Title of the Project:

“Developing and Designing the Drill-in Fluids to Mitigate Formation Damage”

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Abstract:
Formation damage is one of the most important concerns in oil and gas industry. To drill the reservoir section, drill-in fluids should be designed with appropriate physical and chemical properties to mitigate formation damage which results in failure in field analyses. As the number of horizontal wells and extended reach wells and also vertical ones with open hole completions increases the need for a specialized drilling fluid to drill the reservoir section efficiently increases as well. The properties of drill-in fluids should be studied before taking part in the drilling operation. These properties are mudcake properties, filtrate and spurt loss characteristics, types of bridging agents, particle size distribution and clean up process. These are the most important aspects of appropriate drill-in fluid which should be taken in account to drill the reservoir section effectively.

Introduction:

Formation damage is one of the most important concerns in oil and gas industry. Damage to producing formation can reduce the production rate significantly resulting in failure in field management goals and economic analyses. Three mechanisms of formation damage are as follows:
1. Reduction in absolute permeability caused by solids blocking and clay problems.
2. Reduction in relative permeability due to changes in fluid saturation and rock wettability.
3. Damage due to an increase in fluid viscosity resulted from the formation of an emulsion between oil and water system.

Generally formation impairment depends on many factors such as mineralogical composition of the formation, fluid and spurt loss characteristics of the contacting fluids, erosional behavior of the deposited mudcake, margin of overbalance, wettability alteration, rate of production etc.

In most cases, drilling operation is carried out under overbalance conditions. This overbalance drilling leads to an invasion of spurt loss into the formation and making a mudcake on the wall of the wellbore. Depending on the depth of invasion and with respect to the chemical composition of the mud filtrate, it may lead to sever impairment to the reservoir. Beside this invasion, the solid particles which make a filter cake on the wall of reservoir can plug the pore throats of the producing formation and result in damage to permeability which is the most important properties of a reservoir. This is an unavoidable phenomenon. In vertical wells that the producing zone is cased and
cemented after drilling operation, damage to the reservoir will be overcome if perforation job is carried out effectively. In this case, there is no need to change the drilling fluid and reservoir section can be drilled with the same fluid as the upper sections have been drilled with. However, in wells completed either open hole or with slotted liner which are drilled vertically or horizontally and also in highly fractured carbonate reservoirs, it is highly needed to drill the reservoir section with precisely designed drilling fluid which is called Drill-in Fluids or sometimes referred to as Reservoir Drilling Fluids (RDF). Recently, drill-in fluids have become more widespread in their use primarily due to the increase of horizontal and multilateral drilling, the increase in open hole completion, and the potential for much higher fluid production after their use. They provide a good drilling performance in horizontal wells and, when combined with open hole completion technique, maximize the well productivity. Contemporary drill-in fluids aim at reaching that. A variety of fluids can be used as drill-in fluids, including water-, oil- and/or synthetic-base fluids. The selection of the most appropriate drill-in fluid depends on the type of formation to be drilled and on the completion method to be applied. Some formations tolerate a wider range of drill-in fluid composition than others do. Lower-permeability sandstones and depleted or unconsolidated sandstone reservoirs do not tolerate fluid and particle invasion without suffering extensive damage. Nowadays, horizontal wells are preferred over vertical wells because they offer a net productivity enhancement as well as an increase of the contact area with the reservoir. This enhancement is also gained by targeting multiple zones. Other benefit of horizontal wells is reduced drawdown to avoid (or to minimize) premature water or gas coning problems. However, formation damage is more critical to horizontal wells because these wells have such long exposed interval that stimulation jobs are not efficient and feasible. In such a case, very shallow damage which is not bypassed by perforations can result in very large skin. This is a critical point for oilfields developed in deep water reservoirs where acceptable development costs are based upon a limited number of high productivity wells. In order to drill horizontal wells adequately, the use of properly designed drilling fluid is crucial for drilling success. Not only does the drilling fluid need to be inhibitive; it must also be capable of laying down an impermeable filter cake to seal off depleted/underpressured intervals.

Specially designed polymer, sized solids drill-in fluids are being effectively applied for drilling horizontal or highly deviated wells worldwide. Ideally, these systems should be compounded with inhibitive brine, shear-thinning polymer additives, and a minimal concentration of soluble bridging solids. Density increases to the system should be made with soluble salt rather than inert particulates to maintain an ultra-thin filter cake. These systems are designed to provide desirable rheological properties for hole cleaning and cuttings transport.

Most muds contain sufficient quantities of particles and cutting debris in the size range capable to cause severe formation damage. This damage depends on the quality of the drilling mud and erosional characteristics of the mudcake. Both solid and liquid phase of drill-in fluids could be a source of damage by interaction with the formation. Drill solids invading the reservoir could seal the pores and pore throats. With respect to lab test on the role of pH and salinity changes in core damage, Mungun (1965) concluded that the primary cause of permeability reduction is the blockage of pore passages by dispersed solid particles. In addition, the investigation conducted by Todd et al. (1990), shows that...
the mud spurt containing very low concentration of solids may play a vital role in near borehole formation damage. Also, experimental study conducted by Gruesberck and Collins (1982), highlights that the entrainment and redeposition of naturally occurring fine particles may cause abnormal productivity decline due to near wellbore formation damage. This happens when the mudcake formed on the borehole wall is partially or totally eroded. Erosional characteristics of mudcake can be significantly influenced by using the different additives in drill-in fluids, Amanullah and Tan (2001) and Amanullah (2002).

Optimized bridging particle size distributions reduce total system solids significantly, yet enhance wellbore stability and protect the formation from liquid and solids invasion into the production zone. One of the critical factors in designing non-damaging fluids to prevent this invasion is by sizing particles in the system to obtain a surface bridge on the formation face with minimum in-depth solids penetration. This can only be accomplished by proper selection of bridging particle sizes in relation to the formation pore openings. Historically, the foundation of these systems has been soluble bridging solids of sodium chloride or calcium carbonate in broad particle distributions designed to bridge a wide range of formation pore sizes. Total solids concentration and volume of filtrate leak off determine filter cake thickness. Consequently, the more particles incorporated in a fluid system, the greater the filter cake thickness for the same volume of filtrate. The most efficiently designed systems should therefore utilize only the concentration of particles necessary to establish a primary bridge over the opening to be sealed. Addition of a sufficient concentration of colloidal components with these solids results in an optimized filter cake composition with a low filtrate. These reduced solids low filtrate systems deposit less filter cake providing maximum removability. This is particularly critical in cases where sand exclusion assemblies are incorporated which could potentially become plugged with solids if little or no filter cake has been removed during completion. As a result, drill-in fluids should be designed with respect to above concerns and they should meet the above requirements to have the desired filtration and non-erosional characteristics in order not to damage the formation. In continue to this paper, formation damage mechanisms are discussed first with respect to their causes and different drilling fluids systems. Next, the ways this damage might be cured or prevented (actually minimized) are investigated with respect to different fluid systems again and finally the above discussions are summarized and concluded.

**Formation damage:**

It is a long time that formation damage is observed in oil and gas industry. This damage is found by reservoir engineers from pressure draw-down data that many wells are producing at less than their full potential. A barrier or skin is found to be around the wellbore. This skin or barrier is caused by a zone of reduced permeability around the well and results from contamination of reservoir zone by mud particles or filtrate. Well productivity is declined by some mechanisms caused by mud particles or filtrate. These ways of damage are listed as follows:

1. 

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1. Capillary phenomena – relative permeability effects resulting from changes in the relative amounts of water, oil and/or gas in the pores; wettability effects; and blocking of the pores by aqueous filtrate.
2. Swelling and dispersion of indigenous formation clays by the mud filtrate.
3. Penetration and plugging of the formation pores by particles from the mud.
4. Plugging of gravel packs, liners and screens by mud filter cake.
5. Mutual precipitation of soluble salts in the filtrate and formation water.

Capillary phenomena:
When the filtrate from a water-base mud invades an oil-bearing formation it displaces the oil. In some cases not all of water is produced back and productivity is impaired. It is commonly called water blocking and was the first mechanism of formation damage to be recognized. The porous media involves irregular and three dimensional network of pores connected by narrow channels showing the capillary phenomena. As most of rocks are water wet\(^1\) the water flows along the surface of the grains and through the minor capillaries while the oil moves through the center of the pores and the larger flow channels. A virgin oil reservoir is at residual water saturation (which is the minimum water saturation when only oil is flowing at given pressure drop and residual oil saturation is the corresponding value for the oil) for the prevailing reservoir pressure. Invasion of mud filtrate drives the oil towards the residual oil saturation and when the well is put on production it drives the filtrate back towards the residual water saturation. If the oil to water viscosity ratio is very low it may take a long time before all the filtrate are expelled from the reservoir and full productivity is obtained. In most virgin reservoirs which have enough pressure this damage is temporary. However, in low pressure and low permeability reservoirs and also in workover wells the capillary pressure is high enough in order to oppose the displacement of the filtrate by the returning (back producing) oil. The pressure drop may not be high enough to drive the filtrate out of the finer capillaries especially at the vicinity of the wellbore where the pressure drop at the oil-water interface approaches zero. This mechanism is called water block which results in permanent damage or even complete shut-off in highly depleted reservoirs.

Damage by indigenous clays:
Clays in reservoir rocks are from two sources. *Detrital* clays which have been sedimented at the time the bed was deposited. *Diagenetic* clays are those which have been precipitated from the formation water or are generated from the reaction between pre-existing clay minerals and formation waters. The ways they occur in the reservoir rocks are different. They might be found in the form of coating platelets on the pore walls, or as a part of the matrix or they might lie loose in the pores. They also might be present as thin layers or partings in the sand beds. Clays are not dominant in carbonate formations and they are usually present in the matrix of these formations. The action of aqueous filtrates on indigenous clays can severely reduce the permeability of the rock but only if the clays are located in the pores\(^1\). Theses formations which their permeability are reduced by aqueous filtrate are called *water sensitive formations*. Works by different investigators show that the decrease in the permeability at low salinities is caused by the
displacement and dispersion of the clay or other fines from the pore walls by the invading fluid and by the subsequent trapping at the pore openings\(^1\). This mechanism is referred to as *clay blocking*. It is greatly affected by some factors. One is the state of the mud whether it is deflocculated or not and it is suggested to avoid using deflocculants such as complex phosphates and tannates when drilling through the water-sensitive formations\(^1\). Another factor affecting clay blocking is the rate of reduction in the salinity of the mud. If the salinity of the mud during the drilling operation decreases gradually in steps the permeability reduction is significantly less. From experimental studies it is found that the permeability reduction is dependent on the type of clays. The most permeability reduction is related to montmorillonite and mixed-layer clays. Permeability reduction is less with illite and is the least with kaolinite and chlorite\(^1\). The third factor governing the clay blockage problem is the effect of Base Exchange reactions which are important when more than one species of cations are present in the clay-brine system. When polyvalent cations such as calcium or magnesium are present in the base exchange positions of the clays in the water-sensitive rocks, the clay aggregate do not disperse even in distilled water resulting in no permeability impairment. However, if the base exchange positions are occupied by monovalent cations such as sodium then the pores will be plugged with distilled water. If sodium chloride brines containing polyvalent cations in significant proportions to monovalent ones are used then clay dispersion is inhibited. It is important to prevent this dispersion and migration of fines as the resulted permeability impairment can not be reversed by high salinity brines. The fourth factor in clay blocking is fine migration caused by shearing force of the fluid or by solution of carbonate cement. The last factor in clay blocking is pH. Generally its effect on the permeability impairment depends on the electrochemical conditions of the system. For instance when the matrix is cemented with silica, fine particles can be released by high-pH filtrate as it dissolves the cement and makes the particles loosened resulting in pore blockage. Clay dispersion is also influenced by pH as it affects the base exchange equilibrium.

**Formation damage Due to Particles from the Mud:**

It is one of the most common reasons for formation impairment as the particles in the drilling fluid invade the producing formation and block narrow paths in the flow channels. This invasion happens only during mud spurt period before the filter cake is established. Once the filter cake is formed it prevents solid particles from entering the formation since it has a low permeability structure. Most of impairment caused by mud particles invasion is concentrated in the first few millimeters of the rock. Any mud that has been used for drilling more than a few feet will contain more than 1 lb/bbl (3kg/m\(^3\)) of particles in the size range of 50 to 2 microns\(^1\). This amount of solids in the mud is enough to bridge the pores of the consolidated rocks which have permeability less than 1 darcy (1000 md). In these situations the productive formation is not necessarily drilled with a new mud and the drilling operation can be carried out with the same drilling fluid as used in the upper sections. However, there are some conditions that need to make sure about appropriate amount and size of bridging particles in the mud. These situations are as follows:

1. **Unconsolidated sands**: They often require particles larger than 50 microns to bridge. Apart from bridging effect of particles in the drilling fluid to minimize the invasion of particles, it is necessary to establish a filter cake on the wall of
formation in order to prevent the unconsolidated sands from slumping and hole enlargement. This cake should form quickly to prevent the highly erosive conditions around the bit and subsequent rapid hole enlargement which imposes additional well problems such as casing buckling, sand production etc. to productivity impairment.

2. **Reservoirs with fractured permeability**: Mostly carbonate reservoirs are fractured and the production is through these fractures rather than porous matrix as their matrix shows very low permeability. Bridging the fractures are much more difficult rather than porous media and if they are not bridge efficiently fine mud particles invade the fractures and filter internally which can not be removed during back flow of the formation. These formations should be generally drilled with a fluid containing degradable solids.

3. **Gun perforating**: When the wellbore is gun perforated there is a crushed zone which shows impairment naturally. If the fluid is damaging this low permeability crushed zone is bridged completely and the productivity of the wellbore is greatly reduced.

4. **Workover wells**: Work over fluids used to have no bridging particles but they caused productivity impairment. Nowadays, it is common to add bridging materials to the fluid. However, there are some problems with formation damage in work over operation. First, previous production may open up differently sized channels to flow and the exact sizes of particles are not known. In addition, changes in the stress field around the wellbore especially in the case of sand production may cause an alteration in the pores structures. Furthermore, the workover wells have low reservoir pressure which might cause an overbalance between the pressure of mud column and the reservoir pressure. This will result in increased mud spurt and loss of circulation through induced fractures. Finally the previous damages are present as well and workover fluids should overcome them.

5. **Gravel packing operations**: The screens of gravel pack tools can be plugged by solids particles on the filter cake when the well is put on back production unless these particles are readily dispersible in the back produced fluids or their size falls between 1/3 of the size of screen openings. Another practice is to use a mud with degradable solids when underreaming prior to gravel packing.

6. **Water injection wells**: After the completion of water injection wells the flow is from the wellbore to the formation opposite to production wells. Any solid particles which are left in the hole after washing operation can invade the formation and make a filter cake and cause severe impairment.

Formation damage mechanisms can be classified with respect to their primary source of occurrence. In this way, the two major parts of a drilling fluid are responsible for different mechanisms of impairment discussed above. These parts are insoluble solids and the liquid fraction. Pore plugging and bridging the pore surfaces are the two mechanisms resulted from solid fraction of water-base muds. This solid fraction includes weighting agents, low-gravity drilled solids and clays, mud make-up materials such as insoluble polymer, corrosion by-products and scale, excess drillpipe dome and insoluble hydrocarbon materials from the reservoir. The actions of liquid fraction are dispersing or flocculating the interstitial clays (resulting in their migrations and blockage the pores.
openings), dissolving the matrix cement material, generating precipitates by reacting with formation crude or connate water, changing the relative permeability of liquid phases in the reservoir and altering the wettability of the reservoir rocks. Another type of drilling fluid which plays a significant role in drilling operations is oil-base muds. The above mechanisms are generally related to water-base muds which are dominant drilling fluids and also used with some changes as completion and workover fluids. Possible causes of formation damage specific to oil muds are as follows:

**Oil wetting**: Theoretically, the emulsifiers and oil-wetting agents that will make the droplets of brine oil wet to form an invert oil emulsion will also make a sandstone reservoir oil wet (changing the wettability of the rocks). If the wettability of the reservoir rocks changes then the relative permeability to oil will decrease. Consequently the mobility of crude oil flow is reduced. This happens due to the mud filtration into the reservoir. By using bridging materials which can be back flushed the filtration rate may be limited. Another effect of mud filtration into the formation is the change in the oil saturation (increasing the saturation) resulting in wettability changes. With advances in bit technology there is no longer high filtrate oil muds as they were needed to increase the rate of penetration with old bit types. Generally the oil wetting damage is not likely as the mud filtrate is limited.

**Emulsion blockage**: The filtrate of an oil mud contains oil with some emulsifiers. If it is mixed with formation water, an emulsion might form in the formation. Since the viscosity of this emulsion is increased, the mobility of the crude oil will be impaired.

**Unreacted or partially soluble emulsifier**: If the emulsifier in the filtrate were to become insoluble in the formation (due to chemical change in soap-type ones), it could cause damage by blocking pore throats. However, this type of damage is not likely nowadays as the chemical properties of emulsifiers are improved.

**Whole-mud invasion**: If the permeability of the reservoir rock is significantly high and/or differential pressure is excessive, whole mud might be forced into the formation. In addition to emulsion blockage and oil wetting, all the mechanisms of damage by water-base muds would be likely for oil muds in a similar way. This can be prevented by the addition of properly sized bridging agents as they minimize the differential pressure to the lowest safe level.

One limitation to oil-based muds is that they can not be used in drilling dry gas sands as not all the oil will be produced back and will leave a second residual phase.

### How to Minimize the Formation Damage- Drill-in Fluids

Not all reservoirs are susceptible to formation damage problem by most drilling fluids. In some cases the damage could be overcomed by efficient clean up operation or good perforation job. For instance, in vertical wells which are cased and cemented, the zone of damage can be bypassed by a precisely designed perforation job and subsequent clean up procedure. Highly fractured carbonate reservoirs are another example in which the plugging of fracture channels can be removed by good clean up operation. However, in these reservoirs appropriate drilling fluids can be used with special bridging materials to protect the channels of the formation from being plugged.
A properly formulated and conditioned reservoir drilling fluid (RDF) deposits a thin, low-permeability filter cake on borehole walls that does not deeply invade formations. Components include polymers for viscosity, bridging and weighting agents, and fluid-loss additives that seal within a few formation-grain diameters to minimize fluid and particulate invasion of productive intervals. Base brines, salts, CaCO₃ and barite are common weighting agents. Bridging agents and fluid-loss additives pack against a borehole wall (Figure 1). Proper RDF conditioning and wellbore displacements remove loose RDF material, or “fluff,” and minimize filter-cake thickness.

The practical limitations to design a proper RDF mainly relate to wellbore cleaning and treatment methods used before the wellbore is going to produce hydrocarbon. Wellbore cleaning methods and materials depend on the type of materials used as drill-in fluids components. One of the bridging materials is sized salt crystals which make a significant portion of mud cake. After drilling, this cake is washed out by undersaturated brine promoting the clean up process. An alternative to sized salt is sized calcium carbonate which can be used as bridging and weighting agent in both oil and water based muds. In this case the filter cake is treated with mild acids to dissolve calcium carbonate. Also cellulosic products which can be used as fluid loss control or as bridging agents may be dissolved using dilute acids or oxidizing agents such as sodium hypochlorite.

**Figure 1**- Filter cake formed on the wall of the producing formation. Note the thickness of filter cake which should be less than 1 mm in optimum operation and drill-in fluid design.

Enzyme breakers are used to attack polymers in water based muds. A variety of solvents and surfactant fluids is available to treat oil base muds filter cakes breaking down the oil wetting character of the cake and allowing it to disperse in aqueous phase or mixed-phase wash fluid. The aforementioned treatments are sometimes problematic. For example, washes may cause significant losses of treatment fluid into the formation. In severe cases; this may lead to costly lost circulation treatments probably resulting in additional damage or well control incidents. Treatment of some OBM filter cakes produces viscous sludge causing damage. Polymer sludge may also result from WBM filter cakes. Acid breakers may cause corrosion problems.
Figure 2-Filter-cake cleanup. Small-scale laboratory tests evaluated filter cake that was formed on cores by a reservoir drilling fluid with CaCO₃, starch and polymer before cleanup (left) and after soaking in hydrochloric acid [HCl] or a chelating agent solution (CAS) at 180°F [82°C]. There is a single dominant conductive path after soaking with HCl (middle) and uniform filter-cake removal with CAS (right).

An alternative is to do away with washes and breakers altogether and back produce the drilling fluid through the completion hardware. Another approach is to minimize the particulate invasion of the formation in first place by creating a filter cake that may be more easily lifted by formation fluid during flow back. An example of such a system is a Bentonite/mixed-metal hydroxide (MMH)/sized carbonate system. MMH fluids are highly thixotropic and laboratory tests show that they have low potential for formation damage, laying down a predominantly external filter cake and thereby avoiding the need for deep penetrating washes (Fraser et al., 1999).

The general considerations on drilling fluids (or drill-in fluids) are as follows³:

All insoluble solids and especially low gravity solids should be minimized.
The cation exchange capacity of the mud should be as low as possible.
If drill-in fluids are used, clay particles should not be used to get a filter cake. Calcium carbonate bridging agent might be used to aid filtration control along with HEC for viscosity and appropriate fluid loss control additives.

Bridging agents are used in Drill-In fluids to prevent problems of massive loss circulation to the formation and formation damage through fine solids migration that invade the hydraulic flow channels of the reservoir rock. One of the most important properties of drill-in fluids which must be precisely studied and designed is sizing particles. To minimize the formation damage potential of drill-in fluids solids must be sized to satisfy two important criteria. First they must be large enough not to invade the rock and second, they must be small enough to form filter cake that effectively filters drill solids and polymers from entering the formation. The depth of invasion of the particulate material and the return permeability is dominantly influenced by the size of the particles in drill-in fluids and the permeability of the formation (Suri, 2004).

The first step when selecting the particle size distribution of bridging agents (specifically CaCO₃) in Drill-In fluids is the petrophysical characterization and pore geometry determination of the rock. In consolidated sands, the criterion of selection of particle size
of bridging agents is: 1/7 D pore throat < D particle < 1/3 D pore throat. This yields a small invasion of solids into the porous media (Cargnel et al., 1999).

The size of bridging particles is important and it should be designed around the pore throat diameter, if known. With return permeability tests on core sample the optimum bridging agents is determined. If a combination of inert bridging solids such as CaCO$_3$ of a size range from one-third pore size upwards together with hydrocolloids like starch is used then there will be a thin filter cake formed on the wall of the formation with minimum spurt loss invasion. The process of filtration and spurt loss is as follows:

First, the coarser particles are deposited (bridged on the wall of the formation) then progressively finer particles are deposited and finally the hydrocolloids progressively block the remaining spaces. During this procedure, spurt loss takes place. At the end, filtration through this filter cake happens and only clear fluid invades the formation.

One of the bridging agents is calcium carbonate. It is so common as it is acid soluble. It can be cleaned off the wellbore by back flushing. To clean calcium carbonate, acidizing should be carried out underbalanced. Otherwise, there is no efficient cleaning. In addition, bridging particles may be dissolved and become smaller resulting in fine migration to sand grains.

Other types of bridging materials are sized salt in saturated solutions and oil soluble resins. Sized salts can be removed by dissolution with water. The oil soluble resin which is not soluble in water can be cleaned off the wellbore by back producing crude oil.

Most drill-in fluids are in a nondispersed condition. Because dispersed muds carry much more damaging low-gravity solids. So the use of dispersants such as lignosulfonates should be avoided. Interstitial clays can be affected by lignosulfonates as well as formation clays and become dispersed in the reservoir pores causing plugging or even weakening the matrix of the rocks. These interstitial clays can be protected by the presence of 2 to 3% potassium chloride present in nondispersed drill-in fluids. Two case studies are available showing the importance of drill-in fluid in increased productivity.

One is related to a field in Zaire where productivity increased from 400 BOPD to 1100 BOPD because of changing from lignosulfonate CMC mud to a lime nondispersed polymer mud. The second is related to Siberia which productivity increased from 40 tons per day to above 120 tons per day. They changed the previously used mud containing dispersants with poor control of solids to a 3% KCl polymer system.

Another factor to consider is pH. High pH can cause the dispersion of interstitial clays and also forming the emulsions dependent on the crude.

The occurrence of precipitates should be avoided. These precipitates are from the reaction of filtrate with connate water. Scales result from the changes in temperature, pressure and chemical composition. Types of scales are:

1. Carbonate scale; generated from the carbonate or bicarbonate ion with the calcium ion.
2. Gypsum or anhydrite scale; from the sulfide ion with the calcium ion.
3. Barium or strontium scale; the barium or strontium ion with the sulfate ion.
4. Iron scales; ferric or ferrous ions usually as corrosion by-products with oxygen or sulfides.
5. Sodium chloride precipitates; changes in pressure and temperature.
Another fundamental consideration is to select Water-base drill-in fluids or Oil-base drill-in fluid? Drillers often prefer synthetic oil-base reservoir drilling fluid over water-base RDF for better lubricity, higher penetration rates, improved hole stability and superior shale stabilization, especially for high-angle or horizontal wells. In addition to extensive experience gravel packing with water-base drilling and completion fluids, completion engineers prefer water-base RDF because of concern about emulsions or sludge that form with some oil-base systems and crude oils. Also, synthetic oil-base carrier fluids that can control well pressures while gravel packing were not available until recently.

Figure 3- Comparison of water-base and oil-base filter-cake removal. In laboratory evaluations, thin-section photographs of filter cake against artificial gravel show significant differences after oxidizer cleanup treatment and flowback. Water-base filter cake remains essentially intact.

Figure 4- Retained permeability is established through pinholes or channels. Oil-base filter cake typically is thinner and easier to remove, and often does not require additional cleanup treatments. The cleanup mechanism for oil-base filter cake is fundamentally different than water-base filter cake; virtually all the filter cake is removed from the core face and dispersed in gravel pore spaces or produced through the gravel.
Conclusions:
1. Drill-in fluids are specialized to drill the reservoir section in horizontal or vertical wellbore with open hole completion and highly fractured carbonate reservoirs.
2. Wellbore cleaning is a concern which is influenced by the type of materials used as drill-in fluid components.
3. The chemical interactions between drilling fluids components and formation components and also between RDF and treatment fluids dictates the efficiency of clean up methods or mud design.
4. Particle size distribution is a very critical stage of mud design to use drill-in fluid effectively.

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