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Volume I

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Low-to-Moderate-Temperature Hydrothermal Reservoir Engineering Handbook

MASTER

**A Joint-Project Report of
Lawrence Berkeley Laboratory and
The Idaho National Engineering Laboratory**

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LOW-TO-MODERATE-TEMPERATURE HYDROTHERMAL RESERVOIR ENGINEERING HANDBOOK

Published June 1982

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and

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FOREWORD

Low-to-moderate temperature geothermal energy will augment the future energy needs of industrial process heat, space heating, and district heating systems. As an industry in its infancy, geothermal reservoir engineering is unique and different from the technologies of petroleum and ground water reservoir engineering.

This document which provides guidelines to developers and consultants in evaluating reservoir characteristics contains sections on reservoir classification, conceptual modeling, testing during drilling, current theory of testing, test planning and methodology, instrumentation, and a sample computer program. Although the developer will find the entire document useful and informative, sections on test planning and methodology, geochemistry, reservoir monitoring, and the appendixes, containing technical detail, are designed specifically for the consultant. Sections 2 through 6 provide the developer background information needed to monitor the program of reservoir evaluation. As technology improves, this document will be modified. Future sections will depend upon ongoing and completed research in the low-to-moderate temperature geothermal industry.

Metric units are used whenever possible. However, some equations employ constants in English units and some instrumentation and oil field records (i.e., pressure gauges, rig recorders, and well logs) are calibrated or recorded in English units. Therefore, soft-metric and English units are used wherever logical or appropriate. Appendix A provides the reader with information on conversions.

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LOW-TO-MODERATE TEMPERATURE HYDROTHERMAL RESERVOIR ENGINEERING HANDBOOK

1. INTRODUCTION

Numerous low- (less than 90°C)-to-moderate temperature (90 to 150°C) geothermal resources occur in many areas of the United States. The number of known geothermal systems increases significantly as the temperature decreases. Geothermal systems occur primarily where the normal geothermal gradient of the earth (30°C/km average) is affected by a positive temperature anomaly. These anomalies are caused by: (a) higher than normal regional heat flow; (b) rocks of low thermal conductivity; (c) higher than normal concentrations of radioactive elements; (d) young magmatic intrusions; and/or (e) hydrothermal circulation.¹

Low-to-moderate temperature geothermal resources have a wide range of direct-use applications in agriculture and industry. Agricultural uses such as greenhousing, animal husbandry, soil warming, mushroom raising, and biogas generation require the lowest temperature, ranging from 20 to 82°C. Industrial uses such as space heating for homes, offices, hospitals, and large district heating systems requires temperatures from 45 to 100°C. Industrial processes require temperature up to 150°C with the use of both steam and superheated water. Industrial uses of geothermal fluids also include food processing, crop drying, and multiple use by the forest products industry. Although the unique aspects of each geothermal resource require individual consideration, most development schemes will employ straightforward engineering, using proven technology and existing system components.

The rationale used in developing a low-to-moderate temperature geothermal resource is the same as that used by a hydrologist or petroleum engineer in designing an optimal development scheme for a given water or oil reservoir. Consequently, the geothermal industry depends on two major areas of expertise: hydrology and petroleum engineering.

Hydrologists have applied ground water hydraulics and theory to low-temperature systems (<90°C) that are single phase and liquid and resemble ordinary ground water systems. However, most ground water theory was developed for application to fluids of about 16°C and did not include temperature dependent fluid properties. Problems with ground water theory applications to geothermal systems include those of nonisothermal flow, temperature dependent fluid properties, and proper interpretation of well tests. For well testing, the two most important temperature dependent fluid properties are density and viscosity. Figures 1 and 2 show the value of these parameters from 0 to 150°C.

The petroleum engineering theory was developed for exploitation of hydrocarbon resources. The great depth of some petroleum reserves, gas content of the fluid, and temperature dependent fluid properties make these petroleum reservoirs similar to high-temperature geothermal reservoirs. Because low-to-moderate temperature resources are rarely two-phase steam water mixtures, or have a high gas content, they do not require the sophistication of some of the petroleum techniques developed. Therefore, the reservoir engineering techniques developed for a low-to-moderate temperature geothermal system borrow the most appropriate methods and terminology from hydrology and petroleum engineering. The theories are very similar but the terminology has created a disparity between the petroleum engineering and hydrologic industries when applied to a low-to-moderate temperature resource.

This disparity has created the need for a handbook that will bridge the theories and methodologies of the hydrologic and petroleum engineering fields. This handbook has been prepared for developers with previous experience in one or more of the following: petroleum engineering, ground water hydrology, and/or high-low temperature geothermal systems. In addition, the handbook should provide a useful tool to both consultants and industry personnel. The handbook identifies significant areas of concern, with reference to other

Figure 1. Density of liquid water at 80 psia.

Figure 2. Viscosity of liquid water at 500 psia.

specific documents for in depth "how-to" discussions. The handbook provides an overview of reservoir engineering, basic and applied theory, conceptual modeling, testing during drilling, test planning and methodology, geochemical applications, and reservoir monitoring; it gives the potential developer a firm understanding of the tasks to be performed and the problems that may be anticipated.

2. RESERVOIR CLASSIFICATION

Individual geothermal systems occur in several different geologic environments. These include:

- Areas of recent intrusion and/or extrusion
- Areas where open fractures allow fluid circulation to depth with subsequent heating by the normal geothermal gradient
- Areas where radiogenic heat is trapped in rocks by overlying sediments
- Geopressured areas where hot fluids are confined under high pressures
- Areas where hot rocks exist without adequate natural fluids to transfer the heat (hot dry rock).

Young igneous environments primarily occur in the tectonically active Western United States (Figure 3). These systems provide the majority of known shallow geothermal reservoirs. The Cascade Mountain Range of Washington and Oregon represents a volcanic region caused from heat generated by the converging of plate margins. The Imperial Valley of Southern California is located in a region of crustal extension due to the East Pacific Rise spreading zone. Here the intrusions are emplaced at shallow depth, providing a heat source for the geothermal resource. The Snake River Plain of Idaho and Yellowstone Park represent volcanic areas caused by intraplate melting. Young volcanic regions also occur in some parts of the Basin and Range Province, and in the Rio Grande Rift. The heat source in volcanic belts is provided by the presence of cooling magma.¹

Deep circulation primarily occurs where the crust of the earth is under tensional stress. The Basin and Range Province and the Rio Grande Rift are extensional environments characterized by active faulting, thick sedimentary basins between young mountain ranges, and occasional sites of active volcanism. The source of heat for this environment comes from higher-than-normal regional heat flow, circulation of fluids to great depths, and igneous intrusions.

Radiogenic heat environments are generally found along the Atlantic Coastal Plain where a thick sedimentary sequence is underlain by granitic rocks. This heat, trapped by rocks with low thermal conductivity, is generated by the decay of U^{238} , Th^{232} , and K^{90} found in high concentrations in granitic intrusions.

Geopressured geothermal reservoirs occur mainly in the Gulf of Mexico where rapid sedimentary loading has trapped the heat under a thick sedimentary blanket. The fluids are under high pressure, usually contain dissolved methane, and are normally 150°C or higher. These reservoirs are not pertinent to a discussion of direct-use application energy resources because of the great difficulty in developing them; however, waters of low-to-moderate temperatures have been found overlying many geopressured zones.

In this handbook, geothermal systems are classified according to the reservoir characteristics that control fluid flow. These controls are either faults, intergranular permeability, or a combination of both. Fault-controlled systems occur primarily in metamorphic and igneous rocks, but can also occur in sedimentary rocks. Fault control is normally associated with hydrothermal convection systems where cold ground water circulates to depth, heats up, then rises along fractured zones. The heat in these systems is dependent on the regional heat flow, the depth of circulation, and the residence time of water at depth. The permeability of these reservoirs depends on the size and number of fractures in the system, the nature of brecciated material along the fault, and the degree of fracture sealing. Geothermal reservoirs controlled by intergranular permeability normally occur in deep sedimentary basins filled with consolidated or unconsolidated sediments. Ground water from adjacent highlands travels down-dip through the sediments and is heated by the thermal gradient of the earth. Heated water moves upward due to density differences to form geothermal reservoirs within economic exploitation depth. Permeability is controlled by the size and continuity of the pore spaces. Many geothermal reservoirs are controlled by a combination of both faulting and intergranular permeability.

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Figure 3. Map of the United States showing geographic features mentioned in the text and selected geothermal installations.

3. RESERVOIR ENGINEERING

Reservoir engineering can be defined “. . . as the application of scientific principles to the drainage problems arising during the development and production of oil and gas reservoirs. The working tools of the reservoir engineer are subsurface geology, applied mathematics, and the basic laws of physics and chemistry governing the behavior of liquid and vapor phases of crude oil, natural gas, and water.”²

Reservoir engineering has been developed to a high level of sophistication in both the petroleum and ground water industries. Geothermal reservoir engineering has borrowed heavily from both of these fields. Some features unique to geothermal reservoir engineering include dynamic hydrothermal regimes and non-isothermal temperature distributions.

Reservoir engineering is used to design development strategy, exploitation strategy, and reservoir management programs. The basic problems that should be considered in geothermal reservoir engineering are: pressure, temperature, fracture flow, chemical changes within the thermal reservoir, and hydraulic connection to regional ground water aquifer(s). Specific aspects include: (a) siting production wells and choosing a completion interval; (b) designing well completions; (c) designing and interpreting well tests; (d) selecting the fluid disposal method, i.e., injection or surface disposal; (e) siting injection wells if any; (f) calculating the number of wells needed to supply the required energy; (g) predicting well drawdown; (h) predicting interference effects; (i) predicting the longevity of the resource; and (j) monitoring the exploitation phase.

The reservoir engineer must design a strategy that ensures not only an adequate supply of fluid, but also a fluid temperature that is sufficient for anticipated use. Predicting production temperatures over the life-time of the project is one of the most challenging tasks for the geothermal reservoir engineer.

Reservoir engineering starts during the exploration phase, when geological and geophysical data are collected. A reservoir engineer uses these data to formulate a preliminary conceptual reservoir model by identifying the reservoir type and its approximate size. Drilling data, borehole geophysics, and testing during drilling improve the conceptual model and provide preliminary well and reservoir parameters.

Well testing and test data analysis are important aspects of reservoir engineering that are used to determine the properties of a reservoir system which control the flow of fluids into a well, the migration path of injected fluid, and the natural and induced recharge.

Thus, the reservoir engineer uses all these phases when developing a geothermal resource.

4. CONCEPTUAL MODELING

Conceptual modeling is an important tool at every stage of reservoir evaluation. A conceptual model of the reservoir is envisioned before drilling a well in order to predict what type of rock formations will be penetrated, the expected temperature, and the target depth for the well. After the well has been drilled, a conceptual model is needed to design the well test and interpret well test data. Finally, the conceptual model is used to plan the locations of production and injection wells, optimize production and injection rates, predict the reservoir lifetime, and estimate the total energy available from the hydrothermal system. The conceptual model will evolve and become more refined each time a new piece of information is obtained, analyzed, and integrated into the existing model.

This section describes the types of data required to formulate a working model of a geothermal resource, especially ways of collecting data and integrating them into the model. Examples of different kinds of data gathered in other disciplines are provided for further understanding and conceptualizing the geothermal resource. Since this section is not a definitive work on the subject, references to additional studies are included. The importance of a conceptual model to the design of the well and the interpretation of the well test data are also discussed.

Before drilling any wells the following information can be used to conceptualize the geothermal resource: geothermometry, surface geology, and geophysical surveys. Comparing the geologic setting of the reservoir under investigation to the geology of many known geothermal resource areas can help classify the reservoir. Although every geothermal resource has unique characteristics, the rapid development of many low- and moderate-temperature geothermal resources has provided an adequate data base so that extrapolation of types of phenomena from one system to another is to some extent plausible. The study of similar types of hydrothermal systems should not be overlooked in developing a conceptual model.

Data obtained during drilling provides information on the subsurface characteristics of the hydrothermal system. Drill cuttings and cores can be used to reconstruct the subsurface lithology penetrated by the borehole. Drilling rates provide information on the structural integrity, hardness, and density of the formations penetrated. Loss of circulation fluid while drilling is often a reliable indication of fractures or permeable strata. Drilling mud temperature and mud chemistry are indicators of subsurface temperature and fluid entry into the wellbore.

After drilling a well, a number of borehole geophysical logs are run from which formation porosity and permeability, lithology changes, and formation temperature can be inferred. Well testing is performed to determine the hydrologic and geometric properties of the system. Well tests can also be helpful for inferring subsurface areal temperature distribution.

The effectiveness (i.e., accuracy and refinement) of a conceptual model is dependent on the information that is incorporated into it. The geologic, thermal, geochemical, and structural complexity of the hydrothermal system dictates the amount and type of data required to have a functional and accurate model. For instance, in a system with a near normal geothermal gradient and relatively simple geologic structure, such as the Madison Aquifer, less reconnaissance and exploration effort will be required. On the other hand, in a shallow, highly faulted, complexly fractured volcanic-type system, such as the Klamath Falls known geothermal resource area (KGRA), a substantial amount of exploratory work is necessary to define the hydrothermal system and to predict reservoir performance confidently. The degree of refinement required for an adequate conceptual model depends on the intended use of the resource. If only a small quantity of geothermal fluid is to be extracted from the reservoir compared with the reservoir potential, less exploration and conceptual model development will be required than if the reservoir potential is to be taxed. The model's refinement also depends on the amount of time and effort available to invest in gathering quality data. It should be emphasized that without quality data it is very difficult to predict confidently the reservoir's behavior during exploitation. Sophisticated methods are now being developed to interpret data from complex geothermal systems. Therefore, every effort should be made to obtain quality data. The following subsections describe what data are important to have, how to process them, how to interpret them, and how the conceptual model can be used to the benefit of the resource developer.

Data Base

Surface Geology. Surface maps are the most readily available piece of information used for delineating geologic features. Information obtained from the surface map will be used for preliminary classification of the hydrothermal system. Geologic mapping has been completed for many areas on a regional or site-specific basis. These maps are available through publications from the U.S. Geological Survey, state geological surveys, and universities.

Aerial photography and landsat imagery interpretation can also be useful tools for delineating major geologic features. They are normally used in conjunction with geologic maps to locate fault lineations, fault intersections, and areas of thermal alteration.

Subsurface Geology. The subsurface geology of an area is usually constructed from data obtained from the examination of drill cuttings, cores, geophysical logs, drillers logs, etc. The drilling rate, circulation fluid record, and drilling fluid temperatures provide data on the physical and thermal properties of the penetrated rock unit. Geophysical logs are also useful tools for identifying subsurface lithologic units and the physical properties of the units. The interpretation of geophysical logs is an important technique in evaluating the subsurface lithology when there are no drill cuttings or cores available. Their use and interpretation are, however, limited depending upon the formation encountered, i.e., porosity and permeability values can be determined from logs run in sedimentary units, but may not always be determined in igneous or metamorphic units. Geophysical logs can be a useful tool for correlating rock units, thermal regimes, and hydrothermal mineralization between wells, and in locating fracture zones in wells.

Many of the low-to-moderate temperature hydrothermal reservoirs in areas with above-normal temperature gradients are associated with faults and fractures. These faults and fractured strata contribute significantly to the permeability of the hydrothermal reservoir; therefore, it is essential to detect their presence and estimate their depth. Among the most useful methods for detecting fractures is the examination of a carefully maintained record of the amount of circulation fluid used. Sudden loss of circulation fluid often indicates that fractures have been penetrated. However, the loss of drill cuttings and circulation fluid is not always indicative of fracture zones. Therefore, all of the subsurface data should be correlated to verify the data interpretation.

Temperature Profiles. Temperature profiles are obtained by measuring wellbore temperatures at a number of depths in the well. Temperature profiles are one of the most useful tools for understanding the hydrothermal system being studied. By carefully examining temperature profiles obtained under a variety of wellbore conditions, producing aquifers can be identified, multiple producing aquifers can be identified, hot water recharge detected, conductive versus convective (hydrothermal circulation) thermal regimes identified, the presence of a caprock and basement rock detected, and the thickness of the hydrothermal reservoir penetrated by the wellbore estimated.

Some caution should be taken when interpreting temperature profiles because circulation of fluid in the wellbore can mask the true formation temperature. An example of this can be seen in Figure 4. The only difference, other than the temperature profiles, between the two wells is the casing schedule. Well YMCA No. 1 is cased to 500 ft (152 m) and well YMCA No. 2 is cased to 980 ft (305 m). By comparing the two profiles obtained in wells 500 ft (152 m) apart with identical lithologic columns, it was determined that water was flowing down the wellbore in the well YMCA No. 1. Cold water entering the wellbore in well YMCA No. 1 at 500 ft (102 m), flowed down the wellbore and enters a second reservoir at 1200 ft (366 m). If the data from well YMCA No. 2 had not been available the temperature profile from well YMCA No. 1 may have been misinterpreted to conclude that the isothermal interval from 500 ft (152 m) to 1200 ft (366 m) was the geothermal aquifer. In reality, the main producing aquifer is in a fractured interval between 1200 (366 m) and 1300 ft (396 m).

Geochemistry. Information about geothermal fields which can be deduced from geochemistry includes: estimated subsurface temperature, location of heat source(s), directions of water movement, source of dissolved solids, sources of recharge, age (possibly), and whether hotter water exists nearby. Contouring maps

Figure 4. Downflow in well as indicated by depressed temperature profile.

or cross-sectional views of chemical concentrations in a geothermal area can provide insight into water movement and the sources of dissolved salts, heat, and water. Care must be taken, however, to ensure that the data being contoured are from the same hydrogeologic unit. For example, in a geothermal area containing shallow domestic and irrigation wells, intermediate depth wells, and deep geothermal production wells, each depth level must be treated separately. Patterns of contours can indicate directions of water movement. A comparison of contour maps or cross-sections for species whose concentrations are related to temperature (SiO_2) and conservative species (Cl^-) can indicate differences between locations of heat sources and high dissolved solids waters. Spatial variations in water chemistry can be due to mixing of waters from different sources, evaporation, steam loss, precipitation of solid phase, or reactions with aquifer materials. Simple mixing calculations can be used to determine if mixing is responsible for spatial variations.

Stable isotopes in water (hydrogen and oxygen) can be used to determine the source of water. Studies have shown that many geothermal waters are comprised of local meteoric water heated by circulation to depth. Variations in the isotopic composition of recharge water can occur by evaporation before recharge, or by recharge occurring at different elevations. If these variations can be traced through the geothermal system, detailed information on sources of water can be obtained.

Geophysics. Geophysical methods used in the exploration for hydrothermal resources can be categorized in five groups: thermal, seismic, electrical, magnetic, and gravity. These methods can provide valuable exploration data, insofar as they are used to delineate the hydrothermal resource. However, because of the ambiguity inherent in their interpretation, these may or may not be the type of data needed for a conceptual model of the resource.

Thermal methods are among the most direct and commonly used methods for determining the location and size of a geothermal system. Thermal methods include: (a) calculation of the heat flow from the earth using thermal gradient data and thermal conductivity measurements, and (b) evaluation of the measured geothermal gradient. Among other things, these data can indicate the size and shape of the hydrothermal anomaly.

Seismic methods can be passive and active. Passive methods monitor natural earthquake activity to infer anomalous stress states due to possible heat sources, abnormal tectonic activity, and/or abnormal hydrostatic conditions. Detailed microearthquake surveys are also used to delineate active fault zones that may serve as potential ground water conduits. The active methods use the amplitude and velocity variation of seismic waves generated by a controlled source, both compressional (P) and shear (S) waves, to infer the characteristics of the medium in which they are propagated. Active reflection techniques are used to infer the location of discontinuities, layer, thickness, and general structure. Depending upon the size and frequency of the source, reflection techniques can "look" as deep as several kilometers and still define fault boundaries and basement structure. Refraction techniques look at the velocity variation of the P-waves to infer layer thickness, fault location, and structural discontinuities. The refraction techniques are not as detailed as the reflection techniques and require larger "spreads" and more powerful sources to look at comparable depths. The refraction techniques can also miss structure that the reflection surveys will detect if the velocity variations with depth are not continually increasing. However, the refraction techniques are much cheaper and require less sophisticated post processing.

Electrical and electromagnetic methods are used to estimate the electrical resistivity of the earth. Electrical resistivity is a measure of the earth's ability to conduct electrical current and depends upon the porosity, fluid saturation, temperature and clay content of the rock, and the salinity of the pore fluid. In general, the higher these parameters are, the lower the resistivity of the medium. Since geothermal areas are associated with high subsurface temperatures and saline fluids, they are characterized by anomalously low resistivity. Electrical and electromagnetic surveys performed on the surface are therefore very effective methods for locating buried geothermal systems. The most commonly used of these methods is the d.c. resistivity method. Low frequency electrical current is injected into the ground through a portable generator and earth electrodes. The resulting potential at a site of specified distance away is then measured. By varying the spacing between current and potential electrodes, a variation of voltage with separation and/or location is obtained. This may be corrected for a variation of electrical resistivity with depth, depth soundings, spatial variation at resistivity, or a mapping survey. Electromagnetic methods use a time varying signal source and obtain earth resistivity information from variation at electrical fields with frequency.

Gravity and magnetic surveys are structural methods used to estimate: the thickness of sediments, the depth to the basement, the density or density contrasts of basement rocks, and buried volcanic or intrusive rocks. Magnetic surveys detect the magnetic susceptibility of subsurface rocks. Because hydrothermal alteration reduces the magnetic susceptibility of the subsurface rocks, a negative anomaly may be indicative of a hydrothermal resource.

Well Testing. Well testing is the most common and reliable method for determining the parameters which control flow of fluid through the reservoir. The parameters which affect the ease with which water will flow through the reservoir are the rock permeability (k), the viscosity of the reservoir fluid (μ), the porosity (ϕ), the formation compressibility (c), and the production geometry (height, areal extent, layers, etc.). Knowing these parameters or the groups of parameters kh/μ (transmissivity) and ϕch (storativity), well drawdown, well productivity, and interference effects can be calculated.

Well tests are typically conducted by pumping or artesian flowing a well for a period of time at a constant flow rate. The pressure changes in the production well are observed over time. The change of pressure is analyzed to obtain the physical parameters of the reservoir system. If there are other wells in the area, these too can be monitored for pressure (or water level) changes as a function of time. Often the data from interference wells will provide more accurate reservoir information due to instrumentation and logistical constraints at the production well. If an array of observation wells is available, accurate information about the reservoir size and geometry can be obtained.

Data Preparation

Before the data from all of the various disciplines can be synthesized, it is important to prepare them correctly. There are four basic types of displays by which data can be processed to provide a visual representation of the various reservoir characteristics: mapping, profiling, contouring, and cross sections. Depending on the amount and quality of data, it may or may not be worthwhile to do all of the types of processing.

Mapping. Mapping is the least sophisticated and most simple display to prepare. It involves locating observed phenomena or physical features on a cartesian coordinate system that overlies the area under study. This type of representation is used when only a two-dimensional representation of the data is required, i.e., when depth is not considered. Temperatures and chemical data from springs are often mapped with this technique. The representation does not account for the fact that the springs may have circulation at different depths, and thus, differing chemical constituents and temperatures.

Mapping is generally used in the early stages of exploration. For example, the relationship between the recent volcanism and the hydrothermal anomaly at Klamath Falls, Oregon, was examined by radiometric dates obtained on rock samples from in and around the Klamath Falls area. A map showing the location and radiometric age of each sample is shown in Figure 5. The concentric pattern of older dates with distance from the Klamath Falls vicinity may suggest that the anomaly is associated with the most recent volcanism in the area.

Profiling. Profiling consists of looking at data from a single penetration through a vertical section. Profiled data are obtained from wellbore surveys. For instance, by plotting the well lithology versus depth a lithologic profile is obtained; by plotting temperature obtained from a temperature survey versus depth, a temperature profile is obtained.

One example of a lithologic column and temperature profile for a well is shown in Figure 6. This type of temperature profile is typical of temperature profiles in shallow fault-charged reservoirs. A comparison of the lithologic column, the drilling circulation record, and the temperature profile shows that a thermal production interval in the well is between 195 ft (59 m) and 240 ft (73 m).

Contouring. Contouring is used to define the shape and extent of the observed physical phenomena. For instance, temperature contours are used to define the areal and vertical extent of a hydrothermal system and can be used to make rough calculations of the amount of hot fluid in place. One of the most common methods of contouring is to plot isotherms, or isobars, at a given depth below the surface. By comparing contours at several elevations, both an areal and vertical description of the phenomena can be obtained.

In Figure 7 the temperatures at three different depths from the Susanville, California wells are contoured. At the shallowest depth, 150 m below surface elevation (1250 m elevation), the hottest part of the anomaly (inside the 60 degree contour) is centered around the Davis well. With increasing depth the shape of the anomaly is asymmetrically elongated around a northwest trending axis. Using these contours and lithologic data, a production well (Susan 1) was sited next to Suzy 9. As predicted from these contours, the new well, Susan 1, was the hottest well drilled thus far.

Concentrations of chemical species may also be contoured at various depths to determine if and how mixing of different fluids is occurring. Static water levels are contoured to determine the extent and direction of regional ground water flow.

Cross Sections. Cross sections are constructed by correlating or comparing profiles at two or more wells. Multiple cross sections, or cross sections and contours, may be used to get a three-dimensional model of the reservoir. Lithologic data are typically processed this way. Correlations of major geologic features, such as fracture zones, producing aquifers, caprock, and basement rock are obtained by constructing cross sections of the reservoir data. Temperature data are also plotted as cross sections and provide a multidimensional view of the hydrothermal structure. Two cross sections of temperature distribution are shown in Figure 8. This

Figure 5. Rock sample locations from Klamath Falls, Oregon.

Figure 6. Temperature profile and lithology for Klamath Falls, City Well No. 2.

Figure 7. Subsurface temperature contours: (a) at 1250 m elevation, (b) at 1200 m elevation, and (c) at 1150 m elevation.

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Figure 8. Cross sections of the Susanville hydrothermal anomaly.

type of thermal structure is indicative of upwelling of heated fluids from depth and lateral transport of fluid along permeable beds and fractures. This type of hydrothermal structure is common in shallow geothermal anomalies in the Cascade Range and the Basin and Range Province.

Borehole geophysical logs, such as electrical and nuclear logs, are also correlated on cross sections and are useful indicators of physical properties of the geologic section penetrated by the wellbore.

Graphically representing data in all of the above display forms helps to synthesize subsurface reservoir data with data obtained from surface reconnaissance. The subsurface reconstruction from each discipline should be compared to obtain a coherent conceptual model. Table 1 lists the various ways to process data.

Table 1. Common methods of data preparation

	<u>Map</u>	<u>Profile</u>	<u>Contour</u>	<u>Cross Section</u>
Surface Geological	X	X	—	—
Geochemical	X	X	X	—
Surface Geophysical	—	—	X	X
Hydrologic	X	X	X	—
Lithologic	—	X	—	X
Geophysical Logs	—	X	—	X
Thermal	X	X	X	X

Data Synthesis

The purpose of synthesizing data from each of the disciplines discussed above is to identify the major lithologic, thermal, petrophysical, and structural controls on the hydrothermal system under investigation. The key parameters that govern how a hydrothermal system behaves are: the permeability, storativity, size, and geometry of the production zone(s), the boundary conditions on the producing aquifer such as lateral recharge (hot or cold) caprock and basement rock leakage; regional ground water flow, and thermal distribution in the resource. Hydrothermal reservoirs are often very complex both lithologically and structurally. For this reason it may be difficult, if not impossible, to identify all of these major features. Nevertheless, an attempt should be made to identify these features because they play a critical role in interpreting well test data, designing the reservoir management program, and providing an overall understanding of the resource.

The first step in synthesizing all of the data is to correlate specific physical, thermal, and lithologic units between wells. If data from only one well are available, correlation between wells will not be possible. However, a thorough evaluation of all of the data from that one well should be performed. The features that identify the production zone, caprock, basement rock, and the physical parameters are discussed below.

Producing Zones. The major production intervals can be identified by numerous features depending on the geologic setting. For instance, in a thick sedimentary sequence, a permeable aquifer will probably occur in a sandstone, and over and underlying impermeable layers will consist of a shale or clay sequence. The temperature profile through such a sequence would consist of several distinct gradients: a convective gradient through the aquifer and a conductive gradient through the underlying boundary layer. An example is shown in Figure 9. In a fractured rock sequence, the production zones (fractures) may be located by fluid entry into the wellbore during drilling, or by loss of circulation fluid into the formation. Production zones in fractured rocks may also be indicated by temperature profiles as was demonstrated in the previous section in Figure 6.

There is no single method of detecting the production zones; however, they can usually be identified by one or more of the following methods:

1. Loss of circulation fluid when drilling through the aquifer
2. A convective thermal gradient as opposed to a conductive gradient
3. Indication of sand zones or high-water-content zones from geophysical logs or cuttings
4. Fluid entry into the wellbore during drilling
5. Fracture zones indicated during drilling
6. Spinner surveys (downhole flow meter).

The properties of the producing aquifer(s) which need to be determined are: transmissivity, storativity, temperature distribution, structure, and geometry.

In general the reservoir transmissivity and storativity can accurately be determined only by well testing. However, before well testing, the type and degree of permeability can be determined by examining items discussed above. The two most common types of permeability are matrix and fracture. Matrix permeability occurs when the fluid flows through porous spaces in the rock. The fluid enters the wellbore from the entire aquifer interval. If the flow in the reservoir is confined mainly to fractures in the rock, then the term fracture permeability is used. In systems with fracture permeability, flow into the well comes only from the fracture, not the matrix of the rock. However, away from the wellbore, fluid may enter the fracture by flowing from the rock matrix into the fracture. The fracture is a conduit for fluid to flow into the wellbore. Many hydrothermal systems are some combination of fracture and matrix permeability and these systems are called dual-porosity systems. In general, hydrothermal systems that occur in volcanic and metamorphic rocks will have a

Figure 9. Example of a typical temperature gradient through of sedimentary sequence showing the caprock, aquifer, and basement.

fracture-dominated permeability. Sedimentary formations, except for carbonate systems, will in general have a type of matrix permeability. There are, however, exceptions to this generalization.

The temperature of the producing aquifer may be measured with a downhole temperature probe. It is important to measure the temperature downhole because any measurement taken at the surface may be affected by cooling and mixing as the fluid moves up the wellbore. Except in deep, near-normal geothermal-gradient type reservoirs, the temperature in the producing aquifer will vary spatially. It is important to have measurements of the temperature in the producing aquifer in as many wells as possible because the spatial variation of temperatures in the aquifer is one of the most useful tools for determining where and if hot water recharge is taking place. Temperature contours, at several depths, should be constructed. The interpretation of this is discussed in the previous section.

The important geometric characteristics of a hydrothermal aquifer are the areal extent, height, and shape. The volume of the aquifer (areal extent multiplied by height) is used to make a first-order estimate of the amount of hydrothermal fluids in place. Obviously, data must be available from more than one well to determine the areal extent of the resource. The shape of the hydrothermal aquifer is one of the major clues to understanding the resource. In near-normal geothermal gradient aquifers, it is the size and shape of the permeable (and porous) aquifer that governs the geometry of the hydrothermal system. In Basin and Range and fault-controlled hydrothermal systems it is usually the extent of the thermal anomaly which governs the geometry of the hydrothermal system. It is important to have some idea of the thermal distribution in the producing aquifer because thermal boundaries can be misinterpreted as hydrologic boundaries due to the temperature dependence of fluid viscosity.

Caprock and Basement Properties. The important properties of the confining strata in a hydrothermal system are permeability, continuity, rock type, and temperature. If the caprock or basement rock is permeable, it will supply fluid to the producing aquifer when it is pumped. Even though physical properties of caprock and basement rock are difficult to determine, proper analysis of well test data can show leakage in caprock or basement rock. This is discussed in the section on well testing. It should be noted that a "true" caprock may not always exist and the resource may be so shallow that the basement characteristics cannot be identified. Caprock and basement rock can be identified by observing one or more of the following items:

1. A conductive thermal gradient as opposed to a convective thermal gradient
2. Delineation of a clay or shale layer from rock cuttings
3. Lack of evidence of fractures during drilling
4. Identification of low water content or shale layers from geophysical logs.

Knowledge of the location and type of confining rock is important because they are used to estimate the thickness of the producing strata and to determine if the wellbore penetrates only part of the hydrothermal aquifer. In this case, partial penetration of the wellbore into the formation, should be considered in the well test analysis.

Boundary Conditions. There are many types of boundary conditions on a hydrothermal aquifer, all of which will affect the results of a well test and reservoir response to sustained production. The aquifer may be infinite, or effectively infinite. The aquifer may be bounded on one side by a linear boundary such as a fault or rapid facies change. The linear boundary may be impermeable to fluid movement, supply a constant flow of hot or cold water into the aquifer, or remain at a constant head. The aquifer may be completely enclosed by impermeable or constant potential boundaries that are square, rectangular, polygonal, or radial. Different types of analysis apply to each of these systems. If the presence of some type of aquifer boundary such as a fault or fracture zone is suspected, the well test should be designed so that it is long enough to determine the hydrologic properties of the boundary. In order to calculate the radius of investigation, the following formula can be used:

$$r = 2\sqrt{\frac{kt}{\phi\mu c}}$$

where

k = permeability (m^2)

t = time (s)

ϕ = porosity

μ = fluid viscosity (Pa·s)

c = total system compressibility $\left(\frac{1}{Pa}\right)$.

In highly fractured and faulted hydrothermal systems, practical experience indicates that it is often difficult to detect the presence and type of reservoir boundaries. This is because the hydrologic systems are so complex that no single phenomena can be isolated and analyzed.

An estimate of the radius of investigation can be obtained even if the parameters are not all precisely known. For example, in a moderately permeable sandstone, the following calculation can be made:

$$k = 100 \text{ md} = 1 \times 10^{-13} \text{ m}^2$$

$$\phi = 20\% (.2)$$

$$C_t = 1 \times 10^{-9} \frac{1}{\text{Pa}}$$

$$\mu = .3 \text{ cp} = 3 \times 10^{-4} \text{ Pa}\cdot\text{s}$$

The radius of investigation for a 10-hour test will be:

$$r = 2 \sqrt{\frac{(1 \times 10^{-13}) 3.6 \times 10^4}{.2 \times 3 \times 10^{-4} \times 1 \times 10^{-9}}} = 490 \text{ m}$$

For a one week test, the radius of investigation will be:

$$r = 1003 \text{ m}$$

5. TESTING DURING DRILLING

Data collected throughout the drilling operation provide a basis for selecting the well test design and analysis methods to be used in evaluating aquifer characteristics. Mandatory data to be collected during operations include:

- Lithologic logging
- Drilling engineering records
- Geophysical logging
- Transient temperature profiles.

Lithologic Logging

Lithologic logging is an important tool used during drilling and should not be overlooked. Through proper lithologic logging one can identify rock type, formation, and position in the stratigraphic section. If used properly, analysis of the drill cuttings can characterize porosity and hydrothermal alteration, and assist in finding faults and zones of fluid entry. Because of rapid and abrupt changes which occur in faulted and altered rock, composite samples should be taken over no more than 10-foot intervals. Analysis of cuttings should be performed by a qualified geologist familiar with igneous, metamorphic, hydrothermally altered rocks, fault gouge, microbreccia, slickensiding, and mylonite. Unwashed samples should be collected to avoid the loss of fine-grained cuttings.

Drilling Engineering Records

Under ordinary drilling conditions, a number of measurements are made and recorded to assist the drilling engineer in making effective drilling decisions. These drilling parameters include drill rate, rotary speed, pump speed, pump pressure, weight-on-bit, and mud volume totalizers. When parameters are properly employed, decisions can be made on bit changes, borehole deflection, lost circulation, casing sizes and settings, etc.

These data also assist the reservoir engineer in evaluating the subsurface. Although these data are not conclusive, tests during drilling in the typical sense of testing, can assist the reservoir engineer in determining rock strengths and porosity from penetration rate; in identifying hot aquifers from circulation fluid temperature-in, temperature-out; and in assessing fractures and fault zones where lost circulation has occurred. All such information will be of a qualitative nature, to be evaluated further by testing methods of a quantitative nature. Nevertheless, they do identify specific sections in the wellbore that merit further evaluation.

Geophysical Logging

Borehole geophysical logging techniques measure the physical properties of the rock. Coupled with other drilling data, the logging analysis can help in defining porosity, rock type, wellbore size, bulk density, dip of rock strata, fluid temperature, and, to a limited degree, rock fractures.

Commercial logging companies provide the log tool service and deliver a graphical output to the customer. These data should be analyzed with input from other drilling information to provide an interpretation of the wellbore and rock conditions. Conventional analytical techniques for sedimentary rocks cannot be routinely

applied to all geothermal resources because of the nature of the rocks encountered (i.e., igneous and metamorphic). Current research efforts are providing interpretive measures for these geothermal environments. Although, it is a fairly expensive service, geophysical logging is a routine tool that should be used for every geothermal well.

Transient Temperature Profiles

The downhole temperature should be measured routinely during the drilling process. Temperature profiles can be performed by a commercial logging company or by a hydrogeologist. Temperature profiles are inexpensive and do not require a long period of time. They can be used to determine cold- and hot-water production zones and loss-of-circulation zones. Temperature logs can provide useful data for determining the depth for setting casing.

The Horner plot method is used to plot transient downhole temperature. The Horner plot is a graph of temperature build-up versus $\log \frac{t_k + \Delta t}{\Delta t}$ where t_k is circulation time before shut-in and Δt is buildup time. The static temperature obtained using the conventional Horner plot is lower than the true reservoir temperature.⁴ For example, let us assume that prior to running a log suite to set a string of casing, the well was circulated for four hours. Following this circulation period, a series of logs were run and the following times and temperatures observed:

Time (hr)	Temperature (°F)	$\frac{t_k + \Delta t}{\Delta t}$
0200	Circulation completed	—
1215	255	14.25/10.25 = 1.39
1500	255	17/13 = 1.31
1630	257	18.5/14.5 = 1.28
1930	260	21.5/17.5 = 1.23
2400	262	26/22 = 1.18

A plot of this data is shown in Figure 10. The estimated static temperature is obtained by an extrapolation of the straight line to a time ratio of unity, which is equal to 272°F. It can be assumed this is probably a lower limit temperature to the true static temperature.

Optional testing methods include:

- Drill-stem tests
- Coring
- Geochemical logging
- Swab and lift tests
- Downhole flow meter tests.

Drill Stem Tests

Drill stem tests (DSTs) are normally conducted in a zone of undetermined potential.³ The drill stem tool is attached to the drill string and lowered into the zone to be tested. A packer is set to isolate the zone. Formation fluids from the isolated zone flow into the drill pipe. A continuous pressure record is obtained during the

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Figure 10. Horner plot of static temperature approximation.

production and shut-in periods. DST data are analyzed to assess preliminary reservoir parameters (i.e., permeability, hydraulic conductivity). At the conclusion of the test, representative fluid samples are collected for further geochemical analysis (refer to Geochemistry Section 8).

An alternative to the drill stem test is a wireline repeat formation test. This test is capable of multiple settings downhole and of retrieving two fluid samples per trip in the hole. The principles governing multiple-level pressure measuring are similar to those of the DST. Wireline testing is attractive because it is fast and less costly than drill stem testing; however, a wireline test is a less accurate method and interpretation of the data is only partially quantitative. Drill stem and wireline formation tests are commonly used in the petroleum industry. Use in geothermal well testing is not expected to be widely applicable due to fractured flow

conditions. In a fractured reservoir environment, the data from these kinds of tests may provide erroneous information due to the short flow durations. However, these types of tests may prove valuable in evaluating the results of well stimulation jobs.

Coring

Core drilling allows for the recovery of whole rock samples from a selected interval. Core samples are used to correlate geophysical logging data with rock properties, to perform laboratory permeability tests, and to delineate stratigraphy and lithology profiles. Core drilling is an important tool used in oil and gas exploratory drilling. The high cost of coring is prohibitive for routine use, but may provide useful information for selected intervals in geothermal wells.

An alternative to core drilling is a technique called sidewall coring. This method uses a wireline for collection of the sample. Sidewall coring is quick and inexpensive; however, core samples are small in size and may have limited laboratory use. Sidewall coring will not provide adequate samples in fracture-dominated geothermal systems due to the limited data regarding fracture density, character, and orientation that can be obtained from the small sample.

Geochemical Logging

Geochemical logging can be useful in identifying geothermal production zones during drilling. Geochemical logging procedures are discussed in detail in Section 8.

Swab and Lift Tests

A swab test is used as a method for withdrawing fluid from a borehole. The procedure employs a swab valve attached to a rig sand line. This method provides limited information on well productivity and allows the collection of representative fluid samples. Swabbing and mechanical surging are commonly used methods for the development of a ground water well but may be of limited use to geothermal resources. This is a hazardous technique because of the possibility of high-pressure vapor and gas blow outs.

Airlifting using compressed air or other gases is another mechanism for withdrawing fluids from the hole. This stimulates the well and yields limited information on well productivity. Approximate flow, water level recovery, and temperature data should be collected. Fluid temperatures are affected by the ambient air temperature. A correction should be made for the estimated cooling effect. The accuracy of reservoir characteristics determined from an airlift test may be questionable, since air or gas may give erroneous flow measurements and water level recovery is difficult to obtain. Nevertheless, geothermal well drillers may employ swabbing and airlifting methods to both develop wells and perform limited well testing.

Downhole Flow Meter Test

Vertical flow of fluids in the borehole can be measured using a downhole flow meter (spinner device). Downhole flow meter tests may be conducted while producing or injecting fluid into a well. The hole should be relatively clean because the instrumentation can be easily plugged by mud or drilling debris. This method is used to indicate production or high permeability zones. The data can be evaluated to determine the amount of fluid entering the borehole from different zones. Used together with a temperature profile, this test may be useful for casing and screen setting decisions.

6. THEORY OF AQUIFER TESTING

Aquifer testing is the correlation of well production at various rates with temporal pressure or water level changes. Inferences may be drawn from such tests about the size and ability of an aquifer or reservoir to transmit and store fluids. Well testing is the only method that provides in situ information about an aquifer or reservoir on a scale meaningful for long-term exploitation of a resource. Despite the fundamental unity in the principles of well testing, the art of well testing has developed in two parallel fields: hydrogeology, following the lead of C. V. Theis⁵ and petroleum engineering, following the early contributions of Hurst.⁶ Hydrologists have been concerned with determining aquifer constants (transmissivity and storage coefficient) and interference-type testing of shallow systems. Petroleum engineers, on the other hand, have been concerned with interpretation of production/injection testing of deep systems. High-temperature geothermal well testing (usually steam flows) has followed the petroleum engineering lead. Low-to-moderate temperature geothermal well testing (usually hot water flows) requires adaptations from both the ground water and petroleum fields.

The equations developed for various aquifer and well conditions provide tools for analyzing data from many different hydrogeologic conditions. However, the simplifying assumptions used to develop the solutions are usually only partially satisfied. In addition, many of the solutions result in curves of similar shape, and thus are not unique to one flow system. Consequently, careful site evaluation and well test design by a qualified petroleum reservoir engineer or hydrogeologist are essential to ensure the success of planned testing.

Essential Elements of Well Tests

Geothermal well testing usually consists of operating the well with a controlled flow rate and measuring three variables (flow rate, water level or pressure, and fluid temperature) as time passes, while other parameters (distance, r , to the observation wells, permeability, reservoir dimensions, and storage capacity) remain constant. The flow rate, water level or pressure, and time are the primary data required for test analysis. Temperature measurements provide data for corrections for temperature effects related to changes in fluid density and viscosity. Fluid chemistry, geology, geophysics, and well construction data are also important parameters in test data interpretation.

Basic Equations

Well testing analysis methods are based on the basic equations of flow through porous media presented below. The symbols used first are those usually found in the water-well literature. The same equations are repeated in the symbols of petroleum engineering references.

Darcy's Law

Darcy⁷ observed from experiments on apparatus similar to that illustrated in Figure 11 that the speed of laminar flow of water through sand is proportional to the hydraulic gradient. He expressed this concept by the following equation now known as Darcy's law:

$$q_s = \frac{Q}{A} = -K \frac{\Delta h}{\Delta \ell} = -K \frac{dh}{d\ell}$$

or

$$Q = KiA \quad (1)$$

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Figure 11. Laminar flow speed measurement apparatus.

where

q_s = specific discharge (L/T)

Q = flow rate (L³/T)

A = cross-sectional area (L²)

K = hydraulic conductivity (L/T)

h = hydraulic head (L)

ℓ = length (L)

$i = \frac{dh}{d\ell}$ = hydraulic gradient (L/L)

and the minus sign indicates a loss of potential in the direction of flow. If the porosity, ϕ , is known, an estimate of the velocity of flow is given by

$$v = \frac{q_s}{\phi} = -\frac{K}{\phi} \frac{dh}{d\ell} \quad (2)$$

The hydraulic conductivity, K , depends on both the properties of the porous medium and the properties of the fluid. Often it is advantageous to separate these effects and define a permeability that depends only on the medium such that

$$K = \frac{k\rho g}{\mu} \quad (3)$$

where

k = intrinsic permeability (L²)

ρ = mass density (M/L³)

g = acceleration of gravity (L/T^2)

$\gamma = \rho g$ = weight density (F/L^3) or (M/L^2T^2)

μ = dynamic viscosity (FT/L^2)

p = pressure (F/L^2)

$\frac{dp}{d\ell}$ = pressure gradient (F/L)

then

$$q_s = \frac{Q}{A} = \frac{-k\gamma}{\mu} \frac{dh}{d\ell}$$

or

$$Q = \frac{-k\gamma A}{\mu} \frac{dh}{d\ell} \quad (4)$$

and in petroleum symbols

$$q_s = \frac{Q}{A} = \frac{-k}{\mu} \frac{dp}{d\ell}$$

or

$$Q = \frac{-kA}{\mu} \frac{dp}{d\ell} \quad (5)$$

Darcy's equation is valid only for laminar flow conditions. Thus, in fractured rock, coarse unconsolidated material, or formations with large solution openings, the equation may not represent the flow.

Steady-State Well Equation. Based on Darcy's work, Thiem⁸ developed an equation for steady (equilibrium) flow toward a well as shown in Figure 12. He assumed that:

- The aquifer is horizontal, homogeneous, and isotropic
- The well is fully penetrating
- The steady flow is maintained long enough so that the zone of influence is no longer expanding with time.

The simple continuity concept of equal flow through adjacent concentric cylinders gives the equation

$$Q = 2\pi Kbr \frac{dh}{dr} \quad (6)$$

where

b = formation (aquifer) thickness (L)

h = height from the bottom of the formation to the piezometric surface at the point indicated by the subscript (L)

Figure 12. Steady flow toward a well.

r_w = radius of well (L)

r_1, r_2 = radial distance from production well to observation wells 1 and 2 (L)

r_e = radius of influence of the well (L).

When integrated between the two observation wells in an unconfined aquifer

$$Q = \frac{\pi K (h_2^2 - h_1^2)}{\ln (r_2/r_1)}$$

or

$$K = \frac{Q \ln (r_2/r_1)}{\pi (h_2^2 - h_1^2)} \quad (7)$$

or in a confined aquifer

$$Q = \frac{2\pi K b (h_2 - h_1)}{\ln (r_2/r_1)}$$

or

$$K = \frac{Q \ln (r_2/r_1)}{2\pi b (h_2 - h_1)} \quad (8)$$

When the limits of integration are the production well and the radius of influence, the equation for a confined aquifer is

$$Q = \frac{2\pi K b (h_e - h_w)}{\ln (r_e/r_w)}$$

or

$$K = \frac{Q \ln (r_e/r_w)}{2\pi b (h_e - h_w)} \quad (9)$$

In petroleum symbols, Equation (9) is

$$q = \frac{0.00708 \, kb (p_e - p_w)}{B\mu \ln (r_e/r_w)}$$

$$k = \frac{qB\mu \ln (r_e/r_w)}{0.00708 \, b (p_e - p_w)} \quad (10)$$

where

q = flow rate (STB/day)

k = intrinsic permeability (md)

p_e = external pressure (psi)

p_w = bottom hole pressure (psi)

B = formation volume factor (RB/STB)

μ = viscosity (cp).

General Differential Equation. Jacob⁹ developed a formal, classical development of the general differential equation for transient flow through a saturated, homogeneous, isotropic porous medium. A more complete development is given by Jacob.¹⁰ Freeze and Cherry¹¹ summarize the development of the equation and the contributions of others to its development. The equation in three dimensions is known as the diffusion equation and is:

$$\frac{\partial^2 h}{\partial x^2} + \frac{\partial^2 h}{\partial y^2} + \frac{\partial^2 h}{\partial z^2} = \frac{S_s}{K} \frac{\partial h}{\partial t} \quad (11)$$

where

S_s = specific storage (1/L)

and the other symbols are as given earlier.

For flow toward a well in a horizontal aquifer of thickness, b , in cylindrical coordinates, the equation becomes:

$$\frac{\partial^2 h}{\partial r^2} + \frac{1}{r} \frac{\partial h}{\partial r} = \frac{S}{T} \frac{\partial h}{\partial t} \quad (12)$$

where

$$T = Kb = \text{transmissivity (L}^2/\text{T)}$$

and

$$S = S_b = \text{storage coefficient (dimensionless).}$$

Any compatible system of units can be used in the equation without introduction of constants. For example, if h and r are in meters and t is in days, the transmissivity, T , is in meters squared per day.

In petroleum symbols and units the equation is:

$$\frac{\partial^2 p}{\partial r^2} + \frac{1}{r} \frac{\partial p}{\partial r} = \frac{1}{C} \frac{\phi \mu c_t}{k} \frac{\partial p}{\partial t} \quad (13)$$

where

$$C = \text{constant depending on units used}$$

$$c_t = \text{system total compressibility (L}^2/\text{F}).$$

With μ in Centipoise, c_t in 1/psi, k in millidarcy, p in psi, r in feet, and t in hours, then $C = 0.0002637$.

Solution of the General Equation. Theis⁵ found a solution of Equation (12) for a steady flow rate, Q , from the well subject to appropriate boundary and initial conditions. The solution, in terms of drawdown, applies to constant discharge from a fully penetrating well in a confined, homogeneous, isotropic aquifer of infinite areal extent with no vertical leakage

$$s = h_0 - h(r,t) = \frac{Q}{4\pi T} \int_u^\infty \frac{e^{-u}}{u} du = \frac{Q W(u)}{4\pi T} \quad (14)$$

where

$$u = \frac{r^2 S}{4Tt} = \text{well function argument}$$

$$s = \text{drawdown at any radius, } r, \text{ at time, } t \text{ (L)}$$

$$h_0 = \text{initial height of piezometric surface above the bottom of the formation (L)}$$

$$h = \text{height of piezometric surface at } r \text{ and } t \text{ (L).} \quad (15)$$

The integral term is known as the well function, $W(u)$, and is available in tabular and graphical form in most ground water literature such as Reference 11. It is represented to any desired degree of accuracy by an infinite series as follows

$$W(u) = (-0.5772 - \ln u + u - \frac{u^2}{2 \cdot 2!} + \frac{u^3}{3 \cdot 3!} - \frac{u^4}{4 \cdot 4!} + \dots) \quad (16)$$

Unsteady State Radial Flow in Isotropic Nonleaky Artesian Aquifer with Fully Penetrating Wells and Constant Discharge Conditions

Analysis in Water Well Terms. Consider Equations (14) and (15) and rewrite them as:

$$\ln s = \ln \left(\frac{Q}{4\pi T} \right) + \ln W(u) \text{ and } \ln t = \ln \left(\frac{r^2 S}{4T} \right) + \ln \frac{1}{u}.$$

This suggests a graphical curve matching technique for analyzing pumping test data. If Q is held constant during the test, then $Q/4\pi T$ and $r^2 S/4T$ are constants and the relationship between $\ln s$ and $\ln W(u)$ is similar to the relationship between $\ln t$ and $\ln 1/u$. When each pair of variables are plotted on the same scale of two different sheets of log-log paper, the resulting curves are similar and are merely displaced horizontally and/or vertically from each other depending on the values of the two constants.

The method proceeds as follows and is illustrated in Figure 13:

1. A reverse type curve, $1/u$ (abscissa) versus $W(u)$ (ordinate) is plotted on log-log paper.
2. The pumping test data, t (abscissa) versus s (ordinate) are plotted on another sheet of the same paper.

Figure 13. Superimposed curves for aquifer constants.

3. The two plots are superimposed on a light table. The two curves are translated vertically and horizontally, keeping the axes parallel at all times, until the best match of the test data with the type curve is obtained.
4. Then a convenient match point near the type curve is selected and the values of the four variables, t , s , $1/u$, $W(u)$ are recorded.
5. Using Equations (14) and (15), the unknown values of the formation coefficients are calculated from:

$$T = \frac{Q W(u)}{4\pi s} \quad \text{and} \quad S = \frac{4tT}{r^2(1/u)}$$

An alternative is to plot the type curve u versus $W(u)$ and the field data s versus (r^2/t) both on log-log paper. The curves are superimposed, match point coordinates are recorded and the aquifer constants calculated as before.

Analysis in Petroleum Engineering Terms. The petroleum engineering approach has been to plot families of dimensionless curves and to fit the well test data to these. Dimensionless time, radius and pressure are defined as:

$$t_D = \frac{0.0002637 kt}{\phi \mu c_t r_w^2}, \quad \text{and} \quad r_D = \frac{r}{r_w}$$

then

$$p_D = f(t_D, r_D, C_D, \text{geometry}) \quad (18)$$

where

C_D = dimensionless wellbore storage factor.

If only the effects of dimensionless time and radius are considered, then

$$p_D = f(t_D, r_D) = -1/2 \operatorname{Ei} \left(\frac{-r_D^2}{4t_D} \right) \quad (19)$$

where

$$\operatorname{Ei}(-x) = - \int_x^\infty \frac{e^{-u}}{u} du$$

The solution of Equation (13) is

$$\Delta p = 141.2 \frac{qB\mu}{kb} f(t_D, r_D) \quad (20)$$

where

$$\Delta p = p_i - p(t, r)$$

$$p_i = \text{initial reservoir pressure (psi)}$$

$p(t,r)$ = reservoir pressure at r and t (psi)

B = formation volume factor (RB/STB)

q = flow rate (STB/D).

Expansion of Equations (19) and (20), and rearrangement of terms shows it to be identical to the water well Equations (14) and (15).

The petroleum method is to plot test pressure, Δp , (ordinate) versus test time, Δt , on log-log paper and to superimpose the plot on a type curve for the value of r_D . A match point is chosen and values of $(\Delta p)_m$, $(\Delta t)_m$, $(p_D)_m$, and $(t_D)_m$ and noted.

Then

$$k = 141.2 \frac{qB\mu}{b} \frac{(p_D)_m}{(\Delta p)_m}$$

and

$$\phi c_t = \frac{0.0002637k}{\mu r \frac{2}{w}} \frac{(\Delta t)_m}{(t_D)_m} \quad (21)$$

Thus, the two methods are seen to be the same in principle.

The petroleum engineers have carried the method further to include other important factors. A more general solution of Equation (13) to include the wellbore storage, geometry, and "skin" effects is:

$$\Delta p = 141.2 \frac{qB\mu}{kb} [f(t_D, r_D, C_D, \text{geometry}) + s_s] \quad (22)$$

$$C_D = \frac{5.6146 C}{2\pi\phi c_t b r \frac{2}{w}} \quad (23)$$

where

C = wellbore storage constant (bb1/psi)

$$C = \frac{\Delta v}{\Delta p} = V_w c$$

and

Δv = change in volume of fluid in wellbore at wellbore conditions (bbℓ)

Δp = change in bottom-hole pressure (psi)

V_w = total wellbore volume (bbℓ)

c = compressibility of the fluid in the wellbore at wellbore conditions (1/psi)

s_s = skin effect, which is a dimensionless pressure drop assumed to occur at the wellbore face ($r_D = 1$) as a result of wellbore damage or improvement. Positive skin effect is due to damage of the wellbore by the drilling process, plugging by mud, etc. Negative skin effect would be an improvement through development of the well, fracturing, reaming, etc.

A variety of type curves including the effects of wellbore storage, reservoir geometry, and skin effects have been developed and many of these are given in Earlougher.³ Skilled use of these curves, where appropriate, allows more information to be extracted from the test data than through use of the simple exponential integral type curve alone. The additional data come from the parameters identifying the various type curves and make possible the computation of wellbore storage and skin effect coefficients, in addition to the permeability and formation storage coefficients already discussed.

Approximate "Straight-Line" Test Methods

The structure of the infinite series in Equation (16) provides a simple test procedure when the value of u is small. As suggested by Cooper and Jacob,¹² all the terms in the series except the first two can be neglected when $u < 0.01$. Then:

$$s = \frac{Q}{4\pi T} \left(-0.5772 - \ln \frac{r^2 S}{4Tt} \right) = \frac{2.3Q}{4\pi T} \log \frac{2.25 Tt}{r^2 S} \quad (24)$$

For most pumping tests, all parameters except t are constant. Thus s will plot as a straight line with $\log t$. The slope of the straight line is seen to be the drawdown over one log cycle, Δs , or

$$\Delta s = \frac{2.3Q}{4\pi T}$$

and

$$T = \frac{2.3Q}{4\pi \Delta s} \quad (25)$$

By extrapolating the straight line to the point where $s = 0$, the intercept, t_0 , on the time axis can be determined. Then:

$$0 = \frac{2.3Q}{4\pi T} \log \frac{2.25 Tt_0}{r^2 S}$$

or

$$1 = \frac{2.25 Tt_0}{r^2 S}$$

and

$$S = \frac{2.25 Tt_0}{r^2} \quad (26)$$

Thus, by plotting s and t on semilog paper, and by noting Δs and t_0 , simple calculations give the aquifer constants. If data from more than three observation wells are available at one time, a distance-drawdown plot can be made of s versus $\log r$; Δs and r_0 can be noted. Then:

$$T = \frac{2.3Q}{2\pi\Delta s}$$

and

$$S = \frac{2.25 T t}{r_0^2} \quad (27)$$

Similarly, if drawdowns in several wells are available over a period of time, plot s versus $\log t$ (t/r^2). Record the drawdown over one cycle, Δs , and the intercept $(t/r^2)_0$. Then:

$$T = \frac{2.3Q}{4\pi\Delta s}$$

and

$$S = 2.25 T (t/r^2)_0 \quad (27a)$$

The three straight-line approximate methods are illustrated in Figure 14.

A similar straight-line approximate method is commonly used in petroleum engineering. The flowing bottom hole pressure, p_{wf} , in psi (ordinate) is plotted against $\log t$ in hours (abscissa). At early times the wellbore storage makes the plot nonlinear, but this is followed by a straight line portion of the plot. The slope, m , in psi/cycle and the intercept, P_{1hr} (where $\log t = 0$ or $t = 1$), on the straight line are recorded. Then:

$$k = \frac{-162.6 q B \mu}{m b}$$

and

$$s_s = 1.1513 \left[\frac{(P_{1hr} - P_i)}{m} - \log \left(\frac{k}{\phi u c_t r_w^2} \right) + 3.2275 \right].$$

For the observation well the skin effect is zero, then the reservoir porosity-compressibility product may be calculated using the equation:

$$\phi c_t = \frac{k}{r^2 \mu} \text{antilog} \left(\frac{P_i - P_{1hr}}{m} - 3.2275 \right).$$

Recovery Tests

Analysis in Water-Well Terms. When a pumping test is discontinued after a period of production, data taken during the recovery period can also be used to determine formation constants. Conditions during the recovery period are represented by imagining that production continues from the well while at the same time an injection well at the same location replaces the fluid produced by the well. The net flow rate is zero and the imaginary injection well can be visualized as representing the recharging fluid coming into the cone of depression from the surrounding area. The drawdown at any point and at any time can be computed by adding the effects of the pumping and the injection as shown in Figure 15.

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Figure 14. Straight line approximate methods.

Figure 15. Drawdown computation.

In terms of well functions, the residual or remaining drawdown

$$s' = \frac{Q}{4\pi T} \int_u^\infty \frac{e^{-u}}{u} du - \int_{u'}^\infty \frac{e^{-u'}}{u'} du' \quad (28)$$

where

$$u = \frac{r^2 S}{4Tt}$$

$$u' = \frac{r^2 S}{4Tt'}$$

and

t = time since pumping began

t' = time since shutoff.

Once t' becomes large, $u' < 0.01$ and the well function can be represented by the first two terms of the infinite series

$$s' = \frac{2.3Q}{4\pi T} \log \frac{t}{t'} \quad (29)$$

and a plot of s' versus $\log t/t'$ is a straight line. If $\Delta s'$ is the drawdown over log cycle, then

$$T = \frac{2.3Q}{4\pi \Delta s'} \quad (30)$$

When concurrent data from one or more observation wells are available, the storativity, S , can be estimated from

$$S = \frac{2.25 T t'/r^2}{\log^{-1} [(s_p - s')/\Delta(s_p - s')]} \quad (31)$$

where

s_p = pumping period drawdown projected to t'

s' = residual drawdown at t'

$\Delta(s_p - s')$ = change in recovery over one log cycle

$(s_p - s')$ = recovery at t' .

Horner Method

Analysis in Petroleum Engineering Terms. The Horner method is used to analyze pressure buildup data. The method has been used extensively in both the geothermal and petroleum industries. The technique is based on superposition of the exponential integral solution. The derivation is as follows:

$\Delta P_{\text{well shut in}} = \Delta P_{\text{due to the well flowing for a time } \Delta t + t \text{ at a rate of } +q,$

$+ \Delta P_{\text{due to a well flowing at a rate of } -q \text{ for a period of time } \Delta t.$

By adding the flow rates at any time the appropriate conditions are modeled:

time $< t$ flow rate = $+q$

time $> t$ flow rate = $+q - q = 0.$

The pressure drop due to a well flowing at $+q$ for a time of $t + \Delta t$ can be expressed:

$$\Delta P(t + \Delta t) = \frac{\mu q}{4\pi kh} \ln \left(\frac{\gamma \phi \mu c r_w^2}{4 k (t + \Delta t)} \right)$$

and similarly,

$$\Delta P(\Delta t) = \frac{-\mu q}{4\pi kh} \ln \left(\frac{\gamma \phi \mu c r_w^2}{4 k \Delta t} \right).$$

Adding these together:

$$P_i - P_{\text{well shut in}} = \frac{q\mu}{4\pi kh} \ln \left(\frac{t + \Delta t}{\Delta t} \right).$$

In standard petroleum engineering units

$$P_i - P_{\text{well shut in}} = 162.6 q \frac{\mu B}{kh} \log \frac{t + \Delta t}{\Delta t}.$$

This equation forms the basis for the Horner method. As can be seen from the equation, when $(t + \Delta t/\Delta t)$ and $P_{\text{well shut in}}$ are plotted on semilog paper, the data should plot as a straight line with the slope

$$= \frac{162.6 q \mu B}{kh}.$$

Therefore:

$$\frac{kh}{\mu} = \frac{162.6 q B}{\text{slope}}$$

The skin value can be calculated as discussed in the previous section:

$$S = 1.151 \left[\frac{P_{1 \text{ hour}} - P_{\text{flowing}}}{\text{slope}} - \log \frac{k}{\phi \mu c r_w^2} + 3.23 \right]$$

In order to estimate the skin value an independent estimate of ϕch must be available. In the petroleum industry, this is usually obtained by testing cores in the laboratory. For geothermal reservoirs this is best estimated from the analysis of interference test data.

Analysis of Unsteady State Radial Flow in Isotropic Nonleaky Artesian Aquifer with Fully Penetrating Wells and Constant Drawdown Conditions

Analysis in Water-Well Terms — Curve Matching Techniques. For a flowing artesian well, it may be simpler to test the well with a constant drawdown and a varying flow rate than with the methods, already discussed, that require a constant discharge and variable drawdown. Under geothermal conditions, the well would need to be preheated by flowing at a low rate before the test so that thermal effects on pressure at the well will be largely eliminated. Jacob and Lohman¹³ found the solution to the general equation for these conditions as follows:

$$Q = 2\pi T s_w G(\alpha)$$

where

$$\alpha = \frac{Tt}{S r_w^2}$$

and

$$G(\alpha) = \frac{4\alpha}{\pi} \int_0^{\infty} x e^{-\alpha x^2} \left[\frac{\pi}{2} + \tan^{-1} \left(\frac{Y_0(x)}{J_0(x)} \right) \right] dx \quad (32)$$

where

$J_0(x)$ = zero order Bessel function of the first kind

$Y_0(x)$ = zero order Bessel function of the second kind.

The function $G(\alpha)$ is available in Jacob and Lohman¹³ or Walton.¹⁴

A curve matching technique is used for the well test. Values of Q/s_w (ordinate) are plotted against t/r_w^2 (abscissa) on log paper (or plot Q versus t). This well test plot is superimposed over the type curve $G(\alpha)$ (ordinate) versus α (abscissa). A match point is chosen and the aquifer constants determined from

$$T = \frac{Q}{2\pi s_w G(\alpha)}$$

and

$$S = \frac{Tt}{\alpha r_w^2} \quad (33)$$

Analysis in Water-Well Terms — Straight Line Approximations. Jacob and Lohman¹³ observed that the function $G(\alpha)$ can be approximated closely by $2/W(u)$ for all except very small values of t . The approximation of $W(u)$ by the first two terms of the infinite series in Equation (16) has already been noted. Thus, it can be expected that (s_w/Q) versus $\log (t/r_w^2)$ will plot as a straight line since by substitution in Equation (32),

$$Q = \frac{4\pi T s_w}{2.3 \log \left(\frac{2.25 Tt}{r_w^2 S} \right)}$$

or

$$\frac{s_w}{Q} = \frac{2.3 \log \left(\frac{2.25 Tt}{r_w^2 S} \right)}{4\pi T} \quad (34)$$

The test data are plotted as (s_w/Q) (ordinate) against $\log (t/r_w^2)$ (abscissa), where Q is the average discharge during a timed interval in the test (L^3/T). A straight line is fitted to the data and the slope (the change in $\Delta(s_w/Q)$ over log cycle) and the intercept (the value of t/r_w^2 at $s_w/Q = 0$) are noted. Then

$$T = \frac{2.3}{4\pi \Delta(s_w/Q)}$$

and

$$S = 2.25 T \left(t/r_w^2 \right)_0 \quad (35)$$

$$S = \frac{2.25 T t/r_w^2}{\log^{-1} \left[\frac{(s_w/Q)}{\Delta(s_w/Q)} \right]} \quad (36)$$

If the intercept is difficult to obtain because of the distant extrapolation required, the S may be determined from Equation 36

where

s_w/Q = value taken near the middle of the straight line plot

and

$\Delta(s_w/Q)$ = change in the value over one log cycle.

Analysis in Petroleum Engineering Terms. The constant-pressure flow testing has been described by Earlougher³ in petroleum terminology. For the curve matching technique, the test data are plotted as flow rate (q) in STB/D (ordinate) against time (t) in hours (abscissa) on log-log paper. The data are superimposed over the type curve, $q_D(t_D)$, on the same type of log-log paper as given by Earlougher.³ Once the best superposition has been found, the coordinates of a match point are recorded. Then:

$$k = \frac{141.2 B\mu}{(p_i - p_{wf})^b} \frac{q_m}{((q_D)_m)}$$

and

$$(\phi c_t b) = 0.0002637 \frac{kb}{\mu r_w^2} \left[\frac{t_m}{(t_D)_m} \right] \quad (37)$$

A zero skin factor is assumed in the type curve, and P_{wf} = flowing bottom hole pressure (psi).

A straight-line method has also been developed which is within 2% when $t_D \geq 5000$. A skin factor is included in the formulation. In the method $1/q$ is plotted versus $\log t$ and a straight line is fitted to the data. The straight line slope, m_q , and the intercept at $t = 1$ hour, $(1/q)_1$ hr are recorded. Then:

$$k = \frac{162.6 B\mu}{m_q (p_i - p_{wf})^b}$$

and

$$S_s = 1.1513 \left[\frac{(1/q)_1 \text{ hr}}{m_q} - \log \left(\frac{k}{\phi \mu c_t r_w^2} \right) + 3.2275 \right] \quad (38)$$

Well Losses

The total drawdown, s , during a test of a production well is made up of some or all of the following parts:

- s_f = formation loss due to the laminar flow through the aquifer towards the well
- s_w = well loss due to turbulent or near turbulent flow through the developed zone and/or the gravel pack and the well screen
- s_p = additional formation loss due to the effects of partial penetration of the well into the aquifer
- s_d = additional drawdown in cases of dewatering a portion of the aquifer
- s_b = drawdown due to barrier boundaries of the aquifer
- s_r = buildup due to recharge boundaries of the aquifer
- s_T = apparent drawdown or buildup due to temperature effects.

Stated as an equation

$$s = s_f + s_w + s_p + s_d + s_b + s_r \pm s_T \quad (39)$$

Step Drawdown Tests for Well Losses

In many wells where there are no effects due to partial penetration or dewatering, the test may not go on long enough to be affected by boundaries and temperature effects may be negligible due to preheating. Thus, only the first two terms of the equation remain.

In laminar flow the drawdown is related linearly to the flow rate, Q , while in turbulent flow it is related to some power of Q near 2 as suggested by Cooper and Jacob.¹²

$$s = s_f + s_w = C_f Q + C_w Q^n \quad (40)$$

Rorabaugh¹⁵ developed a graphical procedure whereby C_f , C_w , and n are evaluated from a step drawdown test. The procedure is to pump the well at a selected Q until s changes little with time; then Q is immediately increased and s is measured after the same time interval as used for the first step; and the process is repeated for four or five values. No recovery of the well is allowed between different pumping rates. Equation (40) can be rewritten as:

$$\frac{s}{Q} - C_f = C_w Q^{n-1}$$

or

$$\log \left(\frac{s}{Q} - C_f \right) = \log C_w + (n - 1) \log Q \quad (41)$$

Thus $(s/Q - C_f)$ versus Q on log-log paper will plot as a straight line with a slope of $(n - 1)$ and an intercept C_w where $(s/Q - C_f) = 1$. Such a plot cannot be constructed, however, since C_f is not known. The procedure is to assume different values of C_f and plot a series of lines until a value of C_f is formed that makes the plot a straight line, as illustrated in Figure 16 which is taken from Bouwer.¹⁶

In the example, $C_f = 0.004$ gives a straight line whose slope is $n - 1 = 1.3$ and thus $n = 2.3$. In actual tests n may be as high as 3.5 but is usually near 2. The value of C_w can be determined by extrapolating the straight line to where $(s/Q - C_f) = 1$ or, alternatively, known values of C_f , n , s , and Q can be substituted into Equation (41).

Once the constants in Equation (41) are known, estimates can be made of the drawdown, s , for different (increased) values of flow rate, Q .

In petroleum parlance, the step drawdown test is called the "flow after flow" test.

Pulse Tests

If the well is allowed to recover for a time between increasing flow rate steps, the procedure is known as a pulse test. In petroleum terms, this test is called the "modified isochronal flow test." A "pulse test" in petroleum engineering is a multiple well test in which flow rate pulses of constant rate with equal shut-in periods in between are produced and the resulting pressure changes are recorded in a nearby observation well.³

Figure 16. A plot to determine C_f .

Superposition of Solutions Applied to Multiple Wells and Multiple Rates

The drawdown at any point in a confined aquifer with more than one well is the sum of the drawdowns that would occur from each well individually. This is so because Equation (12) is linear (that is, there are no cross terms of the form $(\partial h / \partial r) (\partial h / \partial t)$). Thus, in terms of well functions, one can write for a system of n wells, each with different flow rates:

$$s = \frac{1}{4\pi T} \sum_{i=1}^n Q_i W \left(\frac{r_i^2 S}{4Tt_i} \right)$$

$$i = 1, 2, 3, \dots, n \quad (42)$$

where

s = drawdown at a selected location

r_i = distance from the selected location to the i^{th} well

and

t_i = time since pumping began at the well whose flow rate is Q_i .

A negative flow rate can be used to represent injection of fluid at a well. The equation also defines the interference of wells with each other.

This principle can also be applied to multiple flow rates at one well as given by Bear¹⁷ and illustrated in Figure 17. For these conditions

$$s = \frac{1}{4\pi T} \sum_{j=1}^m (Q_j - Q_{j-1}) W \left[\frac{r^2 S}{4T(t - t_j - 1)} \right] \quad j = 1, 2, 3, \dots, m \quad (43)$$

where

$$Q_0 = 0 \text{ at } t \leq 0$$

s = drawdown at a given point a distance r from the well at time t

t_j = time since pumping began at rate Q_j

and

index j identifies the pumping period.

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Figure 17. Multiple pumping rates.

The Effect of Fluid Density on Water Level and Wellhead Pressure Measurements

If it is not possible to obtain downhole pressure transient data, the free water level in a well (or the wellhead pressure) must be used for all pressure transient measurements. When the static level or wellhead pressure is used for pressure transient calculations, it is important to understand the effects of changes in density of the fluid filling the wellbore. The density of the fluid in the wellbore is dependent on the temperature and salinity of the fluid. Since the salinity will probably remain relatively constant throughout the test, only the change in density due to temperature will be considered. The density of water as a function of temperature is plotted in Figure 1.

If static water level (SWL) is the water level in the wellbore, the reservoir pressure can be calculated as follows:

$$P_{\text{res}} = \int_0^{H - \text{SWL}} \rho g \, dz + P_{\text{wellhead}}$$

where

SWL = static water level (m)

ρ = fluid density (kg/m^3)

g = gravitational constant (m/s^2)

z = depth ($z = 0$ reservoir)

H = length of the wellbore (m)

P_{res} = reservoir pressure (Pa).

If the density of the fluid along the entire length of the wellbore is known, then the integral can be evaluated and the reservoir pressure determined. Several examples are given below.

Example 1

What will the SWL be if the temperature of the wellbore changes from a 50°C isothermal profile to a 100°C isothermal profile?

$$P_{\text{res}} = \int_0^{H - \text{SWL}(50^\circ\text{C})} \rho g \, dz = \int_0^{H - \text{SWL}(100^\circ\text{C})} \rho g \, dz$$

If ρ is only a function of temperature, and the temperature is constant, then it is trivial to evaluate the integral

$$P_{\text{res}} = \rho(50^\circ\text{C})g (H - \text{SWL}_{50^\circ\text{C}}) = \rho(100^\circ\text{C})g (H - \text{SWL}_{100^\circ\text{C}})$$

To convert P_{res} from psi to Pa, multiply by 6895 Pa/psi.

The difference in static water level can be calculated for several well depths (h).

P_{res} (psia)	H (m)	SWL _{50°C} (m)	SWL _{100°C} (m)
120	100	13.82	10.73
600	500	69.14	53.65
1200	1000	138.3	107.3
2400	2000	276.6	214.6

Example 2

What will the approximate SWL be in a well with a linear temperature gradient (with 50°C at the SWL and 150°C at the reservoir) compared with a hot wellbore at 150°?

$$P_{res} = \int_0^{H-SWL} \rho g dz$$

$$\rho(T) \approx 980 - 0.75 (T - 50^\circ\text{C})$$

$$T(z) \approx 150 - 100 \frac{z}{H}$$

$$\text{so: } \rho(z) \approx 980 - 75 \left(1 - \frac{z}{H} \right)$$

$$P_{res} = \int_0^{H-SWL} \left[980 - 75 \left(1 - \frac{z}{H} \right) \right] g dz$$

P_{res} (psia)	H (m)	SWL _{Linear Gradient} (m)	SWL _{150°C} (m)
120	100	9.75	6.7
600	500	50.3	33.4
1200	1000	100.6	66.8
2400	2000	201.2	133.7

As can be seen from the two examples presented above, the temperature of the fluid has a large effect on the SWL. When the temperature changes as a function of depth in the wellbore, it is difficult to separate this phenomena from true pressure changes in the reservoir. This phenomena is particularly important to understand in the interpretation of pressure build-up data because the wellbore quickly starts to cool when the well is shut-in. The effects of the density changes in the wellbore fluid on the measured pressure response can be eliminated in two ways: by using downhole pressure instrumentation, or by using a wellbore code to calculate the temperature of the fluid in the wellbore.

As can be seen from the two examples, the density changes of the fluid will have the most pronounced effect on deep wellbores. For a wellbore length of less than 100 m, these changes may not be significant. However, for a deep well (500 to 2000 m), even small temperature changes will dramatically affect the SWL or wellhead pressure.

7. TEST PLANNING AND METHODOLOGY

Preliminary Test Preparation and Design

Before planning a test the developer and his hydrogeologic/reservoir engineering consultant should review the local, state, and federal regulations for fluid production and disposal. These regulations are available through individual state geothermal resource teams, the state water resource or oil and gas department, the U.S. Geological Survey, or the Environmental Protection Agency. Special permits to produce and dispose geothermal fluids may be required. Therefore, any limitations or restrictions must be considered before designing the test. Certain restrictions (i.e., discharge of geothermal fluids to lined ponds only) will raise the cost of testing and limit test duration and/or test discharge rates which could result in inappropriate or inadequate data. The restrictions will probably depend on the water quality, the temperature of the thermal fluid, and/or the compatibility with local water resources. Some eastern states, such as New Jersey, require all geothermal fluid, including any testing fluid, to be discharged into an injection well. Thus, testing of any production or test well will require the additional cost of an injection well.

After the developer or consultant has evaluated and made allowances for testing regulations they need to determine the end use of the well, i.e., whether it will be a production or a test/monitor well. They then need to determine whether the reservoir is intergranular permeable, fracture-controlled, or has dual porosity. If the type of reservoir is unknown, it should be treated as a fracture flow case.

The first design decision to be made is whether to test produce the well using a pump or by natural artesian flow. This decision will be clear cut if artesian conditions are not present. An air lift or nitrogen lift test is not recommended for geothermal resources because flow rate control is at best difficult. For a production well test, the anticipated end-use method of producing the geothermal fluid should be used. However, for test wells, the less expensive method of artesian flow testing is recommended. If a moderate temperature resource is being tested, the additional factor of flashing (boiling) at the wellhead or orifice must be considered. At temperatures greater than approximately 100°F, sufficient pressure must be maintained across a fluid discharge measuring device to prevent flashing, otherwise expensive two-phase measurement equipment will be necessary. If the well is to be artesian flow tested, an additional possibility must be considered, i.e., can the well be completely shut-in? If the well cannot be shut-in, the capability of flow rate regulation is necessary. In all cases the consultant should determine the testing parameters and be sure that all relevant data can be obtained and pertinent variables controlled.

Test Pump. If a pump is required, the consultant must select the pump, determine the pump elevation setting, and evaluate the pump limitations. A combustion-engine-driven pump is recommended for testing as this will allow for a wide range of discharge rates. An additional reason for using a test pump rather than the intended production pump is the potential damage to the pump by the corrosive nature of early postdevelopment discharge fluids. The estimated pump setting depth should be developed from the data collected during the drilling and development process. It is better to set the pump deep rather than run a test at too low a flow rate or for too short a time, or to be forced to pull the pump out and set it deeper.

There are technical problems with off-the-shelf, water well type pumps even at low temperatures. The main problems are in lubrication of moving parts, cooling of motors and moving parts, and differential expansion. Information from several brand name pump distributors suggests that warranties on submersible pump motors will not be honored at temperatures above 37.8°C. Vertical turbine pumps can be used for extended periods of time in geothermal fluids if care is taken to account for differential thermal expansion and lubrication. In addition, the corrosive nature of the geothermal fluid must be considered in selecting pump materials.

Test Instrumentation. After anticipated drawdown, temperature, and flow rates have been estimated, instrumentation suitable to measure those parameters should be chosen. The recommended accuracy and resolution of the data limits or restricts the instruments that should be used. Most off-the-shelf, low-cost

pressure gauges are not sufficiently accurate or do not have sufficient resolution. On the other hand, it may be uneconomical for the developer of a low-temperature resource to use the sophisticated and expensive surface or downhole instrumentation used in moderate- to high-temperature geothermal developments. One alternative for low-temperature resources is that the producing well be supplied with a continuous bubbler tube in conjunction with moderate-cost surface gauges that at least meet the resolution requirements. This will reduce early-time thermal effects and result in accurate relative change of pressure or water level. It is also recommended that fluid discharge temperature data be obtained continuously or at least on the same measurement schedule as pressure and discharge rate. It is also necessary to consider the thermal effects on the instrument operation. Economical instrumentation, due to the required accuracy and resolution and due to thermal problems, is currently a problem in low-temperature geothermal development. Additional cost-effective instrumentation needs to be developed.

Appendix C lists a variety of instruments employed in low-to-moderate temperature systems. A brief discussion of accuracy and resolution is also available for reference.

Test Parameters. General statements on test parameters are difficult to make, because the test design depends on the information needed. The general recommendations provided here should be applied with extreme caution, and used only after the end use of the well and the purpose of the test has been determined.

The test parameters that need to be addressed at this time are a function of the test type, discharge rate, the duration of the test, and fluid temperature. The "test type" refers to the standard procedural well tests in the petroleum and ground water industries, i.e., step test, pulse test, constant-discharge variable-head test, etc. The recommended method and limits will depend not only on the decision path taken during test preparation and test design, but also on the dollar investment of the project. It is assumed for this document that the testing of moderate-temperature resources will be expensive.

Recommendations of test parameters for low-temperature cases are presented in Table 2.

Recommendations of test parameters for moderate-temperature cases are presented in Table 3. There is less divergence from standard ground water or petroleum testing procedures, because downhole instrumentation is subjected to minimal temperature change and eliminates the problems created by borehole density effects. Moderate-temperature cases that do not use downhole pressure/temperature instrumentation should follow the recommendations for low-temperature resources.

Testing Methods. Testing methods may be categorized according to the following:

1. Discharge or injection rate:
 - a. Constant rate flow tests (variable drawdown)
 - b. Multiple flow rate tests
 - c. Variable flow rate tests (constant drawdown).
2. Flow duration:
 - a. Step tests
 - b. Pulse tests
 - c. Short-term tests
 - d. Long-term tests

Table 2. Recommended test parameters for low-temperature hydrothermal systems

Test Parameters	Test Well								Production Well							
	Intergranular Permeable				Fractured or Unknown				Intergranular Permeable				Fractured or Unknown			
	Flow				Flow				Flow				Flow			
	Pump	Shut-In	Rate Control	No Rate Control	Pump	Shut-In	Rate Control	No Rate Control	Pump	Shut-In	Rate Control	No Rate Control	Pump	Shut-In	Rate Control	No Rate Control
Type Test(s)	B CD R — —	B CD R — —	B CD R — —	B — — — CH	B CD R — —	B CD R — —	B CD R — —	B — — — CH	B Pr CD R —	B Pr CD R —	B Pr CD R —	B — — — CH	B Pr CD R —	B Pr CD R —	B Pr CD R —	B — — — CH
Flow Rate	RD	RD	RD	—	MP	MP	MP	—	RD	RD	RD	—	E	E	E	—
Minimum duration (days)	2-4	2-4	2-4	30 +	3-7	3-7	3-7	30 +	5-10	5-10	5-10	30 +	10-20	10-20	10-20	30 +

Legend B = Borehole temperature log (if possible)
 CD = Constant-discharge variable-head
 PR = Pulse and recovery
 R = Recovery
 E = End-use requirements
 MP = Maximum practical
 RD = Reduced discharge rate
 CH = Constant head, variable discharge

Data Requirements^a

	Resolution	Accuracy
Pressure	1.0 psi	±1% F.S.
Temperature	±0.5°C	±1°C
Flow	±0.5% F.S.	±1% F.S.

a. See Reference 18.

Table 3. Recommended test parameters for moderate-temperature hydrothermal resources

Test Parameter	Test Well		Production Well	
	Intergranular Permeable	Fracture Control	Intergranular Permeable	Fracture Control
Type test(s)	StD R —	StD R —	S or P StD R	S or P StD R
Flow rate	RD	MP	RD	E
Minimum duration (days)	0.3-3	3-7	3-7	10-20

Assumes use of downhole instrumentation in production zone

Legend	S or P StD R RD MP E	= Step test or pulse test = Acceptable standard for testing = groundwater or petroleum resources = Recovery = Reduced discharge rate = Maximum practical discharge rate = End use requirements discharge rate	Data Requirements (Lamers, 1974)		
				Resolution	Accuracy
			Pressure	1.0 psi	± 1% F.S.
			Temperature	± 0.5°C	± 1°C
			Flow	± 0.5% F.S.	± 1% F.S.

3. Test geometry:
 - a. Single well test
 - b. Multiple-well production
4. Well tests with observation wells
5. Injection testing
6. Recovery tests.

Constant Rate Flow Tests — Constant rate flow tests are commonly used in both ground water and petroleum industries and are highly recommended for low-to-moderate temperature geothermal well testing. In the constant rate flow test, the desired pumping rate has to be obtained as fast as possible and maintained throughout the test duration. The flow rate is carefully monitored and adjusted if changes are observed. Pumping rates for a constant rate flow test should be carefully designed to provide enough flexibility for these adjustments. Drawdown and temperature data are collected according to a time schedule designed specifically for each test. An advantage to the constant rate flow test method is that analysis techniques are well developed.

Multiple-Flow Rate Tests — Multiple-flow rate tests are used to estimate well losses, specific capacity, well productivity, skin effects, and reservoir parameters. This type of test is commonly conducted before testing at constant rates to aid in subsequent test planning.

Variable Flow Rate Tests — The hydraulic properties of a reservoir can be determined from a well test in which the discharge rate varies with time and the drawdown remains constant.¹⁹ The change in discharge rate is plotted against the logarithm of time. This type of test is most effective for an artesian flowing well. Thermal changes may cause problems in maintaining a constant head. This type of test is not normally used for testing geothermal wells.

Step Tests — A step test consists of an abrupt increase or decrease in the fluid discharge rate with no recovery allowed between steps. Each pumping rate is continued at a constant flow until the well approaches a steady flow condition, after which the discharge rate is abruptly increased or decreased to the next level. Each step interval may last from 30 minutes to four hours. This procedure is continued for several discharge rates. This type of testing is most useful in geothermal wells in which downhole instrumentation, i.e., downhole pressure bombs and temperature probes are used to collect data. This is because some time is required after each discharge change before the surface temperature becomes stable and temperature effects can be neglected.

Pulse Tests — Pulse tests are conducted at increasing or decreasing discharge rates with recovery allowed between each pulse interval. Data are collected for the pumping and recovery portions of each rate. Each pulse interval may last from one hour to several days. In geothermal well testing, longer pulses are recommended to provide enough time so that early recovery data with thermal effects will not have to be used. Pulse testing is not commonly used in the ground water industry. The petroleum industry uses this type of test to determine reservoir anisotropy.

Short- and Long-Term Tests — Duration of a test in terms of "long or short" is a relative measure; however, these terms are commonly used in practice. A test conducted for less than three days should be considered short-term. A long-term test is commonly conducted for more than three days with no defined maximum time limit. Tests of long duration are recommended more often in geothermal aquifer testing than in ground water or petroleum well testing. This recommendation is based on the following factors: the hydrogeology and geologic structure of a geothermal reservoir is often complex; reservoir volumes are so large that long production periods are needed to produce significant pressure responses; and there is no alternative method to predict resource temperature changes.

Single- and Multiple-Well Tests — Classification of tests by geometry includes single well tests and multiple-well tests. The multiple-well production test is more complex, and more difficult to evaluate than single-well production tests. A single-well production test may be needed prior to the multiple well test to provide a basis for comparison. The multiple-well production test should provide information about both interference effects between wells and aquifer properties. In general, less precise reservoir data are obtained from multiple-production well tests due to reservoir heterogeneity.

Well Tests with Observation Wells — Generally, there is little difference between test procedures with or without observation wells. Tests with observation wells provide a more complete data base for evaluating aquifers. These data are average values for a large area of the reservoir. Whenever practical, the use of observation wells is recommended.

Injection Testing — Injection testing may be accomplished by injecting fluids from a body of surface water or a production well. The following factors should be considered when choosing the injection interval:

1. Interference and cooling effect on a production zone
2. Environmental impact of the injected fluid on a potable ground water aquifer
3. Cost of the injection well.

Data on injection rate, wellhead temperature, and wellhead or downhole pressure are collected from the injection well. Injection test data are analyzed by the same methods as the previously discussed test data. Because disposal of the geothermal fluid by injection is often necessary, injection testing may be used frequently in geothermal fields. However, care should be taken to prevent damage to the formation due to clay swelling or fluid incompatibility. Injection testing, as a means of determining reservoir parameters, is not recommended in sedimentary formations.

Recovery or Fall-Off Testing — A recovery or fall-off test should follow all production or injection tests. Measurements of pressure or head recovery begin immediately after pumping or injection is stopped. Theoretically, the recovery phase should last as long as the production/injection phase. If surface instrumentation is used for a geothermal well, time-dependent fluid-density effects will limit the usefulness of early-time data. An advantage in analyzing recovery data is that major fluctuations in discharge have minimal effect. It should be stressed that recovery data are as important as production data and often are of better quality. This is one of the most common test methods used by the oil and gas industry.

Reservoir Parameters

The following well and reservoir parameters, determined by analyzing test data, are given in order of increasing complexity:

1. Specific capacity and well efficiency
2. Aquifer transmissivity (T) and storativity (S)
3. Skin factor and wellbore storage
4. Well-loss constant
5. Aquifer permeability (k), or thickness-permeability product (kh) and porosity-compressibility-thickness product ($\phi c h$).

Definitions of Key Parameters.

Specific Capacity and Well Efficiency — The specific capacity (productivity index) of a well is its yield per unit of drawdown at a specific time and is a practical number characterizing a given well. Generally, high specific capacity indicates high aquifer transmissivity. Correlation between specific capacity and transmissivity can be made;²⁰ however, it is not recommended for final aquifer evaluations. The higher the specific capacity, the better the well. A good geothermal well may have a productivity index as high as 50 gpm/psi drawdown.

Well efficiency is the ratio of the theoretical drawdown in the formation to the actual drawdown measured in a pumped well including well losses. Specific capacity and well efficiency are well parameters widely used in ground water well-testing methods.

The ratio of the rate of production to the pressure drawdown at midpoint of the producing interval is called the productivity index. The productivity index is a term used in the petroleum industry and is equivalent to the term specific capacity used in the water well industry. The index measures the well's potential to produce.

Aquifer Transmissivity (T) and Storativity (S) — Transmissivity is a term used in the ground water industry to characterize the ability of the aquifer to transmit a fluid. The transmissivity (T) is a number indicating the rate at which fluid flows through a unit width of the aquifer under a unit hydraulic gradient. Although, transmissivity characterizes a property of the aquifer, it is also a property of the transmissivity fluid.

Storativity is the ground water term used to express the storage capacity of an aquifer. The storativity (S) is a number indicating the volume of water released from or taken into storage per unit surface area of the aquifer per unit change in head. Storativity (S) is dimensionless.

Skin Factor and Wellbore Storage — The skin factor is a petroleum term which is represented by a steady-state pressure drop of the well face in addition to the normal transient pressure drop in the reservoir.³ The skin factor increases or decreases the pressure change of the well, depending on the flow rate of the well. Wellbore storage affects the short-time transient pressure behavior in the test well. The skin factor and wellbore storage both affect the early-time portion of the data. These effects can be accounted for in test analysis.

Well-Loss Constant — The well-loss constant characterizes the losses due to the well screen plus the gravel pack or developed area near the well and can be evaluated from a step test or several pulse tests. A properly developed well has a well-loss constant less than $5 \text{ sec}^2/\text{ft}^5$.²⁰

Aquifer Permeability, Thickness-Permeability Product and Porosity-Compressibility Thickness Product — Aquifer permeability (k) or the absolute permeability of the rock,² is a property of the rock and not of the fluid which flows through it. The unit of permeability used in the petroleum industry is the Darcy unit. A rock of one Darcy permeability will allow a fluid of one centipoise viscosity to move at a velocity of one centimeter per second under a pressure gradient of one atmosphere per centimeter.²

The thickness-permeability product (kh) is a term characterizing the fluid transmitting ability of the aquifer. The thickness-permeability product is a petroleum industry term which is somewhat similar to the term transmissivity used in the ground water industry. The difference is that the transmissivity characterizes fluid transmitting aquifer properties for a fluid, and thickness-permeability product is independent of the fluid.

The porosity-compressibility-thickness product ($\phi c_t h$) is a term used in the petroleum industry that is equivalent to the term storativity used in the ground water industry. The unit used for the porosity-compressibility-thickness product is in ft/psi .

Analyzing Test Data.

Evaluating Early-Time Data — Data which are not thermally affected are evaluated according to standard petroleum and ground water techniques.^{3,14} However, all of the techniques are not applicable. The methods recommended in Table 4 are general categories of techniques which should be applied. The specific techniques applicable to each category will depend on the quantity and quality of the reservoir test data plus other geologic and hydrologic inferences gathered during the exploration and drilling phases. These specific techniques are described by Walton,¹⁴ Earlougher³ and others conversant in the ground water and petroleum fields.

Early-time data emphasized in the ground water and petroleum industries are often not as useful in analyzing low-temperature geothermal production wells due to thermal and density changes effecting surface data. These problems can be eliminated by collecting downhole data.

The recovery data may also be affected by time-dependent thermal changes if downhole data is not used. The thermal effect increases with time from the start of recovery. This means that early-time recovery data is important and late-time data becomes hard to analyze.

Analyzing Fracture Flow — Fracture flow analysis has been discussed by numerous authors, i.e., Warren and Root, Papadopoulos, Rofail, Gringarten, Streltsova, Dugiud, and Aquilera.²¹⁻²⁸ Most analytical methods assume either a single fracture for production or a block response. The solutions are for the most part not analytical or field oriented, but computer model comparisons. Field analyses of fractured systems have conventionally relied on anisotropic analysis of intergranular permeable systems. The assumption that fracture flow averaged over a large enough area, acts like an intergranular permeable system, is not unreasonable.²⁹ However, this approach suggests that early-time data may not be useful.

Evaluating Reservoir Parameters — A critical part of well test analysis is evaluation of reservoir parameters. The theoretical background and essential elements of well test analysis were presented in Section 6. This section presents several methods developed by the ground water and petroleum industries that are commonly used in the geothermal industry as well.

Table 4. Recommended test analysis methods for low-temperature hydrothermal development

Type Well	Test Type	Considerations	Recommended Methods	
			Intergranular Permeability	Fracture Controlled
Production	Pulse	Transient density skin effects or well loss wellbore storage boundaries	Graphical ^a (straight line)	Graphical ^a (straight line)
	Drawdown	Transient density	Graphical ^a (type curve or straight line)	Graphical ^a (type curve or straight line)
	Recovery	Same Same	Transient and semisteady state (straight line)	Graphical ^a (straight line)
Observation	Drawdown and recovery	Anisotropy, boundaries	Transient and semisteady state (type curve)	Anisotropic and fracture methods (type curve)

a. Use of Q/s_{10} technique.

Evaluating Graphical Methods of Test Data — Graphical methods are commonly used in the water well and petroleum industries. One such method is the type-curve matching method.

Type Curves — The graphical methods of superposition provide one way of evaluating reservoir parameters. The type-curve matching analysis method may be used for drawdown, buildup, interference, and constant pressure testing. The method should be applied where downhole data are being obtained since early-time thermal effects will impact surface readings. Type curves are obtained by plotting selected values of $W(u)$ versus u on a logarithmic graph paper.⁵ For constant flow during a test $W(u)$ is related to u in the same manner as drawdown is related to the r^2/t or $1/t$. Therefore, if the recorded values of drawdown are plotted on a logarithmic scale against r^2/t or $1/t$ on a similar logarithmic scale, the raw data curve should be similar in shape to the type curve. However, the two curves may be displaced both vertically and horizontally.

The type-curve-matching method used in the petroleum industry is similar to that used in the water well industry. Data are typically plotted in terms of logarithm pressure change versus logarithm test time. The type curve is in units of dimensionless pressure versus dimensionless time.

Standard type curves are developed for various aquifer geometries and conditions such as wellbore storage and skin effects. The type curve evaluation technique is widely used in water well industry and to some extent the petroleum industry. Use of type curves for geothermal well testing analysis is limited when using uphole data because of time-dependent thermal effects.

Straight-Line Solutions — The straight-line solution is another graphical method for aquifer test analysis when considering semisteady-state conditions. Typically, time is plotted on the logarithmic scale versus drawdown, which is plotted on a linear scale. The data points should ideally form a straight line.¹² The slope of water level change over one log cycle of time is needed to calculate reservoir parameters.

Recovery data should be analyzed using the ratio of time from start of pumping and time from start of recovery plotted on the logarithmic scales. Reservoir parameters are calculated using the same equation as for a drawdown plot.

If more than one observation well is used for data collection, a distance-drawdown plot may be used for test analysis.⁸ Distance is plotted in the logarithmic scale and drawdown on the linear scale.

The straight-line plot is recommended for geothermal well testing. However, it must be remembered that time-dependent thermal effects on the water level data may significantly influence the plot. For example, an increase in water temperature may have an effect similar to a recharge boundary and a decrease in temperature during shut-in may appear similar to a barrier boundary.

Monitoring Observation Wells (Interference Tests)

Any well or spring within a 1 to 5 km radius of the producing well that is potentially connected hydraulically with the geothermal reservoir should be monitored during testing. The geology and construction of any observation wells should be evaluated. It will be necessary to determine the elevation of a measuring point relative to the producing well, and the use schedule of the observation well, if appropriate. Pressure measurement and the instrumentation for the observation wells should follow water well standards and practices.

There should be no difficulties with thermal conditions at observation wells, unless the well is flowing and cannot be shut-in. If a well or spring is flowing, discharge, temperature and water quality measurements should be obtained.

If there are any wells or springs within a 1 to 5 km radius of the production well which cannot be shut-in for the test duration, it will be necessary to determine if there will be any potential hydraulic interference problems. If there are, discharge should be regulated during and after the test. If this is not possible, then at least a record of production from the observation well should be kept.

Fluid Disposal

The technical aspects of fluid disposal must be considered. This may mean calculating the fill rate of a pond to determine if the test can run for the projected duration at the desired discharge rate. It may mean determining the anticipated thermal or water quality change in a stream at the desired discharge rate. The disposal must consider the waste heat in addition to the water quality.

Because elevated temperatures increase solution kinetics and mineral solubility, geothermal waters tend to be higher in dissolved solids than surrounding ground waters. Thermal waters can also have high concentrations of particular dissolved species that may cause special disposal problems, such as arsenic, mercury, boron, or fluoride. Environmental regulations generally prohibit the disposal of effluents into surface streams where the effluent will degrade the quality. Table 5 lists the dissolved species most likely to be present in troublesome quantities in geothermal fluids. Water samples should be collected and analyzed for these species to evaluate the potential for disposal problems. In addition to chemical aspects, thermal pollution from disposing fluids also must be controlled.

Test Procedures

Before beginning the actual reservoir test, it is necessary to meet all the facility requirements. This may mean installing power for a pump, instruments, or lighting. It would also mean obtaining permission to monitor a well on private land or constructing access roads. The pump, production well instrumentation, and the observation well instrumentation should be installed at this time. Any technicians or professionals who will be involved with the test should be trained in the operation of the pump and testing instrumentation. In addition, the field staff should understand the anticipated data responses during the test.

Table 5. Dissolved species found in geothermal waters

Total dissolved solids	Boron
Chloride	Arsenic
Sulfate	Sulfide
pH	Carbon dioxide
Fluoride	Mercury

The reservoir test begins with obtaining background data on all the wells and springs to be monitored (historic water levels, temperature, chemistry data). These data will be used to determine short- and long-term trends in order to correct the test data for these trends. The required duration of background monitoring will vary according to the site. It is recommended that the minimum duration be at least equal to the duration of the intended reservoir test.

The next step is to determine if sufficient field support has been employed for the reservoir test. The required number of people will depend on the disposal method, the number of monitor wells and springs, the distance or travel time between monitor wells and springs, and the type of instrumentation at each monitoring site. It will be desirable to have more assistance during the early-time rapid measurements of the production and recovery portion of any test. If there is insufficient field assistance, then additional help should be employed and properly trained.

A static or nonproducing borehole temperature log of the production well should be run at or before this time. It may be preferable for technical and economic reasons to run this log before setting a pump. The log should be recorded while entering the well (logging down) to minimize any thermal disturbance (mixing) within the well. Finally, the data will be used for calculating time-dependent changes in fluid density and early-time thermal borehole storage effects in the producing well. A temperature log obtained after drilling was completed may be used, if the time between drilling and testing was less than three to five days. Otherwise, a new temperature log is recommended.

Preheating of the wellbore should be considered before the start of testing if pressure or water-level information during the test is to be obtained in any portion of the well that sees a temperature change. The well or spring should be preheated by producing at 10 to 20% of the intended testing discharge rate. The preheating lessens the time-dependent density changes during the test, and usually does not cause problems with the latter analysis.³⁰ The preheat procedure should continue until the discharge temperature is constant.

A step rate or pulse test should be run in order to determine the optimal flow rate for a long-term test and the productivity index. A standard water well step test and analysis may be run if the pressure or water level data do not have time-dependent density changes (downhole data). A step test is not recommended if downhole data are not available due to probable thermal changes at the differing discharge rates. The variable thermal conditions and the short duration of most step tests make comparison and analysis impractical. At least two pulse steps are recommended, one at a higher rate and one at a lower rate than the intended end-use production rate. The highest rate should be run first to aid in preheating the borehole. The duration of each pulse and recovery will depend on the time required to reach thermal equilibrium at the wellhead and obtain sufficient analyzable pressure or water level data. This may be on the order of four to eight hours per pulse. If a step test is run, one to four hours may be required, since the wellbore should be stabilized by the initial high rate step test.

The discharge rate for the long-duration test will depend on the well type, reservoir type, drilling data, etc. and the pulse test data. The end-use required rate be used for all fracture-controlled type springs or wells. The end-use rate is recommended due to the low reliability of standard extrapolation techniques in fractured rock reservoirs.³¹ A higher than end-use rate is not recommended, as extrapolation of temperature for the lower rate is not reliable. If there is no specified end use requirement, the test should be conducted at the maximum possible rate. A reduced discharge rate (less than the end-use production rate) can be used for intergranular permeable reservoirs.

The recommended test duration for low-to-moderate temperature geothermal resources is somewhat longer than a standard cold-water aquifer or petroleum test to allow for stabilization of early-time thermal effects. Also, the test duration for fracture flow cases should be somewhat longer than intergranular permeable cases due to problems in the analysis and projection of reservoir longevity. In general, the longer the test, the more reliable the data.

After concluding the production phase of a test, it is important to obtain recovery data level/pressure at the production well and at all monitor wells and discharge rates at all springs. The duration of the recovery portion of a test will depend on the type of instruments used and/or the rate of cooling in the production well. In the water well and petroleum fields, one would expect the recovery portion of a test to run approximately the same duration as the production portion. In low-to-moderate temperature geothermal systems, the recovery portion of a test (considering the production well only) will be of shorter duration. This is a result of thermal effects. The recovery data at a production well is especially useful if the discharge rate during the test was somewhat erratic or had several step changes. The evaluation technique assumes a constant discharge rate by averaging the discharge during the production. Recovery data are also useful for a monitor well to confirm that a water level/pressure response was due solely to the test and not part of a short- or long-duration background trend.

8. GEOCHEMISTRY

Geochemical information on geothermal fields both supplements hydrologic information and provides additional data. For instance, chemical logging during drilling can indicate the presence of cold and hot aquifers and aids in the placement of casing. Subsurface temperature can be estimated with chemical geothermometers. Isotopic composition variations in water can be used to determine sources of water, the occurrence of boiling in the reservoir, or the amount of interaction between water and wall-rock. The chemical composition of the water may foretell of problems with corrosion or scaling, or may indicate environmental problems from specific dissolved species. The scope of this section is to provide information available from geochemical studies and to briefly describe the geochemical methods involved.

Chemical geothermometers may be used to estimate aquifer temperatures in wells weeks or months before underground temperatures return to normal after drilling. Flow testing may speed the temperature recovery in the production zone, but interferes with obtaining information about predrilling temperatures elsewhere in the well. Also, extensive flow testing immediately after the termination of drilling is not always possible because of fluid disposal problems or delayed delivery of test equipment. Production and collection of a small amount of fluid at the wellhead or from a downhole water sampler, however, may be all that is necessary to provide a good indication of the aquifer temperature.

Where well design requires interruption of production of a geothermal well to run a temperature log, geochemical temperatures may be monitored. Logging wells is also a relatively slow process, and a temperature survey of a field with several production wells could take many days or weeks. Monitoring temperatures of waters supplying drillholes can be accomplished using the silica content of water where calculated temperatures and downhole measured temperatures are in close agreement. Water samples can be collected without interrupting production. Mahon³² has shown that the silica concentration in the water entering wells decreases at Wairakei, New Zealand, in response to decreasing temperatures in the aquifer.

By producing a well at various flow rates, the contribution to total discharge from multiple aquifers may vary. If different aquifers have different chemical compositions, and different pressures or transmissivities, the chemical composition of the discharge fluid would change as the production rate was varied. Collection of water samples during a step drawdown tests could be analyzed to detect production from different aquifers.

The following subsections present a brief overview of some of the geochemical methods that can be used in low-to-moderate temperature geothermal reservoirs.

Chemical Logging

The growth of the geothermal industry has created a need for techniques that can be used during drilling operations to determine the depth at which to complete a well, depth for casing placement, and the best method for well development. Techniques developed by the petroleum industry, such as geophysical logging, lithologic logging, and core drilling, can be useful. However, little development has been oriented toward the specific conditions encountered during geothermal exploration and well drilling. Chemical logging³³ is one of the methods developed at the Raft River KGRA for geothermal applications.

Chemical logging can indicate the depth and relative flow of geothermal aquifers penetrated during drilling. The method involves periodic collection of drilling fluid for chemical analysis while drilling is in progress. A chemical log is prepared by plotting the concentrations of the analyzed chemical species, or their ratios, versus drill string depth. The resulting log is a profile of chemical changes taking place in the drill fluid during the drilling operation. Changes in the chemical composition of drilling fluids indicate the entrance of formation waters into the wellbore. Changes in particular species indicate the presence of geothermal water.

Changes in the chemical composition of the drilling fluid result from mixing the fluid with water from aquifers penetrated by the drill string. Figure 18 is a cross-sectional view of a drill string that has penetrated several water-bearing strata. Drilling fluid is pumped through the drill stem and bit and returns to the surface between the drill stem and the wall of the borehole carrying the drill cuttings with it. When a water-bearing stratum is penetrated, it contributes water to the drilling fluid, diluting the fluid and causing variations in its chemical composition. Generally, after the drill string passes through the water-bearing stratum, the drilling mud or sediments in the drill water form a mud cake on the walls of the borehole, sealing off the aquifer. If the flow from the stratum is too great and the stratum is not sealed by the mud cake, the incoming water will produce a permanent change in the background chemical composition of the drilling fluid. The chemical log determines the change in chemical composition of the drilling fluid as each aquifer is penetrated; it also determines the separation of this change from the chemical background contributed by the drilling fluid.

Interpretation of chemical logs is complicated by a number of factors, the most important of which are the effects of drilling mud on the composition of drilling fluids. Drilling muds absorb much of the free hydrogen ion in the solution raising the pH, and consequently the alkalinity. Other cations will also be affected by ion exchange reactions, but anions will be relatively unaffected. Problems arising from this will not seriously interfere with the chemical logging technique because the plot with depth will show changes relative to the background, which are more important than the absolute values of species. Instances when the drilling fluid is changed, for example when drilling mud is replaced by mud-free water, will make comparisons between different parts of the hole difficult, if not impossible.

Sampling Procedure

The procedure is to collect samples of the drill return fluid at specified depth intervals. Drill fluid is pumped from the mud pit, through the drill string, and returns up the borehole between the borehole walls and the drill stem. Drilling fluid samples are collected where the drill-return fluid enters the mud pit. Samples of 4 to 5 L should be collected to ensure an adequate sample size when drilling mud is being used. Frequently, water is used as a drilling fluid in geothermal wells, in which case only 1-L samples need be collected.

Sampling frequency depends on the detail desired in the chemical log, and the proximity of the hole to the geothermal resource. Also, changes in drilling rate or other changes in drilling indicate that a sample should be collected. Sample frequency may vary from once every 100 m in the upper portion of the hole, to as often as every 5 to 10 m when proximity to the geothermal resource is anticipated. Sampling depths must be corrected for lag time or travel time in the wellbore. This information can usually be supplied by personnel compiling the mud log.

Drilling mud, cuttings, and other residues are separated from the water sample by centrifuging or filtering. In many cases, centrifuging will not settle gelatinous suspensions of drilling mud. Filtering with a coarse filter in a funnel, and a flask with side tube connected to a hand-operated vacuum pump is readily adapted to field filtration of samples.

Chemical species that will provide the most information when drilling in an area must be determined by comparing chemical analyses of cold-water aquifers, drilling fluid make-up water, and the geothermal resource. Those constituents that show the greatest differences in concentration among these water sources would be the best species to use in constructing the chemical log. Constituents that might commonly be expected to show large differences between geothermal and other waters are silica, fluoride, magnesium, chloride, specific conductance, and alkalinity. Also useful are ratios of constituents. Ratios may produce an even more sensitive log if the two species in the ratio show opposite behavior in the background water and in geothermal water.

By compiling the chemical log in the field, during drilling, the chemical log will have its greatest utility in locating geothermal zones as they are penetrated. During development at Raft River, the most useful log was

Figure 18. Changes in drilling fluid composition by fluid from a geothermal aquifer.

found to be the hardness-alkalinity ratio log. Both hardness and alkalinity can be measured very easily in the field by colorimetric titration. Thus, information gained from this chemical log will be immediately available for decision-making during drilling.

Raft River Example. The concept of chemical logging originated during drilling of exploratory well RRGE-3 at the Raft River KGRA, and was developed and refined during drilling of production wells RRGP-4 and RRGP-5 and injection well RRG1-6. At Raft River, shallow drilling used mud as a drilling fluid. Once casing was set, further drilling used geothermal water as the drilling fluid to prevent possible damage to the formation from the mud. Because geothermal water was used as the drilling fluid, only small chemical differences were anticipated between drilling fluid and any geothermal aquifers that were penetrated. Chemical constituents that would best differentiate between geothermal waters and cold waters, at Raft River, are hardness, alkalinity, fluoride, chloride, and total dissolved solids.

Figure 19 shows the chemical log collected during the drilling of well RRGP-5. The log shows sharp changes in the chemical composition of the drill fluid at 488 m. At this depth, the alkalinity and hardness increase and fluoride and silica concentrations decrease. This would be a typical change in chemical composition when fresh water dilutes the drilling water. The relative constancy in chloride ion concentration and conductivity indicate, however, that the fresh-water aquifer had fairly high dissolved solids, probably from intrusion of geothermal water. The production zone of a geothermal aquifer was penetrated at 1280 m. Because the drill fluid was geothermal water similar to that in the aquifer, only small changes were observed in the drill fluid chemical composition. There was a small increase in SiO_2 concentration and a small decrease in conductivity. The decrease in alkalinity was the only large change detected at this depth.

The hardness/alkalinity log is shown in Figure 20. Evaluation of the hardness/alkalinity log reveals a sharp change in the ratio at a depth of 1220 m. This increase in the hardness/alkalinity ratio was observed until the drill string reached a depth of 1280 m, where a flow of hot water with an estimated rate of 68 L/s was observed. Geothermal water from the 1280 m depth washed away the chemical profile of the well for the remainder of drilling. The lower part of this borehole was lost when a concrete plug was set at 1051 m depth to install the well casing. After the well was cased and reentry was made with the drill string, the concrete plug could not be drilled through. Sidetrack drilling was initiated at the top of the plug, but the second leg either did not penetrate the high-flow zone penetrated in the first leg or the fractures were sealed with concrete. The second leg is shown as Leg B in Figure 20, and indicates the penetration of a narrow, hot-water-bearing aquifer, which flowed at about 13 L/s with a maximum temperature of 123°C.

The hardness/alkalinity ratio log (Figure 20) also showed that as the drill approached a geothermal zone, the ratio increased before the zone was reached, with the resulting chemical log displaced uphole relative to the temperature log. The uphole displacement varied between 16 and 120 m for the wells tested, and appears to be a function of the permeability or fracturing of material above the geothermal aquifer. Additional confirmation of the value of chemical logging was demonstrated during the drilling of RRG1-6. Comparison of the hardness/alkalinity ratio to the temperature log for RRG1-6 revealed similarities as shown in Figure 21. The hardness/alkalinity log is displaced about 60 m uphole relative to the temperature log. This characteristic of the hardness/alkalinity ratio, of anticipating geothermal aquifers, combined with the information on the permeability of stratum already penetrated, furnished by the mud logger, could be used to determine the depth at which to set the well casing.

Figure 22 shows the hardness/alkalinity chemical log collected during the redrilling of well RRGP-4 with the object of converting an injection well into a production well. Sidetrack drilling started at 565 m to a total depth of 1650 m for Leg A. To improve resolution, samples were taken at 15 m intervals with additional samples collected at 8 m intervals where the driller detected structural changes. To make the chemical log more useful as a predictive tool, the hardness/alkalinity chemical log was kept current with the drilling progress. The object was to anticipate any significant temperature changes before the drill string reached a production zone.

An upper geothermal zone was penetrated by the drill between 700 and 870 m, with the hardness/alkalinity ratio increasing sharply through this area. In this upper portion of the hole, drilling mud was being

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Figure 19. Chemical log of all analyzed chemical species for Well RRGP-5.

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Figure 20. Hardness/alkalinity chemical log for Well RRGP-5.

used in the drilling fluid. Although the background chemical composition of the fluid was much different because of the presence of the drilling mud, the change in the ratio is still quite apparent. After casing the upper hole to a depth of 1070 m, the background hardness/alkalinity ratio changed significantly. Comparison of the chemical and lithologic logs of the upper portion of the wellbore shows that the section having high hardness/alkalinity ratios corresponds to a sandstone layer. Geophysical logging confirmed that this sandstone layer is an aquifer. At a depth of 1520 m, the driller noticed a decrease in drilling rate when the drill bit encountered a hard stratum about 10 m before penetration of a narrow, low-producing, hot-water zone. The hardness/alkalinity ratio began to increase about the time the drill reached the hard stratum, and continued to increase as the zone was penetrated. The ratio decreased after the drill passed through the producing zone. This same sequence was repeated at 1580 m. The combined flow of the two producing zones was about 2.25 L/s, with water temperatures above the boiling point.

Corrosion and Scale-Forming Species in Moderate Temperature Geothermal Brines

Geothermal brines, in general, represent an environment that is very corrosive and contains high concentrations of scale-forming species. This subsection provides general guidelines for proper selection of material and scale control techniques to nontechnical individuals that are involved in geothermal applications. Additional information can be obtained from Casper and Pinchback.³⁴ These guidelines presented here will apply to any geothermal area but should not be used in lieu of professional advice.

Corrosion. The predominate factors affecting corrosion in moderate temperature brines are temperature, brine chemistry, fluid velocity, and the specific material in contact with the brine. Specific chemical species associated with corrosion are:

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Figure 21. Hardness/alkalinity chemical log and temperature log for Well RRG1-6.

- Oxygen
- Hydrogen ion (pH)
- Chloride ion
- Hydrogen sulfide
- Carbon dioxide
- Ammonia
- Sulfate ion.

The presence of boron and heavy metals such as copper, mercury, tin, etc., will also affect the corrosion rates of different materials. The specific corrosive effect of each of the materials listed above will vary with the material selected. When two or more of the above species are present, the corrosion rate may be significantly greater than the additive corrosion rates associated with the individual species.

Scaling. The predominant factors affecting scale deposition in pipes are brine chemistry, change in temperature, change in pressure, fluid velocity, and the material in contact with the brine. The specific chemical species associated with scale deposition are:

Figure 22. Hardness/alkalinity chemical log for Well RRGP-4A.

- Silica
- Hardness—recorded as calcium hardness and magnesium hardness
- Hydrogen ion (pH)
- Alkalinity—recorded as total and methyl orange alkalinity
- Sulfate ion
- Fluoride ion.

Corrosion products will also affect scale deposition.

Material Selection. Since scale and corrosion are not mutually exclusive, material should be selected with both in mind. There are a large number of materials to select from, ranging from plastics to carbon steels to exotic alloys.

Plastics — Plastic pipes are relatively free from both scaling and corrosion problems. They may be excellent for transporting fluids from wellhead to process areas, but may not be used where transfer of heat is required. Plastic pipes are available in many different forms and price ranges. Restrictions on their use are those of operating temperature and pressure. The higher the temperature, the lower the operating pressure must be.

Carbon Steel — Carbon steels are readily available and are the most inexpensive kind of metal piping. Carbon steel can be used both as transportation and heat transfer material provided adequate corrosion allowance is made. It may not be used if oxygen is present in the brine or if the pH is below six, as this will result in greatly increased corrosion rates and iron scale deposition.

Copper and Copper Alloys — The use of copper and its alloys represents an approximately three-fold increase in material cost and may be required when oxygen is present. Copper has excellent heat transfer properties but should not be used if the pH is below six, as corrosion rates significantly increase with lowering pH, i.e., more acidic water. Copper may not be used if ammonia or sulfide is present.

Stainless Steels — Stainless steels should not be used in brines as the high chloride concentration may result in early failure of components.

Other Materials — There are many other alloys on the market, such as nickel alloys, chrome-moly alloys, titanium, cobalt, etc. The use of these materials should be made after consultation with a corrosion expert, as they are very expensive.

The following are basic guidelines for selecting materials for a geothermal application.

1. Obtain a water sample of the brine and analyze it for the species listed in the Corrosion and Scaling subsections above. The sample should be unflushed and taken by a reputable firm. If the sample is flashed, the noncondensable gasses such as oxygen, carbon dioxide, hydrogen sulfide, and ammonia will flash, resulting in an inaccurate analysis.
2. Select, tentatively, a material based on the analysis. This selection should be confirmed with a professional corrosion engineer.
3. Determine optimum velocity for the given material. As velocity increases, erosion-corrosion increases dramatically while scale deposition decreases; hence the optimum for the given material.
4. Review the system with a water treatment specialist after the material has been selected. The primary considerations are the analysis at the wellhead and the temperature and pressure drops across the system. Temperature is the largest single factor in the solubility of many chemical species. If a large temperature drop occurs across a system, many chemical species may become supersaturated and deposit a scale. Also if pressure drops occur across the system, i.e., across valves, elbows, carbon dioxide may flash, resulting in calcite deposition. This may be eliminated by maintaining pressure across the entire system.

Chemical Geothermometers

Chemical geothermometers are probably the most recognized contribution of geochemistry to the development of geothermal fields. Application to low- and moderate-temperature reservoirs requires careful assessment of the techniques, as many of the assumptions involved in development of geothermometers are based on high-temperature reservoirs. Geothermometers do not stand alone and must be viewed in the geologic and hydrologic context of the field.

There are five basic assumptions that must be met for the geothermometry techniques to be valid. These are:³⁵

1. Chemical concentrations are determined by water-rock interactions
2. There is an excess of all reactants
3. Water and rock are in equilibrium at reservoir temperature
4. After leaving the reservoir, water does not reequilibrate with rocks
5. Either no mixing occurs with cooler, shallower water, or the mixing can be quantified.

The geochemist must test the validity of these assumptions after he has considered the hydrology, geology, and mineralogy of the reservoir. Water produced from deep wells offers advantages for sampling in that flow up the wellbore can limit external alterations of water chemistry.

Geothermometers most applicable to low- and moderate-temperature reservoirs are the silica and sodium-potassium-calcium (Na-K-Ca) geothermometers. The Na/K geothermometer is generally limited to reservoirs with temperatures over 180°C. Even with the other two geothermometers, however, results at temperatures below 150°C tend to be less consistent than at higher temperatures. This problem is due in part to kinetic effects and the broad range of mineralogic compositions found in lower-temperature reservoirs.

Silica Geothermometer. The silica geothermometer is based on the theoretical solubility curves of various silica phases, and is applicable to the temperature range from 0 to 250°C.^{36,37} The range of temperatures over which the technique works best is from 150 to 225°C. The first consideration in applying this geothermometer is to collect and preserve the sample properly. As waters cool, silica polymerizes and may precipitate. Polymerization can interfere with analysis when colorimetric techniques are used. Water samples, especially if water temperatures are over 140°C, should be diluted as much as 5 to 10 times to prevent polymerization and precipitation.

Silica solubility can be controlled by a number of silica phases, including quartz, chalcedony, and amorphous silica. Equations for calculating estimated reservoir temperatures assuming control of SiO₂ concentrations by these silica phases are:

$$\text{Quartz } t(^{\circ}\text{C}) = \frac{1309}{5.19 - \log C} - 273.15$$

$$\text{Chalcedony } t(^{\circ}\text{C}) = \frac{1032}{4.69 - \log C} - 273.15$$

$$\text{Amorphous silica } t(^{\circ}\text{C}) = \frac{731}{4.52 - \log C} - 273.15$$

Silica concentration, C, is in mg/kg as SiO₂, and the calculated temperature is in degrees centigrade.

In freshly drilled boreholes, in basaltic terrains, or in areas with chert in sediments, quartz may not be the phase controlling silica solubility. If the assumptions of geothermometers are valid for a site, and the proper controlling phase can be determined, the silica geothermometer seems to give the best reservoir temperature estimates.

Na-K-Ca Geothermometer. This geothermometer is based on an ion exchange equilibrium among feldspars controlling the concentrations of sodium, potassium, and calcium.³⁸ The following equation for calculating temperature is empirical, but feldspar control is assumed.

$$t(^{\circ}\text{C}) = \frac{1647}{\log(\text{Na/K}) + \beta [\log(\text{Ca/Na}) + 2.06] + 2.47} - 273.15$$

$$t < 100^{\circ}\text{C}, \beta = 4/3$$

$$t \geq 100^{\circ}\text{C}, \beta = 1/3$$

Na, K, Ca concentrations in mg/kg.

In geothermal systems where calcium concentrations are significantly affected by gypsum or calcite solubility, calculated temperatures may not be valid. Loss of calcium by mineral precipitation will produce anomalously high temperatures. For waters that are fairly high in magnesium, an empirical correction to the Na-K-Ca geothermometer has been proposed by Fournier and Potter.³⁹

Glenwood Springs Example. The situation at Glenwood Springs, Colorado is an example of the equivocality of geothermometers in low-temperature reservoirs. At Glenwood Springs, the temperatures of seven springs, which range in discharge from a fraction of a liter per second to over 125 L/s, are remarkably similar and suggest a fairly uniform reservoir at about 50°C (mean = 48.9°C, standard deviation = 2.7°C).⁴⁰ Quartz geothermometer calculations give closely grouped, although much higher temperatures for the springs, averaging 79.7°C with a standard deviation of 2.2°C. Estimates using the Na-K-Ca (Mg corrected) geothermometer give a much broader range of temperatures, averaging 85.1°C with a standard deviation of 15.5°C. An analysis of the mineralogy of the geothermal reservoir, however, indicates that these geothermometers may not be valid in this case.

There is extensive evidence of the presence of evaporites in the limestone reservoir, mainly gypsum or anhydrite. Thermodynamic calculations show the springs to be supersaturated with calcite, which may, therefore, be precipitating in the subsurface. Lowering of calcium concentrations by calcite precipitation would raise the temperature predicted by Na-K-Ca geothermometer. The wide range in geothermometer temperatures would reflect the variability in calcite precipitation.

Sediments in the reservoir contain chert, which is much more soluble than quartz. Calculations of reservoir temperature using the chalcedony geothermometer give temperature estimates that average 48.6°C with a standard deviation of 2.4°C.

The potential questionability of the quartz and Na-K-Ca geothermometers, and evaluation of mineralogy, spring discharge, measured temperatures, and chalcedony geothermometer suggests that the reservoir temperature is closer to 50°C than 80°C. This difference can mean the success or failure of a low-temperature project. Drilling in the Glenwood Springs area during the fall of 1981 found 52°C water in the Leadville Limestone at a depth of 174 m.⁴¹

Isotopic Composition of Water

Oxygen and hydrogen isotopes in water can be used to indicate sources of geothermal fluids, as evidence for mixing of thermal waters with shallow, cool waters, and to give qualitative estimates of the extent of reaction between water and rock. The most significant contribution of isotopes to the hydrology of geothermal systems was demonstrating that significant quantities of geothermal waters are derived from meteoric sources. Truesdell and Hulston⁴² present an in-depth analysis of isotope methods in geothermal systems, from which this section is excerpted.

Stable Isotopes. During the evaporation of sea water, lighter isotopes of water (oxygen-16, hydrogen) can escape into the vapor phase more readily than the heavier oxygen-18 and deuterium. As this water vapor forms precipitation, the heavier isotopes condense first, resulting in progressively lighter precipitation during movement toward the poles, inland over land masses, and to higher elevations. The average annual precipitation at any location will have a fairly constant isotopic composition reflecting its elevation, latitude, and distance from the ocean.

Oxygen and hydrogen isotopic compositions of precipitation are related by the equation:

$$18 \delta D = 8 \delta^{18} O + 10$$

where δ is the difference in parts per thousand (‰) between a water sample and a standard water known as "standard mean ocean water" (SMOW). Ground waters in an area frequently display the same relation between oxygen and hydrogen isotopes as precipitation. Surface and ground waters that have undergone evaporation fall to the right of the meteoric water line (Figure 22) along lines with slopes of about five. The deuterium isotopic composition can be used as a label reflecting the recharge area and history of a water sample.

The isotopic composition of many high-temperature geothermal waters is related to that of local meteoric water, but indicates a change in oxygen isotopic composition (Figure 23) from exchange between reservoir rocks and hot waters. Because few rock-forming minerals contain very much hydrogen, a concurrent change in hydrogen does not occur. The magnitude of the oxygen isotope shift depends on the original isotopic compositions of water and rock, mineralogy and texture of rocks, temperature, water/rock ratio, and time of contact. Systems with maximum temperatures below 150°C , moderate water/rock ratios, and igneous rocks with original $\delta^{18} O$ values near $+50\text{‰}$ may show little or no isotopic shift. Most low- and moderate-temperature reservoirs would, therefore, be expected to show little or no isotope shift.

Figure 23. Oxygen-18 and deuterium compositions of hot and cold ground waters from the Raft River KGRA.

Mixing with shallow, cooler ground waters commonly occurs in the upper portions of geothermal systems, which may be feeding thermal springs. Isotopic compositions combined with dissolved salt contents may be used to demonstrate this mixing. Correlations between the isotopes of oxygen or hydrogen and dissolved salts would be expected where shallow waters were lower in salt content and isotopically different than thermal waters.

Tritium. Tritium is a radioactive isotope of hydrogen with a half life of 12.3 years, and is produced naturally by cosmic rays. Atmospheric testing of nuclear weapons between 1954 and 1965 produced a 100-fold increase in peak tritium levels in the northern hemisphere. The current detection level for tritium allows dating of waters up to 60 years old. Most measurements of deep thermal waters show no significant tritium, indicating that waters are greater than 60 years old. Measurable tritium in thermal wells and springs probably indicates the mixing of deep thermal waters with recent, shallow ground water.

9. RESERVOIR MONITORING

Reservoir analysis is not complete when the end-use production of a thermal well or well field begins. It is necessary to monitor the hydrologic system(s) to confirm initial predictions; to anticipate and plan for any geochemical changes in pressure and temperature of the resource; and to obtain a larger data base for confirming the reservoir conceptual model. Confirmation of the conceptual model can be used to evaluate reservoir capacity, recharge, and the potential for future expansion.

Monitoring of a well or well field includes pressure monitoring, temperature monitoring, and geochemical sampling of production/injection wells, observation wells, and springs. Observation wells may include fully or partially penetrating wells designed to monitor reservoir response and any deep or shallow existing irrigation or domestic wells. Monitoring also includes discharge/recharge rates for all wells and springs, and geochemical sampling and temperature changes in a disposal stream or pond.

It is essential that monitoring be accomplished throughout the life of any development to ensure economical use and predict potential environmental hazards.

Pressure Monitoring

The completion of a geothermal well and the start of production from the reservoir should signal the beginning of a regularly scheduled, permanent program of pressure monitoring of the following:

1. The producing aquifer or reservoir formation
2. The confining strata above the reservoir
3. The unconfined aquifer above the confining layer (springs)
4. The production and injection wells.

The pressure measurements will usually be done with surface instruments, i.e., pressure gauges installed at the well head. If the well is not under pressure, a bubbler tube must be installed so that the depth to the water level in the well can be conveniently determined. In a few wells on some occasions, downhole pressure may be needed.

The Producing Aquifer or Reservoir Formation. The pressure in all available observation wells open to the geothermal reservoir should be recorded each month. A few important observation wells may be read weekly if there is a need to indicate shorter-term fluctuations of pressure.

The Confining Strata Above the Aquifer. Some observation wells may have been completed in the confining layers above the reservoir. The water level in these also should be observed at least monthly to show the pressure conditions in the confining layer and to give indications of interference problems.

The Unconfined Aquifer Above the Confining Layer(s). Some observation wells (and local water wells) may be open to the unconfined aquifer near the surface. The water level in these wells and also any nearby springs gives a measure of the water table elevation and should be recorded at least monthly. These data, along with the pressure measurements described above, can give an indication of the gradient causing vertical leakage through the confining layer(s) as well as evidence of well interference problems.

Production and Injection Wells. These wells are the most important in the field and should be monitored most often. In fact, a continuous watch of pressure in production and injection wells is probably needed for the operational control of reservoir production. A permanent daily record should be kept of the pressure, temperature, production and injection rates.

Temperature Monitoring

Temperature monitoring should include discharge/recharge measurements at the surface and where feasible, downhole measurements. Surface measurements are inexpensive and easy to obtain. It is recommended that surface temperatures be obtained whenever a pressure measurement is obtained at a production/injection well. At nearby observation wells, springs, or discharge rivers or ponds, it may be sufficient to obtain surface discharge temperature (where appropriate) on a weekly schedule. Downhole temperature data are usually more expensive and may be impractical if a pump is in a well. If downhole data can be collected, it is recommended that measurements be taken at a minimum of every ten feet to total well depth at least biannually.

Confirmation of Reservoir Conceptual Model

As data are gathered from reservoir monitoring, it is necessary to assimilate them into initial projections and note any deviations from these projections. This assimilation is critical for verifying the conceptual model of the reservoir system, which logically ties into not only reservoir longevity, capacity and recharge, but also chemical changes, water level changes, and a group of potential environmental impacts.

Verification of the conceptual model would provide an early-warning system to a developer to modify or correct potential problems before they are encountered. In addition, reservoir monitoring allows the system to be expanded based upon a confirmed conceptual model, provides confidence to investors in reservoir development, and enhances further development of this technology.

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