

**REMOVAL OF BARITE SETTLING WHILE DRILLING
HIGH-PRESSURE HIGH TEMPERATURE WELLS**

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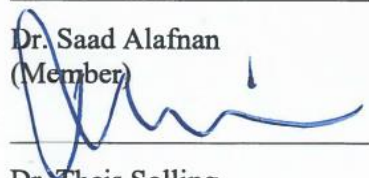
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I Dedicate this work to:

My Father,

My Mother,

My Wife,

My Children,

My Brother,

My Sisters, and

My Family

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LIST OF ABBREVIATIONS

API	:	American Petroleum Institute
WBM	:	Water Based Mud
OBM	:	Oil Based Mud
API	:	American Petroleum Institute
ppg	:	Pound Per Barrel
HPHT	:	High-Pressure High-Temperature
SEM	:	Scanning Electron Microscopy
XRD	:	X-ray Diffraction
XRF	:	X-Ray Fluorescence
KOH	:	Potassium hydroxide
KCl	:	Potassium chloride
IEFs	:	Invert Emulsion Fluids
G'	:	Elastic or Storage Modulus
G''	:	Viscous or Loss Modulus
LVE	:	Linear Viscoelastic
VSST	:	Viscometer Sag Shoe Test

ABSTRACT

Full Name : [Salem Abdullah Basfar]
Thesis Title : [Removal of Barite Settling While Drilling High-Pressure High Temperature Wells]
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Barite sag is a serious problem encountered while drilling high-pressure/high-temperature (HPHT) wells. It occurs when barite particles separate from the base fluid leading to variations in drilling fluid density that may cause a serious well control issue. However, it occurs in vertical and inclined wells under both static and dynamic conditions. This study introduces a combined barite-ilmenite and barite-Micromax weighting material to prevent the barite sag problem in oil and water-based drilling fluid. As well as barite-laponite for water-based drilling fluids. Different drilling fluid samples were prepared by adding different percentages of ilmenite, Micromax, and laponite from the total weight of the weighting agent to the base drilling fluid (barite-weighted). The Sag tendency of the drilling fluid samples was evaluated under static and dynamic conditions to determine the optimum concentration of ilmenite which was required to prevent the sag issue. A static sag test was conducted under both vertical and inclined conditions. The effect of adding these materials to the drilling fluid was evaluated by measuring fluid density and pH at room temperature, and rheological properties at 120/150 °F and high temperature 250/350°F. Moreover, a filtration test was performed at 250/350 °F to study the impact of

adding anti-sagging materials on the drilling fluid filtration performance and sealing properties of the formed filter cake. The results showed that 40% and 50 % of ilmenite was enough to prevent the barite settling of OBM and WBM respectively. The Micromax was more efficient than ilmenite due to more properties explained in this work. The barite was in suspension at only 30% and 25% of Micromax. Barite sagging in the WBM was also been prevented by using laponite at 0.75 lb/bbl.

ملخص الرسالة

الاسم الكامل: سالم عبد الله بصفر

عنوان الرسالة: منع ترسبات الباريت في سوائل الحفر ذات الأساس المائي والزيتي أثناء حفر الآبار ذات الضغط ودرجة الحرارة العاليه

التخصص: هندسة البترول

تاريخ الدرجة العلمية: أبريل 2023

.

يمثل ترسب الباريت مشكلة خطيرة أثناء حفر الآبار ذات ضغط ودرجة الحرارة عالية (HPHT). يحدث ذلك عندما تنفصل جزيئات الباريت عن السائل الأساسي مما يؤدي إلى اختلافات في كثافة سائل الحفر والتي قد تسبب مشكلة خطيرة في التحكم في البئر. يحدث ترسب الباريت في الآبار العمودية والمائلة تحت كل من الظروف سكون ودوران سائل الحفر. تقدم هذه الدراسة خليط من الباريت - الإلمنايت والباريت - والميكروماكس لمنع مشكلة ترسب الباريت في سائل الحفر القائم على الأساس النفطي والمائي. كما هو الحال بالنسبة للباريت - واللابونايت لسوائل الحفر القائمة على الأساس المائي. تم تحضير عينات مختلفة من مائع الحفر بإضافة نسب مختلفة من الإلمنايت والميكروماكس واللابونايت من الوزن الكلي للباريت إلى مائع الحفر الأساسي (وزن الباريت). تم تقييم نسبة ترسب الباريت لعينات مائع الحفر في ظل ظروف ثابتة وديناميكية لتحديد التركيز الأمثل للإلمنايت المطلوب لمنع مشكلة الترسيب. حيث تم إجراء اختبار ترسب الباريت في كل من الظروف الرأسية والمائلة بزوايا 45°. تم تقييم تأثير إضافة هذه المواد إلى مائع الحفر عن طريق قياس كثافة السائل ودرجة الحموضة عند درجة حرارة الغرفة ، والخصائص الريولوجية عند 150/120 درجة فهرنهايت ودرجة حرارة عالية 350/250 درجة فهرنهايت. علاوة على ذلك، تم إجراء اختبار الترشيح عند 350/250 درجة فهرنهايت لدراسة تأثير إضافة مواد مقاومة الترسيب على أداء ترشيح مائع الحفر وخصائص منع التسرب لعجينة المرشح المشكلة. أظهرت النتائج أن 40% و 50% من الإلمنايت كانت كافية لمنع ترسب الباريت في سائل الحفر الزيتي و المائي على التوالي. كان المايكروماكس أكثر كفاءة من الإلمنايت بسبب المزيد من الخصائص الموضحة في هذا العمل. أيضاً كان الباريت معلقاً عند 30% و 25% فقط من المايكروماكس. تم أيضاً منع ترسب الباريت في سائل الحفر ذو الأساس المائي باستخدام مادة اللابونايت عند 0.75 رطل / برميل.

CHAPTER 1

INTRODUCTION

1.1 Background

The great need for increasing efficiency and reducing the cost of oil and gas wells is the most important factor in the oil and gas industry to be able to continue the exploration and production of new fields and improve recovery from already developed fields. One of the major cost drivers in the industry today is drilling. In the drilling segment of the oil industry, there are enormous costs related to rig rates, equipment, and manpower.

The drilling fluid is one of the most important factors in any drilling operation. Its importance is amplified by the severity of losses that can result from its improper selection and control. It may in some cases represent the highest fraction of the overall cost of a drilling operation. Weighting materials are used to increase the density of the drilling fluid. The selection of the weighting agent to be used in drilling fluids is determined by many factors. One of the most important factors is to provide low rheology in high-density fluids and low sag (Zamora and Bell, 2004). To increase the density of mud several weighting materials are used in the oil industry such as barite, manganese tetroxide, ilmenite, and calcium carbonate. The most common weighting material is barite because it has many properties such as it is very dense, economical, widely available, and pure (Nguyen et al., 2011b). However, with these excellent properties, barite drilling fluids have a problem of

settling known as barite sag. Also, barite is very hard to remove from the wellbore except by using expensive multistage chelating agents and barite converters to dissolve it and remove any formation damage (Ba Geri et al., 2017; Mahmoud and Elkatatny, 2018).

1.2 High-Pressure High-Temperature Drilling Challenges

Oil or gas wells that have static reservoir pressure greater than 10000 psi and temperature above 250 °F/300 °F are classified as high-pressure high-temperature wells HPHT (Wagle et al., 2015b). Figure 1. Shows the pressure and temperature limit for HPHT, ultra-HPHT, and extreme-HPHT reservoirs (Maldonado et al., 2006).

Completion of high-pressure high-temperature wells is one of the most challenging in the oil industry. Drilling fluids that are used in such conditions must have specific properties. This complexity in HPHT pushed the researchers to develop a formulation of drilling fluid to meet the requirements, barite weighting material was one of the solutions but, it has a problem related to the settling of its particles.

There is a small window between pore pressure and fracture pressure gradient in HPHT wells, so if the mud has a pressure much greater than the fracture gradient of the formation, it will break down the formation and cause a loss of circulation. On the other hand, if the mud pressure is less than the pore pressure of the formation, it allows the formation fluid to enter the wellbore and causes a kick followed by a blowout.

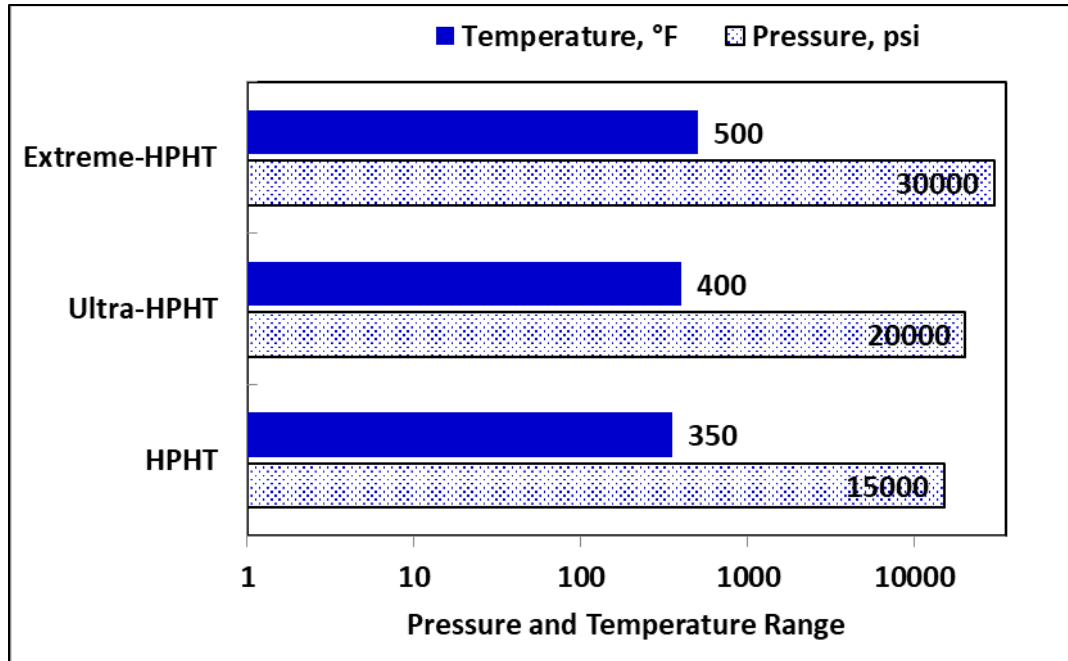


Figure 1 HPHT operation window (Maldonado et al., 2006)

1.3 Drilling Fluids

The drilling fluid is one of the most important components of an oil-well drilling operation. It may in some cases, represent the highest fraction of the overall cost of a drilling operation. Drilling fluids are fluids used in the drilling operations of oil and gas wells. These fluids should have some properties to allow them to drill wells safely and efficiently. The drilling fluid can be classified into three types as shown in, Figure 2 (Simpson, 1971) based on the continuous phase. The drilling fluid can be water-based mud (WBM) in both types of fresh and salty base, oil or synthetic-based mud (OBM), and air drilling fluid. All of the drilling fluids must have or offer different properties, which include (Abraham, 1933):

1. Capability to sustain the integrity of formations.
2. Remove the cutting from the wellbore.
3. Cool and lubricate the drill string and drilling bit.
4. Sustain the formation pressure.
5. Prevent the formation fluids to come into the wellbore.
6. Maintain the wellbore stability.
7. Transmit Hydraulic Horsepower to the bit.
8. Allow the formation evaluation.

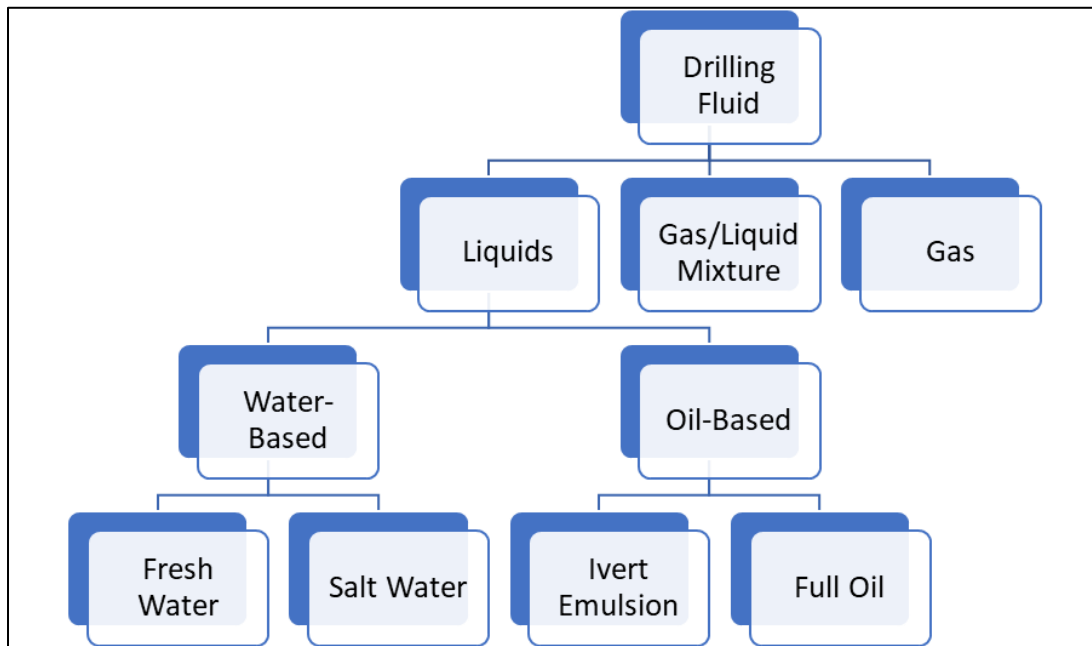


Figure 2 Drilling fluids classification

In the water-based mud (WBM), the water is the base fluid while bentonite and other additives are added for specific properties. The WBM is most used as a drilling fluid due to it is environmentally friendly and inexpensive. On the other hand, the main disadvantage of WBM is shale reaction and instability. The oil and gas industry in the 1970s start to

increase using oil-based mud (OBM) as the solution for drilling shale formation. OBM has a similar composition as WBM except in the OBM the continuous phase is oil while in the WBM, the continuous phase is water. The Invert Emulsion Fluids (IEF) have oil as an external or continuous phase and the water is the internal or discontinuous phase where droplets of oil are uniformly dispersed in a continuous water base. There are some advantages of OBM (Abraham, 1933; Miller, 1951):

1. Shale stability.
2. Stable at high temperatures.
3. less damage to the pay zone
4. Drilling salty, anhydrite, and potash zones.
5. Low corrosive f

1.4 Barite Sag

It is common when the driller waits for some time, they put the drill pipe under low rotation to avoid the pipe stuck, this low rotation causes a break in drilling fluid so, it accelerates the settling of barite which will give sever barite sag. Barite sag is generally defined as the settling of weighting materials in drilling fluid. Sag is often seen when the driller circulates the mud out of the hole after the mud stayed for some time in the well, leading to the confidence that the static settling of mud is the main indicator giving barite sag. Figure 3 showed the fluctuation in the mud density in this case. Sag occurrences in vertical and deviated wells but, it potentially notable in deviated well, in particular, those with an angle between 30° - 75° (Amighi and Moghadam, 2011; Amighi and Shahbazi, 2011; Bern et al., 1996; P. M Hanson et al., 1990) where the viscosity and annular velocity are low. Settling of barite in inclined pipes can be described as boycott settling.

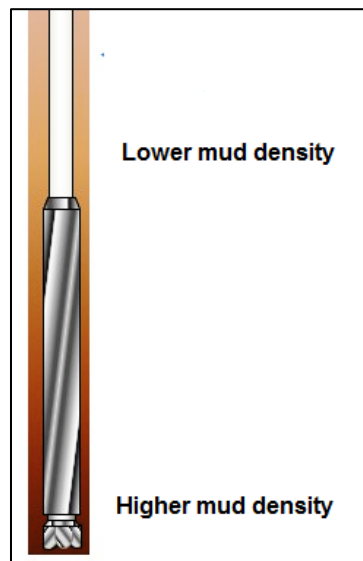


Figure 3 Density variation due to sag

The appearance of barite sag is generally seen when the mud is circulating bottoms up and the resulting mud weight out of the wellbore is less than the original mud weight going to the well. Although barite sag is associated with OBM more than WBM, it can also be seen in WBM (Leaper et al., 2006). As barite particles settle down from the suspension zone to the low side, the free fluid and lighter fluid will keep in the upper part of the cell. This will create a low-density thin layer on the top called free fluid and another just below free fluid. The particles will go down in the cell to make a sedimentation zone as shown in Figure 4

Most problems recognized in drilling and completion operations were referred to as barite sag. These issues such as lost circulation, well-control issues, wellbore instability, and stuck pipe (Massam et al., 2004; Tehrani et al., 2004) Sag factor is defined as the bottom density divided by the summation of top and bottom density as the following equation:

$$SF = \frac{\rho_{bottom}}{\rho_{top} + \rho_{bottom}}$$

where SF is the static sag factor, ρ_{bottom} and ρ_{top} are the density of the mud from the lower and upper parts respectively.

The pressure difference over the fluid cross-sectional area will force the higher fluid to sediment downwards and the lighter fluid to go upwards (Albertsen et al., 2004; Omland et al., 2006). The effect of forcing high-density fluid or particles downwards is called slumping. The flow stream moves along the high side in the deviated well, which will hurry the boycott settling of the weighting materials (Boycott, 1920; Sharman and Belayneh, 2017). Settling of barite occurs more commonly during circulating than in static circumstances, hence barite sag is mostly a dynamic settling problem. When drilling under high-pressure high-temperature (HTHP) situations, the mud weight is generally high, and

temperature is high. This causes the weighting agents separate in settle down due to decreasing the viscosity of the drilling fluid.

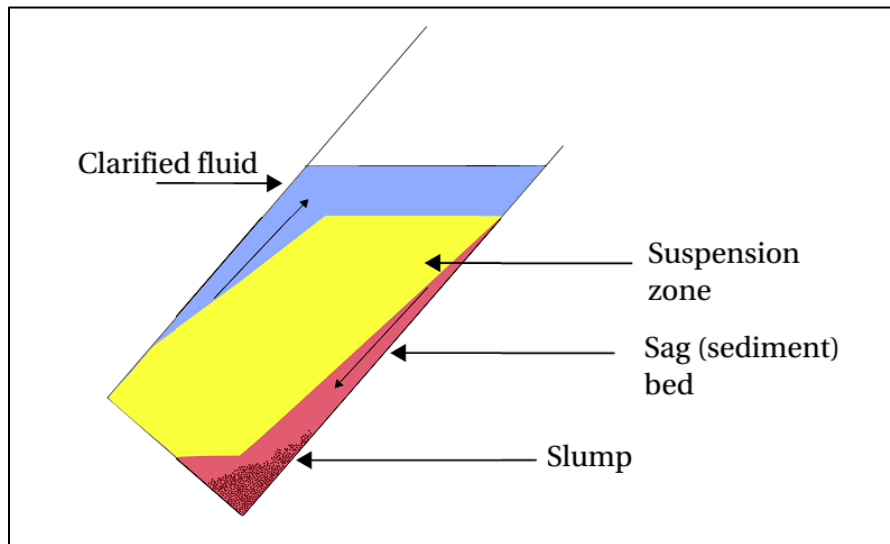


Figure 4 Particles settling in deviated tubes (Sharman, 2015)

CHAPTER 2

LITERATURE REVIEW

There are a variety of methods that have been developed to have a profound understanding of barite settling to lessen the challenge that the industry is currently facing and to select the appropriate drilling fluid additives, which is one of the most important factors for successfully operating a drilling operation. (Binh Bui et al., 2012b; A. Saasen et al., 1995) focused on the linear viscoelastic properties and their applications on OBM. Also, the relation between static and dynamic sag was provided. They provided standard rheological tests to evaluate the viscoelastic properties of drilling fluids by using sixteen different OBM sweep tests. They found that the range of the viscoelastic region was less than 1% at 20 °C. Moreover, as temperature increases and frequency decreases, the gel strength, linear viscoelastic range, and dynamic yield stress decrease. From frequency sweep data, the storage modulus(G') is greater than the loss modulus (G'') in the linear viscoelastic region. This means that the elastic behavior dominates over viscous behavior while the viscous property is dominated at low frequency in the linear viscoelastic range. Oscillation time sweeps have shown that the required time to build gel structure in the sample to achieve stability is often higher than the time recommended by API (30 minutes). The temperature affects storage modulus, loss modulus, and complex viscosity, as the temperature increases the viscoelastic parameters decrease.

(Albertsen et al., 2004; Omland et al., 2006) showed that the ability of invert emulsion OBM to suspend barite depended on the chemical composition of the water base. Four base fluids (mineral oil, linear paraffin, linear alpha-olefin, and Ester) and four different salts (Calcium Chloride (CaCl_2), Sodium formate (NaCOOH), potassium formate (KCOOH), and Ammonium calcium nitrate ($\text{NH}_4\text{Ca}(\text{NO}_3)$) have been used in this study. Ammonium calcium nitrate salt $\text{NH}_4\text{Ca}(\text{NO}_3)$ with mineral oil base has given the lowest 0.505 sag factor at 16 Hrs. compared to the high sag factor achieved by linear paraffin and Potassium Format 0.54 see Figure 5

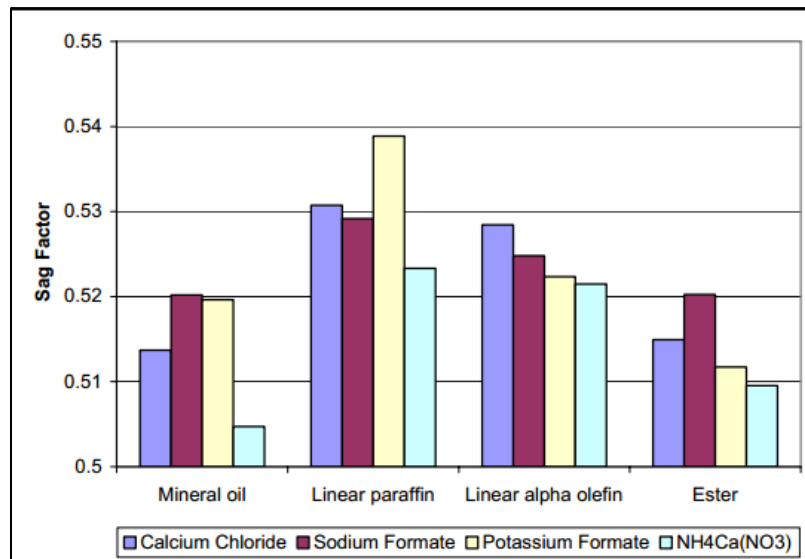


Figure 5 Sag factor of samples aged statically for 16 hours (Albertsen et al., 2004)

(P. M Hanson et al., 1990) investigated the effective ways to minimize sagging in 70 tests of highly deviated wells by a flow loop experiment. Figure 6 showed a plot of flow line mud weight versus circulation time after a trip on a Green Canyon directional well. The mud had an original density of 16 ppg. Samples from shaker underflow were measured in the binging and through mud out trip. The variance between the original weight and flow

mud with time can identify sag. The mud used in this study were OBM and WBM with a density of about 12-20 ppg. They came up with the following: although sag can occur for the existence of the mud in the well for a long time, it may happen while the mud in circulating operation. They gave some recommendations to reduce sagging in deviated well. One recommendation was to not thin the mud before running the casing as this will help fluid particles settle to the bottom of the well-bore. Moreover, dynamic sagging is faster to happen in low fluid velocity which allows the fluid to slump faster at an angle of 40-50. They conclude that dynamic sag is easier seen than static sag.

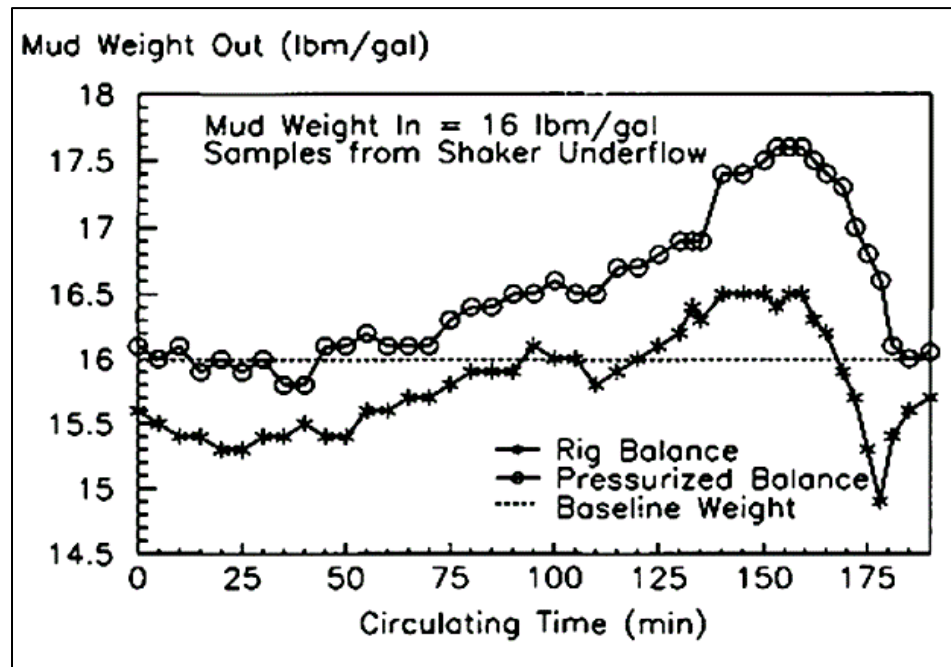


Figure 6 Trip report showing sag in a directional well (P. M Hanson et al., 1990)

(Saasen, 2002) studied in detail the mechanism of sag especially oil-based drilling fluids and how to deal with it. He did a comprehensive study of the weighting material behavior in invert emulsion OBM. This theory discussed that at an ultra-low shear rate, the viscosity of these fluids is low, and the shear thickening happens at a very low shear rate. The

crystalline structure of water droplets creates a low-viscosity environment in invert emulsion fluids which leads to sag. By increasing the shear rate, these water droplets are destroyed in a non-continuous fashion, which reduces static sagging. Moreover, a possible method to minimize sagging is by reducing the water-oil ratio as this will reduce the free space for a water droplet to move before they strike neighboring water droplets. He also suggested reducing free space water droplets but increasing the mixing energy of water with no change in water fraction in invert emulsion fluids

(Tehrani and Popplestone, 2007) investigated the effect of the internal phase (brine viscofiers) of invert emulsion fluids (IEFs) on rheology and barite sag. They used the viscometer sag test (VST) with sag shoe and Fan35 rotational viscometer to measure dynamic sag for fluids that have the same chemical concentration except for brine and organoclay viscofiers. The results showed that the ionic polymer brine viscosifier additive increased the rigidity of water droplets and decrease barite sag by about 30% using a dynamic sag test. But, the polymeric brine additive had some limitations, such as it was incompatible with a polyamide oil-phase viscosifier, lowering the rheology and increasing dynamic sag.

(Ehrhorn and Saasen, 1996) showed that fluids that lose gel strength, can't build bonding forces between its particles, so sagging cannot be avoided in these fluids. Also, they conclude that static and dynamic sag will be not prevented in oil-based fluids. The only method to minimize static and dynamic sag by increasing low shear rate viscosity.

(Tehrani et al., 2004) evaluated the correlation between barite sag and rheological properties of oil and synthetic-based mud at a different quantity of organophilic clay and

polymers in IEFs. From the experiment, the organoclay mud showed a gel structure greater than polymeric mud. For the fluids correlated down the shear rate of 10^{-2}s^{-1} , the organoclay-based fluid showed a good correlation down to a shear rate of 10^{-4}s^{-1} . Viscoelastic properties were also correlated with dynamic sag, organoclay fluids have given a good gel strength at a very low shear rate. Experiments showed that dynamic barite sag decreased when viscoelastic parameters such as storage modulus (G') and complex viscosity η^* increased. Temperature relation showed that as the temperature increases the elasticity of the mud decrease. Finally, dynamic sag was lower in the clay-based fluids tested than those formulated with polymeric additives.

(Savari et al., 2013) searched for a correlation between dynamic sag and rheological behavior of oil-base mud by a performed laboratory test for five field samples. These tests were done by using a dynamic high-angle sag tester (DHAST) and Anton Paar rheometer. All drilling fluids in this study were compared at a low shear rate. Results presented in this paper showed that from shear rate shear stress curves, the fluids which exhibit high slope value, have low sag. Also, there is a good correlation between sweep curves and DHAST. Moreover, from frequency sweep, the fluid has a high G' indicating that this fluid will resist sag. Finally, not all fluid samples have a consistent result, so in barite sag, there are several mechanisms should be involved.

(Nguyen et al., 2011a) evaluated dynamic sag in oil-base mud by using a modified rotation viscometer (MRV) with sag shoe and flow loop. They conducted a range of 0-100 RPM of rotation speed pipe. Moreover, they studied the effect of concentricity and eccentricity of a rotating pipe. The flow loop results indicated that the concentric rotating pipe

significantly decreased the barite sag. The authors noted that the MRV, which sag shoe, does not correlate flow loop sag tests that incorporate pipe rotation, pipe eccentricity, and annular velocity. They also recognized that under static conditions, if the yield stress greater than 12 lb/100ft², the barite did not settle down in the drilling fluid.

(Nguyen et al., 2014) used the Taguchi and Analysis of Variance (ANOVA) method to study the effect of four parameters on dynamic sag. These parameters include pipe rotation, angular velocity, inclination angle, and eccentricity. For each parameter, there are two conditions. The results showed that pipe rotation contributed to preventing dynamic sagging by 21% by increasing the drill pipe rotation from 16.34 ft/min to 65.37 ft/min. while the annular velocity has the major part in reducing sagging by 60% compared to another parameter so, this parameter should have the priority to avoid barite sagging. Also, the inclination angles different from 45° to 60° have a minimum effect in reducing barite sag. Finally, eccentricity has the lowest effect on reducing barite sag. If the solid barite bed was formed, drill pipe rotation and high drill pipe eccentricity together have a good impact to reduce sagging.

(Maxey, 2007) studied the effect of low shear rheological properties on the behavior of the drilling fluid as an indirect method to measure sag. He conducted low-shear viscosity and oscillation sweep tests. From these methods, the potential of static sag in drilling fluid can be better understood. However, the best representation of static sag cannot sufficiently portray the potential for dynamic sag. The results are shown in Figure 7 and Table 1 of four different static sag factors at similar mud densities. Three of them were stable at 0.509 and 0.507 sag factor, while the fourth one had given a severe sag factor of 0.565. He concluded

that by using low shear viscosity and oscillatory frequency, the possibility of static sag of drilling fluids can be understood.

Table 1 Static sag factor for different drilling fluids(Maxey, 2007)

	Fluid#1	Fluid#2	Fluid#3	Fluid#4
Top Density	1.68	1.674	1.549	1.693
Bottom Density	1.741	1.723	1.604	2.196
Sag Factor	0.509	0.507	0.509	0.565

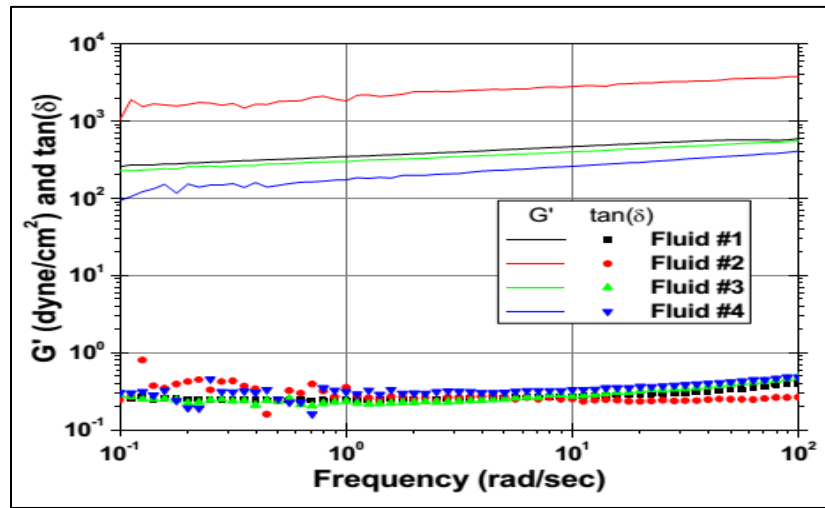


Figure 7 Strong modulus of the sample fluids at 120 °F (Maxey, 2007)

(Wagle et al., 2015b, 2013) studied the effect of adding finely sized (nanoparticles) calcium carbonate, clay-type materials and novel suspension agents to organoclay-free invert emulsion drilling fluid. They added these nanoparticles to three different muds density 9, 12, and 16 ppg in both vertical and inclined at 45°. The result showed that nanoparticles

with rheological modifiers reduce the sag factor of 9 ppg from 0.61 to 0.502 after 24 hrs. and 250°F. Also, for 12 ppg the sag factor has been minimized from 0.67 to 0.505 at the same condition of 9 ppg fluid. For the 16 ppg, the sag factor conducted at 250 °F and 300 °F have given sag factor of 0.512 and 0.52 respectively. The 45 deviated results showed that after adding nanoparticles and rheological modifiers, the sag factor reduced to 0.509, 0.51, and 0.523 for 9, 12, and 16 ppg respectively. Finally, the three drilling fluids showed consistently in HPHT rheology after adding nanoparticles.

(Amighi and Shahbazi, 2010; Jefferson, 1991) studied the most methods to predict barite sag in both conditions static and dynamic. Moreover, they presented some effective ways to avoid the appearance of barite sag in high-pressure high-temperature oil operations. From the field case study, they have given the following points:

- The most severe barite sag occurs at angles 60-75°.
- Eccentric of drill pipe and low annular velocity exacerbate barite sag.
- Dynamic sag can be tough even if the static sag is very small or no sag.
- VG viscometer cannot predict static sagging.
- Sagging can be reduced by using ilmenite weighting or manganese tetroxide material instead of barite.

(Temple et al., 2005) invented a low molecular weight polyalkyl methacrylate to reduce barite sagging in inverted emulsion fluids without significantly increasing the drilling fluid viscosity. The sag factor was reduced from 0.55 to 0.50 by adding 0.5-3 ppb. Also, the additive that had been used did not alter or increase fluid loss.

(Mohamed et al., 2017a) studied the effect of these particle sizes on solubility, stability of HPHT filter press, and sagging. They also studied the effect of temperature on barite settling. The results showed that as temperature increase from room temperature to 270 °F the structure of mud breaks and the barite particles separated downwards. But, after barite particles have micronized the sagging was improved from 0.563 to 0.546 at 270 °F.

Hematite mineral was first introduced in 1976 by (Haaland et al., 1976) as a weighting material and they showed these weighting materials have several advantages, providing high specific gravity, soluble in acid, ability to react with sour acid (Menzel, 1973). The laboratory and field applications confirm that nanoparticle hematite is stable, low toxic, and very multipurpose (Rajendran et al., 2017). Also, by using hematite as a weighting material, the ROP was increased due to the deduction in solid content in the drilling fluid (Tovar et al., 1999). Hematite is more abrasive than barite and has magnetic susceptibilities which will affect upstream equipment and directional drilling, but this problem is solved if its particles are powdered to a fine $D_{95} = 25 \mu\text{m}$ (Tehrani et al., 2014; Yan et al., 2014). However, despite these advantages, API hematite showed both static and dynamic sag problems even at 120 °F.

Manganese tetroxide (Mn_3O_4) or Micromax is a weighting material introduced to the oil and gas industry as a replacement of barite. Micromax is a weighting agent that has ultra-fine particles reach an average particle distribution of less than one μm with a high-density reached 4.8 gm/cm^3 . This unique advantages of high specific gravity with very small particle size enable it to resist the settling in the drilling fluids (HUSSEIN, 2011)

(Al-abdullatif et al., 2015) developed new kill fluids with minimum sagging for abnormal salty water formation in Jilh Saudi formation. This fluid has a density greater than 150 lb/ft³ and consists of 60/40 v/v% micronized barite/manganese tetroxide. The results showed that the sag factor of 100% barite in the vertical and deviated case was 0.52 and 0.53 respectively. For the 60/40 v/v% micronized barite/manganese, the sag factor was 0.51 in both cases.

(Ma et al., 2019) have used the Micromax as a replacement for barite to improve the suspension capacity of the WBM with different density 1.8 to 2.8 gm/cm³. The results showed that all drilling fluids weighted by Micromax have small static and dynamic sag compared with barite. The reason for that is due to the very fine particle size of 0.112 µm. This small size in particles enables the manganese tetroxide to have very small settling velocity. In addition to these advantages, Micromax filter cake can be easily removed using different types of acids

CHAPTER 3

RESEARCH OBJECTIVES AND METHODOLOGY

3.1 Problem Statement

Drilling high-pressure high-temperature reservoirs or deep wells required high mud density with specific characteristics. In these reservoirs, the difference between formation pressure and fracture pressure is located in a narrow window. Barite materials are the most popular weighing agents used for drilling HPHT formations. But barite suffers from settling of its particles downward in the wellbore leaving several problems such as wellbore instability, loss of circulation, stuck pipe, and hole cleaning.

In this study, different solutions to reduce the barite sagging in both water-based and oil-based drilling fluids will be introduced. The effect of these solutions on fluid properties such as density, pH, electrical stability, rheology, and filtration will be investigated.

3.2 Thesis Objectives

The main objective of this work is to develop different solutions to prevent the barite from settling in HPHT wells:

- Prevention of barite sagging using laponite viscosifier for water-based drilling fluid at HPHT conditions.

- Prevention of barite sagging using a combination of different weighting agents (barite/ilmenite) for both water-based and oil-based drilling fluid at HPHT conditions.
- Prevention of barite sagging using a combination of different weighting agents (barite/Micromax) for both water-based and oil-based drilling fluid at HPHT conditions.
- Designing protocol for different drilling fluids with Barite for WBM and OBM at HPHT conditions.

3.3 Experiments Studies and Work Methodology

3.3.1 Drilling Fluids Preparation

In this work, water and oil-based drilling fluids are manually prepared by using a Hamilton mixture as shown in Figure 8 to mix one laboratory barrel equivalent to 350 cm³. The density is measured by mud balance at atmospheric pressure and 120 °F as shown in Figure 9. The type of drilling fluids in this work are water-based mud and inverted emulsion oil base mud. The oil-water ratio is determined by Retort Kit Figure 10. The composition and properties of drilling fluids are given in Table 2. The oil phase is diesel oil with additives such as Geltone is viscosifying clays type, Lime, primary and secondary emulsifiers are Invermul and Ez-mul respectively, water and calcium chloride for activity control, HPHT filtration control agent is Duratone, and weighting material is API barite or combination barite/Micromax or barite/ilmenite. (Falana et al., 2011) stated that primary emulsifiers are used to reduce the interfacial tension between the liquid phases and therefore help the internal phase to disperse in the hole solution, while secondary emulsifiers consolidate the stability of the dispersed phase or stability of the emulsion.



Figure 8 Hamilton drilling fluid mixer



Figure 9 Mud balance (a) Normal, (b) Pressurized



Figure 10 Retort kit 10 cm³

For the WBM, Table 3 shows the composition and the quantity of drilling fluid additives. The base phase of the WBM is distilled water with additives such as defoamer to maintain the bubbles in the mud, xanthan gum, and bentonite are viscosifiers. Sodium carbonate known as (soda ash) is added to treat the calcium ion in the drilling fluid. Potassium hydroxide is to control the alkalinity. Starch and PAC-R chemicals will swell rapidly and seal off the permeable zones effectively. To control the reaction of the mud with shale formation, potassium chloride is required. Finally, different weighting materials such as barite, ilmenite, hematite, and Micromax are added to increase the density to the desired value.

Table 2 Recipe of invert emulsion drilling fluid

Additives	Unit	Quantity	Function
Diesel	bbl	0.491	Base fluid
Invermul	ppb	11.0	Emulsifier
Lime	ppb	6.00	Contaminate remover
Duratone	ppb	7.00	Fluid loss control

Water	bbl	0.143	Activity control
Calcium Chloride	ppb	32.0	
Geltone II	ppb	10.0	OBM Viscofier
EZ-Mul	ppb	4.00	Emulsifier
Calcium Carbonate	ppb	30.0	Bridging material
Barite	ppb	300	Weighting material

Table 3 Recipe of water-based drilling fluid

Name	Unit	Quantity	Purpose
Water	bbl	0.7	Base fluid
Defoamer	lb	0.08	Anti-foam agent
Sodium Carbonate	lb	0.5	Contaminate removal
XC-polymer	lb	1.5	Viscofier
Bentonite	lb	4	Viscofier
Potassium Hydroxide	lb	0.5	pH controller
Starch	lb	6	Fluid loss controller
PAC-R	lb	1	Fluid loss controller
Potassium Chloride	lb	20	Shale Stabilizer
Calcium Carbonate	lb	5	Bridging materials
Barite	lb	350	Weighting agents

3.3.2 Materials Characterization

The weighting material, barite ilmenite, hematite, and Micromax, are characterized by measuring the elemental composition, morphology, and particle size distribution (PSD). Using an X-ray fluorescence spectrometer (XRF) and an X-ray diffractometer, materials characterization testing aims to determine the mineral crystals and components of samples

3.3.3 X-ray Fluorescence

A 5 to 10 gram of selected sample is collected, compressed, and distributed out on the holder. The X-ray fluorescence spectrometer (XRF), M4 Tornado Figure 11, is used to evaluate the sample holder, which takes 200 seconds. An electric current is sent through a filament in a standard X-ray generator, causing an electron to be released. These electrons are therefore accelerated through an anode (objective) by a high voltage (typically around 20 and 100 kV). The spectrum analyzes the results, which include the Rayleigh and Compton scattered distinctive lines from the X-ray source. The peak height of each element is directly connected to the concentration of that element inside the sample volume in this quantitative approach. The XRF data are shown as a percentage of the key components.



Figure 11 M4 Tornado X-ray fluorescence technique

3.3.4 X-ray Diffraction

The X-ray diffractometer shown in Figure 12, often known as an XRD, is a type of analytical tool that can provide in-depth information on crystalline substances. This information can include the identification and quantification of crystalline phases. An X-ray generator, a goniometer and sample holder, and an X-ray detector such as photographic film or a movable proportional counter are the components that make up a diffractometer that uses X-rays. The generation of X-rays in an X-ray tube is accomplished by blasting a metal target with high-energy electrons ranging from 10 to 100 keV to eject core electrons.



Figure 12 X-ray Diffraction

3.3.5 Scanning Electron Microscopy

SEM uses a focussed beam of high-energy electrons to generate surface signals. Electron-sample interactions expose the sample's external morphology (texture), chemical content, crystalline structure, and orientation. In most applications, data are collected over a specified area of the sample's surface, and a 2-dimensional picture illustrates spatial changes. The SEM can also do point studies on the sample, which is valuable for determining chemical compositions (using EDS), crystalline structure, and crystal orientations (using EBSD).

3.3.6 Particle Size Distribution

The particle size distribution of weighting materials plays an important role to prevent the settling of these materials. HELOS Particle Size Analysis shown in Figure 13 is used to identify the distribution of different additives in the drilling fluid.

A particle size distribution can be used to obtain a great deal of statistical information. The cumulative distribution is an excellent choice for accomplishing the aforementioned goal. The percentiles are almost probably one of the most significant parameters to look at. In each instance, these represent the size x below which a certain portion of the sample can be found.



Figure 13 Holes particle size analyzer

3.3.7 Static Sag Test

Barite sagging or weighting material settling is a problem of drilling fluid and it happens when weighting materials separate from the liquid phase and settle down. The method is based on continuously measuring fluid density during the first circulation after the fluid has been static for some time. Although, it can occur in a dynamic situation with low annular velocity. The barite sag can result in big variations in mud density in the wellbore. The light density is on top and the heavy density at the bottom. A static sag in drilling fluid was measured at the static environment to know either mud is stable or fluctuated in density. Sag factor is calculated by equation (1): If the sag factor is higher than 0.53

(Maxey, 2007), the weighting material settles down from drilling fluid. The procedure if the static sag is defined by the following steps:

- Drilling mud is mixed for 15 minutes by a mud mixer.
- Pour the fluid into the Teflon cell and put the Teflon cell inside aging cell Figure 14
- The aging sell is pressurized up to 500 psig by Nitrogen bottle supply
- Enter the aging cell inside the oven and adjust the required temperature.
- After 24 hrs the cell is taken from the oven and called down to room temperature and the pressure is released.
- Open the cell and remove the free oil or water from the fluid. Then, draw 10 ml from the top with a clean syringe and record the weight by 4-digit number mass balance Figure 15
- Determine the drawn fluid density and repeat the previous step but draw from the lower part of the fluid.
- Apply the following equation: Sag factor can be determined by the following equation:

$$SF = \frac{\rho_{bottom}}{\rho_{bottom} + \rho_{top}} \dots\dots\dots(1)$$

Where:

ρ_{bottom} : density of the mud from the bottom of the cell (gm/cm³)

ρ_{top} : density of the mud from the top of the cell (gm/cm³)

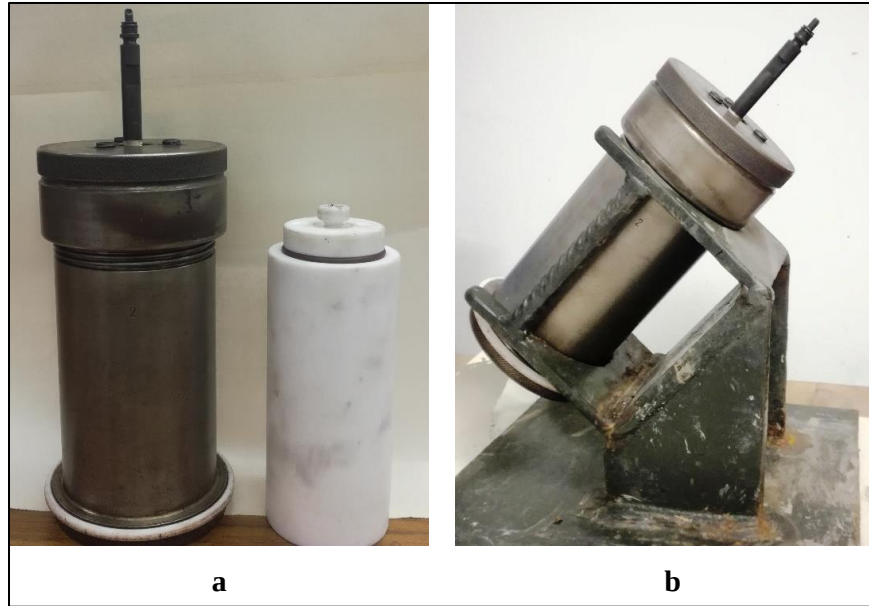


Figure 14 Static sag set up (a) Vertical (b) Inclined 45°



Figure 15 Digital mass balance

3.3.8 Dynamic Sag Test

Viscometer sag shoe test (VSST) Figure 16 is a test used to identify whether the drilling fluid has a dynamic sag or not. The function of this test is to study the sag propensity of different water and oil-based muds using an improved rotational viscometer (MRV). The

sag shoe was introduced by (Zamora and Bell, 2004) to concentrate the weighing particles in the lower part of the thermocouple. The sag shoe allows taking samples from the collection wall. The upper surface of the sag shoe is characterized by two sloped, hemispherical sections. The sloped surface helps to concentrate the weighting material into a single collection well on the sag shoe. The procedure to perform this experiment is the following steps:

- The sag shoe must be inserted into the thermocouple and poured 140 cm³.
- Connect the thermocouple to the viscometer and rise the thermocouple until the upper part of the sag shoe contacts the lower part of the viscometer sleeve. Then lower the thermocouple by 7 mm.
- Adjust the temperature of the viscometer to 120 °F ± 2 °F threshold.
- Set the viscometer rotation to 100 RPM and start the 30-minute timer.
- Using the syringe with the cannula attached and clear of air to extract a 10 cm³ sample and record the weight of the mud-filled syringe, W₁
- Stop the viscometer after 30 min and take another sample of 10 cm³, W₁.
- Calculate the VSST using the following equation 2

$$VSST = 0.834 \times (w_2 - w_1) \dots \dots \dots (2)$$

Where:

VSST: viscometer sag shoe test $\left(\frac{lb}{gal}\right)$

w₁: mass of 10 cm³ at time 0 minute

w₂: mass of 10 cm³ at time 30 minutes

If the VSST value of 1.0 lb/gal or less would indicate a drilling fluid with the least sagging tendency, (Aldea et al., 2001). A VSST value above about 1.6 ppg would specify the start of a probable sag problem (Bern et al., 2010).

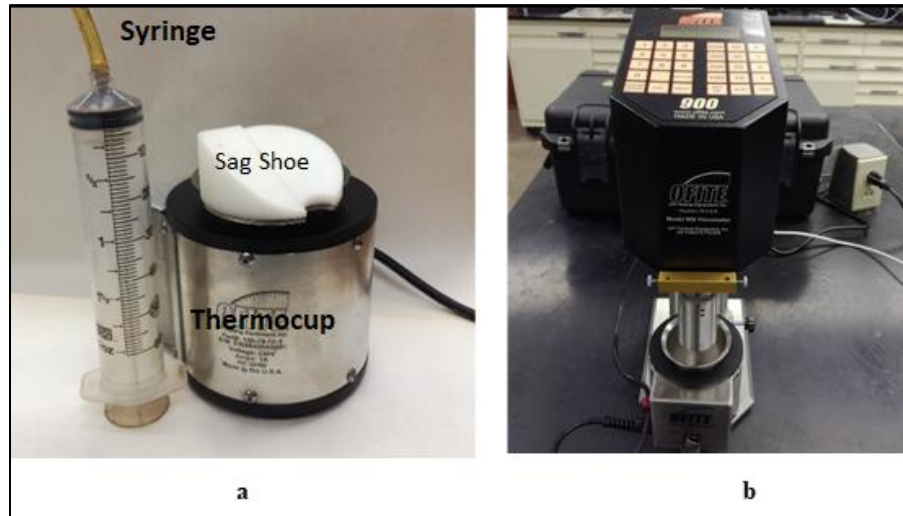


Figure 16 Dynamic sag test set up (a), Viscometer (b) Sag shoe

3.3.9 Rheological and Viscoelastic Properties

The rheological properties such as plastic viscosity (PV), apparent viscosity (AV), yield point (YP), and three gel strengths are measured at HPHT condition using an ofite viscometer as shown in Figure 17. These rheological properties of the drilling fluids are the most important indicators of the sag issue. They are important measurements of the drilling fluid because it gives a relative indication of solids concentration in the mud. The drilling fluid must be strong enough to keep the weighting agents in suspension in the same time with as low as possible viscosity to reduce the friction loss and keep low equivalent circulation pressure (ECD). The settling velocity of the weighting agents is inversely proportional to the viscosity as shown in stoke's equation

$$V_s = \frac{d^2(\rho_s - \rho_f)g}{18\mu}$$

where d is the particle diameter (cm), μ fluid viscosity (cP), g is the gravity acceleration (cm/s^2), ρ_s is the particle density and ρ_f is the fluid density (gm/cm^3).



Figure 17 HPHT viscometer

Viscoelasticity is the term used when the material has viscous and elastic characteristics at the same time when subjected to deformation. The internal force which resists fluid to flow is viscosity and Newton's law is describing this situation, while the ability of materials to restore their original form after unloading is elastic. Drilling fluids display viscoelastic performance and viscoelastic measurements can be involved to evaluate drilling fluid performance in drilling operations. Gel formation and gel structure can be evaluated by the viscoelastic property. To investigate and describe the structure of drilling fluid, dynamic tests, which are the normal rheological strategies, have been conducted. These tests are amplitude sweep and frequency sweep tests. The oscillation amplitude test is firstly applied

to determine linear viscoelastic (LVE) by keeping the frequency constant and free amplitude increase with time. LVE can be determined by plotted storage modulus (G') and loss modulus (G'') against strain or stress on log-log paper. LVE region is defined when (G') and (G'') do not change with increasing strain or stress. After LVE range is determined, the oscillation frequency is applied by letting the frequency free and constant amplitude. The objective of this test is to investigate time-dependent viscoelastic properties. This test can be applied on log-log paper by plotting Elastic modulus (G') and viscous modulus (G'') on Y-axis and angular frequency (ω) on X-axis. The Information is extracted from the amplitude sweep of the highest strain to apply in the frequency sweep test. All these tests are performed using



Figure 18 Anton paar rheometer

3.3.10 HPHT Filtration Test

Filtrate invasion is the mud filtrate that enters the formation and can cause formation damage. This filtration should be minimized by creating a thin impermeable filter cake. A filtration test was performed to evaluate drilling fluids by measuring fluid loss and filter cake thickness. A 10-micron porous ceramic disc, of 2.5-inch diameter and 0.25-inch thickness, is immersed in base fluid and left for one day to completely saturated. The ceramic disc was weighed after saturation and then placed into the filtration cell then, 175 ml of completion fluid was poured into the cell. The cell was closed, a specific differential pressure was applied using a nitrogen cell and the filtration cell was heated gradually up to the desired temperature. The experiment was run for 30 minutes to collect the filtration. Then, the valve was closed, the cell was cooled down and the pressure was released. Finally, the disc was taken out and the filter cake was characterized by measuring the weight and thickness. The setup of the filtration test is shown in Figure 19

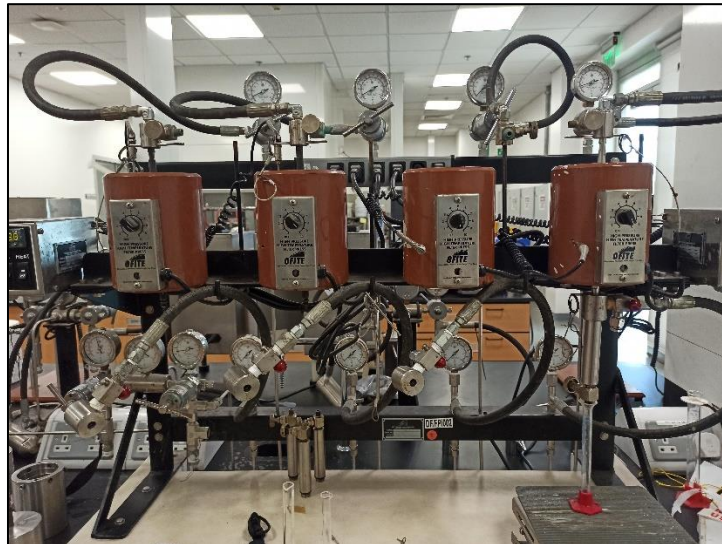


Figure 19 HPHT filtration set up

3.3.11 Electrical Stability and pH Tests

Electrical stability is a test performed to measure the relative stability of water in oil emulsion. This test is measured at 120 °F by Fann electrical stability meter Figure 20.

While the pH meter Figure 21 is used to measure the alkalinity of WBM.



Figure 20 Electrical stability meter



Figure 21 pH meter

CHAPTER 4

COMBINED BARITE-ILMENITE WEIGHTING

MATERIAL TO PREVENT BARITE SAG IN WATER- BASED DRILLING FLUID

Barite sag is a serious problem encountered while drilling high-pressure/high-temperature (HPHT) wells. It occurs when barite particles separate from the base fluid leading to variations in drilling fluid density that may cause a serious well control issue. However, it occurs in vertical and inclined wells under both static and dynamic conditions. This study introduces a combined barite–ilmenite weighting material to prevent the barite sag problem in the water-based drilling fluid. Different drilling fluid samples were prepared by adding different percentages of ilmenite (25, 50, and 75 wt.% from the total weight of the weighting agent) to the base drilling fluid (barite-weighted). The Sag tendency of the drilling fluid samples was evaluated under static and dynamic conditions to determine the optimum concentration of ilmenite which was required to prevent the sag issue. A static sag test was conducted under both vertical and inclined conditions. The effect of adding ilmenite to the drilling fluid was evaluated by measuring fluid density and pH at room temperature, and rheological properties at 120 °F and 250 °F. Moreover, a filtration test was performed at 250°F to study the impact of adding ilmenite on the drilling fluid filtration

performance and sealing properties of the formed filter cake. The results of this study showed that adding ilmenite to barite-weighted drilling fluid increased fluid density and slightly reduced the pH within the acceptable pH range (9–11). Ilmenite maintained the rheology of the drilling fluid with a minimal drop in rheological properties due to the HPHT conditions, while a significant drop was observed for the base fluid (without ilmenite). Adding ilmenite to the base drilling fluid significantly reduced the sag factor and 50 wt.% ilmenite was adequate to prevent solids sag in both dynamic and static conditions with sag factors of 0.33 and 0.51, respectively. Moreover, HPHT filtration results showed that adding ilmenite had no impact on the filtration performance of the drilling fluid. The findings of this study show that the combined barite–ilmenite weighting material can be a good solution to prevent solids sag issues in water-based fluids; thus, drilling HPHT wells with such fluids would be safe and effective

4.1 Introduction

Drilling fluid contains a mixture of solids and polymers. Solids such as weighting materials are used mainly to increase mud density, while clays and polymers are used to control the rheological and filtration properties. For bentonite-based drilling fluid, the rheological and filtration properties can be improved by using chitin nanocrystals from speckled swimming crab shell waste at different ranges of pH (M. C. Li et al., 2018) or by adding cellulose nanocrystals, especially in the case of the low solid content of bentonite–water-based drilling fluid (M.-C. Li et al., 2018). In addition, Wyoming sodium bentonite–water-based drilling fluid has better suspension and filtration control properties when mixing nanoparticles with bentonite particles in different configurations (Vryzas et al., 2019).

Polymers are used heavily in the oil industry for controlling the drilling fluid properties or for enhanced oil recovery applications to extract heavy oil. Polymer flooding is a very important technique to extract heavy oil from thin and heterogeneous reservoirs (Saboorian-Jooybari et al., 2016). Screening criteria and screening algorithms should be developed for enhanced oil recovery techniques (Mashayekhizadeh et al., 2014). Artificial intelligence and data mining can be used to manage the reservoir for polymer flooding, especially in the case of thin and heterogeneous heavy oil reservoirs (Amirian et al., 2018).

Drilling high-pressure/high-temperature (HPHT) oil and gas wells is challenging because it requires a special fluid formulation that can control the high pressure and withstand the elevated downhole temperatures (Mohamed et al., 2017b).. Weighting materials are added to the drilling fluid to attain the high density required to equalize formation pressure and control the well during drilling operations. There are many options for weighting materials that can be used with drilling fluids such as calcite, barite, hematite, manganese tetraoxide, ilmenite, and iron oxide. These materials are different in density and other properties; therefore, the final density of drilling fluid varies accordingly.

Barite is a common weighting material used to formulate high-density drilling fluids because of its high density (4.2–4.48 g/cm³), cheap cost, and low environmental impact. Suspension of weighting agents is critical because settled particulates will not contribute to the hydrostatic column of the drilling fluid, leading to serious well control issues Figure 22. This phenomenon is known as solids sag or barite sag because it is mostly encountered when drilling with barite-weighted fluids. However, barite sag can occur in vertical and directional wells and under dynamic and static conditions, and it is worse in dynamic

conditions. Barite sag can be mitigated by optimizing drilling fluid rheology, implementing sound strategies, and training rig personnel.

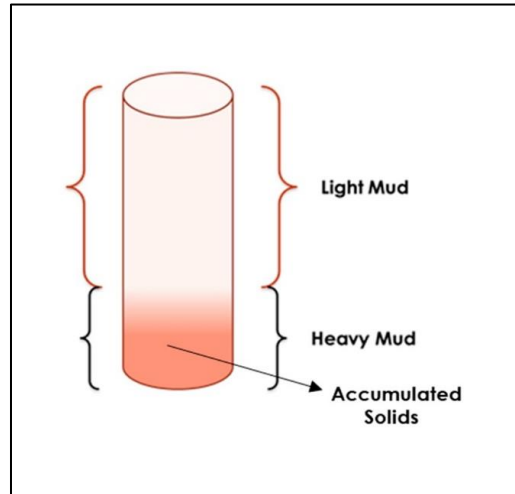


Figure 22 Solids sag phenomenon

Many research studies were conducted to understand and prevent the sagging phenomenon in oil- and water-based drilling and completion fluids. A new method was proposed by (Temple et al., 2005) to prevent barite sag in oil-based drilling fluid by adding polyalkyl methacrylate, which has a low molecular weight, while no copolymer was added; therefore, no additional increase in drilling fluid viscosity would occur. Alabdullatif et al. (Alabdullatif et al., 2014c) introduced a new water-based kill fluid to avoid the barite sag problem. Barite– Mn_3O_4 was used as a combined weighting agent to increase the density of the kill fluid. They concluded that the addition of Mn_3O_4 effectively enhanced fluid stability and reduced barite sag, particularly after a long time under static conditions.

Mohamed et al. (Mohamed et al., 2017b) investigated the effect of barite particle size on water-based drilling fluid stability using a wide range of particle sizes. They found that reducing barite particle size to a micronized size (around 8 μm) slightly enhanced the

stability of the drilling fluid; however, it did not prevent barite sag. Davis et al. (Davis, C.L.; Livanec, P.W.; Shumway, 2018) proposed a new fluid formulation consisting of base fluid (invert emulsion), weighting material (barite), and sag stability enhancer. The sag stability enhancer comprised polyethylene glycol (PEG) having a molecular weight greater than or equal to 200 g/mol [25].

Basfar et al. (Basfar et al., 2018) and Elkatatny (Elkatatny, 2018) studied the effect of adding a new copolymer on the sag tendency of inverted emulsion drilling fluid at different temperatures. They concluded that adding only 1 lbm/bbl of the copolymer to the drilling fluid prevents barite sag in both vertical and inclined conditions at a temperature up to 350 °F. Elkatatny (Elkatatny, 2019) evaluated organophilic phyllosilicate (OP) as a solution to barite sagging in inverted emulsion drilling fluid at elevated temperature (350 °F). He found that adding only

1.5 g of organophilic phyllosilicate was adequate to prevent barite sagging under dynamic conditions. Because of the high demand and limited resources of barite, many research studies were conducted to find another dense-weighting material that can be used to drill HPHT oil and gas wells. Ilmenite is one of the weighting materials that can be used for that purpose because of its high density (4.7–4.79 g/cm³), good performance, availability, and acidity. Ilmenite was introduced to the oil industry as a weighting agent in 1976; however, it was not commonly used because it is abrasive to drilling equipment. To avoid the abrasiveness of ilmenite, the particle size distribution should be optimized, and less than 3% of the large particles (>45 µm) should be used. Elkatatny et al. (Elkatatny et al., 2012) evaluated micronized ilmenite as a weighting agent to be used in water-based drilling

fluids. They concluded that ilmenite-weighted fluids can be a good option for HPHT applications and no solids sag was observed. Xiao et al. (Xiao et al., 2013a) conducted another study using micronized ilmenite with oil-based drilling fluids. They found that ilmenite can be used successfully in oil-based fluids with reduced sag tendency. Another study was also conducted by mixing ilmenite with barite to be used as a weighting material. The effect of using this mixture on drilling fluid density and rheology was studied by Abdou et al. (Abdou et al., 2018). They concluded that this mixture can replace barite because it yields

comparable results with lower solids content, which would reduce the formation damage.

This study introduces a combined (barite–ilmenite) weighting material as a new solution to the barite sag issue in water-based drilling fluids to be used for drilling HPHT oil and gas wells. The effect of using the combined weighting material on all drilling fluid properties was evaluated in this study. Using the combined weighting agent would reduce the sag tendency of barite-weighted fluids and minimize the cost of ilmenite-weighted fluids. Firstly, the methodology followed to conduct this study is presented. Then, the results of this study are discussed. Finally, the findings of this research work are concluded.

4.2 Methodology and materials

4.2.1 Materials

Water-based drilling fluid was formulated by mixing the main drilling fluid additives, obtained from local suppliers, at room temperature using a three-speed mixer. These additives are viscosity and pH control additives, clay stabilizers, bridging agents, and

weighting materials. Barite was used as a weighting agent to attain the high density (15 ppg) of the base drilling fluid. Then, different fluid samples were prepared using a combination of barite and ilmenite with different percentages of ilmenite (25, 50, 75, and 100%) from the total weight of the weighting material. Table 4 describes the drilling fluid formula used in this study, and Table 5 shows the properties of the base drilling fluid (100 wt.% of barite). The barite used in this study has an average particle size (D_{50}) of around 17 microns while ilmenite has an average particle size of around 5 microns. Figure 23 compares the particle size distribution of both barite and ilmenite.

Table 4 Drilling fluid formulation used in this study.

Component	Amount (g)	Mixing Time (min)	Function
Water	245	-	Base fluid
Defoamer	0.08	1	Anti-foam agent
Soda ash	0.5	1	Maintain calcium concentration
XC-polymer	1.5	20	Viscosity control
Bentonite	4	10	Viscosity control
Potassium hydroxide	0.5	1	pH adjustment
Starch	6	10	Fluid loss control
PAC-R	1	10	Fluid loss control
Potassium chloride	20	10	Clay stabilization
Calcium carbonate	5	10	Bridging agent
Barite	350	10	Weighting material

Table 5 Properties of base drilling fluid.

Shear rate, RPM	Shear stress, D.R.
600	95.8

300	64	
200	52.5	
100	38.3	
6	17.9	
3	17.2	
Density	15	ppg
PV	31.8	cP
YP	32.2	lb/100ft ²
Gel strength 10s	16	lb/100ft ²
Gel strength 10/30 min	28/28	lb/100ft ²

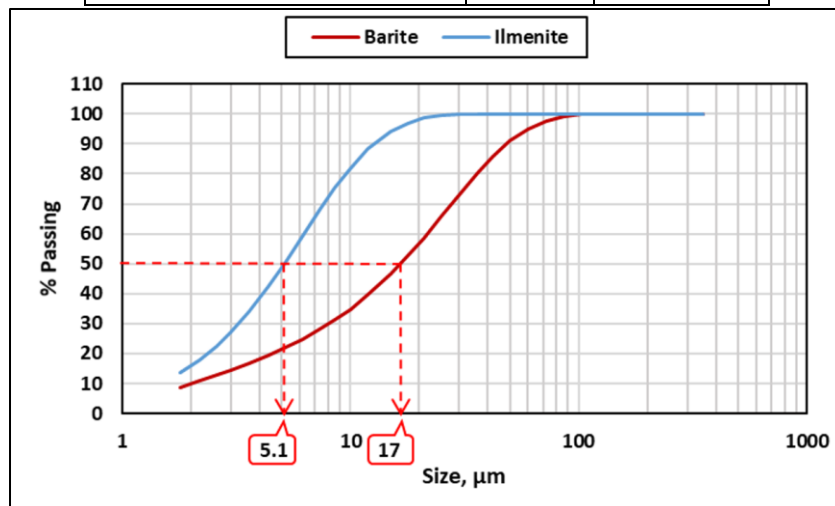


Figure 23 Particle size distribution for the used weighting materials.

4.2.2 Static Sag Test

A static sag test was performed to study the effect of ilmenite on the sag tendency of barite-weighted drilling fluid at static conditions. The test was conducted at vertical and inclined (45°) conditions because the solids sag issue becomes more serious at an inclination angle above 30° (Skalle et al., 1999). Figure 24 shows the experimental setup used to perform the static sag test. It consists of a Teflon liner, an aging cell, and a holder to keep the cell

at 45° during the test. The test was performed at 250°F and 500 psi. The pressure was applied using nitrogen gas. The experimental conditions for the static sag test are shown in Table 6.

After 24 hours, two fluid samples (10 ml) were collected from the top and the bottom of the fluid and weighed then, the sag factor was calculated using equation 1. The acceptable sag factor ranges from 0.50 to 0.53 (Alabdullatif et al., 2014c; Maxey, 2007)

$$\text{Sag Factor} = \frac{w_{Bottom}}{w_{Bottom} + w_{Top}}$$

1

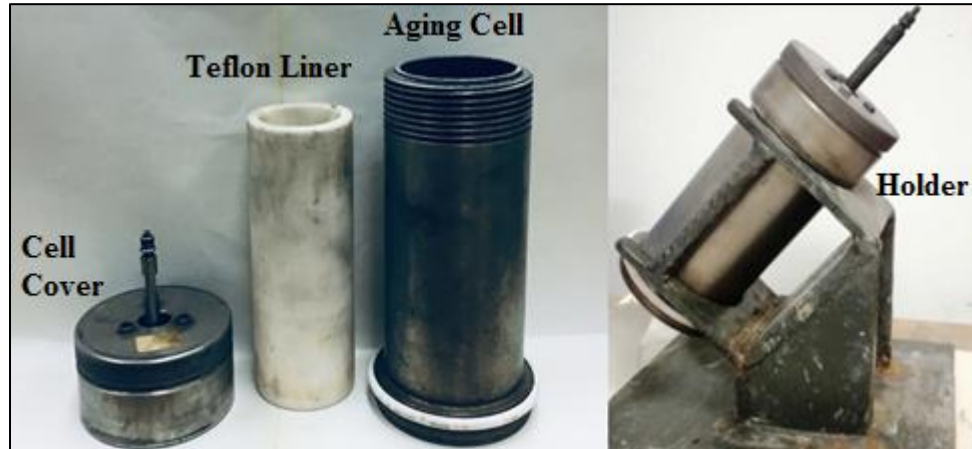


Figure 24 Static sag test setup.

Table 6 Experimental conditions for sag test.

Static Sag Test		Dynamic Sag Test	
Temperature	250 °F	Temperature	120 °F
Pressure	500 psi	Pressure	Atmospheric pressure
Time	24 hrs	Time	30 min
Inclination	Vertical/ 45°		

4.2.3 Dynamic Sag Test

The Sag tendency of drilling fluid samples was evaluated under dynamic conditions using a viscometer sag shoe test, VSST. The test was conducted at standard conditions, i.e. atmospheric pressure and 120 °F (Table 6). Figure 25 shows the experimental setup used to conduct the dynamic sag test. The procedure followed to conduct the test as follows;

- Sag shoe was put in the bottom of the cup and a drilling fluid sample (140 ml) was poured into the cup.
- The fluid sample was heated until reached 120°F and the viscometer was run at 100 RPM (revolution per minute).
- Then, a 10 ml sample was collected from the collection well in the bottom of the sag shoe using a syringe with a cannula and the weight was recorded (W_1)
- After 30 minutes, the viscometer was stopped, and another sample was taken from the bottom and weighted (W_2)
- Dynamic sag factor (VSST) was calculated in ppg using the following equation 2.

$$VSST = 0.834(w_2 - w_1) \quad 2$$

A drilling fluid that has a VSST value equal or less than 1.0 ppg will exhibit good performance and solids sag is unlikely to occur (Aldea et al., n.d.) while, a VSST value of more than 1.6 ppg reflects a bad sag performance and solids sag is highly anticipated (Blomberg et al., 1984).

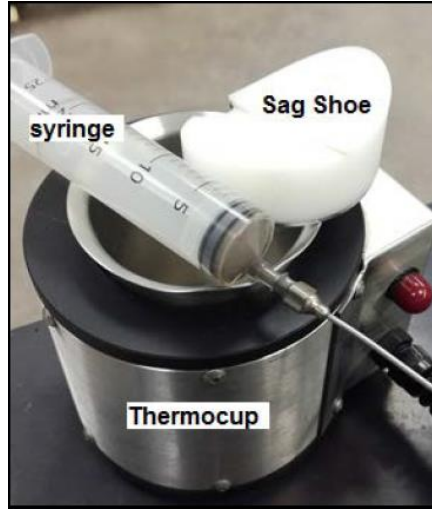


Figure 25 Experimental setup for VSST excluding the viscometer.

4.2.4 Rheology and Viscoelastic Properties Measurements

Drilling fluid rheology was measured at low and high-temperature conditions (120°F and 250°F) to investigate the effect of adding ilmenite on the rheological properties of the drilling fluid formulation. These rheological properties are yield point, plastic viscosity, and gel strength after 10s, 10min, and 30 min. Plastic viscosity (PV) and yield point (YP) were calculated from dial reading data (ϕ) at 600 and 300 RPM using Equation 3 and Equation 4, respectively. While, gel strength data was obtained directly from dial readings at 3 RPM after 10 s, 10 min, and 30 min gel time.

$$PV \text{ (cP)} = \phi_{600} - \phi_{300} \quad (1)$$

$$YP \left(\frac{\text{lb}}{100 \text{ ft}^2} \right) = \phi_{300} - PV \quad (2)$$

Viscoelastic properties of drilling fluid samples were measured by conducting an oscillatory amplitude test and oscillatory frequency test using Anton Paar 302 rheometer. First, an oscillatory amplitude test was conducted to identify the linear viscoelastic range. The test was run at 250°F with a constant frequency of 0.2 s⁻¹. Then, an oscillatory

frequency test was run to obtain the storage modulus G' and loss modulus G'' . Storage modulus can be an indicative tool to detect solids sag tendency (Basfar et al., 2018)

4.2.5 HPHT Filtration Test

Filtration tests were performed to evaluate the effect of adding ilmenite on the filtration performance of the drilling fluid and the sealing properties of the formed filter cake. The test was performed at 250°F and 300 psi differential pressure that was applied using nitrogen gas. A 10-micron ceramic filter disc was used as a filtration medium. The test was started and the filtrate volume was recorded with time for 30 minutes. Then, the weight and thickness of the formed filter cake were measured. Table 7 summarizes the experimental conditions for the HPHT filtration test.

Table 7 Experimental conditions for HPHT filtration test.

Parameter	Description
Condition	Static
Differential pressure	300 psi
Temperature	250 °F
Time	30 min
Filtration medium	10-micron ceramic filter disc

4.3 Results and Discussion

Ilmenite was added to the base barite-weighted drilling fluid with different percentages from the total weighting material (25, 50, and 75 wt.%). Figure 26 shows the effect of adding ilmenite on the density and the pH of the drilling fluid measured at room temperature. The base drilling fluid has a density of 15 ppg and pH of 11. As the concentration of ilmenite increased, the final density of the drilling fluid increased to reach

up to 16.2 ppg when using 100 wt.% ilmenite. This increase is because of the difference between barite density, 4.48 g/cm³, and ilmenite density, 4.79 g/cm³. Therefore, less weighting material is required to formulate a drilling fluid with the same density. In contrast, pH slightly decreased with the increase of ilmenite concentration, and pH dropped from 11 for the base fluid to 9.5 for 100% ilmenite. However, this pH is still within the acceptable range for drilling fluids (pH: 9-11) and it can be adjusted to the required value by adding pH control additives such as sodium hydroxide and potassium hydroxide (Tuntland et al., 1981).

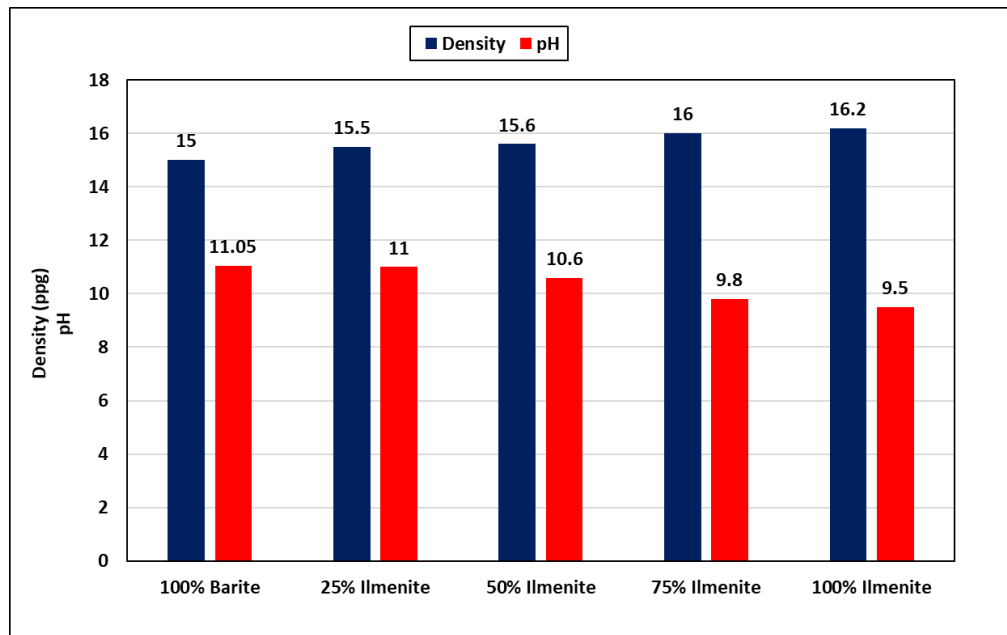


Figure 26 Effect of ilmenite on drilling fluid density and pH at room temperature.

Figure 27 and Figure 28 compare the sag factor of the base fluid (100 wt.% barites) with the other drilling fluid samples (25, 50, 75, and 100 wt.% ilmenite) at dynamic and static conditions, respectively. Under static conditions, base fluid exhibited bad performance with a sag factor of 0.585 and 0.596 at vertical and inclined conditions, respectively which is above the safe range, of 0.50-0.53 (Maxey, 2007). And, the sag factor for dynamic

conditions (VSST) was 1.75 which is higher than the acceptable value (Blomberg et al., 1984). Therefore, barite sag is highly anticipated under dynamic and static conditions which makes drilling with this fluid unsafe. Conversely, it was observed that, for both dynamic and static conditions, as the concentration of ilmenite increased, the sag factor decreased which indicates an improvement in the performance of the drilling fluid. For dynamic conditions, only 25 wt.% of ilmenite was enough to prevent barite sag with a VSST value of 0.67 while for static conditions, adding 50 wt.% of ilmenite prevented barite sag in both vertical and inclined conditions with a sag factor of 0.51.

Figure 29 compares the plastic viscosity and yield point of base fluid, 25 wt.% ilmenite, and 50 wt.% ilmenite at 120 and 250°F. At 120°F, adding ilmenite to the drilling fluid increased the yield point up to 52 lb/100 ft² for 50 wt.% ilmenite while, it was 32 lb/100ft² for the base fluid. In contrast, the plastic viscosity did not change significantly (from 32 to 34 cP) thus, no more frictional pressure drop will result during circulation. Many drilling fluid issues are affected by yield point to plastic viscosity ratio such as hole cleaning, barite sag, equivalent circulating density, and surge and swab pressures (Haaland et al., 1976). Higher YP/PV ratios indicate more stabilization. The increase in yield point values resulting from adding ilmenite to the drilling fluid increased the YP/PV ratio leading to enhancing the drilling fluid stability (Elkatatny, 2012). At 250°F, a huge drop in the plastic viscosity and yield point of the base fluid was observed (51% and 42%, respectively) because of the high temperature while, adding 50 wt.% of ilmenite maintained the rheological properties of the drilling fluid with a drop of 18% and 27% in PV and YP values, respectively. Gel strength data was obtained from the direct reading at 3 RPM after

10 s, 10 min, and 30 min. This data was measured at 120 and 250°F. As shown in Figure 30, at high temperatures base fluid showed a bad performance as gel strength decreased with time therefore, base fluid forms an unstable gel that breaks with time at elevated temperatures. Conversely, adding ilmenite enhanced gel strength and showed better performance at high temperatures. This rheological behavior confirms sag test results that 50 wt.% ilmenite fluid sample is more stable than the base fluid.

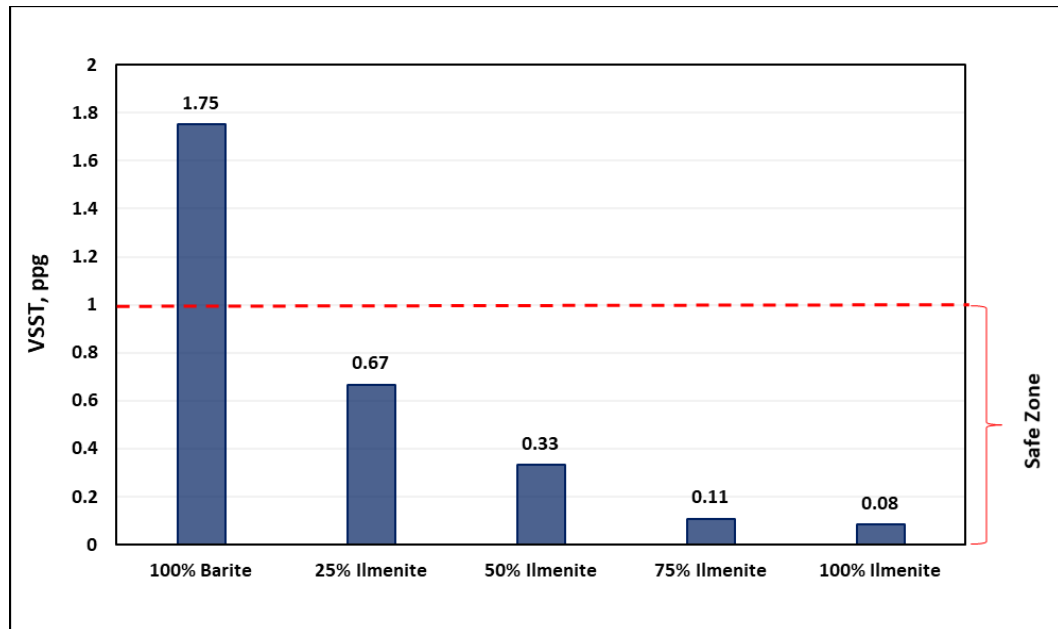


Figure 27 Effect of ilmenite on WBM sag under dynamic conditions (120 °F).

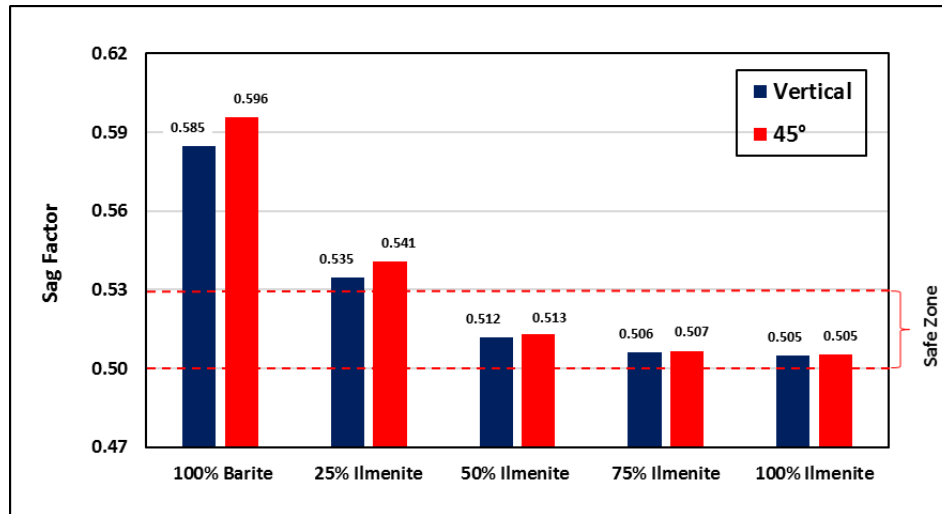


Figure 28 Effect of ilmenite on sag tendency under static conditions (250 °F).

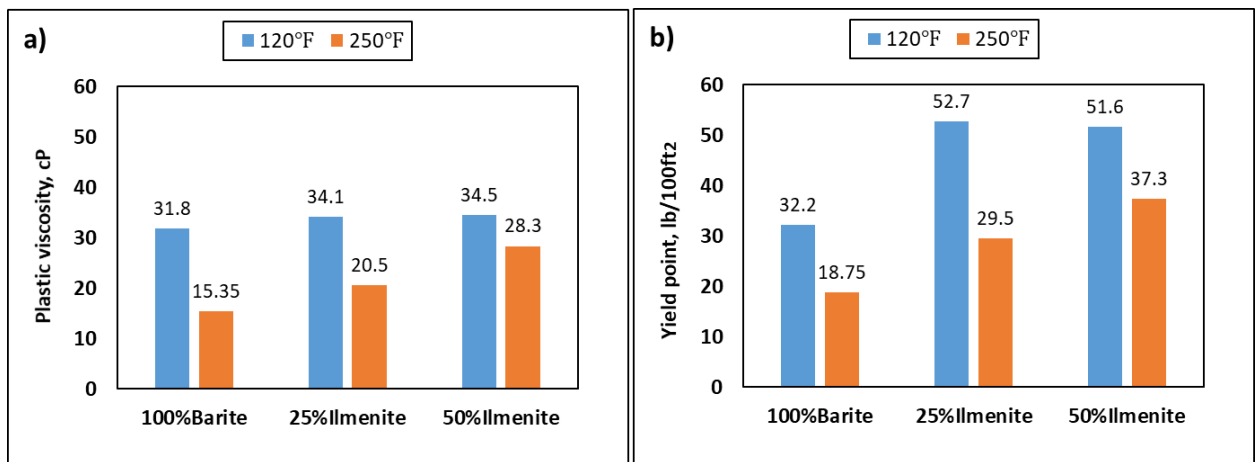


Figure 29 Effect of ilmenite on: a) Plastic viscosity, and b) Yield point.

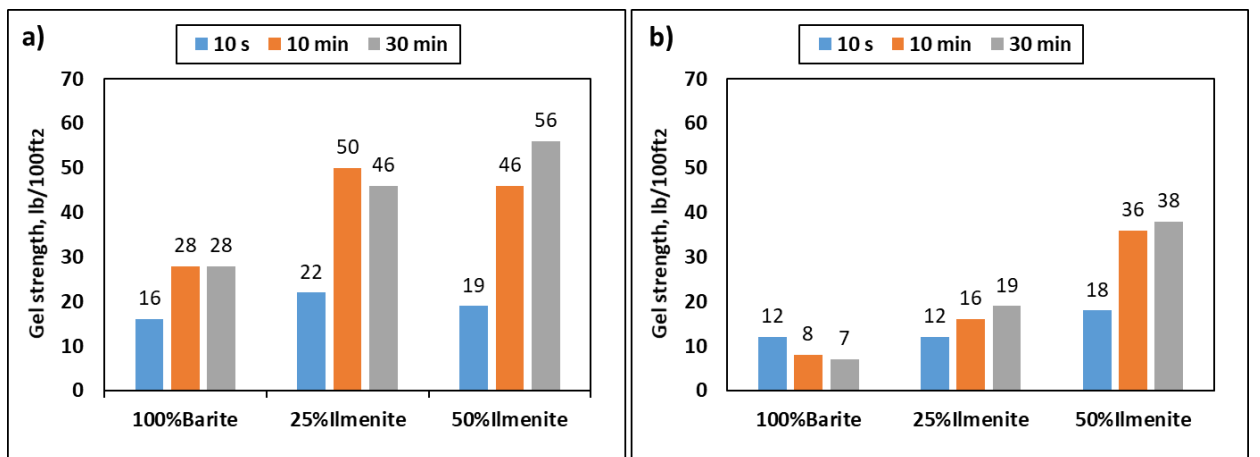


Figure 30 Effect of ilmenite on gel strength at: a) 120 °F, and b) 250 °F.

Figure 31 compares the viscoelastic properties of base fluid, 25 wt.% ilmenite, and 50 wt.% ilmenite measured at 250 °F. It was found that the storage modulus G' is higher than the loss modulus G'' for all the drilling fluid samples which means that the linear viscoelastic range is dominated by the elastic property. Adding ilmenite to the drilling fluid increased the storage modulus reflecting higher elasticity and a more stable gel structure (Abdou et al., 2018).

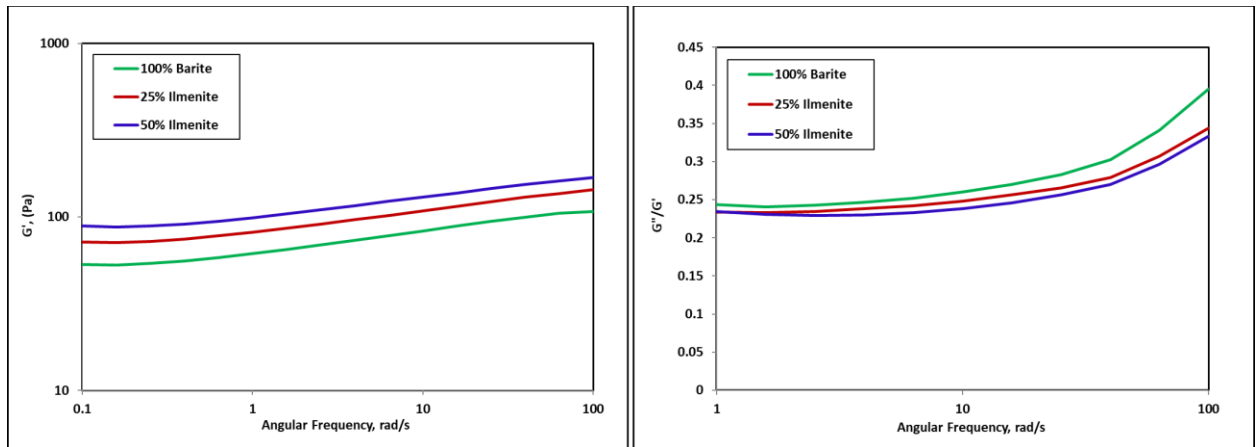


Figure 31 Effect of ilmenite on viscoelastic properties (250 °F).

An HPHT filtration test was conducted to evaluate the effect of combined weighting material on the filtration performance of the drilling fluid. Figure 32 compares the filtration performance of the base fluid, and the 25 wt.% and 50 wt.% ilmenite fluid samples at 250 °F and 300 psi differential pressure. It was found that adding up to 50 wt.% ilmenite (from the total weight of the weighting material) had no impact on the filtration performance. The total fluid filtrate was 6.2 cm³ and a 2.5-mm filter cake was formed in all fluid samples (Figure 33). Table 8 summarizes the filtration test results.

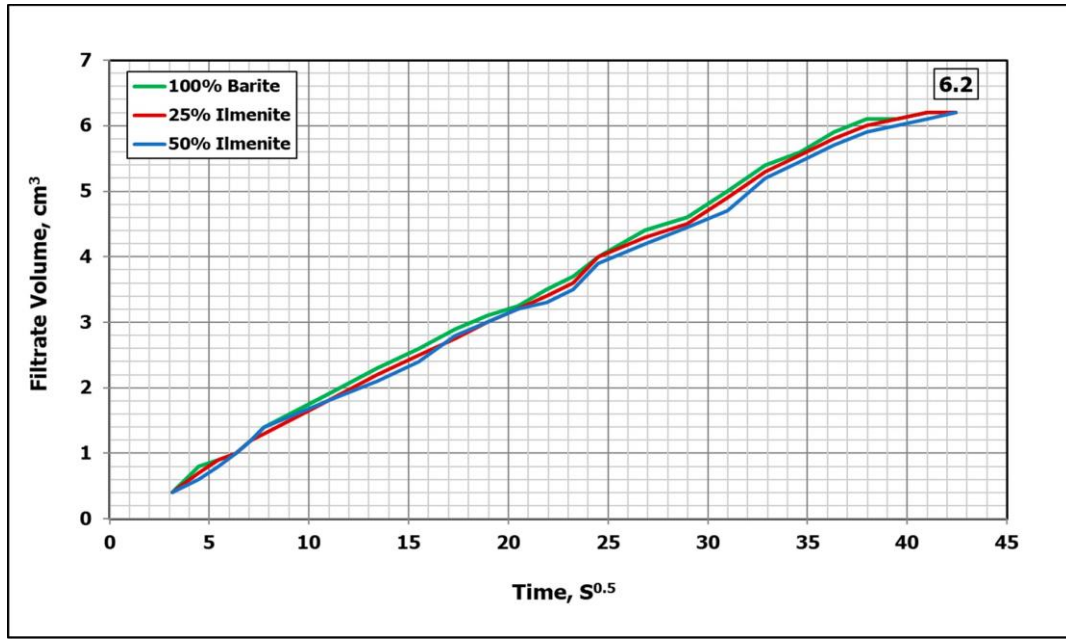


Figure 32 Effect of ilmenite on filtration performance of drilling fluid (250 °F).

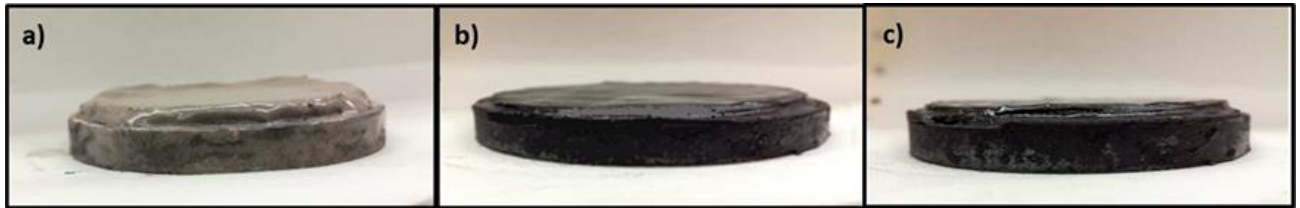


Figure 33 Filter cake: a) 100% Barite (2.59 mm), and b) 50% Ilmenite (2.51 mm).

Table 8 Summary for HPHT filtration test results.

Parameter	100% Barite	50% Ilmenite
Filtrate volume (cm ³)	6.2	6.2
Filter cake thickness (mm)	2.59	2.51
Filter cake weight (g)	23	19.92

4.4 Conclusions

Extensive experimental work was conducted to evaluate the effect of combining barite–ilmenite weighting materials to mitigate the barite sag issue in the water-based drilling fluid. From the results of this work, the following conclusions can be drawn:

- As the concentration of ilmenite was increased, the final density of the drilling fluid increased because of the high density of ilmenite, while the pH of the drilling fluid slightly decreased to reach 9.5 for 100 wt.% ilmenite. However, the pH value is still within the acceptable pH range (9–11) and it can be maintained by adding pH control additives.
- Adding ilmenite enhanced the stability of the drilling fluid and significantly reduced the sag factor for both static and dynamic conditions. The sag factor decreased as the concentration of ilmenite increased, and 50 wt.% ilmenite was adequate to prevent barite sag in both conditions. The sag factor dropped from 0.59 to 0.51 in static conditions, while VSST dropped from 1.75 to 0.33 in dynamic conditions.
- Ilmenite improved the rheology of the drilling fluid and maintained rheological properties under HPHT conditions. In contrast, a huge drop in rheological properties of the base fluid (without ilmenite) was observed because of the high temperature. Similarly, ilmenite enhanced the viscoelastic properties of the drilling fluid by increasing the elasticity of the drilling fluid, which validates the sag test results.

From the HPHT filtration results, adding ilmenite to the base drilling fluid had no impact on the filtration performance and filter cake properties. The total filtrate volume was 6.2

cm³ for both fluids (100 wt.% barite and 50 wt.% ilmenite), while a 2.5-mm filter cake was formed in both cases.

- Based on the rheology and sag test results, 50 wt.% is the optimum concentration of ilmenite, and adding more than this concentration is not recommended as it would add more cost to the drilling operation.
- The combined barite–ilmenite weighting material could be a good option to safely kill or drill HPHT oil and gas wells with minimal sag tendency; however, more research work is needed to remove the composite filter cake in the case of drilling, because the removal process of the filter cake would be more complex as two different materials need to be dissolved. Therefore, a new approach to remove the composite filter cake is required.

CHAPTER 5

COMBINED BARITE-MICROMAX WEIGHTING MATERIAL TO PREVENT BARITE SAG IN WATER- BASED DRILLING FLUID

Over the years, barite (BaSO_4) as a weighting agent was widely used. However, it has an issue with particle settling which is known as barite sagging, that causes a variation in drilling fluid properties and operational problems. This study introduces and investigates a novel combination of Micromax (Mn_3O_4) and barite weighting materials to prevent barite sagging in water-based mud under high-pressure high-temperature (HPHT) situations. Different amounts of Micromax, 0, 25, and 50 wt% from the total weighting material were added to the field formula. Static and dynamic sagging tests were conducted at 250 °F and 120 °F, respectively, to study the sagging tendency and identify the optimum combination. The mud pH and density were measured at ambient conditions. The rheological properties measurements were conducted at 120 °F and 250 °F. The filtration properties were evaluated using the HPHT filtration test at 300 psi and 250 °F. The results showed that adding 25/75 wt% Micromax/barite is enough to eliminate the sag issue in both vertical and 45° inclined positions, as it enforced the sagging tendency to the safe range. The 25/75 wt% Micromax/barite has no significant effect on the rheological properties compared to

the 100 wt% barite, except for the 30 min gel strength which was increased by 19% for better particles suspension while no circulation. The HPHT filtration test indicated a significant decrease in the filter cake thickness and weight with the 25/75 wt% Micromax/barite without significant change in the filtration volume compared to the 100 wt% barite.

5.1 Introduction

Water-based and oil-based are the most common types of these drilling fluids(Caenn et al., 2016; Gray and Young, 1973)... Excellent lubrication, leak off reduction, clay or water sensitive stabilization and thinner filter cake are the advantages of oil-based mud over water-based mud; beside that, it can be sustained the harsh conditions in high pressure high temperature reservoirs (Caenn et al., 2016; Davison et al., 2001; Patel, 1998; Ren et al., 2015). Invert emulsion drilling fluids (IEF) consist of small droplet of water as internal discontinues phase inside the continuous oil phase (Azar and Samuel, 2007). IEF is mostly used among oil-based mud due to having significant properties (Davison et al., 2001; Patel, 1998; Popov et al., 2013; Ren et al., 2015). However, these advantages, there are some limitations. Gas can easily dissolve in oil-based mud make difficult to detect it (Bland et al., 2006). Also, it is more expensive than WBM and more susceptible to loss of circulation (Al-Saeedi et al., 2010). So, working on water-based mud to improve its properties is vital for oil and gas industry.

There are several weighting materials to increase the mud density such as barite, ilmenite hematite Micromax and calcite. Barite is the most popular one because its outstanding properties. However, increase in the equivalent circulation density (ECD), removal issues

special in OBM, excessive torque and settling of its particle known as barite sagging are the serious problems. Static and dynamic sag if not efficiently solved, it can lead to stuck pipe, loss of circulation and wellbore instability (Peter A. Bern et al., 2000a; Dye et al., 2001a; Nguyen et al., 2011b).

The sagging phenomenon is effected by two major keys which are drilling fluid properties, drilling parameters (Amighi and Shahbazi, 2011; Peter A. Bern et al., 2000b; Bern et al., 1996). Replacing barite-weighting agent is one of the efficient solutions to prevent barite sagging. According to Stokes equation, the velocity of particle in the drilling fluid system can be estimated by the following equation:

$$v = \frac{d^2(\rho_s - \rho_f)(g)}{18\mu}$$

Where:

- v : Is the slip velocity of weighting material particle, cm/s
- d : Is particle diameter, cm
- $\rho_s - \rho_f$: Is difference between particle and drilling fluid density, gm/cm^3
- g : Is the acceleration due to gravity, cm/s^2
- μ : Is the viscosity of the drilling fluid, cP

Several studies were conducted to solve solids sag phenomenon in both oil and water-based drilling fluids by introducing filed cases that have barite sag (Paul D. Scott et al., 2004), optimizing drilling fluid rheology using anti-sagging agents and rheology modifiers (Basfar et al., 2018; Davis et al., 2017; Elkatatny, 2019; Temple et al., 2005), reducing the particle size of the weighting material such as micronized barite and ilmenite (Al-Bagoury,

2014; Boyou et al., 2019; S. M. Elkatatny et al., 2012b; Mohamed et al., 2017a). Replacing the weighting material, or adding a combination of weighting materials (Abdou et al., 2018; Alabdullatif et al., 2014a; Basfar et al., 2019; Ma et al., 2019; Mohamed et al., 2019a; Wagle et al., 2015a, 2013).

Barite sag in the earlier experiences didn't cause by only drilling fluid and particle size properties. But also drilling parameters for instance inclination angle, pipe rotation, annular fluid velocity and eccentricity of drill pipe (Dye et al., 2006, 2001b). Low annular velocity, inclined wellbore and low pipe rotation will intensely help to settle down the weighting agents (Peter A. Bern et al., 2000b). The maximum barite sag was observed in the range of 45° to 60° and pipe rotation have contributed to decreases the sag by 60% (Nguyen et al., 2014). Gel strength is a good indicator of particle settling, fragile gel strength allows the particle to settle downward easily. Drilling fluid may exhibits high yield point but when it exposed to small share, it broken gel strength (B Bui et al., 2012; Saasen, 2002).

This work aims to study adding different concentration (w/w) 100% barite, 25/75% barite/Micromax 50/50% barite/Micromax 75/25% barite/Micromax and 100% Micromax in water-based mud at high temperature on both static sag and dynamic sag. Characterization of Micromax and barite in term of XRF, particle size distribution and SEM are performed. The effect of adding these concentrations on pH and density are evaluated. The optimum combination of barite/Micromax then investigated by HPHT rheology and HPHT filtration.

5.2 Materials and Experiments

5.2.1 Materials

Three water-based drilling fluid formulations were prepared using multimixer at ambient conditions. In these formulations the used weighting materials were firstly a 100 wt.% barite, then the Micromax was added to the base barite-weighted drilling fluid with 25 and 50 wt.% from the total weighting material. The remaining key drilling fluid additives were described in Table 9 with their quantities, mixing time and functions.

Table 9 The drilling fluid formulation

Component	Amount (g)	Mixing Time (min)	Function
Water	245	-	Base fluid
Defoamer	0.08	1	Anti-foam agent
Soda ash	0.5	1	Maintain calcium concentration
XC-polymer	1.5	20	Viscosity control
Bentonite	4	10	Viscosity control
Potassium hydroxide	0.5	1	pH adjustment
Starch	6	10	Fluid loss control
Pac-R	1	10	Fluid loss control
Potassium chloride	20	10	Clay stabilization
Calcium carbonate	5	10	Bridging agent
Barite/Micromax	350	10	Weighting material

The weighting materials used in this study (Barite/Micromax) were characterized using Particle Size Distribution (PSD), X-Ray Fluorescence (XRF) and Scanning Electron

Microscope (SEM). The PSD indicated that the average particle size (D_{50}) of the Micromax is 1.66 μm comparing to 16.64 μm for barite Figure 34.

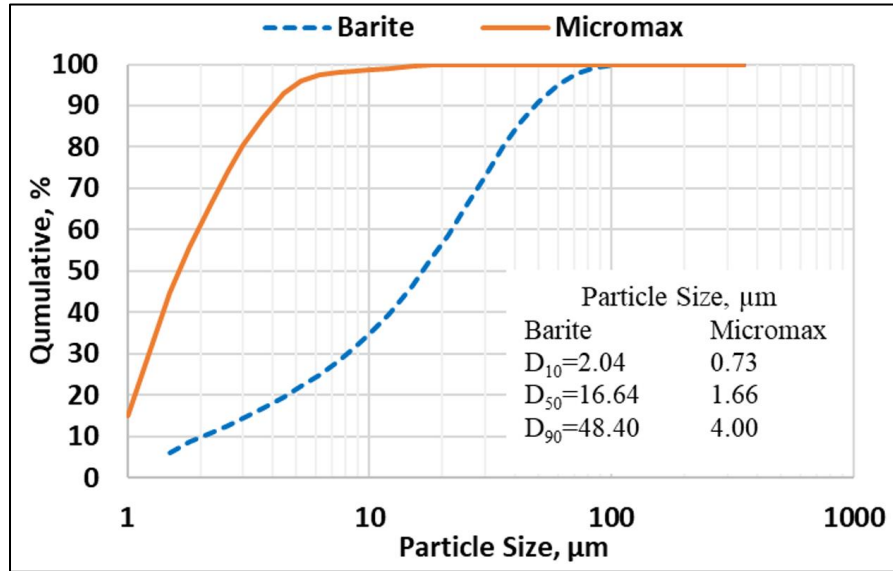


Figure 34 PSD for used weighting materials

The XRF and SEM figured out the compositions of both barite and Micromax as shown in Figure 35 and Figure 36

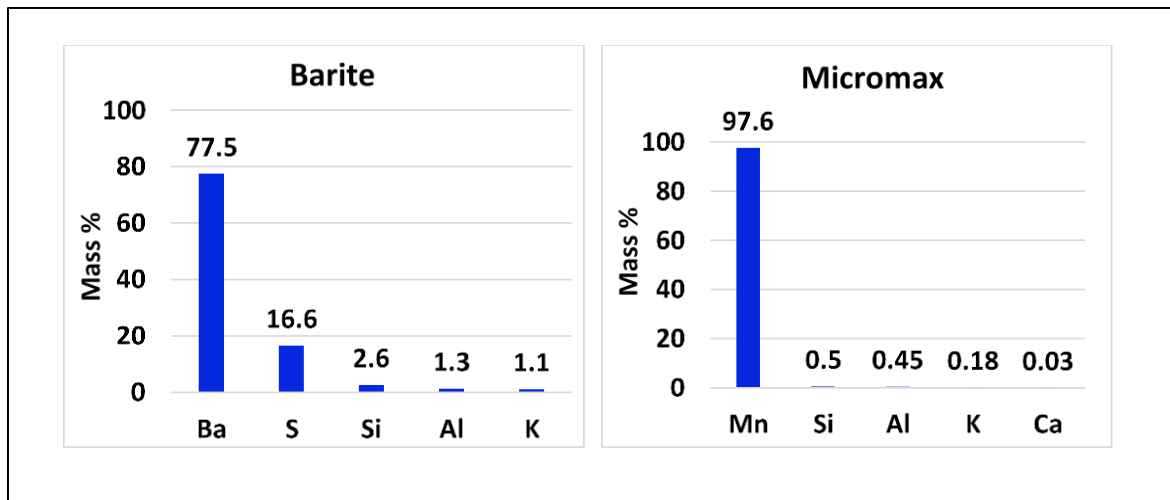


Figure 35 The composition of barite and micromax using XRF

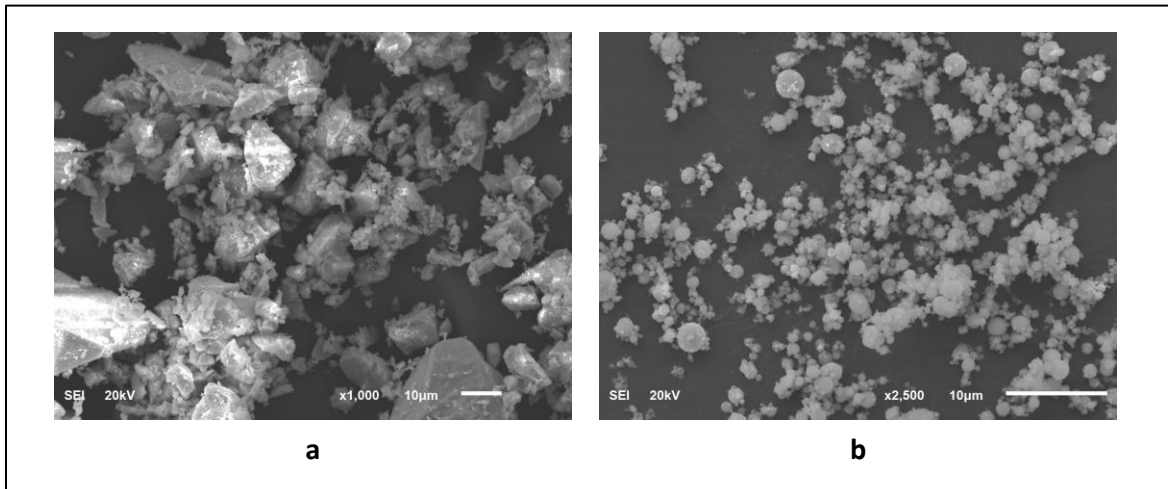


Figure 36 SEM images of a) barite and b) micromax

5.2.2 Experiments

The densities and pH values were measured at ambient conditions for 100 wt.% barite, 25 wt.% Micromax and 50 wt.% Micromax to determine the effect of Micromax.

The effect of Micromax on sagging performance was evaluated by both static and dynamic sag tests to define the optimum Micromax/barite combination percentage. The static sag test was performed by pressurizing the drilling fluid to 300 psi in aging cell and hanged in the oven with temperature 250°F at two positions; vertical and inclined by 45° angle setup. After aging for 24 hours the fluid at the top and bottom portions of the cell were weighted to quantify the sag factor using Equation 1.

$$Sag\ Factor = \frac{W_{bottom}}{W_{bottom} + W_{top}} \dots\dots\dots (1)$$

The dynamic sagging test was performed at atmospheric pressure and 120°F using viscometer to provide the required rotation, then the value of viscometer sag shoe test (VSST) was determined using Equation 2.

$$VSST = 0.834 \times (W_2 - W_1) \dots\dots\dots (2)$$

Where W_1 and W_2 are the weight of the tow samples taken from the cell bottom before and after rotating with 100 rpm for 30 minutes.

The rheological properties were measured at atmospheric pressure and both 120 and 250°F by using Anton-paar rheometer shown in Figure 37. Plastic viscosity (PV), yield point (YP) and three gelling strength are measured to evaluate the effect of adding the recommended weighting material combination on the drilling fluid rheology and compare with the base barite-weighted drilling fluid.

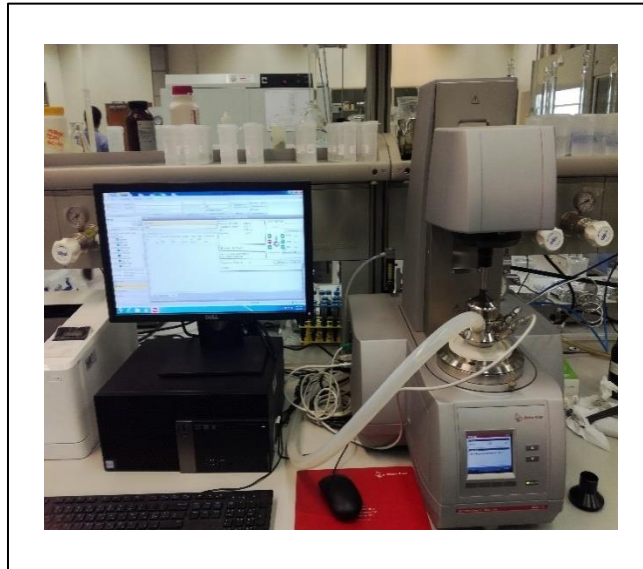


Figure 37 HPHT Anton-paar rheometer

The filtration performance was evaluated under static conditions for a 100 wt.% barite and the recommended combination-weighted mud formulas. The filtration tests were conducted at 300 psi differential pressure and 250°F using a 10 μ m ceramic filtration disc as filtration medium. The filtrate volume was recorded as a function of time for 30 minutes, then the thickness and weight of the formed filter cake were recognized.

5.3 Results and Discussion

Figure 38 shows that adding the Micromax to the base barite-weighted mud increases the density and the pH. The density increased from 14.95 ppg of 100 wt.% barite to 15.60 ppg and 15.90 ppg with 25 wt.% and 50 wt.% Micromax respectively. This increment is justified by the higher density of Micromax 4.88 g/cc (NIOSH) comparing to the 4.48 g/cc for barite density (Hanor, 2019). As well, the pH was increased from 11.0 to 11.3 and 11.4 for 100 wt.% barite, 25 wt.% Micromax and 50 wt.% Micromax, respectively. This slight increase can be easily adjusted to the recommended range (9–11) by using pH control additives (Caenn et al., 2011)

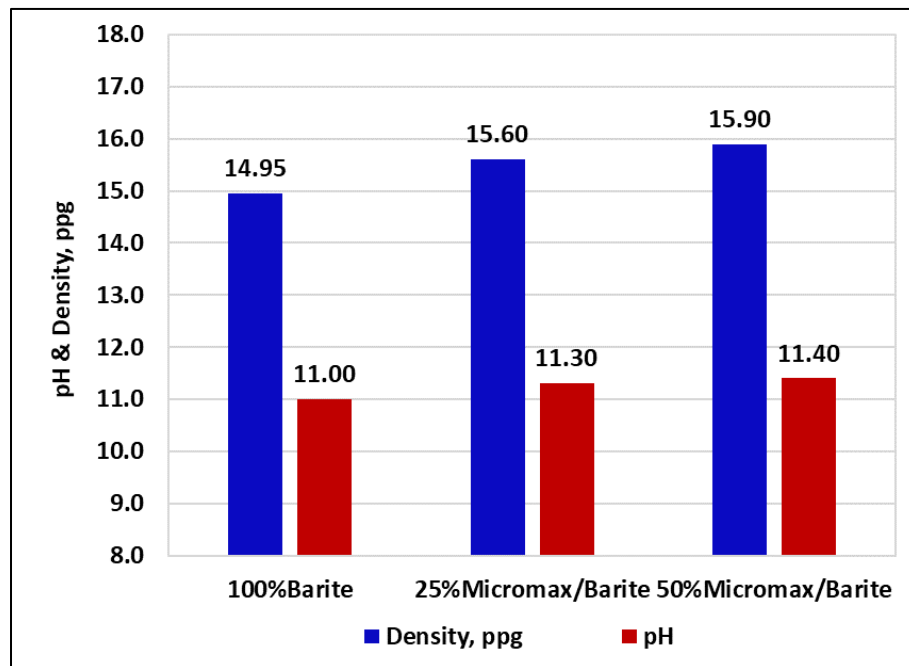


Figure 38 Effect of Micromax on drilling fluid density and pH at ambient condition

The effect of combining Micromax with barite on sagging was studied under static and dynamic conditions. The static sag tests for both vertical and inclined conditions indicated an enhancement in sag factor due to adding Micromax Figure 39Figure 38. The sag factor

for the base barite-weighted mud was 0.58 at vertical state and 0.6 at inclined state, which are out of the recommended range of 0.50–0.53 (Maxey, 2007) and (Alabdullatif et al., 2014a). After adding 25 wt.% Micromax the sag factor reduced to 0.514 and 0.518 for vertical and inclined conditions respectively. While adding 50 wt.% Micromax reduced the sag factor to 0.505 at vertical state and 0.510 at inclined state.

The dynamic sag test showed the beneficial of combining Micromax with barite as the VSST reduced from 2.1 ppg at 100 wt.% barite to 0.52 ppg with 25 wt.% Micromax and 0.05 at 50 wt.% Micromax as shown in Figure 40 and Figure 39, while the recommended VSST value is less than 1.0 ppg. This reduction of sagging when Micromax is used is mainly because of (Aldea et al., 2001) the spherical shape, small particle size, and high density of Micromax compared to the barite.

From these tests, it's recommended to use the combination of 25 wt.% Micromax with barite, which can minimize the sagging performance to the acceptable range under the mentioned conditions.

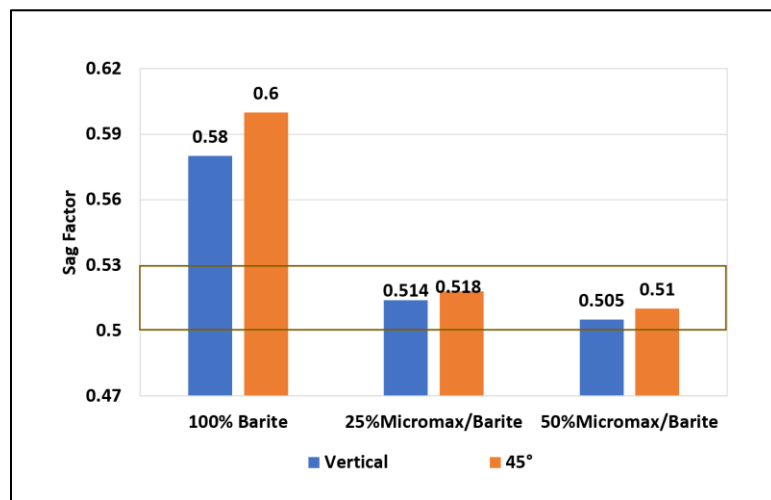


Figure 39 Effect of Micromax on sag factor under static conditions at 250 °F

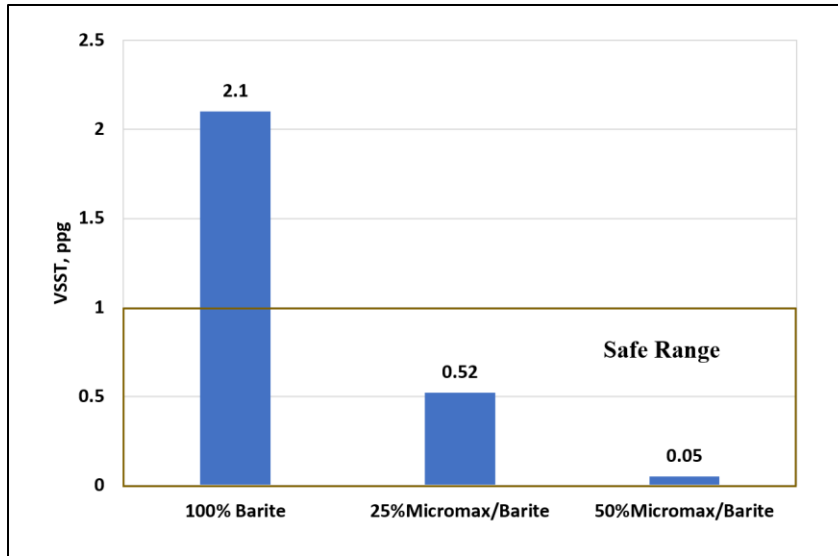


Figure 40 Effect of Micromax on sag factor under dynamic conditions at 120 °F

The drilling fluid rheology was examined to study the effect of adding the recommended 25 wt.% Micromax and compare with 100 wt.% barite. Figure 41 shows that at 120°F the plastic viscosity was slightly reduced from 35 to 32 cP, while the yield point increased from 33 to 43 lb/100ft² for 100 wt.% barite and 25 wt.% Micromax respectively. Accordingly, the YP/PV ratio increased from 0.94 to 1.34 that indicates better stability performance and hole cleaning, and prevents the accumulation of cuttings while drilling highly deviated wells (Caenn et al., 2011; Chilingarian et al., 1983; Hussaini and Azar, 1983). At 250°F, the plastic viscosity reduced to 23 cP for 100 wt.% barite because of the temperature effect, and the yield point increased to 39 lb/100ft². However, adding 25 wt.% of Micromax has no significant effect on either PV or YP at 250°F.

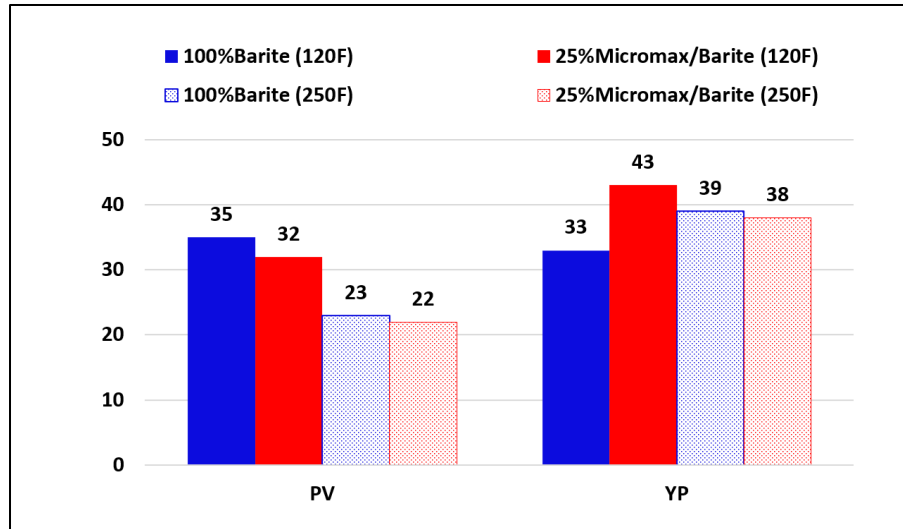


Figure 41 Effect of Micromax on rheology

The gel strength was detected for 100 wt.% barite at 10 seconds, 10 minutes, and 30 minutes as 21, 23 and 26 lb/100ft² respectively, while the values after adding the recommended 25 wt.% Micromax were 21, 24 and 31 lb/100ft² respectively with no significant change, as shown in Figure 42.

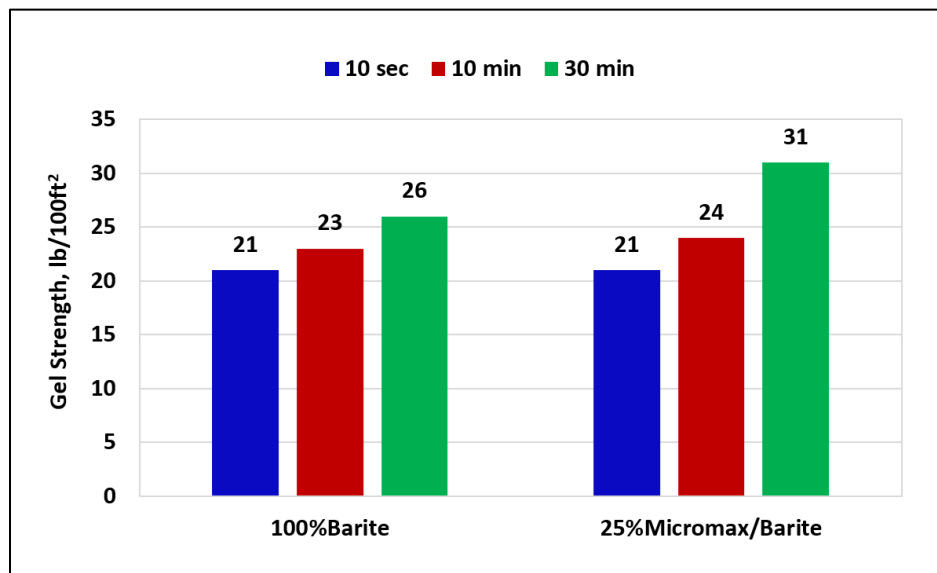


Figure 42 Effect of Micromax on gel strength

The filtration test indicates that adding 25 wt.% Micromax has an insignificant effect on filtrate volume, as the filtration volume after 30 minutes was 7.4 cm³ with a 10% increment Figure 43, while the filter cake thickness and weight were decreased increased from 3.7 to 2.3 mm and from 24.9 to 14.6 g respectively Figure 44.

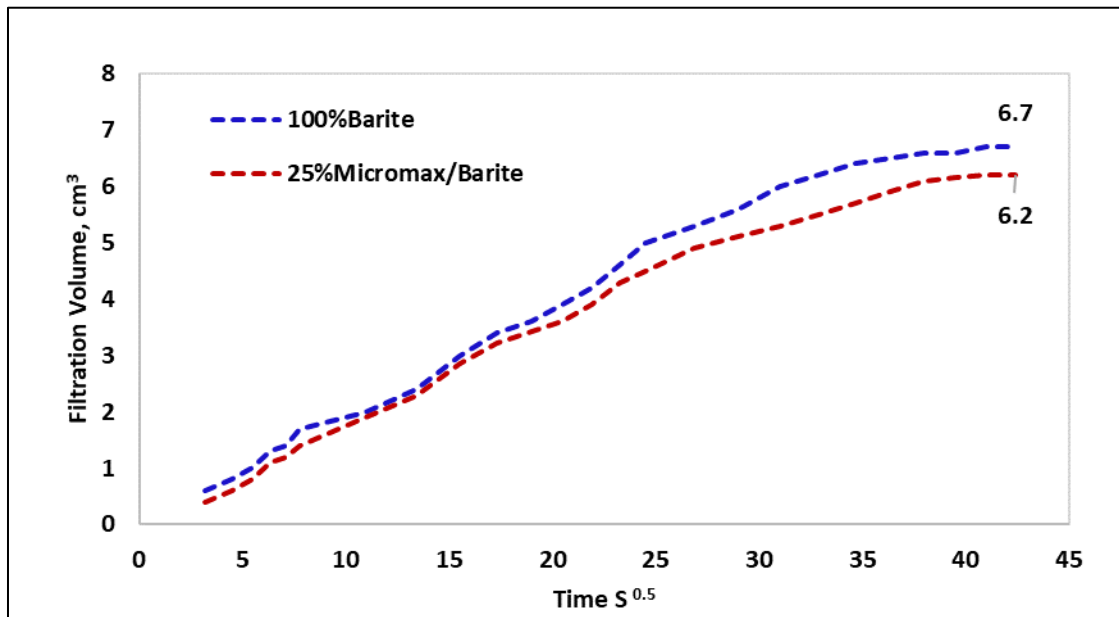


Figure 43 Effect of Micromax on filtration volume

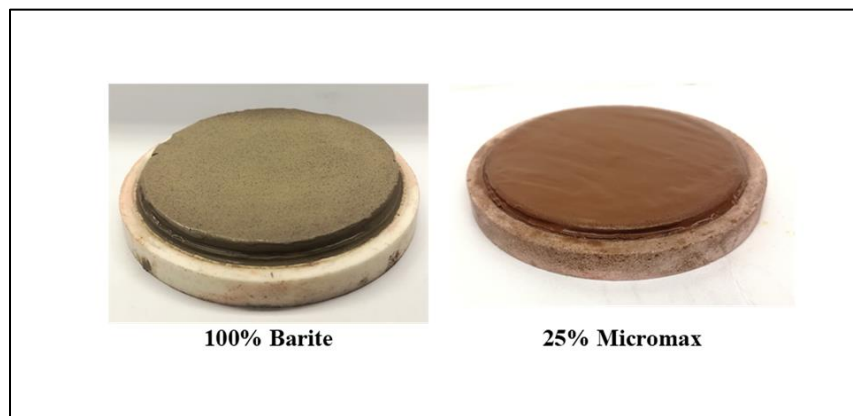


Figure 44 Drilling fluid filter cake

5.4 Conclusions

Worthy laboratory work was performed to investigate the effect of combining the Micromax with barite in sagging tendency and properties for water-based drilling fluid, and to determine the required combination percentage. Based on the obtained outcomes, the following can be concluded:

- The Micromax increased the mud density because of its higher density, which means that the required density can be achieved with less quantity of weighting material.
- The pH was slightly increased when the Micromax concentration increased.
- Inclusion of Micromax improved the drilling fluid stability by minimizing the sag tendency in both static and dynamic conditions.
- The 25 wt.% Micromax from the total weighting material is recommended, since it enforced the sag factor and the VSST values to the safe range.
- Adding 25 wt.% Micromax enhanced the hole cleaning performance by increasing the YP/PV ratio
- The filtration properties were improved by adding 25 wt% Micromax.

CHAPTER 6

ENHANCEMENT OF STATIC AND DYNAMIC SAG

PERFORMANCE OF WATER-BASED MUD USING A

SYNTHETIC CLAY

Fluid homogeneity and stability are of high importance as they greatly affect the fluid performance in drilling operations. Solids settlement, or solids sag, is a severe issue that occurs in weighted drilling muds, especially at elevated temperatures, where weight material tends to settle down causing well control problems. This study evaluates the effectiveness of a synthetic clay (laponite) to prevent the static and dynamic sag tendency of barite-weighted drilling fluid for elevated-temperature drilling applications. Several high-density mud samples were prepared by varying the concentration of the synthetic clay. The sag tendency of the fluid samples was evaluated in the lab using dynamic and static sag tests, and the optimal concentration was determined. The impact of synthetic clay on the density, pH, and rheological properties was also studied. Moreover, the filtration properties of the developed formulation were measured using high-pressure high-temperature (HPHT) filtration experiments. The synthetic clay was found to be effective in reducing the static and dynamic sag tendency of barite-weighted water-based drilling fluids. 0.75 lb/bbl of laponite was adequate to eliminate solids sag at a temperature up to

250 °F. This amount of laponite slightly increased the plastic viscosity with 8% while, an increase of 42% and 43-115% in the yield point and gel strength, respectively, was observed. A significant enhancement in the filtration performance was observed; the filter cake thickness and filtrate volume were decreased by 15-20%. Additionally, the synthetic clay had an insignificant effect on the fluid density and pH.

6.1 Introduction

With the depletion of shallow oil and gas reservoirs, the urge to drill deep reservoirs increased. The temperature of these deep formations may reach more than 300 °F adding more challenges to the drilling operations because the polymeric additives in the drilling fluid start to degrade at that critical downhole conditions affecting the stability of the drilling fluids (Huang et al., 2019). The degradation of fluid stability at that critical conditions leads to the separation of solid particles from the liquid phase of the drilling fluid in what is called solids sag or barite sag. This phenomenon takes place in vertical and inclined wells, under dynamic and static conditions causing variations in mud density along the well depth resulting in serious well control problems (P. A. Bern et al., 2000; P. M. Hanson et al., 1990; T H Omland et al., 2007).

Several laboratory studies were conducted to analyze the sag tendency under static and dynamic conditions. Most of the methods depend on the density measurements to detect the solid particles distribution along the fluid column. This technique is preformed using different set up such as sag cell, viscometer sag show test, and flow loops (Al-abdullatif et al., 2015; Aldea et al., 2001; Basfar et al., 2020, 2018; Boyou et al., 2019; Davis et al., 2017; Elkatatny, 2019, 2018; P. M. Hanson et al., 1990; Saasen and Løklingholm, 2002)...

Another method of barite sag detection relies on rheological and viscoelastic properties measurements using different rheometers. These properties can be correlated with fluid stability to detect solids sag phenomenon (Bern et al., 2010; Chilingarian et al., 1986; Maxey, 2007; Power and Zamora, 2003; Arild Saasen et al., 1995)... Ultrasonic and Nuclear Magnetic Resonance (NMR) methods were also utilized to analyze the sag tendency of the drilling mud by detecting the density stratification using the sound velocity and the influence of the magnetic field, respectively (Omland et al., 2007). (Ofei et al., 2020) also introduced another advancement in solids sag measurement using a cylindrical glass cell with light scattering technique to characterize the homogeneity and settling speed of the solid particles in the drilling fluid.

Many techniques were introduced to enhance the thermal stability of the drilling mud and to mitigate the solids sag at high-temperature conditions. Such as monitoring the rheological behavior of the mud and implementing good practices (Paul D Scott et al., 2004), adding rheology modifiers and/or anti-sagging agents to optimize the rheological properties (Basfar et al., 2018; Basfar et al., 2020; Davis et al., 2017; Elkatatny, 2019, 2018; Temple et al., 2004), decreasing the particle size of the weighting material (Boyou et al., 2019; Mohamed et al., 2017b), and using combined weighting materials (Abdou et al., 2018; Al-abdullatif et al., 2015; Basfar et al., 2019; 2020; Mohamed et al., 2019). All the proposed formulations have some technical or economic limitations that require more research work to come up with an efficient and feasible solution to the barite sag phenomenon.

Optimizing the rheological properties of drilling fluid by adding special additives is one of the successful techniques to improve the stability of the drilling fluids because rheological properties are one of the main factors that control barite sag. Several additives were proposed to maintain the rheological behavior of water-based fluids such as viscosifiers, thinners, dispersants, and stability enhancers (A. Mohamed et al., 2020a). Clays and polymers are added to increase the drilling fluid viscosity (Caenn et al., 2011; M. E. Hossain and Al-Majed, 2015). However, these additives have some limitations. For instance, polymers degrade at high temperatures affecting the drilling fluid viscosity. And, flocculation of bentonite fluids was also observed at high temperatures (Phuoc et al., 2009).

Laponite is a synthetic layered clay that has disk-shaped particles. The electrical double layers give laponite good dispersion and stability in water (Huang et al., 2019, 2018; Jatav and Joshi, 2014; Liu et al., 2017). The excellent properties of laponite make it a good candidate to improve the stability and rheological behavior of drilling fluids, particularly at elevated temperatures. Several studies were conducted to evaluate the thermal stability, rheology, and viscoelastic properties of laponite in water suspension. Huang et al. (Huang et al., 2019) investigated the influence of laponite nanoparticles on the thermal stability of water-based mud using thermogravimetric analysis (TGA) and viscosity measurements at different temperatures. They tested a synthesized polymer and a combination of laponite with the synthesized polymer. Adding laponite substantially increased the fluid viscosity at high temperatures and slowed the thermal degradation of the synthesized polymer. However, no much work on the chemical stability of laponite was conducted (Jatav and Joshi, 2014).

Phuoc et al. (Phuoc et al., 2009) studied the rheological behavior of a synthesized cation-exchanged laponite suspension in the presence of various metals. The cation-modified laponite was synthesized using a laser ablation technique. The aqueous suspension of the modified laponite showed a high viscosity and good shear thinning behavior. However, no mechanism was addressed, and because of the huge amount required for drilling applications, the use of laser technique is economically impractical. Taghipour et al. (Taghipour et al., 2012) studied the rheology of the drilling fluid with xanthan gum polymer and laponite using a flow loop setup and rheometers to tune a model drilling fluid and evaluate the impact of aging time on the drilling fluid rheology. Mouchid et al. (Mouchid et al., 1998) investigated the viscoelastic and swelling properties of the laponite colloidal system to understand the gelation mechanism of laponite suspensions.

Huang et al. (Huang et al., 2018) introduced another application for laponite nanoparticles to serve as a shale inhibitor. They found that laponite suspension is very effective in shale inhibition with a different inhibition mechanism than other shale inhibitors. Liu et al. (Liu et al., 2017) found that laponite suspension has the ability to plug the nano cracks in shale formations preventing the water from penetrating deep inside the formation; therefore, reducing shale swelling. Additionally, laponite mud formed more compact filter cake compared to sodium-bentonite mud making laponite a multi-functional additive for water-based muds.

Many of the previous studies focused on the thermal and chemical stability of laponite suspension by studying the rheological and viscoelastic properties at high-temperature conditions; however, no attention to the barite sag phenomenon was addressed. Therefore,

this study evaluates the influence of laponite clay particles on the dynamic and static sag tendency in vertical and inclined wells at elevated temperatures. Moreover, the influence of laponite on the properties of drilling mud was investigated, such as density, pH, and rheological and filtration properties.

6.2 Materials and Experimental Work:

The drilling fluid was prepared in the laboratory by using water as a base fluid after treatment with sodium carbonate to maintain the calcium ion contamination. The pH of the drilling mud is maintained by adding potassium hydroxide. The viscosity of the mud is maintained by adding bentonite and xanthan gum polymer. Potassium chloride is added as a clay stabilizer, while polyanionic cellulose (PAC-R) and starch are used as fluid loss control additives. Calcium carbonate is added as a bridging agent to help build the filter cake. The required fluid density is maintained by adding barite. A synthetic clay (laponite) is added to the drilling fluid in different concentrations as a stability enhancer.

6.2.1 Material Characterization

Barite and laponite were characterized using X-ray fluorescence (XRF) and X-ray diffraction (XRD) techniques to identify the mineral composition. Additionally, a particle size analyzer was used to measure the particle size distribution of both laponite and barite. The particle size distribution was measured because it has a great impact on the repulsion and attraction forces that influence the sagging phenomenon. Some studies, conducted on the impact of particle size on the solid particles settlement and cuttings transport efficiency, confirmed the importance of particles shape and size in such phenomena (Boyoun et al., 2019; A. Mohamed et al., 2020b; Mohamed et al., 2017b).

6.2.2 Fluid Preparation

A base fluid was prepared with a density of 14.8 ppg by mixing the essential drilling fluid additives using a variable-speed mud mixer. The mixing was done at ambient conditions, and the rotational speed was increased gradually from 10,000 to 17,000 RPM. First, sodium carbonate and potassium hydroxide were added to the base fluid (freshwater) to maintain the water hardness and pH, respectively. Then, bentonite and xanthan gum polymer were used to maintain the viscosity of the mud. Subsequently, the other drilling fluid additives were mixed with the mud formulation. Using the same procedure, two different mud samples were prepared using various concentrations (0.5 and 0.75 lb/bbl) of the synthetic clay. Laponite was added right after adding potassium hydroxide and mixed for 10 minutes. The used fluid formulation is described in Table 10.

Table 10 The used mud formulation (1.0 bbl of mud)

Additive	Amount
Water	0.7 bbl
Sodium carbonate	0.5 lb/bbl
Potassium hydroxide	0.5 lb/bbl
Bentonite	4 lb/bbl
Xanthan gum polymer	1.5 lb/bbl
Potassium chloride	20 lb/bbl
Starch	6 lb/bbl
PAC-R	1 lb/bbl
Calcium carbonate (25 μm)	5 lb/bbl
Barite	350 lb/bbl

Laponite	0-0.75 lb/bbl
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6.2.3 Sag Tests

The effect of laponite on the drilling fluid stability was evaluated using static and dynamic sag tests. First, static sag test was performed at vertical and inclined conditions (45°) using static sag test apparatus. The test was run for 24 hrs at 250 °F and 500 psi. The concept of sag test is to evaluate the homogeneity of the drilling mud by measuring the mud density at the top and bottom of the drilling fluid column after 24 hrs. The sag factor is introduced as an indicator of the fluid homogeneity along the drilling fluid column. The sag factor is calculated from the density of both top and bottom fluid samples using Equation 1. For a stable and homogeneous fluid, sag factor should be ranging between 0.50 and 0.53 while, particles settlement is anticipated when the sag factor is higher than 0.53 (Al-abdullatif et al., 2015; Maxey, 2007)

$$\text{Sag Factor} = \frac{\text{Bottom density}}{\text{Bottom density} + \text{Top density}} \quad (1)$$

Second, the viscometer sag show test (VSST) was conducted to assess the dynamic sag tendency of the mud. The dynamic sag test is conducted at 120 °F and atmospheric pressure. Two 10-mL samples are taken from the collection well, one at the beginning of the test and the other one after 30 min. Dynamic sag factor, VSST, is calculated by Equation 2 using the weight of the fluid samples in grams, W_1 and W_2 . The drilling fluid is considered stable when the VSST is equal to or less than one while, a higher VSST value indicates inhomogeneous and unstable drilling fluid (Aldea et al., 2001). Table 11 summarizes the experimental conditions of the sag tests.

$$VSST = 0.834 (W_2 - W_1) \quad (2)$$

Table 11 Experimental conditions of the sag test

Parameter	Dynamic sag	Static sag
Temperature	120 °F	250 °F
Pressure	Atmospheric	500 psi
Time	30 min	24 hrs
Inclination	-	0° and 45°

6.2.4 Rheology Measurement

The impact of the synthetic clay on the mud rheology was investigated by measuring the rheological properties using a mud viscometer, model Ofite 900. The measured properties are yield point (YP), plastic viscosity (PV), and gel strength. The plastic viscosity and yield points were calculated using equations (i) and (ii) in the appendix. Gel strength was measured after 10 seconds, 10 minutes, and 30 minutes using the direct reading at a rotational speed of 3 revolutions per minute (rpm). All measurements were conducted at 120 °F and atmospheric pressure. Additionally, the fluid density and pH were measured at 80 °F using a standardized mud balance and pH meter.

6.2.5 Filtration Experiments

Filtration tests are conducted to study the influence of laponite on the filtration properties of the drilling mud. The tests were conducted at the same temperature of the static sag test, 250 °F, with a differential pressure of 300 psi, and 10-micron ceramic filter discs were used as a filtration medium. The filtrate volume was collected over 30 min of filtration time, and

the filter cake properties were measured. These properties are the filter cake weight and thickness.

6.3 Results and Discussions:

6.3.1 Material characterization

Barite and laponite samples were obtained from a local supplier. Barite was used in this study as a weighting agent, while laponite was used as an anti-sagging agent. Barite contained barium (75.1 wt.%), sulfur (17.2 wt.%), silicon (5.6 wt.%), and very low concentrations of aluminum (2.1 wt.%). Laponite clay mainly contained silicon (65.7 wt.%), magnesium (31 wt.%), and sodium (3.3 wt.%), Table 12. Figure 45 shows the XRD patterns of barite and laponite samples. The resulted XRD patterns matched the typical XRD patterns of barite and laponite available in the literature (Chen et al., 2019; Jiang et al., 2016; Chen et al. 2019). The barite sample consists of 99.9 wt.% barite with very small traces of impurities (0.1 wt.%) while laponite sample shows 100 wt.% laponite. The particle size distribution of barite and laponite samples was obtained by a particle size analyzer. Barite powder revealed a normal distribution with a D_{10} of 2 μm , D_{50} of 17 μm , D_{75} of 30 μm , and D_{90} of 50 μm . While laponite showed smaller particle size with a D_{50} of 10 μm (Figure 46).

Table 12 The elemental composition of barite and laponite

Element	wt.%	
	Barite	Laponite
Ba	75.11	-
S	17.15	-

Si	5.6	65.65
Al	2.12	-
Mg	-	31.03
Na	-	3.32

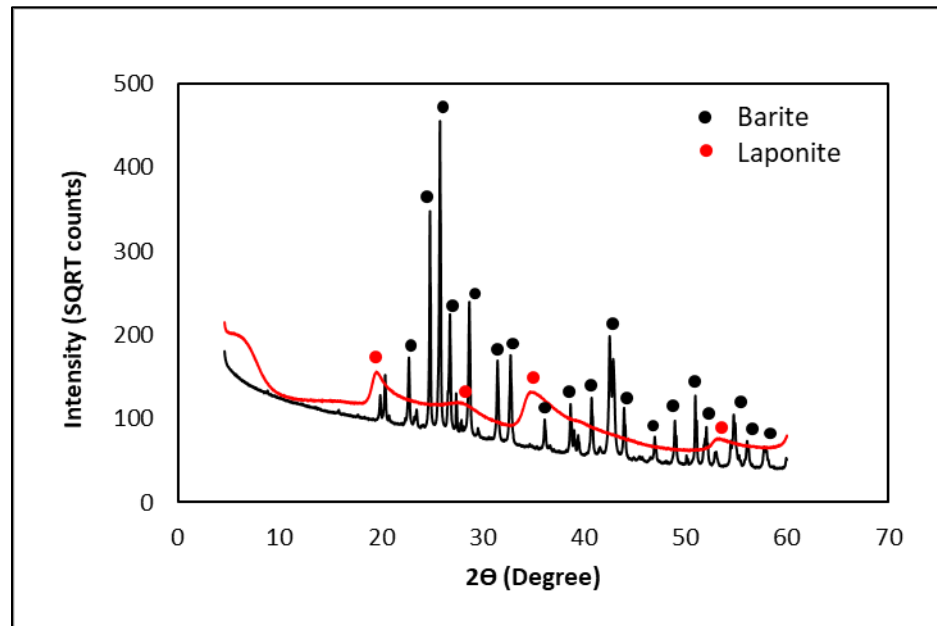


Figure 45 XRD Patterns of barite and laponite samples.

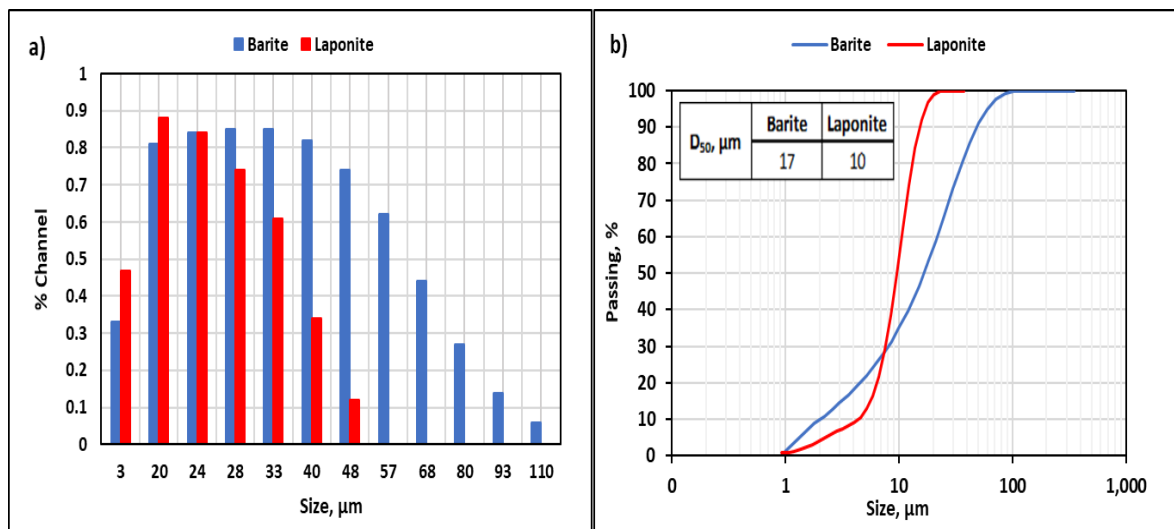


Figure 46 PSD of barite and laponite samples: a) histogram, and b) cumulative.

6.3.2 Sag Tests

Static sag tendency of the mud was measured at different concentrations of laponite under vertical and inclined conditions, Figure 47. The temperature was set at 250 °F because, at this temperature, barite sag is likely to occur (Basfar et al., 2019b; A. Mohamed et al., 2020a)... The base fluid sample, without laponite, showed poor fluid stability at both inclination angles with a high sag factor (around 0.57). The sag factor exceeded the acceptable range, 0.50-0.53, according to the drilling practices, indicating a high tendency of barite sag (Al-abdullatif et al., 2015; Maxey, 2007). Laponite increased drilling fluid stability by reducing the sag factor significantly. At 0.5 lb/bbl of laponite, the vertical and inclined sag factor decreased from 0.569 and 0.58 to 0.532 and 0.542, respectively and these values are still above the acceptable value while, adding 0.75 lb/bbl brought the sag factor to the safe range with a sag factor of 0.502 and 0.51; therefore, less sag tendency is anticipated at that conditions. It was observed that the drilling fluid always performed better in vertical conditions than in inclined conditions because the inclination angle contributes significantly to the sagging phenomenon, and the critical range of inclination is between 30° to 60° as reported in previous studies (Boyou et al., 2019; Skalle et al., 1999). Similarly, the base fluid, without laponite, showed unfavorable sag tendency at dynamic conditions with a sag factor (VSST) of 2.3, Figure 48. Adding 0.5 lb/bbl of laponite significantly improved the mud homogeneity and reduced the VSST to 1.54, which is still above the acceptable value (below one) (Aldea et al., 2001; Murphy et al., 2008). Increasing the concentration of laponite to 0.75 lb/bbl substantially reduced the VSST to 0.17. This value is considered very low, and no solids settlement will be

encountered with this concentration of laponite. The improvement in the dynamic and static sag tendency caused by adding laponite to the drilling mud can be attributed to the improvement in rheological properties that improved the suspension capability of the drilling fluid. Moreover, the electrostatic attractions and hydrogen bonding between xanthan gum polymer and laponite particles helped forming a strong bond that increases the thermal stability of the mud and slowed down the polymer degradation (Chrissafis and Bikiaris, 2011; Huang et al., 2019, 2018). This interaction also preserved the rheological properties of the mud, particularly yield point and gel strength, and mitigated the temperature effect. Laponite costs between 8-11 \$/lb and with the maximum concentration used (0.75 lb/bbl), adding laponite would increase the cost of the drilling fluid by 6-8.25 \$/bbl. However, Laponite is introduced as a solution to a common and serious problem with barite-weighted fluids that could cost a lot of money by increasing the non-productive time and may cost lives in some severe cases when kicks occur. Therefore, solving this issue by adding little extra money to the drilling fluid cost would be technically and economically feasible.

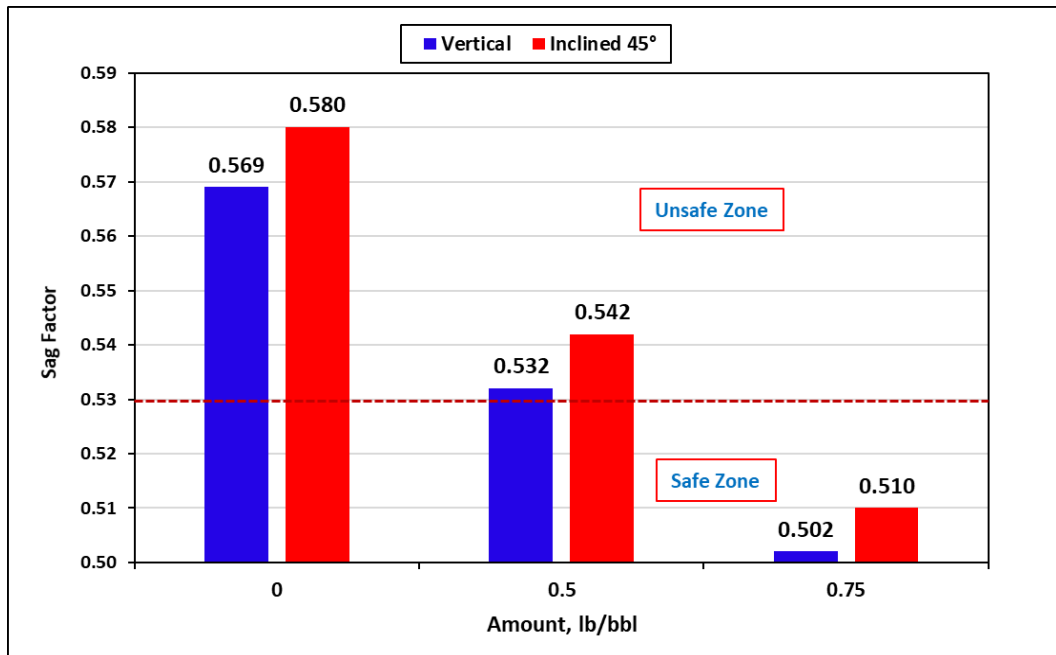


Figure 47 Effect of laponite concentration on the static sag tendency (250 °F).

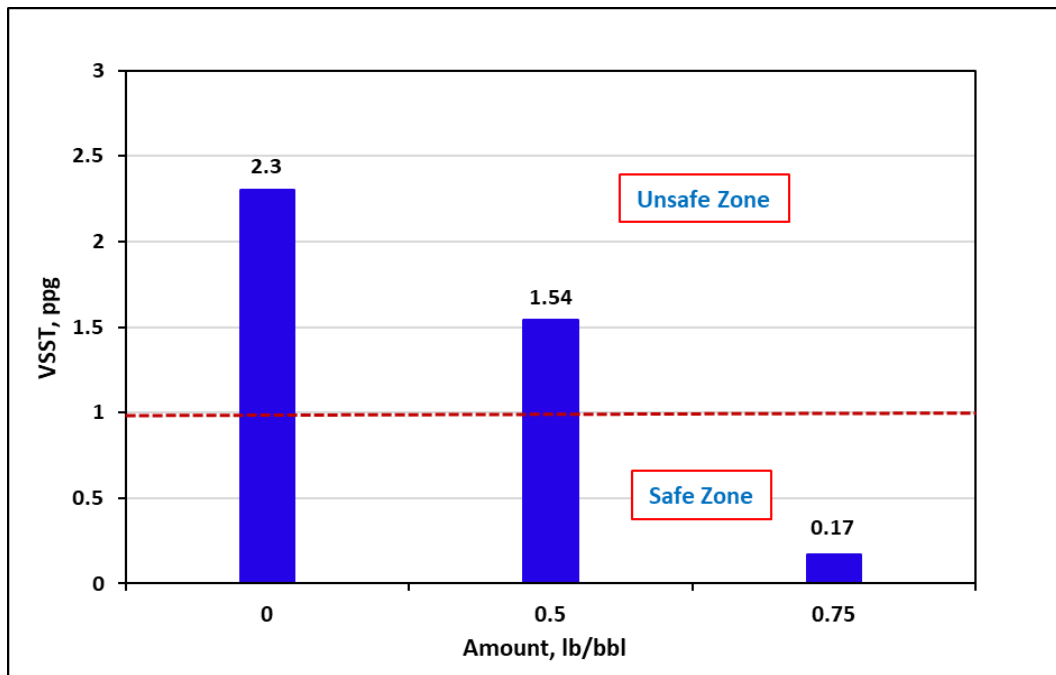


Figure 48 Effect of laponite concentration on the dynamic sag tendency (120 °F).

6.3.3 Rheological Analysis

Figure 49 shows the influence of laponite concentration on the mud density and pH. Laponite had unmeasurable influence on the fluid density because the added concentration was very low, and the density of the mud samples was 14.8 ppb. In contrast, a small increase (0.2) in the fluid pH was observed as the laponite concentration increased from 0 to 0.75 lb/bbl. This increase was because of the dissociation of hydroxide ions (OH^-) from the edges of laponite particles (Jatav and Joshi, 2014; Tomás et al., 2018).

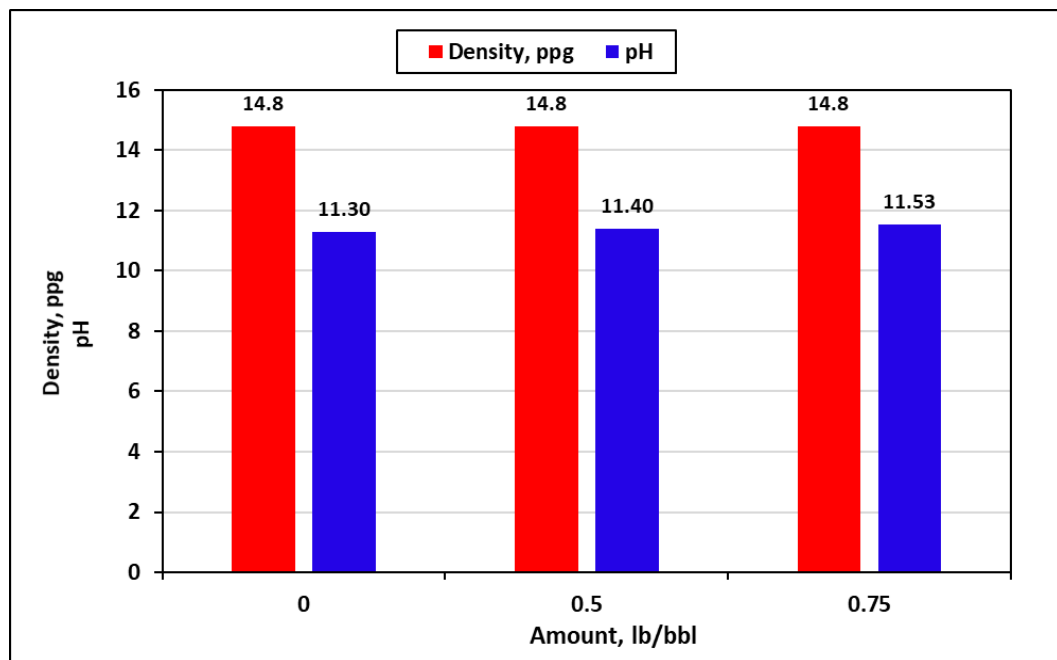


Figure 49 Impact of laponite concentration on mud density and pH.

The flow curve was constructed for the drilling mud samples using the measurements of the shear stress values at the corresponding shear rates (Figure 50). These measurements were obtained at 120 °F using a drilling fluid viscometer. From the flow curves, the drilling fluid samples behave as non-Newtonian fluids. The rheology data was fitted using the

common rheology models such as Power law, Bingham plastic, Herschel-Bulkley, and Casson (Caenn et al., 2011; Skelland, 1967). Table 13 shows the rheology and fitting data for all the mud samples, and the fitting curves are shown in the appendix (Figure 53: A1 to A4). Casson model was the best model to represent the data with an R-squared in the range of 0.996-0.999. As the concentration of laponite was increased, the consistency curve shifted upward, indicating higher values of the shear stress, while the slope of the curve remained almost constant; thus, no significant change in the plastic viscosity will be noticed (Taghipour et al., 2012). Figure 51 shows the effect of laponite concentration on the plastic viscosity and yield point of the drilling fluid. The yield point of the base mud increased from 33 lb/100 ft² to 43 lb/100 ft² and 48 lb/100 ft² when laponite concentration was increased to 0.5 lb/bbl and 0.75 lb/bbl, respectively. This increase in the yield point indicates an enhancement in the mud capability to suspend solids; therefore, improving the homogeneity of the drilling fluid throughout the drilling operation (Bageri et al., 2020; Coussot et al., 2004; Saasen et al., 2009; Saasen and Løklingholm, 2002). Conversely, laponite had an insignificant influence on the plastic viscosity where the plastic viscosity of all the fluid samples was ranging between 33 to 38 cP; consequently, no additional frictional pressure drop will result during fluid circulation (Basfar et al., 2019). Furthermore, the increase in yield point without significantly increasing the plastic viscosity helped maintain the yield point to plastic viscosity ratio (YP/PV) within a good range. YP/PV is an essential parameter in hole cleaning, and it can also be related to the fluid stability and sag performance (Figure 10) (Chilingarian et al., 1986; Power and Zamora, 2003a).

The base drilling fluid sample showed an initial gel strength of 19 lb/100 ft² after 10 s then the gel strength increased to 47 lb/100 ft² after 10 min before it decreased again to 45 lb/100 ft² after 30 min of gel time. While the samples with 0.5 lb/bbl and 0.75 lb/bbl of laponite showed a continuous increase in the gel strength with time, and the higher concentration of laponite yielded higher gel strength values Figure 51. The increase in gel strength was induced by the electrostatic bonds between laponite particles and laponite and xanthan polymer particles, resulting in a stronger and quick gel structure (Liu et al., 2017; Phuoc et al., 2009). The gel structure helps suspend the weighting material and the drilled cuttings when the circulation is stopped (Caenn et al., 2011; M. E. Hossain and Al-Majed, 2015; Mahmoud et al., 2019). The high values of gel strength require more pumping pressure to start the flow; thus, if the pressure required to break the gel exceeds the maximum pump pressure, drilling fluid formulation should be optimized by diluting the mud or adding thinners to attain favorable rheology at such conditions (Paul D Scott et al., 2004).

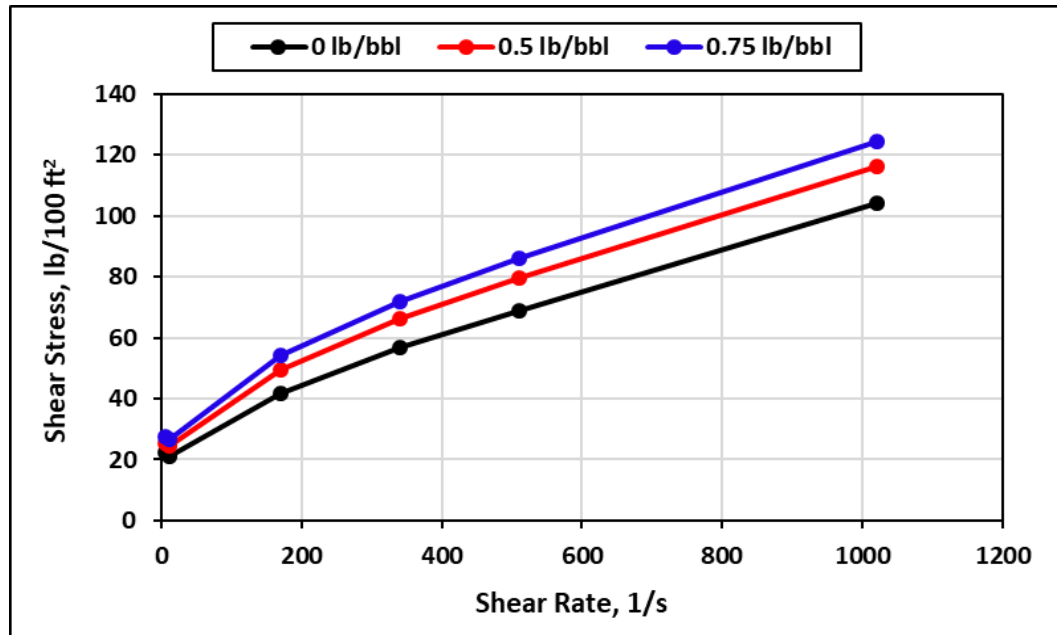


Figure 50 The flow curves at various laponite concentrations (120 °F).

Table 13 Rheology and fitting data for the mud samples

Parameter		Laponite concentration		
		0 lb/bbl	0.5 lb/bbl	0.75 lb/bbl
	Θ_{600}	104.3	116.2	124.5
Dial readings	Θ_{300}	68.9	79.6	86.1
	Θ_{200}	56.7	66.3	71.9
	Θ_{100}	41.6	49.6	54.3
	Θ_6	22	25.3	27.3
	Θ_3	21	24.2	26.6
R-squared	Power law	0.9852	0.9524	0.9567
	Bingham plastic	0.9852	0.9734	0.9701
	Herschel-Bulkley	0.9938	0.9792	0.9696
	Casson	0.9963	0.9984	0.9986

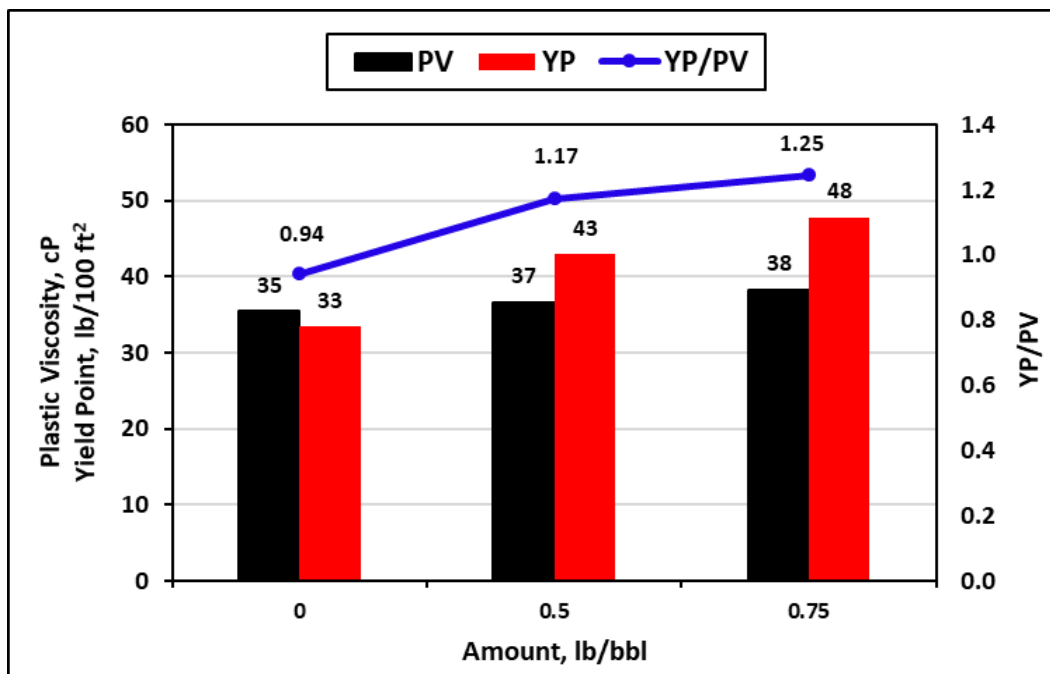


Figure 51 Effect of laponite on the plastic viscosity and yield point (120 °F).

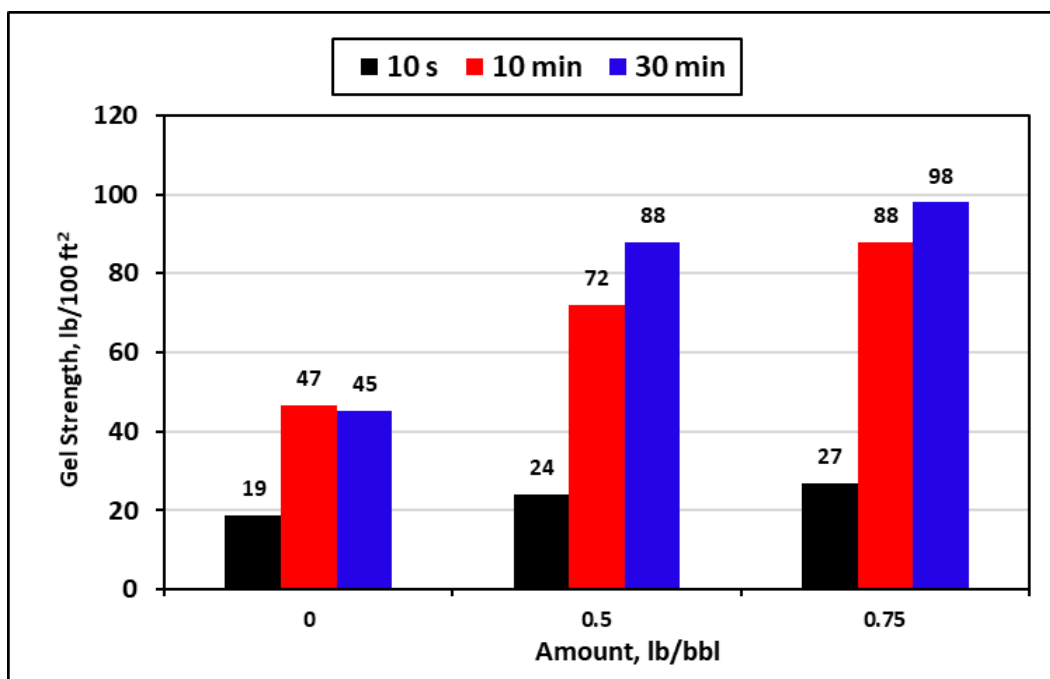


Figure 52 Impact of laponite concentration on the gel strength with time (120 °F).

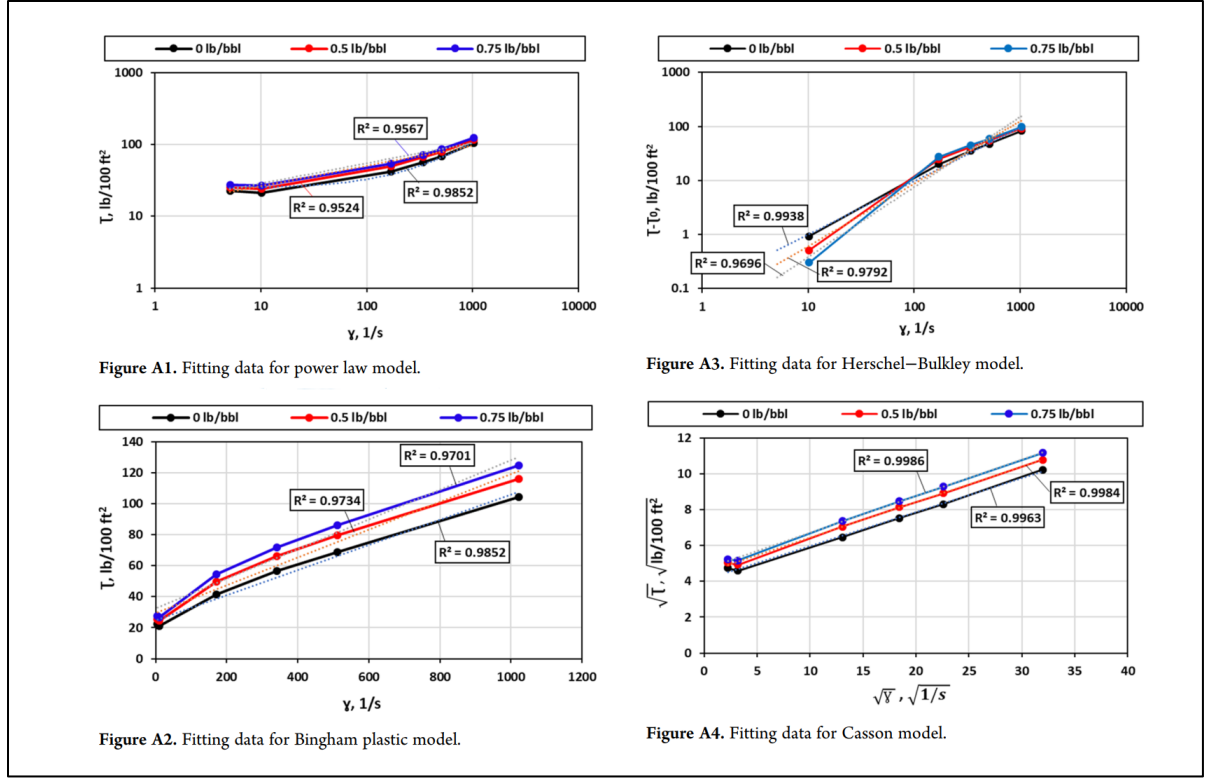


Figure 53 Fitting models of WBM

6.3.4 Mechanisms of Enhancing Drilling Fluid Stability

There are different methods in the literature used to mitigate the sag tendency of the drilling fluid such as reducing the particle size of the weight material (Boyoun et al., 2019; Mohamed et al., 2017b), replacing the weighting agent with more stable alternatives or adding a combination of weighting material (Abdou et al., 2018; Al-abdullatif et al., 2015; Basfar et al., 2019; Basfar et al., 2020; Mohamed et al., 2019), and optimizing the rheological properties of the drilling mud by introducing rheology modifiers or anti-sagging agents (Basfar et al., 2020, 2018; Davis et al., 1955; Elkatatny, 2019, 2018; Temple et al., 2004). The main mechanism of enhancing the drilling fluid stability in this study is the improvement of the rheological properties by adding laponite additive. Rheological properties are the main properties responsible for suspending solid particles and drilled

cuttings under dynamic and static conditions. Laponite is a synthetic nano-sheet material that can easily hydrate and form a gel structure in aqueous solutions that can provide a good rheological performance (Liu et al., 2017). As confirmed by the rheological study, introducing laponite particles to the drilling fluid increased both the yield point and gel strength by 43% which in turn improved the suspension capability of the drilling fluid and significantly reduced the barite sag tendency. Additionally, laponite interaction with xanthan polymer, was another reason for maintaining the yield point and gel strength then, eliminating the sag issue. There are two mechanisms that laponite interacts with the polymer: electrostatic attraction and hydrogen bonding. These two mechanisms helped mitigate the temperature effect by improving the thermal resistance of the mud, slowing down the polymer degradation, and preserving the rheological properties. This can also be achieved by adding bentonite clay to the drilling mud however these bonds are stronger with laponite due to the higher surface area of the laponite disc-shaped particles (Huang et al., 2018).

6.3.5 Filtration Experiments

The effect of laponite concentration on the filtration performance was studied using the high-pressure high-temperature (HPHT) filtration test (Figure 54). The base fluid yielded a total filtrate volume of 6.7 cm³, and a filter cake with 3.71 mm thickness. Increasing laponite concentration enhances the filtration properties of the mud by reducing both the filtrate volume and the filter cake thickness. With 0.75 lb/bbl laponite, the filtrate volume decreased to 5.6 cm³ while the filter cake thickness was reduced to 2.95 mm. The improvement in the filtration performance is attributed to the plugging effect. Laponite

disc-shaped particles have the ability to plug microfractures and the spaces between the particles of bridging agents. Therefore, a more compact filter cake will form with a less fluid invasion into the drilled formation (Huang et al., 2018). Figure 55 shows the filter cake formed with all the drilling fluid formulations. This enhancement on the filtration performance plays a great role in the wellbore stability and mitigating the formation damage that may result from the fluid filtrate and solids invasion (Ba geri et al., 2017; Mahmoud et al., 2019; Abdelmjeed Mohamed et al., 2020; Mohamed et al., 2019b).

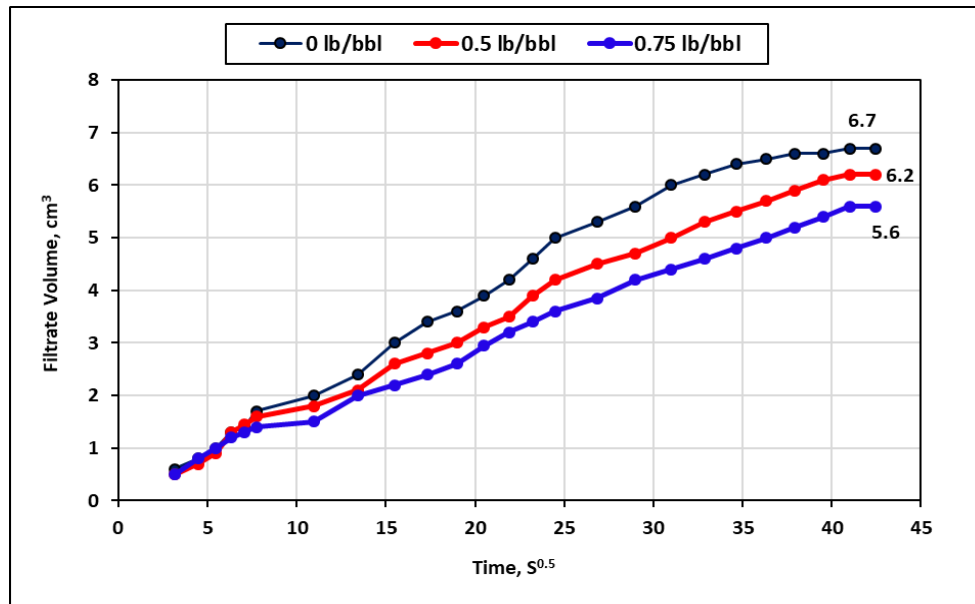


Figure 54 Effect of laponite concentration on the filtrate volume with time (250 °F).

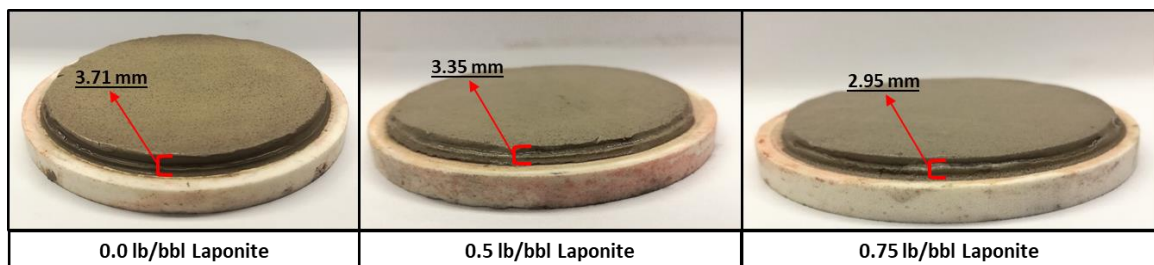


Figure 55 The formed filter cake at various concentrations of laponite.

6.4 Summary and Conclusions:

An experimental study was performed to assess the effect of laponite clay on the static and dynamic sag tendency of water-based drilling fluid where barite is the weighting material.

With the obtained results, the following is concluded:

- The addition of laponite clay improved fluid stability at elevated temperatures by reducing the static and dynamic sag. Only 0.75 lb/bbl of laponite was adequate to bring the sag factor to the safe zone; consequently, no solids settlement will be encountered at these conditions.
- Adding 0.75 lb/bbl of the synthetic clay to the drilling fluid slightly increased the plastic viscosity with 8% and significantly increased the yield point with 42% leading to an improvement in the ability of the drilling mud to suspend the solid particles which confirmed the sag test results. While a high increase, 43-115%, in the gel strength values was observed; therefore, a thinner should be added with the synthetic clay to avoid the very high values of the gel strength.
- Because the required concentration of synthetic clay was very low, no effect on the drilling fluid density was observed. Also, the synthetic clay slightly increased the pH of the drilling fluid because of the detachment of hydroxide ions from the edges of laponite particles. Moreover, laponite particles improved the filtration performance of the mud by reducing the total filtrate by 15% and the filter cake thickness by 20%; thus, minimizing the formation damage induced by fluid invasion.
- The proposed formulation can be used in drilling deep formations with minimal static and dynamic solids sag at elevated temperature, up to 250 °F. However, more research

studies are required to optimize the concentration of laponite and the other drilling fluid additives considering wide range of concentrations, mud densities, barite types, other weighting materials, inclination angles, drilling parameters to ensure optimum results in real field applications. Moreover, further studies should be performed to evaluate the effectiveness of laponite at higher temperatures to be used for HPHT drilling applications.

CHAPTER 7

PREVENTION OF BARITE SAG IN OIL-BASED DRILLING FLUIDS USING A MIXTURE OF BARITE AND ILMENITE AS WEIGHTING MATERIAL

Drilling high-pressure high-temperature (HPHT) wells requires a special fluid formulation that is capable of controlling the high pressure, and stable under the high downhole temperature. Barite-weighted fluids are common for such purpose because of the good properties of barite, low cost, and availability. However, solids settlement is a major problem encountered with this type of fluids, especially at elevated downhole temperatures. This phenomenon is known as barite sag, and it is encountered in vertical and directional wells under static or dynamic conditions leading to serious well control issues. This study aims to evaluate the use of barite-ilmenite mixture as a weighting agent to prevent solids sag in oil-based muds at elevated temperatures. Sag test was conducted under static conditions (vertical and inclined) at 350°F, and under dynamic conditions at 120°F to determine the optimum ilmenite concentration. Afterward, a complete evaluation of the drilling fluid was done by monitoring density, electrical stability, rheological and viscoelastic properties, and filtration performance to study the impact of adding ilmenite on drilling fluid performance. The results of this study showed that adding ilmenite reduces

sag tendency and only 40 wt.% ilmenite (from the total weighting material) was adequate to eliminate barite sag under both static and dynamic conditions with a sag factor of around 0.51, and a VSST of 0.5. Adding ilmenite enhanced the rheological and viscoelastic properties and the suspension of solid particles in the drilling fluid, which confirmed sag test results. Adding ilmenite slightly increased the density of the drilling fluid with a slight decrease in the electrical stability within the acceptable range of field applications. Moreover, a minor improvement in the filtration performance of the drilling fluid and filter cake sealing properties was observed with the combined weighting agent. The findings of this study provide a practical solution to barite sag issue in oil-based fluids using a combination of barite and ilmenite powder as a weighting agent to drill HPHT oil and gas wells safely and efficiently with such type of fluids.

7.1 Introduction

Weighting material is one of the main drilling fluid additives used to achieve the required density to overbalance formation pressure during drilling operations and prevent any loss of well control (Caenn et al., 2011; M. E. Hossain and Al-Majed, 2015; Stroud, 1922). In addition to well control, drilling fluids have many other functions, such as circulating the drilled cuttings to the surface and suspending the cuttings while drilling operation is stopped and cooling and lubricating the drill bit to ease the drilling operation. In high-pressure high-temperature applications, a special drilling fluid formulation is required to meet the critical downhole conditions. In such cases, drilling fluids should have a high density to suppress the high formation pressure with good stability at that elevated temperatures (Mohamed et al., 2017a).

High-density weighting materials are introduced to the drilling fluid formulation to provide the required fluid density, such as barite, hematite, manganese tetroxide, and ilmenite (Al-Yami and Nasr-El-Din, 2007; S. M. Elkatatny et al., 2012b, 2012a; Yao et al., 2014). Because of the high specific gravity (4.2-4.4), low production cost, and low environmental impact, barite is a common weighting agent (Ba geri et al., 2017; Nguyen et al., 2009b; Pozebon et al., 2005). However, solid particles settlement is a common issue while using barite-weighted drilling fluids, and this phenomenon is known as barite sag (Peter A. Bern et al., 2000b; Tor Henry Omland et al., 2007). These settled particles will not contribute to the fluid density leading to serious well control issues (Saasen et al., 2002a; Zamora et al., 2004), and they interfere with drilling and production operations. Moreover, the accumulated solid particles and drilled cuttings increase the possibility of pipe sticking and decrease the rate of penetration (Boyou et al., 2019). Barite sag phenomenon may occur in both vertical and directional wells at static and dynamic conditions, and it is more serious under dynamic conditions with a low shear rate (Murphy et al., 2008). However, maintaining and monitoring drilling fluid rheology and training the drilling rig personnel would mitigate the consequences of solids sag (Paul D. Scott et al., 2004).

Several laboratory studies were performed to understand and prevent barite sag issue in water and oil-based drilling and completion fluids. Temple et al. (Temple et al., 2004) proposed a new approach to reduce barite sag in invert emulsion mud by adding a low molecular weight polyalkyl methacrylate. This formulation reduced sag tendency without increasing the viscosity of the drilling fluids, and no copolymer was added. A new drilling fluid formulation with a reduced sag tendency was introduced by Davis et al. (Davis et al.,

2017). Their formulation consists of invert emulsion mud, barite as a weighting agent, and polyethylene glycol (PEG) as a stability enhancer.

Basfar et al. (Basfar et al., 2018) and Elkatatny (Elkatatny, 2018) performed a study on barite sag prevention in invert emulsion drilling fluid using copolymer. They found that one lbm/bbl of the copolymer was adequate to eliminate solids sag under static and dynamic conditions at 350°F downhole temperature. Another study on barite sag prevention in invert emulsion mud was carried out by Elkatatny (Elkatatny, 2019). In this study, organophilic phyllosilicate (OP) was used as an anti-sagging agent. He concluded that adding only 1.5 grams of the anti-sagging agent (OP) would solve the solids sag issue under dynamic conditions.

Some other research studies suggest playing with the weighting agent as a solution to the solids sag phenomenon. Mohamed et al. (Mohamed et al., 2017b) conducted a study on the effect of barite particle size on sag tendency in water-based drilling fluids. They found that reducing the particle size enhances drilling fluid stability and reduces sag tendency, whereas, it did not eliminate the problem. Alabdullatif et al. (Alabdullatif et al., 2015) introduced a new water-based fluid formulation to kill HPHT wells. They used a mixture of barite and manganese tetraoxide (Mn_3O_4) as weighting material to prevent barite sag. Mn_3O_4 was found to be effective in improving drilling fluid stability and reducing barite sag tendency. Abdou et al. (Abdou et al., 2018) studied the effect of ilmenite and barite mixture on drilling fluid density and rheological properties. They concluded that using this mixture yields comparable performance to barite, and it could be used as a replacement to

barite because of the low solid content and fluid loss that would consequently minimize formation damage.

Basfar et al. (Basfar et al., 2019) evaluated the use of barite-ilmenite mixture as a weighting agent with water-based drilling fluids. It was found that adding ilmenite to barite-weighted drilling fluids enhances the fluid stability and reduces the sag tendency. The optimum ratio of ilmenite to barite was found to be 1 to 1 (50 wt.% ilmenite from the total weighting material).

As the challenges of drilling operations increased with drilling unconventional reservoirs, several studies were conducted using nanoparticles (NPs) to improve the performance of the drilling operations. NPs improves the performance of the drilling fluid in many ways, such as improving the rheological properties, minimizing friction and fluid filtrate invasion, and enhancing the thermal stability of the drilling fluid at HPHT conditions [31-33]. A study was conducted by Boyou et al. (Boyou et al., 2019) to enhance the suspension capability of the drilling fluid to efficiently transport drilled cuttings and prevent the development of cuttings bed by adding nanosilica in different concentrations to water-based drilling fluids. They evaluated the performance of nan-enhanced water-based fluid in directional drilling operations by conducting an experimental study at different angles of inclination using a flow loop setup. It was concluded that nanosilica particles significantly enhanced the cutting transport efficiency in all inclinations by increasing the colloidal interaction with cuttings.

In addition to the barite sag issue, the high demand and limited resources of barite increased the urge to find another alternative weighting agent to drill HPHT wells (Blomberg et al.,

1984). Research work was conducted using ilmenite for this purpose because it has higher specific gravity than barite (4.7-4.79), and it is available and acid-soluble (Tuntland et al., 1981; Xiao et al., 2013b). However, the main disadvantage of ilmenite is the abrasiveness to drilling fluid equipment (Xiao et al., 2013b), and this can be avoided by optimizing the particle size distribution and using small percentages of large particles ($>45\text{ }\mu\text{m}$), not higher than 3% (Blomberg et al., 1984). While most of the previous studies focused on adding a stability enhancer, polymers, or special additives to solve the sag issue, this study suggests playing with the weighting and adding a mixture of barite and ilmenite to be used as a combined weighting agent in oil-based drilling as a solution to barite sag issue. Combining ilmenite with barite would eliminate solids sag in barite-weighted drilling fluids to drill HPHT wells efficiently with such fluids, and reduce the high cost of ilmenite-weighted fluids as well. First, the materials used in this study and the experimental procedures are presented. Then, the obtained results are discussed, and finally, the findings and limitations of this study are summarized.

7.2 Methodology

7.2.1 Material

The invert emulsion mud used in this work was prepared in the lab using a three-speed mud mixer. Diesel was used as the continuous phase of the fluid; then, additives were added and mixed in order; starting by the primary emulsifier (INVERMUL[®]). Lime was used to enhance emulsion stability. To minimize fluid filtrate invasion, a fluid loss control additive (DURATONE[®]) and a bridging agent (CaCO_3) were added. Water was added as the discontinuous phase, and GELTONE[®]II was used as a viscosifier to maintain the rheology

of the drilling fluid , and EZ MUL[®] was added as a secondary emulsifier. The high density of the drilling fluid was achieved by adding barite ($D_{50}= 17\mu\text{m}$). Several drilling fluid samples were prepared by mixing ilmenite ($D_{50}= 5\mu\text{m}$) with barite as a weighting agent. Ilmenite was added in different percentages, 20, 40, 60, 80 wt.% (from the total weighting material). The particle size distribution for both barite and ilmenite is shown in Figure 56. Table 14 and Table 15 show the used fluid formulation and the properties of the base drilling fluid sample.

Table 14 Drilling fluid formulation used in this study (Lab scale).

Additive	Amount
Diesel	171.5 mL
Primary Emulsifier (INVERMUL [®])	11 g
Lime	6 g
Fluid loss control (DURATONE [®])	7 g
Water	49.7 mL
CaCl ₂	32 g
Viscosifier (GELTONE [®] II)	10 g
Secondary emulsifier (EZ MUL [®])	4 g
Bridging agent (CaCO ₃)	30 g
Weighting Material (Barite)	300 g

Table 15 Properties of the base drilling fluid at 350 °F

Shear rate, RPM	Shear stress, D.R.
600	49
300	30

200	25	
100	18	
6	8	
3	8	
Density	14.5	ppg
PV	15	cP
YP	18	lb/100ft ²
Gel strength 10s	7	lb/100ft ²
Gel strength 10/30 min	8/9	lb/100ft ²

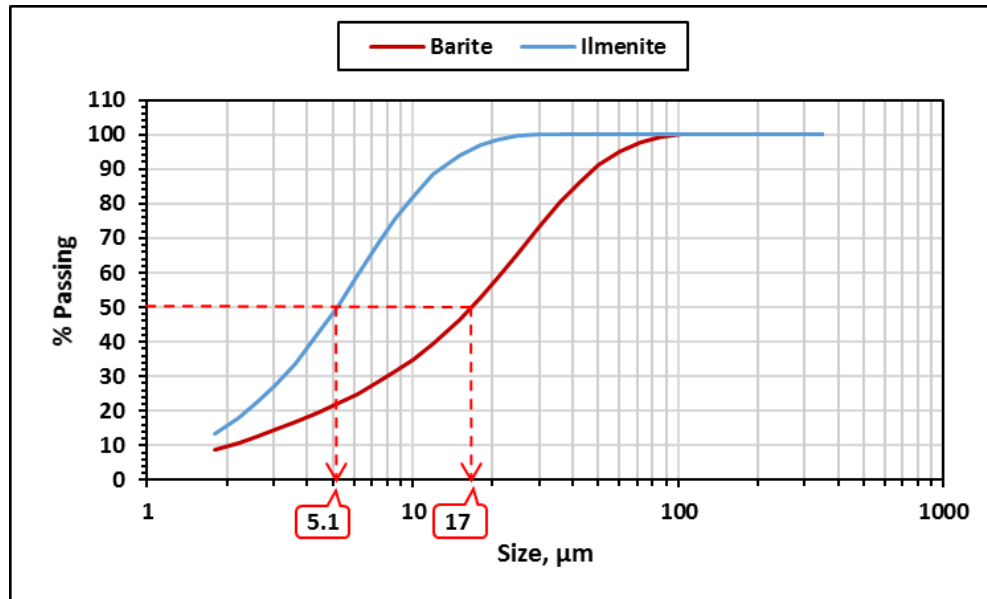


Figure 56 Particle size distribution for the used weighting material

7.2.2 Sag Test

Sag test was conducted to study the impact of adding ilmenite on solids sag tendency at static and dynamic conditions. The static sag test was performed at vertical and inclined (45°) conditions using an aging cell assembly. Tests were conducted at 350°F and 500 psi

and run for 24 hrs. Afterward, two fluid samples were taken from the top and the bottom of the cell using a syringe, and the density of both samples was measured.

Viscometer sag shoe test (VSST) was used to perform sag tests under dynamic conditions. The test was run for 30 min at 100 rpm and 120°F. The experimental procedure for the dynamic sag test is well described in previous studies. VSST was calculated using

A VSST value that is equal to or less than one indicates that the fluid would exhibit acceptable sag performance [39]. Table 16 shows the experimental conditions for static and dynamic sag tests.

Table 16 Experimental conditions for sag test

Parameter	Static Sag Test	Dynamic Sag Test
Temperature	350 °F	120 °F
Pressure	500 psi	Atmospheric pressure
Time	24 hrs	30 min
Inclination	Vertical/ 45°	

7.2.3 Rheology Measurements

After the drilling fluid preparation, the density and the electrical stability were measured for all the drilling fluid samples at room temperature using mud balance and emulsion stability tester, respectively. Rheological properties were obtained from the viscometer dial readings at 350°F and 2000 psi. These properties are plastic viscosity, yield point, and gel strength after 10 s, 10 min, and 30 min of static gel time. The viscoelastic properties of the drilling fluid (storage modulus and loss modulus) were obtained from the oscillatory test

conducted at 350°F using Anton Paar rheometer. Storage modulus could be used as an indication of solids sag tendency (Maxey, 2007).

7.2.4 HPHT Filtration Test

Filtration tests were conducted to study the impact of using the combined weighting material on the filtration performance, and the sealing properties of the resulted filter cake. The filtration test was conducted on a 10-micron ceramic filter disc at 350°F temperature and 300 psi differential pressure. The test was run for 30 min, and the fluid filtrate volume was recorded with time. Afterward, the properties of the formed filter cake were measured (weight and thickness). The filtration performance of the base fluid sample was compared with the performance of the drilling fluid sample with the combined weighting agent under the same experimental conditions.

7.3 Results and Discussions

Different drilling fluid samples were prepared by mixing ilmenite with barite in different concentrations (20, 40, 60, and 80 wt.%). After fluid preparation, density and electrical stability were measured for all drilling fluid samples. Figure 57 exhibits the impact of ilmenite concentration on fluid density and electrical stability. The density of the base drilling fluid was 14.5 ppg, and as the concentration of ilmenite increased, the drilling fluid density slightly increased to reach up to 15.2 ppg for 100 wt.% Ilmenite sample. This increase is due to the difference between ilmenite density (4.79 g/cm³) and barite density (4.48 g/cm³); therefore, when adding ilmenite, less solids will be needed to attain the same density of the base fluid.

In contrast, adding 40 wt.% ilmenite reduced the electrical stability, ES, of the base fluid from 1482V to 682V, then it was stable at around 655V for higher concentrations. The electrical stability is used as an indication of emulsion stability as it measures the voltage of the current flowing in the mud. Electrical stability is affected by many factors, such as viscosity, types and concentrations of solids, and emulsifiers. The observed reduction in electrical stability can be attributed to the value of ilmenite's electrical conductivity as it is much higher than barite conductivity, therefore, replacing barite with ilmenite will increase the conductivity of the drilling fluid, while previous studies reported that adding barite to invert emulsion increases the electrical stability of the drilling fluid. However, this value is still above the acceptable value, 500V, according to oil industry practices, and it can be adjusted by optimizing drilling fluid additives, such as emulsifiers. Moreover, field and laboratory studies confirmed that the electrical stability trend (with time) is the key property in mud stability, not its absolute value; higher ES values do not always mean good fluid stability.

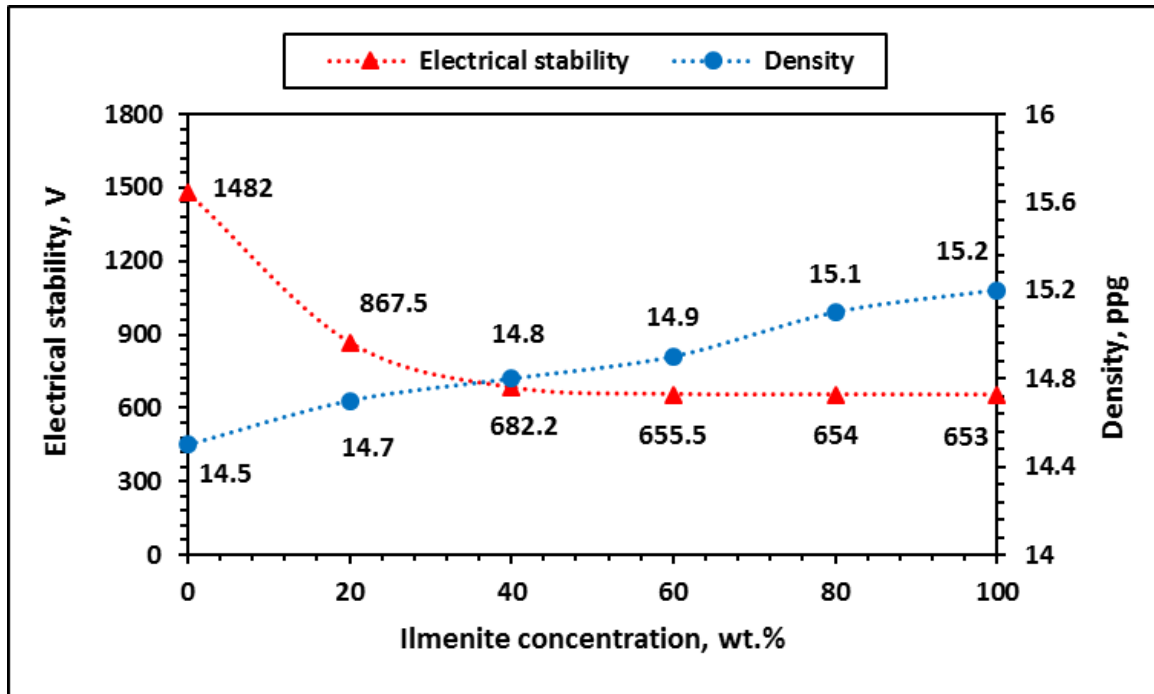


Figure 57 Effect of ilmenite on drilling fluid density and electrical stability

Figure 58 and Figure 59 show the impact of the combined weighting agent on solids sag tendency of invert emulsion drilling fluid under dynamic and static conditions at 120°F and 350°F, respectively. Under both dynamic and static conditions, the base drilling fluid (with 100 wt.% barite) exhibited poor sag performance with a sag factor of around 0.57 and 0.6 at vertical and inclined static conditions, respectively, and with a VSST value of 1.5 at dynamic conditions, therefore, solids settlement is likely to occur. The addition of ilmenite reduced sag tendency of the drilling fluid, and as the concentration of ilmenite increased, sag tendency was reduced. Only 40 wt.% ilmenite was enough to eliminate solids sag in both cases with sag factor and VSST of around 0.5. Higher concentration (>40 wt.%) is not required, and it will increase the cost of the drilling fluid. The static sag factor at an inclination of 45° was slightly higher than at vertical conditions because solids settlement is accelerated at inclination between 30° and 60° (Boyoun et al., 2019; Skalle et

al., 1999). The optimum ilmenite concentration, however, may vary with the used drilling fluid formulations and well conditions which require optimizing the ratio of ilmenite to barite for each formulation before field applications. The improvement of sag performance resulted from adding ilmenite to the drilling fluid can be attributed to the surface charge and the size of solid particles. Surface charge plays a vital role in the stability of colloidal systems that is governed by the repulsive force and attractive force between colloidal particles (Bokern et al., 2003). As reported in the previous studies, the surface charge of ilmenite particles dispersed in water ranges between -30 and -35 mV (S. Elkatatny et al., 2012), while barite has a lower surface charge of around -20 mV (Bokern et al., 2003). The higher the surface charge, the more stable is the colloidal system, and a surface charge that is above ± 30 mV is considered to have good colloidal stability (Joseph and Singhvi, 2019). Moreover, the difference in the particle size between barite and ilmenite (17 μm and 5 μm , respectively) has impact on the capability of the drilling fluid to suspend the weighting material. As the particle size decreases, the ratio of the surface area to the volume increases which increases drag and lift forces on the solid particles to overcome cohesion and gravitational forces and consequently prevents the settlement of solid particles (Boyou et al., 2019).

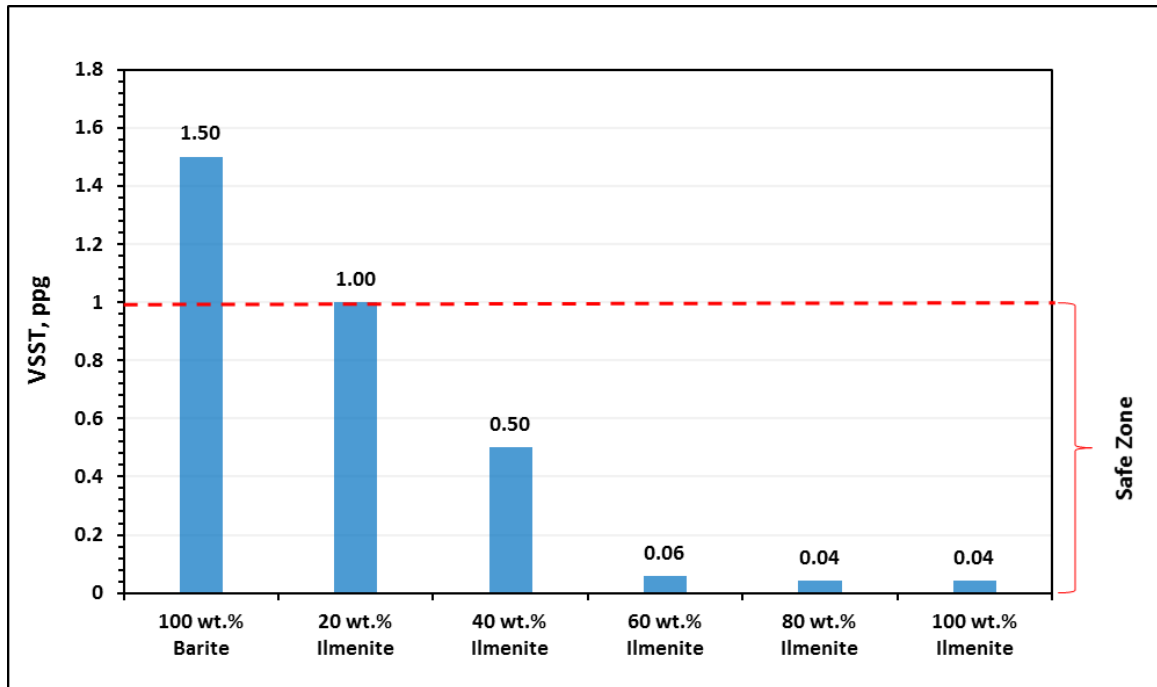


Figure 58 Effect of ilmenite on WBM sag at dynamic conditions (120 °F).

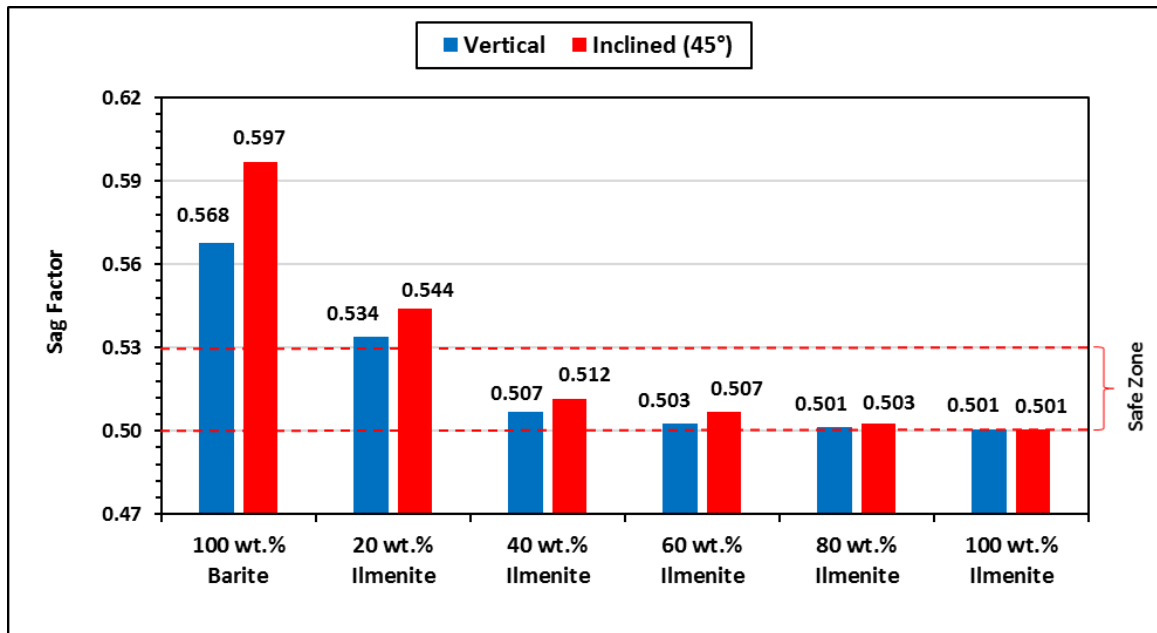


Figure 59 Effect of ilmenite on sag at static conditions (350 °F)

Drilling fluid rheology was measured at 350°F to evaluate the effect of ilmenite concentration on

the drilling fluid rheology at such elevated temperature. Figure 60 compares the rheological properties of 40 wt.% ilmenite fluid sample with the base fluid sample. Adding 40 wt.% ilmenite increased the yield point from 15 to 26 lb/100ft² whereas, the plastic viscosity did not increase significantly, from 15 to 16 cP. Consequently, the yield point to plastic viscosity ratio (YP/PV) increased from 1.2 to 1.6, which indicates an enhancement in the drilling fluid stability and suspension capability of solid particles. The higher the YP/PV ratio, the more stable the drilling fluid (Chilingarian et al., 1983). In addition to barite sag, YP/PV ratio affects many drilling fluid parameters such as equivalent circulating density, hole cleaning, and surge and swap pressure (Power and Zamora, 2003b). Moreover, adding 40 wt.% ilmenite with barite improved the gel strength of the drilling fluid, and validated the results of the sag test. Figure 61 compares the viscoelastic properties of 40 wt.% ilmenite fluid sample with the base drilling fluid sample within the nonlinear viscoelastic range. From G''/G' ratios, the loss modulus G'' is lower than the storage modulus G' for both fluid samples, which indicates that the nonlinear viscoelastic range was dominated by the elastic behavior. Adding 40 wt.% ilmenite enhanced the elasticity of the drilling fluid by increasing the storage modulus; thus, more stable gel structure would result (Binh Bui et al., 2012a). The increase in the yield point, gel strength, and the storage modulus values is because of the slight increase in the fluid density, from 14.5 to 14.8 ppg, resulted from adding ilmenite to the drilling fluid because as the density increases, the fluid resistance for initial flow increases (Boyou et al., 2019).

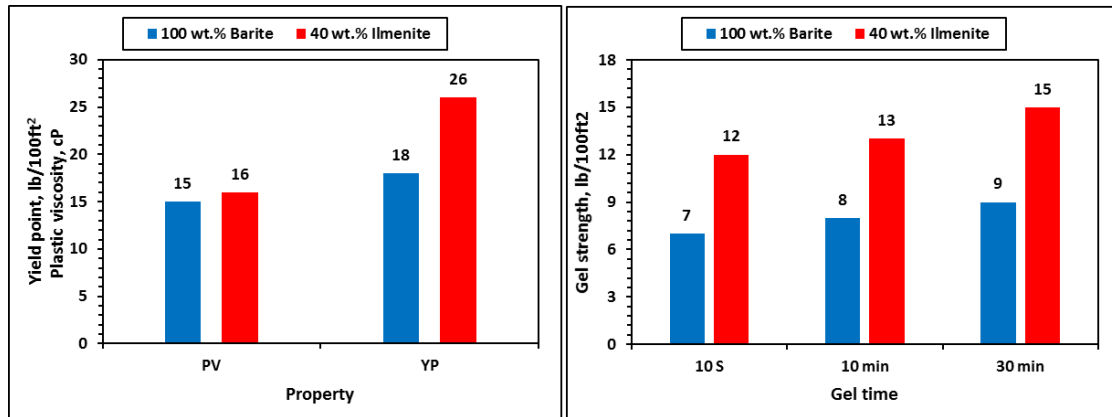


Figure 60 Effect of adding ilmenite on rheological properties (350°F).

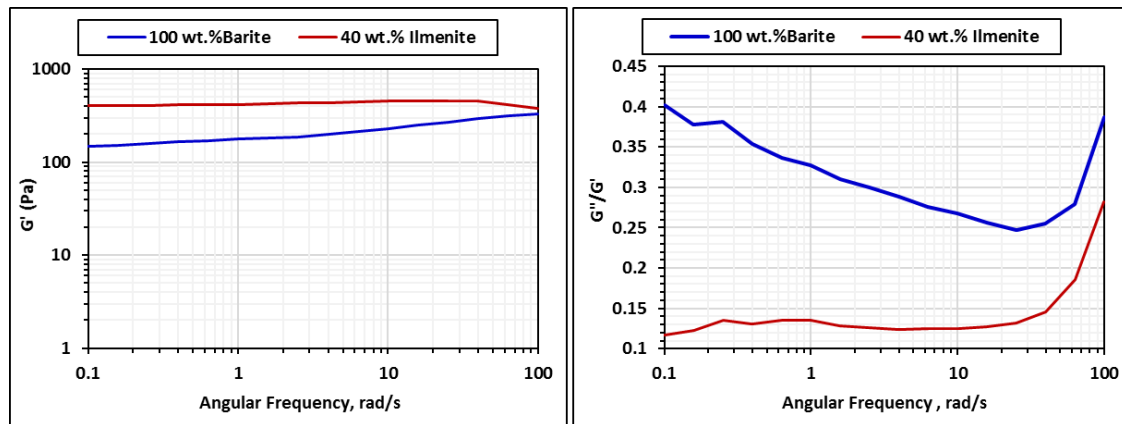


Figure 61 Effect of ilmenite on viscoelastic properties (250 °F).

Figure 62 compares the filtration performance of the 40 wt.% ilmenite sample with the base drilling fluid sample at 350°F. As shown in Figure 61, adding 40 wt.% ilmenite slightly improved the filtration performance. The total fluid filtrate was reduced from 5.6 cm³ to 4.5 cm³, and the thickness of the filter cake was reduced from 2.92 mm to 1.93 mm. This improvement in the filtration performance is because of the particle size distribution of the solid particles in the mud as it plays a vital role in the filtration performance and the sealing properties of the filter cake and this finding is supported by the previous studies micron (Bageri et al., 2020; Mohamed et al., 2017b). The filtration test results are summarized in Table 17. Despite the improvement in the filtration performance of the drilling fluid

resulted from adding ilmenite to the drilling fluid, another challenge will be encountered when using this solution which is the removal of the formed filter cake after drilling operations because the filter cake adds a skin damage that reduces oil and gas production and affects the results of pressure transient tests. It was addressed in some previous studies that the weighting material forms 70-90% of the filter cake mineralogy therefore, in this case, the formed filter cake consists mainly of barite and ilmenite, consequently the process of removing the composite filter cake will be more challenging as it requires a special fluid formulation that can efficiently dissolve both barite and ilmenite.

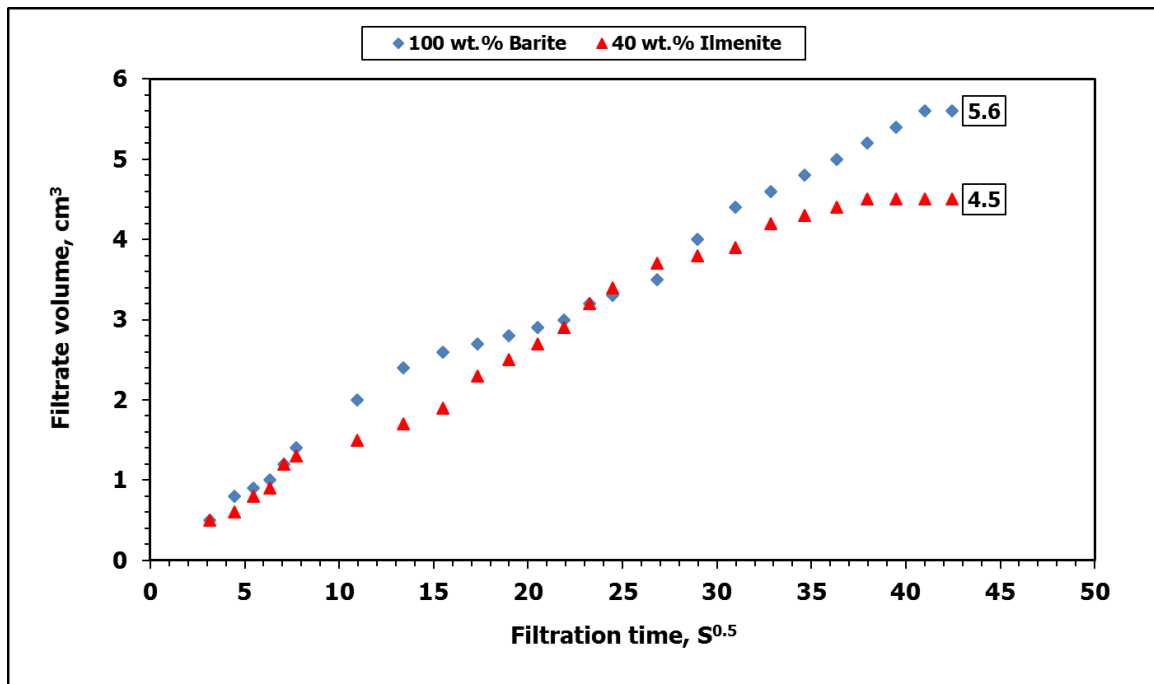


Figure 62 Effect of ilmenite on the filtration performance of OBM at (350 °F).

Table 17 Summary for filtration test results

Parameter	100 wt.% Barite	40 wt.% Ilmenite
Filtrate volume, cm^3	5.6	4.5
Filter cake thickness, mm	2.92	1.93

Filter cake weight, g	13.6	11.9
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7.4 Summary and Conclusions

Experimental work was carried out to evaluate the mixture of barite and ilmenite as a solution to solids sag phenomenon while drilling high-pressure high-temperature wells with oil-based drilling fluids. Based on the findings of this study, the following conclusions can be drawn:

- This study introduces a practical solution to barite sag issue in oil-based muds using a combined weighting material that comprises barite and ilmenite powders.
- Adding ilmenite to barite-weighted oil-based mud slightly increased the drilling fluid density because ilmenite has a higher density than barite. Whereas, ilmenite reduced the electrical stability of the invert emulsion. However, it was within the acceptable value (above 500 V), and it can be maintained by optimizing drilling fluid additives.
- Ilmenite significantly reduced the sag factor under both static and dynamic conditions. Sag factor decreases as the concentration of ilmenite increases, and 40 wt.% ilmenite was adequate to eliminate barite sag in both conditions. Sag factor was reduced to 0.51 in static conditions, while VSST decreased from 1.5 to 0.5 at dynamic conditions.
- Adding ilmenite enhanced the rheological and viscoelastic properties of the drilling fluid, which confirms sag test results.
- A slight improvement in the filtration performance and the filter cake properties was observed with combined weighting material. Less fluid filtrate and filter cake thickness

resulted. However, more research work is required to develop a fluid formulation that can effectively remove the composite filter cake.

- The findings of this study confirmed that the proposed drilling fluid formulation could be used to drill HPHT wells efficiently without solids settlement. With this solution, different formulations of the drilling fluid with different properties and performance can be prepared depending on the purpose and well conditions. Additionally, mixing ilmenite with barite reduces the high cost of ilmenite-weighted fluids as only 40 wt.% ilmenite was found to be enough for sag prevention.

CHAPTER 8

BARITE–MICROMAX MIXTURE, AN ENHANCED WEIGHTING AGENT FOR THE ELIMINATION OF BARITE SAG IN INVERT EMULSION DRILLING FLUIDS

Weighting agents are mixed with the drilling mud to provide the high density required to control high-pressure high-temperature (HPHT) wells throughout the drilling operation. Solids sag occurs when the weighting agent separates from the liquid phase and settles down, causing variations in the drilling fluid density. This study evaluates barite-manganese tetroxide (Micromax) mixture to eliminate solids sag issue encountered with weighted invert emulsion drilling fluids at HPHT conditions. Micromax additive was added to barite-weighted fluids in different concentrations, 0, 15, and 30 wt.% of the total weighting agent. Static and dynamic sag tests were used to evaluate the sag tendency of the new formulation under static and dynamic conditions. The performance of the new formulation was evaluated by measuring the electrical stability, density, rheological, viscoelastic, and filtration properties of the drilling fluid. The obtained results showed that Micromax additive improves drilling fluid stability by reducing the sag tendency. Adding

only 30 wt.% of Micromax additive eliminated barite sag issue in both dynamic and static conditions at 350 °F. 30 wt.% Micromax increased the base fluid density by 5.4% and the yield point by 115% and maintained the gel strength value at 12 lb/100 ft², while it reduced the plastic viscosity by 30%. The addition of Micromax additive improved the viscoelastic properties of the drilling fluid by maintaining a higher storage modulus to the loss modulus ratio when compared with the barite sample (in the range 4-4.5). Furthermore, 30 wt.% Micromax improved the filtration performance by reducing the filtrate volume, filter cake weight, and filter cake thickness by 50%.

8.1 Introduction

Weighting agents are used to increase the density of the drilling fluid to efficiently control oil and gas well throughout the drilling operation (Caenn et al., 2011; E. Hossain and Al-Majed, 2015; Stroud, 1926, 1922). The common weighting agents used in drilling applications are calcium carbonate, barite, ilmenite, manganese tetroxide (Micromax), and hematite (Al-Yami and Nasr-El-Din, 2007; S. Elkatatny et al., 2012; Elkatatny et al., 2013; Tehrani and Popplestone, 2007; Yao et al., 2014). Because of the good properties and low cost, barite is the most widely used weighting agent (Ba geri et al., 2017; Nguyen et al., 2009a; Pozebon et al., 2005). However, barite sag is a serious issue when using barite-weighted fluids. It occurs when solid particles separate from the liquid phase and settle down (Peter A. Bern et al., 2000b; Tor Henry Omland et al., 2007). Because of the solids settlement, the fluid density will vary, causing a severe well control issue (Saasen et al., 2002b; Zamora and Bell, 2004), and interference with the drilling operations (Mohamed et al., 2017a). This phenomenon occurs in both directional and vertical wells, whether under

dynamic or static conditions, most commonly with dynamic conditions at low shear rates (Murphy et al., 2008).

Many parameters affect the sagging phenomenon in drilling operations such as fluid type and density, drilling fluid additives, weighting agent, particle size, low-shear rheology, downhole temperature, wellbore geometry and inclination, drill pipe rotation, and time (P. A. Bern et al., 2000). Several experimental studies were performed to simulate and measure the barite sag tendency in the laboratory under static and dynamic conditions. One of the common methods to evaluate the sag tendency of the drilling fluid is measuring the weight difference between the top and bottom of the fluid column using flow loops, sag cell setup, and viscometer sag show test (Aldea et al., 2001; P. M. Hanson et al., 1990; Murphy et al., 2008; Saasen et al., 2002b; Temple et al., 2005)... Another method of barite sag measurement is using the rheological and viscoelastic properties obtained by different rheometers and correlate the data with sag tendency (Bern et al., 2010; Chilingarian et al., 1983; Maxey, 2007; Power and Zamora, 2003b; A. Saasen et al., 1995). Ultrasonic and Nuclear Magnetic Resonance (NMR) techniques were also utilized to measure the sag tendency of the drilling fluid by detecting the density stratification using the sound velocity and the influence of the magnetic field, respectively (T H Omland et al., 2007). Another advancement in solids sag testing was recently introduced by (Ofei et al., 2020). They used a cylindrical glass cell with multiple light scattering technique to characterize the homogeneity and settling speed of the solid particles in the drilling fluid.

Several studies were conducted to solve solids sag phenomenon in oil and water-based muds by training rig personnel (Paul D. Scott et al., 2004), optimizing the rheological

properties of the drilling fluid using anti-sagging agents and rheology modifiers (Basfar et al., 2018; Davis et al., 2017; Elkatatny, 2019, 2018; Temple et al., 2005), reducing the particle size of the weighting agent (Boyou et al., 2019; Mohamed et al., 2017), replacing the weight material, or adding a combination of weight materials (Abdou et al., 2018; Alabdullatif et al., 2014b; Basfar et al., 2019; Mohamed et al., 2019).

Because of the limited resources and high demand for barite, other alternatives to barite are needed to weight the drilling fluid for HPHT applications (Blomberg et al., 1984). Research studies were conducted on the use of ilmenite as an alternative weighting agent because of its high density (4.7-4.79 g/cm³), availability, and acid solubility (Haaland et al., 1976; Mohamed et al., 2012; Xiao et al., 2013b). However, ilmenite abrasiveness to drilling fluid equipment is a major issue (Xiao et al., 2013b), and it could be mitigated by using ilmenite with small particles (< 45µm), less than 3% of large particles (larger than 45 µm) should be used (Blomberg et al., 1984). Micromax additive is another alternative weighting agent to barite. It has a high specific gravity (4.8), and the fine particles of Micromax additive (about 1 µm) make the abrasiveness and sag tendency of Micromax additive less than that of barite (Ma et al., 2019; Mustapai, 2011a). Micromax additive is reservoir friendly and causes less formation damage compared with other weighting agents (Al-Muhailan et al., 2014a).

To solve the barite sag issue and the high cost of Micromax additive, compared to barite, this study evaluates the mixture of barite and Micromax to provide the required density of invert emulsion muds to drill HPHT wells effectively. Hence the effect of combined weighting agents on sag tendency and drilling fluid properties is evaluated.

8.2 Materials and Methods

Different concentrations of Micromax additive (0, 15, and 30 wt.% of the total weighting agent) were added to the barite-weighted fluid to prepare the drilling fluid samples using the description shown in Table 18. Diesel was used as a continuous phase, while water was the dispersed phase. Primary and secondary emulsifiers (INVERMUL[®] and EZ MUL[®]) were used to create a stable water-in-oil emulsion. Lime was used to enhance emulsion stability by activating the fatty acid emulsifiers, while calcium chloride was used as a clay and shale inhibitor. The viscosity of the invert emulsion mud was maintained using an organophilic clay (GELTONE[®]). Calcium carbonate was used as a bridging agent, and the drilling fluid was weighted using barite and Micromax additive in different ratios. The mixing sequence of the additives is as listed in Table 18.

8.3 Experimental Procedure

8.3.1 Material characterization

The weighting agents, barite and Micromax, were characterized by measuring the elemental composition, morphology, and particle size distribution (PSD) to understand the mechanisms of sagging behavior of the solid particles and how the sag tendency can be reduced with Micromax-weighted fluids. The elemental composition was determined by a small-spot X-ray fluorescence technique (micro-XRF) using the M4 TORNADO instrument. Scanning electron microscopy (SEM) was performed using the JEOL JSM-5900LV instrument to determine the morphology of the weighting agents' particles, while TURBO TRAC particle size analyzer that uses laser diffraction method was utilized to determine the particle size distribution of the weighting agents used in this study.

Table 18 Drilling fluid recipe in field units (1 bbl of mud)

Additive	Amount	Weight percentage, wt. %	Mixing time, min
Diesel	0.48 bbl	13.93	-
INVERMUL [®]	8 lb	0.799	10
Lime	6 lb	0.599	10
DURATONE [®]	4 lb	0.4	10
Water	0.053 bbl	1.85	10
Calcium chloride	7 lb	0.699	10
GELTONE [®]	5 lb	0.5	20
EZ MUL [®]	3 lb	0.3	10
Calcium carbonate (Fine)	5 lb	0.5	10
Calcium carbonate (Medium)	5 lb	0.5	
Weighting agent (Barite- Micromax)	800 lb	79.9	20

8.3.2 Sag Tests

Sag tests, static and dynamic, were used to study the sag tendency of fluid samples to determine the optimum concentration of Micromax additive. The static sag test was carried out for 24 hours under vertical and inclined (45°) conditions at 350 °F and 500 psi, using an aging cell setup, while the dynamic sag test was performed using viscometer sag shoe test at the standard conditions (30 min, 120 °F, and atmospheric pressure). The fluid samples are kept at testing conditions, and with time and due to the high temperature, the

drilling fluid starts to degrade, and solid particles tend to separate and settle down due to the gravity effect. The main principle of the sag test is to measure the weight difference between the top and bottom of the fluid column after the test. The detailed procedure of the static and dynamic sag tests is well explained in the literature (Basfar et al., 2019; Basfar et al., 2018; Mohamed et al., 2019, 2017).

8.3.3 Rheological and Viscoelastic Properties

The impact of adding Micromax additive on the rheological and viscoelastic properties of the mud was studied at 350 °F by measuring plastic viscosity, yield point, gel strength, and the storage and loss modulus. Rheological properties were measured using OFITE 77-HPHT Viscometer. Yield point (YP) and plastic viscosity (PV) were obtained from the viscometer dial reading ($\emptyset$) at 300 and 600 RPM using. While gel strength values were obtained from the direct dial reading at 3 RPM after 10 s, 10 min, and 30 min of static gel time. Storage modulus (G') and loss modulus (G'') were obtained from the frequency and amplitude oscillatory tests conducted using Anton Paar rheometer. First, the amplitude sweep test was conducted to identify the linear viscoelastic range. The test was run at a constant frequency of 10 rad/s while the amplitude of the shear stress was increased gradually. Then, the frequency sweep test was run, using a fresh fluid sample, at a constant strain of 0.1 that falls within the linear viscoelastic range, and the storage modulus G' and loss modulus G'' were obtained at different angular frequencies. Both rheology and oscillatory tests were conducted at 2000 psi and 350 °F.

8.3.4 Density and Electrical Stability

The density and electrical stability of the invert emulsion mud were measured to study the effect of Micromax additive on these properties. The measurements were conducted at ambient temperature using a mud balance and electrical stability tester.

8.3.5 HPHT Filtration

The impact of using Micromax additive on the filtration properties of the drilling mud was evaluated using the HPHT filtration test. The test was conducted at 500 psi differential pressure and 350 °F using a ceramic filter disc with a mean pore diameter of 50 μm as a filtration medium. The experiment was run for the standard test duration, 30 min. The measured filtration properties are filter cake weight, filter cake thickness, and total filtrate volume.

8.4 Results and Discussion

8.4.1 Material characterization

Weighting agents, barite and Micromax, were characterized by measuring the elemental composition using X-ray fluorescence, XRF. Results in Table 19 show that barite mainly contains 77.5 wt.% barium, 17.7 wt.% sulfur, and small traces of silicon, iron, and potassium. While Micromax additive contains 99.2 wt.% manganese, and the remaining weight is small traces of aluminum, silicon, calcium, and potassium. SEM images show that barite has heterogeneous particles with irregular shapes and sharp edges, while the particles of Micromax additive are uniform with a spherical shape, which makes the abrasiveness of Micromax additive less than that of barite, Figure 63. The barite sample

has large particles, and the average particle size was 18 μm , while Micromax additive has fine particles with an average particle size of around 1.7 μm , Figure 64. The fine uniform particles of Micromax additive results in a strong Brownian motion allowing the particles to create random collisions that consequently reduce the gravity effect on the solid particles and enhances the sag performance of the drilling fluid (Ma et al., 2019; Wen et al., 2009).

Table 19 Elemental composition of weighting agents using XRF

Element	Mass percent (%)	
	Barite	Micromax
Ba	77.5	-
S	17.7	-
Mn	-	99.2
K	0.6	0.2
Ca	-	0.05
Al	-	0.5
Si	2.8	0.05
Fe	1.4	-

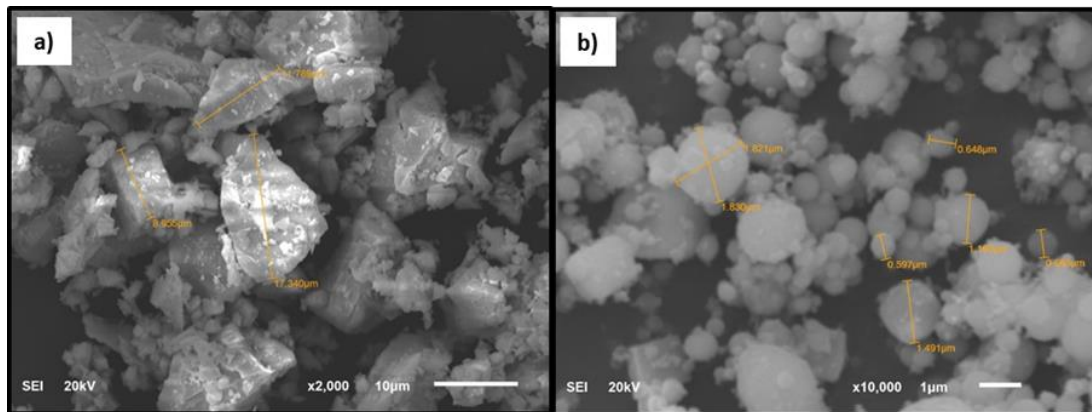


Figure 63 Morphology of weighting agents: a) Barite, and b) Micromax additive.

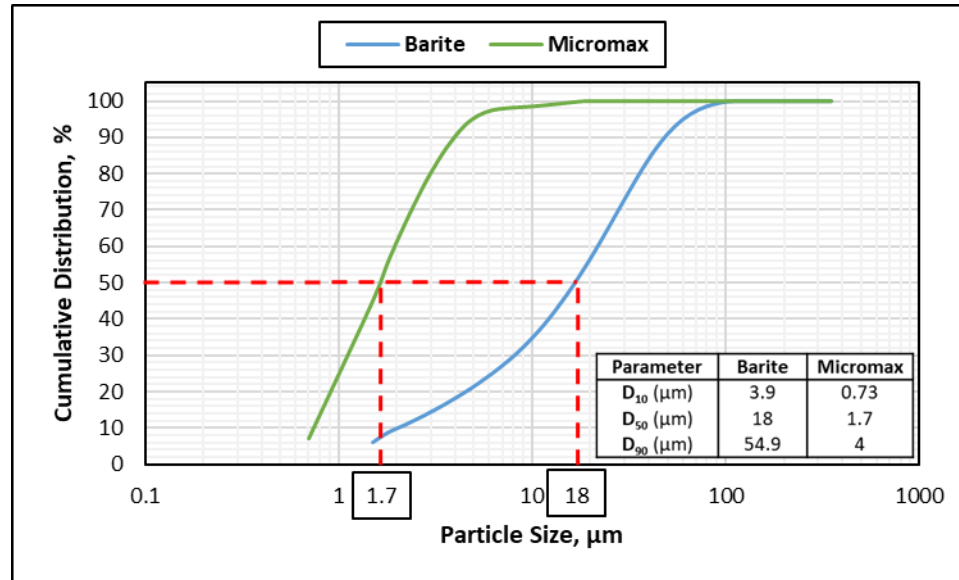


Figure 64 PSD of the weighting agents.

8.4.2 Sag Tests

After preparing the fluid samples, using different ratios of barite and Micromax additive, the sag tendency of these samples was studied under static and dynamic conditions, Figure 65. The base mud sample, 100 wt.% barite, revealed a high sag tendency under both conditions with a dynamic sag factor (VSST) of 1.3 and a sag factor of around 0.6. The addition of Micromax additive improved the stability of the mud and reduced the sag factor and the VSST, and as the concentration of Micromax additive was increased, the sag factor reduced. Only 30 wt.% of Micromax additive was sufficient to bring the sag factor and VSST values to the acceptable range, 0.5-0.53 and 0-1.0, respectively (Alabdullatif et al., 2014c; Aldea et al., 2001; Maxey, 2007). Consequently, solids sag issue will not be encountered, and drilling with this fluid formulation would be safe.

Many factors contributed to the improvement of solids suspension capability when adding Micromax additive to the drilling fluid formulations. Firstly, the strong Brownian motion

of the fine, spherical, and uniform particles of Micromax additive allows the solid particles to make random collisions and reduces the gravity effect on the solid particles (Ma et al., 2019). Secondly, the particles of Micromax additive have a higher surface area to volume ratio compared to barite that makes the lift and drag forces greater than the cohesion and gravity forces (Boyou et al., 2019). Thirdly, Micromax additive has a higher surface charge than barite, and as the surface charge increases, the stability of the colloidal system increases (Joseph and Singhvi, 2019; Mohamed et al., 2019a). Moreover, additional enhancement in the sag tendency will be observed in real cases because the high density of Micromax additive reduces the total amount of the weighting agent required to formulate a drilling fluid with the same weight of the base fluid thus, it reduces the solids loading in the drilling fluid.

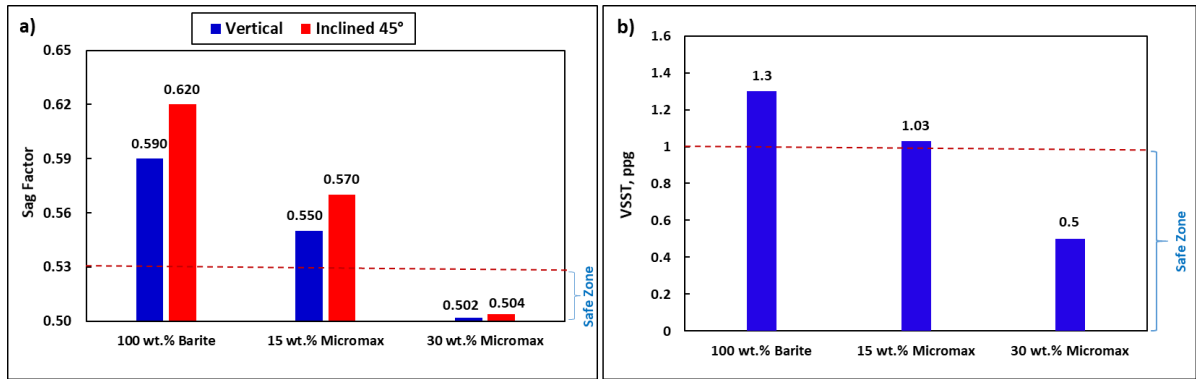


Figure 65 Effect of Micromax on sag: a) static, 350 °F, b) dynamic, 120 °F

8.4.3 Rheological and Viscoelastic Properties

The impact of Micromax additive on the rheological and viscoelastic properties of the fluid samples was investigated at 350 °F. The flow curves (shear stress vs. shear rate) of the drilling fluid samples are presented in Figure 66. As shown in Figure 66, all the drilling

fluid samples behave as non-Newtonian fluids and fit the Bingham plastic model with an R-squared of 0.98. As the concentration of Micromax additive increased, higher shear stress values resulted. Figure 67 shows that increasing the concentration of Micromax additive from 0 to 30 wt.% increased the yield point of the drilling fluid from 14 to 30.2 lb/100 ft², and slightly reduced the plastic viscosity from 25 to 17.3 cP. Consequently, the increase in the yield point and the decrease in the plastic viscosity increased the YP/PV ratio from 0.56 to 1.75. The YP/PV ratio is a very important parameter in drilling fluid design. It affects the drilling fluid performance and controls several drilling parameters such as mud stability, hole cleaning, equivalent circulating density, and surge and swap pressures (Chilingarian et al., 1983; Power and Zamora, 2003b). The yield point indicates the drilling fluid's ability to suspend the solid particles during circulation. The enhancement of yield point confirms the sag test results that adding Micromax additive improves the suspension capability of the mud; however, increasing the YP/PV ratio more than required would result in mud coagulation (Chilingarian et al., 1983). Conversely, the drilling fluid with high plastic viscosity values requires more pumping pressure because of the additional frictional pressure; therefore, adding Micromax additive to barite-weighted fluids would result in less frictional pressure.

Moreover, adding Micromax additive improved the gel strength of barite-weighted fluids. The gel strength indicates the drilling fluid's ability to suspend the solid particles when there is no circulation. For 0 and 15 wt.% Micromax samples, the gel strength showed a slight increase with time while the drilling fluid sample with 30 wt.% Micromax exhibited a flat rheology behavior with a constant gel strength value with time (12 lb/100 ft²)

indicating quick and more stable gel structure Figure 67b. Consequently, solid particles settlement is less likely to occur under that condition. Figure 68 compares the viscoelastic properties of the drilling fluid samples. As shown in Fig. 8a, all the drilling fluid samples showed a linear viscoelastic range below 0.6 % strain where the storage modulus (G') was greater than the loss modulus (G''); thus, the suspensions behave more like viscoelastic solids with a stable gel structure. Form Figure 68b, increasing the concentration of Micromax additive to 30 wt.% resulted in higher ratios of G'/G'' than the other samples. This increase in G'/G'' ratio indicates a stronger gel structure confirming the gel strength and sag test results (B Bui et al., 2012).

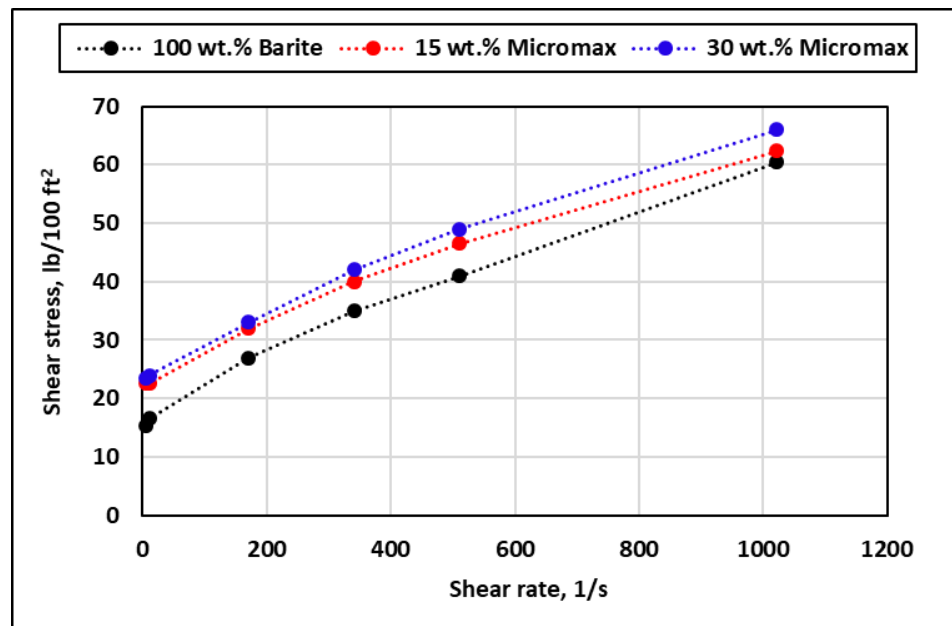


Figure 66 Flow curves for the drilling fluid samples (350 °F)

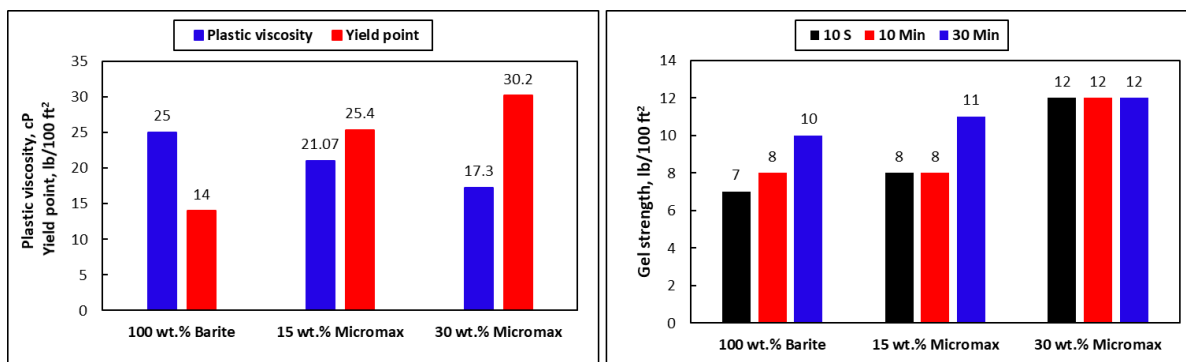


Figure 67 Effect of Micromax on a) PV and YP, and b) gel strength (350 °F)

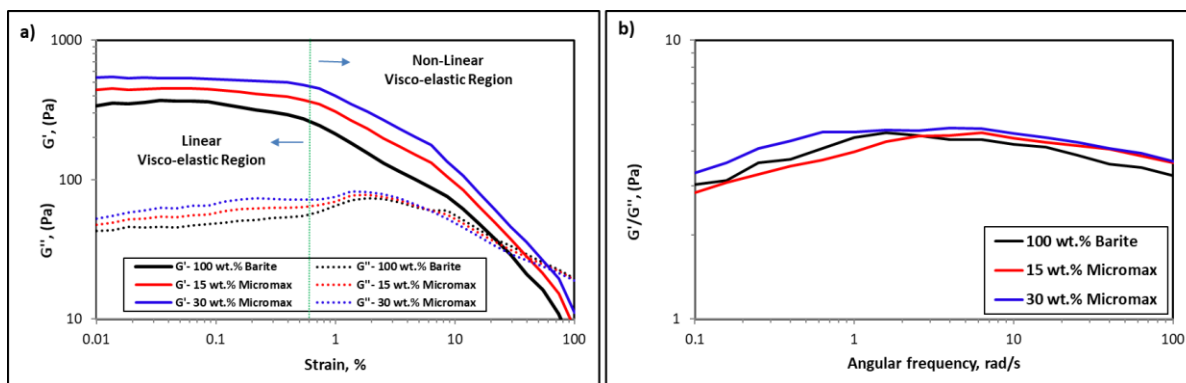


Figure 68 Viscoelastic properties a) amplitude, and b) frequency at (350 °F)

8.4.4 Density and Electrical Stability

The base fluid sample has a density of 20.4 ppg, and electrical stability of 1334 V. Adding Micromax additive to the base fluid sample increased the density of the drilling mud to reach up to 21.5 ppg with 30 wt.% Micromax sample, Table 3. The increase in fluid density is attributed to the high density of Micromax additive (4.8 g/cm^3) compared to that of barite ($4.2\text{-}4.4 \text{ g/cm}^3$); therefore, less solids content will be required to provide the same density (Al-Muhailan et al., 2014b; Caenn et al., 2011; Kewen Li et al., 2014; Mustapai, 2011b)... Conversely, increasing the concentration of Micromax additive up to 30 wt.% slightly decreased the electrical stability to 1140 V because of the difference in electrical conductivity and surface charge, between Micromax additive and barite. This decrease is

not significant because the electrical stability is still far above the acceptable value in drilling practices, 500 V (Van Zanten et al., 2012).

8.4.5 Filtration Properties

The filtration performance of drilling fluid samples was studied at 350 °F and 500 psi. As shown in Figure 69 and Table 20, adding Micromax additive enhanced the filtration performance of the drilling fluid. When the concentration of Micromax additive was increased from 0 to 30 wt.%, the total filtrate volume, filter cake thickness, and filter cake weight were reduced by approximately 50%. The filtrate volume was decreased from 2.6 cm³ to 1.2 cm³, the filter cake thickness was decreased from 2.9 mm to 1.9 mm, and the filter cake weight was reduced from 32.4 g to 14 g. The fine and uniform particles of Micromax additive improved the bridging effect of the solid particles resulting in a thinner and more packed filter cake, Figure 70 (Ma et al., 2019). The less filtrate volume, filter cake weight, and filter cake thickness, the better the filtration performance, and the less damage caused to the drilled formation. Moreover, the thinner the filter cake, the less possibility of stuck pipe will be encountered during the drilling operation.

Table 20 Summary of the drilling fluid properties

Parameter	100 wt.% Barite	15 wt.% Micromax	30 wt.% Micromax
Density, ppg	20.4	21.3	21.5
Electrical stability, V	1334	1250	1140
Yield point, lb/100 ft ²	14	25.4	30.2
Plastic viscosity, cP	25	21.07	17.3
YP/PV	0.56	1.2	1.75

Gel strength (10 s/10 min/30 min), lb/100 ft ²	7/8/10	8/8/11	12/12/12
Filtrate volume, cm ³	2.6	2.1	1.2
Filter cake thickness, mm	3.30	2.54	1.27
Filter cake weight, g	32.3	26.53	14

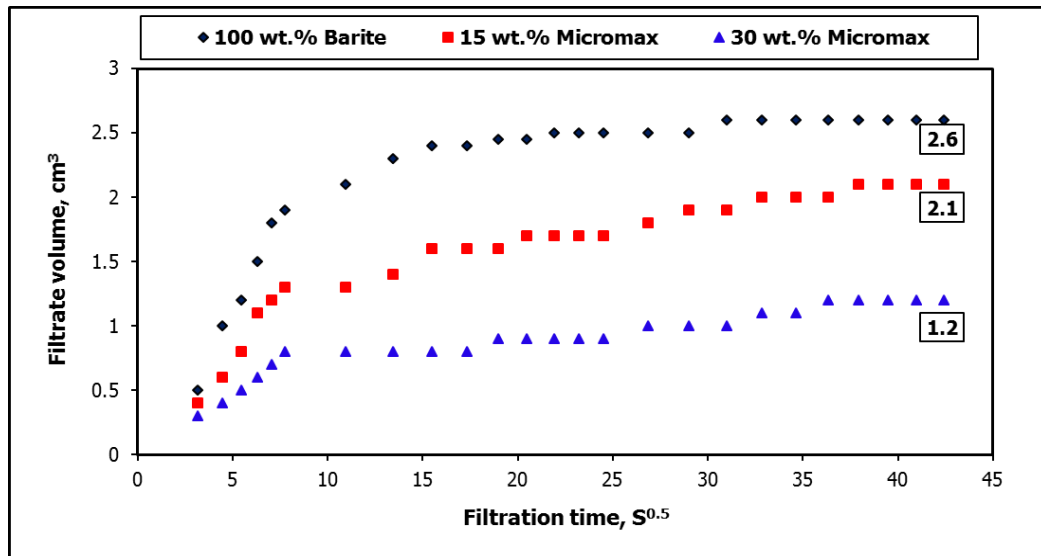


Figure 69 Effect of Micromax on the filtration performance of OBM (350 °F).

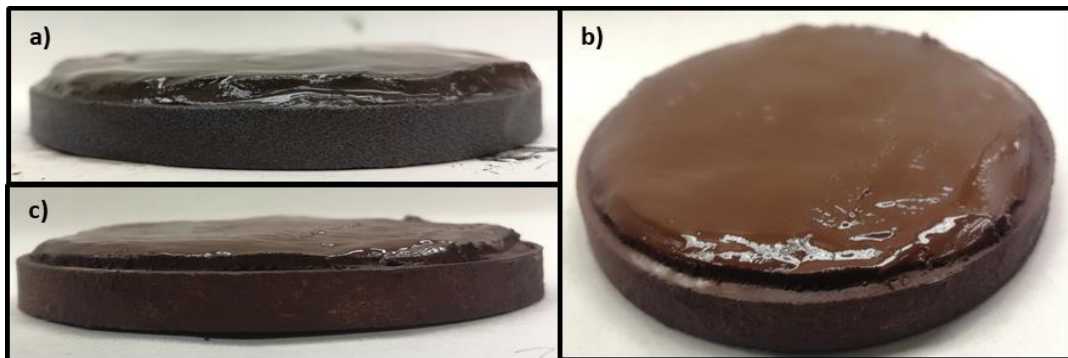


Figure 70 Filter cake of: a) 100% barite, b) 15% Micromax, and c) 30% Micromax.

8.5 Summary and Conclusion

In summary, the addition of Micromax additive to barite-weighted drilling fluid was found effective in reducing sag tendency at HPHT conditions. The addition of Micromax additive increased the fluid density and slightly reduced the electrical stability of the invert-emulsion mud within the acceptable range. Micromax additive improved the rheological, viscoelastic, and filtration properties of the drilling fluid. 30 wt.% Micromax increased the yield point by 115% and maintained the gel strength value at 12 lb/100 ft², while it reduced the plastic viscosity by 30%. The filtrate volume, filter cake thickness, and filter cake weight were significantly reduced by 50%; thus, less formation damage from the fluid filtrate invasion is anticipated. 30 wt.%, of the total weighting agent, was found to be the optimum concentration of Micromax additive because it was enough to eliminate barite sag under dynamic and static conditions and yielded the optimum drilling fluid properties. With this fluid formulation and testing conditions, adding more concentration is not required, and it would add additional cost to the drilling operations.

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Vitae

PERSONAL DETAILS

Name: Salem Abdullah Basfar
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Mobile: +966500964392
Date of Birth: 1 February 1988
Status: married
Nationality: Yemeni
E-mail: salimbafar@gmail.com

CAREER OBJECTIVE

Petroleum Engineer interested in joining drilling fluids projects.

EDUCATION HISTORY

August 2018 – Current	Ph.D. candidate at King Fahd University of Petroleum and Minerals
July 2015 – May 2108	King Fahd University of Petroleum and Minerals , Dhahran KSA Master's in petroleum engineering (3.34/5) Thesis title: Reducing of Barite Sagging by Using Copolymer in High-Pressure High-Temperature Wells.
May 2007 – Oct 2012	Hadhramout University , Hadhramout Yemen, Bachelor of petroleum engineering honor degree (87.83%)
May 2003 – Feb 2006	AL-masmom High School , Hadhramout Yemen, Secondary School Scientific section

WORK EXPERIENCE

Nov 2013– Dec 2014	Academic teacher (Hadhramout University) <u>Responsibilities and achievements:</u> • Explain tutorial problems • Explain Laboratory experiments
April 2013	Petro Masila Petroleum Exploration & Production Company Al-Masila Block (14) Hadhramout Yemen (training 4 weeks)

SKILLS AND CERTIFICATES

Computer Skills:

- TECHLOG formation evaluation program at (KFUPM)
- Diploma in Computer Application Programming (windows, word, excel, power point, typing, internet and outlook)
- (MAT LAB) Course
- "First Aid" Course

Language Skills:

- Arabic (Native Tongue)
- English

Publications

• Patent

- 1) Elkatatny, S., Mohamed, A. and **Basfer, S.**, King Fahd University of Petroleum, 2022. Method of removing calcium carbonate-containing oil-based filter cake using a biodegradable acid solution. U.S. Patent 11,414,589. <https://patents.google.com/patent/US11414589B2/en>

• Journals

- 1) **Basfar, S.**, Ahmed, A. and Elkatatny, S., 2022. Ilmenite Inclusion: A Solution towards Solid Sagging for Hematite-Based Invert Emulsion Mud. *Geofluids*, 2022. <https://doi.org/10.1155/2022/7438163>
- 2) Ahmed, A., **Basfar, S.** and Elkatatny, S., 2022. Sagging prevention for hematite-based invert emulsion mud. *Journal of Energy Resources Technology*, 144(7). <https://doi.org/10.1115/1.4052181>
- 3) **Basfar, S.**, Ahmed, A., Solling, T. and Elkatatny, S., 2021. Using manganese tetroxide for hematite settling prevention in water-based mud. *Arabian Journal for Science and Engineering*, pp.1-8. <https://doi.org/10.1007/s13369-021-06336-6>.
- 4) **Basfar, S.**, Al Jaber, J., Elkatatny, S. and Bageri, B.S., 2021. Prevention of hematite settling using perlite in water-based drilling fluid. *Journal of Petroleum Science and Engineering*, p.110030. <https://doi.org/10.1016/j.petrol.2021.110030>
- 5) Ahmed, A., **Basfar, S.** and Elkatatny, S., 2022. Sagging prevention for hematite-based invert emulsion mud. *Journal of Energy Resources Technology*, 144(7). <https://doi.org/10.1115/1.4052181>
- 6) Ahmed, A., **Basfar, S.** and Elkatatny, S., 2022. Sagging prevention for hematite-based invert emulsion mud. *Journal of Energy Resources Technology*, 144(7).
- 7) Almutawa, W., Ahmed, A., **Basfar, S.**, Elkatatny, S., Haidary, S. and Zitha, P., 2021. Investigation of magnetite-based invert emulsion mud at high pressure high temperature. *Arabian Journal of Geosciences*, 14(18), pp.1-8. <https://doi.org/10.1007/s12517-021-08293-8>.
- 8) Ahmed, A., **Basfar, S.**, Solling, T.I. and Elkatatny, S., 2021. Prevention of Hematite Settling in Water-Based Mud at High Pressure and High Temperature. *ACS Omega*. <https://doi.org/10.1021/acsomega.1c03818>.
- 9) Ahmed, A., **Basfer, S.** and Elkatatny, S., 2021. Sagging Prevention for Hematite-Based Invert Emulsion Mud. *Journal of Energy Resources Technology*, pp.1-19. <https://doi.org/10.1115/1.4052181>.
- 10) Mohamed, A., **Basfar, S.**, Elkatatny, S. and Al-Majed, A., 2021. Enhancement of Static and Dynamic Sag Performance of Water-Based Mud Using a Synthetic Clay. *ACS omega*, 6(12), pp.8179-8188. <https://doi.org/10.1021/acsomega.0c06186>.
- 11) Ahmed, A., **Basfar, S.**, Elkatatny, S. and Gajbhiye, R., 2020. Enhancing Hematite-Based Invert Emulsion Mud Stability at High-Pressure High-Temperature Wells. *ACS omega*, 5(50), pp.32689-32696. <https://doi.org/10.1021/acsomega.0c05068>.
- 12) Mohamed, A., **Basfar, S.**, Elkatatny, S. and Bageri, B., 2020. Impact of Perlite on the Properties and Stability of Water-Based Mud in Elevated-Temperature Applications. *ACS omega*, 5(50), pp.32573-32582. <https://doi.org/10.1021/acsomega.0c04853>.
- 13) **Basfar, S.**, Ahmed, A. and Elkatatny, S., 2020. Stability Enhancing of Water-Based Drilling Fluid at High Pressure High Temperature. *Arabian Journal for Science and Engineering*, pp.1-7. <https://doi.org/10.1007/s13369-020-05126-w>.
- 14) **Basfar, S.**, Mohamed, A. and Elkatatny, S., 2020. Barite–Micromax mixture, an enhanced weighting agent for the elimination of barite sag in invert emulsion drilling fluids. *Journal of Petroleum Exploration and Production Technology*, 10(6), pp.2427-2435. <https://doi.org/10.1007/s13202-020-00892-7>.
- 15) **Basfar, S.** and Elkatatny, S., 2020. Prevention of hematite settling using synthetic layered silicate while drilling high-pressure wells. *Arabian Journal of Geosciences*, 13(12), pp.1-9. <https://doi.org/10.1007/s12517-020-05516-2>.
- 16) Gamal, H., Elkatatny, S., **Basfar, S.** and Al-Majed, A., 2019. Effect of pH on rheological and filtration properties of water-based drilling fluid based on bentonite. *Sustainability*, 11(23), p.6714. <https://doi.org/10.3390/su11236714>.

- 17) Mohamed, A., **Basfar, S.**, Elkatatny, S. and Al-Majed, A., 2019. Prevention of barite sag in oil-based drilling fluids using a mixture of barite and ilmenite as weighting material. *Sustainability*, 11(20), p.5617. <https://doi.org/10.3390/su11205617>.
- 18) Elkatatny, S., **Basfer, S.**, Shawabkeh, R., Bahgat, M. and Mahmoud, M., 2019. Assessment of Using Copper Nitrate for Scavenging Hydrogen Sulfide While Drilling Sour Horizontal Wells. *Journal of Energy Resources Technology*, 141(12). <https://doi.org/10.1115/1.4043879>.
- 19) **Basfar, S.**, Mohamed, A., Elkatatny, S. and Al-Majed, A., 2019. A Combined Barite–Ilmenite Weighting Material to Prevent Barite Sag in Water-Based Drilling Fluid. *Materials*, 12(12), p.1945. <https://doi.org/10.3390/ma12121945>.

• Conferences

- 1) **Basfar, S.**, Elkatatny, S.M. and Mohamed, A., 2020. Preventing Barite Sagging Using New Synthetic Layered Silicate in HP/HT Water-Based Mud. ARMA-2020-1702 paper presented at the 54th US Rock Mechanics/Geomechanics Symposium.
- 2) **Basfar, S.**, Elkatatny, S., Al-Majed, A. and Al Sheri, D., 2020. Prevention of barite sagging for invert emulsion drilling fluid while drilling high-pressure high-temperature wells. IPTC-20095-MS paper presented at the International Petroleum Technology Conference, Dhahran, Kingdom of Saudi Arabia, January 2020. <https://doi.org/10.2523/IPTC-20095-MS>.
- 3) Mohamed, A., Elkatatny, S. and **Basfar, S.**, 2019. One-Stage Calcium Carbonate Oil-Based Filter Cake Removal Using a New Biodegradable Acid System. SPE-198045-MS paper presented at the SPE Kuwait Oil & Gas Show and Conference, Mishref, Kuwait, October 2019. <https://doi.org/10.2118/198045-MS>.
- 4) Elkatatny, S., **Basfer, S.**, Mahmoud, M., Shawabkeh, R. and Bahgat, M., 2018. New Hydrogen Sulfide Scavenger for Drilling Sour Horizontal and Multilateral Reservoirs. SPE-192188-MS paper presented at the SPE Kingdom of Saudi Arabia Annual Technical Symposium and Exhibition, Dammam, Saudi Arabia, April 2018. <https://doi.org/10.2118/192188-MS>.
- 5) **Basfar, S.**, Elkatatny, S., Mahmoud, M., Kamal, M.S., Murtaza, M. and Stanitzek, T., 2018. Prevention of barite sagging while drilling high-pressure high-temperature (HPHT) wells. SPE-192198-MS paper presented at the SPE Kingdom of Saudi Arabia Annual Technical Symposium and Exhibition, Dammam, Saudi Arabia, April 2018. <https://doi.org/10.2118/192198-MS>.
- 6) AL-Dogail, A.S., Baarimah, S.O. and **Basfar, S.A.**, 2018. Prediction of inflow performance relationship of a gas field using artificial intelligence techniques. SPE-192273-MS paper presented at the SPE Kingdom of Saudi Arabia Annual Technical Symposium and Exhibition, Dammam, Saudi Arabia, April 2018. <https://doi.org/10.2118/192273-MS>.
- 7) **Basfar, S.**, Baarimah, S.O., Elkatany, S., AL-Ameri, W., Zidan, K. and AL-dogail, A., 2018. Using artificial intelligence to predict ipr for vertical oil well in solution gas derive reservoirs: a new approach. SPE-192203-MS paper presented at the SPE Kingdom of Saudi Arabia Annual Technical Symposium and Exhibition, Dammam, Saudi Arabia, April 2018. <https://doi.org/10.2118/192203-MS>.
- 8) Elkatatny, S., **Basfer, S.**, Mahmoud, M., Shawabkeh, R. and Bahgat, M., 2018. New Hydrogen Sulfide Scavenger for Drilling Sour Horizontal and Multilateral Reservoirs. SPE-192188-MS paper presented at the SPE Kingdom of Saudi Arabia Annual Technical Symposium and Exhibition, Dammam, Saudi Arabia, April 2018. <https://doi.org/10.2118/192188-MS>.

PERSONAL COMPETENCIES

- Ability to work in a fast-paced environment to set deadlines
- Fast learning
- Enthusiastic self-starter who contributes well to the team