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HPHT Formation Fluid Loss Control without Bridging Particles

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Abstract

Drilling, screen-running, and perforation fluids based on high density cesium and potassium formate brines have, since they were first introduced in the 1990's, been used with great success in many deep HPHT gas fields world-wide. These fluids have in most cases been formulated with biopolymers and a very small amount of bridging material. Calcium carbonate is the preferred solid bridging material, as it can easily be removed with acid. Moreover, the production performance from the wells that have been drilled or perforated with formate fluid has been so good that no form of filtercake breaking has ever been required. Given this very good track record for the low-solids fluid without filtercake breaking, it is logical to assume that a similar fluid that does not need to form a solids-laden filtercake while still yielding adequate fluid loss control will perform at least as good, if not better.

The objective of the study described in this paper was to investigate the possibility of formulating solids-free fluids with formate brines that are fully capable of controlling fluid loss in various well-construction applications.

Pseudoplastic fluids with a non-zero yield stress, such as those viscosified with xanthan gum, are known to control fluid loss by the development of a high apparent viscosity that increases exponentially with the radial distance from the borehole. The increasing apparent viscosity is caused by the decreasing shear rate that the fluid experiences as it progresses radially away from the wellbore. The unique temperature stabilizing effect that formate brines have on some biopolymers such as xanthan gum, combined with their high density, make them excellent candidates for formulating solid-free fluids with good fluid-loss control for various high pressure high temperature (HPHT) applications.

A specially designed radial fluid loss tester was used to measure fluid loss for formate brine with various concentrations of two natural biopolymers, xanthan gum and a membrane-forming additive. The results show that concentrated formate brines viscosified with a moderate amount of either one of these additives can successfully control fluid loss without any solids.

Introduction

Oilfield literature is heavily populated with papers describing the development and use of solids-free fluid-loss pills based on halide brines. The main driver to develop these fluids has been the difficulty of removing the calcium carbonate filtercake due to uneven dissolution with acid.

Almost all published applications of solids-free fluid loss pills have been with halide brines viscosified with HEC or cross-linked HEC. In recent years, viscoelastic surfactants (VES) have also been added to halide brines to formulate solids-free fluid loss pills with higher temperature stability.

Common to all of these halide-based fluid-loss pills, however, is the difficulty of stabilizing their additives at high temperature in high density brines containing zinc bromide (Samuel et al., 2003). Even after chemical stabilization of conventional HEC fluid loss pills, these systems don't seem to be able to reach the high temperature range (Kippie et al., 2002). The addition of stabilizing agents increased the temperature stability in a 13.5 lb/gal (1.62 g/cm^3) $CaBr_2$ brine from about 220°F (104°C) to about 250°F (121°C) and in a 16.0 lb/gal (1.91 g/cm^3) Zn^{2+}-containing brine from about 200°F (93°C) to less than 250°F (121°C) for 10 hours. Kippie indicates that the most challenging conditions for fluid loss control pills are posed by high density brines containing $ZnBr_2/CaBr_2$ (>16.0 lb/gal (1.91 g/cm^3)) and "extreme temperatures" >300°F (149°C). Even with the use of synthetic polymers (Gibsen et al., 2011), temperature limits of around 320°F (160°C) were reported in Zn^{2+}-containing halide brines. Although this is a significant improvement, these conditions can only marginally be classified as HPHT.

Due to the temperature limitations of HEC and cross-linked HEC, viscoelastic surfactant (VES) systems were introduced. These systems extended the temperature range of the $CaCl_2/CaBr_2$ systems, but they were not compatible with high density halide brines containing $ZnBr_2$ (Gomaa et al., 2013). Zinc bromide solution has a negative effect on surfactant structure, which eliminates the ability of the surfactant to form a gel and reduce brine loss. Gomaa et al. developed VES systems that could viscosify brines with zinc bromide up to 300°F (149°C), and demonstrated good fluid-loss control at 158°F (70°C). However, the amount of zinc bromide in these brines was limited to <13%, which doesn't reach the density range required in many HPHT applications.

Based on the available literature, it can be concluded that halide brines are not well suited for use as base fluids for solids-free HPHT fluid loss pills.

No work has been published on the use of formate brines as base fluid for solids-free fluid-loss pills. However, some interesting work has been reported on formulating solids-free drilling fluids based on other monovalent brines. Powell et al. showed in 1995 that xanthan gum is capable of controlling fluid loss when used in low density potassium chloride brines in reservoir drill-in fluids (Powell et al., 1995). Powell's team developed a solids-free fluid with viscoelastic, time-independent pseudoplastic rheological behavior (otherwise known as a VETIP fluid). VETIP fluids are monovalent brines that make use of the viscoelastic and pseudoplastic properties of xanthan gum to control fluid loss without the aid of a filter cake. This drill-in fluid demonstrates a functional true yield stress in the circulating fluid. The yield stress is also present in the filtrate, which limits depth of filtrate invasion.

Powell conducted some interesting laboratory investigations to find valid test conditions that correlate with field performance. He discovered some serious problems with the standard fluid loss tests. The permeability of the Whatman #50 paper used in API HPHT fluid loss tests is so low that it induces the formation of a filtercake (polymer skin), even with clarified xanthan. Once a polymer skin is formed under static filtration conditions, the filtrate viscosity rapidly declines. Similar artifacts are created by core tests that simulate simple line drive linear flow, under constant imposed pressure or constant imposed shear rate. Regardless of whether linear core floods are conducted under static or dynamic flow conditions across the face of the core plug, even pre-filtered polymer formed a skin at the core face. Under these conditions the VETIP yield stress fluids never see any reduction in shear rate that occurs in a radial flow pattern. This reduction in shear rate together with the presence of yield stress leads to exponential increases in viscosity during dynamic filtration, as well as resistance to flow when the fluid is in its static gel state. Powell further showed that by using triaxial dynamic testing to simulate more realistic radial flow wellbore conditions, no filtercake deposition took place. This was the case for both solids-free and solids-laden VETIP yield stress fluid systems. The solids-free systems allowed leak-off of higher polymer filtrate concentrations, which thickened faster as shear rate dropped with increasing distance from the wellbore. This is in strong contrast to the conventional fluids design, which is to deposit a tight filter cake, with a permeability ranging as low as 10^{-5} to 10^{-9} Darcy, excluding polymer from the filtrate. Powell claimed that the absence of filtercake deposition is unique to VETIP yield stress fluids. For comparison, in Powell's study a conventional HEC viscosified fluid system readily deposited a filter cake in the triaxial test configuration.

Powell's work with xanthan gum in monovalent brines is relevant and applicable to formate brines, as these brines are known to increase the temperature stability of xanthan gum (Howard et al., 2015). Combining the ability of xanthan to provide solids-free fluid-los control with the high density of the formate brines, and their ability to protect xanthan gum at high temperature, one should have the ideal combination of properties required for an HPHT fluid with excellent solids-free fluid loss control.

This paper reports the results of an investigation into the formulation of solids-free HPHT formate fluids, and the special radial equipment that has been designed to perform a realistic evaluation of their fluid-loss control.

Solids-free perforating pills with formate brines

The literature generally agrees on the two main mechanisms by which solids-free pills provide fluid loss control (Blauch, 1989; Cole et al., 1995; Vasquez et al., 2010):

1. Linear gels: These fluids help reduce fluid loss to permeable rock formations by viscosity. The mechanism is the development of a high apparent viscosity in a pseudoplastic (shear-thinning) fluid in the formation near the wellbore. As the viscosified fluid moves deeper into the formation, the radius of coverage increases, and the shear rate decreases with a resulting increase in apparent viscosity. Typical polymers in this category are hydroxyethyl cellulose (HEC), xanthan, and succinoglycan.
2. Cross-linked gels: These fluids help reduce fluid loss to permeable rock formations by depositing a thin, cross-linked polymer filtercake at the formation or by entering into the formation and plugging the pore throats with the cross-linked, gelled structure. The most commonly used cross-linked gels are HEC derivatives.

Howard et al. (2015) published the results of a study into the compatibility of several natural biopolymers with formate brines. The biopolymers that were investigated included xanthan gum, welan gum, schleroglucan gum, guar gum, and carboxymethyl guar gum (CM guar gum). The polymers were tested in brines that either contained a carbonate/bicarbonate pH buffer or were unbuffered. They were tested at neutral and alkaline pH. Out of these five natural biopolymers, xanthan gum was the only one that was compatible with buffered formate brines with alkaline pH. Its viscosity (measured at 500 sec-1) in the buffered formate brines almost doubled and its transition temperature (T_m) increased by more than 180°F (100°C) to 363°F (184°C) compared to in water. This is in agreement with prior studies (Downs, 1991; Howard, 1995). The welan gum seemed to be very compatible with unbuffered formate brine at pH = 7, but underwent extreme thermal thinning in a buffered brine at pH = 7, and there was little viscosity development by welan in the buffered, pH 10 formate brine. Since the pH buffer is a very important component in a formate brine fluid system, it was decided not to include welan gum in the current study. Scleroglucan did not develop any significant high shear rate viscosity in any of the formate brines that were tested, not even in the unbuffered brine at pH = 7, and was therefore not considered for this study. Guar gum and CM guar gum developed some viscosity in unbuffered, pH = 7 formate brines, but they exhibited extreme thermal thinning. In buffered formate brines with alkaline pH, there was hardly any viscosity development. However, some unpublished work has previously shown that CM guar gum develops viscosity in formate brines during heating. A thermally activated cesium formate solids-free fluid loss pill has been successfully formulated in the lab and qualified for field use. The fluid was, however, never deployed. Because of the successful qualification testing, it was decided to include the CM guar gum fluid-loss pill in the current study for comparison. In addition to xanthan gum and CM guar gum, a special membrane-forming additive was also included, as it had shown good compatibility with formate brines in screening tests.

Xanthan gum

Previous research has shown that formate brines are capable of increasing the thermal stability of xanthan gum by increasing its transition or melting temperature, T_m, and by providing anti-oxidant protection. (Downs, 1991; Howard, 1995; Howard et al., 2015). The extent to which the thermal stability of xanthan may be increased depends primarily on the type and concentration of the alkali metal formate salt in solution. The most effective brine from this perspective is very concentrated potassium formate brine, which can increase the T_m of xanthan to over 396°F (200°C) and raise the 16-hour thermal stability to almost 356°F (180°C). The use of additives has shown to be an effective method to further enhance the thermal stability of xanthan in formate brines. Messler et al. (2004) designed a potassium formate fluid that maintained viscosity after hot-rolling for 3 hours at 400°F (204°C). He achieved this result by adding an anti-oxidant, removing the pH buffer, and lowering the pH to 7. Additive packages have since been identified that are capable of stabilizing xanthan in an alkaline pH buffered potassium formate brine for 16 hours at temperatures > 381°F (194°C). The best performing additive package was found to be a combination of 5 vol% PEG 200 and 2 lb/bbl magnesium oxide (Howard et al., 2015), which was consistent with findings by van Oort et al. (1997). Kippie et al. (2002) also identified stabilizing agents that are able to increase the temperature stability of xanthan in formate brines. He was able to stabilize xanthan and starch in rather low density sodium formate brine (9.5 lb/gal (1.14 g/cm^3)) to above 350°F (177°C) and thereby significantly improve fluid loss control. Figure 1 shows the transition temperature (T_m) of xanthan as a function of brine type and concentration. The temperature at which xanthan is stable for 16 hours was found to be about 27 – 36°F (15 – 20°C) lower than the transition temperature. However, the addition of stabilizing additives brings the long-term stability very close to the transition temperature. By varying the composition of formate blends, one can manipulate the temperature stability of xanthan. As an example, if one wants to design a viscosified brine with density of 16.7 lb/gal (2.0 g/cm^3) that self-degrades faster than predicted, one could use a higher density cesium formate brine and cut it back with water rather than blending cesium and potassium formate brines to reach this density.

In addition to its excellent temperature stability in formate brines, xanthan gum has shown very good compatibility with reservoirs when used as the primary viscosifier in low-solids formate fluids for many years. Wells drilled and completed in formate brines viscosified with xanthan gum are typically highly productive (Saasen et al., 2002; Howard and Downs, 2005; Roy et al., 2008; Olsvik et al., 2013; Fleming et al., 2015) and the use of breakers has never been required.

Based on the research by Powell and his team (described above), one would expect formate brines viscosified with xanthan to behave like a VETIP fluid. However, testing has shown that when xanthan gum is hydrated in concentrated buffered formate brines, the rheology deviates slightly from that seen in less concentrated brines. The viscosified formate fluids are typically more viscous, less pseudoplastic, and their yield stress is more time-dependent. Radial fluid loss testing is therefore critical in order to qualify xanthan gum to provide sufficient fluid-loss control in solids-free formate fluids.

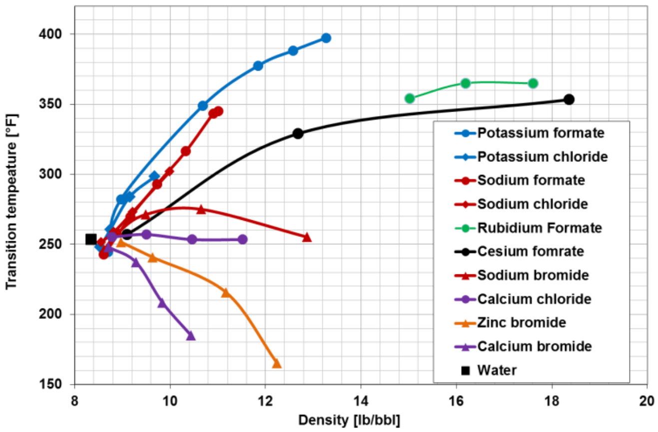

Figure 1 - Transition temperature, T_m, of xanthan gum as function of brine concentration for a variety of typical oilfield brines. The figure is taken from Howard *et al*. (2015).

CM guar gum

Guar gum is a non-ionic, branched chain polysaccharide, chemically known as a galactomannan. It is typically used to create derivatives of conventional guar with improved properties for specific oilfield applications, such as hydraulic fracturing. Carboxymethyl (CM) guar gum is an anionic derivative of guar gum. CM guar gum was used to formulate thermally activated solids-free fluid loss pills based on formate brines in the past, and it was qualified for use in the field by a US operator. CM guar gum is believed to provide fluid loss by forming a polymer skin (filtercake) on the wellbore surface. Little is known at this time about the temperature stability of CM guar gum in formate brines, and its ability to self-degrade.

Membrane-forming additive

A third-party additive, described as a “shear-thinning membrane-forming encapsulator” was included in the testing. The additive, which is based on a natural polysaccharide, is said to have a unique ability to build a filter cake on its own in a solids-free fluid that can easily trap drilled solids and prevent them from getting into the reservoir. When the well is flown back, the filtercake is believed to be stripped off along with any trapped solids. The additive has been successfully used in a range of drilling operations with lower density potassium chloride and potassium carbonate brines, and was very successfully used to drill and ultimately increase reservoir productivity in the Schwarzbach-1 hydrocarbon well in SW Germany.

A quick screening test was performed to compare the pseudoplastic properties of this additive with that of xanthan gum in cesium formate brine. The results, shown in Figure 2, indicate that the two polymers are very similar when hydrated in a cesium formate brine. No viscosity measurements have been made in the very low shear rate range, however, and it is therefore not possible to predict if this fluid has VETIP type properties, described above, and can control fluid loss by the same mechanism as xanthan gum (Powell et al., 1995). The membrane-forming additive appears to be easier to hydrate than xanthan gum, and its yield stress appears to be less progressive. Some other screening tests confirmed that this additive is thermally stabilized by formate brines to temperatures very similar to xanthan gum. No attempts have been made to extend the temperature stability with stabilizing agents, but it is reasonable to assume that these additives should have similar effect on the membrane-forming additive as they have on xanthan.

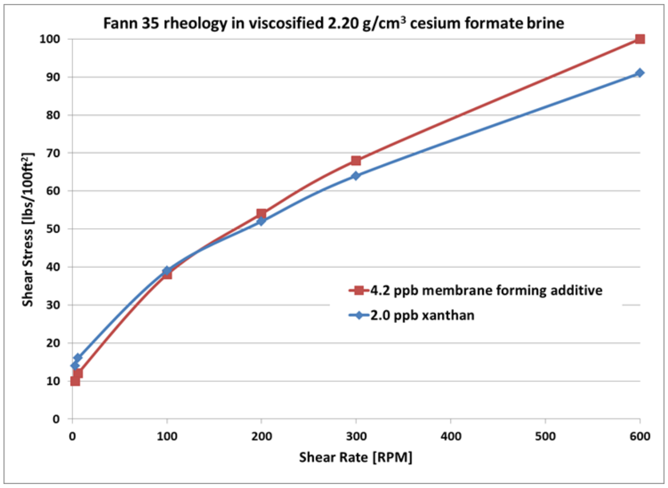

Figure 2. Comparison of Fann 35 rheology for xanthan gum and the membrane-forming additive in 18.4 lb/gal (2.20 g/cm^3) cesium formate brine.

Return Permeability

A well designed fluid, whether it is a reservoir drill-in fluid, a screen-running fluid, a perforating pill, or any other pill that is exposed to the reservoir is supposed to provide well control, prevents loss of expensive fluid into the formation and, at the same time, ensures that the reservoir remains as close as possible to its native state. Internal and external breakers are often used with halide-based solid-free fluid loss pills to aid the breakdown of HEC and cross-linked HEC. For low-temperature applications, natural biopolymers may be so temperature stable in formate brines that breakers are required. The evaluation of breakers for low-temperature applications is not part of this study. In higher temperature applications, however, there is a significant amount of evidence that natural biopolymers added to formate brines clean up with time under influence of temperature (Powell et al., 1995; Roy et al., 2008; Fleming et al., 2015).

Powell showed that the 60+ horizontal wells drilled in Prudhoe Bay, Alaska with solids-free VETIP fluids and completed with slotted liners have higher well productivity indexes than conventional wells or even horizontal wells drilled with solids-laden drilling mud systems (Powell et al., 1995). This is a clear indicator that the drawdown pressures created when the Prudhoe Bay wells were put on production provided enough energy to mobilize the xanthan-viscosified fluid in the formation and enable production of the reservoir hydrocarbons.

Roy reported that the Rhum-wells that had been perforated with a cesium formate perforation pills cleaned up smoothly and quickly with none of the large step function increases in productivity observed during start-up as the filtercake lifted off (Roy et al., 2008). The bottom-hole pressure and bottom-hole temperature indicate that flow was initiated with minimal drawdown. Moreover, after the initial slow ramp-up the well cleaned up very quickly over an 8-hour period. After the initial clean-up period the wells appeared stable, however, both gas production rate and well head pressure increased slightly over the remainder of the flow period, which was carried out at the maximum rate possible (around 72 MMscf/day). Once the wells were put on-line at 150 MMscf/day to the production facility, both the well head pressure and production rate continued to increase gradually on a fixed choke setting over the following weeks, indicating that the well was cleaning up over a long period of time. Roy explained this by assuming large local variations in permeability and also some effects of fluid retention. Another contributing factor could have been that the biopolymers (xanthan and starch) that would be present in the near-wellbore pore throats just needed this amount of time to fully degrade.

Therefore, designing a solids-free perforating pill from just a clear formate brine with a degradable biopolymer should allow for good clean-up, assuming the formate base brine itself cleans up. Return permeability testing performed with just clear formate brine yields return permeabilities around 100% (Downs, 2011). Occasionally one can experience some fluid retention, and the brine may not always come out during the drawdown phase of a short laboratory test. However, experience has shown that formate brine filtrate cleans up with time when used in real well applications (Fleming et al., 2015). Logging and production data from wells that have been drilled with cesium/potassium formate drilling fluid in the past indicate that in real life the formate filtrates are mobile over time (gravity segregation and replacement by hydrocarbons is observed). This is supported by the fact that the already good production from wells that have been drilled/completed with formate brines appears to improve further over time (Berg et al., 2007).

Experimental and Results

In order to gain a good understanding of the mechanism by which the three additives provide fluid-loss control in formate brines, testing was performed in both linear and radial configurations. Linear tests were performed in standard API drilling fluid test equipment on paper and aloxite disks. A specially designed radial fluid loss tester, which resembles the geometry of a perforation channel, was used to measure radial fluid loss.

Linear testing

Standard linear HPHT filter press fluid loss testing was performed on Whatman filter paper #50 and 10 µm aloxite disks. The filter paper has a pore throat size of 2.7 µm, and the 10 µm aloxite disk has a permeability of 775 mD. The fluid samples were statically aged at a test temperature of 302°F (150°C) for one hour before the differential pressure was applied. For safety reasons, the differential pressure was increased in increments up to 500 psi. The disks and paper had a diameter of 2.5” (6.35 cm), which corresponds to a surface area of 4.9 in^2 (31.7 cm^2). The thickness of the aloxite disk was 0.25” (0.635 cm). The fluid that was used for testing was a 15.0 lb/gal (1.80 g/cm^3) cesium/potassium formate blend buffered to pH = 10.3 with a 1.7 lb/bbl potassium carbonate / bicarbonate pH buffer. Various concentrations of xanthan gum and the membrane-forming additive were added to the fluid. The results of the linear testing are presented in Figure 3.

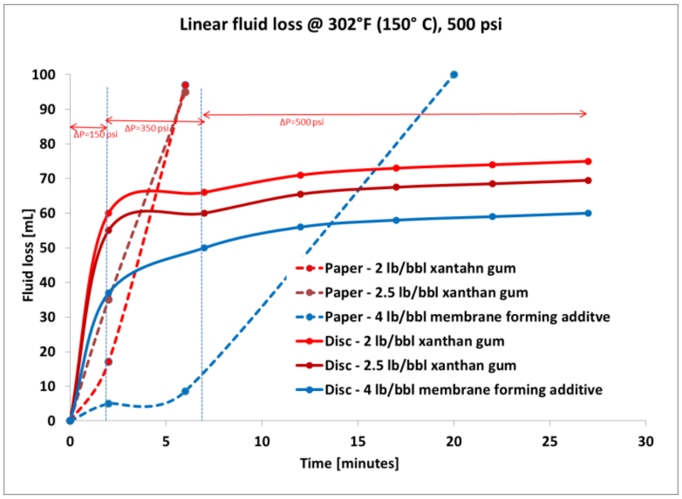

Figure 3 - Results of linear fluid loss testing of a 15.0 lb/gal (1.80 g/cm^3) cesium/potassium formate brine with various concentrations of two different viscosifying additives. Note that none of the fluids tested exhibited control on filter paper, but all of them provided control on permeable aloxite disk.

As can be seen, there is a big difference between the performance on paper and on the much more permeable aloxite disks. None of the fluids were able to provide fluid loss control on paper. The fluid with 4 lb/bbl membrane-forming additive showed some indication of fluid loss control for a few minutes, but failed completely after about 7 minutes. Both concentrations of xanthan gum and the membrane-forming additive all provided very good fluid loss control on the aloxite disk. As expected, all exhibited a relatively high spurt loss volume. The difference between the performance on paper and on aloxite disks indicates that the mechanism for both these two types of fluids to control fluid loss is not only the formation of a membrane / polymer skin / filtercake, but also that the flow of viscous filtrate moving through the disk plays an important role. The viscosity of the filtrate was not measured, but it was visually observed that the filtrate had a higher viscosity than the base brine caused by polymers retained in the filtrate.

Radial testing

Radial test equipment was custom-made for radial fluid loss experiments by MetaRock Laboratories in Houston. The filtration medium was a 5” (12.7 cm) long, 4” (10.16 cm) diameter core with a 0.5” (1.27 cm) borehole in the center. This gives a wall thickness of 1.75” (4.45 cm), which offers significantly more filter medium than the 0.25” (0.635 cm) thickness of the aloxite disk in the linear test (see Figure 1). The filtration area (hole surface area) was calculated to be 7.85 in^2 (50.65 cm^2), which is significantly larger than in the linear test. Berea sandstone with an air permeability of about 120 mD was used for the testing. A high precision rock saw was used to trim the sample ends. Epoxy bond was used on the top and bottom end caps. A sand pack was placed between the core and an elastomeric sleeve. A confining pressure of 2,000 psi was applied to the cell. The core was saturated with 3% NaCl before the test started. The core permeability to the pore fluid was measured at four different flow rates. The test fluid was held in a transfer cylinder. Both the reservoir side and the borehole side of the core were pressurized to 100 psi. Two borehole volumes of test fluid were circulated through the borehole. The test fluid was injected into the borehole after preheating for one hour and the borehole pressure was increased. Two sets of tests were performed. In the first tests, the differential pressure was increased in stages up to 200 psi. In the second set of tests the differential pressure was increased rapidly to 500 psi.

The following fluids were included in the testing:

1. 15.0 lb/gal (1.8 g/cm^3) buffered cesium/potassium formate brine with 1 lb/bbl xanthan additive buffered to pH=10.3 with 1.7 lb/bbl potassium carbonate/bicarbonate.
2. 15.0 lb/gal (1.8 g/cm^3) buffered cesium/potassium formate brine with 2 lb/bbl xanthan gum buffered to pH=10.3 with 1.7 lb/bbl potassium carbonate/bicarbonate.
3. 15.0 lb/gal (1.8 g/cm^3) buffered cesium/potassium formate brine with 2.5 lb/bbl xanthan gum buffered to pH=10.3 with 1.7 lb/bbl potassium carbonate/bicarbonate.
4. 15.0 lb/gal (1.8 g/cm^3) buffered cesium/potassium formate brine with 4.5 lb/bbl membrane-forming additive buffered to pH=10.3 with 1.7 lb/bbl potassium carbonate/ bicarbonate.
5. 18.4 lb/gal (2.2 g/cm^3) cesium formate brine with 3 lb/bbl CM guar gum buffered to pH ~ 10 with ~ 4 lb/bbl potassium carbonate/bicarbonate.

The results of the radial testing are shown in Figure 6 for the 200 psi differential pressure (fluids 1-4), and in Figure 7 for the 500 psi differential pressure (fluid 5). All five fluids that were tested demonstrated controlled fluid loss for the 16 hours duration of the test. The best performances were seen in the fluid containing 2 lb/bbl xanthan gum and the one containing 4.5 lb/bbl membrane-forming additive at 200 psi differential pressure.

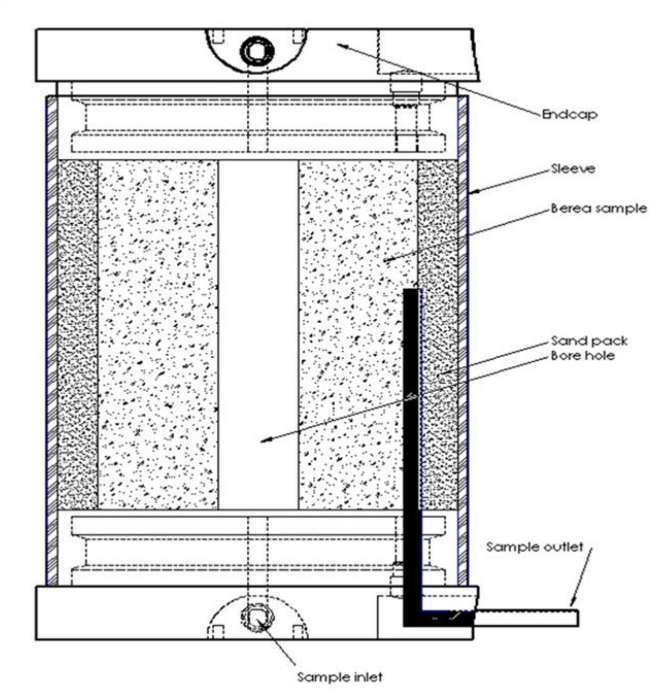

Figure 4 - Schematic drawing of the radial test cell.

Figure 5 – Photograph of the radial test set-up.

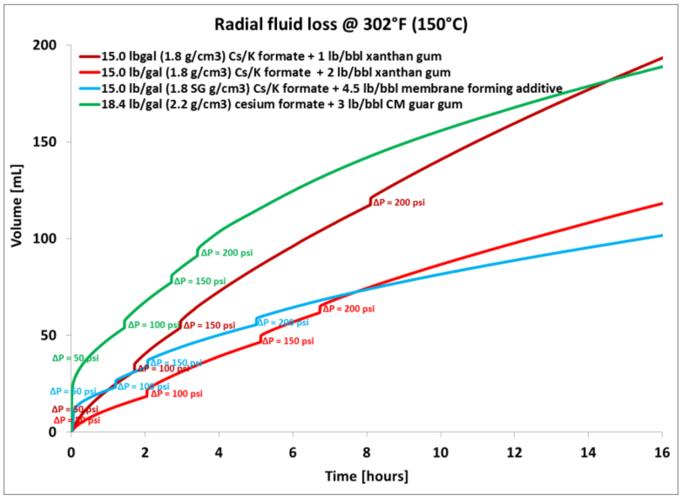

Figure 6 - Results of radial fluid loss testing of a 15.0 lb/gal (1.80 g/cm^3) cesium / potassium formate brine with various concentrations of three different viscosifying additives. The differential pressure is ramped up gradually to 200 psi.

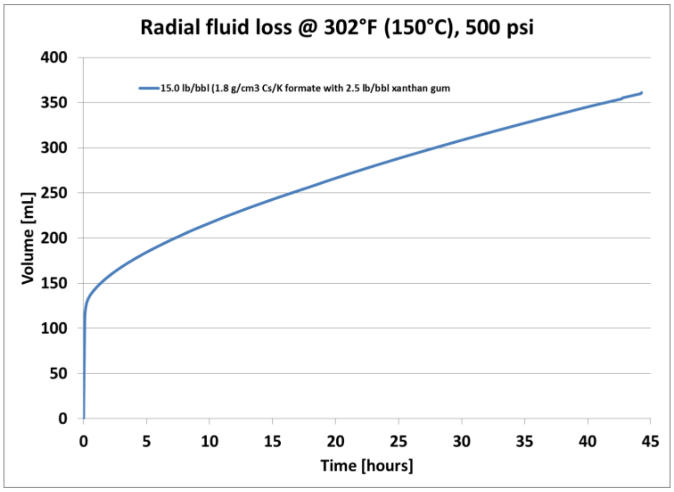

Figure 7 - Results of radial fluid loss testing of a 15.0 lb/gal (1.80 g/cm^3) cesium/potassium formate brine with 2.5 lb/bbl xanthan gum. The testing was performed with a 500 psi differential pressure.

After testing, the cores were photographed (see Figure 8). For the fluids containing 3 lb/bbl CM guar gum and 4.5 lb/bbl membrane-forming additive, one can clearly see a layer of polymers on the inside of the borehole wall. The polymer skin appears green as a dye was added to the fluid in these tests. In the fluid containing 1 lb/bbl xanthan gum, the polymer skin is much less visible. For comparison, a filtercake from a cesium / potassium formate solids-laden fluid-loss pill from a previous study is shown in the same figure. This fluid contained 30 lb/bbl of calcium carbonate, which is a small amount compared to the solids concentration in weighted high-density fluids. In spite of this, a quite significant amount of the bore hole (which could represent a perforation tunnel) is taken up by the filtercake. In our opinion, no more than 15 lb/bbl calcium carbonate should be added to formate perforating fluids if solids are to be added.

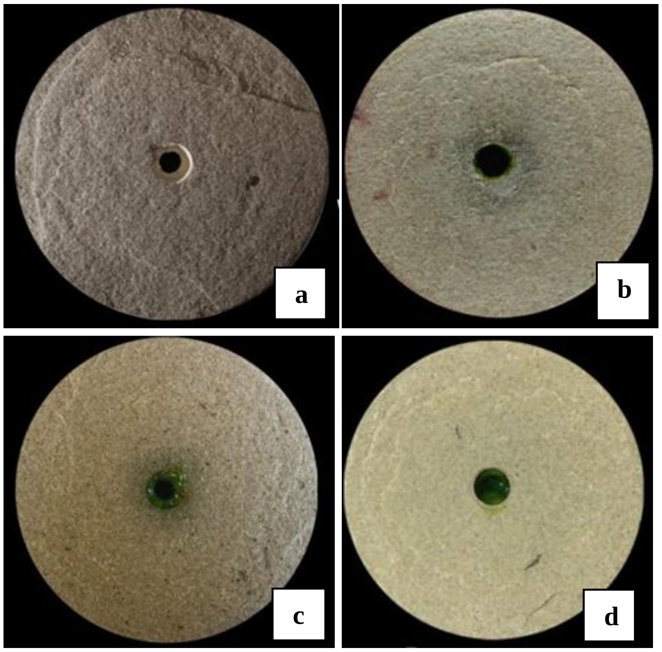

Figure 8 - Photos of the filtercake that has formed in the 0.5" (1.27 cm) wide borehole in four different tests with 15.0 lb/gal cesium/potassium formate fluid-loss pill (1.80 g/cm^3). Photo a) shows the filtercake from a fluid containing about 30 lb/bbl calcium carbonate. Photo b), c), and d) show the fluid with 1 lb/bbl xanthan gum, 4.5 lb/bbl membrane-forming additive, and 3 lb/bbl CM guar gum respectively. The green color in the last three photos is caused by a dye that was added to the fluids.

Polymer degradation testing

In order for a viscosified formate brine to clean up over time without the use of breakers, it is important that the polymers self-degrade within a reasonable amount of time in the given formate brine. Breakers have never been required in the field when biopolymers have been used in combination with calcium carbonate bridging material. In solids-free applications, there will be more polymers entering into the formation, which will need to break down and flow back. The up-side, however, is that there will be no damage caused by solids invasion.

Testing was performed to check to what extent fluids with xanthan gum and the membrane-forming additive lose their viscosity when exposed to downhole temperatures. Two samples of 15.0 lb/gal (1.80 g/cm^3) cesium/potassium formate brine were tested for degradation at 284°F (140°C). One sample contained 2.0 lb/bbl xanthan gum and the other contained 4.0 lb/bbl membrane-forming additive. The samples were hot rolled at 248°F (140°C) and the Fann 35 viscosity was measured at 122°F (50°C) regular intervals. The results are shown in Figure 9 and Figure 10. For the 15.0 lb/gal (1.80 g/cm^3) cesium/potassium formate brine that was used in this study, one can see that the viscosity decreased gradually during the 100 days of testing. Unfortunately the testing was terminated before the viscosity stabilized. The fluid that was left was very thin with a very small amount of residue. The membrane-forming additive seemed to maintain a more constant viscosity for a period of at least 7 days, after which the viscosity dropped rapidly between 2 and 3 weeks.

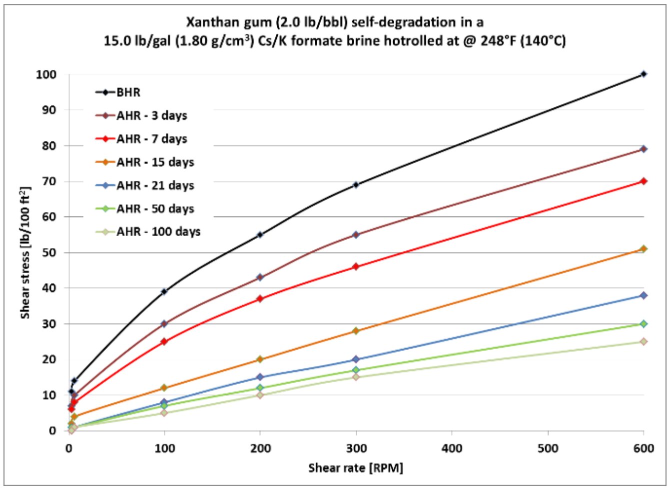

Figure 9 - Self-degradation of 2 lb/bbl xanthan gum in 15.0 lb/gal (1.80 g/cm^3) cesium/potassium formate brine at 284°F (140°C). Fann 35 rheology measured at 122°F (50°C).

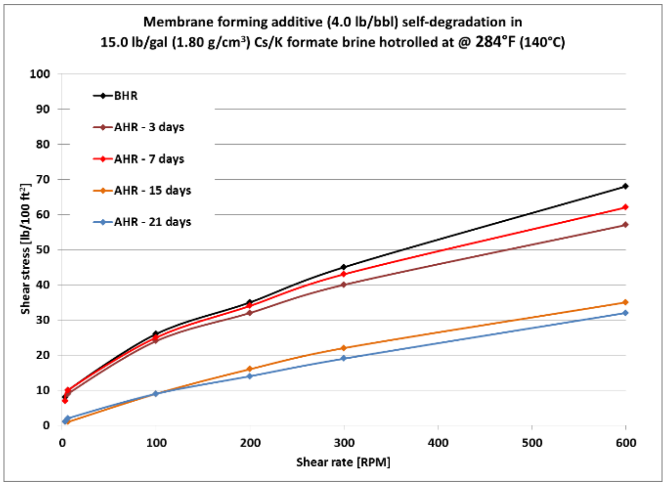

Figure 10 - Self degradation of 4.0 lb/bbl membrane-forming additive in 15.0 lb/gal (1.80 g/cm^3) cesium/potassium formate brine as function of time and temperature. Fann 35 rheology measured at 122°F (50°C).

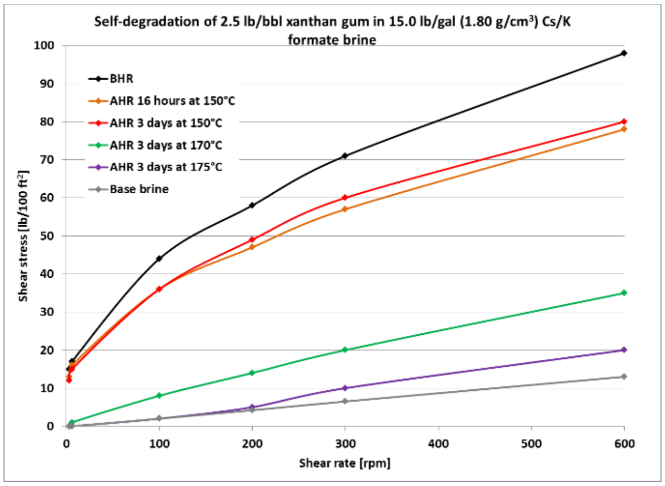

Figure 11 - Self degradation of 2.5 lb/bbl xanthan gum in 15.0 lb/gal (1.80 g/cm^3) cesium/potassium formate brine as function of time and temperature. Fann 35 rheology measured at 122°F (50°C).

Figure 11 shows how 2.5 lb/bbl xanthan gum in 15.0 lb/gal (1.80 g/cm^3) cesium/potassium formate brine degrades with time and temperature. As can be seen, at 347°F (175°C), the polymer is fully degraded after only three days. If three days is too fast for the actual field application, stabilizing agents can be added to increase the temperature stability.

Discussion

The fluid loss test results presented here clearly demonstrate that HPHT solids-free fluids can be formulated with formate brines using only biopolymers for fluid-loss control. One of the goals of the project was to find out whether xanthan gum in formate brines exhibit VETIP-type fluid behavior (Powell, 1995). In order to draw any conclusions, one would need to compare test results from linear and radial testing. One characteristic of a VETIP type fluid is that it should not form any filter cake or polymer skin ("polymer cake") in a radial test configuration. Some skin/cake build-up was seen in all of the tests, and most likely contributed to the observed fluid-loss control.

Testing on filter paper versus testing on porous core material, however, makes a significant difference to the results. Despite the fact that the filter paper compared to the aloxite disk has significantly smaller pore throat size (2.7 µm versus 10 µm in the aloxite disk) and its permeability is much lower, no fluid loss control could be observed on filter paper. This difference between the linear tests on paper and on the 0.25" (0.635 cm) thick aloxite disk means that the filtrate viscosity and non-zero yield stress inside of the aloxite disk must play a part in the fluid loss control mechanism. The difference between the results on paper and the results on the aloxite disk also confirms what Powell (1995) and many other researchers have concluded before, i.e. that filter paper is not a well-suited media for performing realistic fluid loss tests.

Self-degradation tests confirmed that biopolymers in formate brines break down with time and temperature. This is a strong indication that when solids-free formate fluids are used they will clean up with time. Long-term return permeability testing would be required to confirm this. By varying the composition of the formate brine, one can also vary the rate of degradation of the biopolymers. This can be helpful in lower temperature applications, where the strong polymer protection of potassium formate is less desirable. A brine with less potassium formate, more cesium formate, and more water will yield a lower level of polymer protection against temperature degradation. On the other hand, additive packages are available that can enhance polymer stability in higher temperature applications.

Whether the application is drill-in, screen-running, perforating pills, or other fluid-loss pill applications, HPHT solids-free fluids could provide a lot of advantages. Some benefits to consider are:

- Reduced solids yield high lubricity in formate brines.
- Reduced solids promote higher ROP.
- Lowest possible frictional pressure losses due to drag reduction in turbulent flow.
- Minimal screen plugging.
- No filtercake to plug perforation tunnels.

Conclusions

HPHT solids-free fluids consisting of buffered formate brine and biopolymers have successfully been tested for fluid-loss control under high temperature conditions. The two polymers that were tested were a clarified xanthan gum and a membrane-forming additive. When solubilized in high-density formate brines, these polymers generate pseudoplastic fluids with non-zero yield stress that can control fluid-loss through the development of a high apparent viscosity that increases exponentially with the radial distance from the borehole. The increasing apparent viscosity is caused by the decreasing shear rate that the fluid experiences as it progresses radially away from the wellbore.

Linear and specialized radial fluid-loss tests were carried out and results were compared. From testing a 15.0 lb/gal (1.80 g/cm^3) cesium/potassium formate brine at 302°F (150°C), the following could be concluded:

- Linear testing on 0.25" (0.635 cm) thick aloxite disks with 500 psi differential pressure showed good fluid loss control for 2.0 and 2.5 lb/bbl xanthan gum. A 4.0 lb/bbl membrane-forming additive gave slightly better control that xanthan gum. For both additives there was a high spurt loss. Both polymers definitely contributed to the formation of a polymer film (polymer filtercake) at the disk surface. The filtrate was observed to be more viscous than when testing solids-laden formate fluids.
- In the radial testing on 120 mD Berea sandstone and 200 psi differential pressure, fluids with 1.0 lb/bbl or 2.0 lb/bbl xanthan gum provided good fluid loss control. The same was the case for the fluid containing 4.5 lb/bbl membrane-forming additive. A fluid with 2.5 lb/bbl xanthan gum was tested with 500 psi differential pressure and provided good fluid loss control.
- A radial test with 3.5 lb/bbl CM guar gum in an 18.4 lb/gal (2.20 g/cm^3) cesium formate brine was also included for comparison. The results looked acceptable, however, it is currently unknown to what temperature this polymer is stable and whether it will self-degrade and clean up with time.
- Linear testing with filter paper at 500 psi differential pressure produced poor test results for all of the solids-free fluids, indicative of the fact that paper is a non-representative (and therefore inappropriate) filter medium to use to investigate the intricate properties of pseudoplastic fluids.
- By varying the composition of the formate brine, one can vary the temperature stability of biopolymers. This can be helpful in lower-density fluids where the polymer is protected by high concentration of potassium formate brine. For higher temperature applications, certain additive packages can be used with formate brine to increase the thermal stability of biopolymers.

- In order to fully understand the effect of the radial test configuration, it is recommended to perform radial and linear tests on the same core material and replace the thin disks with long cores for the linear testing.
- HPHT solids-free fluids based on formate brines can be useful for drill-inn, screen-running, perforating, and other fluid-loss pill applications. The few fluid loss test results that are reported here show that there are several options for designing such fluids. Fluid loss can be further decreased by increasing the amount of polymeric additives, and it is recommended that the fluid is optimized for the specific application.
- The design of breakers has not been part of this study. However, excellent field experience with drilling and completion fluids viscosified with xanthan combined with very positive test results from self-degradation testing yield confidence that biopolymers that are lost into the formation will degrade with temperature and clean up with time. This, however, will need to be confirmed by long-term return permeability testing.

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Nomenclature

CM = *carboxymethyl*
HEC = *hydroxyethyl cellulose*
HPHT = *High Pressure High Temperature*
HSE = *Health, Safety, and Environment*
PEG = *Polyethylene glycol*
ROP = *Rate of Penetration*
T_m = *Transition temperature / melting temperature*
VES = *Viscoelastic Surfactant*

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