SPE-195189-MS

Application of an Innovative Drilling Simulator Set Up to Test Inhibitive Mud Systems for Drilling Shales

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This paper was prepared for presentation at the SPE Oklahoma City Oil and Gas Symposium held in Oklahoma City, Oklahoma, USA, 9-10 April 2019.

Abstract

Wellbore instability is caused by the radical change in the mechanical strength as well as chemical and physical alterations when exposed to drilling fluids. A set of unexpected events associated with wellbore instability in shales account for more than 10% of drilling cost, which is estimated to one billion dollars per annum. Understanding shale-drilling fluid interaction plays a key role in minimizing drilling problems in unconventional resources. The need for efficient inhibitive drilling fluid system for drilling operations in unconventional resources is growing. This study analyzes different drilling fluid systems and their compatibility in unconventional drilling to improve wellbore stability.

A set of inhibitive drilling muds including cesium formate, potassium formate, and diesel-based mud were tested on shale samples with drilling concerns due to high-clay content. An innovative high-pressure high temperature (HPHT) drilling simulator set-up was used to test the mud systems. The results from the test provides reliable data that will be used to capture more effective drilling fluid systems for treating reactive shales and optimizing unconventional drilling.

This paper describes the use of an innovative drilling simulator for testing inhibitive mud systems for reactive shale. The effectiveness of inhibitive muds in high-clay shale was investigated. Their impact on a combination of problems, such high torque and drag, high friction factor, and lubricity was also assessed. Finally, the paper evaluates the sealing ability of some designed lost circulation material (LCM) muds in a high pressure high temperature environment.

Keywords: Innovative drilling simulator, inhibitive muds, lubricity, lost circulation material, wellbore instability

Introduction

Unconventional shale plays constitute some of the most attractive formations in the US. Shale formations account for more than 70% of the formations drilled in the US. However, shale drilling is not a simple operation and could lead to excessive expenses because of all the possible problems that can be encountered. The most common problem associated with unconventional shale drilling is wellbore instability. More than

90% of the shale drilling problems are associated with wellbore instability (Chenevert et al. 2001). Wellbore instability is a major economic concern for most if not all drilling operations. Cook et al. (2012) reported that wellbore instability has an estimated economic loss of approximately 8 billion US dollars per year.

Wellbore instability is caused by the radical change in the mechanical strength as well as chemical and physical alterations when a formation is exposed to drilling fluids. (Chenevert et al. 2001) reported that the major cause of wellbore instability (in both hard and soft shales) is the shales' ability to absorb water from drilling fluid. The penetration of water into shale formations is a major concern for drilling operations. The water absorption in shale formations results to a reduction in the support pressure of the wellbore known as true overbalance and leads to shale failure (Xianyu et al. 2017). This emphasizes the importance of proper drilling fluid selection during well planning. Poor selection of drilling fluid in a high-clay content formation negatively impacts the stability of the formation, leading to challenges which include but are not limited to pipe sticking, tight hole, hole enlargement, poor cement job, and difficulty in running the casing (Santarelli et al. 1992). All these challenges lead to an excessive increase in the non-productive time (NPT). Transport processes occur in shales (hydraulic flow, osmosis, diffusion ions, and pressure) and the chemical changes (ion exchange, alteration of water content, and swelling pressure) strongly dictate the stability of a high-clay shale formation (Van Oort 1997). Proper characterization of clays in a shale formation and their sensitivity to water helps in selecting the appropriate drilling fluid systems for mitigating the stability issues. The most important clays to consider when selecting the type drilling fluid include smectite, illite, and kaolinite. These clays have different behaviors when exposed to water ranging from swelling to dispersion. Considering the sensitivity of most clays to water, it is imperative to select a drilling fluid with minimum water activity.

Most major shale formations in the United States are clay dominant. A good example is the Tuscaloosa Marine Shale (TMS), which constitutes one of the most attractive shale formations in recent years because of its estimated 7 billion reserves. TMS is characterized by high clay content that exceeds 50 wt% (Hackley et al. 2017). Illite, kaolinite, and chlorite constitutes the major clay type in the formation. The high clay concentration makes TMS one of the most troublesome formations in the United States because it presents a lot of drilling challenges. Dennys (2018) reported that TMS drilling problems include loss circulation due to the presence of natural and induced fractures, pipe sticking, high torque and drag, hole cleaning problems, and hole instability.

Most of these drilling concerns can be limited using the appropriate inhibitive drilling fluid system. The introduction of inhibitive muds in shale drilling has been a major improvement for shale stabilization. Inhibitive fluids can minimize hole instability and cleaning problems. They also provide good lubricity and minimize torque and drag during drilling. Chenevert et al. (2001) reported that proper application of an effective inhibitive mud minimizes the drilling costs, rig time, formation damage, and completion costs by stabilizing the reactive clays. A variety of inhibitive muds including KCl, potassium formate, high performance water-base muds are available for drilling reactive shales such as TMS. Table 1 summarizes the different types of inhibitive muds used for shale drilling.

Nonaqueous based-fluid (NAF) systems such as oil-based mud (OBM) has been used in the TMS formation and other major shale plays to help mitigate shale drilling concerns. Several studies (Shaughnessy et al. 2000, Quanxin et al. 2012, and Ming et al. 2015) revealed that oil-based mud (OBM) is also widely used for drilling high clay shale formations such as TMS, Eagle Ford shale, and Barnett shale. OBM is widely used in shale drilling because of its superior shale stabilization, excellent fluid loss control, low bit-balling tendency, and high drilling performance (Ming et al. 2015). However, Deville et al. (2011) reported that despite the advantages (stabilization, lubricity, and contamination tolerance) of NAF systems in high clay content formations, they pose major environmental concerns. Therefore, some more environmentally friendly inhibitive muds such as high-performance water-based mud (HPWBM) need to be accessed for those shale plays. This paper focuses on testing the effectiveness of inhibitive mud systems in minimizing shale drilling issues using an innovative drilling simulator set-up.

This paper will evaluate a combination of drilling problems encountered in shales including fluid loss through fractures, low rate of penetration, high torque and drag, and high friction factor during drilling. The sealing ability of some designed LCM muds in limited fluid loss will also be evaluated.

Table 1—Types of inhibitive muds used for shale drilling

Number	Mud Types	Field Case Study	Advantages	Disadvantages
1	Cesium Formate	• Mancos Shale • Huldra F ield, Norway • Kvitebjorn field, Norway • Elgin/Franklin field, Central North Sea (CNS)	• Reduce shale swelling • Reduce filtrate invasion • Reduce pore pressure penetration • Good lubricity • Thin filter cake • Better hydraulic (faster • tripping time) Lower ECD • Better hole cleaning	• High cost • Radioactive • Low solid control • Logging challenges
2	Potassium Formate	• Mancos Shale • Huldra Field, Norway • Kvitebjorn field, Norway	• Reduce shale swelling • Reduce filtrate invasion • Reduce pore pressure penetration • Good lubricity • Thin filter cake • Better hydraulic (faster tripping time) • Lower ECD • Better hole cleaning • Limit bit-balling	• High cost • Radioactive • Low solid control • Logging challenges
3	KCl	Most United States Unconventional plays including: Tuscaloosa Marine Shale (TMS), Barnett Shale, Haynesville Shale Kyrtayel Field, Russia	• Limit hydration • Prevent dispersion of formation clays • Limit bit-balling • Prevent tight hole • Prevent clay swelling • Prevent wellbore washout and excessive sloughing • Better bit hydraulics	• Instability in very high temperature • Cutting removal challenges • Pose corrosive challenges
4	Oil-Based Mud (Invert Emulsion	Most Shale formations in USA, Barnett, Bakken, Eagle Ford, Tuscaloosa Marine Shale (TMS)	• Good for HPHT wells • No reaction with the formation clay • Thin mudcake resulting in less pipe sticking • Good lubricant: greatly reducing drilling torque • Limit hydration	• Intermediate Cost • Environmental concern • High methane solubility • High risk of cement contamination • Difficult gas kick detection • Difficult removal of drilled • solids due to high plastic viscosity • Difficult electric logging • Equipment deterioration
5	Silicate-mud Systems	Beryl Field, Southern North Sea (SNS)	• Good shale swelling inhibition • Low depletion rate • High ROP • Sealing of micro-fractured clays • Environmental friendly • Cost effective	• Limited thermal stability • Logistics problems • Problems related to human health

Number	Mud Types	Field Case Study	Advantages	Disadvantages
6	High Performance Water-based muds	• Hayneville Shale • Barnett Shale • Fayetteville Shale	• Excellent shale stabilization • Good lubricity • Proper cuttings transport • Enhanced environmental and economic benefits	• Limited Thermal stability at temperature above 200-F • Variation in designed depending on shale formation

Methodology

Drilling Fluid design

Selecting and designing the appropriate drilling fluid is one of the most crucial steps toward minimizing wellbore instability in unconventional plays mostly shales. The compatibility of the drilling fluid and the shale formation dictates the severity of the hole instability in shale drilling. A variety of drilling fluid systems: water-based mud, oil-based mud, high-performance water- based mud, and formate brine, are available for drilling. However, not all are compatible with shale drilling. In this study, different types of drilling fluids were tested for their compatibility with shale drilling and their impact on drilling parameters. A conventional water-based mud was used as a base fluid for testing. The water-based mud was used as a reference mud because it is the most incompatible drilling fluid for shale drilling. The formulation of the water-based mud (WBM) is reported in Table 2.

Table 2—Water-based mud formulation

Products	Lb/bbl	% by weight	% by volume
Water	306	66.084	87.46
Gel	20.0	4.32	2.38
Caustic Soda	0.5	0.108	0.094
Lignite	4.0	0.8635	0.762
Desco	4.0	0.8635	0.714
Barite	128.6	27.76	8.58

The other mud systems include a set of oil-based muds, cesium formate, and potassium formate. The oil-based mud systems included an integrated oil-based mud (64% oil to water ratio) and an invert mud oil-based mud (80% oil to water ratio). The oil-based mud systems were designed with diesel as the base fluid. These oil-based mud systems were provided by a service company. From the mud reports obtained from the service company, some of the major components of the mud formulation included diesel, water, lime, calcium chloride, cedar fiber, and wall-nut medium. The integrated oil-based mud (64% oil to water ratio) was used as the reference mud in testing the sealing capabilities of a designed LCM mud. The last set of drilling fluid used in this study was the formate brine (cesium, potassium, and mixed formate). The mixed brine consisted of a mixture of potassium and Cesium formate. The formate brine was obtained from another service company for sample analysis. The three (3) types of formate used for this study include Cesium formate, Potassium formate, and mixed formate.

Drilling Simulation

In this study, a HPHT lubricity, filtration, and drilling simulator was used to conduct the experiments for evaluating the effectiveness of the inhibitive mud systems in drilling a high-clay shale formation. This innovative drilling simulator provides a great opportunity to simulate typical downhole drilling conditions. Using a software associated with the simulator, some of the realtime drilling parameters include weight on bit (WOB), rate of penetration (ROP), torque, friction factor, fluid/filtrate loss volume, and rotary speed. The drilling simulator is set to sustain pressure and temperature up to 2000 psi and 500°F respectively. It is designed to hold in cylindrical porous media of specific dimensions, and the material can be a ceramic filter tube, an actual core sample, and a steel slot. In this study, cylindrical core samples from Eagle ford were used in the drilling experiments, 350 mL of cesium formate and water-based mud were used differently as drilling fluids during the experiments. The drilling simulation experiments were conducted at a temperature of 120° F, a rotary speed of 40 rpm, and differential pressure of 100 psi. Each of these parameters can be adjusted to match the downhole conditions required during an actual operation. The simulator uses a 1-inch PDC drill bit to drill the cylindrical core sample (whose diameter is 1.5 inches) and the required drilling parameters are recorded. The simulator is also equipped with a heating jacket that heats up the system to the require temperature. A normal loading system is used to provide the weight on the drill bit. Figure 1 shows the drill bit and the major components of the drilling simulator. The drilling process is programmed using an associated software to acquire real-time drilling data.

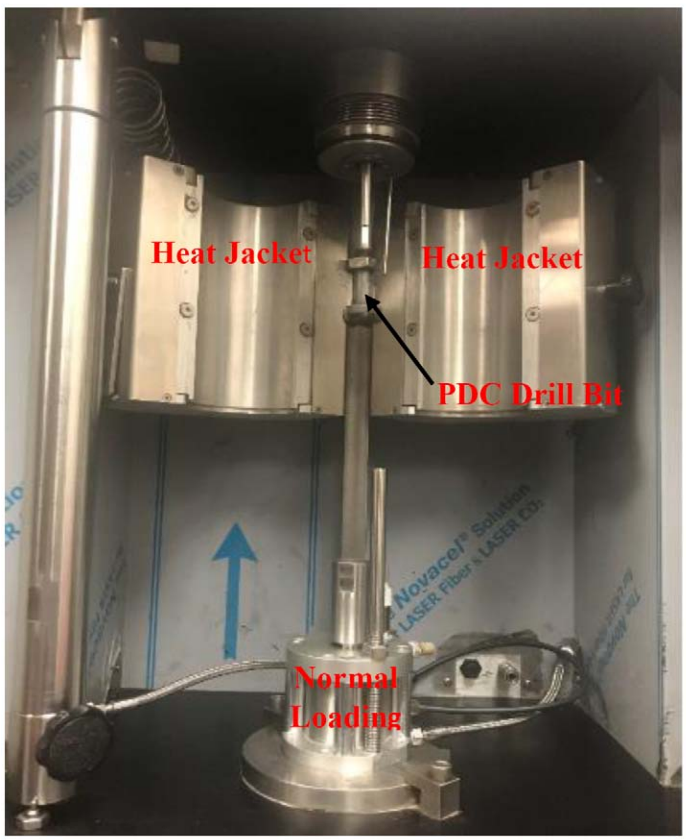

Figure 1—High pressure high temperature drilling simulator

Dynamic Lubricity Tester

In this study, the lubricity of some inhibitive mud systems was tested using the HPHT lubricity, filtration, and drilling simulator. This innovative lubricity tester provides a major advantage over the conventional lubricity tester used in the industry. The most common and traditional lubricity tester is the extreme pressure (EP)/ lubricity tester. During the measurements, a measured force is applied to a torque-sensitive rotating cup using a torque arm. This method involves calibrating the equipment with distilled water for about 15 minutes and a baseline friction torque of 150 in-lbs is applied. The next step of the test involves measuring the torque generated by the fluid and comparing it to the baseline torque (Fann Instrument Company, 2009). Some major limitations of the traditional lubricity tester are that it can only be used at ambient conditions and does not account for surface roughness (Junhao et al. 2017). Factors such as surface roughness, temperature, and pressure highly affect the lubricity measurement and must be considered during testing. The innovative dynamic lubricity tester used in this study ensures consistency in surface roughness and can measure lubricity in different downhole temperature and pressure conditions. This lubricity tester (Figure 2) consists of a cell in which the fluid to be tested is placed and is heated to the selected temperature using the heating jacket. The equipment is set to withstand temperature and pressure up to 500°F and 2000 psi respectively. In our facility, the equipment can be used to test the lubricity of different fluid samples on both a metal steel block and an actual core sample. It uses a steel rubbing shoe that is set to rotate at a selected rotary speed against any of the surfaces (steel metal block and core sample). This lubricity tester, unlike the traditional tester, does not require calibration with water. It also provides a high degree of repeatability and consistency in data. In this study, the effectiveness of a known lubricant in minimizing friction factor was studied. The lubricant was obtained from a service company.

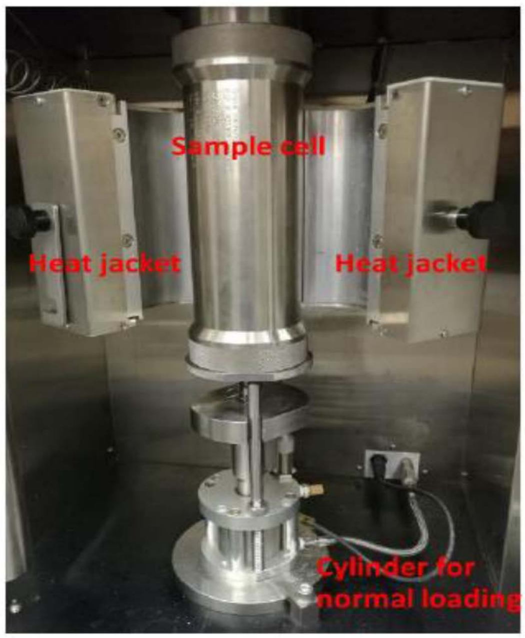

Figure 2—High pressure high temperature innovative dynamic lubricity tester

Results and Discussions

Rheology

The rheological profiles for the inhibitive mud (cesium formate) and the integrated OBM used in designing the LCM mud for fracture testing is shown in Figure 3. The figure shows the shear stress vs. shear rate plots at 120°F. Both fluids systems show a power law trend with consistency index and flow index reported. The plot shows higher shear stress at the same shear rate for the integrated OBM compared to cesium formate. The integrated oil-based mud shows a consistency index greater than one (1), which implies a shear thickening behavior as opposed to the Cesium formate which displays a shear thinning behavior. According to Ezeakacha et al. (2018), a reduction in consistency index of a power law fluid implies more fluid loss, especially the initial flow rate. This emphasizes the significance of the fluid rheology for mitigating fluid loss. The rheological profile of the designed LCM mud with 20 lb/bbl of cedar fiber was not completely determined because of the fiber ability to clog up the space between the rotor and the bob of the viscometer used during measurement. However, visual observations suggested the slurry had high viscosity, which was favorable for mitigating loss circulation.

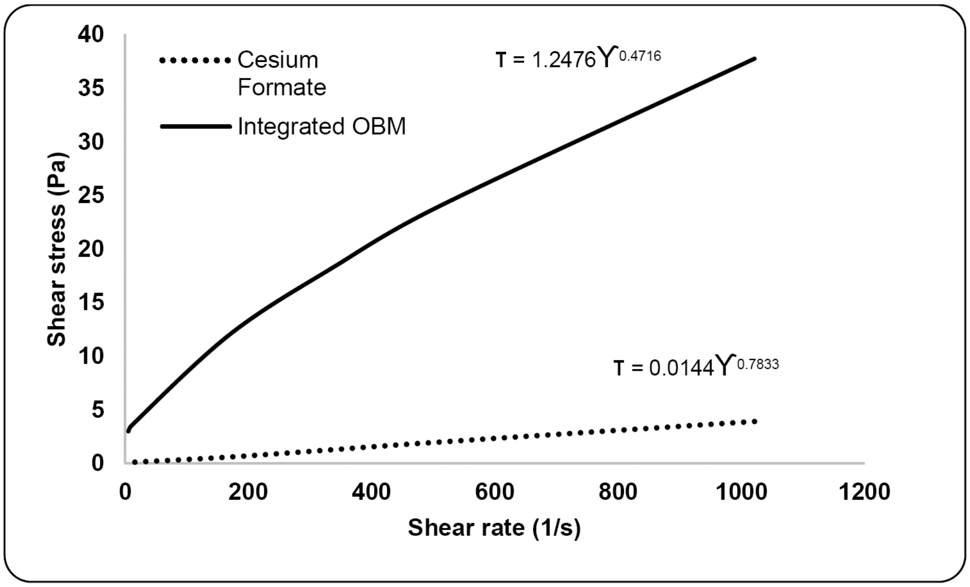

Figure 3—Shear stress vs. shear rate profile for integrated oil-based mud and cesium formate.

Torque

In this study, the impact of the inhibitive muds on torque during drilling was evaluated in a comparative analysis to conventional water-based mud. Excessive torque during drilling is a major concern for all drilling operations. Excessive torque during drilling is an indication of possible pipe sticking, which is one of the causes of wellbore instability. Wellbore instability is frequently encountered in drilling of high-clay shale formations. High torque and drag forces constitute major limitations in extended reach wells and deep wells because they either prevent the operator from reaching the target or increase the total drilling time. Reduction of torque during drilling operations leads to an improvement in drilling performance. The inhibitive mud (cesium formate) used during the drilling experiment showed better torque over time as compared to the water-based mud in Figure 4. A maximum torque of 21.73 lbs.in was achieved compared to 34.39 lbs.in for conventional water-based mud. This shows that a 37% reduction in maximum torque during the drilling operation was obtained using Cesium formate. This shows less risk of pipe sticking when using Cesium formate in high clay shale drilling. The use of Cesium formate provides an improvement in wellbore instability in most shale formations.

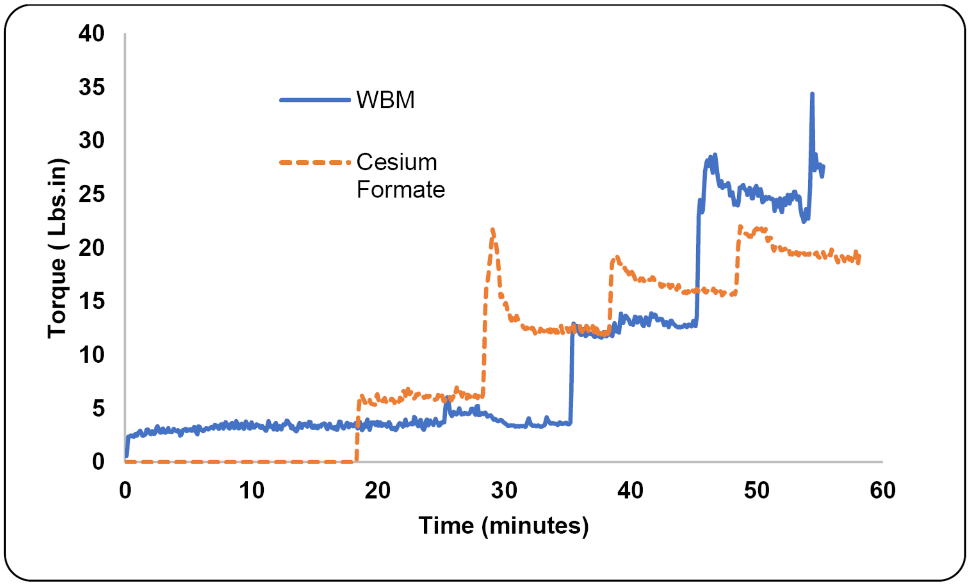

Figure 4—torque profile of an inhibitive mud (Cesium formate) and a conventional water-based mud.

Friction Factor

This study also focuses on the effect of inhibitive mud systems on reducing friction factor during shale drilling. Figure 5 shows the friction factor profiles of two drilling fluids. The study of friction factor is highly important for directional well and extended reach wells. High friction factor during drilling can cause the drill bit to remain stationary at the bottom and unable to rotate effectively, which results in a drastic drop in rate of penetration. Ahmed et al. (2016) reported that an excessive increase in friction causes the drill bit to exceed the drilling string neutral position consequently reducing the angular velocity and eventually stopping the drill string movement. This emphasizes the significance of controlling the friction factor during drilling. The experiments conducted in this study show the improvement in friction factor when using cesium formate as compared to conventional WBM. Cesium formate showed a decrease in friction factor over time while an increasing trend was recorded using the WBM. A maximum friction factor of 0.29 was obtained using cesium formate as compared to 0.39 for water-based mud. A 26% reduction in maximum friction factor was recorded when using cesium formate in place of water-based mud for high clay shale drilling. This emphasizes the effectiveness of using inhibitive mud systems instead of water-based mud for unconventional shale drilling.

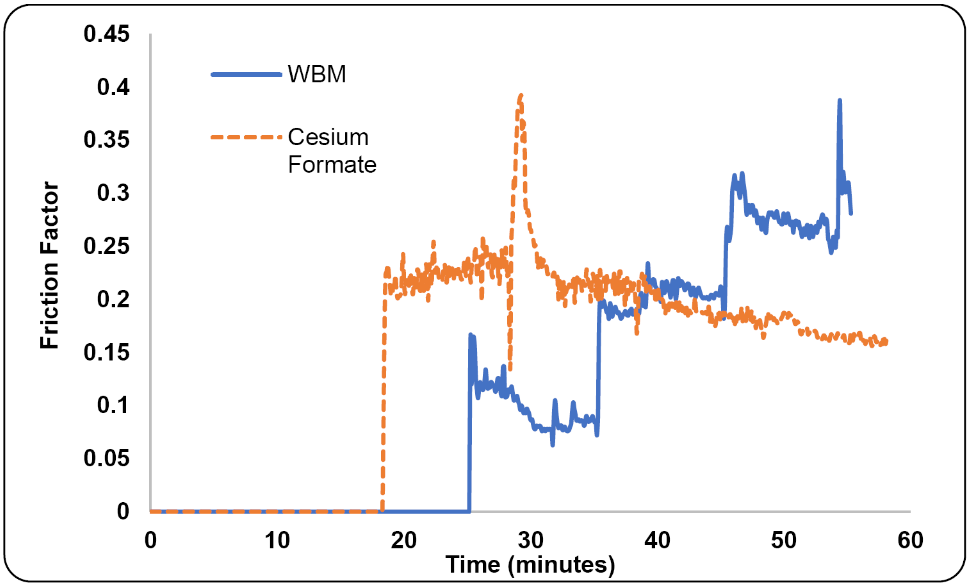

Figure 5—Friction factor profile of an inhibitive mud (Cesium formate) and a conventional water-based mud.

Lubricity

In this study, the lubricity of both cesium formate and conventional water-based mud was evaluated using the dynamic lubricity tester. The lubricity test was performed on both metal-to- metal surface and metal-to-core sample. On both surfaces, cesium formate showed good lubricity as compared to water-based mud. The low friction factor recorded from the cesium formate experiment supports the idea of better drilling performance in high-clay shale. Compared to WBM, Figure 6 shows that cesium formate reduced lubricity by 27% and 17% on steel block and core sample respectively. Cesium formate provides good lubricity which minimizes the need for a lubricant to minimize friction factor. Despite most formate brines not needing a lubricant to maintain good lubricity, some inhibitive mud systems require the use of lubricants to reduce friction factor. The effectiveness of some lubricants obtained from a service company was evaluated in this study. Figure 7 shows that the lubricants tested were very effective in minimizing friction factor. This analysis was performed on a steel block. The friction factor of fresh water was reduced by 25% when 1% of the lubricant was added to water and by 35% when 2% of the lubricant was added. This demonstrates the effectiveness of the lubricant tested in reducing the friction factor during drilling of high clay shale. Some downhole factors such as temperature and pressure can affect the effectiveness of the lubricant because of their impact on the fluid properties such as viscosity, density and mobility. A similar study was performed by Junhao et al. (2017) to evaluate the effect of lubricant on friction factor. Their study revealed that the lubricant used was effective in reducing the friction factor of a water-based mud recipe.

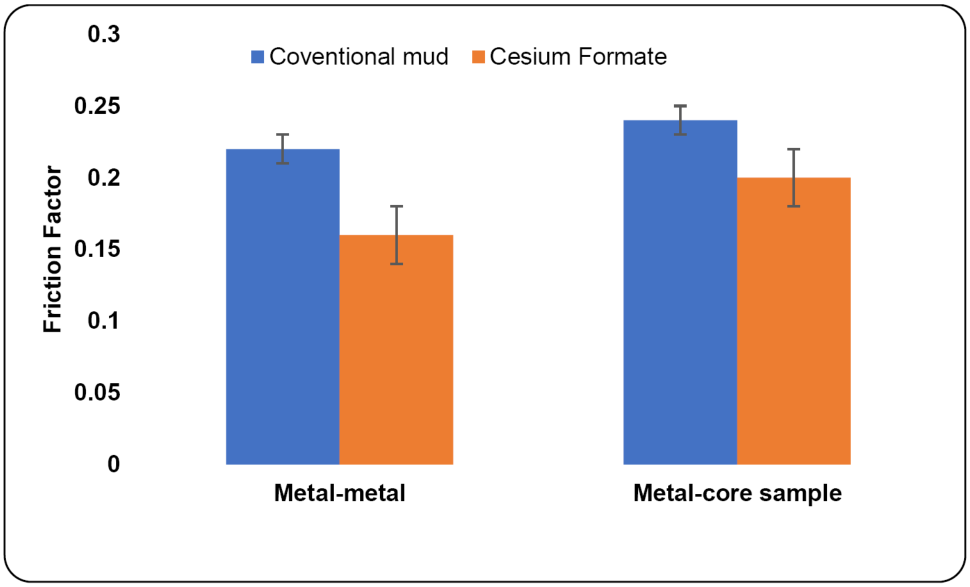

Figure 6—Friction factor profile of an inhibitive mud (Cesium formate) and a conventional water-based mud

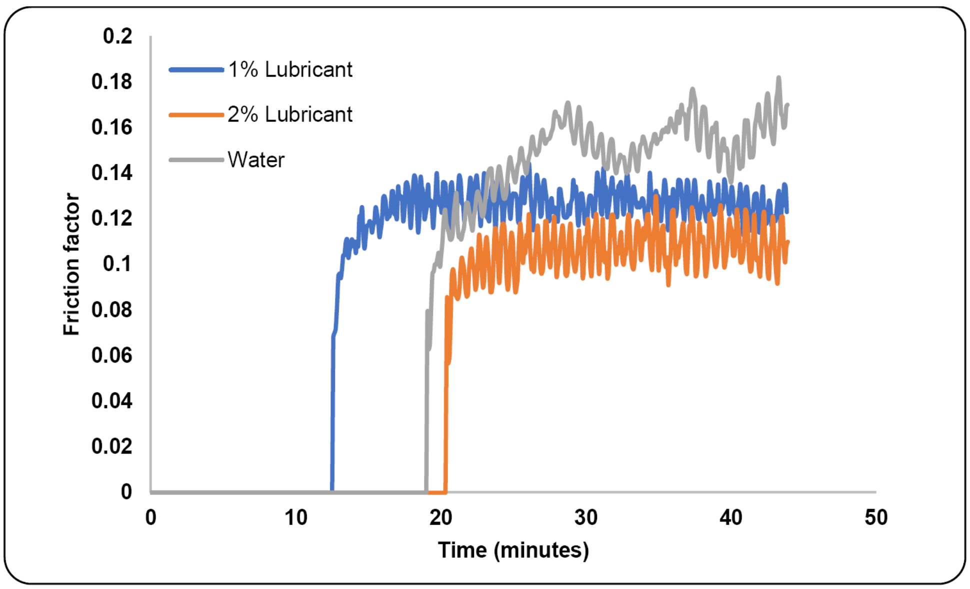

Figure 7—Effectiveness of lubricant in minimizing friction factor.

Fracture Testing

In this study, the sealing efficiency of an LCM mud was tested. The LCM mud was designed using an integrated oil-based mud as base fluid. The oil-based mud was obtained from a service company and mixed with 20 pounds per barrel of fiber. The efficiency of the LCM was tested on a vertical fracture width of 2000 gm (Figure 8). The results show that the LCM was effective in sealing more than 75% of the fracture while limiting the loss across the fracture. Using the LCM mud, the cumulative fluid loss across the fracture was reduced by more than 38% compared to the OBM used as base fluid (Figure 9). The integrity of the seal was affected by continuous rotation of the pipe which led to erosion of the seal and resulted to an increase of 1.03 cm^3 (dotted circle in Figure 9). The test was conducted at differential pressure of 200 psi, temperature of 200°F, and a rotary speed of 75 rpm. The test parameters were selected based on the drilling report of a known unconventional formation. The fluid invasion was recorded for 30 minutes. A similar study was performed by Ezeakacha (2018) to evaluate the effect of various concentrations of fiber on the sealing ability of designed LCM mud with WBM. The author found a significant decrease in the dynamic fluid invasion when the concentration of fiber is increased from 15 lb/bbl to 30 lb/bbl. Additionally, this study showed that the fracture width influences the effectiveness of the LCM for similar concentration. A reduction in dynamic fluid invasion was reported when changing the fracture width from 2000 |im to 500 |im. The author also reported that doubling the differential pressure can cause the seal created by an LCM fluid at a fracture surface to rupture slightly, leading to an increase in fluid invasion.

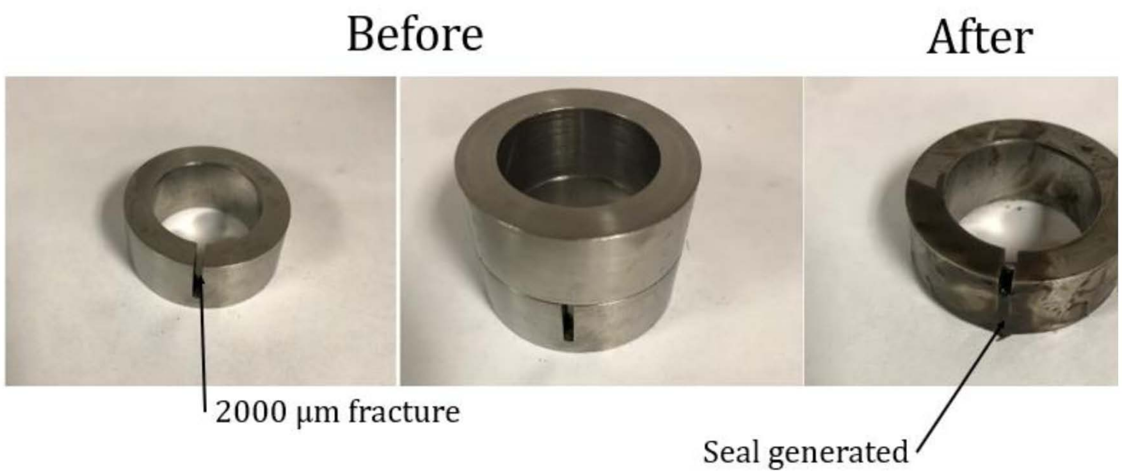

Figure 8—Disk slot before and after fracture sealing test.

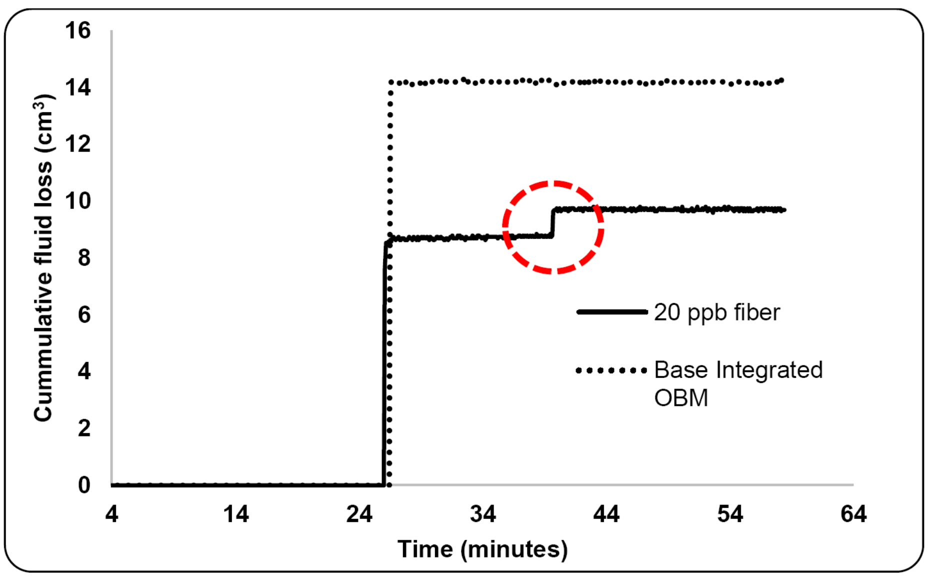

Figure 9—Dynamic fluid invasion profile for base integrated OBM and 20 ppb fiber LCM.

Overall, the fracture test using the innovative lubricity, filtration, and drilling simulator suggests that the LCM mud provides good bridging abilities. The integrity of the seal is highly affected by the wall shear stress caused by pipe rotation. Additionally, factors such as fracture width, differential pressure, and LCM concentration affect the effectiveness of the LCM mud. Ezeakacha (2018) generated an LCM selection criterion for effective fracture bridging considering different operating conditions. The author also showed that an increase in the fracture width leads to an eventual drop in pressure differential required to create spurt invasion. The study of dynamic fluid loss and filtrate invasion is also highly affected by the type of lithology. Some literature, (Ezeakacha et al. 2017, Salehi et al. 2015, Salehi et al. 2016, Ghalambor et al. 2014, Abrams 1997), has evaluated the impact of lithologies on dynamic fluid loss and filtration.

Their works suggested that the heterogeneity, mineralogy, permeability, porosity, and temperature must be considered together when assessing preventive measures for fluid loss and filtration in a porous media.

Conclusions and Recommendations

This paper describes the use of an innovative drilling simulator set-up to characterize inhibitive mud systems used in high-clay shale drilling. It evaluates the effectiveness of the inhibitive mud systems in improving shale drilling. This paper also evaluates the sealing ability of some designed LCM mud systems with of oil-based mud as a base fluid. The results of this study show that the innovative drilling simulator can be effectively used to characterize inhibitive mud systems. The following conclusions were drawn from this study:

- The cesium formate provides a low torque during drilling as compared to conventional water-based mud. A reduction of 37% in maximum torque was recorded when cesium formate was used.
- A very low friction factor was reported during drilling when using inhibitive mud (cesium formate). The friction factor using water-based mud was reduced by more than 27% compared to cesium formate.
- Cesium formate showed good lubricity, which is supported by low friction factor on both steel block and core sample. The results from lubricity test showed that no use of lubricant was required to minimize friction factor when using cesium formate for drilling high clay shale.
- The LCM mud designed by mixing 20 lb/bbl of cedar fiber with an integrated oil-based mud as base fluid was effective in sealing more than 75% of a 2000 gm.
- The dynamic fluid invasion through the fracture was reduced by more than 35% when the designed LCM mud was used as compared to oil-based mud.

Acknowledgements

The authors would like to extend their gratitude to all the service companies that provided the materials needed for this study. The authors would also like to thank Jeff McCaskill of the Well Construction and Technology Center, the University of Oklahoma. The authors would also like to thank Cabot Corporation for providing the Cesium Based muds. Their gratitude also goes to Stuart Leon of Cabot Corporation. This material is based upon work partially supported by the Department of Energy National Energy Technology Laboratory under Award Number DE- FE0031575 (Tuscaloosa Marine Shale Laboratory).

Nomenclature

LCM : Lost Circulation Material
WBM : Water-Based Mud
OBM : Oil-Based Mud
Lb/bbl : Pounds per Barrel

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