DRILLING FLUIDS MANUAL

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Drilling Rig and Drilling Fluid Overview

Section 1

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Types of Drilling Rig (Onshore & Offshore)

Drilling rigs come in various designs to suit their working environment, with six main categories as shown in the photographs below.

All drilling rigs operate in a similar way using similar equipment, but there is a major difference when drilling with a semi-submersible or drill ship because the Blow-Out Preventer (BOP), which is a safety device for securing the well, is located on the seabed instead of in the cellar area underneath the rig floor. A Marine Riser connects the Subsea BOP on the seabed to the Bell Nipple below the rig floor, and this is temporarily disconnected from the the Subsea BOP in bad weather.

The presence of a Marine Riser requires additional planning because the drilling fluid volume in the Marine Riser is usually recovered before it is disconnected from the Subsea BOP. This means displacement procedures and reserve tank space are required to accommodate the riser volume, and the circulating drilling fluid density also has to allow for the Riser Margin (the loss in hydrostatic pressure when drilling fluid in the Riser is displaced to seawater).

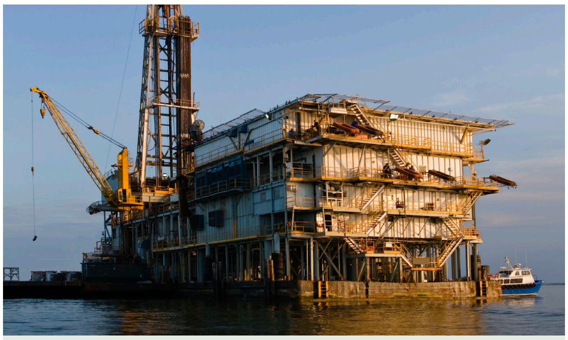

Land Rig


Platform


Jack-Up


Semi-Submersible


Drill Ship


Drilling Barge

Drilling Fluid Functions

Drilling fluid (mud) is pumped down the drill pipe to the drill bit while drilling. The mud then travels up the annulus between the wellbore and the drill pipe, carrying the rock cuttings to surface. The drilling fluid performs several important functions, as follows:

Cool and lubricate the drill bit and down-hole tools

A considerable amount of frictional heat is generated as the rotating drill bit penetrates the formation being drilled. The drilling fluid circulating around the hole removes a significant amount of this heat, which helps to extend the life of the bit and other down-hole tools that would otherwise suffer from premature failure. The drilling fluid is also designed to coat the well bore with a thin, slippery filter cake, which reduces rotational friction of the drill string.

Wells are also becoming deeper and hotter, with bottom-hole temperatures exceeding the thermal tolerance of electronic logging tools. The drilling fluid provides the only means of conducting this heat away, most of which is lost as the fluid cools down on or near the surface. Lubricants and other additives can also be added to the drilling fluid to reduce down-hole friction. Mud coolers are sometimes installed to provide additional surface cooling of the drilling fluid returns for wells with very high BHTs.

Carry drilled cuttings out of the hole

Hole cleaning is critical, otherwise cuttings will remain in the hole and the drill string will eventually get stuck. Drilled cuttings should ideally be carried to surface by the annular velocity of the drilling fluid in the annulus, which is usually possible when drilling smaller hole sections because the annular gap between the drill string and well bore is relatively small.

However, the annular gap is larger in the casing string higher up the hole, and even larger in an offshore riser, so the annular velocity may not be high enough to overcome the slip velocity of a “thin” drilling fluid (i.e. the speed at which the cuttings fall through the drilling fluid). The slip velocity can be reduced by increasing the viscosity of the drilling fluid, and this will improve cuttings removal from the hole.

Keep drilled cuttings in suspension when circulation is stopped

As mentioned in the previous paragraph, slip velocity is the speed at which solids fall through a fluid. Drilling and circulation are often suspended for short periods (e.g. to make a connection), and also for longer periods (e.g. when tripping out of the hole). The drilling fluid is designed to form a gel structure when static, which helps to keep the cuttings in suspension until circulation resumes.

Control formation pressures

Porous formations contain pores that are filled with liquids (hydrocarbons or formation water/brine) or gases, which are pressurized by the weight of the overlying formations and tectonic movements. The density of the drilling fluid is adjusted so that the hydrostatic pressure exerted by the mud in the hole is slightly higher than the formation pressures. This hydrostatic overbalance prevents lighter density formation fluids flowing into the wellbore, which would gradually reduce the hydrostatic pressure in the hole and create a potential well control situation.

Stabilize the wellbore

The forces acting on formations are generally in equilibrium, which is interrupted when the adjacent rock is removed in the form of cuttings and replaced with a wellbore. The hydrostatic pressure produced by the drilling fluid in the wellbore helps to restore the equilibrium of forces acting on the formation, which helps to stabilize the wellbore and prevent the walls of the hole from collapsing.

Drilling fluids are formulated to minimize chemical interactions with formations being drilled, the most problematic being shale hydration. The presence of “free water” in a drilling fluid will allow shales to hydrate, which can destabilize the hole and produce large washouts. Drilling fluids are inhibited by various means to minimize shale hydration, which stabilizes the wellbore. Other mud systems will be salt saturated for drilling salt sections, as this will minimize salt dissolution and hole washout.

Seal permeable formations

The hydrostatic pressure overbalance that controls formation pressures also allows drilling fluid in the wellbore to flow into permeable formations, resulting in down-hole formation losses if nothing is done to control the situation. However, drilling fluids are designed to seal the surface of the wellbore with a thin, slippery filter cake that restricts the amount of drilling fluid flowing into a permeable formation.

Provide buoyancy for the drill string

The buoyancy of a fluid is proportional to its density, with higher density fluids providing greater buoyancy than lower density fluids. The weight of the drill string in the hole is effectively reduced by the buoyancy of the fluid in the wellbore. This helps to reduce the cross-sectional area of the drill string and casing strings, which reduces the loading requirements for the travelling block and mast, and results in a smaller drilling rig design.

Maximize drilling performance

Drilling Performance is usually determined by the Rate of Penetration (ROP), which is affected by several drilling fluid properties. Fluid density, viscosity, lubricity, fluid loss control, solids content and inhibition levels will all affect ROPs and drilling performance. However, ROPs need to be controlled at reasonable levels so that drilling fluids and Solids Control Equipment (SCE) can handle the cuttings returning to surface.

Uncontrolled drilling with excessive ROPs is rarely beneficial because the wellbore may become overloaded with cuttings, which will increase the ECD at the bit with the potential for down-hole losses. The Solids Control Equipment will also struggle to handle the cuttings-laden returns, and more solids will be incorporated in the drilling fluid if coarser shaker screens have to be used. The gains made with uncontrolled ROPs are usually lost later on when drilling has to be stopped in order to circulate and condition the drilling fluid.

Provide corrosion control for down-hole tubulars

Oil-based muds are non-corrosive and water-based muds are treated with additives to maintain alkaline conditions, which suppresses corrosion. However, formation gases such as Hydrogen Sulfide and Carbon Dioxide are corrosive and will gradually reduce drilling fluid alkalinity, so regular treatments are required to maintain alkalinity at effective levels. Corrosion Inhibitors can also be added to the fluid to protect down-hole tubulars from corrosion.

Aeration should be avoided because this will introduce dissolved Oxygen into the drilling fluid, which will encourage corrosion at elevated temperatures and pressures in the hole. An example where aeration can occur is the active tank. If the mud volume in the Active Tank is low then mud returns from the hole will fall a few feet from the flow line into the active tank and this will aerate the mud. This aerated mud will then be circulated down-hole, providing Oxygen for corrosion.

Facilitate formation data acquisition

Information about the well is collected from drilled cuttings, logging tools and core samples. The drilled cuttings samples that are collected by the Mud Loggers at the shale shakers need to be in good condition, with minimal fluid invasion, so that accurate formation analysis can be made. The same applies to core samples. The wellbore needs to be smooth, with minimal filtrate invasion into the exposed formations, so that wire-line logging tools can be run to bottom without problem.

Electronic logging tools in the drilling BHA (i.e. MWD and LWD) use mud pulse telemetry to transmit digital data to surface while drilling. The digital data is transmitted to surface using a mud pulser that opens or closes a valve to restrict the flow of drilling fluid, which has the effect of creating pressure fluctuations inside the drill string that are detected by pressure transducers on surface. For this to be effective, drilling fluids need to be maintained in good condition because mud properties (e.g. high solids or viscosity) will affect the strength of these pulses on surface.

Casing and Cementing

Several formations are penetrated when drilling a well, each requiring different mud densities and inhibitive properties. The upper part of the hole usually involves unconsolidated formations that are drilled using cheap, unweighted mud systems to minimize formation losses. As the hole gets deeper, higher densities and levels of inhibition are required to stabilize the wellbore, requiring more expensive inhibited mud systems. As a result, it is not possible to drill a well straight from surface to total depth (TD) in a single section using a single mud system.

At the Well Construction planning phase, sub-surface surveys and offset data from surrounding wells in the area are analysed to determine formation lithology (physical characteristics of rock formations), formation depths, hydrostatic pressures and mud formulations required to drill a stable well to TD. The well is then divided into sections by grouping “compatible” formations together according to formation characteristics and drilling fluid requirements, the aim being to drill and secure one section before drilling and securing the following section.

Each section is secured by lining the hole with steel casing from surface to section TD. The casing is then cemented in place by displacing cement slurry down the casing string and up the annulus between the casing and wellbore. The next section can then be drilled using a different mud densities and fluid system without encountering potential problems from the previous section. A range of hole and casing sizes are used in the oil industry, the main ones being tabulated below:

Hole Size	Casing Size
36”	30”
26”	20”
17½”	13⅜”
12¼”	9⅝”
8½”	7”
6”	5”

Offshore wells are often drilled with four to six sections, starting with the 36” or 26” section and ending with the 8½” or 6” section. Onshore wells usually start with the 17½” or 12¼” section and end with the 8½” or 6” section. After drilling the reservoir section, a liner string is usually run into the open hole. The liner string is similar to casing, but for reasons of economy does not run all the way to surface. The top of the liner (TOL) sits inside the previous casing string to form a liner lap, and may or may not be cemented in place depending on the completion design.

The casing and liner sizes refer to outside diameters. Each casing and liner size is available in a range of grades (lb/ft), which refers to the weight of steel per foot of casing or liner. A higher casing or liner grade will have a thicker steel wall and a smaller inside diameter. As an example, 10¾” x 51.0 lb/ft casing has 10.75” O/D and 9.850” I/D, while 10¾” x 55.5 lb/ft casing has 10.75” O/D and 9.760” I/D. An open-hope completion refers to a completion without a liner string in the reservoir section.

The purpose of cementing is to provide zonal isolation, especially for the production zone. This is achieved by pumping cement slurry down the casing or liner and up the annulus. Cement spacers are usually pumped ahead of the cement slurry to prevent contamination with the drilling fluid, which could “flash set” the cement slurry before it is in place and require costly remedial cementing operations. Contamination with high salinity muds is particularly critical because salinity accelerates the cement slurry setting times.

Mud removal in the annular area behind the casing or liner can be improved by installing centralizers on the casing string and by ensuring that mud rheology is not excessively high. High mud rheology and gel strengths should be reduced at section TD, where possible, to improve mud removal and reduce surge pressures while running the casing or liner. The mud is circulated again after running the casing or liner in order to reduce gel strengths before displacing the cement slurry, since this will also improve mud removal.

Circulating System

The mud system comprises the following equipment:

- Active Tank(s)
- Reserve Tanks
- Sand Traps and Process Pits
- Slug and Pill Tanks
- Trip Tank & Stripping Tank
- SCE (Solids Control Equipment)
- Mixing System

Active Tank

This is the tank from which drilling fluid is pumped down hole and to which drilling fluid returns from the hole are received. The route taken by the drilling fluid when circulating is called the active (circulating) system. At the start of circulation, the Mud Pumps are lined up on the Active Tank and drilling fluid is pumped to the Stand Pipe Manifold on the drill floor. The drilling fluid then travels up the Stand Pipe and Kelly Hose to the Swivel or Top Drive System (TDS), both of which suspend the drill string and allow it to rotate independently from the Kelly Hose.

Overhead View of Mud Tanks and Mud Pumps.

From there, the drilling fluid travels down the drill string to the drill bit, where it picks up drilled cuttings and carries them up the annulus between the drill string and the well bore. A Bell Nipple underneath the drill floor sends the drilling fluid returns from the hole along a flow line that leads to the Scalping Shaker and Shale Shakers, which remove most of the drilled cuttings. The drilling fluid then passes through the Sand Traps and Process Pits, which contain additional Solids Control Equipment to remove smaller sized solids in the drilling fluid. The cleaned-up mud then flows back to the Active Tank to complete the circulating system.

Mud Tank Decking.

Reserve Tanks

These are used for storing fluids according to requirements. Reserve mud is usually prepared or stored in these tanks, or different fluids in preparation for the next phase (e.g. oil-based mud or completion brine).

Sand Traps and Process Tanks

The Sand Traps are usually positioned below the shale-shakers and act as settling pits for the drilling fluid after passing through the shale-shakers. The drilling fluid then passes through the Process Tanks, comprising degasser, desander, desilter and centrifuge tanks. As the names suggest, these tanks contain degassers along with solids control equipment for removing smaller sized particles from the drilling fluid before being returned to the active tank.

Slug and Pill Tanks

These tanks are smaller than the active and reserve tanks and are used for preparing “slugs” (high density mud that is pumped into the drill string before tripping out of the hole) and pills to address particular situations (e.g. an LCM pill to control formation losses, a special mix to improve drilling fluid properties, etc.).

Trip Tank and Stripping Tank

The Trip Tank is a tall, narrow tank that is located near the flow line and used for monitoring drill pipe displacement volumes accurately while tripping in or out of the hole. Active drilling fluid from the Trip Tank is circulated across the hole and valves in the flow line near the Bell Nipple are realigned to send the fluid returns back to the Trip Tank, forming a very small circulating system. Pipe displacement causes the Trip Tank to fill up when running in hole (RIH), and to empty when pulling out of the hole (POH), so it needs to be emptied or filled at regular intervals while tripping. The Stripping Tank is smaller than the Trip Tank and is used for monitoring pipe displacement volumes when stripping in or out of the hole when the Annular Bag Diverter is closed.

SCE (Solids Control Equipment)

It is important to minimize the build-up of solids in a drilling fluid because they affect drilling performance and can encourage hole problems. A range of equipment is available for removing solids from the drilling fluid, some or all of it found in the following order: Scalping Shaker, Shale-Shakers, Desander, Desilter, Mud Cleaner and Centrifuges.

Mixing System

The mixing system is used for building and treating drilling fluids, and for preparing slugs and pills. Equipment includes centrifugal pumps and mix hoppers, and may include pressurized surge tanks for adding bulk Bentonite or Barite. Fluids can usually be mixed in any of the active, reserve, slug and pill tanks. The mix pumps are also used for transferring fluids to other parts of the rig (e.g. to the trip tank, cement unit, sand traps, etc.), or for back loading fluids to a road tanker or supply boat.

Clay Chemistry for Water-Based Fluids

Contents

Introduction

Clays are composed of layered aluminium silicates in the form of very small particles that usually have a diameter of less than 5 microns (five thousandths of a millimeter). These microscopic particles typically have very strong interactions with water, which is central to their importance in drilling fluid technology. Some clays provide very beneficial properties to drilling fluids, whereas others are the root cause of serious problems while drilling. It is therefore very useful to have an understanding of clay chemistry because it plays such an important role in the success of a drilling operation and the drilling fluids used.

Clays Used as Components of Drilling Fluids

- Bentonite clay for water-based drilling fluids (viscosity and fluid loss control).
- Salt Gel (Attapulgite clay) for brine-based fluids (viscosity and gels).
- Sepiolite clay for high temperature water-based drilling fluids (viscosity and gels).
- Organo-Clays (amine-treated bentonite) for oil-based muds (viscosity, gels and fluid loss control).
- Hectorite for high-temperature water-based fluids and organo-hectorite for high-temperature oil-based mud (more stable viscosity, gels and fluid loss control).
- Formation clays picked up as drilled solids (unwanted viscosity increase).

Clays Found in Producing or Water Injection Formations

- Authigenic Clays, where clay particles have crystallized in the pores of sandstone, can become swollen or mobilized, leading to plugging of formation permeability and loss of production or injectivity in water-sensitive formations.
- Clay particles that are swept into producing formations with invaded drilling fluid, leading to plugging of pores or micro-fractures and loss of productivity.
- Trapped filter-cakes made of insoluble clays that cannot easily be removed, leading to loss of productivity or injectivity.
- Shale Gas reservoirs, which until recently were not regarded as feasible reservoir zones due to the very low permeability of shale formations. However, long horizontal completions and multiple fracture treatments enable the flow of natural gas from shale formations and shale gas has become massively important.

Hole Problems Caused by Clays in Shale Formations

- Non-swelling clays and micas in siltstones can disperse, leading to hole washout.
- Swelling clays such as montmorillonite can lead to tight hole, over-pressure, bit and BHA balling, mud rings and “gumbo attack”.

Evolution of Sedimentary Rocks and Shale Formations

Shale formations are sedimentary rocks formed over many millions of years by mineral particles settling out from the sea to form a mud layer on the sea bed, which then becomes compacted over time as more and more sediment accumulates on top of the mud. The mineral particles may have been clay particles eroded from land deposits. They may also have been other silicate mineral particles that gradually changed into clays on contact with salts in the pore water, the alteration process being helped by increasing temperatures as the layer became buried deeper and deeper.

Compaction and Alteration of Minerals into Clays

Sediments often originate from the erosion and weathering of rock formations, which resulted in silicate mineral particles being carried by streams and rivers towards the sea. Other sediments were formed from volcanic ash clouds that landed on the sea and then settled on the sea bed. As sedimentation builds up, the plate-like clay particles in a mud layer become compacted and aligned as the overburden grows, as shown below:

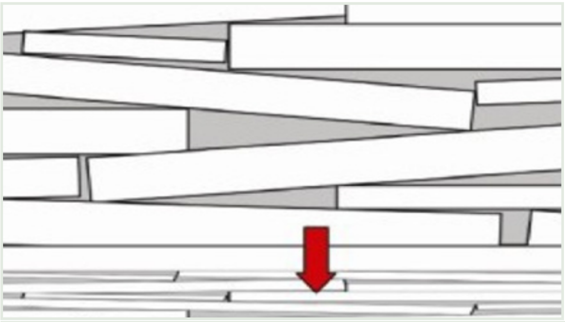


Diagram shows the gradual compaction of clay platelets as sedimentation builds up.

The mineral sediments are subjected to pressure and heat over time, which alters their structure and converts them into various clays, as shown in the following table:

Original Mineral Sediment	**Products of Alteration**
Iron-bearing silcate minerals such as olivine, pyroxene, amphibole, biotite mica	Clay Minerals and Iron Oxides
Feldspars	Clay Minerals especially Kaolinite
Mica such as muscovite	Clays (illite and montmorillonite)
Volcanic ash	Montmorillonite (bentonite)

Volcanic ash sediments have reacted with seawater to produce a unique range of clay minerals, the most common being the montmorillonite/smectite clays. Salts in the seawater and pore fluids from other formations, under pressure and temperature, have gradually altered the volcanic ash to montmorillonite. A layer of volcanic ash in the sea can be altered to smectite over 20 million years.

Photograph shows a dark coloured bentonite deposit in the foreground and horizontal beds in the hills.

In deeper-buried rocks that are older than the Jurassic era, montmorillonite has become altered to less active clays such as kaolinite and illite. Some of the buried clays are then brought to surface following tectonic activity and movement of the earth's crust in the same way that mountains are formed. The colour photograph shows a dark-coloured bentonite deposit in the foreground and horizontal beds in the hills.

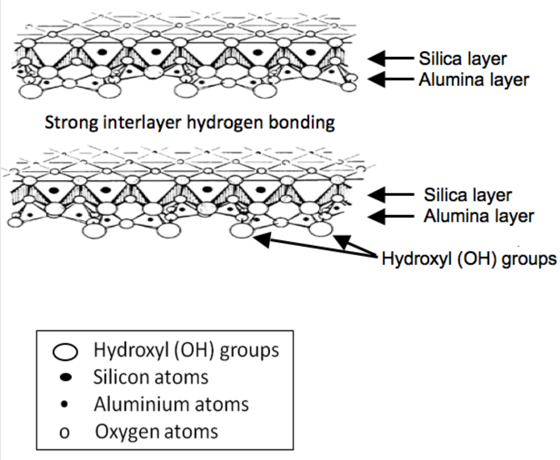
Shale formations, especially those containing montmorillonite, can cause extreme drilling problems that will often define the type and composition of the drilling fluid that needs to be used. The physical and chemical properties of clay minerals that lie behind both their unwanted effects and their beneficial properties is discussed next, while the choice of drilling fluid will be covered in more detail later in this section).

Composition of Clays

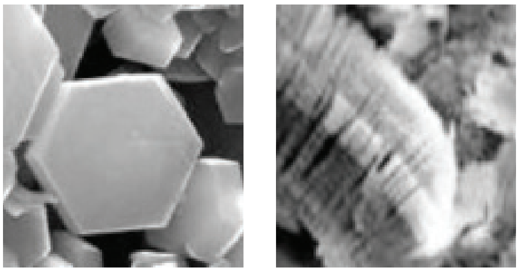
Clay minerals can vary from perfectly crystallized particles with clearly defined shapes to those that are virtually amorphous (shapeless). However, the common feature throughout are the major components: silica (silicon dioxide, which is always present) and alumina (aluminum oxide, which is usually present). Other common but minor components include magnesium, calcium, iron, sodium, potassium and inter-layer water. In almost all the clay minerals, the alumina and the silica are organized in flat parallel layers that stack up on top of each other like a pack of cards. Because of the thin and flat nature of the layers, clays are sometimes called "sheet silicates".

Kaolinite Clay

Kaolinite was named after the Chinese phrase "kao ling", thought to mean "high ridge", a place in Jiangxi Province, China. Kaolin is also called "china clay". Kaolinite is made up of sheets that have two layers, one of silica and one of alumina, with perhaps one or two hundred of these two-layer sheets held flat together by extremely strong hydrogen bonding. The hydrogen bonding is so strong that the clay particles do not swell in water and the sheets do not separate. The sheet structure (edge-on view) of kaolinite is illustrated below:



Sheet Structure (Edge-On View) of Kaolinite.



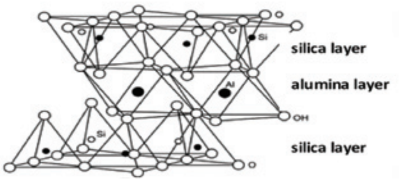
Left: SEM picture showing hexagonal kaolinite crystals
Right: SEM picture showing a stack of kaolinite platelets

Montmorillonite (Bentonite)

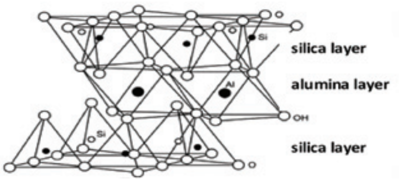
Montmorillonite was named after the town of Montmorillon in France where the clay was first identified. The non-swelling nature of kaolinite is in complete contrast to montmorillonite clay, which swells remarkably in water leading towards the ultimate near-complete separation of the constituent sheets. Montmorillonite has a three-layer repeating sheet made of silica-alumina-silica. It is better known as bentonite, which was named after Fort Benton in Montana, USA.

An important characteristic of montmorillonite is the relatively large gap between adjacent sheets, the width of the gap depending on the type of metal ions associated with the clay. Wyoming Bentonite, which comes from Wyoming in USA, is sodium montmorillonite, and the gap between the sheets is about 15 Angstroms (1.5 nanometers or 0.0015 microns), which is actually about 50% larger than the thickness of each silica-alumina-silica sheet. This relatively large gap accounts for the swelling properties of montmorillonite clay because it allows water to penetrate through the inter-layer space.

The diameter of montmorillonite flakes is normally in the range 0.1 to 2 microns. To get a truer idea of the extremely thin but broad and wide sheets in montmorillonite (but obviously scaled-up enormously), imagine in the following diagram that each of the three sheets shown extends 50 meters left and right as well as forwards and backwards. This is emphasized by the Scanning Electron Microscope picture of crumpled and folded montmorillonite sheets on the following page, and by the second illustration showing the high aspect ratio of the particles. In this example, the aspect ratio (diameter:thickness) of the sheet is 500:1.



*This large gap between the sheets is full of water molecules and cations like Na$^+$, Ca^{2+}, and Mg^{2+} in solution or adsorbed on **cation exchange sites** on the silica layer surface*



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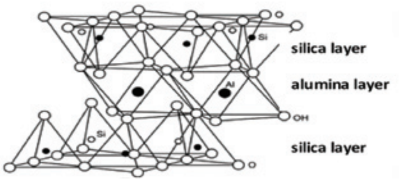
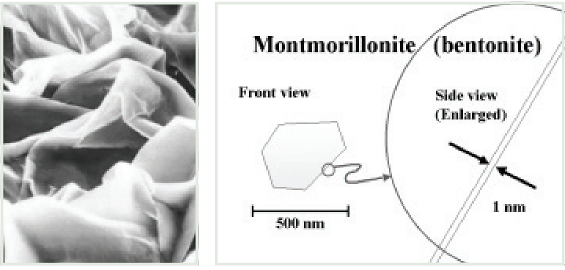


If the picture were to scale, this structure would extend many meters to the right and left as very thin sheets, but for clarity just a small portion is shown.

Microscopic Edge-On View of the Structure of Just Three of Many Parallel Sheets in a Montmorillonite Clay Particle

Bentonite sheets have negatively charged cation exchange sites on their faces, but at alkaline mud pH the edges are positively charged. This is usually attributed to broken edge charges, where broken bonds between atoms are deficient in electrons. In water the opposite charges on the edges and on the faces attract each other, resulting in particles forming edge-to-face structures. This is sometimes likened to a "house of cards structure" as depicted below:



Left: SEM picture showing crumpled and folded montmorillonite. Right: Diagram shows the high aspect ratio (diameter:thickness) of a montmorillonite platelet.

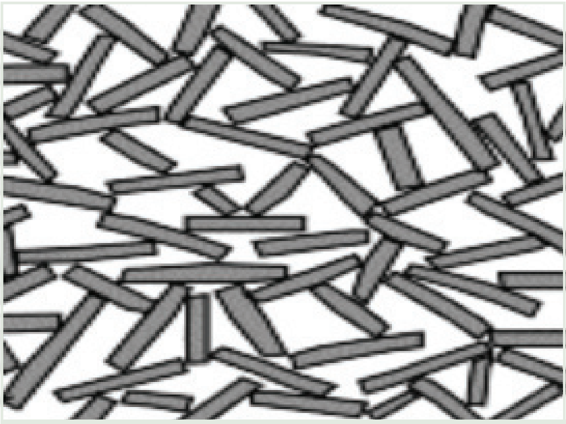


Diagram showing the structure of flocculated bentonite platelets in a fluid.

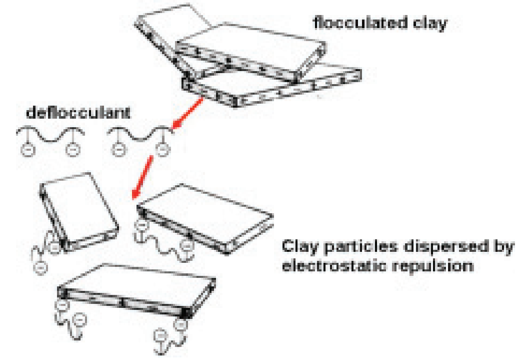


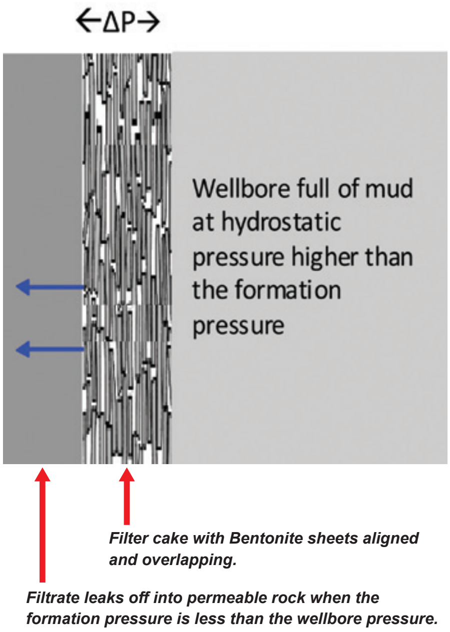
Diagram showing how flocculated clay is dispersed by a deflocculant.

The structure creates gel strength for particle suspension when the fluid is static, but breaks to provide shear thinning rheology under circulating flow. In reality the structure is more complicated than this but it is a convenient model. The structured bentonite platelets shown are in a "flocculated" state, a floc being a gathering of particles. This is much like the state of the particles in a pre-hydrated bentonite slurry prior to mixing with mud chemicals (i.e. very high YP and gels from the structured clay particles).

Normally in a drilling fluid the bentonite slurry is treated with chemicals like lignosulfonate thinners and low viscosity CMC for fluid loss control. These have a deflocculating effect and reduce the inter-particle attractions, yield point and gel strengths. They do this because these chemicals have negatively charged functional groups (such as the sulfonate groups in a lignosulfonate molecule) that adsorb on the positive edge sites. This creates an overall negative charge on the clay particle and the resultant inter-particle electrical repulsion disperses the particles, as shown in the diagram on the next page.

Mud thinners like lignosulfonates are also known as deflocculants or dispersants. Those that act using charge repulsion are most effective in low salinity fluids. At higher salinities typical of more inhibitive muds, higher molecular weight polymers such as PAC (Poly-Anionic Cellulose) are used as they give a thicker adsorbed layer that disperses particles by "steric stabilisation". This is a process where particles are covered in polymers that prevent the particles getting close in the range of attractive forces.

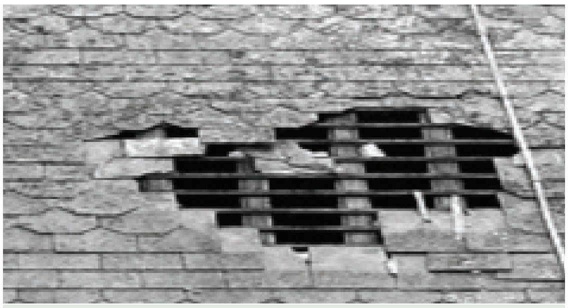
Bentonite provides another useful property to a drilling fluid by contributing to fluid loss control. When the bentonite sheets end up in the mud filter cake lining the wellbore, the differential pressure (ΔP) between the wellbore and formation pressures compresses the filter cake, causing the bentonite platelets to align flat and parallel to one another, as shown in the diagram below:



The aligned bentonite particles reduce the fluid loss pretty much like slates on a roof keep out the rain. They nearly touch each other so the size of the channels along which the filtrate can flow is very small.

The path through the filter cake is very tortuous, with many zig-zags and U-turns. The long pathway reduces the pressure gradient and the filtration rate.

Bentonite-based fluids give good static filtration control but much poorer dynamic filtration control compared with polymer-based water-based mud systems. This can be explained using a similar analogy as slates on a roof. Under circulating conditions the cross-flow of drilling fluid in the open hole can pick up particles on the surface of the filter cake, causing filter cake erosion and increased fluid loss, in the same way that slates on a roof can be lifted off by a cross wind, allowing water to penetrate the building. The polymers in a drilling fluid can be likened to tar on a roof, which sticks the slates together and seals the gaps between the overlapping slates, resulting in reduced fluid infiltration. By a similar process, mud polymers such as starch derivatives, CMCs and PACs will seal the filter cake, reducing porosity and dynamic filtration.



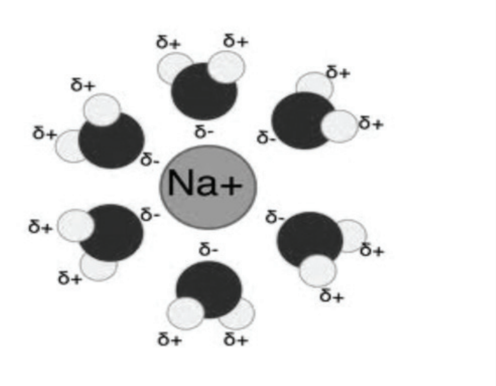
The analogy with roof slates helps to explain static and dynamic filtration control.

Cation Exchange Sites on Montmorillonite Particles

The silica faces of montmorillonite sheets sometimes have a fault where another atom like iron replaces one of the silicon atoms. When this happens, the fault site is left with a negative electrical charge. Also, some of the silicon atoms on the sheet surfaces may have a hydroxyl group attached to them (the silanol grouping, Si – OH). When this happens, the hydrogen atom of the hydroxyl group can ionise off as H^+ and leave a negatively charged site, as follows:

$$\mathrm{Si-OH} \longrightarrow \mathrm{Si-O^-} + \mathrm{H^+}$$

Faults also often occur in the central alumina layer of a montmorillonite sheet, when an atom like divalent magnesium replaces trivalent aluminum. This leaves a permanent negative charge that is weakly neutralized by ions in the open gap between the silica layers. All these negatively charged sites attract positively charged ions (cations) such as Na^+, K^+, Ca^{2+}, and Mg^{2+}. These cations adsorb onto the negative sites on the exposed surface of the silica layer. These cations can also desorb and swap out for other cations at any time, which is why these sites are called Cation Exchange Sites.



Sodium ion with six associated water of hydration molecules.

Some cations leave the cation exchange sites easier than others. As an example, the sodium ion has as many as six molecules water of hydration associated with it ($Na^+.6H_2O$). The hydrated sodium ion is therefore large and does not sit tightly on the cation exchange sites. Under alkaline conditions (e.g. mud pH of 10), sodium-exchanged montmorillonite will ionise very well in water. As the positive sodium ions leave the silica layer surfaces, the sheets become highly negatively charged and neighbouring sheets therefore repel each other strongly, allowing more of the surrounding water to enter into the gap between the sheets. At first the clay sheets swell with water but eventually, as they continue to take in more water, the sheets begin to separate, producing a useful increase in viscosity. Sodium Montmorillonite is better known as a premium bentonite such as Wyoming Bentonite, which is a well known gellant for freshwater and low salinity water-based muds.

In many bentonite mines the clay often occurs as lower grade calcium bentonite. This clay does not readily hydrate because the divalent calcium ion is anchored onto two ion exchange sites making it harder to desorb. However, calcium bentonite can be converted into sodium bentonite by a process known as peptizing, where the calcium is removed from the cation exchange sites and replaced with sodium. This is achieved by mixing calcium bentonite in water along with soda ash (sodium carbonate), with insoluble calcium carbonate being precipitated out as a by-product. The peptized bentonite can be used as a drilling fluid gellant once all the water has been evaporated off.

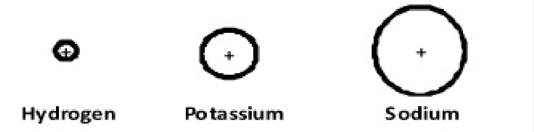
A mud check test for the amount of bentonite or active formation clay in drilled solids is the Methylene Blue Titration (MBT). Methylene Blue is a cationic dye that adsorbs strongly onto the cation exchange sites on the faces of the bentonite particles. The MBT test determines how much active clay is present in the mud by titrating methylene blue into a mud sample until all the cation exchange sites have adsorbed the methylene blue cations. The end point is observed when free methylene blue dye is left in solution, with MBT reported as ppb bentonite equivalent. The MBT test can also be used for measuring the cation exchange capacity of clay samples.

Under high temperature conditions above around 350°F (about 175°C), bentonite and other clay drilled solids that have a high MBT can completely separate into constituent sheets, which leads to a problem in drilling fluids called high temperature gelation. This can be controlled to a certain extent with synthetic thinners like polyacrylates, but it is also usually very important to minimise the concentration of active clays (i.e. maintain a low MBT) in HTHP water-based drilling fluids.

Shale Hydration Inhibition by Cation Exchange

There is another cation exchange reaction that is vital to the success of many wells drilled using water-based mud. It is the exchange of potassium ions for the sodium, calcium and magnesium ions that are commonly associated with the montmorillonite component of swelling shale formations. Calcium is sometimes added to the mud in the form of lime or gypsum to reduce shale swelling and associated hole problems but, while partially effective, calcium is not as effective as potassium for inhibiting swelling shale hydration.

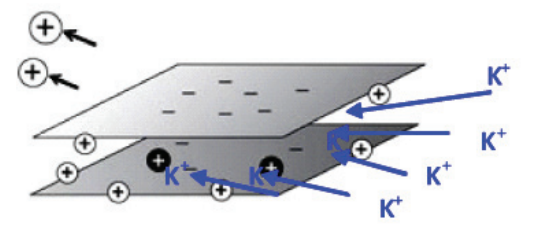
This is because potassium is normally a non-hydrated cation without any water molecules associated with it. Although potassium has a higher atomic weight than sodium, its ionic radius is smaller than the hydrated sodium ion, as depicted below:



Depiction of ionic radius for Hydrogen, Potassium and Sodium.

Because there is little or no water associated with the potassium ion, it is both smaller and faster-moving than hydrated ions like sodium ($Na^+. 6H_2O$), calcium ($Ca^{2+}.6H_2O$) or magnesium ($Mg^{2+}.6H_2O$).

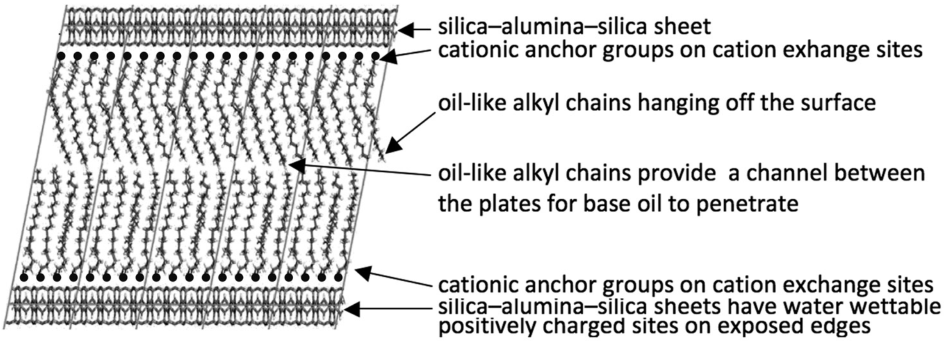
As shown in the following illustration, highly mobile potassium ions can rapidly penetrate the gap between the sheets in montmorillonite and find the cation exchange sites. The small potassium ions then adsorb strongly because they fit so well on the cation exchange sites, knocking off the other ions plus their water of hydration, leading to a near-permanent neutralisation of charge. Water can actually be removed from the gap between the sheets as the larger hydrated ions leave, causing the uncharged sheets to collapse together to an extent. This results in stabilisation of the clay against swelling, leading to much improved wellbore stability and cuttings recovery.



Potassium ions penetrating and adsorbing onto cation exchange sites between clay platelets, displacing other cations and reducing swelling for improved clay stabilization.

Composition of Organoclays

The use of organophilic clays (organoclays) as an important additive for oil-based drilling fluids is a major drilling fluid application enabled by the cation exchange sites on bentonite clay particles. Over 60 years ago mud technologists were searching for materials that would impart good viscosity and gels to oil-based drilling fluids. They knew that bentonite worked fine in water-based muds so it seemed logical to try to make an oil-gelling clay by converting the faces of bentonite layers from being water-wettable to oil-wettable (i.e. from hydrophilic to organophilic).



A cross-section view of organoclay, showing closely-packed alkyl chains between bentonite platelets.

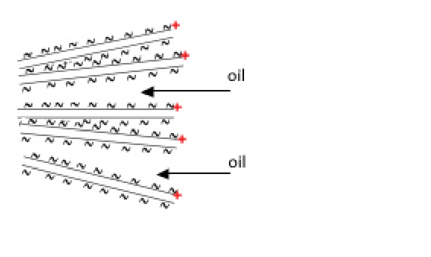
The technologists were aware that organic cations were available that contained long oil-like hydrocarbon chains. They figured that an organic cation such as the quaternary ammonium compound (“quat”), shown below, should adsorb strongly on the cation exchange sites of bentonite leaving the oil-like alkyl chains hanging off the faces of the clay platelets. This should make the clay dispersible in oil (i.e. lipophilic, another word for oil-loving or fat-loving), so that the platelets would form a gel structure in the oil similar to that of bentonite in water. The combination of bentonite and quat was successful, and has been used since.

The picture overleaf shows how the gap between the sheets has been expanded and is filled with closely packed alkyl chains. When the organoclay powder is still in the sack at relatively low temperature, the packed alkyl chain layer is almost waxy in nature. This is part of the reason that organoclays can be slow to generate viscosity, especially at low temperatures. Basically the waxy hydrocarbon “meat in the sandwich” has to melt before the layers can easily separate to allow base oil to penetrate between the layers.

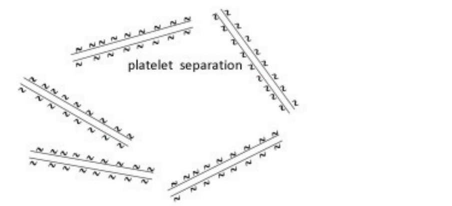
This explains why oil-based muds will not reach maximum viscosity until they have been circulated down hole and heated up. A vital contributor to the yielding of organoclays is high shear rate mixing. This helps in tearing the sheets apart, and it also imparts a useful increase in temperature. Some benefit can be obtained using mud pit recirculation through centrifugal pumps and mud guns, but for best results the mud must be sheared through the bit nozzles or through a specialized mud shearing device.

Another way of accelerating the viscosification process is to add a polar additive or a little water. The polar additive or water will stick to the hydrophilic edges of the platelets, where there are sites that contain “broken edge charges”. These polar sites have positive charges that are usually neutralized by an anion such as chloride. When water or a polar activator adsorb onto these sites they allow ionization, where the chloride ion leaves the site and the edge sites become positively charged. The repulsion caused between positive charges on adjacent platelets causes them to separate, opening the gap between the sheets. This then allows base oil to penetrate and separate the platelets more quickly, as shown in the following diagram:

Water adsorbed on polar sites of organoclay platelet stacks, giving positive charges on sheet edges.



Ionic repulsion prises open the organoclay platelet stacks, allowing the oil to penetrate.

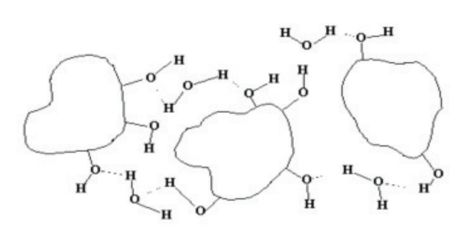


The platelets separate and generate a viscosity and gel structure in oil-based fluids.

Development of Yield Point and Gels by Organoclays

The platelets are well dispersed in the oil phase thanks to their oil-wettable, quat-coated faces, but the edges are still polar and can attract each other when the positive edge sites are neutralised by, for example, chloride ions to give neutral ion pairs. The polar edge sites can also adsorb water as shown in the diagram, which causes edge to edge attraction by hydrogen bonding, and large gelled structures of clay platelets build up.

The flexible sheet-like particles also play an important role in controlling HTHP fluid loss. They are able to either lie flat and overlapped in a filter cake, as discussed previously for water-based muds, or they can provide deformable sealing material in the gaps between larger particles such as barite in the filter-cake.



Adsorption of water molecules on polar edge sites causes edge-to-edge attraction by hydrogen bonding, producing a gelled structure.

Other Clays Used in Drilling Fluids

Attapulgite

Salt Gel, also known as Attapulgite (the mineral name is Palygorskite), is so named because of its ability to gel salt solutions up to saturated sodium chloride brine (in contrast to bentonite which yields viscosity only in fresh water). It is a hydrated magnesium aluminum silicate which occurs in nature as a fibrous clay mineral containing bundles of tightly aligned needle-like crystals. The needles can be several microns in length, but as little as 3 nanometers in width (i.e. the length may be 1,000 times longer than the width).

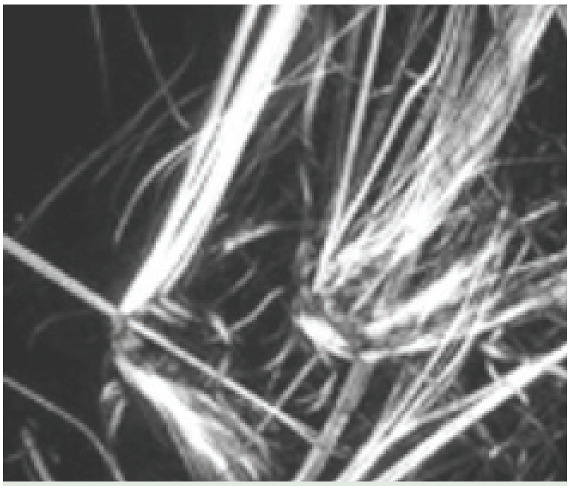
Scanning Electron Micrographs of Bundles of Long Needle-Like Attapulgite Crystals.

Composition	% by weight
SiO_2	58.38
MgO	12.10
Al_2O_3	9.50
CaO	0.40
TiO_2	0.56
MnO	0.05
Fe_2O_3 + FeO	5.26

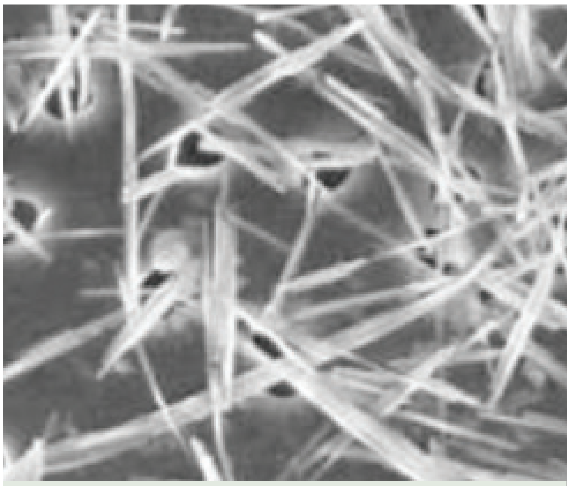
Typical Composition of Attapulgite

Attapulgite has permanent negative charges on its surface along with positively charged sites so, once dispersed, the needles are able to set up a structure. However, the closely aligned needle-like particles in Salt Gel exist as very strongly hydrogen bonded bundles before mixing. High shear is therefore needed to break up the bundles and release the particles.

Where high shear mixing is unavailable, the addition of caustic soda to the salt gel clay slurry can accelerate disaggregation and viscosity development. It should be noted that the resultant high pH can cause problems because starch and starch derivatives are often used in salt gel muds for fluid loss control. Some starch products at high pH such as pH 11 can deflocculate the salt gel particles resulting in a loss



Scanning Electron Micrograph of Attapulgite in Water.



Scanning Electron Micrograph of Sepiolite.

of viscosity and gels. However, reducing the pH will usually reverse the process, enabling viscosity to be regained.

The Scanning Electron Micrograph on the right reveals the gel structure of attapulgite in water as a three dimensional network of matted long needle-like crystals. When the gelled fluid forms a filter cake, the very open porous structure remains in the cake and can result in high fluid loss, which is difficult to control.

Health concerns, high fluid loss, and the sometimes unpredictable performance of Salt Gel fluids have led to less frequent use in recent years. A popular alternative for developing viscosity and gels in brine-based fluids is Xanthan Gum, which is effective in concentrations around 1 to 2 pounds per barrel (approximately 3 to 6 kg/m^3), compared with Salt Gel that requires around 10 to 20 ppb (approximately 30 to 60 kg/m^3). Inhaled Attapulgite dust has been suspected as a cause of cancer, which is disputed, but prolonged exposure can cause pulmonary fibrosis so its use is therefore diminishing.

Sepiolite

Sepiolite is different from most clays because it contains no alumina and is a hydrous magnesium silicate clay mineral with chemical formula $Si_{12}Mg_8O_{30}(OH)_4(OH_2)_4.8H_20$. Structurally it consists of two sheets of SiO_4 (silica) tetrahedrally bonded via oxygen atoms to a central sheet of octahedrally arranged magnesium atoms. The long thin particle shape is shown in the electron micrograph above.

Sepiolite has internal channels called “zeolitic channels”, which run the length of its structure with open pores of varying shapes and dimensions at the surface. Along the edges of the tetrahedral sheets are silanol (SiOH) groups which can readily form hydrogen bonds with water and other polar molecules. The magnesium layer also provides adsorption sites. Like salt gel, sepiolite can develop viscosity in saline fluids, although it usually requires higher concentrations. However, fluid loss control is a little easier in fluids using sepiolite than salt gel, but they usually still need some bentonite in the formulation to improve filter cake quality and fluid loss performance.

The main application for sepiolite is in water-based fluids for geothermal wells. The main feature of sepiolite that has occasionally been exploited in drilling fluids is its thermal stability. Fluids using sepiolite can provide quite stable rheology on exposure to downhole temperatures well in excess of 500°F (260°C). At such high temperatures, bentonite suffers from hyper-separation of the constituent sheets causing high temperature gelation. Attapulgite needles are actually converted to sheet-like smectite clay particles at temperatures around 400°F (200°C), which also makes it unsuitable for use in high temperature fluids.

Clay Chemistry for Water-Based Fluids

	Hectorite	**Bentonite**
Formula	$Na_{0.33}[Mg_{2.67}Li_{0.33}]Si_4O_{10}[OH]_2$	$Na_{0.33}[Al_{1.67}Mg_{0.33}]Si_4O_{10}[OH]_2$
Platelet Shape	Elongated	Equi-Dimensional
Platelet Size	0.8 x 0.08 x 0.001 microns	0.8 x 0.8 x 0.001 microns
Swelling Ability	35 times	15 times
Viscosity at 17.5 ppb	10,000 cP	750 cP

Figure 1: A comparison between hectorite and bentonite.

Hectorite

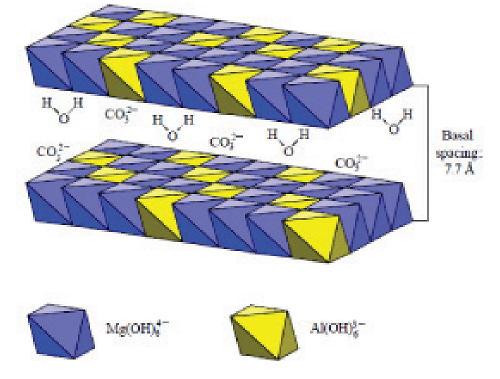
Like bentonite and sepiolite, hectorite is a member of the smectite group of clay minerals. As with sepiolite, it has found use in HTHP water-based fluids where it provides superior rheology control at high temperatures. Hectorite differs from bentonite in that the alumina layer is replaced by a layer containing magnesium and lithium. A comparison between hectorite and bentonite is tabulated in figure 1 above.

Hectorite is also used for making a premium organoclay for HTHP oil-based fluids. It provides much more stable Yield Points and gels compared with bentonite-based organoclays, which tend to lose these properties after exposure to high temperatures (>350°F). The most well known organohectorite is Bentone 38™.

Mixed Metal Hydroxides (MMH)

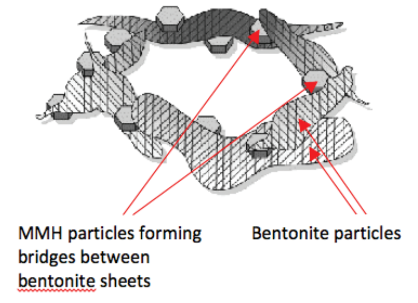
Mixed metal hydroxides are synthetic products rather than naturally occurring clays, but they are occasionally used with bentonite in water-based drilling fluids to develop an extremely non-Newtonian (Bingham Plastic) rheology that provides exceptional hole-cleaning capability. Although not strictly a clay mineral, MMH is composed of microscopic particles with a clay-like layered structure that has sheets of brucite, $[Mg(OH)_6]^{4-}$ and gibbsite $[Al(OH)_6]^{3-}$, more commonly known as magnesium hydroxide and aluminium hydroxide.

Isomorphous substitution of Al^{3+} in the octahedral sites of the brucite (magnesium hydroxide) sheet results in a net positive charge. Isomorphous means “same shape”, so the substitution of the magnesium atom by the aluminium ion does not alter the shape of the layer. The positive charges on the sheets are largely balanced by anions in the interlayer water between the sheets, but there is not enough room in the interlayer gaps for sufficient anions to electrically offset all the positive charges. Therefore, a net positive charge exists on the MMH crystal surfaces.



Composition of Mixed Metal Hydroxide.

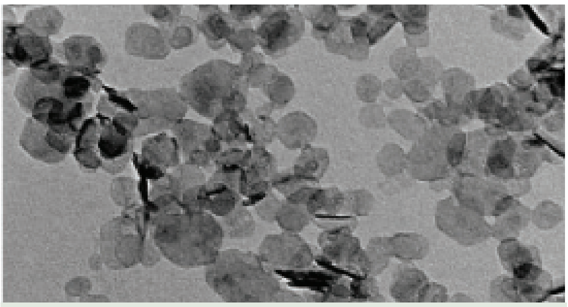
When MMH is added to a bentonite slurry the positively charged MMH particles are attracted to the negatively charged cation exchange sites on the bentonite particle surfaces. The MMH particles can attract more than one bentonite platelet, resulting in the clay particles being joined together by MMH “bridges”. This process of forming flocs of oppositely charged particles is called “heteroflocculation” (hetero = opposite).



Flocculated structure formed by Mixed Metal Hydroxide particles and bentonite platelets.

Clay Chemistry for Water-Based Fluids

Under flowing conditions the inter-particle bridges in an MMH/bentonite fluid are readily broken, resulting in a very low Plastic Viscosity. Under static conditions the bridges re-form almost immediately giving a gel that allows, for instance, excellent cuttings suspension during connections. MMH fluids typically have very good Low Shear Rate Viscosity (LSRV) and high, non-progressive gel strengths. The Transmission Electron Microscope picture of MMH particles (see below) shows the tiny, flat, highly cationic crystals with face dimensions an order of magnitude smaller than the typical bentonite platelet. They have an extremely high diameter:thickness aspect ratio (150 nm = 0.15 microns).



Transmission Electron Microscope picture showing Mixed Metal Hydroxide particles.

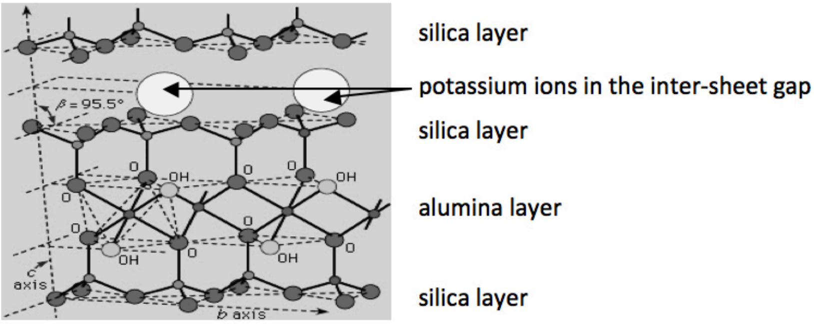
Micas

Although micas are technically not clay minerals they are sheet silcates made up of layers of alumina and silica. Muscovite mica is the type most commonly used in drilling fluids as an additive designed to reduce lost circulation. Similar to the structure of montmorillonite shown earlier, muscovite is composed of triple-layered silica-alumina-silica sheets. The big difference from montmorillonite is that muscovite is much less hydrated due to the presence of potassium ions in the inter-sheet gap, the gap being much smaller than in montmorillonite. The potassium ions are difficult to remove, which explains why mica is non-hydratable.

Montmorillonite will eventually convert into muscovite when treated with large amounts of potassium. Samples of cuttings from active formations are sometimes analyzed by X-Ray Diffraction (XRD) to determine the types of clay present. Because potassium ions collapse montmorillonite sheets towards a mica-like structure, samples of cuttings that were drilled with inhibitive potassium chloride based water-based muds will often show a falsely low XRD result for montmorillonite, along with raised values for mica/illite by the time the sample is tested.

Another big difference from montmorillonite is the very large particle size of mica. Mica as mined is often in the form of large stacks of sheets that can be many centimeters across. During processing for use as LCM in drilling fluids the mica is de-laminated and ground to give coarse, medium and fine particle diameters. Typical average particle diameters are 3.5 mm for coarse, around 700 microns for medium and around 300 microns for fine.

Enlarged photograph of Muscovite Mica.



Structure of Muscovite Mica

Illite

Illite is not a commercial mud additive product, but it is a clay mineral that is frequently picked up by the mud as drilled solids along with the other clays, silica and carbonate minerals associated with the formations being drilled. Its structure is somewhere between that of montmorillonite and muscovite mica. It contains some potassium-rich layers that are like muscovite and other layers that are like montmorillonite. It is therefore known as a "mixed-layer clay", and is frequently poorly crystallized. It is a contributor to the Methylene Blue Titration test result for active clays.

Drilled solids containing illite that are dispersed in an HTHP drilling fluid can cause problems with high temperature gelation. The extreme hydrothermal conditions down hole are able to extract the interlayer potassium ions, effectively converting the illite into montmorillonite. High concentrations of illite in shale formations can also cause wellbore stability problems because illitic shales have moderately high reactivity between relatively inactive, compacted kaolinite-rich formations and the highly reactive and swelling formations containing montmorillonite.

Naturally Occurring Clays in Reservoir Formations

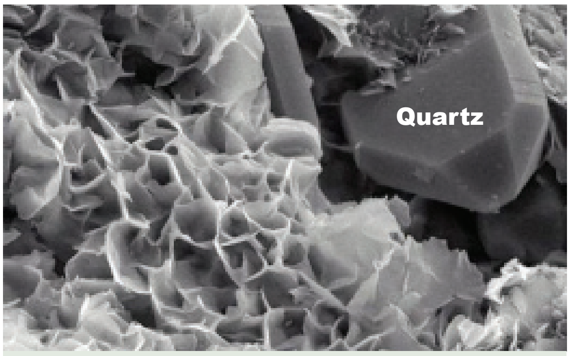
Clay minerals are present in two distinct ways in reservoir rocks: as shale (inter-bedded shale layers and thin shale "stringers"), or as authigenic clays that occur almost exclusively in sandstone. Authigenic means "generated in place", so authigenic clays are clay particles that grew in the pores of sandstone over a long geological period as pore waters containing low concentrations of dissolved silica, alumina, etc. gradually crystallised out. The three Scanning Electron Microscope pictures below show authigenic clays in sandstone reservoir core samples and depict ways in which these authigenic clays can cause reduced production:

The first picture is a low magnification SEM picture of high permeability sandstone. The large pores (with diameters of tens of microns) between large sand grains are coated with small authigenic kaolinite particles. Clay particles also fill some pore throats. Mobilised clay particles would probably be able to move relatively freely in this network of large pores. One way for the kaolinite particles to become dislodged (clay mobilization) is if they are subjected to a change in water chemistry such as mud filtrate invasion.

In particular below, low salinity and/or high pH filtrate will mobilize kaolinite. In this particular case the pore size may be large enough that the loosened particles can move relatively freely in the pore network, but usually they form "log jams" in pore throats that severely reduce permeability. The use of potassium chloride at a concentration of at least 10 ppb in the drill-in fluid, and pH not too high (e.g. pH 9), will help minimize clay mobilization.

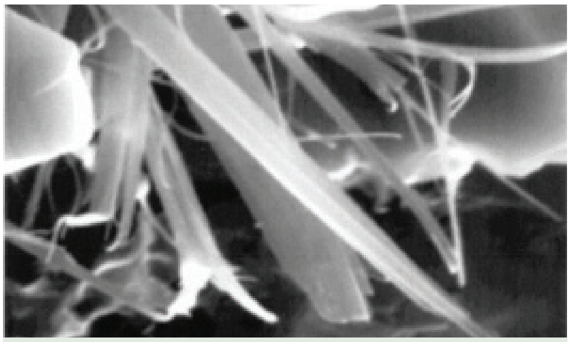
A low magnification SEM picture of high permeability sandstone

This second picture is a high magnification SEM picture of a pore containing an authigenic quartz crystal. The pore walls are coated with "crinkly" montmorillonite, which probably became crinkly while drying out during sample preparation for SEM examination. Permeability will be highly sensitive to low salinity water which swells montmorillonite, causing pore-plugging. If a low salinity mud filtrate entered the pore the montmorillonite would swell causing loss of permeability. Again, the use of potassium salts in the drill-in fluid and pH not too high (e.g. pH 9) will help minimize this.



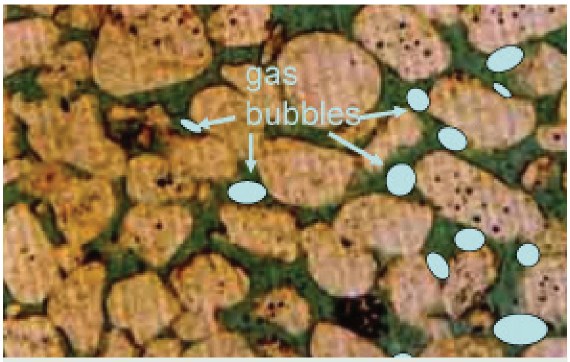
A high magnification SEM picture of a pore containing an authigenic quartz crystal

The third picture (below) is a very high magnification SEM picture of fibrous illite from a pore in “tight” (low permability) gas sandstone. The pores can contain a lot of fibrous clay making it very difficult for produced gas to displace invaded water from the pores, such as mud filtrate. Although some mobilisation and swelling is possible, the main permeability plugging effect here is water blocking, where invaded mud filtrate or completion brine readily displaces gas from the pores.



A very high magnification SEM picture of fibrous illite

When the well subsequently goes into production, the non-wetting gas finds it difficult to intrude through the pore throats and the very small gaps between the illite fibres. To lessen the problem, mud filtration and brine losses must be minimized. Specialized surfactants may also be added to the drilling and completion fluids to lower the interfacial surface tension and lessen the capillary pressure required to push gas through the waterlogged pore network until it reaches the wellbore. An illustration of water-blocked sandstone is shown below:



Depiction of water-blocked sandstone.

The non-wetting gas bubbles cannot easily squeeze through the small pore throats in water-blocked sandstone.

Shale Hydration, Shale Problems and Shale Stabilization

Clays in shale sedimentary rocks are the root cause of many drilling problems. Shale-related problems include high torque and drag, hole washouts leading to inadequate hole cleaning and poor cement jobs, bit balling and cuttings accretion onto bottom hole assemblies (BHAs), which will slow or stop penetration rate, often requiring a premature trip to clean the BHA. Shale-related Lost Time Incidents (LTIs) include stuck pipe, hole collapse, lost BHAs, fishing (trying to recover lost drill strings or BHAs from the hole), and drilling sidetracks after unsuccessful fishing operations. Most of the drilling problems mentioned above are covered in more detail in Section 12.

Swelling and Hydration Potential of Clays in Shale Formations

A comparison of three clays often found in shales is tabulated below:

Clay	Kaolinite	Hydrous Mica/Illite	Montmorillonite
Layer Type (SiO_2:Al_2O_3)	1:1 (non-expanding)	2:1 (semi-expanding)	2:1 (expanding)
Interlayer Condition and Bonding	Lack of interlayer surface with strong bonding	Partial Loss of K with intermediate bonding	Large expansion with very weak bonding
Cation Exchange Capacity (meq/100g)	3 to 15	10 to 40	80 to 150
Specific Surface Area (m^2/g)	5 to 20	50 to 200	700 to 800
Swelling Potential	Almost None	Some	High

As can be seen, the swelling potential is directly related to both the cation exchange capacity (CEC) and the Specific Surface Area, which is the area in square meters of the accessible faces and edges of all the particles in one gram of clay. To get an idea about the meaning of Specific Surface Area, the area of all the surfaces of all the particles in just 10 grams of montmorillonite is as big as a football pitch (about 7,000 square meters). This explains how it can absorb such large quantities of water.

Over geological time, as clay-rich layers of sedimented mud became buried under more and more sedimentary materials, the increasing overburden pressure caused by the weight of overlying sediments pushed the clay particles closer together, squeezing out the water from the pores. However, in montmorillonite shales, because the permeability of the sediment is very low, the pore water often did not drain away efficiently, causing the overburden pressure to be supported by high pressure water in the pores between the clay particles (high pore pressure).

These "over-pressured" shale sections can undergo "plastic creep" into the wellbore or may cause pieces of shale to fall into the hole as cavings. The density of the drilling fluid should be increased when this happens, in order to hold back the formation and keep the hole open. In addition, any montmorillonite in the shale will take on more water if an under-inhibited water-based mud is used, causing further hole-stability problems, sticky cuttings, bit-balling, and "gumbo" attacks (mud rings and large clumps of cuttings that can block the flow-line).

Shale Hydration Inhibition

The best way to avoid shale hydration is to avoid the use of water as the continuous liquid phase of the drilling fluid. That is, use an oil-based or synthetic-based drilling fluid. However, there are many reasons why water-based drilling muds are favoured, including the lower cost/bbl of water-based fluids, environmental impact, cuttings disposal costs and logistics. As a result, the discussion will concentrate on shale hydration inhibition using water-based mud additives. There are three distinct reasons to employ shale hydration inhibitors:

- Improve wellbore stability – The hole section needs to be drilled, cased and cemented before the effects of shale hydration cause wellbore instability.
- Avoid bit balling – The drill bit and BHA should remain clear of cuttings adhesion.
- Increase cuttings removal efficiency – The drilling fluid should remain in good condition without an excessive build up of dispersed drilled solids.

Cuttings Removal Efficiency and Cuttings Hydration

Drilled solids dispersion in the mud will lead to increases in mud weight, plastic viscosity, gels and fluid loss, while at the same time causing a reduction in the shale inhibitive power of the fluid. All of this results in the need to make expensive chemical treatments and dilutions to maintain mud properties within specification. Ideally, the drilled cuttings should be transported from the bit up the annulus without being excessively reduced in size so that, when they arrive at the shale shaker screens, they are easily and efficiently removed. This requires a combination of:

- Efficient hole cleaning provided by an adequate circulation rate and sufficient low shear rate viscosity to carry cuttings in laminar flow up the annulus.
- Inhibition of cuttings hydration and dispersion by chemical additives. Products like potassium chloride and polyglycols will reduce the rate of clay hydration, while high molecular weight polymers such as partially-hydrolysed polyacrylamide (PHPA) will encapsulate the cuttings, holding them together to minimise dispersion.

Bit Balling and Cuttings Accretion

Another reason to inhibit the hydration of cuttings is to minimise bit balling and hard cuttings accretion onto bottom hole assemblies. The pore pressure in an untouched shale formation is considerable and, for good wellbore stability, the hydrostatic pressure created by the mud in the wellbore is usually maintained higher than the pore pressure. However, when a cutting is created by a bit cutter the effects of overburden pressure disappear and the cutting undergoes stress relief, causing some expansion.

Since the porosity of most shales is completely filled with incompressible pore fluids, this expansion results in an immediate large drop in the pore pressure inside the cutting. As a result, the differential pressure between the mud hydrostatic pressure and the pore pressure in the cutting increases dramatically, providing a larger driving force for mud filtrate to hydrate the cutting. The large pressure differential can also be a cause of bit balling or hard cuttings accretion onto BHAs. If a shale cutting is squashed onto a metal surface on the bit or BHA while there is still a reduced pore pressure in the contact zone between the metal and the cutting, the differential pressure will push the cutting onto the metal, causing adhesion.

The problem is worse when using a non-inhibitive water-based mud because a shale cutting will start to hydrate as water from the mud enters it from the moment the shale cutting is created by the drill bit. For moderately to well-consolidated shale formations, the water content of freshly formed cuttings is sufficiently low that they are relatively rigid particles and not sticky. However, as the cuttings take on more water, they become more plastic and sticky. If the cuttings are not removed rapidly from the vicinity of the bit, they can stick together and to the metal of the bit. Once a sticky layer is formed it can rapidly "collect" more sticky cuttings, resulting in classic bit balling.

An example of bit-balling.

The picture shows bit balling on a Polycrystalline Diamond Compact cutter-type bit (PDC bit). The cutter elements are all coated with squashed-together cuttings resulting in loss of penetration rate, which necessitated an unplanned trip out of the hole to clean or replace the bit. A related phenomenon that also happens to shale cuttings is called "dilatant hardening". If a shale cutting is squashed between the wellbore and the rotating heavy weight drill pipe (HWDP) in a deviated well, the cutting is flattened and pushed onto the HWDP surface. The distortion of the cutting leads to a small increase in the cutting volume as the clay particle packing is disturbed, again causing a large drop in the pore pressure.

The flattened cutting is now highly adherent to the HWDP because of the differential pressure holding it down and it has also become harder. The process is known as cuttings accretion because a layer of hard, flattened cuttings builds up or accretes onto the BHA. The accretion can sometimes be so hard that hammers and chisels are required to clean the BHA. Cuttings accretion is most commonly encountered when using highly inhibitive WBMs which slow down the cuttings hydration long enough for the layer to build.

There are two ways that bit balling can be avoided. Either increase the inhibitive power of the mud so that cuttings remain hard and non-adhesive, or decrease the inhibitive power so that any adherent cuttings rapidly hydrate and disperse. As an example, an effective way to drill a top-hole section (e.g. 17½" hole) containing sticky clays is to use a low cost, non-inhibitive seawater-based mud, with a lubricant additive to improve the rate of penetration (ROP) and keep the bit clean.

The cuttings rapidly hydrate, become less sticky so that they do not adhere to the bit or the BHA, and finally they disperse. The undesirable build-up in the mud of Low Gravity Solids (LGS) is controlled by frequent dumping and dilution, and by controlling the ROP to avoid excessive cuttings concentrations in the annulus. The trick is to drill, case and cement the section rapidly before hydration of the near-wellbore shale formation reaches a level to cause wellbore instability.

In older, deeper shale formations, ROPs are likely to be slower and the hole trajectory is more likely to be at higher angles. It is therefore necessary to use a more highly inhibitive mud to provide wellbore stability, to avoid cuttings adhesion to the BHA or bit, and to enable high efficiency cuttings removal. Certain drilling fluid additives also have a strong effect on the plasticity or stickiness of shales, and the following table lists their effects:

Factors that Promote Shale Stickiness	**Factors that Minimize Shale Stickiness**
High pH with NaOH	Lower pH
Sodium Salts	Potassium Salts
Polyphosphates*	Ammonium and Quaternary Ammonium Salts
Sodium Silicate* **	Polyvalent Cations (Al^{3+}, Fe^{3+}, Zr^{4+})
Lignosulfonates*	High Salt Concentrations for Reducing Water Activity
Polyhydroxy Compounds like Polyglycerol	–

**** Polyphosphates like pyrophosphates (SAPP), sodium silicate and lignosulfonates are all known as clay deflocculants. The clay particles in a shale are held together by inter-particle forces. When mud filtrate containing a deflocculant enters the pores on the surface of a shale, it destroys the inter-particle attractive forces and plasticizes the surface layer, causing stickiness.***

***** High concentrations of sodium silicate are used in some shale inhibitive muds. The reduced osmotic transfer of water and the cementitious reactions created by the high silicate content both counteract the deflocculating effect of the silicate polyvalent anion. Potassium salts are usually added to sodium silicate drilling fluids to further counteract the potential for shale stickiness.***

Inhibition Process	Inhibition Mechanism	Typical Products
Cation Exchange	Cations like non-hydrated K+ replace hydrated cations on C.E. sites.	KCl (Some organic cations are also used)
Encapsulation	High molecular weight adsorptive polymers coat the cuttings and wellbore surfaces. Most effectively used against cuttings dispersion.	Partially Hydrolyzed PolyAcrylamide (PHPA)
Reduction of Water Permeation Rate into Shale	Increased fluid viscosity results in decreased rate of flow into shale pores. Only relatively low molecular weight compounds can flow through tiny pores in shale.	Polyglycerols, Polyalkylene Glycols, Methyl-Glucoside, High Salt Concentrations
Replacement of Inter-Layer Water	The water between clay sheets is replaced by more strongly-adsorbing organic molecules (This is often combined with cation exchange).	Polyalkylene Glycols, Amine-Capped PAGs
Reduction or Reversal of Osmotic Transfer of Water into Shale	The use of strong solutions of salt or polyhydroxy compounds in the mud reduces vapor pressure (Water Activity), slowing or reversing the transfer of water molecules into shale.	NaCl, $CaCl_2$, Potassium formate, Methylglucoside
Plugging of Shale Pores to Reduce Pore Pressure Penetration	Micro-colloids enter and plug the tiny pores in the shale. Some polyglycols may come out of solution after penetrating the shale and warming up.	Highly cross-linked polymer microgels, Cloud Point Glycols
Sealing of Shale Micro-Fractures	Some wellbores collapse when mud filtrate enters cracks and micro-fractures. Plasticized particles bridge, coalesce and seal the fractures	Asphalt or Gilsonite particles. Sulfonated Asphalt (e.g. Soltex™)
Reactions with Clays in the Shale to Produce Inter-Particle Cement	Clays react with lime and can become hardened (the pozzolan effect). Clays react with sodium silicate to drop pH and precipitate silica cement. Silicate also reacts with calcium, magnesium, aluminium in clays to cement particles together.	High Lime muds, Sodium Silcate solutions (Potassium Silicate is sometimes used)

Figure 2: The range of inhibition mechanisms and typical product types used for shale inhibition

Shale Inhibitor Chemicals for Water-Based Drilling Fluids

The range of inhibition mechanisms and typical product types used for shale inhibition are tabulated in figure 2 above.

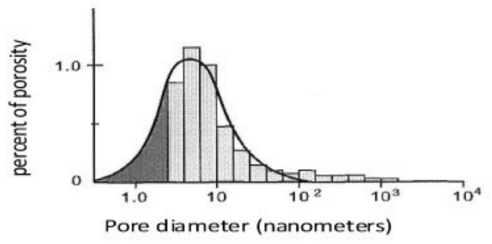
The cost to the industry of hole problems and lost time incidents caused by shale hydration is immense. As a result, considerable research and product development has been invested in products and systems designed to improve wellbore stability and inhibit cuttings hydration. There are many types of shale, many ways in which shale hydration and instability can occur, and many methods that can be employed to minimize the ensuing problems, as explained below:

Cation Exchange of hydrated cations by potassium has been described earlier. Potassium Chloride is very effective at inhibiting the hydration of shales that have a high cation exchange capacity (i.e. shales containing a substantial concentration of montmorillonite and/or illite).

Encapsulation by partially hydrolyzed polyacrylamide (PHPA) is an effective method for dealing with highly dispersive shales such as micaceous siltstones and kaolin-rich formations. Encapsulation is probably better at reducing cuttings dispersion than inhibiting hydration of the near-wellbore shale. PHPA is more accurately described as a high molecular weight copolymer of acrylamide and acrylic acid. The amide and carboxylate functional groups adsorb very strongly onto the surface of the cuttings, coating them with a layer of viscous polymer that helps to slow the flow of filtrate into the formation pores.

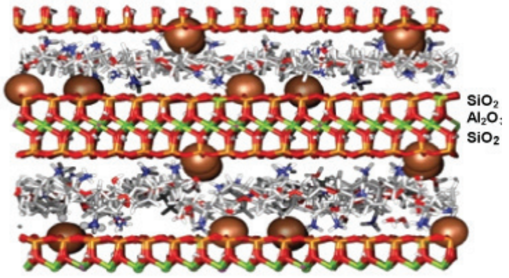
Reduction of Water Permeation Rate into Shale by increasing the viscosity of the aqueous phase obviously slows the hydration process. According to Darcy's Law, the permeation flow rate is inversely proportional to the viscosity, so the flow rate of a salt-saturated filtrate into a porous solid would be half the flow rate of fresh water because the viscosity of saturated sodium chloride solution is twice that of water.

Solutions of only relatively low molecular weight materials (such as salts, polyglycerols, methyl-glucoside and polyalkylene glycols) can flow through shale pores because the pore size is so small. The graph below shows that most of the pores in a typical shale are less than 10 nanometers (0.01 microns) in diameter. For a typical PHPA polymer with a molecular weight over one million, a dissolved PHPA molecule can be as long as about 1,000 nm (or 1 micron), and it therefore cannot flow through the pore network.



Pore size distribution of a typical shale

Replacement of Inter-Layer Water using polyalkylene glycols (PAGs), which are typically low (around 1,000) molecular weight copolymers of ethylene oxide and propylene oxide. Ethylene oxide is sometimes used on its own, as in polyethylene glycol or an ethoxylated alcohol such as butanol ethoxylate. The ethylene oxide type glycols need to be used in conjunction with potassium for good effect.

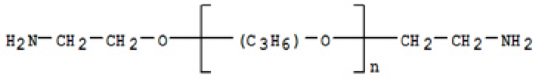


Potassium ions are shown as spheres occupying the cation exchange sites.

The polyalkylene glycol molecules displace water, filling the gap between the sheets.

Edge view of montmorillonite sheets inhibited by polyalkylene glycol and potassium ions

Ethylene oxide and propylene oxide copolymers can be effective on their own, without having to use potassium chloride. The ether-links (-C—O—C-) in PAGs adsorb onto montmorillonite sheet surfaces more strongly than water, so they can infiltrate the gap, displace water, and stop further hydration. Modified PAG molecules have recently been developed that have amine “anchor groups” at each end of a linear PAG molecule, similar to the one shown below:



$H_2N-CH_2-CH_2-O-\left[(C_3H_6)-O\right]_n-CH_2-CH_2-NH_2$

A polyalkylene glycol (PAG).

Besides the PAG displacing water from the gap between clay sheets, the amine groups are cationic in nature and can adsorb strongly on the cation exchange sites, providing doubly effective inhibition. It is possible for several diamine PAG molecules to bridge the gap between two clay sheets, like “nano-ropes” holding the sheets together.

Reduction or Reversal of Osmotic Transfer of Water into Shale requires a Semi-Permeable Membrane that allows water molecules, but not solutes such as salts, to diffuse through the extremely small pores in the membrane. The membrane also restricts the flow of liquid water. To an extent depending on the mineralogy and the level of compaction, shale can be described as a “leaky semi-permeable membrane”. The membrane efficiency can be improved (i.e. reducing the permeability to aqueous solutions) by using pore plugging additives.

Osmosis is mainly an issue with water-based muds, and it is one that has increased in importance as the efficiency of commercial additives has improved over the years. The more the permeability of a shale is reduced and the more the hydration of a shale is inhibited, the more likely it is that the shale approaches the condition of a semi-permeable membrane. Under these conditions it becomes more important to use a reduced Water Activity (Aw) brine phase in the drilling fluid because this will avoid the osmotic build up of high pore pressure in the shale, which can lead to tight hole and/or cavings.

Water Activity is related to water vapor pressure. Water vapor is composed of individual molecules of water. In liquid water, individual molecules of water move around (diffuse) in equilibrium with larger groups of water molecules that are held transiently together by hydrogen bonding. The concentration of single water molecules is a function of temperature. For example, at boiling point several individual water molecules are moving about rapidly enough to create a vapor pressure of 1 atmosphere.

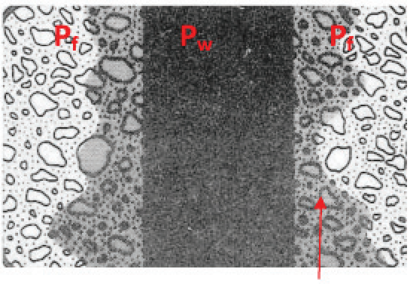
Water vapor pressure is also a function of the concentration of dissolved material in the water. For instance, the vapor pressure of brine saturated in sodium chloride (about 25% by weight NaCl) is lower than that of pure water by a factor of 0.75 and this factor is called the Water Activity (Aw) coefficient. Water molecules randomly diffusing from a drilling fluid in the wellbore into the pores of a shale will be captured by the clay surfaces and the dissolved ions in the pore water in an effort to restore the level of hydration.

If the water activity in the drilling fluid is high then there will be a plentiful supply of water vapor molecules diffusing from the mud into the shale. This will raise the pore pressure, which together with continued diffusion will transport water of hydration further into the shale. If, however, the water activity in the drilling mud is lower than that of the shale, diffusing water molecules are more likely to be captured by the drilling fluid, leading to a net flow into the mud and reduced hydration of the shale. This diffusion and capture of water molecules is a form of osmosis.

As shales became buried over geological time they became compacted and some of the inter-particle water was gradually squeezed out. The ions that were dissolved in the water (e.g. sodium, magnesium, calcium, chloride, etc.) were not as mobile in the shale pores as the water, due to the “leaky semi-permeable membrane” effect, so as the water drained out some of the ions were left behind, resulting in an increase in the pore water salinity. This leads to reduced water activity (i.e. reduced water vapor pressure) in the shale.

In addition, the clay particles became compressed tightly together by the overburden pressure over time, and illite and montmorillonite particles became compressed as inter-layer water escaped. This puts a lot of stored energy into the compressed shale so, given the chance, the shale wants to rehydrate and expand. So the compressed shale itself also results in reduced water activity, which adds to the contribution from the concentrated salts in the pore water. As mentioned earlier, the efficiency of the semi-permeable shale membrane can be improved by using pore plugging additives, described in the next paragraph.

Plugging of Shale Pores to Reduce Pore Pressure Penetration is shown in the following illustration. If permeability of the shale near the surface of the wellbore can be substantially reduced by plugging the pores in the shale with tiny organic colloids or clouded-out PAG droplets, then the wellbore pressure and hydrating water cannot penetrate very far. The hydrostatic pressure of the drilling fluid therefore acts upon the surface of the wellbore and provides support to the near-wellbore shale.



The darker grey area is where the shale pore have been plugged by colloids or by clouded-ou PAG droplets, so that the wellbore pressure (P_w

Diagram showing plugging of shale pores by colloids or clouded-out polyalkylene glycol droplets.

Besides organic colloids and polalkylene glycols, inhibitive drilling fluids based on sodium silicate solutions are thought to cause near-wellbore pore plugging in shale. The alkaline silicate solution reacts with the clay in the shale and the ions in the pore water. The subsequent drop in pH causes silica to precipitate, and calcium and magnesium dissolved in the pore water causes insoluble silicate salts to precipitate. Both of these colloidal precipitates are effective pore-pluggers.

Sealing of Shale Micro-Fractures is important when shales are brittle and contain many small fractures and micro-cracks. As shown in the left diagram below, the mud pressure can leak into the cracks, leading to little or no differential pressure (ΔP) supporting the near-wellbore shale. This can result in spalling, where pieces of shale break off and fall into the wellbore, and hole gauge washouts.

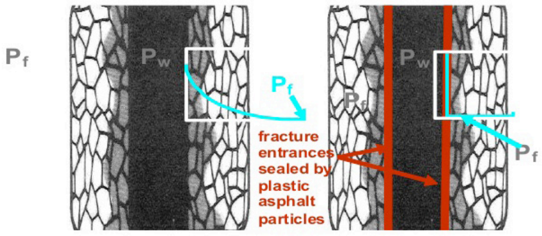


Diagram showing sealing of shale micro-fractures using asphalt particles.

Some materials, such as blown asphalt or gilsonite, are fairly brittle solids at surface temperatures, and can be ground to a size similar to that of the micro-cracks in shale. When added to a drilling fluid the powdered particles lodge in the entrances to fractures in the shale. They are then softened by elevated down-hole temperatures, which allows them to deform and coalesce, sealing the entrances to cracks. This stops the penetration of wellbore pressure beyond the near-wellbore shale, and the differential pressure is able to support the borehole wall, preventing spalling and caving of shale into the wellbore.

Reactions with Clays in the Shale to Produce Inter-Particle Cement was mentioned earlier, where the alkaline filtrate from sodium silicate fluids reacts with clay in the shale. The high alkalinty can dissolve some silica from the clay silica layers, and the alumina layers can transiently dissolve to an extent to give sodium aluminate in solution. These reactions reduce the alkalinity of the invaded filtrate, leading to the precipitation of silica, while the aluminate and silicates combine to drop-out amorphous alumino-silicates.

Besides the pore-plugging effects of these precipitates noted earlier, they act as an inter-granular cement which causes the shale to harden and gain in strength. By these processes sodium silicate fluids have provided on occasions the levels of wellbore stability only obtained previously by using oil-based mud. However, some drawbacks that have been seen with silicate sytems have included cuttings accretion onto BHAs, poor lubricity, interference with MWD tools, and difficulty in obtaining low fluid loss.

It is worth mentioning that high lime fluids have been used in shale drilling. The objective here is that the lime in the filtrate reacts with clay particles in the shale in ways similar to Portland cement, or lime mortars, to produce a calcium silicate cementitious precipitate. The use of lime fluids for shale drilling has declined with the development of more efficient inhibitive fluids and additives.

Polymer Chemistry

Section 3

Contents

Polymer Chemistry

Introduction

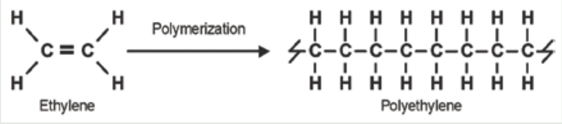
Polymers are very large molecules made up of many chemical units joined together in chains by strong molecular bonds. The word “polymer” is derived from Greek, meaning “many parts”. Polymers often have a repeating unit where many units with identical chemical structures are joined together to form the polymer chain. Many polymers are familiar to us from everyday life. Typical examples include rubber, plastics, synthetic fibers like nylon, natural fibers like cotton (cellulose), natural proteins in meat, and starch in flour and potatoes.

Polymers are extremely important for drilling and completion fluids and the purpose of this section is to provide a grounding in the types of polymers used in drilling and completion fluids, the way in which they work, and their particular characteristics and limitations. This section is primarily concerned with the water-soluble and oil-soluble polymers that fulfill particular functions when added to wellbore fluids. The following table gives an idea of some of the many oilfield applications for soluble polymers:

Application	Polymer Function
Water-Based Drilling and Completion Fluids	Viscosity and Solids Suspension Fluid Loss Control Thinner and Dispersant Shale Hydration Inhibition
Oil-Based Drilling and Completion Fluids	Fluid Loss Control Rheology Modifier Thinner and Deflocculant Shale Hydration Inhibition
Cement Slurries	Fluid Loss Reduction Free Water Reduction Thinner and Dispersion of Cement Particles Retardation of Setting Time
Fracturing Fluids	Polymer Gel to Suspend Proppant Leak-Off Control Friction Reduction for Slickwater Fracs
Well Treatment Fluids	Acid Gels Gels for Lost Circulation Control Diverting Agents and Water Shut Off Gels Sand Consolidation Treatments
Enhanced Oil Recovery	Mobility and Conformance Control
Drilling Waste Treatment	Flocculation

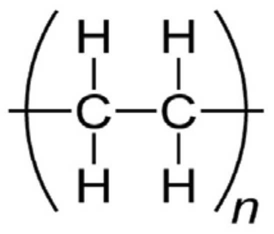
Synthetic Polymers

Synthetic polymers are manufactured by joining together a series of low molecular weight units (monomers) in a process known as polymerization. An example is the polymerization of ethylene to form the polyethylene that is typically used in plastic bags. Ethylene has a molecular weight of 28, whereas in polyethylene many ethylene monomer molecules are joined together to give polymers with molecular weights varying from a few hundred, through to tens of thousands, and up to several million. The product range includes polyethylene wax, low density polyethylene (LDPE) and high density polyethylene (HDPE).



Left: SEM picture showing hexagonal kaolinite crystals
Right: SEM picture showing a stack of kaolinite platelets

An alternative way of representing a polymer (see below) is to place the repeating unit in brackets with a subscript (n) to indicate that several units are conjoined to form the polymer chain. The number of units (n) in a polymer is known as the Degree of Polymerization (DP).



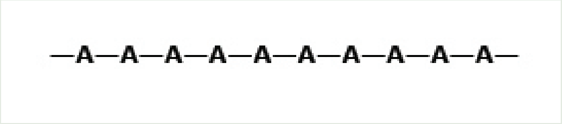
$$\left(-\overset{H}{\underset{H}{C}}-\overset{H}{\underset{H}{C}}- \right)_n$$

Polyethylene, as shown above, is made up from just one monomer, and it is an example of a homopolymer. Polymers are often manufactured using more than one monomer type and they are classified as copolymers. A copolymer made using three different monomers is called a terpolymer.

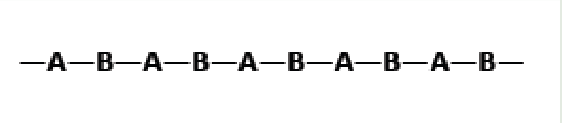
Polyethylene, as shown above, is made up from just one monomer, and it is an example of a homopolymer. Polymers are often manufactured using more than one monomer type and they are classified as copolymers. A copolymer made using three different monomers is called a terpolymer.

The ratio of the monomers used, and the way the monomers join up, can result in a variety of molecular architectures both in terms of the structure of the polymer and the order of the units along the polymer chain. Some examples are shown on the following page, with the letters A, B, and C representing three different monomers. The ratio of the monomer molecules in a copolymer is known as the molar ratio.

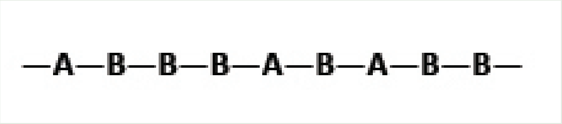
Examples of polymer structures and nomenclature:



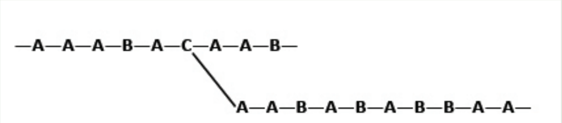
A linear homo-polymer



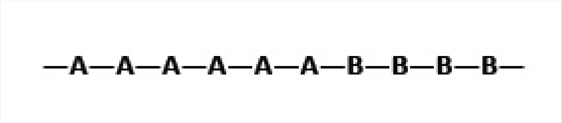
A linear alternating copolymer Molar Ratio = 1:1



A random copolymer Molar Ratio = 1:2 (A:B)



A branched copolymer



A block copolymer

A grafted polymer where a functional group "F" has been grafted onto the main chain (aka polymer backbone)

Functional groups

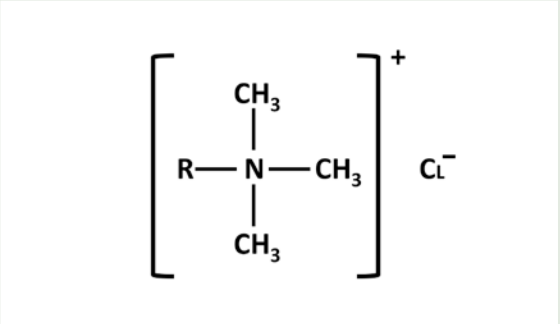
Functional groups are specific groups of atoms within molecules that are responsible for the characteristic chemical reactions of those molecules. For water-soluble polymers the grafted functional group is normally a hydrophilic (water-attracting) molecular group. Hydrophilic functional groups can be classified into four types, as follows:

Nonionic – A group that does not ionize or assume any electrical charge in water. Some examples include hydroxyl groups (–OH), ether links (–Ö–) that are present, for example, in polyethylene glycol chains where the lone pair of electrons on the oxygen atom (Ö) is available for hydrogen bonding water molecules, and amide groups ($-CONH_2$) that are found in polyacrylamide.

which then becomes compacted over time as more and more sediment accumulates on top of the mud. The mineral particles may have been clay particles eroded from land deposits. They may also have been other silicate mineral particles that gradually changed into clays on contact with salts in the pore water, the alteration process being helped by increasing temperatures as the layer became buried deeper and deeper.

Anionic – A group that ionizes in water to assume a negative charge. Anionic groups are basically acidic groups that may be present in a polymer in the acid (protonated) form or they may be neutralized to form a salt with, for instance, sodium ions. Examples include carboxylates (R–COOH or R–COONa, which form the R–COO– anion in water) and sulfonates ($R-SO_3H$ or $R-SO_3Na$, which form the $R-SO_3-$ anion in water), where R represents the rest of the polymer onto which the groups are attached.

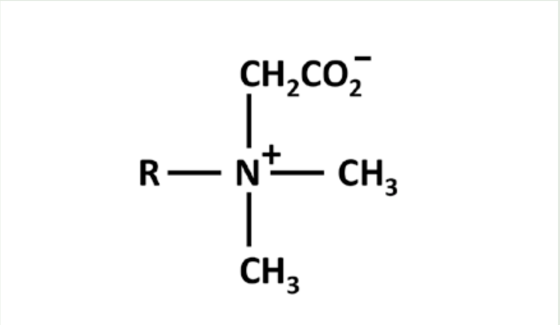
Cationic – A group that ionizes in water to assume a positive charge. Although some phosphonium and sulfonium cationic groups are known, by far the most common cationic functional group is the Quaternary Ammonium ("quat") group. Quaternary simply means that four groups are bonded to the nitrogen atom, such as the one shown below, where R is the rest of the polymer chain to which the quat group is bonded:



$$\left[R - \overset{\displaystyle CH_3}{\underset{\displaystyle CH_3}{N}} - CH_3 \right]^+ Cl^-$$

An example of a cationic functional group, which ionises in water to leave a positive charge on the quat group when the chloride anion diffuses away.

Amphoteric – A group that ionizes in water to give both positive and negative charges. They are not common in drilling fluids, although they are sometimes used as flocculants. An example of an amphoteric functional group is the betaine grouping, as shown below:



$$R - \overset{\displaystyle CH_2CO_2^-}{\underset{\displaystyle CH_3}{N^+}} - CH_3$$

A betaine is a quaternary ammonium grouping in which one of the four groups attached to the nitrogen atom is a carboxymethyl anionic group (-CH2.COO-).

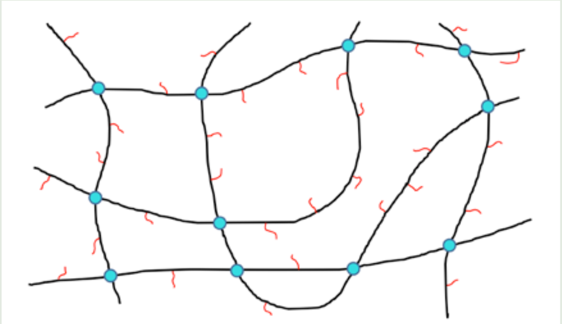
The Functions of Polymers in Drilling and Completion Fluids

Viscosity and Gel Strength – The use of water-soluble polymers to generate viscosity and gels has the advantages (compared with using bentonite) of:

- Much lower concentrations (better logistics)
- Improved tolerance for contaminants
- Improved performance in saline fluids (e.g. salt-saturated or KCl inhibitive fluids)

Water-soluble polymers increase fluid viscosity in two ways. They form a hydration shell of several ordered water molecules that are bound by hydrogen bonding to the polymer chains and, perhaps more importantly, high molecular weight polymer chains form interactions with neighbouring polymer chains when the polymer concentration is high enough.

These polymer-polymer interactions help to build the high viscosity at low shear rates that is needed for effective hole-cleaning, whereas at high shear rates the fragile interactions are broken, leading to much-reduced viscosity when, for instance, the fluid flows through the bit nozzles. This is referred to as "shear thinning behaviour".

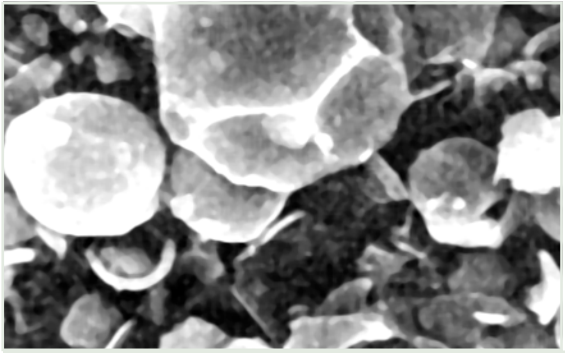


High molecular weight polymer chains in solution at a concentration above the "critical overlap concentration" can interact with each other, forming tenuous links between the chains (as shown in blue).

Good suspension of barite and other weighting materials requires that the fluid has progressive gel strengths, which means that a gel structure strong enough to keep the dense mineral particles from settling out (i.e. barite sag) is established in a relatively short period of time. The only polymers that can reliably provide this are the bacterial polysaccharides, in particular xanthan gum. The development of gel strength from xanthan's rigid double helix and the strong polymer-polymer interactions is covered in more detail later in this section.

Fluid Loss Reduction – There are several ways in which polymers contribute towards reducing the filtration rate of a drilling fluid, otherwise known as "fluid loss control". When the solid particles in the mud (such as barite, drilled solids, clays, calcium carbonate and silica) form a filter cake on the surface of permeable rocks, the particles in the filter cake should pack closely together in order to minimise the size of the flow channels between the particles.

Ideally the particles are deflocculated (dispersed as individual particles) in the mud so that there is no inter-particle structuring (flocculation) that would lead to more open flow channels in the filtercake. Low molecular weight polymers (about 5,000 to 40,000 molecular weight) are effective deflocculants for this purpose. In addition, higher molecular weight polymers (about 200,000 to 1,000,000 molecular weight) should be used for adsorbing onto the surface of the particles as this will prevent the water leaving the dispersed solids.



Assortment of Particles in a Filter Cake

The diagram below shows water-soluble hydrophilic polymer chains partly adsorbed onto the surface of a mud solid particle via the functional groups in parts of the chain length ("trains" as shown). The rest of the polymer chains "hang off" the particle as loops or tails, which are heavily hydrated. In effect, a high viscosity layer of polymer gel is stuck onto the particle surface so that, as soon as it becomes part of a filter cake, it will drastically reduce the flow of water as the gel layers on nearby particles overlap.

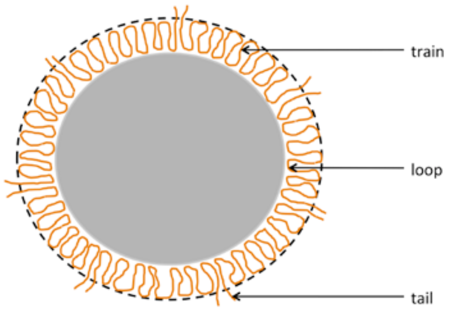
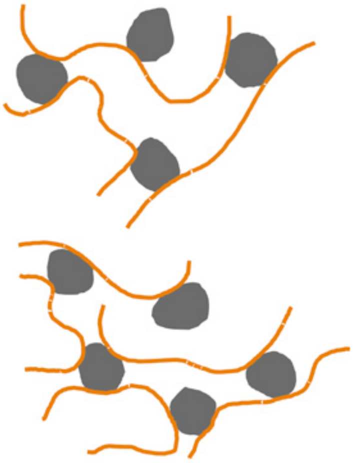


Diagram shows how a high viscosity layer of polymer gel is formed by water-soluble hydrophilic polymer chains partially adsorbing onto the surface of a solid particle.

A third mechanism of fluid loss control is provided by polymers like starch and starch derivatives. In solution in water, these materials form a colloidal dispersion of water-swollen, nano-scale microgel "particles" that are about 100 nanometers diameter (0.1 microns). These microgel particles plug the flow channels in the filter cake because they are of a similar size. In reality the starch microgels can also adsorb onto the particles before they reach a filter cake, thereby carrying the fluid loss reducer into the filter cake.

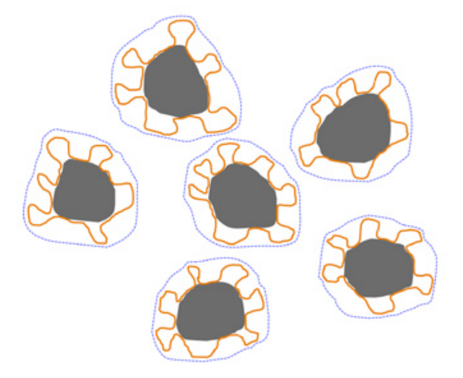
Thinners, Dispersants, Deflocculants and Flocculants – As mentioned previously, low molecular weight polymers (about 5,000 to 40,000 molecular weight) are effective deflocculants. This is in contrast with flocculants, which have a molecular weights of several million.



High molecular weight polymers linking particles to produce Bridging Flocculation

High molecular weight polymers that are used as flocculants (see diagram above) have a long enough chain length that enables one polymer chain to adsorb onto and link more than one particle (bridging flocculation). The functional groups that adsorb on the particle can be non-ionic, anionic, cationic, or amphoteric. Some functional groups adsorb on specific mineral surfaces (selective flocculation).

Low molecular weight deflocculant polymers (see diagram on next page) adsorb onto and coat individual particles so they can move independently without flocculation. The polymers used as mud thinners all have anionic functional groups such as carboxylate or sulfonate. These negatively charged groups adsorb onto barite, calcium carbonate and clay platelet edge sites, giving the particles an overall negative charge. The consequent electrostatic repulsion keeps the particles apart, which reduces the gels, LSRV and Yield Point.

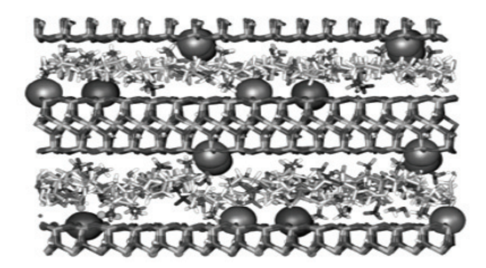


Low molecular weight polymers coating individual particles to prevent flocculation

Shale Inhibitive Polymers – These comprise encapsulating polymers, shale swelling inhibitors and pore pluggers, as follows:

Encapsulating Polymers are very high molecular weight (several million) polymers that adsorb strongly onto shale cuttings and the wellbore wall, coating the surfaces. This slows the movement of water into the formation and cuttings. Such polymers are most useful in reducing the disintegration of cuttings. However, they have little effect in stopping shale swelling.

Shale Swelling Inhibitors are polymers with molecular weights that are low enough (around one thousand or less) to get into the gaps between the constituent sheets of swelling clays such as montmorillonite (see below). They replace water in the gaps and prevent further hydration and swelling. Nonionic and/or cationic functional groups are effective here.

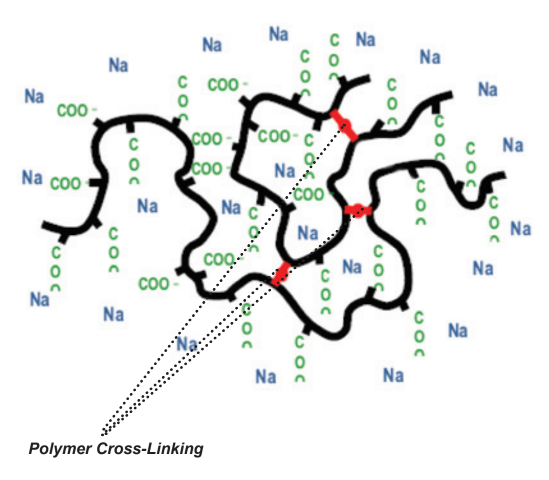


Shale Swelling Inhibitors

Pore Pluggers are low molecular weight polymers that can get into the pores of a shale where they adsorb and concentrate in the pore throats, blocking the flow of water and slowing pore pressure penetration. Some “cloud point glycols” and silicate fluids are reputed to work in this way.

Cross-Linked Polymer Gels for Lost Circulation Control – Certain polymer solutions can be mixed with a delayed cross-linking agent so that the polymer chains remain “un-cross-linked” and the fluid is pumpable long enough for the pill to be displaced into the formation where the losses are occurring. The polymer solution then sets to a firm, rubbery gel that controls the losses, the setting time being a function of time and temperature.

An example is PHPA (partially hydrolysed polyacrylamide). This polymer contains a lot of carboxylate ions ($–COO^–$) that can react with polyvalent cations (i.e. cations having several positive charges), such as the trivalent chromium ion Cr^{3+}. One Cr^{3+} ion can react with carboxylate groups on different polymer chains nearby, forming a stable salt pair. Multiple cross-linking like this can create a very strong gel. The set time can be adjusted using retarding anions like acetate and citrate which, being carboxylic acids, are in competition with the carboxylate groups on the PHPA for the chromium ions.



Cross-Linking between Polymer Chains.

Polysaccharides

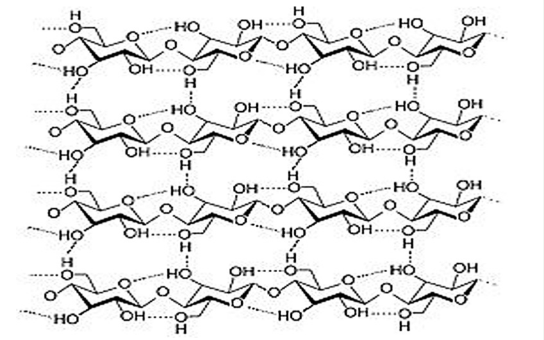
In water-based drilling fluids the most important class of polymers is that of natural polysaccharides and modified polysaccharides. A polysaccharide is made up of sugar-like repeating units, the most useful ones for drilling fluids being:

- **Cellulose**, which is obtained from wood pulp or cotton, and modified to produce water-soluble polymers
- **Starch**, which comes from a variety of plants including potatoes, corn and tapioca
- **Bacterial Gums** such as **Xanthan Gum**, which are produced by bacteria during a fermentation process
- **Seed Gums** from certain plants, such as Guar Gum products that are mostly used in fracturing fluids

Cellulose and Cellulose Derivatives

Cellulose itself is not water-soluble, which at first glance seems surprising because the repeating unit in cellulose is basically the highly water-soluble sugar glucose (more correctly anhydroglucose). Figure 1 below shows four of the many anhydroglucose units in a cellulose molecule:

Cellulose is a linear molecule because of the arrangement of the ether (–O–) link between the hexagonal anhydroglucose rings, and adjacent polymer chains can lie very close to each other as shown in the diagram below. This close spacing and "fit" between adjacent chains allows strong hydrogen bonding between the chains, as represented by the dotted lines in the diagram below. The array of polymer chains in cellulose fibres is so regular that they actually exhibit a high degree of crystallinity as determined by X-ray diffraction techniques.



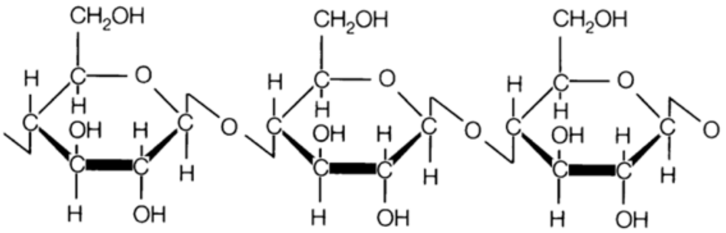
Parallel chains of linear cellulose molecules are held together by strong hydrogen bonding.

The hexagonal anhydroglucose units are correctly shown in their actual puckered "chair" shape, unlike the previous diagram.

This strong hydrogen bonding is not disrupted when cellulose is added to water, and therefore individual polymer chains cannot split off to dissolve in the water. However, cellulose fibres can be swollen by water, especially in the presence of alkali. In order to make useful water-soluble cellulose derivatives, hydrophilic (water-attracting) chemical groups are grafted onto the cellulose main chain.

This has two effects. The first is the increased water-solubility conferred by grafting hydrophilic groups. The second is that pendant (hanging off) chemical groups are also grafted onto the main cellulose chain and these act like molecular wedges. They prise apart the main cellulose chains, making the structure more amorphous and easier to dissolve.

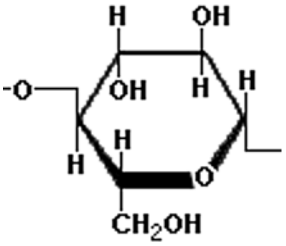
There are two basic types of grafted cellulose used in drilling and completion fluids, carboxymethyl cellulose (CMC) and hydroxyethyl cellulose (HEC). A hybrid of these two is carboxymethyl hydroxyethyl cellulose (CMHEC), which has been used in the past, but there appears to be little or no current use for CMHEC as an additive in drilling fluids.



Repeating Anhydroglucose Units in a Cellulose Molecule.

Polymer Chemistry

Carboxymethyl Cellulose – CMCs are used primarily as fluid loss reducers (FLRs) in both fresh water and saltwater drilling fluids. The high viscosity (HV) grades also contribute to Yield Point and hole cleaning. To make CMC, cellulose is first swollen in water and caustic soda to make it more reactive, then chloracetic acid ($ClCH_2.COOH$) is added. The chlorine atom reacts with the alkali cellulose so that $–CH_2.COO–$ groups are grafted onto the cellulose backbone via ether links, with salt (NaCl) being generated as a by-product. Another by-product, sodium lactate, can be formed by the action of the caustic soda on chloracetic acid. Commercial CMCs usually contain about 70% carboxymethyl cellulose together with about 30% sodium chloride and sodium lactate (Figure 2 below).



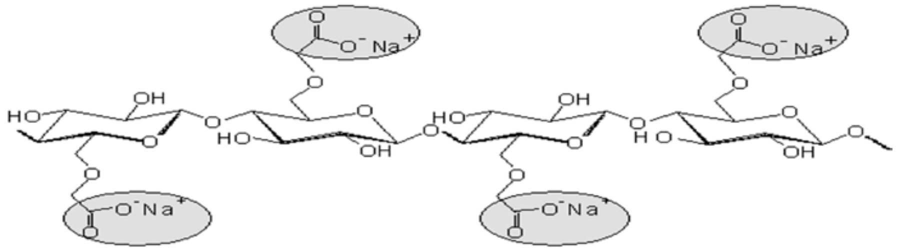
There are three hydroxyl (OH) groups in the repeating anhydroglucose unit of cellulose, so theoretically up to three carboxymethyl groups can be introduced per repeating unit. The number of hydroxyl groups grafted is known as the Degree of Substitution (DS).

The $–CH_2OH$ group is much more reactive than the other two hydroxyl groups, and normally a degree of substitution much lower than three is used. Oilfield grade CMCs typically have a degree of substitution in the region of 0.7.

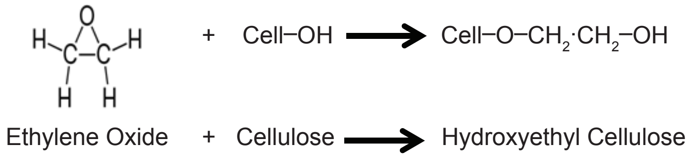
Polyanionic Cellulose – PAC is a particular high performance grade of CMC. PACs have a higher degree of separation in the region of 1.0. They are further distinguished from regular CMC in that high grade cellulose raw material is used, and the salt impurities are usually removed. The CMC molecule depicted at the top of the page is shown with a degree of separation of 1.0 with the carboxymethyl groups grafted onto the more reactive $–CH_2OH$ sites, which is a typical structure of a PAC.

CMCs and PACs are available in a variety of grades: high viscosity (HV), low viscosity (LV) and some ultra-low viscosity (ULV) grades are available. The highest viscosity PACs are produced using high molecular weight cotton cellulose. Cellulose can be degraded by alkaline hydrolysis to produce low molecular weight cellulose as raw material for LV and ULV products.

Generally, because of their higher degree of separation, PACs perform better than CMCs in high salinity fluids. Both PACs and CMCs are moderately resistant to bacterial (enzyme) degradation, but the addition of bactericide to fluids containing polysaccharides is always recommended. Both product types have only moderate compatibility with dissolved calcium and magnesium hardness, especially at high pH. This is because calcium and magnesium ions form stable, non-ionizing salt pairs with the carboxylate anions, causing the polymer to precipitate. The control of hardness with soda ash and sodium bicarbonate treatments is therefore required if calcium or magnesium levels rise.



Carboxymethyl ($-CH_2.COO-$) groups grafted onto a main cellulose chain.



Hydroxyethyl Cellulose (HEC) is manufactured by reacting alkali-swollen cellulose with ethylene oxide.

When high viscosity CMCs and PACs are added to mud with a high clay content, a “viscosity hump” (high YP and gel strengths) usually occurs due to the long polymer chains linking clay particles together (bridging flocculation). On further shearing, particularly through the bit nozzles, these links are broken and the polymer chains are shortened by shear degradation. This promotes the gradual strong adsorption of polymer chains onto individual particles, leading to a gradual loss of YP, low shear rate viscosity (LSRV) and gels.

For these reasons, high viscosity CMCs and PACs cannot always be relied upon to provide stable rheology, and the use of some xanthan gum may be required. Low viscosity and ultra-low viscosity PACs have very good stability at high temperatures up to around 300°F (150°C) and are therefore useful fluid loss reducers for drilling intermediate temperature (sub-HPHT) wells. Because of their low viscosity-increasing (PV) effect, and their solids-dispersing effects, they have good application in high solids/ high weight drilling fluids.

Hydroxyethyl Cellulose – HEC is primarily used as a viscosifier for brine-based completion and workover fluids.

HEC is manufactured by reacting alkali-swollen cellulose with ethylene oxide. Ethylene oxide reacts with hydroxyl groups on the cellulose such that hydroxyethyl groups (–CH_2.CH_2–OH) are grafted onto the anhydroglucose rings.

Additional ethylene oxide molecules can then react with the hydroxyl groups on the hydroxyethyl groups, causing –O–CH_2CH_2–O–CH_2CH_2–O– side chains to grow, hanging from the main chain.

The HEC molecule shown (Figure 3 below) has a degree of substitution (i.e. average number of graft points per anhydroglucose units) of 1.33. However, there is a total of six ethylene oxide units reacted onto three anhydroglucose units, so there is an average of two ethylene oxide units grafted per anhydroglucose unit. This number is known as the Molar Substitution.

Typical high viscosity grade HEC, as used in drilling and completion fluids, is usually more highly substituted than this, with a degree of substitution around 1.5 and a molar substitution around 2.5, and a typical molecular weight around 1.3 million (The degree of polymerization is about 4,800). Lower molecular weight HECs are used in well cementing slurries as fluid loss control agents.

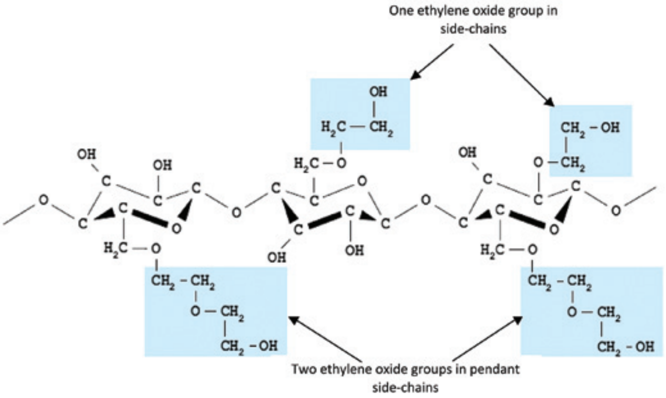


Figure 3: Molecular Structure of Hydroxyethyl Cellulose

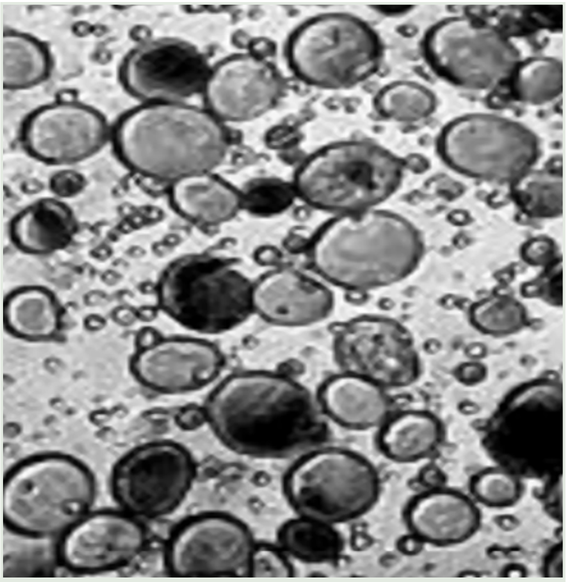
HEC in solution is a very flexible molecule with little interaction between neighbouring polymer chains. It does not therefore build the polymer structures that are needed for good LSRV and gel strengths in fluids. So although it confers good Yield Point values it has relatively poor suspension properties. However, the low gel strengths also allow HEC solutions to flow through permeable rocks with little impairment to permeability. HEC also provides good fluid loss control when formulated with sized calcium carbonate in brine-based loss control pills.

HEC dissolves well in most brines, such as the chloride and bromide completion and work-over brines. However, it is incompatible with formate and carbonate brines. It has also been found to precipitate out of strong sodium or potassium chloride brines at elevated temperatures, causing potential formation damage problems. Other notable characteristics of HEC include the weakness of the polymer to various degradation processes. It will stand temperatures up to about 220°F (105°C) under normal circumstances, and perhaps higher when used in strong brines.

HEC is also very susceptible to bacterial degradation, so should be used in conjunction with bactericide unless the brine density is around 1.2 s.g. (10ppg) or higher, since bacteria cannot survive at higher brine concentrations. However, this weakness can be turned to an advantage during the clean-up of residual HEC fluids that may have invaded the producing formation or been left behind in gravel packs. Residual HEC can be removed using enzyme breakers (based on cellulase enzymes that digest cellulose fibers), or oxidative breakers such as sodium hypochlorite.

Starch and Starch Derivatives

Starch is obtained from many plants such as maize (corn starch), waxy maize, potatoes, wheat and tapioca, but corn and potato starch are the types most commonly used in drilling fluids. Starch occurs in the plants as small granules that have a hard shell that does not readily dissolve in water. A dispersion of starch granules in water is shown in the microscope picture (above).



Dispersion of starch granules in water.

Starch is made soluble in cold water by a pre-gelatinization process. Starch granules are heated with water or steam to a temperature of 100°C and above, which causes the granule shell to burst and the starch polymer chains to dissolve. The solution is then dried to produce pregelatinized starch, which is used as drilling starch.

Like cellulose, starch is basically composed of glucose units. The key differences are that the ether-link bonds between the repeating units are arranged differently, and that starch exists in two forms: amylose and amylopectin. Amylose is a linear polymer with a molecular weight around 500,000 that tends to adopt a coiled structure, as shown below (Figure 4):

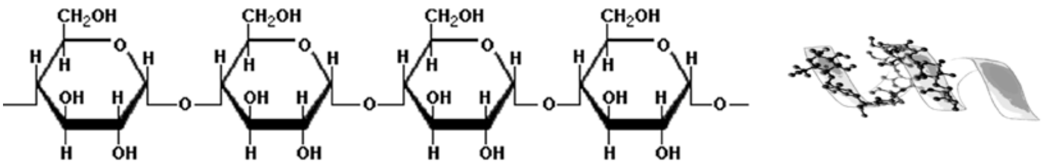


Figure 4: The structure of Amylose Starch

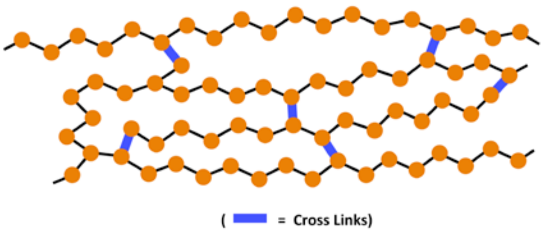
Unlike cellulose, amylose is water-soluble. This is because the coiled structure in solution hinders the close association and hydrogen bonding between chains that occurs with cellulose. Amylopectin has the same glucose repeating unit as amylose, but there are two key differences. Its molecular weight is much higher at over 50 million, and the molecule is branched in many places, with further branches leading off each branch. (Figure 5 below)

A representation of the highly branched structure of amylopectin is shown below:

The highly-branched structure of Amylopectin Starch.

Like cellulose, starch can be derivatised by grafting onto some of the three hydroxyl groups on each repeating unit. The two derivatives most commonly used in drilling fluids are hydroxypropyl starch and carboxymethyl starch. Hydroxypropyl starch is analogous to HEC, but instead of grafting ethylene oxide onto the polymer, propylene oxide is used. These derivatives generally show improved performance in strong brine-based drilling and completion fluids. Hydroxypropyl starch is effective in chloride and bromide brines, whilst carboxymethyl starch works well in formate brine. Cationic starches have also been used.

Starch products are used almost exclusively for fluid loss reduction, and the premium products have often been cross-linked to enhance fluid loss control and minimize viscosity increases. However, while the cross-linking of dissolved polymer molecules causes an increase in fluid viscosity by forming a three dimensional gelled network, the starch products are cross-linked before they are dissolved. This holds neighbouring molecules together tightly enough that, when added to water, they do not separate very far compared to the non cross-linked case. This limits the volume occupied by the colloidally dispersed microscopic globules, and reduces the amount of water associated with the polymer.



Cross-Linking in a starch molecule.

The diagram above is a representation of a cross-linked starch molecule. The cross-links maintain the polymer chains in a less-hydrated globular structure, which is better for plugging the pores in a filter-cake. It also minimises the viscosity increase that would occur if the chains were free to extend in solution. Cross-linked starch products are also more stable at temperatures around 250°F (120°C) and sometimes slightly higher.

The explanation for thermal stability is due to the fact that non cross-linked starch molecules in solution have a more extended structure that makes the chains more vulnerable to hydrolytic or free-radical attack at

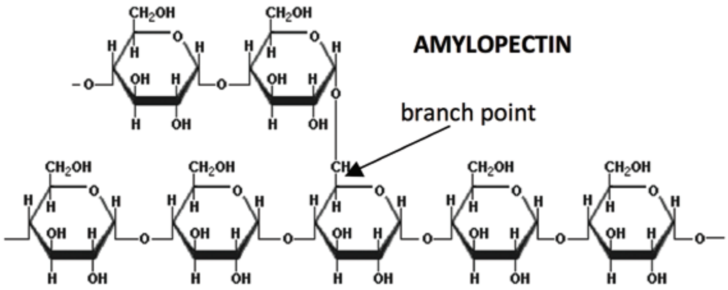


Figure 5: The structure of Amylopectin Starch, showing a branch point.

high temperatures. However, the less hydrated cross-linked globular structure has a more compact line of defense, and even if some chain scission (cut or split) does occur there are enough inter-chain cross-links to maintain the colloidal globular structure.

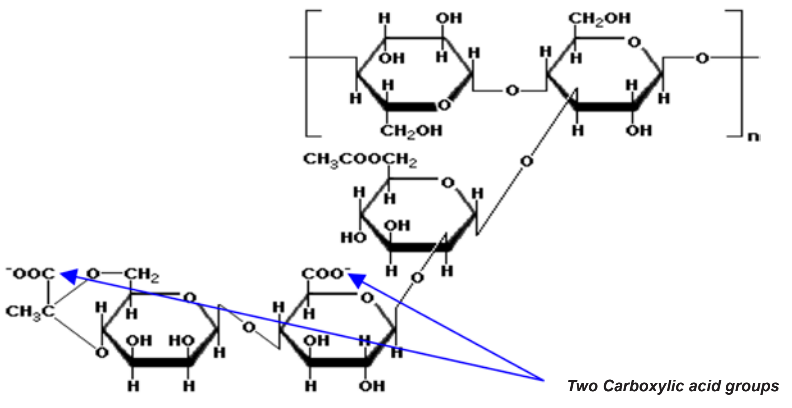
For fluid loss control, starch works in a different manner to CMCs and PACs. For that reason the use of starch in conjunction with CMC or PAC is often more efficient than using a higher dose of just one of the products. Starch products have good compatibility with various salts and fluid additives. They are also resistant to hardness because the amylase and amylopectin components are nonionic, so they do not form insoluble salt pairs with calcium or magnesium ions, and the heavily hydroxylated molecules remain hydrated even in the presence of high salt concentrations.

Starch products provide better fluid loss control in higher salinity fluids, where the globular molecular structure is more compact. In fresh water, the globular molecular structure expands and can generate unwanted viscosity as well as lose much of the fluid loss control function. Starch is also highly susceptible to bacterial degradation, and should be used in conjunction with a bactericide. Some starch products contain a bactericide pre-blended with the dry powder, but there may still not be sufficient bactericide when such materials are mixed into fully formulated mud. However, this susceptibility to bacteria (and hence enzymes) is useful when using amylase-type enzymes to clean up starch based filter cakes and down hole residues.

Bacterial Gums (Xanthan Gum)

Bacterial gums, also known as microbial polysaccharides, have a distinct performance attribute not shown by cellulose or starch derivatives because they provide excellent gel strength and solids suspension in drilling and completion fluids. There are many bacterial gums produced by bacterial fermentation processes including xanthan gum, scleroglucan, succinoglycan, welan gum and diutan gum. By far the most important is xanthan gum.
Xanthan gum is produced from the fermentation of a sugar such as sucrose, glucose or lactose by the bacterium Xanthomonas Campestris. The yield of the product is optimized by using conditions that stress the bacteria, which then protect themselves by forming a coating around themselves of an extracellular slime that is composed of xanthan gum. After fermentation the polymer is precipitated out using isopropyl alcohol and then filtered, dried and ground to the familiar powder.

Xanthan Gum has a high molecular weight, typically around 15 million, and this makes the number of repeating units in the polymer chain about 16,300. This number of repeating units is known as the Degree of Polymerisation (DP).The molecular structure of the repeating unit of xanthan gum is shown below (Figure 6):



Two Carboxylic acid groups

Figure 6: The main chain at the top is basically the same as cellulose. The branched side chain plays a critical role in forming the hydrogen bonded helical structure that produces the high gel strengths and LSRV. The side chain also contains two carboxylic acid groups.

In solution in water, individual xanthan gum chains pair up and form a DNA-like double helix, where strong hydrogen bonding between the side chains maintains the coiled shape. At temperatures above about 120°C (248°F), the double helix starts to unravel to give individual polymer chains in solution. This is called the transition temperature, and strong brines can have a large effect on this temperature. As an example, xanthan gum dissolved in potassium formate brine at 1.50 s.g. (12.5 ppg) has a transition temperature of nearly 200°C (390°F).

The strongly associated double helix (figure 7) has the effect of stiffening the structure into a rigid rod-like conformation. Interactions between neighbouring double-helices cause a gel structure to build whose strength is attributable to the rigidity of the polymer rods. This is in contrast to HEC and CMC, which are both highly flexible molecules and whose solutions have very low gel strengths.

The double helix also has the effect of reducing the adsorption of xanthan molecules onto drilled solids. The rigid structure cannot easily bend to fit onto the surfaces of mineral particles, and many of the adsorptive functional groups are hidden inside the helix. A second benefit is that the double helix imparts high resistance when it comes to breaking the chain length (chain scission) at high shear rates (shear degradation). This is similar to fibres twisted together in string being stronger than the individual fibres.

Xanthan Gum is also very resistant to bacterial degradation because the helix structure protects the molecule. Bacterial degradation generally occurs because the bacteria produce enzymes that have a shape that fits with the polymer chains prior to causing chain scission. The helical structure of xanthan gum inhibits enzyme adsorption and hides points of attack within the helix. The double helix also contributes towards xanthan's good hydrolytic stability at temperatures around 250 to 270°F (120 to 132°C), and higher in some brine types like formates. Unlike guar gum, xanthan is not degraded at high pH.

The combination of all these benefits is what gives xanthan gum outstanding performance as a drilling fluid additive, because it produces LSRV, gels and Yield Point values that are not easily lost over several days drilling. Xanthan gum is compatible with all monovalent brine types over most of the available concentration ranges. Examples include sodium and potassium chloride, bromide, carbonate, silicate, acetate and formate, including caesium formate. However, some of the brines will inhibit xanthan gum solubility as the salt concentration approaches saturation.

Xanthan solutions in potassium formate brine can remain stable up to 350°F (175°C) because this brine forces the polymer to remain in its stable double-helix shape. The mild alkalinity, low oxygen solubility and the somewhat reducing nature of formate brines also help in minimising high temperature degradation.

A limitation, caused by the two carboxylic acid functional groups in xanthan's side chain, is that a combination of high levels of dissolved calcium and high pH can cause the polymer to be precipitated when calcium cations form hydrophobic ion pairs with the carboxylate anionic groups. Xanthan Gum is therefore not suitable for use in dense calcium brines. That said, it is possible to use xanthan gum in calcium chloride brine, but only by maintaining the pH at near-neutral (pH 7.0). However, this is not recommended because it is not easy to guarantee good pH control.

High grade "clarified xanthan", which is used in applications where formation damage must be minimized, is manufactured by removing all the potentially plugging bacterial cell debris prior to precipitating the polymer.

Figure 7: Double Helix Structure of Xanthan Gum in Solution.

Guar Gum

Guar Gum is a polysaccharide that is made up of galactose and mannose sugar units. The guar is extracted from the seeds that are removed from the seed pods of the guar bush, a plant that is grown mainly in India and Pakistan. The guar seeds are dried and then ground to a powder for use in a wide range of industries, including food and cosmetics where it is used as a thickener with its ability to produce very high viscosity at very low concentrations.

Guar Gum is occasionally used in drilling operations, mainly as a spud mud where its rapid hydration and relatively low cost are useful. However, poor stability in solution has generally limited its use in drilling fluids and the main oil industry application for guar gum and modified guar products is as a fracturing fluid (frac fluid) additive. Guar Gum solutions display certain characteristics that are very suitable for this application:

- Intrinsically high Low Shear Rate Viscosity (LSRV) to assist in proppant transport (i.e. for carrying the frac sand or ceramic bead proppant deep into the fractures so that they keep the fracture open when the high pressure pumping stops)
- Easy cross-linking of neighbouring dissolved polymer chains by borate anions to further increase the LSRV and gel strengths, allowing reduced polymer dose and cost
- Low cost polymer for high volume frac operations
- Good leak-off control properties (similar to fluid loss control)
- Easy to break the viscosity using enzymes or oxidizing agent breakers to degrade the polymer chains. The frac fluid gel reverts to a water-thin liquid after the fracture process is complete as the frac fluid warms up and the breaker starts to work. This allows the large volume of fluid pumped to flow back more easily when the well is returned to production.

Some of these properties can be related to the molecular structure of the repeating unit of guar gum, as shown in Figure 8 above.

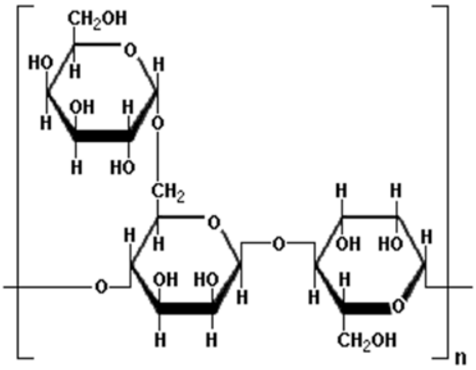


Figure 8: The molecular structure of Guar Gum, which is made up of galactose and mannose sugar units, with mannose forming the main chain. As with xanthan, hydrogen bonding via the side chain (in this case the galactose unit), gives Guar Gum intrinsically high LSRV.

Each sugar unit has a pair of hydroxyl groups pointing in the same direction (cis-hydroxyl groups), which have two effects. They cause strong adsorption onto solids, which assists in leak-off control. The cis-hydroxyl pairs are also receptive to hydrogen bonding with borate anions, enabling the cross linking of neighbouring dissolved polymer chains to form the high LSRV and gel strength required, as shown in Figure 9 below.

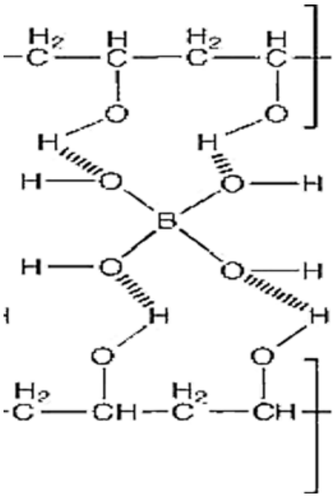


Figure 9: Representation of a borate cross-link between cis-hydroxyl groups on neighbouring polymer chains. In this case the polymer chains are actually polyvinyl alcohol, but the principle remains the same for borate cross-links between adjacent guar gum molecules.

Some of the properties of guar gum that are useful in frac fluids are quite unsuitable for drilling fluids:

- Strong adsorption onto drilled solids leads to unwanted viscosity humps via bridging flocculation, followed by a loss of viscosity due to adsorption of the polymer.
- Easy polymer degradation leads to loss of viscosity due to its vulnerability to bacterial and enzyme attack, and guar degrades if too much caustic soda is added.
- There is enough borate dissolved in seawater to cross-link the polymer on the surface of polymer powder granules that are dispersed in seawater, and this cross-linked coating can hinder the dissolution of the granules.

As with modified cellulose and starch products, guar derivatives are also manufactured, the most common one being hydroxypropyl guar (HPG).

High Temperature Degradation of Polysaccharides

At elevated temperatures, polysaccharide breakdown (chain scission) occurs at the ether links (–O–) between the sugar units (see Fig 10 below). This can lead to a rapid breakdown of molecular weight, and eventual breakdown to individual sugar units. These reducing sugars can then be further oxidised and degraded to various acids, and ultimately to CO_2. This explains the large drop in pH often seen after hot rolling drilling fluids at high temperature.

High temperature chain scission can be caused by hydrolysis, which is catalyzed by extremes of pH under acidic or highly alkaline conditions. Polysaccharides are generally most stable to hydrolysis at about pH 9 to 10. Air entrainment in a drilling fluid can lead to high dissolved oxygen levels which, under HTHP conditions, generate very reactive free radicals and hydroperoxide species. Oxidative processes like this are catalyzed by transition metal catalysts such as the iron oxides in barite and corrosion products.

High temperature breakdown can be minimised if the weak ether links can be protected, or reinforced by other links as in the hydrogen-bonded double helix of xanthan molecules in solution. As mentioned previously, xanthan is stable up to about 350°F (175°C) in dense potassium formate brine where the double helix configuration is maintained up to about 400°F (205°C) for short periods. Similar but less pronounced stabilising effects are seen with some other salts, while de-stabilising effects can occur with other salts such as sodium bromide.

Certain amines are useful high temperature stabilizers for polysaccharides. They are thought to act as pH buffers and free radical acceptors, while forming complexes with transition metal ions. They are also thought to form a preferential solvation shell around the polymer molecules, protecting the weak links from attack. The use of magnesium hydroxide to control pH helps because it buffers pH at around 10, and is believed to form polysaccharide/$Mg(OH)_2$ complexes, which may inhibit the approach of attacking species.

At downhole temperatures much greater than about 300°F (150°), it becomes much more difficult to use polysaccharide type products, and the cost escalates with the large maintenance treatments required. Oxygen scavengers such as bisulfite salts have also been tried, but do not seem successful in providing high temperature stability. Higher temperatures require the use of the much more stable synthetic polymers.

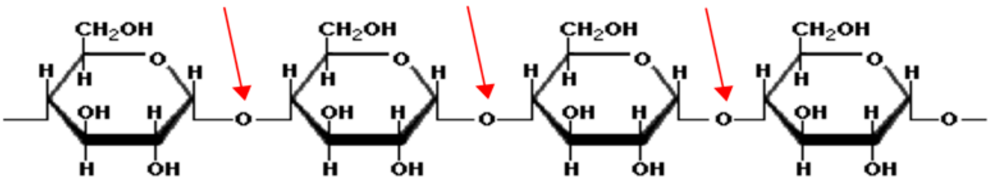
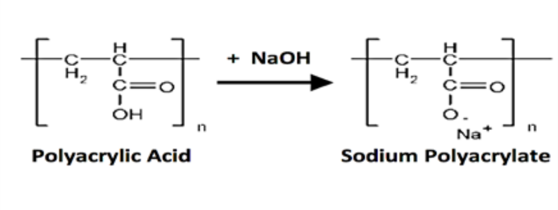


Figure 10: High temperature degradation of polysaccharides occurs at the ether links between the sugar units (indicated by the red arrows), resulting in rapid breakdown of molecular weight and associated viscosity.

Synthetic Water-Soluble Polymers

Synthetic polymers have been used in water-based fluids primarily as fluid loss reducers, deflocculants (thinners) and shale hydration inhibitors. The synthetic polymer fluid loss reducers and thinners are often used where the downhole temperatures exceed about 270 to 300°F (132 to 150°C). At or above this temperature, polysaccharide polymers start to undergo thermal degradation. Until recently no synthetic polymer has been available that could impart the high LSRV and gel strengths that are the familiar benefits obtainable from xanthan gum.

Among the earliest synthetic polymers to be introduced were the polyacrylates, which are made by polymerizing acrylic acid, often in solution in water. The polyacrylic acid (PAA) is then neutralised with caustic soda to give sodium polyacrylate, as shown below:

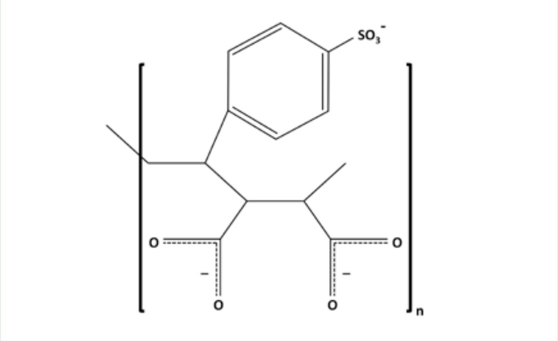


Alternatively, the acrylic acid can be neutralized prior to polymerization. The polyacrylic acid is available as a liquid or as a powder. The molecular weight required for efficient fluid loss reduction is typically in the range 200,000 to 1,000,000. Typical molecular weights for deflocculants (mud thinners) lie in the range of about 4,000 to 40,000.

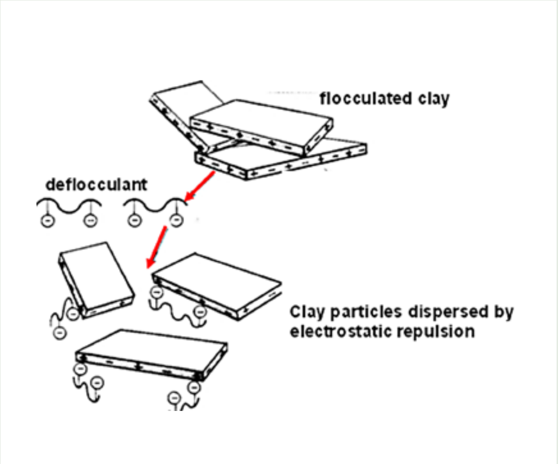
Synthetic Polymer Thinners and Deflocculants

Polyacrylic acid and all the other synthetic polycarboxylate polymers are stable at high temperatures, and can be used as fluid loss reducers in high salinity environments. However they have very limited compatibility with hardness (magnesium and calcium), and are not effective thinners in saline fluids. This is because the carboxylic acid pendant groups are weak acids and do not ionize well to allow the formation of stable ion-pairs in the presence of Ca^{2+} and Mg^{2+} or high concentrations of Na^{+} or K^{+} ions.

These limitations can be overcome by the introduction of the much more ionizing sulfonated groups into the polymer. One of the first synthetic thinners to be effective in high hardness, saline and high temperature conditions was a copolymer of styrene sulfonate and maleic anhydride, which is shown in the following diagram in its hydrolysed form, maleic acid, which is a di-carboxylic acid:



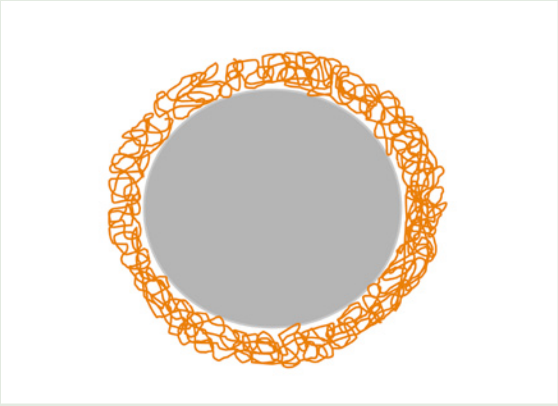
The way in which polyanionic thinners work is shown in the following schematic diagram:



Low molecular weight anionic dispersants adsorb onto the edge sites of flocculated clay particles, creating an overall negative charge on the clay.

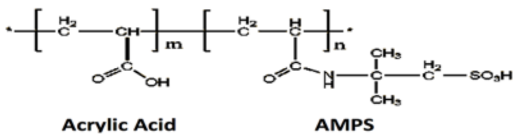
Electrostatic repulsive forces then cause the particles to separate and become dispersed.

Sulfonated copolymers work well at higher salinities because sulfonic acids are strongly ionising and their negative charge is maintained, whereas the ionisation of weaker anionic functional groups (such as the carboxylates in polyacrylic acid) is much-reduced by high concentrations of salt (carboxylic acids are weakly ionising). Another mechanism to provide good solids dispersion under high salinity conditions is to use higher molecular weight polymers (for example about 40,000 to 100,000) that provide a protective colloid action. This is also known as “steric stabilisation”, as explained below:



A particle surrounded with a thicker protective colloid layer of adsorbed polymer molecules, which prevents flocculation or coagulation with other particles. If the polymer contains ionised sulfonate groups then the steric action is combined with electrostatic repulsion. This is known as “electrosteric stabilisation”.

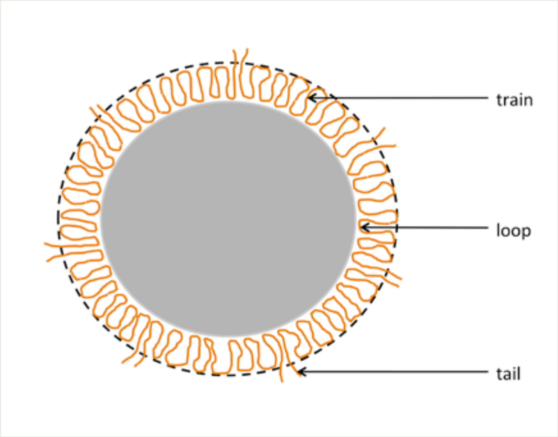
In more recent times, the incorporation of sulfonate groups into polymers has often been made using the AMPS monomer (AMPS = 2-Acrylamido-2-MethylPropane Sulfonic acid). The polymer shown below is a copolymer of acrylic acid and AMPS:



This type of polymer can be used as a deflocculant or as a fluid loss reducer, depending on the molecular weight as discussed previously.

Synthetic Polymer Fluid Loss Reducers

Synthetic polymers specifically designed as high temperature fluid loss reducers (FLRs) often contain a third monomer (i.e. they are terpolymers). One objective of this is to introduce functional groups that adsorb more strongly onto the surfaces of the various mineral particles that are suspended in the drilling mud (e.g. barite, clays, calcium carbonate and silica). As an example, vinyl acetamide units in a polymer will hydrolyse in a hot mud to produce cationic vinyl amine groups, which greatly improves the adsorption of the polymer onto clay particles (N-vinyl pyrrolidone is also sometimes used for the same purpose).



Strong adsorption sticks parts of the polymer onto the particle surface while heavily hydrated loops and tails of the polymer hang off, reducing the mobility of water (i.e. reducing the fluid loss).

In general, the negatively charged anionic functional groups such as carboxylates, sulfonates, and phosphonates will adsorb onto barite, calcium carbonate, and clay platelet edge sites. Cationic functional groups such as amines, quaternary ammonium groups and other nitrogen-containing units will adsorb onto clay platelet face sites, silica and steel. This is only a generalisation because ionic adsorption is dependent on pH and will vary in the presence of various ionic contaminants.

Nonionic hydrophilic groups including ethoxylates (e.g. HEC side chains), cis-hydroxyl groups, and polyglycols such as the shale-inhibiting polyalkylene glycols, will adsorb onto barite, calcium carbonate, clay platelet faces and silica. The adsorption mechanism for these is by either hydrogen bonding or dentate ligand binding.

There are also useful fluid loss reducers that are based on lignite, which is a complex polymeric molecule produced when decaying vegetable matter is buried by sediments, and is similar to brown coal. Lignite can swell and partially dissolve in caustic soda solutions, and causticized lignite can be an effective fluid loss reducer, but only in very low salinity fluids (typically freshwater, bentonite and HOHT drilling fluids).

An impression of what the molecular structure of lignite looks like is shown in figure 11 below. The only hydrophilic groups are the weakly-acidic carboxylic acid (–COOH) and the phenolic hydroxyls (–OH) hanging off the condensed ring structures. However, these carboxylic and phenolic groups ionize poorly, and causticized lignite will not swell or dissolve or reduce fluid loss efficiently in the presence of hardness and salts.

A derivative of lignite is manufactured by a process of sulfomethylation, which introduces ionizing and solubilizing sulfonate groups into the molecule, basically linking $-CH_2-SO_3^-$ sulfomethyl groups onto the phenolic rings using formaldehyde, sodium sulfite and caustic soda. Phenols are well known for reacting with formaldehyde, with phenolic resins such as Bakelite and example of a phenol/formaldehyde resin. The sulfonated lignite derivatives perform much better than lignite in the presence of salts and hardness.

Synthetic Polymer Shale Inhibitors

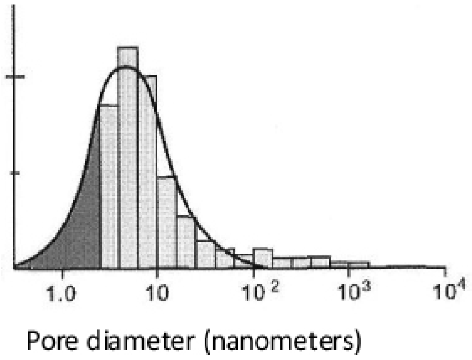
Polymers that are useful as shale hydration inhibitors can be classified into three basic types:

Encapsulating Polymers – These are very high molecular weight polymers such as PHPA (partially hydrolysed polyacrylamide) that adsorb strongly and coat the surface of the shale cuttings and the wellbore, thereby slowing the movement of water into the formation or cuttings. Such polymers are particularly useful for reducing the disintegration of cuttings.

Pore Pluggers – These are low molecular weight polymers that can enter the pores of a shale where they adsorb and concentrate in the pores and pore throats, blocking the flow of water and slowing pore pressure penetration. Some “cloud-point glycols” and silicate fluids are reputed to work in this way.

Shale Swelling Inhibitors (Intercalating Polymers) – These are polymers with a molecular weight low enough that they can enter the gaps (intercalate) between the constituent sheets of swelling clays such as montmorillonite. These include some of the polyalkylene glycols and amine-terminated polyalkylene glycols, as well as the polyamines.

The mechanism for how these polymers work can be illustrated by comparing their molecular sizes with the size of interlayer spacing in swelling clays and the diameter of the pores in shale formations. Some relative sizes of shale pores, montmorillonite spacing, ions, molecules and polymers are shown and tabulated on the next page:



Pore size distribution of a typical shale. Most of the pores are less than 10 nanometers in diameter (one thousandth of a micron), and very few pores are greater than 100 nanometers.

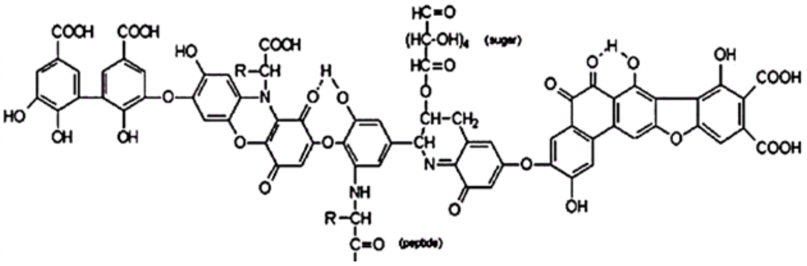
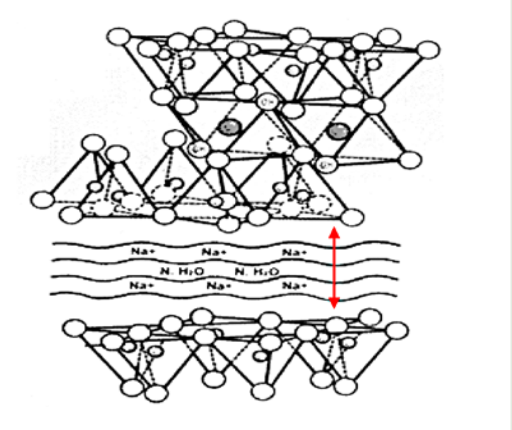


Figure 11. Molecular Structure of Lignite.



Part of the structure of Montmorillonite.

The diagram above shows part of the structure of montmorillonite. The silica-alumina-silica sheet on top is separated from the next sheet at the bottom by an interlayer gap that contains water and dissolved ions. The width of the gap (↕) varies with the degree of hydration of the clay and the nature of the cations in the interlayer gap, but typically the gap is between 1 and 5 nanometers.

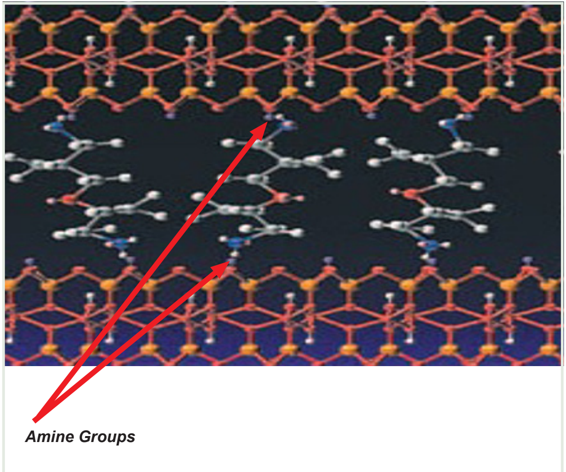
Approximate Size of Some Ions and Molecules	**Nanometers (nm)**
Size of Water Molecule	0.2
Size of Hydrated Sodium Ion	0.7
Size of Silicate Anions and Oligomers (short polymers)	1-2
Length of Polyalkylene Glycol (PAG)	2-5
Length of PHPA Encapsulating Polymer	1,000

From the tabulated size data it can be seen that that PHPA (partially hydrolysed polyacrylamide) has a molecular size that is huge compared to even the largest pores in a typical shale formation, so it can only function by external adsorption (encapsulation). Because the molecular weight is so high (typically a few million), PHPA generates very high fluid viscosity. This makes it difficult to dissolve powder grades cleanly without lumps or “fish eyes” of poorly mixed polymer granules.

A popular alternative is to use liquid emulsion polymer grade PHPA. This contains about 40% microscopic droplets of PHPA as an invert emulsion in oil, enabling much more efficient mixing into water-based fluids. Polyacrylamide derivatives are also used as flocculants in waste treatment processes, and as Friction Reducers in high volume “slickwater fracturing” treatments. Turbulent flow is reduced and this in turn reduces pressure losses, enabling more extensive depth of fracturing to be obtained.

From the tabulated size data it can also be seen that intercalating inhibitive polymers need to be of the order of 5 nanometers or less in length in order to be able to penetrate between the montmorillonite sheets. Typically this could equate to a molecular weight of about 1,000 or less. The polyalkylene glycol (PAG) and polyamine types of shale inhibitor work by virtue of the molecular size being small enough that they can enter (intercalate) the interlayer gaps of expanding clays like montmorillonite.

PAGs often need the presence of KCl so that the potassium ion can adsorb on the cation exchange sites. However, Polyamines can be effective without potassium because the terminal amine groups at each end of the polymer will adsorb on the cation exchange sites, as shown in the following diagram:

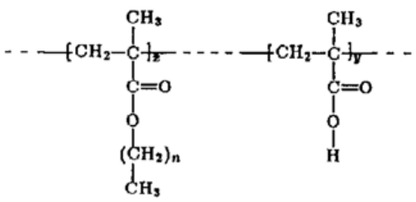


Interlayer gap between montmorillonite sheets intercalated by polyglycols having amine groups at each end that adsorb strongly onto the cation exchange sites on the layer faces. These anchor the sheets together and displace interlayer water, which prevents hydration and swelling.

Polymers Used in Oil-Based Muds

In contrast to water-based fluids, very few polymers are used in oil-based muds. Some of the surfactants used are based on dimer (two units) and trimer (three units) fatty acids, but these are really too short to be classed as polymers. They are really small oligomers (from the Greek “oligo” meaning a few). The dimer and trimer acids are reacted with amines and are used as Rheology Modifiers for increasing the LSRV (6 and 3 rpm Fann 35 readings).

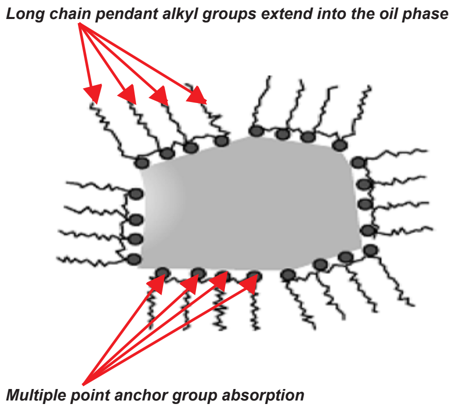
Thinners and Deflocculants – These tend to be co-polymers of an oil-soluble monomer with a polar monomer that introduces adsorptive "anchor groups" into the molecule. The oil- soluble monomer could be an ester like stearyl methacrylate, and the adsorptive monomer could be an unsaturated carboxylic acid like methacrylic acid, as shown below:



Stearyl Methacrylate (when n=17) Methacrylic Acid

The molar ratio is such that there are sufficient methacrylic acid groups to assure good adsorption, and sufficient pendant C_{18} alkyl chains to assure good dispersion in the oil phase. The polymer is described as a comb polymer, as shown in the diagram (top right), where the carboxylate anchor groups ensure firm multi-point adsorption onto the mud solid particle, and the pendant alkyl chains extend into the oil phase to provide excellent dispersion. The molecular weight is short enough that polymer chain bridging between adjacent particles cannot occur.

These hyper-dispersant polymeric thinners are extremely effective at reducing YP, LSRV and gel strengths because they can destroy the viscosity that is obtained using organoclay. Care is required to use the minimum effective treatments, otherwise later additions of organoclay to restore rheology may not be effective.



Fluid Loss Reducers – A traditional HTHP Fluid Loss reducer based upon the natural polymeric material lignite is shown in figure 12 below.

The products are known as Amine Treated Lignites and they are manufactured by grafting lignite with an aminoamide (aka amidoamine) that is typically made from a long-chain (e.g. C18) fatty acid condensed with a polyamine. The grafting of the long-chain alkyl groups causes the product to become more dispersible and "swellable" in the base oil of the oil-based mud. The colloidal dispersion of the amine treated lignite is an effective HTHP fluid loss reducer, even though higher doses in the 5 to 15 ppb range are required.

Amine treated lignites are particularly suited for high density-high temperature applications because they have good temperature stability and their viscosity (PV) increasing effect is low. More recently, co-polymers such as a co-polymer of vinyltoluene and 2-ethylhexyl acrylate (VTAC copolymers) have

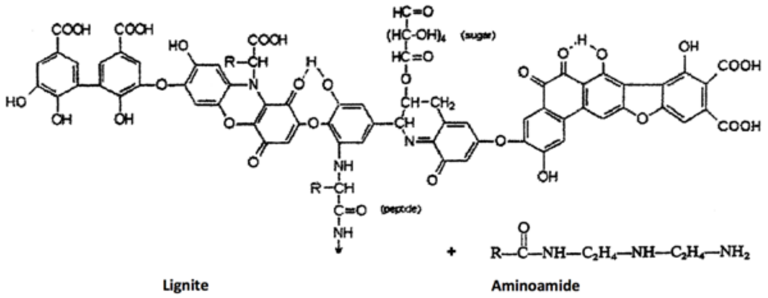


Figure 12: Amine-treated lignites make effective HTHP Fluid Loss reducers.

become popular as HTHP fluid loss reducers. The original VTAC polymers have now largely been replaced by variants that have improved performance and are effective at low doses such as about 2 lbs/bbl.

Styrene-Butadiene Rubber latex (SBR latex) has also been used on occasions as an HTHP fluid loss reducer. The latex is an emulsion of tiny micron-sized polymer “droplets” that have been polymerized in an emulsion of the liquid monomer(s) in water. The latex has the advantage that the tiny rubber particles dissolve quickly in the base oil when the latex emulsion “flips” after being added to oil-based mud.

Viscosifiers – Only one oil-based viscosifying polymer is known to be available at present. It is believed to be a poly-alkylmethacrylate containing a small amount of a much more polar monomer such as acrylic acid. The alkylmethacrylate has long alkyl groups, such as 16 to 18 carbon atoms, which is what makes the polymer oil-soluble. Added to that, the few hydrophilic groups on neighbouring molecules in solution form polar attraction links between polymer chains, which build a breakable/re-formable cross-linked structure in the oil phase. This, and probably some polar attraction links between suspended solids, is what provide the Non-Newtonian rheology and Yield Point. The gel strengths and LSRV from this product are, however, low and solids-suspension is also therefore not that effective.

Water-Based Drilling Fluid Systems

Section 4

Contents

Spud Mud

Spud mud is a simple Bentonite (Gel) mud system that is used when spudding a well to drill the top-hole section. Surface formations are usually unconsolidated, so hole washout and sloughing is common, and fluid inhibition has limited benefit. The priority is to drill the top-hole section as fast as possible, and then run and cement the casing string before the hole starts to collapse. Spud mud is made by mixing Bentonite in fresh water, using Soda Ash to reduce the water hardness and Caustic Soda to obtain alkalinity around 9.5 pH.

Drilling top-hole sections is usually a busy period for building reserve mud due to fast ROPs, but Bentonite takes a few hours to hydrate (yield) fully. To ensure sufficient spud mud is available when drilling top hole, a concentrated Bentonite slurry is usually prepared in the mud tanks at 40 ppb. This volume is then split between two mud tanks before cutting the gel concentration back to 20 ppb with fresh water. The Caustic Soda is then added to the 20 ppb gel before pumping down-hole.

The standard formulation for mixing spud mud is as follows:

Product	Function	Concentration
Fresh Water	Base Fluid	-
Soda Ash	Water Hardness Reducer	0.5 ppb*
Bentonite (Gel)	Viscosifier	40 ppb
Caustic Soda	Alkalinity	0.5 ppb*

***Note** The exact amount of Soda Ash and Caustic Soda required should be adjusted after testing the total hardness of the drill water.*

Mixing Procedure

1. Fill tank with required amount of fresh water.
2. Add 0.5 ppb Soda Ash to reduce the water hardness for optimum gel hydration.
3. Add 40 ppb Bentonite and leave to hydrate (around six hours).
4. Cut the 40 ppb Bentonite concentration to 20 ppb with fresh water.
5. Add 0.5 ppb Caustic Soda (use a chemical barrel) before pumping down-hole.

Offshore exploration wells may not have a Marine Riser when spudding wells, so returns are discharged at the seabed. The top-hole section is therefore drilled with seawater while pumping Bentonite sweeps at regular intervals for hole cleaning. These sweeps are designed to provide high low-end rheology for cleaning large diameter holes that are drilled with seawater. They should be pumped at frequent pre-determined intervals.

The onshore and offshore hole is usually filled with viscous 20 ppb Bentonite slurry, which may be weighted or inhibited for improved wellbore stability, any time that the hole is left static for an extended period, or at section TD before pulling out to run casing. This displacement slurry is designed to keep cuttings in suspension, and improve borehole stability by providing fluid loss control and hydrostatic pressure.

Ideally, the 20 ppb displacement slurry is prepared by cutting 40 ppb pre-hydrated Bentonite with fresh water because this produces a better filter cake and the viscosity is more stable, making it better for maintaining large diameter hole stability. This dilution is made with drill water on land rigs, but seawater is usually used on offshore wells for speed of preparation and to conserve drill water stocks.

In the case of the offshore well, a Temporary Guide Base for the BOP is run with the casing. Once the casing is cemented, the BOP is run with the Marine Riser and is installed on the Temporary Guide Base, enabling returns to be recovered on the rig to form a closed circulating system.

Guar Gum

Guar Gum is often used as an alternative to Bentonite for high-viscosity sweeps when drilling top-hole offshore because it is quick and easy to mix in seawater. Guar Gum is useful for keeping up with drilling progress and for conserving stocks of fresh water and/or Bentonite. The standard formulation for mixing Guar Gum is as follows:

Product	Function	Concentration
Sea Water	Base Fluid	-
Guar Gum	Viscosity	3-4 ppb

Mixing Procedure

1. Fill tank with required amount of sea water.
2. Add 3 ppb to 4 ppb Guar Gum and use when ready.

Guar Gum is not tolerant to high pH or elevated Calcium ion concentrations, so tanks must be clean before mixing. Care is required to add Guar Gum slowly at the mixing hopper in order to prevent “fish-eyes”, which will reduce the effectiveness of the product. Guar Gum will degrade within 24 hours under most conditions, and viscosity will eventually revert back to that of the base fluid (brine or water). The use of a biocide (EMEC Cide) will preserve Guar Gum viscosity for a longer period of time.

Guar Gum sweeps are designed to provide high low end rheology for cleaning large diameter holes that are drilled with seawater. However, viscous Guar Gum is not as effective as viscous Bentonite for hole cleaning, so the volume and frequency of the sweeps should be increased when using Guar Gum. Viscous Guar Gum is not suitable as a viscous slurry for filling the hole before pulling out to run casing because it does not develop effective gel strengths, the viscosity is not long lasting and there is no fluid loss control.

Lime Flocculated Bentonite Fluid System

Pre-hydrated Bentonite flocculated with seawater and Lime is the preferred sweep for drilling top-hole sections. These sweeps are designed to provide high low-end rheology to clean large diameter holes that are drilled with seawater. They should be pumped at frequent pre-determined intervals.

Lime Flocculated Gel Mud is made by mixing 40 ppb Bentonite spud mud with fresh water, and then diluting 2 parts by volume of mud with 1 part by volume of seawater before flocculating with 1 ppb Lime. The standard formulation for Lime Flocculated Gel Mud is as follows:

Product	**Function**	**Concentration**
Fresh Water	Base Fluid	-
Soda Ash	Water Hardness Reducer	0.25 ppb*
Bentonite (Gel)	Viscosifier	40 ppb
Lime	Flocculation/Alkalinity	1.0 ppb

****Note*** *The exact amount of Soda Ash required should be adjusted after testing the total hardness of the drill water.*

Mixing Procedure

1. Fill tank with required amount of fresh water.
2. Add 0.25 ppb Soda Ash to reduce the water hardness for optimum gel hydration.
3. .Add 40 ppb Bentonite and leave to hydrate (around six hours).
4. Transfer required volume to a separate tank and cut back to 30 ppb Gel with seawater.
5. Add 1 ppb Lime to flocculate the Bentonite slurry.

Gel flocculation with seawater and Lime should be performed in a separate tank than that used for preparing the 40 ppb Bentonite pre-mix. However, this may not be possible due to limited tank space or other factors.

The hole is usually filled with viscous 20 ppb Bentonite slurry, which may be weighted or inhibited for improved wellbore stability, any time that the hole is left static for an extended period, or at section TD before pulling out to run casing, using the base formulation for Spud Mud earlier in this section. This displacement slurry is designed to keep cuttings in suspension, and improve borehole stability by providing fluid loss control and hydrostatic pressure.

KCL-PHPA-Polymer Fluid System

The most extensive and difficult formations to drill are those containing shales that have been compressed and partially dehydrated over time. The process of drilling a hole partially relieves the confining stresses on the shale, which may be sufficient to cause mechanical failure of the rock. The mechanism of failure is the initial formation of a crack (crack initiation) followed by many small fissures (crack propagation).

If drilling fluid inhibition is poor then the shale will absorb water from the drilling fluid, swell up and destabilise the surrounding shale. The reaction to water will depend on the exact mineralogy of the clays present, ranging from plastic deformation of the shale to give tight hole conditions, or brittle failure leading to caving and sloughing hole conditions, both of which can be controlled by mud density.

The water-based KCL-PHPA Polymer system addresses the inhibition problem to produce stable drilled cuttings which, combined with a fluids system with lower solids content due to the density provided by the Potassium Chloride brine, combine to give excellent hole cleaning, low erosion rates and fast penetration rates. The water-based KCL-PHPA Polymer system provides effective inhibition when drilling reactive shales through two mechanisms:

1. Potassium Chloride provides a source of Potassium ions, which exchange with sodium or calcium ions already present in certain clay minerals. The Potassium ion is very small, which gives it a relatively high charge density compared to other larger ions. The Potassium ions are small enough to fit between the clay platelets without distorting the shale lattice. After adsorbing onto the exchangeable cation sites in the shale lattice, the higher charge density of the Potassium ions holds the platelets together to produce a stable, non-expanding form. This helps to minimize clay and shale hydration, swelling and dispersion.
2. PHPA (Partially-Hydrolysed Poly-Acrylamide) is a very high molecular weight polymer that adsorbs onto clay and shale surfaces, coating the wellbore and encapsulating drilled cuttings with a viscous polymer layer. This acts as a barrier to prevent water invasion into clays and shales, which once again helps to minimize clay and shale hydration, swelling and dispersion. The PHPA coating helps to keep drilled cuttings intact as they travel up the annulus, improving solids control efficiency on surface and helping to control the build-up of solids in the drilling fluid.

The KCL-PHPA Polymer system is easy to mix and the inhibitive properties are easy to adjust according to clay and shale reactivity while drilling. The cationic exchange is brought about by introducing the potassium ion into the mud as a Potassium Chloride brine solution ranging from 3% to 15% (10 to 50 ppb). However, the Potassium ion concentration needs to be adjusted carefully to suit shale reactivity, because low concentrations will encourage shale hydration and dispersion, while over-treatments may dehydrate and destabilize the wellbore.

Regular treatments are usually required to maintain Potassium ion and PHPA concentrations that are depleted through drilled cuttings removal at surface. The drilling fluid system is versatile and can be converted into more inhibitive water-based drilling fluid systems using appropriate additives. With increasing focus on environmental protection, the discharge of chloride-based fluids is restricted in some environmentally sensitive areas of the world, but Potassium ions can be provided using environmentally acceptable fluids like Potassium Formate.

A typical formulation for a KCL-PHPA-Polymer drilling fluid system is as follows:

Product	Function	Concentration
Water (Fresh or Sea Water)	Base Fluid	1 bbl
Caustic Soda	Alkalinity	0.5 ppb
KCL	Potassium Inhibition	Up to 35 ppb
Xanthan Gum	Viscosifier	1 ppb
PAC	Fluid Loss Control	4 ppb
PHPA	Encapsulating Polymer	1 ppb
Barite	Density	As Required

Mixing Procedure

1. Fill tank with required amount of fresh water or seawater.
2. Adjust pH to around 9.5 to 10.0 with Caustic Soda (use a chemical barrel).
3. Add the required amount of Potassium Chloride powder.
4. Add 1 ppb Xanthan Gum slowly at 5 minutes per sack.
5. Add 4 ppb PAC.
6. Add 1 ppb PHPA slowly at 10 minutes per sack.
7. Add Barite to obtain the required drilling fluid density.

The KCL-PHPA-Polymer system should not be formulated with Bentonite for viscosity because the fluid is designed to control clay and shale hydration. Dispersants and thinners should not be used for similar reasons because one of the objectives of the system is to prevent shale dispersion so that drilled solids can be removed by the Solids Control Equipment.

Fluid System Guidelines

The KCL-PHPA-Polymer fluid system has proven very adaptable to a wide range of conditions world side, and can be formulated in fresh water, seawater and saturated salt water. It is also tolerant to cement and anhydrite contamination. The components that control the hydration and dispersion of water-sensitive shales, namely the Potassium Chloride and the PHPA polymer, do not directly contribute any other property to the drilling fluid, so additional components are required to control flow properties and provide fluid loss control.

Rheology – Rheological properties are controlled through the use of Xanthan gum polymers such as Biopoly-E. The flow properties are unaffected by salinity when using this type of polymer, with good resistance to shear and temperature degradation. The rheology is more shear-thinning than clay-based systems at low densities, with excellent hole cleaning performance. The polymer develops progressive gel strengths, which allow suspension of weighting agents without the need for high viscosities.

Fluid Loss Control – The main fluid loss control additive is PAC, which is effective over a range of salinities. Regular PAC (PAC-R) provides fluid loss control and additional viscosity, for use when rheology also needs to be increased. PAC Super-Lo (PAC-SL) gives fluid loss control without additional viscosity, for use when drilling fluid rheology is already adequate. Polytrex is a non-viscosifying fermentation-resistant starch that can also be used for improving fluid loss control without increasing fluid viscosity.

Shale Inhibition – The main method of inhibition is the Potassium Ion concentration. Laboratory analysis of shale samples from offset wells will give an indication of shale reactivity and the level of inhibition required. However, the actual level of inhibition should be determined by inspecting the drilled cuttings at the shakers. They should be firm and dry on the inside when broken in half, which indicates low fluid invasion. If the cuttings are soft and the MBT (Methylene Blue Test) reveals high clay content, then the level of inhibition needs to be raised by increasing the KCL and PHPA concentrations.

The Potassium ion concentration is measured by precipitating out Potassium Perchlorate in a known volume of filtrate. The filtrate is then centrifuged to determine the volume of precipitate present, which can be converted into the Potassium Ion concentration using a calibration chart. It is important to maintain shale inhibition at the required level because if the KCL concentration is too low then dispersion will occur, which will lead to a build-up in solids. Shale dehydration may occur if the KCL concentration is too high, which may lead to brittle failure in the form of caving and sloughing.

Continuous treatments with Potassium Chloride are required because the Potassium ion concentration will deplete due to adsorption onto the cationic exchange sites on the wellbore and cuttings while drilling. The rate of depletion will depend on shale reactivity and ROPs. Regular monitoring of the Potassium Ion concentration is required to so that correct maintenance treatments are made without under-treating or over-treating.

PHPA Concentration – Shale Drill is a PHPA with extremely high molecular weight (in the 6 to 10 million range) that adsorbs strongly onto clay surfaces to form a viscous layer that minimizes water invasion into micro-fissures, preventing further deterioration of the shale structure. This polymer is effective at low concentrations, so high concentrations should be avoided because this will affect rheology and restrict fluids handling at the shale shakers, which may restrict circulation rates.

As with Potassium Chloride, PHPA will deplete due to adsorption onto the wellbore and onto drilled cuttings that are removed at the shale-shakers while drilling. The rate of depletion depends on the ROP and on the nature of the drilled cuttings. Higher ROPs generally produce larger drilled cuttings, and lower ROPs generally produce smaller drilled cuttings. The depletion rate of PHPA for a fixed volume of smaller drilled cuttings will be higher than that for the same volume of larger drilled cuttings because the smaller cuttings have a larger overall surface area for PHPA adsorption.

Shale Drill is available in powder and liquid form. The powder form, Shale Drill (P), is generally used when mixing fresh mud since there is usually sufficient time for the polymer to yield fully. Shale Drill (L) is the “ready-mixed” form of Shale Drill (P) with 35% activity, which is added slowly to the active tank while drilling, with the agitators running. Overtreatment should be avoided because this will increase the overall fluid rheology, which will make it difficult to screen out solids at the shakers.

Solids Content – The KCL system is a non-dispersed flocculated fluid, so toleration for high levels of active drilled solids is not as good as a dispersed clay system. It is therefore important to concentrate on the primary solids removal equipment by selecting the finest screens for the shale-shakers, where possible. Removal of solids in this type of fluid is facilitated by maintaining low viscosities and low gels, and by avoiding over-treatment with PHPA. Whole mud dilution is effective for controlling the build-up of solids because ultrafine solids are removed from the circulating system while maintaining the Potassium Ion concentration.

Other Properties – Other properties are easy to control and maintenance usually requires minor treatments. The pH is normally maintained around 9.0 since high pH values tend to disperse clays and may have a detrimental effect on polymer performance. High pH will also encourage PHPA hydrolysis, with the release of ammonia gas that is very noticeable. The system has good tolerance to salt contamination, while cement contamination should be treated with Sodium Bicarbonate. The system has proved to be stable in the field to temperatures in excess of 300°F (150°C).

KCL-PHPA-Polymer-Glycol Fluid System

Although suitable for a range of water-based drilling fluid systems, Glycol is usually added to the KCL-PHPA Polymer system to provide enhanced inhibition when drilling highly reactive shales. Glycol is a completely water-soluble synthetic polymer that adsorbs strongly at the surface of troublesome shales to form a water-repellent barrier. This reduces swelling and inhibits shale dispersion, resulting in a high performance drilling fluid that is an environmentally acceptable alternative to oil-based drilling fluid systems.

TAME glycols (Thermally Activated Micro-Emulsions) exhibit “inverse solubility”, in that they are water-soluble at ambient temperatures, but become less soluble at elevated temperatures. The insoluble glycol forms a micro-emulsion at elevated wellbore temperatures, which produces enhanced fluid loss control and inhibition. Other benefits are improved wellbore stability, improved cuttings integrity, reduced bit balling and fewer stuck pipe incidents, along with the fact that glycols are non-damaging to reservoir formations.

If the conventional KCL-PHPA Polymer system is unable to provide the required inhibition, then glycol can be added to convert the fluid into a highly inhibitive system. Drilled cuttings will be firmer and more resistant to dispersion while travelling up the annulus, which will reduce the build-up of solids in the drilling fluid. This will help to improve solids control efficiency and lower dilution rates. Enhanced inhibition is achieved through two mechanisms:

1. **Clay Adsorption** – The glycol competes with water for the same cation sites on the clay surfaces, which reduces water activity and the potential for shale hydration.
2. **Cloud Point Behavior** – The cloud point of a TAME glycol is the temperature where the glycol starts to form micro-bubbles and separate out from the water, blocking the formation pores to prevent filtrate invasion.

Fluid System Formulation

A typical formulation for a KCL-PHPA-Glycol drilling fluid system is as follows:

Product	Function	Concentration
Water (Fresh or Sea Water)	Base Fluid	1 bbl
Caustic Soda	Alkalinity	0.5 ppb
KCL	Potassium Inhibition	Up to 35 ppb
Xanthan Gum	Viscosifier	1 ppb
PAC	Fluid Loss Control	4 ppb
PHPA	Encapsulating Polymer	1 ppb
Glycol	Shale Inhibition	As Required (%)
Barite	Density	As Required

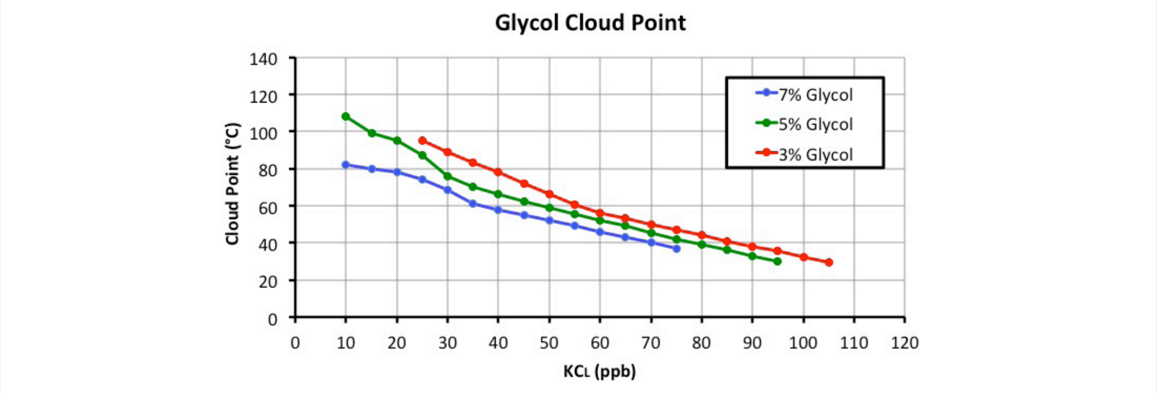
Mixing Procedure

1. Fill tank with required amount of fresh water or seawater.
2. Adjust pH to around 9.5 to 10.0 with Caustic Soda (use a chemical barrel).
3. Add the required amount of Potassium Chloride powder.
4. Add 1 ppb Xanthan Gum slowly at 5 minutes per sack.
5. Add 4 ppb PAC.
6. Add 1 ppb PHPA slowly at 10 minutes per sack.
7. Add the required amount of Glycol
8. Add Barite to obtain the required drilling fluid density.

Fluid System Guidelines

Fluid maintenance is the same as for the KCL-PHPA-Polymer system, the only difference being the presence of Glycol (DCP-208), where cloud point is monitored.

Cloud Point Temperature (CPT) – The Cloud Point Temperature is the temperature at which a TAME glycol starts to separate or “cloud out”, so called due to the cloudy appearance. Glycols never cloud out completely at the CPT, but the volume of clouded-out glycol will increase as the temperature continues to increases. The CPT is affected by the type of glycol, the glycol concentration and the salt concentration. An increase in glycol concentration will decrease the CPT, and an increase in salt concentration will also decrease the CPT, as shown in the chart overleaf.



As can be seen from the chart above, the CPT of a glycol can be adjusted to suit formation temperatures by changing the concentration of the glycol and/or concentration of the KCL brine. The CPT can be increased by reducing the glycol concentration and/or reducing the KCL concentration as drilling progresses, since formation temperatures increase with depth.

CPT Determination – The CPT of a TAME glycol can be measured as follows:

1. Collect a sample of filtrate from a filter press in a measuring cylinder.
2. Place a thermometer in the measuring cylinder and place the measuring cylinder in a flask of water.
3. Place the flask of water on a hot plate and heat slowly.
4. Record the temperature when the filtrate starts to turn cloudy.
5. Remove the flask of water from the hot plate and check that the cloudy filtrate turns clear as it cools down (If the filtrate does not go clear again then the cloudy appearance may be caused by some form of precipitation, such as $CaCO_3$). If this is the case, heat the filtrate again until it becomes really cloudy.
6. If CPT measurements exceed 90°C, add some salt to the water in the flask in order to increase the boiling point.

Glycol Concentration Determination – A close approximation of the Glycol (DCP-208) concentration in a mud system can be obtained by making use of its inverse solubility in water, as follows:

1. Take a sample of active mud that has been allowed to cool to ambient temperature and homogenize for one minute using a Hamilton Beach Mixer at medium speed.
2. Run an HTHP fluid loss test at ambient temperature to collect filtrate for analysis.
3. Saturate the filtrate with Sodium Chloride powder in order to decrease the CPT so that all the glycol will cloud out in the next step (Only a small percentage of the glycol clouds out at the CPT, so the temperature needs to be considerably higher to cloud out all the glycol).
4. Using at least 10 mls of filtrate (use more if possible as this will increase accuracy), place the measuring cylinder in hot water at around 80°C.
5. As the filtrate warms up, a phase separation will occur and the quantity of glycol (DCP-208) can be read from the top from the measuring cylinder. Adding a few drops of light oil after separation has occurred will create a smoother interface at the glycol phase and improve accuracy. The quantity measured can then be expressed as a volumetric percentage of the initial filtrate volume, because the initial filtrate volume will have increased after adding the Sodium Chloride salt. See figure 1 below.

Glycol % (v/v) = [Glycol volume (mls) ÷ Initial Filtrate Volume (mls)] x 100
Glycol Concentration should be reported to the nearest 0.5%.

Figure 1

Saturated Salt Fluid Systems

Saturated salt systems are used when drilling through salt formations (evaporates), which usually take the form of salt domes or massive beds. Salt formations can range from sodium, potassium or magnesium chloride to complex mixed blends, and often contain other evaporate minerals such as anhydrite, gypsum, limestone or dolomite inter-bedded in the salt structure. Saturated Salt systems are designed to maintain wellbore stability while drilling salt formations, which are plastic and deformable at high temperatures and pressures.

The priority while drilling salt formations is to avoid mechanically stuck pipe due to salt creep, and to control the amount of washout. Large washouts will affect hole cleaning efficiency and will also contaminate the saturated salt fluid system with formation salts, which may contain divalent ions like magnesium that could affect fluid rheology through cross-linking of polymers. These problems can be reduced by maintaining the drilling fluid close to saturation in order to minimize the amount of salt formation that dissolves.

The drilling fluid system should be fully saturated before penetrating the salt formation, in order to avoid large washouts at the top of the salt. Saturation is achieved by adding salt (Sodium Chloride) to the mud system until saturation point is reached around 315,000 mg/l, with chloride content around 190,000 mg/l. Chloride salinity should then be reduced and maintained around 155,000 to 165,000 mg/l while drilling the salt formation. This will allow sufficient washout to avoid mechanically stuck pipe due to salt creep.

The salinity of the drilling fluid needs to be checked at regular intervals while drilling salt sections, making dilutions with treated water to reduce salinity when necessary. If salinity is too low then the salt formation will be dissolved by the drilling fluid, which may produce large washouts. If salinity is close to saturation then a gauge hole will be drilled but the BHA may become mechanically stuck due to salt creep. Treated water pills can also be circulated if tight hole is encountered or to free stuck pipe due to salt creep.

Fluid System Formulation

A typical formulation for a KCL-PHPA-Polymer drilling fluid system is as follows:

Product	Function	Concentration
Water (Fresh or Sea Water)	Base Fluid	–
Soda Ash	Calcium Treatment	1.5 ppb
Bentonite	Viscosifier	5 ppb
Caustic Soda	Alkalinity	1.5 ppb
Flowzan	Viscosifier	1 ppb
Antisol 100	Fluid Loss Control	3 ppb
Antisol 30,000	Fluid Loss Control	2 ppb
KCL	Shale Control	As Required
NaCL	Salinity	108 ppb
FC-10	Thinner/Dispersant	As Required
Drilling Detergent	Surface Active Agent	As Required
EMEC Lube	Lubricant	As Required
No Foam	Defoamer	As Required
Barite	Density	As Required

Mixing Procedure

The Saturated Salt fluid system can be formulated with fresh water or seawater. The Potassium Chloride provides inhibition to reduce the hydration and dispersion of shales, which could be present above, below or as inter-bedded stringers within the salt formation.

1. Fill tank with required amount of fresh water or seawater.
2. Add the required amount of Soda Ash to treat out calcium hardness.
3. Add the required amount of Bentonite to improve the quality of the filter cake.
4. Adjust pH to around 9.5 to 10.0 with Caustic Soda (use a chemical barrel).
5. Add 1 ppb Flowzan slowly at 5 minutes per sack.
6. Add Antisol 100 slowly at 2 minutes per sack.
7. Add Antisol 30,000 slowly at 5 minutes per sack.
8. Add the required amount of Potassium Chloride powder for shale inhibition.
9. Add the required amount of Sodium Chloride powder.
10. Add Barite to obtain the required drilling fluid density.

Additions of FC-10, Drilling Detergent, EMEC Lube and No Foam should only be added to the saturated salt fluid system as and when they are required while drilling.

Fluid System Guidelines

The saturated salt fluid system is relatively simple to run, as long as salinity is monitored closely. Foaming may occur with high concentration brine systems, so defoamers (e.g. No Foam) should be available to deal with this issue.

Density – The density is provided by the density of the saturated brine, using barite when higher densities are required. The solids control equipment should be optimized to control any increase in density due to a build up of drilled solids. When density needs to be increased, mud salinity should be checked in case it is on the low side. If this is the case then sodium chloride salt should be added first to restore mud salinity. Barite can then be added to achieve the required mud density. The density should be adjusted according to hole conditions while drilling and should be increased at the first indications of packing-off, pore pressure increase, wellbore instability or salt water flow.

Rheology – Rheological properties are controlled through the use of Xanthan gum polymers such as Flowzan. Plastic Viscosity (PV) should be kept as low as possible through optimum use of all the available solids control equipment to prevent a build-up of LGS, which could have an adverse effect on rheological properties. ROPs should be controlled at all times because high ROPs will load the annulus with cuttings and produce an increase in LGS, resulting in an increase in density and viscosity which could induce formation losses in formations above or below the salt formation. Dilutions or treatments with a thinner (e.g. FC-10) should be made when rheology needs to be reduced.

pH and Alkalinity – Caustic Soda is used for pH and alkalinity control to improve the performance of the mud products and provide corrosion control. The pH should be maintained around 9.5 to 10.0 using pre-dissolved Caustic Soda in a chemical barrel, making sure that the Caustic Soda powder or pellets are added to water in the chemical barrel.

Fluid Loss Control – The main fluid loss control additive is Antisol, a PAC that is effective over a range of salinities. Antisol 30,000 provides fluid loss control and additional viscosity, for use when rheology also needs to be increased. Antisol 100 gives fluid loss control without additional viscosity, for use when drilling fluid rheology is already adequate. Fluid loss control is required for shale, sand or other formations that may be present in the salt formation section.

Salinity (Chlorides) – Mud salinity will naturally increase while drilling salt formations, so it is important to maintain salinity between 155,000 mg/l and 165,000 mg/l in order to allow a controlled amount of salt formation washout as this will prevent potential tight hole due to salt creep. If mud salinity is too low then a large washout could occur and this could affect directional control and other problems. If mud salinity is too high then a gauge hole will be drilled and this will increase the potential for tight hole, salt collapse and stuck pipe

Contaminants – Saturated Salt fluid systems are generally resistant to contamination from cement, gypsum or anhydrite, but Caustic Soda and Soda Ash treatments may be required to restore fluid alkalinity, especially in the case of Calcium Sulfate, which will affect mud rheology and filtration properties.

Foaming – Surface foaming often occurs with saturated salt mud systems, caused largely by fluid returns in the trough cascading into the fluid in the active tank. It may therefore be possible to reduce foaming by minimizing the height between the trough and the surface of the fluid in the active tank by keeping the active tank as full as possible. Foaming can be reduced by raising the alkalinity of the fluid to around 10.0 pH and/or adding a small amount of 10 to 15 ppb pre-hydrated Bentonite to the active tank. Defoamer treatments using 0.1 to 0.15 gal/bbl 'No Foam' will also control foaming for a limited period of time.

Salt Creep – Salt formations have a tendency to creep and this could lead to mechanically stuck pipe. There are occasions when salt creep can be controlled by mud density, but the problem is usually avoided by monitoring mud salinity closely and maintaining it below brine saturation to dissolve and provide a controlled amount of salt washout. Untreated or treated fresh water pills should be circulated around the hole when there are signs of sticking, which often occur around the BHA while tripping, as this will rapidly dissolve and wash out part of the salt formation causing the problem. Treated water pills can be incorporated in the fluids system but untreated water pills should be recovered on surface.

Salt Water Flow – Close monitoring of pit levels is important in order to detect a salt water flow while drilling salt formations, and mud density should be increased at the first sign of a salt water flow.

Lubricity – The use of lubricants should be considered for reducing torque and drag in deviated wells.

Sodium Silicate Fluid System

The Sodium Silicate system is formulated with conventional water-based drilling fluid products to provide enhanced inhibition and well-bore stabilization while drilling highly reactive or fractured shale formations. Sodium Silicate fluids can be prepared using inhibitive brine as the base fluid, or the product can be added to other WBM fluid systems to enhance inhibition for stabilizing water-sensitive shales through low fluid and pressure invasion.

Sodium Silicate creates a highly inhibitive fluid that is close to oil-based systems when drilling reactive clays, and this helps to reduce bit balling, tight hole and stuck pipe. The improved cuttings integrity results in lower dilution rates due to efficient solids removal at the shakers, and this reduces the build-up of solids in the drilling fluid. Sodium Silicate contains simple and complex silicate structures that physically and chemically stabilize reactive shales through two mechanisms:

1. Gelation occurs when silicate in the drilling fluid comes into contact with slightly acidic, multivalent pore water. The pH drops, causing polymerization of soluble silicate structures to form a silicate gel structure that coats the wellbore and cuttings.
2. Precipitation occurs through the cross-linking of silicate molecules by multivalent ions in the pore fluid, which blocks drilling fluid and pressure invasion. Natural fluid loss control is therefore created by sealing off the pores and micro-fractures in the formation, with wellbore stability resulting from low fluid and pressure invasion.

Total inhibition is achieved with the combination of the silicate chemistry and the salt concentration of the drilling fluid. Potassium chloride supplies the potassium cation, which is effective in suppressing the hydration and dispersion of reactive clays. Increased concentrations of sodium and potassium chloride reduce the activity of the aqueous phase to also provide improved inhibition. The product is safe to handle and is not classified as hazardous, so it is suitable as an environmental alternative to oil-based drilling fluids.

The mechanism for physically and chemically stabilizing reactive shales means that sodium silicate is gradually depleted while drilling. The depletion rate will obviously be higher if the formation contains high levels of multivalent ions, and for that reason the sodium silicate system may be unsuitable for certain formations.

Soluble Sodium Silicate is manufactured by fusing sand (SiO_2) with Sodium Carbonate (Na_2CO_3) at around 1200°C. This “glass” is then dissolved using high pressure steam to form a clear, slightly viscous liquid silicate. The molecular ratio between SiO_2 and Na_2O determines the properties of soluble silicate solutions, with low ratios forming simple structures and higher ratios forming complex structures. EMEC usually stocks Sodium Silicate with a molecular ratio of 2, which is "mid-range", containing a combination of simple and complex structures beneficial for shale inhibition and stability.

Fluid System Guidelines

Sodium Silicate fluids are relatively simple to run because the enhanced shale inhibition and cuttings integrity reduces the build-up of cuttings in the drilling fluid and improves solids removal efficiency at the shakers.

pH and Alkalinity – Sodium Silicate fluid systems are designed to be run with pH around 11.5, which is higher than other water-based fluid systems.

Total Hardness – Any calcium or magnesium hardness in the base fluid (water or brine) should be treated out with Soda Ash to avoid being precipitated out by the Sodium Silicate, which will cause unnecessary depletion. Total hardness will always be zero as long as Sodium Silicate is present in the drilling fluid, so the presence of calcium or magnesium hardness will be an indication of total sodium silicate depletion.

Lubricity – Torque and drag is often higher with Sodium Silicate fluid systems compared with other systems, so lubricants may be required to improve drilling performance and reduce friction and wear on tubulars in the hole.

Corrosion Control – Sodium Silicate fluid systems are designed to be run with pH around 11.5, so alkalinity provides effective corrosion control for wellbore tubulars.

Mixed Metal Hydroxide System

This water-based fluid system uses Magnesium Aluminium Hydroxide, a mixed metal hydroxide (MMH) that interacts with hydrated Wyoming Bentonite to form a thixatropic (shear-thinning) fluid with very high but very fragile gels. This produces a drilling and milling fluid with excellent cuttings transport capability, which is ideal for extended-reach and horizontal wells. The fluid is also ideal for controlling losses when drilling unconsolidated, highly fractured or high permeability formations.

Pump pressures and ECDs are relatively low with MMH fluids, so high annular velocities can be used for effective hole cleaning. As soon as circulation stops, MMH fluids develop strong gels almost instantly, keeping cuttings in suspension without any sag. The result is a drilling and milling fluid with excellent cuttings transport capability, especially in extended-reach and horizontal wells.

MMH fluids are also effective for drilling depleted and fractured zones, where formation losses are common. Fluid invasion into the formation is minimal because the fluid in contact with the wall of the wellbore is stationary and develops strong gels, which limits invasion into the formation, effectively providing shale inhibition.

The MMH fluid system is easy to mix and maintain, using 1 ppb EMEC Mil for every 10 ppb Wyoming Bentonite that has been hydrated in fresh water. The strong gels break easily when subjected to shear, so shale-shakers can be dressed with very fine shaker screens for improved solids control efficiency.

Products used in the MMH fluid system are not hazardous, so the fluid system is environmentally acceptable. It should be noted that EMEC Mil only produces such a dramatic thixatropic effect with Wyoming Bentonite, so lower grades of Bentonite are unsuitable for this application.

Fluid System Formulation

A typical MMH drilling fluid formulation is as follows:

Product	Function	Concentration
Fresh Water	Base Fluid	–
Soda Ash	Calcium Treatment	0.5 ppb
Bentonite	Viscosifier	10 ppb
EMEC Mil	Bentonite Extender	1 ppb
Caustic Soda	Alkalinity	For 8.5 to 9.0 pH
EMEC Cide-L	Bactericide	As required

Mixing Procedure

The mix tank and mix lines must be clean and free from contaminants before preparing the MMH fluid system. The mix water must also be clean and free from contaminants for similar reasons.

1. Fill tank with required amount of fresh water.
2. Add 0.5 ppb Soda Ash to treat out calcium hardness.
3. Add 10 ppb Wyoming Bentonite.
4. Add 1 ppb EMEC Mil and leave to hydrate.
5. Adjust pH to around 9.5 to 10.0 with Caustic Soda (use a chemical barrel).
6. Treat system with EMEC Cide-L as and when required.

Fluid System Guidelines

The MMH fluid system is relatively simple to run, but care is required to minimize contaminants and solids control equipment must be optimized to minimize the build-up of drilled solids.

Total Hardness – The MMH system is sensitive to calcium ions, so total hardness should be kept close to zero using Soda Ash.

Rheology – The rheology will remain stable as long as solids are controlled below 5%. The MMH system should be diluted with freshly mixed fluid when rheology starts to increase due to a build-up in solids.

Solids – The solids control equipment should be optimized to keep solids below 5%, otherwise viscosity and gel strengths will become excessive. Dilutions with freshly mixed fluid should be made to reduce solids, when necessary.

Ultra-Low Invasion Fluid System

EMEC's successful Ultra-Low Invasion Fluid (ULIF) was developed to meet the requirements of clients looking for an environmentally acceptable alternative to oil-based drilling fluids, driven by the need to reduce costs associated with waste management and disposal. The EMEC ULIF system uses conventional drilling fluid systems like KCL-Polymer to provide the required chemical inhibition, with additional additives that minimize fluid invasion into the formation pores or micro-fractures.

The EMEC ULIF system creates a low permeability filter cake that acts as a seal to limit the transmission of wellbore pressure to the pore fluid, which effectively imparts wellbore stability to micro-fractured shales and brittle formations. This low permeability seal also increases the fracture initiation pressure, which helps to reduce induced losses while drilling depleted, poorly consolidated formations.

The low permeability seal also helps to prevent the build-up of thick filter cakes while drilling through pressure-depleted formations, which reduces the potential for differential sticking. The EMEC ULIF system has proven itself as a successful drill-in fluid with return permeability as high as 95% due to the fact that the low permeability filter cake created by this non-invasive fluid is easily removed by flow back or by simple wash fluids.

The economics of using the EMEC ULIF system are justified by increased well productivity and the elimination of waste management costs. The improved cuttings integrity results in lower dilution rates due to efficient solids removal at the shakers, which helps to reduce the build-up of solids in the drilling fluid. However, the economics become even more impressive if the fluid is recycled over multiple wells during field development.

Perm Drill Drill-In Fluid System

Perm Drill is an effective non-damaging fluid system that is used as a drill-in, work-over and perforating fluid in production zones. The shale inhibiting polymers in the system form a thin impermeable filter cake that prevents the invasion of fluids and fine solids into the formation, which improves hole stability and produces excellent return permeability. Additional inhibition can be obtained by using Potassium-based brines to reduce shale hydration and minimize hole problems that might occur while drilling.

Density for the Perm Drill system is provided by the choice of brine, so most of the solids in the fluid system comprise bridging agents that plug pore spaces on the wellbore surface and restrict the invasion of solids and fluids into the formation. Fluid density can also be adjusted using sized Calcium Carbonate bridging material, as this will also maintain an effective PSD for optimum pore bridging. The Perm Drill fluid system is safe to handle and non-toxic, subject to choice of brine, making it environmentally acceptable.

The Perm Drill fluid system is a low solids system that produces high ROPs and enhanced drilling performance similar to oil-based drilling fluids. Perm Drill is designed and specifically formulated to introduce ions and special polymers to create a water-based system that provides effective inhibition and fluid loss control. This minimizes shale hydration and maintains wellbore stability, while the thixatropic rheological properties provides effective hole cleaning in deviated and horizontal wells at relatively low flow rates.

Perm Drill is formulated from non-damaging, shale inhibiting polymers that are acid-soluble to minimize formation damage. The thin, impermeable filter cake on the surface of the wellbore reduces fluid and fine particle invasion into the reservoir. The filter cake also lifts off easily and disintegrates when the well is flowed, and will pass cleanly through sand screens without plugging. Any residual wellbore plugging that may affect reservoir productivity can be removed using acid treatments, resulting in excellent return permeability.

Fluid System Formulation

Perm Drill disperses easily with minimum shear when mixed in fresh or hard water, sea water and brines, including formates. A typical formulation for the EMEC Perm Drill fluid system is as follows:

Product	Function	Concentration
Water or Brine	Base Fluid	–
Soda Ash	Calcium Hardness	0.5 ppb
Perm Defoamer	Defoamer	0.2 lt/bbl
Perm Drill	Viscosifier	35 to 50 ppb
Caustic Soda	Alkalinity	0.75 ppb
Calcium Carbonate	Weighting Agent	As required

Mixing Procedure

Perm Drill is mixed through a conventional mixing hopper with concentrations ranging from 35 to 50 ppb depending on required viscosity and fluid loss properties. Perm Drill should be mixed at 35 ppb initially, and the concentration should then be increased to 50 ppb, if required.

1. Fill tank with the required volume of water.
2. Add the required amount of Soda Ash.
3. Add the required amount of Perm Defoamer through the hopper or directly into the pit.
4. Add the required amount of Perm Drill.
5. Add the required amount of Caustic Soda to achieve 9.0 to 9.5 pH.
6. Adjust fluid density with sized Calcium Carbonate.

After mixing, leave to agitate for at least 30 minutes before displacing down hole, as this will give the polymeric viscosifiers time to yield fully and produce the required mud properties.

Fluid System Guidelines

Additives are constantly depleted through filter cake formation and adsorption onto drilled solids. The base fluid (water or brine) will also be lost in the form of filtrate into the formation or through surface evaporation. Additions of base fluid and additives may therefore be required to maintain rheological and fluid loss properties.

Density – Most of the fluid density comes from the brine, with additional density provided by sized Calcium Carbonate that primarily provides bridging particles. The fluid system is usually solids control equipment should be optimized to prevent mud density increasing due to a build up in drilled solids. The mud density should only be increased in response to hole conditions, using sized Calcium Carbonate only.

Rheology – The relatively high annular velocities in the reservoir section will enhance cuttings transport efficiency for effective hole cleaning. As a result, high Yield Points and Gel Strengths should be avoided because they will have an adverse effect on bit hydraulics, which may encourage induced formation losses and hole swabbing problems while tripping. The Plastic Viscosity should be kept as low as possible through optimum use of all the available solids removal equipment as this will keep rheological properties under control. Perm Vis, which is available as a powder or liquid, should be used for raising rheologicl properties, as it is an acid-soluble biopolymer.

Alkalinity – The pH should be maintained around 9.0 to 9.5 using Caustic Soda that has been pre-dissolved in a chemical barrel. The alkalinity improves the performance of the mud products and protects wellbore tubulars from corrosion.

API Fluid Loss – It is important to maintain tight fluid loss control as this will reduce fluid invasion into the formation and minimize hydration of reactive shales, which could affect wellbore stability. Fluid loss control can be improved with Perm Seal, which is an acid-soluble polymer.

Formate Fluid System

The reason for using low solids Formate systems is that Sodium, Potassium and Cesium Formate brines can be blended to cover densities ranging from 11.1 ppg (1.33 sg) to 19.2 ppg (2.3 sg), eliminating the need for Barite or other materials as a weighting agent. As a result, Formate systems have low solids content and this significantly reduces formation damage, making them ideal for drilling low permeability reservoirs. The problem of Barite sag in deviated wells is also eliminated, which provides enhanced well control.

Shale hydration is minimized by limiting the amount of free water in the Formate drill-in fluid, which is achieved by maintaining the blended Formate brine close to saturation. Formate fluids can be run with lower rheology because viscosity is not required for suspending weighting materials, so higher annular velocities and finer shale-shaker screens can be fitted for improved hole cleaning and solids control efficiency, reducing the build-up of fines in the fluid.

Formate fluids are ideal for drilling slim-hole, extended-reach and horizontal wells because frictional problems associated with solids-weighted fluid systems are eliminated. Rheology is lower because there is no requirement for barite suspension, so ECDs are lower, which reduces the potential for induced formation losses. Surge and swab pressures are also lower for similar reasons while tripping, and torque and drag are reduced due to lower solids in the fluid system, which reduces the potential for differential sticking.

Fluid System Formulation

A typical formulation for a Formate drill-in fluid system is as follows:

Product	Function	Concentration
Formate Brine	Base Fluid	–
Biopoly-E (Zanthan Gum)	Viscosifier	0.75 ppb
Antisol FL100 (PAC)	Fluid Loss Control	4 ppb
Starch	Fluid Loss Control	3 ppb
Sodium or Potassium Carbonate	pH Buffer	3 ppb
Sodium or Potassium Bicarbonate	pH Buffer	5 ppb
Calcium Carbonate	Bridging Agent	20 ppb

Mixing Procedure

Due to the amount of sheer required to provide effective yield from viscosifiers and fluid loss additives in formate brines, formate fluids should be circulated for several hours before making additional treatments.

1. Fill tank with the required volume of Formate brine.
2. Add the required amount of Biopoly-E slowly at 10 minutes per sack.
3. Add the required amount of Antisol FL100 at 2 minutes per sack.
4. Add the required amount of Starch at 2 minutes per sack.
5. Add the required amount of Sodium or Potassium Carbonate at 2 minutes per sack.
6. Add the required amount of Sodium or Potassium Bicarbonate at 2 minutes per sack.
7. Add the required amount of Calcium Carbonate bridging agent.
8. Adjust fluid density with Formate brine or powder.

Fluid System Guidelines

Formate fluids are relatively simple to run, but the benefits of the system will be lost if drilled solids are allowed to build up or if the fluid is contaminated with chlorides from other fluids.

Density – Formate fluid density is usually increased by adding formate powder or high density formate brine, and decreased by dilution with lower density brine, as this procedure will minimize the amount of free water in the system.

Rheology – Care is required to avoid over-treating the Formate system when increasing Yield Point because the system may require more shearing time for polymers to yield. Plastic Viscosity should be controlled as low as possible through efficient use of the solids control equipment. Gels are generally lower, flatter and more fragile than found in conventional mud systems.

pH – Formate fluids are usually buffered around 9.5 to 10.5 pH and this should be maintained with Sodium Carbonate and Bicarbonate treatments.

API Fluid Loss – The filtrate volume is usually well below 1 ml and it can take a few hours to collect sufficient filtrate sample for measuring brine volume and performing the necessary chemical checks. The problem is usually resolved by using two API filter presses and leaving them running until sufficient filtrate is obtained.

HTHP Fluid Loss – Formate fluids form a very thin, tough, flexible filter cake, but HTHP (and API) fluid loss will start to increase as fine drilled solids build up in the fluid. The solids control equipment should be optimized and treatments using Antisol FL100 and starch should be made to maintain HPHT fluid loss control.

Calcium Carbonate – Sized Calcium Carbonate is added to provide effective bridging and to improve filter cake quality and fluid loss control. However, the product also acts as a weighting agent and this must be allowed for and included in density adjustment calculations for the circulating system and pre-mixes whenever these additions are made. The shale-shakers are often run with 250-mesh screens while drilling, so regular monitoring of Calcium Carbonate levels is required to replace Calcium Carbonate screened out at the shakers.

LGS – The solids control equipment should be optimized to control the build up of low gravity solids. Formate fluids are usually run with fine shaker screens up to 250-mesh in size, but these screens must be checked for holes at regular intervals because they do not last as long as coarser shaker screens. The centrifuge should be used if LGS continues to build up, although care must be taken to ensure a dry solids discharge. Dilutions with fresh mud can also be made to control LGS.

Foaming – A supply of defoamer (e.g. No Foam) should be stocked in the unlikely event of foaming in the pits, which could present difficulties when monitoring the active circulating volume.

Lubricity – Formate systems do not usually require lubricants to reduce torque and drag in horizontal wells.

LCM Pills – Formation losses are always possible and a suitable LCM pill should be prepared for such an eventuality. Coarser grade LCM samples should be given to the MWD technician to ensure that they are compatible with down hole tools, with no risk of plugging the MWD tool.

Tripping Slugs – Since formate fluids are low solids systems, tripping slugs should be prepared using higher density formate brine, or by adding formate powder to the required volume of active fluid. Tripping slugs should be mixed in and pumped from the cement unit displacement tanks, as this avoids dilution in the larger mud lines to the drill floor.

Oil-Based Drilling Fluid Systems

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Introduction

Oil-Based drilling fluids (often referred to as NAF or Non-Aqueous Fluids) are generally used when water-based fluids cannot provide sufficient inhibition while drilling technically challenging wells. They produce high performance drilling fluids with effective inhibition for highly reactive shales, enabling gauge hole to be drilled while maintaining effective wellbore stability. They are stable at much higher temperatures than water-based fluids, and enhanced lubricity minimizes torque and drag, reducing the potential for differential sticking.

Oil-Based fluids can be formulated using natural mineral oils (i.e. diesel) or synthetic low-toxicity oils, which have similar high performance properties as mineral oils but a much lower environmental impact. Synthetic oils are much safer because the refining process is designed to reduce the concentration of hazardous aromatic hydrocarbons, which are known to be carcinogens, to around 1.5% by weight so that toxicity to human and marine life is considerably reduced after prolonged exposure.

EMEC Base Oil Range

The base oils used in EMEC oil-based fluids include low toxicity mineral oils, synthetic oils and esters, which are environmentally acceptable and/or biodegradable to address pollution and toxicity concerns, in accordance with client requirements, as follows:

EMEC Non-Toxic Oil offers a comprehensive range of base oils specifically designed to provide high performance with low environmental impact, meeting the requirements of the most demanding drilling operations. The base oils are subjected to a severe refining process that reduces the aromatic content, producing a de-aromatized aliphatic hydrocarbon with less than 1.5% w/w aromatics. As a result, toxicity to both marine life and humans is considerably reduced. The relatively high flash point of the base oils reduces the risk of fire without compromising drilling fluid system performance.

EMEC Ecosafe-E offers a comprehensive range of synthetic ester-based drilling fluid systems specifically designed to provide high performance with low environmental impact. The low toxicity ester base fluid is biodegradable in both aerobic and anaerobic environments, making it ideal as a replacement for diesel in environments that require minimum toxicity to both marine life and humans. The ester-based drilling fluid has low kinematic viscosity and is used for formulating drilling fluids that are stable to 300°F (148°C), providing high performance with low environmental impact to meet the demands of the most challenging drilling operations, including deep cold water environments.

EMEC Ecosafe-O offers a comprehensive range of synthetic olefin-based drilling fluid systems specifically designed to provide high performance with low environmental impact. The low toxicity synthetic base fluid is biodegradable and complies with offshore environmental regulations for deep water drilling, making it suitable as a replacement for diesel oils in environments that require minimum toxicity to both human and marine life. It is used when formulating synthetic oil-based drilling fluids that are stable to 350°F (176°C), meeting the demands of the most challenging drilling operations.

Benefits of Oil-Based Drilling Fluid Systems

The most common type of oil-based fluid system is the invert emulsion fluid system, where a water-in-oil micro-emulsion is formed between a brine phase and the oil phase that forms the continuous phase.

Oil-based fluid systems are easy to run and have several advantages over water-based systems. They have a high tolerance to solids and are stable at high temperatures, making them suitable for HPHT wells.

They were developed as an alternative to water-based muds (WBM) for improving drilling performance, especially when drilling water-sensitive shale or salt formations. Invert Emulsion fluid systems use mineral or synthetic oils as the continuous fluid phase, with extremely fine brine droplets present as an emulsion, which gives oil-based muds several advantages over water-based muds, as detailed below:

Shale Stability – The improved inhibition provided by oil-based muds makes them ideal for drilling water-sensitive shales. Oil forms the continuous phase of the drilling fluid, which protects the formation from direct contact with water. However, some of the emulsified brine phase in invert-emulsion systems will inevitably come into contact with the formation. To minimize the effects of shale hydration or dehydration due to osmotic effects, the salinity of the brine phase is adjusted to match the salinity of the brine trapped in the formation pores. The result is a gauge hole with good wellbore stability.

Drilling Salt Formations – The continuous oil phase and the salinity of the emulsified brine phase minimizes the amount of salt that is dissolved while drilling salt formations, resulting in a gauge hole. Saturated salt water-based drilling fluids may not guarantee a gauge hole because solubility increases with temperature, so a salt system that is saturated on surface may not be saturated at bottom-hole temperatures, producing washouts. The increased lubricity of oil-based muds also reduces the effects of salt creep.

Drilling Performance – Oil-based fluid systems generally deliver higher ROPs and improved drilling performance with excellent shale stability when compared with water-based fluid systems.

Lubricity – The enhanced lubricity provided by oil-based mud systems makes them ideal for drilling highly deviated and horizontal wells. The risk of differential sticking is also reduced, due to the combination of high lubricity with the very thin filter cakes that are produced by oil-based drilling fluid systems.

Temperature Stability – Oil-based mud systems can tolerate high temperatures for long periods of time. They have been used with bottom-hole temperatures approaching 550°F (290°C), so they are particularly suited for drilling high-temperature wells. In contrast, the polymers used in water-based mud systems start to degrade at elevated temperatures, resulting in loss of viscosity and filtration control, which restricts the use of water-based muds in some high-temperature wells.

Corrosion Control – Oil-based fluids offer exceptional corrosion protection due to the non-conductive nature of the continuous oil phase, which coats the exposed surfaces of the wellbore tubulars and prevents corrosion cells from forming. The products used in oil-based fluids are also thermally stable, so they do not degrade to form corrosive products, and bacteria do not thrive in oil-based fluids. As a result, corrosion of all tubulars used in well construction is suppressed, compared with some polymers in water-based mud systems that break down to produce a corrosive environment at prolonged elevated temperatures.

Coring Fluids – The lubricity and enhanced shale inhibition provided by oil-based mud systems make them ideal for use as a coring fluid, especially as they can tolerate high temperatures. Another advantage is the fact that oil-based coring fluids will not introduce water into core samples, so water saturation can be determined more accurately.

Packer Fluids – Oil-based fluid systems can tolerate high temperatures and are stable over long periods of time, which makes them suitable as packer fluids. Corrosion is usually insignificant because oil forms the continuous phase, which compares favourably with water-based mud systems when subjected to similar conditions. Oil-based packer fluids can suspend weighting material for extended periods of time when formulated correctly.

Oil-Based Mud Recycling – The oil-based fluid systems are very stable and can be stored for long periods of time for repeated use to drill several wells, without concerns about bacterial growth. The oil-based mud can be conditioned before being used again simply by reducing the drilled solids content with mechanical removal equipment, or by blending with fresh solids-free premix.

Low Pressured Formations – Oil-based mud systems can be formulated with densities ranging from 22.0 ppg (2.64 sg) down to 7.5 ppg (0.90 sg), which gives them an advantage over water-based mud systems for drilling formations that have low pore pressures.

Disadvantages of Oil-Based Drilling Fluid Systems

Although oil-based drilling fluid performance is generally better than water-based drilling fluid performance, there are certain disadvantages that need to be taken into consideration, including the following:

Fluid Cost – The initial cost of an oil-based drilling fluid is considerably higher than most water-based fluids, due to the cost of the mineral or synthetic base oil. However, the high cost is offset by the fact that drilling performance is usually better, which reduces associated drilling costs. Oil-based fluids can often work out more economical than water-based fluids because they can be reconditioned and used on a series of wells, although they can be costly when lost circulation occurs.

Health and Safety – Prolonged exposure and contact with oil-based fluids can cause dermatitis and other skin problems, so proper precautions must be taken to avoid skin contact. Coveralls and clothing soaked in oil-based mud must be removed at the earliest opportunity, and skin should be washed thoroughly with soap and water. Fumes should be avoided as they are an irritant and prolonged exposure could lead to health problems.

Environmental Considerations – Oil-Based fluids can be harmful to the environment, due largely to the fact that they take a very long time to degrade. The discharge of oil-based cuttings and the disposal of solids-laden oil-based mud to the environment is unacceptable in many parts of the world, so rig modifications and additional equipment are required to establish total fluids containment and zero discharge conditions. Waste fluids and cuttings are recovered and sent to approved facilities for disposal, usually by incineration.

Well Control – A gas influx is much easier to detect in a water-based fluid because the gas is insoluble. However, formation gases are soluble in base oils, especially when subjected to high formation pressures and temperatures. As a result, it is often difficult to detect a gas influx because the gas may or may not come out of solution with the reduction in pressure as the gas approaches the surface, and it may even stay in solution on surface. The release of formation gas on surface is potentially very dangerous because it could be poisonous or explosive, containing Hydrogen Sulfide or hydrocarbon gas.

Oil Compressibility – Base oils are much more compressible than water and are affected by temperature, so the down-hole density may vary considerably from that measured at the surface. The density of an oil-based mud sample at 20°C will also be noticeably higher than the density of the same mud sample at 40°C, and this could lead to confusion when measuring and reporting oil-based mud densities. The problem is resolved by using density correction charts, which convert the measured density and temperature to a corrected density at a specified temperature (usually 50°C).

Flash Point – Base Oils have relatively low flash points, which is the temperature where flammable vapours from the base oil form an ignitable mixture in air (A source of ignition is still required to start a fire). Mineral oils and synthetic fluids generally have higher flash points than diesel and crude oils, but care is required because surface temperatures can get close to the flash point when drilling HPHT wells, especially in hot climates.

Elastomers – The base oil in oil-based fluids tends to be more damaging to elastomers than water-based fluids, so high pressure mud pumps often require regular maintenance to replace leaking elastomers on pistons and valves, as well as other elastomers.

Electric Logging – Logging tools that measure resistivity (e.g. resistivity, dipmeter and SP logs) are designed to work in conductive mud systems, so they have to be modified to overcome the non-conductive properties of oil-based muds by incorporating scratcher-pads and other devices.

Invert Emulsion Drilling Fluid Formulation

A typical formulation for an invert emulsion drilling fluid system is shown below:

Product	Function	Concentration
Water	Base Fluid	7.4 gal/bbl
Base Oil	Base Fluid	22.2 gal/bbl
EMEC Mul	Primary Emulsifier	0.6 gal/bbl
EMEC Con	Secondary Emulsifier	1.5 gal/bbl
EMEC Wet	Wetting Agent	0.7 gal/bbl
Lime	Alkalinity	5 ppb
EMEC Vis	Viscosity	8 ppb
EMEC Tone	Filtration Control	8 ppb
EMEC Thix	Rheology Modifier	0.5 gal/bbl
EMEC Carb	Bridging Agent	25 ppb
Calcium Chloride	Water Activity	25 ppb
Barite	Density	171 ppb

The function of the primary emulsifier is to provide an effective emulsion while mixing fresh oil-based fluid at low shear rates using surface equipment. The function of the secondary emulsifier is to provide a strong emulsion when the oil-based fluid is displaced down hole and subjected to high shear at the drill bit.

Invert Emulsion Mixing Procedures

The mixing hoppers cannot generate the high shear rates that are required to create strong oil/water emulsions. High shear rates are also required when mixing organophilic clay viscosifiers. As a result, freshly-mixed oil-based mud properties tend to fall short of programmed requirements and higher concentrations of organophilic clay viscosifier may be required for Barite suspension. However, emulsion stability, rheology and fluid loss control will improve dramatically after a few circulations in the hole due to high shear at the bit.

The ideal situation when mixing oil-based fluids is to have two mix tanks, one tank for mixing the oil phase and one tank for mixing the brine phase. The brine is then transferred slowly into the oil phase to form the fluid emulsion. However, there will be occasions when only one tank is available for mixing oil-based fluids and this requires a slightly different mixing procedure. The mixing time will vary according to the level of shear provided by the mixing equipment. Mixing procedures using two tanks and using one tank are as follows:

Mixing Procedure using Two Mix Tanks – The following procedure is recommended when two mix tanks are available for mixing an oil-based fluid system:

1. Add the required volume of Base Oil to the mixing tank.
2. Add the required amount of primary (and secondary) emulsifiers.
3. Add the required volume of water to a separate mixing tank.
4. Add the required amount of Calcium Chloride powder to the water.
5. Transfer the Calcium Chloride brine slowly into the Base Oil at maximum shear rate.
6. Add the required amount of Lime.
7. Add the required amount of filtration control additives.
8. Add the required amount of organophilic clay viscosifier.
9. Circulate through the shear hopper with full tank agitation for several hours to establish a good emulsion.
10. Add Barite or other weighting materials to obtain the required density.

Mixing Procedure using One Mix Tank – The following procedure is recommended when only one tank is available for mixing an oil-based fluid system:

1. Add the required volume of Base Oil to the mixing tank.
2. Add the required amount of primary (and secondary) emulsifiers.
3. Add the required amount of filtration control additives.
4. Add the required amount of Lime.
5. Add the required volume of water to the above mixture.
6. Add the required amount of organophilic clay viscosifier.
7. Add the required amount of Calcium Chloride powder.
8. Circulate through the shear hopper with full tank agitation for several hours to establish a good emulsion.
9. Add Barite or other weighting materials to obtain the required density.

Calcium Chloride is available as a fine crystalline powder, flakes or pellets. The flakes and pellets are suitable when mixing brine in a separate tank, but fine crystalline powder is preferable when mixing directly into oil-based mud because the flakes and pellets will take longer to dissolve and may settle on the bottom of the mix tank. As mentioned, fluid properties will improve once the freshly-mixed oil-based mud has been sheared through the bit for a few circulations.

The viscosity produced by the organophilic clay will be higher if it is added to the mud after the water is added and before the calcium chloride is added. If brine is used then the gellant is added after the brine and the viscosity will generally be lower. The electrical stability of the mud after mixing will be lower initially if brine used instead of adding calcium chloride to the mud after water is added. The electrical stability and fluid loss control will improve after use due to the shear generated during circulation.

Drilling Fluid Maintenance Procedures

The oil-based drilling fluid system is very tolerant to a wide range of contaminants, including cement, and remains stable at much higher temperatures than water-based systems. The following guidelines should be used when running oil-based drilling fluids:

Density – Oil is a compressible fluid and a pressurized mud balance must always be used when measuring the density of an oil-based mud sample. The temperature of the mud sample must be recorded when drilling high temperature wells, in order to determine the corrected density at a specified temperature (usually 50°C). Fluid density is increased by adding the appropriate weighting agent, and is reduced by running the centrifuge or cutting back with unweighted oil-based premix.

Rheology – The viscosity of oil-based muds is also affected by temperature and pressure, with higher temperatures reducing rheology and higher pressure increasing rheology. The funnel viscosity should therefore only be used for monitoring viscosity trends when temperatures are relatively steady while drilling, because results will be affected by the temperature of the fluid sample. Rheological properties should be measured using a viscometer (rheometer), with a heating cup adjusted to heat the oil-based mud sample to a specified temperature (usually 50°C or 120°F).

The viscosity produced by organophilic clays tends to drop away over time and additional organophilic clay treatments are often required to maintain Yield Point at programmed levels. The Yield Point and Gel Strength, which is an indication of the fluid's ability to suspend solids under static conditions, can be increased by adding organophilic clay. The low-end rheology (i.e. the 6 rpm and 3 rpm readings), which is an indication of a fluid's ability to suspend solids under dynamic conditions, can be increased by adding rheological modifiers.

Rheology can also be increased by adding water to the circulating system, but this should only be done to restore the oil-water ratio if it is increasing due to water evaporation while drilling high temperature wells. The Yield Point and Gel Strengths can be reduced by "dilution" with base oil, especially if it restores the oil-water ratio that might have dropped following an influx of water or as a result of water leakage into the circulating system. They can also be reduced by treating the circulating system with wetting agents or thinners.

The Plastic Viscosity (PV) will increase as drilled solids increases and also if there is an increase in water content caused by an influx of formation fluids or water contamination on surface (e.g. a leaking water supply valve or hose). The water forms emulsified water droplets in the continuous oil phase, which then behave like solid particles. The PV can be reduced by installing finer shale shaker screens and running the centrifuge to remove more solids, or by thinning the oil-based mud with base oil.

Electrical Stability (E.S.) – This is the voltage that is required to break the oil-water emulsion and establish an electrical current between the two electrodes in a probe. The electrical stability is a measure of the strength of the oil-water emulsion. However, lower ES readings will occur due to water contamination or the presence of conductive solids such as hematite and undissolved salt. A drop in ES readings and the presence of water in the HPHT filtrate is an indication of a weak emulsion, which can be remedied by adding emulsifiers and lime.

HPHT Filtration – The HPHT cell is usually heated to 250°F (120°C) when measuring the HPHT filtrate, but the client may request a temperature that is more representative of bottom-hole temperatures under static conditions to determine filtrate volume and filter cake quality. The fluid loss should be low and the filter cake should be thin, firm and slippery. High fluid loss and a thick filter cake are a general indication that drilled solids are building up in the mud.

The HPHT filtrate also gives an indication of emulsion stability because the presence of water in the filtrate can be an indication of a weak emulsion. There should be no water in the filtrate if the emulsion is stable, but a small amount of water is sometimes tolerated. The HPHT fluid loss control and emulsion stability can be improved by treating the circulating system with filtration control additives, emulsifiers and lime.

Water Phase Salinity – The programmed salinity is usually determined using offset well data, and analysis of shale cores. Salinity should be high enough to prevent water migration into the shale, but it should not be too high because this could dehydrate the shale with the potential for shale instability. However, it is sometimes possible to adjust salinity so that sufficient water is drawn from the shale to provide wellbore strengthening. Care is required when adding calcium chloride, because undissolved calcium chloride can cause water wetting problems.

Water Phase Salinity can be increased by adding sodium or calcium chloride powder to the active circulating system. These additions should be controlled because the powder will initially be oil-wet and it will take time and high shear before the powder eventually dissolves in the brine phase. Water Phase Salinity can be reduced by adding water or oil-based premix that contains no salinity in the water phase, to the fluid and making sure that density is maintained if the treatment is made to the active circulating system.

Lime Content – Lime helps to form strong oil-water emulsions when using fatty acid type emulsifiers. Poor emulsion stability may be due to lime deficiency, so lime content should always be checked to determine the amount of excess lime in the oil-based fluid. Emulsifier treatments may not be required if the poor emulsion stability is due to lime deficiency. A decrease in lime content while drilling may indicate acidic gases in the formation (e.g. CO_2 or H_2S) or high temperature decomposition of products in the fluid.

Oil/Water Ratio – This ratio is determined after retorting a sample of oil-based mud to obtain the oil, water and solids content. These figures need to be accurate in order to obtain an accurate Oil-Water Ratio. The water content must also be accurate for salinity calculations, because a small error in water content may produce a large error in water phase salinity. The Oil/Water Ratio is restored by adding base oil or water.

Sulfides – A check for sulfides is always performed by running the Garrett Gas Train on active mud return samples (not filtrate) whenever there is a risk of H_2S gas while drilling. Lime in the oil-based mud will prevent the formation and release of H_2S gas, so lime treatments should be increased when H_2S is present. Zinc Oxide is the preferred product for treating out soluble sulfides.

Troubleshooting Guidelines for Oil-Based Fluids

Problem	Symptoms and Treatment
Low Viscosity	Add organophilic clay (EMEC Vis or Clay Tone II). Add water and emulsifier if Oil/Water Ratio is high. Add polymeric viscosifier on high temperature wells (EMEC Thix). (All these treatments will affect Yield Point, Gel Strength and Low-Shear Viscosity more than Plastic Viscosity).
High Viscosity	Remove Low Gravity Solids (LGS) using solids control equipment. Dilute with base oil if Oil/Water Ratio is low. Add oil wetting agent to reduce viscosity (EMEC Wet or Wet NT).
Low ES	Low ES can be due to high solids, insufficient emulsifier or lime, undissolved calcium chloride, water-wet solids, and recent weighting agent additions. Low viscosity muds also tend to have low electrical stability readings. Determine reason for low ES and treat accordingly.
Water-Wet Solids	Water-wet solids will blind shaker screens and give low E.S. Readings (water-wet solids will disperse easily when added to water). Check that there is no undissolved calcium chloride in the mud. Add oil wetting agent and base oil (EMEC Wet or Wet NT).
High Solids	Mud viscosity will increase and ES readings will decrease, even when emulsifier concentration is adequate. Improve solids removal efficiency by installing finer shaker screens and run centrifuge, if necessary.
High Fluid Loss	Freshly mixed mud may have high HPHT until properly sheared. Ensure mud contains excess lime. Add additional emulsifier if HPHT filtrate contains water. Small amounts of water may help to lower HPHT filtrate when O/W Ratio is high.
Acidic Gas	This is detected by a drop in alkalinity. Add lime if drop in alkalinity is due to CO_2 gas. Add lime if H_2S is detected by the Garrett Gas Train. Add a sulfide scavenger if H_2S is detected (Zinc Carbonate or Zinc Oxide).
Mud Losses	For seepage losses use bridging materials like calcium carbonate to reduce thick filter cakes and minimize differential sticking. For partial losses use bridging materials like calcium carbonate and oil-wettable fibrous materials. For total losses consider organophilic clay squeeze, cement squeeze or displacement to water-based mud until loss zone is cased off.
Oil Separation	Free oil may appear on the surface of the mud tanks after prolonged periods of inactivity. Agitate the mud in the pits and add organophilic clay to increase fluid viscosity.

All-Oil Drill-In Fluids

The all-oil drill-in fluid is formulated as a water-free oil system, although some water is usually picked up from the formation while drilling. The system is primarily used as a low density fluid for under-balance drill-in or coring operations, where the invasion of a drilling fluid containing emulsified water with high concentrations of emulsifiers and wetting agents is undesirable. These systems can be formulated with minimal amounts of emulsifier and wetting agent because they are technically water-free. However, they usually end up with 3% to 5% water picked up from the formation.

The benefits of the all-oil system are natural shale inhibition and wellbore stability, resulting in a gauge hole. Rheology is lower than conventional invert emulsion systems, so ECDs are lower, which means that higher circulating rates can be used for improved hole cleaning. The natural lubricity of the base oil also contributes to higher ROPs. The use of calcium carbonate as a bridging and weighting agent reduces the effects of formation damage. The all-oil system is easy to mix, using a similar mixing procedure as oil-based mud systems.

The all-oil system can be formulated from any base oil (mineral or synthetic), but the difficulty is to obtain adequate viscosity in the single-phase oil system. One solution is to use high concentrations of organophilic clay, or to use special high-yielding organophilic clays. Low HPHT filtrates are a very good indicator for minimizing fluid invasion and, since all-oil fluids are formulated without water, this is achieved by using effective asphaltic-based fluid loss control additives (e.g. Tone 400) along with sized calcium carbonate bridging materials.

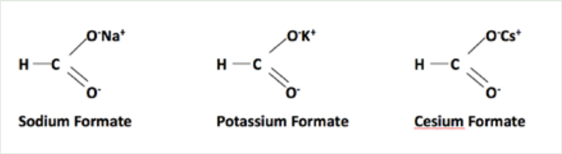
Consideration should be given to converting an all-oil fluid to an invert emulsion system if the all-oil fluid is subjected to severe water contamination. Failure to emulsify the water could result in water-wetting of the formation, which could encourage wellbore instability. The drilled solids could also become water-wet and blind the shaker screens, resulting in whole mud losses at the shale-shakers.

Formate Fluid Systems

Contents

Introduction

Sodium, Potassium and Cesium Formate salts are extremely soluble in water, producing high density formate brines ideally suited for HPHT completion and drill-in fluids. They are environmentally friendly, safe to handle and cover the entire density range up to 2.30 sg (19.2 ppg), so high density drilling fluids can be formulated without the need for weighting agents. The chemical structures of the formate salts are as follows:



The saturated densities of the three commonly used formate brines are tabulated below:

Brine	**Formula**	**Brine Density (s.g.)**	**Brine Density (ppg)**
Sodium Formate	NaCOOH	1.33	11.1
Potassium Formate	KCOOH	1.59	13.2
Cesium Formate	CsCOOH	2.30	19.2

Since fluid density is provided by the formate brine, drill-in fluids can be designed with low solids to produce a fluid with unique propertiezs: drilling parameters can be optimized, well control is enhanced and formation damage is minimized, resulting in improved well productivity. Depending on the application, intermediary densities are obtained by blending a higher density formate brine with a lower density formate brine, or by diluting a higher density formate brine with fresh water.

Brine density is measured with a hydrometer, which usually measures densities in specific gravity that is accurate to 3 decimal places (e.g. 1.873 sg). Formate drilling fluid densities are measured using conventional mud balances, since hydrometers cannot be used with viscous fluids. Software is available for calculating the average wellbore density and bottom-hole pressure of a formate fluid, based on surface density, vertical depth and bottom-hole temperature.

The density of high-concentration formate fluids increases approximately 0.001 sg for every 1°C drop in temperature, so the software is also used for correcting surface densities to 15.6°C (60°F), which is the international standard. So if the formate fluid density is 1.873 sg at 20°C, then the density corrected to 15.6°C is 1.877 sg. Due to this variation, temperatures are recorded whenever formate fluid densities are measured, and these densities are then corrected to 15.6°C to avoid potential confusion when reporting densities, since differences can often be significant with high temperature wells.

The density of formate brines diluted with water can be restored by evaporating off the water or adding sacks of the appropriate formate salt. However, this procedure may not be possible if an intermediary formate brine density has been obtained by blending two formate brines that are close to saturation (e.g. Cesium and Potassium Formate brines), because the resultant formate blend will be close to saturation and evaporation may cause crystallization.

The formate ion is an anti-oxidant that is effective in minimizing corrosion of down-hole tubulars, including those used in HPHT wells. Formate brines are also thermally stable in the field, and on one particular occasion formate brine decomposition was minimal after a temporary suspension lasting several months with 225°C (437°F) bottom-hole temperatures.

A common misconception is that Cesium Formate is radioactive because Cesium is radioactive. However, naturally occurring Cesium is not radioactive and is the 29th most common element in seawater. The radioactive Cesium isotopes that are used in medicine and research are created as a result of nuclear fission.

Careful planning and attention to detail is essential when running formate fluids in the field, in order to avoid accidental dilution with water, contamination with other fluids, or physical losses. As an example, formate fluids provide effective corrosion inhibition, but this could be lost if chlorides get into the system due to contamination with seawater or a KCL mud system.

Displacement pills and spacers will resolve most of the contamination issues, but consideration must also be given to residual volumes left in surface lines. For similar reasons, products must not be added to formate fluid systems without prior thought and approval from both the client and supervisors, since they may not be compatible with, or may have an adverse effect on, formate fluid performance.

Formate Fluid System Properties

Formate brines have a range of unique properties that make them ideal for HPHT wells, as follows:

Corrosion and Corrosion Control – Corrosion inhibitors are not required in concentrated formate fluids because the formate ion is an anti-oxidant and formate fluids are also usually buffered at around 10.5 pH with potassium and/or sodium carbonate and bicarbonate. The result is an effective non-corrosive environment, and the carbonate and bicarbonate buffering enables the formate fluid to maintain alkaline conditions even after large acidic gas influxes. However, corrosion inhibitors may be beneficial for formate fluids that have been diluted with significant amounts of water (e.g. greater than 50% water), since the anti-oxidizing properties of the formate ion will be less effective.

Biocidal Properties and Biodegradability – Biocides are not required in formate brines because they have natural biocidal properties at high concentrations, so the fluid and any additives will not biodegrade during normal field operations. However, these biocidal properties are not so effective at low concentrations, so formate brines subjected to large dilutions become biodegradable, enabling them to be discharged without impacting the environment. In view of this, low concentration formate fluids may experience bacterial activity if natural biocidal properties are not present. Aerobic bacterial growth may occur with low concentration formate fluids on surface, and anaerobic bacterial growth may occur down hole.

Oxygen and Oxygen Scavengers – The presence of oxygen at down-hole temperatures and pressures makes this gas extremely corrosive, which is why halide brines require oxygen scavengers. Being a strong oxidizing agent, oxygen is also responsible for polymer degradation at elevated down-hole temperatures. However, the formate ion is a natural anti-oxidant and free radical scavenger, forming bicarbonate with dissolved Oxygen to remove the potential for corrosion and assisting with polymer stabilization at elevated temperatures. Formate brines also tend to be high concentration blends, which is effective in reducing the level of oxygen solubility. Although oxygen scavengers are not required for high concentration formate brines, they should be considered where lower formate brine densities have been prepared through large dilutions with water, due to reduced formate ion concentration.

Elastomer Compatibility – Extensive testing has been performed to ensure compatibility between formate fluids and oilfield elastomers and seals used in surface and down-hole tools and equipment. The only elastomers to fail these high temperate compatibility tests, which are based on flexibility and dimensional changes, were Nitrile and early generation Viton elastomers, due to the fact that both products are sensitive to alkaline environments and formates are buffered at high pH. This is not a problem for surface equipment, but can be critical down-hole where elastomers are exposed to high temperatures and pressures.

Crystallization Temperature – This can be critical when ambient or deep water temperatures fall below 0°C because this is close to the crystallization temperature of concentrated formate brines. True Crystallization Temperature (TCT) charts exist for formate fluids, but laboratory results are inconsistent, with a wide temperature range that is not reflected by field experience. The potential for crystallization must be considered when using high concentration formate brines in deep water operations because the combination of low temperature and high pressure may encourage crystallization, especially during pressure testing. The TCT of concentrated formate brines can be lowered to safe levels by dilution with water or by blending with other formate brines, if density requirements can still be met. Another method for lowering formate TCTs is to add chloride ions (i.e. Potassium or Sodium Chloride), although this is not the preferred solution because chlorides can cause localized corrosion in tubulars.

Hydrates Suppression – Gas hydrates can occur in certain water-based fluids when an influx of methane, or other natural gases from the reservoir, migrates up the hole. The gas molecules are small enough to occupy the interstitial cavities within the water molecules, creating a solid crystalline structure when subjected to certain temperatures and pressures. The formation of hydrates is a particular concern in deep-water wells, where the combination of low temperatures at the seabed and relatively high fluid pressure can encourage hydrates formation, creating a potential well control situation. High concentration formate fluids, as with all concentrated brines, are very good for suppressing the formation of hydrates, unlike other water-based fluids that require chemical additives like Glycol.

Alkalinity and Buffering of Formate Brines – Buffered solutions maintain a steady pH when subjected to alkaline or acidic fluids. Formate brines are naturally alkaline, but are buffered with Potassium or Sodium Carbonate or Bicarbonate in order to maintain alkalinity and prevent corrosion if acidic influxes (CO_2 or H_2S) occur. Potassium or Sodium Hydroxide can also be used for raising alkalinity, but this will not act as a buffer and alkalinity will fall rapidly if acidic gases are present. Note that the alkalinity of formate brines can be adjusted without precipitating insoluble salts because the formate cations are all monovalent. This contrasts with most other high density brines that are acidic with divalent cations, resulting in the precipitation of insoluble salts when raising alkalinity (e.g. $Ca(OH)_2$ from $CaCl_2$, $Zn(OH)_2$ from $ZnBr_2$). Maintaining alkalinity also helps stabilize polymers and the presence of Carbonate will keep H_2S in solution.

Buffer Treatments – Formate fluids should be buffered with 6 to 12 ppb (17 to 34 kg/m^3) Potassium or Sodium Carbonate and/or Bicarbonate to maintain alkalinity at around 10.0 to 10.5 pH for dealing with acidic formation gases. As mentioned previously, formate alkalinity is measured with a pH meter or pH paper after a 9-to-1 dilution with de-ionized water. Although carbonate provides the buffering, it can also produce very high fluid pH. The reason for adding bicarbonate, which does not provide buffering capacity, is that pH is determined by the carbonate-to-bicarbonate ratio, so it is used for controlling buffering alkalinity at an acceptable level (i.e. 10.0 to 10.5 pH).

The carbonate buffer reacts with acidic formation gases to form bicarbonate, but alkalinity will remain steady at around 10.0 to 10.5 pH until all the carbonate has been converted to bicarbonate. The pH will start to fall once the carbonate buffer has been used up, and buffer treatments should be made to restore alkalinity as soon as this occurs. Additional buffering should be considered if formate is going to be left in the hole for extended periods, such as packer applications or temporary well suspensions.

pH Measurement – Glass electrode pH meters and pH paper do not actually measure pH, which is the hydrogen ion activity of an aqueous solution. Instead, these devices measure the hydrogen ion concentration, which for most diluted fluids is close to the hydrogen ion activity. However, this correlation becomes less accurate as brine concentration increases, and cannot be applied to formates because they are highly concentrated brine solutions. As a result, alkalinity of a concentrated formate fluid cannot be measured directly using glass electrode pH meters or pH paper. However, experience has shown that meaningful pH readings can be obtained by diluting formate brines with nine parts de-ionized water. This will not give an accurate pH measurement because the formate brine has obviously been diluted, but it will verify that the fluid is alkaline, and that the Sodium or Potassium Carbonate or Bicarbonate buffer has not been used up, especially if acidic gases are present. When running formate systems, Sodium or Potassium Carbonate is usually used for controlling pH in preference to Sodium or Potassium Hydroxide, because carbonates maintain buffer capacity without risk of over-treatment. If Sodium or Potassium Hydroxide is used, then care must be taken to avoid over-treatments because very high pH will destroy polymer performance.

CO_2 Influxes – CO_2 gas is highly soluble in water, forming carbonic acid, which can cause pitting, stress corrosion cracking and catastrophic failure in down hole steel tubulars using halide brine systems. These problems are avoided using buffered formate fluids because the CO_2 gas will dissolve to form bicarbonate (HCO_3^-), as long as carbonate and bicarbonate buffering is effective. To maintain effective buffering, alkalinity must be monitored regularly to ensure that it remains steady in the 10.0 to 10.5 pH range. However, if carbonate and bicarbonate buffering is not replenished then it will eventually be depleted by the CO_2 gas and the formate pH will start to drop once that happens, although laboratory tests indicate that alkalinity will not drop below around 6.4 pH.

H_2S Influxes and H_2S Scavengers – Not only is H_2S a poisonous gas that can be fatal at relatively low concentrations, but it is also extremely corrosive, causing rapid catastrophic failure of high strength steel tubulars down hole. Formate fluids are usually buffered at around 10.0 to 10.5 pH with Potassium or Sodium Carbonate and/or Bicarbonate, which are all soluble, enabling formate fluids to deal with large acidic gas influxes. Most of the H_2S in an influx will dissolve to form Hydrogen Bisulphide as long as the buffering remains effective. However, it is important to note that the chemical reaction forming Hydrogen Bisulphide is reversible and dependent on pH, so H_2S gas will start to come out of solution if the pH is allowed to drop due to continued depletion of formate buffering by acidic gas influxes. To maintain effective buffering, alkalinity must be monitored regularly to ensure that it remains steady in the 10.0 to 10.5 pH range, although higher alkalinities may be required to ensure that all the H_2S is converted to Hydrogen Bisulphide, which can be achieved by adding Sodium or Potassium Carbonate. Formate fluids that have not been buffered with carbonate and bicarbonate must not be used if acidic gases are likely to be encountered during well operations.

Field experience has shown that replenishment of carbonate and bicarbonate buffering has only been required after prolonged operations. H_2S Scavengers should be considered if H_2S is a serious risk and if H_2S related corrosion is a concern because the chemical reaction is permanent (i.e. the chemical reaction is not reversible). Two common H_2S scavengers compatible with formate fluids are Ironite Sponge and Iron Gluconate. Ironite Sponge converts the sulphide ions into FeS_2 (pyrite), but the scavenger comprises solid particles and is therefore not suitable for completion brines. Iron Gluconate is another iron-based liquid scavenger that is water-soluble at high pH and reacts very quickly with sulphide ions, although it will give the fluid a dark black color. Other scavengers may also be effective, but they will need to be tested for compatibility with formates. It is important to inform relevant parties when back loading formate fluids that have been exposed to H_2S influxes, so they can take appropriate safety precautions when handling the fluid.

Formation Damage – Ideally, a reservoir should be drilled without damaging the formation in any way, since this will optimize well productivity. The productivity of a well will be restricted if the mud filter cake is difficult to remove, if the reservoir pores are plugged with solids from the mud system, or if ions in the mud system fluid phase react with ions in reservoir fluids to form a precipitate within the reservoir pores. Formate filter cakes are very thin and tough, but are easy to remove and they peel off as soon as the well flows. Formate mud systems have minimal solids content, comprising acid-soluble Calcium Carbonate bridging materials and drilled solids, so pore plugging is minimal. The formate cations (Na^+, K^+, and Cs^+) are all monovalent, so precipitates do not form when formate fluids come into contact with reservoir fluids (Divalent cations such as calcium may form precipitates with reservoir fluids and can be a significant factor in formation damage).

Polymer Compatibility – Most polymers used for viscosity and fluid loss control are effective in formate fluids, and since the formate ion is an anti-oxidant, formates often provide polymer stabilization by suppressing polymer degradation due to oxidation at elevated temperatures. As a result, the thermal stability of conventional water-based viscosifying polymers can often be extended by around 40°C. However, it should be noted that HEC (Hydroxyethyl Cellulose) requires low pH for hydration and is therefore not suitable for formate fluids since they are usually buffered at high pH. Synthetic polymers have been developed to viscosify formate fluids used in high temperature wells above 200°C (400°F). Polymers usually take longer to yield in formate fluids because there is usually less free water in the system, so care must be taken to avoid over-treatment.

Thermal Conductivity – As with all water-based fluids, formate fluids have a relatively high thermal conductivity and specific heat capacity, so they are better than oil-based muds at maintaining lower bottom hole circulating temperatures. Lower temperatures protect polymers from thermal degradation, and protect MWD, LWD and logging tools from exposure to high temperatures. In addition, thermal stabilization is much quicker when circulation is stopped, reducing the time taken for flow checks.

Lubricity – The need for low torque and drag is essential for extended reach and horizontal drilling. Field experience has confirmed that the lubricity of high concentration potassium and cesium formate brines is similar to that of oil-based muds. However, the lubricity of lower concentration formate brines (e.g. sodium formate and lower density sodium-potassium formate blends) is not so effective, so lubricant additives may be required for certain applications.

Logging – Logging presented a challenge when formate fluids were first introduced because formate drilling fluids and filtrates have properties that are significantly different from conventional oil-based and water-based muds. However, logging companies quickly learned how to calibrate and adjust correction factors when logging in formate fluids, and the interpretation of density, resistivity and nuclear logging data is no longer an issue.

Filtration – A twin-pod cartridge filtration unit is recommended for formate brine filtration because filtration losses are relatively small, using 10-micron and 2-micron cartridges. Plugged cartridges removed from the filtration unit will be saturated with formate brine and if this is high value fluid then most of it can be recovered by allowing the cartridges to drain into a suitable container. A DE filter press may be required for heavily contaminated brine, but filtration losses will be higher due to unrecoverable formate brine in the diatomaceous earth.

The Formate Drill-In Fluid System

- The benefit in using the formate system as a drilling or drill-in fluid is due to the fact that the fluid density is provided by the density of the formate brine. As a result, barite and other weighting agents are not required, and formate fluids can therefore be run with a lower rheology since it is not required to suspend weighting agents (e.g. barite, etc.). The result is a low solids, low rheology drilling or drill-in fluid with the following benefits over conventional drill-in fluids:
- No Barite sag, enhancing well control in high-angle wells
- Low gas solubility, enhancing well control due to early detection of gas influxes.
- Lower ECDs because high rheology is not required for barite suspension
- Lower swab and surge pressures while tripping due to lower rheology
- Reduced torque and drag due to lower solids in the fluid system
- Enhanced ROPs since lower ECDs reduce the cuttings hold-down pressure at the bit
- Reduced formation damage due to lower solids in the fluid system
- Environmentally acceptable and safe to handle

The drilling benefits of formate fluids are particularly suited for horizontal or extended reach, slim-hole wells, which are difficult to drill with conventional, high-solids mud systems due to high torque and drag. Lower rheology produces lower ECDs, so higher annular velocities can be used, which is more effective for cleaning the hole. Lower rheology also means that finer screens can be fitted on the shale shakers, improving solids removal and reducing the build-up of fines in the fluid.

The combination of lower solids and lower rheology allows shale shakers to be dressed with finer screens, improving solids removal efficiency. However, finer shaker screens have a shorter life than coarser screens, so frequent checks must be made to ensure that screens with holes are replaced at the earliest opportunity to control the build-up of solids in the formate system. Regular calcium carbonate additions may be required to replace coarser grades removed at the shakers and maintain PSD levels.

Polymers usually take longer to yield in formate fluids because there is usually less free water in the system, so shaker screens must be monitored after polymer additions to make sure polymers are not screened out. The centrifuge can also be used for the removal of fines in the mud, but frequent checks must be made to make sure the solids discharge is always dry, since a wet discharge will result in higher formate fluid losses that can be costly.

Formate System Formulation

The formate fluid system is very simple, comprising the following components:

- Formate brine for density and inhibition
- Viscosifier for bridging agent and drilled solids suspension
- Filtrate Control Additive to control fluid loss
- Graded Calcium Carbonate to improve filter cake and provide bridging
- Sodium or Potassium Carbonate for pH buffering
- Sodium or Potassium Hydroxide for buffering control

Although fluid density is provided by the formate brine density, allowance must be made for any density increase from the Calcium Carbonate bridging particles. The required brine density is obtained by blending saturated Sodium, Potassium or Cesium Formate brines in order to minimize the amount of free water in the system and prevent the hydration of shales.

Barite or other weighting materials should not be added to formate fluid systems because that will increase the amount of solids present and rheology will have to be raised to keep these high density solids in suspension, effectively destroying the advantages of the formate fluid system. However, weighting materials could be added in an emergency if a well control situation were to occur. If this were the case, then barite or other weighting materials can be used, but rheology might have to be raised for high density solids suspension. Although barite is slightly soluble in formate fluids at elevated temperatures, concentrations are not high enough to be a health risk.

Displacement Pills and Spacers

Formate fluid displacement losses can be avoided by the correct use of pills and spacers. The most challenging displacement is from oil-based mud to formate completion brine. If the well is cased and an inflow test has confirmed well integrity, then it may be possible to perform a clean-up and displacement to water before displacing to filtered completion brine, which would be the ideal scenario. Safety constraints and the need to maintain hydrostatic over-balance in the wellbore usually prevent this option, so the ideal displacement would use the following sequence:

1. Base Oil spacer
2. Solvent pill
3. Surfactant pill
4. Viscous water spacer
5. Fresh water spacer
6. Sacrificial mid-density formate spacer
7. Formate completion brine

Once again, safety constraints and the need to maintain hydrostatic over-balance in the wellbore may prevent this option, since the lighter density pills and spacers might bring the well under-balance. Limited tank availability may also be a factor, resulting in a compromise in the number and type of pills and spacers. Experience has shown that viscous sacrificial formate spacers are detrimental when displacing to formate brine because the spacer gets strung out, with some ending up in the formate brine to make filtration difficult.

The priority during any displacement to formate fluid is to prevent formate contamination with chlorides, foreign fluid systems and unwanted solids (e.g. barite), so that the benefits of the formate system are not compromised. This can be achieved by pumping a fresh water spacer and sacrificial formate spacer ahead of the formate fluid. The fresh water spacer is designed to keep chlorides and foreign fluids away from the formate fluids, and the lighter density “sacrificial” formate spacer is designed to prevent excessive dilution of the formate system with the fresh water spacer.

With this arrangement, some of the sacrificial formate spacer will be lost to the fresh water spacer and should be discarded since the water spacer may be contaminated with foreign fluids. Any sacrificial formate spacer returns at the displacement density should be recovered in the tank from which it was pumped. The interface between the sacrificial formate spacer and formate fluid should be recovered in a separate tank since it will have value, and the displacement should be stopped once formate fluid returns are at the displacement density.

Where possible, a density and rheology hierarchy should be applied to the displacement pills and spacers as this will help to maintain integrity and minimize stringing out between all the fluids. To achieve this, the density and rheology of the spacers should be midway between the density and rheology of the adjacent fluids. However, this decision-making process must include flexibility since the ideal displacement train may not be ideal for the formate fluid. A typical example that has already been mentioned is the need to avoid viscosifying polymers creating problems with formate brine filtration.

Displacement Guidelines

Conventional procedures should be applied to minimize the displacement interfaces during displacements, as follows:

Circulating & Conditioning – If the hole is filled with drilling fluid then it should be circulated and conditioned to pick up settled solids and minimize contamination that could have an adverse effect on subsequent operations.

Direction – Lighter fluids will "float" on heavier fluids, and heavier fluids will channel down through lighter fluids, so it is important to minimize the duration that a heavier fluid sits above a lighter fluid during a displacement. The annulus volume is usually much larger than the string capacity, so fluids will travel down the string much faster than travelling up the annulus. Therefore, when displacing fluids with different densities, it is usually preferable to select displacement direction so that heavier fluids are above lighter fluids in the displacement string instead of in the annulus (e.g. conventional circulation when displacing water in the hole to heavy brine, and reverse circulation when displacing heavy brine in the hole to water). This will minimize channelling, especially if the displacement is interrupted for any reason.

The annulus volume and displacement string capacity must always be compared to determine the preferred displacement direction, although the preferred direction may not always be possible if there are special assemblies in the hole. As an example, the capacity of 5" production tubing may be greater than the annulus volume, favouring conventional circulation down the string when displacing heavy brine in the hole to lighter packer fluid. However, there is a risk that the production packer could be set accidently during a conventional displacement, so a reverse circulation displacement is favoured.

Displacement Rate – High displacements rates should be used, where possible, to encourage turbulent flow since this will improve fluid displacement and reduce channelling, especially in high-angle and extended-reach wells. Once again, this might not be possible due to special assemblies in the hole, such as production packers where high flow rates risk washing out the sealing area around the packer seals.

String Rotation & Reciprocation – As with all displacements, rotating and reciprocating the displacement string will improve fluid displacement and reduce channelling, especially in high-angle and extended-reach wells, but this may not be possible if there are special assemblies in the hole.

Formate Fluids Management

Despite the fact that formate fluids are environmentally friendly, they tend to be more expensive than conventional fluids, although any additional cost is insignificant in terms of increased productivity due to minimal formation damage. As a result, every measure should be taken to minimize losses and accidental overboard discharge, which can be achieved by establishing "zero discharge" conditions on the rig. Some of these measures involve sealing the rig floor drains, sealing the mud tank dump valves, and collecting the discharge from the shale shakers in a waste skip, enabling recovery of formate fluid losses across the shaker screens.

The secret for effective formate fluid management is to establish "zero discharge" conditions on the rig while minimizing fluid movements and avoiding the use of "dedicated" formate lines for other fluids, since this will encourage formate losses, contamination and/or dilution. Silicone sealant and expandable foam should be available for sealing leaks in the surface system, and drip trays should be available for temporary recovery of formate fluid until leakages can be sealed. Vacuum pumps, squeegees and buckets, etc. should also be available for recovering residual formate volumes from tanks and lines.

It is important to minimize formate fluid losses, contamination and accidental dilution with water at all times due to the relatively high cost of the system. In order to do this, tight monitoring of fluid volumes and densities must be maintained throughout operations, from the moment the formate fluids are loaded out to the moment they are returned at the end of operations, with losses accountable at every stage. The main cause of formate contamination and losses is usually residual fluid trapped in surface lines. This is almost impossible to remove, but the volume can be minimized by gravity draining or blowing the lines through with rig air.

Transit losses are usually minimal for onshore and offshore operations if the formate fluid is sent to the rig in drums, tote tanks or ISO tanks. If bulk formate fluid is pumped into supply boat tanks for offshore operations then a transit loss is unavoidable due to residual fluid left in the delivery lines. Dedicated boat tanks and delivery lines must be clean, must be flushed with fresh water to eliminate chlorides and other contaminants, must be dry and must be visually inspected before loading bulk formate fluid. The same boat tanks should be used for back loading the formate fluid at the end of operations, and any residual formate volume in the boat tank should be recovered using a vacuum pump.

Careful consideration must be given to tank and line logistics at the rig site, to prevent potential formate contamination with the fluid system that will be displaced from the hole. Rig tanks and lines must be clean and dry after flushing through with fresh water, making sure that residual water has been gravity drained from lines and blown through with rig air, where possible. Low solids formate fluids tend to reveal leaks that are concealed by conventional, solids-laden fluids, so checks must be made to ensure there are no leaks in the surface system. The main areas where surface leaks occur are as follows:

- Dump valves and equalizer valves (seal with silicone sealant or expanding foam)
- Centrifugal mixing and transfer pump packings (repack where necessary)
- Rig tank flow-line (drop-in) gates (seal with silicone sealant or expanding foam)

Consideration should be given to the rig pump pop-off discharge lines, which should be drained where possible to minimize potential formate fluid contamination. This is rarely a problem, but the pop-offs could be activated if the pumps were started while a valve in the stand pipe manifold was still closed, sending a slug of foreign fluid in the pop-off line into the surface tanks.

Formate Fluid Recovery and Reconditioning

The cost of formate fluids increase with density and will eventually reach the point where it becomes economically viable to recover even heavily contaminated formate fluids so they can be sent for reconditioning. Polymers can be destroyed by raising formate brine pH to sufficiently high levels where they curl up and can be screened out over a shale shaker. Oil contamination can then be removed by natural separation. Chemical treatments can be made to precipitate out dissolved ions if their concentrations start to be a problem. Solids and precipitates can then be removed by filtration, using oil-adsorption cartridges if necessary to remove residual traces of oil. Density can be restored by evaporation or by adding the appropriate formate powder if density reduction is due to water dilution, or by blending with high density formate brine if the lower density fluid is already close to saturation.

Formate Testing Procedures

Density and alkalinity (buffer concentration) are the main properties that need to be monitored and maintained when running formate brines. Rheology, fluid loss and solids content also need to be monitored and maintained when running formate drill-in fluids. Although most of the API testing procedures are relevant for formate fluids, it is important to remember two procedures that are significantly different, as follows:

1. **Solids Analysis** – Never run a retort for solids analysis because crystallization might occur in the condensation chamber, causing the retort chamber to rupture with possible injury. Even if it was possible to run a retort safely, the results would be meaningless because most of the solids in the retort chamber would comprise formate salt from the brine phase. A more accurate method for solids analysis has been developed and appears later in this section.

2. **pH Measurement** – Attempts to measure pH using an undiluted formate sample may not give genuine readings, so pH measurements should be taken with pH strips or a pH meter using a 9-to-1 formate dilution with de-ionized water.

Density Measurement – Formate drill-in fluid densities are measured using pressurized mud balances and formate brines are measured using hydrometers. Hydrometers are usually accurate to 0.001 sg and formate brine sample densities are measured by filling a 250 ml measuring cylinder. In both cases, it is important to measure formate fluid sample temperatures when measuring densities, in order to correct measured densities to 15.6°C (60°F). Filtrate densities will be required for solids analysis when running formate drill-in systems and a digital densitometer, which also measures sample temperature, is recommended for this because filtrate volumes are small and the device only requires about a 3 ml sample.

Corrected Density – The measured density is always corrected to 15.6°C (60°F) in order to avoid confusion when reporting densities, since temperature affects formate density. The corrected density is calculated from the measured density and temperature using the formula as shown in figure 1 below.

This formula can be used for preparing simple density correction charts at the rig site. Fluid densities can be increased by adding higher density formate brine, or by adding formate powder if the formate brine is not close to saturation, depending on the most economical solution. Fluid densities can be reduced by adding water or lower density formate brine. Water is the obvious choice if density increases are due to evaporation, which will be noticeable at the flow line. However, water may not be suitable for reducing densities in a formate drill-in fluid because it could reduce the inhibitive properties of the fluid. Software is available for calculating bottom-hole densities based on surface and bottom-hole temperatures, and depth.

Solids Analysis – As mentioned earlier, retorts must not be run for safety reasons because formate salt crystals could plug the condensing chamber, allowing pressure to build up to dangerous levels in the retort chamber. Besides, any results would be meaningless because most of the solids would be salt from the brine phase. Solids analysis is based on the fact that fluid density is provided by the formate brine, so solids in the formate drill-in fluid comprise drilled solids and calcium carbonate bridging solids.

The LGS (low gravity solids) of any fluid can be calculated from mass and volume balance equations, to produce the formula as shown in figure 2 overleaf. Mud density is obviously measured with a mud balance and filtrate density is measured with a densitometer, which only requires a small filtrate sample from a filter press for accurate density measurements. Both densities need to be corrected to 15.6°C for the LGS calculation. With LGS in formate fluids comprising 2.4 sg Calcium Carbonate and 2.6 sg Drilled Solids, an average LGS density of 2.5 sg will give a close approximation for calculating LGS as a percentage of volume.

Once LGS has been determined, drilled solids can be calculated by subtracting the Calcium Carbonate concentration in the fluid, which can be measured using the standard API total hardness testing procedure with Calver II indicator and EDTA, as shown in figure 3 overleaf.

Calcium Carbonate Concentration – The method for measuring calcium carbonate concentrations in formate fluids is based on the standard API Total Hardness procedure for measuring Calcium and Magnesium ion concentration, as follows:

1. Put 1 ml formate drilling fluid in a 100 ml volumetric flask.
2. Add 9 ml 2N or 5N Hydrochloric Acid.
3. Agitate gently to ensure all the Calcium Carbonate has dissolved.
4. Fill the volumetric flask to the 100 ml level with de-ionized water and agitate.
5. Transfer a 10 ml sample from the volumetric flask to a smaller flask or beaker.
6. Add 0.5 ml 8N Potassium Hydroxide (KOH).
7. Check that the pH is at 14 with pH paper, adding more Potassium Hydroxide if required.
8. Add Calver 2 Indicator and titrate with EDTA (0.01 M), recording the volume of EDTA required to change from red to blue.

$Dc = (1.0057723 \times Dm) + (0.001071 \times Tm) - 0.03$ where,

Dc = Corrected Density in s.g.

Dm = Measured Density in s.g.

Tm = Measured Temperature in °C.

Figure 1: Formula for calculating the corrected density of formate brines.

$$\text{LGS (\% vol)} = \frac{(\text{mud density} - \text{filtrate density})}{(\text{LGS density} - \text{filtrate density})} \times 100$$

Figure 2: General formula for determining Low Gravity Solids as part of solids analysis calculations.

[LGS] = [Calcium Carbonate] + [Drilled Solids]
Therefore, [Drilled Solids] = [LGS] – [Calcium Carbonate]

Figure 3: Formula for determining Drilled Solids as part of solids analysis calculations.

$CaCO_3$ (g/l or kg/m^3) = 10 × EDTA (mL)

Figure 4: Titration for determining Calcium Carbonate concentration as part of solids analysis calculations.

The Calcium Carbonate concentration can now be calculated from this titration, as shown in figure 4 above.

It is worth noting that the API Total Hardness procedure is only used for measuring the Calcium Carbonate bridging and weighting material concentration. The test is meaningless for measuring Total Hardness in a buffered formate fluid because Calcium and Magnesium ions in solution will precipitate out as Calcium and Magnesium Carbonate due to Sodium or Potassium Carbonate buffering in the formate fluid.

Calcium Carbonate Bridging Treatments – Graded Calcium Carbonate is used for improving filter cake quality, improving fluid loss control and reducing seepage losses. Very fine shale shaker screens can be fitted when running formate drill-in systems because rheologies and ECDs are lower, with hole cleaning achieved by higher annular velocities. As a result, formate drill-in fluids require regular treatments with coarser grades of Calcium Carbonate in order to maintain PSD requirements. Allowances must be made for the density increase when using Calcium Carbonate as a bridging agent.

Polymer Treatments – Polymers in formate fluids require considerable shear for effective yield and this usually only happens when the fluid is sheared at the bit. As a result, viscosity may appear to be on the low side and fluid loss control may appear to be on the high side when formate fluids are freshly mixed. However, these properties will improve during the first few circulations in the hole, so additional treatments should be delayed for a few circulations in order to avoid the potential for over treating the system.

Operational Experiences

Pressure Testing – There have been occasional problems when pressure testing lines with the cement unit, but this has been traced to the quality of the stick grease used when dressing high pressure chiksan valves. High quality stick grease has rarely been an issue, but the use of general purpose stick grease can be a false economy due to lost rig time with leaking valves while trying to pressure test lines.

Erroneous Gas Alarms – The flow line H_2S gas alarms have occasionally been activated for no apparent reason at bottoms-up after a round trip with formate fluid in the hole. Some H_2S alarms are sensitive to hydrogen gas, which may be generated as a result of minor formate decomposition in high temperature wells that is sufficient to activate the highly-sensitive H_2S alarms for a short period.

Foaming – This can occur when high concentration formate brines fall into the active or trip tanks from the flow line while circulating, making it difficult to monitor these volumes. The severity of foaming can be reduced by maintaining higher formate fluid levels in these tanks to reduce the height of the flow line drop. Defoamers can also be effective in controlling the problem, but checks must be made to make sure there are no compatibility issues with the formate fluid.

Drill-In, Completion and Workover Fluids/Brines

Section 7

DRILLING FLUIDS MANUAL

Contents

Introduction

The fluids used in wellbore operations are usually solids-free brines that need to provide the following functions:

- Minimize formation damage
- Provide hydrostatic well control
- Protect wellbore tubulars from corrosion
- Ensure compatibility with elastomers

The interaction between wellbore tubulars, fluids and fluid additives is complex and dependent on wellbore conditions (i.e. temperature and pressure). Chloride-based brines may encourage chloride stress corrosion cracking in wellbore tubulars under certain conditions. Calcium-based brines may result in formation damage if they mix with reservoir fluids (e.g. connate water) and form precipitates.

Corrosion Inhibitors and Oxygen Scavengers containing sulphur compounds may be effective for most applications, but they may actually encourage corrosion in high temperature wells because the products may break down to form sulphides, resulting in sulphide stress cracking of tubulars. All products used in wellbore fluids should be tested with tubulars under simulated wellbore conditions if there is uncertainty concerning compatibility. This is discussed in greater detail in the Corrosion Control section.

Formation Damage

A well that flows according to calculated expectations is said to have zero skin factor. If flow is higher than expected then the well has a negative skin factor and if flow is lower than expected then the well has a positive skin factor, which indicates flow restriction due to formation damage. The reduction in reservoir productivity due to formation damage is mainly due to fluids that are in contact with the production zone during the drilling and completion phases.

Solids in the drilling fluid (e.g. weighting materials, polymers, drilled solids, etc.) can plug pores in the reservoir, and wellbore fluids can form precipitates with connate water (i.e. the fluid in the formation pores) or form emulsions with hydrocarbons. Formation pores may also be lined with clays that can hydrate or become dislodged following fluid invasion. All of these factors can reduce the pore size or even plug the pores, resulting in a reduction in reservoir permeability. The best way to minimize formation damage when drilling the production zone is to minimize fluid and solids invasion by using a drill-in fluid.

Drill-In Fluids

A drill-in fluid functions in the same way as a regular drilling fluid, but it is designed to minimize formation damage when drilling production zones, since this could have a detrimental effect on well productivity. This is achieved by effective bridging of the pore throats, which minimizes fluid and solids invasion into the reservoir formation. As a result, there is less chance of forming precipitates or emulsions with pore fluids, and less chance of hydrating or dislodging clays that may be lining the pores.

The EMEC ULIF system (Ultra Low Invasion Fluid) is an effective drill-in fluid because it forms a very low permeability filter cake that minimizes fluid and solids invasion into the reservoir. The fluid is formulated with non-damaging additives, using calcium carbonate instead of Barite as a weighting material since it can be acidized if it lodges in the reservoir pores. Sized calcium carbonate is also used as bridging materials. The filter cake lifts off when the well is flowed, and any residual filter cake can be removed with an acid treatment since it largely comprises calcium carbonate bridging and weighting materials.

Completion Fluids

Once the reservoir has been drilled, a string of liner is usually run and cemented in place. The drill-in fluid is then displaced to completion fluid, which is usually a solids-free brine at a suitable density for well control. The displacement is performed using a series of pills and spacers to maximize solids removal and clean the well, which is covered in another section. It is important to remove settled solids during the displacement to completion brine, and to filter the brine thoroughly, as residual solids in the hole could cause problems while running the production assembly (e.g. prevent the production packer from sealing).

A selection of brines are used in completion fluids, the most common being the halide brines due to their low cost. Brines are sometimes blended to obtain required densities. The main brines and their densities are listed below:

Sodium Chloride	Up to 10.0 ppg (1.20 sg)
Calcium Chloride	Up to 11.7 ppg (1.40 sg)
Potassium Chloride	Up to 9.7 ppg (1.16 sg)
Sodium Bromide	Up to 12.7 ppg (1.52 sg)
Calcium Bromide	Up to 15.6 ppg (1.87 sg)
Zinc Bromide	Up to 19.2 ppg (2.30 sg)
Sodium Formate	Up to 11.1 ppg (1.33 sg)
Potassium Formate	Up to 13.2 ppg (1.59 sg)
Cesium Formate	Up to 19.2 ppg (2.30 sg)

The traditional high density brines (especially zinc bromide) are extremely hazardous and require special handling procedures. However, these are generally being replaced by high density formate brines, especially for HPHT wells using corrosion resistant alloys, because they are environmentally acceptable and do not require special handling procedures. The higher cost of formate fluids is outweighed by the fact that they are non-damaging to reservoir formations and provide natural corrosion inhibition for wellbore tubulars, as covered in the section on formate fluids.

Packer Fluids

After running the production tubing, the annulus behind the production string (the "A" annulus") is displaced to packer fluid. The packer fluid is designed to protect the casing and production tubing from corrosion and is usually a solids-free brine. The hydrostatic pressure of the packer fluid in the annulus also reduces the differential pressure across the production packer assembly, and protects the casing string from collapse by reducing the differential pressure between the formation and the inside of the casing. The packer fluid also needs to be compatible with reservoir fluids to prevent formation damage.

Brines are the fluid of choice for packer fluids because they do not contain solids, which would settle out over time and make it more difficult to recover wellbore tubulars during subsequent workover activities. Corrosion control is an important requirement for packer fluids because they have to protect down-hole tubulars during the production life of the well. As a result, most packer fluid brines are treated with three types of chemicals to prevent or minimize tubular corrosion, as follows:

1. Corrosion Inhibitor
2. Biocide
3. Oxygen Scavenger

It is important to ensure that these products are added at the correct stage of the packer fluid displacement and mixed at the programmed concentrations. The biocide and corrosion inhibitor should be added to the packer fluid first. The tank(s) should then be left static for as long as possible, without circulation or agitation, to allow air bubbles to escape. The oxygen scavenger is then added to the suction tank or injected into the suction line just before it is required, so that it does not get depleted by scavenging oxygen from the atmosphere.

The mixing hopper must not be used when mixing oxygen scavenger because it will aerate the packer fluid and the scavenger will then be depleted on surface before it is pumped down hole. The oxygen scavenger should be added from the top of the suction tank a few minutes before the packer fluid is about to be pumped down hole, using the agitator(s) for the duration that it takes to mix the scavenger and switching off immediately after mixing. It may be necessary to repeat the oxygen scavenger treatment if operations are delayed for a significant period of time.

Workover Fluids

Workovers are performed on wells that have previously been completed when it is necessary to improve reservoir productivity or to replace wellbore components that have failed. Workover fluids are similar to completion fluids, but they relate to workover operations. As with completion brines, it is important to ensure that the hole is kept as clean as possible by removing any build-up of settled solids while displacing the hole to the workover fluid, and to make sure that workover brines are filtered thoroughly so that they are always clean and free of solids before they are pumped down hole.

Brine Filtration

The priority in oilfield filtration is to prevent reservoir damage, since contaminants (e.g. clay and rust particles) can block the pores of the production zone during completions, resulting in a reduction in well productivity. Two types of brine filtration units are used for this purpose:

- Cartridge Filtration Unit
- Diatomaceous Earth (DE) Filtration Unit

Cartridge Filtration Unit

This type of unit should only be used when the brine is relatively clean, otherwise the filter cartridges will become plugged fairly quickly, resulting in high cartridge consumption and potential delays to rig operations. The filtration unit usually has two cartridge pods that can hold several filter cartridges. The unit can be operated in series, with coarse cartridges in the first pod and finer cartridges in the second pod, or operated alternately, filtering through one pod while replacing plugged cartridges in the other pod.

The filter cartridges are available in a range of sizes, the most common for oilfield use being 25, 10 and 2 microns, which refers to the size of the filter openings. Most filter cartridge sizes are also available with nominal or absolute size ratings. A 2-micron nominal filter cartridge has openings around 2-microns in size, so some smaller particles will be removed and some larger particles will pass through. A 2-micron absolute filter cartridge is a higher quality product because it will not allow any particles larger than 2-microns to pass through. Oil adsorption filter cartridges are also available for removing dispersed oil, grease and hydrocarbons.

DE Filter Press

This type of unit is used for filtering very dirty brine because it can process much larger volumes before it gets plugged with solids and has to be cleaned. The unit is dressed with Diatomaceous Earth (DE), which is a naturally occurring filtration material that is supplied in sacks. These units are more complicated to run than the cartridge units, and take longer to clean once they become plugged, which may involve operational delays. Brine filtered through the DE Filter Press is usually passed through the cartridge filter unit dressed with 2-micron absolute cartridges before returning to the active tanks.

Filtration Procedures

The filtration units are hooked up to the rig tanks using hoses. The feed hose is connected at the mix pump manifold and the return hose is connected to the mix pump return line or discharges into the designated tank. The centrifugal mix pump provides feed to the filtration units, which prevents damage to hoses and equipment when these units are plugged with solids. The flow rate through the filtration units will gradually decrease and the feed pressure will gradually increase as they plug with solids, eventually reaching the point where they need to be cleaned and redressed.

Dirty brine should always be filtered into a clean tank. When filtering brine from the wellbore, dirty brine returns should be sent to one tank and then filtered across to the suction tank, which should be cleaned to “brine standard”. There is no benefit in returning filtered brine to the same tank because the brine will never become clean. Any brine that is contaminated with hivis pills should be diverted to a separate tank because polymers will soon plug the filter units.

Brine Cleanliness

Two methods are used for determining brine cleanliness:

- Turbidity Meter
- Centrifuge for Solids Measurement

Turbidity Meter

The turbidity of a fluid describes the clarity or cloudiness of a fluid due to suspended colloidal particles and it is measured in NTUs (Nephelometric Turbidity Units). The turbidity meter works by shining a beam of light through a sample of brine. If the brine is absolutely clean then the beam of light will pass through the sample and will not be detected by a light sensor mounted perpendicular to the light source. If the brine contains a suspension of fine solids then some of the light will be reflected off the particles and this will be detected by the light sensor, which converts it into a reading in NTUs.

The turbidity meter is battery-powered and is supplied with a set of three reference samples that are used for calibrating the turbidity meter before use. A set of empty glass bottles are then filled with brine samples when taking turbidity measurements. Care is required to make sure that the outside surface of the glass bottle is completely clean and dry once it has been filled with brine, otherwise turbidity readings could be affected. The sample bottle should also be left for a few seconds to allow air bubbles to escape before taking a turbidity reading.

Centrifuge for Solids Measurement

A laboratory centrifuge or a hand-crank centrifuge with 100 ml graduated glass centrifuge tubes is used for measuring the actual solids in a sample of brine from the hole. The glass centrifuge tubes can measure solids to the nearest 0.25%, although solids can be estimated down to about 0.1%. This is the only real method for determining brine cleanliness because the turbidity meter can sometimes give false readings due to other factors (microscopic air bubbles or brine discoloration).

The completion or workover program will normally specify brine cleanliness requirements either as a turbidity reading, percentage solids, or both. Mud Engineers often prepare a chart that records time, pump strokes, volume pumped, brine turbidity and solids going in the hole, and brine turbidity and solids coming out of the hole. This provides useful information when reviewing the effectiveness of brine filtration and wellbore cleanliness.

The aim of filtration is to remove solids from the hole, which could prevent the production tubing assemblies from sealing and safely isolating the reservoir. A build up of solids could also provide conditions that could encourage corrosion and premature failure of wellbore tubulars. The solids may appear to be in suspension in the brine, but they will eventually settle, so it is always worth calculating potential settled solids while filtering brine. If the hole contains 500 bbls brine and solids is measured at 0.25%, then the hole will contain 1¼ bbls solids and this could occupy several feet or meters of hole, which could interfere with successful running of completion or production assemblies.

Corrosion Control

Section 8

DRILLING FLUIDS MANUAL

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Contents

Introduction

Corrosion is the degradation of a metal due to chemical or electro-chemical reactions with the surrounding environment, usually involving oxygen as an oxidant. It is a diffusion process that occurs on exposed surfaces, either extending across the entire surface of a metal (as with rust), or concentrated locally to form a pit or crack. Whichever process takes place, corrosion rates are generally accelerated at elevated temperatures and pressures. Corrosion inhibition is essential for protecting production tubing for the life of the reservoir, but it is also used for protecting drill pipe and casing while drilling.

The control of corrosion is important in well construction because wellbore tubulars are exposed to harsh environmental conditions that include high temperatures, high pressures and the presence of acidic gases. Well construction requires the use of high strength production tubulars to resist mechanical erosion caused by high velocity production fluids that may contain abrasive particles (e.g. sand). Unfortunately, the benefits of high strength are often compromised by the fact that these tubulars are more vulnerable to some of the corrosion mechanisms described in this section.

Corrosion in down-hole tubulars can occur as a result of contact with liquids (especially halide brines); from acidic reservoir gases (e.g. CO_2 and H_2S); and from oxygen that is unintentionally circulated down-hole in aerated fluids. It is worth noting that even if the reservoir does not contain H_2S gas, it can still be produced through bacterial activity and through the degradation of chemical additives containing sulphur. Therefore, sulphur-based corrosion inhibitors (e.g. sulphites and thiocyanates) and chemical additives may not be suitable for certain high temperature wells.

Factors Affecting Corrosion

Wellbore tubulars are subjected to a wide range of environments and variables that may affect corrosion resistance and corrosion rates, as follows:

1. Tubular Material
2. Wellbore Fluid
3. Fluid pH
4. Dissolved Oxygen
5. Dissolved Carbon Dioxide
6. Dissolved Hydrogen Sulphide
7. Chlorides
8. Wellbore Temperature

Tubular Material

Steel tubulars are manufactured for high strength in harsh working environments, but this makes them vulnerable to certain corrosion mechanisms when subjected to high stress loads, which is discussed later in this section.

Wellbore Fluid

The required density can usually be provided by two or more different packer fluids. The choice of fluid will depend on the steel tubulars and other factors because some fluids may be more corrosive than others under certain wellbore conditions. Corrosion due to dissolved oxygen (see below) is a serious issue, but in brine systems the solubility of oxygen decreases as the salt concentration (i.e. density) increases.

Fluid pH

Corrosion can be controlled by maintaining a high pH, since corrosion rate increases as the pH decreases. However, the pH of a fluid is a measure of the hydrogen ion concentration, so certain corrosion mechanisms may still occur in alkaline fluids due to hydrogen ion diffusion into steel tubulars (see Hydrogen Embrittlement below).

Dissolved Oxygen

The presence of dissolved oxygen in the wellbore at high temperatures and pressures is a major cause of corrosion that can still occur in alkaline fluids.

Dissolved Carbon Dioxide

Carbon Dioxide is an acidic gas that will lower the pH of a fluid, with a resultant increase in corrosion rates. The presence of dissolved carbon dioxide produces carbonic acid, which can result in aggressive corrosion rates when lower grade steel tubulars are used.

Dissolved Hydrogen Sulphide

Hydrogen Sulphide is an acidic gas that will lower the pH of a fluid, with a resultant increase in corrosion rates. The presence of dissolved hydrogen sulphide increases hydrogen ion diffusion into steel tubulars by preventing the ions coming together to produce hydrogen gas (see Sulphide Stress Cracking below).

Chlorides

The presence of chlorides is undesirable because they break down surface films that usually protect steel tubulars from further corrosion, resulting in increased localized corrosion (see Chloride Stress Corrosion Cracking below). Chloride-based packer fluids should be avoided where possible.

Wellbore Temperature

High temperatures will usually encourage increased corrosion rates.

Corrosion Mechanisms

Several corrosion mechanisms exist and two or more may occur at the same time according to the surrounding environment. The main corrosion mechanisms are as follows:

1. Oxygen Corrosion
2. Galvanic Corrosion
3. Acidic Gas Corrosion
4. Pitting Corrosion
5. Crevice Corrosion
6. Stress Corrosion Cracking (SCC)
7. Hydrogen Embrittlement

Oxygen Corrosion

The presence of dissolved oxygen in the wellbore at high temperatures and pressures is a major cause of corrosion. Rust, which is an electro-chemical reaction with the oxygen in the air and water, is the most common form of corrosion that is seen in everyday life. The iron atoms on the steel surface react with oxygen and water to form a layer of rust (iron oxide) that prevents further corrosion of the steel surface. However, corrosion will resume if the layer of rust is removed or eroded.

Galvanic Corrosion

Metals have an electrochemical potential based on their electronic structure. A galvanic cell is formed when two metals with different electrochemical potentials are connected to each other by an electrically conductive path and by an electrolytic path (e.g. seawater or other brine system). The less noble metal slowly dissolves into the electrolyte as an electric current is produced by the electrochemical potential difference between the two metals.

Galvanic corrosion of steel tubulars is always a concern because a range of materials are used in the oil industry and brines provide an ideal electrolytic path, so an unintentional galvanic cell could be created. Galvanic corrosion between two different metals can be prevented by removing the electrically conductive path through the use of effective insulation (e.g. insulated mountings), and by keeping areas dry to prevent an electrolytic path.

Acidic Gas Corrosion

The solubility of acidic formation gases in water (e.g. CO_2 and H_2S) creates problems with down-hole tubulars because the acidified water contains hydrogen ions that can diffuse into the steel tubulars, causing Hydrogen Embrittlement (see below). The acidic water also reacts with the iron atoms on the steel surface to form an iron salt (mainly Iron Carbonate or Iron Sulphate), with the release of hydrogen that is free to diffuse into the steel. The chemical reactions are shown in figure 1 below.

The presence of carbon dioxide and hydrogen sulphide can lead to severe pitting on the surface of tubulars, as well as crack initiation and propagation in stressed components. The hydrogen sulphide precipitate forms a black scale on the surface of tubulars, which can lead to sulphide stress cracking in high strength steels, the mechanism of which is discussed later. Corrosion due to acidic gases can be controlled by maintaining fluid pH at around 10.0 and by using filming amine corrosion inhibitors. An H_2S scavenger should also be used if H_2S is present.

$$CO_2 + H_2O \rightarrow H_2CO_3 \text{ (Carbonic Acid)} \rightarrow 2H^+ + CO_3^{2-}$$
$$Fe^{2+} + H_2CO_3 \rightarrow FeCO_3 \text{ (Iron Carbonate salt scale)} + H_2$$

$$H_2S + 2H_2O + O_2 \rightarrow H_2SO_4 + 2H_2 \rightarrow 2H^+ + SO_4^{2-} + 4H^+$$
$$Fe^{2+} + H_2SO_4 \rightarrow FeSO_4 \text{ (Iron Sulphate salt scale)} + H^+$$

Figure 1

Pitting Corrosion

This type of corrosion is very localized and can result from surface defects (e.g. scratches, manufacturing imperfection or defective protective coating), leading to the development of small pits or holes on the surface of the metal, which penetrate and weaken the metal structure. The pits are often difficult to see because they are small and usually hidden by surface corrosion or corrosion products.

The situation is aggravated by the presence of chloride ions, which are attracted to the pits and holes that are positively-charged with metal ions. Iron hydroxide is formed as a result of the corrosion process with water, leaving excess H^+ ions that make the pits slightly acidic, resulting in accelerated corrosion rates within the metal structure, while the metal surface shows little sign of damage.

Crevice Corrosion

Like pitting corrosion, this type of corrosion is very localized but it occurs in small crevices where fluid is trapped and isolated from the rest of the fluid (e.g. under gaskets, washers, threads, etc.). Crevice corrosion occurs when the fluid in the crevice undergoes chemical changes (e.g. oxygen starvation), which effectively creates a galvanic cell due to the differential concentration between the fluid in the crevice and the rest of the fluid. The fluid in the crevice can become very acidic and destroy the protective layer on the metal surface, leading to aggressive corrosion.

Stress Corrosion Cracking (SCC)

This type of corrosion occurs when a metal is subjected to stress (e.g. tensile load) in a corrosive environment, particularly when chlorides are present at elevated temperatures (e.g. chloride brine systems). Residual stresses in a metal alloy are usually removed with heat treatments during the manufacturing and fabrication process, but the material will still be subjected to other stresses in the working environment (e.g. tensile stress in down-hole tubulars).

SCC produces localized corrosion, with the initiation of cracks in pits or crevices on the metal surface. The tips of these cracks have a very small radius, so they act as stress points with very high stress concentrations, resulting in crack growth and propagation that follows or cuts across the grain boundaries in the metal alloy.

The choice of alloy components is critical for SCC resistance because the microstructure of the resultant metal alloy will affect the crack path and propagation rate.

Austenitic stainless steels (e.g. 304 and 316) are not very resistant to SCC and have been known to fail at relatively low temperatures when exposed to fluids containing relatively low chloride concentrations. For this reason, austenitic stainless steels are not suitable for use in down-hole tubulars above 50°C when chlorides are present. However, carbon steels are resistant to SCC and the presence of nickel in metal alloys improves resistance to SCC, so austenitic stainless steels with high nickel content are also resistant to SCC.

Hydrogen Embrittlement

This is also known as Hydrogen Induced Cracking (HIC) and occurs when metals (especially high-strength steels or alloys) are exposed to hydrogen at elevated temperatures. Hydrogen atoms on the surface of the steel tubular will either combine with other hydrogen atoms to form hydrogen molecules on the steel surface, or they will diffuse into the metal microstructure and combine with other hydrogen atoms to form hydrogen molecules in the steel structure.

The hydrogen molecules that form within the steel structure collect in crevices and the resultant expansion as hydrogen atoms form hydrogen molecules creates localised pressure that may be high enough to initiate cracks in the polycrystalline structure. If the steel tubular is already being subjected to tensile stress in the wellbore, and if the amount of hydrogen within the steel structure continues to build up to a critical level, the tensile strength of the material may eventually be exceeded, leading to brittle failure.

Hydrogen may already be present in the metal from the manufacturing process, or it may be introduced during welding or electroplating activities. However, alloy products that are susceptible to hydrogen embrittlement are usually heat treated to drive out the entrapped hydrogen. Hydrogen can also be absorbed by metals and alloys whenever there is a source of hydrogen atoms, which can be produced by chemical reactions or as a by-product of other corrosion processes.

The priority during well construction is to protect down-hole tubulars by minimizing the presence of hydrogen, which can be generated during thermal degradation of chemical additives in the drilling fluid or completion brine. Hydrogen can also be present in the reservoir in the form of a gas like hydrogen sulphide, which reacts with iron to form a layer of Iron Sulphide on the metal surface, while the hydrogen atoms diffuse into the metal structure (Although hydrogen is involved, this particular process is better known as Sulphide Stress Cracking and is discussed below).

Hydrogen Embrittlement is often confused with Stress Corrosion Cracking, but the mechanism is completely different since hydrogen embrittlement is caused by the diffusion of hydrogen atoms into the metal structure. Hydrogen Embrittlement can obviously be prevented by avoiding sources of hydrogen during manufacture and while in the wellbore, and by controlling stress levels while in service. The potential for Hydrogen Embrittlement also decreases with increasing temperature.

Mild steels tend to blister from the resultant expansion as hydrogen molecules are formed, which is often seen on rusty steel. High-strength steels have a much finer grain microstructure, and cracks will initiate and propagate, resulting in a reduction in ductility and strength. The reduction in cross-section area will eventually lead to premature failure at stresses below the expected yield stress of the material. Metals and alloys that are most vulnerable to hydrogen embrittlement are high-strength steels, low-alloy steels, nickel and titanium alloys.

Sulphide Stress Cracking (SSC)

In this form of corrosion, the steel reacts with hydrogen sulphide to produce iron sulphide and hydrogen atoms on the surface of the metal. The hydrogen atoms usually pair up to form hydrogen gas on the surface of the metal or diffuse into the metal structure. However, sulphides act as a “poison” by preventing the hydrogen atoms from combining to form hydrogen gas, which means that more hydrogen atoms are available to diffuse into the metal.

Sulphide Stress Cracking behaves in a similar way to Stress Corrosion Cracking because corrosion rates are more aggressive if the steel tubular is under tensile stress, especially if the wellbore fluid contains chlorides. Sulphide Stress Cracking also behaves in a similar way to Hydrogen Embrittlement, except that hydrogen diffusion through the metal structure is enhanced by sulphide-poisoning that stops the hydrogen atoms coming together to form hydrogen gas.

Sulphur-Reducing Bacteria

These micro-organisms live in extreme anaerobic environments and can survive on nutrients that are present in wellbore fluids. They break down chemical additives containing sulphur (e.g. thiocyanate corrosion inhibitors or sulphates), with the production of hydrogen sulphide as a by-product. Biocides are usually effective in controlling the growth of these bacteria, along with higher pH, but if this is not the case then the production of H2S could have a significant effect on tubular corrosion.

Steel Tubular Materials

Tubulars have to be resistant to abrasion and corrosion while working in hostile environments, in order to avoid high corrosion rates that could lead to premature failure of the tubular. The choice of steel used in oilfield tubulars (e.g. carbon steel, stainless steel, corrosion resistant alloys, etc.) is generally based on acceptable corrosion rates that will maintain tubular integrity for the working life of the well, determined by the down-hole conditions to which they will be subjected.

Steels are classified according to carbon content, or the content of other metals that form the alloy. Carbon Steels contain iron, carbon, manganese (<1.65%), copper (<0.6%) and small amounts of silicon, sulphur and phosphorus, and are sub-divided as follows:

● Low-Carbon Steels	<0.30% Carbon
● Medium-Carbon Steels	0.30% to 0.45% Carbon
● High-Carbon Steels	0.45% to 0.75% Carbon
● Very-High-Carbon Steels	0.75% to 1.50% Carbon

Low-Carbon Steel, which is often called mild steel, is ductile (flexible) and can be machined or welded. Although the tensile strength of steel increases as the carbon content increases, the ductility decreases and the finer-grained material is vulnerable to brittle failure. The use of high strength tubular goods in wellbore constructions requires finer-grained steels that have lower ductility. This exposes the tubulars to higher risk of brittle failure that may be accelerated by corrosion.

Iron is alloyed with other metals to improve certain properties, and any steel that contains more than 1.65% manganese or 0.60% copper is classed as a steel alloy. The main alloying metals are chromium, nickel, manganese, molybdenum, nickel and vanadium. Chromium improves corrosion resistance. Before discussing some of the steels used in wellbore tubulars, it is worth looking at the structure of metals to get a better understanding of how steels get their properties. Metals have a polycrystalline structure. When molten metal cools down, the metal atoms form a regular crystal lattice structure that grows as other atoms align themselves in a similar pattern to create a grain. Similar grains are formed and grow throughout the metal, but they all have random orientation.

If molten metal is cooled down slowly, then the atoms have time to rearrange themselves and form larger grains. If molten metal is cooled down quickly, then the atoms will have less time to rearrange themselves and grain size will be smaller. Steel strength is determined by grain size, with steel strength increasing as grain size gets smaller. Heat treatments are therefore designed around grain size to obtain the required steel properties. Unfortunately, steel ductility (flexibility) decreases as grain size gets smaller, which is undesirable.

Carbon Steel (Mild Steel)

Carbon steel tubulars are relatively inexpensive and are compatible with most brines for low temperature wells, but they are not suitable for high temperature wells as corrosion rates can be high, leading to premature failure. They are also not very resistant to erosion caused by high production rates, especially if the fluid contains abrasive particles (e.g. sand). Effective corrosion inhibitor treatments must be made if carbon steel tubulars are used in corrosive environments (e.g. acidic reservoir gases). The presence of 0.5% Chromium in carbon steels significantly reduces the tendency for localized CO_2 corrosion.

Stainless Steel

Stainless steel is an alloy of iron containing a minimum of 10.5% Chromium. The austenitic stainless steel tubulars (e.g. 304L and 306L) are more expensive than carbon steel tubulars, but they offer improved resistance to corrosion for a wide range of applications, including sulphide stress cracking. However, they are still vulnerable at elevated temperatures and other alloying elements are usually added to enhance their properties.

Low Carbon 13Cr Stainless Steel

The presence of chromium in stainless steels improves the corrosion resistance of the material because the protective film produced by corrosion inhibitors reforms more easily with increasing chromium content. Tubulars made from 13Cr stainless steel (13% Chromium with reduced carbon content) have better corrosion resistance to CO_2 and H_2S than low alloy steels in HPHT wells, including resistance to sulphide stress corrosion (SSC). However, they are still vulnerable to localized corrosion.

At low temperatures, 13Cr offers corrosion resistance for chlorides below 6,000 ppm. However, 13Cr is not a suitable material when H_2S is present with chlorides at low temperatures because it is vulnerable to sulphide stress cracking resulting from increased hydrogen diffusion caused by sulphide poisoning. Sulphide stress cracking does not appear to occur with 13Cr at elevated temperatures (100°C).

The addition of other alloying elements such as Copper, Molybdenum and Nickel can improve corrosion resistance at elevated temperatures, which makes them suitable for HPHT wells if a chloride-free and bromide-free completion fluid is used. Copper improves corrosion resistance in certain corrosive environments; Molybdenum increases pitting and crevice corrosion resistance of stainless steels; and Nickel extends the working range of stainless steels.

Low Carbon 25Cr Stainless Steel

Tubulars made from 25Cr stainless steel have improved resistance to localized corrosion than 13Cr because the protective film produced by corrosion inhibitors is more effective with increasing Chromium content. However, 25Cr tubing is more vulnerable to stress corrosion cracking than 13Cr tubing, although this is not an issue if the packer fluid is free of chlorides.

Corrosion Resistant Alloys (CRAs)

CRA tubulars are extremely expensive, but they provide better corrosion resistance than other materials for acidic HPHT environments. However, CRA tubulars are not suitable for use with halide fluids in acidic HPHT environments as premature failure could occur from stress corrosion cracking. There are instances where CRA tubulars have suffered premature failure due to stress corrosion cracking within days of installation, which is why compatibility tests are carried out by specialist laboratories at simulated down-hole temperatures and pressures to confirm corrosion inhibitor compatibility with wellbore tubulars.

Corrosion Inhibition

Corrosion inhibition in completion and packer fluids is usually provided by the following products:-

- Biocide
- Oxygen Scavenger
- Corrosion Inhibitor

It is important to ensure that these products are added at the correct stage of the packer fluid displacement and mixed at the programmed concentrations. Oxygen scavenger must be added to the suction tank or injected into the suction line just before it is required, otherwise surface oxygen will be scavenged. Oxygen scavengers should be mixed using the tank agitators, which should be switched off immediately after mixing (The mixing hopper must not be used when mixing oxygen scavenger because this will aerate the fluid and the product will not be effective in the wellbore).

Biocides

Bacteria, including sulphur-reducing bacteria mentioned earlier, can thrive in wellbore environments, surviving on nutrients that are present in wellbore fluids. Bacteria break down chemical additives (e.g. polymers) into by-products that can encourage corrosion, so it is important to treat the fluid with a biocide to eliminate this potential problem. However, it is also important to check that the biocide is compatible with the choice of tubular steel because the product could encourage corrosion under certain wellbore conditions (e.g. product degradation at high temperatures).

Oxygen Scavengers

Corrosion due to the presence of dissolved oxygen can be minimized in down-hole tubulars by using an oxygen scavenger in the form of sodium sulphite powder (OSP) or ammonium bisulphite liquid (OSL). Sulphite ions (SO_3^-) react with dissolved oxygen in the wellbore to form sulphate ions (SO_4^{2-}). The sulphite concentration in the returns is measured using a sulphite test kit and is usually maintained at around 150 mg/l to ensure the presence of excess sulphite in the wellbore.

The required concentration of sodium sulphite powder is added directly into the suction tank(s) just before pumping down-hole, using the agitators for mixing since the hoppers will aerate the fluid and consume the sodium sulphite before reaching the wellbore, where it is needed (the agitator should be switched off immediately after mixing). An alternative method of delivery is to mix sodium sulphite in water at a concentration of 1 lb per gallon which, like the ammonium bisulphite liquid, is then injected into the mud pump suction line while circulating using a chemical injection pump.

Corrosion Inhibitors

As mentioned previously, corrosion is a diffusion process that occurs on exposed metal surfaces. The function of a corrosion inhibitor is to reduce corrosion by creating a barrier in the form of a protective film that prevents contact between steel tubulars and wellbore fluids. The thin protective film is in the form of an iron carbonate precipitate that is adsorbed on the surface of the tubulars.

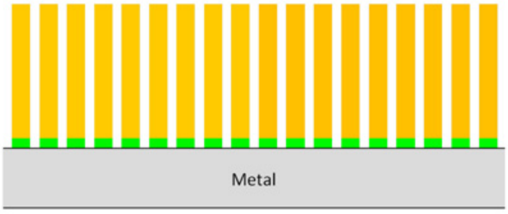
The adsorption of corrosion-inhibiting molecules is stronger on unprotected tubular surfaces than on areas already covered by corrosion-inhibiting molecules, which ensures maximum coverage of corrosion inhibitor. However, the protective iron carbonate film takes time to form and requires a high concentration of corrosion inhibitor initially, with lower maintenance concentrations once the protective layer has formed. The process is temperature-dependent and works faster at elevated temperatures.

The corrosion-inhibiting molecules continuously adsorb onto the metal surface and return to the wellbore fluid, so concentrations must be adequate to ensure that the protective film is maintained and continuously replaced. The adsorption process means that the protective film is effective at low flow rates, but could break down at high flow rates, exposing the tubulars to corrosion. Two types most commonly used corrosion inhibitors in the oil industry are as follows:

- Film-forming amines
- Inorganic Thiocyanates

Film-Forming Amines

These are also known as fatty amines or polyamines. Amines have one or more alkyl groups attached to one or more nitrogen groups. The alkyl group is hydrophobic and the nitrogen group is hydrophilic. The polar amine molecules are adsorbed on the metal surface, forming a single molecular layer or film with the nitrogen group in contact with the metal and the alkyl group providing a hydrophobic barrier for corrosion inhibition, as shown in the following diagram:



Adsorption of nitrogen groups onto a metal surface in a film-forming amine

Inorganic Thiocyanates

The family of thiocyanate inhibitors comprise sodium thiocyanate (NaSCN), potassium thiocyanate (KSCN) and ammonium thiocyanate (NH_4SCN). They were developed for use with high density zinc bromide brines as they are more effective than film-forming amine corrosion inhibitors. However, thiocyanates contain sulphur and hydrogen sulphide is produced when thiocyanates undergo thermal degradation at elevated temperatures.

The presence of hydrogen sulphide is not a problem with zinc bromide packer fluids because the zinc ions scavenge the sulphide ions to precipitate out zinc sulphide. Thiocyanate corrosion inhibitors are also suitable and effective for carbon and low alloy steels at elevated temperatures. However, the use of thiocyanate corrosion inhibitors has been known to cause catastrophic failure of high-strength wellbore tubulars in non-zinc packer fluids at elevated temperatures due to sulphide stress cracking.

The following factors must always be considered when selecting corrosion inhibitors for high-strength wellbore tubulars:

1. Environmentally acceptable (i.e. no heavy metals)
2. Stability at wellbore temperatures
3. Compatibility with wellbore tubulars
4. Compatibility with other chemical additives
5. Non-damaging to the reservoir (i.e. no precipitates)

Corrosion Rings

The corrosive effects of a drilling fluid can be quantified using a corrosion ring, which is placed in one of the drill pipe tool joints while running in the hole. The corrosion ring remains in the drill string for a reasonable period of time (at least two days because initial corrosion rates are usually relatively high), and is recovered a few days later when the drill string is pulled out of the hole. The corrosion rings are manufactured from similar steel as drill pipe, so corrosion rates will be similar.

The corrosion rate, measured as the loss of wall thickness in mm/year, can be calculated from the initial and final corrosion ring weights, and the number of hours in the drill string, using a formula that is supplied by the corrosion ring manufacturer. Corrosion rings are manufactured for each size of drill pipe, with internal diameters matching those of the drill pipe so that flow across the corrosion ring is representative of flow in the drill string. Each corrosion ring has a unique reference number and is pre-weighed by the manufacturers.

Each corrosion ring is supplied in a sealed corrosion-inhibiting wrapper and care is required to minimize other sources of corrosion before or after use. Clean gloves must be used when handling the corrosion ring and placing it in the drill pipe tool joint box, which must be clean to prevent damaging the corrosion ring. When recovering the corrosion ring a few days later, it must be washed and dried thoroughly to prevent further corrosion, and then sent for analysis in the original corrosion-inhibiting wrapper.

Corrosion rings are useful for monitoring the effectiveness of corrosion inhibitor treatments when drilling formations that contain acidic gases. However, the corrosion rate calculation assumes that the reduction in corrosion ring weight is entirely due to corrosion, but it may also be due to erosion if the drilling fluid contains significant amounts of abrasive material (e.g. sand). The surface of the corrosion ring must also be inspected for signs of pitting because the reduction in corrosion ring weight may suggest a low corrosion rate, but internal corrosion due to other mechanisms may be severe.

Corrosion Control with Formate Fluids

High concentration formate brines are ideal for use as packer fluids because they have low oxygen solubility and they are also anti-oxidants. They are also buffered at 10.5 pH with sodium or potassium carbonate and bicarbonate. As a result, formate packer fluids do not usually require biocides, oxygen scavengers or corrosion inhibitors. There are instances where production tubulars have been in perfect condition after recovery from depleted wells following several years' production.

Fluid Testing Procedures

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Safety Precautions When Performing Mud Checks

Precautions must be taken when performing mud checks because dangerous chemicals are often used and some of the mud testing equipment is subjected to high temperatures and pressures. Some basic rules for the mud lab are as follows:-

1. Wear Safety Glasses for protection against chemical splashes.
2. Wear Surgical Gloves to avoid chemical contact with skin.
3. Use a Pipette Bulb/Pump to avoid accidental ingestion of chemical reagents (see below).
4. Use the Fume Cupboard to avoid fumes while performing chemical tests.
5. Bleed off pressure completely before dismantling pressurized equipment (e.g. HPHT cell).
6. Isolate hot equipment (Retort, HPHT cells, etc.) safely when cooling down.
7. Disconnect electrical equipment from the mains before cleaning (e.g. heating cups).
8. Store dangerous chemicals in a secure cabinet below eye level.

Left: Rubber Pipette Bulb
Right: Plastic Pipette Pump

IADC Safety Alert: Catastrophic Failure of 50 cc Retorts

This alert was released following two catastrophic failures of 50 cc Retorts, which occurred during routine oil-on-cuttings checks. Investigations into the root cause of the problem were hampered by the excessive damage caused when the Retort burst: “It appears that the bursting failure occurred as a result of over-pressurization. The Retort separated across the screw thread. Though it cannot be proved, the consensus of opinion is that the spout must have become blocked with a mixture of tars/solids/emulsifiers”. The following guidelines should be followed to ensure the safe operation of Retorts:

1. Retorts must be cleaned thoroughly after every test, particularly the spout.
2. Pipe cleaners and fine wire brushes should be used to scrape any residue out of the spout.
3. The steel wool should be changed out after every test to prevent solids building up.
4. The threads on the Retort should be visually inspected before use.
5. Check for signs of “belling” of the Retort around the threads.
6. Another early warning sign of thread damage is movement (or rattling) during threading.
7. Retorts should be changed out every six months for thorough examination.

Fluid Testing Procedures

Section 9

Fluid Testing Procedures for Physical Properties

The following testing procedures have been standardized in accordance with internationally accepted ANSI/API RP 13B-1 Fourth Edition, March 2009 (Recommended Practice for Field Testing Water-Based Drilling Fluids), which is identical to ISO 10414-1: 2008 (Field Testing of Drilling Fluids Part 1 for Water-Based Mud).

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API and Pressurized Mud Balances for Fluid Density

There are two devices for measuring mud density, the API Mud Balance and the Pressurized Mud Balance. The API Mud Balance is suitable for simpler mud systems in top-hole intervals, while the Pressurized Mud Balance is preferred for deeper intervals because it gives more accurate results by reducing errors due to aeration and compressibility.

API Mud Balance

The API Mud Balance comes in a tough plastic case and comprises a mud chamber connected to a graduated arm with a sliding weight. The mud chamber has a lid and the arm has a balance point with a spirit level. The mud chamber is filled with fluid and, once the lid is in place, the balance point is placed on a knife edge attached to the plastic case and the sliding weight on the graduated arm is adjusted to centralize the air bubble in the spirit level to indicate that the mud balance is level. The density is then read off the graduated scale. The correct procedure for measuring mud density is as follows:

1. Fill the mud chamber with a sample of mud.
2. Place the lid on the chamber and twist firmly down, making sure excess mud escapes from the small hole in the lid before it is seated firmly on the chamber.
3. Cover the hole in the lid with a finger to prevent leakage and wash excess mud from the mud balance.
4. Dry the mud balance, place on the knife edge and adjust the sliding weight to centralize the air bubble in the spirit level to indicate that the mud balance is level.
5. Read the mud density to the nearest division of the appropriate scale on the graduated mud balance arm, using the edge indicated by the arrow on the sliding weight.
6. Wash the mud balance after use, making sure that it is thoroughly clean.

Calibration checks should be made on a daily basis by using the procedure detailed above to weigh a sample of fresh water. If the mud balance is calibrated correctly then the sliding weight will line up with the 1.0 sg or 8.33 ppg graduation, which appears as a calibration marking on the graduated arm. If this alignment is not correct then the mud balance can be recalibrated by adding or removing lead shot from the compartment at the end of the graduated arm.

Pressurized Mud Balance

The Pressurized Mud Balance comes in a hard plastic case and comprises a mud chamber connected to a graduated arm with a sliding weight. The mud chamber has a lid with a screw-down ring and the arm has a balance point with a spirit level. The lid has a central sliding valve that enables the mud sample to be pressurized using a pressurizing pump. The mud chamber is filled with fluid and, after screwing the lid firmly down, the pressurizing pump is filled with mud and inserted onto the sliding valve nipple to pressurize the sample in the mud chamber. The assembly is then placed on a knife edge attached to the plastic case and the sliding weight on the graduated arm is adjusted to centralize the air bubble in the spirit level to indicate that the mud balance is level. The density is then read off the graduated scale. The correct procedure for measuring mud density is as follows:

1. Fill the mud chamber with a sample of mud and measure the mud temperature with a thermometer.
2. Place the lid on the mud chamber and secure in place using the screw-down ring, making sure excess mud escapes from the top of the sliding valve in the lid.

3. Place the mud balance on a firm worktop and fill the pressurizing pump with mud from the same sample.
4. Insert the pressurizing pump onto the sliding valve nipple and hold the body of the pressurizing pump firmly in place.
5. Push the handle of the pressurizing pump firmly down and apply maximum force to pressurize the mud sample in the cup, relaxing the force slightly and reapplying maximum force in cycles as the sliding valve gradually lifts up to isolate pressurized mud in the cup.
6. Wash excess mud off the mud balance and dry thoroughly.
7. Place the mud balance on the knife edge and adjust the sliding weight to centralize the air bubble in the spirit level to indicate that the mud balance is level.
8. Read the mud density to the nearest division of the appropriate scale on the graduated mud balance arm, using the edge indicated by the arrow on the sliding weight.
9. De-pressurize the mud balance cup by inserting the empty pressurizing pump onto the sliding valve nipple and push the handle and body of the pump firmly down to push the sliding valve down, releasing the trapped pressure in the mud balance cup.
10. Unscrew the lock-down ring and remove the lid (If the lid is difficult to remove then insert the pressurizing pump onto the sliding valve nipple and pump a small amount of air into the chamber).
11. Wash all the mud balance components thoroughly after use, including the pressurizing pump, and make sure the sliding valve moves freely.

Calibration checks should be made on a daily basis by using the procedure detailed above to weigh a sample of fresh water. If the mud balance is calibrated correctly then the sliding weight will line up with the 1.0 sg or 8.33 ppg graduation, which appears as a calibration marking on the graduated arm. If this alignment is not correct then the mud balance can be recalibrated by adding or removing lead shot from the compartment at the end of the graduated arm.

The body, lid and lock-down ring components of the pressurized mud balance are often stamped with identical serial numbers to keep them together as a matched set. The O-ring seal around the lid and on the sliding valve should be checked periodically for signs of damage, and replaced where necessary. The sliding valve should also move freely and easily, using WD-40 where necessary.

Marsh Funnel for Viscosity

The Marsh Funnel is a simple device for measuring funnel viscosity. The Marsh Funnel holds around 1.5 litres fluid and is filled by pouring mud through the wire-mesh screen for removing solids that might block the narrow discharge tube at the base of the funnel. The time taken for 1 quart (946 ml) of mud to flow out of the discharge tube, measured using a mud cup, is then recorded as a time in seconds, thicker muds obviously taking longer than thinner muds. The following procedure is used for measuring funnel viscosity:

1. Check that the narrow discharge tube at the base of the funnel is clear.
2. Hold the Marsh Funnel upright, place a finger over the discharge tube and use a mud cup to fill the funnel until level with the wire-mesh screen, using the wire-mesh screen to remove larger particles that might block the narrow discharge tube.
3. Hold the Marsh Funnel above an empty mud cup, remove the finger covering the discharge tube and record the time taken to fill the mud cup with 1 quart (946 ml) mud.
4. Record the Funnel Viscosity as the time taken in seconds. The mud temperature is often recorded at the same time since temperature changes will often account for viscosity changes.
5. Wash the Marsh Funnel after use, making sure the narrow discharge tube is clean.

Calibration checks should be made periodically, using the procedure detailed above, by filling the Marsh Funnel with fresh water and recording the time to discharge 1 quart of water, which should take 26 seconds ± 0.5 seconds for water at 21°C ± 3°C.

Marsh Funnel with Mud Cup

Viscometer for Rheology

A viscometer or rheometer is used for obtaining fluid rheology (apparent viscosity, plastic viscosity, yield point and gel strengths), which is a measure of the resistance of a fluid to flow. Several models are available, powered by hand-crank or electric motor. The instrument comprises a solid pivoted cylindrical bob that is restrained by a torsion spring and connected to a torsion dial. The cylindrical bob sits inside a cylindrical outer sleeve that can be rotated at selected speeds, with a narrow annular clearance between the bob and the sleeve.

Six-Speed Viscometer before and after assembly

The mud sample is placed in a heating cup to bring it to a designated temperature for measuring the rheology (usually 50°C or 120°F, but higher temperatures may be specified for high-temperature wells). The heating cup sits on the adjustable viscometer platform, which is raised until the cylindrical bob and rotating outer sleeve are immersed in the mud sample. Once the mud sample reaches the required temperature, the outer sleeve is rotated at selected speeds, and the resultant deflection of the cylindrical bob can be read off the torsion dial, high viscosity fluids producing larger deflections.

Basic viscometers only give 600, 300 and 3 rpm readings. Most viscometers give 600, 300, 200, 100, 6 and 3 rpm readings, while some also give 60 and 30 rpm readings. The apparent viscosity, plastic viscosity and yield point can all be calculated from the 600 and 300 rpm readings, while the gel strength is given by the 3 rpm reading. Gel strengths are usually recorded after 10 seconds, 10 minutes and occasionally 30 minutes. The correct procedure for measuring fluid rheology is as follows:

1. Fill the heating cup with the fluid sample and place on viscometer platform.
2. Adjust the viscometer platform until the fluid sample level reaches the circumferential groove marked on the rotating outer sleeve.
3. Rotate the outer sleeve to stir the fluid while the sample reaches the required temperature (usually 50°C or 120°F).
4. Once at the required temperature, select the 600 rpm gear and wait for a steady deflection before recording the 600 rpm dial reading.
5. With the motor still running, select the 300 rpm gear and wait for a steady deflection before recording the 300 rpm dial reading.
6. Repeat the procedure for all the other dial readings.
7. To measure the 10 second gel strength, stir the mud at 600 rpm for several seconds to breaks any gels, then select the low speed gear and switch off.
8. After 10 seconds, switch the viscometer back on at 3 rpm and record the maximum dial deflection before the gel breaks, which is the 10 second gel strength.
9. To measure the 10 minute gel strength, stir the mud at 600 rpm for several seconds to breaks any gels, then select the low speed gear and switch off.
10. After 10 minutes, switch the viscometer back on at 3 rpm and record the maximum dial deflection before the gel breaks, which is the 10 minute gel strength.
11. Repeat the procedure if the 30 minute gel strength is also required.
12. Wash the viscometer by carefully removing the rotating outer sleeve, which has a small slot that locks onto a pin. The cylindrical bob can then be wiped cleaned with a cloth or paper tissue, taking care not to bend the fragile assembly. The heating cup must be disconnected from the mains before cleaning.

The fluid rheology can be calculated using the equations in Figure 1 below.

Viscometer calibration is a specialized procedure and faulty units should be returned for repair by trained technicians. Note that viscometers are available for 50 Hz and 60 Hz frequencies, so it is important to check that the frequency of the viscometer matches that of the power supply to ensure that the motor runs at the correct speed.

Plastic Viscosity tends to increase while drilling due to the build-up of ultra-fine solids in the drilling fluid. Some drilled solids are too small to be removed by the Solids Control Equipment, so they remain in the drilling fluid and are gradually eroded into ultra-fine particles, along with other fine particles that are designed to pass through the shale-shaker screens (e.g. barite, calcium carbonate, etc.). The increase in solids results in an increase in friction between the solids, which increases the Plastic Viscosity of the drilling fluid.

Yield Point helps to keep drilled solids and weighting materials (e.g. barite and calcium carbonate) in suspension. If the Yield Point is too low then solids will gradually settle out when circulation is halted during a connection or while tripping out of the hole. Solids could then build up in a deviated part of the hole, or collect around the BHA, with the potential for getting mechanically stuck in the hole. Solids falling out of suspension will also reduce the mud density in highly deviated sections, resulting in a reduction in hydrostatic pressure when it reaches the vertical part of the hole when circulation resumes, with the potential for a well control incident.

If the Yield Point is too high then circulating pressures and ECDs will be high, with the potential for induced mud losses to the formation. Gel Strengths, which is a measure of the attractive forces between the particles when the drilling fluid is static, also need to be controlled. Progressive gels are another indication of high solids in the mud and will affect surge and swab pressures while tripping in or out of the hole. Higher gels will also require higher pump pressures to break circulation, which could increase the potential for induced mud losses to the formation.

Apparent Viscosity = [600 rpm reading]/2, reported in cP (centipoise)
Plastic Viscosity = [600 rpm reading] – [300 rpm reading], reported in cP
Yield Point = (2 x [300 rpm reading]) – [600 rpm reading], reported as lb/100ft^2
Gel Strength readings are reported as lb/100ft^2

Figure 1: Calculations for determining essential rheological properties.

API Filter Press for Fluid Loss

The low temperature API filter press, which is operated at room temperature and low pressure, is used for measuring fluid loss only with water-based drilling fluids. A sample of mud is pressurized in a chamber while the volume of filtrate that passes through filter paper over a specified time period is measured. The quality and thickness of the filter cake deposited on the filter paper is also checked after the device has been dismantled for cleaning.

API Filter Press before and after assembly.

API fluid loss is conducted at surface temperature at 100 psi pressure, and is recorded as the number of milliliters lost in 30 min. The device comprises a mud cell that is pressurized with a CO_2 cartridge using a pressure gauge and regulator. The mud cell comes in three parts: cylindrical body, base with filtrate discharge tube, and top with pressurization system. The mud cell sits in a frame and filtrate is then collected in a graduated glass measuring cylinder.

Besides measuring fluid loss control and filter cake quality, filtrate from the API filter press is used for some of the mud check chemical analysis, so it is important to make sure that the filter press components are clean and dry, with no traces of contaminants that could affect chemical analysis results (e.g. salt crystallization). The following procedure is used for measuring fluid loss control at ambient temperatures:

1. Check that the rubber gasket is seated correctly in the base of the filter press mud chamber, insert the circular gauze frame and place Whatman No. 50 filter paper on top of the gauze frame.
2. Place a rubber gasket on top of the filter paper, engage the pins on the cylindrical body of the mud chamber with the slots in the base of the chamber and twist firmly to lock the assembly together.
3. Fill the mud chamber with mud, keeping the air gap at the top to a minimum.
4. Place the mud chamber in the filter press frame, check that the rubber gasket is seated correctly in the mud chamber lid and place over the cylindrical body of the mud chamber.
5. Turn the screw in the filter press frame to lock and seal the lid firmly down on the mud chamber.
6. Place a graduated measuring cylinder on the adjustable platform below the mud chamber and adjust the height so that filtrate can be collected from the discharge tube in the base of the mud chamber.
7. Insert a new CO_2 cartridge in the pressure assembly on the lid of the mud chamber.
8. Adjust the pressure regulator to apply 100 psi to the mud chamber and record the start time.
9. Measure the spurt loss volume recovered in the graduated measuring cylinder during the first few seconds, if it is significant.
10. Check the pressure gauge at regular intervals to make sure that 100 psi pressure is maintained throughout the 30 minute test period.
11. When the 30 minute test period is over, close the pressure regulator, pull the red bleed-off knob to release the pressure in the mud chamber and record the volume of filtrate collected in the graduated measuring cylinder, which is reported as fluid loss in milliliters.
12. Carefully dismantle the mud chamber without damaging the filter cake on the filter paper.
13. Remove the filter paper and gently rinse off the surface mud on the filter cake.
14. Measure the thickness of the filter cake to the nearest 1/32nd of an inch, and note any relevant observations about filter cake quality (e.g. firm, slick, etc.).
15. Use the filtrate collected in the graduated measuring cylinder for the chemical analysis part of the mud checks.
16. Remove the used CO_2 cartridge from the pressure assembly.
17. Wash the filter press components thoroughly and leave to dry, in preparation for future tests

Fluid loss control is not so important for surface hole sections, but it is important for deeper sections because it gives an indication of the mud filtrate that invades the formation. Drilling fluids with poor fluid loss control (i.e. high fluid loss) produce thick filter cakes that can encourage differential sticking and other hole problems. Drilling fluids with good fluid loss control (i.e. low fluid loss) produce thin filter cakes that improve drilling performance.

HPHT Filter Press for Fluid Loss

The HPHT filter press, which is operated at elevated temperature and pressure, is used for measuring fluid loss for all types of drilling fluids. A sample of mud is pressurized in a chamber while the volume of filtrate that passes through filter paper over a specified time period is measured. The quality and thickness of the filter cake deposited on the filter paper is also checked after the device has been dismantled for cleaning.

HPHT Filter Press before and after assembly

The HPHT filter press is used for measuring the filtration and filter-cake building properties of a fluid at elevated temperature and pressure. The instrument comprises a mud cell that can be pressurized with back-pressure through valve stems. The mud cell is placed in a thermostatically controlled heating jacket and heated to the required temperature (usually 300°F or 148°C). The mud cell is then pressurized to 600 psi, with 100 psi back-pressure, to provide 500 psi differential pressure while measuring the volume of filtrate recovered over a 30-minute period.

The reason for applying back-pressure is to prevent evaporation of the hot filtrate, which would distort results. Note that the HPHT filter paper size is half the API filter paper size, so the HPHT filtrate volume recovered over the 30-minute test period must be doubled. Caution is required when running the HPHT filter press due to the high temperatures and pressures, and the condition of the HPHT filter press components and seals must be checked carefully for signs of damage.

Care is required when dismantling the cell after running a test because the mud could still be hot. The pressure in the mud cell is released by carefully opening valve stems on the mud cell. The reduction in pressure could cause the mud to boil and escape through the valve stem. For this reason, stand clear while the pressure is being released and cover the valve stem with a piece of cloth if necessary. Care is also required when releasing the locking screws to remove the lid, in case of trapped pressure due to a plugged valve stem. The following procedure is used for measuring HPHT fluid loss control:

1. Switch the heating jacket on and leave to warm up, inserting a dial thermometer in the small hole in the body of the heating jacket to monitor the temperature.
2. Check that the valve stem for the mud cell is not plugged, screw into the mud cell body and close the valve stem using an adjustable spanner
3. Check that the locking screws around the mud cell have all been retracted and do not intrude into the internal surface of the mud cell.
4. Fill the mud cell with a sample of mud, leaving a ½” gap below the O-ring groove to allow for heat expansion.
5. Check that the O-ring in the mud cell is undamaged and seated correctly, and place one of the HPHT filter papers on top.
6. Check that the O-ring around the lid is undamaged, align the recesses in the lid with the locking screws in the body, and push the lid firmly down onto the mud cell body (a smear of high temperature grease on the lid O-ring will make this easier)
7. Use an Allen Key to engage the locking screws in the lid and tighten evenly before closing the filtrate discharge valve stem in the lid with an adjustable spanner.
8. Place the mud cell in the heating jacket with the filtrate discharge valve stem facing down, and rotate the mud cell until it slots into a pin in the bottom of the heating jacket.
9. Insert a dial thermometer in the small hole in the mud cell to monitor the temperature.
10. Insert a new CO$_2$ cartridge in the pressure assembly, place on the upper valve stem of the mud cell and insert the locking pin.
11. Adjust the pressure regulator to apply 100 psi and open the upper valve stem with a ½-turn to pressurize the unit and stop the mud from boiling as it is brought up to the required temperature.

12. Insert a new CO_2 cartridge in the back-pressure assembly, place on the lower valve stem and insert the locking pin.
13. When the mud cell reaches the required temperature (usually 150°C or 300°F), adjust the pressure regulator on the lower valve stem to apply 100 psi back-pressure, but leave the valve closed.
14. Adjust the pressure regulator on the upper valve stem to increase the pressure in the mud cell from 100 psi to 600 psi.
15. Open the lower valve stem with a ½-turn and record the start time.
16. Monitor the back-pressure during the test and bleed off any increases in pressure by draining filtrate into a graduated glass measuring cylinder to maintain the 500 psi differential pressure.
17. When the 30 minute test period is over, close the lower and upper valve stems, close the pressure regulators, and pull the red bleed-off knobs to release trapped pressure.
18. Drain residual filtrate into the graduated glass measuring cylinder and record the volume of filtrate collected in milliliters (this figure needs to be doubled when reporting the HPHT fluid loss, because the area of the HPHT filter paper is half that of the API filter paper).
19. Remove the locking pins and remove the upper and lower pressure assemblies.
20. Lift the hot, pressurized mud cell out of the heating jacket, place in a safe area (e.g. fume cupboard), and leave to cool in an upright position.
21. When mud cell is cool, bleed off the cell pressure by carefully opening the valve stems.
22. Use an Allen Key to carefully loosen the locking screws in the lid of the mud cell (check for residual trapped pressure), and carefully dismantle the mud cell without damaging the filter cake on the filter paper.
23. Remove the filter paper and gently rinse off the surface mud on the filter cake.
24. Measure the thickness of the filter cake to the nearest 1/32nd of an inch, and note any relevant observations about filter cake quality (e.g. firm, slick, etc.).
25. The filtrate collected in the graduated glass measuring cylinder should be thrown away as it cannot be used for mud checks.
26. Remove the used CO_2 cartridge from the pressure assemblies.
27. Wash the mud cell components thoroughly and leave to dry, in preparation for future tests.

Fluid loss control is not so important for surface hole sections, but it is important for deeper sections because it gives an indication of the mud filtrate that invades the formation. Drilling fluids with poor fluid loss control (i.e. high fluid loss) produce thick filter cakes that can encourage differential sticking and other hole problems. Drilling fluids with good fluid loss control (i.e. low fluid loss) produce thin filter cakes that minimize shale hydration and improve drilling performance.

The HPHT filter press is useful for determining the quality of the oil-water emulsion in oil-based drilling fluids. The presence of “free water” in the filtrate is an indication that the emulsion is weak and, if this is the case, more emulsifier should be added to the oil-based mud to prevent deterioration in drilling performance.

Sand Test Kit for Sand Content

A sand test kit is used for measuring the sand content in the mud, comprising a 200-mesh sieve, a plastic funnel and a graduated glass tube that is calibrated to measure the sand content as a percentage. The 200-mesh sieve is designed to trap particles that are larger than 74 microns, which is much coarser than barite particles. However, the sieve will also trap other coarse particles (e.g. coarse Calcium Carbonate LCM particles), which could distort results if ignored. Every effort must be made to keep sand content as low as possible because it is extremely abrasive and can damage pumps and tubulars, as well as causing an undesirable increase in mud density.

Sand Test Kit used for measuring Sand Content in the mud

The following procedure is used for measuring sand content:

1. Fill the graduated glass tube with a sample of mud to the line marked, “Mud to Here”.
2. Fill the rest of the graduated glass tube with clean water to the line marked, “Water to Here”.
3. Place a thumb over the mouth of the glass tube and shake vigorously.
4. Pour the contents of the graduated glass tube onto the 200-mesh sieve, tapping the side of the sieve to improve flow and discarding everything that passes through the screen.
5. Refill the graduated glass tube with clean water and repeat the process until all residual solids have been removed from the glass tube.
6. Wash the sand particles trapped in the sieve under running water, gently rubbing the sand particles with the tip of a finger to break up and flush away any clay particles.
7. Place the funnel over the sieve and then place the tip of the funnel in the mouth of the clean, empty graduated glass tube.
8. Use gentle running water on the reverse side of the sieve to flush all the sand particles into the graduated glass tube without over-filling.
9. Allow time for the sand to settle at the bottom of the graduated glass tube and record the sand content as a percentage of the mud volume; along with the mud sampling location (e.g. flow line, active tank, etc.).
10. Wash the components of the sand content kit and leave to drain.

The graduated glass tube may contain other coarse solids, such as LCM and Calcium Carbonate, but these should be easy to identify because the heavier sand will settle first. If the “sand” at the bottom of the graduated glass tube contains a significant amount of Calcium Carbonate, then the water should be poured away without disturbing the “sand”, and acid should be added to dissolve the Calcium Carbonate. The real sand content (% by volume) can then be recorded.

Retort for Oil, Water and Solids Analysis

A retort is used for determining oil, water and solids content in the mud, comprising a sample chamber assembly of known volume filled with mud. The sample chamber is put in a heating chamber to boil off the water (and oil), which passes via a condenser tube into a graduated glass measuring cylinder, where the water (and oil) volume can be recorded.

Retort Kit before and after assembly

The volume of solids left in the sample chamber (obtained by subtracting the liquid volume from the sample chamber capacity) will include dissolved solids in brine-based mud systems, but "corrected" solids can be calculated by adjusting for brine salinity in the solids analysis formulae at the end of this procedure. The amount of weighting materials (HGS or High Gravity Solids) and drilled solids (Low Gravity Solids) can be calculated using retort results.

Retorts are available with 10 ml, 20 ml and 50 ml retort chamber capacities, the 50 ml chamber providing greater accuracy. It is important to make sure that the discharge tubes in the retort chamber assembly and condenser do not get plugged, as pressure will then build up in the retort chamber (Refer to the IADC Safety Alert concerning catastrophic failure of 50 cc retorts at the beginning of this chapter). The following procedure is used for operating the retort to measure solids content:

1. Switch the retort on and leave to warm up.
2. Ensure the retort chamber assembly is clean and dry, using the special spatula to remove solids trapped in the bottom of the retort chamber cup.
3. Use a pipe-cleaner to make sure the retort expansion chamber discharge tube is not plugged. Dress the expansion chamber with fine steel wool to prevent solids-laden mud boiling up into the measuring cylinder.
4. Clean the threads of the retort chamber assembly with a wire brush and smear a thin layer of high-temperature grease (Never-Seez), which provides a vapor seal and makes it easier to unscrew the assembly after retorting.
5. Fill the retort chamber cup with a representative sample of mud that has been screened through a Marsh Funnel to remove unrepresentative large particles, tap the side of the chamber lightly to expel any trapped air, rotate the lid until seated firmly in place, and wipe excess mud that escapes from the small hole in the top of the lid.
6. Screw the retort expansion chamber firmly onto the retort chamber cup, keeping the assembly upright at all times.
7. Use a pipe-cleaner to make sure the retort condenser is clean and dry, and screw the condenser firmly onto the retort chamber assembly discharge tube.
8. Place the retort chamber assembly in the heating jacket and close the insulated lid.
9. Place two drops of wetting agent in the bottom of a graduated glass measuring cylinder and place underneath the condenser to collect the water and oil that evaporates off (the wetting agent produces a better oil-water interface).
10. The fluid that condenses in the measuring cylinder should be clear (If mud is seen then the retort needs to be repeated using more wire wool in the retort expansion chamber).
11. When all the fluid has been retorted, record the volume of oil and water that has been recovered in the measuring cylinder (take readings from the bottom of the meniscus).
12. The volume of solids can be calculated by subtracting the volume of oil and water from the retort chamber capacity.
13. The percentage oil, water and solids can be calculated from the volume of oil, water and solids relative to the retort chamber capacity (i.e. retort volume), as shown in Figure 2 overleaf.
14. Switch off the retort apparatus, remove the retort assembly and leave to cool down naturally (use the fume cupboard for safety).
15. Once cool, dismantle and clean all the retort components, and dress the expansion chamber with unused fine steel wool.

The Oil/Water Ratio (O/W Ratio) of an oil-based drilling fluid is an important property that is calculated from retort results, as shown in Figure 3 overleaf.

$$\%\ \text{Water} = \frac{\text{Volume Water} \times 100}{\text{Retort Volume}}$$

$$\%\ \text{Oil} = \frac{\text{Volume Oil} \times 100}{\text{Retort Volume}}$$

$$\%\ \text{Solids} = 100 - \%\ \text{Water} - \%\text{Oil}$$

Figure 2: Equations for calculating water, oil and solids content as percentages.

Water = 9 ml　Oil = 34 ml　Solids = 7 ml

$$\text{Oil Fraction} = \frac{V_{\text{oil}}}{V_{\text{oil}} + V_{\text{Water}}} = \frac{34}{34 + 9} = 0.79$$

$$\text{Water Fraction} = \frac{V_{\text{Water}}}{V_{\text{oil}} + V_{\text{Water}}} = \frac{9}{34 + 9} = 0.21$$

$$\text{O/W Ratio} = \text{Oil Fraction / Water Fraction} = 79/21$$

Figure 3: Method for calculating oil/water ratio, using typical results from a 50 ml retort.

Chemical Testing Procedures for Water-Based Fluids

The following testing procedures have been standardized in accordance with internationally accepted ANSI/API RP 13B-1 Fourth Edition, March 2009 (Recommended Practice for Field Testing Water-Based Drilling Fluids), which is identical to ISO 10414-1: 2008 (Field Testing of Drilling Fluids Part 1 for Water-Based Mud).

Contents

pH

Fluid pH is an important property for monitoring because it affects clay interactions, corrosion processes and solubility of certain additives. Fluid pH can be measured using pH Strips or a pH Meter, as follows:


pH Strips and pH Meter with Calibration Fluids

pH Strips contain a row of pH sensitive indicators that change color according to the pH of the fluid. The pH is determined by matching the color changes on the pH stick with the color chart supplied with the pH sticks. They are easy and convenient to use, with accuracy to the nearest 0.5 pH, although interpretation of colors on the pH strips may be difficult if the fluid is discolored by additives in the fluid. High chloride concentrations above 10,000 ppm can also affect the accuracy of the results. The pH strips can only be used once and must then be thrown away. The procedure for using pH strips is as follows:

1. Place the pH strip face down on a sample of fluid or filtrate (i.e. coloured indication squares in contact with the fluid), and leave for several seconds until no further color changes are observed on the pH strip.
2. Shake off excess fluid.

Match the color changes on the pH strip with the color chart supplied with the pH strips box, to determine the pH of the fluid to the nearest 0.5 pH.

pH Meters are much more accurate than pH strips, as long as regular checks are made to ensure that they are calibrated correctly. The device has a glass electrode probe that measures the hydrogen ion concentration of the fluid. A range of pH meters are available, with operating instructions varying according to each model. However, the general procedure for using glass electrode pH meters involves calibrating the pH meter, measuring the pH of the sample and finally cleaning and storing the probe, as follows:

1. Remove the end-cap, rinse the probe with distilled water and blot dry.
2. Wait until the sample is at the same temperature as the calibration buffer solution and the probe, preferably 70-80°F (20-28°C).
3. Measure the temperature of the pH 7 buffer solution.
4. Place the probe in the pH 7 buffer solution, switch on the pH meter and wait for the digital reading to stabilize.
5. Adjust the temperature knob on the pH meter to the temperature of the pH 7 buffer solution and adjust the calibration knob to display the temperature-corrected pH (The buffer bottle will list the correct pH value for various temperatures). Once this is done, rinse the electrode with distilled water and blot dry.
6. Repeat Steps 3, 4 and 5 using either pH 4 or pH 10 buffer solution, choosing the buffer closest to the sample pH (usually pH 10 for muds). If the pH meter does not display the correct buffer pH value, adjust the calibration knob to obtain the correct pH reading. Rinse the electrode with distilled water and blot dry.
7. Place the probe back in the pH 7 buffer solution and re-check the pH. If the displayed pH value is different from that previously read in Step 5, use the slope adjustment screw located at the back of the pH meter to set the correct pH reading.
8. Repeat Step 7 using either pH 4 or pH 10 buffer solution, adjusting the slope adjustment screw until the pH meter reads the correct buffer value.
9. After calibrating the pH meter using two buffer solutions, rinse the probe and blot dry before placing it in the sample.
10. Stir gently and allow the digital reading to stabilize, recording the sample pH to the nearest 0.1 and the sample temperature in °F or °C.
11. Unplug the meter and clean the probe with distilled water. Saturate the cotton in the end cap with pH 4 buffer and place the cap on the pH probe.

pH meters should be checked at regular intervals and re-calibrated in accordance with the instructions supplied with the model in use, whenever necessary. The glass electrode should be cleaned occasionally with mild detergent and a soft brush, to prevent the porous surface of the glass electrode getting plugged with fine solids. Note that the pH of the filtrate may be different to the pH of the mud.

Filtrate Alkalinity (Pf and Mf)

The alkalinity is important in water-based drilling fluids because it can affect the performance of some treating chemicals in the water-based fluid, especially if they require alkaline conditions for effective performance. Sodium or Potassium Hydroxide usually provides the hydroxyl ions (OH^-) for adjusting the pH of water-based fluids. However, carbonate (CO_3^{2-}) and bicarbonate (HCO_3^-) ions also provide fluid alkalinity, along with formation contaminants (e.g. H_2S or CO_2 gas).

Equipment used for measuring Filtrate Alkalinity

However, fluid alkalinity from carbonates and bicarbonates can often have a detrimental effect on mud properties, resulting in high viscosities, poor fluid loss control and clay flocculation. The reason for measuring the alkalinity of mud filtrate samples is to determine the amount of carbonate and bicarbonate contamination in the mud system, so that effective treatments can be made to restore mud properties, as detailed at the end of the test procedure. The following equipment is required for measuring alkalinity:

1. Sulfuric Acid (0.02N)
2. Phenolphthalein indicator solution.
3. Methyl Orange indicator solution.
4. Titration dish (white ceramic or white polyethylene crucible)
5. Graduated Pipette 1 ml
6. Graduated Pipette 10 ml
7. Glass stirring rod
8. Syringe 1 ml

The procedure for measuring **Filtrate Alkalinity (Pf and Mf)** is as follows:

1. Transfer 1 ml mud filtrate into a titration dish using a 1 ml pipette.
2. Stir with a glass rod while adding a few drops Phenolphthalein indicator solution (A pink color will appear if alkalinity is present).
3. Titrate with 0.02N Sulfuric Acid using a 1 ml graduated pipette while stirring the contents of the titration dish with the glass rod until the pink color disappears, which occurs when pH 8.3 is reached.
4. Report the Phenolphthalein alkalinity of the filtrate, Pf, as the volume (ml) of 0.02N Sulfuric Acid (per milliliter of filtrate) required to reach the Phenolphthalein end point.
5. To the same sample that has just been titrated to the Pf endpoint, add a few drops of Methyl Orange indicator solution, titrate with 0.02N Sulfuric Acid using a 1 ml graduated pipette while stirring the contents of the titration dish with the glass rod until the yellow/orange color changes to red, which occurs when pH 4.3 is reached.
6. Report the Methyl Orange alkalinity of the filtrate, Mf, as the total volume (ml) of 0.02N Sulfuric Acid (per milliliter of filtrate) required to reach the Methyl Orange endpoint (i.e. including the volume for measuring Pf).

It is important to be aware that anionic thinners and fluid loss additives will contribute to the Mf alkalinity value and may also mask the endpoint color change, so the accuracy of the results may be affected when these additives are present in significant quantities. However, the presence of hydroxide (OH^-), carbonate (CO_3^{2-}) and bicarbonate (HCO_3^-) ions can be estimated from the alkalinity results for the mud filtrate (Pf and Mf), as shown in Figure 4 overleaf.

a. If $P_f = 0$, then alkalinity is due to bicarbonate ions.
[Bicarbonate] = M_f x 1,220 mg/l

b. If $P_f = M_f$, then alkalinity is due to hydroxide ions.
[Hydroxide] = P_f x 340 mg/l

c. If $2P_f < M_f$, then alkalinity is due to carbonate and bicarbonate ions.
[Carbonate] = $2P_f$ x 600 mg/l
[Bicarbonate] = $(M_f - 2P_f)$ x 1,220 mg/l

d. If $2P_f = M_f$, then alkalinity is due to carbonate ions only.
[Carbonate] = M_f x 600 mg/l

e. If $2P_f > M_f$, then alkalinity is due to hydroxide and carbonate ions.
[Hydroxide] = $(2P_f - M_f)$ x 340 mg/l
[Carbonate] = $(M_f - P_f)$ x 1,200 mg/l

Figure 4: Method for determining hydroxide, carbonate and bicarbonate ion concentrations in water-based fluids.

The filtrate alkalinity measurements will indicate the presence and concentrations of carbonate and/or bicarbonate contamination, enabling effective treatments to be made if mud properties are being affected (e.g. high viscosity, poor fluid loss control, clay flocculation). The presence of bicarbonate ions often makes the mud system difficult to control, but this is relatively simple to remedy because bicarbonate ions can be converted to carbonate ions by adding hydroxide ions in the form of Sodium or Calcium Hydroxide.

Mud Alkalinity and Lime Content

The procedure for measuring **Mud Alkalinity (Pm)** is similar to that for measuring Filtrate Alkalinity, using the following equipment:

1. Sulfuric Acid (0.02N)
2. Phenolphthalein indicator solution
3. Titration dish (white ceramic or white polyethylene crucible)
4. Syringe 1 ml
5. Graduated Pipette 1 ml
6. Graduated Pipette 10 ml
7. Glass Stirring Rod or Magnetic Stirrer with Bar Magnet

Equipment used for measuring Mud Alkalinity

The procedure for measuring **Mud Alkalinity (Pm)** is as follows:

1. Add approximately 25 ml distilled water to a clean titration dish and place on a magnetic stirrer, if available.
2. Transfer 1 ml mud sample into a titration dish using a 1 ml pipette.
3. Use a magnetic stirrer with bar magnet to agitate the fluid in the titrating dish while adding the test chemicals, otherwise use a glass stirring rod.
4. Add a few drops Phenolphthalein indicator solution (a pink color will appear if alkalinity is present).
5. Titrate with 0.02N Sulfuric Acid using a 1 ml graduated pipette while stirring the contents of the titration dish with the glass rod until the pink color disappears, which occurs when pH 8.3 is reached.
6. The volume (mls) of 0.02N Sulfuric Acid (per milliliter of mud) required to restore the original color of the diluted mud sample is the **Phenolphthalein alkalinity of the mud, Pm**.

If the mud is contaminated with cement, then the titrated sample will gradually turn pink again after a few seconds. If this is the case then the titration should be performed as quickly as possible until the pink color first disappears, in order to eliminate distortion of the Pm reading due to cement contamination.

Lime Content

The Lime Content can be calculated from the following mud properties, as measured in previous procedures:

- Mud and Filtrate Alkalinities (Pm and Pf)
- Water Fraction from Retort Results

The water fraction is simply the water percentage divided by 100 (i.e. 78% water from the retort results is equivalent to 0.78 Water Fraction). See Figure 5 below.

Estimated Lime (ppb) = 0.26 x [Pm – (Pf x Water Fraction)]

Figure 5: Calculation for estimating Lime Content.

Total Hardness as Calcium

Water “hardness” refers to water that contains dissolved Calcium and Magnesium salts, which in high concentrations will reduce the effectiveness of Bentonite and polymers, resulting in higher consumptions. The hardness of mix water is reduced with Soda Ash treatments to precipitate out the Calcium and Magnesium ions as Calcium and Magnesium Carbonate.

Equipment used for measuring Total Hardness as Calcium.

The following equipment is required for measuring Total Hardness (Calcium and Magnesium) as Calcium:

1. Distilled Water
2. Ammonium Buffer Solution in dropper bottle
3. Hardness Indicator Solution
4. 0.02N EDTA Titrating Solution (0.01M)
5. Graduated pipettes (1 ml and 2 ml)
6. Titration dish (white ceramic or white polyethylene crucible)
7. Glass Stirring Rod or Magnetic Stirrer with Bar Magnet

The procedure for measuring Total Hardness (Ca^{2+} and Mg^{2+}) in mix water or mud filtrate is as follows:

1. Add approximately 25 ml distilled water to a clean titration dish and place on a magnetic stirrer, if available.
2. Use a magnetic stirrer with bar magnet to agitate the fluid in the titrating dish while adding the test chemicals, otherwise use a glass stirring rod.
3. Add 10 drops of Ammonium Buffer solution.
4. Add 5 drops of Hardness Indicator solution. If calcium and/or magnesium is present in the distilled water, a wine-red color will develop. If not, the solution will remain blue.
5. Use a 1 ml pipette to transfer a 1 ml sample of mix water or mud filtrate into the titration dish, which will turn wine-red if calcium and/or magnesium are present.
6. Titrate with 0.02N EDTA (0.01M) using a 2 ml graduated pipette while stirring the contents of the titration dish until the wine-red color turns blue (check carefully that all traces of red have been removed). See Figure 6 below.

When testing the hardness of mix water, a larger sample volume (e.g. 10 mls) should be used as this will give a more accurate result (the EDTA titration volume is then divided by the sample volume).

Total Hardness (mg/l as Calcium) = (ml of EDTA x 400) / (ml of sample used)

Figure 6: Calculation for determining Total Hardness as Calcium.

Calcium and Magnesium Ion Content

The Calcium Ion Content of the filtrate sample is determined using a similar procedure for the total hardness, but using a different indicator solution.

Equipment used for measuring Chloride Ion Content

The following equipment is required for measuring Calcium Hardness:

1. Distilled Water
2. Calcium Buffer Solution (1N Sodium Hydroxide in a dropper bottle)
3. Calver II Indicator in pillows or grains
4. 0.02N EDTA Titrating Solution (0.01M)
5. Graduated pipettes (1 ml and 2 ml)
6. Titration dish (white ceramic or white polyethylene crucible)
7. Glass Stirring Rod or Magnetic Stirrer with Bar Magnet

The procedure for measuring Calcium Ion Content in mud filtrate is as follows:

1. Add approximately 25 ml distilled water to a clean titration dish and place on a magnetic stirrer, if available.
2. Use a magnetic stirrer with bar magnet to agitate the fluid in the titrating dish while adding the test chemicals, otherwise use a glass stirring rod.
3. Add 1 ml Calcium Hardness Buffer solution and several grains of Calver II indicator powder (a wine-red color will develop if calcium is present).
4. Titrate with 0.02N EDTA (drop by drop) while stirring until sample color changes from wine-red to blue, but do not go past the end point.
5. Use a 1 ml pipette to transfer a 1 ml sample of mud filtrate into the titration dish.
6. Add 2 drops of Calcium Buffer Solution (1N Sodium Hydroxide), which will precipitate out the magnesium ions as magnesium hydroxide.
7. Add several grains of Calver II Indicator solution, which will turn the sample wine-red.
8. Titrate with 0.02N EDTA (0.01M) using a 2 ml graduated pipette while stirring the contents of the titration dish until the wine-red color turns blue (check carefully that all traces of red have been removed). See Figure 7 below.

Magnesium Ion Content

The Magnesium Ion Content can be calculated by subtracting the Calcium Ion Content from the Total Hardness. See Figure 8 below.

If the water “hardness” is too high (i.e. high concentration of dissolved Calcium and Magnesium salts) then the effectiveness of Bentonite and polymers in the fluid system will be reduced, resulting in higher consumptions. Hardness can be reduced by treating the mix water or circulating system with Soda Ash or Sodium Bicarbonate, as this will precipitate out the Calcium and Magnesium ions as Calcium and Magnesium Carbonate.

Calcium Ion Content, mg/l = (ml of EDTA x 400) / (ml of sample used)

Figure 7: Calculation for determining Calcium Ion Content.

Magnesium Ion Content, mg/l = [(Total Hardness, mg/l) – (Calcium, mg/l)]

Figure 8: Calculation for determining Magnesium Ion Content.

Chloride Ion Content

The water-based fluid may contain chlorides from the base fluid (e.g. Sodium or Potassium Chloride), or may pick up chlorides while drilling. Measuring chloride concentration is useful for determining any unexplained changes in water-based mud salinity, because an increase or reduction in salinity will indicate salt or water contamination.

Equipment used for measuring Total Hardness as Calcium.

The equipment required for measuring chlorides is as follows:

1. Phenolphthalein indicator solution
2. Sulfuric or Nitric Acid, 0.02N
3. Potassium Chromate indicator solution
4. Silver Nitrate solution, 0.0282N or 0.282N depending on mud salinity
5. Distilled Water
6. Titration dish (white ceramic crucible)
7. Glass stirring rod, or magnetic stirrer with magnet
8. Graduated pipette, 1 ml x 0.01 ml graduations
9. Graduated pipette, 10 ml x 0.1 ml graduations

The procedure for measuring chlorides is as follows:

1. Pipette 1 ml filtrate into a titration dish containing around 25 ml distilled water.
2. Add five drops Phenolphthalein indicator solution and if the indicator turns pink then add 0.02N Sulfuric or Nitric Acid (drop by drop), stirring the sample with a glass stirring rod until the pink color disappears.
3. Add around 10 drops Potassium Chromate indicator solution, turning the fluid yellow.
4. Use a glass rod, or magnetic stirrer with bar magnet, to stir the solution continuously while adding Silver Nitrate solution with a pipette until the yellow color turns to orange-red and persists for 30 seconds (Use 0.0282N $AgNO_3$ for chlorides below 10,000 mg/l and 0.282N for chlorides above 10,000 mg/l).
5. The chloride concentration in mg/L can be calculated according to $AgNO_3$ strength used for the titration. See Figure 9 below.

A larger water or filtrate sample volume should be used for checking fluids with low chlorides, as this will give a more accurate measurement (e.g. titrate with a 10 ml sample when checking the chlorides in mix water).

Chlorides should be around 175,000 to 185,000 mg/L in salt saturated mud systems.

For Chlorides below 10,000 mg/l:

Chlorides, mg/l = 1,000 x (ml of 0.0282N $AgNO_3$) / (ml of filtrate used)

For Chlorides above 10,000 mg/l:

Chlorides, mg/l = 10,000 x (ml of 0.282N $AgNO_3$) / (ml of filtrate used)

Figure 9: Calculations for determining Chloride Ion Content.

MBT (Methylene Blue Test) for Cation Exchange Capacity

This test is used for measuring the Cation Exchange Capacity (CEC), which determines the reactive clays in the mud system.

MBT Kit used for measuring Cation Exchange Capacity

The test requires the following equipment:

1. 250 ml glass conical flask
2. A 2 ml or 5 ml syringe
3. 50 ml graduated burette or 10 ml graduated pipette
4. 50 ml graduated measuring cylinder
5. Glass stirring rod
6. Hot Plate
7. Whatman Filter Paper #1
8. Methylene Blue solution
9. Hydrogen Peroxide (3 % solution)
10. Sulfuric Acid (5N solution)

The procedure for performing the Methylene Blue Test is as follows:

1. Use the syringe to transfer a 2 ml mud sample into the glass conical flask containing 10 ml distilled water.
2. Use the graduated measuring cylinder to add 15 ml of 3% Hydrogen Peroxide (H_2O_2) to the conical flask, add 0.5 ml of 5N Sulfuric Acid using a dropper bottle and mix thoroughly by shaking the conical flask.
3. Place the conical flask on the hot plate and boil gently for 10 minutes without boiling dry (The Hydrogen Peroxide is designed to remove the effects of organic materials in the drilling fluid that absorb methylene blue, ensuring that the test only determines reactive clay content).
4. After boiling, remove the conical flask from the hot plate and bring the total suspension volume in the conical flask to about 50 ml with distilled water.
5. Add 0.5 ml Methylene Blue to the conical flask using the burette or pipette, and stir thoroughly for several seconds.
6. Shake the conical flask and use the glass rod to transfer a drop of fluid from the conical flask onto a piece of Whatman Filter Paper #1 and check for the appearance of a "blue halo" on the edge of the blue circle.
7. If no halo appears then add another 0.5 ml Methylene Blue to the conical flask and keep repeating Steps 5 and 6 until a "blue halo" appears, keeping a record of the total amount of Methylene Blue added.
8. When a "blue halo" appears, repeat Step 6 after two minutes to check that the "blue halo" is still present, confirming the end point of the titration.
9. The methylene blue test results are reported as Methylene Blue Capacity (MBC) or as Bentonite Equivalent (lb/bbl). See Figure 10 below.

MBC = [ml of Methylene Blue] / [ml of Mud Sample]
Bentonite Equivalent (ppb) = 5 x [ml of Methylene Blue] / [ml of Mud Sample]

Figure 10: Calculations for determining Methylene Blue Capacity and Bentonite Equivalent in the mud system.

Measuring Cation Exchange Capacity for Shale Samples

The procedure for measuring the Cation Exchange Capacity of shale samples follows a similar format as that for mud and requires the following equipment:

1. 150 ml glass conical flask
2. Graduated pipette
3. Glass stirring rod
4. Hot Plate
5. Whatman Filter Paper #1
6. De-Ionized water
7. Methylene Blue solution
8. Sulfuric Acid (5N solution)

The following procedure is used for measuring the CEC of a shale sample:

1. Accurately weigh around 1 gram of dried ground shale sample.
2. Place the shale sample in the glass conical flask containing 50 ml de-ionized water.
3. Add 0.5 ml 5N sulfuric acid.
4. Place on the hot plate and boil gently for 10 minutes.
5. Remove from the hot plate and leave to cool down.
6. Add 0.5 ml Methylene Blue to the conical flask using the burette or pipette, and stir thoroughly for several seconds.
7. Shake the conical flask and use the glass rod to transfer a drop of fluid from the conical flask onto a piece of Whatman Filter Paper #1 and check for the appearance of a “blue halo” on the edge of the blue circle.
8. If no halo appears then add another 0.5 ml Methylene Blue to the conical flask and keep repeating Steps 6 and 7 until a “blue halo” appears, keeping a record of the total amount of Methylene Blue added.
9. When a “blue halo” appears, repeat Step 7 after two minutes to check that the “blue halo” is still present, confirming the end point of the titration.
10. The CEC of the Shale, expressed in milli-equivalent per 100 gm, is calculated. See Figure 12 below.

$$\text{CEC (meq/100gm)} = \frac{\text{Methylene Blue (ml)}}{\text{Weigh of Shale Sample (gram)}}$$

Figure 12: Calculation for determining the Cation Exchange Capacity of a shale sample.

Potassium Ion Concentration

It is important to monitor and control the Potassium ion concentration for fluid systems that use Potassium for shale inhibition because it will deplete as it is adsorbed onto shales. Depletion needs to be monitored and effective inhibition levels need to be maintained in the mud system. The Potassium ion concentration is determined by adding excess Sodium Perchlorate to a measured volume of mud filtrate to precipitate out Potassium Perchlorate. The precipitate is then centrifuged and the volume of the compacted precipitate is converted to Potassium ion concentration by reference to a calibration curve, which must be prepared using the test reagents at the rig site (see overleaf).

Equipment used for measuring Potassium Ion Concentration

The following equipment is required for measuring Potassium ion concentration:

1. Standard Sodium Perchlorate solution (150.0 g per 100 cm^3 de-ionized water)
2. Standard Potassium Chloride solution (14.0 g per 100 cm^3 de-ionized water)
3. Hand-crank or electrical centrifuge (1,800 rpm)
4. Graduated Pipettes (1 ml and 10 ml)
5. Graduated centrifuge tubes (10 ml)
6. Calibration curve for Potassium Chloride

Calibration Curve – A calibration curve must be prepared using the test reagents at the rig site. In most instances, the calibration curve will be similar to those prepared on previous wells, but a new curve must always be prepared in case there are variations in reagent concentrations. The calibration curve is prepared as follows:

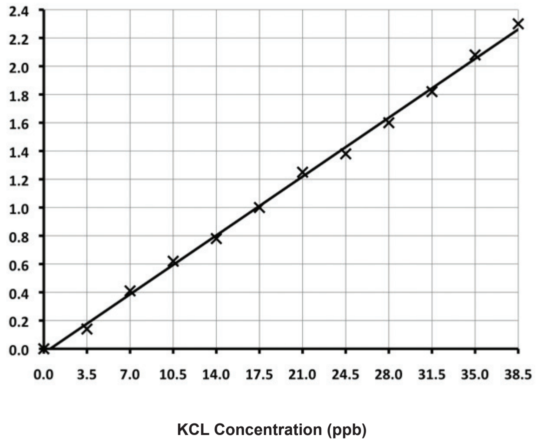
1. Prepare Standard Potassium Chloride solution using 14.0 gm Potassium Chloride powder made up to 100.0 cm^3 with de-ionized water.
2. Use a pipette to transfer 0.5 ml Standard Potassium Chloride solution to a clean, empty graduated centrifuge tube, dilute to the 7.0 ml mark with de-ionized water and agitate. This gives 3.5 ppb KCl concentration, but higher KCl concentrations can be prepared in the centrifuge tube for all the other points in the calibration curve, as shown in Figure 11 below.
3. Add 3.0 ml Sodium Perchlorate solution to the graduated centrifuge tube but do not agitate – a white precipitate is formed.
4. Place the centrifuge tube in the centrifuge and counterbalance the centrifuge with a similar centrifuge tube filled with water. Centrifuge at constant speed (around 1,800 rpm) for one minute and read the volume of the precipitate immediately afterwards.

Standard KCl Solution	De-Ionized Water	Final Volume	KCl Concentration
0.5 ml	6.5 ml	7.0 ml	3.5 ppb
1.0 ml	6.0 ml	7.0 ml	7.0 ppb
1.5 ml	5.5 ml	7.0 ml	10.5 ppb
2.0 ml	5.0 ml	7.0 ml	14.0 ppb
2.5 ml	4.5 ml	7.0 ml	17.5 ppb
3.0 ml	4.0 ml	7.0 ml	21.0 ppb
3.5 ml	3.5 ml	7.0 ml	24.5 ppb
4.0 ml	3.0 ml	7.0 ml	28.0 ppb
4.5 ml	2.5 ml	7.0 ml	31.5 ppb
5.0 ml	2.0 ml	7.0 ml	35.0 ppb
5.5 ml	1.5 ml	7.0 ml	38.5 ppb

Figure 11: Chart for preparing a range of Potassium Chloride Concentrations

The speed of an electrical centrifuge can usually be adjusted to 1,800 rpm using the dial. The speed of a hand-crank centrifuge can be adjusted to 1,800 rpm by turning the crank handle slowly and counting the number of centrifuge arm revolutions for one full turn of the crank (handle). From this, the number of crank turns required to obtain 1,800 rotor revolutions can be calculated. Dividing the number of crank turns required for 1,800 revolutions by 12 will give the number of handle turns required every 5 seconds, and hand crank speed rate can then be adjusted to obtain 1,800 rpm by using a stopwatch. As an example, if one full turn of the hand-crank centrifuge handle produces 10 full centrifuge arm revolutions, then 180 handle turns are required to obtain 1,800 centrifuge arm revolutions. A centrifuge speed of 1,800 rpm can therefore be obtained by 180 full handle turns per minute, which is equivalent to 3 full handle turns per second or 15 full handle turns every 5 seconds.

5. Repeat Steps 2 to 4 using higher KCl concentrations as tabulated above. Always use a pipette when transferring the required amount of Standard Potassium Chloride solution to the clean, empty graduated centrifuge tube. Plot the volume of Precipitate (ml) against KCl Concentration (ppb), from which a straight line can be produced, similar to that shown below.



Standard Curve for Potassium Chloride

KCl Concentration Measurements – The concentration of KCl in the mud can be measured once the calibration curve has been prepared, as follows:

1. Use a pipette to transfer 7.0 ml mud filtrate into the graduated centrifuge tube.
2. Add 3.0 ml Sodium Perchlorate solution, but do not agitate. If potassium is present then a white precipitate is formed at once.
3. Counterbalance the centrifuge with a similar centrifuge tube filled with water, centrifuge at 1,800 rpm for one minute, and read the volume of the white precipitate.
4. Use the calibration curve to convert the precipitate volume to KCl concentration.
5. Add 2 or 3 drops Sodium Perchlorate to the centrifuge tube after centrifuging, to confirm that all the Potassium has been precipitated out by the Sodium Perchlorate. If more precipitate appears, then the KCl concentration is too high for the test procedure and the test should be repeated using a smaller mud filtrate volume as per the following table:

KCl (lb/bbl)	K+ (mg/l)	Filtrate Volume (ml)
3.5 to 18	5,250 to 27,000	7.0
18 to 35	27,000 to 52,500	3.5
35 to 70	52,500 to 105,000	2.0
Above 70	Above 105,000	1.0

The smaller filtrate volume should then be increased to 7 ml with de-ionized water and agitated before adding the Sodium Perchlorate. When smaller filtrate volumes are used, the KCl concentration of the mud system can be calculated using the equation in Figure 13 opposite.

The KCl depletion rate will depend on the shale reactivity and drilling ROPs, so regular KCl treatments may be required to maintain concentration at the required level for effective inhibition. The Potassium concentration can be converted to other units as shown in Figure 14 opposite.

$$\text{KCl Concentration (ppb)} = \frac{7}{\text{Filtrate Volume (ml)}} \times \text{KCl Concentration from Calibration curve}$$

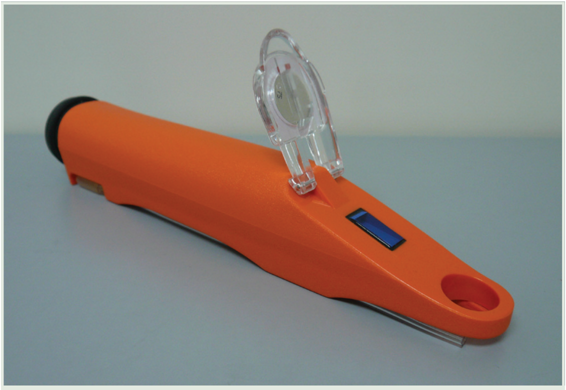
Figure 13: Calculation for determining Potassium Chloride Concentration.

KCl (gm/l) = KCl (ppb) x 2.85714
KCl (% Vol) = KCl (ppb) ÷ 3.5
$[K^+]$ (mg/l) = KCl (ppb) x 1,500

Figure 14: Conversion factors for reporting Potassium Chloride Concentrations in different units.

Glycol Concentration

Glycol is generally used in KCl-Polymer fluid systems when enhanced shale inhibition is required. Glycol will be lost through adsorption on exposed shale formations in the wellbore and on the cuttings, and the glycol depletion rate will be a function of drilling ROPs and cuttings size. The glycol concentration therefore needs to be monitored to ensure that levels are maintained for effective shale inhibition.



Refractometer used for measuring Glycol Concentration

The concentration of glycol in the mud can be determined using a Refractometer, which measures the refraction of light through a liquid, since the amount of refraction will depend on the concentration of the fluid. The procedure requires the preparation of a calibration curve so that refraction readings can be converted into glycol concentrations. The following equipment is required for measuring Glycol concentration:

1. Refractometer suitable for the Glycol Volume % range used in the mud system.
2. Reference glycol for calibrating the Refractometer.
3. 10 ml or 50 ml retort
4. 10 ml or 50 ml graduated measuring cylinder

Calibration Curve – A calibration curve must be prepared using a reference glycol (The actual glycol that is being added to the mud can be used when reference glycol is not available). The calibration curve is prepared using linear graph paper by adding increasing volume percentage glycol to deionized water, and then plotting the corresponding refractive index or Brix reading from the Refractometer against the volume percentage glycol added.

The following procedure is used for determining the glycol content in the liquid phase of the fluid:

1. Without touching the prism surface, calibrate the refractometer by placing a few drops of distilled water on the face of the prism and make sure that the entire prism surface is covered with water.
2. Close the prism cover and look through the refractometer window with the prism end pointing towards a light source.
3. Check to see if the boundary line coincides with the 1.000 line on the Specific Gravity scale, or 1.333 on the Refractive Index scale (If not, adjust the line by turning the scale-adjustment screw).
4. Dry the prism surface and prism cover with a paper tissue.
5. Run a retort on the drilling fluid and record the volume percent liquid.
6. Shake up the liquid collected in the graduated measuring cylinder from the retort (the mud filtrate collected from the HPHT test can also be used).
7. Without touching the prism surface, place 2-4 drops of the fluid sample on the refractometer prism surface and make sure that the entire prism surface is covered with the fluid sample.
8. Close the prism cover and look through the refractometer window with the prism end pointing towards a light source.
9. Read the Refractive Index or Brix value where the boundary line intercepts the scale.
10. From the glycol calibration curve obtain the corresponding glycol volume percentage.
11. Multiply the glycol volume percentage value by the liquid fraction of the mud (Fw) to get the glycol concentration of the whole mud.
12. Wipe and clean the prism surface and prism cover with a paper tissue and distilled water.

Chemical Testing Procedures for Oil-Based Fluids

The following testing procedures have been standardized in accordance with internationally accepted API RP 13B-2 Fourth Edition, March 2005 (Recommended Practice for Field Testing Oil-Based Drilling Fluids):

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Electrical Stability (ES)

The Electrical Stability of an oil-based mud is a measure of the strength of the oil/water emulsion. The ES Meter is a battery-powered device with a digital voltage display connected to a probe that contains two flat-plate electrodes a fixed distance apart. The probe is immersed in the oil-based mud sample and a voltage is applied to the electrodes on the probe. The voltage automatically increases until it is high enough to break down the oil/water emulsion.

ES Meter used for measuring Electrical Stability

A weak emulsion will break down with a relatively low voltage across the electrodes but a strong emulsion will require a much higher voltage before breaking down. The voltage required to break down the emulsion appears on the digital voltage display. The Electrical Stability is usually measured at 120°F (50°C) using the rheometer heating cup before or after taking rheometer readings.

The procedure for measuring Electrical Stability is as follows:

1. Fill the rheometer heating cup with oil-based mud that has been screened through a Marsh Funnel.
2. Check that the gap between the ES probe electrodes is clean and dry, and stir the mud with the ES probe until the mud sample temperature is uniform at 120°F (50°C)
3. Hold the probe steady in the mud sample, making sure the probe does not touch the side or bottom of the heating cup.
4. Start the voltage ramp test until the digital voltage reading becomes steady, which gives the Electrical Stability (ES) of the mud (in peak volts).
5. Stir the same mud sample with the ES probe and confirm the ES reading by repeating the measuring procedure in Steps 3 and 4 (both ES readings should be within 5% of each other). The ES meter and probe may be faulty if the difference between the two ES readings is greater than 5%.
6. The average of the two ES measurements should be reported.
7. Clean the ES probe and check that the gap between the electrodes is clean and dry for future use.

The Electrical Stability is usually maintained above +/- 300 volts. The ES may drop if the mud has been static for an extended period of time (i.e. during round trips), but it usually recovers once circulation resumes and the mud has been sheared through the bit, which restores the quality of the emulsion. ES readings can be improved by adding emulsifiers to improve the oil/water emulsion.

Whole Mud Alkalinity and Lime Content

Alkaline products help to stabilize oil-water emulsions and they also neutralize acidic gases that may be encountered while drilling (e.g. CO2 and $_H$2S), which is why oil-based muds are formulated with Lime. The Whole Mud Alkalinity test is a titration method for measuring the amount of Lime that is present in the oil-based mud (i.e. Excess Lime).

Equipment used for measuring Whole Mud Alkalinity and Lime Content.

The test requires the following equipment:

1. Propylene Glycol Normal Propyl Ether (PNP) solvent
2. 400 ml glass beaker
3. Graduated measuring cylinder (100 ml)
4. 5 ml syringe
5. De-Ionized Water
6. Phenolphthalein indicator solution
7. Sulfuric Acid (0.1N solution)
8. Sodium Hydroxide (0.1N solution)
9. 1 ml graduated pipette
10. 10 ml graduated pipette
11. Magnetic Stirrer with plastic-coated stirrer bar

The titration procedure for determining alkalinity in OBM requires 100 ml PNP solvent. This solvent will consume a small amount of alkalinity and this is known as the Base Alkalinity Demand (BAD). The BAD can be determined and added to the alkalinity measurement for the OBM, to produce a more accurate representation of the alkalinity/lime content.

The procedure for performing Whole Mud Alkalinity is as follows:

Base Alkalinity Demand

1. Use a graduated measuring cylinder to transfer 100 ml Propylene Glycol Normal Propyl Ether (PNP) solvent into the 400 ml glass beaker.
2. Add 200 ml de-ionized water, 15 drops of phenolphthalein indicator solution and mix using the magnetic stirrer.
3. Titrate immediately with 0.1N NaOH solution, while stirring, until a pink color just appears.
4. Continue stirring for 5 minutes. If the pink color remains, the end point has been reached. If the pink color disappears then continue the titration by repeating Step 3. The Base Alkalinity Demand (BAD) can be calculated from the volume of 0.1N sodium hydroxide used in the titration as shown in Figure 15 below.

Whole Mud Alkalinity

1. Use a graduated measuring cylinder to transfer 100 ml Propylene Glycol Normal Propyl Ether (PNP) solvent into the 400 ml glass beaker
2. Fill the 5 ml syringe with a sample of oil-based mud, making sure that it contains no bubbles, and displace 2 ml of this mud into the 400 ml glass beaker
3. Swirl the contents of the glass beaker until the oil-based mud and solvent is homogeneous.
4. Add 200 ml de-ionized water to the glass beaker and add 15 drops of phenolphthalein indicator solution (Alkalinity from the Lime will turn the solution pink)
5. Place the plastic-coated stirrer bar in the beaker, place the beaker on the magnetic stirrer and adjust speed to stir the contents rapidly
6. Use a 1 ml or 10 ml pipette to carefully titrate the fluid in the glass beaker with 0.1N sulfuric acid until the pink color just disappears.
7. Continue stirring the fluid for one minute, then stop stirring and leave the fluid to stand for five minutes. Continue titrating with 0.1N sulfuric acid if a pink color reappears, otherwise the end point has been reached.

Base Alkalinity Demand (BAD) = ml of NaOH (0.1N) solution

Figure 15: Calculation for determining Base Alkalinity Demand.

8. The Whole Mud Alkalinity can be calculated from the volume of 0.1N sulfuric acid used in the titration (ml). See Figure 16 below.

$$\text{Whole Mud Alkalinity} = \frac{\text{ml 0.1N sulfuric acid used + (BAD)}}{\text{Mud sample volume (ml)}}$$

$$\text{Whole Mud Alkalinity} = \frac{\text{ml 0.1N sulfuric acid used + (BAD)}}{\text{2ml}}$$

$$\text{Lime Content (lb/bbl)} = \text{1.295 x whole mud Alkalinity}$$

Figure 16: Calculations for determining Whole Mud Alkalinity and Lime Content.

Whole Mud Chloride Content (Water Phase Salinity)

The water or brine phase of an oil-based mud usually comprises calcium or sodium chloride brine, with salinity adjusted so that the Water Activity (Aw) of the brine matches that of the fluid trapped in the shale pores. If the water activity of the oil-based mud brine phase is too high or too low relative to formation fluids, then there will be a natural movement of fluid into or out of the formation until the water activity is equalized. A shale formation may therefore be subject to hydration or dehydration, and potential wellbore instability, if there is a significant mismatch in water phase salinity. The aim while drilling is to maintain balanced activity.

Equipment used for measuring Whole Mud Chloride Content.

The Whole Mud Chloride Content is usually measured with the same fluid sample after measuring Whole Mud Alkalinity. The procedure is similar to the Silver Nitrate titration method used on water-based fluids to precipitate out Silver Chloride. As with the water-based procedure, the titration must be performed under acidic conditions. The additional equipment required for measuring Whole Mud Chloride Content is as follows:

1. Potassium Chromate indicator solution
2. Silver Nitrate reagent (0.282 N)
3. Sulfuric Acid (0.1N solution)
4. 1 ml graduated pipette
5. 10 ml graduated pipette

The procedure for measuring Whole Mud Chloride Content is as follows:

1. Make sure the sample to be titrated for chlorides is acidic (below pH 7.0) by adding 10 to 20 drops 0.1N sulfuric acid to the same sample used for the Alkalinity test.
2. Add 10 to 15 drops Potassium Chromate indicator Adjust the speed of the magnetic stirrer so that the contents of the glass beaker are stirred rapidly.
3. Use a 1 ml or 10 ml pipette to carefully titrate the fluid in the glass beaker with 0.282N Silver Nitrate reagent until the fluid turns salmon-pink in color and remains stable for at least one minute.
4. The Whole Mud Chloride Content can be calculated from the volume of 0.282N Silver Nitrate used in the titration (ml). See Figure 17 below.

The Whole Mud Chlorides can be attributed to the brine phase as long as the brine phase is below saturation point. The Water Phase Salinity is important for shale inhibition and also for calculating corrected solids from the retort results, since the “solids” reading from the retort will include the dissolved salts in the brine phase.

$$\text{Whole Mud Chloride Content (mg/l)} = \frac{\text{10,000 x ml 0.282N Solver Nitrate}}{\text{Mud Sample Volume (usually 2ml)}}$$

Figure 17: Calculation for determining Whole Mud Chloride Content.

Whole Mud Calcium Content

The test for whole mud chlorides may be useful for determining water phase salinity, but it does not distinguish between sodium and calcium chloride in the brine phase. Whole Mud Calcium is a titration method for measuring calcium concentration in the mud, which enables the calcium chloride concentration in the brine phase to be calculated. Calcium in the mud will come from calcium chloride and lime (calcium hydroxide) used in the formulation, but may also come from the formation in the form of gypsum or anhydrite (calcium sulfate).

Equipment used for measuring Whole Mud Calcium Content.

The test requires the following equipment:

1. Propylene Glycol Normal Propyl Ether (PNP) solvent
2. 500 ml glass conical flask with stopper
3. Graduated measuring cylinder (100 ml)
4. 5 ml syringe
5. De-Ionized Water
6. Sodium Hydroxide buffer solution (1N)
7. Calver II indicator powder
8. 1 ml graduated pipette
9. 10 ml graduated pipette
10. EDTA reagent (0.1M)
11. Magnetic Stirrer with plastic-coated stirrer bar

The procedure for measuring Whole Mud Calcium Content is as follows:

1. Use a graduated measuring cylinder to transfer 100 ml Propylene Glycol Normal Propyl Ether (PNP) solvent into a 500 ml conical flask.
2. Fill the 5 ml syringe with a sample of oil-based mud, making sure that it contains no bubbles, and transfer 2 ml of this mud into the conical flask.
3. Place the stopper on the conical flask and shake vigorously until the mixture is homogenous.
4. Add 200 ml de-ionized water to the conical flask.
5. Add 6 ml 1N Sodium Hydroxide buffer solution to the conical flask.
6. Add Calver II indicator powder to the conical flask.
7. Place the stopper on the conical flask and shake vigorously for two minutes.
8. The presence of calcium will produce a red coloration in the lower aqueous phase as the oil and water separates out to form two layers.
9. Place the plastic-coated stirrer bar in the conical flask, place the flask on the magnetic stirrer and adjust the speed to stir the contents without actually mixing the oil and aqueous phases.
10. Use a 1 ml or 10 ml pipette to carefully titrate the water phase in the conical flask with 0.1M EDTA until the color of the fluid changes from red to blue-green.
11. The Whole Mud Calcium Content can be calculated from the volume of EDTA used in the titration (ml). See Figure 18 below.

$$\text{Whole Mud Calcium} = \frac{4{,}000 \times \text{ml } 0.1\text{M EDTA}}{\text{Mud Sample Volume (ml)}}$$

$$\frac{4{,}000 \times \text{ml } 0.1\text{M EDTA}}{2 \text{ ml}}$$

Figure 18: Calculation for determining Whole Mud Calcium.

Testing Procedures for Workover/Completion Brines

Brine cleanliness is critical for completion and production operations because the presence of solids can prevent successful running, setting and sealing of down-hole assemblies. Two brine properties are used for measuring brine cleanliness, as follows:

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Turbidity Meter for Brine Clarity

Turbidity describes the clarity or cloudiness of a fluid due to suspended colloidal particles and it is measured in NTU (Nephelometric Turbidity Units). The turbidity meter works by shining a beam of light through a sample of brine. If the brine is absolutely clean then the beam of light will pass through the sample and will not be detected by a light sensor mounted perpendicular to the light source. However, if the brine contains a suspension of fine particles then the light will strike the particles in solution and will be scattered in all directions. The scattered light is detected by the light sensor, which converts it into a reading in NTU.

Turbidity Meter used for measuring brine cleanliness

The turbidity meter is battery-powered and is supplied with a set of three reference samples (0 NTU, 1 NTU and 10 NTU standard solutions) that are used for calibrating the turbidity meter before use, along with a couple of empty glass sample tubes. The glass sample tubes must be clean before use, making sure there are no marks on the glass surface, which could affect turbidity readings. The glass sample tube is filled to the mark with a representative sample of brine and sufficient time should be allowed for air bubbles to escape to surface before taking a turbidity reading. The procedure for measuring brine turbidity is as follows:

1. Press the “On” button to turn the meter on.
2. Press the “OK” button to select “Measure”.
3. Rinse a clean glass tube three times with “blank fluid” (0 – 0.1 NTU water).
4. Fill the glass tube to the fill line with “blank fluid”, pouring it down the inside of the tube to avoid creating bubbles.
5. Dry the glass tube with lint-free cloth, put the (dry) positioning ring in place and cap the tube before wiping the tube thoroughly again with lint-free cloth.
6. Open the meter lid, place the glass tube in the chamber and align the index notch on the positioning ring with the index arrow on the meter before closing the lid.
7. Press the “OK” button to select “Scan Blank” and wait until a digital reading is displayed, which should be very close to 0.00 for the “blank fluid”.
8. Rinse the glass tube three times with the sample fluid to be tested (for best results, use the same glass tube for the blank fluid and for the sample).
9. Fill the glass tube to the fill line with the sample fluid, pouring it down the inside of the tube to avoid creating bubbles.
10. Dry the glass tube with lint-free cloth, put the (dry) positioning ring in place and cap the tube before wiping the tube thoroughly again with lint-free cloth.
11. Open the meter lid, place the glass tube in the chamber and align the index notch on the positioning ring with the index arrow on the meter before closing the lid.
12. Press the “OK” button to select “Scan Sample” and wait until a digital reading is displayed and record the result.
13. If necessary, repeat the measuring steps to confirm the result.
14. Press the “Off” button to turn the meter off.

Turbidity readings are quick and easy, but they should only be used as a guide to fluid cleanliness because they can be affected by fluid discoloration and give misleading results, even when the fluid contains no solids. The completion program will usually have a specification for brine turbidity, which is usually around 20 to 30 NTUs. Filtration will generally continue until this target is achieved or, following a decision by the client representative, until there is no further improvement in turbidity readings.

Centrifuge for Solids Content

A laboratory centrifuge or a hand-crank centrifuge with 100 ml graduated glass centrifuge tubes is used for measuring the solids content of a brine sample from the wellbore. The glass centrifuge tubes can measure solids to the nearest 0.25 %, although solids can be estimated down to about 0.1 %. This is the only real method for determining brine cleanliness because the turbidity meter can sometimes give false readings due to other factors (microscopic air bubbles or brine discoloration).

The completion or workover program will normally specify brine cleanliness requirements either as a turbidity reading, percentage solids, or both. Mud Engineers often prepare a chart that records time, pump strokes, volume pumped, brine turbidity and solids going in the hole, and brine turbidity and solids coming out of the hole. This provides useful information when reviewing the effectiveness of brine filtration and wellbore cleanliness.

The aim of filtration is to remove solids from the hole, which could prevent the production tubing assemblies from sealing and safely isolating the reservoir. A build up of solids could also provide conditions that could encourage corrosion and premature failure of wellbore tubulars. The solids might look to be in suspension in the brine, but they will eventually settle, so it is always worth calculating potential settled solids while filtering brine. If the hole contains 500 bbls brine and solids is measured at 0.25 %, then the hole will contain 1¼ bbls solids and this could occupy several feet or meters of hole.

Pilot Testing

It is sometimes useful to perform pilot tests before making full-scale treatments to the entire circulating mud system, to confirm that a particular treatment will have the desired effect or to avoid potential over-treatments. Pilot testing is carried out for a variety of reasons, one of which is to check the tolerance of the mud system if certain contaminants are expected while drilling.

Pilot testing can also be used for confirming the effectiveness of potential treatments in restoring mud properties after incidents such as severe cement contamination, acidic gas influxes (e.g. CO_2 or H_2S) or contaminants from the formation being drilled (e.g. anhydrite or salt). Pilot testing at the rig site has distinct practical advantages compared with sending mud samples to a laboratory or preparing mud in the laboratory for pilot testing. Rig site testing allows actual material and active mud to be used, and the pilot test results are available for evaluation by the rig supervisor and mud engineer relatively quickly.

Pilot testing is usually carried out using a 1 lab barrel (350 ml) fluid sample, and the fact that 1 gm/350 ml is equivalent to 1 lb/bbl, which is a simple conversion based on 159 liter/bbl. A beam balance or electronic scales accurate to 0.1 gram are used for measuring the correct weight of treating products (in gram) to obtain the required concentrations (in lb/bbl). The treating products are then mixed into a 350 ml sample of active mud (1 lab barrel), and sheared at high speed using a Hamilton Beach mixer.

As an example, a pilot test might be carried out on a sample of cement-contaminated water-based mud using 2 lb/bbl Sodium Bicarbonate. To do this, 2 gm Sodium Bicarbonate would be added to a 350 ml sample of the cement-contaminated mud while shearing on the Hamilton Beach mixer. If relatively large amounts of treating products are being added then the mud sample volume should be reduced to allow for the displacement volume of the treating product(s), so that 1 lab barrel (350 ml) is obtained after adding the treating product(s).

Some pilot tests require a portable roller oven so that samples can be hot-rolled at simulated down-hole temperatures for a specified period of time. When this is the case then an untreated sample of mud should also be hot-rolled so that results after hot-rolling can be compared. Caution is required when reviewing pilot test results because they may not always be replicated on the mud circulating in the hole, since down-hole conditions are constantly changing.

Solids Control Equipment

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Introduction

The Solids Control Equipment (SCE) is designed to remove drilled solids (i.e. cuttings) from the drilling fluid. In an ideal situation, drilled cuttings generated at the bit would be large and the drilling fluid would carry them to the surface, where they would then be separated out and discarded. In reality, drilled cuttings range in size according to drilling conditions and end up in the drilling fluid if they are too small to be removed by the Solids Control Equipment. As a result, drilling fluids usually contain two types of solids:

- HGS = High Gravity Solids (weighting agents like Barite at 4.2 sg)
- LGS = Low Gravity Solids (drilled solids around 2.6 sg)

Drilling fluids may also contain insoluble solids from product additives (e.g. bridging materials), but concentrations are usually relatively low compared to HGS and LGS. Larger solids are relatively easy to separate out at surface and their presence in the drilling fluid is generally not a problem. However, if larger solids are not removed when they arrive at surface then they will be recirculated in the hole and get eroded into smaller particles, making them even more difficult to remove. A build-up of ultra-fine particles that cannot be removed from the drilling fluid will have a detrimental effect on drilling fluid performance, including some or all of the following:

- Undesirable increase in fluid density, resulting in higher ECDs
- Undesirable increase in fluid viscosity, resulting in higher ECDs
- Reduction in filter cake quality, resulting in increased shale hydration
- Higher ECDs may increase the drilling fluid losses to the formation
- Higher fluid viscosity will increase swab and surge pressures while tripping
- High solids content and poor fluid loss control may encourage differential sticking

As a guide, ultra-fine drilled solids (i.e. Low Gravity Solids) are usually controlled below 8% or even 5% for un-weighted water-based drilling fluids. Higher limits can be set for oil or synthetic-based drilling fluids because they are more tolerant to solids. If the drilled solids are too small to be removed by the SCE, then they can be controlled by diluting the drilling fluid with freshly-mixed fluid, but this creates a large volume of fluid that is uneconomical in terms of fluid cost and storage space requirements.

The uncontrolled build-up of ultra-fine solids will eventually affect the quality of the filter cake produced by the drilling fluid, which should be thin, slick, impermeable, and compressible. A poor filter cake will provide conditions for severe shale hydration, hole problems and reduced ROPs, resulting in increased drilling fluid costs and increased fluid disposal costs. For similar reasons it is important to remove solids larger than 74 microns because their presence in the drilling fluid will also produce a poor quality filter cake, with potential hole problems.

The effective use of SCE will reduce well costs by slowing down the build-up of drilled solids in the drilling fluid. This will extend the life of drilling fluid, as well as reducing storage space requirements. The ideal situation is to remove all the cuttings from the hole as soon as they are carried to the surface in the drilling fluid, but this is not possible because some of the cuttings will be subjected to chemical or mechanical erosion, allowing drilled solids to build up in the drilling fluid. Controlling the build-up of drilled solids in the drilling fluid can be achieved by a combination of chemical inhibition and mechanical or physical separation.

Chemical Inhibition

It is important to maintain effective inhibition, as explained in other sections of this manual, in order to minimize clay and shale hydration and dispersion. Keeping the pH around 8.5 to 9.0 will help to achieve this by discouraging hydration and enhancing polymer performance, resulting in aggregation of drilled solids into “flocs” or clumps that are large enough to be removed from the drilling fluid using fine-mesh shale-shaker screens.

Chemical control is further assisted by using fluid loss control additives, which effectively “tie up” the free water in the drilling fluid. This restricts the amount of water available for hydrating shale that is exposed on the surface of the wellbore and drilled cuttings moving up the annulus. Less hydration leads to improved wellbore stability and less sloughing (wellbore collapse).

Mechanical Erosion

This is the mechanical breakdown of cuttings into smaller fragments through abrasion. The surface of the wellbore and the drilled solids in the annulus are subjected to mechanical erosion caused by the movement of the drilling fluid and the drill string in the hole. Mechanical erosion can be minimized by optimizing the pump rate to ensure laminar flow in the annulus, in order to minimize erosion of the wellbore by the drilling fluid.

Any drilled solids that are not removed by the Solids Control Equipment will remain in the drilling fluid and be subject to additional mechanical erosion by the mud pumps and surface lines, before being pumped down hole again. This will gradually create ultra-fines in the drilling fluid and eventually colloidal particles that are impossible to remove. Ideally, Barite should be retained in the drilling fluid, but the removal of some Barite with drilled solids is economically viable because the cost of Barite additions to maintain fluid density is considerably cheaper than the cost of building fresh mud for dilutions.

If the build up of fine solids in the drilling fluid reaches the level where increasing viscosity and gels cannot be controlled, then it may be necessary to “dump-and-dilute”, where a quantity of solids-laden mud is removed from the circulating system and replaced with freshly-mixed mud. This is only effective if a significant volume of the circulating system is replaced with fresh drilling fluid. As a rough guide, dumping and diluting anything less than 25% of the circulating system is unlikely to be effective, but that will depend on the situation and the amount of hole to be drilled.

Particle Size

Particles in the drilling fluid (e.g. Drilled Solids, Barite, LCM or Bridging Agents) are usually categorized as follows:

Particle Classification	Particle Size	Sieve Size
Coarse	Above 2000 micron	10-mesh
Intermediate	250 to 2000 micron	60-mesh
Medium	74 to 250 micron	200-mesh
Fine	44 to 74 micron	325-mesh
Ultra-Fine	2 to 44 micron	-
Colloidal	Below 2 micron	-

Poor solids control will allow larger particles to be retained in the drilling fluid, and large particles produce a poor quality filter cake with poor fluid loss control, which can lead to differentially stuck pipe and other mud-related problems. The large particles eventually get broken down into smaller particles during subsequent circulations around the hole, making them more difficult to remove, if not impossible. It is therefore advantageous to remove all larger solids, whether drilled solids or Barite.

It is important to remove cuttings at the earliest opportunity because they will be subjected to chemical and mechanical erosion the longer they remain in the circulating system. This can be achieved by installing the finest shale-shaker screen mesh size that can handle the flow-rate. It is equally important to check the screens regularly to make sure that they are all in good condition and not damaged.

Allowing drilled solids to pass through coarse or damaged screens will eventually result in some of them being recirculated down hole, and they will be eroded into finer particles by the time they return to surface, making them more difficult to remove. However, even if the finest shale shaker screens (325-mesh screen size) could handle the flow, they would not be able to screen out ultra-fine particles below 44 microns, which would gradually be eroded into colloidal particles as they are repeatedly circulated around the hole.

Centrifuges can remove some of the ultra-fine particles, but they can only handle a relatively small percentage of the drilling fluid returns from the hole. As a result, there is no way to prevent a gradual increase in the volume of colloidal particles in the circulating system, which may eventually reach the point where viscosity starts to increase, along with progressive gels and a reduction in drilling performance. At this point there may be no choice but to “dump-and-dilute” with fresh mud.

It is important to note that most Barite particles are in the 2 to 44 micron size range. However, up to 3% weight of Barite that meets API Specifications may have particle sizes larger than 74 microns, so a significant amount of Barite may be discarded by the Solids Control Equipment following any additions of Barite to the circulating system.

Solids Control Equipment

The equipment listed below is usually available at the rig site for removing drilled solids from the circulating drilling fluid:

1. Scalping Shaker
2. Shale Shaker
3. Gas Buster and Degasser
4. Desander
5. Desilter
6. Mud Cleaner
7. Centrifuge

Scalping Shaker

The scalping shaker is similar to a conventional shale-shaker (see below), but is dressed with a very coarse vibrating screen that is designed to remove large cuttings and clumps of sticky clays in the solids-laden drilling fluid returns. The scalping shaker is usually dressed with a 20-mesh or 40-mesh screen, and is effective for removing "gumbo" (large clumps of very sticky clay) from the circulating system without getting blinded.

The scalping screen slopes down slightly, so the larger cuttings and clumps of sticky clays gradually travel along the screen before dropping off the end into a cuttings discharge chute. The underflow from the scalping shaker travels along a flow line to the shale-shakers. Some shale-shakers are fitted with a coarse scalping screen that is mounted above the conventional shale-shaker screens, eliminating the need for a separate scalping shaker.

Shale-Shaker

Shale-Shakers come in a variety of designs and are the primary means of separating cuttings and drilled solids from circulating drilling fluids. As with the scalping shaker, drilling fluid returns from the hole are passed over vibrating shaker screens to remove larger particles, while allowing barite and smaller particles to pass through the screens with the drilling fluid. Shale shakers will work efficiently and keep drilling fluids in good condition as long as screen size is optimized for maximum solids removal and damaged screens are replaced at the earliest opportunity.

A Pair of Shale Shakers

Cuttings being removed by the shale-shaker screens

Coarser shaker screens are built using a stronger wire mesh and usually last much longer than finer shaker screens. However, all shaker screens should be checked for damage or holes at regular intervals, usually when the mud pumps are shut down while making a connection. During periods of slow drilling, when it might take a few hours between connections, flow should be diverted to the other shale-shakers while circulating, so that screens can be checked and damaged screens can be replaced.

Damaged or holed shaker screens must be replaced as soon as possible, in order to minimize the amount of solids getting into the drilling fluid. The damaged areas of a shaker screen can be sealed using patches or silicone sealant, in order to extend the life of the shaker screen, but the screen should not be used if 30% of the screen area has been repaired, since this will affect flow handling capacity.

Several factors will affect choice of shaker screen size. Coarser shaker screens can handle higher flow rates, but more drilled solids will pass through the screens and into the circulating system. Finer shaker screens will remove more solids, but they may not be able to handle higher circulating rates. Other factors such as fluid rheology, temperature and solids content will also affect choice of shaker screen size. Care should be taken when treating the circulating system with polymers, especially starches and PHPA, because they may blind the shaker screens if they have not had a chance to shear thoroughly.

Shaker screens can sometimes get blinded when fine particles (especially sand) are of similar size and therefore lodge in the screen openings, which restrict the flow of fluid through the shaker screens. The natural tendency is to install coarser screens, but this will allow more drilled solids to enter the circulating system. However, the installation of finer shaker screens may also solve the sand blinding problem if the mesh size is fine enough to prevent sand particles plugging the screen mesh, and this would prevent the unnecessary ingress of drilled solids.

There are usually two or more shale-shakers for separating drilled solids from the drilling fluid returns from the hole. Drilling fluid returns from the hole (and scalping shaker, if installed), travel along a flow line and into a distribution box, where flow can be directed to the header box (possum belly) of one or more shale shakers. The drilling fluid then flows onto a vibrating screen that removes the solids, which are discharged at the front of the shale-shaker. The drilling fluid passes through the vibrating screen to the shaker bed, and from there to the process tanks.

The aim should be to install the finest shaker screens that can handle the flow rate, but it is important to note that API 200 shaker screens (200-mesh with 74-micron screen openings) may remove some Barite because API specifications state that 3% Barite can be larger than 74-microns. Finer screens may also be possible, but these will almost certainly start to remove Barite from the circulating system, so the mud density returns to the active tank should be monitored closely.

The aim is to remove drilled solids without losing too much drilling fluid, which requires the drilling fluid "pond" on the shaker screen to occupy about two-thirds of the shaker screen, with a "beach" at the cuttings discharge end that shakes off excess fluid on the solids. The pond will get larger if the shaker screens struggle to handle the flow, and if this happens then the beach length will get shorter, producing a wetter solids discharge. If the circulating flow rate cannot be reduced then it may be necessary to install coarser shaker screens to maintain an effective beach length and minimize drilling fluid losses.

Shale-Shakers are available that apply circular, elliptical or linear motion to the shaker screens. The shaker screens on circular and elliptical motion shale-shakers generally slope down towards the discharge chute so that cuttings move in that direction. Linear motion shale-shakers are generally more effective because the linear motion is applied at an angle approximately 45° to the shaker screens, resulting in horizontal and vertical forces acting on the shaker screens.

The horizontal force acting parallel to the shaker screen pushes the cuttings towards the discharge chute and is powerful enough to transport cuttings uphill with the shaker screens sloping back. This slope helps to keep drilling fluid away from the discharge end, resulting in less fluid retention on the cuttings, and also forms a pool of fluid at the back of the shaker screens which, combined with the vertical force acting down on the shaker screens, pushes more fluid through the screen openings, increasing fluid handling capacity and efficiency.

The angle of the shaker screen slope can be adjusted using mechanical or hydraulic jacks fitted near the front of the deck, allowing the slope to be reduced for improved cuttings removal when drilling stickier clays. Other factors that will also affect the fluids handling performance of the shale-shaker and shaker screen are vibration frequency and strength, fluid properties (viscosity and density), ROP and type of drilled cuttings.

Some shale-shakers have single deck screens while others have multi-deck screens that allow coarser screens to be placed on the top deck for removing larger cuttings. This reduces the solids loading on the lower deck(s), which can then be dressed with finer screens. The result is greater fluid handling capacity and longer shaker screen life. A scalping screen is sometimes fitted above single-deck shale-shakers for removing clumps of sticky clay, but this does not mean that it is classed as a double-deck shale-shaker.

Cuttings Shape and Behaviour – Observation of the cuttings screened out at the shakers will reveal the effectiveness of cuttings transport in the annulus. If cuttings transport is good then the larger cuttings should have sharp edges, reflecting the way they are broken off by the drill bit. If cuttings transport is poor then the cuttings will spend longer getting knocked around in the annulus and will be more rounded by the time they arrive at surface.

Small cuttings and fine solids arriving at surface are coated by a layer of drilling fluid and the surface tension of this fluid causes the solids to agglomerate together as they leave the pond and start moving up the beach. As a result, instead of passing through the shaker screen openings, a significant volume of fine solids stick together to form larger beads that are bigger than the screen openings.

The use of a spray bar to keep cuttings mobile on the beach area is of limited benefit because the water spray has a tendency to break up the beads, allowing fine solids to pass through the screen openings. Another practice to be avoided is that of partially bypassing the shakers when they are struggling to handle the drilling fluid returns. This simply increases the amount of solids in the drilling fluid, which will make the situation worse after the next circulation.

Shaker Guidelines – The following guidelines should be used for shale-shakers:

1. The drilling fluid pool on the shaker screens should cover roughly two-thirds of the screen area for maximum efficiency. A larger pool area will produce wetter cuttings and a smaller pool area is a sign to fit finer screens.
2. Check the shaker screens at regular intervals (e.g.when circulation is stopped to make a connection), and replace damaged screens as soon as possible as this will reduce the build up of solids in the drilling fluid.
3. Finer shaker screens usually have a shorter life than coarser shaker screens, so should be checked more often. Where possible, damaged shaker screens should be replaced when circulation is stopped during a connection.
4. Never bypass the shale-shakers because this will increase the build-up of solids in the drilling fluid and make the situation worse later on.
5. Check that the shale-shaker bypass valves are closed at all times while drilling, so that cuttings from the hole are sent to the shale-shakers.
6. If the shale-shakers are struggling to handle the flow rate, and the flow rate cannot be reduced, then coarser shaker screens may be necessary.
7. Try to run the same screen size if each deck accommodates two or three shaker screens. If a coarser screen is required to handle the flow, then keep the finer screens at the back and fit the coarser screen at the front, near the cuttings discharge chute (the cuttings will aggregate into larger particles and march across the coarser shaker screen).
8. Use the water-spray bars sparingly when it is necessary to assist with the removal of sticky cuttings, because the water will wash fine solids back into the drilling fluid and may also reduce the fluid density.
9. The use of high-pressure wash-down guns to clean shaker screens should be avoided, unless they have been removed from the shale-shaker, because this will erode the solids into smaller particles and force them through the shaker screen openings.
10. Remove the shaker screens, wash with water, check for damage and install back on the shale shakers if circulation is suspended for a long period, to prevent drilling fluid drying out and plugging the screen openings.
11. If water needs to be added to the circulating system then this should be done at the active tank and not at the shale-shakers, to prevent fines being washed into the drilling fluid.
12. The header-box (possum belly) should be discharged into a waste pit if it fills up with solids. The solids should never be drained down to the sand traps as this will return solids back to the drilling fluid.

If the shale shaker screens start to blind, resulting in the loss of whole mud across the front of the shakers, then coarser screens should be fitted after asking the driller to reduce the circulation rate if required. Screen blinding usually occurs while drilling fine sand formations, when the sand particles are about the same size as the shaker screen openings. When this happens, the sand particles plug the screen openings and this prevents drilling fluid from passing through. Screen blinding may also be resolved by fitting finer shaker screens because by doing this the sand particles may be too large to lodge in the smaller screen openings.

There is a tendency to increase the shale shaker inclination to control whole mud losses at the front of the shakers. However, this is not good practice, especially with fine shaker screens, because it makes it difficult for the cuttings to move along the beach. Instead, the shaker pond becomes overloaded with cuttings and this leads to premature shaker screen failure. The correct procedure is to select shaker screen size so that cuttings can move freely up a gently inclined beach. This will ensure that the shaker screens are not overloaded with cuttings, which will increase the life of the screens.

Screen Mesh and Mesh Size – Shaker screens are manufactured with square and oblong (rectangular) mesh, and mesh size is defined as the number of openings (or wires) per linear inch. A 120-mesh shaker screen will therefore have 120 openings or wires per linear inch in both directions, indicating that it has a square mesh. A 40x80 mesh shaker screen will have 40 openings or wires per inch in one direction, and 80 openings or wires per inch in the other direction, indicating that it has an oblong mesh.

The screen mesh size is different to the screen opening size, but the two are related. The size of the openings on a shaker screen (i.e. distance in microns between adjacent wires) is determined by the screen mesh size (i.e. wires per linear inch) and the wire size (i.e. wire diameter). As an example, a 120-mesh screen with 94-micron wire diameter will have 117-micron screen openings (1 inch = 25,400 microns; wire pitch = screen opening + wire diameter = 25,400 ÷ 120 = 211 microns; screen opening = 211 – 94 = 117 microns).

Identifying shaker screens by mesh size has its limitations because screen manufacturers use a range of wire diameters in order to achieve optimum screen performance, according to three categories: Market Grade (MG), Tensile Bolting Cloth (TBC) and Extra-Fine Wire Cloth (XF). A shaker screen manufactured with larger diameter wire will be stronger and more resistant to abrasion than a similar shaker screen size manufactured with thinner wire. The screen openings will also be smaller, which means that smaller solids will be removed, but the flow area will also be smaller and flow rates may be significantly restricted with larger diameter wires.

Screen identification is further complicated by the arrival of three-dimensional “corrugated” screens in the 1990s. With this design, drilled solids move along the “troughs” and the drilling fluid passes through the inclined “corrugated” mesh, which provides a larger surface area than flat shaker screens and increases the fluid capacity for a particular mesh size. Shaker screen development has also produced screens that are layered to form complex opening patterns. As a result, a new system has been created to take the guesswork out of screen selection.

Shaker Screen Identification – Identifying screens by mesh size (the number of openings per inch) was effective in the past, when screen openings were square-shaped, but mesh size on its own is now almost meaningless following all the developments in shaker screen technology. Shaker Screens are now identified according to API (American Petroleum Institute) standards, as follows:

- API Number (e.g. API 120 = 120-mesh)
- Microns (The screen opening size)
- Conductance (The ease with which a liquid can flow through the screen)
- Non-Blanked Area (The surface area of the screen that is open for fluid to pass)

The API number still refers to the mesh size, but it enables API Standards to conform with ISO (International Standards Organization) Standards by eliminating the inch as a unit of measure.

Shaker Screen Care – Whenever shaker screens are removed from the shale shakers due to mesh damage or change of screen size, then they should be cleaned away from the shaker area by hosing down with fresh water to remove residual solids and salts, in order to avoid corrosion. Screens that are in good condition can then be stored for re-use and preparations can be made to repair damaged screens.

Screen repairs are usually made by smearing a layer of silicone sealant or resin across the broken mesh grid section, or by cutting out the damaged mesh grid section and inserting a plastic plug that is supplied by some screen manufacturers. The surface flow area of the shaker screen will obviously reduce as more grid sections are repaired and, as a guide, the screen should be scrapped when repairs cover around one-third of the original surface flow area.

Gas Buster and Degasser

The gas buster and degasser are designed to remove entrained gas from drilling fluids that are exposed to formation gases. It is important to remove entrained gas in any drilling fluid returns for safety reasons. The gas may be toxic and therefore hazardous (i.e. Hydrogen Sulfide); and the density of gas-cut mud returns is often significantly lower than normal, so the hydrostatic pressure in the hole is reduced, creating potential conditions for a kick. Gas-cut fluid will also affect pump performance, with potential loss of suction. The normal procedure for dealing with gas-cut mud returns is to increase the hydrostatic pressure in the hole by increasing the mud density.

Gas Buster – If the gas-cut returns are severe, then the annular preventer will be closed and the returns will be diverted through the Gas-Buster before returning to the flow line leading to the scalping or shale shakers. The Gas Buster is usually located on or behind the rig floor and comprises a large vertical cylindrical chamber fitted with a series of baffles. The gas-cut returns enter the chamber and impact the baffles, releasing the entrained gas as they work their way down the baffles.

The drilling fluid then collects at the bottom of the chamber and flows through a “U”-tube leading back to the flow line. The “U”-tube acts as an air-lock to prevent gas escaping to the working areas of the rig, so the gas collects at the top of the chamber and travels up a pipe leading to the top of the mast where it is released to the atmosphere. The Gas Buster handles all the drilling fluid returns from the hole and will remove most, but not all, of the gas in the gas-cut returns.

Degasser – If gas-cut returns are observed at the shale-shakers, then the entrained gas is removed by the Degasser, which is available in a variety of shapes and sizes and usually located above the Desander Pit. The Degasser comprises a vacuum chamber with various devices for improving the removal of entrained gas (e.g. jet spray, baffles, plates, etc.). A vacuum pump creates a partial vacuum in the vacuum chamber that sucks gas-cut drilling fluid up from the Desander Tank.

The gas bubbles expand in the partial vacuum and burst when they reach the surface of the drilling fluid. The gas is then sucked through the vacuum pump and vented to the atmosphere in a safe area. The drilling fluid that collects at the bottom of the Degasser is pumped across to the Desilter Tank. The degasser has a float system that breaks the vacuum when the drilling fluid reaches a certain level in the vacuum chamber, which prevents the chamber from over-filling.

The Degasser is effective in removing entrained gas, but it can only process part of the drilling fluid returns passing through the Desander, which means that some of the gas-cut returns will reach the Desilter Tank and remain untreated.

Desander

Desander units comprise one or two rows of identical hydro-cyclones (vortex cones), which are simple devices that achieve solids separation by subjecting drilling fluids to high centrifugal forces inside the cones. Desanders are particularly useful while drilling surface holes because they are effective in controlling the build-up of drilled solids when high ROPs in large diameter holes make it difficult to install finer shale-shaker screens. They are efficient at removing finer sand-sized particles and drilled solids that may be too fine to be removed by the shale-shakers and sand-traps.

A centrifugal pump provides tangential feed to the hydro-cyclones, subjecting the mud to centrifugal forces that separate the suspended solids from the drilling fluid. Most hydro-cyclones are designed to operate at a fixed input pressure for maximum solids-separating efficiency (usually 75 ft head = 32 psi), so the feed rate through each Desander cone is the same for a given fluid viscosity. Hydro-cyclones have no moving parts and are therefore easy to maintain, although they should be checked at regular intervals in case they are plugged with debris.

The Desander unit is usually installed to take suction from the Desander Tank, with returns going to the Desilter Tank. A centrifugal pump delivers solids-laden mud to a tangential feed nozzle in the side of the Desander cone. The high flow rate imparts a high centrifugal force on the drilling fluid due to circular motion inside the cone, so heavier solids migrate to the side of the cone, and lighter density fluid containing smaller particles is left swirling around the central axis of the cone.

A typical desander unit.

The heavier solids slide down towards the bottom of the hydro-cyclone and are discharged as “underflow”. The discharge port at the bottom of the hydro-cyclone is restricted, which prevents the lighter density drilling fluid (containing smaller particles) from escaping with the underflow. As a result, the lighter density fluid is forced to spiral up the central axis of the cone and is discharged from the top of the cone as “overflow”.

Some Desander cones are fitted with a “vortex finder”, which is a hollow tube that extends down from the top of the hydro-cyclone. This reduces intermixing between the two contra-rotating fluids, which improves separation efficiency. Fluid entering the vortex finder flows into a return manifold that collects the lighter density overflow from all the hydrocyclones in the Desander. From there, the return flow discharges into the Desilter Tank, ready for the next step in the solids processing procedure.

It is important to note that the upward moving fluid creates a low-pressure zone in the centre of the cone, which sucks in air from the solids discharge port. When working correctly, the solids-laden underflow should appear as a cone-shaped spray discharge from the cone apex, with air being sucked up the hollow centre, since this maximizes solids removal without the loss of whole mud. The spray discharge can be adjusted by rotating the apex assembly. However, the spray discharge will change to a “rope” discharge if the drilling fluid is over-loaded with solids or has high fluid viscosity, or if the underflow discharge opening is blocked.

A “rope” discharge may appear to be more effective for solids removal than a spray discharge, but this is not the case. Rope discharge occurs when the opening at the bottom of the Desander cone cannot handle the amount of solids moving down the inner wall of the cone. Solids collect at the base of the cone, restricting the underflow discharge rate and closing the central air gap. As a result, some of the solids are sucked up with the lighter density fluid spiraling up the centre of the desander cone to join the overflow that returns to the circulating system.

The density of the rope discharge may be heavier than the density of the spray discharge, but that is simply because the solids in a rope discharge are drier than those in a spray discharge. However, the high velocity spray discharge discards more solids than the slow moving rope discharge, which is less efficient because more solids are retained in the overflow that returns to the circulating system. If rope discharge is due to high solids content, then dressing the Shale Shakers with finer shaker screens will reduce the solids loading in the drilling fluid, and this should eventually restore the spray discharge.

A 12-inch desander cone can process around 500 gpm fluid (12 bbl/min) with a median cut around 100 microns, while a 6" cone will process around 110 gpm (2.5 bbl/min) with a median cut around 40 microns. A Desander unit with several cones can therefore process a greater flow rate than the drilling fluid returns from the hole. For this reason, the Desander Tank must always be equalized with the Desilter Tank when running the Desander in order to maintain volume in the suction tank.

Desanders will remove drilled solids down to around 50-microns, which complements the shale-shakers that will remove drilled solids down to around 74-micron size when dressed with 200-mesh screens. However, Desanders will also remove Barite and other weighting materials, so care must be taken to maintain the required density of the drilling fluid in the active tank.

Desander Guidelines – The following guidelines should be followed whenever the Desander is running:

1. Equalize the Desander suction and discharge tanks to maintain full volume in the suction tank.
2. Run the Desilter continuously while drilling with unweighted drilling fluids.
3. Check that the pressure gauge on the Desander feed manifold is operational and that the centrifugal pump is supplying the correct feed pressure.
4. The Desilter cones should produce a spray discharge for maximum efficiency, along with a central air suction core.
5. Perform regular checks to ensure the Desilter cones are not plugged with debris.
6. Plugged cones can be cleared by opening the apex assembly and inserting a steel rod (welding rod) to dislodge debris blocking the discharge.
7. Try to avoid using the Desander immediately after adding Barite or treating chemicals to the active circulating system because any larger particles will be removed, reducing the effectiveness of the treatment.
8. Cone performance in an in-line manifold is never uniform because feed concentrations and particle size distributions are different for the various cones (The last cones tend to receive a higher concentration of coarser particles).
9. If rope discharge is observed, check the feed pressure and check that the underflow and overflow ports are not plugged. Other factors for rope discharge are high solids content and high fluid viscosity.
10. Run the Desilter while tripping as this will remove additional solids.
11. Inspect the inside of the Desilter cones during round trips and replace worn or damaged components.

Desander usage should be restricted with water-based fluid systems containing Barite and/or high-value additives because some of these solids will be lost with the discharge. API Barite is designed to pass through 74-micron screen openings, although 3% is allowed to be larger than this size according to API specifications, so Barite will also be discharged with drilled solids by the Desander. Desanders are not recommended for oil-based drilling fluids due to the amount of liquid discharged with the solids.

The density of the Desander cone underflow should not be used as an indicator of Desander performance because hydro-cyclones produce a wet discharge compared with shale shakers and centrifuges. Desander performance improves with low viscosity fluids because solids separation is more efficient, and Desander performance deteriorates as the solids content increases because separation efficiency decreases with larger particles being removed at the expense of smaller particles.

The Desander can be used as an effective device for reducing mud density without the need for expensive dilutions. However, the Desander (or Desilter) should not be used for reducing solids in drilling fluids that contain significant amounts of Barite because the Desander median cut (D50 cut point) is around 25 to 30 microns. Since most Barite particles are in the 2 to 44 micron size range, with some smaller than 2 microns and some larger than 44 microns, a large amount of Barite would be discarded with the drilled solids underflow.

Desilter

The Desilter works in exactly the same way as the Desander, the only difference being that the internal diameter at the tangential feed is six inches or larger for a Desander cone and less than six inches for a Desilter cone. The centrifugal forces acting on the solids particles in the smaller Desilter cones are therefore significantly higher. The larger Desander cones are designed to remove coarser drilled solids in the 50 to 80 micron size range, while the smaller Desilter cones are designed to remove smaller particles down to around 15-microns.

The smaller Desilter cones can process 40 to 100 gpm flow rates (1 to 2.5 bbl/min), according to cone size and design. A standard four inch Desilter cone can process 50 gpm fluid (70 bbl/hr) and remove 4 gpm of solids (around 5.5 bbl/hr). Therefore, a unit with 16 x 4" Desilter cones can remove around 90 bbls drilled solids per hour, which is the volume of drilled solids generated by a 17½" drill bit with ROPs around 300 ft/hr. From this it can be seen that effective solids removal can be achieved if the Desilter is maintained in good working order.

As with the Desander, the Desilter is designed to remove solids from unweighted drilling fluids and should not be used for reducing solids in expensive drilling fluid systems or fluids containing significant amounts of Barite. This is because a significant amount of valuable drilling fluid and Barite will be discarded with the drilled solids underflow. However, the Desilter unit can be used for reducing solids to an acceptable level if drilled solids are a problem or if density needs to be reduced, which avoids the need for expensive dilutions.

The Desilter unit is usually installed to take suction from the Desilter Tank, with returns going to the Centrifuge Tank. They should be capable of processing 150% of the active circulating flow rate, so the Desilter Tank must always be equalized with the Centrifuge Tank when running the Desilter in order to maintain volume in the suction tank. All the comments and guidelines relating to Desanders in the previous section apply to Desilters, since both are designed around hydrocyclones.

Mud Cleaner

A Mud Cleaner is effectively a Desilter mounted above a Shale-Shaker dressed with fine screens (200-mesh or finer), and was developed as a means of recovering Barite and fluids from the wet discharge of the Desilter underflow when using weighted or high value drilling fluid systems. The vibrating Mud Cleaner screen openings are large enough to allow Barite and fluid in the Desilter cone underflow spray to pass through and return to the circulating system, but small enough so that coarser particles than Barite are screened out (i.e. particles larger that 74-microns).

The Mud Cleaner usually replaces the Desilter unit because it can be operated as a Desilter for unweighted drilling fluid systems simply by removing the Mud Cleaner screens and diverting the underflow from the Desilter cones to a waste tank. The Mud Cleaner shaker screens can then be installed to recover Barite and discard larger sized low gravity solids in weighted drilling fluid systems, or to recover high value drilling fluids that would otherwise be discarded with the Desilter cone underflow.

Modern Mud Cleaners have linear-motion shaker units, which improves solids removal and therefore their ability to handle the discharge rate of the Desilter underflow. As with the shale-shakers, the Mud Cleaner should be dressed with the finest screens that can handle the flow, since this will minimize the amount of low gravity solids returning to the circulating system. The screens must also be checked at regular intervals to make sure that the screen mesh is not broken, otherwise low gravity solids will return to the circulating system.

The Mud Cleaner is effective in reducing drilling fluid costs because drilling fluid and Barite are recovered and retained in the circulating system, which is particularly useful for high value fluid systems. The Mud Cleaner is also effective in minimizing waste volumes and disposal costs when using oil-based and synthetic-based drilling fluids, which cannot be discharged for environmental reasons. However, low gravity solids fines will also pass through the Mud Cleaner screen openings with the Barite and end up back in the circulating system.

The underflow from the Desilter cones should be wet in order to improve solids separation and transportation across the Mud Cleaner screen. This can also be achieved by diverting some of the low-solids overflow from the Desilter cones onto the screens. The excessive use of water or base oil to improve Mud Cleaner cuttings transportation is not recommended because this will dilute the circulation system.

The Mud Cleaner should be able to process 150% of the active circulating flow rate, and should be operated continuously while drilling in order to screen out larger particles. If the unit is only operated periodically, then larger particles will remain in the circulating system and erode into smaller particles during subsequent circulations, making them even more difficult to remove. Once the particles are the same size or smaller than Barite then they cannot be screened out by the Mud Cleaner without screening out an excessive amount of Barite at the same time.

The density of the drilling fluid usually decreases while running the Mud Cleaner, for the simple reason that solids are being discarded from the fluid. It is often assumed that Barite added to maintain the fluid density is simply replacing Barite that has been removed by the Mud Cleaner, but this is not the case. The Barite additions are actually replacing drilled solids discarded by the Mud Cleaner, resulting in a reduction in solids content, an improvement in filter cake quality and less chance of differential sticking.

Solids discarded by the Mud Cleaner should be examined at regular intervals to make sure that drilled solids are being removed, because drilled cuttings from dispersible shales may break up while travelling up the annulus. If these drilled solids are not being removed by the Mud Cleaner, then the only option is to use a centrifuge. However, centrifuges are limited by the fact that they can only handle a small percentage of the circulating returns, so the build-up of fines in the drilling fluid will probably continue at a lower rate.

Centrifuge

The reason for centrifuging weighted drilling fluids is to remove colloidal solids when the concentration of fines builds-up to the point where it starts to have a detrimental effect on mud rheology and filter cake quality. When this happens, drilling performance will be affected, with reduced ROPs and hole problems that could result in the loss of the drill string in the hole, or loss of the hole itself. Centrifuges reduce colloidal solids to acceptable levels, resulting in an improvement in drilling fluid quality without the need for costly dilution treatments.

Centrifuges are very effective at removing solids from drilling fluids, but they can only process a relatively small part of the drilling fluid returns, so low gravity solids will still be retained in the circulating system. The centrifuge comprises a rotating bowl that spins at high speed (around 2,500 rpm), with a close-fitting scroll (concentric auger) that spins at a slightly slower speed. Drilling fluid is pumped from the centrifuge tank into the centrifuge feed port using a Moineau Pump (screw or cavity pump), which allows the feed rate to be controlled accurately.

The drilling fluid is subjected to a high centrifugal force and forms a layer of fluid (a pool or pond) on the inside surface of the rotating centrifuge bowl, with coarser solids (drilled solids and Barite) being thrown against the inside surface of the bowl. One end of the rotating bowl slopes gently towards the rotational axis, which forms a “beach” that keeps drilling fluid away from the discharge ports when the centrifuge is running.

The scroll moves at a slightly different speed to the bowl and drags the solids towards and up the beach, which helps to remove excess fluid before reaching and escaping as a “cake” from the “underflow” discharge ports. The slower the feed rate and differential scroll speed, the drier the solids discharge which, as mentioned previously, contains coarser solids (drilled solids and Barite). The lighter density “overflow” contains finer solids (drilled solids and Barite) and leaves the centrifuge through ports at the other end of the centrifuge.

There are usually two centrifuge tanks, one to provide feed for the centrifuge and one for centrifuge returns. Centrifuge feed is taken from the upstream tank and “overflow” returns from the centrifuge are sent to the downstream tank. Although centrifuge feed rates are relatively low, the centrifuge tanks must be equalized whenever the centrifuge is running, in order to maintain volume in the suction tank. The downstream centrifuge tank should have an agitator so that lighter density centrifuge returns mix thoroughly with the active mud.

The ideal situation for effective solids removal is to have a thin fluid and a slow centrifuge feed rate because the solids will migrate through the fluid faster and will spend longer being centrifuged. In reality, the drilling fluid will probably be fairly viscous due to the build-up of fines, and the centrifuge feed rate will probably be fairly high in order to process an acceptable percentage of the active circulating fluid returns. As a guide, the centrifuge should be able to process around 10% to 15% of the active circulating rate to be effective.

It is important to realize that centrifuges cannot separate high gravity solids (i.e. Barite) from low gravity drilled solids. What they do is separate larger Barite particles from smaller ones, and larger low gravity solids particles from smaller ones. For this reason, the practice of running two centrifuges in series, commonly referred to as “Barite Recovery” mode, is a false economy. It is based on the assumption that the first centrifuge runs at a lower rotational speed in order to remove the Barite, which is returned to the circulating system, while the overflow feeds the second centrifuge.

The second centrifuge is designed to run at a higher rotational speed in order to remove the finer drilled solids, while returning “solids-free” drilling fluid back to the circulating system. In reality, drilled solids and Barite are present in the underflow from both centrifuges, and the overflow from the second centrifuge still contains ultra-fines and colloids that are sent back to the circulating system. Experience has shown that the amount of low gravity solids removed using this arrangement does not justify the amount of Barite that is also removed.

Centrifuges are cost-effective because they remove significant amounts of colloidal particles that cannot be removed by other solids control equipment. As a result, centrifuges extend the life of drilling fluids and reduce the need for dilution treatments, which can be costly. Dilutions also generate large volumes of waste fluid, with associated disposal costs, and still leave colloidal fines in the drilling fluid rather than removing them.

Centrifuge Guidelines – The following guidelines should be used when running the centrifuge:

1. Before starting the centrifuge, rotate the bowl by hand to make sure it rotates freely.
2. Start the centrifuge and make sure it runs smoothly before starting the feed pump.

3. Start the feed pump and adjust the feed rate and scroll speed to obtain a dry cut.
4. Before stopping the centrifuge, stop the feed pump and allow time for the fluids and solids to exit the centrifuge bowl.
5. The centrifuge can be switched off when no more solids or fluids are being discharged.
6. If the centrifuge is run to remove fines from the active mud in the surface tanks while out of the hole, then the density must be restored with Barite before circulation resumes, otherwise lighter density mud will be pumped into the hole.

Solids analysis should be carried out on the centrifuge discharge at regular intervals to determine the level of high and low gravity solids (HGS and LGS). If the low gravity solids continue to build up in the active circulating system, then mud viscosity and gels will start to climb. The usual remedy at this stage is to bleed in fresh mud over one full circulation while removing a similar volume of solids-laden mud at the shakers, a procedure known as “Dump and Dilute”. This will reduce the level of solids and should restore the mud properties.

Centrifuges are also used for recovering and re-using water from drilling fluids, in environmentally sensitive areas where drilled solids and drilling fluid cannot be discarded at the onshore or offshore rig location. Discarded water-based drilling fluids are subjected to chemical flocculation, which causes colloidal and ultra-fine particles to form aggregates that are large enough to be removed by centrifuge. This dewatering process is described in further detail below.

Dewatering Unit

Dewatering units are used at the rig site for removing all traces of colloidal matter from water-based (and oil-based) fluids in order to minimize the volume of waste sent for disposal (i.e. solids only), and associated costs. Dewatering units were originally introduced for environmental protection and to avoid pollution when drilling in sensitive areas (e.g. close to fishing areas or fresh water sources). However, as the technology has been refined, they are now used in areas where fresh water is hard to access and where the high cost of waste disposal makes them economically beneficial.
Dewatering units achieve colloidal separation in the same way as the conventional high-speed centrifuges at the rig site, but chemical additives are used for enhancing separation down to clear water by applying clay chemistry. Clay particles have negatively charged surfaces, but the edge charges are dependent on the pH of the fluid. The edge charges are negative at high pH, so clay particles tend to repel each other and that makes them difficult to remove. However, the edge charges become positive at low pH, so they are attracted to the negatively charged surfaces.

With this knowledge, the first step in the dewatering process is to remove the repulsive forces of the colloidal particles by lowering the pH of the fluid below 6.0 with acid. This reduction in pH encourages the colloids to agglomerate into larger particles, and the fluid is then treated with coagulants and flocculants that create larger clusters that can be removed using a high-speed centrifuge. The water can then be reused, treated for discharge or sent for disposal. Any oil in the water will float to the surface where it can be skimmed off.

Dewatering units usually comprise a holding tank for the waste fluid to be processed, followed by separate tanks each with controllable feed pumps for the chemical additives (acid, coagulant and flocculant). Careful adjustment of the feed rates will ensure that most of the additives work on the solids, with minimal amounts remaining in the liquid phase. A transfer pump then sends the treated fluid to the high-speed centrifuge, which removes the coagulated solids and discharges clear fluid that is recovered in a storage tank. Oil-based muds can also be dewatered, but they need to be treated with demulsifiers first in order to break the oil-water emulsion.

Standard Procedures for Evaluating Solids Control Equipment

It is important to obtain representative discharge samples when evaluating the performance of SCE equipment, so the following procedure should be used when obtaining samples for SCE Underflow Calculations:

1. Determine the underflow rate of a cone in seconds per quart by recording the time taken to fill a mud viscosity cup to the one quart level (“t” seconds).
2. Convert the underflow rate to gallons per minute by dividing the seconds per quart into 15 (e.g. If “t” = 40 seconds then underflow rate = 15/40 = 0.375 gallons per minute).

3. Obtain the discharge rate for the entire unit by multiplying the gallons per minute for one cone by the total number of cones.
4. Calculate the underflow discharge rate for the unit in gallons per hour by multiplying gallons per minute by 60.
5. Collect a representative sample of underflow from the unit and retort it to obtain the solids content (% by volume).
6. Perform solids analysis using EMEC software to obtain the following results:
    a. % by volume low gravity solids (i.e. drilled solids)
    b. % by volume high gravity solids (i.e. barite)
7. Calculate the underflow discharge rate in gallons per hour for drilled solids (LGS) and Barite (HGS), as shown in figure 1 below.
8. The efficiency of the equipment can be calculated by dividing the drilled solids discharge from the under flow (lbs/hr) by the drilled solids discharge from the over flow (lbs/hr), and multiplying the result by 100, as shown in figure 2 below.

LGS Rate (gallons per hour) = Underflow Discharge Rate (gallons per hour) x %LGS
LGS Rate (lb per hour) = LGS Rate (gallons per hour) x 21.6 (= 2.6 x 8.33)

HGS Rate (gallons per hour) = Underflow Discharge Rate (gallons per hour) x %HGS
HGS Rate (lb per hour) = HGS Rate (gallons per hour) x 35.5 (= 4.25 x 8.33)

Figure 1: Procedure for calculating the discharge rate of high and low gravity solids (see Step 7 above).

$$\text{Efficiency} = \frac{\text{LGS Rate from Underflow}}{\text{LGS Rate from Overflow}} \times 100$$

Figure 2: Procedure for calculating the efficiency of any item of solids control equipment (see Step 8 above).

Hole Cleaning and Hydraulics

Contents

Introduction

Effective hole cleaning is essential while drilling and the ideal scenario would be for all the drilled cuttings to be removed by the solids control equipment as soon as they arrive on surface. In reality this is not possible because some drilled solids will always be small enough to pass through the solids control equipment and remain in the active circulating system. This will make them even harder to remove after the next circulation because they will be subjected to mechanical erosion as they are recirculated around the hole, making them even smaller.

Allowing solids to build-up in the mud will increase mud density and rheology, which will eventually have a detrimental effect on drilling performance. A build-up of drilled solids will also increase the Equivalent Circulating Density (ECD), which could fracture the formation and induce down-hole losses. It will also produce thicker filter cakes in the hole, which will increase the risk of differential sticking. Increased solids and rheology will make it more difficult for the shaker screens to handle the flow, and fitting coarser screens will only make the situation worse.

Hole cleaning efficiency is dependent on a range of parameters including mud rheology, mud density, annular velocity, cuttings shape, cuttings size, hole size, hole angle and ROP. The use of down-hole motors will also affect hole cleaning efficiency because the drill string above the mud-motor does not rotate during directional drilling, so solids may settle on the low side of the hole. Most of these parameters cannot be adjusted, but mud rheology and annular velocity are adjustable and are interrelated when it comes to removing drilled cuttings from the hole.

The priority for effective hole cleaning is to keep all the drilled cuttings in suspension and to pick up any solids that have settled on the low side of the hole. If the fluid is static then solids will slowly migrate through the fluid under the force of Gravity. The speed at which a solid particle migrates through the fluid is called the Slip Velocity, and this is a function of particle size, particle density and fluid viscosity. The slip velocity of a particle will obviously be faster in a low viscosity fluid and slower in a high viscosity fluid.

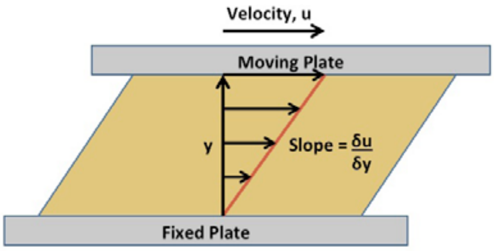
Hole cleaning in a vertical hole is rarely a problem because the annular velocity is generally greater than the slip velocity of the cuttings in the fluid, even if the fluid is water in large diameter top-hole sections or in the marine riser. Most of the cuttings will have been circulated out of the hole before tripping out, so there is little risk of getting stuck due to a build up of cuttings. However, the presence of hole fill after tripping back into the hole is an indication of poor hole cleaning in vertical wells.

The situation changes as hole inclination increases because the vertical distance that the cuttings have to travel before settling on the side of the hole reduces, and slip velocity increasingly comes into play. In a horizontal well, the hole diameter becomes the maximum distance that cuttings have to fall through the fluid before settling on the low side of the hole, which might not take long. Rotary drilling usually stirs up the settled solids, but this is not the case while sliding with a down-hole motor.

EMEC has developed an in-house Hole Cleaning Processor (HCP), which is a complex software package for analysing how cuttings behave in the annulus. The software analyses the forces acting on the cuttings as they travel up the annulus, and determines the location and severity (i.e. cuttings depth) of any cuttings beds that might form. The HCP software is covered in greater detail later on in this section.

Newton’s Law of Viscosity (μ)

All fluids have viscosity, which describes the resistance of a fluid to flow when it is subjected to shear stress. In a simple fluid (e.g. water or oil), viscosity is a result of the cohesive molecular forces within the fluid, which creates resistance to sheer deformation. Fluids with high viscosity resist sheer deformation more than fluids with low viscosity (e.g. water). Newton’s Law of Viscosity can be summarized by observing the behavior of a fluid between a fixed plate and a moving plate, as shown below:



Fluid Shear Between A Fixed Plate and A Moving Plate

Shear Stress, $\tau = \mu \frac{\delta u}{\delta y} = \mu \gamma$

where μ = dynamic viscosity and γ = Shear Rate.

Figure 1

Friction between the fluid and the moving plate will cause the fluid to shear as layers of fluid particles slide past each other. If the velocity of the moving plate is “u” then the velocity of the fluid in contact with the moving plate will also be “u”, while the velocity of the fluid in contact with the fixed plate will be zero. Frictional Drag between the fluid particles will produce a uniform velocity profile that increases from zero at the fixed plate to “u”, the velocity of the moving plate.

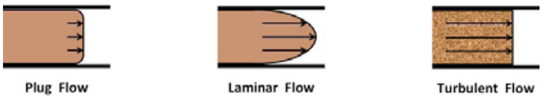
The viscosity of the fluid will determine the magnitude of the Shear Force (frictional drag) required to slide the moving plate at constant speed relative to the fixed plate. The Shear Force will also be dependent on the surface area of the fluid in contact with the fixed and moving plates, as well as the velocity gradient between the plates (Shear Rate). Newton’s Law of Viscosity shows the relationship between Shear Stress (τ = Shear Force divided by fluid contact area) and Shear Rate ($\delta u/\delta y$), as shown in figure 1 above.

Fluids that follow the linear relationship given by Newton’s law of Viscosity are called “Newtonian Fluids”. Typical examples are simple solids-free fluids like water and oil, where viscosity is a result of the cohesive molecular forces within the fluid. Most drilling fluids contain suspended solids (weighting materials, drilled solids, etc.), so viscosity is a combination of cohesive molecular forces combined with friction and physical interactive forces between the solids within the fluid. As a result, they do not conform to the Newtonian flow model.

Shear Stress is usually reported using the units “pounds force per hundred square feet” (lb/100ft^2), while Shear Rate is reported using the units “reciprocal seconds” (sec^{-1}). Viscosity is affected by temperature and pressure. Elevated temperatures reduce the cohesive molecular forces within the fluid, making the molecules more mobile and therefore reducing viscosity. Elevated pressures force the molecules closer together, making them less mobile and therefore increasing viscosity.

Flow Regimes

There are three flow regimes: plug flow, laminar flow and turbulent flow. When fluid travels through a pipe, the fluid particles in contact with the pipe wall are stationary and the velocity of the fluid particles generally increases towards the centre of the pipe, producing what is known as a velocity profile. The differential velocities between adjacent fluid particles creates shear stresses within the fluid, which disappear if the fluid is stationary or if the fluid particles are all moving at the same velocity. The three flow regimes are shown below:



Velocity Profile for the Three Flow Regimes

Plug Flow occurs at low flow rates, especially with viscous fluids. The velocity profile of the fluid (represented by the arrows in the diagram) is flat, being almost uniform across the pipe or annulus. Plug flow usually occurs while pumping high viscosity sweeps or using flocculated Bentonite systems in large diameter vertical top hole sections. Cuttings removal in top hole sections is effective as long as the annular velocity is higher than the cuttings slip velocity, and sufficient time is allowed for circulating the cuttings out of the hole.

The lower annular velocities associated with plug flow makes this flow regime less aggressive against the wellbore. This helps to reduce erosion and hole enlargement while drilling top hole sections, which usually comprise unconsolidated formations. Plug flow also reduces mechanical erosion and dispersion of the cuttings as they are transported up the annulus, which helps to reduce the build-up of solids in the mud if a closed circulating system is being used. The shear-thinning properties of fluids that exhibit plug flow helps to improve solids separation at the shale-shakers, further improving solids control efficiency.

Reynolds Number, $Re = \frac{vD}{\upsilon} = \frac{\rho vD}{\mu}$

where v = Fluid Velocity, D = Pipe Diameter, υ = Kinematic Viscosity,
ρ = Fluid Density and μ = Dynamic Viscosity.

Figure 2

Laminar Flow occurs in faster moving fluids. The fluid particles glide over each other forming smooth layers (lamina) parallel to the pipe or annulus walls. The velocity profile of the fluid is parabolic, being slow near the walls and increasing towards the centre of the pipe or annulus. Laminar flow is recommended for drilling most formations because it provides effective cuttings removal without eroding the surface of the wellbore. Cuttings removal in larger diameter top hole sections and high inclination sections is not so effective with laminar flow, due to slow moving fluid layers near the side of the hole.

Most hole sections are drilled with the mud exhibiting laminar flow in the annulus. The velocity profile should be kept fairly shallow because this will ensure that most of the drilled cuttings remain in the central part of the velocity stream. As a result, the drilled cuttings will be carried to surface with minimal slippage and will therefore be subjected to less mechanical erosion and dispersion. This will enhance hole cleaning and solids control efficiency, since the drilled cuttings will be removed at the shale-shakers with minimal erosion and dispersion.

A steep velocity profile usually results in poor hole cleaning efficiency because the drilled cuttings tend to be pushed from the high velocity section of the flow stream towards the low velocity flow stream near the walls of the annulus. In this area, the slip velocity of the drilled cuttings can be higher than the fluid velocity, so the cuttings will fall down the hole until eventually finding their way back into the high velocity section of the flow stream. The cuttings are usually more rounded in appearance after spending so much time in the annulus.

Turbulent Flow occurs when fluids are travelling at high velocity. As flow rate increases, the fluid particles eventually reach a critical velocity where they start to take random paths in all directions, which breaks up the laminar flow pattern and produces turbulent flow. The velocity profile of the fluid is flat because the turbulence produces a uniform profile across the pipe or annulus. Turbulent flow will provide effective cuttings removal and will also stir up settled solids, but it may mechanically erode the cuttings, filter cake and softer formations, producing washouts and over-gauge hole.

Turbulent flow is useful for improving hole cleaning in deviated and extended-reach wells, where cuttings tend to settle on the low side of the hole. It is also useful when performing mud and cement displacements, or during well clean-outs, because it improves mud and solids removal, and reduces the size of the interface. The critical velocity for turbulence increases as mud viscosity increases, so certain pills and spacers are not viscosified in order to encourage turbulence and improve mud and solids removal.

Reynolds Number

Osborne Reynolds (1842–1912) was an engineer who conducted extensive research on fluid dynamics in England. He studied flow characteristics in pipes and discovered a dimensionless relationship between pipe diameter, fluid velocity and fluid viscosity for determining if the fluid would be in laminar or turbulent flow. This dimensionless relationship subsequently became known as the Reynolds Number, which is calculated using the equation shown in figure 2 above.

Reynolds discovered that flow in pipes will be laminar if the Reynolds Number is below 2,320 and will be turbulent if the Reynolds Number is above 4,000. The flow regime cannot be predicted in the transition zone between these two numbers because it may either be laminar or turbulent. Thinner fluids will become turbulent at the lower end of the transition zone and higher viscosity fluids will become turbulent at the higher end of the transition zone.

The high fluid velocity required for turbulent flow means that it may not be possible to establish

$$\text{Shear Rate } (\gamma) = \frac{\text{Differential Velocity (cm/sec)}}{\text{Separation (cm)}} = \frac{\Delta v}{X}$$

Figure 3: Relationship for Shear Rate

$$\text{Shear Stress } (\tau) = \frac{\text{Applied Force (dynes)}}{\text{Surface Area (cm}^2\text{)}} = \frac{F}{A}$$

Figure 4: Relationship for Shear Stress

turbulence in larger diameter surface hole sections. It may also not be possible to establish turbulence in smaller hole sections if there is a need to control ECD or pump pressure, or if there are mud motor flow rate restrictions. The Reynolds number can be calculated for other pipe profiles by using a special formula to calculate the "equivalent diameter".

Measurement of Rheological Properties

Several instruments are available for measuring the fluid rheology, or flow characteristics, of a fluid. A viscometer technically measures only one flow condition, while a rheometer has a range of speeds for measuring several flow conditions. Rheometers comprise a pivoted cylindrical bob that is connected to a torsion dial while being restrained by a torsion spring. The bob sits inside a cylindrical outer sleeve that can be rotated at selected speeds, with a narrow annular clearance between the bob and the sleeve. The cylindrical bob and rotating sleeve assembly is then immersed in the fluid whose rheological properties are to be measured.

Shear Rate (γ) – The shear rate of a fluid is the velocity gradient between fluid layers. For fluids moving between a fixed and a moving parallel plate, Shear Rate is the differential velocity divided by the distance separating the plates, the unit of measurement being $\sec^{-1}$ (Reciprocal Seconds). In the case of a rotating sleeve viscometer, the velocity of the fluid in contact with the rotating sleeve can be calculated from the internal diameter and rotational speed (rpm) of the rotating sleeve. The annular gap between the rotating sleeve and cylindrical bob gives the distance separating the fluid layers, enabling the shear rate to be calculated as shown in figure 3 above.

Typical shear rates in the wellbore, while circulating, are as follows:

Shear Rate inside drill pipe - 100 to 500 $\sec^{-1}$
Shear Rate inside drill collars - 700 to3,000 $\sec^{-1}$
Shear Rate at bit nozzles - 10,000 to 100,000 $\sec^{-1}$
Shear Rate in annulus - 10 to 500 $\sec^{-1}$

Shear Stress (τ) – The shear stress of a fluid is the force applied per unit area to overcome the resistance of a fluid to flow due to interactions between adjacent layers of molecules in the fluid, the unit of measurement being dynes/cm^2. In the case of a rotating sleeve viscometer, the force required to overcome the resistance of a fluid to flow is measured by the deflection of the torsion dial. The area of the applied force is the surface area of the cylindrical bob, enabling the shear stress to be calculated as shown in figure 4 above.

Rheological Flow Models

Accurate flow modelling is required when analysing rig hydraulics in order to calculate friction, pressure losses and flow rates while circulating or drilling. Fluids can be divided into two types, according to the mathematical relationship between shear stress and shear rate, as follows:

1. Newtonian Fluids
2. Non-Newtonian Fluids
   a. Bingham Plastic Model
   b. Power Law Model
   c. Herschel-Bulkley Model

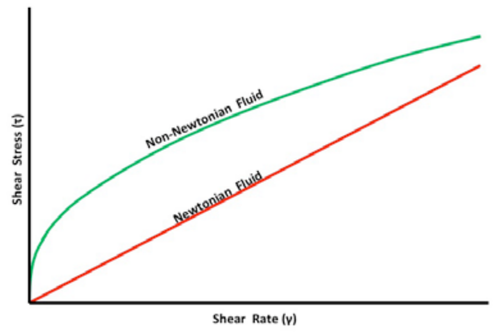
Newtonian Fluids are simple solids-free fluids like water and oil, where viscosity is a result of the cohesive molecular forces within the fluid. The shear stress of a Newtonian fluid in laminar flow is directly proportional to the shear rate, so a rheology curve produces a straight line that passes through the axis, while viscosity is defined by the slope of the line. As a result, viscosity is the only parameter required

Shear Stress, $\tau = \mu\gamma$
where μ = Viscosity and γ = Shear Rate.

Figure 5: Mathematical Relationship for the Rheological Flow Model of a Newtonian Fluid

to define the flow characteristics of a Newtonian fluid because the viscosity does not change with shear rate at constant temperature and pressure. Newtonian Fluids can be modeled using the following mathematical equation to define the relationship between shear stress and shear rate, shown above in figure 5.

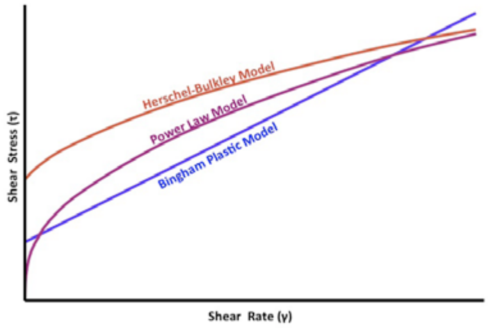
Most drilling fluids are Non-Newtonian because they do not conform to the Newtonian flow model. The reason for this is the fact that they contain suspended solids (weighting materials, drilled solids, etc.), so viscosity is a combination of cohesive molecular forces along with friction and physical interactive forces between the solids within the fluid. As a result, most drilling fluids cannot be modeled accurately using the Newtonian flow model and Non-Newtonian flow models have been developed for greater accuracy, as described below.



Newtonian and Non-Newtonian Fluids

Non-Newtonian Fluids are effectively fluids that do not conform to the Newtonian flow model, since they do not exhibit the linear relationship between shear stress and shear rate like Newtonian fluids. They also require a certain amount of shear stress to initiate flow because friction and interactive forces between the solids particles creates a shear-resistant fluid that eventually flows at what is known as the Yield Point. The rheology curve of a Non-Newtonian fluid is non-linear and does not pass through the axis.

The presence of suspended particles (weighting agents, drilled solids, etc.) will affect the viscosity of a fluid and could convert a Newtonian Fluid into a Non-Newtonian Fluid. Most drilling fluids are shear-thinning (pseudoplastic), which means that fluid viscosity decreases as the shear rate increases. However, some fluids can be shear-thickening, which means that fluid viscosity increases as the shear rate increases. The main Non-Newtonian flow models that are used for modeling drilling fluids are the Bingham Plastic Model, the Power Law Model and the Herschel-Bulkley Model, as shown below:



Rheological Modeling for Non-Newtonian Fluids

The Bingham Plastic Model is the most common rheological model used for describing the flow characteristics of most drilling fluids because it allows for the fact that shear stress must reach a certain level (the Yield Point) before the fluid starts to flow. After reaching the Yield Point, the fluid behaves like a Newtonian Fluid, with a linear relationship between shear stress and shear rate. The Bingham Plastic Model uses the following mathematical equation to define the relationship between shear stress and shear rate as shown in figure 6 overleaf.

The two-speed rheometer was developed for the Bingham Plastic Model because the flow characteristics of a drilling fluid can be defined using this model, which gives good correlation at shear rates between 300 and 600 rpm. The Yield Point should be

Shear Stress, $\tau = YP + (PV \times \gamma)$
where YP=Yield Point; PV = Plastic Viscosity & γ = Shear Rate

Figure 6: Mathematical Relationship for the Power Law Rheological Flow Model.

Shear Stress, $\tau = k(\gamma)^n$
where k = Consistency Index; γ = Shear Rate & n = Flow Index

Figure 7: Mathematical Relationship for the Power Law Rheological Flow Model.

Shear Stress, $\tau = \tau_o + k\gamma^n$
where τ_o = Yield Stress; k = Consistency Index; γ = Shear Rate and n = Flow Index

Figure 8: Mathematical Relationship for the Herschel-Bulkley Rheological Flow Model.

high enough to carry drilled cuttings out of the hole, but if it is too high then pump pressures may also be too high when starting circulation. The slope of the line gives the Plastic Viscosity (PV), which should be controlled as low as possible by minimizing the build-up of solids in the drilling fluid.

The Power Law Model is an improvement on the accuracy of the Bingham Plastic Model when defining the flow characteristics of certain drilling fluids. Water-based polymer mud systems tend to fit the Power Law Model better than the Bingham Plastic Model. The Power Law Model uses the following mathematical equation to define the relationship between shear stress and shear rate as shown in figure 7.

The Consistency Index (k) relates to the viscosity of the fluid, while the Flow Index (n) relates to the shear-thinning or shear-thickening behavior of the fluid. If n=1 then the Power Law Model reverts to the flow model for a Newtonian Fluid (i.e. $\tau = k\gamma$). If n>1 then the Power Law Model represents a dilatants or shear thickening fluid (i.e. viscosity increases as shear stress increases). If n<1 then the Power Law Model represents a pseudoplastic or shear thinning fluid (i.e. viscosity decreases as shear stress increases). Most drilling fluids are pseudoplastic (shear thinning), so n<1.

The Power Law Model gives a good representation of fluid behavior as long as shear stresses are obtained for a variety of shear rates. As a result, a multi-speed rheometer should be used when applying the Power Law Model so that flow properties at various shear rates can be defined more accurately.

The Herschel-Bulkley Model is more accurate for defining the rheological characteristics of a fluid than the Bingham Plastic or Power Law Models, provided sufficient shear stress and shear rate data is available. As with the Bingham Plastic Model, the Herschel-Bulkley Model allows for the fact that shear stress must reach a certain level (Yield Stress) before the fluid starts to flow. The Herschel-Bulkley Model uses the following mathematical equation to define the relationship between shear stress and shear rate as shown in figure 8 above:

As with the Power Law Model, a multi-speed rheometer should be used when applying the Herschel-Bulkley Model so that flow properties at various shear rates can be defined more accurately. It is worth noting that all the other flow models follow the Herschel-Bulkley Model, so it can be applied to a range of fluids. The Herschel-Bulkley Model can be used for Newtonian Fluids by inserting zero for the Yield Stress (τ_o) and for the Flow Index (n). The Herschel-Bulkley Model can also be used for fluids that follow the Bingham Flow Model by inserting 1 for the Flow Index (n), and by inserting zero for Yield Stress (τ_o) in the case of fluids that follow the Power Law Model.

Rig Hydraulics

Ideally, drilling should occur at maximum flow rates so that annular velocities can be maximized for effective cuttings removal from the hole. In reality,

$$\text{Pump Pressure} = \Delta P_{\text{surface lines}} + \Delta P_{\text{drill pipe}} + \Delta P_{\text{BHA}} + \Delta P_{\text{mud motor}} + \Delta P_{\text{bit}} + \Delta P_{\text{annulus}}$$

Figure 9: Relationship between Pump Pressure and Frictional Pressure Losses while circulating.

flow rate may be restricted for a variety of reasons, including rig pump pressure rating, formation erosion, prevention of tubular washout, ECD restrictions and down-hole motor restrictions. All the variables that affect rig hydraulics are interrelated and the aim with rig hydraulics is to obtain the best compromise so that drilling performance and hole cleaning are optimized while maintaining well control.

The limiting factor concerning rig hydraulics is the rating of the rig pumps. The rig pumps must be powerful enough to overcome frictional pressure losses in the circulating system, while still delivering sufficient flow rate for effective hole cleaning. Frictional pressure losses are dependent on fluid viscosity, flow rates and flow area, and the frictional pressure losses will increase if fluid viscosity or flow rate increases, or if flow area decreases. The frictional pressure losses (ΔP) while drilling can be summarized as shown in figure 9 above.

When drilling large diameter surface hole, frictional pressure losses are usually well within the pressure rating of the rig pumps, so flow rate is usually the limiting factor. As the well gets deeper and hole sizes get smaller, the frictional pressure losses will increase and the pump pressure rating will become the limiting factor.

Hydraulics covers the static and dynamic behavior of fluids, especially when subjected to pressure. Hydraulics is important for drilling fluids because the annular hydraulics required for effective hole cleaning may conflict with the bit hydraulics required for effective bit cleaning, and both may be limited by pump pressure or flow rate restrictions. Annular hydraulics usually covers annular velocity, hole cleaning, flow regime, slip velocity and ECDs, while bit hydraulics covers nozzle size, nozzle velocity and hydraulic horsepower at the bit (impact force).

Rig hydraulics covers various activities, including the following:

1. Prevent cuttings sticking to the drill bit by effective use of jet nozzles
2. Transport cuttings from the bottom of the hole to surface
3. Facilitate removal of drilled solids by the Solids Control Equipment
4. Minimize friction pressure losses in the hole
5. Minimize ECDs to avoid formation losses
6. Minimize surge and swab, especially when annular clearances are small
7. Optimize fluid displacements (e.g. cement slurries or completion fluids)

In order to achieve the above, rig hydraulics takes various factors into consideration, including the following:

1. Rig Pump Rating (Horsepower, Pressure and Flow Rate)
2. Well Bore Tubular Dimensions
3. Hole Size
4. Drill Bit and Nozzle Data
5. Drill String Tubular Dimensions
6. Drilling Fluid Properties (Density, Viscosity and Flow Characteristics)
7. Friction Losses
8. Flow Rate Restrictions (e.g. Down Hole Motor)
9. Formation Data (Pore Pressure and Frac Pressure Gradients)

Bit Hydraulics

The size and type of drill bit, and the number and size of bit nozzles (jets), is an important factor in rig hydraulics. The annular flow area around a PCD bit is usually smaller than the flow area around a similar size tri-cone bit, so pressure loss across a PCD bit will generally be larger. The pressure loss will also be larger for a bit that is dressed with smaller bit nozzles compared with one that is dressed with larger bit nozzles.

Dressing the bit with small nozzles will produce high fluid velocity and impact force to clean the bit and

Frictional Drag Force, $F_d = 6\pi\mu Rv$
where μ = Dynamic Viscosity, R = Spherical Radius and v = Slip Velocity

Figure 10: Stokes Law

remove cuttings from the bottom of the hole. However, rig pump flow rate may have to be reduced to compensate for the resultant increase in pressure loss across the nozzles, and this could have a detrimental effect on hole cleaning in the annulus higher up the hole. Flow rates can obviously be increased by inserting larger bit nozzles for improved cuttings transportation up the annulus, but fluid velocity and impact force for bit cleaning will be reduced.

Stokes Law and Cuttings Slip Velocity

Cuttings will slowly migrate through the drilling fluid naturally due to the force of gravity. The speed at which the cuttings migrate through the fluid is known as the Slip Velocity, and this is a function of particle size, particle density and fluid viscosity. The slip velocity of a particle will obviously be faster in a low viscosity fluid and slower in a high viscosity fluid. Cuttings slip velocity is not so critical in vertical holes, but it is important in highly deviated wells because the cuttings do not have to fall so far before settling on the low side of the hole.

George Stokes (1819-1903) was a mathematician and physicist who carried out research on hydrodynamics and produced an equation in 1851 for calculating the frictional (drag) force exerted on a small spherical object falling through a viscous fluid. Although cuttings are not spherical, the equation can be applied for estimating cuttings slip velocity due to gravitational pull by taking an average diameter (or radius) for the cuttings. The Stokes equation subsequently became known as Stokes Law, which is shown in figure 10 above.

Boycott Settling and Barite Sag

The Boycott Effect, also known as Boycott Settling, was first identified in the 1920s by the pathologist Arthur Boycott, who noticed that blood cells settled faster when test tubes are inclined instead of vertical. When particles fall in a vertical tube, they displace fluid in an upward direction and this upward movement restricts the particle settling rate. When particles fall in an inclined tube, they also displace fluid in an upward direction but the particles do not have to travel so far before settling on the low side of the inclined tube.

As particle settling continues in an inclined tube, a layer of lower density fluid gradually forms on top of a layer of higher density fluid. This creates an increasingly unstable situation until the layer of higher density fluid starts to slide down along the low side of the tube while the layer of lower density fluid moves up along the high side of the tube, accelerating the separation process that occurs in an inclined tube. A similar situation is often observed in deviated wells, where Boycott Settling is responsible for accelerated gravity-driven Barite sag in drilling fluids.

Severe Barite sag due to Boycott Settling is particularly noticeable when wellbore inclination is in the critical 30° to 60° range, because the cuttings beds will not be stable and will tend to slide down the hole. Boycott Settling can be even more severe when circulating slowly at low flow rates because mud gel strength is reduced, so accelerated Barite sag takes place as the drilling fluid flows along the upper side of the inclined hole, above the higher density layer formed by settled solids. This effect is also called dynamic sag and it is more difficult to prevent than static sag.

Barite sag is usually observed by a drop in density when circulation resumes, and can be a serious problem because the reduction in hydrostatic pressure can cause a kick and a well control incident. The presence of settled solids can also result in Stuck Pipe. The Boycott Effect can never be eliminated completely, but increasing mud rheology and gel strength will help to reduce Barite sag. High circulation rates, while rotating and reciprocating the drill string, will also help to prevent solids settling, as long as the resultant increase in ECDs does not induce formation losses.

The best way to remove settled solids is to establish turbulent flow by increasing the circulation rate, assisted by rotation and reciprocation. Turbulent flow may occur unintentionally if the normal flow area has been restricted by the build-up of settled solids, due to the increase in flow velocity in that part of the hole. Turbulent eddies will be created as flow velocity increases, and these will disturb and gradually erode the settled solids, sending them back into suspension. However, increased circulating rates may not be possible because the resultant increase in ECDs could induce formation losses.

Indications of Poor Hole Cleaning

Increased torque (frictional resistance to rotation of the drill string) and drag (frictional resistance to upward or downward movement of the drill string) are usually the first indications of poor hole cleaning, as a result of friction caused by the build-up of drilled cuttings in the hole. There may also be an increase in pump pressure due to the reduction in flow area in part of the annulus where a cuttings bed has formed on the low side of the hole. Any restriction in the annulus will increase down hole ECDs, which could induce formation losses.

Observation of the cuttings and of the cuttings activity at the shale-shakers (i.e. the amount of drilled cuttings travelling across the shaker screens) should give an indication on the effectiveness of hole cleaning. Cuttings should have sharp edges from the way they were broken off by the bit, but if hole cleaning is poor then the cuttings will spend longer in the annulus and the sharp edges will become rounded due to mechanical erosion. If the wellbore is unstable and sloughing, then the characteristic profile of shale cavings may be present.

The cuttings activity at the shakers should reflect ROPs, after taking bottoms-up lag time into consideration. If ROPs are high but cuttings activity at the shakers is low, then check with the mud loggers to determine the duration when ROPs were high and compare it with the bottoms-up time. If cuttings activity at the shakers shortly after bottoms-up does not appear to correspond with ROPs at the time, then hole cleaning may not be effective and cuttings are probably building up in the hole.

Good drilling practices are essential for effective hole cleaning and for avoiding problems when hole cleaning is poor. Problems usually occur when the rig pumps are stopped (e.g. to make a connection) or while tripping. The sudden removal of annular velocity could make the cuttings bed unstable, or drill string movement could disturb the cuttings bed, which could slide down the hole and pack-off around the drill string further down the hole. Tripping speeds are usually controlled in these circumstances to avoid getting mechanically stuck.

The build-up and mechanical erosion of cuttings in the annulus will generate smaller-sized particles that are difficult to remove using the solids control equipment on surface. As a result, low gravity solids (LGS) will increase and this will have a detrimental effect on drilling performance and hole condition, which makes hole cleaning so important. The following are usually indications of poor hole cleaning in a deviated or extended-reach hole:

- Increased torque while drilling
- Increased ECDs due to higher rheology resulting from build-up of solids in the mud
- Fluctuations in pump pressure if cuttings build up around the drill string
- Reduced ROPs
- Thicker but poor quality filter cake on wellbore
- Increased drag while making connections
- Increased over-pull while tripping due to settled solids
- Tight hole due to settled solids
- Longer tripping times due to build-up of settled solids
- Hole pack-off due to build-up in solids
- Mechanically stuck pipe due to build-up of settled solids
- Differentially stuck pipe due to high solids and poor quality filter cake
- Reduced Solids Control Efficiency due to build-up of fines in the mud

Hole Cleaning Guidelines

Stuck Pipe incidents due to poor hole cleaning usually occur while making a connection or while tripping, when the pumps are off. The cuttings bed either slides down the hole and packs-off around the drill string, or the BHA is pulled through the cuttings bed too fast and gets stuck. It becomes increasingly difficult to keep cuttings in suspension as hole inclination increases because the distance the cuttings have to fall before settling on the low side of the hole gets increasingly smaller. A deviated well can be divided into four sections, as follows:

- Vertical and low deviation sections up to around 35° deviation
- Transition Zone between around 35° and 55° deviation
- Highly deviated section above around 55° deviation
- Horizontal section

Hole cleaning is relatively simple in vertical or low deviation wells up to around 35° inclination because the cuttings will be carried to surface as long as the annular velocity is greater than the cuttings slip velocity. Cuttings will gradually slide down the hole when the pumps are off (e.g. during connections), but the hole angle is too steep for a cuttings bed to form. High viscosity sweeps can also be circulated around the hole to improve hole cleaning in vertical or low inclination wells.

Hole cleaning can be troublesome on drill-ships and semi-submersibles, because the BOP is installed on the seabed with a marine riser running up to surface. The marine riser is relatively large (around 20" diameter), so annular velocities in the marine riser may not be high enough for effective cuttings removal while circulating normally, especially if ECDs have to be controlled. The riser is often "boosted" while circulating the hole clean, which involves pumping mud from the active tank down the booster line to the bottom of the marine riser using the spare rig pump, in order to increase annular velocities in the marine riser.

In highly deviated or horizontal wells, annular velocity tends to push or roll settled cuttings along the low side of the hole, the "rolling" speed of the cuttings slowing down as the climbing angle gets steeper. Between around 35° and 55° inclination, the climbing angle gets too steep for the cuttings to continue rolling along the low side of the hole and they form a cuttings bed in this part of the hole. A rotating drill string will help to stir up the cuttings but there may be times when the drill string is stationary while using a down hole mud motor for directional control.

It is important to make sure that the hole in the critical area is clean before tripping out of the hole because the cuttings bed could become unstable and build up around the drill string, with the potential for stuck pipe. A simple bottoms-up circulation will never clean a deviated hole, so circulation should continue until the amount of cuttings appearing at the shale shakers dies away. The drill string should be rotated while cleaning the hole in order to stir up settled cuttings, as mentioned previously. The following guidelines should be observed for effective hole cleaning:

ROP – It is important to control ROPs because high ROPs will increase the cuttings loading in the hole (i.e. the volume of cuttings) and this will reduce hole cleaning efficiency and increase the depth of the cuttings bed in deviated wells. The shale-shakers may struggle to handle the amount of cuttings in the returns, resulting in surface losses or a build-up in drilled solids if it is necessary to install coarser shaker screens. High ROPs could will also increase the hydrostatic in the hole, which will increase the ECD with the potential for induced formation losses.

Mud Rheology – A fluid with higher rheology is recommended for hole cleaning in larger diameter vertical top hole sections because the annular velocity tends to be fairly low due to the large hole sizes. However, fluid rheology needs to be controlled when drilling highly deviated and horizontal wells because this will enable the annular velocity to be maximized for effective hole cleaning. Consideration should be given to reducing fluid rheology if higher annular velocity is required for effective hole cleaning. Although turbulent flow is ideal for hole cleaning and cuttings bed removal, care is required in case it leads to wellbore erosion and washouts in softer formations.

Low Shear Rate Viscosity and Gel Strengths – The Fann 6 and 3 rpm readings are generally regarded as being more representative of the Low Shear Rate Viscosity (LSRV) that affects hole cleaning in highly deviated sections. If rheology is on the low side then the drilling fluid should be treated with a product that improves LSRV. The Gel Strengths (10 second and 10 minute) also represent suspension properties when subjected to static or low shear rate conditions. Drilling fluids should ideally have high fragile gels that collapse easily when circulation resumes. Gels that are excessively high and progressive, usually due to the build-up of fine solids in the drilling fluid, should be avoided because the resultant increase in pumping pressures could induce formation losses.

Mud Density – The buoyancy and slip velocity of drilled cuttings suspended in drilling fluids is dependent on the relative densities between the cuttings and the fluid. Cuttings buoyancy will increase and cuttings slip velocity will decrease as fluid density increases, and vice versa, provided that all the other fluid parameters (e.g. rheology) remain unchanged. However, increasing fluid density in order to improve cuttings suspension and hole cleaning is usually not possible because the resultant increase in ECDs may induce formation losses.

High Viscosity Sweeps – These are effective in vertical and low deviation wells where cuttings cannot settle on the low side of the hole. High viscosity sweeps are not that effective in high deviation or horizontal wells because the viscous sweep will not actually pick up settled solids. However, a high viscosity pill may be effective if it is part of a tandem pill, which is discussed in the next paragraph.

Tandem Pills – These can be very effective for stirring up settled cuttings and removing them from the hole. A tandem pill comprises a low viscosity unweighted pill that is pumped ahead of a high viscosity weighted pill. The first pill is based on the fluid formulation, but without adding the viscosifier, weighting agent or products containing solids (Base Oil is the first pill in an oil-based mud system). The second pill is based on the fluid formulation with additional viscosifier and weighting agent. The density of the second pill is adjusted so that the combined density of the unweighted and weighted pills is the same as the active circulating density.

The low viscosity unweighted pill is designed to be pumped in turbulent flow in order to pick up settled solids. The high viscosity weighted pill is designed to increase cuttings suspension and buoyancy, helping to lift settled cuttings and carry them to surface. The size of each pill is generally based on covering around 150 ft of open hole as a minimum. However, the reduction in wellbore hydrostatic should be calculated for when the unweighted pill is in the annulus, to ensure the well does not go under-balance and produce a kick.

Other Sweeps – Circulating a pill formulated using LCM products (e.g. EMEC Plug) can be effective for improving hole cleaning efficiency because the LCM products help to erode the depth of the cuttings bed by picking up settled solids. SunSweep™ is another product that is designed to improve hole cleaning if a build-up of cuttings is affecting drilling performance. It is a fibrous material that disperses easily in all drilling fluids for the effective removal of cuttings and other debris. Refer to the SunSweep™ Product Data Sheet for recommended sweep concentrations, which may need to be adjusted to avoid plugging MWDs and mud motors.

Pipe Rotation and Reciprocation – This is effective for cleaning the hole in deviated wells because the rotating drill pipe helps to stir up the cuttings bed and also helps to keep the cuttings in suspension. Pipe rotation is particularly important after periods of sliding using the down-hole mud motor for directional control, because the drill pipe will have been stationary and this will allow cuttings beds to form on the low side of the hole. Pipe reciprocation is also recommended to avoid the potential for differential sticking while circulating at a particular depth in open-hole.

Annular Velocity – This is important in highly deviated and horizontal wells where the vertical distance that cuttings travel before settling out on the low side of the hole gets progressively shorter. Pipe rotation will stir up the cuttings bed and annular velocity will carry suspended cuttings or “roll” settled cuttings up the annulus. Annular velocities may be restricted by ECD or rig pump pressure restrictions, so it is important to run the solids control equipment at maximum efficiency in order to prevent an increase in mud weight and rheology due to the build-up of solids in the mud.

Circulating The Hole Clean – The hole should be circulated clean using maximum allowable flow rates, and rotating and reciprocating the drill string, in order to remove drilled cuttings before tripping out of the hole. The only way to do this is to monitor cuttings activity at the shale-shakers until the amount of cuttings coming over the shaker screens dies away.

EMEC Hole Cleaning Processor (HCP)

The efficient transport of drilled cuttings from the drill bit to surface is critical when drilling inclined or horizontal wells. The Hole Cleaning Processor (HCP) software package has been developed by EMEC to predict and analyse the transport of drilled cuttings in inclined wells using fluid dynamics principles, enabling the field engineer to ensure efficient hole cleaning while drilling. The software can be run as a stand-alone application using Microsoft Windows.

The theory of fluid mechanics and dynamics are used for deriving the critical velocity of the cuttings particles within the annulus, and for analyzing the force balance and movement of the cuttings bed. This analysis uses a three-layer model for cuttings transport consisting of three components – a stationary bed of particles of uniform concentration, a moving bed layer in which particle concentration is varied, and a heterogeneous suspension layer on top. The following inputs are required when running the EMEC HCP software:

- Well Geometry (e.g. hole size, casing sizes, interval depths, inclination, etc.)
- Drilling Parameters (e.g. flow-rate, pipe rotation, ROP, drill pipe eccentricity, etc.)
- Fluid Properties (e.g. fluid density, rheology, etc.)
- Cuttings Characteristics (e.g. cuttings density and cuttings size).

Once all the data has been entered, the software performs hydraulics and hole cleaning simulations, displaying numerical results in tabulated form. The software also produces a pictorial display of the hole, predicting areas where cuttings may build up. These plots show the stationary bed layer, the moving bed layer and the suspension layer with the position of the drill pipe added for clarity. Cross sectional plots of the wellbore taken at five degree intervals can also be displayed, once again showing the stationary bed layer, moving bed layer, suspension layer and the drill pipe.

The software has the capability to maintain several sets of results data simultaneously, allowing the operator to adjust the input parameters and directly compare output results to optimize circulating rates for effective cuttings removal at the bit and in the annulus. On calculating results, data can be displayed graphically in a variety of forms enabling the user to visually interpret the data. The calculated results can also be stored in data files and reloaded into the program as and when required.

Surge and Swab

The relatively small clearance between the drill bit and the wellbore creates a piston effect whenever string assemblies (e.g. drill, casing or completion strings) are moved in or out of the wellbore while tripping or making a connection. Surge pressures are generated when the string is lowered into the wellbore, the magnitude depending on how fast the fluid displaced by the string can escape up the annular clearance. Swab pressures are generated when the string is lifted up the wellbore, the magnitude depending on how fast the fluid can flow down the annular clearance to replace the volume previously occupied by the string.

The surge pressure, when added to the hydrostatic pressure in the wellbore, should be kept below the fracture gradient to avoid inducing formation losses. For similar reasons the swab pressure, when subtracted from the hydrostatic pressure in the wellbore, should be maintained above the pore pressure to avoid an influx that could induce a kick. However, the swab pressure may also need to be controlled in order to minimize a reduction in bottom-hole pressure that could destabilize the wellbore.

Several factors will affect surge and swab, the main ones being annular clearance, tripping speed, rheological properties and whether the string is open-ended or closed (e.g. The presence of a float will prevent back-flow up the inside of the string). The surge and swab pressures will be higher when annular clearances are smaller, when tripping speeds are faster and when fluids are more viscous, because these factors will restrict movement of the fluid being displaced up or down the annulus. Surge and swab pressures will also be higher with certain down-hole tools (e.g. scraper or packer assemblies), because annular clearances are usually smaller.

String speed is critical because it is the only variable parameter that can be controlled while moving the string up or down. High surge pressures, which could fracture the formation and induce losses due to the increase in bottom-hole pressure, can be generated if the string speed is too fast while running in and the fluid displaced from the hole does not have time to escape up the annular gap. High swab pressures, which could induce a kick due to the reduction in bottom-hole pressure, can be generated if the string speed is too fast while pulling up, and the fluid does not have time to replace the volume previously occupied by the string.

The EMEC Well Data Simulator (EWDS) calculates surge and swab pressures, which are used for determining the maximum tripping speed when moving the string up or down. This ensures that the bottom-hole pressure is always maintained above the pore pressure but below the fracture pressure, which reduces the potential for fracturing the formation or inducing a kick if the well is under-balance. Tripping speeds can be faster higher up the hole, especially if the string is in larger-diameter casing, because the effects of surge and swab will be reduced.

Stuck Pipe

Contents

Stuck Pipe

Introduction

There are several ways that the drill string can get stuck in the hole. Many stuck pipe incidents are associated with formation stability, but other factors may include hole condition, fluid properties and operational error. The main causes of stuck pipe are as follows:

- Differential Sticking
- Hole Pack-Off
- Cuttings Accumulation
- Formation Collapse
- Key-Seating
- Gauge Drill Bit Stuck in Under-Gauge Hole
- Junk in the Hole
- Collapsed Casing

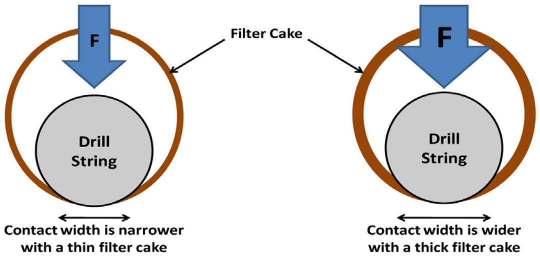
Differential Sticking

Differential sticking occurs when differential pressure between the wellbore and the formation forces the drill string against the side of a permeable formation (e.g. sandstone or limestone). While drilling, the drill string is “bouncing” around the hole and probably removing excess filter cake deposited on the wellbore. However, when drilling is suspended (e.g. to make a connection or trip out of the hole), the drill string rests on the low side of the hole and will sink into the filter cake.

Since the hydrostatic pressure of the drilling fluid in the wellbore is higher than the formation pressure, differential pressure will act on the contact area between the pipe and the filter cake, creating a lateral force that pushes the pipe against the side of the hole. If the drilling fluid has poor fluid loss control and high solids content, then fluid filtration into the permeable formation will continue and more filter cake will be deposited on the wellbore, increasing filter cake thickness.

The contact width between the pipe and the filter cake will get larger as the filter cake increases in thickness. As a result, the magnitude of the lateral force pushing the pipe against the side of the hole will increase as the contact area gets larger. Eventually, the lateral force may be high enough to prevent the pipe from being pulled free, at which point the pipe is said to be differentially stuck.

Differential sticking usually occurs across larger diameter tubulars in the BHA (e.g. drill collars) because the contact area is larger for a given filter cake thickness compared with smaller diameter tubulars (e.g. drill pipe). Differential sticking also tends to occur after raising the mud density in response to some other hole-related issue (e.g. gas-cut mud). Time is a critical factor in freeing differentially stuck pipe because the filter cake will continue to build up and increase in thickness, and this will increase the lateral force acting on the tubulars.



Relationship between filter cake thickness and contact width/area for differential sticking.

Differential Sticking occurs when the string is stationary in the hole, usually while making a connection or tripping, which is one of the reasons for rotating and reciprocating the drill string in open hole. When pipe is differentially stuck, it cannot be moved or rotated, but the hole can still be circulated with normal pump pressures, which helps to distinguish differential sticking from mechanically stuck pipe when the hole is packed-off. Differential Sticking can be prevented or minimized by applying the following measures:

1. Avoid high differential pressures by controlling drilling fluid density
2. Keep the drill pipe moving in the hole whenever possible (rotate and reciprocate)
3. Minimize the duration that the drill string is static in the hole (e.g. connections)
4. Maintain tight fluid loss control to minimize filtrate invasion
5. Keep solids content as low as possible by effective use of solids control equipment
6. Treat the mud system with lubricants such as EMEC Lube or HP Lube

7. Treat the mud system with detergents that prevent clay balling (e.g. EMEC Surf)
8. Incorporate drilling jars in the drill string to help free differentially stuck pipe
9. Use shorter BHAs with spiral drill collars to reduce the contact area, and compensate for loss of BHA weight by using more heavy weight drill pipe (HWDP).

The following actions should be taken if differential sticking occurs:

1. Attempt to pull free by working the pipe and activating the drilling jars.
2. Reduce the hydrostatic pressure in the hole, if safe to do so, by reducing the drilling fluid density (or displacing the Riser in offshore wells to water).
3. Spot a soak solution such as EMEC Spot across the differentially stuck zone to penetrate and gradually break down the filter cake, which will destroy the pressure seal and allow the pipe to be pulled free.

EMEC Spot Soaking Solution

EMEC Spot is supplied in 55 gal drums and is an effective soaking solution for freeing differentially stuck pipe. The product is mixed with diesel or crude oil, displaced down hole and then left to soak across the stuck pipe zone. The recommended volume of soak solution is the annular volume of the stuck pipe zone plus 50% to allow for hole washout. The EMEC Spot pill should be displaced into the annulus to cover the stuck pipe zone, leaving sufficient volume inside the string for pumping a small volume (¼ bbl to 1 bbl) every 15 minutes.

EMEC Spot is designed to gradually penetrate, break up and disperse the filter cake that has built up between the drill pipe and permeable formation. Sufficient time must be allowed for this process to take place (6 to 8 hours), while working the pipe at the same time and activating the drilling jars. The differential contact force holding the pipe against the permeable formation will gradually reduce as the contact area decreases due to filter cake disintegration, until tension applied to the drill pipe eventually releases the stuck pipe.

The EMEC Spot pill should be weighted to the same density as the drilling fluid, in accordance with mixing procedures for EMEC Spot in the EMEC Product Manual. Provided there are no environmental restrictions, the EMEC Spot pill can be incorporated in the drilling fluid after use since it is at the same density, the slight increase in oil content acting as a lubricant to improve drilling performance. If there are environmental restrictions then the pill may need to be recovered on surface for disposal.

The size of the spotting pill is usually calculated on the annular volume to cover the BHA or the entire annulus across the permeable formation, with additional volume for displacing out of the string at regular intervals. If the string is stuck higher up the hole then a Free-Point Indicator Tool (FPIT) may be run on wire-line to determine the location of the stuck string, as this will facilitate precise positioning of the spotting pill. Preparations may be made to sidetrack the well if all attempts to free the pipe are unsuccessful.

Hole Pack-Off

A hole can pack-off while drilling for the following reasons:

- Build up of drilled cuttings due to poor hole cleaning
- Collapse of unconsolidated formation into the wellbore
- Formation relaxation into the wellbore with plastic shales and salt

Cuttings Accumulation

Hole cleaning is critical, especially when drilling high inclination wells, as drilled cuttings can build-up around the drill string. This usually happens after shutting down the pumps to make a connection, which allows the cuttings to fall slowly through the drilling fluid and settle around the drill string (slip velocity). Poor hole cleaning also allows drilled cuttings to settle on the low side of the hole, forming a cuttings bed that will increase drag and produce over-pull while tripping. This could result in a pack-off if the cuttings pile up around the drill string while being dragged up an inclined hole.

Formation Collapse

Part of the formation may collapse into the wellbore even after taking all precautions to maintain wellbore stability (i.e. correct density, effective inhibition, tight fluid loss control, etc.). This may occur while drilling a weak bedding plane at a very shallow angle, or a highly fractured formation that has been broken into several small pieces, or a tectonically stressed formation that cannot be controlled by mud density. The movement of the drill string against such formations could cause collapse into the wellbore.

The hole can also pack-off if unconsolidated formation collapses into the wellbore while drilling and ends up burying the drill string. This often occurs after shutting down the pumps, when the removal of ECD and annular flow destabilises part of the wellbore, which collapses and buries the drill string. A packed-off hole can be distinguished from differential sticking because some movement and rotation of the drill string may be possible, but circulating pressures will be considerably higher due to the restriction in the annulus, assuming that circulation is possible.

Trying to pull the drill string through the packed-off hole is rarely successful and usually makes the situation worse because the drilled cuttings or collapsed formation end up getting compacted together. The priority after a pack-off is to re-establish circulating rates to the level where annular velocities provide effective hole cleaning, and to work the pipe without compacting the debris that has caused the pack-off.

When circulating rates are high enough for effective hole-cleaning, attempts can be made to back-ream the drill string carefully through the packed-off part of the hole, paying close attention to the drill string weight. This could be a lengthy process since the location of the pack-off could be higher up the hole, and it may be necessary to back-ream carefully all the way up to the casing shoe to make sure that the entire hole is in good condition. If attempts to get free are unsuccessful then the only option may be to cut the drill string above the pack-off and prepare for a sidetrack.

Formation Relaxation

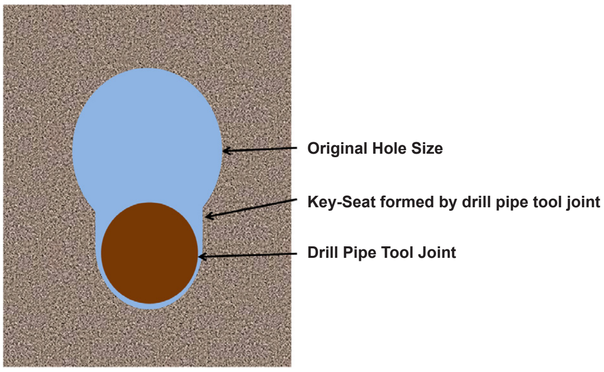
Drilling plastic shales and evaporites (salt formations) may also lead to hole pack-off because these formations will slowly creep into the wellbore and make the hole under-gauge, a situation that cannot always be controlled by mud weight. The technique for drilling these formations is to make frequent back-reaming wiper trips to prevent the hole from going under-gauge. The amount of creep tends to die away when drilling plastic shales, with less and less over-pull on each wiper trip, but salt formations continue to creep in at a steady rate.

A gradual increase in circulating pressure is an indication that the hole is starting to pack-off. In the case of plastic shales, back-reaming will restore an under-gauge hole to its original size. A similar technique is used for salt formations, except that fresh water pills are also circulated around the hole at frequent intervals while drilling in order to dissolve the salt. Care is required when drilling thick salt sections because the fresh water pills will dissolve salt in the lower part of the section and will therefore be less effective at dissolving salt higher up the hole.

If the string gets stuck in a salt section, then it might not be possible to circulate a large volume of fresh water around the hole because the reduction in hydrostatic pressure might create problems in other parts of the hole. A fresh water pill should be spotted across the zone where the string is stuck, leaving sufficient water in the string for displacement into the hole at regular intervals to dissolve additional salt in the stuck zone.

Key-Seating

A key-seat is formed when the rotating drill pipe wears a slot in the side of the wellbore, usually at a bend (dog-leg) and especially if the formation is relatively soft in that area. The width of the slot is roughly the diameter of the drill pipe tool joints. When tripping out of the hole, drill collars that are slightly larger than the tool joints will follow the drill pipe into the the key-seat and may get stuck. The risk of key-seating increases with dog-leg severity since this provides an opportunity for key-seats to form.



Key-Seating

Normal circulation should be possible when key-seating occurs and the string cannot be pulled out. However, it may be possible to rotate and/or work the BHA back down and clear of the key-seat area before back-reaming carefully through the key-seat. Key-seating can be minimized by designing a stiff drilling BHA in order to minimize dog-leg severity. Installing a key-seat wiper between the drill pipe and drill collars is also effective for dealing with key-seats because it acts like a reamer for enlarging the key-seat to the drill collar diameter while back-reaming, allowing the BHA to pass through.

Other Causes of Stuck Pipe

The remaining causes for stuck pipe are self-explanatory. If a drill bit is found to be badly worn and under-gauge after tripping out of the hole then the lower part of the hole is likely to be under-gauge. Care is therefore required when running in with a new drill bit, otherwise the gauge bit could get jammed in under-gauge hole. There have been incidents when metal junk (e.g. slip or tong dies) have fallen into the hole and become wedged in the narrow clearance between the BHA and wellbore, restricting movement of the drill string. There have also been incidents when casing has collapsed after being subjected to formation pressures that have exceeded the casing collapse pressure.

Lost Circulation

Section 13

Contents

Introduction

Lost circulation occurs when the fluid in the hole (usually drilling fluid) flows into the formation due to the type of formation and the hydrostatic overbalance of the fluid in the hole. Losses can occur naturally, or they can be induced when drilling fluid or drilling parameters are not controlled properly. Lost circulation generally occurs in the following types of formation:

Unconsolidated Formations

This type of formation usually occurs at shallow depths near the surface, comprising sand and loose gravel.

Naturally Fractured Formations

This type of formation usually occurs at greater depths and may be present in consolidated sands, chalk, limestone, dolomite and shale.

Cavernous Formations

This type of formation usually occurs in coarse gravel or limestone that has been washed out over time by the action of percolating water. The losses are usually sudden, when the bit penetrates the cavern, and the volume of fluid lost will depend on the size of the cavern. The Driller may also observe a reaction on surface as the drilling bit falls into the cavern.

Induced Fractures

These can occur in any formations and are usually associated with weak bedding planes when the hydrostatic pressure of the fluid exceeds the formation pressure to the point where the fracture opens up and results in induced losses.

Classification of Lost Circulation

Although there are no universally agreed figures for loss rates, formation losses are usually categorized according to severity, as follows:

- Seepage (up to 10 bbl/hr)
- Partial (10 to 60 bbl/hr)
- Severe (over 60 bbl/hr)
- Total (no returns)

Seepage Losses

These losses can occur in any formations if the hydrostatic pressure of the fluid in the hole exceeds the formation pressure, and if formation porosity and permeability are high enough for flow to occur. Seepage losses often occur while drilling porous formations and the loss rate tends to increase as drilling progresses and exposes more formation. Controlled drilling (i.e. cutting back on ROP) will reduce the increase in density created by the volume of cuttings in the hole, and this will help to reduce the ECD and seepage loss rate. A reduction in circulation rate will also help to reduce the ECD and seepage loss rate, provided hole cleaning remains effective. Reducing mud density is also an option as long as this does not affect well control or well-bore stability. Seepage losses may gradually reduce over time as drilling progresses, because solids and cuttings in the mud may start to plug the formation. Treating the circulating system with low concentration LCM is usually effective in treating seepage losses.

Partial Losses

These losses usually occur in unconsolidated or naturally fractured formations. As with seepage losses, the loss rate can usually be reduced by reducing the ECD in the hole, either by reducing the circulating rate, reducing the ROP to minimize cuttings loading in the hole (controlled drilling), and/or reducing mud density. The conventional treatment for partial losses is to treat the circulating system with higher LCM concentrations or to spot a high concentration LCM pill across the loss zone.

Severe Losses

These losses can occur suddenly and without warning in cavernous formations, large natural fractures or large induced fractures. Reducing the ECD in the hole may help to control the loss rate, but the usual course of action is to try to spot a high concentration LCM pill across the loss zone. The losses may stop if the caverns or fractures are eventually filled with mud, but that will depend on the size of the cavern or fracture.

Total Losses

These losses usually occur in long sections of unconsolidated formations such as gravel, in cavernous formations, and in natural and induced fractures, with no fluid returns to surface. Every attempt must be made to maintain hydrostatic pressure in the hole by keeping it filled with mud, in order to avoid wellbore stability or well control problems. If all the drilling fluid on surface has been pumped down hole and fresh mud cannot be built to meet demand, then water should be used to keep the hole filled with fluid in order to maintain well control. The losses should eventually stop once the subsurface voids are filled or, in the case of filling the hole with lighter density fluid including water, when the reduced hydrostatic pressure in the hole balances the formation pressure. Measures can then be taken to identify and seal the loss zone.

Induced Losses

Besides the four natural types of losses categorized above, formation losses can also be induced, which occurs when the fracture strength of the formation is exceeded and wellbore fluids are forced into the formation. This is usually caused by high ECDs (Equivalent Circulating Densities) but can also occur if the hole packs-off or if the fluid is subjected to high back-pressures while circulating. Good drilling practices are effective in keeping ECDs below the fracture strength of the formation and minimizing induced losses, but ECDs can increase due to changes in one or more of the following parameters:

1. **Mud density** – The circulating density must be checked at regular intervals to make sure that it is steady and not increasing due to a build up of solids in the mud, which can be caused by shale-shaker screens that are damaged, or too coarse for the solids being removed.
2. **Mud rheology** – The funnel viscosity will give an indication that rheology is steady if mud temperature is also steady. A build up of solids in the mud due to coarse or damaged shale-shaker screens, or over-treatment with viscosifier, will result in an increase in mud rheology and a resultant increase in ECD.
3. **Circulating Rate** – The higher the circulating rate, the higher the ECD, which may encourage induced losses.
4. **ROP** – High ROPs will increase the volume of cuttings (cuttings loading) in the annulus, which could encourage induced losses, so ROPs should be adjusted with circulating rates to avoid an excessive volume of cuttings in the annulus.
5. **Surge Pressure** – The drill string should be lowered into the hole reasonably slowly as this will minimize surge pressures, which could break down the formation and encourage induced losses. Rotating and slowly pulling up on the drill string while carefully breaking circulation after a round trip will help to break mud gels and minimize initial surge pressures.

LCM Treatments

Formation losses usually account for most of the additional costs when actual drilling fluid costs exceed estimated figures, which is why so much effort goes into preventing down-hole losses in the first place. If offset data is known, then wells can be designed to isolate lost-circulation zones behind casing before drilling deeper formations that require higher mud densities. However, this is not always possible and a range of Lost Circulation Material (LCM) treatments are available to try to prevent or cure formation losses, which will be discussed later.

The first thing to do when losses occur is to check the surface system to make sure that active fluid is not being lost at surface due to surface leaks or other factors (e.g. whole mud losses caused by blinded shaker screens or shale-shaker power failure). Formation losses may not occur when the circulating rate is reduced or stopped, but the Equivalent Circulating Density (ECD) will increase while circulating or drilling, and this may result in losses. Circulation rates and ROPs should therefore be controlled when formation losses occur, in order to reduce the ECD and help to minimize losses.

The required course of action to take once down-hole formation losses have been confirmed must be discussed with the client representative before taking corrective action, and will usually be determined by a Formation Losses Decision Tree that will have been prepared for the drilling campaign during the well planning stage, an example of which is shown at the end of this section. This decision tree contains recommended circulating fluid treatments and LCM (Lost Circulation Material) pill formulations based on the severity of the down-hole losses.

The simplest way to reduce formation losses is usually to reduce the circulating rate and/or ROP, as this will reduce down-hole ECDs by reducing friction in the hole and reducing cuttings loading in the annulus. It may also be possible to reduce the drilling fluid rheology without affecting hole cleaning efficiency, or reduce the drilling fluid density without destabilizing the hole or inducing a kick. If formation losses are severe and cannot be controlled then it may be necessary to suspend drilling, or to drill “blind” while circulating with reduced or no returns, before setting an intermediary casing string to isolate the thief zone.

LCM Materials

Several cheap materials are available for treating lost circulation, including Nut Plug, Mica, Sawdust, Wood Chips, Fibers, Calcium Carbonate and Marble Chips, along with more expensive specialist products. The choice of treatments for lost circulation will depend on the formation being drilled, hole size and the loss rate. Information may be available from adjacent (offset) wells to indicate if losses are likely to occur while drilling, detailing the formations and depths where losses occurred, and the treatments used to cure the problem. If the exploratory well is being drilled in an area where offset data does not exist, then mud density should be kept as low as possible to minimize losses.

Care must be taken when using coarser grades of LCM because there are often limitations on LCM concentrations and particle sizes that can be pumped through the MWD and LWD tools. There is also the possibility of plugging the bit jets, especially if the LCM has been mixed quickly and is still lumpy as it is pumped down-hole. The relevant service engineers should be shown coarse grade LCM samples for confirmation that these products will not plug their down-hole tools if pumped down the drill string. Care is also required when preparing high concentration coarse grade LCM pills because they can plug the jet nozzles of the bit.

Conventional LCM materials (e.g. Nut Plug, Mica, etc.) should not be used when trying to cure losses in the production zone because this might damage the formation and reduce productivity. Losses in the reservoir should be treated using sized Calcium Carbonate bridging material, which can be acidized, along with specialist LCM products that have been designed for use in production zones.

As with all deviations to the drilling program, potential LCM formulations must be discussed with, and approved by, the Company Man and the EMEC supervisor in town before preparing and pumping any treatments. If an agreed losses plan does not exist, then EMEC recommends the following active fluid treatments, pill formulations and procedures for dealing with formation losses:

Seepage Losses

The recommendation for seepage losses depends on the loss rate. If the loss rate is tolerable, then it might be possible to reduce or prevent further losses by reducing the circulating rate in order to reduce down hole ECD. It may also be possible to reduce the mud density. Check that the shale-shaker screens are not damaged or too coarse, as a build up of solids could result in an increase in mud density and rheology, which will also increase down hole ECD and encourage formation losses.

Seepage losses often continue as new formation is constantly being exposed while drilling, so it is usually more effective to treat the entire circulating system with LCM rather than prepare and pump LCM pills. The recommendation is to treat the active circulating system with 5 ppb to 10 ppb fine grade lost circulation material, such as Nut Plug, Mica or Calcium Carbonate. Regular dosing with LCM will be necessary at the mixing hopper to maintain an effective LCM concentration and compensate for LCM screened out at the shale-shakers.

The shale-shaker screens may get blinded by LCM in the mud, leading to surface losses, but they should not be bypassed because drilled solids will then build up in the mud. This will increase the drilling fluid density and rheology, with the potential to encourage more formation losses. The hole can also be swept periodically with fine and medium grade Quick Seal and Mica, or fine and medium grade Calcium Carbonate bridging particles if in the production zone.

Partial Losses

The recommendation for partial losses, which usually occur while drilling fractured formations, is to spot a viscous pill comprising 30 ppb to 40 ppb fine and medium grade LCM (Nut Plug, Mica and K.Seal) across the suspected loss zone. The drill string should then be pulled up into the casing shoe to minimize the potential for differential sticking while leaving the LCM pill to soak in the loss zone for a few hours. The annulus should be kept filled with mud to maintain fluid hydrostatic throughout this period, before running back to bottom and gradually increasing the circulating rate while monitoring for losses. Repeat or adjust the LCM concentration if the first attempt is unsuccessful.

Total Losses

The recommendation for complete losses is to spot one or more pills comprising 100 ppb or more fine, medium and coarse grade LCM across the loss zone and applying pressure to squeeze the LCM pill into the loss zone. As mentioned previously, care must be taken when using coarser grades of LCM to avoid any risk of plugging the down-hole tools, and LCM pills in the production zone should be formulated with sized Calcium Carbonate bridging particles in order to minimize formation damage.

A gunk squeeze (using Base Oil and Bentonite) or a cement plug should be considered if the high-concentration LCM pills are unsuccessful in curing total losses across a fractured formation. However, there may be occasions when nothing can be done to prevent losses, due to the size of the fracture, vug or cavern, for the simple reason that LCM particle sizes are not large enough to bridge the pore throat without first plugging the jet nozzles in the bit.

When losses cannot be cured, there may be little choice but to drill "blind" and to keep the hole filled with mud as best as possible. If the cuttings are large enough then they will act as bridging particles, or the void may eventually fill up, restoring mud returns at surface. The following procedures are recommended when drilling blind:

- Pump 50 bbl high viscosity sweeps for each stand drilled, to help push cuttings above the bit and BHA.
- Control ROPs to prevent a build up of cuttings in the annulus.
- Spot high viscosity, unflocculated Gel mud across any unconsolidated sand sections prior to tripping, as a precaution against possible caving.
- Fill the hole with high viscosity, unflocculated Gel mud prior to tripping out to run casing.

LCM pills are usually prepared using mud from the active circulating system. However, this will produce a higher density pill once all the LCM products have been mixed and this might increase the hydrostatic pressure of the fluid and the loss rate to the formation when pumped down hole. The density of the LCM pill should be checked before pumping down hole, to make sure it is the same as the active circulating mud density. LCM pills should not be lighter because this could destabilize the well bore or bring the well under balance and create a well control situation.

The shale shakers should not be bypassed or fitted with coarser shaker screens when treating the circulating system with LCM because this will increase the drilled solids in the mud, which might result in an increase in density and rheology. If this happens then the circulating ECDs will increase and encourage more mud losses to the formation.

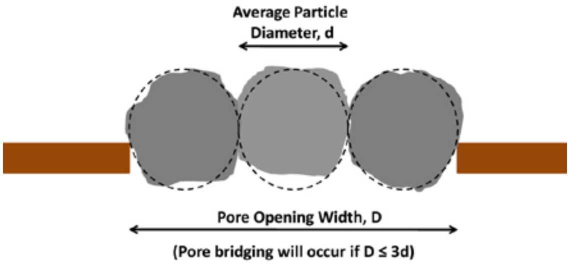
LCM Bridging Theory

When encountering losses, the priority is to determine if the losses are flowing into the formation structure or into a fracture. Losses into the formation structure are usually indicated by an increasing loss rate as drilling exposes more formation, whereas losses into a fracture are usually sudden. The type of loss will determine the suitable size and choice of material for bridging or plugging the loss zone.

If losses are into the formation structure then the task is to plug the pore throats with larger-sized particles first (Coarse LCM), then plug the channels between the larger-sized particles with medium-sized particles (Medium LCM), and finally seal the channels between the medium-sized particles with a filter cake of small-sized particles (Fine LCM). Barite and drilled solids (cuttings) also contribute to this bridging process.
There is a correlation between pore size (in microns) and formation permeability (in milli-Darcies), as follows:

$$\text{Pore Size} = \sqrt{(\text{Formation Permeability})}$$

Research also confirms that particles with an average diameter one third the size of the pore throat diameter will form a bridge across the pore throat when subjected to differential pressure, as shown in the diagram on the next page. Differential pressure in the wellbore is provided by the over-balance between the drilling fluid hydrostatic pressure and the pore pressure. With this knowledge, effective LCM treatments can be formulated by measuring the permeability or pore throat size from core samples obtained from representative offset wells.



Bridging theory

Particle Size Distribution (PSD)

Bridging and LCM materials are generally categorized as fine, medium and large. However, the particles in each category will range in size and this is called the Particle Size Distribution. Sophisticated electronic laboratory equipment is available for measuring the PSD of bridging materials in a fluid (e.g. laser diffraction technology), and the concentrations of these materials can then be adjusted to suit the formation being drilled in order to produce a low permeability filter cake. Typical particle size ranges for EMEC CARB Bridging Material grades are as follows:

EMEC Fine	5 to 400 microns
EMEC Medium	100 to 1000 microns
EMEC Coarse	60 to 2500 microns
EMEC Ground Marble Grade E	1 to 160 micron

Most Barite particles range from 2 to 44 microns and will therefore provide effective bridging for pore throat sizes ranging up to 132 microns, so pore sizes above this will require LCM bridging materials. Based on the relationship between pore size and permeability, 2 micron Barite particles will theoretically bridge 6 micron pore throats, which equate to a 36 milli-Darcy permeability. Similarly, 44 micron Barite particles will theoretically bridge 132 micron pore throats, which equate to a 17,424 milli-Darcy (i.e. 17 Darcy) permeability.

The PSD for Barite includes particles that are larger than 44 microns, so Barite is therefore effective for bridging high permeability sands before whole mud starts to be lost to the formation. As a general guidline, whole mud losses do not occur in formations with permeabilities below 50 Darcies when Barite is used as a weighting agent.

Wellbore Strengthening

In depleted reservoirs, the pore pressure gradually declines as the reserves decline, weakening hydrocarbon-bearing rocks. However, adjacent and inter-bedded low permeability shales may maintain their pore pressure, making drilling extremely difficult because the mud weight to support these shales exceeds the fracture resistance of the depleted sands and silts. Wellbore strengthening is designed to strengthen the wellbore so that depleted reservoirs can be drilled with higher mud weights without inducing down-hole losses due to formation breakdown (i.e. the fracture resistance of the formation is increased).

Wellbore strengthening is achieved by creating a “stress cage” in the wellbore using bridging particles (marble and graphite) and an ultra low fluid loss mud system. Short fractures are deliberately allowed to form at the wellbore wall. The bridging particles and a mud filter cake rapidly form at the fracture mouths. The fractures are then propped open by the bridging particles (marble) and ultra low fluid loss filter cake prevents fluid invasion across the mouths of the bridged fractures. Adjacent rock is put into compression by the fractures to form a “stress cage”, which effectively strengthens the wellbore for use in the following applications:

- Drilling depleted reservoirs adjacent to formations with higher pore pressures.
- Deep water drilling with a narrow window between pore pressure and fracture gradient.
- Minimizing losses when running or cementing casing.
- Providing improved well control.
- Reducing the number of casing strings in a well.

Stress Cage Theory

The theory behind stress cage wellbore strengthening is to allow small fractures to form in the wellbore wall and hold them open using bridging particles near the fracture opening. The bridge must have low permeability to provide pressure isolation. This will create an increased hoop stress around the wellbore (a “stress cage” effect), provided the induced fracture is bridged at, or close to, the wellbore wall. The aim is to be able to achieve this continuously while drilling, by adding appropriate materials to the mud system, producing in effect a “designer mud”.

Theory suggests that increases in effective wellbore strength of around 1,000 psi can be achieved with fracture widths as small as 1 mm. Particle size distribution (PSD) in the fluid would need to range from colloidal clays up to values approaching 1mm, to give a smooth PSD profile and produce a low permeability bridge. PSD would then need to be maintained while drilling. Theory also suggests that short fractures are best, so it is necessary to arrest fracture growth very quickly as the fracture starts to grow (long fractures are easier to re-open and propagate). This means high concentrations of bridging additives are preferable. The additives need to be physically strong enough to resist the closure stresses, and sized to bridge near the fracture mouth to produce a stress cage near the wellbore.

Permeable Formations

The particle bridge does not need to be perfect when drilling permeable formations because fluid passing through the bridge will leak away from the fracture into the rock matrix, so there will be no build up in pressure in the fracture to initiate fracture propagation. Even if a filter cake forms initially on the walls of the fracture, the fracture would grow by a small amount to expose new surface and this would relieve the pressure.

If the mud contains particles that are too small to bridge near the fracture mouth, the fracture could still become sealed as filter cake built up inside the fracture. However, the sealing/bridging will be slower and the fracture length might extend too far to form a useful stress cage effect. This can be seen in the mud losses observed using ordinary mud systems. However, one advantage of running ultra low fluid loss muds in permeable formations is the reduced risk of differential sticking.

Low Permeability Formations

The particle bridge needs to have extremely low permeability when drilling low permeability formations because this will prevent pressure transfer into the fracture, which would otherwise initiate fracture propagation. This explains the need for fluids that produce filter cakes with an extremely low fluid loss. The initial rush of fluid into the fracture when it forms will deposit the bridging solids at the fracture mouth, but a differential pressure is then required to hold this bridge in place. A slow pressure leak-off into the shale may maintain this pressure differential, but ultra-low fluid loss is required so that the bridge at the fracture mouth has sufficiently low permeability to maintain differential pressure across the bridge. With a low permeability bridge, flow rate of fluid into the fracture is extremely small once the bridge has formed. If pressure builds in the fracture, then the fracture would only need to grow by a small amount to relieve this pressure. Therefore, it may suffice to achieve a bridge with very low permeability rather than “zero” permeability.

The ideal scenario would be the formation of many narrow localized fractures around the wellbore to produce the stress cage, which would then require very small bridging particles to seal them. This never happens in reality, which is why larger bridging particles are also required. An important factor is to form a stable bridge that is flexible enough to withstand the fluctuations in pressure and rock movements, which explains why graphite is included in the bridging particles.

Operational Considerations

Running designer muds requires non-standard drilling practices. The circulating system must be loaded with larger bridging solids and the PSD must be maintained with continuous additions of these larger materials. Optimally, around 40 ppb bridging solids must be kept in the system. Coarser shaker screens must be used to avoid stripping out bridging particles while circulating, which means that the mud weight and rheology will gradually increase due to the build-up of drilled solids. As a result, more dilutions may be required while drilling.

Logging Tools for Detecting Loss Zones

LCM treatments may be ineffective for the simple reason that they are not being spotted across the thief zone where formation losses are occurring. If this is the case, and if the loss rate is significant, then the following logging tools can be run to locate the thief zone:

Temperature Log

Mud flowing into the formation will cool the area where losses are occurring and this can be detected by running a temperature log inside the drill pipe.

Spinner Log

This is a propeller device that measures flow in the wellbore, enabling significant formation losses to be detected if the drill pipe is out of the hole.

Noise Log

This uses a very sensitive microphone (hydrophone) to detect noise created by turbulent flow in the region where fluid is passing into the formation.

Cross-Linking Polymers for Severe Losses

A cross-link is a chemical bond that joins two separate polymer chains together. When this happens, the free movement of individual polymer chains is restricted. The fluidity of the polymer chains reduces as the degree (density) of cross-linking increases, and this will affect the physical properties of the fluid. The viscosity of the fluid will increase as cross-linking density increases, turning into a gel-like fluid with medium density cross-linking and eventually producing a rigid structure with high density cross-linking. The flexible, elastic gel structure produced with medium density cross-linking is this property that makes cross-linked polymers effective as a cure for severe formation losses after conventional LCM treatments have been unsuccessful.

The cross-links are produced by chemical reactions that are usually initiated by heat, pressure or adjustments to pH. The cross-linking process is often slow, but the cross-links that form are permanent. However, the process can be speeded up by adding a catalyst or “activator” to initiate the chemical reaction. The activator is usually added to the cross-linking mix just before pumping down-hole, and the cross-linking polymer pill is designed to be pumped through mud motors and down-hole assemblies (e.g. MWD and LWD tools), avoiding the need for a round trip. Once spotted across the loss zone, the product gradually forms a matrix in and across natural fissures and induced fractures.

The use of Cross-Linked Polymers can be effective for dealing with formation losses when traditional LCM treatments have been unsuccessful for the following applications:

- Curing severe losses in weak or fractured zones
- Controlling induced losses
- Consolidating loose formations

Cross-linking polymer systems usually comprise three components:

- Cross-Linking Polymer to provide viscosity and for sealing the loss zone
- Activator to initiate the cross-linking process for gel formation
- Retarder to delay the cross-linking process for high BHT

Cross-linking polymer products usually come with detailed mixing procedures to prevent contamination that could have a detrimental effect on setting times, but in all cases lines and tanks must be clean and flushed with fresh water before mixing. High Calcium levels in the mix water may also need to be treated out. The cross-linking polymer is then mixed at a controlled rate and sheared through the hopper for a recommended period to ensure complete dispersion and hydration. At this point, conventional weighting materials can be added to obtain the required displacement density. The cross-linking pill can then be stored for use when required, although biocide treatments may be required for long-term storage.

Prior to pumping down-hole, the required concentration of activator is quickly added at the mix hopper and the cross-linking pill is then pumped quickly down the drill string. Cross-linking polymer products usually come with detailed pumping procedures and the spotting method will usually depend on the nature of the losses. When dealing with open fractures, the cross-linking polymer pill should be pumped carefully out of the drill string to prevent localized losses that might prevent coverage of the entire loss zone. When dealing with induced losses, the cross-linking polymer pill should be squeezed into the weak formation.

The drill string is then usually pulled clear of the cross-linking polymer pill so that it can be flushed through with mud. The cross-linking polymer pill should then be left in place for the recommended setting time, applying pressure if required, before resuming drilling. In the meantime, the mix tank and associated lines should be flushed and cleaned immediately after use, before any residual cross-linking polymer has had time to set. Cross-Linking polymers are usually designed to be non-damaging and can be removed by drilling, jetting or acidizing.

Retarders are usually available to delay the cross-linking process and avoid premature setting of the pill on surface in hot regions, or while pumping down-hole with high bottom-hole temperatures or long pumping times.

Gunk Plug or Squeeze

The use of a gunk plug or squeeze may be considered if conventional LCM pills are unsuccessful in reducing or curing formation losses. The traditional gunk plug or squeeze involved dispersing Bentonite in diesel and spotting the resulting gunk plug across the thief zone. The gunk squeeze involves closing the annular BOP and squeezing the gunk plug into the thief zone in an attempt to cure the formation losses. This method should not be used for curing losses in the reservoir section due to resultant formation damage.

A gunk plug can be formulated using any mineral or synthetic base oil, because the primary function of the oil is to prevent hydration while displacing a concentrated suspension of Bentonite down the drill string to the thief zone. The procedure for a typical gunk plug and squeeze that is mixed at the cement unit is as follows:

1. Flush the cement pump and associated lines with base oil to remove all traces of water.
2. Make sure the cement mix tank is clean and dry.
3. Fill the cement mix tank with 25 bbl base oil.
4. Switch on the mix tank agitator.
5. Add 300 ppb Bentonite to form a concentrated suspension in base oil.
6. Keep circulating the mix tank to disperse and suspend the Bentonite.
7. Displace a 10 bbl base oil spacer into the drill string.
8. Displace the gunk pill into the drill string.
9. Displace a 10 bbl base oil spacer into the drill string.
10. With the drill bit just above the thief zone, pump the gunk pill down to the bit.
11. Close the annular BOP and squeeze the gunk pill into the thief zone.
12. Pull up into the casing shoe and maintain pressure for approximately 4 hours.

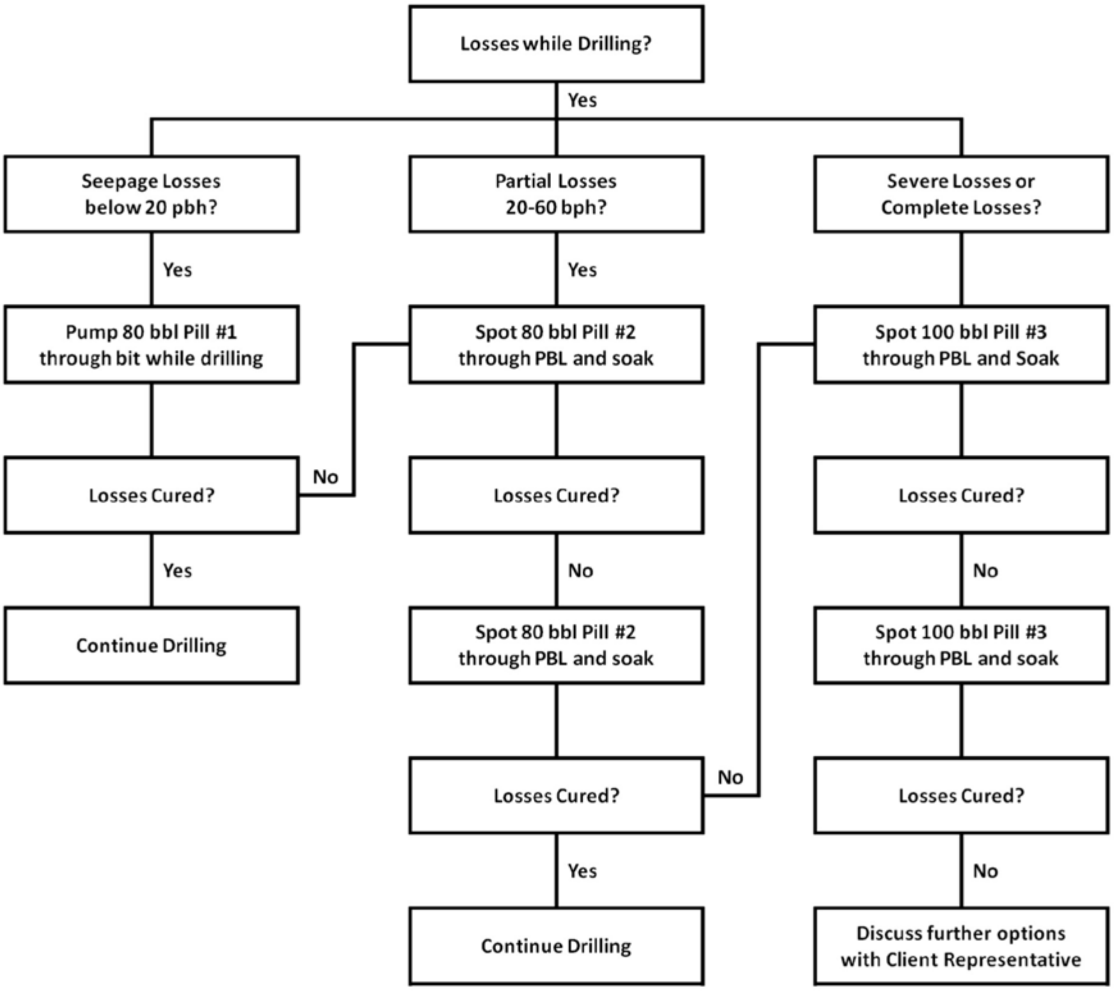
During the squeeze, the base oil is pushed into the thief zone and the Bentonite is then hydrated by water from the water-based mud, which will form a thick, putty-like material that is designed to seal the thief zone. The gunk plug or squeeze will only be effective if the exact location of the thief zone is known, which can be determined by running logs (e.g. wellbore temperature log), and the diesel spacers must be large enough to prevent Bentonite hydration before the gunk pill has left the drill string.

Cement Plug

A cement plug may be spotted across the thief zone when all other attempts to cure formation losses have failed. This may be followed by a cement squeeze, which is achieved by closing the annular BOP and applying pressure to squeeze the cement slurry further into the thief zone. The cement plug is designed to seal off any fractures and voids, enabling drilling to resume after drilling through the cement plug.

Lost Circulation Decision Tree

A typical lost circulation decision tree appears overleaf. Decision trees are generally developed for each field and for each well interval, based on offset well data, so there is no guarantee that they will be effective if used in other fields.



Pill #1 Formulation (40 ppb)

15 ppb CalCarb Fine
15 ppb CalCarb Medium
10 ppb Dynared

Pill #2 Formulation (80 ppb)

20 ppb CalCarb Fine
15 ppb CalCarb Medium
15 ppb CalCarb Coarse
20 ppb Dynared
10 ppb SX-Plus

Pill #3 Formulation (120 ppb)

30 ppb CalCarb Fine
30 ppb CalCarb Medium
20 ppb CalCarb Coarse
30 ppb Dynared
10 ppb SX-Plus

Lost Circulation Decision Tree

Displacement Pills, Spacers and Procedures

Section 14

DRILLING FLUIDS MANUAL

Contents

Introduction

A variety of wellbore displacements are performed during well construction operations, including the following which are discussed later in this section:

1. Displacement from Water or Brine to WBM or OBM
2. Displacement from WBM to a different WBM
3. Displacement from WBM to OBM
4. Displacement from WBM to completion brine
5. Displacement from OBM to WBM
6. Displacement from OBM to completion brine
7. Riser Displacements
8. Cement Spacers

The function of pills and spacers is to keep both fluids apart in order to prevent or minimize contamination. They may also be required to remove other potential contaminants in the wellbore, including settled solids, filter cake, grease, pipe dope, scale and rust, since this will minimize reservoir formation damage. Finally, the pills and spacers may be required to make the tubular surfaces of the wellbore water-wet after exposure to base oil in oil-based drilling fluids, or lubricants used in some water-based drilling fluids for reducing torque and drag.

Displacements can be performed in open hole, where the wellbore is exposed to formation pressures or in cased hole, where the wellbore is isolated from formation pressures. They can also be direct displacements or indirect displacements. A direct displacement involves displacing one fluid directly to another fluid in one circulation. An indirect displacement is a longer procedure that involves displacing the wellbore to water first, so that a thorough clean-out can be performed before a second displacement to the final fluid.

Direct displacements are always performed in open hole because the wellbore is exposed to formation fluids, so some or all of the pills and spacers have to be weighted in order to maintain hydrostatic pressure. Direct displacements are also performed in cased hole if water is in limited supply or simply to save rig time. Indirect displacements are recommended when there is a need for improved hole cleaning before displacing to completion brine and the wellbore is isolated from formation pressures, so pills and spacers do not need to be weighted to maintain wellbore hydrostatic.

Displacing a water-based drilling fluid from the hole is simpler than displacing an oil-based system because settled solids and debris associated with water-based fluids are easier to remove. As a result, the pill and spacer requirements are simpler for water-based fluids. The pill and spacer requirements are more complex for oil-based fluids because additional surfactant and solvent pills are required for effective cleaning, and the tubular surfaces must end up water-wet.

General Displacement Guidelines

Several procedures are available for improving wellbore displacements and they need to be considered when planning a displacement in order to prevent or minimize fluid contamination. However, operational factors may restrict the use of some of the following procedures, as discussed later:

- Direct and Indirect Displacement
- Displacement Direction
- Displacement Rate
- Spacer and Pill Volume and Contact Time
- Displacement Density Hierarchy
- Displacement Viscosity Hierarchy
- Scraper and Brush Assembly
- Pipe Rotation and Reciprocation
- Fluid Circulation and Conditioning

Direct and Indirect Displacements

The nature of the displacement and whether it is performed in open hole or cased hole usually determines the choice between a direct or indirect displacement. A direct displacement occurs when one fluid is displaced to another fluid in a single circulation, using various pills and spacers to separate the fluids and/or clean the hole. An indirect displacement occurs when one fluid is displaced to an intermediate fluid first (usually water or seawater), which is then circulated until the hole is clean before displacing to the final fluid.

Indirect displacements are usually performed in cased hole, when the reservoir is isolated and when a plentiful supply of water is available (e.g. seawater). An inflow test is usually performed to confirm safe isolation of the reservoir when this has been achieved using a production packer assembly. Indirect displacements are beneficial for well clean-ups because water can be circulated at high flow rates until tubular surfaces are clean. Additional surfactant pills and viscous spacers can also be circulated to ensure that the wellbore is clean before displacing to completion brine.

Direct displacements must be performed in open hole because hydrostatic pressure has to be maintained to control formation pressures. However, direct displacements are also performed in cased hole, and various pills and spacers are available for improving the effectiveness of these displacements. Displacements from water-based fluids to oil-based fluids are not so critical because oil-based fluids can tolerate contamination due to water-based fluids and residual solids, so a direct displacement will obviously save rig time.

Displacement Direction

Fluids can be pumped down the drill pipe and up the annulus (conventional circulation), or down the annulus and up the drill pipe (reverse circulation). When circulating fluids with different densities around the hole, the heavier fluid will sit on top of the lighter fluid either in the string or in the annulus. It is desirable to minimise the duration that the heavier fluid sits on top of the lighter fluid because this will reduce the size of the interface, produced as the heavier fluid channels down through the lighter fluid.

The annulus volume and displacement string capacity should always be compared to determine whether a conventional or reverse circulation is preferable. A reverse-circulation displacement is preferable when the annulus volume is larger than the string capacity and a higher density fluid is being displaced to a lower density fluid, because this will minimize the time that the higher density fluid is above and channelling down through the lower density fluid in the string.

The preferred displacement direction may not always be possible, especially if there are special assemblies like production packers in the hole. The production packer is set after displacing the brine in the wellbore to packer fluid, but there is a risk of accidentally setting the production packer prematurely during a conventional circulation displacement, so a reverse circulation displacement is performed even if a conventional circulation displacement is preferred for minimizing fluid channelling.

Displacement Rate

High displacements rates should be used, where possible, to encourage turbulent flow since this will help to stir up settled solids and other debris in the hole. It will also minimize channelling, especially in high-angle and extended-reach wells. There are usually no restrictions with displacement rates in cased hole, unless there are special down-hole assemblies, such as production packers, where high flow rates might wash out the sealing area around the packer seals.

Most displacements are carried out after cementing the casing or liner string, so flow rates can be maximized without affecting the formation. However, displacement rates in open hole may need to be restricted in order to control ECDs and bottom-hole pressures. This is particularly relevant for reverse-circulation displacements because ECDs and bottom-hole pressures are usually higher due to higher friction in the drill string. The displacement rate is often reduced towards the end of the displacement to make it easier to catch the arrival of the various interfaces and minimize contamination of fluids on surface.

Spacer and Pill Volume and Contact Time

Spacers and pills form interfaces with the fluids that they come into contact with, so they need to be large enough to keep adjacent fluids apart. Contact time is also important so that the chemicals can penetrate, break down and wash away settled solids and associated debris in the wellbore. It is difficult to specify volumes for pills and spacers because they may be limited by surface tank restrictions and, when they are unweighted, the need to maintain hydrostatic pressure in the wellbore.

As a general guide, chemical spacer and pill volumes should be sized to give 10 minutes contact time in the critical part of the wellbore, and to maintain 1,000 ft separation in the largest part of the annulus. A spacer volume around 130 bbls will provide 1,000 ft separation for 5” drill pipe in 13⅜” casing, and a spacer volume around 55 bbls will provide 1,000 ft separation for 5” drill pipe in 9⅝” casing, depending on the grade of casing used.

The contact time will obviously vary in different annular sections of the wellbore and will depend on the displacement rate, which should be high enough to produce turbulent flow in the critical annular section. "Inert" pills and spacers (e.g. high viscosity spacers, base oil pills) generally range from 25 bbls to 50 bbls.

The number of pills and spacers used for a clean-out displacement may be restricted by limited surface tank availability. However, it may be possible to prepare two similar pills or spacers using one tank. As an example, if a viscous spacer will be followed later on by a viscous surfactant spacer, then a large viscous spacer volume can be prepared in one tank and surfactant can be added to the remaining viscous spacer in the tank once the initial viscous spacer has been pumped.

Displacement Density Hierarchy

A lower density fluid will "float" on top of a higher density fluid and a high density fluid will tend to channel down through a lower density fluid. As a result, a higher density spacer will tend to improve effectiveness when displacing a lower density fluid from the wellbore. This is not always possible, especially if the spacer is separating a high density fluid that is being displaced to a lower density fluid.

The density of the spacer should ideally be midway between the adjacent fluid densities when displacing to a higher density fluid. When displacing to a lighter fluid, the density of the spacer should be the same as the lighter density fluid, so that most of the channelling takes place between the heavier density fluid and the "sacrificial" spacer, which is usually discarded at the end of the displacement.

Displacement Viscosity Hierarchy

High viscosity spacers tend to be in plug flow, which will minimize channeling and produce a smaller interface while displacing a lower viscosity fluid from the wellbore. However, if the higher viscosity spacer is followed by a lower viscosity fluid then channeling could be severe, resulting in a larger interface. The main fluids involved in the displacement will determine the required spacer properties, especially if the wellbore is being displaced to brine.

It is important to make sure that polymers in viscous spacers are kept away from completion or work-over brines because they will create filtration problems, with potential loss of rig time due to prematurely plugged filters. Consideration should be given to including an additional "sacrificial" spacer between a viscous spacer and the completion brine, especially when using a high-value brine system, in order to minimize polymer contamination at the interface.

Scraper and Brush Assembly

Debris will collect in the wellbore while drilling, including drilled solids, metal shavings, pipe dope, rust and scale. All of these items can be found in the wellbore tubulars and can have a detrimental effect on completion operations, especially when running production assemblies. A scraper/brush assembly is usually included in the displacement string when displacing the hole to brine in order to remove this debris and to make sure that critical parts of the wellbore are clean (e.g. the production packer setting area).

Pipe Rotation and Reciprocation

The action of rotating and reciprocating the displacement string will break down any gelled mud, at the same time stirring up and suspending settled solids. It will also improve the displacement by reducing fluid channelling, especially in high-angle and extended-reach wells. However, rotation and reciprocation may not be possible if the displacement string contains special assemblies, or if the annular BOP or pipe rams are closed for a reverse circulation displacement.

Fluid Circulation and Conditioning

If the hole contains drilling fluid then it should be circulated and conditioned at maximum allowable flow rates, while rotating and reciprocating the drill string, before starting the displacement. This will help to pick up and suspend settled solids, and will also bring the mud up to circulating temperatures, which will reduce high viscosity and gels associated with cold mud. If the rheology of the warm mud is still on the high side then consideration should be given to thinning the mud in order to improve flow characteristics for an effective displacement.

Types of Displacement

As mentioned at the beginning of this section, a variety of displacements are performed during well construction operations, including the following:

1. Water or Packer Fluid to WBM or OBM
2. WBM to another WBM

3. WBM to OBM
4. OBM to WBM
5. WBM to Completion Brine
6. OBM to Completion Brine
7. Riser Displacements
8. Cement Spacers

Ideally, most wellbore displacements would involve indirect displacements, where the hole is displaced to water before displacing to another fluid system, because this procedure eliminates fluid contamination and enables the hole to be cleaned thoroughly. However, indirect displacements require a plentiful supply of fresh water or seawater, and require considerable storage space to meet zero discharge requirements. They also require additional rig time, and cannot be used if hydrostatic pressures have to be maintained in the wellbore.

In reality, most displacements are direct displacements, where one fluid system is displaced to another fluid system in one circulation using pills and spacers. The potential for fluid contamination is increased, but direct displacements do not require a plentiful supply of fresh water or seawater, so they eliminate the amount of storage space necessary to meet zero discharge requirements. Direct displacements are also faster than indirect displacements because they are completed in one circulation, and are used when hydrostatic pressures must be maintained in the wellbore.

1. Displacing Water or Packer Fluid to WBM or OBM

This type of displacement is relatively simple because it usually involves displacing a low density, low viscosity fluid (i.e. water or packer fluid) to a higher density, higher viscosity fluid, so a spacer is not generally required unless it is necessary to prevent contamination of the water-based mud. The spacer can be prepared by transferring some of the water-based or oil-based mud that is going to be displaced into the hole across to a separate tank (e.g. Pill Tank) and adding additional viscosifier. A typical displacement from water or packer fluid to water-based or oil-based mud might be as follows:

- Run in with the displacement assembly (drill string) and start circulating water or packer fluid to confirm that there are no restrictions in the wellbore.
- **Pump a Viscous Spacer,** if required.
- Displace the water or packer fluid in the hole to water-based or oil-based mud at maximum allowable flow rates.
- Recover the interface in a separate tank, if necessary, and continue circulating until the mud returns are at the same density as the mud being pumped.
- Establish a closed circulating system on the Active Tank and drill ahead.

2. Displacing WBM to another WBM

This type of displacement is usually performed in cased hole after running and cementing the casing string, or after drilling through the casing shoe and cleaning out the rat-hole. The displacement procedure is relatively simple, especially if a lower density fluid is being displaced to a higher density fluid. A spacer may not be required unless it is necessary to prevent contamination of one or both water-based mud systems. If a spacer is required then it can be prepared by transferring some of the water-based mud that is going to be displaced into the hole across to a separate tank (e.g. Pill Tank) and adding additional viscosifier. A typical displacement from water-based mud to another water-based mud might be as follows:

- Run in with the displacement assembly (drill string) and circulate and condition the existing water-based mud in the hole to suspend settled solids.
- **Pump a Viscous Spacer,** if required.
- Displace the water-based mud in the hole to the new water-based mud at maximum allowable flow rates.
- Recover the water-based mud interface in a separate tank, if necessary, and continue circulating until the mud returns are at the same density as the mud being pumped.
- Establish a closed circulating system on the Active Tank and drill ahead.

3. Displacing WBM to OBM

This type of displacement is usually performed in cased hole after running and cementing the casing string, or after drilling through the casing shoe and cleaning out the rat-hole. A spacer is recommended between the water-based mud and the oil-based mud to minimize contamination between both drilling fluid systems, especially if the water-based mud is a high-value system that will be recovered for future use. The spacer is usually prepared by transferring some of the oil-based mud that is going to be displaced into the hole across to a separate tank (e.g. Pill Tank) and adding additional viscosifier. A typical displacement from water-based mud to oil-based mud might be as follows:

- Run in with the displacement assembly (drill string) and circulate and condition the existing water-based mud in the hole to suspend settled solids.
- **Pump a Viscous Spacer,** if required.
- Displace the water-based mud in the hole to oil-based mud at maximum allowable flow rates.
- Recover the viscous spacer in a separate tank and continue circulating until the oil-based mud returns are at the same density as the oil-based mud being pumped.
- Establish a closed circulating system on the Active Tank and drill ahead.

4. Displacing OBM to WBM

The priority when displacing the hole from oil-based mud to water-based mud is to change the oil-wet surface of the wellbore to a water-wet condition through the use of surfactants. If the oil-based mud is being displaced to a water-based drill-in fluid, then the other priority is to remove settled solids and filter cake, because this could contribute to formation damage and poor reservoir productivity. The following pills and spacers are generally used for such a displacement:

- Base Oil Pill
- Viscous Surfactant Spacer
- Solvent Pill
- Surfactant Pill
- Viscous Spacer

Base Oil Pill – This is usually around 20 bbls to 30 bbls in size and is designed to thin the oil-based mud and provide preliminary cleaning of the wellbore surface, especially when pumped in turbulent flow for maximum effectiveness. This will improve the performance of the surfactant and solvent pills and spacers that are pumped after the base oil pill. Some of the base oil is usually recovered on surface with the oil-based mud, depending on the severity of contamination with other fluids.

Viscous Surfactant Spacer – This is mixed in fresh water or seawater and is designed to push the oil-based mud and base oil pill out of the hole, along with any settled solids that are picked up along the way. The surfactant also helps to change the surface of the wellbore from oil-wet to water-wet. The viscosity and density of this spacer should be higher than that of the oil-based mud to maintain viscosity and density hierarchies recommended during displacements, unless hydrostatic pressure and/or ECDs have to be controlled.

Solvent Pill – This is mixed in fresh water or seawater and is designed to dissolve and remove oil-based mud residue, filter cake and other debris from the surface of the wellbore. The solvent pill is designed to be pumped in turbulent flow for maximum effectiveness.

Surfactant Pill – This is mixed in fresh water or seawater, but it should not be viscosified because it is designed to be pumped in turbulent flow in order to improve removal of residual debris. The surfactant mix also acts as a chemical wash to remove residual traces of oil so that the surface of the wellbore is completely water-wet.

Viscous Spacer – This may be pumped ahead of the water-based mud, if required, by transferring some of the water-based mud that is going to be displaced into the hole across to a separate tank (e.g. Pill Tank) and adding additional viscosifier. A simple, low-cost water-based viscous spacer can also be used, if necessary, to prevent contamination of high-value water-based mud systems. The viscous spacer should be weighted to the same density as the water-based mud system when hydrostatic pressure has to be maintained.

Two displacement options are available when displacing oil-based mud to water-based mud. The indirect displacement is generally more effective than the direct displacement because additional cleaning and circulating can be performed to ensure that oil-based mud residue and debris are removed from the wellbore.

Indirect Displacement – The first stage of the indirect displacement from oil-based mud to water-based mud, where circulating rates and hydrostatic pressures are not restricted by formation pressures and ECDs, involves an initial displacement to water. This is followed by the displacement to water-based mud once the wellbore has been cleaned using surfactant and solvent pills and spacers. A typical indirect displacement from oil-based mud to water-based mud might be as follows:

1. Run in with the displacement string and rotate and reciprocate the string while circulating and conditioning to warm up the oil-based mud and suspend settled solids, making sure the shale-shakers are dressed with fine-mesh screens.
2. **Pump a Base Oil Pill –** This will thin the oil-based mud and provide preliminary cleaning of the wellbore surface, especially if pumped in turbulent flow, which will improve the performance of the surfactant and solvent pills and spacers.
3. **Pump a Viscous Surfactant Spacer** – This will push the oil-based mud and the base oil pill out of the hole, along with any settled solids that are picked up along the way. The surfactant will also help to change the surface of the wellbore from oil-wet to water-wet. The viscosity and density of this spacer should be higher than that of the oil-based mud to maintain viscosity and density hierarchies recommended during displacements.
4. **Pump a Solvent Pill** – This is designed to dissolve and remove oil-based mud residue, filter cake, grease and pipe dope from the surface of the wellbore. The solvent spacer is designed to be pumped in turbulent flow for maximum effectiveness.
5. **Pump a Surfactant Pill** – This pill should not be viscosified because it is designed to be pumped in turbulent flow in order to remove residual debris. The surfactant mix acts as a chemical wash to remove residual traces of oil so that the surface of the wellbore is completely water-wet.
6. **Pump a Viscous Spacer** – This is designed to remove residual traces of debris and can be pumped ahead of the water-based mud to minimize channelling. The viscous spacer can be prepared by transferring some of the water-based mud that is going to be displaced into the hole across to a separate tank (e.g. Pill Tank) and adding additional viscosifier.
7. Displace the hole to water while continuing to rotate and reciprocate the displacement string, and recover the oil-based mud on surface.
8. Continue circulating once the pills and spacers are out of the hole, and pump additional surfactant and solvent pills and spacers if necessary, until the wellbore is clean.
9. Displace the hole to water-based mud at maximum allowable flow rates, making sure the string is on bottom when the spacers and pills enter the annulus.
10. Recover uncontaminated water-based viscous spacer returns in a separate tank and continue circulating until the water-based mud returns are at the same density as the water-based mud being pumped.
11. Establish a closed circulating system and drill ahead.

Direct Displacement – The priority for a direct displacement from oil-based mud to water-based mud is to change the oil-wet surface of the wellbore to a water-wet condition through the use of surfactants, while removing settled solids, filter cake and debris that could damage the reservoir formation if displacing to a water-based drill-in fluid. Displacement rates and ECDs will need to be controlled if the wellbore is exposed to formation pressures. A typical direct displacement from oil-based mud to water-based mud might be as follows:

1. Run in with the displacement string and rotate and reciprocate the string while circulating and conditioning to warm up the oil-based mud and suspend settled solids, making sure the shale-shakers are dressed with fine-mesh screens.
2. **Pump a Base Oil Pill** – This will thin the oil-based mud and provide preliminary cleaning of the wellbore surface, especially if pumped in turbulent flow, which will improve the performance of the surfactant and solvent pills and spacers.
3. **Pump a Viscous Surfactant Spacer** – This will push the oil-based mud and the base oil pill out of the hole, along with any settled solids that are picked up along the way. The surfactant also helps to change the surface of the wellbore from oil-wet to water-wet. The viscosity and density of this spacer should be higher than that of the oil-based mud to maintain viscosity and density hierarchies recommended during displacements.
4. **Pump a Solvent Pill** – This is designed to dissolve and remove oil-based mud residue, filter

cake, grease and pipe dope from the surface of the wellbore. The solvent spacer is designed to be pumped in turbulent flow for maximum effectiveness.

5. **Pump a Surfactant Pill** – This pill should not be viscosified because it is designed to be pumped in turbulent flow in order to remove residual debris. The surfactant mix acts as a chemical wash to remove residual traces of oil so that the surface of the wellbore is completely water-wet.
6. **Pump a Viscous Spacer** – This is designed to remove residual traces of debris and can be pumped ahead of the water-based mud to minimize channelling. The viscous spacer can be prepared by transferring some of the water-based mud that is going to be displaced into the hole across to a separate tank (e.g. Pill Tank) and adding additional viscosifier.
7. Displace the hole to water-based mud at maximum allowable flow rates, making sure the string is on bottom when the spacers and pills enter the annulus.
8. Recover uncontaminated water-based viscous spacer returns in a separate tank and continue circulating until the water-based mud returns are at the same density as the water-based mud being pumped.
9. Establish a closed circulating system and drill ahead.

5. Displacing WBM to Completion Brine

This type of displacement will depend on the type of completion assembly that is programmed for the well (standard liner, slotted liner, open-hole, etc.). The displacement is usually performed inside casing or liner after isolating the reservoir and performing pressure tests to confirm integrity. This allows displacement rates to be maximized without ECD restrictions. If the reservoir has been isolated with a packer assembly, then hydrostatic pressure will need to be maintained in the wellbore unless an inflow test has been performed to confirm packer integrity.

The priority when displacing the hole to completion brine is to remove all traces of mud, settled solids, filter cake, rust, scale, grease and pipe dope from the walls of the wellbore to leave a clean wellbore filled with clean filtered brine. A significant amount of debris can be removed by incorporating scrapers and brushes in the displacement string assembly and by circulating the hole to suspend settled solids before starting the displacement.

The pills and spacers pumped during the displacement are designed to remove residual debris from the surface of the tubulars in the wellbore. A poor clean-out will leave residual solids and debris in the hole and this will require additional brine circulation and filtration in order to achieve the programmed brine cleanliness (i.e. solids and turbidity). Failure to remove solids and debris from the wellbore could prevent successful setting of the production packer and/or reduce well productivity by plugging the pores of the reservoir.

The clean-out spacers and pills are designed to provide effective wellbore cleaning during displacements to completion fluid in open or cased/lined hole. A high viscosity weighted spacer is generally used for pushing a water-based drilling fluid out of the hole. A weighted surfactant pill is then pumped to make the tubular surfaces water-wet, since most water-based drilling fluids contain lubricants for reducing torque and drag. A viscous brine spacer can then be pumped to remove residual solids and debris.

An indirect displacement to water is preferable if the wellbore is isolated from reservoir pressures, if there is a plentiful supply of water (e.g. seawater), and if there is sufficient storage for waste fluids. The indirect displacement procedure may take longer, but the clean-up will be more effective because water can be circulated at high flow rates, along with additional pills and spacers, until the wellbore is clean. The wellbore can then be displaced to filtered completion brine. The cleanliness of the displacement string while pulling out of the hole will give an indication of the effectiveness of the clean-up and the cleanliness of the wellbore tubulars.

Indirect Displacement – A typical indirect displacement from water-based mud to completion brine, where circulating rates and hydrostatic pressures are not restricted by formation pressures and ECDs, might be as follows:

1. Run in with the displacement string and rotate and reciprocate the string while circulating and conditioning to suspend settled solids, making

sure the shale-shakers are dressed with fine-mesh screens.

2. **Pump a Viscous Spacer** – This is mixed in fresh water or seawater and is designed to push the water-based mud out of the hole and prevent dilution with water, which could allow solids to settle out. The viscosity of the spacer should be higher than that of the water-based mud because this will maintain the viscosity hierarchy recommended during displacements.
3. **Pump a Surfactant Pill** – Most water-based drilling fluids contain lubricant additives for reducing torque and drag. The surfactant pill is designed to wash away residual lubricants, grease and pipe dope so that the surface of the wellbore is clean and completely water-wet. The pill should not be viscosified because it is designed to be pumped in turbulent flow for maximum cleaning effect.
4. Displace the hole to water at maximum allowable flow rates and recover the water-based mud on surface. Continue circulating clean water down hole once the pills and spacers are out of the hole, and pump additional pills and spacers if required, until the cleanliness of the returns (solids and turbidity) meets programmed requirements.
5. Displace the water in the hole to filtered brine and continue circulating until the brine returns are at the same density as the brine being pumped.
6. Establish a closed circulating system, filter the brine returns across to the active tank and continue circulating filtered brine around the hole until the cleanliness of the brine returns (solids and turbidity) meets programmed requirements.

Direct Displacement – A typical direct displacement from water-based mud to completion brine, where circulating rates and hydrostatic pressures are restricted by formation pressures and ECDs, might be as follows:

1. Run in with the displacement string and rotate and reciprocate the string while circulating and conditioning to suspend settled solids, making sure the shale-shakers are dressed with fine-mesh screens.
2. **Pump a Weighted High-Viscosity Spacer** – This is mixed in fresh water or seawater and is designed to push the water-based mud out of the hole. The viscosity and density of the spacer should both be higher than that of the water-based mud because this will maintain the viscosity and density hierarchy recommended during displacements.
3. **Pump a Weighted Surfactant Pill** – This is mixed in fresh water or seawater and is designed to wash away traces of lubricant that may have been added to the water-based drilling fluid to reduce torque and drag, along with grease and pipe dope, leaving the tubular surfaces clean and water-wet. The surfactant pill will obviously need to be viscosified if it has to be weighted for maintaining wellbore hydrostatic, so it might not reach turbulent flow while being pumped around the wellbore.
4. **[Pump a Viscous Spacer]** – This should only be used if there is a need to prevent contamination of the brine with surfactant (i.e. when using high-value brine systems). The viscous spacer should be unweighted, if safe to do so, because this will prevent solids (i.e. Barite) being pumped down-hole ahead of the solids-free brine. The size of the viscous spacer should be designed so that wellbore hydrostatic pressure is maintained above formation pressures.
5. Displace the hole to filtered brine at maximum allowable flow rates, making sure the displacement string is on bottom when the spacers and pills enter the annulus.
6. Continue circulating until the pills and spacers are out of the hole, and the brine returns are at the same density as the brine in the suction tank. The interface between weighted pills or spacers and the completion brine should be discarded because the presence of polymers in the brine will make filtration difficult (Interfaces containing high value brine should be recovered for special reconditioning by the brine supplier).
7. Establish a closed circulating system, filter the brine returns across to the active tank and continue circulating filtered brine around the hole until the cleanliness of the brine returns (solids and turbidity) meets programmed requirements.

A direct displacement can obviously be performed in cased hole, even if there is a plentiful supply of water and the wellbore is isolated from reservoir pressures. A direct displacement is obviously quicker than an indirect displacement, but any potential savings in rig time will be lost if the direct displacement clean-up is less effective and results in additional brine filtration to remove residual solids. This is particularly the case in highly deviated wells where settled solids are more difficult to remove and could contribute to formation damage.

6. Displacing OBM to Completion Brine

This type of displacement will depend on the type of completion assembly that is programmed for the well (standard liner, slotted liner, open-hole, etc.). The displacement is usually performed inside casing or liner after isolating the reservoir and performing pressure tests to confirm integrity. This allows displacement rates to be maximized without ECD restrictions. If the reservoir has been isolated with a packer assembly, then hydrostatic pressure will need to be maintained in the wellbore unless an inflow test has been performed to confirm packer integrity.

The priority when displacing the hole from oil-based mud to completion brine is to clean the wellbore by removing settled solids, filter cake, grease, pipe dope, rust and scale, since this could contribute to formation damage and low productivity. A significant amount of debris can be removed by incorporating scrapers and brushes in the displacement string assembly and circulating the hole to suspend settled solids before starting the displacement. Surfactants will also make the wellbore surface water-wet.

The pills and spacers pumped during the displacement are designed to remove residual debris from the surface of the tubulars in the wellbore. A poor clean-out will leave residual solids and debris in the hole and this will require additional brine circulation and filtration in order to achieve the programmed brine cleanliness (i.e. solids and turbidity). Failure to remove solids and debris from the wellbore could prevent successful setting of the production packer and/or reduce well productivity by plugging the pores of the reservoir.

The clean-out pills and spacers are designed to provide effective wellbore cleaning during displacements from oil-based mud to completion fluid in open or cased/lined hole. A base oil pill is usually followed by a high viscosity weighted spacer to push the oil-based drilling fluid out of the hole. This is followed by a solvent pill to dissolve and remove oil-based mud residue and debris, and a weighted surfactant pill to make the tubular surfaces water-wet, since most water-based drilling fluids contain lubricants for reducing torque and drag. A viscous brine spacer is then be pumped to remove residual solids and debris.

An indirect displacement to water is preferable if the wellbore is isolated from reservoir pressures, if there is a plentiful supply of water (e.g. seawater), and if there is sufficient storage for waste fluids. The indirect displacement procedure may take longer, but the clean-up will be more effective because water can be circulated at high flow rates, along with additional pills and spacers, until the wellbore is clean. The wellbore can then be displaced to filtered completion brine. The cleanliness of the displacement string while pulling out of the hole will give an indication of the effectiveness of the clean-up and the cleanliness of the wellbore tubulars.

Indirect Displacement – A typical indirect displacement from oil-based mud to completion brine, where circulating rates and hydrostatic pressures are not restricted by formation pressures and ECDs, might be as follows:

1. Run in with the displacement string and rotate and reciprocate the string while circulating and conditioning to warm up the oil-based mud and suspend settled solids, making sure the shale-shakers are dressed with fine-mesh screens.
2. **Pump a Base Oil Pill** – This will help to thin the oil-based mud and provide preliminary cleaning of the wellbore surface, especially if pumped in turbulent flow, which will improve the performance of the surfactant and solvent pills and spacers. A 25 bbl to 50 bbl pill size is recommended, some of which is usually recovered on surface with the oil-based mud, depending on the severity of contamination with other fluids.
3. **Pump a Viscous Surfactant Spacer** – This will push the oil-based mud and the base oil pill out of the hole, along with any settled solids that are picked up along the way. The surfactant also helps to change the surface of the wellbore from oil-wet to water-wet. The viscosity and density of this spacer should be higher than that of the oil-based mud because this will maintain viscosity and density hierarchies recommended during displacements. However, this may not be possible if hydrostatic pressure and ECDs have to be controlled to avoid formation losses.

4. **Pump a Solvent Pill** – This is mixed in fresh water or sea water and is designed to dissolve and remove oil-based mud residue, filter cake, grease and pipe dope from the surface of the wellbore. The solvent spacer should not be viscosified because it is designed to be pumped in turbulent flow for maximum effectiveness.
5. **Pump a Surfactant Pill** – This is mixed in fresh water or sea water and should not be viscosified because it is designed to be pumped in turbulent flow in order to remove residual debris. The surfactant mix also acts as a chemical wash to remove residual traces of oil so that the surface of the wellbore is completely water-wet.
6. **Pump a Viscous Spacer** – This is designed to remove residual solids and can be prepared by transferring some of the brine that is going to be displaced into the hole across to a separate tank (e.g. Pill Tank) and adding viscosifier.
7. Displace the hole to water at maximum allowable flow rates and recover the oil-based mud on surface. Continue circulating clean water down hole once the pills and spacers are out of the hole, and pump additional pills and spacers if required, until the cleanliness of the returns (solids and turbidity) meets programmed requirements.
8. Displace the hole to filtered brine at maximum allowable flow rates until the brine returns are at the same density as the brine in the suction tank.
9. Establish a closed circulating system, filter the brine returns across to the active tank and continue circulating filtered brine around the hole until the cleanliness of the brine returns (solids and turbidity) meets programmed requirements.

Direct Displacement – A typical direct displacement from oil-based mud to completion brine, where circulating rates and hydrostatic pressures have to be controlled, might be as follows:

1. Run in with the displacement string and rotate and reciprocate the string while circulating and conditioning to warm up the oil-based mud and suspend settled solids, making sure the shale-shakers are dressed with fine-mesh screens.
2. **Pump a Base Oil Pill** – This will help to thin the oil-based mud and provide preliminary cleaning of the wellbore surface, especially if pumped in turbulent flow, which will improve the performance of the surfactant and solvent pills and spacers. A 25 bbl to 50 bbl pill size is recommended, but the volume may need to be restricted to ensure that wellbore hydrostatic pressure is maintained above formation pressures. Some of the base oil pill is usually recovered on surface with the oil-based mud, depending on the severity of contamination with other fluids.
3. **Pump a Viscous Surfactant Spacer** – This will push the oil-based mud and the base oil pill out of the hole, along with any settled solids that are picked up along the way. The surfactant also helps to change the surface of the wellbore from oil-wet to water-wet. The viscosity and density of this spacer should be higher than that of the oil-based mud to maintain viscosity and density hierarchies recommended during displacements. However, this may not be possible if hydrostatic pressure and ECDs have to be controlled to avoid formation losses.
4. **Pump a Solvent Pill** – This is mixed in fresh water or seawater and is designed to dissolve and remove oil-based mud residue, filter cake, grease and pipe dope from the surface of the wellbore. The solvent spacer should not be viscosified because it is designed to be pumped in turbulent flow for maximum effectiveness, so the volume may need to be restricted to ensure that wellbore hydrostatic pressure is maintained above formation pressures.
5. **Pump a Surfactant Pill** – This is mixed in fresh water or seawater and should not be viscosified because it is designed to be pumped in turbulent flow in order to remove residual debris. The surfactant mix is also designed to act as a chemical wash to remove residual traces of oil so that the surface of the wellbore is clean and completely water-wet. The volume may need to be restricted to ensure that wellbore hydrostatic pressure is maintained above formation pressures.
6. **Pump a Viscous Spacer** – This can be prepared by transferring some of the brine that is going to be displaced into the hole across to a separate tank (e.g. Pill Tank) and adding viscosifier.
7. Displace the hole to filtered brine at maximum allowable flow rates while recovering the oil-based mud on surface, along with the pills and spacers.

8. Continue circulating filtered brine down-hole until the brine returns are at the same density as the brine in the suction tank.
9. Establish a closed circulating system, filter the brine returns across to the active suction tank and continue circulating filtered brine around the hole until the cleanliness of the brine returns (solids and turbidity) meets programmed requirements.

A direct displacement can obviously be performed in cased hole, even if the wellbore is isolated from reservoir pressures and there is a plentiful supply of water. A direct displacement is obviously quicker than an indirect displacement, but any potential savings in rig time will be lost if the direct displacement clean-up is less effective and results in additional brine filtration to remove residual solids. This is particularly the case in highly deviated wells where settled solids are more difficult to remove and could contribute to formation damage.

7. Riser Displacements

Drill-Ships and Semi-Submersible drilling units have a marine riser that is connected to the BOPs on the seabed. It is sometimes necessary to disconnect the riser from the BOP in rough weather, before the vertical movement of the vessel exceeds the allowable movement of the telescopic slip joint, which is connected to the diverter box (bell nipple) at the top of the riser. Before doing so, the blind rams are closed to secure the wellbore and the mud in the riser is then recovered on surface by pumping suitable pills and spacers down the riser booster lines, followed by seawater.

Displacing water-based mud from the riser is relatively simple and is usually achieved by pumping a high viscosity spacer ahead of the seawater. Displacing oil-based mud from the riser is also relatively simple and is usually achieved by pumping a base oil pill to thin the mud and then pumping a high viscosity water-based spacer ahead of the seawater. The internal surface of the riser does not have to be perfectly clean, but it must be clean enough to prevent contamination of the seabed.

Once the riser has been displaced to seawater, it can be disconnected at the BOPs and pulled to surface for the duration of the storm. When the weather eventually improves, the riser is run back down to the seabed and reconnected to the BOP. Pressure tests are then performed to make sure that control lines and seals have not been damaged before displacing the riser back to water-based or oil-based mud. A spacer is not usually required when displacing the riser back to water-based or oil-based mud because the mud is thicker and heavier than the seawater in the riser.

8. Cement Spacers

The choice of cement spacers will depend on the type of fluid in the hole. The aim is to prevent contamination of the cement slurry while it is pumped down-hole, and to make sure that filter cake and debris have been removed from the annular area where the cement slurry will be spotted. Cement spacers perform the following functions:

- Maintain hydrostatic pressure in the wellbore
- Prevent contamination of the cement slurry with wellbore fluids
- Remove filter cake and debris from the wellbore annulus to be cemented
- Make sure the wellbore annulus is water-wet to ensure a good cement bond
- Prevent the formation of a micro-annulus between the cement and casing string

Contamination of the cement slurry while it is being displaced down-hole can accelerate or retard the cement setting time according to the type of contaminant. The salts in most drilling fluids (i.e. chlorides) can act as an accelerant at low salinities and as a retardant at high salinities. There have been occasions when cement slurries have flash-set while still in the drill string, due to contamination with other fluids. Residual filter cake, debris and oil-wet surfaces can produce a poor cement bond and leave a micro-annulus that provides a potential path of communication for formation pressures to reach the surface.

The cementing service companies are responsible for designing and supplying the spacers required for cementing casing and liner strings, and these are usually prepared in the cement mix tanks. However, when a large cement slurry volume is required then one of the mud tanks may be used for the storage of cement mix water, which is then transferred to the cement unit while the cement slurry is being mixed and displaced down-hole. Care is required to make sure that the mix and transfer lines are flushed clean with fresh water.

Pit Management and Displacement Plan

A pit management and displacement plan should be prepared ahead of any displacements involving pills and spacers because this will give essential personnel (e.g. Company Representative, Tool Pusher, Driller, A/D, Derrickman and Mud Loggers) an opportunity to review and check that the procedure is effective. It will also eliminate confusion on the mud tanks during the displacement, which will help to minimize contamination between the various fluids as the respective interfaces arrive on surface.

The pit management plan should include a simplified layout of all the surface tanks (Active, Reserve, Slug, Pill, Process and Trip tanks, along with the cement displacement tanks, if required), with details of contents (e.g. drilling fluid, pills, spacers, brine, waste fluid, etc.), as well as volumes and any other relevant information (e.g. density) at the start of the displacement. The plan should then have a detailed pumping sequence and identify the tanks where the various fluid and interface returns will be recovered.

The pit management plan should also include a pre-displacement and post-displacement checklist so that unplanned incidents can be avoided. As an example, water supply lines to the tanks should be isolated as any water leakage could result in fluid dilution, which could be critical for well control. A good pit management and displacement plan will assist the Derrickman, Driller and Mud Loggers to see where the various fluids are going when they arrive on surface, which will help to ensure a smooth displacement.

Tank availability is often limited during wellbore clean-out displacements, so pill and spacer returns are often recovered in the tanks from which they were pumped, especially if there is limited space in the waste tank. The interface between viscous spacers and most completion brines should be discarded because any residual polymers in the brine will make filtration difficult and result in operational delays. However, the interface between viscous spacers and high-value brines should be recovered for eventual reconditioning.

Cleaning Tanks and Surface Lines

A logical sequence is required for cleaning the tanks and surface lines in preparation for displacing the wellbore to completion brine. This will depend on rig equipment and system flexibility. Failure to clean the system in the correct sequence could contaminate parts of the system that have already been cleaned, or contaminate the clean brine, resulting in operational delays or additional brine filtration. Some or all of the following will need to be cleaned to prevent potential brine contamination:

- Designated Brine, Spacer and Pill Tanks, as required
- Mix Lines, Mix Manifold and Gun Lines
- Line from Mix Manifold to Cement Unit
- Line from Mix Manifold to Trip Tank
- Cement and Test Lines from Cement Unit to Cement Manifold on Drill Floor
- Trip Tank and Associated Lines
- Flow Line from Bell Nipple to Shale Shakers
- Shale Shakers, Header Box and Shaker Bed
- Process Tanks, Associated Lines and Equipment (Sand-Traps, Degasser, etc.)
- Flow Line from Process Tanks to Mud Tanks
- Choke and Kill Lines
- Standpipe, Cement, Choke and Kill Manifolds on Drill Floor
- Rig Pump Suction Lines and Suction Manifold
- Stand Pipes to Stand Pipe Manifold on Drill Floor

Some lines and equipment (e.g. trip tank, choke and kill lines) cannot be cleaned before the displacement, but a procedure should be prepared for displacing them to brine at the start of the displacement. This will minimize the potential for contaminating the completion brine with “slugs” of mud trapped in one or more lines. As an example, there are normally two stand pipes on the drill floor in case one of them starts to leak, so the reserve stand pipe should be flushed clean in case it needs to be used during the displacement.

Surface cleaning procedures should be coordinated with the Derrickman and Assistant Driller because they will be familiar with the rig layout and will have past experience in this area. Some of the cleaning tasks can be performed before reaching TD, but only if safe to do so without interfering with drilling operations. There is also a risk that drilling fluid may need to be pumped through part of the system that has already been cleaned, due to unforeseen circumstances.

A wash pill for cleaning surface lines and equipment can be prepared by adding a drum (208 liters) EMEC Detergent to a clean mud tank filled with fresh or sea water. The surfactant wash pill can then be flushed through the surface lines and transferred from tank to tank to clean the system. Care must be taken to avoid contaminating the active mud system when circulating the wash pill through surface lines. The tanks and surface lines should then be flushed with water to remove any residual surfactant wash pill.

When flushing surface lines, the discharge valves should be functioned (opened and closed) for a short period in order to flush residual mud and solids that may be trapped behind the valves. Leaks may suddenly appear around valve and pump seals after cleaning and flushing surface lines. This usually results from the removal of solids and filter cake that effectively seal and conceal these leaks until they are flushed away during the cleaning process. Leaking valves and pump seals should be repaired or replaced at the earliest opportunity.

Residual water should be drained from tanks and surface lines once they have been cleaned, and water supply lines should be isolated to prevent leakage into tanks that have been designated for completion brine use. Silicone sealant is an effective product for sealing leaking valves, and expanding foam in aerosol cans is effective for sealing the drop-in gates in the process pits and in the flow line trough.

Well Control

Contents

Introduction

Well Control is related to the control of formation pressures. The flow of formation fluids (gas or liquid) into the wellbore is called an influx, and this will occur if the formation pressure is higher than the hydrostatic pressure exerted by the drilling fluid in the hole. If left unchecked, a gas influx could reduce the hydrostatic pressure in the hole through gas migration and expansion while travelling up the hole, and a liquid influx could reduce the hydrostatic pressure through mud dilution. Either way, an influx could result in a kick and a well control incident.

In the past the Mud Engineer used to assist the Client Representative with kill sheet calculations during a well control incident, but computers have taken over this role so the Mud Engineer usually assists the Derrickman to prepare kill mud at the required density calculated by the Client Representative. The purpose of this section is to give an overview of well control procedures and factors that are important for well control.

Formation Pressures

Formation pressure changes with depth, although not in a uniform way and it is not uncommon to encounter deeper formations with lower pressures than the overlying formations. The aim while drilling is to adjust the drilling fluid density so that it always provides a hydrostatic overbalance, which means that the hydrostatic pressure exerted by the drilling fluid in the hole is always slightly higher than the formation pressure being drilled. If the hydrostatic overbalance is too high then there is a risk of fracturing the formation, resulting in down-hole losses.

Formation pressures can often be predicted from offset wells in the area, but this may not be available for exploration wells. Offset formation pressure data may not always be reliable because some formations may be over-pressured due to tectonic activity or localized sedimentary compaction. Some causes for over-pressured formations are as follows:

- Compaction with trapped pore fluids
- Tectonic Activity (i.e. formation movement)
- Plastic deformation of salt domes
- Communication with higher-pressure formations along a fault

Important observations can be made while drilling to indicate that formation pressures are increasing, as follows:

- Drilling Break (increase in ROP)
- Increase in connection and/or trip gas
- Gas-Cut mud returns
- Abnormal shale cuttings appearance (larger, sharper, curved)
- Real Time Data from MWD and LWD tools (Resistivity, etc.)

It is important to inform the Mud Loggers, Driller, Toolpusher and Company Representative whenever unexpected changes occur while drilling, such as gas-cut mud returns, abnormal shale cuttings appearance, mud gains or mud losses, because these can be early warning signs of a potential well control situation, enabling corrective action to be taken. Never assume that the Mud Loggers will be aware of such developments because the changes could occur shortly after collecting a cuttings sample, or their monitoring equipment could be faulty.

Low levels of gas are always present while drilling gas-bearing formations because the gas in the cuttings will expand and escape into the mud as the cuttings are carried up the annulus to surface, where it is detected at the flow line. This gas is monitored by the Mud Loggers and is called “drilled” or “background” gas. The concentration of background gas is obviously related to drilling parameters and will reduce if the ROP slows down or if the circulating rate is increased, and will increase if the ROP speeds up or if the circulating rate is reduced.

Another gas encountered during normal drilling operations is connection gas, which is detected at the flow line on circulating bottoms-up after making a connection. This is slightly higher than background gas levels and is due to formation gas expansion following the reduction in hydrostatic pressure in the hole due to the loss of ECD when the pumps are shut down to make a connection. Increasing levels of background and connection gas are reliable signs that formation pressures are increasing, but this is not so noticeable in mineral or synthetic oil-based fluids where formation gases are soluble.

It is possible to have a situation where hydrostatic over-balance exists in the hole while circulating and drilling, but becomes under-balanced due to loss of ECD when the pumps are shut down to make a connection, to perform a flow check or for any other reason. In this situation, formation gas will flow from the wellbore and keep flowing for the duration that the pumps are shut down. This might not be noticeable for the relatively short time it takes to perform a connection, but it could be significant for the time taken to perform a wiper trip to the casing shoe, providing conditions for a potential kick.

Shallow Gas

Shallow gas is occasionally encountered while drilling offshore, comprising pockets of gas that may be at high pressure. This can be hazardous to rig personnel and equipment because it occurs relatively close to the surface, where formations are less compact. Attempts to shut-in or circulate out kicks may not be effective because the pressure of the gas could fracture unconsolidated formations and escape to surface.

Kill mud is usually prepared in areas where shallow gas is expected, ready for pumping into the hole. If the kill mud is not required then it is often incorporated into the mud system once past the danger zone. A pilot hole is also usually drilled in areas where shallow gas is expected, using a smaller bit (e.g. 8½") before drilling the main hole. The pilot hole is drilled before installing the riser as this avoids the hazard of gas travelling up the riser to the rig.

Formation Pressure Tests

A formation pressure test is always performed after cementing casing and drilling a few feet or meters of new formation at the start of each new section. The purpose of this pressure test is to confirm the integrity of the cement around the casing shoe, and to determine the maximum mud density that can be used while drilling the formation without fracturing the formation. The pressure tests are also important for well control to ensure that a kill mud density does not fracture the formation. There are two types of pressure test, as follows:

Leak-Off Test (LOT) – The leak-off test is performed after circulating the mud to confirm that density is uniform throughout the hole. The well is then shut-in and mud is slowly pumped from the cement unit to pressurize the hole. A plot of "pressure" against "volume pumped" generally produces a straight line, until mud starts to "leak-off" into the formation, at which point the pump is shut down. The pressure is then bled off by opening the bleed-off valve and taking mud back to the cement displacement tanks, which enables mud losses to the formation to be measured accurately.

The formation fracture pressure can be calculated by adding the leak-off pressure to the hydrostatic pressure produced by the mud density, as shown in figure 1 below.

The formation break-down pressure can then be converted back to an equivalent mud density, which is the maximum density that can be used while drilling the section, as shown in figure 2 below.

As an example, if the leak-off pressure at 7,500 ft TVD is 420 psi using 10.5 ppg mud in the hole, then the hydrostatic pressure exerted by the mud is 4,095 psi and the formation break-down pressure is 4,515 psi. This gives a maximum allowable mud density of 11.5+ ppg.

$$\begin{aligned}\text{Formation Fracture Pressure (psi)} &= \text{Hydrostatic Pressure of Mud (psi)} + \text{LOT (psi)}\\ &= [\text{M.Wt. (ppg)} \times 0.052 \times \text{TVD (ft)}] + \text{LOT (psi)}\end{aligned}$$

Figure 1: Calculating the Formation Fracture Pressure from the Leak-Off Test (LOT).

$$\text{Maximum Mud Weight (ppg)} = \frac{\text{Formation Fracture Pressure (psi)}}{[0.052 \times \text{TVD (ft)}]}$$

Figure 2: Calculating the Maximum Mud Weight from the Formation Fracture Pressure.

Formation Integrity Test (FIT) – The formation integrity test is similar to the leak-off test, but the pressure is only increased to a level equivalent to the maximum mud density likely to be required while drilling that particular section. FITs are usually performed when formation pressures are well known, as in the case of development wells, and are preferable to LOTs because they do not induce fractures that occasionally create problems while drilling the section.

Primary and Secondary Well Control

Primary Well Control is provided by the density of the drilling fluid in the hole. The aim is to select a density that produces a hydrostatic pressure greater than the formation pressure in order to prevent formation fluids entering the wellbore, but less than the fracture pressure in order to avoid drilling fluid losses to the formation. The drilling fluid density is usually selected so that the hydrostatic pressure is slightly higher than the formation pressure, providing an over-balance that is known as the trip margin. This trip margin helps to maintain an over-balance to counter the effects of swabbing while tripping out of the hole.

All fluids have a certain amount of compressibility and they are affected by temperature and pressure. The density of a fluid will decrease as the temperature increases, and the density will increase as the pressure increases. It is therefore important to make corrections when densities are measured on surface to ensure consistency, especially when drilling HPHT wells with OBM systems because they have higher compressibility. When measuring density, the temperature of the mud sample is also measured and the measured density is then converted to a “corrected” density at a reference temperature (usually 50°C).

Secondary Well Control is provided by the BOPs, which enable the well to be shut-in if the formation pressure is higher than the hydrostatic pressure provided by the drilling fluid density. This usually occurs when drilling into a high pressure formation, but other factors can produce a reduction in drilling fluid hydrostatic pressure, including the following: Barite sag in high angle hole sections; incorrect monitoring of circulating mud density (e.g. mud balance out of calibration); reduction in circulating density due to removal of solids using solids control equipment (e.g. centrifuge); accidentally pumping a lighter density fluid from the wrong tank into the hole.

If the formation pressure is higher than the hydrostatic pressure of the drilling fluid, then formation fluids will enter the wellbore and the active volume on surface will start to increase. It is important to detect the volumetric gain on surface as soon as possible in order to close the BOPs and shut-in the well without delay, as this will minimize the size of the influx. Any delays in shutting-in the well will allow more formation fluids to enter the wellbore, which may make the corrective actions to restore well control more difficult.

Blow Out Preventer Stack (BOP Stack)

The BOP Stack is an assembly of rams with sealing surfaces that can be closed around drill pipe or other tubulars to secure the well in the event of a well control incident. The BOP Stack is installed on the wellhead after cementing surface casing in the hole, and typically contains components listed below:

1. Annular Preventer (Annular Bag), which comprises a steel reinforced elastomer packing assembly that can be closed around any tubulars in the wellhead, as well as sealing open hole.
2. Blind Ram Preventer, for securing the wellhead if there are no tubulars in the hole.
3. Pipe Ram Preventer, for closing around drill pipe in the wellhead.
4. Shear Ram Preventer, for shearing any tubulars in the wellhead and sealing the wellhead.
5. Choke and Kill lines below all the preventers, for bleeding off pressures in the annulus and for pumping fluids to kill the well.

International legislation requires BOP tests to be performed every two weeks to make sure that all the rams function correctly and seal the well. This is usually done at the end of each section after cementing the casing string. If the two week deadline is reached while still drilling an interval, then choices are available according to the circumstances. The BOP test may be performed when the drill string is pulled to surface (e.g. to change the bit, BHA or down-hole tools), the drill string may be pulled up into the casing shoe in order to perform the BOP test, or a request may be submitted to the authorities to delay BOP testing during critical activities.

Kicks

Kicks occur when the formation pressure is higher than the hydrostatic pressure in the wellbore, allowing formation fluids (oil, water and/or gas) to flow into the wellbore. If corrective action is not taken quickly, the hydrostatic pressure exerted by the drilling fluid will steadily be reduced through dilution or through gas expansion further up the wellbore, increasing the rate at which formation fluids continue to enter the wellbore. Several situations can lead to a kick, due to insufficient hydrostatic pressure in the hole, including the following:

- Drilling into a high-pressure formation
- Incorrect drilling fluid density
- Loss of ECD when pumps are off
- Hole swabbing induced by fast tripping speeds
- Pumping un-weighted pills or spacers
- Failure to keep the hole full (e.g. while tripping out)
- Unable to keep the hole full due to lost circulation

Most kicks can be caught at an early stage through careful monitoring of the following indicators:

- Unexplained increase in active or trip tank volume
- Sudden increase in ROP (i.e. drilling break)
- Incorrect string displacement volumes while tripping
- Mud returns while the pumps are off

The corrective action to take when a kick is suspected while drilling is to pull the bit off-bottom and perform a flow check. If the volume in the hole is stable, indicating that the well is static, then drilling can resume. However, if there are signs of flow then the well should be shut-in by closing the annular preventer, followed by the pipe rams if necessary, allowing the string and annulus pressures to be monitored safely. This procedure effectively restores well control and stabilizes the situation while preparations are made for killing the well.

If nothing is done to control a kick, then the continued reduction in hydrostatic pressure will lead to a blowout, which is the uncontrolled escape of hydrocarbon fluids from a well. Other circumstances that can lead to a blowout include mechanical failure of the BOP when shutting-in the well; casing failure after shut-in that allows hydrocarbon fluids to escape to surface up the outside of the casing; and poor cement bonding around the casing that allows hydrocarbon fluids to escape to surface all the way up the outside of the casing.

Good communication is important between the Mud Engineer, Derrickman, Driller and Mud Loggers so that everyone is aware of drilling fluid activities that could hide a real, or create a false, well control situation. Adding products (e.g. Barite) or premix to the active pit will produce a volumetric gain, and switching on pumps or solids control equipment will produce a volumetric loss, which could both cause confusion. It is important to inform the Driller and Mud Loggers before starting and finishing a task that affects surface volumes.

It is important to be aware that a gas influx may not be detected in OBM due to gas solubility at bottom-hole pressures. The dissolved gas may break out near the surface of the hole, releasing large volumes of gas and increasing the severity of the well control incident. This problem does not occur with WBM.

Shutting-In the Well

There are two established methods for shutting-in a well, the Hard Shut-In and the Soft Shut-In, as follows:

Hard Shut-In – With this method, the choke line valves are placed in the closed position while drilling, and the BOP is closed in the event of a well control situation. This is the fastest method for shutting-in the well, with the advantage that it minimizes the size of the influx into the wellbore. This method is used when the pressure in the annulus or Shut-In Casing Pressure (SICP) is unlikely to exceed the maximum allowable casing pressure.

Soft Shut-In – With this method, one of the choke line valves is placed in the open position before closing the BOP in the event of a well control situation. The choke valve is then closed gradually to shut-in the well while monitoring the build-up in pressure. This procedure takes slightly longer than the hard shut-in and the size of the influx will therefore be larger before the well is completely shut-in.

The hard shut-in may appear to be the best method because it is faster, but it should only be used when the maximum allowable casing pressure is higher than any expected Shut-In Casing Pressures. The soft shut-in allows surface pressures to be monitored at the choke during the well shut-in process, so if there is a risk of rupturing the casing, then choke adjustments can be made to keep SICP below the maximum allowable casing pressure.

Safety Drills – Drill crews perform a range of safety drills at regular intervals so that they are familiar with procedures for shutting-in the well while drilling, tripping, running casing or logging. This ensures a quick response when shutting-in the well, which minimizes the size of the influx entering the wellbore in the event of a well control situation. Smaller influxes are easier to manage because casing pressures are smaller while circulating these influxes out of the hole, and there is less chance of breaking down the formation, which could cause an underground blow out.

Well Kill Techniques

Once the well is shut-in, the Shut-In Drill Pipe Pressure (SIDPP) and Shut-In Casing Pressure (SICP) are monitored, and checks are made to determine if the well is stable. If the well is found to be stable, then the well is opened and a flow-check is performed before drilling resumes. If surface pressures indicate that the well is not stable, then preparations can be made to kill the well by circulating out the influx and filling the hole with higher density drilling fluid to control further influxes. There are three recognized methods for killing a well, as follows:

Driller's Method – The well is killed in two circulations using this method. The influx is circulated out with the existing drilling fluid during the first circulation before preparing and displacing surface mud at the calculated kill weight around the hole, based on SIDPP. The advantage of this procedure is that the well kill can start immediately, but it requires two circulations with the risk of washing out the choke assembly.

Wait and Weight Method – The well is killed in one circulation using this method. Surface mud is prepared at the calculated kill weight based on SIDPP, and displaced into the hole to kill the well while circulating out the influx. The advantage of this procedure is that the well is killed in one circulation and wellbore pressures are lower, which places less demand on the choke assembly. However, gas migration and expansion up the hole can occur during the time delay while weighting up the mud.

Concurrent Method – The well is killed by circulating out the influx while weighting up the mud towards the kill density in stages. More circulating may be involved with this procedure in order to fill the well with the required kill weight fluid.

In all three cases, the choke is adjusted to maintain constant bottom-hole pressure as the heavier kill mud moves up the annulus, according to a calculated pressure-displacement chart, with back-pressure falling to zero when the kill mud arrives at surface. The required density of the kill mud is calculated using the SIDPP, since the drill pipe is filled with drilling fluid at a known density. The required kill mud density cannot be calculated from the SICP because the density of the fluid in the annulus is not uniform due to the presence of the influx.

Measurement of the SIDPP is critical for calculating kill weights and this is obviously complicated when the drill string contains a float, which is a non-return flapper valve to prevent back-flow up the drill string. In this situation, the SIDPP can be measured by slowly increasing the string pressure to the point where the pressure gauge measuring the annulus pressure starts to increase. At this point, the SIDPP is measured and the Formation Pressure can be calculated using the equation shown in Fig.3 overleaf.

The density of the kill mud that is required to balance the formation pressure can then be calculated using the equation shown in Fig.4 overleaf.

Formation Pressure (psi) = Hydrostatic Pressure of Mud (psi) + SIDPP (psi)
= [M.Wt. (ppg) x 0.052 x TVD (ft)] + SIDPP

Figure 3: Equation for calculating the Formation Pressure after measuring the SIDPP.

$$\text{Kill Mud Weight (ppg)} = \frac{\text{Formation Pressure (psi)}}{[0.052 \times \text{TVD (ft)}]}$$

Figure 4: Equation for calculating the Kill Mud Weight from the Formation Pressure.

Stripping In with Pipe

If a kick occurs while tripping or when out of the hole, then the well is shut-in at the BOP, but the drill string needs to be back on bottom in order to kill the well. Stripping Pipe is the technique for tripping in or out of the hole with the BOP closed for maintaining pressure on the wellhead. A float in the drill string prevents fluids and pressure from travelling up the string, and annulus pressure is maintained by keeping the Annular Preventer closed around the drill pipe while tripping in.

The Annular Preventer closing pressure is usually reduced to allow the drill pipe and tool joints to pass through the elastomer packing element while still maintaining an effective seal to hold the pressure in the annulus. The drill pipe needs to be well lubricated when stripping pipe as this will reduce wear on the elastomer packing element. A Stripping Tank is also used as volumes can then be monitored accurately while stripping pipe. This tank is very small and is usually located next to the Trip Tank.

Reporting and Documentation

Contents

Introduction

This document provides a checklist for improving rig procedures and to ensure that everything is taken into consideration when working at the rig site (How often are test chemical expiry dates or test equipment calibration dates checked?). The guidelines also contain suggestions for improving the comments in DMRs and in End of Well Report discussions, to provide the client and EMEC with a detailed document containing accurate information about fluid performance.

Communication is very important at the rig site and Mud Engineers must inform the Client Representative, Tool Pusher, Driller and Mud Loggers about relevant activities. As an example, they must be informed about any activities that increase or reduce the active circulating volume, such as adding chemicals to the active system or transferring active mud to the Slug Tank, so that there is no confusion with a well kick or formation losses.

Clients expect field engineers to be proactive concerning QHSE (Quality, Health, Safety and the Environment) because it is just as important as their engineering specialization. EMEC engineers are expected to participate in all QHSE activities at the rig site by writing safety observation cards (e.g. STOP/START cards), keeping the chemical storage area tidy, and making sure that expiry dates for calibrated mud testing equipment and chemical testing reagents are not exceeded.

Client Representatives appreciate service engineers who provide a good service and make their life easier, so they will always do what they can to keep the engineers they value. They will pass on their preferences to their colleagues looking after operations in the office, and this will be an important factor when considering service companies for future work, so the success of a Mud Engineer at the rig site will affect the success of EMEC as a company.

Check List for Field Engineers

Before going to the rig site, Mud Engineers should check with their office-based supervisor that the following are available:

- Copy of Mud Programme.
- Copy of relevant parts of Fluids Contract.
- Electronic file containing EMEC Product Data Sheets.
- Electronic file containing Product MSDS.

Rig Site Safety

Mud Engineers have a duty to brief Roustabouts and drill crew about potential hazards before handling or mixing mud products, along with corrective actions to take. Rig Site Safety applies to you as well as to everyone else. If you were to get Caustic Soda in your eyes, would you trust those around you to take immediate correct action? Are they familiar with the MSDS, and the locations of eye-wash bottles and First Aid kits? If not, why not? It is in your interest to make sure that they know.

- Check that MSDS for all products and test chemicals are readily available at the rig site.
- Check that EMEC Safety Posters are displayed at critical locations (e.g. chemical storage area, mixing area, etc.).
- Check that eye wash bottles are located at critical locations (e.g. chemical storage area, mixing area, mud pit area, etc.).
- Check that Roustabouts wear the correct PPE whenever mixing chemicals.
- Prepare a JSA (Job Safety Analysis) or JHA (Job Hazard Analysis) as and when required.
- Brief the Roustabouts and drill crew about potential hazards before handling or mixing chemical additives, along with the corrective actions to take and the locations of eye-wash bottles and First Aid kits.
- Participate in the Safety Observation Card reporting system (HOC, START or STOP Cards) and, if possible, scan or take a photocopy of each completed card and send it to the office-based supervisor.
- Inform EMEC Supervisor if any MSDS for products, or EMEC Safety Posters, are missing.

Reporting and Documentation

When evaluating the performance of a service company, clients always look to see if the service engineers actively contribute to the Safety Observation Card reporting system. The importance of this system cannot be underestimated because, apart from the safety aspect, clients keep a record of participation by all the rig site service providers and it is a factor when they evaluate a service company for future contracts. The Safety Observation Card reporting system has proved to be a simple and effective way to enhance safety, and clients usually expect every person at the rig site to complete one Safety Observation Card a day.

Mudlab

- Keep the mudlab clean, tidy and safe at all times.
- Store hazardous chemicals (e.g. acids and alkalis) in a lockable cupboard below chest height.
- Check that all the test chemicals have expiry dates, and that these dates have not passed.
- Check that all the items of test equipment are tagged with calibration test dates, and that the expiry dates have not passed.
- Inform EMEC Supervisor if mud lab equipment is faulty or if test chemicals are about to expire, so they can be replaced as soon as possible.

Rig Site Activities

Field engineers must monitor the fluids system at regular intervals to check the quality of the cuttings (to ensure correct inhibition, no cavings, etc.). They also need to inspect the shale-shaker screens for holes, and to ensure that there are no surface mud losses. In addition, there are critical times when the fluids engineer must be at the shale-shakers, in order to monitor returns and report back to the Driller and Company Man, as follows:

- To catch the interface during displacements.
- To check for increased cuttings at the shakers whenever a hivis sweep is circulated around the hole.
- To monitor returns during potential well control situations (gas-cut returns, lost circulation, a kick, etc.).
- To check for cement contaminated mud returns while circulating bottoms-up after a cement job, diverting severely contaminated returns to a waste pit.

It is important to ensure that the shale shaker screens are sized to remove most of the cuttings produced while drilling, and that there are no holes in the screens. Corrective action must be taken at the earliest opportunity, or solids will build up in the mud, resulting in an increase in density and Plastic Viscosity, and making it even more difficult to control mud properties.

Reporting Procedures and Duties

Mud Engineers must maintain a close working relationship with their office-based supervisors and communicate with them on a daily basis to discuss operational plans, mud treatments and product requirements before taking action at the rig site. Mud Engineers are responsible for the following activities at the rig site:

- Establish a good working relationship with the Client Representative and service company representatives.
- Look after the mud system and maintain fluid properties within the programmed specifications.
- Perform mud checks to ensure that the drilling fluid is maintained within programmed requirements.
- Recommend and discuss mud treatments with the office-based supervisor and then with the Client Representative.
- Discuss any deviations from the fluids programme with the office-based supervisor first, before getting approval from the Client Representative.
- Plan ahead to avoid operational delays due to mud-related issues.
- Maintain accurate records of treating chemical consumption and inventory.
- Review treating chemical inventory with the office-based supervisor and order additional treating chemicals in good time to meet operational requirements.
- Keep the product storage area clean and tidy, using tarpaulins to protect treating chemicals from sun damage where possible.
- Monitor shale-shaker screen inventory and inform the Client Representative or Tool Pusher of any potential shaker screen requirements.
- Check that all the safety equipment required for mixing treating chemicals is available and operational, and inform the rig site Safety Representative or Tool Pusher of any shortfall (e.g. eye-wash bottles, emergency shower, face shields,

rubber aprons, rubber gauntlets, etc.).

- Make sure that rig crew are familiar with any hazards associated with treating chemicals and that they wear the correct PPE in accordance with MSDS recommendations.
- Inform the office-based supervisor if products are sent to the rig site incorrectly packaged (e.g. badly palletized, incorrect documents, etc.), so that procedures can be improved for future deliveries.
- Prepare a Daily Mud Report (DMR) in accordance with client requirements.

Daily Mud Checks

Three mud checks must be performed every day if drilling is continuous, approximately eight hours apart. A mud check should also be performed during the bottoms-up circulation before tripping out of the hole. The Client Representative usually requires a mud check for the midnight report, for the morning call to town and for the afternoon call to town. Mud Engineers should find out when the mud checks are required by the Client Representative at the start of a new contract with a new client, or whenever a new Client Representative arrives at the rig site.

Frequency of testing should only be reduced when mud is not circulating in the hole (i.e. during round trips). The Mud Engineer should perform all the tests for mud properties listed in the Daily Mud Report (DMR), recording the time the sample was taken along with well depth. The mud checks should be performed on mud returns from the hole. Tests on active and reserve tank mud samples are additional to the three mud checks performed on mud returns, and must not be used as replacement mud checks.

Test results and appropriate process control actions are recorded initially in the Mud Engineer’s Tally Book and then transferred daily to the Daily Mud Report form. Reasons for omission of any properties not recorded, or any tests not performed, must be explained in the comments section of the Daily Mud Report. The Mud Engineer should take appropriate action to optimize the mud properties according to the specified mud parameters in the Drilling Fluids Programme, hole conditions and additional instructions from the Client Representative. If necessary, the instructions for mud preparation and treatments should be revised.

Mud Maintenance Treatments

A comparison of actual mud properties with specified requirements in the Drilling Fluids Programme may indicate the need for adjustments. If this is the case then the Mud Engineer must prepare written instructions for restoring the properties of the active circulating system in line with programmed requirements. These instructions should specify the exact quantities and types of chemicals to be mixed, and mixing rates to ensure proper mixing, if relevant (e.g. Viscosifiers must be added very slowly and steadily at around 10 minutes per sack to avoid “fish-eyes”).

The instructions must be written legibly and clearly on paper and given to the Tool Pusher who will arrange manpower to complete the task. The Mud Engineer should brief the designated crew members about the task, highlighting any chemical hazards and any special PPE to be worn. He should also monitor progress regularly to ensure that the instructions are carried out correctly. Any problems should be reported to the Tool Pusher for correction, and noted by the Mud Engineer in the DMR.

Daily Mud Report (DMR)

A DMR must be prepared and submitted for each day of the well, whatever the activity. The Daily Mud Report is to be filled out neatly and accurately with three full mud checks, details of product consumptions, and comments covering operational activities. This should include the start and end hole depths, the formations being drilled and any special information related to drilling fluid activities. Comments, recommendations and client instructions should also be recorded clearly and comprehensively in the Daily Mud Report.

When writing comments in the daily mud report, provide as much information as possible to avoid any misunderstanding or confusion:

- Explain product usage along with treatment concentrations (e.g. Treated active circulating system with 0.25 ppb (5 sacks) Antisol 100 to improve fluid loss control).
- Explain significant volume losses (e.g. Lost 40 bbls mud at the shale shakers due to plugged screens).
- Explain reason for using products that are not programmed for the section.

- Mention the reason for each round trip, along with hole condition as reported in the IADC Report (e.g. POH due to MWD failure. Hole slick while POH, but wash/ream tight spot at 11,285 ft while RIH with new MWD).

After a mud check, review all the mud properties before making a mud treatment, because mud properties are often inter-related and any changes to one property may produce a change in other properties. As an example, increasing mud density with Barite will increase the amount of solids in the mud, which may increase Plastic Viscosity. Or the Pf and Mf of a water-based mud will change if the pH changes. Always check to make sure that fluid properties entered in the DMR reflect any changes to the fluid system.

It is important that information in the DMR agrees with information in the daily IADC report, because provisional figures are occasionally revised later on to allow for corrections (e.g. depths may be adjusted to allow for correction factors, etc.). As a result, Mud Engineers should review the IADC report before completing the DMR in order to avoid any conflicting information. The completed DMR is usually signed by the Mud Engineer and countersigned by the Client Representative at the rig site.

End of Well Summary

The purpose of the End of Well Summary (or Well Recap) is to document how a well was drilled, in order to provide a record and useful information for future wells, and to ensure that incidents or facts do not get distorted. It should mention any problems or events that occurred while drilling each section, along with details of how they were resolved.

The report should start with an "Introduction", giving brief details about the well with a basic summary of events that will be described in greater detail later in the report. The Introduction should give the reader (i.e. the client or EMEC) an impression of how things went without having to read through the whole report, which is particularly useful when trying to remember a particular well.

The "Discussion" for each section should include detailed explanations for any significant deviations from the fluids or drilling programme relating to products, volumes, concentrations, etc. This information is useful when making modifications for the next well programme. Some examples are listed below:

- If the fluid system performed well, without any hole problems and according to the fluids programme, then state that this was the case and mention any special procedures that may have contributed to this success.
- If there were problems, then try to explain why they happened and how they could be avoided on future wells (e.g. the fluid density was difficult to control because coarser shaker screens had to be used, allowing solids to build up in the mud).
- Explain why product usage was higher or lower than programmed for a particular section (e.g. Baryte consumption was higher than programmed following the decision to raise the fluid density from X ppg to Y ppg; 80 sacks viscosifier were programmed for the section but 110 sacks were used because hole temperatures were higher than expected, destroying the effectiveness of the polymer).
- Explain why fluid volume consumption was higher or lower than programmed for a particular section (e.g. the shaker screens were constantly blinded by sand, resulting in whole mud losses over the shakers).
- Provide details of pill and spacer volumes, formulations and effectiveness (e.g. displacement spacers, LCM pills, etc.).
- Avoid very long sentences and use paragraphs to break up long discussions, with 6 to 8 lines per paragraph.
- Avoid too many abbreviations in discussions (e.g. write "casing point" instead of "csg. pt.").
- Use correct abbreviations (the abbreviation for metres is "m" and not "mt", which is the abbreviation for metric tonnes). Correct abbreviations for all parameters can be found in the "Units Converter" section of "EMEC Tools".

There should also be a “Conclusions & Recommendations” section at the end of the report to discuss mud-related issues affecting the well and to suggest recommendations that might improve operational effectiveness on future wells (e.g. A larger stock of 200-mesh screens are recommended for the next well because they did not last very long on this well and constantly needed to be repaired; Torque was higher than expected during a particular section and a contingency stock of lubricant is recommended for the next well to improve fluid lubricity).

The District Managers often have to visit clients to give a presentation on how well EMEC fluids have performed, so your detailed input is essential because you were there to witness events at the rig site. The well summary discussions should be updated every day, when events are still fresh in the mind, rather than at the end of the section or well, when events or explanations may have been forgotten.

Useful Formulae

Contents

Conversion Factors

Density

1 lb/gal (ppg) = 52 psi/1000 ft (pptf)
1 s.g. = 8.33 lb/gal (ppg)
1 s.g. = 433 pptf

Flow Rate

1 bbl/min = 42 gal/min
1 gal/min = 3.79 lt/min

Length

1 inch = 25.4 mm
1 meter = 3.281 ft
1 meter = 100 cm
1 meter = 1,000,000 microns

Weight

1 kg = 2.205 lb
1 MT = 1,000 kg = 2,205 lb
1 kg = 1,000 grams

Pressure

1 bar = 14.504 psi

Volume

1 bbl = 42 gal
1 bbl = 159 liters
1 bbl = 9702 in^3
1 gal = 3.7854 liters
1 m^3 = 6.2898 bbl

Concentration

1 lb/bbl = 2.85 kg/m^3

Formulae

Pressure Gradient

Pressure Gradient in psi/ft = s.g. x 0.433

Pressure Gradient in psi/ft = ppg x 0.052

Hydrostatic Pressure

Hydrostatic Pressure (psi) = ppg x 0.052 x TVD in feet

Hydrostatic Pressure (psi) = ppg x 0.052 x TVD in meters x 3.281

Maximum Allowable Mud Density from Leak-Off Test

Density Margin (ppg) = Leak-Off Pressure (psi) ÷ 0.052 ÷ Casing Shoe TVD (ft)

Maximum Allowable Mud Density = Current Density (ppg) + Density Margin (ppg)

Pump Output (Triplex Pump)

bbl/stroke = 0.000243 x (liner diameter in inches)^2 x (stroke length in inches)

(This equation assumes 100% pump efficiency, which is usually adjusted for actual efficiency that is generally recorded at around 95% to 97% in the daily IADC Reports)

Pump Output (Duplex Pump)

bbl/stroke = [0.000162 x (liner diameter in inches)^2 x (stroke length in inches)]
+ [0.000162 x (liner diameter in inches)^2 x (stroke length in inches)]
- [0.000162 x (rod diameter in inches)^2 x (stroke length in inches)]

= [0.000324 x (liner diameter in inches)^2 x (stroke length in inches)]
- [0.000162 x (rod diameter in inches)^2 x (stroke length in inches)]

(This equation assumes 100% pump efficiency, which is usually adjusted for actual efficiency that is generally recorded at around 95% to 97% in the daily IADC Reports)

Flow Rate

Flow Rate (bbl/min) = Pump Output (bbl/stroke) x Stroke Rate (strokes/min)

Tubular Capacity

Tubular Capacity (bbl/ft) = (Tubular I/D in inches)^2 ÷ 1029.39

Tubular Volume

Tubular Volume (bbl) = Tubular Capacity (bbl/ft) x Tubular Length

Tubular Displacement

Tubular Displacement (bbl/ft) = (O/D^2 – I/D^2) ÷ 1029.39

Tubular Volume

Tubular Volume (bbl) = Tubular Capacity (bbl/ft) x Tubular Length

Tubular Displacement

Tubular Displacement (bbl/ft) = (O/D^2 – I/D^2) ÷ 1029.39

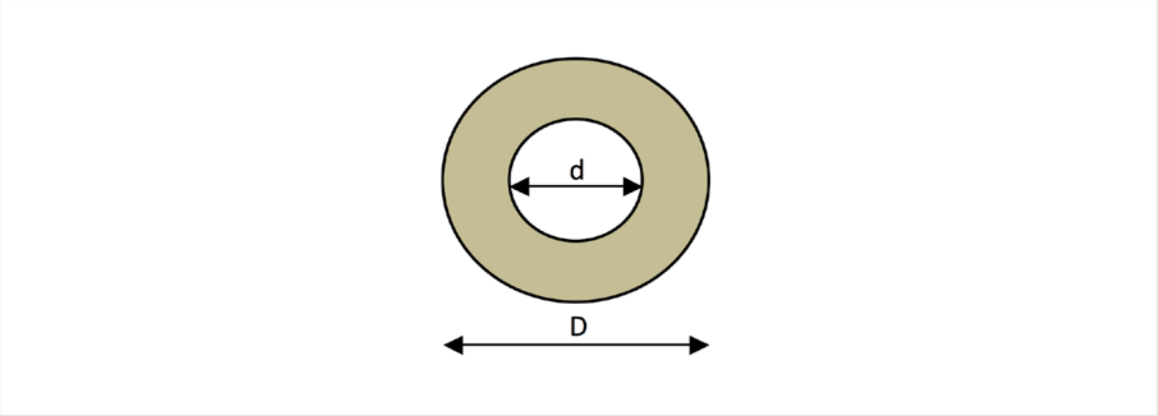
Annular Capacity

Annular Capacity (bbl/ft) = (D^2 - d^2) ÷ 1029.39

Annular Volume

Annular Volume (bbl) = Annular Capacity (bbl/ft) x Annular Length (ft)

Useful Formulae



D = Open Hole or Casing/Liner I/D in inches
d = Tubular O/D in inches

Annular Velocity

Annular Velocity (ft/min) = Pump Rate (bbl/min) ÷ Annular Capacity (bbl/ft)

$$\text{Annular Velocity (ft/min)} = \frac{\text{Pump Rate (bbl/min)} \times 1029.39}{(D^2 - d^2)}$$

$$\text{Annular Velocity (ft/min)} = \frac{\text{Pump Rate (gal/min)} \times 24.51}{(D^2 - d^2)}$$

Hole Displacement Volume

Hole Displacement Volume = Open Hole Volume – String Displacement Volume
Hole Displacement Volume = String Capacity (bbl) + Annulus Volume (bbl)

Pump Displacement Strokes

Pump Displacement Strokes = Displacement Volume (bbl) ÷ Pump Output (bbl/stroke)

Temperature

Temperature (°F) = [Temperature (°C) x 9/5] + 32
Temperature (°C) = [Temperature (°F) – 32] x 5/9

(Note that rheometer heating cups are are usually set at 50°C (120°F)

Weighting Up with Barite (4.2 sg)

$$\text{Barite (lb/bbl)} = 1470 \times \frac{\text{(Required Density in ppg – Current Density in ppg)}}{\text{(35 – Required Density in ppg)}}$$

$$\text{Barite (kg/m}^3\text{)} = 4190 \times \frac{\text{(Required Density – Current Density)}}{\text{(4.2 – Required Density)}}$$

Weighting Up with Calcium Carbonate (2.7 sg)

$$\text{Calcium Carbonate (lb/bbl)} = 945 \times \frac{\text{(Required Density in ppg – Current Density in ppg)}}{\text{(22.5 – Required Density in ppg)}}$$

Useful Formulae

Density Reduction with Water

$$\text{Water (bbl)} = \frac{\text{(Current Density in ppg – Required Density in ppg)}}{\text{(Required Density in ppg – Water Density in ppg)}} \text{ x Current Volume (bbl)}$$

Density Reduction with Oil

$$\text{Oil (bbl)} = \frac{\text{(Current Density in ppg – Required Density in ppg)}}{\text{(Required Density in ppg – Oil Density in ppg)}} \text{ x Current Volume (bbl)}$$

Blending Calculations

Density = Mass ÷ Volume, therefore Mass = Density x Volume

Mass Balance Equation

Final Mass, $M_F = \text{Mass}_1 + \text{Mass}_2$

$(\text{Volume}_F \text{ x Density}_F) = (\text{Volume}_1 \text{ x Density}_1) + (\text{Volume}_2 \text{ x Density}_2)$

Engineering Data and Tables

Contents

Drill Pipe Dimensions, Capacities and Displacements

Size (inches)	Weight (lb/ft)	I/D (inches)	Capacity (bbl/ft)	Displacement (bbl/ft)	Capacity (l/m)	Displacement (l/m)
2⅜	6.65	1.815	0.00320	0.00228	1.669	1.189
2⅞	10.4	2.150	0.00449	0.00354	2.343	1.846
3½	13.3	2.764	0.00742	0.00448	3.872	2.336
3½	15.5	2.602	0.00658	0.00532	3.431	2.777
4	14.0	3.340	0.01084	0.00471	5.653	2.455
4½	16.6	3.826	0.01422	0.00545	7.418	2.844
4½	20.0	3.640	0.01287	0.00680	6.715	3.548
5	19.5	4.276	0.01776	0.00652	9.266	3.403
5½	21.9	4.778	0.02218	0.00721	11.570	3.761
5½	24.7	4.670	0.02119	0.00820	11.052	4.278

Note: This table does not contain all the drill pipe sizes that are available. The displacement volumes do not include tool joint displacement.

HWDP Dimensions, Capacities and Displacements

Size (inches)	Weight (lb/ft)	I/D (inches)	Capacity (bbl/ft)	Displacement (bbl/ft)	Capacity (l/m)	Displacement (l/m)
3½	25.0	2.063	0.00413	0.00777	2.157	4.051
4	29.7	2.563	0.00638	0.00916	3.329	4.780
4½	41.0	2.750	0.00735	0.01233	3.833	6.430
5	49.3	3.000	0.00874	0.01554v	4.561	8.109

Note: This table does not contain all the HWDP sizes that are available. The displacement volumes do not include tool joint displacement.

Drill Collar Dimensions, Capacities and Displacements

Size (inches)	Weight (lb/ft)	I/D (inches)	Capacity (bbl/ft)	Displacement (bbl/ft)	Capacity (l/m)	Displacement (l/m)
3⅛	22	1¼	0.00152	0.00797	0.792	4.157
3½	27	1½	0.00219	0.00971	1.140	5.068
4⅛	35	2	0.00389	0.01264	2.027	6.596
4¾	47	2¼	0.00492	0.01700	2.566	8.869
5	53	2¼	0.00492	0.01937	2.566	10.104
6	83	2¼	0.00492	0.03005	2.566	15.679
6	75	2 13⁄16	0.00768	0.02729	4.009	14.236
6¼	91	2¼	0.00492	0.03303	2.566	17.231
6¼	83	2 13⁄16	0.00768	0.03026	4.009	15.788
6½	99	2¼	0.00492	0.03613	2.566	18.846
6½	91	2 13⁄16	0.00768	0.03336	4.009	17.403
6¾	108	2¼	0.00492	0.03934	2.566	20.525
7	117	2¼	0.00492	0.04268	2.566	22.267
7	110	2 13⁄16	0.00768	0.03992	4.009	20.824
7¼	119	2 13⁄16	0.00768	0.04338	4.009	22.629
8	151	2 13⁄16	0.00768	0.05449	4.009	28.425
8¼	160	2 13⁄16	0.00768	0.05843	4.009	30.484
9	196	2 13⁄16	0.00768	0.07100	4.009	37.041
9½	217	3	0.00874	0.07893	4.561	41.176
9¾	230	3	0.00874	0.08361	4.561	43.615
10	243	3	0.00874	0.08840	4.561	46.117
11	300	3	0.00874	0.10880	4.561	56.760

Note: This table does not contain all the HWDP sizes that are available. The displacement volumes do not include tool joint displacement.

Casing Dimensions, Capacities and Displacements

Size (inches)	Weight (lb/ft)	I/D (inches)	Capacity (bbl/ft)	Displacement (bbl/ft)	Capacity (l/m)	Displacement (l/m)
5	13.0	4.494	0.01962	0.00467	10.235	2.435
5	18.0	4.276	0.01776	0.00652	9.266	3.403
5	21.0	4.154	0.01676	0.00752	8.745	3.925
5½	15.5	4.950	0.02380	0.00558	12.417	2.913
5½	23.0	4.670	0.02119	0.00820	11.052	4.278
6	18.0	5.424	0.02858	0.00639	14.909	3.335
6	23.0	5.24	0.02667	0.00830	13.915	4.329
6⅝	25.0	5.880	0.03359	0.00905	17.522	4.721
6⅝	29.0	5.761	0.03224	0.01014	16.820	5.423
7	23.0	6.366	0.03937	0.00823	20.538	4.295
7	26.0	6.276	0.03826	0.00934	19.961	4.871
7	32.0	6.094	0.03608	0.01152	18.820	6.012
7⅝	26.4	6.969	0.04718	0.00930	24.613	4.852
7⅝	35.5	6.710	0.04374	0.01274	22.818	6.647
9⅝	32.3	9.001	0.07870	0.01129	41.059	5.890
9⅝	42.0	8.799	0.07521	0.01478	39.236	7.712
9⅝	47.0	8.681	0.07321	0.01679	38.191	8.758
9⅝	53.5	8.535	0.07077	0.01923	36.917	10.031
10¾	46.2	9.950	0.09618	0.01609	50.173	8.392
10¾	49.5	9.850	0.09425	0.01801	49.170	9.396
10¾	54.0	9.784	0.09299	0.01927	48.513	10.053
10¾	55.5	9.760	0.09254	0.01973	48.275	10.290
13⅜	48.0	12.715	0.15706	0.01673	81.932	8.727
13⅜	68.0	12.415	0.14973	0.02405	78.112	12.547
13⅜	72.0	12.347	0.14810	0.02569	77.259	13.401
16	75.0	15.125	0.22223	0.02646	115.935	13.802

Note: This table does not contain all the HWDP sizes that are available. The displacement volumes do not include tool joint displacement.

IADC Dull Bit Grading System

An internationally recognized drill bit grading system has been developed by the IADC to describe wear on drill bits, based on eight factors that are listed below. The codes used in the dull bit grading system are suitable for grading roller cone and fixed cutter bits, with the first four factors describing the cutting structure. More detailed information can be obtained by referring to dull bit grading charts supplied by bit manufacturers, but the condition of a drill bit that has been graded as 3,4,BT,N,E,¼,CT,TD can be determined from the following explanation:

1. Inner Cutting Structure – A scale of 0 to 8 is used when describing the condition of the inner rows of the cutting structure, with 0 representing no lost, worn or broken teeth/inserts, while 8 representing 100% lost, worn or broken teeth/inserts.

2. Outer Cutting Structure – A scale of 0 to 8 is used when describing the condition of the gauge rows of the outer cutting structure, with 0 representing no lost, worn or broken teeth/inserts, and 8 representing 100% lost, worn or broken teeth/inserts.

3. Dull Characteristics – The following codes are used when describing dull characteristics:

BC	Broken Cone
BF	Bond Failure
BT	Broken Teeth/Cutters
BU	Balled Up Bit
CC	Cracked Cone
CD	Cone Dragged
CI	Cone Interference
CR	Cored
CT	Chipped Teeth/Cutters
ER	Erosion
FC	Flat Crested Wear
HC	Heat Checking
LD	Junk Damage
LC	Lost Cone
LN	Lost Nozzle
LT	Lost Teeth/Cutters
OC	Off Centre Wear
PB	Pinched BiT
PN	Plugged Nozzle/Flow
RG	Rounded Gauge
RO	Ring Out
SD	Shirt Tail Damage
SS	Shelf Sharpening Wear
TR	Cone Tracking
WO	Wash Out
WT	Worn Teeth/Cutters
NO	No Dull Characteristics

4. Location – This refers to the location of the dull characteristics on the bit, as follows:

A	All Rows or Areas
C	Cone on Fixed Cutter
G	Gauge Row
M	Middle Row
N	Nose
S	Shoulder
T	Taper

5. Bearings and Seals – This only applies to roller cone bits and is marked with an "X" when grading a fixed cutter bit. A linear scale from 0 to 8 is used for estimating bearing life for non-sealed bearings, with 0 representing no life used and 8 representing 100% bearing life used. The following codes are used for sealed bearings:

E	Effective Seals
X	Fixed Cutter Bit
F	Failed Seals
N	Not Able to Grade

6. Gauge – This refers to the gauge of the bit, which is measured in 1/16ths of an inch, so a bit that is ¼" under gauge would be classified as ¼. A bit that is still in gauge is marked with an "X".

7. Other Dull Characteristics – The dull characteristic codes listed in 3 are used when describing other dull characteristics of the bit.

Reason for Pulling Bit – This refers to the location of the dull characteristics on the bit, as follows:

BHA	BHA Change
DMF	Down-hole Motor Failure
DTF	Down-hole Tool Failure
DSF	Drill String Failure
DST	Drill Stem Test
DP	Drill Plug
CM	Condition Mud
CP	Core Point
FM	Formation Change
HP	Hole Problems
LIH	Left In Hole
HR	Hours on Bit
LOG	Run Logs
PP	Pump Pressure
PR	Penetration Rate
RIG	Rig Repairs
TD	Total Depth
TW	Twist Off
TQ	Torque
WC	Weather Conditions

Physical Properties of Sodium Chloride Solutions (100% Purity at 20°C)

Weight (%)	Specific Gravity	Density (ppg)	NaCL (ppb)	Water (gal/l)	NaCL (mg/l)	Chlorides (mg/l)	Volume Increase	Crystallisation Point (°F)	Aw
1.0	1.007	8.40	3.5	41.87	10,070	6,108	1.003	31.0	0.996
2.0	1.014	8.46	7.1	41.75	20,286	12,305	1.006	30.0	0.989
3.0	1.021	8.52	10.7	41.63	30,630	18,580	1.009	28.8	0.983
4.0	1.029	8.58	14.4	41.46	41,144	24,957	1.013	27.7	0.976
5.0	1.036	8.65	18.2	41.34	51,800	31,421	1.016	26.5	0.970
6.0	1.043	8.70	21.9	41.18	62,586	37,963	1.020	25.3	0.964
7.0	1.050	8.76	25.8	41.02	73,500	44,584	1.024	24.1	0.957
8.0	1.058	8.83	29.7	40.86	84,624	51,331	1.028	22.9	0.950
9.0	1.065	8.89	33.6	40.70	95,850	58,141	1.032	21.5	0.943
10.0	1.073	8.95	37.6	40.54	107,260	65,062	1.036	20.2	0.935
11.0	1.080	9.01	41.6	40.38	118,800	72,062	1.040	18.8	0.927
12.0	1.088	9.08	45.7	40.19	130,512	79,166	1.045	17.3	0.919
13.0	1.095	9.14	49.9	40.00	142,350	86,347	1.050	15.7	0.910
14.0	1.103	9.20	54.1	39.85	154,392	93,651	1.054	14.1	0.901
15.0	1.111	9.27	58.4	39.66	166,650	101,087	1.059	12.4	0.892
16.0	1.118	9.33	62.7	39.44	178,912	108,524	1.065	10.6	0.882
17.0	1.126	9.40	67.1	39.25	191,420	116,112	1.070	8.7	0.872
18.0	1.134	9.46	71.5	39.03	204,102	123,804	1.076	6.7	0.861
19.0	1.142	9.53	76.0	38.85	216,980	131,616	1.081	4.6	0.850
20.0	1.150	9.60	80.6	38.64	229,960	139,489	1.087	2.4	0.839
21.0	1.158	9.66	85.2	38.43	243,180	147,508	1.093	0.0	0.827
22.0	1.166	9.73	89.9	38.22	256,520	155,600	1.099	-2.5	0.815
23.0	1.174	9.80	94.6	37.97	270,020	163,789	1.106	-5.2	0.802
24.0	1.183	9.87	99.5	37.74	283,800	172,147	1.113	1.4	0.788
25.0	1.191	9.94	104.4	37.50	297,750	180,609	1.120	15.0	0.774
26.0	1.199	10.01	109.3	37.27	311,818	189,143	1.127	25.0	0.759

Physical Properties of Calcium Chloride Solutions (100% Purity at 20°C)

Weight (%)	Specific Gravity	Density (ppg)	100% $CaCl_2$ (lb/bbl)	Water (gal/l)	100% $CaCl_2$ (lb/bbl)	Chlorides (mg/l)	Volume Increase	Crystallisation Point (°F)	Aw
1	1.009	8.42	3.53	41.93	10,085	6,454	1.002	31.1	0.998
2	1.017	8.49	7.13	41.85	20,340	13,018	1.004	30.4	0.996
3	1.026	8.56	10.78	41.78	30,765	19,690	1.006	29.5	0.993
4	1.034	8.63	14.50	41.69	41,360	26,470	1.008	28.6	0.989
5	1.043	8.70	18.27	41.60	52,125	33,360	1.011	27.7	0.984
6	1.051	8.77	22.11	41.49	63,060	40,358	1.013	26.8	0.979
7	1.060	8.84	25.99	41.38	74,165	47,466	1.016	25.9	0.973
8	1.068	8.91	29.94	41.27	85,440	54,682	1.018	24.6	0.967
9	1.077	8.98	33.95	41.14	96,885	62,006	1.021	23.5	0.959
10	1.085	9.05	38.03	41.01	108,500	69,440	1.024	22.3	0.951
11	1.094	9.13	42.18	40.90	120,340	77,018	1.027	20.8	0.942
12	1.103	9.20	46.39	40.76	132,360	84,710	1.030	19.3	0.933
13	1.113	9.28	50.69	40.65	144,625	92,560	1.034	17.6	0.932
14	1.122	9.36	55.05	40.53	157,080	100,531	1.037	15.5	0.912
15	1.132	9.44	59.49	40.40	169,725	108,624	1.041	13.5	0.900
16	1.141	9.52	63.98	40.25	182,560	116,838	1.044	11.2	0.888
17	1.151	9.60	68.55	40.10	195,585	125,174	1.048	8.6	0.875
18	1.160	9.68	73.18	39.95	208,800	133,632	1.051	5.9	0.862
19	1.170	9.76	77.91	39.80	222,300	142,272	1.056	2.8	0.847
20	1.180	9.85	82.72	39.65	236,000	151,040	1.060	-0.4	0.832
21	1.190	9.93	87.59	39.48	249,900	159,936	1.065	-3.9	0.816
22	1.200	10.01	92.53	39.31	264,000	168,960	1.069	-7.8	0.800
23	1.210	10.10	97.55	39.14	278,300	178,112	1.074	-11.9	0.783
24	1.220	10.18	102,62	38.95	292,800	187,392	1.078	-16.2	0.765
25	1.231	10.27	107,82	38.76	307,625	196,880	1.084	-21.0	0.746
26	1.241	10.36	113,09	38.57	322,660	206,502	1.089	-25.8	0.727
27	1.252	10.44	118,44	38.37	337,905	216,259	1.095	-31.2	0.707
28	1.262	10.53	123,85	38.16	353,360	226,150	1.100	-37.8	0.686
29	1.273	10.62	129,39	37.96	369,170	236,269	1.107	-49.4	0.665
30	1.284	10.71	135,00	37.75	385,200	246,528	1.113	-50.8	0.643
31	1.295	10.81	140,70	37.53	401,450	256,928	1.120	-33.2	0.620
32	1.306	10.90	146.48	37.30	417,920	267,469	1.126	-19.5	0.597
33	1.317	10.99	152.32	37.06	434,610	278,150	1.134	-6.9	0.573
34	1.328	11.08	158.25	36.81	451,520	288,973	1.141	4.3	0.548
35	1.340	11.18	164.32	36.57	468,825	300,048	1.149	14.4	0.522
36	1.351	11.27	170.47	36.32	486,360	311,270	1.156	24.1	0.496
37	1.363	11.37	176.76	36.06	504,310	322,758	1.165	33.4	0.469
38	1.375	11.47	183.13	35.81	522,500	334,400	1.173	42.1	0.441
39	1.387	11.57	189.53	35.53	540,735	346,070	1.183	49.6	0.413
40	1.398	11.67	195.99	35.23	559,200	357,888	1.192	55.9	0.384

Physical Properties of Calcium Chloride Solutions (95% Purity at 20°C)

Weight (%)	Specific Gravity	Density (ppg)	95% CaCl$_2$ (mg/l)	Water (gal/l)	95% CaCl$_2$ (mg/l)	Chlorides (mg/l)	Volume Increase	Crystallisation Point (°F)	Aw
1	1.009	8.42	3.72	41.91	10,085	6,454	1.002	31.1	0.998
2	1.017	8.49	7.50	41.81	20,340	13,018	1.004	30.4	0.996
3	1.026	8.56	11.35	41.71	30,765	19,690	1.007	29.5	0.993
4	1.034	8.63	15.26	41.6	41,360	26,470	1.010	28.6	0.989
5	1.043	8.70	19.23	41.48	52,125	33,360	1.013	27.7	0.984
6	1.051	8.77	23.27	41.35	63,060	40,358	1.016	26.8	0.979
7	1.060	8.84	27.36	41.22	74,165	47,466	1.019	25.9	0.973
8	1.068	8.91	31.52	41.08	85,440	54,682	1.022	24.6	0.967
9	1.077	8.98	35.74	40.93	96,885	62,006	1.026	23.5	0.959
10	1.085	9.05	40.03	40.77	108,500	69,440	1.030	22.3	0.951
11	1.094	9.13	44.40	40.63	120,340	77,018	1.034	20.8	0.942
12	1.103	9.20	48.83	40.47	132,360	84,710	1.038	19.3	0.933
13	1.113	9.28	53.36	40.33	144,625	92,560	1.041	17.6	0.932
14	1.122	9.36	57.95	40.18	157,080	100,531	1.045	15.5	0.912
15	1.132	9.44	62.62	40.02	169,725	108,624	1.049	13.5	0.900
16	1.141	9.52	67.35	39.85	182,560	116,838	1.054	11.2	0.888
17	1.151	9.60	72.16	39.67	195,585	125,174	1.059	8.6	0.875
18	1.160	9.68	77.03	39.49	208,800	133,632	1.064	5.9	0.862
19	1.170	9.76	82.01	39.31	222,300	142,272	1.068	2.8	0.847
20	1.180	9.85	87.07	39.13	236,000	151,040	1.073	-0.4	0.832
21	1.190	9.93	92.20	38.93	249,900	159,936	1.079	-3.9	0.816
22	1.200	10.01	97.40	38.73	246,000	168,960	1.084	-7.8	0.800
23	1.210	10.10	102.68	38.52	278,300	178,112	1.090	-11.9	0.783
24	1.220	10.18	108.02	38.3	292,800	187,392	1.097	-16.2	0.765
25	1.231	10.27	113.49	38.08	307,625	196,880	1.103	-21.0	0.746
26	1.241	10.36	119.04	37.86	322,660	206,502	1.109	-25.8	0.727
27	1.252	10.44	124.67	37.62	337,905	216,259	1.116	-31.2	0.707
28	1.262	10.53	130.37	37.38	353,360	226,150	1.124	-37.8	0.686
29	1.273	10.62	136.20	37.14	369,170	236,269	1.131	-49.4	0.665
30	1.284	10.71	142.11	36.90	385,200	246,528	1.138	-50.8	0.643
31	1.295	10.81	148.11	36.64	401,450	256,928	1.146	-33.2	0.620
32	1.306	10.90	154.19	36.38	417,920	267,469	1.155	-19.5	0.597
33	1.317	10.99	160.34	36.1	434,610	278,150	1.163	-6.9	0.573
34	1.328	11.08	166.58	35.81	451,520	288,973	1.173	4.3	0.548
35	1.340	11.18	172.97	35.53	468,825	300,048	1.182	14.4	0.522
36	1.351	11.27	179.44	35.24	486,360	311,270	1.192	24.1	0.496
37	1.363	11.37	186.06	34 .95	504,310	322,758	1.202	33.4	0.469
38	1.375	11.47	192.77	34.65	522,500	334,400	1.212	42.1	0.441
39	1.387	11.57	199.50	34.33	540,735	346,070	1.224	49.6	0.413
40	1.398	11.67	206.31	33.99	559,200	357,888	1.236	55.9	0.384

Physical Properties of Potassium Chloride Solutions (100% Purity at 20°C)

Weight (%)	Specific Gravity	Density (ppg)	KCl (mg/l)	Water (gal/l)	KCl (mg/l)	Chlorides (mg/l)	Volume Increase	Crystallisation Point (°F)
1.0	1.005	8.37	3.5	41.8	10,000	4,756	1.005	31.2
2.0	1.011	8.42	7.1	41.6	20,200	9,606	1.009	30.3
3.0	1.017	8.47	10.7	41.4	30,500	14,506	1.013	29.5
4.0	1.024	8.53	14.4	41.3	41,000	19,499	1.017	28.6
5.0	1.030	8.59	18.1	41.1	51,500	24,493	1.022	27.8
6.0	1.037	8.64	21.8	40.9	62,200	29,582	1.026	26.9
7.0	1.044	8.69	25.6	40.7	73,000	34,718	1.031	26.1
8.0	1.050	8.75	29.4	40.5	84,000	39,950	1.035	25.2
9.0	1.057	8.8	33.3	40.4	95,100	45,229	1.039	24.3
10.0	1.063	8.86	37.3	40.2	106,300	50,556	1.045	23.4
11.0	1.070	8.90	41.2	40.0	117,700	55,977	1.050	22.4
12.0	1.077	8.97	45.3	39.8	129,200	61,447	1.055	21.4
13.0	1.084	9.03	49.4	39.6	140,900	67,011	1.061	20.4
14.0	1.091	9.08	53.5	39.4	152,700	72,623	1.066	20.0
15.0	1.097	9.12	57.6	39.1	164,600	78,282	1.072	18.5
16.0	1.104	9.20	61.9	38.9	176,700	84,038	1.078	17.0
17.0	1.111	9.26	66.1	38.7	188,900	89,840	1.084	16.0
18.0	1.119	9.32	70.5	38.5	201,300	95,737	1.090	15.0
19.0	1.126	9.38	74.9	38.3	213,900	101,730	1.097	14.0
20.0	1.133	9.44	79.3	38.0	226,600	107,770	1.104	13.0
21.0	1.140	9.51	83.9	37.8	239,500	114,000	1.111	22.0
22.0	1.147	9.56	88.4	37.6	252,400	120,040	1.117	34.0
23.0	1.155	9.64	93.1	37.4	265,700	126,473	1.125	48.0
24.0	1.162	9.68	97.7	37.1	278,900	132,643	1.132	59.0

Oilfield Abbreviations

A

AADE	American Association of Drilling Engineers
AFE	Authorization for Expenditure
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials

B

BBL	Barrel
BHA	Bottom-Hole Assembly
BHCT	Bottom-Hole Circulating Temperature
BHP	Bottom-Hole Pressure
BHST	Bottom-Hole Static Temperature
BHT	Bottom-Hole Temperature
BOP	Blow Out Preventer
BPD	Barrels Per Day
BPH	Barrels Per Hour
BPV	Back Pressure Valve
BRT	Below Rotary Table
BSR	Blind Shear Rams
BTU	British Thermal Units

C

C1	Methane
C2	Ethane
C3	Propane
C4	Butane
CBL	Cement Bond Log
CCL	Casing Collar Locator
CET	Cement Evaluation Tool
CGL	Core Gamma Log
CHRT	Casing Hanger Running Tool
CITHP	Closed In Tubing Head Pressure
CIV	Chemical Injection Valve
CMC	Carboxy Methyl Cellulose
CRA	Corrosion Resistant Alloy
CSG	Casing
CT	Coiled Tubing
CTD	Coiled Tubing Drilling

D

D&C	Drilling & Completion
DC	Drill Collar
DD	Directional Driller/Drilling
DDR	Daily Drilling Report
DF	Drill Floor
DHSV	Down-Hole Safety Valve
DMR	Daily Mud Report
DP	Drill Pipe
DPDV	Dynamically-Positioned Drilling Vessel
DST	Drill Stem Test
DSV	Diving Support Vessel or Drilling Supervisor
DWOP	Drilling Well on Paper

E

E&P	Exploration And Production
ECD	Equivalent Circulating Density
EDP	Emergency Disconnect Package
EGMBE	Ethylene Glycol Mono Butyl Ether
EMW	Equivalent Mud Weight
EOR	Enhanced Oil Recovery
EOW	End Of Well
ERD	Extended Reach Drilling
ESD	Equivalent Static Density

F

FC	Float Collar
FCP	Final Circulating Pressure
FIT	Formation Integrity Test
FIV	Formation Isolation Valve
FPIT	Free Point Indicator Tool
FPSO	Floating Production Storage And Offloading Vessel
FSV	Fail Safe Valve
FSO	Floating Storage Offloading vessel
FV	Funnel Viscosity Or Float Valve

H

HAZID	Hazard Identification
HGS	High Gravity Solids
HHP	Hydraulic Horse Power
HL	Hook Load
HPHT	High Pressure, High Temperature
HSE	Health, Safety And Environment
HTHP	High Temperature, High Pressure
HUD	Hold Up Depth
HWDP	Heavy Weight Drill Pipe

I

IADC	International Association Of Drilling Contractors
IBC	Intermediate Bulk Container
ID	Internal Diameter
IF	Internal Flush (tool joint)
ISO	International Organization For Standardization

Oilfield Abbreviations

IWCF	International Well Control Federation
IWOCS	Installation/Workover Control System

J

JB	Junk Basket
JV	Joint Venture

K

KB	Kelly Bushing
KOP	Kick-Off Point
KRP	Kill Rate Pressure

L

LCM	Lost Circulation Material
LGS	Low Gravity Solids
LOT	Leak-Off Test
LP	Low Pressure
LPG	Liquified Petroleum Gas
LSRV	Low Shear Rate Viscosity
LTOBM	Low Toxicity Oil-Based Mud
LWD	Logging While Drilling

M

MAASP	Maximum Allowable Annular Shut-In Pressure
MAWP	Maximum Allowable Working Pressure
MBD	Thousand Barrels Per Day
MBOD	Thousand Barrels Of Oil Per Day
MD	Measured Depth
MD	Milli-Darcy
MEG	Mono-Ethylene Glycol
MFCT	Multi-Finger Caliper Tool
MMBD	Million Barrels Per Day
MMBOD	Million Barrels Of Oil Per Day
MMSCFD	Million Standard Cubic Feet per Day
MODU	Mobile Offshore Drilling Unit
MOPU	Mobile Offshore Production Unit
MPD	Managed Pressure Drilling
MSL	Mean Sea Level
MWD	Measurement While Drilling

N

NB	Nominal Bore
NPT	Non Productive Time
NRV	Non Return Valve
NTU	Nephelometric Turbidity Unit

O

OBM	Oil-Based Mud
OD	Outer Diameter
OEM	Original Equipment Manufacturer
OH	Open Hole
OHV	Open Hole Volume
OIM	Offshore Installation Manager
OWC	Oil Water Contact

P

P&A	Plug And Abandon
PAC	Poly Anionic Cellulose (a type of polymer)
PBR	Polished Bore Receptacle
PBTD	Plug Back Total Depth
PBU	Pressure Build Up
PDC	Polycrystalline Diamond Composite
PE	Petroleum Engineer
PGB	Permanent Guide Base
PI	Productivity Index
PLT	Production Logging Tool
PMV	Production Master Valve
POB	Personnel on Board
POH	Pull Out of Hole
PPA	Permeability Plugging Apparatus
PPB	Pounds Per Barrel (lb/bbl)
PPCF	Pounds Per Cubic Foot
PPG	Pounds Per Gallon
PPTF	PSI Per Thousand Feet
PSD	Particle Size Distribution
PSIA	Pounds Per Square Inch Atmospheric
PSIG	Pounds Per Square Inch Gauge
PSV	Pressure Safety Valve
PV	Plastic Viscosity
PVD	Pure Vacuum Dried
PVT	Pressure Volume Temperature
PWD	Pressure While Drilling

Q

QC	Quality control

R

RBP	Retrievable Bridge Plug
RCA	Root Cause Analysis
RE	Reservoir Engineer
RIH	Run In Hole
RKB	Rotary Kelly Bushing
ROP	Rate of Penetration
ROV	Remotely Operated Vehicle
RTTS	Retrievable Test-Treat-Squeeze (packer)

Oilfield Abbreviations

S

SBF	Synthetic Base Fluid
SBM	Synthetic Base Mud
SBM	Synthetic-Based Mud
SCE	Solids Control Equipment
SCF	Standard Cubic Feet (natural gas)
SCSSV	Surface Controlled Subsurface Safety Valve
SEM	Scanning Electron Microscope
SG	Specific Gravity
SICP	Shut-In Casing Pressure
SIDPP	Shut-In Drill Pipe Pressure
SIMOPS	Simultaneous Operations
SIP	Shut In Pressure
SITHP	Shut In Tubing Hanger/Head Pressure
SPE	Society of Petroleum Engineers
spm	strokes per minute
SPP	Stand Pipe Pressure
SSCS	Sub Sea Control System
SSSV	Sub-Surface Safety Valve
SSV	Surface Safety Valve
STOP	Safety Training Observation Program
SV	Sleeve Valve

T

TCA	Total Corrosion Allowance
TCI	Tunsgten Carbide Insert (part of a drill bit)
TD	Total Depth
TDS	Top Drive System
TEG	Tri-Ethylene Glycol
TFA	Total Fluid Area
TGB	Temporary Guide Base
TH	Tubing Hanger
THP	Tubing Hanger Pressure
TIW	Texas Iron Works (valve)
TOC	Top of Cement
TOL	Top of Liner
TQM	Total Quality Management
TRSCSSSV	Tubing Retrievable Surface Controlled Sub-Surface Safety Valve
TRSCSSV	Tubing Retrievable Surface Controlled Sub-Surface Valve
TRSSSV	Tubing Retrievable Sub-Service Safety Valve
TRSV	Tubing Retrievable Safety Valve
TVBDF	True Vertical Depth Below Drill Floor
TVD	True Vertical Depth
TVDSS	True Vertical Depth Sub-Sea

V

VOC	Volatile Organic Compound

W

WBM	Water-Based Mud
WE	Well Engineer
WEG	Wireline Entry Guide
WHP	Wellhead Pressure
WI	Water Injection
WOB	Weight on Bit
WOC	Wait on Cement
WOE	Well Operations Engineer)
WOW	Wait on Weather
WP	Working Pressure
WR	Wireline Retrievable
WRSCSSV	Wireline Retrievable Surface Controlled Sub-Surface Valve
WSS	Well Services Supervisor
WT	Well Test

X

XRD	X-Ray Diffraction

Y

YP	Yield Point

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