Drill-In Fluids

Introduction

Drill-in fluids are specially designed, non-damaging drilling fluids for use in reservoir intervals.

Drill-in fluids are specially designed, non-damaging drilling fluids for use in reservoir intervals. They are formulated to maximize drilling performance as they minimize formation damage, thereby preserving potential well productivity. Generally, conventional drilling fluids cannot be converted into drill-in fluids.

Conventional drilling fluids can cause serious damage to productive reservoirs. This impact can be minimized somewhat by reducing fluid loss and controlling progressive gel strengths. These practices reduce fluid invasion into the formation and assist in obtaining zonal isolation when cementing casing strings. For conventional cased and perforated completions, the perforations usually penetrate past any near-wellbore damage. Elevated drawdown pressures and larger-diameter perforations can assist in reducing the effects of formation damage caused by conventional drilling fluids.

Drill-in fluids are extremely important in horizontal wells...

In open-hole completions (wells completed without cementing the casing through the producing formation), the fluid and filter cake must be able to be removed without remedial clean-up treatments. Drill-in fluids are specially designed to reduce formation damage and improve clean-up in such wells. Drill-in fluids are extremely important in horizontal wells, where low drawdown pressures make clean-ups more difficult. Gravel packs and prepacked screens restrict the size of solids that can be produced back from the well; therefore, solids-laden conventional drilling fluids should be avoided when drilling horizontal intervals through producing zones. Instead, non-damaging drill-in fluids should be used.

A variety of fluids can be used as drill-in fluids, including water-, oil- and synthetic-base fluids. Fluid selection depends on formation type, formation fluid composition, formation damage mechanism and completion method. Most wells drilled with drill-in fluids are completed without cementing and perforating a casing or liner through the producing zone.

The following steps are the recommended selection process for an appropriate drill-in fluid (see Figure 1):

1. Identify the formation type and permeability.
2. Select the completion type.
3. Select the drill-in fluid.
4. Select the clean-up method.

Formation damage can be quantified by several means. In the laboratory, relative measurements such as return permeability, filter-cake solubility and lift-off pressure are used to compare the suitability of a fluid for drilling a specific formation. In the field, calculated skin factors and productivity indices are used to measure damage to the formation.

A drill-in fluid should have the following characteristics:

1. Formation damage control:
   a) The drill-in fluid should not contain clays or acid-insoluble weight materials which can migrate into the formation and plug pores.
   b) It should be formulated with breakable or acid-soluble viscosifiers, fluid-loss materials and properly sized plugging agents, all of which limit fluid loss to the formation and assure good clean-up.
   c) The filtrate should be formulated to prevent clays in the producing zone from swelling, migrating or plugging the formation.

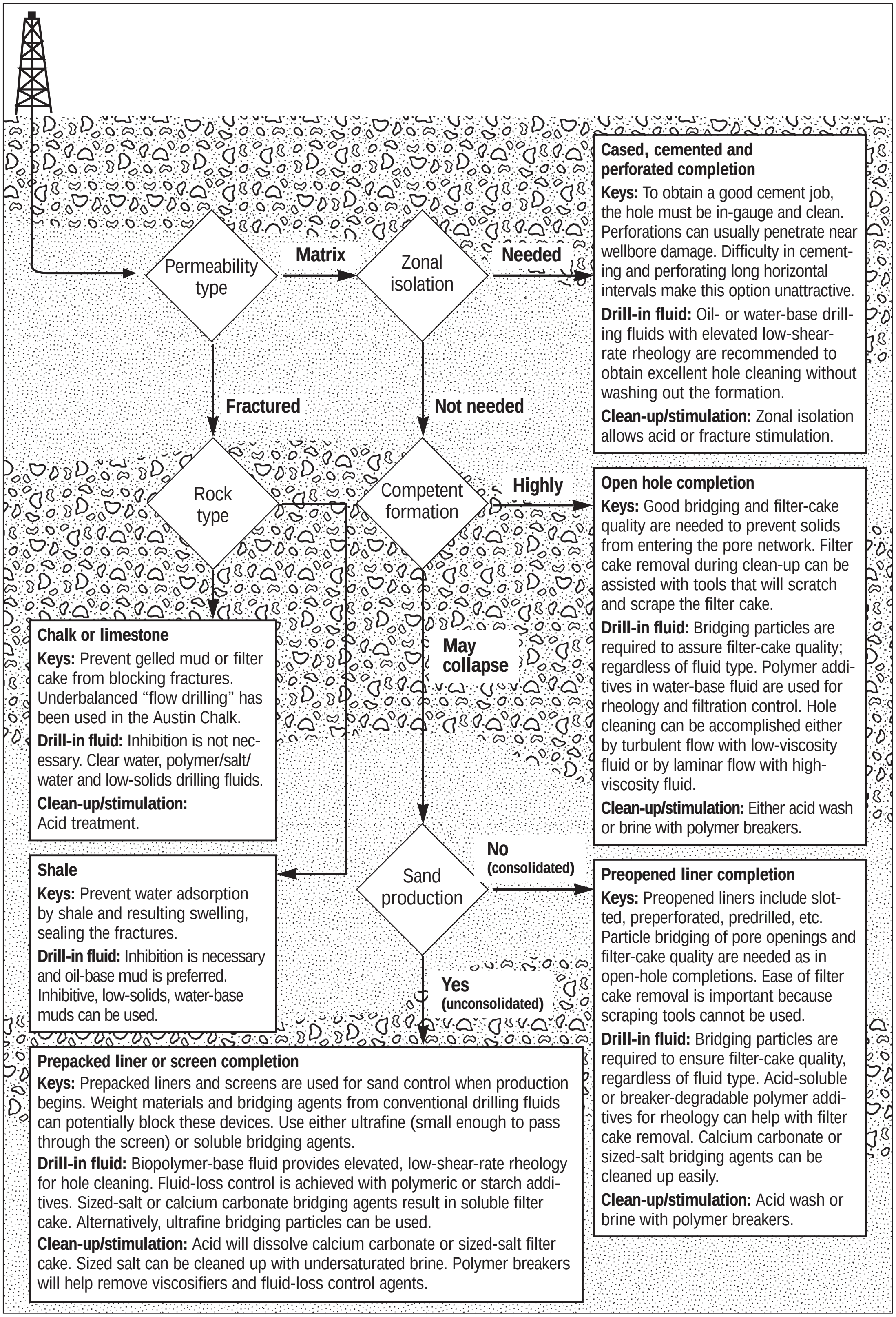

Figure 1: Guide for selecting non-damaging drill-in fluids.

d) The filtrate should be compatible with formation fluids so that it will not precipitate mineral scales.
e) The fluid and filtrate should not change the wetting characteristics of the formation from either water-wet to oil-wet or from oil-wet to water-wet.
f) The filtrate should not form emulsions with formation fluids and block the formation.

2. Drillability:
   a) The drill-in fluid should provide good hole-cleaning, lubricity and inhibition.
   b) It should minimize hole enlargement and provide wellbore stability.
3. Compatibility with completion equipment and procedures:
   a) Particles should be sized for formation pore throat bridging yet be small enough to pass through completion equipment.
   b) The fluid should be formulated with acid-soluble, water-soluble, oxidizer-degradable or solvent-soluble materials, which will not cause precipitates or emulsions.
   c) Breakers should be compatible with formation fluids and drill-in fluid filtrate.

Susceptibility to different types of formation damage varies greatly and is dependent on the formation type and well conditions. Some formations tolerate a wider range of drill-in fluid composition more than others. When production is from carbonate fractures, as it is in the Austin Chalk formation, significant amounts of insoluble materials can be tolerated without a significant reduction in productivity. Usually, fluids which invade these types of formations can be produced back from the well. Lower-permeability sandstones and depleted or unconsolidated sandstone reservoirs do not tolerate fluid and particle invasion without causing extensive damage. Detailed knowledge of the formation, permeability, pore pressure, mineralogy and formation fluid composition must be called upon to assist in selecting the proper drill-in fluid.

Formation-Damage Mechanisms

Compressible and deformable solids…are the most difficult… to remove.

A number of detrimental mechanisms restrict production and reduce the amount of recoverable reserves. Some of the most common ones are described below, with potential prevention techniques.

Solids plugging. Formation pore throats can be plugged by solids contained in a drilling fluid and cause formation damage. These solids can be added materials, such as commercial clays, drilling fluid chemicals or incorporated drill solids. Compressible and deformable solids, such as hydrated clays, are the most difficult (or impossible) to remove. In addition, solids can plug the completion assembly, restricting production. To prevent plugging, solids added to a drill-in fluid should be sized appropriately to bridge formation pore throats, and only acid-soluble materials should be used (see Figure 2).

A D90 particle size equal to the larger pore throat diameters, and a bridging agent concentration above 2% by volume, will provide excellent plugging and a good base for filter-cake deposition. Drill-in fluid filter cakes trap fine solids — which can cause considerable damage — and prevent their entry into the formation. If solids in the drill-in fluid are too fine to bridge and initiate a filter cake on the face of the wellbore, they will invade the reservoir matrix and can build an internal filter cake resulting in formation damage. A filter cake on the face of the formation is much easier to remove than one inside the formation. To reduce the likelihood of particle invasion, an aggressive solids-control program should be used to remove drill solids during their first circulation from the well. If drill solids are allowed to be recirculated, they will degrade in size and disperse, creating an accumulation of fine solids. Minimizing the overbalance also will help reduce the depth of solids invasion and, hence, the amount of formation damage.

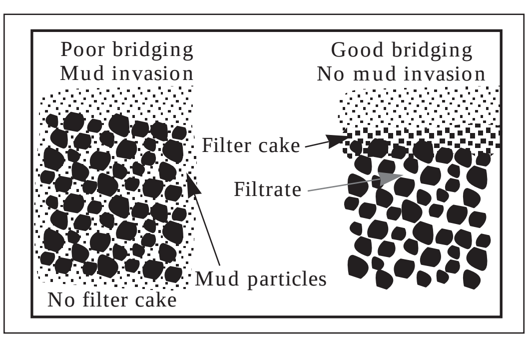

Figure 2: Bridging comparison.

Formation clay hydration and/or migration. Sandstone formations vary from clean (containing only sand) to very dirty (containing significant quantities of clay). These interstitial clays can hydrate, deform or migrate, causing formation damage when exposed to drilling fluid filtrate, cement or other fluids such as acid and spacers. This impedes the flow of reservoir fluids during production. A variety of inhibitive fluids can prevent the swelling and migration of formation clays. These include oil- and synthetic-base fluids, as well as fluids which are compatible with the formation clays. Completion fluids may include produced brines, high-salinity brines and water-base fluids that use potassium chloride or other clay-stabilizing chemical additives.

Emulsion blocking. An emulsion of drill-in fluid filtrate and formation fluid can occur, causing formation damage and restricting the flow of reservoir fluids during production. Emulsion blocking may be caused by fine solids in the fluid filtrate combined with asphaltines in the oil, by surfactants or emulsifiers in the fluid emulsifying formation fluids, or by exposing certain crude oils to a chemical environment that reacts to form emulsifiers. Oil- and synthetic-base fluids may alter formation wettability, releasing water to be emulsified.

In water-base fluids, filtrate compatibility can be tested and adjusted with alternative formulations and non-emulsifiers. Reducing fluid loss from the drill-in fluid also minimizes the depth of potential emulsion damage.

Scaling. Chemical incompatibility between the drill-in fluid and the formation or formation fluids can cause a precipitate (scale) to form, which results in formation damage. The most common example of this is a calcium-containing filtrate that reacts with soluble carbonates or sulfates in formation fluids to form a calcium carbonate or calcium ("gyp") scale. Knowing formation fluid composition and designing a compatible drill-in fluid can eliminate this potential problem.

Drill-In Fluid Types and Applications

FLO-PRO systems...are designed for trouble-free drilling...

Acid or oxidizers can be used to clean up...

A wide variety of options exists for choosing drill-in fluids. The selection of the most appropriate drill-in fluid depends not only on potential formation damage mechanisms, but also on the type of formation to be drilled and the completion method to be used. Temperature, density and known drilling problems also must be considered. Listed below are some potential drill-in fluid options and the primary application for each.

Clear fluids with viscous sweeps. Clear water or brine drill-in fluids can be used for mechanically competent formations that are not adversely affected by the intrusion of large volumes of fluid into the reservoir. These non-viscosified fluids are often used in fractured limestones and dolomites, as well as in reef formations; fractured sandstones; and clean, low-permeability sandstones.

These fluids require turbulent flow and high-viscosity sweeps to clean the hole adequately. The high-viscosity sweeps should be free of clay, and should be composed of Hydroxyethylcellulose (HEC) or xanthan gum (DUO-VIS,® FLO-VIS®).

Flocculants may be used to precipitate drilled solids in the surface system and maintain a clear fluid. These wells, drilled in competent formations, are generally completed open-hole or with a slotted or perforated liner.

HEC fluids. Hydroxyethylcellulose-base fluids can be used under conditions similar to those in which the clear fluids discussed above are, i.e., in competent formations. HEC provides carrying capacity, but has minimal gel structure and poor suspension characteristics. The low-shear rheology and suspension characteristics can be enhanced by adding xanthan gum (DUO-VIS or FLO-VIS). HEC will viscosify a variety of fluids from freshwater to salt-saturated fluids such as sodium, potassium and calcium chlorides, as well as sodium, calcium and zinc bromides. However, HEC provides only limited filtration control. Further filtration control must be achieved with starch-base additives such as FLO-TROL™ or POLY-SAL.™

Again, wells in competent formations are generally completed open-hole or with a slotted or perforated liner. Acid or oxidizers can be used to clean up the HEC, xanthan and starch polymers prior to production, if desired.

FLO-PRO.® FLO-PRO systems are rheologically engineered, minimal solids, non-damaging drill-in fluids designed for trouble-free drilling of producing formations subject to damage from conventional drilling fluids. This system has particular application in horizontal wells drilled in unconsolidated reservoirs. Vertical wells and other formation types also benefit from the level of performance and degree of protection provided by FLO-PRO. To minimize formation damage by clays, FLO-PRO systems use polymers for both rheology and filtration control.

The polymer-base FLO-PRO systems have an ultra-high LSRV...

The polymer-base FLO-PRO systems have an ultra-high, Low-Shear-Rate Viscosity (LSRV) compared to alternative systems or typical clay-base drilling fluids. The elevated LSRV provides excellent cuttings suspension in high-angle and horizontal wellbores and reduces hole erosion. The high LSRV is critical, not only for optimized hole cleaning and drilling performance, but also for minimizing filtrate invasion and the invasion of whole fluid into the formation. LSRV is measured with a Brookfield viscometer at 0.0636 sec^{-1} (equivalent to 0.037 RPM with a VG meter). FLO-PRO systems contain only a minimal amount of solids. FLO-PRO systems are formulated from a brine of appropriate density, using only enough acid-soluble, sized calcium carbonate (ground marble) or sized salt to achieve good pore throat bridging. These brines not only provide density, but inhibit the swelling of formation clays as well.

FLO-VIS, a premium-grade, clarified xanthan gum, is the primary viscosifier. FLO-TROL, a starch derivative, is the primary fluid-loss-control agent. FLO-TROL combines synergistically with FLO-VIS to provide additional viscosity. SAFE-CARB,™ a sized calcium carbonate (ground marble), is used as the bridging agent and is more than 98% acid-soluble in 15% HCl at 76°F (24.5°C) (see Figure 3).

FLO-PRO formulations are flexible and can be tailored for specific reservoirs. Standard FLO-PRO formulations use various brines to provide a density range

Grind Size	Fine	Medium	Coarse
Finer than 40 mesh	—	—	>99%
Finer than 200 mesh	—	70 - 80%	<20%
Finer than 325 mesh	>99%	—	—
Median (μ)	6 - 9	35 - 45	100 - 125

Figure 3: SAFE-CARB grind sizes.

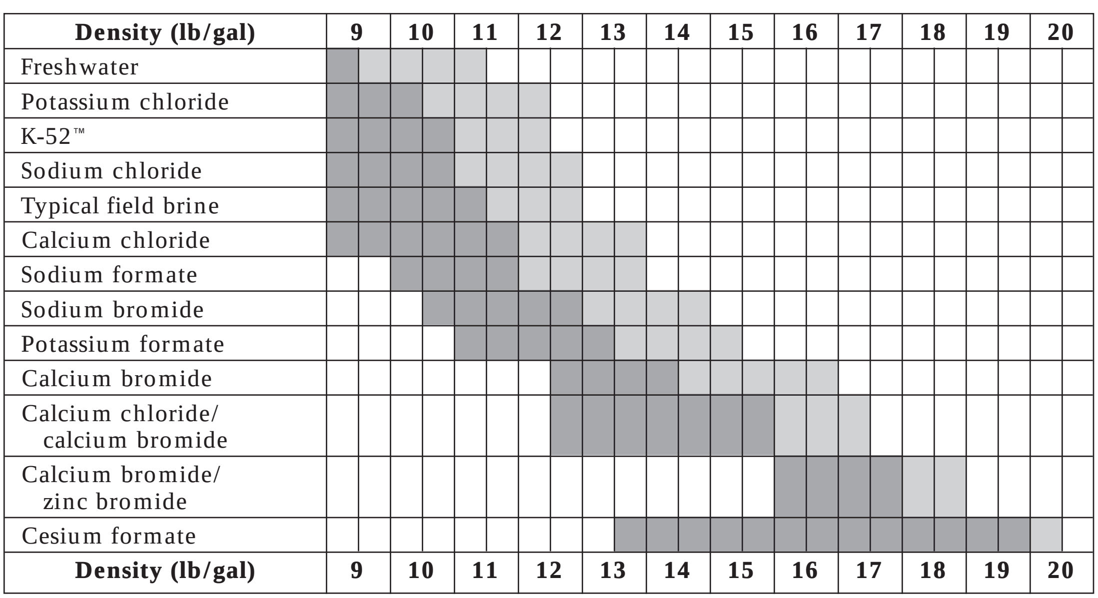

Figure 4: FLO-PRO density range brine selection.

FLO-PRO is compatible with all completion techniques...

of 8.4 to 14.7 lb/gal without the addition of solids for increased density (see Figure 4). Loss of whole fluid to the formation is controlled by quickly and effectively bridging the pore throats with sized calcium carbonate and/or relying on the LSRV provided by FLO-VIS to control leak-off. LSRV has prevented significant invasion of sands up to 2 darcies with more than 1,000-psi overbalance. Effective bridging has sealed acidized limestone reservoirs and sands to 6 darcies. For ultra-low, fluid-loss requirements or for formations that are sensitive to filtrate invasion, FLO-PRO can be formulated with less FLO-VIS and more FLO-TROL, or alternative filtration-reducing additives.

All of the products used in FLO-PRO systems are soluble in acid, oxidizer or water. After installing the completion assembly, the recommended procedure is to displace with a solids-free pill, then break and degrade the filter cake with an oxidizer or enzyme breaker and, if possible, acid prior to production to minimize potential damage not only to the formation, but also to the completion assembly. FLO-PRO is compatible with all completion techniques, including slotted liners, prepacked screens and open-hole gravel packs.

Sized-salt systems. Sized-salt (NaCl) systems are used to drill unconsolidated sand reservoirs. These systems are based on a saturated salt brine using xanthan gum for viscosity and a combination of starch and sized-salt particles for fluid-loss control. The elevated starch concentration and salt bridging agents provide excellent fluid-loss control. To maintain bridging, the system must be saturated with salt. These systems have a narrow density range from 10 to 12 lb/gal. Sized-salt systems generally provide acceptable wellbore and temperature stability.

These systems can be used with any type of completion assembly. They are usually cleaned up with a two-step procedure:
- An acid soak to destroy the polymers, followed by,
- An unsaturated water wash to remove the salt particles.

VERSADRIL® /VERSACLEAN® /VERSAPORT.™ These are oil-base systems that can be formulated to have non-damaging characteristics for drill-in applications. VERSADRIL has a diesel oil base. VERSACLEAN has a mineral oil base. VERSAPORT is formulated to have an elevated LSRV using VERSAMOD™ or VERSA-HRP® (in either diesel or mineral oil) for enhanced hole cleaning in high-angle wells.

An important application for oil-base, drill-in fluids is in very dirty sands. If such sands are drilled with water-base fluids, they develop a water block or are damaged by clay swelling. Such conditions do not develop in oil-base filtrate. Oil-base fluids also provide significantly better shale stability for production intervals where shale sections are interbedded with the producing formation.

Oil-base fluids have thin filter cakes, excellent inhibition and good lubricity. These qualities simplify many aspects of particularly problematic horizontal wells. For example, the improved lubricity of oil-base fluids allows the drilling of a well with complex hole geometry or an extended horizontal interval. Such wells cannot be drilled with a water-base fluid.

The oil/water ratios for these fluids can vary from 100/0 to 50/50. Generally, acid-soluble sized calcium carbonate, such as SAFE-CARB, is used as the weighting agent for wells completed with prepacked screens. Calcium carbonate drill-in fluids can

The synthetic fluids find application in environmentally sensitive areas...

Synthetic drill-in fluids provide advantages similar to those provided by oil-base fluids...

weigh up to 12.5 lb/gal. For higher densities, barite, hematite or alternative-weight materials must be used (for special formations and applications) and usually the well must be completed with an assembly that will allow the weight material to be produced back through the slotted liner or wire-wrapped screen.

A clean completion fluid displacement is critical to effective removal of filter cake produced by an oil-base fluid. Surfactants and mutual solvents are required to reverse the wettability of the filter cake so that it can be dissolved by acid. In addition, the type of acid stimulation should be designed to dissolve the filter cake uniformly.

NOVADRIL®/NOVAPLUS®/NOVATEC.™ These are synthetic-base mud systems that can be formulated with non-damaging characteristics. NOVADRIL is a polyalphaolefin-base system. NOVAPLUS is an isomerized olefin-base system, and NOVATEC is a linear alpha olefin-base system. Each of these systems can be modified rheologically to have an elevated LSRV using NOVAMOD™ or VERSA-HRP for enhanced hole cleaning in high-angle wells. Synthetic drill-in fluids provide advantages similar to those provided by the oil-base fluids discussed above. They are, however, significantly more expensive than comparable oil-base systems. These fluids are approved for offshore cuttings discharge in many locations around the world — contingent upon local regulations.

The synthetic fluids find application in environmentally sensitive areas, particularly where the production zone is an easily damaged sandstone with high clay content. The filtrate from synthetic-base fluids generally does not disturb interstitial clays. Also, synthetic-base fluids provide significantly better shale stability for production intervals where shale sections are interbedded with the producing formation.

The synthetic/water ratios for these fluids can vary from 100/0 to 50/50. Generally, acid-soluble sized calcium carbonate, such as SAFE-CARB, is used as the weighting agent for wells completed with prepacked screens. These calcium carbonate drill-in fluids can weigh up to 12.5 lb/gal. For higher densities, barite, hematite or alternative-weight materials must be used (for special formations and applications) and usually the well must be completed with an assembly that will allow the weight material to be produced back through the slotted liner or wire-wrapped screen.

As with oil-base fluids, clean completion fluid displacement is critical to the effective removal of filter cake formed by synthetic fluids. Too, surfactants and mutual solvents are required to reverse the wettability of the filter cake so that it can be dissolved by acid. In addition, uniform dissolution of the filter cake depends on the proper design of the acid stimulation.

CHAPTER

21B Completion and Workover Fluids

Introduction

Clear, solids-free brines are the most commonly used fluids...

Completion and workover fluids are specialized fluids used during well completion operations and remedial workover procedures. These fluids must control not only subsurface pressure with density, but also must minimize formation damage during completion and workover operations.

The use of fluids that cause minimal formation damage can result in dramatically improved production. Most reservoirs are sensitive to any fluids other than those contained in them naturally. Therefore, any fluid introduced that is chemically and/or physically different from natural formation fluids may cause some reservoir damage. All wells are susceptible to formation damage to some degree, from a slight reduction in the production rate to complete plugging of specific zones. The objective is to use a fluid that causes the least possible damage to the producing zone, because the potential for permanent damage is greater during completion and workover operations than it is during drilling.

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Completion fluids are placed across the chosen payzone after the well has been drilled but prior to putting it on production. Workover fluids are used during remedial work in producing wells, usually as an attempt to enhance or prolong the economic life of the well.

Functions of completion and workover fluids are to:
• Control subsurface pressures.
• Minimize formation damage.
• Maintain wellbore stability.
• Control fluid losses to the formation.
• Transport solids.
• Maintain stable fluid properties.

The types of completion and workover fluids can be categorized into:
• Clear, solids-free brines.
• Polymer-viscosified brines with bridging/weighting agents.
• Other fluids: oil-base, water-base, converted muds, foam.

Clear, solids-free brines are the most commonly used fluids in completion and workover operations. Brines also are viscosified with polymers and may incorporate solids that can be dissolved later, such as acid-soluble calcium carbonate (SAFE-CARB™) or sized sodium chloride salt, for increased density or bridging to limit leak-off (fluid losses and invasion of the reservoir). Chloride- and bromide-base inorganic brines are the most widely used completion and workover brines. Recently, formate-base organic brines have been introduced as alternatives. Other fluid options are generally related to more conventional muds, even though they, too, may be formulated with acid-soluble bridging/weighting agents.

The primary selection criterion for an appropriate completion or workover fluid is density. Brine temperature should always be measured and recorded when checking fluid density, and the density corrected to the standard reporting temperature of 70°F. The densities of the common clear brines are listed in Figure 1.

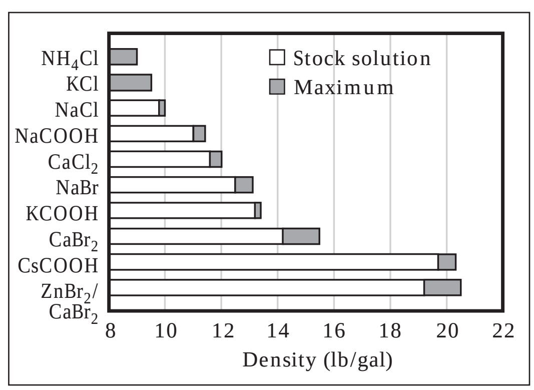

Figure 1: Density range for clear brines.

NOTE: High temperature causes thermal expansion of brines, which causes a reduction in density and hydrostatic pressure. Both temperature and pressure effects should be considered when selecting a brine with density appropriate for completion and workover fluids.

A related fluid category is drill-in fluids, which are fluids used for drilling and completing special reservoir sections such as horizontal wells (described in detail in the chapter on Drill-In Fluids). Drill-in fluids must provide the multifunctional requirements of drilling fluids; however, they must also minimize formation damage and be compatible with the formation and completion methods used.

Packer fluids are placed in the annulus of a well and remain above the packer for the life of the well. Packer fluids are usually modified completion brines or conditioned drilling muds. They are selected and formulated for a number of reasons: (1) to be non-corrosive to casing or production tubulars, (2) so that weight materials (or other solids) do not settle out on top of the packer, and (3) so that they remain stable and do not solidify over long periods of time.

Well Completion Overview

It is critical to match the completion method and fluid requirements with the formation characteristics.

While many important procedures are involved in the successful production of oil and gas from a petroleum reservoir, probably none is more important than the actual completion of the well. After a well has been drilled, there is only one opportunity to complete it properly. The completion affects all subsequent events during the entire producing life of the well.

The fluid used during the completion of a well has a significant impact on preserving the potential for satisfactory production. It is critical to match the completion method and fluid requirements with the formation characteristics.

Completing a well is essentially preparing it to produce oil and/or gas. The most common completion method is made up of the following steps:

1. The production casing is run into the well and cemented.
2. Flow-control valves are installed at the wellhead, and production tubing is run into the well and sealed inside the casing with a packer.
3. The well is perforated opposite the producing zone and production begins.

A typical well completion includes the following subcomponents (see Figure 2):

1. A wellhead assembly which seals and controls well pressure and flows at the surface (valves, spools and flanges).
2. A casing and tubing arrangement to provide zonal isolation and allow fluids to flow from the producing zone to the surface.
3. A bottom-hole completion assembly which seals and provides control over the producing zone.

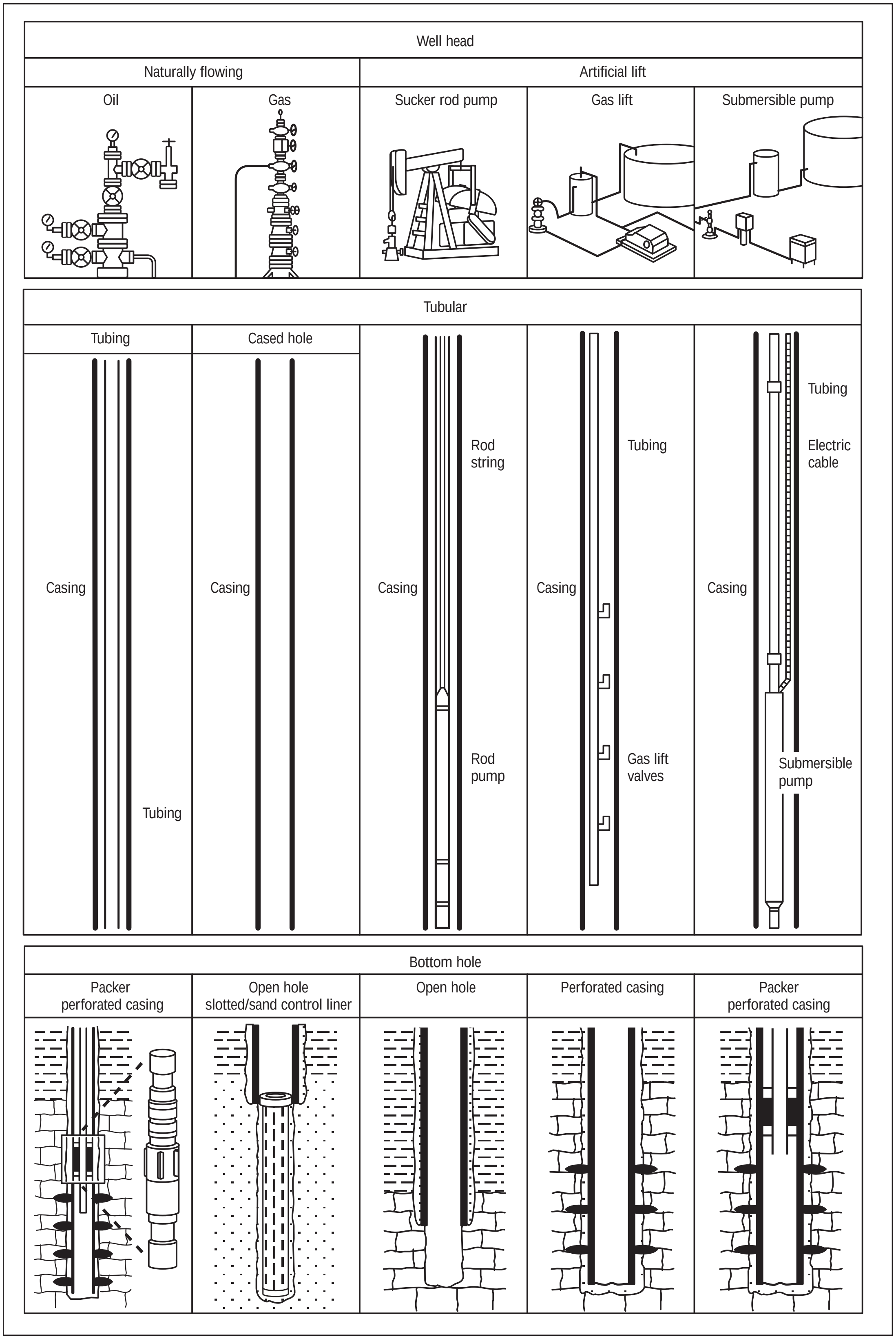

Figure 2: Various well completion alternatives (modified after Petroleum Production Operations).

Formation Damage

Minimizing near-wellbore reductions in permeability is critical to the success of any well completion...

Minimizing near-wellbore reductions in permeability is critical to the success of any well completion, as well as to preserving well productivity. Any activity, material or circumstance that reduces the permeability of a productive reservoir to the flow of hydrocarbons can be classified as formation damage. Wells requiring sand control are especially susceptible to near-wellbore damage since the primary technique for controlling sand production — gravel packing — requires potentially damaging fluids and gravel pack sand to come into contact with the reservoir. The best approach to a successful completion is to ensure that formation damage is minimal — from the moment the drill bit enters the payzone until the well is brought on production.

Damage mechanisms can be classified into the following general categories:

- Swelling clays or fines migration.
- Solids invasion.
- Wettability changes.
- Chemical reactions — scale precipitation.
- Emulsion or water blocks.

The degree of damage that results from these mechanisms depends upon the formation and the fluid used during workover or completion operations. To determine the best or most suitable type of fluid to be used in a well, its susceptibility to formation damage should be considered. For most reservoirs, any additional expense for a clear brine completion fluid would be regained through reduced formation damage and improved production.

Formation damage is often expressed numerically in terms of a unitless *Skin factor* (S). S is positive for a damaged formation and negative for an improved one. This value is calculated from production tests which measure changes in permeability and the radial depth of the altered zone. Another measure of productivity and formation damage is the Productivity Index (PI).

Clear Brines

Salt solution blends must be selected to be chemically compatible with one another.

In many instances, completely removing all solids from the completion and/or workover fluid will reduce formation damage. Clear, solids-free brines are the most common non-damaging completion and workover fluids. Brines used in completion/workover applications may be single-salt brines or brines that are mixtures of two or three different salt compounds. Brines are true solutions, meaning that they contain only water and dissolved salts (ions), with no undissolved solids. True solutions can be filtered without removing dissolved salt or dissolved solids.

Commonly used salts include: sodium chloride ($NaCl$), sodium bromide ($NaBr$), ammonium chloride (NH_4Cl), potassium chloride (KCl), calcium chloride ($CaCl_2$), calcium bromide ($CaBr_2$) and zinc bromide ($ZnBr_2$) blends. These salts may be used alone or mixed in specific combinations to form a brine with the required properties. Each salt is water-soluble, and when dissolved, yields clear brine — as long as it is below saturation. Salt solution blends must be selected to be chemically compatible with one another.

The advantages of using clear brines are that these solutions are:

- Solids-free.
- Inhibitive.

- Available in a wide density range.
- Capable of being reclaimed for reuse.
- Widely used and well known.

Considerations for selecting an appropriate clear brine for completion and workover operations include:
- Fluid density.
- Wellbore temperature.
- Crystallization temperature.
- Formation fluid compatibility.
- Corrosion control.
- Health, Safety and Environmental (HSE) characteristics.
- Economics.

DENSITY

...the primary criterion for fluid selection is density.

As mentioned earlier, the primary criterion for fluid selection is density. The formation pressure and temperature should be established or estimated before selecting a well-servicing fluid or any other chemicals. The fluid density is usually selected so as to exceed the reservoir pressure plus a predetermined safety margin. Commonly used overbalance levels are 200 psi (13.6 bar) for oil wells and 300 psi (20.4 bar) for gas wells. This should be sufficient to keep formation fluids from entering the wellbore due to swabbing pressure created by tool movement.

Permeability (md)	Required Underbalance (psi [bar])	
	Oil	Gas
>100	200 - 500 (13.6 - 34)	1,000 - 2,000 (68 - 136)
<100	1,000 - 2,000 (68 - 136)	2,000 - 5,000 (136 - 340)

Table 1: Recommended level of underbalanced pressure (after Bell).

In some cases, wells are perforated in an underbalanced pressure situation. The level of differential pressure is important in creating open, undamaged perforations. Past field experience is the best guide for selecting the optimum density balance. If the completion is underbalanced, then the fluid does not have to control total subsurface pressure, but only enough to allow surface equipment to control the underbalanced portion of reservoir pressure. If the completion is balanced or overbalanced, then the fluid density must be equal to or greater than formation pressure.

If a decision has been made to perforate underbalanced, Bell's criteria (1984) are recommended. To select an appropriate level of underbalanced pressure, see Table 1.

TEMPERATURE

Bottom-hole temperature, both static and circulating, is an important factor when selecting a well-servicing fluid and chemicals. All well-servicing fluids will be affected by temperature. The density of a brine decreases as the temperature increases due to the fluid's thermal volumetric expansion. As true solutions, brines are especially susceptible to density changes with temperature. If the hydrostatic pressure from a fluid column decreases due to thermal expansion, well control may become a problem. The density of the brine must be corrected for temperature and pressure. Temperature also affects the stability of various additives, as well as the corrosion rate. Standard additives or corrosion inhibitors may have to be changed, depending on the bottom-hole temperature and the anticipated length of exposure. For illustrative purposes, Figure 3 shows the effect of temperature on the density of $CaCl_2$ at atmospheric pressure.

All well-servicing fluids will be affected by temperature.

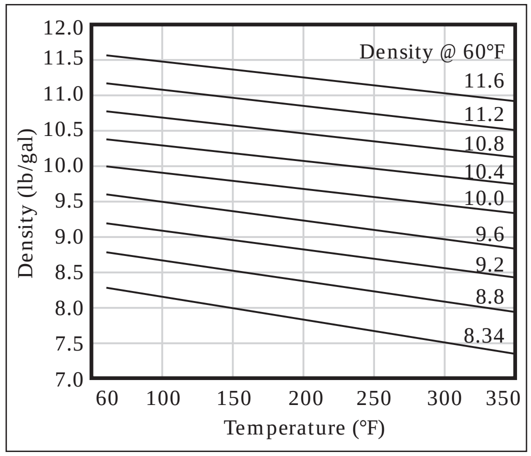

Figure 3: Density reduction due to thermal expansion ($CaCl_2$).

CRYSTALLIZATION TEMPERATURE

The seasonal ambient temperature must be considered when selecting a completion or workover fluid. If the temperature drops too low for the selected fluid, the fluid will crystallize or freeze. Each brine solution has a point at which crystallization or freezing occurs. Three different test methods and crystallization-point measurements are used (see Figure 4).

Each brine solution has a point at which crystallization or freezing occurs.

- **First Crystal To Appear (FCTA).** The temperature at which the first visible crystals start to form as the solution is cooled. It is the lowest point on the crystallization curve. It generally includes some "super-cooling" or cooling below the actual crystallization temperature.
- **True Crystallization Temperature (TCT).** As crystallization occurs, there is an abrupt increase in the temperature of the solution, which eventually levels off to a constant value before continuing to cool (showing a change in the slope of the crystallization curve). This higher, "flatter" temperature, which occurs after crystals form during the cooling cycle, is related to the thermodynamics of crystallization. This temperature "jump" is most pronounced in calcium salts.
- **Last Crystal To Dissolve (LCTD).** After crystals form, if the solution is allowed to warm, the warming curve will show a change in slope as the last heat-absorbing crystals disappear at the LCTD. LCTD is strongly influenced by contamination with trace amounts of other salts.

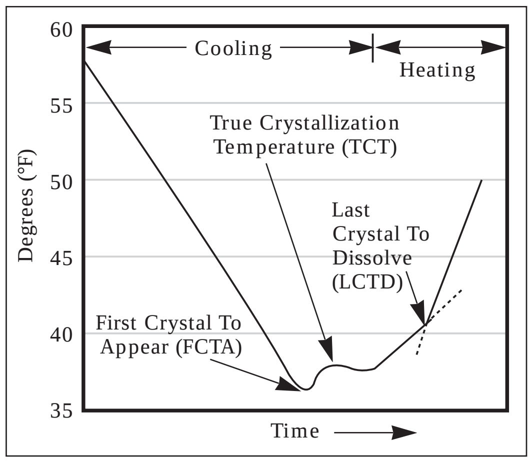

Figure 4: Crystallization-point designations.

The eutectic point is the lowest possible crystallization temperature...

Once the crystallization point of a fluid is determined, it can be reasonably assumed that the fluid will not crystallize or freeze at a temperature higher than the LCTD. Many operators specify a TCT that is 15 to 20°F below the lowest temperature to which a brine will be exposed. Since salt crystals have a smaller specific volume than the brine, brines do not expand during crystallization. Therefore, fluid lines, valves or pump heads will not rupture as they can when water freezes.

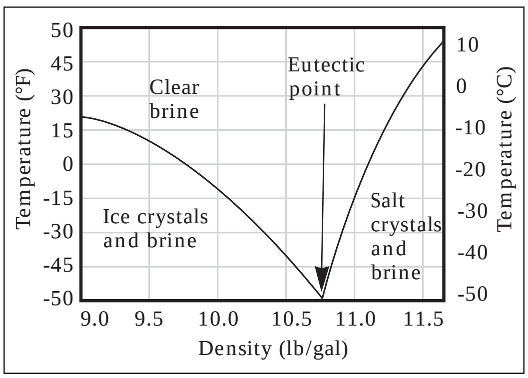

Figure 5: Effect of density on crystallization temperature ($CaCl_2$).

Several salt blends can be formulated for a particular density, each having a different crystallization temperature. Generally, the lower-crystallization-temperature brines will be more costly. The most economical brine is usually the formulation with the highest safe crystallization point. Figure 5 shows the crystallization temperature of calcium chloride as a function of increasing density or a higher concentration (% by weight) of salt.

As the salt concentration increases, the crystallization temperature decreases up to the eutectic point. In this region, the crystallization temperature indicates the point below which freshwater ice crystals form, producing a brine with a higher salt concentration. The eutectic point is the lowest possible crystallization temperature, and is indicated by an inflection point. At salt concentrations above the eutectic, the crystallization temperature indicates the precipitation of salt crystals (not ice).

Special brine formulations are used to accommodate seasonal changes in temperature. Summer blends are fluids appropriate for use in warmer weather. Their crystallization points range from approximately 45 to 68°F (7 to 20°C). Winter blends are used in colder weather or colder climates and have crystallization points ranging from approximately 20° to below 0°F (-7 to -18°C). At times, special formulations are required to provide an intermediate blend with a crystallization point between those of summer and winter blends. Figure 6 indicates the crystallization temperatures for various brines at different temperatures.

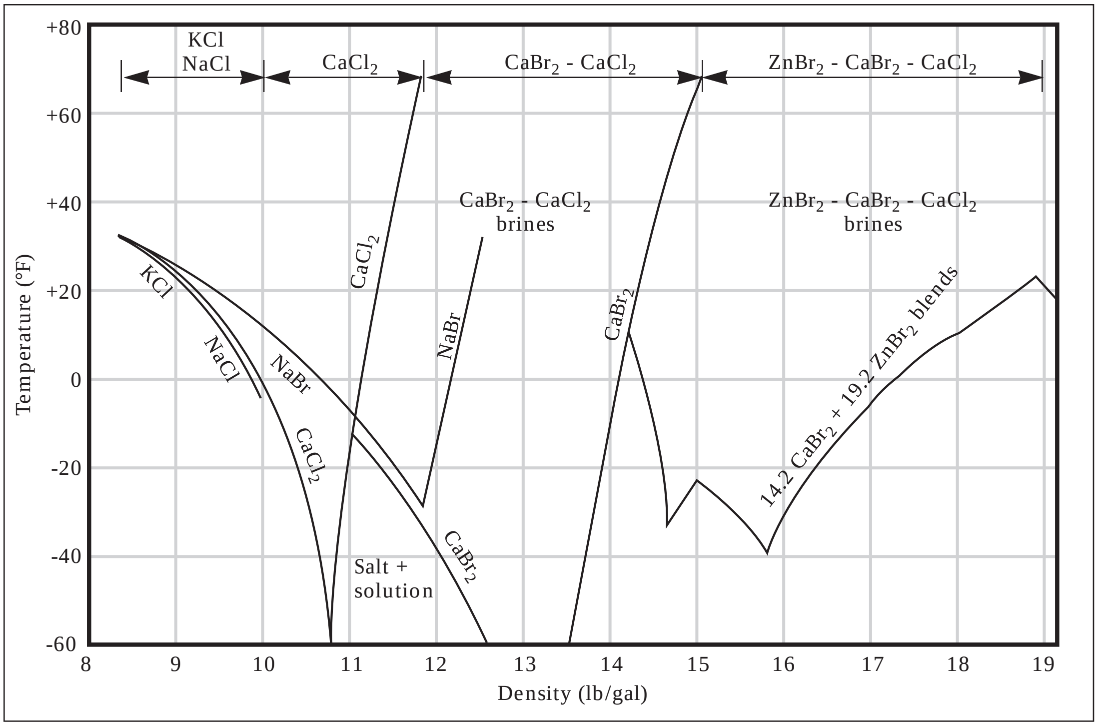

Figure 6: Crystallization temperatures of clear brines.

Incompatibility can cause formation damage...

Properly prepared brines are essentially solids-free, relying only on dissolved salts for density. One measure of the cleanliness (lack of solids) of a brine is its *turbidity* (the opposite of *clarity*). Turbidity is measured with light-scattering instruments called turbidity meters, and the unit of measure for turbidity is the Nephelometer Turbidity Unit (NTU). Even the cleanest well and drillstring will introduce solids into a completion and workover fluid, which can cause formation damage. For this reason, these clear fluids usually are filtered during the completion process and during reconditioning to remove solids and improve clarity (reduce NTUs). Also, see the Filtration section later in this chapter.

Compatibility with the Formation

An important selection criterion is whether the completion fluid is chemically compatible with the formation. By formation, we mean formation rock, water and hydrocarbons. Incompatibility can cause formation damage, which results in lost productivity or the need for remedial treatment.

Clay swelling and migration can block pore openings.

Scale is most often caused by the precipitation of multivalent cations...

Compatibility with formation clays

The chief concern is whether a completion brine will cause swelling, deflocculating and/or migration of formation clays, especially in "tight" high-clay sandstone. Clay swelling and migration can block pore openings. Both mechanisms can cause clay particles to detach from one another and from pore walls, and block pore openings. Pore-throat plugging caused by clay migration is the most common formation damage mechanism related to clay. To prevent clay swelling, the completion brine must have a composition and concentration of salts that are compatible with the particular formation. Some salts are better clay stabilizers than others, and can prevent clay swelling and migration. Two inhibitive salts frequently used in seawater for completions are 3% NH4Cl or 3% KCl.

Compatibility with formation water

The chief concern here is the formation of scale due to chemical reactions between completion brines and formation water. Scales are deposits of inorganic minerals. Scales can form due to mixing incompatible waters, solubility changes with temperature, solubility changes with pressure and water evaporation. Scale is most often caused by the precipitation of multivalent cations such as calcium (Ca^{2+}), magnesium (Mg^{2+}) and iron (Fe^{3+}). These cations can react with sulfate (SO_4^{2-}) and carbonate (CO_3^{2-}) anions to impair permeability.

Compatibility with formation crude and natural gas

The chief concern here is the formation of oil/water emulsions and/or sludge, both of which may block pores and cause formation damage. The emulsions, if allowed to be produced, also may cause upsets in surface production processing. Brine/crude incompatibility is especially important when heavy (low-pH) brines are used and during acid stimulation. Natural gas may contain significant quantities of CO_2 that cause calcium carbonate to precipitate if mixed with a high-pH brine that contains calcium.

Corrosion

Dissolved oxygen is the primary corrosive agent...

Salt solutions are often highly corrosive. Dissolved oxygen is the primary corrosive agent in sodium-, potassium-, calcium-chloride- or bromide-brine-base completion fluids. The solubility of oxygen in these brines decreases as saturation with the salt is approached. Even though initially it may contain dissolved oxygen, if the brine is not circulated during the completion in a manner that will replenish the dissolved oxygen, the corrosion rate will decrease as the oxygen is depleted.

Oxygen scavengers are not normally needed for brine fluids that will not be circulated. For brines that are circulated, injection of an oxygen scavenger such as SAFE-SCAV Na™ or SAFE-SCAV Ca™ into the flow stream, using a metering pump is suggested, along with increasing the pH to about 8.5 if possible.

...soluble iron...can lead to formation damage and will contaminate a solids-free brine.

High-density zinc bromide blends are used in very high-pressure situations for well control. These brines have a low pH. Raising the pH would be detrimental, causing precipitation. The acidity of the zinc can cause severe corrosion, unless proper protection is provided with an appropriate corrosion inhibitor. Most oilfield zinc bromide completion brines contain a thiocyanate (or other sulfur-base) corrosion inhibitor that forms a protective film on the surface of steel.

In addition to the monetary cost associated with corrosion itself, soluble iron resulting from the corrosion process can lead to formation damage and will contaminate a solids-free brine. If soluble iron comes in contact with formation connate water, a precipitate may form, reducing effective permeability.

Treating a completion fluid during reclamation for iron contamination normally involves adding a source of hydroxide (caustic or lime) to initiate precipitation, flocculating the solids, and then filtering out the precipitate. Certain oxidizer chemicals can also be used. This reclamation process is both difficult and time-consuming, and is not normally attempted at the rigsite.

Brine Systems

AMMONIUM CHLORIDE (NH_4Cl)

Ammonium chloride powder is a high-purity, dry, crystalline, inorganic salt used occasionally for its clay stabilization and swelling inhibition during workover and completion operations. It is available commercially as a dry-sack material, and can formulate clear fluids to a density of 9.0 lb/gal (SG 1.08). It is most often used (at 2 to 7%) in other clear-water completion fluids, such as seawater, as a clay and shale stabilizer in gravel pack and acidizing operations where its compatibility with hydrofluoric acid is a benefit.

POTASSIUM CHLORIDE (KCl)

Potassium chloride is used extensively due to its capacity to inhibit shales. It is available commercially as a high-purity, dry, crystalline inorganic salt. It can be used to formulate clear fluids to a density of 9.7 lb/gal (SG 1.16). It is used frequently (at 2 to 7%) in other clear-water completion fluids, such as seawater or sodium chloride, as a clay and shale stabilizer.

SODIUM CHLORIDE (NaCl)

Sodium chloride, or common table salt, a widely available commercial chemical, is an economical product for formulating clear workover and completion fluids to a density of 10 lb/gal (1.20 SG). Sodium chloride brines and sacked salt are readily available wordwide. Liquid, stock sodium chloride brine with a density of 10 lb/gal (SG 1.20) and a TCT of around 23°F is usually available. In areas where the brine solutions are not readily available, they can be prepared from dry-sacked, fine-evaporate-grade sodium chloride salt. Drilling-fluid applications for sodium chloride include: increasing density, increasing shale inhibition by decreasing water activity, reducing salt dissolution when drilling halite salt sections, reducing the freezing point of water-base fluids and reducing the potential for gas hydrate formation.

Sodium formate ($NaCOOH$)

Sodium formate is a commercial chemical which has gained acceptance as an alternative to chloride brines. It can be used in workover and completion operations that require clear fluids with a density up to 11.0 lb/gal (1.32 SG) and as a base liquid for drill-in fluids. For many applications, formate-base brines are considered to have better HSE characteristics than chloride and bromide brines. Formate brines also provide excellent thermal stabilization to natural polymers used as viscosifiers. Sodium formate is available as a dry-sacked material and as a stock liquid.

Calcium chloride ($CaCl_2$)

Calcium chloride can be used to prepare clear fluids to a density of 11.8 lb/gal (SG 1.41) or may be blended with heavier brines for higher-density applications. Liquid calcium chloride brine is available at 11.6 lb/gal (SG 1.39) with a TCT near 34°F, or it may be formulated from dry-sacked pellets or powder. Generally, anhydrous (94 to 97% pellets or 95% powder) should be used. These dry products should be carefully chosen to be sure that they do not contain contaminants such as iron or other heavy metals.

Calcium chloride has a positive heat of solution; i.e., heat is given off when dry calcium chloride is added to water. In fact, enough heat can be generated to cause boiling. Therefore, the amount of calcium chloride required to obtain the desired density should be determined prior to preparing the solution, since the resulting density will be lower at elevated temperature. When preparing calcium chloride brines from dry salt, the dry salt must be added very slowly to prevent boiling. Care should also be taken to protect skin from contact and dehydration which can lead to severe burns. Freshly prepared calcium chloride solutions are mildly alkaline and are considered mildly corrosive. A corrosion inhibitor will help lower the corrosion rate. Due to the divalent calcium, care should be taken to ensure compatibility with reservoir fluids.

Sodium bromide ($NaBr$)

Sodium bromide brine is used as a clear-brine workover and completion fluid for a density up to 12.8 lb/gal (1.53 SG). Although more expensive, it is used as an alternative to calcium-base brines when formation waters contain high concentrations of bicarbonate and sulfate ions. A wide range of densities can be obtained by blending sodium bromide brine with other brines. Sodium bromide is typically blended with sodium chloride to produce intermediate-density brines (10 to 12.5 lb/gal). It is available as a stock liquid at 12.5 lb/gal (1.50 SG), and as a sacked, powdered salt.

Potassium formate ($KCOOH$)

Potassium formate is available as a stock, clear fluid which can be used in workover and completion operations that require a density to 13.2 lb/gal

(1.58 SG) and as a base liquid for drill-in fluids. Potassium formate is a limited-availability product introduced as an alternative to chloride or bromide brines. Formate-base brines are considered to have better Health, Safety and Environmental (HSE) characteristics that chloride and bromide brines for many applications. Although more expensive than alternative brines, potassium formate brines show excellent thermal stabilization effects on natural polymers, and the potassium ion provides excellent clay stabilization and swelling inhibition of shales.

CALCIUM BROMIDE ($CaBr_2$)
Calcium bromide solutions can be prepared to a density of 15.5 lb/gal (1.85 SG). Calcium bromide is usually available as a 14.2 lb/gal (1.40 SG) stock, liquid product with a TCT around 0°F (-18°C). It also is available as a sacked, powdered salt. It is frequently blended with calcium chloride liquid or spiked with dry calcium chloride salt for greater flexibility and economics. Like calcium chloride, calcium bromide has a positive heat of solution and is hydroscopic. Similar precautions should be observed.

CESIUM FORMATE (CsCOOH)
Cesium formate is being produced as a 19.7-lb/gal (2.36-SG) stock liquid. Formate-base brines are considered to have better HSE characteristics than chloride, bromide and zinc brines for many applications. Although extremely expensive, cesium formate brines have certain advantages to zinc bromide, such as reduced corrosion. Cesium formate also produces excellent thermal stabilization effects in natural polymers, and provides clay stabilization and inhibits swelling of shales. Cesium may be considered toxic for marine discharge.

ZINC BROMIDE ($ZnBr_2$/$CaBr_2$)
Zinc bromide/calcium bromide brine, often referred to only as *zinc bromide*, is available as a stock liquid weighing 19.2 lb/gal (2.29 SG). It is 54.5% zinc bromide and 19.5% calcium bromide with a TCT near 10°F. It is very expensive and is frequently blended with additional calcium bromide or calcium chloride for greater flexibility and economics. The maximum density for zinc bromide blends is 20.5 lb/gal (2.46 SG). Zinc bromide has a very low pH — from 4.5 for a 16.0-lb/gal (1.92-SG) blend to around 1.5 for the stock, 19.2-lb/gal (2.29 SG) blend, so it must be handled with special care. It is also very corrosive. The discharge of zinc to the environment is often restricted, contingent on local environmental regulations. Due to the high concentration of dissolved salts and the low pH, zinc bromide brines must be handled with maximum precaution, using the same personal protection equipment required for corrosive chemicals.

Additives

SAFE-COR corrosion inhibitor is an amine-type additive designed to protect all oilfield tubular goods.

It is essential to have a thorough knowledge of the uses and limitations of each additive product.

WEIGHTING AGENTS

SAFE-CARB ground marble is a high-purity, acid-soluble calcium carbonate used as a bridging and weighting agent in drilling, drill-in and workover/completion fluids. It is preferred to limestone because it is generally purer, with a higher hardness. High purity provides better acid-solubility and high hardness provides a greater resistance to particle-size degradation. SAFE-CARB is available in three standard grind sizes: Fine (F), Medium (M) and Coarse (C).

CORROSION INHIBITORS

SAFE-COR™ corrosion inhibitor is an amine-type additive designed to protect all oilfield tubular goods. It helps prevent general corrosion attack on casing, tubing and downhole tools in contact with clear completion brines.

SAFE-COR C corrosion inhibitor is an amine-type additive designed to protect all oilfield tubular goods. It helps prevent general corrosion attack on casing, tubing and downhole tools in contact with clear completion brines. SAFE-COR C is a highly concentrated product designed and packaged for use in clear workover and completion brines.

SAFE-COR HT (High-Temperature) corrosion inhibitor is an inorganic, thiocyanate-base additive designed to protect all oilfield tubular goods. It helps prevent general corrosion attack on casing, tubing and downhole tools in contact with clear workover or completions brines. Although SAFE-COR HT was developed for use in fluids with a temperature range from ambient to 450°F (232°C), it is most effective in applications for temperatures in the 250 to 400°F (121° to 204°C) range. SAFE-COR HT is particularly effective in zinc-bromide-base completion fluids.

BACTERICIDE

X-Cide® 102 liquid bactericide is a 25% active glutaraldehyde and is a product of Petrolite Corporation.

Green-Cide® 25G liquid biocide is a 25% glutaraldehyde and is a product of Special Products.

pH MODIFIERS

Caustic soda is sodium hydroxide (NaOH) that can be used in monovalent brines as a source of hydroxyl ions to control pH. Other common names for sodium hydroxide are caustic, alkali and lye. It is a strong base which is extremely soluble in water and dissociates into sodium (Na^+) and hydroxyl (OH^-) ions in solution.

Citric acid ($H_3C_6H_5O_7$) is a commercial chemical used to reduce pH and remove calcium when drilling cement, to reduce the potential of crosslinking polymers (xanthan and others) from iron, and to prevent “fish-eyes” when mixing dry polymers to clear brines. Citric acid is a powdered organic acid and is less reactive than sulfuric or hydrochloric acid, thereby being somewhat safer to handle.

MagOx (magnesium oxide) is used to increase pH in divalent or complex brines. This sparingly soluble chemical generally forms a buffered pH of 8.5 to 10.0, depending on the ionic environment.

Lime ($Ca(OH)_2$) can be used to increase pH in certain divalent or calcium brines.

SCALE INHIBITORS

SI-1000™ scale inhibitor is a blended product containing a water-soluble, organic phosphorus compound. SI-1000 limits the deposition of mineral scales

SAFE-SCAV Na... reacts with, and eliminates, dissolved oxygen as a possible source of corrosion...

Lithium hypochlorite is a strong oxidizer used in water-base drill-in fluids as a breaker for various polymers.

such as $CaCO_3$ and $CaSO_4$ on downhole tubulars and associated surface equipment.

OXYGEN SCAVENGERS

SAFE-SCAV™ Ca oxygen scavenger is an organic, sulfur-free additive for use in calcium-base brines. It is a fast-acting material that is effective even at low temperatures.

SAFE-SCAV Na oxygen scavenger is a liquid bisulfite-base additive designed to be used in sodium- and potassium-base brines. It reacts with, and eliminates, dissolved oxygen as a possible source of corrosion in workover and completion fluids, as well as in packer and drilling fluids.

In addition to reducing oxygen corrosion, oxygen scavengers are essential to extending the temperature limit of polymers, such as FLO-VIS® (xanthan gum) and FLO-TROL™ (modified starch), used in the FLO-PRO® drill-in fluid system.

DEFOAMERS

SAFE-DFOAM™ is a blended, alcohol-base additive designed to reduce foaming and prevent entrained air in all fluids. It is particularly effective in workover and completion fluids ranging from 3% KCl-inhibited seawater to saturated brines.

VISCOSIFIERS

SAFE-VIS™ Hydroxyethylcellulose (HEC) viscosifier is a non-ionic, modified, high-molecular-weight, natural polymer. This easily breakable, non-fermenting polymer will increase viscosity and carrying capacity of workover and completion fluids and heavy brines and is not adversely affected by polar compounds or divalent cations such as calcium and magnesium, or by cement contamination. SAFE-VIS is a high-purity, dispersible powder that can be used in all standard completion brines.

SAFE-VIS E liquid viscosifier is a suspension of high-quality HEC polymer in a synthetic carrier. The low-toxicity synthetic carrier assists in dispersion of the HEC polymer and helps prevent lumps or fish-eyes so that the polymer rapidly and smoothly viscosifies without the need for high shear.

FLO-VIS premium-grade, clarified xanthan gum is the primary viscosifier for FLO-PRO drill-in fluid systems and can be used in most low- to medium-density brines. It produces elevated Low-Shear-Rate Viscosity (LSRV) and high, but fragile, gel strengths. These properties provide superior hole cleaning and suspension, improved hydraulics, reduced torque and drag, and they assist in minimizing filtrate invasion.

DUO-VIS® xanthan gum is a high-molecular-weight biopolymer used for increasing rheology in water-base systems. Small quantities provide viscosity and suspension for most low- to medium-density brines. DUO-VIS has the unique ability to produce a fluid that is highly shear-thinning and that develops a true gel structure.

BREAKERS

Lithium hypochlorite is a strong oxidizer used in water-base drill-in fluids as a breaker for various polymers. It is commonly available as a blended product referred to as lithium chlorine beach. It will break (reduce) the viscosity of xanthan polymer and HEC solutions, and will degrade starch. Hypochlorites are often used to help break or loosen the filter cake so that bridging particles can be produced back through sand-control liners or be more effectively acidified. The rate of reaction by a hypochlorite solution is directly related to the concentration of hypochlorite used, the length of exposure time, the temperature and the amount of material present to be oxidized.

Lithium, sodium and calcium hypochlorites are commonly referred to as bleaches. Lithium hypochlorite is the strongest of the three compounds on a per-pound basis, and lithium offers some degree of ion exchange, clay-stabilizing potential.

CAUTION: Never mix hypochlorite solutions with acidic solutions because poisonous chlorine gas will be produced.

DISPLACEMENT SPACER CHEMICALS

SAFE-SURF™ W wellbore cleaner is a surfactant blend formulated to remove Water-Base Mud (WBM) and residue from casing, pipe and rig equipment. This strong water-wetting additive helps displace mud and solids from tubulars so that a clean wellbore is obtained for the completion fluid displacement. The product can be used during oil-base mud displacements (after the solvent flush) to restore tubulars to a water-wet condition. SAFE-SURF W effectively disperses WBM solids, and unlike many surfactant blends, does not cause water-wet barite to "hard settle."

Displacements to Clear Fluids

When the well fluid is changed from drilling mud to completion fluid, the status of each component must be reviewed for any necessary actions.

Efficient well fluid change-out between drilling and completion operations is critical to minimize filtration time and to obtain clean, solids-free fluids. Clean, clear fluids are particularly important for high-productivity completions during which the formation will be exposed to overbalanced fluid columns. The most efficient and economical fluid changeover procedures include all of the circulating system in an integrated approach.

The well fluid system consists of the clear fluid and all the components involved in circulation, including storage tanks, solids-removal equipment, manifolds, pumps, discharge lines, return lines and the wellbore itself. When the well fluid is changed from drilling mud to completion fluid, the status of each component must be reviewed for any necessary actions.

An optimized, multistage displacement process can be used for the efficient removal of Oil-Base Mud (OBM), Synthetic-Base Mud (SBM) and WBM.

COMMON DISPLACEMENT PROCESSES

The displacement system is designed to maximize mud and solids cleanout in one pass of each of the multiple stages through the wellbore. Combining the use of the single-pass clean-out system with preparation of the mud, the wellbore and the fluid-handling equipment minimizes contamination of the completion fluid with drilling mud. Certain displacement processes or procedures are common to any type of fluid displacement, be they OBM/SBM or WBM.

Having a well-conditioned drilling fluid is the single most significant factor in obtaining effective mud displacement.

Following closely behind mud conditioning in importance is the need to employ pipe movement...

PREPARING THE WELLBORE

Having a well-conditioned drilling fluid is the single most significant factor in obtaining effective mud displacement. Low-viscosity spacers/flushes placed ahead of the completion fluid and pipe movement, coupled with mechanical scratchers/wall cleaners, can help remove gelled mud or filter cake. But there is no substitute for maintaining drilling fluid properties and flow rates that enhance the mobility of the mud, enabling displacement by the completion fluid.

The key parameters governing the mobility of the mud are: fluid loss which controls filter-cake buildup; and yield point and 10-min gel strength which indicate how readily the gelled, immobile mud regains its fluidity. Another way to improve mud mobility (to enhance its displacement capability) is through pre-job circulation to thoroughly fluidize the mud before displacement. To further improve its mobility, the viscosity and gels of the drilling fluid should be reduced, if possible, during the pre-job circulation period.

The greatest displacement efficiencies consistently occur at the highest displacement rates, regardless of the flow regime of the completion fluid. The highest displacement efficiency occurs under turbulent flow conditions. However, if turbulent flow cannot be achieved, displacement is consistently better at the highest rates attained under like conditions for similar brine compositions.

Frequently, turbulent flow is not a viable option, for instance, when hole and formation conditions create frictional pressures exceeding the fracturing gradient of the formation. Test data clearly indicate that even when turbulence is not possible, pump rates should be maximized.

Following closely behind mud conditioning in importance is the need to employ pipe movement, either rotation or reciprocation. Pipe movement helps break up pockets of gelled mud and loosens cuttings that may accumulate within the pockets.

Most wells are not truly vertical; some deviation of the hole is virtually assured as the well is drilled. The drillstring will not be positioned concentrically in the hole and will lie against the low side of the casing/liner wall at various points. Fluid flow is restricted or virtually non-existent at these points and solids will collect unless the drillstring is rotated. Rotation also distributes the flow path of the displacement fluid across the entire hole section.

Mechanical scratchers or scrapers attached to the drillstring can further enhance the beneficial effects of pipe movement.

PREPARING THE RIG EQUIPMENT

Preparation includes cleaning, draining and inspecting the surface fluid-handling equipment before the completion fluid is introduced. Drain tanks, slugging pits, mud lines, solids-control equipment and mud ditches should be thoroughly cleaned and dried.

USING SPACERS

The strategy of the displacement design is to displace the drilling mud in a "piston-like" manner. Simultaneously, surfactants are used to clean the casing/formation surfaces.

QUANTITY OF SPACER VOLUME (CONTACT TIME)

Closely related to the use of spacer fluids is the quantity of fluid used. The amount of time this fluid is in contact with a section of casing and formation fill has a direct influence on the amount of mud displaced.

The minimum recommended fluid volume and contact time vary somewhat, according to specific conditions.

...generally, contact time for all displacement fluids is about 10 min...

A primary function of spacers is to separate two potentially incompatible fluids.

But generally, contact time for all displacement fluids is about 10 min, with the displacement fluids pumped at the highest velocity possible without exceeding well-control limits. This means having a spacer fluid volume that gives an annular length of 500 to 1,000 ft at the largest annular diameter.

Viscosity/density differences

A primary function of spacers is to separate two potentially incompatible fluids. To do this, the spacer must be more viscous than either of the fluids it separates. A greater viscosity helps to retain the integrity of the spacer by enabling it to stay in plug or laminar flow at higher pump rates than the other fluids. However, some commingling with the other fluids will occur. Therefore, the spacer also must provide enough distance between the two fluids to keep them from coming into contact with one another.

Density differences do not affect displacement efficiency as significantly as the other factors listed previously. The recommendation regarding density differences is that it is advantageous when the completion fluid has a higher density than the drilling fluid.

Typical staged spacer systems

WBM displacement

1. First spacer — viscosified water with surfactant.
2. Second spacer — chemical wash.
3. Third spacer — viscous brine.
4. Circulate completion fluid after the spacers. Divert spacers to a separate pit. Continue to circulate and filter the completion fluid until the specifications for turbidity are reached.

OBM/SBM displacement

1. First spacer – base oil/synthetic preflush.
2. Second spacer – viscosified water spacer with surfactant.
3. Third spacer – chemical wash.
4. Fourth spacer – viscous brine.
5. Circulate completion fluid after the spacers. Divert the fluid containing chemical wash to a clean pit for salvage. Continue to circulate and filter the completion fluid until the specifications for turbidity are reached.

Reverse circulation

The density of the brine and the density of the fluid that it displaces will determine the flow path of the fluid during displacement.

The fluid should be pumped down the annulus and up the tubing or wash pipe when the brine is lighter than the fluid that is being displaced. There is a good reason for this flow direction. Under static conditions, heavier fluids will sink through lighter fluids due to the force of gravity. Even though a spacer may separate the two fluids, commingling can occur. When the fluids are pumped down the annulus, the heavier fluid must be below the lighter-weight fluid to help prevent such commingling.

Commingling may occur in the tubing, but this poses little problem in keeping the annulus clean. Conversely, the flow direction should be down the tubing and up the annulus when the brine is heavier than the fluid it is replacing. However, pressure-drop values should be calculated and compared to tubing burst strengths before a final decision is made.

Filtration

...every clear completion or workover fluid should be filtered to reach some low level of turbidity.

The filtration of clear fluids consists of removing dispersed solids or insoluble liquids from the brine. Since these particles are not uniform in size, various methods of removal can be used. Solids can plug the pore throats of permeable formations, resulting in formation damage. Regardless of which filtration system is used, every clear completion or workover fluid should be filtered to reach some low level of turbidity.

Modern well completions use a two-step filtration method for the inherently viscous, higher-density brines. The first stage uses a Diatomaceous Earth (DE) filter medium and the second stage uses wound-fiber cartridge filters to ensure the clean, non-damaging character of the fluids. Since filtering takes valuable rig and personnel time, the level of brine clarity (turbidity) desired is therefore an economic decision that requires an understanding of filter characteristics.

Only cartridge filters can ensure the desired absolute particle-size filtration efficiency.

Diatomaceous earth filters

Plate-and-frame diatomaceous earth filters have the advantages of low cost, near indestructibility and ease of internal inspection. They have the lowest volume-to-area ratio, which makes them the most efficient for the washing of filter cakes. This also gives them the smallest unfiltered portion remaining at the end of a cycle.

Diatomaceous earth is composed of the skeletons of microscopic, fossilized water plants called *diatoms*. This material tends to pack well and form a highly permeable, stable and incompressible filter cake that can remove large solids efficiently. As solids are removed, the filter cake thickens to some predetermined limit, then the cycle is terminated and the filter is cleaned and again precoated with DE. Cleaning and precoating the press usually takes 20 to 30 min, depending on the number of plates. DE is available in many different grades and particle sizes; most field applications use a coarse grade.

Cartridge filters

A cartridge filter unit is necessary downstream from the DE filter to remove any DE that bleeds through the DE press. Disposable wound-fiber cartridge filters are used alone, in combinations (series) or in tandem with other types of prefiltration equipment. When very large particles or high-solids concentrations are present, conventional solids-control equipment may be used as prefilters if they are thoroughly washed and cleaned prior to use. Only cartridge filters can ensure the desired absolute particle-size filtration efficiency.

Turbidity describes the relative clarity of a fluid.

The potential for contamination of clear brines is strong...

Turbidity testing

Turbidity describes the relative clarity of a fluid. The word comes from the word "turbid" which simply means cloudy, hazy or impure. Brines contain certain concentrations of dispersed, suspended solids such as silt, clay, algae, organic and inorganic matter, and various micro-organisms. Filtering eliminates most of this particulate and the better the filtration, the clearer (or purer) the water. As stated before, turbidity is recorded in nephelometer turbidity units. The lower the NTU reading, the better the fluid clarity.

Turbidity is an optical property of the interaction between light and suspended particles in a clear fluid. When a beam of light is passed through ultra-pure, deionized water, its path remains relatively undisturbed. When suspended particulate is present in the water sample, it will interfere with the light beam and either absorb the light energy and/or scatter the light.

Turbidity readings have no direct relationship to total suspended solids (recorded in ppm). The degree of turbidity in a sample is strongly dependent upon the particle size, shape and color; the host liquid's refractive index; the wavelength of the observation light; and the viewing geometries. Therefore, turbidity measurements are only proportional to mass concentrations if all these parameters are constant.

Contamination

The potential for contamination of clear brines is strong, given the chemical nature of the base salts and additives. Several of the more common contaminants already have been discussed, one being soluble and insoluble iron, created when uninhibited brine is pumped through metal piping systems.

Another major source of contamination is unfiltered solids remaining in the wellbore. These solids may be drilled formation solids, oil, condensate, grease, pipe dope or impurities in the base salt. Regardless of their source, they usually create problems with filtration and can potentially cause formation damage. Contamination can also be caused by the chemical reactions of brines, additives and surfactants with formation rocks, hydrocarbons or formation waters.

Brine Polymer Systems

Another category of completion fluids is brine/polymer systems. These systems use polymers for viscosity, weight material support and fluid-loss control. They are formulated in brine water for inhibition, using sized particles as bridging material to help prevent loss of filtrate to the formation. They are often used in workover operations, where open perforations would allow high fluid losses to occur. Specially designed brine/polymer systems can be classified into three major types:

- Acid-soluble brine/polymer systems, usually calcium carbonates.
- Water-soluble brine/polymer systems, usually sized salt.
- Oil-soluble resin brine/polymer systems.

The use of barite is excluded, since it is not soluble in acid, water or oil.

The key to sealing off a production zone is a proper mixture of bridging solids, colloidal solids, and sub-colloidal particles.

Bridging/Weighting Agents

Fluid-loss control in brine/polymer systems is achieved by using a blend of solids and polymers. The key to sealing off a production zone is a proper mixture of bridging solids, colloidal solids and subcolloidal particles. This combination creates an impermeable bridge and filter cake across the face of the production zone, minimizing filtrate invasion. Bridging agents are selected so that they are soluble in either acid, water or oil.

Coarser particles tend to bridge on the pore spaces around the wellbore. This reduces the porosity and permeability at the surface of the wellbore. This bridge is then sealed by colloidal and subcolloidal particles, which plug the fine inter-particle spaces of the bridging solids, allowing only a small amount of clean, solids-free liquid to enter the formation. Normally, the colloidal and subcolloidal particles are a combination of polymers, modified starches and calcium lignosulfonate. Some of the more common soluble weighting agents for well-servicing fluids and their corresponding specific gravities are presented in Table 2.

Bridging/Weighting Agents	Specific Gravity
Calcium carbonate ($CaCO_3$) (SAFE-CARB)	2.7 - 2.8
Sodium chloride (NaCl)	2.1 - 2.2
Iron carbonate (Fe_2CO_3)	3.70
Hematite (Fe_2O_3) (FER-OX®)	5.00
Oil-soluble resins	Variable

Table 2: Specific gravity of removable weighting/bridging agents.

VISCOSIFYING AGENTS

Brines have a natural viscosity that depends on the concentration and types of salts in the blend. Typical base brine viscosities can be found in Table 3.

From this table, it is evident that the Yield Points (YP) of stock, clear brines are very low. This reduces their ability to carry or suspend solids. However, by increasing the pump rate, the annular velocity may be enough to carry solids out of the well, especially in the higher-density brines. Once the brine is circulated back to the surface, it can be processed and filtered before being pumped back down the hole.

Viscosifying agents or polymers are used to overcome the low carrying capacity of brines and to control fluid losses (leak-off) to the formation. Generally, the higher the viscosity of the brine, the lower the leak-off. The ability of a polymer to function properly over a wide range of environmental combinations is important.

Generally, the higher the viscosity of the brine, the lower the leak-off.

Brine	Density (lb/gal)	Funnel Viscosity (sec/qt)	PV (cP)
Freshwater	8.33	26	1
NaCl	10.0	28	—
NaBr	12.5	27	—
$CaCl_2$	11.6	34	9
$CaBr_2$	14.2	31	—
$CaCl_2/CaBr_2$	15.1	52	40
$CaBr_2/ZnBr_2$	19.2	41	40

Table 3: Typical brine viscosities.

The ability of each polymer varies widely, and depends upon:
- Temperature/viscosity relationships.
- Compatibility with base brine.
- Thermal stability.
- Susceptibility to shear degradation.
- Potential for formation damage.

The suspending ability of a polymer solution is related to rheology. The ability of a fluid to suspend particles is related to the low-shear-rate viscosity. Solutions showing the most pseudo-plastic behavior also perform best in sand-settling tests. Table 4 shows the characteristics of the most common water-soluble polymers.

Polymer Type		Viscosity	Filtration Control	Suspension Properties	Acid Solubility	Temperature Stability	Brine Tolerance
HEC (SAFE VIS)	NI	Excellent	Poor	Poor	Excellent	275°F (135°C)	Excellent
HEC (SAFE VIS E)	NI	Excellent	Poor	Poor	Excellent	275°F (135°C)	Excellent
Xanthan gum (DUO-VIS)	A	Fair	Poor	Excellent	Good	275°F (135°C)	Fair
CMC	A	Good	Good	Fair	Poor	250°F (121°C)	Poor
Polyanionic cellulose (POLYPAC®)	A	Poor	Good	Poor	Poor	250°F (121°C)	Poor
Starch derivative (FLO-TROL)	NI	Good	Good	Good	Good	250°F (121°C)	Good
Guar	NI	Excellent	Poor	Poor	Fair	250°F (121°C)	Good

NI = Non-ionic. A = Anionic.

Table 4: Characteristics of water-soluble polymers used for viscosity, suspension or filtration control.

Hydroxyethylcellulose (HEC)

HEC is almost universally accepted as being the least damaging polymer viscosifier for clear brines or for systems where prolonged suspension of solids is not essential. Being non-ionic, HEC's utility extends to almost all brine types. For a good quality HEC, the yield time and mixing procedure will vary with the brine composition, concentration, free water, temperature and shear, as shown in Table 5.

Xanthan gum

Xanthan gum, a high-molecular-weight natural polymer, is produced by the bacterial fermentation of the microorganism *Xanthomonas Campestris*. This polymer is slightly anionic, but it is still compatible with most electrolyte solutions. The M-I trade names for xanthan gum are DUO-VIS and FLO-VIS. One of the most important properties of xanthan gum is its ability to provide suspension properties (gels and low-shear viscosity), something most other polymers do not provide. Solutions of xanthan are pseudo-plastic and shear-thinning, so that shear stress increases as shear rate is reduced.

...xanthan polymer is stable to around 275°F in most brines...

One of the most important properties of xanthan gum is its ability to provide suspension properties...

Xanthan gum is used where suspension of solids and carrying capacity are necessary and where high downhole temperatures preclude the use of HEC. Xanthan is characterized by a flatter temperature-vs.-viscosity curve. Although all polymer systems lose some viscosity and prolonged stability at higher temperatures, xanthan polymer is stable to around 275°F (135°C) in most brines or up to about 300°F (149°C) with the addition of thermal stabilizers.

The rheology of xanthan polymer solutions provides excellent suspension of calcium carbonate and salt-base bridging agents. Low plastic viscosities provide good flow properties at high solids loading. The shear-thinning effect (pseudo-plastic behavior) provides lower friction pressures at high pump rates. Xanthan polymers are degradable with hypochlorite or acids, as well as with temperature and time.

	Hours to Develop Full Viscosity		
Brine	At 75°F	At 150°F	At 200°F
$CaCl_2$ (10 lb/gal)	0.1	<0.1	<0.1
$CaCl_2/CaBr_2$ (12.5 lb/gal)	1.0	0.5	<0.5
$CaCl_2/CaBr_2$ (15.0 lb/gal)	5.0	1.0	0.5
$CaBr_2/ZnBr_2$ (16.5 lb/gal)	N/A	5.0	2.0

Table 5: HEC viscosifier hydration rate.

Health, Safety and Environmental Considerations

Completion fluids are often regulated differently from drilling fluids...

High-density brines have unique chemical properties, and thus should be handled with more caution than most drilling muds. The hygroscopic brines can quickly draw water from whatever they contact and can burn skin or sensitive tissue. Historically, incidents have been related to splashes. Personal protective equipment is necessary when working with these systems (refer to the Material Safety Data Sheet (MSDS) for specific personal protective equipment and precautions). Completion fluids are often regulated differently from drilling fluids with respect to environmental and disposal issues. Consult the local regulatory authority for the specific environmental regulations regarding the use and discharge of completion and workover fluids.

Transporting

To help maintain the density and prevent contamination of brine during transport, ensure the tanks on boats or trucks are clean and dry before loading. Tie fluid-transfer hoses securely and continually monitor tanks and pump hoses for leaks or breaks. Carefully measure and record the volume loaded into the boat or vacuum truck tanks. Strap the tanks on boats or trucks and check the density of the brine being shipped. Have all parties (service company, transportation company and customer) witness and agree on the volume and density. These measures will help explain any losses in density and/or gains or losses in volume once the material is received at the rigsite.

Preparing the Rig for a Clear Brine

Ensuring a successful completion or workover operation requires following certain precautions to help prevent fluid loss due to contamination and equipment leaks.

Before receiving the fluid, wash and dry all pits and/or tanks to be used in handling the fluid. Flush all lines and pumps with seawater or freshwater. Disconnect or plug all water and diesel lines leading to pits or tanks. Tie down fluid-delivery hoses to prevent accidents or loss of expensive fluid. Hold a meeting to establish the methods of emergency communication with boat or truck personnel to allow for rapid shutdown of fluid transfer if problems develop.

While receiving the fluid, monitor the tanks, pumps and delivery hoses for breaks or leaks. Monitor pits and dump valves for leaks. Maintain communications with the boat or truck for estimated volumes pumped.

After receiving the fluid, mark the fluid level in pits and monitor them for losses. Inspect pits and dump valves for leaks. Use completion fluid to flush seawater or freshwater from all lines, pumps, solids-control equipment and degassers. Again measure and record brine volume and density received, having all parties agree to these values.

...pipe dope can contaminate clear brine, causing formation damage and filtering difficulties.

During completion or workover operations, monitor fluid level in pits and dump valves for losses. Monitor pits for accidental water additions. Restrict the use of pipe dope to a light coating on pin ends only, since pipe dope can contaminate clear brine, causing formation damage and filtering difficulties.

Other Completion and Workover Fluids

Oil-base fluids

Oil-base fluids are sometimes used as completion and workover fluids. These are generally invert emulsions where calcium chloride brine is emulsified in some type of oil, so that the oil is the external or continuous phase. These fluids are minimally damaging to certain formations and the filtrate is also oil, so that sensitive clays are not affected. The thin, low-permeability filter cake also limits solids from invading the producing zone. Oil-base fluids are often formulated with acid-soluble bridging/weighting agents so that any residual filter cake or solids can be acidized for removal.

Oil-base fluids are sometimes used as completion and workover fluids.

The use of oil-base fluids offers several advantages. These include:
1. Relatively low cost and wide availability.
2. High-temperature stability.
3. Wide density range.
4. Low corrosion.
5. Maximum inhibition.
6. Minimum filtrate invasion.
7. Resistant to contamination

Oil-base fluids do have potential disadvantages. For example, they may:
1. Be restricted for environmental reasons.
2. Change the wettability of the formation.
3. Cause emulsion blocks.
4. Damage dry gas sands.
5. Increase safety concerns.

Stricter environmental regulations are making it more difficult to use oil-base fluids in some situations without the use of expensive handling equipment and higher disposal costs.

Water-base fluids

Water-base fluids are less frequently used as completion and workover fluids and cover a variety of systems. The term “water-base” refers to systems that are formulated from water or brine. The aqueous phase can range from freshwater to a high concentration of soluble salts. Water-base fluids can be divided into these categories:
1. Conventional water-base muds.
2. Clear-water fluids.
3. Brine/polymer systems (mentioned earlier).
4. Clear brines (mentioned earlier).
5. Foam.

M-I does not recommend using conventional water-base drilling mud for completions or workover operations unless it is known absolutely that muds will not damage the formation during these operations. Such muds may appear attractive, considering that they are readily available, inexpensive and require minimum treatment. However, they have proven to be disastrous, causing permanent damage to many producing formations.

Most water-base drilling muds rely on clays such as bentonite for viscosity, weight material support and fluid-loss control. Clays are compressible and potentially damaging. In addition, most water-base drilling muds contain potentially damaging fine drill solids and weight materials. The filtrates usually are freshwater or water of very

These so-called "clean" fluids can be very damaging if the proper steps are not taken.

low salinity. The fresh filtrate could lead to swelling and/or migration of clays and silt in the formation. Since the filtrate is water and usually contains reactive chemicals, water blocking or emulsion blocking are also possibilities. Any or all of these characteristics together may cause severe, permanent damage. For many formations, there is no practical method for preventing damage of these types when using water-base drilling muds.

A similar, but distinctly different, category of a water-base system is drill-in fluids. These are specially designed, non-damaging fluids used for drilling and completing special reservoir sections such as horizontal wells (described in detail in a separate Drill-In Fluids chapter). Not only must drill-in fluids provide the multifunctional requirements of drilling fluids, but also they must be minimally damaging and compatible with the formation and completion methods.

Clear-water fluids

This group includes waters of diverse origins such as seawater or produced brines with different salts in solution. Although formation water is considered a clean, ready-to-use fluid, many times it contains fine solids, treating chemicals, paraffin, asphaltene or scale. All of these compounds, if not controlled, may cause serious formation damage. The water should be filtered before use. Seawater is frequently used in coastal areas due to its availability. Depending on salinity, it may be necessary to add NaCl, KCl or NH_4Cl to avoid clay swelling.

These so-called "clean" fluids can be very damaging if the proper steps are not taken. They do not contain bridging or fluid-loss control additives, and usually contain (or are contaminated by) potentially damaging solids or multivalent ions, such as Ca^{2+}, Mg^{2+} and Fe^{3+}. Seawater and bay water contain micro-organisms such as bacteria and plankton (known plugging materials). Seawater may have a high sulfate concentration that can plug the well with scale. Freshwater may damage by allowing clays to hydrate. Dissolved iron may be present, which will form iron hydroxide, a flocculating compound which may further consolidate clay and silt to plug pores.

Foam

Foam is used occasionally as a circulating fluid for workover and completion operations. It has particular application in low-pressure reservoirs for sand clean-out. Foam is a very good workover medium, due to its low density, which allows an underbalanced working environment and because of its high carrying capacity and effective viscosity.

Well Data Guide for Completion Fluid Section

The following table summarizes information necessary to design a completion and its appropriate completion fluid.

Company name: **Address:**			**Field:** **Well:** **Field location:** County: State: Country: Offshore Land Inland waters **Type** Oil Gas Water injection **Well:** Gas injection Steam injection Other		
Country of final material destination:			Number of wells:		
Number of copies of bid required:			Scheduled date of first completion:		
Please attach diagram showing anticipated well completion scheme					
	Size	**Weight**	**Grade**	**Thread**	**Depth**
Casing					
Liner					
Tubing					
Well head	Manufacturer: Model:		Size: Rating: Trim:		Type of connector: Top: Wing:
Pressure data	**Bottom hole**	**Surface**	**Treating**	**Testing**	
	Static:	Static:	Flowing:	Surface:	
	Flowing:	Flowing:			
Temperature data	**Static bottom hole:**		**Ambient surface:**	**Flowing surface:**	
Production data	**Completion fluid**		**Perforation depth**		
	Density:	Type:	TVD:	Measured:	
	% H_2S:	% CO_2:	Oil gravity	S.G. gas	S.G. water
			GLR	GOR	
	Desired production rate		Sand/paraffin etc. (approximate volume or %)		
Corrosion data	Anticipated Yes No	Inhibitor treatment: Amines: Yes No		Specific type:	
	Injection method		Continuous	Batch	Other
	Special heat treatment, materials or coatings to be applied				
Gas lift data	**Static fluid**	**Gas pressure**	**Flow line**	**Other**	
	Level:	Knock out available	Size:	Lift gas gravity:	
	Gradient:	Maximum operating	Length:	Separator pressure:	
Safety valve data	Controlled from		If subsurface controlled		Setting depth
	Surface		Differential pressure operated		
	Subsurface		Ambient pressure operated		

Table 6: Well data guide.

Coring Fluids

Introduction

When designing a coring fluid, it is imperative that a complete understanding of the geological interpretation requirements of the coring program be understood before the coring fluid is built. It is equally important when designing a coring fluid to make sure that wellbore stability and safety requirements are met.

Coring

Coring involves the use of special bits… to retrieve cylindrical sections…of formation.

Coring involves the use of special bits (natural-diamond and PDC) to retrieve cylindrical sections (cores) of formation. Cores are the largest samples obtained from subsurface formations and are generally recovered in 30- to 90-ft (9- to 27-m) sections. These cores provide the most reliable information concerning lithology, hydrocarbon saturation, texture, rock structure, fossil content, dips and tectonic disturbance. Laboratory analysis of cores determines valuable information on porosity, permeability, hydrocarbon content and salinity of connate water. Pressure coring, the retrieval of rock samples under reservoir pressure, is desirable in formation evaluation and secondary or tertiary recovery projects where the best possible fluid saturation data are required. Directionally oriented coring provides important information for reservoir and geological mapping.

Coring significantly increases the cost of drilling a well. Consequently, the core must provide the anticipated economic and geological information to justify the cost of the project. Generally, a coring fluid should:

- Consistently provide core material within an uninvaded center.
- Provide a filtrate that does not alter connate water saturations or rock wettabilities, nor affect geological interpretation.
- Provide all of the fluid properties required to cut and retrieve the core from the wellbore.

Coring Fluid Types

…there are three different types of coring fluids commonly used.

Generally, there are three different types of coring fluids commonly used. These include a modification of the existing drilling fluid, a "bland" water-base coring fluid and an oil-base coring fluid. An example of each of these coring fluid types will be discussed later in this chapter.

There are a number of different items that need to be addressed if a coring fluid is to meet the geological objectives of the coring program. The following items may be of importance in designing the optimum coring fluid:

- Low High-Temperature, High-Pressure (HTHP) filtration.
- Bridging materials.
- Filtrate composition.
- Organic material.
- Tracers.

Low HTHP filtration is a very good indicator of the coring fluid's ability to provide a tight filter cake on the core. This "tight" filter cake is extremely important to minimize fluid invasion. In water-base muds, low HTHP filtration can be achieved by using prehydrated bentonite, POLYPAC® and SP-101®. In

Bridging materials ***are extremely important in minimizing core invasion.***

oil-base fluids, low HTHP filtration can be achieved by using a combination asphalt-type additives, such as STABIL-HOLE® and VERSATROL® I.

Bridging materials are also extremely important in minimizing core invasion. Calcium carbonate is an excellent bridging agent. The quantity and the particle-size distribution of the bridging agent are important. The selection of the particle size of the bridging agent to be used is based on the pore-throat diameter of the formation to be cored. The general rule of thumb is one-half to one-third of the largest pore throat diameter. Laboratory and field experience indicate that a minimum of 30 lb/bbl of bridging agent is required. Some formations may require higher concentrations of bridging agent to provide a core with an uninvaded center.

The **filtrate composition** of the coring fluid is determined by the geological objectives of the program. These objectives can require that the fluid be freshwater, brine-base or oil-base, depending on the type of analysis that will be performed.

Organic materials in a coring fluid can adversely impact the geological interpretation of the core. The requirements of the coring program must be understood if organic material is used in the fluid's composition. In any coring project, it is important to take samples of the coring fluid and the materials used in its construction.

Tracers are added to coring fluids to quantify the amount of filtrate invasion and to verify that core centers are uninvaded. Nitrates and bromides are commonly used tracers in water-base coring fluids. Iodonaphthalene and other special-application tracers have been successfully used as tracers in oil-base coring.

Conversion of a Drilling Fluid to a Coring Fluid

In many situations, conversion of the normal drilling fluid to a coring fluid is all that is required. For high-density coring situations, the existing system is usually converted to the coring fluid. This is most common in exploratory situations where the cost of moving additional materials to build a coring fluid would be prohibitive. If a water-base drilling fluid is to be converted to a coring fluid, the HTHP filtration values can be lowered and additional sized bridging material can be added to the system. Normally, only the addition of bridging materials is required when oil-base muds containing asphalt are used for coring. In either water- or oil-base fluid, tracers may need to be added to the fluid. The coring fluid must still provide the properties that are required to maintain a stable wellbore.

Water-Base, "Bland" Coring Fluid

The use of a bland coring fluid is particularly important when organic materials are omitted from the fluid.

The use of a bland coring fluid is particularly important when organic materials are omitted from the fluid. The general design of a bland coring fluid includes bentonite, fluid-loss-control polymers and calcium carbonate. The following formulation is a typical, "bland," freshwater coring fluid with a mud weight of 9.2 lb/gal:

M-I GEL®	10 lb/bbl
POLYPAC® UL	3.75 lb/bbl
POLYPAC (regular)	0.25 lb/bbl
SP-101®	0.5 lb/bbl
LO-WATE™	65 lb/bbl

Typical properties:

PV (cp)	25
YP (lb/100 ft^2)	30
Gels (lb/100 ft^2)	6/12
API (cm^3/30 min)	4.0
HPHT (cm^3/30 min)	10.0

The following formulation is for a 10-lb/gal, 3% KCl "bland" coring fluid:

M-I GEL®	9 lb/bbl
POLYPAC® UL	2.75 lb/bbl
POLYPAC (regular)	0.25 lb/bbl
Potassium Chloride	10.5 lb/bbl
LO-WATE™	60 lb/bbl
M-I BAR®	28 lb/bbl

Typical properties:

PV (cP)	27
YP (lb/100 ft^2)	25
Gels (lb/100 ft^2)	6/23
API (cm^3/30 min)	4.4
HTHP (cm^3/30 min)	11.0

Mineral-Oil Coring Fluid

Oil-base coring fluids are normally used in oil-producing formations. The design of oil-base coring fluids limits the use of emulsifiers; they are generally water-free. Refer to the VERSACORE™ discussion in the Oil-Base Systems chapter for recommendations and formulations.

The following formulation is for a typical 10.3-lb/gal, water-free, VERSACORE mineral-oil coring fluid formulation:

Mineral oil	0.75 bbl
VG-HT™	8 lb/bbl
Lime	3 lb/bbl
VERSAMOD™	2 lb/bbl
STABIL HOLE®	30 lb/bbl
LO-WATE™	170 lb/bbl

Typical properties:

PV (cp)	24
YP (lb/100 ft^2)	11
Gels (lb/100 ft^2)	9/19
HTHP (cm^3/30 min)	2.0

Introduction

Air or gas drilling is all-inclusive terminology, encompassing four distinct but related systems...

...air plainly has the least density of all possible circulating fluids...

Air or gas drilling is all-inclusive terminology, encompassing four distinct but related systems that use volumes of compressed air (or gas) as all or part of the circulating medium. The four systems — dry air (dust), mist, foam and aerated mud — individually offer exceptional drilling performance and production advantages when compared to traditional fluids, but in applications that are considerably more restricted. It is easy to identify potential production while air (dust) and mist drilling and it is common to drill with produced flowing gas and oil.

As illustrated in Figure 1, air plainly has the least density of all possible circulating fluids, thus allowing for the greatest reduction in differential pressure. The high negative differential pressure achieved with air (dust) systems translates into substantially higher penetration rates and more footage per bit. Circulating with variations of compressed air exerts less pressure on downhole formations than conventional mud systems, making the technique particularly applicable in drilling lost-circulation zones.

The ability to achieve density less than that of oil, plus faster drilling rates, longer bit life, lower chemical requirements and the expansion of underbalanced drilling, gives air-base systems clear economic advantages over their liquid counterparts.

On the other hand, the viable applications for any of the air-base systems are somewhat limited and mainly reserved for development wells in mature theaters where the geology is well known and predictable. Since air (dust), mist, foam and aerated mud do not generate the bottom-hole pressure required to safely drill pressured formations, well-control considerations make air-base systems unsuitable for some situations. Furthermore, most air-base systems permit the entry of formation fluids that will be encountered in most wells, and present concerns with well control, fluid handling and the threat of downhole fires. Because of wellbore stability, variations of air (dust) drilling systems are generally not applicable in areas where weak or fractured formations result in wellbore sloughing or cavings. Hence, these techniques are used most often in hard, dry and competent formations.

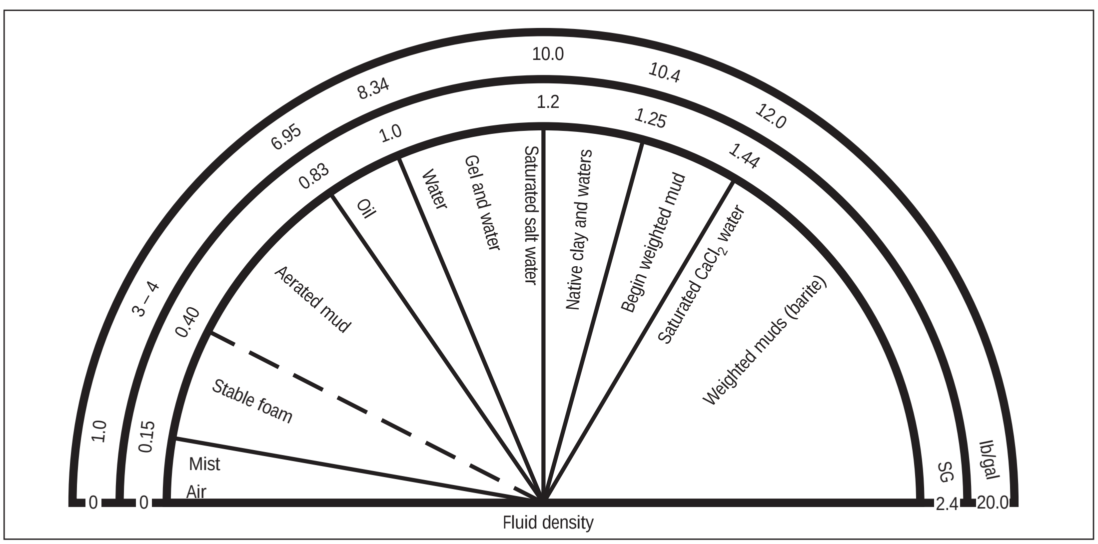

Figure 1: Range of air drilling — drilling fluid density (modified after Hutchinson and Anderson).

Following is a discussion of the four air-base drilling systems, distinguished by the approximate volume of air used in the drilling operation. Each of these systems has specific applications with distinct advantages and disadvantages.

Air (Dust) Drilling

Air or dust drilling... maintains the lowest possible downhole pressure.

Air or dust drilling, in which the circulating medium is air only, maintains the lowest possible downhole pressure. Also, this technique can only be used when the formation is completely dry or the water influx slight enough to be absorbed by the air and cuttings annular stream. Dust drilling is most applicable in hard, strong and competent formations and in environments where severe lost circulation and unacceptably low penetration rates are the norm. Optimum drilling rates are achieved and the cuttings return to the surface as a cloud of dust.

Besides very high penetration rates, the elimination of lost circulation and significantly lower bit costs, circulating with pure air/gas also accommodates continual formation tests and dramatically minimizes damage to water-sensitive producing zones. Further, air (dust) drilling results in lower water usage, low mud and/or chemical costs and less environmental impact.

Air (dust) drilling, however, presents drawbacks that significantly limit its range of applications. As mentioned, air (dust) drilling produces very small cuttings, is intolerant to water and upon encountering wet formations can accumulate into what is commonly referred to as a “mud ring.” When this occurs, the build up of sticky cuttings in the annulus continues, eventually restricting the airflow. This can result in stuck pipe or a downhole fire (burn-off).

The threat of hole erosion makes air (dust) drilling unsuitable for unconsolidated, brittle or high-dip formations. This procedure should not be employed in similarly unstable formations since it does not generate hydrostatic pressure or contain additives to stabilize the wellbore or build a wall cake.

In addition, the high air flow rate and low density require the use of stronger drill pipe and drilling rig equipment. Also, air (dust) drilling is generally reserved for low or normally pressured formations where minimum hydrostatics have no adverse impact.

Mist Drilling

...mist drilling is used to prevent mud rings and to keep water from accumulating in the well.

In some air-drilling applications, the hole produces too much water and/or other liquids, making it impossible to air (dust) drill with air only. For these situations, mist drilling is used to prevent mud rings and to keep water from accumulating in the well. Water, containing a foaming agent (soap), is injected into the air stream at the surface and discharged as a wet mist. Mist drilling utilizes 96 to 99% air with 1 to 10 gallons per minute (gpm) water containing 0.25 to 1% foamer, as a rule of thumb.

Mist drilling is primarily used when the probability of a downhole fire or explosion is too great for air (dust) drilling and when both water and sensitive shales (brine) are exposed. Mist drilling is used extensively in deep gas and geothermal drilling or when additional protection against corrosion and erosion is needed.

This technique creates slightly larger cuttings and offers the same high penetration rates and long bit life as conventional air (dust) drilling. In addition, the small water/cuttings droplets produced are dispersed as a fine mist in the returning air stream, thereby effectively removing them from the hole without the threat of bit balling or the formation of mud rings. This technique can utilize inhibitive chemicals (such as KCl and polymers) to help protect sensitive shales, is less erosive and allows for the addition of corrosion chemicals.

Like air (dust) drilling, mist drilling has some definite drawbacks. Since it wets the borehole, mist drilling increases the possibility of sloughing, swelling and erosion. Furthermore, required air flow rates with mist are generally ±30% greater than for air (dust) drilling with corresponding higher pressures in the 400 to 1,200 psi range as compared to 200 to 800 psi for dry air (dust) drilling. The foamer and corrosion chemicals needed to handle the influx of water, which is limited to about 100 gpm, results in higher chemical costs.

Foam Drilling

Foam drilling increases hydrostatic pressure...

Foam drilling is often subdivided into stable- and stiff-foam drilling. Generally, stable-foam drilling utilizes 55 to 96% air, with a mixture of freshwater, 0.5 to 1% foamer and chemical additives forming a stable air-in-water emulsion or foam. Stable foam is what most people refer to as just “foam.” Conversely, with stiff foam, bentonite and polymers are incorporated to produce a foam with improved hole-cleaning properties and a “stiffer” foam structure that is longer lasting. Stiff foam is specifically beneficial in drilling large-diameter holes where air volume capacity is insufficient to effect proper cleaning with a normal foam.

Foam drilling is particularly advantageous in low-pressure zones with higher water influx or in areas where lost circulation is severe. Foam drilling is also applicable where a 2 to 4 lb/gal Equivalent Circulating Density (ECD) is needed to control the wellbore or for cleaning out producing wells that have sanded up.

Foam drilling increases hydrostatic pressure, offers excellent hole cleaning capabilities and possesses the ability to suspend cuttings when circulation is stopped. In addition, the air volumetric requirement is lower and wellbore stability is increased. Foam drilling allows for the application of chemicals and produces larger drill cuttings that are more reflective of the formation, simplifying geological analysis.

Since the liquid generally cannot be reused, chemical costs are high, as is water consumption. Foam drilling requires an exact proportioning of the air and foam mixture volume and also requires additional specialized equipment, such as a middle-sized foamer pump in the 25- to 100-gpm range.

Aerated Mud

In aeration, both air and mud flow simultaneously in the annulus...

In aeration, both air and mud flow simultaneously in the annulus as air bubbles dispersed in a liquid to reduce the ECD below that of water. Generally, aerated mud is applicable when drilling subnormal-pressured formations or when high-rate water flows occur when air or foam drilling, such as in geothermal or artesian well drilling. Aerated mud often is used successfully when prevailing lost circulation makes traditional mud drilling too expensive. Aerated mud is used in applications that require a 4- to 8-lb/gal density for controlling the wellbore and where higher penetration rates are desired. Aerated muds should have low gel strengths to facilitate breaking out of the air, low viscosity and good corrosion-control characteristics.

Like foam drilling, aerated mud increases hydrostatic pressures...

Like foam drilling, aerated mud increases hydrostatic pressures above that of air or mist drilling and facilitates good hole cleaning, resulting in penetration rates that can be 2 to 3 times that of conventional mud systems. Injecting air into a fully formulated mud permits good filter-cake and fluid-loss control and results in normal-sized drill cuttings. It combines the best of air (dust) drilling with a conventional mud system and is ideal when drilling unstable formations where lost circulation is a primary concern.

Conversely, drilling with aerated mud requires additional equipment, has higher (often severe) rates of corrosion, can have unsteady surging and heading problems in large-diameter sections, and exposes the wellbore to turbulent flow.

There are several different arrangements to achieve aerated mud in the annulus:

- Direct injection of air into the mud at the standpipe.
- Parasite tubing injection of air near the last casing shoe.
- Microannulus injection of air between the last casing and a second non-cemented string of casing hung in the well temporarily.

Direct injection of air and mud at the standpipe is the most commonly used method.

With parasite tubing, which is run with the last casing string, air is circulated down the tubing into the annular mud flow near the casing shoe. Conversely, mud is circulated down the drill pipe as usual. This results in aerated mud flow in the annulus from the casing shoe to the surface. Since mud flow is independent of air and vice versa, parasite aeration is easier to control and requires a lower air pressure.

Parasite aeration has distinct disadvantages. They primarily center on the greater time and higher costs associated with running the tubing, the need to drill a larger hole size during the previous interval, and the need for extra mechanical equipment to effect proper pressure control. Furthermore, the minimum achievable ECD is higher than can be obtained with standard aeration due to the restricted air volume capacity of the tubing and the depth of injection being shallower.

With microannulus injection, a second, temporary casing string is run inside the last casing and gas is injected down the annulus between the two strings while mud is being circulated down the drill pipe. In some cases, the microannular gas injection system can utilize conventional wellhead facilities, thus avoiding the wellhead complexities associated with parasite tubing. On the other hand, the size of the intermediate casing may have to be increased to accommodate a temporary string with adequate drift diameter for the targeted hole section. To do so, the previous hole section may have to be drilled to a larger-than-planned diameter, while the aerated section may have to be reduced.

Like the flow of a water/mud mixture in a conventional fluids program, compressed air serves to cool the bit and

Air Volumetric Flow Rate Requirements

...air and mist systems are completely dependent on the flow rate to provide a sufficiently high annular velocity to remove cuttings.

associated components, clear cuttings from the hole bottom and carry the drilled cuttings to the surface. While conventional drilling fluids use viscosity to assist annular velocity for hole cleaning, air and mist systems are completely dependent on the flow rate to provide a sufficiently high annular velocity to remove cuttings. Table 1 provides general specifications for the air, pressure and liquid requirements of the four air drilling techniques and the equipment necessary to meet those requirements (equipment specifications will be discussed later in this chapter). Air volumetric flow rates are measured at standard conditions, temperature and pressure and stated in U.S. units as Standard Cubic Feet per Minute (SCFM).

Specific volumetric flow rate requirements for a targeted application, however, depend solely on the parameters of the individual well — total depth, penetration rate, annulus cross-sectional area (hole size and drill pipe), the formation type, cuttings size and whether the compressible fluid is air or gas. The well profile also has a notable effect on air volume as high-angle or horizontal hole requirements are significantly higher than those for vertical wells.

Regardless, it is critical to determine the correct air/gas volume in the wellbore for the system to have sufficient lifting capacity to clean the hole. It is generally accepted that a minimum annular velocity of 3,000 ft/min of air is required to adequately clean the hole when air (dust) drilling. More precisely, the actual air capacity requirements should be calculated based on the area of the annulus where lifting is determined to be most difficult. It is reasonable to assume that a volumetric design based on that criterion will provide sufficient circulation throughout the wellbore to exceed the slip velocity of drilled cuttings. Otherwise, the cuttings will not be removed from the hole, resulting in poor hole cleaning and a proportionate decrease in overall drilling efficiency.

Figure 3 shows the pressure and velocity changes throughout the wellbore circulating cycle with air drilling. As can be seen, because air and gas are

Method	Air (SCFM)	Pressure (psi)	Liquid (gpm)	Equipment
Air/dust drilling	1,250 – 6,000	200 – 800	None	2 – 6 compressors
Mist drilling	1,250 – 6,000	400 – 1,200	1 – 10	2 – 6 compressors
Foam drilling	400 – 1,600	400 – 1,200	10 – 100	1 small compressor
Aerated mud	500 – 1,500	600 – 1,200	100 – 400 (mud)	1 compressor

Table 1: Typical air drilling volume requirements.

Figure 2 shows an example of the recommended air/gas flow rate required to adequately clean a well. Contact an M-I air drilling supervisor for a particular air volume recommendation for a specific application.

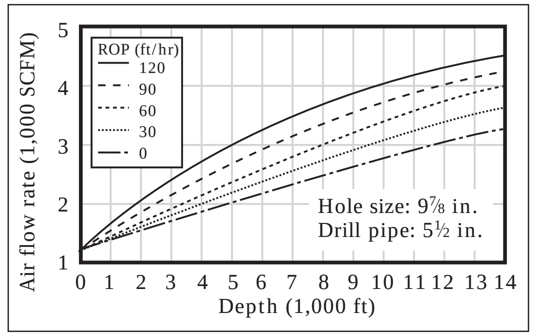

Figure 2: Air drilling flow rate requirement example (after Guo, SPE 27510).

Pressure/Velocity Profile

compressible, the annular velocity increases tremendously as the pressure decreases and the air expands as the air is circulated up the annulus.

Figure 4 shows the various flow regimes as one moves from straight air/gas drilling to a conventional mud. As mentioned, volumetric flow rate

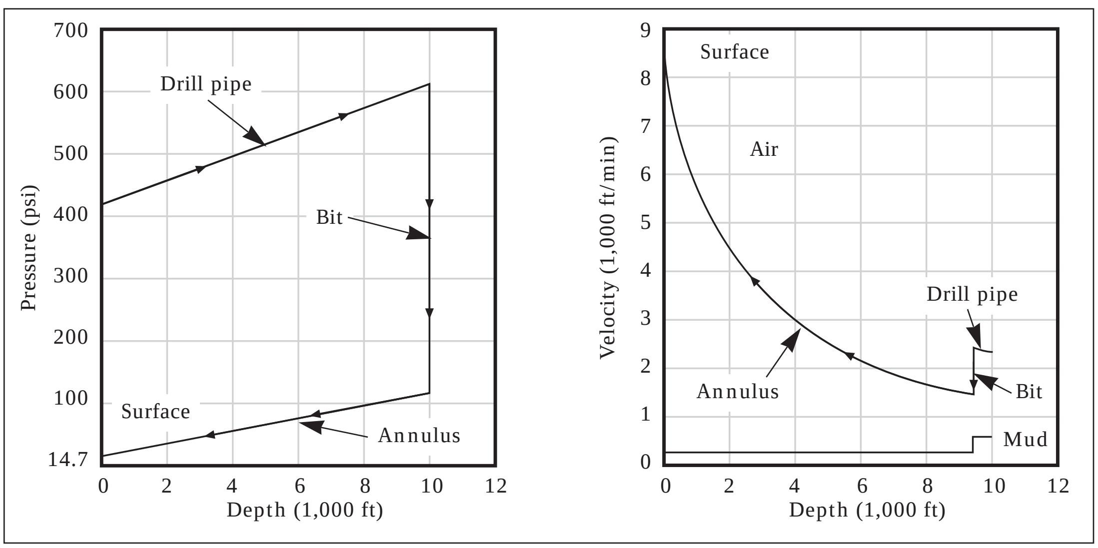

Figure 3: Pressure and velocity changes (after Lyons).

Flow Regimes

...volumetric flow rate requirements ...differ widely between a vertical and horizontal profile.

requirements, and thus the flow regimes, differ widely between a vertical and horizontal profile. The flow rate of air volume required to adequately clean the lateral section in directional or horizontal holes is greater than that required for a vertical well. Further, mist or foam drilling is recommended over dry air for horizontal wells because it will more effectively remove cuttings and cool the bit.

The threat of fires and explosions downhole is a serious concern when air (dust) drilling. During air (dust) drilling, downhole fires can occur when a combustible

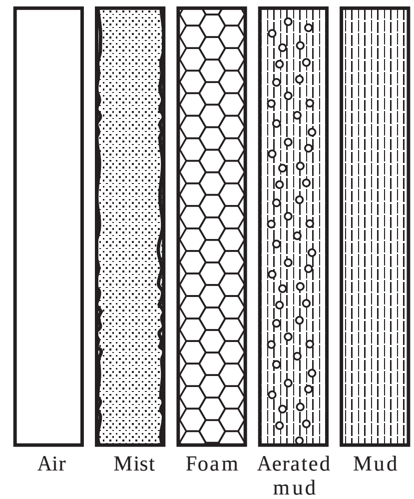

Figure 4: Air drilling flow regimes.

Downhole Fires

Ignition generally occurs when the gas-to-air ratio exceeds 5 to 15% methane with an oxygen content above 5%...

gas or oil mixture encounters sufficient temperature and pressure to cause ignition. Annular pressures increase if a mud ring is formed and any downhole sparks or high temperatures can cause ignition. Mist drilling reduces the possibility of a mud ring forming and, consequently, downhole burn-offs.

Ignition generally occurs when the gas-to-air ratio exceeds 5 to 15% methane with an oxygen content above 5%, as shown in Figure 5. Sparks can occur when tungsten carbide bit inserts, drill collars and tool joints strike the borehole walls while drilling hard quartzitic sands. Even friction or air flowing through a small hole (200 to 400 psi) in the drillpipe can generate enough heat to cause a hot spot. Like downhole sparks, this hot spot can cause ignition if the proper fuel-to-air mixture is present.

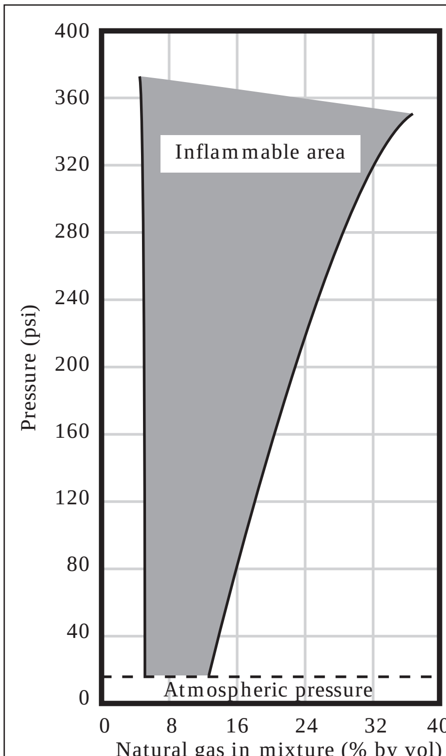

Figure 5: Range of flammability, effect of gas concentration and pressure.

Figures 6 and 7 show a typical layout of surface equipment required for an air drilling operation. Following is a

Equipment

brief description of the additional air/gas equipment available to provide, maintain and monitor the necessary volumetric air-flow rate for the four types of air drilling.

...rotating drilling heads are diverters and not Blowout Preventers.

Compressors

Compressors must be portable, yet provide adequate air volumes. Today, the most common large-capacity compressors used in air (dust) drilling are positive displacement piston or oil-flooded progressive cavity screw multistage units. Output is dependent on altitude or ambient pressure, temperature and humidity. The stated capacity of compressors is measured at standard conditions (sea level ambient pressure and 60°F). Compressors used for air (dust) drilling should always have orifice meters to constantly monitor the pressure and volume of air while drilling. This ensures that adequate hole cleaning is being achieved and that downhole conditions can be observed (mud rings and washouts).

Compressors used for air (dust) drilling should always have orifice meters...

Rotating heads

A rotating drilling head is required to seal the annulus at the surface and divert air, cuttings, and produced gas and liquids through the blooie line and away from the rig. It must be emphasized that rotating drilling heads are diverters and not Blowout Preventers (BOPs). They have rotating elastomer rubbers that can wear and must be replaced from time to time, so the BOPs will have to be closed to control the well while the rotating head is being serviced.

Nitrogen generators

An inert gas like nitrogen is preferred to ambient air to prevent downhole fires and limit corrosion. While liquid nitrogen is occasionally used, more recently developed molecular sieve membrane separators are being used to generate nitrogen on a continuous basis on location. These nitrogen units add an additional expense and require additional air capacity to be supplied to produce the necessary nitrogen flow rate to drill.

Mist or foamer pump

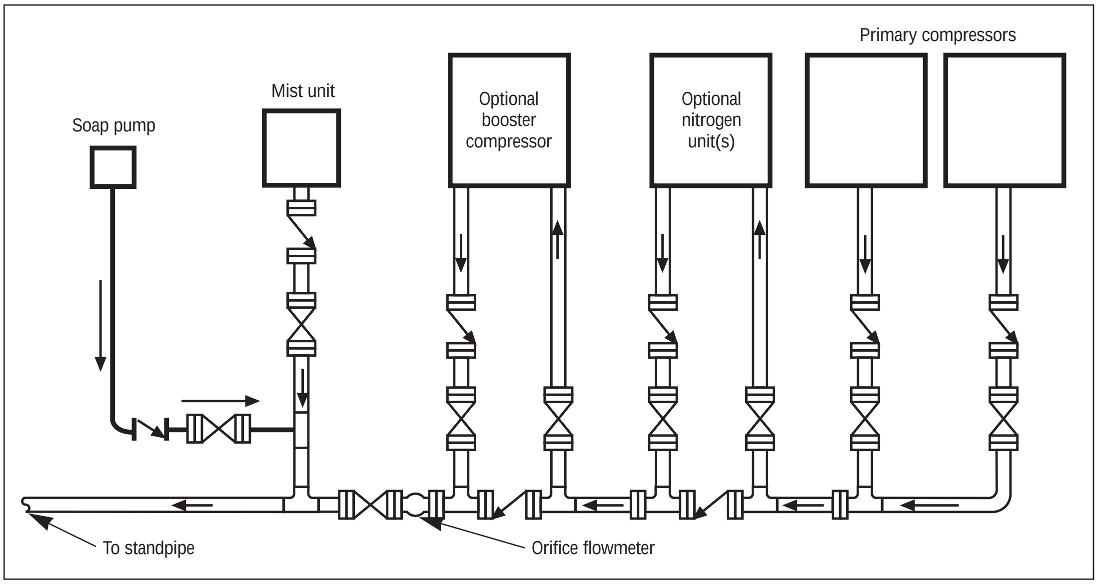

Figure 6: Typical air drilling equipment layout.

A small liquid-metering pump or a small triplex liquid pump is used to inject foamer and water to achieve a soapy mist. This may be sized for 1 to 10 gpm for mist drilling. Other chemicals such as corrosion inhibitors may need to be mixed and pumped with similar equipment. For foam drilling, the pump will need a higher capacity, in the 25- to 100-gpm range, depending on the hole size and air volume used.

...high-speed reciprocating impact hammers and bits... can reduce drilling costs as much as 80%.

AIR HAMMERS AND BITS

Air hammers are pneumatic percussion hammers operated by the air pressure. These air bits and hammers offer excellent penetration rates in hard rock and are especially beneficial in maintaining straight profiles in areas where crooked holes are commonplace. Recent developments in polycrystalline diamond coatings have allowed a curved diamond coating to be placed on the tungsten carbide inserts on the percussion bits so that bit life is greatly increased. The high-speed reciprocating impact hammers and bits drill by impact (crushing the rock) and, where applicable, can reduce drilling costs as much as 80%.

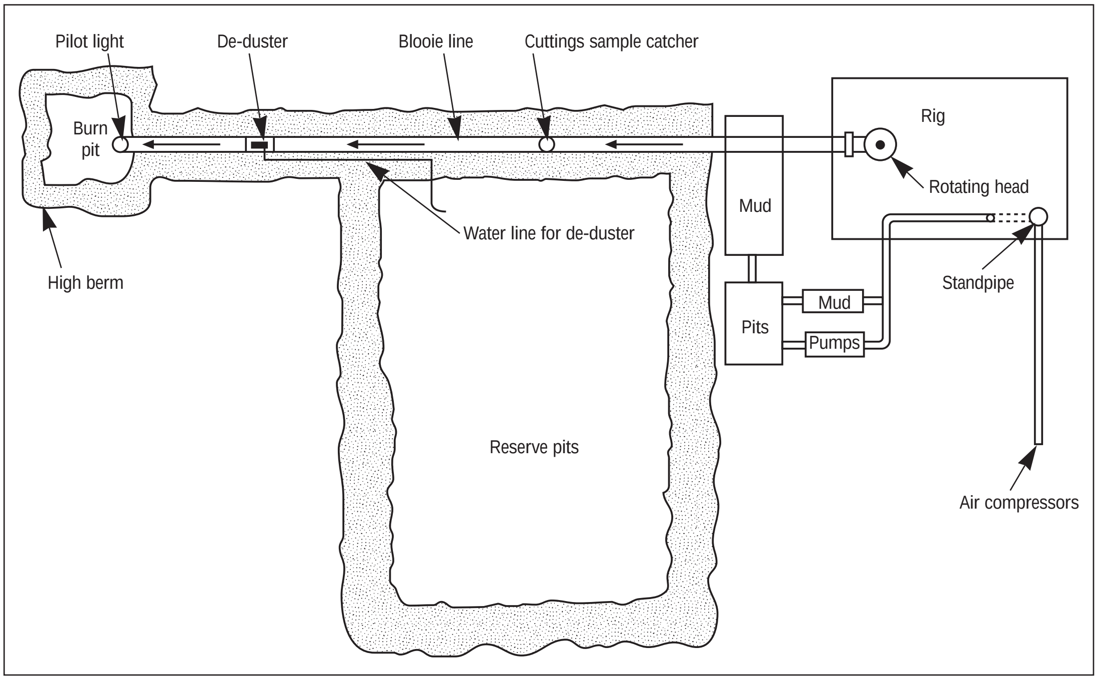

Figure 7: Typical rigsite layout for air drilling.