Memo for Utilization Assessment

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Projected included members from Cornell University, Southern Methodist University, and West Virginia University.

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The Utilization effort for the Geothermal Play Fairway Analysis of the Appalachian Basin (GPFA-AB) included two broad types of data: 1) residential – community 'Places' and 2) site specific users with high heating demands such as universities, industrial users, government facilities, etc. to be considered as part of Phase 2. Below is a description of the data collected, the programs used. For results and a discussion of the effort, see the Final Report for Phase 1 of the Low Temperature Geothermal Play Fairway Analysis for the Appalachian Basin, DOE Contract Award Number: DE-EE0006726.

The process for the GPFA-AB was primarily based on the previous research by students at Cornell University and West Virginia University. Below are main steps from this project and the last section includes the Chapter 3 details submitted by Tim Reber (2013) for his MS degree with every parameter described.

Steps in Determining the Surface Levelized Cost of Heat

The foundation source code used for the utilization risk assessment is the program GEOPHIRES, (GEOthermal Energy for Production of Electricity and Heat Economically Simulated). The software uses key data as input to calculate Levelized Cost of Heat (LCOH). Because we have characterized the subsurface as part of other tasks (thermal resources and natural reservoir quality), we modified GEOPHIRES to only focus on those remaining elements, which includes demand for heat as calculated from population and climate data, and the surface costs associated with delivering that heat to those in demand. Thus, in our implementation, the final output is a Surface Levelized Cost of Heat (SLCOH). The SLCOH includes the surface piping, heat exchange equipment (residential and/or commercial), operations, upfront capital cost, and maintenance costs over the lifetime of a 30 year project. A MATLAB¹ program serves as an interface between the Microsoft Excel files of collected input data and the GEOPHIRES program. The MATLAB code and Microsoft Excel files are included with the resulting data as part of the Catalog submission to the National Geothermal Data System (NGDS).

1. The U.S. Census Bureau maintains a database of information that includes state, county, county subdivision, under the broader term 'Place.' A Place is used to identify all individual cities, towns, villages, boroughs, universities, and other Census-Designated Places (CDP's) defined as "settled concentrations of population that are identifiable by

¹ http://www.mathworks.com/products/matlab/

name but are not legally incorporated" (Census Bureau, 2012). The population and scope of a single Place may vary from the whole of New York City proper, with a population of over 8,000,000, to the smallest villages with populations as low as 10. In the New York, Pennsylvania, and West Virginia area we are using the 2010 Census data collection that includes 3,355 Places. These were downloaded via the FactFinder website (http://factfinder.census.gov).

- 2. Starting from the New York, Pennsylvania, and West Virginia 3,355 places, using ESRI ArcGIS, the broader Place data were linked to their county and county subdivision. In order to complete this task, shapefiles of the Census Places and county subdivisions were put into ArcGIS. By using a spatial join and having the program find the Places within the county subdivision, this resulted in joining the attributes tables of the two files, allowing for the information for Places to have corresponding county subdivision data. Finally, all sites were checked and any places without a successful join had data manually added. This process was repeated to relate places with county information.
- 3. The place list was next limited to only those within the project Appalachian Basin outline, which includes a 10 km outer buffer. We used the Golden Software program Mapviewer and ArcGIS for a comparison to confirm accuracy of locations within the project boundary. This reduced the number of possible Places for the project to 1,697.
- 4. For this Play Fairway Analysis project, a minimum population threshold of 4,000 residents per Place was applied for all three states, to focus on those Places with a sufficient number of users to justify the initial capital investment associated with a district heating system. There were 1,449 Places with populations of less than 4,000, leaving the final number of Places for the SLCOH analysis to be 248. In order to have those Places with fewer than 4,000 people appear as red (unfavorable) on the final maps, they were assigned the same arbitrarily high SLCOH of \$100/MMBTU. The actual input data associated with these places would lead to a different SLCOH and can still be calculated for future analyses as appropriate. The population threshold can be set as low as 1,500 residents per Place, and in doing so, makes the majority of the Places meet the criteria of good enough to consider. Although a positive outcome, we determined the 4,000 resident level for population of increased value in focusing the attention to sites most likely to be first users of this new energy concept.
- 5. The next parameter is the building density and heating demand per building (i.e. detached single-family, attached single-family, 2 unit buildings, 3-4 unit buildings, 5-9 unit buildings, 10-19 unit buildings, 20-49 unit buildings, and 50+ unit buildings). These detailed data are included within the Census Factfinder under "American Community Survey" using the 2010 5-year estimates and code B25024, representing the number and

type of housing units per residential building category. The Energy Information Agency (EIA) performs a Residential Energy Consumption Survey (2009) that we used to determine average square footage of each designated unit and related heating load on a Census region basis.

- 6. Within many Places are commercial buildings, which can be put into 12 categories: 1) Accommodation, 2) Food, & Other Services, 3) Administrative and Waste Management and Remediation Services, 4) Arts, Entertainment, and Recreation, 5) Educational Services, 6) Health Care & Social Assistance, 7) Information Geographic Area Series, 7) Manufacturing, 8) Other Services, 9) Professional Scientific & Technical Services, 10) Real Estate & Rental and Leasing, 11) Retail Trade, and 12) Wholesale Trade..
 - a. In order to determine the heating loads for commercial sites within our Place dataset, we combined the energy consumption for building types, the square footage of a building, and the type of commercial application based on the 12 categories above. Three datasets were used: the EIA manufacturing *energy consumption* data (http://www.eia.gov/consumption/manufacturing/), the EIA's 2006 report of Commercial Buildings Energy Consumption Survey (CBECS) for the *floor space*, and the US Factfinder 2007 'Economic Data' for categories.
 - b. From these files, the number of establishments and number of employees were collected for each "economic place". Unfortunately, the term "economic place" did not equate to that of the census definition of Place. The "economic place" can be related to the census classification of "county subdivision", which we did have linked to each Place. Following the methodology of (Reber, 2013) and Tester et al. (2015), in the instance where a single "county subdivision" (i.e. "economic place") contained multiple Places (typically around metropolitan areas) the data on commercial establishments for that county subdivision was divided amongst the Places within that county subdivision based on the relative population of each Place. In addition, due to the potentially identifiable nature of the reported economic data, some employment sizes were represented by a letter which stood for a range of values (ex. "A" meant an establishment had less than 20 employees, "B" meant an establishment may have between 20 to 99 employees, "C" means 100 to 249 employees, etc.). For these sites, the average of the range rounded up to the next integer was used for the model (ex. "A" would have 10 employees, "B" would have 60 employees, "C" would have 175 employees, etc.). This allowed for the MATLAB/GEOPHIRES model to have a numerical value to perform the calculations.

- 7. Another dataset included was the location of roads (Road shapefiles from the TIGER dataset). The total length of roads within each Place was used as a method to estimate the required piping length required to service a given location (Reber, 2013) and Tester et al. (2015). Based on Reber's conclusions, the GEOPHIRES program uses 75% road coverage to provide adequate piping density required to reach all buildings for geothermal district heating system.
- 8. The MATLAB script estimated the cost of a system for a lifetime of thirty years. The program uses a fixed annual charge rate (FACR), which allows the user to specify several factors, including discount rates. As reported by Shaalan (2001), this annual fixed-charge rate "represents the average or 'levelized' annual carrying charges including interest or return on the installed capital, depreciation or return of the capital, tax expense, and insurance expense associated with the installation of a particular generating unit" (Shaalan, 2001). A FACR of 6% was used for this Play Fairway Analysis effort. According to the U.S. Department of Commerce it calculated an effective discount rate of 3% in 2011 for Federal and Public energy projects. Therefore 1% was also added to this value, resulting in a discount rate of 4% applied to SLCOH.
- 9. The GEOPHIRES result output of SLCOH is a spreadsheet (.csv format). The output was grouped by state and then sorted based on the population size and the resulting SLCOH in the units of dollars per one million BTU (British Thermal Unit). \$/MMBTU. For all Places with a population of less than 4000 the SLCOH was assigned an arbitrary but high value of \$100/MMBTU. This allows us to continue to keep smaller communities in the workflow as we get ready for Phase 2. We will be able to improve our cost estimates for the entire Place list, since the GEOPHIRES and MATLAB programs allow updates for a few or many sites with the same amount of effort.

For the resulting 248 Places assessed, the best case (least expensive SLCOH) is 7 \$/MMBTU and the highest (most expensive SLCOH) is 65 \$/MMBTU. The Places were differentiated into three thresholds with the best case scenario for the SLCOH between \$7 and \$13.5, good between \$13.5 and \$16, and low or unlikely potential as \$16 to \$25 SLCOH. The distribution of the 248 Places are displayed in the Table 1 below, except for values of SLCOH over \$25 since it is considered not currently economically viable. In addition, there were 1,449 places assigned an SLCOH of \$100 because of low population.

Table 1: Distribution of 248 Census Places over 4,000 in population within the Appalachian Basin for
NY, PA, and WV based on a three color ranking of the calculated Surface Levelized Cost of Heat
(SLCOH).

State	Best Case (Green) \$5 – \$13.5/ MMBTU SLCOH	Good (Yellow) \$13.5 - \$16/ MMBTU SLCOH	Unlikely (Red) \$16 - \$25/ MMBTU SLCOH
New York	43	21	29
Pennsylvania	57	37	17

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A second set of values were assigned for the five-threshold combined layer risk assessment. Here the values were \$5 to \$12 (green - best), \$12 to \$13.5 (greenish yellow), \$13.5 to \$16 (yellow), \$16 to \$20 (orange) and \$20+ (red - worst). At the level of this Phase 1 project there is not enough site knowledge, even at the Place level, to assign increased levels of significance in the dollars amounts for the SLCOH. These were developed for the consistency of the combined risk task input files (see Catalog for the Combining Risk Factors Memo).

Error estimates for the Utilization risk factor were not calculated. Rather for the level of detail of Phase 1, the entire area is given a uniform uncertainty of approximately 5% based on changes in population and cost.

Steps for Inclusion of Site Specific Industrial Sites

In addition to the US Census 'Place' areas, this project researched low-temperature direct use geothermal energy applications for numerous industries, including aquaculture, green houses, and food processing such as dehydration and dairy processing (Lienau, et al., 1994). For the Appalachian Basin region and the anticipated temperatures at depths less than 3 km depth, potential users of the geothermal heat occur in the following industry categories: paper mills, wood drying kilns, dairy processing (includes yogurt and milk pasteurization products), college and university campuses, and select military locations. Typical temperature ranges for these applications are listed in Table 2.

Table 2:	Site-Specific	industries	of interest	and requ	uired tem	perature	ranges.
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Industry	Temperature Range
Dairy	Butter/Yogurt production 80 – 90 °C Traditional pasteurization 72 – 75 °C
Wood Drying	43 – 82 °C
Paper/Pulp Mills	66 - 150 °C
University/College Campus	100 - 150 °C
Military Bases/Stations	100 - 150 °C

Each industrial site was located using a Google Map search for each category, except for the locations of the diary processing sites found on the Dairy Plants USA website. All of these potential industrial users have a component of their process(es), which could benefit from incorporating a geothermal element into their system, either by preheating or reducing electrically heated steps.

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Chapter 3

Regional District Heating Modeling and Supply Curve Development

Now that a newly refined geothermal resource map for the Appalachian Basin of New York and Pennsylvania has been developed, as documented in Chapter 2, the next step is to further explore opportunities for development of Enhanced Geothermal Systems (EGS) in the region. The remainder of this thesis will focus exclusively on geothermal district heating (GDH), as it was determined in Chapter 2 that direct-use and district heating applications were likely the most appropriate given the geothermal resources available in New York and Pennsylvania.

In order to better characterize and evaluate EGS opportunities in the region, a supply curve will be developed. Such a curve will be able to show the estimated cumulative heating capacity that could be sold at or below a given price by plotting the total cumulative heating capacity in the study region against the projected levelized cost of supplying that heat, with the least-cost capacity plotted first followed by successively higher cost capacity. This will help identify GDH opportunities in two ways: (1) by highlighting specific locations where EGS GDH would be most affordable relative to the rest of the study area and (2) by providing a tool to easily visualize and compare where potential for cost-reduction might be greatest for GDH development in the region.

3.1 Background

The U.S. Department of Energy and other organizations have been using supply curve analysis to evaluate renewable energy technologies for decades. Recently, the National Renewable Energy Lab (NREL) published a supply curve for geothermal electricity production in the United States (Augustine et al. 2010; Augustine 2011). However, that study evaluated geothermal electricity production exclusively while neglecting geothermal direct-use and district heating possibilities. This leaves an opportunity for development of a supply curve exclusively for district heating applications, of which there have been very few, if any, attempts to do. The overall framework of the supply curve developed here will be loosely based on the framework employed by NREL to develop their geothermal electricity supply curve.

According to NREL the two primary steps in developing a supply curve involve estimating the resource potential and determining the cost of developing that resource (Augustine et al. 2010). However, developing a supply curve for geothermal district heating requires one additional step that is not necessary for a geothermal electricity supply curve: assessing the heating demand for each specific GDH network. This is necessary due to the location-dependent nature of geothermal district heating. In geothermal electricity production the assumption can be made that a resource may be developed anywhere and the power produced can simply be sold to the national power grid where there will be an essentially limitless demand for it. However, in geothermal district heating applications, the hot water produced can only be transported a few kilometers before it loses so much heat it becomes economically infeasible to transport it further. Heavily-insulated piping and high flow rates can increase the distance hot geofluid may be transported, but they also significantly increase the capital cost of the piping and the pumping costs, respectively. Additionally, much like electricity, hot geofluid cannot be stored in large quantities, meaning it must be produced and used on an as-needed basis. In fact, the EGS resource itself actually acts as the storage medium for heat prior to its extraction.

As a result, GDH systems can only be effectively developed where the resource also coincides spatially with an area that has a high heating demand that would ideally be constant throughout the year. Hence development of a geothermal district heating supply curve will have three primary steps: (1) assessment of the resources, (2) assessment of the demand, and (3) estimation of the cost to develop and operate the resource. The first step, resource assessment, was completed in Chapter 2. Chapter 3 will present the methods used to achieve the second and third steps. Estimated levelized cost of heat (LCOH) will serve as the final metric as it permits easy comparison of both locations and technology assumptions relative to one another. Figure 3.1 provides a modestly detailed schematic of the overall method and data processing workflow.



Figure 3.1 Overall workflow for data processing methods. Blue items represent inputs obtained from published data, green items represent inputs left to the user's discretion, and red items represent calculated and derived intermediates and outputs. A larger version of this figure is reproduced in the Appendix.

The NREL supply curve study began with the national geothermal resource base as estimated by the USGS 2008 Geothermal Resource Assessment and MIT's 2006 *The Future of Geothermal Energy* report (Williams et al. 2008; Tester et al. 2006; Augustine et al. 2010). The cost to develop this resource for electricity production was then evaluated using the Geothermal Electricity Technology Evaluation Model (GETEM), a Microsoft Excel-based tool maintained by the Department of Energy's Geothermal Technologies Program. GETEM accepts a series of user-defined inputs for a theoretical geothermal electricity plant and then outputs the levelized cost of electricity (LCOE) for that plant. To produce the NREL supply curve, a reference power plant was modeled by GETEM and then iterated repeatedly under different resource conditions and technology assumptions (Augustine et al. 2010).

This study will follow a similar path to the NREL report. It will begin with the geothermal resource assessment as previously presented in Chapter 2. To estimate the cost of developing this resource and the associated LCOH for district heating, this study will utilize a newly updated EGS modeling software package: "Geothermal Energy for Production of Electricity and Heat Economically Simulated," or GEOPHIRES for short. The original source-code for GEOPHIRES comes from an EGS modeling package developed at MIT in the late 1990's, which is described in Kitsou et al. (2000) (formerly known as MIT-EGS). This code was updated and adapted by students at Cornell University in 2012 to become the new GEOPHIRES model, for which a report appeared at the 2013 Stanford Geothermal Workshop (Beckers et al. 2013). The software, which operates with either user-defined or built-in inputs, will simulate a single EGS reservoir and plant and return an estimated LCOE or LCOH, depending on whether the user specified an electric generation or direct-use application. In this thesis, the direct-use (LCOH) option was always selected. Unfortunately, GEOPHIRES does not yet have the capability to model district-heating surface equipment such as heat exchangers, distribution networks, and distribution pumping costs, so those parameters had to be modeled upstream of GEOPHIRES and then fed into the software as a pre-defined input.

A shell interface was developed in the MATLAB programming environment to permit repeat iterations of the GEOPHIRES model with a single command. This MATLAB shell module is responsible for (1) reading all required inputs from an Excel input spreadsheet; (2) performing preliminary calculations including estimating temperature and demand profiles, reinjection temperatures, required mass flow rates, surface infrastructure equipment sizes and costs, and pumping costs; (3) executing the GEOPHIRES software package with the appropriate inputs and rerunning it if need be to ensure accurate results; (4) storing pertinent variables, including the GEOPHIRES output LCOH, and writing them to an output spreadsheet; and (5) iterating the entire workflow for each town, community or other "place" of interest in the study group.

3.2 Demand Assessment

3.2.1 "Places" Data

Because GDH systems can only be constructed in regions of moderate to high heating demand where people live, population centers first had to be identified. While New York and Pennsylvania certainly satisfy the heating demand requirement with 6116 and 5913 average heating degree days per year, respectively, identifying and locating population centers requires more effort. The U.S. Census Bureau maintains a GIS shapefile database under the name TIGER (Topologically Integrated Geographic Encoding and Referencing) that contains a wealth of information regarding populations, political boundaries, roads, and other information. The database information is available at several scales including state, county, county subdivision, and "place." The official Census Bureau designation of "place" is used to identify all individual cities, towns, villages, boroughs, universities, and other "census-designated places" (or CDP's, defined as "settled concentrations of population that are identifiable by name but are not legally incorporated") (Census Bureau 2012). The population and scope of a single "place" may vary from the whole of New York City proper, with a reported population of 8,175,133, to the smallest villages and CDP's with populations as low as 10. Because it is the official term of the U.S. Census Bureau and represents the smallest population unit for which census data is available, the "place" designation will be used throughout this thesis as the base unit representing population centers.

Data for New York and Pennsylvania from the 2011 release of the TIGER database were obtained and mapped in ArcGIS (Census Bureau 2011a). 2955 places, each identifiable with a unique "GeoID," were identified in the two states. After removing places with insufficient information (explained in the next section) the final dataset contained 2894 places that formed the base unit for which district heating plants were modeled and LCOH evaluated.



Figure 3.2 Locations of all 2955 U.S. Census Bureau "Places" (grey polygons) shown with the average minimum January surface temperature. Notice the concentrations of "places" around metropolitan areas such as Pittsburgh, Philadelphia, Buffalo, New York City, Rochester, Albany, Scranton – Wilkes-Barre, and Long Island.

3.2.2 Building Data

The energy consumption and heating load is not known for each place, so it had to be estimated from other available data. Data from the 2010 American Community Survey 5-year estimate on the total number of housing units and the number of housing units per residential building category (i.e. detached single-family, attached single-family, 2unit buildings, 3-4 unit buildings, 5-9 unit buildings, 10-19 unit buildings, 20-49 unit buildings, and 50+ unit buildings) were obtained for each place through the U.S. Census Bureau's American Fact Finder (Census Bureau 2011b). With this data, the number of residential buildings of a given size category could be estimated. Several places for which housing or commercial data did not exist were removed from the dataset. These included several small villages with fewer than 100 residents and some universities identified as CDP's by the Census Bureau. In order to estimate the total residential heating load, residential floorspace for each "place" had to first be estimated. The Energy Information Agency (EIA) performs a Residential Energy Consumption Survey (RECS) every few years, the most recent of which was published in 2009. This survey contains, in addition to energy consumption data, statistical information on the average square footage of individual housing units by region and the size of the building to which the unit belongs (again, detached single-family, attached single-family, units in 2-unit buildings, etc.). These data were obtained for the Northeastern region, to which New York and Pennsylvania belong, and then used to estimate the residential floorspace for each "place" in the study area (EIA 2009).

Accurate data on commercial buildings proved more difficult to obtain. Different types of commercial establishment will have different energy requirements. For example, a restaurant will have a much different hot water and heating demand than say a theater or a warehouse. Data published by the 2007 Economic Census containing the number of commercial establishments by industry (Table 3.1) for "economic places" in the United States was obtained through American Fact Finder (Census Bureau 2011c). The designation of "economic place" however, does not coincide with the census definition of "place," creating a small disconnect. Rather an "economic place" corresponds to the census designation of "county subdivision," meaning the data had to be corrected. In many instances, "place" and "county subdivision" were the same and thus the Economic Census data could be used directly. However, in cases where a single "county subdivision" (i.e. "economic place") contained multiple "places" (typically around metropolitan areas) the data on commercial establishments for that county subdivision was divided amongst the "places" within that county subdivision based on the relative population of each "place." In this way a rough estimate of commercial establishments by industry type was obtained for every "place" in the dataset.

The EIA's Commercial Buildings Energy Consumption Survey (CBECS), the last release of which was in 2006, was used to estimate the total floorspace for each industry type for each "place." To ensure compatibility between the North American Industry Classification System (NAICS) used by the 2007 Economic Census and the "principal building activities" as designated by the CBECS, descriptions of each classification system had to be used to identify and assign

the most suitable CBECS building activity for each NAICS classification, as seen in Table 3.1

(Census Bureau 2007; EIA 2012).

Table 3.1 Commercial activities as designated by the 2007 Economic Census in accordance with the North American Industry Classification System (NAICS); and the principal building activity to which each industry classification was assigned for use with the Commercial Building Energy Consumption Survey (CBECS).

Economic Census Industry Designation (NAICS)	CBECS Principal Building Activity
Accommodation and Food Service	Lodging; Food Service
Administration, Support, Waste, and Remediation	Office
Arts, Entertainment, and Recreation	Public Assembly
Educational Services	Education
Health Care and Social Assistance	Health Care
Information	Office
Manufacturing	N/A
Professional, Scientific, and Technical Services	Office
Real Estate and Rental and Leasing	Office
Retail Trade	Retail
Wholesale Trade	Retail
Other Services	Service
Residential (American Community Survey)	Residential (RECS)

CBECS data were obtained on the total number of commercial buildings in the mid-Atlantic region by both principal building activity and number of establishments in the building (EIA 2006). From these data the average number of establishments per building by industry type was determined.

A scaling factor for each "place" was calculated as the average residential housing units per building at that "place" divided by the overall average residential housing units per building for the entire dataset. This scaling factor was then used to scale the "place"-specific estimates for commercial establishments per building, based on the assumption that "places" with higher-density housing would also have a higher-density of commercial establishments. This operation yielded final estimates for the total number of commercial buildings of each industry type at each "place." Using the average floorspace of commercial buildings by principal building activity from CBECS, the estimated total commercial floorspace by principal building activity at each census "place" was finally determined.

3.2.3 Space and Water Heating Demand

Average space heating and hot water demand intensity (BTU/ft²/year) were obtained for residential homes and commercial buildings (by principal activity) from the RECS and CBECS, respectively (Table 3.2) (EIA 2001; EIA 2006). For residential homes, data from the 2001 RECS had to be used because more recent RECS did not contain information specific to space and water heating in terms of energy per unit area. The energy intensities in Table 3.2 were then scaled to the mid-Atlantic based on the average intensity of the mid-Atlantic census region divided by the overall U.S. average intensity.

Table 3.2 Space heating and water heating energy intensities (in units of MBTU/ft²/year) based on principal building activity. Commercial intensities are from the 2003 CBECS and the residential intensity is from the 2001 RECS.

Principal Building Activity	Space Heating (MBTU/ft ² /yr.)	Water Heating
		(MBTU/ft ² /yr.)
Education	39.4	5.8
Food Service	43.1	40.4
Health Care	70.4	30.2
Lodging	22.2	31.4
Retail	24.8	1.1
Office	32.8	2.0
Public Assembly	49.7	1.0
Service	35.9	1.0
Residential	25.7	8.0

In order to obtain a curve representing the demand profile throughout the year, a representative annual temperature curve first had to be derived. Data used included the mean annual temperature (T_{ave}), mean temperature in the coldest month of the year, January (T_{Jan}), and the average minimum temperature in January (T_{minJan}). The average instantaneous extreme minimum temperature (T_{absmin}), averaged over a 50-year period, was also obtained for each "place." These values were acquired as ESRI grid files from the WorldClim database (Hijmans et al. 2005) and then spatially matched to each census "place" from the TIGER shapefiles using ArcGIS. T_{ave} and T_{Jan} are then provided as inputs into the main MATLAB shell, which calculates a temperature curve for each census "place" according to the equation:

$$Temp(i) = T_{ave} + (T_{ave} - T_{Jan}) \cdot sin(2\pi(i - 112)/365)$$
(3.1)

where i = 1:365 and represents each day of the year. The result is a sinusoidal temperature curve with a minimum on January 21 (day 21) at T_{Jan} , a maximum on July 22 (day 203), and an average annual temperature of T_{ave} . A 5-day cold-spell is then assumed (from January 18-22) based on the average minimum January temperature (T_{minJan}) at each "place" to account for below average cold periods. Figure 3.3 compares the calculated representative temperature curve to real 10-year daily temperature averages from the period 1995-2005 for three "places" in the dataset.

Daily temperature and energy use data for Cornell University was used as a reference case from which a linear relation for demand intensity (MBTU/ft²/day) as a function of outdoor ambient air temperature was determined:

The sclSH term is a scaling factor calculated as the estimated overall average space heating intensity of the "place" in question divided by the average space heating intensity of Cornell University, for which equation 3.2 was initially formulated. To calculate the overall average space heating intensity of each "place," the published space heating intensity (Table 3.2, after



Figure 3.3 Sample sinusoidal temperature profiles generated with equation 1 compared to daily temperature data averages from the period 1995-2005.

being scaled to the mid-Atlantic) was multiplied by the estimated total floorspace of each building category (as determined in section 3.2.2) and then divided by the net total floorspace for the entire "place." Finally, the correlation in equation 3.2 estimates demand for each single day of the year by assuming that the entire year is spent at the outdoor air temperature of that day, resulting in units of BTU/ft²/year (for each one of the 365 days of the year), meaning the entire result must then be divided by 365 to get to BTU/ft²/day. Equation 3.2 is calibrated to an indoor temperature set-point of 21°C (70°F). In cases where the outdoor temperature was high enough that estimated demand was negative, demand was instead set to zero.

To obtain the total thermal demand for each day, water heating demand intensity was added to the space heating demand curve assuming hot water demand is constant throughout the year. The net result is an average daily thermal demand in MTBU/day for each day of the year. Average annual daily demand (MBTU/day), average maximum daily demand (MBTU/day), and total annual heat demand (MBTU/year) were then calculated over the year.



Figure 3.4 Example demand profile. Demand is predicted for each day of the year. GDH systems are designed to meet the average peak demand in January (based on T_{minJan}), leaving any instantaneous extremes (not pictured on profile but calcualted from T_{absmin}) to be met by peak boilers.

In addition, instantaneous absolute peak demand was estimated using the fifty-year average annual extreme minimum temperature (T_{absmin}) and equation 3.2. This peak demand was used when designing the GDH system capacity to estimate the instantaneous peak load that must be met with gas-fired peaking boilers. Each GDH system was designed assuming that all heat demand associated with the average minimum January temperature (T_{minJan}) would be met with geothermal heat (i.e. the "average peak demand"). Any excess demand associated with T_{absmin} (assumed to occur for 30 hours each year) would then be met with these peak boilers (i.e. the "instantaneous extreme demand").

A typical demand profile appears in Figure 3.4. Note that each demand curve is represented in MATLAB as a 365-element vector with each element representing the demand in MBTU/day for that day of the year. Each "place" then has a unique demand vector. Most of the ensuing calculations (i.e. temperatures, flow rates, pumping energy, etc.) were performed for each day of the year at each place using this 365-element vector format. Hence most of the equations that follow will use a simplified format to represent these annual vectors that are iterated at each "place." For example, fluid mass flow rate would appear simply as [<u>m</u>] where:

$$\left[\underline{\dot{m}}\right] = \begin{bmatrix} \dot{m}_1 & \dots & \dot{m}_{365} \end{bmatrix}_k$$

where k = 1:2894, iterated for each "place" in the dataset.

3.3 Surface Equipment and Infrastructure

3.3.1 Distribution Network Length

To estimate the size and total length of distribution piping required to meet full demand at each "place," the total length of roads within each "place" was used as a proxy. As most existing water, sewer, and gas mains in the Unites States follow existing roads it is a fair assumption to assume that district heating mains will similarly follow existing roadways. This would be the simplest way to organize and install a DH network in the case of a community retrofit, and a brief review of the schematics for many existing DH networks reveals that this generally appears to be the case for most networks (e.g. Brown 2007; Zinko 2008; Skagestad & Mildenstein 2002).

Road shapefiles were obtained from the TIGER dataset for all roads in New York and Pennsylvania, excluding only the smallest local roads of less than 150m in total length, and mapped in ArcGIS. A "place" identity was then established for each road so that the total length of all roads within the boundaries of a single census "place" could be determined. The roads database was then split into 500-by-500 meter units and limits were applied so that a single unit square could not exceed a certain road density (total road distance per unit area). This limit was set at 10 km of road per square kilometer of land area. This was done to limit the effect of "places" with a high road density where DH piping would not need to be laid under every single road in town. Once the limits were applied, the total length of all roads in each "place" was summed. Finally, a variable "road coverage" proportion was applied to account for the use of intelligent piping routes that would negate the need to lay DH distribution piping under every single road in a given town.

With these factors, a total required DH piping network length could be estimated for each "place." Google Earth was used to estimate the road density in several towns, outline an estimated piping network, and estimate average distance of all buildings from the nearest DH main piping. The results for three locations are shown in Figure 3.5. For these cases it was determined that about 75% road coverage was sufficient and that around 7.0-7.5 km of DH piping per km² would be the maximum piping density required to reach all buildings. Hence for the base reference case road coverage was assumed to be 75% of all roads. This methodology yielded a maximum DH piping density for the base case of (10km/km²)·75% = 7.5 km/km².

From these Google Earth estimates the typical distance from the nearest DH main to a typical building was estimated and 35 meters was decided upon as a representative base-case value for the average branch distance (i.e. the length of small-diameter service pipe required to connect each building to the main distribution network). With this plan, a typical medium-density neighborhood would have main piping on every-other street with branch lines running from the main to the front of houses on the distribution street and from the main to the back of



Figure 3.5 Three example district heating networks in New York State depicted using Google Earth (http://earth.google.com). The bold blue boxes each outline a 1km² area and the smaller yellow lines represent potential district heating network layouts. Also estimated are typical service distances from distribution main to buildings. "Short service" is the distance from the main to the front of buildings on the distribution street, "long service" is to the back of buildings on the off-street, and "max service" is the single longest required service distance in the example area.

houses off the distribution street. Typical main to front distance is about 10 m while typical main to back distance is about 45-75 m, resulting in an average of roughly 35 m.

3.3.2 Distribution Pipe Size

Required piping size was determined based on the maximum required flow rate, which was determined from the average maximum daily demand and the primary fluid supply (T_{ps}) and return (T_{pr}) temperatures. T_{ps} is provided as a user-defined input and T_{pr} is determined based on the radiator system design in the buildings (more detail in section 3.3.3). Once the maximum required flow rate is determined, required pipe size is calculated as:

$$D_{in} = 1.5197 (\dot{m}_{max})^{0.427} \tag{3.3}$$

where D_{in} is the interior pipe diameter in inches. This is then rounded up to the nearest 1" diameter. Equation 3.3 was created by fitting a curve to 14 experimental D_{in} to \dot{m}_{max} relationships for 0.63" < D_{in} < 12.20", as published in the *Total Hydronic Balancing* handbook for heating and ventilation systems (Petitjean 2004). A linear extrapolation was then used to expand the equation to include diameters between 12 to 16 inches. The uncertainty in the published measurements themselves is quite small and the R-squared value for the final curve was a robust 0.997.

Required service line size was determined in the same manner using the estimated perbuilding peak heating demand rather than the average maximum daily demand for the entire census "place." Peak building heat demand was estimated for each building size (i.e. detached single-family, 2-4 units/building, 5-9 units/building, etc.) using equation 3.2, the instantaneous extreme annual minimum temperature, the average heating intensity of each "place," and the average unit size for each building category. The average peak building demand (by building size) was then obtained based on the number of units per building for each building category.

3.3.3 Heat Exchangers and Building Equipment

Primary Heat Exchanger Sizing Daily primary fluid mass flow rates and return temperatures (T_{pr}) were estimated using simple heat exchanger theory (e.g. see Lienau et al. 1998 Chapter 11). First, however, the primary heat exchanger size had to be determined. This was achieved by defining a set of user-defined design conditions for the system. For the initial base reference case, these design conditions can be found in Table 3.3. For building secondary heating systems (i.e. the radiator system) the operating temperature regime is often given as a ratio of $T_{sr,o}/T_{sr,o}$ where $T_{ss,o}$ is the secondary heating fluid supply temperature at design conditions and $T_{sr,o}$ is the secondary heating fluid return temperature at design conditions. For the initial base case a secondary fluid $T_{ss,o}/T_{sr,o}$ regime of 70/40°C (~158/104°F) setup was chosen based upon the assumption that although many current hot water radiators and forcedair heating systems are designed for an 80/60°C regime, evidence suggests they can operate at 70/40°C conditions with only a minor loss in performance (Ryan 1981; Myhren and Holmberg 2008; Lienau et al. 1998; Skagestad and Mildenstein2002). By choosing a 40°C secondary system return temperature $(T_{sr,o})$ hot water could then also be modeled together with space heating, as was done by Zinko et al. (2008), which vastly simplified ensuing flow and temperature calculations.

Required heat exchange area was determined assuming that each GDH plant would have a central heat exchanger facility to transfer heat from the primary to the secondary fluid, which would then be pumped directly to and through buildings' space heating systems (i.e. a 'centralized' system). This type of system would be much easier to maintain compared to an indirect system in which each building has its own heat exchanging substation. It is also simpler to model and typically more cost-effective.

Table 3.3 Design conditions during primary heat exchanger sizing for the initial base case. These conditions were assumed during the period of maximum daily demand. From this, the primary heat exchanger was sized and daily mass flow and T_{pr} vectors were calculated.

Design Parameter (abbr.)	Value	Description
Primary Supply Temp (T _{ps,o})	75–125 °C (167-257 °F)	Geofluid production temperature
Secondary Supply Temp (T _{ss,o})	70°C (158 °F)	Radiator supply temp
Secondary Return Temp (T _{sr,o})	40 °C (104 °F)	Radiator return temp
Minimum Pinch Temp (T _{pinch})	3°C (5.4 °F)	Min ΔT between 1° and 2° fluid
Primary Return Temp (T _{pr,o})	T _{sr,o} + T _{pinch}	Geofluid reinjection temperature
Primary Mass Flow Rate (ṁ _{p,o})	30 kg/s (~475 gal/min)	Max wellhead production rate
Indoor Temp Set Point (T _i)	21 °C (70°F)	Desired indoor air temperature

The secondary fluid mass flow rate at design conditions ($\dot{m}_{s,o}$) was calculated using the basic steady-state energy balance:

$$Q = C_{p} (T_{ps,o} - T_{pr,o}) \dot{m}_{p,o} = C_{p} (T_{ss,o} - T_{sr,o}) \dot{m}_{s,o}$$
(3.4)

where all but $\dot{m}_{s,o}$ are known at design conditions.

The central heat exchanger was sized according to the heat exchanger heat transfer equation (Ljunggren and Wollerstrand 2006; Karlsson and Ragnarsson 1995; Lienau et al. 1998):

$$Q = U \cdot A \cdot LMTD \tag{3.5}$$

Where Q is the amount of heat transferred, U is the overall heat transfer coefficient (W/m^{2.o}C), A is the area of the heat exchanger (m²), and *LMTD* is the logarithmic mean temperature difference:

$$LMTD = \frac{(T_{1,in} - T_{2,out}) - (T_{1,out} - T_{2,in})}{ln\left(\frac{T_{1,in} - T_{2,out}}{T_{1,out} - T_{2,in}}\right)}$$
(3.6)

With two heat exchangers in each loop (the central heat exchanger and the building radiator), two LMTD's can be calculated:

$$LMTD_{HX} = \frac{(T_{ps} - T_{ss}) - (T_{pr} - T_{sr})}{ln\left(\frac{T_{ps} - T_{ss}}{T_{pr} - T_{sr}}\right)}$$
(3.7)

$$LMTD_{rad} = \frac{(T_{ss} - T_i) - (T_{sr} - T_i)}{ln(\frac{T_{ss} - T_i}{T_{sr} - T_i})}$$
(3.8)

At design conditions, *Q* is taken as the average maximum daily demand (see section 3.2.3) and *U* is assumed to be 5000 W/m².°C, a good estimate for geothermal applications according to Zhu and Zhang (2004) and Lienau et al. (1998). Equation 3.5 can then be solved by plugging in LMTD_{HX} (equation 3.7) at design conditions to obtain the size of the primary heat exchanger, *A*. Depending on the temperature regime selected, the peak community-wide

demand, and the proportion of a community's demand being met by a single GDH plant, central heat exchanger areas may vary by an order of magnitude from roughly 50-500 m².

Flow Rate and Temperature Calculations To estimate pumping costs, an average system ΔT , and the system-wide capacity factor daily flow rate and return temperature vectors were calculated.

First, the secondary fluid return temperature (T_{sr} – fluid returning from buildings' heating systems) was estimated using the following empirical correlation for radiators (Ljunggren and Wollerstrand 2006; Karlsson and Ragnarsson 1995):

$$\frac{\left[\underline{LMTD}_{rad}\right]}{LMTD_{rad,o}} = \left(\frac{\left[\underline{Q}_{rad}\right]}{Q_{rad,o}}\right)^{n}$$
(3.9)

Setting [\underline{O}_{rad}] equal to the daily demand vector (see section 3.2.3), LMTD_{rad,o} equal to its scalar value at design conditions, $Q_{rad,o}$ equal to the peak design demand (scalar), and assuming a typical radiator constant, n, of 1.3 (Karlsson and Ragnarsson 1995; Lukawski 2010), equation 3.9 can be solved (for each day of the year) to yield a daily [<u>LMTD_{rad}</u>] vector. From this, a daily secondary fluid return temperature [\underline{T}_{sr}] vector was calculated using equation 3.8, given that T_{ss} and T_i are assumed constant throughout the year. A daily secondary fluid mass flow rate [$\underline{\dot{m}}_s$] vector was finally calculated using the basic thermodynamic relation in equation 3.4.

With a $[\underline{T}_{sr}]$ vector, equations 3.5 and 3.7 were then used to calculate the daily primary fluid return temperature $[\underline{T}_{pr}]$ vector. However, the heat transfer coefficient, $[\underline{U}]$, varies as a function of the Nusselt, Prandtl, and Reynolds numbers of the fluid (Karlsson and Ragnarsson 1995). This can be simplified using the following approximation for U from Lukawski (2010):

$$U = C \cdot \left(\frac{1}{\dot{m}_p^{0.7}} + \frac{1}{\dot{m}_s^{0.7}}\right)^{-1}$$
(3.10)

where *C* is a constant that can be determined given the known values of $\dot{m}_{p,o}$, $\dot{m}_{s,o}$ and U_o at design conditions. Equations 3.10 and 3.7 were then substituted into equation 3.5 to yield:

$$[\underline{Q}] = C \cdot \left(\frac{1}{[\underline{m}_{p}]^{0.7}} + \frac{1}{[\underline{m}_{s}]^{0.7}}\right)^{-1} \cdot A \cdot \frac{(T_{ps} - T_{ss}) - ([\underline{T}_{pr}] - [\underline{T}_{sr}])}{\ln\left(\frac{T_{ps} - T_{ss}}{[\underline{T}_{pr}] - [\underline{T}_{sr}]}\right)}$$
(3.11)

However, equation 3.11 is still a single equation with two unknowns: $[\underline{T}_{pr}]$ and $[\underline{\dot{m}}_{p}]$. Thus equation 3.4 was solved for $[\underline{\dot{m}}_{p}]$ and then plugged into equation 3.11 to yield:

$$[\underline{Q}] = C \cdot \left(\left(\frac{[\underline{m}_s](T_{ss} - [\underline{T}_{sr}]]}{T_{ps} - [\underline{T}_{pr}]} \right)^{0.7} + [\underline{m}_s]^{-0.7} \right)^{-1} \cdot A \cdot \frac{(T_{ps} - T_{ss}) - ([\underline{T}_{pr}] - [\underline{T}_{sr}])}{In \left(\frac{T_{ps} - T_{ss}}{[\underline{T}_{pr}] - [\underline{T}_{sr}]} \right)}$$
(3.12)

Equation 3.12 was solved in MATLAB to obtain the daily primary fluid return temperature vector (T_{pr}) given the daily \dot{m}_s , T_{sr} , and Q (demand) vectors, while T_{ps} , T_{ss} , C, and A are constant. With the daily T_{pr} vector, equation 3.4 was used one last time to solve for the daily primary mass flow rate vector $[\dot{m}_p]$.

At this point daily vectors for demand [Q], primary fluid return temperature [\underline{T}_{pr}], primary fluid mass flow rate [$\underline{\dot{m}}_p$], secondary fluid return temperature [\underline{T}_{sr}], and secondary fluid mass flow rate [$\underline{\dot{m}}_s$] were determined. With these values the average flow rate, average power delivered, average return temperature, and total daily and annual energy delivered could be estimated for each plant. These variables were later used during levelized cost calculations to estimate the net heat sold each year and each GDH plant's capacity factor.

Peak Boilers GDH plants were sized to meet the average maximum daily demand, leaving any instantaneous extreme peak demand to be met by peak boilers (for example if the temperature drops to -20°C (-4°F) for six hours overnight). The required capacity of peaking boilers was determined by multiplying the instantaneous extreme peak demand (calculated using T_{absmin}) by the proportion of total demand met by a single plant (calculated as the max power from a single GDH plant divided by the community's average maximum design demand) and then subtracting the maximum power of a single GDH plant (as calculated by GEOPHIRES). In this way, the peak boiler capacity that must be installed with each GDH plant was estimated:

(3.13)

3.3.4 Surface Equipment Investment Costs

Note: all costs presented have been normalized to 2012 USD unless otherwise noted.

Piping Capital costs for distribution piping were obtained from Rafferty (1996). The costs were broken down into component parts (i.e. piping and joints, thrust blocks, road cutting and repaving, labor, etc.) and the United States Bureau of Labor Statistics Producer Price Index (PPI) was used to bring each component cost to 2012 dollars, resulting in the following curve:

$$k_{pipe} = 80.08 \cdot D_{in} + 195.96 \tag{3.14}$$

where D_{in} is the pipe diameter and k_{pipe} is the installed unit cost of distribution piping (\$/m).

Equation 3.14 represents the total net capital cost of purchasing and installing preinsulated ductile iron piping in a double-loop (that is, supply and return piping in the same trench). According to Lienau et al. (1998) ductile iron piping seemed to be the piping of choice for district heating systems around the turn of the century. The net installed costs range from \$473/m for 3" diameter piping to \$1168/m for 12" pipe. The total estimated piping length (section 3.3.1) and required pipe diameter (section 3.3.2) were used to determine the total cost of piping required at each "place."

The capital cost of distribution pumps was calculated using the maximum daily required pumping energy (see section 3.3.5) and a cost of \$150/kW installed pumping capacity.

Heat Exchanger Substations Heat exchanger costs were determined in two ways: (1) a centralized setup, with a single central heat exchanging facility at the well site and (2) an "indirect," decentralized setup where each building has its own heat exchanging substation. Once the two costs were determined, the lesser of the two was noted and selected as the most economic heat exchanger setup.

It was assumed that plate-and-frame heat exchangers would be used in the case of a central heat exchange system, as they are larger and heavier-duty than brazed-plate or shelland-tube exchangers and are commonly used in geothermal applications (Zhu and Zhang 2004).

In the case of individual building heat exchangers, brazed-plate heat exchangers were assumed since they tend to be cheaper but are limited to smaller sizes (Lienau et al. 1998). Purchased cost curves from Lienau et al. (1998) for plate-and-frame (>25 ft²) and brazed-plate (<20 ft²) heat exchangers were aggregated and brought to 2012 dollars using the PPI to yield:

$$k_{hx} = 222.36 \cdot A_{hx}^{-0.379} \tag{3.15}$$

where k_{hx} is the cost factor for a plate heat exchanger (\$/ft²) of size A (ft²). Multiplying k_{hx} by A_{hx} provides the net purchased cost of the heat exchanger.

For the centralized heat exchange facility, the heat exchanger area required for the whole community (as determined in section 3.3.3) was multiplied by the proportion of the community demand being met by a single GDH plant (see section 3.4.2, step 6) and the cost then estimated according to Equation 3.15. The additional cost of the heat exchange facility (i.e. instruments and controls, piping, pumps, installation costs, and the building itself) were estimated from Rafferty (1996) based on the maximum capacity of the heat exchange facility (i.e. the max capacity of a single GDH plant) and brought to 2012 dollars. This resulted in a final installed cost for the central plant of:

$$K_{CentalPlant} = 34290 \cdot Q_{max} + 74987 + k_{hx} \cdot A_{hx}$$
 (3.16)

For a decentralized heat exchange system each building has its own small heat exchanging substation, typically ranging roughly two orders of magnitude from around 10 m² or more for the largest apartment buildings and malls to as small as 0.1 m^2 for the smallest homes and businesses. In this scenario PHEs were sized similarly to the method used in section 3.3.3 only the average peak heat demand for each building was used (see section 3.3.2) rather than the peak heat demand for the entire community. From this, the required heat exchanger area to meet the demand for each building size was determined, with typical values ranging from <0.5 m² to nearly 100 m² depending on the temperature regime and building size and type. The purchased cost was then estimated according to equation 3.15 and the number of buildings of each size summed to obtain a total estimated heat exchanger cost for a decentralized building substation setup. Installation costs for this scenario were estimated and calculated on a perbuilding basis as an additional 10% of the total building retrofit cost (see below).

The lesser of either the centralized or decentralized heat exchanger setup in terms of total capital cost per GDH plant was then selected for use in LCOH calculations.

Other Building Costs Several other costs associated with outfitting buildings for GDH were incorporated into the model. Service pipe sizes were estimated in section 3.3.2. A cost curve for pre-insulated cross-linked polyethylene (PEX) service lines was estimated using data in Rafferty (1996), Lienau et al. (1998), and the 2011 PPI, resulting in:

$$k_{srvc} = 132.90 \cdot D + 53.36$$
 (3.17)

where k_{srvc} is the unit cost (\$/m) for PEX service pipe of diameter *D* (inches), valid for service lines of up to 3" diameter. The length of service lines was then estimated at 35 meters/building for the base reference case (see section 3.3.1).

The other costs associated with retrofitting a building, such as the additional cost of wall cuts, building piping, controls, coil heaters or unit heaters (if required), etc. were estimated from Rafferty (2003) and a 2012 report from the BioRegional Development Group (BioRegional 2012). These costs were split into two categories: costs required on a per unit basis and those

required on a per building basis, and summed based on the total number of units and buildings of each category served by a single GDH plant to provide an estimate of the total cost of retrofitting. Costs assumed on a per unit basis include control units and interconnections to existing heating systems, which were estimated at \$2000/unit. In reality, costs would likely be lower for units with older hot water radiator heating and more costly for units with forced-air heating due to the ease of retrofitting hot-water based heating systems and the added equipment required to retrofit a forced-air system to accept a hot-water or steam input. Costs assumed on a per-building basis are summarized in Table 3.4 and include outside wall cuts, main/tap boxes, building pipe, booster pumps (if necessary), and additional hot water retrofits (if necessary).

	to per building by building size.
Building Size	Estimated Building Retrofit Costs
Detached	3000
Attached	3000
2-4 units in building	4000
5-19 units in building	5000
20-49 units in building	6000
50+ units in building	8000
Commercial buildings	3000*(est. commercial units/building)

Table 3.4 Additional estimated retrofit costs per building by building size.

For example, a single detached house (1 unit) would have a total estimated retrofit cost of:

$$2000 \frac{\$}{unit} \cdot 1 unit + 3000 \frac{\$}{bldg} \cdot 1 bldg = \$5000$$

And a 5-19 unit apartment building (13 units assumed) would have a retrofit cost of:

$$2000 \frac{\$}{unit} \cdot 13 \text{ units} + 5000 \frac{\$}{bldg} \cdot 1 \text{ bldg} = \$31000$$

Peak Boilers The installation cost of peak boilers was estimated from costs published by the Consortium for Energy Efficiency (2001). The installed cost was roughly estimated based on the excess instantaneous peak demand needing to be met (MBTU/hr. – section 3.2.3):

3.3.5 Surface Equipment Operation and Maintenance Costs

Pumping Costs In order to calculate distribution pumping costs, pressure losses in the distribution piping network first had to be determined. This was accomplished using the equation for head loss due to friction in piping:

$$h_f = f_m \cdot \frac{L}{D} \cdot \frac{V^2}{2g} \tag{3.19}$$

where *L* is the length of piping (m), *D* is the diameter of pipe (m), *V* is the fluid velocity (m/s), *g* is the gravitational constant (m/s²) and f_m is the dimensionless friction factor. *L*, *D*, and *g* are known, and *V* can be calculated for each day given the primary fluid mass flow rate vector, the pipe diameter, and the density of water. Using a Moody diagram and assuming a turbulent flow regime in iron piping, f_m was assumed to be 0.27. With equation 3.19 solved, pressure losses in the pipe were then be calculated as:

$$\Delta p = \gamma \cdot h_f \tag{3.20}$$

where γ is the specific weight of the primary fluid ($\rho \cdot g$ – units of kg/m²s²), h_f is the head loss (m), and Δp is the pressure loss in N/m², or pascals. Finally, required pumping energy was determined as:

$$P_{pump} = \Delta p \cdot \frac{\dot{m}_{p}}{\rho} \cdot \frac{1}{\eta}$$
(3.21)

where \dot{m}_p/ρ (mass flow / density) is the volumetric flow rate of the primary fluid (m³/s), η is the pump efficiency, assumed to be 80%, P_{pump} is the required pumping power (W), and the primary fluid is assumed to be incompressible.

The above calculations were all performed in the MATLAB shell using the daily mass flow rate vector (section 3.3.3), which resulted in a daily pump power vector with units of W/day. This was then multiplied by 24/1000 to convert from average watts required each day to net kWh/day. The pump power vector was then summed and multiplied by the 2012average price of electricity for industrial purchasers in New York and Pennsylvania: 7¢/kWh (EIA 2012). This yielded a total annual estimated distribution pumping cost per plant per "place."

Maintenance Costs Other service, maintenance, and repair costs for the district heating network and substations were obtained from Schmitt and Hoffmann (2002) and brought to 2012 dollars, resulting in an overall estimated maintenance cost of \$7.65 per year per meter of network.

Peaking Fuel Cost The cost of fuel required to satisfy instantaneous peak demand periods was estimated assuming that extreme excess peak periods would occur for only 30 hours per year (section 3.2.3). Assuming a standard boiler efficiency of 85% and using the 2012 average natural gas price for industrial consumers in NY and PA of \$7.51/MCF (EIA 2012c), the peak fuel costs were calculated as:

$$PeakfuelCost = \frac{ExcessPeakMBTU/hr \cdot 30hrs}{0.8 \cdot 1020 \ MBTU/MCF} \cdot $7.51/MCF \qquad (3.22)$$

3.4 Model Implementation

3.4.1 Temperature and User-Input Selection

Several input variables were left to the user's discretion, including the production temperature, distribution heat losses, the maximum well flow rate, and the secondary heating system temperature regime.

A short literature review provided guidance for the selection of appropriate production temperatures (T_{ps}). Of 22 U.S. GDH systems reviewed by Thorsteinsson (2008) the highest operating temperature was 99°C and highest system $\Delta T (T_{ps} - T_{pr})$ was 37°C, while the averages were 73°C and 22°C, respectively. Skagestad and Mildenstein (2002) observed that even on a more global scale, typical GDH systems operate with production temperatures in the range of 68-85°C and a ΔT of 20-34°C. They reference a single 140/75 system (T_{ps}/T_{pr} ; $\Delta T = 65°$ C) as an extreme case. According to Gustaffson et al. (2008), "low tempered systems with an outgoing temperature between 70 and 110°C are found to be energy efficient, and are hence used at a large extent." Brown (2007) noted that the Klamath Falls GDH system was initially designed for a ΔT of 40°C and that only with new improvements may ΔT soon increase to 60°C.

Piping and technology assumptions also provide constraints on the acceptable production temperatures. According to Skagestad and Mildenstein (2002), "it is common to operate the supply water temperature below 120°C. Studies have shown that by reducing the normal operating temperature and by reducing the effects of pressure fluctuations, the life of the pipe work can increase dramatically." They suggest that at 120°C the expected lifetime for typical DH distribution equipment is around 30 years, while increasing T_{ps} only slightly to 130°C may decrease expected equipment lifetime to as little as 10 years (Skagestad and Mildenstein 2002). Of course there is equipment that can withstand the higher temperatures and more extreme pressure fluctuations associated with a higher T_{ps} and ΔT , but this equipment also costs significantly more than the equipment modeled in this study.

Therefore, six production temperatures were investigated: 75, 85, 95, 105, 115 and 125°C. A maximum system-wide ΔT of 65°C was also applied as an extreme constraint on the primary fluid return temperature (T_{pr}).

Heat losses in the distribution network were modeled very simply as a linear function of the network length. This assumption was based on the work of Ryan (1981), who suggested a temperature loss rate of roughly 0.25°C per km of distribution piping for buried 6" insulated piping (the most common size modeled in this study). By keeping production temperature to a minimum, the difference between the fluid temperature and the temperature of the surrounding earth can be minimized, reducing heat losses in the network and providing yet another reason to limit T_{ps} to less than 125°C. Allowing T_{ps} to significantly exceed 125°C would render the 0.25°C/km heat loss rate too low an estimate. In theory the insulation thickness of the system piping could be increased in order to further reduce heat losses, but the capability to model the added costs and effects of this were not compatible with and thus not incorporated into the model developed.

3.4.2 Three Deployment Scenarios

In order to evaluate the potential for EGS district heating in the near future, three base case scenarios corresponding to various levels of technologic achievement and phases of deployment were evaluated: (1) an **Initial Learning** phase, (2) a **Midterm Development** phase, and (3) a **Commercially Mature** technology. Assumptions for the Initial Learning phase were made using known conservative values and costs that are possible given today's technology. Assumptions for the Midterm Development phase and Commercially Mature technology were then made assuming that improvements to technology and reductions in costs would occur due to the effects of learning and given proper commitment to R&D.

For the Initial Learning phase, maximum mass flow through an EGS reservoir was assumed to be 30 kg/s. This value coincides with the highest known flow rates for the Soultz EGS demonstration project, which has produced at 25 kg/s and is expected to be capable of 35 kg/s under the right conditions (Genter et al. 2010). In their respective studies, Augustine et al. (2010) at NREL and the MIT *Future of Geothermal Energy* report both assumed a 30 kg/s EGS reservoir production rate for their baseline reference cases. This initial flow rate was expected to increase to 50 kg/s and 80 kg/s for the Midterm Development and Commercially Mature cases, respectively. Secondary heating system operating temperatures were set at 70/40°C for the Initial Learning phase, the logic for which was given in section 3.3.3. It was assumed that improvements to home heating system technology would reduce the required secondary heating regime to 50/30°C by the time the Commercially Mature phase is reached.

It was also assumed that reductions in the capital and operating costs of EGS district heating would occur due to learning, research, and economies of scale. A simple multiplier was applied to the capital and O&M costs prior to evaluating the final LCOH (section 3.4.2) to account for these effects.

Several other assumptions were varied between the three deployment scenarios including increases in the price of natural gas, efficiency improvements, and advances to heat exchanger technology. Table 3.5 summarizes all constant, user-defined inputs and assumptions in the model for the three deployment scenarios.

Parameter	Initial Learning	Midterm Development	Commercially Mature
i di dificter	(years 0-5)	(years 6-20)	(years 20+)
Maximum Flow Rate	30 kg/s	50 kg/s	80 kg/s
Lifetime	30 years	30 years	30 years
Drilling/Comp Costs	100%	90%	85%
Plant/Network Costs	100%	95%	90%
O&M Costs	100%	95%	90%
Secondary Temperature Regime	70/40 ºC	60/35 ºC	50/30 ºC
Minimum Pinch Temperature	3.0 ºC	2.5 ºC	1.5 ºC
Production Temperature Range	75 – 125 ºC	75 – 125 ºC	75 – 125 ºC
Maximum System-Wide ΔT	65 ºC	65 ºC	65 ºC
HX Heat Transfer Coefficient	5000 W/(m ² ·K)	5500 W/(m ² ·K)	6000 W/(m ² ·K)
Discount Rate (CBO rate)	4.0%	4.0%	4.0%
Portion of Roads w/DH Network	75%	75%	75%
Branch Distance (service lines)	35 m	35 m	35 m
Network Pump Efficiency	80%	85%	85%
Peak Boiler Efficiency	85%	90%	90%
Network Maintenance Costs	7.65 \$/m/yr	7.65 \$/m/yr	7.65 \$/m/yr
Natural Gas Purchase Price	7.51 \$/MMBTU	8.26 \$/MMBTU	10.51 \$/MMBTU
Electricity Purchase Price	7 ¢/kWh	7 ¢/kWh	7 ¢/kWh
Well Separation	500 m	500 m	500 m

Table 3.5 Constant user-defined inputs and their values for the three deployment scenarios.

3.4.3 Levelized Cost of Heat Calculations

The levelized cost of heat was estimated in two ways: using a fixed-charge rate method and a simple discounted cash-flow method.

The levelized cost calculations built into GEOPHIRES use a fixed-charge rate method to estimate the cost of energy by applying a user-defined fixed annual charge rate (FACR) to the capital investment (I), adding the annual operation and maintenance cost (O&M), and dividing by the annual production (Q) to determine the estimated cost of heat (COH) in \$/MMBTU:

$$COH = \frac{I \cdot FACR + O\&M}{Q}$$
(3.23)

The fixed charge rate methodology "allows for quick determination of the amount of revenue needed to cover investment costs for simple, straightforward investments" and can be used for projects that "not only have constant output, but also constant O&M and no financing" (Short et al. 1995). Such are the assumptions for the simple model presented here. Specifically, the FACR represents "the average, or 'levelized' annual carrying charges including interest or return on the installed capital, depreciation or return of the capital, tax expense, and insurance expense associated with the installation of a particular generating unit" (Shaalan 2001). For a typical investor-owned commercial scale utility the FACR may run 15-20%, while the FACR for a publicly owned utility is generally around 5% (Shaalan 2001). For the base reference case, a FACR of 6% was chosen to represent a typical value for a publicly-owned utility yet still provide a slightly conservative estimated COH.

The major drawback with the fixed annual charge rate methodology is that effects of changes in the plant lifetime are wrapped up in the assumed FACR value, making sensitivity analyses evaluating plant and equipment lifetime difficult. For this reason, a second levelized cost of heat (LCOH) methodology was used outside of the GEOPHIRES model. This utilized a discounted cash-flow methodology:

$$LCOH = \frac{\sum_{t=1}^{Lifetime} (I_t + 0\&M_t) / (1+d)^t}{\sum_{t=1}^{Lifetime} Q / (1+d)^t}$$
(3.24)

where *I*^{*t*} is the capital investment in year *t*, *O*&*M*^{*t*} is the total operation and maintenance cost in year *t*, *Q* is the energy sold in year *t*, and *d* is the discount rate. To make the comparison between the two cost estimation methods comparable, typical discount rates for public utilities rather than investor-owned utilities were used. The U.S. Department of Commerce calculates an effective discount rate for use with analyses of federal and public energy projects that is based on the average long-term Treasury bond rates and the inflation rate. For 2011, this discount rate was 3% (Rushing et al. 2011). As was done with the FACR rate above, 1% was added to this to ensure a conservative estimate for the base reference case. Thus, the discount rate applied to LCOH calculations for the base reference case was 4%.

A four-year building period was allowed during LCOH calculations. Drilling and completion costs were divided in two and applied equally to years 1 and 2 of the building phase. Total surface costs were then spread over years 2-4 at rates of 1/6, 2/6 and 3/6 of total cost each of years 2, 3 and 4 respectively. First production would thus begin in year 5 for each project.

3.4.4 Overall Model Workflow

At this point all the necessary calculations and inputs have been explained. Figure 3.1 previously offered a visual representation of how all the pieces fit together within a single, fluid model. The workflow can be broken down into nine steps, also illustrated in Figure 3.6 (p. 59):

 From ArcGIS the geothermal gradient, surface temperatures, and length of road (as described in section 3.3.1) at each of the 2894 census "places" was determined and stored in a single input spreadsheet in Microsoft Excel. Building data (section 3.3.2) was also pulled into this input spreadsheet. Figure 3.7 (p. 60) shows an example snapshot of the input spreadsheet.

- The MATLAB shell program is initiated and MATLAB reads and stores the input data from the input spreadsheet. The shell program also contains all other user-defined input values.
- Beginning with the first census "place" on the input spreadsheet, MATLAB performs the necessary demand, temperature, flow, sizing, and cost calculations as described above in sections 3.2 and 3.3.
- 4) GEOPHIRES 1.0 is executed by the MATLAB shell. MATLAB passes the geothermal gradient, the design injection temperature, the maximum well flow rate, the plant lifetime, the fixed annual charge rate, the surface equipment investment and operating costs, and the electric price to GEOPHIRES. MATLAB also makes initial guesses at the drilling depth required to reach the desired production temperature and the capacity factor of the geothermal plant.
- 5) For the given set of inputs, GEOPHIRES calculates the estimated drilling and completion costs, wellfield operation costs, the average production temperature, the maximum thermal power, and the projected LCOH for the GDH plant. These values are then returned to MATLAB.
- 6) MATLAB compares the production temperature as determined by GEOPHIRES with the user-defined production temperature and, if the difference is greater than 0.5°C, adjusts the depth guess accordingly. From the max thermal power returned by GEOPHIRES and the average community-wide peak demand, MATLAB also determines the proportion of the total community demand that a single GDH plant can satisfy. This proportion is then used to scale the required primary fluid mass flow rate and the surface equipment sizes and costs (all described in section 3.3). In this way a GDH plant that is only capable of serving 20% of a community. Rather it will only incorporate 20% of the total community costs and required flow rate; the underlying assumption being that 5 individual GDH plants will then be constructed to serve the whole community. Finally, the capacity factor of each plant is also updated based on the max thermal power and the demand profile for each GDH plant.

- 7) The new values are returned to GEOPHIRES, which repeats step 4. Steps 4 and 5 are then iterated in a loop until a final drilling depth, thermal power, and LCOH are converged upon.
- 8) MATLAB stores all the results in a series of matrices and then moves on to the next census "place" and repeats steps 3 through 7. Once all census "places" have been run through the program for a given temperature, MATLAB repeats the entire process again for the next desired production temperature. In this way the MATLAB shell can perform the necessary calculations and LCOH estimates at all 2894 "places" for up to 6 production temperatures with a single click of a button.
- 9) Once all calculations are finished, MATLAB prints the stored results to an output Excel spreadsheet.

These steps are illustrated in Figure 3.6. Note that Figure 3.6 differs from Figure 3.1 in that it attempts to illustrate the chronological order of computational steps, whereas Figure 3.1 attempts to illustrate the overall data analysis strategy organized by conceptual rather than computational divisions. Processing time for a single data run (steps 2-9, as step 1 was only



Figure 3.6 Chronology of computation steps as performed during a single data processing run. Dark grey boxes represent individual software suites, light grey boxes represent excel spreadsheets, and red numbers correspond to the nine steps as outlined above.

•	om_Bld	455.785	508.866	547.786	520.804	612.707	616.674	518.39	374.086	484.841	454.789	418.903	448.091	455.597	472.847	808.303	788.719	785.138	309.546	430.03	295.328	421.690	257.639	706.954	303.679	345.972	294.643	710.395	311.267	586.822	265.768	306.325	329.756	293.599	94.1175	661.225	337.603	471.435	301.130	200.573	<u>277.236</u> ▼
c	es_Units 🗸 C	27095	31552	19439	28432	30136	20956	17258	29584	19128	24595	25649	23914	19467	15013	13936	24071	14184	23473	17557	19340	13512	14602	11730	15070	12442	17778	11433	14789	13276	15025	14884	12032	11363	15723	10594	10360	13268	11399	10688	10378
•	es_Bldgs V R	19116	18641	17550	17137	14055	16711	16313	12904	15399	14388	9979	10502	12034	12639	12915	9235	12518	11206	10672	9442	10769	11165	10959	10101	10679	9195	10326	10034	9654	8788	9971	10006	9829	6474	9498	9534	8752	8965	8917	9783
c	adLocal V Re	21.928068	25.677076	24.15	24.046732	24.15	25.697781	24.15	24.15	28.447271	23.490889	24.15	24.15	21.064878	24.15	24.15	24.15	24.15	27.264914	21.032795	24.15	23.202709	25.587881	24.15	24.15	24.15	24.15	24.15	25.495802	30.74338	24.15	24.715105	24.15	24.15	24.15	24.15	24.15	28.563536	29.140625	28.568665	24.15
Z	network 🔻 G	288682.0725	237439.9019	245857.116	317305.9403	237659.0405	238833.8522	171442.6326	110962.2585	277738.9206	235357.6957	176479.8253	142030.8888	155953.1135	171457.8407	163162.2158	184826.8606	209255.1515	200478.6334	226083.3942	124519.6456	222316.5309	175190.0384	252917.077	118550.1561	129806.4708	93530.32722	260243.7757	401299.1508	263716.3695	232267.3348	179012.5853	89163.89574	108949.2974	114015.4441	130936.5999	185867.9378	293320.2911	163273.5968	282163.4023	74060.07946
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н С	. min_est ▼ sfRes	-23.390337 5891	-27.820372 5756	-18.272699 5352(-28.37991 5323	-18.05991 5245	-23.179361 5189	-17.557985 4877	-18.007509 48738	-23.392874 46928	-26.619226 4607:	-18.364054 4444	-18.31719 4310	-22.892426 40940	-17.681717 3879	-17.70974 3859:	-18.807005 3810	-18.09483 3774	-27.270109 3717	-23.40457 3646:	-19.178482 36394	-23.435959 3432	-23.54183 34138	-18.348732 33288	-17.254038 3328:	-17.491623 32954	-17.376202 3294	-20.432276 31650	-28.777672 31560	-23.46995 31558	-18.023909 3113	-24.84169 30328	-17.221895 3010	-17.174297 3009	-17.379908 2896	-18.26557 2881	-18.056948 2875	-29.189915 28579	-24.01351 2810	-23.450256 2803	-17.313381 2753
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Figure 3.7 Snapshot of an input spreadsheet. Note that this a modified sample version and that not all variables are shown. The true input table has 37 columns of input data and 2894 rows - one for each "place."

performed once) varies to a small degree, but typically takes around 12-14 hours to process all 2894 "places" at 6 production temperatures, or about 2 hours to process all "places" at a single production temperature (Dell Optiplex 780 running an Intel Core 2 Duo processor at 2x 3.0 Ghz with 4.0 GB RAM). The MATLAB shell code in its entirety can be found in the Appendix.

3.5 Summary

With the model and data processing approach described here, census information and climate data were combined in a new way to obtain estimates for the spatial and temporal variability in space and water heating demand in New York and Pennsylvania. To this, geothermal resource maps, surface equipment and reservoir modeling, and unit cost estimates were added so that the final cost of providing heat from Enhanced Geothermal Systems (EGS) for each unique community in New York and Pennsylvania could be estimated. From these results, real opportunities for EGS district heating can be evaluated in a way that provides meaningful insight into the future of EGS district heating in New York and Pennsylvania. The core results and a discussion of the opportunities they illuminate will be the topic of Chapter 4.