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Novel Dispersant for Enhanced Rheology Control in High-Temperature High-Density Water-Based Drilling Fluids

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Abstract

Drilling operations often require high-density drilling fluids to counter high downhole pressures. These fluids require large amounts of weighting agents to achieve the density target, resulting in undesired rheological properties such as elevated plastic viscosity and yield point. This study aims to address these challenges without relying on expensive heavy brines and weighting materials.

The research focuses on the development of a high temperature (HT) dispersant designed to stabilize high-density high-temperature water-based drilling fluids. Extensive laboratory testing revealed promising results. The new HT dispersant demonstrated great stability at elevated temperatures, enduring conditions above 350°F. It also proved effective at reducing viscosity in high-barite environments, accommodating concentrations of up to 550 lb/bbl. The HT dispersant's compatibility with saturated NaCl brines enhances its versatility for various drilling conditions and has outperformed existing dispersants by facilitating the dispersion of larger quantities of barite with minimal impact on polymer viscosity, mitigating sag concerns.

This study is based on laboratory findings, and field tests are necessary and being planned to validate the new HT dispersant's performance in barite-laden, high-temperature water-based drilling fluids. In conclusion, the new HT dispersant presents a promising solution for formulating high-density drilling fluids, potentially improving efficiency and cost-effectiveness in drilling operations.

Introduction

In drilling operations, particularly in the Middle East market, the prevalence of high-temperature, high-pressure (HTHP) wells pose significant challenges. These wells, characterized by temperatures exceeding 300°F, demand fluids capable of withstanding extreme conditions to ensure operational efficiency and safety. Conventional water-based fluids, relying on biopolymers, falter beyond this threshold, leading to fluid degradation and wellbore instability. Synthetic polymer-based fluids offer resilience to elevated temperatures, yet the intersection of high temperature and high pressure necessitates high-density fluids for effective compensation (Panamarathupalayam et al., 2019). Achieving densities above 15.0 lb/gal, critical for HTHP wells, involves a delicate balance of brines and weighting materials, while cost considerations drive the utilization of conventional brines such as NaCl and weighting materials such as barite. However, the challenge lies in maintaining cost-effectiveness while ensuring optimal fluid density and rheological properties. This paper addresses these challenges by introducing a newly developed HT dispersant to solve the high-density problem for high-temperature water-based drilling fluid systems.

Effects of Solids/Weighting Materials

It is well known that water-based drilling fluids are more sensitive to solids contamination than oil/synthetic based fluids (Amanullah, 2016), whether it's low gravity solids picked up while drilling or weighting agents added to the fluid to increase density (Joel et al., 2012). The excessive increase in viscosity associated with high solids content used to achieve high densities often renders the water-based fluid unusable due to poor rheological profiles. Common solutions include the use of high-density brines as the base fluid to decrease the amount of weighting materials needed (Howard, 1995), or to use a higher specific gravity weighting material to reduce the concentration (Abdou et al., 2018; Sindi et al., 2019; Bageri et al., 2021). Though effective, these techniques are often associated with higher costs and confine the use of high-density water-based fluids to specialty wells. Therefore, there is a need to explore economical options to build these high-density fluids to not only expand the usage of water-based fluids, but also make it an attractive replacement to traditionally used oil/synthetic based fluids for wells that require high density fluids. The focus of this study will then be to design a high-density water-based fluid, defined as at or above 15 lb/gal, using common and cost-effective oilfield chemicals such as NaCl brine and barite for density.

First, the impact of weighting materials on rheology must be characterized. A high-temperature polymer water-based fluid was used to illustrate the detrimental effects of excessive solids content on rheology, shown in Table 1. The formulation contains only necessary additives and uses saturated NaCl brine (10 lb/gal) for maximum density and limits the amount of barite needed. Barite is then added to achieve densities ranging from 15 lb/gal – 19 lb/gal.

Table 1. 15 lb/gal to 19 lb/gal Water-Based Fluid Formulation

Components	Concentration (lb/bbl)
10 lb/gal NaCl Brine	332 - 264
Defoamer	0.35
HT Polymer	5
Organic pH Buffer	4
Barite	309 - 545

Figure 1 shows the rheology measured at 120ºF with a direct-indicating viscometer, specifically plastic viscosity (PV) and yield point (YP) values as the fluid density increases. The components in the formulation remained the same for all densities from 15 lb/gal to 19 lb/gal except for the NaCl brine and barite concentration. The liquid fraction of the fluid, or the amount of NaCl brine, is reduced as density increases to accommodate larger volumes of barite needed to achieve the final density.

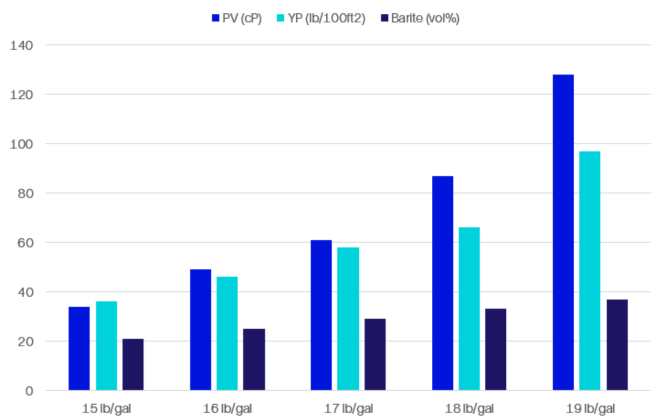

Figure 1. PV and YP values of 15 lb/gal to 19 lb/gal water-based fluid with 10 lb/gal NaCl base brine and barite.

The fluid rheology increased exponentially as density increased, especially above 18 lb/gal. Typical acceptable values of YP is < 40 lb/100ft^2 and PV as low as possible for optimal fluid performance. As shown, the PV and YP values for densities above 15 lb/gal far exceed the tolerance due to both decreased liquid fraction (NaCl brine) in the fluid to accommodate more weighting material (barite), but also the effects of increasing the solids fraction. The results show that a high-density water-based fluid with good rheological properties cannot be formulated simply by adding barite to low density brines at fluid densities above 15 lb/gal.

High-Temperature Dispersant

Maintaining constant fluid density throughout the well construction cycle is one of the most important criteria. This implies that the amount of weighting material and/or brine weight must be held constant and cannot be reduced. As seen in the previous section, cost-effective solutions do not yield ideal rheological profiles at densities above 15 lb/gal. As such, another method was attempted to address the high viscosity issue associated with high-density water-based fluids.

Thinners, or dispersants, can be added to the drilling fluid to reduce viscosity contributed by the polymer used for solids suspension or weighting material used for fluid density. There are various types of dispersants that target different components in the drilling fluid, such as clay deflocculation through charge repulsion or static hinderance to reduce interaction between solids, polymer, or the combination of both. As most wells that require high-density fluids often have bottom hole temperatures exceeding 300ºF, a synthetic polymer water-based fluid capable of withstanding high temperatures, such as the one shown in Table 1, was used to validate the newly developed HT dispersant. Continuing with the objective of keeping the drilling fluid cost low, NaCl brine and barite will be used for density. Therefore, the HT dispersant must (1) reduce fluid viscosity without negative impacts such as poor fluid loss control, (2) remain stable at temperatures above 300ºF, (3) tolerate high salinity conditions, and (4) outperform current available dispersants.

Screening

The newly developed HT dispersant was compared to other available dispersants in the market. Table 2 shows the formulation used in this study. A 16 lb/gal high-temperature water-based fluid was formulated, then 1 vol% active equivalent of dispersant was added to the fluid before comparing the percent reduction in viscosity.

Table 2. 16 lb/gal Water-Based Fluid Formulation Used for Dispersant Screening

Components	Concentration (lb/bbl)
10 lb/gal NaCl Brine	303.1
Defoamer	0.35
HT Polymer	5
Organic pH Buffer	6
Barite	357.3
Dispersant	1 vol% active equivalent

Six different dispersants were compared to the new proprietary HT dispersant. Dispersants 1 and 2 are anionic polyacrylate thinners, Dispersant 3 is sodium styrene sulfonate, Dispersant 4 is ethoxylated sulfate surfactant, Dispersant 5 is sodium xylenesulfonate and Dispersant 6 is sodium pyrophosphate. Dispersants such as lignite and lignosulfonates were not considered due to incompatibility with high salinity environments. Figure 2 shows the change in PV, YP and low-shear yield point (LSYP) after adding dispersants to the fluid. For simplicity, lower PV indicates reduced solids interaction and lower YP and LSYP indicate reduced chemical interaction. The results show that only the HT dispersant, Dispersant 2 and Dispersant 5 decreased overall rheology – PV, YP and LSYP, while the other dispersants did not reduce all three or contributed to PV, YP or LSYP gain after the addition. The HT dispersant provided the largest reduction in YP, LSYP and especially PV.

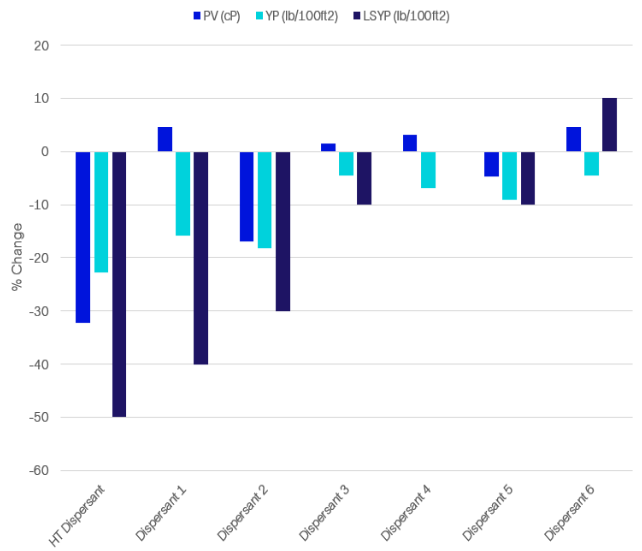

Figure 2. PV, YP, and LSYP % reduction after adding 1 vol% active equivalent dispersant into 16 lb/gal water-based fluid.

Temperature Stability and Salt Compatibility

After verifying the HT dispersant's viscosity reduction performance, the salt tolerance and thermal stability were examined. The same 16 lb/gal water-based fluid, shown in Table 2, was used for this experiment. The formulation contains high salinity NaCl brine (25 wt%) and large amounts of barite. The formulation was selected to ensure the HT dispersant itself can tolerate high salt conditions and to check its viscosity reduction performance after subjecting it to high temperatures. Two samples were prepared, one without any dispersant as the reference and one with 1 vol% active equivalent of HT dispersant added. The rheology was checked at 120ºF before and after dynamic aging at 350ºF for 16 hours. HTHP fluid loss was also performed after dynamic aging at 500 psi overbalance and 350ºF for 30 minutes on filter paper. Figure 3 shows the 16 lb/gal water-based fluid properties with and without dispersant before and after dynamic aging at 350ºF.

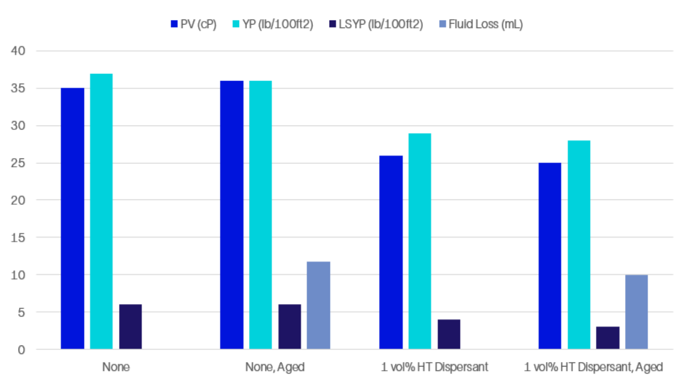

Figure 3. 16 lb/gal water-based fluid properties with and without 1 vol% HT dispersant, before and after dynamic aging at 350°F.

The HT dispersant was able to fully disperse in the fluid when added initially and remained dispersed after dynamic aging for 16 hours at 350ºF. Both high salinity and high temperature did not affect the HT dispersant's performance as the PV, YP, and LSYP values were still lower compared to the fluid without dispersants before and after aging. Fluid loss performance of the water-based fluid was not impacted and in fact showed minor improvements with the addition of the HT dispersant.

Limitations of Current Polymeric Dispersants

Once the HT dispersant's tolerance to high salinity, high temperature and performance without negative impacts such as fluid loss control was confirmed, the next step was to compare it to currently available polymeric dispersants. The goal is to examine if current available polymeric dispersants can reduce viscosity enough to make NaCl brine/barite high-density water-based fluids viable and compare that with the HT dispersant. From Figure 2, the HT dispersant and Dispersant 2 performed best in terms of overall PV, YP and LSYP reduction. A 19 lb/gal water-based fluid built with NaCl and barite with high PV, YP, and LSYP values were used as an example to showcase the performance of the HT dispersant and the dispersant currently in use (Dispersant 2). HT dispersant and Dispersant 2 were added to the 19 lb/gal fluid at 1 vol% active equivalent increments up to 4 vol% active equivalents. Figure 4 shows the PV and YP value difference between the HT dispersant and Dispersant 2 at various concentrations.

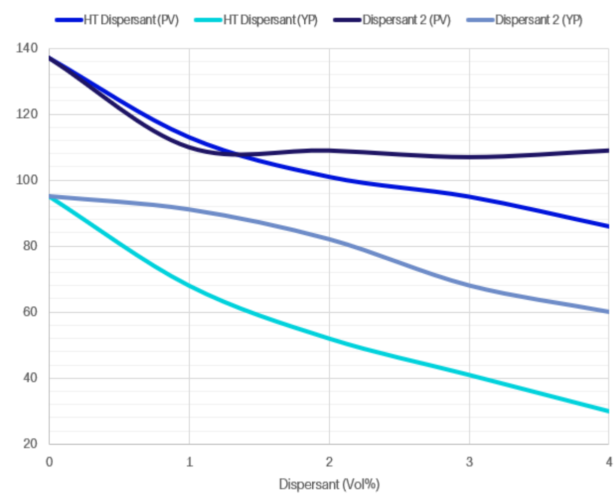

Figure 4. 19 lb/gal water-based fluid properties with HT dispersant and Dispersant 2.

As seen in Figure 4, Dispersant 2's ability to reduce PV diminishes as there were no change at concentrations past 2 vol%. On the contrary, the HT dispersant was able to continue reducing both PV and YP with increasing concentration. The data shows that the current "best" polymeric dispersant evaluated in this study (Figure 2) has limitations and may not reduce viscosity enough to formulate ultra-high-density fluids using only NaCl brine and barite. Nevertheless, the PV values of the formulation with HT dispersant still exceed what is acceptable for drilling, suggesting more work must be done to optimize its use in extreme cases such as 19 lb/gal or heavier fluids.

Example Formulations

Lastly, the HT dispersant's performance and readiness for field introduction were validated in the lab with actual high-density water-based fluid requests. Most designs requested range from 15 – 18 lb/gal and utilize NaCl brine with barite as the weighting agent.

Table 3 shows a 15.5 lb/gal high temperature water-based design and its properties after aging for 16 hours at 355°F. Comparing to reference PV and YP values without HT dispersant of 15 lb/gal fluid at 34 and 36 and 16 lb/gal fluid at 49 and 46, respectively, as shown in Figure 1, the 15.5 lb/gal fluid formulated with HT dispersant demonstrated significant improvement in YP value.

Table 3. 15.5 lb/gal Water-Based Fluid Design and Properties

Components	Concentration (lb/bbl)
Water	216.9
NaCl, dry	77.28
Defoamer	0.5
Soda Ash	0.5
HT Polymer	5
Organic pH Buffer	6
Shale Stabilizer	8
Oxygen Scavenger	1
Fluid Loss Additive	7
Barite	328
HT Dispersant	2.5 vol%
Properties after 16-hour dynamic aging at 355ºF	
PV (cP)	41
YP (lb/100ft^2)	22
LSYP (lb/100ft^2)	5
HTHP Fluid Loss (mL)	8

Table 4 shows an 18.3 lb/gal high temperature water-based design and its properties after aging for 16 hours at 325°F. The HT dispersant provided significant improvement in fluid viscosity (i.e., greater than 30% reductions) when compared to reference 18 lb/gal fluid with PV and YP values at 87 and 66, shown in Figure 1.

These example formulations confirm that the newly developed HT dispersant (1) is capable of reducing fluid viscosity without impacting fluid loss control and other fluid properties, (2) exhibits temperature stability above 300ºF, (3) works in high salinity conditions, and (4) outperform those existing dispersants normally used in the industry. Even though the extreme cases such as 19 lb/gal or heavier fluids may require additional work and optimization, the HT dispersant demonstrates feasibility up to 18.3 lb/gal water-based drilling fluid.

Table 4. 18.3 lb/gal Water-Based Fluid Design and Properties

Components	Concentration (lb/bbl)
Water	190.05
NaCl, dry	66.50
Defoamer	0.5
Soda Ash	0.5
HT Polymer	4.75
Organic pH Buffer	4
Fluid Loss Additive	6
Barite	490
HT Dispersant	2 vol%
Properties after 16-hour dynamic aging at 325°F	
PV (cP)	59
YP (lb/100ft^2)	42
LSYP (lb/100ft^2)	8
HTHP Fluid Loss (mL)	10.5

Conclusions

- The newly developed HT dispersant provided the best reduction in viscosity as seen by decreases in PV, YP and LSYP when compared to conventional dispersants.
- No negative impact on fluid properties, such as fluid loss, were observed when using the HT dispersant.
- The HT dispersant can be used in high salinity NaCl brines and withstand temperatures above 350°F.
- High-density water-based fluids with good rheological properties can be formulated up to 18.3 lb/gal without relying on costly heavy brines or high specific gravity weighting materials when using the HT dispersant.
- Field readiness of the HT dispersant has been validated in the lab and ready for deployment, potentially increasing water-based fluid usage.

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