The State of Geothermal Technology

Part I: Subsurface Technology

Geothermal exploration prospect in the Great Basin, drill rig operating at The Geysers (photos by M. Taylor)

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Executive Summary

Introduction

Operating geothermal power plants utilize fluids that flow through fracture networks of heated subsurface rock which creates reservoirs of hot fluid or steam. Prior to constructing and connecting a geothermal plant to the grid, developers must go through several steps to locate and harness these reservoirs. The steps to subsurface resource development are: 1) exploration, 2) drilling, and 3) reservoir management.

Successful completion of these steps involves the employment of numerous subsurface technologies. These technologies, which include both the tools used and approaches taken to develop a given resource are effective in only the best of conditions. To utilize most of the geothermal resource base subsurface technologies would need to be improved, new exploration technologies developed, and costs for drilling significantly reduced.

Exploration

Currently, the only way to know for certain whether or not a given site contains an economic geothermal resource would be to drill. The great cost of geothermal drilling most always prohibits its use in the early stages of exploration. Instead, to predict the subsurface location of a resource, assess its commercial likelihood, and decrease the risk of drilling a dry or cool well, developers perform a wide variety of geoscientific surveys; these include geological, geochemical, and geophysical studies.

Potential oil and gas resources can be identified with much confidence prior to drilling through the utilization of available geophysical techniques. These techniques are useful in geothermal exploration, but because of several factors characteristic of geothermal resources they are not as effective and do not provide the same level of confidence in defining geothermal reservoirs as they do in oil and gas exploration.

Most hydrothermal resources developed in the US have been found through surface manifestations such as hot springs. It is predicted that these types of resources represent only a very small fraction of an incredibly large, 'hidden,' US resource base. Advances in exploration technology are hoped to develop highly advanced instrumentation and techniques leading to increased confidence and drilling success, as well as means of discovering thousands of megawatts of 'hidden' resource.

A large portion of the hydrothermal resources are predicted to exist in the Great Basin and in varied geographic locations including the Cascades Range in the Pacific Northwest, the Imperial Valley in California, the Snake River Valley in Idaho, and in several areas of Alaska. Several geothermal projects in the Great Basin and Imperial Valley have given developers a decent idea of what types of exploration tools and approaches work in these areas—and we have learned that different tools work better in different geologic settings. But, commercial geothermal development has not taken place in the other regions in part because of the lack of geo-scientific knowledge to effectively characterize the region, and the lack of effective resource characterization increases the risk of development. Resource characterization and geologic research similar to that being conducted in the Great Basin is needed to better understand these other geologic settings and determine which exploration techniques work best in them.

Drilling

Geothermal drilling is a complex and expensive process. Although geothermal and oil & gas drilling operations may seem interchangeable, there are significant differences. The geologic formations encountered and fluid flow rates required for commercial production cause geothermal drilling contractors to use different methods and tools than those used in oil & gas drilling. Some of these include training specialized crews, drilling to maximize well diameters to increase flow potential, and using several pieces of equipment altered to be effective in geothermal drilling projects. While the industry has made several technological advances that help drill contractors cope with difficult drilling environments, further advances will allow them to reach their target depths with fewer problems and less cost.

A major reason that many geothermal prospects go undeveloped is that they are too deep to be drilled economically. If advances are made that significantly reduce drilling costs, resources at previously uneconomical depths would then become feasible development prospects.

Reservoir Management

From the time a well is drilled, the resource is actively monitored and managed to maintain its long term production potential. Reservoir engineers use copious amounts of data gathered from well-testing, drilled rock cores, tracers, and several other geoscientific sources to develop models and computer simulations designed to identify and predict changes in the resource—based on these studies, actions are taken to enable sustained production from the reservoir. The longer a reservoir is in production, the more these methods will support effective management which is considered to be the best way to protect investment in a geothermal project. Industry experts state that tools need to be further developed to better predict reservoir evolution, and do so earlier in reservoir life.

Emerging Technologies

Enhanced Geothermal Systems (EGS) are those in which low or non-producing resources are engineered to become commercially viable. As this subsurface technology has the potential of providing on the order of a hundred thousand megawatts of geothermal energy, it has and continues to receive a great amount of attention. Although there have been several successful tests examining parts of EGS technology, what is needed is the significant commitment of funds to determine if EGS is technically feasible by building a facility that produces electricity over a period of time. This would allow both technical and economic questions to be resolved.

There are potentially thousands of megawatts of unused geothermal energy from thermal fluids commonly co-produced from oil and gas wells. Developing the technology necessary to utilize such resources is a matter of engineering and demonstration that is starting to be done on a limited basis. Due to several natural and artificial characteristics of oil fields, geothermal production at these resources could also provide a venue to better develop the technology needed for EGS, and some view them as potential sites for full-scale EGS power development.

Deep volcanic, or supercritical, resources also hold the potential of adding hundreds of megawatts to the US geothermal resource base. These resources are heated by subsurface magma in volcanic regions. Technological needs for this type of resource involve the development of equipment that can function properly and for extended periods of time at extremely high temperatures.

Geopressured systems are a readily available source of energy which have been demonstrated to hold producible natural gas (methane) and geothermal fluids. While found in several areas of the country, the most significant resource is in the Gulf Coast region. Geopressured systems containing thermal fluid and natural gas, trapped under pressure and heated between layers of hot rock underlie areas of Texas and Louisiana and extend into the Gulf. While the past demonstration effort failed to be economically viable, scientists are examining new approaches. As geothermal technology advances, and fossil fuel prices rise, these historically uneconomical systems could become a significant source of both natural gas and geothermal power.

The State of Geothermal Technology

Part I: Subsurface Technology
Part II: Surface Technology

INTRODUCTION

In the past few years, there has been a debate in Washington about the state of geothermal energy technology. Some have called it a "mature" technology, while others have responded that our understanding and development of geothermal technology was barely beginning. But to understand this question, and even begin to resolve any controversy, one should begin by answering the question, "What is technology?"

The literature is replete with references to the many misconceptions about what the term "technology" means. People appear to often think of technology as a particular thing, device, or widget. But, technology is much more complex, and the physical objects we use are only one aspect of technology.

The International Technology Education Association explains that "technology is how people modify the natural world to suit their own purposes... generally it refers to the diverse collection of processes and knowledge that people use to extend human abilities and to satisfy human needs and wants."[1]

According to one federal technology education curriculum, "Technology is a body of knowledge used to create tools, develop skills, and extract or collect materials. It is also the application of science (the combination of the scientific method and material) to meet an objective or solve a problem."[2]

The United Kingdom's Technology Education Center breaks down technology into several constituent parts. "Throughout the twentieth century the uses of the term have increased to the point where it now encompasses a number of "classes" of technology:

1. Technology as Objects: Tools, machines, instruments, weapons, appliances - the physical devices of technical performance
2. Technology as Knowledge: The know-how behind technological innovation
3. Technology as Activities: What people do - their skills, methods, procedures, routines
4. Technology as a Process: Begins with a need and ends with a solution
5. Technology as a Sociotechnical System: The manufacture and use of objects involving people and other objects in combination"[3]

In our approach to providing a report on the status of geothermal technology, we sought to do so using a broad sense of the term. We decided to look at what companies and developers were doing to harness the heat from the earth for our energy needs, which means focusing on more than hardware. We also approached what people were doing in essentially the order that the actions occurred for geothermal power projects currently under development.

That means we begin with trying to find and exploit heat under the ground – subsurface technology. We examine the series of steps that a geothermal project takes from exploration to resource confirmation. This was built upon interviews and site visits with companies actively developing projects today, and portrays the state of geothermal technology from their perspective. How does a geoscientist explore for geothermal energy? How does a drilling contractor penetrate the resource? These are some of the questions that this paper addresses in Part I: Subsurface Technology.

Once a resource is found and characterized, the heat from underground needs to be utilized using technology largely above the ground – surface technology. This paper examines the increasingly complex approaches companies are taking to transforming geothermal resources into useful energy and the technologies used to address potential impacts to the environment. These are the areas examined in Part II: Surface Technology.

Recognizing that technology is always changing, both Part I and Part II also give a glimpse into the ideas, activities, processes, and other technological advances that the companies and people interviewed highlighted as potentially important future opportunities to enhance geothermal energy production.

Together, Part I and Part II portray a complex mosaic of decisions and actions. The reader will find that the pathway to utilizing the heat of the earth is clearly not a straight line, but has many different branches and approaches that change as our understanding of geology changes and as geothermal technology evolves.

Acknowledgements

As this paper is intended to describe what people are currently doing to develop geothermal resources, and what they are thinking about as far as future innovations, it was necessary of course to talk to a lot of people who are actively working in the geothermal field today. I thank each of them for taking the time from their busy and demanding schedules to assist in this work.

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OVERVIEW OF SUBSURFACE TECHNOLOGY

I. Geothermal Reservoirs

In order to best describe the complicated methods and tools associated with the subsurface development of a geothermal resource, we must start with a brief explanation of the nature of geothermal reservoirs. The Encyclopedia of Physical Science and Technology[4] defines a geothermal reservoir as a, "Geometrically definable volume of permeable rock which contains a proven reserve of thermal energy, such as water or steam that can be extracted in a practical, economic way."

Despite the relative simplicity of this definition, many geoscientists agree that geothermal reservoirs are extremely complex bodies that are quite difficult to characterize, and from the point of view of the developer, quite difficult to locate. Geoscientist Albert Waibel explains that there are several different types of geothermal reservoirs. Three types found in the US are:

1. Enclosed, static trap reservoirs, similar to typical oil and gas reservoirs;
2. Stratigraphic-bound reservoirs that are trapped between layers of sedimentary rock—such reservoirs are found and utilized in the Imperial Valley of southern California; and,
3. Continuously-flowing fluid reservoirs in which fluid percolates through dynamic, permeable fault and fracture systems.

In each case you have the fundamental characteristics of trapped heat and water with enough permeability to allow them to interact and create geothermal steam or hot water system large enough to support a surface power plant. But beyond the fundamentals, the structures and operational characteristics of each of these three types are quite different.

Figure 1: Representation of geothermal reservoir

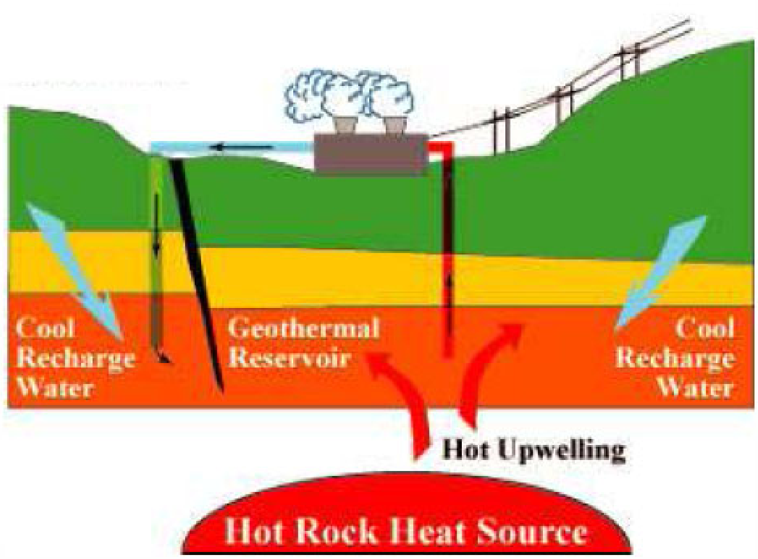


Figure 1 presents a visualization of the third type of reservoir.[5] Because readily detectable surface manifestations such as hot springs or fumaroles are often associated with these systems, this type of reservoir represents most of the geothermal resources currently being utilized for electricity production.

In this type of system, simply described, rainwater sinks into the subsurface where it percolates through faults and fractures. If the permeable rock through which the fluid flows is hot, it acts as a natural heat exchanger and the circulating fluid become hot as it contacts the rock. This hot fluid can be brought to the surface, converted to steam which is used to spin a turbine that powers an electrical generator (see Part II of this report for description of power generation process). An advantage of a reservoir through which fluid is constantly flowing is that it has the potential for sustainable production because a continual supply (which can be natural, artificial, or both) of water passes through it.

II. Overview of Subsurface Development

So, how do we find geothermal reservoirs underground and go about utilizing them for energy production?

In Part I we will describe the steps associated with the subsurface development of a geothermal resource which can be outlined simply as: 1) locate a resource, 2) drill a well that penetrates the resource, and 3) extract hot fluid from the resource which is then used to run an electrical power plant, hopefully for several decades. Of course this is an extremely simplified description of the process. Subsurface development, which includes exploration, drilling, and maintaining the utility of the reservoir, or reservoir management, are each astonishingly complicated endeavors that require the best technical expertise, the latest geoscientific tools, and millions of dollars.

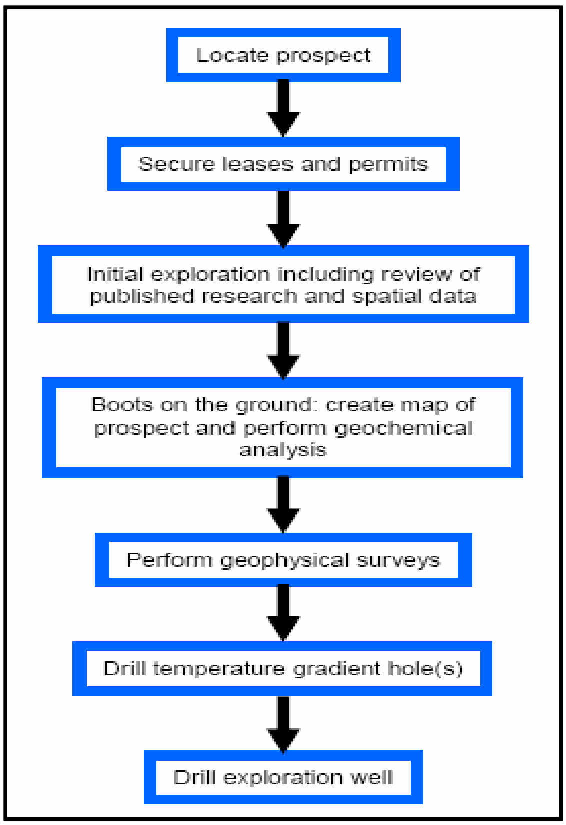
In addition to describing the tools and processes employed in the development of resources that are commercially viable at this point in time, we will also outline several emerging technologies that have the potential to greatly increase the available US resource base. Because of their potential to provide a means to significantly add to the domestic energy supply, these new technologies are hoped by many to be an answer for providing significantly amounts of clean energy in the future.

Exploration Technology

III. Exploration Overview

The first goal for developing geothermal energy is obtaining a resource that is both sufficiently hot, and flows at a rate that would make production economical. These resources are typically obtained by one of three principal approaches: (1) purchasing one already developed or under development; (2) "re-discovering" one that was explored—even drilled—in the past, but that was dropped as uneconomical in the fiscal climate of the time; and (3) finding a new one.[6] Here we will largely focus on the last two approaches which typically require some degree of exploration. The process, tools, problems, and future goals and directions of exploration will be described.

Figure 2: Basic outline of exploration process



Exploration is quite costly and is the riskiest part of geothermal development. GEA's Report, *Factors Affecting Costs of Geothermal Power Development*, breaks down exploration activities into three phases: regional reconnaissance, district exploration and prospect evaluation. For a 100MW project, this report estimated that the exploration costs would be $770,000 for regional reconnaissance, 1.5 to 3 million US$ for district exploration, and about $7.7 million for prospect evaluation.[7]

Despite potential rewards for securing and exploiting geothermal resources, the costs of doing so are great, and they might only come after several challenges. Because of these challenges, which will be discussed later in this chapter, only one in five deep geothermal-exploration wells historically have become commercially viable. This reflects the difficulty in obtaining high-resolution knowledge of the subsurface characteristics of a geothermal resource.[8] Because of this lack of characterization ability, geothermal exploration relies heavily on surface manifestations of subsurface heat such as hot springs or fumaroles. This sort of anomaly hunting approach often draws the comparison that the state of geothermal exploration is similar to that of oil and gas decades ago when exploration in that industry was based on drilling near surface oil seeps.[9] There are several apparent differences between exploration for oil and gas, and for geothermal resources:

- Geothermal exploration is largely confined to a small part of the hydrothermal resource base – the portion that exhibit surface manifestations, largely in the form of hot springs or fumaroles.[10] So, while both oil and gas and geothermal energy report similar success ratios for exploration, roughly one in five, the geothermal exploration is taking place in only the best areas for success.
- The oil and gas industries, because of the geology in which their resources are found, have developed geophysical techniques (to be described later in this chapter) that have allowed them to go beyond looking for surface oil seeps to imaging 'hidden' oil reserves. These subsurface imaging techniques are less effective in geothermal environments because of the different geologic setting in which most geothermal resources are found.[11]
- One successful geothermal well is often not enough to ensure economic production. To obtain an economical amount of heat, the geothermal resource commodity, fluid exiting a wellbore must have a temperature and flowrate at or above a given threshold. These requirements often necessitate the drilling of multiple wells, an expensive process that does not guarantee success.
- Oil and gas exploration when successful usually identifies a resource that can be quickly brought to market and sold.[12] This improves the rate of return on the investment made in exploration and reduces the time required for a payback. When an explorationist discovers a geothermal resource several uncertainties exist: (1), the price at which energy (electricity or heat) can be sold, (2) whether transmission will be available to bring energy to market, and (3) the years necessary to bring the resource into production even in the best of circumstances. As a result, compared to geothermal energy, oil and gas exploration is a considerably lower financial risk for the speculative investor.
- Proving the existence and delineating the characteristics of a geothermal reservoir can take longer and be more expensive because the geology of geothermal systems can be much more complex than most oil and gas resources.[13] Even where there are surface hot springs or fumaroles, it can take considerable work to find and characterize the complex geothermal resource. Remember, a geothermal reservoir is a network of fractured rock through which fluid percolates. So, even when exploration efforts strongly suggest the presence of a resource, fluid-containing fractures can be small - inches wide and over a mile deep. These structures can be quite difficult to hit when drilling from the surface.

In order to overcome some of the problems associated with geothermal exploration, several involved in the industry believe that the first priority should be to greatly increase the probability of drilling productive wells by more fully characterizing geothermal resources— this improved characterization will be done by developing the technology to image geothermal sources in the subsurface. In the past, the cost of exploration has proven an insurmountable obstacle for the entry of several businesses into the industry, as well as being the downfall of others. Although there is significant risk and up-front cost associated with exploration using current technology, numerous companies and government organizations are finding ways to deal with exploration challenges expanding their success in locating economic geothermal resources.

IV. Initial phases of exploration

Although each exploration project is different and carries its own set of unique features, the basic approach to exploration is the same: Begin with a broad idea of where a geothermal resource might be located and develop as detailed of a scientific model of what is going on in the subsurface that time, economics, the accuracy of the instruments used, and the skill of the scientists carrying-out the exploration will allow.[14]

According to several exploration scientists, the key to successful exploration is developing a good conceptual model of the potential geothermal resource. As in any field of science, the exploration scientist makes observations and formulates hypotheses based on those observations. In geothermal exploration, the initial hypothesis will often be that if there are geological, geochemical, and geophysical data that suggest the presence of hot water in the subsurface at an attainable depth, then at that depth there could exist an economic geothermal resource. As more and more exploration data is amassed, hypotheses may be modified or rejected; conceptual models refined or discarded; and the property further explored or dropped.[15] In an article outlining advances in geothermal exploration published this year, Monastero and Coolbaugh[16] include, "a famous 1952 quotation from Wallace Pratt," eminent geologist, scholar, and businessman, who believed that "where oil is first found, in the final analysis, is in the minds of men."[17] Several prominent exploration geologists would agree that this quotation applies not just to oil exploration, but for that of hot, flowing water.

To begin to build a model and locate a viable geothermal resource, the first thing an exploration group or company is likely to do is decide on a piece of land they believe might hold a geothermal resource. To make this decision, they look to a variety of sources that might tell them about their potential geography[18]—remote sensing data, published heatflow data, available data from wells drilled by the oil/gas and mining industries, data from the US Geological Survey containing maps, or geochemical analyses that might hold clues to geothermal activity, or known signs of geothermal activity such as hot springs or fumaroles (see Figure 3).[19]

Figure 3: Readily detectable surface manifestations: hot spring, fumarole, boiling mud pit

Although there are differences of opinion on the matter, many involved in geothermal exploration believe the necessary data for a prospect is actually quite difficult to obtain. Reasons for this might include such difficulties as: (1) data from studies done by the oil and gas industries, if not long since disposed of or hidden in scientists' garages, are often proprietary and therefore unavailable, or available for a price; (2) much data from past studies, like that for projects compiled in The Division of Oil, Gas, and Geothermal Resources (DOGGR) of the California Department of Conservation, is not digitized making it tedious and time-consuming to correlate old and current data sets; (3) many USGS reports that are available to the public do not include the raw data which is necessary for exploration scientists; and (4) no group or government agency has made an attempt to compile detailed success and failure case studies which could prove useful as a tool to better understand both the geologic setting of geothermal reservoirs and what exploration techniques work in those settings.[20]

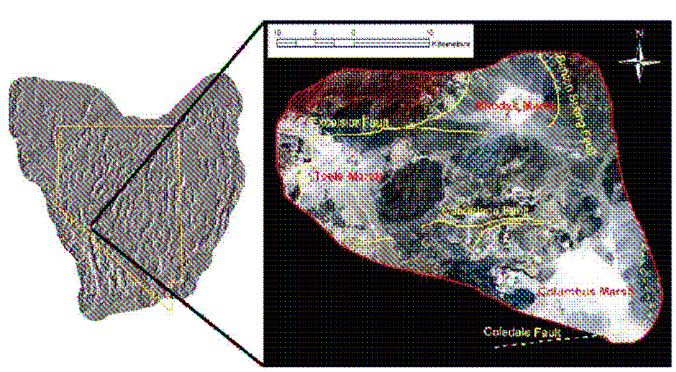
Currently, there is no centralized location for the data essential to geothermal exploration—each geologist, therefore, has his/her preferred method of locating necessary data.[21] It is the opinion of several exploration scientists that a pooling of data into a solitary location would not only help exploration scientists plan better projects and better assess a given site, but would potentially yield incredible amounts of basic scientific knowledge pertaining to the geology and the resource, something that would be invaluable to the geothermal industry.

The Great Basin Center for Geothermal Energy has made considerable progress in improving the accessibility of data sets for the Great Basin.[22] This is encouraging, but similar undertakings in other geographic locations need to occur.

Part of the initial data collection might also include less conventional surveys such as talking with ranchers or farmers who may have noticed hot water in their irrigation ditches or wells, or finding-out from local people that there might be areas of ground where snow does not accumulate or melts faster than its surroundings.[23] An example of such a survey is the Raft River site in southern Idaho which has a 30MW power plant to come online as early as October 2007. The site was initially explored because over twenty years ago the Bureau of Land Management drilled a stockwater well for a local rancher and was surprised to find that the water that came out of the hole was hot.[24]

According to many, 'hidden' geothermal reservoirs, or ones with no hot springs or fumaroles such as the Raft River prospect, are quite numerous and may actually outnumber the current known resource base.[25] Joe Moore of the Energy and Geosciences Institute at the University of Utah says that, "in Utah, there are hundreds of megawatts undiscovered."[26] Since the vast majority of clear surface manifestations (hot springs) of geothermal energy

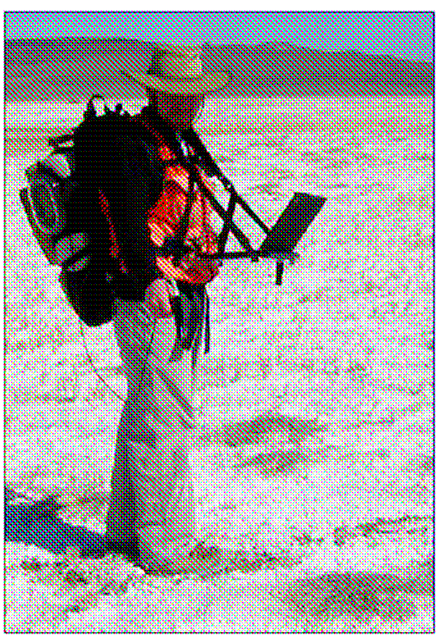
Figure 4: Satellite image of geothermal prospect



have already been found, many of these hundreds of megawatts will have to come from geothermal resources that are as yet hidden or have much more subtle surface clues (for a description of subtle indicators of subsurface heat, please see section III). Increasing numbers of such sites are being identified by less obvious surface manifestations which include altered rock, salt crusts/evaporites, tufas, travertines, sinter and opal, many of which are easily detectible over large areas with remote sensing techniques.[27] These techniques, which include airborne and satellite-based observation methods, extend what can be seen through walking the ground alone thereby revealing hidden geothermal reservoirs.[28]

Remote sensing has become an invaluable resource for exploration projects. This toolset gives the exploration scientists an excellent idea of the 'lay of the land' before ever even having a chance to walk the land and 'kick rocks.' This becomes extremely beneficial particularly with regard to land rights issues—a company can get a good idea of what a particular plot of land looks like with regard to geothermal potential, and then decide if it is worth the almost inevitable difficulties associated with obtaining land rights.[29] Satellite imagery and other remote sensing technologies, although in use for quite some time, are now able to render quite detailed images (see Figure 4).[30] Chris Kratt of the Desert Research Institute describes remote sensing technology.[31] Using sophisticated sensors designed to detect different wavelengths of light, the airborne or satellite-mounted instrument is able to differentiate between surface rock types. Kratt states:

Figure 5: Kratt using an Analytical Spectral Devices field spectrometer (ASD) to check remote sensing data results

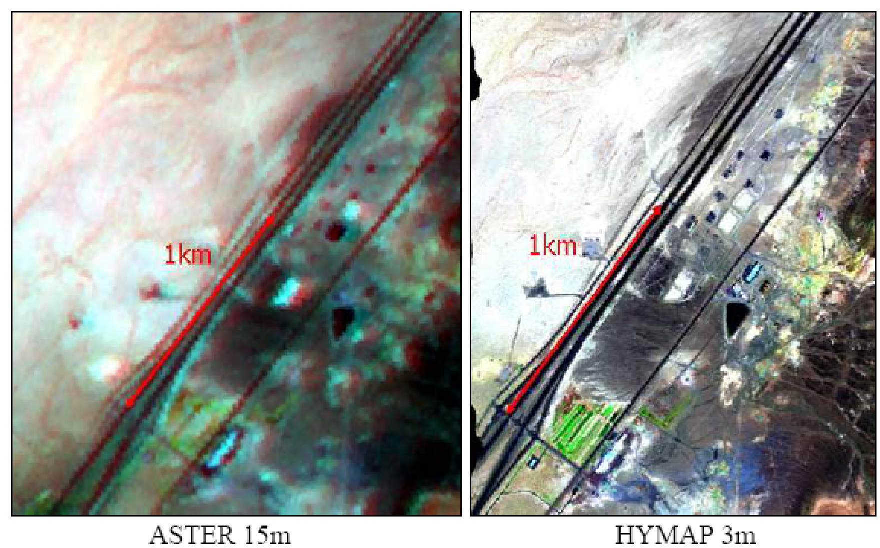


"When this type of analysis is applied to an entire image it is then possible to identify rock-forming minerals associated with geothermal activity, such as iron-oxides, borates, sulfates, carbonates, and clays. The spatial distributions of different rock/mineral classes can help elucidate the orientation of structural controls, such as faults and confining stratigraphic layers, on the pathways of geothermal fluids. These types of features are often times more apparent with a birds-eye view. Furthermore, a much greater area can be more quickly analyzed with remote sensing data than by field work. Taking advantage of wavelength regions beyond what the human eye is sensitive to also expands the scope of observation."

As remote sensing has become more sophisticated, the extent of what can be seen in an image has become greater. Kratt continues and compares satellite imagery to airborne hyperspectral surveys (see Figure 6)[32]:

"…improvements in technology have led to hyperspectral instruments that use hundreds of channels and result in detailed spectral signatures. Hyperspectral data sets with ~ 1 meter spatial resolution are most commonly acquired with airborne instruments. The tradeoffs with satellite data is that far less area is imaged for a much greater cost with hyperspectral data, but for the benefit of much greater spatial and spectral resolution. These data sets allow specific minerals to be mapped, rather than mineral groups, only. This sort of information, combined with the spatial detail, helps to build a more complete geologic story of rocks that have undergone changes by fluids at various temperatures. Minerals in these environments are often found in sequences that may indicate a central upwelling zone and where to go for field measurements. As demand for exploration increases, hyperspectral data makes it possible to target resources that are not overtly expressed with active geothermal features, such as fumaroles and hot springs."

Figure 6: Comparison of two remote sensing techniques: ASTER is a spaceborne multispectral instrument with a total of 9 channels in the 0.45-2.5 micrometer region. In contrast, HyMapTM is an airborne multispectral instrument that uses 127 contiguous channels in the same region



As more minerals and surface features are able to be specifically identified using the tools mentioned by Kratt, remote sensing technology will hopefully become increasingly useful in locating currently 'hidden' geothermal reservoirs.

Table 1: Techniques used in early stages of exploration

Data Source	**Aims and Advantages:**
Published USGS or Industry Data	• Much data published regarding downhole temperatures of thousands of wells • Locations of known hot springs or fumaroles • Existing maps of prospect • Geochemical data for prospect • Very inexpensive part of exploration process
Remote Sensing[33]	• Obtain detailed aerial views of prospect • Map surface features prior to detailed walk-over • Locate indicators of subsurface heat • Can identify various types of minerals

	• Get detailed picture of prospect without owning permits • Satellite and airborne technologies rapidly advancing
Heatflow Data[34]	• Get a good idea of how much hotter the ground is at prospect—heat is the resource, water the carrier • Much data already exists
Mapping of Surface	• Get detailed understanding of fault locations and types • Directly observe geothermal signatures such as hot springs, fumaroles, altered biological or mineralogical features
GPS Data[35]	• Determine whether broad areas of land are stretching or contracting (strain rates)—conflicting movement leads to shearing, a feature likely to create fractured rock
Geochemistry[36]	• Gain understanding of possible composition of geothermal fluid • Get idea of temperature through dissolved minerals and/or gases present in surface water or soil
Analytical Spectral Devices Field Spectrometer (ASD)[37]	• Handheld instrument that is pointed at the ground to measure solar reflected energy—signal is transmitted via a fiber-optic to backpack detectors (see Figure 5).[38] • Used to validate laboratory analysis of airborne and spaceborne measurements • Used as stand-alone exploration tool by making reconnaissance foot traverses • Spectral resolution is very good and allows rather specific mineral identification—particularly useful because many of the evaporite minerals are white and the Analytical Spectral Devices can help us differentiate the evaporites that might be geothermally related, such as borate and sulfates
Talking with locals	• Find out existing peculiarities of landscape suggesting subsurface heat

V. Geologic Study

When asked to describe the next steps in geothermal development, exploration geologist Jeff Hulen[39] states:

"The regional assessment ideally leads to selection of one or more individual prospects that appear particularly favorable for discovery of a high-quality geothermal resource. Appraisal of these prospects, the next step in the process (land-acquisition issues are dealt with elsewhere in this document), requires geoscientists on site—geologists, geophysicists, and geochemists: The first to visit is typically a geologist.

The geologist ideally is experienced in examining and evaluating not only geothermal resources but certain gold and silver deposits (which are nothing more than metalliferous, fossil geothermal systems). He or she first will complete a reconnaissance of the new prospect and immediate vicinity, looking for clues—whether obvious or subtle—to the concealed presence of a circulating hydrothermal system. Those clues might include the following: (**1**) vegetation anomalies (variously: selectively deceased, stressed, or unusually vigorous plant communities); (**2**) surficial thermal features, such as warm or hot springs, fumaroles; and "warm ground;" (**3**) active or geologically recent, warm- or hot-spring deposits, typically consisting of various combinations of silica (opal or chalcedony) and calcium carbonate (aragonite or calcite); (**4**) rocks or surficial deposits that may have been recently altered—in appearance and composition—and mineralized by chemical interaction with percolating thermal waters. Finding enough of these clues will support more detailed geologic mapping.

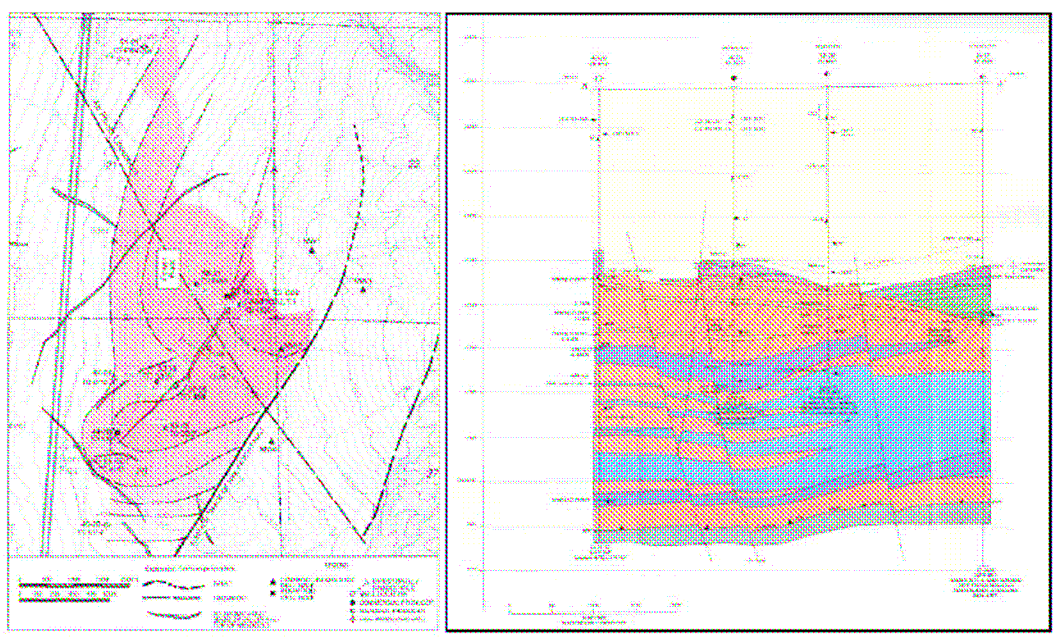
The principal objectives in detailed mapping are: (**1**) to identify and precisely diagram a prospect's salient geologic and geothermal features as exposed at the surface; (**2**) to use this work to prepare one or more three-dimensional site-specific conceptual models of the geological architecture controlling the postulated geothermal resource at depth at a given site. Perhaps the most geothermally relevant aspects of a prospect's surface geology are the styles and configurations of its faults and fracture networks. The subsurface projections and extrapolations of these features are likely to be critical parameters in a hydrothermal system's storage volumes and thermal-fluid conduits."

Figure 7: Geologic survey of land. Left, exploration geologist Jeffrey Hulen surveying geothermal prospect. Right, fault visible in surface rock.

The complexity of geothermal resources makes it necessary to create such detailed site-specific conceptual models (see Figure 8).[40] Geothermal reservoirs, as described in section I, are networks of fractured rock through which fluid flows. The role of the explorationist is to attempt to delineate the extent of the reservoir to increase the chances of drilling an exploration well that can become commercially viable. More data acquired means a better understanding of the reservoir and improved chances of successful development.

Hulen continues, “At this stage of the investigation, it is also prudent to complete geochemical analyses and evaluations of any springs or seeps discovered on the prospect. The results of such work provide insight not only into the composition of a prospective geothermal resource, but also into the actual temperature of even the most deeply concealed geothermal system. Terrestrial geothermal fluids are created by the heating of descending rain, snowmelt, or lake waters, either by a shallow, cooling, igneous intrusion or by especially rapid descent in a region of slightly elevated heat flow. The heated waters are less dense than surrounding groundwaters, and accordingly rise, sometimes issuing at the surface as springs. Semi-quantitative, chemical geothermometry of the springs is possible because at depth, the thermal waters systematically dissolve minute amounts of the rocks through which the fluids percolate. As a thermal water cools in transit to the surface, it nonetheless retains a sizable fraction of these dissolved constituents in solution. The amounts and proportions of the dissolved elements—sodium, potassium, calcium, magnesium, silicon, and others—are (in a general sense) proportional to the maximum temperature the water has experienced.”

Figure 8: Rye Patch Geothermal Prospect. Left: contour map. Right: Geological cross-section.



In addition to gaining a better idea as to possible temperature ranges of the geothermal fluid, geochemical analyses can be used to predict possible problems that might be associated with development of a particular reservoir. For example, the reservoir might be surrounded by porous rock, or contain soluble minerals that have already, or could eventually infiltrate and close-off the reservoir fractures. According to several exploration scientists, geochemical analyses rank among the most important of all exploration activities.

Geological/geochemical surveys and conceptual modeling of a given prospect facilitate the design of geophysical surveys intended to characterize the prospects subsurface in greater detail. With input from these surveys, the conceptual models are refined, and are used to guide the next stage in development, which involves costly drilling activities.

VI. Geophysical Study

Upon completing geological and geochemical analysis of the prospect, an exploration group will most often want to further enhance its site-specific conceptual model by employing a variety of geophysical techniques (Table 3).The oil/gas industry, after almost a century of exploration, has found that a geophysical technique known as 3D Seismic Tomography works almost as a panacea for locating subsurface resource. Although geothermal experts agree that there is no "magic bullet"—a technique that would enable an explorationist to peer directly into a concealed geothermal system—they also agree that geophysical means are still the best available for mapping the extent and geometry of a geothermal resource. The combination of geophysical surveying techniques actually deployed at a given site are chosen on the basis of both intrinsic and extrinsic factors[41]—the former, for example, including local geology and hydrogeochemistry; the latter encompassing such factors as time, economics, weather, and land issues. Table 2 outlines the various geophysical exploration techniques used today, and explains their basic characteristics.

Table 2: Geophysical exploration techniques[42]

Method	Characteristics:
Magnetotellurics (MT)	• Measure subsurface electricity created by naturally occurring magnetic fields (magnetic fields caused by lightning, solar winds, and ionosphere • Indirectly detects temperature and permeability patterns by imaging the resistivity pattern associated with temperature-sensitive clay alteration • Can measure tens of kilometers deep • Can be used to develop 3D images of subsurface (reliability and resolution are matters of some concern) • Very commonly used • Said to be cost-effective
Controlled Source Audio-Frequency Magnetotellurics (CSAMT)	• Similar to MT, but uses a man-made signal source • Lower cost than MT and works near power lines • Used for measurements of relatively shallow depths: 20-2000m
Time Domain Electromagnetics (TDEM)	• Electrical signal from artificial circuit placed on surface creates magnetic field—over time,

	field transmits deeper and deeper and dies-out depending on conductivity of subsurface geology • TDEM has no static distortion, unlike MT, CSAMT, E-Scan and all other techniques that use electrodes
DC Resistivity, Electrical Resistivity, Schlumberger, Vertical Sounding (VES)	• Electrical currents are sent into the subsurface creating voltages by which resistivity and its inverse, conductivity, can be measured • Resistivity depth is directly proportional to distance between surface electrodes • Resistivity methods very widely used; much data from previous studies already available
E-Scan	• E-Scan is somewhat commonly used and relatively new proprietary method of DC resistivity • Not always cost-effective, especially for large prospect areas
3D Seismic Tomography	• Seismic waves are directed into the subsurface using sources such as explosives or vibrators. Waves that are reflected off of subsurface structural features are recorded, rendering a 3D image of the subsurface. • Used very commonly in geothermal, as well as oil and gas exploration • Few well targeting success case histories are published • Among the more costly geophysical surveys
Self-Potential (SP)	• Electrodes placed in contact with surface at a number of survey stations—from these stations measurements of natural subsurface electrical potentials are taken. • Most useful when shallowest groundwater flow is of interest • Relatively inexpensive
Induced Polarization (IP)	• Direct current is run between electrodes placed in contact with the surface. When shut-off, measurements are taken of residual conductivity • IP data difficult to interpret over most geothermal fields
Aeromagnetics	• Detection instrumentation is flown over a given area in equally spaced flight lines—subsurface magnetic fields are recorded. • Detects demagnetization related to low

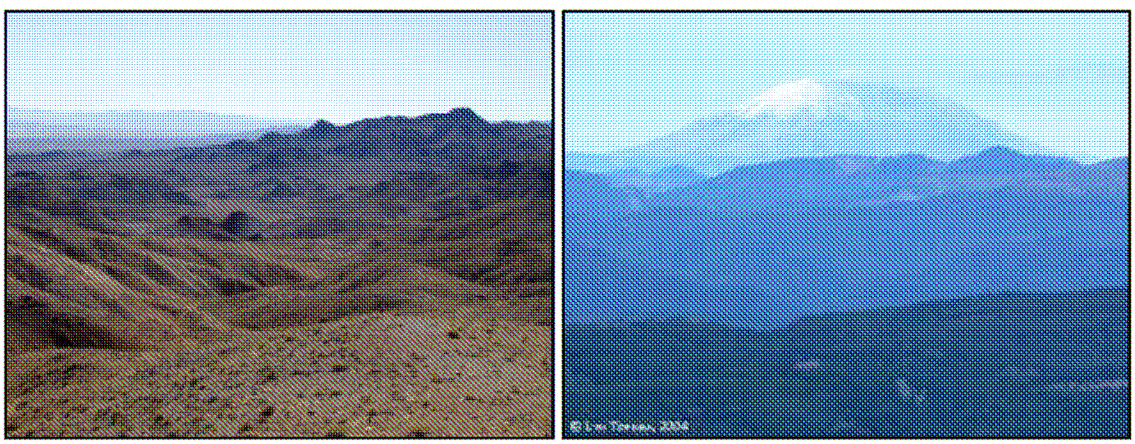
	temperature geothermal alteration • Currently some problems with noise from lava flows (when done in volcanic regions) • Data already exist and are available for much of the US • Can do without land ownership
Paleomagnetics[43]	• Small cores of rock are drilled and subjected to intensive analysis using instrumentation that measures variation (rotation) of the magnetic field as chronicled in rocks • Used to locate dilations in crust • Dilations used to predict possible geothermal resources
Synthetic Aperture Radar (InSAR)[44]	• Detection instrumentation is flown over a given area in equally spaced flight lines on two different dates—detects subsidence and inflation due to changes in reservoir (usually from pumping)—measures contraction caused by cooling of rock or volume change. • Contraction data then used to map prospect • Works well in arid regions and pine forests • Can do without land ownership
Gravity	• Gravitational field measurements are taken at several locations on prospect—varying subsurface rock types are identified based on different density profiles • Used to render structural image of subsurface landscape • Relatively inexpensive

The ways in which intrinsic and extrinsic factors influence the selection of geophysical techniques can be exemplified by the different exploration approaches required for the arid Great Basin and more humid Cascade Range (see Figure 9 for examples of each).[45] Surface exposures are excellent in the sparsely-vegetated and comparatively little-eroded Great Basin, and much can be learned about the probable nature of a concealed geothermal resource here by careful evaluation of the ground (and surface thermal phenomena). In the Cascades, by contrast, the rocks are extensively concealed, commonly deeply weathered, and often heavily vegetated. As a result, surface exploration techniques are less illuminating, and subsurface methods including TGH drilling and geophysical surveying assume much greater roles.[46]

A matter of considerable debate it the extent to which 3D seismic technique work to visualize subsurface faults and fracturing in these regions. Some experts assert that the rocks are much too broken-up for 3D seismic to be effective.[47] Since this technology bounces sound waves off the rock formations to render a picture of the subsurface, the broken rocks make for shoddy relay of the waves, and an incredibly poor picture. 3D seismic surveys work best in areas with folded and faulted stratified rock formations. In such regions, like those common to oil and gas fields as well as the known geothermal area of California's Imperial Valley, the orderly rock formations allow reportedly excellent images to be made from the transmitted sound waves.[48]

While 3D seismic has been found to be almost a panacea for oil and gas exploration, the more complex geology of geothermal systems reduces its effectiveness. With improvements it could become more useful and important in locating geothermal reservoirs, but currently it does not appear to achieve the same level of success as it does in the oil industry for geothermal exploration. Several experts agree that for geothermal resources there is no *one* technique that works best, and today geophysical exploration programs are best carried out using a combination of methods.

Figure 9: Left, scene from the Great Basin. Right, scene from The Cascades.



The geologic setting makes a significant difference for the effectiveness of different exploration techniques, and as more experience is gained in a particular geologic area the ability of explorationists to choose the right methods and apply them will grow.

An example of how this effects development is the efforts underway in the Cascade ranges of California, Oregon and Washington. As this area is predicted to contain vast geothermal resources, development plans for The Cascades are becoming an increasingly frequent topic of conversation. However, as mentioned above, since there are considerably less surface geologic clues suggesting subsurface fracturing and/or heat, explorationists rely more on geophysical and geochemical surveys. What types of surveys work best in this region is subject to considerable debate. With regard to this question and the surrounding debate, the truth is that it is not *really* known. Up to now, there have not been any projects in the Cascades taken to completion. It appears that those who have strong opinions regarding what geophysical techniques work and do not work in the Cascades have come to these opinions based on data and case studies from other locations with similar geology, such as The Philippines.

It is unlikely that there will be a consensus about what techniques work most effectively in this region until several projects are brought into production. The geologic experience gained will both help guide future efforts and improve techniques and tools. Our understanding of geothermal science and technology is being expanded as new regions are developed. The Cascades and other areas with potentially significant geothermal resources but little development -- such as the Snake River Valley of Idaho, Alaska, and others areas -- present fundamental challenges to geothermal exploration.

VII. Thermal Gradient Holes

There are several approaches that can be taken to measure subsurface temperatures, which can help define whether a prospect has the right heat conditions for a geothermal reservoir. Table 3 outlines these approaches and their relative advantages. The most important technique is the drilling of temperature gradient holes.

Before a company drills a full-scale exploration well, and sometimes before carrying-out some geophysical surveys, they will drill what are known as temperature or thermal gradient holes (TGH).[49] The purpose in drilling these boreholes is to assess whether deeper temperatures may be hot enough to support commercial production, and to delineate a thermal anomaly which may help define the extent of the resource.[50] Drilling a TGH is often a relatively straightforward and inexpensive method of obtaining a direct measurement of temperature of the subsurface rock and possible presence of geothermal fluid. The process of drilling, and the materials used, will be discussed in detail in the next chapter.

Figure 10: Air hammering technique

When an exploration team sets-out to make a TGH, they will typically do it in three stages.[51] First, they will drill shallow holes (very much like exploration holes done in the mining industry) 500-1000 feet deep. Although TGH can be considerably more expensive than geological, geochemical, and even some geophysical surveys, it is widely accepted that the boreholes can provide a wealth of subsurface information far more cost-effectively than full-scale production or injection wells. Second, the team will drill between 1000 to 4000 feet to try to penetrate the reservoir. Third, if the TGH shows good geothermal potential, the team will likely drill a production well (process to be described in the following chapter). The production well will either be drilled very close to the TGH, or the TGH itself will be drilled to a larger diameter.

For each prospect, the potential merits of drilling TGH must be weighed against risk and cost estimates of the entire exploration program. True, a TGH can be incredibly revealing in terms of presence and temperature of a geothermal reservoir. However, there are certain situations that might render a TGH an uneconomical or unbeneficial option. As mentioned throughout this chapter, mitigating or at least reducing risk and, thereby, cost are the main goals of geothermal exploration. With regard to these goals and TGH, geoscientist Mitch Stark[52] of Calpine Corporation states that, "TGHs can range in depth to from hundreds to thousands of feet, depending on geologic and hydrologic conditions. For example, in arid sedimentary environments, a program of a dozen or two TGHs to depths of about 500' can delineate the thermal anomaly at minimal cost. In volcanic settings with thick "rain curtains", TGHs may have to be drilled to depths of thousands of feet and can be quite expensive to drill safely. In some of these situations, TGHs may not even be cost-effective." Many experts will agree that despite the several advantages, for a variety of reasons, TGHs are not always a cost-effective part of an exploration program. It is important that care is taken to ensure that TGHs are informative *and* economical.

Table 3: Techniques for measuring subsurface temperature

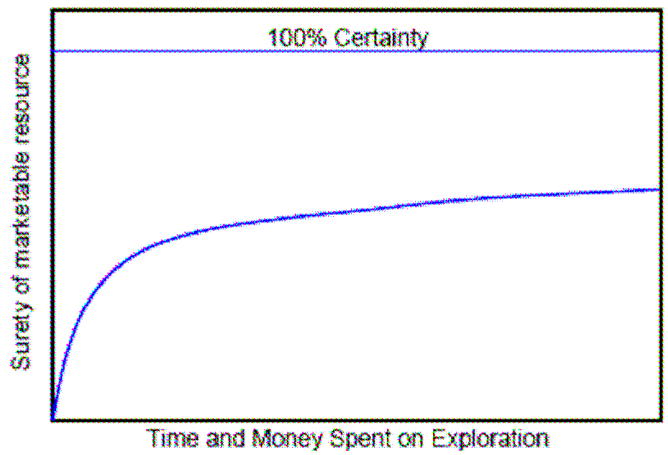
Method	How Completed and Advantages:
Auguring[53]	• Drill several shallow holes ~5-10 ft, measure temperature at each • Can give idea of heat from subsurface source spread-out at surface • Inexpensive
Air Hammering[54]	• Hollow tube hammered ~2m into ground in several locations—thermometer run down tube at each location to measure shallow heat (see Figure 10)[55] • Can give idea of heat from subsurface source spread-out at surface • Inexpensive
Slimhole (TGH)	• Drill non-production sized hole to 1000+ feet • Measure temperature gradient—observe temperature increases • Observe subsurface geology • Relatively inexpensive compared to production wells

VIII. Risk Management

Whereas the tools used on some projects are dictated by region and local geology, the tools used on others are determined by factors such as time, economics, and land issues.[56] As mentioned above, collecting known data, geologic reconnaissance and mapping, and performing geochemical assays are relatively cheap.[57] However, it is not all that uncommon for an exploration group to forego more expensive and time-consuming geophysical surveys. Basically, the exploration process is an exercise in risk management.[58] A group will want to maximize how much they know, within a certain set of limitations including finances, before putting the drill in the ground. Because there is no magic bullet in geothermal exploration, groups involved in these projects work to minimize their risk of drilling failure, given that only by drilling will they know with certainty whether they have discovered an economical geothermal resource.

There is currently significant debate in geothermal exploration as to whether it is better to gather absolutely as much information as possible before drilling, or if it might be better to accrue only the information that is predicted to be most valuable. Some exploration scientists claim that it is impossible to predict the value of information gathered, and that when faced with the prospect of spending millions or tens of millions on a full scale production well, it is an absolute that the more information accrued the better.

Figure 11: Potential cost-benefit of exploration activities. Current exploration techniques used prior to drilling are not conducive to 100% certainty of marketable resource.



Geophysicist Bill Cumming[59] describes this debate: “Even after a reservoir is fully developed, some resource risk remains. Therefore, the objective of collecting new information at the exploration stage is the management of risk using the most cost-effective means, not the elimination of risk using a magic bullet.” “A value of information analysis usually combines an economic risk analysis of the decision process with a probabilistic assessment of how much the new information is likely to affect the decision outcome. The promoters of a technology are often handicapped when making such assessments because of their inherent conflict of interest and their lack of familiarity with the full range of issues affecting the economic decision process.” Therefore, “…an objective assessment of the likely value of specific types of geoscience information in different geothermal contexts may require a cooperative effort among academic and private technology promoters, smaller geothermal developers with case history experience, and larger geothermal developers with expertise in both risk-weighted decision processes and geoscience technology.”

Until better exploration tools are developed, or methodologies established by adequate successful experience, it is likely that a complex and uncertain process of information and risk management will continue to characterize geothermal exploration.

IX. Problems with Exploration

A major issue impacting exploration is timing.[60] A lease issues in the Cascades in August leaves little time that year for any exploration: Cold-weather exploration is far more difficult than that conducted under warmer conditions[61] and is actually nearly impossible in regions with heavy snowfall. As a result, exploration groups may feel compelled either to rush, or to defer their efforts to the following year. Both of these options can result in problems. In the first case, abbreviated exploration can result in unacceptable uncertainty; in the second, time waiting can mean added costs for a project or lost revenue for developer carrying-out the exploration.

Described rather extensively in section II, another considerable problem in geothermal exploration is the difficulty in obtaining existing data for possible exploration sites. Monastero and Coolbaugh[62] provide useful websites to find information regarding rock geochemistry, downhole temperatures, seismicity, and surface geomorphics. Although advances have been made in the recent past to make such data publicly available, many involved in exploration still take issue with the unavailability and non-digitization of data. For example, there are actually copious amounts of publicly available data from the USGS or state geologist's offices. The problem, however, is that like the case of the non-digitized data in California, much of the data is rather difficult to obtain—it is often not collated, coordinated, or web-accessible.[63] An additional difficulty is faced in obtaining relevant exploration data from the oil/gas and mining industries which have drilled literally thousands of holes throughout the United States. According to some geothermal explorationists, most of these holes include measurements of downhole temperatures. This information could be of great value to those doing geothermal exploration, but are unavailable due to lack of industry cooperation.[64]

Along with those of lack of data and data sharing, a common complaint amongst exploration scientists is that several problems with geothermal exploration come because of human error.[65] There are several reasons for this. One example might be that a scientist is an expert in a particular geophysical technique and is hired to do an exploration at a site where it does not work well. The scientist is likely to accept the engagement, but will also probably use the technique that he or she knows. The resulting data might be unclear and possibly misleading. Another related possibility is that an exploration scientist or group does not put in effort, or does not know how to build a detailed scientific model of the subsurface. This could be because of a rush job, lack of training, relying too heavily on a particular kind of measurement, or any number of other reasons.

It is widely accepted in the industry that well-trained geoscientists are still the best exploration tools. In fact, a number of industry experts agree that probably the best way to facilitate the development of needed exploration technology would be to enhance graduate programs designed to train the next generation of explorationists. Such program upgrades would not only produce skilled scientists, but would likely yield new exploration technologies.

Costly, production-scale deep drilling is still the ultimate test of a geothermal prospect.[66] No matter how encouraging the results of exploration, a given prospect can still prove to be non-commercial. Our tools are imperfect, and geology can fool even the best efforts at surface characterization. For example, an impressive shallow thermal gradient might arise from an immediately underlying but comparatively tepid aquifer (beneath which cooler conditions readily could prevail). As another illustration, from geologist/geochemist Denis Norton's pioneering numerical modeling of magmatic-hydrothermal systems, we now know that a thermal "pulse" (with attendant, anomalous thermal gradient) just approaching the surface can overlie a deep heat source that already may have cooled below temperatures requisite for commercial production.[67] Moreover, as exploration geologist Fraser Goff states, there is still no reliable way to "predict permeability at depth."[68] Still, if exploration is done and the potential rewards of developing a geothermal system are deemed great enough, the developers will then take on the considerable cost and risk of deep drilling, as described in the next section.

X. Advances in Exploration

The exploration geologists interviewed for this report largely agreed that the industry still needs critical improvements in the exploration technologies already deployed, as well as the development of new search methods capable of defining a potential resource prior to production-scale drilling with far greater fidelity than currently possible. Below are outlined a number of advances that have been made and proposed ideas that will potentially bring about improved geothermal exploration tools and methodologies.

Monastero and Coolbaugh[69] state that, 'the common denominator in…these [recent] advances is their roots in the explosion in computer technology.' In recent years, enhanced computing power has allowed for greatly improved collection, management, and analysis of data. It has also allowed for more sophisticated, high-throughput geological models to be built using data from remote sensing, geochemical, and geophysical sources.

Table 4: Potential future exploration technologies

Developed Improved Technology that: **Enhances Data Management:**
•Compile known data into centralized database, including detailed case histories
•Develop better algorithm to sift existing data and data from new surveys
Improves Satellite Imaging:
•Use advanced computing power to:
•Improve image resolution
•Further develop hyperspectral imaging technology (mineral identification)
•Combine hyperspectral imaging with thermal infrared for added surface heatlflow imaging
Improves Geochemistry:
•Improve reliability and reproducibility of data from geothermometers
•Develop geothermometers that can detect new targets (i.e. soil/water gases, dissolved minerals, isotopes)
Enhances Geophysics:
•Improve resolution, reliability, and reproducibility, and decrease noise from geophysical surveys (see table ___ for list of surveys)
Develop New Technology That:
• Can identify permeability at depth
• Has the ability to identify fluids at depth

In speaking with several exploration experts, it is near consensus that the most important short-term technological advance to be made is that of a consolidation of all the current publicly available data. Coupled with the advanced computing power mentioned above, such a database and/or research center will potentially allow exploration scientists to assemble detailed models of heatflow, geochemistry, geology and other features that might indicate subsurface geothermal activity relatively inexpensively before even venturing into the field. Building such conceptual models should assist those carrying out the exploration to use more refined methodologies, and make better choices. Additionally, a database like this one might hold case histories and data such that an exploration team doing a current project can look at past projects for similarities in geology, chemistry, temperatures and any number of other data features—then look at which of these past projects were successful and how the exploration was executed. There are several existing exploration tools that could be improved, and others that are in development or are being thought about that could change the exploration approaches currently used. Table 4 is a list of categories of such tools. While it is by no means an exhaustive list, it gives a sense of the range of what is possible in the future as technology develops.

XI. What is Needed for Exploration

Commonly heard among exploration scientists is that the end goal of research to improve geothermal exploration is, above all else, simply to get a much better idea of whether and "where to put the drill."[70] Although this sounds simple, it is actually a formidable challenge.

This simple goal can be separated into more specific tasks that can be realized by the scientific advances and tools listed in Table 4**.** The first of which, and probably most important, is to define and understand the physical properties of the sought resource. There is actually substantial difference of opinion in the geothermal community as to exactly what characteristics define a geothermal resource. Although it is generally accepted that a geothermal reservoir is a subsurface network of heated, fractured rock through which fluid percolates, there are several features of these reservoirs that remain at least somewhat speculative. Some of these include: (1) the precise geologic composition and structure of the reservoir and surrounding rock, (2) the structure and appearance of the reservoir fracture network, (3) the exact size of a given reservoir, (4) the dynamics of the heat source-rock-fluid interface, and (5) in some cases, the complete geochemical composition of the fluid. Defining the resource is likely to help researchers develop specific detection tools.

The second goal is closely connected with the goals of resource characterization. Virtually all experts agree that methods need to be developed to visualize the subsurface. Included in this are ways to visualize the fracture distribution and fluids in a given region. Although the development of such a tool, or set of tools, sounds like a difficult and costly endeavor, when compared to the benefit, the cost is thought by many to be truly minimal. Several in the geothermal community believe that fully understanding the resource and having a way to visualize it in the subsurface are critical, yet currently unrealized steps in greatly increasing the reliability of explorations and uncovering thousands of geothermal resources.

Links to find out more:

General Data and Information:
http://www.unr.edu/geothermal/ExplAssessData.html
Geochemical Data:
http://www.unr.edu/geothermal/geochem.html
www.navdat.org
www.earthchem.org
Downhole Temperature Data:
www.smu.edu/geothermal/heatflow /heatflow.htm
Seismicity Data:
http://www.scec.org/
http://www.seismo.unr.edu/
Remote Sensing Data:
http://earth.google.com/
http://www.hyvista.com/

DRILLING TECHNOLOGY

XII. Drilling Overview

New Mexico's largest city, Albuquerque with a population of about 500,000, straddles the Rio Grande rift, a region favorable for geothermal resources. On the south side of Albuquerque and just south of the airport a planned commercial and residential development, Mesa Del Sol, is in the initial stages of development (see Figure 12).[71] Beneath Mesa Del Sol, an important and potentially productive deep-seated geothermal resource exists at around 13,000 ft depth in a Permian-Triassic, limestone-sandstone reservoir according to James Witcher, a geologist from Las Cruces, New Mexico.[72] Temperatures over 320^{o}F exist and the reservoir rock, an important ground water aquifer when near the surface, may be highly productive when pumped or allowed to flow. The reservoir has not been tested for flow or sustainability; but potential for binary electrical power exists given the reservoir temperature and, of course, district heating for the residential and commercial buildings in the area. However, because of the current cost of drilling, the reservoir may be too deep for economic geothermal utilization for power or heat.

Figure 12: Urban construction project under development in Mesa Del Sol, New Mexico

Even where we have good reason to believe there is a geothermal resource, a major obstacle to its development is the cost and difficulty of drilling. In this chapter, the process of geothermal drilling will be outlined as well as developments that aim to decrease overall drilling costs, thereby making utilization of geothermal reservoirs like the one outside Albuquerque economically feasible.

According to Louis Capuano, CEO of ThermaSource LLC, the drilling stage of geothermal development has three steps. The first step is planning, which includes designing and estimating the cost of the well, then using the well design information and plan to secure any necessary permits to drill. The second step requires gathering all the necessary equipment for the project. Finally, the third step is actually drilling and completing the well.[73]

Figure 13: Comparison of Oil and Gas and Geothermal Drilling

Differences Between Oil/Gas and Geothermal Drilling

- People:
  - Geothermal requires different training—crews are not interchangeable
- Drill Rigs:
  - Geothermal drilling rigs are sometimes elevated as much as 30 feet off the ground in order to accommodate additional safety equipment
- Drilling diameters:
  - Oil/Gas can extract marketable resource using relatively small diameters
  - In geothermal, economics are based on amount of heat obtained from hot water—larger diameters make for more production capacity
- Rock formations and temperatures encountered:
  - Oil/Gas wells are usually drilled through soft sedimentary rock at relatively low temperatures
  - Geothermal wells are usually drilled through hard volcanic rock at high temperatures
- Drillbits:
  - Oil/Gas uses diamond PDC bits (scraping action) and roller cone bits (crushing action)
  - Geothermal uses roller cone bits (crushing action) almost exclusively
- Exploration methods and signatures:
  - Oil/Gas uses 3D seismic reflection and looks for anticlines as indicators of resource
  - Geothermal does not have a 'magic bullet' sort of exploration tool, and looks for surface indicators of subsurface heat

XIII. Pre-Drilling Process

Finding a Contractor

In America, there are approximately 1000 drill contractors currently carrying-out projects.[74] Supply and demand would dictate that this would be a fantastic position for companies looking to complete the drilling phase of geothermal development. Such is not the case, however, because of these thousand or so drilling companies, only five to ten of them specialize in geothermal drilling or have the expertise required to do the job successfully--the rest work in the oil/gas or mining industries.[75] The rigs used in oil/gas are similar to those used in geothermal drilling, but the rig crews are not trained for geothermal drilling, which is significantly different. (See Figure 13) So despite first appearances, the market for geothermal drilling contractors is quite small.

In order to set-up a drilling contract, a geothermal company also known in this case as an operator, issues a request for proposals among the geothermal drilling firms. This proposal request lists the minimum specifications of the rig and the logistics of the project—basically what the operator is looking for to get the project done. The drillers will then respond to the request with bids for the project. Every bid will include, among other details, two costs:

1. The cost of mobilization and demobilization. This is actually a very expensive and intensive process that will be of great importance to the operator. For example, if a contractor has a rig of the right size and will be available, but the

project is in the Imperial Valley of California, and the rig is currently in southern Idaho, then the cost of transport will be high and possibly prohibitive.

2. The daily rate of the drill rig. This number is how much it costs to both rent and operate the drill rig per day.

A third cost to be considered, but is often determined by the operator, and not the drilling contractor is the 'outside daily rate.' This term refers to how much it is predicted to cost for the rentals of other equipment (see section V) and ancillary services.[76] This cost is usually quite significant. Eduardo Granados, a drilling expert with the geothermal consultancy GeothermEx explains that the daily rate of the rig is really only one of many costs to the operator in connection to the drill project. The operator may be paying $20k per day for the rig operation, but likely $40k or more in ancillary services—things like air compressors, engines, mud and mud-logging, drill bits and many more.

Beyond simply the cost of the project, the operator is interested in a number of other factors. The capacity of the rig, as mentioned above, is definitely a concern, but so is the maintenance record of the rig. Included in the maintenance are the mechanical and safety histories of the rig. The operator wants to know if the rig is reliable, and if the contractor operates in a safe manner. A red flag in either of these areas could be a significant impediment to the project and would likely pose a great cost to the operator.

Another logistical concern associated with contract acquisition is the specific requirements of the state where the drilling is to occur. Granados provides the example of California. This state has among the most stringent emissions standards, to which the rig (which is sometimes powered by a diesel generator) must comply. Nevada, on the other hand, does not have as high of emissions standards. He gave the example that an old oil rig from Texas or Oklahoma might be able to be used in Nevada, but not California. The operator must, therefore, take care to comply with all state laws and regulations.[77]

Drafting the Contract

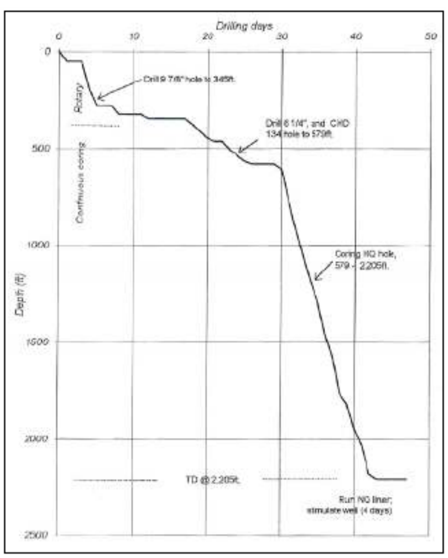
To determine the logistics and cost of the project, the contractor and operator engage in an ongoing dialogue. This is a critical step in the drilling process to ensure both the quality of the project and that both parties get a mutually acceptable price. There are myriad possibilities of things that could go wrong if extensive pre-drilling communication does not take place between the company and the drilling contractor. In order to design a proper well and drilling program, Louis Capuano, a contractor with decades of experience in geothermal drilling, asked the following list of questions of a client about a particular job:[78]

1. Nature of resource? Is it hot water, steam, or a mixture of both? This helps us determine the type of completion we may need.
2. Depth of resource? Helps us determine casing program.
3. Will the resource flow or have to be pumped? Helps us determine sizes (diameter) of upper casing for setting of large diameter pumps.

4. Temperature of resource? Helps us determine casing types and casing setting depths.
5. Formations to be encountered? Helps us determine the casing setting depths and the number of casing strings required. This also gives us some idea of penetration rates so that we can determine a drilling rate and establish a drilling curve of days vs. depth.
6. Where is the well? State requirements vary and we need to know the requirement to determine the blow out preventer needed as well as casing setting and cementing requirements. This also helps us determine availability of drilling tools and resources needed in the drilling operation.
7. Any data on the corrosiveness of the resource. This helps us determine grade and weight of casings needed.
8. Any useable water available in upper hole? These waters will have to be protected.
9. Can the well be tested? This relates to water and air quality concerns.
10. Distance from services: phone, electric, water, etc?
11. What production rate is expected from the well?

This list is aimed to help the drilling team run the project as smoothly and economically as possible. The answers to the questions help Mr. Capuano understand what his team will be drilling through, and for what—basically they want to know everything they can in order to gather the right tools for the job. Once sufficient information about the project is communicated between the drilling contractor and the operator, the contractor can create a predicted drilling curve (see Figure 14)[79] and a better price estimate. A drilling curve, according to Louis Capuano III also of ThermaSource, "is time vs. days, how long will it take and how long each section of the hole will take to drill and complete."[80]

Figure 14: Drilling Curve- Days vs. Depth



An example of a drilling curve is seen in Figure 14. With regard to price, this list of questions and general due diligence is so important because it gives the drilling contractor, in this case Mr. Capuano, a better idea of what he needs and through what he will be drilling. Equipment and conditions are likely to drastically affect the cost of his efforts, which in turn may drastically affect the cost and feasibility of the project to the client company. If, for example, a project is to take place in California's Imperial Valley where the geothermal fluid is extremely caustic, this will necessitate the use of more resistant, and more expensive materials such as titanium well-liner.[81] Of course the list of questions above is not exhaustive, and is not generalized to all types of projects; it is simply a starting point to begin communications in order to complete a drilling project smoothly. In the due diligence of all projects, details and unique features will be discussed.

Designing the Well

Once the operator and the winning contractor have finished negotiations, or at some other point, the structure of the well is designed. The drill contractor typically does not design the well. This is usually done by someone within the operating company, or by a geothermal consultant. To begin to draft the well structure, the designer will speak with exploration scientists and reservoir engineers to get a good picture of what the drill team will be working through.[82] They want all the information they can find about the field and answers to questions like the ones posed by Mr. Capuano. From this information he or she can begin to design the well. According to those involved in the design process, this information is absolutely crucial. If the well is designed on limited data that does not take into account the worst-case stress that the well might see, it could be detrimental to the success of the well. For example, a well might be drilled then lined using a simple carbon steel casing (to be described in the following section). Ed Granados relates that it is possible that the weight of the heavy cement surrounding the casing might be too much for the lighter, less pressurized geothermal fluid inside, which could crush the casing and completely ruin the well. If this possibility was better explored prior to drilling, casing, and cementing the well, there is a much greater likelihood that a more durable casing would be used, thus saving the well.[83]

The structures of and principles behind geothermal well design vary quite a great deal from those in oil and gas. In the oil and gas industries, the goal is simply to extract resource. Therefore, oil and gas drilling can be completed to great depths using very small diameter bits. This, however, is not advisable in geothermal drilling. GeothermEx advises its clients to drill as wide of a diameter hole as possible. If a team takes the normal completion diameter of 8.5” to 12” it will, at least in theory, greatly increase fluid flow and almost double the production rate.[84]

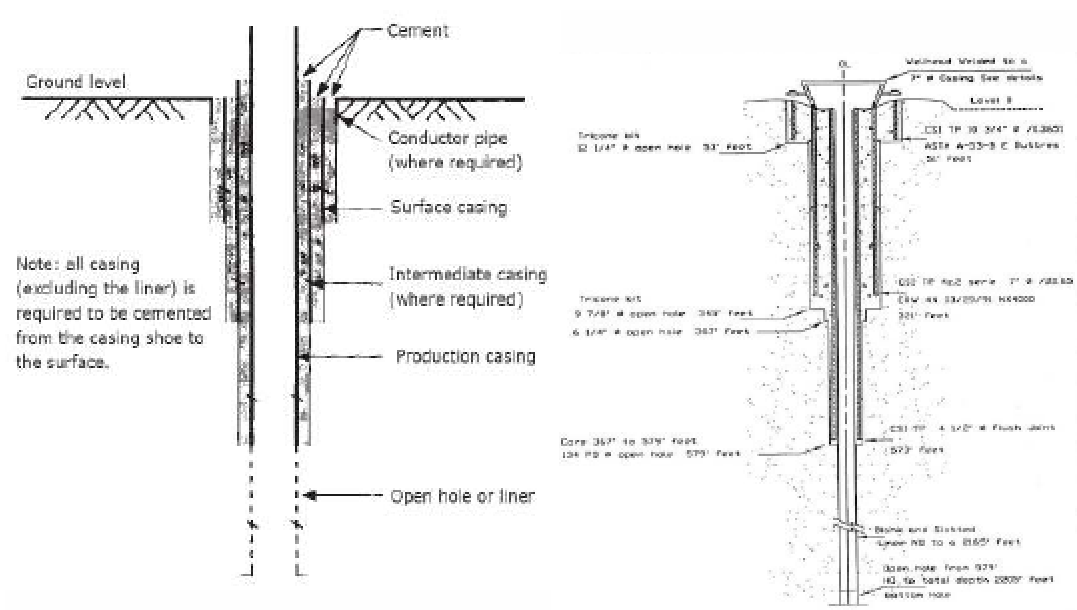
Figure 15: Drill pad with multiple wellheads

The decision for the diameter of the well is based on a number of different factors. The well-designer will gather as much information as possible from the exploration scientists to get a good idea of the subsurface geology. Additionally, the diameters will be chosen based on the capacity of the rig. Because of the excessive friction and torque at depth, deeper drilling is harder on rigs than shallow. Therefore, the diameter of the hole is limited by the size of the rig. At depth, it also must be taken into account that a hole with a larger diameter might be more prone to borehole collapse.[85] A hole with a large diameter might have to be double-cased.

A designer may design a well that does not go straight down, but curves. This is done by first drilling straight down, then doing what is called a 'kick-off' to change the direction of drilling. Such designs are often chosen if the target is not directly below the drilling rig. Directional drilling is a widely used and is an important tool for addressing specific reservoir challenges. There are multiple reasons for doing it, some of which include:[86]

- If a drill company already has a drill pad completed where other wells have been drilled, it is likely economical for the company to not spend the money to create another pad, but drill in another direction.
- If a rig is already in place, it is more economical to drill from there in a direction away from the rig rather than moving the whole rig.
- Because of environmental or other issues, the Bureau of Land Management might prohibit the placement of a rig at a certain location.
- The terrain directly over the desired target might not be suitable for placement of a drill pad.
- An operator might want to create what is called a 'multiple completion well,' which is designed to produce from two legs protruding from one original well.
- A target might not be reached. If such is the case, instead of abandoning an entire well, the well can be plugged at a certain depth, then drilled in a different direction.
- Having many wells on the same drill pad minimizes construction of pipelines that connect the wells to the power plant.[87]

Figure 16: Well design: Left, sample. Right, design for well at Blue Mountain.



In the following sections, a case study of a drilling project at Blue Mountain in Nevada will be used to illustrate aspects of the drilling process.[88] A design of the well that will be described is shown in Figure 16.[89]

Geothermal well design can be summarized as follows:[90]

1. Taking geological and reservoir engineering advice on likely subsurface conditions;
2. Determining whether the well will require directional drilling
3. Determining depths for casings and well completion;
4. Selecting casing diameters, casing type and cementing materials;
5. Selecting wellhead components;
6. Determining whether the well will flow or will need to be pumped;[91] and
7. Identifying the necessary equipment, tools, materials, and support facilities.

Gathering Equipment

A major function of the questions posed by Mr. Capuano is to help get a good idea of the equipment the drilling team will need to carry-out the project. Each drilling project will carry with it specific requirements and issues, these will in turn necessitate specific equipment. For example, to prevent borehole collapse, and for a variety of other reasons described later in this section, wellbores are lined with a protective metal casing. The type of metal used depends almost entirely on the nature of the predicted resource. If the fluid is rather mild, a simple carbon steel will do. However, in such areas as the Salton Sea in the Imperial Valley of California, as mentioned above, the fluid exiting the wellbore is extremely corrosive—here, because of its incredible resilience, titanium casing is often used.

Although the most visible part of the operation, the drill rig is only one of over 50 significant pieces of equipment that needs to be acquired.[92] Below is a list of much of the equipment needed for a drilling operation. It is not meant to be exhaustive, but illustrates the major groups of tools needed to carry out a drilling project. The acquisition of this equipment is usually not the responsibility of the drilling contractor. The drilling contractor is responsible for the rig and parts associated directly with it. It is highly unlikely to own the other large machinery involved. In most cases, a drilling contractor will be willing to secure the other needed equipment, but will do so at an additional cost to the operator. Therefore, most operators prefer to work arrangements with ancillary equipment contractors themselves.

Figure 17: Drill Rigs

Types of Equipment Used – listed below are the major types of equipment needed for geothermal drilling:

Drill Rigs

- Varying sizes and types—on the left is a large, surface-mounted rig that can drill to depths in excess of 10,000 feet.[93] On the right is a smaller, truck-mounted rig that is used for shallower drilling[94]
- Demand for drill rigs in the US right now is extremely high—waiting in line for a drill rig after choosing a site can take anywhere

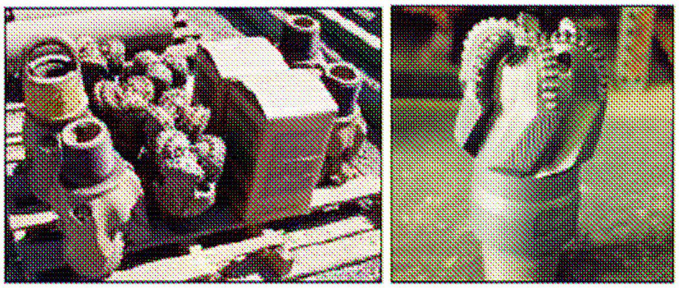
from 6-18 months[95]

- There is an effort to decrease this wait time by geothermal drilling contractors and development companies purchasing their own rigs[96]

Drill Bits[97]

- Due to the hard rock formations and heat encountered in geothermal drilling, contractors in the industry typically prefer to use rotary cone bits—these bits have three rotating knobbed (or buttoned) cones that act to grind and crush rock
- The diamond PDC bit, the mainstay of drilling for oil and gas, is not as commonly used in geothermal drilling—however, research is in process to make PDC bits a practical geothermal option
- Diamond coring bits are also used in cases where there are extended loss of circulation zones (see section VI)

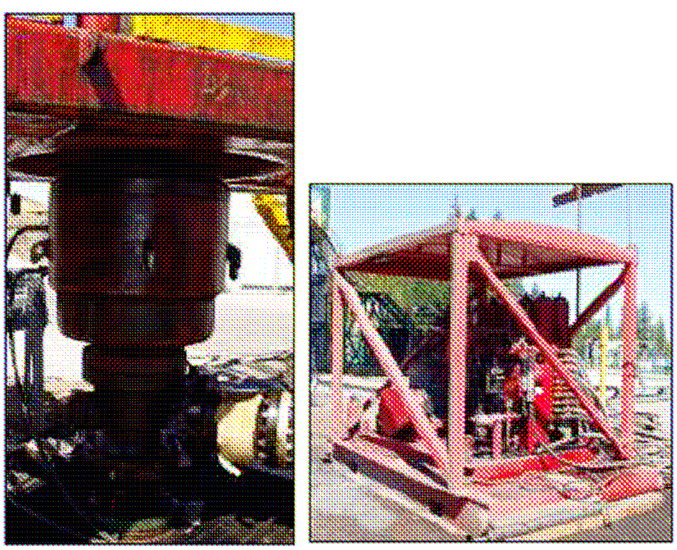
Figure 18: Drill bits: Left: rotary cone bits, Right: polycrystalline diamond compact (PDC) bit



Blowout Preventers (BOPs)[98]

- Valve used to stop uncontrolled upflow of fluid (blowout). Blowouts are safety hazards for the crew, and possibly damaging to the rig and wellbore
- There are many different types and styles of blowout preventer. Two families are:
  - Annular BOPs—these seal around either the open hole or pipe components
  - Ram BOPs—these have hydraulic rams that either pinch or shear the pipe in the event of a blowout or any case the well might need to be shut
- BOPs are manufactured and ordered by the drill contractor according to size and rating—for example, a ~900 rating can work against a high-pressure blowout at pressures up to 3000 psi

Figure 19: Blowout Preventer (BOP), and accumulator



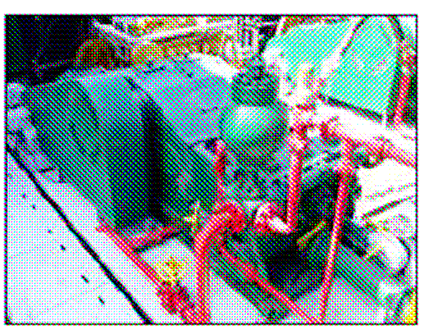
- An accumulator is a hydraulic system used to open and close the BOP equipment on the wellhead

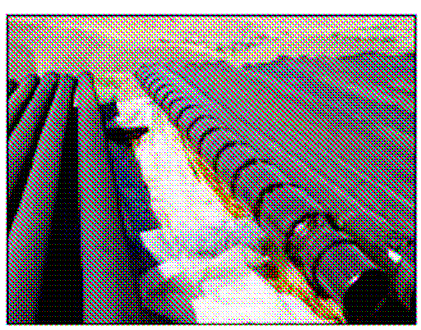
Figure 20: Casing

Casing/Tubing:

- The following is a list of reasons for inserting metal tubing or casing into a drilled wellbore:[99]
  - To prevent wellbore collapse;
  - To support drilling and permanent wellheads;
  - To contain well fluids;
  - To control contamination of subsurface aquifers;
  - To counter circulation losses during drilling; and
  - To protect the integrity of the well against corrosion, erosion or fracturing
- Casings are made of various materials to be used under conditions of varying corrosiveness. For example, carbon steel is used in less corrosive environments whereas Nickel Chrome or Titanium casings are used in under harsher conditions
- The photo on the left shows casing that has been taken out of the wellbore due to scaling, a problem discussed in section XVIII and XIX. The photo on the right shows casing being lowered into a wellbore[100]

Figure 21: Pumps



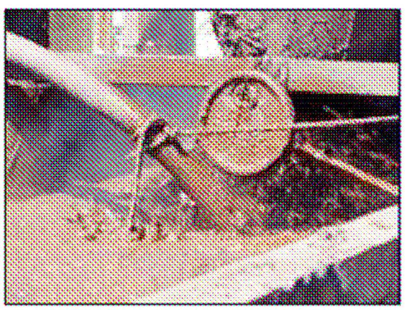


Pumps:[101]

- These photos represent two different types of pumps used. On the left is a mud pump, and on the right are several casing joints and a vertical turbine pump to be set downhole for extraction of resource. They serve very different purposes. The mud pump is used to circulate drilling muds in the wellbore during the drilling process. It is removed upon completion of the well. The vertical turbine pump is added upon completion and is used to enhance production from the well.

- The vertical turbine pump is run by a motor located on the surface and is used to pump hot brine into the heat exchanger
- Not shown is a pump that is used less often in geothermal applications, an electric submersible pump. This pump performs the same function as the vertical turbine pump, but is run by a motor located below the pump and is powered by a cable run from the surface.
- If a vertical turbine, or submersible, pump is to be installed, the drilling team must ensure that (1) the section of the wellbore where the pump will be installed is as close to vertical as possible, and (2) the diameter of the wellbore and casing is large enough to accommodate the pump.

Figure 22: Mud at surface after circulation down wellbore



Muds:[102]

- Conditioned mud is pumped down the drillstring and circulated back up the wellbore for a variety of reasons:
  - Cool drill bit/formation interface
  - Lubrication
  - Deliver rock cuttings up to surface for disposal
  - Hold back reservoir pressure
  - Support rock formations during drilling
- There are several types of mud and conditioning:
  - Aerated muds
  - Gels or gel/water combinations used in place of conventional muds
  - Muds are kept at a pH of 10 and sometimes chemicals are added to decrease corrosion of pipe and wellbore
- If there are extended loss of circulation zones, or other reasons mud cannot be used, a switch is made to air drilling where compressed air is pumped down the wellbore—this is not desired as mud drilling is cheaper and cleaner
- Photo shown is of mud that has been re-circulated out of the wellbore and contains subsurface rock cuttings

Figure 23: Air compressor

Air Compressor[103] and Other Ancillary Equipment:[104]

- Air compressors are used to:
  - Aerate mud or whatever drilling fluid is being used
  - Supply air for air drilling if it needs to be done

- Supply air to stimulate well (described in following chapter)

- Other pieces of ancillary equipment include, but are not limited to:
  - Shale shaker
  - Mud agitator
  - Mud-gas separator
  - Mud tanks
  - Water tank

Figure 24: Diesel rig engine

Engine[105]

- Engine is used to drive the rotation of the drill bit—shown is an example of a diesel engine
- Electrical generators are also used for the same purpose

People Involved in a Drilling Project

As mentioned previously, a crew knowledgeable in geothermal drilling is needed to carry-out a project. Upon completion of the well design by the drilling engineer, it is handed-over to the drilling contractor who follows it to create the specified well. Louis Capuano III of ThermaSource, describes the drilling crew:[106] "In many cases the engineer will still be involved with a drilling foreman or "company man" on location 24 hours a day, 7 days a week to verify that the hole is drilled as planned, or if not, that it is changed to be able to accomplish the same goals at the same cost, safely. The drilling rig is then staffed with a toolpusher who basically is the job supervisor who also will be on location 24 hours per day and 7 days per week. His responsibility is to keep the rig machinery running, make repairs and perform maintenance on the equipment. He also makes sure that the rig is equipped with full crews. Most rigs are equipped with 25 man crews who work 12 hour shifts. (12:00 noon to 12:00 midnight and then 12:00 midnight to 12:00 noon) These crews work 7 days straight and then are off 7 days. One rig requires a minimum of 22 men to maintain full crew (4-5 man crews and 2 toolpushers). A crew is made up of first the driller, who is the lead man of each crew. Second in control is the derrick man, he is the man who works in the derrick during trips in and out of the hole with the drill pipe. Third in control is the motorman, who is responsible for motor maintenance then 2 floormen, who work the rig floor during trips. Rig workers must work each position to work his way up to toolpusher. These men must work well together as it requires a great deal of coordination to make successful and timely execution of rig tasks."

In addition to the drilling crew, there are a number of others on site as well. These include operators of ancillary equipment sent from the respective contractors of such equipment. Additionally, each drilling project has a mud engineer, or mud logger who is employed usually by an ancillary services provider, and sometimes by the drilling contractor. The role of this individual is to collect samples from the mud that returns to the surface, recording the drilling progress, the types of rock seen, the condition and weight of the mud, and any other analysis points that the drilling foreman deems relevant.[107]

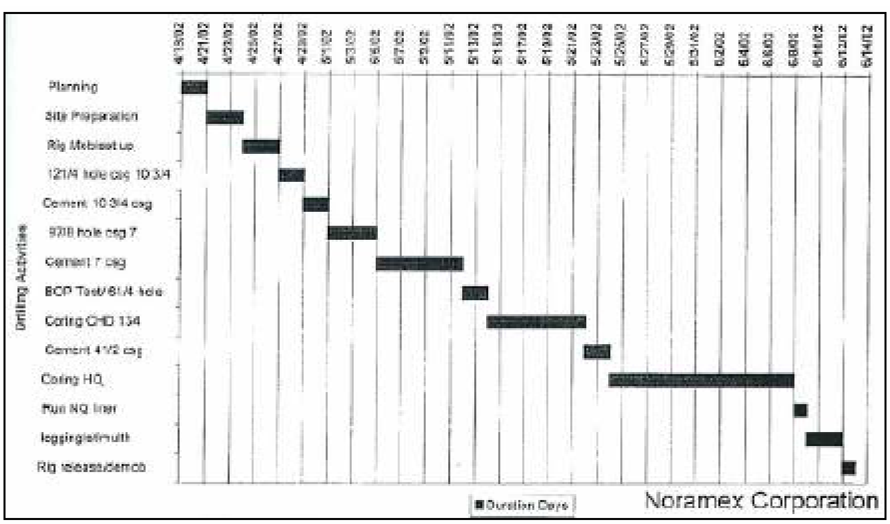
Figure 25: Mudlogger covered in his trade

At Blue Mountain, the crew consisted of two teams, each of which included a driller and two assistants. The teams worked alternating 12-hour shifts, just as described above. A mudlogger from a mud contracting company was also on site.[108]

<u>XIV. Drilling the Well</u>

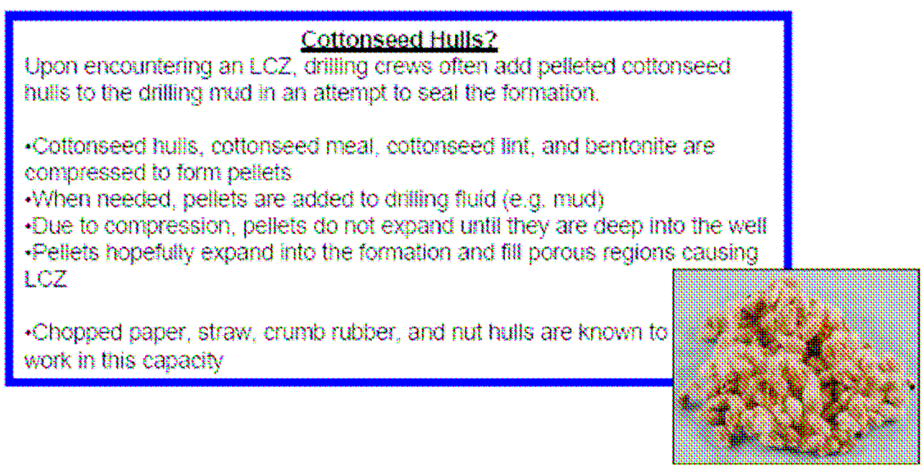
The drilling project at Blue Mountain[109] is a good example of what happens once geothermal drilling is underway. Drilling operations began there by starting, or 'spudding' the hole using a 12 ¼" rotary drill bit and mud down to a depth of 53'. Upon reaching this depth, a wiper was sent down the hole to swab the sides to ensure a clean surface of uniform diameter. This either did not work, or the effect did not last because when the team attempted to install the 10 ¾" surface casing, or conductor pipe, it got caught at ~20 feet and had to be pulled-out. The wiper was run down the hole again and

Figure 26: Chart of activity vs. days at Blue Mountain. Compare with drilling curve for same project (Figure 14)



an attempt to re-install the casing resulted once again in a hang-up. The hole was then reamed to widen its diameter and the casing was run back in, reaching the target depth of 51'. Once the surface casing was in place, the casing was reinforced with cement. In this process, known as cementing, cement is conveyed to the bottom of the well from surface pumps through the drill pipe or casing; the cement is pumped out and its dynamic properties as a fluid will cause it to run up the space between the outside of the casing and the wall of the well, referred to as the annulus. The cement at the bottom of the casing will harden, but once ready the team will simply drill through the hardened cement and onto greater depths.

Figure 27: Cottonseed hulls in geothermal drilling



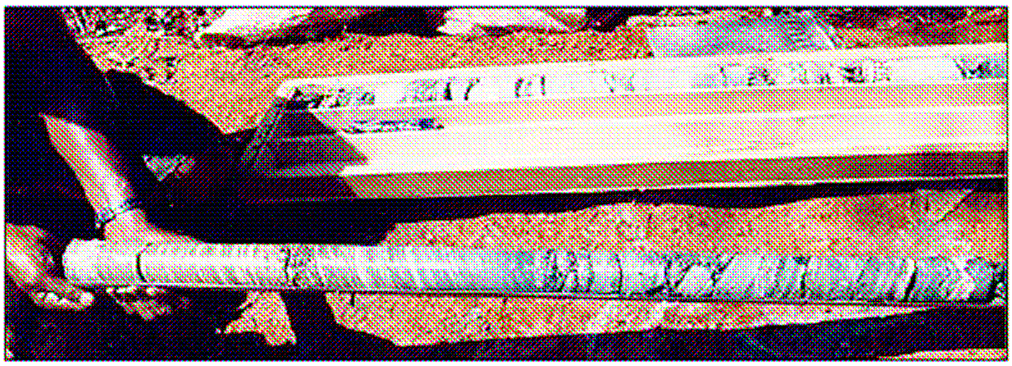
Once the team drilled through the cement, they pressed on using a 9 ¾" rotary bit but made slow progress. This progress was halted, however, when they encountered what is known as a loss of circulation zone (LCZ). In this term, circulation refers to the mud used in drilling. As described in section VIII, it must remain in constant circulation from the end of the bit back up to the surface as two of its main jobs are keeping the drill bit cool and lubricated, and expelling the drilled rock cuttings from the hole. An LCZ, which is typically caused by a fracture which may or may not contain geothermal fluid, allows the mud to disperse through the surrounding rock thus hindering the drilling process. More technically stated, an LCZ occurs when rock formation fluid pressure is less than the column pressure in the wellbore hole—the fluid therefore escapes into the rock rather than re-circulating back up the well. Since there is no fluid return to the surface in the case of an LCZ there is nothing in the wellbore keeping the walls from sloughing off rock, washing-out, or collapsing. LCZs are serious problems, and unfortunately one of the most common encountered in geothermal drilling. In an attempt fill-in the gap in the formation and work past this LCZ, the drilling team delivered cottonseed hulls[110] down the well. Circulation was gained and drilling resumed but another LCZ was encountered just three feet deeper. Compounding this problem, the team experienced problems with their mud pump. In order to try to be done with the LCZ issue, the drill team ran down more cottonseed hulls, and five cement plugs. Here, cement is pumped down with the idea that it will disperse into the formation and dry. Circulation can be regained as the cement fills the LCZ—the team can therefore bypass the LCZ by drilling directly through the cement plug. Once past this LCZ, the drill team ran down a 7" casing to the bottom of the borehole.

Figure 28: Text box on geothermal core drilling, and image showing a drilled rock core

Core Drilling

A method of drilling in which a drill bit with a hollow center is used to extract cylinders, or 'cores,' of rock as the wellbore is drilled deeper.

- Used to recover cores that are analyzed to understand subsurface geology and locate fractures
- Can be utilized in significant or complete loss of circulation zones (LCZ)
- Is more expensive and slower than traditional drilling techniques
- Core drilling done typically by PDC or natural diamond bits



At this point, the team installed at the surface three different kinds of blow-out preventers (BOPs): pipe ram, blind ram, and hydril annular preventer. Following this installation, the team continued drilling for depth, but LCZs were frequently encountered halting mud circulation and inhibiting progress almost completely. To deal with these problems, the team decided to change or 'trip' the rotary drill bit and continue the drilling using a coring bit (see Figure 28).[111] The drill team made slow but steady progress using the continuous coring method—they reached their target depth (TD) of 2205 feet. The team washed the hole with swabs, then installed a 4" liner to the bottom of the well using slotted liner in the production zone. The annular BOP was removed and a wellhead with a horizontal discharge valve installed in preparation for well-testing. The well was closed and allowed to heat for well-testing. The time from planning and rig set-up to completing the well and rig take-down was 54 days (see Figure 26).[112]

XV. Difficulties with Geothermal Drilling

By nature of the task—drilling into hot, pressurized, extremely hard volcanic rock to depths of hundreds or thousands of feet—geothermal drilling faces many obstacles. Some of these are physical impediments that make progress quite difficult. Others are issues that simply drive the cost of drilling continually upward. Both types make reaching the target depth much more difficult.

A geothermal drilling team is prepared for the innumerable problems that can and often do occur. According to one expert, geothermal drilling is an endless stream of tough decisions.[113] He offers one example: imagine a drill has made it to a substantial depth—just above the predicted reservoir. They cement the casing and proceed to drill into the proposed production zone. Here, the company man must be extremely careful as to how quickly and how far they go into this area. They are drilling into fractured rock that is under an enormous amount of pressure. They continually face the risk of the bit getting trapped or the well collapsing, causing them to lose the entire well. There are cases where the bit and the leading few joints of the string can get trapped. This occurs by a trapping event, or when too much torque is applied to the drillstring and the leading section shears or 'twists-off.' This trapped section is referred to as the 'fish,' and efforts to retrieve it, naturally, as 'fishing.'[114] If the fish is not recovered the drill team will have to either abandon the well or install a kick-off above the fish to drill in a different direction. There are several other possible problems that occur on the way to the target depth.

As encountered in the drilling case study at Blue Mountain[115], extended loss of circulation zones (LCZ) are hindrances to achieving target depth, and are incredibly costly. In such cases, the drilling team might have to change from conventional muds to more expensive core or air drilling techniques.[116] Corrosive brines, a problem mentioned in section IV, seems to be a perennial issue in the Imperial Valley which necessitates the use of more- expensive titanium casing. Environmental and other job conditions create unique conditions, many of which drive up the price, making cost a greater obstacle to reaching the target depth. Roads must be built, area cleared for a drill pad, and several other issues, many of which are costly, and increase in cost with distance to the nearest town.[117] Additionally, the great strain on equipment is sometimes too much, calling for their replacement. At Blue Mountain, for example, the mud pump broke-down, halting drilling progress for two days.[118] The cost of the repair or replacement and time lost while still paying for the rig is detrimental to a project and could possibly lead to its discontinuation.

XVI. Future Directions

> "…the greatest improvements that can be made in drilling are actually in geothermal exploration."
> - Louis Capuano, Jr., CEO ThermaSource LLC

According to Louis Capuano, the greatest improvements that can be made in drilling are actually in geothermal exploration.[119] He states that the current 20% drilling success rate is too low and can be improved only if we better know where to drill. When asked the same question, Randy Normann, an engineer at Sandia National Laboratories, seconds Capuano by saying that the way to improve geothermal drilling is to develop a better way to map the subsurface.[120]

On the whole, geothermal drilling techniques and equipment have improved greatly over the years and, according to some drilling experts, are actually quite good.[121] It is believed by many in the drilling industry that the major obstacle to depth is not the tools available, but rather the tangential costs of excessive borehole sizes, casing tonnage, and other materials. True, improved exploration would drive down the cost associated with drilling, but there also continues to be development of and need for new tools. For example, Jeffery A. Spray of Dynamic Tubulars states that "more than half the cost of a drilling project somehow goes to geologic instability, generally lost-circulation or pressure control problems."[122] Because of this, his company and others are working to reduce these non-productive costs by raising the effectiveness of construction materials. They are developing casings and liners that they claim: (1) are more resistant to corrosion, (2) able to withstand pressures in excess of 10,000 psi, (3) expand to fit the borehole, ideally eliminating the need for and, thereby, the cost of cement, and (4) substantially reduce the overall cost of exploration and drilling. Along with improvements in casing, many involved in drilling would like to see better muds, cements, and drill bits developed. Additionally, more-advanced computing power and algorithms is also high on the wish list of those involved in geothermal drilling.

Up to now, most of the technology for geothermal drilling has been borrowed from the oil and gas, and mining industries.[123] The drilling in those businesses is most often done in soft, sedimentary rock that lacks significant heat. The development of high temperature equipment specific to the geothermal industry would likely have significant, visible effects. The geothermal program at Sandia National Laboratories, among other research and commercial institutions, is working to develop high temperature equipment.

In geothermal drilling, a problem often encountered at depth is vibration in the drillstring.[124] This vibration is amplified at the end of the string, causing the bit to bounce off the rock. In a paper published this year from the laboratory of Dr. David Raymond, the authors state that, "In harder formations, these vibrations can cause cutter damage and even complete failure of the bit cutting structure."[125] Raymond and his associates are working to mitigate this problem by developing dampers for the drillstring. These dampers will help the bit to stay in contact with the rock, thus increasing the bit performance and progress made. Such a suspension system appears to show promise in allowing the geothermal industry to use diamond, or PDC, drill bits. These bits are currently the gold standard of the oil and gas industry, but up to now have proven largely unsuccessful in the hard rock typically drilled in the geothermal industry. Researchers at Sandia are also working on this problem, developing PDC bits that are effective in geothermal drilling environments.[126]

As improvements continue to be made in the tools available, it should allow geothermal drilling to be done more economically and at greater depths, both with the goal of reducing the risk of drilling and extending geothermal development capabilities.

Information on Geothermal Drilling:

Equipment:
www.airdrilling.com
www.thermasource.com
www.torquato.com

Some current geothermal drilling projects:
www.thermasource.com
www.geo-energy.org
www.enex.is

General Drilling Information:
http://www.glossary.oilfield.slb.com/

RESERVOIR MANAGEMENT

XVII. Reservoir Management Overview

Upon completion of a well, the obvious goal is to connect it to a power plant to begin electricity production. But before production begins, a company typically develops a reservoir management strategy. Before this can be done, and as an ongoing effort once production has begun, the developing company will attempt to establish as best they can the production potential of the particular well and the reservoir as a whole, including optimization of the cooled geothermal fluid reinjection strategy.

Susan Petty of Black Mountain Technology sets-forth five goals of reservoir management/engineering:[127]

1. Maintain the temperature of the production fluid
2. Optimize heat mining
3. Maintain production rate
4. Prevent/Reduce fluid loss
5. Reduce risk of seismic activity

Figure 29: Well logging trucks taking measurements at newly completed well

When an injection plan that meets these goals is established, the geothermal company has the potential to economically and sustainably produce from the reservoir for a very long time.

Industry experts reiterate that geothermal reservoirs should not be thought of as static pools of subsurface fluid, but ever evolving zones of fractured rock through which fluid flows. Reservoir management is a process that continues for the duration of the reservoir life and, and as will be explained later in this chapter, gets better with production from the reservoir over time. Often a geothermal company will have their own in-house reservoir engineer, or team of engineers. It is almost as common, however, for a company to hire independent consultants to assist them with their reservoir management needs.

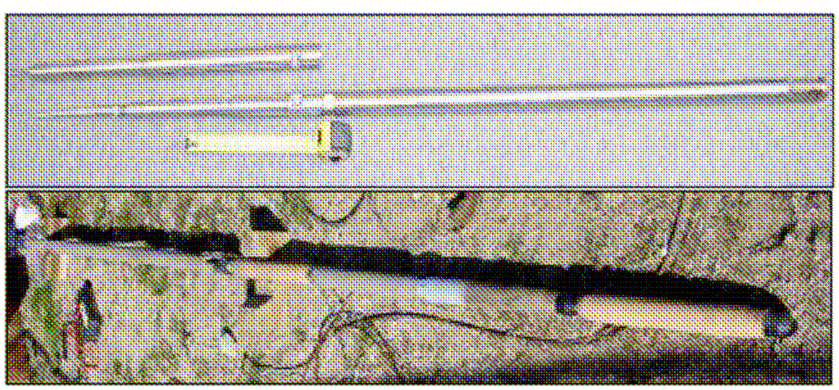
John Pritchett of SAIC relates that reservoir engineers are hired to perform basically two functions.[128] First, they are contracted to work on older, already existing fields. In such reservoirs, they devise methods of remediating problems through building conceptual models and computer simulations of what is occurring in the geothermal system. Second, in a new field, the engineer works to predict how long the reservoir will last, and forecast problems that might occur with time as the reservoir evolves.

In this chapter, the process of reservoir engineering will be described, paying special attention to characterizing the reservoir, developing reservoir models, developing production strategies, and problems associated with reservoir management.

XVIII. Well Characterization

Beyond the data acquired during the exploration and drilling stages of development, the first step in understanding the geothermal resource, as described by a number of reservoir engineers, is reservoir characterization.[129] Data for this characterization is initially gathered upon completion of each well and is most often carried-out by an independent well-logging and characterization contractor. The well-logging company sets-up equipment at the newly completed well and runs measurement tools down the hole taking a variety of readings (see Figures 29 and 30).[130] According to several experts interviewed for this report, the most important of these measurements is the temperature and pressure of the fluid exiting each well.[131]

Figure 30: Well logging instruments: On top, a common well logging tool using two different cable attachments, wireline and tubing. The lower tool is a common well logging tool with experimental protective coating. These tools are using high temperature electronics and can operate without a Dewar flask at 500F.



The goal of the data gathered in this stage, unlike the data previously recorded, is to obtain measurements yielding information that pertains directly to the production potential of the reservoir.

At the Blue Mountain site in Nevada, the well-logging company took readings of the down-hole temperature, pressure, and gamma ray emission.[132] Even though not all possible measurements were taken at Blue Mountain, there are several tests that can be done, with a specific tool for each test, to characterize each well and the entire reservoir. Some of these tests are listed in Table 5. Along with understanding the immediate production potential of the reservoir, characterization tests are designed to provide information regarding the evolution of the resource.

A priority of the reservoir engineer is to understand how the reservoir is likely to change over time with particular attention given to the likelihood of reservoir decay.[133] Additionally, when characterizing a well drilled in an already existing field, the reservoir engineer is extremely interested in whether the production from the new well is robbing pressure from the existing wells. This can help the reservoir engineer get an idea of the connectivity or "communication" that exists between wells in the reservoir. It is also crucial for the reservoir engineer to understand not only if production from one well is robbing pressure from other wells, but by how much it is taxing the reservoir water supply. Reservoir pressure decline is known as pressure draw-down. As decreased reservoir pressure means decreased output and electricity production, understanding this feature is necessary to the long term utilization of the resource. Following downhole measurements, the crew at Blue Mountain ran a drill bit, soap and water down the well to wash out the drilling muds. The team then looked closer at the production potential of the well by inducing fluid flow from the well and measuring the flow rate upon exit.[134]

The induction of fluid flow from geothermal wells can be accomplished through several means; probably the most widely used of these is the airlift method.[135] Here, a technician

Figure 31: Technician inducing well flow using airlift method

pumps compressed air down the well forcing the water level in the well to drop (see Figure 31). He halts the flow of air, thereby allowing the water level to rise. Because of the sudden drop in pressure, the fluid rises quickly and 'flashes' to the steam state. If the induction is successful the fluid will continue to flow and produce steam whose rate is then measured.

The result of the flow test is extremely important. All production wells have minimum flow requirements. If a flow tests finds a well to produce under this minimum, the utilization of the well is likely not economical. The company then has the options of stimulating the well, drilling deeper, drilling in another direction, plugging and abandoning the well, or using it as an injection well.[136]

Table 5: Well characterization techniques[137]

Test	Purpose
Heat-Up	• To measure natural state temperature of reservoir • Upon completion of wellbore, allow a few days for well to stabilize, then run temperature tool down well—repeat on 2-3 more separate dates
Flow	• To measure flow-rate out of production well upon stimulation
Draw-Down	• To measure changes in reservoir fluid level and pressure upon production • Extremely important data point for reservoir mangers—if reservoir pressure decreases, output from production wells decreases also
Reservoir Recovery	• After fluid flows out of reservoir, measure how much time is required for reservoir fluid to restore to full pressure
Fluid Chemistry	• To understand mineral composition of geothermal fluid • Could give idea of problems that might arise later such as scaling or mineral deposits closing reservoir fractures
Spinner	• Subsurface measure of fluid flowrate • Tool is placed in borehole which has a fan-like attachment, or 'spinner' • Spinner can also measure changes in flow direction which can occur at different locations along wellbore
Spectral Gamma Emission	• Assay of gamma rays emitted from wellbore rock • Certain types of rocks emit gamma rays • Data used to better understand subsurface geology
Acoustic Borehole Televiewer	• Reflects sound waves off borehole wall and measures amplitude and travel time, thereby creating acoustic image of well • Fractures located by discontinuities in acoustic reflection • Creates high resolution image • Fracture location, aperture, and orientation can be determined
Optical Borehole Televiewer	• Instrument that takes actual video or still photos of subsurface rock • Useful in locating subsurface fractures • Useful in examining tubulars for leaks and weak areas

	• Lens known to be vulnerable to damage by varying fluid temperatures
Downhole Tilt	• Use tiltmeter to measure angle with respect to surface at given locations along wellbore • Can render picture of wellbore path
Caliper	• Used to measure thickness of wellbore at given locations • Sensitive tool has several flexible appendages that run along wellbore walls continually measuring diameter

Well Stimulation

It is important to note that the term 'stimulation' is sometimes cause for confusion—it is often used to describe two separate actions. One of these is the induction of fluid flow mentioned in the preceding paragraph; a process carried-out upon completion of a new well or for resuming flow following a routine shut-off. For the purposes of this paper it will be termed 'induction,' or 'induction of fluid flow.' The other is whatever a company might do in order to increase the fluid flow of a well. Here, a developer often seeks to change the structure of the subsurface rock immediately surrounding, or in the region of the wellbore in an effort to increase the overall flowrate of the well, and or the reservoir at large.[138] If used more broadly, it could even be argued that injection of fluids back into the subsurface is a form of stimulation.[139] For example, injection of fluids into the subsurface at The Geysers in California is sufficient to increase steam production from the field.

This type of stimulation is used quite frequently to increase production from newly drilled wells, and is expected to allow the creation of artificial geothermal reservoirs known as Enhanced Geothermal Systems (EGS) which will be described in the following chapter of this report. If flow induction of a well drilled into a conventional geothermal reservoir is, as stated by Roy Mink of US Geothermal, 'not quite up to expectations,' a developer will often opt to stimulate the well. This is done largely due to the fact that stimulation is almost always less expensive and difficult than resuming drilling operations. Since the process of well stimulation is said to be virtually identical between the hydrocarbon and geothermal industries, geothermal developers most often hire well stimulation contractors from the oil and gas industries.[140]

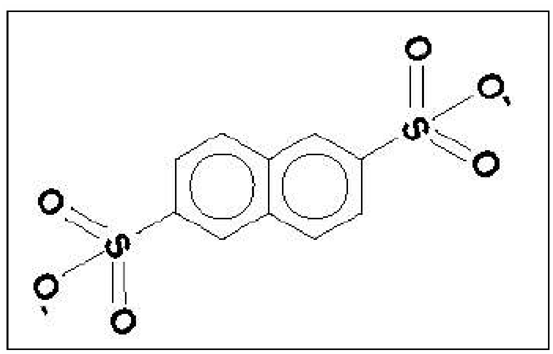
Broadly stated, stimulation protocols are usually carried out by chemical methods, mechanical methods, or a combination of the two.[141] Each method is intended to dilate existing fractures, displace existing joints, or create entirely new fractures.[142] Using the chemical method, a well stimulation contractor injects a caustic chemical solution into the well that is designed to dissolve the rock of the fractures surrounding the wellbore thereby dilating them as the fluid percolates through. This method is known to be especially effective in soluble rock types such as calcium carbonate.[143] Chemical stimulation solutions are usually acidic and are sometimes used in lower concentrations during the wellbore cleaning process. Mechanical approaches are carried out by using surficial pumps to inject large amounts of highly pressurized water into the wellbore. The pressurized water forces its way into the surrounding rock enlarging existing fractures and-or creating new ones. When used in combination, the highly pressurized fluid often contains an additional solvent intended to multiply the effects of hydraulic fracturing. In order to prevent dilated or new fractures from closing, proppants are most often incorporated into the injected fluid. Refined sand, as well as glass, silica, or ceramic beads are often employed as proppants as they readily fill-in fractures, yet still allow fluid to pass through.[144]

Tracers[145]

A tracer is a substance that is introduced into an injection well and tracked exiting other wells in the field. Its purpose is to measure the connectivity between the wells and to determine the reservoir fluid volume. These data are widely accepted as critical to economical production from the field. If a fluid that is cooled in the power plant, then injected back into the reservoir to be heated does not stay in the reservoir long enough reheat, then energy production from the reservoir will cease. Tracers, along with the useful information gained, are advantageous because they are believed to be stable and relatively inexpensive.

As mentioned above, a tracer test is conducted by injecting a known amount of the tracer into an injection well (usually 100kg or less), followed by monitoring its recovery from surrounding wells. The data can be misleading, however, since lack of tracer return does not necessarily indicate a lack of connectivity, since the tracer may be lost through thermal degradation or adsorption onto reservoir rock. For this reason, laboratory studies under controlled conditions that simulate a geothermal reservoir are required in order to confirm that the tracer of choice will behave conservatively and follow the path of the injected fluids.

Figure 32: Diagram of a Naphthalene Sulfonate, a family of molecules used as tracers



According to Dr. Peter Rose of the Energy and Geoscience Institute at the University of Utah, the uv-fluorescent polyaromatic sulfonates have proven to be excellent tracers in high temperature geothermal reservoirs because they are (1) environmentally benign, (2) readily detectable by fluorescence spectroscopy, (3) affordable, and (4) thermally stable. Rose and his group at EGI have recently studied eight of the naphthalene sulfonates (see the structure of one of these compounds in Figure 31)[146] in the laboratory and have found them to be suitable for use as conservative tracers in geothermal reservoirs as hot as 340°C. Numerous field tests in geothermal reservoirs with temperatures up to 320°C further confirm the long-term stability of these chemicals.

Other tracers currently being studied and used are aliphatic alcohols, and various freons. These molecules, although more difficult to work with, are useful as they are able to flash to and travel with the steam phase of the geothermal fluid. This is particularly useful in tracking the resource of such fields as the steam-only reserve at The Geysers in California.

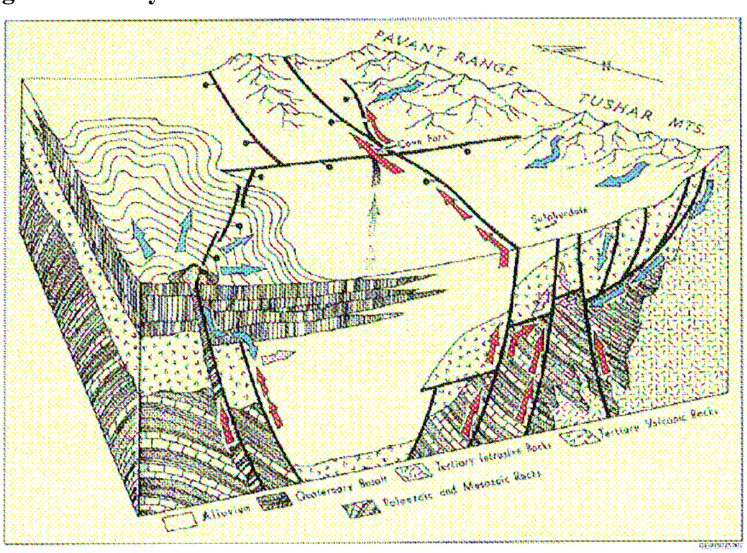
Whereas the information gathered currently by utilization of tracers is quite useful, there is much speculation and anticipation for the future of tracer technology. According to Rose and other scientists interested in tracer development, the holy grail of tracer technology is to develop a tracer that can be used to measure the surface area and thus heat exchange capacity of the rock encountered. Of course there are and will be other issues, but a tracer developed to take such a measurement will likely be what is referred to as a 'reactive tracer.' These tracers, in theory, will react with subsurface rock or decompose in such a way that should yield relevant information. Additionally, there is much talk and wide-eyed speculation that nanotechnology will be utilized in tracer measurements.[147] Much information can potentially be garnered from nanoparticles, but they are larger than small chemical compounds, which raises the concern that they will be trapped in very narrow fractures thus skewing the data.

XIX. Reservoir Modeling

One of the most important tasks of the reservoir engineer is to use the acquired data to create a working model of the geothermal reservoir. These models help the engineer achieve the purposes for which he or she was hired, as outlined in the introduction. On a broader scale, models of the reservoir serve several functions, some of which might include:[148]

- Predicting reservoir requirements
- Predicting how long the reservoir will last
- Facilitate design of a development scheme
- Facilitate identification of characteristics that cause changes in the reservoir

Figure 33: Conceptual model of Cove Fort/Sulphurdale, Utah geothermal system



One result of the assimilation of the acquired data is the creation of a conceptual model of the reservoir. Such a model is intended to combine all the acquired field and well data into a simple graphical representation. Creation and study of a good conceptual model can provide insight into the characteristics and possible behavior of a particular geothermal system. An example of one such model can be seen in Figure 33 for the Cove

Fort/Sulphurdale, Utah geothermal system.[149]

In connection with the last function listed, in a presentation given by Karsten Pruess of Lawrence Berkeley Laboratories, he stated that it is the goal that once these characteristics are identified, a plan can be made and action taken to amplify changes that are beneficial to the longevity and production of the reservoir, or diminish changes that are detrimental.[150] One such detriment is scaling. This occurs when minerals drop out of the fluid solution and build up on the well casing or in the fracture itself. Scaling can be a huge problem as it can decrease or completely halt production from a well.[151] If from well characterization or modeling activities scaling is predicted to be a likely problem, the developer will most likely take action to prevent it. For example, calcite precipitation is a common scaling problem. However, this issue is often pre-empted when a company runs a capillary tube down a well, below the flashpoint ("flashpoint" is the point at which the temperature and pressure in the well bore allow liquid water to turn into (literally "flash") liquid vapor (steam)), so that it comes in direct contact with the fluid, and injects a chemical that acts as a scaling inhibitor.[152] Table 2 lists changes that hinder reservoir longevity and production, and is adapted from a list by A. J. Mansure, a researcher at Sandia National Laboratories:[153]

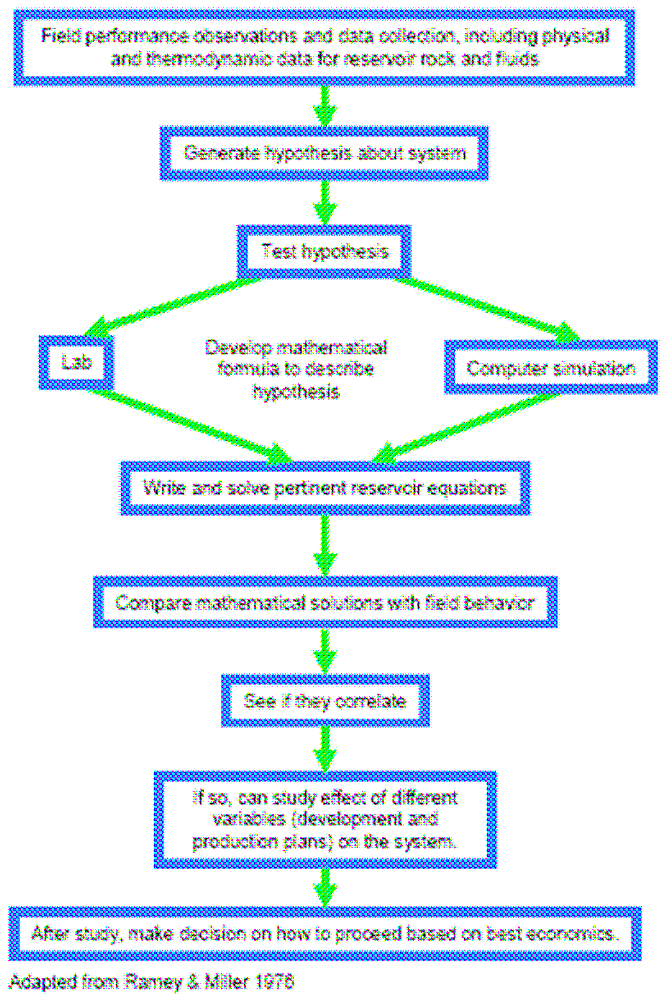
Table 6: Common reservoir problems

Problem	Description
Reservoir Volumetric Changes (pressure Draw-Down)	• Decreased fluid in reservoir often caused by production beyond capacity • Causes decrease in pressure and flowrate of production fluid • Counteracted by reinjection of fluid into the reservoir • Draw-down can cause scaling
Thermal Decline	• Decrease in temperature of production fluid • Can be caused by injection well placement too close to production well
Thermal Profile	• Shows best reservoir zone(s) for production
Productivity Index Decline	• When reservoir becomes less able to move fluids to wellbore • Can occur for a variety of reasons
Short Circuiting	• Direct connection between injector and producer—leads to decreased fluid residence time in subsurface and cooling of rock fracture (fluid path). • Both cause decrease in temperature and, thereby, electricity production
Fluid Quality	• Fluid might have elevated level of minerals that could lead to back-up of injection well, corrosion of power plant equipment and pipes, etc.

Scaling	• When dissolved minerals precipitate out of fluid and deposit on wellbore casing, on rock formation, or anywhere else fluid might contact • Can greatly diminish or even halt production from a given well or formation

Figure 34 outlines the basic process of model creation and reservoir management. The process described is from a paper by Ramey and Miller from 1976, but the ideas thereon are still applicable.[154] Before discussing the process of reservoir modeling in any detail, it must be noted that according to many reservoir engineers, the most useful reservoir models are made for already existing fields. The reason for this is that for older fields there are copious amounts of empirical data that has been collected over the years regarding the temperatures, flow rates, and pressures in the reservoir. From this data the reservoir engineer can see how the reservoir has changed over time, and how it is likely to change in the future.[155] He or she can then build a model from which meaningful, logical decisions can be made.

Figure 34: Basic process of model creation and reservoir management



It must be noted, however, that although good predictions can be made using a well-designed model, they remain predictions—for whatever reason the dynamic geothermal field could change in a manner not accounted for by the model. In a new field, not a lot is known about the reservoir and how it will change with time. Therefore, from exploration and well characterization data, predictions can be made regarding the evolution of the reservoir, but not with near the same accuracy as can be made with the data from an existing field. In reservoir engineering and management, there is no substitute for accurate and thorough data collection.[156] Because of this initial lack of data, reservoir engineer John

Pritchett of SAIC suggests that with new fields the developer really should just hook it up to the grid and produce from the field, then after a given period do the extensive data analysis and modeling. It is also reported that the application of simple statistical techniques to initial well characterization can serve well as 'first guess' approach to assessing production potential.

To begin to build a model, the reservoir engineer gathers absolutely as much relevant data as he or she can about the reservoir. Below are data that a reservoir engineer might deem relevant and is adapted from a list by John Pritchett:[157]

- Drilling Information
- Temperature history
- Geological information
- Results of well characterization tests, especially temperature/pressure spinner tests
- Map of reservoir
- Production history, or if it is a green-field, the natural state of the field
- Neighboring activities—example: several companies each produce from the same field at the Geysers in California. The production of one company operation could seriously affect the production of a neighboring company.

As seen on the flowchart above, the reservoir engineer uses the compiled data to write descriptive algorithms and computer simulations to understand past behavior and predict future changes. Some of the most widely used reservoir modeling programs are TOUGH2 by Karsten Pruess, STAR by John Pritchett, and TETRAD which is a simulator that started in the oil industry and has since been modified by geothermal reservoir engineers.[158] The computer simulations are then sometimes verified or calibrated by empirical tests. Although up for some debate, tracer tests are a good way to calibrate a simulated reservoir model.[159] They are a means to verifying that what the model predicts is actually occurring in the reservoir. When asked, Pritchett stated that he uses tracers in his work about a third of the time. He also states, however, that the reasons for this are not that tracer tests are necessarily unreliable, but that the tests were either not carried out at all, or were done in a manner that produced meaningful or relevant results.[160] Pertaining to Pritchett's concern of possibly irrelevant results, a more general counter argument for the use of tracers to verify a reservoir model is that reservoirs are dynamic, changing bodies, which makes tracer data sometimes difficult or too subjective to accurately interpret. This reservoir feature also makes tracer tests less predictive than many engineers would like them to be.

Once a computer simulation is created it is used to make predictions about how the reservoir is expected evolve over time and under different conditions. Variables can be added to the program that will allow the engineers to predict what would happen if, say, production from one well were shut-off. Would the pressure at the other wells ramp-up in order to compensate for the loss? What long-term effects would this have on the field? From thought experiments and questions like these, using the quantitative computer model, the reservoir engineers can begin to meaningfully organize and manage the reservoir.

XX. Development Strategy

Most reservoir engineers will attest that one of the main goals behind model creation is to estimate sustainable reservoir capacity.[161] This estimation can then be used to develop a strategy to manage the reservoir in such a way that it is producing as closely to that capacity as possible, but without depleting or damaging the field. Management activities might include increasing or decreasing production at certain wells, drilling new production wells, drilling injection wells, knowing whether pumps will be needed for these wells, and maintenance procedures such as well workovers for more efficient production. It is understood by many in the industry that knowing where to place new wells is, even with the best reservoir engineering people and technology available, somewhat of a gamble. When drilling in an existing field, the rate of success at drilling a productive well greatly increases, but that does not mean that the newly productive well will be beneficial to the overall production and longevity of the field. This is, however, a risk that geothermal companies are almost always willing to take.[162] Recently, a reservoir engineer in the oil industry, Marco Thiele of Streamsim Technologies, Inc., stated that although it is difficult to say exactly where to drill new production wells, a great use of reservoir engineering and modeling is to say where *not* to drill.[163] This elimination places development teams at points in the field where they are more likely to drill productive wells.

Figure 35: Technicians installing a vertical turbine pump—for a description of the pump, see the chapter entitled *Drilling Technologies*

Another important consideration for reservoir managers with respect to well placement is the location of the injection well(s).[164] Injection well placement is complicated by two issues. First, if the injection well is placed too close to the production wells, the residence time of the injected fluid will be too low, causing the fluid to not re-heat properly resulting in a fluid temperature reduction. Second, if the well is drilled too far away from the production wells, the connectivity of the wells is decreased which will often lead to decreased pressure of the fluid exiting the production well. It is reported that in addition to being a critical problem for the geothermal industry reservoir engineers, well patterns are also one of the most crucial issues facing reservoir engineers of the oil and gas industries.[165]

Reservoir Operations

As reservoirs are constantly changing, it is necessary for reservoir managers to continually update their development strategy. The desired result is to increase the longevity of the reservoir.[166] The flow, fluid loss, temperature maintenance, stress measurements and geochemistry are parameters that should be actively monitored to understand and respond to changes in the reservoir. For example, the geochemistry of a field is thought by some to be the leading cause of reservoir production decline.[167] Dissolution of minerals that fill-up fractures in the reservoir or scale the equipment is a major concern and should be kept in check.[168] In the changing field, wells may need to be replaced, put further-out, pumped in or out, re-worked, or drilled deeper (see Figure 35).[169]

XXI. Problems and Needs in Reservoir Management

On the whole, reservoir management does not face nearly as many problems as other phases of geothermal development. Over the years a reservoir is in use, prodigious amounts of data is acquired that helps reservoir engineers perform sophisticated computer modeling that assists their efforts in developing good ideas of how to organize the resource utilization in the most effective and long-term manner. According to several reservoir engineers, however, sometimes development companies inadequately protect their investment for the future by not carrying-out proper reservoir monitoring and management procedures.[170]

Another problem mentioned by some reservoir engineers is the disconnect or lack of communication between those that do the field measurements of well performance and those that use the gathered data to make reservoir simulation models. Because of this communication lapse, the data the reservoir engineer is given often has gaps of information or some other fatal flaw that renders it unusable.[171] This type of issue is especially magnified when the reservoir engineer is contracted to work on a field whose production is in the process of decline. The unusable data is likely to limit his or her ability to discover and remedy the problem. Many reservoir engineers would agree that if a conversation runs continuously between the field managers collecting the data, the operating company, and the reservoir engineer, models can be constantly updated and improved, and the production life of the reservoir greatly extended.

Despite possible human error, not actively managing a reservoir, or lapses in communication, the greatest technical shortcoming of reservoir management, according to John Pritchett and just like exploration and drilling, is the inability to image fluids in the subsurface.[172] If subsurface fluids could be imaged, it would potentially allow for reservoir flows to be mapped and greatly reduce uncertainty in developing effective reservoir management strategies. Subsurface fluid imaging is currently a hot research topic and will most likely continue to be until better technology is developed.

In addition to understanding the subsurface fluid, there is a great need in reservoir management, as noted by several reservoir engineers, to better characterize the properties of subsurface rock. As stated above, dissolution of rock is a major hindrance to the longevity of a geothermal field. A better understanding of the geology will likely yield improved methods of managing mineral deposits thus increasing the productive longevity of the field. Imaging subsurface fluids, coupled with a better understanding of their geochemical properties should provide a framework for reservoir engineers to develop more accurate conceptual models of how geothermal fields evolve. This idea is best summarized by Professor Roland Horne of Stanford University when he stated in a recent presentation that reservoir engineers, "need a set of tools to understand how reservoirs change over time, so [they] can change [their management] strategy if necessary."[173]

Although the technology in reservoir management is relatively good when compared to other stages of geothermal development, there are still significant improvements that can be made that could help the industry to more effectively produce from geothermal resources.

Information on Reservoir Management:

Well Characterization:
www.geologging.com
www.geologging.com/english/news/news.htm

Tracers:
http://www.egi.utah.edu/geothermal/Tracer/tracer.htm

Reservoir Modeling:
www.tough2.com
www.uib.no/cipr/research/ReservoirModelling/ReservoirModelling.htm

EMERGING SUBSURFACE TECHNOLOGIES

XXII. Emerging Subsurface Technologies Overview

The words 'advanced geothermal technologies' often brings-up the term "hot dry rock" or the heat mining concept known as "enhanced geothermal systems," or EGS. This technology, despite the amount of press and attention it receives, is only one of several emerging geothermal technologies tied to advances in subsurface tools and methodologies that could make production of energy possible from an expanded range of geothermal resources.

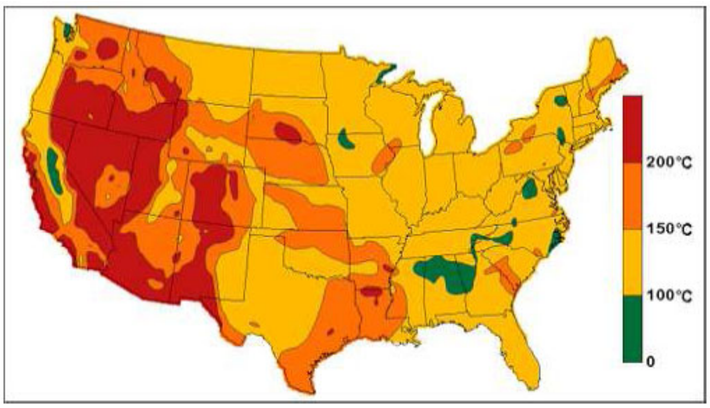
The USDOE defines EGS as, "engineered reservoirs that have been created to extract economical amounts of heat from low permeability and/or porosity geothermal resources."[174] A graphical representation of this concept is shown in Figure 38—here, water is pumped down an injection well into the subsurface where it diffuses through fractured rock, which has been naturally or artificially fractured, and is heated before returning to the surface via a production well.[175] The definition set forth by the DOE is used in this work and other advanced technologies (which are sometimes included in the discussion about EGS) are treated separately: hidden hydrothermal systems, supercritical volcanic systems, oil/gas geothermal co-production, and geopressured geothermal systems. Jefferson Tester, H.P. Meissner professor of Chemical Engineering at MIT, and an advisory board of technical experts, in a 2006 report entitled 'The Future of Geothermal Energy,' set forth their view that EGS is part of a continuum, where the development of tools and techniques in any of these areas can be used to expand production from currently non-commercial or non-conventional areas, to areas where there are no geothermal systems, but only hot rock. An example of such is outlined in section XXVI where co-production of geothermal fluid and hydrocarbons is described.

XXIII. Enhanced Geothermal Systems (EGS)

In the 2006 MIT report, the authors posit, "EGS technology as being able to provide 100,000 MW of additional electrical capacity competitively by 2050."[176] The prospect of hundreds of thousands of megawatts of clean, renewable baseload power from almost anywhere is very enticing. Several governments and private organizations around the world have made EGS a top priority and are working on developing the needed technology. Projects are currently underway in the United States, Australia, France, Germany, Switzerland, the Czech Republic, the United Kingdom, and in several other locations.[177]

EGS makes it possible to think about utilizing geothermal energy for electricity production in places where it would otherwise not be possible. For example, in the United States, the crust of the Great Basin Region in the west is much thinner than that of the rest of the country. Therefore, in this region there is significantly more heatflow from the earth's interior that results in accessible geothermal fluid or hot rock. In other parts of the country, such as the Appalachian Mountains, for instance, the crust is thicker with a lower geothermal gradient, requiring deeper drilling to reach hot rock (see Figure 36).[178] Harvesting the heat from the subsurface rock, whether it be in the thin crust of the Great Basin or deep in the subsurface of the Appalachians, is the purpose of EGS technology development.

Figure 36: Heat Flow map of conterminous United States at 6 km depth



Tester *et al.* in their 2006 report, "The Future of Geothermal Energy" state that, "without question, the largest part of the EGS resource base resides in the form of thermal energy stored in sedimentary and basement rock formations, which are dominated by heat conduction and radiogenic processes."[179] Throughout the United States, if drilled deep enough, heat adequate to boil water and run a power plant are found in the subsurface regardless of the geographic location. However, varying rock types and depths at which hot rock is located lead to diverse challenges associated with EGS development in different parts of the country. For example, the hot crystalline rock typical of the Great Basin region is found at economically attainable depths, but is extremely difficult to fracture (a process known also as *stimulation*, which is most often carried out as highly pressurized water is pumped down a well into the subsurface, forcing its way into and dilating existing fractures, and or creating an entirely new fracture network). As an alternative example, the sedimentary rock of the Gulf Coast region is much easier to fracture than the crystalline rock of the Great Basin, and fracturing this rock has been repeatedly proven to be effective in projects in the oil and gas industries, but the heat is located at much greater depths.[180] Drilling to such depths has been a significant financial obstacle to developing EGS in this region.

Prior to a more in-depth discussion of how EGS might work, an underlying issue should be discussed about the term. Some discuss the idea of EGS as limited to projects where geothermal energy cannot or does not already exist. Others understand the concept of EGS to be simply extending the reaches of currently used geothermal tools and techniques to produce power from currently non-commercial areas; the eventual goal here being to extend to areas, such as those classified by the antiquated term 'hot-dry rock,' where geothermal systems need to be totally "engineered."[181] In some ways, this is more a question of how to conduct the research needed than it is a question of what an EGS system would eventually look like and require. Those that subscribe to the former view of EGS are likely of the opinion that research dollars should be spent on projects that directly explore the possibility of fully engineered systems. And naturally, those who hold the latter stance are likely to advocate focusing research efforts on non-conventional geothermal resources such as those described in sections XXIV-XXVII, arguing their development would yield the tools necessary for the creation of commercially viable EGS systems.

EGS Creation and Utilization

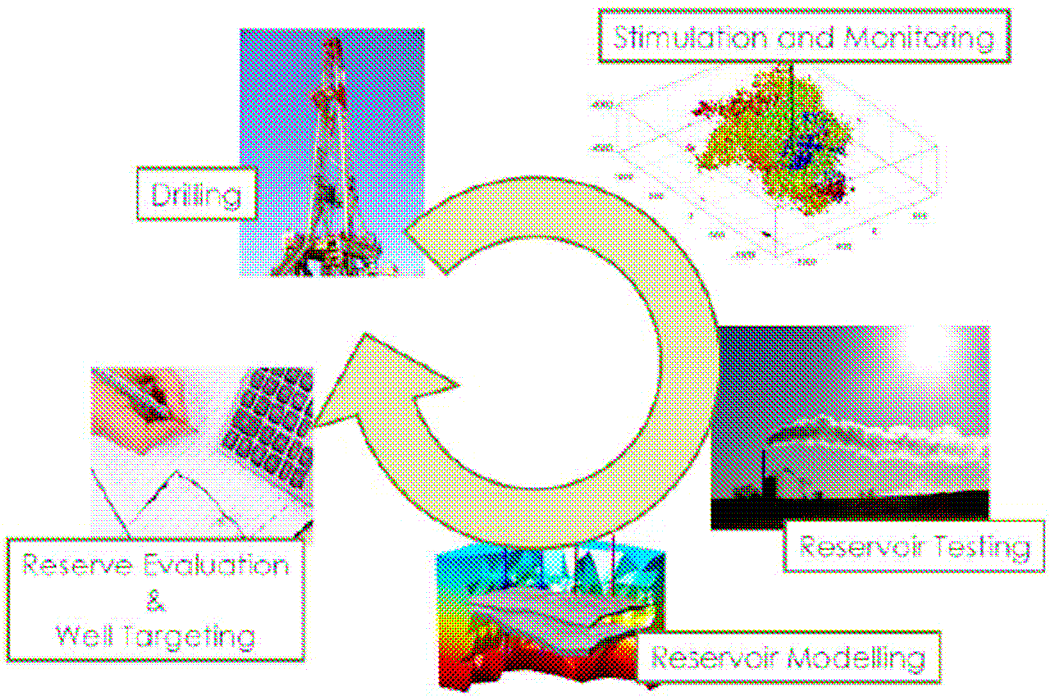
Currently, the USDOE is preparing a report outlining the technological status of EGS. That report, along with the MIT report published last year, describes EGS development in great detail.[182] As those publications explain in sufficient technical detail the process of creating an EGS system, an attempt to do so is not made here, but rather a simple description of the process.

The beginning stages of EGS and conventional geothermal development are quite similar. A fully engineered or field extension prospect is located, permitted, leased, explored, and then eventually drilled. For an EGS reservoir, there are at least two wells drilled, an injection well and a production well. Water is pumped into the subsurface through the injection well where it percolates and is heated through hot fractured rock before returning to the surface through the production well. This is illustrated in Figure 38.[183] In a recent EGS workshop sponsored by the DOE, John Pritchett stated that the eventual goal of a large scale EGS field would be to have on the order of hundreds of wells thereby increasing the efficiency of circulation.[184]

Upon drilling of at least one of the wells, two critical parameters need to be quantified: the natural joint (fracture) network and the stress profile.[185] Natural fractures can be verified by analysis of cores retrieved through core drilling or by obtaining wellbore images using ultrasound scanning tool such as an acoustic borehole televiewer. If the rock does not contain fractures, or more are desired, the group attempting to create an EGS reservoir will then fracture the rock artificially. The creation of new fractures or dilation of existing ones, an undertaking also common to conventional geothermal development, is known as stimulation (this process is described in section XXIII and in the preceding chapter). Prior to step, a stress profile is completed to accurately predict what pressure will be necessary for stimulation activities and the direction the fluid should migrate.[186]

Once an EGS system is stimulated or existing fractures deemed sufficient, the next step is to circulate fluid through the system to 1) verify that it works, 2) address any problems that might arise (see section XIX, Table 6 for list of common reservoir problems) and 3) eventually use the heat from the circulated fluid to produce electricity. The development process is outlined in Figure 37, and is a slide from a presentation made by Ralph Weidler, a reservoir engineer from the German EGS company Q-Con GmbH.[187]

Figure 37: Process of EGS resource development



The understanding of the interaction between the underground stress and the natural fracture behavior when hydraulic injection is carried out has improved a great deal over 30 years of research at Los Alamos (USA), Rosemaowes (UK) and Soultz (European Project in France). According to one expert directly involved in several EGS projects, the industry is now in position to be able to cope with varying degrees of stresses in a majority of geological conditions.[188] This is incredibly important as it improves the probability of creating a successful underground reservoir.

At the same USDOE EGS workshop, eminent reservoir engineer Karsten Pruess sets forth that a good EGS reservoir will have the following properties.[189] First, it will have good permeability; the water will circulate sufficiently to heat in the subsurface and there is enough connectivity between the wells that injected water will reach the production well. Second, the system will have good injectivity, meaning, water will gain access to the fractured rock and not back-up. Third, it will contain no major short-circuiting pathways that will conduct water directly from the injection to the production well(s) thereby prematurely cooling the system. And finally, the system does not deteriorate upon injection. As mentioned in the chapter on reservoir management, geothermal systems that are circulating water, and subsurface rock structure, are constantly evolving, so an additional challenge will be to maintain the artificially created geothermal system in a productive balance over time.

Obstacles to Commercial EGS Development

Roy Baria of Mil-Tek UK proposes that a major non-technical difficulty in the development of EGS[190] is the confidence of investors and the public that EGS works.

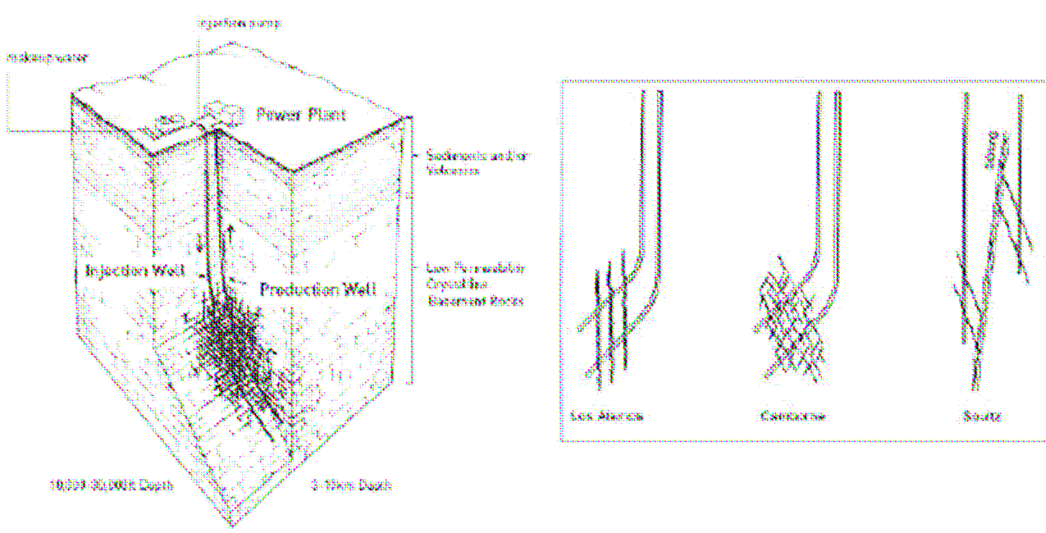
This is conceivable given that commercial-scale EGS projects have not yet been successfully demonstrated. Baria also makes note that for the development of commercial EGS, several technical challenges need to be addressed by current and future EGS research projects. Two of these issues are the need for a prolonged circulation test in a completed EGS fracture network, and the need to carry out EGS test projects in different stress and geological settings. Such tests should provide necessary answers to questions posed by Baria, like:

- What are the long term effects on the life of the reservoir?
- What geochemical issues might arise?
- How should an EGS reservoir be properly managed?
- What should be the economic and technical focus areas of future EGS test projects?
- How can seismic events associated with EGS be reduced or eliminated?

It is worth noting here that Ernest Majer, head of the Energy Resources Program at Lawrence Berkeley National Laboratories and specialist in Seismology, stated that although seismic events either caused by or that are associated with EGS projects receive a significant amount of press, they are of low in magnitude and should not to be regarded as threatening.[191] Seismic activity (recorded at ~3 on the Richter Scale) at a test project at Basel, Switzerland, caused much discontent in the community—however, it is reported that the uproar associated with this event was more an issue of public relations rather than public safety.[192]

Answers to these and similar questions will give a much greater understanding as to what is needed to make EGS a widespread technology.

Figure 38: Left, artistic depiction of how EGS is proposed to work. Right, depiction of fluid path between injection and production wells at three EGS test sites



EGS Needs

As stated in the previous section, there has not yet been a successful commercial-scale EGS demonstration project.[193] There have been successful parts of projects like drilled hot dry rock, created fracture networks, and even somewhat extended circulation tests. Some of these projects, according to Roy Baria, have been quite successful and encouraging. He points out a number of highlights from recent test projects:[194]

1. We can drill successfully deviated wells to 5 km at a cost of around $10M
2. We can successfully create a fractured reservoir with large heat transfer area with the separation between the injection and production well in the range of 600 m
3. The flow impedance between the wells can be improved by a factor of around 20 giving something like 0.2MPa/l/s. This is a key operating figure to reduce pumping power for circulating fluid through a fractured reservoir.
4. We can control calcite and silica precipitation by using pressure and pH.
5. We have developed knowledge base to handle the creation of a fractured reservoir in a variety of environments.
6. We can control fluid losses in either open or closed systems.
7. We have circulated hot fluid at around 190°C and 25 l/s over few months between a pair of wells to test the system.

It is true that the results of these projects are quite encouraging for the prospect of future EGS success. According to several government officials and experts involved in the development of EGS technology, economic EGS is very much a possibility that is likely to succeed, but before this can occur, developers face enormous challenges.[195] Up to now, and as seen on the above list of successes, EGS projects have been done on a relatively small scale to examine parts or microcosms of the entire EGS process. It is apparent to all involved in EGS development that what is needed to determine commercial feasibility is at least one large-scale test project that fully integrates all aspects of EGS and answers the questions listed in the previous section.[196] A number of projects have been done using one injection well to one or a couple of production wells. As mentioned previously how water will travel the path of least resistance, this path might be away from the production well. If the water does make it from the injection to production well in any appreciable amount at all, it still might not be in an amount that is economical for electricity production; the water loss might be too great.[197] A related issue is short circuiting, which occurs when there is *too* good of a connection between the injection and production wells.[198] In such a situation, where there is likely a small number of very good fractures going from the injection to production wells, as surface water is injected it will cool the rocks of the fracture that leads to the production well. The decreased temperature of the rock fracture causes a decrease in heat transfer to the injected fluid and a subsequent decline in potential for electricity production. Ideally, the EGS system will contain several fractures (and thereby much surface area for heat exchange) through which the fluid can diffuse and percolate, gathering heat at economically favorable flow and water loss rates.[199] Along these lines, if an EGS system is developed with one or a few injection wells in the midst of, say, ten or more production wells, then the chances of injected water reaching an production well in sufficient amount and flowrate for electricity production greatly increase.[200] A large scale test project like this that is then allowed to circulate water on the order of months or years should give a much improved picture of what is likely to occur in a commercial EGS production system.[201]

Beyond the technical questions and challenges, there is the major barrier of cost. To complete this type of project would cost in the range of the hundreds of millions of dollars, in contrast to the current projects that are in the tens.[202] Whether the technology can be developed and applied at a cost which would be competitive with alternatives can only be answered by future efforts. It is true that the upfront risk is great, but the rewards, especially if 100,000 MW of clean energy might actually be a reality, could be enormous.

XXIV. 'Hidden' Hydrothermal Resources

Another area for advanced technology to focus is on 'hidden' hydrothermal, or conventional, geothermal resources. These are resources that show no surface manifestations of heat. With an estimated 80,000 – 100,000 MW of power potential estimated by the USGS to be in such systems, developing the tools and methodologies to find these resources has significant pay-off.[203] As noted in several previous sections, numerous industry experts hold that what is needed to find these resources is advanced exploration technologies, such as a way to image permeability in the subsurface. The development of such a tool would unlock the substantial potential of hidden resources.

XXV. Supercritical Volcanic Geothermal

A supercritical fluid is one that reaches high enough temperature and pressure that it can behave as both a liquid and a gas. Such fluids have a unique ability to pass through solids. The temperature and pressure required are specific to the type of fluid. Water passes into this supercritical state when it reaches both a pressure of 218.3 atm, and a temperature of 374.1°C.[204,205] Fluid at such a pressure and temperature can be reached deep in the subsurface in volcanic regions. Efforts to reach these magmatically heated fluids are underway in three wells in the Iceland Deep Drilling Project (see Figure 39)[206], with the idea that since the fluid is in a supercritical state, when reached it will readily move up a wellbore.[207] It has been calculated that with the increased temperature and pressure, wells drilled in these volcanic systems have the potential of delivering at least an order of magnitude more electricity per well.[208] These predictions are shown in Table 7, from the IDDP.[209] In the United States, supercritical geothermal projects are feasible for the Cascade Mountains in the Pacific Northwest, the Alaskan

Figure 39: Iceland Deep Drilling Project site

Peninsula, Hawaii, and other young volcanic regions.[210] In order for this technology to be realized, extremely high-temperature deep drilling tools must be developed.

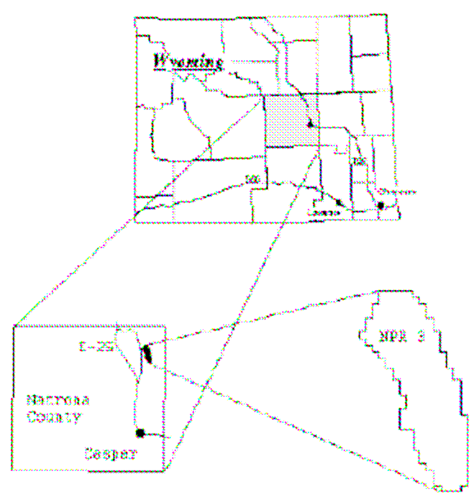
Table 7: Comparison between production features of conventional and supercritical volcanic wells

	Conventional dry-stream well	IDDP well
Downhole temperature	235°C	430 - 550°C
Downhole pressure	30 bar	230 - 260 bar
Volumetric rate of inflow	0.67 m^3/s	0.67 m^3/s
Electric power output	~ 5 MW_e	~ 50 MW_e

XXVI. Oil/Gas Co-Production

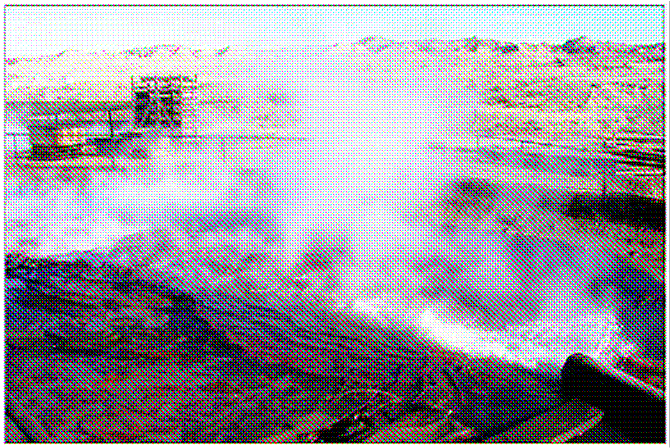
In several oil fields across the United States, including ones in Alabama, Arkansas, California, Florida, Louisiana, Mississippi, Oklahoma, and Texas, a common by-product of oil production is hot water. Ranging from 120°C to over 200°C, this geothermal fluid is not currently utilized for electricity production, but is treated as waste; the disposal of which is quite costly.[211] The idea behind the co-production is that the hot water, upon separation from the hydrocarbons in a separator located on the surface, would pass through a binary power plant (see Part II of this report for description) then disposed of or used for other purposes.[212] An apparent advantage to geothermal co-production in hydrocarbon fields is that much of the work leading up to electricity production has already been done.[213] McKenna, Blackwell, Moyes, and Patterson in a 2005 publication state that, "Collecting and passing the fluid through a binary electrical plant would take some engineering but is a relatively straightforward process since most of the produced fluid already is passed to a central collection facility for hydrocarbon separation and water disposal. Hence, piggy-backing on existing infrastructure should eliminate most of the need for expensive drilling and hydrofracturing operations thereby reducing the majority of the upfront cost of geothermal electrical power production."[214]

Figure 40: Location of NPR-3



A demonstration of the feasibility of geothermal co-production with oil and gas is being undertaken in central Wyoming at the U.S. Government-owned Naval Petroleum Reserve-3 (NPR-3) which is part of the Rocky Mountain Oilfield Testing Center (RMOTC) (see Figures 40 and 41).[215] At NPR-3, the fluid flowing from the oil wells in the field is 190°F and all the wells combined flow at a total rate of 6.4 billion liters (1.7 billion gallons) per day.[216] This resource will be used to generate electricity which will be used to power the pumps and other electrical needs of the oil field. It is expected to start operation in late 2007.[217]

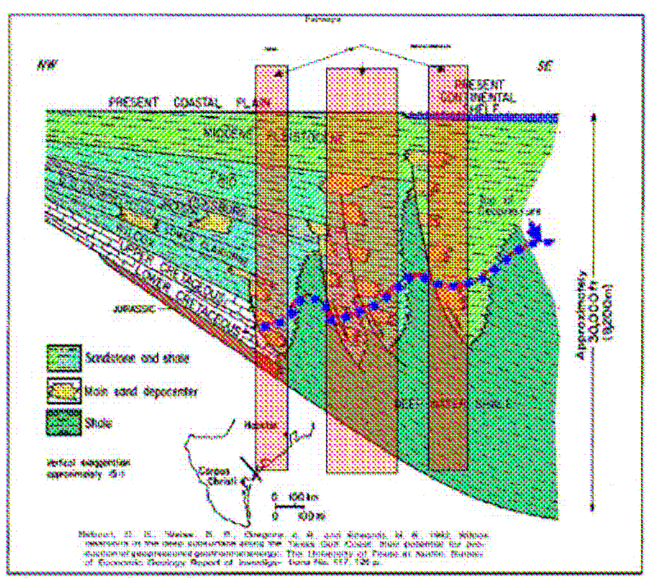
Figure 41: Geothermal fluid produced along with oil at NPR#3



The potential for production from oil fields is substantial. From several thousand to tens of thousands of megawatts of power could be produced from the hot water coming out of oil and gas wells in the US today.[218] McKenna *et al.* set forth that, "if the entire volume of processed water arising from existing hydrocarbon production were run through a heat exchanger, we estimate that the combined geothermal electrical power of the 7 states nearest the Texas Gulf Coast Plain would be about 1,000-5,000 MW."[219] The total output of all geothermal fields currently in production is ~3000 MW.

In addition, these hydrocarbon fields could become sites for greater geothermal production using EGS techniques, according to Tester *et al* in the 2006 MIT report.[220] In connection with this discussion of EGS (outlined in section XXIII) and how the development of other technologies appears to be a likely method of eventually developing fully engineered EGS systems, McKenna, Blackwell, and Moyes state, "By developing EGS and-or more conventional types of geothermal reservoirs in existing hydrocarbon fields, particularly in the Midcontinent and the Atlantic-Gulf coastal plains, it is possible to take advantage of the confluence of high permeability engineered reservoirs, high temperatures, high flow rates, and existing infrastructure."[221] Developing such geothermal systems in this region using these aides would likely prove to be a stepping stone to engineering commercially successful EGS under several, possibly less forgiving, conditions and depths.[222]

Figure 42: Artistic representation of geopressured system



XXVII. Geopressured Systems

Because of geological similarities, geopressured fields are often found in areas containing oil and gas reserves as well.[223] A geopressured reservoir is formed in sedimentary formations when water percolates into the pores of a layer of sand. When non-porous shale settles on top, it traps the fluid into the sand layer at very high pressures. Over millions of years, this pressure increases even more as additional sedimentary layers build on top of the reservoir (see Figure 42).[224] If the sand body in which the water is trapped is large enough, the reservoir can economically produce energy for quite a long time. An important characteristic of geopressured reservoirs, at least from an energy perspective, is that they contain dissolved methane, or natural gas. This, therefore, yields three sources of energy that can be utilized from the reservoir:[225]

1. Hydraulic energy from extreme pressure
2. Heat energy from the fluid
3. Dissolved natural gas

Compared to other natural gas reservoirs, the amount of dissolved methane in these types of reservoirs is very small. For the natural gas alone, the reservoir would be uneconomical. However, with two more sources of energy, their utilization becomes worthwhile.

According to David Blackwell, geopressured reservoirs exist in, 'almost all deep sedimentary basins.' Particularly large formations are known to be found in the Gulf Coast regions of Texas and Louisiana. The geopressured formations in the Gulf are estimated to hold tens of thousands of megawatts of geothermal energy, and a hundred year supply of natural gas for the United States. [226] Yet, only one major test of this technology has been carried-out. At the Pleasant Bayou site (see Figure 43)[227] near Houston, a 1 MW binary power plant was run off of a geopressured system as a demonstration from January to May of 1990.[228] It also produced electricity by burning natural gas in a reciprocating-engine-operated electric generator. Although run successfully as a demonstration, it was not considered economic at the time and was dismantled by the Department of Energy.

Figure 43: Power plant at Pleasant Bayou geopressured reservoir

However, researchers argue that a fresh approach to geopressured resources is called for. Advanced technology, coupled with greater need for domestic energy and higher values for both electricity and natural gas, could result in economical production from the substantial geopressured resource base.

More Information on Emerging Technologies:

All Tech. Listed Below:
http://www.smu.edu/geothermal/Oil&Gas/2007/Blackwell%20-%20Assessment%20of%20the%20Enhanced%20Geothermal%20System%20Resource%20Base%20of%20the%20United%20States.pdf

EGS:
http://www1.eere.energy.gov/geothermal/egs_technology.html
MIT Report: http://geothermal.inel.gov/publications/future_of_geothermal_energy.pdf
http://geothermal.inel.gov/
http://www1.eere.energy.gov/geothermal/egs_technology.html
IEA: http://www.iea-gia.org/annex3.asp
EU: http://ec.europa.eu/research/energy/nn/nn_rt/nn_rt_geo/article_1133_en.htm
Commercially Funded EGS Projects:
Australia: http://www.geodynamics.com.au/IRM/content/home.html
Germany: http://www.geox-gmbh.de/

Supercritical Volcanic Systems:
http://www.iddp.is/
http://www.geothermie.de/egec-geothernet/prof/0616.PDF
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