Chapter 6
DRILLING AND WELL CONSTRUCTION

Gene Culver
Geo-Heat Center
Klamath Falls, OR 97601

6.1 INTRODUCTION

Drilling and well construction (probably one of the most expensive features of a geothermal direct use project) is often the least understood. This chapter provides the basics of equipment and methods used for drilling and completion of geothermal wells. It provides data needed by architects, engineers, and consultants to assist them in specification writing, selection of contractors, and drilling and completion inspection.

Most direct use geothermal wells can be drilled using conventional water well technology and equipment. Most of the wells will produce water at temperatures less than boiling and without artesian flow at the surface; however, some will be hotter or will flow. Blowout preventers and other sophisticated safety equipment are not usually required; however, this does not mean that there are not significant safety considerations that should be addressed. Many of the wells have water above 140ºF and this will scald. Public and drilling crew safety must be ensured.

The cementing portion may appear to be overly detailed and long. However, the author's view is that, all too often, cementing is considered simply as a means of plugging up the annulus between the casing and borehole wall. Little attention is paid to methods and materials, and a poor cement job is the result. This can result in lost production zones, cold water leaking into production zones, geothermal water leaking into freshwater zones, and reduced useful well life. Also, in view of the increasing awareness and concern about inter-zonal migration and possible fresh water aquifer contamination, proper cementing is of increasing importance.

A glossary of drilling terms is included at the end of this chapter. For some readers, it may be wise to read this section first in order to fully understand the text.

6.2 DRILLING EQUIPMENT

Two basic types of drilling rigs are used for drilling wells: cable tool (percussion) and rotary. There is just one basic cable tool rig, but there are several variations of rotary rigs. The following is a brief description of these rigs.

6.2.1 Cable Tool

This is not a drill in the common sense, because it is not power rotated. This drilling method uses a heavy bit that is repeatedly lifted and dropped that crushes and breaks the formation. Figure 6.1 shows the basic elements of a cable tool rig (Anderson & Lund, 1979). With a cable tool rig, an experienced driller can drill through any formation, including large crevices and caverns that can cause problems with other drilling methods. This method's main disadvantage is that it is slow.

Drilling is accomplished with a tight drill line, as shown in Figure 6.1. The pitman arm and spudder beam impart an up-and-down motion to the cable and drill bit. The length of cable is adjusted so that on the down stroke the tools stretch the line as the bit hits the bottom of the hole, striking with a sharp blow and immediately retracting. The twist, or lay, of the cable imparts a slight turning motion to the tools so the bit hits a new face with each stroke. Left lay cable is used so that the twisting action tightens the tools screwed connections on each upstroke. If the borehole is dry, water is added to form a slurry that is bailed out. Usually about 5 ft of well hole is drilled between bailing.

In consolidated formations, no casing is required for drilling. If the formation caves, 5 to 10 ft of hole is drilled; then casing with a drive shoe is driven to the bottom with driving clamps attached to the tools. With this casing in place, another 5 to 10 ft is drilled, and the operation is repeated again. Because the bit must be lowered through the casing, the diameter of the casing must be larger than the diameter of the bit. Driving the casing enlarges the hole and eventually friction prevents further advancement of the casing. Under these conditions, smaller casing is telescoped inside and drilling continues with a smaller bit.

A method used to increase driving depth is to utilize an oversized drive shoe, slightly opening the hole. A bentonite slurry, placed around the casing, helps hold unconsolidated material in place and lubricates the casing. The bentonite also serves to seal leaks around the casing because of artesian pressure or differences in pressure in different aquifers.

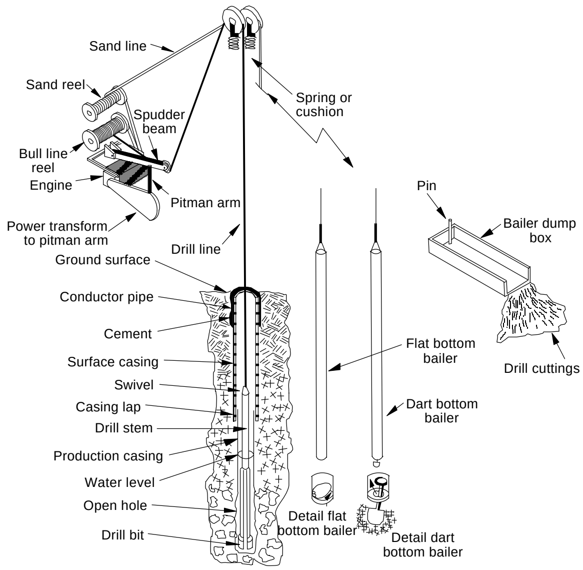

Figure 6.1 Basic elements of a cable tool drilling rig.

Most states require cementing water well casings to the borehole wall down to some competent formation. In a geothermal well, it is usually cemented down to the geothermal zone to prevent mixing of geothermal fluids with shallower fresh surface waters. This also prevents mixing that reduces the water temperature. Any pipe driven down to that level must be considered a temporary casing and must be removed before or during cementing of the well. This places serious restrictions on any drill and drive technique.

Although drilling is very time consuming at depths over 1,500 to 2,000 ft, because of the time it takes to trip bailers and tools, deep holes can be drilled. The depth record is 11,145 ft, completed in New York in 1953 (Campbell, 1973).

Large rigs can drill 18 to 24 in. holes to several hundred feet.

Cable tool rigs have several advantages over certain rotary methods:

1. There is no potential for plugging producing formations with drilling muds.

2. Rigs cost less, are simpler to maintain, and can be operated by one or two persons. Transportation and setup are easy and less water is required.

3. Sampling and formation logging are simple and fairly accurate. There is little chance for contamination by previously drilled zones, especially in consolidated-formations. In unconsolidated formations, there is always some chance the cable, tools, or bailer will wipe the side walls, carrying material down to be sampled later.

4. Qualitative and quantitative data can be obtained during drilling, including good flow estimates, and temperature, static water level, and water chemistry measurements.

The disadvantages are:

1. Depth and penetration rates are limited.

2. Blowout preventers are not easily adapted.

3. In unconsolidated formations, casing must be driven as the hole progresses.

4. There is a lack of experienced personnel. Cable tool drilling is somewhat of an art and the preponderance of rotary drilling means a cable tool driller with wide experience may be hard to find.

5. The method is limited to vertical holes.

Accurate sampling, the ability to assess downhole conditions, and suspicion that drilling mud can adversely affect low- and moderate-temperature geothermal wells, are the reasons that some engineers are specifying the use of cable tool rigs in geothermal production zones. Holes are drilled to a specified formation, temperature, or simply the first lost circulation zone at elevated temperature, by conventional mud rotary method; then, the hole is completed using a cable tool rig. Temperatures can be measured at the surface, after water is brought up in the bailer. If the hole is deep and the static water level shallow, the measurements will only be approximate. Flows can be estimated from bailing rates. There is very little chance of mud and debris filling cracks and crevices in the producing zone.

Although relatively high temperature bores have been successfully completed by continuous flooding with cold water, the method is not applicable: (1) where expected temperatures are higher than 250°F, (2) where significant artesian flows at the surface are expected, or (3) where depths are so great the cable tool rig is simply uneconomical. Unfortunately, it is not always easy to determine what is the best level in the borehole to change drilling methods. This problem will be discussed further under drilling fluids.

6.2.2 Rotary Drilling

Rotary drilling is the most common drilling method in both water and geothermal well drilling. There are several variations, each having their advantages and disadvantages. Figure 6.2 shows the basic elements of a conventional rotary mud rig.

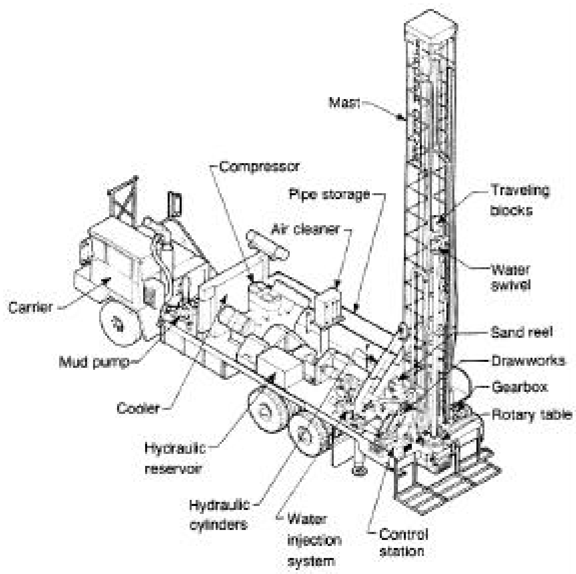

Figure 6.2 Schematic diagram of a direct rotary rig illustrates the important operational components of this truck-mounted drilling machine. This machine, operating with either an air-based or water-based drilling fluid, can drill more rapidly than a cable tool rig (Gardner-Denver Co.)

The drill bit, usually a tricone roller, is rotated by the hollow drill collar and drill pipe. Torque is applied through the rotary table and kelly. Drilling fluid is circulated down the drill pipe and out openings in the bit where it cleans cuttings from beneath the bit, cools the bit and carries cuttings to the surface where they are separated from the fluid. Weight on the bit is applied by the heavy drill collar assembly. The drill pipe is held in tension by the traveling block. Too much weight on the bit tends to drill crooked holes and, in some formations, slows down drilling because of insufficient cleaning action at the drilling face.

Rigs with top head drive do not use a rotary table and kelly. Instead, a hydraulic motor that travels up and down the mast supplies torque directly to the drill pipe. Often a much shorter and lighter collar is used, and the rigs have pull-down chains to utilize part of the rig's weight at shallow depths.

Although smaller in size than a large conventional rotary table rig, top head drives are capable of drilling most direct use wells. Rigs with masts and draw works capable of lifting 150,000 lb and with drives producing 140,000 in. lb of torque are available.

Drilling fluids can be water, mud (water with additives such as bentonite, polymer, etc.), air and water (mists), air, or air and water with foaming agents. Conventional circulation means that the fluid goes down the drill pipe and up the annulus. When drilling with mists or air, the mud tank or pit is replaced by a cyclone-type separator. Air or mist drilling provides good formation sampling and can give reasonable estimates of geothermal fluid production.

6.2.3 Other Types of Rotary Drilling

Downhole Hammer

One of the more popular methods for drilling geothermal wells is the air hammer method. It is especially suited to drilling hard igneous and metamorphic formations. It is not a true rotary method, but a percussion method adapted to a rotary rig.

A pneumatic hammer, similar in action to a large jack-hammer, operates at the downhole end of the drill pipe on 100 psi or higher compressed air. The hammer face has tungsten carbide inserts to provide chipping capabilities. Air hammers are available in 3 in. to at least 17 in. diameter and will provide between approximately 800 to 2,000 strokes/min. The drill pipe and hammer are rotated slowly so the inserts continually strike a new surface to provide even penetration and drill a straight hole. Hammer exhaust or excess air or both is directed to clean the chips away as they are formed, providing a clean surface and increasing drilling rates from 50 to 100% faster than tricone rollers. The exhaust air carries cuttings up the annular space and out the hole.

When drilling below static water level, pressure differences across the hammer must be maintained so air pressure is increased to accomplish this. Foams can be utilized to reduce the pressure in the borehole. Large hammers require large volumes of air at high pressures. Compressors and their operation significantly increase costs.

Reverse Circulation

In reverse circulation, drilling fluid (usually water or very thin mud) flows down the annulus, up the drill pipe to the suction side of a pump, and into the tank or pit. Cuttings are lifted inside the drill pipe that has a smaller cross section than the annulus. Suction lift of the pumps limits this method to approximately 450 ft depth at sea level (Driscoll, 1987). The method that is preferred for geothermal wells utilizes an air pipe inside the drill pipe to provide the lift, and a cyclone or similar separator to separate air from the water and cuttings mixture. The air lift greatly increases depth capacity. Fluid level in the annulus is maintained at or very near the surface. The drill pipe is similar to conventional air drilling pipe (Figure 6.3).

The advantages of reverse circulation are:

1. The reduction of velocity in the annulus reduces the possibility of wall erosion.

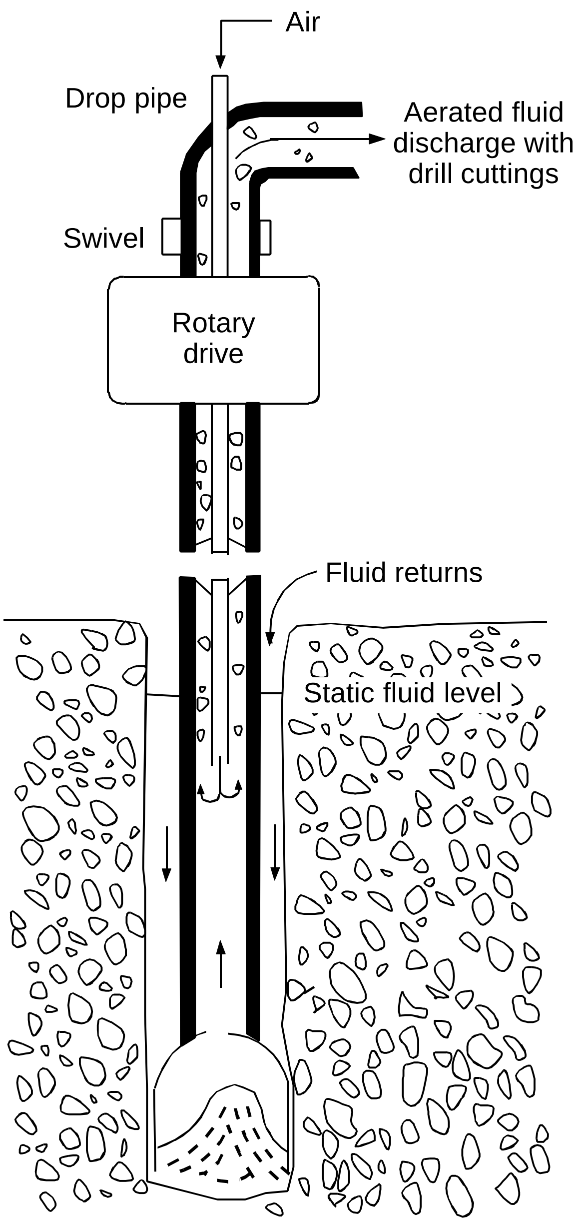

Figure 6.3 Reverse circulation drilling (Johnson Division, 1966).

2. The increase in velocity up the drill pipe provides less time lag to the surface and less mixing of cuttings, which enhances sampling.

3. Because water or very thin light mud is used, there is less possibility for formation damage by mud invasion.

The disadvantages are:

1. Large amounts of water can be required because there is very little or no filter cake to prevent losses to permeable zones. Fluid loss can be minimized by a good fluids program.

2. Since annulus fluid level is at the surface, it effectively prevents under-pressured geothermal fluid from entering the hole for detection by temperature or chemistry change.

3. If geothermal fluid does enter, the chemistry can be changed by the large amount of air that effectively scrubs out carbon dioxide (CO_2) and hydrogen sulfide (H_2S), and may remove minor amounts of other species.

A second reverse circulation method uses 6 in. or larger drill pipe and centrifugal or ejector pumps. Until recently, pipe joints were flanged, 10 in. or more in diameter, and holes were limited to about 16 in. or larger in order to maintain low fluid velocities around the flanges. Fragile, unconsolidated formations tended to wash out, sometimes creating small caverns around the flanges. This created serious problems in cementing the casing. Because of the large diameters, the method is not applicable to most geothermal wells, except possibly large water source heat pump wells.

This method is most suited to drilling softer and unconsolidated formations and usually use drag bits, which cannot drill cobbles and boulders. Large roller bits are available, but expensive. Circulation rates of 500 gpm are not uncommon. Because of the large volume of water, special sampling boxes are recommended.

Some newer reverse circulation pipe is threaded. This permits drilling smaller diameter holes with tricone bits, increases depth capability and speeds drilling because the time required to add or remove drill pipe sections is greatly reduced.

A third reverse circulation system utilizes a dual-ducted swivel and special drill pipe to convert a conventional top head drive to a reverse circulation top head drive. Compressed air flows down through the swivel and special top coupling into pipes outside the drill pipe, then back to the main part of the drill pipe where it provides the lift for circulated fluid and cuttings. Fluid and cuttings flow up the drill pipe and out the second duct in the swivel. Conventional drill pipe is used between the point of air injection, which may be several hundred feet below ground surface, and the bit or collar.

<u>Drill Through Casing Driver</u>

Top head drive, direct circulation air rotary rigs can have casing drivers attached to the mast. The driver is similar to an air-driven pile driver. Using the driver, casing can be driven during drilling, similar to the drill and drive method used by cable tool rigs. Since sections of casing must be the same length as the drill pipe, they are usually pre-assembled. The bottom of the casing is equipped with a drive shoe.

When drilling unconsolidated formations, the bit fits inside the casing and the drive shoe shaves the formation during driving. Casing can be driven ahead of the bit which drills out the plug; or the bit can drill ahead of the casing, then be pulled back into the casing and casing driven; or the casing is driven just behind the bit at the same rate as bit penetration. Friction between the casing and borehole limits the amount of casing, of a given size, that can be driven.

When it is necessary to set casing through a hard or well consolidated formation, an under-reaming bit, usually a downhole hammer, can be used.

Because the casing seals off all but the near bottom formation cuttings, sampling is excellent, lost circulation problems are eliminated, and accurate estimates of water production can be obtained.

The requirement for pulling the casing before cementing (similar to drill and drive cable tool) and the additional noise of the casing driver are the main disadvantages.

Dual Tube Reverse Circulation

This method is probably not applicable for most production wells because the largest outside tube diameter available is 9 5/8 in. It is, however, an excellent test well or pilot hole drilling method because it provides excellent cutting sampling and flow estimates.

The drill pipe is double wall, usually flush jointed. Drilling fluid can be air, foam or light bentonite, or polymer muds. Fluid is circulated down between the pipe walls, through a bit sub, inward across the bit, picking up cuttings, and up through the inner pipe. The bit is normally one nominal size large than the outer pipe; therefore, a good seal between the pipe and well wall is obtained (Figure 6.4).

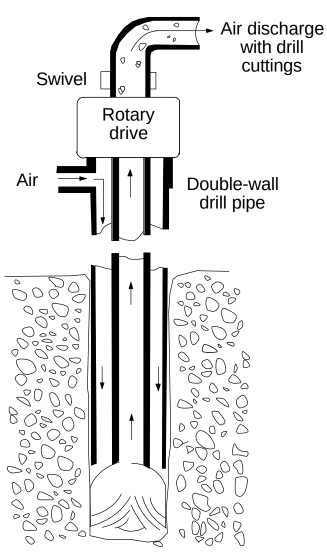

Figure 6.4 Dual tube reverse circulation drilling (Johnson Division).

When using a tricone bit, the distance between the bit and the bottom of the outer pipe is only a few inches, so samples are very representative of the formation actually being drilled. When using a downhole hammer, air flows through a hammer sub and the hammer, out the bottom of the hammer and up around the hammer to the sub where it is channeled to the inner pipe. The formation sample will be primarily from the hammer face, but the water samples could come from anywhere along the length of the hammer (Figure 6.5).

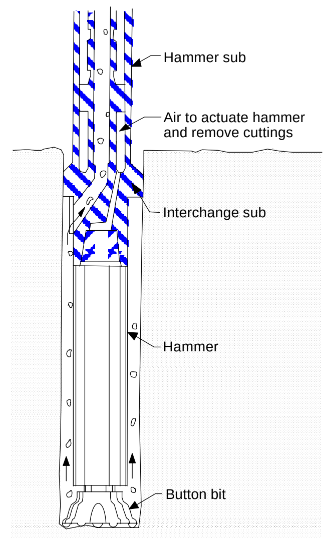

Figure 6.5 Use of an interchange sub (Drilling Service Company).

The cross-over channel in the interchange sub mounted on top of the hammer permits the cuttings to enter the inner casing.

Drilling depth, limited by friction between the well wall and outer casing, can be approximately 2,000 ft in consolidated formations.

6.2.4 Core Drilling

Core drilling is basically an exploration method. This technique is widely used in mineral exploration, civil works foundation investigation, and wells for scientific investigation. It is also used for geothermal test and/or temperature gradient well drilling where accurate and complete lithology are required. It would rarely be used for production wells since the largest standard hole diameter is 4.828 in. and the method is very expensive.

Core drilling equipment is designated by a letter size. Table 6.1 shows dimensions of core, hole, and drill rods for commonly used letter sizes (B, N, H, and P).

Table 6.1 Common Core Sizes Normally Use for Geothermal Drilling

Designation	Drilling Equipment B	N	H	P
Core size	1.432	1.875	2.500	3.345
Hole size	2.360	3.040	3.850	4.828
Drill rod ID	1.813	2.375	3.063	4.063
Drill rod OD	2.188	2.750	3.500	4.625

There are several core drilling methods, but the usual method used in geothermal work is known as the wire line method. In this procedure, hollow drag-type bits with an ID of the core sizes and OD of the hole sizes, as shown in Table 6.1, are rotated by the drill rod. A core barrel (a pipe with grips to hold the core) is lowered inside the rod by means of a cable, and over the core being cut. When the barrel (usually 10 ft long) is full, it is pulled out and replaced with another. The core is removed from the barrel, laid out in core boxes, labeled, and the barrel is readied for the next trip. The result is a more or less continuous sample of the material drilled in nearly the same form as it existed at depth.

Usual practice is to drill 200 to 500 ft using a tricone roller bit, set and cement casing, (and install blowout prevention equipment if required), before starting the coring operation. The core bits (Figure 6.6) are usually faced with a powder metallurgy diamond grit material. Water or thin bentonite drilling fluid is circulated for bit cooling and drill rod lubrication. Surface returns of drilling fluid are desirable, but drilling without returns is practical, because the cuttings are very fine and not as likely to stick the downhole string as in conventional rotary drilling. Fluid circulation rates are low because the annulus is small and drilling fluid is not a major expense.

Figure 6.6 Core bits (Tonto Group of Companies).

The drilling rigs are small, can be mounted on a single truck, and can be readily moved. Depths to 7,500 ft are possible, usually starting with a large size drill and reducing the size as drilling progresses. A drill rod string and bit can be left in place and a smaller size started through it. When the hole is completed, the drill rod strings are removed and casing installed, or the hole is cemented and abandoned, depending on its purpose.

6.2.5 Directional Drilling

Ordinarily, a well is drilled as straight and plumb as reasonably possible, particularly for direct use projects. This makes well completion and pump installation much easier and more economical. Directional drilling is often used in geothermal electrical generation reservoirs where there are economics realized by drilling several wells from one drill pad and steam gathering systems are simplified. To date, the only directional drilling for direct use projects has been to sidetrack junk in a hole, i.e., twisted off drill pipe that cannot be fished out. Directional drilling could be used to intersect a fault for increased production, or to parallel in close proximity to a fault to reduce the possibility of fault movement shearing off a casing. However, the economics of direct use projects usually will not permit the additional expense.

Modern controlled directional drilling is accomp-lished by using a downhole motor driven by drilling fluid pumped down the drill string. The motor is attached to the string by a bent sub and non-magnetic sub. The drill string and subs do not rotate. The bent sub is angled one to three degrees and is oriented to guide the drill motor and bit in the desired direction. Periodic surveys using plumb bobs and magnetic compasses with cameras to record their readings allow the directional drilling engineer to plot the course of the well and make changes to direct the hole in the desired direction. New downhole electronics provide continuous monitoring of magnetic signals and the high side, providing the drilling engineer with real time tool orientation and steering capabilities.

In order to get around junk in the hole in direct use projects, the old fashioned whipstock or a knuckle joint are more appropriate, if the proper tools can be located. The use of downhole motors has become so common that whipstocks are sometimes in short supply.

A whipstock is a long steel wedge-shaped tool that is concave on one side to hold and guide a whipstock drilling assembly. If the hole is not cased, a removable whipstock can be set and a small diameter rat hole drilled 10 to 20 ft beyond the whipstock toe. The whipstock is then removed, the hole reamed, and drilling continued with a full gauge bit and stabilizers to get around the junk.

If the hole is cased (usually a permanent whipstock is set, sometimes in a cement plug), diamond or carbide mill bits are used to drill out the side of the casing. Several feet of open hole is required before the standard drill bit is again used. Full size stabilizers maintain hole direction until the junk is by-passed.

A knuckle joint is a spring-loaded universal joint located between the drill string and the bit, allowing the bit to drill at an angle with the drill string. The direction cannot be controlled as it can with the whipstock or drilling motor, but this is usually not important when side tracking around junk.

Once the initial hole deflection has been established by one of the above methods, the angle can be controlled by the proper selection of stabilizers and subs.

To increase the drift angle, a full-size stabilizer is inserted into the string just above the bit and a limber subassembly used. As weight is applied to the bit, the limber sub deflects and the stabilizer has a crowbar effect, increasing the drift (Figure 6.7).

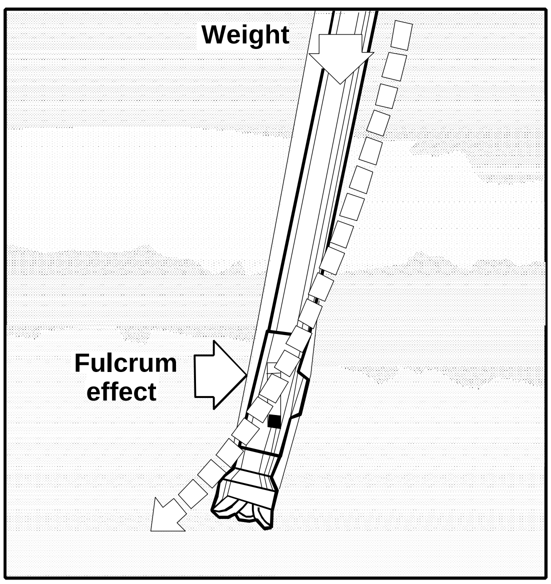

Figure 6.7 Fulcrum effect (Eastman Whipstock).

To maintain hole direction, a full-size stabilizer is used just above the bit, a stiff drill collar, and another full-size stabilizer. The stiffness of the assembly and close fit with the hole resist curving and the bit moves forward along a straight but inclined line (Figure 6.8). The longer the stabilizers and stiffer the collar, the better the hole direction is maintained.

To decrease the angle, the stabilizer at the bottom is removed and a more limber collar is used. The upper stabilizers hold the top of the collar away from the low side of the hole and gravity acts on the limber collar and bit to bring the hole back to vertical (Figure 6.9).

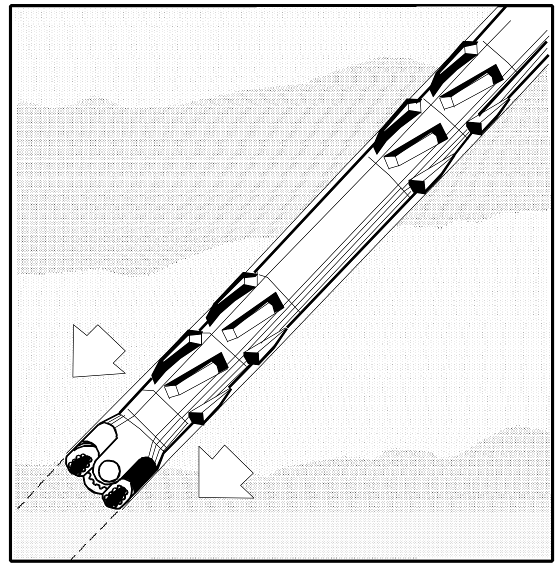

Figure 6.8 Use of a stabilizer (Eastman Whipstock).

By selecting the size and location of the stabilizers, stiffness of the collars and carefully controlling drilling weight, the rate of hole drift, either increasing or decreasing, can be controlled.

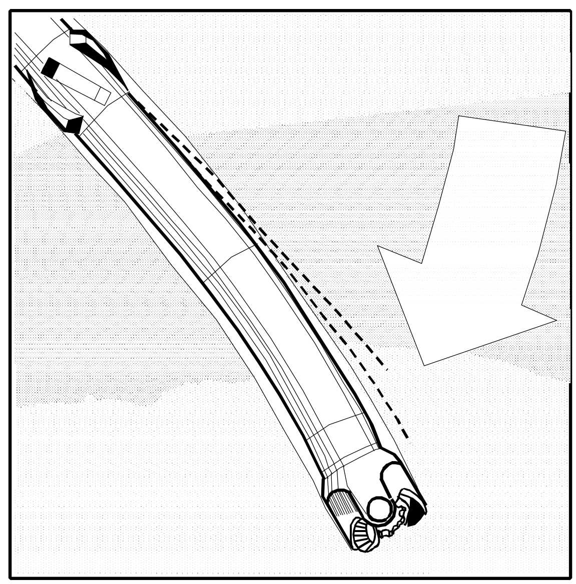

Figure 6.9 Bringing drill head to vertical (Eastman Whipstock).

6.3 DRILLING FLUIDS

Most low- and moderate-temperature geothermal aquifers will be confined, but wells will usually not flow. Static water levels generally vary from a few tens to a few hundreds of feet below the surface. Many are fault controlled, and very often drilling will be in areas of uplifted or down-thrown subsurface blocks. Depth to the aquifer and production rates can vary substantially over short distances, and temperatures sometimes change rather dramatically with small changes in depth. Temperature reversals are often experienced with increasing depth after drilling through an aquifer (see Figure 7.10). In the western U.S. and many other locations throughout the world, drilling is often in fractured and faulted metamorphic and igneous rocks, and production is from weathered or inter-bedded lavas and contacts between lithologic units. Production zones may be only a few feet thick. Because most direct use projects cannot afford extensive geological and geophysical work or test drilling, it is important that all production zones be recognized.

The above conditions require careful selection and maintenance of drilling fluids. In many areas, air or foam are the preferred fluids. However, it is recognized that other fluids will be used because of caving hole conditions, for control of downhole pressures, availability and capability of rigs, or preference. Both the engineer and the driller must be aware of the possible consequences of fluid selection and maintenance.

All drilling fluids perform three basic functions:

1. Cooling of the drill bit.

2. Removal of cuttings as they are produced at the drilling face.

3. Transporting cuttings up the hole.

Depending on local conditions, most drilling fluids (usually mud) may also:

1. Stabilize the hole to prevent cave-ins.

2. Minimize formation fluid migration into the hole.

3. Minimize fluid losses to the formation.

4. Lubricate mud pump, bit and the annulus between the drill string and the hole.

5. Reduce drill string corrosion.

6. Suspend cuttings during periods of non-circulation.

7. Assist in collection and interpretation of samples and borehole geophysical logs.

8. Release cuttings in the mud tank or pit.

Ideally, fluids used in most direct use drilling should also permit immediate and accurate detection of geothermal fluids, temperature changes, and production zone lithology. Unfortunately, fluid characteristics allowing these to be accomplished are in almost direct contradiction to characteristics required to accomplish most of the other requirements listed above.

Drilling fluids fall into one of three general classes: water based, air based, or oil based. Oil-based fluids may be used in petroleum drilling, but are not appropriate for low-to- moderate temperature geothermal drilling because of the danger of contamination of aquifers. Mists fall into the air classification because most of the characteristics are similar, and water into the mud class because recirculated water is very thin mud containing suspended particles of drilled formations. Mud is probably the most common drilling fluid and, while useful for the purposes listed above, presents many of the problems encountered in geothermal drilling.

6.3.1 Lost Circulation

Lost circulation is the loss of drilling fluid from the borehole through cracks, crevices, or porous formations. It can be partial or complete, depending on the conditions. Lost circulation is sometimes referred to as lost returns, either partial or complete, because part or all of the fluid fails to return to the surface. When circulation is lost, the drilling fluid is not performing one of its major functions, that of transporting the cuttings up the hole where they can be released in the mud tank or pit. If the cuttings are not removed from the hole, they will pack around the drill string above the bit, resulting in stuck pipe and possible loss of the bit, collars, part of the string and perhaps, the hole.

If the formation has large cracks or crevices, the fluid may carry the cuttings into the formation and away where they cannot pack around the drill string, but there is no way of being assured that this is the case. Drilling without circulation is known as drilling blind. Complete loss of circulation usually results in the fluid level dropping to considerably below the surface with the resultant complete or partial loss of fluid pressure stabilizing the hole walls. This can result in cave-ins, another cause of stuck pipe.

Lost circulation is probably the most important problem encountered in drilling. It results in: (1) loss of expensive fluid components, (2) loss of drilling time, (3) use of potentially expensive lost circulation materials to keep the losses from plugging possible production zones, and (4) leads to cementing problems, in addition to possible loss of equipment in the hole, as noted above.

Despite the severity of the problems, most experts agree that probably one-half the lost circulation problems can be avoided and many are driller induced. Proper planning and rig operation are important. Some of the techniques involved in proper planning and operation are listed below:

1. Insofar as possible, use nearby well logs and geologic information, and carefully plan the hole and the casing program.

2. Treat the well bore gently. Raise and lower drill strings and casing slowly. Do not spud or swab. Start fluid pumps at slow rates and increase slowly. Maintain fluid velocity in the annulus at the lowest rate to assure cuttings removal. Do not drill so fast as to overload the annulus with cuttings.

3. Make frequent measurements of mud properties to maintain minimum weight, viscosity, and filtration.

6.3.2 Drilling Muds

Modern drilling muds are primarily mixtures of western bentonite (sodium montmorillonite) and water. Organic polymers, dispersants, wetting agents, weighting materials, thinners and lubricants are added to modify properties to meet changing hole conditions or counteract changes previously made by the driller.

When bentonite is added to water, several changes in physical properties take place. Some of the more important are increases in density and viscosity; and gelation, lubricity, and filtration properties are added. As the mud is used, there are changes in suspended solids and sometimes chemical changes that affect physical properties. Some of the mud properties can be relatively easily measured and related to performance.

Density

Mud density or mud weight is measured by a simple balance beam or mud balance and is usually expressed in pounds per gallon (lb/gal). As density is increased, the buoyant effect increases carrying capacity for cuttings but decreases settling rate in the mud pit. Increased density increases borehole pressure and the ability to prevent caving and flow into the hole. Conversely, it increases the tendency to flow out of the hole and into the formation, and therefore, may result in increased loss of circulation. In fact, lost circulation can sometimes be regained by the simple expedient of reducing density. The generally recommended maximum density is 9 lb/gal; less is highly desirable.

Density can be increased by the addition of barite without unduly altering other mud properties. Solids such as sand, fine cuttings, silt, etc., increase density and are undesirable because they increase pump and other components' wear rate, retard drilling rate, form a thick filter cake, and increase power requirements of the mud pump. Hydrostatic pressure can be calculated by:

$$P = 0.052\, ed$$

where

P = hydrostatic pressure (psi)
e = fluid density (lb/gal)
d = depth (ft).

Example: If geothermal water at 200°F (density = 8.049 lb/gal), which if unrestricted would rise to 300 ft below the surface, is encountered at 1,500 ft using 9 lb mud, the pressure keeping geothermal water out of the hole and tending to force mud into the formation is the pressure caused by mud minus the pressure caused by water giving:

$$P = (0.052 \times 9.000 \text{ lb/gal} \times 1{,}500 \text{ ft}) - (0.052 \times 8.049 \text{ lb/gal} \times 1{,}200 \text{ ft})$$

$$P = 200 \text{ psi.}$$

This applies only when mud is not circulating. When circulating, the pressure would be higher, depending on viscosity, borehole and drill string diameters, filter cake thickness, etc. Rapidly raising or lowering the drill string during tripping or spudding significantly changes downhole pressures. Pressure will be increased in the direction of movement, possibly causing mud invasion into the formation and lost circulation or both. Rapidly raising the string creates a swabbing effect and lower pressure below the string. In high temperature and/or pressure situations, this can induce a well to flow or flash, resulting in a possible blowout.

Although drilling with pure water eliminates the possibility of mud damage to the formation, the pressure difference is still approximately 148 psi, which effectively reduces the possibility of detecting geothermal water when the producing formation is encountered.

Viscosity

Mud viscosity is primarily a measure of its ability to carry cuttings up the hole, drop them in the mud pit, and to form a gel. It is changed by varying the amounts of bentonite and water or by adding polymers to thicken or phosphates to thin. There is no simple, accurate and economical method of field measurement, but apparent or funnel viscosity is obtained by measuring the time it takes a measured amount of mud, usually one quart, to flow through a standard Marsh funnel.

Water has a funnel viscosity of 26 seconds/quart (s/qt) at 70°F. A good drilling mud has a funnel viscosity of 32 to 38 s/qt. Funnel viscosity is affected by density and the type of suspended solids. Well rounded sand can decrease funnel viscosity by 10 s or more but the true viscosity changes very little. Funnel viscosity means very little by itself, but in combination with other mud measurements can be useful to the experienced driller.

Sand Content

Sand content affects mud density and apparent viscosity, equipment wear (especially mud pumps), bit life, drilling rate and formation damage. Sand content is measured by carefully washing a measured volume of mud on a 200 mesh screen. The material held on the screen is poured into a cone shaped graduated container. The desired maximum limit is 2% by volume.

Sand content can be controlled by using low viscosity mud, multiple pits and tanks of adequate volume designed to eliminate short circuit flows and the use of de-sanders. Mud pits or tanks should have a volume of at least three or four times the finished hole volume and the pump intake should be suspended near the surface.

Because a high sand content increases density, it decreases the likelihood of detecting an under-pressured geothermal resource. For the driller, the investment in materials and time to regularly measure sand content will soon repay itself in reduced wear of mud pumps, swivels, etc.

Filter Cake

When the mud is in the borehole, pressure in the annulus tends to force it into any porous formation. Clay platelets build up on the formation and reduce fluid loss. This buildup of clay is called the filter cake. Some water filters through the cake and is water loss while loss of both clay (and other constituents) and water is mud loss. It is desirable to maintain a thin, easily removed filter cake while minimizing water loss and maintaining circulation.

Water loss and filter cake thickness are measured using a standard API filter press. Filter paper is supported in a mud filled standard cell and 100 psi is applied and maintained by a pressurized gas cylinder. The amount of water passing through the filter paper in 30 minutes is measured and the buildup of filter cake on the paper measured to 1/32 in. Desirable properties are 15 cm^3/30 min and 2/32 in. thickness.

Gelling

One of the properties of a bentonite and water mixture, thixotropy, is its ability to gel. The mixture is fluid while being stirred, but stiffens after standing. When stirred again, it becomes a fluid. This property helps suspend drill cuttings during non-circulation periods. Gel strength yield point and time are very seldom measured by small rig operators but are related to funnel viscosity readings taking other factors into consideration.

The ability to gel is the property that makes mud highly undesirable while drilling in many geothermal production zones. When circulation is lost or reduced, mud flows into the fractured or unconsolidated formation. As long as flow is maintained, the mud acts like a viscous fluid and will continue to flow until the frictional resistance equals the pressure difference between the annulus and the formation. In conventional drilling, the mud also carries small cuttings into the formation. Cuttings may partially fill the voids, increasing resistance to flow, and circulation may be regained or lost circulation materials may be added and circulation regained. If circulation is regained, mud flow in the formation stops and, unless sufficiently diluted by formation water, the mud gels. Gelling is progressive; that is, gel strength increases with time and, in the more commonly used bentonite muds, increases with temperature.

Gelling is one method of stopping lost circulation. Viscosity is increased by adding bentonite, sometimes to the point where the pump will hardly pump it. Some of the thick mud is pumped, filling the formation, then the bit pulled back a safe distance and the hole allowed to set for several hours to a day. Continued drilling with very light mud, slow rotation and slow mud pump speed will sometimes permit finishing the hole or drilling to where casing can be set. In either case, if the zone was a potential geothermal producer, it may be lost forever.

Once the gel forms at some distance from the bore it is difficult, if not impossible, to remove by ordinary development methods. Mixtures of hydrochloric and hydrofluoric acids, and phosphate thinners, with vigorous swabbing at about 4 hr intervals are sometimes effective but expensive. There is always some element of risk in acidizing because the acid doesn't always go where it is needed.

Lost Circulation Materials

Lost circulation materials (LCM) are materials that bridge across openings in the formation, providing a foundation for the buildup of filter cake. Almost every conceivable material has been used including sawdust, alfalfa pellets, chicken feathers, ground walnut shells, cotton seed hulls, hog hair, and many others. There are also a variety of gelling agents or mixtures that form stiff gels when mixed with water or salt water. A bentonite and diesel oil slurry, when mixed with water, forms a thick putty-like mass. In the trade, this is often referred to as gunk. Flo-Chek (Halliburton Services, undated) forms a similar thick gel when mixed with salt water.

Many of the LCMs are organic and may have the potential to promote undesired organic growth or degrade water quality or both. Because in many areas, low-to-moderate temperature geothermal fluid has the potential to mix with underground fresh water supplies, the use of these material is prohibited. In areas where the geothermal fluid is bottled as mineral water, the bottlers would very emphatically oppose their use.

Inorganic materials, such as mica flakes and gilsonite, or inert materials such as some of the plastics can be used, although they are not always as effective. The best materials will be a mixture of flake and fiber of various sizes in order to effectively bridge openings in the formation.

Recognizing Geothermal Zones

Geophysical logging and interpretation can detect zones that may be low-temperature geothermal production zones. A good estimate of the geology and hydrology conditions by a qualified geologist is always helpful for log interpretation in an unknown or exploration area. However, logging is expensive and most direct use applications cannot afford frequent logging and interpretation.

Monitoring mud entering and return temperatures can sometimes indicate higher temperature zones. This can indicate approaching a production zone. When the production zone is encountered, circulation will probably be lost or reduced. However, increases in temperature are frequently masked by cold strata above the drilling level, cooling the mud as it rises up the annulus. The effectiveness of the technique depends on the formation temperatures, drilling rate versus downhole temperature, temperature measure-ment frequency, and weather conditions (more difficult in hot weather with low formation temperatures). Continuous monitoring and recording is best, but few water well drillers have the recording equipment. At the minimum, temperatures should be recorded each 30 minutes or 20 feet of drilling.

Temperature logging between trips has not been very indicative of downhole conditions. Recently circulated drilling fluid produces a nearly isothermal temperature log. If drilling is stopped regularly overnight, temperature logging before circulation each day has been indicative of rock temperature trends but is usually several degrees lower than if the hole sits several days to a week.

In summary, recognizing and evaluating a low temperature, under-pressured geothermal aquifer while drilling with mud is next to impossible. About the best that can be done is to drill to a lost circulation zone that should be hot, stop circulating mud immediately, clean the hole and air lift or test pump. If a geothermal aquifer is confirmed, drilling can be continued with air, pure water or cable tool. An over-pressured aquifer, in flowing resources, is more easily detected by increased mud pit level and higher temperatures.

6.3.3 Polymer Fluids

There is a wide variety of polymers used in water well and petroleum drilling, both natural and synthetic. Synthetic polymers may imitate natural polymers or be totally different; and they may be either organic or inorganic. Many of the natural polymers are biodegradable. Others are easily broken down by oxidizers such as weak acids. Polymers have essentially no gel strength but provide high viscosity; therefore, they carry cuttings up the hole and drop them in the mud pit quickly. Because they are readily broken down and have no gel strength, they have been suggested for low-temperature geothermal wells to eliminate some of the problems with bentonite.

Some of the polymers are temperature sensitive; they lose viscosity quickly at temperatures of approximately 100°F and therefore, are not suitable. However, others are stable to 300°F. Because of the potential for pollution, some states have prohibited or restricted use of some, if not most, organic material in domestic water wells. Synthetic duplicates would also be included. Because low-temperature geothermal wells are treated as groundwater wells in many states, and low-temperature geothermal aquifers may be hydraulically connected to drinking water aquifers, use of polymers may be restricted.

Geothermal fluids contain chemicals and dissolved gases that may react with polymers, especially at elevated temperatures. Reactions could either break the long molecules reducing viscosity, or cross link molecules forming a thick gel. Before using any polymer, it would be wise to consult the manufacturer giving him the expected temperature and water chemistry and, if possible, testing the polymer with a sample of the geothermal fluid from another well or spring.

6.3.4 Air-Based Fluids

Drilling with *dry air* is the simplest air drilling technique. Obviously, when water is encountered in the hole, its no longer dry and must be converted to mist or foam. In general, the lifting capacity of air is proportional to its density and to the square of its annular velocity. Velocities of 3,000 to 5,000 ft/min are usually required (Driscoll, 1987). For a given hole and drill pipe size, air volume requirements are directly related to depth. As the hole depth increases, expansion at the bit is less (therefore, velocity is less) because of the increased weight of cuttings supported and pressure buildup because of friction. Excessive air velocity can lead to erosion of softer formations which, in turn, requires more air to maintain adequate velocities in the enlarged annular space. Excessive air pressure can cause air loss to the formation. Air loss, like lost circulation when drilling with water-based fluids, results in cuttings not being lifted and the danger of sticking tools.

Unconsolidated formations and, to a large extent, excessive cold water invasion from overlying aquifers can be controlled with drill and drive methods. Small amounts of formation water, when mixed with cuttings dust, particularly shales, can cause mud rings to form on the drill pipe and hole wall. Below these rings, pressure buildup reduces velocities and can cause air losses to the formation. Air systems provide little support to unconsolidated formations and there is danger from caving, possibly resulting in stuck tools. Consolidated formations, where air drilling is at its best, do not present that danger.

Air mist drilling is the result of adding small amounts of water at the surface. Wetting agents are often added to help remove mud rings and control dust. Air volume requirements are increased because of the increased density of the air column, resulting in increased pressure at the bottom of the hole. Air mist techniques can be used satisfactorily as long as only small amounts of water (15 to 25 gpm) enter from the formation (Driscoll, 1987).

Foam drilling is used when larger amounts of water enter the hole. Usually foam is thought of as a small amount of air in a large amount of water. Drilling foam, however, is a small amount of water with a large amount of air, similar to the soap on top of a dish pan. Drilling foam is made by injecting water and additive into an air stream. Foam drilling occurs when the liquid volume fraction (LVF) is <-2.5%. LVFs >2.5% are usually termed aerated fluids.

Stable foams are produced by adding surfactants. Polymers and clays may be added to increase viscosity and density. The addition of surfactants provides:

1. Ability to lift large volumes of water.

2. Reduced air volume requirements.

3. Greater solids carrying capacity.

4. Reduced erosion of poorly consolidated formations.

Annular velocities as low as 50 to 100 ft/min can be used with <u>stiff</u> foams made with polymers (3 to 6 lb/100 gal) or bentonite (30 to 50 lb/100 gal) and 1 to 2% surfactant. Bentonite should not be used with a downhole hammer, but other types of foam can be used. <u>Wet</u> foams, which may require annulus velocities up to 1,000 ft/min, are made with 0.25% surfactant and no other additives. Surfactant and other additives are mixed in a large tank and injected into the air stream by a metering pump. Maximum lift is obtained using 2% liquid volume fraction (2% of the free air volume) (Driscoll, 1987).

Being a compressible fluid, air follows the ideal gas laws. This holds for all air-based drilling, dry air, mists and foams, with appropriate modifications for any additions to the air. Pressure and temperature are high and the volume is small in air feed lines and drill pipe. At the bit, expansion occurs with a drop in temperature and pressure unless downhole temperature is high, in which case expansion is further increased. Expansion occurs until pressure at the bit equals pressure caused by resistance to flow, plus any cuttings and water load. When using stiff foams, considerable expansion occurs all the way up the annulus. Figure 6.10 shows how the temperature, pressure and volume change during drilling.

a. Basic components of an operating air rotary circulation system showing the pressure and volume conditions in the drilling fluid at various sites. Greatest pressure and volume changes generally occur at the bit, which is the most critical point in an air drilling-fluid system.

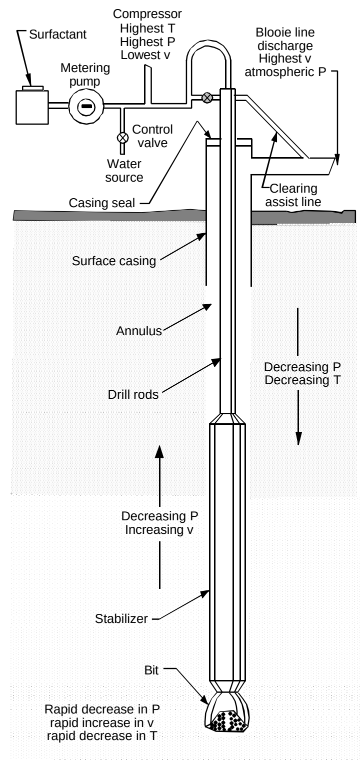

Figure 6.10 **Pressure and volume relationships during drilling (Driscoll, 1987).**

b. P = Pressure, T = Temperature, v = Volume.

Compared to water-based fluids, air-based fluids have the following advantages:

1. Higher penetration rates, especially in hard rock.

2. Easy detection of aquifers and estimation of potential flow rates.

3. Reduced formation damage.

4. Longer bit life.

5. No water (or very little) required for drilling.

6. Usually better formation samples.

The major disadvantages of air are associated with the advantage that all air systems bring the water to the surface. Although this enables the detection of production zones, it presents the problem of disposal of the fluids and the dangers associated with hot water. If a flow of 500 gpm is encountered and drilling is continued for 12 hours in an attempt to get additional flow, the fluid produced will be 1.1 acre-ft. If the water is hot, near or above boiling downhole for example, and is high in dissolved solids, disposing of it can be a major problem in some locations.

Water at 140°F or above will scald. If temperature near or above this are anticipated, appropriate equipment, i.e., rotating head, banjo box, blooie line, safety apparel, fencing, etc., must be used.

If water is above the boiling point at the drill site altitude, the air lift may reduce the pressure above the water to the point where flashing will occur (Figure 6.11). Flashing will often continue unaided. This is why blowout prevention equipment is required when elevated temperatures are, or will possibly be, encountered. The rotating head constrains the steam and air; steam and cuttings flow out through the banjo box and blooie line. Other disadvantages of air drilling include:

1. Higher cost for equipment and fuel costs for driving compressors.

2. Dust.

3. Noise of compressors and blooie exhaust.

6.3.5 Plumbness and Alignment

Any well drilled more than a few tens of feet is probably not perfectly plumb or straight. Some misalignment is permissible; but, lineshaft pump life can be reduced if the well is overly crooked because it places extra loads on the column bearings. Straightness is more important than plumbness. There are many ways of checking geometry with fairly sophisticated logging tools that check deviation and compass direction. Few drillers have these instruments and the cost will be more than many direct-use projects can afford. Simpler, more economic methods are usually specified.

One method of checking well geometry is to use a rigid pipe dummy two casing lengths (usually 40 ft long), with an OD ½ in. smaller than the casing in the section to be checked; assuming that if the dummy passes, the pump will pass and operate satisfactorily. A well with a deep pump setting could have an S curve that would allow the dummy to pass but bind a pump column and cause early bearing failures.

Another method is to use a plumb bob and line. The bob can be anything heavy enough to keep the line taut, 1/4 in. smaller in diameter than the inside of the casing and longer than its diameter. The bob is usually an adjustable spring steel wire cage. If the bob is suspended from a pulley above the casing top and the line comes off the pulley exactly over the center, the deviation at any depth can be calculated from:

$$X = \frac{D(H + h)}{h}$$

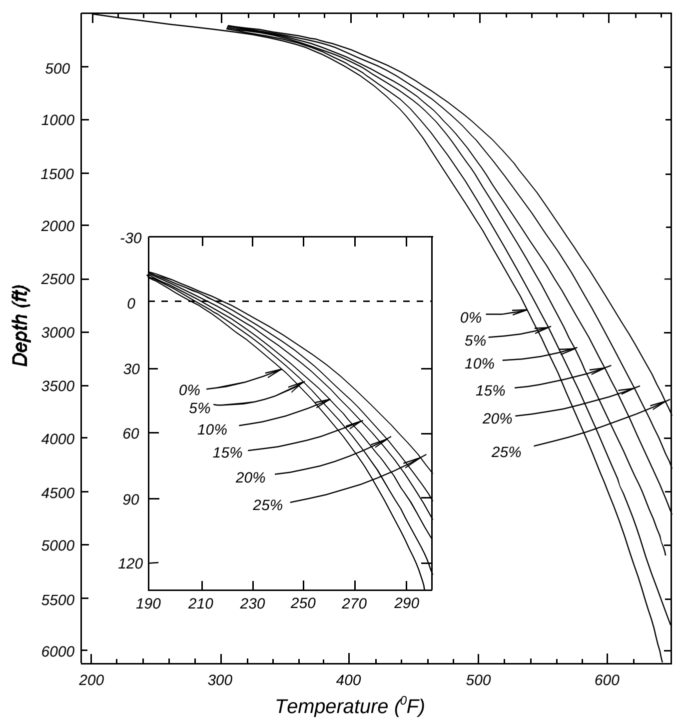

Figure 6.11 **Boiling-point curves for H_2O liquid (in wt percent) and for brine of constant composition NaCl. The insert expands the relations between 194° and 300°F. The temperature at 0 ft for each curve is the boiling point for the liquid at 1.013 bars (1.0 atm) load pressure which is equivalent to the atmospheric pressure at sea level.**

where

X = deviation at given depth (in.)
D = distance the line moves from the center of the casing (in.)
H = distance from casing top to cage (ft)
h = distance from center of pulley to casing top (ft).

If the pulley is exactly 10 ft above the casing and readings are taken at 10 ft increments, the calculations are simplified. Both direction and total deviation can be plotted on a scaled deviation plot and an outline of the casing drawn. After plotting the casing, a straight line is drawn from the casing top to the depth where alignment is to be maintained. The casing should not be closer to the plotted center line than the maximum amounts shown in Figure 6.12.

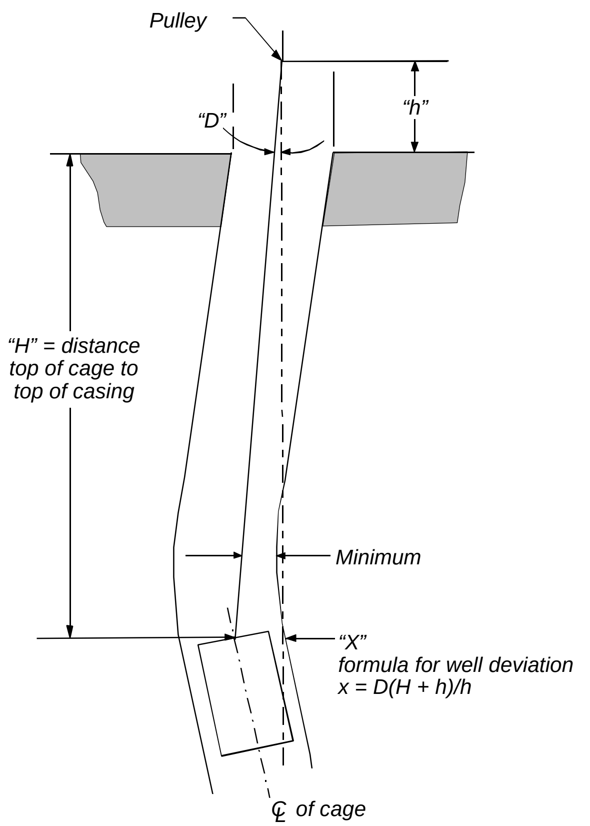

Figure 6.12 Plumbness and alignment (Roscoe Moss Company).

a. Minimum amount (as shown above):

8" for 24" ID well casing
7" for 20" ID well casing
6" for 18" ID well casing
5" for 16" ID well casing
4" for 14" ID well casing
3" for 12" ID well casing
2" for 10" ID well casing

The usual standard for plumbness allows 6 in. out of plumb for every 100 ft of well depth. Some engineers feel that 6 in./100 ft is excessive and allow only 3 in./100 ft (Roscoe Moss Co., 1985).

The proposed 15th edition of the Hydraulics Institute's Standard for Well Straightness states "shall not deviate more than 1 in./100 ft and be without double bend" (Cherry, 1987).

Table 6.2 gives relative drilling rates of seven drilling methods in various formations. Rates were modified somewhat from Driscoll (1987) after discussions with experienced geothermal direct use drillers.

6.4 WELL DESIGN

Well design involves specifying well depth, casing diameters, materials, thickness, lengths and pump setting. Once these are determined, other parameters such as wellbore diameter, completion methods, procedures, and perhaps, drilling methods can be decided. An initial design must be prepared in order to write specifications and obtain a bid; but, probably more often than not, the design changes as actual hole conditions become known. Some requirements may be specified by state, federal or local agencies. Other factors may be partially or wholly determined by local practices and equipment availability. In many cases, it is prudent to hire a qualified geologist to thoroughly review well logs and published geologic information before the initial design is made, and to interpret cuttings and logs as the well is drilled. There are often critical decisions that must be made during drilling. Having a geologist on-site to help in decision-making can help make drilling proceed smoothly and efficiently.

Most direct use wells consist of three main parts: pump housing or surface casing, the inlet portion, and the production casing between them. Flowing artesian wells do not require a pump housing, if flow is sufficient for the intended use.

Depth is usually determined by that required to obtain sufficient flow or temperature, or both, for the intended use. The controlling factors are depth to aquifer, thickness of the aquifer, transmissivity of the aquifer, and flow requirements. As noted earlier, the first three may be estimated from nearby wells; but in fractured and faulted areas, there may be considerable differences in depth to geothermal aquifers and flow rates in adjacent wells. Many direct use wells have temperature reversals and get cooler with increased depth, once the aquifer has been fully penetrated.

In pumped wells, the final pump setting is determined from well testing, usually with a portable pump. These data should provide water levels for various pumping rates, and perhaps, estimates of long-term drawdown, depending on

Table 6.2 Relative Drilling Rate in Various Formations

	Loose Sand Gravel	Alluvial Fans, Glacial Drift with Loose Boulders	Clay, Silt Shale	Sandstone Cemented Conglomerates	Limestone	Limestone Cavernous	Basalt Layers	Basalt-Highly Fractured-Lost Circulation Zones	Granite & Other Non-Fractured Metamorphics
Cable tool	Slow	Slow-difficult	Slow, medium In brittle shale	Slow	Slow	Medium	Slow to medium	Slow, sometimes difficult	Slow
Direct rotary (air)	(------------------NOT RECOMMENDED-------------)			Fast	Fast	Slow,	Fast	Medium	Med. to fast
Direct rotary (fluid)	Fast	Impossible to very slow	Fast	Med. to fast	Med. to fast	Slow to impossible	Slow to medium	Slow to impossible	Slow to medium
Air hammer	(------------------NOT RECOMMENDED-------------)			Harder types Fast	Very fast	Fast	Fast	Medium to fast	Fast
Reverse rotary	Fast	Medium	Fast	Med. to fast	Medium	Slow to impossible	Slow to medium	Slow to impossible	Slow to medium
Drill thru-casing driver	Very fast	Medium to difficult	Fast	(--NOT APPLICABLE--)					
Dual wall	Very fast	Medium	Fast	Med. to fast	Med. to fast	Fast	Fast	Medium to fast	Slow to medium

the degree of sophistication of the test. Deep and/or high production wells for district heating or industrial uses should have a good testing program unless the reservoir is well known. See Chapter 7, Reservoir Engineering, for test program descriptions. Space heating for residential or light commercial applications probably cannot justify extensive testing but, if they are in known areas, expected pump settings can be obtained from nearby wells. Air lift or bailing with the drilling rig can provide information on the expected flow rates and drawdowns. Consideration should also be given to possible long-term water level declines, reduction in well efficiency over its life because of scaling and possible increased production requirements at some later date. The pump itself is relatively easy to set deeper; well work over to lower the surface casing is much more expensive and sometimes impossible.

Surface casing size is set by the pump bowl diameter. Pumping rate from a given pump diameter can vary considerably and pump suppliers should be consulted before drilling to determine the least life-cycle cost for the pump and well. Larger diameter, low-speed lineshaft pumps are usually more efficient and require less maintenance than smaller, high-speed pumps with the same flow and head. However, where settings are deep and drilling difficult, the cost of a larger diameter well may not justify the savings in maintenance and pumping power.

Surface casing diameter should be two nominal pipe sizes larger than the pump bowls. This permits easy installation and allows for some well deviations. One nominal pipe size larger is permissible, but not recommended. In case of necessity, the outside diameter of pump bowls can be trimmed a small amount. Table 6.3 is based on pump data from several manufacturers, for both lineshaft and submersible, and provides a general idea of the diameter required for given pumping rates.

Because many geothermal aquifers are confined, they will have high static (close to the ground surface) and pumping levels. In this situation, casing and/or bore sizes, or both, can be reduced below the surface casing pump chamber. Many times, at least a portion of the well, between the pump chamber and well bottom, will be in rock and can be left open hole if state regulations permit. In shallow wells, the surface casing is often extended into rock above the aquifer and cemented in place with open hole the rest of the way to total depth. This method of completion simplifies grouting.

Table 6.3 Surface Casing Diameters

Production Rate (gpm)	Nominal Pump Diameter (in.)	Nominal Surface Casing Diameter (in.)
<100	4	6
100 to 175	5	8
175 to 350	6	10
350 to 700	8	12
700 to 1,000	10	14
1,000 to 1,600	12	16
1,600 to 3,000	14	18

In deeper wells, it may be necessary or economical to install one or more casing strings of successively smaller diameters such as when drilling and driving when the casing cannot be driven further. A similar situation occurs when a slotted liner or screen is telescoped through the casing. In water well drilling it is not uncommon to seal the casing/ screen overlap with a lead packer to facilitate screen removal and replacement. Because many geothermal fluids will leach lead (see Chapter 8), the water chemistry should be checked if the use of lead is considered. Cement should always be used at casing overlaps. If removal of the slotted liner or screen is anticipated, a high-temperature elastomer seal can be used.

Most states regulate the length and annulus space for casing overlap. In the case of water wells and, in some states, low-temperature geothermal wells, the required overlap may be <10 ft. Because sulfate ions, present in most geothermal fluids, attack cements, the length of overlap should be increased to a minimum of 20 ft and the use of high sulfate resistant cement considered, if the sulfate concentration is high. Most states require a minimum of 50 ft overlap in geothermal wells, but those requirements were usually written with high-temperature geothermal fluid in mind. The length of overlap required by regulations may depend on how the well is classified, and not necessarily reflect the best design. Most agencies will permit variances to obtain the best design for the particular situation.

The minimum diameter of any open hole or casing string should be selected so that fluid velocities at maximum pumping rates are <5 ft/s. For wells that flow at the surface, velocity (therefore, friction losses that reduce flow) might be lowered by increasing the diameter to obtain greater flows. The additional well costs should be balanced against pumping costs.

The diameter of the inlet portion at the bottom of the well should be chosen to accept the water available from the aquifer. Equations in Chapter 7, based on Darcy's basic flow equation, show that productivity is determined to a much greater extent by permeability than by diameter. For identical conditions of permeability, drawdown and radius of influence, doubling the wellbore diameter increases production approximately 10% in an unconfined aquifer and only approximately 7% in a confined aquifer.

When a slotted liner or screen is used, the open area of the liner or screen may be the limiting factor (Figure 6.13). Open areas of continuous slot screens typically range from approximately 16% to 50% and slotted pipe approxi-mately 1% to 12%. Therefore, when a screen or slotted liner is required and the thickness of the aquifer limits the length, it may be necessary to increase the diameter in order to utilize all the water the aquifer will provide. Velocity through the open area of the screen or liner should be 0.10 to 0.25 ft/s (Campbell, 1973).

Well screen and filter pack are used to prevent sand and fines from entering the well and becoming a sand pumper. Screen openings are small (0.006 to 0.150 in.) and the filter pack is clean graded sand selected to hold back fines from the aquifer, yet not pass through the screen. Selection of the filter pack size and gradation requires sieve analysis of the producing formation and careful selection of filter material size. Because very few geothermal wells are screened, the methods will not be covered here. Methods and information are contained in Driscoll, 1987.

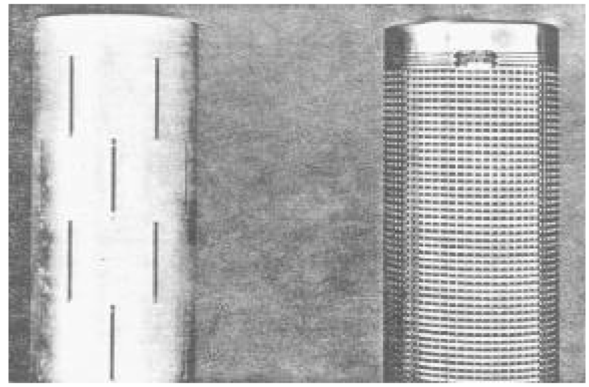

Figure 6.13 Slotted liner and screen (Johnson Division, 1966).

Formation stabilizer is coarser material (1/8 to 5/16 in. gravel) used to prevent sloughing of borehole walls in the production zone. Slotted liner with openings ranging from 0.120 to 0.250 in. supports the stabilizer material. Many geothermal wells require formation stabilizers. The term gravel pack is often used for both filter pack and formation stabilizer.

Placement of filter pack is critical because it contains several selected sizes of material, which tend to separate if just poured down the annulus. Filter pack is carefully placed through a tremie pipe. Formation stabilizer, on the other hand, is usually screened to obtain uniform size and can be poured down the annulus. When cementing is required above the stabilizer or filter pack, 3 to 5 ft of sand is poured or tremied in to prevent cement from entering the stabilizer material.

6.5 CASING MATERIALS

Casing materials, minimum thickness for various diameters, maximum depth for various diameters and ASTM or API standards are specified by some states, but may vary from state to state. Local and state regulations must be checked to assure that the well design meets the applicable codes.

Casing materials for low-to-moderate temperature geothermal wells include thermoplastics, fiberglass and steel. Concrete and asbestos cement casings are also used in water well construction and may be suitable for groundwater heat pump applications. Steel is by far the most common. Properties of casing materials are given in Table 6.4.

Table 6.4 Comparison of Well Casing Materials

	Material					
	Fiberglass			Asbestos	Low-Carbon	Type 304
	ABS	PVC	Epoxy	Cement	Steel	Stainless Steel
Specific gravity	1.04	2.40	1.89	1.85	7.85	8.0
Tensile strength (psi)	4,500	8,000	16,750	3,000	35,000 yld[a] 60,000 ultimate	30,000 yld[a] 60,000 ultimate
Tensile modulus (10^6 psi)	.30	.41	2.30	3.00	30.00	29.00
Impact strength (ft·lb/in.)	6.0	1.0	20.0	1.0	b	a
Upper temperature limits (°F)	180	140	200[c]	250	800 to 1,000	800 to 1,000
Thermal expansion (10^{-6} in./in. °F)	55	30	8.5	4.5	6.6	10.1
Heat transfer (Btu in./h ft^2 °F)	1.35	1.10	2.30	3.56	333.0	96.0
Water absorption (wt %/24 h)	0.30	0.05	0.20	2.0	Nil	Nil

a. Yield strength is the tensile stress required to produce a total elongation of 0.5% of the gauge length as determined by an extension meter. Expressed in psi.

b. Because testing methods for steel and other materials are not the same and the results are not comparable, the impact strength values for steel are not shown. In any event, the actual impact strength of steel is so high relative to the demands of water well work that it can be ignored in design considerations.

c. May be higher with special formulations.

Steel casing is pipe manufactured to ASTM standards A-53 and A-120, or line pipe manufactured to API standards 5L, 5LX (high strength), and 5A. Pipe is available with either threaded and coupled or beveled ends for welding. Most low-to-moderate temperature casing is welded because this is the most common practice in water well construction. Welding should be to American Welding Society standards, fully penetrating multiple pass welds. In oil and gas producing areas, threaded and coupled pipe may be more readily available in sizes below approximately 8 in. Welded pipe is usually used, since it is less costly and welded joints are stronger than threaded and coupled joints for the same pipe thickness.

Most direct use wells are shallow enough that casing tensile and compressive strengths are not a problem. Collapse pressure is greatest during cementing and collapse stresses will probably be the critical design factor. Table 6.5 gives physical characteristics of blank steel casing based on the following formulas (Roscoe Moss Co., 1985):

The values for collapse pressure in Table 6.5 were determined by:

$$P_e^2 - \left(\frac{2S}{\frac{Do}{t} - 1} + [1 + 3(\frac{Do}{T} - 1)e]Pcr \right) P_e + \left(\frac{2SPcr}{\frac{Do}{t} - 1} \right) = 0$$

where Pcr = theoretical collapse strength of a perfectly round tube written as:

$$Pcr = \frac{2E}{1 - M^2} \left(\frac{1}{\frac{Do}{t} - 1} \right)^3$$

where

E = Youngs modulus = 30 x 10^6 psi
M = Poisson's ratio = 0.3
Do = casing OD
t = casing wall thickness

Table 6.5 Physical Characteristics Blank Casing

Nominal Diameter	Wall Thickness	Outside Diameter	Inside Diameter	Weight	Collapsing Strength		Axial Compressive Strength	Tensile Strength
Inches	Inches	Inches	Inches	LB/FT	PSI	Ft. Water	Tons	Tons
8	1/4	8.625	8.125	22/36	755.54	1745.29	115.11	197.33
10	1/4	10.750	10.250	28/04	461.08	1065.10	144.32	247.40
12	1/4	12.750	12.250	33/38	36.09	707.06	171.81	294.52
14	1/4	14.00	13.500	36/71	242.43	560.02	188.99	323.98
14	5/16	14.00	13.375	45/58	418.68	967.15	235.16	403.13
14	3/8	14.00	13.250	54/57	636.10	1469.39	290.90	481.55

e = casing ellipticity = 1%
S = yield strength = 35,000 psi
P_e = collapse pressure with ellipticity (psi).

The values for casing tensile strength set forth in Table 6.4 were determined by:

$$casing\ tensile\ strength\ (ton) = St \left(\frac{Do - t}{2{,}000} \right) t\ \pi$$

where

St = tensile strength = 60,000 psi.

The values for casing axial compressive strength were determined by:

$$casing\ axial\ compressive\ strength\ (ton) = \frac{S(Do - t)\,t\pi}{2{,}000}$$

where

S = yield strength = 35,000 psi.

Collapse strength is reduced by ellipticity, bending and axial stress, and increased by compressive stress. Ellipticity of 1% is allowed in the ASTM and API standards and taken into account in the above equation. Additional ellipticity caused by rough handling and bending, and axial stresses induced during installation such as in crooked holes, should be allowed for by an appropriate safety factor. If an accurate plot of the well geometry has been made, the additional stresses can be calculated using standard strength of materials calculations.

All steel well casing tends to corrode faster in an area above the water line where water vapor and air mix. This is exaggerated in geothermal wells because the higher temperature increases both the amount of water vapor and the distance it moves up the casing. Sealing the top of the casing and any openings such as for air lines and access ports for measuring devices will minimize oxygen intrusion and corrosion. Increasing the wall thickness will increase well life. Unfortunately, there is no good standard practice or rule of thumb for increasing thickness, because temperature and water chemistry vary so widely. Each application should be judged individually. Past experience based on local practice can sometimes help, but often other wells have not been in use long enough to give a good indication of expected life.

Thermoplastic well casing standards are covered in ASTM Standard F-480, which includes a method for calculating collapse strength. Care should be exercised when specifying thermoplastic casing for elevated temperatures because collapse strength is reduced drastically. As with any casing, the collapse pressure will be greatest during cementing and the placement method should be chosen so as to equalize pressures inside and out as much as possible. Heat generated during curing of cement grout further increases the temperature that the casing must withstand. Use of thermoplastic pipe is discussed in Chapter 10, which gives strength decreases with rise in temperature. These factors are also applicable for collapse strength reductions.

Fiberglass-reinforced epoxy or polyester casings and pipe are produced with many resin formulations and winding procedures that affect the temperature and strength characteristics. At the present time, there is no standards covering all the various resins and construction methods for well casings; however, pressure piping is covered by several standards (see Chapter 10). Pressure piping is available for temperatures up to 300ºF.

Fiberglass-reinforced casing has several advantages, including excellent corrosion resistance, light weight and high strength-to-weight ratios. It is available with several thread type connections, including threaded and O-ringed, and bell and spigot with locking keys that permit speedy installation. Resin joining of bell and spigot or tapered joint couplings requires considerable time, experienced workmen and heat curing for use at elevated temperature.

The major disadvantage of fiberglass is cost, which is higher than steel on a per foot basis. Installed cost may be competitive when using the threaded or keyed couplings. Another disadvantage is that pump housings must be plumb and probably larger diameter to ensure that pump parts do not contact the inside of the casing. Pump vibrations will wear a hole in the inner lining permitting hot water to wick along the fiberglass filaments and lead to separation of filaments and resin.

6.5.1 Centralizers

Casing should be run with centralizers or centering guides to assure that all voids are filled and channeling does not occur during cementing. Centralizer spacing depends on hole straightness and clearance between the casing and bore. Plastic casing requires closer spacing than steel casing. Some states regulate the maximum spacing.

Centralizers for shallow, straight wells are typically fabricated from 1-1/2 to 2 in. x 1/4 to 5/16 in. steel flat bar, bent and welded to steel casing to provide 1/4 to ½ in. clearance with the well walls. For thermoplastic casing, centralizers are strapped to the casing with stainless steel clamps. Screws should not be used because they are subject to corrosion, leaving holes in the casing. Fiberglass centralizers are available for fiberglass casing.

Centralizers used in the petroleum industry (for deep or crooked holes or both) float on the casing and are held in vertical spacing by lock collars (Figure 6.14). This permits the casing to be rotated. Wall scratchers or cleaners attached to the casing clean filter cake from the bore walls, providing better cement bonding to the formation and reduce cement channeling.

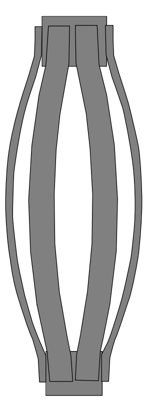

Figure 6.14 Centralizer.

6.6 GROUTING/CEMENTING

6.6.1 General

Grouting and cementing have become synonymous. Grouting may be more technically correct, because grouting is the act of implacing any sealing material. Cement is the usual grouting material for wells, although clays are permissible (in some states) where their location will not permit drying and shrinkage. Cementing is probably the more common terminology in geothermal work.

Grout is placed in the annulus between the casing and well walls or between strings of casing of different diameter to prevent mixing and/or contamination of aquifers by undesirable aquifers or surface water. Because its purpose is to protect aquifers, most states have adopted regulations specifying acceptable materials and methods of placing grout.

Portland cement is the most common grouting material. ASTM Types I, II, and III are commonly used in water wells. The petroleum industry has developed eight classes of cement to meet the special conditions of deep oil and gas wells.

API Classes A, B, and C correspond to Types I, II, and III respectively. The other classifications were devel-oped to permit the use of accelerators, retarders and other additives to meet special requirements. Because the ele-vated temperatures of geothermal wells are similar to oil and gas conditions, many of the materials and techniques used in petroleum industry are applicable.

The following information on basic cementing material is provided courtesy of Halliburton Services (undated).

6.6.2 Cement Types and Classifications

A basic cementing material is classified as one that, without special additives for weight control or setting properties, when mixed with the proper amount of water, will have cementitious properties.

Cements are made of limestone (or other materials high in calcium carbonate content), clay or shale, and some iron and aluminum oxides if they are not present in sufficient quantity in the clay or shale. These dry materials are finely ground and mixed thoroughly in the correct proportions either in the dry condition (dry process) or mixed with water (wet process). This raw mixture is then fed into the upper end of a sloping, rotary kiln, at a uniform rate, and slowly travels to the lower end. The kiln is fired with powdered coal, fuel oil, or gas to temperatures of 2,600 to 2,800ºF.

All cements are manufactured in essentially the same way and are composed of the same ingredients, only in different proportions. The water requirement of each type of cement varies with the fineness of grind or surface area. High-early-strength cements have a high surface area (fine grind), the retarded cements have a low surface area, and the Portland cements have a surface area slightly higher than the retarded cements. The chemical retarder used in retarded cements may be added to the clinker during the secondary grinding stage to provide uniform distribution. It may also be added to the finished product.

Following is a brief summary of the characteristics of the various types of cement. These data are obtained from two sources: API Specification 10, API Specification for Materials and Testing for Well Cements, whose well depth limits are based on the conditions imposed by the casing-cement specification tests (Schedules 1, 4, 5, 6, 8 and 9) and should be considered as approximate values; and ASTM C 150, Standard Specification for Portland Cement. Copies of the specifications are available from the American Society of Testing and Materials, 1916 Race Street, Philadelphia, PA 19103. In the cement industry, symbols for chemical compounds are often abbreviated: C = CaO, S = SiO_2, A = Al_2O_3, F = Fe_2O_3.

For example:

C_3A = 3 CaO Al_2O_3.

API Class A & B Cement (Common Portland Cement)

This cement is intended for use in oil wells from surface to 6,000 ft depth when no special properties are required. The recommended water-cement ratio, according to API, is 0.46 by weight (5.2 gal/sk). It is more economical than premium cements and should be used when no special properties are desired and well conditions permit.

API Class C Cement (High Early Cement)

This cement is intended for use in oil wells from surface to 6,000 ft depth. It is ground finer than Portland and has a high C_3S content, both of which contribute to the higher strength. The API water requirement for this cement is 0.56 (6.3 gal/sk). The compressive strength of this cement is greater than Portland cement at curing times up to 30 hours; and the pumping time slightly less under the same test conditions. This cement is more expensive than Portland and, unless its special properties are needed, should not be used. Generally, Portland with calcium chloride or other accelerators will give better strength than this type of cement without accelerators.

API Classes G or H Cement (Basic Cement)

This cement is intended for use as manufactured from surface to 8,000 ft or it can be modified with accelerators or retarders to meet a wide range of temperature conditions. It is chemically similar to API Class B cement but is manufactured to more rigorous chemical and physical specifications, which result in a more uniform product. As manufactured, it contains no accelerators, retarders or viscosity control agents other than gypsum normally ground with the cement clinker. All necessary additives are blended by the service company. The API water require-ments for Class G is 0.44 (5.0 gal/sk) and for Class H is 0.38 (4.3 gal/sk).

API Class G cement is currently being used on the West Coast, where it was developed, and in the Northern Rocky Mountain area. Class H cement is used predominately along the Gulf Coast and in the Mid-Continent area.

API Class D, E, and F Cements (Retarder Cement)

Most of these cements are retarded with an organic compound, while some are retarded by chemical composition and grind. The most common retarders are of the lignin type; the most widely used being calcium lignosulfonates similar to HR-4. These cements are more expensive than Portland cement and, unless their special properties are needed, should not be use.

Pozmix Cement

This basic cementing composition consists of Portland cement, a pozzolanic material (Pozmix), and 2% bentonite based on the total weight of cement. By definition, a pozzolan is a siliceous material that reacts with lime and water to form calcium silicates having cementing properties. Advantages of this reaction are utilized with Pozmix Cement, because Portland cements release 15% free lime when they react with water, and the lime subsequently reacts with the Pozmix to yield a more durable mass of calcium silicates. Because this type of composition is less expensive than the other basic materials and performs well with most additives, it has almost universal application in well cementing according to Halliburton Services.

Neat Cement

Neat cement should not be used at temperatures >230ºF, because it loses strength and increases permeability above that temperature. The process is time and temperature dependent. In a test of API Class G (the usual high-temperature oil well cement), it was found that neat cement compressive strength decreased by 77% from 5,050 to 1,150 psi, and permeability increased from 0.012 to 8.3 millidarcies in 60 days at 320ºF in geothermal brine. Regression is somewhat dependent on geothermal fluid chemistry (Gallus, et al., 1978).

6.6.3 Silica Flour and Sand Effects

Mixtures of silica flour and silica sand in ratios of 40 to 80% by weight with API Class G cement have been found to reduce strength and permeability degradation in hot wells. API Class A cement (ASTM Type I), with addition of 30 to 50% silica flour has performed satisfactorily for conductor and surface casing in steam wells and should be satisfactory for most higher temperature direct use wells.

6.6.4 Effects of Sulfates

At temperatures up to 180ºF, sulfates attack cements. Sulfate attack is most pronounced at 80 to 120ºF, then declines as temperature increases, and is negligible above 180ºF. Sodium sulfate, common in geothermal fluids, is considered to be the most detrimental, with magnesium sulfate and magnesium chloride close seconds.

Sulfates react with the tricalcium aluminate in the set cement, forming large crystals. Because the crystals are larger than the original materials, they cause expansion, which results in cracking spalling, and ultimate disintegration. Loss of the solid cement sheath protecting the casing creates voids and weakens the casing-cement composite, and can lead to electrolytic corrosion.

Even though bottom-hole temperature may be above 180ºF, sulfate resistant cement should be used if the hole penetrated zones of sulfated fluid at temperatures <180ºF. Halliburton Services recommendations are provided in Table 6.6.

Table 6.6 Sulfate Concentrations and Applicable Cement

Concentrations (mg/L = ppm)	Cement Type
0 to 150	Ordinary basic cement
150 to 1000	Moderate sulfate resistant
1000 to 2000	High sulfate resistant
2000+	Severe attack, even with high sulfate resistant cement

6.6.5 Effects of Carbon Dioxide (CO_2)

It is a well-known fact that carbon dioxide-laden water will attack Portland cements. In the simplest terms, the carbon dioxide and water form carbonic acid, which leaches out cementitious material and ultimately reduce the cement to a soft amorphous silica gel. During the process, the cement becomes more permeable and allows ions such as Cl and H_2S, which may also be present in geothermal fluid, to penetrate the cement sheath and attack the casing. This has apparently happened in the CO_2-rich Broadlands field in New Zealand, where rapid corrosion of cement occurred within a few months (Milestone, et al., 1986).

Considerable work has been performed investigating CO_2 corrosion, both in geothermal wells and for CO_2 enhanced recovery in oil wells. Unfortunately, most of the work was performed at higher temperatures and/or CO_2 partial pressures than are usually found in direct use wells. However, Bruckdorfer (1985), using micro cylindrical cement samples 0.275 in. diameter x 0.5 in. long, found there was only a 5 to 10% decrease in strength loss of samples at 125ºF compared to samples at 175 ºF. This indicates that, at least below 230ºF, the corrosion is not especially temperature sensitive.

There is good agreement in the industry literature that nonporous, high-density cements made with low water-to-cement ratios are more resistant to attack, and the addition of diluents such as lost circulation materials and silica decrease resistance. Silica additions above 10 to 20%, even at temperatures above 230ºF, and the addition of bentonite at only 3% decrease resistance (Milestone, et al., undated).

At the present time, published guidelines regarding the CO_2 concentrations that cause various degrees of attack or estimated corrosion rates at given CO_2 concentrations are only general. Downhole conditions obviously have an important part in the corrosion rate. If the water is static around the cement, the carbonic acid would soon be essentially neutralized and the corrosion rate will diminish; however, if there is a continuing supply of CO_2 rich fluid, corrosion will continue. Cements high in calcium hydroxide are more resistant to corrosion by CO_2 because an impervious layer of calcite forms on the outside, slowing attack by CO_2 and other species (Milestone, et al., 1986).

In the Broadlands, the problem was noted not in the production zone, but in a CO_2-rich zone above that is pene-trated and cemented off. Temperatures are approximately 320ºF, CO_2 is approximately 10,000 ppm, fluid is acidic and moves through the zone. Downhole test samples with 30% silica were completely carbonated in a few months. While these conditions are not likely to be encountered in a direct use well, there are scattered springs and wells with several hundred ppm of CO_2 that are slightly acidic. Because carbonation of cement is time and concentration dependent, and a direct use well should last at least several decades, well drillers and designers should be aware of the potential problem.

6.6.6 Potential Problems in Cementing

A 94-lb sack of Portland cement can be completely hydrolyzed with 2-1/2 to 3 gals of water. Extra water is added to improve mixing and rheology, but limited to prevent solids from settling out and limit shrinkage (more water--more shrinkage). Clean, fresh water should be used. The mixture will weigh between 15.6 and 16.4 lb/gal--nearly twice the density of water and much heavier than most drilling mud. Although the apparent viscosity of 125 Saybolt Universal Seconds is much higher than water or drilling mud, neat cement has no filtration properties and the increased density will probably result in cement losses in lost circulation zones. It may also result in hydraulic fracturing of weak formations and losses to zones that main-tained circulation during drilling. This limits the vertical height of the column, unless weight reducers are added.

Many shallow cementing jobs are done with a float shoe (cement shoe) or other drillable packer at the bottom of the casing (Figures 6.15 and 6.16). The high density of neat cement increases casing collapse pressure far above normal hydrostatic pressure unless the casing is filled with

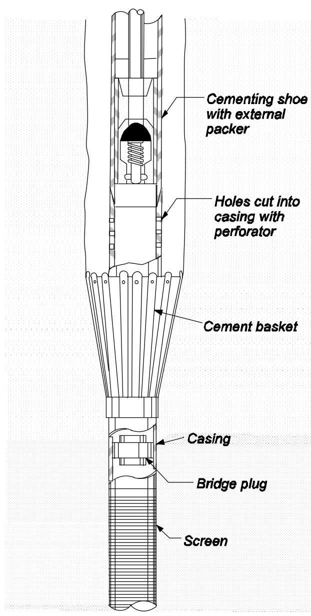

Figure 6.15 **Grouting with cement shoe. A cementing shoe can direct the grout out into the annulus above one or more cement baskets mounted at any position in the casing string. The grout passes through holes cut into the casing by a mills knife or other kind of perforator (Halliburton Services).**

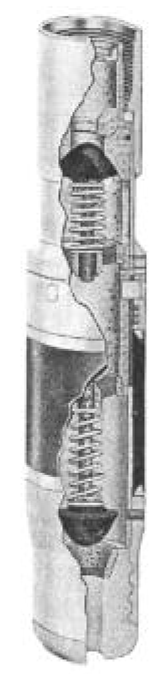

Figure 6.16 **External packer with float shoe. An external packer equipped with a float shoe can be installed in the casing string to facilitate placing cement grout (Halliburton Services).**

water or drilling mud to reduce the pressure differences. Also, the packer or plug makes the casing a loose fitting piston when lowered into the hole. If fluids are present, high lowering rates can create downhole pressure surges to the point of creating new loss zones and opening up previously sealed ones. Lowering rates should be 0.5 ft/s or less when considerable lost circulation or weak formation are encountered.

When placing cement through a float shoe or other methods involving a pumping or pressure at the bottom to force cement up the annulus, the increased density and viscosity raise annulus pressures. Eliminating pressure surges and maintaining pump pressure as low as possible, consistent with reasonable pumping time, reduces the possibility of losses and an incomplete cement job. Weight reducers and dispersants can be added to control density and viscosity if required.

Loss of cement to formation results in:

1. No cement ever reaching the surface.

2. Fall back after cement reaches the surface in the annulus and pumping is stopped.

3. The top and bottom sealing but there are voids along the casing.

These require a top outside job, placing cement through a tremie pipe in the annulus - or a squeeze job - downhole perforation of the casing, setting a packer or packers and squeezing cement through the perforations until it fills the annulus. Both are very effective solutions but costly and time consuming.

Cement top, after a fall back, and voids can be detected by temperature logs that detect the heat of hydration or by a sonic cement bond log. These logs may be required in some states and will be an additional cost.

At approximately 170ºF or higher, cement thickening time is reduced to the extent that placement times may become critical. In order to prevent premature cement thickening times, chemical retarders are added to the cement system to control the pumping time of the cement slurry. Chemical additive concentrations can be tailored to meet a broad range of well conditions.

Hole preparation before casing and cementing is an important step. The hole should be cleaned of any drill cuttings or cave-ins by making a hole cleaning trip. This assures that the casing can be set to the desired depth and removes excess filter cake that may have built up if the hole was drilled with mud. The objective is to have cement in intimate contact with the formation, yet maintain a thin filter cake to prevent cement losses.

If lost circulation was experienced and heavy cement is to be used, it may be wise to spot non-fermenting cellulose or polymer gel in the loss zones. This is faster and less expensive than repairing a poor cement job. Other alternatives are to prepare lower density cementing com-positions, i.e., spherelite, perlite, bentonite or nitrogen foam, or add lost circulation materials to the slurry.

6.6.7 Cement Placement Methods

When cementing surface casing, quite often the hole will have been drilled deeper than the depth to where casing is to be set or cemented. If the casing is to be cemented to its full depth, a bridge or drillable plug can be set in the open hole, or the hole can be backfilled with sand such as plaster or mortar sand.

If the casing is to extend beyond the cementing depth, a cement basket can be clamped to the outside of the casing or an expandable packer and float shoe installed in the casing string at the required depth. Often the extension will be slotted casing or screen and formation stabilizer or filter pack is placed, with sand above, to prevent cement from entering the stabilizer.

One method of placing cement is to use a tremie pipe (Figure 6.17). This is often referred to as a top outside job and the tremie pipe as a macaroni string. The borehole must be sufficiently larger than the casing, usually 4 to 8 inches in diameter, to permit running the tremie pipe, and centralizers should be aligned. Tremie pipes as small as 3/4 in. ID have been used when friction reducers are added to cement, permitting pumping rates of 6 to 8 ft^3/min at 750 psi.

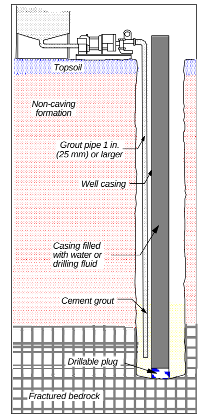

Figure 6.17 **Tremie pipe grouting. Grouting can be accomplished by means of a tremie pipe sus-pended in the annulus outside the casing. During grouting, the bottom of the tremie should always be submerged a few feet beneath the grout level. As the grout rises, the tremie should be withdrawn at approximately the same rate (Johnson Division).**

The casing is seated on the bottom, or baskets or a packer is used, depending on conditions. The casing is usually filled with water or drilling fluid. The tremie is lowered to the bottom and conditioned mud or other fluid is circulated to be sure there are no obstructions. When good returns are observed, cement is immediately pumped through the tremie. Because cement is heavier than the mud, it displaces the mud as cement is pumped. Depending on the depth and cement pumps available, the cement can be placed in one continuous operation until good cement is observed at the surface. Then the tremie can be removed.

For deeper jobs or when the cement pump pressure is not high enough to place all the cement with one tremie setting, the tremie can be raised, usually one or two pipe joints, as cement is placed. The end of the tremie should always be submerged in the slurry. If water or air is trapped in the pipe as joints are removed, the pipe should be pulled back above the slurry surface and water or air displaced by cement before submerging again in order to prevent voids in the annulus.

Most drillers will limit top outside jobs to several hundred feet if possible. Placing the tremie, obtaining high pressure pumps, and removing the tremie in sections are all troublesome. Tremies have been successfully employed to depths of 10,000 ft (Evanoff, 1987).

In order to reduce the volume of cement to be displaced in large diameter casing and holes, cement is sometimes placed by the inner string method. Hole diameters are usually 2 to 4 inches larger than the casing, depending on the state regulations and depth.

In this method, a cement shoe (float shoe) with a check valve and stabbing arrangement is installed on the first (bottom) section of casing. The casing is lowered to within a few feet of the bottom, suspended and filled with water or drilling fluid. A tremie or the drill string is stabbed into the shoe and fluid circulated to clean the hole (Figure 6.18). Cement is pumped until clean cement is observed at the surface. The tremie is removed from the shoe and water pumped to clean out the inside of the casing string. The check valve prevents cement from entering the casing. The float shoe, cement below it, and the bridge or plug in the open hole below that is then drilled out after the cement cures.

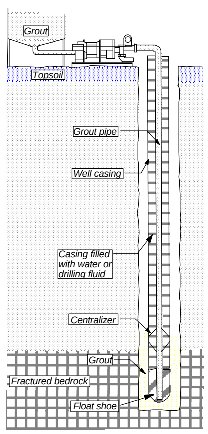

Figure 6.18 **Inner-string method of placing grout. A cementing (float) shoe is attached to the bottom of the casing before the casing is placed in the borehole. A tremie pipe is lowered until it engages the shoe (Johnson Division).**

There are several variations of the so called Halliburton or through-the-casing cementing method. All are adapted from the oil and gas industry where the methods were first developed. Figure 6.19 shows the basics of the operation.

The casing is set without a float shoe and suspended a few feet from the bottom. Water or drilling fluid is circulated to clean out the hole. A plug is inserted to separate the water or drilling fluid from the cement; a measured amount of cement is pumped in above the plug and a second plug inserted. More water, pumped in above the second plug, forces the plugs and contained cement down, causing cement to come up the annulus. The pumping is stopped when the second plug is 10 to 20 ft above the bottom of the casing. Pressure is held until the cement hardens. The plugs and cement are drilled out after

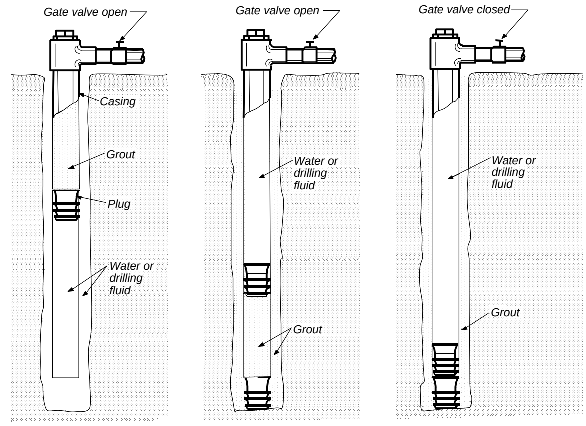

Figure 6.19 **Casing method of grouting. Grout can be placed in the casing and then forced out the bottom and up the annulus. This is called the casing method of placing grout. Plugs are used to separate the grout from the drilling fluid and the water used to drive the grout into place. The plugs and float shoe are drilled out after the grout hardens. The casing method of grouting was originally used in the oil well industry (Halliburton Services).**

the cement hardens. This method ensures a good seal at the bottom of the casing because there is no dilution of cement by water, which is behind the second plug, and minimizes dilution ahead of the first plug. The location of the second plug should be monitored by a wire line through a seal at the surface or by carefully measuring the amount of fluid pumped for displacement. Plugs are made of a drill able material. Cement, plastic, and wood have been used. Wood is usually a poor choice when drilling with a tricone bit.

When bonding becomes critical, holding pressure is not a good practice. Heat of hydration and resulting expansion of the annular cement causes pressure buildup outside the casing. Holding any pressure on the casing allows the formation of a micro annulus between the cement and pipe when pressure is relieved. Later in the life of the well, this can cause problems that include migration of fluids and loss of zonal isolation, corrosion, etc. Operators commonly use a back pressure valve in the lower casing string to prevent having to hold pressure on the casing.

One variation uses only one plug, behind the cement, to prevent dilution. Any cement diluted by the elimination of the first plug must be wasted at the surface to ensure a good surface seal. Because only one plug is used, a landing collar can be installed at the desired height (10 to 20 ft above the casing bottom) to stop the plug inside the casing. This eliminates the problem of knowing exactly where the second plug is and when to stop it as in the first method.

Another version utilizes a float shoe installed at the bottom of the casing and viscous fluid spacers rather than rigid plugs. The fluid spacers must be compatible with both mud and cement, and are usually polymers, water, and weighing materials to achieve a density of 0.5 to 1.5 lb/gal more than the drilling fluid. The viscous spacers are especially effective in obtaining good mud displacement (Shyrock and Smith, 1983).

All of the above methods can incorporate additives to produce a better cement job. Surfactants and mud thinners can be added as hole cleaners (not to be used where lost circulation exists). Reactive flushes can be used to clean mud off the outside of the casing to achieve good bonding, and friction reducers can be used to lower pumping pressures. Accelerators and retarders can control hardening at different temperatures and pressures along the length to be cemented. Lost circulation materials, density reducers, temperature stabilizers, and other additives have their uses to promote a better cementing job. Some of these can be accomplished by injecting additives while pumping batch mixes; other require continuous mixing with additions during placement. Tables 6.7, 6.8 and 6.9 are taken from Halliburton Services (undated) and summarize additives, factors to consider, and equipment. Although these are intended primarily for deep high-temperature wells, they contain useful information for low-temperature work also.

A relatively new technique of foaming cement with nitrogen gas appears to have good possibilities for use in low- and moderate-temperature wells and perhaps, even in standard water-well practice. The technique was developed for use in steam injection wells in oil fields for insulation. It has been successfully used in high-temperature geothermal wells with lost circulation where its low density and increased gel strength are advantageous. Also, it provides thermal insulation with K factors ranging from 0.15 to 0.4 Btu/h ft^2 ^{o}F.

The cement used in high-temperature work is API, Class G, with 40% silica flour to prevent strength regression at high temperatures. Other mixtures should be satisfactory at lower temperatures. The cement is mixed at 15.6 lb/gal surface density and can be foamed from 4 to 15 lb/gal downhole density.

Gel yield point increases with reduced density. The 4 lb/gal density has a yield point of 80 lb/100 ft^2 compared to 34 lb/100 ft^2 at 15.6 lb/gal. This means that once the foam has stopped flowing in a loss zone, it will stay in place. Strength is somewhat less than standard cement but appears to be high enough to support casings during thermal cycling.

The cementing design is usually a constant volume. That is, because hydrostatic pressure at the bottom of the hole is highest, more standard ft^3 (free air volume) of nitrogen are injected into the cement that will be placed near the bottom. More nitrogen is injected as cementing pro-ceeds because the last cement pumped ends up at the bottom. Foam cementing requires some method of holding back pressure on the annulus to prevent the nitrogen bubbles in the cement from expanding too much, in order to produces the desired density. A neat cap slurry is pumped first to provide a good seal at the top, then foamed cement, followed by a neat tail slurry to provide a good seal at the bottom.

At the present time, foam cementing is only applic-able to expensive or difficult holes because the technology is new and requires equipment ordinarily associated with oil field practices plus a foam generator. As the technology matures, simpler and less expensive techniques will probably evolve.

6.7 BLOWOUT PREVENTION EQUIPMENT

Blowout prevention equipment (BOPE) consists of combinations of valves, rams, packers and rotating heads enabling control of fluids and gases that could flow from the well. The equipment is attached to a casing that is securely cemented to prevent fluids or gases from escaping to the surface around the casing. All state and federal agencies having jurisdiction over drilling of geothermal wells will require BOPE when: (1) expected temperatures are above some limit, usually somewhere between 150^{o}F and the boiling point at the elevation of the wellhead, 150^{o}F and the boiling point at the altitude of the well-head, (b) (2) subsurface pressures may cause flow of fluids or gases, (3) combustible gas may be encountered, or (4) the subsurface conditions are unknown. Often, the first well in an area will have BOPE installed. If high temperatures, pressures, or combustibles are not encountered, subsequent wells will not require BOPE. Usually, the equipment is rented and installed to meet the expected conditions or agency requirements.

Figure 6.20 schematically shows a typical BOPE stack for high-temperature air and mud drilling. Figures 6.21 and 6.22 shows typical low-temperature BOPE for mud and air drilling, respectively. Gate valves may be required at the casing flange if flow to the surface is anticipated or in an unknown area. Figure 6.23 is a photo of a double ram preventer.

Table 6.7 Summary of Oil Well Cementing Additives

Type of Additive	Use	Chemical Composition	Benefits	Type of Cement
Accelerators	Reducing WOC time Setting surface pipe Setting cement plugs Combatting lost circulation	Calcium chloride Sodium chloride Gypsum Sodium silcate Dispersants Sea water	Accelterated setting High early strength	All API Classes Pozzolans Diacel systems
Retardents	Increasing thickening time for placement Reducing slurry viscosity	Lignosulfonates Organic acids CMHEC Modified lignosulfonates	Increased pumping time Better flow properties	API Classes D, E, G and H Pozzolans Diacel systems
Weight-Reducing Additives	Reducing weight Combatting lost circulation	Benitonite-attapalgite Gilsonite Diatomaceous earth Perlite Pozzolans	Ligher weight Economy Better fluid Lower density	All API Classes Pozzolans diacel systems
Heavy-Weight Additives	Combatting high pressure Increasing slurry weight	Hematite Limonite Barite Sand Dispersants	Higher density	API Classes D, E, G and H
Additives for Controlling Lost Circulation	Bridging Increasing fluid Combatting lost circulation	Gilsonite Walnut hulls Cellophane flakes Gypsum cement Benitonite-diesel oil Nylon fibers	Bridged fractures Lighter fluid columns Squeezed fractured zones Minimized lost circulation	All API Classes Pozzolans Diacel systems
Filtration-Control Additives	Squeeze cementing Setting long liners Cementing in water -sensitive formations	Polymers Dispersants CMHEC Latex	Reduced dehydration Lower volume of cement Better fluid	All API Classes Pozzolans Diacel systems
Dispersants	Reducing hydraulic horsepower Densifying cement slurries for plugging Improving flow properties	Organic acids Polymers Sodium chloride Lignosulfonates	Thinner slurries Decreased fluid loss Better mud removal Better placement	All API Classes Pozzolans Diacel systems
Special Cements or Additives				
Salt	Primary cementing	Sodium chloride	Better bonding to salt, Shales, sands	All API Classes
Silica Flour	High-temperature cementing	Silicon dioxide	Stablized strength Lower permeability	All API Classes
Mud Kit	Neutralizing mud-treating chemicals	Paraformaldehyde	Better bonding Greater strength	API Classes A, B, C, G and H
Radioactive Tracers	Tracing flow patterns Locating leaks	Sc 46		All API Classes
Pozzolan Lime	High-temperature cementing	Silica-lime reactions	Lighter weight Economy	
Silica Lime	High-temperature cementing	Silica-lime reactions	Lighter weight	
Gypsum Cement	Dealing with special conditions	Calcium sulfate Hemihydrate	Higher strength Faster setting	
Hydromite	Dealing with special conditions	Gypsum with resin	Higher strength Faster setting	
Latex Cement	Dealing with special conditions	Liquid or powdered latex	Better bonding Controlled filtration	API Classes A, B, G and H

Table 6.8 Factors Affecting Primary Casing Cementing

Personnel	Well owners responsibility, service company responsibility
Drilling Rig Operations	Running time of casing, rate of running casing, fracture gradient, position of collar on landing joint, circulating time after running casing
Drilling Fluid	Composition, weight, viscosity, water loss and filter cake, gel strength, admixes
Borehole	Diameter, depth, straightness, formation characteristics
Casing	O.D. casing versus hole size, depth of casing set versus total depth
Special Tools	Guiding and floating equipment (shoes, collar), centrilizers, scratchers, stage cementing, casing movement (reciprocating vs. rotation)
Cementing Materials	Slurry volume required (caliper survey, estimate), type of cement (API classification, admixes), mixing water (supply, impurities, temperature), slurry weight (volume--cu. ft/sack, volume to be mixed)
Mixing and Pumping of Cement Slurry	Plugs (bottom, top, location of top plug, compression of fluid), spacers-flushes (water, special fluid), time (mixing, displacement), mixing units (number, type, mixer)
Cementing Head and Connections	Swage, quick change, plug container, opening in head, valves on head, floor manifold

Table 6.9 Digest of Cementing Equipment and Mechanical Aids

Cementing Equipment and Types	Application	Placement
Floating Equipment		
1. Guide Shoes	Guides casing into well; Minimizes derrick strain.	First joint of casing.
2. Float Collars	Prevents cement flow back; Create pressure differentials to improve bond; Catches cementing plugs.	1 joint above shoe in wells less than 5,000 ft, 2-3 joints above shoes in wells greater than 6,000 ft.
Automatic Fill-Up Equipment		
1. Float Shoes	Same as Float Collars and Shoes except fill-up is controlled by hydrostatic pressure in annulus.	Same as Float Collars or Guide Shoes.
Formation Packer Tools		
1. Formation Packer Shoes	Packer expands to protect lower zones while cementing.	First joint of casing.
2. Formation Packer Collars		As hole requirements dictate.
Cementing Stage Tools 2-Stage 3-Stage Full Opening Tools	When required to cement two or more sections in separate stages.	Based on critical zones and formation fracture gradients.
Plug Containers		
1. Quick Opening	To hold cementing plugs in string until released.	Top joint of casing at surface of well.
2. Continuous Cementing Heads		
Cementing Plugs		
1. Top and Bottom Wiper Plugs	Mechanical spacer between mud and cement (bottom plug) and cement, and displacement fluid (top plug).	Between well fluids and cement.
2. Ball Plugs		
3. Latch Down Plugs		
Casing Centralizers Variable Types	Center casing in hole or provide minimum stand-off to improve distribution of cement in annulus, prevent differential sticking.	Straight hole--1 per joint through, and 200 ft above and below pay zones; 1 per 3 joints in open hole to be cemented. Crooked hole--Variable with deviation.
Scratchers or Wall Cleaners		
1. Rotating	Remove mud cake and circulatable mud from well bore.	Place through producing formations and 50 to 100 ft above. Rotate pipe 15 to 20 RPM.
2. Reciprocating	Aid in creating turbulence, improve cement bond.	Placement is same as rotating. Reciprocate pipe 10 to 15 ft of bottom

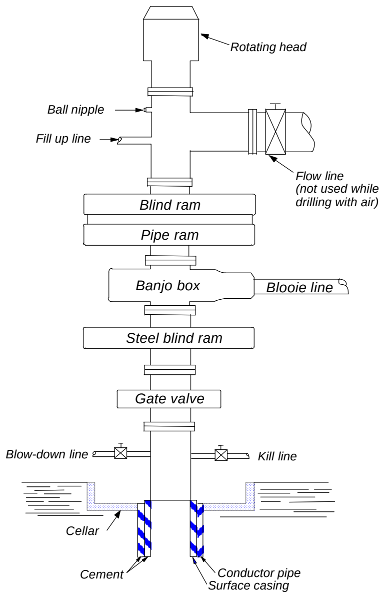

Figure 6.20 Typical high-temperature geothermal BOPE (Mud) stack (Wygle, 1997).

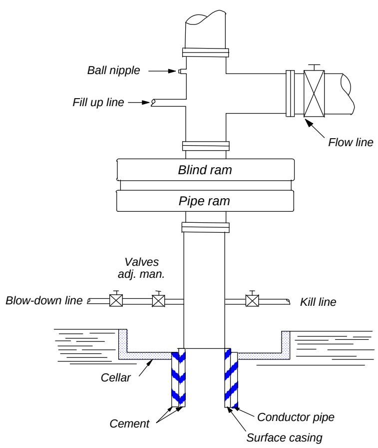

Figure 6.21 Typical low-temperature geothermal BOPE (Air) diverter stack (Wygle, 1997).

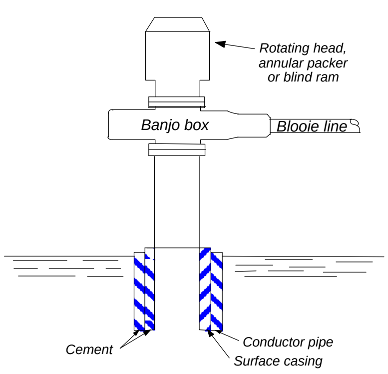

Figure 6.22 Typical low-temperature geothermal BOPE stack (Wygle, 1997).

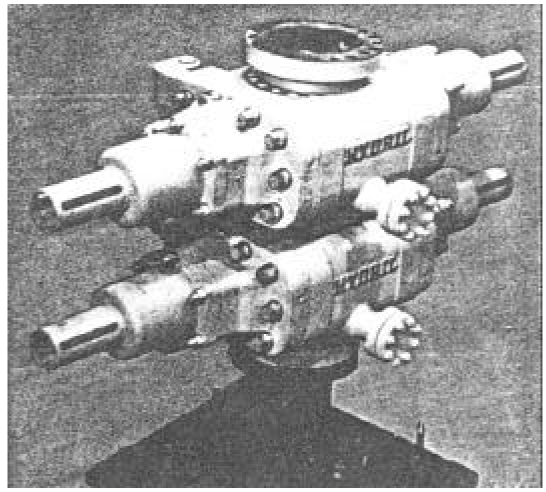

Figure 6.23 Double ram-type preventer. Two ram-type preventers built into one casing conserve vertical space, minimize the number of connections, and simplify installation. Usually, choke and kill connections are made to a drilling spool below the preventers. Such connections may be made to the side outlets, visible on the preventer body, but this is not common practice. A flange failure at one of the side outlets might necessitate changing the entire preventer (Hydril Company).

Rams and packers are usually hydraulically operated, and a gas over hydraulic accumulator or manual operation is required in order to operate the devices if all power fails. BOPE is installed on the surface casing after casing cement has hardened. The system is pressure tested before drilling out the cement and cement shoe in the bottom of the surface casing in order to ensure it will withstand the pressure specified by the controlling agency, usually with an official of the agency witnessing the test.

6.8 INJECTION WELLS

In 1974, Congress enacted the Safe Drinking Water Act, Public Law 93-523, to protect the public health and welfare, and to protect existing and future underground sources of drinking water. Under this act, the Environmental Protection Agency (EPA) has been developing, and continues to develop, regulations for protection of the underground sources from contamination by injection wells. Five classes of wells have been defined and established. Geothermal injection wells are included in Class V. Class V is a kind of catchall that includes all the wells not mentioned in the other classes, and that typically inject non-hazardous fluids into or above underground sources of drinking water.

In 1980, EPA chose to defer establishing technical requirements for Class V wells, and they were authorized by rule. This means that injection into Class V wells is authorized until further requirements under future regulations are promulgated by EPA. However, Class V wells are prohibited from contaminating any underground source of drinking water and minimal inventory, and reporting is required of Class V well owners/operators (Council and Fryberger, 1987).

The EPA underground injection control regulations may be administered by federally approved state programs (primacy states) or by EPA (direct implementation states). See Chapter 19, Institutional, Legal and Permitting Requirements, for information on specific states. Currently, EPA considers geothermal injection a low priority item and specific regulations for construction and operation of geothermal injection wells are not likely to be developed for some time (Council, 1987).

Agencies in several states, notably those with active geothermal projects, have developed specific geothermal injection regulations and are currently seeking primacy status. In all likelihood, the regulations will be based on waste disposal, geothermal electric power production, and petroleum wells, or experience, and may seem overly restrictive for many direct-use injection wells. It can only be hoped that with experience and good injection well design, adequate but reasonable protection of the drinking water will be ensured. One thing is certain, injection wells will be required in more and more cases. Water levels have declined in some aquifers supplying direct use applications and the public will require increasingly stringent environmental protection measures.

The injection well survey noted earlier appears to have included at least the major direct use injection wells. Only 21 were noted in the U.S. Considering the much larger number of direct use applications on-line, two conclusions can be made. There is a substantial number of direct use applications that are discharging substantial amounts of heat and chemicals to the surface, usually to surface waters, and there is very little experience with direct use injection wells. See Chapter 7, Figure 7.6 for a list of direct-use injection wells.

The drilling and completion of an injection well is similar to that of a production well; the same drilling and completion methods generally can be used, but more care should be taken to ensure that the wellbore is clean and adequately cemented. After the initial development, the well accepts fluid rather than producing it; therefore, there is no opportunity for mud or fines left in the formation to come out. Instead, they tend to form bridges for the almost inevitable silt and corrosion products pumped into the well that (over time) leads to plugging of the formation. Drilling fluid monitoring and control are even more important in drilling injection wells than production wells.

The federal Geothermal Resources Operational Order (GROs) define procedures for drilling and completing wells (see Chapter 19).

Most states will require that casing be set and cemented from the top of the accepting formation to the surface. The accepting formation is generally an aquifer of similar or worse water quality. A few states may permit the casing to be adequately cemented into the confining formation immediately above the accepting formation in some cases. California, Nevada, and perhaps other states, require double wall injection. At least one wall is a casing string and the other may be an injection tube extending to a permanent packer set just above the injection zone. This double wall requirement may be waived for low pressure injection of non-aggressive fluids in relatively well-known areas.

In order to reduce the possibility of formation plugging when drilling with mud, many drilling consultants recommend drilling to the accepting formation, then changing to water or air. The casing can be set and cemented, if required, to prevent caving. When conditions permit, open-hole completion is preferred because it elimin-ates the possibility of encrustation and clogging of screens or the slotted liner. If the injected water is significantly cooler than the accepting formation, thermal stresses may fracture the rocks. This has been postulated as one possible explanation of injection wells in New Zealand increasing acceptance over time (Armstead, 1978). If spalling fractures occur, the well could partially fill with debris.

Because injecting fluid creates a cone of recharge (similar in shape but the opposite of a cone of depression surrounding a pumped well), there is a tendency for the injected fluid to migrate up the outside of the casing, possibly into fresh water aquifers. Proper cementing techniques are required. If drilling mud was used, better bonds between casing and cement, and cement and formation can be achieved by:

1. Flushing with clay dispersants such as one of the poly phosphates.

2. Flushing with plenty of water at sufficient flows to create turbulence in the annulus.

3. Use of wall scratchers.

4. Pumping cement fast enough to create turbulence.

5. Flushing with paraformaldehyde to neutralize mud additives, etc.

If a fresh water aquifer was penetrated, as is usually the case, additives must be EPA/state approved. If clay formations have been drilled, polyphosphates should be used with caution, because they could make the clay near the hole unstable. Injection temperatures are likely to be in the range where sulfate resistance of cement is lowered (100 to 180ºF).

The design of the injection portion of the well is open to question and each case should be considered on an individual basis. For cold water injection wells, a general rule of thumb is that the injection area (bore area, slot area, or open area of screen, as applicable) should be twice to three times as large as for a well producing the same amount of fluid. This probably holds for injection in relatively tight formations and water source heat pump injection wells. Tight formations tend to clog with silt and corrosion products. Heat pump injection wells often operate in the optimum temperature range for iron bacteria clogging and even twice the area may not be sufficient if iron bacteria are present. Open formations such as fractured and weathered basalts may require only modest increase in area, if any.

If CO_2 and hydrogen sulfide are present, and pressures are reduced, or the system is open to atmosphere, allowing the gases to come out of solution, pH changes will occur. This upsets the chemical equilibrium of the water resulting in precipitation, scaling, and plugging of the injection zone. In general, systems should be closed and pressure maintained, including the injection well. Water should not be allowed to free fall into a well even though it accepts the fluid while maintaining a water level below the surface. Microscopic bubbles form that will block acceptance of the formation.

In some cases, injected water may be at a higher temperature than the receiving aquifer, such as when injecting near the boundaries of the reservoir. If the system is closed so pH remains constant, acceptance may increase with time because there may be a tendency to dissolve materials in the formation.

6.9 WELL SPECIFICATIONS

Well specifications are the basis for inviting bids from drilling contractors. As such, they should be written: (1) so as to make it easy to compare bids on a cost basis, (2) to ensure that the well will be constructed of suitable materials and in a manner that ensures a reasonable life, (3) so the well will produce the required flows, and (4) to serve as a guide for the final completion. The specifications must also be reasonably flexible because subsurface conditions are rarely accurately known.

Many state or other governmental entities have minimum standards of construction that must be met. These standards may cover such items as depth of surface casing, casing material and thickness, cementing materials and placement procedures, safety items such as blowout preventer requirements and even disposal of drilling cuttings, fluids, and mud. In all cases, the intention is to provide for public safety, protection of fresh water supplies and the environment and conservation of geothermal resources.

Unfortunately, there is wide variation in the standards and regulations depending on how geothermal energy is classified (water, mineral, or petroleum), because the standards are written from different perspectives by staff with different backgrounds. In some states, the classification changes with depth, temperature, or intended use. In Oregon, water well regulations apply to a depth of 2,000 ft and/or temperatures below 250ºF. For deeper or hotter wells, Division of Geology and Mineral Industry's regulations apply. In California, any well that may tap water with temperatures greater than the average ambient temperature is geothermal and is regulated by the Division of Oil, Gas and Geothermal Resources. In practice, wells 86ºF or hotter are considered geothermal (Thomas, 1987). Nevada has three divisions of geothermal wells, depending on proposed use and flow rates.

There may be overlaps and conflicts in standards and jurisdiction between different agencies. A good example is in some homestead parcels where the surface is under private control but the federal government retains the mineral rights, therefore, geothermal rights and controls. In many cases, the overlaps and conflicts have been at least tempered for electric power production by agreements between agencies. Little attention has been paid to lower temperature direct use applications, that logically should have different requirements, but often do not. In some instances, variances will have to be requested with substantiating information, because the standards were written with electric power production in mind and do not necessarily give the best construction for lower temperature wells.

Consultation with appropriate federal, state, and local officials is mandatory. Some agencies require proposed well specifications with the permit application; others only a record of what was performed. Plenty of lead time should be allowed because it may take longer to determine the appropriate agency than it does to drill the well (see Chapter 18 for details on individual states).

Most technical specifications start with a scope of work. There is considerable variation in detail depending in part on knowledge about the site and in part on the engineer's preference for including details in the scope or in the body of the specifications. At a minimum, the scope should contain the exact location, proposed flow, use, pumping equipment, anticipated temperature, depth, casing, and completion program, and a drawing that may or may not be dimensioned depending on knowledge about the site.

Any known geologic conditions may be included in the summary or as an appendix containing this and nearby well logs, etc. Providing as much information as possible results in a more accurate and usually lower bid because there are fewer unknowns in the risk factor. Any adverse conditions such as major lost circulation problems, caving, squeezing clays, etc., should be at least noted in the scope, perhaps with details in the appendix.

Attention should be given to local practices because they can vary considerably, and drillers usually find and use what works best in their area. If the practices are sound from an engineering and hydrological standpoint, inclusion or allowances as alternatives may result in lower costs.

Drilling a pilot or test hole may or may not be included. Sometimes the additional costs will be prohibitive; but, if the hole is very large or deep, it often requires drilling and reaming because of equipment limitations. When drilling in an unknown or highly variable area, a pilot hole provides: (1) lithology, (2) an opportunity to run logs, (3) refines the details of the well completion, and (4) ordering of required materials.

The drilling method is normally not specified unless there are known or suspected conditions that exclude a particular method. It is not uncommon to specify one method to some depth or formation, then specify a non-mud method in the production zone. Drilling methods for test holes may be prescribed when there are special sampling requirements.

In many cases, specification writing can be greatly simplified by making the appropriate state agency rules and regulations a part of the specifications. Casing and liner wall thickness may be increased to allow for accelerated corrosion and increased weight of deeper settings in geothermal wells. Rules and regulations usually also include abandonment specifications, which should always be included in case of an unacceptable well.

Although it would seem to be advisable to use a driller experienced in geothermal well drilling (and there-fore presumably knowledgeable about the appropriate state agency rules and regulations included in the specifications), this may not always be the case. A water well driller may bid on a geothermal job or the well may have a different classification than that in which the driller has experience. There have been too many instances where a driller has bid and been accepted for a job without being familiar with the appropriate rules. The result is an underbid job, an unhappy driller trying to make up the difference even though it was his/her own fault, and general disagreement with the owner and the regulating agency. Sometimes the driller pushes his equipment too fast, resulting in break-downs or fishing jobs. Depending on how the contract is written, these may result in extra cost to the owner and, at a minimum, cause delays.

One way to help prevent this problem is to require in the bid a statement that the bidder has read and understands the current rules and regulations, by their numbers, as stated in the specifications. This serves to motivate the bidder to understand the rules and provides the owner with additional protection should a dispute arise. This requires that the owner also be familiar with the rules in order to correctly write the specifications and to detect bids that do not meet the requirements.

Agency rules and regulations include only completion and abandonment specifications. Items such as drilling fluids, properties, working hours, cutting samples, noise, etc., should be added if applicable.

Sampling cuttings at 10 to 20 ft increments and/or changes in lithology should be required. These should be washed, bagged in small plastic sacks and labeled as to depth, date and other pertinent information such as drill rate, loss of circulation, etc. Only a few tablespoons full are required for a sample. They may or may not ever be inspected; but if disputes or problems arise, they may be very useful. If nothing else, they inspire more careful logging by the driller if a geologist is not on-site.

6.10 BID SHEETS

In order to evaluate bidders, a well-written bid sheet should be included in the technical specifications and serve as the basis for payment. Fixed costs should be lump sum, variable costs should be shown as unit prices, and their extension based on the well design.

Fixed costs could include:

1. Mobilization and demobilization of drill rig.
2. Development, if for a specific time.
3. Mobilization and demobilization of logging and survey equipment.
4. Test pump furnishing, installation and removal.
5. Wellhead equipment.
6. Site preparation and restoration.
7. Standby time (as directed by the engineer or owner).

Standby, start-up and non-chargeable time should be specified; i.e., if a normal workday is 8:00 a.m. to 5:00 p.m. and the engineer stops the rig at 3:00 p.m. and resumes again at 10:00 a.m. the next day, only 4 hours standby are allowed.

Variable costs include:

1. Drilling - each diameter a separate item L.F.
2. Furnish and install casing - each diameter separate item including cementing as required L.F.

3. Logs and hole surveys L.F.

4. Gravel pack feed pipe L.F.

5. Gravel pack L.F.

6. More or less developing time hour

7. More or less pumping time hour

8. Abandonment L.F.

Unless the owner or engineer is familiar with all possible bidders, bidders should be required to submit their qualifications, similar work performed with names and addresses of contacts for references, complete equipment submittals, licenses, bonds, etc. If the well is of significant cost or complexity and drilling muds will be used, it is common to require a proposed mud program and to have a qualified mud expert (usually an employee of a materials' manufacturer) on-site or available on short notice.

The American Water Works Association Standards for Wells (AWWA 100-84) sets standards for municipal wells, many of which will be applicable.

The Manual of Water Well Construction Practices (EPA 1975) contains a matrix diagram listing items to be considered in well specifications. Included in the list of well uses are heating, cooling and geothermal water. The heating and cooling standards appear to have been based on heat pump and very low-temperature wells and may not contain some desirable items, or be overly permissive; while the geothermal standards appear to have been based on high-temperature wells for electric power production and will be overly restrictive for many direct use wells.

Sample specifications and bid schedules are contained in Ground Water and Wells (Driscol, 1987), and Water Well Specifications, 1981. These were written with large industrial or municipal wells in mind and contain items such as screens, filter packs and disinfection that may not be required, and do not include items such as disposal of cuttings and test pump fluid that may be required by some states.

The Engineers Manual for Water Well Design (Roscoe Moss Co., 1985) contains separate guidelines specifications and bid proposals for cable tool, direct rotary and reverse circulation drilling and completion. Again, these are for cold water wells.

6.11 WELL COSTS

It is virtually impossible to provide accurate universal guidelines for estimating well drilling and completion costs because of too many variables in geology, well design, location, drilling regulations, etc. In general, drilling costs depend on depth, diameter, and difficulty.

Depending on the locality, there seems to be an increase and a difference on how costs are charged, for drilling beyond 500 to 600 feet. Up to this depth, for drilling in relatively soft formations, the cost will be charged in $/ft of drilling. In harder rock, where drilling rates drop to three or four feet per hour, the driller may charge by the hour--approximately $150/hr. For deeper drilling, the cost is often by the hour and will run $200/hr including crew and fuel. In some cases, this rate may increase 10 to 15% for each additional 200 to 250 feet. Mobilization and demobili-zation cost may be extra, and depend on the rig travel distance and site preparation.

The formation to be drilled has a large affect on drilling costs. Obviously, soft formations can be drilled easier than hard formations; but, there are also other factors, such as lost circulation, caving problems, stuck tools, etc., which are estimated by the driller and included in his bid. For low-to-moderate temperature wells, cost can be estimated on a dollar per inch of diameter per foot of depth according to the following:

Depth (ft)	Cost ($/inch/ft)	
0 - 500	1.80 soft	5.00 hard
500 - 1200	3.00 soft	6.25 hard
1200 - 2000	4.75 soft	9.00 hard
2000 - 3000	8.50 soft	11.00 hard

As discussed above, depth greater than 500 to 600 feet, and hard rock drilling may be charged by the hour. Casing cost are in addition to the above and run between $0.75 and $1.00/inch/ft for welded 0.250 inch thickness.

The actual drilling costs typically represent between 40 and 60% of the total completed cost, depending on the casing program, mud costs, cement and cementing aids (i.e., cementing shoes and centralizers), wellhead equipment, etc. Depending on local custom or bid sheet design or both, even drill bits may be excluded from the cost/ft bid price and included as separate items.

Detailed cost information is difficult to gather and, even then, usually little is provided concerning the formations drilled, problems encountered, etc. Overall costs for 20 wells drilled to <600 ft around 1990 ranged from $3.00 to $6.03/in. of pump housing casing diameter per ft of total depth. Based on this, a 12 in., 600 ft well would cost between $26,350 and $43,400. These 20 wells included wells drilled in California, Nevada, New Mexico, Oregon and Utah. Wells in the 1,600 to 2,000 ft range cost $4.25 to $8.96/in./ ft. There seems to have been very little increase in the cost of drilling direct use wells since this time. This is more of a general feeling than a demonstrable fact, because each well is different, but drilling cost/in./ft, casing and rig time have held stable or increased very little since 1990.

If directional drilling is required, say to get around tools stuck in a hole, it may be necessary to set a cement plug with a whipstock, then rent the services and equipment to directionally drill around the obstruction. If a cement service company is hired to set the plug and whipstock, and the well site is some distance from their nearest facility, the job can be expected to cost $3,000 to $5,000, depending on the distance; if the driller can set the plug, the cost might be about half.

Table 6.10 lists approximate costs to drill around the obstruction.

Table 6.10 Approximate Costs To Drill Around An Obstruction

Item	Cost ($)
Directional drilling supervisor	$580/d + mileage
Bent subs	$400
Drill motor (10 h minimum)	$2,400 + freight
Additional operating h	$240/h
Standby time	$70/h

The job could probably be done in 1 day plus 1 day of travel time. The total estimated cost would be between $4,000 and $5,000.

The rig will be used to set the plug and run the directional drill, and will be on standby waiting on services and for cement to set. It will also have been used and be on standby several days for fishing attempts. At $200/h, the estimated rig cost could range between $12,000 and $15,000; possibly more.

Considering the additional cost of the lost tools, fishing tools, and other services, it can be seen why directional drilling is seldom used in direct use wells, and stuck tools are to be avoided.

GLOSSARY

Anchor String - The string of casing to which the BOPE stack is flanged.

Annular Preventer (bag preventer) - A device that can seal around almost any object in the wellbore or upon itself. Compression of a reinforced elastomer packing element by hydraulic pressure effects the seal.

Banjo Box - A thick-walled drilling spool used when drilling with air. The spool routes returning air and drill cuttings to a blooie line.

Bell Nipple (flow nipple, mud riser) - A piece of pipe with an inside diameter equal to, or greater than, the blowout preventer bore. It is connected to the top of the blowout preventer or marine riser. A side outlet directs the mud returns to the shale shaker or pit. It usually has a second side outlet for a fill-up line connection.

Blind Rams (blank, CSO, complete shutoff, master) - Rams that are not intended to seal against any drill pipe or casing. They seal against each other to effectively close the hole.

Blind-Shear Rams - Blind rams with a built-in cutting edge that will shear pipe in the hole, allowing the blind rams to seal the hole. Used primarily in subsea systems.

Blooie Line - A large diameter pipe that routes returning air and drill cuttings to a separator and muffler. The line may be equipped with high-pressure nozzles that both spray water to settle dust, and spray sodium hydroxide and hydrogen peroxide to eliminate hydrogen sulfide odors.

Blowout - An uncontrolled flow of well fluids and formation fluids, or both, from the wellbore to the surface, or into lower pressured subsurface zones (underground blowout).

Bridge Plug - A device to close off or bridge an opening such as the bore hole or casing.

Casing Shoe - A heavy-walled steel coupling or band attached to the lower end of the casing. There are several types for specific applications. A drive shoe is heavy hardened steel, usually designed to shave off the inner edges of the bore hole during drill and drive operations. A guide shoe is slightly tapered to guide casing down the bore hole and protects the end of the casing.

Cement Basket - A device attached to the outside of casing designed to contact the bore wall to catch and hold cement at that point. Usually, a series of flexible steel staves with a flexible liner. Flexibility allows fluid in the hole to pass in the upward direction, while setting casing, circulating, or cementing, but prevents flow downward, thereby, supporting the cement column above it.

Drag Bit - Equipped with short blades and a body fitted with water courses that direct the drilling fluid stream to keep the blades clean. Assists penetration by means of a jetting action against the bottom of the hole.

Draw Works - The hoisting equipment consisting of power source, cable drums, brakes, controls, etc., used to generate the lifting capability of a drill rig.

Fill-Up Line - A line, usually connected into the bell nipple above the blowout preventers, which allows the addition of mud to the hole while pulling out of the hole, in order to compensate for the displacement of the drill string.

Fish - Any object lost in a bore hole.

Fishing - The act of attempting to remove a fish.

Flow Line - A line connecting the wellbore to the hole fluid storage or processing area.

Internal Preventer - A device, which acts as a check valve, that can be installed in the drill string. It allows fluid to be circulated down the drill string but prevents back flow.

Kelly Cock, Lower - A full opening valve installed immediately below the kelly, with outside diameter equal to the tool joint outside diameter. Can be closed to remove the kelly under pressure, and can be stripped into the hole for snubbing operations.

Kelly Cock, Upper - A valve immediately above the kelly that can be shut to confine pressures inside the drill string.

Kick - The intrusion of formation liquids or gas that results in an increase in pit volume. Without corrective measures, this can result in a blowout.

Kill Line - A high pressure line between the pumps and zone point below a blowout preventer that allows fluids to be pumped into the well or annulus when the preventer is closed.

Open Hole - Bore hole without casing or other support or protection.

Packer - A device to close off an annular opening such as between casing and bore hole or concentric casings.

Packoff or Stripper - A device with an elastomer packing element that depends on pressure below the packing to effect a tight seal in the annulus. Used primarily to run or pull pipe under low or moderate pressures. Cannot be depended upon under high differential pressures.

Pipe - Drill string.

Pipe Rams - Rams with faces contoured to seal around pipe to close the annular space. Unless special rams accommodating various pipe sizes are used, separate rams are necessary for each pipe size in use.

Rotating Head - A rotating, pressure-sealing device used when drilling with air, gas, foam, or any other drilling fluid with hydrostatic pressure less than the formation pressure.

Spot - To selectively place material at some location in the bore. Usually used as in pumping lost circulation materials, cement, etc., through a pipe with the end or openings at the desired level. Hydrostatic pressure forces the material into the formation.

Spudding - To move up and down. Derived from the spudding arm of a cable-tool drill rig that imparts the up and down motion to the cable-tool drill bit.

Sub - A short piece of pipe, usually drill pipe, with special ends for attaching various tools or bits.

Test Joint (testing sub) - A pipe joint or sub designed for use in conjunction with a test plug to simulate pipe in the hole when pressure testing the pipe rams or annular preventer.

Test Plug (boll weevil plug) - A tool designed to seal the well bore immediately beneath the BOP stack, which allows high pressure testing of the stack and auxiliary equipment without the risk of pressure damage to the casing or to exposed formations.

Tool Pusher - Foreman in charge of the drilling rig.

Tripping - Movement of drilling tools and equipment into or out of the hole or both; round trip, trip in, trip out.

Under-Ream - Enlarging or reaming the hole to a greater diameter below some obstruction, formation or casing. Special tools that can be rotated on eccentrics or otherwise enlarge are used.

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