ABSTRACT: Weighting agents such as barite, micromax, ilmenite, and hematite are commonly added to drilling fluids to produce high-density fluids that could be used to drill deep oil and gas wells. Increasing the drilling fluid density leads to highly conspicuous fluctuation in the drilling fluid characteristics. In this study, the variation in the drilling fluid’s rheological and filtration properties induced by adding different weighting agents was evaluated. For this purpose, several water-based drilling fluid samples were prepared and weighted up using the same concentration of various weighting materials including barite, micromax, ilmenite, and hematite. The characteristics of the used weighting agents’ (particle size distribution and mineralogy) were measured. Subsequently, the rheological properties of the drilling fluid were obtained using a Fann viscometer at 80 °F. The filtration test was carried out at 200 °F and 300 psi differential pressure to form a filter cake over the sandstone core samples. The properties of the formed filter cake layer such as thickness, porosity, and permeability were determined. Furthermore, the typical properties of core samples including porosity and permeability were assessed before and after the filtration test. The displayed results confirmed that the plastic viscosity (PV), yield point (YP), and filter cake sealing properties were all significantly influenced by the ratio of the large to fine particle size (D_{90}/D_{10}) of the weighting agents irrespective of the weighting material type. Among the examined weighting agents, barite showed novel potency to control both rheological and filter cake properties for 14 ppg drilling fluid. The results showed that D_{90}/D_{10} is a key factor for the PV and YP properties as increasing the D_{90}/D_{10} ratio caused PV increase and YP decrease, which indicated that the interaction among the loaded weighting materials in the drilling fluid dominated its viscosity.

INTRODUCTION

Conventional overbalanced drilling fluids have been employed in vertical and horizontal drilling processes to afford many functions such as cleaning the well, lubricating and cooling the drill string and bit, controlling the downhole pressure, and protecting the hydrocarbon formation, in addition to many other essential tasks.

The drilling fluid, consisting of suspended solids in a colloidal base provided using a mixture of clays and polymers, is pumped through the drilling pipes to the driled section and returns to the surface through the annular to fulfill these functions. Therefore, an efficient design of drilling fluid additives is vital for successful drilling operations. Designing the drilling fluid involves comprehensive laboratory and field tests to examine the density, rheology, filtration properties, and other important properties to select appropriate drilling additives. There are practical issues that commonly occurred during the drilling operations owing to the drilling fluid compositions because of the invasion of the solids of weighting materials, which cause the formation damage. The use of drilling fluids includes several difficulties because of the complexity of operation conditions and contradiction between the different required functions. For instance, effective operation conditions call for maintaining the equivalent circulating density through a narrow safe window of the fracture and pore pressures and also reducing the viscosity of the drilling fluid to reduce the friction, while decreasing the viscosity characteristics of the drilling fluid through the essential design or according to the operation conditions will reversely affect the carrying capacity of the drilling fluid and lead to weaken sagging stability and bad hole cleaning.

The worldwide growth of the drilling technology has necessitated improving the drilling properties especially for deep oil and gas wells where the target hydrocarbon formation was found to be in deep depths. This has encouraged the researchers to investigate the application of varied materials to enhance the properties of the high-density drilling fluid. Accordingly, there were extended attempts to come up with an applicable weighting agent to match the requirements for such conditions.
growth in the drilling activities for ultradeep drilling. This leads to broadening the use of various substances as weighting agents such as ilmenite, hematite, micromax, manganese tetroxide, micromanganese, dolomite, Tiro (Stibnite), Kaun (Potash), and galena as alternative weighting agents to be used in the drilling fluid instead of the predominant agent (barite) in different areas of the world, which disseminate the use of the local resources of the weighting agents and cut the cost of the drilling operations. The demand has extended to formulate the drilling fluid with a mixture of weighting agents such as barite—micromax, barite—ilmenite, and hematite—barite, to minimize the associated issues and yield higher stability to increase the drilling efficiency. Moreover, the applications of nanoparticles, numerous natural and synthetic polymers, and surfactant are introduced for improving the drilling fluid rheology, providing good lubricity, preventing the sagging issues, and enhancing the stability of the drilling fluid.

In this context, the formation damage has been identified as one of the most significant challenges related to the high-density drilling fluid, which could be reflected in the following two reasons. One was the high solid content of the weighting agent particles, and the other was the harsh operation conditions of high temperature and high pressure (HTHP), where the performance of the drilling additives degrades rapidly. While not preventable, many investigations have been established to understand the structure of the filter cake and to enhance the sealing properties of the filter cake layer formed around the wellbore and hence mitigate the induced damage. These studies have detected that the filter cake layer was mainly formulated by the weighting agents. The formation drilled cutting could occupy 20% and even higher of the filter cake structure if not appropriately handled through the solid separation equipment in the surface. The presence of the cuttings in the filter cake structure could have a severe impact on its properties such as thickness and porosity. The filter cake layer was found to be an effective key factor to prevent the formation damage in high-pressure drilling operations. Typically, the filter cake permeability must be very low (ranged from $10^{-5}$ Darcies to $10^{-7}$ Darcies) for protecting hydrocarbon formation and obstructing solid invasion. Over the years, a variety of drilling fluid additives have been recommended to form a desired filter cake layer to withstand the HTHP drilling.

Withstanding the due importance of the filter cake layer, various tools are introduced to characterize the filter cake including X-ray computed tomography (CT scan), nuclear magnetic resonance (NMR), and scanning electron microscopy (SEM). The properties of the filter cake layer including the thickness, porosity, and permeability are very sensitive to the drilling fluid and formation properties. Moreover, the filtrate passed through the filter cake layer has a great impact on the drilled rock characteristics and significantly affected the rock pore structure.

Furthermore, increasing the solid content of the weighting agent particles in drilling fluid formulation influenced the rheological properties. A sketch behavior of the rheological models for the weighted drilling fluid with a high solid content is complicated owing to numerous factors that essentially need to be considered. First, the weighting agents might form a bridge network and hence affect the fluid viscosity. In addition, the effect of the associated trace content in the weighting agent, if not treated well, would be an extra factor to be addressed. Moreover, up to a certain level of the solid concentration where the particle dispersion form transforms from the discrete state to particulate dense state, the interaction between the high-concentration weighting material solid particles was obviously influenced by the fluid viscosity. In addition, harsh conditions such as high formation temperature and high operation pressure are extremely complicated, and hence it was found to be a hard task to control the rheological properties using the traditional additives.

The aforementioned discussions revealed that the solid type and content significantly affect the drilling fluid performance, filter cake structure, and its sealing properties. This was well studied in terms of evaluating the influence of the cuttings and different polymers on the fluid rheological and filtration properties. However, there is still no sufficient evaluation research that covers the effect of weighting agents on filter cake properties including its porosity and permeability. Different from previous predominant studies, the filtration tests of this work were conducted using sandstone core samples as the filter medium to mimic the actual formation properties instead of utilizing ceramic desks. Furthermore, the current study extends...
the knowledge observed in the previous study7 that highlighted the impact of the weighting agents on the pore system of the sandstone rock using NMR; however, the current study provided a different scope for deep investigation about the role of the weighting agent properties in the fluid rheological and filtration characteristics. In this work, the effect of different weighting agents including barite (BaSO4), micromax (manganese tetraoxide; Mn3O4), ilmenite (FeTiO3), and hematite (Fe2O3) on the filtration properties was investigated. In particular, the influence of weighting materials on filter cake porosity and permeability was addressed. Additionally, this study highlights the fluctuation in the drilling fluid rheological characteristics caused by altering the type of the weighting agent.

## MATERIALS AND EXPERIMENTS

This study provides a comprehensive analysis to investigate the impact of the weighting agents on the drilling fluid properties and the filter cake characteristics. Figure 1 represents the layout for the investigational analysis that was performed for the weighting agents, drilling fluids, rock samples, and filter cake. The following sections discuss in detail the experimental work for each phase.

**Weighting Agents.** In this study, four types of weighting materials were used. The characteristics of the weighting materials such as particle size and particle size distribution (PSD) were evaluated using a Wet Dispersion Unit ANALYSETTE 22 Nano Tec plus. Figure 2 presents the PSD of the weighting agent. The figure displayed the median particle size of the used weighting agents (D50) and the size of the fine and large particles in terms of D10 and D90. The data showed that the size of the barite particles was larger compared with the size of the weighting agents, while the micromax particles had the lowest size in terms of D10, D50, and D90.

The elemental analysis of the weighting materials was performed using X-ray fluorescence spectroscopy (XRF). The results of XRF are presented in Figure 3. It can be seen that purity of barite particles considering the barium and sulfur percentage was about 86%. The rest was traces of Si, Al, Rh, and others, while the purity of other weighting agents considering their formulation exceeded 95%. Figure 4 shows the SEM images of the weighting agents. It can be seen that the micromax particles have a spherical shape while the particles of the other weighting agents tend to have an irregular shape. The SEM image showed that ilmenite particles have a sharp edge compared with barite and hematite particles. The specific gravity (SG) of the used weighting agents was 4.3 for barite, 4.8 for micromax, 4.8 for ilmenite, and 5.0 for hematite.

**Drilling Fluid.** Essentially, the objective of this study is to investigate the effect of using different weighting agents on the rheological properties of the drilling fluid and filtration loss. Hence, the fresh drilling fluid, as shown in Table 1, was made up of the standard water-based mud (WBM) formulation consisting of bentonite, Xanthan gum (XC polymer), starch, and calcium carbonate. The viscosity of the fresh drilling fluid formulation was controlled by the XC polymer and bentonite, while the starch was used as a fluid loss agent, and calcium carbonate was added as a bridging agent to improve the filtration properties. The pH of the drilling fluid was adjusted using KOH, and KCl was added to inhibit the clay swelling. Subsequently, the freshly prepared drilling fluid was weighted by different weighting agents (the most applicable weighting agents including barite, micromax, ilmenite, and hematite). The high-density drilling fluid was formulated accordingly by adding a constant concentration of the weighting agent (300 g) to the fresh formulation. This was referred as the weighting agent in Table 1.

The properties of the prepared drilling fluid samples including the density and rheological properties were evaluated at room temperature (80 °F). The density of the drilling fluid was evaluated using the mud balance (+0.1 ppb). The rheological properties were measured using a Fann viscometer. The plastic viscosity (PV), apparent viscosity, and yield points (YPs) were determined using the dial readings at 300 and 600 RPM (O600 and O600) as shown in eqs 123, while the gel strengths (10 s and 10 min) were obtained directly from the dial reading at 3 RPM after the static gel time.

\[
\text{Plastic viscosity (PV)} = \frac{\Omega_{600} - \Omega_{300}}{2}
\]

\[
\text{Apparent viscosity (AV)} = \frac{\Omega_{600}}{2}
\]

\[
\text{Yield point (YP)} = \Omega_{300} - \text{PV}
\]

**Rock Sample.** Core samples (i.e., sandstone Berea Buff) with 1.5 inches diameter and 2 inches length were used as a filter medium in the filtration test to form the filter cake. To prevent the clay swelling, 3 wt % potassium chloride solution was utilized to saturate the sandstone core samples. The mineral composition of the rock samples was determined using X-ray diffraction. The obtained data showed that the Berea Buff sandstone samples consisted of 95% of quartz and microcline, where the rest were 5% clay minerals including kaolinite, smectite, and muscovite.

It is worth stating that from this point forward, we will refer to the rock samples used in this work as sample 1, sample 2, sample 3, and sample 4 for the barite-, hematite-, micromax-, and ilmenite-weighted drilling fluid, respectively. This means that sample 1 represents a filtration loss test that was performed using the barite-weighted drilling fluid. The porosity of the Berea Buff sandstone samples was found to be in the average of 20%, and the permeability ranged from 168 to 185 mD, as listed in Table 2.

**HPHT Fluid Loss Test.** The filter cake was formed under HPHT conditions using the fluid loss test. The static filtration test was conducted at 300 psi differential pressure and 200 °F. The filter cake was formed on the face of the sandstone core samples. The test was repeated under the same conditions using different drilling fluids as listed in Table 1 to investigate the
effect of the weighting material on the performance of the filtration properties including the filter cake thickness, filter cake porosity, filter cake permeability, and solid invasion. The weight of the filter cake over the saturated ceramic disk was recorded. After this step, the disk with the filter cake was placed in an oven for 24 h at 250 °F to evaporate the water. The dry weight of the filter cake was recorded after this step.

The porosity of the formed filter cake \( \Phi_{fc} \) was calculated using the following equation:

\[
\Phi_{fc} = \frac{V_p}{V_b}(4)
\]

where \( V_p \) and \( V_b \) are the pore and bulk volume of the filter cake, respectively. The pore volume of the filter cake was estimated at the end of the filtration test with eq 5 using the wet and dry weight of the filter cake as inputs, while the bulk volume of the filter cake was measured using the filter cake dimensions (thickness and diameter) as per eq 6:

\[
V_p = \frac{FC_{\text{wet}} - FC_{\text{dryw}}}{\rho_f} \tag{5}
\]

\[
V_b = \frac{\pi}{4} (D^2)_{FC} (h)_{FC} \tag{6}
\]

Where \( FC_{\text{wet}} \) = net wet weight of the filter cake, gm; \( FC_{\text{dryw}} \) = net dry weight of the filter cake, gm; \( \rho_f \) = density of the filtration fluid, gm/cm³; \( (D)_{FC} \) = filter cake diameter, cm; and \( (h)_{FC} \) = filter cake thickness, cm.

The permeability of the formed filter cake \( K_{fc} \) was calculated using the following method, which applied Darcy’s equation for the pressure drop across the filter cake:44

Table 1. Drilling Fluid Formulation

| component          | amount | unit |
|--------------------|--------|------|
| water              | 290    | cc   |
| defoamer           | 0.09   | g    |
| XC polymer         | 1.5    | g    |
| bentonite          | 4      | g    |
| starch             | 6      | g    |
| KCL                | 20     | g    |
| KOH                | 0.3    | g    |
| CaCO₃              | 5      | g    |
| weighting agent    | 300    | g    |

Table 2. Porosity and Permeability Analysis for the Sandstone Core Samples

| sample no. | crosslinking weighting agent used for the filtration loss test | % porosity | permeability (mD) |
|------------|---------------------------------------------------------------|------------|-------------------|
| sample 1   | barite-WBM                                                    | 20.8       | 168               |
| sample 2   | hematite-WBM                                                  | 21.3       | 185               |
| sample 3   | micromax-WBM                                                  | 20.9       | 172               |
| sample 4   | ilmenite-WBM                                                  | 21.3       | 185               |

Figure 3. XRF elemental analysis of the weighting particles (a) barite, (B) hematite, (C) ilmenite, and (d) micromax.

Figure 4. SEM images for the weighting agent particles (a) barite, (B) hematite, (C) ilmenite, and (d) micromax.
\[ K_{fc} = 14700 \frac{q h_{fc} \mu}{P_{fc}} \] (7)

Where \( K_{fc} \) = permeability of the filter cake, md; \( q \) = filtration rate, cm/sec; \( h_{fc} \) = filter cake thickness, cm; \( \mu \) = viscosity of the filtrate, cP; and \( p \) = pressure across the filter cake, psi.

The flow rate can be estimated from the slope of the straight-line region of the filtrate volume versus time (according to the data obtained from the filtration test). The slope is divided by the total filtration area (inside diameter of the filtration cell) to obtain the parameter \( q \) (flow rate per area unit) in eq 4.

### RESULTS AND DISCUSSION

**Effect of Weighting Agents on Drilling Fluid Properties.** The density of the prepared drilling fluids loaded by the four weighting agents has little difference in the range of 14 ppg (±0.1 ppg). Based on the result of this work, the prepared drilling fluid densities were 14.1 ppg, 14.0 ppg, 14.0 ppg, and 13.9 ppg for ilmenite, barite, micromax, and hematite, respectively. At this time, the effect of adding the same concentration of these materials (under the dosage of 300 g of the weighting agents) on the drilling fluid density was negligible. This is due to the close-range SG values of 4.3 to 5.0 as shown in the Materials section. The difference in the absolute values of the densities was found to be in the range of 0.20 ppg between the highest and the lowest densities, which is equivalent to 10 psi per 1000 ft. in terms of the hydrostatic pressure of the drilling fluid column downhole. This unmeasurable difference could be an experimental error because of the loss of some amount of weighting agent solids during the mixing process or even because of the accuracy of the mud balance (±0.1 ppg). Eventhough the produced density of the barite mud according to its lower SG of 4.3 compared to other three weighting agents (4.8–5.0) should be the lowest, however, the experimental results were not matching the expected calculated density because of the aforementioned justifications. Assuming that the drilling fluid mainly consists of the water phase and weighting agent phase, the expected density can be calculated as:

\[
\text{expected mud density} = \frac{\text{weight of water} + \text{weight of weighting agent}}{\text{volume of water} + \text{volume of weighting agent}}
\] (8)

As per Table 1, the weight of the weighting agent was 300 g, and the volume of the weighting agent is equal to (W/SG). The weight of water is equal to its volume 290 g = 290 mL. Hence, the expected density of the prepared drilling fluid is shown in Table 3.

Consequently, it can be concluded that the drilling fluid density was not a major factor for selecting one of these weighting materials under the dosage of 300 g of the weighting agents. However, in the case of high density, for example, the density of the drilling fluid exceeds 20 ppg; the amount of weighting agents with different SG values varies greatly, and the influence on the performance of drilling fluid is also more obvious. For example, the amount required to prepare 2.3 SG WBM was 988 g of API barite, while the required amount of ilmenite to prepare the same WBM was 904.16 g.

The experimental results of this study showed that in terms of apparent viscosity the values of the four prepared drilling fluids were close to each other in the range of 44 to 51 cP as shown in Figure 5. The drilling fluid weighted using barite particles had lower apparent viscosity (44.3 cP) than the other three formulations weighted by ilmenite (48.1 cP), hematite (49.45 cP), and micromax (51.7 cP). Effectively, the ideally preferred rheological properties to operate the well are to prepare drilling fluids with low viscosity (i.e., plastic) and high YP values, which reflect higher flowability and higher carrying capacity of the fluid and require a minimal pumping pressure.

The PV for the micromax, barite, and ilmenite drilling fluid ranged from 27 to 30 cP while the hematite showed a higher PV value of 36.6 cP. YP is an important property that reflects the solid carrying capacity of the drilling fluid. The yield point to plastic viscosity (YP/PV) ratio provides an indication of the efficiency of drilling fluid carrying capacity and hole cleaning. The results showed that the barite and ilmenite drilling fluids achieved a similar YP/PV ratio, which is equal to 1.15. However, the micromax weighting agent yielded the highest carrying capacity upon the YP/PV indicator that is equal to 1.76; this was associated with higher apparent viscosity at the same time, which is undesirable from the operation point of view. Meanwhile, it was detected that the YP/PV ratio of the hematite drilling fluid was the lowest (0.70), which indicated low performance of this weighting material compared with the other three weighting agents. Furthermore, the high value of the PV for the drilling fluid formulation weighted by hematite will disable the rate of penetration. According to the rheological property analysis, with these AV, PV, and YP characteristics, it can be concluded that the drilling fluid weighted by barite particles has shown higher ability to flow (relatively lower AV and PV) compared with the three other samples and acceptable carrying capacity at the same time as indicated by YP/PV. One can argue that the formulation weighted using ilmenite had a similar YP/PV index of barite-weighted drilling fluid. Hence, it can be observed that the barite formulation provided a higher ability to flow compared to the ilmenite formulation. The relatively lower AV and PV values (44.3 cP and 32.4 cP) for the barite-weighted agent compared with the achieved values by

### Table 3. Drilling Fluid Density Calculation

| Weighting agent phase | Drilling fluid expected density | (g/cm³) | PPG |
|-----------------------|--------------------------------|--------|-----|
| barite                | -                              | 1.64   | 13.66 |
| micromax              | -                              | 1.67   | 13.94 |
| ilmenite              | -                              | 1.67   | 13.94 |
| hematite              | -                              | 1.68   | 14.0  |

**Figure 5.** Drilling fluid apparent viscosity, PV, and YP.
ilmenite (48.1 cP and 35.2 cP) will certainly exhibit better fluidity for the barite formulation than ilmenite. Moreover, as shown in Figure 6, gel strength values (10 s and 10 min) were

![Figure 6. Drilling fluid gel strengths (10 s and 10 min).](image)

yielded by the drilling fluid formulation weighted by ilmenite compared with others. This will cause elevated pressure spikes once breaking the drilling fluid circulation. The values of the 10-s and 10-min gel strengths for the other three weighting agents were to a certain extent proximate to one another, as shown in Figure 6.

Generally, the results of many studies have detected that the rheological properties of the high-density drilling fluid might be promoted through different factors. Thus, the following two aspects herein will be highlighted for a better understanding of the viscosity features of the high-density drilling fluid. One was the structural viscosity that formed under the mechanism of clay dispersion and hydration, in addition to the recent breakthrough of improving the structural viscosity through the water-soluble polymers and clays that establish the bridge network structure. The other was nonstructural viscosity triggered by the interaction between the solid particles in the continuous phase through the friction, collision, and extrusion. In this study, because the formulation of the fresh drilling fluid before adding the weighting material has been fixed, the key question is how to figure out the rule for the physical properties of these weighting materials on the viscosity. Accordingly, we have tried to plot in the x-axis the values of weighting agent’s median particle diameter (D50) versus the viscosities PV, YP, and gel strength in y-axis.

The YP showed an acceptable correlation with the particle’s diameter (R2 = 0.68). It is worth mentioning that the same analysis using D10 and D90 instead of D50 has been repeated. The results still did not form a good correlation. In contrast, the ratio of large to fine particles showed good correlations for both PV (R2 = 0.62) and YP (R2 = 0.87), as shown in Figure 7. The PV increased with the increase of the ratio of the large to fine particles, which indicated that the fine particles were filled into some pore space of the structure between the large particles and hence produced a dense packing structure. This is translated by more friction, collision, and extrusion, which caused the PV to increase. On the other hand, as the ratio increased, the YP decreased, which emphasized the limitation at a certain level of the proportion of the large and small particles where the dispersion in the particle’s distribution may affect the sagging stability.14,55 The settling rate of the particles strongly depends on the particle size. Therefore, the high ratio of D90 to D10 indicated the different settling tendency, which indirectly lowered the YP. Finally, according to the produced correlation in this study, it is highly recommended to keep the ratio of D90/D10 lower than 14, as shown in Figure 7. In this range, the YP/PV ratio would be greater than one, which will ensure better carrying capacity and better hole cleaning.

Characteristically, altering the weighting material in the same formulation of the drilling fluid caused considerable variation in the rheological properties (i.e., apparent viscosity, PV, YPs, and gel strength) of the prepared fluid. The high- and ultrahigh-density drilling fluids are usually used to drill deep gas and oil wells. These harsh conditions at such depths are extremely complicated to operate where the temperature reached up to a high level and hence placed further stringent requirements on the drilling fluid. The reduction of the viscosity features at high temperature could diminish the suspension (i.e., sag stability) and carrying capacity of the drilling fluid. Thus, it is significant to interpret the appropriate criteria for selecting a suitable weighting agent. The obtained results in this work showed that each feature of the rheological properties was influenced upon changing the weighting material. This confirmed that the change in chemical and physical properties of the solid phase in the drilling fluid significantly affects the rheology of the fluid, with consideration of no change in the liquid phase properties.14,56

**Effect of Weighting Agents on Filter Cake Properties.** The filtration characteristics of the prepared drilling fluid including the filter cake thickness and filtration volume were reported. The filtration loss test was performed at 300 psi differential pressure and 200 °F. The experimental results showed that the barite-weighted drilling fluid yielded a lower filter cake thickness (3.0 mm) and a lower cumulative filtration volume (5.3 cm3 after 30 min) compared with the other three weighted drilling fluids, as shown in Figures 8 and 9. According to the measured permeabilities of the core samples (Table 2), core samples 2 and 4 (used hematite and ilmenite weighting agents, respectively) had the same permeability value of 185 mD. However, the filtration volume was 6.3 and 8.3 cm3 for the hematite- and ilmenite-weighted drilling fluids, respectively. It could be clearly seen that for uniform formation properties (porosity and permeability) and constant drilling fluid composition, shifting the weighting agent type could cause a significant increment in the filtration properties. For instance, using ilmenite instead of hematite as a weighting agent increased the cumulative filtration volume by 2 cm3 and formed a thicker...
filer cake of 7.6 mm instead of 4.1 mm, as shown in Figures 8 and 9 with consideration of similar formation properties and drilling fluid additives.

Based on the measured filter cake thickness and the reported weight for the dry and wet filter cake layer, the porosity of the filter cake was calculated using eq 1. Among the four weighting agents, the formulation weighted using barite particles showed lower filter cake porosity, as shown in Figure 10. The filter cake permeability, in particular, was measured by applying the permeability model as per eq 4 for filtration volume versus the time data in Figure 9 where the time ranged from 5 to 30 min, as shown in Figure 9. This range describes the final permeability of the formed filter cake layer. It was obvious that the filter cake build-up process was passed through two stages (two layers57).

One was the early stage that formed the inner layer of the filter cake, which depends on the type and concentration of the bridging agent used in the drilling fluid. The high concentration of the weighting agents would inevitably influence the performance of the bridging agent. Thereby, it was found that the inner layer of the filter cake (early time build-up process) was directly affected by the type of the weighting agents. Another was the outer filter cake layer where the filtration rate is lower and maintained constant. The calculation of this period reflected the final filter cake permeability. Overall, because the fresh drilling fluid formation for the four samples was kept constant with considering the same properties of the filtration medium (sandstone core samples), the difference in the filter cake permeability explains the inherent impact of the weighting agents on filter cake properties including the porosity and permeability.

Figure 10 shows the filter cake permeabilities for the different weighing agents. The results of the filter cake indicated that three types of the used weighting materials including barite, ilmenite, and hematite showed good matching between the permeability and porosity in the semilog scale, as shown in Figures 10 and 11. The low-porosity filter cake promoted a lower permeability layer, except the micromax filter cake where the permeability was low even though the porosity was quite high. Presumably, the lower size of the micromax particles, as shown in Figure 2, plugged the tiny pores and so disabled the connection between the pores of the filter cake, and as a result, its permeability was reduced accordingly. In addition, the filter cake porosity also showed a good correlation with the filter cake thickness, as shown in Figure 12. This remark confirmed the same observation for the previous study.58 Simultaneously, the
it can be observed that the drilling fluid formulation weighted using barite weighting particles had better filtration properties in terms of filter cake thickness, filtration volume, filter cake porosity, and permeability.

The quality of the filter cake including the thickness and sealing properties (porosity and permeability) would mainly depend on the dispersion and distribution of the particle size for the weighting agents and other clays. The SEM images of the formed filter cake layers are shown in Figure 14 using small (10 μm) and large (100 μm) scales. It can be seen from the small size SEM images that the shape of the weighting agents demonstrated the aggregation of these particles in the filter cake. The large size images illustrated that the filter cake formed by barite drilling fluid was flat and had fewer pores, which was the reason for displaying the lowest value of porosity and filtration volume as shown in Figure 10. Similarly, the SEM image of the hematite filter cake was relatively closer to that of the barite with more pores, which indicated the higher value of hematite’s filter cake porosity compared to the barite filter cake. In contrast, the micromax filter cake had many perspicuous pores. Presumably, the spherical fine particles could migrate with the filtration passed through the filter cake layer. Thereby, the micromax filter cake displayed the highest porosity in Figure 10. The SEM image showed that the filter cake formed by the drilling fluid formulated by ilmenite had obvious wrinkles. This could be attributed to the sharp edge of the ilmenite particles. Thus, the porosity calculation as shown herein could eliminate the objective of using SEM.

To understand the rule of the particle size characteristics, several analyses and plotting of the properties of the filter cake versus the particle size features individually (as D10, D50, and D90) and as ratios (D90/D10, D90/D50, and D50/D10) were performed. It can be concluded that the filter cake thickness showed a good correlation versus the large size proportion of the particle size (R2 = 0.73), as listed in Table 5. The reasonable factor (D90) can control the bulk volume of the filter cake and accordingly the thickness of the filter cake. However, the filtration volume did not show good matching with the particle size. This is because the filtration will mainly depend on the filter cake sealing properties, as shown in Figure 13.

Table 4 summarized the filtration loss properties of the different weighting agents. Compared with the viscosity analysis, it can be observed that the drilling fluid formulation weighted using barite weighting particles had better filtration properties in terms of filter cake thickness, filtration volume, filter cake porosity, and permeability.

| Table 4. Drilling Fluid Filtration Properties |
|---------------------------------------------|
| FC thickness, mm | filtration volume, cm³ | % FC porosity | FC permeability, mD |
| micromax | 5.7 | 7.1 | 5.0 | 0.0016 |
| ilmenite | 7.6 | 8.3 | 4.7 | 0.0025 |
| barite | 3.0 | 5.3 | 2.5 | 0.0006 |
| hematite | 4.1 | 6.3 | 3.4 | 0.0010 |

CONCLUSIONS

The current study conducted deep investigation on the role of different weighting agents in the drilling fluid rheological and filtration properties. Several series of experimental investigations were conducted for this purpose. The filtration loss test was carried out to form the filter cake layer over sandstone core samples to mimic the reservoir condition. The following conclusions are accordingly drawn:

1. The weighting agents significantly affected the drilling fluid rheological and filter cake properties. Regardless of the type of the weighting agent, PV increased with increasing the large to fine particle size ratio (D90/D10) of the weighting agent, while the YP decreased with increasing the ratio.

2. As the ratio of the large to fine particles skip 14, the drilling fluid carrying capacity index (YP/PV) laid lower than one, and hence, it is recommended to have a narrow window with a ratio of D90/D10 lower than 14 for improving the rheological characteristics. Nevertheless, more extension appraisals are required in further research.

3. Barite weighting agent particles yielded astonishing potency to form a thin impermeable filter cake compared with the other examined weighting agents. In particular, the thickness of the filter cake layer formed by the barite-weighted drilling fluid was, respectively, 26, 47, and 60% less than the layer formed by hematite-, micromax-, and ilmenite-weighted drilling fluids, in addition to an...
approximate reduction of the barite pore volume by 25, 46, and 50% compared with the porosity of the filter cake formed by hematite-, ilmenite-, and micromax-weighted drilling fluids, respectively.

4. According to the experimental data points, the measured filter cake parameters such as porosity and permeability can be correlated with the reported filter cake thickness and filtration volume. Another obtained curve showed good agreement between the porosity and permeability of the filter cake layer.

Table 5. Correlation Coefficient Map for the Filter Cake Thickness and Filtration Volume as a Function of Particle Size Characteristics of the Weighting Agents

|                   | $D_{10}$ $\mu m$ | $D_{50}$ $\mu m$ | $D_{90}$ $\mu m$ | $D_{50}/D_{10}$ | $D_{90}/D_{50}$ | $D_{90}/D_{10}$ |
|-------------------|------------------|------------------|------------------|-----------------|-----------------|-----------------|
| FC thickness      | 0.65             | 0.69             | 0.73             | 0.41            | 0.696           | 0.31            |
| filtration volume | 0.66             | 0.65             | 0.68             | 0.32            | 0.628           | 0.23            |

Figure 14. SEM images for the filter cake formed by different weighting agent particles (a) barite, (B) hematite, (C) ilmenite, and (d) micromax. Using 10 and 100 $\mu m$ scales.

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