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ASSESSMENT OF COMBINED HEAT AND POWER SYSTEM "PREMIUM POWER" APPLICATIONS IN CALIFORNIA

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ABSTRACT

The effectiveness of combined heat and power (CHP) systems for power interruption intolerant, "premium power", facilities is the focus of this study. Through three real-world case studies and economic cost minimization modeling, the economic and environmental performance of "premium power" CHP is analyzed. The results of the analysis for a brewery, data center, and hospital lead to some interesting conclusions about CHP limited to the specific CHP technologies installed at those sites. Firstly, facilities with high heating loads prove to be the most appropriate for CHP installations from a purely economic standpoint. Secondly, waste heat driven thermal cooling systems are only economically attractive if the technology for these chillers can increase above the current best system efficiency. Thirdly, if the reliability of CHP systems proves to be as high as diesel generators they could replace these generators at little or no additional cost if the thermal to electric (relative) load of those facilities was already high enough to economically justify a CHP system. Lastly, in terms of greenhouse gas emissions, the modeled CHP systems provide some degree of decreased emissions, estimated at approximately 10% for the hospital, the application with the highest relative thermal load in this case.

INTRODUCTION

There is great deal of interest in redundant systems for distributed power generation in a number of industries where the cost of power, and more importantly power interruptions, is substantial. These premium power applications are the focus of this analysis. Some examples of such facilities are manufacturing plants, data centers, hospitals, and nursing homes. Premium power applications are characterized by their need for backup power in the event of a utility power outage. These backup systems are traditionally diesel generators, but increasingly Combined Cooling Heat and Power (CCHP) systems are being installed at these sites to provide base load power or peak-shaving. Such systems typically consist of on-site generation fueled by either natural gas or solar energy providing electricity and thermal energy for cooling and heating loads. These CCHP systems can also act as backup generators in some cases, thus obviating the need for diesel backup generators.

In this paper we analyze the economic feasibility of combined heat and power (CHP) for premium power applications as installed in representative case studies. Each of the selected sites currently has a CHP or Combing Cooling and Power (CCP) system in addition to diesel backup generators. In all cases the CCHP systems are rated at a small fraction of the electrical capacity of the diesel generators. Although none of the selected sites currently has the ability to run the CCHP systems as emergency backup power, all could be retrofitted to provide this blackout ride-through capability (for at least some critical circuits if not the entire facility), and new CCHP systems can be installed with this capability. We modeled the existing case study systems with blackout ride-through capability to find what the economic and environmental consequences of this mode of operation would be.

1 DER-CAM OVERVIEW AND MODELING APPROACH

As the basis for an economic analysis of the case study sites, we used the Distributed Energy Resources Customer Adoption Model (DER-CAM) that was developed at the Lawrence Berkeley National Laboratory [3].

DER-CAM is an economic model of customer Distributed Energy Resources (DER) adoption implemented in the general algebraic modeling system (GAMS) optimization software. DER-CAM's goal is to minimize the cost of supplying electric and heat loads of a specific customer site by optimizing the installation and operation of distributed generation, combined heat and power, and thermally driven cooling equipment. In other words, the focus of the modeling effort is primarily economic, but environmental externalities, such as carbon emissions, can also be calculated with the appropriate technical inputs.

To achieve the DER-CAM economic optimization objective, the following issues must be addressed:

- Which is the lowest-cost combination of distributed generation technologies that a specific customer can install?
- What is the appropriate level of installed capacity of these technologies that minimizes cost?
- How should the installed capacity be operated so as to minimize the total customer energy bill?

With the assumption that the customer desires to install distributed generation to minimize the cost of energy consumed on site, it is possible to determine the technologies and capacity the customer is likely to install and to predict when the customer will be self-generating electricity and/or transacting with the power grid, and likewise when purchasing fuel or using recovered heat.

The DER-CAM model chooses which distributed generation (DG) and/or CHP technologies a customer should adopt and how that technology should be operated based on specific site load and price information, along with performance data for the available equipment options.

Key inputs into the DER-CAM model are:

- the customer's end-use load profiles (typically for space heat, hot water, gas only, cooling, and electricity only)
- the customer's default electricity tariff, natural gas prices, and other relevant price data
- the capital, operating and maintenance (O&M), and fuel costs of the various available technologies, together with the interest rate on customer investment
- the basic physical characteristics of alternative generating, heat recovery and cooling technologies, including the thermal-electric ratio that determines how much residual heat is available as a function of generator electric output.

Outputs to be determined by the optimization model are:

- the capacities of DG and CHP technology or combination of technologies to be installed
- when and how much of the installed capacity will be running
- the total cost of supplying the electric and heat loads.

Key DER-CAM assumptions are:

- customer decisions are made based only on direct economic criteria (in other words, the only possible benefit is a reduction in the customer's energy bills);
- no deterioration in output or efficiency during the lifetime of the equipment is considered, and start-up and other ramping constraints are not included;
- reliability and power quality benefits, as well as economies of scale in O&M costs for multiple units of the same technology are not directly taken into account; and
- possible reliability or power quality improvements accruing to customers are not explicitly considered.

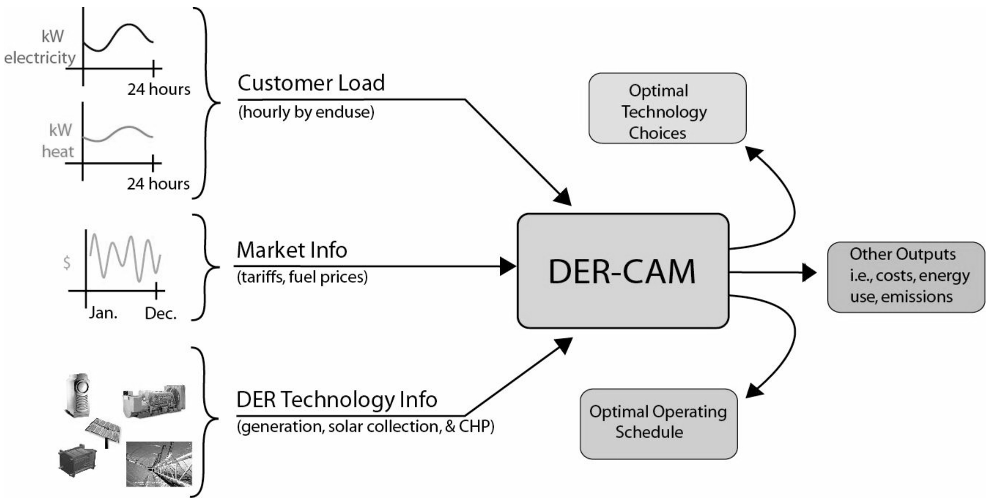

Figure 1: DER-CAM Structure [3]

We note that a more recent version of DER-CAM has been developed that includes consideration of reliability and power quality improvements and other benefits to the CHP or microgrid system host site. See reference [5] for further details.

1.1 Simultaneous Optimization Approach

Figure 2, below, shows a high-level schematic of the energy flows modeled in DER-CAM. Possible energy inputs to the site are solar insolation, utility electricity and natural gas. For a given DG investment decision, DER-CAM selects the optimal combination of utility purchase and on-site generation required to meet the site's end-use loads at each time step. The model allows that:

1. electricity-only loads (e.g. lighting and office equipment) can only be met by electricity;
2. cooling loads can be met either by electricity or by heat (via absorption /

adsorption chiller);
3. hot water and space heating loads can be met either by recovered heat or by natural gas; and
4. natural gas-only loads (e.g. some cooking) can only be met by natural gas.

With these constraints, the model then attempts to find the best strategy for meeting the various energy needs at the lowest cost using a mathematical optimization formula described in reference [4].

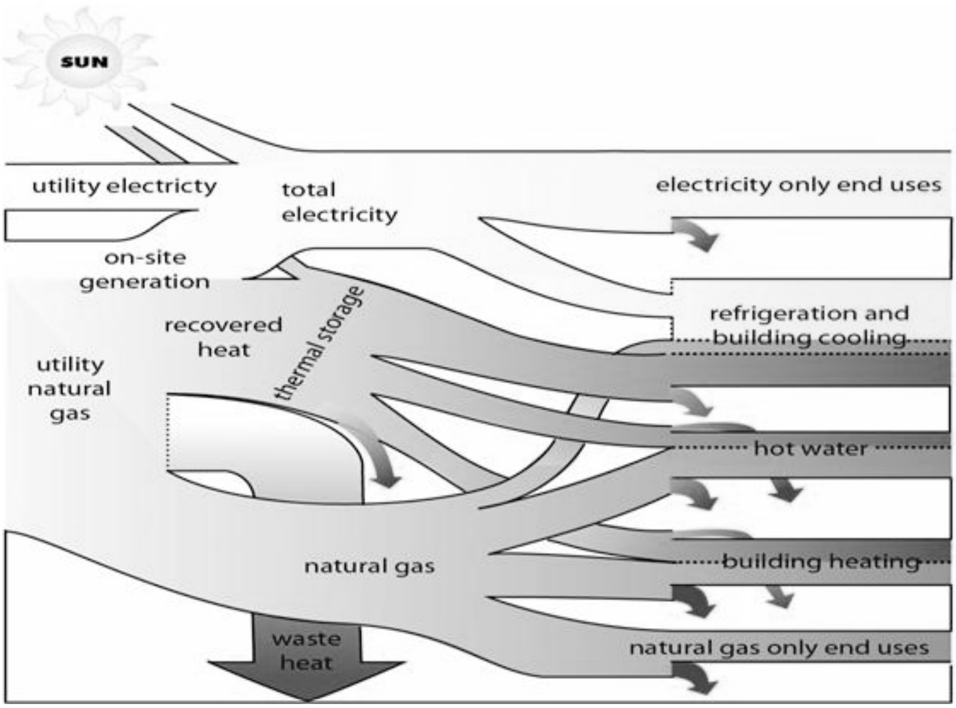

Figure 2: Energy Input and End-Use Flows as Assessed in DER-CAM [3]

1.2 Selected CCHP Sites

The physical sites selected for this analysis are described below.

1.2.1 Sierra Nevada Brewery

Using 1 MW of molten carbonate fuel cells operating on a combination of digester gas (from the beer brewing process) and natural gas, this CHP system can produce electricity and heat for the brewery and attached bottling plant. The major thermal load on-site is to keep the brewing tanks at appropriate temperatures [7].

1.2.2 NetApp Data Center

Using 1.125 MW of Hess Microgen natural gas-fired reciprocating engine-generators, with exhaust gas and jacket water heat recovery attached to over 300 tons of adsorption chillers, this CCP system provides electricity and cooling to a data center with a 1,200 kW peak electrical load [7].

1.2.3 Kaiser Permanente Hayward Hospital

With 180kW of Tecogen natural gas fired reciprocating engine-generators this CHP system generates steam for space heating, and hot water for a city hospital.

1.3 Modeling Scenarios

For all sites, similar assumptions are made about the economic and technological constraints of the power generation system. We model three representative scenarios for each site in DER-CAM and find the optimal operation schedule, minimal yearly energy cost, and optimal energy technology investments for each scenario.

1.3.1 Scenario 1

Diesel generators and CCHP equipment as installed in the current facility. Scenario 1 represents a baseline forced investment in currently installed energy equipment.

1.3.2 Scenario 2

Existing CCHP equipment installed with blackout ride-through capability to replace approximately the same capacity of diesel generators. In scenario 2, some diesel generator cost is avoided at the expense of additional controls and switchgear for blackout ride-through capability.

1.3.3 Scenario 3

Fully optimized site analysis, allowing DER-CAM to specify the number of diesel and CCHP units (with blackout ride-through capability) to minimize the total cost function ignoring any constraints on backup generation. Scenario 3 allows DER-CAM to select generation units from only the currently available technologies at a particular site.

1.4 Building Load Data and Equipment

In this analysis, hardware data sheets and actual historical load data, as opposed to building performance models, form the basis for energy demand at each site. Real energy load and equipment performance data provide a better basis for future performance than models, so we went through the pain-staking process of data mining the necessary historical facility data.

Average weekday and weekend loads for each month, as extrapolated from the historical facility data, are used as inputs to DER-CAM. For all sites, 2006 load data is used when available, but due to lack of availability some 2007 and 2008 data was supplemented in the Kaiser and NetApp models to fill in gaps in the 2006 data. Careful care is taken to ensure weekday, weekend and seasonal loads are appropriately aligned in all sets of merged data from multiple years so that seasonal and weekly variations are properly reflected for modeling purposes.

Since construction was completed on the Sierra Nevada and NetApp systems in the last four years, we use the reported capital cost of the CCHP equipment ignoring any state or federal rebates or incentives. Capital costs for the Kaiser facility, owing to the older age of that system, are obtained from a vendor quote for a nearly equivalent system with modern equipment [11]. We also obtained a quote for a similar system installed with blackout ride-through capability for comparison. Industry price quotes were obtained for diesel generator equipment costs [10]. Service contracts to determine variable and fixed operation and maintenance costs are either real costs or estimates from the contractors who installed that equipment.

In order to accurately model the yearly energy cost for each facility, a five percent interest rate is assumed per annum. Model inputs for fuel costs for diesel, natural gas and electricity are prices paid by Sierra Nevada in 2006. Kaiser and NetApp electricity prices are based on utility tariffs in May 2008, and the diesel price used in the model was the actual local price in May 2008. Natural gas prices for Kaiser and NetApp are based on the January-May historical prices and the futures spot market prices adjusted for location for the period from June-December 2008.

Table 1: Fuel cost data used for modeling each site [8] [9]

Site	*Electricity*	*Natural Gas*	*Diesel*
Sierra Nevada	PG&E E-20, May 2006	PG&E G-NT, May 2006	Actual prices paid, 2006
NetApp	PG&E E-19, May 2008	PG&E G-EG, January - May 2008 Futures price, June - December 2008	Local price, May 2008
Kaiser	PG&E E-20, May 2008	PG&E G-NT, January - May 2008 Futures price, June - December 2008	Local price, May 2008

The efficiency of the chillers, CHP units, and diesel generators are calculated from the actual power production and fuel consumption when possible, and from manufacturers' data sheets in all other cases. The overall "macrogrid" electrical conversion efficiency was assumed to be 34%. To determine the relative carbon emissions of each proposed scenario, a value for the marginal Northern California electrical grid carbon intensity of 0.14 kg C/kWh is used [2].

In order to be able to meaningfully compare the economics of CCHP systems to those of backup generators, the increased cost of blackout ride-through capability is incorporated into the capital cost of the CHP/CCHP technology for Scenario 2 and Scenario 3 at each site. Industry price quotes allow us to put a price on this blackout ride-through capability at $75-$200/kW for engine generator models [12]. However, in some situations where much of the electronics/switchgear are already in place, the cost of adding the blackout ride-through capabilities could be much less. For example, one site reported that adding this capability for its existing 1.2 MW microturbine system would cost on the order of $10,000-$15,000, or more like $10/kW, and a cost of $25/kW is estimated to allow blackout ride-through capability in a CERTS Microgrid configuration in reference [5].

We do not explicitly find the average cost of adding this capability to a fuel cell system such as the one installed at the Sierra Nevada brewery. Because the ramp rate and min/max capacity range of a fuel cell is limited, this cost would depend much more on how steady the load was when the fuel cell was supplying back-up power. In such a case, a battery system, or uninterruptible power supply (UPS) would probably be necessary to smooth transient loads. We assume a $200/kW (capacity) price premium for this blackout ride-through capability across both the fuel cell and engine-generator CHP units. The actual cost of doing this for a fuel cell system could be greater depending on the factors mentioned above.

In addition, other problems can be encountered with CHP as emergency backup. For instance, at the NetApp facility, the UPS, combined with the electromechanical controls on the Hess Microgen unit, contributed to a problem where the load was being dumped too quickly on the Microgen units, causing them to shut down. A different UPS, or more sophisticated load ramping algorithms on the CHP units could improve blackout ride-through capability in this scenario.

The capacity factor for each facility is based on actual average run time in 2006 when the systems were intended to be operating continuously. For NetApp, data for a representative year is unavailable so we assume continuous operation. At the other two facilities, Sierra Nevada and Kaiser, the actual run time was considerably less than the intended operating schedule of 8,760 hours/year (i.e., 24hrs * 365 days/year). Sierra Nevada's fuel cells only operated an average of 6,640 hours/year, and Kaiser's CHP units for 6,648 hours/year, or just over 75% of the time they were scheduled to operate.

Although valuation of reliability differences between diesel generators and other CHP technology was considered in our analysis, the reliability difference of switching from diesel generators to CHP units for emergency power is difficult to quantify and relatively small. Based on average cost per outage and yearly reliability event data for industrial/commercial facilities of this size, the cost of all outages over the course of a year would be:

$$\begin{aligned} CoAO &= (SAIFI \times CPSO) + (MAIFI \times CPMO) \\ CoAO &= (1.3 \times \$4{,}111) + (2.3 \times \$1{,}881) \\ CoAO &= \$9{,}671 \end{aligned} \tag{1}$$

Where:
CoAO = Cost of All Outages
SAIFI = System Average Interruption Frequency Index (per year)
CPSO = Cost Per Sustained Outage
MAIFI = Momentary Average Interruption Frequency Index (per year)
CPMO = Cost Per Momentary Outage

Reliability and cost per outage data for California for this example is based on a previous study conducted by the Lawrence Berkeley Lab [1], and assumes all three sites are roughly comparable in terms of total energy use. Given that there is a small fraction of generators that fail during emergency backup operation, only a small amount of this $9,671/yr could be recovered by increased backup system reliability. Since the annual energy costs exceed $1 million for each site, this effect on the order of $1,000 in value is "in the noise" and certainly shouldn't affect the relative costs of the three modeled scenarios. Therefore, any difference in diesel backup and CHP generator reliability is ignored in this analysis.

2 SUMMARY OF MODELING RESULTS

For a complete summary of the DER-CAM modeling inputs and results, please refer to the full Pacific Region Combined Heat and Power Application Center (PRAC) publication, Appendix A on the web at http://www.chpcenterpr.org/PRACLibrary/Reports/PDF/PRAC%20premium%20power%20final.pdf. In summary, the results shown in the following tables and figures show that there is significant room for savings in both the technologies chosen, and the scheduling of on-site generation at these facilities. By comparing the carbon emissions and yearly energy cost of scenario 3 to scenario 1 in Tables 2-4, one can compare the economic and environmental efficacy of the currently installed CHP technologies at each site. For Sierra Nevada and NetApp, investing in a CHP system (without state incentives such as SGIP) is not, from a purely economic standpoint, optimal. Yet for Kaiser, increasing the total installed capacity of CHP units from 180 kW to a total 600 kW of on-site generation would provide the lowest yearly energy cost.

Not surprisingly, due to their inherent efficiency (heat plus electricity generation), scenarios with the greatest number of natural gas CHP technologies had the lowest carbon emissions. For Kaiser Hayward, installing the full complement of 600 kW of CHP units with blackout ride-through capability would provide an approximately 10% reduction in carbon emissions, and approximately 3% cost reduction over the optimal scheduling of their currently installed system. In the Sierra Nevada and NetApp cases, in the absence of any state or federal incentives to install CHP, the least expensive method to power the facility would be to buy all electricity and natural gas from the utility company. However, this would correspond to a greater than 12% increase in carbon emissions for Sierra Nevada, and an approximately 1% increase in carbon emissions for NetApp as compared to optimal scheduling of their currently installed system. The NetApp case shows that at a coefficient of performance of 0.8, for instance, an adsorption chiller paired with a natural gas generator may cost no less on a yearly basis than purchasing electricity and natural gas directly from a utility.

Table 2: Sierra Nevada Brewery Overall DER-CAM Results (2006 Prices)

	Scenario 1	*Scenario 2*	*Scenario 3*
Objective Function Value ($)			
(= Total Annual Energy Costs)	2,607,401	2,586,022	2,044,065
Installed Units			
200 kW natural gas fuel cell CHP unit	4	4	0
750 kW diesel generator	3	2	0
Emissions			
Annual Total Carbon Emissions (kg)	2,787,459	2,786,924	3,127,592

Notes:
Scenario 1: Diesel generators and CCHP equipment as installed in the current facility.
Scenario 2: Existing CHP equipment installed with blackout ride-through capability to replace approximately the same capacity of diesel generators.
Scenario 3: Fully optimized site analysis, allowing DER-CAM to specify the number of diesel and CCHP units (with blackout ride-through capability) to minimize the total cost function ignoring any constraints on backup generation.

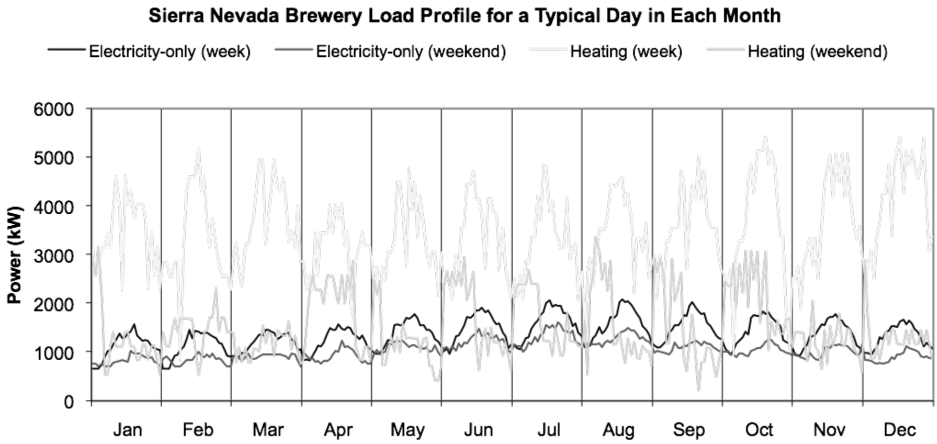

Figure 3: Electrical and Heating Loads for the Sierra Nevada Brewery

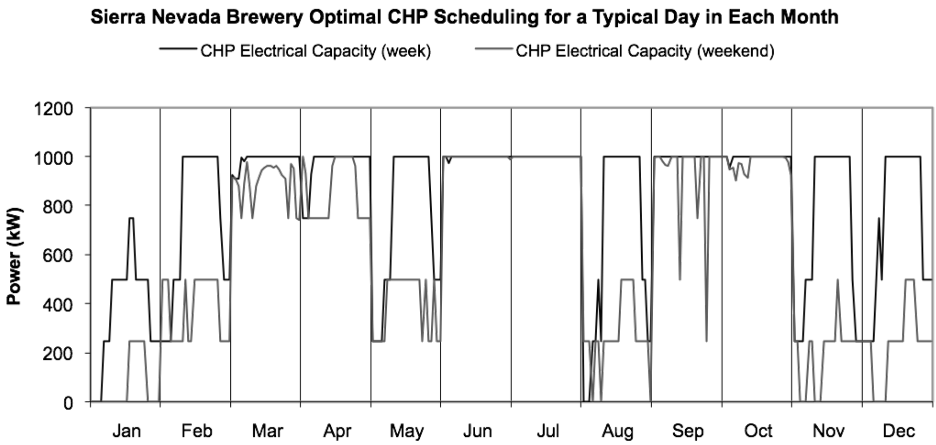

Figure 4: Economically Optimal Scheduling of CHP for Sierra Nevada

Table 3: NetApp Data Center Overall DER-CAM Results (2008 Prices)

	Scenario 1	*Scenario 2*	*Scenario 3*
Objective Function Value ($) (= Total Annual Energy Costs)	1,630,858	2,219,106	1,061,670
Installed Units			
2 MW diesel generator	2	1	0
375 kW natural gas CCHP unit	3	6	0
Emissions			
Annual Total Carbon Emissions (kg)	1,369,578	1,369,421	1,383,748

Notes:
Scenario 1: Diesel generators and CCHP equipment as installed in the current facility.
Scenario 2: Existing CHP equipment installed with blackout ride-through capability to replace approximately the same capacity of diesel generators.
Scenario 3: Fully optimized site analysis, allowing DER-CAM to specify the number of diesel and CCHP units (with blackout ride-through capability) to minimize the total cost function ignoring any constraints on backup generation.

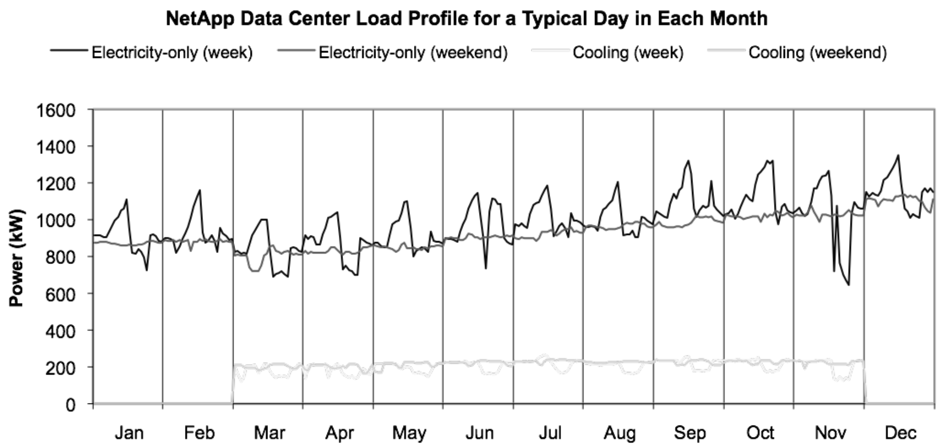

Figure 5: Electrical and Heating Loads for the NetApp Data Center

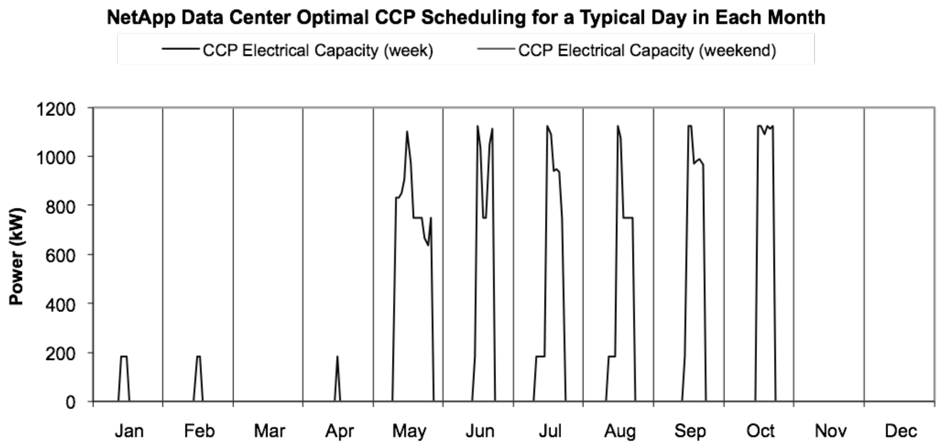

Figure 6: Economically Optimal Scheduling of CHP for NetApp

Table 4: Kaiser Hayward Hospital Overall DER-CAM Results (2008 Prices)

	Scenario 1	*Scenario 2*	*Scenario 3*
Objective Function Value ($) (= Total Annual Energy Costs)	1,773,688	1,766,464	1,721,870
Installed Units			
350 kW diesel generator	2	2	0
260 kW diesel generator	1	0	0
60 kW natural gas CHP unit	3	4	10
Emissions			
Annual Total Carbon Emissions (kg)	2,199,106	2,169,773	1,980,507

Notes:

Scenario 1: Diesel generators and CCHP equipment as installed in the current facility.

Scenario 2: Existing CHP equipment installed with blackout ride-through capability to replace approximately the same capacity of diesel generators.

Scenario 3: Fully optimized site analysis, allowing DER-CAM to specify the number of diesel and CCHP units (with blackout ride-through capability) to minimize the total cost function ignoring any constraints on backup generation.

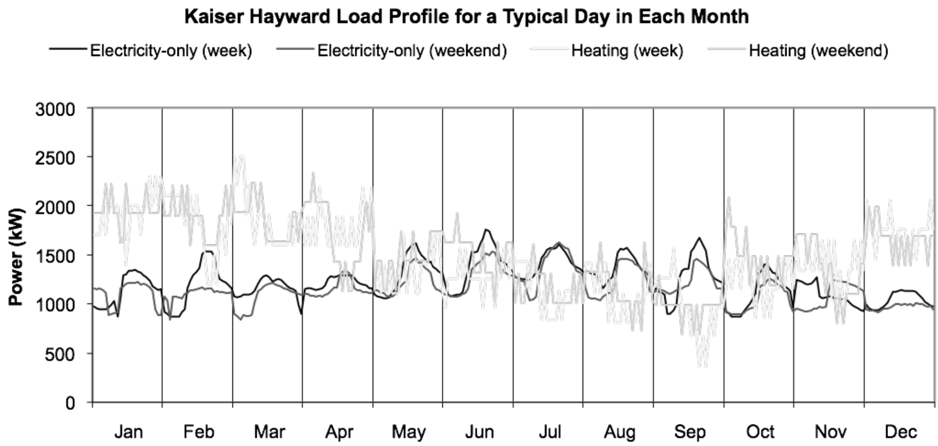

Figure 7: Electrical and Heating Loads for the Kaiser Hayward Hospital

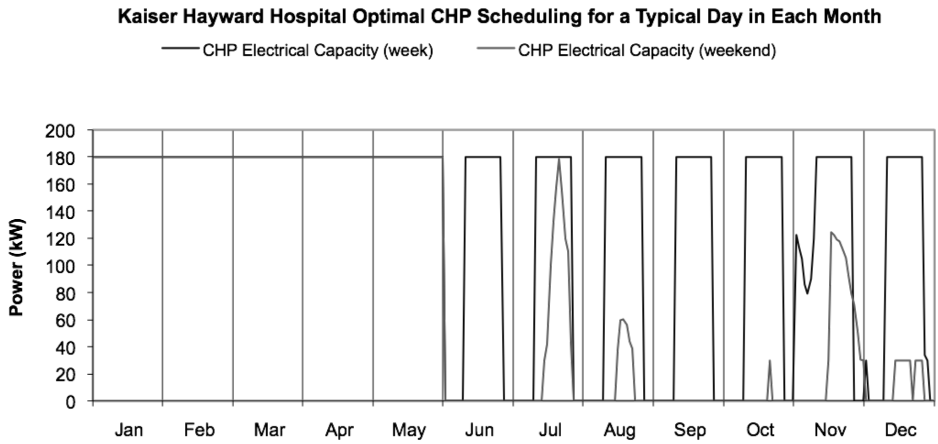

Figure 8: Economically Optimal Scheduling of CHP for Kaiser

Comparing Scenario 2 to Scenario 1 in Tables 2-4 shows the cost and benefit of substituting for diesel generation with a nearly equivalent capacity of CHP units. In Scenario 2 we assume that the CHP/CCHP system is installed with the capability for blackout ride-through capability and no diesel generators were previously installed at the site. For Sierra Nevada and NetApp, the carbon emissions savings for this blackout ride-through capability would only be a few hundred kilograms annually; a nearly break-even proposition. For NetApp, however, the cost of installing additional CCHP units to replace the diesel generators would be substantial, adding ~36% to the yearly energy cost compared to the current system. Our analysis shows no clear economic or environmental incentive to provide blackout ride-through capability for Sierra Nevada or NetApp. For Kaiser Hayward, however, substituting for one of the 260 kW diesel generators with 240 kW of natural gas reciprocating engine CHP units with blackout ride-through capability would provide a <0.5% reduction in annual energy cost and a 1.3% reduction in carbon emissions compared to the existing system; a small but significant difference.

Optimal scheduling of the various CHP technologies and facilities is shown in Figures 4, 6, and 8. It is not surprising that these results show operation of the CHP systems at midday and in the summer, when waste heat could be used for cooling, provided the most economic incentive for the data center. For the hospital, with higher heating loads in the winter, the CHP units were scheduled to run throughout that period on both weekdays and weekend days. All other things being equal, the results show that facilities with steady electrical demand will have a lesser benefit from installing CHP technologies than will those facilities with peaking demand during the middle of the day when electrical prices are at their highest. Peak pricing times are exactly when operating the CHP units will provide the most economic benefit by shaving peak demand. Conversely, looking at the results in Figure 6, one can see, for the data center, that the steady electrical demand and reduced TOU peak tariffs during the weekends (as compared to the weekdays) results in the CCP system remaining always off, as purchase of electricity to drive the compressor chillers would be less expensive than generating electricity and cooling with the CCP system.

3 CAVEATS AND DIRECTIONS FOR FUTURE WORK

It is important to recognize the limitations and strengths of the type of economic optimization performed in this analysis. Because the objective of this optimization is to minimize total yearly energy costs, economic externalities, many of them environmental, are ignored. Although the model does evaluate the direct carbon dioxide emissions from all energy generation technology, it does not optimize for this parameter by assigning it a monetary value, such as could be done in DER-CAM with a carbon tax. Additionally, embedded energy in manufacturing / transportation and life cycle greenhouse gas (GHG) emissions of the various energy generation technologies is ignored. Future work to look more seriously at the relative GHG life cycle emissions from each of these technologies could motivate a multi-objective optimization based on some combination of economic and environmental parameters [6].

Also not included in this analysis are the various state and federal incentives for installing CHP technologies, many of which were used in the installation of the systems at the facilities we analyzed (e.g., the California Self-Generation Incentive Program). Because these incentives vary widely from state to state, can also vary from year to year, and also because they do not represent a uniform market discount, these incentives were not included. We note that at present the SGIP program in California only provides incentives for fuel cell technologies as CHP resources, and is not providing an incentive for combustion technologies.

In addition to the factors above, there were many approximations and concessions made in constructing the load profiles for a couple of the facilities selected. Due to incomplete availability of data for NetApp, the cooling load was assumed to be negligible in the coldest months of the year (December through February) when it is assumed that outside air economizers can provide the vast majority of cooling. The electrical work used to power the fans for this cooling source was also uniformly ignored. In addition, because a composite of load data from the years 2006 and 2007 were used in the Kaiser and NetApp facilities some of the 'typical' load profiles input to our economic model may be skewed slightly because in some cases cooling load is coming from a month of data in for instance 2007, while CCHP system output may be from the same month in 2006. Because of the methodology used, the typical week/weekend day loads for each month are not strictly an average of every week/weekend day, but instead the actual profile for a day chosen because it most closely matched the average week/weekend daily load for that particular month. This methodology attempts to capture the complicated transient loads that may be present in a typical day, but hidden on average. This methodology also must be considered in viewing the modeled results, especially the optimal scheduling of the CHP system (Figures 4, 6, 8). This scheduling is therefore the optimal scheduling for a typical day, and should not to be strictly used in actual scheduling of the CHP systems. For that purpose, an algorithm which took into account time of year and historical average weather conditions would be more appropriate. Additionally, frequent repeated start-ups and shutdowns, as shown in the optimal scheduling figures, will obviously be detrimental to the longevity of any CCHP system and should be avoided.

Finally, this analysis did not, by any means, try to evaluate all potential DG technologies, and in fact, some obvious technologies, such as solar were not even considered because they were not installed at any of the selected sites. In fact, no attempt to assess the relative benefit of any CCHP technologies not already installed at the sites was made (with the obvious exception of blackout ride-through capability; the addition of which was considered in scenario 2 for all sites). A comprehensive analysis and optimization over all possible technology choices using DER-CAM could guide future DG technology selection for premium power applications, although caution should be taken because the costs from site to site can vary dramatically depending on the mechanical and electrical upgrades that may be needed for any DG system installation.

4 CONCLUSIONS

Through comparison of representative scenarios for each of three premium power sites (a brewery, a data center, and a hospital) with CHP systems, some broad observations can be made about the economic and environmental effects of such installations. It is shown that the economically optimal (i.e. lowest cost without state incentives) technology investment for two of the sites is to not invest in the CHP systems at all. For both the brewery and data center, the cost of the CHP system is either too great (e.g. fuel cell systems at the brewery), or the system is too inefficient (e.g. adsorption chillers at the data center) compared to the price of electricity and natural gas from the utilities to justify installing and operating such a system. For the hospital, however, the currently installed CHP system is an underinvestment, and due to the large and steady heat demands, a greater investment in CHP could significantly benefit the facility in terms of both cost savings and reduction in carbon dioxide emissions.

Overall, no matter what technology was chosen, the underlying theme of this study is that a facility's load profile will determine the relative environmental effect that any CHP system will achieve, and a combination of load profile and fuel prices (e.g. TOU tariffs) will determine the economic costs. A system with a high cooling load and no heating load (such as a data center) has comparatively lesser economic benefit than one with a large heating load (such as a hospital) due to the relatively low-cost of heat recovery systems as compared to adsorption/absorption chiller systems. So, facilities with high thermal loads will be ideal candidates for CHP systems. Additionally, more expensive and efficient electrical generation technologies (i.e. fuel cells) may provide no better performance for facilities with high heat loads (such as a hospital or brewery) than natural gas-fired reciprocating engine technology with heat recovery, but they do provide environmental benefits in reducing combustion byproducts.

Optimal scheduling of any selected technology will be largely determined by the time period of highest thermal demand and highest electrical pricing, with the latter being the dominant factor in determining the most cost effective operation schedule. Of course, running CHP systems at the time of peak electrical pricing will mean running them at the time of the day when ambient air pollution may also be the worst, and therefore may be disadvantageous in urban and some suburban settings.

Finally, this analysis looks at the possibility of replacing existing diesel generation with CCHP systems with blackout ride-through capability. For the brewery, the additional yearly cost and emissions savings from this option would be negligible, assuming the capital cost of installing such capability is $200/kW [12] beyond that of the existing CHP system. For the hospital, a slight benefit could be achieved by replacing some diesel generators with a natural gas fired reciprocating engine CHP system; this would be on the order of a 1% yearly energy cost and carbon emissions reduction using current tariffs. For the data center, however, a negligible environmental benefit was shown and a significant yearly energy cost increase (36%) was predicted in a diesel replacement by CHP scenario. If cost of providing seamless blackout ride-through capability in these CHP systems can be reduced to the $25/kW figure as suggested in reference [5], the proposition of replacing all the diesel generators with CHP units could become economically feasible. Additionally, if the cost of thermally driven chillers came down, or real-time pricing of electricity was widely available, CCHP systems would be more viable for the types of facilities studied in this paper.

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