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Evaluation of Battery/Microturbine Hybrid Energy Storage Technologies at the University of Maryland

A Study for the DOE Energy Storage Systems Program

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Abstract

This study describes the technical and economic benefits derived from adding an energy storage component to an existing building cooling, heating, and power system that uses microturbine generation to augment utility-provided power. Three different types of battery energy storage were evaluated: flooded lead-acid, valve-regulated lead-acid, and zinc/bromine. Additionally, the economic advantages of hybrid generation/storage systems were evaluated for a representative range of utility tariffs. The analysis was done using the Distributed Energy Technology Simulator developed for the Energy Storage Systems Program at Sandia National Laboratories by Energetics, Inc. The study was sponsored by the U.S. DOE Energy Storage Systems Program through Sandia National Laboratories and was performed in coordination with the University of Maryland's Center for Environmental Energy Engineering.

Acknowledgements

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Acronyms and Abbreviations

ABESS	advanced battery energy storage system
BCHP	building cooling, heating, and power
BES	battery energy storage
CHP	cooling, heating, and power
CT	current transformer
DER	distributed energy resources
DETS	Distributed Energy Technology Simulator
DOE	U.S. Department of Energy
ESS	energy storage system(s)
HVAC	heating, ventilation, and air conditioning
NRECA	National Rural Electric Cooperative Association
OG&E	Oklahoma Gas and Electric
O&M	operations and maintenance
PEPCO	Potomac Electric Power Company
PT	potential transformer
RTU	roof-top unit
SCE	Southern California Edison
SOC	state of charge
SNL	Sandia National Laboratories
T&D	transmission and distribution
TOU	time of use
UM	University of Maryland
VAV	variable air volume
VRLA	valve-regulated lead-acid
Zn/Br	zinc/bromine

Introduction

The nation's electricity delivery system is straining in the face of escalating demand for power. Electricity shortages, power quality problems, rolling blackouts, and electricity price spikes are becoming more and more common in many areas. In general, these 'events' result from two problems with the current electricity delivery system—first, there is not always enough power generation available to meet peak demand for a given area and, second, in certain areas existing transmission lines cannot carry all of the electricity needed by consumers. Distributed energy resources (DER) offers a solution to both of these problems that is both faster and less expensive than constructing large, central power plants and high-voltage transmission lines.

DER refers to a variety of small, modular power-generating technologies that can be combined with energy management and storage systems and used to improve the operation of the electricity delivery system. DER technologies are playing an increasingly important role in the nation's energy portfolio. They can be used to meet base load power, peaking power, backup power, remote power, power quality, and cooling and heating needs. In grid-connected applications, DER involves using small electricity generators and, when appropriate, energy storage technology to augment the electricity supplied by a large, central-station power plant.

Energy storage systems (ESS) are also gaining acceptance in certain applications (*i.e.*, power quality and peak shaving) for commercial and industrial power users. In the simplest terms, ESS store energy for use when other means of supplying power are unavailable, uneconomical, or when additional power is necessary. The storage device (battery, flywheel, etc.) can be charged by grid-supplied electricity, by electricity generated from a renewable resource (*e.g.*, wind or solar energy), or by electricity supplied by a distributed generation resource such as a generator or microturbine.

Purpose

Many commercial and industrial power users have distributed generation systems available on-site and the use of ESSs on both the supply and demand side is becoming more common. Nevertheless, hybrid generation/storage systems are not in widespread use among grid-connected commercial and industrial customers. Evaluating the effectiveness of such hybrid systems is a necessary first step for identifying possible obstacles to their widespread use. The purpose of this project was to identify and describe the technical and economic benefits (if any) of incorporating an ESS into an existing DER setting (specifically, an office building with microturbine generation). This work was accomplished at the University of Maryland (UM) using existing DER equipment and facilities and the Distributed Energy Technology Simulator (DETS) developed by Energetics, Inc. for Sandia National Laboratories (SNL), which manages the U.S. Department of Energy's (DOE's) ESS Program.

Scope

To assess the technical benefits of the hybrid system, three different battery energy storage (BES) technologies were evaluated in simultaneous simulations: flooded lead-acid, valve-regulated lead-acid (VRLA), and zinc/bromine (Zn/Br). Because the additional generation/storage capabilities of the UM system are primarily used to offset additional load during the cooling season (June through October), the simulations were optimized to model a peak-shaving application. The technical benefits evaluation comprised several steps:

- Customizing the DETS to include VRLA and Zn/Br modules.
- Installing the DETS at the demonstration site.
- Completing a demonstration where the virtual batteries supplied electricity to the building at peak times and recharged at off-peak times.
- Completing a second demonstration during the cooling season to ensure that the full capabilities of the hybrid generation/storage system were evaluated.

Using the data gathered for the technical evaluation, the economic impact of the added storage capabilities was evaluated. Because significant cost savings were not expected due to the favorable rate structure UM has negotiated with the local utility, additional rate structures were evaluated to identify the economic thresholds required to make hybrid systems an economically viable option. Energy and demand charge combinations for utilities in different sections of the country were compared to determine whether hybrid generation/storage systems might be economically viable for areas with rate structures different from that of UM.

Demonstration Application and Site

Integrated systems for cooling, heating, and power (CHP) are an example of an application where the use of distributed generation technology is gaining acceptance among commercial and industrial energy users. Nevertheless, such systems are also an example of an application that could potentially benefit from (but to date has rarely incorporated) an energy storage component. Consequently, studying the effects of adding energy storage to an existing CHP system could prove extremely useful for encouraging future use of hybrid generation/storage in other CHP systems.

CHP systems incorporate multiple technologies for providing energy services to a single building (which is then called BCHP) or to a campus of buildings. Electricity for such systems is generally provided by an electric utility, but is routinely supplemented by a distributed generation system (*i.e.*, on-site or near-site power generators that use one or more of the many available options: internal combustion engines, combustion turbines, or microturbines, and fuel cells). In CHP systems, waste heat from the distributed generation resource(s) is recovered and used to operate equipment for cooling, heating, and/or controlling humidity in the system's building(s). CHP systems provide many benefits over traditional heating, ventilation, and air conditioning (HVAC) systems, including:

- reduced energy costs,
- improved power reliability,
- increased energy efficiency, and
- improved environmental quality.

University of Maryland Chesapeake Building

UM, like many commercial and industrial users of electric power, currently operates its own BCHP systems on campus. UM's Chesapeake Building houses the CHP systems for the Buildings Integration Test Center, which was designed to investigate how to integrate CHP systems into existing buildings. This medium-sized office building is representative of 23% of commercial buildings. It is four stories (50 ft) tall and measures 128 ft by 96 ft, for a total of 53,700 ft^2 of floor space (see Figure 1). It houses several administrative departments and 200 employees. Generally, the building is occupied from 9 a.m. to 5 p.m., Monday through Friday.

Figure 1. Chesapeake Building with microturbine in foreground.

Chesapeake BCHP System

The Chesapeake Building's BCHP system includes two state-of-the-art CHP systems that have been integrated with the building's pre-existing HVAC system. Both the building and the BCHP system components have been equipped with data gathering instrumentation that monitors the thermal performance of the building and the system's electrical power (*i.e.*, what is generated and the load on the system). All of the equipment is controlled and monitored via computer from a control room located on the ground floor of the building.

HVAC System

The Chesapeake Building's original HVAC system is a variable air volume (VAV) system with fan-powered VAV boxes located around the building that are served by two 90-ton (316.5-kW) electric roof-top units (RTUs). Cooling for the RTUs themselves is provided by a direct-expansion system with two electrical reciprocating compressors. Electric reheat coils in the VAV boxes are used for heating from November through May. When necessary (*i.e.*, rarely), off-hours and morning heating is supplemented by the RTUs' natural gas burners. Each RTU serves one of two zones, each consisting of two floors (see Figure 2).

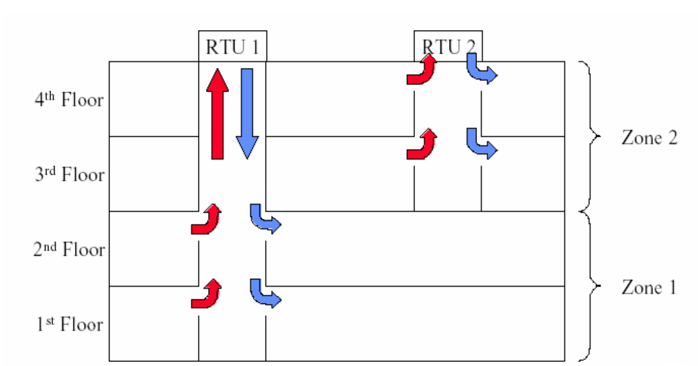

Figure 2. Building HVAC zones.

From 6 a.m. to 10 p.m. Monday through Friday, and 7 a.m. to 6 p.m. Saturday and Sunday (per staff request), the HVAC system operates normally; the rest of the time the system is disabled according to the schedule set by UM's Department of Facilities Management.

CHP Systems 1 and 2

The CHP components of the BCHP system were integrated with the building's original HVAC system (described above). Both CHP systems operate from June to October to provide cooling to the building. CHP System 1 consists of two Goettl engine-driven air conditioning units, HVAC RTU 1, and a Kathbar liquid desiccant system[1], all of which are installed on the roof (see Figure 3)[2]. CHP System 2 consists of a 60-kW Capstone microturbine, a 20-ton Broad absorption chiller, an ATS solid desiccant system, and HVAC RTU 2 (see Figure 4). The microturbine and absorption chiller are installed on the ground and the RTU and solid desiccant system are installed on the roof. Figure 5 is a photograph of all of the major equipment items installed on the roof. Figure 6 is a photograph of the equipment installed on the ground. A computer located in the BCHP control room controls each system. Additionally, CHP System 2 can be controlled from any remote computer with access to the internet (remote access is an upgrade that is also planned for CHP System 1).

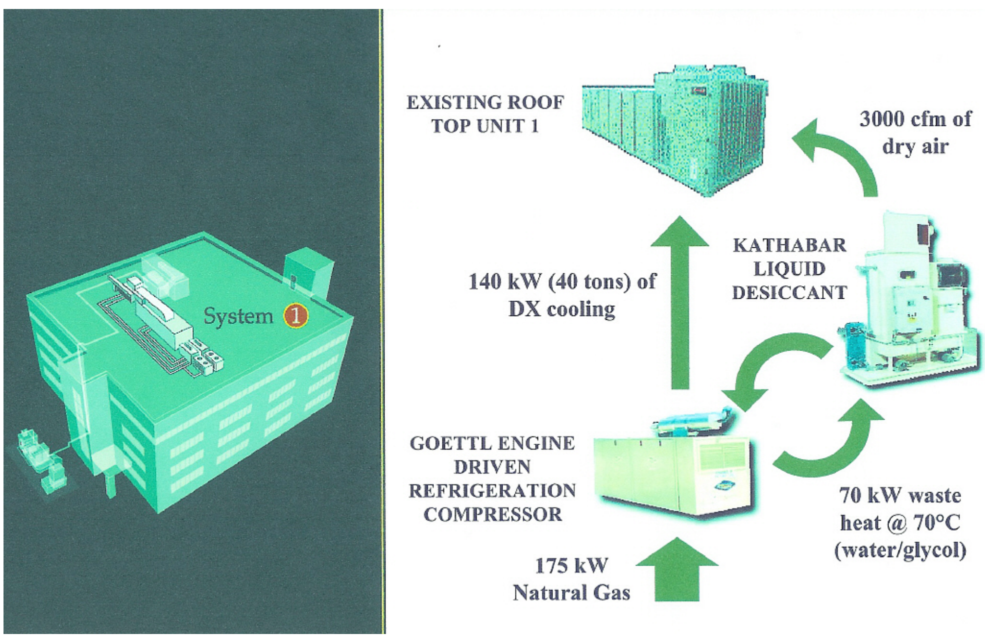

Figure 3. CHP System 1 overview.

[1] Desiccant systems remove humidity from the air by using chemical compounds that attract water vapor. In liquid desiccant systems, the air to be dehumidified is passed through a desiccant solution spray. The solution has a lower water vapor pressure than the air, so water vapor becomes trapped in the desiccant solution. In solid desiccant systems, desiccant compounds are deposited on honeycombed surfaces, which provide a large surface area for water vapor to be absorbed. When water saturated (humid) air is blown through the honeycombs, the water is absorbed by the desiccant and dry air exits the system.

[2] Figures 3 and 4 provided by University of Maryland Center for Environmental Energy Engineering, Dr. Reinhard Radermacher and Dr. Sandeep Nayak, "Introduction to the Combined Cooling, Heating and Power Consortium," http://www.enme.umd.edu/ceee/bchp/files/CHPIntro030701.pdf.

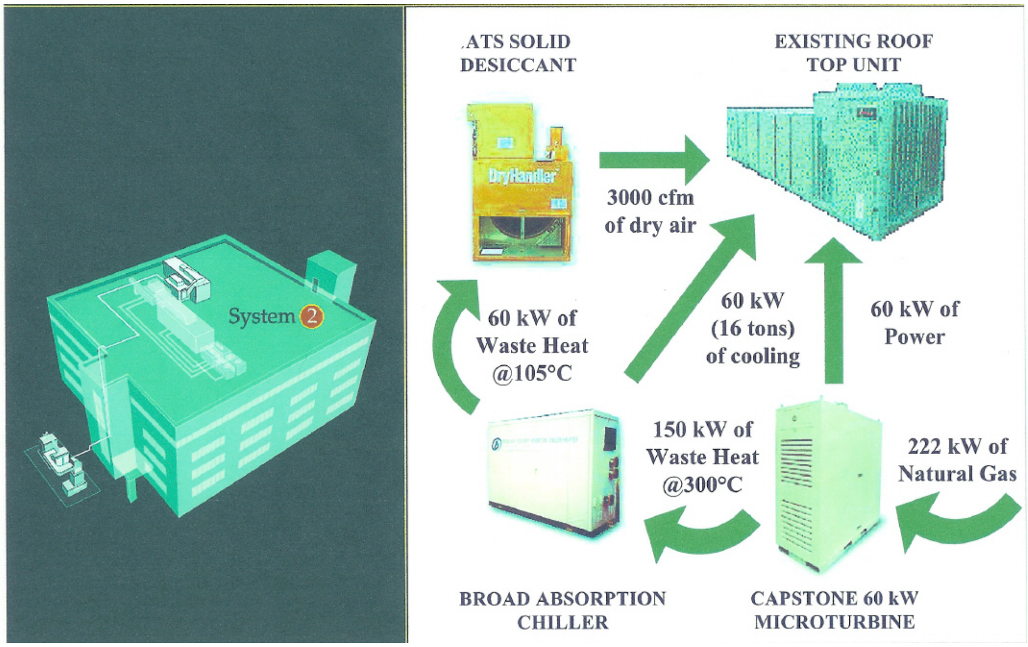

Figure 4. CHP System 2 overview.

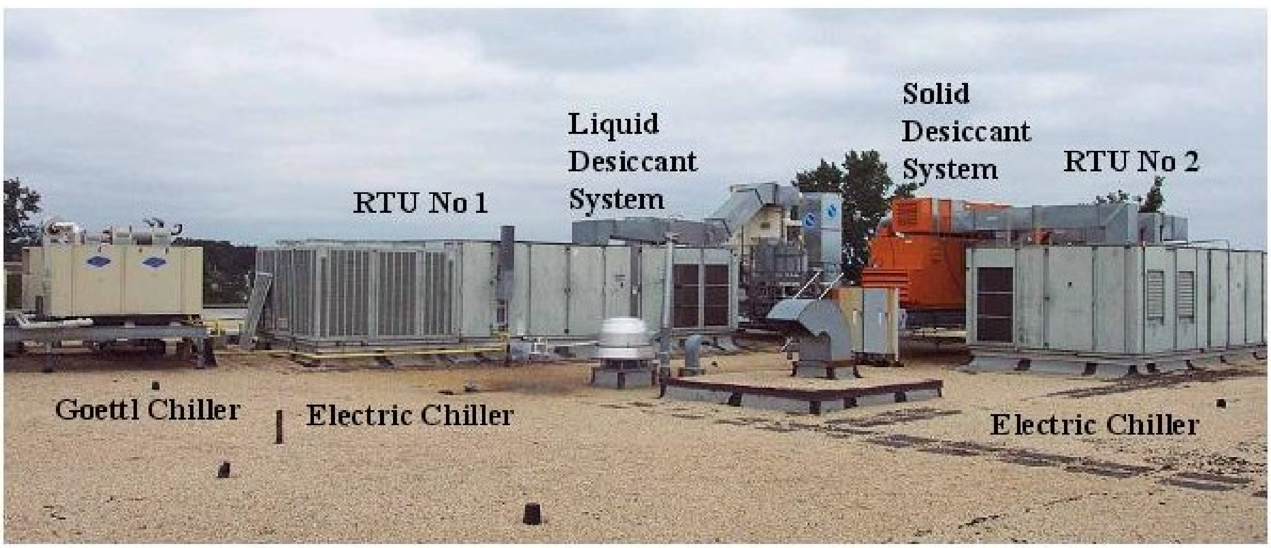

Figure 5. Rooftop CHP components.

Figure 6. Ground-level CHP components.

Chesapeake Building Load Profile

Building Energy Use Overview

The majority of the building's energy is supplied by electricity from Potomac Electric Power Company (PEPCO), the local utility. Low- and high-voltage electrical panels on each floor tie into a main electrical panel. The low-voltage circuits provide power to convenience outlets, dedicated outlets for kitchen and office equipment, and the building's lighting. The high-voltage circuits power the VAV boxes. Each of the two RTUs also has a dedicated circuit tied into the main electrical panel.

Natural gas is used to power the microturbine, the Goettl engines, the solid desiccant system, an emergency generator, a hot water heater, and the (seldom-used) RTU burners. The microturbine and the hot water heater consume the largest portion of natural gas. The microturbine is connected to the grid and supplies part of the 300-kW electricity load of the building. Thermal energy from the microturbine's exhaust (at 500^{o} F) is used to operate the adjacent chiller. The fuel-to-electricity efficiency of the microturbine is 26.5%. The overall efficiency improves to 63.5% by capturing its exhaust.

Electricity Use Overview

The Chesapeake Building's average daily electric consumption is 200 to 250 kW, and peak consumption is about 300 kW. Daily electric consumption includes both low- and high-voltage power. The load is higher between 9 a.m. and 5 p.m. when the building is occupied and lower when the building is unoccupied. Because the building is used mainly for administrative office work, the occupancy schedule remains fairly consistent throughout the year. As would be expected, low-voltage power consumption (*i.e.*, for lighting and convenience outlets) rises dramatically when the building is occupied. Nevertheless, even when the building is occupied low-voltage power demands are small compared to the power demands of the building's HVAC system.

Seasonal Load Profiles

The Chesapeake Building's high-voltage power consumption depends heavily on outside air temperature. During the heating season (November through May), the VAV boxes, which use electric fans and reheating coils to distribute warm air throughout the building, can consume two-thirds of the total electric load. The RTUs consume less than a tenth of the load during these cooler months. During the cooling season (June through October), the RTUs consume the majority of the load. Indeed, RTU use during the cooling season can peak at well over two-thirds of the building's total electric load. With the CHP systems cooling the building, the RTUs are still used, but at a reduced rate.

The Chesapeake Building's seasonal load profiles are shown in Figure 7. The summer load profile is shown without CHP operation, which would reduce the peak electricity demand by approximately 50 kW. This graph displays—

- Summer 2001 electricity demand without microturbine or CHP operation on a day with high load (top line),
- Winter 2002 electricity demand without microturbine or CHP operation (middle line), and
- Winter 2002 electricity purchases, as reduced by the microturbine (bottom dashed line).

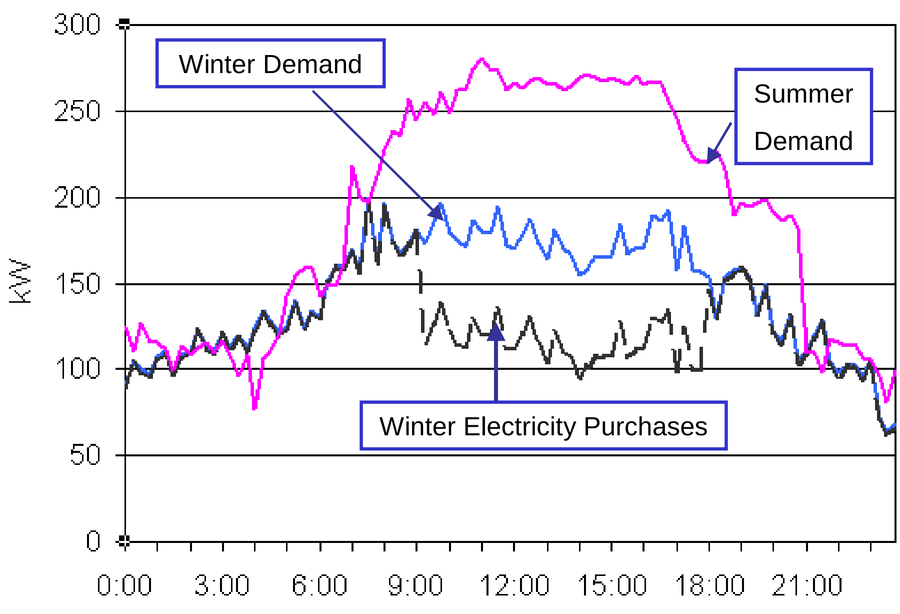

Figure 7. Chesapeake Building load profiles.

These load profiles indicate that integrating an ESS with the current BCHP system could reduce energy charges by shaving the load at utility-designated peak times and recharging at off-peak times and by turning on when the electricity demand exceeds a set threshold (*e.g.*, before 9 a.m. or after 5 p.m., particularly in the winter) to avoid high demand charges. Additionally, the ESS would provide power quality protection for the building should it become necessary (at present there are no highly sensitive loads in the building).

Distributed Energy Technology Simulator

Simulator Development Overview

Development of the DETS began in 1997 as a joint project sponsored by the DOE ESS Program and the National Rural Electric Cooperative Association (NRECA). The project's goal was to develop a means of predicting the technical performance and performing a cost/benefit analysis for various distributed generation and energy storage technologies. Initially, one simulator was developed to emulate the use of flooded lead-acid batteries for energy storage in each of two specific applications (power quality and peak shaving). The ESS Program was responsible for coordinating the development and validation of these first two simulators.[3] NRECA's area of responsibility was to coordinate field demonstrations for the simulators and, later, to develop and validate a third simulator for diesel generation.

Each of the three original simulators had different hardware and software. The simulator hardware originally included a custom-designed power monitoring board and a laptop computer connected by communication links. The power monitoring board sampled the current and voltage delivered by the utility and sensed when the utility sent a peak-shave signal. It then transmitted this information to the laptop computer, which ran the software used to perform the calculations that comprised the simulation.

In 1999, it was decided to redesign the individual simulators into one unified unit capable of simulating multiple technologies. In addition to two of the existing technologies (peak-shaving battery, and diesel generation) software modules to simulate microturbines and fuel cells were developed and validated.[4] Because the laptop was not robust enough to perform next to vibrating and noisy technologies, it was replaced with an industrially hardened embedded controller that was packaged with a modem, a battery, and other power electronics that support remote data acquisition.

Currently, the unified DETS comprises two boxes (see Figure 8)—the AC power monitoring box and the embedded simulation controller. A block diagram of the system is shown in Figure 9. The AC power monitoring box is connected at the customer's site to measure current and voltage delivered to the site. These measurements are sent to software in the simulation controller, which uses the information to mimic the operation of the distributed generation technology being simulated in real time. This data is recorded as ASCII text by the controller. A monitor, keyboard, and mouse (not shown in the figure) can be connected to the controller to adjust the simulation parameters using Energetics' Unisim software (the user interface for the DETS). A remote host computer and PC Anywhere software is used to download the recorded data from the simulation controller via modem. The remote host computer then uses Energetics' EnergyAnalysis software to calculate the peak and off-peak energy demands that would result from the use of the simulated technology.

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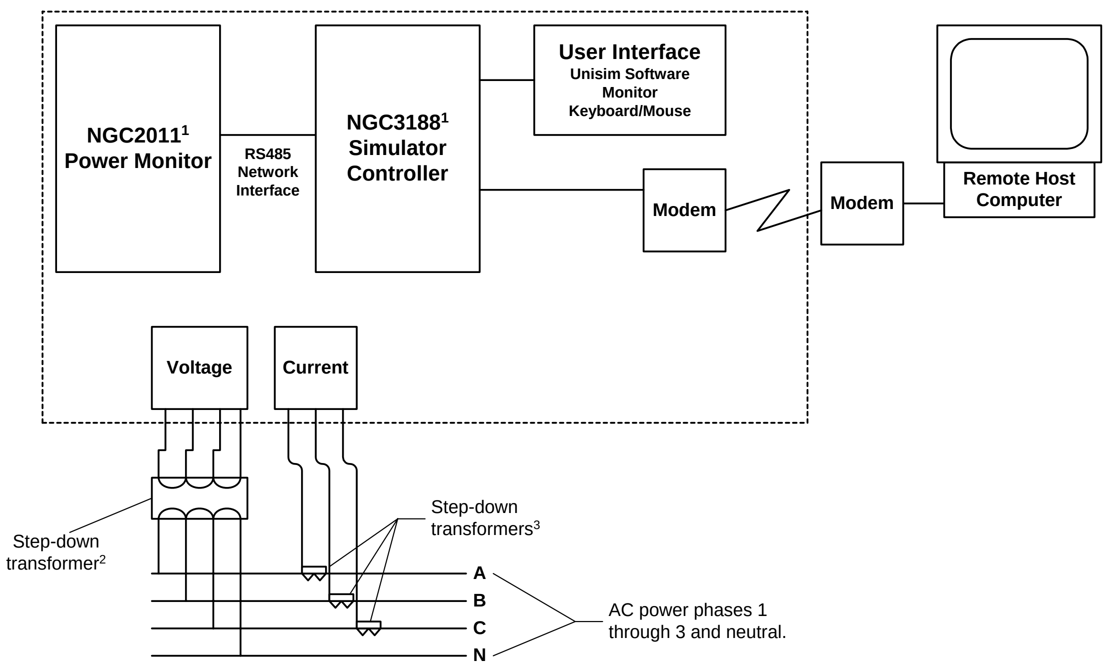
[3] Additional information about the development and validation of the peak-shaving battery simulator is documented in the paper "Assessing Battery Performance and Distributed Energy Technology Simulators" by Mindi Farber de Anda and Ndeye K. Fall of Energetics, Inc. The paper was presented at the Electric Energy Storage Applications and Technologies (EESAT) conference in 2002.

[4] For technical reasons, the power-quality battery simulation software was not incorporated into the unified DETS.

Figure 8. Simulator embedded controller (left) and AC power monitor (right).



[1] Board numbers for the simulator's hardware components.

[2] Voltage for all phases is monitored as one voltage and stepped down by the transformer to be readable by the simulator.

[3] Current for each phase is monitored individually and stepped down by the transformers to be readable by the simulator.

Figure 9. Simulator block diagram.

The unified DETS was designed to provide real-time information to quantify the energy and expense savings realized from a particular distributed generation technology in order to justify the installation and operating costs of that technology. To facilitate comparisons of multiple technologies, the DETS operates unattended and can run up to five simulations simultaneously.

The EnergyAnalysis software used in the DETS can provide daily, weekly, and monthly comparisons of the simulated technologies. Data can be retrieved via modem from any remote host with PC Anywhere software.[5] The data and analysis provided by the DETS is more precise and no more expensive than a traditional paper feasibility study. And while the information provided by the simulator is not detailed enough to use as a basis for procuring the equipment necessary for implementing a given technology, DETS users can gain a clear indication of which technology is the most competitive at their site and for their application.

Customizing the Simulator

This project served as a field demonstration of the DETS in a hybrid generation/storage environment. To accomplish the work it was necessary to customize the DETS to include ESSs based on two additional battery technologies: VRLA and Zn/Br. The Zn/Br technology was of particular interest because of space limitations at the Chesapeake Building's site. It was also necessary to develop the analytical methods necessary to analyze the data for applications that use hybrid generation/storage systems.

For each of the new simulation modules (VRLA and Zn/Br), software had to be developed and validated before the simulator could be installed at the Chesapeake Building. The goal of validation is to determine that the software accurately mimics the hardware being simulated. Generally, validation involves connecting the simulator to a fully functional system that is using the hardware being validated and comparing the results of the simulation to data recorded for the actual hardware. The validation process usually takes from two to four weeks.

Development of the VRLA module required only slight revisions of the software used for the existing flooded lead-acid battery module. The software was revised to handle the discharge and recharge nuances specific to VRLA batteries. Because the simulator had already been validated for flooded lead-acid batteries, validation of this module was accomplished without connecting the simulator to an operating VRLA battery. The VRLA battery module was validated using research, software testing, and written reports and assistance from GNB, the largest stationary battery manufacturer in the U.S.

The Zn/Br battery module was validated using a ZBB advanced battery energy storage system (ABESS) in July 2001. The simulator was connected to the ABESS while the ABESS was being tested as a grid-connected peak-shaving device to offset summer air conditioning loads at a Detroit Edison transformer site in Lum, Michigan. Throughout the test period, the ABESS typically discharged to shave peaks during the afternoon and recharged at night. The simulator was connected to the ABESS for two days to measure battery output.

The validated modules for both technologies and the associated economic and environmental data were incorporated into the Unisim software. A Zn/Br battery simulation screen is shown in Figure 10. This screen is representative of those used for VRLA and flooded lead-acid batteries as well. The monitored data includes voltage and current measurements from all three phases of the site's AC power, as well as the power factor, temperature, and real and reactive load of the site. The power factor is the ratio between the real power and the total power supplied. The real and reactive loads are calculated from the measured voltage and current. The simulated data set includes the simulated load and attributes of the virtual technology such as current, voltage, and–for batteries–state of charge (SOC). The simulated facility load is the real load minus the power

[5] The EnergyAnalysis software must be loaded on the remote host to analyze the downloaded data.

provided by the simulated technology. The simulation screen also shows the daily and monthly peak of the facility load. The target peak is the maximum energy demand specified by the user during the peak-shaving time interval.

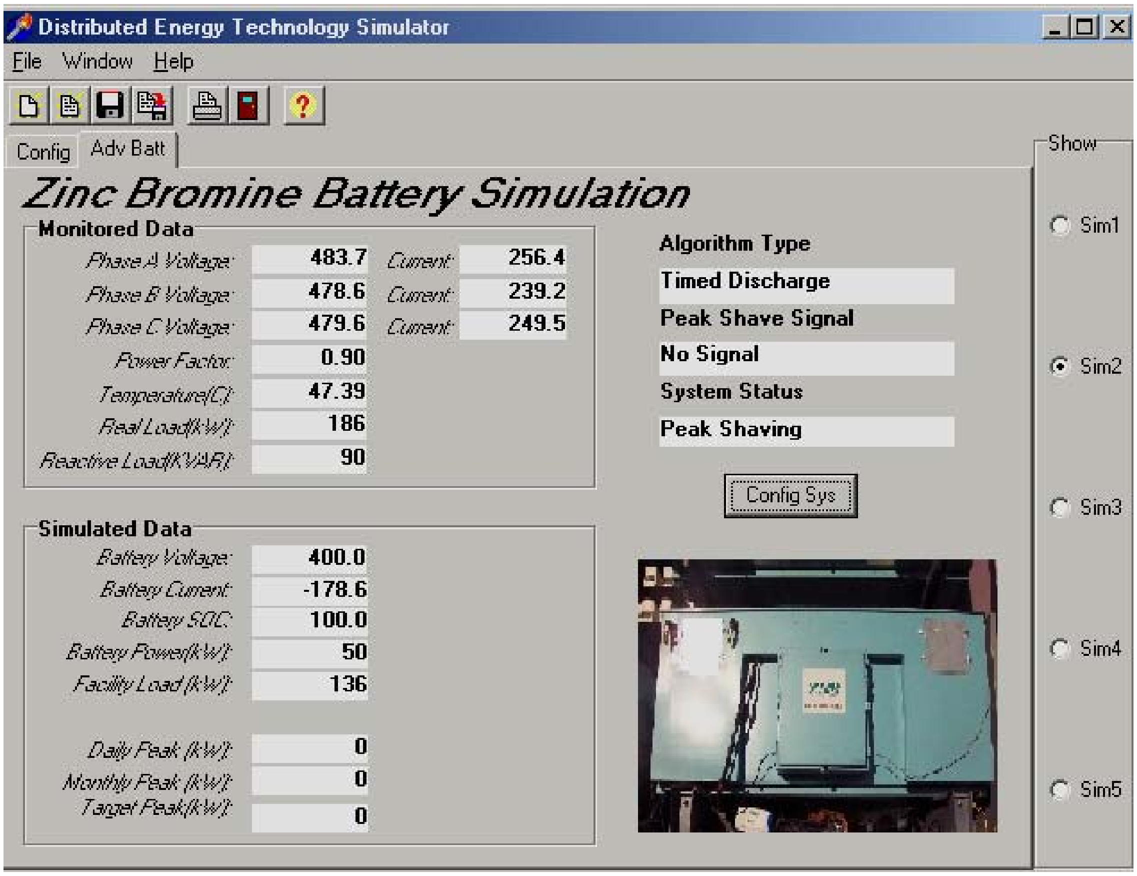


Figure 10. Zn/Br battery simulation screen.

Installation and Integration of the DETS at the Demonstration Site

Once the new simulator modules had been validated and added to the DETS software, the simulator was ready to be installed at the Chesapeake Building. The building's existing CHP systems, however, were in the process of being upgraded. Delays in the installation of a new chiller resulted in delays in the simulator installation. Additionally, once the simulator was installed, the Capstone microturbine (which was replacing an older Honeywell microturbine) and desiccant dehumidifier had to be installed and commissioned prior to the building's CHP systems being fully operational for the demonstration.

The simulator was connected to the Chesapeake Building's switchgear (see Figure 11) using current transformers (CTs) and potential step-down transformers (PTs) with ratios of 800:5 and 2.4:1, respectively. These CTs and PTs had been installed inside the switchgear in the building's mechanical room (see Figure 12). The simulator's AC power monitoring board was wired to the CTs and PTs to read the amount of current and voltage delivered to the building.

Figure 11. Simulator connected to the Chesapeake Building's switchgear.

Figure 12. CTs used to measure the building's current consumption.

Simulation Parameters

The following three battery technologies were simulated during this study: flooded lead-acid, VRLA, and Zn/Br. Simulations for each of the three technologies were run simultaneously. The simulations lasted for one month without any breaks for maintenance. Peak demand times and office operation hours served as the basis for sizing the virtual batteries. The Chesapeake Building currently has a summer peak demand that exceeds 250 kW, a daily peak energy consumption of 1,000 kWh, and a daily off-peak energy consumption of 3,500 kWh. The virtual batteries were sized at 50 kW/400 kWh to balance capital costs with the savings generated.

The power/energy output and operational algorithms were determined for each of the simulations. The virtual batteries can be operated according to four algorithms that exist in the simulator software:

- **Timed discharge—**The device is turned on and off at scheduled times each day, coinciding with the peak period.
- **Auto-bulk peaking—**A maximum peak energy demand is chosen, and the device is triggered to provide full power whenever the energy demand rises above this threshold.
- **Auto-variable peaking—**A maximum peak energy demand is chosen, and the device turns on whenever energy demand rises above this threshold; however, the device provides just enough power to keep the energy demand below threshold.
- **Peak-shave signal—**The device turns on when the facility receives a peak-shave signal from the utility, indicating that peak demand rates are in effect.

The timed discharge and auto-bulk peaking algorithms were chosen because they were the most appropriate for this hybrid battery microturbine demonstration.[6] During the winter demonstration five simulations were run. The three virtual battery modules (flooded lead-acid, VRLA, and Zn/Br) operated under the timed-discharge algorithm from 12 p.m. to 5 p.m., and two of the modules (VRLA and Zn/Br) operated under the auto-bulk peaking algorithm with a threshold set at 150 kW. During the summer demonstration, one of each of the three virtual battery modules operated from 6 a.m. to 10 a.m. and 5 p.m. to 10 p.m. to shave electric spikes before and after microturbine operation.

The simulator's virtual technology modules are not programmed to mimic the operation of proprietary designs for specific hardware. Rather, each module is programmed to be indicative of general hardware operation for a given technology. Consequently, the following simplifying assumptions, based on best use practices for each technology, were made:

- The flooded battery module operated at constant power discharge and recharge and stopped discharging at 40% SOC.
- The VRLA battery module operated at constant power discharge and recharge and stopped discharging at 20% SOC.
- The Zn/Br battery module operated at constant power for a full discharge and recharged at constant current.

Working from these assumptions, the simulator was able to perform data capture and analysis in 15-minute intervals.

To perform the economic analysis it was also necessary to program the University's electric rate structure into the simulator. Table 1 presents the electric rates that UM has negotiated with its utility company, PEPCO, for all buildings on all campuses. These rates are very low relative to those charged elsewhere in the U.S. Due to this extremely favorable rate structure, cost savings were not as great as they would be for a facility operating under a more 'average' rate structure.

[6] The peak-shave signal algorithm can only work if the host site receives radio signals from the utility that alert it to peak demand periods. The auto-variable algorithm works best in a season when peak demand can increase over time.

Table 1. PEPCO Electric Rates for University of Maryland

Rate	Time	Summer (Jun-Oct)	Winter (Nov-May)
On-peak electric (¢/kWh)	12 p.m. - 8 p.m.	5.76	4.90
Intermediate electric (¢/kWh)	8 a.m. - 12 p.m., 8 p.m. - 12 a.m.	5.09	4.34
Off-peak electric (¢/kWh)	12 a.m. - 8 a.m., weekend/holidays	3.5	3.06
Peak demand charges ($/kW)	24 hours every day	15.00	4.00

Demonstration Results

Originally, simulator installation was planned to allow for evaluation of peak shaving throughout most of the cooling season (May through October), especially the summer months (June, July, August). However, the simulator could not be installed until the microturbine and CHP systems had been successfully upgraded. The new Capstone microturbine was installed in January 2001, and the upgraded CHP systems became operational only in May 2001. Therefore, the simulator installation was not completed until August 2001. Consequently, the initial evaluation was of winter (rather than summer) data.

Shortly after the simulator was installed, a brief, preliminary analysis was performed to provide an initial comparison of the technologies being simulated. The results of this preliminary analysis are provided in Table 2. The relatively low monthly cost savings are due to the favorable rate agreement UM has negotiated with PEPCO.

Table 2. Simulated Technology Comparison—October 29 to November 12, 2001

Measure	Flooded	Zn/Br		VRLA	
	Timed	Timed	Auto-bulk	Timed	Auto-bulk
Energy Output (kWh)	2,675	2,672	2,712	2,687	2,649
Peak kWh Purchases	7,939	7,854	8,484	7,927	8,547
Off-peak kWh Purchases	40,334	40,206	39,623	40,987	40,366
Energy-charge Savings ($)	76	84	82	57	56
Demand-charge Savings ($)	164	250	250	186	186
Monthly Savings ($)	240	334	332	243	242

Winter Demonstration Results

The one-month winter demonstration ran from February 4, 2002 to March 4, 2002. The goal of this demonstration was to use the simulated batteries to reduce the peak kWh purchases and demand charges as much as possible. Table 3 displays the peak and off-peak kWh purchases for the Chesapeake Building without microturbine generation and without CHP operation and compares this to the purchases with the batteries. Microturbine generation was excluded because the meter at which the simulator was connected reported total electricity demand for the building; it did not differentiate between the power supplied from the microturbine and that supplied by PEPCO.

All batteries operated from 12 p.m. to 5 p.m. on weekdays in the winter. Those on a timed-discharge dispatch (scheduled discharges coinciding with periods of peak usage) displaced the same amount of on-peak kWh. The Zn/Br and VRLA batteries operating under the auto-bulk peaking algorithm also displaced the same amount of on-peak kWh, as they discharged when the load exceeded 150 kW. As can be seen in the table, the modules operating under the auto-bulk algorithm displaced 19% fewer peak kWh because they were only discharged when the load exceeded the threshold and not for set periods of time. The differences in the amount of off-peak kWh purchases are explained by the variations in batteries' recharge methods. The flooded battery module was set to recharge to 105% SOC, followed by a trickle-charge to 115% of its rated capacity. The VRLA battery module was recharged to 100% SOC and then trickle-charged to 105% of its rated capacity. These charging practices are fairly standard for lead-acid batteries and help to maximize battery life. Zn/Br batteries use a completely different method for recharging. They are recharged at a constant current for a specific period of time (to ensure proper zinc loading). Zn/Br batteries are considered fully charged based on the amount of zinc in the solution, not on their SOC. Consequently, Zn/Br batteries are not finish or trickle charged. As a result the simulated Zn/Br battery required the least off-peak kWh purchases because, in general, recharging a Zn/Br battery as recommended requires much less time than properly recharging lead-acid batteries.

Table 3. Simulated Battery Technical Comparison—February 4 to March 4, 2002

Battery	Operating Algorithm	Displaced Peak kWh	Peak kWh Purchases	Off-peak kWh Purchases
No Battery	NA	0	17,783	69,458
Flooded	Timed	5,250	12,533	75,772
VRLA	Timed	5,250	12,533	75,462
	Auto-bulk	4,275	13,508	74,693
Zn/Br	Timed	5,250	12,533	74,288
	Auto-bulk	4,275	13,508	73,408

An economic comparison of the three technologies based on energy cost savings and demand charge savings is shown in Table 4. This table does not reflect the technologies' capital or operation and maintenance (O&M) costs.[7] Energy cost savings vary according to the number of off-peak kWh purchased and the amount of peak energy displaced. The Zn/Br batteries, which displace the same amount of peak energy as the lead-acid technologies but do not require finish or trickle charging (and thus require fewer off-peak kWh to be purchased), show the biggest savings. The batteries running the timed-discharge algorithm showed better energy savings than those running the auto-bulk algorithm because they displaced more peak energy. Demand charges vary based on the difference between the customer's peak use and their nominal (normal) use. The higher the peak use, the higher the demand charge. The more such demand peaks are reduced, the greater the monthly demand-charge savings. The batteries running the timed-discharge algorithm also showed better demand-charge savings because they reduced the highest peak from 200 kW to 168 kW. The batteries running the auto-bulk algorithm reduced the highest peak to 173 kW. Overall, the Zn/Br battery yields the largest monthly savings of the three technologies. It is important to note, however, that because it is still an emerging technology, its capital cost is twice that of the lead-acid technologies.

[7] This analysis was focused on monthly savings, not payback or net present value of overhaul, which are calculated from monthly savings and capital and O&M costs.

Table 4. Simulated Battery Economic Comparison—February 4 to March 4, 2002

Battery	Operating Algorithm	Energy-charge Savings ($)	Demand-charge Savings ($)	Monthly Savings ($)
Flooded	Timed	68	200	268
VRLA	Timed	77	200	277
	Auto-bulk	52	183	235
Zn/Br	Timed	112	200	312
	Auto-bulk	91	183	274

Because the meter from which the simulator was reading the building's power demands could not supply data specifically on power provided by the building's microturbine, the data above does not reflect the microturbine operating in hybrid with the batteries, which was one of the main goals of this study. Because the benefits of distributed (*i.e.*, microturbine) generation were not included, and because simulated winter cost savings were very low (due to UM's favorable rate structure and lower overall energy use in winter) it was decided to run a follow-on summer demonstration.

Summer Demonstration Results

The summer demonstration ran from July 29, 2002 to August 26, 2002 and was designed to more fully evaluate the benefits of simulated hybrid generation/storage systems. This demonstration included both microturbine generation and battery energy storage. Additionally, it reflected the period of the highest loads on the building and thus provided the greatest opportunity to realize cost savings from peak shaving.

Throughout this demonstration a simulated microturbine supplied 480 kWh of electricity to the building (60 kW for 8 hours a day) seven days a week. Each of the simulated battery technologies ran from 6 to 10 a.m. and 5 to 10 p.m. on weekdays to shave electric spikes before and after microturbine operation. Each of the battery simulations ran the auto-bulk peaking algorithm with the threshold set at 220 kW. Load data was collected and the energy costs with and without the simulated technologies were calculated and compared.

Figure 13 shows the building load profiles on a Monday and Thursday. The graph shows the battery recharging between the hours of 12 a.m. and 5 a.m. The simulated microturbine supplied 60 kW to the building between 9 a.m. and 5 p.m. Between 6 a.m. and 10 a.m., and between 5 p.m. and 10 p.m., the virtual batteries supplied 50 kW to the building whenever the load exceeded 220 kW. The batteries helped reduce demand tremendously during the week. However, the building's HVAC system was also fully operational on the weekends (when the virtual batteries were turned off) at the request of UM staff members. Consequently, the building's maximum load reached values as high as 240 kW on weekends, even when supplemented with microturbine-generated power.

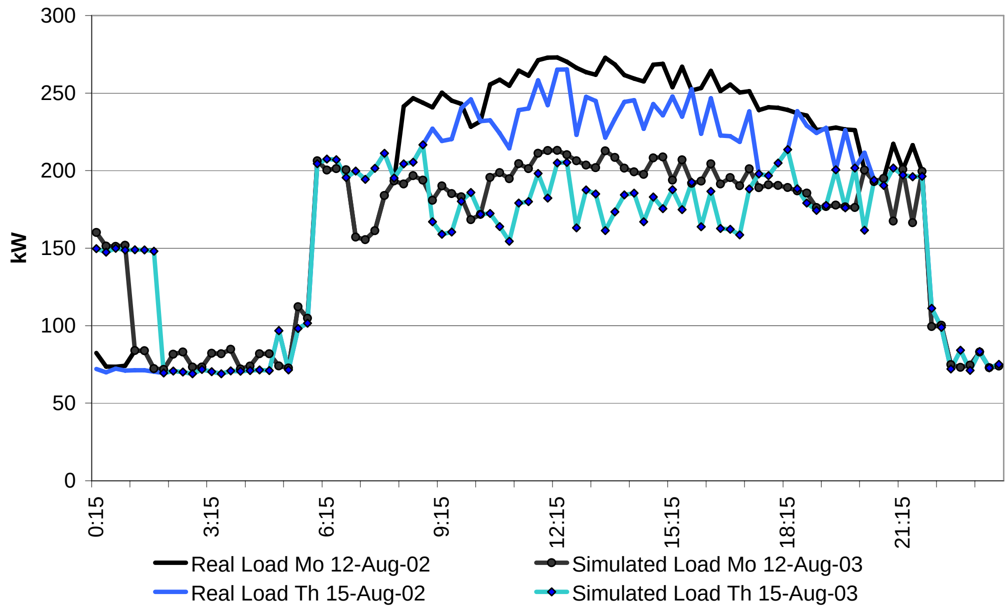


Figure 13. Chesapeake Building summer weekday load profiles.

Table 5 shows the peak load and the peak and off-peak kWh purchases for the Chesapeake Building during the demonstration period. During the demonstration, the building's CHP systems were not operating. The peak and off-peak energy purchases shown include the energy displaced by the microturbine, which is why they are lower than those for the winter demonstration even though the demand was greater. Each of the batteries displaced approximately the same peak energy. The difference in off-peak kWh purchases is explained by the variations in batteries recharge methods as explained earlier.

Table 5. Technical Comparison of Hybrid Technologies—July 29 to August 26, 2002

Microturbine +	Maximum Demand (kW)	Peak kWh Displaced by Battery	Peak kWh Purchases	Off-peak kWh Purchases
No Battery	273	0	36,265	64,757
Flooded	232	4,088	31,671	71,696
VRLA	228	4,200	32,064	70,854
Zn/Br	228	4,200	32,064	69,204

The economic comparison of the hybrid technologies in Table 6 shows the monthly savings that would result from augmenting the microturbine generation with a battery energy storage system. As in the winter demonstration, the Zn/Br battery yielded the greatest monthly savings. The VRLA and Zn/Br batteries showed the same demand-charge savings because they both reduced the highest peak to 228 kW. Energy cost savings varied in accordance with the off-peak kWh purchased and energy displaced. Again, the Zn/Br batteries, which do not require finish or trickle charging, showed the biggest savings.

Table 6. Monthly Savings of Simulated Hybrid Technologies—July 29 to August 26, 2002 ($/month)

Battery	Energy-charge Savings	Demand-charge Savings	Monthly Savings
Flooded	10	615	625
VRLA	29	670	699
Zn/Br	86	670	756

Analysis of Multiple Tariffs

In general, electric utilities use a combination of two sets of charges (or tariffs)–demand charges and energy charges–to determine a customer's monthly electric bill. In theory, demand charges represent a utility's fixed costs for providing a given level of power to a customer and energy charges represent the variable portion of the customer's electric bill (how much power was used). Demand charges are based on the maximum amount of power used during a given time period and are judged against a baseline that is considered the 'normal' use for customers of a given size (*i.e.,* load). Consequently, demand charges vary month to month based on the difference between the customer's peak use and their nominal (normal) use. The higher the peak use, the higher the demand charge. The more such demand peaks are reduced, the greater the monthly demand-charge savings that can be realized. Energy charges are based on the customer's total cumulative power use (the number of kW supplied) per month. Electric utilities can charge either a flat fee per kW used or can adopt a time-of-use (TOU) rate structure that charges customers more per kW for power supplied during peak demand times (*e.g.,* weekday afternoons in summer in hot locations such as southern California) and less for power supplied during off-peak hours (at night and/or on weekends, in the above example, when business use of air conditioning is generally reduced). Under such TOU rate structures, energy charges vary according to the number of peak and off-peak (and in some cases partial- or mid-peak) kWh purchased. Under such rate structures, the more peak power consumption that can be displaced by distributed generation and/or energy storage the greater the cost savings.[8]

Under virtually any circumstances, the rates that UM has negotiated with PEPCO are too low for on-site microturbine generation to be economically viable (especially for recharging the batteries during winter when electricity rates are cheap when compared to natural gas prices). Nevertheless, cost trade-offs among demand charges, various TOU energy charges, and natural gas prices could make a hybrid distributed generation/energy storage system a cost-effective option. Therefore, the rate structure thresholds required to make hybrid generation/storage technologies economically viable options were investigated.

Twenty different TOU tariffs for general service customers sized similarly to the Chesapeake Building (up to 500 kW demand) were identified. Three of these were selected as indicative of a representative range of tariffs. The simulator software was enhanced to handle the complexities of multiple utility tariffs and the two simulations were run again for each of the three identified utilities.

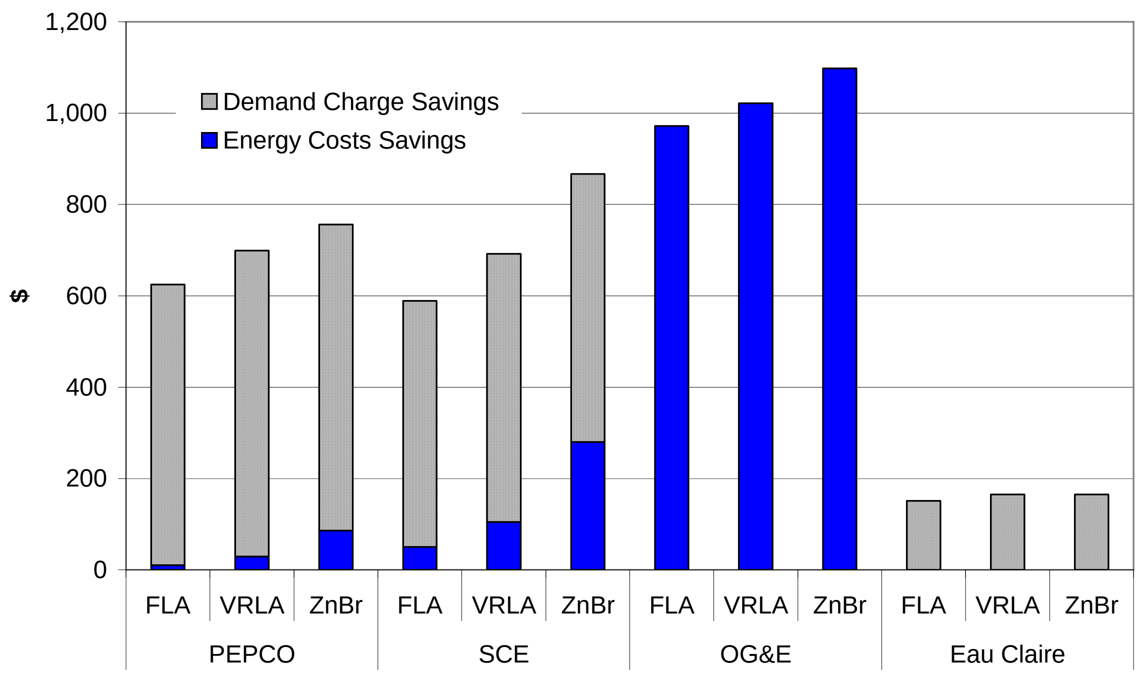
Table 7 shows the summer energy charges for the tariffs used in this analysis. The general-service/demand/TOU rate schedule for Southern California Edison (SCE) represents a rate structure with both high peak-demand and high peak-energy charges. The general service/TOU schedule for Oklahoma Gas & Electric (OG&E) was used as representative of a rate structure that has no demand charge but high peak-energy charges. Finally, the Large Power TOU schedule of Eau Claire Electric Co-op, in Wisconsin, was used to represent a rate structure with mid-range peak-demand charges and flat-fee energy charges (the fee varies from summer to winter, but not based on days of the week or hours of peak usage).

[8] Note: Each utility's rate structure (both for demand and energy charges) is defined by the utility itself and approved by the appropriate regulatory agency. Consequently, rate structures vary widely from utility to utility. The definitions provided are meant as a general clarification of the concepts on which these individual rate structures are based.

Table 7. Summer Electric Rates Used for the Multiple Tariffs Analysis

Rate	PEPCO	SCE	OG&E	Eau Claire
On-peak electric (¢/kWh)	5.76	17.88	30.97	4.20
Mid-peak electric (¢/kWh)	5.09	12.20	N/A	4.20
Off-peak electric (¢/kWh)	3.5	10.59	4.57	4.20
Peak demand charges ($/kW)	15.00	13.15	0.00	12.35

Figure 14 shows the potential energy- and demand-charge savings for a hybrid generation/storage system operating under these different utility rates. The savings were calculated assuming that the batteries were operated in the same way as in the summer demonstration under the PEPCO tariffs, because even the enhanced simulator programming did not allow for discharging the virtual batteries to correspond with more than one set of peak demand parameters. Consequently, Figure 14 provides only a general idea of the potential savings that can be realized from the hybrid technology.



FLA = Flooded Lead-acid Battery, VRLA = Valve-regulated Lead-acid Battery,
ZnBr = Zinc Bromine Battery

Figure 14. Hybrid technology savings under different summer tariffs.

The figure shows that OG&E, due to the high gap between its peak and off-peak energy prices, realized the biggest savings, even without any demand-charge savings. SCE obtained the second highest savings primarily due to its high demand charges and the noticeable difference between peak and off-peak energy charges. Eau Claire realized the smallest savings. No energy cost savings were realized because the rates at night when the batteries were recharged were as expensive as the daytime rates. Additionally, Eau Claire's rate structure yielded the smallest demand-charge savings because the batteries reduced the demand of the building at times when Eau Claire's demand charge was $3.70/kW; the $12.35/kW demand charge applied only between 5 p.m. and 9 p.m., times during which the batteries did not reduce the demand of the building.

Overall, the monthly summer savings in these four cases varied dramatically, from a low of $151 to a high of $1,098. The tariffs used by each utility yield very different results. For instance, there was almost no variation across technology choices (flooded lead-acid, VRLA, or Zn/Br) for Eau Claire because demand-charge savings were not affected by the different recharge profiles. Energy-charge savings, however, varied significantly especially for SCE. If the virtual batteries' discharge times had been programmed to correspond to each utility's specific peak use hours (see Table 8) and, consequently, to optimize the potential savings for each utility's TOU structure, it is expected that even more energy-charge savings would have been realized.

Table 8. Utilities' Peak and Mid-peak Hours for Summer 2002

Hours	PEPCO	SCE	OG&E	Eau Claire
On-peak	M-F 12 p.m. - 8 p.m.	M-F 12 p.m. - 6 p.m.	M-F 2 p.m. - 6 p.m.	M-F 5 p.m. - 9 p.m.
Mid-peak	M-F 8 a.m.-12 p.m. & 8 p.m.-11 p.m. excluding holidays	M-F 8 a.m.-12 p.m. & 6 p.m.-11 p.m. excluding holidays	N/A	N/A

Conclusions and Recommendations

The goal of this project was to determine whether a battery would be beneficial if added to the microturbine/CHP systems already installed at University of Maryland's Chesapeake Building. The scope of this study was to evaluate the technical and economic benefits of the various BES technologies on a monthly basis. **The demonstrations show that any of the three battery technologies investigated, when used in hybrid with microturbine generation, can reduce the Chesapeake Building's monthly electricity bill by a minimum of $600 per month during the summer.** When other utility rates were considered, the monthly savings varied significantly from one utility to another. In most cases, the savings grew as a function of the gap between peak and off-peak electricity rates. Consequently, Zn/Br batteries, because of the way that they are recharged, are somewhat favored when there is a difference between peak and off-peak electricity charges.

A detailed evaluation of the capital and O&M costs of the systems was not within the scope of this study. Nevertheless, these costs and the average calendar life of the systems would be significant and relevant to any commercial installations of BES in a hybrid environment. In general, the discounted payback time calculations showed an average of 10 years to repay the technology costs at UM's current utility rates and 7 years to payback with OG&E rates. Additionally, while on a strict monthly savings basis the Zn/Br technology yields the highest savings, it must be remembered that because it is still an emerging technology, the capital cost of a Zn/Br BES is twice that of the two lead-acid technologies. Therefore, additional analysis is recommended that considers capital and O&M costs in addition to monthly electric bill savings.

Ideally, further studies in this area would incorporate actual (rather than simulated) microturbine generation and more specifically analyze the benefits to be gained with the addition of the storage component as compared to those provided by distributed generation alone. It might also be useful to determine for what rate structure(s) (if any) it would be cost-effective to recharge the batteries from the microturbine instead of from off-peak energy purchases.

Finally, in addition to cost savings for electricity customers, it should be remembered that both distributed generation and energy storage technologies offer other important benefits. They can play an important role in supporting the country's existing electricity infrastructure, provide a means of deferring transmission and distribution (T&D) costs for electric utilities, and help to conserve fossil fuel resources.

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