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A New Low-Solids, Brine-Based, HP/HT Fluid for Well Testing

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Abstract

Transient pressure measurement is an important evaluation tool used for determining asset potential and economic viability as well as valuable information for reservoir management. Clear brines are generally used in these well testing fluids. For high pressure/high temperature (HP/HT) wells, very high-density brines, such as cesium formate and zinc bromide, need to be used. These brines, however, are either very expensive or have significant health, safety, and environment (HSE) impact.

This paper presents the results of the first field application of a new low-solids, brine-based, clay-free fluid system designed for well testing in HP/HT conditions. The fluid used a calcium bromide brine (14.2 ppg) as the base fluid, and micronized manganese tetroxide as the weighting agent to achieve the desired fluid density. A newly developed synthetic polymer, stable at high temperatures in divalent brines, was selected as the rheology modifier to mitigate solid settling at high temperatures during predictably long static periods.

The well was displaced with the newly designed high performance completion fluid and well testing objectives were successfully achieved. Downhole tools operated without any disruption, indicating that the fluid permitted undisturbed pressure propagation. Although unplanned delays were experienced during operations and the fluid remained in the well for a total of 25 days, the fluid remarkably showed stable density and no indication of solids settlement.

Introduction

Well testing provides important information on the reservoir and is usually performed for exploration and producing wells. A clear brine fluid is generally preferred to ensure unimpeded pressure transmission to operate downhole tools. The brines can be either monovalent brines, such as sodium chloride (NaCl), potassium chloride (KCl), sodium bromide (NaBr), and formate brines (sodium, potassium, and cesium formates), or divalent brines, such as calcium chloride ($CaCl_2$), calcium bromide ($CaBr_2$), and zinc bromide ($ZnBr_2$) brine. Table 1 shows the maximum density of different brines that are used in the field. The maximum density is lower than the maximum density at room temperature because of the requirement in true crystallization temperature (TCT). This is especially important for deep-water wells. For instance, $CaBr_2$ can reach a density of 15.2 ppg at room temperature but is generally used at a density of 14.2 ppg because of its low TCT (10°F versus 70°F).

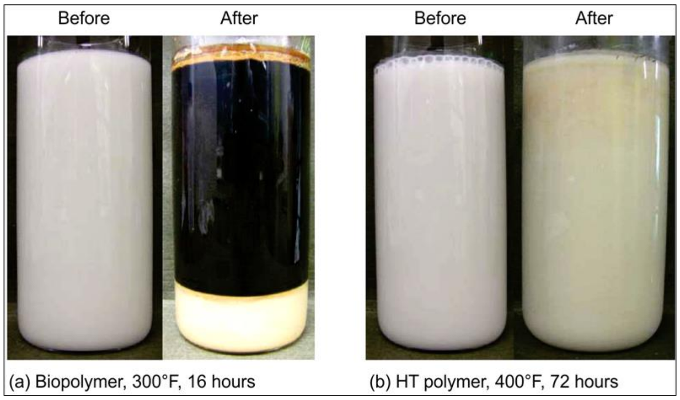
Table 1. Densities of various brines that are used in the field

Salts	Density (ppg)	SG	TCT (°F)
Potassium chloride (KCl)	9.5	1.14	18
Sodium chloride (NaCl)	10.0	1.20	25
Sodium bromide (NaBr)	12.5	1.50	45
Calcium chloride ($CaCl_2$)	11.6	1.39	44
Calcium bromide ($CaBr_2$)	14.2	1.70	10
Zinc bromide ($ZnBr_2$)	19.2	2.30	16
Cesium formate (HCOOCs)	19.2	2.30	62

As operators drill into deeper wells, high density well testing fluids (> 14.5 ppg) are needed for pressure control. As shown in Table 1, there are only two brines, $ZnBr_2$ and cesium formate, that can reach a density of 19.2 ppg. These two brines, however, have their own issues. For instance, $ZnBr_2$ is acidic and has significant corrosion and HSE issues, and cesium formate is so expensive that it must be rented, and the cost of renting the cesium formate brine is higher than $CaBr_2$ brine. Therefore, there is a need for low-cost well testing fluids based on $CaBr_2$ brine that can achieve densities of at least 14.5 ppg.

Solids can be added to $CaBr_2$ brine to increase the density. The solids, however, need to be kept suspended in the base brine during operation to prevent them from settling down, as this can cause well plugging and impede pressure transmission. Typical biopolymeric viscosifiers, such as xanthan gum, diutan, and crosslinked starch, can provide excellent suspension of the solids, but they have thermal stability issues at temperatures above 300°F, and the majority of these deep wells also have high bottom hole temperatures (BHT) up to 400°F.

In recent years, crosslinked synthetic polymers have been developed as viscosifiers and fluid loss control additives for HP/HT wells (Zhou et al. 2015a, Zhou et al. 2015b, Zha et al. 2015, Galindo et al. 2015, Panamarathupalayam et al. 2019, Morrison et al. 2021). These polymers can maintain thermal stability up to 425°F and are designed as high temperature alternatives for the biopolymeric materials. Figure 1 shows pictures of two $CaBr_2$-based drill-in fluid samples before and after static aging: One with conventional biopolymers was static aged at 300°F for 16 hours, the other with synthetic polymer (HT polymer) was static aged at 400°F for 72 hours. The pictures clearly demonstrated the exceptional thermal stability of the synthetic polymers as compared to the biopolymers.



(a) Biopolymer, 300°F, 16 hours (b) HT polymer, 400°F, 72 hours

Figure 1. Drill-in fluid samples before (left) and after (right) static aging at (a) 300ºF for 16 hours, and (b) 400ºF for 72 hours

Using the new developed synthetic polymer for divalent brine fluid systems, well testing fluids were developed using $CaBr_2$ brine (14.2 ppg) as the base fluid. To minimize the amount of solids in the well testing fluid, micronized manganese tetroxide was used as the weighting agent as it has higher density than the commonly used barite (SG 4.86 versus 4.20). The fluids were tested at densities up to 17.5 ppg and at temperatures up to 400°F. This paper presents the development, testing results, and first field application of the high density well testing fluids.

Fluid Formulation and Testing

The development HP/HT wells were in the western Mumbai Offshore Basin in India. Downhole temperatures were as high as 400°F, and fluid densities up to 17.5 ppg (2.1 SG) were required. Many of these wells could not be tested to their full potential due to lack of an appropriate and cost-effective HP/HT testing fluid. The specific development well that this HP/HT testing fluid was used on had a BHT of 305°F and required a density of 15.2 ppg with low sag tendency (SAG < 0.52) after 72 hours.

The 15.2 ppg test fluid was formulated as shown in Table 1. The fluid used a 14.2 ppg $CaBr_2$ brine as the base fluid and micronized manganese tetroxide as the weighting agent to increase the fluid density to 15.2 ppg. HT polymer was used as the dual functional viscosifier and fluid loss control additive to suspend the solids and reduce fluid loss. Other additives, such as alkalinity agents, defoamers, corrosion inhibitors, and oxygen scavengers were also added for improved fluid performance.

Table 1. Test fluid formulation (15.2 ppg)

Fluid formulation	#1	#2
$CaBr_2$ brine (14.2 ppg), ppb	491.4	483.7
Defoamer, ppb	0.5	0.5
Alkalinity agent, ppb	3.5	3.5
HT polymer, ppb	7.0	8.0
Micronized manganese tetroxide, ppb	127.1	134.4
Corrosion inhibitor, ppb	7	7
Oxygen scavenger, ppb	0.5	0.5

The fluid (4 lab bbl, 1.4 L) was prepared on a Silverson mixer at 6,000 rpm in the order as shown in Table 1. After adding defoamer into the base brine, the fluid was mixed on Silverson while adding the HT polymer. The fluid was mixed for 10 minutes after each addition of the additives except for the oxygen scavenger, which was added separately into the aging cell right before aging with minimal hand stirring. This can prevent the oxygen scavenger from being consumed up by the oxygen during mixing.

Fluid rheology was measured at 120°F. After measuring the initial fluid rheology (BHR), the fluid was split into four portions (1 lab bbl each): one hot-rolled at 305°F for 16 hours, the other three static aged at 305°F for extended hours (in this case 72 hours). The aged samples (both hot-rolled and static aged) were mixed on a Multimixer for 5 minutes before measuring fluid rheology at 120°F. For the static aged samples, top brine separation was first measured, followed by sag factor measurement before measuring fluid rheology. To measure the sag factor (SAG), the density of top fluid (1.2 inches from the fluid surface after removing top brine) and bottom fluid (1.2 inches from the bottom of the aging cell) was measured using a 50 mL retort cup. The sag factor is calculated using Equation 1 shown below:

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

Both API and HP/HT fluid loss of the aged samples were measured following the API procedures (API RP 13B-1, 2019). The API fluid loss was run at room temperature on filter paper with 100 psi differential pressure, and the HP/HT fluid loss was run at 305°F on a 20-micron ceramic disk with 500 psi differential pressure. The volume of the filtrate was multiplied by 2 to give the final HP/HT fluid loss.

Table 2. Fluid properties before and after aging

Fluid properties	#1			#2		
	BHR	AHR	ASA	BHR	AHR	ASA
Aging Temp. (°F)	305					
Aging time (hours)	-	16	72	-	16	72
600 rpm	83	91	94	118	119	120
300 rpm	53	61	63	78	81	82
200 rpm	42	49	51	62	65	66
100 rpm	29	35	36	43	47	48
6 rpm	11	14	14	16	18	19
3 rpm	9	13	13	13	17	18
PV, cp	30	30	31	40	38	38
YP, lb/100ft^2	23	31	32	38	43	44
τ_0, lb/100ft^2	14.4	8.3	10.1	11.0	12.2	13.1
Gel 10 sec, lb/100ft^2	9	13	13	13	17	18
Gel 10 min, lb/100ft^2	-	14	14	-	18	19
API, mL	-	1.2	-	-	0.8	-
HP/HT @ 305°F, mL	-	7.2	-	-	5.6	-
SAG Test (static aged for 72 hours)						
Free water, mL	-	-	35	-	-	14
Top density, ppg	-	-	15.1	-	-	15.2
Bottom density, ppg	-	-	15.9	-	-	15.8
Sag factor	-	-	0.51	-	-	0.51

Table 2 shows the properties of the two fluids before and after aging. Both fluids showed acceptable and stable fluid rheology even after static aging at 305°F for 72 hours. The fluids showed excellent API and HP/HT fluid loss control of less than 2.0 and 8.0 mL, respectively, indicating very good fluid loss control using the HT polymer. No sag was observed after static aging for 72 hours with measured sag factor of 0.51 in both cases. The low sag tendency of these fluids is due to their high yield stress (τ_0) both before and after aging. τ_0 is the shear stress at zero shear rate. The suspended solids must overcome this shear stress to start settling down. τ_0 is calculated using the Herschel-Bulkley equation from the rheology data and is a more accurate and better way of evaluating solids transport and suspension.

To push the testing fluid density and temperature to the limit, two additional fluids with densities of 16.8 and 17.5 ppg, respectively, were also prepared as shown in Table 3. The mixing and testing procedure were the same, except that the samples were aged at 400°F instead of 305°F. For static aging, the time was 24 and 120 hours, respectively.

Table 3. Test fluid formulation (16.8 and 17.5 ppg)

Fluid formulation	#3	#4
Density	16.8 ppg	17.5 ppg
$CaBr_2$ brine (14.2 ppg), ppb	499.2	483.1
Defoamer, ppb	0.5	0.5
Alkalinity agent, ppb	3.5	3.5
HT polymer, ppb	8.0	8.0
Micronized manganese tetroxide, ppb	185.9	231.5
Corrosion inhibitor, ppb	7	7
Oxygen scavenger, ppb	0.5	0.5

Table 4. Properties of Fluid #3 before and after aging

Fluid properties	#3 (16.8 ppg)			
	BHR	AHR	ASA	ASA
Aging Temp. (°F)	400			
Aging time (hours)	-	16	24	120
600 rpm	123	164	160	30
300 rpm	80	117	111	16
200 rpm	64	98	90	12
100 rpm	46	74	64	7
6 rpm	18	36	25	2
3 rpm	15	32	23	1
PV, cp	43	47	49	14
YP, lb/100ft^2	37	70	62	2
τ_0, lb/100ft^2	13.6	27.8	16.5	1.3
Gel 10 sec, lb/100ft^2	15	32	16	1
Gel 10 min, lb/100ft^2	18	34	30	3
API, mL	-	1.2	-	-
SAG Test (static aged for 72 hours)				
Free water, mL	-	-	5	137
Top density, ppg	-	-	16.8	16.6
Bottom density, ppg	-	-	17.1	18.9
Sag factor	-	-	0.50	0.53

Table 4 shows the properties of testing fluid #3 (16.8 ppg) before and after aging. Because of the increased amount of solids (weighting agent), the initial fluid rheology was higher than that of the 15.2 ppg fluid (BHR rheology in Table 2), indicating polymer-solid interaction. Rheology also increased more significantly after hot-rolling, which is likely due to the slow hydration of the polymer chain in the high-density brine because of the very low "free water" in the brine. The fluid was able to maintain the rheology and suspension of the solids after static aging at 400°F for 24 hours, indicating very good thermal stability. After 120 hours, however, the fluid rheology dropped significantly due to polymer degradation, and the τ_0 dropped down below 2 lb/100 ft^2. As a result, the sag factor increased to 0.53. The results show that the polymer is stable at 400°F for at least 24 hours in this test fluid but starts to degrade after extended aging time. Testing fluid #4, with the density of 17.5 ppg, showed similar trend as demonstrated in Table 5.

Table 5. Properties of Fluid #4 before and after aging

Fluid properties	#4 (17.5 ppg)			
	BHR	AHR	ASA	ASA
Aging Temp. (°F)	400			
Aging time (hours)	-	16	24	120
600 rpm	144	213	142	27
300 rpm	96	155	99	15
200 rpm	77	134	81	10
100 rpm	54	104	60	6
6 rpm	20	53	29	2
3 rpm	18	50	25	1
PV, cp	48	58	43	12
YP, lb/100ft^2	48	97	56	3
τ_0, lb/100ft^2	14.0	41.2	22.9	1.3
Gel 10 sec, lb/100ft^2	18	47	16	2
Gel 10 min, lb/100ft^2	23	57	28	2
API, mL	-	1.0	-	-
HP/HT @ 400°F, mL	-	12.4	-	-
SAG Test (static aged for 72 hours)				
Free water, mL	-	-	2.5	145
Top density, ppg	-	-	17.5	17.4
Bottom density, ppg	-	-	17.7	20.3
Sag factor	-	-	0.50	0.54

Field Mixing and Testing

The 15.2 ppg testing fluid (Fluid #2) was mixed in the field following the order shown in Table 1. To ensure better dispersion of the polymer powder into the brine, the fluid was sheared by passing through a HP shear unit at 180-240 gpm for 1.5-2.0 hours after adding the HT polymer. After that, the fluid was weighed up with micronized manganese tetroxide, followed by the corrosion inhibitor and oxygen scavenger. The fluid was then placed into the well, and one cycle of circulation was done through the bit to properly shear and mix the fluid. Initial fluid rheology after adding the HT polymer was low but picked up after shearing and sitting for 24 hours.

The field fluid sample was tested in the lab by aging at 305°F for 72 hours (Table 6). Again, the fluid showed similar stable fluid rheology to the lab prepared fluids (Fluid #2 in Table 2). After static aging, the field fluid showed less top brine separation (6.5 versus 14 mL) and even lower sag value (0.50 versus 0.51).

The field fluid was also tested under HP/HT conditions on a Fann® 77 viscometer by increasing temperature and pressure stepwise to 300°F and 8,000 psi. Table 7 shows the HP/HT fluid rheology of the field fluid. As shown in Table 7, although the high-end dial readings (600/300 rpm) dropped with increasing temperature and pressure, the low-end dial readings (6/3 rpm) increased slightly. The stable low-end dial readings show that the testing fluid can maintain high low-shear rate rheology even with increased temperature. This is critical as high low-shear rate rheology is required to keep the solids suspended under static conditions.

Table 6. Properties of field mixed testing fluid

Fluid properties	Fluid mixed in the field		
	BHR	AHR	ASA
Aging Temp. (°F)	305		
Aging time (hours)	-	16	72
600 rpm	108	113	122
300 rpm	73	78	89
200 rpm	59	64	73
100 rpm	42	46	54
6 rpm	14	19	25
3 rpm	12	17	22
PV, cp	35	35	33
YP, lb/100ft^2	38	43	56
τ_0, lb/100ft^2	8.3	13.5	17.4
Gel 10 sec, lb/100ft^2	12	18	22
Gel 10 min, lb/100ft^2	14	20	26
SAG Test (static aged for 72 hours)			
Free water, mL	-	-	6.5
Top density, ppg	-	-	15.1
Bottom density, ppg	-	-	15.4
Sag factor	-	-	0.50

Table 7. HP/HT rheology profile of the field sample

Temp. (°F)	100	120	150	200	250	300
Pressure (psi)	44	44	2,000	4,000	6,000	8,000
600 rpm	124	113	102	94	84	74
300 rpm	85	79	74	72	66	57
200 rpm	69	65	62	62	57	51
100 rpm	49	48	46	48	46	42
6 rpm	19	20	21	25	26	23
3 rpm	18	19	20	24	24	22
PV, cp	39	34	28	22	18	17
YP, lb/100ft^2	46	45	46	50	48	40
τ_0, lb/100ft^2	12.4	13.5	14.0	16.4	19.3	16.5

More direct evidence of the excellent solid suspension property of the field fluid is shown as the yield stress (τ_0) under HP/HT conditions (Figure 2). The field fluid showed high yield stress of 12.4 lb/100 ft^2 at 100°F and 44 psi. Unlike typical polymer-based systems, in which the yield stress decreases with increased temperatures, the yield stress of the fluid increased slightly to 16.5 lb/100 ft^2 at 300°F and 8,000 psi. This is probably due to stronger polymer-solids interaction at elevated temperatures. The increased yield stress at higher temperatures helps the fluid maintain excellent solid suspension properties downhole under static conditions.

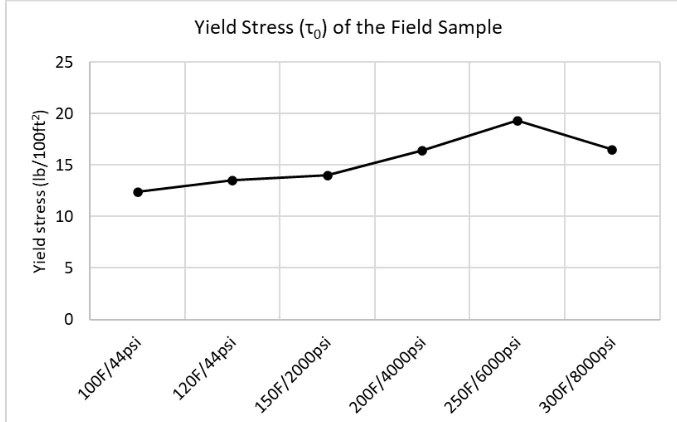


Figure 2. Yield stress of field sample measured by Fann® 77.

Because the operator was planning to use diesel in tubing for draw down, contamination test of the testing fluid with diesel was conducted in case there was leakage in the tubing while lowering the tool for testing. The field sample was contaminated with 5, 10, and 15 vol% of Diesel, respectively, and checked for fluid rheology. Test results show that the fluid rheology remained nearly the same with 10 vol% of diesel and increased only slightly with 15 vol% of diesel (Table 8).

Table 8. Field sample contaminated with diesel

Fluid properties	Vol% of diesel		
	5	10	15
600 rpm	112	124	146
300 rpm	77	86	100
200 rpm	63	70	80
100 rpm	44	49	56
6 rpm	16	17	19
3 rpm	14	15	16
PV, cp	35	38	46
YP, lb/100ft^2	42	48	54
τ_0, lb/100ft^2	9.8	9.5	10.8
Gel 10 sec, lb/100ft^2	14	15	15
Gel 10 min, lb/100ft^2	17	19	19

Field Application

The well was initially drilled with an invert-emulsion fluid and was displaced with base oil, a push pill, a wash pill, and sea water before finally displaced with the testing fluid. After placing the testing fluid in the well, a TCP-DST bottom hole assembly was lowered with a production string. The tubing was filled with diesel. The well was perforated as per plan in the testing fluid, and all testing tools operated smoothly. The testing fluid transmitted pressure to operate the downhole tools during perforation and subsequent well testing operations.

The testing fluid demonstrated a remarkably high stability during the 25 days it remained in the wellbore at almost static conditions with only occasional circulations and minor treatments. The key rheological indicators remained stable throughout: density of the fluid was shown to be unchanged despite the challenging conditions, indicating no solids settlement that could jeopardize further operations and cause non-productive time (NPT). Further corroboration of fluid stability was inferred by the ease of unsetting the packer and visual inspection of the bottomhole assembly (BHA) at the surface as reported by the rig and operator.

The HP/HT well test fluid was recovered and stored at a local liquid mud plant (LMP) facility for re-use in the next HPHT well. It required minimal reconditioning and product treatment. This practice would allow the customer further savings in subsequent well applications.

Considerable cost savings were realized in the form of a 45% saving of the rental cost of the high-density cesium formate brine.

Conclusion

- A HP/HT low-solids, brine-based, clay-free fluid system was designed for well testing using a newly developed HT polymer as the rheology modifier to ensure required thermal stability over extended periods of time.
- The well testing fluid used 14.2 ppg $CaBr_2$ as the base brine and helped the operator save 45% of the rental cost of the high-density cesium formate brine.
- Lab testing of the well testing fluid (both lab and field mixed) confirmed the excellent thermal stability, with sag factor less than 0.52 after static aging at 305°F for 72 hours, and sag factor of 0.50 after static aging at 400°F for 24 hours.
- During field application, the fluid provided smooth pressure transmission during perforation and subsequent well testing operations.
- The well testing fluid remained thermally stable in the well even after 25 days.
- The well testing fluid could be recovered for use in the next wells with minimal reconditioning and product treatment, which allowed for more savings in subsequent well applications.

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Nomenclature

AHR = After hot rolling
ASA = After static aging
bbl = barrel
BHR = Before hot-rolling
BHT = Bottom hole temperature
DST = Drill stem testing
gpm = gallons per minute
ppb = Pounds per barrel
ppg = Pounds per gallon
psi = Pounds per square inch
rpm = Revolutions per minute
SG = Specific gravity
TCP = Tubing conveyed perforating

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