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Utilizing the Unique Properties of Multi-Hydroxyl Alcohols to Drill Reactive Shales while Maintaining Environmental Compliance.

James P. Gaertner, Corey Peterson, ViChem Specialty Products; Chico Fox and Grant Peterson, Conquest Drilling Fluids

Abstract

In recent decades, the pressure to satisfy energy demand while safeguarding the environment has been a major challenge for the oil and gas industry. Furthermore, the development of unconventional shales has pushed the limits of drilling technologies. The use of diesel or synthetic emulsion based muds (EBMs) have long been considered the gold standard for drilling long laterals and/or highly reactive shales however, environmental concerns and regulations are increasingly limiting their use.

High performance water based muds have tried to address the environmental issues but many times have failed to overcome the inherent difficulties necessary to meet the high demands of drilling fluids today. The Multi-Hydroxyl Alcohol (MHA) System (ViChem Specialty Products, LLC) is an advanced drilling fluid system specifically designed with the lubricity and inhibition necessary to drill long laterals in highly reactive shales. The combination of proprietary lubricants and shale inhibitors with multi-hydroxyl alcohols provide this water-based fluid stability and performance characteristics comparable to EBMs while preserving environmental compliance. The results of laboratory tests and field trials demonstrate the MHA System provides the characteristics necessary to meet the operational demands and challenges placed on drilling fluids while minimizing health, safety and environmental costs and concerns.

Introduction

In recent decades, the demand for petroleum resources has reached all-time highs and continues to increase. The increased demand has, in some capacity, been met with new technologies allowing the oil and gas exploration industry to economically extract petroleum resources from unconventional shales. Over 75% of formations currently being developed worldwide are shale formations. Development of these unconventional resources has stretched the limits of drilling technologies to meet the challenges presented by high angle and extended reach drilling in reactive formations. This in turn has placed high demands on drilling fluids performance.

Operators have struggled to meet the high demands placed on drilling fluids in these technically demanding wells while maintaining environmental compliance. Growing concerns for safeguarding the environment have driven the increasing regulation of oilfield operations and especially of downhole fluids and waste disposal. Despite these intensifying concerns and regulations, emulsion based muds (EBMs) composed of diesel or synthetic oil bases continue to be the gold standard for drilling fluids on technically challenging wells. The decision to continue to use EBMs is made primarily based on two common misconceptions. 1) EBMs better address all of the potential problems associated with drilling a well. 2) All water based muds are alike.

Do EBMs better address all problems?

Do EBMs better address all of the potential problems accompanying drilling operations? EBMs are generally chosen due to their high stability, ability to inhibit shale hydration and potential to produce high rates of penetration (ROP). However, there are some problems associated with the use of EBMs which can somewhat diminish the perceived benefits of their use despite the overwhelming beliefs to the contrary. The most obvious disadvantage of using EBMs is the accompanying health, safety and environmental hazards associated with its use. EBMs are considered hazardous based on their toxicity and flammability and, along with cuttings created, EBMs must be disposed of accordingly. Waste generated from drilling operations using EBMs carry the burden of cradle to grave liability. Disposal and liabilities can add significantly to the overall cost of a project in the best of circumstances and can increase dramatically in the case of an accidental discharge.

EBMs also have a high unit cost when compared to water based muds (WBMs). This high cost of EBMs is magnified by their sensitivity to losses. Problems with lost circulation are considered to happen more frequently and are oftentimes more severe with EBMs because of the lack of availability of loss circulation materials for oil wet applications. Although EBMs are generally highly inhibitive to reactive shales it is also known that they create a less efficient membrane than WBMs (Dye 2005). There is some evidence suggesting that fluid penetration into the pore throats or micro-fractures of some shales is more significant in EBMs than WBMs (Hemphill 2009). Without an efficient membrane, fluid can more easily enter the formation and potentially weaken the bedding planes and cause dispersion despite the fluids non-reactive qualities (Boyd 2012). It is possible to have a highly inhibitive fluid that can still cause well bore destabilization by dispersion (Boyd 2012, Hemphill 2009). And finally, several studies have shown the potential for EBMs to cause skin damage to the payzone of a well (Beck 1993, Fjelde 2007). Reduction of the production potential of a well would have serious consequences in the overall economics of the project.

Are all WBMs the same?

Are all WBMs the same? The answer to that question is quite simply no. Most WBMs however, share several characteristics that make their use appealing to operators in some cases. Conventional WBMs are generally very economical to run on projects that do not require a drilling fluid with high performance. WBMs are also inherently environmentally friendly. The basic components of most WBMs are generally biodegradable and non-toxic, making them especially attractive in areas with more stringent environmental regulations. It is good policy for operators to use less toxic alternatives to chemicals at the well-site whenever possible. Public perception of oil and gas exploration is currently at an all-time low and must be addressed. One survey found that 72% of Americans surveyed in November 2010 would 'favor cleaner energy sources that involve the lowest possible risk to the public and environment' (Infogroup 2010).

There is a wide variety of loss circulation materials available for use in WBMs utilizing different technologies. Common loss circulation materials available include cloth fibers, wood shavings, and rice hulls or other crushed up seed coatings all of which are water-wet and not effective on oil-wet drilling fluids. It is common to switch to WBMs when a well is experiencing significant losses with EBMs because of the ability of WBMs to more effectively combat the problem. Finally, WBMs, overall, have more attractive logistics than EBMs. There are a broad variety of products available for use in WBMs that are widely available and easy to warehouse. Because WBMs can be built on site and do not have to be trucked in, they are logistically less demanding and reduce the operators over the road liability and associated costs. One of the most frequent complaints about energy projects is the truck traffic they create.

WBMs can be assembled from a variety of components to provide the characteristics necessary to perform efficiently. Those components generally consist of a weighting agent, viscosifier and water loss reagent. Additional additives to provide shale inhibition, lubricity and control over losses can also be added as necessary. Conventional WBM formulations are primarily composed of bentonite clay as the main viscosifier. These traditional formulations are economical, versatile and have been used to drill thousands of wells; however, they suffer from several serious setbacks. These formulations are susceptible to contamination by a variety of constituents including chlorides, carbonates and low gravity solids which can lead to unstable rheologies and reduction in API filtrate control. The properties of conventional formulations can also be sensitive to adverse effects caused by the interaction of drilling fluid additives including some lubricants and shale inhibitors.

The new generation of WBMs are commonly referred to as high performance water based muds (HPWBMs) and generally consist of bio-polymers for use as viscosifiers and water loss reagents. HPWBMs have several advantages over conventional WBMs. They are mainly composed of polymers and lack the high concentration of clays found in conventional WBMs and are therefore generally more resistant to contamination (Gallino 1999). Another advancement is the formulation of fluids specifically designed to maximize payzone protection (Beck 1993). Although there are competing opinions on the matter, it is frequently stated that HPWBMs show no evidence of increased hole problems over competing EBMs and that a properly formulated HPWBM can have performance characteristics similar to EBMs (Beck 1993, Boyd 2012, Dye 2005).

The Multi-Hydroxyl Alcohol (MHA) Drilling Fluid System (ViChem Specialty Products, LLC, Conroe, TX) utilizes a unique approach to formulation which combines the flexibility and value of HPWBMs with a base fluid formulated from a proprietary mix of multi-hydroxyl alcohols. The MHA Base Fluid acts as an environmentally friendly alternative to diesel or synthetic bases used in EBMs. Similar to synthetic and diesel based fluids, the MHA Base is composed of short-chain organic molecules that provide stability and performance characteristics analogous to oil, with the exception that the hydroxyl groups of the MHA Base make it completely miscible in water with no emulsification required. The absence of emulsifiers reduces the possibility of skin damage that may occur to the payzone due to emulsion block which can theoretically reduce the production potential of a well (Beck 1993, Fjelde 2007). The MHA Base is composed of low-polar organic compounds which have been shown to reduce the water activity of a drilling fluid which can, in turn, decrease invasion of fluid into the shale on a scale very similar to EBMs (Dearing 2004, Lal 1999). Unlike the base fluids of synthetic and diesel based muds, the MHA Base is completely biodegradable and cleanup (whether scheduled or due to a mishap) is immensely easier and less costly than with EBMs.

The MHA System was designed specifically to replace EBMs for horizontal wells in reactive shales with the specific goals of wellbore stability, shale inhibition, high lubricity and stability, reduced drilling costs and health, safety and environmental compliance.

Shale Stability Testing

A large portion of oil and gas production today comes from formations composed primarily of shale. As much as 90% of wellbore stability problems in those formations occur because of complications resulting from shale instability (Dye 2005, Han 2009, Lal 1999, Simpson 1998). There are two basic instability mechanisms acting on shale, hydration and dispersion. Hydration is generally caused by the expansion of clays due to the absorption of water. This is most pronounced in shale formations high in smectite content due to its susceptibility of water infiltration into the c-space between clay platelets. Hydrated shale can cause instability of the wellbore by its swelling action contributing to tight holes and stuck pipe. Furthermore, hydratable clays can cause bit balling and accretion and are more likely to cause problems with API filtrate control and unstable rheologies if allowed to solubilize and accumulate in the drilling fluid. Dispersion is the mechanical breakdown of the clay fabric generally acting on micro-fractures in the shale or the cementous material running through the shale. Dispersion can be due to physical disturbance from the activity of bit or drill string as well as from pressure differentials created when shale is exposed at the interface between the formation and the wellbore, or when shale is broken off and no longer exposed to formational pressures. Dispersion can also be caused by the invasion of fluid into the micro-fractures or pore throats of the formation. Failure to suppress dispersion and/or hydration in reactive clays can result in serious problems for the project, and it is not uncommon to have to redesign well trajectory or casing design or even abandon a well.

Shale inhibition studies were conducted using several MHA formulations with both primary methods of instability in mind. The shale particle disintegration or dispersion test (ISO 2009) was chosen to best challenge the drilling fluid's ability to inhibit both hydration and dispersion of shale samples. Shale samples were collected from the Eagle Ford, Jackson, Midway and Marcellus formations for testing. Approximately 40 g of shale was pre-weighed and added to a 500 mL OFITE stainless steel aging cell containing 400 mL of drilling fluid. The aging cells were sealed and placed in a roller oven pre-heated to 120°C and allowed to roll at 60 rpms for 16 hours. After allowing the cells to cool, the fluid was poured out and rinsed over a sieve to collect remaining shale. After gently rinsing, the shale pieces were recovered and placed onto a pre-weighed boat for drying overnight at 100°C. Samples were then re-weighed to determine the percent of the shale recovered. The percent recovery was subtracted from 100% and recorded in Table 1 and Figure 1 as the percent inhibition of the fluid.

Table 1 shows the percent inhibition of several different drilling fluid formulations on samples taken from four different shale formations. The "Base Lab Mud" (BLM) consisted of xanthan polymer, starch and/or other polymeric water loss reagent as the base with concentrations of L-20 Lubricant (3% by volume), MHA Base Fluid (60% bv) and SI-60 Shale Inhibitor (2% bv) (ViChem Specialty Products, Conroe, TX) added where specified. The "Example Optimized System" was a formulation consisting of a balance of polymers, water loss reagents, L-20, MHA Base Fluid and SI-60 optimized by testing to deliver optimal shale inhibition for each of the shale samples. Each of the aqueous drilling fluids was pH adjusted to 9.0. The "Diesel Based EBM" consisted of 70:30 diesel:CaCl.

Results in Table 1 reaffirm the supposition that shale samples taken from different formations can react differently when exposed to the same drilling fluid under similar conditions. This is partially due to the reactivity of the clay itself determined by the composition of the formation with clays high in smectite content, usually very reactive while those high in illite or kaolinite are less reactive. The reactivity of the clay is also dependent on its physical structure which can range from almost uniform to highly fractured. Its reactivity is also dependent on the composition of non-clay material generally running through the formation which can react with the drilling fluids or pressure differentials resulting from drilling or swelling activity. This study indicated that representative shales from the Eagle Ford (39.0% inhibited) and Marcellus (48.0%) formations reacted readily under experimental conditions with the polymer based lab mud while the Midway (69.0%) and Jackson (76.4%) shales were more stable.

While the untreated WBM used in this study reacted readily with shale samples, results indicate that the fluid treated with additives possessing shale stabilizing properties were considerably more inhibitive (Table 1). For example, the most reactive shale (Eagle Ford) was only inhibited 39.0% by the base lab mud without treatment. That same shale was inhibited by 73.3% with the addition of MHA Base Fluid and as much as 93.1% with the addition of SI-60 shale inhibitor. This trend held true for all of the shale samples tested with the inhibitive effects of additives less pronounced on the less active shales. For example, Jackson shale increased in stability only slightly, from 76.4% (untreated) to 78.2% with treatment of L-20 and inhibition increased to 91.9% with the addition of SI-60. These results clearly demonstrate the ability of WBM additives to inhibit shale within the parameters of this study.

The example optimized MHA System, in all cases, closely approached the inhibitive properties of the diesel based EBM tested. The differences in percent inhibition of shale of the optimized MHA System and the EBM varied from 2.5% in the Marcellus shale (95.9% vs. 98.4% in the MHA System and EBM respectively) to as little as 0.6% in both the Jackson and Midway shales (98.5% and 99.1% for EBMs vs. 97.9% and 98.5% for MHA in the Jackson and Midway shales respectively). These results confirm previous studies suggesting that HPWBMs can have performance attributes closely resembling EBMs and are therefore a potentially viable alternative for drilling reactive shales (Beck 1993, Boyd 2012, Dye 2005).

The MHA System can closely match the ability of an EBM to inhibit shale when optimized to a particular formation. This is primarily because the individual components contributing to inhibition have each been carefully chosen to inhibit shale swell and dispersion based on a different methodology and therefore complement each other. The L-20 lubricant has a uniquely high ability to coat the surfaces of the wellbore and cuttings. This is demonstrated by the high film strength presented in Tables 2 and 3. Encapsulation of wellbore and cuttings by the L-20 helps to stabilize the shale and prevent dispersion and infiltration by water. L-20 can also act to help seal and stabilize micro-fractures, further preserving shale integrity.

The MHA Base Fluid is composed of a proprietary mix of organic compounds containing multiple hydroxyl functional groups linked to a carbon chain. The hydroxyl groups give the base fluid its hygroscopic nature which allows the addition of MHA Base Fluid to lower the water activity of the resultant MHA System. Osmotic pressure created by the MHA Base Fluid prevents the water molecules from interacting with the crystal surfaces of clay platelets and causing surface hydration. This is a method that has proven to be effective in inhibiting shales in other, similar formulations (Dearing 2004, Simpson 1998). Hydroxyl groups also give the base fluid its low-polar attributes which allow it to bind to the clay platelets and physically block the c-space while the size of the molecule, based on the length of the carbon backbone, prevent it from entering and causing swelling. The MHA Base Fluid also gives viscosity to the filtrate which may decrease penetration of fluid that escapes into the formation. Finally, the SI-60 shale inhibitor utilizes a blend of cationic inhibitors which have been shown to chemically stabilize the clay structure by exchanging with existing ions on the surface of clay particles and successfully outcompeting water molecules for accessibility to those sites, thereby preventing hydration and dispersion (Dye 2005). It is the combination of encapsulation, reduction of water activity and chemical stabilization of the shale that gives the MHA System its ability to effectively inhibit shale.

Lubricity Testing

The process of drilling a well is largely dependent on delivering kinetic energy to the drill bit. It has been estimated that as much as 70% of that energy can be lost due to friction (Dunn 2005, Navarro 2011). That number is certainly inflated by the high angle and extended reach wells commonly drilled today. As frictional forces mount up, they absorb energy created by the drilling rig at some point halting all progress. The failure to mitigate frictional forces can prevent the operator from reaching the project's target and thereby limiting access to the payzone. Limiting access to the payzone can potentially reduce the production potential of the well by millions of dollars.

Other benefits of lubricity include faster rates of penetration, decreased torque and drag, increased equipment life due to reduced vibration and material wear, fewer problems running casing, faster trips and increased ability to stay on track by keeping bit face and improved sliding. With all of this considered, frictional forces are potentially one of the most costly problems to consider in a typical well.

Lubricity and film strength were measured in this study with the OFITE Lubricity/EP Tester Model #111-00. Lubricity was measured on metal to metal surfaces at standard conditions (60 rpm and 150 inch-lbs. torque) by submerging the lubricity block and ring in pre-mixed drilling fluid formulations. Lubricity readings were recorded from the display after torque readings stabilized. Extreme pressure or film strength readings were obtained by submersing the EP block and ring under prepared drilling fluid while rotating at 1,000 rpm. Pressure was added to the torque arm at a rate of five inch-pounds per second until a seizure occurred or the maximum torque reading was reached. The block was removed from the tester and the length of the scar determined using the OFITE 7x magnifier with inch scale. Results of testing are presented in Tables 2 and 3.

The first phase of testing was performed using drilling fluid prepared in the lab containing 0.75 ppb xanthan gum, 1.5 ppb polymeric water loss reagent, 25 ppb rev dust and then brought up to the desired weight using barite. Several commercially available lubricants were tested in the fluid. The coefficient of lubricity and film strength from the highest and lowest performing lubricant as well as a representative of the median lubricant are presented with the results obtained from testing of the MHA System in Table 2. Lubricant 1 had very poor performance in terms of coefficient of lubricity and film strength for both the 9.5 ppb and 10.5 ppb drilling fluids. It essentially did not significantly help the lubricity and actually decreased the film strength by as much as 80% in the 10.5 ppb drilling fluid. Furthermore, it adversely affected the rheological properties of the laboratory drilling fluid which is usually an order of magnitude more forgiving than fluid collected from field drilling operations. However unlikely this may seem, this is not an uncommon result and could have caused catastrophic failures if used carelessly in the field. Lubricant 2 was included as the approximate median of lubricants tested. The typical market lubricant is generally going to drop the coefficient of lubricity of a laboratory mud approximately 20-50% while increasing the film strength around 100-200%. We chose to report lubricant 3 because of its notable lubricating qualities. Lubricant 3 reduced the coefficient of lubricity nearly 70% in both drilling fluids sampled and increased the film strength of the 10.5 ppb drilling fluid 234% to 26,200 psi.

The complete MHA System out performed all lubricants tested. The coefficient of lubricity as measured for the two MHA System formulations was 89.2% and 68.4% lower than the 9.5 ppb and 10.5 ppb base drilling fluids respectively. Furthermore, the film strength was 305% higher than the 9.5 ppb base drilling fluid and 353% higher on the 10.5 ppb base drilling fluid. The difference in film strength of the MHA System over conventional WBMs is its truly exceptional quality. A film strength of 22,000-24,000 psi is generally considered excellent and numbers that high are sometimes seen on drilling fluids properly treated with lubricant. However, the MHA system routinely scores at and above 40,000 psi on laboratory fluids and up to 35,000 psi on field muds. We believe this is due mainly to the fact that most WBMs add lubricant in after the fact, whereas every component of the MHA System is designed specifically with lubricity in mind.

Samples of drilling fluid were also collected from the field and tested for lubricity and film strength using the OFITE Lubricity/EP Meter. Whenever possible, laboratory tests were performed the same day as collection or as soon as possible thereafter. Samples were thoroughly mixed in the laboratory and tested according to procedures stated above.

Although access to competitor's field drilling fluids was limited, the results of testing routinely demonstrate that the MHA System is superior to conventional WBMs both in terms of lubricity and film strength. Film strength of field MHA Drilling Fluid is routinely three to five times higher than others tested.

The MHA System also matches up well with low weight field EBMs which generally have a coefficient of lubricity between 0.100 and 0.130 (0.108 in this case) compared to a similarly weighted MHA which is commonly between 0.120 and 0.140 (0.135 for this fluid tested). Although the data for a weighted MHA system is presented here, there is currently not enough data to determine if these results are typical.

The MHA Drilling Fluid System has been designed from conception to deliver lubricity above that possible with conventional WBMs. It is built around the MHA Base Fluid which has extremely high lubricity and film strength due to its hydrocarbon influence. Furthermore, the choice of the L-20 lubricant was chosen not only because of its lubricating properties, but also based on its high compatibility with the MHA Base Fluid and has been tested extensively in the laboratory and field. The other components of MHA including shale inhibitors and biocide were also chosen specifically not to interfere with lubricity. This product is built as a system rather than a group of components which is typical of a conventional WBM.

Field Trials

The MHA System has been deployed on 16 Eagle Ford / Woodbine and five Marcellus well at the date of publication. It was designed specifically to address shale and wellbore stability problems at the northern most stretch of the field in Leon Co., TX. Significant improvements were immediately noticed. All projects drilled in the field using MHA have successfully reached their target with the exception of one which had significant difficulties due to loss circulation. However, in this particular case, the MHA System was exposed to open hole through the Midway shale for 71 days before casing without significant damage to the wellbore.

We had the chance to perform two well-designed case studies on off-setting wells with the cooperation of operators. The first case study compared the total depth versus days from surface hole of wells drilled with a conventional WBM and with the MHA System in an Eagle Ford/Woodbine horizontal well (Figure 2). The MHA System drilled without incident to 13,500' in less than 18 days. This was significantly better than the off-set well drilled with the conventional WBM which took 29 days to reach a depth of 10,800' and routinely pulled tight, taking considerable reaming upon completion to run the final string of casing. From Figure 2 it is clear that the MHA system saved the customer time and increased the production potential of the well because of the additional length of the horizontal in the payzone. The superior ROP of the MHA System is clear in both the intermediate hole and lateral.

The other case study completed to date compared the performance of two off-setting wells drilled from the same pad, one using the MHA System and the other a synthetic based EBM in Marshall Co., WV in the Marcellus shale. The performances of the two fluid systems were very similar although the MHA system reached a total depth of 300' deeper than the EBM (11,910' for MHA vs. 11,675' for the synthetic EBM) and finished the project in one less day (20 vs. 21). Although the synthetic based EBM did have a higher maximum daily ROP for this well, this benefit was somewhat negated by the additional time required to displace, wash the rig and weight up before the curve. There are a lot of factors to consider when evaluating the performance of a drilling fluid in the field over the course of an entire well. The authors of this paper took care to attempt to eliminate as many confounding factors as possible by choosing off-set wells drilled back to back with the same rig. The best available data are presented until larger studies can be completed.

Conclusions

- Emulsion based muds (EBMs) do not address all of the potential problems associated with drilling a well.
- Although EBMs are generally thought of as the gold standard in drilling fluids, it is important to note that they are not superior to water based muds (WBMs) in every aspect and have several drawbacks namely a high unit cost; susceptibility to losses; increased health, safety and environmental risks; and the potential to damage the payzone.
- Not all water based muds are the same. Conventional WBMs can be very cost effective and have drilled thousands of wells. High performance water based muds have demonstrated their applicability in technically demanding wells and offer the flexibility to address some of the weaknesses of EBMs.
- The Multi-Hydroxyl Alcohol (MHA) Drilling Fluid System uses a base fluid consisting of a mixture of low-polar organic molecules that do not require emulsification to provide the system its superior performance.
- The MHA System has performance and stability characteristics similar to EBMs while preserving the environmental compliance, flexibility and value of a WBM.
- Laboratory and field studies have demonstrated the ability of the MHA System to outperform WBMs and directly compete with EBMs.

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Nomenclature

EBM = *Emulsion based mud*
MHA = *Multi-Hydroxyl Alcohol*
WBM = *Water based mud*
API = *American Petroleum Institute*
ISO = *International Standards Organization*
HPWBM = *High performance water based mud*
BLM = *Base lab mud*
bv = *By volume*
EP = *Extreme pressure*
ppb = *Pounds per barrel*
psi = *Pounds per square inch*
ROP = *Rate of penetration*

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Table 1: Percent Inhibition of Shales by Drilling Fluid Formulations

	Eagle Ford	Jackson	Midway	Marcellus
Base Lab Mud	39.0	76.4	69.0	48.0
BLM + 3.0% L-20	80.4	78.2	83.2	76.3
BLM + 60% MHA	75.3	82.5	87.1	78.2
BLM + 2.0% SI-60	93.1	91.9	95.3	93.6
Example Optimized System	96.2	97.9	98.5	95.9
Diesel Based EBM	98.3	98.5	99.1	98.4

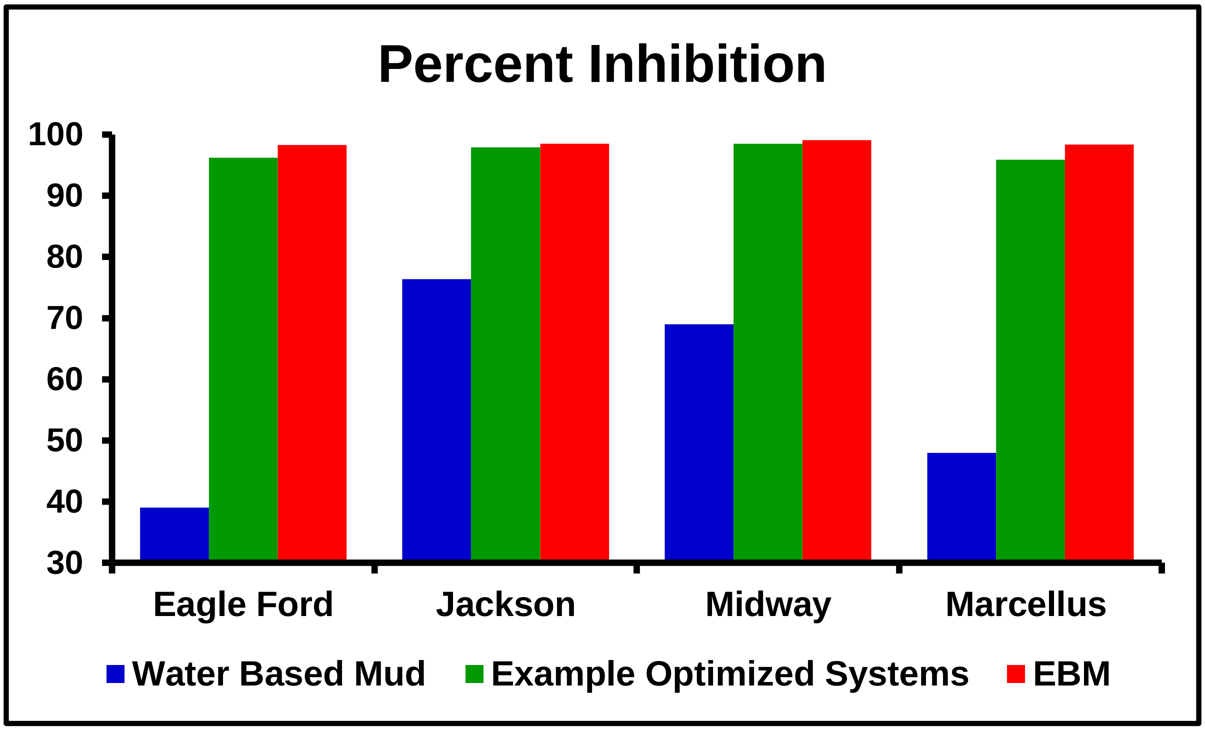

Figure 1: Results from inhibition testing on four different shale types showing the inhibitive properties of an optimized Multi-Hydroxyl Alcohol Drilling Fluid System. The inhibition of the MHA System exceeds that of typical water based muds and is designed specifically to compete with diesel and synthetic emulsion based muds (EBMs) for drilling reactive shales by offering the added flexibility of custom blending shale inhibitors to meet the specific needs of the customer.

Table 2: Laboratory Drilling Fluid Lubricity Testing

	9.5 ppb Drilling Fluid				
	Base Lab Mud (BLM)	BLM + Lubricant 1	BLM + Lubricant 2	BLM + Lubricant 3	MHA System
PV/YP	14/8	21/13	18/10	15/9	**16/9**
Coef. Lubricity	0.214	0.212	0.162	0.065	**0.023**
% Reduction	--	0.93%	24.3%	69.6%	**89.2%**
Film Strength	16,000	7,200	26,500	32,400	**48,800**
% Increase	--	0.45%	166%	202%	**305%**

	10.5 ppb Drilling Fluid				
	Base Lab Mud (BLM)	BLM + Lubricant 1	BLM + Lubricant 2	BLM + Lubricant 3	MHA System
PV/YP	18/10	28/22	24/14	19/11	**20/11**
Coef. Lubricity	0.402	0.381	0.303	0.131	**0.127**
% Reduction	--	5.22%	17.9%	67.4%	**68.4%**
Film Strength	11,200	2,340	16,300	26,200	**39,500**
% Increase	--	0.21%	146%	234%	**353%**

Table 3: Field Drilling Fluid Testing

Description	Weight (ppb)	% Solids	Coef. Lubricity	Film Strength (psi)
Competitors WBM 1	9.4	5	0.280	10,200
Competitors WBM 2	12.2	20	0.351	4,830
MHA System 1	**9.5**	**7**	**0.135**	**34,600**
MHA System 2	**14.6**	**27**	**0.196**	**24,600**
Diesel EBM 1	16.1	32	0.131	--
Synthetic EBM 2	10.7	13	0.108	--

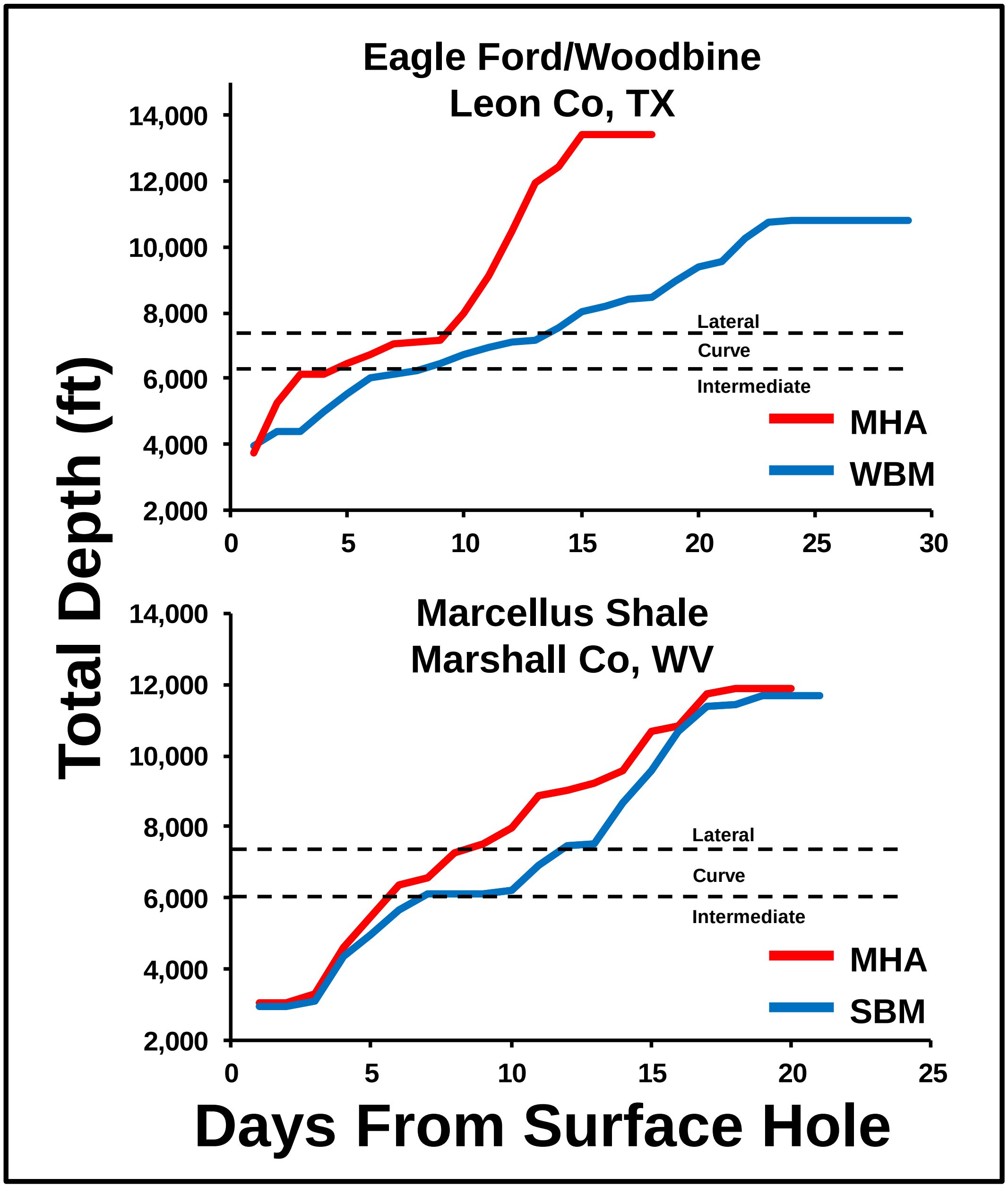

Figure 2: Rate of penetration (days from surface hole vs depth) of off-setting wells drilled using the Multi-Hydroxyl Alcohol (MHA) Drilling Fluid System compared to a conventional water based mud (WBM) and an synthetic emulsion based mud (SBM)