September 6, 2012

NAVY GEOTHERMAL PROGRAM OFFICE

Hawthorne Army Depot

Geothermal Direct Use Feasibility Study

EPSILON PRIME CONTRACT NUMBER
N68936-07-D-0005

SUBCONTRACT NUMBER
12DHS0012
Delivery Order 99

POWER ENGINEERS PROJECT NUMBER:
126923

PROJECT CONTACT:
Ray Arguello

EMAIL:
rarguello@powereng.com

PHONE:
208-288-6493

POWER ENGINEERS

PREPARED FOR: Navy Geothermal Programs Office
PREPARED BY: POWER ENGINEERS, INC.

REVISION HISTORY		
DATE	REVISED BY	REVISION
03 July 2012	Ray Arguello	A
16 Aug. 2012	Ray Arguello	B
06 Sept. 2012	Ray Arguello	0

EXECUTIVE SUMMARY

The purpose of this report is to present a strategy for potential district heating configurations for the Hawthorne Army Depot (HWAD). The overall goal of the project is to use direct use geothermal fluid to reduce the use of diesel fuel in the boilers. This report assesses the potential to utilize geothermal fluid available from low-temperature (140°F, 60°C) wells. The assessment considers several scenarios, ranging from augmentation of the existing diesel-fueled boiler to a dedicated geothermal district heating system using geothermal fluid with a temperature range of 140°-180°F (60°-82°C).

The preliminary issuance of the report contained design criteria developed during the kickoff meeting and site visit. The design criteria presented outline key equipment configuration and design parameters. These choices were reviewed and revised for this final report.

The site visit was conducted at Hawthorne Army Depot (HWAD) on May 29, 30 and 31. POWER Engineers (POWER) attendees were Ray Arguello (Project Manager), Greg Wittman (Hydrologist and Geologist) and Justin Beaucannon (Mechanical Engineer). The team initially met with John Peterson (the Government's Facilities Management Specialist) and Dave Musselman (the Base Operations Support Contractor's Manager of Maintenance and Utilities) to get an overall understanding of current boiler operations. Kelly Blake and Steve Alm (Navy Geothermal Program Office) met POWER's team at the Hawthorne Army Depot.

During the first day POWER's team met with Dave Musselman and discussed the general operation of the boilers and heating system. Dave showed POWER's team the location of the boilers and provided a layout drawing of the boiler room. The current cost of utilities for HWAD is $3.85 per gallon for diesel (Defense Logistics Agency Price which fluctuates every month but $3.85 was used for purposes of this study) and electricity is priced 5.5 cents per kilowatt (does not include the charges for peak loads). These costs are used for the cost analysis calculations. The boilers are in operation to provide steam for heating from September 1st to May 31 each year (273 heating days).

Past and recent studies associated with the geothermal potential at the HWAD site have been completed through the NGPO. The geophysical and geological studies for this site focus on local and regional geothermal source delineation of faults and structural trends.

Based on water levels measured during 2001, the groundwater gradient in the HWAD area appears to generally flow from south to north towards Walker Lake. The contours show a general groundwater movement from the El Capitan well area to the north towards the HWAD. The influence of range-front recharge on the groundwater flow direction was difficult to evaluate due to the lack of wells on the western edge of the valley. Temperature profiles from wells HHT-1 and Quarters B wells suggest the plume of higher temperature water thins and rises as it approaches the HWAD. Existing geochemical studies for the area include information on groundwater chemistry, fluid inclusion analysis, and isotope research.

The HWAD potable water well in use produces water out of the ground at 128° F. This well is at a depth of 370 feet. The hot potable water is pumped to a storage pond and then passes through a cooling tower (the potable water is cooled to approximately 70° F) before entering the water treatment plant. The potable water is stored in two (2) 500,000 gallon storage tanks for use on HWAD. This potable water is the source of the make-up feedwater for the boilers.

There are two 500 HP Nebraska boilers producing steam for district heating of the office buildings and the housing units known as “the bricks”. The boilers operate at 100 psig and are fed by a deaerating feedwater tank that stores the feedwater at 190° F. Only 40% of the steam that goes out to the buildings is returned as condensate to be reused in the boilers. Due to low rate of condensate return, approximately 60% of the water going into the boilers is make-up feedwater. The make-up feed water is heated from approximately 60-65° F (temperature of the potable water) to 190° F in the deaerating feedwater tank using steam from the boilers.

Three scenarios for utilizing geothermal energy are presented in this study. Scenario A envisions a complete replacement of the existing building heating system with a geothermal district heating system. In order to convert this steam heating system to direct heat geothermal fluid all of the steam piping, condensate piping and pumps going to and from the HWAD office buildings and housing units would have to be changed out. It is a major project to change out all of the piping systems. Scenario A requires a geothermal fluid with a temperature of 180°F.

Scenario A assumes that the existing 6-inch steam piping to the housing and office buildings would be replaced using 4-inch piping to carry the hot water from the heat exchanger through the buildings and back to the heat exchanger. The 2-inch condensate line would be eliminated. A 6-inch line would be needed to bring the geothermal fluid from the geothermal well to the new district heating system heat exchanger and back to the injection well. Under this scenario all of the office piping systems and heaters as well as the in housing units piping and the in-house radiators would need to be replaced.

Scenario B envisions using geothermal heat to preheat the boiler makeup feedwater. Scenario C envisions using geothermal heat to preheat both the boiler makeup feedwater and the condensate return. The difference between Scenario B and Scenario C is the temperature of the available geothermal fluid. Scenario C requires a geothermal fluid with a temperature of 180°F. Scenario B assumes that the temperature of the geothermal fluid is 140°F.

For purposes of this study the figure of 3,000,000 gallons of makeup water consumption is used for system sizing and financial calculations. In 2010-2011 the total makeup feedwater used in the boilers for heating totaled 2,958,000 gallons. In 2011-2012 the total makeup feedwater used in the boilers for heating totaled 2,573,200 gallons. The figure of 3,000,000 gallons is a reasonable assumption for the rough order of magnitude calculations in this study.

The existing boiler system can be augmented with direct use geothermal fluid. Since 60% of the current steam comes from makeup feedwater there is an opportunity to provide significant savings by preheating the makeup feedwater before it enters the deaerator. Using a geothermal fluid and a plate and frame heat exchanger, the feedwater could be preheated from 65° F to 130° F and avoid a portion of fuel input to the boiler. This temperature changed is used in this report for makeup feedwater used per heating day and described in Scenario B. It is recognized that there are significant fluctuations in the daily use of feedwater based on the temperature of the outside air. If a higher temperature resource is encountered that could heat both the boiler makeup water and the condensate return to the boiler, then this Scenario C could utilize approximately 76% more thermal energy than Scenario B (3,000 MBtu/year versus 1700 MBtu/year).

The payback period for preheating feedwater is directly related to the temperature of the geothermal fluid delivered to the boiler room. Since the well for the geothermal fluid has not been drilled, POWER assumes that the temperature of the geothermal fluid at the boiler room will be between 140° F and 180° F. If the geothermal fluid is at 140° F at the boiler room, the feedwater can be preheated to approximately 130° F. If the geothermal fluid is at 180° F at the boiler room, the feedwater and condensate can be preheated to approximately 170° F. This 40° F variation in geothermal fluid temperature is assumed to span anticipated temperature variations that might be encountered for the well to be drilled at HWAD.

The installation of a makeup feedwater system will include the following:

- Geothermal production well, geothermal injection well, two well pads, two well casings and well pump and valves
- Piping system run underground from the well site to the existing boiler room
- Plate and frame heat exchanger(s), piping, valves and controls
- Modification to the piping for the deaerator tank
- Pumps to transfer the geothermal heating fluid from the boiler room to the injection well head. This function may be provided by the production well pump, if the pressure is sufficient.
- Electrical and control systems

The evaluation of the various scenarios spans from Scenario A (high cost, high use of energy, shorter ROI), to Scenario B and C (medium cost, lower use of energy, longer ROI). The total project cost of Scenario A is on the order of $7.5 Million with an ROI (simple payback) of 6 years. Scenario B is on the order of $3.9 Million with an ROI (simple payback) of 53 years. Scenario C is on the order of $4.4 Million with an ROI (simple payback) of 30 years.

The high cost of the geothermal well drilling and development is the key cost driver for these scenarios. Scenario A is projected to save up to 256,000 gallons of fuel oil per year (gpy), Scenario B 12,300 gpy and Scenario C 21,724 gpy. Using a simple payback method, the payback ranges from 6-30 years for the various scenarios, using the prevailing cost ($3.85) of fuel.

Based upon our analysis of the available options and payback chart on page 38 of this study, the only real viable energy payback option is scenario A. It is recognized that because of the historic nature of the housing units, there could be barriers to implementation of a district geothermal heating system. The final consideration of the preferred option should be made based on updated drilling results, the rate of return for the project, and the requirement for DoD facilities to utilize more renewable energy and provide more energy security for their facilities. A district heating system is likely to be viewed favorably by Army in meeting renewable energy and energy security goals.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

INTRODUCTION

Hawthorne Army Depot is a US Army ammunition storage site located near the town of Hawthorne in western Nevada. It is directly south of Walker Lake. The depot covers 147,000 acres. The Naval Ammunition Depot (NAD) Hawthorne was established in September 1930. In 1977, NAD was transferred to the Army, and renamed the Hawthorne Army Ammunition Plant (HWAAP). In 1980, HWAAP was redesignated as a government-owned contractor-operated facility. Day & Zimmermann Hawthorne Corporation (DZHC) is the current operating contractor. In 1994, the facility received its current name of the Hawthorne Army Depot (HWAD).

The purpose of this report is to present a strategy for potential district heating configurations for the Hawthorne Army Depot. The overall goal of the project is to use direct use geothermal fluid to reduce the use of diesel fuel in the boilers.

The site visit was conducted at Hawthorne Army Depot (HWAD) on May 29, 30 and 31. POWER Engineers (POWER) attendees were Ray Arguello (Project Manager), Greg Wittman (Hydrogeologist and Geologist) and Justin Beaucannon (Mechanical Engineer). The team initially met with John Peterson (the Government's Facilities Management Specialist) and Dave Musselman (the Base Operations Support Contractor's Manager of Maintenance and Utilities) to get an overall understanding of current boiler operations. Kelly Blake and Steve Alm (Navy Geothermal Program Office) met POWER's team at the Hawthorne Army Depot.

The *Design Criteria* section presents notes and constraints collected from the kickoff meeting and site visit that will guide the subsequent design. Recommendations are included for well locations, gathering system constraints, boiler system and building modifications, and economic evaluation parameters, among other things.

The *Resource Evaluation* section presents a review of the NGPO resource data; evaluating available temperatures, potential flow rates, water chemistry, and geologic data. We identify reasonable resource withdrawal rates, and identify gaps where more data or testing should be pursued.

The *Heating System* section presents available options for retrofitting the existing boiler and building systems around geothermal solutions. This section identifies other direct use options that may be applicable at the HWAD. The section presents estimated costs for various retrofit scenarios. This section also presents concepts for delivery of the geofluid from the wells to the boiler plant, and from the plant to injection wells. This section presents indicative routing and sizing for the pipelines.

The *Cost Analysis* section presents a summary cost estimate for the preferred utilization strategy. The capital costs are contrasted to the 'do-nothing' option of continuing to use the diesel-fired boiler. A simple payback analysis is used to compare the various options.

Appendices are included which discuss deaerator operation, stiff diagrams, and present the details of the cost estimate.

DESIGN CRITERIA

This section presents design criteria for the HWAD district heating system. These are intended as general design constraints for the design work in the future phase. NGPO should confirm highlighted items as we progress through to the next phases of the project, and update items as new information becomes available, especially in the case of resource data.

General

The base serves as an ammunition storage depot, and was originally established in 1930. The site is in western Nevada, approximately 3 miles from the town of Hawthorne (population ~3300).

Many buildings on site date from this period. A golf course and other housing are located on the base. The existing boiler heating system provides heating from September 1-May 31 (273 heating days) to the general office buildings and "the bricks" housing unit in the center of the HWAD complex. The current heating system returns approximately 40% of the outgoing steam as condensate. This situation presents an opportunity to improve efficiency of the system with direct use geothermal fluid to either replace the current heating system, preheat the boiler feedwater or preheat the boiler feedwater and returning condensate.

Site Specific Conditions

Environmental Conditions

All equipment supplied will be suitable for installation and service under the following conditions.

Table 1: Design Parameters

Design Parameters	
Plant Location (approx)	Lat 38.545 Lon -118.658
Elevation, above sea level	4167 ft
Atmospheric pressure	12.6 psia
Ambient Temperatures:	
Summer dry bulb (mean, August)	70.2 °F
Winter dry bulb (mean, January)	25.1°F
Winter dry bulb (building HVAC design)	11 °F
Winter dry bulb (freeze protection w/15 mph wind)	-3 °F

Table 2: Historical Monthly Mean Temperatures

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Ambient Temp (˚F)	35°	40°	46°	52°	61°	70°	77°	75°	66°	55°	44°	36°
Humidity (%)	55	50	40	35	35	26	25	28	29	35	47	50

Table 3: Geothermal Fluid Assumptions

	Elevation [ft]	Flow Rate [gpm]	Downhole Temperature [°F]
Production Well	4238	see discussions	see discussions
Total Production		1000	
Injection Well	4230	Minimum Injection Temperature TBD °F – assumed 20 °F less than supply temperature Anticipated Injection Pressure 12.6 psia at up to 600 gpm	

Table 4: Brine Composition based on analysis collected from Drill Hole HAAD-2, 6/17/2009

Item	Unit	Result of Analysis
pH	-	
Conductivity	mS/m	6.17
Na	mg/L	1512.42
K	mg/L	36.83
Li	mg/L	1.05
Ca	mg/L	62.40
Mg	mg/L	1.86
F	mg/L	1.24
Cl	mg/L	2060.00
SO_4	mg/L	431
HCO_3	mg/L	72.6
HBO_2	mg/L	Not Available
T-SiO_2	mg/L	41.20
T-Fe	mg/L	0.00
Al	mg/L	0.00
As	mg/L	0.57

Existing Heating System

Existing Boiler House

Figure 1: HWAD Boiler House

During the first day, POWER's team met with Dave Musselman (the Base Operations Support Contractor's Manager of Maintenance and Utilities) to get an overall understanding of current boiler operations. Dave showed the POWER team the boiler room and explained the general operation of the boilers and the steam heating system. Dave provided the POWER team with a tour of the boiler room and provided a layout drawing of the boiler room.

Existing Boilers

Figure 2: Boiler #2, 500 Horsepower Nebraska

There are two 500 HP Nebraska boilers producing steam for district heating of the office buildings and the housing units known as “the bricks”. Figure 2 shows one of the boilers. These are steam generating boilers that operate at 100 psi and are fed makeup feedwater by a deaerating feedwater tank that stores the feedwater at 190° F (87.8° C). Approximately 60% of the water going into the boilers is make-up feedwater. Approximately 40% of the steam that goes out to heat the buildings and “the bricks” housing units is returned as condensate to be reused in the boilers. For the purpose of this study, the condensate return temperature is estimated to be 140° F (60° C) based upon the return condensate entering the deaerating feedwater tank. The make-up feed water is heated from approximately 60-65° F (15.6 ° -18.3° C) (temperature of the potable water) to 190° F (87.8° C) in the deaerating feedwater tank using steam from the boilers.

Existing Distribution System

The two 500 HP Nebraska boilers produce steam for district heating of the office buildings and the housing units known as “the bricks”. The 100 psi steam is fed into a 6-inch steam line that is below ground in a utility corridor. The utility corridor is accessible via removable concrete covers. The steam lines and condensate return lines are located in the same utility corridor. The steam is reduced to 15 psi via a steam reducer before it enters the housing units and buildings that are served.

Figures 3 and 4 show typical structures served by the district heating system. Figure 5 shows steam distribution piping; condensate collected is returned to the deaerator in a condensate return line. Figure 6 shows a typical radiator in a home.

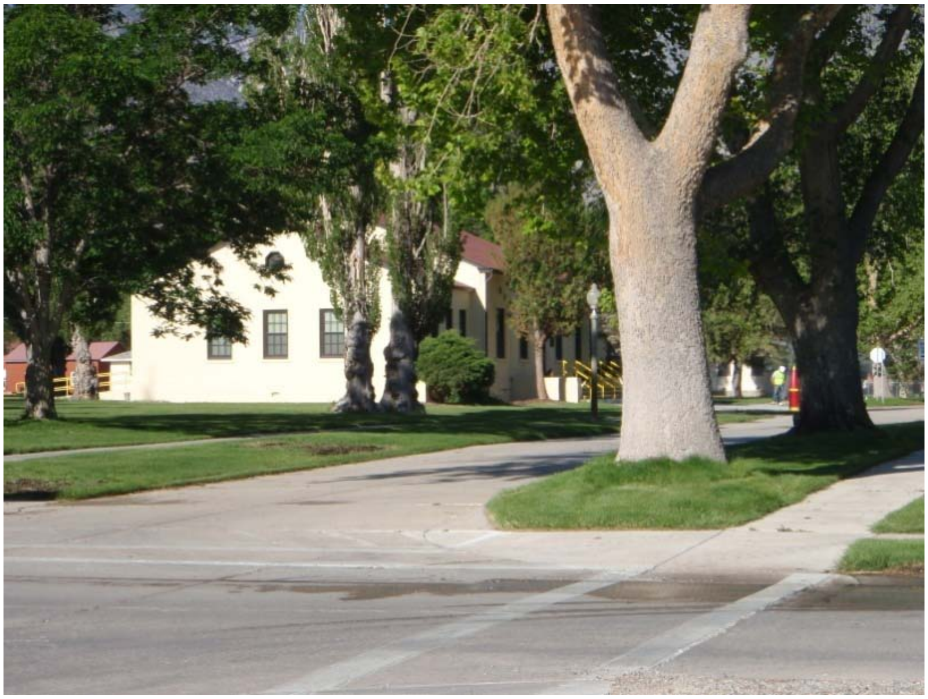


Figure 3: Typical office building heated with steam

Figure 4: Typical house in "The Bricks" housing area

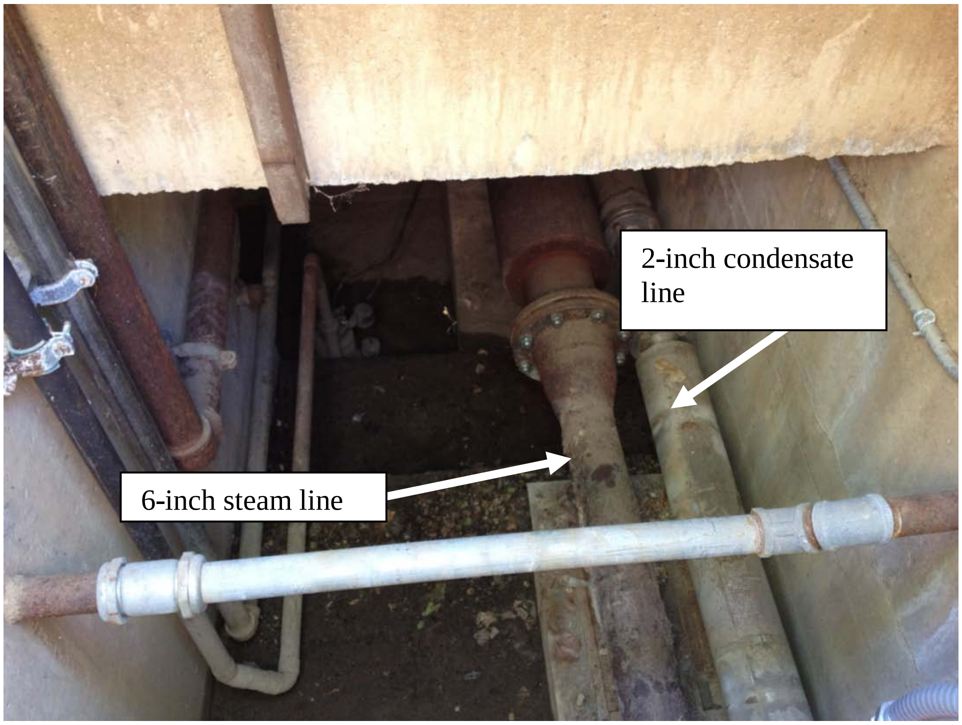


Figure 5: Utility corridor showing steam supply and condensate return lines

Figure 6: Typical steam radiator heaters in "The Bricks" housing units

Economics

The current cost of utilities for HWAD is \$3.85 per gallon for diesel (Defense Logistics Agency Price which fluctuates every month) and electricity is priced 5.5 cents per kilowatt hour (does not include the charges for peak loads). For the purpose of this study, these costs are assumed to be constant and were used in all of cost analysis calculations. The boilers are in operation to provide steam for heating from September 1st to May 31 each year (273 heating days).

Redundancy

Adequate redundancy or standby capability shall be provided to prevent the failure of auxiliary components from forcing the plant off-line when they fail. Similarly, the plant electrical power distribution system shall be designed with redundancy to minimize plant shutdowns due to a failure from a single electrical component. The following table indicates the expected level of redundancy for selected equipment.

Table 5: Component levels of redundancy

Component	Minimum Expected Redundancy
Production well pump	1 x 100%
Geothermal heat exchanger	1 x 100% - for preheat systems 2 x 100% - for full retrofits
Booster or circulating water pumps, if needed	2 x 100%

GATHERING SYSTEM

Wellpads

New wellpads are anticipated to be approximately 400-600 square feet in size and will include the production well pumps, electrical building, piping, and required instrumentation.

The production well pumps shall be vertical (similar to existing well pump as shown in Figure 7) or submersible type pumps, sized to provide the required flow.

Pumps and piping may be sized larger if desired for future expansion. Piping line sizes will be based on an economic optimum of capital cost versus cost of parasitic power, as well as reasonable industry standards for fluid velocities.

Pumps and instrumentation will be enclosed similar to current well pad configurations.

At a minimum, the wellpad shall be equipped with pressure, temperature, and flow instrumentation at the wellhead to measure supply conditions.

Figure 7: Existing well pump #11

Gathering System Piping

Piping design will be per ASME B31.1 code for power piping. ASME B31.1 prescribes minimum requirements for the design, materials, fabrication, erection, test, inspection, operation, and maintenance of piping systems typically found in electric power generating stations, industrial and institutional plants, geothermal heating systems, and central and district heating and cooling systems. For lines with supply temperature less than 140 $^{\circ}$F (60 $^{\circ}$C), High Density Polyethylene (HDPE) may be used. When the well supply temperature approaches or exceeds 140 $^{\circ}$F (60 $^{\circ}$C), the gathering system piping shall be constructed of fiberglass reinforced piping (FRP). Piping will interface with production pumps and any other connecting equipment via flange connection.

Piping shall be routed from the well pads heading north; as the line approaches the project site the piping is anticipated to be routed along the west side of the site (around the golf course) and will then be routed east along the northern edge of the site towards the boiler building. The site terrain, as can be seen in Figure 8, is relatively flat and does not present major routing obstacles such as thick trees or rocky areas.

Figure 8: View of main base from a road in the well field

The piping will tie in to the geothermal heat exchanger inlet at the specified tie point inside the boiler house. Injection well piping will follow a similar routing from the outlet of the heat exchanger heading west along the north side of the site and south towards the injection well location. Injection well pumps on the outlet of the heat exchanger may or may not be required depending on the pressure requirements and distance to the injection well. This study assumes no injection pumps will be required.

If piping is to be buried, the piping shall be buried at sufficient depth for heat conservation as well as live load requirements for passing under roadways and structures. Piping will require the use of bell and spigot joints for thermal expansion capabilities and may require anchor blocks to control thermal movement and protect the piping system. If piping is to be routed above ground, insulation will be required. Above ground piping will require additional pipe supports. Both above and below ground piping shall be supported such that loads exerted on the nozzle of connecting equipment are within the allowable loads provided by the vendor.

Gathering System Electrical Distribution

Electrical tie-ins for the production well pumps with remote starters will be made to the existing power lines. It is anticipated that the communications will be wired, however this may be modified depending on the final locations of the wellheads if wireless may be more suitable for some instrumentation.

It is assumed the injection pressure is low enough such that no injection well pumps are required.

RESOURCE EVALUATION

The Navy Geothermal Program Office (NGPO) contracted POWER to review the data associated with past geothermal resource evaluations at the HWAD. The site was visited on May 29 through May 31, 2012 to inspect the facilities and collect geothermal related data. The site tour included a geologic overview of the area with an emphasis on the structural setting and the locations of several key wells. The geologic data was provided to POWER on four compact disks that included past reports, well information, geophysical studies, and geochemical data.

Past and recent studies associated with the geothermal potential at the site have been completed through the NGPO. The geophysical and geological studies for this site focus on local and regional geothermal source delineation of faults and structural trends. The existing reports include geologic mapping, geophysical surveys, geochemical analysis, geothermometry, isotope studies and information pertaining to well drilling activities. The geological and geophysical information has been used by others to develop 3-Dimensional geologic models (Moeck, I. et al, 2010) for the area. These models depict the relationship of regional and local structures to the Walker Lake Valley and identify faults that may be potential pathways for upwelling geothermal fluids.

Based on water levels measured during 2001, the groundwater gradient in the HWAD area appears to generally flow from south to north towards Walker Lake (Figure 9). Groundwater level measurements are listed for many of the wells in the database; however, finding level measurements that were collected within a similar time period (year) was difficult. In addition, the influence of range-front recharge on the groundwater flow direction was difficult to evaluate due to the lack of wells on the western edge of the valley. Existing geochemical studies for the area include information on groundwater chemistry, fluid inclusion analysis, and isotope research. Groundwater geochemistry data indicates that subsurface water in the southern part of the Walker Lake Valley, and groundwater from mountain block recharge from the west, is generally calcium-bicarbonate rich water as shown on the stiff diagram[1] for the Berry Well in Figure 10. Groundwater encountered near and down-gradient from the wells producing geothermal waters is sodium-sulfate type water (Katzenstein et al, 2002) as shown by the HWAD-2 Well stiff diagram in Figure 10. Wells MC-5 and WO-6, located near the town of Hawthorne, NV and HWAD, appear to have been completed within the mixing zone of these two types of water chemistries.

The geothermal water was discovered through the installation of multiple temperature gradient holes over that last several years. By compiling and analyzing the existing data from these temperature gradient

[1] A stiff diagram is a graphical representation of chemical analyses that is widely used by hydrogeologists and geochemists to display the major ion composition of a water sample. They are useful in making visual comparisons between water from different facies or sources and can also be used to help visualize ionically related waters from which a flow path can be evaluated, or if the flow path is known, to help show how the composition changes over space and/or time. Additional stiff diagram discussion is provided in Appendix B.

holes, groundwater temperatures for the calcium bicarbonate water typically appear to be below 77° F (25° C), and the sodium sulfate waters typically appear to be greater than 188 °F (87° C). There does not appear to be evidence of surface flow of geothermal water on the west side of the Walker Lake valley near the HWAD. Municipal wells west of Hawthorne, NV produce elevated water temperatures of 198 F (92° C)and 200° F (93° C) in wells near El Capitan and Maples wells respectively (Trexler and others, 1981). Two additional wells were drilled in 2009 near the El Capitan wells to test deeper levels for potentially higher temperatures (Figure 11). The two 2009 wells are HWAAD-2A and HWAAD-3 with reported temperature of 207° F (97°C)and 192° F (89° C) respectively (Lazaro et al, 2010). Elevated groundwater temperatures occur in several wells drilled to the north of the HWAAD-2a and HWAAD-3 well locations. While the data reviewed contain water temperatures measured in several wells, many of the wells do not have measurements from the same time period which presents challenges in interpreting and correlating the data. Variations in temperature in all of these wells are expected both seasonally and over longer periods of time. The plot (Figure 11) of the various well temperatures provides a general thermal trend in groundwater encountered in the area. Figure11 shows the contours for maximum groundwater temperature measured for the well and it provides a general sense of groundwater flow direction. The contours show a general groundwater movement from the El Capitan well area to the north towards the HWAD. Temperature profiles from wells HHT-1 and Quarters B wells suggest the plume of higher temperature water thins and rises as it approaches the HWAD (Katzenstein et al, 2002). The higher temperature groundwater appears to flow north towards supply Well 11 where the temperature drops to approximately 121° F (49°C). Elevated groundwater temperatures measured in wells TGH-1 at 125° F (52°C) (Katzenstein et al, 2002) and supply Well 5 at 121° F (49°C) (Musselman, D., 2012, Personnel communication) may represent influence of geothermal waters originating from fault controlled pathways along the west side of the valley.

The solid line on Figure 11 from point 148 north to Point 122 represents the direction of the water flow. Figure 12 is a representation of the geothermal water flow to the north on the HWAD site.

A recent survey was conducted using 2 m temperature probes and temperature gradient holes to provide details of the soils temperature and heat flow associated with the shallow thermal groundwater plume underlying HWAD (Kratt et al, 2010, Pennfield et al, 2010). The 2 m thermal survey outlined three areas of elevated shallow temperatures in the valley. One of the thermal anomalies is located west of the HWAD between wells TGH-1 and TGH-23 (Figure 11). A 1500 foot test hole is planned in this area by the Navy Geothermal Program (NGPO) near the location plotted in Figure 11.

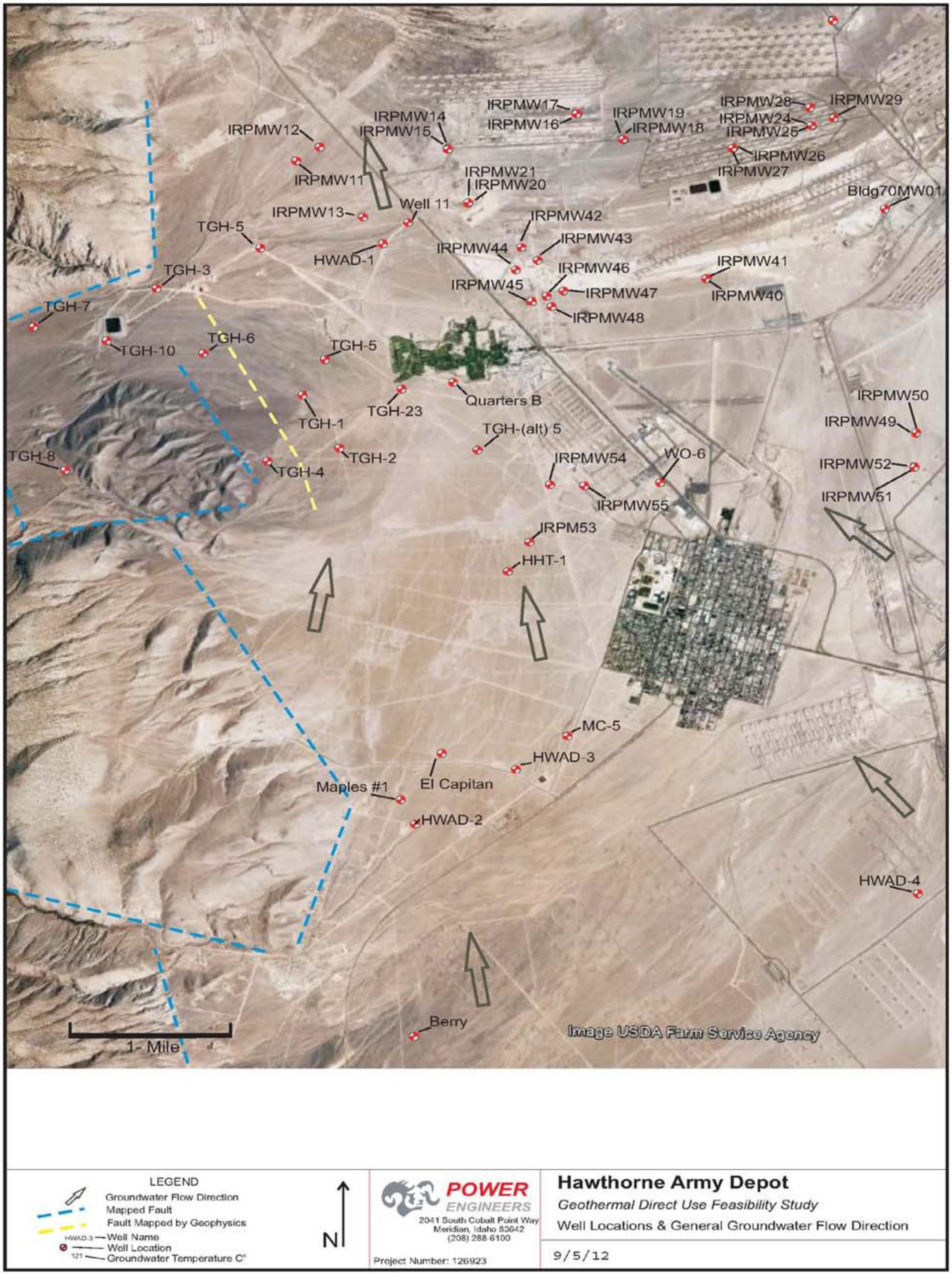


Figure 9: Base and Well Locations

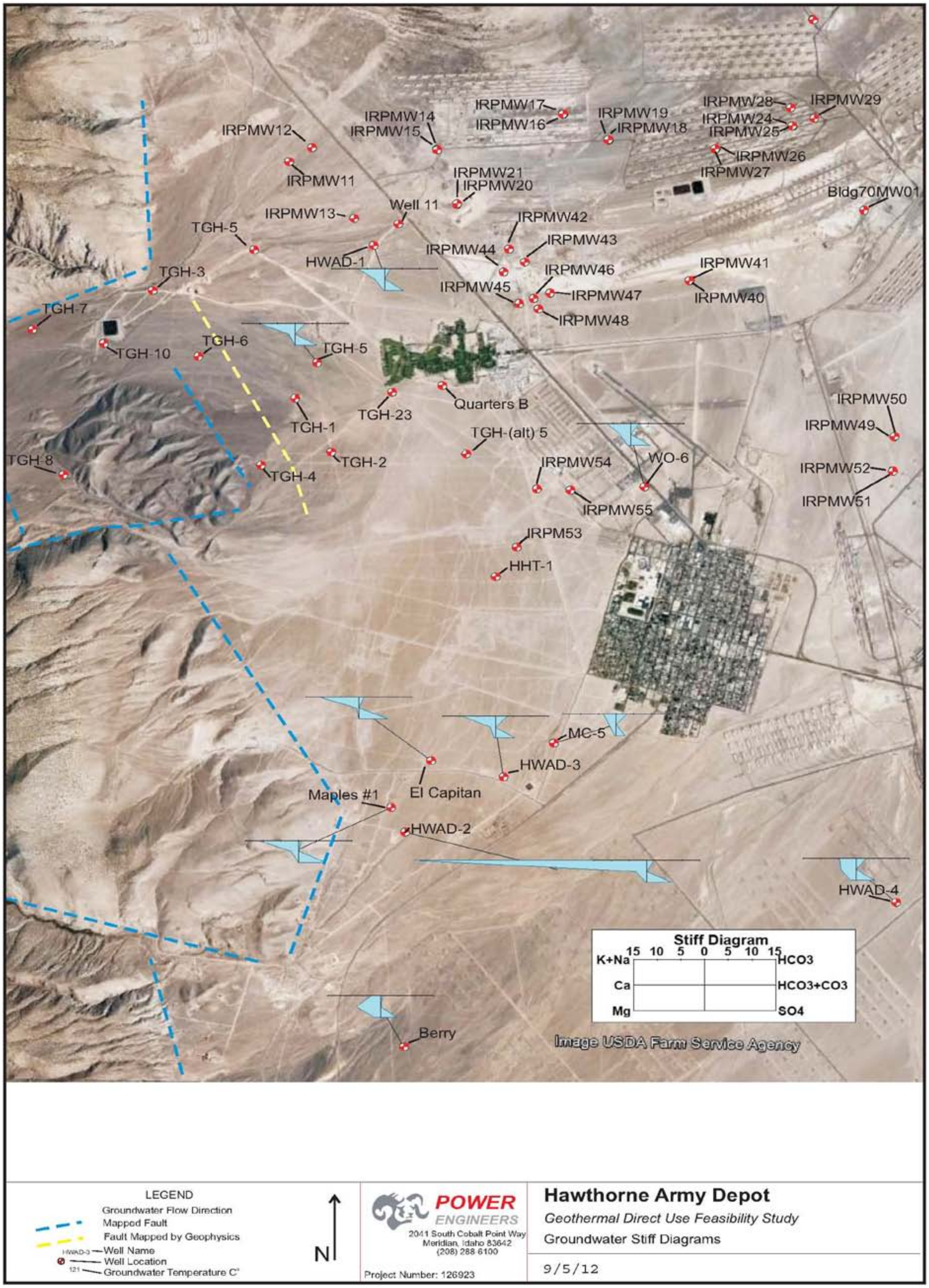


Figure 10: Groundwater Stiff Diagrams

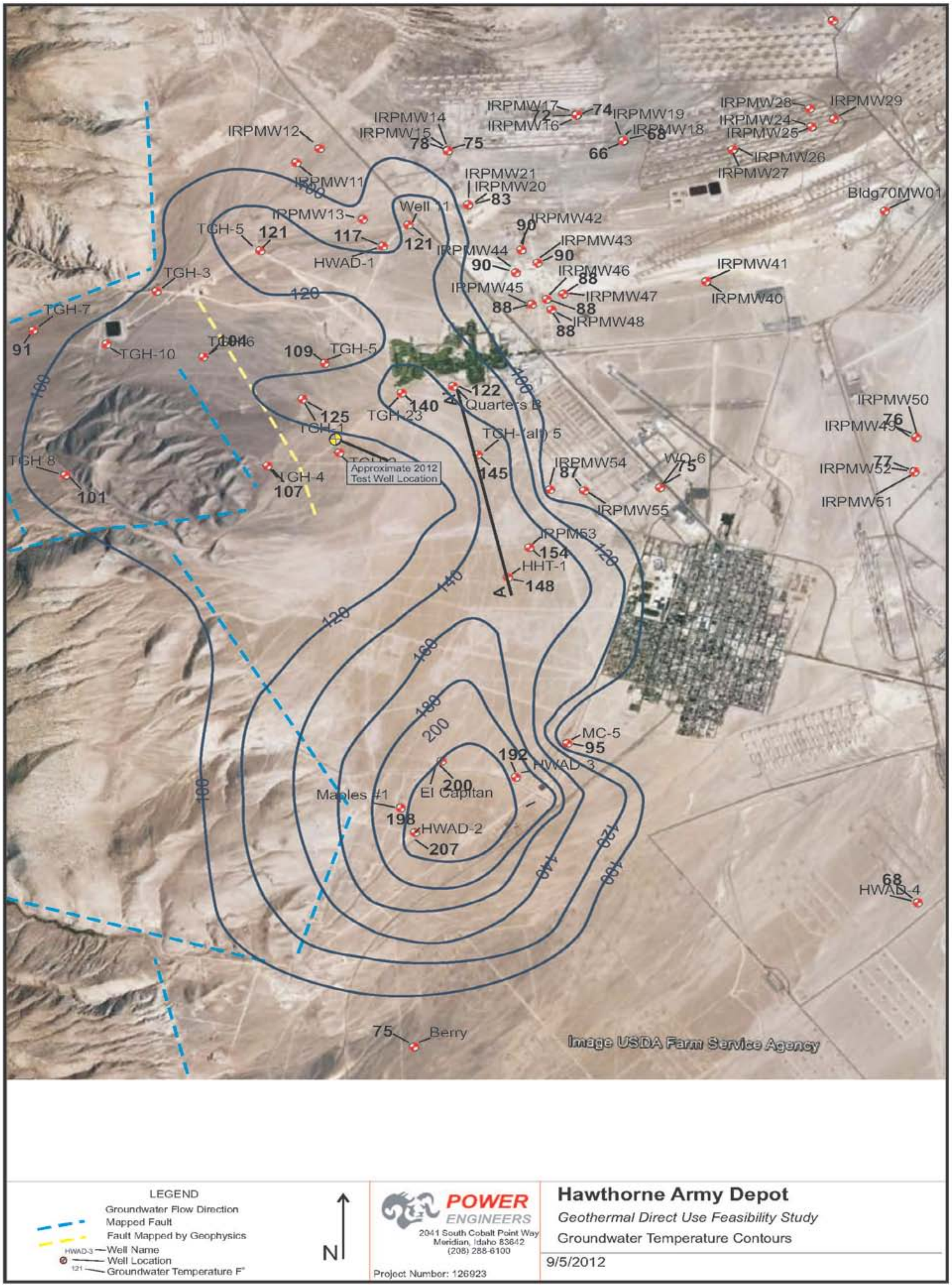


Figure 11: Groundwater Temperature Contours

Data Gap Analysis

Past and present studies of the HWAD geothermal resource provide a large and extensive database (provided to POWER by the NGPO on CDs) that provides insight to potential drill targets in the area. There are a few gaps in the database identified during this review. The HWAD site database includes numerous wells drilled and screened at various depths. The spreadsheets (provided by NGPO) list well locations and data that have a few location and well naming issues for some of the wells. The database would be more useful if well locations were corrected and the names of the wells checked for accuracy. A description of the survey method for locating the wells would also be helpful.

The database contains geochemical analyses and groundwater level data for many of the wells. There does not appear to be project-site geochemistry or groundwater information that was collected within a similar time frame (i.e. same day or week). The lack of data within a similar time frame limits the ability to evaluate seasonal variations and long-term trends for regional and local groundwater flow and geochemistry. Selection of a set of wells at and around the HWAD that could be sampled and tested on preferably a quarterly basis would significantly increase the reliability of the database and associated groundwater system.

The groundwater system near the HWAD area has limited aquifer testing information. The aquifer testing described in the reports provided by the NGPO include slug testing and one short pumping test. The development of a direct use geothermal system will require knowledge of the aquifer properties to evaluate pumping and re-injection rates. The new well planned by the NGPO will have an aquifer test preformed after the hole in completed. This aquifer test should include a 24-hour constant-rate drawdown test preceded by a step drawdown test to evaluate sustainable pumping rates. It is recommended the new test well and nearby well be instrumented with data loggers to record drawdown fluctuations.

Resource Assessment

Geological, geophysical and geothermometry studies have identified an area west of the HWAD that appears to have potential for development of geothermal waters. Wells drilled in this area have elevated water temperatures that range from approximately 100 to 200° F ((38 to 93°C). The highest groundwater found in this area originates at the El Capitan well with water temperatures ranging up to 200° F (93°C). Geothermally heated waters from the El Capitan wells area flow to the north towards the HWAD. These waters mix with the local aquifer waters forming a thermally heated groundwater plume. The warmer groundwater plume appears to rise and thin as it migrated to the north near the HWAD site with water temperatures ranging from approximately 120 to 140° F ((49 to 60°C). Contouring measured groundwater temperatures in wells show warmer groundwater flowing from the area west of the HWAD site. These elevated groundwater temperatures may represent thermally heated waters originating from faults mapped along the Wassuk range front. The NGPO plans to drill a 1500 foot test well to the west for the HWAD site that will evaluate this target area. Water temperature in well TGH-1 closest to the proposed test well location is approximately 125° F (52°C) at a 500-foot deep well. It may be possible to find geothermal waters that may produce higher temperatures flowing from the deeper targeted fault zones targeted by the test well. The exact test well site location will be critical to maximize the chances of intersecting the mapped target faults within the 1500 foot drilling depth limit.

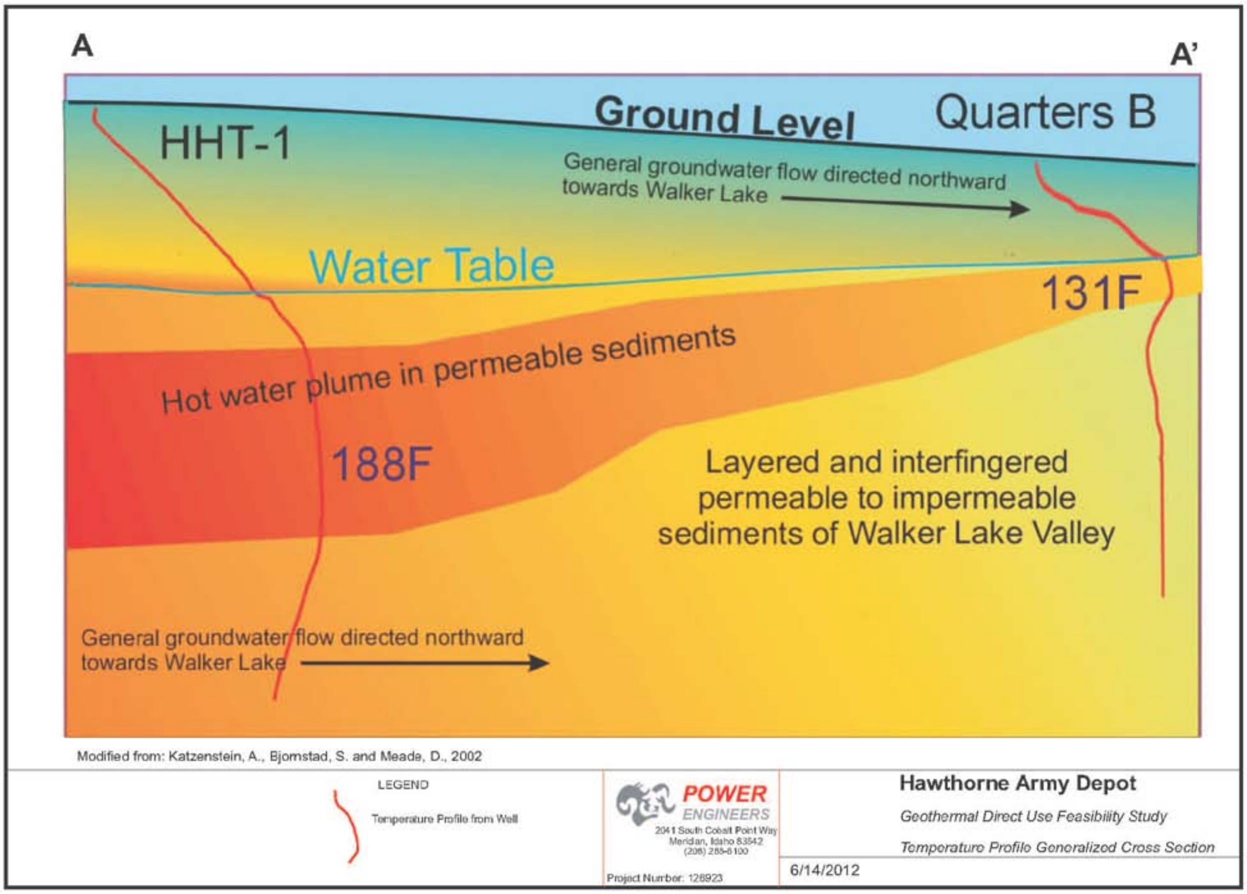


Figure 12: Temperature Profile Generalized Cross Section

DRILLING PROGRAM AND COST ESTIMATE

The NPGO test well planned for the fall of 2012 will assess the potential fault-supplied geothermal source to the west of the HWAD. The location and target depth of any new geothermal will be determined after the analysis of data from the NPGO test well. The cost of a new geothermal production and injection wells to supply the direct use system can then be assessed based on the location and the drill hole depth.

The well costs are the major component of this project. Mansure and Blanketship provide periodic updates on average geothermal well costs, which are strongly dependent on depth and the formation type. They are also sensitive to quantity of wells drilled in a field, diameter, rig rates, steel, cement, and labor prices. Figure 13 shows estimated well costs as a function of depth; note that most geothermal power production wells may be deeper and larger bore than those anticipated for this study, and also note that basis of Figure 13 was year 2000 USD.

Mansure and Blanketship (2011) provide a more current correlation for average geothermal well costs as a function of depth, using this, it is estimated that a 500 foot geothermal production well will cost up to $2.0 million; a 1500 foot geothermal production well will cost up to $2.3 million.

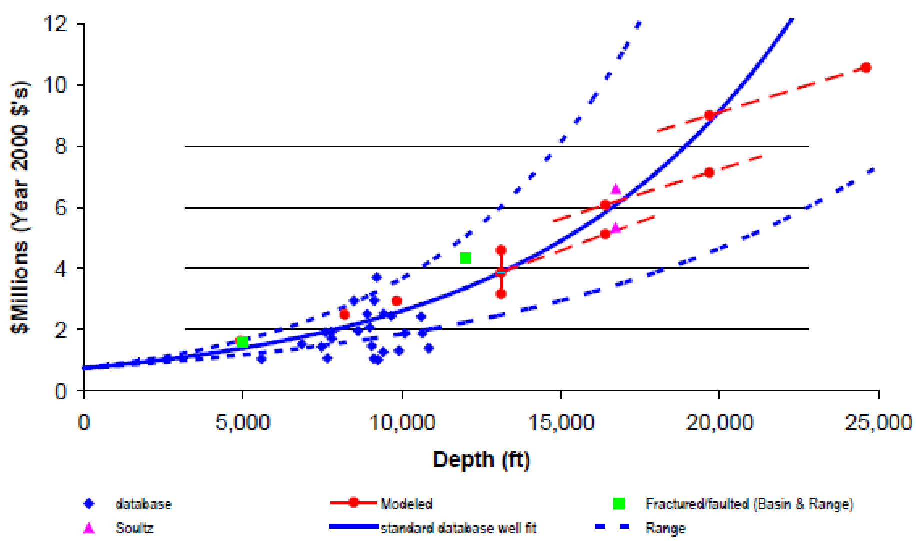


Figure 13: Geothermal well costs since 1985, basis in 2000 USD (Mansure et al, 2006)

Inflation in recent years has been high due to the increase oil and gas drilling in the US; Mansure and Blanketship report that over 2010-2011 prices increased by 14%, and note that so long as oil prices stay high, rig rates and well costs are unlikely to decrease.

For purposes of this study, we will make the rather optimistic assumption that smaller bore; lower temperature wells for this project (production or injection) could be drilled and completed, with the requisite production well pump, for a cost of $1 million each. This will be separately listed in the cost estimate section, and once more accurate costs are identified for this specific location the economic analysis can be reviewed.

HEATING SYSTEM EVALUATION

Introduction

This section provides commentary on potential options for district heating systems at HWAD. The Design Criteria section presented an evaluation of the existing equipment, as observed during the site visit. Based on these observations, we propose several scenarios that might be explored:

Scenario A: Full system retrofit with 180 °F (82.2 °C) resource
Scenario B: Makeup water preheating with 140 °F (60 °C) resource
Scenario C: Makeup water and condensate return preheating with 180 °F (82.2 °C) resource

The configuration of each system is described in more detail below. Certain criteria were common to each scenario's evaluation and used as the basis for estimates:

1. Annual boiler makeup water consumption for the preheating scenarios is assumed to be 3 million gallons per year.
2. Assume the condensate return to the boiler is at a temperature of 155 °F (68.3 °C) and a flow rate of 2 million gallons per year.
3. Current boiler operations provide saturated steam at 100 psig (112.6 psia).
4. The geofluid returned to the reservoir will be assumed to be at a temperature 20 °F less than the supply temperature, to minimize the propensity for solids precipitation (scaling). This temperature drop affects the flow rate required, line sizing, pressure at the injection well, and production well pump power consumption, and would be more closely optimized and refined during a detailed design.
5. The injection pressure at the injection wellhead is assumed to be at atmospheric pressure for this study.
6. Heat losses in insulated pipelines are assumed to be negligible. Insulation will be included in the cost estimate.
7. The system is in operation for 273 heating days per year. Average daily water or energy uses are calculated using this value. It is assumed that peak daily heating loads at the coldest periods might be double the average, not to exceed the 1000 HP of the existing boilers.

Figure 14 shows indicative locations of new production and injection wells. The length of the production well pipeline is approximately 9000 feet, and the injection pipeline approximately 7500 feet.

Figure 14: Assumed layout of gathering system

Scenario A: Full system retrofit

Scenario A presupposes that a new geothermal well is capable of delivering 180 °F (82 °C) fluid. This fluid would be pumped via cross country pipeline to a central heat exchanger, heating water for a new closed loop district heating system. The closed loop exchanger would heat water from approximately 130 °F (54 °C) to 170 °F (77 °C). A new distribution system would be installed, including new radiators (baseboard type heaters) in all locations currently serviced by the existing boilers. Spent geothermal fluid would be reinjected into the aquifer.

Figure 15 shows a schematic of this concept. The total peak heating load served by this system is anticipated to be less than 1000 HP (34.5 million Btu/hr); this is equal or less than the capacity of the existing boilers. This assumption for the peak duty seems to be far larger than what would actually be required. Based on the calculations of makeup water, it appears that the average load is far less, around 5.4 MBtu/hr. For the purposes of this study and sizing of major components we will assume this load is constant throughout the year. The system will be sized for 600 gpm to provide some margin for colder days and heavy system use.

We view this as a 'large cost, maximum benefit' scenario that sets an upper bound on the amount of geothermal energy that can be utilized at the HWAD. Estimates of the economics of this project are presented in the Project Cost Estimate Section.

The major components and capacities of this system would include:

- One production well, 180 °F (82.2 °C) fluid
- Production well pump, submersible, ~600 gpm, (this symbol ~ is used to designate approximately) approx 125 hp (93 kW), with variable frequency drive (VFD)
- One injection well
- Production and injection wellpads, piping and valves
- Gathering system piping, 6" buried high temperature fiberglass reinforced polyester (FRP)
- District heating heat exchanger, plate and frame type, 6 MBtu/h capacity
- District heating distribution piping, 4" supply and return mains, carbon steel
- District heating circulating water pumps, 2 x 100%, 300 gpm (2 x $5000), with VFDs
- District heating radiators (baseboard heating) and branches, 30 buildings ($20,000 ea)
- Electrical works (motors starters, wiring, etc)
- PLC-based Controls ($15,000)
- System instrumentation

Based on the current estimates of makeup water and condensate flows, it is estimated that the annual thermal demand of the current system using steam is approximately 35.4 billion Btu/yr. Replacing the existing steam heating system entirely with a geothermal district heating system will displace equivalent diesel fuel oil consumption (assuming 5.8 MBtu/barrel) of 6100 barrels per year (256,200 gallons per year).

Scenario A has a simple payback period of approximately 6 years. This is the type of energy savings project that the Army is seeking to increase energy security and make use of renewable energy. The HWAD should review the Army's requirements for energy savings projects and determine if this scenario would qualify for funding.

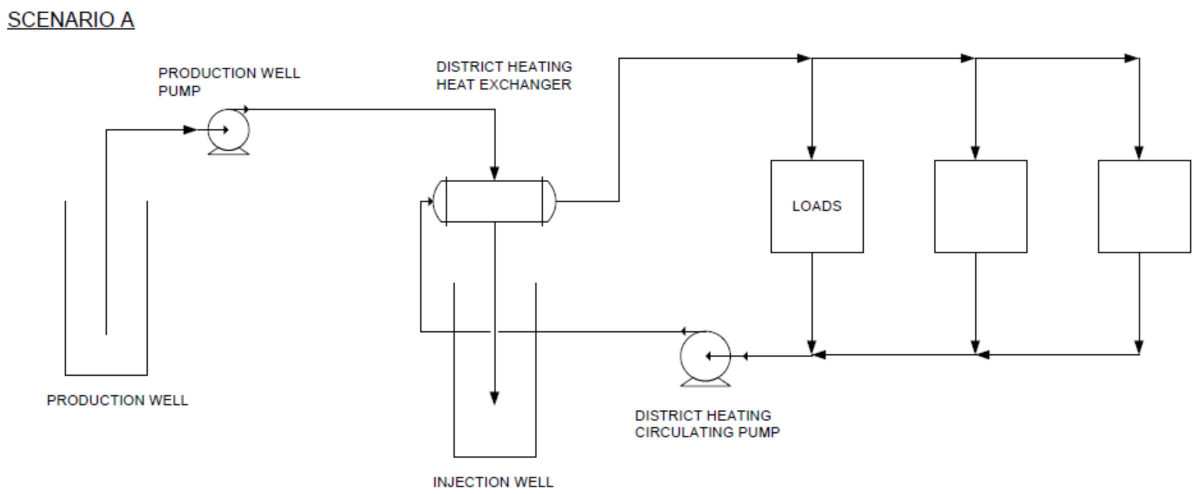


Figure 15: Scenario A – full system retrofit

This scenario shows geothermal fluid coming out of the production well and being pumped to the district heat exchanger. The heat is transferred from the geothermal fluid to the closed loop hot water heating system for the office buildings and housing units. The geothermal fluid is returned to the aquifer via the injection well. The closed loop hot water system uses a circulating pump to move the hot water into and through the buildings needing heat. Temperature controls will control the amount of hot water entering each building's baseboard heating system.

Scenario B: Makeup water preheating

Scenario B leverages the existing facilities by keeping the boiler, distribution piping, and radiators in place. Water from a geothermal well at an assumed temperature of 140 °F (60 °C) is used to preheat the makeup water to the boiler, reducing but not eliminating diesel fuel usage. It is likely that of the 273 heating days, makeup water consumption varies in accordance with the load. If it were evenly distributed, this would equate to 7.6 gpm; assuming demands may be lower in the 'shoulder seasons' and higher in winter, a peak demand might be around 20 gpm. The potable makeup water would be heated from approximately 60 °F (15.6 °C) to 130 °F (54.4 °C).

Scenario B is viewed as a 'medium cost, low benefit' scenario. Figure 16 shows a schematic of this system.

The major components and capacities of this system would include:

- One production well producing, 140 °F fluid
- One injection well
- Production well pump, submersible, ~50 gpm, approx 20 hp (15 kW)
- Production and injection well piping and valves
- Gathering system piping, 2" buried high temperature fiberglass reinforced polyester (FRP)
- Makeup water preheater, plate and frame type, 0.27 MBtu/h capacity
- Boiler piping modifications
- Booster pump, 2 x 100%, 10 gpm
- Electrical works (motors starters, wiring, etc)
- PLC-based controls ($15,000)
- Field instrumentation

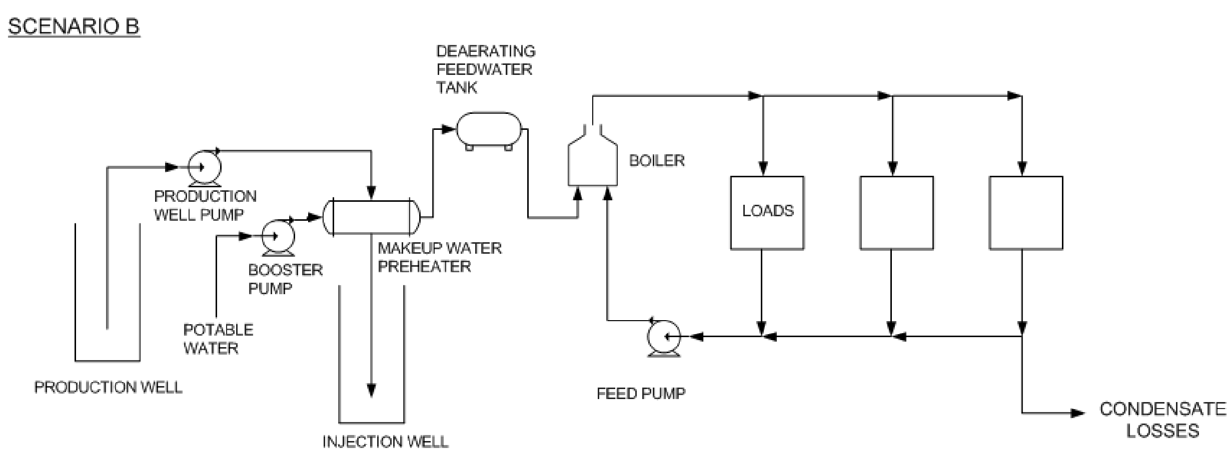


Figure 16: Scenario B – makeup water preheating

Preheating 3 million gallons per year of water from 60 to 130 °F requires 1.7 billion Btu. This equates to an equivalent diesel fuel oil savings (assuming 5.8 MBtu/barrel) of 293 barrels per year (12,310 gallons). This scenario shows geothermal fluid coming out of the production well and being pumped to the make-up water heat exchanger. The heat is transferred from the geothermal fluid to the potable water being used for make-up feedwater entering the deaerating feedwater tank and then the boiler. The geothermal fluid is returned to the aquifer via the injection well.

Scenario C: Makeup water and condensate return preheating

Scenario C leverages the existing facilities by keeping the boiler, distribution piping, and radiators in place, and uses higher temperature geothermal fluid (180°F). Fluid from a geothermal well at a temperature of 180 °F (82 °C) is used to both preheat the makeup water to the boiler and preheat the return condensate. The potable makeup water (3 million gallons per year) would be heated from approximately 60 °F (15.6 °C) to 170 °F (76.7 °C), and the condensate return (2 million gallons per year) is heated from 155 °F (68.3 °C) to 170 °F (76.7 °C).

Scenario C is viewed as a 'medium cost, medium benefit' scenario. Figure 17 shows a schematic of this system.

The major components and capacities of this system would include:

- One production well, 180 °F fluid
- One injection well
- Production well pump, submersible, ~50 gpm, 7.5 hp (6 kW)
- Production and injection well piping and valves
- Gathering system piping, 3" buried high temperature fiberglass reinforced polyester (FRP)
- Makeup water preheater, plate and frame type, 0.42 MBtu/h capacity
- Condensate return water preheater, plate and frame type, 0.04 MBtu/h capacity
- Boiler piping modifications
- Booster pumps, two pairs of 2 x 100%
- Electrical works (motors starters, wiring, etc)
- PLC Controls
- Field instrumentation

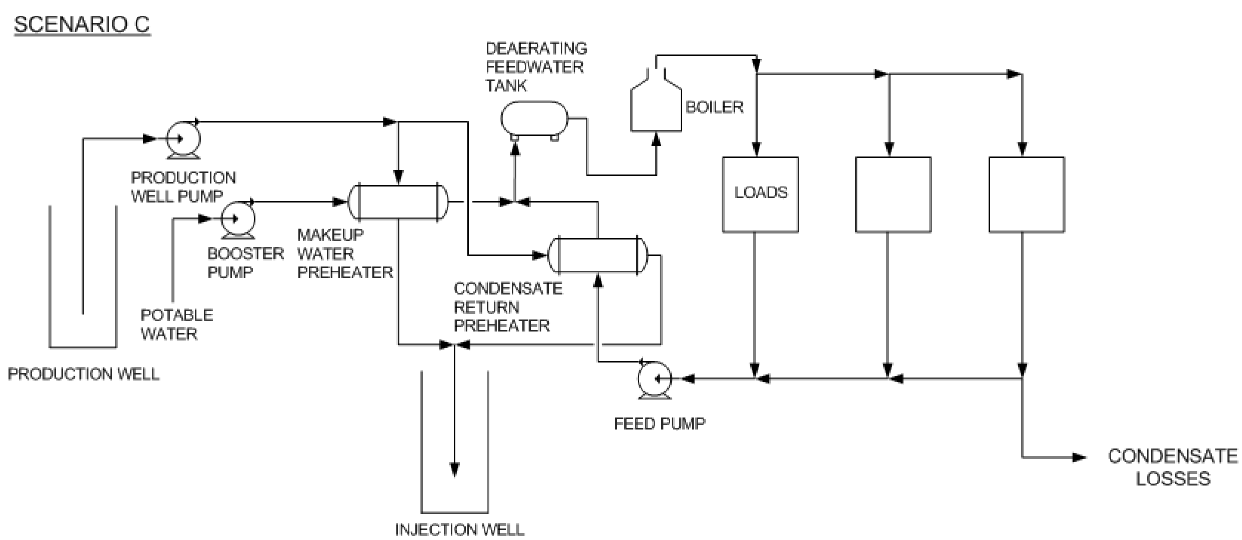


Figure 17: Scenario C – makeup water and condensate preheating

This scenario shows geothermal fluid coming out of the production well and being pumped to the make-up water heat exchanger and the condensate return preheater. The heat is transferred from the geothermal fluid to the potable water being used for make-up feedwater entering the deaerating feedwater tank and the condensate being returned to the system. The make-up feedwater and condensate enter the deaerating feedwater tank and then the boiler. The geothermal fluid is returned to the aquifer via the injection well.

Table 6 shows the various parameters for the system under scenarios B and C, and the estimated fuel savings.

Table 6: Scenario B and C thermal and fuel savings

Parameter	Units	Scenario B	Scenario C
Geofluid inlet temperature	˚F	140	180
Geofluid injection temperature	˚F	120	160
Geofluid flowrate (average)	gpm	~27	~45
Production well pump parasitic load	hp (kW)	20 (15)	7.5 (6)
Makeup water inlet temperature	˚F	60	60
Makeup water outlet temperature	˚F	130	170
Makeup water flowrate (average)	gpm	~7.6	~7.6
Condensate return water inlet temperature	˚F	-	155
Condensate return water outlet temperature	˚F	-	170
Condensate return water flowrate (average)	gpm	-	~5
Annual thermal energy savings	MBtu/yr	1700	3000
Equivalent fuel savings	gallons	12,310	21,724

Preheating 3 million gallons per year of water from 60 to 170 ˚F requires 2.75 billion Btu; preheating 2 million gallons per year of water from 155 to 170 ˚F requires 0.25 billion Btu, for a total of around 3 billion Btu saved per year. This is an equivalent diesel fuel oil savings (assuming 5.8 MBtu/barrel) of 517 barrels per year (21,724 gallons).

For scenario C, the major benefit from the higher temperature resource comes through additional heating possible for the makeup water. The benefit of heating the return condensate, due to its higher inlet temperature and consequent smaller temperature rise, is only around 10% of the total heat input to the makeup water.

These considerations also highlight the benefits of tracking down and eliminating leaks in the current condensate return system. While some losses such as boiler blowdown are inevitable, any system improvements planned should be prefaced by fixing any identifiable leaks, so as much of the high temperature condensate as practical can be returned to the boiler.

Other scenarios contemplated

Potable water recuperator

The large and relatively fixed costs of the wells and gathering system impose a burden on a smaller project. One alternative to avoid investments in new geothermal wells would be to use energy from the existing potable water well, which as noted earlier is quite warm at 128 °F (53.3 °C). The facility uses cooling towers to cool this down to ~70 °F before it enters a water treatment facility. Instead of using a new geothermal well to preheat the boiler makeup water, in theory the warm potable water could be used to preheat the cold potable makeup water via a regenerative heat exchanger. This would both reduce fuel usage in the boiler and reduce the need for cooling of the potable water in the cooling tower, possibly resulting in some fan parasitic power savings. However a limitation of this approach is the long distance (several miles) from the potable water well, cooling towers, and pond, to the point of use at the boilers, where the preheater would be installed.

We view this as a 'lower cost, low benefit' scenario, and did not evaluate it in detail due to the smaller temperature difference and flowrate, and distance required.

The major added components and capacities of this system would include:

- Potable water booster pump, 1 x 100%, ~10 gpm
- Potable water overland piping, 2" buried high temperature fiberglass reinforced polyester (FRP)
- Recuperator, plate and frame type
- Boiler piping modifications
- Controls and instrumentation

Binary power generation

A binary power plant (Figure 18) operates by using the geothermal fluid to vaporize a lighter working fluid, such as pentane or butane, which is used to drive a turbine. This allows power generation from resources that are at too low of a temperature to generate large volumes of steam to drive a steam turbine. Binary power plants are installed at many locations throughout the U.S. and worldwide, typically using resource temperatures in the 250-400 °F (120-200 °C) range. These are available from multiple suppliers and for small units can often be modular; easily to ship and install.

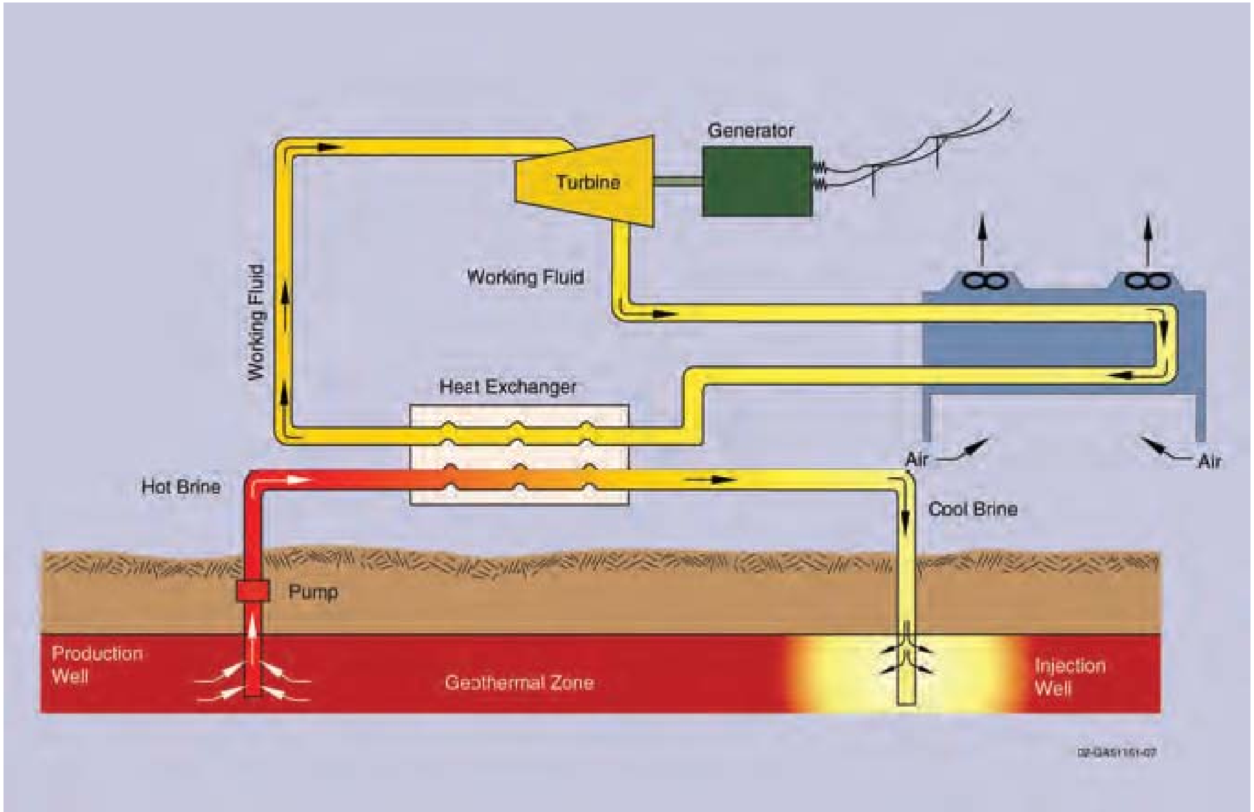


Figure 18: Geothermal binary plant (DOE)

The fact that binary plants are able to generate power from lower temperature fluids does not make them immune from the laws of thermodynamics, however. The efficiency of the plant is quite sensitive to the geofluid temperature, the injection temperature (which affects the total amount of energy extracted from the fluid), and the ambient temperature (affecting its ability to reject heat). The resource temperatures under consideration here (140-180 °F, or 60-82 °C) are quite low by binary power plant standards. Figure 19 shows the output per flow geofluid from resources of various temperatures. This curve does not show the sensitivity to the heat rejection temperature. Our temperatures would be an extrapolation off this curve, but one might expect the generation to be as little as 4-5 kW per kg/s of flow, or about 0.3 kW per gpm.

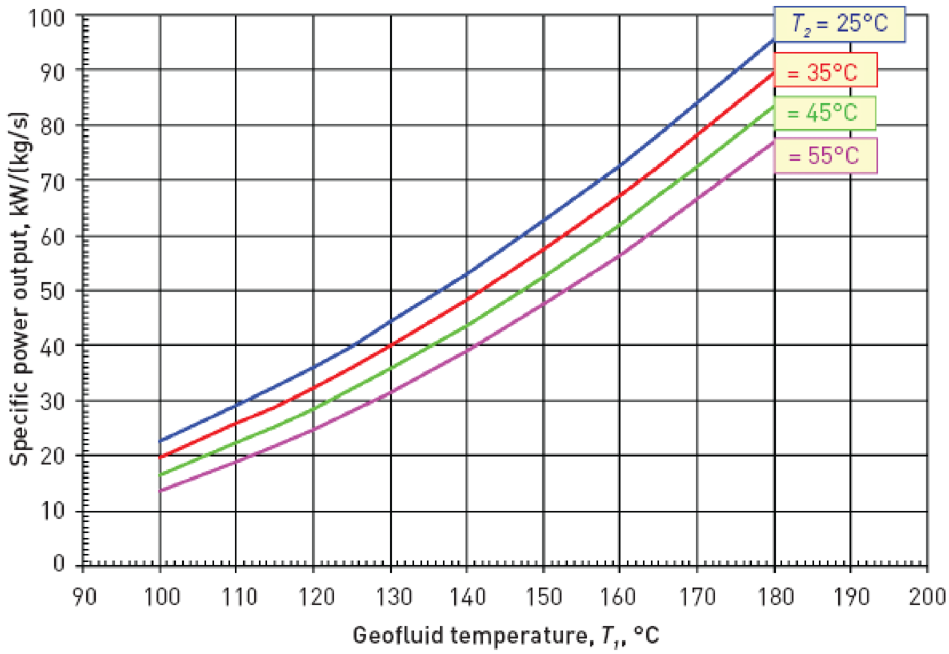


Figure 19: Binary plant specific output as a function of resource temperature (MIT, 2007)

If a well were discovered that produced fluid in 180 °F+ range at a flowrate of 500+ gpm, it might be possible to install a small modular package such as the PureCycle units installed at Chena Hot Springs in Alaska; a unit of this type could potentially generate 100-200 kW from these resource conditions. Figure 20 shows the two units installed at Chena. Chena benefits from extremely cold cooling water readily available; at HWAD these units would require a wet cooling tower. Air cooling would likely not be an option due to the small temperature difference. Electratherm also manufactures small packaged binary modules (“Green Machines”) around 50 kW.

Figure 20: PureCycle binary units at Chena, Alaska (Holdmann, 2007)

The economics of binary power generation would probably not be appealing at this site, given that existing electricity rates at the HWAD are quite reasonable at 5.5 cents per kWh. Binary plants typically require prices in the 10-15 cents per kW range to be economical. If NGPO discovers a specific well that has a higher productivity than is required for displacing heating purposes at the site, and sufficiently high temperatures, then a closer review of binary plant sizing and economics could be made. It is also possible that the binary plant could operate as a ‘topping’ cycle in conjunction with a ‘bottoming’ heating system, if temperatures and flows were more than ample for the heating purposes. A PureCycle unit installed at the Oregon Institute of Technology (OIT) campus at Klamath Falls, Oregon operates in this fashion. However, the economics would need to be reviewed and still may not be competitive with the existing power rates.

Downhole Heat Exchanger

This concept is not often used, but might in theory be suitable for the modest preheating needs of the boiler for our scenarios B and C. It is possible to extract heat from a well even when it does not flow copious amounts of water, simply by relying on heat transfer via conduction from the surrounding rock. Figure 21 shows a schematic of a downhole (or borehole) heat exchanger that might be used for preheating boiler feedwater.

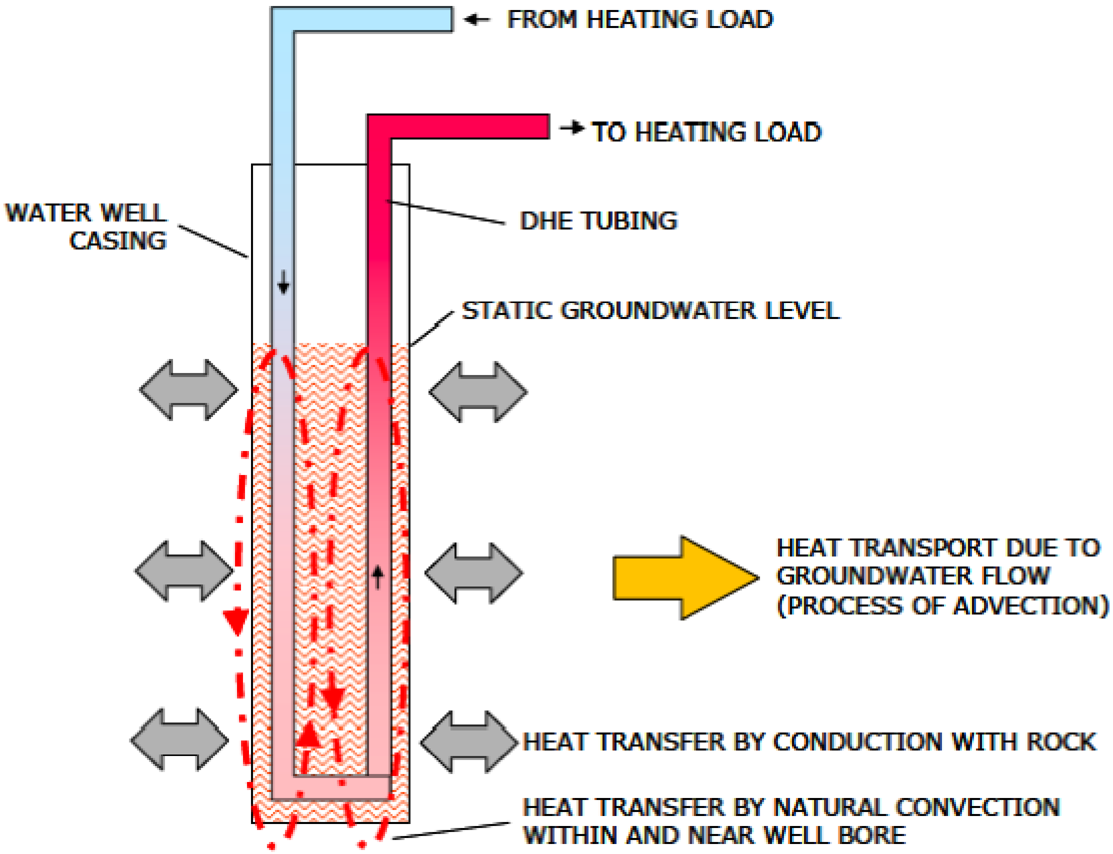


Figure 21: Heat transfer mechanisms in a downhole heat exhanger (adapted from Lund, 2007)

The amount of energy that can be extracted from a well such as this depends on the depth and the surrounding characteristics, but is much less than a freely flowing typical geothermal well. These may be applied at locations with hot but 'dry' abandoned boreholes. The closed loop also means a separate injection well for disposal of produced geofluid is not required. If there were a hot dry well in close proximity to the HWAD, it might be possible to utilize this for some water preheating, without a more extensive gathering system and multiple production/injection wells. A scheme such as this would require more detailed analysis around an actual candidate well.

PROJECT COST ESTIMATE

Introduction

This section presents estimated costs for the project, based on the design criteria for the wells, gathering system, and boiler modifications previously discussed under scenarios A, B, and C. The information below presents a discussion of estimate types, accuracies, and the methodology used.

Review of Estimate Accuracies

The purpose of this study was to produce a Rough Order of Magnitude (ROM) cost estimate. The accuracy of the estimate can be assessed by reference to a methodology developed by a recognized entity which deals with cost estimates.

One such source is The Chemical Engineers' Handbook which, in the "Fixed Capital Cost Estimation" chapter, describes the types of cost estimates and their accuracy based on how much is known about the project and the level of engineering work completed and used as the basis. The Chemical Engineers' Handbook methodology, which is essentially based on guidelines from the American Association of Cost Engineers (AACE), recognizes five basic levels of cost estimates.

The first of these is the "order of magnitude" or Class 5 estimate that is essentially a rule-of-thumb type estimate for the facility based on costs of similar facilities. The accuracy range of this estimate exceeds ±30%.

The next level of estimate is the "study" or Class 4 estimate which, using the guidelines, has a ±30% range of accuracy. This estimate is based on rough design sketches and preliminary flow sheets. It can be prepared at a relatively low cost and is typically used to evaluate the economics of a proposed plant to see if it is worthwhile to pursue or not. With preparation of indicative arrangements and listing of key equipment, the estimate in this study most nearly falls into this category.

The third estimate type is the "scope or budget authorization" or Class 3 estimate which has a ±20% range of accuracy. This estimate requires preparation of considerable engineering work but much of it still preliminary in nature. Engineering work products for this estimate include a site plot plan, preliminary process flow diagram, preliminary equipment sizing and material specifications, preliminary building sizes and types of construction, preliminary general arrangement, preliminary utility system requirements, preliminary motor list, and overall electrical one-lines to define the substation and major electrical items.

The "project control" or Class 2 estimate has a ±10% accuracy level and is based on a significant level of design work (as much as 30% of the total design) being completed. This is one step ahead of the final level of estimate which is the "firm or contractor's" or Class 1 estimate, based on fully completed engineering and contractor bids for construction. The firm estimate is considered to have a ±5% accuracy range.

Based on the conceptual deliverables, this estimate classification would fall between the Class 5 and Class 4 AACE estimate levels, implying a budget level accuracy of between 30-50%.

	ESTIMATE CLASSIFICATION				
General Project Data:	**CLASS 5**	**CLASS 4**	**CLASS 3**	**CLASS 2**	**CLASS 1**
Project Scope Description	General	Preliminary	Defined	Defined	Defined
Plant Production/Facility Capacity	Assumed	Preliminary	Defined	Defined	Defined
Plant Location	General	Approximate	Specific	Specific	Specific
Soils & Hydrology	None	Preliminary	Defined	Defined	Defined
Integrated Project Plan	None	Preliminary	Defined	Defined	Defined
Project Master Schedule	None	Preliminary	Defined	Defined	Defined
Escalation Strategy	None	Preliminary	Defined	Defined	Defined
Work Breakdown Structure	None	Preliminary	Defined	Defined	Defined
Project Code of Accounts	None	Preliminary	Defined	Defined	Defined
Contracting Strategy	Assumed	Assumed	Preliminary	Defined	Defined
Engineering Deliverables:					
Block Flow Diagrams	S/P	P/C	C	C	C
Plot Plans		S	P/C	C	C
Process Flow Diagrams (PFDs)		S/P	P/C	C	C
Utility Flow Diagrams (UFDs)		S/P	P/C	C	C
Piping & Instrument Diagrams (P&IDs)		S	P/C	C	C
Heat & Material Balances		S	P/C	C	C
Process Equipment List		S/P	P/C	C	C
Utility Equipment List		S/P	P/C	C	C
Electrical One-Line Drawings		S/P	P/C	C	C
Specifications & Datasheets		S	P/C	C	C
General Equipment Arrangement Drawings		S	P/C	C	C
Spare Parts Listings			S/P	P	C
Mechanical Discipline Drawings			S	P	P/C
Electrical Discipline Drawings			S	P	P/C
Instrumentation/Control System Discipline Drawings			S	P	P/C
Civil/Structural/Site Discipline Drawings			S	P	P/C

Figure 22: Estimate classifications (AACE)

Methodology

In order to assess the project costs, POWER Engineers employs AspenTech's In-Plant Capital Cost Estimator software (V7.2) henceforth known as "Aspen". This software uses cost indices for all aspects involved in the cost of construction. For this estimate, the project will reference US cost indices as a basis. Known cost data referenced from other sources considered higher quality (i.e. more accurate) will override those assumed indices.

The following lists shows the elements and area of the costs estimate.

A. DIRECT FIELD COSTS (DFC)

Costs of completing work that is directly attributable to its performance and is necessary for its completion. In construction, the cost of installed equipment, material, labor and supervision directly or immediately involved in the physical construction of the permanent facility. The costs for each element are divided into labor costs and material costs. For this effort, the following accounts are used to comprise the direct field costs:

- Equipment – The majority of the project costs are due to major equipment and related labor. Accurate pricing of these components are critical because of the large inherent cost. As such, costs for equipment are taken from equipment vendor budgetary quotes when possible.
- Piping Field Costs – Piping field quantities were estimated from the plan routing of the gathering system.
- Civil – Equipment foundations (concrete, rebar, grouting), excavation, shoring, backfilling and other associated costs.
- Steel – Pipe Supports, Pipe rack structures.
- Instruments – Bulk material costs, installation labor costs (routing, terminations).
- Electrical – Major Components (MCC, transformers, ducts, feeders etc)

B. INDIRECT FIELD COSTS

Costs not directly attributable to the completion of an activity. Indirect costs are typically allocated or spread across all activities on a predetermined basis. In construction, all costs which do not become a final part of the installation, but which are required for the orderly completion of the installation and may include, but are not limited to, field administration, direct supervision, capital tools, startup costs, contractor's fees, insurance, taxes, etc.

- Field Construction Supervision – Cost of supervision
- Misc costs (Insurance etc)
- Equipment Rental – Cranes, specialized equipment etc.
- Vendor Reps – On site representation of equipment vendors.
- Overtime Premium – Increased wage rate for workers over 40 hours per week.
- Consumable supplies – Welding rod, grinding wheels, small tools etc.

C. NON FIELD COSTS

Miscellaneous costs not tied direct to either direct or indirect field costs but are necessary for the completion of the project.

- Domestic Freight – Shipping costs to site.
- Materials Taxes – Taxes on equipment and other materials.
- Engineering – Home office engineering expense.
- Contract Fee – Contractor’s markup (profit). Typically this value is around 15-20% for an EPC project. For the Hawthorne project, we will assume this work is performed under a turnkey/EPC basis and this fee is included. Depending on the project structure, this may or may not be applicable.
- Permits, Bonds – Licensing etc.
- Project Management – On site and off site management.
- Contingency – A fraction of project costs set aside for unforeseen burdens / costs.
    - Major scope changes such as changes in end product
    - Specification, capacities, building sizes, and location of the asset or project.
    - Extraordinary events such as major strikes and natural disasters.
    - Management reserves, escalation and currency effects.
    - In this study the contingency has been set to 0.

D. LABOR WAGE RATE

Labor wage rates are generally classified as either direct or indirect. Direct field labor (DFL) is applied to meeting project objectives and is a principal element used in costing, pricing, and profit determination; indirect labor is a component of indirect cost, such as overhead or general and administrative costs. For this effort, the following assumptions have been made:

- Fully burdened wage rates are used to calculate the labor component of direct field costs.
- For this estimate, PEI has used default US labor rates and efficiencies.

Basis of the Cost Estimates

The cost estimates include the following key items, as appropriate for the scenario:

- Production and injection wells
- Production well pump, assumed to be included in well cost
- Wellpad site work
- Gathering system piping and electrical works
- Heat exchanger and boiler piping modifications
- Plant control system (PCS)
- Plant engineering
- Installation labor, overhead, fringe benefits
- Construction supervision
- Construction overhead
- Freight costs
- Taxes

The following key items were *not* included in the plant cost estimate:

- Owner Internal Overhead and Management Costs
- Environmental Permitting Costs
- Overall Cost Contingency
- Cost of Project Financing

Project Cost

Table 7 summarizes the total costs associated with the full retrofit for Scenario A. See Appendix D for detailed cost reports.

Table 7: Scenario A project cost summary

TABLE 7 - OVERALL PROJECT SUMMARY				
Account	MH	Labor Costs	Material Costs	Total Costs
Equipment	117	7,572	2,022,613	2,030,185
Piping	27280	831,013	1,011,264	1,842,277
Civil	11683	171,430	667,119	838,549
Steel	6	310	503	813
Instruments	4699	231,426	181,618	413,044
Electrical	3853	106,953	75,728	182,680
Insulation	6728	309,852	185,491	495,343
Paint	42	1,156	1,088	2,244
Direct Totals	54,408	$1,659,712	$4,145,424	$5,805,135
Construction Equipment and Indirect Costs				$255,986
Freight				$414,542
Taxes and Permits				$414,542
Engineering				$290,257
Contract Fees (contractor)				$363,667
Indirect / Non-Field Totals				$1,483,008
Total Power Plant Cost (USD)				$7,544,129

The primary costs associated with Scenario A consist of both of the geothermal wells (production and injection) as well as piping costs. The geothermal wells (26.9%) and the piping costs (24.4%) account for over half of the overall project cost. Variability in the costs of the wells (assumed $1 million) has a minor effect on the overall project cost as a $2 million well cost increases the overall cost by 35% ($10,184,574) and a $500K well cost decreases the overall cost by 17% ($6,261,627)

The significant piping costs are comprised of both gathering system/injection piping as well as a full piping replacement in each heated building on the campus. The campus piping is assumed to be fully insulated carbon steel piping.

Table 8 summarizes the total costs associated with Scenario B (makeup water preheat). See Appendix D for detailed cost reports.

Table 8: Scenario B project cost summary

TABLE 8 - OVERALL PROJECT SUMMARY				
Account	MH	Labor Costs	Material Costs	Total Costs
Equipment	60	3,845	2,006,627	2,010,472
Piping	5648	127,442	327,400	454,842
Civil	4614	171,430	67,118	238,548
Steel	6	310	503	813
Instruments	489	21,039	29,746	50,785
Electrical	3853	106,953	75,728	182,680
Insulation	29	1,344	992	2,336
Paint	42	1,156	1,088	2,244
Direct Totals	14,740	$433,519	$2,509,202	$2,942,721
			Construction Equipment and Indirect Costs	$118,376
Freight				$250,920
Taxes and Permits				$250,920
Engineering				$147,136
Contract Fees (contractor)				$183,666
			Indirect / Non-Field Totals	$832,642
Total Power Plant Cost (USD)				$3,893,739

The primary cost associated with Scenario B consists of both of the geothermal wells (production and injection). The geothermal wells (51.6%) account for over half of the overall project cost. As a result variability in the costs of the wells (assumed $1 million) has a significant effect on the overall project cost as a $2 million well cost increases the overall cost by 67% ($6,502,544) and a $500K well cost decreases the overall cost by 34% ($2,569,867).

The other significant costs in Scenario B consist primarily of the civil work and piping (17.8%) for the geothermal gathering system as well as the injection piping due to significant underground piping distances and the associated excavation required.

Table 9 summarizes the total costs associated with Scenario C (makeup and condensate preheating). See Appendix D for detailed cost reports.

Table 9: Scenario C project cost summary

TABLE 9 - OVERALL PROJECT SUMMARY				
Account	MH	Labor Costs	Material Costs	Total Costs
Equipment	28	1,818	2,008,253	2,010,071
Piping	11540	247,318	574,576	821,894
Civil	4614	171,430	67,119	238,549
Steel	6	310	503	813
Instruments	489	21,039	29,746	50,785
Electrical	3853	106,953	75,728	182,681
Insulation	29	1,344	992	2,336
Paint	42	1,156	1,088	2,244
Direct Totals	20,601	$551,368	$2,758,005	$3,309,373
Construction Equipment and Indirect Costs				$141,968
Freight				$275,801
Taxes and Permits				$275,801
Engineering				$165,469
Contract Fees (contractor)				$207,080
Indirect / Non-Field Totals				$924,151
Total Power Plant Cost (USD)				$4,375,492

The primary cost associated with Scenario C consists of both of the geothermal wells (production and injection). The geothermal wells (45.9%) account for nearly half of the overall project cost. As a result variability in the costs of the wells (assumed $1 million) has a significant effect on the overall project cost as a $2 million well cost increases the overall cost by 60% ($7,000,787) and a $500K well cost decreases the overall cost by 30% ($3,062,844).

The other significant costs in Scenario C consist primarily of the civil work and piping (24.3%) for the geothermal gathering system as well as the injection piping due to significant underground piping distances and the associated excavation required.

Project Economics

We assess the benefit of each project by considering the maximum anticipated annual fuel savings. Note that it is possible that during the coldest periods, additional fuel might be required to meet peak demands that these design flows would be insufficient for; this variation was not considered in the analysis.

Table 10 shows a summary of fuel savings, annual expenses avoided, total project costs, and simple payback. This neglects owner's soft costs as previously discussed, and neglects O&M costs, which are assumed to be comparable to the existing system. A fuel cost of $3.85 per gallon and electricity cost of 5.5 cents per kWh were used.

Given the large assumed fixed costs of the wells, Scenario A would offer the shortest simple payback. While Scenario C has more appealing simple payback than Scenario B, it would only be an option if a higher temperature (~180^{o} F) resource were encountered.

Table 10: Comparison of economic parameters

Parameter	Units	Scenario A	Scenario B	Scenario C
Resource temperature	^{o}F	180	140	180
Annual fuel savings	gallons	256,200	12,310	21,724
Equivalent fuel savings	$/year	$986,370	$47,394	$83,637
Estimated parasitic load	kW	93	15	6
Equivalent power expenditure, See Note	$/year	$33,514	$5,405	$2,162
Net annual savings	$/year	$952,856	$41,989	$81,475
Total project cost	M$	$7.5M	$3.9M	$4.4M
Simple payback	years	8	93	54

Notes – Power expenditure based on 5.5¢ per kWh

Sensitivity and Value Engineering

Like many geothermal projects, well costs are a major contributor to project cost, and any effort to reduce well costs would benefit the overall economics. Figure 23 shows the sensitivity of simple payback for scenarios B and C as a function of per well cost over a range of $500,000 to $2 million per well.

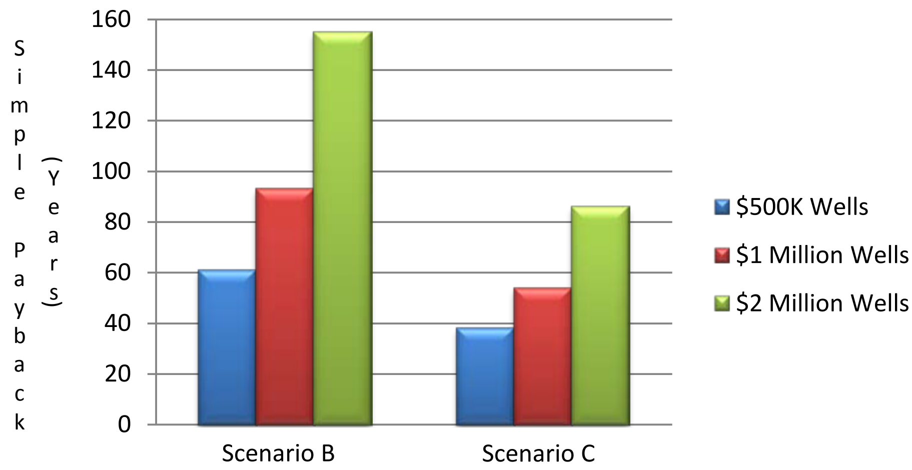


Figure 23: Simple payback for scenarios B and C as a function of well cost

One of the limitations with the existing diesel-based heating system is that it relies on such high temperature steam (100 psi ~ 330+ $^{\circ}$F). Thus the low temperature geothermal resource, while it would be well suited for district heating in a dedicated system, cannot be used to supply energy to the existing system other than by preheating the incoming feedwater water, which is only approximately 10% of the total thermal duty. The quantity of water required for the preheating strategies (<100 gpm) is rather small compared to a reasonably productive geothermal well. Thus, one way to improve the overall economics of the system might be to broaden the coverage of the heating system to include new purpose-build geothermally-heated facilities, perhaps in the adjacent town of Hawthorne.

This might take some creative commercial structures to serve loads both in the base and town, but overall would better utilize the resource. If there were large, fewer, more easily modifiable loads, such as industrial buildings or swimming pools, those might be prime candidates for extension of this system. This would amortize the considerable costs of the wells over a broader base. If a well is developed which has surplus capacity compared to the base needs, the gathering system could be designed with provisions for future expansion to make full use of it, by some demand which may not be currently identified. We do note that the El Capitan area might have a higher temperature resource than the areas examined in this study, and is closer to Hawthorne, thus it might be more suitable for a development that serviced the town.

While the cost of power produced from a binary plant would likely not be competitive with the existing power rates, it is possible that this would still be economical if those rates are anticipated to increase in the future. It might also help contribute to renewable energy portfolio standards. This potential should be reviewed when actual production well data are available.

Contracting Arrangements

It is unlikely that HWAD would perform this work themselves. The most likely contracting method is to award this project to an entity under a variety of different contracting scenarios. In any event we imagine that the responsibility for drilling would be by the Owner. However, the balance of plant works in the gathering system and boiler upgrades could be:

- Performed as a design/bid/build, where the Owner would purchase the major equipment, and hire an Engineer to develop the detailed design. This design would be bid out to local contractors, who would procure bulk materials. This is often the most economical approach.

- Assigned as a lump sum (EPC) contract to a Contractor. The Contractor would procure all equipment and materials. The Owner would be responsible for operations after handover.
- Structured under a tolling arrangement, where the Owner agrees to pay a Developer a fixed rate for thermal energy provided or diesel fuel costs avoided. The Developer would hire a Contractor to perform the engineering and work. The logistics of operations and responsibility for maintenance of pipelines and equipment would need to be negotiated; presumably the Owner would want to use the existing staff. It is possible that this is performed under a transfer arrangement, where after a certain number of years ownership of the facility would revert to the Owner.

SUMMARY

This feasibility study has reviewed the potential use of geothermal energy for heating purposes at the HWAD. The goal of any projects would be to displace fuel oil currently used in the existing boiler plant. Based on the drilling data, temperature of extracted fluid from wells in this area is expected to range from 100 to 200° F ((38 to 93°C). Another test well is planned in the fall of 2012.

If a well is encountered which can produce fluid in the 140 to 180° F ((60 to 82°C) range, it could be utilized at the HWAD in a variety of ways. If the entire heating system is retrofit to a lower temperature, water-circulated system, (Scenario A), then it may be possible to displace most of the current fuel consumption with geofluid flows of 500-600 gpm at 180 °F. This scenario requires a considerable capital investment of $5-6 million. The resultant fuel savings would also be considerable however, at around $1 million per year, resulting in a relatively short payback (approximately 6 years).

If retrofit of the existing heating system is not feasible, either due to economic or aesthetic/historical reasons, then two scenarios (B and C) have been presented that augment the existing system to reduce fuel consumption. These scenarios are slightly lower cost but offer only about 10-20% of the fuel savings compared to a full retrofit, thus the payback periods are longer at 50-90 years.

As the Department of Defense moves to energy security and renewable energy, scenario A may qualify as a special project. The Army is looking for energy savings projects that have a good payback. Scenario A would seem to meet most of the criteria.

The economics of any project will hinge on three major aspects:

- Costs of drilling
- Productivity and temperature of the produced fluid
- Ability of the base (or other users) to make full use of the produced fluid

The feasibility of various alternatives for utilization should be revisited once more tangible results are available from the next test well, scheduled to be drilled in the fall of 2012.

REFERENCES

Holdmann G. 2007. The Chena Hot Springs 400 kW geothermal power plant: experience gained during the first year of operation. GRC Transactions, Vol. 31.

Katzenstein A, Bjornstad S, Meade D. 2002. Geothermal Resource Evaluation of the Hawthorne Army Ammunition Depot (HWAD), Hawthorne, NV. Internal Navy GPO report.

Kratt C, Sladek C, Coolbaugh MF. 2010. Boom and Bust with the Latest 2m Temperature Surveys: Dead Horse Wells, Hawthorne Army Depot, Terraced Hills, and Other Areas in Nevada. GRC Transactions, Vol. 34.

Lazaro M, Page C, Tiedeman A, Sabin A, Bjornstad S, Alm S, Meade D, Shoffner J, Mitchell K, Crowder B, Halsey G. 2010. United States Department of the Navy Geothermal Exploration Leading to Shallow and Intermediate/Deep Drilling at Hawthorne Ammunition Depot, Hawthorne, NV. GRC Transactions. Vol. 34.

Mansure, AJ, Bauer SJ, Livesay BJ, Petty S. 2006. Geothermal well cost analyses 2006. GRC Transactions, Vol. 30.

Mansure, AJ, Blanketship DA. 2011. Geothermal well cost analyses 2011. GRC Transactions, Vol. 35.

Massachusetts Institute of Technology. 2006. The Future of Geothermal Energy. Boston (MA).

Moeck I, Hinz N, Faulds J, Bell J, Kell0Hills A, Louie J. 2010. 3D Geological Mapping as a New Method in Geothermal Exploration: A Case Study from Central Nevada. GRC Transactions, Vol. 34.

Penfield R, Zehner R, Coolbaugh M, Shevenell L, Hastings J, Johnson G, Snyder W, Morgos D, Kurz K, Sabin A, Lazaro M, Bjornstad S, Halsey G. 2010. Geothermal Site Assessment using the National Geothermal Data System (NGDS), with Examples from the Hawthorne Ammunition Depot Area. GRC Transactions, Vol. 34.

Trexler D, Koenig B, Bell E, Ghusn G. 1981. Area Specific Geothermal Assessment, Nevada; Hawthorne, Paradise Valley and Carson Sink. Nevada Bureau of Mines and Geology, 203 p. for the US DOE: *DOE/NV/I0039-3*.

APPENDIX A—DEAERATOR OPERATION

A **deaerator** is a device that is widely used for the removal of oxygen and other dissolved gases from the feedwater to steam-generating boilers. In particular, dissolved oxygen in boiler feedwater will cause serious corrosion damage in steam systems by attaching to the walls of metal piping and other metallic equipment and forming oxides (rust). Dissolved carbon dioxide combines with water to form carbonic acid that causes further corrosion. Most deaerators are designed to remove oxygen down to levels of 7 parts per billion by weight (0.005 cm^3/L) or less as well as essentially eliminating carbon dioxide.

The deaerator used at the Hawthorne Army Depot is a spray-type with a horizontal cylindrical vessel. The horizontal cylindrical vessel serves as both the deaeration section and the boiler feedwater storage tank. The deaerator removes oxygen and non-condensable gases in addition heating the incoming makeup feedwater before it enters the boiler.

Figure A-1: HWAD Deaerator

Spray-type deaerator diagram and operation

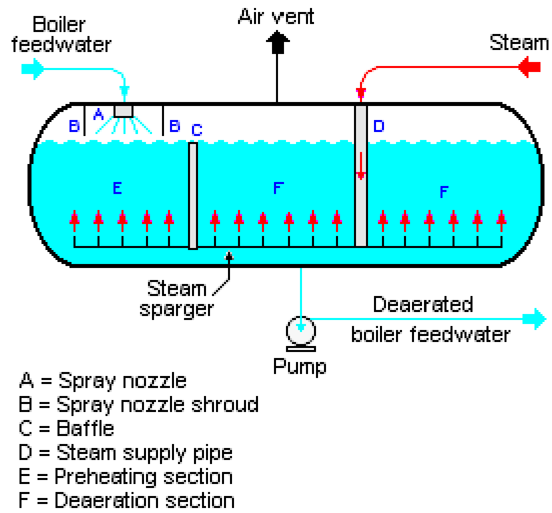


Figure A-2: Schematic of a typical spray-type deaerator

As shown in the figure above, the typical spray-type deaerator is a horizontal vessel which has a preheating section (E) and a deaeration section (F). The two sections are separated by a baffle(C). Low-pressure steam enters the vessel through a sparger in the bottom of the vessel.

The boiler feedwater is sprayed into section (E) where it is preheated by the rising steam from the sparger. The purpose of the feedwater spray nozzle (A) and the preheat section is to heat the boiler feedwater to its saturation temperature to facilitate stripping out the dissolved gases in the following deaeration section.

The preheated feedwater then flows into the deaeration section (F), where it is deaerated by the steam rising from the sparger system. The gases stripped out of the water exit via the vent at the top of the vessel. Again, some designs may include a vent condenser to trap and recover any water entrained in the vented gas. Also again, the vent line usually includes a valve and just enough steam is allowed to escape with the vented gases to provide a small and visible telltale plume of steam.

The deaerated boiler feedwater is pumped from the bottom of the vessel to the Nebraska 500 HP boilers.

APPENDIX B—STIFF DIAGRAM

A stiff diagram is a graphical representation of chemical analyses. It is widely used by hydrogeologists and geochemists to display the major ion composition of a water sample. A polygonal shape is created from four parallel horizontal axes extending on either side of a vertical zero axis. Cations are plotted in milliequivalents per liter on the left side of the zero axis, one to each horizontal axis, and anions are plotted on the right side. The plotted points are connected to form a stiff pattern (polygon) for individual samples. Stiff patterns are useful in making a rapid visual comparison between water from different facies or sources. Stiff diagrams can also be used to help visualize ionically related waters from which a flow path can be evaluated or if the flow path is known, to help show the ionic composition of a water body changes over space and/or time (Fetter, 1994).

Examples of typical stiff diagrams are shown below. By standard convention, they are created by plotting the equivalent concentration of the cations to the left of the center axis and anions to the right. The points are connected to form the figure. When comparing Stiff diagrams between different waters it is important to prepare each diagram using the same ionic species, in the same order, on the same scale.

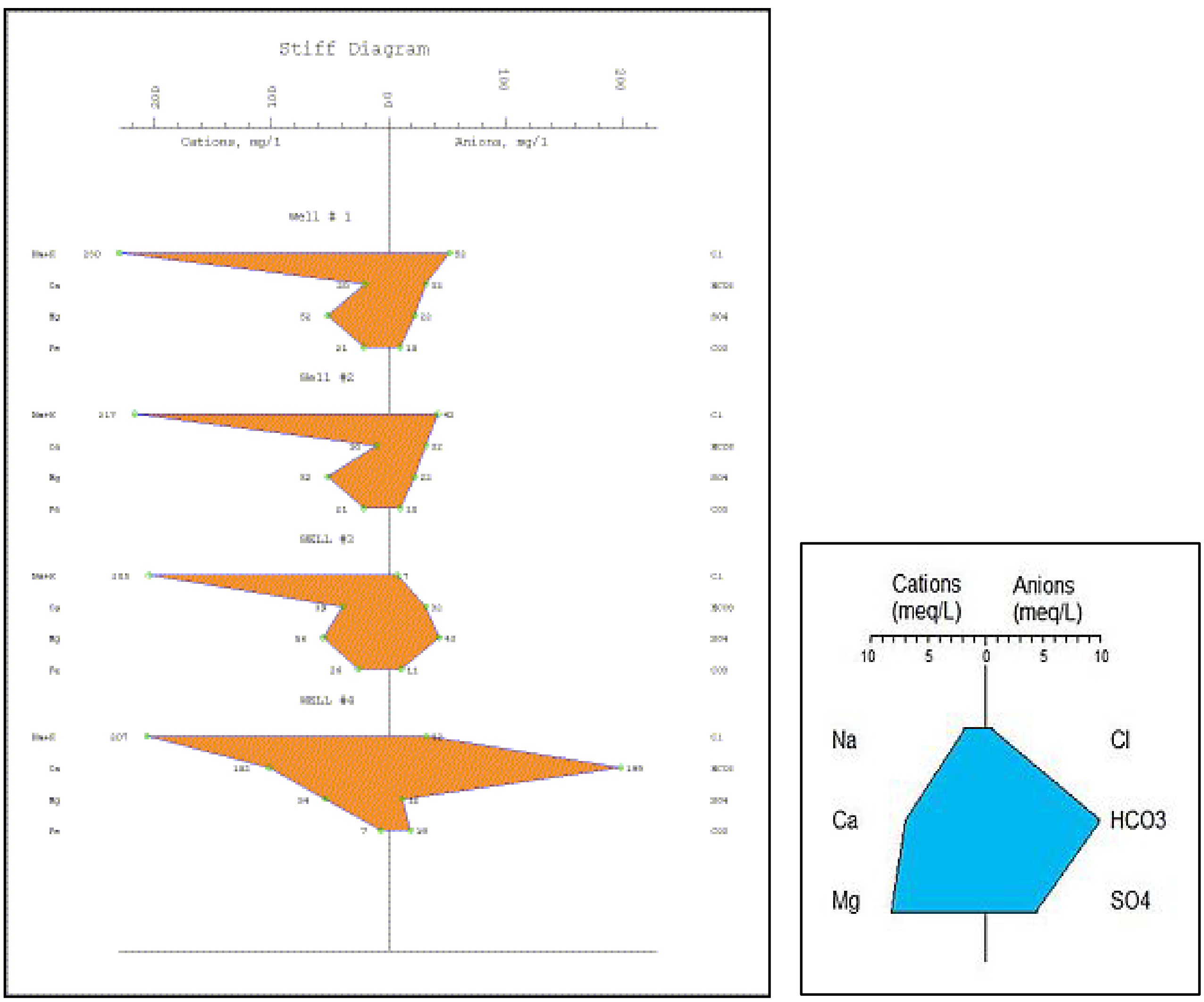
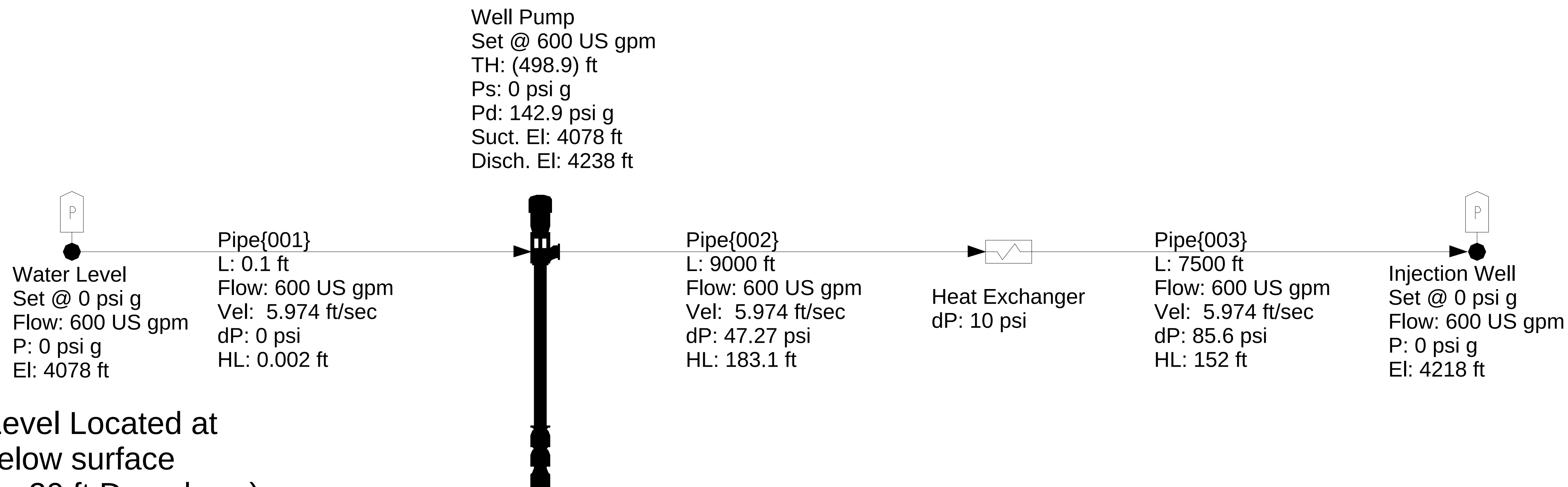


Figure B-1: Stiff Diagram and Standard Cation/Anion Diagram

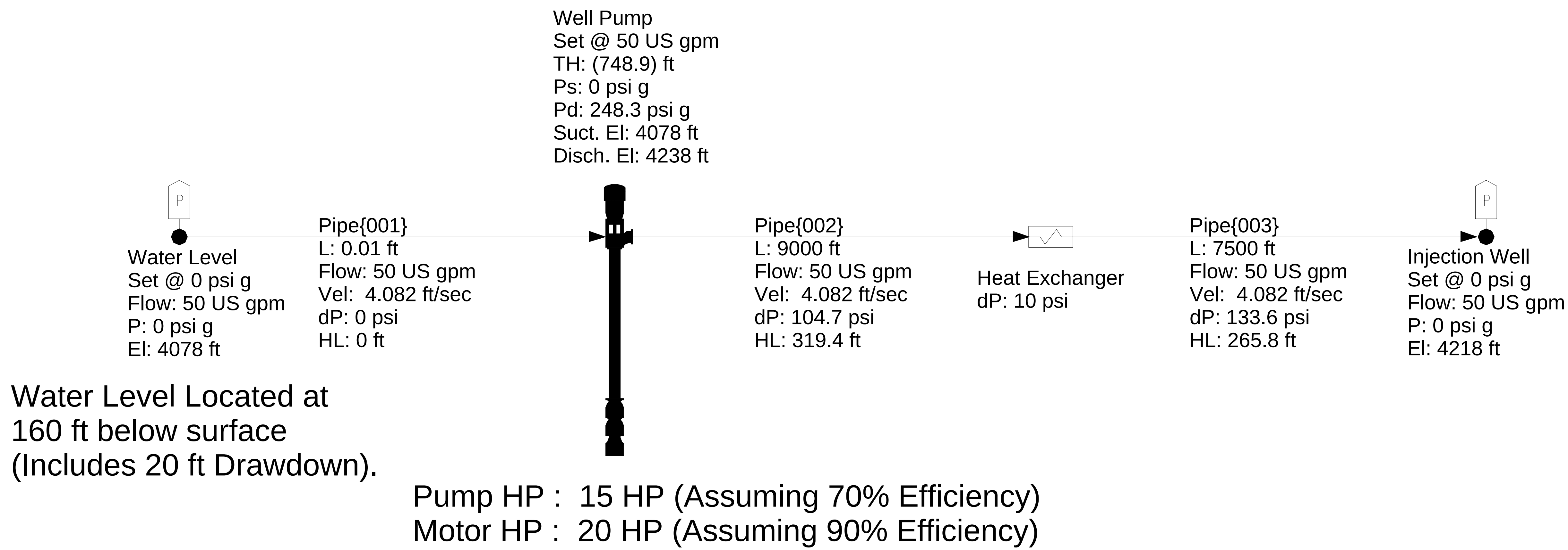
APPENDIX C—GATHERING SYSTEM FLOW CALCULATIONS



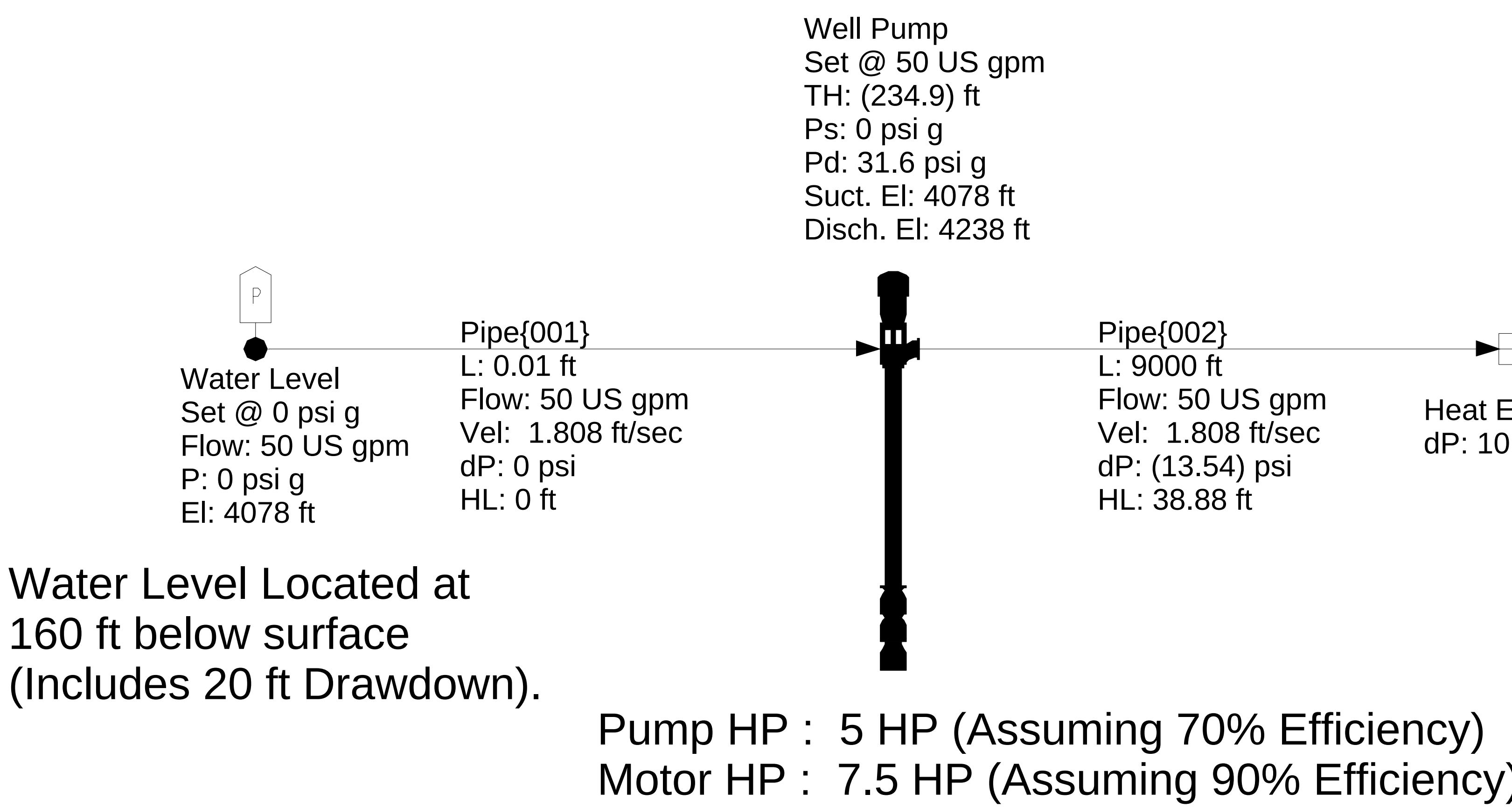
Water Level Located at
160 ft below surface
(Includes 20 ft Drawdown).

Pump HP : 100 HP (Assuming 70% Efficiency)
Motor HP : 125 HP (Assuming 90% Efficiency)

Lineup:	*<Design Case>*	Darcy-Weisbach		PIPE-FLO 2009
System:	Scenario A		Flow:	US gpm
Date:	08/10/12 11:46 am		Pressure:	psi g
Company:	POWER Engineers		Size:	in
Project:	126923 Navy Geothermal		Elevation:	ft
by:	J.Chilcote		Velocity:	ft/sec
	Scenario A		Length:	ft
			Volume:	gallons



Lineup:	<Design Case>	Darcy-Weisbach		PIPE-FLO 2009
System:	Scenario B		Flow:	US gpm
Date:	08/10/12 11:47 am		Pressure:	psi g
Company:	POWER Engineers		Size:	in
Project:	126923 Navy Geothermal		Elevation:	ft
by:	J.Chilcote		Velocity:	ft/sec
	Scenario B		Length:	ft
			Volume:	gallons



Lineup:	*<Design Case>* Darcy-Weisbach		PIPE-FLO 2009
System:	Scenario C	Flow:	US gpm
Date:	08/10/12 11:45 am	Pressure:	psi g
Company:	POWER Engineers	Size:	in
Project:	126923 Navy Geothermal	Elevation:	ft
by:	J.Chilcote	Velocity:	ft/sec
	Scenario C	Length:	ft
		Volume:	gallons

APPENDIX D—DETAILED COST ESTIMATES

Economic Evaluation

Direct Account Totals

Key Quantity Code of Account Group Summary

Project Title: Hawthorne Army Depot **Prep. By:** J.Chilcote
Project Name: HWAD **Scenario Name:** A **Proj. Location:** Hawthorne, NV
Estimate Date: 14AUG12 13:53:38 **Est. Class:** **Job No:** **Currency:** DOLLARS USD

Account	Category	Key Qty	Key Units	MH	Labor	Matl	Total
(2) Equipment	(160) Pumps	4	ITEM(S)	117	7,572	2,010,000	2,017,572
(2) Equipment	(260) Heat Exchangers	2	ITEM(S)			12,613	12,613
(3) AG Pipe	(300) Piping - General			1,643	34,131		34,131
(3) AG Pipe	(310) Carbon Stl Pipe/Fittings			8,301	319,312	96,749	416,061
(3) AG Pipe	(310) Carbon Stl Pipe/Fittings	23,623	FEET			203,454	203,454
(3) AG Pipe	(360) Piping Specialties			5,233	195,226	143,192	338,417
(3) UG Pipe	(340) Lined Pipe/Fittings					839	839
(3) UG Pipe	(350) Non-Metal Pipe/Fittings			7,729	151,546	183,020	334,566
(3) UG Pipe	(350) Non-Metal Pipe/Fittings	16,500	FEET			324,652	324,652
(3) UG Pipe	(360) Piping Specialties			1,348	50,285	44,112	94,397
(3) UG Pipe	(370) Firewater, Buried Pipe			3,027	80,514	15,247	95,761
(4) Bldg - Arch	(470) Buildings			7,568	29,668	619,496	649,164
(4) Concrete	(440) Concrete			850	26,937	15,499	42,436
(4) Concrete	(440) Concrete	165	CY	356	15,583		15,583
(4) Concrete	(450) Rebar, Formwork, Etc.			2,909	99,241	32,124	131,365
(5) Steel	(530) Other Steel Items	0	TONS	5	291	503	794
(5) Steel	(590) Other Steelwork			0	19		19
(6) Instrumentation	(610) Field Instrumentation	164	EACH	2,216	145,170	124,447	269,617
(6) Instrumentation	(620) Panels, Panel Devices			381	7,655	15,000	22,655
(6) Instrumentation	(630) Instrument Runs			860	44,315	30,296	74,610
(6) Instrumentation	(640) Instr. Support & Encl.			1,069	26,008	11,875	37,883
(6) Instrumentation	(690) Other Instrument Work			173	8,278		8,278
(7) AG Electrical	(790) Other Electrical			3	73		73
(7) UG Electrical	(710) Wire, Cable, Etc.			487	12,477	17	12,494
(7) UG Electrical	(710) Wire, Cable, Etc.	54,060	FEET			10,697	10,697
(7) UG Electrical	(720) Conduit, Trays, Etc.			1,618	39,358	18,114	57,471
(7) UG Electrical	(760) Buried Cable			1,745	55,044	46,900	101,944
(8) Pipe Insulation	(810) Insulation			6,728	309,852	25,063	334,914
(8) Pipe Insulation	(810) Insulation	26,874	FEET			160,428	160,428
(9) Paint	(910) Painting	4,800	SF	34	957	1,088	2,045
(9) Paint	(920) Surface Preparation			8	199		199
Totals:				**54,408**	**1,659,712**	**4,145,424**	**5,805,135**

Economic Evaluation

Direct Account Totals

Key Quantity Code of Account Group Summary

Project Title: Hawthorne Army Depot **Prep. By:** J.Chilcote
Project Name: HWAD **Scenario Name:** B **Proj. Location:** Hawthorne, NV
Estimate Date: 14AUG12 14:06:10 **Est. Class:** **Job No:** **Currency:** DOLLARS USD

Account	Category	Key Qty	Key Units	MH	Labor	Matl	Total
(2) Equipment	(160) Pumps	4	ITEM(S)	60	3,845	2,005,000	2,008,845
(2) Equipment	(260) Heat Exchangers	1	ITEM(S)			1,627	1,627
(3) AG Pipe	(300) Piping - General			453	8,071	10,000	18,071
(3) AG Pipe	(310) Carbon Stl Pipe/Fittings			68	2,992	4,586	7,578
(3) AG Pipe	(310) Carbon Stl Pipe/Fittings	43	FEET			788	788
(3) AG Pipe	(360) Piping Specialties			11	402	353	755
(3) UG Pipe	(340) Lined Pipe/Fittings					206	206
(3) UG Pipe	(350) Non-Metal Pipe/Fittings			2,874	56,344	109,260	165,604
(3) UG Pipe	(350) Non-Metal Pipe/Fittings	16,500	FEET			190,939	190,939
(3) UG Pipe	(370) Firewater, Buried Pipe			2,242	59,633	11,267	70,900
(4) Bldg - Arch	(470) Buildings			499	29,668	19,496	49,164
(4) Concrete	(440) Concrete			850	26,937	15,499	42,436
(4) Concrete	(440) Concrete	165	CY	356	15,583		15,583
(4) Concrete	(450) Rebar, Formwork, Etc.			2,909	99,241	32,124	131,365
(5) Steel	(530) Other Steel Items	0	TONS	5	291	503	794
(5) Steel	(590) Other Steelwork			0	19		19
(6) Instrumentation	(610) Field Instrumentation	14	EACH	201	13,197	10,913	24,110
(6) Instrumentation	(620) Panels, Panel Devices			96	696	15,000	15,696
(6) Instrumentation	(630) Instrument Runs			78	4,029	2,754	6,783
(6) Instrumentation	(640) Instr. Support & Encl.			97	2,364	1,080	3,444
(6) Instrumentation	(690) Other Instrument Work			16	753		753
(7) AG Electrical	(790) Other Electrical			3	73		73
(7) UG Electrical	(710) Wire, Cable, Etc.			487	12,477	17	12,494
(7) UG Electrical	(710) Wire, Cable, Etc.	54,060	FEET			10,697	10,697
(7) UG Electrical	(720) Conduit, Trays, Etc.			1,618	39,358	18,114	57,471
(7) UG Electrical	(760) Buried Cable			1,745	55,044	46,900	101,944
(8) Pipe Insulation	(810) Insulation			29	1,344	145	1,489
(8) Pipe Insulation	(810) Insulation	109	FEET			847	847
(9) Paint	(910) Painting	4,800	SF	34	957	1,088	2,045
(9) Paint	(920) Surface Preparation			8	199		199
Totals:				**14,740**	**433,519**	**2,509,202**	**2,942,721**

Economic Evaluation

Direct Account Totals

Key Quantity Code of Account Group Summary

Project Title: Hawthorne Army Depot **Prep. By:** J.Chilcote
Project Name: HWAD **Scenario Name:** C **Proj. Location:** Hawthorne, NV
Estimate Date: 14AUG12 14:36:39 **Est. Class:** **Job No:** **Currency:** DOLLARS USD

Account	Category	Key Qty	Key Units	MH	Labor	Matl	Total
(2) Equipment	(160) Pumps	4	ITEM(S)	28	1,818	2,005,000	2,006,818
(2) Equipment	(260) Heat Exchangers	2	ITEM(S)			3,253	3,253
(3) AG Pipe	(300) Piping - General			885	16,564	10,000	26,564
(3) AG Pipe	(310) Carbon Stl Pipe/Fittings			68	2,992	4,586	7,578
(3) AG Pipe	(310) Carbon Stl Pipe/Fittings	43	FEET			788	788
(3) AG Pipe	(360) Piping Specialties			11	402	353	755
(3) UG Pipe	(340) Lined Pipe/Fittings					596	596
(3) UG Pipe	(350) Non-Metal Pipe/Fittings			7,716	151,285	284,732	436,018
(3) UG Pipe	(350) Non-Metal Pipe/Fittings	16,500	FEET			259,132	259,132
(3) UG Pipe	(370) Firewater, Buried Pipe			2,860	76,074	14,389	90,463
(4) Bldg - Arch	(470) Buildings			499	29,668	19,496	49,164
(4) Concrete	(440) Concrete			850	26,937	15,499	42,436
(4) Concrete	(440) Concrete	165	CY	356	15,583		15,583
(4) Concrete	(450) Rebar, Formwork, Etc.			2,909	99,241	32,124	131,365
(5) Steel	(530) Other Steel Items	0	TONS	5	291	503	794
(5) Steel	(590) Other Steelwork			0	19		19
(6) Instrumentation	(610) Field Instrumentation	14	EACH	201	13,197	10,913	24,110
(6) Instrumentation	(620) Panels, Panel Devices			96	696	15,000	15,696
(6) Instrumentation	(630) Instrument Runs			78	4,029	2,754	6,783
(6) Instrumentation	(640) Instr. Support & Encl.			97	2,364	1,080	3,444
(6) Instrumentation	(690) Other Instrument Work			16	753		753
(7) AG Electrical	(790) Other Electrical			3	73		73
(7) UG Electrical	(710) Wire, Cable, Etc.			487	12,477	17	12,494
(7) UG Electrical	(710) Wire, Cable, Etc.	54,060	FEET			10,697	10,697
(7) UG Electrical	(720) Conduit, Trays, Etc.			1,618	39,358	18,114	57,471
(7) UG Electrical	(760) Buried Cable			1,745	55,044	46,900	101,944
(8) Pipe Insulation	(810) Insulation			29	1,344	145	1,489
(8) Pipe Insulation	(810) Insulation	109	FEET			847	847
(9) Paint	(910) Painting	4,800	SF	34	957	1,088	2,045
(9) Paint	(920) Surface Preparation			8	199		199
Totals:				**20,601**	**551,368**	**2,758,005**	**3,309,373**