

A Comprehensive Review on the Advancement of Non-damaging Drilling Fluids

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Abstract

The ever-increasing targets of drilling depth and reach, coupled with locational disadvantages have driven the oilfield drilling operations into new technology frontiers. Drilling fluids being an essential component of any successful drilling operation, adequate understanding of the impact of drilling fluid characteristics can eliminate a range of difficulties encountered during drilling operations and reduce drilling cost significantly.

This article presents a comprehensive review of various types of drilling fluid systems and technology advancements and also the significant challenges faced by a drilling fluid engineer, starting with the basics and ending with extreme reservoir Conditions, with special emphasis on non-damaging drilling fluids. This paper is specially written for fresh petroleum engineering graduates and entry level drilling fluid engineers and drilling engineers as well as for drilling fluid research groups who would find many important information for a given drilling and reservoir challenge.

Keywords: Drilling fluid, Water base mud, Oil base mud, Mud formation damage

Introduction

Drilling fluids and *Drilling muds* are sometimes used interchangeably; however, the term "fluids" is much wider and is preferred by most drilling companies and authors. Several definitions are used by the industry to describe the drilling fluids without placing any restrictions either on the composition or on the properties of the drilling fluids. Some of the available definitions, taken from different sources are mentioned below:

A drilling fluid is defined as the fluid that encompasses all of the compositions used to aid the production and removal of cuttings from a borehole in the earth [1].

Baker Hughes Drilling Fluids Reference Manual, mentions that a drilling fluid is a fluid formulated with chemicals to obtain specific chemical and physical characteristics for circulating during the rotary drilling process [2].

The American Petroleum Institute (API) defines the drilling fluid as a circulating fluid used in rotary drilling to perform any or all of the various functions required in drilling operations [3].

According to Schlumberger Oilfield Glossary, a drilling fluid is defined as any number of liquid and gaseous fluids and mixtures of fluids and solids used in operations to drill boreholes into the earth [4].

It is worth noting that the wide and restriction free definition adopted by the industry has given the opportunity to new compositions and properties of drilling fluids to arise throughout the history of drilling, which is the topic of discussion in this article.

Functions and Properties of Drilling Fluids

During the primitive stages of oil well drilling, drilling fluids were initially required to function as a vehicle for the removal of drill cuttings from the borehole while and after drilling. As drilling operations continued towards deeper reservoirs and more challenging environment (such as deep water and higher temperature formations), new conditions were encountered and new and more demanding functions were required from the drilling fluids. Below are some of the minimum required functions of drilling fluids [5]:

- Removing cuttings from the hole
- Cleaning the hole bottom
- Cooling and lubricating the bit and drill pipe
- Preventing cuttings settling in the hole and surface pits
- Deposition of impermeable wall cake to prevent fluid loss.
- Overcoming formation pressures to prevent ingress of oil, gas or water.

With passage of time and enhanced awareness on health safety and environment and also concerns on economics, new criteria are introduced, in addition to the normal drilling fluid functions. Below are some of these additional requirements that the drilling fluids are expected to possess [1]:

- Not to injure drilling personnel
- Not to be damaging or offensive to the environment,
- Should not require unusual or expensive methods of completion of the drilled hole
- Should not interfere with the normal productivity of the fluid-bearing formation
- Not to corrode or cause excessive wear of drilling equipment.

In order for drilling fluids to perform their required functions effectively, several principal properties related to their performance should be controlled and evaluated. The principle properties of drilling fluids to be controlled within a given limit are:

- Specific weight
- Particle size and shape
- Colloidal properties
- Flow properties
- Filtration properties
- pH
- Alkalinity
- Cation exchange capacity
- Electrical conductivity
- Lubricity
- Corrosivity

Evaluation and testing of the drilling fluid properties are described in the API publication RP 13B-2 which includes equipment and detailed laboratory procedures [6].

Classification of Drilling Fluids

Drilling fluids have undergone significant development in various aspects keeping pace with the advancement of drilling technology, since the time they were first used in the rotary

drilling process sometime between 1887 and 1901 [7]. Such development resulted in an obvious increase in number of available drilling fluid types and thus a continuous update of drilling fluids classification criteria was necessary. Several classification attempts taken from different sources are given below:

Drilling fluids can be classified on the basis of their principal component into water, oil and gas base drilling fluids [1]. This classification was the most commonly used [7].

All drilling fluids may be divided into two main categories based on their specific weight [7]. Drilling fluids with specific weight equal or less to 78 lb./cu ft. may be considered as non-weighted, whereas any drilling fluid that is heavier than 83 lb./cu ft. may be considered as weighted drilling fluids.

Drilling fluids can also be classified based on several aspects like their fluid phase, alkalinity, dispersion, the type of chemicals used in their formulation and the degrees of inhibition. According to such classification, drilling fluids are divided into five main categories [8].

- Freshwater muds-dispersed systems
- Inhibited muds-dispersed systems
- Low solids muds-nondispersed systems
- Non-aqueous fluids
 - Oil-base muds
 - Invert emulsion muds

According to ASME Shale Shaker Committee [9], drilling fluids are classified (according to the type of the base fluid and other primary ingredients), into gaseous, aqueous and non-aqueous drilling fluids. Detailed and farther classifications can be employed to describe the composition of the fluids more precisely.

Due to different bodies and opinions from experts in the classification of drilling fluids, often more confusion were created, thus by singling out the main component (the fluid media) that clearly defines both the function and performance, drilling fluids are classified into water-base, oil-base and gaseous drilling fluids and adopted by the industry [4].

Liquid Drilling Fluids

Liquid Drilling fluids are classified into water-base muds and oil-base muds with water and oil being the continuous phase respectively. Water-base muds may contain oil and oil-base muds may contain water in their formulation [10]. The amount of water present in oil-base muds should not exceed the amount of oil and vice versa [3]. The most commonly used drilling fluids are the water-base muds, whereas oil-base muds are limited to drilling sensitive formations with special drilling requirements (to be discussed later) or formations that are affected adversely by water-base muds. Water-base muds are less expensive and require less stringent pollution control procedures compared to the oil-base muds [11]. Further description of water-base muds and oil-base muds will be covered in the following sections.

Water-base muds (WBM)

WBMs are classified into different categories based on their compositions or functions, as well as whether they are

used for pay-zone drilling or non-pay-zone drilling. Conventional compositions can be used for preparing WBM for non-pay zone drilling with less worries about formation damage, taking advantage of its low cost. However, for a drilling fluid to be used for pay zone drilling, the most important property should be minimum damaging effect or if possible non-damaging to the pay formation. For a water-base mud to be a non-damaging fluid, several modifications within the composition and properties must be made. The resultant drilling fluid is called the drill-in fluid and is described further below.

Water-base mud types include;

- Spud muds
- Dispersed muds
- Lime muds
- Gypsum muds
- Salt water muds
- Non-dispersed polymer muds
- Inhibitive potassium muds
- Cationic muds
- Mixed metal hydroxide muds.

The widespread use of water-based muds is attributed to its universal distribution of water, its low cost, compatibility with human health and the satisfactory nature in its application. Moreover, mud cuttings resulting from drilling using water-base muds can be easily disposed onsite at most onshore and offshore locations. This in turn reduces the total drilling costs as no extensive and expensive treatment or transportation is required prior to cuttings disposal.

Despite the environmental compatibility, water-base muds with conventional compositions possess several deficiencies related to their performance. Poor performance against shale inhibition, lubricity and thermal stability are examples of such deficiencies [3]. Therefore, the composition of water-base muds is modified through the use of special additives in order to enhance their performance against the previously mentioned deficiencies.

The usual composition of water-base muds contain clays, water soluble chemicals (including salts), a pH control additive (hydroxyl source), and one or more organic polymers, surfactants, and deflocculants [2]. Other special dissolved substances may include rheology controller, friction reducers and thermal stabilizer [3]. Newly introduced chemicals to encounter extreme temperature and pressure (Perfluoro-Polyethers) base polymers and surfactants, multiwall carbon nanotubes based WBM, are also under development and trial [12] [13]. Insoluble and suspended materials such as polymers, barite, clays, and cuttings in suspension may be contained within water-base muds.

Poor thermal stability of conventional water-base muds refer to their viscosity decrease with increasing temperature. A decrease in viscosity results in several problems such as a reduction of the cutting lifting ability of the water-base muds. The poor thermal stability can be treated by adding formate based salts such as potassium and sodium formates in the polymer-based aqueous fluids [14] [15] [16]. Other less

expensive means are also available. Xanthan gum and polyacrylamide are added to water-base fluids to enhance thermal stability up to a certain temperature limit based on the polymer type and their molecular structure. Thermal degradation and special chemical application is discussed in a later section of this article.

Shale encapsulators are added to water-base muds to reduce the swelling tendency of the shale formations in the presence of water. Quaternary polyacrylamide is the conventional shale encapsulator used in most cases. Other commercial shale encapsulators for low salinity conditions and fresh water muds are available [17]. Specific formulations that provide membrane formation over a specific shale formation are used to increase the wellbore stability by allowing the relatively free water movement through the shale and significantly restricting the movement of ions into the shale.

Modification of the water-base composition to account for its deficiencies resulted in an increase in its cost, however its environmental compatibility compared to other drilling fluids has kept it as the most widely used and accepted drilling fluid.

Oil-base muds (OBM)

The continuous phase of OBM is a liquid hydrocarbon instead of water. Conventional OBM contains diesel as the continuous phase due to its favorable viscosity characteristics, low flammability and low solvency for rubber elements in drilling equipment [11]. Light crude oil is also used extensively as the base fluid, however due to the relatively large amounts of aromatics and n-olefins present in crude oils, they generally exceeds the toxicity limit which encouraged the use of low toxicity mineral oils and ester base synthetic oils [18] [19]. Water can be present in oil-base muds intentionally (for economic reasons) or unintentionally during drilling operations. The presence of water in oil-base muds will form an emulsion. If the water is added intentionally to the oil-base muds, the resulting mixture is called an invert emulsion mud. The amount of water in an invert emulsion is generally more than 5% of the entire composition [3]. On both conditions, water-emulsifying agents must be added, to prevent the coalescence and settlement of water droplets out of the emulsion [20]. A wettability reversal agent is also added to invert the tendency of solids being water wet to being oil wet. This in turn prevents the solids from being absorbed by the water which can lead to high viscosities and eventual settlement of barite. Other materials like clays or colloidal asphalts to provide viscosity, weighting agents and other additives are also added to the oil-base muds.

As mentioned previously, oil-base muds are used for special purpose drilling, having advantage of their unmatched performance. The special advantages of OBM are their good rheological properties at temperatures as high as 500°F, more inhibitive than inhibitive water base muds, effective against all types of corrosion, superior lubricating characteristics, and permits mud densities as low as 7.5 ppg. Additional advantages include resistance to chemical contamination, gauge hole in evaporate formations, reduced production damage, and ability to be re-used [2].

OBM vs WBM

It is obvious that there are several advantages of using water base muds over the oil base muds. Examples of such advantages are being less damaging to the formation media compared to oil based muds (in terms of wettability alteration) and the possibility of cuttings to be disposed on site unlike the coated cuttings resulting from oil-base muds. Water base muds have undergone several important developments allowing them to be used as an alternative to oil base muds in some cases [21]. However, with complex types of wells such as deviated and S-shape wells, using the water base muds becomes more challenging because of higher friction and stuck pipe issues. The most important reason is due to the fact that water base muds are not naturally lubricious unlike the oil base muds. Though lubrication additives can be added to water base muds, it is much convenient to use oil base muds in such cases as they are readily lubricious. In addition to being lubricious, oil base muds provide a higher rate of penetration as well as more stable wellbore as they have been proven to have very low tendency of soaking the formation. The other advantage of OBM over WBM can be summarized as follows:

1. Water-based mud can swell shale formation, collapse boreholes and impact drilling outcome in the shale formation drilling.
2. Gases produced among shale cracks whose non-organic part is possibly aqueous wetting phase can be easily displaced by water, offsetting the well loggings.
3. Water-based mud can easily block the layers of very low permeability and influence the capability to produce hydrocarbon.
4. Oil-based mud can support the shale formation and its oil molecules cannot penetrate into tiny organic and non-organic pores under the capillary pressure.
5. Oil-based mud typically creates thin mud cake. This reduces the risk for stuck-pipe problem.
6. Oil-based mud can be treated and reused; thereby in the long run overall drilling mud cost is reduced.
7. Oil base as external phase is good lubricant so it greatly reduces drilling torque.
8. Hydrate formation problem at high pressure wells such as deep water drilling can be avoided by using oil base mud.
9. Typically, when drilling with oil base mud, gauge hole can be easily achieved.

In spite of the above advantages there are several disadvantages of using OBM, particularly in the offshore environment [22].

1. Environmental concern- OBM and the cutting generated during drilling with OBM are considered as toxic waste therefore it cannot be disposed directly into the environment unless treated well to meet the local regulations. Needs a good waste management while drilling with oil base mud.
2. Personnel Health – OBM has hazardous vapors which will cause health problem to the working personnel.

Need to use proper protective equipment in order to handle it. OBM vapor can irritate worker's skin.

3. Cost – Cost of OBM is much higher than most WBMs in terms of cost per barrel.
4. Gas kick detection – Gas kick is very difficult to identify while drilling with OBM because gas is soluble in oil. The gas kick can only be detected through volume gain in the mud pit. This enhances the drilling hazard.
5. Cleanliness – More time and effort is required to clean drilling area where the OBM spills.
6. Equipment damage – Rubber parts are easily deteriorated by oil base mud. Therefore, frequently check of rubber parts exposed to OBM is essential. This also enhances drilling risk.

To sum up, there is not so far a unified commitment or a generalized decision regarding the use of oil base muds over the water base muds or vice versa. However, the use of conventional oil base muds that won't degrade easily has been banned in many areas of the world [21].

Drilling-related Formation Damage

Reservoir formation damage is a serious concern in optimizing well productivity and profitability, which can take place in operations related to drilling, completion, cementing and fracturing [23] [24]. When the drilling fluid comes into contact with the porous formation, formation damage can happen either due to filtrate and fine solid invasion or due to remaining filter cake in the wall of the well. 'Filtrate' and 'filter cake' are two commonly used terms in describing formation damage. Filtrate refers to the liquid that passes into the permeable formation from the drilling fluid slurry, leaving the solids residue deposited on the medium face. Such solids are known as the filter cake [4].

Formation damage caused by drilling operations is divided into two categories, damage caused by chemical incompatibility and damage caused by blocking of pore spaces. Chemical incompatibility takes place through different mechanisms including:

- Reactions between formation fluids and filtrate resulting in scale or insoluble salt formation.
- Formation wettability changes due to excessive emulsifier invasion, resulting in emulsion blockage.
- Contamination of the reservoir oil with filtrate resulting in precipitation of asphaltic materials.

The mechanisms of pore spaces blockage takes place through:

- Invasion of drilling fluid and solids into the formation resulting in blockage of pore spaces and the formation of an internal filter cake.
- Deposition of an ineffective filter cake on the formation face by the drilling fluid.
- Lack of efficient solid control equipment.

The interactions between the invading particles and the formation are caused by one or more of the following mechanisms [25]:

- Penetration of solid particles into the formation pore and eventually being deposited within the porous

matrix. This mechanism is known as the standard blocking filtration and it can only occur if the penetrating particles are much smaller than the pores.

- Particles are too large to penetrate and eventually results in the formation of an external filter cake on the surface of the formation. This mechanism is known as the complete blocking filtration and it is at its maximum when the particles and pores are at similar sizes.
- Particles are individually small enough to penetrate but eventually forming a bridge across the pores. This mechanism is known as bridging filtration and requires the simultaneous approach of particles smaller than the pore size (but not too small) to form a bridge.

The three mechanisms are shown in the following figures:

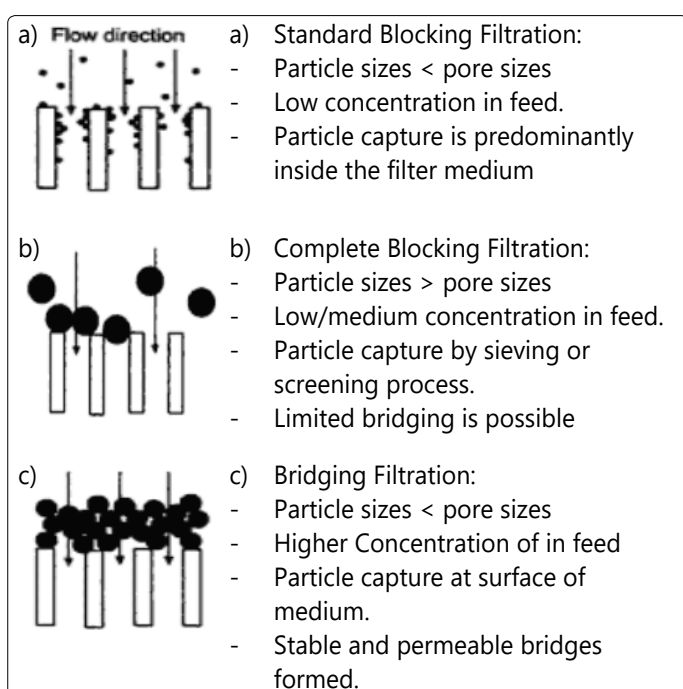


Figure 1: Mechanisms of filtration [25]

Similarly, the solid invasion into the porous formation can be classified into three main types: surface bridging, shallow plugging, and deep invasion. The fine solids penetrate into the porous formation and eventually accumulate and block the pore throats by forming an internal filter cake [26].

Minimizing formation damage

Though the accumulation of filter cake and filtrate invasion is directly related to the formation damage, if the drilling fluid is capable of forming an impermeable filter cake opposite to the producing zone, it will reduce the filtration loss and hence the formation damage [7]. Since the initial filtrate loss, known as the spurt loss, is usually the highest, the formation of the impermeable filter cake has to take place quickly. Moreover, the filter cake has to be thin in order to avoid stuck pipe problems [7].

The formation of such filter cake should take place in the near wellbore pores (i.e. an external filter cake) [26]. This will help minimize formation damage by avoiding the formation

of an internal filter cake which is harder to remove [27]. Moreover, the external filter cake should be easily removed by a suitable treatment or cleanup operation. These requirements have led to the development of Drill-in-fluid, which is commonly used in drilling the pay formation of most oil reservoirs [28].

Drill-In Fluids

As mentioned previously, drill-in fluids are drilling fluids (either water or oil based) designed specifically for pay zone drilling operations, thus drill-in fluids are expected to be non-damaging to the producing formations. In other words, drill-in fluids should be designed in such a way that an impermeable and thin external filter cake is formed which would resist the invasion of either filtrate or fine solids. Moreover, conventional drilling fluid additives need to be replaced with non-damaging ones. For example, the use of bentonite, a conventional rheology additive, is not accepted in the formulation of drill-in fluids. Instead, it is replaced with other non-damaging and bio-derived additives such as starch and xanthan gum.

It is obvious that the size of the particles within a drilling fluid slurry relative to the size of pores in the opposite producing zone, is an important aspect with regards to the formation damage. As mentioned previously, depending on the relative size (bigger or smaller), invading particles can either block or bridge the porous media. Therefore, controlling the size of such particles is highly necessary for damage control [23] [25]. Researchers have shown that the formation of an impermeable and thin external filter cake can be facilitated by the addition of properly sized bridging particles to the drill-in fluids [27] [29] [30]. Bridging particles are solid additives, used to bridge across the pore throats and hence form a filter cake to prevent invasion of particles and liquids [4].

Selection of bridging particles

The primary types of bridging particles used in the industry are calcium carbonate and sodium chloride [29]. Different sizes and grades of each type are available as well. Even though calcium carbonate and sodium chloride can both be used as drilling fluids bridging particles, they have different properties as mentioned by Davidson and Stewart [28]. For example, sodium chloride is water soluble, whereas calcium carbonate is acid soluble. Therefore, residual filter cakes formed by drilling fluids with sodium chloride are treated and cleaned by using under-saturated brine. On the contrary, residual filter cakes formed by drilling fluids with calcium carbonate can be cleaned using acids. The cuttings disposal from drilling fluids with sodium chloride always presents a higher polluting potential than cuttings from drilling fluids with calcium carbonate [28]. Another significant point is that the chemical driving force between an acid and carbonate is much stronger than that between water and salt. This implies that over the same period of time, there will be more complete dissolution of carbonate by acid than of salt by water. Higher preference to calcium carbonate is evident, as it possesses proper mechanical and chemical stability and

it is highly acid soluble [26]. Such properties allow the formed filter cake to have mechanical consistency, resistant to the drilling impacts and high-pressure differentials, and allow for better removal to recover the original permeability of the reservoir rock. In cases when the use of acid based treatments is not acceptable, or the well to be drilled is a water injector or producer, sodium chloride has an advantage over calcium carbonate. That is because; the injected or produced water is expected to dissolve any residual filter cake [28]. The aforementioned aspects have to be taken into consideration in the selection of bridging particle type.

Selecting bridging particle size distribution

Selection of bridging particle size distribution needs careful evaluation of the following:

Reservoir rock-pore size distribution

This is an important aspect that has to be carefully considered in selecting the size distribution of the bridging particles to be used in the drill-in fluids. It is worth noting that the size distribution has to be considered regardless of the type of the bridging agent [28]. The first step in selecting the bridging particle size distribution in drill-in fluids is to determine the pore geometry and the petro-physical characterization of the reservoir rock [29]. Various techniques and analyses are available for reservoir rock characterization, and each possesses some advantages and limitations.

The most commonly laboratory based techniques of pore system characterization in reservoir rocks, are thin-section analysis, mercury injection, scanning electron microscopy (SEM) analysis and CT scanning techniques [30]. Below is a comparison between the aforementioned techniques [30]:

- Thin-sections analysis: it is inexpensive relative to other methods and offers direct measurement of the pore size. However, the measurement is two dimensional only and it is operator dependent (i.e. Human error dependent). The detectable pore size range using thin-section analysis is 2 to 5000 microns.
- Mercury injection: it is less operator dependent than thin section analysis. However, it may not detect the largest pore sizes in many reservoir formations. The detectable pore size range using mercury injection is 0.0025 to 100 microns.
- SEM analysis: it is extremely practical to measure very small pores (i.e. micro-porosity). However, it is less practical to measure large pores due to high cost and time. The detectable pore size range using SEM analysis is 0.05 to 5000 microns.
- CT scanning: it can evaluate the three-dimensional pore geometry and pore size statistics. However, it is difficult to encompass the entire range of pore sizes.

In the field scale, the Full-bore Formation Micro-Imager (FMI) allows much enhanced evaluation of complex reservoirs by using micro-electrical arrays [31]. It enables an in-situ description of the reservoir without having to resort to full-hole coring over the entire zone of interest. The imaging tool

provides images of the borehole wall at a resolution of 0.2 inches. The borehole coverage of this new tool is 80% in an 8 inches borehole. Application of such tool include fracture identification, analysis of small-scale sedimentological features, evaluation of net pay in thinly bedded formations and the identification of borehole irregularities.

Methods of bridging particles size distribution

Different approaches are followed to deduce the required bridging particles size distribution in a given reservoir condition. These approaches can be divided into two main categories, Abram's Rule and the Ideal Packing Theory (IPT). It is worth mentioning that the IPT has undergone continuous improvement since it was first proposed. Though Abram's Rule is still being applied, limitations within its applicability have been recognized especially in carbonate reservoirs. Detailed view towards each of the aforementioned theories is described below.

Abram's rule [32]

Abram's Rule states that muds with bridging particles having median size equal or slightly greater than one-third of the median pore size of the formation will cause damage due to solid invasion which occurred to a depth of less than 1 inch. Such damage depth is normally penetrated by perforations and does not significantly affect the injectivity or productivity of the wells. The concentration of these bridging particles must be at least 5% by volume of the total solids in the final mud mix. The limitation of Abram's Rule is that it only addresses the size of the particles required to initiate a bridge. That is, it does not provide an optimum size or state an ideal packing sequence for minimizing fluid invasion and optimizing formation sealing [29]. Moreover, Abram's Rule may be very effective in homogenous formations; however, it is difficult to maintain the optimum particle size distribution in heterogeneous formations [33].

Abram's guidelines are still usable when little is known about the pore size distribution in a particular reservoir [27]. In such cases, a wide range of bridging particles is added to the drilling fluid in an attempt to provide a wide range of bridging capabilities.

Ideal Packing Theory

Unlike Abram's Rule, the Ideal Packing Theory (IPT) is concerned with the packing sequence for formulating a minimally non-damaging fluid [34]. It provides the full range of particle size distribution required to effectively seal all the pores, including those created by bridging agents. This subsequent layering of bridging agents results in a tighter and less invading filter cake [29].

The first form of IPT described the correlation between particle size distributions using a relationship between the cumulative volume percentage (CV) and the particle diameter d [35]. The relationship was given as, where n is a variable exponent. With regards to this relationship, the IPT suggests that there is a value of n at which the size distribution tends to result in bridging particles forming a filter cake with minimal voidage [34]. The maximum packing density obtained

following this relationship was when lays between 0.5 and 0.67.

It is a worth noting that different values have different meanings. If α is equal to 1, a linear relationship is present, meaning there is an equal volume of particles of each size. If α is less than 1, a higher proportion of small particles is present. If α is larger than 1, a higher proportion of large particles are present. Too high concentration of small particles would displace and wedge the larger particles apart and therefore interfere with packing efficiency. On the other hand, too high concentration of larger particles would leave voids that are not sufficiently plugged with small particles. Therefore, it may be expected that there is an optimum value of α or at least an optimum range [25].

The literature includes various suggestions with regards to the IPT, some important ones with the optimum value of α are mentioned below:

- Furnas [36] suggested that the optimum value of α is a function of several factors such as the size distribution, shape, packing structure randomness. Therefore, there is no single grading curve sufficient for all types of material, and hence, will need to be experimentally determined.
- Bo et al [37]. showed that for particles of similar size limits, the porosity of packed beads decreases as the value of α approaches 1.
- Dick et al [29]. suggested that the ideal packing occurs when the cumulative volume percentage vs. particle size diameter raised to the power of 0.5 forms a straight line relationship.
- Chellappah and Aston [25], showed from their experimental results that the optimum value of α to be closer to 1 than 0.5.

In Ideal Packing Theory, it is desirable to select a particle size distribution that will quickly bridge the largest pore openings, the medium pore openings and a smaller pore size fraction. These targets fractions are generally based on the D90, D50 and D10 of the reservoir pore throat distribution [27], where DA is the particle size at which the percentage of total solids (by volume) are smaller than A. No additional improvement can be observed when more than three varieties of bridging agents are used [33]. On the contrary, it was proven that when sufficient pore data is known, matching the pore size distribution with additional target fractions, D75 and D25, would result in higher return permeability [27].

Other Drill-in Fluids Additives

Drill-in fluids are generally water-based muds which contain a combination of additives. This combination is made of a viscosifier, fluid loss additive and sized particles (i.e. bridging particles) [37]. Xanthan gum is used as a viscosifier while modified starches and cellulose polymers are used for filtration loss [38]. Xanthan gum and modified starch have some advantages over the conventional mud additives. Conventional mud additives such as bentonite should be avoided as they were proved to cause damage to the

formations ultimate performance. The following sections shed light on the use of bentonite and similar compounds compared to the use of degradable polymers.

Disadvantages of Bentonite and Other insoluble rheology controllers

Bentonite is a naturally-occurring clay material, which is composed mainly of sodium montmorillonite⁴. Bentonite swells to many times its dry volume when hydrated by water. Therefore, it forms a viscous fluid with high gel strength making it an excellent additive when used as a viscosifier as well as it works well as a sealant. However, the filter cake formed by bentonite is found to be highly detrimental to the formation performance. The main reason behind this effect is that, once bentonite is hydrated and forms the protective mud cake it cannot be easily removed. As mentioned previously, a desirable mud cake has to be easily removable in order to restore the well productivity/injectivity. In case of bentonite, this requirement is not satisfied. Consequently, the only effective way to restore the well is by physically removing the bentonite from the well. This is usually done through mechanical or hydraulic agitation, which is not effective enough in most wells. Moreover, due to the swelling effect, a very limited open area may be available for a chemical injection or mechanical agitation especially in horizontal wells. This results in an inefficient removal of the filter cake, leaving the well performance much lower than expected [39]. In order to overcome some of the disadvantages of bentonite, Nano-Enhanced drilling fluids are designed which demonstrated superior lubricity and hole cleaning properties while retaining suitable viscosity and density [40], however the post-drilling hole clean up still remains an issue.

To overcome the wellbore clean up issues with bentonite as rheology controller, degradable polymers and related rheology controlling additives; such as xanthan gum, modified starch and modified cellulose products (polyanionic cellulose being the most preferred one) are in use as viscosifier and rheology controller. They provide similar characteristics as the conventional mud additives, however, unlike the conventional additives, they are able to breakdown naturally within a few days. If necessary, the break down process may be accelerated to a few hours through the use of specific enzymes. Therefore, biopolymers are much less likely to cause formation damage and can provide as much as 40 times the flow rate of wells drilled with Bentonite [39]. On the other hand, biopolymers cost much more than conventional bentonite. However, when considering the ultimate well performance provided by their use, the initial cost of biopolymers is more than compensated [39].

Drilling Through Depleted & Under-pressure Reservoirs

Drilling through depleted and under-pressured reservoirs is quite challenging due to the technical and economic problems that often make it unprofitable to further develop such fields [41]. The most common problems related to such type of drilling are the uncontrollable losses of mud or mud filtrate and differential sticking of drill string. In order to

overcome such problems, APHRON drilling fluids were introduced. APHRON drilling fluids refer to a special type of drilling fluids which are designed to be used for drilling depleted reservoirs and other under-pressured zones by controlling losses through high-permeability sands while stabilizing the pressured shales or other formations [41]. APHRON drilling fluids are highly shear-thinning water base fluids containing stabilized air-filled bubbles and are able to seal loss zones with non-permanent formation damage [42]. The air that is used to generate APHRONS is usually incorporated into the fluid with conventional mud mixing equipment at ambient pressures. As a result, the cost and safety concerns associated with air or foam drilling are reduced. Although the performance of APHRONS in the fields as cost effective alternative to under balance drilling is well documented, the mechanisms through which they work is still questionable [42]. Below is the survey findings that was conducted under the auspices of the U.S. Department of Energy in order to develop further understanding of APHRONS role. The findings of this study included [41]:

- APHRONS can survive elevated pressures for a much longer time than conventional bubbles.
- In loss zones, APHRONS can migrate faster than the base liquid and concentrate at the fluid front, and hence, building an internal seal in the pore network of the rock.
- The APHRONS are able to reduce the rate of invasion through the aid of a micro gel network formed by particulates in the pore network of the rock.
- As the fluid slows, the low shear-rate viscosity of the base fluid enables the fluid to generate high viscosity rapidly.
- Bridging and formation of a low-permeability external filter cake also occur to ultimately reduce the rate of invasion to that of ordinary fluid loss.
- APHRONS have very little attraction for each other or for mineral surfaces. Consequently, they do not readily coalesce nor stick easily to the pore walls. This is important when production starts.

The combination of the above features is expected to result in low formation damage and minimal requirements for cleanup [42].

Fluid Invasion into the formation

APHRON drilling fluids have proven the ability to seal-off rocks as permeable as 80 Darcy, as static linear leak-off tests have demonstrated [42].

The following figure shows the role of APHRON drilling fluids when used with Aloxite cores with permeabilities of 0.75 to 10 Darcy.

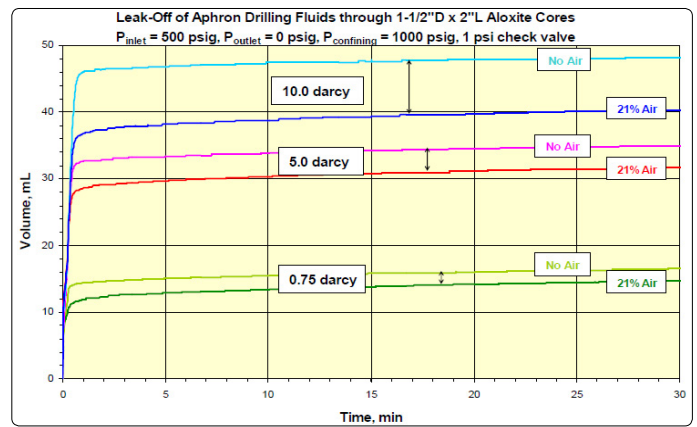


Fig 2. APHRON Drilling Fluids sealing ability with high permeability formations [42]

Figure 2 demonstrates that for each curve, there is a high rate spurt loss stage, at which the volume increases linearly with time. APHRON drilling fluids contain low levels of particulates that combine to form an external filter cake and shut down whole mud loss. As shown in figure 2, APHRONS are able to reduce the spurt loss below the levels afforded by the base fluid. Surprisingly, at low pressures, APHRONS can form an internal seal, while becoming an integral part of the filter cake [42].

APHRONS-related Formation Damage

In order to confirm the non-damaging ability of APHRONS, several return permeability tests were conducted using Berea sandstone core plugs along with APHRONS, a well-constructed reservoir mud and Hydroxyethyl cellulose mud [42]. The following figure shows the results of these tests:

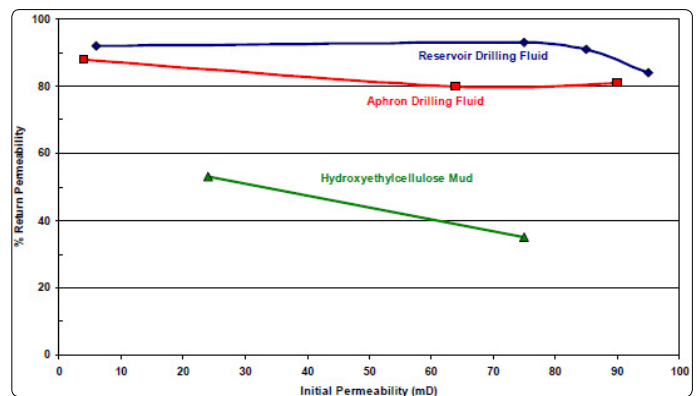


Fig 3: Return permeability of APHRONS vs reservoir mud & Hydroxyethyl cellulose mud [42]

Figure 3 shows that the formation damage potential of APHRONS is quiet low and is close to that of a well-constructed reservoir drilling mud [42].

Compatibility with formations and produced fluids

As mentioned previously, APHRONS resist coalescence and aggregation, and they have the ability to remain as discrete bubbles in the circulating fluid during a lost circulation event [43]. APHRON’s low wettability implies an easy cleanup of the pay zone post to drilling operations. By examining the wetting behavior of oil and APHRONS, it was concluded that whether the oil is applied to the drilling fluid or the fluid is applied to the oil (see Fig 4), the applied phase spreads over

the substrate phase, indicating a very low contact angle. Therefore, APHRONS and oil are highly compatible phase [43]. The following figure shows the contact angle in both cases.



Fig 4. APHRON drilling fluids and crude oils are very compatible as shown by the low contact angles [43].

Application of Nanotechnology in Drilling Fluid

Nanotechnology has been applied in the oil industry after being proven successes in a variety of fields such as electronics, material composites and medical goods. In order for nanotechnology to be successfully applied in drilling fluids, it must satisfy two main conditions which are [44]:

- Provide what conventional technologies are not capable of.
- Have advantages over a colloidal or micro-sized method.

Nano-particles as an additive in drilling fluids has been studied for several years especially in the fields of rheology, fluid loss, system enhancement or shale stability [45], which are discussed below.

Rheology and Fluid Loss Control

One of the important properties of nanomaterials is their strong particle-particle interaction, making them high potential viscosifying additives. For example, addition of graphene oxide (GO) to a water base mud containing

bentonite and barite has shown a quiet substantial effect when added only 2 lb/bbl of GO in the mud. Table-1 shows the effect of such addition.

Graphene oxide sheet-like structure has attracted attention to the researchers due to its applicability to be used as a fluid loss controller. The results of adding graphene oxide to a fresh water drilling system has proven effective impact on both rheology and fluid loss [46]. Amazingly, adding 1 lb/bbl of graphene oxide functioned as effective as adding 5lb/bbl of

Table 1. Effect of graphene oxide addition [45]

Product	Units	Test #1	Test #2	Test #3	Test #4
Freshwater	g	160	159	159	159
GO	g	0	0	1	1.5
Gel	g	0	5	0	0
Barite	g	39	39	39	39
OCMA Clay	g	5	5	5	5
After aging at 150 °F for 16 hrs.					
Rheology Temperature	°F	120	120	120	120
6-rpm Dial Reading	cP	1	5	9	28
3-rpm Dial Reading	cP	1.5	5	9	27
Gels 10-sec	lb/100 ft ²	2	7	10	27
Gels 10-min	lb/100 ft ²	2	9	15	38
Plastic Viscosity	cP	3	4	8	9
Yield Point	lb/100 ft ²	-1	2	11	37
API Fluid Loss	mL/30 min	83	23.6	23.4	16.8

conventional gel. Table-2 shows the effect of adding graphene oxide on fresh water base mud.

Table 2: fluid loss effect of adding graphene oxide [45]

Product	Units	Test #1	Test #2	Test #3	Test #4
Freshwater	ml	329	327	326	321
Gel	lb/bbl	5	5	5	5
GO	lb/bbl	0	2	4	6
Barite	lb/bbl	80	80	80	80
OCMA Clay	lb/bbl	10	10	10	10
Rheology Temperature	°F	120	120	120	120
6-rpm Dial Reading	cP	1	4	11	17
3-rpm Dial Reading	cP	0	3	12	15
Gels 10-sec	lb/100 ft ²	1	5	13	25
Gels 10-min	lb/100 ft ²	2	6	13	14
Plastic Viscosity	cP	4	8	7	3
Yield Point	lb/100 ft ²	-1	4	16	42

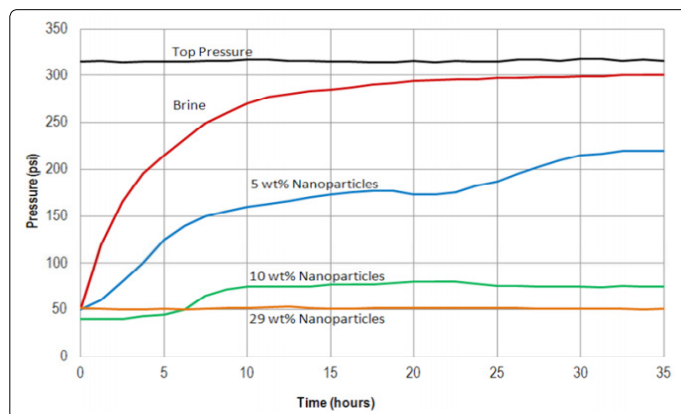


Fig 5: Sealing performance of Nano silica on shale [47].

Drilling HT-HP reservoirs

Drilling deep reservoirs generate technical challenges due to their extremely high pressures and temperatures, which

may go up to 1400 bar and 300°C respectively. It is difficult for most conventional mud additives to withstand such extreme condition, and they undergo thermal degradation, which results in loss of the required mud properties, such as rheological properties. This has motivated huge research interest and several laboratory level successes are reported.

Formate based brines are in the market for quite some time which, uses sodium, potassium and cesium formate brines in drilling HP-HT wells and an established field proven water based drilling fluid, though cesium formate is cost ineffective and rarely in use [48] [49]. A new water based mud is developed with manganese tetroxide as the weighting agent modified poly-acrylics and polyvinyl-pyrrolidone, whose properties are thermally stable up to 180°C [50].

Water base mud containing Multiwall Carbon Nanotubes (MWCNTs) are tested up to 500 °F temperature and up to 25,000 psi pressure and compared with high temperature stable oil base mud. The rheological properties of the new mud offered better environmental acceptance with improved rheological properties [50].

Conclusion

In conclusion, the success of any drilling operation is strongly related to the performance of the drilling fluid. The drilling fluid performance is a function of several factors such as drilling-related formation damage and wellbore. However, a high performance drilling fluid should also comply with the general concerns and requirements of the industry. Therefore, the evaluation of any drilling fluid is based not only on its performance, but also on its cost and its effect on health, safety and environment. In general, there isn't (so far) such an ultimate type of drilling fluid that can fulfill all the industry requirements. Until then, the drilling fluids will continue to develop with new types and formulations. The review work is being summarized in the table below, which may serve as a ready reference for a specific type of drilling fluid requirement.

Development	Purpose or field/ Brief description	Reference number
Water-base muds (WBM) & Oil-base muds (OBMs)	In this paper, the rheological characteristics of WBM & OBM were compared to help decide the most suitable mud type for HPHT drilling. The tests were conducted at temperature range of 120 F to 500 F with pressure between 14.7 to 25,000 psi. It can be stated from this study that the OBM are more effective in HPHT drilling, whereas WBM offers better choice for environmental concerns. However, some WBM-performance-enhancement additives such as MWCNTs are not environmentally friendly.	12
Drill-in fluids (DIFs)	In this study, the filtration characteristics of different DIFs formulations were compared through dynamic filtration tests. It can be stated from this study that the formulation of DIF (especially bridging particles) depends on the geometric characteristics of the porous media and the conditions under which the filtration occurs.	26

Abram's Rule	In this study, laboratory tests on two different types of rock system were conducted in order to determine the depth of mud impairment as well as productivity impairment. It can be stated from this study that the mud must contain bridging particles with diameter greater than or equal to one-third the formation median pore size at concentration levels of at least 5% by volume of the mud solids.	32
Ideal Packing Theory	This study added on Abram's Rule by stating that the selection of bridging particles size distribution must also account for the pores created by bridging particles themselves. This study suggested that the ideal packing occurs when the cumulative volume percentage vs. particle size diameter raised to the power of 0.5 forms a straight line. The laboratory results showed return permeabilities a high as 100%.	29
Sized Calcium Carbonate & Sodium Chloride	This paper presented DIF formulations, properties and some examples of field performance with a discussion of relative advantages and disadvantages of each system. The paper stated that several factors need to be taken into consideration when selecting between calcium carbonate and sodium chloride due to different characteristics of each one. However, the paper stated that calcium carbonate is more preferable due to its chemical and mechanical stability as well as its high solubility in acid.	28
Bio-polymer additives	This paper compared the performance of conventional mud additives such as Bentonite with the bio-derived polymers such as xanthan gum and starch. The paper stated several advantages of using biopolymer additives over the conventional ones despite their initial higher cost. The paper also mentioned that the initial cost of biopolymers is more than compensated when compared to additional costs required to develop a bentonite-drilled well.	39
APHRONS	This paper described the development and application of APHRONS for controlling downhole mud loss in a North Sea depleted reservoir. The paper mentioned a successful implementation of a project (using APHRONS) in which a well was planned to be deepened from the main reservoir to the lower reservoir. The APHRON based mud was able to seal the existing perforations, the milling operation was successfully completed and the drilling proceeded to the required depth successfully without any mud losses.	41
Nano-technology in Wellbore Stability	This study was designed to stabilize the Marcellus shale in USA. The commercially available silica nanoparticles were screened based on their stability in brines as well as thermal stability prior to be tested for filtrate loss and TEM analysis. The tests results showed that silica nanoparticles were able to reduce the shale sample permeability by 98%. The permeability remained low even after 15 hours of exposure.	44
HPHT Drilling	This paper described a novel water-based drilling fluid designed for HPHT drilling. The novel drilling fluid is thermally stable with minimum fluid loss at temperatures as high as 180 °C with good inhibitive and lubricating properties.	50

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