkWh_{i} + \sum_{i}\sum_{m}\sum_{t}\sum_{h}\sum_{u} GenL_{i,m,t,h,u}\cdot DEROMvar_{i}$$

$$+\sum_{i}\sum_{m}\sum_{t}\sum_{h} GenL_{i,m,t,h}\cdot CTax\cdot CRate_{i}$$

$$+\sum_{i} InvGen_{i}\cdot DERmaxp_{i}\cdot\left(DERcapcost_{i}\cdot AnnuityF_{i} + DEROMfix_{i}\right)+\sum_{m} NGBSF_{m}$$

$$+\sum_{m}\sum_{t}\sum_{h}\sum_{u} GasP_{m,t,h,u}\cdot NGHR\cdot\left(NatGasPrice_{m,t,h} + CTax\cdot NGCRate\right)$$

(1)

Subject to:

$$Cload_{m,t,h,u} = \sum_{i} GenL_{i,m,t,h,u} + DRLoad_{m,t,h,u} + \beta_{u}\cdot GasP_{m,t,h,u} + \sum_{i}\left(\gamma_{i,u}\cdot RecHeat_{i,m,t,h,u}\right)+\delta_{u}\cdot OutHeat_{m,t,h,u}\ \forall\, m,t,h,u \quad (2)$$

$$\sum_{u} GenL_{i,m,t,h,u} \le InvGen_{i}\cdot DER\max p_{i} \quad \forall\, i,m,t,h \quad (3)$$

$$\sum_{m}\sum_{t}\sum_{h}\sum_{u} GenL_{i,m,t,h,u} \le InvGen_{i}\cdot DER\max p_{i}\cdot DERhours_{i}\ \forall\, i \quad (4)$$

$$\sum_{u} RecHeat_{i,m,t,h,u} + InHeat_{i,m,t,h} \le \alpha_{i}\cdot\sum_{u} GenL_{i,m,t,h,u}\ \forall\, i,m,t,h \quad (5)$$

$$RecHeat_{i,m,t,h,u} = 0 \quad \forall\, i,m,t,h \quad if \quad u \notin S(i) \quad (6)$$

$$GenL_{i,m,t,h,u} = 0 \quad \forall\, i,m,t,h \quad if \quad u\in\{space\ heating, water\ heating\} \quad (7)$$

$$GasP_{m,t,h,u} \le \mathrm{DCCap}\cdot\mathrm{DC} \quad \forall\, m,t,h \quad if \quad u\in\{cooling\} \quad (8)$$

$$DRLoad_{m,t,h,u} = 0 \quad \forall\, m,t,h \quad if \quad u \in \{space\ heating, water\ heating\} \tag{9}$$

$$StoHeat_{m,t,h+1} = \ \varepsilon \cdot StoHeat_{m,t,h} + \sum_{i} InHeat_{i,m,t,h} - \sum_{u} OutHeat_{m,t,h,u}\ \forall\, m,t\ if\ \ h \neq \text{ '24'} \tag{10}$$

$$StoHeat_{m+1,t,1} = \ \varepsilon \cdot StoHeat_{m,t,24} + \sum_{i} InHeat_{i,m,t,24} - \sum_{u} OutHeat_{m,t,24,u}\ \forall\, t\ if\ \ m \neq \text{'12'} \tag{11}$$

$$OutHeat_{m,t,h,u} = 0 \quad \forall\, m,t,h \quad if \quad u \in \{electricity\ only\} \tag{12}$$

$$StoHeat_{m,t,h} \leq SH\mathrm{Cap} \cdot SH \quad \forall\, m,t,h \tag{13}$$

$$StoHeat_{\{January\},t,1} = \ 0\ \forall \mathrm{t} \tag{14}$$

$$StoHeat_{\{December\},t,24} = \ 0\ \forall\, t \tag{15}$$

$$OutHeat_{m,t,h,u} = 0 \quad \forall\, u,t \quad if \quad m = \text{'}\,January\text{'}, h = \text{'1'} \tag{16}$$

$$\delta_u \cdot OutHeat_{m,t,h,u} + \sum_{i} \gamma_{\mathrm{i,u}} \cdot \mathrm{Re}\,cHeat_{i,m,t,h,u} \leq \sum_{i} \alpha_i \cdot \gamma_{\mathrm{i,u}} \cdot InvGen_i \cdot DER \max p_i \quad \forall\, m,t,h,u \tag{17}$$

$$\sum_{u} OutHeat_{m,t,h,u} \leq StoHeat_{m,t,h} \quad \forall\, m,t,h \tag{18}$$

$$SHCap = \max_{m,t} \left\{ \sum_{h} Cload_{m,t,h,u} \right\} if\ \ u\ \in \{cooling,\ space\ heating,\ water\ heating\} \tag{19}$$

Equation (1) is the objective function that states that the site will try to minimize total energy cost, consisting of facilities and customer charges, monthly demand charges, coincident demand charges, and utility energy charges inclusive of carbon taxation. In addition, the site incurs on-site generation fuel and O&M costs, carbon taxation on on-site generation, and annualized DER investment costs. Since we would like to estimate how much a given kWh of heat storage capacity is worth to a typical consumer, we set the cost of the heat storage unit to zero. While use of a non-zero cost for the storage unit may change the optimal solution, the results will, nevertheless, be internally consistent in providing implied benefits from storage. Finally, for natural gas used to meet heating and cooling loads directly, there are variable and fixed costs (inclusive of carbon taxation).

The constraints to this problem are expressed in equations (2) through (19):

- equation (2) enforces energy balance (it also indicates the means through which the load for energy end use *u* may be satisfied)
- equation (3) constrains technology *i* to generate no more than its installed capacity
- equation (4) places an upper limit on how many hours each type of DER technology can generate during the year since local air quality regulations may restrict the yearly operating hours of certain technology types
- equation (5) limits how much heat can be recovered for both immediate usage and diversion to storage from each type of DER technology
- equation (6) prevents the use of recovered heat by end uses that cannot be satisfied by the particular DER technology
- equations (7) and (9) are boundary conditions that prevent electricity from being used directly to meet heating loads
- equation (8) prevents direct burning of natural gas to meet the cooling load if no absorption chiller for this purpose is purchased
- equation (10) is the heat inventory balance constraint: it states that the total amount of heat stored at the beginning of an hour is equal to the non-dissipated heat stored at the beginning of the previous hour plus recovered heat that has been diverted towards storage during that hour minus stored heat that is released to meet end-use loads during that hour (since the three day types in this model are simply multiplied by number of such days in each month, there is no overnight storage of heat within a month)

- equation (11) is the same as equation (10), but it is written for the first hour of a month: here, the total heat stored at the beginning of the first hour of a month is equal to the non-dissipated heat stored at the beginning of the last hour of the previous month plus the inflow and minus the outflow of heat during that hour
- equation (12) prevents stored heat from being used by end-use loads such as electricity only
- equation (13) prevents the quantity of heat stored from exceeding the storage capacity
- equation (14) initializes the heat stored to zero
- equation (15) indicates that the stored heat is released at the end of the year
- equation (16) prevents the use of heat from storage during the first hour of the year
- equation (17) prevents the use of recovered heat from generation or storage for a particular end use unless an appropriate CHP technology is installed (this constraint further implies that the amount of stored heat plus recovered heat to be used in any given hour is limited by the capacity of the HXs installed)
- equation (18) prevents the use of stored heat unless a heat storage unit has been purchased
- equation (19) sets the heat storage capacity to the maximum of the sum of the total daily load of the cooling, space-heating, and water-heating end uses

Data

For this research, DER-CAM is applied to a cross-section of hypothetical commercial buildings in San Francisco, California, USA. This section describes the data sources of the essential inputs to DER-CAM.

Load Data

Data from the 1999 Commercial Buildings Energy Consumption Survey (CBECS, see EIA 2003) are used to identify the five most common commercial building types:

- mercantile
- lodging
- education
- healthcare
- office

For each building type, a small and large building is modeled. *Small* buildings have peak electric loads on the order of 300 to 500 kW, the smallest size buildings that typically install DER. *Large* buildings have peak electricity loads in the range of 1 – 2 MW, the largest loads typically met by the technologies of primary consideration here: microturbines and reciprocating engines. The set of two building sizes for each of the five building types leads to ten buildings to be modeled in DER-CAM.

The building energy simulation software DOE-2, developed by the Department of Energy (DOE), is used to generate typical energy end-use load data for the ten buildings. The primary task of this software is to supply input information on building hourly loads for DER-CAM.

Method

Given the selected building types, which are defined based on CBECS, DOE-2 is used to model various building types and determine hourly building energy loads. Based on the output, we then process the data into an hourly data file containing electricity-only, cooling, space-heating, and water-heating loads.

Building Characteristics

DOE-2 simulation requires the following input elements:

Building Description	Location, building type, building size, and number of floors.
Envelope Characteristics	Vintages, construction, insulations, window-to-wall ratio, window panes, and shading coefficient.
Operational Characteristics	Average hot water intensity, peak lighting intensity, peak gas cooking load, and peak electric cooking load. Hours of equipment operation, equipment control strategies, and thermostat set points.
Equipment Characteristics	Vintage, system types, and plant type.

Existing research (see Huang *et al.* 1992) has categorized thirteen prototype commercial buildings in thirteen regions. Standard building profiles with the aforementioned characteristics were defined, and a large database of hourly load profiles is established through simulation. In this project, five of the most promising building types for DER are chosen, and the standard buildings in the existing research are used to carry out the simulation. The location consists of geographical information, which is obtained from the typical meteorological year (TMY) data sets derived from the 1961-1990 national Solar Radiation Data Base. The TMY data sets were produced by the National Renewable Energy Laboratory's (NREL's) Analytic Studies Division under the Resource Assessment Program, which is funded and monitored by the US DOE's Office of Solar Energy Conversion.

Selection of the Building Size

Building data are compiled from the 1999 CBECS to examine the distribution of total commercial floor space among buildings of different sizes, for each of the commercial building types examined in this study. These distributions, along with energy intensity information by building type, are used to determine the presence of buildings in the sizes most conducive to DER. The CBECS data used for this study are in Table 1.

Figure 3 below shows that these CBECS total floor-space values (for 1999) accurately compare with the floor-space assumptions in the National Energy Modeling System (NEMS), which is a tool developed by the DOE to analyze domestic energy markets by modeling the economics of the supply and demand of energy, for 2004, the lowest year of the current NEMS forecast. As expected, the NEMS floor-space values are slightly higher to account for the growth in commercial floor space between 1999 and 2004. The one exception is the mercantile category, which has much higher total floor space in NEMS than in CBECS. This is because the NEMS Mercantile category also includes service buildings, while the CBECS does not.

For each of these five building types, the peak demand *intensity* is calculated from DOE-2 simulations (the peak demand intensity is the building peak load in kW divided by the total building size). This peak demand intensity is then multiplied by the median building size in each of the eight building size categories shown in Table 2. This approximates a total building peak electricity load for each building type, shown with the total corresponding commercial floor space. Table 3 below shows the results of this calculation. By ranking the potential market, peak loads from 300 kW to 2000 kW have been selected for the purpose of this project. This is done by using building size ranges that correspond with the minimum and maximum peak load for the DOE-2 simulation as small- and large-sized building.

Results

Table 4 indicates the peak load, total electricity use, total fuel use, and the fuel-to-electricity (F/E) ratio of the five buildings in San Francisco. The F/E ratio is highest for the educational building, followed by healthcare and lodging. Examples of hourly load shapes (electricity only, cooling, space heating, and water heating) for a large-size healthcare building are shown below (see Figures 4 to 7).

Figures 4 to 7 show the total electricity load and total heating loads in a peak electricity day in January and July each for a healthcare building in San Francisco. It is typical for San Francisco's climate that there is no significant difference between summer and winter in both electricity and natural gas usage. Cooling electricity loads can be observed in the winter, while heating occurs even in July in this unique moderate climate. The peak electricity-only load is 894 kW in January and is 892 kW for July at around time 1100. The peak cooling load occurs at 1400 with 175 kW in July and 85 kW in January.

Space heating for the healthcare building peaks and remains at a high level during the evening but declines during the day. This can be attributed to the thermal gain from higher occupancy and the higher outdoor temperature. Hospitals require frequent air changes to keep the indoor air clean, and they also have occupants at night. Because clinical zones in hospitals require 100% outside air, a heating ventilation and air conditioning (HVAC) system with variable air exchange was applied to maintain air quality, which results in considerable heating load during San Francisco's cool evenings and nights. The gas load for heating during January weekdays typically ranges from approximately 85 to 1048 MJ with the peak load of 1048 MJ at 0700. There is also significant hot water demand in healthcare buildings. The gas load for hot water ranges from 233 to 1295 MJ, with a peak of 1295 MJ also at 0700.

Tariff Data

Electricity

Utility electricity service is provided to San Francisco by Pacific Gas and Electric (PG&E); the electricity tariff for San Francisco commercial customers is obtained from the Tariff Analysis Project's database (see LBNL 2005) of US electricity rates. The three main components of the electricity tariff are volumetric, demand, and fixed fees. *Volumetric* fees are in proportion to the electricity consumed each month and vary with the time of day. *Demand* fees are in proportion to the *maximum power demand* during the month, regardless of how often the maximum level occurs. There are different rates for different times of the day. The *monthly* fee is a fixed charge each month. Table 5 summarizes these rates. Our DER capital costs are typical turnkey costs, which includes upfront interconnection equipment, installation, and registration fees. In California, DG customers who are not qualifying facilities must pay standby charges, which we do incorporate in our model. If they are *qualifying facilities*, i.e., they do not have system efficiencies greater than 60%, then they remain on the default (pre-DG) tariff.

Natural Gas

Natural gas rates for San Francisco are obtained from the Annual Energy Outlook 2005 (see EIA 2005a). The rate used is the average commercial rate for the Pacific region. The volumetric cost of natural gas is \$8.89 x 10^{-6}/kJ for heating applications and DER.

Carbon Tax

In addition to the electricity and natural gas tariffs, which reflect the current state of energy costs in San Francisco, a hypothetical carbon tax of US\$100/ton-carbon is included to address future uncertainties about the costs of emissions.

Technology and Thermodynamic Data

DG Cost and Performance

Three natural gas fired DG technology types are considered: microturbines, reciprocating engines, and turbines. Cost and performance data for these technologies are interpolated from data provided in Goldstein *et al.* 2003, with additional data provided from Firestone 2004. Microturbines and reciprocating engines are considered in two sizes each, and turbines in one size. In DER-CAM, each device can be purchased in one of three packages: 1) as an electricity generation unit, 2) as an electricity generation unit with heat recovery for space and water heating applications, or 3) as an electricity generation unit with heat recovery for space and water heating applications and for cooling using an absorption chiller. Cost and performance data for these technologies is summarized in Table 6. The heat-to-electricity ratio for each unit is the α_i expressed as HHV, which is used throughout DER-CAM. In the cases where heat storage is available, it is assumed to be free. We then try to estimate its economic benefits.

Other Technologies

For this project, HXs used to convert waste heat from DG equipment to useful end-use heat are assumed to be 80% efficient, as are combustors used to convert natural gas to useful end-use heat. This implies that both the β_u and $\gamma_{i,u}$ for the space- and water-heating loads are 0.80. The coefficient of performance (COP) of electric chillers is assumed to be 5 and that of absorption chillers to be 0.70. Therefore, the corresponding $\gamma_{i,u}$ (and β_u if a direct-fired absorption chiller is installed) for the cooling load is 0.13. As for the centralized generation, we assume that it has an efficiency of 0.34 (see Tables 8.2a and 8.4b of EIA 2005b). Furthermore, the fraction of stored heat that can produce useful heat to meet a load, δ_u, is also taken to be 0.13 for cooling and 0.80 for the heating loads. Finally, we assume that the fraction of stored heat that is retained from one hour to the next, ε, 0.99.

Results

In order to determine the impact of heat storage on costs and operation, we run three DER-CAM cases for each of the ten customer sites in San Francisco:

- No DER: the customer is not allowed to adopt any DER and must meet all electricity and heating loads via off-site purchases of electricity and natural gas
- DER No Heat Storage: the customer may adopt DER (including HXs and absorption chillers), but no heat storage unit
- DER Heat Storage: the customer may adopt DER freely and heat storage units up to a capacity size that is the maximum total daily heating and cooling load

Across these ten sites, we identify the conditions under which heat storage would be economical to adopt. Furthermore, we also gain insight into how stored heat would be used, i.e., whether it would complement or supplement recovered heat. For illustrative purposes, we focus on three customer sites with various relationships between the electricity and heating loads. The emphasis on this indicator derives from its importance in traditional evaluation of CHP systems. The ratio is actually not a particularly good indicator of the attractiveness of CHP in general, simply because the electricity output often has much more economic value than displaced heating fuel. Nonetheless, because of the focus here on heat storage, it is a convenient benchmark. Finally, we determine the relationship between energy cost savings due to heat storage and the capacity of the heat storage unit.

Low Ratio of Heating to Electricity Loads

For the small mercantile facility customer site, the heating loads are too small relative to the electricity loads for heat storage to be used. In fact, the cumulative heating loads are only about 2% of the cumulative electricity loads. As a result, not only is heat storage unattractive, but also HXs and absorption chillers are not adopted. The relationship between the heating and electricity loads is evident from Figures 8 to 11 in which the only heating of significance is for space heating during winter mornings. The installed 500 kW natural gas reciprocating engine is used to meet most of the electricity-only and cooling loads, while the relatively small heating loads are always met by burning natural gas (see Figure 12 and Figures 14 to 17). The energy and financial results indicate that adoption of DER reduces the customer's annual energy bill by 8% via lower utility purchase of electricity, particularly during on-peak hours (see Tables 7 and 8).

It is also useful to note that when DER-CAM is run without the heat storage option, the shadow price, which is the dual variable on the heat storage capacity constraint is simply the value of an additional kWh of heat storage capacity (see Nash and Sofer 1996), of equation (13) of the mathematical model is zero for most hours (see Figure 13). This indicates that, *ceteris paribus*, that there is no value to adopting heat storage. For some of the morning hours, it seems that the shadow price of heat storage capacity is negative, thereby implying that it would be cost-reducing to install a heat storage unit. However, because a HX would be necessary for heat storage to be functional, the negative shadow price is somewhat misleading as the cost of purchasing and installing a HX would be greater than the resulting savings via either heat recovery or storage.

Medium Ratio of Heating to Electricity Loads

The small lodging facility site has a moderate ratio of cumulative heating to cumulative electricity loads, i.e., around 32%. More important, however, the heating loads peak at 0800 on January weekdays, precisely when the electricity-only load is settling down to its base level and the cooling load is still ramping up (see Figures 18 through 21). In the case with DER, but no heat storage allowed, the site adopts a 200 kW natural gas reciprocating engine with a bundled HX and absorption chiller. This results in most of the electricity-only load's being met by on-site generation during on-peak hours and by utility purchases during off-peak hours (see Figure 22). In order to limit the amount of on-peak electricity purchases, the site uses the absorption chiller to meet a large fraction, i.e., 60%, of the cooling load with the recovered heat from the on-site electricity generation being almost completely sufficient to meet the heating loads (see Figures 24 and 27).

As the shadow price of heat storage indicates, however, there is substantial potential value to installing a heat storage unit (see Figure 23). This is especially true during the winter mid- and off-peak hours when it is uneconomic to run the on-site generator to cover the electricity-only load and use the recovered heat for the heating loads. Indeed, during such hours, it is cost-effective to use stored heat from the day to meet the heating loads and turn off the generator to rely on relatively cheap utility purchases. Once the adoption of heat storage is allowed, then this is precisely the result as stored heat is used to meet about 30% of the heating loads and 10% of the cooling load (see Figures 28 through 32). Furthermore, stored heat is also deployed during some on-peak hours in order to facilitate greater usage of the absorption chiller for cooling purposes, either directly or via stored heat. This then reduces the need for on-site generation as more of the cooling load is displaced.

Overall, adoption of DER without the heat storage option reduces the customer's energy bill by 9% relative to the case in which no DER is allowed. As the free heat storage is made available, a further 1% cost reduction is attained primarily via less on-site generation of electricity during off-peak hours due to heat storage. To a lesser extent, the elimination of natural gas purchases for meeting heating loads also contributes to this cost saving (see Tables 9 and 10). The "production" from the absorption chiller is in terms of the MWh of electricity displaced by absorption cooling. The same principle applies to stored heat used for cooling. Nevertheless, it is ability of the customer to hold an inventory of heat that provides it with the flexibility to rely less on electricity generation. In particular, the total amount of cooling and heating loads that are met on-site (via either recovered or stored heat) increases to 260 MWh and 395 MWh, respectively even as on-site generation drops to

928 MWh from 956 MWh. Indeed, by being able to use the heat when it is most valuable, the customer is able to realize additional cost savings.

High Ratio of Heating to Electricity Loads

Unlike the small lodging facility, the small educational facility site has a higher ratio (52%) of cumulative heating to electricity loads. Interestingly, the space-heating load peak occurs at 0700 in December and is non-coincident with the electricity loads. By contrast, the water-heating load peaks at 1400 and is coincident with both electricity loads (see Figures 33 through 36). In the case with DER allowed but no heat storage, a 200 kW natural gas reciprocating engine with a HX is installed. Since no absorption chiller is installed, on-site electricity generation is crucial in meeting most of the on-peak electricity-only and cooling loads. In effect, 76% of the electricity-only and 68% of the cooling loads are met via on-site generation (see Figure 37). The resulting heat that is recovered from this generation is then used to meet 92% of the space-heating load and 100% of the water-heating load (see Figures 39 and 42).

Using the shadow price on the heat storage constraint, we determine that the value of heat storage is relatively high during the morning mid- and off-peak hours (see Figure 38). This is because there is a moderately high space-heating load, but a very low electricity load (including cooling needs). Consequently, the site operates its on-site generator to meet the electricity load simply to obtain some recovered heat even though off-peak utility purchases would be more economical. It is constrained to such a policy because it wishes to reduce its bill for burning natural gas to meet the space-heating load.

When adoption of the free heat storage unit is permitted, the customer site optimally uses it to store heat during winter mornings and deploys it to meet the space- and water-heating loads (see Figures 44 through 47). The availability of this resource also implies that the facility can reduce its on-site electricity generation during off-peak hours (see Figure 43). Overall with heat storage, about 74% of the electricity-only and 54% of the cooling loads are met via on-site generation, a reduction from the case in which no heat storage is allowed. The increased costs resulting from higher mid- and off-peak utility purchases are more than offset by lower electricity costs from on-site generation (see Tables 11 and 12). On top of this, the use of heat storage allows 57% of the space-heating load and 66% of the water-heating load to be met via on-site means, thereby lowering costs even further for the facility. While most of this occurs during mid- and off-peak hours (in the case of the space-heating load), some amount is also deployed during on-peak hours for the water-heating load as heat stored from the morning and early afternoon is used.

While the installation of DER alone (without heat storage) is able to lower the customer's overall energy bill by 7%, it still requires purchase of 24 MWh of natural gas each year to meet the heating loads directly. The use of inventory enabled by the heat storage unit lowers the energy bill by another 1% per year by significantly reducing the amount of natural gas purchased for direct end usage. As a result, the overall annual amount of heating loads met on-site increases to 304 MWh from 291 MWh. Effectively, the customer purchases more electricity from the utility during mid- and off-peak hours, a cost increase that is more than offset by the savings from less on-site generation and fewer purchases of natural gas for direct end usage.

Hence, unlike the small lodging facility, the small educational facility saves as much from lower electricity costs as it does from lower natural gas costs.

Estimation of Heat Storage Costs

In aggregate, the relationship between heat storage costs and capacity can be determined from the results of our analysis. Specifically, for each customer site, the cost reduction (in US$) from the DER without heat storage case to the DER with heat storage case is plotted with the heat storage capacity (in kWh) as indicated by the maximum total daily heating and cooling load. An ordinary-least squares (OLS) regression is then performed to yield a best-fit line to the data (see Figure 48). The slope of the OLS regression line will then indicate the average value in US$ of a kWh of heat storage capacity.

Using the results for the ten San Francisco test sites, we find that heat storage capacity is valued, on average, at US$1.25/kWh. Overall, test sites with greater capacity needs will be able to justify the investment because of the greater cost savings that result. Intuitively, the greater the heating requirements, the greater the value of the heat storage unit. While this relationship holds in aggregate, there are some exceptions, viz., the large educational facility (see Table 13). Unlike the other large facilities, the fraction of cumulative heating and cooling loads met by heat storage for this site is rather low, i.e., less than 20%. This is due largely to the fact that it has a very low electricity-only load factor (see Figure 49), which implies that it needs to maintain on-site generation. In effect, the high cost of purchasing a large amount of electricity from the utility during on-peak hours dominates any cost savings from potentially fewer natural gas purchases. Therefore, unlike the sites examined in the previous two sections, there is no clear-cut advantage to lowering on-site generation during on-peak hours via greater use of heat storage (or a combination of storage and absorption cooling in case of the cooling load). Consequently, the use of heat storage is secondary and limited mostly to off-peak hours, thereby resulting in a lower economic benefit. Finally, the fact that the unit is free may distort its adoption decision, i.e., it may be adopted even if it is sparingly used.

Conclusions

On-site generation of electricity via DER located close to the loads offers certain customers with the option to circumvent many of the drawbacks of centralized production of energy. In particular, DER enables energy needs to be met more reliably and at a lower cost than with centralized generation. Since we consider the adoption of DER from a strictly cost-minimizing perspective, we do not account for its additional reliability. However, DER is advantageous to centralized generation, which has a significant fraction of its costs resulting from transmission and distribution of electricity.

This advantage of DER is amplified when CHP applications are included in the analysis. Indeed, the use of recovered heat tilts the balance in favor of DER since it allows heating loads to be met essentially for free. While our previous efforts in this area included the use of recovered heat for heating end uses, we did not allow for heat storage over time. In this paper, we extend our model to explore this possibility for a set of representative test sites in the San Francisco region. It should be noted that there are many barriers to DG adoption which keep the amount of adoption below DG's full potential, including state and local regulation, business-practice, financial uncertainty, uncertainty about the future energy costs and the future regulatory environment, and skepticism among potential adopters. The key to further adoption is to remove or reduce these barriers.

In order to determine the suitability of heat storage, we examine the conditions under which it is economically beneficial to deploy. Not surprisingly, we find that for a site with a small heating load, there is no incentive to use heat storage. In fact, even a HX or absorption chiller is not beneficial to adopt. On the other hand, a customer with a medium ratio of heating to electricity loads uses heat storage to meet 30% of the heating loads and 10% of the cooling load. The heat storage unit works in tandem with the HX and absorption chiller by enabling the use of stored heat during mid- and off-peak hours and reducing the need for on-site generation. The site is then able to take advantage of relatively inexpensive utility purchases during these hours to meet its electricity-only load. As for the test site with a high ratio of cumulative heating to electricity loads, about 60% of the heating loads are met via heat storage. Since no absorption chiller is installed, heat storage does not benefit the cooling load. Again, there is decreased on-site generation during mid- and off-peak hours as the constraint to generate in order to meet heating loads with stored heat is relaxed. However, since some of the heating load is met directly via natural gas in the case without heat storage, the availability of heat inventories enables stored heat to be used for this purpose. The resulting displacement of natural gas purchases contributes as much to the cost savings as the savings from on-site generation.

By performing this analysis across a range of sites, we also provide a crude measure of the economic benefit resulting from an extra kWh of heat storage capacity. Overall, there is a persistent linear relationship between the value of heat storage and its capacity. Specifically, we find that each additional kWh of heat storage capacity lowers energy costs by US$1.25 on average. The one exception to this is the large educational facility, which has a low electricity load factor. This requires it to maintain its on-site generation during on-peak hours, the savings from which dwarf any savings from lower natural gas purchases.

In this paper, we have circumvented the constraint that recovered heat must be used immediately by allowing for heat storage with losses from dissipation. The approach, however, is kept simple in order to ease implementation and the revelation of intuitive insights. In future work, we would like to examine a more realistic framework in which overnight heat storage is possible along with incorporation of ambient and water temperature properties to gauge more accurately the effect of heat lags. Comparison of the results for the San Francisco test sites with those in a more seasonal climate, such as that of Chicago, would also be interesting. An additional challenge would be to incorporate storage of electrical power via batteries alongside stored heat.

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Table 1. The Distribution of Total Commercial Floor Space Among Different Building Sizes (source: 1999 Commercial Buildings Energy Consumption Survey)

	Building Size							
Square Meters (Thousand Square Feet)	93-465 (1 – 5)	465-930 (5 – 10)	930-2,325 (10 – 25)	2,325-4,650 (25 – 50)	4,650-9,300 (50 – 100)	9,300-18,600 (100 – 200)	18,600-46,500 (200 – 500)	> 46,500 (500)
	Total Commercial Floor Space (Million Square Meters)							
Health care	18	Q	13	25	24	29	70	71
Lodging	Q	26	41	106	70	49	74	Q
Mercantile	86	97	198	93	139	164	40	149
Education	31	41	82	168	199	138	122	Q
Office	113	99	138	111	181	160	145	173

Q= Data withheld because either the relative standard error was greater than 50% or fewer than twenty buildings were sampled
1 Square Foot = 0.093 Square Meters

Table 2. Commercial Building Size Distribution Corresponding with Building Peak Load

Building Size (m^2)	93-465	465-930	930-2,325	2,325-4,650	4,650-9,300	9,300-18,600	18,600-46,500	> 46,500
Median Size (m^2)	233	698	1,628	3,488	6,975	13,950	32,550	60,450
Peak Loads (kW)								
Healthcare	18.25	54.75	127.75	273.75	547.50	1095	2555	4745
Lodging	7.00	21.00	49.00	105.00	210.00	420	980	1820
Mercantile	8.75	26.25	61.25	131.25	262.50	525	1225	2275
Education	11.50	34.50	80.50	172.50	345.00	690	1610	2990
Office	10.75	32.25	75.25	161.25	322.50	645	1505	2795

too small (less than 200 kW)
slightly too small (200 to 300 kW)
worth considering in DER-CAM (300 - 2000 kW)
too large to justify using DER-CAM (larger than 2000 kW)

Table 3. Addressed Building Sizes

	Building Size	
Peak Loads	Small	Large
Healthcare	7,200 m^2	13,936 m^2
Lodging	13,936 m^2	32,516 m^2
Mercantile	13,936 m^2	60,387 m^2
Education	7,200 m^2	32,516 m^2
Office	7,200 m^2	32,516 m^2

Table 4. Energy Use of Five Prototype Buildings in San Francisco

		Healthcare		Lodging		Mercantile		Education		Office	
Building Size		Small	Large	Small	Large	Small	Large	Small	Large	Small	Large
Peak Load	kW	539	1112	383	1646	498	1133	304	1382	338	1342
Total Elec	MWh	3223	6597	1828	7890	2293	5300	559	2577	1081	4457
Total Gas	GJ	7731	12776	3151	14404	278	395	1959	8322	1650	3707
Fuel/Elec ratio	MWh/MWh	0.67	0.54	0.51	0.51	0.03	0.02	0.97	0.90	0.42	0.23

Table 5. PG&E Electricity and Power Tariff

	summer*	winter**
Volumetric ($/kWh)		
on-peak***	0.16	N/A
mid-peak****	0.10	0.11
off-peak*****	0.09	0.09
Demand ($/kW)		
on-peak***	14.35	N/A
mid-peak****	5.20	5.20
off-peak*****	2.55	2.55
Monthly fee ($)		
	175.00	175.00

*summer months: June-September
**winter months: January-May and October-December
***on-peak hours: summer, 1200 - 1800
****mid-peak hours: summer, 0700 - 1100 & 1900 - 2200, winter, 0700 - 2200
*****off-peak hours: all months, 0100 - 0600 & 2300 - 2400

Table 6. DG Technology Data

DG Option	Lifetime	Capital costs			Maintanence costs		Energy output	
		electricity generation only	with heat recovery for heating	with heat recovery for heating and cooling	fixed annual cost for units with absorption chilling	variable costs	electrical efficiency	heat to electriciy ratio
	(years)	*($/kW installed)*			*($/kW installed)*	*($/kWh generated)*		
1 MW turbine	20	1403	1910	2137	11.9	0.010	0.219	2.45
100 kW microturbine	10	1700	1980	2419	17.1	0.015	0.260	2.29
250 kW microturbine	10	1400	1650	1976	12.8	0.015	0.280	2.29
200 kW reciprocating engine	20	900	1225	1629	15.9	0.015	0.308	1.88
500 kW reciprocating engine	20	795	1065	1339	11.0	0.012	0.332	1.55

Table 7. Small Mercantile Facility Energy Results

Case	*Generation Installed*	*Equipment*	*Annual Utility Purchase*			*Annual DER Production*				
			Electricity (MWh)	*Gas for DER (MWh)*	*Gas for direct end use (MWh)*	*Electricity Loads (MWh)*	*Abs. Cool (MWh)*	*Thermal Loads (MWh)*	*Stored Heat for Cooling (MWh)*	*Stored Heat for Heating (MWh)*
No DER			2313	N/A	60	N/A	N/A	N/A	N/A	N/A
DER No Heat Storage	500 kW	reciprocating engine	611	5126	60	1702	0	0	N/A	N/A
DER Heat Storage	500 kW	reciprocating engine	611	5126	60	1702	0	0	0	0

Table 8. Small Mercantile Facility Financial Results

Case	*Capacity Installed*	*Equipment*	*Investment Costs (kUS$/a)*	*Annual Utility Bills*			*Carbon Emissions Cost (kUS$)*	*Total Energy Cost (kUS$)*	*Average Energy Price (US$/kWh)*	*Bill Savings Over No DER Case (%)*
				Electricity (kUS$)	*Gas and O&M for DER (kUS$)*	*Gas for direct end use (kUS$)*				
No DER				326	N/A	3	22	351	0.1486	N/A
DER No Heat Storage	500 kW	reciprocating engine	39	65	185	3	31	323	0.1368	8%
DER Heat Storage	500 kW	reciprocating engine	39	65	185	3	31	323	0.1368	8%

Table 9. Small Lodging Facility Energy Results

Case	*Generation Installed*	*Equipment*	*Annual Utility Purchase*			*Annual DER Production*				
			Electricity (MWh)	*Gas for DER (MWh)*	*Gas for direct end use (MWh)*	*Electricity Loads (MWh)*	*Abs. Cool (MWh)*	*Thermal Loads (MWh)*	*Stored Heat for Cooling (MWh)*	*Stored Heat for Heating (MWh)*
No DER			1836	N/A	494	N/A	N/A	N/A	N/A	N/A
DER No Heat Storage	200 kW	reciprocating engine with HX and absorption chiller	732	3102	2	956	148	394	N/A	N/A
DER Heat Storage	200 kW	reciprocating engine with HX and absorption chiller	748	3014	0	928	135	270	25	125

Table 10. Small Lodging Facility Financial Results

Case	*Capacity Installed*	*Equipment*	*Investment Costs (kUS$/a)*	*Annual Utility Bills*			*Carbon Emissions Cost (kUS$)*	*Total Energy Cost (kUS$)*	*Average Energy Price (US$/kWh)*	*Bill Savings Over No DER Case (%)*
				Electricity (kUS$)	*Gas and O&M for DER (kUS$)*	*Gas for direct end use (kUS$)*				
No DER				264	N/A	19	20	283	0.1269	N/A
DER No Heat Storage	200 kW	reciprocating engine with HX and absorption chiller	35	86	114	1	22	258	0.1155	9%
DER Heat Storage	200 kW	reciprocating engine with HX and absorption chiller	35	87	110	1	22	255	0.1145	10%

Table 11. Small Educational Facility Energy Results

Case	*Generation Installed*	*Equipment*	*Annual Utility Purchase*			*Annual DER Production*				
			Electricity (MWh)	*Gas for DER (MWh)*	*Gas for direct end use (MWh)*	*Electricity Loads (MWh)*	*Abs. Cool (MWh)*	*Thermal Loads (MWh)*	*Stored Heat for Cooling (MWh)*	*Stored Heat for Heating (MWh)*
No DER			601	N/A	387	N/A	N/A	N/A	N/A	N/A
DER No Heat Storage	200 kW	reciprocating engine with HX	150	1464	24	451	0	291	N/A	N/A
DER Heat Storage	200 kW	reciprocating engine with HX	170	1397	7	430	0	119	0	185

Table 12. Small Educational Facility Financial Results

Case	*Capacity Installed*	*Equipment*	*Investment Costs (kUS$/a)*	*Annual Utility Bills*			*Carbon Emissions Cost (kUS$)*	*Total Energy Cost (kUS$)*	*Average Energy Price (US$/kWh)*	*Bill Savings Over No DER Case (%)*
				Electricity (kUS$)	*Gas and O&M for DER (kUS$)*	*Gas for direct end use (kUS$)*				
No DER				96	N/A	14	7	117	0.1290	N/A
DER No Heat Storage	200 kW	reciprocating engine with HX	24	21	54	2	9	110	0.1205	7%
DER Heat Storage	200 kW	reciprocating engine with HX	24	23	51	1	9	108	0.1192	8%

Table 13. Energy Cost Savings from Heat Storage Capacity

Site	*Storage Capacity (kWh)*	*Cost Savings (US$)*
Small Merc	0	0
Small Office	1640	1386
Small Lodging	2338	2255
Small Educational	2394	1145
Large Merc	2639	1388
Large Office	3681	4043
Small Healthcare	4962	6051
Large Healthcare	8382	12143
Large Educational	10018	4514
Large Lodging	10039	17276

Figure 1. Growth of Fossil Fuel Based Waste Heat Production from US Power Generation
(sources: International Energy Agency, Energy Information Administration, and Berkeley Lab analysis)

Figure 2. Energy Flows in a Commercial Building CHP Installation

Figure 3. A Comparison of CBECS and NEMS Total Floor-Space Values

Figure 4. Healthcare January Electricity Load

Figure 5. Healthcare July Electricity Load

Figure 6. Healthcare January NG Load

Figure 7. Healthcare July NG Load

Figure 8. Small Mercantile Facility Weekday Electricity-Only Load

Figure 9. Small Mercantile Facility Weekday Space-Heating Load

Figure 10. Small Mercantile Facility Weekday Cooling Load

Figure 11. Small Mercantile Facility Weekday Water-Heating Load

Figure 12. Small Mercantile Facility Weekday Total Electricity Generation

Figure 13. Small Mercantile Facility Weekday Heat Storage Shadow Price

Figure 14. Small Mercantile Facility January Weekday Space-Heating Supply

Figure 15. Small Mercantile Facility July Weekday Space-Heating Supply

Figure 16. Small Mercantile Facility January Weekday Water-Heating Supply

Figure 17. Small Mercantile Facility July Weekday Water-Heating Supply

Figure 18. Small Lodging Facility Weekday Electricity-Only Load

Figure 19. Small Lodging Facility Weekday Space-Heating Load

Figure 20. Small Lodging Facility Weekday Cooling Load

Figure 21. Small Lodging Facility Weekday Water-Heating Load

Figure 22. Small Lodging Facility Weekday Total Electricity Generation (No Storage Adoption Allowed)

Figure 23. Small Lodging Facility Weekday Heat Storage Shadow Price (No Storage Adoption Allowed)

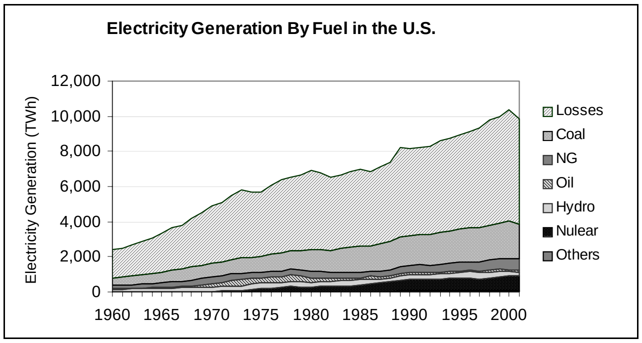


Fig. 1

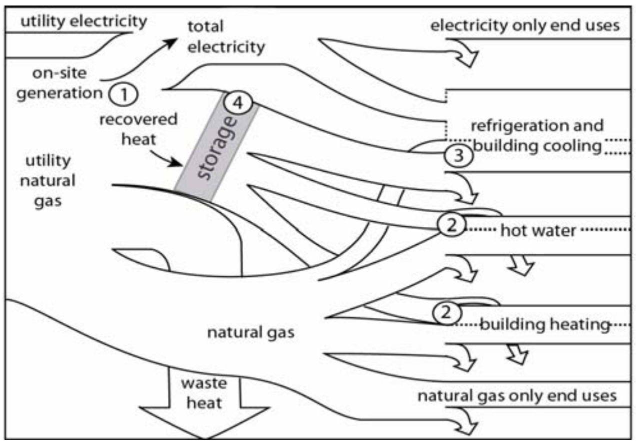
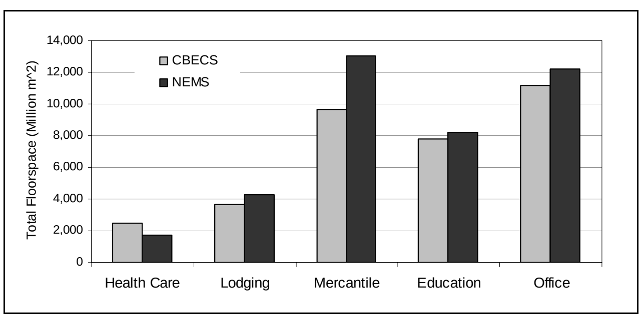


Fig. 2



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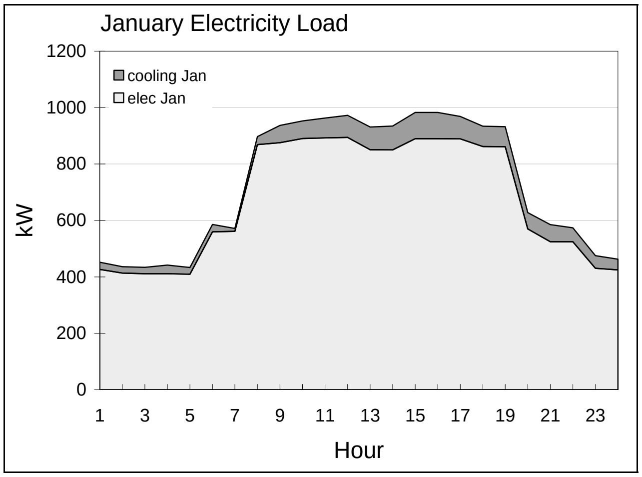

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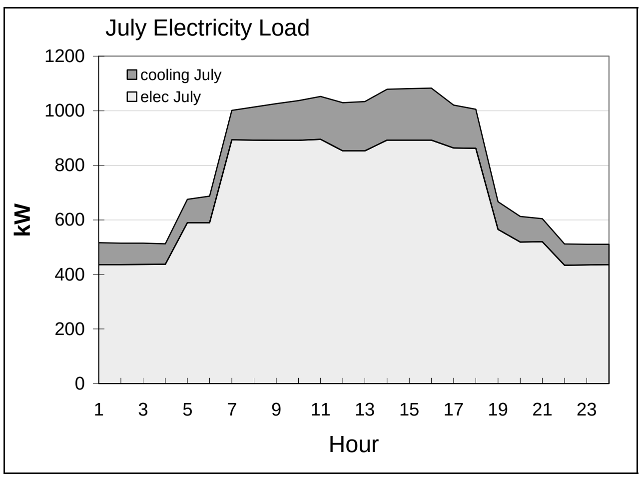

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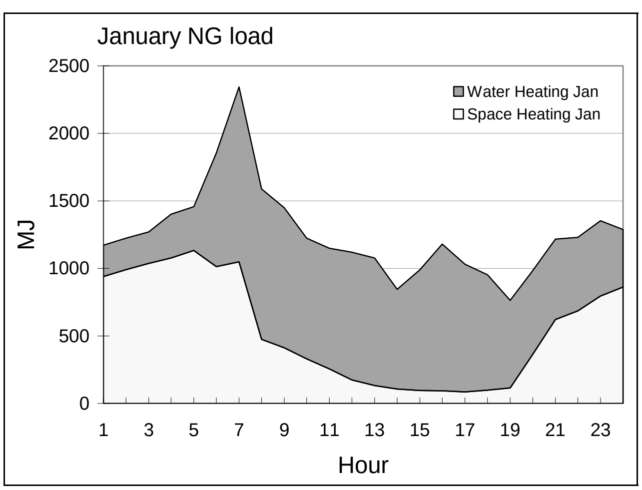

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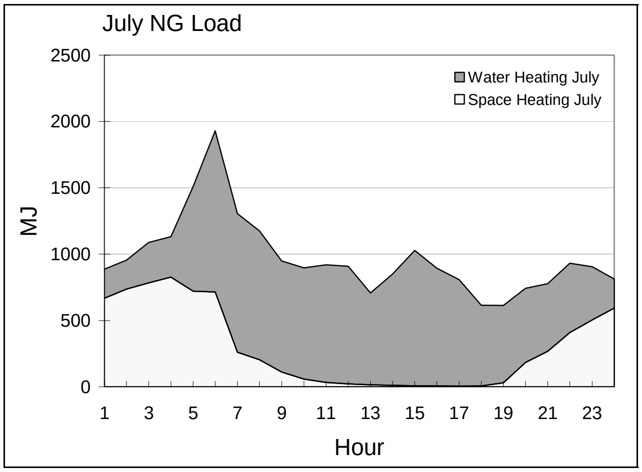

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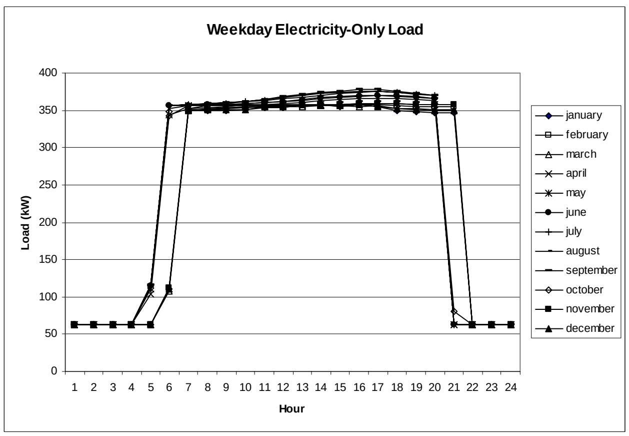

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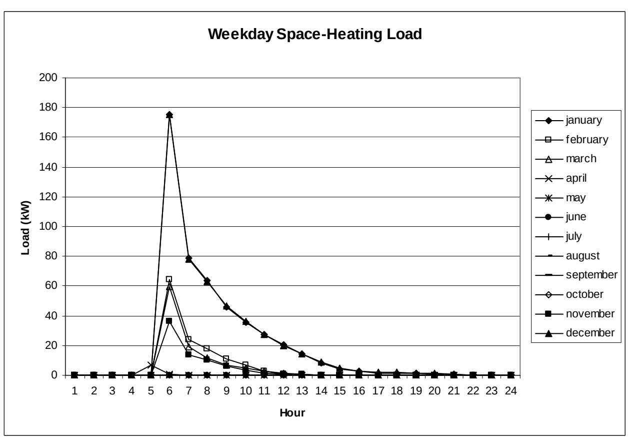

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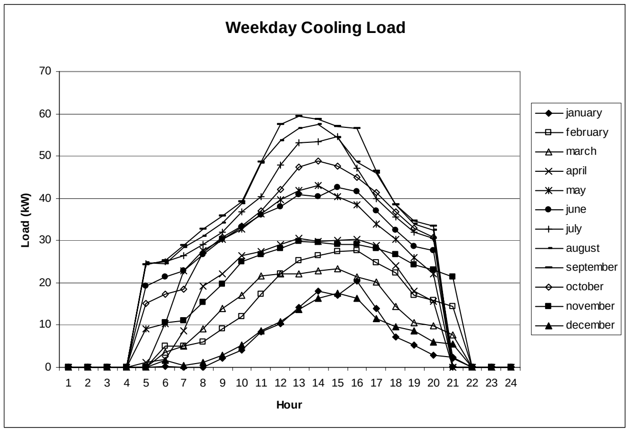

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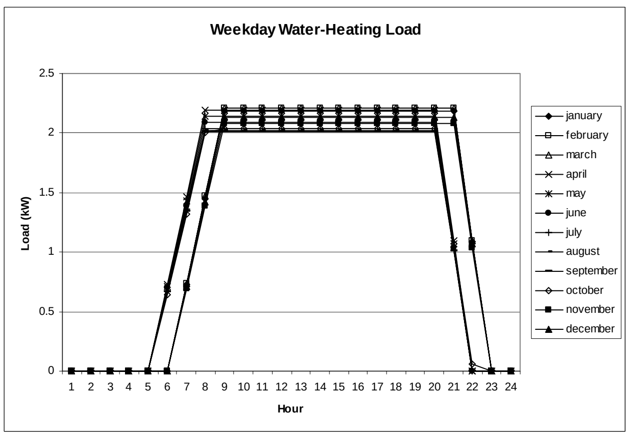

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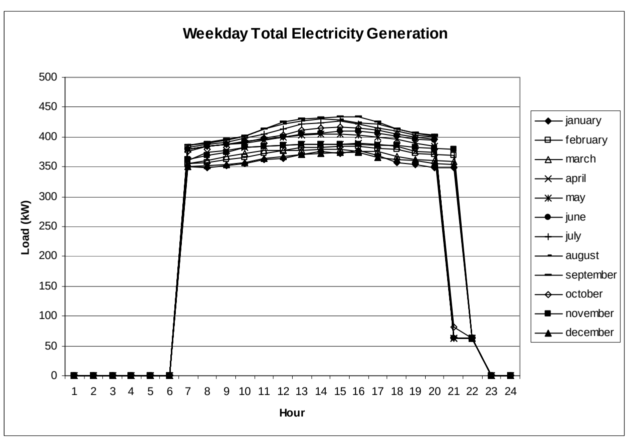

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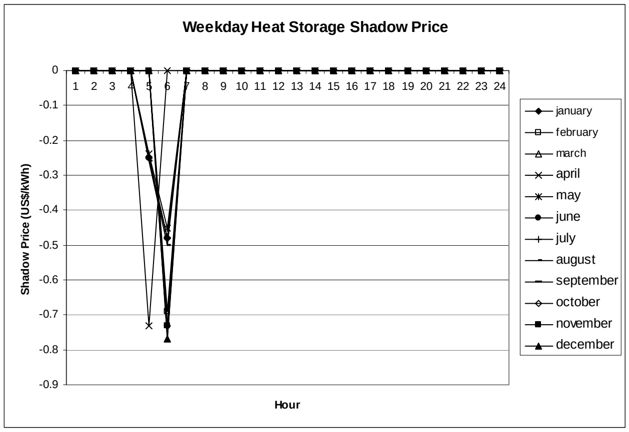

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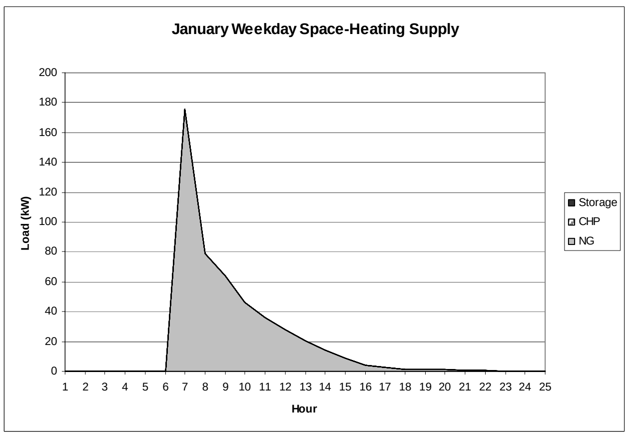

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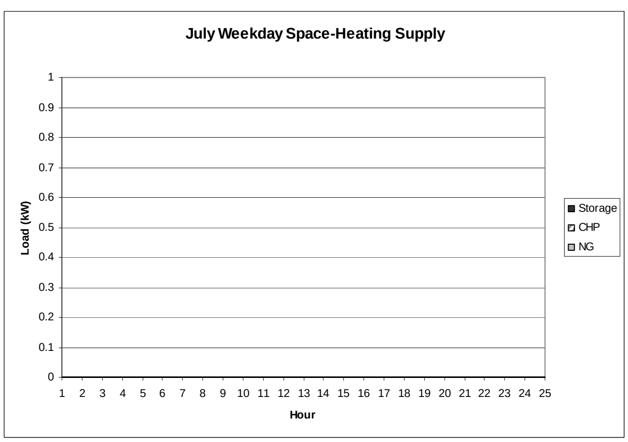

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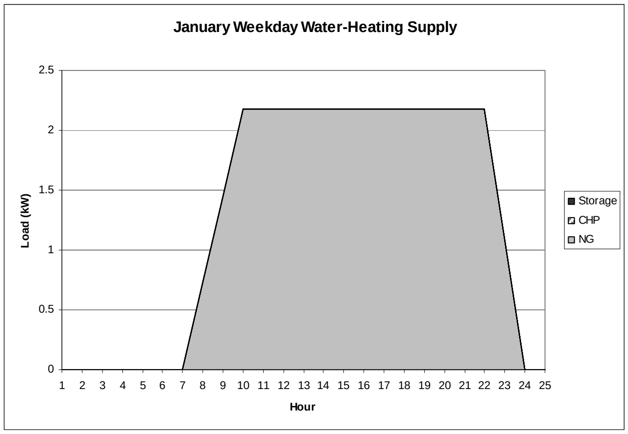

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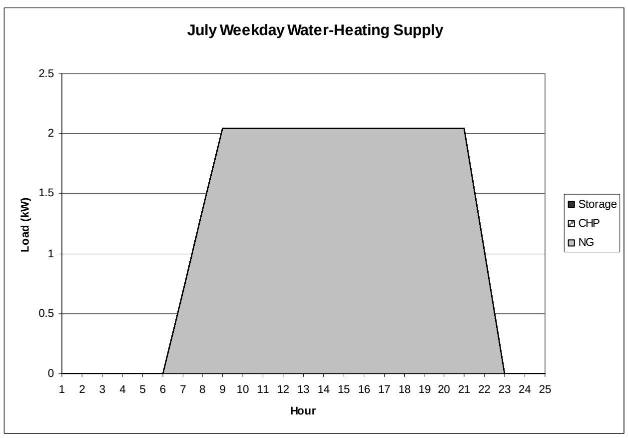

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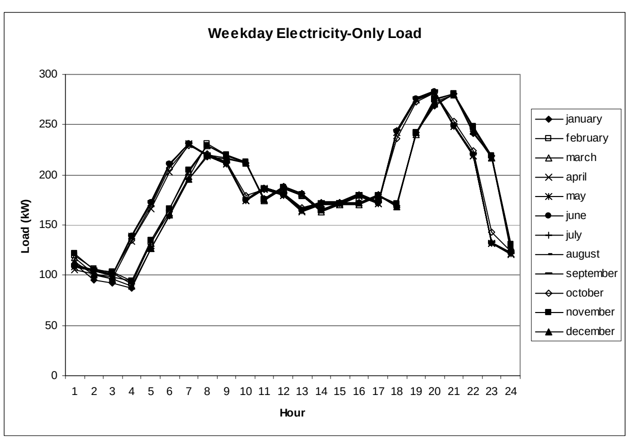

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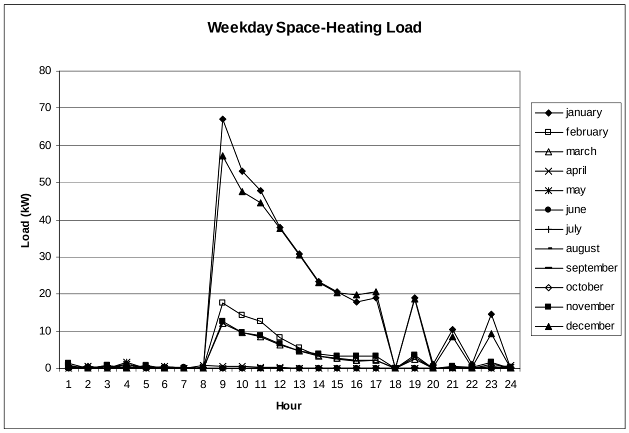

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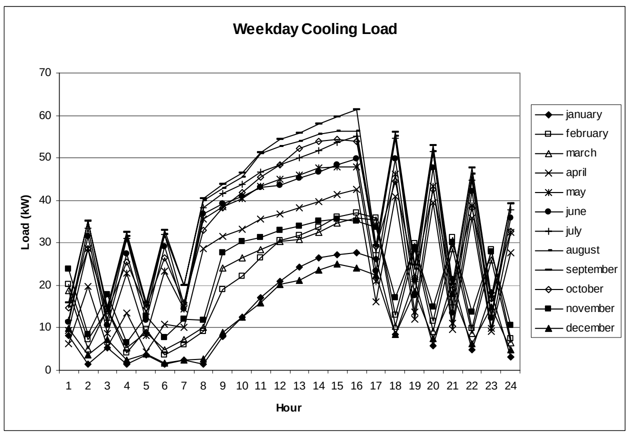

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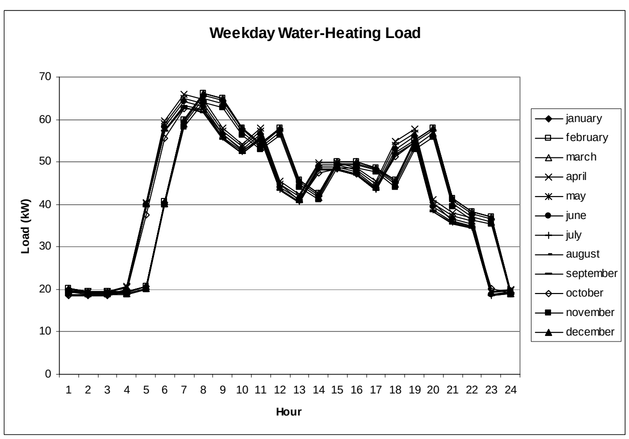

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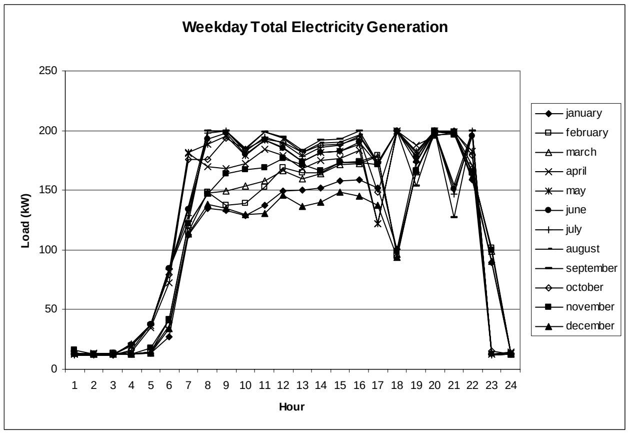

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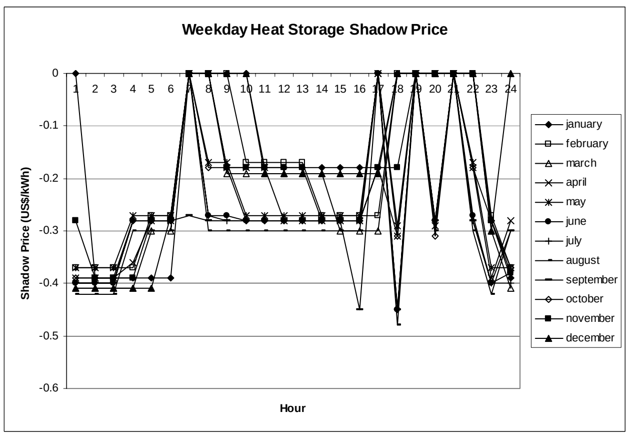

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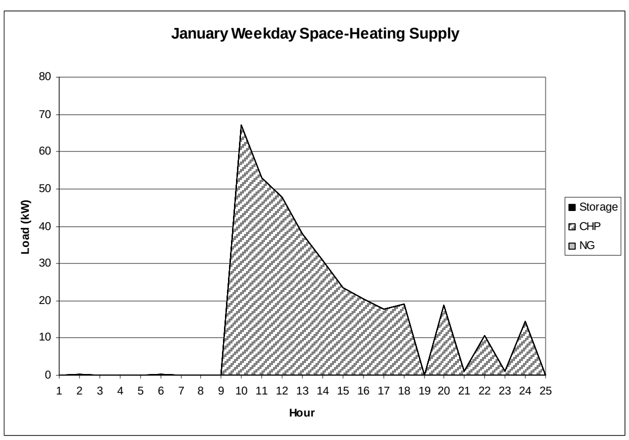

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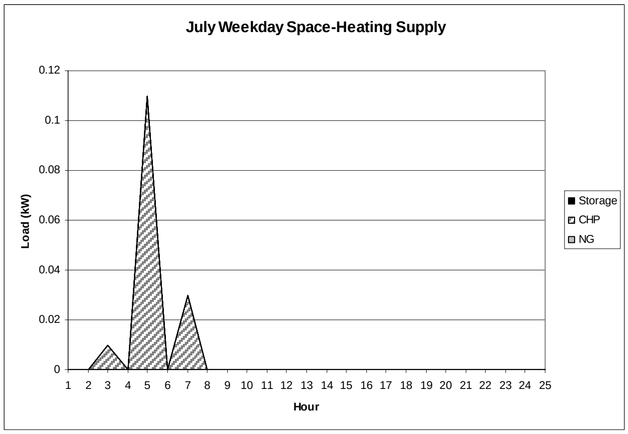

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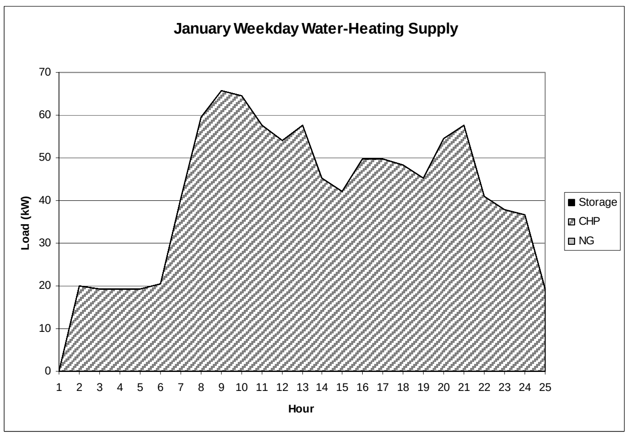

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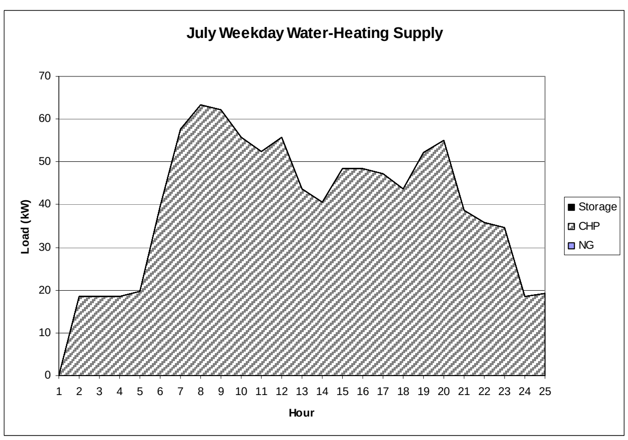

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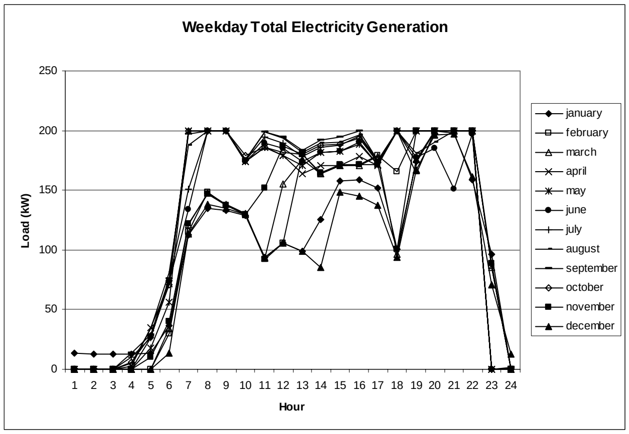

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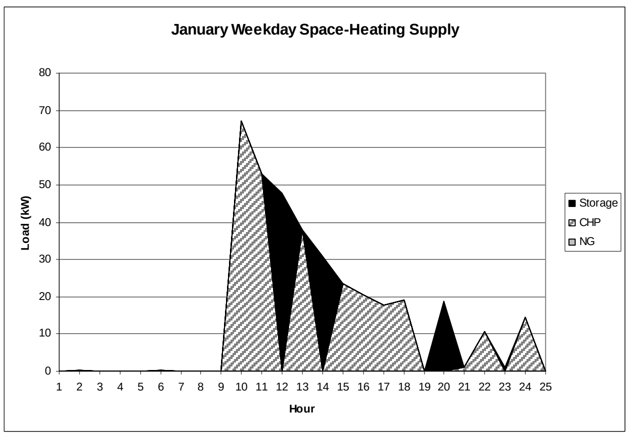

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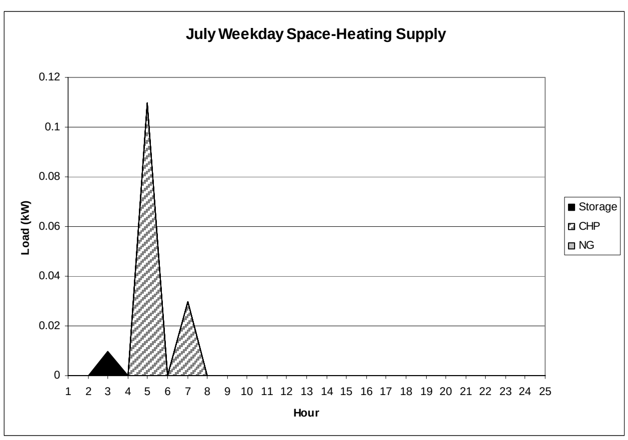

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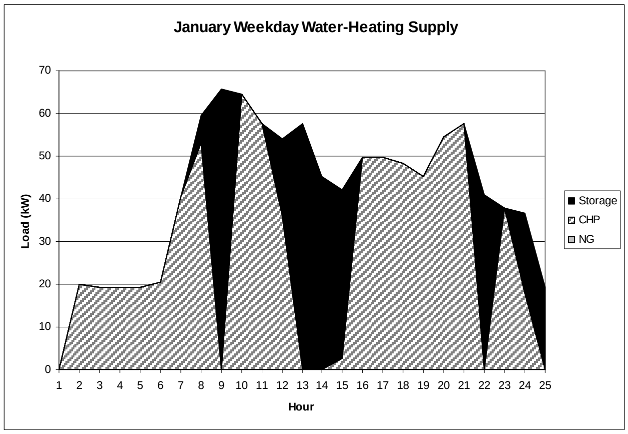

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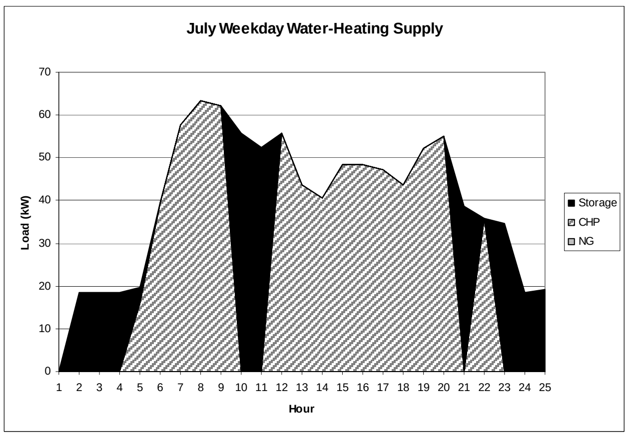

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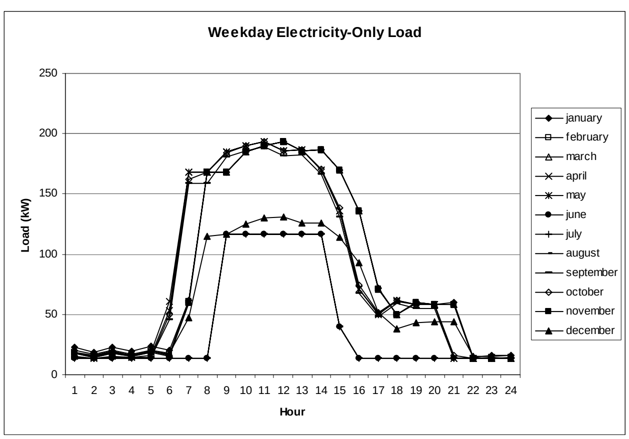

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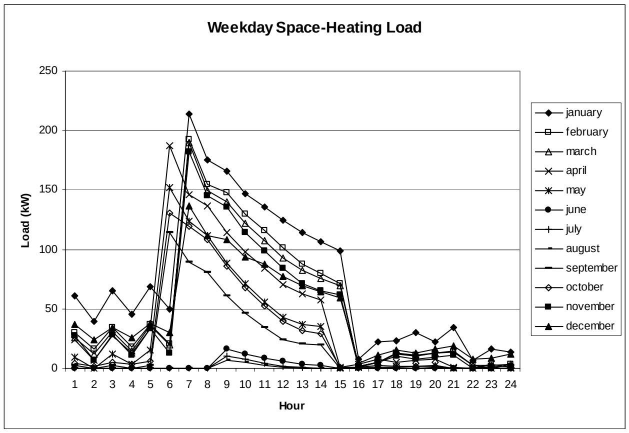

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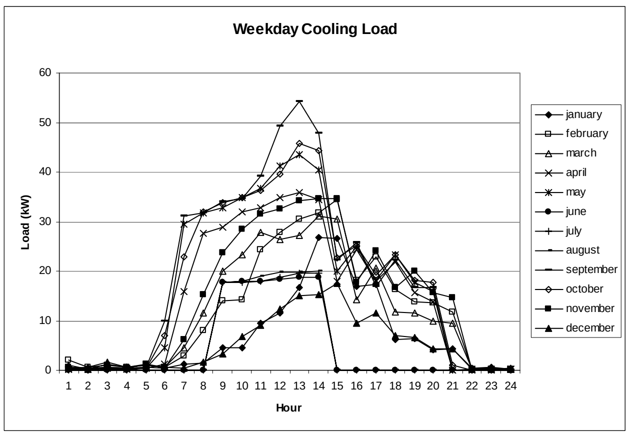

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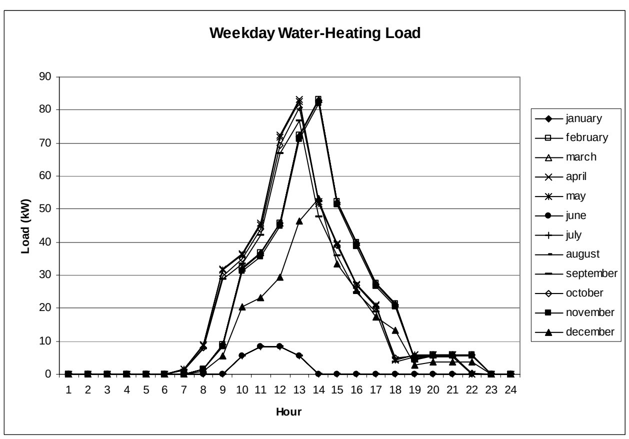

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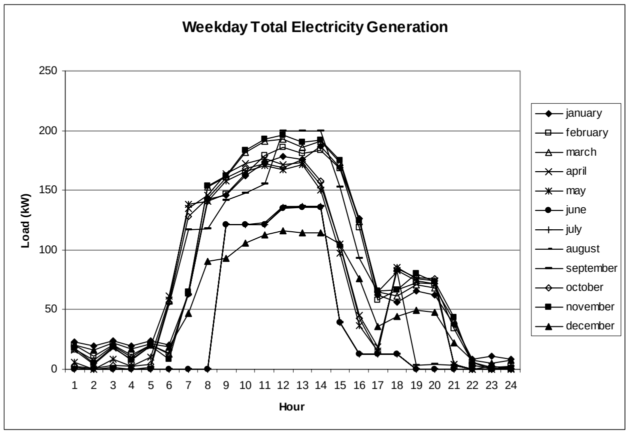

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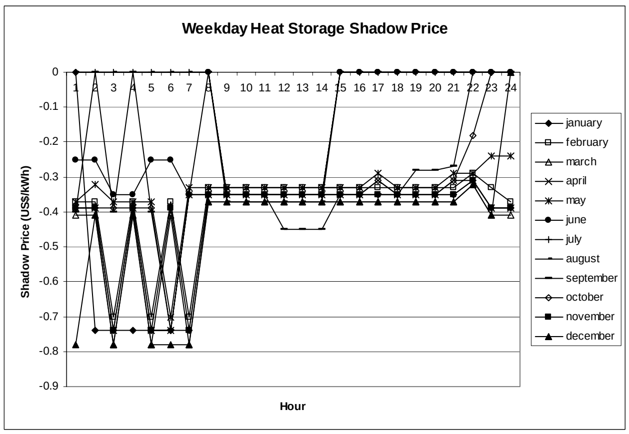

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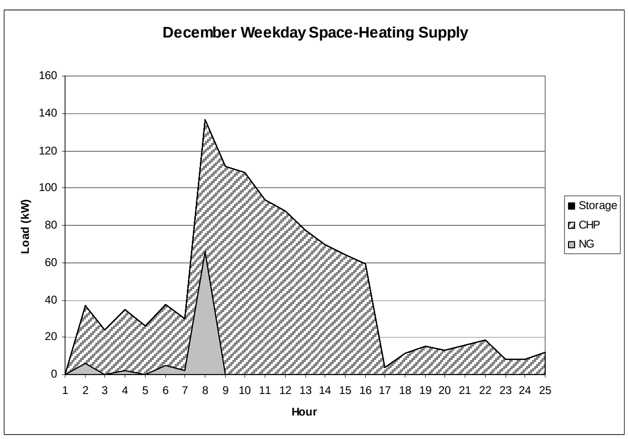

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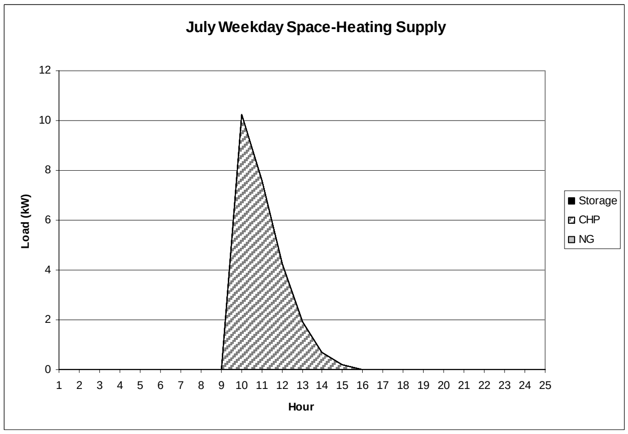

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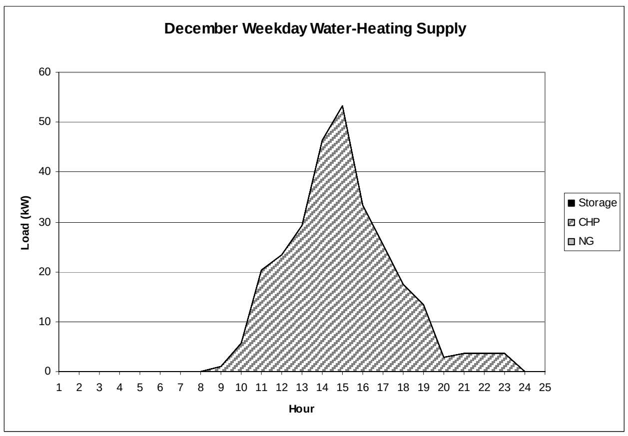

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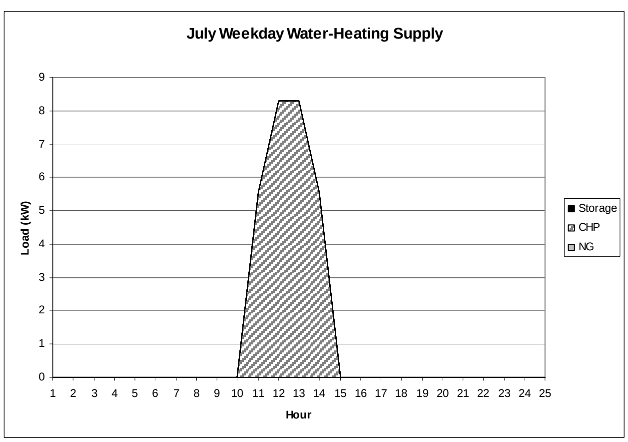

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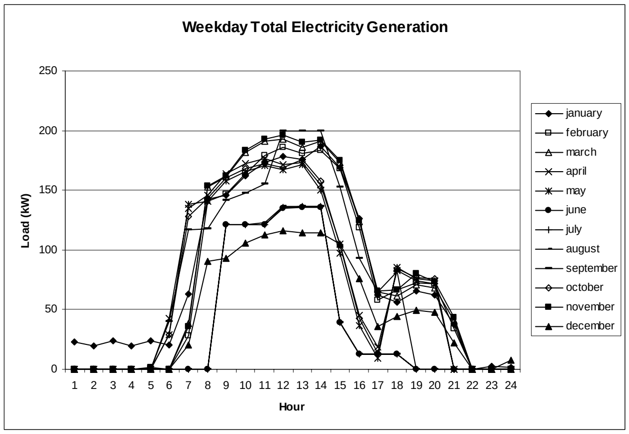

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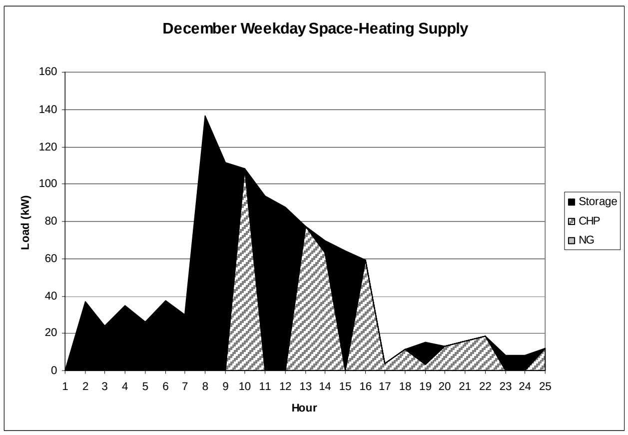

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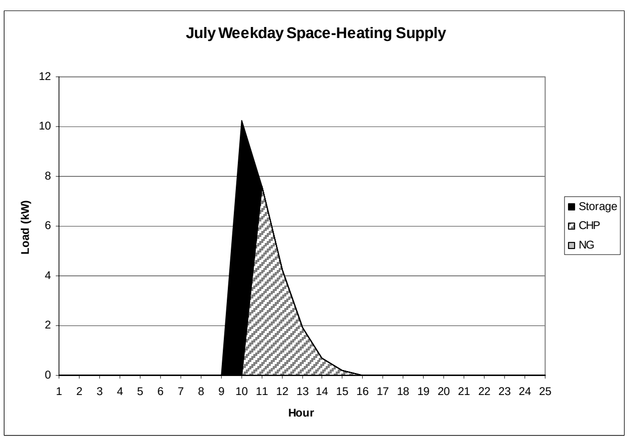

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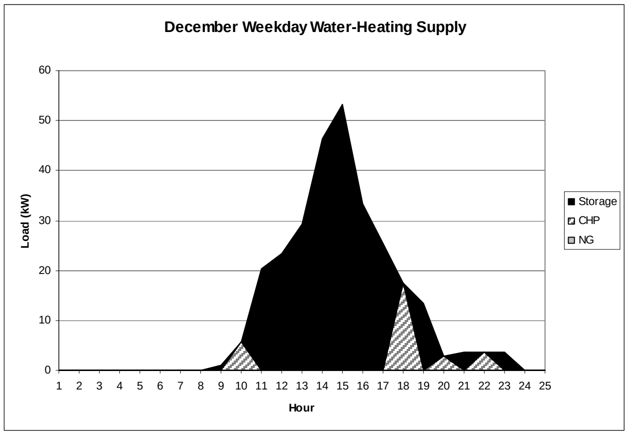

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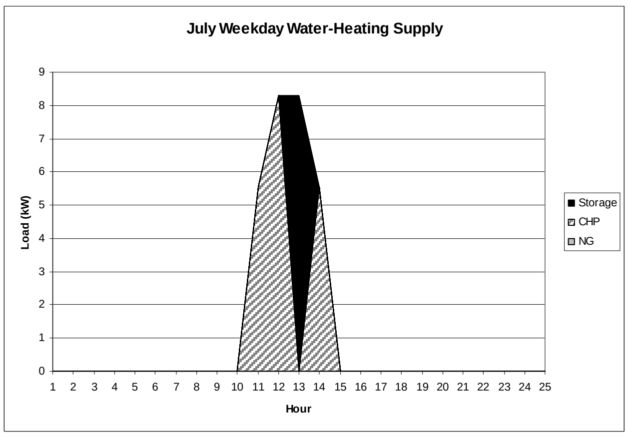

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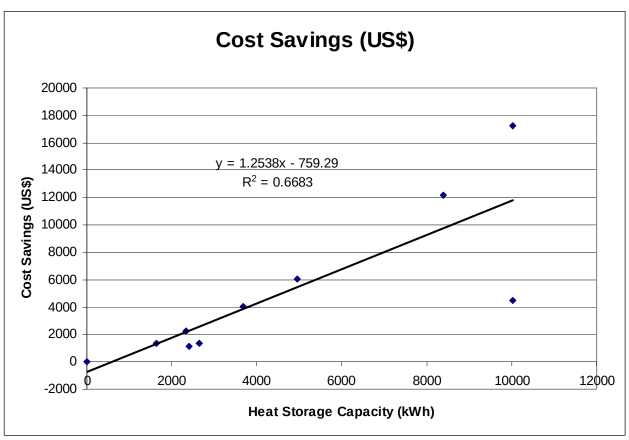

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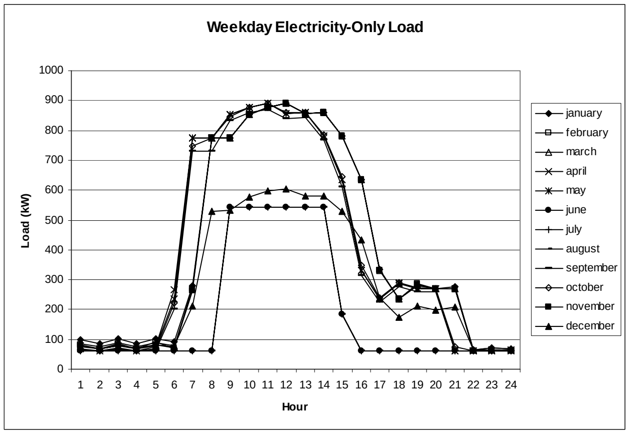
Weekday Electricity-Only Load
Load (kW)
Hour
january
february
march
april
may
june
july
august
september
october
november
december

Fig. 49