An Investigation into the Seasonal Economic and Energy Performance of CO_2 Plume Geothermal (CPG) Power Plants.

A Thesis
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Dedication

This thesis is dedicated to my mom, Sharon Peterson, and my dad, Jim Peterson, who have given me everything I have, everything I am, and all of my grit.

It is dedicated to my grandma, Helen Peterson, who taught me the meaning of the word “resilience”, my grandpa, Sam Spaeth, for showing me what it means to work hard, and my grandma, Queen Marlys, for showing me how to do so with style.

Abstract

CO_2 Plume Geothermal (CPG) energy production is a renewable form of energy that combines geothermal technology with CO_2 sequestration, using the CO_2 as the working fluid in naturally permeable thermal reservoirs. In this thesis, we compare the energy and economic performance of an electricity production only CPG plant, as well as CPG plants with that of a combined heat and power (CHP) and district heating cooling (DHC).

Initially, the monthly economic parameters of electricity-only CPG power plants are modeled for six cities: Williston, ND, Dallas, TX, New Orleans, LA, Houston, TX, Sacramento, CA, and Williamsport, PA. Meteorological data for each city are used to determine energy production and electric power is assumed to be sold in a competitive market. The monthly economic performance of each plant is compiled over 20 years, the assumed lifetime of a CPG plant, and used to determine each plant's potential for profit.

It is found that it is crucial to consider location when determining the economic potential of CPG plants. Cool climates tend to result in higher electricity production as a result of a higher thermodynamic plant efficiency; however, it is also necessary to consider the economic environment, as electricity prices can have just as much of an impact, if not more, on a plant's financial performance. CPG power plants are also found to be economically competitive with other renewable energy options at the same capacity level and current CO_2 sequestration and tax incentives can make unfavorable CPG power plants profitable.

Next, CPG CHP DHC plants are considered, and three cases of heat production are investigated. Case 1 assumes the system meets peak winter heat demand, Case 2 assumes that some form of thermal storage is available and the system meets average monthly heat demand, and Case 3 assumes that all possible heat produced during winter months is sold. Electricity and heat are assumed to be sold in a competitive market. Six cities are considered, Williston, ND, Dallas, TX, New Orleans, LA, Houston, TX, Sacramento, CA, and Williamsport, PA, spanning 4 of the 5 US climate zones (Zones 1, 2, 3, and 5). Meteorological data are used to estimate energy production and heat demand.

CPG is found to produce CO_2 at high enough temperatures to be used in a district heating system. Case 1 most closely matches actual demand ratios for power vs heat in the various cities. CPG CHP/DHC plants in cities located in Zone 1 and Zone 2 climates have a higher net present value (NPV) than electricity-only plants. Case 2 and Case 3 CPG CHP/DHC plants in Zone 3 and Zone 5 can have a higher NPV than electricity only, but more consideration must be given to heat demand to ensure profit is increased. In all cities considered, tax credits and CO_2 sequestration benefits can increase financial performance of CPG CHP/DHC plants.

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Foreword

Deep below the earth's surface lies hot basins of sedimentary rock. For thousands of years, humans have been using this heat to their advantage (Cataldi, 1999). Initially, geothermal use was limited to gathering water from hot springs and warming stones for heat, but today it is used for heat pumps, space heating, greenhouses, aquaculture, and industrial purposes (Lund, 2010). Starting in 1913 and proceeding to present day, people have begun to use this geothermal heat commercially for electricity generation (Fridleifsson, 2001) thanks to sophisticated heat engine and turbine technology.

Enhanced Geothermal Systems (EGS) have been developed to convert the earth's heat into electricity. This technology, however, requires fracking of rock in the earth's subsurface and has proved risky in inducing seismicity in surrounding areas (Kraftet et al., 2011), limiting a widespread adoption of the technology. At least twice, the public has expressed such concern over seismic risk that EGS projects have fallen victim to not only delays, but threats of cancellation as well (Majer et al., 2011). The potential of canceling a project mid-development proves not only to be a risk geologically, but largely financially. It is evident that a fracking-free geothermal heat engine is crucial to the development of geothermal energy worldwide, and CO_2 Plume Geothermal (CPG) aims to serve such a purpose.

CO_2 Plume Geothermal (CPG) uses sequestered CO_2 to extract heat from the earth's subsurface. By drilling into the earth's surface, we can attempt to harvest this low-grade energy, heat, and use some of it to create high grade energy, electricity. CPG is different than traditional geothermal, such as EGS, as it uses CO_2 instead of brine as the working fluid and does not rely on fracturing rock, as it takes advantage of naturally porous sedimentary basins. CPG is also able to take advantage of sites that do not have the high temperature gradients required by EGS, as it does not require the high temperatures needed when using brine.

1. Thesis Organization

This thesis considers the economic implications of the mechanical performance of CPG plants in six U.S. cities: Williston, ND, Dallas, TX, New Orleans, LA, Houston, TX, Sacramento, CA, and Williamsport, PA. It is comprised of two papers which consider two different methods of utilizing the hot CO_2 produced by CPG plants.

Chapter 1: Electricity Production Only

Impact of Seasonality on Financial Performance of CO_2 Plume Geothermal Energy Production in Various US Cities.

Chapter 2: District Heat and Electricity Production

The Energy and Economic Implications of Integrating Combined Heat and Power (CHP) and District Heating and Cooling (DHC) Technology with CO2-Plume Geothermal (CPG) Energy Production in Various Climate Zones.

2. An Introduction to CPG and its Benefits

The benefits provided by this technology are twofold, as it addresses CO_2 emissions in the atmosphere, and the search for sustainable renewable energy sources. For decades, the United States Environmental Protection Agency (EPA) has been working toward reducing harmful CO_2 emissions to the atmosphere. One of the more recent efforts is the promotion of CO_2 capture and sequestration (CCS), allowing fossil fuel power plants to continue to produce electricity, while limiting the amount of CO_2 released into the atmosphere. This entails capturing CO_2 from power plant combustion exhaust, compressing it, then transporting it via pipeline to an underground injection well, used to geologically sequester the CO_2 into a sedimentary basin overlain by a caprock.

CPG technology can also provide an alternative energy solution to renewable energy technologies that exist today. Although wind and solar energy are both at the forefront of developing renewable energy sources, they are both limited by erratic resources. The first wind machine to produce energy in the United States was installed in 1888 (Kaldellis, and Zafirakis, 2011) there is currently over 62,000 MW of wind capacity installed in the United States (US Department of Energy, 2014). There is, however, a problem with consistency when dealing with wind power, as wind energy production is dependent on uncontrollable wind speed. Likewise, the presence of solar energy in the United States is ever on the rise. It is estimated that 36% of all new electric capacity in 2014 is from solar energy (Solar Energy Industries Association, 2014). This brings the total solar electric generating capacity for 2014 in the United States to over 17,500 MW (Solar Energy Industries Association, 2014); however, like wind, solar energy production fluctuates with daylight, cloud coverage and seasonal weather behavior, leaving the source unreliable and unpredictable. This development of wind and solar makes it clear that there is a demand for renewable energy sources. A key aspect of the energy produced by a CPG plant is that it is dispatchable, as the plant can run at all hours of the day, regardless of weather conditions. Also, unlike its renewable counterparts, it can be used to support baseload electricity.

3. CPG Development

Using CO_2 as a working fluid in EGS was first proposed by Pruess in 2006. In 2010, Randolph and Saar showed that power from CO_2 systems can be produced in relatively shallow, cool and naturally permeable rock (no required fracking). Adams showed that direct CO_2 systems produce more energy than direct brine systems (Adams, 2015) and that the energy production of a CPG plant corresponds to daily and seasonal changes in energy demand (Adams, 2012). The financial performance of CPG power plants has been studied for a constant ambient temperature of 288 K (15 C) and a power purchase agreement of 70 $/MWh (Bielicki et al., in preparation), and was shown to be cost competitive with other renewable energy sources of similar capacity levels.

4. Impact

For its research, the CPG group at the University of Minnesota was awarded a $1.9M National Science Foundation (NSF) Sustainable Energy Pathways (SEP) four-year grant #1230691. The grant laid out a comprehensive list of research goals for its four year lifespan, starting in 2012. The research detailed in this thesis aims to maximize energy performance and profit potential of CPG plants. Its focus falls under the NSF Section **3.2.4.** ***Reservoir Engineering and Management****:* Optimal Mass Flowrates, Thermosiphon Effects, and Maximizing Energy and Profit.

Working closely with economist Bolormaa Jamiyansuren, two CPG economic models are completed: The Seasonality Model and The Heating Model. The Seasonality Model is used to analyze the effects of seasonality and location on the energy and economic performance of electricity production only CPG plants. The Heating Model is used to determine the energy and economic implications of integrating district heating into said direct CPG system. By providing a thorough economic analysis of these systems, the economic feasibility of CPG plants is investigated. One can look forward to actual test developments of these sites, as investors are provided better insight into the profit potential of CPG plants. Finally, publication in economic journals increases the visibility of this research.

Chapter 1

Electricity Production Only

Preface

The economic analysis of CPG technology was started by Bielicki in his paper Engineering Cost-Competitive Electricity from Geologic CO2 Storage Reservoirs. In his preliminary analysis, Bielicki found optimal well sizes to maximize profit for a variety of potential CPG plants in a "constant city"—one which exhibits no seasonality and is assumed to have a constant ambient temperature of 288K (or 15°C). The energy produced was assumed to be sold in part of a power purchase agreement at a rate of $70/MWh. The study showed CPG has the potential to compete with other forms of renewable energy options on the market today; however, its assumptions left many unanswered questions about the profitability of CPG power plants located in actual U.S. cities which are subject to seasonality and electricity market limitations.

The Seasonality Model attempts to address these factors by studying six potential CPG plant locations. Local weather and electricity pricing data are used to predict power production and electricity profit. It is found that even with seasonality effects, CPG plants can compete with other renewable energy sources; however, CPG plants need support from tax credits or public policy in order to produce a profit.

Impact of Seasonality on Financial Performance of CO_2 Plume Geothermal Energy Production in Various US Cities.

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1. Introduction

CO_2 Plume Geothermal (CPG) is a new way to expand existing geothermal potential with the added benefits of using a low kinematic viscosity substance as the working fluid, promoting heat advection (Adams et al., 2015). Compared to brine, the density of CO_2 also varies greatly with temperature. The cool, dense CO_2 in the injection well and the hot, light CO_2 in the production well create a thermosiphon through the system, minimizing or eliminating the need for a pump to circulate the CO_2 (Adams et al., 2014). Perhaps most importantly, CO_2 can be used to extract heat from naturally permeable basins (Randolph and Saar, 2010) and thus, unlike the commonly used EGS technologies, it requires no fracking of the earth's subsurface. This efficient use of CO_2

to extract the earth's heat can be used in relatively shallow and low-temperature reservoirs, covered by a low-permeability caprock (Randolph and Saar, 2010).

As with all sources of energy, CO_2 Plume Geothermal plants must be a cost effective solution in order to expect widespread adoption. In a previous study, it was found that CPG plants can be designed to be cost competitive with other forms of renewable energy production, such as wind, solar, and nuclear (Bielicki et al., in preparation). By selecting proper operating conditions, both the capital costs and the levelized cost of electricity can be compared directly with these renewable energy sources. However, this model analyzes a "constant" city with a constant ambient temperature and cost of energy. Thus, this model is restricted, as location of the plant may have a great impact on its financial performance.

In order to determine how location affects the financial performance of a CPG plant, we have selected six cities in the United States and studied the impact of seasonality on power production (which varies by location and month) and electricity price. Each of the six cities was selected based on availability of energy pricing data, geothermal resources, and weather data. In this paper, we will look at this improved financial model of the CPG plant in order to address its feasibility and investment options, as well as the impact of seasonality (ambient air temperature, price) and location differences. Using this information, it will be possible to pinpoint exactly which cities provide the financial and geographical environment necessary for the success of a CPG power plant.

2. Model

Geothermal systems operate as a heat engine, creating high-grade useable energy (electricity) through the transmission of low-grade energy (heat). In this paper, geothermal refers to deep geothermal that is 1 km to 5 km well depths. It is important to differentiate this system from the much more common residential shallow geothermal systems, as they operate on an entirely different set of principles. A drawing of a heat engine is shown in Figure 1. For the heat engine to function, a high-temperature resource (T_{hot}) is used as an energy source, and it is coupled with a low-temperature resource (T_{cold}) which is used as a heat sink. In geothermal heat engines, the high-temperature resource is a geothermal reservoir and the low-temperature resource is the ambient air at the surface.

2.1. Ambient Air Temperature and Heat Engine Efficiency

The typical geothermal gradient in the western U.S. is 34° K km^{-1} (Nathenson & Guffanti, 1985), thus, as a well is drilled deeper, the temperature in the reservoir increases. In geothermal energy production, the portion of this heat from the hot resource which may be theoretically converted to electrical energy is limited by the Carnot efficiency, shown in Figure 1. For example, a Carnot efficiency of 20% indicates that a maximum of 20% of the heat energy taken from the hot resource (Q_H) may be converted to electricity (W_{cycle}), and the remainder of the heat is rejected to the low temperature resource (Q_C). A typical deep geothermal plant operates at 30% to 40% of the Carnot Efficiency (DiPippo, 2008).

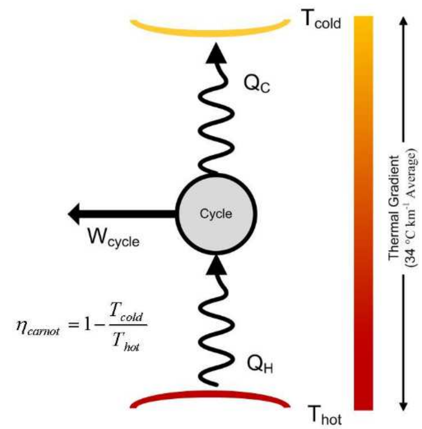

Figure 1: Abstract Geothermal Heat Engine. A geothermal heat engine creates high-grade useable energy (electricity) through the transmission of low-grade energy (heat). The high-temperature resource is a geothermal reservoir and the low-temperature resource is the ambient air at the surface. As the difference between these two resources grows, the efficiency of the engine increases.

There are three variables associated with the Carnot heat engine that can increase electricity production: increasing temperature of the high-temperature resource, decreasing the temperature of the low-temperature resource, or increasing the conversion efficiency of the plant to approach that of the Carnot Efficiency. For a given reservoir and surface plant configuration, the high-temperature resource temperature and conversion efficiency are constant; however, the temperature of the low-temperature resource will vary with the outdoor air conditions, changing the power production.

This can prove to have a dramatic effect. For example, given a resource temperature of 373 K (100 C) and a surface temperature of 288 K (15C) the Carnot Efficiency is 23%. If the surface temperature decreases to 273 K (0 C), the Carnot Efficiency increases to 27%. For a plant generating 1 MWe at 288 K, this would increase output 17% to 1.17 MWe. Variations in surface temperature affect those with cooler resources (e.g. geothermal 373 K ~ 473 K) much more than hotter resources (e.g. coal ~ 673 K), and thus, the ambient air conditions for a geothermal power plant can substantially change the plant output without modifying any other operating parameters.

In this paper, we examine the relationship between outdoor ambient air temperature and the power production of the CPG power plant.

2.2. Physical Plant Parameters

The CPG plants considered in this paper consist of 25 wells and are modeled as a direct system where the CO_2 passes directly through a turbine.

2.2.1. CPG Plant Well Pattern

The physical plant layout utilized in this model reflects the inverted 5-spot pattern. In this pattern, there is one injection well, surrounded by four production wells, with the injection well at the center of a square formed by the production wells. In our model, cool, dense CO_2 is injected into the injection well, it flows through the high temperature reservoir, and the hot, high pressure CO_2 produced in the production wells is used to produce electricity. The CO_2 is then circulated through the system and reinjected at the injection well. It is possible to combine 5-spot well patterns to incorporate more production and injection wells in the pattern, provided the increase in electricity produced outweighs the cost associated with operating and maintaining additional wells. This model will consider a pattern with 25 injection wells, spanning 25 km^2, as this pattern is the most robust configuration economically and technically (Beilicki et al., in preparation).

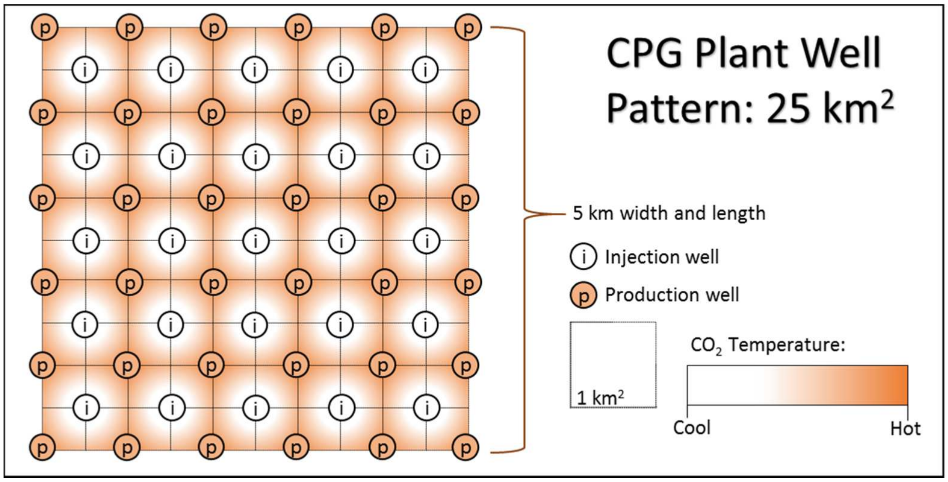

Figure 2: CPG Plant Well Pattern. The well field has 25 injection wells and spans 25 km^2. It has 16 middle, 16 edge, and 4 corner production wells.

One benefit of using the inverted 5-spot well pattern is that it allows the developer of the CPG field to take advantage of pre-existing CO_2 Enhanced Oil Recovery (CO2-EOR) fields. In this model, we will analyze brownfield projects which consist of a field that has already been developed for CO2-EOR. That is, the CO_2 geothermal developer is not responsible for the costs associated with acquiring the site, drilling the production wells, or maintaining the system. As such, the geothermal developer does not receive revenue associated with sequestering CO_2; however, the developer does receive a revenue for the energy produced.

2.3. Mechanical and Geological Model

The abstract heat engine of Figure 3 was modeled in actuality as a direct system, shown in Figure 1.

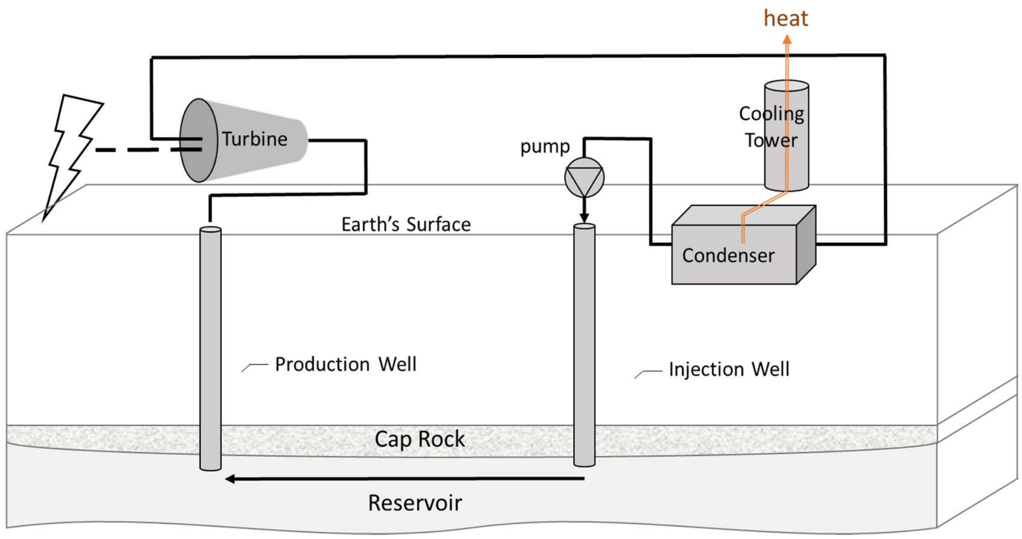

Figure 3: Direct CO_2 System. In a direct CO_2 system, the geothermal fluid is expanded directly through a turbine at the surface. Because, compared to brine, CO_2 arrives at the top of the production well at a low temperature but high pressure, the direct system produces more electricity than an indirect CO_2 system that uses an Organic Rankine Cycle.

The CO_2 is injected as a liquid at the surface into the injection well where it increases in temperature and pressure as it travels down the well. As it moves through the reservoir, it is heated through its interaction with the hot reservoir rock. Once the CO_2 arrives at the production well, it travels to the surface, decreasing in temperature and pressure, where it is produced at the production wellhead. It passes through a turbine, creating electricity, and then is cooled via a condenser and cooling tower. In the condenser and cooling tower, it is cooled to 7 K above the ambient temperature or, in other words, it has an "approach temperature" of 7 K.

It is important to note that the back pressure of the turbine follows the ambient air temperature and pressure, which has a direct effect on the turbine power output. The equation for turbine power output is displayed below in Equation 1.

$$Power_{turbine} = \dot{m} \int \frac{dP}{\rho} \tag{1}$$

As the ambient air temperature and pressure changes, the pressure differential and the density of the CO_2 changes as well, affecting the power output of the turbine.

After the CO_2 is cooled and condensed, it is reinjected into the reservoir through the injection well. A pump is used to ensure the correct pressure at injection. The direct CO_2 system is explained in detail in Adams et al.

To model the flow through the wells, each well was divided into 100m long vertical elements, and the conservation of mass, patched Bernoulli, and the first law of thermodynamics were used to determine the state of the fluid at the start of each element (Adams et al., 2015). Engineering Equation Solver (EES) was used to model fluid flow in the system. It was coupled with TOUGH2, which modeled the heat extraction through the geothermal reservoir.

For a configuration number of 5, the power output was calculated for a temperature gradient of 35 K km^{-1}, a depth of 2500m, a permeability of 5E-15, and an approach temperature of 7 K.

Table 1. Base Case Parameters – Varying Ambient Temperatures.

Parameter	Value
Temperature Gradient (K km^{-1})	35
Depth (km)	2.5
Permeability (m^2)	5×10^{14}
Approach Temperature (K)	7
Configuration Number	5

2.4. Power Plant Financial Model

Consistent cost and financial assumptions were made in order to predict and optimize the financial performance of CPG plant locations.

2.4.1. Plant Cost Information

The cost of equipment was extracted from Geothermal Electricity Technology Evaluation Model (GETEM). The costs for drilling wells, documented in GETEM, proved to be constant for a range of diameters. Because it was found that larger diameters correspond to a higher energy output due to the fact that they can accommodate more flow (Bielicki et al., in preparation), the largest diameter for a given cost was chosen. They are as follows (in meters): 0.14, 0.27, 0.33, and 0.41.

The costs for operation and maintenance of the CPG plants are calculated using a modified GETEM spreadsheet. The cost for the turbine is calculated using an equation derived from GETEM values, and then multiplied by three to account for the use of high pressure CO_2. The cooling tower cost and performance data comes from Baltimore AirCoil for condensing tower model PC2-509-1218-30, and cooling tower models FXV-0812B-12D-J and FXV-1212C-16Q-K.

Using the financial assumptions documented in *Lazard's Levelized Cost of Energy Analysis—Version 8.0* (2015) along with cost information from GETEM, it is possible to produce annual economic performance parameters. For more cost information about the equipment considered, as well as a complete description of economic assumptions, please reference Bielicki et al paper, *Engineering Cost-Competitive Electricity from Geologic CO_2 Storage Reservoirs.*

2.4.2. Cost Optimization Approach

In order to determine the well diameters that produce the most energy while minimizing capital cost, an optimization approach was used. The coupled programs EES and TOUGH2 were used to determine the energy output of the plant for a variety of key physical parameters. These parameters are referenced in Table 2 below. The physical parameters of the plant were subject to certain limitations. It was not always possible to select parameters that yielded the highest energy results, as the plant parameters must be consistent with the values provided by GETEM in order to calculate plant costs.

Table 2: Physical Parameters Considered for Modeling.

Parameter	Value
Well Diameter (m)	0.14, 0.27, 0.33, 0.41
Reservoir Thickness (m)	305
Temp Gradient (K km^{-1})	20, 35, 50
Porosity	10%
Permeability (m^2)	$1x10^{-13}$, $1x10^{-14}$, $5x10^{-14}$, $1x10^{-15}$, $1x10^{-15}$,
Depth (km)	1.5, 2.5, 3.5, 5.0
Approach Temperature (K)	7, 10

The capital cost for each scenario was calculated for a brownfield plant with a pump. For a given well setup, there were certain instances where the capital cost per energy produced was the same, but the combination of well diameters varied. In these instances, in order to be consistent in diameter choice, it was decided that the best scenario was that which utilized the largest corner wells, then edge, and then middle wells.

In the Seasonality Model, the temperatures and electricity prices varied for every city and for every month. The Carnot efficiency equation explains a linear relationship between power output and wet bulb temperature. Thus, in order to counteract computational limitations, a linear relationship between the ambient temperature and power production was utilized. Figure 4 below shows such a relationship for configuration number 5.

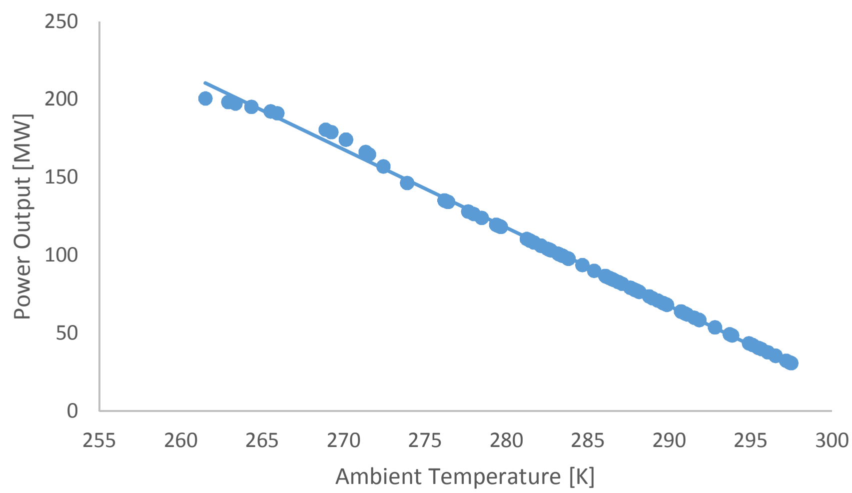

Figure 4. Power Output in Relation to Ambient Temperature. Power output is displayed for N=5 and various values for ambient temperature. The equation for Carnot efficiency explains the near linear relationship between power output and ambient temperature.

For each physical set up, three key points were calculated using EES and TOUGH2 and used to determine this linear relationship in order to calculate the energy production for the remaining temperatures. These calculated values are the values reported in the Seasonality Model.

3. Seasonality Model Results

Using the Seasonality Model, the lifetime economic performance is calculated for each city: Williston, Dallas, New Orleans, Houston, Sacramento, and Williamsport.

3.1. The Implications of Variable Temperatures

The Seasonality Model uses monthly average ambient air temperatures (dew point and temperature mean) over 30 years from the National Climate Data Center to calculate the monthly wet bulb temperature and to assess the total electricity production. Ambient wet bulb temperatures are cooler than dry bulb temperatures and due to the fact that the efficiency of the Carnot heat engine increases as the temperature differential between the hot and cold resource increases, the CPG heat engine utilizes a wet cooling tower where the wet bulb temperature becomes the heat sink temperature, not the dry bulb temperature. Figure 5 below displays the monthly wet bulb temperatures each of the six cities.

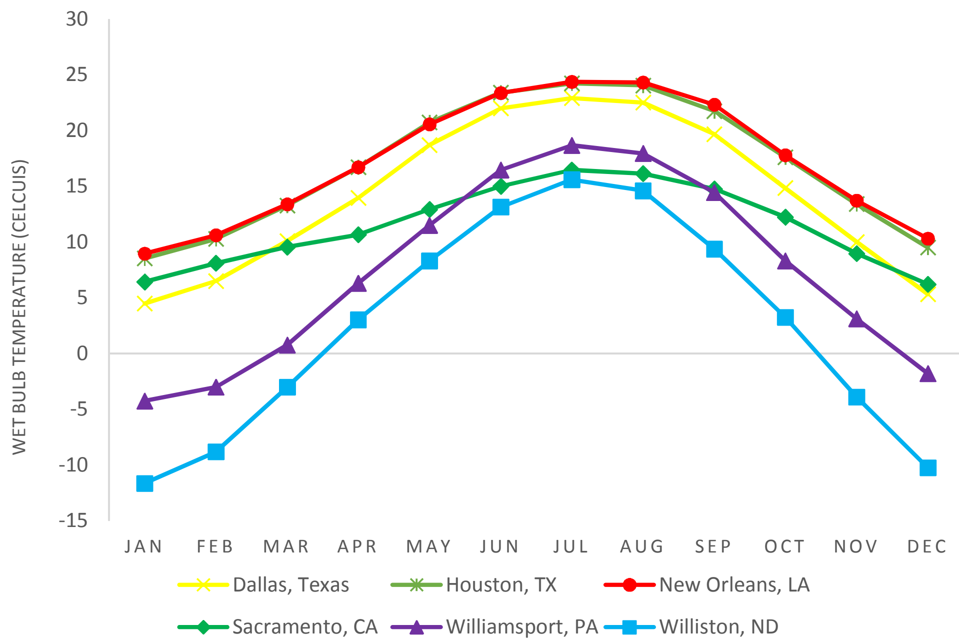

Figure 5: Ambient Wet Bulb Temperature by Months. Because wet bulb temperatures are always lower for a given location than dry bulb temperatures, they are the temperatures utilized in this model. The monthly average ambient air temperature (dew point and temperature mean) over 30 years were acquired from the National Climate Data Center and used to calculate the monthly wet bulb temperature.

Recall that total electricity produced is dependent on the ambient air temperature. For each city, the relationship between ambient wet bulb temperature and power produced was used to predict power production for each month. Figure 6 shows monthly energy production by city. As predicted, the months that correspond to a high wet bulb temperature—June, July, and August—also correspond to the months with the lowest energy production. The opposite can be observed for the coolest months: December, January, and February.

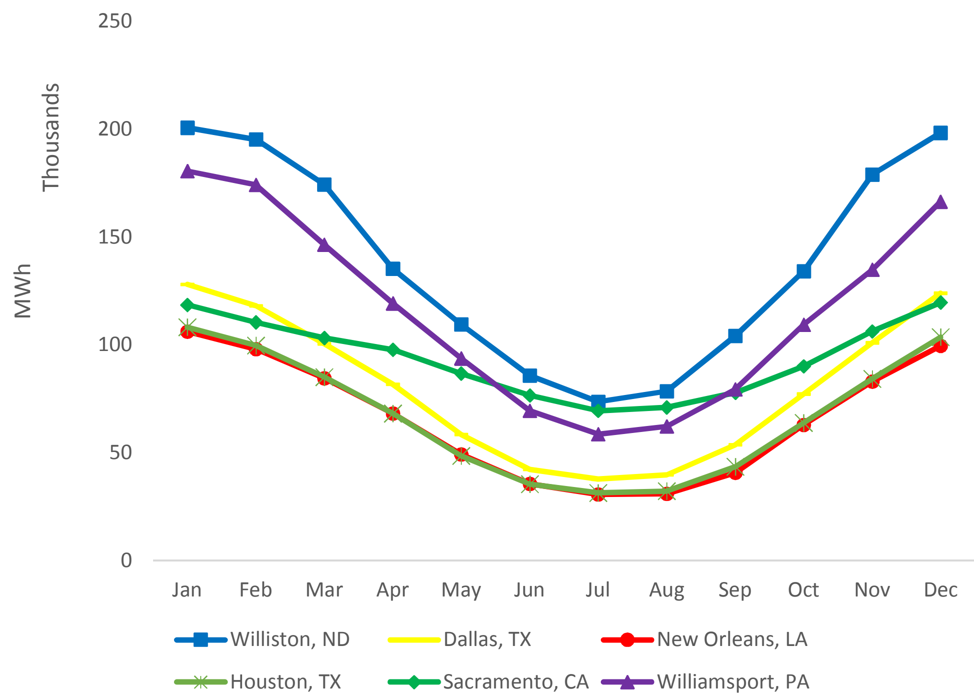

Figure 6: Monthly Energy Production by Location. The energy production values are produced by the EES and TOUGH2 model.

Once the values for electricity production are obtained, it is possible to calculate the levelized cost of electricity (LCOE) for each location. The LCOE is calculated by adding the capital costs and operational costs over the lifetime of the plant, and dividing it by the total amount of electricity produced. The LCOE represents the average price of electricity that the plant would need to sell at in order to obtain a net profit of zero. Listed below in Table 3 is the LCOE for each plant location.

Table 3: Levelized Cost of Electricity for each plant location – Base case parameters

Plant Location	Levelized Cost of Electricity ($/MWh)
Williston, ND	77.35
Williamsport. PA	92.07
Sacramento, CA	112.3

Dallas, TX	131.77
Houston, TX	156.96
New Orleans, LA	159.69

The cities with lower ambient temperatures correspond to the cities with the lowest LCOE. New Orleans, for example, with an average wet bulb temperature of over 17 C has a LCOE over double that of Williston, with an average wet bulb temperature of 2.47 C. This is explained by considering the Carnot efficiency of each location. For each city, the hot temperature, that of the reservoir, remains constant. However, the cool temperature, the ambient wet bulb temperature, varies by location, and as it decreases, the efficiency of the CPG power plant increases. With an increase in efficiency comes an increase in electricity production which decreases the LCOE.

3.2. CPG Performance in Today's Renewable Energy Market

In order for CPG plants to be widely adopted, there are two requirements that must be met: 1. The LCOE must be comparable with, if not better than, other renewable energy sources, and 2. the plant must be profitable to plant developers.

The figure below, Figure 7, compares the LCOE of CPG power plants with various sources of electricity. The LCOE and capacity of the energy sources considered are summarized in *Lazard's Levelized Cost of Energy Analysis—Version 8.0* (2015). These energy sources are compared with the LCOE of the base case of each city's CPG plant. For each city, the capacity reported is the average capacity across all twelve months.

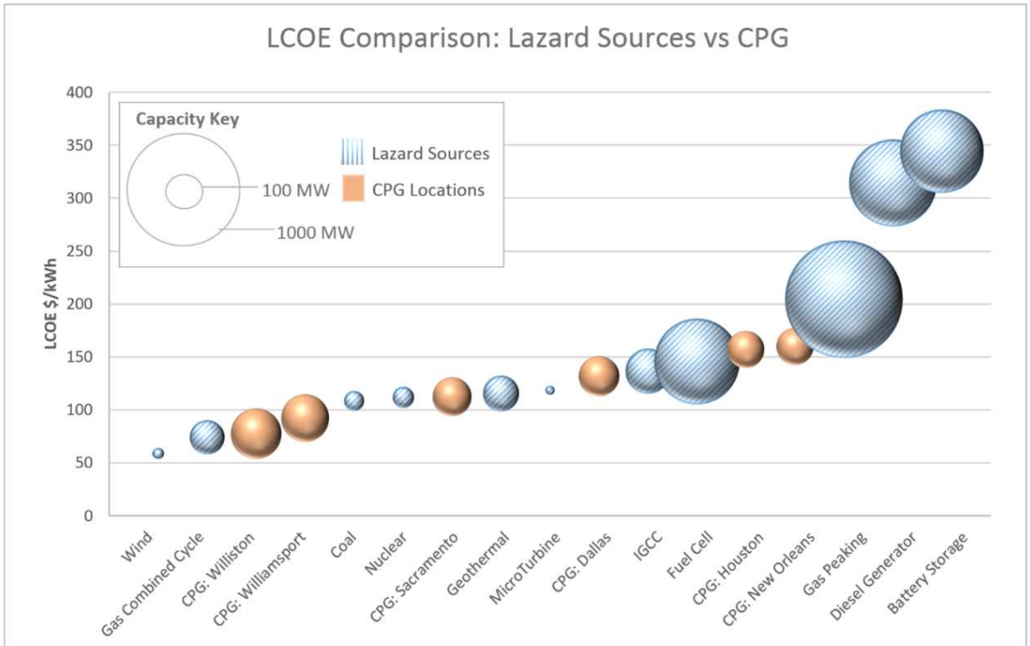

Figure 7: LCOE Comparison: Lazard Sources vs CPG. The LCOE of various electricity sources are compared with the LCOE of CPG power plants. The size of each bubble accounts for the capacity of each plant.

It can be seen in Figure 7 that the LCOE of CPG power plants is competitive with other sources of electricity. In considering the base case, in order to obtain a financially competitive plant, it is necessary to select a location with a cool climate to maximize energy production. In New Orleans, the LCOE is almost double that of wind; however, in Williston, the LCOE of wind and the LCOE of the CPG plant are nearly identical. The capacities of these plants are comparable to the capacity of other renewable resources at the same cost level. By locating cities with low ambient wet bulb temperatures, it is possible to produce a plant that can compete with current electricity options.

Recall that it is not sufficient that CPG be competitive with other renewable energy sources; CPG plants must also produce a profit. Thus, it is necessary to consider wholesale price data based on the model assumption that the plant will sell all its created power to the central system at a competitive price on the market, and not through a power purchase agreement. Historical locational marginal pricing (LMP) data for each electricity market was collected over the years 2010, 2011 and 2012. Hourly price data is used to calculate the average monthly electricity price based on the 3 year average for each location. LMP data was collected from a variety of sources. Williston's LMP data was gathered from the Midcontinent Independent System Operator (MISO). Sacramento's and Louisiana's data was obtained from the ICE (Intercontinental Exchange) Day Ahead Power Price Report. Houston's and Dallas's data was gathered from The Electric Reliability Council of Texas, and the data for Williamsport was obtained from the Federal Energy Regulatory Commission (FERC). The results can be seen below in Figure 8.

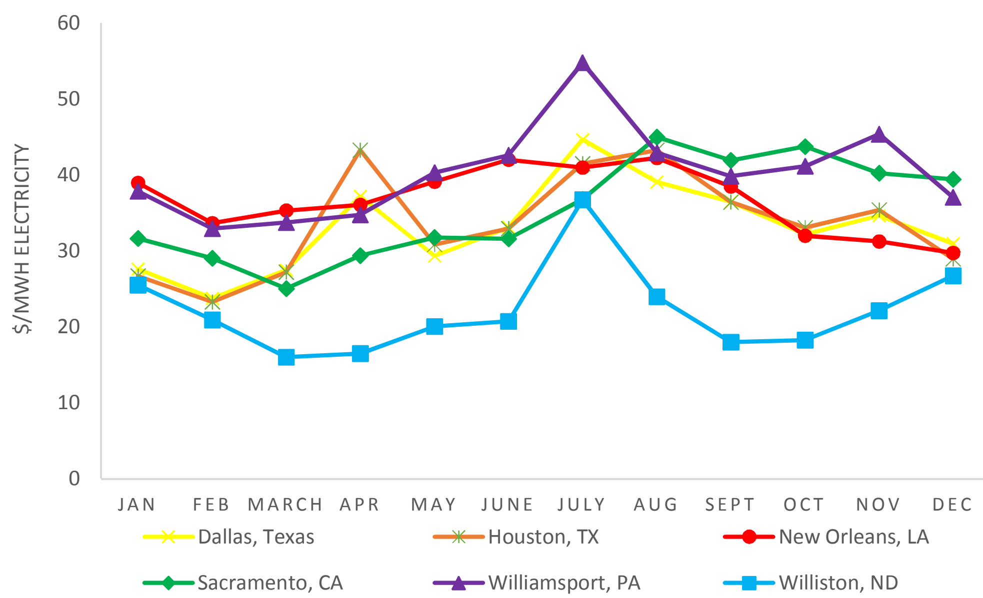

Figure 8: Wholesale Electricity Price by Location (2012). The electricity pricing information displayed here was extracted from MISO data and US Energy Information Administration, as the electricity produced by the CPG power plant is assumed to be sold to the central system at a competitive price on the market.

In order to obtain profit values for each month, the values for electricity production are multiplied by wholesale electricity prices. These profit values are compared to the profit necessary for the CPG plant to break even. These values are obtained by multiplying electricity production by the LCOE for each plant. Figure 9 below shows the results for both profit based on wholesale electricity prices and profit based on the LCOE.

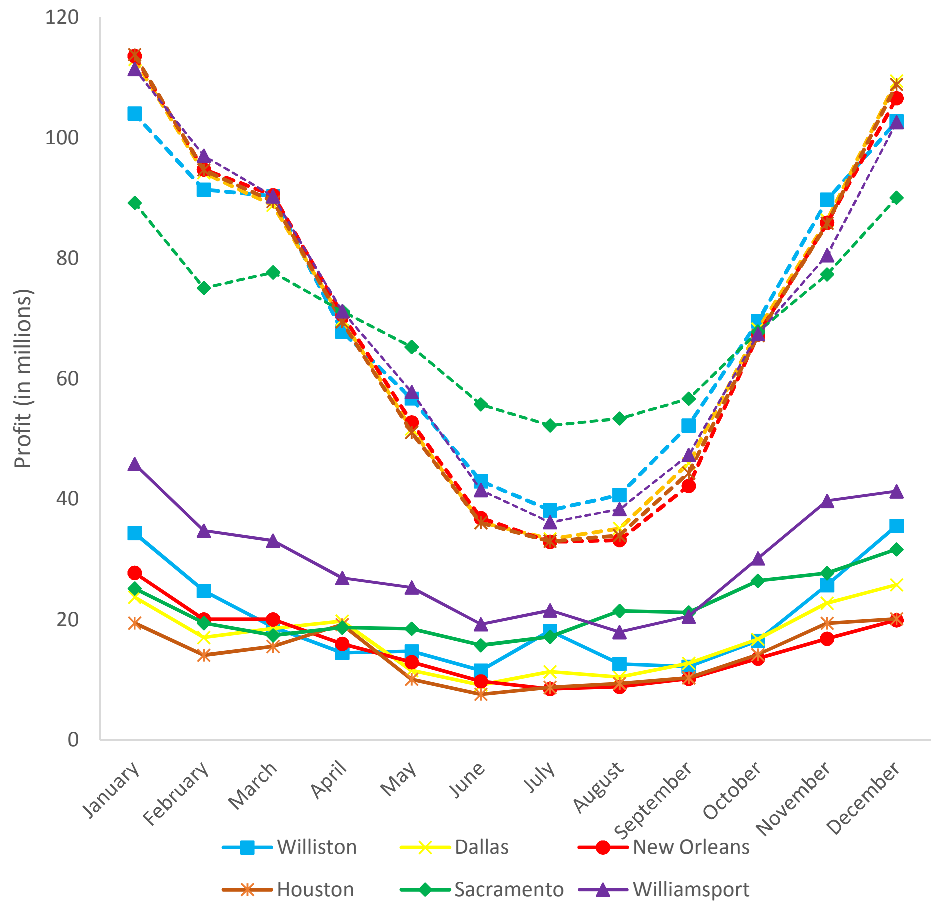

Figure 9: Year One Profit: Comparison of Market Value Sales to Hypothetical LCOE Sales. Solid lines display profit based on wholesale values of electricity and dashed lines display profit based on LCOE values. The area between each city's dashed and solid lines represents net profit.

It can be seen in Figure 9 that for every city, electricity prices are not high enough to ensure that CPG plants produce a profit. This discrepancy between LCOE profit and actual profit is made evident by the net present value (NPV) for each plant. Table 4 shows the NPV for each city.

Table 4: Net Present Value (NPV) for each plant location

	Williston	Dallas	New Orleans	Houston	Sacramento	Williamsport
NPV (in millions)	-$486	-$516	-$527	-$545	-$451	-$360

Surprisingly, although Williston, ND has the lowest average wet bulb temperature, and therefore, produces the most energy, it does not have the highest NPV. In fact, it is third to both Williamsport, PA, and Sacramento, CA. The discrepancy in the relationship between power output and NPV can be accredited to the higher electricity prices offered in Williamsport and Sacramento than in Williston. Typically, as ambient temperatures drop, so does the price of electricity; thus, it is important to choose a location where temperature does not significantly deteriorate electricity prices. In Sacramento, the average price of electricity is 35 $/MWh, over 150% the average price of electricity in Williston (22 $/MWh). In Williamsport, the average price for electricity is 40 $/MWh, almost double that of Williston. This reinforces the notion that the local cost of electricity can be as significant, if not more significant, than the average ambient temperature when determining a CPG plant's financial potential.

By observing the NPV of CPG plants at each location, it is clear that in order to be financially feasible, CPG plants must take advantage of funding options available to increase profitability.

4. CO_2 Utilization and Public Policy

In this section, we will present the net present value (NPV) of CPG plants, and options available to increase profitability. Note that our calculations up to this point have been based on having no federal or state subsidies.

4.1. Renewable Energy Production Tax Credits

One tax credit applicable to CPG power plants is the production tax credit available to renewable energy sources. Table 5 below shows the NPV of the base case plants in each city before and after an electricity production tax credit of $22 per MWh is applied. The tax credit is based on the 2.3 cent per KWh rebate amount and available for ten years (Lazard, 2015). For each city, prices are assumed to escalate at 2.5% annually (inflation).

Table 5: NPV of CPG Plants after Applying the Production Tax Credit. Details for the Production Tax Credit were obtained from Lazard, 2015. NPV

	NPV, Post Production Tax Credit	Change in NPV
Williston, ND	-$271	$215
Dallas, TX	-$323	$193
New Orleans, LA	-$339	$188
Houston, TX	-$351	$194
Sacramento, CA	-$270	$181
Williamsport, PA	-$195	$164

Even with the production tax credit, the CPG plants have a negative net present value. In order for CPG power plants to be successful, they will need support not only from federal tax credits, but from public policy, and other renewable energy incentives as well. Below, we consider various sources of funding and incentives.

4.2. CO_2 Sequestration Benefits

Recall that a major benefit of CPG power plants is that it sequesters CO_2 from the atmosphere. CO_2 emissions have a negative effect on the atmosphere and as such, its sequestration is an effort that is widely supported by the government and public policy. This support from public policy and federal tax credits can prove to be very beneficial to a CPG power plant. Two CO_2 revenue programs are considered in Table 6 below. The first option is designed to promote carbon capture, utilization, and storage, and it is a rebate program that provides plant operators with a financial rebate proportional to the total amount of CO_2 circulated (Tonnes CO_2 circulated) for electricity during the lifetime of a plant. The second option is designed to promote carbon capture and storage, and it is a revenue program offered to encourage the sequestration of CO_2 by offering a revenue for the total amount of CO_2 sequestered (Tonnes CO_2 sequestered) at the over the lifetime of the plant.

Table 6: CO_2 Revenue Options. By applying CO_2 rebate and revenue options to CPG plants, it is possible to raise the NPV to zero. That is, the plant neither makes nor loses money.

	Tonnes CO_2 circulated (in millions)	CO_2 rebate to bring NPV=0	Tonnes CO_2 sequestered (in millions)	Revenue from CO_2 to bring NPV=0
Williston	8,713	\$0.13	4.6	\$238.1
Williamsport	8,068	\$0.10	4.6	\$176.2
Sacramento	7,386	\$0.14	4.6	\$221.0
Dallas	6,903	\$0.17	4.6	\$252.8
Houston	6,442	\$0.19	4.6	\$267.1
New Orleans	6,400	\$0.19	4.6	\$258.1

The rebate for tonne CO_2 circulated for energy is offered to plants as an incentive for plant operators to continue the use of CPG power plants, as they have a net negative CO_2 footprint and are a renewable energy resource. In every case, the CO_2 rebate necessary to bring the NPV to zero (that is, the plant is neither making nor losing money) is on the order of cents per tonne CO_2 circulated for electricity. This may not seem like much money, but it can prove to make a huge difference in the profit of a CPG plant. The revenue offered for a one time sequestration of CO_2 is offered as an incentive to site developers to sequester CO_2. This revenue is substantially higher per tonne of CO_2; however, it is a one-time payment to the developer and can be useful in promoting the construction of new CPG plants. It is important to note that the amount of money provided by each rebate is the same amount when summed up over the lifetime of the plant.

Another CO_2 rebate option considered is one which is presented by *Lazard's Levelized Cost of Energy Analysis – Version 8.0*. It is a carbon abatement rebate in which carbon emissions and LCOE of renewable energy sources are compared to coal and gas. Each plant is sized to produce 4,888 GW of power per year (that is, an effective facility output of 558 MW). The difference between the total cost of energy produced between the renewable resources and gas and coal is divided by the difference in carbon emissions. A carbon abatement rebate suggests that the government credit the operators of the renewable energy sources an amount of money equal to the money saved per tonne of carbon not emitted into the atmosphere. This is called the "abatement cost".

Figure 10 below shows the carbon abatement costs for wind, solar, and two instances of CPG plants. Two CPG plants of 558 MW effective facility output are considered. The first plant is located in New Orleans and is consistent with the base case parameters except for its temperature gradient of 50 K km^{-1}. The second plant is in Sacramento and is consistent with base case parameters except for its well depth of 5000 m.

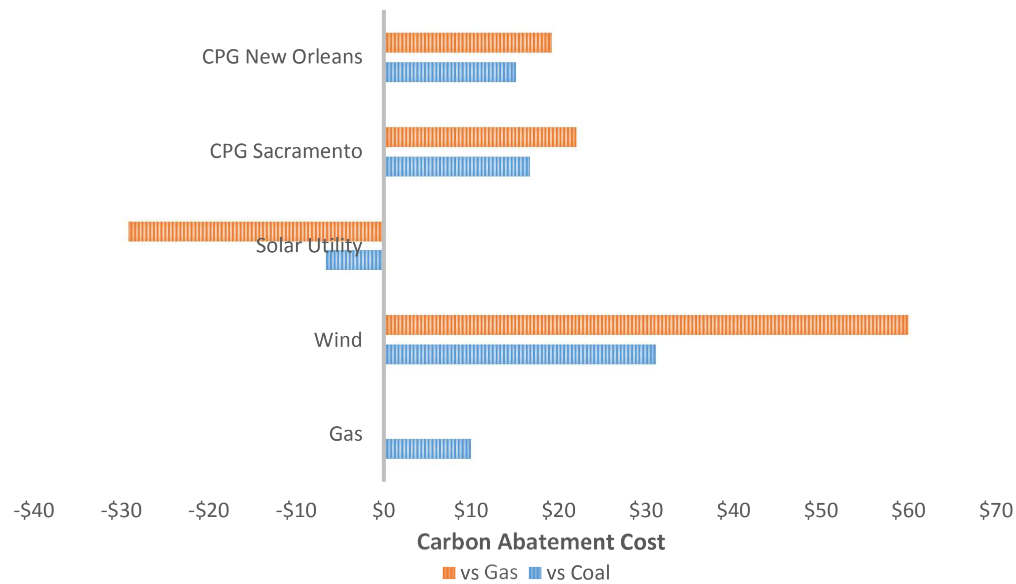

Figure 10: Carbon Abatement Costs of Wind, Solar, and CPG. The carbon abatement costs indicate amount of money saved by renewable energy sources per tonne of carbon not emitted into the atmosphere, compared to gas and coal.

The carbon abatement cost for solar is negative, indicating that when utilizing solar instead of gas and oil, it actually costs money to prevent carbon emissions. Solar is not a cost effective method of decreasing carbon emissions; and thus, it cannot be considered for a carbon abatement rebate. The carbon abatement costs of wind and both CPG locations are positive; however, the carbon abatement cost of CPG is less than that of wind. This indicates that CPG offers a higher reduction in carbon emissions per dollar saved; thus, in order to reduce carbon emissions, it is most cost efficient for the government to support CPG technology.

5. Conclusions

Location matters. In developing CO_2 Plume Geothermal power plants, picking an optimal location will determine whether or not the plant will ultimately be profitable or lose money long term. Plants located in cool climates produce the most energy, as the cool ambient temperature increases the efficiency of the heat engine; however, a cool climate is not necessarily the best location for a CPG power plant. It is also necessary to consider the economic environment. Cool weather may lower the demand for electricity, reducing electricity prices. It is necessary to look for a location that not only offers cool ambient temperatures, but also a standard of living that supports high electricity prices. For example, of all the cities considered, Williston, ND had the coolest average ambient temperature and the highest power production capability, but it is not the most profitable location. The most profitable plant was that of Williamsport, PA, as it is possible to sell electricity at higher prices in such a location.

Seasonality matters. When trying to analyze the economic performance of a CO_2 Plume Geothermal power plant, it is crucial to account for seasonality changes. Seasonality changes in temperature impact not only the power production of a CPG plant but, even more so, the changes in electricity prices throughout the year. These changes in electricity prices can drastically change the outcomes of the plant's economic indicators.

After accounting for location and seasonality effects, CPG technology is cost competitive with other renewable energy sources. By plotting LCOE and capacity, it is possible to see that compared to the LCOE values reported in Lazard (2015), the CPG plant is cost competitive in today's electricity market. Compared to power plants with similar capacity, the CPG plants offer a lower LCOE, which is crucial for the success of a plant. With a temperature gradient of 35 C/km, in order to compete with other renewable resources, such as wind and solar, it is necessary to choose a location with a cool wet bulb temperature, or a high temperature difference between the reservoir and the ambient air. Overall, the capacity of the CPG power plants is greater than the renewable energy sources presented by Lazard. By comparing these LCOE values, it is possible to see that CPG power plants can be an answer to the current demand for cost effective renewable energy.

Incentives for CO_2 sequestration and use can make unfavorable locations financially viable. The benefits of CO_2 Plume Geothermal are threefold. First of all, it provides a system in which geothermal energy, a renewable resource, can be used without fracking the earth's subsurface. Secondly, the primary working fluid is CO_2, thus it saves water resources, and finally, it sequesters harmful CO_2 from the atmosphere. Two CPG incentives are considered in this study: a rebate regulation that provides plant operators with a financial rebate equal to the total cost per tonne of CO_2 circulated for electricity necessary to bring NPV to zero, and a revenue program to provide plant operators with a revenue equal to the cost per tonne CO_2 sequestered over a plants' lifetime. For all cities, the rebate for circulated CO_2 necessary to bring the NPV of the plant to zero was on the order of cents per tonne CO_2 circulated for electricity. The revenue for initial sequestered CO_2 to bring the NPV of the plant to zero was substantially higher, between \$58 and \$87; however, the lump sum rebate may help to promote construction of new CPG sites. It is important to note that the lifetime sum of these rebates is the same.

CPG technology is a cost effective solution to reducing carbon emissions. The carbon abatement cost is the difference between the LCOE of the renewable resources and gas and coal divided by the difference in carbon emissions. In a carbon abatement rebate, the renewable energy sources are credited for the amount of money they save per tonne of carbon not emitted into the atmosphere. The carbon abatement cost of solar is negative, indicating it costs money to reduce carbon emissions with this technology. The carbon abatement cost for both wind and CPG is positive, but CPG's costs are less than that of wind, indicating it is most cost efficient for the government to support CPG technology.

Chapter 2

District Heating and Electricity Production

Preface

Electricity production only CPG plants do not produce a profit; therefore, another method of using the hot CO_2 is considered: district heating, a centralized heating network that distributes heat from an integrated source to surrounding commercial and residential buildings via a network of pipelines. Although heat prices are typically not has high as electricity prices, it is possible to produce more sellable heat than electricity.

The Heating Model analyzes the profit potential of CPG plants producing heat and electricity in six different U.S. cities, spanning four of the five AIA and IECC/ASHRAE climate zones. Both electricity and heat are assumed to be sold in a competitive market. It is found that in cooler climates, adding district heating significantly increases the net present value of the plant; whereas in warmer climates, the heat demand limits the profit potential of heat to the extent that the cost of adding district heating to the plant outweigh the profit obtained selling heat.

The Energy and Economic Implications of Integrating Combined Heat and Power (CHP) and District Heating and Cooling (DHC) Technology with CO_2-Plume Geothermal (CPG) Energy Production in Various Climate Zones.

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1. Introduction

CO_2 Plume Geothermal (CPG) uses sequestered CO_2 to extract heat from the earth's subsurface. By drilling into the earth's surface, we can attempt to harvest this low-grade energy, heat, and use some of it to create high grade energy, electricity. CPG is different than traditional geothermal, such as Enhanced Geothermal Systems (EGS), as it uses CO_2 instead of brine as the working fluid and does not rely on fracturing rock. Multiple benefits are associated with using CO_2. It has a lower kinematic viscosity than brine, allowing CO_2 to move through porous reservoirs without requiring fracking of the subsurface. Although the study of negative effects of fracking are inconclusive (Kraft et al., 2011), it is still poorly perceived by the public (Majer et al., 2011), making its utilization a liability. The density of CO_2 compared to water also varies more with temperature, minimizing or possibly eliminating the need for circulating pumps (Adams et al., 2014). This efficient use of CO_2 to extract the earth's heat can be used in relatively shallow and low-temperature reservoirs, covered by a low-permeability caprock (Randolph & Saar, 2010).

The benefits of CPG technology includes more than its efficient energy production using CO_2. It also addresses two of the environment's most pressing calls to society: the need for sources of renewable energy, and the harmful effects of CO_2 emissions. Renewable energy research is ever on the rise; however, the two of most recent interest in America, wind and solar, are limited by weather conditions. Wind energy is only available when the wind is blowing and solar energy is only produced when the sun is shining; thus, both of these resources are unreliable, as their production is intermittent. In contrast to wind and solar, CPG provides energy continuously, regardless of weather conditions, and corresponds to energy demands (Adams et al., 2012). CPG is also a net negative carbon energy source. The Environmental Protection Agency has recently started promoting CO_2 capture and sequestration (CCS) to reduce CO_2 emission to the atmosphere. CPG not only captures CO_2 from power plants, transporting the compressed CO_2 via pipelines to an underground injection well, but it also uses the CO_2 to produce renewable energy, falling into a new category titled CO_2 Capture, Utilization, and Storage (CCUS).

Using CO_2 as a working fluid in EGS was first proposed by Pruess in 2006. In 2010, Randolph and Saar showed that power from CO_2 systems can be produced in relatively shallow, cool and naturally permeable rock (no required fracking). Adams showed that direct CO_2 systems produce more energy than direct brine systems (Adams, 2015) and that the energy production of a CPG plant corresponds to daily and seasonal changes in energy demand (Adams, 2012). The financial performance of CPG power plants has been studied for a constant ambient temperature of 288 K (15 C) and a power purchase agreement of 70 $/MWh (Bielicki et al., in preparation), and for various cities and seasons using competitive market prices (Jamiyansuren et al., in preparation). In both financial evaluations, CPG power plants were found to be competitive with other renewable energy sources. In this paper, we evaluate the financial performance of CPG energy production from a cogeneration facility, one that produces both district heat and electricity, also known as combined heat and power (CHP).

Up to this point, CPG plants have been modeled as a heat engine. In these models, CPG direct use systems were found to produce more electricity than those which utilize brine (Adams et al., 2015); however, because they are modeled as electricity production only, they are limited by the Carnot efficiency. The Carnot efficiency is a maximum thermal efficiency—that is, the maximum percent of heat energy in the system which may be converted to electricity. However, it is possible to increase the efficiency of a CPG plant over its Carnot efficiency value by using the heat from the hot CO_2 for space heating. This is not an uncommon practice today, as 37% of direct use geothermal worldwide is dedicated to space heating (Bloomquist, 2001) and in theory and in practice, it has proven to be a profitable solution (Kaarsberg et al., 1999). This heat can be supplied to one or more customers as part of a "district heating/cooling" system, or DHC system.

District heating and cooling (DHC) is a centralized heating/cooling network that distributes heat from an integrated source to surrounding commercial and residential buildings via a network of pipelines. In district heating networks, the heat is transported by a fluid, usually hot water. Because district heating systems must be connected via a pipeline to its customers, they are most commonly used in high-density urban areas, such as downtown districts, college campuses, and hospital facilities. In these systems, water is heated by the centralized source, transported via pipeline to all affiliated buildings, and the heat is transferred through a heat exchanger to the building's internal heat distribution system.

There are many benefits to using a district heating system instead of individual boiler units. Typical savings of district heating vs natural gas-fired boilers is approximately 30-50% per year (Lund, 2010). Because of the infrastructure required by a districting heating system, using these systems encourages building owners to replace less efficient equipment with a newer, more efficient centralized system. According the US Energy Information Administration's 2005 Residential Energy Consumption Survey, space heating accounts for over 40% of residential energy use. By supplying this heat with a district heating system, it is possible to promote supplying this energy demand with renewable and non-carbon sources of energy.

In this paper, the CPG CHP/DHC system is studied for six cities using monthly average temperatures and electricity prices: Williston, ND, Dallas, TX, Houston, TX, New Orleans, LA, Sacramento, CA, and Williamsport PA. The cities considered are selected based on location of geothermal resources and availability of electricity pricing data. First, we describe the geothermal, mechanical, and economic models developed for CPG technology, then we compare the energy and economic performance of CPG electricity production only and CPG CHP/DHC plants.

2. CHP & DHP: Review of technology and CPG Potential

Combined heat and power was born in 1882, when Thomas Edison designed and built the world's first cogeneration system at Pearl Street Station in Manhattan, New York (DOE, 2003). Thanks to Edison's venture in the late 19th century, cogeneration has now been used for over 100 years (Rosen et al., 2005) and currently generates around 10% of global electricity generation (IEA. 2009). When compared to systems that produce heat and power separately, cogeneration systems provide electric and thermal energy far more efficiently (Kaarsberg et al., 1998). Due to the higher efficiency, systems provide reduced overall energy costs, improved system reliability, reduced thermal energy consumption (Chittum & Kismohr, 2014), as well as reducing greenhouse gas emissions and other pollutants (Rezaie & Rosen, 2011). Combined heat and power systems provide benefits to more than the environment. They give communities control over their own power supply (Chittum & Kismohr, 2014) and can offer substantial cost savings over separate heat and power systems (Kaarsberg et al., 1998).

Today, these systems are becoming increasingly popular on a national scale which, after a brief review of their benefits, should come as no surprise. In 2007, the IEA created the CHP/District Heating and Cooling (DHC) Collaborative to pull together international knowledge and experience to promote future deployment of clean and efficient CHP and District Energy technologies. The CHP/DHC Collaborative currently has collected reports from a wide range of countries in North America, Europe, and Asia, and is continuing to document best practices and assess global markets and policies. The information collected can be used to predict the success of a CPG CHP/DHC plant today.

2.1. CHP & DHC in North America

In order to analyze the potential for CPG cogeneration adoption in the United States, it is necessary to evaluate the current state of technology and CHP/DHC cases of success.

Starting in the late 1970's, after the introduction of the Public Utilities Regulatory Policies Act (PURPA), the presence of cogeneration systems has grown steadily in the United States. Between 1980 and 2000 cogeneration capacity increased from 12 GW to 60 GW (IEA, 2014). This growth dramatically slowed in the mid 1990's (Kaarsberg et al., 1998) after it became possible for independent power producers to sell electricity directly to the grid. In 2001, nearly 7 GW of cogeneration capacity was installed in the United States, but installation has been steadily dropping since then (ICF International and Oak Ridge National Laboratory, 2013). Today, CHP represents 8% of U.S. electricity generation capacity and over 12% of annual U.S. power generation: 23% of the United States' installed CHP capacity is used for district heating and cooling (IEA, 2014).

Although the United States houses the largest district energy system in the world, Con Edison Steam Operations in Manhattan, only about 1.3% of commercial buildings are heated using district heating networks in the U.S (USEIA, 2003). There are currently more than 837 district energy systems in the United States (IDEA, 2009) of which the most common applications are urban settings and college campuses. In the U.S., 55 of the 375 university campus district energy systems utilize cogeneration (ICF International and Oak Ridge National Laboratory, 2013), representing 26.4 GWth of heating capacity, 7.6 GW of cooling capacity, and 2.9 GW of cogenerated power production (IEA, 2014).

2.2. CHP & DHC Case Studies

Two cases are considered in order to assess potential for CPG CHP & DHC plants: St. Paul District Energy in St. Paul, MN, and Unterhaching Geothermie, in Unterhaching, Germany.

2.2.1. A U.S. Urban Setting Case Study: St. Paul District Energy, MN

One of the country's best known urban CHP and DHC systems is located in St. Paul, MN. The District Energy St. Paul plant primarily uses biomass collected locally to power a wood-fired boiler. The boiler is coupled with a superheater to produce high pressure steam that is used to spin a turbine and produce electricity, with a capacity of 25 MWe. The extracted steam is then sent to a heat exchanger to produce hot water for the district heating system. In order to consistently meet heating demand, the District Energy St. Paul plant also utilizes four natural gas boilers and, in peak demand months, a coal-natural gas boiler. District Energy St. Paul also offers district cooling, which utilizes a chiller to send chilled water underground to the company's clients.

This St. Paul system has operated for more than 20 years and it currently services over 80% the downtown area with electricity and thermal energy (Chittum & Kismohr, 2014). The plant largely owes its success to its consistent ability to meet peak heat demand and its ability to react to advancements in technology and environmental demands. The plant has undergone many changes to produce cleaner power, included a retrofit in order to better incorporate biomass, and the addition of solar panels to supplement the district heating hot water supply. Today the plant operates at an efficiency of over 85% (Chittum & Kismohr, 2014) and it has greatly reduced heating costs for St. Paul downtown clients.

The success of District Energy St. Paul is good indication of the potential for CPG cogeneration in the United States, as it is a renewable energy based system in an urban setting. In order to look specifically to geothermal CHP & DHC, however, we must look to our neighbors across the Atlantic in Europe.

2.2.2. A Geothermal Case Study: Unterhaching Geothermie, Germany

Unterhaching Geothermie is one of two geothermal CHP and DCH plants in Germany. It is located on the upper Bavarian Bolasse Basin, with an aquifer 3 km below the surface, called Malmkarst (Malm). The plant consists of a production well, injection well, a district heating network, and an electricity generation plant which uses the Kalina process. For redundant/peak load heating, the plant is equipped with a fossil fueled plant. It also features a connection to a neighboring geothermal plant, Grünwald, which serves the same purpose as the fossil fueled plant. The Kalina plant is sized at 3.36 MW, designed for the minimum heat demand of the heating grid in the summertime.

Unterhaching Geothermie, though a fairly new development, has been extremely successful. Running at a heat cycle effectiveness of 91%, the district heating system was initially sized at 30 MWth, but has been expanded to 60 MWth and, upon final expansion, should reach 90 MWth, providing thermal heat to the entire community. This economic success and unexpected expansion can be linked to multiple factors. First, the high price of oil and gas during 2008 and the rising awareness of climate change raised the demand for the district heat (Richter, 2010). The project also has a 20 year guarantee that the regional electricity supplier will buy Unterhaching's produced electricity at a fixed rate, set by the Renewable Energy Law of the Federal Republic of Germany. And finally, Unterhaching has been able to adjust the plant operations based on market demand. The facility was originally planning on primarily producing electricity, and using the remaining energy for heating. However, with such a high demand for heat, the plant reprioritized so that heat demand is met first, and the remaining energy is used for power production.

Although Unterhaching uses brine as its working fluid, the similarities between Unterhaching's CHP/DHC plant and a potential CPG CHP/DHC allow us to make some conclusions and assumptions about our economic model. The expansion of the districting heating network indicates that there is a demand for heat production, and thus, CPG CHP/DHC plants will be sized at maximum heat production and distribution.

3. Methods

Geothermal energy production is a renewable resource which uses the extraction of heat from within the earth. The temperature of the earth increases on average 34 K km^{-1} with depth, creating hot resources (Nathenson & Guffanti, 1985). The high temperature resource within the earth can drive a heat engine, shown in Figure 1 by exchanging thermal energy between a hot resource (the geologic reservoir) and a cool resource (ambient air temperature), generating mechanical work in the process. Generally, this mechanical work is in the form of electricity, which is easily distributed. As ambient air temperature changes due to changes in location or seasonality, electricity production changes (Jamiyansuren et al., in preparation).

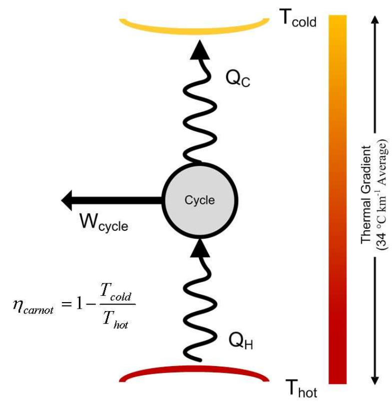

Figure 1: Abstract Geothermal Heat Engine. A geothermal heat engine creates high-grade useable energy (electricity) through the transmission of low-grade energy (heat). The high-temperature resource is a geothermal reservoir and the low-temperature resource is the ambient air at the surface. As the difference between these two temperatures grows, the efficiency of the engine increases.

The amount of work which a heat engine may generate is limited by the laws of thermodynamics by the Carnot efficiency, also shown in Figure 1. For low temperature geothermal resources, the Carnot efficiency is typically small, about 20%, and generally the actual thermal efficiency is lower than this theoretical maximum, about 10%. In other words, for every 10 MW of heat extracted from the ground, only 10% of that, or 1 MW may be converted to electricity, and the remaining 9 MW of heat must be rejected to the air.

The Carnot efficiency limitation can be overcome, so to speak, if the geothermal system isn't creating electricity, but rather providing heat energy. If 10 MW of heat energy is extracted from a geothermal resource, all 10 MW can be used to provide thermal energy to a system where electricity is not a factor. For example, in the United States manufacturing sector, 54% of total energy consumption is for process heating—a large percentage of which likely does not require electricity (EIA, 2012). By utilizing geothermal energy in these process heating loads to replace electrical or fossil fuels, the conversion inefficiencies of Carnot-limited electrical energy production can be avoided while supplying carbon-neutral geothermal energy.

3.1. Geologic Modeling

The CPG CHP/DHC facility considered here extracts its energy from a 1 km^2, 300 m thick, CO_2 -filled reservoir established in sedimentary rock. Sedimentary basins are targeted for CO_2 injection due to their natural permeability, allowing CO_2 to flow through the rock. In addition, they are ubiquitous throughout the United States and are relatively homogenous when compared to typical geologic fracture-based reservoirs (Global CCS Institute, 2012). The reservoir pressure losses were modeled using TOUGH2 software with the ECO2N module (Pruess 2004, 2005) as presented in earlier works (Randolph and Saar, 2011).

3.2. Surface Power Plant and District Heat Model

The CPG CHP/DHC plant consists of a turbine, wet cooling tower, condenser, district heating heat exchanger, injection wells, and production wells.

3.2.1. CPG CHP/DHP Well Pattern and Parameters

The injection and production wells are in what is referred to as an inverted 5-spot pattern, in which one injection well is surrounded by four production wells. It is possible to combine several inverted 5-spot patterns in order to increase power and heat production (Bielicki et al., in preparation). Compiling 5-spot patterns can be described by the plant's configuration number, N. As N increases, the number of injection wells increases by N^2. Figure 2 below shows an example of a well pattern with N=5.

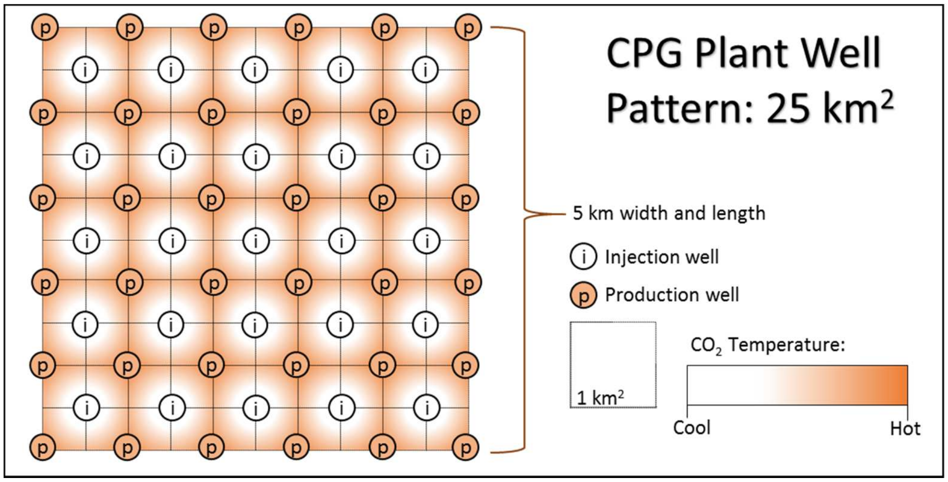

Figure 2: CPG Plant Well Pattern with N=5. This pattern has 25 injection wells and covers 25 km^2. It has 16 middle, 16 edge, and 4 corner production wells.

It can be seen in Figure 2 that combining 5-spot patterns creates three distinct types of production wells: corner, edge, and middle wells. Corner wells are those at the four corners of the pattern, edge wells are along an edge that are not at a corner, and middle wells are those surrounded by injection wells. Corner wells produce at a fourth the mass flow rate of an injection well, edge wells produce at half, and middle wells produce at the same mass flow rate as injection wells. Inverted 5-spot patterns are commonly used by enhanced oil recovery (EOR) fields, allowing CPG to take advantage of existing infrastructures.

For configuration number 5, the power and heat production are calculated for a reservoir depth of 2.5 km, a geothermal temperature gradient of 35 K km^{-1}, and a reservoir permeability of 5E-14 m^2. The well diameters are determined from the Monthly Model's power optimization methods and consist of 0.41 m for injection wells, edge, and middle wells, and 0.27 m for corner wells. These conditions are summarized in Table 1.

Table 1: Model parameters for CPG CHP/DHC plant. The values for well diameters are optimized for maximum power production (Jamiyansuren et al., in preparation).

Configuration Number, N	5

Well Diameters	
Injection	0.41 m
Corner	0.27 m
Edge	0.41 m
Middle	0.41 m
Reservoir Conditions	
Depth	2500 m
Temperature Gradient	35 K km^{-1}
Permeability	$5x10^{-14}$ m^2

3.2.2. Engineering Modeling

The power plant was modeled similar to a direct CO_2 power system as described in detail in Adams, Kuehn, Bielicki, Randolph, and Saar (Adams et al., 2015), which contains detailed assumptions and methodology. A schematic of the CHP facility is shown in Figure 3.

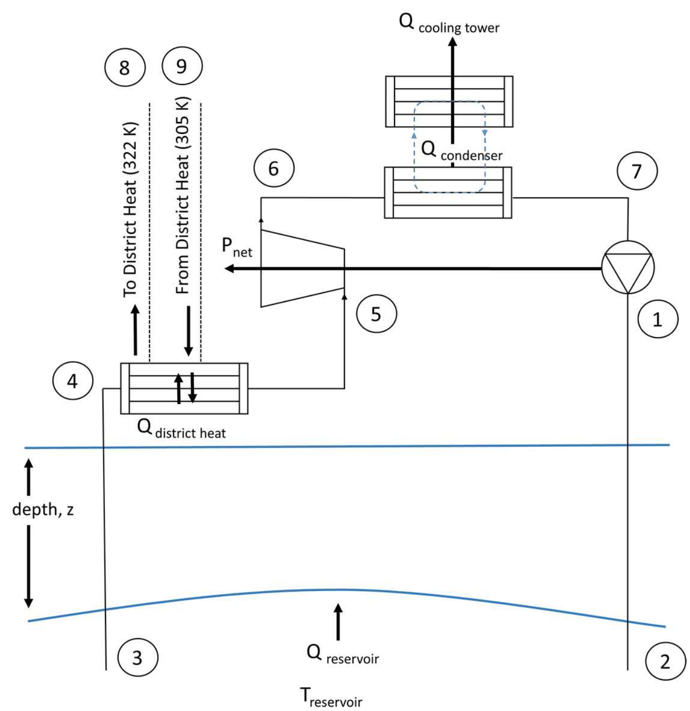

Figure 3: Direct CPG CHP/DHC System. In a direct CPG CHP/DHC system, the geothermal fluid is first passed through a heat exchanger, and then expanded directly through a turbine at the surface. In the heat exchanger, the CO_2 heats the water to a temperature of 322 K that is retuned from the load at 305 K. The pinch point at the outlet of the heat exchanger is set at 7 K.

Liquid, condensed CO_2 is injected at the surface (State 1), compressing, increasing in temperature and pressure as it travels down and into the reservoir (State 2). The CO_2 is heated as it flows through the sedimentary basin until it reaches State 3. The CO_2 expands up the production well, decreasing in temperature and pressure to the production wellhead (State 4). For a 2.5 km well with a 35 °K km^{-1} thermal gradient, the production wellhead conditions are 333 K (60 C) and 11 MPa. The CO_2 exchanges heat with the district heating fluid in a counterflow heat exchanger to State 5. The heat exchanger is assumed to have a 7 K minimum temperature difference, fixing the outlet to district heat (State 9) at a temperature 7 K less than the wellhead temperature (State 4); likewise the CO_2 temperature at the inlet to the turbine (State 5) can be no less than 7 K above the inlet from district heat (State 8). An impulse turbine expands the fluid to the condensing pressure (State 6) which is 7 K above ambient temperature (that is, it has an "approach temperature" of 7 K), where it is condensed and cooled in a cooling tower to a saturated liquid (State 7). It is then pressurized with a surface pump (State 1) to a pressure necessary to achieve the necessary downhole reservoir pressure.

For simulation purposes, the wells are divided into 100 m vertical elements, and the first law of thermodynamics, patched Bernoulli, and the conservation of mass are used to determine the fluid state at the start of each element (Adams et al., 2015). The power plant performance was simulated using Engineering Equation Solver (EES), a simultaneous equation solver which provides property values for CO_2 from Span and Wagner (1996).

The CHP system differs from the direct system analyzed previously (Adams, et al., 2015) by way of a heat exchanger placed before the turbine to extract heat from the produced geologic fluid for district heating. The district heating heat exchanger was placed before the turbine to produce the highest temperature district heating fluid while still producing electrical power through the turbine. The heat removal to the district heat system is variable, quantified by the effectiveness, ε, (Equation 1), which is the ratio of heat rejected to the district heating system divided by the total heat rejection at the surface.

$$\varepsilon = \frac{Q_{District\ heat}}{Q_{District\ heat} + Q_{condenser}} \qquad (1)$$

The effectiveness of the CHP system may be varied from 0 to 1, representing 0% to 100% of the heat rejected at the surface which goes to the district heating. The change in power generation and heat removal to the district heating system for a single well pairing, 2.5 km geothermal system with a 35 K km^{-1} thermal gradient and 5 x10^{-14} m^2 permeability is shown in Figure 4 below.

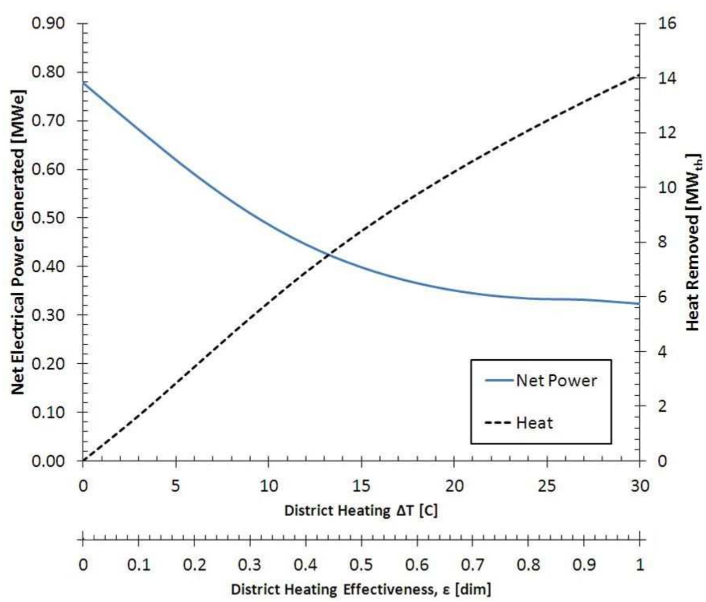

Figure 4: Effectiveness vs Net Electrical Power Generation and Heat Removed. Maximum power production occurs at an effectiveness of 0 and decreases at a rate of a second order polynomial as ΔT increases. District heating increases nearly linearly with effectiveness.

At an effectiveness of 0, no heat is removed from the CO_2, and the system behaves exactly like a direct CO_2 system, generating approximately 0.8 MWe of electricity. As the effectiveness increases, the heat removed increases nearly linearly, while the electricity output decreases asymptotically towards a value 40% of the maximum. The change in power generation as heat removal increases for the same system is shown in Figure 5 below.

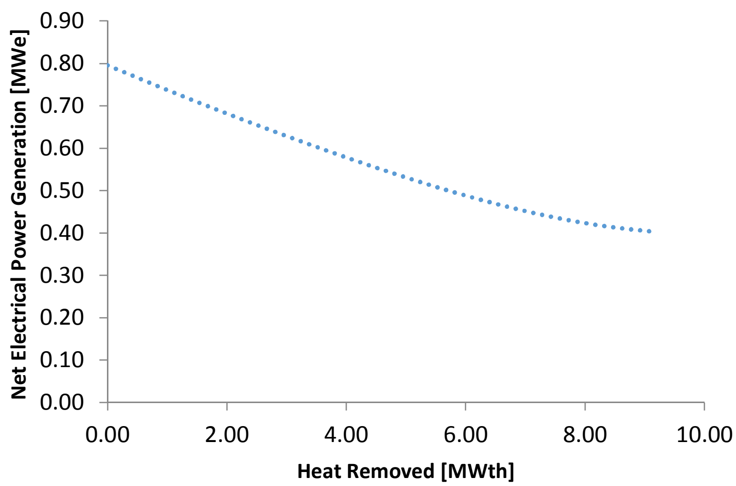

Figure 5: Relationship between Heat Removed and Power Production. Power production decreases as heat is removed from the CO_2 because, although pressure remains nearly constant, as temperature decreases, the density of the CO_2 increases, decreasing net power production.

The power decreases nearly linearly as more heat is removed. The pressure difference across the turbine (States 5 to 6) remains nearly constant for all heat removal values; however, the decrease in turbine inlet temperature increases the CO_2 density, decreasing the overall turbine power production. At the maximum value of heat removed, all heat at the surface is removed through the district heating heat exchanger, having a temperature difference between the district heating inlet and exit, and no heat is rejected through the condenser—the outlet of the turbine (State 6) is a saturated liquid.

To calculate the relationship between net power production, P_{net}, and heat production, $Q_{district\ heat}$, for a given ambient temperature, the EES model was used to calculate power and heat production for seven different temperatures ranging from 253 to 285 K, and a heat exchanger effectiveness of 0, 0.5, and 1. For each value of effectiveness, $Q_{district\ heat}$ vs P_{net}, is plotted and a linear regression is performed of the form $P_{net} = \delta + \epsilon \cdot Q_{district\ heat}$, where intercept δ is set to $P_{net_{max}}$, the value of P_{net} when effectiveness is equal to 0. The resulting coefficients, δ and ϵ, are calculated for each temperature, and are represented by a single data point shown in Figure 6 below.

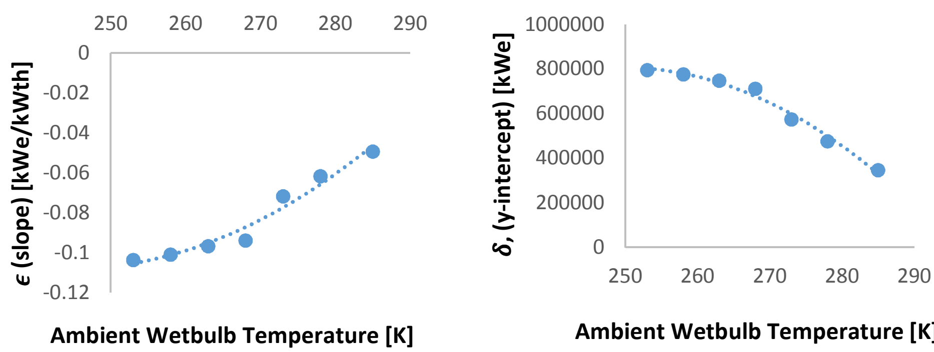

Figure 6: Slope and intercept for P_{net} vs $Q_{district\ heat}$ relationship varying with temperature. The slope and y-intercept for the linear relationship between P_{net} and $Q_{district\ heat}$ is displayed above on the right and left respectively. Both the slope and y-intercept vary with temperature at the rate of a second degree polynomial.

Once a relationship between P_{net} and $Q_{district\ heat}$ is obtained for varying temperatures, The ratio of $P_{net_{max}}$, to the minimum value of P_{net}, or $P_{net_{min}}$ (value of P_{net} when effectiveness is equal to 1), is found in order to calculate $Q_{district\ heat_{max}}$. For each temperature value, $P_{net_{max}}/P_{net_{min}}$ is calculated, and a polynomial regression of the form $P_{net_{max}}/P_{net_{min}} = \gamma_3 + \gamma_2 \cdot T + \gamma_1 \cdot T^2$ is performed.

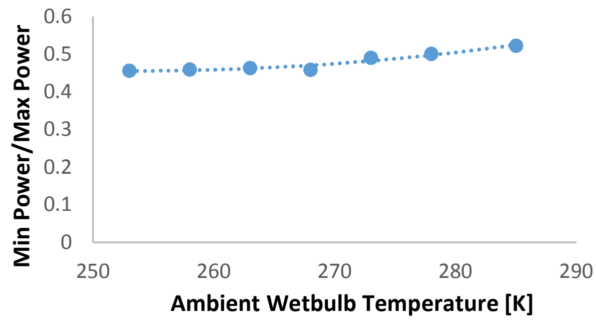

Figure 7: Ratio of minimum to maximum power vs ambient wet bulb temperature. The ratio of maximum power/minimum power slowly increases as temperature increases.

Electricity production is linearly dependent on the ambient temperature at values greater than 273 K, as $P_{net_{max}} = \alpha + \beta \cdot T$. At temperatures less than 273K, a fourth degree polynomial is observed of the form $P_{net_{max}} = \tau_4 + \tau_3 \cdot T + \tau_2 \cdot T^3 + \tau_1 \cdot T^3$. The Carnot Efficiency predicts that electricity production will decrease linearly with increase in ambient temperature; however, as CO_2 approaches its critical point at 273 K, the relationship is better modeled as a third degree polynomial. These relationships are used to calculate power production at intermediate temperature values. Figure 8 below shows such a relationship for N=5. As the ambient air temperature increases, power production decreases due to a decrease in thermodynamic cycle efficiency.

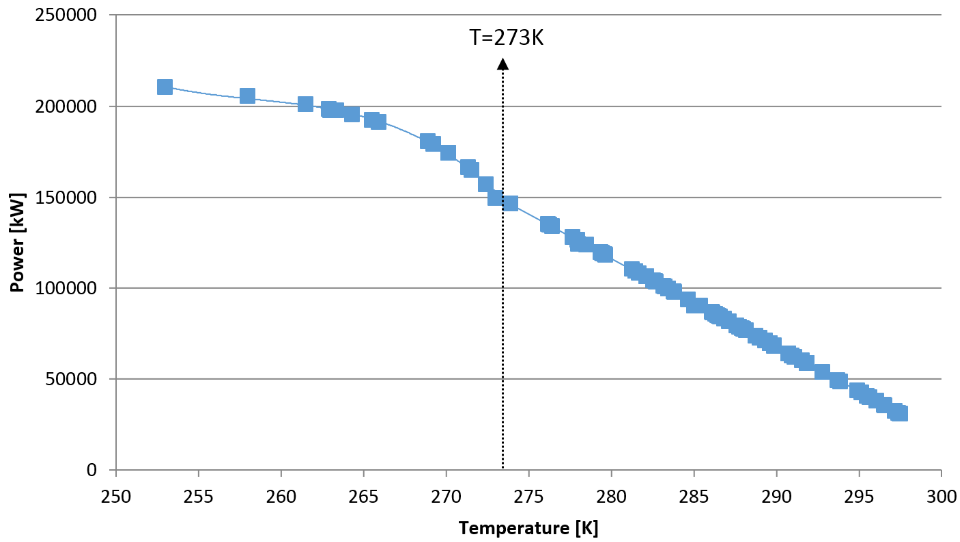

Figure 8: Relationship between Ambient Temperature and Power Production. As temperature increases, the temperature differential in the Carnot Efficiency decreases, which decreases power production. Power production is related to temperature as a third order polynomial until it approaches T=273 K due to CO_2 approaching its critical point. At temperatures greater than 273 K, power decreases linearly with temperature, as predicted by Carnot Efficiency.

The monthly average ambient air temperature (dew point and temperature mean) over 30 years were acquired from the National Climate Data Center and used to calculate the monthly wet bulb temperature. Power was calculated for the monthly average wet bulb temperature for each of the six cities. Once $P_{net_{max}}$ is calculated for a given temperature, it is possible to use the relationships described above to calculate all remaining variables.

For each location, three cases of heat demand are studied. In each case, heat is said to be required when average monthly dry bulb temperature is less than 286 K (55 F). These months are called heating months. During months with dry bulb temperatures greater than 286 K, only electricity is produced. Table 2 shows the annual average temperatures and ASHRAE's 99% Design Temperatures for each city.

Table 2: Average Annual and Design Temperatures. Average annual dry bulb temperatures are from congealed National Climate Data Center data. 99% Design Temperatures are from ASHRAE's Handbook--Fundamentals.

Temperatures [K]	Williston	Dallas	New Orleans	Houston	Sacramento	Williamsport
Average Annual Dry Bulb	279	292	294	294	289	283
99% Design (ASHRAE)	245	269	274	273	273	259

- **Case 1**: HX Meets Peak Winter Demand

Case 1 assumes that no thermal storage is available and the CPG CHP/DHC system must be able to meet peak heating demand. To calculate peak demand load, ASHRAE's 99% design temperatures are used. For each city, using maximum values for $Q_{district\ heat}$, a heat loss coefficient *UA* is calculated such that:

$$Q_{district\ heat_{max}} = UA(286\ \mathrm{K} - T_{99\%\ design\ temperature})$$

Where the *UA* product is the effective heat loss coefficient for all the buildings on the district heating system. The minimum value of *UA* over all 12 months, called UA_1, is selected as the heat loss coefficient for the system. $Q_{district\ heat}$ is then calculated for each heating month by multiplying UA_1 by the difference between monthly average dry bulb temperatures and 286 K, $(286\ \mathrm{K} - T_{dry\ bulb})$.

- **Case 2**: HX Meets Average Monthly Demand

Case 2 assumes that there is some form of thermal storage available in the CPG CHP/DHC system and the heat exchanger must only be able to meet average monthly demand. For each city, using maximum values for $Q_{district\ heat}$, a heat loss coefficient *UA* is calculated such that:

$$Q_{district\ heat_{max}} = UA(286\ \mathrm{K} - T_{dry\ bulb}).$$

The minimum value of UA over all 12 months, called UA_2, is selected as the heat loss coefficient for the district heating system. $Q_{district\ heat}$ is then calculated for each heating month by multiplying UA_2 by the difference between monthly average dry bulb temperatures and 286 K, ($T_{dry\ bulb} - 286$ K).

- **Case 3**: All Heat Produced is Sold

Case 3 assumes that all heat that is produced in heating months is sold to the market. No heat loss coefficient is calculated.

3.3. The Economic Model

In this model, we will analyze brownfield projects only. A brownfield project consists of a field that has already been developed for CO_2-EOR, thus the CPG plant developer is not responsible for the costs associated with acquiring the site, drilling the production wells, or maintaining the system. As such, the geothermal developer does not receive revenue associated with sequestering CO_2; however, the developer does receive revenue for the energy produced.

Various financial assumptions had to be made in order to calculate the Net Present Value (NPV) of CPG CHP/DHC plants. The lifetime of each CPG CHP/DHC plant is assumed to be twenty years, annual rate of increase of electricity prices and the production tax credit is assumed at 2.5% (Lazard, 2014), and the duration of the production tax credit is set at ten years (DOE, 2013).

3.3.1. Initial Investment and O&M Cost

The initial costs and the operating and maintenance costs must be calculated for both the electricity production and the district heating system.

For the electricity plant, the costs for required infrastructure are the same as those in the annual model (Bielicki et al., in preparation) and the Monthly Model (Jamiyansuren et al., in preparation). The cost of the turbine is obtained from GETEM. The cost information was regressed in order to obtain a cost equation based on capacity and operating temperatures, and then multiplied by a factor of three to account for the costs associated with using high pressure CO_2. The cooling tower cost and performance data comes from Baltimore AirCoil for condensing tower model PC2-509-1218-30, and cooling tower models FXV-0812B-12D-J and FXV-1212C-16Q-K (Bielicki et al., in preparation).

The operating and maintenance costs also come from a modified GETEM sheet and are dependent of the capacity of the plant. For our model, O&M costs are adapted from the values reported in the Monthly Model (Jamiyansuren et al., in preparation). For each city, the O&M costs are separated into two categories: costs that vary with operation and those that are independent of operation.

Table 3: Non-varying and Varying O&M Costs. Costs come from a modified GETEM sheet.

Non-varying O&M costs [$]	*Varying O&M costs[$/kWh]*
Well Reworking Costs	Plant O&M Costs
Annual monitoring cost	
Annual site cost	
Insurance cost ($/year)	
Annual injection well related cost	
Annual well related cost	

Costs that vary with operation are calculated for a year of electricity production (no heat) and divided by the total kWh of electricity produced in that year, giving an O&M cost for each kWh electricity produced. Each location has a unique varying and non-varying O&M cost value. This value is assumed to increase at a rate 2.5% each year (Lazard, 2014). In order to obtain each month's O&M costs, the $/kWh varying O&M value is multiplied by the turbine output after accounting for power losses due to extraction of heat, and then added to the non-varying O&M costs., as seen in Equation 2.

$$Cost\ of\ O\&M_{total} = \left[O\&M\ Cost_{varying} \cdot P_{net}\right] + \left[O\&M\ Cost_{non-varying}/12\right] \quad (2)$$

It is assumed that the CPG CHP/DHC plant utilizes an existing district heating network, thus no costs are incurred for transporting hot water to customers. Similar to the turbine, the cost of the heat exchanger comes from regressed GETEM data for brine heat exchangers. A cost equation was developed based on the log mean temperature difference (LMTD) of the heat exchanger. This was then multiplied by a factor of three to account for costs associated with using high pressure CO_2. The heat exchanger is assumed to be insured at a rate of 3% each year.

The operation and maintenance costs for the district heating systems comes from Lund's 2010 Direct Utilization of Geothermal Energy report, and once again, is multiplied by a factor of three to account for working with high pressure CO_2. This value for O&M is assumed to increase at a rate of 2.5% annually and is constant for all six cities. Overall, the O&M costs of the district heating system are substantially lower than those of the electricity production plant.

3.3.2. Electricity and Heat Pricing

The Heating Model, like the Monthly Model, assumes that the electricity produced will be sold in a competitive market to a central system, so the prices used for electricity reflect average wholesale monthly market prices. The electricity pricing information was obtained from MISO data and the US Energy Information Administration. Hourly values were obtained and congealed into monthly averages. The results can be seen below in Figure 9.

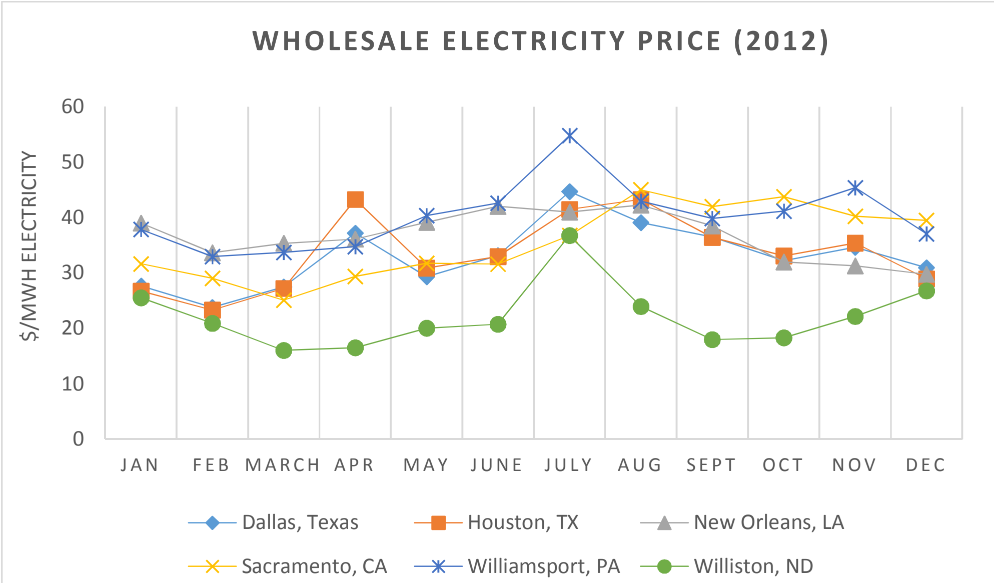

Figure 9: Wholesale Electricity Price by Location (2012). The electricity pricing information displayed here was extracted from MISO data and US Energy Information Administration, as the electricity produced by the CPG power plant is assumed to be sold to the central system at a competitive price on the market.

For heat, prices were obtained from the EIA's Heating Fuel Comparison Calculator (2014). Like electricity production, the price of heating needs to be competitive in the current market, so it is assumed that the heat produced by each CPG plant is sold at a price equal to the cost incurred by heating the same space with a natural gas furnace or boiler.

Table 4: Heat Prices for CPG DHC plant. Cost comes from EIA's Heating Fuel Comparison Calculator (2014) and prices are assumed to inflate 2.5% every year.

Natural Gas Prices	
$/Million BTU	$/kWh
12.22	0.04170

4. Results

The EES model was first used to calculate values for heat production for the various well sizes, ambient temperatures, and reservoir conditions. Excel was then used to calculate the heat loss coefficient for each city and the economic parameters.

4.1. EES and TOUGH2 Seasonal Simulation Results: Heat and Power Production

Compared to brine, CO_2 does not arrive at the production well heads at the high temperatures reached in the geothermal reservoir; thus we were not confident that the produced CO_2 would be hot enough to heat the district heating water to the required 322 K (120 F). The EES model was used to simulate the district heating potential for a variety of ambient wet bulb temperatures and it was observed that starting around 293 K, a variety of wells are unable to produce CO_2 at a temperature high enough to be used for district heating. Because heating is only required at an ambient dry bulb temperature of 286 K and below the production temperature of CO_2 does not limit the potential for district heating.

The monthly values for heat production are used to calculate the heat loss coefficient for each case. Table 5 below shows the maximum monthly heat production and the UA-value for each city.

Table 5: Maximum Heat Production and Heated Space Coefficient.

	Williston	Dallas	New Orleans	Houston	Sacramento	Williamsport
Maximum Heat Production [MWth]						
	1102	992	918	927	967	1074
Heat Loss UA-Value [kWth/K]						
Case 1	24851	55866	78700	68048	70892	34898
Case 2	46557	189559	789754	644212	192731	69804
Case 3	N/A	N/A	N/A	N/A	N/A	N/A

The city with the highest maximum heat production is Williston, ND, and interestingly, it is also the city with the lowest heat loss coefficient, less than a third of the UA-value of New Orleans. That is explained by the drastic difference in ambient temperatures of the cities. Because of its higher temperatures, less heat is required in New Orleans, and it is able to heat a space with a larger UA-value. It is important to note, however, that homes in warmer climates tend to have higher U-values due to decreased necessity for high performing insulation. This higher U-value decreases the serviceable envelope area, indicating that fewer buildings can be provided with district heat.

Once UA-values are calculated, the heat demand for each month is determined based on ambient air temperature. Recall that this heat demand is used to determine the amount of electricity produced. The correlated heat and power production is displayed in Figure 10 below. The dashed lines indicate monthly power production and solid lines indicate heat production.

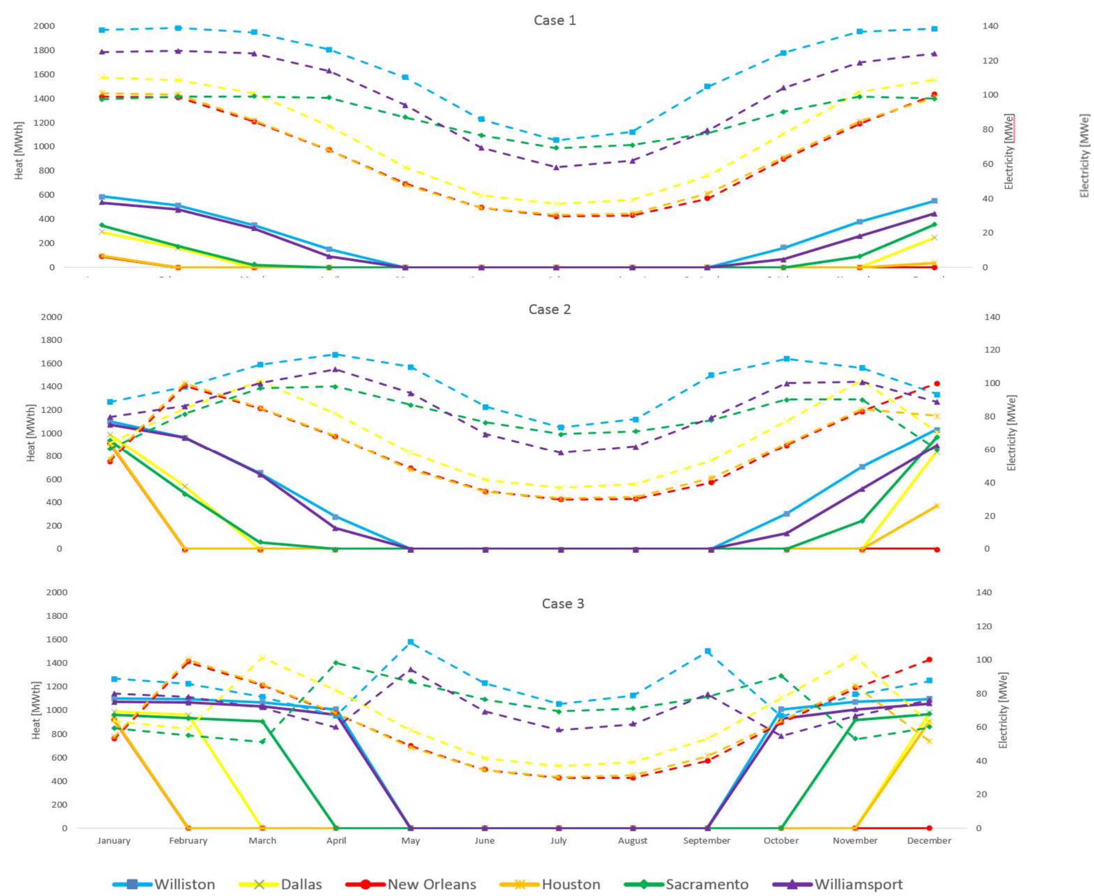

Figure 10: Heat and Electricity Production for CHP. Temperature data were used to calculate power production and electricity demand for each city. Solid lines indicate heat production. Dashed Lines indicate power production.

Annual heat produced changes drastically with each city. While Williston and Williamsport require heat for eight months out of the year, New Orleans required heat only in January. Case 1 produces the least amount of heat, an implication of meeting peak winter demand. The maximum amount of heat produced in the winter months varies substantially for each city, as the temperature during the winter months plays a major role in the UA-value for the heated space.

Power and heat production in Case 2 follow a similar trend to that of Case 1; however, heat production values are substantially higher, as UA-values are not limited by peak winter demand. It is also interesting to note that for Case 2, the values for maximum heat demand (those in the coldest month, January) are far more comparable for each city. This is because UA-values are calculated based on maximum heat production, not temperature differences. Because the values for maximum heat production for each city are far more similar compared to their 99% design temperatures, the maximum heat demanded is also far more similar in Case 2 than in Case 1.

The values for heat and power production for Case 3 are substantially different from those in Case 1 and Case 2, as no consideration is given to demand. By producing all possible heat, heat production values increase up to five times that of the values based on demand. Because all possible heat is produced, power production values are greatly affected and total power production for the year is decreased substantially.

Using the space heating energy consumption values reported in the U.S. Energy Information Administration's (EIA's) 2009 Residential Energy Consumption Survey (RECS), the demand calculated is compared to actual heating demands. For each location, average state values are used. The percent of household energy used for space heating (Actual) is compared to the percent of total energy produced in CPG CHP/DHC plants used for district heating. Figure 11 displays this comparison for each district heating case (Case 1, Case 2, and Case 3) considered. Case 1 is consistently the closest to actual percent space heating values, as Case 1 is the most conservative method when calculating demand.

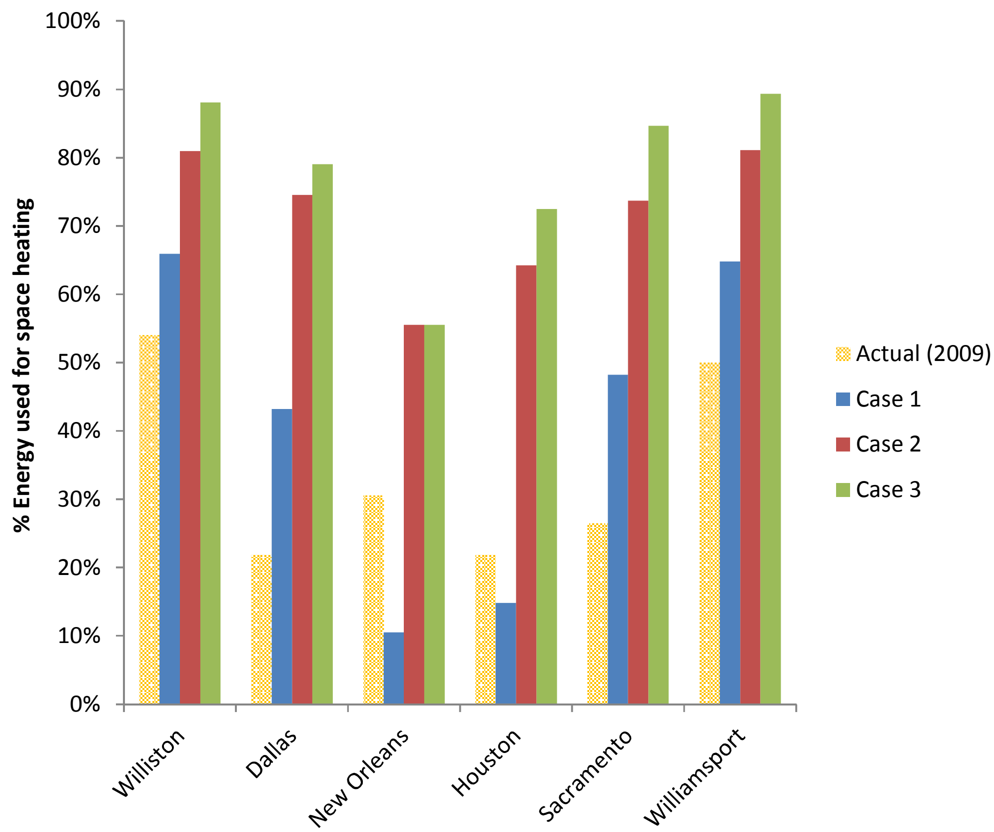

Figure 11: Percent Energy Usage for Space Heating. Average state space heating data is taken from the EIA's 2009 RECS and compared to the percent district heating energy produced in CPG CHP/DHC plants.

Figure 11 brings up an important point when considering the practicality of the three different district heating cases. While Case 2 and Case 3 produce more sellable heat than Case 1, it is not always realistic to assume that all the heat produced will have a market in the various CPG CHP/DHC locations. For example, in Sacramento, 26% of total household energy consumed is used for space heating; however, the percent of CPG CHP/DHC energy produced used for heating in Case 2 is over twice that amount, at 74%. Case 3 more than triples that of actual demand, at 88%. In Case 2 and Case 3, special circumstances, such as large factories or dense urban areas, are required to ensure that all heat produced is sold.

4.2. Economic Performance of CPG CHP/DHC Plants

Values for each location's monthly heat and power production over the twenty year lifetime of the plant are used to produce the net present value for each case. Figure 12 below displays the NPV for each city. They are compared with the NPV for electricity production only.

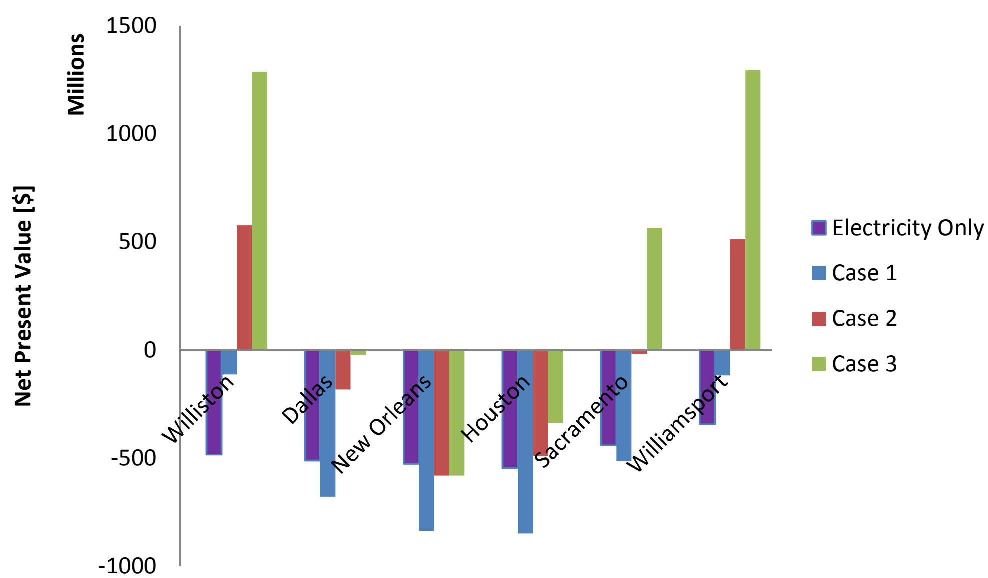

Figure 12: Comparison of Net Present Values for CPG CHP/DHC Plants. NPV based on a twenty year plant lifetime. Electricity is sold at market price and heat is sold at the price of natural gas. Prices for electricity and heat inflate at a rate of 2% per year.

It can be seen in Figure 12 that in most cases, adding district heat to CPG plants increases the plant's NPV; however, it does not always do this. There are multiple cases where the profit from selling heat during winter months does not outweigh the cost of adding a heat exchanger to the system. In order to optimize the profit of CPG plants, the climate of each city needs to be considered.

4.2.1. Optimal Locations of CPG CHP/DHC Plants

The Energy Consumption Division in the EIA has divided the United States into five different climate zones based on long-term weather condition effects on heating and cooling loads of buildings. The zones were selected from seven original categories presented by the American Institute of Architects (AIA) for the U.S Department of Energy (DOE) and U.S Department of Housing and Urban Development (EIA, 2009). The AIA zones are compared with the International Energy Conservation Code (IECC) and American Society of Heating, Air Conditioning, and Refrigerating Engineer (ASHRAE) developed climate regions. The 24 original regions have been consolidated into five regions by the DOE's Natural Renewable Resources Laboratory and are the regions used for reporting purposes (Baechler, 2010). Figure 13 below shows the AIA climate zones and the IECC/ASHRAE climate regions of the CPG plant locations considered in this study.

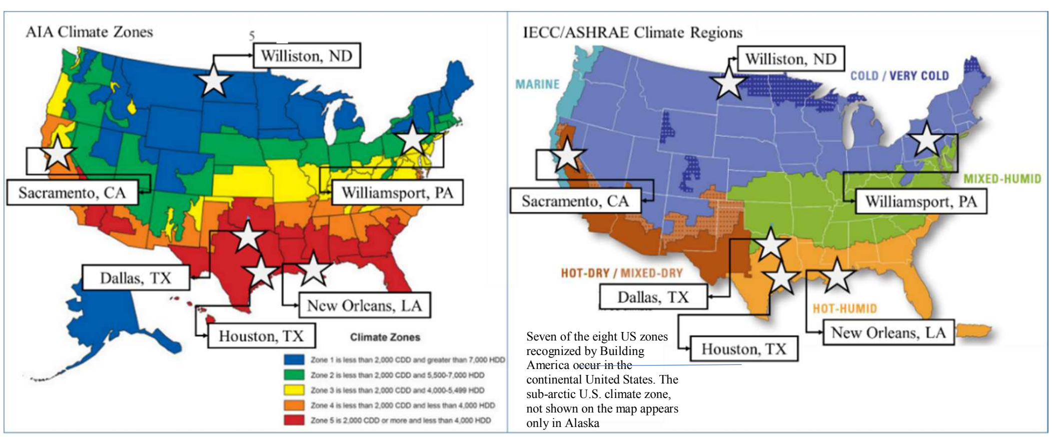

Figure 13: Climate Zones/Regions of Considered CPG CHP/DHC Plant Sites. The climate zone map on the left is taken from the AIA climate zones presented in the EIA Residential Energy Consuption Survey (RECS). Climate zones are based on number of cooling (CDD) and heating degree days (HDD). The climate zone map on the right is presented by IECC/ASHRAE and the regoins are based on HDD, average ambient temperature, and precipitation.

Dallas, Houston, and New Orleans are all located in the AIA's Zone 5 with the fewest number of heating degree days and IECC/ASHRAE's Hot-Humid region. Sacramento is located in AIA's Zone 3 and ASHRAE's Hot-Dry Zone, Williamsport is located in AIA's Zone 2 and IECC/ASHRAE's Cold region, and Williston is located in Zone 1, with the highest number of heating degree days, and IECC/ASHRAE's Very Cold region. These zones are summarized below in Table 6.

Table 6: Climate zones of cities considered.

	Williston	Dallas	New Orleans	Houston	Sacramento	Williamsport
AIA Climate Zones						
	Zone 1	Zone 5	Zone 5	Zone 5	Zone 3	Zone 4
IECC/ASHRAE Climate Regions						
	Very Cold	Hot-Humid	Hot-Humid	Hot-Humid	Hot-Dry	Cold

The climate groupings associated with the AIA Climate Zones are consistent with those of the IECC/ASHRAE climate regions. In order to determine the effect of climate on the NPV of CPG CHP/DHC plants, the NPV is plotted against average annual dry bulb temperature and divided into climate zones. Figure 14 below shows the NPV of CPG CHP/DHC plants in various climate zones.

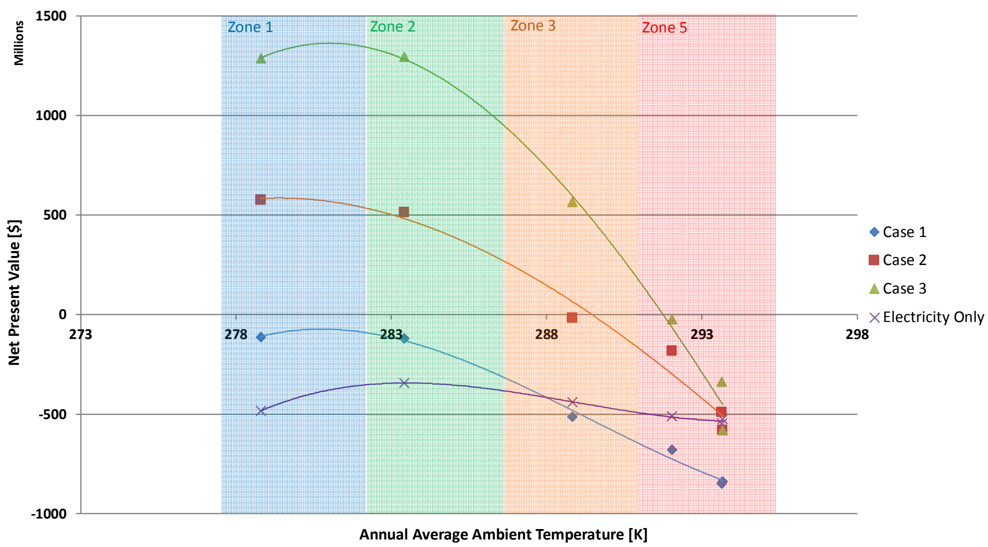

Figure 14: Net Present Value of CPG CHP/DHC Plants Based for Varying Climates. Climate zones considered are given by the AIA climate zones presented in the EIA Residential Energy Consuption Survey (RECS) and the regoins given by IECC/ASHRAE.

When considering electricity production only, Zone 2 and Zone 3 have the highest NPV, though in all four zones considered, the CPG plants lose money for electricity production only, on the order of hundreds of millions of dollars. This is consistent with the findings of the Monthly Model study (Jamiyansuren et al., in preparation). In Zone 1 and Zone 2, the magnitude of that debt decreases greatly by adding a Case 1 district heating system, and Case 2 and Case 3 actually raise the NPV to positive values. In Zone 3 and Zone 5, Case 1 actually decreases the NPV of the plant while Case 2 and Case 3 can increase the NPV; however, for some instances in Zone 5, none of the district heating cases have a positive effect on the NPV of the CPG plant.

In order to isolate the effects of adding district heating to CPG plants in the four climate zones considered, the sum of district heating costs occurred over the lifetime of the plant is divided by the plant's lifetime heat revenue. This cost/revenue ratio is plotted against average annual dry bulb temperature and divided into climate zones. Figure 15 below shows the district heating cost/revenue ratio of CPG CHP/DHC plants in various climate zones.

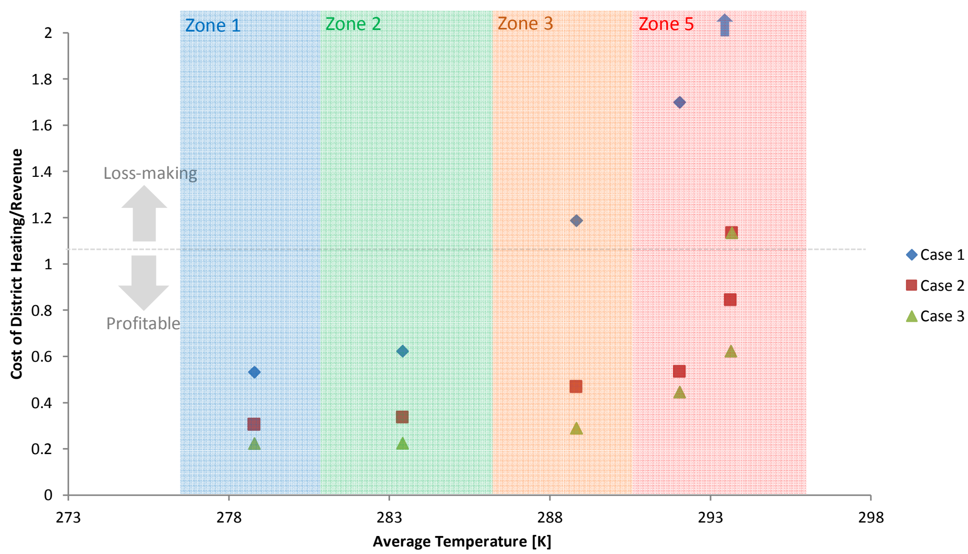

Figure 15: Cost Ratio (Cost/Revenue) of District Heating Addition to CPG Plants. The ratios plotted are calculated by dividing district heating costs occurred over the lifetime of the plant by the revenue from heat summed up over the CPG CHP/DHC plants' lifetimes.

For all cost/revenue ratio values greater than one, the district heating addition to the CPG plant is losing money. In Zone 1 and Zone 2, all district heating cases have revenue that outweighs the cost of the district heating addition; thus, for CPG plants in climate Zone 1 and Zone 2, adding district heat is economically beneficial. In Zone 3, Case 2 and Case 3 district heating systems add profit to the plant; however, Case 1 has a profit ratio greater than one, and thus, adding a Case 1 district heating system increases net losses. In Zone 2, adding a Case 2 or Case 3 district heating system in economically beneficial.

In Zone 5, a Case 1 district heating system always loses money. Case 2 and Case 3 have the potential to generate a positive profit; however, it is necessary to consider specific heating requirements at each location to determine profit potential. For example, Houston, TX and New Orleans, LA are both in Zone 5 and they both have an average annual temperature of 294 K. In Houston, there are two heating months but in New Orleans, there is only one month in which is it possible to sell heat. These characteristics are reflected in the district heating cost/revenue ratio for each plant. The second month of selling heat makes a big difference for the CPG plant in Houston, as both Case 2 and Case 3 district heating produces a profit, whereas in New Orleans, both Case 2 and Case 3 district heating systems cost more money than the revenue incurred by selling heat for one month each year.

Ultimately, in order for CPG CHP/DHC plants to expect widespread adoption, they must be profitable to plant operators. In order to analyze the profit potential of CPG CHP/DHC plants in the four climate zones considered, the sum of all costs incurred over the lifetime of the plant is divided by the plant's total revenue summed over its lifetime. This total cost/revenue ratio plotted against average annual dry bulb temperature is compared for the four difference climates. Figure 16 below shows the total cost/revenue ratio of CPG CHP/DHC plants in various climate zones.

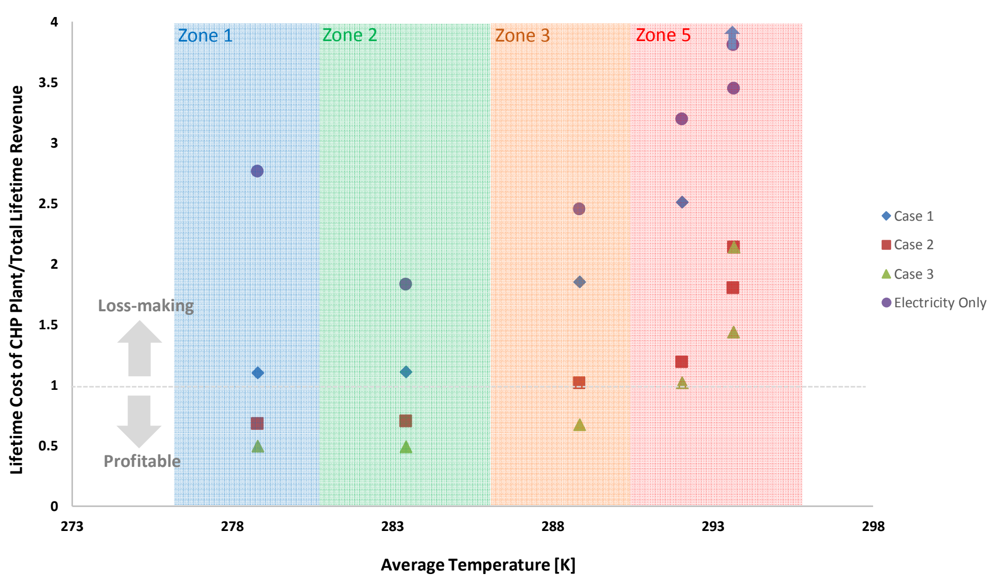

Figure 16: Cost Ratio (Cost/Revenue) of CPG CHP/DHC Plants. The ratios plotted are calculated by dividing district heating costs occurred over the lifetime of the plant by the revenue from heat summed up over the CPG CHP/DHC plants' lifetimes.

The cost/revenue ratio for electricity production only CPG plants are consistently higher than that of CPG CHP/DHC plants, except in Zone 5, where the warmer climates are unable to recover the cost of the heat exchanger in the limited months where it is possible to sell heat. Case 2 and Case 3 always have a lower cost/revenue ratio than that of electricity only and Case 1; however, recall that Case 2 and Case 3 are not as likely to have a consistent market for the amount of heat produced.

Although Case 2 and Case 3 CPG CHP/DHC plants do have instances of producing a positive profit, a majority of the CPG CHP/DHC plants do not create enough revenue to overcome costs associated with the plant. In order for these CPG CHP/DHC power plants to be successful, they will need support from public policy, federal tax credits, and other renewable energy incentives. Below, we consider various sources of funding and incentives.

4.2.2. CPG CHP/DHC in Today's Economic Environment

There are a wide range of government incentives available to renewable energy sources in today's economic environment that CPG CHP/DHC plants can take advantage of in order to increase potential profit. Note that up to this point, all values presented have not considered tax incentives.

Recall that a major benefit of CPG plants is that they utilize sequestered CO_2. Because of the harmful environmental effects of CO_2, its sequestration is incentivized by the government. The first incentive considered for CPG CHP/DHC plants is a federal rebate option proportional to the amount of CO_2 sequestered over the lifetime of the plant. Table 7 below shows the price per tonne CO_2 sequestered that is required in order to bring the NPV of the plant to zero.

Table 7: Price per Tonne CO_2 Sequestered to Bring NPV to Zero.

	Williston	Dallas	New Orleans	Houston	Sacramento	Williamsport
Case 1	$55	$332	$410	$415	$252	$58
Case 2	N/A	$89	$285	$240	$9	N/A
Case 3	N/A	$12	$285	$165	N/A	N/A
Electricity Only	$237	$251	$257	$267	$215	$168

Adding district heating to CPG plants can significantly decrease the rebate required to bring the NPV of the plant to zero. In Williston and Williamsport, the price per tonne CO_2 required for a Case 1 CHP/DHC plant is less than half of that required by producing electricity only. Case 2 dramatically reduces the rebate required for Dallas and Sacramento, with Sacramento at a value of only nine dollars per tonne CO_2 sequestered. Case 2 and Case 3 is an improvement over electricity production for all cities except New Orleans, as it never recovers the cost of a district heating addition.

The second incentive considered is a tax credit available to renewable energy sources. The rebate is priced at $22/MWe produced and is applied to electricity production over the first ten years of the plant's lifetime (Lazard, 2014). The rebate is said to inflate at the same rate as electricity prices, 2.5%. Figure 17 below shows the NPV of each plant after the production credit is applied.

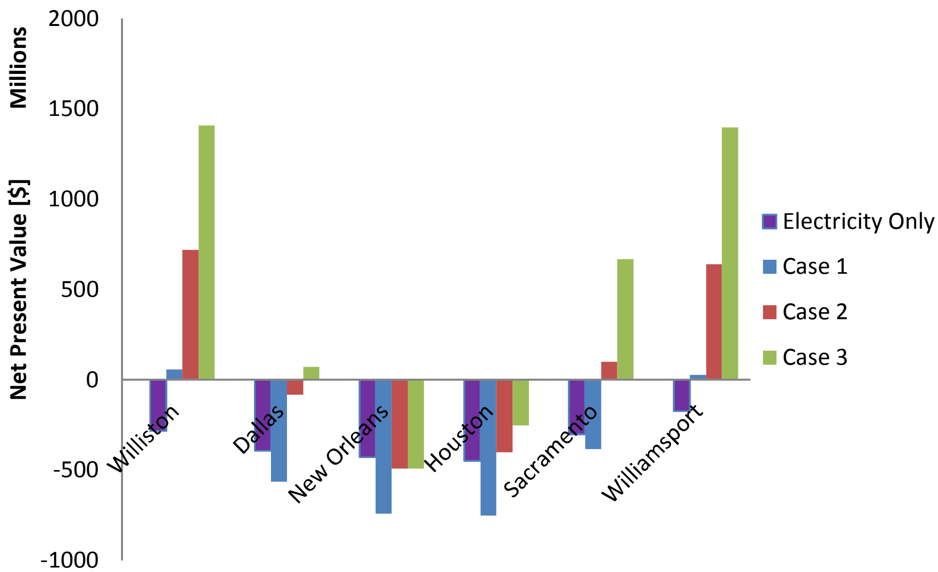

Figure 17: Comparison of Net Present Values for CPG CHP/DHC Plants after Applying the Production Tax Credit. The production tax credit is valued at $22/MWh electricity produced and applied to the first 10 years of electricity production, inflating at a rate of 2.5% per year (Lazard, 2014).

The production tax credit can make a significant difference for CPG CHP/DHC plants. In Williston and Williamsport, the tax credit is enough to increase Case 1 NPV to a positive value. Case 2 in Sacramento and Case 3 in Dallas are also made positive by the production tax credit. However, for the remainder of the cities, while it does increase the overall NPV of the plants, the production tax credit increases the magnitude of the negative effect of adding Case 1 district heating to an electricity only CPG plant.

5. Conclusions

CPG technology has the potential to be successfully integrated with CHP/DHC technology. Heat production was modeled for a variety of ambient wet bulb temperatures and, although CO_2 does not maintain production wellhead temperatures to the extent of brine, CPG plants are not limited by the temperature of CO_2 when considering using hot CO_2 for district heating. The locations with maximum heat production values also have the lowest UA-values, due to the cooler temperatures and thus, higher heating loads.

It is important to consider local demand when sizing a plant's heat production. Although Case 2 and Case 3 produce more sellable heat than Case 1, Case 1 better correlates to actual values for percent household energy consumption used for space heating reported by the EIA's 2009 RECS. Because the price of a heat exchanger increases exponentially as heat production is increased, it is important to size the exchanger to the amount of heat that can be sold. In order for Case 2 and Case 3 to sell all of the heat produced, special circumstances are required, such as a set of large factories or a dense urban area.

Adding district heating can be economically beneficial. District heating systems have substantially lower operating and maintenance costs than that of power plants, and in all cities considered, except New Orleans, district heating has the potential to increase the net present value of CPG plants. Case 1 increases the NPV for Williston and Williamsport, while it decreases the NPV for Dallas, New Orleans, and Sacramento. Case 2 and Case 3 district heating systems increase the NPV for all locations except New Orleans. In the case of electricity production only, all locations have a negative NPV; however, CPG CHP/DHC plants in Williston, Sacramento, and Williamsport have the potential to produce a positive profit. In New Orleans, it is never cost effective to add a district heating system.

Climate matters. Climate plays a crucial role in determining the economic success of a CPG CHP/DHC plant. The cities considered fall into climate zones 1, 2, 3, and 5. In Zone 1 and Zone 2, all cases of district heating additions to CPG power plants increase the NPV of the plant. In Zone 3, only Case 2 and Case 3 district heating systems increase the NPV of CPG plants, while Case 1 decreases the NPV. In Zone 5, Case 1 always decreases CPG plant's NPV; however, when considering Case 2 and Case 3, it is necessary to determine specific heating requirements at each location to determine profit potential. Case 2 and Case 3 district heating systems have the potential to increase or decrease NPV. In the instance where Case 2 and Case 3 decrease NPV, the number of heating months is only one, whereas the remaining Zone 5 locations have a number of heating months greater than or equal to two. The extra heating months make a significant difference when considering the profit of CPG CHP/DHC plants in Zone 5.

Tax credits/CO_2 sequestration costs can make non-favorable CPG CHP/DHC plants profitable. District heating can decrease the CO_2 sequestration rebates required to bring the NPV of CPG CHP/DHC plants to zero. Case 1 district heating systems decreases the Williston and Williamsport required rebates. Case 2 and Case 3 decreases the required rebates for all cities except New Orleans. In New Orleans, adding a district heating system always requires a higher CO_2 rebate. A production tax credit is also considered, and found to increase the financial performance of CPG CHP/DHC plants. In Williston, Dallas, Sacramento, and Williamsport, the production tax credit increases the NPV of CPG CHP/DHC plants to positive values.

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Appendix 1: Heat Exchanger Costs

The cost of the heat exchanger comes from regressed GETEM data for conventional brine-based geothermal heat exchangers. Coefficients *C10*, *C11*, *C12*, *C20*, *C21*, *C22*, and *C23* in the equations below are provided by GETEM. They are used to calculate *C1* and *C2*, which are, in turn, used to calculate the price of a brine heat exchanger, $HX\ Cost_{brine}$ [$/kWe]. Using the values for heat exchanger efficiency, $HX\ Cost_{brine}$ [$/kWth] is calculated and plotted against the log mean temperature difference (LMTD). In order obtain a value for the cost of a CO_2 heat exchanger, $HX\ Cost_{CO2}$ [$/kWth], the cost of a brine heat exchanger, is multiplied by three to account for the increased cost of heat exchangers working with high pressure CO_2. These values are plotted against 1/LMTD and a linear regression is performed. The resulting equation is the equation used by EES to calculate $HX\ Cost_{CO2}$ [$/kWth].

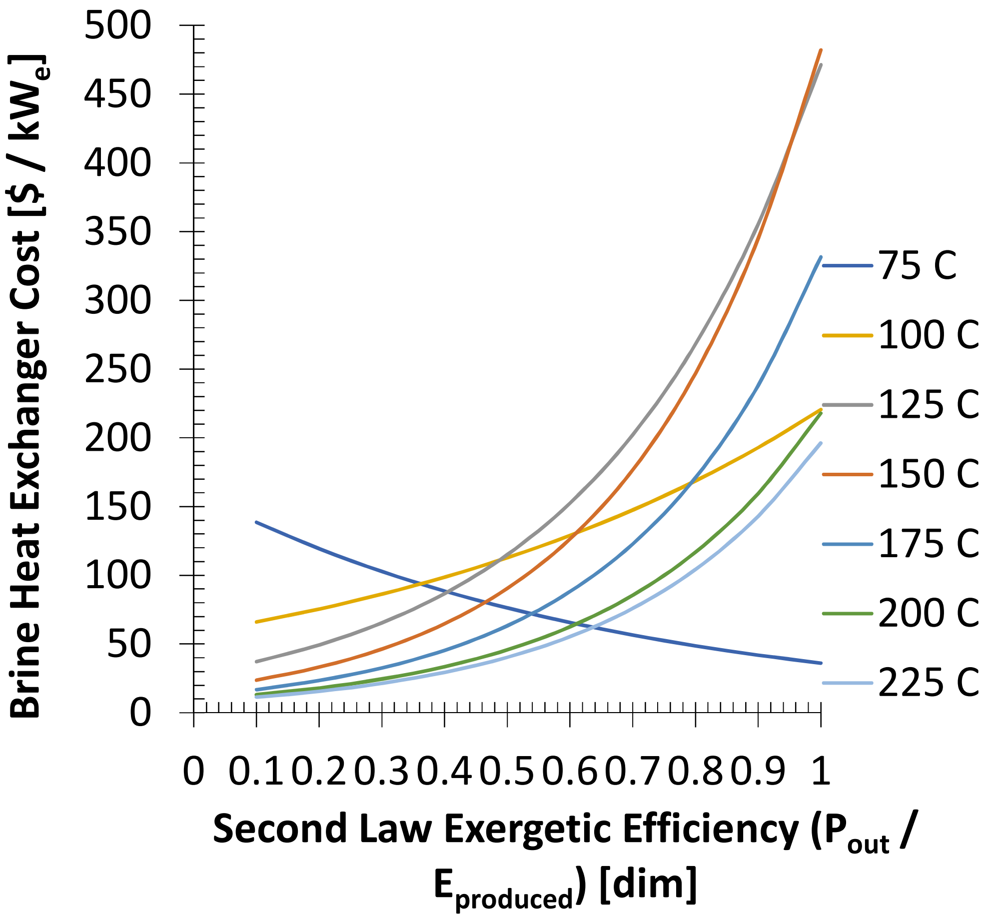
$$C1 = C10 + C11 * T_{in}^{C12}$$
$$C2 = C20 + C21 * T_{in} + C22 * T_{in}^{2} + C23 * T_{in}^{3}$$

T in [C]	eta_2nd	C10	C11	C12	C20	C21	C22	C23	C1	C2
225	0.1	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	8.31	3.16
225	0.2	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	8.31	3.16
225	0.3	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	8.31	3.16
225	0.4	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	8.31	3.16
225	0.5	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	8.31	3.16
225	0.6	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	8.31	3.16
225	0.7	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	8.31	3.16
225	0.8	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	8.31	3.16
225	0.9	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	8.31	3.16
225	1	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	8.31	3.16
200	0.1	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	9.64	3.12
200	0.2	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	9.64	3.12
200	0.3	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	9.64	3.12
200	0.4	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	9.64	3.12
200	0.5	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	9.64	3.12
200	0.6	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	9.64	3.12
200	0.7	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	9.64	3.12
200	0.8	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	9.64	3.12
200	0.9	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	9.64	3.12

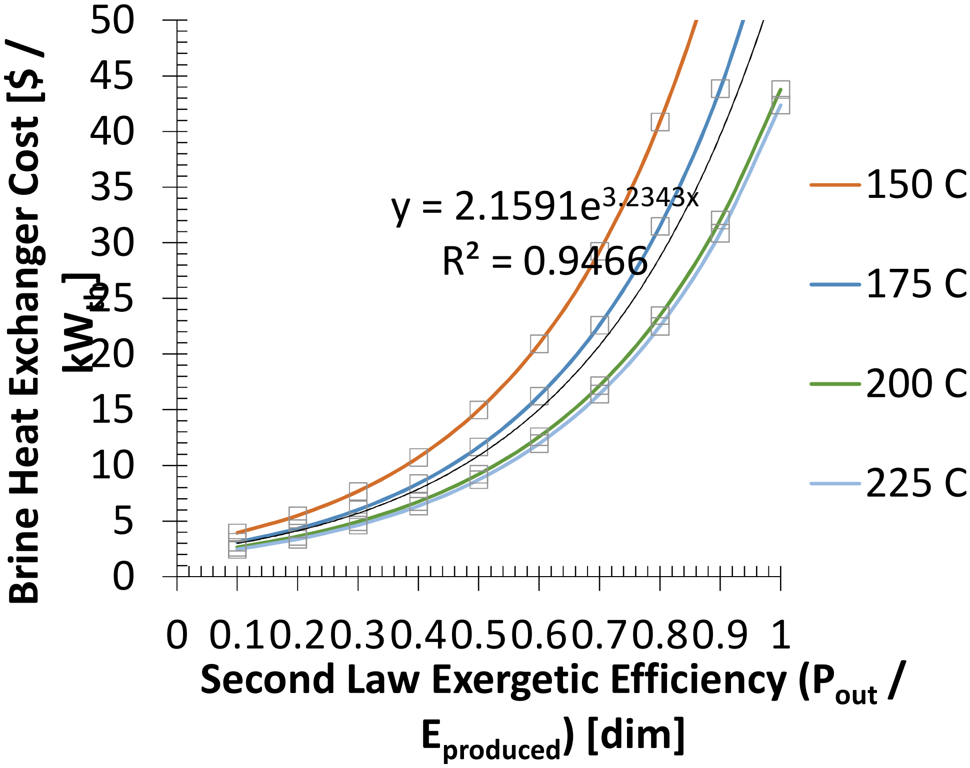
200	1	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	9.64	3.12
175	0.1	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	12.09	3.31
175	0.2	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	12.09	3.31
175	0.3	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	12.09	3.31
175	0.4	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	12.09	3.31
175	0.5	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	12.09	3.31
175	0.6	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	12.09	3.31
175	0.7	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	12.09	3.31
175	0.8	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	12.09	3.31
175	0.9	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	12.09	3.31
175	1	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	12.09	3.31
150	0.1	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	16.99	3.35
150	0.2	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	16.99	3.35
150	0.3	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	16.99	3.35
150	0.4	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	16.99	3.35
150	0.5	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	16.99	3.35
150	0.6	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	16.99	3.35
150	0.7	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	16.99	3.35
150	0.8	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	16.99	3.35
150	0.9	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	16.99	3.35
150	1	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	16.99	3.35
125	0.1	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	28.07	2.82
125	0.2	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	28.07	2.82
125	0.3	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	28.07	2.82
125	0.4	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	28.07	2.82
125	0.5	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	28.07	2.82
125	0.6	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	28.07	2.82
125	0.7	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	28.07	2.82
125	0.8	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	28.07	2.82
125	0.9	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	28.07	2.82
125	1	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	28.07	2.82
100	0.1	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	57.73	1.34
100	0.2	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	57.73	1.34
100	0.3	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	57.73	1.34
100	0.4	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	57.73	1.34
100	0.5	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	57.73	1.34
100	0.6	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	57.73	1.34
100	0.7	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	57.73	1.34
100	0.8	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	57.73	1.34
100	0.9	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	57.73	1.34
100	1	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	57.73	1.34
75	0.1	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	160.91	-1.49
75	0.2	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	160.91	-1.49
75	0.3	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	160.91	-1.49
75	0.4	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	160.91	-1.49
75	0.5	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	160.91	-1.49
75	0.6	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	160.91	-1.49
75	0.7	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	160.91	-1.49

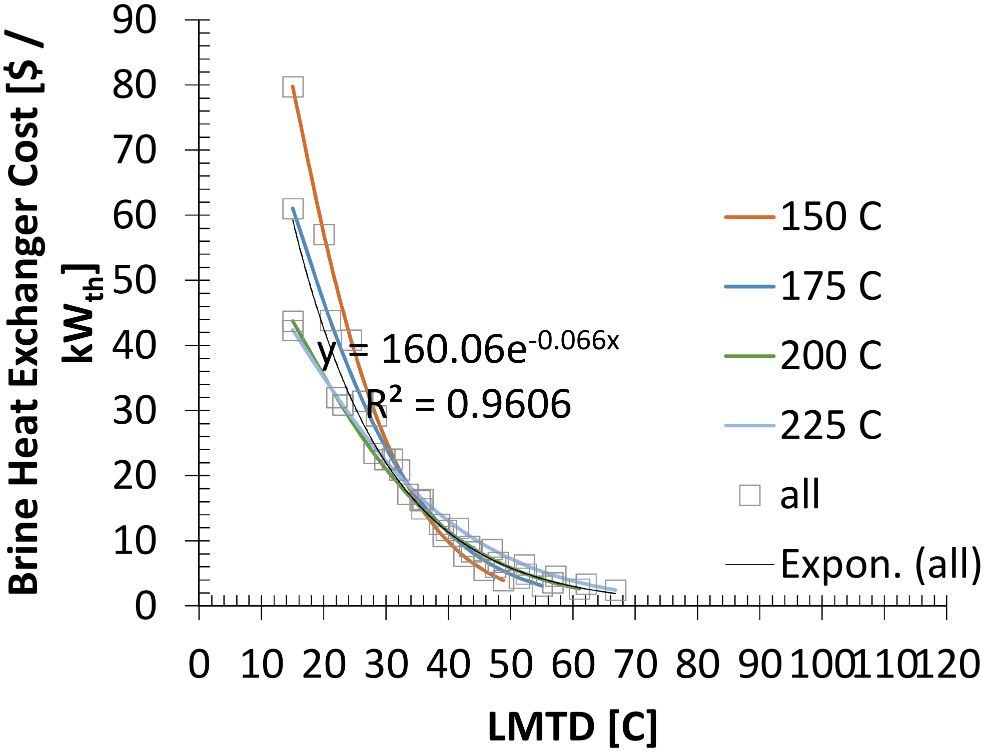
75	0.8	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	160.91	-1.49
75	0.9	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	160.91	-1.49
75	1	6	2E+09	-3.81	-22.099	0.4	-0.002	4.2E-06	160.91	-1.49

$$\boldsymbol{HX\ Cost}_{\,\boldsymbol{brine}}[{}^{\$}/_{\mathbf{kWe}}] = \boldsymbol{C1} + \boldsymbol{e}^{(\boldsymbol{C2}*\boldsymbol{\eta_{2nd}})}$$

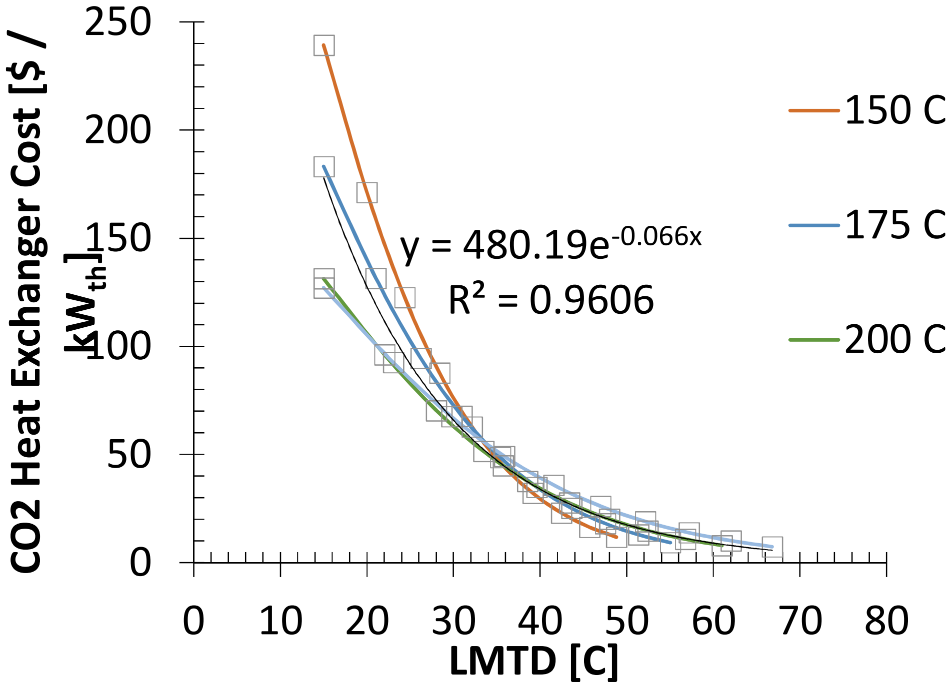


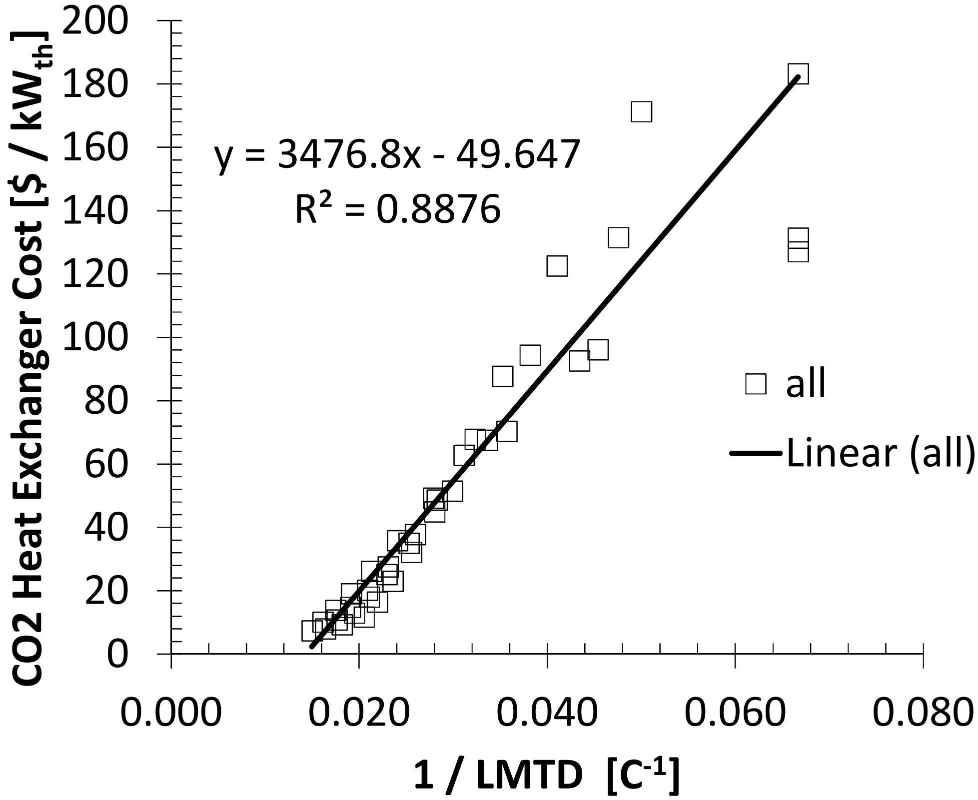
$$HX\ Cost_{\ brine}\left[{}^{\$}/_{\mathbf{kWth}}\right] = HX\ Cost_{\ brine}\left[{}^{\$}/_{\mathbf{kWth}}\right] * \eta_{thermal}$$





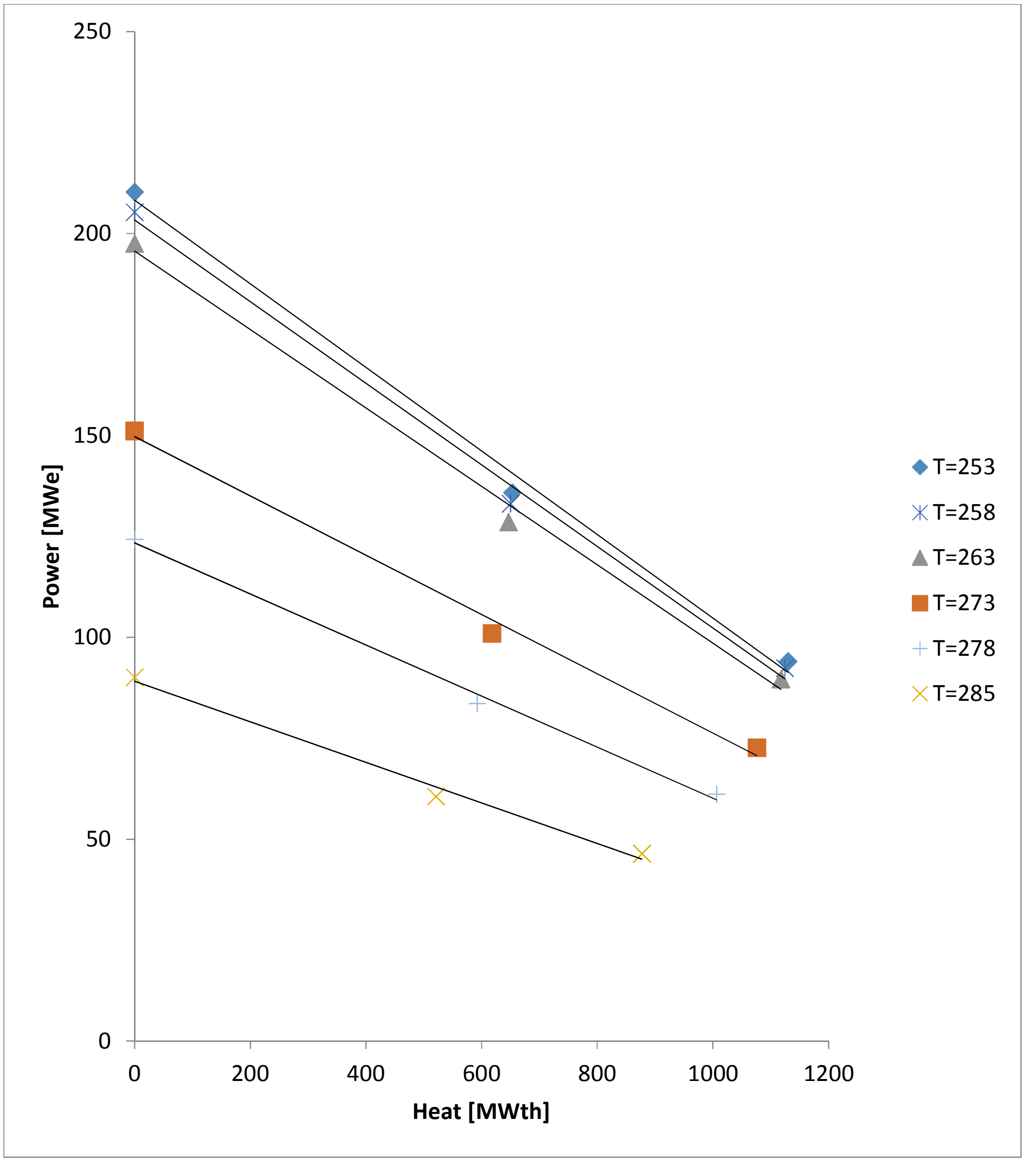
$$HX\ Cost_{CO2}[\$/_{kWth}] = 3 * HX\ Cost_{brine}[\$/_{kWth}]$$





Appendix 2: Fits for Heat, Power Production, Max Power Ratio, and HX Cost.

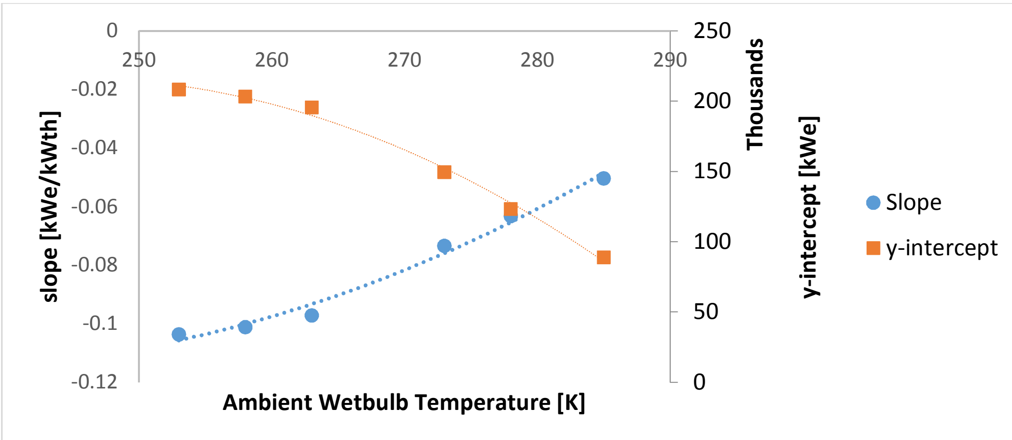
EES results for power and heat output. Power production is plotted against heat output and a linear fit is performed for each temperature.



The Y-intercept is consistently 99% of the value for max power output. Below are the slope values for each temperature.

Temp [K]	253	258	263	273	278	285
M [kWe/kWth]	-0.1	-0.1	-0.1	-0.07	-0.06	-0.05

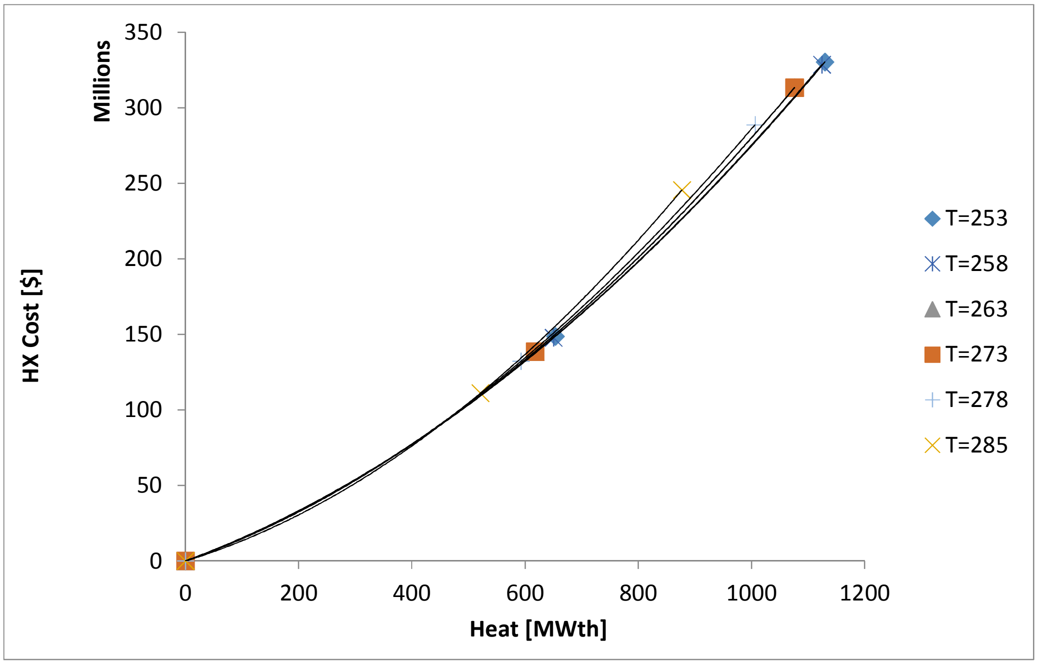
Slope and y-intercept vs temperature are plotted and fit to a second degree polynomial.



Slope was fit to a second order polynomial of the form $M_3 + M_2 \cdot T + M_1 \cdot T^2 = m$ and similarly, the y-intercepts were fit to a second order polynomial of the form $B_3 + B_2 \cdot T + B_1 \cdot T^2 = b$. Below are the resulting coefficients.

M1	M2	M3
0.00003	-0.011747199	1.3E+00
B1	**B2**	**B3**
-81.081	39714.25554	-4.6E+06

EES results for heat exchanger price and heat production values for various temperatures.

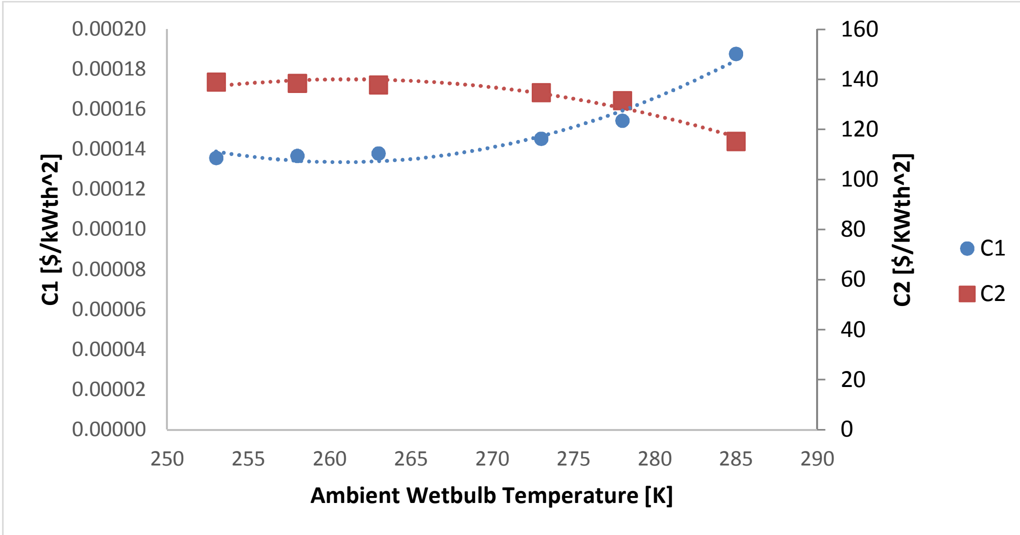


Heat exchanger price is plotted against heat output and a second order polynomial fit is performed for each temperature of the form $C_2 \cdot Q + C_1 \cdot Q^2 = HX\ Price$. Coefficient values for each temperature.

T=253		**T=258**		**T=263**		**T=273**	
C1	C2	C1	C2	C1	C2	C1	C2
0.00014	139	0.00014	138	0.00014	138	0.00015	135

T=278		**T=285**	
C1	C2	C1	C2
0.00015	132	0.00019	115

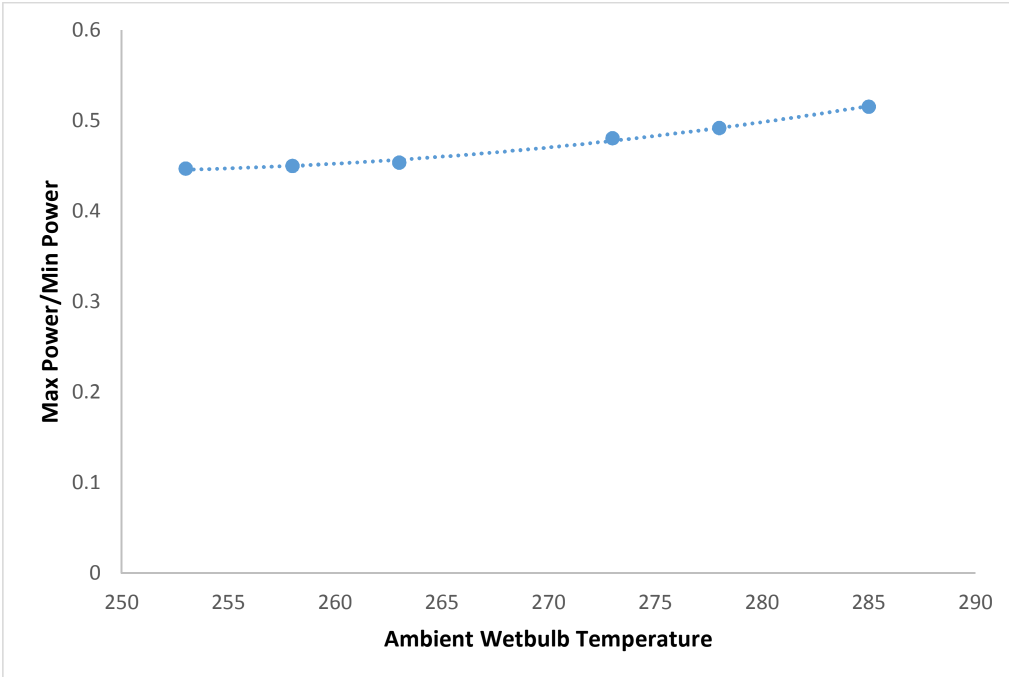
C_1 and C_2 vs temperature is fit to a second order polynomial.



C_1 values are fit to a second order polynomial of the form $C_{13} + C_{12} \cdot T + C_{11} \cdot T^2 = C_1$ and similarly, C_2 values are fit to a second order polynomial of the form $C_{23} + C_{22} \cdot T + C_{21} \cdot T^2 = C_2$. The table below displays the resulting coefficients.

C11	C12	C13
0.00000	-4.52934E-05	6.0E-03
C21	**C22**	**C23**
-0.04053	21.17309939	-2.6E+03

Maximum power production/minimum power is plotted against heat output and a second order polynomial fit is performed for each temperature of the form $P_3 + P_2 \cdot T + P_1 \cdot T^2 = P_{max}/P_{min}$.

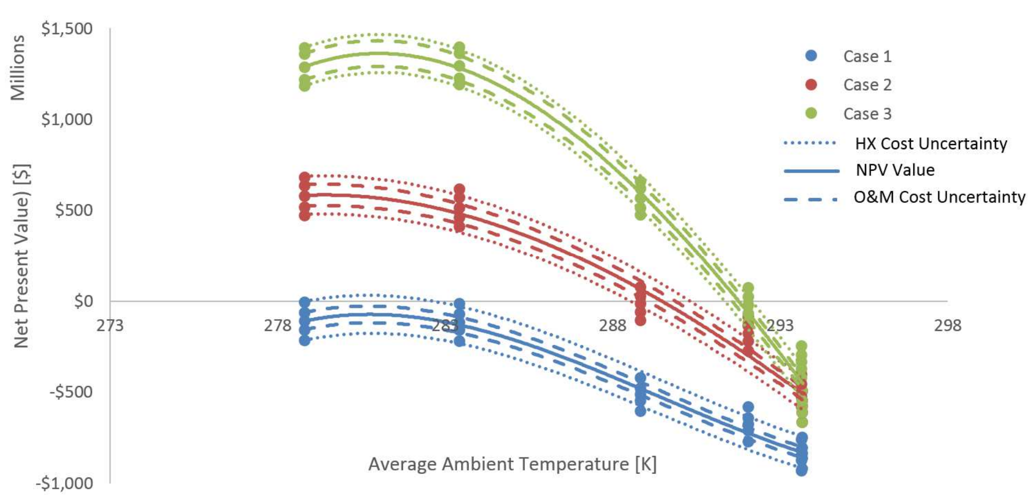


Below are the resulting coefficients.

P1	P2	P3
0.00005	-0.024715942	3.5E+00

Appendix 3: Uncertainty Analysis

	Williston	Dallas	New Orleans	Houston	Sacramento	Williamsport
Average Dry Bulb Temp	279	292	294	294	289	283
HX Cost Uncertainty						
Case 1 Low	-$218,000,000	-$772,000,000	-$923,000,000	-$935,000,000	-$606,000,000	-$221,000,000
Case 1 High	-$7,000,000	-$583,000,000	-$751,000,000	-$760,000,000	-$422,000,000	-$15,000,000
Case 1	**-$113,000,000**	**-$678,000,000**	**-$837,000,000**	**-$848,000,000**	**-$514,000,000**	**-$118,000,000**
Case 2 Low	$470,000,000	-$276,000,000	-$667,000,000	-$577,000,000	-$109,000,000	$411,000,000
Case 2 High	$681,000,000	-$87,000,000	-$495,000,000	-$403,000,000	$74,000,000	$617,000,000
Case 2	**$576,000,000**	**-$181,000,000**	**-$581,000,000**	**-$490,000,000**	**-$17,000,000**	**$514,000,000**
Case 3 Low	$1,181,000,000	-$118,000,000	-$667,000,000	-$424,000,000	$473,000,000	$1,191,000,000
Case 3 High	$1,392,000,000	$71,000,000	-$495,000,000	-$249,000,000	$657,000,000	$1,397,000,000
Case 3	**$1,286,000,000**	**-$24,000,000**	**-$581,000,000**	**-$337,000,000**	**$565,000,000**	**$1,294,000,000**
O&M Cost Uncertainty						
Case 1 Low	-$160,000,000	-$711,000,000	-$865,000,000	-$876,000,000	-$548,000,000	-$162,000,000
Case 1 High	-$66,000,000	-$644,000,000	-$809,000,000	-$819,000,000	-$480,000,000	-$75,000,000
Case 1	**-$113,000,000**	**-$678,000,000**	**-$837,000,000**	**-$848,000,000**	**-$514,000,000**	**-$118,000,000**
Case 2 Low	$517,000,000	-$223,000,000	-$613,000,000	-$525,000,000	-$60,000,000	$459,000,000
Case 2 High	$635,000,000	-$139,000,000	-$549,000,000	-$456,000,000	$25,000,000	$569,000,000
Case 2	**$576,000,000**	**-$181,000,000**	**-$581,000,000**	**-$490,000,000**	**-$17,000,000**	**$514,000,000**
Case 3 Low	$1,215,000,000	-$68,000,000	-$613,000,000	-$373,000,000	$512,000,000	$1,225,000,000
Case 3 High	$1,357,000,000	$21,000,000	-$549,000,000	-$300,000,000	$618,000,000	$1,363,000,000
Case 3	**$1,286,000,000**	**-$24,000,000**	**-$581,000,000**	**-$337,000,000**	**$565,000,000**	**$1,294,000,000**



	Williston	Dallas	New Orleans	Houston	Sacramento	Williamsport
Average Dry Bulb Temp	279	292	294	294	289	283
Total Cost Uncertainty						
Case 1 Low	-$228,000,000	-$778,000,000	-$927,000,000	-$939,000,000	-$612,000,000	-$230,000,000
Case 1 High	$3,000,000	-$577,000,000	-$747,000,000	-$756,000,000	-$416,000,000	-$6,000,000
Case 1	**-$113,000,000**	**-$678,000,000**	**-$837,000,000**	**-$848,000,000**	**-$514,000,000**	**-$118,000,000**
Case 2 Low	$455,000,000	-$285,000,000	-$673,000,000	-$584,000,000	-$118,000,000	$397,000,000
Case 2 High	$696,000,000	-$78,000,000	-$489,000,000	-$396,000,000	$41,000,000	$631,000,000
Case 2	**$576,000,000**	**-$181,000,000**	**-$581,000,000**	**-$490,000,000**	**-$17,000,000**	**$514,000,000**
Case 3 Low	$1,159,000,000	-$128,000,000	-$673,000,000	-$432,000,000	$459,000,000	$1,170,000,000
Case 3 High	$1,414,000,000	$23,000,000	-$489,000,000	-$242,000,000	$671,000,000	$1,418,000,000
Case 3	**$1,286,000,000**	**-$24,000,000**	**-$581,000,000**	**-$337,000,000**	**$565,000,000**	**$1,294,000,000**