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Advancements in Oil-in-Brine Direct Emulsion Drilling Fluids: Field Trial Success and Performance Improvements in West Texas

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Abstract

Oil in Brine direct emulsion drilling fluids are utilized when drilling formations with high potential of water/brine influx from the salt formation. Forming a direct emulsion in saturated NaCl brine that also contains divalent ions is extremely challenging. Typically, the industry relies on excessive viscosity to stabilize a direct emulsion which leads to entrapped air in the fluid, foaming, and excessive corrosion.

We have developed a commercially successful product that is able to stabilize oil-in-brine emulsion without excess viscosity and concomitant issues brought on by a thicker fluid. This direct emulsion fluid has been successfully used in New Mexico and West Texas in 22 wells with BHST of 180°F. Additional benefits of our direct emulsifier include a built-in future potential for simple separation of water and oil with potential for oil recycle for reduced carbon emissions.

In this paper we will compare first version of direct emulsion with the second version from the field and present solutions related to improvements in emulsifier based on the feedback from the operations teams in West Texas.

Introduction

Continuous improvement of drilling fluids system is imperative for the sustainability of our industry and business. By means of improving existing systems, drilling operations can become more efficient and stable thus reducing the overall costs to drill the target zone.

Formation of a stable direct emulsion without excessive addition of viscosifier is challenging in saturated brines. There are commercial product offerings that claim to be able to stabilize direct emulsion. These products are based on sulfonated asphalt chemistry. However, these additives do not appear to be stable and have resulted in brine/diesel separation after shear in less than 20 minutes. The separation is often masked due to the dark coloration of such systems and requires backlighting for accurate reading (Figure 1). Our second generation emulsifier significantly exceeds the stability relative to alternative products on the market.

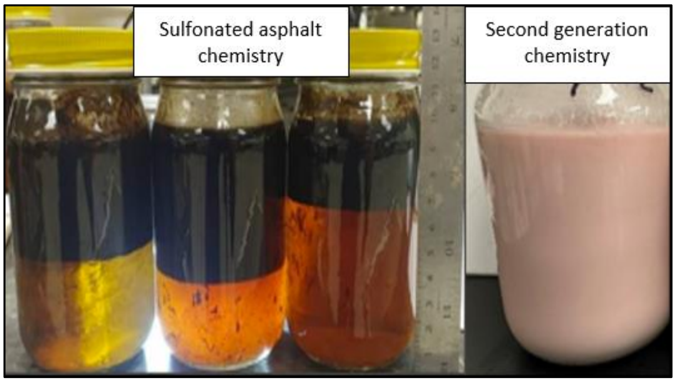

Figure 1. Brine/diesel separation using sulfonated asphalt chemistry compared to second generation chemistry.

The first generation direct emulsion water-based mud (DEWBM) system was introduced as an alternative to conventional water-based mud (WBM) systems, saturated NaCl field brine water-based systems and oil-based mud (OBM) systems. The latter systems both come with their inherent advantages and disadvantages. Freshwater WBM systems saturate to 10.0 lbm/gal when drilling through the salt formations. In combination with when freshwater is required to control mud weight (MW), the system is diluted and thus, drilling through salt formation, causes substantial washout, up to 40% in some circumstances. As a result, cement jobs become more challenging. With OBM, the cost is inherently high. In the Permian basin, the increased likelihood of water influxes can be costly to the system itself requiring substantial treatments, with catastrophic increases to treatment and overall costs, especially if the fluid is no longer usable and disposal is required. Thus, the previous generation of DEWBM system was introduced as a solution to both cost and performance, giving balance between both (Hoelscher et al., 2019).

After the first generation system was field trialed, though it displayed effective and generally good performance, several learnings were documented. Improvements were made on several aspects. Foaming proved a challenge and was addressed. A mechanical emulsion stabilizer (in the form of a viscosifier) was used in the first generation system but this led to potentially entrapping air when coupled with foaming. This aspect was improved such that a viscosifier is no longer required since the second generation system maintains stability strictly with the oil-in-water emulsifier package and contributing to a naturally lower viscosity system. Overall, the system still performs in high calcium contaminated environments and is highly tolerant to water influxes and solids intrusion (Smith et al., 2023).

Direct Emulsion Drilling Fluid

The profound necessity to utilize a drilling fluid that maintains functional stability while having water influx events, tolerate low gravity solids, and minimize washout of salt formations all while maintaining desirable rheology without promoting air entrapment and corrosion is evident. With these challenges being faced in the Permian Basin, an enhanced direct emulsion fluid system was developed. The first generation of direct emulsion systems were used in the region and globally, however, with the challenges cascading as below:

- Foaming
- Entrapped air
- Excessive corrosion
- Intolerance to solids

Field Trial in Permian Basin

The second generation DEWBM was field trialed near Carlsbad, New Mexico, drilling the 9 7/8” intermediate section which had a length of approximately 10,300 ft on the well selected. This area was ideal since the formation was susceptible to losses and water influx events and drilling through a plethora of lithologies including salt zones, anhydrite, sandstone, limestone and shale.

The technical objectives for the field trial of the second generation DEWBM were:

- Convert seed fluid from previous well to the second generation system using an initial concentration of 6.0 lbm/bbl second generation emulsifier
- Build second generation DEWBM on the rig
- Drill 9 7/8” section to TD with comparable ROP without any fluid related issues
- Run 7 5/8” casing to desired depth and perform cement job with no issues
- Maintain emulsion stability during drilling and casing running with no phase separation
- Maintain target mud weight per request without any fluid related restrictions
- No foaming and air entrapment (< 0.3 lbm/gal variance between atmospheric and pressurized mud balance readings in tandem) with a target of zero concentration of defoaming agents
- Maintain rheology in specification as drill solids are incorporated when drilling ahead
- Able to easily handle and treat water influx from formation while drilling
- Optimize solids control equipment (SCE) by screen sizes and centrifuge speeds
- No corrosion issue on drill string or downhole tools
- No HSE concerns or issues

The second generation DEWBM was mixed on site using a blend of other fluid providers seed fluid and a combination of 6.0 lbm/bbl second generation emulsifier and 1.0 lbm/bbl Lime. Additional batches were treated with 4.0 lbm/bbl second generation emulsifier and 1.0 lbm/bbl Lime during drilling operations. The Brine to Oil ratio (BOR) of the seed fluid was 42:58. Furthermore, a neat volume of second generation DEWBM was built on location using field brine (10.0 lbm/gal) with 6.0lbm/bbl second generation emulsifier and 1.0 lbm/bbl Lime. An initial density of 8.9 lbm/gal was targeted and achieved.

No foaming or entrapped air was experienced with the second generation DEWBM both visually and by measurement, and by extension, required no defoaming agents. This was a significant challenge faced with the first generation system since it could lead to inaccurate MW, pump cavitation and corrosion. When comparing tandem MW measurements using the atmospheric and pressurized mud balance, all checks showed no variation > 0.1 lbm/gal in the second generation system whereas the first generation system showed delta densities consistently > 0.3 lbm/gal and as high as 0.7 lbm/gal (Figure 2).

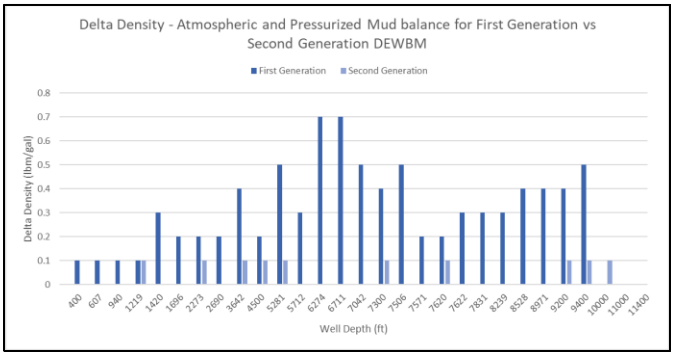

Figure 2. Delta density between atmospheric and pressurized mud balances for first generation and second generation DEWBM.

The fluid in the pits showed no sign of instability i.e. diesel coalescence on surface or brine separation. With the first generation DEWBM, there was an instance of diesel coalescence when an LCM pill was mixed, however, the same was not observed for the second generation using a comparable LCM formulation (Figure 3).

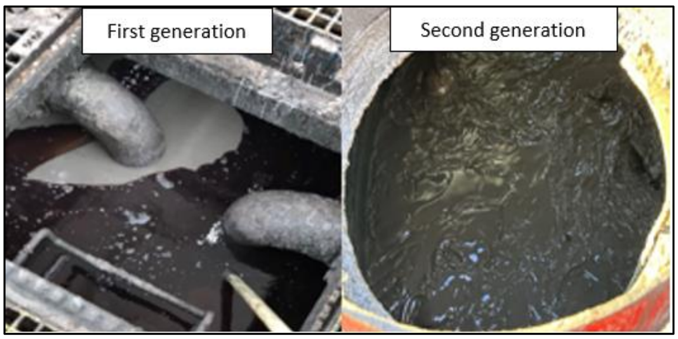

Figure 3. DEWBM LCM pill for both generations.

As drilling progressed and dilution of the system occurred coupled with a water influx, the emulsifier concentration was allowed to reduce from 6.0 lbm/bbl. Stability was maintained up to a minimum of 3.4 lbm/bbl (Figure 4). These samples were placed on the bench at room temperature for a 24 hr period. There was no issue observed with stability or rheological properties when the system was weighted to 13.0 and 14.1 lbm/gal with API barite for trip slugs.

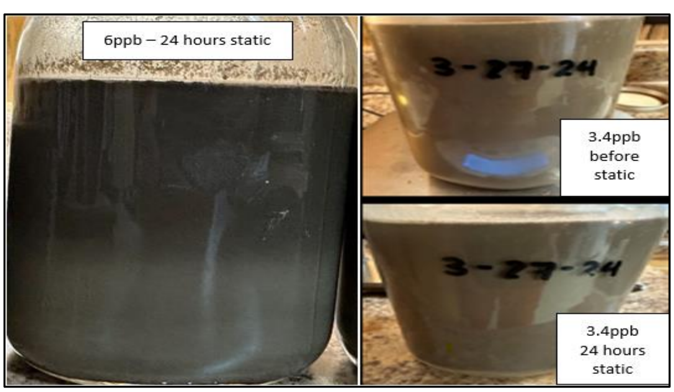

Figure 4. Bench test of fluid stability of DEWBM for concentration range and 24 hr room temperature static age.

The average volume of water influx was measured at over 125 barrels (bbls) on this well, which is substantially lower than the field trials carried out with the first generation system where 1,500 bbls was taken in on average. During all the water influxes across field trials, the emulsion stability remained stable, and no free oil was observed in the pits.

The neat batches of the second generation system showed lower PV (57%) and YP (80%) than the first generation (Table 1). This is a direct result of not requiring a viscosifier to assist with maintaining fluid stability.

Table 1. Comparison of PV, YP reduction between first and second generation neat DEWBM due to no viscosity requirement for fluid stability in second generation.

Properties	Units	First generation	Second generation	Reduction (%)
MW@Temp	lbm/gal	9.5@ 70	8.9@ 70	6
Rheology Temp	°F	120	120	-
R600/R300	Dial	24/17	8/5	67/70
R6/R3	Dial	4/3	1/0	75/30
PV	cP	7	3	57
YP	lb./100 ft²	10	2	80
BOR	-	88.1/11.9	58/42	-

The second generation system displayed lower PV (64%) and YP (43%) rheology than the first generation system after displacement (Table 2) and throughout drilling. At end of drilling (Table 3), the rheological profile was similar, but the BOR was also lower compared to the first generation system. Thus, with a higher concentration of diesel as well as viscosity from the seed fluid, it was still capable of displaying similar PV, but 42% lower YP attributes. The overall lower rheology of the fluid combined with optimum hole cleaning, allowed the shakers to utilize up to API 170 screens, which had initial coverage of 75% and decreased to 20% showing unproven potential to utilize higher API screens. The centrifuges were run at full speed to remove low gravity solids without separating the emulsion and diesel dilution was used, both with the aim of offsetting increase in MW due to drill solids incorporation. Additionally, the fluid loss was maintained lower than the previous system, however, as the concentration reduced to 3.0 lbm/bbl, there was a marked increase which produced fluid loss values like the previous generation system.

Though both generations of the DEWBM displayed high tolerance to calcium contamination, the second generation system showed tolerance up to 12,000 mg/l with no effect on the system. Neither accretion nor bit balling was observed on trips to surface due to non-fluid issues and on completion of the interval. As well, no corrosion was recorded. Casing was run without incident and the cement jobs were confirmed to surface with excess. The cost of drilling saw significant reduction, decreasing by 56% when compared to the previous field trial.

Table 2. Properties of first and second generation DEWBM after displacement.

Properties	Units	First generation	Second generation
MW@Temp	lbm/gal	9.8 @ 70	9.2 @ 90
Rheology Temp	°F	120	120
R600/R300	Dial	34/22	23/15
R200/R100	Dial	17/14	11/7
R6/R3	Dial	3/2	4/3
PV	cP	12	8
YP	lb./100 ft²	12	7
Gels- 10sec/10min/30min	lb./100 ft²	5/6/7	4/5/5
API Fluid Loss	cc/30 min	10.8	25.0
Cake API	1/32"	2	2
pH@Temp in °F	pH unit	9.0 @ 70	11.0 @ 70
Total Hardness (as Ca^{2+})	mg/L	8,920	12,000
Chloride	mg/L	188,000	160,000
BOR	-	52/48	46.1/53.9

Table 3. Properties of first and second generation DEWBM at end of drilling.

Properties	Units	First generation	Second generation
MW@Temp	lbm/gal	9.6 @ 70	8.9 @ 85
Rheology Temp	°F	120	120
R600/R300	Dial	36/25	16/12
R200/R100	Dial	21/16	8/6
R6/R3	Dial	6/5	4/3
PV	cP	11	4
YP	lb./100 ft²	14	8
Gels- 10sec/10min	lb./100 ft²	5/6	4/5
API Fluid Loss	cc/30 min	3.6	9.0
Cake API	1/32"	1	2
pH@Temp in °F	pH unit	9.5 @ 70	12.0 @ 70
Total Hardness (as Ca^{2+})	mg/L	2,800	2,700
Chloride	mg/L	188,000	155,000
BOR	-	17.4/82.6	58/42

Conclusion

- The second generation DEWBF showed better performance than the first generation by way of no foaming issues, no entrapped air, a steady rheological profile with 50% lower PV and 35% lower YP for comparable MWs and lower BOR
- Stable emulsion achieved in the second generation system despite introduced solids such as API barite and LCM as well as contaminants such as water influxes and drill solids
- Both systems perform well in the presence of high calcium concentrations
- Potential to increase SCE with higher API shakers screens
- The ROP and torque are similar between both systems
- Decreased drilling cost by 56%

Definitions

NaCl = Sodium Chloride
°F = Degrees Fahrenheit
h = hours
DEWBM = Direct emulsion water-based mud
BOR = Brine-oil ratio
lbm/gal = pounds per gallon
lbm/bbl = pounds per barrel
LGS = Low-gravity solids
HSE = Health, Safety, and Environmental
PV = Plastic viscosity
YP = Yield point
MW = Mud weight
Temp = Temperature

References

1. Hoelscher, K. P., Zhang, J., Smith, J., Huang, W., McLeod, M., & Rabon, C. J. (2019). Direct Emulsion Fluid Improves Performance and Reduces Cost in the Permian Basin. *American Association of Drilling Engineers*.
2. Smith, J., Foster, L., & Khramov, D. (2023). Low-Viscosity, Direct- Emulsion Drilling Fluid Addresses Conventional Emulsion System Limitations. *American Association of Drilling Engineers*.

Appendix

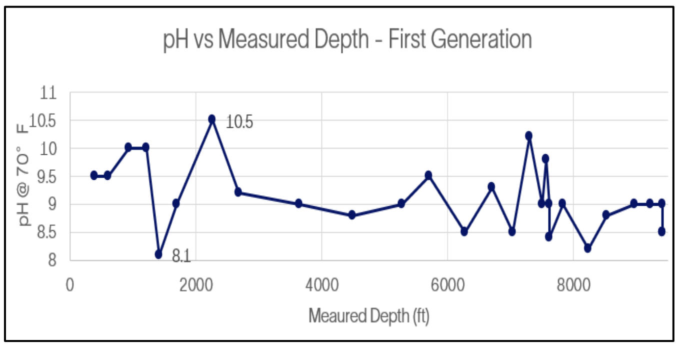

Figure 5. DEWBM first generation pH vs Measured Depth

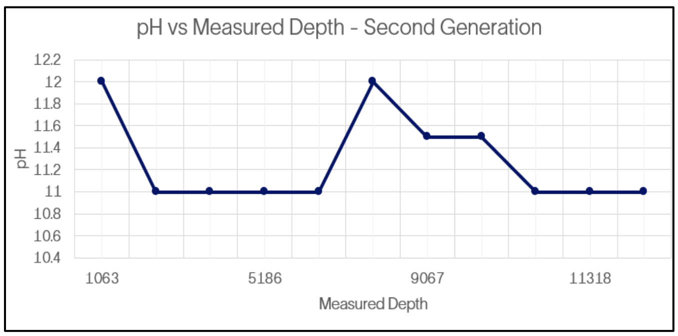

Figure 6. DEWBM second generation pH vs Measured Depth

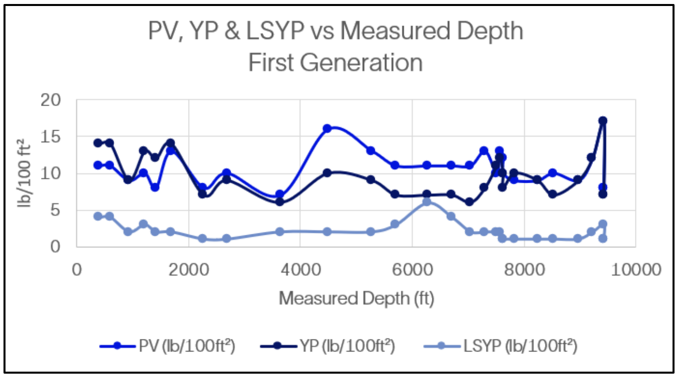

Figure 7. DEWBM first generation PV, YP, LSYP vs Measured Depth

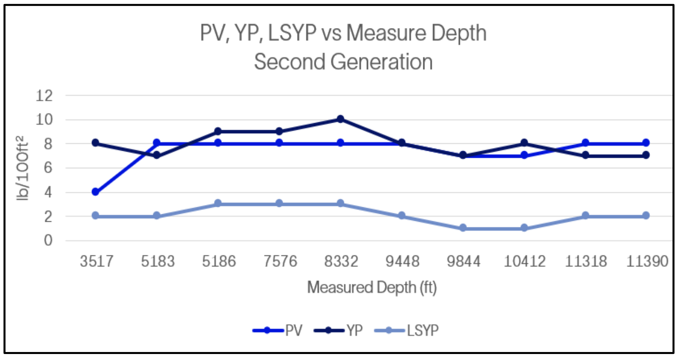

Figure 8. DEWBM second generation PV, YP, LSYP vs Measured