2015

Modeling and Analysis of UVM's Campus Energy System with Energy Hubs

Micah Botkin-Levy
mbotkinl@uvm.edu

Follow this and additional works at: http://scholarworks.uvm.edu/hcoltheses

Recommended Citation

This Honors College Thesis is brought to you for free and open access by the Undergraduate Theses at ScholarWorks @ UVM. It has been accepted for inclusion in UVM Honors College Senior Theses by an authorized administrator of ScholarWorks @ UVM. For more information, please contact donna.omalley@uvm.edu.
Modeling and Analysis of UVM’s Campus Energy System with Energy Hubs

Micah Botkin-Levy
University of Vermont
May 2015

Mentor: Prof. Mads Almassalkhi

Committee Members: Prof. Walter Varhue, Prof. Paul Hines
# Contents

Abstract ................................................................................................................................. 2  
Introduction and Motivation ................................................................................................. 3  
Literature Review/Background .............................................................................................. 5  
    UVM’s Campus Energy System ......................................................................................... 7  
Hypothesis & Objectives ....................................................................................................... 9  
Methodology .......................................................................................................................... 10  
    Assumptions and System Calculations .......................................................................... 11  
Results .................................................................................................................................. 19  
    Current UVM Energy System ....................................................................................... 19  
    System with Electric Chiller and Storage: .................................................................... 23  
    System with CHP ............................................................................................................ 26  
    System with Electric Chiller, Chilled Water Storage, and Combined Heat and Power Units .................................................................................................................. 30  
Analysis and Discussion ....................................................................................................... 32  
    Cost Summary ............................................................................................................... 32  
    Detailed Simulation Cost Analysis .................................................................................. 33  
    Demand Charges Analysis .............................................................................................. 40  
    Simple Payback Period Analysis ................................................................................... 42  
Conclusions ........................................................................................................................... 45  
Future Work .......................................................................................................................... 47  
References ............................................................................................................................. 48
Abstract

Due to the aging power system, increase in energy demand, dependency on limited fossil resources, and climate change there is significant need in the future for a restructured power system. It is essential for the new power grid to bring together the concepts of distributed micro grids as well as synergy between multiple energy carriers to increase the reliability and economics of the system. One way to model the new network is to use the idea of an energy hub where a local system contains distributed and renewable generation and integrated multi-carrier energy sources. The benefits of utilizing the energy hub as a modeling framework include reduced energy prices and demand for consumers as well as reduced peak demand for the local distribution companies. This project models and analyzes the UVM’s campus energy system using energy hubs and Matlab simulations, which together form the energy tool called “Hubert”. Various what-if simulations with modification to the current system are run in Hubert to find ways to increase energy efficiency and reduce the associated cost of the UVM energy system.

The three main modifications to the current system which are simulated are the addition of an electric chiller, a combined heat and power generator, and a chilled water thermal energy storage tank. The total cost of generation for the current UVM energy system was simulated to be $37,361.01 for a winter day and $23,717.62 for a summer day. The system with an electric chiller and chilled water storage saw a savings of $365 for the summer simulation but no saving for the winter since there is no cooling load. The payback period analysis on this system showed that it would take 31.45 years to pay off the assets. When the system with a cogeneration unit is compared with the current UVM system the savings are $18,748.70 for the winter simulation and $11,633.30 for the summer simulation. The payback period analysis on this system showed that it would take 3.57 years to pay off the new CHP unit. Finally if all three new assets are installed the savings would be $18,748.70 for the winter and $13,300.00 for the summer. The payback period analysis on this system showed that it would take 3.79 years to pay off the assets.

Demand charges were added to the daily cost of generation by averaging the estimated monthly on-peak and off-peak electric peaks over the appropriate hours. Calculations found that current UVM’s cost of generation with demand costs raised the costs to $53,240.05 and $43,234.18 for winter and summer days, respectively. For the system with the CHP unit, the summer daily cost of generation with demand charges is $19,526.90, however, this cost spiked up to $20,685.15 or $30,442.60 if the CHP unit failed during off-peak or on-peak hours, respectively.
Introduction and Motivation

The electric power system forms the back-bone of our modern society and supports almost every avenue in industry, service, and security. However, due to the aging power system, increase in demand, climate change, and our dependency on limited fossil fuel resources it is unclear whether our current system will be able to meet the needs of our society in the future. The majority of the current energy infrastructure was built over the course of the second half of the twentieth century [4] As a result, many components of the system are reaching their life expectancy. In addition, the continuous growth in demand for energy is often a strain on the transmission system of yesterday and causes system congestion. Climate change and the scarcity of non-renewable fossil fuels also are motivation for changes in the system. Many system planners are trying to build new plants and new transmission lines but it is possible that piecemeal changes in the system might not be enough. A full restructuring of the power system may be necessary in order to incorporate distributed and renewable power generation, increases in real-time data and communication, and a more integrated and responsive network.

One version of a restructured power industry would be able to produce and deliver energy locally. It would also take full advantage of opportunities for co-generation and tri-generation. It would have more interconnected scheduling of different energy carriers. Each of the network nodes would have the ability or the potential to store, convert and produce energy. This replaces the current nodes, such as substations, that are mostly passive nodes only relaying and potentially converting energy.

The concept of an energy hub is one useful method of modeling and analyzing the restructuring of the power grid. An energy hub is a system where multiple energy carriers can be produced, conditioned, and stored. It often utilizes co-generation to increase energy efficiency by exploiting coupling between the production, transmission, and consumption of energy. The inherent flexibility of the energy hub model has allowed it to incorporate dynamic price signals and demand changes. The system that is being modeled can contain multiple production facilities, storage units, converters, and loads. By interconnecting energy hubs from the output of one to the input of the next a new power grid can be created that is energy-efficient, reliable and dynamic.

An example of a campus modeled as an energy hub is shown in Figure 1. Where C is a chiller system, B is a boiler system with absorption chillers, Cogen is a cogeneration natural gas turbine unit, T is a heat-recovery-enabled transformer, and TES is thermal energy storage. The inputs to this system are natural gas and electricity, which satisfy the cooling, heating, and electricity loads. The natural gas is either converted to steam by the boiler or used in the cogeneration unit to create both electricity and steam. The electricity is either converted by the transformer from HV to LV for use or used to power the chiller to meet the cooling load.

Figure 1: Example of a 2-input/3-output energy hub system [1]
The energy hub system benefits from the synergy amongst multiple energy carriers. By optimizing the scheduling of different energy sources, an energy hub can take advantage of the unique characteristics that each one has. For example, the low transportation losses for electricity or the easy storability of natural gas and thermal energy. Energy hubs are also considered to have the advantages of generality, scalability and modularity [7]. These benefits result in positive returns for both the power grid customers as well as the local distribution companies. The correct optimization of an energy hub can result in savings in energy prices and demand charges for customers as well as reduce peak demand for the local distribution companies. For an energy hub to be effective it must have the proper conversion processes and it is important to study the right system configuration before an energy hub system is realized.

There are many benefits to performing modeling and optimization analysis on the UVM energy system. If the results of the analysis are substantial it could influence the physical plant to purchase new assets or change how they monitor and control the system. This could potentially lead to significant decreases in costs from decreased electricity purchases or due to increases in efficiencies.
The idea of an energy hub adds more dimensions to the already complicated and difficult to solve equations related to the power system. The basic system optimization question of an established energy hub is to find the optimal quantities of each energy carrier the energy hub should consume and how they should be converted to meet loads. An example of this would be to avoid consuming expensive electrical energy during peak hours by using a microturbine instead. The optimal energy hub dispatch will lead to decreases in cost, losses, and emissions.

Geidl and Andersson present a power flow and optimization technique for distributed systems that use multiple energy carriers without storage in [5]. They focus on a general method that explicitly models the couplings between power flows of different energy sources. Using the hybrid energy hub concept defined as the “interface between power producers, consumers, and the transportation infrastructure”, they created a model that includes the power flow within and between hubs. To model the power flow within each energy hub they used the matrix equation

\[ L_{in} = C_{imn}P_{im} \]

Where L and P are vectors with length of the number of energy carriers and C is the forward coupling matrix that describes the conversion of power between input m and output n. For the network power flow for carrier \( \alpha \), the exchange of power between energy hubs can be modeled with the matrix equation

\[ A_{\alpha}F_{\alpha} = P_{\alpha} \]

Where A is the connectivity matrix, F is the line flows, and P includes all hub inputs of the carrier \( \alpha \). To find the optimal power flow, the paper makes a few assumptions including the cost of energy carriers are independent of each other and converters operate with constant efficiencies. The paper aims at minimizes total energy cost for the whole system. The work in this paper establishes a model for the optimization of coupled power flows of different energy carriers. This work sets the building blocks for more research and work in this area.

The researchers in [3], *Model-based predictive control applied to multi-carrier energy systems*, took the energy hub concept a step further and included energy storage and focused their paper on the model-based predictive control of multi-carrier energy systems. The addition of storage components with dynamic behavior required the optimization to occur over multiple time steps. The paper used the model predictive control to predict the behavior of individual energy hubs. In the system described in the paper, the control of the system is performed by a supervisory, central controller that defines the set points of all energy generation units. The ideas in this paper are important because they utilize storage components and their optimization framework can take into account forecasts of energy prices, demand profiles and operational constraints.

A group of researchers, [8], published a paper that created a procedure for minimizing the operating costs of a combined cooling, heating, and power plant (CCHP) at the University of California, Irvine using modeling and optimization. The multi-energy facilities were modeled as an energy hub with natural gas, solar energy, and electrical power supplies as the inputs that fed electric, heat, and cooling loads of the campus. The energy system utilized co-generation as well as thermal energy storage. The group used reduced-order
modeling and an optimization framework with a 24-hour look-ahead period to analyze the system. They found that the use of optimization software with the co-generation and storage ability was able to increase the efficiency and decrease the cost of operation. In their case study they compared the optimization approach to two baseline studies and saw an 8.5% improvement in the operating cost.

In [2], the authors published a paper in 2011 called *Optimization Framework for the Analysis of Large-scale Networks of Energy Hubs* that presented a tool for designing, modeling, and analyzing general energy hub networks. The tool is called *Hubert* and implements a hybrid energy hub model (with continuous and discrete states), which was fully described by a concise ASCII format to enable efficient Matlab simulations. The model controls conversion, generation, and energy storage processes and constructs an energy hub around 5 building blocks: inputs sources, input storage, converters, output storage, and output sources. The basic equation that is used to perform the simulation is:

\[ L_h = C_h P_h - S_h Q_h \]

Where C is the converter coupling matrix, S is the input storage coupling matrix, P is the input flow, Q is the storage flow, and L is the output flow. However, they create a set of mixed-integer linear equations to model any energy hub ‘h’. The ASCII-based format makes for easy Matlab interface. It includes a header that describes the number of hubs and networks as well as the number of time-intervals. The system is then described using four matrices: the input storage coupling matrix, output storage coupling matrix, dispatch flow matrix, and the converter coupling matrix which are constant parameters. In their simulations they found the use of storage to produce an overall saving of 5% as compared to the same system without storage. This project will leverage the flexibility of Hubert to perform modeling and analysis of UVM’s campus energy system.
University of Vermont operates the UVM Physical Plant which uses a centralized steam and chilled water plant and an electric network to meet the electric, steam, and cooling loads of the university. A simplified diagram of the system can be seen in Figure 2. Five boilers and two steam-driven chillers produce pressurized steam and chilled water which are distributed to buildings through underground pipes. The boilers are dual-fuel meaning they can run on natural gas or #2 fuel oil. The steam is generated at 220 psi and 398°F and the five boilers have a maximum combined capacity of 224,500 lbs/hr. The chilled water is generated at 42°F and a maximum pressure of 100 psi and has a maximum cooling capacity of 2730 refrigeration tons. In addition, there is 1.1 MW back-up generator that runs on diesel onsite. The decisions of which assets to be turned on is controlled by the UVM Physical Plant staff based on the current system needs, costs, and extensive operator experience. [9]

Burlington Electric (BED) sets the electricity rates for the University’s electric power. Each building on campus has its own BED meter and therefore falls under its own rate structure. The breakdown of the accounts throughout the University are summarized in Table 1.
Table 1: Summary of UVM’s Electric Accounts Rate Classifications [9]

<table>
<thead>
<tr>
<th>Rate Classification</th>
<th>Number of Accounts</th>
</tr>
</thead>
<tbody>
<tr>
<td>Primary Service</td>
<td>5</td>
</tr>
<tr>
<td>Large General Service &lt; 25 kW</td>
<td>19</td>
</tr>
<tr>
<td>Large General Service &gt; 25 kW</td>
<td>35</td>
</tr>
<tr>
<td>Small General Service</td>
<td>40</td>
</tr>
<tr>
<td>Residential Service</td>
<td>3</td>
</tr>
<tr>
<td>Total Accounts</td>
<td>102</td>
</tr>
</tbody>
</table>

Each classification has its own customer charge, energy rate, as well as some having additional demand charges. This makes modeling the total electricity rate structure very difficult.

Demand charges are monthly costs that are added in addition to the energy (kWh) costs that are paid to BED. These are assigned according to the peak electric demand and are $/kW rates. Burlington Electric defines their demand charges in the following:

“Demand charge is based on the greater of the current month’s demand or 50% of the highest summer month’s demand (June through September) occurring within the preceding 11 months”. [10]

According to the UVM Physical Plant, approximately 33% of their electricity costs can be from demand charges [19].

Vermont Gas supplies the University of Vermont with its natural gas needs that supply many buildings on campus. For the purpose of this study, only the natural gas that is provided to the UVM Central Heating Plant which is used in the boilers is considered and the rest of the natural gas that is used in the other buildings for cooking or natural gas fireplaces is ignored. The Central Heating Plant is on an interruptible rate classification. This means that if called upon they have 2 hours to switch over to fuel oil instead of natural gas. The rate structure for the interruptible is dynamic and set by a combination of market price and a fixed price. According to the UVM Physical Plant, these combination ranges from 90% fixed and 10% market pricing to 50% of each in the winter and summer, respectively. [9]
Hypothesis & Objectives

The first objective of this paper is to model the UVM campus system with energy hubs. The model is based on physical data from the energy components and schematics of energy system. The remainder of the paper is focused on setting up and performing energy hub simulations and analyzing the results. These simulations are designed to test how the efficiency and cost of operations of the UVM’s campus energy system can be improved. The following systems are modeled, simulated, and compared with a base case that is the current UVM’s campus energy system:

- System with Summer Load Profiles
- System with Winter Load Profiles
- System with Electric Chiller and Chilled Water Storage
- System with a Combined Heat and Power Generator

From the results, the optimal energy hub dispatch of each energy carrier will be discovered. The analysis of the simulations can show how energy and cost can be save which leads to suggestions of how the UVM physical plant can most efficiently satisfy their annual electric, heating, and cooling loads. A better sense of the optimal dispatch may save the university on cost and energy.
Methodology

The first step of the project is gaining knowledge and understanding of the current UVM system and existing Matlab code. This involved trips to the UVM physical plant, visiting with operators and managers, obtaining schematics and outlining the current blackbox diagram of the system (seen in Figure 10). The important assets and components of the energy system are identified and related efficiencies are calculated below. Considerable time was necessary to become familiarized with the Matlab code that was built previously by Prof. Almassalkhi to take an energy system and run the Gurobi optimization software. Next, for each energy system a txt file that describes the system components is constructed. The configuration file for the current UVM energy system is shown in Figure 3. Once this is completed, the specialized simulations are designed and ran for each system modification. Each simulation needs a specific system configuration as described by the configuration file based on the physical energy system that will be manually created. Lastly, the simulation results are compared with the baseline case and analyzed. Important factors to consider will be total energy input and total cost.

```
SYS 2 5 24
H 1 6 2 2
(1,1) d(1,5) c(1,0.83) (4,1)
(1,1) d(2,5) c(1,0.83) (4,1)
(1,1) d(3,5) c(1,0.83) (4,1)
(1,1) d(4,5) c(1,0.83) (4,1)
(1,1) d(5,5) c(1,0.83) (4,1)
(2,1) d(1,1) c(1,0.95) (3,1)
H 2 2 1 1
(4,1) d(1,2) c(1,1.263) (5,1)
(4,3) d(2,2) c(1,1.263) (5,1)
```

```
%Network 1 = natural gas
IC 1 1 1 0 1 0 0
Generators
1 lim(0,1000) (C1_gen2)

%Network 2 = HV electricity
IC 2 2 1 0 1 0 0
Generators
1 lim(0,1000) (C1_gen1)

%Network 3 = LV electricity
IC 3 2 1 0 0 1 0
Loads
1 lim(0,D1_load1)

%Network 4 = heating
IC 4 1 1 0 0 1 0
Loads
1 lim(0,D1_load2)

%Network 5 = cooling
IC 5 1 1 0 0 1 0
Loads
1 lim(0,D2_load1)

END
```

Figure 3: Hubert configuration ASCII file for the Current UVM System
Assumptions and System Calculations

General System Assumptions:

The following per unit system is used based on the electricity load peaks.

Per unit power base: 10MW
Per unit energy base: 10MWh
Per unit monetary base: $1,000

For the all of the simulations, some assumptions about the system were made to make the modeling and analysis easier. First, the system in Figure 2 has been simplified from the actual UVM energy system. In reality each building on campus has its own meter, however for the simulation the electrical network is simplified to one high voltage line to a transformer which is then satisfying one electric load. In addition the steam and cooling loads on campus have been reduced to only those which are satisfied by the steam and chilled water that is produced in the UVM Physical Plant. Second, there are a few simplifications that the code makes. The code does not implement any upper capacity production limits on the converters as there are in real components. Also, the converter efficiencies are constant values which are independent of the current percent production of nameplate capacity. In reality, the efficiency of most energy converters decreases as the production decreases from its maximum. This means in the code the converter can produce anywhere from 0 to infinite energy at the same efficiency.

Cost of Generation:

Electricity:

A combined approach is used to estimate the electricity costs that the university pays due to the complex Burlington Electric price rates. A Time-Of-Use rate for large general services as described in Table 2 is used for the on-peak hours for summer and winter. For the off-peak hours, an average electricity cost is used which was found using a weighted average of energy rate by kWh in March 2015 [9].

Average electricity cost: $0.0792/kWh

\[
\frac{0.0792 \text{ (} 1000 \text{ kWh})}{1 \text{ e. u.}} \left( \frac{1 \text{ m. u.}}{1 \text{ e. u.}} \right) = \frac{0.792 \text{ m. u.}}{1 \text{ e. u.}}
\]

These were increased to the Summer On-Peak and Winter On-Peak values for the times and rates shown in Table 2.
Table 2: Burlington Electric Time-of-Use rates for Large General Service

<table>
<thead>
<tr>
<th></th>
<th>On-Peak Rate ($/kWh)</th>
<th>On-Peak Months</th>
<th>On-Peak Hours</th>
</tr>
</thead>
<tbody>
<tr>
<td>Winter</td>
<td>0.115459</td>
<td>December-March</td>
<td>6:01 AM – 10:00 PM</td>
</tr>
<tr>
<td>Summer</td>
<td>0.107754</td>
<td>June-September</td>
<td>12:01 PM – 6:00 PM</td>
</tr>
</tbody>
</table>

Burlington Electric has set its winter on-peak rate higher than its summer on-peak rate. One possible reason for this is due to the fact that the summer electrical peak is higher than the electrical peak in the winter. Burlington Electric might have to use higher on-peak rates in the winter since there is less energy being bought to make it profitable.

**Natural gas:**

The natural gas cost used is from the General Service High Usage, High Load Factor on the Vermont Gas website [16] and is a flat rate for all hours of the day.

Natural Gas cost: $0.5203/Ccf

2014 average heat content of natural gas: 1 Ccf = 102,800 Btu [21]

\[
\frac{0.5203}{Ccf} \left( \frac{1 \text{ Ccf}}{102,800 \text{ Btu}} \right) \left( \frac{1,000,000 \text{ Btu}}{1 \text{ MMBtu}} \right) = \frac{5.06}{\text{MMBtu}}
\]

\[
\frac{5.06}{\text{MMBtu}} \left( \frac{1 \text{ MMBtu}}{293.07 \text{kWh}} \right) \left( \frac{10,000 \text{kWh}}{1 \text{ m.u.}} \right) \left( \frac{1 \text{ m.u.}}{1 \text{ e. u.}} \right) \left( \frac{1 \text{ $/1000}}{\text{MMBtu}} \right) = \left( \frac{0.1727 \text{ m.u.}}{\text{e. u.}} \right)
\]

The cost of generation curves for a summer and winter day are shown in Figure 4 and Figure 5.
Load Profiles:

Since the demand for energy can change so drastically depending on the season it is worthwhile to consider simulations with winter and summer load profiles.

Electricity:

The electricity load profiles were created from observations of past electricity loads from UVM Physical Plant data. The average daily peak for a weekday is around 13500 kW and the base load for the university is around 5000 kW. According to the UVM Physical Plant [19], the summer electric peak load is higher than the winter peak load. However, the winter electricity load in New England is usually at higher levels for more of the day during the day time due to heating demand. Figure 6 was created from this information and shows the summer and winter electric load profiles.
Heating and Cooling Load Profiles:

The heating and cooling load profiles were calculated using a combination of boiler and chiller data and temperature data for Burlington, VT. The correlation between wet bulb temperature and the demand for heating and cooling was taken from the work of fellow EE undergraduate student Anna Towle. The summer and winter wet bulb temperatures were taken for two specific days for Burlington, VT (Data collected from MesoWest.utah.edu).

Heating:

UVM Physical Plant operates steam at 220PSI and 398°F. Using a Mollier diagram the conversion between BTUs and pounds of steam is approximately 1200BTU= 1 lb steam. However, the feedwater to the boiler has approximately 250 BTU per pound. Therefore, a change in energy of 950 BTU is needed to produce 1 pound of steam.

For wet bulb temperatures over 65°F:

$$1.5767T_w - 79.4148 = H [KPH]$$

For wet bulb temperatures under 65°F:

$$-1.0503T_w + 97.0859 = H [KPH]$$

where $T_w$ is the wet bulb temperature and $H$ is the heat demand or power in the steam.

$$H[KPH] = 1000 \times H \left[ \frac{lbs}{hr} \right] \left( \frac{950 Btu}{1lbs} \right) = H \left[ \frac{Btu}{hr} \right]$$
\[ \frac{H}{[\text{Btu/hr}]} \left( \frac{1 \text{W}}{3412.14 \text{ Btu/hr}} \right) \left( \frac{p.u.}{10000 \text{kW}} \right) = H[p.u.] \]

**Cooling:**

For wet bulb temperatures above 45°F:

\[-0.001073T_w^4 + 0.23596T_w^3 - 17.36T_w^2 + 540.5189T_w - 6064.1745 = C[RT]\]

For wet bulb temperatures under 45°F the cooling load is approximately 0.

\[C[RT] \left( \frac{3.5168525kW}{1 RT} \right) \left( \frac{p.u.}{10000kW} \right) = C[p.u.]\]

where \(T_w\) is the wet bulb temperature and \(C\) is the power in the chilled water.

Figure 7 and Figure 8 show the predicted heating and cooling loads for a summer and winter day in 2014.
As shown in Figure 8, there is no cooling load for a winter day. By running water through pipes that are exposed to the outside air when the temperatures are under 45°F the plant cannot offset any cooling energy demand.

**Converter Efficiencies:**

**Boiler Efficiency:** 83% [18]

Although there are five boilers and in reality the efficiency of each would be slightly different, in the simulations they are all set at an equal efficiency. The reason behind this is due to that fact that the current code does not implement any upper generation limits on the boilers. Therefore, the system would automatically generated all the needed steam through the lowest efficiency boiler without turning on the other boilers which is not realistic.

**Steam Driven Chiller Efficiency:**

Assume an input of 9500 Btu/hr:

\[
\text{Input} = 9500 \frac{Btu}{hr} \left( \frac{1kW}{3412.14 Btu/hr} \right) = 2.784kW
\]

Assume 10 pph of steam into chiller gives 1 ton, then at a steam enthalpy of 950 Btu/lbm:
\[ \text{Output} = \frac{9500\text{Btu}}{\text{hr}} \left( \frac{1\text{lbm}}{950\text{Btu}} \right) \left( \frac{1\text{ton}}{10\text{lbm/hr}} \right) = 1\text{ ton} \]

\[ \text{Output} = 1\text{ton} \left( \frac{12000\text{Btu}}{\text{hr}} \right) \left( \frac{1\text{kw}}{3412.14\text{Btu/hr}} \right) = 3.517\text{kw} \]

\[ \text{Efficiency} = \frac{\text{Output}}{\text{Input}} = \frac{3.517}{2.784} = 126.3\% \]

The chiller efficiency is greater than 100% since they meet the cooling load by moving heat around instead of creating it. A chiller removes heat from a liquid via a vapor-compression or absorption refrigeration cycle. This liquid is then circulated through a heat exchanger. The efficiency of the chiller can exceed 100% since the chillers are solely consuming energy to be a transporter of a great quantity of energy.

Transformer efficiency: 95%

A conservative estimate is used as a representation of the distribution transformer efficiency and the electrical network losses. [13]

Electric Chiller Efficiency:

Assume 0.5 kW gives 1 ton, then:

\[ \text{Output} = 1\text{ton} \left( \frac{12000\text{Btu}}{\text{hr}} \right) \left( \frac{1\text{kw}}{3412.14\text{Btu/hr}} \right) = 3.517\text{kw} \]

\[ \text{Efficiency} = \frac{\text{Output}}{\text{Input}} = \frac{3.517\text{kw}}{0.5\text{ kw}} = 703.4\% \]

Chilled Water Storage Efficiency:

Charging Efficiency: 99%
Discharging Efficiency: 95% [17]
Chilled Water Storage Capacity:

The capacity of the thermal energy storage was calculated based on the Cooling Load for a summer day seen in Figure 9. The peak cooling demand is around 2 PM but the peak hours are between 10 AM and 6 PM.

Total hourly load over peak hours: 3.7711 e.u.

\[
3.7711 \text{ e.u.} \left(\frac{10,000 \text{ kWh}}{1 \text{ e.u.}}\right) \left(\frac{1 \text{ ton - hr}}{3.516 \text{ kWh}}\right) = 10,725.5 \text{ ton - hrs}
\]

Peak capacity + 10% buffer = 12000 ton-hr = 4.22 e.u

Storage Ramping Limits:

The storage ramping limit sets a maximum energy that can be stored in the thermal energy storage during any single time interval. This parameter is set in Hubert to assure the limit is followed in the simulation.

Assume a ramping limit of 0.5 p.u. per time stamp (1 hour):

\[
Q_{\text{ramping}} = 0.5 \text{ p.u.} \left(\frac{10,000 \text{ kW}}{\text{p.u.}}\right) \left(\frac{1 \text{ tons}}{3.5168525 \text{ kW}}\right) = 1421.73 \text{ tons}
\]

This is a reasonable allowed limit and could offset the production of about one steam driven chiller.

CHP Efficiencies:

Assumed efficiencies of combined heat and power generator:

Electric Efficiency: 35%

Steam Efficiency: 45% [14]
Results

The following sections shows the results of the simulations ran for the current UVM system as well as each modified system. The results will show the cost breakdown and the power and energy summary for each system.

Current UVM Energy System

![UVM Energy System Diagram](Image)

**Figure 10: UVM Energy System Diagram**

Results:

**Summer Day:**

Total Cost for Summer Day: $23,717.62

The plot in Figure 11 shows the total cost of generation at each time interval. The baseline cost is around 0.7 m.u. per hour. However, this price spikes up to 1.7 m.u. per hour at peak hours due to the on-peak electricity pricing and load profiles.
The top graph in Figure 12 displays the power that inserted into the hub at each time interval and the bottom graph shows the power that is used at each time interval by the three loads.
Figure 13: Sankey Diagrams of Energy and Cost Flows

Seen in Figure 13 are two Sankey Diagrams. Sankey diagrams are a depiction of flow where the width of the arrows are proportional to the flow quantity. On the left side of each diagram are the input arrows and on the right are the output arrows. The left Sankey diagram shows the energy flow where the one on the right show the flow of the costs of energy. As seen in Figure 13, the electricity is only 35.9% of the energy input but takes up 74.8% of the costs. This represents a large cost to energy usage disparity.

**Winter Day:**

Total Cost for Winter Day: $37,361.01
Figure 14 shows the total cost of generation at each time interval. The baseline cost is around 1 m.u. per hour but increases to over 2 m.u. during the peak. The two Sankey diagrams below summarize the energy flow and the energy costs over the whole day. Similar to the summer simulation the natural gas is a large portion of the energy usage but electricity is the majority of the costs.

![Sankey Diagrams](image)

Figure 15: Sankey Diagrams of Energy and Costs Flows

With a daily summer cost of $23,717.62 and a daily winter cost of $37,361.01 the total annual energy budget is estimated to currently be:

\[
(182 \text{ summer days} \times $23,717.62) + (183 \text{ winter days} \times $37,361.01) = $1.12 \text{ M}
\]

For a large energy system, this is a realistic energy budget for the University. In the latest data found online the estimate energy cost for the University of Vermont for 2006 was $13-15 Million [12]. This includes fuel oils, natural gas, water and electric for the whole campus so $1.1 Million is realistic for the UVM Physical Plant energy costs.
System with Electric Chiller and Storage:

The system shown in Figure 16 is the same as UVM’s current system except an electric chiller is added as another option to meet the cooling demand. A chilled water storage is also added downstream of the chillers.

Results:

Summer Day:

Total cost for summer day: $23,352.56
Figure 17 represents the total cost of generation at each time interval.

There are three different plots in Figure 18. The top (a) shows the power that is inserted into the hub at each time interval and the middle graph (b) shows the power that is used at each time interval by the three loads. The bottom plot (c) shows the total energy that is being stored in the chilled water storage at any given time interval. As shown the storage is charged during the morning when the demand and electricity prices are low up to about 3 p.u. and then discharges in the afternoon. The two Sankey diagrams in Figure 19 summarize the energy flow and the energy costs over the whole day.
Winter Day:

Total cost for winter day: $37,361.01

Since there was no cooling load for the winter day, the added electric chiller and thermal energy storage has no effect on the system and therefore the total cost remains the same.
System with CHP

The system shown in Figure 20 is the UVM’s current system except with an added cogeneration or combined heat and power unit. The CHP converter block in the diagram is really two separate components. The first is a turbine which is able to produce electricity through the use of natural gas fuel. The second is a heat recover unit which uses the heat energy in the exhaust gases of the turbine and creates steam.

Results:

Summer Day:

Total cost for summer day: $12,084.29
Figure 21 shows the total cost of generation at each time interval. The baseline cost is around 0.35 m.u. per hour but increases to over 1 m.u. during the peak.

![Figure 21: Hourly Costs for Summer Day](image)

The top graph in Figure 22 displays the power that inserted into the hub at each time interval and the bottom graph shows the power that is used at each time interval by the three loads. Compared the power injected in the current UVM system the HV Elec is much less. The two Sankey diagrams in Figure 23 summarize the energy flow and the energy costs over the whole day. For both the natural gas is the main component of the input.
Winter Day:

Total cost for winter day: $18,612.27

Figure 23: Sankey Diagrams for Energy and Cost Flows

Figure 24: Hourly Costs for Winter Day
Figure 24 shows the cost of generation per time interval in the simulation. It is different than the hourly cost curves seen so far since there is really no peak and the cost stay around 0.8 m.u./hour for the whole day. The reason for this is that there is no HV electricity injected into the system which is shown in Figure 25 and Figure 26.

Figure 25: Summary of Power in CHP System for Winter Day

Figure 26: Sankey Diagram of Energy Flow
System with Electric Chiller, Chilled Water Storage, and Combined Heat and Power Units

The last system seen in Figure 27 includes all three units: electric chiller, combined heat and power unit, and thermal energy storage.

![Diagram](image)

**Figure 27: UVM Energy System with added Electric Chiller, Combined Heat and Power, and Chilled Water Storage**

**Summer Day:**

Total cost for summer day: $10,417.59
Figure 28 shows the total cost of generation at each time interval. The baseline cost is around 0.35 m.u. per hour and increases to just over 0.8 m.u. during the peak. There are three different plots in Figure 29. The top (a) shows the power that is inserted into the hub at each time interval and the middle graph shows the power that is used at each time interval by the three loads. The bottom plot (c) shows the total energy that is being stored in the chilled water storage at any given time interval. As shown the storage is charged during the day up to just under 3 p.u. and then discharges in the late night time hours.

Winter Day:

Total cost for winter day: $18,612.27

The addition of the electric chiller and thermal energy storage did not have any effect of the system with the CHP since there was no cooling load in the winter. See the plots for the system with CHP for a winter day.
Analysis and Discussion

This section will go into detail about the findings in the results section. First, a comparison between the different simulations will be looked at followed by an in-depth analysis of each simulation. Also, there is a demand charge analysis and a payoff period analysis.

Cost Summary

The summary of the total cost of generation for the eight major simulations are shown in Table 3. The greatest savings are from installing the cogeneration unit. Also, for both seasons according to these simulations the complete system modification which includes cogeneration, electric chiller, and thermal energy storage would cut the cost of generation in half.

Table 3: Summer and Winter Cost Summary for Eight Simulations

<table>
<thead>
<tr>
<th></th>
<th>Total Cost of Winter Day ($)</th>
<th>Total Cost of Summer Day ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current UVM System</td>
<td>37,361.01</td>
<td>23,717.62</td>
</tr>
<tr>
<td>System with Electric Chiller and Chilled Water Storage</td>
<td>37,361.01</td>
<td>23,352.56</td>
</tr>
<tr>
<td>System with CHP</td>
<td>18,612.27</td>
<td>12,084.29</td>
</tr>
<tr>
<td>System with CHP, Electric Chiller, and Chilled Water Storage</td>
<td>18,612.27</td>
<td>10,417.59</td>
</tr>
</tbody>
</table>

Table 4 breaks down this total cost of generation by the fuel type. Table 5 shows the energy breakdown of each simulation by fuel type. In the current system, the majority of the energy costs comes from electricity which contradicts that most of the energy is provided by natural gas. With the implementation of the combined heat and gas unit these two isolated systems are interfaced and the cost and energy percentages are more balanced.

Table 4: Cost Percentages for Eight Simulations by Fuel Type

<table>
<thead>
<tr>
<th></th>
<th>Winter</th>
<th>Summer</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Natural Gas Cost Percentage</td>
<td>Electricity Costs Percentage</td>
</tr>
<tr>
<td>Current UVM System</td>
<td>37.54</td>
<td>62.46</td>
</tr>
<tr>
<td>System with Electric Chiller and Chilled Water Storage</td>
<td>37.54</td>
<td>62.45</td>
</tr>
<tr>
<td>System with CHP</td>
<td>100.00</td>
<td>0.00</td>
</tr>
<tr>
<td>System with CHP, Electric Chiller, and Chilled Water Storage</td>
<td>100.00</td>
<td>0.00</td>
</tr>
</tbody>
</table>
Table 5: Energy Percentages for Four Simulations by Fuel Types

<table>
<thead>
<tr>
<th></th>
<th>Winter</th>
<th>Summer</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Natural Gas</td>
<td>Electricity</td>
</tr>
<tr>
<td></td>
<td>Percentage</td>
<td>Percentage</td>
</tr>
<tr>
<td>Current UVM System</td>
<td>79.17</td>
<td>20.83</td>
</tr>
<tr>
<td>System with Electric Chiller and Chilled Water Storage</td>
<td>79.17</td>
<td>20.83</td>
</tr>
<tr>
<td>System with CHP</td>
<td>100.00</td>
<td>0.00</td>
</tr>
<tr>
<td>System with CHP, Electric Chiller, and Chilled Water Storage</td>
<td>100.00</td>
<td>0.00</td>
</tr>
</tbody>
</table>

**Detailed Simulation Cost Analysis**

The following sections go into detail about each modification and the corresponding simulations. The objective of this analysis is to prove the savings that is shown in the difference in the total cost values.

**Electric Chiller and Storage Analysis**

Table 6: Energy Analysis of Electric Chiller and Storage for Summer Day

<table>
<thead>
<tr>
<th></th>
<th>Energy into chiller hub from NG (e.u.)</th>
<th>Energy into chiller hub from Elec (e.u.)</th>
<th>Generation Side Chiller Energy from NG (e.u)*</th>
<th>Generation Side Chiller Energy from Elec (e.u)*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current UVM System</td>
<td>6.5000</td>
<td>0</td>
<td>7.8313</td>
<td>0</td>
</tr>
<tr>
<td>System with Electric Chiller and Chilled Water Storage</td>
<td>0</td>
<td>1.1849</td>
<td>0</td>
<td>1.247</td>
</tr>
</tbody>
</table>

*Generation Side Energy = \( \frac{\text{Output of Hub 1 Energy}}{\text{Converter efficiency}} \)

Table 7: Cost Analysis of Electric Chiller and Storage for Summer Day

<table>
<thead>
<tr>
<th></th>
<th>Total Natural Gas Costs ($)</th>
<th>Total Electricity Costs ($)</th>
<th>Cooling Costs from NG ($) *</th>
<th>Cooling Costs from Elec ($) *</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current UVM System</td>
<td>5,988.10</td>
<td>17,729.50</td>
<td>1,352.47</td>
<td>0</td>
</tr>
<tr>
<td>System with Electric Chiller and Chilled Water Storage</td>
<td>4,635.65</td>
<td>18,716.91</td>
<td>0</td>
<td>987.41</td>
</tr>
</tbody>
</table>

*Cooling Costs = Generator Side Energy * Cost of Generation
The simulation with the electric chiller and thermal energy storage has a total cost of $23,352.56 which is a savings of $365.06 as compared to the current UVM system. This number was proved in Table 7 by comparing the cooling load costs from natural gas in the current system to the cooling costs from electric in the new system. In order to break down these savings more another simulation must be run. A simulation with just the electric chiller added yields a total cost of $23,467.21. The difference between this cost and the cost with the electric chiller and storage is $114.65. These savings can be proved with the calculations below.

**Savings from storage offset:**

Power in to storage hub: 3.1514 p.u.

Power out of storage hub: 3.02632 p.u.

Offset “on-peak tons“: 3.1514 p.u.

On other side of Chiller Hub:

\[
3.1514 p.u. \left( \frac{1}{7.034} \right) = 0.4480 p.u.
\]

At electric generator:

\[
0.448p.u \left( \frac{1}{0.95} \right) = 0.4716 p.u
\]

\[
0.4716 p.u \left( \frac{10000kW}{p.u.} \right) \left( \frac{1 \text{ RT}}{3.5168525kW} \right) = 1340.93 \text{tons}
\]

Cost offset:

\[
1340.93 \text{tons} \left( \frac{0.5kW}{1 \text{ton}} \right) = 670.464 kW \text{ saved}
\]

\[
670.646kW \left( \frac{0.02858}{kWh} \right) * 6 \text{peak hours} = $114.97
\]

No analysis is needed for the winter day as there is no cooling load.
Combined Heat and Power Analysis

Summer Day:

The energy flows in per unit for the current UVM energy system and a system with an added cogeneration unit is shown in Figure 30. In the current UVM system, there are two isolated networks. The high voltage electricity serves the electric load and the natural gas source serves the steam and cooling load. However, in the adapted system the cogeneration unit acts as connection between these two and allows energy to flow between them. For the summer day system, the majority of the energy that is passed through Hub 1 is through the combined heat and power.

Originally it was thought that the CHP would be able to provide both the electrical load and steam load without using the boilers or HV electricity since this would be more economical. However, the reason that this does not happen is the peak of the electricity load does not match up with the peak of the heating and cooling load as shown in Figure 22. At any given time interval the CHP will keep generating until either the electrical load or the steam load is met. In the morning, the CHP unit is initially electrically limited since the electrical load is low. Therefore, not enough steam is produced by the CHP and the boilers have to be turned on. In the afternoon, however, at a certain point the CHP can no longer produce low cost electricity.
since the steam demand has already been met. Therefore, the system has to buy energy from the high voltage electricity grid.

Peak reduction of cogeneration unit:

![Comparing Electric Generation between Current System and System with CHP](image)

In Figure 31, a comparison of the electric generation is seen for the current UVM energy system and the system with a CHP on a summer day. The electricity generated is significantly decreases and is only needed for the peak hours.

Table 8 shows a breakdown of the energy and costs based on fuel type for the system with the cogeneration.

<table>
<thead>
<tr>
<th></th>
<th>Total Natural Gas Cost ($)</th>
<th>Total Electricity Cost ($)</th>
<th>Electric Energy from CHP (e.u.)</th>
<th>Electric Energy from HV Elec (e.u)</th>
<th>Electric Costs from Natural Gas ($)</th>
<th>Electric Costs from Electricity ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current UVM System</td>
<td>5,988.10</td>
<td>17,729.50</td>
<td>0</td>
<td>19.4</td>
<td>0</td>
<td>17,729.50</td>
</tr>
<tr>
<td>System with Combined</td>
<td>9,638.25</td>
<td>2,446.04</td>
<td>46.1649*</td>
<td>2.3919</td>
<td>7,972.67**</td>
<td>2,446.04</td>
</tr>
<tr>
<td>Heat and Power</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*Energy from CHP = \(\text{Electrical Load} - \text{input of Electrical generator} \times 95\%\) / \(\text{CHP Electrical Efficiency}\)

**Electric Costs from Natural Gas = Energy from CHP * Natural Gas Generation Costs
Winter Day:

Figure 32 shows the energy flow of the UVM system on a winter day before and after the installation of a CHP unit. Before the CHP, the entire steam load is satisfied by natural gas and the electric load is met by HV electricity. Once the CHP is installed the natural gas is now able to supply electricity as an alternative to HV electricity. Since the natural gas is less expensive the CHP provides all the electricity and no power is bought from the electricity utility. The CHP also produces steam however the rest of the needed steam is provided by the boilers since the electrical demand has already been met.

A breakdown of the energy and costs based on fuel type for the system with the cogeneration is displayed in Table 9.

Table 9: Cost Analysis of CHP for Winter Day

<table>
<thead>
<tr>
<th></th>
<th>Total Natural Gas Cost ($)</th>
<th>Total Electricity Cost ($)</th>
<th>Electric Energy from CHP (e.u.)</th>
<th>Electric Energy from HV Elec (e.u)</th>
<th>Electric Costs from Natural Gas ($)</th>
<th>Electric Costs from Electricity ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current UVM System</td>
<td>14,026.36</td>
<td>23,334.65</td>
<td>0</td>
<td>21.3684</td>
<td>0</td>
<td>23,334.65</td>
</tr>
<tr>
<td>System with Combined Heat and Power</td>
<td>18,612.27</td>
<td>0</td>
<td>58.00*</td>
<td>0</td>
<td>10,0166.00**</td>
<td>0</td>
</tr>
</tbody>
</table>

*Energy from CHP = \( \frac{\text{Electrical Load–input of Electrical generator} \times 95\%}{\text{CHP Electrical Efficiency}} \)

**Electric Costs from Natural Gas = Energy from CHP * Natural Gas Generation Costs
Unaccounted for savings
Summer: $4,322.54
Winter: $5,580.09

The cost savings between the current UVM system and the system with the added combined heat and power generator are $11,633.30 and $18,748.70 for summer and winter days, respectively. However the savings proved in Table 8 and Table 9 are only $7,310.79 and $13,168.70. The rest of the “invisible” savings come from the advantages of the CHP unit. Since the CHP has a dual output it is able to produce two energy carriers at a relatively high combined efficiency. Adding the electric efficiency (35%) with steam efficiency (45%) gives an overall energy input to output efficiency of 80% for the cogeneration unit. Since the cost of producing electricity from natural gas is so much less expensive than using HV electricity the CHP produces most of the electricity in both simulations. In the meantime, steam is also being created by the CHP. This means that the energy system is paying for electricity for less than it would have paid the electric utility and getting “free” steam energy for it as well. It is this subsidy that produces the extra savings and is why the combined heat and power generator is so cost effective.

The savings from the system with the added cogeneration unit are very substantial. These can be explored further by showing what is replacing the purchase of high voltage electricity. Usually if the system purchases 1 e.u. to produce 0.95 e.u. of low voltage electricity during on-peak for the summer, it pays 1.07754 m.u.

\[
\text{Input Cost} = \frac{\text{output energy (e.u.)}}{\text{efficiency}} \times \frac{\text{Cost (m.u.)}}{\text{input energy (e.u.)}}
\]

\[
\text{Input Cost}_{HV\text{electricity}} = \frac{0.95 \text{ e.u.}}{0.95} \times \frac{1.07754 \text{ m.u.}}{1 \text{ e.u.}} = 1.07754 \text{ m.u.}
\]

However, if the CHP produced the electricity it would pay:

\[
\text{Input Cost}_{CHP \text{electricity}} = \frac{0.95 \text{ e.u.}}{0.35} \times \frac{0.1727 \text{ m.u.}}{1 \text{ e.u.}} = 0.46876 \text{ m.u.}
\]

In addition to the 0.95 e.u. the CHP produces 1.22 e.u. of steam, which offsets what would have had to be bought and converted by the boilers:

\[
\text{Input Cost}_{\text{steam}} = \frac{1.22 \text{ e.u.}}{0.83} \times \frac{0.1727 \text{ m.u.}}{1 \text{ e.u.}} = 0.25384 \text{ m.u.}
\]

The CHP is saving:

\[
\text{Savings} = \text{cost difference} + \text{offset} = (1.07754 \text{ m.u.} - 0.46878 \text{ m.u.}) + 0.25384 \text{ m.u.} = 0.8626 \text{ m.u}
\]

Which means that the system with the CHP is savings 0.8626 m.u. for every 1 m.u. it would have bought in on-peak high voltage electricity. These savings add up quickly and make the CHP a very cost effective system.
Completely Modified System Analysis

It was not expected that the simulation would result in a charging of the thermal energy storage in the afternoon since that is when the electricity prices are the highest. The reason for this is similar to the reason not all the steam and electricity can be met by the cogeneration unit. In the afternoon, the system would like to use the CHP to generate electricity since it is less expensive than the on-peak electricity prices. However, at a certain point the steam demand has been met and the system has to do something with the excess steam. The thermal energy storage acts as an addition steam load via the chillers. This allows the CHP to produce more electricity and reduces the need to buy expensive electricity from the high voltage grid. The energy storage is then discharged later that evening. The reason that the opposite event does not occur in the morning when the CHP is electrically limited is the high electricity prices is preventing the inflation of the electric load by using the electric chiller to charge the thermal energy storage.

<table>
<thead>
<tr>
<th>Table 10: Summary of Summer Simulations</th>
<th>Total Cost of Summer Day ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current UVM System</td>
<td>23,717.62</td>
</tr>
<tr>
<td>System with Electric Chiller and Chilled Water Storage</td>
<td>23,352.56</td>
</tr>
<tr>
<td>System with CHP</td>
<td>12,084.29</td>
</tr>
<tr>
<td>System with CHP, Electric Chiller, and Chilled Water Storage</td>
<td>10,417.59</td>
</tr>
</tbody>
</table>

Money saved from system with electric chiller and storage: $365.06

Money saved from system with combined heat and power: $11,633.30

Money saved from system with both: $13,300.00

This simulation shows a great example of synergy. The cost analysis shows that the whole system with all three added assets is greater than the sum of the separate systems. These result most likely come from a more holistic approach to scheduling the energy carriers so they produce the lowest cost solution to meet the demand. By adding more interactions and pathways for the energy sources to travel to the energy demand, the system is able to reduce the cost.
Demand Charges Analysis

Burlington Electric charges the following for any Large General Time-of-Use service:

Demand (kW) -- Summer On-Peak: $25.47
Demand (kW) -- Winter On-Peak: $25.47
Demand (kW) -- Off-Peak: $3.53

To simulate demand charges, an electric peak for June and January was assumed to be 15,000 kW and 14,000 kW. Assume off-peak electric peaks of 6,000 kW for winter and 8,000 kW for summer. To apply the demand charges, the total cost of the months demand charges were separately averaged across all of the on-peak and off-peak hours.

June:

\[
Total\ On-Peak\ Demand\ Charges = 15,000\ kW \times \frac{25.47}{kW} = 382,050
\]

\[
Hourly\ On-Peak\ Charges = \frac{382,050}{6\ summer\ on-peak\ hrs} \times \frac{21\ weekdays}{June\ 2014} = \frac{3032.14}{on-peak\ hr}
\]

\[
Total\ Off-Peak\ Demand\ Charges = 8,000\ kW \times \frac{3.53}{kW} = 28,240
\]

\[
June\ 2014\ Off-Peak\ Hours = 21\ Weekdays \times \frac{18\ hours}{weekday} + 9\ Weekend\ Days \times \frac{24\ hours}{Weekend\ Day} = 384\ hours
\]

\[
Hourly\ Off-Peak\ Charges = \frac{28,240}{384\ hours} \times \frac{June\ 2014}{\text{off-peak\ hr}} = \frac{73.54}{\text{off-peak\ hr}}
\]

These values of $3032.14 and $73.54 represent the addition costs that are added to each on-peak hour and off-peak hour to represent the estimated the daily demand charges.

January:

\[
Total\ Demand\ Charges = 14,000\ kW \times \frac{25.47}{kW} = 356,580
\]

\[
Hourly\ On-Peak\ Charges = \frac{356,580}{16\ summer\ on-peak\ hrs} \times \frac{January\ 2014}{23\ weekdays} = \frac{968.97}{on-peak\ hr}
\]
Total Off-Peak Demand Charges = \(5,000\text{kW} \times \frac{3.53\text{\$/kW}}{1\text{kW}} = 17,650\) dollars

January 2014 Off-Peak Hours = 23 Weekdays \(\left(\frac{8\text{ hours}}{1\text{ Weekday}}\right)\) + 8 Weekend Days \(\left(\frac{24\text{ hours}}{1\text{ Weekend Day}}\right) = 376\text{ hours}\)

Hourly Off-Peak Charges = \(17,650 \times \left(\frac{\text{Jan 2014}}{376\text{ hours}}\right) = \frac{46.94\text{ dollars}}{\text{off-peak hr}}\)

<table>
<thead>
<tr>
<th>Table 11: Demand Charge Analysis</th>
<th>Total Cost of Winter Day ($)</th>
<th>Total Cost of Summer Day ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current UVM System</td>
<td>37,361.01</td>
<td>23,717.62</td>
</tr>
<tr>
<td>Current UVM System including demand charges</td>
<td>53,240.05</td>
<td>43,234.18</td>
</tr>
</tbody>
</table>

The actual demand charges that Burlington Electric calculates for UVM can either be from the current month’s peak or from a “rider”: 50% of the highest summer month’s demand in the previous 11 months. This can have very significant implication in a system with a CHP unit if that unit were to fail. If the cogeneration was not able to help offset the electricity load during a peak hour and all the electricity had to be purchased from the high voltage electricity grid this could set an extremely high demand charge for the entire year.

If you assume that the system with the CHP has an on-peak electric peak of 6,000 kW and a off-peak peak of 1,000 kW (see Figure 31) during the month of June 2014, then the total cost of a summer day if the monthly demand charges are averaged similar to above is $19,526.90. If the CHP fails at any point during the day the UVM energy system will be forced to buy high voltage electricity from the grid which returns the peak to the original system. If the CHP fails during off-peak hours the new total cost of the summer day would be $20,685.15. However, if the CHP fails during on-peak hours the new June on-peak peak would be 15,000kW and the new cost would be $30,442.60. This is a significant increase and a reason why a system with a CHP unit would be in danger of incurring high demand charges if it failed.
Simple Payback Period Analysis

In the following section the payback period for the initial investment for each modified system is analyzed. This is calculated by figuring out the estimated price of the new units and the estimated savings per year. The result is an amount of time when the new system will have paid for its capital investment.

**Electric Chiller and Chilled Water Storage**

**Thermal Energy Storage:**
Cost: $100/ton-hr [11]
Total cost of 12,000 ton-hr system: $1,200,000

**Electric Chiller:**

**Capacity:**
Maximum Cooling Load on summer day: 0.4952 p.u.

\[
0.4952 \text{p.u.} \times \left( \frac{10,000 \text{kW}}{1 \text{p.u.}} \right) \left( \frac{1 \text{ton}}{3.516 \text{kW}} \right) = 1,408.42 \text{ton}
\]

Capacity + 5% buffer = 1,500 ton

**Cost:**

A linear interpolation was used to find the cost per ton for a 1500 ton electric chiller.

\[
\text{Cost per ton} = \frac{-53}{500} \times \text{tons} + 281
\]

\[
\frac{-53}{500} (1500 \text{tons}) + 281 = $121/\text{ton}
\]

\[
\frac{$121}{\text{ton}} \times 1500 \text{tons} = $181,500
\]

**Table 12: Cost of Electric Chiller**

<table>
<thead>
<tr>
<th>Tons</th>
<th>Cost ($)</th>
<th>Cost per ton</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>500</td>
<td>114,400</td>
<td>228.8</td>
<td>[15]</td>
</tr>
<tr>
<td>1000</td>
<td>175,900</td>
<td>175.9</td>
<td>[15]</td>
</tr>
<tr>
<td>1500</td>
<td>181,500</td>
<td>121.0</td>
<td>interpolated</td>
</tr>
</tbody>
</table>

Maintenance cost associated with an electric chiller: $15 per ton per year [15]
Annual Maintenance = \[ \frac{15 \text{ dollars}}{\text{ton}} \times (1500 \text{ tons}) = 22,500 \text{ dollars} \]

Payback period = \[ \frac{\text{initial investment}}{\text{monetary savings per period}} \]

Initial investment for electric chiller and storage system = $1,381,500

\[ \text{Annual monetary savings} = \text{Annual energy costs savings} - \text{Annual maintenance} \]

Savings per year:

The electric chiller and storage system saved $365 on a summer day. However, UVM Physical Plant only needs to run the chiller for half the year [18].

\[ \text{Annual energy cost savings} = \frac{365 \text{ dollars}}{\text{day}} \times 182 \text{ days} = 66,430 \text{ dollars/year} \]

\[ \text{Annual Savings} = 66,4430 - 22,500 = \frac{43,930 \text{ dollars}}{\text{year}} \]

\[ \text{Payback period} = \frac{1,381,500}{43,930 \text{ dollars/year}} = 31.45 \text{ years} \]

Combined Heat and Power Unit

One consideration is that the capacity of the CHP system below is set to be peaking meaning it is designed to meet the entire electrical load. However, in reality most of the time it would be operating under its capacity which would result in lowered efficiencies. This would result in a loss in energy and money. Some research would be necessary to see if a system that was designed to meet the base load would be more cost effective.

Capacity:

Maximum output of the CHP on summer day: 0.9347 p.u. = 9,347 kW

Capacity + 5% buffer = 10,000 kW

Cost: $19,664,200 [20]

Maintenance Cost = $0.0120/kWh [20]

Assume CHP generate 75% of electricity load in a year.

Annual kWh load for Physical Plant in 2014: 3,836,173 kWh
Annual Maintenance Cost = \( \frac{0.012}{kWh} \times 3836173 kWh = \$46,034 \)

The CHP system saved $11,633.30 and $18,748.70 for summer and winter days, respectively.

\[
\text{Savings per year} = \frac{11,633.30}{\text{day}} \times 182\text{days} + \frac{18,748.70}{\text{day}} \times 183\text{days} = \$5,548,272.70/\text{year}
\]

Annual monetary savings = Annual energy costs savings – Annual maintenance

\[
\text{Annual monetary savings} = \$5,548,273 - \$46,034 = \$5,502,238
\]

\[
\text{Payback period} = \frac{\$19,664,200}{\$5,502,238/\text{year}} = 3.57 \text{ years}
\]

CHP, Electric Chiller, and Thermal Energy Storage

\[
\text{Payback period} = \frac{\$21,045,700}{\$5,546,168/\text{year}} = 3.79 \text{ years}
\]
Conclusions

The objectives of this paper were met by modeling the current UVM’s campus energy system and performing simulations to predict how to increase the energy and cost savings through system modifications. The current UVM’s campus energy system is simulated to have a total cost of generation of $37,361.01 and $23,717.62 for winter and summer days, respectively. In the current setup, the electric network is completely separate from the natural gas, steam, and cooling networks. This prevents any optimizing the scheduling of energy carriers. The result is a large disparity between the cost and energy use percentages for natural gas and electricity. For the summer day simulation, electricity costs were 75% of the total cost of generation but electricity only provided 36% of the total energy demand.

The first system modification was to add an electric chiller and chilled water storage. This allowed the cooling load to be fed by either electricity or natural gas as well as the ability to store cooling energy when the generation pricing was low. The total cost of this system is $37,361.01 and $23,352.56 for the winter and summer days, respectively. This represents a saving of $365 for the summer simulation but no saving for the winter since there is no cooling load. The payback period analysis on this system showed that it would take 31.45 years to pay off the assets.

The next system that was simulated was the system with an added combined heat and power unit that can produce electricity or steam from natural gas. This setup allowed the electricity load to be supplied by high voltage electricity or natural gas. The total cost of this system is $18,612.27 and $12,084.29 for the winter and summer days, respectively. The savings as compared the current UVM system are $11,633.30 for the summer simulation and $18,748.70 for the winter simulation. The interconnection of the electricity and natural gas reversed the disparity and energy usage to cost percentages were much more balanced. The payback period analysis on this system showed that it would take 3.57 years to pay off the new CHP unit.

The last simulation was with a system with the combined heat and power, electric chiller, and chilled water storage. The total cost of this system is $18,612.27 and $10,417.59 for the winter and summer days, respectively. The savings from this simulation were $18,748.70 for the winter and $13,300.00 for the summer. Note that the savings with all three components was greater than the sum of the two separate simulations with just the electric chiller/storage and CHP. This further solidifies the advantages of optimizing the scheduling of multiple energy carriers. The payback period analysis on this system showed that it would take 3.79 years to pay off the assets.

A large part of the UVM electricity bill which is not represented in the simulation is the demand charges. These are set by Burlington Electric based on the on-peak and off-peak electric peaks and added to the monthly bill. By averaging the on-peak and off-peak demand charges over the hours in the month, an estimation of the daily cost with demand charges can be calculated. Compared with the daily costs of generation of $37,361.01 and $23,717.62 for winter and summer, respectively, the demand costs raised the costs to $53,240.05 and $43,234.18. An addition analysis is ran for the system with the CHP unit which found
that the summer daily cost of generation with demand charges is $19,526.90. However, this cost spiked up to $20,685.15 or $30,442.60 if the CHP unit failed during off-peak or on-peak hours, respectively.

Overall, the simulations proved that the new components are able to reduce the total cost of generation. In addition, they are able to even the energy cost and energy usage disparity that is a result of the isolated systems and high electricity prices. The exchange of energy between the different networks allowed for flexibility and the ability to meet the energy demands at a lower overall cost. The payback periods for the systems with the cogeneration unit or all three components seem worthwhile in the long run and it is recommended to further investigate these options.
Future Work

There are many open issues still to be explored by future work. First, with more data from the UVM Physical Plant, Burlington Electric, or Vermont Gas, the load profiles and cost of generation curves could be more accurate. Additional modifications to Hubert could also make the simulations more realistic and give a lower optimal costs. For instance, it would be worthwhile to be able to implement multiple storages in a single hub, have non-linear efficiencies for converters, and place a generation limit on hub converters.

Another major change that would affect the optimization would be to enhance the economics by predicting demand charges. Since electric demand charges represent a third of the electric energy costs that UVM Physical Plant has to pay, minimizing these could have a significant effect on the electricity bills. The code that would need to be implemented would predict whether the electricity peak for the current day would set a new monthly or yearly peak and avoid it. Even if it was more expensive at the time to produce electricity through natural gas it could save money overall by decreasing the demand charges.

Additions simulations would also increase the range of possibilities for energy and cost savings. Potential systems that could be simulated and analyzed could be:

- System with significant solar or wind power combined with electrical storage
- System integrated with McNeil Generating Station
- System with 1 MW generator with heat recovery

By running more simulations, a better grasp of the opportunities for a more energy efficient and cost effective energy system would be gained.
References


