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Gellant for Oil-based Drilling Fluid Behind Casing

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Abstract

Oil-based drilling fluid (OBDF) left behind casing for even a few weeks can have a significant impact on wellbore pressure. Barite settling can affect the annular pressure buildup by sealing the pore throats in any exposed formation, reducing the density of fluid in the upper-hole section, and allowing for the possibility of gas migration.

The gellant system introduced in this paper significantly reduces barite settling experienced by OBDF by developing a high viscosity and gel structure at elevated temperatures. At room temperature, the fluid system does not have significant gel structure and its rheology is equivalent to a conventional drilling fluid, which makes it easy to pump downhole. The temperature-dependent rheological behavior of this system was investigated by conducting rotational as well as oscillatory tests using an advanced rheometer. This was confirmed in fluids having very similar density in the top 1/5 portion compared to the bottom 1/5 portion of the fluid column, even after six months static at test temperature.

This same system can also be used with a fluid spotted into the wellbore during tripping operations or when a well is temporarily abandoned. When drilling operations are resumed, the gellant can be diluted to break its structure.

The gellant system reduces barite settling, thus helping reduce annular pressure buildup and wellbore pressure differentials. This should lead to reduced risk and increased safety for rig workers. It also leads to more uniform fluid density in spotting fluids used during tripping operations.

Introduction

Oil-based drilling fluids (OBDF) left behind casing for even a few weeks can significantly impact wellbore pressure when barite sag occurs along the column of the wellbore, increasing the density of the fluid near the bottom of the column section and reducing the density of the fluid column at the top of the wellbore section. This can result in a section where the barite has “packed off” forming a nearly solid column which cannot be moved without drilling the column out of the wellbore. It can also result in the flow of low density fluids, including gas, into the annular space which can leak out of the wellhead if there is communication to the wellhead.[1,2]

Barite that has formed a nearly solid mass can also produce a seal in the annulus leading to annular pressure buildup and casing collapse. This results in expensive remediation and wellbore work-over in order to repair the damage.

The gelling agent described in this paper is a white free flowing powder which readily disperses into an oil-based fluid and does not form a gel until the fluid is at an elevated temperature for several hours. It does not form a gel for at least 21 hours at 70°F and at least 10 hours at 120 °F. However, after 2 hours at 150°F, a gel forms. This allows enough working time to mix the material on the surface before pumping it before cement or as a temporary spotting fluid.

Experimental

Static Aging Tests

Static aging tests were conducted using 12 lb/gal synthetic based drilling fluid (OWR 80/20) which had been conditioned for 16 hours at 150°F. The formulation is shown in **Table 1**. The gelling agent was then added at a concentration of 3 lb/bbl and half lab barrel quantities of the fluid were dynamically aged at 150°F for 1 or 2 hours and then static aged at room temperature, 40, 150, or 190°F in the vertical position. The duration of the static aging tests was 12 days or 4, 12, or 24 weeks with a starting nitrogen gas cap of 100 psi to reduce the amount of entrained gas after the static aging period. After static aging, the gelled fluid samples were cooled to room temperature before determining the density of each 1/5 portion using an 11.6 mL pycnometer and then calculating the sag factor.[3] The exception of this testing was the two week duration test which only determined the top density and the bottom density using mass and water displacement in a graduated cylinder.

Table 1 Base Fluid Formulation

Density	**12 ppg**
OWR	**80/20**
Material	**Amount**
IO base oil, bbl	0.58
Primary emulsifier, lb	14
Secondary emulsifier, lb	3
Lime, lb	4
250,000 ppm $CaCl_2$ brine, bbl	0.16
FLC, lb	6
Suspension products, lb	20
Viscosifier, lb	2
Drill solids, lb	20
Barite , lb	211.3

To determine if the gelling agent would add considerable viscosity while still being mixed into the fluid, a sample of fluid with 3 lb/bbl gellant was allowed to sit at room temperature for 21 hours and the viscosity of the fluid was determined several times using a standard oilfield viscometer. The dial reading and gel strength values were compared to those from the base fluid and the initial values recorded after the fluid was first mixed.

Rheological Tests

The rheology tests include rotational and oscillatory tests on an advanced rheometer. The aging conditions are simulated by subjecting the fluid in the rheometer to 150°F for 2 hours and then ramping down the temperature to either 70°F or 40°F where it is maintained for at least 0.5 hours. The rotational tests were conducted on a parallel plate geometry (~ 2 mm gap) by subjecting the fluid to a shear rate of 1.5 s^{-1}. The oscillatory tests were conducted on a parallel plate geometry (~ 2 mm gap) by subjecting the fluid to an angular frequency of $\omega = 1$ rad/s and strain amplitude of $\gamma = 0.1$ %.

Results

Sag Tests

The results for barite settling during the initial 12 day static aging tests at various temperatures are shown in **Table 2** and a picture of the samples is shown in **Figure 1**. The small density difference between the two portions tested results in a low sag factor for the three test temperatures shown.

Table 2 Initial measured densities and sag factors

	40 °F	70 °F	150 °F
Top Density, g/mL	1.49	1.49	1.44
Bottom Density, g/mL	1.56	1.53	1.56
Sag Factor	0.51	0.51	0.52

Figure 1: Fluids after static aging for 12 days

After this initial set of data was collected, the test duration was increased and focused on the highest temperature of 190°F. The results after static aging for 4, 12 and 24 weeks are shown in **Table 3** and the gelled fluid is shown in **Figure 2**. The sag factor does not change over the test duration at this temperature so this material can be safely used at this temperature for several months.

Figure 2: Fluid sample after long term static aging at 190°F

Table 3 Measured densities and sag factors

Test Duration, weeks	**4**	**12**	**24**
Top Density, g/mL	1.47	1.42	1.46
Bottom Density, g/mL	1.51	1.45	1.50
Sag factor	0.51	0.51	0.51

The results from the room temperature static aging sample are shown in **Table 4**. There is an initial increase in viscosity of the sample after addition of the gellant. After this initial increase, the plastic viscosity and yield point change only slightly.

Table 4 Viscosity data for room temperature sample

Dial Reading	**Base**	**Gellant at 3 lb/bbl**				
Hours	**Fluid**	**0**	**1**	**2**	**4**	**21**
600 RPM	148	207	212	221	220	230
300 RPM	83	120	124	124	128.5	135
200 RPM	59	87	90	89.5	93	97
100 RPM	34	50	52	53	54.5	56
6 RPM	7	9	10	12	11.5	11
3 RPM	6	7	8	9.5	9	9
10 sec gel	8	10.5	11.5	14	12.5	11
10 min gel	15.5	22	26	29	27	24
PV, cP	65	87	88	97	91.5	95
YP, lb/100ft^2	18	33	36	27	37	40
τ_0, lb/100ft^2	4.47	4.17	4.9	8.07	6.31	5.51

To determine if the material would begin to swell and gel at temperatures lower than 150°F, a sample fluid containing 3 lb/bbl of the gellant was placed in a water bath at 120°F. The resulting fluid, which sat in the bath for up to 10 hours, is shown in **Figure 3** and the fluid still flows after this amount of time at elevated temperature. This is a good indication that this material can be mixed in surface conditions with elevated temperatures.

Figure 3: Fluid with gellant after 7 and 10 hours at 120°F

Rheological Results

The base fluid, as expected, did not show any increase in viscosity with time (**Figure 4**). The fluids containing the gellant material, however, have shown significant increase in the viscosity (15 to 20 times) as the particles swell with time at 150°F; the viscosity response reaches a plateau in 1.5 to 2 hours. After about 2 hours, when the temperature of the sample is gradually decreased up to 40 or 70°F, the viscosity further increases to 70 to 80 Pa.s as shown in Figure 4. Owing to the increased viscosity, it is expected that the fluid with gellant will have more resistance to sag, especially at lower temperatures.

The base fluid, as expected, did not show any increase in storage modulus G' with time (**Figure 5**). The fluids containing the gellant material, however, showed an order of magnitude increase in the G' (10^2 times) as the particles swell with time at 150°F; the elasticity response reaches to a plateau in about 2 hours. At the end of 2 hours, when the temperature of the sample is gradually decreased up to 40 or 70 °F, the G' further increases and reaches to steady state as shown in Figure 5. Owing to the increased fluid elasticity, it may be expected that the fluid with gellant will have more resistance to sag especially at lower temperatures.

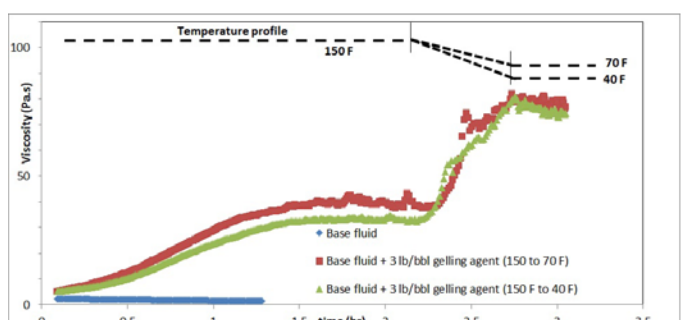

Figure 4: Rotational test (shear rate = 1.5 s^{-1}) on parallel plate geometry

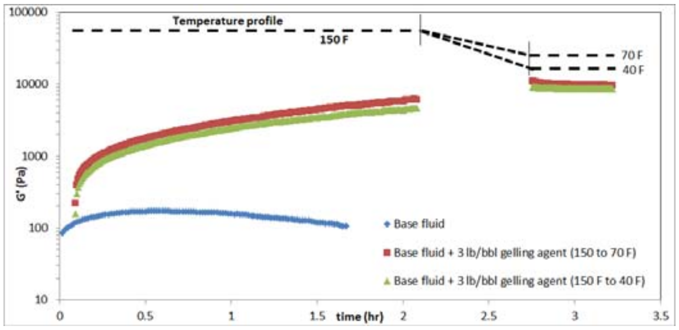

Figure 5: Oscillatory test (ω = 1 rad/s and γ = 0.1%) on parallel plate geometry

Conclusions

- The rheological tests shown above indicate that, at 150 °F, the fluids with the gelling agent show a large increase in viscosity and close to a 100-fold increase in the storage modulus of the fluids. The tests also show that the activation time is about two hours over which the fluid transforms into a solid like gel.
- The rheological response at 150°F was consistent with the sag behavior which exhibits very little barite settling, as seen in the sag factors which are close to 0.50 for fluids which were aged up to 24 weeks. A sag factor of 0.50 signifies that a fluid has the same top and bottom density.
- This same gelling agent is not activated until the temperature is below 120°F which can simplify mixing and pumping on the rig site.

Acknowledgments

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Nomenclature

OBDF	= *Oil-based Drilling Fluid*
bbl	= *barrel*
RPM	= *Revolutions per minute*
PV	=*Plastic Viscosity*
YP	= *Yield Point*
τ_0	= *Herschel-Buckley Yield stress*
G'	= *Storage modulus of the fluid*
G''	= *Loss modulus of the fluid*

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