NOVEL APPLICATION OF COMBINED HEAT AND POWER FOR MULTI-FAMILY RESIDENCES AND SMALL REMOTE COMMUNITIES

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By
Saeed A. Alqaed

UNIVERSITY OF DAYTON
Dayton, Ohio
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NOVEL APPLICATION OF COMBINED HEAT AND POWER FOR MULTI-FAMILY RESIDENCES AND SMALL REMOTE COMMUNITIES

Name: Al qaed, Saeed A.

APPROVED BY:

Kevin P. Hallinan, Ph.D.  
Advisory Committee Chairman  
Professor  
Mechanical Engineering

Andrew D. Chiasson, Ph.D.  
Committee Member  
Assistant Professor  
Mechanical Engineering

Robert B. Gilbert, Ph.D.  
Committee Member  
Professor  
Mechanical Engineering

Robert J. Brecha, Ph.D.  
Committee Member  
Professor  
Department of Physics

Robert J. Wilkens, Ph.D., P.E.  
Associate Dean for Research and Innovation  
School of Engineering

Eddy M. Rojas, Ph.D., M.A., P.E.  
Dean, School of Engineering
ABSTRACT

NOVEL APPLICATION OF COMBINED HEAT AND POWER FOR MULTI-FAMILY RESIDENCES AND SMALL REMOTE COMMUNITIES

Name: Alqaed, Saeed A.
University of Dayton

Advisor: Dr. Kevin P. Hallinan

Combined heat and power (CHP) systems are increasingly used in conjunction with traditional grid power for industrial and residential applications. This technology most often involves the on-site combustion of primary fuel, such that both electrical and thermal energy can be utilized to increase overall efficiency. It is also possible to create electrical and thermal energy from solar radiation, using hybrid photovoltaics and thermal (PVT) collectors. These are designed to lower the photovoltaic temperature, improving electrical efficiency, while providing useful thermal energy. One of the key steps in deploying CHP technology is optimal sizing and energy dispatch for a particular application. This work considers these problems for a natural gas powered CHP in a multi-family residential building in North America, and PVT for desalination in remote areas in the Kingdom of Saudi Arabia (KSA).

It has already been established that CHP for building applications can reduce grid power requirement and lower overall energy costs. However, no comprehensive study
has considered optimizing CHPs for multi-family residences. Although this type of building represents a significant fraction of overall energy consumption in the US and world, they have been shown to be significantly less efficient than other types of residences. Also, due to significant thermal demand in the form of hot-water, multi-family residences are particularly well-suited for CHP.

Two separate natural gas powered CHP designs for a multi-family residence are presented in this work, both conceived as retrofits to an existing building. These designs use historical demand data from an all-electric 120-unit multi-family residence in Columbus, Ohio, US that was built in 2008 to minimum code standards. The first design uses a CHP that operates intermittently to meet partial loads for electricity and hot water in order to reduce overall energy cost, when considering a demand sensitive grid power cost pricing schedule. A mathematical model is developed for activating the CHP and dispatching its electric power to the building and thermal energy to a central hot water tank. The modeling includes a detailed cost function, which is optimized over the CHP and storage tank sizes under a constraint on the CHP duty cycle.

The second CHP design for a multi-family residence considers a cold climate, such that the building would have greater thermal energy needs. In this case, the CHP is used in conjunction with a ground-coupled geothermal heat pump (GCHP) system, forming a hybrid design. GCHP systems use the ground as a heat source or sink to improve the efficiency of space heating and cooling, and GCHP is often used in residential and commercial buildings due to their higher efficiency and lower environmental impact. However, for a heating-dominated climate, the residential building would take more thermal energy from the ground in the winter than it returns in the summer, causing the
ground temperature to drop over time. To correct this, the design presented here operates the CHP continuously, and passes its excess thermal energy to the ground, thus enabling the possibility for balancing the heating and cooling of the ground over each year. On the electrical side of the system, a battery storage element is added to better match the variations in load to the continuous CHP electrical output.

The third CHP design considered in this work uses PVT for desalination in a hot, dry climate. As global demand for fresh water increases, desalination technology is becoming more important because natural supplies of fresh water are fixed. Desalination activity is largely concentrated in the Middle East, where dry Arab countries rely on desalination to meet their fresh water demand. The energy needed for desalination in the Middle East is mainly provided by burning oil, raising concerns about greenhouse gas (GHG) emissions and, frankly, increasingly depleted supply. In this context, this work presents a PVT design to power reverse-osmosis membrane desalination, most appropriate for small, remote communities in KSA. It has been shown that the energy demands for RO can be reduced by pre-heating the feed brine. Therefore, the design uses the thermal energy from PVT to pre-heat the feedwater and the electrical energy to satisfy the RO pumping demands. Thermal and battery storage, along with conventional backup power, are necessary in order to operate the RO continuously and utilize all of the renewable energy collected by the PVT. The design allows for sizing of the components in order to achieve minimum cost at any desired level of renewable energy penetration.

The performance of each design presented in this work is measured primarily in terms of economic cost and carbon reduction. Savings relative to using conventional grid power are computed, allowing for determination of payback time and net present value.
Results indicate that each CHP design provides both cost advantage and carbon reduction, spread out over the system lifetime. The scale of the advantages is examined as a function of parameters such as natural gas and grid power prices.
To my Father, a man that I truly admire and respect. I am grateful to have such a positive role model in my life who is compassionate about my goal of higher education. I feel I can achieve my dream because my father has sacrificed much in his life to help me to improve my life, by providing both moral and financial support. It is with much love that I express my thankfulness to him and hope my father will be proud of my educational accomplishments. To my beloved mother, whom I adore. She has encouraged me to be strong and do well in my studies and I will always be thankful for her caring and support. I’m grateful to my mother for the morals she taught me that make me the man I am today. I pray blessings for my mother because she is always there for me. Also, to my siblings Ahmed, Mohamed, Salha, Elham and Zohra. I’m thankful for their support and for the well-received encouragement of my family which I am blessed to be a part of. Thanks to everyone in my family because they are all my true source of inspiration. Finally, to my beloved wife who has been by my side through this unpredictable journey in life. I’m thankful to her for not only being my wife but also my friend. I am truly thankful for her sacrifice as well because without her love and support I could have never survived the countless hours of commitment to my work to achieve my educational goals.
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CHAPTER I

INTRODUCTION

1.1 Motivation for Using CHP Systems

Only about 30% of the energy stored in fossil fuels is converted into useful electric power by conventional power plants [1]. The remaining energy in the fuel is exhausted through waste heat. Furthermore, as the electric power is transmitted long distances and distributed to customers, more energy losses occur. The large amount of wasted energy associated with conventional electricity production is motivating researchers and engineers to develop distributed power systems that produce usable electricity and thermal energy near the site of consumption from a single fuel source. This is known as combined heat and power (CHP) systems, and these systems are capable of converting 75-80% of the energy in the fuel into useful energy for the customer [2]. CHP places power production at or near the end-user’s site so that the heat released from power production can be used to meet the user’s thermal requirements while the power generated meets all or a portion of the site electricity needs.

The higher efficiency for CHP energy production leads to a potential decrease in greenhouse gas (GHG) emissions relative to conventional power production. Worldwide, GHG emissions will continue to follow an upward trend in the coming years as more energy is utilized by a growing population. Significant threats from GHG are imminent,
such as rising global temperatures, raising sea levels, more frequent flooding, droughts, and contagious diseases. From 1990-2005, various policies implemented within the European union caused a reduction in greenhouse gas emissions of 382 Mt, and the use of CHP systems represented 15% of this total (57 Mt) [3]. There is now significant pressure to develop technology that provides power with less GHG production. By 2030, the expected reduction in GHG emission due to CHP development is 10%, or 950 Mt/year [4].

Another motivation for transitioning to distributed power generation is that centrally produced power can be unreliable and vulnerable to natural disasters or terrorism [5]. Having many small, distributed power generation facilities supplying site power can permit much more reliable and secure power. Facilities that use CHP do not need to have backup power generation, and they have greater control and incentives to use the CHP efficiently for their application. The effect of losing a central power plant to a disaster is much larger than losing one or a few small distributed supplies. When distributed power is used in conjunction with centrally produced power, there is redundancy and therefore much greater reliability for the entire grid system.

Another benefit of using a CHP to supply part of the power for a facility is that it gives the customer more control over when they use grid power and the profile of the demand that they present to the grid. The fluctuations in power that a facility draws from the grid partly determine the price of that power. Some utility companies include demand variability in their pricing structure. If they openly communicate their pricing to consumers, there is potential for using CHP to reduce the cost per kWh of grid electricity.
1.2 Multi-Family Residences in the US

In the US, the residential sector is responsible for over a third of the country’s total CO2 emissions [6]. This fraction is higher than other countries due to the greater energy utilized in American homes for heating and cooling, lighting, and other electrical equipment. Multi-family housing (buildings with many rental units) represents a significant fraction of the total residential energy consumption in the US, because one-third of the population lives in a half a million multi-family buildings [7]. These buildings have been shown to be significantly less efficient than owner-occupied homes or rented single-family homes. A recent study documents that rental multi-family residences have energy intensities that are 37% higher than for owner-occupied multi-family units (i.e. condos or co-ops), 41% higher than for renter-occupied single family detached units and 76% higher than in owner-occupied single family detached units [8]. This is partly due to the fact that renters often do not directly pay utility bills, which causes them to be less concerned with energy consumption. For example, renters who do not pay utilities directly use an estimated 30% more energy for heating than renters who pay their own utilities [9]. Furthermore, even when renters directly pay their utility costs, the building owners lack incentive to invest in efficiency improvements. This barrier is referred to as the split incentive barrier, and it contributes to the efficiency gap for multi-family housing.

Efficiency upgrades for the multi-family building sector have the potential to improve its energy efficiency by about 30%, and reduce overall CO2 emissions in the US by 50 to 100 Mt/year [10]. Potential cost savings from such upgrades are estimated to be $3.4 billion per year. There are often tax incentives for efficiency upgrades to help realize
these savings. Other options, such as programs to educate building owners, are being explored to improve this problem [11].

1.3 CHP Applications for a Single Facility

Due to their size and highly inefficient use of energy, large residential buildings are a good application for CHP technology. Figure 1 shows a typical CHP system for a residential building, which can be based on an internal combustion engine, steam turbines, micro turbines, fuel cells, etc. Any of these CHP technologies will convert an incoming supply of fuel into flows of electric and thermal energy. The thermal energy is used to meet heating loads directly, and it can also be used to meet cooling loads if an absorption chiller is part of the system. If the CHP does not generate enough thermal energy, and auxiliary boiler can make up the difference. Similarly, the CHP electric output is used to meet all or part of the building’s electrical demand. Grid power purchases are used to satisfy any remaining power needs.

![Figure 1: Block diagram showing typical CHP system for a facility](image)

Figure 1: Block diagram showing typical CHP system for a facility [12]
The International Energy Agency predicted that the 13 largest energy consuming nations had the potential to raise their CHP capacity to 430 GWe in 2015 by 2015, and to more than 830 GWe by 2030 [3]. In 2012, the entire CHP electrical capacity was estimated to be 82 GWe in the U.S [12]. By 2025, projections of European CHP capacity are in the range of 150-250 GWe [13].

The deployment of CHP is in the early stages, and there is a lot of unrealized potential for its application in the US. CHP can be used for many types of facilities, including hospitals, university campuses, prisons, military bases, and industry. The focus in this work, however, will be the multi-family residential building sector. This type of building is well-suited to CHP technology for several reasons. First, since this type of building is occupied all the time, it has consistent and well-understood electrical and thermal loads throughout the year. This is important because CHP requires significant investment, and it needs to be used constantly in order to justify that investment. Hot water demand for a large residential building is significant, and this is an appropriate application for CHP thermal output. Second, a CHP has the potential to provide residential building owners another avenue for making profit, by giving them control over energy purchased from the grid and allowing them to take advantage of grid power or fuel pricing fluctuations. Third, the residential building sector is unusually energy inefficient, as previously discussed, which makes it an appropriate target for CHP deployment.

1.4 CHP Literature Review

1.4.1 Prime Movers for CHP

There is a growing body of literature that discusses CHP applications and related engineering problems. This section describes and gives examples from the literature about
the large areas of interest. All CHP systems have in common the idea of burning fuel on-site in order to create useful electrical and thermal energy and to avoid the inefficiencies from centralized production and transmission of energy. There are many different types of prime movers, however, that can be used in a CHP application. For example, reciprocating internal combustion engines powered by diesel fuel or natural gas can be used for a wide range of power needs, from 10 kW to over 5 MW [14]. Electrical efficiency for this type of CHP is in the range of 22-40%, and overall efficiency is 70-80% [15]. The heat generated by the engine is collected from the coolant and exhaust, with temperatures appropriate for supplying hot water. Pollution from NOx emissions is a problem if diesel fuel is used; although this can be handled by catalytic systems [14]. Major advantages of internal combustion engines include the facts that they maintain their electrical efficiency under partial load and can be rapidly started and stopped [15].

For larger scale systems, from 50 kW to hundreds of MW of electrical power, steam turbines can be used [14]. These run pressurized steam through a turbine to spin a generator, and many different fuels can be used. Steam turbine systems have a long lifetime and have 80% efficiency at full load. However, they do not have good electrical efficiency under a partial load, and they cannot be turned on and off rapidly. Typically, these are used for larger scale purposes that have a steady electrical and thermal load.

Gas turbines are another category of prime mover for CHPs, which operate by combusting a fuel (usually natural gas) and using the high-pressure exhaust to spin a turbine and generator. These can create electrical power in the range of 500 kW to 250 MW, for large-scale co-generation purposes. Of greater interest for distributed power, however, is a more recently developed technology called micro-turbines, which produce
electrical power in the range of a few kW to several hundred kW [16]. Large scale gas turbines have overall efficiencies in the range of 70-75% (25% electrical and 50% thermal, for example) whereas micro-turbines usually have lower overall efficiencies in the range of 65-75%. Although micro-turbines are expensive and have problems with low electrical efficiency, they are small and lightweight, have low noise and emissions, and have many advantages for distributed power generation [14].

1.4.2 CHP System Design Choices

Besides the choice of prime mover and fuel type, there are many other design decisions for a CHP application. These options can be separated according to electrical and thermal categories. On the electrical side, the CHP can provide all of the electrical load or only a part of it, with grid power purchases making up the remainder. If there is excess electrical CHP production, this might be sold back to the grid in some locations. On the thermal side, all of the thermal load can be met with the CHP or only a part of it can be met, with a backup boiler or grid power making up the difference. The thermal energy can be used directly for hot-water or building heating, but a chiller unit is required to use the CHP thermal energy to meet a cooling load.

The design decisions for implementing a CHP system for a building begin with the choice of prime mover. The load characteristics play an important role in making this choice, in terms of the average and peak kW needs, the ratio of the thermal load to the electrical load, the shape of the load profiles, seasonal load variations, and the amount of heating versus cooling that the application requires. Some CHP applications are intended primarily as backup power source, others are intended to be a primary source of power (running part of the time or all the time). Other factors that affect the decision of prime mover are...
mover include the type of fuel available, emission and noise pollution restrictions, and economic considerations. Selecting the appropriate prime mover for a given situation can have a large impact on the efficiency of the system [16].

Along with choosing the prime mover, the deployment strategy for the CHP powers must be chosen. There are two primary strategies presented in the literature: following the electric load (FEL) or following the thermal load (FTL). FEL means that the system prioritizes electrical needs, and satisfies the entire electrical load, tracking the electrical demand. In this case, all or part of the thermal load may be met, with an auxiliary boiler making up the difference. For FTL, the thermal load is prioritized, and the CHP thermal output tracks the thermal load. The electrical output meets all or part of the electrical demand, with grid power making up the difference. Besides these two cases, there are many deployment strategies in the literature, which seek to optimize some measure of performance such as operating cost, primary fuel consumption, or efficiency.

1.4.3 CHP System Performance Measures

All of the design decisions regarding a CHP system are intended to optimize the performance of the system. However, there are different ways of defining system performance. Economic considerations are often the main measure of performance, because CHP systems involve a large up-front capital investment that is gradually paid off over time. Economic performance can be specified in terms of an annual operating cost, net present value calculations for the system, internal rate of return, or a payback period. Environmental impact is another way to measure the performance of a CHP installation, usually in terms of the carbon-dioxide emissions. This requires an understanding of the pollution caused by grid power, and may require a full life-cycle analysis to fully
understand. The primary energy savings is another performance measure, which compares the primary fuel usage of a CHP system to the fuel usage of a conventional (usually utility grid power) system. Finally, a full thermodynamic analysis can explore the exergetic efficiency of a CHP system and seek to optimize that quantity. It is important to identify the performance measure before designing the system, because different performance measures can lead to much different systems. For example, if emissions are to be minimized, then diesel fuel would probably not be considered.

1.4.4 Optimization of CHP Systems

In order to optimize a chosen performance measure, the size and type of energy dispatching must be correctly chosen. CHP optimization is of major significance in the literature, because incorrect choices may increase pollution or cost relative to conventional power supply. Many researchers use a linear-programming (LP) approach to determine CHP size for a given operating strategy [17]. LP can also be used to determine best power dispatching between components, and when the CHP is on or off [18]. Optimization literature sometimes focuses on a single type of prime mover, with multiple objectives [19][20]. It has been shown that the optimal CHP setup can depend on the type of performance measure. For example, optimizing cost and optimizing CO2 cannot necessarily be done at the same time [21].

Several studies perform detailed exergy analyses to optimize a CHP employing internal combustion engines, and to compare the exergetic efficiency of a CHP to conventional energy [16]. Researchers have developed exergoeconomics, which combines economic and exergy considerations [16].
Other optimization algorithms utilized include: stochastic optimization, genetic algorithm, sequential quadratic programming (which is used in this work), particle-swarm algorithm, and multi-objective optimization [15].

1.5 Hybrid Geothermal Literature Review

Geothermal heat pumps for heating and cooling of buildings are efficient and environmentally beneficial. These systems operate by extracting heat from the ground in winter to support the building’s heating load, and transferring excess heat to the ground in summer to support the building’s cooling load. This process takes advantage of the ground’s ability to absorb large quantities of heat without having its temperature change significantly.

There are some disadvantages to geothermal heat pump systems. First, these are costly to implement, due to high cost of drilling vertical boreholes. This cost is highly dependent on the total length of all the boreholes. Another disadvantage is that if there is an imbalance in the heating and cooling loads over the course of a year, then the ground temperature can drift over time, causing a “ground fouling” problem. For example, if the building is heating dominated, too much heat can be extracted from the ground from year to year, gradually lowering the ground temperature, and reducing the heating efficiency for the system. A third disadvantage is that the sizing of borehole systems to meet the building’s full thermal loadings is very difficult, and there is no standard method for optimizing the size.

One way to address these problems is to utilize hybrid geothermal systems. From the literature on this topic, hybrid geothermal systems can take two forms. In the first form, the geothermal system can be used to satisfy part of the building load, and conventional
power (like a boiler) can be used to satisfy peak building loads. This allows for shorter borehole length, lowering the cost of the borehole system at the expense of a conventional system. The second type of hybrid system seeks to balance heating and cooling loads by adding or removing heat to the ground. For example, a solar-thermal collector can add heat to the ground to balance the loads in a heating-dominated climate [22].

Using the excess thermal energy from a CHP to balance the ground loads for a heating-dominated building is a new idea that is not well explored in the literature. This has the potential to reduce the borehole length, balance heating and cooling loads, and make optimization of boreholes easier. This work develops this idea in Chapter 3.

1.6 Photovoltaic-Thermal Literature Review

Photovoltaic (PV) cells convert solar radiation into electrical power, but their efficiency is reduced when their temperature increases. One way to overcome this problem is to cool the solar cells with a circulating flow of coolant, which improves electrical efficiency while producing thermal energy. The result is a hybrid PV-thermal (PVT) unit [23]–[26]. Because electricity production is most often the priority, PVT is not used as much as PV or solar collector units alone. However, PVT systems have a lower cost per unit of electricity and heat produced for the same total surface area needed for their installation [24]. The total area requirements for a PVT collector system are about 40% less (IEA, 2007) than separate PV and solar thermal collectors with the same total capacity. In many applications of hybrid PVT systems, the electrical output is prioritized, such that the operating conditions of the heat transfer unit are controlled in order to maximize electrical output, not thermal output. However, PVT can be designed in order to optimize heat transfer, creating higher outlet fluid temperatures while sacrificing some PV efficiency.
PVT is therefore adjustable depending on the energy requirements for the application. Because of its flexibility in terms of thermal versus electric energy outputs, PVT could be appropriate for desalination applications in KSA, where high-temperatures reduce the efficiency of PV systems.

1.7 Summary of Research and Development

It is clearly established that CHP technology for building applications can reduce grid power requirement and lower overall energy costs. It is also possible that CHP units can serve to reduce production of carbon dioxide. However, no comprehensive study has considered optimizing CHPs for multi-family residences. Therefore, this analysis seeks to develop a cost optimal CHP system for a multi-family building. The performance measure of interest will be system cost, although CO2 emission savings will also be estimated. Comparisons will be made between the overall costs of the CHP system to the cost of supplying the building’s energy needs with conventional grid power.

A specific 120-unit residential building in Columbus, Ohio, built in 2008 to minimum energy code standards, is the intended target for a CHP retrofit design. The building is all-electric, and meter data is available for each apartment for the span of a year at hourly increments. The aggregate demand over all apartments is used frequently throughout this work, with the restriction that this demand is met by the power source at each hour. The demand data shows that the building energy needs are slightly heating dominated, which is an issue for one of the designs considered.
1.7.1 Cost-Optimal CHP Retrofit for a Multi-Family Building

The first design considered in this work seeks to incorporate a CHP into the building with minimal physical alterations. The CHP is chosen to provide a fraction of the electrical load, and the thermal output will be used for the building’s hot water needs. This choice is made because applying the CHP thermal output for heating would require running new ductwork or piping throughout the building, which is too invasive. Using the thermal energy for cooling would require a chiller, which is not practical due to the small fraction of time that cooling is necessary through the year. The hot water demand is consistent throughout the year, and easier to match to a CHP output. To simplify the thermal side of the design, a central hot-water tank is included, to act as a buffer between the hot water supply and demand. If CHP output cannot meet either the thermal or electrical load at any given time, then grid power is used to make up the difference.

The power dispatching algorithm for the first design employs the CHP at its rated electrical capacity as long as the electrical demand is greater than this capacity. If the electrical demand drops below the CHP rated electrical capacity, then the CHP is turned off and grid power is used at those times. The benefit of this dispatching strategy is that the CHP is always operated at its rated output, where it has its best efficiency. Running a CHP at partial load reduces efficiency. With this dispatching strategy, it is possible to simulate the hourly energy power flows from the CHP to the electric and thermal loads, and also from the grid to the loads.

A model is developed for the first design which includes amortized capital cost of the CHP and a water storage tank. The dispatching simulation allows for an operating cost to be developed that accounts for NG fuel purchases for the CHP and grid electricity
purchases. Furthermore, the pricing for the grid electricity is a function of the shape for the portion of the load that the grid supplies, in terms of its load factor, which is defined as the ratio of peak hourly power to the average power over a month. High load factors yield a lower grid purchase power price, since this corresponds to a smoother load profile that is less expensive for the utility to provide. The load factors for each month of the original all-electric load are affected by the CHP operation, which will affect the grid pricing. To measure the performance of the CHP retrofit, the total annual cost for the design is compared to the cost of using grid electricity alone to supply the loads.

The total annual cost for the first design is optimized relative to two parameters: the CHP rated electrical output, and the tank storage capacity. This nonlinear optimization is constrained such that a minimum duty cycle can be specified. The duty cycle is the percentage of time that the CHP is operating during the year. A large CHP will run with a lower duty cycle than a small CHP. The optimized cost is then compared to the cost of supplying the load with grid power alone.

1.7.2 Hybrid CHP/Geothermal System for Heating Dominated Multi-Family Buildings

The first CHP based design for the building retrofit does not consider heating and cooling as separate building loads. It combines these as part of the overall electrical load. However, the second design considers the heating and cooling loads separately, and it will supply these load components with a ground-coupled geothermal borehole (GCHP) system. In addition, the second design will also include the following elements: a CHP that operates continuously, battery storage to buffer the electrical output from the CHP, grid
purchases to supplement peak load times, and grid sell-back (also called net metering) at times when the load is low.

GCHP systems use the ground as a heat source or sink to improve the efficiency of space heating and cooling. The earth provides temperatures for cooling that are lower than the ambient air temperatures in summer, and temperatures for heating that are higher than the ambient air temperatures in winter. A large number of GCHP systems have been used in residential and commercial buildings due to their higher efficiency and lower environmental impact [28]. However, the imbalance between the heating and cooling loads is a problem for conventional GCHP systems. For this case, the residential building is heating-dominated, which means that it would take more thermal energy from the ground in the winter than returned to the group during the summer, causing the ground temperature to drop over time. To correct this, it is possible to add other components that reject heat to the ground, to offset the imbalance. In this case, some of the CHP thermal energy can be passed to the ground when the CHP thermal energy produced exceeds the thermal demand in the building, thus enabling the possibility for balancing the heating and cooling of the ground over each year. Systems that operate in this way are known as hybrid GCHP systems. The advantage of a hybrid arrangement is that it serves to reduce the size, and therefore cost of the GCHP, as compared to a non-hybrid system [29].

With a hybrid geothermal system to absorb excess heat from the CHP, the CHP capacity can be larger in the second design in comparison to the first design, and it can be operated continuously. Therefore, there will be enough thermal energy from the CHP to provide the building hot-water supply completely, and all excess energy is passed into the ground to balance the heating and cooling loads. On the electrical side of the system, the
constant CHP electrical output is used directly by the load, stored in a battery, or sold back to the grid (net metering).

This system lowers costs in several ways: by reducing grid power purchases, by improving heating and cooling efficiency with GCHP, and by reducing the necessary size of the GCHP system by using excess CHP heat to balance annual thermal loads.

The design objectives for the second design are to choose a CHP and battery size such that two constraints are met. First, the cost of the total power purchases should equal the value of the total power sold back to the grid. This is known as “net-zero metering”. Second, the excess thermal energy passed to the ground from the CHP, after meeting the hot water load, must be sufficient to balance the heating and cooling loads, such that the ground temperature does not drift over time.

As with the first design, a detailed cost model is developed, which is a function of the CHP rated output, the battery storage capacity, and the total length of the borehole system. The cost model included capital costs as well as operating costs. The cost is optimized with the net-zero metering constraint in place. After the optimization is performed, the geothermal system is modeled to confirm that the heating and cooling loads are properly balanced.

In order to study the effect of the size of the heating and cooling imbalance, the second design is explored for two locations: Columbus, Ohio which is slightly heating dominated, and Winnipeg, Canada which is highly heating dominated. System costs between these locations are compared, as well as compared to the cost of supplying the loads with grid power completely.
1.7.3 PVT System with Desalination

Renewable version of this technology also exists in the form of hybrid photovoltaics and thermal (PVT) collectors. These are designed to lower the photovoltaic temperature, improving electrical efficiency, while providing useful thermal energy. PVT for desalination in a hot, dry climate. As global demand for fresh water increases, desalination technology is becoming more important because natural supplies of fresh water are fixed. Desalination activity is largely concentrated in the Middle East, where dry Arab countries rely on desalination to meet their fresh water demand. The energy needed for desalination in the Middle East is mainly provided by burning oil, raising concerns about greenhouse gas (GHG) emissions. In this context, this work presents a novel PVT design to power reverse-osmosis membrane desalination, most appropriate for small, remote communities in KSA. It has been shown that the energy demands for RO can be reduced by pre-heating the feed brine. Therefore, the design uses the thermal energy from PVT to pre-heat the feedwater and the electrical energy to satisfy the RO pumping demands. Thermal and battery storage, along with conventional backup power, are necessary in order to operate the RO continuously and utilize all of the renewable energy collected by the PVT. The design allows for sizing of the components in order to achieve minimum cost at any desired level of renewable energy penetration.
CHAPTER II

DEVELOPING A COST-OPTIMAL RETROFIT CHP SYSTEM FOR MULTI-FAMILY BUILDING USING HISTORICAL DEMAND

2.1 Overview

Combined heat and power (CHP) systems are increasingly used in conjunction with traditional grid power for industrial and residential applications. Because multi-family residences in the US are the least energy efficient type of building, this study considers a CHP application for an all-electric 120-unit multi-family residence in Columbus, Ohio, US that was built in 2008 to minimum code standards. This building is data rich; with historical data available from unit-level interval meters for electricity and water. A CHP system is considered to meet partial loads for electricity and hot water in order to reduce overall energy cost, when considering a demand sensitive grid power cost pricing schedule. A mathematical model is developed for deploying the CHP and dispatching the generated electric power to the facility and thermal energy to a central hot water tank, as well as dispatching stored thermal energy to individual apartment units for hot water service. This model enables optimal management of the power dispatching in order to reduce overall energy cost. The modeling results indicate that a CHP with electrical output of 60 kWe and a hot-water tank capable of storing 400 kWh of thermal energy will optimally reduce total annual energy costs for the multi-family residence. In this case, the total annual cost is
reduced by 23%, from $114,850 to $88,336, and the CHP provides 65% of the total demand. Total carbon emissions are reduced by 32% for this best case.

2.2 Introduction

Multi-family housing energy consumption represents a significant fraction of the total residential energy consumption in the US; one-third of the population lives in a half a million multi-family buildings [7]. In addition, these buildings have been shown to be significantly less efficient than owner-occupied homes or rented single-family homes. A recent study documents that rental multi-family residences have energy intensities that are 37% higher than for owner-occupied multi-family units (i.e. condos or co-ops), 41% higher than for renter-occupied single family detached units and 76% higher than in owner-occupied single family detached units [8]. This is partly due to the fact that renters often do not directly pay utility bills, which causes them to be less concerned with energy consumption. For example, renters who do not pay utilities directly use an estimated 30% more energy for heating than renters who pay their own utilities [9]. Furthermore, even when renters directly pay their utility costs, the building owners lack incentive to invest in efficiency improvements. This barrier is referred to as the split incentive barrier, and it contributes to the efficiency gap for multi-family housing.

Upgrading the multi-family building sector has the potential to improve its energy efficiency by about 30%, and reduce overall CO2 emissions in the US by 50 to 100 million tons per year. Potential energy cost savings are estimated to be $3.4 billion per year, according to the American Council for Energy-Efficient Economy [10]. There are often tax incentives for efficiency upgrades to help realize these savings. Other options, such as programs to educate building owners, are being explored to improve this problem [11].
2.2.1 Co-generation (Combined Heat and Power, CHP)

One possibility for improving energy efficiency in and reducing carbon emissions from multi-family residences is through the use of combined heat and power systems (CHP). CHPs have been identified as a practical solution to reduce overall energy demand and greenhouse gas emissions, offering a nearly uninterruptible source of electricity. Some countries, such as Japan, have already extensively incorporated CHP technology over the past 20 years, but primarily in the manufacturing and commercial sectors. In the US, there were 43 GW of CHP capacity in the electric power sector as of 2011, mostly powered with natural gas, accounting for about 7.9% of electricity generation [30]. Most of the CHP power in the US is used by large industries, although there is potential for growth of small-scale systems to power individual buildings such as hotels, campuses, and multi-family residences, where there is balanced energy requirements between year round water heating and electricity, a perfect condition for deploying CHPs. In the US there are federal and state policies that favor CHP technology, but more research and development on their application is needed, as well as tax incentives for investing in this technology [31].

CHP technology has several significant advantages over traditional energy generation. First, it is more efficient than traditional power plants, which waste as much as 70% of their thermal energy to create electricity. CHP systems are physically located close to where the energy is being consumed so that the heat can be used. This leads to an overall efficiency of greater than 75% for CHPs. The second advantage is energy reliability due to the fact that CHP systems can serve as an energy backup to grid electricity. Facilities that use CHP do not need to have backup power generation, and they have greater control and incentives to use the CHP efficiently for their application. A third advantage is that by
using a CHP the fluctuations in power that a facility needs to draw from the grid are reduced. Utility companies include the variability in their pricing structure, so a CHP has the potential to reduce the cost per kWh of grid purchased electricity.

For multi-family residence applications, the thermal energy output from a CHP can be used for directly heating the building, providing hot-water, or cooling the building if it is used in conjunction with an absorption refrigeration unit. Application of CHP systems into multi-family residences is very limited, however. One study in Edinburgh, Scotland applied a CHP to a collection of 192 apartments and eight business units [32]. The apartments in this study were a mix of studio, 1-bedroom, and 2-bedroom units. Four CHP systems were installed. These provided 74% of the total heating and hot water demand and 54% of the total electricity demand. The size of each unit was 15 kW for electricity and 30 kW for thermal energy. In this application, the CHP units operated on average about 20 hours per day, and reduced the carbon footprint by 20%.

2.2.2 Objective

It is clearly established that CHP technology for building applications can reduce grid power requirement and lower overall energy costs. It is also possible that CHP units can serve to reduce production of carbon dioxide. However, no comprehensive study has considered optimizing CHPs for multi-family residences. Therefore, this analysis seeks to develop a cost optimal CHP system for a multi-family building. Considered in this study is the impact of the CHP on grid energy purchases, in terms of offsetting purchased electricity from the grid and altering the price per kWh of grid energy. Assumed in this study is central water heating system; thus all recovered thermal energy from the CHP is to be stored in a large water tank.
2.3 Methodology

A framework for developing a cost optimal CHP system for multi-family residences with known historical power and water demand is established. Two design variables are introduced: CHP electrical capacity (kWe) and central hot water tank capacity (kWh). The CHP on/off status each hour is determined by the size of the electrical load, such that the CHP operates at 100% capacity when the load is greater than the peak CHP electrical output. Otherwise the CHP is turned off. This means that a larger CHP will have a lower monthly duty cycle (percentage of on-time each month). This analysis thus assumes that at times it will be more cost effective to not operate the CHP. Considered also in the framework are the capitals costs associated with the CHP system and central hot water tank, addressed annually through loan payments or assessed property costs where Property Assessed Clean Energy (PACE) financing is employed.

There is a certain economically beneficial limit associated with increasing the CHP and thermal storage capacity, primarily due to increased capital costs and due to diminishing returns associated with use of the generally lower cost natural gas (NG) relative to electricity cost for equivalent energy in supplanting electricity at periods of time when the real-time grid power costs are lower. The unit cost of grid power is sensitive to load factor (LF), which is defined as the ratio of the average power to the peak power. A large CHP operating with low duty-cycle has the potential to increase the LF and thus decrease the unit grid power cost. However, the CHP capital cost is very nearly proportional to CHP capacity. A small CHP operating with high duty-cycle is likely to decrease the LF and thus increase the unit grid power cost. The idea is to choose a capacity that optimally lowers the total or levelized costs for energy purchase.
Figure 2 presents a block diagram describing how the CHP could be incorporated into the apartment energy system. As shown, it will be used to provide electrical energy to meet heating/cooling, lighting, and appliance demands in addition to thermal energy to meet hot water demands. The thermal energy from the CHP can either be directed to meet immediate hot water needs or can be used for thermal storage in a hot water tank. This thermal storage tank can store thermal energy generated by the CHP, up to a maximum amount $E_{tank}$.

Figure 2: Energy flow diagram of multi-family CHP system design

A dynamic model must be developed in order to predict the total system cost as a function of the CHP and tank capacities. This model begins with an estimation of the load profiles for heating/cooling, lighting/appliances, and water heating for the apartment complex as it now stands using historical unit level interval data for energy and water. It then considers a demand-dependent grid power pricing scenario coupled with an investment recovery strategy. An economic cost function that includes loan payback from investment, grid power purchase, and natural gas purchase is detailed. Finally, an optimization model is
developed to maximize the economic benefit of the CHP given this cost function. Table 1 summarizes the modeling variables used throughout this chapter.

Table 1: Modeling nomenclature for the CHP system

<table>
<thead>
<tr>
<th>Variable Name</th>
<th>Units</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>$CHP_{cap}$</td>
<td>KWh</td>
<td>CHP capacity</td>
</tr>
<tr>
<td>$T_{cap}$</td>
<td>KWh</td>
<td>Hot Water tank capacity</td>
</tr>
<tr>
<td>$S$</td>
<td>KWh</td>
<td>Total hourly CHP output</td>
</tr>
<tr>
<td>$S_E$</td>
<td>KWh</td>
<td>Hourly CHP electrical output</td>
</tr>
<tr>
<td>$S_H$</td>
<td>KWh</td>
<td>Hourly CHP hot water output</td>
</tr>
<tr>
<td>$S_1$</td>
<td>KWh</td>
<td>Hourly CHP hot water directly supplied to load</td>
</tr>
<tr>
<td>$S_2$</td>
<td>KWh</td>
<td>Hourly CHP hot water stored in the tank</td>
</tr>
<tr>
<td>$E$</td>
<td>KWh</td>
<td>Hourly amount of hot water stored in the tank</td>
</tr>
<tr>
<td>$R$</td>
<td>KWh</td>
<td>Hourly hot water released from tank</td>
</tr>
<tr>
<td>$L_{HW}$</td>
<td>KWh</td>
<td>Hourly aggregate hot water load for the complex</td>
</tr>
<tr>
<td>$L_E$</td>
<td>KWh</td>
<td>Hourly aggregate electrical load for the complex</td>
</tr>
<tr>
<td>$G_E$</td>
<td>KWh</td>
<td>Hourly grid power to supply the electrical load</td>
</tr>
<tr>
<td>$G_{HW}$</td>
<td>KWh</td>
<td>Hourly grid power to supply the hot-water load</td>
</tr>
<tr>
<td>$LF$</td>
<td>-</td>
<td>Monthly load factor</td>
</tr>
<tr>
<td>$P_{mean}$</td>
<td>KWh</td>
<td>Average aggregate monthly power demand</td>
</tr>
<tr>
<td>$T_{CC}$</td>
<td>$$/KWh</td>
<td>Tank capital cost per KWh</td>
</tr>
<tr>
<td>$CHP_{CC}$</td>
<td>$$/KWh</td>
<td>CHP capital cost per KWh</td>
</tr>
<tr>
<td>$T_{SYS}$</td>
<td>years</td>
<td>Lifetime of the system</td>
</tr>
<tr>
<td>$I$</td>
<td></td>
<td>Loan interest rate</td>
</tr>
<tr>
<td>$g$</td>
<td>kWh/CCF</td>
<td>Energy conversion for a CCF volume of NG to kWh.</td>
</tr>
<tr>
<td>$C_{NG}$</td>
<td>$$/CCF</td>
<td>Cost of NG per unit volume</td>
</tr>
<tr>
<td>$C_{Total}$</td>
<td>$</td>
<td>Total annual system cost.</td>
</tr>
<tr>
<td>$C_{gen}$</td>
<td>$</td>
<td>The monthly generation cost of grid electricity</td>
</tr>
<tr>
<td>$C_{trans}$</td>
<td>$</td>
<td>The monthly transmission cost</td>
</tr>
<tr>
<td>$C_{grid}$</td>
<td>$</td>
<td>The total grid cost</td>
</tr>
</tbody>
</table>

2.3.1 Load Profile Estimation

The residential load data used for this study is from a multi-family residence in Columbus, Ohio, consisting of 120 apartments of various sizes. This complex was constructed in 2008 and was built to minimum efficiency code standards for lighting, appliances and HVAC. The heating and hot water energy supply is completely electric, and
each apartment has an air-source heat pump with back-up electric resistance heating. For many of the units, the back-up resistance heating operates for the entire heating season.

In a previous study, Raziei et al. utilized hourly demand data available for the apartments for the 6-9-2013 to 6-9-2014 year to estimate hourly demand loads for weather independent electricity, heating, and water heating according to figure 2.

Figure 3: Hourly aggregate apartment power for heating, cooling, and weather independent use for the time period beginning 06-09-2013 to 06-08-2014 [11]

2.3.2 Demand Sensitive Grid Power Pricing Scenario

The optimal size of the CHP is influenced by the impact that the CHP has on the cost of the price of electricity from the grid. There are many pricing strategies used nationwide, but only a demand risk power pricing strategy is considered in this study, as this strategy offers the ability for grid cost savings through supply-side management. A lower load factor is associated with higher energy cost because across a utility district or grid it forces use of less efficient and more costly power generation assets. The pricing
structure considered includes separate monthly generation and transmission prices, both of which are functions of the monthly LF. Figure 5a and 3b illustrate these prices, showing the cost advantage for increasing the LF [33].

Figure 4: (a) Monthly grid pricing generation fee and (b) transmission cost schedule versus load factor [11]

For a constant level of power consumption, the load factor is unity. The measured monthly load factors over the time period considered in the study range from 38% to 53%. At a 38% LF, the combined generation and transmission price is about 0.13 $/kWh, and this decreases to about 0.11 $/kWh for a 53% LF. In order for the CHP to increase LF for grid purchases, a large CHP would be chosen and operated during hours of peak demand, with a low duty cycle, to flatten the grid load. However, this may not be the best strategy, because of the higher cost of the CHP and because the total energy supplied by the CHP would be small due to the low duty cycle. An alternative strategy is to select a smaller CHP and operate it with a higher duty cycle. This will decrease LF, increasing the grid energy price, but this is offset by the large decrease in energy purchases from the grid.

2.3.3 CHP Related Investments

In order to upgrade the apartment complex with CHP, there are many other associated costs that must be taken into account to give a complete understanding of the
economics of the upgrade. As the facility presently has stand-alone electric water heaters, in order to use the thermal energy that the CHP produces, investments in a central hot water storage tank, additional piping to distribute the hot water to the individual apartments, and pumps to move the water are needed. Labor costs would also be incurred in installing these systems.

The electrical side of the CHP upgrade will require a control panel that monitors the real-time load and decides when to turn the CHP on. It also integrates the CHP electrical power with the grid power, so that a mix of the two can satisfy all electrical demands.

### 2.3.4 Cost Function for Optimizing CHP Economic Benefit

In this section, the model used to evaluate the economic benefit of the CHP is described. This model most importantly considers the supply-side economic impact of the CHP, through consideration of grid power reduction from employing the CHP, as well as the effect of the CHP in changing the grid power unit purchase price for the remainder of the electrical demand not supplied by the CHP.

The costs for this system includes: the capital and installation costs described in the previous section, the cost of the natural gas (NG) needed to operate the CHP, and the grid electrical power cost. The capital costs are treated as investments to be paid back via a loan or property assessment (if PACE financed). The total loan or property assessment amount is given by:

\[
\text{Capital Cost} = (1 - \text{Federal Tax Credit}) \times (\text{CHP}_{CP} \times \text{CHP}_{cap} + T_{CC} \times T_{cap} + \text{Pipe}_{C})
\]

where \( \text{CHP}_{CP} \) is the cost per kWe for the CHP, \( \text{CHP}_{cap} \) is the rated electrical output, \( T_{CC} \) is the capital cost per kWh for the storage tank, \( T_{cap} \) is the tank’s maximum thermal storage
capacity, in kWh, and $Pipe_C$ is re-piping costs. The federal tax credit in equation 1 effectively reduces the loan amount for the CHP. The total investment cost increases linearly with CHP capacity. It should be noted that many U.S. states offer additional incentives which can further reduce the capital cost outlay.

The cost of the system is spread out over the lifetime of the CHP, $T_{SYS}$, assumed to be 20 years [34]. The resulting annual loan payment is:

$$Annual \ Loan \ Payment = Capital \ Cost \times \frac{I}{1 - \frac{1}{(1 + I)^{T_{SYS}}}} \quad (2)$$

where $I$ represents the interest rate for the loan, assumed to be 0.05.

The cost of natural gas used to fuel the CHP considers both the displacement of grid electrical power to meet heating/cooling, lighting and appliance loads, and displacement of grid electrical power for water heating from CHP thermal energy. The electrical and thermal energies produced by the CHP for one month are $CHP_E$ and $CHP_{TH}$, respectively. The CHP electrical conversion efficiency is $\eta_E$, and the CHP thermal conversion efficiency is $\eta_{TH}$. Monthly natural gas consumption, $V_{NG}$, for the CHP in units of ccf is specified as follows:

$$V_{NG} = \frac{CHP_E}{\eta_E g} = \frac{CHP_{TH}}{\eta_{TH} g} \quad (3)$$

Here, $g$ is the unit energy from the natural gas in units of kWh per ccf. The cost per unit volume of NG is $C_{NG}$, leading to a monthly NG cost of:

$$NG \ Cost (\$/month) = V_{NG} \times C_{NG} \quad (4)$$

The monthly grid power displaced each month from CHP use is determined in the next section, using the simulation of the CHP.
The monthly grid electrical power cost will be reduced as a result of employing the CHP. However, the grid power price may increase or decrease, depending on how the CHP is deployed and its impact on monthly LF. The grid power cost dependence on LF was described in section 2.3.2.

The total annual cost for supplying power to the apartments forms a nonlinear objective function which is minimized over CHP and storage tank capacities. The objective function is expressed as:

\[ C_{Total} = \text{Annual Loan Payment} + \text{Annual NG Cost} + \text{Annual Grid Cost} \]  \hspace{1cm} (5)

2.3.5 CHP Design

In this context, this study presents a methodology to identify an optimal mixture of grid electrical power and CHP electrical power and heat, fueled by natural gas, for the apartments to minimize the total cost given in the previous section. A family of optimal CHP systems is developed for various fuel pricing structures.

The CHP is activated at each hour the electrical demand is greater than the peak CHP electrical output. This strategy is chosen in order to use all of the CHP’s output electrical energy. The CHP output is not variable; it is either zero or at its rated peak for each hour. With this deployment strategy, a smaller CHP will operate for a greater percentage of hours each month (higher duty cycle) than a larger CHP. Additionally, the heat generated by the CHP will be used to heat hot water directly to meet immediate hot water needs or will be stored in a thermal storage tank. This stored thermal energy can be used later to meet hot water demands.
As shown in figure 2, the CHP output for every hour \((k)\) is divided into CHP supplied electricity, \(S_E(k) = \eta_E \times S(k)\), and CHP thermal energy, \(S_H(k) = \eta_H \times S(k)\) where the efficiencies \(\eta_E\) and \(\eta_H\) represent the fraction of the input energy \(S(k)\) converted into electricity and heat, respectively. The quantity \(S(k)\) is either equal to \(\text{CHP}_{\text{cap}}/\eta_E\) or zero, depending on whether or not the CHP is turned on. The rule for turning on and off the CHP can be expressed as follows.

\[
S_E(k) = \begin{cases} 
\text{CHP}_{\text{cap}} & \text{if } L_E(k) \geq \text{CHP}_{\text{cap}} \\
0 & \text{if } L_E(k) < \text{CHP}_{\text{cap}} 
\end{cases}
\]  

(6)

The electrical load for the apartment complex must be satisfied each hour by the grid and CHP, such that \(L_E(k) = G_E(k) + S_E(k)\), where \(G_E(k)\) is the remaining power supplied from the grid. Similarly, the hot water load must be satisfied according to \(L_{\text{HW}}(k) = S_1(k) + R(k) + G_{\text{HW}}(k)\), where \(S_1(k)\) is directly from the CHP, \(R(k)\) is from the hot water tank, and \(G_{\text{HW}}(k)\) is from the electrical energy supplied by grid for the purpose of hot water heating.

The amount of heat stored in the hot water tank each hour is represented by \(E(k)\), which is updated iteratively each hour according to:

\[
E(k) = E(k - 1) + S_2(k) - R(k)
\]  

(7)

Rules are developed for whether or not heat is added or removed from the storage tank. These are summarized in Table 1.

The dynamic model is initialized by assuming that the hot water storage tank begins with no stored heat. Using the rule for activating the CHP in equation (6), the storage tank energy balance given by equation (7) and the rules described in Table 2, a reduced grid
supply is determinable. The original load for the grid is simply \( L_E + L_{HW} \), and the modified load that the grid must satisfy is:

\[
G = G_E + G_{HW} = L_E + L_{HW} - S_E - S_1 - R
\]

(8)

The total original cost is \( C_{grid} = C_{gen} + C_{trans} \) where \( C_{gen} \) and \( C_{trans} \) are the monthly generation and transmission costs of grid electricity, respectively, given by

\[
C_{gen}(LF, E_{month}) = \text{Gen Price}(LF) \times E_{month}
\]

(9)

\[
C_{trans}(LF, E_{month}) = \text{TransPrice}(LF) \times E_{month}
\]

The dependency of the prices on the monthly load factor LF is illustrated in Figure 4.

Original Total Cost = \( C_{grid}(LF, \sum_k L_E(k) + L_{HW}(k)) \)

(10)

Table 2: Energy dispatching rules for managing CHP, grid, and stored thermal energy

<table>
<thead>
<tr>
<th>Condition</th>
<th>Description</th>
<th>Equations</th>
</tr>
</thead>
<tbody>
<tr>
<td>( S_H(k) &lt; L_{HW}(k) ) AND ( E(k) = 0 )</td>
<td>Hot water load is more than the CHP thermal output, and the hot water tank is empty. Use available thermal energy from CHP, supply the rest from grid.</td>
<td>( R(k) = 0 ) ( S_1(k) = S_H(k) ) ( S_2(k) = 0 ) ( G_{HW}(k) = L_{HW}(k) - S_1(k) )</td>
</tr>
<tr>
<td>( S_H(k) \geq L_{HW}(k) )</td>
<td>Hot water load is less than the CHP thermal output. Satisfy the load with the CHP thermal output, pass the remaining energy into the storage tank. No grid power is used.</td>
<td>( R(k) = 0 ) ( S_1(k) = L_{HW}(k) ) ( S_2(k) = S_H(k) - S_1(k) ) ( G_{HW}(k) = 0 )</td>
</tr>
<tr>
<td>( S_H(k) &lt; L_{HW}(k) ) AND ( E(k) &gt; L_{HW}(k) - S_H(k) )</td>
<td>Hot water load is more than the CHP thermal output, and the storage tank contains enough energy to make up the difference. Use storage tank energy and CHP thermal output to satisfy the load, no grid power is used.</td>
<td>( R(k) = L_{HW}(k) - S_H(k) ) ( S_1(k) = S_H(k) ) ( S_2(k) = 0 ) ( G_{HW}(k) = 0 )</td>
</tr>
<tr>
<td>( S_H(k) &lt; L_{HW}(k) ) AND ( 0 &lt; E(k) &lt; L_{HW}(k) - S_H(k) )</td>
<td>Hot water load is more than the CHP thermal output, and the storage tank does not have enough energy to make up the difference. Use all available CHP output and stored energy for the load, and use grid power to make up the difference.</td>
<td>( R(k) = E(k) ) ( S_1(k) = S_H(k) ) ( S_2(k) = 0 ) ( G_{HW}(k) = L_{HW}(k) - S_1(k) - R(k) )</td>
</tr>
</tbody>
</table>
After implementing the CHP system, the total cost will include the capital costs and NG costs, but the grid purchase will decrease to offset these. The total cost after CHP implementation is given by:

\[
\text{New Total Cost} = C_{\text{grid}} \left( L_{F_{\text{new}}} \sum_k G(k) \right) + \text{Annual Loan Payment}
\]

\[
+ \text{Annual NG Cost}
\]

where \( L_{F_{\text{new}}} \) represents the new monthly load factor seen by the grid, and \( G(k) \) is the hourly grid power as given in equation (8). The new total cost is a nonlinear function of the CHP and storage tank capacities. The cost is minimized over these parameters using a non-linear, constrained optimization solver (fmincon) in Matlab. The optimization problem can be expressed as finding the optimal CHP and tank capacities that minimize the total cost, subject to the constraint that electrical and thermal loads are satisfied at each hour.

2.4 Results

2.4.1 Cost Optimization

Figure 5 shows a bar graph of the actual monthly load totals, split into electricity and hot water, along with the total original cost for each month. The electric component of the load consists of heating, cooling, plug loads, and appliance loads. The total hot water load is consistent from month to month, but the electrical load varies seasonally with heating and cooling demands.
Figure 5: Original monthly load totals and costs. The load is divided into an electrical component (heating, cooling, plug loads, and appliances) and a hot water component.

The system turns on and off the CHP in order to reduce the peak loads that the grid must satisfy. This is illustrated in Figure 6 (top) which shows the hourly total demand for about one week, along with the on/off action of the CHP to reduce demand peaks. When the dynamic model is executed, the CHP supplies thermal energy to satisfy the hot water load or, if there is extra hot water, it stores it in the thermal tanks. Figure 6(bottom) shows the hourly hot water entering the storage tank, the current stored amount of hot water, and the hot water drawn from the tank.
The size of the CHP is the strongest factor for determining costs. Figure 7 plots total cost versus CHP size for three different tank capacities. The minimum cost is at a CHP size of about 60 kWe using a tank capacity of 400 kWh. The duty-cycle for this size is about 63%; e.g., the CHP is used 63% of the time.

To further explore the effect of CHP capacity on cost, Figure 8 presents a bar graph that shows the different costs versus CHP capacity, using the optimized tank size of 400 kWh. Additionally, Figure 9 shows the effect of CHP capacity on duty cycle and LF. It is clear that a larger CHP leads to improved (higher) LF but lower duty cycle. These effects have opposite impacts on the cost. An increasing LF serves to decreases the grid purchase price, but a decreasing duty cycle leads to an increased unit grid purchase price.
Figure 7: Duty-Cycle and total cost versus CHP_CAP for three thermal storage tank capacities

Figure 8: Cost categories and savings ratio as a function of CHP capacity
The monthly reduction in grid power at the optimal condition is illustrated in Figures (10) and (11). The CHP output varies seasonally; for example, there are more peaks in the demand in January, which causes greater CHP operation. Figure (10) also summarizes the monthly improvements to the total cost by using the CHP system for the optimal system. The original grid cost is shown next to the new grid cost. Figure (11) further illustrates the monthly costs associated with the optimal CHP and storage size broken down by the various costs included in the analysis.
Figure 10: Monthly energy from the grid before and after the CHP installation

Figure 11: Summary of monthly costs before and after CHP installation

The present value for each of these yearly savings is computed assuming an interest rate on the loan of 5%. The CHP system capital costs are assumed to be incurred completely
at the beginning of the lifetime as a negative quantity, and the summation of these values produces NPV. The IRR for this scenario is defined as the interest rate that would drive the payback time to be the entire lifetime, such that it requires the full 20 years achieving a zero NPV. The IRR is a measure of the value of the initial investment. Table 3 below shows the NPV and IRR calculations.

### Table 3: NPV and IRR calculations for the CHP system

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional Grid Power Cost ($/year)</td>
<td>$115,310</td>
</tr>
<tr>
<td>Inflation rate for Grid Power</td>
<td>5%</td>
</tr>
<tr>
<td>NG Cost ($/year)</td>
<td>$11,331</td>
</tr>
<tr>
<td>Inflation rate for NG</td>
<td>3%</td>
</tr>
<tr>
<td>Initial Capital Cost</td>
<td>$231,300</td>
</tr>
<tr>
<td>Loan Lifetime (years)</td>
<td>20</td>
</tr>
<tr>
<td>Loan Interest Rate</td>
<td>5%</td>
</tr>
<tr>
<td>Net Present Value</td>
<td>$612,530</td>
</tr>
<tr>
<td>Internal Rate of Return (IRR)</td>
<td>20%</td>
</tr>
</tbody>
</table>

#### 2.4.2 Parameter Sensitivity

The annual cost relies on many parameters, such as prices, which are random in nature. Because of this, it is important to understand the sensitivity of the annual cost to variations in these parameters. A Monte Carlo risk analysis is presented here to study this issue. The results of such a risk analysis can help with the decision of whether or not to implement a CHP upgrade. The table below describes the parameters influencing cost and the distributions chosen for each.

### Table 4: The parameters influencing cost and the distributions

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Distribution</th>
</tr>
</thead>
<tbody>
<tr>
<td>NG Price ($/CCF)</td>
<td>Uniform from 0.3 to 0.5</td>
</tr>
<tr>
<td>Tank Price ($/kWh)</td>
<td>Uniform from 40 to 60</td>
</tr>
<tr>
<td>CHP Price ($/kWh)</td>
<td>Uniform from 1300 to 1700</td>
</tr>
<tr>
<td>Demand Distribution Charge ($/kW)</td>
<td>Uniform from 3 to 4</td>
</tr>
<tr>
<td>Demand Generation Charge ($/kW)</td>
<td>Uniform from 8 to 10</td>
</tr>
</tbody>
</table>
The Monte Carlo risk analysis proceeds by randomly selecting values for the parameters in Table 4 according to their distributions, and computing cost. This process is repeated many times, and a histogram of the cost is created. Figure 11 illustrates two such histograms. The histogram centered at $115,000 represents the cost for supplying energy to the building using only grid power. The histogram centered at $88,000 represents the cost associated with the CHP system. Because the histograms have no significant overlap, the CHP system is not likely to increase costs, meaning that implanting the CHP system is low-risk.

![Histogram of annual cost for CHP system and grid-only supply](image)

Figure 12: Distributions of annual cost for the CHP system and for a grid-only supply, using 1000 Monte Carlo repetitions

To examine which parameter in Table 3 most affects the cost, the Monte-Carlo simulations can be conducted by randomly varying one parameter at a time, while keeping the others constant. Figure 12 illustrates three cost distributions created in this manner, associated with NG price variations, grid price variations, and CHP price variations. The sensitivity of the cost to NG pricing is nearly the same as the sensitivity to grid pricing. Both of these
lead to a standard deviation of about 1.6 on the CHP cost. The sensitivity to CHP price is much smaller, which leads to a cost standard deviation of about 0.4.

Figure 13: CHP cost distributions created by varying one parameter at a time, using 1000 Monte-Carlo simulations

2.5 Conclusion

In this study, a CHP system is considered in an all-electric multi-family residential building in order to reduce peaks in the total power demand. The CHP thermal energy is used along with a hot-water storage tank to meet some of the building’s hot-water demand. A mathematical model is developed for minimizing total cost as a function of the CHP and hot-water storage tank capacities, along with a parameter that governs CHP on-time. Total cost is most sensitive to CHP capacity. As this capacity increases, the CHP can smooth peaks in the electrical load (increasing load factor) and more effectively reduce grid electrical cost. However, there is a point at which the growing capital costs for the system will overtake the savings from the grid power purchase.
The dynamic modeling for this study indicates that the optimal CHP and hot water tank capacities are 60 kWe and 400 kWh, respectively. In this case, the CHP provides 65% of the total demand, which reduces total annual cost from $114,850 to $88,336 (23% reduction).

This work demonstrates real opportunity for broad inclusion of CHPs in multi-family residences in supply-side power management schemas. The relatively high hot water heating loads present in multi-family residences are particularly well-suited to CHP application. The demand sensitive grid pricing cost scenario considered here for the Midwest in the US yields quite conservative results. When grid pricing has even greater variation as in US states such as California and New York, the opportunity to employ CHPs for power and water heating in this building sector is even more promising.
CHAPTER III

HYBRID CHP/GEOTHERMAL BOREHOLE SYSTEM FOR MULTI-FAMILY BUILDING IN HEATING DOMINATED CLIMATES

3.1 Introduction

In the United States, about one third of the population resides in about 500,000 multi-family buildings. This building sector accounts for roughly 15% of the total residential energy consumption [7]. Despite the magnitude of energy consumption, energy efficiency in this sector is lagging. Recent studies indicate that energy intensities for multi-family rentals are 37% higher than multi-family owner occupied units such as condos or co-ops, 41% higher than single family stand-alone rentals, and 76% higher than single family, owner-occupied stand-alone units [8]. There are several reasons for this higher energy consumption. First, if energy bills are included in the rent, renters have little motivation to save energy. Renters who are responsible for directly paying their utility bills generally consume less energy than renters who pay indirectly [9]. Secondly, landlords have little motivation to invest in energy efficient upgrades, especially if renters pay the bill, as residents would be the beneficiaries of the investment, not the owner.

According to the American Council for Energy-Efficient Economy, there is immediate potential to improve energy efficiency of multi-family buildings in the US by 30%, thereby significantly reducing CO2 emissions and saving an estimated total of $3.4
billion in energy costs yearly [10]. To encourage these savings, there are often tax incentives for upgrading to more energy efficient systems and programs that educate building owners [11]. However, there is a long way to go for education to reach owners and to yield action from the education.

3.1.1 Combined Heat and Power

Combined heat and power (CHP) systems are one possibility for improving energy efficiency for multi-family housing and to reduce carbon emissions. In a sense, a CHP can represent another possible on-site income source for a landlord. A natural-gas powered CHP that provides both electricity and heat to the building could be profitable in terms of energy sales to residents, especially given the relatively low cost of natural gas.

CHP’s can provide an almost uninterrupted source of electricity and heat, and they have been shown to be a very practical solution that can reduce total energy requirements and greenhouse gas emissions. When creating electricity with traditional power plants, most of the thermal energy is wasted. CHP devices are also more efficient because they are located close to where both thermal and electrical energy is needed, negating transmission losses. This leads to a much higher overall efficiency for a CHP, as high as 75%. In the US, there were 43 GW of CHP capacity in the electric power sector as of 2011, mostly powered with natural gas, accounting for about 7.9% of electricity generation [30]. Most of the CHP power in the US is used by large industries, although there is potential for growth of small-scale systems to power individual buildings such as hotels, college campuses, and multi-family residences, where there is balanced energy requirement between year round water heating and electricity, a perfect condition for deploying CHPs. Tax incentives and a good regulatory environment are helpful for driving investment in
CHP technology for the residential sector, but more research and development on its application is necessary to employ the federal and state policies in the US that favor CHP systems [35].

For multi-family residence applications, the thermal energy output from a CHP can be used to directly heat a building, providing hot-water, or cooling the building if it is used in conjunction with an absorption refrigeration unit. However, in heating dominated environments, the thermal power requirements (heating and water heating) can dominate electricity demand. This work explores the possibility of integrating a CHP with a ground coupled heat pump (GCHP) for a multifamily residence. The GCHP serves to meet a large part of the heating and cooling demand, while the CHP supplies electrical energy and heat for hot water. In this hybrid system, excess thermal energy from the CHP can be passed to the GCHP for earth storage. This energy can then be extracted during winter months to address the increased heating loads in the winter.

3.1.2 Geothermal Vertical Heat Exchanger

GCHP systems use the ground as a heat source or sink to improve the efficiency of space heating and cooling. The earth provides temperatures for cooling that are lower than the ambient air temperatures in summer, and temperatures for heating that are higher than the ambient air temperatures in winter. A large number of GCHP systems have been used in residential and commercial buildings due to their higher efficiency and lower environmental impact [28].

One of the most significant ground properties is its undisturbed temperature. For heating applications, a higher ground temperature leads to a more efficient system, and for cooling applications a lower ground temperature is better. However, a range of
temperatures is useful for both applications throughout the year. Over many years, it is possible for the ground temperature in a borehole field to gradually increase or decrease, depending on which load (cooling or heating) is greater on average. This gradual temperature change can degrade the performance of the system.

In systems that have a large imbalance between the heating and cooling loads, it is possible to add other components to the system that can extract or reject heat to the ground, to offset the imbalance. For example, if cooling is the dominant load, then the ground temperature could rise over time, which would degrade the cooling performance of the system. To offset this imbalance, it is necessary to extract excess heat from the ground, which could be achieved with a cooling tower or a solar collector array that circulates the medium fluid and radiates heat to the atmosphere [29]. If the heating load is dominant, it is possible to pass supplemental heat to the ground from a heat source. Systems that have such additional heat rejection or extraction components are known as hybrid GCHP systems. The advantage of a hybrid arrangement is that it serves to reduce the size, and therefore cost, of the GCHP, as compared to a non-hybrid system [29].

In this research, a hybrid CHP and GCHP system is considered for a heating-dominated application. The electrical output from the CHP source will satisfy the building electrical load, and the CHP thermal output will satisfy the building hot-water demand. Any excess thermal energy not capable of being used immediately for water heating will be passed into a vertical borehole heat exchanger in order to balance the annual GCHP thermal loads. Furthermore, excess electrical generation is stored in batteries for later use or is sold back to the grid.
This system lowers have the potential to lower cost in several ways: by reducing grid power purchases, by improving heating and cooling efficiency with a GCHP, and by reducing the necessary size of the GCHP system as a result of using excess CHP heat to balance annual ground storage thermal loads.

3.2 Objectives

The objectives of this study are to:

1) demonstrate the feasibility of hybrid CHP and GCHP systems for a multifamily residential building in heating dominated climates order to achieve net zero grid energy purchases;
2) optimize the cost of a combined CHP, GCHP, and battery storage for multi-family residences over the size of the CHP and battery storage capacity; and
3) evaluate the sensitivity of the optimal system configuration to changes in climate.

3.3 Methodology

Figure 14 provides a schematic of the CHP, GCHP, and battery storage system as integrated into a multi-family residence. In order to extract maximum benefit from the CHP, continuous operation of the CHP is assumed. As well, the CHP electrical output dispatching is prioritized to meet building demands directly to meet building demands. Any excess power generated is dispatched to the battery for later use by the building. If the battery is fully charged, any excess CHP power output is sold back to the utility grid. The thermal energy from the CHP is prioritized to meet hot water demand. Any remaining thermal energy is transferred to the vertical boreholes via a heat exchanger labeled HX.
The geothermal heat pump (HP) is used to extract or reject heat to the boreholes in order to heat or cool the building.

![Energy flow diagram of multi-family CHP and geothermal vertical heat exchange system design](image)

**Figure 14**: Energy flow diagram of multi-family CHP and geothermal vertical heat exchange system design

### 3.3.1 Load Profile Estimation

In order to evaluate the potential value of this combined system from both cost and carbon perspectives in heating dominated climates, two climate conditions for testing are considered (Columbus, OH, US and Winnipeg, CA). Demand data available for a multifamily residence in Columbus, Ohio is used to construct comparable demand data in Winnipeg, CA. The Columbus site consisted of 120 all-electric apartments of various sizes constructed in 2008 to minimum efficiency code standards for lighting, appliances and HVAC. The baseline energy use for this complex was previously established, including estimation of the hourly aggregate energy use for heating, cooling, water heating, and all other appliances and devices [11].
The disaggregated components of the energy consumption are illustrated in Figure 15 on an hourly basis over the course of an entire year. Figure 15a shows the baseline, weather-independent electrical demand associated with appliances and lighting, and hourly hot-water demand is shown in Figure 15b. Figure 15c shows the hourly heating and cooling loads.

Heating and cooling demand data for Winnipeg are constructed from the Ohio heating and cooling demand data by scaling the Ohio data by the ratio of the degree-day values (Canada to Ohio). The result of this is shown in Figure 15d, where the heating and cooling loads are respectively less than the Ohio data [36].

Figure 15: Aggregate hourly building loads a) electrical, b) hot-water, c) heating/cooling for Ohio, and d) heating/cooling for Winnipeg
3.3.2 Power Dispatching

As depicted in Figure 14, the electrical side of the system requires a dispatching algorithm that allocates CHP electrical power to the load and battery, decides when to discharge the battery or use grid power, and decides when to sell excess power back to the grid. The dispatching at all times is governed by the residential electrical load and battery storage charge level. If the building electrical load exceeds the CHP electrical output, then all of the CHP electrical power is dispatched to the building and, if possible, the battery satisfies the remainder. Grid power is used if the CHP and battery cannot meet the load. If the CHP electrical output exceeds the load, then excess CHP power is stored in the battery or is sold back to the grid if the battery is fully charged.

The input energy to the CHP each hour from natural gas, is denoted by \( S \) (kBTU/hr or kW), and is considered constant for continuous operation. This input energy is divided into an electrical component \( S_E = \eta_E S \) and a thermal component \( S_H = \eta_H S \), where efficiencies \( \eta_E \) and \( \eta_H \) are the fractions of the input energy converted into electricity and heat, respectively. For each hour \( k \), the electrical energy output from the CHP, \( S_E \), is dispatched to: support the building load, \( E_2(k) \), charge the battery, \( E_1(k) \), or sold back to the grid, \( E_4(k) \). This dispatching action requires that:

\[
S_E = E_1(k) + E_2(k) + E_4(k) \tag{12}
\]

The electrical load for the apartment complex must be satisfied at each hour, from the electrical energy coming from the CHP, \( E_2(k) \), from energy dispatched from the battery, \( E_3(k) \), or, if these collectively are insufficient, from energy supplied by the grid, \( E_G(k) \).

\[
L_E(k) = E_3(k) + E_2(k) + E_G(k) \tag{13}
\]
The battery charge level is $B(k)$ is updated each hour according to
\[ B(k) = B(k - 1) + E_1(k) - E_3(k). \] (14)

Lastly, the battery storage is characterized by three parameters: a maximum storage capacity $B_{\text{max}}$, a minimum storage capacity $B_L$, and the number of hours $h$ required to charge or discharge the battery. This means that there is a limit on the hourly energy transfers to and from the battery, according to
\[ E_3(k) \leq \frac{B_{\text{max}} - B_L}{h} \] (15)
\[ E_1(k) \leq \frac{B_{\text{max}} - B_L}{h} \]

Additionally, the battery is not permitted to charge and discharge at the same time. At each hour, the dispatching is based on equations (12)-(15) and a few simple rules. If the building load exceeds CHP output, then all of the CHP electrical output is dispatched to the building and the battery satisfies as much of the remaining load as possible. Grid power is used if the former are insufficient to supply the load. If CHP electrical output exceeds the load, then as much of the excess CHP power as possible is stored in the battery. Any remaining power is sold back to the grid.

Figure 16 - Figure 18 illustrate the functioning of this dispatching algorithm. Figure 16 shows how the CHP output electrical power is distributed, according to equation 1, to either the load, battery, or grid. The battery charge level, along with power flows to and from the battery, are illustrated in Figure 17. Finally, Figure 18 illustrates the hourly energy flows into the load, according to equation (13). Only when the battery is at its minimum charge level is grid power used, such as at hour 1300.
Figure 16: Hourly CHP electrical outputs to the load, battery, and grid

Figure 17: Hourly energy flows in and out of the battery, along with the battery charge level
The CHP thermal output $S_H(k)$ is assumed to be always greater than the hot-water load, $L_{HW}(k)$. The remaining thermal energy from the CHP is transferred into the geothermal field through the ground loop heat exchanger, $Q_{geo}(k)$. Thus,

$$Q_{geo}(k) = S_H(k) - L_{HW}(k)$$  \hspace{1cm} (16)

The ground loop heat exchanger is assumed to have a constant effectiveness, such that the same percentage of $Q_{geo}$ is transferred into the boreholes each hour.

### 3.3.3 Borehole Length Calculation

The GCHP system consists of a rectangular array of uniformly spaced vertical boreholes, each with the same depth, having a single u-tube in each borehole. The model for this system follows the development described by Chiasson and Elhashmi, who treated the array as a single vertical line source. This model uses an alternate approach to Eskilson’s g-function, a dimensionless temperature response factor that allows for...
computation of the temperature change at the borehole wall in response to a thermal step input. The goal of the modeling implemented in Matlab is to determine the optimum number of boreholes along each dimension of the array, as well as the optimum borehole depth. The volume of earth occupied by the array must be sufficiently large to handle the heat rejection from the CHP and cooling load, and the heat extraction due to the heating load. Besides the loads themselves, key modeling parameters include ground thermal conductivity, the combined thermal resistance of the borehole piping, medium fluid, and grout material, the undisturbed ground temperature, and the mass flow rate for the medium fluid.

The GCHP modeling involves two parts. First is an optimization of the borehole configuration and length for the given heating and cooling loads as well as the supplemental CHP heat. The second part is a simulation of the ground temperatures that arise when the optimized borehole configuration is used with the specified annual loadings. The temperature simulation process covers the full system lifetime, using a repetition of the same annual load each year.

3.3.4 System Cost Model

This section presents the total system cost model. This model accounts for: the capital costs for the CHP, battery, and geothermal systems, the cost of the natural gas (NG) needed to operate the CHP, and the net grid electrical power purchases and sell-back. The system is envisioned as a retrofit, such that the building already has central hot water heating that the CHP can supply. The capital costs are treated as investments to be paid back via a loan with a fixed interest. Determining the NG requirements, electrical purchases
and sell-back requires running the dispatching model simulation for a full year for typical weather conditions. Table 5 lists variables required to determine system cost.

Table 5 : Variables used for calculating annual system cost

<table>
<thead>
<tr>
<th>Variable</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$CC$</td>
<td>Total system capital cost ($)</td>
</tr>
<tr>
<td>$TC$</td>
<td>Federal tax credit (%)</td>
</tr>
<tr>
<td>$CC_{CHP}$</td>
<td>CHP capital cost ($/kW)</td>
</tr>
<tr>
<td>$CHP_{cap}$</td>
<td>CHP electrical capacity (kW)</td>
</tr>
<tr>
<td>$CC_{bat}$</td>
<td>Battery capital cost ($/kWh)</td>
</tr>
<tr>
<td>$B_{cap}$</td>
<td>Battery capacity (kWh)</td>
</tr>
<tr>
<td>$CC_{ghp}$</td>
<td>GCHP capital cost ($/ft)</td>
</tr>
<tr>
<td>$D_{ghp}$</td>
<td>Borehole depth (ft)</td>
</tr>
<tr>
<td>$N_{ghp}$</td>
<td>Number of boreholes</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Variable</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$T_{sys}$</td>
<td>System lifetime (years)</td>
</tr>
<tr>
<td>$l$</td>
<td>Loan interest rate</td>
</tr>
<tr>
<td>$g$</td>
<td>NG energy density (kWh/kBTU)</td>
</tr>
<tr>
<td>$C_{NG}$</td>
<td>NG price ($/CCF)</td>
</tr>
<tr>
<td>$V_{NG}$</td>
<td>NG consumption (kBTU/month)</td>
</tr>
<tr>
<td>$H_{mth}$</td>
<td>Hours per month (hr)</td>
</tr>
<tr>
<td>$P_{tran}$</td>
<td>Grid transmission price ($/kWh)</td>
</tr>
<tr>
<td>$P_{gen}$</td>
<td>Grid generation price ($/kWh)</td>
</tr>
<tr>
<td>$HE$</td>
<td>Heat exchanger capital cost ($)</td>
</tr>
</tbody>
</table>

The full system capital cost is determined by the four largest hardware components: CHP, batteries, boreholes, and ground loop heat exchanger. The CHP capital cost is proportional to the rated electrical output, $CHP_{cap}$. The battery capital cost is proportional to its storage capacity $B_{cap}$. The geothermal borehole capital cost is computed on a per-meter basis. A federal tax credit, $TC$, reduces the loan amount for the entire system, which is given as follows using the variables defined in Table 5.

$$CC_{tot} = (1 - TC) \times (CC_{CHP} \times CHP_{cap} + CC_{bat} \times B_{cap} + HE + CC_{ghp} \times D_{ghp}) \times N_{ghp}$$  \hspace{1cm} (17)

It should be noted that many U.S. states offer additional incentives to further reduce this capital cost.

The entire system is assumed to operate for a lifetime $T_{SYS}$, and the loan amount is spread out over this period of time [37], leading to the following annual loan payment.
Annual Loan Payment = CC_{tot} \cdot \frac{l}{1 - \frac{1}{(1 + I)^{F_{SYS}}}} \quad (18)

The NG flow rate into the CHP depends on its rated electrical capacity CHP_{cap} and the conversion efficiency, \( \eta_E \). To obtain the monthly NG volume, this rate is multiplied by the number of hours in the month and divided by a conversion factor \( g \) to convert kWh into volume units of CCF.

\[
V_{NG} = \frac{CHP_{cap}}{\eta_E} \cdot \frac{hr_{mth}}{g} \quad (19)
\]

Using the cost per unit volume of \( C_{NG} \) leads to the following monthly NG cost.

\[
NG \ Cost = V_{NG} \cdot C_{NG} \quad (20)
\]

The annual grid cost is found by running the dispatch model for each hour of the year, and summing all of the hourly grid energy purchases \( E_G(k) \) and sellback \( E_4(k) \) energies. The price for grid energy purchases is a function of the load factor presented to the grid, which is affected by the CHP operation [11]. This price is composed of a generation fee, \( P_{gen} \), and a transmission fee, \( P_{tran} \). The price for energy sold back to the grid is also a function of load factor, but sell-back is generally only credited with the generation price. This means that the per-kWh price for grid purchased electricity is higher than the per-kWh sell-back price. The total annual grid purchase and grid-sell back values are computed, and the difference of the two is the net grid purchase cost, as shown in the following equation.

\[
Annual \ Net \ Grid \ Cost = (P_{gen} + P_{tran}) \cdot \sum_k E_G(k) - P_{gen} \cdot \sum_k E_4(k) \quad (21)
\]
The total annual cost for supplying power to the building is the sum of the annual loan payment, NG purchases, and net grid purchases. The annual NG and net grid costs are found by summing the monthly costs generated using the simulation.

\[
\text{Total Cost} = \text{Annual Loan Payment} + \text{Annual NG Cost} + \text{Annual Net Grid Cost}
\]  

(22)

3.3.5 Optimization Process

The total annual system cost is viewed as a nonlinear objective function of the CHP rated electrical output \( CHP_{cap} \) and the battery storage capacity \( B_{cap} \). Cost is minimized over these variables. The geothermal component of the cost depends on the total length, which is a function of the \( CHP_{cap} \) according to the extra heat available from the CHP to put into the boreholes. Evaluating the cost objective function requires the following steps.

1. Input the CHP rated electrical output and battery storage capacity.
2. Compute the excess annual thermal energy from the CHP by subtracting total hot-water load from the total thermal energy produced by the CHP.
3. Optimize the geothermal borehole array size, depth, and borehole spacing based on the heating and cooling loads and excess CHP thermal energy, as discussed in section 3.3.3.
4. Run the CHP electrical dispatching model for a year according to the equations in section 3.3.2 to predict annual NG purchases and net grid purchases
5. Evaluate the total system cost using equations (17) – (22).
The cost objective function is optimized using Matlab’s “fmincon” command, which implements sequential quadratic programming to find CHP capacity and battery capacity to minimize total cost. Additionally, it is useful to view the cost as a function of CHP capacity while holding battery capacity constant. One possible way to constrain the system operation is to set the power sold back to the grid equal in value to the power purchased from the grid, such that there is net-zero grid cost. This target is similar to those established by the US government for federal building energy consumption in the near future [38].

3.4 Results

3.4.1 Minimum Cost with Net Zero Grid Constraint

The overall cost is first explored for combinations of CHP rated electrical output $CHP_{cap}$ and battery capacity $B_{cap}$. Figure 19 shows plots of this cost versus $CHP_{cap}$ for three different battery capacities at both locations, Ohio and Winnipeg. These plots indicate a cost trade-off between the battery and CHP components. It is possible to achieve the minimum cost with a larger battery (450 kWh) and smaller CHP (75 kW), or with a larger CHP (100 kW) and smaller battery (350 kWh). Another interesting observation is that the same size CHP can minimize the cost at both of the locations, even though the Winnipeg location has a significantly higher heating load. The reason this occurs is that the CHP sizing is determined primarily by the electrical load, which is assumed the same for both locations considered. The larger heating load in Winnipeg has the effect of increasing the borehole size, causing a vertical shift in the cost curves.
The results in Figure 19 are generated with no constraints on the CHP and battery sizes. If the net-zero grid purchasing constraint is in effect, then the battery size effectively becomes a function of the CHP capacity. Figure 20 and Figure 21 show this effect for Ohio and Winnipeg, respectively. The upper plot in both figures shows the battery capacity as a function of CHP size necessary to minimize the absolute difference between the annual grid purchases and sell-back. Battery capacity decreases as a function of CHP size, in order to maintain the net-zero constraint. The middle plots in each figure show that cost increases as CHP size increases. The bottom plot in each figure confirms whether or not the constraint is met. Notice that it is possible to match the purchase and sell-back amounts only for CHP sizes from about 80 kW to 100kW. Below this range, the purchases are greater than the sell-back. Above this range, the sell-back is greater than the purchases. For both locations, the CHP size that minimizes cost and satisfies the constraint is about 80
kW. The minimum annual Ohio and Winnipeg total costs are approximately $65,000 and $83,000, respectively.

Figure 20: Optimization results for Ohio under the constraint that annual grid purchases are the same as annual grid sell-back

Figure 21: Optimization results for Winnipeg under the constraint that annual grid purchases are the same as annual grid sell-back
3.4.2 Borehole Length and Temperature

Table 6 illustrates parameters necessary for determining borehole length and temperature as a function of the heating load, cooling load, and CHP size. The table presents parameter values used in the Ohio location. The values used for the Winnipeg location are the same, except for the average earth temperature and thermal conductivity, which are 4°C and 1.4 W/m·C, respectively.

<table>
<thead>
<tr>
<th>Variable</th>
<th>Description</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bore Radius</td>
<td>Radius of each borehole</td>
<td>0.0635</td>
<td>m</td>
</tr>
<tr>
<td>Peak Duration</td>
<td>Time for the maximum load</td>
<td>6</td>
<td>hrs</td>
</tr>
<tr>
<td>Tg</td>
<td>Average underground earth temperature</td>
<td>10.88</td>
<td>C</td>
</tr>
<tr>
<td>Kg</td>
<td>Average ground thermal conductivity</td>
<td>1.731</td>
<td>W/m·C</td>
</tr>
<tr>
<td>VHC</td>
<td>Average ground volumetric heat capacity</td>
<td>2.34</td>
<td>MJ/m3·C</td>
</tr>
<tr>
<td>m</td>
<td>Design flow Rate</td>
<td>2-3</td>
<td>gpm</td>
</tr>
</tbody>
</table>

Using these parameters and the heating and cooling loads for the two locations, the length optimization process described in section 3.3.3 is implemented for different CHP sizes. The total system cost depends on the optimum borehole length, which is a function of the heating and cooling loads, as well as the CHP size. Therefore, it is necessary to explore how the borehole length changes with respect to CHP size. Figure 22 plots borehole length versus CHP size for each location. From this figure, it is clear that a CHP size of about 65 kW produces the shortest borehole depth for Ohio, and a CHP size of about 80 kW produces the shortest borehole depth for Winnipeg. Figure 22 also illustrate the effect that the colder Winnipeg winter has on the necessary borehole depth relative to Ohio.
Performing the optimization described in section 3.3.3 on a stand-alone GHP system over a 20-year period, with no supplementary CHP heat, yields the heat pump entering fluid temperatures shown in Figure 23. Two curves are shown; one for Ohio and one for Winnipeg. A gradual decrease in borehole temperature from year to year is evident due to the fact that the heating load is larger than the cooling load in both locations. The imbalance is larger for Winnipeg, leading to a greater temperature drop over time for that location. Even after 20 years of operation, the temperature in the ground storage volume has not quite reached steady-state. For both locations, the optimized borehole configuration was 10 x 10 boreholes with 7 m spacing in a square pattern. The borehole depths considered in this plot were respectively 120 m and 210 m for the Ohio and Winnipeg locations.
Because the CHP continuously produces excess thermal energy, the hybrid GCHP system can accept a fraction of this excess energy necessary to balance the heating and cooling loads. When the loads are balanced, the temperature drifts illustrated in Figure 23 are corrected. For the Ohio location, 70% of the excess heat available from the 80 kW CHP is sufficient to balance the loads. For the Winnipeg location, 100% of the excess heat from the same size CHP will very nearly balance the loads. Performing an optimization on the hybrid CHP/GCHP system generates the temperature profiles shown in Figure 24. For both locations, the optimized borehole configuration was 10 x 10 boreholes with 7 m spacing in a square pattern. The optimal borehole depth determined to be respectively 60 m and 100 m for the Ohio and Winnipeg locations. For the Ohio location, there is sufficient excess energy to prevent ground temperature drift over the system lifetime, although 20% of the

Figure 23: Heat pump entering fluid temperature variation for a stand-alone GCHP
excess CHP energy is wasted. For the Winnipeg location, all of the excess CHP energy is utilized, and only a slight temperature drift is observed.

Figure 24: Hybrid GCHP heat pump entering fluid temperatures for a 20-year period

3.4.3 Reduction in Cost and CO2 Production

Figure 25 and Figure 26 bar graphs for Ohio and Winnipeg that illustrate the cost benefit of the hybrid CHP/Geothermal borehole system on a monthly basis. Each graph compares an original monthly energy cost assuming all of the loads are satisfied with grid power to the optimized hybrid system cost. The life-cycle cost analysis compares the value of the hybrid system relative to using grid power for all building loads. Predictions of the yearly savings for a 20-year lifetime are made. The yearly cost for conventional power is found by adding the monthly values in Figure 26, considering an annual energy inflation rate of 5%. The annual hybrid system operating costs are computed for each year of the system lifetime, also by adding the monthly NG prices shown in Figure 26, and an inflation
rate of 3% for NG cost. This permits estimation of the yearly savings over the lifetime of the investment.

Figure 25: Original all-electric monthly energy costs compared to hybrid CHP/geothermal costs for Ohio

Figure 26: Original all-electric monthly energy costs compared to hybrid CHP/geothermal costs for Winnipeg
The present value for each of these yearly savings is computed assuming an interest rate on the loan of 5%. The hybrid system capital costs are assumed to be incurred completely at the beginning of the lifetime as a negative quantity, and the summation of these values produces NPV. The IRR for this scenario is defined as the interest rate that would drive the payback time to be the entire lifetime, such that it requires the full 20 years achieving a zero NPV. The IRR is a measure of the value of the initial investment. Table 7: NPV and IRR calculations for the hybrid system in Ohio and Winnipeg below shows the NPV and IRR calculations for two locations: Ohio and Canada. The IRR for the two locations is estimated to be 17% and 20% for Ohio and Winnipeg, respectively. These results indicate the cost advantage of operating in a location that is heating dominated.

Table 7: NPV and IRR calculations for the hybrid system in Ohio and Winnipeg

<table>
<thead>
<tr>
<th></th>
<th>Ohio</th>
<th>Winnipeg</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional Grid Power Cost ($/year)</td>
<td>$115,310</td>
<td>$115,310</td>
</tr>
<tr>
<td>Inflation rate for Grid Power</td>
<td>5%</td>
<td>5%</td>
</tr>
<tr>
<td>NG Cost for Hybrid System ($/year)</td>
<td>$26,831</td>
<td>$26,831</td>
</tr>
<tr>
<td>Inflation rate for NG</td>
<td>3%</td>
<td>3%</td>
</tr>
<tr>
<td>Initial Capital Cost</td>
<td>$827,240</td>
<td>$1,211,200</td>
</tr>
<tr>
<td>Loan Lifetime (years)</td>
<td>20</td>
<td>20</td>
</tr>
<tr>
<td>Loan Interest Rate</td>
<td>5%</td>
<td>5%</td>
</tr>
<tr>
<td>Net Present Value</td>
<td>$1,240,900</td>
<td>$3,097,200</td>
</tr>
<tr>
<td>Internal Rate of Return (IRR)</td>
<td>17%</td>
<td>20%</td>
</tr>
</tbody>
</table>

For the hybrid system, CO2 production comes from the NG burned by the CHP, and from the purchased grid power. Each thermal of NG is assumed to produce 11.02 pounds of CO2, and each kWh of grid power produces 1.4 pounds of CO2. With the original all-electric system, only grid power produces CO2, at the same rate. The CO2 reduction of the hybrid system is 15% for Ohio, and 30% for Canada. This model does not take into account the CO2 produced when the CHP and other hardware is manufactured.
3.5 Conclusion

This work presents a design for a hybrid CHP and GCHP system for a multi-family building, such that the CHP electrical output satisfies the electrical load and the CHP thermal output meets demand for hot water. On the electrical side, batteries are used to store and release electrical energy to better match the CHP supply to the load. Grid power is used as backup during times of high demand, and any excess CHP electrical power can be sold back to the grid during times of low demand. The building’s heating and cooling loads are provided by the GCHP. In a heating-dominated climate, excess CHP heat that is not used for hot water is passed into the borehole system in order to balance the heating and cooling loads, and prevent ground temperature drift.

The hybrid system was simulated using historical loads from a multi-family residence in Ohio, along with a GCHP model and a dispatching algorithm for handling electric and thermal energy flows, and battery state of charge. The simulation determines power flows from the CHP to each system element, and predicts ground temperature drift caused by any heating and cooling imbalance presented to the GCHP system. Optimization is performed to minimize an annual system cost, with the constraint that the net grid energy purchases is equal to the energy sold back to the grid (net-zero metering).

Results are generated by operating the system in two locations: Columbus, Ohio in the US, and Winnipeg in Canada.
CHAPTER IV

PV-THERMAL SYSTEM WITH DESALINATION

4.1 Introduction

As global demand for fresh water increases, desalination technology is becoming more important because natural supplies of fresh water are fixed. Currently, nearly 40% of the world’s population is affected by water shortages [39]. The global desalination capacity is 90 million m$^3$ per day, far too small to offset shortages [40]. Much of this is concentrated in the Middle East, where dry Arab countries have used desalination to meet their fresh water demand [41].

The Kingdom of Saudi Arabia (KSA) is the largest producer of desalinized seawater, with 17% (17.2 million m$^3$ per day) of the worldwide capacity. Over the next 20 years, it is predicted that the KSA will need to increase this output by 6 million m$^3$ per day [42]. The energy needed for desalination in the Middle East is mainly provided by burning oil. For example, the KSA currently consumes more than 1.5 million barrels of oil per day to operate its desalination plants [43]. A barrel of oil has enough energy to produce about 5 m$^3$ of desalinized water [42]. The fossil-fuel energy consumed in seawater desalination raises concerns about greenhouse gas (GHG) emissions.

The use of renewable energy for powering desalination is of great interest, in order to reduce oil-consumption, although currently only about 0.02% of the world’s production
is renewable-powered [44]. Solar photovoltaic (PV) or solar thermal represents most of this fraction, and these technologies are appropriate for the Middle East due to the large levels of solar radiation there. Countries in and around the Middle East are trying to transition to renewable solar desalination, although the technology is expensive relative to burning oil, and it can be difficult to implement.

In the KSA, desalination plants are dual-purpose, producing both electricity and water for coastal urban centers. To avoid transportation costs, large-scale plants are mostly located on the Red Sea or the Gulf, where there is a supply of seawater and dense populations to use the product. Inland KSA cities sometimes incur a high cost for pumping. To avoid pumping costs, isolated facilities can use small-scale desalination plants (mobile or stationary) which can supply hotels, hospitals, offshore platforms, ships, etc. with fresh water. In remote communities that have periodic water shortages, small mobile desalination units are often used.

There are two basic types of desalination: thermal, and membrane. Globally, 68% of desalination is membrane based, 30% is thermal, and the remainder uses other processes [45]. Within the thermal desalination sector, multi-stage flash (MSF) technology is the most common, and reverse-osmosis (RO) is the most common membrane process [46]. MSF operates by passing heated seawater into a sequence of vacuum chambers, to promote flash evaporation. The resulting vapor condenses onto heat exchangers which transfer thermal energy to the incoming feed seawater. Because MSF is reliable and is easy to operate, and can be powered by burning fossil fuels, it is frequently used in Middle Eastern nations [41]. RO operates by allowing passage of water molecules through special membranes by applying high pressure. RO is the most common membrane process because
of its low energy intake and greater recovery percentage [47]. The performance for an MSF system depends on many factors. One factor of interest that affects performance is the temperature of the feedwater [46]. For example, if the feedwater temperature is too low, then the salinity of the product water becomes too high [48]. Plus, there is a seasonal effect on the quality of water produced from this process. Several researchers concluded that summer distillate is higher than winter production due to the higher summer feedwater temperatures [49].

In contrast, RO desalination is also affected by feedwater temperature. The RO recovery ratio, consumed energy per cubic meter, and the salt rejection are impacted by the feedwater temperature, as revealed by many studies [50]. Higher feedwater temperatures have been shown to improve the recovery ratio and reduce power consumption [51]. MSF requires a mix of thermal and electric energy (for pumping), whereas RO primarily requires electrical energy. However, if the RO feedwater is to be heated in order to improve performance, then RO also requires thermal energy.

Solar radiation can be converted into thermal or electric energy, and therefore most attention for renewable desalination focuses on solar based systems. Renewable desalination is appropriate for dry, sunny, and remote regions where no other mode of power is possible. Photovoltaic (PV) cells convert solar radiation into electrical power, but their efficiency is reduced when their temperature increases. One way to overcome this problem is to cool the solar cells with a circulating flow of coolant, which improves electrical efficiency while producing thermal energy. The result is a hybrid PV-thermal (PVT) unit [23]–[26].
Because electricity production is most often the priority, PVT is not used as much as PV or solar collector units alone. However, PVT systems have a lower cost per unit of electricity and heat produced for the same total surface area needed for their installation [24]. The total area requirements for a PVT collector system are about 40% less (IEA, 2007) than separate PV and solar thermal collectors with the same total capacity. In many applications of hybrid PVT systems, the electrical output is prioritized, such that the operating conditions of the heat transfer unit are controlled in order to maximize electrical output, not thermal output. However, PVT can be designed in order to optimize heat transfer, creating higher outlet fluid temperatures while sacrificing some PV efficiency [27]. PVT is therefore adjustable depending on the energy requirements for the application. Because of its flexibility in terms of thermal versus electric energy outputs, PVT could be appropriate for desalination applications in KSA, where high-temperatures reduce the efficiency of PV systems.

The concept for the current work is to optimize the integration of PVT for small-scale desalination appropriate for a remote community in KSA. The design considers using a mix of PVT and conventional electrical power to drive RO desalination. The PVT thermal output can raise the feedwater temperature, improving RO performance, and the PVT electrical output provides some of the RO power needs. Excess PVT electrical power may be stored in a battery for nighttime desalination, along with grid power as needed, to maintain continuous RO production.
4.2 Methodology

4.2.1 Plant Design

Figure 27 contains a block diagram of the PVT with RO design. The feedwater source is assumed to be a reservoir of brackish water, and it provides a constant mass flow to the system, part of which flows through the PVT array in order to gain thermal energy and reduce the PV cell temperature in the array. The PVT array tilts to track the sun. At night or during times when the air temperature is too low, the feedwater is shunted around the PVT array so that it does not lose heat to the atmosphere. The thermal storage tank contains a fixed volume, and the temperature in the tank fluctuates according to the feedwater temperature and solar energy fluctuations. The heated water stored in the tank then provides a fixed flow to the RO, and its higher temperature serves to reduce the electrical power needs for various pumps throughout the system. On the electrical side of the system, the PVT array provides as much electrical power as possible for pumping requirements. Excess electrical power generated during the day is stored in a battery, which is then used by the system at night. Grid power makes up the remaining electrical needs in the early morning hours, after the battery has drained.
4.2.2 PVT Modeling

Although there are several PVT configurations, the type considered here is a flat-plate collector. The basic structure of this collector is shown as a cross section in Figure 28. Fluid circulates beneath a layer of standard PV cells, extracting heat from the cells and allowing them to operate at higher electrical efficiency. There are ways to make such a structure favor the electrical or thermal output. For example, using an extra layer of glass on top of the PV cells increases the temperature and improves thermal performance, but degrades electrical performance somewhat [52]. A glazed PV/T configuration is selected since it promotes thermal energy production [53]. Equations for thermal and electrical modeling are required to model both outputs from the PVT, along with information about fluid mass flow, inlet temperature, and PVT array configuration in terms of parallel and series connection of individual panels [54].
4.2.3 Thermal Equations

The PVT model equations are based on heat transfer principles [53]. The array is assumed to consist of \(N_p\) collectors in parallel and \(N_s\) in series, for a total number of \(N_s \times N_p\) panels. The total thermal power transferred by the entire array to the fluid is \(\hat{Q}_{\text{u,total}}\), given by the following equation.

\[
\hat{Q}_{\text{u,total}} = N_p \times \hat{Q}_{\text{u,Ns}}
\]  

(23)

The quantity \(\hat{Q}_{\text{u,Ns}}\) represents the thermal power transferred to the fluid flowing through \(N_s\) panels in series.

\[
\hat{Q}_{\text{u,Ns}} = N_s A_C F_R \left[ S \left( \frac{1 - (1 - K_K)^{N_S}}{N_S K_K} \right) - U_L \left( \frac{1 - (1 - K_K)^{N_S}}{N_S K_K} \right) (T_{fi} - T_a) \right]
\]  

(24)

In this equation, \(A_C\) is collector area, \(F_R\) is a heat removal factor, \(S\) is solar radiation per unit area absorbed by the collector, \(U_L\) represents the overall thermal conductance for heat losses, \(T_{fi}\) is inlet flow temperature, and \(T_a\) is ambient air temperature. The quantity \(K_K\) is given by

\[
K_K = \frac{A_C F_R U_L}{m C_p}
\]  

(25)
where \( m \) is the fluid mass flow rate and \( C_p \) is the fluid specific heat. The solar radiation per unit area absorbed by an individual PVT panel is

\[
S = I(\alpha \tau) \left(1 - \eta_c / \alpha\right)
\]

(26)

where \( I \) is solar irradiation intensity, \( \eta_c \) is electrical efficiency at cell temperature, \( \alpha \) is the absorptance of the collector, and \( \tau \) is the transmittance of the glazing on the collector.

The outlet fluid temperature from \( N_s \) panels in series is given by

\[
T_{fo} = \left[ \frac{S}{U_L} + T_a \right] \left[ 1 - e^{-\left(\frac{-N_sA_cF_RU_L}{mc_p}\right)} \right] + T_{fi} e^{\left(\frac{-N_sA_cF_RU_L}{mc_p}\right)}
\]

(27)

The collector heat removal factor is given by the following equation,

\[
F_R = \frac{mc_p}{U_L} \left[ 1 - e^{-U_L'F'/mc_p} \right]
\]

(28)

where \( F' \) is a constant collector efficiency factor. The PV/T cell temperature \( T_C \) is calculated using the following equation:

\[
T_C = \frac{I(\alpha \tau) + U_{tc,a} T_a + h_{c,p} T_P}{U_{tc,a} + h_{c,p}}
\]

(29)

where \( T_P \) is plate temperature, and \( U_{tc,a} \) and \( h_{c,p} \) are taken from Duffie and Beckman (1991), Tiwari (2005) and Tiwari and Sodha (2006). The PVT thermal efficiency of panel can be defined as

\[
\eta_{th} = \frac{\dot{Q}_{u,total}}{N_S N_P A_C I}
\]

(30)

**4.2.4 Electrical Equations**

The electrical power from the PVT panel is given by:
The electrical efficiency of the PV/T panel is given by:

\[
\eta_c = \eta_r [1 - \beta_r (T_c - 25)]
\]  

where \( \eta_r \) is the electrical efficiency for a cell temperature of 25 C, and \( \beta_r \) is a temperature coefficient for solar cell efficiency, with a value of \( \beta_r = 0.0045 \, 1/C^\circ \).

### 4.2.5 Solar Irradiation, Ambient Temperature, and Feed-water Temperature

Typical meteorological year (TMY) data for a specific location are used to provide hourly solar irradiation, \( I \), and ambient temperature, \( T_a \). The solar irradiation, \( I \), is generated assuming that each panel in the array tilts on a fixed axis in order to track the angle of the sun [55]. The effect of wind on the heat transfer from the PVT array is ignored. The feed-water is assumed to be pumped out of the ground and into a holding reservoir before being pumped through the PVT array. In this case, the feed-water temperature, \( T_{fi} \), is approximated by low-pass filtering the ambient air temperatures, such that the feed-water temperature tracks the low-frequency variations in air temperature. Figure 29 shows a plot of air temperature from a TMY3 data file, and the filtered air temperature as a model for feed-water temperature. This allows for modeling the effects of the large thermal mass of the feed-water reservoir.

Using the solar irradiation, ambient air temperature, and feed-water temperature, the useful thermal and electrical PVT outputs are computed from equations (23) to (33).
4.2.6 Tank Temperature Modeling

A direct (open) configuration is defined for the storage tank system, such that the water in the tank does not circulate through the PVT array. Instead, some of the brackish source water passes through PVT array in order to gain heat, and then flows directly to the storage tank. At night or when the air temperature is too low, the source water bypasses the PVT array and flows directly to the tank. The total volume of feedwater entering and leaving the tank at each time interval is constant. The temperature in the tank therefore fluctuates according to the available solar energy. Auxiliary heating is used to maintain the tank temperature above a specified temperature, $T_{min}$.

The following energy balance equation governs the thermal energy stored in the tank, and it will be used to determine the tank temperature.

$$ M_T C_p \frac{dT_T}{dt} = \dot{M}_f C_p (T_{fi} - T_T) + \dot{Q}_{u,\text{total}} + \dot{Q}_{aux} + \dot{Q}_{loss} $$  \hspace{1cm} (34)
The tank mass, $M_T$, feedwater mass flow, $\dot{M}_f$, and heat capacity, $C_p$, are constants in this equation. The useful heat from the PVT array that is passed into the tank, $\dot{Q}_{u,total}$, is determined by equation 1. The auxiliary heat added to the tank, $\dot{Q}_{aux}$, to maintain its temperature above, $T_{min}$, and the thermal losses, $\dot{Q}_{loss}$, from the tank are given by the following equations.

$$\dot{Q}_{aux} = \begin{cases} 0 & \text{if } T_T \geq T_{min} \\ (M_T C_p (T_{min} - T_T)) & \text{if } T_T < T_{min} \end{cases}$$

(35)

$$\dot{Q}_{loss} = U_T A_T [T_a - T_T]$$

(36)

The tank surface area is $A_T$, and $U_T$ is a constant loss coefficient. In order to use the differential equation to model tank temperature, the equation is discretized using a time interval, $\Delta t$, such that

$$\frac{dT_T}{dt} \approx \frac{T_T(t + \Delta t) - T_T(t)}{\Delta T}$$

(37)

Making this substitution into the differential equation and solving for $T_T(t + \Delta t)$ gives the following update for the tank temperature.

$$T_T(t + \Delta t) = T_T(t) + \frac{\dot{Q}_{u,total}(t) + \dot{Q}_{aux}(t) + \dot{Q}_{loss}(t) + \dot{M}_f C_p [T_{fi}(t) - T_T(t)]}{M_T C_p} \Delta t$$

(38)

4.2.7 Reverse-Osmosis

RO operates by forcing brackish water to flow through a membrane under high pressure, as illustrated in Figure 30. Water molecules pass through the membrane, forming fresh water, while other molecules are rejected with wastewater.
The mass balance of water and salts across the membrane is calculated by [56]:

\[
\dot{M}_F = \dot{M}_P + \dot{M}_C
\]

\[
\dot{M}_F . C_F = \dot{M}_P . C_P + \dot{M}_C . C_C
\]

where \( i \) = \{F, P, C\} it represents the feed, permeate and concentrate water streams respectively, \( \dot{M}_i \) is the water stream mass flow rate, and \( C_i \) is water stream salts mass concentration. RO modeling is based on the solution diffusion principle. The membrane permeate mass flow rate \( \dot{M}_P \) is given by [56]:

\[
\dot{M}_P = (J_W + J_S) \times S_M
\]

where \( J_W \) is the permeate mass flux through the membrane, \( J_S \) is the salts mass flux through the membrane and \( S_M \) is membrane active area. The permeate mass flux, \( J_W \), through the membrane is modeled by Fick’s law:

\[
J_W = A \left( \Delta P - \Delta \pi \right)
\]

where \( A \) is the membrane pure water permeability, \( \Delta P \) is the transmembrane pressure and \( \Delta \pi \) is the transmembrane osmotic pressure. The salts mass flux, \( J_S \), through the membrane is modeled by:

\[
J_S = B \left( C_W - C_P \right)
\]
where $B$ is the membrane salts permeability, $C_w$ is the wall mass salts concentration, and $C_p$ the permeate mass salts concentration in kg of salts per kg of water. The transmembrane pressure, $\Delta P$, is calculated with:

$$\Delta P = P_F - P_P - \frac{\Delta P_{drop}}{2}$$  \hspace{1cm} (43)

where $P_F$ is the applied feed pressure, $P_P$ is the resulting permeate pressure, $\Delta P_{drop}$ the pressure drop along the membrane channel.

The power requirements for RO operating at a fixed production level are dependent on the temperature of the incoming brackish water. For higher temperatures, the pressure requirement is less, which reduces the RO power needs. In order to develop the dependency of RO power on temperature, the membrane water permeability, $A$, is approximated as a function of feedwater temperature[56]

$$A = A_{ref}(\Delta \pi) \cdot FF \cdot TCF$$  \hspace{1cm} (44)

where $A$ is the membrane pure water permeability, $A_{ref}(\Delta \pi)$ is the reference permeability at $T_0 = 298K$ without fouling, TCF is the temperature correction factor at $T$, and FF is the fouling factor. The temperature correction factor is given using an Arrhenius type correlation:

$$TCF = e^{\frac{e}{R} \left[ \frac{1}{T_0} - \frac{1}{T} \right]}$$  \hspace{1cm} (45)

where $T$ is the water temperature in K, $T_0$ is the reference water temperature equal to 298 K, $e$ is the membrane activation energy, and $R$ is the universal gases constant. Based on DOW technical documentation, $e$ is estimated for all reverse osmosis membranes to be 25,000 J/mol when $T \leq 298$ K, and 22,000 J/mol when $T > 298$ K.
4.2.8 Plant Power

There are two components to the power consumed by the plant: power to drive the high-pressure pump that pushes the brackish water through the RO, and power to pump water through the PVT and tank from the reservoir source. The RO requires two large high-pressure pumps, and there will be $N_p/2$ smaller pumps for moving the water through the PVT array.

The RO power required is expressed by:

$$P_{RO} = P_{HP} - P_{ER}$$

(46)

where $P_{HP}$ is the power required by the high pressure pump, and $P_{ER}$ is the power recovered from the concentrate water stream. The high pressure pump power is defined by:

$$P_{HP} = 27.78 \frac{P_F M_F}{\eta_{HP}}$$

(47)

where $P_F$ is membrane feed pressure and $\eta_{HP}$ is the pump efficiency. $P_{ER}$ is the power recovered from the concentrate water streams.

$$P_{ER} = 27.78 P_C \dot{M}_C \eta_{ER}$$

(48)

where $P_C$ represented concentrate water pressure and $\eta_{ER}$ is efficiency of the energy recovery system.

The electrical power required for pumping the brackish water through the PVT array and tank is given by:

$$P_{sys} = \frac{\rho g h \dot{M}_F}{3.6 \times 10^6 \eta_{HP}}$$

(49)
where $\rho$, $g$, and $h$ represent water density, gravitational acceleration, and pipe height, respectively.

The total electrical power consumption for the plant is the summation of RO power and electrical power requires for pumping the brackish water through the system.

\[ P_{\text{Total}} = P_{\text{RO}} + P_{\text{sys}} \quad (50) \]

### 4.3 Electrical Power Dispatching

Referring to Figure 21, the electrical side of the system requires a dispatching algorithm that allocates PVT electrical power $Q_e$ to the load and battery, decides when to discharge the battery, and decides when to use grid power. The dispatching is determined hourly by the plant electrical load and the battery storage charge level. If the plant electrical load exceeds the PVT electrical output, then all of the PVT electrical power is dispatched to the plant and, if possible, the battery satisfies the remainder. Grid power is used if the PVT and battery cannot meet the load. When PVT electrical output exceeds the load, the excess power is stored in the battery.

The PVT electrical output is split at each hour $t$ into energy, $E_2(t)$, sent directly to the load, and energy, $E_1(t)$, to charge the battery. Therefore

\[ Q_e(t) = E_1(t) + E_2(t) \quad (51) \]

The total electrical load, $P_{\text{Total}}(t)$, for the plant must be satisfied at each hour, such that

\[ P_{\text{Total}}(t) = E_3(t) + E_2(t) + E_G(t), \quad (52) \]

where $E_3(t)$ is the battery output to the load and $E_G(t)$ is the energy purchased from the grid. The battery charge level is $B(t)$, which is updated each hour according to
\[ B(t) = B(t-1) + E_1(t) - E_3(t) \]  

(53)

The battery storage is characterized by three parameters: a maximum storage capacity \( B_H \), a minimum storage capacity \( B_L \), and the number of hours \( h \) required to charge or discharge the battery. This means that there is a limit on the hourly energy transfers to and from the battery, according to:

\[ E_3(t) \leq \frac{B_H - B_L}{h} \]  

(54)

\[ E_1(t) \leq \frac{B_H - B_L}{h} \]

Additionally, the battery is not permitted to charge and discharge at the same time. At each hour, the dispatching proceeds based on equations 29-32 and a few simple rules. If electrical load exceeds PVT output, then all of the output is dispatched to the system and the battery satisfies as much of the remainder as possible, with grid power used as a last resort. If PVT output exceeds the load, then as much of the excess PVT power as possible is stored in the battery, and any remaining power is sold back to the grid.

4.3.1 System Simulation

Using the models for the PVT, storage tank, RO, and electrical dispatching, a single dynamic model simulation for the system is constructed. The system is characterized by a fixed production level of 362 m³/day of distilled water, a location for the TMY3 data, and four system parameters: \( N_s, N_p, M_T, \) and \( B_{cap} \). To illustrate the action of the system, plots are included here for a single case for a location in KSA for the following conditions: \( N_s = 10, N_p = 80, M_T = 250,000 \text{ kg}, \) and \( B_{cap} = 1000 \text{ kWh} \). Figure 31 shows the total system electrical load along with the PVT electrical output, indicating the peaks due
to solar activity during each day. Also shown is the tank temperature, and it is clear that the load drops decrease for higher temperatures. The variations in tank temperature are about 5 degrees, causing a power variation of about 10 kW, which represents about 15% of the peak load.

![Graph showing total system electrical load, PVT electrical output, and tank temperature](image)

Figure 31: Total system electrical load, PVT electrical output and tank temperature (bottom)

The PVT electrical output is only large enough to meet the full load during part of the day. At other times, either the battery or the grid power must be used to make up the rest of the load. Figure 32 illustrates the dispatching model results to meet the load. This clearly shows a similar daily cycle, where PVT output can meet the load during the sunny hours, the battery then meets the load in the early evening and night hours, and the grid meets the load in the early morning hours after the battery has drained and before solar activity begins again. The battery and PVT array sizes are chosen such that all of the PVT electrical power output can be utilized by the load (zero curtailed PVT power).
Figure 32: Electrical dispatching to meet the load, including direct power from PVT, stored battery power, and grid power

To get a sense of average system performance, Figure 33 illustrates monthly totals for the year in terms of three categories of power used to meet the load: power directly from the PVT to the load, power indirectly to the load from the PVT via the battery, and grid power. The figure shows that for the system parameters selected, the typical monthly PVT power penetration is about 70%. In other words, about 70% of the load is satisfied by the renewable power generated by the PVT array.

The system performance as illustrated by Figure 31 – 33 is a function of the PVT array size, the tank volume, and the battery capacity. Average renewable penetration for the year is a single performance measure that can characterize the system as a function of the system parameters. The next section develops economic cost for the system as another measure of performance.
Figure 33: Monthly totals for the year in terms of three categories of power used to meet the load

4.4 System Cost Model

This section presents a model for total annual plant cost, represented as the sum of a payment towards an amortized loan, and annual operating costs (grid-power purchases plus maintenance). Both the loan payment and operating costs are functions of the PVT array size, the battery capacity, and the tank size. The up-front system capital cost is treated as an investment to be paid back via a loan with a fixed interest. Operating costs are determined by running the simulation for the year. Table 1 lists variables required to determine system cost.

Table 8: Variables used for calculating annual system cost

<table>
<thead>
<tr>
<th>Variable</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$CC$</td>
<td>Total system capital cost ($).</td>
</tr>
<tr>
<td>$RC$</td>
<td>KSA renewable-energy credit (%).</td>
</tr>
<tr>
<td>$CC_{PVT}$</td>
<td>PVT capital cost ($/panel).</td>
</tr>
<tr>
<td>$N_c$</td>
<td>Number of PVT panels in series.</td>
</tr>
<tr>
<td>$N_p$</td>
<td>Number of PVT panels in parallel.</td>
</tr>
<tr>
<td>$CC_{bat}$</td>
<td>Battery capital cost ($/kWh).</td>
</tr>
</tbody>
</table>
The full system capital cost is determined by the following components: PVT array, batteries, RO, storage tank, high-pressure pumps for the RO, and low-pressure pumps for moving water through the PVT. The PVT capital cost is computed as the product of the number of panels with a per-panel price. Similarly, the battery capital cost is proportional to its storage capacity \( B_{cap} \), and the storage tank capital cost is proportional to its volume. The RO capital cost is proportional to production capacity \( RO_{cap} \). The full capital cost is found by summing all of the individual component costs, as follows.

\[
CC = CC_{PVT} \cdot N_s \cdot N_p + CC_{bat} \cdot B_{cap} + CC_T \cdot V_T + CC_{RO} \cdot RO_{cap} + CC_{NP} \cdot N_{HP} + CC_{LP} \cdot N_{LP} \tag{55}
\]

KSA encourages and offers incentives to effectively reduce this up-front cost burden, modeled here as a renewable-credit \( RC \). Additionally, KSA offers lower interest rates \( i \) for financing renewable-energy projects are available[57]. The entire system is assumed to operate for a lifetime \( T_{SYS} \), and the loan is amortized over this period of time, leading to the following annual loan payment.
\[ \text{Annual Loan Payment} = CC \cdot (1 - RC) \cdot \frac{i}{1 - \frac{1}{(1+i)^{T_{SYS}}}} \quad (56) \]

The annual grid cost is found by running the dispatch model for the full year, and summing all of the hourly grid energy purchases \( E_G(t) \) energies. Currently, KSA electrical prices are increasing, which serves to further motivate the renewable approach [58]. The grid electrical purchases are computed on a flat price per-kWh basis \( P_{gen} \).

The total annual cost for the plant is the sum of the annual loan payment, and the grid energy purchases.

\[ \text{Total Cost} = \text{Annual Loan Payment} + \text{Annual Grid Cost} \quad (57) \]

4.5 Optimization Process

The total cost is viewed as a nonlinear objective function, which depends on the PVT array size, the tank volume, and the battery storage capacity. The total cost can be optimized over these variables, while keeping all other parameters (interest rate, prices, plant location, production level, etc.) constant. Furthermore, it is possible to perform the cost optimization while constraining the average renewable penetration level. Evaluating the cost objective function requires the following steps.

1. Input the PVT array size, tank volume, and battery capacity.
2. Compute the hourly PVT useful heat and electrical energy output, tank temperatures, and RO electrical demand.
3. Operate the hourly electrical dispatching simulation in order to determine system energy flows, grid purchases, etc.
4. Determine the average renewable penetration.
5. Evaluate the total system cost using equations (53) - (57).

The cost objective function is optimized using Matlab’s “fmincon” package, which implements sequential quadratic programming to find the two PVT array dimensions, tank volume, and battery capacity to minimize cost with constraints on the renewable penetration.

4.6 Results

The cost function is minimized when the PVT supplies 70% of the total system electrical energy needs (70% penetration), with conventional grid power supplying the remaining 30%. In this case, the PVT array size is 10 panels in series \((N_s = 10)\) by 80 panels in parallel \((N_p = 80)\). The tank volume required is 250 \(m^3\), and the battery capacity is 1000 \(kWh\). The annual cost for the PVT system is 18% less than the annual cost for driving the plant with 100% conventional electricity and no pre-heating of the feedwater. The production level is fixed at 362 \(m^3/day\) of distilled water. The following sub-sections describe the performance of the individual system components in detail, along with the components of optimized cost.

4.6.1 PVT Performance

The fluid circulation increases the pumped water temperature in order to improve the system water production. Compared to a PV panel in the same climatic conditions, PVT panel is able to produce more electrical energy due to the decrease in cells temperature caused by the coolant circulation.
Figure 34 shows plots of hourly temperature for the PVT cells, the output water, and the tank temperature. Clearly, the tank serves to buffer the output water temperature, to avoid sending overheated water to the RO, which could damage it. The PV cell temperatures reach as high as 80°C at peak times during the day, which reduces efficiency, but this is within the safe temperature range for their operation.

![Graph showing temperature trends](image)

Figure 34: PVT cell temperature and fluid output temperature, along with tank temperature, for several summer days of operation

The hourly thermal and electric powers from the PVT are shown in Figure 35, on a per-unit-area basis. The PVT generates 3-4 times as much thermal as electric power at peak times. At night, there is no electric power produced, but it is possible to collect thermal energy if the ambient air temperature is higher than the incoming feed-water temperature. This occurs at night during the summer months.
Figure 35: Hourly PVT thermal and electric power production for in summer days

The thermal efficiency as defined by equation (23) is plotted in Figure 36, along with electrical efficiency as determined by equation (33). The definition for thermal efficiency only applies during hours when sunlight is incident on the collector. The results show that at peak times, from 60-70% of the incoming solar energy is converted into useful heat, and that about 12-16% of the incoming energy is converted into electrical energy. The electrical efficiency does drop when the PV temperature is high. Combined peak efficiency for the PVT array is therefore about 80%, which is close to reported values for this type of system.
4.6.2 Cost Optimization with Penetration Constraints

The non-linear cost objective function was minimized with constraints on the renewable energy penetration. This allows for identifying the level of penetration that produces the lowest cost, and it allows for a comparison of extreme cases (very low and very high penetration). Figure 37 shows this result, and the cost is minimized when the PVT supplies 70% of the total system energy needs (70% penetration).
4.6.3 PVT Load and Cost Reduction

Each cubic meter of purified water produced by the RO system requires a certain amount of electrical energy, depending on the feed-water temperature. Figure 38 compares the monthly energy required per cubic meter for two cases: when the feed-water enters the RO directly with no PVT heating, and for the cost-optimized system at 70% penetration that uses PVT feed-water heating and thermal storage. The average monthly percent reduction in energy needs due to the PVT heating is 16%.

Figure 37: Minimized total annual cost as a function of the penetration constraint
In terms of economic cost, the PVT and additional hardware increase the portion of the annual cost due to payment towards capital. The benefit for PVT, however, is the lower operating costs, due to the fact that the PVT reduces the RO electrical energy needs and supplies 70% of that electrical energy.

Figure 39 illustrates monthly average cost per cubic meter of production, for a plant that has no PVT (100 grid power), and a plant that uses the optimized PVT system. The total annual costs for each case are split between the portion allocated to capital, and operating costs. On average, the PVT system serves to reduce cost by 30% relative to a conventional fossil fuel powered system with no PVT. This is a big accomplishment. The PVT augmented RO system is the cost optimal option.
4.7 Conclusion

This work presents a design for optimizing the integration of PVT for small-scale desalination appropriate for a remote community in KSA, such that the PVT electrical output and conventional electrical will satisfy the electrical load for the plant and the excess PVT electrical power may be stored in a battery for nighttime desalination, along with grid power as needed to maintain continuous RO production. The PVT thermal output can raise the feedwater temperature, improving RO performance. It has been shown that the energy demands for RO can be reduced by pre-heating the feed brine.

The non-linear cost objective function was minimized with constraints on the renewable energy penetration. The cost is minimized when the PVT supplies 70% of the total system energy needs (70% penetration). The dynamic modeling for this study indicates that the optimal PVT, hot water tank, and battery capacities are $N_s = 10$, $N_p = 80$, $M_T = 250 \ m^3$ and $B_{cap} = 1000 \ kWh$, respectively. In this case, on average, the PVT
system serves to reduce costs by 30% relative to a conventional fossil fuel powered system with no PVT.
CHAPTER V
CONCLUSION AND FUTURE WORK

5.1 Conclusion

This research has made several significant contributions to the literature on the efficient and economical utilization of CHP technology. First, this work presents a unique in-depth study of a CHP retrofit for a multi-family residence, using real load data as a guide. Modeling results indicate that CHP has real potential to lower overall energy costs along with carbon production for such a building. The first multi-family residence design uses CHP to supply part of the building’s electrical and hot water demand, essentially replacing grid purchases with natural gas to achieve cost savings and improve efficiency. The second multi-family residence design presents a novel hybrid CHP and GCHP system for energy delivery in a cold climate, achieving a balanced ground-loading by passing excess CHP heat to the ground. Despite the fact that the heating load is greater, the second design shows a larger cost reduction than the first design. This is because the second design was capable of achieving net-zero energy purchases, selling as much power to the grid as was purchased. Also, using the GCHP system for heating and cooling loads improved efficiency relative to the first design, which satisfied these load components with electrical power. This work therefore demonstrates that CHP has the potential to make GCHP more feasible in colder climates, which is a significant engineering and business opportunity.
The design and modeling work for RO water desalination is also a new contribution of this work. Normally, RO is considered to have only electrical demands for pumping. However, researchers have shown that heating the feedwater can reduce those demands. Additionally, in hot climates PV tends to lose efficiency due to overheating. This information forms the basis for a new design, using a PVT array to simultaneously pre-heat the RO feedwater while providing power for pumping. The modeling of this design manages both thermal and electrical storage, and determines when backup power is necessary to maintain constant RO output. This design is appropriate for hot, remote regions, and it has potential to reduce the significant GHG emissions caused by water desalination.

5.2 Future Work

Future development of these ideas would initially focus on improved physical models. Currently, the modeling involves CHP energy dispatch in kWh, regardless of load type (thermal or electric) without regard to electrical or thermodynamic issues such as voltage and frequency control, temperature transients, etc. Also, it has been shown that the optimal designs were dependent on one variable which was optimizing cost. It can be multi-variables. For example, optimizing cost, optimizing CO2, and optimizing performance.

Further work could also be done with control algorithms, for example, studying how to incorporate load forecasting into the dispatching algorithm. This would be most appropriate for the residential loads, which follow a relatively predictable weekly routine.
Besides further modeling, future work could involve experimental prototypes. Results could be used to validate the modeling, and control algorithms could be tested.

Natural gas powered CHP designs for a multi-family residence are presented in this work but it can use biogas which can be produced sustainably from raw materials such as municipal waste, sewage, green waste or food waste that will be available in a multi-family complex. Biogas is considered a renewable energy source because it exerts a very small carbon footprint. Therefore, it would be a good idea to study the feasibility of having a small scale biogas plant inside the complex to power CHP for a multi-family residential building in heating dominated climates in order to achieve minimum cost and CO2 production.

Other designs could include coupling PVT with CHP, since the CHP can be ramped up or down to complement the PVT output. The design could be made to optimize the size of each component as a function of climate and location.

Additional designs could include coupling PVT with combined MSF and RO, the thermal output from PVT entered into the MSF unit which will increase the production of MSF. Then, the rejected brine of the MSF unit which is hot is split into two streams. One stream is fed into the RO unit and the other stream goes out to the sea. The electricity output from PVT will drive the power consumption for MSF and RO.
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