Drilling fluid

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Drilling fluids are used primarily to keep a bore hole open & clean while earth drilling. The term fluids encompasses a broad range, including muds, water, and air.

Functions of Drilling Fluids

Primarily, the function of a drilling fluid is to:

- Cool & clean the drill bit.
- Provide up hole velocity for drill cuttings to get them out of the hole.
- Keep the annular bore hole space clean to prevent friction & clogging.
- Balance hydraulic pressures exerted by the earth on the bore hole.

Types of Drilling Fluid

[1] Many types of drilling fluids are used on a day to day basis. Some wells require that different types be used at different parts in the hole, or that some types be used in combination with others. The various types of fluid generally fall into a few broad categories:

- Air - compressed air is pumped either down the bore holes annular space or down the drill string itself.
- Air/water - Same as above, with water added to increase viscosity, flush the hole, provide more cooling, and/or to control dust.
- Air/polymer - A specially formulated chemical, most often referred to as a type of polymer, is added to the water & air mixture to create specific conditions. A foaming agent is a good example of a polymer.
- Water - Water by itself is pumped down the bore hole or drill string.
- Mud - Mud drilling is the use of water, or other medium, mixed with various clays, polymers, and/or other additives. Probably the most flexible type of drilling fluid.
- Specialty drilling fluid - A synthetic fluid designed to do very specific things in very specific formations.

References

1. ^ Oil Online, Glossary of Terms [1]


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Drilling Fluid

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PURPOSE OF FLUIDS

An essential element of drilling a well is the drilling fluid or mud. Drilling fluids serve a number of functions:

- Removal of cuttings from the bottom of the hole
- Suspend cuttings and weight material
- Transport cuttings and gas to the surface
- Cool and lubricate the bit and drill string
- Add buoyancy to the drill string
- Control subsurface pressures

The most important feature of any drilling fluid (or mud) system is that the interaction between the mud and the drilled formations must have a minimal effect on the mechanical properties of the formation. This is essential to maintaining an open hole and successfully completing the drilling operation.

PROPERTIES OF FLUIDS

The large number of functions performed by the drilling fluid require that some minimum properties of the fluids be maintained. The measurement of these properties gives the mud engineer a "status report" of the fluid and how it is reacting with the formation and the subsurface environment. The most critical of the properties are density, viscosity, fluid loss control, and chemical composition.

Density

The correct drilling fluid density is dependent on the subsurface formation pressures. Strong, competent formations can be drilled with a density less than 1.0, but overpressured shales and high pressure formations may require a fluid with specific gravities approaching 2.4. The density can be adjusted with soluble salts or by addition of solids, termed weight material (for example, barite is added to the mud to increase the density). Density values can be expressed as one of the following:

- ppg = pounds per gallon (United States)
- S.G. = specific gravity (dimensionless) (international)
- psi/ft = pounds per square inch per foot (uncommon)
- pcf = pounds per cubic foot (California)

Table 1 summarizes how these different measurements of mud density compare with one another.

Viscosity

The flow properties of the mud depend on the depth of the hole and the annular viscosities. In the upper hole, water may be sufficient, but at greater depths more viscous fluids may be required. Deep wells, directional wells, high penetration rates, high mud weights, and high temperature gradients create conditions requiring close attention to the flow properties. The viscosity can be adjusted upward with polymers or clay material or adjusted downward with chemical thinners or water.

Fluid Loss Control

The fluid loss gives a relative indication of how the mud is controlling loss of the base fluid into the formation. This becomes important when porous formations, particularly those containing oil or gas, are drilled. In porous formations, the drilling fluid may penetrate the rock and cause formation damage. (However, a low fluid loss does not always ensure minimal formation damage.) There are many types of fluid loss additives, such as bentonite, that can be used in the mud to help mitigate this problem.

Chemical Composition

Drilling fluids are two-phase compounds: a fluid and a solid phase. The character of the fluid phase is determined by chemically analyzing the concentrations of calcium, chlorides, hydroxides, bicarbonate and carbonate ions, sodium, potassium, and nitrates. The character of the solid phase is tested to determine solids concentration, specific densities, and particle sizes. The primary means of controlling solids are by removal via shale shakers, desanders, desilters, and/or dilution.

TYPES OF FLUIDS

Drilling fluids include three main types: water-based muds, oil-based muds, and air. Air drilling fluids, such as mist, foams, and stiff foams, are used in only very specific, limited applications.

Water-Based Muds

Water-based drilling fluids are the most commonly used of the mud systems. They are generally less expensive and less difficult to maintain than oil muds, and in some special types of systems, they are almost as shale inhibitive. However, inevitably the action of drilling the hole in a consolidated formation relieves stress. If a water-based fluid is used, the water will tend to enter the formation and change the mechanical properties of the rock. These changes may be enough to cause formation damage and borehole instability. These damaging effects can be minimized by using an inhibited water-based fluid. The inhibited water-based systems cannot totally prevent water wetting of the rock pores, but they can minimize it.

Water-based muds fall into two basic categories: dispersed and non-dispersed muds.
Table 1. Mud Density Measurements Comparison

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<th>psi/ft</th>
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Dispersed Muds

These muds have a chemical dispersant added to the system which is used to deflocculate mud solids. Most of the chemical dispersants in use (such as lignite and lignosulfonate) are acidic and require an alkaline environment in which to function properly. Of all the water-based muds, high pH muds are the most tolerant of solids and contamination. They are, without a doubt, the least difficult of the water muds to maintain. Clay (bentonite) is used as a viscosifier and fluid loss agent. Dispersants are used to permit enough clay into the system to control fluid losses. Caustic soda (NaOH) is used for pH control, and the density is adjusted with weight materials.

Dispersed muds can be broken into two smaller categories: calcium-based and seawater muds:

- **Calcium-Based Mud**—Calcium-based mud systems maintain a desired amount of calcium in the water phase. The calcium concentration can be maintained by using gypsum (CaSO₄) or lime (Ca(OH)₂). These muds are more inhibitive and can tolerate cement and anhydrite contamination better than a freshwater-dispersed fluid. However, their thermal limitation is somewhat reduced.

- **Seawater Mud**—In seawater muds, the upper limit for conventional dispersed fluids to function efficiently is 20,000 mg/L chlorine (which is the salinity of seawater). The cost for this type of system is slightly higher than that of a freshwater system. However, in offshore environments, this cost is offset by allowing muds to be run using native seawater rather than transporting in freshwater.

Nondispersed Muds

A basic difference between dispersed and nondispersed muds is the lack of dispersants. Nondispersed drilling muds do not require an elevated pH. By not having a dispersant present, they are less tolerant of solids and contamination.

The majority of the fluid loss control and viscosity is maintained via polymers, and these products are very susceptible to contamination from the formation, produced gases, and fluids.

**Oil-Based Muds**

Oil-based muds were developed to prevent water from entering the pore spaces and causing formation damage. There are several advantages and disadvantages of this type of mud system. The advantages include the following:

- **Shale inhibition**—In highly smectitic or "gumbo" shales, the borehole maintains stability and cuttings samples are generally intact.
- **Reduction of torque and drag problems**—Since oil is the continuous phase, the borehole and the tubulars are wetted with a lubricating fluid. This is a distinct advantage in deviated wells.
- **Thermal stability**—Oil-based muds have shown stability in wells, with BH Ts of 585°F.
- **Resistance to chemical contamination**—Carbonate, evaporite, and salt formations do not adversely affect the properties of an oil mud. CO₂ and H₂S can easily be removed with the addition of lime (CaCO₃).

Disadvantages of oil-based mud systems include the following:

- **High initial cost**—The oil fraction alone of a barrel of oil mud may cost $40–70 per barrel. This is considerably higher than most water-based muds at any weight.
- **Slow rates of penetration**—Oil muds historically have had lower rates of penetration as compared to water-based muds.
- **Pollution control**—Most areas where oil muds are used have environmental restrictions. Rig modifications may be necessary to contain possible spills, to clean up oil mud cuttings, and to handle whole mud without dumping.
- **Disposal**—Oil mud cuttings may have to be cleaned up before dumping. Some regulatory agencies require cuttings be sent to a designated disposal area.
- **Kick detection**—H₂S, CO₂, and CH₄ are soluble in oil muds. If gas enters the wellbore, it can go into solution under pressure. As the gas moves up the wellbore, it can break out of solution at the bubble point and rapidly evacuate the hole, blowing the mud with it.
- **Formation evaluation**—Some wireline logs should not be run in oil-based muds. Also, additional steps are needed to remove oil coatings from cuttings before they are described. (For more information on wireline tool compatibility with drilling fluid composition, see chapter on "Basic Tool Table" in Part 4, and for more on removing oil coatings from cuttings, see "Mudlogging: Drill Cuttings Analysis" in Part 3.)

Oil-based muds contain three phases: oil, brine, and solids phase.
Oil Phase

The oil phase is the continuous phase in which everything else in the system is mixed. The oil can be diesel, mineral oil, or one of the new types of synthetic oils.

Brine Phase

The brine phase is present in the system as a high concentration salt solution that is emulsified into the base oil. Usually a solution of calcium chloride is used because it gives a greater flexibility in adjusting the concentration of the salts. This phase is difficult to control because, if the salt concentration nears saturation, the emulsifiers and oil-wetting compounds precipitate.

Solids Phase

The solids phase includes the weight material, viscosifiers, and fluid loss reducers. A primary requirement for this phase is that it remain oil wet. Compounds exclusively developed for this purpose are included in the oil mud make-up. If the solid phase ever becomes water wet, the system is said to have “flipped” and the consequences are severe and operationally expensive. The system will separate into two phases: solid and liquid. The solid phase will pack and plug the wellbore, necessitating remedial drilling.

Air Drilling

Under a restricted set of conditions, air can be used as the drilling fluid when drilling through formations having little or no permeability to water. Although classified as “air” drilling, several types of gasses are actually used.

Dry Air

Air is compressed and pumped down the drill pipe at 500–800 ft³/min (cfm). The returned air is blown out the “blopie” line to a pit designed to retain the dust and cuttings. Dry air is preferred for fast drilling in dry, hard rock conditions with no water influx.

Mist

Mist drilling follows the same format as dry air drilling, but brine water is injected into the air stream. This is the method of choice when drilling wet formations with minimal water influx. The brine mist is injected to minimize reaction of the formation with a freshwater influx.

Foam

Foam drilling follows the same format as mist drilling, but with a foaming agent introduced into the mist stream. Foam is preferred when drilling stable formations that may have a moderate influx of water.