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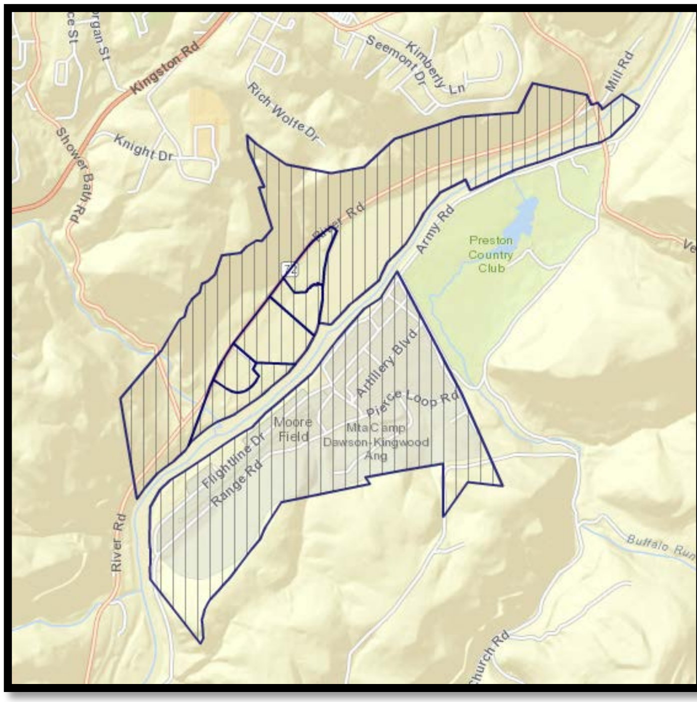

Evaluation of Geothermal and Natural Gas Resources Beneath Camp Dawson and Opportunities for Deep Direct Use of Geothermal Energy or Natural Gas for Heat and Electricity Production

4 May 2017

U.S. DEPARTMENT OF ENERGY | NATIONAL ENERGY TECHNOLOGY LABORATORY

Office of Fossil Energy

NETL-TRS-8-2017

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Cover Illustration: Regional map surrounding Camp Dawson.

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Evaluation of Geothermal and Natural Gas Resources Beneath Camp Dawson and Opportunities for Deep Direct Use of Geothermal Energy or Natural Gas for Heat and Electricity Production

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Acronyms, Abbreviations, and Symbols

Acronym	Descriptive Name
BCF	Billion Cubic Feet
Btu	British Thermal Unit
CF	Capacity Factor
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
DG	Distributed Generation
DOE	U.S. Department of Energy
EGS	Enhanced Geothermal System
EPA	U.S. Environmental Protection Agency
FE	Office of Fossil Energy
GWh	Gigawatt Hours
GPM	Gallons per Minute
GTO	Geothermal Technologies Office
GTW	Gas Turbine World
H_2O	Water
H_2S	Hydrogen Sulfide
HDD	Heating Degree Days
HVAC	Heating, Ventilation, and Air Conditioning
ID	Inside Diameter
kWe	Kilowatt Electric
kWh	Kilowatt Hours
LCOE	Levelized Cost of Electricity
LCOH	Levelized Cost of Heat
MBH	Thousands of Btu's per Hour
MCA	Mountaineer Challenge Academy
MCF	Thousand Cubic Feet – A measure of natural gas at 70°F and 1 atm
md	Milli-Darcys – Units of permeability of rock
MMBtu	One Million British Thermal Units
MMCF	Million Cubic Feet
MPB	Multi-Purpose Building

Acronyms, Abbreviations, Symbols (cont.)

Acronym	Descriptive Name
MW	Megawatts
mW/m^2	Milliwatt per Square Meter
NETL	National Energy Technology Laboratory
NGLs	Natural Gas Liquids
NOx	Nitrogen Oxide
O&M	Operation and Maintenance
OD	Outer Diameter
ORC	Organic Rankine Cycle
PDE	Partial Differential Equation
POC	Proof-of-Concept
RTI	Regional Training Institute
SMU	Southern Methodist University
SOFC	Solid Oxide Fuel Cell
TPC	Total Plant Cost
USGS	United States Geological Survey
W/mK	Watts per Meter Kelvin
WVGES	West Virginia Geological and Economic Survey
WVNG	West Virginia National Guard
WVU	West Virginia University

Acknowledgments

This work was completed as part of the National Energy Technology Laboratory's (NETL) research for the U.S. Department of Energy's (DOE) Geothermal Technologies Office (GTO) and NETL's Natural Gas Program (Office of Fossil Energy). The authors wish to acknowledge Brigadier General Harrison B. Gilliam (WVNG), Captain Kyle McGaha (WVNG), Arlene Anderson (GTO), Jared P. Ciferno (NETL), Shailesh D. Vora (NETL), West Virginia Governor's Office, and Brian Anderson (WVU) for programmatic guidance, direction, and support. Technical contributions were made by Albert B. Yost II (NETL), Jessica Spears (NETL-ORISE), and Ronald R. McDowell (WVGES). Supplemental information on drilling and well costs were provided by Brooks Javins (Javins Corporation), Lowell Warden (Energy Corporation of America), and Mike Rogers (Alpha Hunter Drilling, LLC). Supplemental Information on 3D seismic surveys was provided by Third Coast Enterprises, Inc. and Dawson Geophysical Company. Support for the cost analysis was provided by Morgan Summers (NETL-SEA). Support and guidance for ORISE interns were provided by Kelly Rose (NETL).

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ABSTRACT

NETL has reviewed available information and evaluated the deep geothermal and natural gas resources located beneath the Camp Dawson National Guard Training Center in West Virginia. This facility is located in the northeastern portion of the state in Preston County, near the town of Kingwood. This study reviews options for the onsite drilling of wells for the production of geothermal heat or natural gas, as well as the utilization of these resources for on-site power and heating needs. Resources of potential interest are at subsurface depths between 7,000 feet and 15,000 feet. NETL considered several utilization and energy conversion options under the study, including:

1) Natural gas produced onsite to feed the existing boilers at Camp Dawson
2) Geothermal heat produced onsite to directly heat buildings
3) Natural gas produced onsite to feed a combustion turbine-generator system that produces electricity combined with a waste heat capture system to heat the buildings
4) Geothermal heat produced onsite to feed an "organic Rankine cycle (ORC)" system that produces electricity
5) Natural gas produced onsite to feed a high-efficiency solid oxide fuel cell (SOFC) that produces electricity combined with a waste heat capture system to heat the buildings

This work was performed at a preliminary level to determine feasibility and rough estimates for the costs of the various options studied. It aims to support a decision by the West Virginia National Guard (WVNG) on which options, if any, the Guard would like to pursue further. NETL expects additional analyses would be done on any selected option or set of options to more accurately assess resource availability and to determine project costs and feasibility. In doing so, the *WVNG should employ a competent engineering firm to make detailed plans for wells and above ground equipment, as well as refined estimates of costs.*

1. INTRODUCTION

The objective of this report is to provide a preliminary evaluation of the economic and technical viability of using geothermal energy and/or natural gas found deep beneath Camp Dawson to provide heat for at least nine buildings and electricity for most (if not all) operations on the Camp Dawson property. The goal is to obtain secure, long-term supplies of heat and electricity with reduced carbon dioxide (CO_2) emissions associated with these supplies. The geothermal portion of the study was sponsored by U.S. Department of Energy's Geothermal Technologies Office (DOE-GTO) and focused on evaluating opportunities for direct use of geothermal resources with temperatures greater than 150°F. The natural gas portion of the study was sponsored by NETL's Natural Gas Program (DOE Office of Fossil Energy [FE]) and focused on evaluating opportunities to access and use on-site natural gas resources for both electricity production and space heating. Systems for energy conversion covered in this report include an ORC that uses only geothermal energy, a conventional combustion turbine generator that uses only natural gas, and an SOFC system currently under research sponsorship by NETL. In some cases, these technologies are configured to provide a combination of heat and power. Ground-sourced heat pumps are not within the scope of this study.

A regional map of West Virginia and the adjacent states shows the location of Camp Dawson, as seen in Figure 1.

Figure 1: Regional map showing location of Camp Dawson.

The Opportunity for Use of Geothermal Energy

One motivating factor for conducting this case study is the prior work sponsored by the U.S. DOE's GTO and Google to evaluate opportunities for the use of deep geothermal resources within the coterminous United States, including West Virginia. In 2011, the Southern Methodist University's (SMU) Geothermal Laboratory prepared a heat flow map of the United States (Figure 2). Their study shows a geothermal anomaly in east central West Virginia, extending into Preston County, which has a higher heat flow than most other areas of the eastern United States (see also Frone and

Blackwell, 2010; Frone, 2012). A closer review of that data, and a first-order analysis for employing such heat toward meeting the heating loads for the nine buildings noted, is a focus of this report. In addition, for sufficiently hot geothermal temperatures found at greater depths, consideration can be given toward using geothermal energy in the production of electricity. Some success in this area has been obtained in Europe (see, for example, Baujard et al., 2015). The primary approach currently used to convert low-temperature geothermal energy to electricity is through a binary-fluid ORC system or a Kalina cycle system (see generally, Gehringer and Loksha, 2012). Such cycles are necessarily of low energy-conversion efficiency due to the physics of this type of system; however, if the capital costs are low for accessing the energy, the economics can still be better than alternative technologies. This may be a challenge in the eastern portion of the United States as recently reported by the Gas Equipment Engineering Corporation in a study of the viability of geothermal power generation in the eastern United States, sponsored by the GTO (GEECO, 2012). This report analyzes both electric power production using an ORC system, as well as deep direct use of geothermal energy for heating buildings.

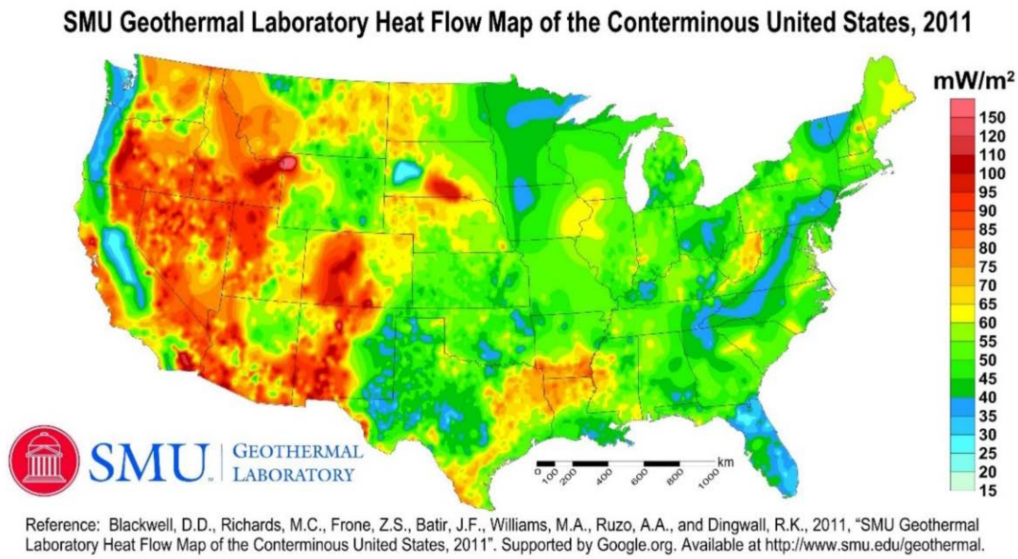

Figure 2: SMU Geothermal Laboratory heat flow map of the conterminous United States, 2011.

The Opportunity for Use of Fossil Energy

Over the past 10 years, thousands of Marcellus Shale wells were drilled in West Virginia and Pennsylvania. The western side of the productive trend (Pennsylvania/Ohio border) produces considerable natural gas liquids (NGLs), especially ethane, whereas in Preston County, due to the higher maturation of the hydrocarbons in this eastern portion of the basin, production from the Marcellus Shale is dry natural gas (mostly methane). By accessing the expected natural gas resource under Camp Dawson, and perhaps adding additional resource volume through acquisition from adjoining properties, both heating and electrical needs for Camp Dawson can potentially be supplied for many years. There are a variety of possible commercial solutions that can be pursued in the production of on-site electricity and heat, such as gas turbine engines or reciprocating engines. In this report, consideration is given to a combustion turbine generator for electricity production, combined with waste heat recovery and use for space heating. Also covered is an advanced fossil energy conversion system under development by NETL called an SOFC. The latter provides clean power with high efficiency.

2. HEAT AND ELECTRICITY DEMANDS AT CAMP DAWSON

2.1 CURRENT NATURAL GAS USAGE

Natural gas data for all buildings and uses, given in thousands of cubic feet (MCF) by month for four sales meters, was provided by the West Virginia National Guard (WVNG) for the time from July 2013 through June 2015. Most of Camp Dawson's use of natural gas is for space heating. This data was summed for each month and graphed to show the seasonal variation of volumes used – see Figure 3 and Appendix A for details. During the 5 months from December through April, the buildings require from 5,000 to 8,000 MCF/month. The remaining 7-month demand drops to an average of around 2,000 MCF/month. The average annual quantity of natural gas demand is 40,350 MCF per year for these 2 years of data, corresponding to about 13,000 megawatts (MW) of thermal energy use over a year. The average annual cost of natural gas consumed is $301,875.00. The monthly cost for natural gas from July 2013 through June 2015 can also be found in Appendix A. There has been a recent downturn in natural gas prices, but it is questionable whether those costs will decrease further. It is possible that future costs may be lower or higher depending on the details of the Camp's natural gas service contract and local market prices.

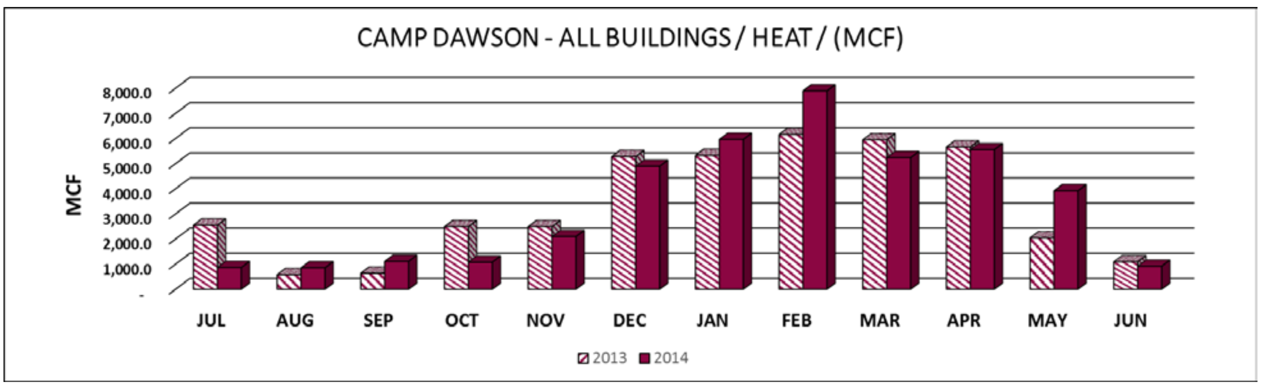

Figure 3: Monthly natural gas usage at Camp Dawson over a 2-year period (MCF); 1 MCF = 1.035 million British thermal units [Btu]).

2.2 CURRENT ELECTRICITY DEMAND

The quantity of electricity used, given in kilowatt hours (kWh), was graphed for a 2-year, 8-month time period – see Figure 4 (and Appendix B for details). Instead of seasonal variations like those seen with the natural gas usage, it shows a baseload requirement of about 1,100,000 kWh/month or 12,800,000 kWh/year (based on 32 months of data). The corresponding costs for the first 2 years were approximately $61,000.00/month and increased to about $79,000.00/month from July 2015 to February 2016 due to additional demand. The total average annual cost of electricity is expected to exceed $827,000.00 (see Appendix B for details). This results in an overall cost of electricity of $64/MWhr.

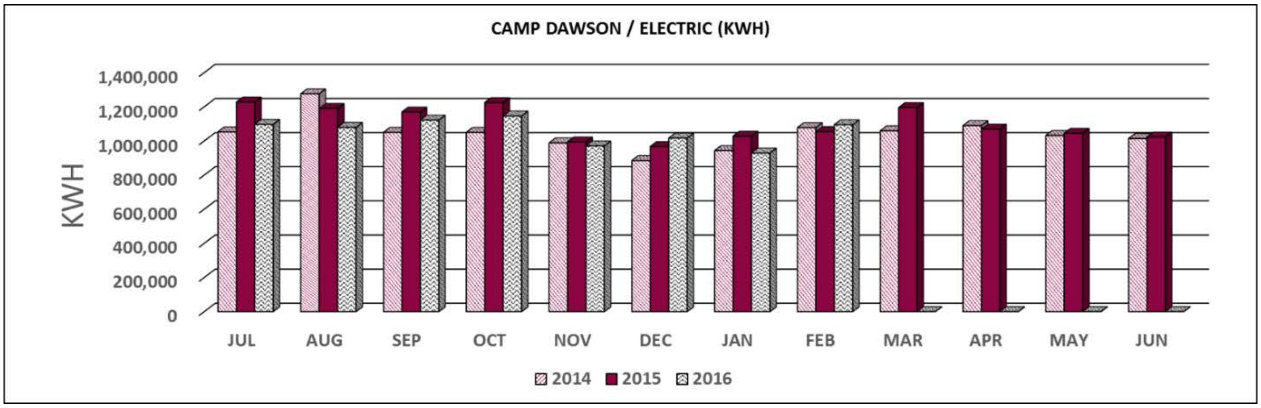

Figure 4: Total electrical consumption at Camp Dawson over a 3-year period.

2.3 HYDRONIC HEATING DEMANDS AT CAMP DAWSON

As shown in Figure 5, the nine buildings at Camp Dawson having hydronic heating and being considered for this study consist of the Multi-Purpose Building (MPB) 203, the Mountaineer Challenge Academy (MCA) Building 443, the four barrack buildings numbered 241, 243, 245, and 246, the old A1000, new A1000, and the Operations Building Regional Training Institute (RTI) 1001A. The old A1000 and the new A1000 are connected, but derive their heating source from different locations. The old A1000 is the training and hotel center, and the new A1000 is the new wing of the hotel. The buildings vary widely in age from a few years old to the four barracks built before World War I. These buildings are already equipped to use geothermal heat since they are all heated with hot water supplied from one or more natural-gas-fired hot-water boilers, which are located inside a mechanical room in each building, with the exception of the new A1000, which is supplied with hot water from the Operations Building RTI 1001A. Hot water is fed to coils in air handling units to heat the air within these buildings.

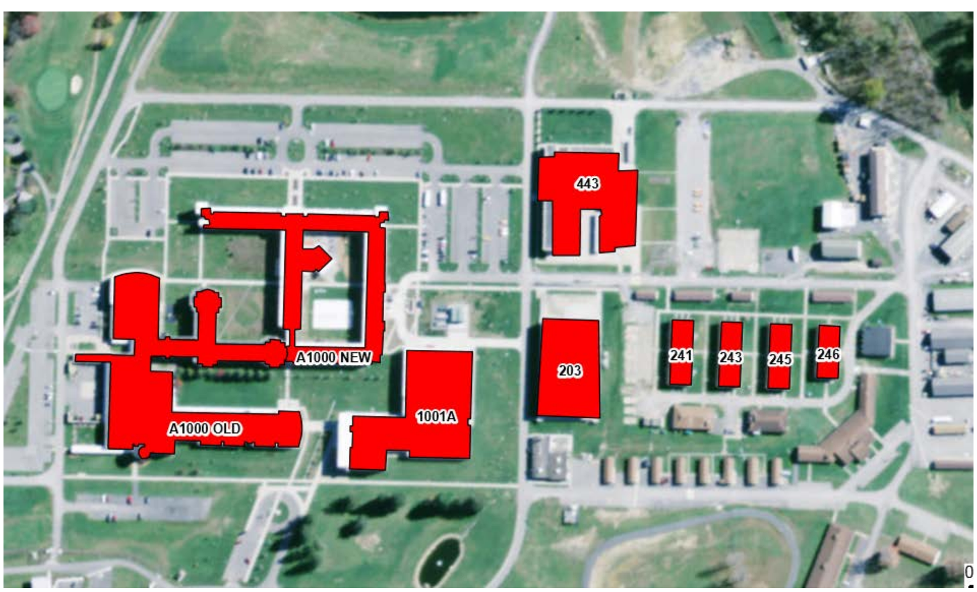

Figure 5: Buildings at Camp Dawson that are currently heated by hydronics.

Two of the buildings are shown in the photos below (Figure 6).

Figure 6: Operations Building RTI 1001A (left) and the new A1000 hotel complex.

The minimum number of boilers is two per building, with up to five in the Barrack buildings. Typical boilers are shown in Figure 7.

Figure 7: Typical boiler installations in buildings at Camp Dawson.

The sizes of the heating plants for the nine buildings are listed in Table 1.

Table 1: Hydronic Boiler Plant Sizes Based on Equipment Specifications

Facility	Heat Source	Input*
Barrack 241	5 Boilers	225 MBH each
Barrack 243	4 Boilers	210 MBH each
Barrack 245	4 Boilers	210 MBH each
Barrack 246	3 Boilers	900 MBH each
MPB 203	2 Boilers	1,500 MBH each
Old A1000	5 Boilers	1,000 MBH
New A1000	Located in 1001A	
OPS RTI 1001A	5 Boilers	1,000 MBH each
MCA 443	2 Boilers	750 MBH each

***MBH = Thousand Btu per Hour**

The buildings were designed and built at various times over several decades, and as a result have different hydronic design conditions. As shown in Table 2, the newer buildings have a design supply temperature of 135°F, while the older buildings have higher supply temperatures at 160° to 180°F (old RTI A1000). Without a redesign of the hydronic systems (especially for old RTI A1000), the supply water temperature from the alternative technologies under study here (geothermal well or combined heat and power [CHP] units) will need to be at the higher supply temperature (180°F). The buildings with lower design supply temperatures may be able to accept 180°F water by using mixing valves, by adjusting the control systems of the air handling equipment, or by using a heat exchanger. Some of the boiler systems are on an outdoor air temperature reset, which allows lower hot water supply temperatures at higher outdoor air temperatures.

Key Building Heating Design Data—Hot Water Supply Temperatures, Peak Hot Water Flow Rate, Water Temperature Drop

While the above data provides high-level information about the present fuel requirements for the entire site and high-level information on how each building's heating system is designed to meet the building's heat demands, it is informative to understand each building's peak heating requirements as it provides the maximum flow rate of natural gas (or heat). In addition, system design requirements for each building determine the operating temperatures and water temperature drop data. Since monthly building performance is not available, this information is developed following standard building design calculations. In the design of a heating, ventilation, and air conditioning (HVAC) system, the regional environmental design conditions determine the peak thermal heating load for a building. Based on West Virginia State building design standards, the winter design temperature for this area is 0°F. Due to lack of information, it is not clear if all buildings in the group used this as a design temperature. There may be some overdesign in some of the older systems, such as the Barrack Buildings 241-246. To arrive at other design data, three sources of information were used: architectural drawings when available, natural gas bills for the buildings, and temperature control system data from the current operation readouts of select buildings. Data was compared from the three sources when possible. Table 2 below shows the results of the calculated peak hot water demands for this group of buildings and the other noted building design data.

Table 2: Calculated Peak Hot Water Demands

Facility	Design Hot Water Supply (°F)	Design Hot Water ΔT (°F)	Hot Water Supply Flow Rate @ Design (GPM)	Heat Supplied (MBH*)
Multi-Purpose Building (MPB) – 203	135	20	82.5	825
Mountaineer Challenge Academy (MCA) - 443	137.5	20	149.5	1,495
Old RTI A1000	180	20	400	4,000
New A1000 and OPS RTI 1001A	135	20	700	7,000
Barracks -241	160	20	93.5	935
Barracks -243	160	20	93.5	935
Barracks - 245	160	20	93.5	935
Barracks - 246	160	20	70	700
		TOTAL	**1,683**	**16,825**

***MBH = Thousand Btu per Hour**

The demand for hot water at the peak design condition (1,683 gallons per minute [GPM]) occurs for only a few hours each year (e.g., 408 hours below 17°F out of 4,258 hours in the heating season based on the available data). For most of the heating season in any given year, the demand is much lower. The average winter temperature for the area is approximately 40°F. At this temperature, the demand is far less, in the range of 600–700 GPM of 180°F water. The design (peak load) temperature drop is 20°F for all building air handling heat exchangers. When the heat demand is less on moderate days, the temperature drop for the hot water through the heating system of a given building will be considerably less. For example, on NETL's first visit to Camp Dawson in January 2016, the outside temperature was in the 30's. In the mechanical room of the Operations Building, the control screen showed the supply water temperature to be 126°F with a return water temperature of 123°F and a flow rate around 600 GPM. This means that the thermostats in the rooms were satisfied at their set points, and the hot water was being bypassed around the heat exchangers by the temperature control system.

Seasonal Building Heating Loads from Climatic Data

Aside from understanding peak heating demands for each building, it is also important to understand the month-to-month heating demands to determine the variability in demand through the year. This will allow us to understand the entire annual range of heat load and the flow rates required from the geothermal wells, as well as look for opportunities to optimize the design by looking at the baseload provided by geothermal energy, with the peak load possibly provided by existing natural gas boilers. Local climate data (based on 30-year statistical data) and standard building HVAC design calculations were used to assess a given building's monthly heat demand. The available 30-year statistical data that most closely represents the conditions at Camp Dawson came from Elkins, West Virginia. With this approach, it was found that there is agreement when using the heating degree days (HDD) method of energy estimation (ASHRAE, 2013) and the natural gas bills provided by Camp Dawson. The boiler inputs were used with an assumed 80 percent thermal efficiency and the monthly gas usage was predicted. The results are shown in Appendix C, summarized in Table 3 below, and are used in the annual load calculations shown in Section 5.

The actual site gas usage provided by Camp Dawson for a recent year (see Appendix A) was used to help validate the above calculations. As shown in Appendix A, the natural gas consumed per year is around 40,350 MCF. The yearly natural gas demand for heating predicted via the above approach is 43,267 MCF (Appendix D). Also included in the gas bill are domestic water heating and cooking, which are relatively small uses and occur mainly during the summer months, but were not included for the predicted gas usage. The calculated usage and the actual usage are expected to differ slightly, but are close for energy estimation purposes.

Table 3: Monthly Energy Usage for Nine Buildings – Heating Season Data Only

Month	January	February	March	April	May	September	October	November	December
Btu (X 10^6)	8713.7	7376.1	6090.7	3829.4	1929.8	1029.7	3575.3	5228.7	7658.7

Geothermal System Sizing

There are several options in the design of a geothermal system to provide direct heating to the Camp's buildings. It is possible for a geothermal system to be designed to supply heat to satisfy all building demands, including peak demands. Given that peak demand only occurs for a fraction of a year, however, the system would then be oversized regarding other times of the year, and given the anticipated cost of a geothermal system, may not provide the best solution if overall cost is a concern. A more cost effective approach could be to design a geothermal system to meet a majority of a heating season's load and to meet peak demands with the existing boiler systems fueled by natural gas.

To examine the best size for a "baseload" system (and its associated peaking system), it is helpful to perform a statistical analysis of the data. This may be done using the bin method of energy analysis where the heating season is divided into 5°F bins, and the number of hours during the heating season that lie within each bin are recorded. The bin data for Elkins is shown in Appendix D, and the bin calculations are shown in Appendix E. The winter heating season for the immediate area is 4,285 hours out of the 8,760 hours in a year on average, so some level of heating is required 49 percent of the time. Using the bin hours, it is possible to estimate the percent of heating load that exists at any outdoor temperature level for the nine buildings at Camp Dawson, as shown in Figure 8. It may be seen from Figure 8 that at a design flowrate of 1,100 GPM from the geothermal well, about 80 percent of the demand through the year will be satisfied. A geothermal system can then be coupled with the existing natural gas boiler systems now in place in the buildings to provide heating in the extreme climate conditions that occur less frequently. In average winter conditions, the geothermal well(s) would provide essentially all of the hot water required for heating the nine buildings. To address the few remaining higher heat load days would require a geothermal system sized to around 1,763 GPM, or nearly 60 percent greater in size (and significantly more in cost).

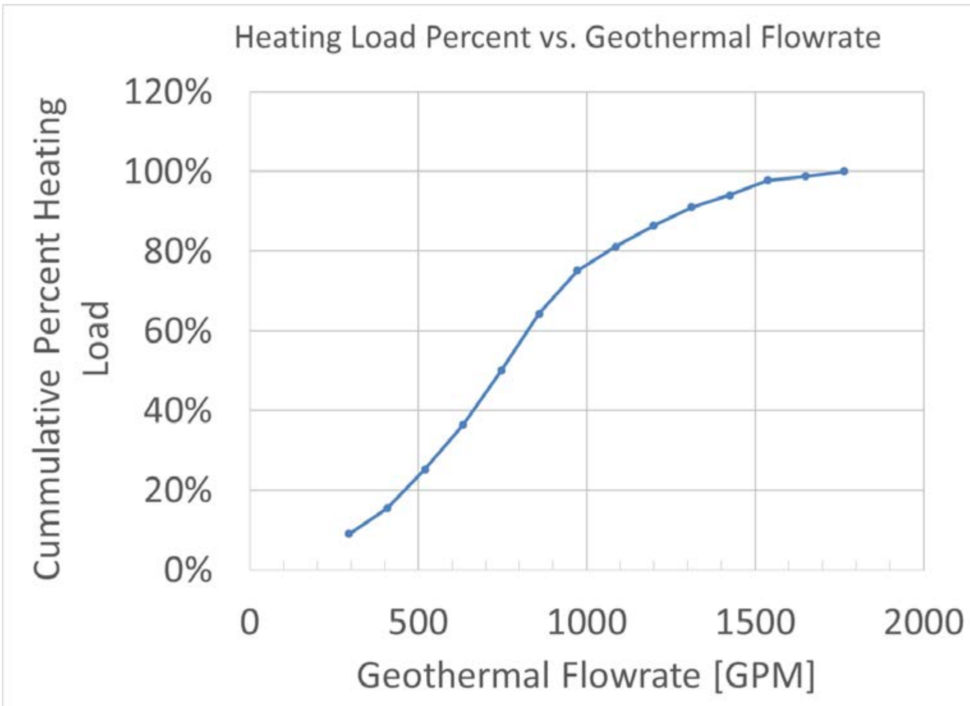

Figure 8: Percent heating load versus geothermal flow rate (assuming ∆THXGR=20°F).

Another way to examine the data is to compare the peak, yearly average, and yearly minimum heat load cases. Table 4 shows the peak winter demand, which occurs in January, and its associated average hourly demand. Similar data is provided for the minimum heating demand, which occurs in September (far right columns), and an overall yearly average heating demand (middle columns). Flows from the geothermal well(s) to meet these average monthly demands range from 1,171 GPM in January to 143 GPM in September. The flow rate to meet the overall average yearly heating demand would require 699 GPM. The same information is portrayed graphically in Figure 9.

Table 4: Range of Monthly Heating Demands for the Nine Buildings

Building	Peak Design for Heating Demand [Btu/hr x 10^6]	Average Heating Energy for January [Btu x 10^6]	Average Hourly Load Rate for January [Btu/hr x 10^6]	Geothermal Flow Required for Average January Load [GPM]	Average Hourly Heating Load for Year [Btu/hr x 10^6]	Average Geothermal Flow Required [GPM]	Minimum Heating Average Hourly September [Btu x 10^6]	Average Hourly Load Rate for September [Btu/hr x 10^6]	Geothermal Flow Required for Average September Load [GPM]
RTI A1000 and OPS	7.000	3625.3	4.873	487	2.912	291	428.4	0.595	60
Multi-Purpose Building 403	0.825	427.27	0.574	57	0.343	34	50.49	0.070	7
Mountaineer Challenge Academy	1.495	774.26	1.041	104	0.622	62	91.49	0.127	13
RTI A1000	4.000	2071.6	2.784	278	1.664	166	244.8	0.340	34
Barracks 241	0.935	484.24	0.651	65	0.389	39	57.22	0.080	8
Barracks 243	0.935	484.24	0.651	65	0.389	39	57.22	0.080	8
Barracks 245	0.935	484.24	0.651	65	0.389	39	57.22	0.080	8
Barracks 246	0.700	362.53	0.487	49	0.291	29	42.84	0.060	6
Total	16.825	8713.67	11.712	1171	6.999	699	1029.69	1.430	143

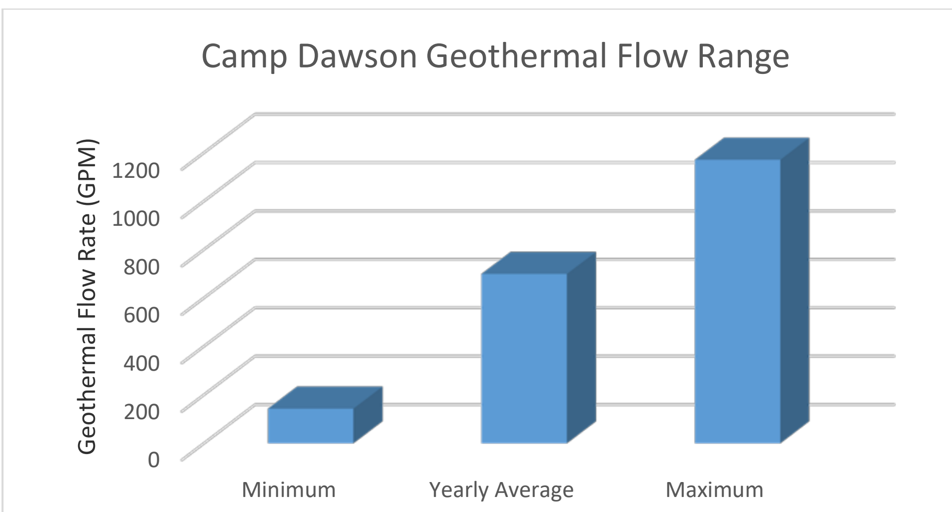

Figure 9: Range of monthly heating demands for Camp Dawson hydronic buildings.

The information in Figures 8 and 9, as well as Table 4, can be informative in establishing an economical approach to some of the technologies under review. For example, if there is an interest to achieve a level of renewable resource usage on site, but do so at a more effective cost, the Camp could consider satisfying a portion of the heat load by geothermal energy while leaving the balance of heat load satisfied by conventional (perhaps the already existing) boiler systems. In this manner, the size of the renewable geothermal system can be significantly lowered to avoid the high cost of meeting the peak heat load demands that only occur infrequently through the year (i.e., 1,171 GPM per Table 4), and instead be operated at a more constant rate at say 699 GPM (average yearly heat demand rate). The smaller system also implies a lower energy extraction rate, which will allow the resource to last longer and help achieve an overall lower levelized cost of heat (LCOH). For most cases analyzed for on-site heating (Section 6), a value of 1,100 GPM is targeted, which essentially represents the January average load amount, and per Figure 8, remains significantly below peak requirements (and their associated high cost.)

Building Efficiency Assessment

The Energy Use Intensity factor is a measure of energy efficiency for a building, and is a measure of the energy used per square foot for an entire year. It can be seen in the data given in Tables 1 and 2 that the energy used in the oldest buildings is sometimes four times higher than in the newer buildings, such as the Operations Building RTI 1001A. Since the Barrack facilities date back to the pre-World War II era, they are likely to be uninsulated or poorly insulated, and not using energy as efficiently. This disparity in energy efficiency indicates that there is a great opportunity to improve the energy efficiency of some of the buildings in the hydronic group. From the viewpoint of the geothermal resource usage, enacting energy efficiency measures will allow the life of the wells to be extended, and for either geothermal or CHP based systems, could also allow for a smaller sized system to be installed.

Energy Use for Domestic Hot Water and Cooking

The use of Camp Dawson as a training center results in a higher use of natural gas for domestic hot water and cooking. In addition, the Mountaineer Challenge Academy has more than 150 students plus staff that regularly use domestic hot water for showers and cooking. There are 500 hotel rooms and efficiency apartments where the onsite staff reside. The occupancy rate for the hotel at any one time varies with 80 percent being a typical occupancy rate. The demand for natural gas, which includes its use for domestic hot water and for cooking, may be seen in Figure 3 where during the summer months there are no space heating demands. However, the domestic hot water demands are greatest during the warmer months from May to October when most training takes place. During the winter months the domestic hot water demand is less due to the reduced occupancy at the camp, which consists of the Mountaineer Challenge Academy and the permanent staff on the base.

The high-use period occurs from May until September, when the hot water demand is estimated to be approximately 22,750 gallons of 120°F water. Cooking would require 2,925 gallons of 140°F water per day. Together, this amounts to 542 MCF of natural gas use per month during the summer. This energy could also be provided by the geothermal well system when the demand for space heating is not present.

During the winter period, Camp Dawson has a much reduced occupancy consisting of the permanent staff and the Mountaineer Challenge Academy. This reduced occupancy results in a lower demand for hot water and cooking of 9,875 gallons per day, which would require 173 MCF per month of natural gas. This amounts to 4,292 MCF per year, which is approximately 10 percent of the total natural gas usage for the generation of hot water. Some natural gas is also used in cooking equipment such as stove burners and ovens (and this quantity is not in the 4,292 MCF total), but the amount is relatively small in comparison.

2.4 POTENTIAL GROWTH AT CAMP DAWSON

The Mountaineer Challenge Academy has plans to add a 100,000 ft^2 dormitory facility in the future. The hot water required for this additional space would be approximately 175 GPM at the peak winter design load based on a comparison to the new A1000 and Operations Building. While this magnitude of increase is not likely to dictate which technology or technologies are considered in future follow-on studies, it should be considered when developing the final solution toward meeting on-site energy demands.

3. GEOTHERMAL AND NATURAL GAS RESOURCES AT CAMP DAWSON

Physiographic Setting

Camp Dawson is located on the floodplain of the Cheat River, near the town of Kingwood, West Virginia. In the vicinity of Camp Dawson, the Cheat River runs northeast on a bearing of around N45E. The river is a regional drainage way. It averages about 250 feet wide and 2 feet deep. In this region, the Cheat River has carved a deep, steep-walled valley. The floodplain is narrow, ranging up to a few thousand feet in width, and at the Camp the floodplain is at an elevation of approximately 1,240 feet. To the east, the valley walls rise to a ridge crest that averages nearly 1,800 feet in elevation locally and trends about N30E. To the west, the valley walls are less high, rising to elevations around 1,650 feet. Overall, topography further to the west averages around 1,800 feet in elevation, whereas further to the east it mostly exceeds 2,000 feet in elevation (with ridges over 2,800 feet). Camp Dawson's main campus is positioned on a long, narrow strip of floodplain, 6,800 feet long and a maximum of 2,700 feet wide on the east side of the river. There is also a narrow strip (1,200 feet wide maximum) of active floodplain across the river from the main camp area. Some of the WVNG property and facilities are located on the west side. The geometry and orientation of the land parcels (including areas in which mineral rights are held) affects the placement and possible orientations of wells; the topography affects the geothermal gradient beneath Camp Dawson.

For purposes of estimating local geothermal gradients, the ground temperature must be estimated at depths of about 100 feet. The average annual temperature of the air above the ground surface closely matches the shallow ground temperatures in most places; therefore, weather data is used from a nearby weather station or reporting locality. For the required data, the reporting locality most similar to Camp Dawson is Albright, West Virginia. Albright is located a few miles downstream from Camp Dawson, and is situated in almost the same topographic setting and almost the same elevation. Two different websites were found to report average annual temperatures for Albright. USA.com (7/31/2016) reports an average annual temperature of 51.1°F, whereas WeatherDB.com (7/31/2016) reports an average annual temperature of 51.35°F. For this report, 51.1°F will be used for the temperature at shallow depths beneath Camp Dawson.

Overview of the Geological Structure, Sedimentary Rock Strata, and Geothermal Gradients Beneath Camp Dawson

West Virginia and Camp Dawson are within the confines of the Appalachian Basin, a large structural trough containing a thick sequence of sedimentary rocks and having its long axis trending northeast to southwest. To the east of Camp Dawson, there are the highly faulted and folded sedimentary rock layers of the Allegheny Mountains. To the west of Camp Dawson, the folding and faulting is much less intense. Total sediment thickness in this part of the basin may exceed 22,000 feet, containing mostly shale, sandstone, and limestone. Several formations are likely to yield natural gas, and some may be favorable for the withdrawal of geothermal heat. Generally, permeability within the sedimentary rock layers decreases with depth.

A generalized vertical stratigraphic column (Figure 10) and structural cross sections (Figures 11 and 12) show the various names, approximate depths, and estimated minimum (uncorrected) temperatures of the rock layers beneath Camp Dawson. The subsurface structure may be complex due to the camp's position between the moderately deformed strata to the west

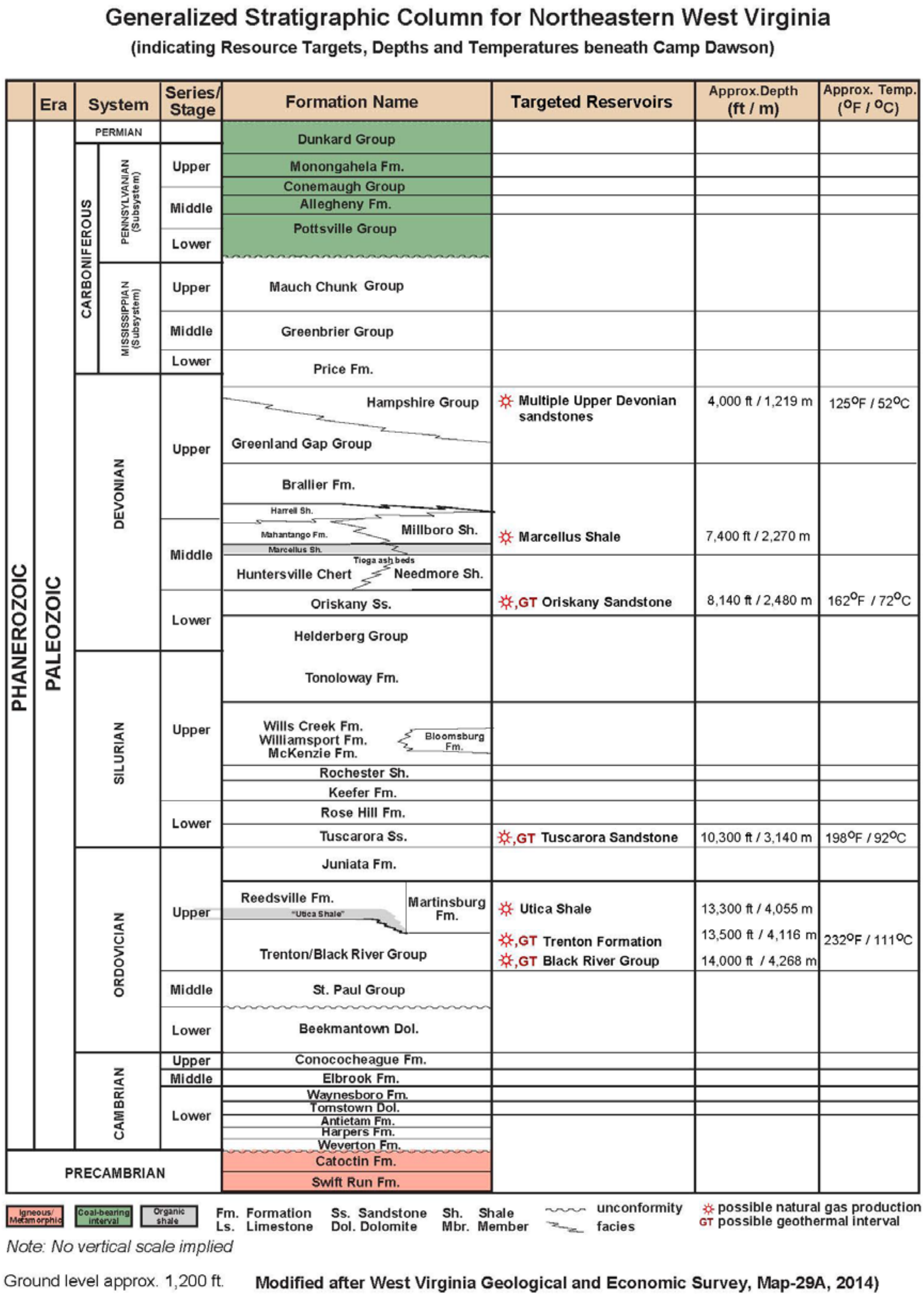

Figure 10: Generalized stratigraphic column for eastern West Virginia, including Camp Dawson. Temperatures estimated from WVGES Interactive Mapping Portal maps.

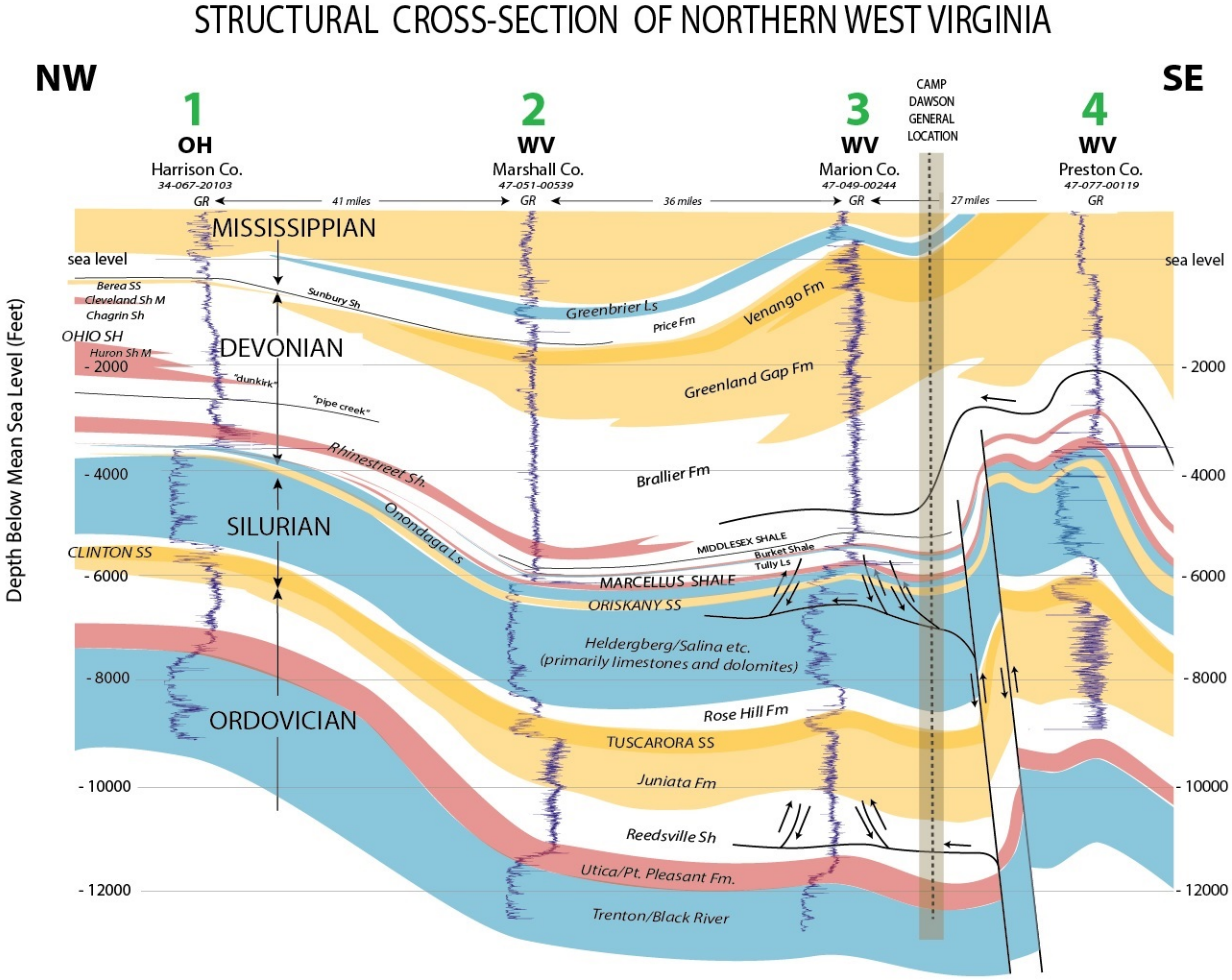

Figure 11: Simplified cross section oriented generally west to east from Ohio through Preston County, West Virginia. This cross section shows strata chosen for both geothermal and natural gas resource assessments in this report. Yellow indicates sandstone-dominated strata, blue indicates limestone-dominated strata, and red indicates organic-rich shales (natural gas source rocks).

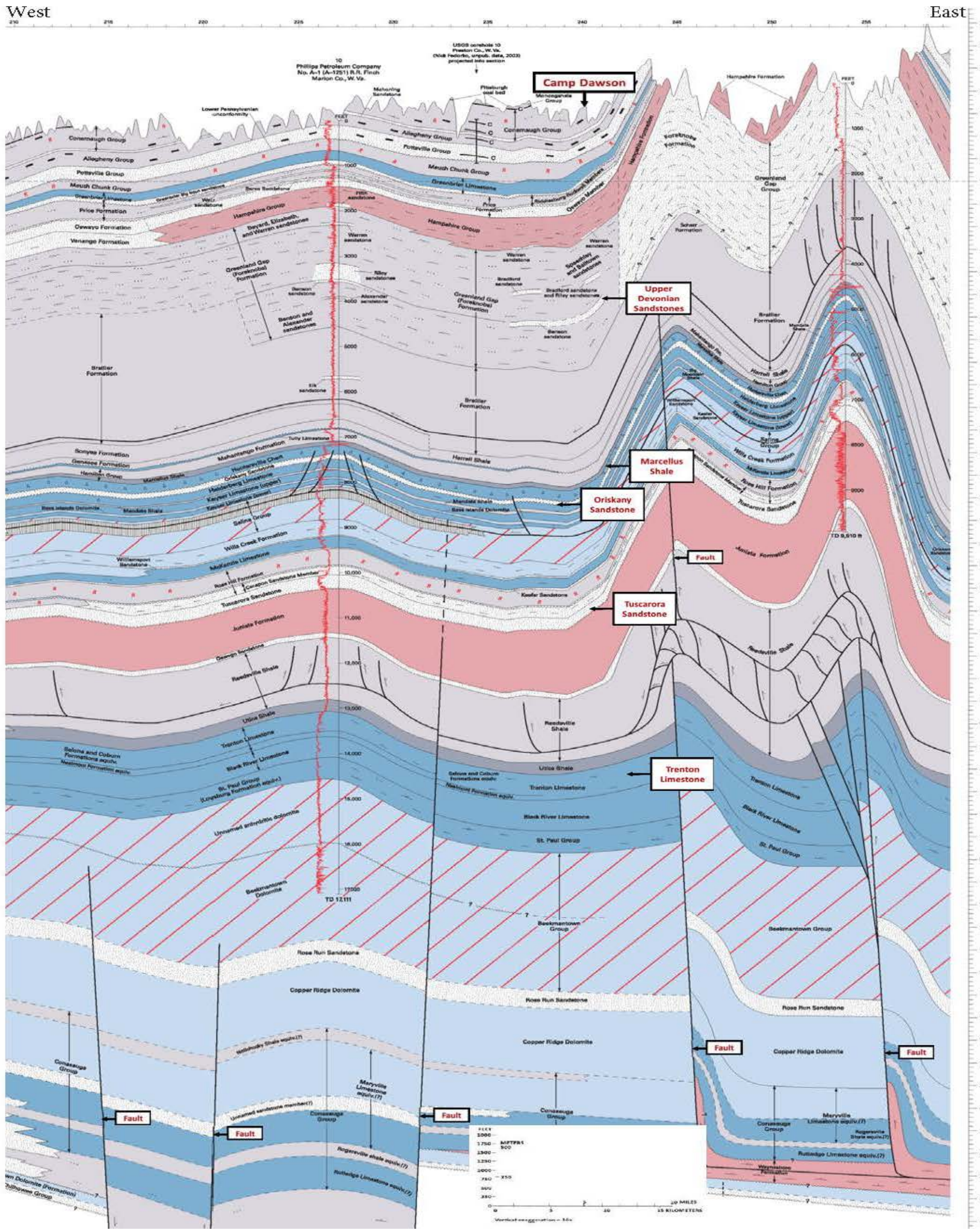

Figure 12: Structural cross section near Camp Dawson area (Ryder et al., 2009). (Modified from USGS Scientific Investigations Map 3067, 2009)

and the more intensely deformed strata to the east. Tectonic events long ago pushed the sedimentary layers westward, creating folds, faults, and fractures in the rock layers. Pressure associated with the depth of burial and the tectonic events affected the rock, causing compaction, deformation, and pressure solution of the mineral grains in the rocks, with the result that the original intergranular permeability was greatly reduced. However, faults and fractures, if not completely filled with minerals, can act as additional conduits for fluid flow. Hydrothermal fluids may migrate in the subsurface both vertically and laterally. Depending on the composition of the fluid, and the type of rock the fluid encounters, rocks may become hydrothermal reservoirs because of the dissolution of mineral grains, which leads to the development of secondary porosity and permeability. Hydrothermal fluids may also destroy these reservoir qualities by the precipitation of minerals. A method to interpret the subsurface structure (i.e., to identify the folds and faults with larger offsets) is to evaluate data from surrounding wells and construct geologic maps. Such mapping is limited by available data density, and provides only a regional picture. To better predict details of the geologic conditions beneath Camp Dawson, WVNG could access or acquire a seismic survey. This would allow a geologist to interpret the orientation of target strata, as well as predict within these strata the location of faults and possibly even swarms of open fractures. This is especially important if horizontal wells need to be drilled through a specific portion of a reservoir.

In Figure 10, the potential reservoirs for geothermal heat are labeled with estimates of the corresponding depths and temperatures. These reservoir temperature estimates are based on information from the website of the West Virginia Geological and Economic Survey (WVGES) and in this report are considered the minimum temperatures likely to be found in these reservoirs because necessary corrections have not been applied in the making of the WVGES maps. Geothermal gradients indicated in the geologic literature vary considerably for the region around Camp Dawson (see Appendix H). Higher gradients were reported in recent years (2010 to present; see Frone and Blackwell, 2010) by researchers associated with SMU. While the most recent work by researchers at SMU is likely to be the most accurate because of the rigor in their analyses (see Frone et al., 2015), it has not been confirmed with equilibrium temperature measurements in any deep wells (> 8,000-foot depth with measurements in the Oriskany or deeper strata) located within the most elevated heat flow region. Thus, the temperature in each target stratum beneath Camp Dawson is uncertain. Accurate formation temperatures beneath Camp Dawson will only be obtained when a well is drilled and appropriate temperature measurements made.

Temperature mapping by the WVGES (on-line mapping portal, see Appendix H) for the Camp Dawson area is based on temperature data from wells located to the east in an upland area (e.g., south of Terra Alta, WV) and to the west at elevations higher than Camp Dawson. While the WVGES made efforts to use the best temperature measurements from deep boreholes (holes bored thousands of feet deep), WVGES did not correct the measurements for the cooling that occurs during drilling while cooler drilling fluids circulate from the ground surface to the bottom of the well to push out the cuttings. Furthermore, none of the wells used to map the geothermal gradients near Camp Dawson were located in the deep narrow valley where Camp Dawson is located. The wells are located in nearby upland areas that average 1,000 feet to 1,700 feet higher in elevation to the east, and 400 feet to 900 feet higher to the west of Camp Dawson. Modeling of the effects of the significant topographic variation across this region was not performed by WVGES, but would result in higher estimates of the geothermal gradient beneath Camp Dawson (Lachenbruch, 1968).

WVGES also did not account for the thermal properties of the rock layers, the effects of folds and faults, and perhaps other effects that could change the local geothermal gradient. Many of these effects were included in the most recent work at SMU. While the most recent SMU work partially retracts their previously published descriptions of the magnitude of the geothermal hotspot in east central West Virginia, it still affirms a substantial geothermal anomaly in parts of east central West Virginia, and this likely includes the Camp Dawson area. Figure 13 from Frone et al. (2015), suggests temperatures beneath Camp Dawson may approach 194°F (90°C) in the Oriskany, 230°F (110°C) in the Tuscarora, 254°F (123°C) in the Oswego, and 284°F (140°C) in the Black River limestones. SMU's modeling is for a traverse 9 miles south of Camp Dawson, so gradients may be less beneath Camp Dawson.

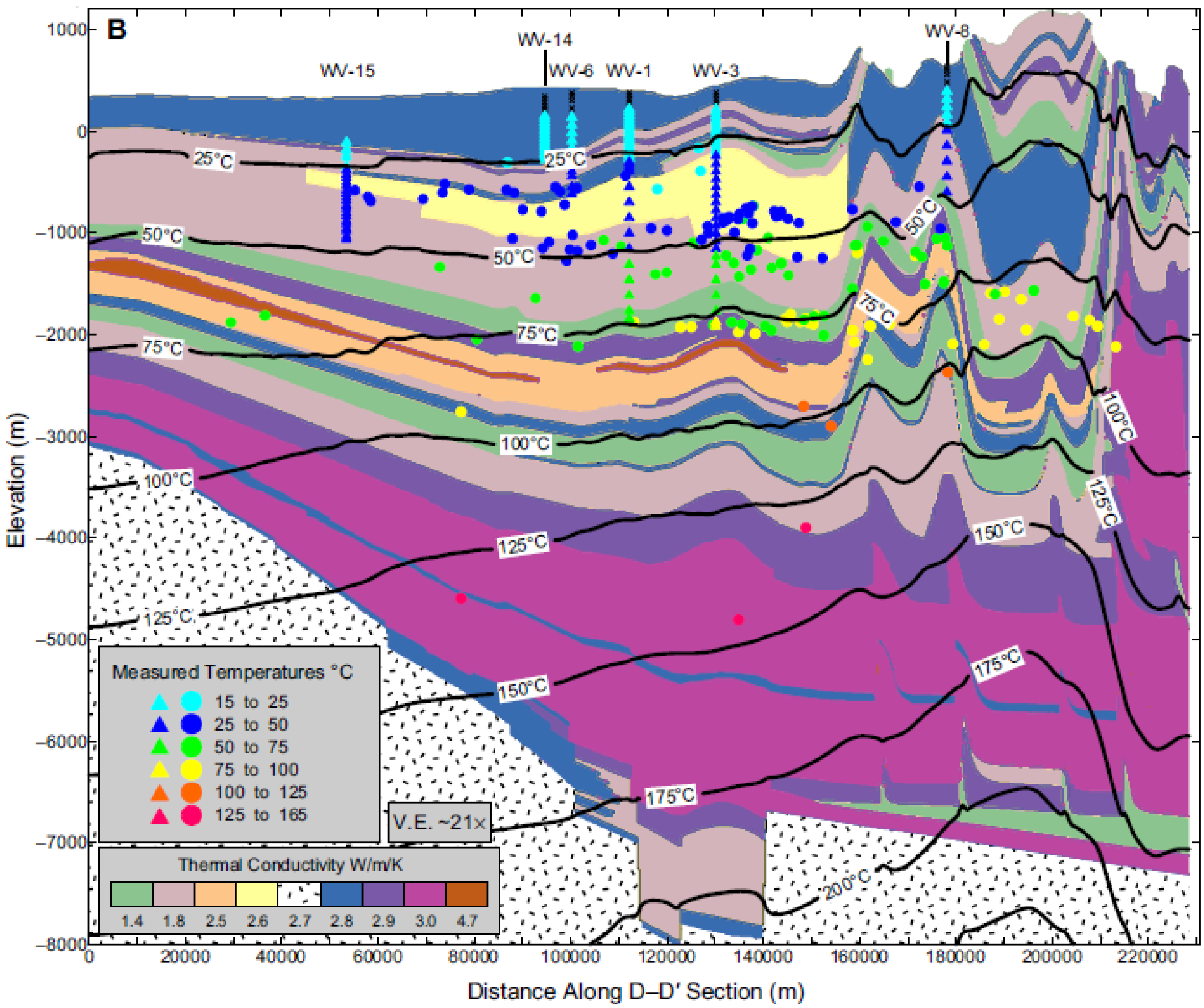

Figure 13: Geothermal gradients as modeled by Frone et al. (2015), on the cross section of Ryder et al. (2009). This cross section is oriented generally west to east and passes Camp Dawson to the south about 9 miles. Temperatures at depth may be slightly less beneath Camp Dawson.

Camp Dawson is located in the transition area (between the complex folding and faulting to the east and the less intense deformation to the west), which may be favorable for finding either geothermal or natural gas reservoirs with permeability created by natural fractures, but which may also be unfavorable due to natural drainage of the natural gas. Both the folds and faults may affect deep subsurface flow patterns for hydrothermal waters, as well as the local geothermal gradients, adding to the complexity in estimating both the temperature and the permeability within the target zones beneath Camp Dawson.

At depths of interest for geothermal resources (greater than 8,000 feet), fractures and faults often provide the best flow pathways for water and brine. Cores and fracture detection logs from deep wells, along with the analysis of reservoir and aquifer performance, have all indicated the presence of fractures in the deep rock layers with the densities varying from layer to layer and varying laterally within the layers. These fractures commonly provide the dominant flow pathways near wells. In a study of a natural gas field located to the south of Camp Dawson, NETL (McKoy, unpublished notebooks) found that fractures in the reservoir had orientations similar to those reported by others for fractures observed in surface exposures of rock throughout the region. In this gas field, a fracture detection log from a horizontal well in the Oriskany Sandstone had a dominant set of fractures oriented N83E (North 83° East), interpreted to have formed before the folds in the rock layers. This was a moderate density set but was not sufficiently open or interconnected to control the gas flow directions in the reservoir. Another dominant set of fractures paralleled the fold axes and major thrust-fault planes. These fractures are believed to be at low density in most places, but were observed to have a high density near fold axes and faults (both normal faults and thrust faults). These tended to dominate the gas flow within the reservoir, presumably because they are more open. In the reservoir, there were a moderate density set of fractures perpendicular to the N83E set and a set of low-density fractures oriented about N124E (interpreted as local tectonic fractures that helped to accommodate folding and lateral displacement of the sedimentary layers). These latter two sets did not seem to dominate flow directions but did appear to allow important cross flow between the more dominant fractures paralleling the fold axes. Because of the regional nature of these fractures, they are likely to be found in the strata of interest beneath Camp Dawson, only their densities and conductivities will not be known until a horizontal well is drilled (and logged) into the rock layers of interest beneath Camp Dawson. Wells drilled beneath Camp Dawson, particularly those intended to extract geothermal heat, will need to be designed to best utilize the natural permeability of the strata, especially any open natural fracture sets.

Although natural gas may be found at several intervals below 2,500 feet, only formations below 8,000 feet are considered for supplying geothermal heat since it has been determined that a minimum water temperature of 180° F is preferred at the point of use during peak demand. A brief description for each of the prospective reservoirs, listed by depths from shallow to deep, capable of producing either natural gas or hot water (sufficient for space heating) are discussed below.

Overview of Stratigraphy of Interest

2,500–4,000 feet (762–1,219 m) – Upper Devonian Sandstones: These shallow sandstones have produced significant quantities of natural gas 25 miles to the west in both Monongalia County, West Virginia, and to the north in Fayette County, Pennsylvania. The quality of the reservoirs, however, gets poorer to the east, as evidenced by the lack of wells drilled this far east of the productive fairway. It is unlikely that sufficient volumes of natural gas will be found in this interval.

7,400–7,500 feet (2,256–2,286 m) – Marcellus Formation (shale): Over the past 10 years, thousands of Marcellus wells were drilled in West Virginia and Pennsylvania. The western side of the productive trend (WV/OH border, PA/OH border) produces considerable NGLs. In Preston County, due to the higher maturation of the hydrocarbons in this eastern portion of the basin, production from the Marcellus shale will be dry natural gas (i.e., only methane). Structure (folds and faults) maps (e.g., Figure 14) indicate that the Marcellus is expected to occur at a depth of about 6,200 feet below sea level or about 7,400 feet below the land surface at Camp Dawson. An isopach (thickness) map of the organic-rich portion of the Marcellus shale (Figure 15) shows an expected thickness of 70 to 85 feet for the Camp Dawson site. This range is consistent with the shale's thickness in the productive areas of western West Virginia and Pennsylvania.

Figure 16 is a map of Preston County showing the locations of wells having available production data from the Marcellus Shale. The first 12 months of production, in million cubic feet (MMCF), for each well is given next to the well's location. Note that there is a large variation of first year values for the wells. This may be due to a well only being drilled and produced vertically, a short lateral drilled through the reservoir, a mechanical failure, or simply a location in an area with poorer production. However, it is encouraging that some of the better producing wells are along the structural trend to the northeast of Camp Dawson.

A generalized production decline curve (Figure 17) was constructed for the local Marcellus formation from the 11 most recent wells with production data. This graph represents initial production from a Marcellus well with a horizontal lateral of 4,000+ feet (estimate based on the drilling dates) in length. Because of the lower productivity of natural gas in this region, this graph is not representative of the more productive wells located further west in the Marcellus play. According to this generalized curve, the production rate does not fall below the average annual natural gas use rate at Camp Dawson (40,350 MCF) until about Year 9. However, the production in Years 1 through 8 greatly exceed the current demand at Camp Dawson. The sum of the production during years 1 through 9 (1,234,000 MCF) equals Camp Dawson's current use rate for approximately 30 years (assuming the excess gas is not sold). The total 30-year resource is estimated at more than 1,400,000 MCF.

Due to the shape and small size of Camp Dawson's main parcel of property, a maximum length of 2,000 feet for a well lateral is expected, keeping the well within the boundaries of the parcel and orienting the well lateral in a northwest direction. A 2,000-foot lateral would be expected to yield about half as much natural gas as a 4,000-foot lateral (i.e., only 700,000 MCF over its life span). If this is the case, about 50 percent of the production shown on the graph is likely to be produced on an annual basis. This lower production rate would supply the Camp's current natural gas needs (as described in Section 2) for about 15 years before another well would need to be brought into service if 100 percent self-sufficiency is to be maintained. There would still be production from the first well for at least 7 more years although at lower rates. The remaining production from the first well would supplement the production from a new second well and would extend the life of the second well to about 17+ years after it is brought into production, assuming no overlap of the drainage areas of the two wells. Under this simple analysis, two horizontal wells with laterals 2,000 feet in length could supply Camp Dawson's current needs for about 32 years in aggregate, whereas two wells with 4,000-foot laterals could supply Camp Dawson's current needs for about 65 years. If natural gas is used to generate electricity in addition to space heating, the years of service would be much less and dependent upon the efficiency of the energy conversion system. A second gas well would be drilled parallel to the first well throughout its horizontal extent and located 750 feet to

1,000 feet to the southwest (or northeast, depending on placement of the first well) with a similar length for the well lateral.

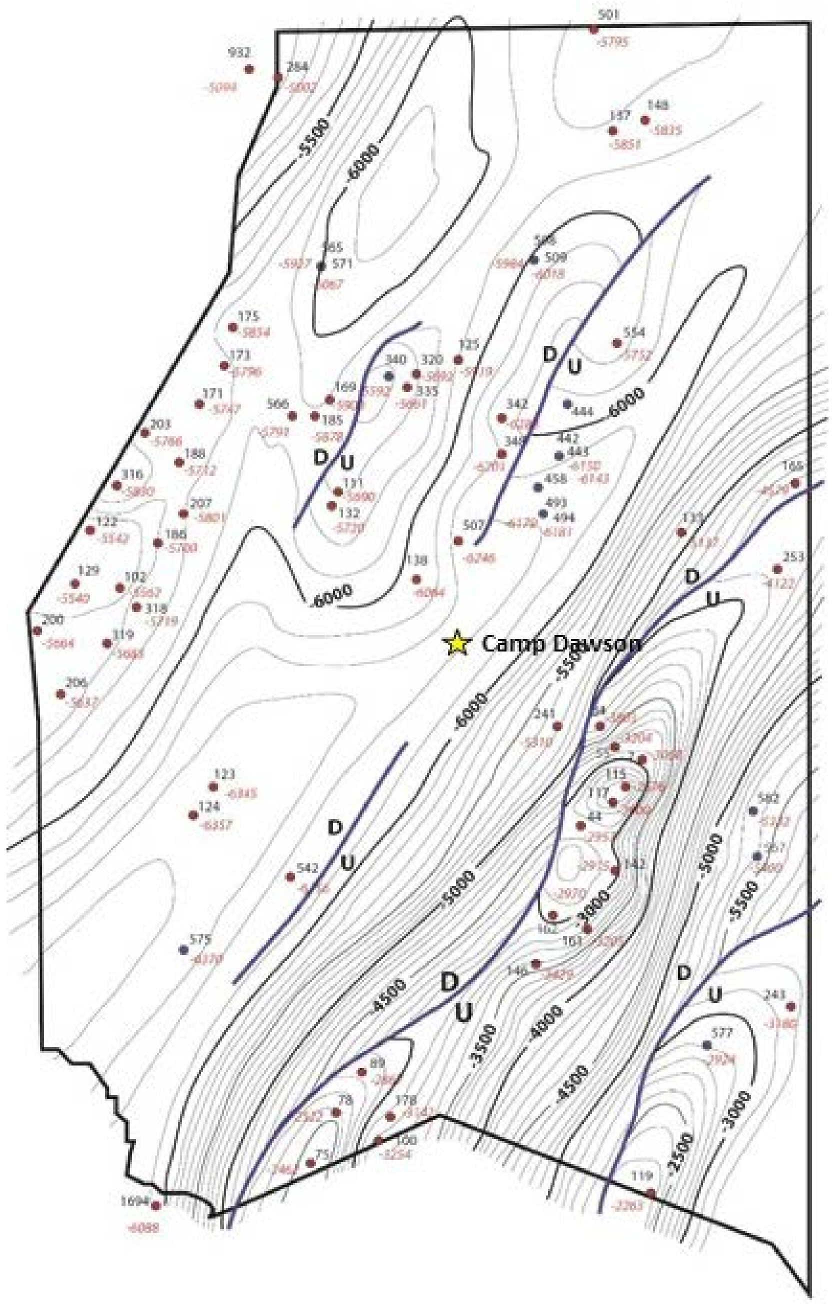

Figure 14: Structure contour map of the Marcellus formation in Preston County, West Virginia: Location of known faults in the Marcellus and elevation (below sea level) of the upper surface of the Marcellus formation. Red dots are the wellhead locations of vertical wells, and blue dots are the wellhead locations of horizontal wells. According to this map, the top of the Marcellus is at a depth of about 7,440 feet below ground surface at Camp Dawson.

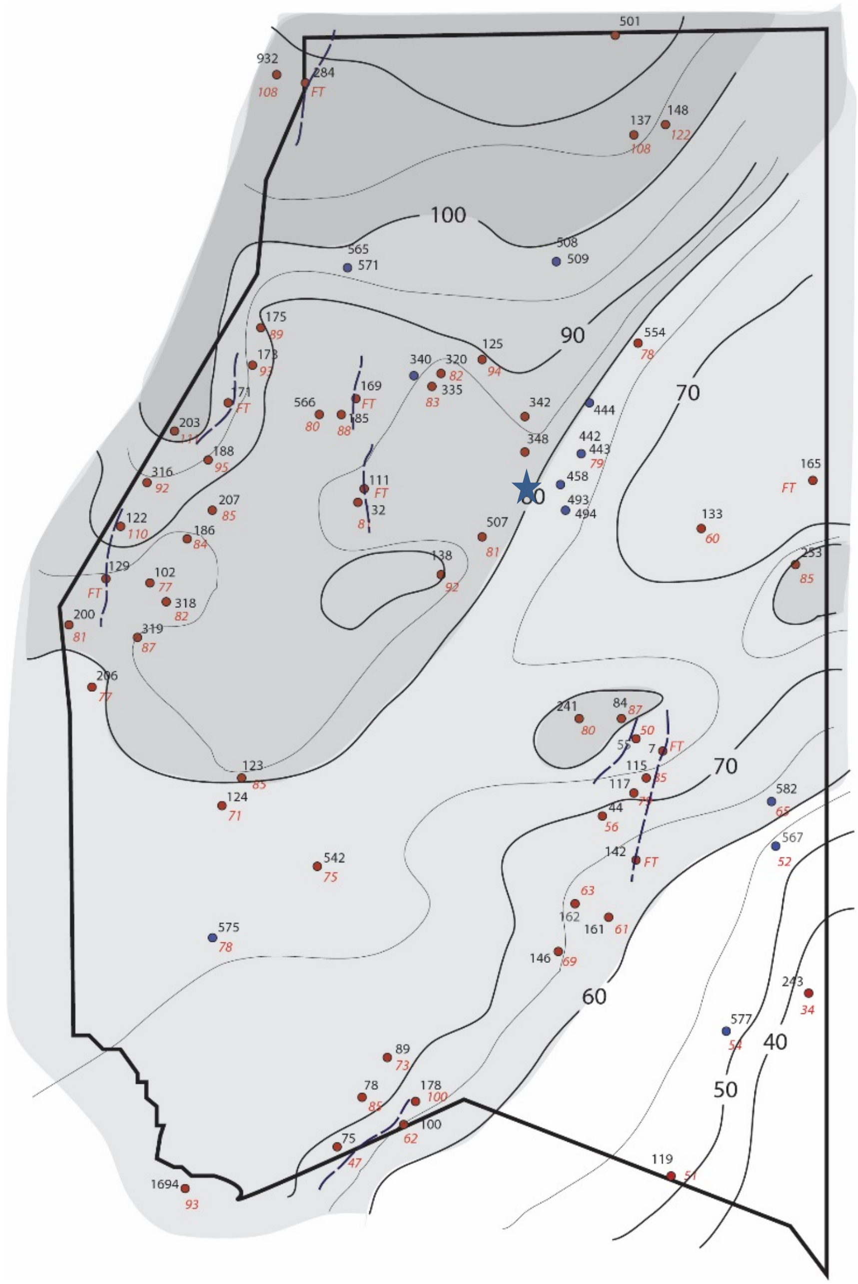

Figure 15: Isopach (thickness) map of the organic-rich shales within the larger Marcellus formation, Preston County, West Virginia. Mapping excludes wells (marked as "FT") where the Marcellus thickness is exaggerated due to fault duplication at the Marcellus level.

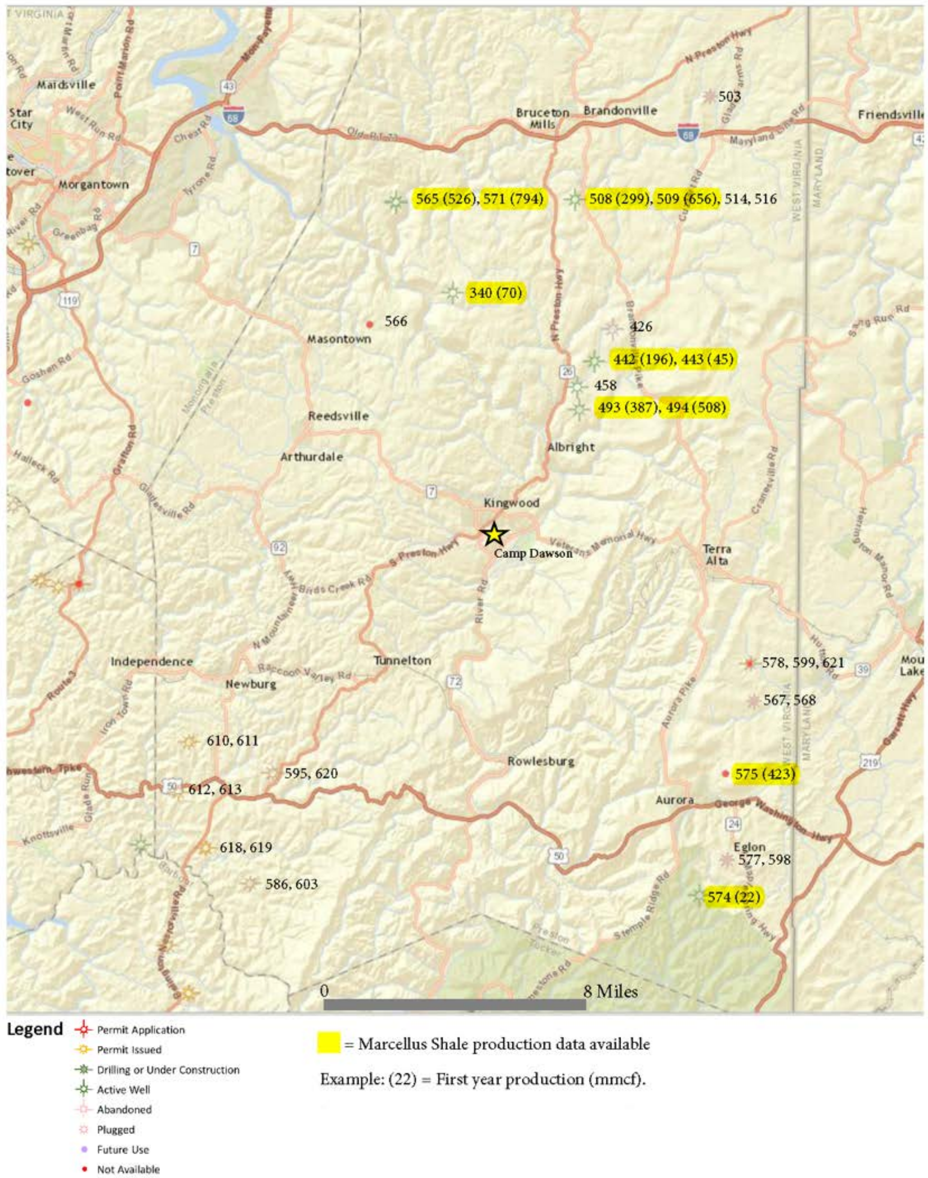

Figure 16: Marcellus Shale map showing wells with production data available. (Well locations and data obtained from WVDEP http://tagis.dep.wv.gov/oog/)

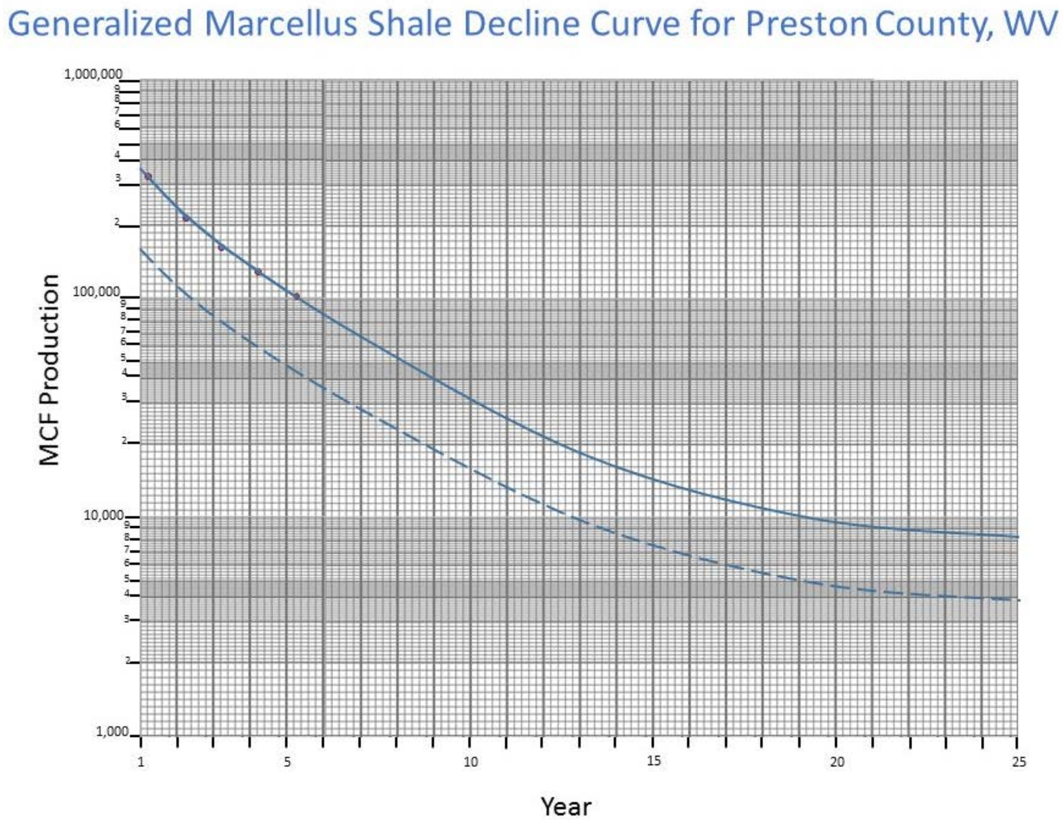

Figure 17: Generalized natural gas production decline curve for a Marcellus Shale well in Preston County based on a 4,000-foot horizontal wellbore. The dashed curve represents the decline for a 2,000-foot horizontal wellbore. Data was generated based on available production data spanning five years.

If the longer lifetime noted above is important to Camp Dawson, it may be possible that the adjoining subsurface natural gas rights to the west can be leased from the mineral owners to allow 4,000 feet or longer laterals to be drilled. The properties could be unitized, and each mineral owner could receive their pro rata royalty share in cash or natural gas. Alternatively, the natural gas rights of adjoining parcels could be purchased in fee.

7,500–7,700 feet (2,286–2,347 m) – Huntersville Chert and Oriskany Sandstone: The Oriskany Sandstone has produced natural gas from several small fields within Preston County. The closest field is the Terra Alta Field located about 6.6 miles (straight line distance to the compressor station) east-southeast of Camp Dawson. It was discovered in 1944 (William E. Snee No. 1. J.F and H. Sisler well) on a subsurface structural high (anticline). There were a total of 60 wells drilled, 40 of which were productive. The Oriskany Sandstone and overlying Huntersville Chert were found to be faulted and fractured, which enhanced the production from the field. The field has since been converted to natural gas storage.

The structure (folds and faults) at the top of the Oriskany Sandstone is expected to be similar to that shown for the Marcellus in Figure 14. As seen in this figure, Camp Dawson overlies a structurally low (synclinal) area. The Oriskany Sandstone is one of the potential geothermal reservoirs of interest. Note that the faults trend northeast-southwest. The dominant direction of open natural fractures is likely to be the same. Furthermore, this direction is likely to be approximately the direction of any hydraulically created fractures. This is significant when laying out drilling locations. Drilling wells perpendicular to the faults and fractures (i.e., drilling northwest-southeast) allows for the horizontal wellbores to intersect the maximum number of open natural fractures.

Drilling depths to reach the Oriskany Sandstone would be around 8,140 feet and its thickness is expected to be in the range of 100 feet to 140 feet. It is a clean, low-porosity sand, with the most permeable zone located near the top of the layer (Figure 18 shows the distribution of slightly elevated porosity). Underneath is clean limestone of the Helderberg Group; above is the Huntersville Chert (a siliceous layer).

Since the Huntersville Chert and Oriskany Sandstone are located in a structurally low position, any gas production found will likely be in uneconomical quantities. However, these formations will likely contain water and may be used for a geothermal supply of relatively low temperature water. The water temperature in the Huntersville Chert and Oriskany Sandstone interval is expected to be at least 160^{o} F (actual temperatures are likely to be higher). Based on SMU's rigorous modeling of geothermal data for the cross section shown in Figure 12, Frone et al. (2015), indicate in Figure 13 a temperature around 194°F in the Oriskany at a location about 9 miles south of Camp Dawson. Although most of the hydronic heating requires a water temperature of at least 135°F, during peak demand periods in the winter, a water temperature of 180°F is needed for one building. If this depth is chosen and the temperature is found to be only 160°F, a supplemental heat source from natural gas or another energy source would be required. Furthermore, the period of geothermal heat mining to deliver 135°F water to buildings would be relatively a few years. If heat storage is practiced as part of a CHP system, the Oriskany could be a good choice for heat storage and geothermal assist.

Based on anecdotal evidence and experience, NETL's geologists expect the Oriskany formation to have a better chance than other strata of containing intergranular porosity and permeability (whether original or created through dissolution of mineral grains and grain cements) sufficient for geothermal heat extraction (if the temperature of this formation is adequate). Figure 18 shows a series of well logs across central Preston County for which slightly higher porosity zones appear to be semi continuous locally. Most of the formation appears to have minimal porosity (and presumably very low permeability), with a few zones having more modest porosities of around 4 percent but ranging up to perhaps 8 percent in a few thin layers (based on interpretation of these logs). Higher porosity tends to correlate positively with higher permeability. The Oriskany, however, is notorious for varying greatly in its permeability over very short horizontal distances, primarily a result of spatially varying precipitation and dissolution of carbonates between the sand grains (e.g., Kostelnik and Carter, 2009). It may also have significant permeability along faults and fracture zones. The oil and gas industry has found faults and fractures to be the source of sufficient permeability in several anticlines across this region to permit the Oriskany to be used as commercial storage fields after the initial gas production was depleted. The previously mentioned Terra Alta gas storage field is one example.

About 45 miles south of Camp Dawson, there is another example of a gas storage field that exists because of the extra permeability associated with open fractures concentrated around fold axes and faults. Permeability of the unfractured rock averages 0.01 milli-darcys (md), while the bulk permeability of the reservoir averages around 10 to 20 md (fractures plus matrix), but within fracture zones, the bulk permeability is about 200 md. The porosity of the unfractured rock averages only 0.3 percent (core measurements), while the bulk porosity of the reservoir is 2 to 3 percent for purposes of gas storage (total porosity would be higher).

Similar porosities and permeabilities are reported or suggested by Kostelnik and Carter (2009) for neighboring counties (e.g., Fayette and Somerset) in Pennsylvania. They stated, “Neutron- and density-porosity logs were evaluated from 13 wells in Pennsylvania and West Virginia. Total porosity values range from 1.8 to 7.2 percent, with an average porosity of 4 percent. If matrix porosity (as determined by sonic logs) is known along with total porosity, the fracture porosity of the reservoir can be determined.”

Permeable fractures intersected by a well are susceptible to partial obstruction by drilling muds during the drilling process, so careful control of mud weight and substantial cleaning of the well bore is needed when the well is completed. Gas storage fields have been developed along anticlinal axes where the permeability has been found to be much higher than on the limbs of the folds, raising questions about whether permeability may be found lower on fracture limbs and in synclines (where Camp Dawson is positioned). Furthermore, the lack of water drive in at least some of these Oriskany fields further suggest that fracture permeability is a local phenomenon.

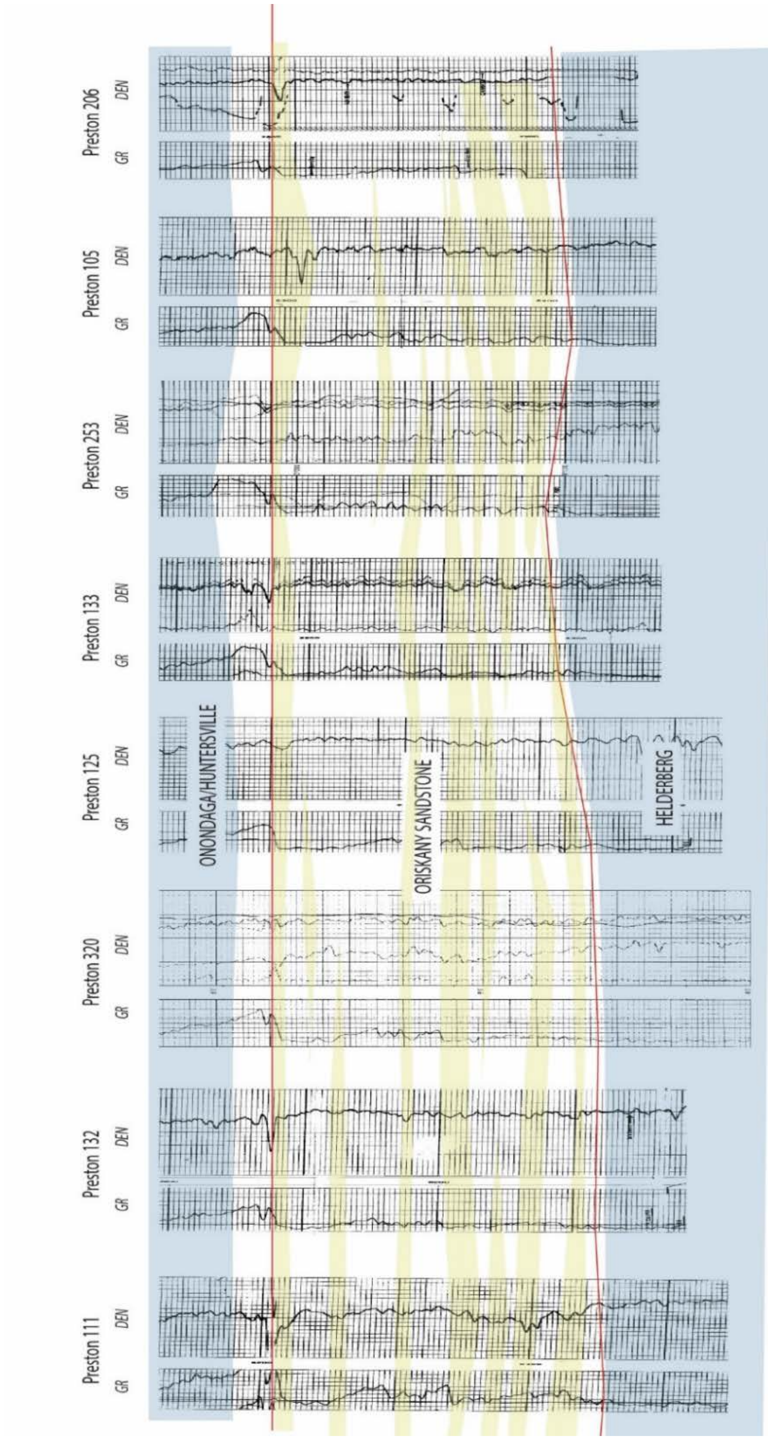

Figure 18: Correlation of porosity zones in the Oriskany Sandstone, as observed in well logs from several wells across central Preston County, West Virginia. Oriskanyis 120–140 feet in thickness. Porosity is poorly developed with much of the unit at 0 to 1 percent. Up to 8 percent porosity in thin zones near the top of the unit (P105; P206). These may be poor log resolution of fractures. Numerous thin zones throughout with porosity up to 4 percent. Well logs from WVGES.

10,300–10,800 feet (3,139–3,292 m) – Tuscarora Sandstone: The Tuscarora sandstone has been the target of natural gas exploration and production in West Virginia, including Preston County. It has a reputation of having low porosity and permeability (e.g., Kramer, 2013) due to pressure solution of the sand grains and the filling of remaining intergranular space with silica cements. Sublayers of very clean sandstone retain some porosity and permeability, perhaps only locally, and therefore contribute to the production of natural gas. This production has occurred along anticlines with fracture-enhanced permeability (Avary, 1996), such as the Leadmine gas field in southern Preston County (Ryder and Zagorski, 2003). The more intensely folded and faulted Allegheny mountain province, to the east of Camp Dawson, may have the best reservoirs because of a greater intensity of fracturing (Wescott, 1982). Figure 19 below from Kramer (2013) indicates a total thickness of 400 to 450 feet in the vicinity of Camp Dawson. Figure 20 also from Kramer (2013) indicates the Tuscarora's best permeabilities and porosities are in northeast West Virginia, including the Camp Dawson area. Kramer (2013) found the upper Tuscarora has more porosity than the middle and lower subunits, although Kramer (citing Mitra, 1988) notes that the position of a well in the Tuscarora relative to the fold axes may be important for fracture intensity, which he claims is also factored in the porosity estimates for his map. If true, porosity and permeability in the synclines could be much lower than the map indicates. Kramer (2013) gives temperature information for the Tuscarora, although this information is averaged across West Virginia and, therefore, not useful for our purposes. Avary (1996) found vertical permeability ranges from 0 md to 12.2 md and horizontal permeability ranges from 0 md to 10.7 md in the Leadmine gas field of southern Preston County and northern Tucker County. Geologic structures seem to play a dominate role in gas production (and permeability) in the Leadmine field, with significant variation occurring in short distances.

An exploratory vertical well drilled in western Preston County by Cities Service (#1-Q U.S.A.) from 1963 to 1964 encountered 459 feet of Tuscarora Sandstone with several intervals flowing natural gas. After a 7-inch casing was installed and perforated, the well flowed 16,300 MCF, a significant natural flowing rate given that the formation was not treated with acid or hydraulically fractured. Although no production figures are available from the WVGES, it is assumed the production was short-lived because no other wells were subsequently drilled near this well.

A core report from the Cities Service well includes test data from selected portions of the reservoir. Twelve samples over a 139-foot interval had an average porosity of 4.7 percent and a permeability of 3.2 md. Both of these values are sub-marginal for a geothermal reservoir to circulate adequate volumes of water for hydronic heat. However, these measurements were on core, rather than on the reservoir where natural fractures can contribute to the permeability. Based on the initial large flow rate of gas within the top 141 feet of the reservoir, it is likely that the gas flowed from natural fractures within the sandstone. It is possible that natural fractures can supply enough permeability for effective heat extraction; if not, natural fractures can be hydraulically enhanced and new fractures induced hydraulically.

A reservoir temperature of at least 190°F is anticipated (note: higher temperatures are likely, as indicated in the next subsection) in the Tuscarora Sandstone, which is slightly above the 180°F needed to supply all of the current hydronic heating needs at Camp Dawson. Based on SMU's rigorous modeling of geothermal data for the cross section shown in Figure 12, Frone et al. (2015), indicates a temperature around 230°F in the Tuscarora at a location about 9 miles south of Camp Dawson. If the Tuscarora beneath Camp Dawson is actually 230°F, it could meet the space heating needs at Camp Dawson for a considerable period of time if a sufficiently large volume of reservoir can be heat mined efficiently.

Due to the typically poor intergranular permeability and unproved natural fracture permeability, it is assumed that two vertical wells would be insufficient and either two horizontal wells or four vertical wells need to be drilled and hydraulically fractured to establish the required flow rate for hot water. In terms of permeability, the Tuscarora is perhaps the next best target compared to the Oriskany – and it is sure to be hotter. It is possible that the Tuscarora will be too hard for horizontal drilling at reasonable costs. In this case, strata below the Tuscarora, most likely the Oswego sandstone, could be tested and drilled for geothermal heat extraction

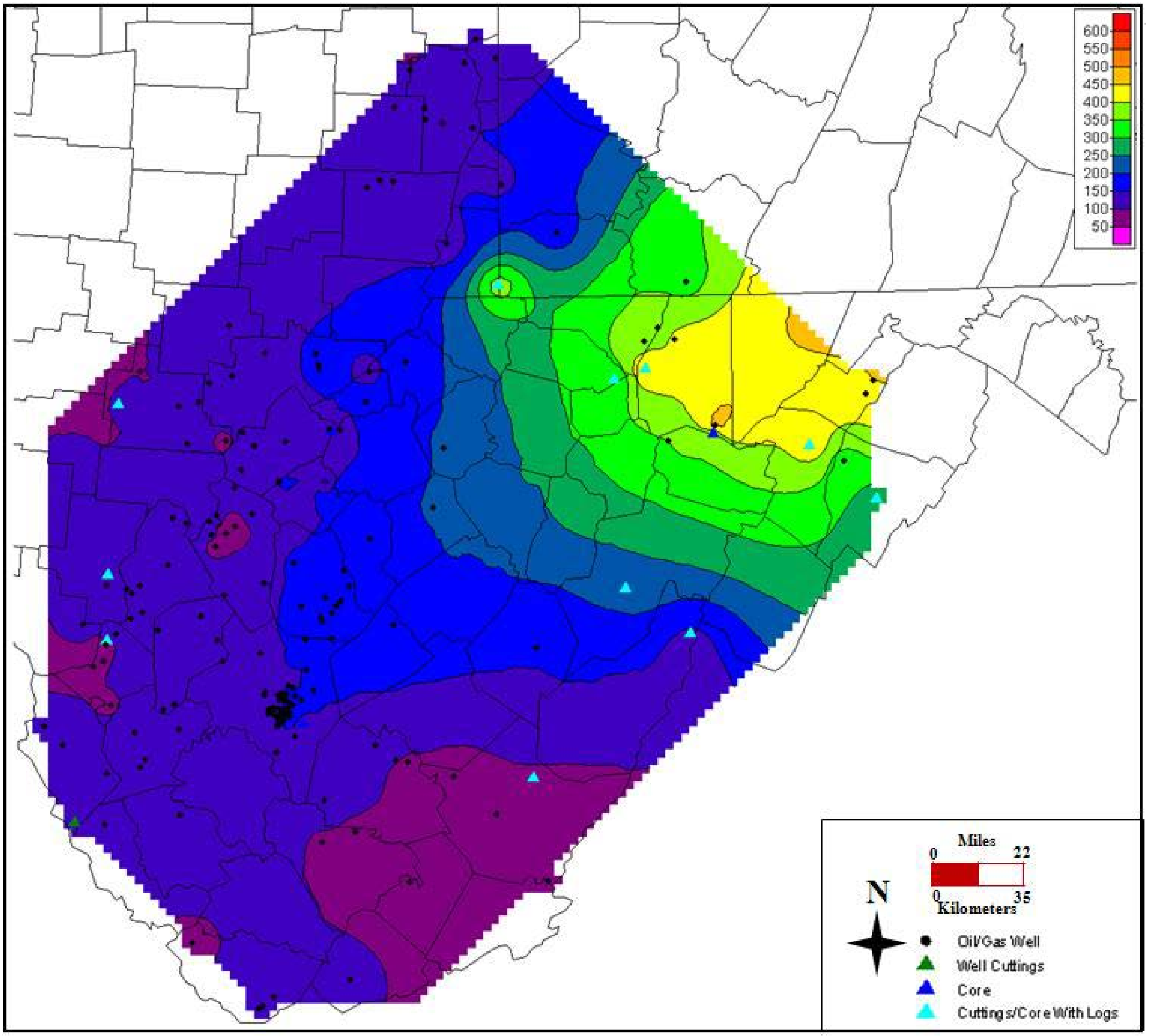

Figure 19: Kramer's (2013) gross thickness map of the Tuscarora Sandstone. Faulting and folding may cause the Tuscarora to appear thicker than it really is in the more intensely deformed strata of eastern West Virginia, including eastern Preston County and the Camp Dawson area.

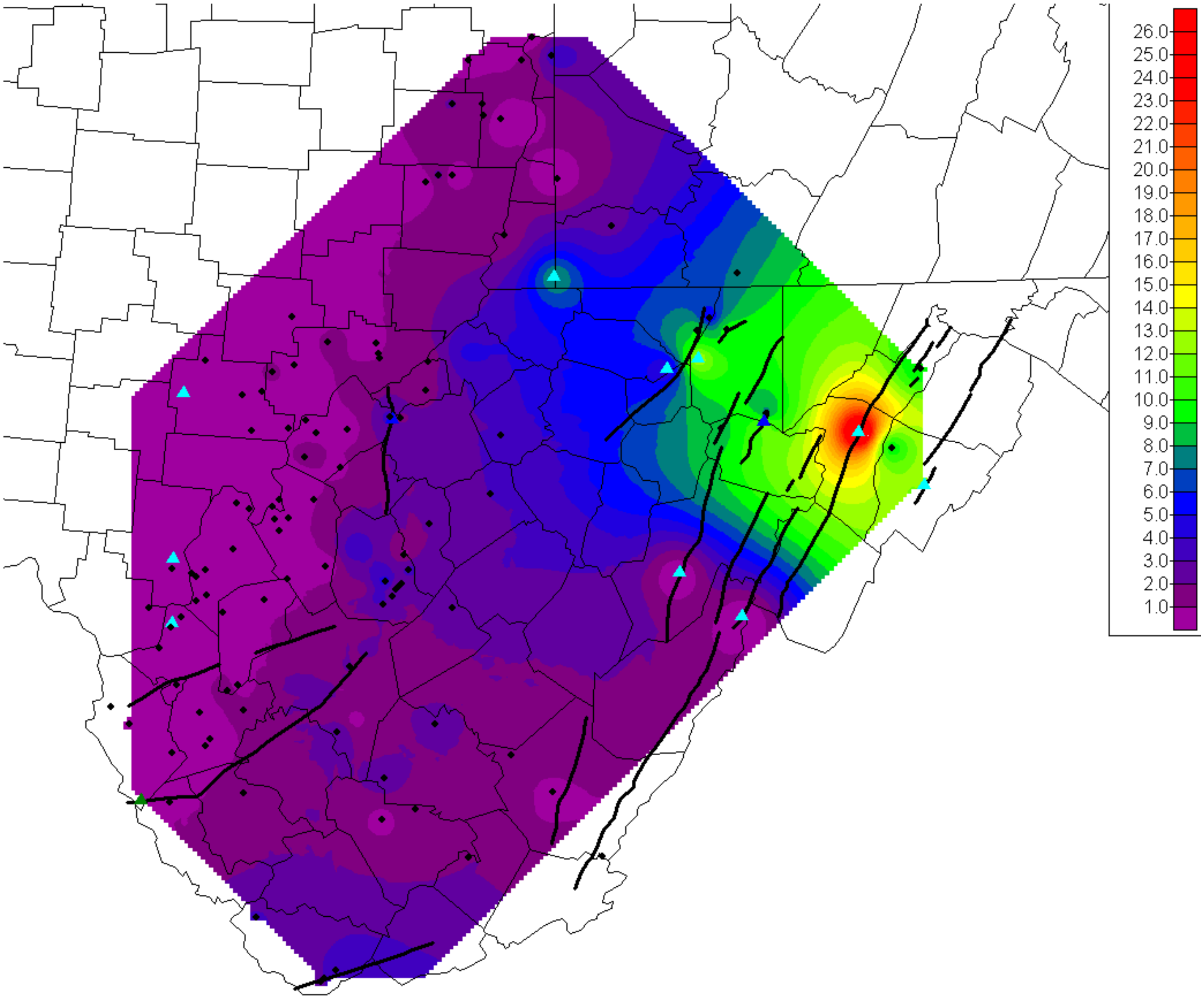

Figure 20: Kramer's (2013) porosity-feet map for the Tuscarora Sandstone, including the location of major anticlines (black lines) in West Virginia. "Porosity-Feet" is the net thickness of the strata multiplied by the average porosity (decimal). The small triangle symbol is pointing to wells drilled on the crest of the Wills Mountain anticline in Grant County. The anomalously high pore-feet value in this data point is related to high fracture intensity due to steepening of forelimbs during folding. Kramer (2013) suggests that higher fracture intensities (and therefore greater permeabilities) may be found on the steeply dipping west limbs of anticlines than on the gently dipping east limbs. Camp Dawson is on a steeply dipping west limb of an anticline but is very near the synclinal (down fold) axis. Higher porosities and permeabilities may also exist in the Allegheny mountain region (immediately east of Camp Dawson) due to dissolution of feldspar grains and calcite cements. (Kramer, 2013, referencing also Westcott, 1982, and Mitra, 1988)

13,300–13,500 feet (4,054–4,115) – Utica Shale: This black, highly organic, shale produces significant volumes of natural gas and NGLs in western Pennsylvania and eastern Ohio. In the eastern side of the Appalachian Basin, including Preston County, it is untested. At the Camp Dawson location, the Utica is outside the maximum assessed gas production sweet spot (Hohn et al., 2015). Although the unit is expected to have sufficient organic content and thickness to be a target for natural gas exploration, it is likely to be thermally over-mature (overheated relative to the temperatures that cause thermogenic production of natural gas) and therefore is expected to yield only dry natural gas, if any gas at all. It is essentially unknown what its production capabilities are in the Camp Dawson area. The Utica Shale is estimated to be about 200 feet thick based on Map 3067 from the United States Geological Survey (USGS) (2009).

13,500–13,700 feet (4,054–4,481 m) – Trenton & Black River Limestones: Immediately below the Utica Shale is the 1,200-feet thick Trenton and Black River Limestone strata. A structure contour map showing elevations on the top of this unit is presented in Figure 21. This map can be used to determine the total depth to the top of the formation by adding the surface elevation to the subsea depth (below sea level) value shown on the map, giving an estimate of 13,640 feet. A note on this map from the WVGES indicates they have determined it to be a fractured limestone. Depending on the nature and extent of the natural fractures, a naturally fractured limestone could serve as a good geothermal reservoir. However, these rock layers do not have a history of producing oil or natural gas anywhere near Camp Dawson. Due consideration should be given to the fact that few wells have penetrated this strata in the vicinity of Camp Dawson because it is deep and because of the lack of production from the few exploratory wells drilled. Little information is available on this target, so it presents a higher risk for finding sufficient natural permeability. Hydraulic fracture stimulation – perhaps intense hydraulic fracturing – may be required to permit circulation of water through this formation sufficient for a geothermal project at Camp Dawson. A reservoir temperature of at least 232°F (at top of the Trenton formation) is anticipated (note: again, higher temperatures are likely as indicated in the next subsection). Based on SMU’s rigorous modeling of geothermal data for the cross section shown in Figure 13, Frone et al. (2015), indicates a temperature around 284°F in the Black River formation at a location about 9 miles south of Camp Dawson. Thus, these formations are likely to have sufficient temperatures for spacing heating and generation of electricity and were selected for focused study in the following analysis; the only question is whether they have sufficient permeability.

Geothermal Reservoir: Conceptual Model

The conceptual model for geothermal heat extraction used in this project will be based on pumping water through nearly horizontal or gently dipping strata (perhaps a single sedimentary rock unit, such as the Tuscarora Sandstone) between two horizontal wells or four vertical wells. The idea is that the circulated water would flow within the target strata, rather than vertically across many strata at the location of a fault or fault zone. Heat stored within the target strata and adjacent layers would be mined, with the natural heat flux within the Earth providing only a small contribution. Flow pathways in the target strata would be a combination of natural fractures, which tend to be strata-bound, and thin layers of rock with higher intergranular porosity and permeability. This would be a strata-bound natural geothermal system. If the bulk permeability of the target strata is slightly insufficient to allow the amount of flow needed, the permeability of natural fractures could be increased by applying pulses of hydraulic pressure. If the permeability of the target strata is unsuitable for hydraulic pulsing of natural fractures to provide sufficient permeability, the target strata would be hydraulically fractured in the same way that shale gas wells are hydraulically fractured, with the horizontal wells spaced sufficiently close to permit hydraulic communication between the wells. This would be an enhanced geothermal system (EGS). Beneath Camp Dawson, the rocks are anticipated to be saturated with brines at normal hydrostatic pressure and with a hydraulic head equal to the level of the Cheat River (potentially even a little higher), so significant water losses are not expected. Natural brines in the target strata would serve as the working fluid for heat mining. Very large vertical faults are unlikely to have sufficient permeability to permit long distance vertical flow of brines and may not exist directly beneath Camp Dawson.

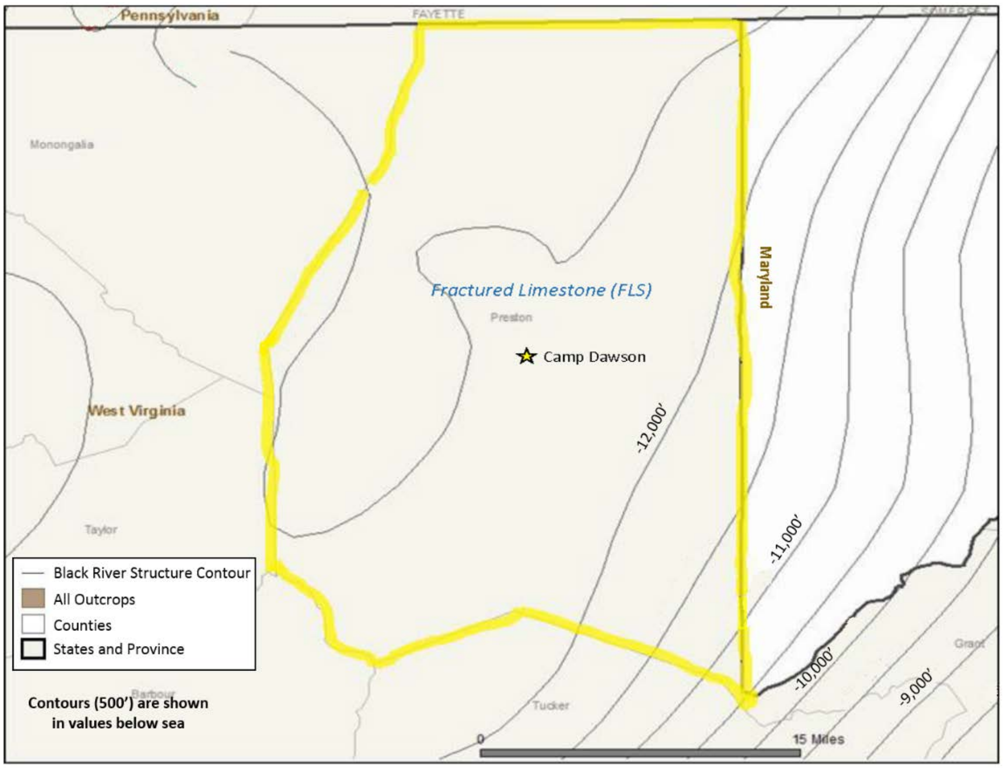

Figure 21: Map of subsea-level elevations on the top of the Trenton-Black River Limestone. (Modified after WVGES file map)

Rock Properties and Estimates of Geothermal Gradient

Information on the relevant properties of rocks are not available for the immediate vicinity of Camp Dawson; therefore, information was sought from a larger region. Typical bulk properties for sedimentary strata are reported by Shope et al. (2012). Table 5 displays the average thicknesses (feet) and thermal conductivity values (watts per meter Kelvin [W/mK]) for various formations within the Rome Trough, a geologic region that includes Camp Dawson. In general, sandstone, limestones, and dolomites have higher thermal conductivity than shales and therefore make better geothermal reservoirs. Thickness and thermal conductivity values are used to help evaluate the potential of various reservoirs beneath Camp Dawson. [Note: The "Ridgeley," as shown in this table, is another name for the Oriskany Sandstone, and the "Antes formation" correlates with rock referred to as the Utica Shale. The Coburn, Salona, and Nealmont formations are equivalent to the Trenton limestones, whereas the Benner down through the Hatter limestones are considered to be Black River Group equivalents.]

Some typical specific heat values for the relevant types of dry geologic materials are listed in Table 6. The important thing to notice is that these values do not differ much between the different types of Earth materials listed. These values are useful when estimating values of heat yield for each stratum at depth, accounting for porosity and pore fluid types.

An expanded list of potential geothermal reservoirs is presented in Table 7. All depth and thickness values were estimated from the USGS cross section (Ryder et al., 2009) – see Figure 12. Uncertainties in formation tops and average thicknesses result from the approximation of the location of Camp Dawson along cross section. Camp Dawson is positioned about 9 miles to the north of the cross section. Thermal conductivity values are not calibrated for formation heterogeneity, estimated thicknesses, water saturation, and other factors.

NETL's initial attempts to determine temperatures in potential geothermal targets at depths used an interactive mapping system of the WVGES (see Appendix H). These values are presented above in Figure 10 as minimum temperatures expected. The WVGES interactive mapping portal indicates that geothermal gradients in the vicinity of Camp Dawson are approximately 1.3°F per 100 feet of depth, which is close to the average value for the continental crust of the Earth (e.g., Wikipedia on Geothermal Gradients claims an average gradient of 1°F per 70 feet or 1.4°F per 100 feet in continental crust). Most notable is the fact that various temperature corrections were not applied in these maps, and the user must take this fact into account when applying the information to specific problems.

Subsequently, NETL reviewed SMU's database of bottom-hole temperature measurements in wells and produced a series of maps of local geothermal gradient, heat flux, and depth to 180°F, as shown in Appendix H. The local gradient map (made from SMU's database) is also presented below as Figure 22. This map uses the natural neighbor interpolation technique to estimate the gradient beneath Camp Dawson and includes only corrections applied by SMU in their database. As with the WVGES products, the geothermal gradient at Camp Dawson is estimated at 1.34°F/100 feet, which is considered to be the minimum likely value. Estimates of local geothermal gradients from the WVGES and NETL mapping efforts, as minimum likely gradients, should be compared to Figure 13 from Frone et al. (2015), which probably represents maximum likely gradients.

NETL geologists recognize the elevated geothermal gradients reported for southeastern Preston County could be a product of natural gas production in nearby anticlines. One of the geothermal gradient maps posted by SMU (Figure H.3 in Appendix H) indicates that the elevated gradients in Preston County arise from bottom-hole temperatures in wells located in the Terra Alta gas field. This field went into production during the 1940s and has seen a substantial amount of natural gas removed. It is possible that the removal of natural gas and coincident reduction of pressure in the reservoir along the axis of the anticline induced an up-dip flow of warmer water toward the wells. Subsequently drilled wells, which had bottom-hole temperature measurements, may then have encountered warmer temperatures due to this up-dip transport of heat with the water. This theory deserves further investigation.

Table 5: Revised Stratigraphy for the Rome Trough (Shope et al., 2012) with Average Thicknesses and Thermal Conductivity Values for Various Formations. Sandstones are in Yellow, Shales in Grey, Dolomites in Light Blue, and Limestones in Blue

Units in stratigraphic order		
Unit names	**Average Thickness (ft)**	**Thermal Conductivity (W/mK)**
Unnamedsandstone	722	3.34
MonogahelaORUniontown/Pittsburgh	299	2.22
ConemaughORCasselman/Glenshaw	866	1.6
Allegheny	279	2.91
Pottsville	194	3.25
MauchChunk	456	2.15
Greenbrier	118	3.1
Burgoon/RockwellORShenango	636	2.91
VenangoORCatskillORHampshire	1545	3.17
Chadakoin/BradfordORLockHaven	1739	3.05
Brallier	2884	2.25
Harrell	459	1.02
Tully	66	2.45
Mahantango	240	1.98
Marcellus	121	1.52
Selinsgrove	16	2.45
Huntersville	105	2.33
Needmore	23	2.12
Ridgeley	98	3.42
LickingCreekORShriver	85	2.08
Mandata	23	1.43
Corriganville	10	2.45
NewCreek	10	2.45
KeyserFormation	89	2.45
Tonoloway	69	2.31
WillsCreek	577	2.26
LockportORMcKenzie	164	1.9
ClintonGroup	531	2.51
TuscaronaFormation	292	4.6
QueenstonORJuniata/BaldEagle	1276	3.34
Reedsville	764	2.15
AntesFormation	177	1.72
CoburnFormation	246	2.5
SalonaFormation	128	2.01
Nealmont	256	2.5
Benner	148	2.7
Snyder	89	3.35
Hatter	157	3.35
Loysburg	141	3.35
BeekmantownGroup	2224	3.35
Gatesburg	948	3.35
WarriorFormation	440	3.35
PleasantHill	794	2.31
Waynesboro	994	2.51
Tomstown	1640	3.4
Unnamedsandstone	1640	3.4

Table 6: Specific Heat Values for Different Geologic Materials that are Dry

Product	Specific Heat *(kJ/kg K)*
Clay	0.92
Dolomite rock	0.92
Limestone	0.84–0.908
Sandstone	0.92

Sources: http://www.engineeringtoolbox.com/specific-heat-solids-d_154.html

Table 7: An Expanded List of favorable Geothermal Reservoirs near the Camp Dawson Site. Estimated Approximate Formation Top Depths, Average Thicknesses, and Thermal Conductivities – Sandstones are in Yellow, Shales in Grey, Dolomites in Light Blue, and Limestones in Blue

Favorable Geothermal Lithologies in Depth Order	Approximate Formation Top Depth from USGS Cross Section (feet)	Approximate Average Thickness (feet)	Approximate Thermal Conductivity (W/mK) (within Rome Trough)
Tully Limestone	7,500	<50	2.45
Onondaga/Huntersville Chert Formation	8,100	150	2.45
Ridgeley/Oriskany Sandstone	8,300	100	3.42
Helderberg Limestone	8,400	150	2.08
Keyser Formation	8,600	200	2.45
Keefer Formation (Clinton Group)	10,200	<50	2.51
Medina Group/Tuscarora Formation	10,900	500	4.60
Trenton Group (Salona, Coburn, Nealmont)	14,200	500	2.01–2.50
Black River Group (Snyder/Hatter)	14,800	600	3.35
Loysburg/St. Paul Formation	15,500	250	3.35
Beekmantown Group	16,000–17,500	2,100	3.35
Rose Run/Upper Sandy Member (Gatesburg Formation)	19,200	350	3.35
Copper Ridge/Warrior Formation	19,500	1,200	3.35

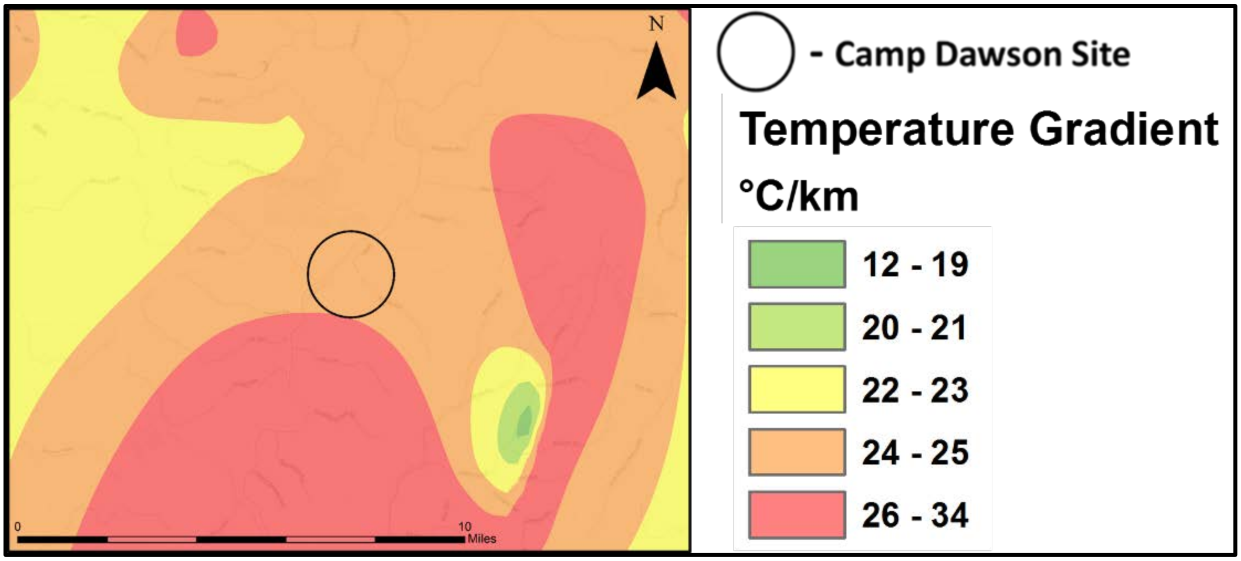

Figure 22: NETL's interpolation of geothermal gradient in the vicinity of Camp Dawson based on the bottom-hole temperature measures in wells, as reported from SMU's database.

The most recent draft geothermal map from WVGES, which includes Preston County, West Virginia, may suffer the same defect. This map suggests that most of east central West Virginia lacks a geothermal anomaly and is relatively cool – see Figure H.11 in Appendix H.

Uncertainty also arises from other issues. Except for the work of Frone et al. (2015), estimates of the geothermal gradient presented in this report have not accounted for terrain effects that can alter the estimates of the depth beneath Camp Dawson to reach various temperatures. Wells used to make the published maps appear to be in upland areas to the east and west of the Cheat River valley, but none were located in the Cheat River valley bottom. A rough linear correction was made for topographic effects based on temperatures measured at the bottom of a well located about 5 miles to the southeast and another well located about 3.8 miles to the northwest. In this case, a depth estimate of 8,100 feet was determined for a temperature of 180°F (compared to a depth estimate of more than 9,500 feet if no correction for topographic effects is made, as illustrated in Figure H.15) and a depth estimate of 12,400 feet was determined for a temperature of 240°F beneath Camp Dawson. Additional corrections may be needed to get accurate estimates.

Furthermore, except for the work of Frone et al. (2015), estimates of geothermal gradient presented in this report have not accounted for the thermal blanket (insulation) effect of the thick shale layers, which have significantly lower thermal conductivities compared to clean sandstones and clean carbonates. Thus, a heat-trapping function is expected from the thick Devonian shales in the upper part of the geologic sequence of sedimentary rock layers and from the thick Ordovician shales (Utica, Martinsburg, and Reedsville shales) in the middle of the geologic sequence of sedimentary rock layers. Gas-saturated shales, such as the Marcellus and Utica, have even lower thermal conductivities, which are one-third the conductivities of clean sandstones and clean carbonates and therefore significantly affect the geothermal gradient. These insulation effects should be included, along with the folding and faulting of the rock layers, to improve the accuracy of the estimates of temperature in various rock layers at any given point in underground space.

All of the geothermal gradient maps presented in this report (including Appendix H), considered together, indicate a range of values that probably bound the true geothermal gradient. Equally important, these maps considered together indicate the uncertainty in geothermal gradients and the estimates of temperatures at any particular depth. Table 8 contains a summary of information for the selected geothermal targets and indicates the range of uncertainty.

Table 8: Summary Data on Temperatures and Rock Properties in Example Geothermal Reservoirs Beneath Camp Dawson.

Strata	Depth	SMU Temps (°F)	WVGES Temps (°F)	NETL Interns Temps (°F)	Permeability	Typical Heat Capacity	Typical Thermal Conductivity
Oriskany	~ 8,140	194	>162	>161	low	0.92	3.42
Tuscarora	~10,300	230	>198	>190	v. low	0.92	4.60
Oswego	~12,000	254	>226	>212	v. low	0.92	
Trenton/BR	~13,500	284	>232	>233	v. low?	0.84 – 0.92	2.01-3.35
		Frone et al., 2015	Internet Portal	SMU well data	best guess	kJ/kg-K	W/m-K

Along with sufficient temperatures, successful geothermal projects require that the chosen geothermal reservoir have permeability characteristics sufficient to circulate water at a rate that can deliver the needed heat (Btu's) to the surface facilities. Permeability is the most difficult parameter to estimate in the rock strata beneath Camp Dawson. The oil and gas industry has found that deeply buried rocks tend to not have sufficient permeabilities and porosities for the injection of waste water, for example.

It is expected that beneath Camp Dawson, the rocks will retain very small amounts of their original permeability. Most of the present-day permeability will result from open fractures, and these may be found primarily where the rock has undergone movement along the fractures within the relatively recent geologic past. Thus, active faults and fracture swarms around active faults may provide the most permeable zones. On the other hand, faults that are open and susceptible to water flow are also prone to slippage that can cause micro-seismicity, or even felt seismicity. Pairs of geothermal wells are used to inject water at one location and withdraw it at another. By using a pump on each producing well, a low pressure zone is created around each production well, so the water pressures at depth throughout the rock formations are much less likely to induce seismicity.

4. MATHEMATICAL MODEL AND GEOTHERMAL RESOURCE ASSESSMENT CALCULATIONS

Resource Lifespan Analysis

The basic problem under analysis is shown in Figure 23, with focus here on the heat extraction from the geothermal reservoir where water flows from the injection well to the production well. To predict the lifespan of a pair of geothermal wells capable of providing 100 percent of the heat for the nine buildings of interest, a mathematical model was created. The calculations completed by this model are based on a simple linear model involving a number of parallel, equidistant, vertical fractures of uniform aperture. The fractures are separated by blocks of homogeneous, impermeable rock. The volume of the fractures is assumed to be negligible compared with the volume of the rock. The water is injected into a layer of thickness, h, through a well lateral of length, L_w, and produced from a parallel well lateral of equal length spaced a distance, d, from the injector. The model assumes that flow is distributed uniformly from bottom to top of the layer. Details of the water flow are not modeled. It is assumed that the water flow rates required to meet the energy demand may be obtained with an acceptable pressure drop. If the fractures are spaced *s* distance apart, then L_w/s fractures are assumed to intersect each of the laterals and that the flow is distributed evenly among these fractures. With these assumptions, the model reduces to a two-dimensional model where the solution yields a rock temperature, $T_r(x, z)$, and the water temperature, $T_w(x, z)$, where x is the horizontal distance from the injector and z is the vertical distance measured downward from the surface.

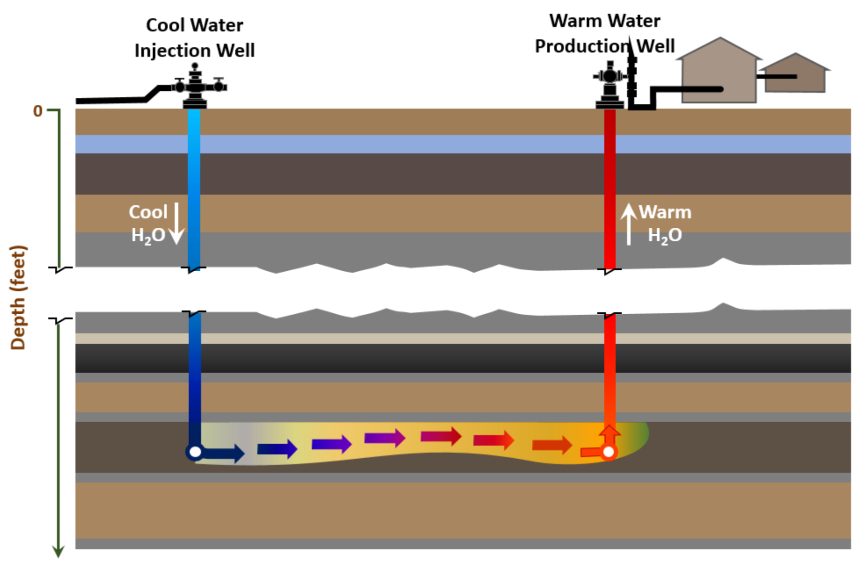

Figure 23: Cross section of the geometry analyzed.

The following simplifying assumptions are made:

- The water and rock specific heats and densities are constant. The heat capacity of the water-saturated rock can be calculated from the respective rock and water heat capacities and the porosity of the rock.
- The rock thermal conductivity is constant and the same in both the x and z directions.

- Heat transfer for the circulated water is by means of convection alone, and heat transfer in the rock is by means of conduction alone.
- The volume of the fractures is so small compared to that of the rock that it can be neglected when writing the energy balance for the water in the fractures.
- The water and rock temperatures are initially the same and are computed from a specified thermal gradient and surface temperature.

The energy balance for mobile water flowing in fractures yields the following equation:

$$v_S \rho_W C_{V,W} \frac{\partial T_W}{\partial x} + H(T_W - T_R) = 0 ,$$

where v_s is the superficial velocity of water, ρ_w is the density of water, $C_{v,w}$ is the specific heat of water, and H is the volumetric heat transfer coefficient. For the purpose of this calculation, H is approximated as $4k/s^2$, where k is the thermal conductivity of the rock and s is the fracture spacing.

The energy balance for the rock, along with the immobile water contained within its pores, is:

$$\left[(1-\varphi)\rho_R C_{V,R} + \varphi \rho_W C_{V,W}\right] \frac{\partial T_R}{\partial t} - k\left(\frac{\partial^2 T_R}{\partial z^2} + \frac{\partial^2 T_R}{\partial x^2}\right) - H(T_w - T_R) = 0 ,$$

where φ is porosity, ρ_R is the density of the rock, and $C_{V,R}$ is the specific heat of the rock.

The boundary conditions are:

$T_w(0, z) = T_{in}$

$T_r(x, 0) = T_{surface}$ and the gradient of T_r is equal to the natural thermal gradient at a depth below the injection, z_{max}, that is believed to be sufficiently distant from the injection zone to be unaffected by the project.

The rock equation applies for $0 < x < d$ and $0 < z < z_{max}$, while the water equation applies only in the region $0 < x < d$ and $z_{top} < z < z_{bottom}$, where z_{top} and z_{bottom} are the depths of the top and bottom of the injection zone respectively.

The partial differential equations (PDEs) for the water and rock were discretized by finite difference/finite volume methods, and the resulting set of algebraic equations was solved numerically using Gauss elimination. The prescribed flow velocity appearing in the PDE for water was calculated based on a monthly energy demand schedule (flow rate in GPM versus month that would satisfy the total heat demand for the given month – see Table 3) and the current water temperature at the production well. The spatial discretization in the x direction was uniform, while variable gridding was used in the z direction. The z increments were constant in the injection zone and were increased geometrically above and below the injection zone. The temperature of the outlet water from the injection zone was averaged to obtain the outlet water temperature.

The following parameters were used for the base case simulation representing the maximum depth resource analyzed in this study (Trenton Black River Limestone at 14,000 feet depth):

Surface temperature = 60.0°F
Target formation temperature = 240°F
Minimum required water production temperature (defines limit at abandonment) = 180.0°F

Water injection temperature = 160.0°F
Density of water = 62.4 lb/ft^3
Specific heat of water = 1.0 Btu/lb°F
Density of rock = 165.4 lb/ft^3
Specific heat of rock = 0.22 Btu/lb°F
Thermal conductivity of rock = 1.45 Btu/ft°F hr
Porosity of rock = 0.20
Length of lateral = 2,000.0 ft
Distance between laterals = 1,500 ft
Thickness of injection zone = 100 ft
Spacing between fractures = 10 ft
Thermal gradient = 0.015°F/ft
Depth to top of formation = 12,000 ft
Number of x grid points = 40
Number of z grid points in injection zone = 10
Number of z grid points below injection zone = 20
Number of z grid points above injection zone = 54

The model runs until the temperature of the produced water drops below the minimum required temperature. The time at which this occurs is termed the time to abandonment. Table 9 tabulates the time to abandonment for various pattern sizes and energy demands.

Table 9: Effects of Reservoir Area and Energy Requirement on Time to Abandonment

Lateral Length (ft)	Lateral Separation Distance (ft)	Pattern Area (ft^2)	Fraction of Base Heat Flow	Time to Abandonment (years)
1,000	1,000	1,000,000	1.00	12.00
1,000	1,000	1,000,000	0.50	33.00
1,000	1,000	1,000,000	0.25	101.08
2,000	1,500	3,000,000	1.00	63.08
2,000	1,500	3,000,000	0.75	101.25
2,500	1,500	3,750,000	1.00	91.08
2,500	2,000	5,000,000	1.00	149.17

Table 9 clearly shows the strong dependence of the time to abandonment on the pattern area. It is noteworthy how the increase in lateral length from 2,000 feet to 2,500 feet significantly increases the project life as a result of the non-linear response from heat conduction from the surrounding resource. The row highlighted in blue is used in a proposed design for a geothermal system later in this report – see Section 6.

Representative results using the base case are shown in Figures 24 to 27.

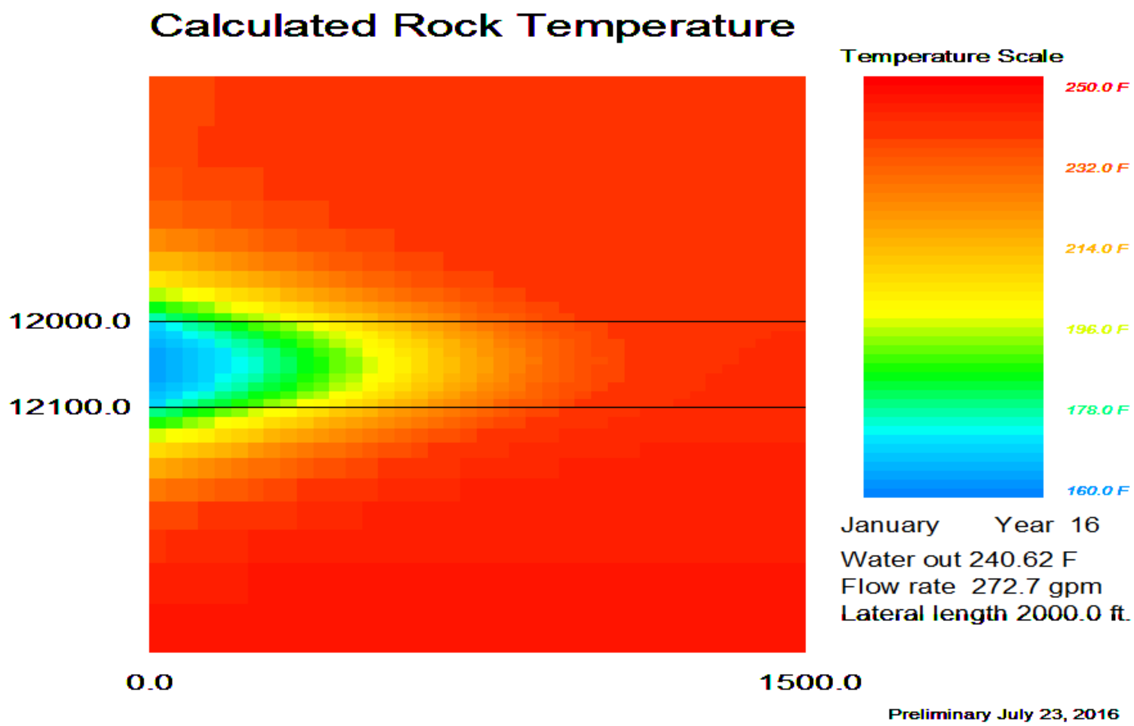

Figure 24: Time history of the base case. Time = Year 16.

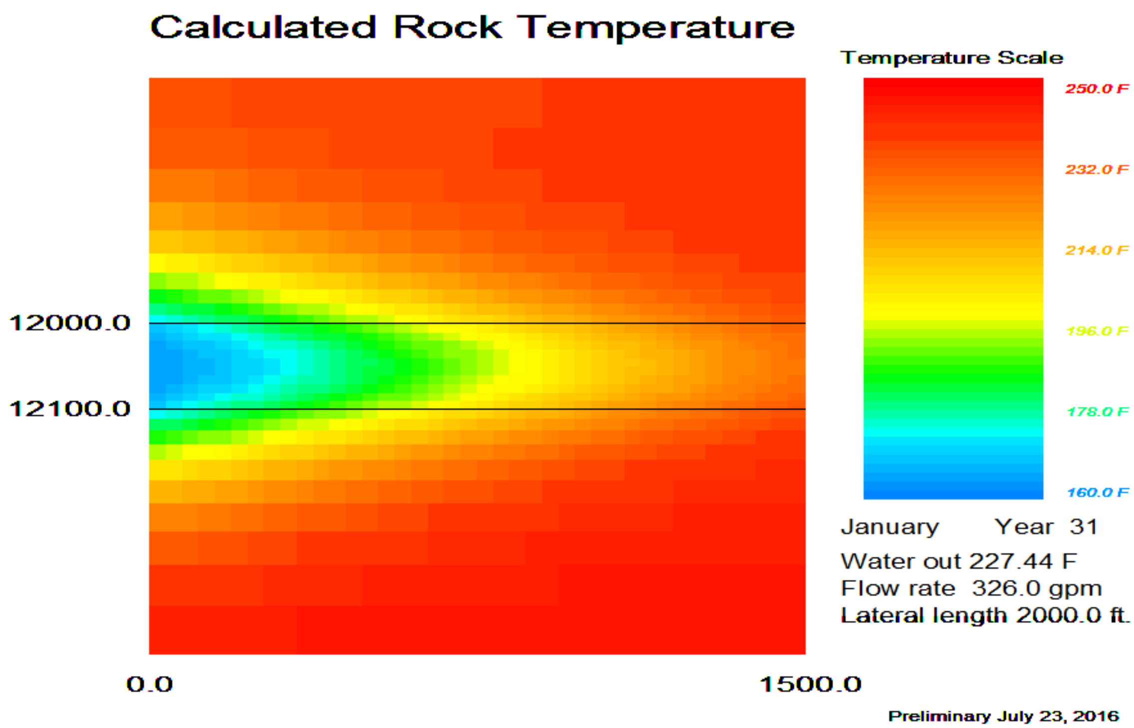

Figure 25: Time history of the base case. Time = Year 31.

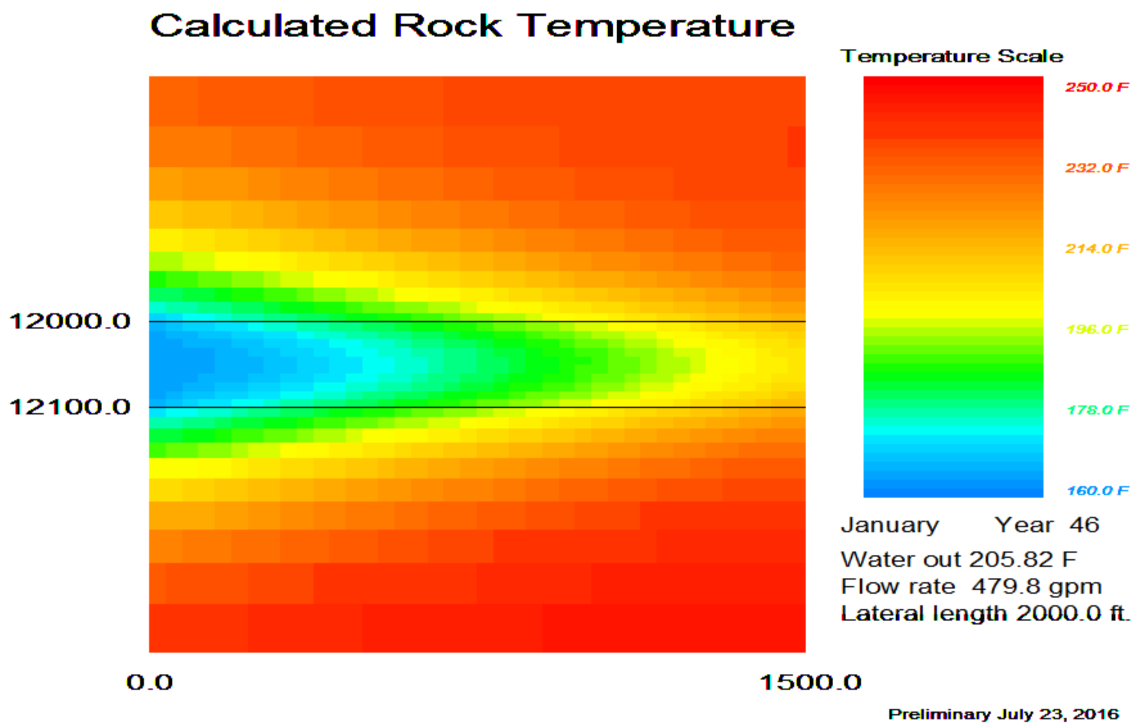

Figure 26: Time history of the base case. Time = Year 46.

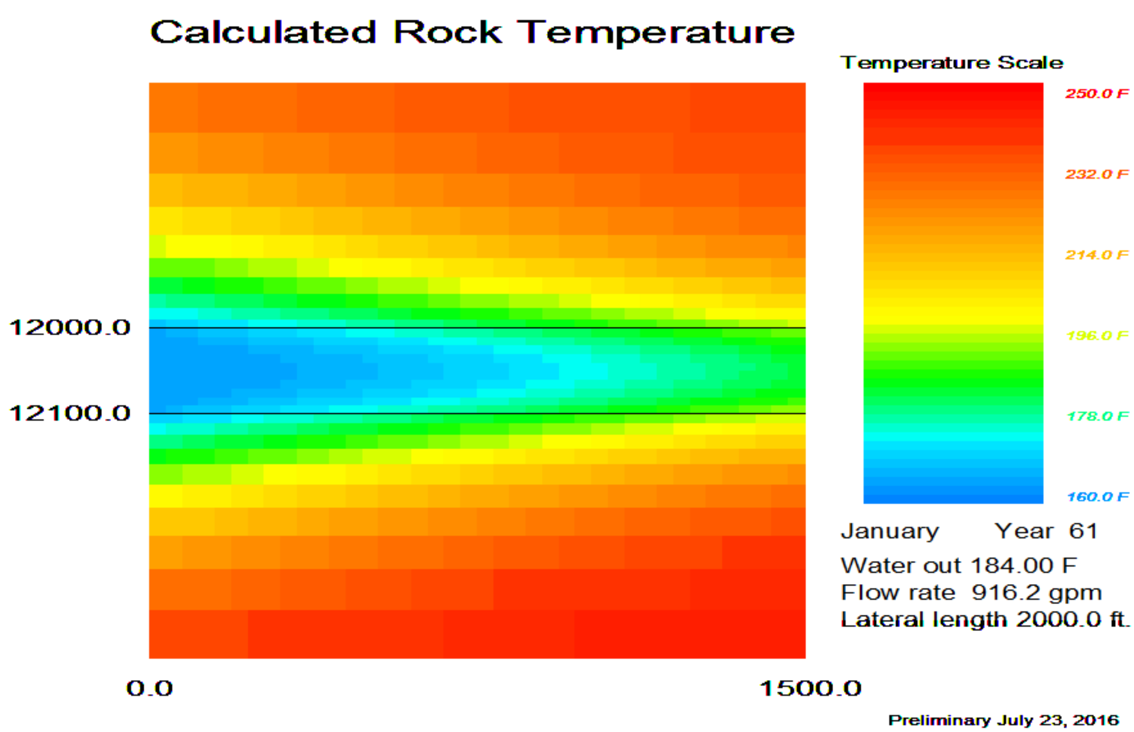

Figure 27: Time history of the base case. Time = Year 61.

Analysis of Heat Loss through Injection/Production Wells

The first order, inhomogeneous, differential equation governing heat loss as water travels up the production well or down the injection well is:

$$\frac{d\left(T_w(z)-T_{earth}(0)\right)}{dz}+a\left(T_w(z)-T_{earth}(0)\right)=a\frac{\Delta T}{\Delta z}z \quad ,$$

where z is depth, $\Delta T/\Delta z$ is the initial undisturbed temperature gradient of the earth, which is assumed to be 1.5°F/100 ft (27.3°C/km), and a is a constant:

$$a=\frac{2\pi}{Q\rho_W C_{V,W}\left(\frac{1}{k_{12}}\ln\left(\frac{r_2}{r_1}\right)+\frac{1}{k_{23}}\ln\left(\frac{r_3}{r_2}\right)+\frac{1}{k_{34}}\ln\left(\frac{r_4}{r_3}\right)\right)}.$$

It assumes no film resistance.

The volumetric flow of water is Q, and k_{ij} is the thermal conductivity of the material in the zone between radius i and radius j. The well inside diameter (ID) is 10 inches, so that r_1 is 5.0 inches. Three zones were arbitrarily selected: 0.25-inch casing thickness with thermal conductivity 20 Btu/(F ft hr); 0.5-inch thick cement annulus with thermal conductivity 0.17 Btu/(F ft hr); and 24 inches of earth with thermal conductivity of 1.16 Btu/(°F ft hr). At r_4 the temperature of the earth is taken to be the initial, undisturbed temperature at that depth.

The analytical solution for the differential equation for Q = 1,500 gal/min is presented in Table 10. It shows that the overall temperature loss from the production well depends upon the depth at which the water enters the well and the assumed values for the estimated parameters.

The results for four different depths and therefore four different initial temperatures are summarized in Table 10. As expected, it shows that the deeper and hotter the water, the more energy is lost by conduction to the surrounding earth.

Table 10: Overall Temperature Loss from the Production Well

Depth (ft)	Temperature at Depth (°F)	Temperature at Surface (°F)	Temperature Decrease (°F)	5-Feet Earth Temperature Decrease (°F)	5-Inch ID Temperature Decrease (°F)
12,150	242.3	231.2	11.1	7.5	7.4
10,800	222.0	213.3	8.7	6.0	5.8
9,500	202.5	195.7	6.8	4.6	4.5
8,000	180.0	175.2	4.8	3.3	3.2

The estimated temperature decreases indicate trends rather than firm numbers. The temperature decrease estimates depend on the selected values for the thermal conductivities and the widths of the annular material, neither of which are certain. For example, if the earth returns to its undisturbed temperature at 5 feet from the cement annulus rather than 2 feet, and all other parameters are the same, then the estimated temperature decrease is 7.5°, 6.0°, 4.6°, and 3.3°F, respectively.

If the water moves at a much faster velocity as would be the case if the well ID were 5 inches instead of 10 inches, then a smaller temperature decrease would occur because the water spends less time in the well. All parameters being the same except for the pipe diameter being 5 inches instead of 10 inches causes the respective estimated temperature decreases to be 7.4°, 5.8°, 4.5°, and 3.2°F.

Values for the temperatures at depth and the physical properties of the geothermal reservoir are best estimates. Table 11 indicates the possible ranges of such properties.

Effect of Fracture Spacing on Lifespan

The dependence of time to abandonment on fracture spacing is illustrated in Figure 28.

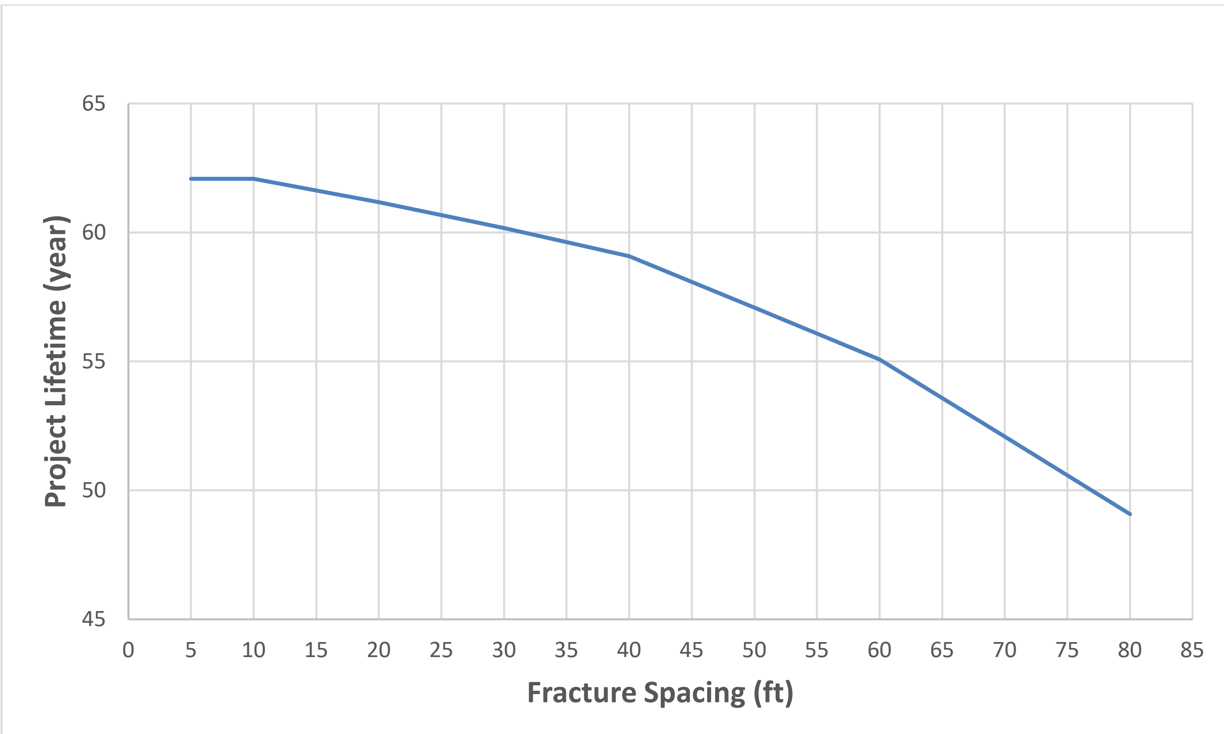

Figure 28: Effect of fracture spacing on time to abandonment.

The project lifetimes contained in this report are based on a simple heat transfer model applied to an idealized flow geometry. The model includes rock mass above and below the reservoir itself. For the parameters used in the model, which are thought to be typical of reservoir rocks in the region, the rock mass outside of the reservoir had a significant impact on the predicted project lifetimes. The fracture spacing used as the base case (10 feet) is representative of a natural fracture system. This close fracture spacing in conjunction with the good thermal conductivity results in most of the available thermal energy being mined from the reservoir during the project life. The efficient mining of energy in the reservoir in turn allows time for partial recharge from the surrounding rock, further extending the life of the project. In fact, for the base case approximately two thirds of the energy produced originated from outside the reservoir with temperature of the rock being effected more than 200 feet above and below the reservoir.

Table 11: Possible Range of Physical Properties

Stratum:	Oriskany	Tuscarora	Trenton-Black River	Sander (Germany)	Generic	Gaziantep (Turkey)	Generic	Construction	Construction
Rock:	Sandstone	Sandstone	Limestone	Sandstone	Sandstone	Limestone	Limestone	Sandstone	Limestone
Depth: ft (m)	6890 (2100) [a]	8711 (2655) [d]	14010 (4270) [i]						
Thickness; ft (m)	165 (50) [a]	300+ (92+) [d]	500 (152) [i]						
Temperature: F ©	122 (50) [a]	160 (71) [d]	240 (116) [d]						
Porosity	0.10 [a]	0.11 [d]	0.01 [c]	0.1954 [e]	0.011 [c]		0.004 to 0.12 [c]		
Density: lb/ft^3 (kg/m^3)	162 (2590) [c]	162.3 (2600) [c]	169 (2700) [c]	134.2 (2135) [e]	144 (2300) [h]		162 (2600) [h]	140 (2250) [f]	169 (2700) [f]
Specific heat: Btu/(lb F) (kJ/(kg K))	0.203 (0.85) [b]	0.203 (0.85) [b]		0.234 (0.98) [e]	0.201 (0.84) [h]		0.203 (0.851) [h]	0.220 (0.92) [f]	0.217 (0.908) [f]
Thermal conductivity: BTU/(ft hr ΔF) (W/(m K))				1.47 (2.55) [e]	1.47 (2.55) [h]	1.39 (2.41) [g]	1.62 (2.81) [b]	1.7 (3.04) [f]	1.30 (2.27) [f]

a) J. C. Keen and T. R. Carr, AAPG Poster: Hydrogeologic Analysis of the Oriskany Sandstone of the Appalachian Basin: Implication for Large-ScaleGeologic Storage of CO2, 2009, www.searchanddiscovery.com/documents/2009/80056skeen/images/poster2.

b) E. C. Robertson, USGS Report 88-441: Thermal Properties of Rocks, 1988

c) G. E. Manger, USGS Bulletin 1144-E: Porosity and Bulk Density of Sedimentary Rock, 1963, http://pubs.usgs.gov/bul/1144e/report.pdf

d) C. T. Kramer, WVU Geology Thesis: Regional stratigraphic framework of the Tuscarora Sandstone: A model for geologic CO2 storage in West Virginia, 2013, gradworks.umi.com/15/23/1523607.html

e) M. Abid, U. Hammerschmidt, and J. Koehler, Thermophysical Properties of a Fluid-Saturated Sandstone, International Journal of Thermal Sciences, 76:43-50, 2014

f) www.engineeringtoolbox.com

g) H. Canakci, R. Demirboga, M. B. Karakoc, and O. Sirin, Thermal Conductivity of Limestone from Gaziantep (Turkey), Building and Environment 42: 1777-1782, 2007

h) L. Eppelbaum, I. Kutasov, and A. Pilchin, Applied Geothermics, Chapter 2, Springer, ISBN: 978-3-642-34022-2, 2014

i) R. McDowell, personal communication, West Virginia Geological and Economic Survey, 30 March 2016

The flow through a uniformly spaced set of closely spaced fractures represents a best case scenario. If there is insufficient natural fracturing to permit the flow rates required by the heat demand, hydraulic fracturing will be necessary. In the case of hydraulic fracturing, the fracture spacing will be of the order of 150 feet with the result that energy mining within the reservoir will be less effective with more of the available energy left in place. The more rapid decline of the accessible energy in the reservoir reduces the time available for partial recharge, further shortening the project life. The simple two-dimensional model used for this study is not expected to be adequate for the wider fracture spacing. Calculations done with a simple three-dimensional model indicate that with 150-foot hydraulic fracture spacing, the project life will be only one half that of the base case. With 200-foot hydraulic fracture spacing, which is typical for a gas well, the project life will be only one third of that for the base case.

Even without hydraulic fracturing, the project life may be considerably shorter than that predicted for uniformly distributed flow. This will occur when there are a few highly conductive fractures that carry most of the flow. In this situation the energy will be mined out of the regions surrounding the highly conductive fractures with the regions surrounding the low capacity fractures remaining near their initial states and unable to supply sufficient energy to heat the water to the required temperature.

Effect of Initial Rock Temperature

Finally, the dependence of the time to abandonment on initial rock temperature is illustrated in Figure 29. Since there is a lower limit to the water temperature that will satisfy the heat demand for the buildings at Camp Dawson (see Section 2.3) as the geothermal resource cools and eventually reaches that temperature, it will no longer be able to satisfy the heat demand. The hotter the initial rock temperature, the longer it will take to reach that limiting operable temperature. Figure 26 shows the critical importance of the initial rock temperature as a result of this behavior. The ability to obtain sufficiently hot rock at an attainable depth is an important factor in determining the viability of the project.

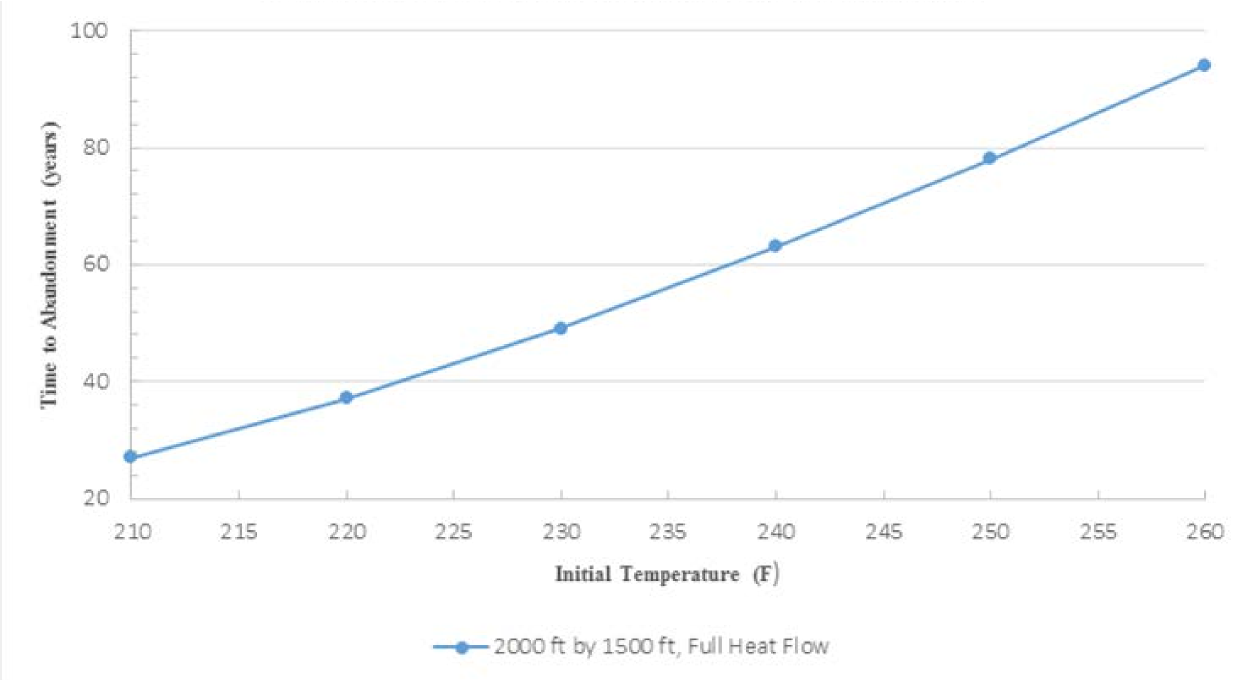

Figure 29: Effect of initial reservoir temperature on time to abandonment.

5. DETAILED ANALYSIS OF THE MARCELLUS SHALE FOR NATURAL GAS PRODUCTION POTENTIAL AT THE CAMP DAWSON SITE

Numerous potential natural gas reservoirs occur within northcentral West Virginia. The region is pervasively charged by natural gas; however, the rock units are very old (~300 million years and older) and therefore are commonly of low reservoir quality. To the west, natural gas has been successfully extracted from numerous Upper Devonian and Mississippian sandstone formations since the late 1800s. However, central Preston County has shown limited hydrocarbon potential in these units (e.g., Roen and Walker, 1995). Older units have also proven productive along the crest of folded structures within Preston County where natural fracturing has enhanced reservoir quality; however, these structures cannot be reached from the Camp Dawson location and the known structures have been extensively drilled and produced. Recent drilling has had some success in producing natural gas from the Middle Devonian Marcellus formation in locations near Camp Dawson, however. The following text outlines the interpreted condition of the Marcellus at the site. The last section provides information on further actions needed to assess the design and nature of a potential production well.

Marcellus Formation

The Marcellus formation is a large continuous expanse of highly organic but clay-poor shale that was deposited within the Appalachian region during the Middle Devonian period (~370 million years ago). With subsequent burial and heating, the unit generated enormous quantities of hydrocarbons, a large portion of which was expelled from the unit and migrated into overlying sediments where it generated the majority of the natural gas and oil fields within the basin. Along the eastern margin of the basin, the unit has been extensively deformed by subsequent geologic events; however, where the unit is less structurally deformed within the basin center and western margins, the unit retains large volumes of hydrocarbons. Recent technological advances (horizontal drilling plus large scale hydraulic fracturing) now enable a portion of these remaining hydrocarbons to be produced. In the past 10 years, thousands of wells were drilled from central West Virginia through extreme eastern Ohio, as well as western, northern, and northeastern Pennsylvania. The Marcellus produces dry gas exclusively where it is more deeply buried along the eastern margin of its extent, including Preston County (Figure 31).

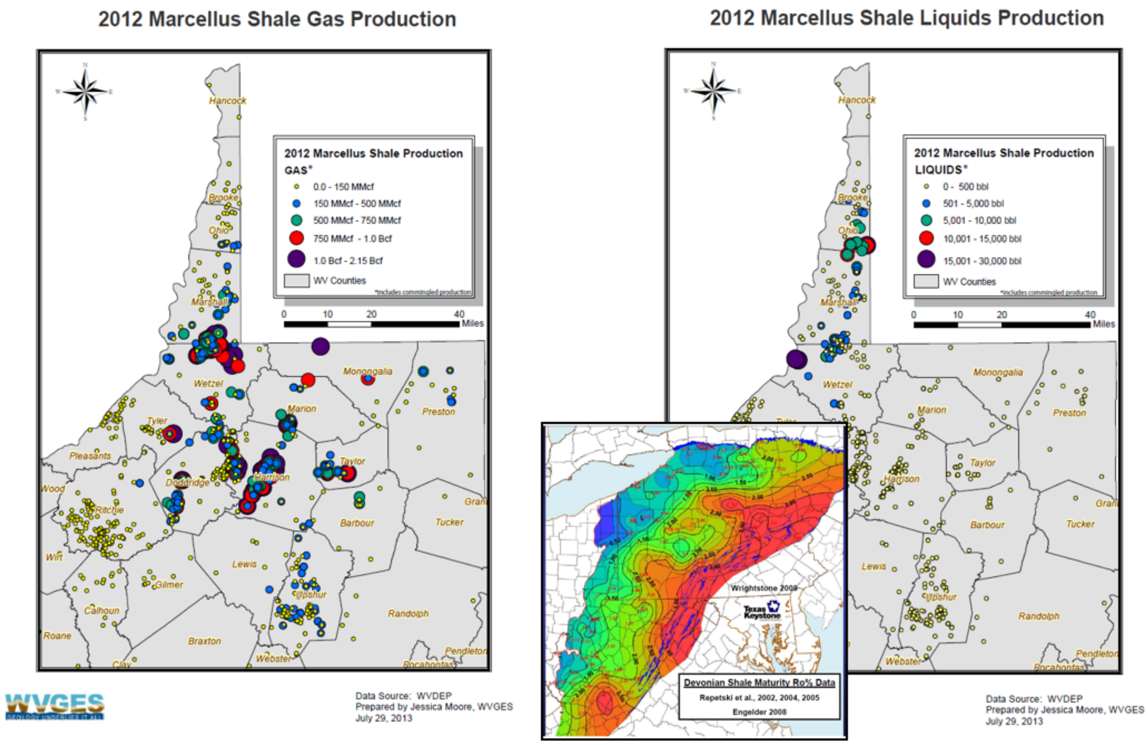

Figure 30: Marcellus Production in 2012 showing that Preston County occurs on the eastern margin of established production and that production is primarily gas. (Courtesy J. Moore, WVGES)

At the Camp Dawson site, the Marcellus formation is expected to be approximately 80 feet thick and represented by three formal members, including the basal Union Springs Member (~40 feet of black shale), the middle Purcell Limestone Member (~10 feet), and the upper Oatka Creek Member (~30 feet of black shale) (Figure 31).

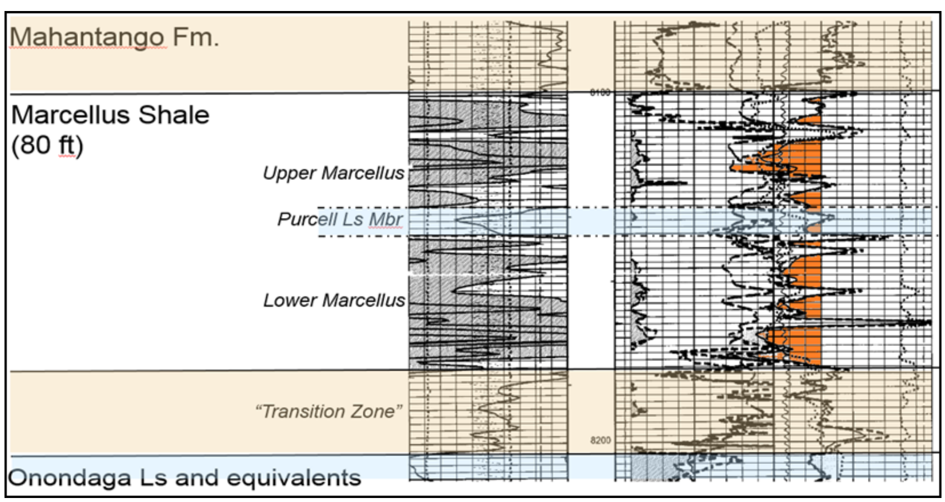

Figure 31: Stratigraphy of the Marcellus Shale in well Preston-542. See Figure 33 for location. Likely target zone would be the "lower" Marcellus (Union Springs Member).

The most likely target for the horizontal well would be the Union Springs Member, which has a significantly higher organic carbon content (estimated at 8-10 percent based on work conducted by Wang, 2012) and lower clay volume (< 20%, Wang, 2012) (Figure 32).

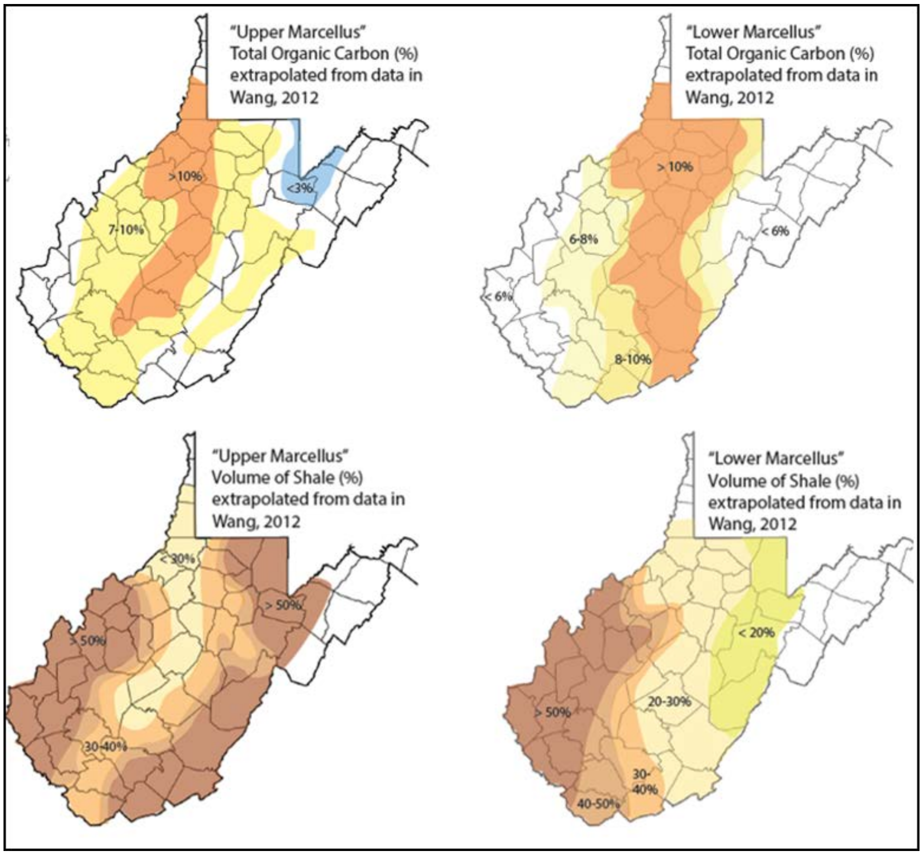

Figure 32: Estimates of total organic carbon and volume of shale within the Upper (Oatka Creek) and Lower (Union Springs) members of the Marcellus formation. (As estimated by Pool et al., 2013; from data presented by Wang, 2012)

These conditions render the unit more gas charged and mechanically brittle ("frackable") than the Oatka Creek Member in Preston County. The unit will occur at a drilling depth of approximately 7,400 feet below land surface (see Figure 11). The geologic risk to encounter gas-bearing Marcellus at the site is considered to be low. Successful wells were drilled in analogous locations both to the north and to the south of the Camp Dawson site (Figure 33). The primary risks relate to the geologic structure.

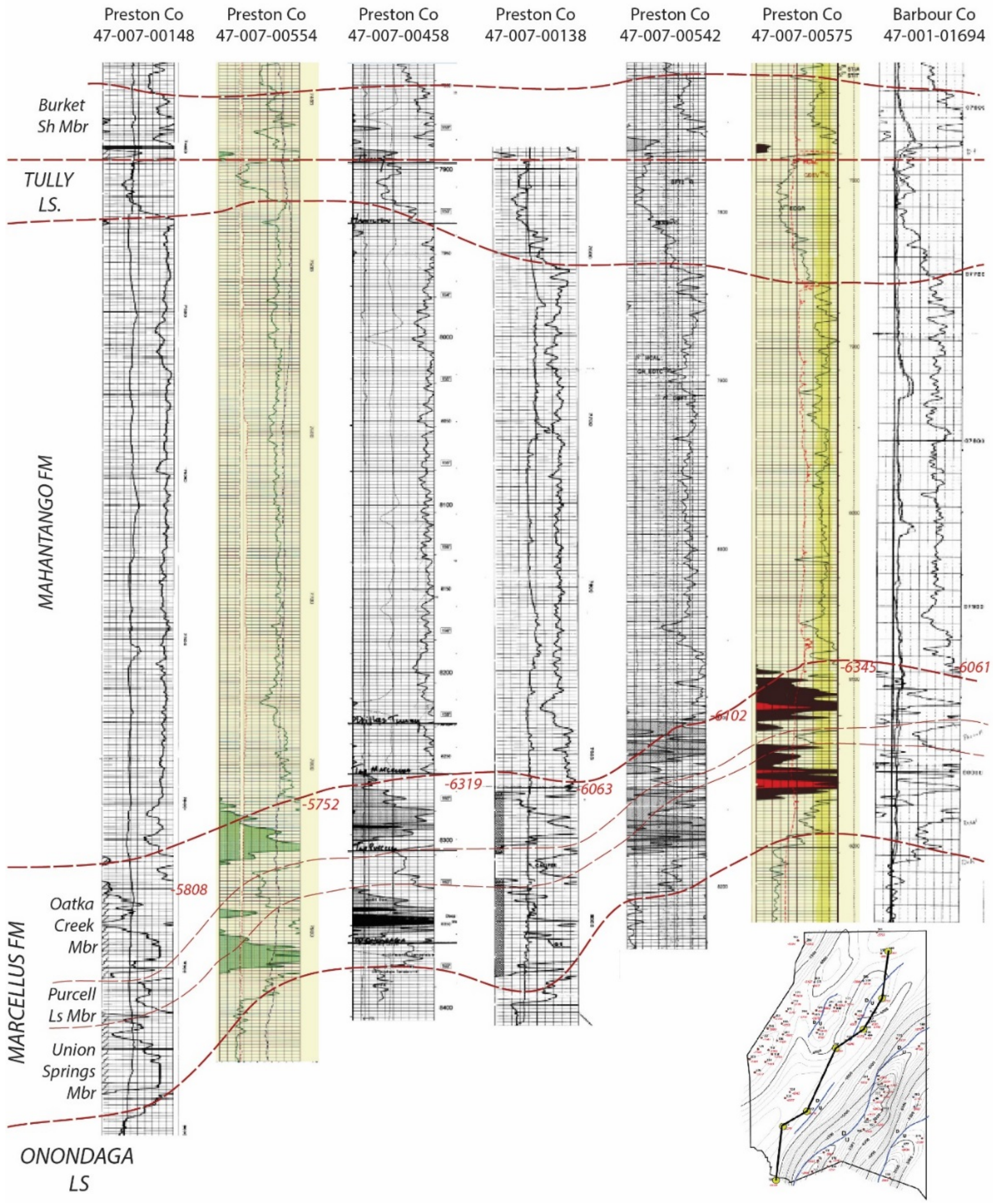

Figure 33: Well log data from wells in Central Preston County. The location of wells and Camp Dawson (green box) are shown in the inset. The Marcellus has a very distinctive gamma ray signature, making it one of the easiest formations to identify with common well logs. Higher organic content, and hence a greater hydrocarbon source, is associated with these spikes in gamma ray signature. This does not guarantee high production rates of natural gas today, however.

The Camp Dawson site lies to the east of the axis of the Ligonier syncline (Figure 34). The unit is expected to have a slight to modest dip to the west. At this location, the potential for faulting at the Marcellus level is significant. The bounding anticline to the east (the Etam Anticline) is a large structure that accommodates more than 3,000 feet of local uplift (for example, at Terra Alta, the Marcellus occurs within 5,000 feet of the surface). This deformation resulted in significant thrust faulting along the western limb of the anticline (see Figures 35 and 11). Faults can be readily seen displacing the Marcellus at a location just west of Camp Dawson (Figure 36) and at a location just to the east of the Preston-542 well located a short distance to the southeast of Camp Dawson (Figure 37).

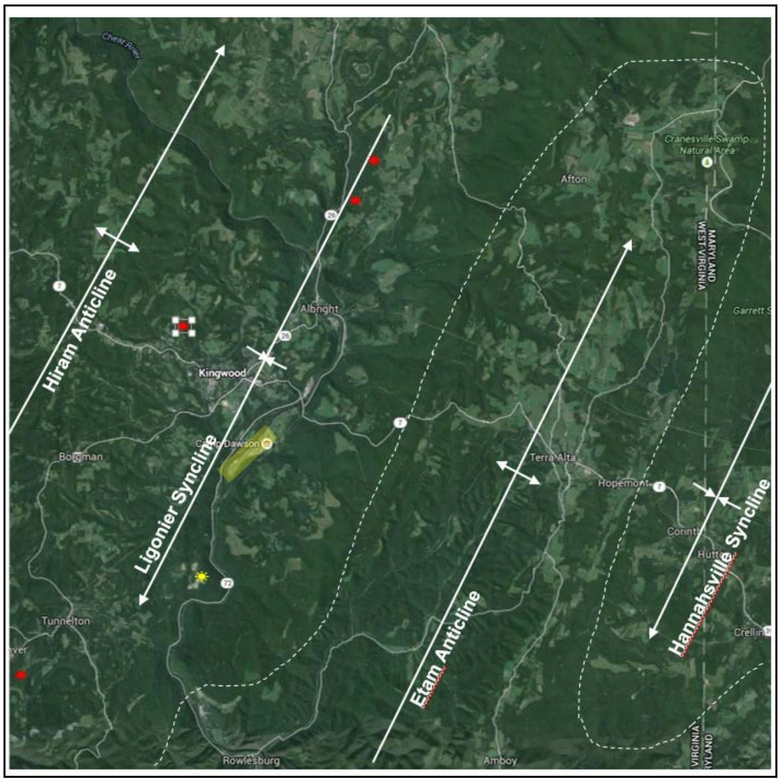

Figure 34: Aerial photo of central Preston County showing the Camp Dawson site (yellow box), drilled (red), permitted wells (yellow), and the trends of major structural features (white).

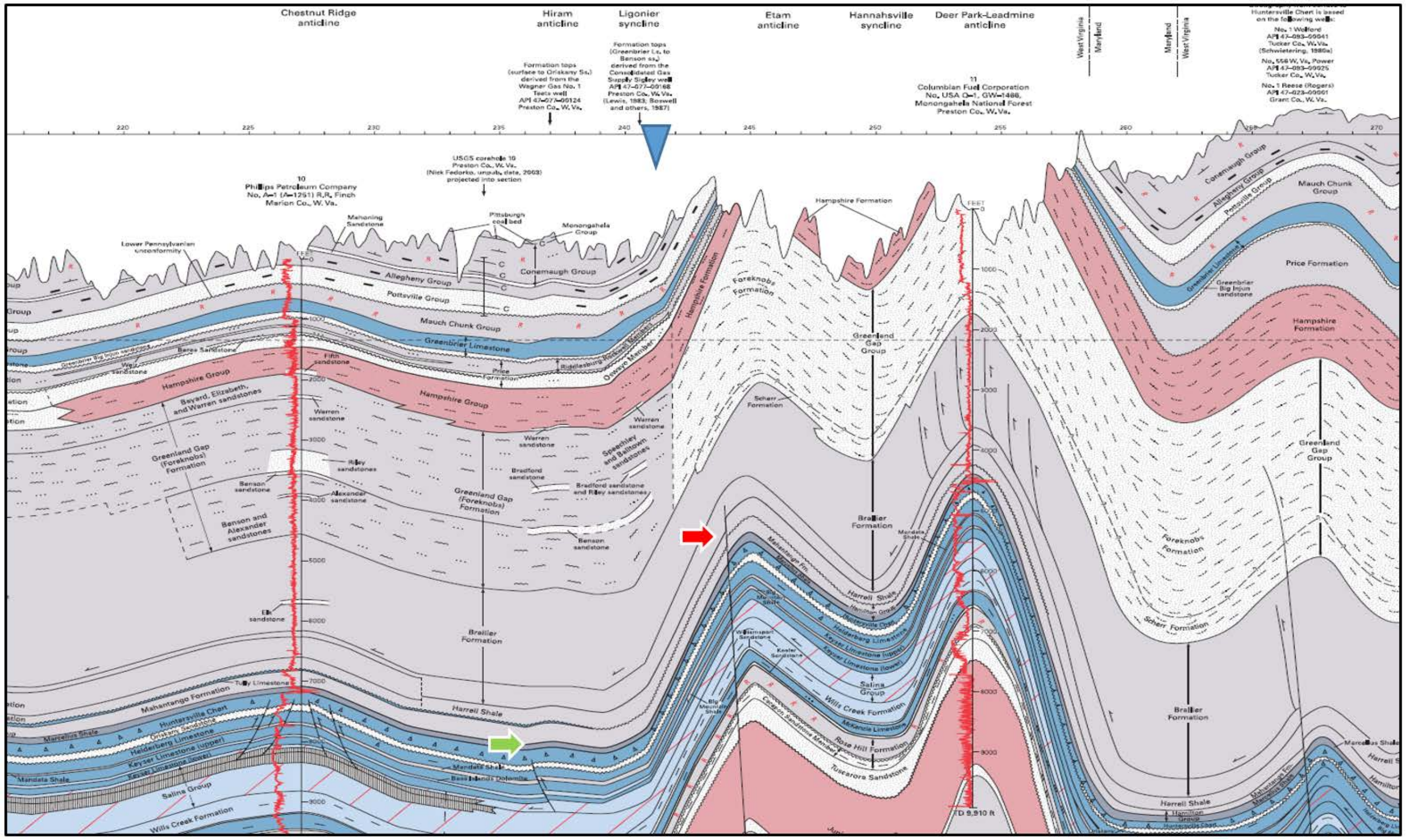

Figure 35: Portion of geologic cross section D-D' (Ryder et al., 2009) showing the location of the Camp Dawson (blue triangle) near the axis of the Ligonier syncline. The ascending fold limb to the east is prone to the occurrence of large thrust faults (red arrow) and the whole region features numerous smaller faults. Location of the Marcellus formation is marked by the green arrow.

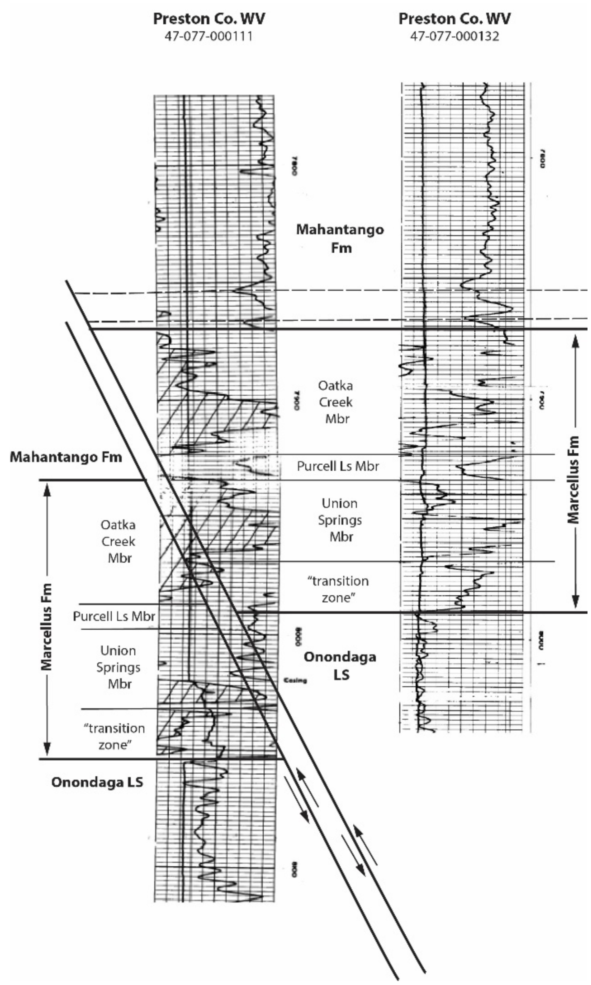

Figure 36: Preston-132 and -111 well logs, showing considerable thickness differences as a result of duplication of the Purcell and Oatka members of the Marcellus caused by a thrust fault. These wells are located in central Preston County, a few miles west of Camp Dawson.

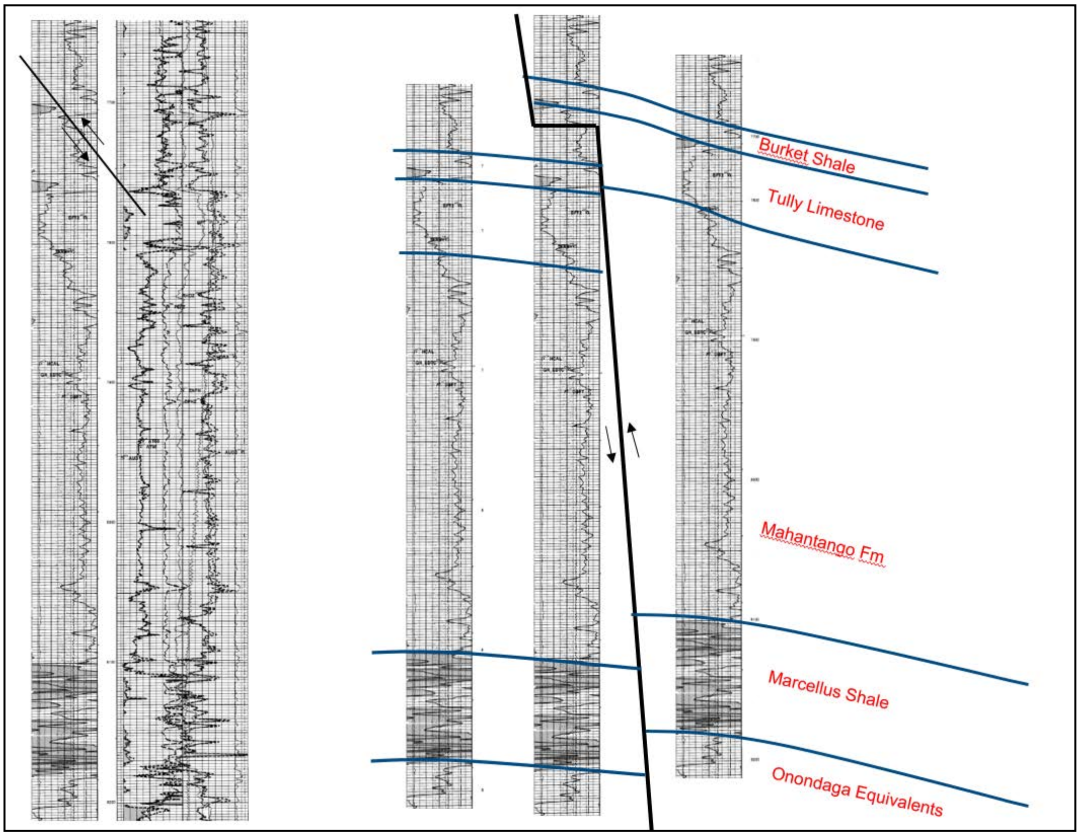

Figure 37: Preston-542 well log, showing duplication of the upper Tully Limestone and Burket shale indicating a thrust fault with approximately 50 feet of displacement. This well is located along the strike (the azimuthal direction of fold axes) to the southwest of Camp Dawson.

The potential for faulting and unanticipated folds in the strata deep beneath Camp Dawson necessitates the evaluation of all available data to mitigate risks undertaken when attempting to successfully drill into the Marcellus with a horizontal well (i.e., successfully hitting the target). Single faults can displace the reservoir such that a well within the unit could cross a fault and immediately exit the reservoir. **Large numbers of smaller faults, or zones of intensive fracturing, can result in the prior draining of the reservoir of much of its hydrocarbon.**

A regional evaluation of the Marcellus formation (Pool et al., 2013) indicated a likely gas-in-place resource density within central Preston County of approximately 10 billion cubic feet (BCF) per square mile. Expected production volumes under standard completion and production procedures (which are not expected at Camp Dawson where the well may be placed in a suspended status for long periods or flowed at low rates for indefinite periods of time) are difficult to assess from existing information. Many nearby Marcellus wells were drilled and completed as vertical wells, which may be a cost-efficient option for the Camp Dawson project. However, productivity would likely be increased (as would costs) should a lateral well be drilled to the extent enabled by the Camp Dawson property. This is an issue that requires more detailed reservoir engineering analyses to provide reasonable estimates of reservoir response and the potential benefits versus costs. The orientation of horizontal industry wells drilled in Preston County (primarily wells located to the south and southeast of Camp Dawson) is predominantly NNW-SSE (Figure 38). Industry normally orients wells approximately perpendicular to the propagation direction of induced hydraulic fractures (which parallel the maximum and intermediate principal stress directions) and such that the ambient subsurface stresses are less prone to close induced fractures (i.e., fractures open in the direction of the minimum principal stress).

The Utica Shale is an organic-rich shale of Silurian age that is increasingly produced within the central Appalachian basin. Recent drilling has resulted in very large and productive wells in locations within Greene, Washington, and Westmoreland Counties of southwestern Pennsylvania. The Utica would be very thick beneath Camp Dawson; however, the unit would be very deep (~13,000 feet) and very mature thermally (with all existing production being far to the west and therefore shallower and cooler). It likely has limited hydrocarbon potential compared to areas further west (Figure 39). Any deep well drilled at the site should attempt to gather geologic information from the zone to evaluate its potential.

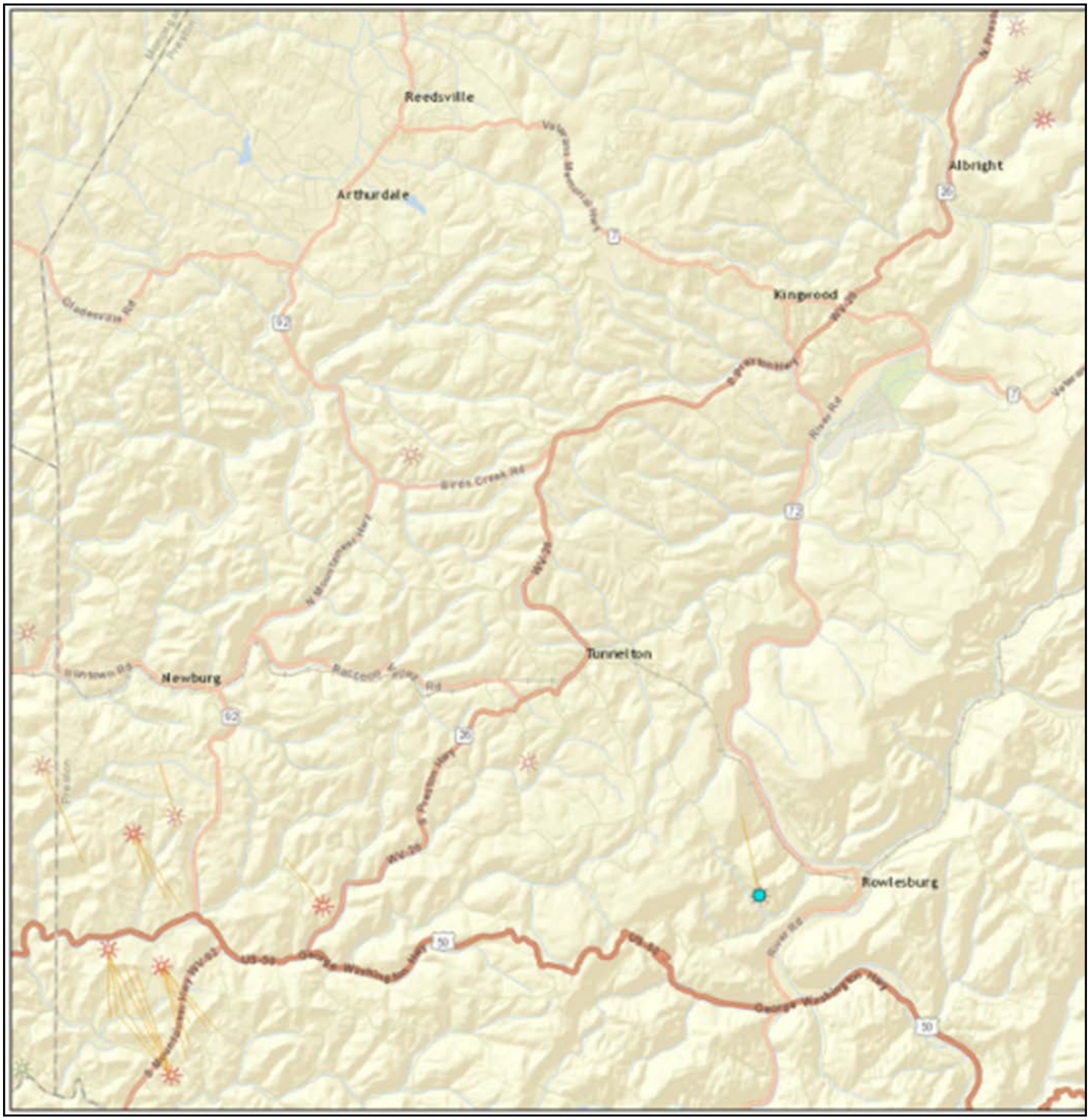

Figure 38: Marcellus wells in central Preston County include both vertical and horizontal wells (Figure 11 shows their distribution). Horizontal wells drilled in southeast Preston County show a preferred lateral orientation of NNW-SSE. Data from the West Virginia Department of Environmental Protection's website for Oil and Gas Well Permits.

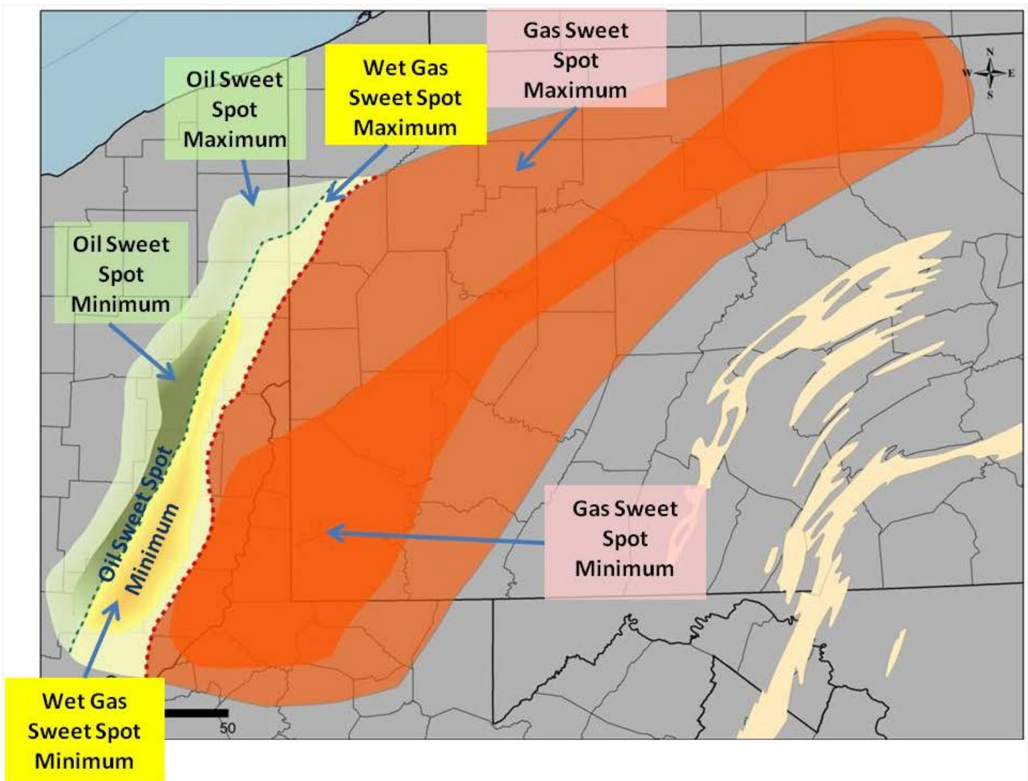

Figure 39: Estimated occurrence of significant concentrations of oil and gas within the Utica Shale in the Central Appalachian. "Sweet" spots are areas that are likely to yield profitable production of oil and/or gas. The Camp Dawson location is likely too far to the east (over mature). From Hohn et al. (2015).

6. OPTIONS TO MEET HEAT AND ELECTRICITY DEMANDS

The following subsections review options for the utilization of geothermal and fossil energy resources available to Camp Dawson. While certain technical details are provided to describe the operation of each option (efficiency of operation, etc.), the estimated lifetime of an option and its annualized cost of operation are the main parameters used as a means to compare the different options. To make comparisons with the different cases, an LCOH and/or electricity (LCOE) was calculated, which is then used to determine the *annual costs* of each case based on the known annual electric demand. The LCOE values are based on a standard costing method from NETL using information on system capital cost, performance, and service data for a given system. It is assumed that because these will be government funded projects, there are no loans and no need for return on investment. Inflation rates on general operations and escalation rates for heat and/or electricity were all the same for all cases (3 percent and 2.5 percent, respectively). Every case includes the capital cost associated with the initial well drilling and completion. In this study, certain commercial systems (e.g., turbines, heat exchange, etc.) were reviewed for assessment purposes. However, given the level of information available and the conceptual nature of the study, this report is considered *informational*, and additional detailed engineering designs and analyses will be needed to more accurately assess the benefits of using on-site power generation and to select a best value commercial system. Given the level of detail for the cost analyses performed here, an anticipated cost uncertainty of greater than +/- 20 percent should be expected for any given option presented.

Section 6.1 below summarizes the data in Section 2, which reviewed Camp Dawson's current energy use. The following sections review specific energy options, such as the direct use of geothermal energy for heating, gas turbine power generation for both electrical and heating needs, and other advanced energy conversion options, specifically ORCs, and SOFCs.

6.1 SUMMARY OF CURRENT CAMP DAWSON OPERATIONS

To establish a comparison to the several energy utilization options presented below, this section presents a summary of the current state of operations at Camp Dawson. As described in detail in Section 2, Camp Dawson currently operates nine buildings using a hydronic heating system in each building. The average annual cost for natural gas (mostly for space heating) is around $301,875. The average annual cost for electricity is around $827,000. These costs vary due to changes in the local prices for natural gas and electricity, as well as weather and operations at Camp Dawson. Recent trends suggest decreasing prices, but this can reverse in the future during the timeframes relevant to each case. The total average annual cost for heating and electrical operations is approximately $1,129,000.

6.2 USE OF ON-SITE NATURAL GAS TO FUEL EXISTING BOILERS FOR HYDRONIC HEAT AND OTHER EXISTING USES

This case evaluates an on-site Marcellus Shale well for the production of natural gas for space heating. The well is assumed to have a 2,000- to 4,000-foot horizontal lateral (depending on access to adjacent properties). The cost for drilling, completing, and getting the well into production would be approximately $5.05 million for a gas well with a 4,000-foot lateral and a 2D seismic survey – see Table 12. Given the current natural gas usage rate of about 40,350 MCF/year, a 4,000-foot horizontal well producing from the Marcellus Shale would be expected to provide all of Camp Dawson's needs for approximately 30 years (see analysis in Section 3).

The well would continue to produce for another 10+ years but at a lower rate. Starting around Year 30, additional gas would need to come from a second well or from a third-party gas supplier. Assuming that one well would be sufficient to sustain all Camp Dawson's needs (at current usage rate) for around 30 years, there would be an expected net annual savings of about $133,500 per year (= $301,875-$5,050,000/30 year) relative to today's operations. This simple analysis ignores the costs of well operation and maintenance (O&M) and the continued production of natural gas beyond year 30, meeting less than 100 percent of the current use rate. Estimates based on one industry source (SWN, 2016) suggests that an additional $60,000, or 20 percent, annual cost can be expected due to O&M. The U.S. Energy Information Administration report (EIA, 2016) suggests that the O&M cost may be as high as $120,000/year; adding an estimated $60,000/year in O&M costs would reduce the net annual savings for this option to about $73,000 per year.

The main parcel of land on the east side of the Cheat River will not accommodate a 4,000-foot lateral drilled in a northwest–southeast direction. Perhaps it can accommodate only a 2,000-foot lateral (see Figure 6.1). In this case, the costs of the well would be less. NETL has not sought information on the cost of this well with a 2,000-foot lateral; however, NETL expects the costs to be around $4 million, including the 2D seismic survey. As indicated in Section 3, a well with a 2,000-foot lateral would be expected to supply sufficient gas for about 15 years before a second well would be needed. Amortizing the costs over 15 years for the first well, the net annual savings would be approximately $35,000 (= $301,875-$4,000,000/15 year). The economics would improve for the second well drilled because the first well would continue to produce for another 10+ years to supplement the production from Well 2. Including an estimated O&M cost as given above, the net annual savings would essentially be -$25,000 (a loss). Again, a detailed analysis is needed to resolve the true net savings at this level of margin.

While the simple analysis presented above suggests a substantial financial benefit of drilling a longer well lateral, doing so would require access to neighboring property owner gas resources. Doing so would also reduce the risk/reward ratio taken on the well, given the 4,000-foot well lateral would access twice as much resource. Overall, based on these results, this option is expected to cost about as much as purchasing natural gas at today's prices, with potential for lower costs provided access to neighboring resources and a longer (4,000+ feet) well lateral can be achieved. It also can provide energy security (independence in natural gas supply) to the camp, albeit for a limited number of years (15 years for a single well with a 2,000-foot lateral, 30 years for a single well with a 4,000+ foot lateral, and longer but at decreased capacity as the resource depletes; see discussion surrounding Figure 17).

NETL's geologists believe that there is a risk that the Marcellus Shale beneath Camp Dawson will produce much less than the forecast amount, with most of this risk associated with the possibility that the gas has leaked out of this area along faults. Furthermore, NETL has not estimated the costs of well maintenance specifically for this project, but this could include costs for periodic removal of brine accumulations in the well, disposal of produced brine, servicing of valves and gauges, removal of deposited substances from inside the well, the purchase of natural gas while the well is being serviced, and other costs. Additionally, there has been no accounting of costs to remove hydrogen sulfide (H_2S) or other undesirable gases if concentrations of these gases exceed the specifications for the systems receiving the natural gas. Costs presented above would include minor well site equipment such as a water-gas separator and a storage tank for produced brine and ejected "frac" water, and minor site preparation costs.

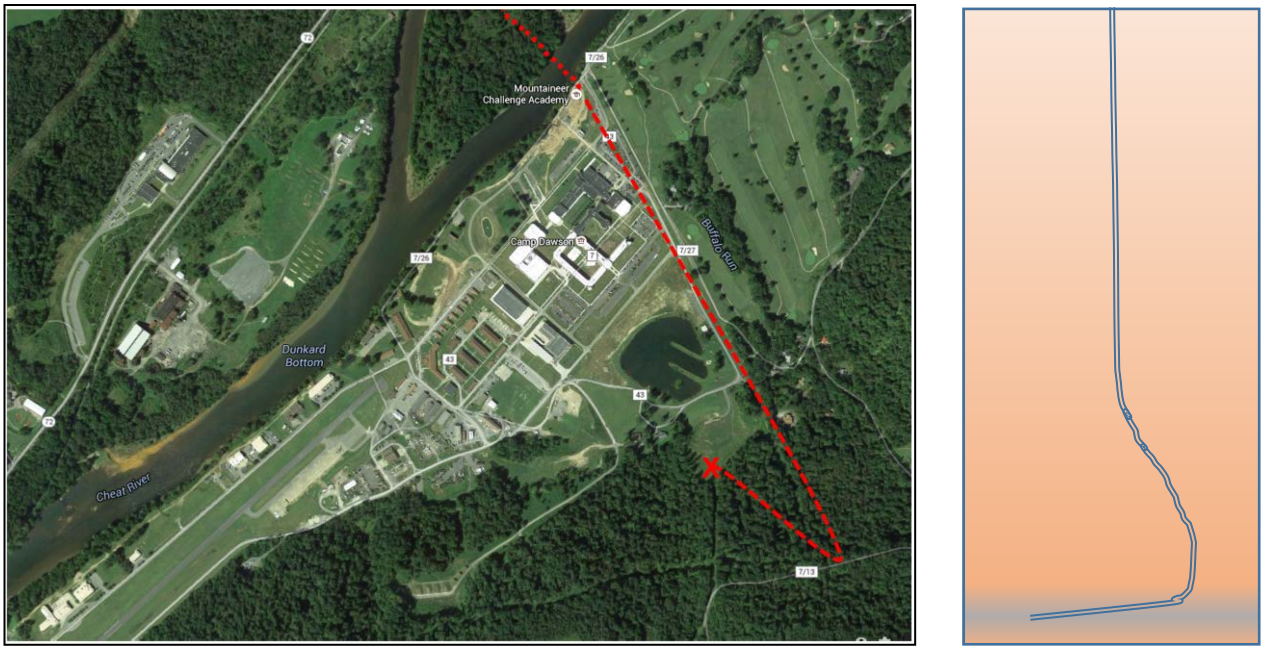

Figure 40: Aerial photo of Camp Dawson showing one potential well path in plan view (left) and x-section (right). A vertical well is also a possibility. Within the boundaries of the main parcel, the maximum lateral penetration is probably 3,300 feet or less.

6.3 DIRECT USE OF GEOTHERMAL HEAT

This case evaluates a geothermal system for space heating in the nine buildings currently using natural-gas-fueled hydronic heating. Two example well configurations are considered for accessing the geothermal heat. If the system is designed to meet the heat demand for the nine buildings 100 percent of the time, the wells and geothermal reservoir would need to circulate water at rates up to 1,763 GPM. This requires wells to be much larger in diameter than the typical commercial (natural gas) wells drilled to the depths of interest. It also requires the geothermal reservoir to have very high permeability, assuming only 2,000-foot laterals are drilled in the reservoir. Hence, the costs and risks go up significantly in an effort to meet the peak heating demand. In this situation, it would be more cost effective to drill smaller diameter wells (to take advantage of lower costs) and accept something less than 100 percent supply from the geothermal system. For example, in both configurations of wells, the system could be sized for 1,100 GPM and this would supply sufficient heat up to 82 percent of the time (see Section 2), with a temperature drop of $\Delta T = 20°F$ in the water as it goes through the geo-fluid heat exchanger. The balance of heat demand would then come from purchased natural gas and the existing boiler systems. Other sizes of the geothermal system could be more cost effective, but this type of optimization is not included in this study. If more buildings or other uses are added to the list of existing hydronic heat users, the configuration of wells and sizing of system components (including well diameters and reservoir area) would need to be reconsidered. Furthermore, it may be cost effective to replace the hydronic heating equipment in the buildings using lower temperature systems so that the input temperature requirements are lower and therefore the depths of drilling could be reduced. This latter option has not been assessed in this report.

Costs and equipment presented in this report are rough estimates. A detailed design of wells and above ground equipment, plus up-dated estimates of costs, should be completed by an engineering firm capable of doing this work.

Option 1 – Horizontal Wells: For this option, WVNG would drill two horizontal wells into suitable strata. The first well would be a vertical exploratory well drilled to a depth with suitable temperatures, but not exceeding 15,000 feet. Ideally, it would be drilled deep enough to allow evaluation of all three potential geothermal reservoirs (Oriskany Sandstone, Tuscarora Sandstone, and the Trenton-Black River Limestones), but this is not required. If any sandstone (or limestone) reservoir is confirmed to have a favorable temperature, permeability, and thickness, vertical drilling can stop and the well can have a horizontal lateral drilled into this layer. For direct use of geothermal heat, it is preferable for the selected reservoir to have at least 240°F temperature, 200 md permeability, and 100 feet of effective thickness. While these parameters are preferred, reservoirs that are cooler or thinner can be acceptable, but sufficient permeability must exist, either natural or man-made (e.g., hydraulic fractures). Chosen strata need to be suitable for installing two wells each having at least a 2,000-foot long lateral within the target strata. The two well laterals should be drilled approximately parallel to each other and have a spacing that results in a geothermal reservoir preferably with at least 3 million square feet of effective areal extent. A formation with a tight fold or with faults of large vertical offset may not allow for the drilling of well laterals that stay within the target strata. Minimum and maximum distance between the two well laterals have not been pre-determined, but instead would be a function of the length of the well laterals and the permeability characteristics of the strata or hydraulic fractures. It is highly preferable to find strata with sufficient natural permeability (via natural fractures and interconnected pores), rather than strata requiring hydraulic fractures, as the latter will cost considerably more and limit the distance between the two well laterals. Hydraulic enhancement of natural fractures may be of practical advantage where natural fractures of marginal permeability exist. Both the principal minimum stress direction and the expected dominant natural fracture direction dictate the preferred direction for horizontal drilling through the target strata. This direction of horizontal drilling is expected to be the northwest–southeast direction.

After the first well is completed and tested, a second well would be drilled to the same formation, with its lateral drilled through the target strata. To complete a circuit, one well would supply hot water via a pump to surface equipment (a heat exchanger), while the other well would inject the cooled water back into the reservoir after it has been circulated through the heat exchanger that serves a district heating loop. Figure 41 illustrates the nature of the horizontal wells. Assuming the design suggested in this figure circulates water efficiently through approximately 3 million square feet of geothermal reservoir having an initial temperature of 240°F, the reservoir simulation results shown in Table 9 indicate a potential lifetime of approximately 63 years for meeting the total heating load of the nine buildings with hydronic heating systems. An important assumption is that the circulated water flows throughout the areal extent of the geothermal reservoir to efficiently capture the heat – short-circuiting of the subsurface water flow must be minimal to achieve longevity in geothermal heat yield.

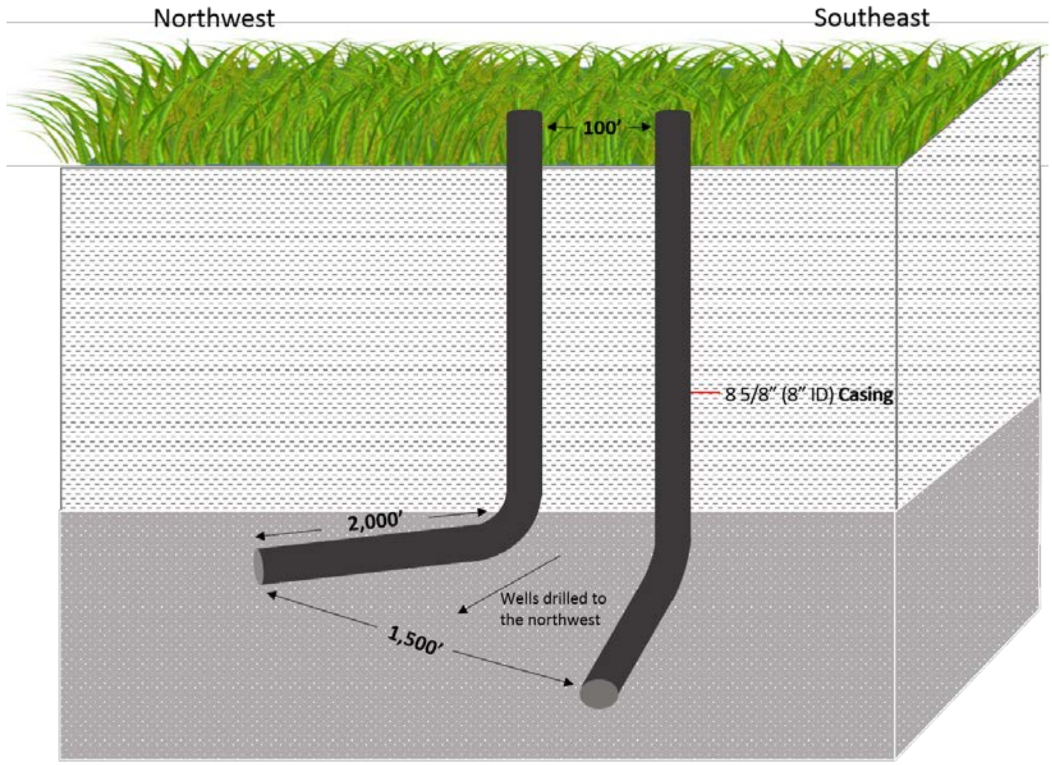

Figure 41: Geothermal wells schematic for two horizontal wells from one well pad.

The exploratory well could be drilled to 15,000 feet vertical depth using air to remove cuttings, unless drilling mud is required due to borehole conditions. Temperature measurements and drill stem tests would be conducted in various strata as the hole is drilled to probe the heat supply and permeability of each tested formation. Once drilling is completed, a suite of geophysical logs should be made to better identify lithology (rock type), porosity, water/gas saturations, and the locations of natural fractures. Based on this information, sidewall cores may be taken for further laboratory analyses. If a promising zone is identified at depth, a lateral can be drilled into this zone for more accurate flow testing and for mapping the natural fractures. If the decision is to complete the well for further use, a production casing may be installed and cemented down to or through the zone of greatest interest. Production casing or production tubing should have at least an 8-inch ID (to accommodate at least 1,100 GPM of flow), except that the upper part of the production well would need at least a 10-inch diameter production casing to accommodate a submersible pump. Completion of the well within the production zone would be a function of the integrity of the surrounding rock, the existence of open natural fractures, intergranular permeability, and other factors. Figure 42 illustrates one possible plan view of the two proposed horizontal wells beneath Camp Dawson and their orientation to the northwest. Both wells can be drilled from the same pad, located at a position to be selected on the eastern side of Camp Dawson. Well costs for this option are summarized in Table 12, and are comprised of a seismic survey, drilling the exploratory well, drilling production wells, etc. The total costs are likely to range from \$26.3 million to \$33.2 million depending on the depth of the wells, the length of horizontals, the completion design, and the amount of hydraulic fracturing. Exploration is a very significant part of the costs presented.

If exploration stops at the first (shallowest) strata that meets the requirements for the geothermal reservoir, the costs could be reduced by up to $5 million (if exploration stops in the Oriskany). In addition to stopping the exploration well at a shallower depth, costs could be further reduced if the selected formation has sufficient permeability to circulate water between the two wells without the need for hydraulic fractures (another $5.2 million in savings). If the selected formation has sufficient rock strength to not require a well casing to keep the borehole open, perhaps another million could be saved in casing, cementing, and casing perforations in the part of the wells within the target formation. Under the most optimistic conditions, total costs could be as low as $13.3 million for two wells drilled into the Oriskany or $15.5 million for two wells drilled into the Tuscarora.

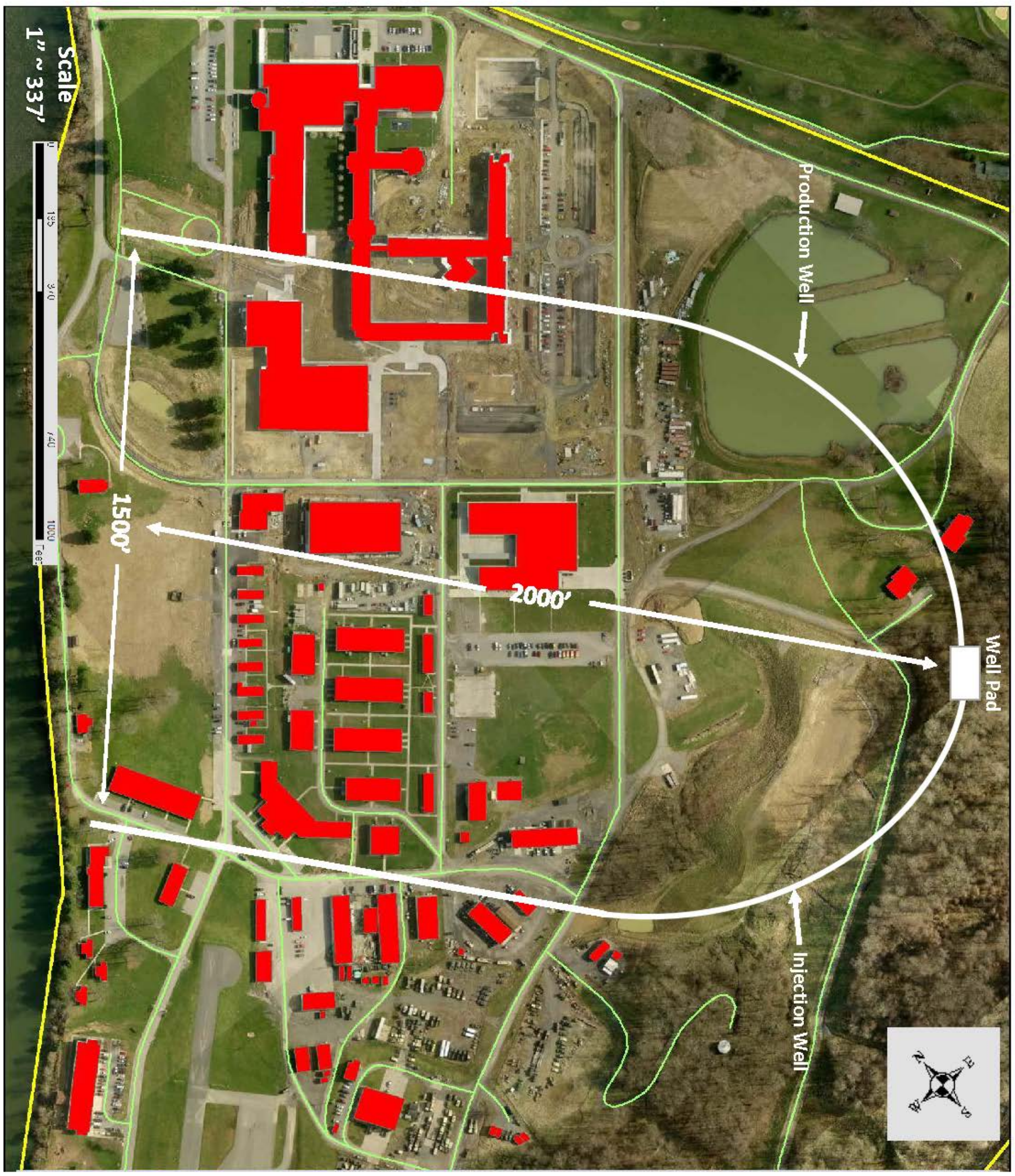

Figure 42: Plan view of proposed horizontal wells for geothermal heat capture. (Map of buildings provided by Camp Dawson)

Table 12: Estimated Cost for the Different Natural Gas and Geothermal Well Configurations

Natural Gas Well		**Total Cost ($MM)**
2-D seismic survey.		0.25
Drill, case, complete (hydraulically fracture), and set production equipment for one horizontal Marcellus Shale well (8.5-inch hole with 5.5-inch casing O.D., 4,000 feet lateral).		4.8
Total Cost of Natural Gas Well:		**5.1**
Geothermal Wells		
3-D seismic survey, 9 to 16 square miles.	**Initial vertical well**	0.9 to 1.4
Requirement for both Options 1 and 2: Drill initial vertical exploratory well (10 reduced to 8-inch ID casing) through the Trenton-Black River Limestone (15,000 feet). Evaluate potential geothermal reservoirs.		10.0
Total cost for seismic and initial vertical well.		**10.9 – 11.4**
Decision point whether to continue or stop further development.		
Two Horizontal Wells, Option 1	**Additional Cost ($)**	
If a favorable reservoir is identified, the exploratory well will be re-entered and drilled horizontally through the selected formation (8-inch ID casing, 4,000 feet lateral). Hydraulic fracturing cost included; ROP = 200 ft/d, $4.2MM for drilling and casing; $2.6MM fracturing at 150 foot stages.	6.8	
Total cost of initial well (vertical well converted to horizontal).		**17.7 – 18.2**
A second geothermal well (8-inch ID casing) will be drilled into the same formation. It is assumed that the wells will need to be hydraulically fractured.	**Second horizontal well**	
Drill horizontal Oriskany Sandstone well (8,100 feet TVD plus 4,000 feet lateral length, 8-inch ID casing, includes $2.6MM for fracturing at 150 foot stages). $6.5MM – $8.65MM.	8.6	
Drill horizontal Tuscarora Sandstone well (11,000 feet TVD plus 4,000 feet lateral length, 8-inch ID casing, v. slow drilling rates, includes $2.6MM for fracturing). $7.7MM to $12.7MM.	12	
Drill horizontal Trento-Black River Limestone well (14,900 feet TVD plus 4,000 feet lateral length, 8-inch ID casing, includes $2.6 MM for fracturing). $8.6MM to $16.8MM.	15	
Total Cost for Option 1:		**26.3 – 33.2***
	Depending on the depth of the reservoir that is completed.	

Four Vertical Wells, Option 2		
Cost for seismic survey + vertical exploratory well (described above).		10.9 - 11.4
Hydraulic fracturing of vertical well.		0.17
Total cost for seismic and initial vertical well		**11.1 - 11.6**
Decision point whether to continue Three additional vertical wells will be drilled into the same formation. It is assumed that the wells will need to be hydraulically fractured:	**Additional Wells**	
Drill three vertical Oriskany Sandstone wells (6-inch ID casing, 8,100 feet each).	6.5	
	or	
Drill three vertical Tuscarora Sandstone wells (6-inch ID casing, 11,000 feet each).	9.5	
	or	
Drill three Trenton-Black River Limestone wells (10-inch ID, 14,900 feet each).	12.5	
Total Cost for Option 2:		**17.6 – 24.1****
	Depending on the depth of the reservoir that is completed.	

* **For Horizontal Geothermal Wells:** If exploratory drilling stops in the Oriskany, the vertical well could cost as little as $3MM for a well with an 8-inch ID casing, including a well test for permeability and well logging. If the permeability of the Oriskany is sufficient to circulate 1,100 GPM such that hydraulic fracturing is not required and the formation is competent, the horizontal portion of the well could cost as little as $3.8MM. The total cost of this first geothermal well could be a low as $6.8 MM. The second geothermal well could cost as little as $6.5 MM. Thus, total costs for the subsurface system would be **$13.3 MM**. This option could be chosen if the temperature in the Oriskany is adequate for a reasonable geothermal system lifetime and if the permeability is high.

** **For Vertical Geothermal Wells:** If exploratory drilling stops in the Oriskany, the vertical exploratory well could cost as little as $2.4 MM for a well with a 6-inch ID casing, including a well test for permeability and well logging. Three additional wells could cost about $6.5 MM, as indicated in the table. Thus, total costs for the subsurface system would be **$8.9 MM**. This option could be chosen if the temperature in the Oriskany is adequate for a reasonable geothermal system lifetime.

Option 2 – Vertical Wells: For this option, WVNG would drill four vertical wells into suitable strata. Two would be hot water production wells to deliver heat to the heat exchanger; the other two would be injection wells to inject into the geothermal reservoir the cooled water coming from the heat exchanger (Figures 43 and 44). The wells are positioned relative to the principal rock stress directions and the expected fracture flow directions (if open natural fractures exist) to create the most efficient water flow pattern for extracting heat in the rock between the two injection wells and the two producing wells. A vertical well is exposed to only a small portion of the reservoir compared to a horizontal well. Unless extremely high inter-granular permeability exists in the target strata, vertical wells must have hydraulic fractures extending from the wells out into the target strata to gain sufficient surface area to permit the flow of water from the wells into or out of the rock. The effective half-lengths of these hydraulic fractures are likely to be no more than 600 feet, and may be only 300 feet. Thus, the total lateral reach of each vertical well with its hydraulic fractures is likely to be between 600 feet and 1,200 feet. Prior analysis of a nearby fractured reservoir by NETL and the orientations of all the horizontal wells in this region both indicate the minimum principal rock stress direction, which would control the orientation of induced hydraulic fractures in deep reservoirs. The minimum principal rock stress direction in the strata at these depths is expected to be horizontal and to the northwest-southeast. The hydraulic fractures are expected to be ellipsoidal in a vertical plane with their longest dimension in the northeast to southwest direction. Because induced hydraulic fractures will tend to parallel the most conductive natural fractures, rather than intersecting large numbers of these fractures, the strategy will be to force the circulated water to flow across the dominant fracture flow direction. This strategy would cause the injected water to seek cross fractures that connect between the dominant fractures and to spread across a broad area where it can more efficiently encounter and extract geothermal heat and deliver the required heat to the surface equipment over a longer span of time.

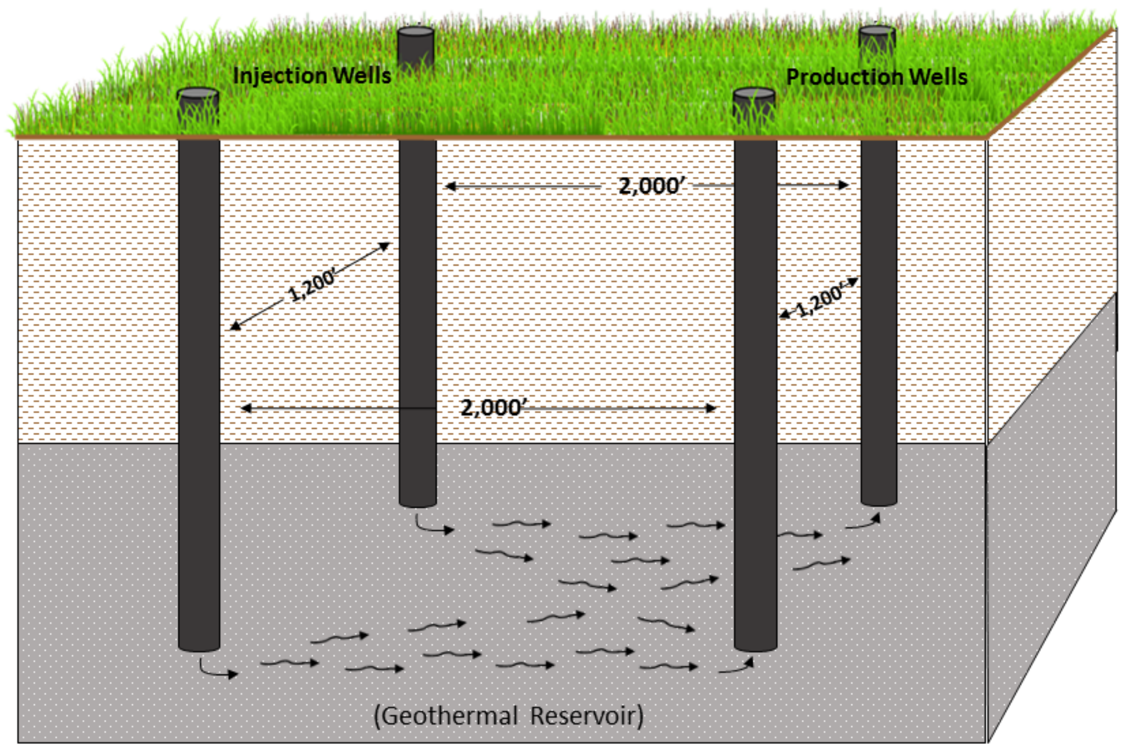

Figure 43: Geothermal wells schematic for four vertical wellbores. Hydraulic fractures are not shown.

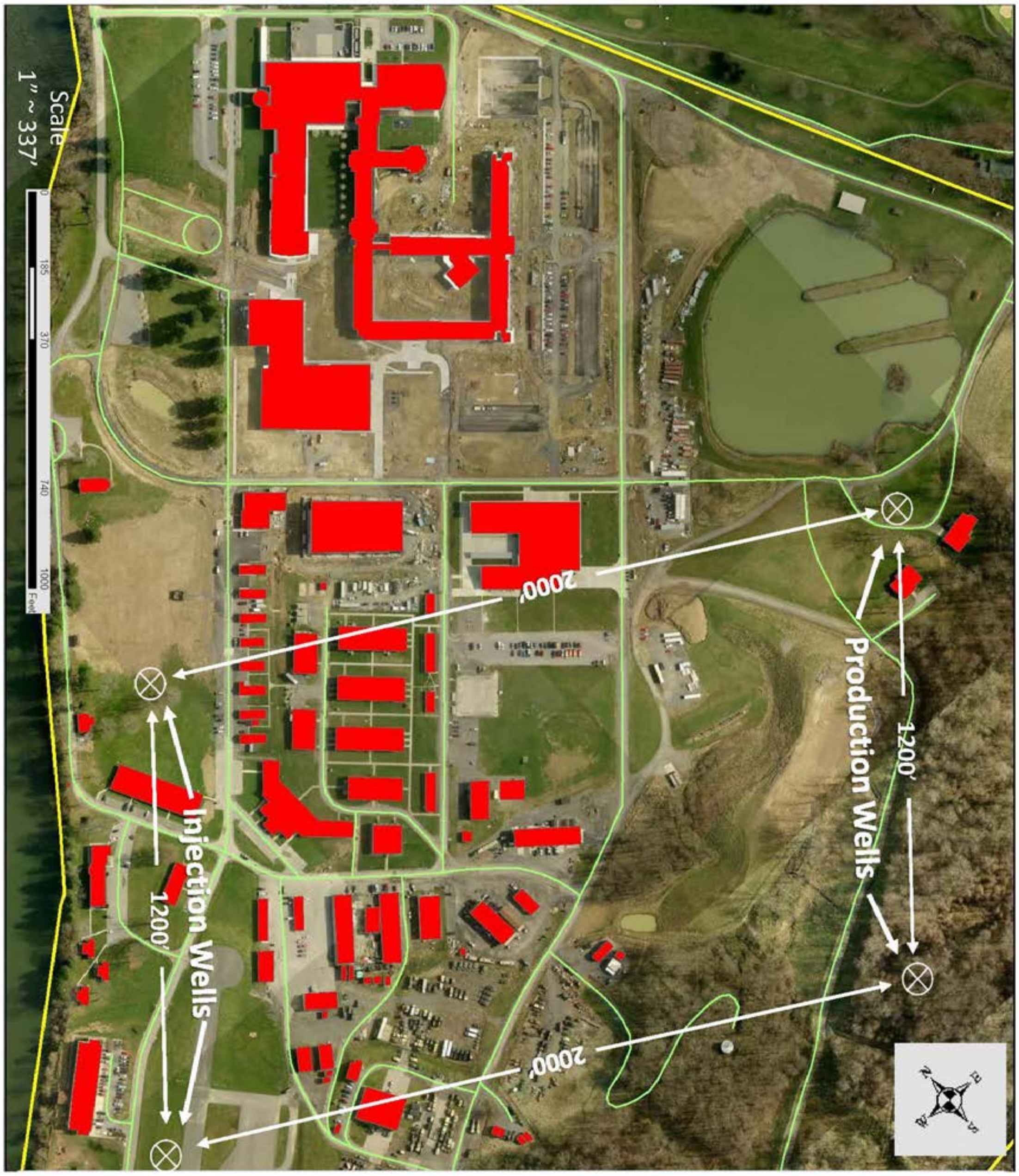

Figure 44: Plan view of proposed vertical wells for geothermal heat capture. Injection wells and production wells would be aligned on the east and west, so that water flow in the geothermal reservoir would be in the direction of northwest-southeast. (Map of buildings provided by Camp Dawson)

The initial vertical exploratory well will serve as one of the vertical wells, so the system needs only three additional vertical wells. These wells should have production casings (or production tubing) sized so that the two production wells (and the two injection wells) in combination can convey 1,100 GPM of flow. This flow rate could be achieved with reasonable flow velocities (about 12 ft/s) and frictional resistance in two wells with production casings 5 inches ID, not accounting for the diameter needed to accommodate a submersible pump. Assuming the layout presented in Figure 43, which has a pattern area of around 2,400,000 square feet, the lifetime would be approximately 50 years. Well development costs for this option are also listed in Table 12 and are comprised of a seismic survey, drilling the exploratory well, drilling production wells, etc. The total costs will likely range from $17.6 million to $24.1 million, again depending on the depth to which the resource is drilled to obtain suitable temperatures. Again, exploration is a very significant part of the costs presented. If exploration stops at the first (shallowest) strata that meets the requirements for the geothermal reservoir, the costs could be reduced by up to $5 million (if exploration stops in the Oriskany). If the selected formation has sufficient rock strength and integrity to not require the well casing to keep the borehole open, a little more money could be saved in casing, cementing, and casing perforations in the part of the wells within the target formation. Under the most optimistic conditions, total costs could be as low as $8.9 million for four vertical wells drilled into the Oriskany or $13.4 million for four vertical wells drilled into the Tuscarora. A plan view of proposed vertical wells for geothermal heat capture is shown in Figure 44.

Geothermal Well Hydronic Piping System

To create a circuit for the production, use, and subsequent injection of geothermal water (actually a brine), the system will require an insulated underground piping system between the supply and injection wells. This piping, along with the wells, well pumps, and geothermal reservoir, will complete the “geothermal loop.” A “district loop,” constructed of insulated underground piping and having a circulator pump, will circulate heat in clean water to the buildings. These loops constitute two separate systems that interface through a plate heat exchanger. This separation is necessary since the ground water from the geothermal well(s) will likely contain high concentrations of dissolved solids in forms that can precipitate in the pipes and other system components. A typical arrangement is shown in Figure 45 below. Notice that a peaking and backup unit is also in the district loop. These are the existing natural gas boilers in the nine buildings.

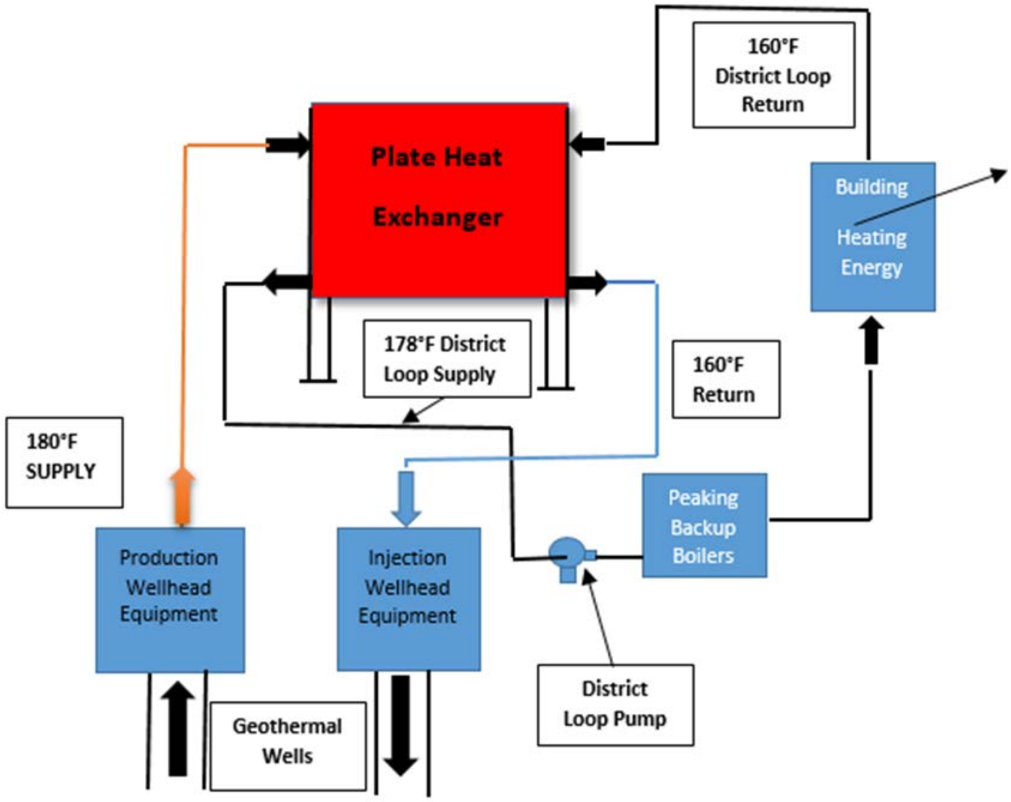

Figure 45: Geothermal distribution system.

A geothermal loop requires at least one production well and at least one injection well. The geothermal water is injected into the geothermal reservoir via the injection well, perhaps aided by a pump with enough power to overcome the flow resistance through the well casings and the strata at the bottom of the well called the reservoir. Most likely, the pressure of the injection pump would not push the water back to the land surface through the production well, so an additional submersible well pump would be required in the production well. Permeability of the reservoir is a critical parameter in the design of a geothermal system, and is used to plan the configuration and spacing of the wells, the type of treatment of the reservoir formation (e.g., hydraulic fracturing, hydraulic enhancement of natural fractures, acid treatment), and the sizing and energy requirements of the pumps. Usually, permeability cannot be determined with sufficient accuracy in advance of drilling and testing the reservoir. Permeability in reservoirs is both heterogeneous and anisotropic.

Since the buildings are separated by short distances, a district heating loop can be installed to deliver heated clean water to each building. As it comes out of the production well, the water will be at least 180°F (or the chosen threshold temperature). The heat exchanger will transfer a portion of the heat to the district loop to be sent to the buildings. The piping is to be buried in a trench 3–4 feet deep as shown in Figure 46, with supply and return pipes sharing the same trench where possible. The piping should be an insulated pipe with a PVC external jacket that will provide protection underground. The production and injection wells will be separated by some distance and can be 2,000 feet or more apart. The pipe should be an insulated direct burial pipe similar to that manufactured by Ricwel called Terra Guard.

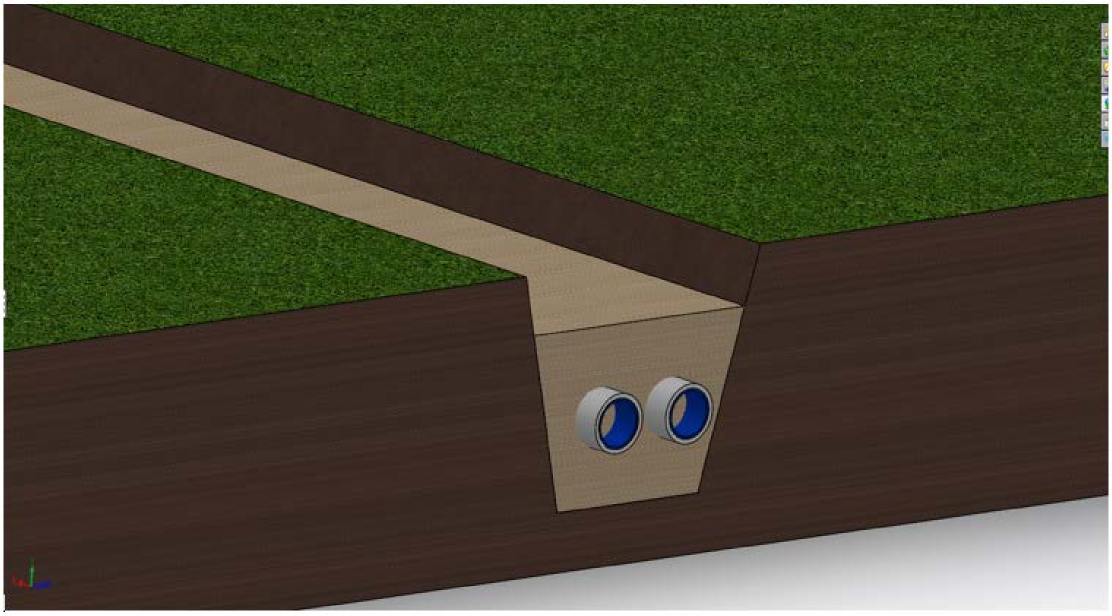

Figure 46: Buried hydronic piping.

The size of the pipe from the production and injection wells will be an 8-inch ID to handle the flow of 1,100 GPM with a reasonable pressure drop of 2.5 feet of water per 100 feet of pipe. As the water is distributed to the buildings, the size of the pipe may decrease accordingly depending on system design. Table 13 (below) shows an estimated total length and cost of pipe required.

Table 13: Piping Cost Estimate

Pipe Size (inch)	Length (feet)	Cost/Foot Installed ($)	Total Cost ($)
8	5,041	325	1,640,000
6	502	237	120,000
4	890	161	143,290
21/2	890	100	89,000
Fittings			50,000
Excavation			75,000
Backfill			30,000
Building Modification			90,000
Totals	**7,323**	**$306/Foot**	**2,237,290**

(RSMeans Mechanical Cost Guide, 2010)+

Heat Exchanger Between the Geothermal Loop and the District Loop

The most common type of heat exchange for this application is a plate heat exchanger. Thermoflo Equipment Company sized a plate type heat exchanger for saline ground water to supply heat to the district loop's hot water supply. The conditions were 180°F supply from the well and 160°F return to the injection well with a maximum flow rate of 1,500 GPM. This is more than the proposed design flow rate of 1,100 GPM to allow for possible future demand increases. The heat exchanger is shown in Figure 47. On the district side of the exchanger, the input water is at 160°F, and it leaves the heat exchanger to supply the buildings at 178°F. The cost of the heat exchanger is $115,000 plus installation costs, which could be approximately $15,000. Table 14 gives the specifications for the heat exchanger.

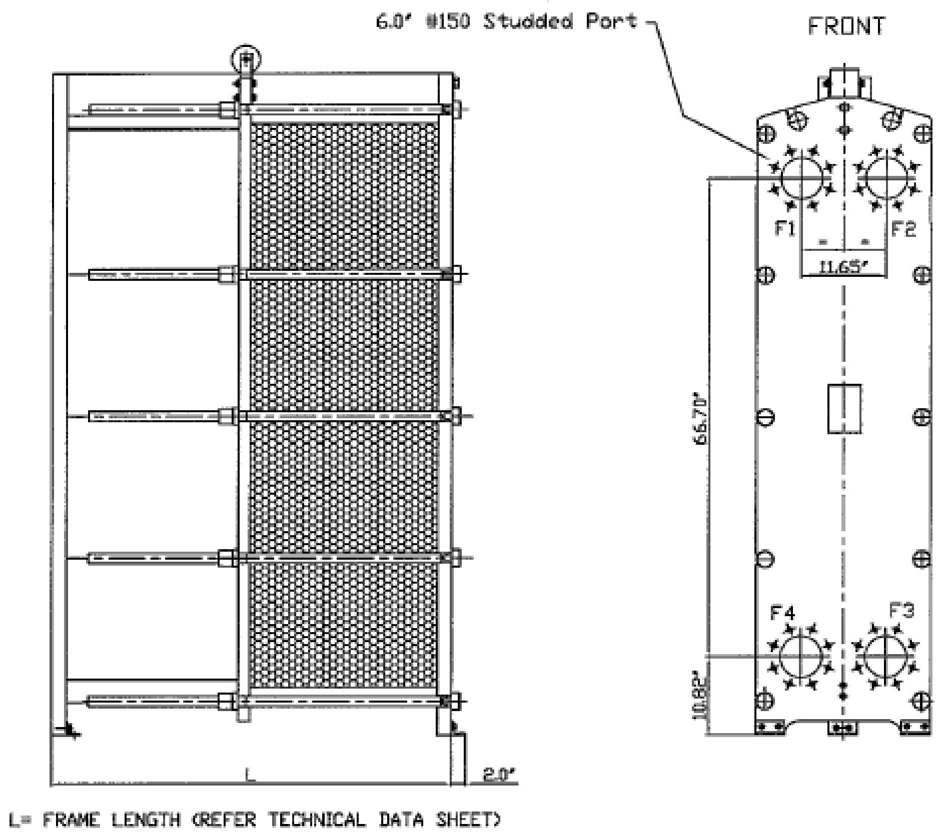

Figure 47: Geothermal plate heat exchanger.

Table 14: Geothermal Heat Exchanger Specifications

Sondex, INC - Design & Datalist

			V10A36
Hoffman and Hoffman	Ken		4/6/2016
211	S 1604002R		Item: 1
PHE-Type S86-IS10-418-TLX-LIQUID		Hot side	Cold side
Flowrate	(g.p.m.)	1500.00	1500.00
Inlet temperature	(°F)	180.00	160.00
Outlet temperature	(°F)	161.99	178.00
Pressure drop	(PSI)	19.97	19.82
Heat exchanged	(Btu/h)	13187910	
Thermodynamic properties:		Water	Water
Density	(Lb/Ft³)	60.76	60.80
Specific heat	(Btu/Lb*F)	1.00	1.00
Thermal conductivity	(Btu/h*Ft*F)	0.38	0.38
Mean viscosity	(cP)	0.39	0.40
Wall viscosity	(cP)	0.40	0.39
Inlet branch		F1	F3
Outlet branch		F4	F2
Design of Frame / Plates:			
Plate arrangement (passes*channel)		1 x 208 + 0 x 0	
Plate arrangement (passes*channel)		1 x 209 + 0 x 0	
Number of plates		418	
Effective heat surface	(Ft²)	4,030.07	
Plate material		0.0236 inch TITAN	
Gasket material		NITRIL SONDER LOCK (S)	
Max. design temperature	(°F)	200.00	
Max. Working/test pressure	(PSI)	100.00	130.00
Approval		ASME with stamp	
Liquid volume	(Ft³)	39.75	
Frame length	(Ft)	10.17	Max. No. of Plates 468
Net weight	(Lb)	5777	
Frame type		IS	
Connections HOT side :	6 INCH studded end connection with rubberlined,#150		
Connections COLD side:	6 INCH studded end connection with rubberlined,#150		

Pumping Equipment

- **District Loop Pump**

  The pump that circulates the hot water from the heat exchanger to the nine buildings must be able to deliver 1,100 GPM at approximately 250 feet of water head pressure or 114 psig. It is assumed that each building served by the district loop will retain its existing hot water pumps for delivery within the buildings. The distribution loop pump should be controlled by a variable speed drive to allow for varying demands of hot water supply throughout the heating season. The main circulation pump selected could be a base mounted or vertical centrifugal pump. Every pumping system needs a redundant pump in case one fails or needs maintenance. This pump must have the power to deliver the proper flow to the nine buildings on site. The motor would likely be in the 50 HP range (Crane, 2009), and the pump would cost approximately $15,000. Typical pumps are shown in Figure 48.

Figure 48: Centrifugal pumps and packaged systems for variable speed control.

- **Geothermal Loop Pumps**

  The most difficult part of this study is to determine the geothermal reservoir characteristics that underlie Camp Dawson. Temperature estimates are from nearby wells drilled for natural gas (and not for geothermal heat extraction). Unlike temperature measurements that are often reported to the regulatory agencies, permeability measurements or estimates are not reported. More importantly, permeability of rock layers is notorously variable from place to place, and permeability is virtually impossible to detect remotely via seismic surveys or other geophysical prospecting. Wells and well tests at the point of interest are required. Both reports from a field engineer for a nearby gas storage field in the Oriskany Sandstone and an unpublished well test analysis by NETL indicated a bulk reservoir permeability in the more intensely fractured areas (naturally fractured folds and fault zones in the Oriskany Sandstone) of about 200 md. In that storage field, the field engineer estimated the bulk permeability elsewhere in the field to be 10 to 20 md. Given this information from a nearby gas storage field, an approximate calculation can be made for the pressure drop between two horizontal wells with 2,000 feet laterals each, with a uniform distance between the wells of 1,500 feet. For water temperatures of 240° F, a water flow rate of 1,100 GPM, and a bulk reservoir permeability of 200 md, the pressure drop for water flowing through the reservoir between the two horizontal wells would be around 311 psi. As the temperature drops in the reservoir over time to 180° F, the pressure drop between the wells would increase to 429 psi. If the bulk reservoir permeability is only 20 md, the pressure drop between the wells would be ten times as high. Thus, knowing the reservoir permeability is necessary for sizing the pumps on the geothermal loop and choosing the type and placement of the pumps, the primary pump would likely be a submersible pump installed in the production well. It is preferable to drive the circulation of the geo-fluid with a submersible pump because this configuration avoids the pressure buildup that otherwise would occur near the injection wells, thereby decreasing the chance of induced seismicity and water loss. If the geothermal reservoir is very tight, a pump on the injection well may be used in addition to the submersible pump.

  Pressure drop in the well casing is a function of the flow rate, friction factor, and water viscosity. For a pair of horizontal wells, the wells would consist of an 8-inch ID casing handling variable flow rates between 600 to 1,600 GPM at temperatures of 160°F to 180°F. Figure 6.10 below shows the pressure drop as a function of flow rate in a 12,000-

foot deep well. The drop would be similar in either the supply or injection well. Thus, the pressure drops for the two pumps would be 70 psi in the supply well, plus 70 psi in the injection well, plus the reservoir impedence which at this point is unknown. The velocity in the pipe varies from 3.8 to 10.2 feet/second, and the Reynolds Number varies from 0.6×10^6 at 600 GPM to 1.6×10^6 at 1,600 GPM, which is in the turbulent flow regime.

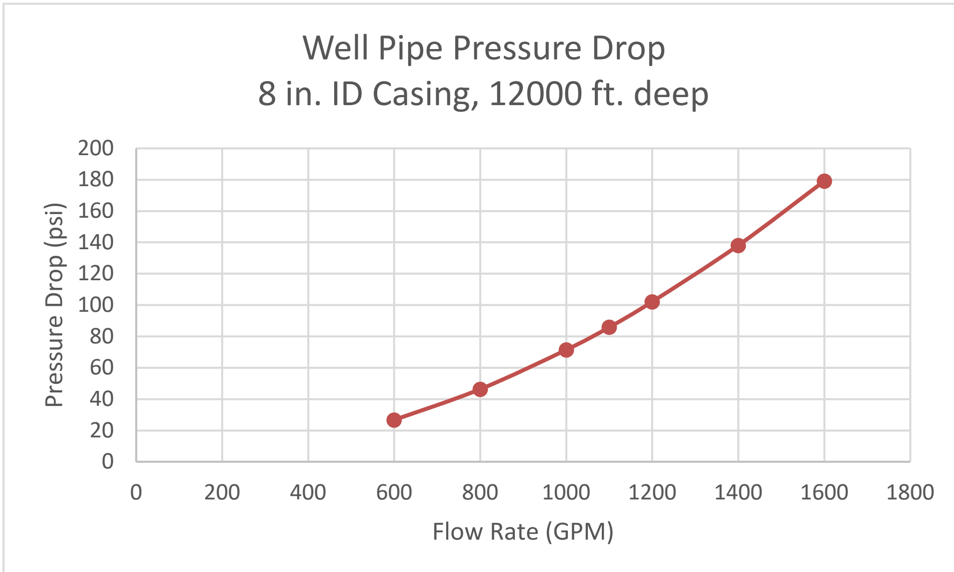

Figure 49: Pressure losses during flow within the well bore as a function of flow rate for a specified casing ID and well depth.

Finally, if hydraulic fracturing is used to create flow pathways through the reservoir between the injection well(s) and the production well(s), two problems may occur. First, the distance between the injection and production wells may be relatively short, with the consequence that the volume of reservoir may be less than required to provide a long life of suitable heat yield. Second, the hydraulic fractures cannot be made with equal flow conductivities, with the consequence that flow is concentrated through the most conductive fractures where the heat is quickly mined out and the actual life span of the system is much shorter than the expected life span. There are flow controllers that can be installed in cased wells to regulate flow through perforations in the casing and thereby mitigate the second problem stated above (“short circuiting”).

As highlighed above, the energy required to move water through the reservoir depends on several factors. They include the depths of the injection and supply wells, the well pipe diameters, water level in the ground, and the reservoir permeability. In a new project many of the below ground factors are unknown and must be estimated on available data from nearby wells if test data at the site is not known. It is currently expected that deep geothermal systems will require both an injection pump at the injection well and a deep submersible pump at the supply well. To provide the required flow, the injection pump will assist the production well’s pump in creating a pressure differential between the wells sufficient for the required flow rates. Injection pressures are kept to the point below where fracturing of the rock in the reservoir takes place. The production well will have an electric submersible pump sized to lift the supply water to the surface through the well casing. The head pressure depends on natural water pressure in the reservoir, the length and size of the supply well casing, and the required flow rate. If the geothermal loop only provides heat to the nine buildings, the casing is likely to be 8 inches in diameter (ID), which would allow for the 1,100 GPM of hydronic flow needed. If the geothermal loop provides heat to a binary ORC system for production of electricity, the flow rate would depend on the chacteristics of the ORC system. An example of an electric submersible pump is shown in Figure 50 below. The pump shown here is a REDA Maximus and is able to withstand the environment encountered at depths where the geothermal resources are located. The cost of these pumps will be determined by the flow rate, head pressure, and environmental constraints. The cost may be in the range of $250,000–$300,000. Pumping costs can be a factor in the efficiency of a geothermal system and can be determined after the characteristics of the reservoir are known.

Figure 50: Electric submersible pump (REDA/Schlumberger).

Make-Up Water Suppl

Although not anticipated at this site, on some geothermal applications in various parts of the world, water injected under pressure into a deep reservoir and extracted from a production well is lost to imbibition into gas-filled rock or through leakage routes that extend into other strata. Therefore, it is sometimes necessary to make up that water loss by adding water from a nearby source such as a lake, river, or domestic supply. When make-up water is needed, infrastructure must be in place to allow for replacement of lost water. Injection of water at surface temperatures will have an adverse effect on the life of the reservoir that can be estimated when the quantity of make-up water is known. This infrastructure would include piping and pumps from the water source.

Surface Structures

It will be necessary to house the pumps, heat exchangers, electrical panels, and other equipment for the project. This structure(s) would likely be located at the well heads for the geothermal wells. This can be in a pre-engineered metal building, which is economical and relatively fast to construct. According to the 2014 Means Building Construction Cost for a 50-foot wide structure, the cost per square foot installed is approximately $20/ft^2. Alternatively, WVNG can choose to put equipment in subsurface vaults for security reasons. Such costs have not been considered here.

Summary of Costs by Geothermal Design Option

The total cost for the Geothermal Systems for the two proposed well configuration options at three specified depths can be seen in Table 15 below. The potential cost savings mentioned in Table 12 Notes have not been considered in the cost estimates of Table 15.

Table 15: Total Geothermal System Cost Summary

Well Depth	Well Cost	Piping/Pumping System Costs	Total System Costs
Option 1 (2 Horizontal Wells)—63 Year Lifetime			
Oriskany Sandstone	$26,800,000	$2,400,000	$29,200,000
Tuscarora Sandstone	$30,200,000	$2,400,000	$32,600,000
Trenton-Black River Limestone	$33,200,000	$2,400,000	$35,600,000
Option 2 (4 Vertical Wells)—50 Year Lifetime			
Oriskany Sandstone	$17,570,000	$2,400,000	$19,970,000
Tuscarora Sandstone	$21,070,000	$2,400,000	$23,470,000
Trenton-Black River Limestone	$24,070,000	$2,400,000	$26,470,000

While little is known regarding O&M costs for these geothermal systems, it is likely to be a little more expensive than natural gas wells, and for estimating purposes $100,000 per year was used. Annual costs for operating a system can now be estimated, and for the Black River Limestone Option 1 case, the annual costs for employing this option will be $725,000 (= $35,600,000/63yr + Peak NG Heat Costs of $60,000 + O&M of $100,000). Hence, the potential annual cost savings relative to current operations for well Option 1 range from -$423,000 (loss) to -$981,000 (loss), depending on the depth of the resource. For Option 2, the range of potential annual cost savings is from -$627,000 to -$387,000. This cost assessment accounts for the additional costs to the utility to pay for the peak heating demand and estimates for O&M. As seen here, all cases will require an annual expenditure that is more than current costs (approximately $302,000 per year) to achieve a significant level of independence, with Option 1 having the most likely lower overall cost because of its potential longer lifespan. As before, a more detailed analysis is needed to provide confidence in the overall annual cost for these systems.

Electrical Infrastructure

Electricity would be needed for the well pump(s), as well as for the circulator pump in the district loop. The costs listed above do not include these electrical costs since the resource is not sufficiently characterized to determine pressure drop versus flow rate. At the time of the exploratory well, it is suggested that permeability assessments be performed to better determine this operational cost.

6.4 NATURAL GAS FOR ON-SITE POWER AND HEAT

This section considers the use of natural gas from a reservoir beneath Camp Dawson for electric-power generation (non-CHP case), as well as combined heat and power generation (CHP case). For both, three baseload cases are reviewed using three different gas turbine systems, along with two full-demand following cases. Baseload is defined as the average annual site load, which is approximately 1.4 MW.

Capital Cost Estimation

NETL reviewed several gas turbine engines that fit Camp Dawson's on-site electricity demands. Their respective cost data were obtained from the available literature (Gas Turbine World, 2012), (Van der Putten, 2016), and Catalog of CHP Technologies (EPA, 2015). However, only one turbine (the Capstone C200) was priced both in non-CHP and CHP-ready configurations. A comparison of non-CHP and CHP-ready prices for the C200 shows a 46 percent increase in costs, which was applied to the other turbines under study to obtain their CHP-configured costs. Table 16 identifies the turbines selected for this study and their respective costs. Performance values for the five cases studied are shown in Table 17.

Calculations for the LCOE assume the following values: zero cost for fuel, a fixed capital cost for natural gas wells, a typical scaling of non-fuel variable O&M costs for the natural gas well and turbine (Lo, 2014). Details for other financial parameters are given in Appendix G. The heat rate (efficiency) for a single turbine is taken directly from the literature. Where multiple turbines may be needed (e.g., to meet peak electricity needs), the heat rate for the combined system is a capacity-weighted average value of their individual heat rates. Capacity factors are calculated using reported electricity-demand totals (found in Appendix B). Capacity factor (CF) is defined as the total power generated divided by the total power that may have been generated if the plant ran at full nameplate capacity for a year with no downtime:

$$CF = \frac{AnnualLoadSupported}{TurbineAnnualMaxCapacity}$$

Table 16: Turbine Cost Data – All Costs Given Using 2011 Dollars

Quoted Turbine Cost	Capacity	2016 basis [$/kW]	2016 basis [$]		Notes
C200					
[$/kW]	[kW]	[$/kW]			
$ 1,100	200	$ 1,144	$ 228,800	Stock Turbine	just the turbine
$ 2,120		$ 2,136	-		turbine and heat-recovery equipment
		$ 992	-		Delta for heat recovery
		46%	-		Proportion for heat recovery
		$ 1,675	$ 335,041	CHP-ready Turbine	
C1000					
$ 1,710	1,000	$ 1,723	$ 1,722,654	Stock Turbine	
		$ 2,523	$ 2,522,553	CHP-ready Turbine	
Heron H-1					Not yet commercially available. Manufacturer's Expected pricing
$ 1,564	1,407	$ 1,563.61	$ 2,200,000	Stock Turbine	
		$ 2,290	$ 3,221,551	CHP-ready Turbine	
M1A-13D					
$ 757	1,485	$ 787	$ 1,169,111	Stock Turbine	
		$ 1,153	$ 1,711,977	CHP-ready Turbine	

Table 17: Turbine Performance Data

TURBINE PERFORMANCE		Baseload	Baseload	Baseload	Full-load	Full-load
Turbine	[-]	H-1	C1000 +C200	M1A-13D	H-1 + C1000	M1A-13D + C1000
Capacity	[kW]	1407	1400	1485	2407	2485
LHV Efficiency	[%]	43%	30%	24%	36%	26%
HHV Efficiency	[%]	39%	27%	22%	33%	23%
HHV Heat Rate	[Btu/kWh]	8,824	12,832	15,797	10,489	14,604

The annual CF was determined as follows. The turbine rating was multiplied by the number of hours in the month. This all-out-running product was then compared to the power demand for that month. If the all-out-running product exceeded the month's power demand, the all-out-running product was reduced by the difference. If the power demand exceeded the all-out-running product, the remainder was noted as power to buy or make up. After addressing each month, the total MWh generated by the turbine for the year was divided by the total it could have generated if it ran all-out every hour of the year, yielding an "estimated" CF for the turbine. If this "estimated" CF was greater than the target CF (98 percent) cited in the literature (EPA, 2015), the amount of power produced in May was reduced until the annual CF reached a value of 98 percent (Hodge, 2010). May was chosen because of its low combined electrical and heating demand. Note that Table 18 shows the Heat Made values for June, July, and August in grey. This denotes the assumption, from records, that no heat will generally be needed in these months. Thus, the heat made in this interval is not included in the comparison between heat made via the turbine and heat needed by the Camp.

Table 18: Capacity Factor Calculations for Baseload and Full-Demand Support Cases

			Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	CF
H-1	PWR	[MWh]	986	946	1,047	1,013	974	1,013	1,047	1,047	1,013	1,047	988	956	
	PWR to Buy	**[MWh]**	**0**	**121**	**81**	**67**	**65**	**6**	**79**	**135**	**101**	**94**	**0**	**0**	
	Heat Made	[MMBtu]	1,821	1,747	1,934	1,872	1,799	1,872	1,934	1,934	1,872	1,934	1,825	1,767	
	Heat to Buy	**[MMBtu]**	**6,893**	**5,629**	**4,157**	**1,958**	**131**	**0**	**0**	**0**	**0**	**1,641**	**3,404**	**5,892**	**0.980**
C1000 + 2(C200's)	PWR	[MWh]	986	941	1,042	1,008	958	1,008	1,042	1,042	1,008	1,042	988	956	
	PWR to Buy	**[MWh]**	**0**	**126**	**86**	**72**	**80**	**11**	**84**	**140**	**106**	**99**	**0**	**0**	
	Heat Made	[MMBtu]	3,653	3,486	3,860	3,735	3,551	3,735	3,860	3,860	3,735	3,860	3,660	3,544	
	Heat to Buy	**[MMBtu]**	**5,061**	**3,890**	**2,231**	**94**	**0**	**0**	**0**	**0**	**0**	**0**	**1,568**	**4,115**	**0.980**
M1A-13D	PWR	[MWh]	986	998	1,105	1,069	1,038	1,019	1,105	1,105	1,069	1,105	988	956	
	PWR to Buy	**[MWh]**	**0**	**69**	**23**	**10**	**0**	**0**	**21**	**77**	**45**	**36**	**0**	**0**	
	Heat Made	[MMBtu]	7,033	7,119	7,882	7,628	7,408	7,267	7,882	7,882	7,628	7,882	7,047	6,823	
	Heat to Buy	**[MMBtu]**	**1,681**	**257**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**836**	**0.964**

			Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	CF
H-1 + C1000	PWR	[MWh]	986	946	1,047	1,013	974	1,013	1,047	1,047	1,013	1,047	988	956	0.98
	PWR to MakeUp	[MWh]	0	121	81	67	65	6	79	135	101	94	0	0	
	Heat Made	[MMBtu]	1,821	1,747	1,934	1,872	1,799	1,872	1,934	1,934	1,872	1,934	1,825	1,767	
	Heat to MakeUp	[MMBtu]	6,893	5,629	4,157	1,958	131	0	0	0	0	1,641	3,404	5,892	
	PWR	[MWh]		121	81	67	65	6	79	135	101	94			0.085
	PWR to Buy	**[MWh]**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
	Heat Made	[MMBtu]		506	337	278	271	23	331	566	422	391			
	Heat to Buy	**[MMBtu]**	**6,893**	**5,123**	**3,820**	**1,679**	**0**	**0**	**0**	**0**		**1,250**	**3,404**	**5,892**	
	Combined CF (PWR)	[frac.]													**0.608**
M1A-13D + C1000	PWR	[MWh]	986	998	1,105	1,069	1,038	1,019	1,105	1,105	1,069	1,105	988	956	0.964
	PWR to MakeUp	[MWh]	0	69	23	10	0	0	21	77	45	36	0	0	
	Heat Made	[MMBtu]	7,033	7,119	7,882	7,628	7,408	7,267	7,882	7,882	7,628	7,882	7,047	6,823	
	Heat to MakeUp	[MMBtu]	1,681	257	0	0	0	0	0	0	0	0	0	836	
	PWR	[MWh]	0	69	23	10	0	0	21	77	45	36			0.085
	PWR to Buy	**[MWh]**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
	Heat Made	[MMBtu]	0	287	94	44	0	0	89	323	187	149			
	Heat to Buy	**[MMBtu]**	**1,681**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**836**	
	Combined CF (PWR)	[frac.]													**0.589**

For a given case, it is assumed that one 4,000-foot lateral natural gas well is developed at a cost of $5.05 million. It is also assumed that the well adds to the capital cost at the beginning of the project. Applying the estimated total natural gas resource of 1,400,000 MCF to turbine firing gives the lifetimes for each case, as shown in Tables 19 and 20.

Table 19: LCOE for Non-CHP Cases (Electric Power Only)

	Baseload	Baseload	Baseload	Baseload & Peaking	Baseload & Peaking
	Turbine Power	Turbine Power	Turbine Power	Turbine Power	Turbine Power
Case Number	11	12	13	14	15
	H-1 NG Well 4000 ft lateral	C1000+2(C200) NG Well 4000 ft lateral	M1A-13D NG Well 4000 ft lateral	H-1&C1000 NG Well 4000 ft lateral	M1A-13D&C1000 NG Well 4000 ft lateral
Well Cost ($)	$5,050,000	$5,050,000	$5,050,000	$5,050,000	$5,050,000
Full Year Annual Thermal-energy Demand	45,432	45,432	45,432	45,432	45,432
Fraction of Total Annual Thermal Demand	0%	0%	0%	0%	0%
Full Year Annual Electrical-Energy Demand	12,823	12,823	12,823	12,823	12,823
Fraction of Total Annual Electrical Demand supplied by Case Configuration	94%	94%	98%	100%	100%
Plant Performance					
Fuel	None	None	None	None	None
Energy units	MWh	MWh	MWh	MWh	MWh
Capacity	1.407	1.400	1.485	2.407	2.485
Capacity Factor [%]	98%	98%	96%	61%	59%
BTU/kWh	8,824	12,832	15,797	10,489	14,604
Life of Plant (Years)	13	9	7	10	7
Total Overnight Capital [1000$]	$7,250	$7,001	$6,219	$8,973	$7,942
Cost of Product					
	Project	Project	Project	Project	Project
COP units	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh
Dollar Year used in finance calculations	2016	2016	2016	2016	2016
LCOE/LCOH (Heat=$/MMBtu; PWR=$/MW	$52.68	$71.25	$76.98	$73.77	$92.15
Capital Component	$46.18	$64.72	$70.83	$69.97	$88.48
O&M Component	$6.49	$6.52	$6.15	$3.79	$3.68
Fixed O&M Component	$0.00	$0.00	$0.00	$0.00	$0.00
Fuel Component	$0.00	$0.00	$0.00	$0.00	$0.00
COP in First Year of Operation	$55.34	$74.85	$80.88	$77.50	$96.82
	$ 636,069	$ 856,344	$ 965,579	$ 945,917	$ 1,181,662
	MMBTU	MMBTU	MMBTU	MMBTU	MMBTU
Heating Supplied per Year	-	-	-	-	-
	0.00	0.00	0.00	0.00	0.00
MakeUp Heating Purchased	$301,875	$301,875	$301,875	$301,875	$301,875
Total annual HEATING cost	$301,875.00	$301,875.00	$301,875.00	$301,875.00	$301,875.00
Percent of Today's Heating Cost	100%	100%	100%	100%	100%
	MWh	MWh	MWh	MWh	MWh
Electricity Supplied per year	12,075	12,019	12,543	12,823	12,823
	0.94170	0.94	0.97814458	1.00000	1.00000
MakeUp Electricity Purchased	$48,219	$51,825	$18,076	$0	$0
Total annual ELECTRICITY cost	$684,288	$908,169	$983,655	$945,917	$1,181,662
	$685,910.85	$909,764.43	$986,520.47	$977,265.65	$1,214,538.11
	$143,598	-$80,283	-$155,769	-$118,031	-$353,777
Percent of Today's Electric Cost	83%	110%	119%	114%	143%
Total annual ENERGY Cost	$986,163	$1,210,044	$1,285,530	$1,247,792	$1,483,537
Percent of Today's ELECTRIC + HEATING Cost	87%	107%	114%	110%	131%

Table 20: LCOE for CHP Cases (Electric Power + Heat)

		Baseload	Baseload	Baseload	Baseload & Peaking	Baseload & Peaking
		Turbine CHP	Turbine CHP	Turbine CHP	Turbine CHP	Turbine CHP
	Case Number	16	17	18	19	20
		H-1 (CHP) NG Well 4000 ft lateral	C1000+2(C200) (CHP) NG Well 4000 ft lateral	M1A-13D (CHP) NG Well 4000 ft lateral	H-1 &C1000 (CHP) NG Well	M1A-13D &C1000 (CHP) NG Well
	Well Cost ($)	$5,050,000	$5,050,000	$5,050,000	$5,050,000	$5,050,000
	Full Year Annual Thermal-energy Demand	45,432	45,432	45,432	45,432	45,432
	Fraction of Total Annual Thermal Demand	36%	73%	146%	41%	148%
	Full Year Annual Electrical-Energy Demand	12,823	12,823	12,823	12,823	12,823
	Fraction of Total Annual Electrical Demand supplied by Case Configuration	94%	94%	98%	100%	100%
	Plant Performance					
	Fuel	None	None	None	None	None
	Energy units	MWh	MWh	MWh	MWh	MWh
	Capacity	1.407	1.400	1.485	2.407	2.485
	Capacity Factor [%]	98%	98%	96%	61%	59%
	BTU/kWh	8,824	12,832	15,797	10,489	14,604
	Life of Plant (Years)	13	9	7	10	7
	Total Overnight Capital [1000$]	$8,272	$7,908	$6,762	$10,794	$9,285
	Cost of Product					
		Project	Project	Project	Project	Project
	COP units	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh
	Dollar Year used in finance calculations	2016	2016	2016	2016	2016
	LCOE/LCOH (Heat=$/MMBtu; PWR=$/MW	$59.18	$79.62	$83.17	$87.97	$107.11
	Capital Component	$52.69	$73.10	$77.02	$84.18	$103.44
	O&M Component	$6.49	$6.52	$6.15	$3.79	$3.68
	Fixed O&M Component	$0.00	$0.00	$0.00	$0.00	$0.00
	Fuel Component	$0.00	$0.00	$0.00	$0.00	$0.00
	COP in First Year of Operation	$62.18	$83.65	$87.38	$92.43	$112.53
		$ 714,650	$ 957,026	$ 1,043,131	$ 1,128,062	$ 1,373,486
HEAT ANALYSIS		MMBTU	MMBTU	MMBTU	MMBTU	MMBTU
	Heating Supplied per Year	16,569	33,085	66,449	18,776	67,210
		0.36	0.73	1.46	0.41	1.48
	MakeUp Heating Purchased	$191,781	$82,043	$0.00	$177,117	$0.00
	Total annual HEATING cost	$208,350.20	$115,128.02	$66,448.90	$195,893.18	$67,209.87
		$93,524.80	$186,746.98	$235,426.10	$105,981.82	$234,665.13
	Percent of Today's Heating Cost	69%	38%	22%	65%	22%
ELECTRICAL ANALYSIS		MWh	MWh	MWh	MWh	MWh
	Electricity Supplied per year	12,075	12,019	12,543	12,823	12,823
		0.94170	0.93734	0.97814	1.00000	1.00000
	MakeUp Electricity Purchased	$48,219	$51,825	$18,076	$0	$0
	Total annual ELECTRICITY cost	$762,869	$1,008,851	$1,061,207	$1,128,062	$1,373,486
		$764,491.69	$1,010,446.65	$1,064,072.76	$1,159,410.65	$1,406,361.68
		$65,017	-$180,965	-$233,321	-$300,176	-$545,600
	Percent of Today's Electric Cost	92%	122%	128%	136%	166%
Total	Total annual ENERGY Cost	$971,219	$1,123,979	$1,127,656	$1,323,955	$1,440,696
	Percent of Today's ELECTRIC + HEATING Cost	86%	99%	100%	117%	128%

On-Site Electric Power Only (Non-CHP Case)

Table 19 shows the results for the non-CHP cases, where only electric power is generated. Five cases are shown, three where only the average site power (baseload case) is generated, and hence, the balance of power is assumed to come from the local utility to help meet peak needs. Two cases (far right in the table) show power generation that meets both baseload and peak needs. The lowest cost *baseload case* is the H-1 turbine having a levelized cost of $52.68/MW-hr. Current Camp Dawson electricity costs are estimated at $64.44 per MW-hr based on available utility bill data. The total power generated for the H-1 baseload case is 12,048 MWh, which can be calculated from the monthly data in the table above, with the highlighted cells showing power production capped at the turbine capacity. Hence, a savings of approximately $143,000 might be expected per year using on-site generated baseload power (($52.68–$64.44) x 12,048). Finally, the lowest cost base plus peak power case is the H-1 with a C1000 unit, the latter for meeting peak electric needs and together providing the entire 12,800 MW-hr annual load. The LCOE is shown to be $73.77/MW-hr, which will require an additional $118,000 per year to support operations for fully independent (apart from the electric utility) on-site electricity generation. The relatively short lifetimes and high well costs associated with these plants are major factors in this cost analysis.

On-Site CHP

Similar results are shown in Table 20 for the CHP scenarios. The data here shows the additional cost of heat exchangers and other control systems to make heat from the turbine system available to the existing hydronic heating systems within the buildings. To be clear, for the CHP cases, heat from the turbine system is only generated to the extent that the electric power demand will generate that heat, in other words, the system is operated to meet electricity demand, rather than heat demand, with the consequence that sometimes there is not enough heat delivered by this system. Hence, if the building heat demand exceeds the heat generated from the CHP system, then additional heat will be needed for the buildings.

To estimate the benefits of employing on-site CHP, the Camp's monthly heat and electricity demand and costs data were used for each case (see Table 20). The resultant overall annual cost can be compared to today's annual costs of electricity plus heat, as an *estimate* for the financial benefit of using on-site CHP. Supplemental heat (from natural gas) and electricity are purchased at the average annual price Camp Dawson currently pays.

The total cost of operations (electricity + heat) for a given month are determined by adding the calculated annual cost of generating heat and power to the cost of buying make-up heat and power, as needed. In the CHP cases, the only cost for generating heat comes from the additional capital cost for a turbine fitted to exchange heat with the buildings' hydronic system. Here, for the assumed 4,000-foot lateral well, it is found that the lowest annual cost for CHP operations is approximately $971,219, or 86 percent of the current total costs of $1.13M to meet both heat and power demands for Camp Dawson. This annual cost is slightly lower than that for providing only baseload power showing that the additional cost of heat exchangers to capture the waste heat are nearly evenly offset by the savings from reducing the amount of natural gas needed for heating on site buildings.

Note: while the *extra needed natural gas for heating* can also be obtained from the on-site well, this would deplete the natural gas resource more quickly. CHP is likely to be a less costly approach compared to the approach of using the on-site natural gas supply for peak heating needs, given current well costs. Such additional configurations can be considered in greater detail in any future study for Camp Dawson, if needed.

6.5 RECIPROCATING ENGINES FOR ON-SITE ELECTRIC POWER

At lower generating capacities (smaller physical size), reciprocating engines are generally more efficient than turbines. To review the capabilities of reciprocating engines in serving the electric power needs of Camp Dawson, a GEJ JMS-416B85 Jenbacher engine has been selected and analyzed (Table 21). Notice that the Jenbacher reciprocating natural gas engine has a lower heat rate (i.e., a higher efficiency) than all but the H-1 turbine reviewed in Section 6.4; however, as noted in Table 16, H1 is an engine which is not yet commercially available. The reciprocating engine chosen provides 1.12 MW of electrical power, which is less than the 1.4 MW baseload of Camp Dawson, which means additional cost for meeting peak power needs will be incurred. It also has a slightly higher fuel consumption rate per MW than the H-1 Turbine reviewed previously. The lower capacity, however, allows the engine to demand less of the natural gas reservoir, which results in a longer lifetime (16 years, compared to the 13 for the H-1 turbine), and helps offset the lower efficiency and higher O&M costs of the Jenbacher as compared to the H-1. Even so, for baseload power (1.12 MW), the reciprocating engine’s economic performance is slightly worse than a highly-efficient H-1 turbine with an overall annual savings on electricity now being $50,000 per year.

6.6 BINARY GEOTHERMAL ORGANIC RANKINE CYCLE (ORC)

Most opportunities for geothermal power generation arise where there is abundant geothermal energy close to the surface and at temperatures greater than 350°F. However, recent research is now working to identify commercially viable *deep geothermal resources* for power generation (Allis et al., 2015). For the completeness of this report, the case where on-site electricity is generated using an ORC was examined. Based on the results for Section 3, the maximum likely temperature of geothermal water delivered to the wellhead (accounting for heat losses in the well bore and temperature drawdown in the reservoir) at Camp Dawson is about 240°F (sourced from the Trenton Black River Limestone). EPRI characterizes this temperature as a “low grade” resource for power production, as shown in Table 22.

Table 21: LCOE for Reciprocating Engine (Electric Only)

		Baseload Recip. Engine PWR
	Case Number	22
	Well Cost ($)	$5,050,000
	Full Year Annual Thermal-energy Demand	45,432
	Fraction of Total Annual Thermal Demand	0%
	Full Year Annual Electrical-Energy Demand	12,823
	Fraction of Total Annual Electrical Demand supplied by Case Configuration	94%
	Plant Performance	
	Fuel	None
	Energy units	MWh
	Capacity [MW]	1.121
	Capacity Factor [%]	98%
	BTU/kWh	9,264
	Life of Plant (Years)	16
	Total Overnight Capital [1000$]	$7,702
	Cost of Electricity	
	COE units	$/MWh
	Dollar Year used in finance calculations	2016
	LCOE/LCOH (Heat=$/MMBtu; PWR=$/MW	$58.18
	Capital Component	$50.04
	O&M Component	$8.15
	Fixed O&M Component	$0.00
	Fuel Component	$0.00
	COE in First Year of Operation	$61.13
		$ 571,361
HEAT ANALYSIS		MMBTU
	Heating Supplied per Year	0.00
	MakeUp Heating Purchased	$301,875.00
	Total annual HEATING cost	$301,875.00
	Percent of Today's Heating Cost	100%
ELECTRICAL ANALYSIS		MWh
	Electricity Supplied per year	9,620.74
	MakeUp Electricity Purchased	$206,536
	Total annual ELECTRICITY cost	$777,897
	Percent of Today's Electric Cost	94%
Total	Total annual ENERGY Cost	$1,079,772
	Percent of Today's ELECTRIC + HEATING Cost	96%

Table 22: Geothermal Grade Classification by Temperature (Risch & Eastham, 2012)

Classification	Temp Min (°C)	Temp Max (°C)	Temp Min (°F)	Temp Max (°F)
Non-electrical-grade	0	100	0	212
Low-grade	100	150	212	300
Mid-grade	150	200	300	400
High-grade	200	None	400	None

Electric Power Research Institute (EPRI), 2010.

As a point of reference, Table 23 shows examples of plants operating on "low grade resources" similar to Camp Dawson. A distinction these hold, however, is that the hot geothermal brine is not accessed via deep wells.

Table 23: Binary Cycles with Similar Resource Temperature to Camp Dawson (DiPippo, Geothermal Power Plants 3rd Edition, 2012)

Plant name	Location	Brine inlet temp.	Thermal efficiency	Capacity	Brine Flow
		[°F]	[%]	[kW]	[gpm/kW]
Amedee	CA	217.4	5.8	1,600	2
Wabuska	NV	221	8	500	1.65
Husavic	Iceland	251.6	10.6	2,000	0.71

If a binary cycle working between the brine-supply temperature of 240°F and a sink temperature of 70°F is assumed, the *theoretical maximum* thermal efficiency is 14 percent. Since the brine cools as it transfers energy to the working fluid, the efficiency is not calculated via the Carnot cycle having constant source and sink temperatures. Instead, efficiency is calculated via a triangular cycle comprising isobaric heat addition up to the brine inlet temperature, isentropic expansion, and finally, isothermal heat rejection (DiPippo, Geothermal Power Plants - Principles, Applications, Case Studies and Environmental Impact, 2012). A literature review revealed data to show relationships between geofluid temperature and specific power for ORC and Kalina binary cycles. Figure 51 shows examples of these relationships. While every geothermal case is unique to itself, overall the literature reviewed to date suggests that the efficiency advantage of Kalina Cycle over ORCs diminishes with lower geofluid temperatures (Guzovic et al., 2014). Since reservoir lifetime is the key economic driver for these low efficiency cycles, data from a single configuration were used to generate inputs for the reservoir lifetime model discussed in Section 4 of this report. Figure 52 shows the trend lines used to determine the demand a 1.4 MW 2-stage binary ORC would place on the geothermal resource. The resource is allowed to cool in order to maximize the time it is used for 1.4 MW power-generation (changing temperatures are captured within the red ellipses in Figure 52).

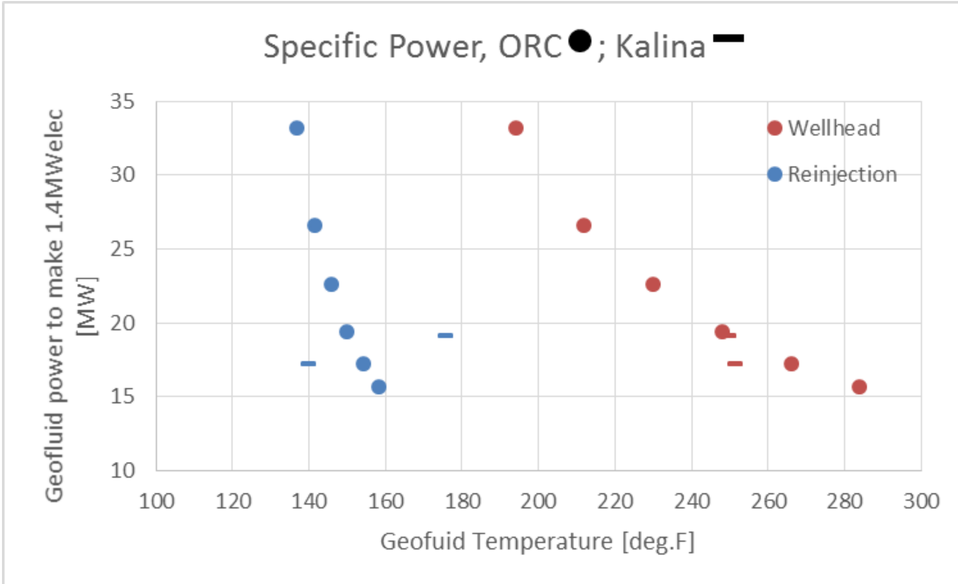

Figure 51: Water energy flow needed to provide 1.4 MW electric power from given water temperature. Organic Rankine Cycle (ORC) and Kalina Cycle comparison.

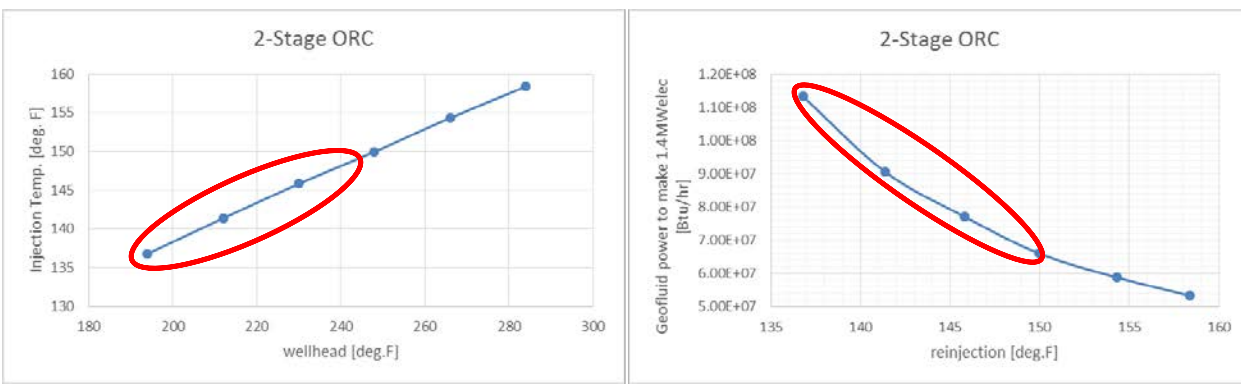

Figure 52: Organic Rankine Cycle operational parameters for 1.4 MW electric power from given water temperature.

Based on an analysis similar to that laid out in Section 4 where two wells with 2,000-foot laterals are placed 1,500 feet apart, the resource life span was analyzed. The resource remains viable for power generation for 23 months under this scenario. The reasons for short project life compared to that of the space heating case (Section 6.3) are a higher (versus that for heating) flow rate, a higher cutoff temperature, and only a small energy flux from outside the reservoir. For the hydronic heating application, the outlet temperature remains constant for 20 years, but the project continues an additional 42 years. With the higher flow rate, the reservoir's ability to take in heat from its surroundings is outstripped by the amount of heat used for making electricity. Longer laterals on the geothermal wells, allowing the wells to access a larger area of geothermal reservoir, can mitigate this short life span for the system.

Organic Rankine Cycle (ORC) System Cost

The cost for on-site geothermal power generation is assessed by reviewing the literature for cases that closely match that of Camp Dawson. The air-cooled 200kW Ormat unit installed at the Rogner Bad Blumau Hotel and Spa in Austria is reported to have cost $1,800 per kW (the plant was mated to equipment for an existing balneological system at the spa, so no drilling costs were incurred). This plant uses 215°F geofluid for power, sending the 191°F spent geofluid on for district heating. Geofluid flow for this plant is 475 GPM (2.375 gal/kilowatt electric [kW_e]). Another example is the Oregon Institute of Technologies' geothermal plant. This water-cooled plant generates up to 150 kW_e using 192°F geofluid. Its installed cost (no drilling costs incurred) was $6,333/kW, which in part is attributed to its lower operating temperature versus the above example. Figure 53 gives additional cases for the cost-performance of small binary cycles. As can be seen, wide ranges of costs are possible depending on the specifics of a site.

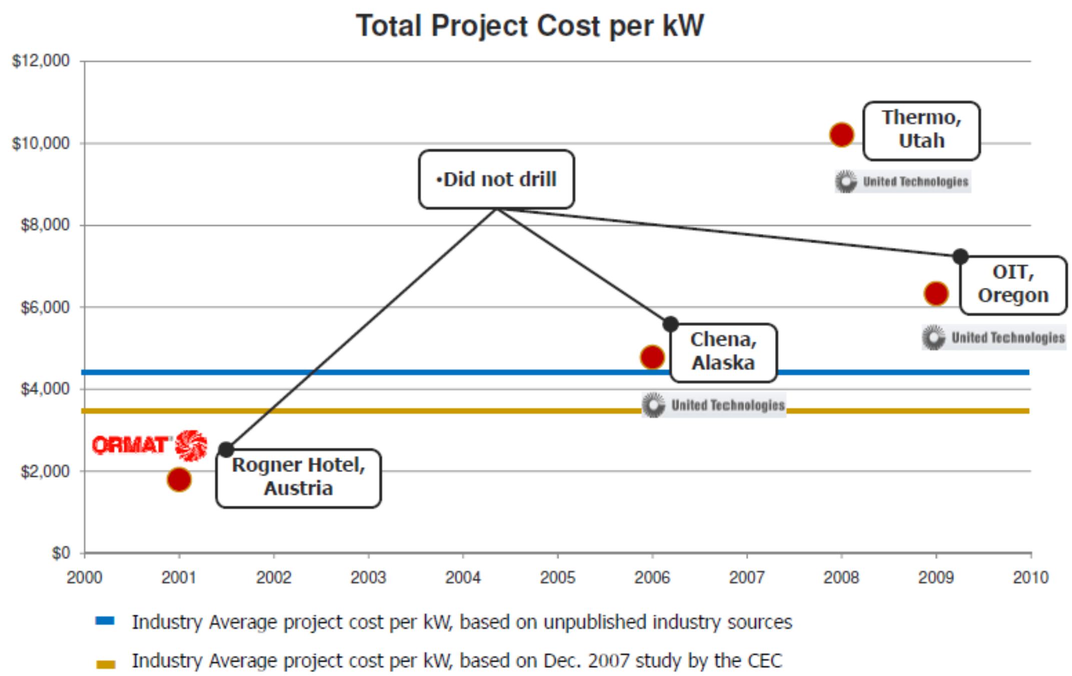

Figure 53: Reported costs for small binary cycles. The cases shown as "Did not drill" did not require extensive drilling operations (and cost) to access the geothermal resource. (Ormat; Nordquist, Joshua, 2009)

At the average cost shown in Figure 53, $4,630/kW, the capital cost for a 1.4 MW plant, with its well to the Trenton Black River formation, would be about $32,952,000. Over the short lifetime, the resulting LCOE is $1,395.86/MWh, as shown in Table 24. The amortized annual cost for this system would be about $17,118,845. Such costs greatly exceed that of current electricity costs, making this ORC generation system less appealing. The LCOE can be reduced if a greater volume of reservoir can be accessed as a result of much longer well laterals and more favorable formation permeability (avoiding the need for hydraulic stimulation and allowing more distance between the injection well and production well).

Table 24: LCOE for an ORC System Employing Trenton Black River Geofluid

		Baseload
		Binary Power
	Case Number	21
		ORC Four Vertical Wells Trenton Black River
	Well Cost ($)	$26,470,000
	Fraction of Total Annual Thermal Demand (heating) supplied by Case Configuration	0%
	Fraction of Total Annual Electrical Demand supplied by Case Configuration	94%
	Plant Performance	
	Fuel	None
	Energy units	MWh
	Capacity [MW]	1.400
	Capacity Factor [%]	98%
	BTU/kWh	42,457
	Life of Plant (Years)	1.9
	Total Overnight Capital [1000$]	$32,952
	LCOE/LCOH	$1,395.86
	Capital Component	$1,370.86
	O&M Component	$25.00
	Fuel Component	$0.00
	COE in First Year of Operation	$1,466.53
		$ 17,118,845
HEAT ANALYSIS		MMBTU
	Heating Supplied per Year	0.00
	MakeUp Heating Purchased	$301,875
	Total annual HEATING cost	$301,875.00
	Percent of Today's Heating Cost	100%
ELECTRICAL ANALYSIS		MWh
	Electricity Supplied per year	12,019
	MakeUp Electricity Purchased	$51,866
	Total annual ELECTRICITY cost	$17,170,711
	Percent of Today's Electric Cost	2074%
Total	Total annual ENERGY Cost	$17,472,586
	Percent of Today's ELECTRIC + HEATING Cost	1547%

To maximize the average lifetime efficiency, the assumed two-stage binary power plant chosen is designed for the minimum geofluid inlet temperature. Temperatures in excess of this design point result in increased efficiency and an increased lifetime of the resource. Even so, the lifetime of the resource, which lies within Camp Dawson's current mineral rights, is exhausted in less than two years if it is converted to electricity at the expected binary power plant thermal efficiency (5–8 percent). The higher flow rate and lower reinjection temperature, compared to those required to support the heating load at Camp Dawson, are such that producing baseload power outstrips the ability of the reservoir to be rewarmed by surrounding geothermal energy. This short reservoir service life is the primary driver of the high annual cost for electric power. Under this case, a full power plant would be constructed for only 23 months of continuous service

6.7 SOLID OXIDE FUEL CELL (SOFC) FOR POWER AND HEAT

The nearly reversible process of electrochemical conversion of chemical energy to electrical energy using fuel cells has long been recognized. In particular, the solid-state technology of SOFCs, with its potential to generate power at electric efficiencies that are higher than conventional Carnot-cycle based heat engines, has been considered to be well suited for stationary power generation. In addition, these systems can provide process heat and deliver the energy from different fuel gas sources (e.g., natural gas, shale gas, landfill gas) in a fashion that is environment friendly, with negligible nitrogen oxide (NOx) emissions, minimum water use, combined with their amenability to carbon capture. As described below, NETL has an SOFC development program underway to make this technology economically viable for use within the United States.

A reference SOFC distributed generation (DG) system is shown in Figure 54 that features internal (to the stack) reformation of natural gas. Desulfurized natural gas is fed directly to the SOFC module and mixes with the recirculated anode off-gas, which supplies the steam required for reformation of inlet natural gas to syngas. To prevent cracking and deleterious carbon formation, a pre-reformer, which converts the higher hydrocarbons into methane, is generally included before completing the reformation internal to the stack. Internal reformation, while eliminating the need for specialized process equipment, utilizes part of the heat generated in the stack directly for the endothermic reformation reaction, and consequently reduces the airflow rate needed to maintain a desired stack temperature gradient resulting in higher process efficiency. Air supplies the oxidant to the cathode, and heat exchangers on both the anode and cathode side are appropriately designed to keep the desired temperature gradient across the stack. The heat that is created from burning the electrochemically unutilized fuel, along with the thermal content of the cathode exhaust, are available for thermal use. This represents heat available for heating water at Camp Dawson.

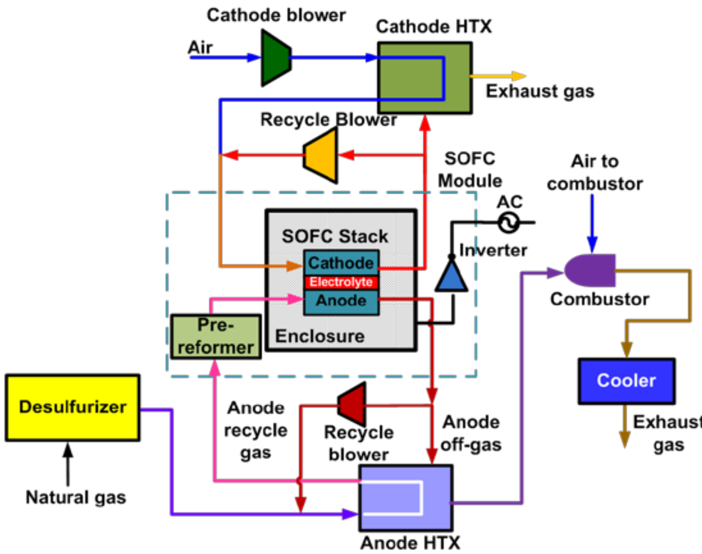

Figure 54: Reference SOFC DG system.

NETL Solid Oxide Fuel Cell (SOFC) Program

The NETL SOFC Program is developing the technology base for natural gas fueled, grid-independent distributed generation applications. Presently, the SOFC Program is supporting two 50 kWe-class stack tests and two 125 kWe-class proof-of-concept (POC) module tests. The stack tests are demonstrating thermally self-sustaining stack technology and in-stack fuel reformation; they are expected to operate for more than 1,000 hours at a degradation rate of less than 0.5 percent/1,000 hours. The POC module tests will be fueled by pipeline natural gas, export AC-power to the grid, and integrate commercial-scale balance-of-plant subsystems; the expected test duration is 2,500 hours. These systems will serve as the building blocks for entry into service power systems.

A 400 kWe-class fully integrated, natural gas fueled SOFC power system will be field tested in FY16. The program anticipates two additional 400 kWe-class field tests in the FY17 timeframe. As shown in the analysis presented below, Camp Dawson represents an opportunity for implementing a nominal 400 kWe-class system. This initial study has also shown that DG SOFC systems are a good match to the power generation requirements of typical military facilities, particularly in light of the Department of Defense energy strategy.

These would be followed by an MWe-class demonstration circa 2020. The MWe demonstration will validate the technology foundation and acquire the operational experience necessary for large-scale, multi-megawatt demonstrations. Figure 55 presents the SOFC Program technology development timeline.

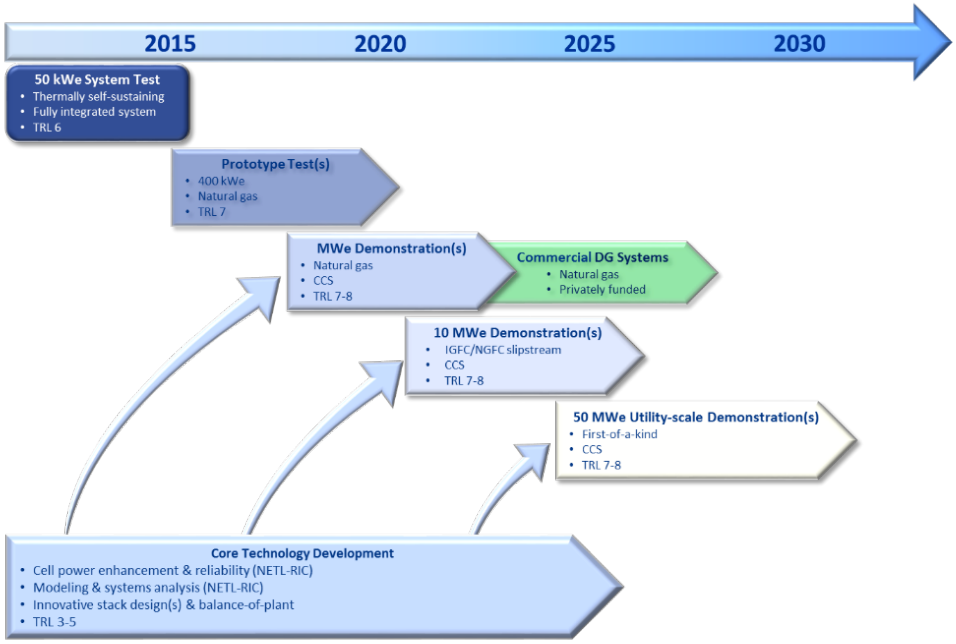

Figure 55: SOFC program development timeline.

Camp Dawson SOFC Reference Plant Capacity

The Camp Dawson Energy Survey Report (Banta and Crowe, 2014) presents the peak electricity demand for the time period from December 2012 to April 2014 as 2,376 kW in July, with less than 1 percent of demand intervals greater than 2,000 kW and less than 4 percent greater than 1,800 kW. The base load demand throughout the year is approximately 1,000 kW. Data from May 2014 to May 2015 shows similar demand capacity with the primary demand between 1,100 and 2,200 kW. Accordingly, a 1 MWe SOFC plant design producing AC electric power, which is consistent with the NETL fuel cell program, is selected for this initial study. This unit would provide base load electric power during the year. The thermal heating load varies with the season. As a reference, the quantity of hot water that can be produced from the 1 MWe system, assuming 160°F water demand, can be calculated. This reference plant provides a basis for evaluating future combined heat and power plant designs.

The SOFC system can be designed to include carbon capture. Previous studies are available that provide comparisons of 1 MW capacity systems with and without carbon capture.

SOFC System Performance and Cost

Table 25 provides a summary of the SOFC design assumptions, inverter efficiency, SOFC stack cost, and system capacity factor. The design assumptions and stack cost reflect achievement of the NETL program goals.

Table 25: Salient DG SOFC System Process and Cost Parameters

Case Carbon Capture Configuration	DG-1 No CCS
Reformation	100% Internal
SOFC Operating Pressure	Atmospheric
Cell Overpotential, mV	70
Fuel Utilization, %	90
Current Density, mA/cm^2	400
Degradation, %/1,000 hr	0.2
Inverter Efficiency (%)	98
Stack Cost ($/kW)	225
Capacity Factor (%)	85

The performance and cost results for the SOFC system operating to produce electric power are summarized in Table 26.

Table 26: Summary of Performance Results for the DG SOFC Cases Analyzed

Case		DG-1
Carbon Capture Configuration		No CCS
SOFC (Parameters)	Cell Voltage	0.827
	Inlet Nernst Voltage (V)	0.897
	Overall FU (%)	90.0
	In-Stack FU (%)	79
PERFORMANCE		
Gross Power (kWe)		**1,033**
Auxiliary Loads (kWe)		**32.8**
Air Separation Unit (kWe)		0.0
CO_2 Drying, Purification, and Compression (CPU) (kWe)		0.0
Blowers and Miscellaneous (kWe)		32.8
Net Power (kWe)		**1,000**
NG Flowrate (lb/hr)		248
NG Thermal Input (MMBtu/hr)		5.6
Net Electric Efficiency, HHV (%)		61.0
Net Plant Heat Rate, HHV (Btu/kWh)		**5591**
CO_2 Capture Rate (%)		**0**
CO_2 Emissions (lb/MWhgross) (lb/MWhnet)		524 (541)
Raw Water Consumption (GPM/MWnet)		**0**
Raw Water Discharge (GPM/MWnet)		**0**
COST		
Capacity Factor (%)		**85**
Total Plant Cost (TPC) (1,000$)		1,012
Total Overnight Cost (TOC) (1,000$)		1,074
Total As-Spent Cost (TASC) 1,000$)		1,224
Cost of Electricity ($/MWh)		
Variable COE		**46.5**
Fuel (NG@$6.13/MMBtu)		34.3
Variable O&M		12.2
Fixed O&M		**10.5**
Capital Charges		**17.9**
Total First-Year COE (excluding T&S) ($/MWh)		74.9

As shown in Appendix B, Camp Dawson's total electrical demand in a given year is about 12.9 GWh. For assumed continuous base load operations of the SOFC at 1 MW, all but 4.1 GWh will be satisfied using the SOFC system, and the balance will need to come from the local utility. At a cost of $40.6/MWh (=$74.9/MWh - $34.3/MWh given that fuel will be free), the annual cost of operation for the SOFC alone will be $355,000. Together with the cost of utility power for supporting the balance of power, the total electrical costs will be about $619,000 per year. At the drawdown rate shown in Figure 17 for a 2,000-foot lateral, a single well will last about 12 years. At a cost of $4.5 million per well installed into Marcellus Shale, the additional effective annual well costs will be about $361,000 per year for a total cost of $980,000 per year, which is more than today's cost of $850,000 per year. Adding the estimated $60k per year in O&M costs raise this to $1,040,000 per year. For a single 4,000-foot lateral well, the lifetime of the resource would be about 24 years, and the total cost per year would be about $869,000 including O&M, or about $42,000 more than the current annual operating costs.

SOFC System Providing Combined Heat and Power: The SOFC exhausts from both the cathode and the anode side have considerable heat content (a total of 2.2 MMBtu/hr is rejected as waste heat from the reference 1 MW SOFC unit) that can be used readily for CHP applications. Hot water for space heating can be provided through straightforward heat exchange with anode and cathode exhausts. High quality steam, if desired, can also be generated by appropriately designing the heat extraction. Based on a water inlet temperature of 135°F, approximately 1.3MMBtu/hr of the 2.2 MMBtu/hr waste heat in the SOFC exhaust is usable for water heating. Accordingly, the 1 MWe reference SOFC plant can satisfy the base load power and the base load hot water heating demand typically experienced at the Camp Dawson facilities during the summer season. The reference plant could supply about 8.5 percent of the 15.8 MMBtu/hr peak heating demand at Camp Dawson and can satisfy the thermal demand of an entire barrack. The avoided costs (vs. purchasing natural gas from a utility) is $69,000 per year, which could help offset the additional annual cost of electricity noted above, making the annual cost of operation about $1,190,000 for the case where the well has a 2,000-foot lateral, including the cost to supply the balance of heat using the existing boiler system and utility natural gas as well as O&M. Based on this heat usage, the overall energy efficiency of the reference SOFC-based CHP plant is approximately 85 percent. The SOFC plant exhaust can also be integrated with the geothermal system to optimize a solution for electric power demand and heat demand for the camp.

7. SUMMARY COMPARISON OF OPTIONS

A summary of the different options and their potential cost savings is given in this section. As presented in Section 6 for the analysis of each option, each one was considered separately, apart from any possible hybridization with the others. It is possible that certain combinations of resource utilization are of interest, and some, when combined, may offer overall improved cost savings, robustness to the energy system of the site, and overall improved security. Such further review is possible, but will require a more detailed follow-on analysis. As a special note, the analysis considers cases of natural gas supply from the Marcellus Shale resource only. Additional natural gas resources exist, but they have not been assessed as part of this effort (e.g., Utica).

Table 27 summarizes the data for each of the options reviewed in Section 6. Based on current cases analyzed, however, if the goal of Camp Dawson is long-term energy independence, then direct use of deep geothermal energy stands out as the best candidate for supplying heat to buildings, while natural gas is the best candidate for producing electricity. The single resource best able to provide both heat and electricity is natural gas, especially if a CHP configuration is used. Given the available Marcellus Shale resource, however, lifetimes less than 10 years should be expected when using conventional gas turbine or reciprocating engine technology, but could be up to 20 years if more efficient advanced systems are employed, i.e., SOFC. Geothermal resources could heat the nine buildings for a relatively long period of time at perhaps twice the current costs of natural gas, but could not supply sufficient energy for electricity production at reasonable costs unless exploration finds temperatures in the deep subsurface are near the maximum of the range presented in this report and the natural permeability of the selected stratum is relatively high.

Table 27: Summary Comparison of Energy Resource Utilization Options

Type H=Heating E=Electric Power	Description	Percent of Load Met (%)	Potential Lifetime (yr)	Annual Costs [$k] (Cost Relative to Present Operations)	Potential Annual Savings ($k)
H	Present Utility Provided Natural Gas Fired Boilers	100%	-	$302 (100%)	-
E	Present Utility Provided Electric Power	100%	-	$827 (100%)	-
H	On-Site Natural Gas for Existing Boiler Heating	100%	15 (one 2,000 ft. lateral well)	$327 (108%)	-$24 (loss)
			30 (one 4,000 ft. lateral)	$228 76%	$74
H	Direct Use of On-Site Geothermal Energy (Black River Limestone)	80% (+balance provided by NG boilers)	63 (two horizontal wells; 2,000 ft.)	$725 (240%)	-$423
			50 (four vertical wells; 2,000 ft. apart)	$689 (228%)	-$387
E	On-Site Natural Gas Turbine for <u>Baseload</u> Electric Power (non-CHP)	94% (+balance from utility)	13 (one 4,000 ft lateral well)	$684 (83%)	$143
E&H	On-Site Natural Gas Turbine for Electric Power and Heating (CHP)	94% E 36% H (+balance)	13 (one 4,000 ft lateral well)	$971 (86%)	$158
E	On-Site Natural Gas Recip. Engine for Baseload Electric Power	75% (+balance)	16 (one 4000 ft lateral well)	$778 (94%)	$50
E	On-Site Geothermal Energy for Electric Power (ORC Cycle)	94%	1.9 (four vertical wells, 2,000 ft apart)	$17,170,000 (2,074%)	-$16,344
E	On-Site Natural Gas for SOFC Power Generation—With Grid Support for Peak Load *(Assumes a purchased commercial system meeting DOE cost targets.)*	68% (+balance)	12 (one 2,000 ft. lateral well)	$1,040 (126%)	-$212
			24 (one 4,000 ft. lateral well)	$870 (105%)	-$42
E&H	On-Site Natural Gas for SOFC Power and Heat Generation	68% E 26% H	12 (one 2,000 ft. lateral)	$1190 (106%)	-$65

8. EXPLORATION PLAN FOR SUBSURFACE RESOURCES

8.1 EXPLORATION PLAN

The text below presents some considerations that should go into a plan for exploration, including an exploratory well. NETL anticipates WVNG would make a plan after they make a decision to go forward with an exploration phase and have chosen a reasonable cost limit for the exploration phase and perhaps a depth limit.

Seismic Survey

The complexity of folds and faults found at depth in rock strata near Camp Dawson result in a high risk of not being able to steer the drilling of a horizontal well within the target strata. To mitigate risks, a seismic survey can be done to map the folds and faults within the strata of interest. A seismic survey of high quality and resolution can identify advantageous structural features and swarms of open natural fractures that can make the difference between project success and failure. The survey should cover the strata to depths of at least 15,000 feet and sufficient distances away from the property boundaries of Camp Dawson to permit the interpreter to see the trends of faults extending into the rock strata directly beneath Camp Dawson. Where resolvable faults end, the faults continue with less than resolvable offsets, and eventually they end in a swarm or zone of fractures (which could have favorable permeability). Preferably, the seismic survey would be a 3D, three-component survey. Two or more 2D seismic survey lines made in the northwest to southeast orientation (across the trend of the folds) can be used to see the major folds and faults, but these do not permit the detection of zones of natural open fractures nor do they resolve the strata and faults to the degree achieved by 3D surveys. NETL's geologists further recommend that seismic attributes from the 3D, three-component seismic survey be considered and interpreted to help identify possible zones or swarms of open natural fractures that can be exploited beneficially for geothermal heat extraction or natural gas production. Tools now exist for identifying and mapping subtle features such as zones of open natural fractures. Gas-filled strata can sometimes be detected as well.

The interpreted seismic survey would further guide well pad placement and would better enable the well trajectories to hit favorable areas or avoid unfavorable areas. For drilling highly inclined or vertical wells in an area with as much structural complexity as Camp Dawson, drilling with minimal or no interpreted seismic data will most likely result in costly multiple attempts to drill into the intended strata and foregone opportunities to hit sweet spots.

Based on recently obtained acquisition and costs factors (Sloane et al., 2016), it is estimated that a 3D seismic survey would need to be conducted over a ground surface area of 9 to 16 square miles, centered on Camp Dawson. Seismic data acquisition costs would range between $675,000 and $1,400,000, depending on the size of the area covered. Data processing and interpretation are estimated to add another $200,000 to the costs.

A few seismic survey lines have been made in the vicinity of Camp Dawson during the past. Some of these (e.g., Amoco lines 5MU-4 and 5NE-206) are available for purchase from SEI. A few interpreted images are published in Kulander and Ryder (2005). While the published interpretations give useful insight into the larger structural features of the region, they are not sufficient for planning the trajectory of horizontal wells and do not permit the identification of zones of open natural fractures.

Drilling Strategy

To lower the financial risks on an exploratory well for geothermal heat, NETL recommends that the exploratory well be drilled, logged, and tested to search for both natural gas and geothermal resources. If adequate geothermal reservoir conditions are not found within the depth limit established for exploration, the well can have a horizontal lateral drilled into a suitable formation (e.g., the Marcellus) for completing a natural gas well. On the other hand, if natural gas is sought but not found, the well could be completed deeper for geothermal heat. A second well would need to be drilled in the future to enable use of the first geothermal well.

If WVNG decides to drill a well for natural gas in the Marcellus formation, it may be worthwhile to drill slightly deeper and test the Oriskany Sandstone or other rock strata for geothermal potential, and then drill a lateral into the shales to produce natural gas. With this strategy, geothermal information would be obtained for future use at much less cost than drilling another exploratory well in the future.

Casing

The casing or tubing in the well through which fluid flows must be larger for a geothermal well than for a natural gas well. Recent natural gas wells drilled into the Marcellus or shallower strata have a 5-1/2 inch OD, 5-inch ID casing for the inner casing string. This casing is too small to convey the minimum 1,100 GPM of water flow except via high pressure pumps and high flow rates (> 12 f/s) and significant pressure losses to friction. A geothermal well needs at least a 6-inch and perhaps an 8-inch ID casing or tubing to convey the minimum 1,100 GPM of water at low pressures and moderate to slow flow rates (12 to 8 ft/s, respectively) with moderate to minimal pressure losses to friction. Most down-hole electric submersible pumps of sufficient pumping capacity would require a minimum 10-inch ID casing, at least in the upper part of the production well. For gas wells drilled in this area, a 9-5/8 inch OD intermediate casing string is installed, but only to depths of a few thousand feet. Conductor casings are 20 inches OD and surface casings are 13-3/8 inches OD. Surface casings are set several hundred feet deep. For a geothermal well, either all of these casing strings would need to be increased in diameter by 1 to 3 inches, or the intermediate casing would need to be extended much deeper. According to a driller contacted by NETL, natural gas wells installed into the deep Utica Shale use larger casing diameters than the Marcellus Shale wells and have 9-inch casings installed to depths of 12,000 feet. Drilling costs would likely increase in proportion to the increase in diameters for the casing used in a geothermal well. If WVNG intends for the exploration well potentially to serve as a geothermal well at any point in the future, this well would need to be planned, drilled, and constructed with larger diameter casings with the inner (“production”) casing having at least 8 inches of ID. If a submersible pump is to be installed, the 8-inch casing could suspend from a shallower 10-inch ID casing.

For geothermal wells drilled into competent rock layers (sandstones and limestones), the portion of the well, whether vertical or horizontal, within the competent target strata may be uncased. The decision on whether this part of the well can be uncased should be made with the benefit of consultation with experienced drilling engineers. If uncased, cost reductions would come from the reduced amount of casing purchased and installed, and the lack of need for perforating the casing and “stimulating” the rock at the perforations. Uncased wells can have much better connection of the well with natural fractures and permeable sublayers and have less restriction of flow at the perforations. However, casing may be necessary for the propagation of larger hydraulic fractures. Horizontal wells will need casing in the curved part of the wells given the less competent shale layers that would be penetrated in this part of the well.

Another factor important to the siting of the well pad and trajectory of horizontal geothermal wells is that larger diameter casings require a longer radius of curvature in the curved part of the wells. This means that the well achieves its horizontal trajectory at a greater lateral distance from the wellhead. This becomes important when the dimension of the parcel of land is relatively small in the direction of drilling. NETL has not determined the horizontal distance to achieve a horizontal trajectory for either a 5.5-inch well or an 8-inch (or 10-inch) well. It is a trespass to drill beneath land where the right of access has not been acquired.

Drilling/Coring

The exploratory well would be drilled vertical, at least initially. As candidate reservoirs are encountered, they can be tested for initial production using drill stem tests and pressure fall-off tests. Open-hole segments should have logging tools run before installing casing.

To accommodate an inner casing string that is at least 8 inches ID, the exploration well would need to be drilled with larger bits. If larger bits are used, drilling will be incrementally slower and more costly. If larger bits are used, the drilling costs will likely be based on the drill rig's "day rates" rather than on "per foot" drilling costs. Also, drilling into hard sandstones (such as the Tuscarora) will result in much slower drilling rates and the payment of day rates on the drill rig.

NETL suggests coring in the Marcellus and in the candidate rock strata for geothermal reservoirs, including the rock strata above the candidate geothermal reservoirs through a thickness of about 100 feet of overlying strata. The core would be used to assess the integrity of the rock (for decisions about open-hole completions or even open-hole logging), the thermal conductivity and heat capacity of the rock, the susceptibility of the rock to acid treatment and hydraulic fracturing, and the intergranular porosity and permeability of the rock (for planning the stratigraphic location of horizontal wells). Small side wall cores can be obtained instead of the much more expensive whole cores, but these do not result in a continuous vertical sample.

Well Tests

As candidate strata are encountered during drilling, drilling should be paused and "mini-frac" tests or formation breakdown tests conducted. These tests are used to determine the fluid pressure in the borehole at which hydraulic fractures initiate and the fluid pressures at which induced fractures close (mini-frac tests give the minimum principal stress magnitude). If these sections of the well bore are subsequently imaged with a fracture detection log prior to casing, the direction of the minimum principal stress can be identified for purposes of planning the orientation of horizontal wells and subsequent hydraulic fracture. Perpendicular to the minimum principal stress direction is the maximum horizontal stress direction, which is also the direction most likely to have open natural fractures.

Drill stem tests should be conducted to estimate the bulk formation permeability, at least near the well bore. Other than measuring the temperature, this test will be the primary means of initially identifying the potential suitability of candidate rock strata for use as a geothermal reservoir.

Water withdrawal/injection permeability tests should be conducted after the well is drilled to its intended final configuration to determine the injectivity to water in GPM. This information would help with the planning for completion (e.g., open hole versus cased hole with hydraulic fractures) of the well and with estimating the volume of reservoir connected to the well. For a second geothermal well, a water withdrawal/injection permeability test, combined with pressure (or water table) monitoring in the first well, would allow for estimation of the degree of interconnection between the two wells. After completion and stimulation (i.e., hydraulic enhancement of natural fractures, creation of hydraulic fractures, or acid treatment), the well should again be tested with either an injection test or a fluid withdrawal test.

Biofouling

Among the issues in developing a geothermal system are concerns about (1) the potential for and control of biofouling (buildup of biofilms in system components or in the subsurface) if conditions are altered in the subsurface; and (2) deposition inside system components with silica, gypsum or carbonate scales or hydroxide films, and chemical corrosion and reactions. Samples of formation waters (and core) should be analyzed for scale-forming constituents, microbes, and the potential for biofouling when an exploratory well is drilled. In a closed geothermal loop, scaling is likely the bigger issue. Hence, there is added risk that the heat exchanger will need to be replaced every few years.

Logging

Before open-hole sections of the well are cased through Marcellus and deeper strata, a suite of logging tools should be deployed to gather information indicating the stratigraphic boundaries, the lithology, density and porosity of the strata, the water/gas saturations of the strata, salinity of formation waters, well bore breakouts and deformation, and locations of natural fractures. At a minimum, the following logs should be made: gamma ray, neutron, density, sonic, resistivity, and facture detection logs (fmi/fms with estimates of fracture apertures).

9. CONCLUSIONS

- **Heat Supply:** Of the options investigated for heat supply at Camp Dawson, direct use of geothermal energy stands out as having the longest lifetime (potentially exceeding 60 years). This result is significant if long-term energy security is important for Camp Dawson operations. This heat supply will come with additional costs to the camp, however, with current estimates at more than twice the current natural gas costs for heating. **On-site natural gas is much less expensive than geothermal,** but this solution enables secure heating for a relatively shorter duration (15–30 years). The best (least cost and longest lifetime) scenario for natural gas requires access to neighboring resources, however. Note: Doing the same for the geothermal solution will proportionally extend its lifetime as well beyond the 60-year period, and it reduces the risks of short-circuiting and insufficient permeability near the well bores.
- **Electricity Supply:** The best available resource for generating electricity at Camp Dawson is natural gas. Among the conventional energy conversion technologies reviewed (e.g., gas turbine engines), natural gas could offer approximately 13-year to 7-year lifetimes for base load and full load scenarios, respectively, for the least cost scenarios in each case. Annual costs could be close to the current purchases of electricity if using sufficiently high efficiency engines (which therefore offer longer lifetime). Reciprocating engine generators were also considered in this study and were found to have comparable performances to high efficiency turbines.
- **Future Energy Conversion Technology:** As advanced power generation technologies (e.g., SOFCs) become more cost effective and commercialized, they should also be considered for their increased efficiency and their improved environmental performance. Currently, NETL manages the development of these systems in collaboration with industry, and demonstration units are planned in the ca. 2018 time frame.
- **Cost Effectiveness of Wells:** Whether drilling for natural gas or geothermal energy, **horizontal wells could offer the best long-term return on capital investment and the lowest risk profile if the wells can be drilled laterally within the target stratum for a sufficient distance.** The longer the horizontal lateral within the target stratum, the more resource accessed. Camp Dawson's main parcel of land on the east side of the Cheat River would allow a gas well to be drilled with little more than 2,000 feet of lateral (perhaps 3,200 feet maximum), whereas geothermal wells (with larger diameters and longer radii of curvature) may be challenged to achieve 2,000 feet laterals. Access to property on the west side of the Cheat River for purposes of drilling and resource extraction could allow for much longer well laterals. If property on the west side of Cheat River cannot be accessed for geothermal resources, vertical wells may offer a lower cost option.
- **Depth of Geothermal Resources:** Potential geothermal reservoirs beneath Camp Dawson reside at depths exceeding 8,000 feet. The depth to strata having useful temperatures for direct use of geothermal heat for space heating in buildings at Camp Dawson is a function of the local geothermal gradient, which is not well determined but is believed to be between 1.3°F/100 feet and 1.8°F/100 feet. These are average to slightly above average values. **The local geothermal gradient beneath Camp Dawson cannot be determined with further accuracy without drilling a deep well and measuring the temperature gradient.** Shallow geothermal gradient wells are likely to give misleading

results because of the insulating blanket effect of the Devonian shales and because of local topographic effects, so this exploratory tool is not recommended.

- **Target Geothermal Resource Temperature for Heat Supply:** Ideally, rock strata should have an initial temperature of at least 240°F to meet the full needs of the existing hydronic heating systems at Camp Dawson (one building needs hot water ranging up to 180°F). Lower initial reservoir temperatures may be acceptable if a reduced lifespan for the geothermal system is acceptable, if natural gas is used to help meet peek demands, or if some of the hydronic heating equipment in buildings is replaced with equipment designed to use lower temperatures. **It may be cost effective to retrofit the hydronic heating systems in certain buildings to lower the temperature requirements so that lower temperature water can provide adequate heating of these buildings. The costs of retrofits would likely be more than offset by reduced well costs for shallower wells.**
- **Supplementation of Geothermal Heat:** A geothermal system that delivers water to the buildings at less than 180°F would need supplemental heat from another source. A logical supplemental source would be the existing natural gas boilers (fueled by either purchased or on-site natural gas). **Use of the existing natural gas boilers for peak heating needs, while using geothermal heat for most of the cold weather heating needs, could be a cost effective combination.** Cost could increase substantially if the geothermal system is sized to meet 100 percent of the peak demand. Peak demand would require larger diameter wells (i.e., more capital costs) and either much greater reservoir permeability (which may not be available) or more borehole penetration (which for vertical wells may not be available given thickness of the target strata, and for horizontal wells may not be reasonable given the size and shape of the Camp Dawson property holdings).
- **Target Geothermal Resource Depth for Heat Supply:** If the geothermal gradient is not elevated, but instead is normal, the depth to strata at 240°F would likely exceed 11,000 feet (less than the depth of the Oswego) and may exceed 13,500 feet. This latter value would be the maximum depth of drilling that could be required to reach the preferred temperatures for direct use in space heating.
- **Quality of Geothermal Reservoirs:** The quality of geothermal resources is a function of permeability and porosity of the rock, rock type (which affects thermal conductivity), degree of water saturation, and temperature. **In the rock strata beneath Camp Dawson, permeability is the factor of greatest concern** because natural permeability needs to be sufficient for circulation of large volumes of water through the rock formation between the injection well(s) and the production well(s). In the Appalachian Basin, rocks tend to be less permeable at greater depths. The mitigation for low permeability rock is longer horizontal wells and increasing amounts of hydraulic stimulation. While drilling deeper means encountering higher temperature rock, the ability to circulate water through this rock is likely to be less. Sandstone layers would tend to be the best geothermal reservoirs because of their higher thermal conductivity and porosity, and they tend to have better intergranular and fracture permeability. Shales would be of the lowest quality. Limestones would be of intermediate quality.

- **Dimensions of a Viable Geothermal Reservoir:** A geothermal reservoir that would serve Camp Dawson's needs for heating the nine buildings currently having hydronic heating systems would ideally have an areal extent of at least 3 million square feet. This may be accomplished with placement of two horizontal wells within the same rock stratum, with the wells oriented parallel to each other for a distance of 2,000 feet and having a distance between the wells of 1,500 feet. Thickness of the target stratum is less important for heat extraction but may be more important for permeability and hydraulic conductivity sufficient to transmit the large flow rates needed. The initial temperature is also important. The higher the initial temperature, the less areal extent of reservoir is needed. Also, the nature of the permeability is important. A 3-million square foot reservoir would be insufficient if only a few flow pathways exist between the injection well(s) and the production well(s), as the heat would be quickly exhausted along the few flow pathways. The flow pathways, whether natural or created, must spread the flow throughout the active reservoir to efficiently capture the heat and avoid short circuits.
- **Design of Geothermal Wells:** Drilling wells with greater penetration through the target rock strata is one means of accessing sufficient flow capacity for the circulated water to travel between the injection well(s) and the production well(s). The goal is to increase the surface area for water to flow into and out of the target strata and to increase access to natural fractures and sublayers of greater permeability. Vertical wells, if chosen, can be installed to access a longer section of open hole or slotted casing. Horizontal wells can be drilled longer (within the limits of property rights) or can use more than one well lateral. Both natural fractures and hydraulic fractures increase the effective contact area between the wells and the surrounding reservoir rock. Natural fractures, if insufficiently open, can be hydraulically enhanced. If needed, hydraulic fractures can be created to better connect the well(s) with natural fractures and permeable sublayers of rock. Where the combination of natural fractures and interconnected pore space is insufficient to transmit the circulated water, longer hydraulic fractures would need to be induced to connect the injection well(s) with the production well(s). It is expected that vertical wells, if constructed, would have large hydraulic fractures induced. For horizontal wells, the degree of natural permeability encountered would determine the need and extent of hydraulic stimulation. Hydraulic fractures tend to lose aperture and conductivity at distances greater than 300 feet from a well due to the limit of proppant emplacement. Thus, hydraulic fracturing cannot alone sufficiently interconnect injection wells with production wells that are spaced more than 600 to 1,000 feet apart. Hydraulic fractures propagate in a direction determined by the principal stress directions in the target rock strata; therefore, the design, orientation, and placement of wells must take this into account. While well laterals as short as 2,000 feet have been assessed in this report, this is based on the dimensions of the main parcel of land hosting the Camp (i.e., the parcel on the eastern floodplain of the Cheat River). In reality, the length of the well laterals would need to be sufficient for circulating at least 1,100 GPM through the geothermal reservoir, given the natural or enhanced permeability of the reservoir between the wells.
- **Information Needs for Geothermal Wells:** Wells cannot be completely designed until more information is obtained on the rock strata beneath Camp Dawson. **For geothermal resources, temperature measurements and permeability tests of candidate strata must be undertaken with the exploratory well** to gain sufficient information for planning the conversion of the exploratory well into a production or injection well, and for planning the second (or additional) wells. The competency of the rock within and

above the target rock strata also must be ascertained from the exploratory well to determine whether (and where) the wells can have open-hole (uncased) intervals. The main Camp Dawson property on the east side of the Cheat River may not be sufficiently wide for installing a large-diameter, cased horizontal well to access the geothermal resources. If true, either two smaller-diameter laterals must be drilled from the vertical part of each well, or only vertical wells can be used, or access rights must be obtained on adjoining properties.

- **Subsurface Risks on a Natural Gas Well:** A natural gas well is a lower-risk option than geothermal wells and has the best economic profile over time. However, the lifetime for this resource is much less than for the geothermal resource. Also, even a well drilled into the Marcellus Shale would have non-trivial risks of performing far below expectations. **It is possible that the folding and faulting of the rock during the geologic past allowed the natural gas to escape such that little remains now.** If access rights can be acquired to permit drilling and extraction of natural gas under property west of the Cheat River, the chances increase for accessing sufficient natural gas.
- **Utica Shale Natural Gas:** The Utica Shale presents a greater risk than the Marcellus because of the fact that no Utica wells have been drilled near Camp Dawson (the nearest wells are in the western margins of Pennsylvania and West Virginia). **Due to the depth and the lack of information, the Utica has not been further considered in this report.** If an exploratory hole is drilled to the Trenton and Black River limestones, the Utica should be tested for its natural gas potential, as this would be of considerable scientific and commercial interest.
- **Drilling for Geothermal is more Costly**: Drilling a horizontal well in any of the suggested geothermal reservoirs will be substantially more costly than drilling in shales. The Oriskany sandstone is typically composed of quartz sand grains and carbonate grains cemented with carbonates, and in some places quartz. Thus, drilling rates are much slower than in shales, and costs would be based on the “day rate” (instead of the “per foot” rate) – probably at least 20 percent more total cost for a well of the same diameter. Notably, horizontal wells have been drilled in the Oriskany where natural gas storage fields exist. The Tuscarora is notoriously hard (“hammer-ringing hard”) as a result of quartz infilling of much of the pore space between the quartz sand grains such that horizontal drilling would proceed very slowly compared to shales. Total well cost for a horizontal well in the Tuscarora may be 30 to 70 percent higher than for a conventional gas well of the same diameter drilled to the same depth but in shales. Casing is probably not needed in either the Oriskany or the Tuscarora. The benefit of no casing in the reservoir is that the cost and risk (of loss of the well) is reduced, and access to natural fractures and permeability is greatly improved. The drawback is that hydraulic fracturing in stages may be precluded.
- **Seismic Survey:** Because of the complexity of folds and faults in the vicinity of Camp Dawson, **NETL’s geologists consider it essential to have a seismic survey and expert interpretation of the seismic survey as a prelude to drilling an exploratory well for either natural gas or geothermal heat.** The survey should cover the strata to depths of at least 15,000 feet and sufficient distances away from the property boundaries of Camp Dawson to permit the interpreter to see the trends of faults extending into the rock strata directly beneath Camp Dawson. Where resolvable faults end, the faults continue with less than resolvable offsets, and eventually they end in a swarm or zone of fractures (which

can have favorable permeability). Preferably, the seismic survey should be a 3D, three-component survey. NETL's geologists further recommend that seismic attributes from the seismic survey be considered and interpreted to help identify possible zones or swarms of open natural fractures that can be exploited beneficially for geothermal heat extraction or natural gas production.

- **Subsurface Exploration Plan:** If the WVNG decides to explore geothermal heat, **NETL's geologists recommend that an exploration plan be devised and followed to explore for both natural gas and geothermal reservoirs.** If geothermal reservoir conditions are not found to be suitable, the exploratory well could be converted into a natural gas production well if this resource is encountered. In this approach, the financial risk taken is greatly reduced. **The lowest cost option would be to drill an exploratory well into the Oriskany Sandstone and conduct tests in both the Oriskany and the overlying Marcellus Shale to assess the quality of each potential resource.**
- **Opportunities to Reduce Costs of Geothermal Wells:** The exploratory well is currently assigned a cost for drilling to the maximum depth, about 15,000 feet. If exploratory drilling stops in the first stratum found to have sufficient permeability and temperature, costs could be reduced significantly. The amount of reduction depends on the depth where the first acceptable geothermal reservoir is found. If exploratory drilling stops in the Oriskany, the vertical well could cost as little as $3 million (instead of $10 million for a maximum depth well) for a well with 8-inch ID casing, including a well test for permeability and well logging. If the permeability of the stratum is sufficient to circulate 1,100 GPM such that hydraulic fracturing is not required and the formation is competent such that casing is not required in the horizontal portion of the well, the horizontal portion of a horizontal well could cost as little as $3.8 million for a 4,000-foot lateral (instead of $6.8 million). The total cost of this first horizontal geothermal well could be a low as $6.8 million under ideal circumstances. If $1 million to $2 million (or more) is spent on a 3D-3C seismic survey to identify zones of open natural fractures, there is a potential to save up to $5 million on a pair of horizontal wells by putting the wells into a zone of open natural fractures instead of making hydraulic fractures. This is a gamble, but perhaps one worth taking. The strength and integrity of the rock in the geothermal reservoir should be examined to assess whether casing and casing cement is needed in the part of the well within the target stratum. Perhaps up to $0.8 million could be saved here alone. Consideration should also be given to whether 6-inch ID well casings could be used. If so, perhaps 20 percent could be saved on the costs of drilling, casings, and cements.

Finally, it is clear from the study performed herein that new approaches to reduce the cost of drilling wells to access deep geothermal resources is needed. Geothermal well development dominates the cost of geothermal energy. Innovation is needed both in drilling technology, as well as in business strategies to access geothermal energy more cost effectively. Concepts for doing so are already being considered at NETL, such as assessing the feasibility of "dual completion wells," where drilling for both natural gas and geothermal energy via the same borehole is pursued. Both concurrent natural gas and geothermal energy mining may be possible, or production of both resources may occur sequentially where natural gas is first removed, followed by additional drilling through the same hole to access deeper geothermal energy. By mining two natural resources using the same well investments, overall costs can be reduced.

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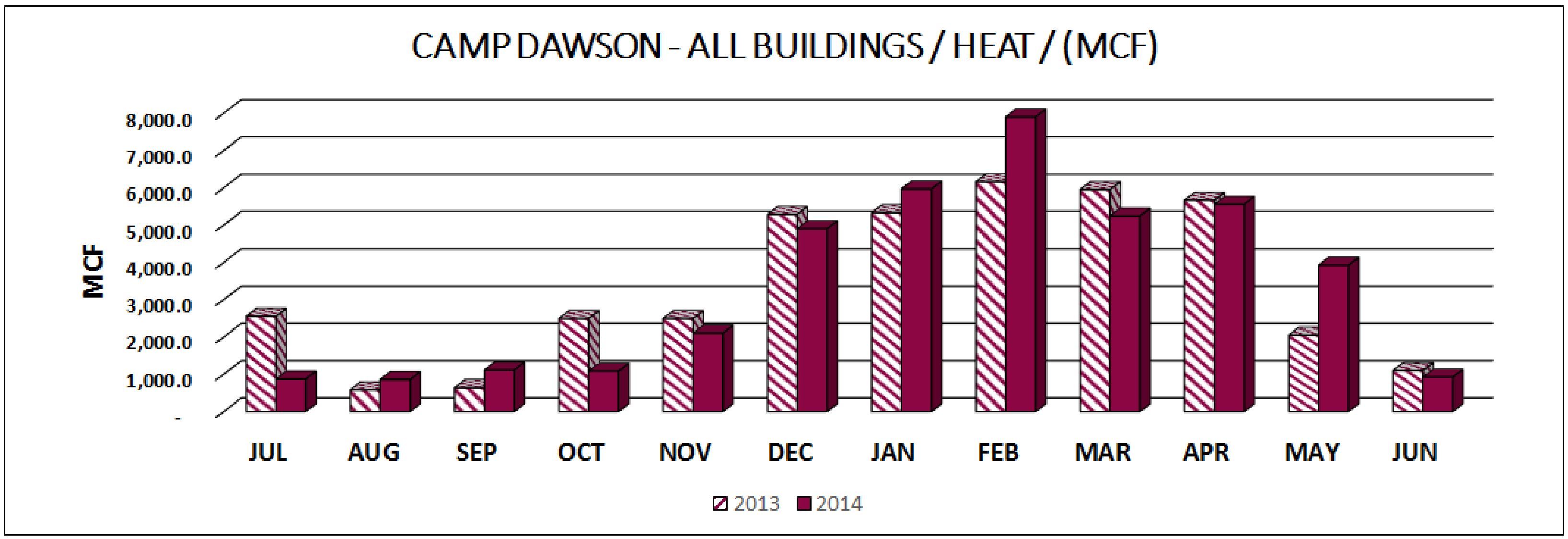
APPENDIX A: NATURAL GAS USAGE DATA FROM CAMP DAWSON

CAMP DAWSON - ALL BUILDINGS (MCF)
July 2013 through June 2015

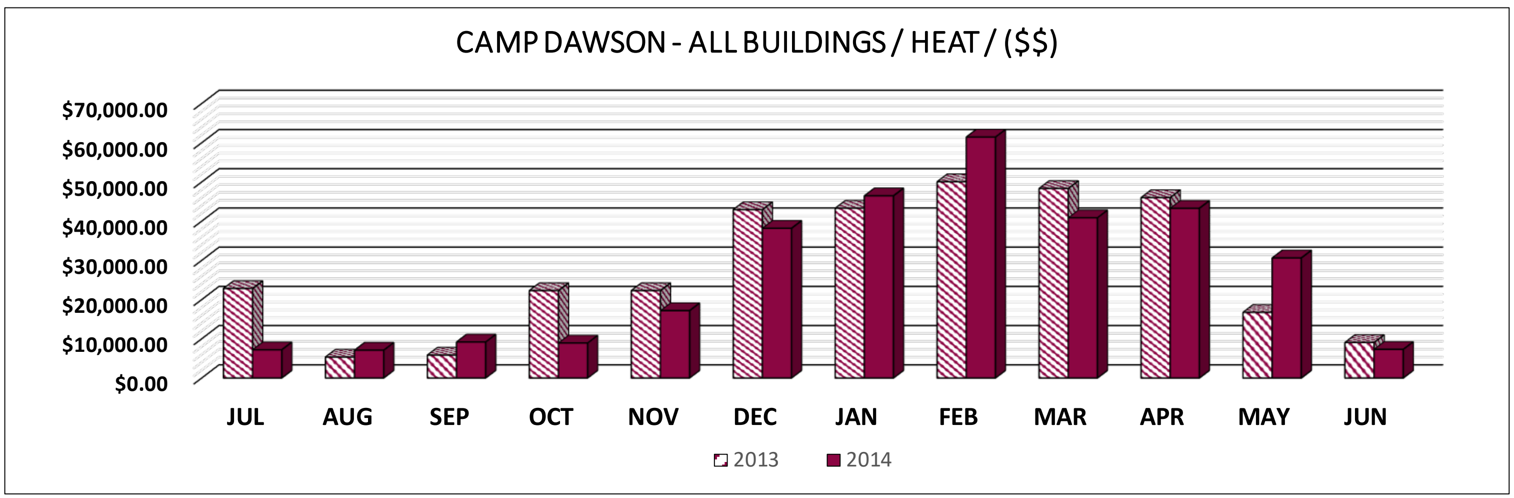
HEAT MCF	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2013/2014 (CD)	2,142.0	116.0	146.0	1,732.0	993.0	2,325.0	934.0	2,323.8	1,121.0	2,138.0	685.0	376.0	
2013/2014 (99th RRC)	11.0	3.0	3.0	13.0	50.0	165.0	190.0	150.3	176.1	118.0	41.0	17.0	
2013/2014 (AFRC)	60.0	14.0	14.0	67.0	266.0	884.0	1,019.0	806.0	945.0	632.0	218.0	93.0	
2013/2014 (RTI)	342.0	448.0	477.0	682.0	1,186.0	1,908.0	3,185.0	2,881.0	3,706.0	2,774.0	1,104.0	610.0	
2013/2014 TOTALS	**2,555.0**	**581.0**	**640.0**	**2,494.0**	**2,495.0**	**5,282.0**	**5,328.0**	**6,161.1**	**5,948.1**	**5,662.0**	**2,048.0**	**1,096.0**	**40,290.2**
Quarterly Totals			**3,776.0**			**10,271.0**			**17,437.2**			**8,806.0**	
2014/2015 (CD)	40.0	87.0	658.0	825.0	1,087.0	1,692.0	2,821.0	2,906.0	1,440.0	2,054.0	2,574.0	444.0	
2014/2015 (99th RRC)	8.0	5.0	4.0	10.0	43.0	118.0	112.0	214.0	150.0	127.0	52.0	12.0	
2014/2015 (AFRC)	43.0	25.0	20.0	54.0	229.0	634.0	602.0	1,146.0	807.0	682.0	278.0	63.0	
2014/2015 (RTI)	777.0	738.0	431.0	193.0	742.0	2,454.0	2,429.0	3,628.0	2,843.0	2,692.0	1,016.0	400.0	
2014 TOTALS	**868.0**	**855.0**	**1,113.0**	**1,082.0**	**2,101.0**	**4,898.0**	**5,964.0**	**7,894.0**	**5,240.0**	**5,555.0**	**3,920.0**	**919.0**	**40,409.0**
Quarterly Totals			**2,836.0**			**8,081.0**			**19,098.0**			**10,394.0**	



Appendix A: Natural Gas Usage Data from Camp Dawson (Continued)

CAMP DAWSON - ALL BUILDINGS ($$)
July 2013 through June 2015

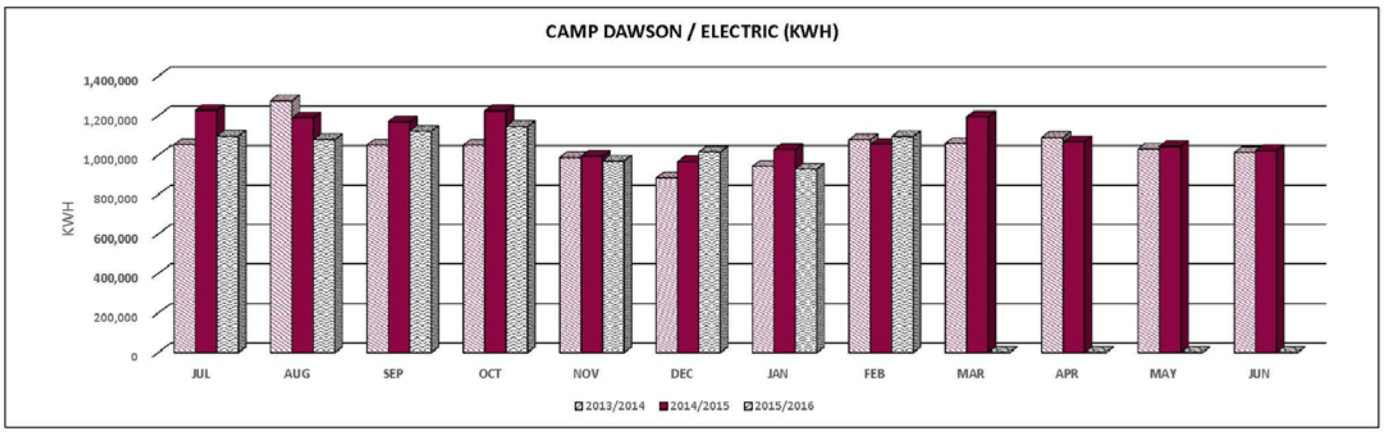
HEAT $$	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	SUBTOTAL	MCA REIMB	TOTAL
2013 (CD)	$19,173.18	$1,206.62	$1,476.20	$15,539.07	$8,982.08	$19,006.14	$7,737.31	$18,993.19	$9,255.31	$17,488.95	$5,726.27	$3,222.98		($24,387.55)	
2013 (99th RRC)	$98.36	$23.54	$22.57	$111.45	$439.96	$1,333.95	$1,537.58	$1,216.81	$1,425.52	$953.40	$328.78	$141.05			
2013 (AFRC)	$527.72	$126.33	$121.09	$597.99	$2,360.55	$7,157.13	$8,249.68	$6,528.63	$7,648.48	$5,115.36	$1,764.04	$756.80			
2013 (RTI)	$3,029.31	$3,975.52	$4,226.49	$6,047.98	$10,513.90	$15,445.55	$25,782.52	$23,320.53	$30,005.40	$22,461.54	$8,941.22	$4,940.18			
2013 TOTALS	**$22,828.57**	**$5,332.01**	**$5,846.35**	**$22,296.49**	**$22,296.49**	**$42,942.77**	**$43,307.09**	**$50,059.16**	**$48,334.71**	**$46,019.25**	**$16,760.31**	**$9,061.01**	**$335,084.21**	**($24,387.55)**	$310,696.66
Quarterly Totals			**$34,006.93**			**$87,535.75**			**$141,700.96**			**$71,840.57**			
2014 (CD)	$501.92	$883.24	$5,508.49	$6,854.86	$8,982.49	$13,312.37	$21,034.93	$21,077.50	$10,093.49	$14,958.59	$19,711.64	$3,468.30		($24,804.61)	
2014 (99th RRC)	$64.87	$38.16	$29.89	$81.15	$345.44	$916.87	$908.38	$1,729.12	$1,218.34	$1,027.81	$420.10	$95.26			
2014 (AFRC)	$348.03	$204.72	$160.37	$435.37	$1,853.43	$4,919.35	$4,873.78	$9,277.39	$6,536.82	$5,514.57	$2,254.01	$511.53			
2014 (RTI)	$6,292.21	$5,975.66	$3,491.80	$1,560.10	$6,008.04	$19,046.52	$19,661.14	$29,369.05	$23,016.93	$21,794.43	$8,248.20	$3,239.61			
2014 TOTALS	**$7,207.03**	**$7,101.78**	**$9,190.55**	**$8,931.48**	**$17,189.40**	**$38,195.11**	**$46,478.23**	**$61,453.06**	**$40,865.58**	**$43,295.40**	**$30,633.95**	**$7,314.70**	**$317,856.27**	**($24,804.61)**	$293,051.66
Quarterly Totals			**$23,499.36**			**$64,315.99**			**$148,796.87**			**$81,244.05**			



APPENDIX B: ELECTRICITY USAGE DATA FROM CAMP DAWSON

CAMP DAWSON - (KWH)
July 2013 through February 2016

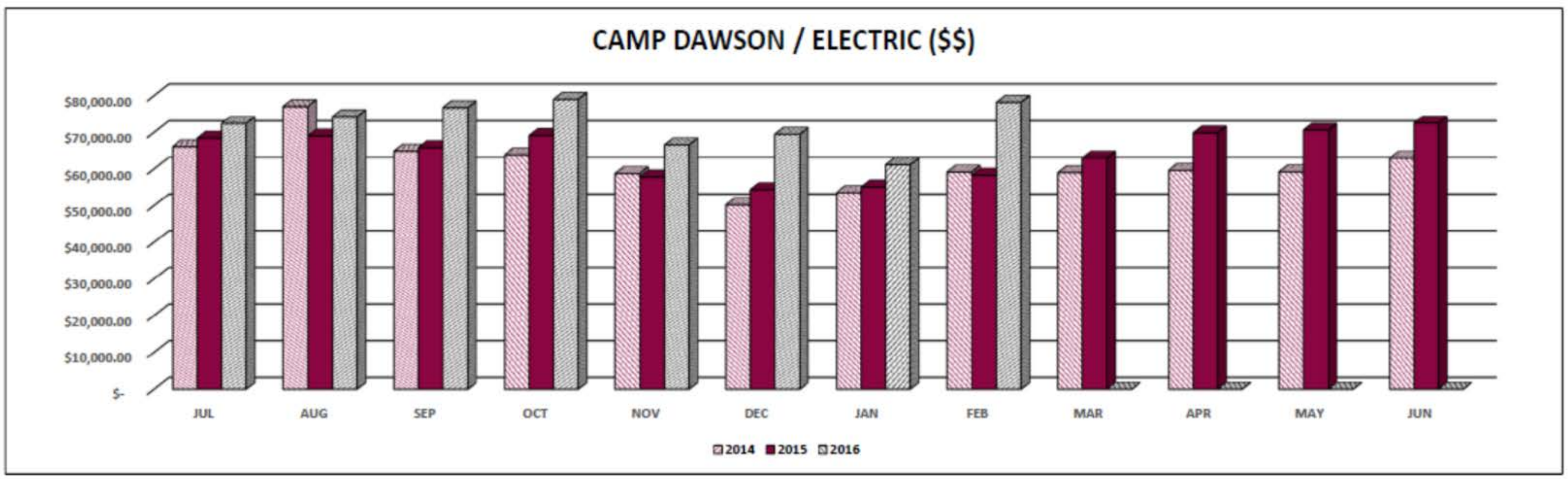
ELECTRIC KWH	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2013/2014 (CD/MCA)	6,338	8,624	8,422	8,081	7,415	6,675	4,670	5,796	5,373	6,273	6,938	8,662	83,267
2013/2014 (CD/RTI BLDG 1(	256,988	319,035	259,444	231,494	162,808	167,781	146,278	169,526	152,937	180,630	174,550	232,044	2,453,515
2013/2014 (CD)	789,903	948,445	782,648	810,936	818,415	710,780	792,330	902,885	901,090	903,008	850,655	773,371	9,984,466
Totals	**1,053,229**	**1,276,104**	**1,050,514**	**1,050,511**	**988,638**	**885,236**	**943,278**	**1,078,207**	**1,059,400**	**1,089,911**	**1,032,143**	**1,014,077**	**12,521,248**
Quarterly Totals			**3,379,847**			**2,924,385**			**3,080,885**			**3,136,131**	
2014/2015 (CD/MCA)	6,687	8,299	9,427	9,035	7,582	6,122	5,142	5,051	4,975	6,983	7,141	8,967	85,411
2014/2015 (CD/RTI BLDG 1(	249,396	268,305	278,714	202,403	167,239	163,144	169,895	143,507	134,199	173,271	175,954	248,305	2,374,332
2014/2015 (CD)	971,673	913,803	881,289	1,013,149	819,156	797,822	853,221	906,396	1,056,164	889,066	861,579	765,900	10,729,218
Totals	**1,227,756**	**1,190,407**	**1,169,430**	**1,224,587**	**993,977**	**967,088**	**1,028,258**	**1,054,954**	**1,195,338**	**1,069,320**	**1,044,674**	**1,023,172**	**13,188,961**
Quarterly Totals													
2015/2016 (CD/MCA)	8,009	8,705	10,643	8,944	8,198	6,380	5,472	0	0	0	0	0	56,351
2015/2016 (CD/RTI BLDG 1(	242,520	257,796	275,167	231,733	178,032	157,364	0	0	0	0	0	0	1,342,612
2015/2016 (CD)	846,489	812,999	836,215	905,333	784,502	852,946	923,792	1,094,890	0	0	0	0	7,057,166
Totals	**1,097,018**	**1,079,500**	**1,122,025**	**1,146,010**	**970,732**	**1,016,690**	**929,264**	**1,094,890**	**0**	**0**	**0**	**0**	**8,456,129**
Quarterly Totals			**3,298,543**			**3,133,432**			**2,024,154**			**0**	



Appendix B: Electricity Usage Data from Camp Dawson (Continued)

CAMP DAWSON - ALL BUILDINGS ($$)

ELECTRIC KWH	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
2014 (CD/MCA)	$ 397.39	$ 540.72	$ 528.06	$ 506.68	$ 464.92	$ 418.52	$ 292.81	$ 363.41	$ 336.89	$ 393.32	$ 435.01	$ 543.11	$ 5,220.84
2014 (CD/RTI BLDG 100)	$ 16,113.15	$ 20,003.49	$ 16,267.14	$ 14,514.67	$ 10,208.06	$ 10,519.87	$ 9,171.63	$ 10,629.28	$ 9,589.15	$ 11,325.50	$ 10,944.29	$ 14,549.16	$ 153,835.39
2014 (CD)	$ 49,581.33	$ 56,501.65	$ 48,075.43	$ 48,852.92	$ 48,064.12	$ 39,259.44	$ 44,092.29	$ 48,151.50	$ 49,059.44	$ 47,876.71	$ 47,826.30	$ 47,872.27	$ 575,213.40
Totals	**$ 66,091.87**	**$ 77,045.86**	**$ 64,870.63**	**$ 63,874.27**	**$ 58,737.10**	**$ 50,197.83**	**$ 53,556.73**	**$ 59,144.19**	**$ 58,985.48**	**$ 59,595.53**	**$ 59,205.60**	**$ 62,964.54**	**$ 734,269.63**
Quarterly Totals			**$ 208,008.36**			**$ 172,809.20**			**$ 171,686.40**			**$ 181,765.67**	
2015 (CD/MCA)	$ 372.47	$ 462.25	$ 525.08	$ 503.25	$ 422.32	$ 341.00	$ 286.41	$ 281.34	$ 277.11	$ 388.95	$ 397.75	$ 499.46	$ 4,757.39
2015 (CD/RTI BLDG 100)	$ 13,891.36	$ 14,944.59	$ 15,524.37	$ 11,273.85	$ 9,315.21	$ 9,087.12	$ 9,463.15	$ 7,993.34	$ 7,474.88	$ 9,651.19	$ 9,800.64	$ 13,830.59	$ 132,250.29
2015 (CD)	$ 54,139.86	$ 53,591.35	$ 49,793.45	$ 57,361.21	$ 48,079.04	$ 44,940.34	$ 45,331.25	$ 49,993.56	$ 55,265.68	$ 59,806.75	$ 60,403.59	$ 58,215.64	$ 636,921.72
Totals	**$ 68,403.69**	**$ 68,998.19**	**$ 65,842.90**	**$ 69,138.31**	**$ 57,816.57**	**$ 54,368.46**	**$ 55,080.81**	**$ 58,268.24**	**$ 63,017.67**	**$ 69,846.89**	**$ 70,601.98**	**$ 72,545.69**	**$ 773,929.40**
Quarterly Totals			**$ 203,244.78**			**$ 181,323.34**			**$ 176,366.72**			**$ 212,994.56**	
2016 (CD/MCA)	$ 528.59	$ 574.53	$ 702.44	$ 590.30	$ 541.07	$ 421.08	$ 361.15	$ -	$ -	$ -	$ -	$ -	$ 3,719.17
2016 (CD/RTI BLDG 100)	$ 16,006.32	$ 17,014.54	$ 18,161.02	$ 15,294.38	$ 11,750.11	$ 10,386.02	$ 10,961.48	$ -	$ -	$ -	$ -	$ -	$ 99,573.87
2016 (CD)	$ 55,900.05	$ 56,688.56	$ 57,884.02	$ 63,132.14	$ 54,296.21	$ 58,652.89	$ 49,815.14	$ 78,205.17	$ -	$ -	$ -	$ -	$ 474,574.17
Totals	**$ 72,434.96**	**$ 74,277.63**	**$ 76,747.48**	**$ 79,016.82**	**$ 66,587.39**	**$ 69,459.99**	**$ 61,137.77**	**$ 78,205.17**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 577,867.21**
Quarterly Totals			**$ 223,460.07**			**$ 215,064.20**			**$ 139,342.94**			**$ -**	



APPENDIX C: CALCULATIONS FOR CAMP DAWSON ENERGY ESTIMATING HEATING DEGREE DAY METHOD

	Peak Demand	Jan	Feb	March	April	May	June	July	August	Sept	Oct	Nov
	Btu/hr	Btu/hr	Btu/hr	Btu/hr	Btu/hr	Btu/hr	Btu/hr	Btu/hr	Btu/hr	Btu/hr	Btu/hr	Btu/hr
Degree Days		1133	959	792	498	251	70	15	23	134	456	719
New RTI A1000 & OPS	7000000	3.63E+09	3.069E+09	2534000000	1593200000	802900000	224000000	48300000	73500000	428400000	1.49E+09	2.3E+09
Multi-Purpose Building 403	825000	4.27E+08	361680000	298650000	187770000	94627500	26400000	5692500	8662500	50490000	1.75E+08	271095000
Mountaineer challenge Academy 443	1495000	7.74E+08	655408000	541190000	340262000	171476500	47840000	10315500	15697500	91494000	3.18E+08	491257000
Old RTI A1000	4000000	2.07E+09	1.754E+09	1448000000	910400000	458800000	128000000	27600000	42000000	244800000	8.5E+08	1.314E+09
Barracks 241	935000	4.84E+08	409904000	338470000	212806000	107244500	29920000	6451500	9817500	57222000	1.99E+08	307241000
Barracks 243	935000	4.84E+08	409904000	338470000	212806000	107244500	29920000	6451500	9817500	57222000	1.99E+08	307241000
Barracks 245	935000	4.84E+08	409904000	338470000	212806000	107244500	29920000	6451500	9817500	57222000	1.99E+08	307241000
Barracks 246	700000	3.63E+08	306880000	253400000	159320000	80290000	22400000	4830000	7350000	42840000	1.49E+08	230020000
Total	16825000	8.71E+09	7.376E+09	6090650000	3829370000	1929827500	538400000	116092500	1.77E+08	1029690000	3.58E+09	5.529E+09
Average Hourly load/month		11711919	10976310	8186357	5318569	2593854.167	747777	156038	237449	1430125	4805528	7678743
Predicted Natural Gas Usage (MCF)	**16.825**	**8713.668**	**7376.08**	**6090.65**	**3829.37**	**1929.8275**	**538.4**	**116.0925**	**176.6625**	**1029.69**	**3575.313**	**5528.695**

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APPENDIX D: BIN ESTIMATE OF ANNUAL HYDRONIC ENERGY DEMAND FOR CAMP DAWSON

(Highlighted row corresponds to average net heat loss conditions for January)

BINS Outdoor Temperature	Heat Loss per °F	ΔT	Net Heat Loss	System Output Capacity	Run Time	Seasonal Hours	Seasonal Input	Cumulative Percent of Heating Season	Cumulative Heating load	Geothermal Flow Rate
(°F)	(BTU/HR-ΔT)		(BTU/HR)	(Btu/hr)	(%)		(BTU)	(%)	(BTU)	(GPM)
62		8	1808576	1808576	100%	670	1211745920	3.8%	1211745920	181
57		13	2938936	2938936	100%	555	1631109480	9.0%	1631109480	294
52		18	4069296	4069296	100%	497	2022440112	15.4%	3653549592	407
47		23	5199656	5199656	100%	591	3072996696	25.2%	6726546288	520
42		28	6330016	6330016	100%	560	3544808960	36.5%	10271355250	633
37		33	7460376	7460376	100%	572	4267335072	50.0%	14538690320	746
32		38	8590736	8590736	100%	524	4501545664	64.3%	19040235980	859
27	226072	43	9721096	9721096	100%	350	3402383600	75.1%	22442619580	972
22		48	10851456	10851456	100%	175	1899004800	81.1%	24341624380	1085
17		53	11981816	11981816	100%	138	1653490608	86.4%	25995114990	1198
12		58	13112176	13112176	100%	112	1468563712	91.0%	27463678700	1311
7		63	14242536	14242536	100%	67	954249912	94.1%	28417928600	1424
2		68	15372896	15372896	100%	76	1168340096	97.8%	29586268700	1537
-3		73	16503256	16503256	100%	20	330065120	98.8%	29916333830	1650
-8		78	17633616	17633616	100%	21	370305936	100.0%	30286639770	1763
					TOTAL	4258	**31498385688**			
					Input Energy (BTU) (Based on HXGR Effectivenes of 70%)		**44997693840**			
					Input Energy (MMCF)		**43267**			

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APPENDIX E: BIN HOURS FOR ELKINS, WEST VIRGINIA

ELKINS, WV													
Bin weather data converted from TMY2 hourly weather data using TMY2BIN by Randall C. Wilkinson													
Bin Low (°F)	**Bin High (°F)**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
115	120	0	0	0	0	0	0	0	0	0	0	0	0
110	115	0	0	0	0	0	0	0	0	0	0	0	0
105	110	0	0	0	0	0	0	0	0	0	0	0	0
100	105	0	0	0	0	0	0	0	0	0	0	0	0
95	100	0	0	0	0	0	0	0	0	0	0	0	0
90	95	0	0	0	0	0	0	0	0	0	0	0	0
85	90	0	0	0	0	0	3	0	2	0	0	0	0
80	85	0	0	0	0	1	38	53	53	0	0	0	0
75	80	0	0	0	13	19	60	88	91	32	0	0	0
70	75	0	0	2	9	35	58	75	76	53	9	0	0
65	70	0	0	8	22	59	86	113	132	91	21	7	0
60	65	4	1	28	68	86	102	135	114	70	35	16	11
55	60	12	8	27	58	95	62	32	62	90	49	42	18
50	55	23	16	48	51	63	81	1	16	65	62	51	20
45	50	39	13	47	75	64	32	7	6	68	139	60	41
40	45	25	60	73	66	76	5	0	0	32	64	114	45
35	40	49	78	124	48	31	1	0	0	3	66	89	83
30	35	100	111	100	46	18	0	0	0	0	39	55	55
25	30	69	44	55	21	5	0	0	0	0	32	51	73
20	25	39	39	18	3	0	0	0	0	0	7	40	29
15	20	33	42	22	0	0	0	0	0	0	5	3	33
10	15	44	43	0	0	0	0	0	0	0	0	0	25
5	10	35	9	0	0	0	0	0	0	0	0	0	23
0	5	40	13	0	0	0	0	0	0	0	0	0	23
-5	0	5	3	0	0	0	0	0	0	0	0	0	12
-10	-5	9	0	0	0	0	0	0	0	0	0	0	12

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APPENDIX F: PEAK AND AVERAGE MONTHLY ESTIMATES OF HYDRONIC HEATING DEMAND FOR CAMP DAWSON

Camp Dawson Yearly Hydronic Heating Demands	Peak Demand	January	February	March	April	May	June	July	August	September	October	November	December	Total	AREA		Average
Average Hourly load/month **(Btu_HHV/hr)**		1.17E+07	1.10E+07	8.19E+06	5.32E+06	2.59E+06	7.48E+05	1.56E+05	2.37E+05	1.43E+06	4.81E+06	7.68E+06	1.03E+07				6999490.037
	Btu/hr	**Btu**	**Btu**	**Btu**	**Btu**	**Btu**	**Btu**	**Btu**	**Btu**	**Btu**	**Btu**	**Btu**	**Btu**	**Btu**	Sq. ft.		Hourly Load
Building																	**Btu/hr**
Degree Days		1133	959	792	498	251	70	15	23	134	456	719	996	6046		Hydronic EUI	
New RTI A1000 & OPS	7.00E+06	3.63E+09	3.07E+09	2.53E+09	1.59E+09	8.03E+08	2.24E+08	4.83E+07	7.35E+07	4.28E+08	1.49E+09	2.30E+09	3.19E+09	19372500000	397171	48776.21981	4549671.207
Multi-Purpose Building 403	8.25E+05	4.27E+08	3.62E+08	2.99E+08	1.88E+08	9.46E+07	2.64E+07	5.69E+06	8.66E+06	5.05E+07	1.75E+08	2.71E+08	3.76E+08	2283187500	35800	63776.18715	536211.2494
Mtneer challenge Academy 443	1.50E+06	7.74E+08	6.55E+08	5.41E+08	3.40E+08	1.71E+08	4.78E+07	1.03E+07	1.57E+07	9.15E+07	3.18E+08	4.91E+08	6.81E+08	4137412500	45786	90364.13969	971679.7792
Old RTI A1000	4.00E+06	2.07E+09	1.75E+09	1.45E+09	9.10E+08	4.59E+08	1.28E+08	2.76E+07	4.20E+07	2.45E+08	8.50E+08	1.31E+09	1.82E+09	11070000000	315427	35095.28354	2599812.118
Barracks 241	9.35E+05	4.84E+08	4.10E+08	3.38E+08	2.13E+08	1.07E+08	2.99E+07	6.45E+06	9.82E+06	5.72E+07	1.99E+08	3.07E+08	4.26E+08	2587612500	17280	149746.0938	607706.0827
Barracks 243	9.35E+05	4.84E+08	4.10E+08	3.38E+08	2.13E+08	1.07E+08	2.99E+07	6.45E+06	9.82E+06	5.72E+07	1.99E+08	3.07E+08	4.26E+08	2587612500	13668	189319.0299	607706.0827
Barracks 245	9.35E+05	4.84E+08	4.10E+08	3.38E+08	2.13E+08	1.07E+08	2.99E+07	6.45E+06	9.82E+06	5.72E+07	1.99E+08	3.07E+08	4.26E+08	2587612500	13668	189319.0299	607706.0827
Barracks 246	7.00E+05	3.63E+08	3.07E+08	2.53E+08	1.59E+08	8.03E+07	2.24E+07	4.83E+06	7.35E+06	4.28E+07	1.49E+08	2.30E+08	3.19E+08	1937250000	10748	180242.8359	454967.1207
														46563187500			10935459.72
Total	1.68E+07	8.71E+09	7.38E+09	6.09E+09	3.83E+09	1.93E+09	5.38E+08	1.16E+08	1.77E+08	1.03E+09	3.58E+09	5.53E+09	7.66E+09	46580012500	849548	54829.17092	10939411.11
Predicted Natural Gas Usage (MCF)	16.825	8713.6675	7376.08	6090.65	3829.37	1929.8275	538.4	116.0925	176.6625	1029.69	3575.3125	5528.695	7658.74	46580.0125			

1. Begin *with Appendix A – Camp Dawson Energy Estimates Heating Degree Day Method (HDD)*
    a. To heat a gallon of water from 160-180 deg. F requires an addition of 167 Btu.
    b. For a given month: *Average Hourly Load* [Btu/hr] / 167 [Btu/gal] = *Average hydronic flow-rate* [gal/hr].

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APPENDIX G: ELECTRICAL DEMAND AND FINANCIAL PARAMETERS USED FOR CHP AND NON-CHP STUDY

Financial Inputs	
Finance Structure Description	**Government Funded**
Financial Methodology	Project
Debt Percentage Applied to TASC or TOC?	TOC
Enter Debt Percentage	0%
Equity Percentage	100%
Economic Life of Plant (Years)	7
Construction/Capital Expenditure Period (Years)	**2**
Debt Repayment Term (Years) for Project Financing	1
Base year (Year of Dollar value Entries)	2,016
Investment Tax Credit (%TOC)	0%
Maximum Tax Credit (1000$)	$ -
Tax Rate	0%
Carbon Tax ($ per tonne of CO_2-e)	$ -
Capital Depreciation Schedule (See Depreciation Table on Dep_CF_Tables Sheet)	SL15-1/2 yr
Number of years for Straight Line Depreciation if SL selected	7
Capital Depreciation number of years	1
Dollar Basis for Analysis type?	Nominal
Inflation Rate	3.0%
Real Escalation Rate for COP and All O&M (See Note 1)	-0.5%
Nominal Escalation Rate for COP and All O&M (See Note 1)	2.5%
Nominal Cost of Debt /Interest Rate	0.0%
Real Cost of Debt /Interest Rate	-2.9%
Nominal Internal Rate of Return on Equity (IRROE)	2.5%
Real Required Internal Rate of Return on Equity (IRROE)	-0.5%
Construction / Capital Expenditure Input	
Nominal Capital Cost Escalation During Capital Expenditure Period (annual rate)	0.0%
Real Capital Cost Escalation During Capital Expenditure Period (annual rate)	-2.9%
Include Interest During Construction?	No
Capital Disbursements per year (for interest calculation)	12
Capital Distribution over expenditure period	
% First year	100%
% Second year	0%
% Third year	0%
% Fourth year	0%
% Fifth year	0%
% Sixth year	0%
% Seventh year	0%
% Eighth year	0%
% Ninth year	0%
% Tenth year	0%
TOTAL	100%

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APPENDIX H: GEOTHERMAL GRADIENTS: INFORMATION FROM VARIOUS SOURCES

Different estimates of the geothermal gradient in the region surrounding Camp Dawson exist. The continental average thermal gradient is 13.7°F per 1,000 feet (25°C per km depth from https://en.wikipedia.org/wiki/Geothermal_gradient and reported by Armstead and Tester (1987), "*Heat Mining: A New Source of Energy*, E. & F.N. Spon, Ltd., London and New York).

An example of the early maps of geothermal gradients was reproduced in a report sponsored by the Los Alamos National Laboratory. This report by Hendry et al. (1982), showed a below normal geothermal gradient in the vicinity of Camp Dawson. A geothermal hotspot was recognized, but the mapping delineated a less intense hotspot compared to the recent work at SMU. The map is reproduced here as Figure H.1.

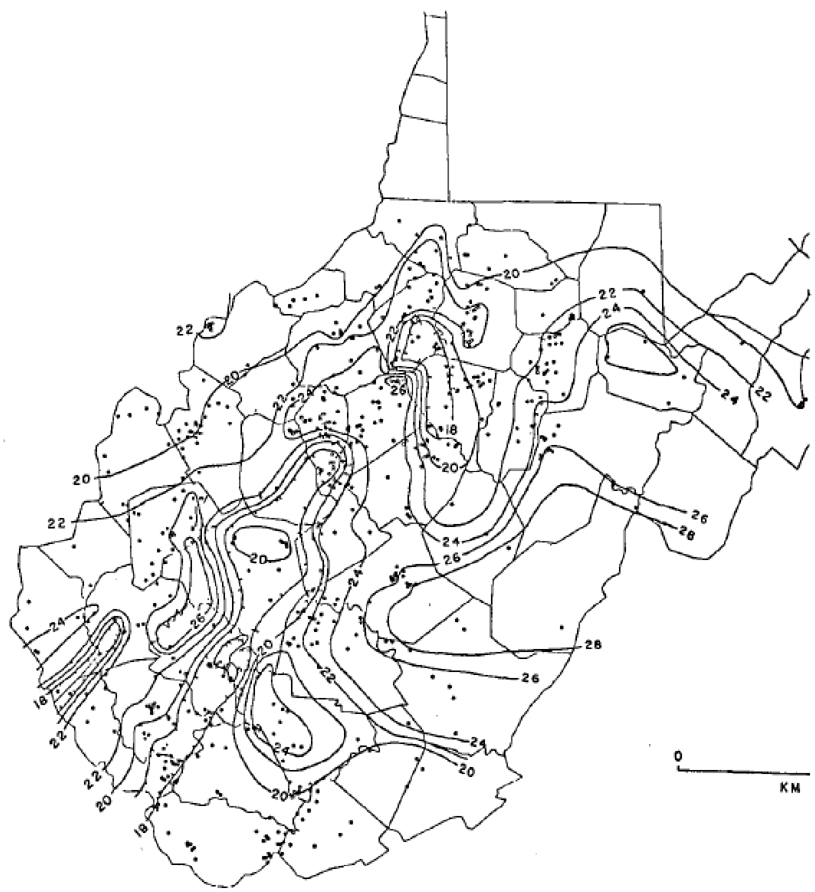

Figure H.1: An early geothermal gradient map for West Virginia as presented in Hendry et al. (1982). The dots are locations of wells. The contour interval is 2°C/km. Temperature data from the wells were not corrected for cooling during the circulation of drilling fluids or other effects.

In 2010, the geothermal gradient was reevaluated by the Geothermal Laboratory at SMU. Two of the early nationwide maps from SMU are reproduced here:
(http://www.smu.edu/Dedman/Academics/Programs/GeothermalLab/DataMaps)

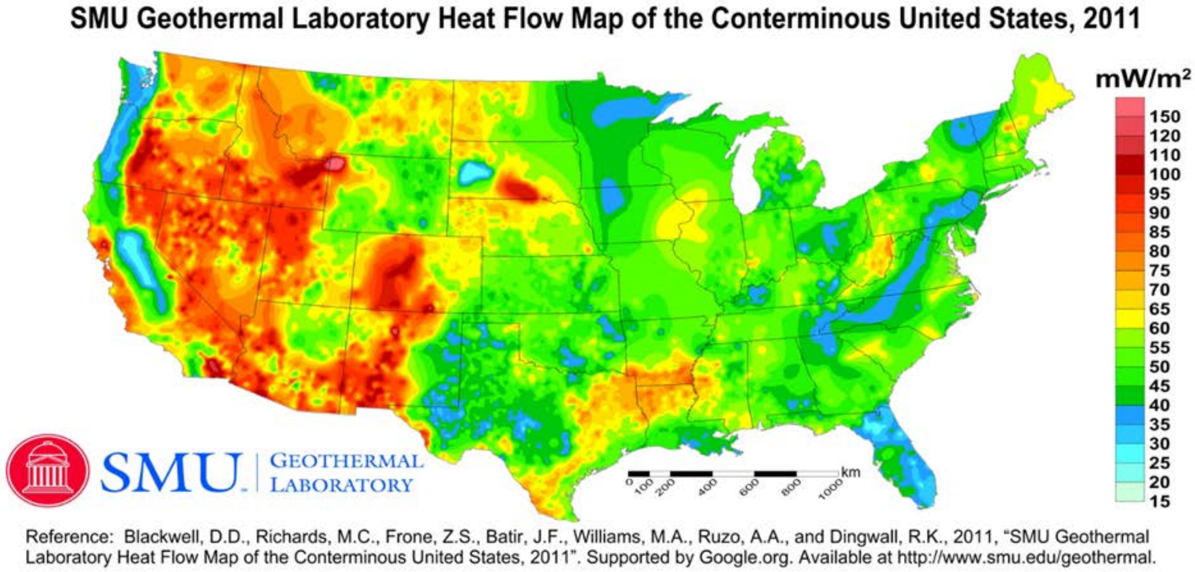

Figure H.2: A recent example of the geothermal maps available. This one displays heat flux, rather than heat gradient. Heat flux is the product of the gradient and the average thermal conductivity.

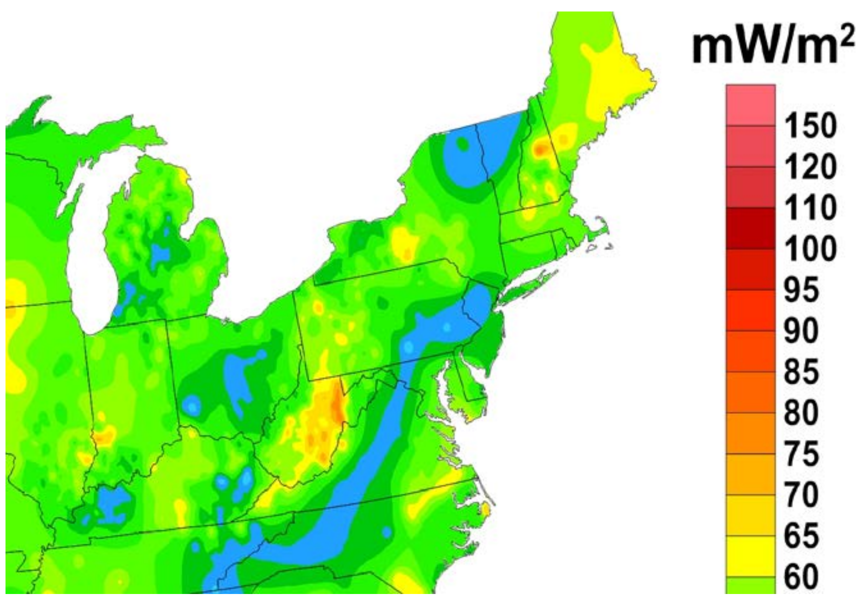

Figure H.3: An enlargement of a portion of the SMU heat flow map of the coterminous United States (2011), showing a hot spot in northeastern West Virginia, including central and southern Preston County.

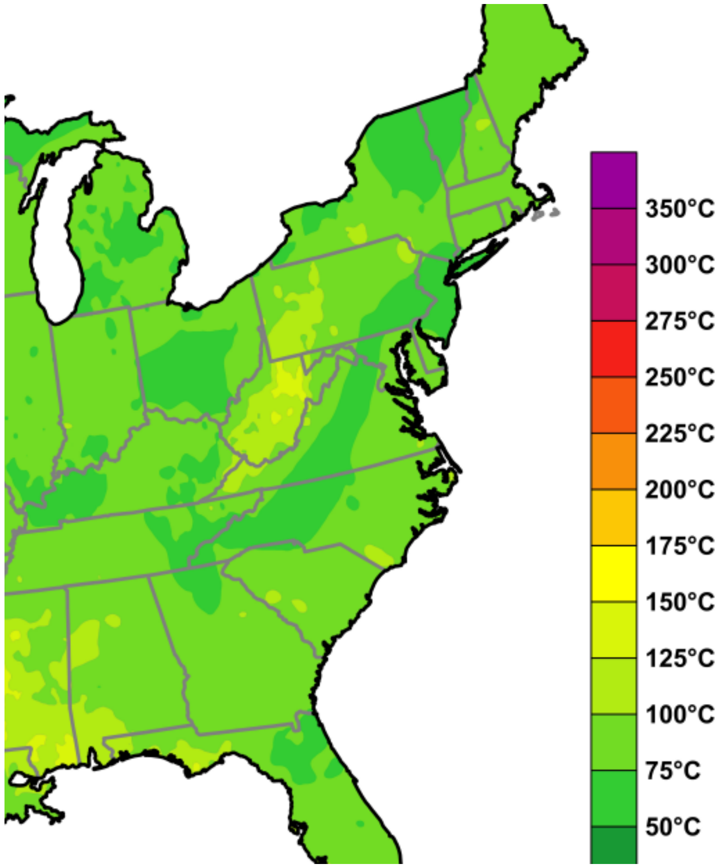

Figure H.4: Enlargement from the 2011 SMU temperature map of the coterminous United States at a depth of 3.5 km (11,500 feet) below the surface.

An example SMU map, shown in part here as Figure H.4, indicates the temperature at 11,500 feet (3.5 km) beneath Camp Dawson to be between 212 and 257°F (100°C and 125°C). That means a regional geothermal temperature gradient between 14.0 and 17.9°F per 1,000 feet (25.6 and 32.7°C per km).

The WVGES website (http://www.wvgs.wvnet.edu/) has several interactive maps prepared using data available in the well log files of WVGES, including some of the same well data used by SMU. Those maps indicate a lower regional geothermal gradient surrounding Camp Dawson than that estimated by SMU because the WVGES data are uncorrected for temperature upsets from drilling. Typically, the downhole temperature measurement is made soon after drilling stops and before the disturbed zone around the well has reached thermal equilibrium with the surrounding rock. The following five maps were prepared by Ron McDowell of the WVGES and are available on the Interactive Mapping Portal:

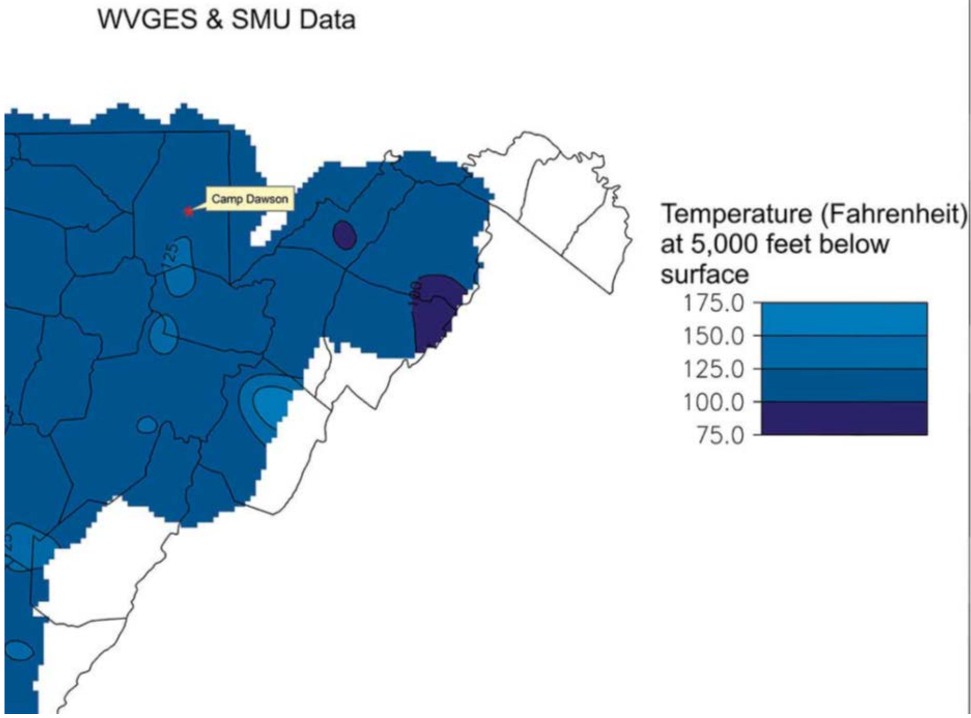

Figure H.5: Temperature map (5,000 feet depth) from the WVGES interactive mapping portal.

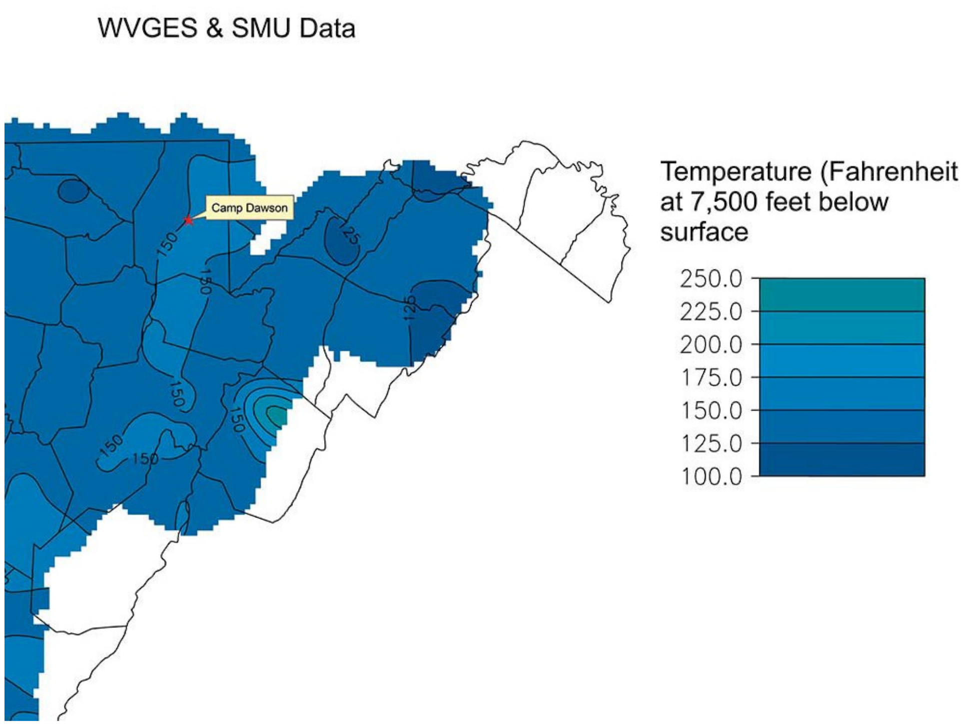

Figure H.6: Temperature map (7,500 feet depth) from the WVGES interactive mapping portal.

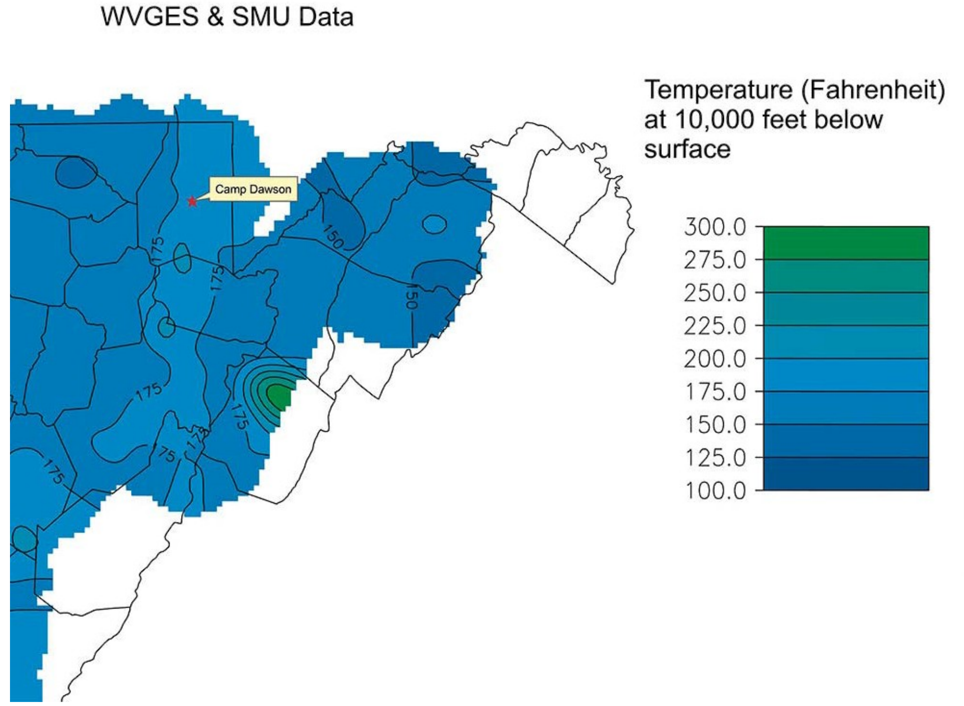

Figure H.7: Temperature map (10,000 feet depth) from the WVGES interactive mapping portal.

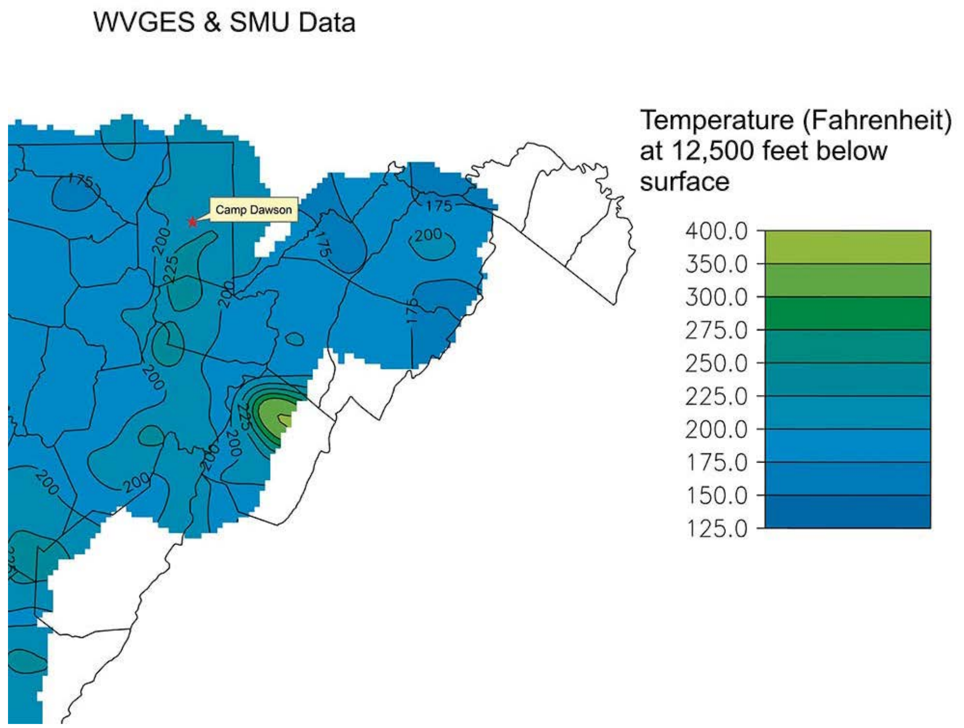

Figure H.8: Temperature map (12,500 feet depth) from the WVGES interactive mapping portal.

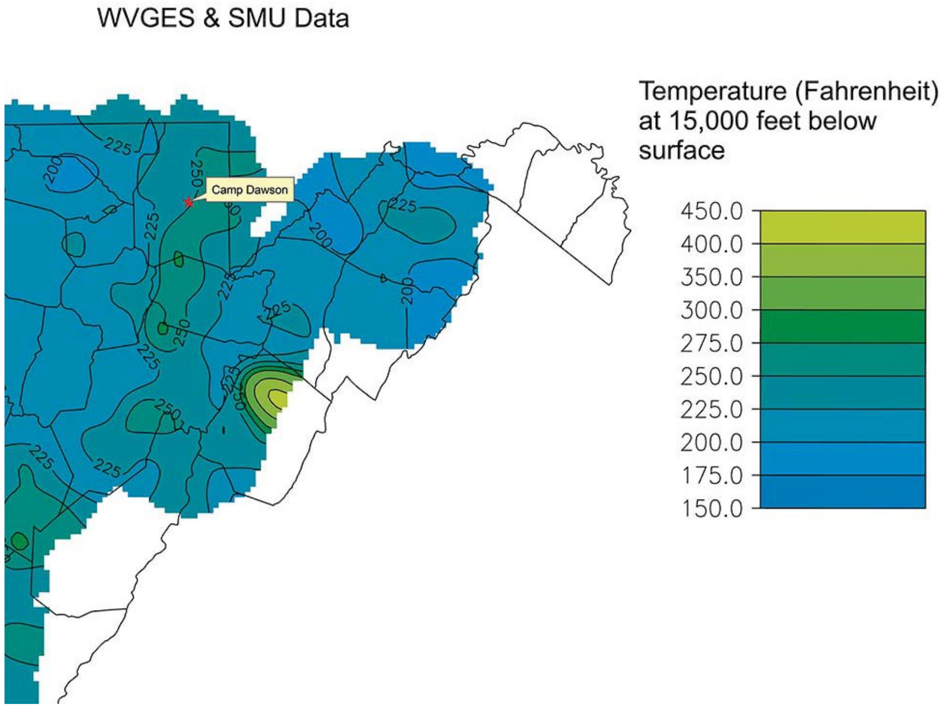

Figure H.9: Temperature map (15,000 feet depth) from the WVGES interactive mapping portal.

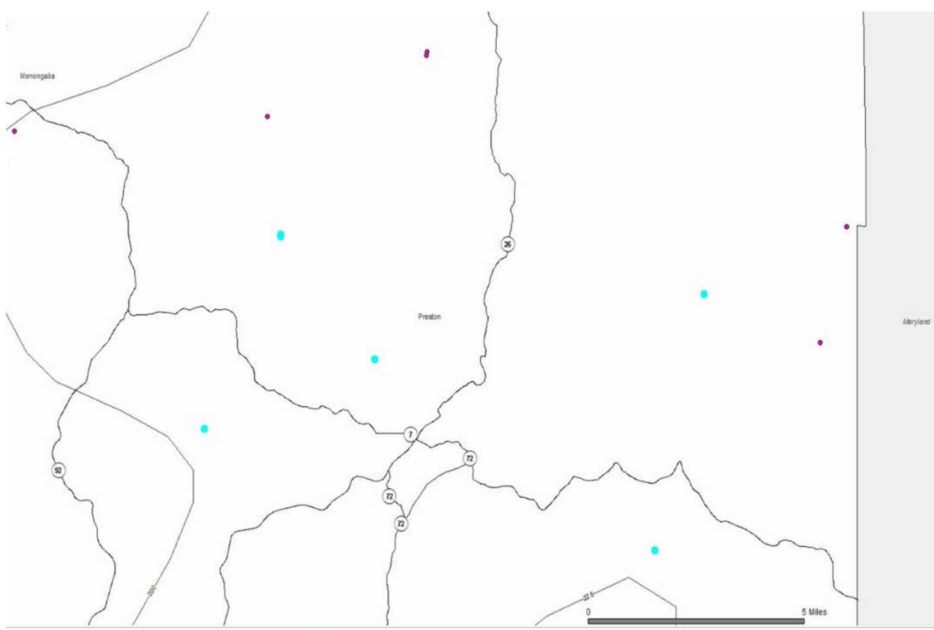

Figure H.10: Map from the West Virginia Geological and Economic Survey showing the relevant portion of Preston County, West Virginia. The locations of the wells used in the SMU survey of the geothermal potential of the United States, and isothermal lines showing the 200°F contour and 225°F contour at 12,500 feet depth.

A more recent geothermal gradient map has been provided to NETL by the WVGES, although this map is still in preliminary (draft) form.

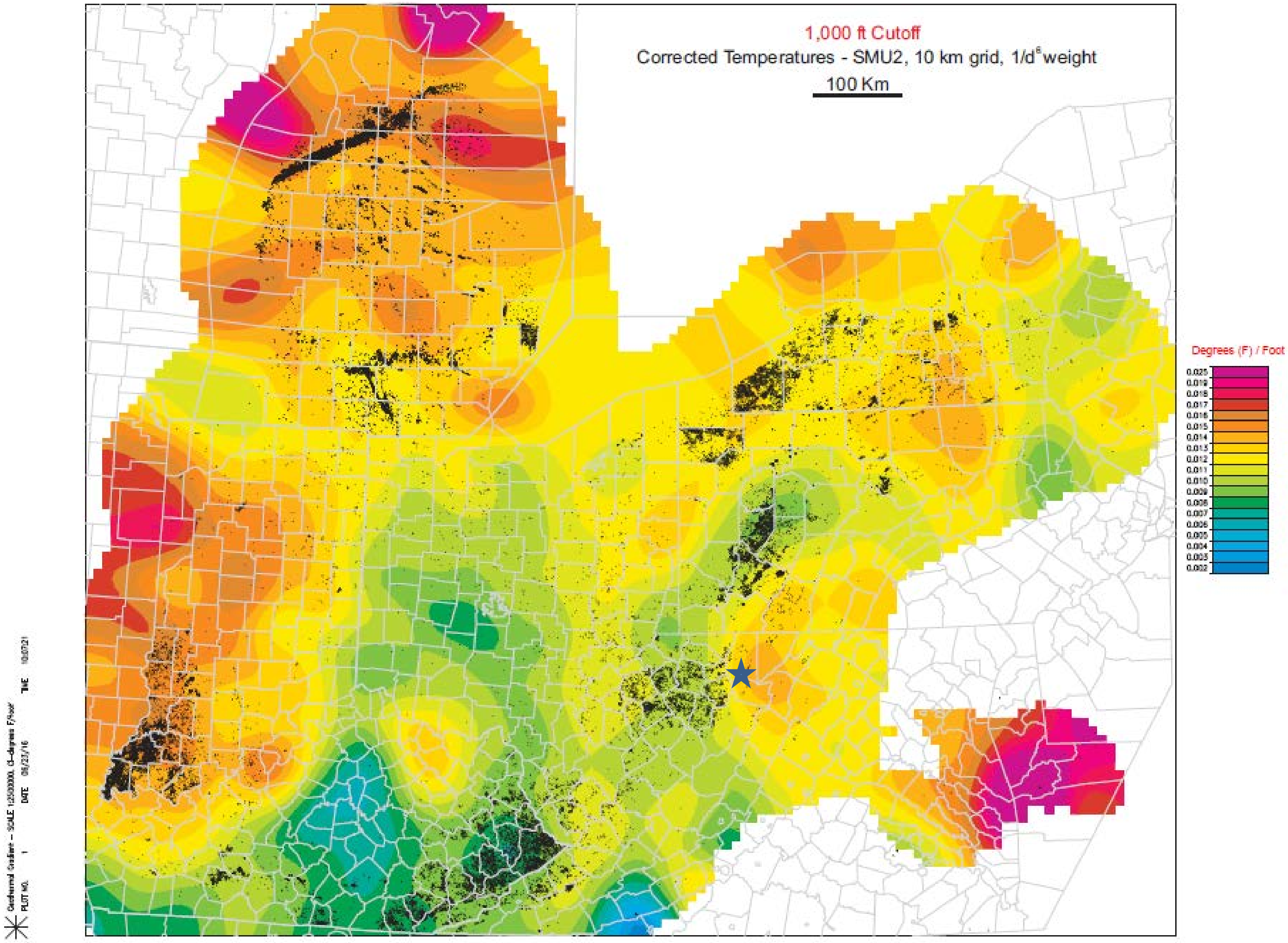

Figure H.11: Estimated Geothermal Gradients in the Central Appalachian Basin – Preliminary. (McDowell, 2016)

NETL further attempted to estimate temperature gradients and heat flow values for the Camp Dawson site using wellbore data as modified and presented by SMU (see Figure H.12 for well locations). To obtain values for the temperature gradient and heat flow in the Camp Dawson vicinity, the natural neighbor interpolation method was used because it accounts for spatial irregularity of the data points and is ideal for varying data densities (Shope et al., 2012). Uncertainties have not been estimated at this time. The map below (Figure H.13) shows the estimated geothermal temperature gradient around the Camp Dawson site, which is approximately 25–35°C/km (1.37–1.92°F/100 feet) by this technique. Figure H.14 is a map of the estimated heat flow, which is approximately 73–87 milliwatt per square meter (mW/m^2) in the vicinity of Camp Dawson. Using the temperature gradient map, the depths needed to drill to 180°F or 82.2°C were estimated to be approximately 10,000 feet below ground level (see Figure H.15). This estimation assumes a linear geothermal gradient over the depths of interest and a near ground surface temperature of 51.1°F or 10.6°C (average annual temperature at Albright, West Virginia, from USA.com [http://www.usa.com/albright-wv-weather.htm]).

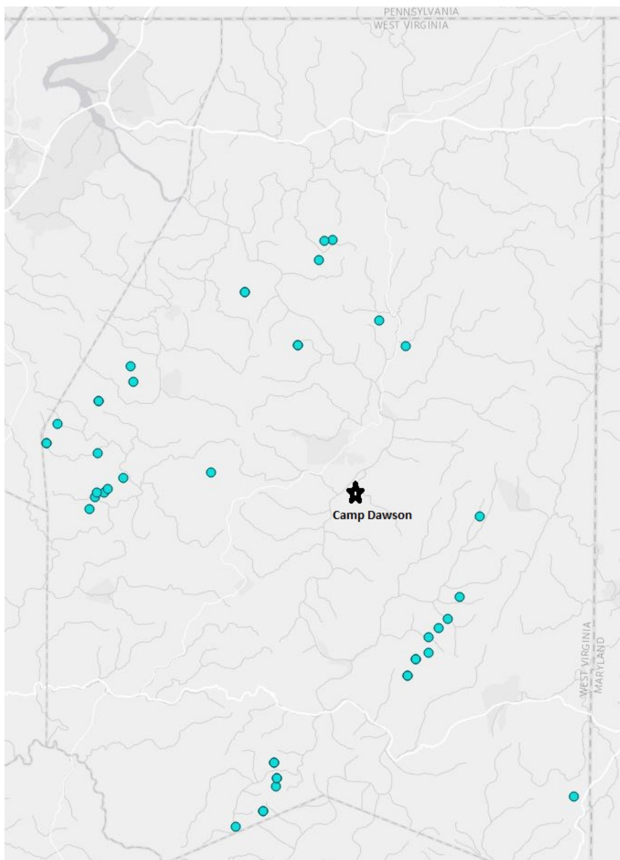

Figure H.12. Preston County wells used in geothermal maps by SMU. (Spears, 2016)

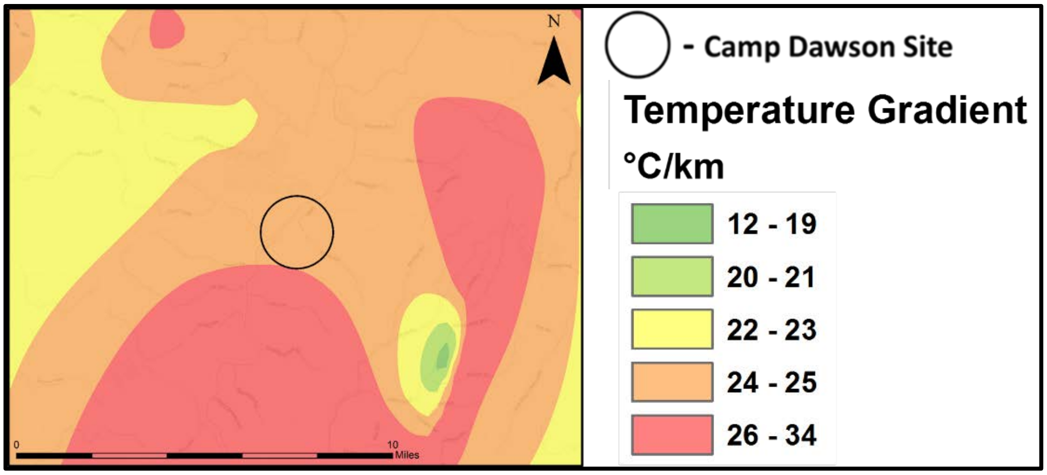

Figure H.13: Interpolation for temperature gradient (C/km) in the Camp Dawson vicinity.

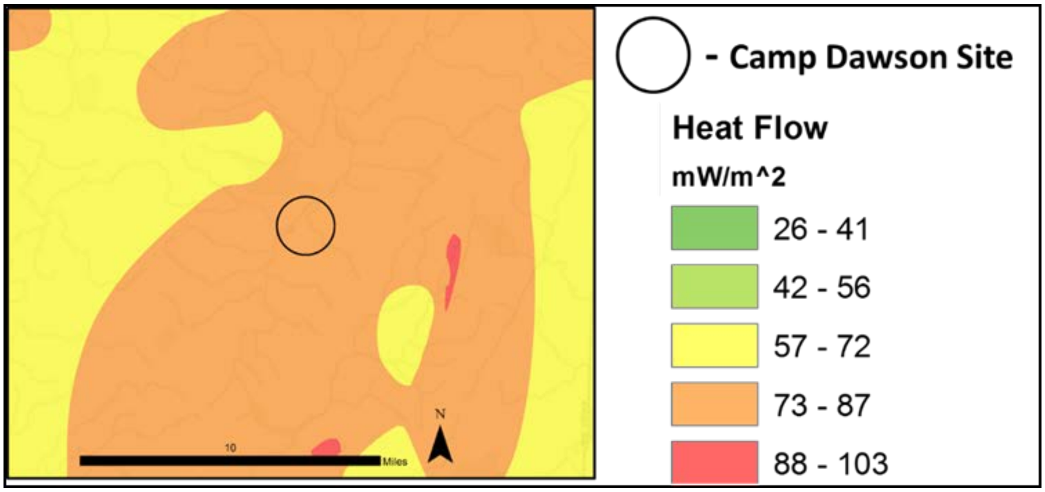

Figure H.14: Interpolation for heat flow (mW/m^2) in the Camp Dawson vicinity.

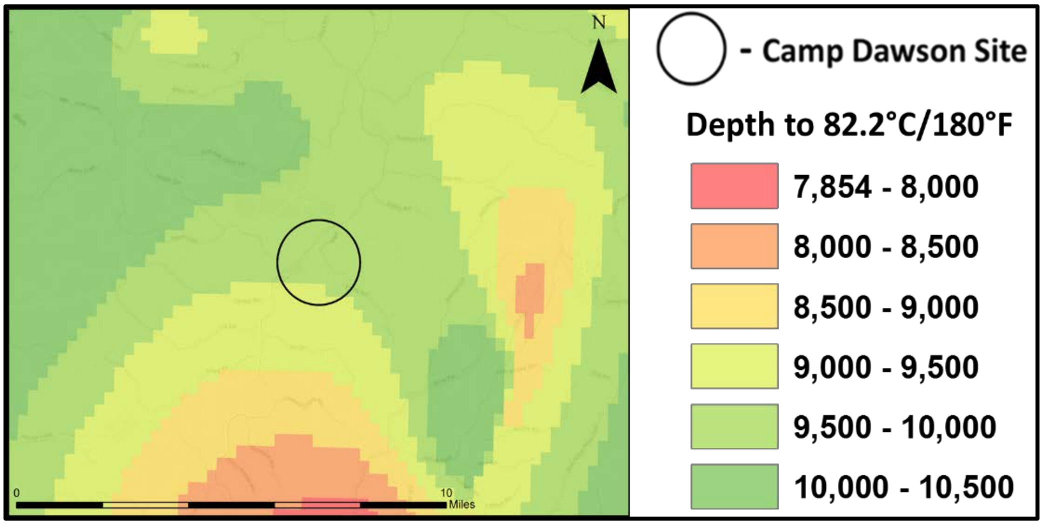

Figure H.15: Interpolation estimate for depth needed to reach ~180°F/82.2°C.

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