CHALLENGES FOR DRILLING FLUIDS IN HPHT WELLS

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Abstract:

This study has been undertaken to investigate that how to overcome the challenge of barite sagging issue which will commonly encounters in drilling HPHT wells. A sag test was performed under static (vertical and 45° incline) and dynamic conditions in order to evaluate the copolymer's ability to enhance the suspension properties of the drilling fluid. In addition, the effect of this copolymer on the filtration properties was performed. The obtained results showed that adding the new copolymer with 1 lb/bbl concentration has no effect on the density and electrical stability. The sag issue was eliminated by adding 1 lb/bbl of the copolymer to the invert emulsion drilling fluid at a temperature >300°F under static and dynamic conditions. Adding the copolymer enhanced the storage modulus by 290% and the gel strength by 50%, which demonstrated the power of the new copolymer to prevent the settling of the barite particles at a higher temperature. The 1 lb/bbl copolymer's concentration reduced the filter cake thickness by 40% at 400°F, which indicates the prevention of barite settling at high temperature.

Keywords: barite sagging; invert emulsion; high-pressure high-temperature; storage modulus; sag factor

1. Introduction:

High pressure/high temperature (HP/HT) wells are those where the undisturbed bottom hole temp at potential reservoir depth or total depth is more than 300°F or a 150°C, and either the maximum expected pore stress of any porous formation to be drilled through exceeds a hydrostatic gradient of 0.8 psi/feet, or a properly requiring pressure manipulate gadget with a rated operating pressure in extra of 10000 psi. Drilling wells with those characteristics pose unique challenges.

The three are different categories as follows:

- HPHT wells
- Ultra- HPHT wells
- HPHT –HC

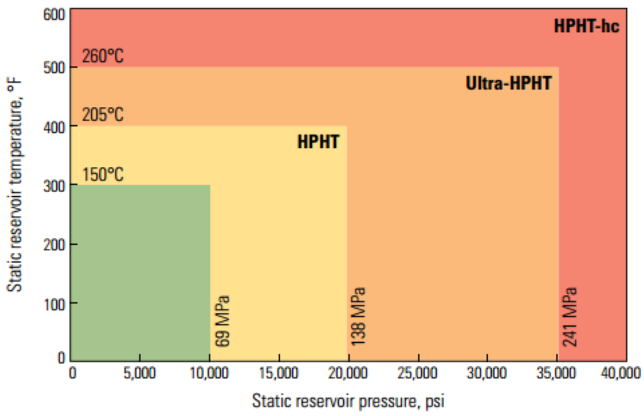

Fig. HPHT classification system

Drilling muds can be classified into three basic types depending upon what their" base" fluid is. They are:

- **Water Based Muds (WBM):** Water is the base fluid and clays and other minerals are added to it to impart specific properties.
- **Oil Based Muds (OBM):** Diesel oil or some other petroleum product is the base fluid.
- **Synthetic Based Muds (SBM):** Synthetic oil is the base fluid, typically used in offshore wells.

HPHT conditions may reach pressures greater than 10,000 psi and temperatures greater than 300 F [1]. Drilling wells at HPHT conditions require a special design, especially for the drilling fluid properties. The drilling fluid should provide a high density (19 ppg or more) and stable rheological properties.

Zhang et al. [2] stated that the drilling fluid should provide stable and optimal rheological properties by providing shear thinning and thixotropic properties. Polymers and nano particles play a vital role in providing stable rheological properties and reducing the filtration of the drilling fluid into the formation [3]. Li et al. [4] evaluate the effect of using cellulose nano particles (CNPs) as a modifier for rheological and filtration properties of bentonite water-based drilling fluid (BT-WBDF). They concluded that adding cellulose nano crystals (CNCs) to the BT-WBDF enhanced the rheological properties, especially at higher temperature, and reduced the fluid loss into the formation, and in addition, the formed filter cake was thin when compared with BT-WBDF. Rasool et al. [5] developed a nano composite of ZnO-interlinked chitosan (Ch) nano particles (CZNCs) as a new biocide. They concluded that the developed green biocide can be used for the oil and gas industry with no impact on the environment.

Barite is the most common weighting materials used to provide the required density for HPHT wells. Barite settling, also known as sagging, is a common issue when using barite as a weighting material to drill HPHT wells [6–8]. Barite sagging causes mud density variations in both vertical and deviated wellbores, but especially in deviated wells. Barite sagging may also lead to many problems such as well control problem, mud losses, stuck pipe, or wellbore instability [9,10].

Sag is often seen when a driller circulates the mud out after a period of tranquil, leading to the confidence that the static settling of mud is the main indicator of barite sagging. Sag occurs in vertical and deviated wells, although potentially happens at angles between 30 –75 in the deviated Section [11–15].

Zamora and Bell [16] stated that a large change of the drilling fluid density might result from dynamic sag. Temple et al. [17] used a low molecular weight polymer to reduce the barite sagging. They concluded that using polyalkyl methacrylate with an average molecular weight ranging from about 40,000 to about 90,000 prevented the barite sagging and at the same time did not cause a change in the rheological properties of the drilling fluid. Dynamic sag can be predicted from the low shear rheological properties [18–20].

Sag factor greater than 0.53, implying that the drilling fluid will create sag tendency, and a change in mud density of the top and bottom greater than 0.5 ppg along the mud column is an indicator of a barite sag occurrence [19].

Sag may occur more rapidly in a fluid that has a weaker gel structure. Sag issues occur under dynamic or static conditions. Dynamic sag is related to low shear viscosity and it can be severe even if there is no static sag issue [21, 22].

Dye et al. [23, 24] reported that at an annular velocity of 100 ft/min, the dynamic barite sag is low. They concluded that at a low shear rate, less than 4 S^{-1}, dynamic sag occurs in deviated wells that are drilled using invert emulsion mud as the well-section angle increases from 45 to 60, in this case, the mud weight has less impact than shear rate viscosity.

Nguyen et al. [25, 26] found that under the static condition, when the yield stress is greater than 12 lb/100 ft^2, no sag occurs. They stated that annular velocity and pipe rotation contribute individually to sag prevention by nearly 60% and 21%, respectively. Bern [27] studied the effect of the annular velocity on barite sag and they found that an annular velocity closer to 30 ft/min motivated barite sagging.

Wagle et al. [28, 29] showed that invert emulsion drilling fluids (IEFs) formulated with nano particles and rheology modifiers (RM) were stable at 250 F and 300 F and exhibited no sag tendency for 9, 12, and 16 ppg drilling fluid density in both vertical and 45 deviated tests. In addition, the HPHT rheology of IEFs showed consistency before and after adding nano particles.

Elkatatny et al. [30, 31] and Al-Bagoury [32] investigated the use of micronized ilmenite as a weighting martial in both water-based mud (WBM) and oil-based mud (OBM). The result showed that micronized ilmenite reduced dynamic sag better than barite with no effect on rheology and HPHT filtration. Mohamed et al. [33] assessed the effect of reducing the barite particles' size to micro-sized and they showed that micronized barite yielded insignificant improvement in preventing sag.

3. RESEARCH METHODOLOGY:

3.1 Materials: The invert emulsion consisted of the subsequent components: diesel (172mL), as a continuous phase; water (50mL), as a dispersed phase; EZ-mul (15 g), as an emulsifier and oil-wetting agent; invermul (11 g), as a number one emulsifier; lime (6 g), as a contaminate remover; geltone II (2 g), as a Viscosifier, that is an organophilic clay used to impart viscosity and suspension residences; calcium chloride (2 g), as a shale inhibitor; calcium carbonate (30 g), as a bridging cloth; RM-63 (1 g), as a Rheology modifier to improve rheological and suspension traits of invert emulsion fluids; and barite (560 g) as a weighting agent. The composition of drilling fluid listed in desk underneath.

Table no.1 Drilling fluid formulation for lab scale, equivalent to 1 bbl.

Additives	Functions	Base fluid	New fluid
Diesel (cm^3)	Continuous phase	172	172
EZ-Mul	Emulsifier and Oil-wetting agent	15	15
Invermul (g)	Primary Emulsifier	11	11
Lime (g)	Contaminate remover	6	6
Geltone II (g)	Viscosifier	2	2
Water (cm^3)	Dispersed phase	50	50
Calcium Chloride-$CaCl_2$ (g)	Shale inhibitor	32	32
Calcium Carbonate (25 micron, g)	Bridging agent	30	30
RM-63 (g)	Rheology modifier	1	1
New Copolymer (g)	Rheology modifier and solid suspension	0	0
Barite (g)	Weighting material	560	560

3.2 Experimental Procedure:

The accompanying system was performed so as to assess the impact of utilizing the copolymer on the alter emulsion drilling liquid properties:

1. Set up the drilling fluid mixture at encompassing temperature;
2. Measure the density and electrical stability at encompassing temperature;
3. Run the static sag test at various temperatures under vertical and decrease circumstances;
4. Run the dynamic hang test utilizing the sag shoe and the rheometer at 120 F and 100 rpm;
5. Run the amplitude sweep test at 350 F to determine the linear elastic region of the fluid;
6. Run the angular frequency test at 350 F to determine the storage modulus of the invert emulsion drilling fluid;
7. Measure the rheological properties over a wide scope of temperatures (200– 400 F);
8. Measure the filtration properties at 400 F and 400 psi differential weight.

3.3 Dynamic Sag Test:

The viscometer list shoe test (VSST) is a well site and lab test to gauge the weight-material list propensity of a field and lab-arranged drilling liquid under powerful conditions. The thought is that the slanted surface of the thermoplastic shoe quickens settling and focuses the weighting material into a solitary gathering admirably at the base of the canteen container, as shown in figure

Fig Equipment for dynamic sag test (VSST excluding the viscometer).

The accompanying methodology is prescribed for the shoe test

1. Addition the list shoe into the thermo container and set up it together on the viscometer plate.
2. Pour the drilling liquid inside the thermo glass and raise it until the upper surface contacts the lower some portion of the viscometer sleeve. At that point bring down the container around 7 mm.
3. Warmth the 140 mL drilling liquid with the hang shoe to 120 ^{0}F ± 2 ^{0}F.
4. Set the viscometer at 100 rpm and begin a 30 min clock.
5. Utilizing the syringe with the cannula, remove a 10 mL test and record the heaviness of the drilling liquid filled syringe, W_1.
6. Stop the viscometer after 30 min and take another example of 10 mL.
7. Record the heaviness of the drilling liquid filled syringe (W_2).

8. Compute the VSST utilizing Equation (1).

$$VSST = 0.833 \times (W_2 - W_1) \; \ldots \; (1)$$

Where, VSST speaks to the viscometer sag shoe test in ppg.

A VSST estimation of 1.0 ppg or less would infer a drilling liquid with the negligible hanging propensity.

VSST esteem above 1.6 ppg would demonstrate the start of a conceivable.

3.4 Rheology and Filtration Tests

In the wake of setting up the drilling liquid, a Grace M5600 HPHT rheometer was utilized for the HPHT Rheology estimations. The test was performed at various temperatures (200, 300, and 400 F) under a wide scope of shear rates going from 5.1 to 1020 S-1. Utilizing the shear pressure information at an alternate shear rate, the rheological properties were resolved, for example, plastic consistency and the yield point. The gel quality was estimated at a low shear rate of 5.1 S-1 at various time spans (10 s and 10 min).

A HPHT channel press was utilized to play out the filtration test for the drilling liquid at 400 F and connected weight of 400 psi. A ceramic disk of 63.5 mm distance across and 6.35 mm thickness was utilized as a filtration medium.

4. RESULTS AND DISCUSSIONS

The invert emulsion drilling fluid was arranged and blended as clarified in Table no 1. The density of drilling fluid was 19 ppg, which demonstrates that this liquid could be utilized for controlling the weight for high-weight wells. The electrical strength at encompassing temperature was 1180 V. In the wake of including 1 lb/bbl of the new copolymer, the thickness and electrical steadiness were estimated again and demonstrated no adjustments in the ir qualities.

4.1 Effect of Temperature on Static Sag Test:

A static vertical list test was performed utilizing a maturing cell with a Teflon liner (Figure 2a). The hang factor of strayed well was assessed utilizing a 45 base setup as delineated in Figure 2b. The drilling fluid was put in the Teflon liner inside the maturing cell. The cell was pressured (400 psi) and heated in a stove for 24 h at 250 F under a static condition, at that point left to chill off and the weight was discharged. Two drilling liquid examples were taken from the top and base of the Teflon liner. The sag factor was calculated using Equation.

$$SF = \rho_{bottom} / (\rho_{bottom} + \rho_{top})$$

Where SF is static sag factor, and ρ_{bottom} and ρ_{top} are the bottom and top drilling fluid densities, respectively.

Fig Basic equipment for static sag test: (a) vertical setup aging cell and (b) 45°setup aging cell.

Figure shows that at 250 F, the sag factor was 0.503 indicating the stability of the drilling fluid and no barite settling occurred. At 300 F, the sag factor increased to 0.530, which is the border of the safe region. At 350 F, the sag factor increased to 0.531, which indicates the start of the instability of the weighting material in the drilling fluid. The sag factor increased to 0.542 at 400 F, which confirmed that at this temperature, the invert emulsion drilling fluid was not stable and could not provide the required suspension for the weighting materials that settled down in the Teflon liner, Figure

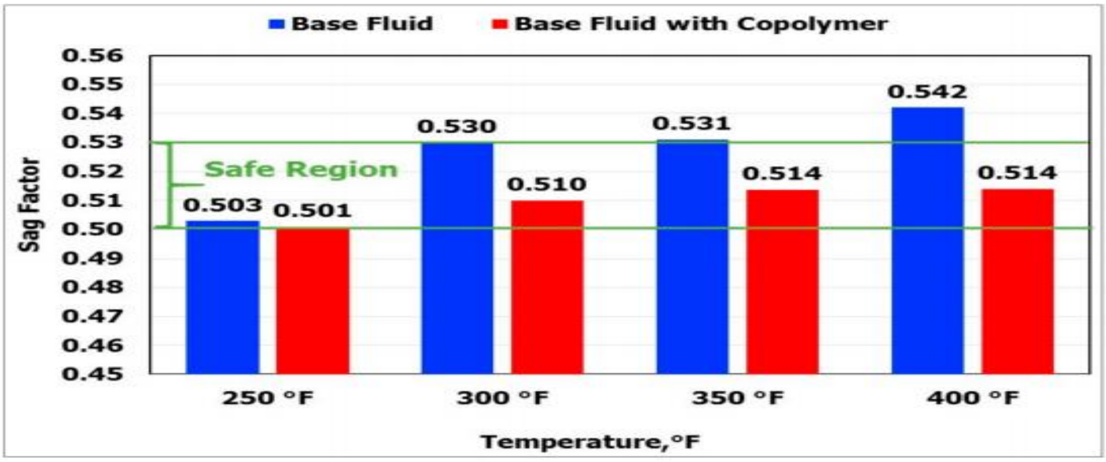

Fig Static vertical sag factor for the drilling fluid with and without the copolymer at different temperatures.

After adding the new copolymer, the static vertical sag test was repeated under the same above-mentioned conditions. Figure shows that the sag factor for the drilling fluid with the copolymer was 0.501 at 250 F. At 300 F, the sag factor increased to 0.51, which is in the safe region. By increasing the temperature to 350 and 400 F, the sag factor for the drilling fluid with the copolymer stayed in the safe region with a constant value of 0.514. These results confirmed that adding the copolymer (1 lb/bbl) enhanced the sag factor for the invert emulsion drilling fluid at a higher temperature (>300 F) for vertical wells.

The static hang factor was determined under static conditions for the base liquid utilizing the slanted position of the maturing cell (45°). Figure 4 demonstrates that the based liquid had a decent strength at a temperature equivalent to or under 300 F where the list factor was in the protected locale. At 350 F, the hang factor expanded to 0.587 affirming the basic condition for the barite drooping. At 400 F, the list factor expanded to 0.611 affirming the requirement for another added substance to keep the barite settling at high temperatures. The list factor was determined, in the wake of including the copolymer, at a scope of temperatures for the slanted setup (45°). Figure 4 demonstrates that adding the new copolymer to the transform emulsion drilling liquid improved its soundness where the list factor stayed in the sheltered area, even at 400 F. The hang factor was 0.531 at 400 F. These outcomes affirmed that including the copolymer (1 lb/bbl) to the drilling liquid improved its suspension properties and averted barite settlement in a slanted position.

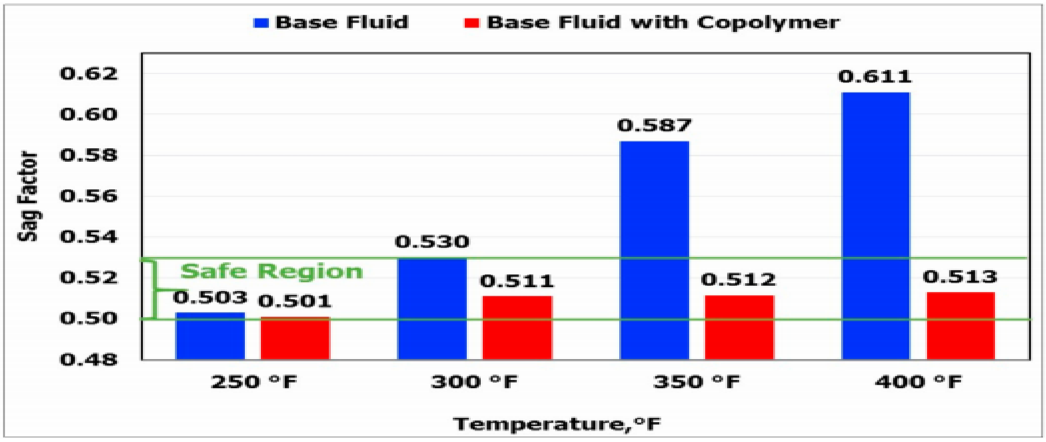

Fig. Static inclined (45°) sag factor under different temperatures for the drilling fluid with and without the copolymer

4.2 DYNAMIC SAG TEST:

The dynamic sag test was performed as explained in the experimental procedure section. Figure 5 shows that the invert emulsion drilling fluid had a viscometer sag shoe test value (VSST) of 1.75 ppg after 30 min of rotation (100 rpm) at 120 F. This result confirms the instability of the suspension property of the invert emulsion under dynamic conditions, where a VSST value greater than 1.6 indicates the occurrence of settling.

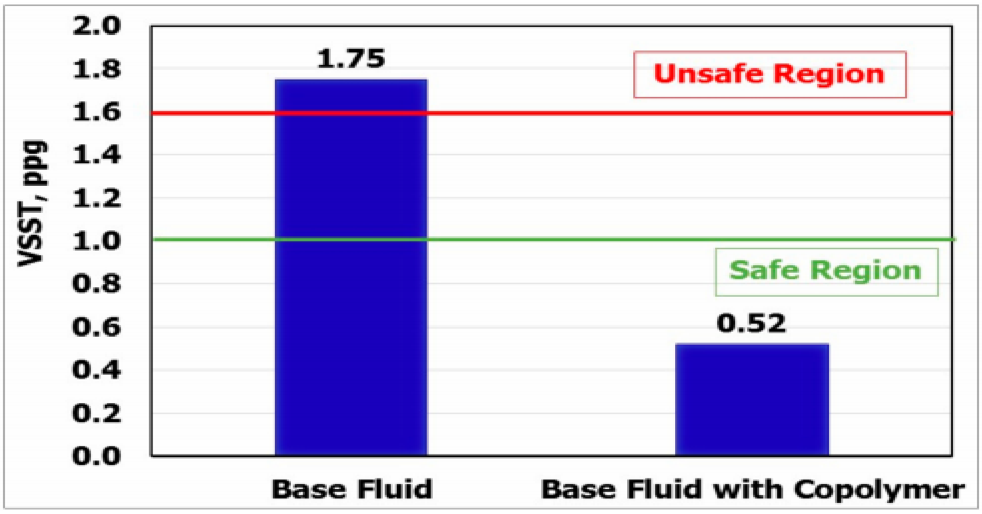

Fig Dynamic sag test for the drilling fluid with and without the copolymer.

The dynamic sag test was repeated after adding the copolymer with invert emulsion drilling fluid. Figure shows that the VSST value was 0.52 ppg after 30 min of rotation (100 rpm) at 120 F. This result confirms the stability of the drilling fluid after adding the copolymer, where a VSST value less than 1 ppg indicates a minimal sag tendency.

Conclusion:

The broad research facility tests were directed to decide the impact of utilizing another copolymer on the solidness and the rheological properties of the modify emulsion drilling liquid for HPHT applications. In light of the got outcomes, the accompanying ends can be drawn:

1. Including the copolymer (1 lb/bbl) had no impact on the thickness and electrical solidness of the upset emulsion drilling liquid.
2. The hang issue was killed under static and dynamic conditions for both vertical and slanted borehole areas in the wake of including the copolymer.

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