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Handbook of Best Practices for Geothermal Drilling

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Abstract

This Handbook is a description of the complex process that comprises drilling a geothermal well. The focus of the detailed Chapters covering various aspects of the process (casing design, cementing, logging and instrumentation, etc) is on techniques and hardware that have proven successful in geothermal reservoirs around the world. The Handbook will eventually be linked to the GIA web site, with the hope and expectation that it can be continually updated as new methods are demonstrated or proven.

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1. Introduction to Geothermal Energy

The word "geothermal" comes from the combination of the Greek words gê, meaning Earth, and thérm, meaning heat. Quite literally geothermal energy is the heat of the Earth. Geothermal resources are concentrations of the Earth's heat, or geothermal energy, that can be extracted and used economically, now or in the reasonable future.

All existing applications of geothermal energy use a circulating fluid to carry the heat from depth to its use at the surface. In most cases, that fluid originates in the geothermal reservoir, but where permeability is low or there is no in-situ fluid, there are techniques for injecting cooler water at the surface, circulating it through natural or induced fractures in the rock to gain heat, and returning it to the surface for use. Produced fluids at lower temperatures (below about 135ºC) are suitable for "direct use" such as space heating for buildings, food drying, or industrial processes. These applications can be very cost-effective, especially where conventional fuel prices are high, but have the principal disadvantage that they must be near the resource. With higher temperature and sufficient flow rate, geothermal fluids can be used to generate electricity, allowing the end use to be geographically distant from the geothermal resource. This requirement for fluid, however, emphasizes the need for drilling. Except for the few cases where direct use applications can be supplied from natural hot springs, access to the geothermal fluids can only be achieved through drilling into them–and in many cases, the fluids must be re-injected into the reservoir once their heat is surrendered, requiring even more holes.

Spatial variations of the thermal energy within the deep crust and mantle of the Earth give rise to concentrations of thermal energy near the surface of the Earth that can be used as an energy resource. Heat is transferred from the deeper portions of the Earth by conduction through rocks, by the movement of hot, deep rock toward the surface, and by deep circulation of water. Most high-temperature geothermal resources are associated with concentrations of heat caused by the movement of magma (melted rock) to near-surface positions where the heat is stored. Since rocks have relatively small thermal conductivity, very large intrusions of magma may take millions of years to cool.

Exploration for geothermal resources typically uses geologic mapping, geochemical analysis of water from hot springs and geophysical techniques commonly used by the mining industry. With advances in seismic techniques, reflection seismic surveys are increasingly being used. Geothermal drilling relies on technology used in the oil and gas industry modified for high temperature applications and larger well diameters. Well testing and reservoir engineering rely on techniques developed in the oil and gas industry for highly fractured reservoirs because the high flow rates needed for economic production usually require fractures.

Occurrence of Geothermal Energy

Temperature increases with depth within the Earth at an average of about 25ºC/km. So if the average surface temperature is 20ºC, the temperature at 3 km is only 95ºC. Although direct use applications of geothermal energy can use temperatures as low as about 35ºC, the minimum temperature suitable for electrical generation is about 135ºC. Geothermal resources occur in areas of higher than average subsurface temperatures.

***Heat Flow and Temperature*:** The heat of the Earth is derived from two components: the heat generated by the formation of the Earth, and heat generated by subsequent radioactive decay of elements in the upper parts of the Earth. Birch, et al.[1] found that heat flux can be expressed as $q = q^* + DA$, where q^* is the component of heat flow that originates from the lower crust or mantle and DA is the heat generated by radioactive decay in the shallow crust. DA is the product of depth (D) and the energy generated per unit volume per second (A). Because A varies with depth, calculation of heat flow and, consequently, temperature with depth is complex. For most general heat flow studies in conductive areas, the change in heat flow with depth can be ignored.

Temperature at depth (T) is given by $T = T_{surface} + D\Gamma$, where Γ (temperature gradient) is related to heat flow and K (rock conductivity) by $q = -K\Gamma$. Diment et al.[2] provide a generalized review of temperatures and heat flow with particular emphasis on heat content in the United States.

In older areas of continents, such as much of North America east of the Rocky Mountains, heat flow is generally 40 to 60 mWm^{-2}. This heat flow coupled with the thermal conductivity of rock in the upper 4 km of the crust yields subsurface temperatures of 90 to 110^{o}C at 4 km. It is apparent that depths on the order of 5 to 7 km are needed to attain the temperature (~135ºC) required for electrical generation from geothermal energy in stable continental areas of moderate to low heat flow. Because it is not economically feasible to drill this deep for electrical power generation, exploration for geothermal energy focuses on areas where higher than normal heat flow is expected.

***Tectonic Controls*:** The unifying geologic concept of plate tectonics provides a generalized view of geologic processes that move concentrations of heat from deep within the Earth to drillable depths, and areas likely for geothermal development can be identified. The heat can be related to movement of magma within the crust or deep circulation of water in active zones of faulting. Figure 1 shows the major geothermal provinces in the world.

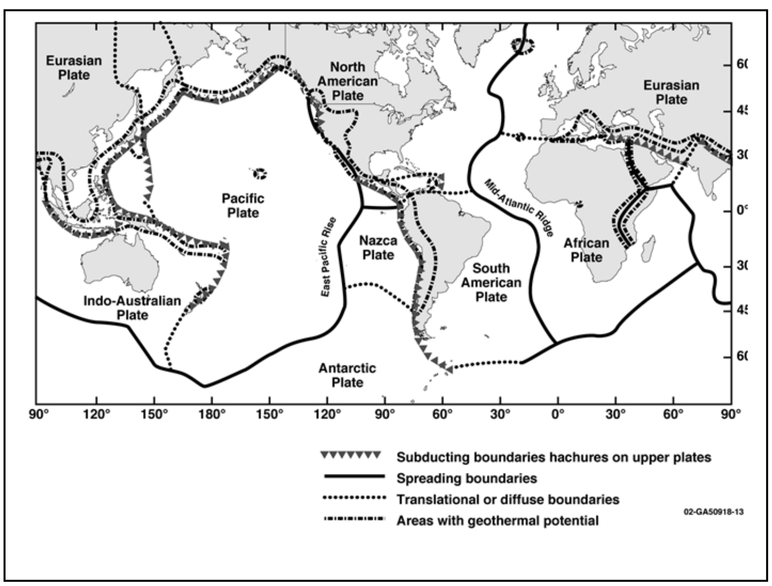

Figure 1 Major geothermal provinces.

The brittle and moving plates of the lithosphere (crust and upper mantle) are driven by convection of plastic rocks below. Convection causes the crustal plates to break and move away from zones of upwelling hot material. Magma moving upward into a zone of separation brings with it substantial amounts of thermal energy, but most spreading zones are within ocean basins and unsuitable for geothermal development. The ocean spreading centers give rise to the mid-oceanic ridges.

Rifting of the Earth's crust can also occur in continental blocks. Two of the better-known examples of such rifting are the East African Rift and the Rio Grand Rift in New Mexico. These rift zones both contain young volcanism and host several geothermal systems, including Olkaria in Kenya and the Valles Caldera in New Mexico, U. S.

Where continental and oceanic plates converge, the oceanic plate (because it is usually more dense) is thrust or subducted under the continental plate. The subduction causes melting near the leading edge of the subducted plate and, as a result, lines of volcanoes form parallel to the plate boundary and above the subducting plate. Many of the world's most important geothermal regions are associated with these features: Indonesia, Japan, Mexico, New Zealand, the Philippines, and the fields in Central and South America.

Translational plate boundaries, locations where plates slide parallel to one another, may develop extensional troughs, known as pull-apart basins such as the Salton Trough of Southern California.[3] Volcanism associated with the Salton Trough generated the heat in the Salton Sea, Cerro Prieto and Imperial Valley geothermal fields. Tensional features further north on the San Andreas and related faults may be the source of the volcanism thought to be the heat source for The Geysers geothermal field about 90 miles north of San Francisco.

A third source of elevated heat flow and volcanism are "hot spots" (volcanic centers thought to overlie rising plumes of hot mantle material). Hot spots most commonly occur in the interior of plates, but can occur on ocean ridges as well. Several important geothermal systems are associated with recent volcanism caused by hotspots: Yellowstone, U.S.A., the geothermal fields in Iceland and those of the Azores.

Geothermal resources also have been developed in areas of anomalously high temperatures with no readily apparent active volcanism, such as the Basin and Range physiographic province in the western United States. Although the tectonic framework of the Basin and Range is not fully understood, the elevated heat flow of the region is likely caused by a thinner than average continental crust undergoing tensional spreading. The elevated heat flow and deep circulation along recently active faults has generated many geothermal sites exploited in Nevada. These geothermal fields are not associated with recent volcanic activity, and while there is no evidence of mid-level crustal magmatic activity, it cannot be ruled out.

Several geothermal fields are, however, associated with recent volcanism along the margins of the Basin and Range. The Coso and Mammoth Lakes fields in California and the Cove Fort and Roosevelt fields in Utah are examples.

Types of Geothermal Systems

Exploitable geothermal resources are hydrothermal systems containing water in pores and fractures with sufficient permeability to produce fluids in adequate volume. Most hydrothermal resources contain liquid water, but higher temperatures or lower pressures can create conditions where steam and water or steam alone are the continuous phases.[4,5] Examples of steam-alone fields are among the oldest developed geothermal fields, Larderello in Italy and The Geysers in Northern California.

Other geothermal systems that have been investigated for energy production are: 1) Geopressured-geothermal systems which contain water with somewhat elevated temperatures (above normal gradient) and with pressures well above hydrostatic for their depth,[6] 2) Magmatic systems, with temperature from 600 to 1400^{o}C,[7] and 3) Hot Dry Rock (HDR) geothermal systems, with temperatures from 200 to 350^{o}C.[8] HDR systems are characterized, as are subsurface zones, with low natural permeability and little water. Currently, only hydrothermal systems shallower than about 3 km and containing sufficient water and high natural permeability are exploited.

Much of the worldwide geothermal research at present is focused on a class of geothermal resources known as "Enhanced Geothermal Systems" (EGS).[9] These resources span reservoir descriptions between the HDR and hydrothermal systems, in that they are either fluid starved or of too low permeability to be commercial at this time. The US Department of Energy sponsored a major overview of this concept in a 2006 report titled "The Future of Geothermal Energy", available on-line at http://www1.eere.energy.gov/geothermal/future_geothermal.html. It has extensive discussion of resource estimates, reservoir design and stimulation, drilling cost and technology, energy conversion systems, and environmental impact.

2. Overview of Geothermal Drilling

Background

Geothermal energy is a growing enterprise. Worldwide electricity production increased from 6833 MWe (megawatts electric) in 1995 to 9966 MWe in 2008, and direct use in 2005 displaced more than thirty million barrels of oil[10]. In spite of this growth, geothermal drilling activity is minuscule compared to oil and gas—fewer than 100 geothermal wells were drilled in the US during 2008, while the total for oil and gas exceeded 50,000[11]. If we consider typical production from a geothermal well of 6-10 MW_e, along with injection wells equal to one-third the number of producers, this represents a total of only 1000 to 1600 active wells. This number is somewhat misleading because many more wells have been drilled than are currently active. There are exploratory wells that were once needed to identify and evaluate the geothermal reservoirs; there are many former production or injection wells that have been plugged and abandoned; and much workover drilling for active power plants is required by the corrosive and solids-laden brines in many geothermal reservoirs. In spite of all this, the market is still so small that few drilling contractors or service companies can be sustained solely by their geothermal drilling business.

Approach in this Handbook

The audience for this Handbook is assumed to be familiar with the general nature of drilling, so there is no attempt to give procedures and guidance for every step needed to drill a geothermal well. The focus instead is on the differences between geothermal drilling and other conventional disciplines such as oil and gas or deep water wells.

If more information about a specific topic is required, there are extensive references in this Handbook, and other resources are available. Both the Society of Petroleum Engineers (www.spe.org) and the Geothermal Resources Council (www.geothermal.org) provide searchable databases of their own publications that include detailed descriptions of geothermal drilling technology. All of the cited references from *Geothermal Resources Council TRANSACTIONS* are available through the GRC web site (free to members, nominal charge to non-members). Stanford University hosts an annual Geothermal Workshop, and papers from those meetings, as well as from World Geothermal Congresses, can be located through http://pangea.stanford.edu/ERE/db/IGAstandard/search.htm. The Office of Science and Technology Information maintains the Department of Energy's Geothermal Technologies Legacy Collection (http://www.osti.gov/geothermal/) and many of the papers cited in this Handbook are available through that resource. The U.S. Bureau of Land Management provides a summary document describing regulatory requirements for exploration, drilling, production, and abandonment on Federal geothermal leases[12] and The Standards Association of New Zealand has published a 93-page manual that combines regulatory requirements with suggestions on operational practices for drilling, maintenance, repair, and abandonment[13]. Finally, the oil-field service companies Schlumberger (http://www.glossary.oilfield.slb.com/) and Baker-Hughes-Inteq (http://investor.shareholder.com/bhi/Tools/oil_glossary_a_c.cfm/) maintain on-line glossaries containing definitions of many common drilling terms.

Nature of Geothermal Formations

Common rock types in geothermal reservoirs include granite, granodiorite, quartzite, greywacke, basalt, and volcanic tuff. Compared to the sedimentary formations of most oil and gas reservoirs, geothermal formations are, by definition, hot (production intervals from 160°C to above 300°C) and are often hard (240^+ MPa compressive strength), abrasive (quartz content above 50%), highly fractured (fracture apertures of centimeters), and under-pressured. They often contain corrosive fluids, and some formation fluids have very high solids content (TDS in some Imperial Valley brines is above 250,000 ppm). These conditions mean that drilling is usually difficult—rate of penetration and bit life are typically low,[14] corrosion is often a problem,[15] lost circulation is frequent and severe, and most of these problems are aggravated by high temperature.

Lost circulation and reservoir damage deserve special mention. Time and materials for lost circulation treatment can represent 15% of well cost, and the underpressured formation aggravates differential sticking, so these can be major impacts on drilling cost. Lost circulation is often massive, with complete loss of returns at pumping rates of hundreds of barrels per hour. Geothermal wells have been abandoned because of the inability to get through a loss zone,[16] and many more have needed an unplanned string of casing to seal off a problem. Lost circulation treatment is complicated by the requirement that the treatment must not damage the producing formation, and this distinction is often difficult. Geothermal wells have been drilled into "live" production zones; that is, the hole is producing steam or hot brine during drilling. This is conventional practice in The Geysers, where the production zone is air-drilled and the produced fluid is dry steam; this is often described as "drilling a controlled blowout." Drilling with brine inflow is much riskier, so an alternative is to allow moderate losses and to lose drilling mud into the producing fractures, with a later backflow from the production interval to clean up the formation. Productivity of most production wells up to 340 mm casing is .75-1.0 million kg/hr, so the formation has very little skin damage initially. If wells are to be drilled after brine production has begun (often a clean-out workover), this requires mufflers, rotating heads, mud coolers, and high-temperature wellhead/BOP equipment. It also means making connections in a hot hole, and sometimes running liners in a live well. Although some of these operations are similar in principle to under-balanced drilling (UBD), the temperature and flow rates mean that the problems are much different from oil and gas UBD and must be well understood to avoid damage or injury from loss of well control.

Lost circulation material (LCM) is sometimes effective,[17] but often fails because losses are through fractures with apertures of several centimeters, so that the LCM particles are not large enough to bridge the loss zone. If zones with fractures must be sealed in the upper intervals of the well, cement is usually the treatment of choice but is hard to place accurately. It is much more important to repair loss zones where casing will later be set than in production intervals. Cotton-seed hulls are used to provide temporary LCM in Imperial Valley production zones because they eventually disintegrate and produce little residue in the wellbore flow-back for cleanup. When possible, cement plugs are not used in the production zone because extensive lost circulation in the reservoir indicates good fractures, and thus good productivity. If cement must be used, much of the fractures' transmissivity can often be recovered by acidizing the wellbore.

Depth and temperature of geothermal resources vary considerably. Several power plants, (e.g., Steamboat Hills, Nevada and Mammoth Lakes, California) operate on lower-temperature fluid (below 200°C) produced from depths of approximately 330 m, but wells in The Geysers produce dry steam (above 240°C) and are typically 2500 to 3000 m deep. In an extreme case, an exploratory well with a bottomhole temperature of 500°C at approximately 3350 m has been completed in Japan,[18] and experimental holes into molten rock (above 980°C) have been drilled both in Hawaii and in Iceland.

Well Cost Drivers

Geothermal drilling is more expensive (in cost/depth) than on-shore oil and gas drilling for three principal reasons:

1. Technical challenge: the conditions described above mean that special tools and techniques are required for the harsh downhole conditions.
2. Large diameters: because the produced fluid (hot water or steam) is of intrinsically low value, large flow rates and thus, large holes and casing, are required.
3. Uniqueness: almost every geothermal well is different, so a new well presents a new learning curve much more often than with oil and gas.

Taken together, these factors can drive the cost of drilling the production and injection well field toward 50% of the total project cost for a geothermal power plant. It is clearly important, then, to drill the well as effectively and inexpensively as possible. Some specific aspects of drilling with a major impact on well cost are described below.

Well design: Design of a geothermal well is a "bottom-up" process. Location of the production zone determines the well's overall length, and the required flow rate determines diameter at the bottom of the hole – the well's profile above the production zone is then set by iteration of the successively larger casing strings required by drilling or geological considerations.

Because of the large diameters in geothermal wells, however, casing and cementing costs form a relatively large share of the cost, and the ability to eliminate one string of casing would have a major impact.

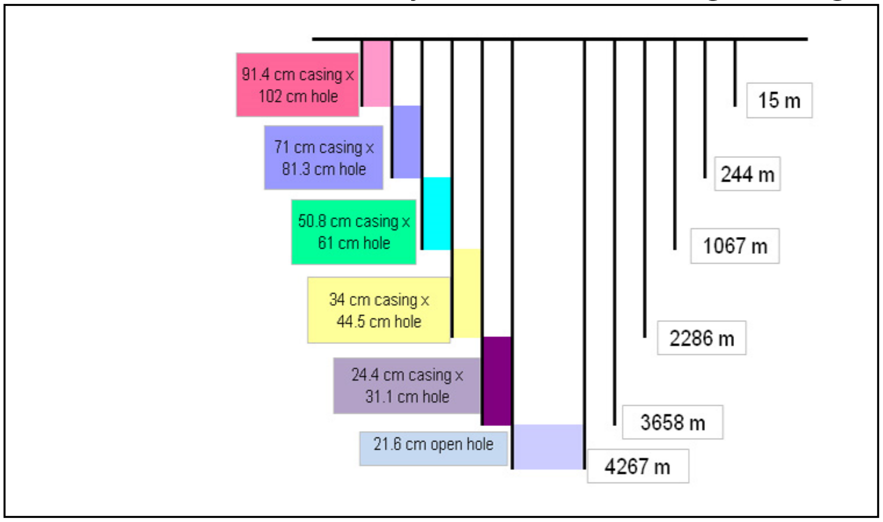

Figure 2 Representative geothermal well design.

The need for directional drilling and the accuracy with which the hole trajectory must be controlled are also important factors in cost, but if directional drilling is dictated by the well design, there is usually little choice about these requirements.

Trouble: "Trouble" is a generic name for many sorts of unplanned events during drilling, ranging from minor (small amounts of lost circulation) to catastrophic (the BHA is stuck in the hole and the drill string is twisted-off). In some cases, experience in the same or similar reservoirs will give a hint that certain types of trouble are likely, but at other times events are completely unexpected. It is difficult, therefore, to estimate a precise budget for trouble, but all well expenditure planning must contain some contingency funds, and this number is often taken to be around 10% of the total budget.

Rate of penetration (ROP): Many of the costs attributed to drilling are time-dependent (primarily related to the rental rate on the rig) so it is clear that anything to speed up the hole advance is beneficial. (Keep in mind, however, that increased ROP at the expense of more trips, or lower tool life, is usually not effective. See the next paragraph.) A tremendous amount of research has been done to improve bit performance, both in terms of drilling speed and life, and there is no doubt that today's bits are far better than those of an earlier generation. Still, even with improved bits it is not always easy to optimize the performance with a new bit design drilling an unfamiliar formation. The three parameters that can be easily changed for any bit/formation combination are rotary speed, weight on bit (WOB), and hydraulics (combination of jet size and flow rate) and it often takes some experimentation to determine the best combination of these values.

Bit and tool life: Much of the commentary above about ROP applies to bit and tool life. Improved tool life means, of course, that the expense of replacing a bit or other piece of equipment can be avoided or delayed, but there is also a time saving if trips can be eliminated. This becomes more important as the hole gets deeper and the trips take more time.

3. Planning a Geothermal Well

Overview

There are two separate but closely related parts of preparing for a drilling project—*planning* the well and *designing* the well. "Planning" means to list, define, schedule, and budget for all the multitude of individual activities required to drill the well, and "designing" means to specify all the physical parameters (depth, diameter, etc.) that define the well itself. Detailed instructions on how to complete this process for even one well would need a sizable volume in itself, and so that is well beyond the scope of this Handbook, but the following discussion will present a sort of checklist that identifies many of the questions that must be considered during these preparations. (The geographical location of the well can have a major impact on cost, schedule, and even well design, but that choice is a function of exploration for the resource, and thus is too variable to be considered as a generic part of well planning.)

Careful planning is critical for any drilling operation. It will not only minimize cost, but will reduce the risk of injury or property damage from unexpected events. A drilling plan should list and define all the activities required to complete the well, with their related costs and times, and should give sufficient descriptions of individual tasks to make clear the sequence in which they must be performed. (A "critical path" approach, showing which operations must be sequential and which can be simultaneous, is often useful. The crux of this technique is that any delay along the chain of sequential operations – the critical path – will cause a delay in project completion, while delay in some other operation may not.) It is also essential that all the contractors and service companies should meet, or at least thoroughly communicate, during the planning stage, so that the plan assigns responsibilities for the various activities and there is no confusion as to what person or company performs each step.

Descriptions in the plan must be relatively detailed. For example, to specify drilling an interval between two given depths and running casing in it would typically require, at minimum, the following information:

- Hole size and suggested bit type (include weight on bit and rotary speed, if available from similar wells)
- Definition of all components of the bottom-hole assembly, and whether downhole motors are to be used
- Expected rate of penetration and bit life (thus, expected time to drill the interval)
- Any directional drilling instructions
- Drilling fluid type and flow rate
- Any required logging during drilling or before casing is run
- Size, weight, and grade of casing
- Proposed cementing program
- Any problems expected in that interval, or special precautions to be taken.

A plan can be as simple as a written outline, in list format, of the various activities, or can be quite detailed and in active electronic format. Management software ranges from simple spreadsheets, through freeware available on the Web, to sophisticated planning tools such as

Microsoft Project[19]. If one considers commercial planning software specific to drilling, make sure that it can include services that are common in geothermal drilling but not often used in oil and gas, such as mud coolers, high-temperature tools and cement, etc. Clearly, the drilling plan must also be flexible enough to accommodate unexpected events, or trouble, during the project, and there must be a well-defined process to identify the person who is responsible for changes in the plan.

To begin designing the well, a great variety of information is desirable, but it is not always possible to get the complete package. It is worth considerable effort to get as much of it as possible, but sometimes the designer must just go with the best available data. The desirable information includes, but is not limited to, the following parameters.

- Purpose of the well: A given well may serve any one of several different functions—production, injection, exploration, or workover—and the well design will be influenced by its purpose. For example, an exploration well might be of smaller diameter than one intended for production and, because it might be scheduled for abandonment once the reservoir is characterized, it might also be completed with less attention to the well's longevity (different cement, casing material, or the like.) Some considerations for hole diameter in small exploration wells, or "slimholes" are described in the Section on Rig Selection.
- Reservoir conditions: It is extremely useful to know as much as possible about the prospective reservoir; such information might come from previous temperature and pressure logs in offset wells, nearby thermal gradient holes, or geophysical information. Clearly, temperature and pressure are crucial, but brine chemistry is also very important because it can have a major impact on casing selection and cost.
- Logistical requirements: It is common that, for reasons including the lease, a power sales contract, other financing requirements, or even weather, a drilling project must be completed on a given schedule. If this is the case, it can complicate planning because of factors ranging from drill rig availability to acquisition of the necessary permits. It is also more or less a standard condition that any lease site will have regulatory stipulations that affect drilling fluid disposal, cuttings disposal, possibly water supply, and even air-quality requirements that will necessitate emissions control on the rig engines. The well planner has little recourse in dealing with these factors, but it is certainly essential to consider them in the planning process.
- Likely problems in drilling: Experience in similar wells or general knowledge of the reservoir can sometimes offer a prediction of what problems may be encountered in drilling the well. If this knowledge is available it will guide the preparations in many ways: having lost circulation material for underpressured formations; appropriate drilling fluid additives for corrosive brines or for exceptionally high temperatures; high-temperature logging or steering tools and drilling motors if those tools will be used in a hot hole; and stand-by fishing tools and possibly shock absorbers in the BHA if there is likely to be rough drilling with twist-offs. It may also provide better definition of the best operating envelope (weight on bit, rotary speed, hydraulics) for the bit in specific formations.
- Casing requirements: The heart of well design is the specification of the casing program, which will be discussed in more detail in the following Chapter.

Drill Rig Selection

Most of the criteria used to select a drill rig will be derived from well parameters; specifically diameter, depth, and casing design. The process of planning and designing the well will have established the diameter, which is the primary criterion for whether the well is considered a "slimhole" or will be a conventional well and, thus, what kind of rig will be used.

Several factors define the minimum hole diameter, and also bear upon whether a core rig can be used for the hole.

- Logging tools - Typical temperature-pressure-spinner logging tools will fit into almost any reasonable hole size, but if more complex tools, especially imaging tools such as a formation micro-scanner or a borehole televiewer are to be used, the heat-shielding they require at high temperature sometimes defines a minimum hole size.
- Core size – If core is required to validate a geologic model of the reservoir or to assess the fracture dip, density, and aperture, then a coring rig is advantageous, compared with taking core samples with a rotary rig, but the core size must be considered. Diameter is not too important for fracture data, but sometimes a rock mechanics evaluation will need a minimum core diameter. Larger diameter core also gives better recovery in highly fractured or unconsolidated formation.
- Packers - Inflatable packers are sometimes used to isolate a specific section of the wellbore for injection tests, fluid sampling, or other diagnostics. In general, this means that some kind of logging or sampling tool must be run through the packer into the zone below it, and the size of this tool will determine the minimum size of the packer and thus the hole. Based just on the diameter of the cable head for most logging cables, it would be very difficult to run a pass-through packer in a hole smaller than approximately 100 mm diameter.

Figure 3 Typical coring rig, mast is ~ 15 m high.

- Flow test - If a flow test is expected after drilling, there are two advantages to keeping the hole diameter as large as possible: scaling up for predicted flow in a large-diameter well will be more accurate; and if the combination of depth, pressure, and temperature means that the well's ability to produce is marginal, a larger diameter hole is more likely to flow. The larger-diameter wellbore is particularly important if the flow turns two-phase.

If all these factors indicate that a slimhole will satisfy the requirements, then a minerals-type coring rig can often yield significant cost savings for two reasons:

- Smaller casing, tools (bits, reamers, etc.), and cementing volumes, and
- The ability to drill with complete lost circulation (no returns to the surface).

Coring rigs (see Figure 3) are fundamentally different from rotary rigs in the way that they retrieve core. In a typical coring rig used for minerals exploration, the core is cut by the bit and is stored in a tube in the lower end of the drill string as the hole advances. At the end of the coring run, a wireline is lowered down the inside of the drill string and is latched into the top of the core tube to retrieve it to the surface. This not only gives a continuous core over the interval of the hole, but is much faster than tripping the drill string to retrieve the core sample as is done in rotary rigs.

Figure 4 Rotary drill rig, mast is ~ 55 m high.

If a large-diameter hole is required, then a conventional rotary rig (see Figure 4) will probably be used and the basic choice to be made is whether it should be a top-drive. For many years, in "traditional" drill rigs, the drill string was turned by a "rotary table" in the rig floor. A square or hexagonal bushing in this table applies torque to the "kelly" (the topmost part of the drill string), which is square or hexagonal in cross-section, so that it can be turned by the table and still slide downward as the hole advances.

In the early 1980s, however, a new system in which the drill string was turned by an electric or hydraulic motor hanging directly beneath the traveling block gained commercial acceptance. (see Figure 5) This "top drive" technique has at least two critical advantages: instead of adding drill pipe one joint at a time as the hole advances, the driller can work with stands (two or three joints) of pipe, eliminating time and connections, and the driller can rotate and circulate while tripping into the hole. Detailed comparison of operations for one offshore platform[20] showed an 11% decrease in drilling time, and the ability to circulate while tripping is especially important for geothermal wells, because it allows protection of temperature-sensitive tools while tripping into the hole. In one geothermal reservoir[21], it was reported that bit life was improved three- to six-fold by circulating during trips into the hole. The circulation/rotation capability is also useful for avoiding stuck pipe and for working through tight spots during tripping. Top-drive rigs generally cost more in daily rental, but it is often cost-effective to use one.

Figure 5 Top drive, photo courtesy of National Oilwell Varco.

Many considerations will affect the final rig choice but, aside from the purely economic factor of the price quoted by the drilling contractor, the following aspects of the rig should be the minimum list of qualities upon which to make a decision.

Rig capacity: This usually refers to hook load—the weight that can be suspended from the rig's hoisting system. Clearly, the drill string weight, with all the bottom-hole assembly, is a necessary part of this requirement, but it should be remembered that the casing is often the heaviest load handled during a drilling project.

Rig footprint: The drilling contractor should provide a dimensioned diagram or map of the rig set up in operating mode. It should clearly show: access points and traffic patterns to various parts of the rig; where different operations (mixing mud, mud logging, etc) are performed; and the locations where various consumables are stored. If the planned drilling operation includes mud pits, or a water well, those should also be on the map. The contractor's quote will give a cost figure for mobilizing and de-mobilizing the rig (moving the rig to and from the drilling location) but there should also be an indication of how many truck loads this will entail, and what road clearances are required, in case there are regulatory issues at sensitive locations.

Pump capacity*:* As discussed under "Drilling Fluids", the pumps must have enough volumetric capacity to give sufficient velocity in the annulus to lift the cuttings. The pumps must also have enough pressure capacity to give the desired pressure drop through the bit jets, and possibly drive a downhole drilling motor, if that is planned or a likely contingency. Because of the generally larger hole sizes (and volumes) in geothermal wells, pumps (and pits) will be bigger than for oil wells of comparable depth. The pumps should also be able to handle lost circulation material (LCM), which is discussed in more detail later.

Fluid cleaning*:* These requirements should be defined in consultation with the mud engineer/company, and the rig's shakers, desanders, desilters, and centrifuges should be adequate to the job. There should be some operational consideration of the rig's compatibility with any environmental regulations that affect disposal of the drilling fluid and cuttings, such as the requirement for a closed-loop fluid system with no discharge to the environment. LCM will also complicate the mud cleaning, because it must be removed before the cuttings and fines can be removed from the drilling fluid.

Drill string and BHA*:* The bottom-hole assembly design should be defined during planning, so the rig must have the correct tools, tongs, and fixtures (bit breakers, elevators, etc.) to handle all components of the drill string. It should also be made clear in the contractor's quote whether drill pipe is included in the rig's daily rate. If so, the planner should make certain that it is the correct size, weight, and grade and, if not, the planner should assure that another source of pipe is available.

High-temperature capability*:* When drilling geothermal wells, it is clearly necessary that any of the rig's downhole or surface equipment that will be exposed to high temperature has that capability. This may be especially noticeable in drilling fluid returns, which will probably be much hotter than in conventional drilling. In most locations, regulatory guidelines will require use of mud coolers when returns exceed a specific temperature, but even with coolers, operating personnel should be aware that hot fluid will create higher-than-normal thermal expansion forces, and that any elastomer seals may become vulnerable to the high temperature.

Rig instrumentation*:* Complete information about the rig's performance is essential for safe, efficient operation, and the project planner should include an instrumentation list in the rig criteria. Detailed requirements will vary from project to project, but a typical set of desirable measurements includes the following: drilling fluid inflow and outflow rates, drilling fluid inflow and outflow temperatures, standpipe pressure, rotary speed, weight on bit, torque, and kelly height, if available. All these measurements should be digitally recorded on a data logger at reasonably short intervals so that they can be easily stored and retrieved, but selecting the interval between measurements is not straightforward. For "steady-state" drilling, in which operations are routine, data points every 5 to 10 seconds are adequate, but for transient events such as the beginning of a new bit run or the onset of unstable, possibly damaging, drilling conditions, high-resolution data can be extremely valuable. Collecting high-speed data implies very large data files on long drilling projects, which may be a storage problem, but low-speed collection that gives more manageable amounts of data may not give the resolution needed for short-duration events. Rig instrumentation is often coordinated between the drilling contractor and mud logging company; see Chapter 9—Logging and Instrumentation.

***Support**:* In general, rig malfunction or breakdown is one of the less likely kinds of drilling trouble. If the drill site is in an especially remote location, however, it is worth considering how far away the rig's support services may be.

***Crew and training**:* It is not always possible to know in advance who will be working on the rig, but the importance of a well-trained, experienced crew to the project's success cannot be overstated. In the course of evaluating proposals from drilling contractors, every effort should be made to find out the experience and qualifications of the rig crew and supervision.

Like many aspects of drilling, selecting a rig often turns out to be more complicated than it first appears. Keys to a successful choice revolve around having a clear and detailed concept of what is needed for the project. It is frequently very valuable to have an experienced geothermal drilling engineer assigned to the specific task of rig selection, because any extra cost incurred here will almost certainly prove to be well-spent.

Case Histories of Two Geothermal Wells: To give a more intuitive feel for actual geothermal drilling, case histories for two wells are summarized in Tables III-1 through III-4. Because certain data related to specific wells are proprietary, the wells are identified only as "Steam well" and "Brine well." Both wells were drilled in the mid-1990s, so an inflation factor should be applied to the costs, and both wells were drilled in geothermal fields where there was extensive previous experience. In both tables, ROP means rate of penetration.

***Steam Well**:* This well was designed to be a two-leg well with casing to approximately 1500 m and two open-hole branches to approximately 3000 m, but the first leg encountered no steam entries. It was plugged back and two additional branches were drilled (i.e., three holes were drilled from approximately 1350 to approximately 3000 m.) Although drilling three legs is not required for all wells in this reservoir, it is not uncommon, and drilling records from this well can be extrapolated back to one- or two-branch wells. The hole was drilled with mud to the 1500 m casing point; then all branches were air-drilled.

Total time over the hole was approximately 90 days and total well cost was approximately $3 million. There was no significant lost circulation in the mud-drilled part of the hole. Other events included milling two windows in the 298 mm casing and four twist-offs, three of them in the air-drilled intervals. Although more footage was drilled than planned, this was considered a relatively trouble-free well.

***Brine Well**:* This is a self-energized geothermal production well drilled in sedimentary formations. The well is cased to approximately 640 m and has an open-hole production interval from there down to approximately1500 m. The corrosive nature of the brine requires titanium casing, but standard practice is to avoid drilling inside this very expensive tubular. Procedure is to drill 37.5 cm hole to TD and flow test well through 40.6 cm steel casing, then run and cement 34 cm titanium production string inside the 40.6 cm casing.

Total time over the hole was approximately 50 days (but approximately 10 days went to flow testing the well and cementing the titanium casing) and total well cost was approximately $3.7 million, with approximately $1.4 million of this total for the titanium production string. There were four significant events of lost circulation (total mud lost > 7000 bbl), all of which were controlled with LCM. Problems in stage-cementing the 40.6 cm casing led to a major fishing job. There were no fishing jobs during drilling. This was also considered a relatively trouble-free well.

Table 3- 1 Steam Well Borehole Profile.

Hole Diameter, cm	Casing Diameter, cm	Setting Depth, m
66	55.9	91
52	40.6	457
37.5	29.8	1524
27	Openhole	3048, 3 times

Table 3- 2 Steam Well Bit Summary.

Bit Diameter, cm	No. Bits Used	Avg. ROP, m/hr	Avg. Life, m
66	1	11.6	91+
52	2	6.4	183
37.5	4	5.2	1 @ 610 3 @ 152
27	17	29	335

Table 3- 3 Brine Well Borehole Profile.

Hole Diameter, cm	Casing Diameter, cm	Setting Depth, m
102	91.4	30.5
44.5 w/91.4 ur*	76.2	91
44.5 w/76.2 ur	61	305
44.5 w/61 ur	50.8	457
44.5 w/55.9 ur	40.6	640
	34 Ti	640
37.5	openhole	1524
*ur = underreamer		

Table 3- 4 Brine Well Bit Summary.

Bit Diameter, cm	No. Bits Used	Avg. ROP, m/hr	Avg. Life, m
44.5	1	na	640
37.5	7	4.6	122

4. Wellbore Design – Casing and Cement

Overview

When wells are drilled to depths of more than a few hundred feet, conventional practice is to set successive, separate strings of casing as the well gets deeper. The depth of each string is determined by several factors, including rock properties (fracture gradient, sloughing, swelling, unstable, or unconsolidated formation), formation fluids (pore pressure much less or much greater than drilling fluid pressure), or even regulatory requirements[*]. These criteria apply to most kinds of drilling – onshore or offshore oil and gas, geothermal, or even minerals exploration – and they are further complicated by the ever-present possibility of unexpected trouble, which can mean an extra string of casing is run to prevent or remedy some downhole problem. This is expensive for more than one reason, as described in more detail below.

Parameters that determine the casing requirements include the following: nominal production rate from the well and the casing diameter implied by that flow rate, depth of the production zone, expected temperature, brine chemistry, whether the completion will be open-hole or slotted liner, well trajectory (vertical, directional, or multi-leg), kick-off point (if directional), need for special casing connections, and the length of individual casing intervals.

In general, the well is designed from the bottom up; that is, the expected depth of the production zone and the expected flow rate will determine the wellbore geometry and casing program and most of the equipment requirements will follow from those criteria. Because geothermal wells produce a relatively low-value fluid—hot water or steam—flow rates must be much higher (often >100,000 kg/hr) than for oil and gas wells, and geothermal wells produce directly from the reservoir into the casing, instead of through production tubing inside casing as in most oil wells. If there is two-phase flow in the wellbore, larger casing diameter where flow is vapor-dominated will significantly reduce pressure drop, improving productivity.[22] Finally, many lower-temperature geothermal wells are not self-energized and must be pumped, either with line-shaft pumps driven from the surface or with downhole submersible pumps (and so the well's design must allow for pump removal). All these factors combine to drive geothermal casing diameters much larger than oil and gas wells of comparable depth – typical casing sizes in geothermal production zones are 20 to 34 cm.

There are three important implications of this process:

- Because each casing string limits the diameter of the drill bit and successive casing strings that can pass through it, the hole diameter decreases as the well gets deeper.
- Because of casing costs and diameter reduction, it is beneficial to make the intervals between casing points as long as possible.
- Problems or trouble most often occur while drilling the wellbore intervals between casing points.

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[*]Most agencies require that the surface casing cover at least 10% of the wellbore down to the next casing point, and below that at least 1/3 the hole must always be behind casing.

The two latter points counter each other – it is highly desirable to drill long intervals between running successive casings, but doing so greatly increases the probability of trouble. If a "contingency string" is needed to isolate a troublesome zone, this imposes a significant cost for the additional casing and cementing and for the necessity of larger diameter casing above the contingency string, so that the required bottomhole diameter can be preserved at the designed dimension.

Casing design

Given a bottom-hole depth and diameter, determination of the casing intervals above that depends on several factors, including rock properties, formation fluids, or regulatory requirements. There are many common reasons to set casing in a particular interval:

- Protect an aquifer—regulations require sealing off aquifers to prevent their contamination by wellbore or drilling fluids.
- Isolate troublesome formations—these can be unstable (sloughing, swelling, or unconsolidated) formations, zones with high or incurable lost circulation, or a depleted-pressure zone above the production horizon.
- Fluid pressure control—although more common in oil and gas than in geothermal, drilling fluids often contain additives that bring the specific gravity of the fluid well above that of water, so that the weight of the fluid column will control the downhole pore pressure in the formation. This often leads to the situation in which the higher pressure of the drilling fluid exceeds the fracture gradient of the formation, leading to lost circulation or even loss of well control.
- Define the production zone—geothermal reservoirs can have more than one productive zone and casing is sometimes set to preferentially allow production from the selected zone.

There are many other reasons that casing might be set at a particular depth, but this list gives a flavor of how variable those reasons can be. Once the general casing profile is selected, the casing for each individual interval, or string, is characterized by three basic measurements: diameter, weight, and grade. Diameter is straightforward, it is just the nominal outside diameter for that interval (although this does not include the couplings, which are larger than the casing body and control the smallest possible inside diameter of the next larger string.) Weight, expressed in weight units per unit length, is actually a measure of the wall thickness of the casing; heavier casing has smaller inside diameter, since the outside diameter must remain constant for a nominal size. The casing's grade is primarily related to the material's tensile strength, although there are some metallurgical variations aimed to withstand specific effects, such as corrosion, of the wellbore fluid chemistries.

Casing has to withstand different kinds of loading in different situations, and the most common design criteria are for burst pressure, collapse pressure, axial tension, and buckling. Burst pressure and axial tensile strength for a given casing size are a function of the casing grade, but collapse and buckling are more related to the wall thickness, because they are determined by the material's elastic properties and geometry more than its tensile strength.

As suggested above, the casing design has a significant impact on well cost. Because of the large casing diameters in most geothermal wells, casing and cementing can represent more than 40% of total well cost, and the possibility of eliminating one string of casing when the well is designed can yield a cost reduction approaching 20%. Clearly, the potential cost saving must be balanced against the risk of a lower “safety factor”, but this emphasizes the importance of close examination of the casing program.

Several other considerations in geothermal casing design are the following:
Strength at high temperature—Common casing materials lose strength at elevated temperature and the loss is more pronounced in higher grades of steel. For example, the yield strength of K-55 casing decreases from 388 MPa 25^{O}C to 359 MPa at 371^{O}C, but quenched-and-tempered L-80 goes from 632 MPa to 484 MPa over the same temperature range[23].
Casing availability—It is not uncommon for casing procurement to have a very lengthy lead time (many months), especially for higher grades. The well designer should check on this early in the process, so that alternatives can be pursued if the specified casing is not available in time to meet the schedule.
Corrosion resistance—A number of geothermal reservoirs are plagued by problems driven by the brine chemistry. Brine quality varies greatly, ranging from near-potable in some moderate-temperature systems to highly corrosive with high dissolved solids in some high-temperature systems. Many techniques – cement-lined casing, exotic alloys, and corrosion-resistant cement – have been applied to the casing corrosion problem, which is especially severe in the Imperial Valley of Southern California. Shallow and hot, CO_2 bearing zones there drive an external corrosion rate approaching 3 mm of carbon steel per year, which once necessitated plugging after 10 to 12 years even when well life was extended by cementing in smaller production strings. Most production wells in the Imperial Valley have now been completed or retrofitted with titanium casing, which has proved to be cost effective in spite of its very high capital investment (casing cost approximately US$3000 /m.)

Although reasonably simple casing designs can be done with hand calculations and manufacturers’ handbooks, the general topic is very complex, and detailed procedures for casing design are well beyond the scope of this Chapter. Extensive resources are available. All drilling engineering textbooks[24] have sections on casing design, and an Internet search for “casing design software” will indicate the multitude of options to be found among drilling service companies. Although all of these methods are likely to produce satisfactory casing designs, engineering judgment is still important and it is a significant benefit to have a veteran drilling engineer with geothermal experience to at least review a proposed casing program.

Cementing

Casing has traditionally been cemented in place by pumping a calculated amount of cement into the casing, placing a movable plug on top of the cement, and then displacing the plug downward by pumping drilling fluid on top of it[*]. This forces the cement to flow out the bottom of the

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[*] There is normally a “float shoe” (essentially a check valve to prevent the heavier cement from flowing back up the inside of the casing) at the bottom of the casing, and often a “float collar” (redundant float, one or more joints of casing above the shoe.) The float collar means that the

casing and up the annulus between the casing and wellbore. In most oil and gas wells, the casing is cemented in place only at the bottom, with a completion fluid between the balance of the casing and the wellbore wall, but geothermal wells must have a complete cement sheath from bottom to surface[25]. This cement has two important functions: to give the casing mechanical support under its sometimes-intense thermal cycling between production and shut-in, and to protect the outside of the casing from corrosion by in-situ fluids.

This implies that geothermal cements should have high bond strength to the casing and should be impermeable, but it is also very advantageous for the cement to be light weight (at least compared to conventional cement, which has a specific gravity of approximately 1.6). Light weight is important because of the oft-encountered lost circulation described above. If the formation's pore pressure will not even support drilling fluids, then it is impossible to lift a column of normal-weight cement back to the surface when casing is cemented in place. One solution to this problem is foam cement, which has gas injected into it, in the same way as drilling fluid is aerated to make it lighter. Recent experience with difficult wells in California[26] and Hawaii[27] has also shown that reverse circulation foam cementing, where the cement is pumped down the annulus and flows back up drill pipe from the bottom of the casing, has several advantages.

Even with light-weight cement, however, it is often impossible to lift a column of cement back to the surface without breaking down the formation. The casing can be designed with "stage collars", which have ports that can be opened in the side of the casing to allow cementing in stages, rather than all at once, to reduce the cement pressure on the formation. A similar alternative is to perforate the casing at the top of the first cement after it has cured and force additional cement out into the annulus to extend further toward the surface. This process can be repeated if one squeeze does not completely cement the full annulus.

If cement returns have not quite reached the surface in a conventional cement job (i.e., there is only a relatively short uncemented annulus around the top of the casing) then a "top job" can be done. This means that small-diameter lines (tremie lines) are inserted into the annulus and cement is pumped into them to fill the annular volume. The risk in this is that liquid (water or drilling fluid) will be trapped between the upper and lower volumes of cement (see below in *Completions*), so all possible precautions should be taken to avoid this. If the resources are available, the annulus can be dried with steam[28], to assure the absence of liquid.

Conventional oil well cements are not only too heavy for many geothermal wells, but are susceptible to attack by acids and by CO_2, both of which are common in geothermal reservoirs and both of which degrade the impermeability and strength of the cement. Historically, the major modification to Portland cement for geothermal use is the addition to standard Class G cement of retardants and approximately 40%, or more, silica flour[29], but this does not eliminate the problem of CO_2 and acid attack. Brookhaven National Laboratory carried out a major research program on geothermal cement, intended to mitigate or eliminate these effects. The R&D effort comprised: characterization of cements then used in geothermal environments[30,31], the extension of hydrothermal cements to higher operating temperatures[32]**,** and the development

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mud/cement interface will be inside the casing, reducing the risk of contaminating the cement around the shoe.

of new materials such as phosphate-bonded cements[33], polymer cements[34], and other new compositions[35].

BNL worked with cost-sharing industry partners (Halliburton, Unocal, and CalEnergy Operating Company) toward the specific goal of a lightweight cement with outstanding resistance to acid and CO_2 at brine temperatures up to 320^{O}C. Reviews of this work before[36] and after[37] 1997 are provided in detailed reports. BNL succeeded in synthesizing, hydrothermally, two new cements: calcium aluminate phosphate (CaP) cement; and sodium silicate-activated slag (SSAS) cement. The CaP cements were designed as CO_2-resistant cements for use in mildly acidic (pH ~ 5.0) CO_2-rich downhole environments. The SSAS cements were designed to resist a hot, strong acid containing a low level of CO_2. Both of these were economical cements because they used inexpensive cement-forming by-products from coal combustion and steel-manufacturing processes. In 1997 Unocal and Halliburton completed four geothermal wells in Sumatra with CaP cement, the first field use of this formulation, and in 1999 Halliburton commercialized it under the name "ThermaLock Cement". SSAS cements have received less attention than CaP, but autoclave experiments in the lab have demonstrated good performance in high-acid environment and, in fact, after undergoing acid damage, the SSAS cement exhibited a self-repairing characteristic. Addition of fly-ash further improved its acid resistance, so SSAS is promising as low-cost geothermal well cement in high-acid conditions up to 200^{O}C.

Completions

Apart from the requirement for a complete cement sheath around the casing, factors that influence completion design include brine chemistry; multi-branch completions; and whether the production interval is stable enough to be open hole or must be completed with a slotted liner.

Brine chemistry can cause two major problems: corrosion, as described above, and scaling. Scaling, the buildup of mineral deposits both inside the casing and in the production interval, is a problem in geothermal plants around the world[38], and can lead to frequent workovers. In severe cases untreated scaling can reduce the flow area of casing by half in a matter of months. Casing scale can sometimes be removed with high-pressure jets[39], but scaling in the wellbore often seals the formation and must be drilled out with an under-reamer (an expandable bit that can drill a hole below casing that is larger than the inside diameter of the casing). It is highly preferable to inhibit or prevent scale formation than to remove it, and there are many chemical techniques for this[40], but discussion of those is beyond the scope of this Chapter.

When casing is cemented, it is also critical that no water be trapped between the cement and the casing, especially in intervals where one casing is inside another, because the water can become hot enough to flash to steam as the well goes on production and heats up. If the collapse rating of the inner casing is lower that the saturation pressure of the water, the casing will buckle (if the trapped-water location has formation outside it, the fracture gradient is sometimes low enough to allow the pressure to bleed off into a fracture.) These failures can be serious enough that the production casing is imploded and ruptured to the extent that it will reduce production and will provide a path from the formation into the cased hole[41].

Finally, it is necessary to decide whether the production interval of the well is competent enough formation so that it can be left as-drilled (open-hole completion) or whether a slotted liner will be necessary to protect against sloughing or caving into the wellbore. Some indications can be gained from the geologic samples acquired during drilling, or from imaging logs, if available, but this decision is often made based on experience gained from other wells in the same reservoir.

5. Drilling Fluids

Overview

Drilling fluid flows down the drill pipe, through nozzles in the bit, and back up the annulus between the pipe and wellbore wall, carrying the cuttings produced by the bit's action on the rock. (An alternative method, called reverse circulation[42], is sometimes used—the fluid flows in the opposite direction, down the annulus and up the inside of the drill pipe, but it is not common.) Drilling fluids can be either liquid or gas, and liquid-based fluid is universally called "mud" because the first fluids were just a mixture of water and clay. Large hole volumes and frequent lost circulation mean that expensive mud has a significant impact on drilling cost. Drilling records from a number of geothermal wells in several reservoirs showed the typical property ranges below:

• Density	1.03 – 1.15 g/cm^3
• Funnel viscosity	35 – 55 sec
• pH	9.5 – 11.5
• Plastic viscosity	0.01 – 0.02 Pa-s
• Yield point	35 – 125 kPa

Drilling mud is made up of three principal components:

- Base liquid: Oil, fresh water, or salt water can be used as a base liquid in drilling muds, but oil and salt water are almost totally restricted to hydrocarbon drilling. Fresh water muds are used for geothermal drilling.
- Active Solids: Active solids are the clays and polymers added to the water to produce a colloidal suspension. They determine the viscosity of the mud and are known as viscosifiers.
- Inert Solids: Inert solids are those added to the mud either by drilling (i.e., particles of the formation) or by using barite as a weighting material. These solids increase the density of the mud without appreciably affecting the viscosity.

There are also soluble components of the system; products in solution in the base liquid that cannot be filtered or removed mechanically. These ions must be chemically analyzed and chemically treated. Undesirable ions such as calcium, magnesium, arsenic, and chlorine may be present in the make-up water or they may be present in drilled formations and become dissolved in the mud system. Some water sources may contain too many undesirable ions to treat out, and thereby require locating a better source of water.

Historically, most geothermal drilling fluids that are liquids have been a fairly simple mixture of fresh water and bentonite clay, possibly with polymer additives[43]. Aerated mud has a gas, usually air but sometimes nitrogen if corrosion is serious, injected into the liquid to lighten it; aerated mud is common where lost circulation is a significant problem. Drilling with air only is also relatively common, especially in areas like The Geysers in northern California, where the reservoir produces dry steam. Air drilling also has advantages in drilling performance because the rate of penetration is usually higher than with mud or aerated mud.

Drilling fluid functions

As noted above, the principal function of drilling fluid is to clean the hole of cuttings, but there are several other purposes:

- Cool and clean the bit: keeping the bit cool, especially if it has elastomer seals, is critical to its life.
- Lubricate the drill string: this can be a significant factor in deviated (non-vertical) wells, where the drilling string is lying against the wellbore wall.
- Maintain the stability of the borehole: the proper drilling fluid can help control swelling or sloughing formations, thus lessening the risk of stuck drill pipe. It is also important that the fluid hold the cuttings in suspension when circulation is stopped, so that they do not fall back and pack around the bit and BHA.
- Allow collection of geological information: the cuttings brought back to the surface by the fluid help to identify the formation being drilled.
- Form a semi-permeable filter cake to seal the pore spaces in the formations penetrated; this prevents fluid loss from the wellbore.
- Control formation pressures: if high downhole pressures are present or expected, dense material can be added to the drilling fluid to increase its specific gravity, thus resisting the downhole pressure.
- Transmit hydraulic horsepower: this power can be used for driving a drilling motor or for cleaning the hole and/or the bit.

Drilling fluid system

It should be emphasized that the drilling fluid is part of a circulating system, comprising the fluid itself, the mud pumps, and mud cleaning equipment. The pumps must have sufficient capacity (flow rate and pressure) to provide adequate bottom-hole cleaning, high annular velocity to lift the cuttings, and enough hydraulic horsepower to drive downhole motors and provide the designed pressure drop through the bit jets.

When the cuttings-laden mud returns to the surface, it passes through a series of devices to remove the cuttings. The first of these is usually the shale shakers, which have tilted, vibrating screens that filter out larger cuttings and let them slide off into collection containers; next are usually hydrocyclones (figure 6), which use fluid inertia to swirl the fluid in a conical chamber, letting the solids drop out the bottom; and finally, centrifuges spin the fluid to extract the finest particles through their density difference. Effective mud cleaning is important for drilling performance as well as cost control. If the fluid has to be discarded because of inadequate cleaning, it is expensive both in material cost and in time loss.

Drilling fluid properties

The drilling fluid will be designed to have certain properties, and it is critical to monitor and control these properties at all times. Design and maintenance of drilling fluids is a complex topic, covered in great detail in many sources[44,45] but primary attributes of fluid for a given well include the following.

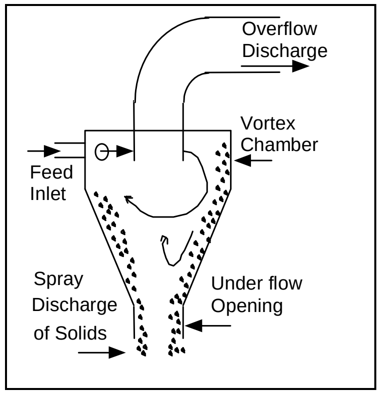

Figure 6 Hydrocyclone.

- Viscosity: it is vital that the fluid's viscosity be high enough to lift cuttings out of the well as the fluid circulates, and to hold the cuttings more or less in suspension when circulation is stopped.
- Density (or specific gravity): if formation pressures are expected to be high, then the fluid can be weighted to help control them but, as is often the case in geothermal wells, if formation pressures are low, then the fluid should be as light as possible to avoid lost circulation.
- pH: the alkalinity of the fluid is important for corrosion control and for its reaction with certain formation constituents; normal pH is 9.5 to 10.5, but higher values are not uncommon.
- Filter cake: this is a measure of how well the fluid forms an impermeable layer on the borehole wall to prevent leakage into the formation's natural permeability. (This is typically more important in oil and gas drilling than in geothermal.)
- Solids content: this is a measure of how well the mud is being cleaned, and can also determine when the mud should be discarded or diluted.

There are standard procedures[46] for testing these and other parameters of the drilling fluid, and this testing is normally done at least daily in the field by the drilling fluid specialist or "mud engineer".

Successful mud systems need at least these three attributes:

- Stability: The desired properties of the fluid, once established, should be stable under normal drilling conditions.
- Easy treatment: If the desired fluid properties are lost, treatment should be available to restore them.
- Property testing: Tests and testing equipment should be available to identify fluid properties and indicate any treatment required.

These attributes can be achieved by the following principles.

1. Formula: Have the proper mixture of products to satisfy anticipated downhole conditions.

2. Application: Have the mud properties as needed BEFORE drilling into known or anticipated problems. Don't wait until you have a problem and try to fix it. Use preventive maintenance.
3. Flexibility: Always maintain a system in which the properties may be adjusted without drastic changes in the mud. Don't "shock" holes by rapidly changing properties.
4. Monitor and Maintain: Monitoring is analyzing certain parameters of the mud (viscosity, weight, filtrate, chemical composition, pH, etc.) on a regular basis (every tour). Maintaining is continually adding the necessary products to maintain the required fluid properties. Drilling mud is continuously being "used up." Polymers are adhering to solids and dissipating, water added for volume needs to be treated. The mud at the beginning of the shift is not the same mud at the end of the shift unless it has been monitored and maintained on a regular basis. At crew changes, do NOT discard the mud and prepare a new batch with different properties.
5. Pumps: Have pumps with adequate pressure and volume capacity to circulate and mix mud.
6. Mixing capacity: The rig should be able to mix bentonite, polymers and other additives through a high-shear hopper mixer, a high-speed hydraulic Thiessen type mixer, or similar adequate mixers.
7. Adequate pits and solids control: Letting solids build up, particularly in a core fluid, is an ***absolute*** prohibition. Solids build-up can cause differential-pressure sticking, wear on pump parts, induced loss of returns, and numerous other problems. Pits should be designed to baffle the mud flow, change direction of flow, and cause the mud to flow from one pit to the other. General Rule - Pit volumes should be three times the hole volume at total depth.

Although the underlying principles of drilling fluids described in the extensive literature are the same for oil/gas and geothermal drilling, high temperatures affect many of the clays and additives used to tailor the fluid properties. Some considerations unique to geothermal drilling are listed below, based heavily on the cited reference[47]:

- Viscosity control: high-quality bentonite clay is the principal vicosifier used in geothermal drilling. Several polymers, available both in liquid and powder form, are also useful but they tend to degrade at high temperatures over long periods of time, so their principal use is for high-viscosity sweeps to clean the hole before cementing, trips, or other activities that require stopping circulation. It is also sometimes necessary to decrease the viscosity, if drilled solids or high-temperature gelation have raised it too high. Proprietary blends of low-molecular-weight polymers and starch derivatives have recently been developed and are effective both in thinning the mud and in inhibiting gelation.
- Solids removal: at high temperatures, the drilled solids tend to take up the available water more vigorously than at lower temperatures, so effective mud cleaning is even more important than usual to prevent gelation and viscosity increase.
- Filtrate (water loss) control: in the past, geothermal filtrate requirements were often more rigorous than necessary. It is important to analyze the filtrate requirements, not only for each well, but for each interval, so that expensive additives are not used without good cause. Lignite has long been the most common geothermal water-loss reducer, but proprietary polymers are also becoming common.

- Alkalinity: high pH is necessary to control the effect of some wellbore contaminants (CO_2 and H_2S), to reduce corrosion, and to increase the solubility of some mud components (lignite, etc.). Addition of caustic soda (NaOH) has been the traditional method of increasing alkalinity, but caustic potash (KOH) is becoming more common in geothermal drilling because of its benefits to wellbore stability.
- Lubricity: the drill string sometimes needs extra lubrication when directional drilling, and lubrication is very often needed when core drilling, especially when drilling without returns. Hydrocarbon-based lubricants often lose their effectiveness at high temperature, but there are proprietary, environmentally friendly lubricants that offer good performance at sustained high temperature.

Finally, there are instances in which it is desirable to drill with clear water, or clay-free drilling fluids, especially in production zones where conventional clay-based muds create a risk of formation damage. This technique requires a copious water supply, and cannot be used in all wells, but has proven successful in Iceland and in Mexico[48].

Planning the mud program

Some general guidelines[49] for planning the drilling fluids program are given below, with a reminder that every well is different and there are very few, if any, generic procedures that can be used without modification. A pre-spud meeting of all operating, drilling, environmental and service company personnel is highly recommended. Discussions of the drilling plan and contingencies may eliminate trouble later in the program. Once there is agreement on the drilling plan, then the mud program should be planned with the following considerations.

1. Water: Since water is basic to the mud system, it is important to know the quality, quantity and cost involved with the make-up water. Poor quality make-up water may require chemical treatment prior to its use.
2. Type and thickness of the geologic strata: This is not always known before drilling, but fluid properties must be planned with the best available information about downhole conditions, i.e., the reactions between drilling mud and formation.
3. Site Accessibility: Make sure that supply trucks have reasonable access to the site and that rig placement in relation to pits, bulk storage, etc. is convenient to reduce handling.
4. Climate: Extremes of heat, cold, and precipitation can affect the mud system and products.
5. Drilling equipment: Make sure that the surface equipment, such as: pumps, mixing and circulating tanks, mixing equipment, and solids control capabilities are adequate for the hole size, downhole tools, etc.
6. Environmental considerations: If at all possible, use non-toxic, easily disposed drilling fluids. All personnel should know all regulations pertaining to the job.
7. Manpower: The experience, skill, supervision, and attitude of the rig crews are of paramount importance to a successful drilling program.

This chapter is intended to give some flavor of the complexity of the process that is designing and maintaining a drilling fluid system. It is worth a great deal of attention in preparation for a project, because a high percentage of the problems encountered in drilling are related in some way to the fluids.

6. Drilling Tools

The most common tools used in drilling include the components of the drill string and bottom-hole assembly described below.

Bits:

The bit is usually either a roller-cone, which crushes and gouges the rock as the cones turn and their teeth successively come in contact with unbroken areas, or a drag bit, which shears the rock in the same way that a machine tool cuts metal. Because of this shearing action, drag bits are inherently more efficient than roller-cone bits.

The great majority of roller-cone bits today have three cones, with either milled steel teeth (see Figure 7) that are part of the cone itself or hard-metal (usually tungsten carbide) teeth (see Figure 8) inserted into the body of the steel cone. Milled-tooth bits are less expensive but are suited only for softer formations. Insert bits are used in medium to harder formations, with the size, shape, and number of inserts varied to fit the specific drilling conditions. The bits are available with either roller or journal bearings, depending on operating conditions, and the bearings, seals, and lubricants should all be specified to withstand high temperatures if the bits are to be used in geothermal drilling. Roller-cone bit technology is very mature—over 100 years since the first patent[50]. Although bit companies still do constant research, and have made significant progress over the last 20 years, the improvements have been incremental. Since the 1950s, R&D for roller-cone bits has alternated between better bearings and more durable cutting structures, depending on which is the dominant failure mode at the time. Roller cone bits dominate drilling for geothermal resources because of their durability in the hard, fractured rocks that are characteristic of those reservoirs.

Figure 7 Milled tooth roller-cone bit, photo courtesy of Reed-Hycalog NOV.

Figure 8 Insert roller-cone bit, photo courtesy of Reed-Hycalog NOV.

Figure 9 PDC drag bit, photo courtesy of Reed-Hycalog NOV.

Because drag bits reduce rock with a shearing action, they are inherently more efficient than roller-cone bits. Drag bits with polycrystalline-diamond-compact (PDC) cutters (see Figure 9) began to be widely used in the early 1980s for their ability to drill faster and last longer in soft to medium formations, and they now dominate oil and gas drilling. A particular advantage of drag bits for geothermal drilling is that they do not have any moving parts, so temperature limitations on bearings, seals, and lubricants are not a factor. Unfortunately, PDC bits usually do not have acceptable life in hard or fractured formations, and are not generally used in geothermal drilling. A great deal of work has been done to extend their use to harder rocks[51,52,53], and significant progress has been made, but they have not yet been accepted by the geothermal industry. Wider use of these more efficient bits would be a significant technology advance.

Many exploratory slimholes have been drilled with minerals-type core rigs, and those bits are completely different from the "rotary drilling" bits described above. In a minerals-type system, the core is removed from the hole by retrieving a "core tube" from the BHA with a wireline, instead of tripping the entire drill string, as is done with oil-field type coring. It is consequently much faster to retrieve core, although the rate of penetration for coring is usually fairly low. Much of the rock volume removed from the hole is in the form of core, and the rock cuttings themselves are much smaller, because virtually all hard-rock coring is done with diamond-impregnated bits (see Figure 10) that grind away the rock.

Figure 10 Diamond-impregnated core bit.

Principal variations in this kind of bit are the diamond grain size, the diamond grain density, and the hardness of the matrix metal in which the diamond grains are embedded. These bits typically turn at much higher speeds than conventional rotary bits (either roller-cone or drag) and have a much lower drilling fluid flow rate because of the smaller annulus between the drill rods and the borehole wall.

Other reasons for coring

Slimhole exploration is usually done because in many circumstances it is cheaper than rotary drilling in the same reservoir, but there are other significant benefits to having complete core samples over the depth of the hole.

Because geothermal reservoirs produce primarily through fractures, it is extremely useful to know the fracture density, spacing, and aperture, the combination of which gives a measure of the reservoir's transmissivity. The fractures' orientation (dip and strike) gives information on how production wells should be directionally drilled in order to intersect the maximum number of fractures. This information about fractures can be obtained from imaging logs in production-sized holes, but the logging is expensive and the instruments are often limited in the temperatures that they can withstand. Wireline coring is routinely done at temperatures well above $200^{O}C$, and the core can be oriented with a relatively simple method, given that the hole inclination is more than 5^{O} from vertical. Although these measurements are not always required, core samples can also provide rock properties and an opportunity to look for thermal alteration in the formation.

Percussion drilling

The hard, fractured rock typical of geothermal formations is well-suited to impact drilling because there is little or no plastic deformation of the rock. Percussion drilling uses a reciprocating downhole piston/anvil assembly to apply impact loading either to a conventional roller-cone bit or to a one-piece bit set with tungsten-carbide inserts (figure 11). Sandia Laboratories investigated percussion drilling in the early 1980s and demonstrated ROP above 20 m/hr in granite[54]. Other results showed that a hammer, designed for air operation, could be operated with stable aqueous foam as the drilling fluid, giving a greater cuttings-carrying capacity; and an air-powered hammer was run at high temperature ($200\text{-}220^{O}C$) for 14+ hours (its failure mode did not appear related to the temperature.)

Figure 11 Solid-head bits for percussion drilling.

All of the hammer tests showed greater penetration rates than conventional drilling under comparable conditions, but the major handicaps were gage wear on the solid-head bits and the necessity for accurate weight-on-bit control. This drilling technology appeared to offer promise for better penetration rates, but Sandia could develop no interest in the geothermal industry for trying it in a field test. With the current interest in EGS geothermal systems, the hardness and depth of formations being drilled will increase and the potential use of hammers should be re-evaluated.

Drill pipe

Choosing the drill pipe specifications can be complicated in some cases, but the primary considerations are the following.

- Strength: The principal requirements are for tensile and torsional strength, so that the pipe can pull the drillstring out of the hole (often with some overpull required because of tight spots, or even partially stuck pipe) and can apply the torque needed to rotate the bit. Internal pressure may become an issue in some cases, and bending strength is important in directional drilling.
- Size: Given that several different pipe configurations might be strong enough, a major driver for size selection is hydraulics. The internal diameter of the pipe must be large enough to avoid excessive pressure drop in the circulating drilling fluid. It is also necessary that the inside diameter of the pipe be large enough to pass any expected logging tools, and there are sometimes considerations of whether the pipe size is adaptable to fishing tools in the event of trouble. On the other hand, the outside diameter of the drill pipe tool joints must clearly be small enough to pass through the smallest casing to be used, with enough clearance for the same fluid flow, again without excessive pressure drop, on the outside of the pipe.
- Corrosion resistance: Many formation fluids are corrosive; this is especially true in much geothermal drilling. There are a number of special grades of drill pipe made from alloys designed for corrosive environments.
- Wear resistance: Because many geothermal formations are extremely abrasive, drill pipe tends to wear much faster than in other types of drilling. “Hard-banding” (applying layers of wear-resistant material such as tungsten carbide to the outside diameters of the tool joints) is common in geothermal drilling, although hard-banding can also damage the casing if extended time is spent drilling.

Because of the low-value fluid (steam or hot water), geothermal wells must produce large fluid volumes and so tend to be larger diameter than oil and gas wells; typical geothermal production intervals are 219 to 340 mm in diameter. Unlike oil and gas wells, geothermal production is from the open hole or through a slotted liner, not through tubing. This means that both drillpipe and casing are usually larger than for oil and gas wells at the same depth.

Insulated drill pipe (IDP)

As drilling fluid flows down the drill pipe, through the bit, and up the annulus it is almost always transferring heat to or from the formation. Because the steel drill pipe acts very much like a counter-flow heat exchanger, drilling fluid temperature inside the drill pipe is very near its temperature in the annulus at the same depth, and both are close to the formation temperature. This means that, in high-temperature formations, all the drilling tools in the bottom-hole assembly (BHA) are bathed in a hot, or very hot, fluid. This has several unfortunate effects: elastomer components (seals, downhole motor stators) are challenged; expensive and delicate electronic steering and logging tools can be damaged or destroyed; corrosions rates increase; and the drilling fluid itself can be degraded. All of these problems can be solved or mitigated by adding insulation to the drill pipe wall, so that the drilling fluid reaches the bottom of the hole at a much lower temperature, as shown in Figure 12. IDP has been demonstrated in the laboratory and in limited field experience[55], and is commercially available, but has not yet seen significant use by industry.

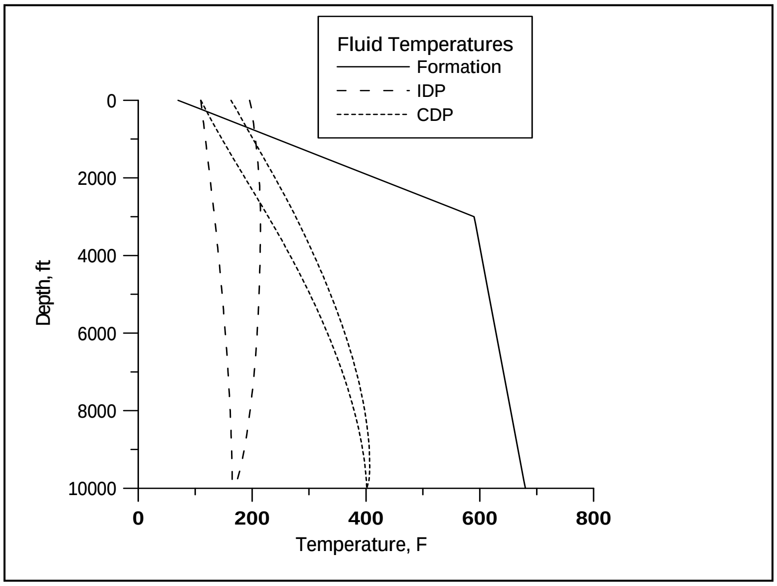

Figure 12 Comparison of drilling fluid temperatures in conventional and insulated drill pipe. In the fluid temperature curves, the left-hand side is in the pipe, the right-hand side is in the annulus.

Dual-tube reverse circulation (DTRC)

Another technology that is useful with lost circulation is dual-tube reverse circulation[56]. This method uses a drillstring of two concentric tubes, with the drilling fluid passing down the annulus between the inner and outer tubes, circulating out through the bit, and carrying the cuttings back up through the center tube (figure 13). This means that it is only necessary to maintain fluid around the bit and bottom-hole assembly, so drilling with complete lost circulation is possible. This technique has been used on several geothermal wells[57] and in one case[58] reduced the cost per foot of drilling comparable wells by more than one-third. A number of contractors offer this service, and it is readily capable of operation at geothermal temperatures.

Bottom-hole assembly (BHA)

A drill sting is relatively flexible compared to its length [a scale model, dimensionally, of a 3000 m drillstring is a piece of steel wire, the thickness of a human hair, one meter long.] The total weight of the drillstring is generally much greater than the desirable force on the bit, so the rig's hoisting capability holds back some of the string weight to control force on the bit. The upper part of the drillstring is therefore in tension, while the lower part that applies force to the bit is in compression. Drilling with the relatively thin drill pipe in compression is likely to cause buckling, so it is important that the neutral point (where the drillstring stress changes from tensile to compressive) falls within the drill collars. The outside diameter of the collars is controlled by the necessary annulus between the collars and the wellbore, the inside diameter by hydraulic consideration (large enough to prevent excessive pressure drop), and the overall length by that required to provide maximum expected weight on bit, and to capture the neutral point. Other components that are often part of the BHA include the following.

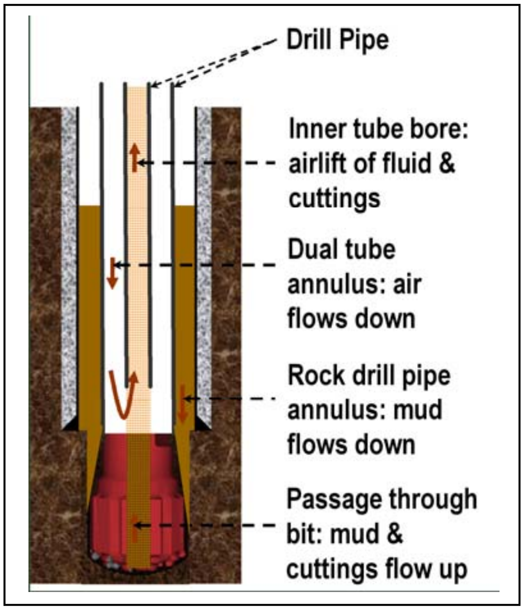

Figure 13 Diagram of dual-tube reverse circulation.

- Stabilizers: Because the drill collars and other components must be smaller than the wellbore diameter to provide a path for fluid circulation, they can have major lateral deflections. This can produce serious vibration as well as high fatigue loads in the threaded connections, so stabilizers that have full wellbore diameter on ribs along the outside surface but leave a flow path between the ribs (see figure 14), are widely used at multiple points in and above the bottom-hole assembly.
- Reamers: The outside diameter, or “gauge” of drill bits tends to wear, causing the hole to be smaller than the nominal diameter. When a new bit is tripped in, it has to ream the smaller hole out to the desired diameter, which is time consuming and which causes the new bit to wear prematurely on its own outside diameter. Additional cutting elements, either as fixed cutters or as toothed, cylindrical rollers are often added to the BHA just above the bit, to help maintain the full hole diameter. This is more common in abrasive geothermal formations than in much of oil and gas.
- Shock absorbers: When drilling in hard or fractured formations, or those in which soft and hard stringers are inter-bedded, high vibration loads are common. Shock absorbers, or dampers, are used to attenuate the vibrations transferred to the upper part of the BHA and drillstring.

Figure 14 Various sizes of stabilizers.

- Jars: If the drillstring is stuck in the hole, it can sometimes be released by the impact force produced by jars. These function by suddenly releasing energy stored in the drillstring by pulling up on it and stretching it. The two principal types are mechanical jars and hydraulic jars, but both operate on the same principle. Jars are generally used when fishing, but some drillers prefer to have jars already in the drillstring during normal drilling.

Directional Drilling

During normal drilling, the pendulum effect of the heavy drill collars tends to keep the hole vertical, but for many of the following reasons it is often necessary to guide or steer the hole's trajectory in a specific direction—institutional, legal, or topographic issues prevent the drill rig from being directly over the geologic target; it is economical to drill several wells from one prepared site; and, particularly for geothermal wells, it is important for the wellbore to intersect as many formation fractures as possible.

Directional drilling is a relatively complex technology and there are a number of ways to drill a deviated hole, but the most common is to use a downhole motor (hydraulically powered by drilling fluid flowing through it) that turns the drill bit without rotating the drillstring. A "bent sub" points the motor and bit at a slight angle to the axis of the drillstring, and since there is no rotation, the bit continues to drill in the direction it is pointed. The difficulties inherent in directional drilling are aggravated in geothermal wells because both the electronic tools used to control and survey the well trajectory and elastomer elements in the motors are susceptible to high temperature. Progress has been made in both of these areas, but it is still often a technical challenge.

Neither positive-displacement motors nor steering and measurement-while-drilling (MWD) tools operate reliably at high temperature, so most corrections are done at depths where the formation is still cooler than 175ºC. Kick-offs in higher temperature formations can be done with whipstocks if they can be oriented with high-temperature survey instruments. High-temperature turbines have been demonstrated and service companies have recently begun to offer high-temperature positive displacement motors (PDM); this technology is relatively new, but could be a significant asset for geothermal drilling. If moderate fluid loss occurs while drilling with mud motors, the addition of fresh mud sometimes makes it possible to continue drilling for the life of the bit in a hot hole. When motors fail because of high temperature, it is often on trips back into the hole. The ability of a top-drive unit to circulate while tripping into or out of the hole is a significant advantage for this operating method. High-temperature electronics for steering tools can also be a problem, but technologies exist for operating unshielded electronic components above 260ºC.[59]

7. Potential Problems

Lost circulation

The most expensive problem routinely encountered in geothermal drilling is lost circulation, which is the loss of drilling fluid to pores or fractures in the rock formations being drilled. Lost circulation represents an average of 10% of total well costs in mature geothermal areas[60] and often accounts for more than 20% of the costs in exploratory wells and developing fields. Well costs, in turn, represent 35-50% of the total capital costs of a typical geothermal project; therefore, roughly 3.5-10% of the total costs of a geothermal project can be attributable to lost circulation.

This loss is harmful for several reasons (and the tendency toward lost circulation is aggravated by the pressure imbalance between the relatively cool—denser—column of drilling fluid and the hot—lighter—geothermal fluids in the formation.)

- If the drilling fluid fails to clean the hole and return cuttings to the surface, the cuttings can fall back on the bottom-hole assembly and stick the drilling assembly.
- Drilling fluid, especially in many high-temperature formulations, is expensive and losing it to the formation instead of re-circulating it is costly.
- In geothermal wells, the production zone is usually a lost-circulation zone, so it is sometimes difficult to cure a harmful lost circulation zone while preserving its productive potential.
- Lost circulation can suddenly lower the fluid level in a well. Decreasing the static head of drilling fluid in a hot formation can allow the mud to flash into steam and may cause a loss of well control. This can occur either in productive or non-productive zones.
- In the intervals that are not to be produced, the lost circulation zone must be "sealed" to provide a wellbore that can be cased and cemented to the surface. The problems of sealing the zone to allow for cementing the casing are a major part of lost circulation problem.
- Placement of lost circulation materials (LCM) is difficult because the top and bottom of the loss zone are often not well known. The LCM or cement being used to heal the loss zone are especially likely to migrate away from the targeted placement zone if drilling has continued well past it into another loss zone, or if there is considerable rat hole below the original loss zone.
- In many areas where geothermal drilling is done, water is in short supply.

Uncontrolled loss to the formation places a cost limit on drilling. Drilling without returns may not be an acceptable approach for the reasons given above.

Combating lost circulation can be approached in different ways—drill ahead with lost circulation; drill with a lightweight drilling fluid that will have a static head less than the pore pressure in the formation; mix the drilling fluid with fibrous material or particles that will plug the loss apertures in the formation; or pause in the drilling and try to seal the loss zones with some material that can be drilled out as the hole advances.

Drill with lost circulation: Under some conditions it is practical to drill without returns, particularly in the case of core drilling, where the cuttings are very fine and where much of the rock comes out of the hole in the form of core. In many slimhole exploration holes, intervals of hundreds of meters have been drilled with complete lost circulation[61], but this can only be done if the formations are competent enough to remain stable.

Another technology that is useful with lost circulation is dual-tube reverse circulation[62] (DTRC), described earlier in Chapter 6. If either of these methods is used to drill with lost circulation, it should be remembered that cementing casing later will almost certainly be difficult.

Lightweight fluids: Aerated fluids—liquid with gases injected into it—produce a static head less than the pore pressure and are a common remedy for lost circulation in geothermal drilling. Aqueous (water-based) foam is attractive because of its simplicity, but it is important to use the proper surfactant that has stable properties at high temperature. Considerable modeling was done in the early development of aqueous foam for geothermal drilling[63,64]. In addition to numerical models of the foam structure and rheology, a laboratory flow loop measured pressure, temperature, and flow rate at different points, to allow experimental confirmation of a rheological model.

Aerated drilling is now used extensively in many locations, and recent experience has shown that its use not only avoids problems with lost circulation, but improves the well's productivity after drilling[65].

Lost circulation materials (LCM): Lost circulation problems can generally be divided into two regimes, differentiated by whether the fracture aperture is smaller or larger than the bit's nozzle diameter. Clearly, LCM particles that will plug the bit are unacceptable, but for smaller fractures or for matrix permeability, the wellbore can theoretically be sealed by pumping solid or fibrous plugging material mixed with the drilling fluid—this method is much less effective with larger fractures. Many substances have been used in the oil and gas industry to plug lost circulation (LC) zones, but most of them have been organic or cellulosic materials that cannot withstand geothermal temperatures. LC zones in oil and gas also tend to be dominated by matrix permeability, rather than the much larger fracture apertures common in geothermal reservoirs. Although traditional organic LCM can be used in the upper, cooler, intervals of a well, and several candidate materials that will withstand high temperature have been identified[66], LCM, in general, has often been unsuccessful in geothermal drilling.

Wellbore sealing: Fractures too large to be plugged by LCM can only be sealed by withdrawing the drill string from the hole and injecting some liquid or viscous material that will enter the fractures, solidify to seal them, and then have its residue removed by resumption of drilling. Conventional lost-circulation treatment practice in geothermal drilling is to position the lower end of an open-end drill pipe (OEDP) near the suspected loss zone and pump a given quantity of cement (typically 10 m^3) downhole. The objective is to emplace enough cement into the loss zone to seal it; however, this does not always occur. Because of its higher density relative to the wellbore fluid, the cement often channels through the wellbore fluid and settles to the bottom of the wellbore (the larger diameters of geothermal wells aggravate this problem, compared to oil and gas). If the loss zone is not on bottom, the entire wellbore below the loss zone must sometimes be filled with cement before a significant volume of cement flows into the loss zone. Consequently, a large volume of hardened cement must often be drilled to re-open the hole, which wastes time and contaminates the drilling mud with cement fines. Furthermore, because of the relatively small aperture of many loss-zone fractures, the loss zone *may* preferentially accept wellbore fluids, instead of the more viscous cement, into the fractures. This causes dilution of the cement in the loss zone and loss of integrity of the subsequent cement plug. As a result, multiple cement treatments are often required to plug a single loss zone, with each plug incurring significant time and material costs. At least three different approaches have tried to improve this process.

- Cementitious mud: As implied by the name, this is drilling fluid with cement and other materials added to satisfy the criteria: 1) compressive strength above 3.4 MPa after 2 hours cure, 2) permeability to water < 10 millidarcies, and 3) volume increase with curing. Brookhaven National Laboratory found that rapid-setting, temperature-driven cement could be formulated by mixing conventional bentonite mud with ammonium polyphosphate, borax, and magnesium oxide[67]. Significant compressive strength was developed by such admixtures in less than two hours when sufficient concentrations of the magnesium oxide accelerator were used; and the setting time decreased with increased temperature. Furthermore, the material expanded approximately 15% upon setting. These setting characteristics were ideal for plugging major-fracture loss zones, but more control over the setting process was necessary to ensure that the cement would not set up inside drill pipe during field application.
- Better cement placement: Sandia National Laboratories developed a drillable straddle packer[68] (DSP) as a way to improve the effectiveness and reduce the cost of a typical cement treatment by controlling the cement flow into the loss zone and by reducing dilution of the cement caused by other wellbore fluids flowing into the loss zone. An assembly on the end of the drillstring carries two fabric bags that straddle the loss zone and provide zonal isolation. The bags are inflated with cement and seal against the wellbore wall, thereby forcing most of the cement to flow into the loss zone. After pumping a specified volume of cement, the straddle packer assembly is disconnected from the drillstring and left in the wellbore while the drillstring is tripped out of the hole. The packer assembly is constructed of drillable materials: aluminum, fiberglass, and, in some applications, CPVC plastic—after the cement sets, the DSP is drilled out and the operation resumes. This device was successfully tested in a full-scale wellbore and complete design drawings are contained in the reference, but it was never commercialized.
- Polymeric grout: The concept of using polyurethane grout instead of cement to seal fractures was investigated in the 1980s but early efforts were not successful[69]. Recent encouraging laboratory work and the growing use of polyurethane grouting in civil engineering projects[70], however, stimulated new interest in this technology. An opportunity to evaluate polyurethane grout in the field came with a DOE grant to Mt. Wheeler Power that required re-opening a well near Rye Patch NV. This well had been temporarily abandoned after 20 cement plugs had failed to cure lost circulation problems, but a prototype grouting apparatus, combined with DTRC, was successful in sealing a loss zone approximately 6 m in length and allowing the well to be re-opened[71]. The polyurethane grout used in the Rye Patch well is not suited for higher geothermal

temperatures, but other polymeric grouts have been developed[72] that can withstand 260^{O}C for eight weeks.

Despite the demonstration of methods described above, familiarity with cementing practice and ready availability of the equipment and materials mean that it is still the dominant method of formation sealing today.

Stuck pipe

In addition to the "mechanical" sticking caused by chips and cuttings collecting on top of the drilling assembly (described above), the pipe can also be held against the wellbore wall by differential between the drilling fluid pressure and the pore pressure. Many intervals encountered in geothermal drilling are under-pressured. This means that the pore pressure is less than that of a column of cooler water at the same depth, which provides a pressure drop that tends to hold the pipe against wellbore wall. Differentially stuck pipe will not rotate nor can pulling move it.

Wellbore instability

Wellbore instability has a number of effects, which can cause widely varying kinds of problems.

- The wellbore may be mechanically unstable because the rock is fractured or it can occur due to degradation of the wall from the invasion of liquid from the drilling fluids. The wellbore wall, especially in formations with significant clay content, may become weakened by adsorption of water into the clay of the wellbore rock.
- Sloughing or unconsolidated formations can aggravate hole-cleaning problems, can fall in around the drill pipe to stick it, and can wash out to a very large diameter. Large washouts not only complicate cementing, but lower fluid velocity in the larger diameter reduces cuttings-carrying capacity.
- Swelling or squeezing clays may reduce hole diameter to a point that will either stick the pipe or prevent running casing.

Each of these problems will make it difficult to clean the hole of drilled cuttings and will ultimately make cementing the casing or liner in place very difficult.

Difficult cement jobs

Because geothermal casings must be cemented completely back to surface, there is often a problem getting a competent cement job where the formations have shown either low strength or lost circulation. This results from the cement's higher density, and thus higher static head, relative to drilling fluid. It is also critical that no water is trapped between the cement and casing, for it will either flash to steam or the liquid will thermally expand, with the possibility that either can collapse the casing as the wellbore goes through its temperature cycles.

Methods using very light-weight cement (less than 1.5 g/cm^3) have sometimes been successful in low pressure/low strength zones. Lost circulation during cementing often results in incomplete cement jobs that must be repaired either by top jobs, where the cement is placed into the annulus between casings by small-diameter tubing, or by perforation and squeezing, where the inner casing is perforated above the top of the incomplete cement and additional cement is displaced through the holes up the annulus. (This method has the weakness that it depends only on the cement (not steel) to seal the perforations and is therefore vulnerable to cement degradation.) Failed cement jobs are very difficult to repair.

The need for a full-length cement sheath creates other problems that dictate how the well is drilled and completed. Standard geothermal practice is that lost circulation zones must be fixed as they are encountered so that they will not interfere with the cementing work. This is expensive because some lost circulation zones require 10 to 20 cement plugs to seal them[73] and allow drilling to resume. Each plug requires cementing the loss zone and waiting on cement until it is sufficiently set to re-enter the well and to drill ahead. This means that even a one-plug lost circulation seal will take 12 to 24 hours. Foam cement (the cement is foamed with nitrogen or air bubbles in the cement) is an approach that has been tried successfully. There are some concerns about the fact that the foamed cement is hard to control and that the resulting cement does not have the same very low permeability of regular cement to seal the casing from formation fluid chemicals.

Wellbore diameter reduction

All wells are designed to be completed with a given size production interval, but the casing program is aimed at minimizing the total amount of casing because it is very expensive – casing and cement can account for 30 to 35% of total well cost[74]. This is particularly important in geothermal wells, where the large flow rates require larger-diameter production intervals than is typical in oil and gas wells. If unexpected problems require an extra string of casing not in the original design then the production casing will be smaller than planned, reducing the potential flow rate and adding cost. To guard against such a situation the casing program is often designed with the upper casing one size larger than required, in case a contingent string is needed. In general, geothermal wells have self-powered production through boiling in the wellbore, which lightens the fluid column enough for the formation pressure to drive the fluid up the well. This means that a reduction in diameter can result in much less production than planned for. There are no simple or cheap solutions to this problem.

Temporary zone closure

Many high-energy geothermal wells are intended to penetrate more than one fractured production zone. Often when the first production zone is drilled there is severe lost circulation (as with most prolific geothermal production zones). Most geothermal production zones have very high permeability values. If the first encountered zone will take fluid in large quantities, but the fractures are not large enough to swallow the cuttings as well, this is an almost guaranteed stuck-pipe situation. This problem occurs in many multi-zone geothermal production wells in the Philippines and Indonesia.

8. Well Control

Well control, in general, has to do with controlling the flow of drilling fluids and formation fluids out of the wellbore. If the hole advances into a fractured or permeable stratum where the pore pressure is higher than the static head of the drilling fluid, the formation fluid will flow into the wellbore—this is called a "kick"—and that flow must be controlled. If control of that flow is lost, then the resulting disaster is a "blowout" which, at the least will be very expensive and, at worst, can result in loss of life, equipment, and the drill rig.

Because geothermal formations are usually underpressured (pore pressure less than fluid pressure in a full wellbore), influx into the wellbore during normal drilling is rare. Two situations that can cause loss of control are: an unexpectedly hot formation is encountered at a shallow depth where the annulus pressure is insufficient to keep the drilling fluid or the formation fluid from flashing to steam; or lost circulation causes the fluid level, and thus the pressure, in the wellbore to suddenly fall far enough for the same thing to happen. If complete control is not lost, simply pumping cold water into the wellbore can usually kill the well.

The apparatus that controls a kick and potential outflow at the wellhead is called the blowout preventer (BOP) or blowout prevention equipment (BOPE). The BOP stack comprises four types of device to shut off the wellbore and prevent fluid flow out of it: annular preventers, pipe rams, blind rams, and shear rams. The basic function of each is to shut off the wellbore, but they operate in slightly different ways.

- Annular preventer – This is an inflatable bladder which seals around drillpipe, casing, drill collars, or irregularly shaped components of the drillstring. It usually has the lowest pressure and temperature ratings of the stack components.
- Pipe rams – These are two sliding gates, each with a semi-circular cutout, that come together from each side of the drill pipe. The hole in the center fits and seals around the outside diameter of the drill pipe.
- Blind rams – These are also sliding gates, but there is no hole in the center; they are used when the drill pipe is out of the hole.
- Shear rams – A last resort, the sliding gates have sharp, hardened, overlapping edges and are designed to sever anything hanging in the wellbore. If these are used, then anything cut by them falls into the hole and becomes a fish.

Below the BOP stack, two valved lines (called the choke and kill lines) are connected to the wellhead so that fluids can be either released from or pumped into the wellbore as part of the well-control process. There will usually be detailed regulatory requirements for the BOPE (see the California manual[75], for example, which is also an excellent reference for information on BOPE) but the critical factors are to make sure that the BOP pressure rating is adequate and that all the elastomer seals in the equipment are qualified for high temperature. Because a primary well-control technique for geothermal drilling is to pump cold water down the well, it is also important to make sure that an adequate water supply is available.

The primary method of detecting a kick is to compare measurements of the drilling fluid inflow and outflow; if outflow is greater, there is a kick, if inflow is greater, there is lost circulation.

Traditional methods of measuring these flows have been a stroke counter on the mud pumps (a volumetric calculation gives fluid inflow) and a paddle meter on the return line (a flat vane extends into the mud returns such that the angular displacement of the paddle indicates flow rate). Each of these techniques has inaccuracies: pump efficiency (and therefore displacement per stroke) varies with wear and clearances on the pumps, and the paddle meter can be influenced by any number of variables[76]. Research has shown that better methods (magnetic or Doppler flow meters for inflow and rolling float meter for returns) are available[77], and if well control is expected to be an issue, these methods should be investigated.

In contrast to oil and gas wells, which are often over-pressured and where those pressures are controlled by weighted drilling fluids, geothermal wells most often are under-pressured. This means that the formation pressure is *less* than the drilling fluid head, which is the effect that causes lost circulation, as discussed in a previous section. There are exceptions such as wells in Cooper Basin, South Australia, with wellhead pressures of approximately 35 MPa[78] but the principal issues in geothermal well control usually involve unexpected steam flow. This can be caused by drilling into a formation that is at much higher temperature or much higher pressure than predicted, such as an event that occurred in Hawaii[79], or by sudden, major lost circulation, which can drop the drilling fluid level to the point that its static head no longer exceeds the saturation pressure at the formation's temperature, and either the drilling fluid or formation fluids flash into steam. Unexpected steam flow in permeable formation that is not completely sealed by casing is particularly dangerous, because steam can begin to flow up the outside of the previous casing string (this is called an "underground blowout".) This will eventually destroy the casing's integrity and often causes loss of the drill rig[80]. Pressures in geothermal drilling are almost always lower than those encountered in oil and gas drilling. For temperatures less than approximately 275^{o}C the well can be controlled with cold water. As the temperatures increase above 320^{O}C the accompanying saturation pressure exceeds 13.8 MPa. If the permeability is high, as it is in most geothermal resource areas, then a prolific flow of fluid will occur which may be difficult to control. The key to control is having adequate casing setting depths, which will permit shutting the well in under all circumstances.

As in many contexts, prevention of a problem is more efficient than a cure. A number of methods are available to estimate the wellbore temperature profile and warn that a problem may be near: comparison of drilling fluid inflow and outflow temperatures; maximum-reading thermometers either run just above the bit or lowered through the drill pipe on a wireline; or on-board logging tools that can transmit temperature data in real time. Although none of these is guaranteed to provide early warning of a potential kick, it is always important to know as much as possible about the downhole environment.

Having discussed above the problems of steam flow in the wellbore, however, it should be noted that in reservoirs with a dry (superheated) steam resource, such as the Geysers, the production interval is drilled with air to avoid formation damage and plugging[81]. This means that the drilling returns include produced steam from the reservoir. The top of the wellbore is closed by a "rotating head" that seals around the drill pipe, while allowing it to rotate and move downward. The gaseous returns are sent through a manifold called a "banjo box" above the BOP, and then to the "blooie line", which exhausts a distance away from the drill rig and where the returns receive chemical treatment for H_2S abatement. This is very similar to the technique called "managed pressure drilling" in oil and gas reservoirs, where it has been discovered that productivity is much improved if drilling fluid has not been forced into the formation by excessive downhole pressure.

Well control can be a complex topic, but it is clearly critical to a successful drilling operation. Well-control procedures should be part of well planning, so that the proper actions will be established and crews will be familiar with them when drilling begins. It is essential that rig crews be trained to react quickly and appropriately to an unexpected event that might jeopardize the well.

9. Instrumentation and Logging

This description of instrumentation deals only with those measurements applied to the drilling process, and does not address logging for formation evaluation done during or after drilling. Drilling information comprises both surface measurements—those taken on or around the drill rig—and downhole data retrieved by some type of logging tool that is either lowered into the borehole or forms a part of the BHA.

Surface measurements

A summary list of desirable measurements for the drill rig was given in Chapter 3 (drilling fluid inflow and outflow rates, drilling fluid inflow and outflow temperatures, standpipe pressure, rotary speed, weight on bit, and torque) but many others exist. The drill rig will have at least a minimum set of instruments that are required for its normal functions, but additional instrumentation and data can be provided by the drilling contractor, the mud logging company (MLC), or an independent service company. It is most commonly done by the MLC, in conjunction with their primary job of recording the geology of the well, based on the cuttings brought back to surface by the drilling fluid. The MLC also keeps a record of many of the drill rig's operating conditions—a representative MLC, for example, lists all the following measurements as available, so it is the well planner's responsibility to decide which are necessary.

- Depth
- Block Height
- Rate of Penetration
- Bit Depth Tracking While Tripping
- On Bottom/Off Bottom
- Hook Load
- Weight On Bit
- Rotary RPM & Torque
- Top Drive RPM & Torque
- Standpipe Pressure
- Casing Pressure
- Pump Stroke Rates
- Pump Stroke Counters
- Totalized Pit Volumes
- Individual Pit Volumes
- Trip Tank Volumes
- Mud Gain/Loss
- Mud Flow Rates
- Mud Temperature In & Out
- Mud Weight In & Out
- Mud Resistivity In & Out
- CO_2 & H_2S

Understanding how to use the measurements is clearly important, and should be part of the driller's training. Some comparisons, such as mud flow rates in and out of the wellbore, have been described previously as diagnostics for lost circulation and/or well-control issues. Others, such as a sudden drop in standpipe pressure as an indication of a washout in the drillstring, should be part of training. Many of the measurements made by the MLC can be combined electronically in such a way that an alarm will sound if undesirable conditions appear (e.g., the difference in flow rates becomes large.) Virtually all modern MLCs present and record data in digital format, so that it is easily stored, retrieved, and displayed at multiple locations (including a web site, if desired.)

It is also possible to use longer-term data—torque and weight on bit related to rate of penetration, pump efficiency compared to mud flow rate, temperature change as a function of depth—to establish statistical trends that are a measure of drilling performance or downhole conditions. It is also possible, in principle, to combine surface measurements in a way that provides diagnostics for various drilling conditions and then employs an expert-system approach to recommend subsequent action. This has been investigated in the laboratory[82] and some versions of it have been commercialized.

Downhole measurements

During drilling, downhole data can represent reservoir conditions or drilling performance or both, and this information can lead to: a change in drilling method for greater efficiency (and lower cost); a decision to set casing; initiation of lost-circulation mitigation; or possibly even preventive measures that can avert a disastrous loss of well control. During production, downhole monitoring gives a more accurate picture of pressure and temperature at the production horizon and enables more efficient reservoir management to maximize useful life of the resource. Finally, the extensive logging and testing that usually follows drilling is critical in verifying the value of the reservoir and in making decisions about further development.

Surface measurements are often ambiguous because there is more than one downhole condition that can produce the same readings at the surface, so downhole measurements are valuable in resolving this discrepancy. Downhole measurements can be made in several different ways:

- A sensor package can be lowered into the hole on an electrically-conducting cable (wireline), sending back signals in real time as it traverses the wellbore. This method usually requires a specialized wireline truck operated by a logging service company (i.e., this method is relatively expensive and there is some lead time involved unless the truck and crew are on standby at the drill site.) Real-time information is advantageous when a very dynamic situation such as drilling is in progress, especially if there is reason to believe that some downhole condition (e.g., pressure, lost circulation, bit dysfunctions) may be harmful, hazardous, or expensive.
- A logging tool with on-board memory can be lowered into the hole on an ordinary cable (slickline), taking readings as it traverses the wellbore, and then brought back to surface where data is downloaded. If real-time data is not required, this method tends to be cheaper and more convenient, because the memory tool can be operated by the rig crew on the rig's hoisting equipment.
- A memory tool can also be part of the BHA, retrieved either when tripping the drillstring or by slickline. This method is particularly useful when a slimhole is being drilled with a coring rig, because the memory tool can be part of the core tube and data can be retrieved with every core run.
- An instrumentation package that is part of the BHA can send signals back to the surface through pressure pulses in the drilling fluid. This "mud-pulse telemetry" is most often used for directional drilling, where it provides survey information for steering the hole's trajectory, but it can also send back information on downhole conditions such as pressure and temperature, or on drilling parameters such as shock and vibration. This method provides real-time data from the bottom of the hole, but has a number of disadvantages,

in that it is very expensive, is susceptible to high temperature, cannot operate in aerated mud or air, and has a very low data rate (less than 10 baud).

- Signals can also be sent back to surface from a near-bit instrument package through stress waves in the steel drill pipe. This “acoustic telemetry” is reasonably rugged, has a higher data rate than mud-pulse (above 20 baud), can operate in any drilling fluid, and has been commercialized by a company in Canada[83].

All of this technology is very mature for the oil and gas industry, but high temperature is a barrier for much geothermal work. Although other parts of a downhole instrumentation package (e.g., seals, the wireline cable head, and sensors) become more difficult in high temperatures, electronic components are the principal challenge. Commercially available electronic components are generally rated at only about 85°C[#], unsuitable for use in geothermal environments, so there are three choices: 1) develop electronic components that can withstand higher temperatures, 2) shield conventional components from the high-temperature environment, or 3) use a combination of 1 and 2.

Electronic components can be protected from high temperature by enclosing them in a thermal flask, or Dewar. A Dewar functions like a Thermos bottle, with an evacuated volume between concentric shells providing insulation for the components inside. Like a Thermos bottle, a Dewar in a hot well will eventually[*] allow the components inside to heat up to a point at which they may fail. Dewars provide only temporary protection and are expensive and fragile, but even when using high-temperature electronics, they will give the logging tool additional life. Almost all logging tools, both wireline and memory, used in geothermal environments are protected by Dewars.

Electronic components that can operate, unprotected by thermal flasks, at geothermal temperatures, are the ultimate goal. Two technologies—silicon-on-insulator (SOI) and silicon-carbide (SiC)—approach that goal. SOI semiconductors can operate virtually indefinitely[84] at 300°C; SiC semiconductors above 450°C—well above existing electronic packaging technology. Some SOI electronic components have been commercially available for several years[85], and a basic suite (pressure/temperature) of SOI-based logging tools is commercially available now[86].

Of the many measurements that can be made by logging downhole, by far the most useful for drilling purposes is temperature. Apart from the clear necessity to know whether the hole is approaching a geothermal resource, temperature logs can clarify a number of other drilling situations.

- Logs can provide warning if any temperature-limited downhole equipment (including drilling fluid) is approaching its limit.
- If a lost-circulation zone appears during drilling, logs can often define its location, (it is not always at the bottom of the hole).
- Logs can guide the amount of retarder to add to cement before cementing casing.

[#] This is a “guaranteed” operational temperature, although selected components will operate at higher temperatures.
[*] The length of time that the Dewar will protect the electronics is a function of the wellbore temperature, power dissipation requirements of the electronics package, conductivity of the Dewar, and the heat sink inside the package. For typical geothermal applications the operating envelope is 6 to 16 hours.

- Because cement has an exothermic reaction as it cures, logs can locate the top of the cement column if returns do not reach the surface.
- For an injection test in a potential production zone, logs can identify fracture locations.
- Logs can usually identify favorable (impermeable) zoned for setting packers, if that is part of the test program.

This is only a sample of the applications that temperature logs can have and, for the cases cited above, real-time data is not critical, so memory tools would be quite adequate. These examples indicate the versatility of temperature logs, so having this capability as a standard part of the drilling program is highly useful.

Other geothermal logs

Although pressure and temperature are most common, a number of other logs are possible in geothermal wells. Some of the most common are described below.

- Caliper: Caliper logs measure the borehole diameter, using a varying number (minimum of four) of arms that protrude from the tool's body. Knowing the diameter at all points is not only necessary for an accurate calculation of cement required, but can be a diagnostic for improper hydraulics when the interval was drilled. If a packer is to be set, it must not be done in an oversize hole, or the packer's inflation element will likely rupture. High temperature calipers are readily available.
- Spinner: A spinner measures the relative velocity of fluid past the tool. It is most often used during production flow tests, where it is almost always combined with pressure and temperature as a so-called PTS log. High temperature spinners are available from several sources.
- Gamma ray and spectral gamma: Virtually all rocks contain naturally-occurring radioactive elements and these elements emit gamma radiation. Different kinds of rocks have varying amounts of radioactive material, and the significance of gamma emissions in geothermal reservoirs is that the presence of radioactive elements often signals fractures. In The Geysers, for example, gamma logs are critical for identification of fractured zones, steam-entry zones, and various formations such as greenstone, rhyolite, and argillite[87]. GR logs are frequently run in conjunction with other types of log and, because they produce a unique signature with depth, are used for depth correlation between multiple logs. A standard "natural gamma" logging tool simply counts the combined emissions from all the varied constituents and presents the results as total counts, but the energy displayed by each gamma strike on the detector can be used to discriminate which element has produced it. A "spectral-gamma" tool apportions the counts into various "windows", each of which is indicative of a specific radioactive material, so that at any given point in the wellbore the dominant radioactive material can be determined. To provide a spectral-gamma tool for geothermal logging, Sandia Laboratories designed and built a downhole tool with Dewared electronics[88]. It was rated to withstand 69 MPa pressure at 350^{O}C temperature. The tool was successfully used to log portions of the S8-15 corehole in The Geysers. Although high-temperature gamma ray tools exist in the oil and gas industry[89], there is (to the authors' knowledge) no other existing high-temperature spectral-gamma logging tool.
- Fluid sampling: Obtaining samples of formation fluids (steam and/or liquid) at a specific depth is important for development of a geochemical reservoir model that describes: a)

production of corrosive gases or liquids that damage tubulars or turbines, b) production of non-condensable gases that degrade turbine performance, and c) the influence of injected fluids meant to prolong reservoir life. Fluid samples taken at the wellhead, of course, give an average composition of fluids produced throughout the wellbore, but acquisition of samples from a specific depth interval is difficult. Lysne and others describe[90] in detail the problems with then-existing fluid samplers, and in the early 1990s Sandia Laboratories (in cooperation with Unocal Geothermal, DOE Basic Energy Sciences, and Thermochem, Inc.) began conceptual design of a new sampler that would operate at high temperature and would have an on-board computer to control operation of the sampler's valves. The prototype tool was approximately 5.1 cm diameter and 180 cm long, so that it is easily transportable and is usable in slimhole wells. The on-board computer can be programmed in the field to open and close the valves on a number of different triggers: time, temperature, time-rate-of-change in temperature, or other signals. As the tool is lowered into the well, the on-board memory also creates a temperature log to specify conditions at the sample point. Finally, the sampler is battery-powered, so that it can be run with simple slickline logging equipment. The prototype was tested in production wells at The Geysers, showing good repeatability, and was later commercialized, with higher-pressure valves, by Thermochem. Improvements continue to the present, with current upgrades to the electronics under way. This tool's capabilities, which are believed to be unique, are especially valuable in vapor-dominated fields such as The Geysers and many of those in Indonesia.

- Imaging: As discussed above, it is critically important to know the orientation, aperture (width), and density of fractures in a geothermal reservoir. Gaining this knowledge, however, is neither easy nor inexpensive. One method of continuously imaging the wellbore wall is the acoustic borehole televiewer, which uses the travel time of acoustic pulses to measure the distance from the rotating transducer to the wellbore wall. Since a fracture appears as a sudden drastic increase in diameter, it shows up as a distinct line on the televiewer output[91]. (The televiewer also serves as a very accurate caliper gage.) Sandia Laboratories developed a prototype televiewer around 1983 by taking a commercially available instrument and upgrading it with (military-specification) high-temperature electronics, seals, and materials so that it would operate, protected by a thermal flask, or Dewar, at 275^{O}C for significant periods. In 1985 Sandia, in partnership with two geothermal operators, placed a contract to develop a commercial logging tool based on this prototype, but the televiewer manufacturer later redirected manufacturing toward other products and all the televiewer components and design information reverted to Sandia. Sandia completed the proposed design modifications in-house and this tool was successfully field tested in several hot wells[92]. Two copies of this tool were built—a geothermal operator lost one in the hole in Indonesia, and the other is on loan to the US Geological Survey. There is no domestic commercial high-temperature version of this instrument, although a modified version is available from a European company. A "slimhole" version of the televiewer, sized to run in 99 mm core holes, is commercially available, but is not qualified for high temperature. In 2003, Sandia supported a collaborative effort between two companies, Mount Sopris (US) and Advanced Logic Technology (Belgium) to develop a new-generation televiewer to be used at the US Navy's Coso geothermal field in California. This Dewared tool operates at high temperature (275^{O}C for ten hours) and high pressure (83 or 138 MPa, depending on model). During the Hot Dry Rock project in the 1970s and 1980s, Los Alamos National Laboratory also developed a version of the televiewer with modular construction and an on-board microprocessor to control data collection and transmission; this was done in conjunction with Westfalische Berggewerkschaftskasse—WBK—of West Germany.)

- Explosive tools: Los Alamos also developed a number of explosively-actuated tools, for the functions described below. Even though none of these tools was commercialized, it is useful to know that the primary accomplishment of this development was the consistently safe use of thermally stable explosives with high-temperature detonators in multiple applications.
  1. Back-off shots—used for unscrewing the drill string at a designated depth, when tools below that point were stuck.
  2. Acoustic-source detonator—could sequentially fire up to 12 detonators, generating signals for geophone calibration in adjacent wells.
  3. Drill-pipe or casing cut-off tool—used a shaped charge to cleanly sever tubulars at designated depth.
  4. Explosive fracture-initiation tool—used a shaped charge to initiate fractures in a specified open-hole interval (initial fracture is extended by hydraulic pressure).
  5. Explosive side-tracking tool—created a ledge in the borehole wall to provide a kick-off point for directional drilling.
- Optical fiber: Although not a logging tool per se, optical fiber provides a cheap and reliable way to obtain a wellbore temperature profile. The conventional method of getting a temperature profile in a well is to lower a logging tool (as discussed above) into it and to retrieve the temperature readings on the surface. This requires a winch to handle the wireline or slickline, and either method interferes with other drilling operations. A relatively new method[93] of temperature measurement is the use of optical (glass) fibers (figure 15) illuminated by pulses of laser light. As the laser pulse travels down the fiber, it undergoes both Rayleigh and Raman scattering. The Raman scattering is divided into two components, one with a shorter wavelength than the original pulse, and one with a longer wavelength. The ratio of these two components is a function of temperature and, combined with the time-of-flight for the pulse, indicates the temperature of the fiber at a known distance from the emitting laser. If we suspend a fiber in a well, or even emplace it outside the casing, it will provide a continuous, near-instantaneous picture of the temperature distribution in the hole. Optical fibers can withstand high temperatures quite well for short times, but there are problems in trying to meet a project objective of survival at 250^{O}C for four years with less than 2^{O}C temperature drift. The principal source of attenuation or degradation in the signal is free hydrogen, which tends to combine with oxygen in the glass. Sandia researchers believe that optical fiber will become the industry standard for monitoring geothermal well performance if the hydrogen problem can be solved. Sandia has a patent ("Downhole Geothermal Well Sensors Comprising A Hydrogen-Resistant Optical Fiber", No. 6,853,798 B1) on an improved doping material to reduce the hydrogen problem. The market has so far been unable to justify a new fiber process to be used in high-temperature geothermal wells.

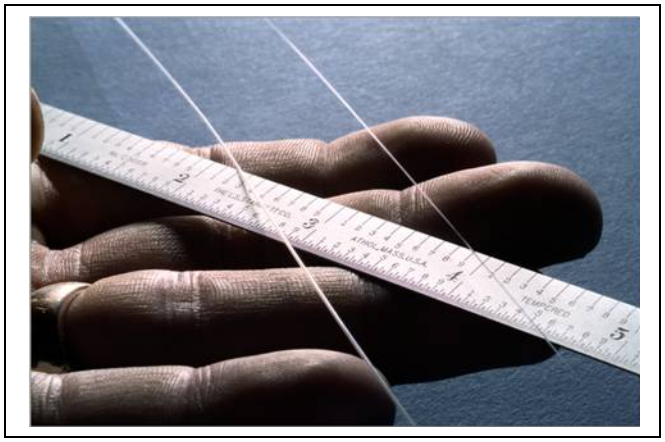

Figure 15 Typical fibers used for temperature measurement.

10. Emerging Technologies

The future direction of geothermal drilling is, in many ways, undefined. This uncertainty stems from the multiple development scenarios that can be envisioned for the industry. It is widely believed that Enhanced Geothermal Systems (EGS) will provide the bulk of new geothermal capacity, worldwide, but many aspects of EGS development are unresolved. Resource location, reservoir creation, and reservoir management will all require different techniques and technologies when applied to EGS than is the case in conventional hydrothermal practice, and these differences could well drive drilling research and development in a new direction compared to past R&D for hydrothermal resources.

Costs and risks may also follow a different pattern with EGS. It is well known that geothermal wells cost more than oil and gas wells of comparable depth, and that drilling costs increase more than linearly with depth. Costs for deep geothermal wells, however, do not increase as rapidly with depth as costs for deep oil and gas wells[94]. There are, in general, four ways to reduce well cost: eliminate “trouble” costs, improve the efficiency of standard operations, introduce new and more efficient operations, or change the well design[95]. Because the “average” EGS well is expected to be considerably deeper than the “average” hydrothermal well, however, the focus of cost reduction may shift among these priorities.

Regardless of the directions that drilling research and EGS development may follow, it is still likely that most innovation in geothermal drilling will derive from technology used in the oil patch because the geothermal drilling market will remain so small, relative to the oil and gas market. Given that assumption, it is useful to look at several drilling methods and technologies that have gained wide acceptance in the oil and gas industry but have been applied sparingly, if at all, in geothermal wells. The following sections describe these technologies, summarize their advantages (with focus on the geothermal context), and discuss the barriers to their use in geothermal drilling.

Drilling with casing (DWC)

The casing can be used as the drill string, rotating to turn a bit and advancing with the hole as it gets deeper, so that it is already in place when the hole reaches desired depth. There are two basic ways that the bit can be attached to the casing: 1.) it can be semi-permanently mounted, so that it can either be dropped off the end of the casing at final depth, or can be drilled through for passage of a subsequent casing string; or 2.) it can be mounted on a drilling assembly that is retrieved either by wireline or drill pipe when the bit needs to be changed, or when the hole is at design depth. If a retrievable bit is used, then it must be small enough to pass through the casing’s inside diameter; and therefore it must use an under-reamer to cut a diameter that is large enough to pass the outside diameter of the casing couplings and to provide an annulus for the drilling fluid return flow.

The casing must always be rotated by a top drive unit, and can be connected to the top drive by either screwing into the top coupling of the casing or by a fixture that stabs into the top joint of casing, locking and sealing to its inside diameter. The top drive circulates drilling fluid through the casing’s inside and back up the outside, just as it would with drill pipe. As in conventional

use, the top drive also has the ability to circulate continuously, which can be important in geothermal drilling with heat-sensitive downhole tools.
There are several advantages to this technology, as described in the cited reference[96].

- Eliminate costs, time, and problems related to tripping drill pipe – Time to trip drill pipe and handle the BHA is a significant fraction of total time (and cost) on some wells[97], but it is also the case that many problems of well control and hole stability are associated with trips.
- Reduce lost circulation problems – DWC systems can continue drilling when lost circulation is encountered. The rock cuttings tend to be washed into the fractures or permeable zones, acting effectively as lost circulation material. The relatively narrow annulus also means that fluid flow rates can be lower than would be used with conventional drilling in the same size hole.
- Gain casing setting depth – The ability to drill through lost circulation zones, or other weak formations, means that sometimes the casing can reach a greater depth than would be the case with conventional drilling. It is possible, for some well designs and lithologies, that the casing program could be re-designed to eliminate one string of casing. As shown in the Well Cost section, this is a major saving.
- Improve safety – Handling drill pipe has one of the highest accident incidences in drilling; eliminating this activity means that the crew is exposed to less risk.

Although this technology has been used on hundreds of oil and gas wells, it has not yet been tried for geothermal. There is an issue with retrievable drilling assemblies, because they contain some elastomer components, but the larger factor is hard rock. The cutting structure for most DWC bits uses PDC cutters and, as discussed previously, these cutters have not been notably successful in geothermal formations. Some field experience with hard rock in oil and gas drilling, however, indicates that reasonable performance with roller-cone bits and PDC under-reamers is available[98]. Although a number of questions remain to be answered, this technology appears to have enough potential to warrant further investigation devoted specifically to geothermal drilling.

Expandable tubulars

As described earlier, casing is installed in successively smaller diameters (see Figure 2) as the hole gets deeper, so that maintaining the correct diameter in the production zone means having much larger holes and casing at the top of the well. It should also be noted that there is a sizable difference in diameter (10-20 cm) between successive casing strings, so that in the example figure, a 21.6 production interval requires drilling a 102 cm hole at the top. This difference in diameter is required to allow clearance for the couplings on the outside of the inner casing string, to compensate for the fact that the previous casing may not be in a straight hole, and to give sufficient annular area that cement can easily flow through it.

The larger casing sizes and cementing jobs at the top are expensive, however, and drilling larger diameter holes often is slower than drilling a smaller diameter would be. A relatively new technology (first field tested in 1998) makes it possible to run a string of casing with normal clearances and then expand the diameter of the inner string so that the clearance between the two strings is negligible. This diameter increase is implemented by an "expansion cone" in the bottom of the inner casing string. (Figure 16) Once the hole is drilled, the liner, with the cone assembly in the bottom joint, is made up until the desired length is complete. Drill pipe is then screwed into the cone launcher assembly and the liner is run into the hole on the drill pipe. Cement is pumped in the normal way (except less volume than would normally be used) and the cone is forced up the liner by a combination of hydraulic pressure beneath it (delivered through the drill pipe) and pulling with the drill pipe. As the liner expands, it forces the cement upward until the liner annulus is completely cemented.

As shown in Figure 17, using this system (called SET – solid expandable tubulars – by one manufacturer) means that much less clearance between successive casing strings is necessary and, therefore, the upper casings can be smaller for a given production zone diameter than with conventional casing[99].

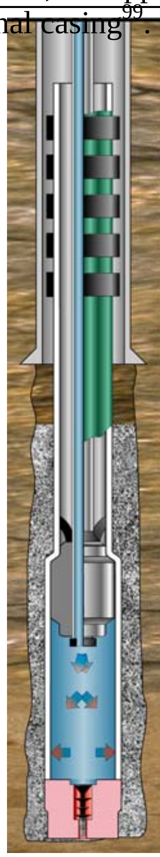

Figure 16 Expandable liner, diagram courtesy of Enventure Global Technology.

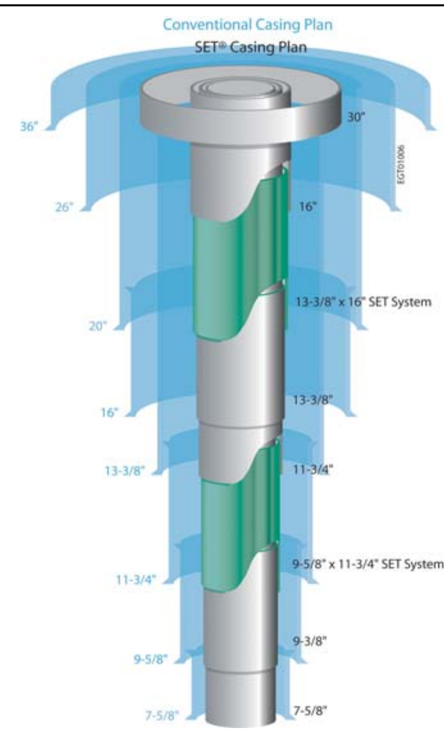

Figure 17 Comparison of casing diameters between SET technology and conventional casing, diagram courtesy of Enventure Global Technology.

When considering this system for geothermal drilling, there at least two potential vulnerabilities: the expandable tubulars depend on elastomer seals in some applications, so the temperature rating of the seals is critical; and the inside of the casing has a proprietary coating to ease the cone's passage through the pipe. It is not clear how this coating would be affected by high temperature, but the system has been used in the field[100] at temperatures above 160^{O}C, and tests are underway to qualify seals for use above 250^{O}C in steam-enhanced oil recovery (SAGD).

Because geothermal casing needs a complete cement sheath, it would also be necessary to assure that the cement displaced in this method would be continuous and competent. It is possible regulatory agencies unfamiliar with this technology would be reluctant to issue a permit for a well designed in this way.

Another possible use for expandables is to repair or mitigate lost circulation. A section of casing can be expanded into open hole, rather than into a previous casing string and, if the open hole section has been slightly under-reamed, there will be little, if any, loss of diameter because of the patch. Since no cement is used in this treatment, the casing depends entirely on its external elastomers for zonal isolation, making this component especially important for this application. If it can be shown that all components of expandable tubulars can withstand high temperature, then it appears that there are at least two valuable applications for expandable tubulars in geothermal drilling.

Better downhole feedback

Downhole measurements are mentioned in the Instrumentation section, but those were generally measurements related to the state of the wellbore (deviation and trajectory), not real-time data for drilling performance. A few exceptions exist; there is experience with using mud-pulse telemetry to send vibration data uphole[101], but the low mud-pulse data rate limits the applications of these systems. Low data-transmission rates also mean that the downhole sensor package must include a great deal of data processing and, as described previously, keeping the electronics functional at geothermal temperatures is a challenge.

Better real-time data collection, transmission, and interpretation is a high priority in drilling, corroborated by an industry forum[102] that identified this as the most important technology need for reducing flat time (defined as the time the rig is over the hole, with the hole not advancing). The principal barrier to much of this activity has been the lack of a transmission method with adequate bandwidth. In the last decade, however, drill pipe with built-in instrumentation cable has been developed[103]. This pipe has been used at high bandwidth in the field[104], although not at geothermal conditions, and it offers a very promising opportunity for expanded use of real-time downhole data.

The list of measurements that can be made and transmitted is, of course, very large but they fall into three general categories:

- Improve drilling performance – One of the most common causes for poor bit performance, especially with PDC bits, is excessive shock and vibration. Sandia National Laboratories developed a high-data-rate downhole sensor package to improve PDC performance, and field tests[105] with and without the package demonstrated that it significantly lengthened the life of a PDC bit in hard rock. The primary benefit of the real-time data system was to allow destructive downhole conditions to be immediately recognized and mitigated, but it also showed that surface readings for some parameters (e.g., weight on bit) were much different from the values actually measured near the bit.

A later version of this system, modified for high temperature, was run in a geothermal well[106], but it has not been commercialized. Other bit dynamics packages are commercially available, although generally not at high bandwidth.

- Avoid trouble – Aside from the problem of bit failure, many other kinds of trouble (well control, lost circulation, unexpectedly high temperature) can either be avoided or recognized much earlier, allowing more effective treatment, with real-time data.
- Eliminate logging time – With properly configured downhole packages, the well can be logged as it is drilled, eliminating the time (sometimes days) at the end of an interval, or the end of the well, normally required to log it. In some cases, logging could be done with a memory tool, rather than with real-time instrumentation, but there is a risk that failure in the logging tool would go undetected until drilling was over.

All of these uses imply high-bandwidth transmission systems and, for geothermal drilling, high-temperature downhole electronics (as well as high-temperature batteries). All of these technologies exist in some form, but they have not yet been put together for geothermal drilling.

11. Glossary

annular preventer - part of the BOP stack; an inflatable bladder which seals around drillpipe, casing, drill collars, or irregularly shaped components of the drillstring.

annulus - Drilling: the space between outside of drill string and inside of casing or wellbore. Casing: the space between outside of casing and the hole.

backside - annulus between drillpipe and casing or wellbore

balling, bit balling - lumps or balls of clay which form around a bit's cutting structure when drilling soft formations. Balling prevents the bit cutting effectively.

barrel – an extremely common unit of volume in the drilling industry, equal to 42 US gallons or 178 liters

block, or blocked run - a core run is blocked when fractured rock wedges into the core tube before the tube is full and prevents further drilling.

blow out - uncontrolled flow of fluids from a wellhead or wellbore.

Bowen spear - a fishing tool which expands inside a fish when the drillstring is pulled up

BOP - blow out preventer; one or more devices used to seal the well at the wellhead, preventing uncontrolled escape of gases, liquids, or steam. Also BOPE - blow-out prevention equipment. See *annular preventer*, *rams*.

boot, booting - forming a plug of drilled material or fill above the bit, usually caused by inadequate hole cleaning or swelling clays.

bottom hole assembly (BHA) - the assembly of heavy drilling tools at the bottom of the drill string; normally includes bit, reamers, stabilizers, drill collars, heavy-weight drill pipe, jars, and other miscellaneous tools.

bridge - a downhole obstruction, usually caused by part of the wellbore wall falling into the hole.

button bit - see tri-cone bit

cave - debris that falls off the wellbore walls and accumulates in the bottom of the hole.

CIP - cement in place

Dewar, Dewared - a Dewar is a double-walled container or heat shield, similar to a vacuum flask, which insulates a piece of equipment from high temperature.

drawworks - the large winch on the rig floor which takes up and pays out the drilling line, thus controlling the movement of the hoist or traveling block.

drilling break - an occasion during drilling when the rate of penetration suddenly increases.

fish - any part of the drillstring, or other tools, accidentally left in the hole

fishing - trying to retrieve a fish

float - essentially a check valve, used in the drillstring or casing to keep liquid from flowing back up the drillpipe or casing

float collar - a coupling with built-in float; placed near the bottom of a casing string to prevent the heavy cement column in the annulus from flowing back into the casing. After displacing the cement in the casing with mud, the casing between the float collar and the shoe will be full of cement

float shoe - a casing shoe with built-in float; used like a float collar

Geoset - a type of synthetic diamond cutter used in impregnated bits

H or HQ - designation of a coring tool size; outside diameter of rod is 89 mm, bit is approximately 99 mm OD and 63.5 mm ID

H_2S - hydrogen sulfide; a poisonous gas sometimes found in geothermal drilling

jars - tools which apply an impulse force to the bottom of the drillstring when the string is pulled up; usually used for fishing, but sometimes included in the string for normal drilling

lay down - to take a piece of equipment out of service; e.g., to lay down a worn core rod

LCM - lost circulation material; any material used for plugging formation fractures to avoid loss of drilling fluid

lubricator - sealing element attached to the wellhead which allows a wireline to pass up and down, or which allows a logging tool to be transferred into or out of the wellbore, while there is pressure in the wellbore

matrix - the hard metal portion of an impregnated bit that holds the diamond cutting elements in place

mill tooth bit - see tri-cone bit

mislatch - the condition when the core tube, or inner barrel, is not latched into the outer rotating barrel, sometimes caused by core dropped out of the core tube. If the core tube can't be worked down over the core in the barrel, then the drillstring must be tripped to clear it.

MRT - maximum reading thermometer; a mercury thermometer which retains the reading of the highest temperature it has seen (which may not be at the bottom of the hole)

N or NQ - coring tool size; rod OD is 70 mm, bit is approximately 75.7 mm OD and 47.6 mm ID (can drill N-size hole inside H rods)

nipple up (down) - to assemble (disassemble) something; usually the wellhead or BOP stack

OEDP - open ended drill pipe; drillpipe without a bit or other bottomhole assembly, generally used to place cement at a specific point in the wellbore.

overshot - in general, any tool that latches around the outside top of another tool; usually refers to the assembly which retrieves the core tube with the wireline, or to a fishing tool which extracts a fish by gripping it around the top

PTS - pressure-temperature-spinner tool; downhole instrumentation to measure these quantities (spinner output is an indication of velocity or flow rate)

pick up - to put any piece of equipment into use; e.g., to pick up a new bit

pitcher nipple - the vertical tube around the top of the blow-out preventer; it collects the drilling mud returns and empties them back into the mud tanks

POOH - pull out of hole; bringing the drill string and tools out of the hole

possum belly - manifold which connects the return line to the shale shaker

rams, pipe or blind - rams are part of the blow-out preventer; pipe rams seal around the drill pipe if it is in the hole, blind rams seal against each other if the pipe is not in the hole

rathole - either additional hole drilled below the target depth to give room for debris, fill, etc. or, on a rotary rig, where the kelly is stored while tripping pipe

RIH - run in hole; inserting the drillstring and tools into the hole

shoe - a heavy, tapered cap that attaches to the bottom of the casing string and protects it as the casing is lowered into the hole

spud - to begin drilling a well

squeeze - to deliberately apply pressure to the wellbore, usually by closing the BOP and pumping into the well. Often done to force cement into the formation at the casing shoe or into the annulus through perforations in the casing stab(s) *n.* - stabilizer, or stabilizers; bottom-hole-assembly components which are almost hole diameter, used to keep the drill pipe relatively centered in the hole above the bit.

stab *v.* – to insert the pin-end of a drillstring component into the upward-looking box.

stand - more than one joint of drill pipe screwed together; when tripping, pipe is handled in stands to avoid making and breaking every connection - for a coring rig, a typical stand is four joints (12.2 m) but for a large rotary rig, a stand is three joints (~ 27.4 m).

strip – 1) to wear away the matrix in an impregnated diamond bit; the bit must strip to expose the diamond cutting surfaces; 2) to pull out of the hole under pressure, with the annular preventer closed around the drill pipe

swage, inside or outside - a fishing tool which grabs the inside or outside of a fish by forcing an interference fit

TDS – total dissolved solids; a measure of the minerals dissolved in a fluid, usually applied to produced brine from a geothermal well

TOC - top of cement

top job - casing cement which is placed from the top, rather than being displaced through the casing shoe. It is either pumped directly into the top of the annulus, or pumped through a tremie line to get a deeper placement in the annulus.

tremie line - a small-diameter pipe or tube run down the annulus outside of casing

tri-cone bit - a bit having three toothed, conical rollers which rotate as the bit turns and crush the rock at the bottom of the hole. The teeth can be either steel, milled into the cones (mill tooth), or tungsten carbide buttons set into the steel cones (button bit, insert bit, TCI bit)

trip - any event of pulling the drillstring or core barrel out of the hole and returning it

underreamer – an expandable tool that can drill a hole larger than the inside diameter of the casing just above it

wash - to run in the hole with circulation, usually required to get back to the bottom of a previously drilled hole when there is fill or cave in the hole

washout – (1) a leak in the flow path through the drillstring, usually at a threaded connection in the drillpipe or drill collars. The hole is enlarged by high-pressure drilling fluid passing through it, and frequently causes the drillstring to fail and separate; (2) a section of the wellbore with enlarged diameter, usually caused by soft or unstable formation, or by excessive hydraulic energy while drilling.

wet pull – pulling the drill string out of the hole with something plugging the bit or drill pipe that keeps it full of mud, rather than having it drain out as normally happens.

wiper trip - running the drill string, with a bit, to the bottom of the hole to make sure there are no obstructions in the hole

WOC - wait on cement, time spent waiting for cement to cure

WOO - wait on orders, time spent waiting for directions

xover or xo - crossover; a coupling used to adapt from one thread size to another

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