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Separating Fact from Folklore about Drilling Fluids

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Abstract

The properties of drilling fluids are critically important to successfully drill oil and gas wells. However, misunder-standings about how these fluids work can give rise to errors in drilling operations and in optimization of the properties of the fluids. This paper discusses some common misconceptions about drilling fluids, with the objective of improving how we work with them.

Drilling fluids are slurries that are intrinsically unstable in various ways, ranging from phase separation to changes in composition, yet they are made to be stable long enough to perform their many functions during the drilling of wells. How drilling fluids perform their functions – especially those involving interfacial phenomena – is shrouded in stories that often sound reasonable but are incorrect. These include how drilling fluids affect wellbore stabilization, lubrication, bit-balling, wellbore invasion and filter cake formation. In addition, various facets of these fluids and their components, such as the roles played by different kinds of solids and the nature of invert emulsion fluids, are not fully appreciated by most workers in the industry. These and other important misunderstood aspects of drilling fluids are explored.

Introduction

It would be wonderful to use a drilling fluid that behaves like a material produced in a chemical plant, whose composition and properties are controlled and are perfectly reproducible and predictable. Unfortunately, every drilling operation has unique requirements that necessitate differences in the fluid design. Worse yet, as we drill a well we purposely and continuously contaminate the fluid with varying assortments of materials (whatever the rock formation contains) and simultaneously add fluid and various additives as we increase the depth of the hole. Since economics dictates that we re-use the fluid, we remove some of the contamination and use dilution with fresh fluid so as to maintain properties that will permit the fluid to continue performing its many functions.

Fortunately, drilling fluid properties typically need to be controlled for only a short period of time. For this task, we have discovered that we can create fluids with all kinds of useful properties that do not have long-term stability but have sufficient stability over the course of the drilling operation to be viable. Indeed, many of the functions of the fluid may be of a temporary nature or involve slowing reactions in the wellbore just long enough to enable setting casing in the hole.

Because so much about drilling fluids is variable, it is no wonder that the industry's understanding of how fluids work is fraught with many misconceptions. This paper touches on a number of these, with the objective of helping us to improve how we run these fluids and realize their potential more fully.

Fact vs Folklore

Wellbore Stability

"The effect of a drilling fluid on drilled cuttings indicates how well the fluid stabilizes the wellbore."

Drilled cuttings result from destabilization of rock by the impact of the bit cutters with the formation. Cuttings/Cavings Analyses are widely accepted rigsite techniques to judge the chemical impact of the drilling fluid on the wellbore (Cuttings Analysis) and the physicomechanical impact of the fluid density on the wellbore (Cavings Analysis). Clay-containing cuttings that are firm and clearly show the imprint of the bit cutters are generally indicative of little chemical impact from the drilling fluid on the formation. The converse may also, though not necessarily, be true, namely that cuttings that are soft or have little definition may indicate absorption of water and weakening of the rock structure. However, young clay-bearing formations may be soft and replete with water, and therefore the appearance of the cuttings may not be a good indication of how chemically stabilizing the drilling fluid might be.

Even more of concern are laboratory tests of the inhibitive or stabilizing ability of a drilling fluid. Since clay-laden rock is usually encountered in intermediate zones in the well and not in the reservoir, this rock is seldom cored, so inhibition tests usually are run with cuttings. Not only are the cuttings themselves already severely contaminated with drilling fluid, in contrast to native core material, but the inhibition tests themselves do not simulate downhole conditions, e.g. overbalance, and usually do not even simulate downhole temperature. Thus, the experience of a formation during the creation of a wellbore and the subsequent continuous exposure of the rock to high-velocity fluid at elevated temperature and pressure is well-nigh impossible to mimic with cuttings.

A related problem with young formations is bit-balling.

Usually a drilling fluid that exhibits some inhibition of cuttings hardens the cuttings and the wellbore. In young, wet formations inhibition may actually make the cuttings and the wellbore stickier. This exacerbates bit-balling, decreasing the drilling rate and exposes the wellbore to the fluid for a longer time, thereby increasing the risk of wellbore destabilization.

The adhesive nature, or stickiness, of clays is dependent on a multitude of properties, but the concept of non-plastic/plastic/viscous properties of cohesive soils as first described by Atterberg (as cited by Friedheim 1999) is helpful to explain the role played by water content, as depicted in **Fig. 1**. This indicates that for (fine-grained) clay-bearing rock there is an intermediate range of water concentration that leads to the rock being most sticky and, by implication, most apt to cause bit balling. To minimize this risk, a drilling fluid must pull sufficient water from the cuttings to drive them to a drier, less sticky state, or alternatively, increase the imbibition of water and disperse the cuttings.

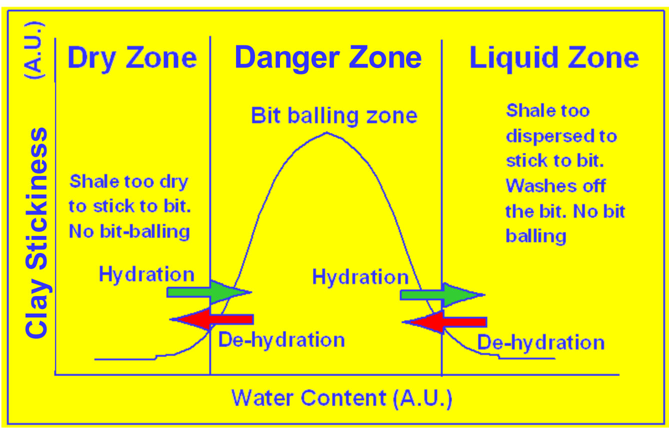

Fig. 1 – Moisture content limits for bit-balling (Friedheim 1999).

"Shale can be inhibited only by chemical means."

Stabilization of clays in the wellbore and cuttings is usually carried out in water-based drilling fluids using "shale inhibitors", which are either intercalators or encapsulators, or in invert emulsion fluids by controlling the salinity of the internal brine phase. However, the rate of interaction of a drilling fluid with clays is a function not only of specifically adsorbing species in the fluid and water activity, but also of the overbalance and viscosity of the fluid. The diffusion rate of water into clays is inversely proportional to the pressure differential across the fluid/formation interface and to the viscosity of the fluid. Thus, reducing overbalance is inhibitive, as is using a highly viscous fluid.

Regarding high viscosity, however, it is generally considered a better practice to use a low fluid viscosity – to minimize the equivalent circulating density, or ECD, and the risk of lost circulation – and to focus on high annular velocity for good hole cleaning. Nevertheless, both goals may be reached by using low high-shear-rate viscosity to minimize ECD and high low-shear-rate viscosity to minimize interaction with the wellbore. In a fractured wellbore, this highly shear-thinning fluid provides the added benefit that invasion in the fractures slows rapidly, thereby limiting lost circulation.

"Sensitivity of shale to water is determined entirely by its smectite content."

The stability of clay-containing rock to water-containing fluids depends strongly on the nature of the clays, including smectite content. However, smectite content is not everything. As shown in **Table 1**, the mineral composition of the cuttings from three types of South American shales is essentially the same. So is the Cation Exchange Capacity (CEC), another indicator of clay reactivity.

Table 1 – Composition of South American Shales from X-Ray Diffraction and Chemical Analysis

Mineral	Wt (%)		
	Tena	Tiyuyuaca	Napo
Quartz	54	60	42
Feldspar	3	2	2
Calcite	4	3	3
Siderite	1	1	1
Hematite	3	4	2
Kaolinite	12	10	20
Illite	8	6	15
Smectite/Mixed Layer Clays	15	14	15
CEC* (meq/100 g)	12	11	12

*Cation Exchange Capacity as measured by methylene blue adsorption

However, dispersion and bulk hardness tests on these cuttings in a gel-water drilling fluid (**Fig. 2)** indicate that the reactivities of the three shales are quite different.

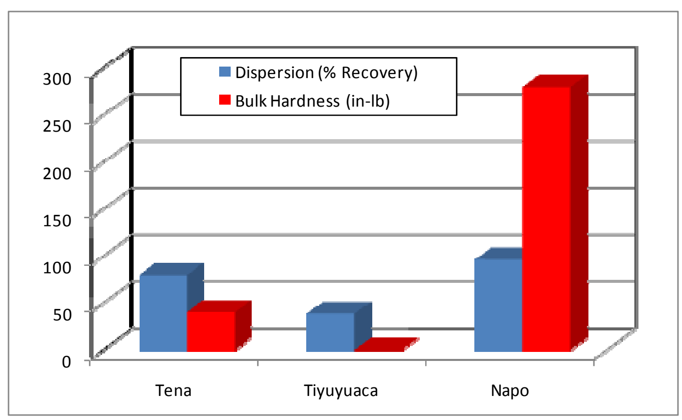

Fig. 2 – Dispersion and bulk hardness test results for South American shales.

Clay-bearing formations have a heterogeneous structure that includes, among other things, cementitious material, whose role in holding the structure together may be affected by water even more than smectite content but may not lead to swelling. Indeed, for some clays this "dispersive" nature can dominate their "swelling" nature. Not only is this manifested

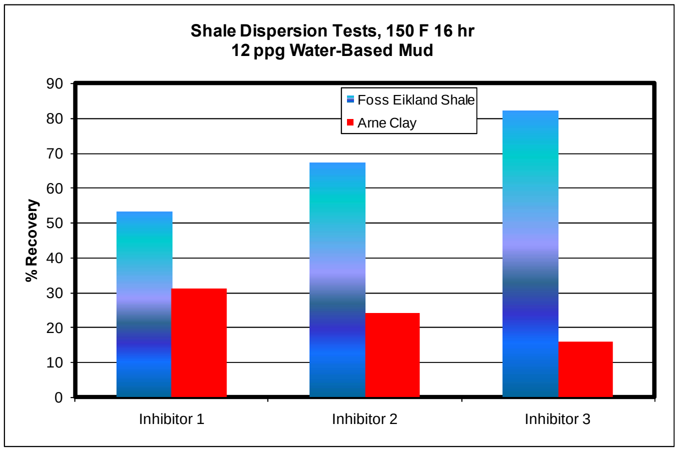

Fig. 3. Dispersion test results for three additives on two types of shales.

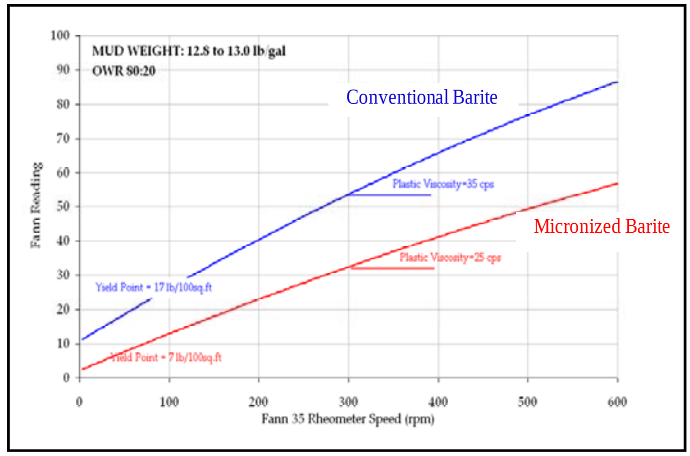

Fig. 4 – Fann 35 rheograms for 12.9-lb/gal oil-based drilling fluids weighted with conventional (API) and micronized barite.

in phenomena such as that noted in **Fig. 2**, it can also show up when testing various candidate shale inhibitors. **Fig. 3** shows an example of how the performance of inhibitors can vary with different types of shales.

This is also why "universal" inhibitors do not exist – some inhibitors are more effective for some kinds of shales, other inhibitors are more effective for other kinds of shales.

Density/Solids Control

"Fine particles in mud increase viscosity."

Drilling fluids generally follow the Einstein equation with respect to the effect of particulates on viscosity. This says that the viscosity (Plastic Viscosity) increases linearly with the concentration of inert solids up to 5 to 10 vol% and then rises exponentially. This is observed, for example, with API barite. However, micronized barite, which has a median particle size at least an order of magnitude smaller, does not have this effect (Massam 2004). Instead the viscosity rises very little with increasing mud weight, with the result that equivalent circulating density (ECD) is affected very little by the barite, and, because the particles are so small, barite sag is minimized. **Fig. 4** compares the viscosity profile of an oil-based drilling fluid weighted with conventional API barite and the same fluid weighted with micronized barite.

"Barite sag can be controlled by maintenance of a sufficiently high Yield Stress."

High gel strength is known to suppress static settling of barite and cuttings. High Yield Stress, as expressed in the Herschel-Bulkley viscosity equation, is critical for suppressing dynamic settling, especially in deviated wellbores while circulating. Unfortunately, the correlation with high yield stress is not exact, and it appears that geometric considerations such as eccentricity of the pipe and fluid characteristics derived from its viscoelastic nature – especially the loss modulus – can play a critical role, too (Zamora 2009). In addition, if a significant bed of barite is formed, aging of the bed and various properties of the fluid can affect the packing of the barite particles and the ease with which the bed can be removed.

"Gas added at the surface reduces mud density downhole."

Gas (N_2, Air) that is pumped continuously downhole so as to maintain a certain quality (% gas) will definitely reduce the mud density downhole. Gas volume in the mud column will vary inversely with pressure, and consequently, with depth, but the quality and density of the mud throughout the annulus can be regulated by controlling the influx of gas into it. However, if gas is only added at the surface, as is the case with some mud systems where air is naturally entrained in the mud pits, the air will compress to a miniscule volume and contribute very little to the overall density reduction (Growcock 2006). Boyle's Law says that the volume of gas is approximately 1/pressure. A drilling fluid with 15 vol% air at the surface will, when compressed to 15,000 psi, possess only 0.015 vol% air, and thus will affect the density by only 0.001 lb/gal. Even that will not be seen, because all of it will go into solution: Henry's Law states that solubility of air in water is proportional to pressure, i.e. if solubility of air at atmospheric pressure is 8 ppm (about 0.0008 vol%), at 15,000 psi as much as 0.8 vol% can go into solution.

Lubricants/Drag Reducers

"Oils in WBM can reduce turbulent friction and serve as drag reducers."

Polymers like xanthan gum can reduce WBM drag (pressure loss in pipes and annuli) by suppressing transitional flow and increasing the Reynolds number for the onset of turbulent flow. Oils added to WBM can function as efficient lubricants to reduce mechanical friction between the drillpipe and casing or wellbore, but there is no evidence that oils can also reduce pressure drop in the pipe or annulus (**Fig. 5**).

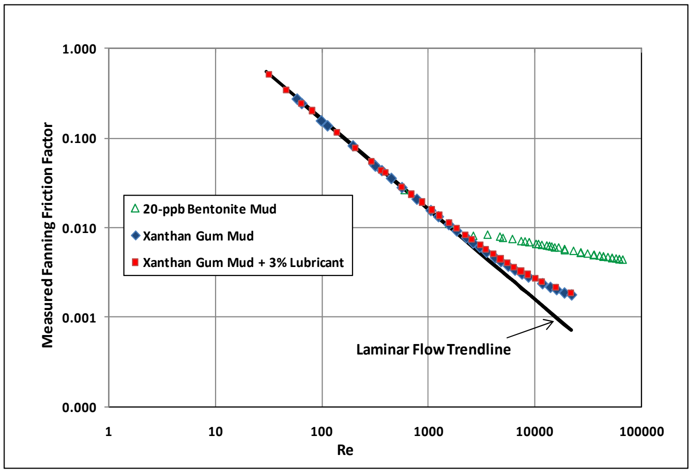

Fig. 5. Friction Factor vs Reynolds Number diagram showing extension of laminar flow regime by xanthan gum, but no effect from lubricant.

"Lubricants lose effectiveness because they become emulsified."

Liquid and solid lubricants both lose the ability to reduce the coefficient of friction with increased residence time in the well. SPE 50710 (Growcock 1999) teaches that liquids lose their effectiveness because of depletion on surfaces of the tubing and particulates in the mud, but just as importantly because shear at the bit reduces the droplet size to the point where the droplets are so stable that the energy barrier to adsorb on the surface cannot be surmounted. **Fig. 6** shows an example of the effect of shear over time on the performance of a lubricant.

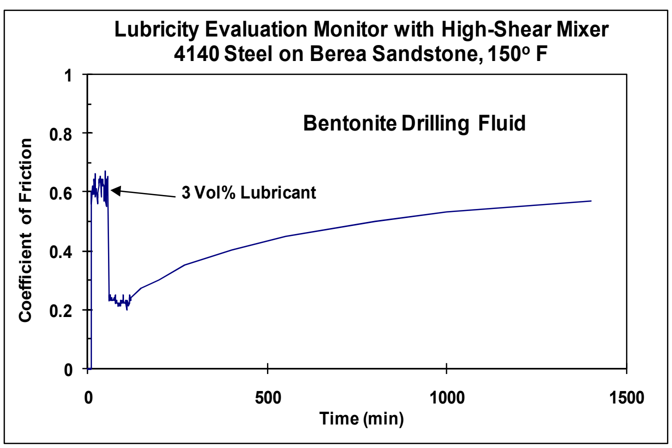

Fig. 6. Effect of shear on performance on lubricant (after Growcock 1999).

Solid lubricants are comminuted (ground down) at the bit, too, and become more stably dispersed as they become smaller, thus making it more difficult for them to "leap to the surface" and adsorb there.

"Coefficients of Friction (CoF) measured for steel-on-steel represent downhole conditions."

Most measurements of coefficient of friction involve measurements of torque or drag between two steel surfaces. Indeed, most of the tests involve low mechanical stress and are conducted at ambient temperature and pressure. Generally tests are no longer conducted at high stress levels, because so much drilling is now conducted with PDC bits, rather than rock or tricone bits with high bearing loads. However, the latter are still in general use, especially for hard rock drilling, and the impacts between drillpipe and casing or drillpipe and rock are still very high. Consequently, it behooves us to develop lubricants that can handle high impact loads (Aston 1998). Furthermore, it is now well known that coefficients of friction for steel-on-steel do not correspond to those measured for steel on rock surfaces (Growcock 1999). And lubricants themselves are notoriously fickle about the surfaces to which they adhere; indeed, most lubricants are not nearly as effective for steel-on-rock as for steel-on-steel. In some cases, a material that reduces CoF of steel-on-steel can actually increase the CoF for steel-on-sandstone (see **Fig. 7**).

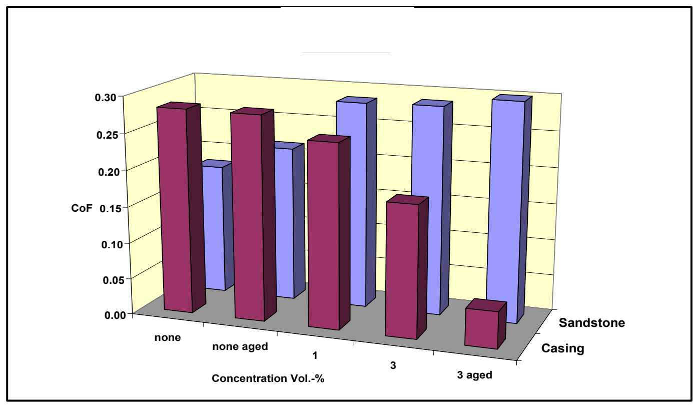

Fig. 7. Coefficient of Friction for steel-on-casing and steel-on-sandstone at ambient conditions measured on Lubricity Evaluation Monitor: 0 to 3 vol% lubricant in a reservoir drilling fluid.

Another issue is that many lubricants fail when exposed to elevated temperature and/or pressure. Finally, most test methods cannot measure the performance of mechanical lubricants like polymer beads or graphite, because the roller action that most devices use sweeps away the lubricants from between the contact surfaces. All of these variables need to be considered and appropriate test protocols used to obtain CoF measurements that are valid for downhole applications.

Hole Cleaning

"Back-reaming should be an integral part of any hole-cleaning operation."

Back-reaming operations are designed to remove detritus that clings to the hole, not for hole cleaning (K&M Technology Group). Good hole cleaning practices focus on optimization of hydraulics, moving the pipe, maintaining the proper viscosity of the fluid and controlling the rate of penetration. Frequent sweeps are often important, too, especially for deviated wellbores. In the event that these are not successful, back-reaming may be beneficial, but it is especially dangerous in highly deviated wellbores, where it may result in pulling cuttings into a bed and raising the prospect of stuck pipe.

Formation Damage

"Drilling underbalanced eliminates formation damage."

Although using a wellbore pressure less than the pore pressure can prevent invasion of the drilling fluid into the formation, in some operations when making connections the underbalance is lost, and the wellbore pressure is allowed to rise and perhaps reach the pore pressure. Since no protective filter cake has been formed on the wellbore, the drilling fluid can invade the formation. Furthermore, drilling underbalanced runs the danger of producing wellbore instability, wellbore collapse and stuck pipe. For this reason, it is generally recommended to drill overbalanced but to use appropriate bridging and fluid-loss-control agents to form a tight seal on the wellbore as one drills ahead.

"'Solids-Free' fluids are less damaging than solids-laden fluids."

Everyone knows that solids invasion can create formation damage through pore blocking and the buildup of a so-called internal filter cake. Why not eliminate solids from the drilling fluid, and avoid this source of damage! The problem is that one must drill. In order to make new hole, one must inevitably create cuttings that circulate up the annulus and can enter the formation. Cuttings are of arbitrary size and shape determined by a host of factors including rock properties, bit type, cutter design, ROP, etc. However, this generally does not result in creating the right particle sizes and distribution to create a tight, external filter cake. Generally speaking, cuttings sizes span a range from ultra-fines created by crushing individual mineral grains up to decimeter-sized ribbons of adhering rock slices.

Many studies have shown (Dick 2000) that a large particle of approximately the size of the largest surface pore is needed to initially block the opening. In addition, a carefully selected range of particles of decreasing size is needed to bridge the ever smaller pores between the filtered out particles. Until a tightly packed, moderately fluid tight cake has been established, cuttings particles are free to invade and damage the formation.

Further, the cuttings must be gotten out of the hole. While in relatively narrow vertical holes this can be accomplished by pumping at sufficient velocity, deviated wells require the drilling fluid to have viscosity, or better a rheological profile, that can carry the cuttings up the hole. Clarified xanthan gum can provide such a profile, but even the clearest xanthan is subject to forming filter cake on fine formations (Powell 1995) which can be difficult to completely remove (Luyster 2000).

Lost Circulation

"Lost circulation materials can be added or combined in any fashion to reduce downhole losses of whole mud."

When encountering severe loss of whole mud – usually through fractures – it is very tempting to start throwing anything into the mud that might stop or at least reduce the rate of loss. This tactic can work, but usually it is much more effective to design a particle mix that can form a tight pack within the fractures. **Fig. 8** demonstrates this with laboratory Permeability Plugging tests.

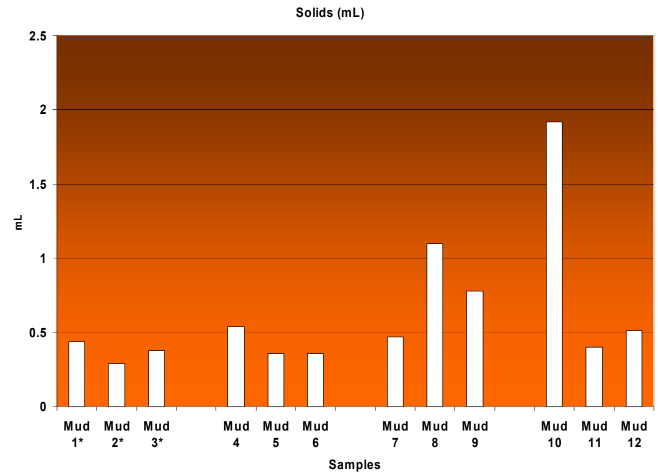

Fig. 8. Total Fluid Loss through 35-µm ceramic disks in 30 min using 2500 psi and 150 °F. WBM 1 through 6 contain 30-lb/bbl $CaCO_3$ sized to seal 35-µm openings. WBM 7 through 12 contain 30-lb/bbl $CaCO_3$ with random assortments of particle sizes.

It is for this reason that reservoir drilling fluids are designed with a blend of $CaCO_3$ that follows Ideal Packing Theory or some other similar concept involving use of a particle size distribution that covers openings ranging from the largest to the smallest. Mixing particles of different shapes and sizes with no thought to the resulting packing process is a recipe for disaster; indeed, some materials may disrupt the packing obtained with other materials.

"Power-Law fluids with lower 'n' value invade more deeply into permeable or fractured formations."

It has been shown that the more shear-thinning a fluid is, the deeper it will invade into fractures (Majidi 2009). This leads some to believe that shear-thinning fluids should be avoided when drilling into formations with pre-existing fractures or with a high risk of fracturing. Fortunately, this is not the case. The flow behavior of most drilling fluids can be described fairly well with the Power Law ($\tau = K \gamma^n$) or the Yield Power Law, also known as the Herschel-Bulkley equation ($\tau = \tau_y + K \gamma^n$), where τ is the shear stress, K is the consistency index, n is the power law index and τ_y is the yield stress.

Most drilling fluids that exhibit a Power Law Index $n < 1$ (shear-thinning fluids) also exhibit a Consistency Index K >> 1. Indeed, n and K are not independent of each other. Generally, fluids which possess low values of n will initially invade fractures more rapidly than high-n fluids, but they will also slow more rapidly. And fluids that possess high values of τ_y will actually stop. Fluids that do not have τ_y will continue invading, but if the K-values are sufficiently high, fluid invasion will slow rapidly and effectively reach a near-zero value.

Both xanthan gum- and MMO-based fluids, because of their shear-thinning nature and high low-shear-rate viscosities will tend to invade fractures more rapidly initially, but they will slow rapidly, too, so that in the end they will invade much less deeply than conventional fluids. This phenomenon is observed in openings that are large enough to admit the whole fluid, e.g. fractures, though the effect tapers off with increasing size of the openings. An example of these effects is shown in **Fig. 9**, where WBM A is a xanthan gum polymer mud, WBM D is a MMO mud and the others are more conventional fluids. Clearly WBM A (black) and D (blue) penetrate less deeply than the others.

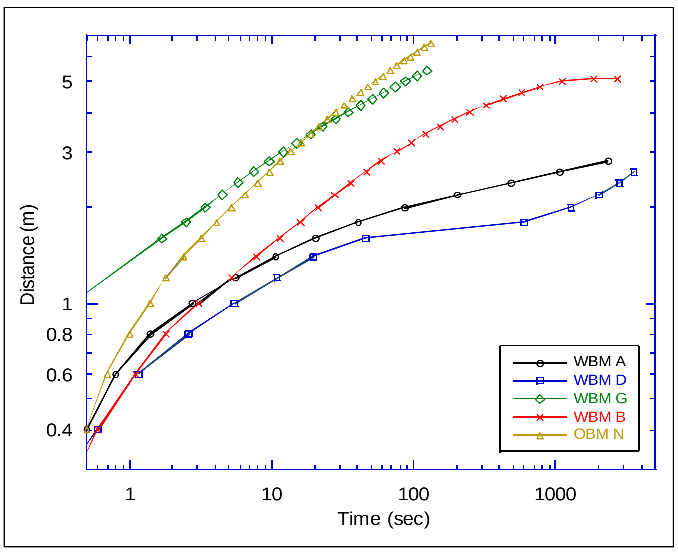

Fig. 9 – Distance of penetration in 2.5-mm ID pipe vs time *t* for various fluids, with ΔP = 10 psi (after Adachi 2004)

Even more striking differences are observed during drilling because of the radial flow pattern that most fluids follow when moving away from the wellbore, especially in a multiply fractured environment. In radial flow, the velocity of any fluid decreases with the depth of invasion; for a highly shear-thinning fluid with high K-values, the viscosity rises rapidly at the same time, resulting in the velocity dropping off even more rapidly. The net effect is that the slowing of high-viscosity shear-thinning fluids like xanthan gum polymer and MMO muds can be so rapid that the depth of invasion in fractures may be several orders of magnitude less – perhaps 1/100 to 1/1000 times less – than that for water.

Non-Aqueous Fluids

"Water in invert emulsion drilling fluids is present as stabilized droplets."

The convenient mental picture that is usually drawn for invert emulsion muds is that of aqueous droplets stabilized with surfactant and dispersed in oil. Although this may be a fairly reasonable portrait of solids-free invert emulsions, drilling fluids always have drilled fines and, in most cases, organophilic clays. Photomicrography of full invert muds shows no evidence of water droplets. Indeed, photographs at high magnification of the gap between the electrodes during Electrical Stability tests show that, as the voltage is ramped up, solids align between the electrodes to form a short-circuiting bridge. As the voltage nears the breakdown value, the solid particles begin to express aqueous droplets, which grow and at breakdown form a continuous strand of water beads.

Continuing efforts to understand the complex nature of invert emulsion drilling fluids by simplifying the system (Fjelde 2009) finds emulsified, micron and sub-micron droplets are present after initial mixing at low shear, but these droplets are firmly associated with fine clay and other particles. However freshly made invert drilling fluids that have not seen the extensional shear of pasting through the bit or the ultrafines created by drilling may display micron-sized brine droplets. Tightly-emulsified field muds almost never display the unique spherical shape associated with 'stabilized droplets'. Indeed, this is one of the reasons why it is difficult to completely reproduce all of the properties of field muds with laboratory-prepared muds. One of the authors (Growcock 1994) examined many field OBM in a study of electrical stability, and found no evidence of visible 'droplets'.

As porous rock surface is freshly exposed, more or less whole drilling fluid can spurt into openings that are larger than the largest particles in the fluid. Depending on the sizes of the openings within the rock, the flow can continue indefinitely, as might occur in vugs or fractures. As the openings approach some small multiple of that particle size, bridging can occur to eventually block the entrance of whole fluid. As the openings approach the average particle size, a random amount of whole fluid can enter before a particle of the right size arrives to plug the opening. Even relatively small openings admit finite amounts of essentially whole fluid that lack a large particle. These intrusions of essentially whole fluid are referred to as 'spurt'.

However, once a filter cake begins to build, the particles of the drilling fluid quickly pack into a tight filter cake. Invert emulsion filter cakes are typically less than 3 mm thick. From permeability and cake thickness, Aston (2002) estimates the final openings are about 5 nm – far smaller than the size of a brine/clay adduct as in water-based muds. Thus, after the initial spurt, the filtrate is essentially oil solution, which includes dissolved, but not emulsified, water.

"Water-based muds are better than NAF for coring."

Although water-based muds can be designed with a minimum of surface active materials, so as to minimize interaction with reservoir rock, they will penetrate water-wet rock. NAF can be designed to minimize interaction with reservoir rock, typically using weak surfactants at very low concentrations (Bloys 1993). When designed properly, they will penetrate water-wet rock to an even smaller extent than water-based muds, thereby yielding lower formation damage potential.

Conclusions

Misconceptions about how drilling fluids work can affect how they are designed and maintained to carry out their many functions. A few misconceptions have been highlighted here that pertain to wellbore stability, density and solids control, lubricants/drag reducers, formation damage, lost circulation and non-aqueous fluids. It should also be noted that in most cases laboratory and rigsite tests are not intended to provide absolute measures of what is going on downhole, but rather to serve as trend indicators. Fluid loss tests, for example, do not predict the rate of filtration of fluid into a formation. Rather, they provide some measure of the quality of the particulates in the fluid.

Acknowledgments

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Nomenclature

γ	= *Shear Rate*
K	= *Consistency Index*
n	= *Power Law Index*
NAF	= *Non-Aqueous Drilling Fluid*
OBM	= *Oil-Based Drilling Fluid*
Re	= *Reynolds Number*
ROP	= *Rate of Penetration*
τ_y	= *Yield Stress*
WBM	= *Water-Based Drilling Fluid*

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