Introduction

The duty of those charged with drilling the hole...

The objective of a drilling operation is to drill, evaluate and complete a well that will produce oil and/or gas efficiently. Drilling fluids perform numerous functions that help make this possible. The responsibility for performing these functions is held jointly by the mud engineer and those who direct the drilling operation. The duty of those charged with drilling the hole — including the oil company representative, drilling contractor and rig crew — is to make sure correct drilling procedures are conducted. The chief duty of the mud engineer is to assure that mud properties are correct for the specific

drilling environment. The mud engineer should also recommend drilling practice changes that will help reach the drilling objectives.

Drilling Fluid Functions

Drilling fluid functions describe tasks which the drilling fluid is capable of performing, although some may not be essential on every well. Removing cuttings from the well and controlling formation pressures are of primary importance on every well. Though the order of importance is determined by well conditions and current operations, the most common drilling fluid functions are:

1. Remove cuttings from the well.
2. Control formation pressures.
3. Suspend and release cuttings.
4. Seal permeable formations.
5. Maintain wellbore stability.
6. Minimize reservoir damage.
7. Cool, lubricate, and support the bit and drilling assembly.
8. Transmit hydraulic energy to tools and bit.
9. Ensure adequate formation evaluation.
10. Control corrosion.
11. Facilitate cementing and completion.
12. Minimize impact on the environment.

1. Remove cuttings from the well

As drilled cuttings are generated by the bit, they must be removed from the well. To do so, drilling fluid is circulated down the drillstring and through the bit, entraining the cuttings and carrying them up the annulus to the surface. Cuttings removal (hole cleaning) is a function of cuttings size, shape and density combined with Rate of Penetration (ROP); drillstring rotation; and the viscosity, density and annular velocity of the drilling fluid.

Viscosity. The viscosity and rheological properties of drilling fluids have a significant effect on hole cleaning. Cuttings settle rapidly in low-viscosity fluids (water, for example) and are difficult to circulate out of the well. Generally, higher-viscosity fluids improve cuttings transport.

The use of shear-thinning, thixotropic fluids with high Low-Shear-Rate Viscosity...

Most drilling muds are *thixotropic,* which means they gel under static conditions. This characteristic can suspend cuttings during pipe connections and other situations when the mud is not being circulated. Fluids that are shear-thinning and have elevated viscosities at low annular velocities have proven to be best for efficient hole cleaning.

Velocity. Generally, higher annular velocity improves cuttings removal. Yet, with thinner drilling fluids, high velocities may cause turbulent flow, which helps clean the hole but may cause other drilling or wellbore problems.

The rate at which a cutting settles in a fluid...

The rate at which a cutting settles in a fluid is called the *slip velocity*. The slip velocity of a cutting is a function of its density, size and shape, and the viscosity, density and velocity of the drilling fluid. If the annular velocity of the drilling fluid is greater than the slip velocity of the cutting, the cutting will be transported to the surface.

The net velocity at which a cutting moves up the annulus is called the *transport velocity*. In a vertical well:

Transport velocity = Annular velocity – slip velocity

(Note: Slip velocity, transport velocity, and the effects of rheology and hydraulic conditions on cuttings transport will be discussed in detail in another chapter.)

Cuttings transport in high-angle and horizontal wells is more difficult than in vertical wells. The transport velocity as defined for vertical wellbores is not relevant for deviated holes, since the cuttings settle to the low side of the hole across the fluid's flow path and not in the direction opposite to the flow of drilling fluid. In horizontal wells, cuttings accumulate along the bottom side of the wellbore, forming cuttings beds. These beds restrict flow, increase torque and are difficult to remove.

Two different approaches are used for the difficult hole-cleaning situations found in high-angle and horizontal wellbores:

a) **The use of shear-thinning, thixotropic fluids with high Low-Shear-Rate Viscosity (LSRV) and laminar flow conditions.** Examples of these fluid types are biopolymer systems, like FLO-PRO®, and flocculated bentonite slurries like the Mixed Metal Hydroxide (MMH) system. Such drilling fluid systems provide a high viscosity with a relatively flat annular velocity profile, cleaning a larger portion of the wellbore cross section. This approach tends to suspend cuttings in the mud flow path and prevent cuttings from settling to the low side of the hole. With weighted muds, cuttings transport can be improved by increasing the 3 and 6 RPM Fann dial readings (indications of LSRV) to 1 to 1½ times the hole size in inches and to use the highest possible laminar flow rate.

b) **The use of a high flow rate and thin fluid to achieve turbulent flow.** Turbulent flow will provide good hole cleaning and prevent cuttings from settling while circulating, but cuttings will settle quickly when circulation is stopped. This approach works by keeping the cuttings suspended with turbulence and high annular velocities. It works best with low-density, unweighted fluids in competent (not easily eroded) formations. The effectiveness of this technique can be limited by a number of factors, including large hole size, low pump capacity, increased depth, insufficient formation integrity, and the use of mud motors and downhole tools that restrict flow rate.

Density. High-density fluids aid hole cleaning by increasing the buoyancy forces acting on the cuttings, helping to remove them from the well. Compared to fluids of lower density, high-density fluids may clean the hole adequately even with lower annular velocities and lower rheological properties. However, mud weight in excess of what is needed

Higher rotary speeds also aid hole cleaning...

to balance formation pressures has a negative impact on the drilling operation; therefore, it should never be increased for hole-cleaning purposes.

Drillstring rotation. Higher rotary speeds also aid hole cleaning by introducing a circular component to the annular flow path. This *helical* (spiral- or corkscrew-shaped) flow around the drillstring causes drill cuttings near the wall of the hole, where poor hole-cleaning conditions exist, to be moved back into the higher transport regions of the annulus. When possible, drillstring rotation is one of the best methods for removing cuttings beds in high-angle and horizontal wells.

2. Controlling formation pressures

As mentioned earlier, a basic drilling fluid function is to control formation pressures to ensure a safe drilling operation. Typically, as formation pressures increase, drilling fluid density is increased with barite to balance pressures and maintain wellbore stability. This keeps formation fluids from flowing into the wellbore and prevents pressured formation fluids from causing a blowout. The pressure exerted by the drilling fluid column while static (not circulating) is called the *hydrostatic pressure* and is a function of the density (mud weight) and True Vertical Depth

(TVD) of the well. If the hydrostatic pressure of the drilling fluid column is equal to or greater than the formation pressure, formation fluids will not flow into the wellbore.

Keeping a well "under control" is often characterized as a set of conditions under which no formation fluid will flow into the wellbore. But it also includes conditions where formation fluids are allowed to flow into the wellbore — under controlled conditions. Such conditions vary — from cases where high levels of background gas are tolerated while drilling, to situations where the well is producing commercial quantities of oil and gas while being drilled. Well control (or pressure control) means there is no *uncontrollable* flow of formation fluids into the wellbore.

Hydrostatic pressure also controls stresses adjacent to the wellbore other than those exerted by formation fluids. In geologically active regions, tectonic forces impose stresses in formations and may make wellbores unstable even when formation fluid pressure is balanced. Wellbores in tectonically stressed formations can be stabilized by balancing these stresses with hydrostatic pressure. Similarly, the orientation of the wellbore in high-angle and horizontal intervals can cause decreased wellbore stability, which can also be controlled with hydrostatic pressure.

Normal formation pressures vary from a pressure gradient of 0.433 psi/ft (equivalent to 8.33 lb/gal freshwater) in inland areas to 0.465 psi/ft (equivalent to 8.95 lb/gal) in marine basins. Elevation, location, and various geological processes and histories create conditions where formation pressures depart considerably from these normal values. The density of drilling fluid may range from that of air (essentially 0 psi/ft), to in excess of 20.0 lb/gal (1.04 psi/ft).

Often, formations with sub-normal pressures are drilled with air, gas, mist, stiff foam, aerated mud or special ultra-low-density fluids (usually oil-base).

The mud weight used to drill a well is limited by the minimum weight needed to control formation pressures and the maximum mud weight that will not fracture the formation. In practice, the mud weight should be limited to the minimum necessary for well control and wellbore stability.

3. Suspend and release cuttings

Drilling muds must suspend drill cuttings...

Drilling muds must suspend drill cuttings, weight materials and additives under a wide range of conditions, yet allow the cuttings to be removed by the solids-control equipment. Drill cuttings that settle during static conditions can cause bridges and fill, which in turn can cause stuck pipe or lost circulation. Weight material which settles is referred to as *sag* and causes a wide variation in the density of the well fluid. Sag occurs most often under dynamic conditions in high-angle wells, where the fluid is being circulated at low annular velocities.

High concentrations of drill solids are detrimental to almost every aspect of the drilling operation, primarily drilling efficiency and ROP. They increase the mud weight and viscosity, which in turn increases maintenance costs and the need for dilution. They also increase the horsepower required to circulate, the thickness of the filter cake, the torque and drag, and the likelihood of differential sticking.

Drilling fluid properties that suspend cuttings must be balanced with those properties that aid in cuttings removal by solids-control equipment. Cuttings suspension requires high-viscosity, shear-thinning *thixotropic* properties, while solids-removal equipment usually works more efficiently with fluids of lower viscosity. Solids-control equipment is not as effective on non-shear-thinning drilling fluids, which have high solids content and a high plastic viscosity.

For effective solids control, drill solids must be removed from the drilling fluid on the first circulation from the well. If cuttings are recirculated, they break down into smaller particles that are more difficult to remove. One easy way to determine whether drill solids are being removed is to compare the sand content of the mud at the flow line and at the suction pit.

4. Seal permeable formations

Permeability refers to the ability of fluids to flow through porous formations; formations must be permeable for hydrocarbons to be produced. When the mud column pressure is greater than formation pressure, mud filtrate will invade the formation, and a filter cake of mud solids will be deposited on the wall of the wellbore. Drilling fluid systems should be designed to deposit a thin, low-permeability filter cake on the formation to limit the invasion of mud filtrate. This improves wellbore stability and prevents a number of drilling and production problems. Potential problems related to thick filter cake and excessive filtration include “tight” hole conditions, poor log quality, increased torque and drag, stuck pipe, lost circulation, and formation damage.

In highly permeable formations with large pore throats, whole mud may invade the formation, depending on the size of the mud solids. For such situations, bridging agents must be used to block the large openings so the mud solids can form a seal. To be effective, bridging agents must be about one-half the size of the largest opening. Bridging agents include calcium carbonate, ground cellulose and a wide variety of seepage-loss or other fine lost-circulation materials.

Depending on the drilling fluid system in use, a number of additives can be applied to improve the filter cake, thus limiting filtration. These include bentonite, natural and synthetic polymers, asphalt and gilsonite, and organic deflocculating additives.

5. Maintain wellbore stability

Wellbore stability is a complex balance...

Wellbore stability is a complex balance of mechanical (pressure and stress) and chemical factors. The chemical composition and mud properties must combine to provide a stable wellbore until casing can be run and cemented. Regardless of the chemical composition of the fluid and other factors, the weight of the mud must be within the necessary range to balance the mechanical forces acting on the wellbore (formation pressure, wellbore stresses related to orientation and tectonics). Wellbore instability is most often identified by a sloughing formation, which causes tight hole conditions, bridges and fill on trips. This often makes it necessary to ream back to the original depth. (Keep in mind these same symptoms also indicate hole-cleaning problems in high-angle and difficult-to-clean wells.)

Wellbore stability is greatest when the hole maintains its original size and cylindrical shape. Once the hole is eroded or enlarged in any way, it becomes weaker and more difficult to stabilize. Hole enlargement leads to a host of problems, including low annular velocity, poor hole cleaning, increased solids loading, fill, increased treating costs, poor formation evaluation, higher cementing costs and inadequate cementing.

Hole enlargement through sand and sandstone formations is due largely to mechanical actions, with erosion most often being caused by hydraulic forces and excessive bit nozzle velocities. Hole enlargement through sand sections may be reduced significantly by following a more conservative hydraulics program, particularly with regard to impact force and nozzle velocity. Sands that are poorly consolidated and weak require a slight overbalance to limit wellbore enlargement and a good-quality filter cake containing bentonite to limit wellbore enlargement.

In shales, if the mud weight is sufficient to balance formation stresses, wells are usually stable — at first. With water-base muds, chemical differences cause interactions between the drilling fluid and shale, and these can lead (over time) to swelling or softening. This causes other problems, such as sloughing and tight hole conditions. Highly fractured, dry, brittle shales, with high dip angles, can be extremely unstable when drilled. The failure of these dry, brittle formations is mostly mechanical and not normally related to water or chemical forces.

Various chemical inhibitors or additives can be added to help control mud/shale interactions. Systems with high levels of calcium, potassium or other chemical inhibitors are best for drilling into water-sensitive formations. Salts, polymers, asphaltic materials, glycols, oils, surfactants and other shale inhibitors can be used in water-base drilling fluids to inhibit shale swelling and prevent sloughing. Shale exhibits such a wide range of composition and sensitivity that no single additive is universally applicable.

Oil- or synthetic-base drilling fluids are often used to drill the most water-sensitive shales in areas with difficult drilling conditions. These fluids provide better shale inhibition than water-base drilling fluids. Clays and shales do not hydrate or swell in the continuous phase, and additional inhibition is provided by the emulsified brine phase (usually calcium chloride) of these fluids. The emulsified brine reduces the water activity and creates osmotic forces that prevent adsorption of water by the shales.

6. Minimize formation damage

Protecting the reservoir from damage…is a big concern.

Protecting the reservoir from damage that could impair production is a big concern. Any reduction in a producing formation's natural porosity or permeability is considered to be formation damage. This can happen as a result of plugging by mud or drill solids or through chemical (mud) and mechanical (drilling assembly) interactions with the formation. Frequently, formation damage is reported as a skin damage value or by the amount of pressure drop that occurs while the well is producing (drawdown pressure).

The type of completion procedure and method will determine which level of formation protection is required. For example, when a well is cased, cemented and perforated, the perforation depth usually allows efficient production, even if near-wellbore damage exists. Conversely, when a horizontal well is completed with one of the "open-hole" methods, a "drill-in" fluid — specially designed to minimize damage — is required. While the effect of drilling fluid damage is rarely so extensive that oil and/or gas cannot be produced, consideration should be given to potential formation damage when selecting a fluid for drilling potential reservoir intervals.

Some of the most common mechanisms for formation damage are:

a) Mud or drill solids invading the formation matrix, plugging pores.
b) Swelling of formation clays within the reservoir, reducing permeability.
c) Precipitation of solids as a result of mud filtrate and formation fluids being incompatible.
d) Precipitation of solids from the mud filtrate with other fluids, such as brines or acids, during completion or stimulation procedures.
e) Mud filtrate and formation fluids forming an emulsion, restricting permeability.

The possibility of formation damage can be determined from offset well data and studies of formation cores for return permeability. Drilling fluids designed to minimize a particular problem, specially designed drill-in fluids or workover and completion fluids, all can be used to minimize formation damage.

7. Cool, lubricate and support the bit and drilling assembly

Considerable frictional heat is generated by mechanical and hydraulic forces at the bit and where the rotating drillstring rubs against the casing and wellbore. Circulation of the drilling fluid cools the bit and drilling assembly, *The lubricity of a particular fluid is measured by...*

Hydraulic energy can be used to maximize ROP...

transferring this heat away from the source, distributing it throughout the well. Drilling fluid circulation cools the drillstring to temperatures lower than the bottom-hole temperature. In addition to cooling, drilling fluid lubricates the drillstring, further reducing frictional heat. Bits, mud motors and drillstring components would fail more rapidly if it were not for the cooling and lubricating effects of drilling fluid.

The lubricity of a particular fluid is measured by its Coefficient of Friction (COF), and some muds do a better job than others at providing lubrication. For example, oil- and synthetic-base muds lubricate better than most water-base muds, but lubricants can be added to water-base muds to improve them. On the other hand, water-base muds provide more lubricity and cooling ability than air or gas.

The amount of lubrication provided by a drilling fluid varies widely and depends on the type and quantity of drill solids and weight material, plus the chemical composition of the system — pH, salinity and hardness. Altering mud lubricity is not an exact science. Even after a thorough evaluation, with all relevant factors considered, application of a lubricant may not produce the anticipated reduction in torque and drag.

Indications of poor lubrication are high torque and drag, abnormal wear, and heat checking of drillstring components. But be aware that these problems can also be caused by severe doglegs and directional problems, bit balling, key seating, poor hole cleaning and incorrect bottom-hole assembly design. While a lubricant may reduce the symptoms of these problems, the actual cause must be corrected to resolve the problem.

The drilling fluid helps to support a portion of the drillstring or casing string weight through buoyancy. If a drillstring, liner or casing string is suspended in drilling fluid, it is buoyed by a force equal to the weight of the mud displaced, thereby reducing hook load on the derrick. Buoyancy is directly related to the mud weight, so an 18-lb/gal fluid will provide twice the buoyancy of a 9-lb/gal fluid.

The weight that the derrick can support is limited by its mechanical capacity, a consideration that becomes increasingly important with increased depth as the weight of the drillstring and casing becomes tremendous. While most rigs have sufficient capacity to handle the drillstring weight *without* buoyancy, it is an important consideration when evaluating the *neutral point* (where the drillstring is in neither tension nor compression). However, when running long, heavy strings of casing, buoyancy can be used to provide a significant benefit. Using buoyancy, it is possible to run casing strings whose weight exceeds a rig's hook load capacity. If the casing is not completely filled with mud as it is lowered into the hole, the void volume inside the casing increases buoyancy, allowing a significant reduction in hook load to be used. This process is referred to as "floating in" the casing.

8. Transmit hydraulic energy to tools and bit

Hydraulic energy can be used to maximize ROP by improving cuttings removal at the bit. It also provides power for mud motors to rotate the bit and for Measurement While Drilling (MWD) and Logging While Drilling (LWD) tools. Hydraulics programs are based on sizing the bit nozzles properly to use available mud pump horsepower (pressure or energy) to generate a maximized pressure drop at the bit or to optimize jet impact force on the bottom of the well. Hydraulics programs are limited by the available pump horsepower, pressure losses inside the drillstring, maximum allowable surface pressure and optimum flow rate. Nozzle sizes are selected to use the available pressure at the bit to maximize the effect of mud impacting the bottom of the hole. This helps remove cuttings from beneath the bit and keep the cutting structure clean.

Drillstring pressure losses are higher in fluids with higher densities, plastic viscosities and solids. The use of small-ID drill pipe or tool joints, mud motors and MWD/LWD tools all reduce the amount of pressure available for use at the bit. Low-solids, shear-thinning drilling fluids or those that have drag-reducing characteristics, such as polymer fluids, are more efficient at transmitting hydraulic energy to drilling tools and the bit.

In shallow wells, sufficient hydraulic horsepower usually is available to clean the bit efficiently. Because drillstring pressure losses increase with well depth, a depth will be reached where there is insufficient pressure for optimum bit cleaning. This depth can be extended by carefully controlling the mud properties.

9. Ensure adequate formation evaluation

Accurate formation evaluation is essential to the success...

Accurate formation evaluation is essential to the success of the drilling operation, particularly during exploration drilling. The chemical and physical properties of the mud affect formation evaluation. The physical and chemical wellbore conditions after drilling also influence formation evaluation. During drilling, the circulation of mud and cuttings is monitored for signs of oil and gas by technicians called *mud loggers*. They examine the cuttings for mineral composition, paleontology and visual signs of hydrocarbons. This information is recorded on a *mud log* that shows lithology, ROP, gas detection and oil-stained cuttings plus other important geological and drilling parameters.

Electric wireline logging is performed to evaluate the formation in order to obtain additional information. Sidewall cores also may be taken with wireline-conveyed tools. Wireline logging includes measuring the electrical, sonic, nuclear and magnetic-resonance properties of the formation to identify lithology and formation fluids. For continuous logging while the well is being drilled, LWD tools are available. Drilling a cylindrical section of the rock (a core) for laboratory evaluation also is done in target production zones to obtain desired information. Potentially productive zones are isolated and evaluated by performing Formation Testing (FT) or Drill-Stem Testing (DST) to obtain pressure and fluid samples.

All of these formation evaluation methods are affected by the drilling fluid. For example, if the cuttings disperse in the mud, there will be nothing for the mud logger to evaluate at the surface. Or, if cuttings transport is poor, it will be difficult for the mud logger to determine the depth at which the cuttings originated. Oil

Dissolved gasses...can cause serious corrosion problems...

muds, lubricants, asphalts and other additives will mask indications of hydrocarbons on cuttings. Certain electrical logs work in conductive fluids, while others work in non-conductive fluids. Drilling fluid properties will affect the measurement of rock properties by electrical wireline tools. Excessive mud filtrate can flush oil and gas from the near-wellbore region, adversely affecting logs and FT or DST samples. Muds that contain high potassium ion concentrations interfere with the logging of natural formation radioactivity. High or variable filtrate salinity can make electrical logs difficult or impossible to interpret.

Wireline logging tools must be run from the surface to bottom, with the actual measurement of rock properties being performed as the tools are pulled up the hole. For optimum wireline logging, the mud must not be too thick, it must keep the wellbore stable and it must suspend any cuttings or cavings. In addition, the wellbore must be near-gauge from top to bottom, since excessive bore enlargement and/or thick filter cakes can produce varying logging responses and increase the possibility of sticking the logging tool.

Mud for drilling a core is selected based on the type of evaluation to be performed. If a core is being taken only for lithology (mineral analysis), mud type is not a concern. If the core will be used for waterflood and/or wettability studies, a "bland," neutral-pH, water-base mud without surfactants or thinners will be needed. If the core will be used for measuring reservoir water saturation, a bland oil mud with minimal surfactants and no water or salt is often recommended. Many coring operations specify a bland mud with a minimum of additives.

10. Control corrosion

Drillstring and casing components that are in continual contact with the drilling fluid are susceptible to various forms of corrosion. Dissolved gasses such as oxygen, carbon dioxide and hydrogen sulfide can cause serious corrosion problems, both at the surface and downhole. Generally, low pH aggravates corrosion. Therefore, an important drilling fluid function is to keep corrosion to an acceptable level. In addition to providing corrosion protection for metal surfaces, drilling fluid should not damage rubber or elastomer goods. Where formation fluids and/or other downhole conditions warrant, special metals and elastomers should be used. Corrosion coupons should be used during all drilling operations to monitor corrosion types and rates.

Mud aeration, foaming and other trapped-oxygen conditions can cause severe corrosion damage in a short period of time. Chemical inhibitors and scavengers are used when the corrosion threat is significant. Chemical inhibitors must be applied properly. Corrosion coupons should be evaluated to tell whether the correct chemical inhibitor is being used and if the amount is sufficient. This will keep the corrosion rate at an acceptable level.

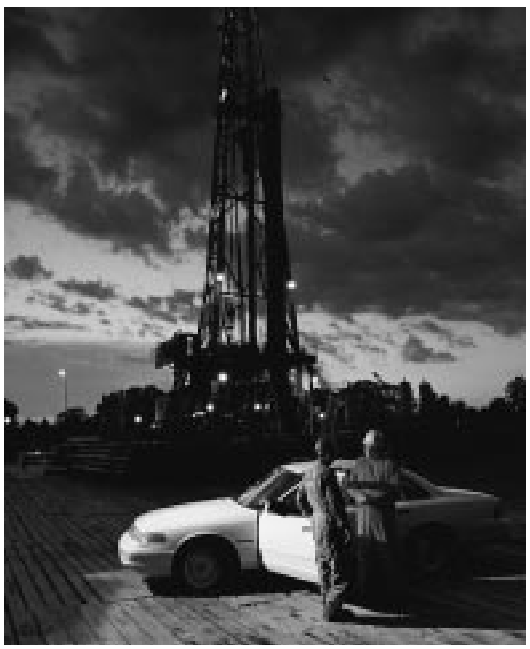
Hydrogen sulfide can cause rapid, catastrophic drillstring failure. It is also deadly to humans after even short periods of exposure and in low concentrations. When drilling in high H_2S environments, elevated pH fluids, combined with a sulfide-scavenging chemical like zinc, should be used.

11. Facilitate cementing and completion

The drilling fluid must produce a wellbore into which casing can be run and cemented effectively and which does not impede completion operations. Cementing is critical to effective zone isolation and successful well completion. During casing runs, the mud must remain fluid and minimize pressure surges so that fracture-induced lost

The mud should have a thin, slick filter cake.

circulation does not occur. Running casing is much easier in a smooth, in-gauge wellbore with no cuttings, cavings or bridges. The mud should have a thin, slick filter cake. To cement casing properly, the mud must be completely displaced by the spacers, flushes and cement. Effective mud displacement requires that the hole should be near-gauge and the mud must have low viscosity and low, non-progressive gel strengths. Completion operations such as perforating and gravel packing also require a near-gauge wellbore and may be affected by mud characteristics.



12. Minimize impact on the environment

Eventually, drilling fluid becomes a waste product, and must be disposed of in accordance with local environmental regulations. Fluids with low environmental impact that can be disposed of near the well are the most desirable.

In most countries, local environmental regulations have been established for drilling fluid wastes. Water-base, oil-base, non-aqueous and synthetic-base fluids all have different environmental considerations, and no single set of environmental characteristics is acceptable for all locations. This is due mainly to the changing, complex conditions that exist around the world — the location and density of human populations, the local geographic situation (offshore or onshore), high or low rainfall, proximity of the disposal site to surface and underground water supplies, local animal and plant life, and more.

Summary

Recommending a drilling fluid system should be based on the ability of the fluid to achieve the essential functions and to minimize anticipated well problems. Although the functions discussed in this chapter may provide guidelines for mud selection, they should not be the sole basis for selecting a drilling fluid for a well. The selection process must be founded on a wide experience base, local knowledge and consideration of the best technology available.

Mud selection. Initially, anticipation of well problems helps in selecting a particular drilling fluid system for a particular well. However, other considerations may exist that dictate use of a different system. The cost, availability of products and environmental factors are always important considerations. But it is usually the oil company representatives' experience and preferences that are the deciding factors.

Many wells are drilled successfully with fluids that were not selected for performance alone. The success of these wells results from experienced mud engineers who adapt the drilling fluid system to meet the unique conditions encountered on each well.

Mud properties vs. functions. Different mud properties may affect a particular mud function. Even if the mud engineer changes only one or two properties to control a given drilling fluid function, another may be affected

Drilling fluid engineering almost always requires tradeoffs...

as well. Mud properties should be recognized for their influence on all functions and the relative importance of each function. For example, formation pressure is controlled primarily by changing mud weight, but the influence of viscosity on annular pressure losses and Equivalent Circulating Density (ECD) should be considered to avoid lost circulation.

When functions clash. Drilling fluid engineering almost always requires tradeoffs in treating and maintaining the properties needed to accomplish the required functions. A high mud viscosity might improve hole cleaning, yet it might lower hydraulic efficiency, increase drill solids retention, slow the penetration rate, and change dilution and chemical treatment requirements. Experienced drilling fluid engineers are aware of these tradeoffs and understand how to improve one function while minimizing the impact of mud property changes on other functions.