Deepwater Drilling

Selecting and applying the correct drilling fluid is one of the keys...

Deepwater exploration and production have significant potential in many offshore locations around the world. Deepwater drilling, in general, has a greater degree of difficulty than conventional drilling and presents many operational challenges. Recent advances in technology have prompted the current expansion into deepwater drilling and production, and the trend around the world continues to be toward deeper water. Selecting and applying the correct drilling fluid is one of the keys to successful deepwater drilling.

When used to describe drilling and production, the term "deepwater" can mean different things. For the purposes of this chapter, however, it will refer to wells drilled in water depths greater than 1,500 ft. Such wells are characterized by the use of either dynamically positioned or chain-anchored floating rigs of either the semisubmersible or drillship design, using subsea wellheads and long riser systems (see Figure 1). The wells are drilled in younger formations that have narrower fracture-gradient-to-pore-pressure profiles, requiring more casing strings and exhibiting high operating costs. Because of the high daily operating costs, selection of the right drilling fluid system is critical. If improved performance can be achieved, higher drilling fluid costs are justified, since they will result in overall cost savings.

Many of the issues discussed here will apply to any well that requires a rig that uses a subsea wellhead and riser system. The difficulty in drilling, completing and producing these types of wells demands careful design of the fluid systems. A list of fluid design issues and considerations includes:

- Gas hydrates.
- Geology/reactive formations.
- Pore pressure and low fracture gradients.
- Riser volumes/large-casing well designs/logistics.
- Lost circulation.
- Low flow line temperatures.
- Hole cleaning.
- Well control.
- High daily rig costs.

Designing and applying the right fluid system requires balancing each of these issues with regard to its impact on the deepwater project. Not every deepwater well will present all of the issues listed above, but many of them will be present. Each of these issues will be discussed in this chapter.

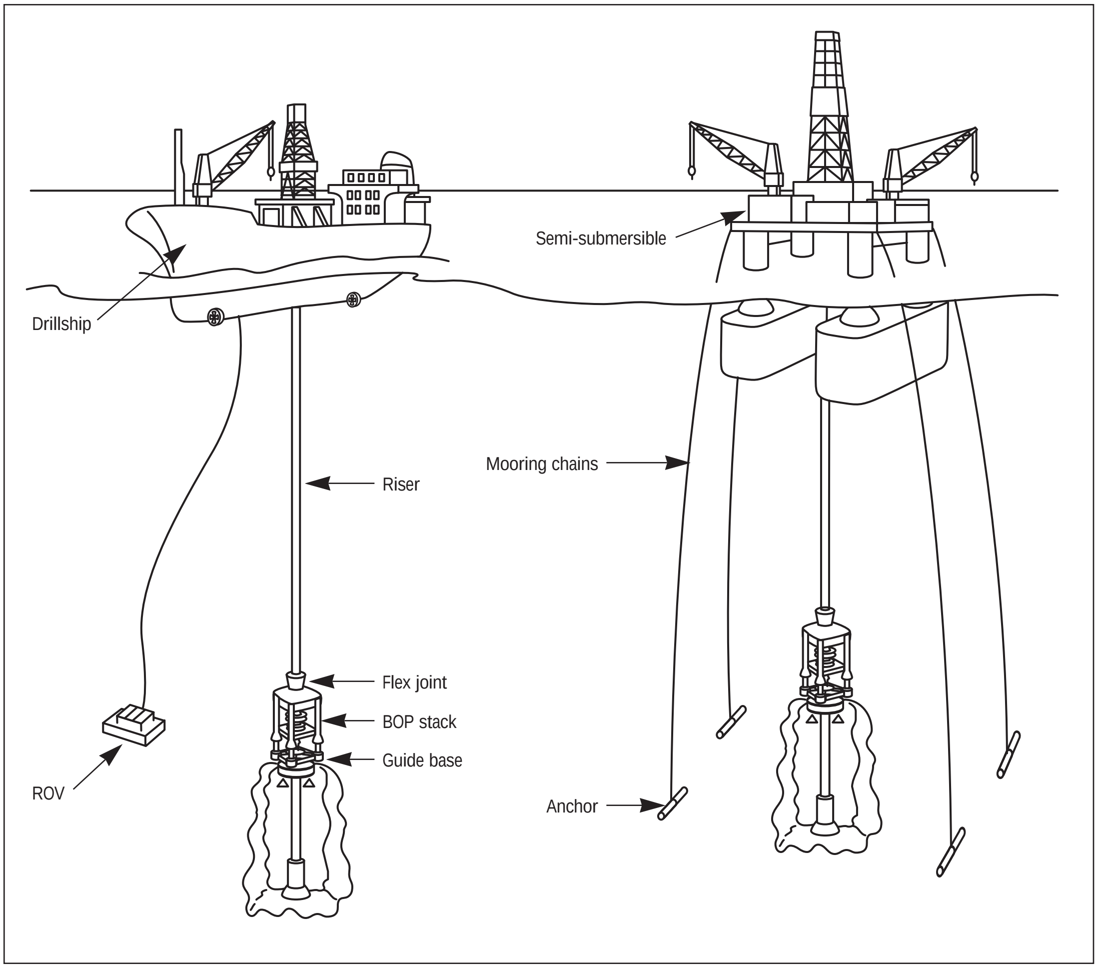

Figure 1: Illustration of deepwater rigs.

General

...semisubmersibles and drillships are the basic rig types used to drill in deep water.

The riser is a piping system that connects mud flow from the well to the rig...

Before discussing the challenges of deepwater drilling, some understanding of the rigs and equipment used to drill these wells is needed.

As mentioned earlier, semisubmersibles and drillships are the basic rig types used to drill in deep water. Operating water depths for drillships can range from several hundred to more than 10,000 ft. Usually, drillships are used for drilling in the deepest waters and in more remote locations. After the deepwater discovery wells are drilled, specially designed fixed or floating platforms and rigs are normally used to develop and produce them. In general, semisubmersible rigs are limited to water depths of 6,500 ft or less.

Semisubmersible rigs and drillships share a common characteristic: they are floating drilling platforms that move up and down with both tidal and wave action. These rigs have motion compensators, which smooth out the wave action and allow a constant bit weight and riser tension to be applied. The Blowout Preventers (BOPs) are positioned on the ocean floor and are connected to the rig by a riser system. The riser is a piping system that connects mud flow from the well to the rig at the surface. In addition, the riser system includes redundant choke-and-kill lines and usually a dedicated mud circulating line to allow a higher annular velocity in the larger-diameter riser for better hole cleaning.

In shallow to medium water depths, these rigs are moored to anchors on the ocean floor. At extreme water depths, a dynamic positioning system of thruster propellers is used to keep the rig over the location without the need for mooring lines and anchors. Dynamic positioning, sometimes called dynamic station-keeping, is more common on drillships and the ultra-deepwater semisubmersibles.

Typically, an acoustical signal with sonar and a Remotely Operated Vehicle (ROV) with video are used to position the rig and connect the riser to the subsea BOP stack. The riser must be supported by the rig to prevent the hydrostatic pressure of the water and the weight of the riser from collapsing (buckling) the riser, much in the same way that the drillstring is run in tension to prevent buckling. Therefore, tension must be applied to the riser while it is connected. The riser often is coated with a foam jacket to increase its buoyancy and reduce the load on the rig. The riser has a slip joint on top to allow for wave motion, plus ball-joint swivel connections top and bottom to allow for angular movement.

The subsea BOP stack is unitized with double redundancy and can be left in position on the ocean floor even if the riser is disconnected and retrieved. Most risers have at least four separate choke-and-kill lines that can be activated, if necessary. Floating drilling rigs have blowout diverter systems in addition to the choke-and-kill lines and subsurface BOP stack systems. Diverter systems are used to handle shallow-interval well-control situations and uncontrollable situations. They “divert” the flow of fluids away from the main part of the rig.

In cases of shallow-interval well control, the fracture gradient is too low for the shut-in kick pressure, and will cause an underground blowout. The diverter system allows gas and fluids to flow up the wellbore and through surface piping to a safe point for discharge. Diverter systems are subject to extreme erosion from sand and can quickly wash out.

Mud Systems

Many different mud systems can and have been used in deepwater applications. They range from systems as simple as seawater-base lignosulfonate muds to environmentally approved high-performance synthetic muds. By far, Partially Hydrolized Polyacrylamide (PHPA)/20% salt systems, such as the POLY-PLUS® system, have been the most widely used water-base systems. Low-viscosity synthetic fluids, such as the NOVAPLUS® system, have gained increased use in deepwater drilling. These synthetics have become popular due to the increased drilling performance and improved wellbore stability that can be achieved as compared to water-base fluids. Natural gas, CO_2 and H_2S are highly soluble in diesel, mineral oil and synthetic fluids. Gas solubility and its affect on kick detection and well control should be considered for all deepwater wells. Synthetic systems are expensive and are not recommended for areas where there is a high probability of lost circulation. Again, the proper drilling fluid selection and correct design will result from considering the most important deepwater issues for a given project, as well as customer issues and preferences. As technology grows, new mud systems will surely be developed to surpass today's systems in addressing deepwater issues. Specific issues concerning mud systems will be attended to as they relate to the deepwater drilling issues discussed below.

Gas Hydrates

Gas hydrates are an "ice-like" mixture of gas and water.

Gas hydrates are a key concern for operators drilling in deep water. Gas hydrates are an "ice-like" mixture of gas and water. At atmospheric pressure, freshwater freezes at 32°F (0°C). At high pressures, gas hydrates will form at moderate temperatures — even as high as room temperature. Gas hydrates occur naturally in arctic permafrost and deepwater seabed deposits, usually at depths greater than 800 ft. They occur naturally in the Gulf of Mexico at depths as shallow as 1,750 ft and at a temperature of 45°F (7.2°C). One cubic foot of gas hydrates can contain 170 ft^3 of natural gas. Naturally occurring gas hydrates can pose a well-control problem when drilled, but gas hydrate formation in the drilling fluid is a more significant well-control problem in deepwater situations.

Gas hydrates can form in low-salinity drilling muds under pressure/temperature conditions as mild as 480 psi and 45°F (7.2°C), conditions which are common when controlling kicks in deep water. During well-control situations, hydrates can plug risers, BOP lines and choke-and-kill lines, interfering with effective well control. Although reported cases of gas hydrates are few, the risk of loosing the ability to operate BOP equipment adequately is always present. For this reason, all deepwater mud systems must be formulated to suppress the formation of gas hydrates.

Increasing the salinity of water-base muds is the common method used to suppress hydrates. The standard deepwater water-base mud system uses 20% by weight salt to inhibit gas hydrates. Increasing the salinity of a water-base mud system will reduce the temperature at which gas hydrates can form at a given pressure. The amount of salt required depends on both hydrostatic and shut-in pressures and the seafloor temperature. Twenty percent salt muds are not sufficient for ultra-deep or arctic deepwater drilling. At higher pressures and colder temperatures, a combination of salt and either glycerol or water-soluble glycol is recommended for greater inhibition. M-I has identified many factors which affect the formation of gas hydrates. The company's technical services group can assist in determining an appropriate formulation to suppress hydrates for a particular well.

Diesel oil, mineral oil and synthetic systems all provide excellent hydrate suppression.

Diesel oil, mineral oil and synthetic systems all provide excellent hydrate suppression. This inhibition is a result of the limited amount of water contained in them and the fact that the water phase generally has a high concentration (>25% wt) of calcium chloride. Natural gas, CO_2 and H_2S are all highly soluble in diesel, mineral oil and synthetic fluids. This solubility actually increases the contact area with the emulsified brine phase and would accelerate the formation of gas hydrates if it were not for the high salinity. Gas solubility and its affect on kick detection and well control should be considered for all deepwater wells. These systems are attractive in deepwater drilling because they also provide excellent shale inhibition and lubricity. They are expensive systems and are not recommended for areas where there is a high probability of lost circulation.

Geology/Reactive Formations

The geology of deepwater drilling is different from that on land and in shallow water. The formations, for example, are relatively young and very reactive. The clays and silts have not been altered by extreme heat or pressure and are not significantly dewatered. Sands are often unconsolidated and have not been compacted. Shallow clay formations, referred to as gumbo, are very soft and sticky. Cuttings from these formations can cause hole pack-off, plugged flow lines, balling of bit and bottom-hole assembly, and reduced Rate of Penetrations (ROPs). The mechanism that causes these problems is both mechanical (gouging from stabilizers) and chemical (hydration). Also, the young clays contain high volumes of water and can be extremely sticky and problematic regardless of the degree of inhibition. Swelling and dispersion of the reactive shale must be addressed when drilling in deep water. Synthetic, diesel, mineral, PHPA, enhanced chloride and lignosulfonate systems all have been used in deepwater applications. Synthetic and oil-base muds provide excellent inhibition, virtually eliminate problems with gumbo (due to the oil-wetting of sticky surfaces), and provide good lubricity and gas hydrate suppression. Water-base systems will require additives to increase performance and to minimize trouble with soft, sticky gumbo and for hydrate inhibition. Even so, water-base mud systems cost less and may be the system of choice when low fracture gradients and lost circulation are concerns.

Pore Pressure and Low Fracture Gradients

Surge, swab and ECD pressures are a significant concern...

In deepwater drilling, challenges exist that are related to formation pore pressures and fracture gradients being very close at shallow depths. For deepwater applications, the fracture gradient and equivalent pore pressure decrease as water depth increases. At extreme water depths (±10,000 ft), this low fracture gradient (due to the lack of overburden) and low equivalent pore pressure make drilling impractical, even with unweighted mud, due to annular pressure losses increasing the Equivalent Circulating Density (ECD). Many schemes have been proposed to lighten the density of the mud column in the riser for these extreme water-depth situations. In routine deepwater depths (1,500 to 5,000 ft), the low fracture gradients complicate well-control situations, since the casing seat will not hold a high shut-in casing pressure. The typical deepwater well uses frequent shallow casing strings to seal off low-fracture-gradient formations. The low fracture gradients also present lost-circulation problems from both surge and swab pressures. This is especially true with synthetic, mineral oil and diesel systems, which are compressible and tend to reduce the allowable fracture gradients. Surge, swab and ECD pressures are a significant concern for all deepwater drilling operations, particularly while running and cementing casing. Understanding the effects of temperature and pressure on hydraulics and drilling fluid rheology is very important in deepwater applications. Low water temperatures and the resulting low riser temperatures can result in elevated fluid rheology and high surge and swab pressures.

Riser Volumes/Large Casing/Logistics

...wells drilled in deep water require long risers and large-diameter casing strings.

As stated earlier, wells drilled in deep water require long risers and large-diameter casing strings. The riser, large-diameter casing and large hole sizes call for large mud system volumes. A 20-in. ID riser in 2,500 ft of water has a volume of 972 bbl. It is not uncommon for a deepwater drilling operation to have a circulating system of 4,000 bbl or more. These large systems require proportionately larger quantities of mud additives for maintenance and treating.

The quantities of additives required and the limitations imposed by space and deck loads make inventory management critical. The distance of these wells from dockside facilities and the logistics of operating offshore mean it may take a significant amount of time to deliver mud materials to the well. Other conditions, such as work boat availability and sea conditions, can extend the delivery time even more. Finally, minimum inventory requirements cannot be estimated solely from previous days' usage. Changing conditions and treatment requirements must be anticipated.

Alternative product packaging should be considered. In many cases, bulk or liquid premixed delivery may be advantageous. Salt, for example, is required for the water-base systems typically used in deep water. Bulk delivery or 1-ton big-bag sacks provide more flexibility for product additions, storage and transportation. Salt also is available as brine, rather than in sacks or bulk bags. Many floating rigs have liquid storage capacity that can be used

A bulk-handling system for other products should be considered as an option...

for brine, which will leave deck space for other products.

A bulk-handling system for other products should be considered as an option for streamlining logistics, reducing product waste and cutting down on container disposal. Although these systems may require rig modifications, their potential for savings is significant in high-cost, deepwater operations. The use of computerized monitoring and product additions can make these systems very effective in providing a uniformly treated mud system.

Proper estimates of materials usage and planning for product supply are necessary for a successful project. As with all the issues discussed in this chapter, they are a part of the total deepwater drilling system.

Lost Circulation

Lost circulation is always a potential problem and a matter for concern when drilling in deep water. This is due to the narrow range between pore pressure and fracture gradient and the effect of annular pressure losses. With total drilling costs which can exceed $10,000/hr (1997), any delays in drilling, such as time spent treating lost circulation, add significantly to well costs. In deepwater drilling, where a long riser is employed to connect to ocean-bottom BOPs, lost circulation presents unique problems that do not occur when drilling with surface-mounted BOPs. If total loss of circulation occurs and the level of mud in the riser drops, the hydrostatic pressure of the sea water can collapse and damage the riser.

Lost circulation due to weak or porous formations and low fracture gradients are typical of deepwater drilling projects. Tripping speeds, drilling rates, equivalent circulating densities, fluid viscosity and mud density must be properly managed to prevent lost circulation. Lost circulation is a special concern when operators “push” casing setting depths. This practice is common when unplanned drilling events occur and require that casing be set at shallower depths and lower fracture gradients than planned. To reach the planned depth and fracture gradient for the next casing string, operators sometimes are forced to drill with a lower margin between the mud weight and fracture gradient. This is done so the total well depth can be reached with the planned casing size. This practice presents a high risk of losing circulation. The mud weight required to drill to the next planned casing depth may exceed the fracture gradient at the shoe of the previous casing and cause lost circulation.

Lost circulation is a special concern when operators “push” casing setting depths.

Optimization of the drilling operation and drilling fluid properties can make the difference in preventing lost circulation and reaching the planned TD. Both swab and surge pressures should be calculated before tripping to determine the maximum safe tripping speeds. Hydraulics modeling programs should be used to evaluate the effects on the equivalent circulating density of such factors as pump rate, drill rate, well geometry, hole cleaning, rheology and mud density. Adjustments in these parameters may be required to prevent lost circulation. When drilling with oil-base or synthetic mud systems, M-I’s VIRTUAL HYDRAULICS® software should be used to analyze the effects of downhole temperatures and pressures on the rheology, ECD and density.

The type and concentration of lost-circulation material to be used is determined by the type of loss zone, compatibility with the mud system, *Most lost-circulation materials are compatible with water-base muds...*

and the drilling equipment in use. Most lost-circulation materials are compatible with water-base muds, but some are not compatible with oil-base and synthetic fluids. Fibrous cellulose materials, such as paper, shredded bark or ground agricultural materials, absorb the liquid phase of the mud and increase viscosity. Calcium carbonate, mica, granular graphite and nut hulls are usually acceptable in oil-base and synthetic muds. Lost-circulation material must not plug downhole equipment such as MWD, LWD, mud motors and small bit nozzles. Before they are added to the mud system, the proposed lost-circulation materials and their concentrations should be discussed with the equipment operator to determine their acceptability. Plugged equipment requires extra trips and costs in addition to the lost-circulation problem. In practice, the limiting factors of lost-circulation material additives should be discussed in the planning phase of the well and confirmed at the well site before any problems arise.

Low Flow Line Temperatures

...viscometer data can be used... to build a wellbore rheological profile...

As explained earlier, water temperature decreases with depth. Long risers surrounded by cold sea water will result in much colder mud temperatures and higher vicosities in the riser and at the flow line. The increased viscosity from temperature, particularly in oil-base and synthetic muds, may limit the shale shaker screens — which can be used without losing mud — to relatively large mesh sizes. Often, there is a temptation to treat the mud system to reduce the viscosity at the flow line, but this should be avoided, since it will reduce hole cleaning in the riser. Circulating a third “boost” mud pump on the riser will limit the amount of cooling that occurs in it. A Fann Model 70 HTHP viscometer can be used to provide a more accurate profile of the effects of cold and hot temperatures and pressures on a particular mud. The viscometer data can be used with M-I’s VIRTUAL HYDRAULICS program to build a wellbore rheological profile for a mud system in a specific well.

Hole Cleaning

Hole cleaning is a critical factor when drilling in deep water.

Hole cleaning is a critical factor when drilling in deep water. Failure to clean the hole or riser can result in lost circulation, cuttings beds, hole packoff and stuck pipe. Because of these issues, it is critical to plan for and monitor hole cleaning. The mud rheology, flow rate and penetration rate must be considered and balanced to achieve proper hole cleaning. Hydraulics analysis should include calculations of the equivalent circulating density and the effect of cuttings concentrations on ECD. High ECDs due to poor hole cleaning or excessive ROP, combined with low fracture gradients in deepwater environments, create a formula for lost circulation. The mud's low-shear-rate rheology is critical to hole cleaning. It should be monitored and adjusted to deliver the required hole cleaning for the planned wellbore profile. Hole cleaning can be a problem even when the mud rheology is optimized for carrying capacity (i.e.: low slip velocity), unless an adequate circulation rate and good drilling practices are employed. High ROP and low flow rates can generate drill cuttings faster than they can be removed from the hole. After mud rheology is optimized, the ROP may have to be controlled and/or the flow rate increased to keep the hole clean. It may be difficult to clean the riser even when all the parameters for cleaning the hole are correct. Often, a third "boost" mud pump is used to pump down a dedicated riser boost line to provide sufficient flow and velocity to clean the riser. A buildup of cuttings in the riser or in the subsea BOP stack can cause costly rig delays when BOP tests fail, or for circulating or drilling cuttings out of the riser or pulling the riser and subsea BOP stack for cleanup and repair.

Well Control

Diverter systems are used to control kicks from shallow gas zones.

The low fracture gradient common in wells drilled in deep water does not allow high shut-in casing pressures, especially in the shallow intervals. High shut-in casing pressure in shallow intervals could cause an underground blowout. Diverter systems are used to control kicks from shallow gas zones.

The riser complicates well-control situations. It is a relatively low-pressure pipe and is not designed to contain high pressures. In well-control situations, the riser is bypassed with the subsea BOP equipment and the well is circulated down the drill pipe, up the annulus, through the BOPs and up the choke line alongside the riser to the choke, which is on the deck of the floating rig.

Long choke-and-kill lines require modifications in the typical BOP kill procedure. The small-diameter choke lines have high pressure losses which apply a back pressure on the mud column and formation. The initial casing pressure (choke pressure) must be reduced by a pressure equal to the Choke-line Pressure Loss (CPL). If this is not done, the resulting bottom-hole pressure can be much higher than necessary to control the kick and may cause an underground blowout. Two or more choke lines can be used simultaneously to reduce the CPL, which must be subtracted from the initial Shut-In Casing Pressure (SICP).

If a kick occurs, the pressures should be determined and the Kill Sheet filled out. Then the surface mud system must be weighted up to the kill weight with the well shut in. Finally the pump is started and the choke is used to maintain the casing pressure at the initial SICP minus the CPL until the pump reaches the slow pump rate. Once the slow pump rate is reached, the choke and standpipe pressure gauges are used to maintain the Kill Sheet pressure schedule. When any gas or lighter fluids reach the choke lines and displaces heavier mud, the hydrostatic pressure acting on the well is decreased and the choke must be closed to maintain a constant drillpipe pressure. Once the well is killed, the riser must be displaced with kill weight mud and any gas trapped in the BOP stack must be displaced before the well can be opened and circulated.

High Daily Rig Cost

Any drilling fluid system or process that can help reduce the time required to reach the operator's objectives should be considered...

As stated earlier, the practices of drilling and completing wells in deep water are high-cost operations. Optimization can be achieved through proper, coordinated planning and implementation of all of the related efforts on a deepwater project to reduce cost and maximize productivity. However, a low-cost approach to fluids is not always the correct approach for deepwater projects. Any drilling fluid system or process that can help reduce the time required to reach the operator's objectives should be considered, regardless of cost. The cost of a high-performance mud system can be offset easily by the savings in rig cost realized by reducing the number of days required to complete the project.

Summary

Deepwater drilling is a complex and costly undertaking. The issues and problems are unique and require careful planning and consideration. Due to the high cost structure, contingency planning is suggested. High-performance drilling fluids are required to optimize hole cleaning, borehole stability and the inhibition of gas hydrates. When combined with good drilling practices, they have the potential to deliver the greatest likelihood of success at minimum well costs.

Drilling Salt

Introduction

The chemistry of…salts can vary significantly, even within a single bed…

Although drilling salt may appear to be simple, salt behavior can be complex.

Salt formations are encountered in many oil-producing regions of the world. These salt zones can be in a variety of forms — salt domes, massive beds, and sheets or lenses. The chemistry of these salts can vary significantly, even within a single bed, from pure sodium chloride to very complex blends of mixed chloride salts. The main salt types are:

- Halite (NaCl)
- Sylvite (KCl)
- Bischofite ($MgCl_2 \cdot 6H_2O$)
- Carnalite ($KMgCl_3 \cdot 6H_2O$)
- Polyhalite ($K_2MgCa_2(SO_4)_4 \cdot 2H_2O$)
- Tachydrite ($CaCl_2 \cdot MgCl_2 \cdot 12H_2O$)

There also are physical or mechanical differences in salt structures. Salt is impermeable and deformable. Salt domes, and to a lesser extent massive beds, are plastic and can readily deform, depending on the temperature and overburden pressure. Some salts are mobile while others are fractured. Salt formations often have other evaporite minerals such as anhydrite ($CaSO_4$), gypsum ($CaSO_4 \cdot 2H_2O$), kieserite ($MgSO_4 \cdot H_2O$), limestone ($CaCO_3$) or dolomite ($CaMg(CO_3)_2$) associated with their structure. These can be deposited on top of, around or interbedded in the salt structure. These zones may be reef-like, vugular or fractured. They may have salt in the pore structure or contain other fluids.

Although drilling salt may appear to be simple, salt behavior can be complex. Drilling fluids saturated with drill cuttings from these mixed salt formations have a particularly complex chemistry which can be difficult to understand and control. There are several problems that can occur while drilling salt sections.

- Dissolution of salt resulting in hole enlargement.
  - Due to subsaturation.
  - Due to chemical variation.
  - Due to temperature fluctuations.
- Deformation of salt, reducing the hole diameter and leading to stuck pipe.
- Well control — flow of hydrocarbons, CO_2, H_2S or brine liquids, and lost circulation.
- Recrystallization of salt and other precipitates, stripping emulsifiers and wetting agents from oil- and synthetic-base muds, resulting in water-wet solids.

Drilling Fluid Options

Water-base systems

One of two approaches is used with water-base fluids: (1) the use of a saturated salt system or (2) the use of a slightly undersaturated system to encourage hole enlargement which keeps deformation of the salt from causing stuck pipe. The undersaturated option is sometimes difficult to manage, depending on the actual conditions, and can easily lead to excessive hole enlargement which may cause further complications in obtaining a collapse-resistant, cemented casing.

Saturated-saltwater-base systems. Water-base drilling fluids should be designed to be compatible with the salt to be drilled. This can be difficult for mixed salt formations, like carnalite, where non-standard oilfield salts, like magnesium chloride, would be required and may not be readily available. It is important to have the system completely saturated when the salt is first penetrated to prevent excessive hole enlargement in the top of the salt. While the salt is being drilled, the system will stay mostly saturated.

These saturated salt systems are different from other water-base muds in that they rely mainly on polymers, not clays, to obtain good properties. When a prehydrated freshwater bentonite slurry is added to a saturated salt fluid, the clays will flocculate, increasing rheology and fluid loss. After this initial flocculation, bentonite-generated viscosity will diminish with time. Prehydrated bentonite is often beneficial for sweeps and for obtaining good filter-cake quality, even if its benefit is somewhat diminished with time. Dry bentonite will not yield once the chlorides are greater than 10,000 mg/l. SALT GEL® (attapulgite) or DUROGEL® (sepiolite) can be used to provide viscosity in saltwaters. Polymers like Hydroxyethylcellulose (HEC), DUO-VIS®, XCD® or FLO-VIS® will yield to provide rheological properties. HEC will not provide low-shear-rate viscosity, critical for suspension.

Prehydrated bentonite is often beneficial for sweeps and for obtaining good filter-cake quality…

Fluid-loss control can be obtained with HEC, POLY-SAL™, MY-LO-JEL™ or FLO-TROL™ starch or ultra-low, super-low viscosity Polyanionic Cellulose (PAC) additives like PAC PLUS™ UL, POLYPAC® UL, etc. Special-application, high-temperature-stable and calcium/magnesium-tolerant polymers can be used for fluid-loss/rheology control under high-temperature (>275°F or 135°C) conditions. It should be noted that the performance of many polymers is reduced in the presence of high-hardness brines, particularly anionic polymers such as PACs and Partially Hydrolyzed Poly Acrylamides (PHPA). The combined presence of high pH (e.g., after drilling cement) and high hardness can also reduce the performance of xanthan viscosifying polymers.

Depending on the type of salt drilled, some precipitates can be formed. The precipitates could be salt or hydroxide compounds. The discussion of mutual solubility of salts is covered in the hole-enlargement section. Magnesium chloride can precipitate magnesium hydroxide in a high lime or high pH mud.

Undersaturated water-base systems. In some areas, the use of undersaturated salt systems has been perfected so that the rate of salt dissolution is matched to the rate of salt creep. One difficulty with this approach is that for long salt sections, the rate of creep can vary widely from top to bottom, and the mud in the annulus may become saturated at the bit (from salt cuttings) so that it can not dissolve any more salt as it circulates up the annulus. This method should only be used in areas where the salt section is short and where it is a common practice on offset wells.

Several tests can be used to anticipate a water-wetting problem...

Invert-emulsion systems

Oil- or synthetic-base muds can also be used to drill salt sections. The oil-wetting ability and lower water content reduce salt dissolution and control hole enlargement, but salts will still dissolve into the water phase, keeping it saturated. There are several reactions that can occur due to the excess lime concentration and high chlorides. The reactions can be unpredictable and vary depending on salt composition and temperature. These systems can be formulated with a variety of salts in the water phase as an alternative to calcium chloride. Sodium-chloride and magnesium-chloride internal-phase systems have been used successfully. Although oil-base systems are preferred for drilling salt so that a gauge hole can be preserved, salts can actually be more detrimental to invert emulsion muds than to water-base muds. The most damaging aspects are recrystallization of salt and magnesium hydroxide precipitation. Both reactions produce extremely fine particles with a tremendous surface area. This can lead to a rapid depletion of emulsifiers and oil-wetting agents. Consumption of the emulsifiers and wetting agents can result in water-wetting of solids.

The stability of invert-emulsion systems should be monitored as discussed at the end of this chapter. Water-wetting can be monitored as discussed in the chapter on non-aqueous emulsions. Water-wetting is most obvious by a grainy, not glossy, appearance and by the removal of water-wet solids (barite) at the shale shaker. Several tests can be used to anticipate a water-wetting problem, including the weight-up test and glass jar test.

Treatments to avoid mud instability in oil-base muds include adding water to dissolve the precipitates, and significantly increased daily treatments of emulsifier and wetting agent. Complete saturation should be avoided; for calcium chloride this is roughly 38% wt. The addition of water is especially important for High-Temperature, High-Pressure (HTHP) wells where high flow line temperatures cause the evaporation of water leading to saturation and precipitation of salt crystals.

Dissolution — Hole Enlargement

The solubility of different salts in a given fluid will control the amount of formation dissolved.

Water-base fluids should be saturated with respect to the composition of the salt formation prior to drilling the salt section, in order to minimize the amount of salt dissolved and the resulting washout. Maintaining a near-gauge wellbore improves cementing across these sections and will minimize the potential for casing failures due to salt deformation. Hole enlargement due to dissolution can not be totally avoided with a water-base fluid, but it can be minimized to an acceptable level. There are several factors contributing to the dissolution of salt.

The solubility of different salts in a given fluid will control the amount of formation dissolved. Calcium and magnesium chloride are more soluble than sodium and potassium chlorides. The importance of the relative solubility of salts is that in solution, the salt with the lowest solubility will precipitate first. For example, if calcium chloride (higher solubility) were mixed into water saturated with sodium chloride (lower soluble), sodium chloride would immediately precipitate. Therefore, if a saturated sodium chloride drilling fluid is used to drill a salt section containing calcium chloride, the calcium chloride will go into solution and sodium chloride will be precipitated. Depending on the solubility of each salt, a mutual solubility equilibrium will be reached. Figure 1 shows the mutual solubility for calcium, sodium and potassium chloride salts.

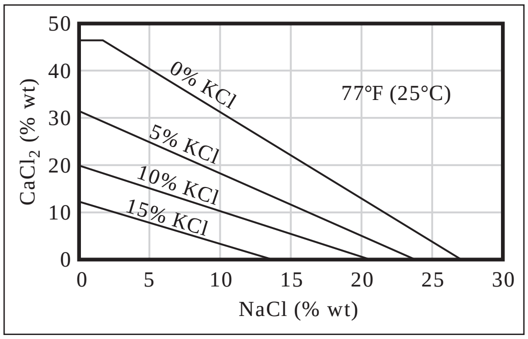

Figure 1: Mutual solubility of $CaCl_2$, NaCl and KCl (after Kemp, SPE 16688).

Mutual solubility can be very complex. There is considerable variability concerning *which* salt goes into solution and *when* it will go into solution. It depends on which other salts are present, in which order they are added, in what concentration and at what temperature. The solubility of the salts are listed in the following order from most soluble to least: $CaCl_2$ > $MgCl_2$ > NaCl > KCl. As different types of salts are drilled, this complex equilibrium can shift. Calcium chloride is the "preferred" salt. It will stay in solution at a higher concentration when other salts are added to the fluid, although some calcium chloride can be displaced by the other salts.

Calcium chloride is the "preferred" salt.

Another reason for dissolution is related to temperature effects. As shown in Figures 2 and 3, salts are more soluble at higher temperatures and their mutual solubility relationships change with increased temperature. More salt will go into solution downhole at higher temperatures. As the circulating fluid approaches the surface, the temperature will decrease, crystallizing salt, and a portion of the salt crystals will be removed by solids-control equipment. As circulation continues, the fluid is reheated downhole, and there is more capacity for salt to go into solution. This heating and cooling cycle is repeated on each subsequent circulation, resulting in greater salt dissolution and a larger hole diameter. Chemical crystallization inhibitors and heated mud pits (discussed later) can be used to maintain saturation downhole. This change in solubility with temperature also indicates that salt crystals should always be present at the flow line when drilling salt. If crystals are absent, the mud is probably not saturated under downhole conditions.

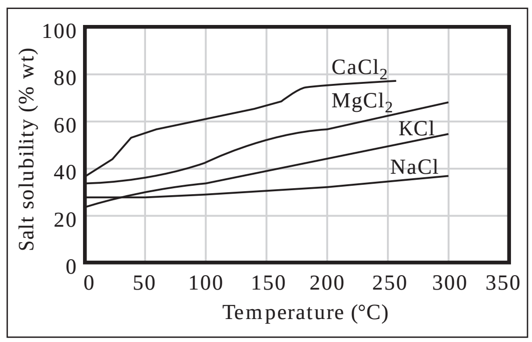

Figure 2: Effect of temperature on solubility of individual salts.

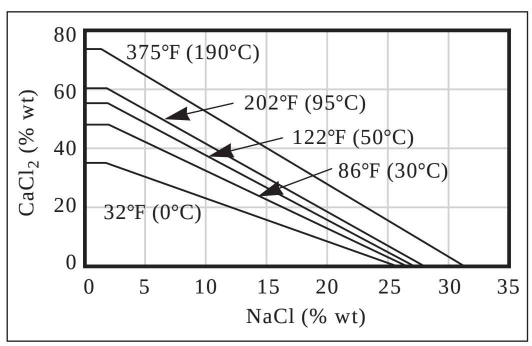

Figure 3: Effect of temperature on mutual solubility.

Deformation — Plastic Flow

...a salt section tends to be more sensitive to temperature and pressure than the adjacent formations.

Salt sections exhibit plastic-flow characteristics under sufficient temperature and pressure. Although it is difficult to correlate the magnitudes required to initiate plastic salt flow because of the variety of environments, it is a known fact that a salt section tends to be more sensitive to temperature and pressure than the adjacent formations.

Salt formations are rarely plastic or problematic if they are at depths of less than 5,000 ft, at temperatures below 200°F (93°C) or less than 1,000 ft thick. In the case of salt beds, the deformation can be much less apparent. When a well is drilled through a salt section, stress within the salt is relieved and the salt flows toward the wellbore. For this reason, salt sections should be short-tripped and reamed on a regular basis.

A salt can flow sufficiently to close off the wellbore and stick the drillstring.

A salt can flow (“creep”) sufficiently to close off the wellbore and stick the drillstring. Freshwater sweeps can be used to dissolve the salt that is creeping and to liberate stuck pipe. A freshwater pill of 25 to 50 bbl is usually sufficient to free stuck pipe. Good drilling practices can also minimize salt-deformation problems. Drilling each joint or stand and wiping over that section prior to making the next connection will help ensure the salt has been opened sufficiently and stabilized. Regular wiper trips back through the salt to casing will also help ensure the hole has remained open.

Increasing the mud weight is the only practical way to control the rate at which the wellbore closes. The closure may never be eliminated, but it can be controlled to an acceptable level during the interval of time it takes to drill the section. The force extruding the salt is equal to the weight of overburden. This means that mud weights can be very high. Generally speaking, the greater the depth of burial, the higher the mud weight. Mud weights required for drilling salts can be in excess of 20.0 lb/gal (2.4 SG). As shown in Figure 4, the mud weight required to reduce salt creep to less than 0.1% per hour can be estimated from the formation temperature and depth.

In the case of a completed well, salt can flow sufficiently to collapse casing. In some cases, the movement of the salt is so slow, it takes years before this problem is manifested. High-strength casing and a good cement job after drilling a nearly gauge wellbore tend to distribute the salt loading more evenly over the interval, thereby reducing the potential for casing collapse. Experience has shown that it is a good practice to use a high-compressive-strength, salt-saturated-resistant cement and high-strength casing designed for 1.0 psi/ft collapse.

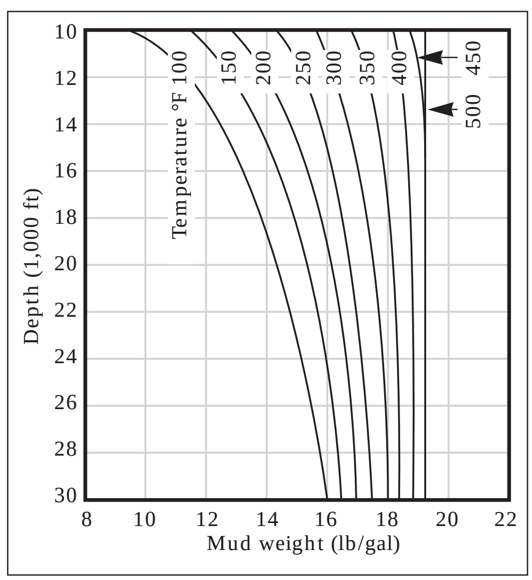

Figure 4: Mud weight required to control salt creep.

Well Control

Salt is also a trap or barrier to the migration of oil, gas and waters.

It is important to understand the subsurface stress and pressure environment near and in salt structures. Because salt is less dense (about 2.1 SG) than the surrounding formations, it tends to be buoyed or float in the subsurface environment over geological time. This accounts for the formation of salt domes and salt migration. Due to these forces and movements, the stresses around and in salt structures can be great and troublesome to stabilize. The boundary zones between the salt and surrounding formations are often geologically complex mixtures of highly altered and disturbed rocks. It is not uncommon for there to be a very narrow window of mud weight which will control formation pressures and fluids without causing lost circulation.

Salt is also a trap or barrier to the migration of oil, gas and waters. This is one of the reasons so much drilling and production occurs near salt formations. It is also the reason why there are so many hole problems at salt boundary zones. In subsalt drilling it is believed that trapped water may cause these boundary zones to be saturated with water, almost mud-like and very weak, with no real formation strength. Both shales and sands cannot be compacted under these conditions and may have retained their original soft, unconsolidated constitution, regardless of age. In these situations, the formations are very dispersive and fracture easily (losing circulation), yet kick with only small changes in mud weight.

Since salt is plastic, the rock stress environment is different from shale, sand or carbonate formations. In shale, the maximum stress is normally in the vertical direction, and there is an overburden/pore/intergranular-pressure situation. In salt, the pressures and stresses are equal in all directions because it is a plastic material. This causes all of the overburden to be translated into pore pressure, and as the salt section is drilled, all of the weight of the salt will be added to the overburden and may need to be equalized with increased mud weight. Salt has a specific gravity of about 2.1, so for some situations, the mud weight in a salt section may need to be increased by 0.9 psi/ft, depending on the section length and temperature. If compressed fluids within a porous formation underlying salt sections are trapped by the deposit of impermeable salt above, reservoir pressure of the fluids below this salt deposit will probably equal the overburden pressure.

Salt sections are often associated with other evaporite or carbonate sections, anhydrites, limestones and dolomites, which can contain permeability and porosity in the form of vugs or fractures. In some cases, these pore spaces are filled with salt, but in many places, there are fluids, gas, oil or brine, under high pressure. In some cases, fractures within the salts contain fluids. Most salts are self healing; therefore fractures usually will not exist, but high-pressure kicks have occurred in the fractured salts in Michigan. Gas associated with these formations can be carbon dioxide, hydrogen sulfide, methane or hydrocarbon liquids.

The drilling fluid should have sufficient density to control the pressure. In many cases there is a fine line between controlling a kick and loosing circulation, due to the fractured and weak nature of these formations. Lost-circulation material selection can be limited due to the elevated viscosity of the fluid as well as reduced free water.

The drilling fluid should also be treated to counteract or remove the contaminants, as discussed in the

Contamination and Treatment chapter. Density should be increased to eliminate the influx of fluids. Carbon dioxide should be treated out by raising the pH >10 with lime. Precipitation from increasing the pH may cause excessive viscosity, pilot test in complex divalent salts. Hydrogen sulfide should be treated by raising the pH >11 with lime or caustic soda and using a zinc-base sulfide scavenger, such as SULF-X®, zinc carbonate or SV-120™ in sufficient concentration to remove the sulfides.

Recrystallization

Recrystallization is the result of lowering the temperature of a supersaturated salt solution or the introduction of a more soluble salt.

Recrystallization is the result of lowering the temperature of a supersaturated salt solution or the introduction of a more soluble salt. The least soluble salt is the first to recrystallize. One problem with recrystallization is that the mass of small crystals have a huge surface area, which is preferentially water-wet to a high degree and difficult to oil-wet in invert-emulsion fluids. In oil-base systems, these particles quickly adsorb wetting agent and emulsifier, resulting in fluid instability. Crystal growth begins on a nucleation site. This can be the surface of a drilled solid, casing or solids-control equipment surfaces. In many cases, recrystallization will be most evident at shakers where the screens will become plugged and blinded by aggregated solids and salt crystals.

Salt has been reported to build up on the casing shoe sufficiently to prevent tripping a bit out of the hole.

In addition to salt recrystallizing as individual particles, salt can recrystallize downhole in the form of massive agglomerations. Salt has been reported to build up on the casing shoe sufficiently to prevent tripping a bit out of the hole. Water-wet solids have built up on the inside of drill pipe, causing an increase in standpipe pressure. This mass of salt can be removed with freshwater sweeps. The potential for this type of recrystallization can be minimized by controlling the solids in a fluid with a good solids-control program.

During drilling, lower temperatures are encountered in deepwater risers and on the surface. In northern climates, it has been observed that recrystallization problems are more severe during the spring and fall when there is a greater variance in surface temperatures between day and night. In the summer, as well as winter, the temperature will generally fluctuate less between day and night, although the difference between downhole temperatures and surface temperatures is greater in the winter. In some cases, heated surface mud systems have been used to keep the mud in a saturated condition to prevent recrystallization.

Chemical salt-precipitation inhibitors are sometimes employed in water-base muds to prevent recrystallization by maintaining super-saturation of the brine. These materials interfere with the crystal structure formation. Often these materials only raise the saturation point of the brine and do not overcome the recrystallization problem. Sufficient inhibitor concentration is required to prevent recrystallization. While drilling salt, the system is dependent on the inhibitor. If the inhibitor concentration is not maintained or is depleted on drilled solids, severe recrystallization can occur.

Treating Invert Emulsion Fluids While Drilling Salt

It is best to pretreat an invert-emulsion system for drilling salt...

It is best to pretreat an invert-emulsion system for drilling salt, particularly for the highly soluble calcium/magnesium salts. The following guidelines will help maintain fluid stability while drilling salt with an invert system.

1. Maintain a high synthetic:water or oil:water ratio to reduce the impact of potential water or brine contamination of the system and minimize the volume of the aqueous phase available to dissolve salt.
2. Monitor the salt composition of the water phase of the mud to keep it from being supersaturated with one of the monovalent cations. For halite formations, this means using the binary salt titrations and calculations as described in the Non-Aqueous Emulsions chapter. If the sodium-chloride concentration of the internal phase increases, it may be necessary to first treat the mud with emulsifier and wetting agent then add water and possibly even calcium chloride to the system. Neither water nor dry salt should be added to a system if it is exhibiting fluid loss or emulsion instability.
3. Run the rheology at lower acceptable levels, in order to minimize any viscosity increase which will occur from a brine influx.
4. Under “normal” drilling conditions monitoring HTHP fluid loss and Electrical Emulsion Stability (abbreviated simply “ES”). Use these values as a guide to determine daily emulsifier treatments, which should be in the range of 0.25 to 0.5 lb/bbl for each emulsifier. Before drilling the salt formation, the mud should be treated with 1.0 lb/bbl of emulsifier and wetting agent. Determine the HTHP fluid loss at two temperatures (for instance 300°F and 250°F). The higher-temperature test results will provide an early indication of any emulsion weakening.
5. Check “flow line” HTHP, sand content and ES on a regular basis. These properties will provide early indications of mud problems. Sand content measurements are essential as water-wet solids will show up as a high sand content due to the aggregation of the solids (including barite) into sand-sized particles. If the sand content rises significantly against the background level, then a mud problem may exist. This must be checked upstream of the shakers otherwise any larger water-wet particles will have been screened out.
6. Drilling salt formations may result in erratic ES readings. Monitor the emulsion stability by using the HTHP results.
7. Measure the magnesium, calcium and excess lime content. The actual Mg^{2+} content of the mud **may** remain unchanged as $Mg(OH)_2$ will be precipitated and taken out of the system by the shakers, resulting in low Mg^{2+} contents. While drilling, the following will indicate an influx of magnesium salts:
   - Lime content drops sharply.
   - Plastic Viscosity (PV) increases.
   - Oil:water ratio decreases.
   - HTHP **decreases** (due to $Mg(OH)_2$ plugging the filter paper).
8. If H_2S is a potential hazard, a zinc-base sulfide scavenger, such as SULF-X or zinc carbonate, should be carried in inventory as a contingency product in the event of an influx. Measure the sulfide concentration regularly using the Garrett Gas Train.

9. Maintain an excess lime content of between 3 to 5 lb/bbl. This should be determined using the direct titration method. The back titration method can give erratic results due to the interference of $Mg(OH)_2$.
10. In order to ensure adequate oil-wetting whenever barite is added to the system, the concentration of emulsifiers/wetting agents should be increased.
11. In order to anticipate potential mud instability during any possible mud weight increases, a pilot weight-up tolerance test should be performed prior to drilling and regularly while drilling salt.

WEIGHTING-UP TEST:

1. Take a quart or liter sample of mud from the active system.
2. Add barite to raise mud weight by 3.0 lb/gal (0.36 SG) for mud weights <15 lb/gal. For mud weights >15 lb/gal, add enough barite to increase the density to 18 lb/gal.
3. Perform a complete mud check on the above mud including HTHP at 300°F (149°C).
4. If the results from the mud check indicate mud instability, then treatments of base oil, emulsifiers and wetting agents, possibly with water additions, should be pilot tested.

Introduction

Classifying a well as HT or HTHP usually elevates it to a "critical and difficult" status.

Classifying a well as High-Temperature (HT) or High-Temperature, High-Pressure (HTHP) usually elevates it to a "critical and difficult" status. Wells are classified as HTHP when their formation pressures exceed a 15-lb/gal equivalent and when static bottom-hole temperatures are greater than 350°F (177°C). Corresponding downhole pressures may require mud weights as high as 20 lb/gal to maintain well control.

In traditionally overpressured and hot-hole areas, such as South and East Texas, Mobile Bay, Mexico, Northeast Brazil, the North Sea, Italy, and Yugoslavia, it is not uncommon for formation temperatures to exceed 400°F (204°C). In many geothermal and deep gas wells, such high temperatures are the rule, rather than the exception. In geothermal drilling, for instance, it is not uncommon to have temperatures above 350°F (177°C) at depths as shallow as 2,500 ft. In such situations, flow line temperatures become excessive (>200°F or 93°C) and mud coolers often are required. After trips, the mud may become so hot that it will flash to steam during the initial bottoms-up circulation.

Historically, properly formulated HT oil-base systems have provided better temperature stability than water-base muds, thereby making them preferred for HTHP wells. However, due to ever-tightening environmental restrictions, low-colloid (reduced active solids), water-base systems have been developed which are suitable for the HTHP environment. The continuous development of new HT additives exhibiting increased temperature stability promises to make water-base fluid systems an even more viable alternative to oil-base muds in the future. Increased emphasis on solids control, improved wellsite engineering and the appropriate testing regime has increased the use — and success — of HTHP water-base muds.

Effects of Temperature

When exposed to high temperatures, all muds become thinner to a point, then stabilize before reaching their thermal limit. Figure 1 illustrates the effects of high temperatures on the plastic viscosity of a water-base mud. As shown, up to a temperature of 225°F (107°C), the plastic viscosity of the mud decreases with temperature at essentially the same rate as the viscosity of the water. Up to a temperature of 300°F (149°C), however, the plastic viscosity begins to increase slowly. Above 300°F (149°C), the mud most likely will thicken quite rapidly. The initial decrease in viscosity should be considered, since it will affect hole-cleaning and other downhole functions.

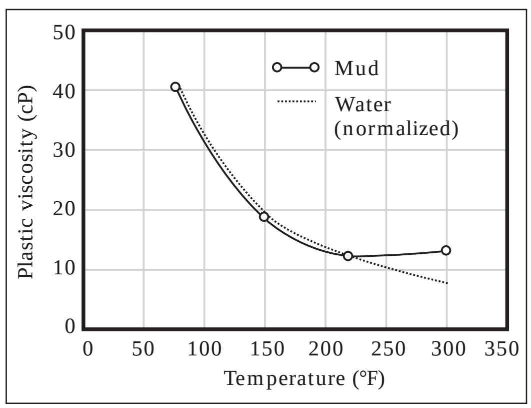

Figure 1: Thermal thinning of water-base mud compared to water (after Annis, SPE 1698).

...the abnormal pressures experienced in HTHP wells require higher mud densities.

When static downhole temperatures become excessive, both gelation and excessive viscosity become major concerns. Rheological properties affect many downhole parameters, including Equivalent Circulating Density (ECD), hole cleaning, barite sag, surge/swab pressures during tripping, pump pressures and bit hydraulics. Instruments like the Fann Model 50 for water-base muds and the Fann Model 70/75 for oil- and synthetic-base fluids can measure this change in properties. Such measurements can then be used in the VIRTUAL HYDRAULICS® computer program to model and estimate the behavior of the fluid. VIRTUAL HYDRAULICS contains TPRO, a circulating temperature simulator to estimate mud temperatures and properties.

Rheology takes on an even greater importance in deep HTHP wells where the typically smaller hole diameter increases ECD pressures. Correspondingly, the abnormal pressures experienced in HTHP wells require higher mud densities. The increasing solids concentration of even the non-reactive weight material will also reduce the thermal stability of the fluid as the amount of "free," or available, base liquid is reduced by the surface area of the solids. Excessive viscosity and gelation increase the possibility of lost circulation. The temperature stability of a mud can be determined easily by static heat-aging, as described at the end of the chapter, and measuring the static shear strength and properties after aging. The static shear strength is similar to gel strength and is measured with a special shear tube and weights.

The risk of becoming differentially stuck increases in an HTHP well because the mud weight needed to control pressures may be much higher than the pressure in other exposed formations. If the high temperatures cause the fluid loss to become unstable, then stuck pipe will be a significant concern. It is critical to monitor and control the HTHP fluid loss at the bottom-hole temperature. Contamination also will have a destabilizing affect on filtration control and will reduce the thermal stability. If contamination is anticipated, additional filtration and plastering materials may be required. The lubricity of the filter cake is an important factor in avoiding stuck pipe, especially in extended-reach, high-angle wells. Since oil-base and synthetic fluids exhibit better lubricity than water-base systems, they may be preferred for highly deviated wells.

Effect of Reactive Solids

The detrimental effects of drill solids at high temperatures have been well-documented. At low temperatures, a fluid can tolerate large amounts of reactive solids with little adverse effect. However, at high temperatures, reactive solids flocculate and begin to gel, resulting in high viscosity and possibly solidification. The specific temperature at which a fluid will become unstable depends on the type of solids and their concentration, as well as the degree of chemical treatment. As shown in Figure 2, increasing the concentration of bentonite above 9 lb/bbl in an unweighted water-base mud causes a significant decrease in temperature stability as indicated by the increasing 30-min gel strength.

Bentonite is more reactive than drill solids, but an increased drill-solids concentration will have the same effect. The amount of bentonite or drill solids that a mud will tolerate, and remain stable at a particular temperature, decreases as the mud weight increases. As shown in Table 2 for the DURATHERM™ system, the amount of bentonite is decreased in the formulation as the mud weights increase. The specific temperature limit decreases with increasing reactive solids content.

The MBT of the CEC of a water-base mud is an excellent measure of the reactive solids content.

To improve and stabilize the rheology of high-temperature water-base fluids, anionic materials are used to prevent flocculation. This helps prevent gelation. Anionic thinners include organic materials such as lignosulfonate (SPERSENE™) and lignite (TANNATHIN®), as well as synthetic polymers like TACKLE®, DURALON™

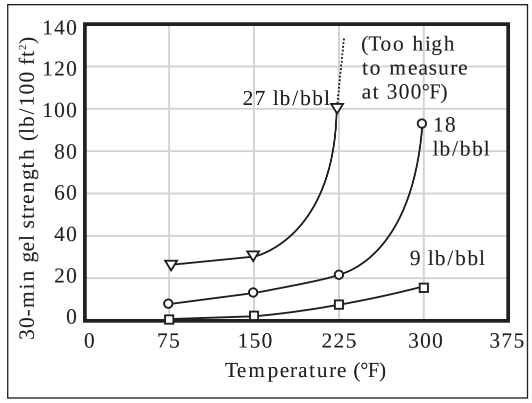

Figure 2: Effect of bentonite concentration on thermal stability (after Annis, SPE 1698).

and RHEOSTAR™. These anionic materials adsorb to the edges of clay platelets, thereby neutralizing the cationic edge charges and preventing flocculation.

Reactive solids include bentonite, added for viscosity and filtration, plus drill solids that contain shale and clay materials. The Methylene Blue Test (MBT) of the Cation Exchange Capacity (CEC) of a water-base mud is an excellent measure of the reactive solids content. For many HTHP water-base muds, the MBT must be kept below a 15-lb/bbl equivalent.

To minimize the adverse effects of high temperature on mud properties, it is important to:

- Maintain low reactive solids content.
- Properly treat the system with thermal-stabilizing additives for rheology and filtration control.
- Buffer pH at a level to extend the effectiveness of additives and reduce the impact of contamination.

Fluid Selection

If contamination is anticipated, then oil-base muds are preferred…

A number of factors must be taken into consideration when selecting a fluid for HTHP wells. These include:

- **Temperature.** The thermal stability of both the entire system and the associated additives must be determined.
- **Wellbore stability.** Since most HTHP wells do not contain as many water-sensitive formations as normal wells, shale stability is usually more a function of mud weight. However, in selecting a fluid system, it is still important to determine the chemical or water sensitivity of the various formations to be drilled.
- **Mud density.** As a general rule, low-density fluids are more easily formulated. For higher-density applications, either oil-base systems or dispersed water-base systems will be required. For exploratory drilling in which the required mud weight schedule is not well known, water-base muds are suggested because the problem of gas solubility makes it difficult to detect kicks with oil-base systems.
- **Contamination.** It is critical to anticipate possible contamination. This includes gases such as hydrogen sulfide (H_2S) and carbon dioxide (CO_2), or salts and other contaminants. If contamination is anticipated, then oil-base muds are preferred because they are less susceptible to most chemical contaminants.
- **Environmental/safety considerations.** Environmental restrictions often impact mud selection. The system selected must comply with local regulations and be capable of maintaining control of the well.
- **Economic considerations.** The base cost of the system, anticipated penetration rates, logistics, solids-control efficiency and the probability of lost-circulation zones must all be considered when deciding whether to use an oil-, synthetic- or water-base mud.

Geothermal Drilling

Low-density, water-base muds are almost always used for geothermal drilling.

Much of the criteria for selecting mud systems for HTHP oil and gas wells also holds true in drilling geothermal wells. The primary differences are in the pressures encountered, the densities used, the frequency and severity of the lost circulation encountered, and the type of formation fluids produced.

Since pressures in most geothermal wells are subnormal to normal, weight material is rarely required. Low-density, water-base muds are almost always used for geothermal drilling. Once the reservoir network is drilled, lost circulation usually occurs because reservoir pressures are significantly lower than the hydrostatic pressure of water. The drilling fluid should be temperature-stable so that lost fluid does not solidify and impair production. Geothermal drilling fluids have been developed that use sepiolite (DUROGEL®), a rod- or needle-shaped clay similar to attapulgite (SALT GEL®). Sepiolite does not flocculate and cause gelation at high temperatures, but because of its shape, sepiolite is not a good filtration-control additive. Normally, formulations use 10 to 20 lb/bbl sepiolite or a blend of 5 to 10 lb/bbl sepiolite plus 5 to 10 lb/bbl bentonite.

Whether geothermal production is “dry” (no liquid water) or “wet” steam (which is liquid downhole and will flash to steam near the surface), also has a bearing on the mud system used to drill the production interval. In formations with dry steam production, air is often used to drill the reservoir underbalanced, producing steam as drilling continues. In wet-steam or hot-water reservoirs, either water or aerated-water systems are used. Air drilling is not possible in most wet-steam reservoirs since the water influx will be too great.

Regardless of type, the drilling fluid proposed for any HTHP well must have been tested under simulated conditions at the maximum temperature expected. Both rheology and fluid loss should be measured and stabilized. It is essential that the mud engineer be made completely aware of the performance of all additives under variations in downhole temperature. It is highly recommended that the number of products used in a high-temperature formulation be limited. This simplifies the mud engineering aspect of the formulation at the wellsite and avoids confusion.

If a water-base system is used, it must be carefully monitored throughout the course of the well, and the formulation may need to be changed as the temperature increases with depth. The dilution rate of HTHP drilling fluids depends on the type of mud and the solids-control equipment used. The rate of evaporation in an oil-base mud can increase both the water-phase salinity (decreasing stability) and the oil-to-water ratio. Water-base fluids will require regular dilution to maintain an acceptably low solids content and MBT value. A discussion of the procedures and equipment employed to test HTHP fluid systems follows at the end of this chapter.

Oil-Base Mud Systems

…these systems…are inherently more temperature-stable and resist the effects of most drilling contaminants.

Oil-base systems are sensitive to both temperature and pressure. As mentioned, these systems historically have been preferred for drilling hot and highly pressured wells, because they are inherently more temperature-stable and resist the effects of most drilling contaminants. Oil-base fluids thin with increasing temperature and expand so that viscosity and downhole density may be different from that measured on the surface. Fortunately, due to compression, high pressures with high-density fluids counteract this expansion.

Normally, oil-base fluids for HTHP applications do not require extensive additional treatments or frequent dilution. Formulations should be made with special high-temperature organophilic clays like VG-HT™ and should use a high concentration (5 to 15 lb/bbl) of high-temperature-softening-point asphaltic materials like VERSATROL® I to increase viscosity and decrease fluid loss. For hostile environments in which acid gases are anticipated, the excess lime content should be kept at a higher-than-normal level (>10 lb/bbl).

However, oil muds will not solve all the problems inherent in drilling an HTHP well. Some of their limitations include:

- **Lost circulation.** Can be very expensive when running these systems and is often difficult to control.
- **Gas-kick detection.** The solubility of the gas within the system makes kick detection difficult.
- **Barite stripping.** Gas influxes decrease viscosity of the fluid phase, causing barite to strip or settle.
- **Environmental.** May not comply with local regulations.
- **Logging.** Some exploratory situations require logs that must be run in water-base fluids.

Water-Base Mud Systems

...water-base fluids are preferable environmentally and have a lower unit cost.

Conventional water-base systems are sensitive to temperature, but are not very compressible. Generally, water-base fluids are preferable environmentally and have a lower unit cost. However, they are less resistant to contamination and do not provide the same level of lubricity as oil-base fluids.

By controlling the concentration of bentonite and active solids, and by employing stabilizing additives, high-temperature, low-colloid, water-base systems can be formulated. Critical to the successful application of water-base systems are superior solids control and adequate dilution.

As discussed previously, active clays can promote gelation and other rheological problems at high temperatures. In low-colloid systems, the concentrations of bentonite and active drill solids are minimized. Generally, in an 18-lb/gal mud, the bentonite concentration should be reduced to about 5 lb/bbl. As discussed, when designing a water-base system for HTHP applications, the bentonite concentration must be kept low, and the concentration of reactive solids should be monitored using the methylene blue test.

With the low gel content of these systems, barite settling would appear to be a real possibility, but this has not been encountered in the field. In one case cited in the literature, a wellbore had not been circulated for 40 days. Upon recirculation, the properties of the water-base system had deviated little since the original displacement. No settling was observed, and the system exhibited an extremely high tolerance for temperature.

Since the circulating fluid temperature in HTHP wells is significantly less than that of the formation temperature, products are not exposed to the highest temperatures, except during trips. When temperatures increase during trips, viscosifiers like Polyanionic Cellulose (PAC) and xanthan polymers may degrade, but they do not produce contaminating by-products. These viscosifying polymers, which are used above their temperature limit, are called “sacrificial” viscosifiers. Although the viscosifying benefit of the polymers will be lost, it will be offset with an increase in viscosity from the thermal flocculation of reactive solids. Thus, the suspension and viscous properties are maintained, alleviating the possibility of settling. Further, product consumption is limited to the small quantity of drilling fluid exposed to higher formation temperatures. Using an alternative viscosifier such as sepiolite (DUROGEL) or attapulgite (SALT GEL) helps achieve an adequate viscosity without using too much bentonite. In water-base systems, low-gravity solids should be maintained at less than 6%, drill solids <4%, MBT <15 lb/bbl at 10 lb/gal and <5lb/bbl at 18 lb/gal, depending on the temperature.

Other requirements specific to water-base muds include:

- Addition of thermal rheological stabilizers, such as anionic thinners.
- Use of thermally stable fluid-loss additives.
- Maintaining a stable pH.
- When additives that degrade into CO_2 — such as lignosulfonate and lignite — are used, a small amount of excess lime should be added to prevent contamination.

High-Density Mud Systems

This reduced liquid phase increases the effective concentration of the additives used...

As discussed earlier, mud weights as high as 20 lb/gal have been used to control HTHP wells. The increase in solids concentration and surface area limits the amount of available "free" liquid and results in a fluid that has a high plastic viscosity and a low tolerance for many reactive solids. The reduced amount of "free" liquid also makes it more difficult for the other additives to solubilize and work effectively. This reduced liquid phase increases the effective concentration of the additives used, as shown in Figure 3. The volume factor is the reciprocal of the water fraction and can be used to determine the liquid phase concentration of an additive. Due to the reduced liquid phase, the concentration of products required to achieve a desired result is reduced, especially clay-base viscosifiers. This helps to explain

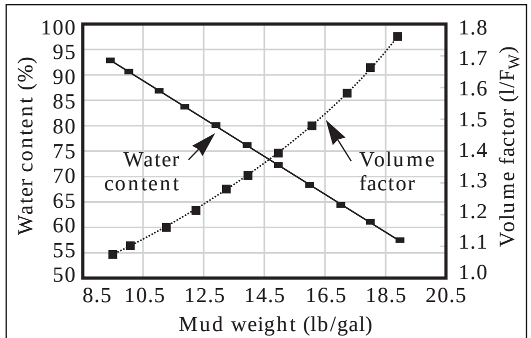

Figure 3: Water content and volume factor vs. mud weight.

why less bentonite is needed as the density increases. If, for example, a 10-lb/bbl treatment is made to a 19-lb/gal mud, then the reduced liquid phase volume results in a multiplyer or volume factor of 1.754, which makes this equivalent to a 17.5-lb/bbl (1.754 x 10) treatment in an unweighted mud with nearly 100% liquid.

High-Temperature Water-Base Systems

The low-colloid DURATHERM system is stable in the presence of contamination from acid gases, salts and drill solids.

Water-base fluids are often preferred when there are environmental, formation evaluation, kick-detection or lost-circulation concerns. Also they have a lower unit cost.

M-I has three water-base fluid systems for HT applications: the DURATHERM, ENVIROTHERM™ and POLYSTAR™ 450 systems.

THE DURATHERM SYSTEM

The DURATHERM system is designed for use in holes with bottom-hole temperatures to 550°F (287°C). The system can be formulated to 25 lb/gal (2.4 SG). The DURATHERM system evolved from similar formulations used as packer fluids, where long-term rheological stability is necessary. *NOTE: The DURATHERM system utilizes a chrome additive, XP-20®, and is not recommended in environmentally sensitive areas.*

The low-colloid DURATHERM system is stable in the presence of contamination from acid gases, salts and drill solids. The stability of the DURATHERM system is achieved by minimizing the concentration of bentonite and active solids, adding a sacrificial polymer (POLYPAC®) to obtain viscosity for suspending barite in the pits, and adding XP-20 for its thermal stabilizing effect on reactive solids. Additionally, RESINEX® is often used to provide HTHP filtration control. This combination of additives, shown in Table 1, reduces the gelation problems caused by the flocculation of active clays at high temperatures, and improves the fluid's resistance to contamination.

To convert an existing mud into a DURATHERM system requires a reduction in the reactive solids content either by dilution or by using solids-control equipment. When the active solids have been reduced to achieve an MBT of less than 15 lb/bbl, treatments with XP-20 and RESINEX can then be used to achieve the required HTHP fluid properties. The pH and alkalinity should be adjusted to a level of 9 to 10.5 with caustic soda, caustic potash and/or lime. Freshly prepared muds will have low viscosity, yield points and gels. Such fresh muds should be treated with additional POLYPAC (or DUO-VIS®) to increase the viscosity in the pits, thereby preventing barite-settling. Once drilling begins, however, the drill solids will accumulate, giving the fluid enough rheology to support weight material.

The concentration of XP-20 should be roughly equal to the mud weight once the bottom-hole temperature exceeds 350°F (176°C). Generally, treatments with lignosulfonate (SPERSENE) should be discontinued at bottom-hole temperatures above 325°F. Solids-control equipment — shakers, hydroclones and centrifuges — must be operated as efficiently as possible to minimize maintenance costs.

Additive	Material	Function
XP-20	Chrome lignite	Viscosity stabilizer and fluid-loss control
RESINEX	Resin polymer	HTHP fluid loss
TANNATHIN	Lignite	Fluid-loss control
DUO-VIS	Xanthan gum	Viscosity and suspension
POLYPAC R or UL	Polyanionic cellulose	Viscosity and fluid loss
M-I GEL	Bentonite	Filter cake and viscosity
Caustic	Sodium hydroxide	Alkalinity and pH control
Lime	Calcium hydroxide	Alkalinity and pH control
Gypsum	Calcium sulfate	Alkalinity and pH control
FER-OX®	Hematite	Weight material
LO-WATE™	Calcium carbonate	Weight material
M-I BAR®	Barite	Weight material

Table 1: DURATHERM system — product function.

The order of addition is important when preparing a fresh mud.

ENVIROTHERM was designed as a chrome-free DURATHERM-type system.

DURATHERM 400°F (204°C) FORMULATION

Table 2 can be used as a guide when preparing a new DURATHERM system. The order of addition is important when preparing a fresh mud. First, the pH should be adjusted to a level of 9.5 to 10.0 with caustic soda or caustic potash. Then, the calcium should be reduced to <100 mg/l with soda ash or potassium carbonate. M-I GEL® may then be added and allowed to hydrate. Polymeric materials are then added for rheology and fluid-loss control. Other additives can be introduced next, either singly or in combination with the weight material.

Be aware that freshly prepared DURATHERM formulations are thin and require hourly treatments of polymer for suspension until some drill solids build-up in the system. For this same reason, these fluids often appear to be too thin and settle during laboratory evaluations.

THE ENVIROTHERM SYSTEM

ENVIROTHERM was designed as a chrome-free DURATHERM-type system. Currently, there are two basic variations in the ENVIROTHERM system:

One variation, shown in Table 3, is used primarily in the Western Hemisphere and is similar to a chrome-free DURATHERM using TANNATHIN and SPERSENE CF for rheology control, and THERMEX™ for fluid-loss control. Freshly prepared muds will have low viscosity, yield points and gels. These fresh muds should be treated with additional POLYPAC (or DUO-VIS) to increase the viscosity in the pits to prevent barite settling. Once drilling begins, the drill solids will accumulate and give the fluid enough rheology to support weight material.

Mud Weight (lb/gal)	Water (bbl)	M-I GEL (lb/bbl)	DUO-VIS (lb/bbl)	POLYPAC (lb/bbl)	XP-20® * (lb/bbl)	Caustic (lb/bbl)	M-I BAR (lb/bbl)
9	0.937	16	0.25	1	10	2	11
10	0.897	15	0.25	1	10	2	66
11	0.866	14	0.25	1	11	2	12
12	0.826	13	0.25	1	12	2	179
13	0.788	11	0.25	1	13	2	236
14	0.751	10	0.25	1	14	2	291
15	0.714	9	0.25	1	15	2	348
16	0.674	8	0.25	1	16	2	404
17	0.640	6	0.25	1	17	2	461
18	0.608	5	0.25	1	18	2	517

*5 lb/bbl of RESINEX can be substituted for 5 lb/bbl of XP-20 to help provide lower HTHP fluid-loss values.

Table 2: DURATHERM 400°F (204°C) formulation.

Mud Weight (lb/gal)	Water (bbl)	M-I GEL (lb/bbl)	POLYPAC (lb/bbl)	TANNATHIN (lb/bbl)	SPERSENE CF (lb/bbl)	THERMEX (lb/bbl)	Caustic (lb/bbl)	M-I BAR (lb/bbl)
9	0.937	16	1	5	5	5	2	11
10	0.897	15	1	5	5	5	2	66
11	0.866	14	1	5	6	6	2	12
12	0.826	13	1	5	6	6	2	179
13	0.788	11	1	5	6	6	2	236
14	0.751	10	1	5	7	7	2	291
15	0.714	9	1	5	7	7	2	348
16	0.674	8	1	5	8	8	2	404
17	0.640	6	1	5	8	8	2	461
18	0.608	5	1	5	8	8	2	517

Table 3: ENVIROTHERM 400°F (204°C) formulation.

The other ENVIROTHERM variation, shown in Table 4, is used primarily in the North Sea and contains a variety of synthetic polymers and unique products, as described in this table.

Additive	Material	Function	Concentration
M-I GEL	Bentonite	Filter cake and viscosity	15 - 50 kg/m³ (5 - 18 lb/bbl)
ENVIROTHERM V	Synthetic AMPS polymer	Viscosifier and fluid loss	0 - 6 kg/m³ (0 - 2 lb/bbl)
ENVIROTHERM F	Polyacrylamide copolymer	HTHP fluid loss	2 - 8 kg/m³ (1 - 3 lb/bbl)
ENVIROTHERM D	HTHP synthetic polymer blend	Dispersant and fluid loss	5 - 10 kg/m³ (1 - 4 lb/bbl)
ENVIROTHERM DL	Polyacrylate thinner, liquid	Thinner	As required
ENVIROTHERM DP	Polyacrylate thinner, powder	Thinner	As required
ENVIROTHERM R	Polyanionic lignin polymer	Fluid loss and dispersant	6 - 12 kg/m³ (2 - 4 lb/bbl)
ENVIROTHERM T	Modified lignin	Dispersant	As required
SPERSENE SP	Modified iron lignosulfonate	Dispersant and fluid loss	As required
Lime	Calcium hydroxide	pH	0.3 - 0.8 kg/m³ (0.1 - 0.3 lb/bbl)
Soda ash	Sodium carbonate	pH and calcium reducer	0.5 - 1.0 kg/m³ (0.2 - 0.4 lb/bbl)
GLYDRIL™ MC	Polyglycol	Temperature and shale stability	0 - 5% (by volume)
FER-OX	Hematite	Weight material	As required for MW
LO-WATE	Calcium carbonate	Weight material	As required for MW
M-I BAR	Barite	Weight material	As required for MW

Table 4: ENVIROTHERM polymer system.

...the POLYSTAR 450 system is a synthetic, polymer-enhanced, water-base system that can withstand temperatures to 450°F.

THE POLYSTAR 450 SYSTEM

A recently developed, high-temperature, water-base fluid is the POLYSTAR 450 system, which is a synthetic, polymer-enhanced, water-base system that can withstand temperatures to 450°F (232°C). It is chrome-free, using no lignite or lignosulfonate additives, as shown in Table 5.

The system is quite simple and uses RHEOSTAR to control rheology, DURASTAR to control the HTHP fluid loss, and GEL SUPREME™ for filter cake and viscosity.

Additive	Material	Function
RHEOSTAR	Synthetic polymer/ copolymer blend	Rheology control
DURASTAR	Synthetic terpolymer	Fluid-loss control
GEL SUPREME	Bentonite	Filter cake and viscosifier
Caustic	Sodium hydroxide	Alkalinity
FER-OX	Hematite	Weight material
LO-WATE	Calcium carbonate	Weight material
M-I BAR	Barite	Weight material

Table 5: POLYSTAR 450 system product function.

High-Temperature Drilling Fluid Testing

Heat-aging can be used to monitor the rheology and filtration parameters of the mud used in HTHP drilling.

In these critical applications, careful monitoring of the fluid system is vital to maintaining stable properties and preventing detrimental events such as stuck pipe, gelation, lost circulation and others. An outline of the applicable tests and equipment follows.

HIGH-TEMPERATURE HEAT-AGING (PRESSURIZED TESTING CELL)

Static heat-aging (as opposed to rolling) normally is used to measure the amount of gelation or settling that may occur at high temperatures. The most critical measurement is the static shear strength, as described at the end of the chapter. Heat-aging can be used to monitor the rheology and filtration parameters of the mud used in HTHP drilling.

- Using Table 6, determine the liquid volume and initial pressure to use for filling the heat-aging cell. Due to the expansion of liquids under increasing temperatures, it is imperative not to over-fill the cell for a given temperature.
- After filling the cell with the specified volume of mud, assemble the cell and pressurize to the level shown under the "Suggested Pressure" column in Table 6, using nitrogen to prevent vaporization. The manifold for the high-pressure filter press normally can be used for pressuring-aging cells.
- Place the filled and pressurized cell in the heat-aging oven in an upright position. Heat-age the cell at the desired temperature for the desired length of time (usually the bottom-hole temperature for 16 to 24 hr).
- Remove the cell and air-cool until the temperature is less than 200°F. *CAUTION: Always handle hot heat-aging cells with special high-temperature gloves to prevent burns.*
- After examining the mud in the open cell, report the condition of the aged sample as "fluid," "gelled," "plastic" or "hard."
- Determine shear strength as described in the next section.

Drilling muds tend to develop shear strengths under static conditions when exposed to elevated temperatures.

SHEAR-STRENGTH MEASUREMENT USING SHEAROMETER TUBE (AFTER API RP13B -1: APPENDIX B)

Description of procedure

Drilling muds tend to develop shear strengths under static conditions when exposed to elevated temperatures. Excessive shear strengths require high pump pressures to "break" circulation, thereby raising the possibility of lost circulation. High shear strength also may cause difficulties in logging, perforating and other downhole operations.

The following procedure can be used to determine how high shear strengths will develop in a particular mud. Since

Aging Temperature		Suggested Pressure		Coefficient of Expansion for Water	Mud Volume	
°F	°C	psi	kPa	Factor	260-ml cell*	500-ml cell
212	100	25	172	1.04	225	450
250	121	50	345	1.06	225	450
300	149	100	690	1.09	200	400
350	177	150	1,034	1.12	200	400
400	205	250	1,724	1.16	*	350
450	232	300	2,068	1.27	*	350

* Do not use unpressurized cells at temperatures of 350°F (177°C) or higher.

Table 6: Recommended mud volume and pressure for high-temperature aging.

shear strength is measured on a mud sample that has been static heat-aged, aging temperatures must be near the estimated bottom-hole temperatures of the well. Since static shear strengths are comparable to gel strengths, the same units will apply for both.

Equipment

1. Stainless steel shearometer tube.
   - Length .... 3.5 in. (89 mm)
   - Outside diameter .... 1.4 in. (36 mm)
   - Wall thickness .... 0.008 in. (0.2 mm)
2. Platform for weights.
3. Stackable weights.
4. Ruler (in.).

Procedure

1. Carefully place and balance the shear tube and platform on the surface of the aged sample, which has been cooled to room temperature. To ensure the tube will penetrate the mud vertically, it may be necessary to shift the weights on the platform.
2. Carefully place just enough gram weights on the platform to cause the shear tube to descend. With ideal weight, the tube will stop at the point at which the shear strength of the aged mud, acting against the surface of the tube, is sufficient to support the weight applied. At least half of the length of the tube should be submerged.
3. Record the total weight, including the platform and weights (20 g), in grams. Measure the submerged portion of the tube in inches. The submerged length of the tube is most accurately determined by measuring the length of the non-submerged portion while the tube is at its maximum penetration depth. The measurement can be taken by holding a small ruler at the surface of the mud and alongside the tube. Thus, the length of the tube minus the exposed length equals the submerged portion.

The Model 50 can be used to measure the fluid viscosity at any or all shear rates plus gels, as the temperature is increased.

Calculation

Shear strength (lb/100 ft^2) =

$$\frac{3.61\,(Z + W)}{L} - 0.256\,A$$

Where:

Z = Weight of shear tube (20 g)
W = Total shear weight (g) (sum of platform and weights)
L = Submerged length of shear tube (in.)
A = Mud weight (lb/gal)

HIGH-TEMPERATURE TESTING EQUIPMENT

Fann Model 50 high-temperature viscometer

The Model 50 rotational viscometer is a high-temperature (500°F or 260°C), lower-pressure (1,000 psi/6,894 kPa) device which can measure rheological properties under simulated downhole conditions. It is entirely sufficient for measuring the thermal behavior of a water-base mud, since such fluids are not affected by compressibility.

The Model 50 can be used to measure the fluid viscosity at any or all shear rates plus gels, as the temperature is increased. This data can be used to determine the flow properties under downhole conditions. If the fluid is held at each elevated temperature for a sufficient amount of time, then the thermal stability limit of the mud can be determined. A plot of a typical thermal stability test, using

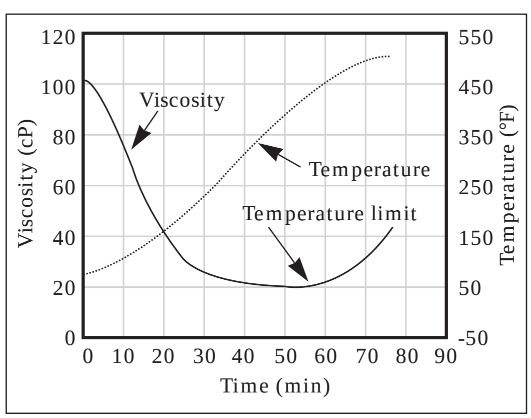

Figure 4: Model 50 test results.

This unit can measure the fluid viscosity at any or all shear rates plus gels, as first the pressure, then the temperature, is increased.

HTHP fluid loss is an excellent tool for evaluating the thermal stability and condition of a high-temperature or HTHP drilling fluid.

only the 100-RPM shear-stress measurement, is shown in Figure 4. As demonstrated, as the temperature increases, the viscosity decreases. Then, at some temperature, it will begin to increase, thickening above its thermal stability limit. Oil-base muds are more compressible, so their viscosity must be measured at elevated pressure to obtain accurate viscosity data, as described below for the Fann Model 70/75.

Fann Model 70/75 HTHP viscometer

The Model 70/75 rotational viscometer is a high-temperature (500°F or 260°C), high-pressure (20,000 psi/140,000 kPa) device which can measure rheological properties under simulated downhole conditions. It is most applicable for testing oil- or synthetic-base fluids because they are compressible. This unit can measure the fluid viscosity at any or all shear rates plus gels, as first the pressure, then the temperature, is increased. With increasing pressure, the rheological profile increases. As the temperature increases, the viscosity decreases. Then, if the fluid is held for a sufficient time at these elevated temperatures, the viscosity will begin to increase, thickening above its thermal stability limit.

Frequently, the Fann Model 70/75 is held at elevated temperature only long enough to measure the shear-stress readings. It is difficult to determine anything about the ultimate thermal stability of the mud from these results. However, this viscosity data can be used in the VIRTUAL HYDRAULICS program to obtain the best estimation of true thermal, rheological and hydraulic behavior.

Fann Model 5STDL HTHP consistometer

The consistometer is a device that uses an oscillating magnetic field to raise and lower a magnetic bob through a mud under HTHP conditions. The time required to raise and lower the bob is an indication of viscosity and gelation. A plot of this equivalent viscosity vs. time and temperature will indicate the thermal limit of the mud, as shown in Figure 5.

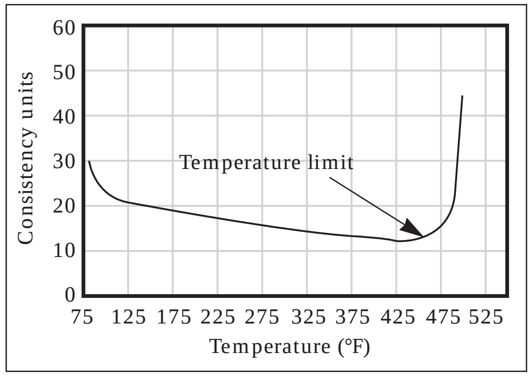

Figure 5: Consistometer evaluation of thermal stability.

HTHP fluid loss

HTHP fluid loss is an excellent tool for evaluating the thermal stability and condition of a high-temperature or HTHP drilling fluid. Monitoring and maintaining a low fluid loss and thin filter cake at high temperature are essential to preventing wellbore problems.

Particle-size analysis

The particle-size range in a drilling fluid will determine the viscosity and filtration properties. It is the combination of the total solids content and the percentage of particles that are less than 4 microns in size. This determines whether the fluid has a fine-solids problem. This test can show a trend, which will predict the future direction of these properties. It indicates the performance of solids-control equipment and the need for dilution. It also identifies the probable effect of filtration-reducing additives. This test cannot be carried out at the wellsite.

Introduction

The term milling is used...to describe the mechanical cutting and removal of a steel structure from the well.

The term *milling* is used in the drilling industry to describe the mechanical cutting and removal of a steel structure from the well. Steel objects which are often milled include junk in the hole, a liner hanger, parts of a stuck or twisted-off drillstring, or casing when cutting a window for a sidetrack or re-drill. Cutting a window in casing is becoming more common during the redevelopment of high-cost or aging fields.

For instance, a drilling and production platform is very expensive and the number of available drilling slots is limited, so when a well fails or becomes depleted, it is an economic necessity to maintain the number of producing wells, as this is directly linked to the continued profitability of the development. The need to salvage uneconomical well slots and the introduction of horizontal drilling (exposing longer sections of the reservoir), has led to a increase in section milling during the redevelopment or recompletion from existing wellbore and cased holes.

Most drilling fluids are designed to provide good hole cleaning of drill cuttings from sedimentary formations which have a Specific Gravity (SG) of roughly 2.6. During a milling operation however, the density of the material that has to be transported to the surface by the fluid, is roughly 3 times higher; steel has a SG of about 7.8. The most efficient casing section mills can now remove 8 to 15 feet per hour (ft/hr) of casing, with instantaneous rates of 35 to 70 ft/hr. In order to transport such a large volume of dense material efficiently from the well, substantial increases in the fluid hydraulics and carrying capacity of the drilling fluid are necessary.

Milling Fluid Options

Numerous fluids have been designed for efficient removal of steel cuttings. The most successful systems have two common features. They are:

1. Shear-thinning fluids with extremely high carrying capacity, due to elevated Low-Shear-Rate Viscosity (LSRV).
2. Low-pressure-loss/drag-reducing fluids, which create less pressure loss in the drillstring and allow higher flow rates to be utilized.

By successfully combining these two features, a fluid with exceptional carrying capacity becomes a fluid which can achieve high annular velocities.

There are three basic fluid systems that are commonly used on milling operations. The formulation of each is described in the water-, oil- and/or synthetic-base systems chapters.

1. The VERSAPORT™ or NOVAPLUS® system with elevated LSRV, using VERSAMOD™ or NOVAMOD™ (respectively) for increasing viscosity.
2. The FLO-PRO® system with elevated LSRV (0.3 RPM Brookfield viscosity over 60,000 cP), using FLO-VIS® for increasing viscosity.
3. The Mixed Metal Hydroxide (MMH) system. This system is basically a pre-hydrated bentonite system flocculated with MMH.

Both the MMH and the FLO-PRO systems exhibit both high LSRV and the pressure-loss/drag-reduction features.

Hole Cleaning

High annular velocity and high carrying capacity are the two main properties needed to obtain good hole cleaning…

High annular velocity and high carrying capacity are the two main properties needed to obtain good hole cleaning for a successful milling operation. In order to efficiently transport steel shavings from the hole, both the Annular Velocity (AV) and LSRV of the fluid have to be substantially increased over what is normally used for drilling operations.

Flow rates. As a rule, the AV should be increased by 50 to 75% over the normal AV for a given hole size. This usually works out to require 35 to 50 gal/min per inch of hole diameter. AVs as high as 250 to 350 ft/min may be required. The following equation has been used to calculate the minimum flow rate for milling operations:

$$Q\text{ (gpm)} = 600 \times \frac{D_{HOLE}^2 - D_{PIPE}^2}{D_{HOLE} \times MWt}$$

Where:
D_{HOLE} = Casing diameter (in.)
D_{PIPE} = Pipe diameter (in.)
MWt = Mud Weight (lb/gal)

If the total flow area of the mill can be adjusted with nozzles, it should be maximized to allow the highest possible flow rate.

During milling operations, the LSRV… should be kept above 25.

Rheology. During milling operations, the LSRV, as measured by the 3-RPM dial reading, should be kept above 25. LSRV or low-shear-rate yield point should be used instead of the Bingham plastic yield point, since the low-shear rheology gives a better indication of the true carrying capacity.

Suspension. To suspend steel particles when the pumps are shut down, it is important to have high initial gel strengths (over 30 lb/100 ft^2). At the same time, it is important that the 10-minute gel structure is not too high. High 10-minute gels and progressive gel structures make it difficult to break circulation after trips and can lead to excessive downhole pressures and possibly lost circulation.

Sweeps. Sweeps should be used when milling casing to help clean steel cuttings from the well and hopefully dislodge any accumulated shavings. The composition, frequency and volume of sweeps depends on the area and operation. For high-rate section milling of casing, 2 to 3 sweeps per hour (or 1 sweep every 10 to 15 ft) should be pumped. The sweep volume is usually 25 to 50 bbl, again depending on hole size and depth. All sweeps should be monitored when they return to the flow line for their viscosity and effectiveness.

If an increase in viscosity is not noted, the sweep viscosity and volume should be increased. If poor steel shavings removal is suspected, and the sweep does not cause an increase in the volume of steel shavings, a short trip may be needed. The method for formulating sweeps is usually to add bentonite to obtain a 70- to 90-second-per-quart funnel viscosity, combined with 25 to 50 lb/bbl of blended Lost-Circulation Material (LCM). Fibrous or blended LCMs are preferred and give the sweeps more mechanical carrying capacity. The most common LCMs used for sweeps are M-I-X II,™ cottonseed hulls, sawdust, drilling paper, M-I SEAL,™ KWIK SEAL® and NUT PLUG.®

"Bird Nests"

Birds nest *is a term used...to describe the accumulation of steel shavings...*

Birds nest is a term used in the milling operations to describe the accumulation of steel shavings into a mass which becomes tangled and stuck somewhere in the well. Bird nests normally develop in areas of mechanical interference or where the annular velocity is reduced, such as at the milled edge of the casing, at a liner hanger, in the Blowout Preventer (BOP) cavity or in the large-diameter marine riser.

While older mills produced long slivers of steel shavings, modern mills produce shorter steel strips (chips) which are usually 1⁄32 to 1⁄8 in. thick, 1⁄8 to 1⁄4 in. wide, and 1⁄2 to 1 in. long. The ability to obtain these shorter steel shavings has greatly reduced, but not eliminated, problems with bird nests. These smaller shavings accumulate into small balls which can further accumulate into larger bird nests and can restrict flow and be difficult to remove.

It is useful to have a jetting tool that can be put into the string with the mill on bottom, and can wash out the BOP cavity and boost the riser flow. When a bird nest develops in the BOP, it acts like a trap and prevents cuttings from being circulated past the obstruction, restricting flow and potentially leading to lost circulation or restricting pipe movement. It is also extremely important to flush out the BOP cavity when the milling operation is completed. It is almost impossible to get a good BOP test with steel shavings present in the area of the pipe rams.

Solids Control

When section milling casing, it is beneficial to have scalping shakers...

When section milling casing, it is beneficial to have scalping shakers which can remove the larger steel chips from the fluid. The primary rig shakers will then remove cement or other particles from the mud. The scalping shakers should use coarse screens to remove the steel shavings, and the primary rig shakers should use fine mesh screens to further clean the fluid.

Every effort should be made to reduce the accumulation of steel shavings in the surface solids-control equipment and to facilitate their removal. The bell nipple and flow line should be constructed with plenty of vertical drop and gentle bends (no 90° bends) and should have hydraulic washout or physical clean-out capabilities. The scalping shakers should be elevated so the steel shavings can drop straight into a container for material-balance estimates.

Ditch magnets should be used to collect as much of the steel shavings as possible which pass through the shaker screens. One set of magnets should be placed in the possum belly of the primary shakers and one set in the flow line back to the pits. If fine steel particles remain in the fluid, they can cause severe damage to the mud pumps and other rig equipment. An estimate of the amount of steel collected by the magnets and off the scalping shaker should be made to estimate the amount of material left in the hole which may be forming bird nests. A collection rate over 70% is considered satisfactory.

Guidelines for Milling with Flocculated Bentonite Systems

Flocculated bentonite systems...are thinned by anionic materials...

Viscosity. Flocculated bentonite systems, like mixed metal hydroxide, are thinned by anionic materials such as POLYPAC,® SPERSENE™ or TANNATHIN.® To prevent cross-contamination from a previous system, be sure all lines and pits are flushed and cleaned before mixing the flocculated bentonite system. The thinning effect from anionic materials will decrease the carrying capacity of the fluid. When milling casing with a flocculated system, the milling fluid often becomes contaminated with old mud and cement spacers left behind the casing, again possibly causing a severe drop in viscosity.

Loss of viscosity. If contamination of the fluid occurs, resulting in a loss of viscosity, another approach to obtaining viscosity should be used. The most common method is to convert the flocculated system to a xanthan polymer viscosified system. DUO-VIS® or FLO-VIS® should be added as soon as a reduction in viscosity is recognized. It has proven impossible to restore the fluid viscosity of a flocculated MMH system, once anionic materials have entered the system. The fluid viscosity can be restored in one circulation with the proper treatments of polymers, and very little rig time is spent.

Filtration control. If a flocculated system is being used in a situation where low fluid loss is required while milling casing, a truly non-ionic starch, like FLO-TROL,™ should be used. These systems are very sensitive to anionic materials and become even more sensitive to anionic contamination once starch is added to reduce fluid loss.

Coiled-Tubing Drilling

Introduction

The coiled-tubing method greatly facilitates lowering and retrieving the drilling assembly.

Coiled-tubing drilling employs a continuous string of coiled tubing and a specialized, coiled-tubing drilling rig. Rather than drilling with separate joints of the traditional, larger-diameter, rigid drill pipe, the drillstring is smaller-diameter, flexible tubing. Unlike drill pipe, which is screwed together to form the drillstring, and which must be disconnected into stands that are racked in the derrick during trips, the tubing comes rolled on a reel that unwinds as drilling progresses and is subsequently rewound onto its spool during trips. The coiled-tubing method greatly facilitates lowering and retrieving the drilling assembly.

Traditionally, coiled-tubing rigs have been used for workover and completion operations where mobility and compact size were important. With the development of downhole mud motors which do not depend upon a rotating drillstring for their power, coiled-tubing units are now functioning as true drilling rigs.

A Brief History

Coiled-tubing-drilling hole sizes are usually in the 2¾- to 4¾-in. range.

In 1962, the first prototype “continuous-string light workover unit” was developed for washing out sand bridges in Gulf Coast oil and gas wells. The injector head was built for 1.315-in.-OD pipe and could handle surface loads up to 30,000 lb. The unit successfully performed concentric (tubing inside of production string) workovers on land and offshore South Louisiana for several years.

In 1964, a slightly different design, built to run ¾-in. coiled tubing, was introduced. It was also used for wellbore cleanouts. In 1967, an injector head sized for ½-in. coiled tubing was used to backwash saltwater disposal wells with nitrogen. Later, 12 coiled-tubing units capable of handling up to 5,000 lb of ½-in. coiled tubing were built. In late 1968, a coiled-tubing injector head for 8,000 lb of ¾-in. coiled tubing was developed.

By the mid 1970s, more than 200 coiled tubing units were built to perform sand cleanouts and nitrogen jet services. By 1985, a number of different injector heads and other coiled-tubing equipment became available, with numerous revisions in design and maintenance schedules that improved equipment capability and reliability. Drilling with coiled-tubing units became possible when new types of downhole directional equipment and drilling motors became available. Coiled-tubing-drilling hole sizes are usually in the 2¾- to 4¾-in. range.

Coiled-Tubing Procedures

Present usage of coiled tubing includes the following:

- Wellbore cleanouts.
- Unloading wells and initiating production.
- Formation stimulation.
- Cementing.
- Sand consolidation.
- Services in pipelines and flow lines.
- Through-tubing milling.
- Plug and abandonment.
- Fishing.
- Various coiled-tubing-conveyed tool services.
- Coiled-tubing drilling.
- Whipstock milling.
- Running screens.

Advantages

Coiled tubing provides the following advantages:

- Work on live wells (pressure at surface).
- Efficient well entry and exit.
- Quick rig up/fast trip times.
- Small surface footprint compared to workover rig.
- Efficient offshore mobilization because of modular components.
- Continuous circulation of fluids, even while tripping.
- Performing work while the well is producing (underbalanced).
- No threaded connections, flush outside diameters.
- Wide range of tools available, adapted from workover, drilling and wireline operations.
- Adaptation to permanent completions.

Limitations

Coiled tubing must operate within these restrictions:

- Fatigue cracking due to repeated bending (cycling).
- Ballooning due to differential pressures.
- Tubing mechanical damage from use and handling.
- Environmental and chemical damage from acid, oxygen and other chemicals used.
- Limits of coiled tubing strength in burst, collapse and tension.
- Uncertainties in derating used coiled tubing.
- Challenges of tube-to-tube butt welding.
- Surface equipment operational limits such as:
  a) Plugging.
  b) Well-control working pressure.
  c) Push or pull loads.
  d) Allowable pipe deformation.
- Downhole operation limits such as:
  a) Plugging.
  b) Push or pull loads.
  c) Frictional pressure losses through tubing string.
  d) Collapse resistance due to ovality of the coiled tubing.

Basic Equipment

...the entire operation could take as little as half a day or up to a week.

- The equipment listed below is required for basic drilling operations. Depending on the specific procedures involved, the entire operation could take as little as half a day or up to a week. If nitrogen is used, additional equipment is required. A basic trailer-mounted coiled-tubing unit is shown in Figure 1.
- Injector head, with support.
- Tubing guide arch.
- Coiled tubing reel.
- Control console.
- Well control stack, with flow "T" and valve.
- Return tank.
- Fluid pump.

Horizontal work involves more equipment and time. The more sophisticated Bottom-Hole Assemblies (BHAs) require a mast, for example. The drilling fluid will probably be in use longer and exposed to more drill solids. More solids-control equipment will be necessary to maintain the best low solids content. In many drilling applications, the coiled-tubing unit will be mated to a workover rig. New coiled-tubing units are being built specifically for drilling applications.

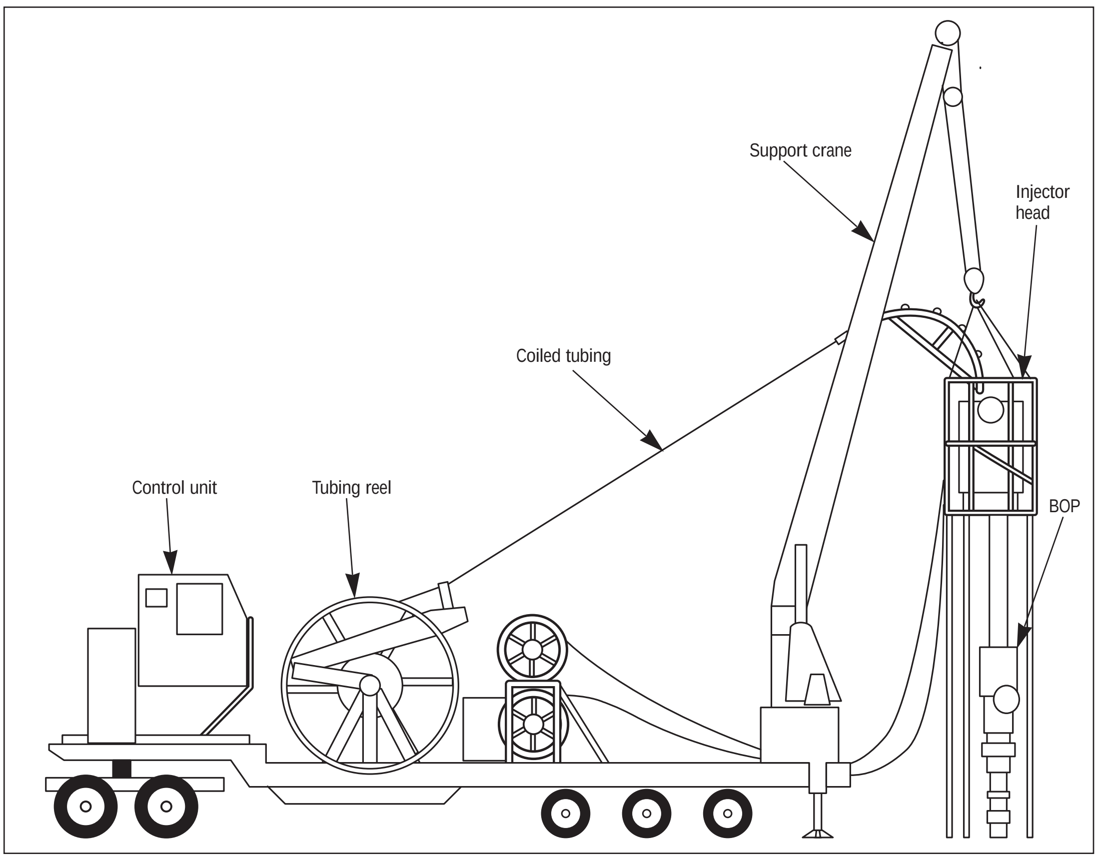

Figure 1: Coiled-tubing unit (trailer mounted).

The injector head should be capable of 120% of the maximum force expected…

INJECTOR HEAD

The injector head should be capable of 120% of the maximum force expected to pull the coiled tubing out of the well when at the total depth, including friction losses in the stripper. The maximum pulling force is the maximum tensile force that the injector can apply to the coiled tubing immediately above the stripper at the manufacturer-recommended hydraulic operation pressure.

The injector head should also be capable of a maximum snubbing force that is 120% of the maximum snubbing force expected to snub the coiled tubing into the well through the stripper and against the maximum expected wellhead pressure. The maximum snubbing force is the maximum compressive force the injector can apply to the coiled tubing immediately above the stripper at the manufacturer-recommended hydraulic operating pressure.

The injector and power supply should be capable of developing this maximum pulling and snubbing force while the coiled tubing is stationary and while moving at speeds up to 30 ft/min. The unsupported length of coiled tubing between the injector and the stripper should be minimized to prevent tube buckling at maximum snubbing force.

The injector should be able to apply sufficient traction to the coiled tubing so that coiled tubing covered with normal protective lubricant will not slip through the injector at either the maximum pulling force or maximum snubbing force. Damage to the coiled tubing should be minimized when maximum traction forced is applied. Provisions should be available to provide traction in the event the power supply or prime mover fails.

The injector must be supported to prevent a bending moment from being applied to the wellhead under normal planned operating conditions. Any load due to the weight of the injector, well-control equipment and the hanging weight of the coiled tubing that is transmitted to the wellhead should be transmitted along the axis of the wellhead.

The injector should have a dynamic braking system that prevents the coiled tubing from moving uncontrollably due to load when no hydraulic pressure is being applied to the hydraulic motors. The injector should also have a secondary mechanical brake, that is set automatically or manually, when the injector is stopped. Both the normal and the secondary braking systems must be capable of holding the maximum pulling force and the maximum snubbing force.

...the tubing guide arch radius should be at least 30 times the coiled tubing diameter.

TUBING GUIDE ARCH

Certain types of injectors utilize a tubing guide arch located on top of the injector that guides the coiled tubing from the reel into the top of the injector. There are lower rollers, and there should be upper rollers, that center the coiled tubing as it travels around the guide arch. The tubing guide arch radius is defined as the radius of curvature of the centerline of the inner rollers. The bending radius of the tubing guide arch is more important than the bending radius of the reel because twice as many bending cycles occur at the tubing guide arch as occur at the reel. For coiled tubing used repeatedly in service and drilling applications, the tubing guide arch radius should be at least 30 times the coiled tubing diameter. This factor may be less for coiled tubing that will be run only a few times, such as in permanent installations.

Some guide arches have a roller that can be adjusted to cause a reverse bend in the coiled tubing just before it enters the chains. This reverse bend allows the coiled tubing to exit the chains below the injector and enter the well with less residual bend. It typically does not cause the coiled tubing to be perfectly straight. Reverse bending increases the fatigue damage to the coiled tubing and frequently causes an error in the weight indicator reading.

Spooling of the coiled tubing back and forth across the width of the reel changes the "fleet angle" at which the coiled tubing approaches the tubing guide arch. The fleet angle is the maximum angle between a line passing through the center of the tubing guide arch and the center of the reel, and a line passing through the flange of the reel. The end of the tubing guide arch should not interfere with the coiled tubing as it passes through this fleet angle. The tubing guide arch must support side loading caused by this fleet angle. A schematic of an injector head and tubing guide arch with stripper assembly and Blowout Preventer (BOP) stack is shown in Figure 2.

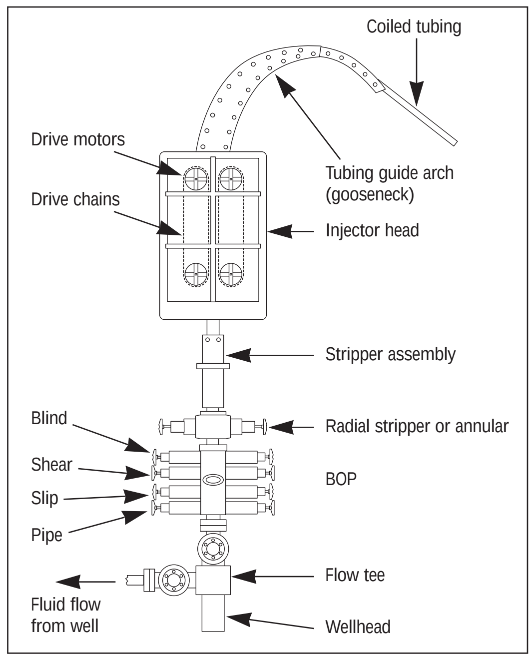

Figure 2: Injector head, tubing guide arch and well-control stack.

...the core radius should be at least 20 times the coiled tubing diameter.

COILED-TUBING REEL

The reel serves as the storage mechanism during transport and as the spooling device during coiled-tubing operations. The length of coiled tubing that can be stored on a reel is the reel capacity for that particular-diameter coiled tubing. The core radius of the reel defines the smallest bending radius for the coiled tubing. For coiled tubing used repeatedly in service and drilling applications, the core radius should be at least 20 times the coiled tubing diameter. This factor may be less for coiled tubing that will be run only a few times, such as for a permanent installation. The reel drive system must produce enough torque to bend the coiled tubing over the tubing guide arch and onto the reel. It must also be able to accelerate the tubing drum from stop to maximum injector speed at an acceptable rate with the drum full of tubing, and with the tubing full of fluid. The coiled tubing stored on a reel has the potential to unwrap and spring outward from the reel if the tubing back-tension is released. The free end of the coiled tubing must always be kept in tension. The reel brake is used to restrain the reel when it is not in motion, and can also minimize springing of the tubing on the reel in case of loss of hydraulic pressure and loss of back tension.

Control Console Job Parameters

Load is the tensile or compressive force in the coiled tubing just above the stripper.

Load is the tensile or compressive force in the coiled tubing just above the stripper. Load should be measured directly using a load cell that measures the force the coiled tubing is applying to the injector. Load may be affected by the following factors:

- Hanging weight of the coiled tubing.
- Wellhead pressure.
- Stripper friction.
- Reel back tension.
- Density of the fluid(s) inside and outside the tubing (buoyancy).

Measured depth is the length of coiled tubing that is deployed through the injector. It can vary significantly from the actual depth in the well due to stretch, thermal expansion, wellbore washouts and other factors.

Coiled-tubing inlet pressure is the pressure at the inlet to the coiled tubing. It is used to understand well conditions and for calculating fatigue factor in the coiled tubing.

Wellhead pressure is the pressure around the outside of the coiled tubing at the wellhead. It is also used to understand well conditions and also for calculating fatigue factor in the coiled tubing.

Well-Control Equipment

Coiled-tubing, well-control equipment is designed to allow safe well intervention services to be performed under pressure. However, well pressure should be kept at a minimum to avoid unnecessary wear and tear on the well-control equipment. The minimum well-control stack should include the following from the top down:

- One stripper or annular-type well-control component.
- One blind-ram well-control component.
- One shear-ram well-control component.
- One kill-line outlet with valve.
- One slip-ram well-control component.
- One pipe-ram well-control component.

This equipment should be considered as the *primary barrier* for well control purposes. In situations that require a *secondary barrier*, the wellhead equipment should serve as the secondary barrier, if such equipment is capable of mechanically severing the coiled tubing should the wellbore need to be sealed. When well-servicing conditions warrant a dedicated kill line, it should be equipped with two in-line valves rated to the same working pressure as the well-control stack. These valves should be tested to the rated working pressure of the well-control stack, or the christmas tree, whichever is less. The kill-line outlet on the well-control stack should not be used for taking fluid returns from the wellbore.

Blind rams isolate pressure from the well when the bore of the well-control stack is unobstructed.

Shear rams should be designed with the capability to shear the wall thickness and yield strength of the specified coiled tubing OD size as test-certified at the rated working pressure of the well-control stack.

Slip rams should be capable of holding the coiled tubing in the pipe-heavy mode to the minimum yield of the coiled tubing at the rated working pressure of the well-control stack. They should be capable of holding the coiled tubing in the snub mode at a minimum of 50% of the minimum yield of the coiled tubing. The slip rams should have pipe guides, and be designed to minimize tubing damage, such as slip marks and deformation.

Pipe rams close and seal around the coiled tubing and should include pipe guides. Pipe rams are always placed in the bottom cavity of a single quad well-control stack.

Usually, work done with coiled tubing includes the return of liquids and gases to the surface through the coiled-tubing-well tubular annulus. Sometimes this return flow contains highly abrasive materials such as sand. The typical flow path for fluid return is a flow tee located below the well-control stack that leads to the surface-treatment equipment.

A downhole check valve is typically attached to the coiled tubing connector at the downhole end of the coiled tubing to prevent wellbore fluids from entering the coiled tubing string in the event treatment fluids are not being pumped. In addition, the check valve assembly provides an essential safety barrier against wellbore fluid influx up the coiled tubing in case of a seal or joint failure in the BHA. The check valve also provides a safety barrier if the tubing should fail or be damaged at the surface. Check valve designs can be categorized as either the more common ball-and-seat check valves or flapper check valves.

...the check valve assembly provides an essential safety barrier against wellbore fluid influx...

Equipment for hydrogen sulfide service should comply with API Recommended Practice 53, Section 9. Hydrogen sulfide (H_2S, sour service) environment is common when the equipment will be exposed to hydrogen sulfide gas zones that have partial pressure of hydrogen sulfide exceeding 0.05 psi absolute in the gas phase. Many metals are subject to sulfide-stress cracking when exposed to hydrogen sulfide. Well-control equipment, including studs and nuts, lines, valves, fittings, gaskets, and elastomers should be reviewed when entering into hydrogen sulfide environment.

Fluids for Coiled-Tubing Drilling Operations

All drilling is done in the slide mode; there is no pipe rotation.

Frequent backreaming is used to improve hole cleaning...

Coiled-tubing operations are similar to conventional drilling rig operations in some ways, and very different in other ways. Fluids used in coiled-tubing operations reflect this same mixture of characteristics. The fluids are circulated conventionally through the tubing, with returns being taken from the annulus. Circulation can be constantly maintained while tripping. The same amount of drillstring is used throughout, regardless of the bit depth. Smaller, more flexible tubulars restrict pump pressure. All drilling is done in the slide mode; there is no pipe rotation. The more flexible drillstring will tend to buckle more readily and can reduce the Rate of Penetration (ROP) due to the inability to transfer weight to the bit. Understanding these unique aspects of coiled tubing is critical to designing a fluid to perform successfully.

Fluid functions

- Transport cuttings to surface.
- Minimize pump pressure.
- Control leak-off or fluid loss to reservoir sections.
- Prevent stuck pipe.
- Provide lubricity between tubing and the wellbore.
- Cool and lubricate the bit and downhole motor.
- Stabilize the wellbore.
- Minimize formation damage.

M-I's FLO-PRO® and FLO-PRO SF systems are ideal for coiled-tubing drilling operations. Both systems uniquely satisfy all the functions listed.

The transport of cuttings to the surface in a coiled-tubing operation is frequently through a variety of annular geometries at various angles. This may include very small diameters with high annular velocities that open up into very large diameters with low annular velocities, as found in many re-entry projects. The fluid must be very shear-thinning to properly clean both sections of the hole. Horizontal drilling with coiled tubing also requires different procedures. Frequent backreaming is used to improve hole cleaning since all drilling is done in the slide mode.

Lower pump pressures result in longer life for the coil. To minimize pump pressure, it is important to use a clean fluid that provides minimal plastic viscosity as well as drag reduction inside the drillstring. The optimum fluid uses only a small amount of FLO-VIS® polymer for viscosity, keeping solids content to about 1% or less. The viscosity created has low-plastic viscosity, good yield point and gels, and excellent low-shear viscosity. Elevated-plastic viscosity translates into higher pump pressure, whether caused by solids, polymers or emulsions. Drag reduction is the ability of a fluid or material to decrease pump pressure while in the turbulent flow regime. Drag reduction is not possible unless turbulent flow is present. Turbulent flow will occur inside the drillstring.

Leak-off or fluid loss to the formation must be controlled not only to minimize the potential for stuck pipe and wellbore instability but also to minimize formation damage. Leak-off can be controlled by laying down a thin, impermeable filter cake or by relying on elevated Low-Shear-Rate Viscosity (LSRV). A thin, impermeable filter cake requires bridging solids and fluid-loss-control agents. These materials will increase the plastic viscosity of the fluid. A thin, impermeable filter cake can also create a dramatic pressure gradient across its thickness that may increase the potential for differentially sticking a non-rotating drillstring. By elevating the LSRV of the fluid, leak-off can be controlled without creating a dramatic pressure gradient across the formation face.

It is important to have good lubricity due to the lack of pipe rotation.

It is important to have good lubricity due to the lack of pipe rotation. The ability to transfer weight to the bit can be reduced due to buckling (sinusoidal as well as helical) of the flexible coil if adequate lubricity is not present. The ability to transfer weight in conventional drilling is enhanced with pipe rotation. Minimizing solids and soft-settled cuttings, as well as the use of lubricants, reduces mechanical friction coefficients.

Wellbore stability is assured primarily with mud density, but inhibition and viscosity also assist somewhat with controlling wellbore stability. Inhibition prevents clays from swelling and restricting the wellbore. Elevated viscosity provides suspension and carrying capacity when the wellbore fails, preventing a tough cuttings bed or dune from restricting pipe movement through the hole.

Formation damage must be minimized with coiled-tubing operations. The small hole size and lighter weight coiled tubing mean that any clay swelling or formation instability will result in stuck pipe and reduced production. Pump pressure, clay swelling and formation instability are the primary reasons clay is not used in fluids for coiled-tubing operations. Additional effort is made to control drill solids buildup. Rental of adequate solids-control equipment is one option to control drill solids. Another option is to exchange whole fluid periodically, substituting fresh, clean fluid.

When coiled-tubing operations include horizontal work, the fluid should have elevated LSRV as measured on a Brookfield viscometer at a shear rate of 0.0636 sec^{-1}. Rheologically engineered fluids, such as FLO-PRO, with elevated LSRVs have been used to drill horizontally with both conventional and coiled-tubing drilling rigs since 1991 with dependable success. FLO-PRO prevents cuttings beds in the horizontal portion of the hole without excessive reliance on drilling practices such as backreaming and circulation.

LSRV is generated by FLO-VIS, a premium-grade, clarified xanthan gum. Conventional rheological properties, yield point and RPM can be adjusted at relatively low polymer concentrations, but LSRV does not develop until a critical polymer concentration has been exceeded. LSRV, being the last rheological property to develop, is also the first to be degraded. A premium-grade xanthan such as FLO-VIS minimizes the concentration of polymer required to create LSRV and also to maintain it. In areas where non-clarified xanthan has been used to replace the premium-grade, *clarified* xanthan due to inventory shortages, it takes twice as much to maintain the desired LSRV. FLO-VIS, which has the bacterial residue from the manufacturing process removed, was chosen to minimize potential formation damage as well as minimize the amount of polymer required to attain the desired LSRV.

Density of these fluids is maintained with salts. A variety of salts, NaCl, KCl, NaBr, Na-formate and K-formate can be used in the fluid to salt saturation. In addition, $CaCl_2$, K-acetate, freshwater, seawater and field brines can be used for density. The salt concentrations can be adjusted for density and/or inhibition. In addition, liquid shale hydration suppressants, either amphoteric or cationic, can be used to control inhibition levels without increasing density. Glycols may also be used in the system to improve inhibition.

The fluid pH can be controlled with caustic soda, KOH, soda ash or magnesium oxide. The pH is generally maintained around 9.

Fluids have been used with and without bridging agents. The presence of bridging agents increases pump pressure and therefore limits the length and diameter of coiled tubing that can be used on a well. Short coils with adequate diameter can use bridging agents in the fluid. However, when the measured depths are great and the diameter is small, bridging agents cannot be used. For example, tubing with a 2-in. diameter and a length of 15,000 ft, could not stand the pressure created with the use of bridging agents.

A "solids-free" fluid without bridging agent, such as FLO-PRO SF, can keep pressures in a 2-in. diameter, 15,000-ft coil to less than 4,000 psi. The "solids-free" fluid relies on elevated LSRV to control the invasion of filtrate into the formation. As fluid leaks off radially to the formation, the shear rate decreases and viscosity prevents further penetration. Depth of penetration will vary from formation to formation and is controlled by, among other things, temperature, overbalance pressure, formation permeability and porosity, and formation fluid viscosity.

Solids-free fluids do not form a filter cake on the face of the formation creating a high-differential-pressure gradient, but rather a gradual gradient over some distance. This reduces the potential for stuck pipe in the non-rotating annulus.

Summary

Coiled-tubing drilling is designed for smaller-diameter, slim-hole wells that flow at less volume.

Coiled-tubing drilling can be successfully used to drill horizontal wells in overbalanced conditions. Minimizing solids and using "solids-free" rheologically engineered fluids like the FLO-PRO system are critical to maximizing drilling parameters while minimizing formation damage. A combination of elevated LSRV and back-reaming optimize hole cleaning in through-tubing re-entries. Solids contribute to higher pump pressures, shorter coil life, potential stuck pipe, greater formation damage and higher mechanical friction coefficients.

Drilling with coiled tubing will never replace drilling with rotary rigs. Rigs must be used on wells that require large-diameter holes and heavy, large-diameter pipe. Coiled-tubing drilling is designed for smaller-diameter, slim-hole wells that flow at less volume. Most of the coiled-tubing wells drilled today are sidetracks. These are wells that are drilled off of an older wellbore. Since the infrastructure of the older wellbore can be used, significant cost savings are achieved.

Through-Tubing Drilling

...the main advantage to rotary drilling over coiled-tubing drilling is the amount of horizontal section that can be drilled.

Through-tubing drilling with rotary drilling rigs in small-diameter hole sizes have benefited from the same improvements in downhole directional equipment and drilling motors that have made coiled-tubing drilling feasible. There are some advantages to using rotary drilling in through-tubing drilling applications. The ability to turn the drillstring reduces friction in the wellbore, improves hole cleaning and can increase rates of penetration. In addition, since the fluid only has to be pumped through the pipe that is in the hole, pump-pressure limitations are not as important in through-tubing drilling.

Through-tubing drilling benefits by the same fluid design as coiled-tubing drilling. However, with the lower pump-pressure requirements and the ability to rotate the pipe, more conventional fluids can be successfully used. These include fluids with:

- Solid bridging materials.
- Solid weighting materials.
- Invert oil emulsion muds.

Presently, the main advantage to rotary drilling over coiled-tubing drilling is the amount of horizontal section that can be drilled. In rotary drilling, the pipe connections provide more stability to the drillstring than is the case with coiled-tubing drilling. The technology of coiled-tubing drilling is improving, but currently the outer limit of a horizontal section drilled with coiled-tubing unit appears to be about 3,000 ft. This compares to about 5,000 ft with a rotary-drilling unit drilling through tubing.

Conclusion

Both coiled- and through-tubing drilling technologies are advancing rapidly. They offer significant economic advantages over conventional rotary drilling in certain situations. The unique requirements of these techniques place unusual demands on the design of drilling fluids. To accommodate these changing technologies we anticipate improvements and changes in the drilling-fluid technologies as well.