

Formate Fluid Design, Testing, and Modeling for Slim-Hole and Coiled Tubing Operations

Siv Howard, Stuart Leon, Johan Løchen, and Ben Abrahams, Cabot Specialty Fluid; Eric van Oort, EVO Energy Consulting

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Abstract

Despite excellent compatibility between high density formate brines and commonly used biopolymeric viscosifiers that exhibit strong drag reducing properties when circulated in transitional and turbulent flow regimes, the uptake of formate fluids in the field for coiled tubing, slim hole, and extended reach high-pressure/high-temperature applications, has been lagging. One likely explanation for this is that conventional hydraulics software is not capable of handling drag reduction, a phenomenon that occurs when long-chain polymers, like xanthan gum, are circulated in transitional and turbulent flow. The fact that conventional hydraulic software significantly overpredicts frictional pressure losses in applications where transient and turbulent flow is present in parts of the circulating system means that many critical applications are deemed impossible to perform, even though with a properly designed fluid system they are fully feasible.

To rectify this problem, a series of flow loop tests have been performed in a concentrated cesium formate brine with various concentrations of xanthan gum at temperatures up to 230°F (110°C). Testing was also performed on an identical brine that contained a small amount of an alternative biopolymeric viscosifier. Both polymers demonstrated strong drag reducing properties in transient and turbulent flow. Reduction of frictional pressure losses up to 74% was seen in a ½-in diameter pipe section.

The full set of flow loop data with cesium formate brine and xanthan gum has been compiled and used to build a model for frictional pressure loss prediction using advanced machine learning techniques, which has been implemented into an existing hydraulics software package.

The new modelling tool was used to study the hydraulic fluid behavior in a high-pressure high-temperature (HP/HT) slim-hole drilling application. While two conventional hydraulics software packages had previously deemed it impossible to drill with a formate/polymer-based drilling fluid, the new software accounting for drag reduction showed it to be quite feasible. The new modeling result shows that drag reduction is significant in many applications and should not be ignored. The failure to include it when performing hydraulic modeling can lead to significant overestimation of frictional pressure losses for certain fluid types.

The fact that commonly used biopolymeric viscosifiers

provide high-density formate brine with both pseudoplastic and drag reducing properties means that they together form fluids with unique properties, not only for slim hole and coiled tubing drilling, but also for other challenging applications such as extended reach drilling, openhole gravel-packing, and coiled tubing interventions, in the full density and temperature range.

The inclusion of drag reduction in hydraulics software also provides a new tool for drilling fluid evaluation and formulation. Today, when formulating drilling fluids based on formate brines, operators typically demand strict specs on parameters such as PV, YP, and fluid loss, which typically have been optimized for oil-based muds to avoid problems such as differential sticking and barite sag. Optimization for differential sticking and sag is irrelevant for low-solids drilling fluids based on formate brines with biopolymeric viscosifiers, which generate thin filter cakes and do not suspend weighting solids. With the new software, such fluids can now be optimized based on parameters and behavior that really matter, such as reduced pressure losses and improved equivalent circulating density (ECD).

Introduction

The unique ability of high-salinity, high-density formate brines to stabilize xanthan gum at high temperatures was discovered by Shell in the 1980's (Clarke-Sturman and Sturla, 1988; Downs, 1991). This discovery led to the development of the formate technology for many applications, including coiled tubing (CT) and slim hole drilling (Downs, 1992; Howard, 1995). The pseudoplastic (shear-thinning) behavior of the xanthan polymer, combined with the almost solids-free nature of the fluid, provide very favorable behavior with minimum ECD for all drilling applications. In addition to this already excellent rheological behavior of the fluid, the ability of xanthan to provide drag reduction (or friction reduction) allows for elevated pump rates with minimal frictional pressure losses in transient and turbulent flow, which further lowers pump pressures and ECD in slim hole and CT applications. With the naturally lubricating properties of the formate brines themselves when in contact with many steel types, these fluids should have all the right properties for extended reach CT and slim hole applications under HP/HT conditions.

To date, formate fluids have been used in hundreds of applications, mostly HP/HT reservoir drilling and open-hole

completions. With few exceptions, these have not been CT or slim-hole applications, despite the fact that the drag-reduction benefits of formate brines viscosified with xanthan gum were clearly demonstrated in flow loop experiments already in the 1990's (Howard, 1995).

One reason for the lagging uptake of biopolymer viscosified formate fluids for CT and slim-hole application in the field could be the difficulty of demonstrating the drag reducing advantages of these fluids with conventional hydraulics software, which typically does not account for the drag reduction effects of fluids circulated in transient and turbulent flow. This is an oversight, as formate fluids overcome many of the downsides of routinely-used high-density halide-based fluids, which are inherently incompatible with biopolymers, leading to their early degradation in slim-hole and CT applications.

To rectify this problem, an advanced hydraulics software package has been developed that considers the drag reduction properties of formate brines viscosified with xanthan, using lab data generated in a flow-loop under challenging conditions of turbulence and high shear (Gul et al., 2019).

This paper discusses the unique compatibility of formate brines with biopolymers, summarizes the drag reduction flow-loop test results with xanthan gum and another biopolymeric viscosifier, provides a brief description of the hydraulic software package, and finally presents the hydraulics results of a challenging HP/HT slim-hole drilling application, which two conventional hydraulic software packages had deemed impossible to drill with a formate/polymer-based drilling fluid.

Drag Reducers in High-Density Brines

It is a known phenomenon that under turbulent and transient flow conditions, frictional pressure losses can be reduced drastically by adding small quantities of high molecular weight polymers, fibers, or surfactants to the fluid. These additives are referred to as drag reducers or friction reducers, and the phenomenon is called drag reduction or friction reduction.

The phenomenon of drag reduction, although first discovered as early as 1948, is not fully understood (Shah et al., 2018). Experimental and analytical results have shown that drag reducers interact with turbulent eddies, but there is no theory to describe the flow, which makes it impossible to quantitatively characterize the behavior of polymers in solutions (Ross et al., 2017). This is the reason that most commonly used hydraulics software packages are unable to consider drag reduction and can under certain circumstances give erratic results.

There is a lot of information on drag reducers designed for use in water and low-salinity fracturing fluids (slick water) in the oilfield literature, but very little about the use of drag reducers in heavy brines or high-density fluids in slim hole and coiled tubing applications. Commonly used drag reducers are long chain polyacrylamides that can have anionic or cationic species (Rodvelt et al., 2015). Common for these synthetic polymers is that they are not very temperature- and shear-resistant and degrade quickly during use (Shah et al., 2018). Typically, polyacrylamide polymers with a molecular chain length that is too short will not provide enough drag reduction,

while the ones with longer chain lengths easily break when exposed to high shear (scissoring) and thereby provide inadequate drag reduction (Ross et al., 2017). Polymers that perform well as drag reducers are high molecular weight polymers that are linear and uncoiled. Unfortunately, linearity and coiling are affected by the presence of ionic agents that can electrostatically reduce the radius of gyration of the polymer and sometimes cause crosslinking to other polymers, creating a non-linear network which may adversely affect drag reduction performance.

Patel et al. (2013) discuss the use of drag reducers in drilling and completion applications and point out that the drag reducers most commonly used are very high molecular weight linear molecules such as partially hydrolyzed polyacrylamide (PHPA) and polyacrylates. However, these polymers are ineffective in divalent heavy brines because they precipitate. To overcome the compatibility limitations, these PHPA and polyacrylates polymers are copolymerized with sulfonated or phosphonated monomers. The discussion on these materials is, however, limited to divalent halide brines and does not consider heavy formate brines, which are monovalent.

Ke et al. (2006) tested the performance of drag reducers in high-density halide brines for use in CT applications at high temperatures. The study was limited to water-soluble polymers that are already used in high density brines for completion and workover applications, because the commonly used drag reducers, designed for water and low-salinity fluids were considered ineffective due to their concerning solubility and dispersion characteristics along with the fact that their performance can be affected by the presence of salt and lack of free water. The two water-soluble polymers that were included in the study were selected from polyacrylamide, guar gum, xanthan gum, polyethylene oxide, hydroxyethyl cellulose (HEC) and carboxymethyl cellulose. The purpose of the study was to qualify a drag reducer for use in a 11.0 lb/gal (1.32 g/cm³) CaCl₂ brine for a 400°F (204°C) CT well drillout application. However, the fluids were only heat-aged at 300°F (148°C) for 1.5 hours before they were tested. Ke et al. did not disclose which type of friction reducer performed best but concluded that brine type had a significant effect on the friction-reducing property and thermal stability of the drag reducers. The drag reducers performed better in monovalent NaCl and NaBr brines than in the divalent CaCl₂ and CaBr₂ brines.

Fryzowicz and Maas (2011) investigated the suitability of various biopolymers for drag reduction and carrying capacity for CT-conveyed sand jetting perforation on a deep tight gas well. Their requirement was a fluid that exhibits pseudo-plastic behavior in the entire operation. It should be a sand carrier in low-shear conditions, drag reducing, gel forming, tolerant to elevated pH levels, and none-impairing after final treatment. Based on their flow-loop test results, the common biopolymers were ranked in the following order from best to worst drag reduction capability: 1) xanthan gum, 2) guar gum (including chemically modified guar), 3) HEC.

These results are very much in agreement with a study performed by Shah and Zhou (2003), which compared the drag reducing effect of four polymer solutions in 1, 1½, and 2¾ -in

CT applications. The polymers were xanthan gum, guar gum, PHPA, and HEC. For the flow investigated, the drag reduction effect ranked in the order from best to worst: 1) xanthan gum, 2) PHPA, 3) guar gum, and 4) HEC. In fact, in the 2 $\frac{3}{8}$ -in CT case, HEC exhibited no drag reduction at all.

In preparation for a very challenging extended reach coiled tubing drillout, Ahn (2015) did a thorough fluid system investigation and concluded that xanthan gum is the recommended polymer for coiled tubing cleanouts (CTCO) because, in addition to exhibiting strong drag reduction, it exhibits high LSRV (low shear rate viscosity) values and also demonstrates power law behavior at much lower shear rate than other traditional polymers such as guar gum or HEC.

In conclusion, from published literature it appears that synthetic polymers that are used extensively with good results in fresh water and low-salinity applications are unsuitable for use in slim hole and CT applications with heavy brines due to their shear sensitivity and temperature limitations. Out of the more shear-resistant biopolymers, xanthan gum appears to be the one with the best drag reducing properties.

Biopolymeric Viscosifiers as Drag Reducers in High-Temperature Formate Brines

Previous research has shown that formate brines have a unique ability to stabilize xanthan gum at high temperature by increasing its transition or melting temperature, T_m , and by providing anti-oxidant protection. (Downs, 1991; Howard, 1995; Howard et al., 2015; Howard et al. 2017). 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 exhibits strong water-structure making properties and increases the T_m of xanthan to over 396°F (200°C) and raises the 16-hr thermal stability to almost 356°F (180°C). 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.

Many papers have been published on how the temperature stability of xanthan in formate brines can be further enhanced using additives (van Oort et al., 1997; Kippie et al. 2002; Messler et al., 2004; Howard et al., 2015). Examples are given of a viscosified potassium formate brine being stable for three hours at 400°F (204°C). A well performing additive package is a combination of 5 vol% PEG (polyethylene glycol) 200 and 2 lb/bbl magnesium oxide (Howard et al., 2015). The addition of stabilizing additives brings the long-term stability very close to the transition temperature.

In addition to xanthan, there are other biopolymers that have been found to gain some favorable temperature stability when protected by formate brines. Examples of these are polyanionic cellulose (PAC) and starch (Howard, 1995). As these are not long chain polymers, they are most likely not as efficient for drag reduction as xanthan gum.

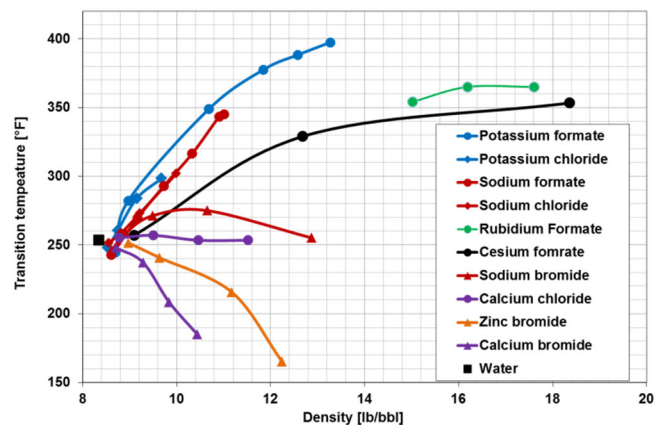


Figure 1 - Transition temperature, T_m , of xanthan gum as function of brine concentration for a variety of typical oilfield brines. The figure is adopted from Howard et al. (2015).

Another biopolymer that has shown to display properties very similar to that of xanthan gum when dissolved in formate brines is discussed by Howard et al. (2017). This polymer, referred to as a ‘membrane forming additive’ has been found to be a good replacement for xanthan gum in applications where very high viscosity is required, such as viscous pills and gravel packing carrier fluids. In such high viscosity applications, xanthan gum can generate some significant but fragile gel structure when left static in buffered formate brines under ambient temperature conditions. This is likely due to some cross-linking taking place with the divalent carbonate ion present in the pH-buffer. Although these gels are very fragile, there are applications where such behavior is unwanted. As it is not advised to remove the buffer (Howard & Downs, 2009), this ‘membrane forming’ biopolymeric viscosifier is a good alternative to xanthan gum in certain applications. There is currently no information in the literature whether this alternative viscosifier has drag reducing properties.

Previous Use of Formate Fluids in Slim Hole and CT Applications

The first ever use of a formate drilling fluid was indeed in a successful CT drilling application. Simmons and Adam (1993) describe Shell’s first use of a sodium formate drilling fluid to re-enter a well in the Berkel field in the Netherlands with coiled tubing.

In 1997, Shell Expro followed up with the successful use of potassium formate brine for their first CT drilling project in the North Cormorant field (Lord et al., 1997). Surface testing had revealed that oil-based mud (OBM) at 11.5 lb/gal (1.38 g/cm³) could not be pumped at the required rate (2 bbl/min) because friction pressures exceeded the maximum allowable value of 4,000 psi (276 bar) as well as being detrimental to CT fatigue life. A new candidate well was then selected that allowed for a larger hole size (3 $\frac{3}{4}$ in). New pumping tests were done, this time with a potassium formate fluid included. With the potassium formate fluid, the required 2 bbl/min rate was achieved without exceeding the 4,000-psi surface pressure limit. Again, the OBM

failed the test. The potassium formate fluid was successfully used to drill the CT sidetrack.

Beck et al. (1993) and Powell et al. (1995) describe the drilling of many horizontal wells with coiled tubing with xanthan gum in monovalent brines in Prudhoe Bay, Alaska. Although the brines used for this were mainly lighter potassium chloride brines, the principle is the same. The fluid was designed with xanthan gum in monovalent brines for optimum shear-thinning rheology. The authors report that standpipe pressures had been 15-20% below those predicted by conventional friction pressure loss calculations, confirming the drag reduction properties of xanthan gum.

Encouraged by this success with drilling horizontal sidetracks with xanthan-viscosified monovalent brines in Prudhoe Bay, Statoil chose a solids-free potassium formate fluid to drill a well with a very challenging well path with CT (Samsonsen et al., 1998). After an initial attempt with mud weight being too low, the well was successfully drilled.

The most impressive application of xanthan-viscosified formate brines for challenging CT applications to date is the Tuscaloosa 400°F (204°C) CTCO job (Messler et al., 2004). Previously, a large amount of high-density OBM had been lost to the formation when drilling the well, which led to dehydration of barite in the perforation tunnels and even encroachment into the wellbore. In this application, the potassium formate fluid enabled the CT milling job to go forward as planned after two unsuccessful attempts with unviscosified halide brine. The ability of the formate brine to stabilize the xanthan at the required high temperature provided the fluid with the necessary drag reducing properties for this very high-temperature application. The first attempts to perform this workover with the near-Newtonian fluid had failed due to the inability to reach the top of the barite plug at 19,412 ft (5,917 m). CT pickup weights had reached 80% of maximum overpull at the liner top at 16,231 ft (4,947 m), and it was deemed too risky to continue. The successful potassium formate fluid underwent extensive laboratory testing and qualification before use. Manipulation of biopolymer concentration and stabilizing additives led to achieving the goal of reducing the PV as low as possible while maximizing the low shear rate viscosity (LSRV). High LSRV (>25,000 cP at 0.0636 sec⁻¹) was required for removing barite solids, yet a low PV was required to prevent excessive pump pressures. The authors of the paper claimed that the development of this milling fluid had broken new ground in CT fluids technology for deep hot wells.

Flow-Loop Testing

The University of Texas at Austin has carried out extensive flow loop testing of cesium formate brine viscosified with biopolymers to obtain drag reduction data that can be used for hydraulic modeling. The full details of the testing equipment, procedures, and calibrations have been published elsewhere (Vajargah et al., 2017; Johnson et al., 2018; Gul et al., 2019). The pressure loss was measured over 10 ft (3.05 m) in two 18 ft (5.18 m) long pipe sections. The outer diameters of the pipes were ½ in (1.270 cm) and ⅜ in (0.9525 cm), and the wall thickness for both pipes was 0.035 in (0.089 cm).

Testing with Xanthan Gum

A total of 11 cesium formate fluids were tested, all based on an 18.6 lb/gal (2.20 g/cm³) cesium formate brine, buffered with about 3 lb/bbl (8.6 kg/m³) KHCO₃/K₂CO₃. One test fluid was just the cesium formate brine, and the others were added increments of 0.25 lb/bbl (0.714 kg/m³) up to a total of 2.50 lb/bbl (7.14 kg/m³) purified xanthan gum. This range covers the concentrations of xanthan that are normally used in the field, typically 0.25 – 0.75 lb/bbl (0.71 – 2.14 kg/m³) for drilling fluids, and generally not exceeding 2.50 lb/bbl (7.14 g/m³) for various types of viscous pills. The fluids were tested at temperatures of 100°F (38°C), 150°F (66°C), and 230°F (110°C). Flow-loop tests were limited to an upper temperature of 230°F (110°C).

The xanthan-viscosified fluids tested were shear-thinning and thixotropic; when left static they generated a significant but fragile gel structure. It was therefore imperative before performing measurements to circulate the fluid in the flow loop at low temperatures in turbulent flow until the frictional pressure drop readings stabilized. A rotational viscometer was used to obtain the rheological parameters in accordance with a yield-power-law (YPL) rheological model.

The results of the flow loop testing are presented in more detail elsewhere (Johnson et al., 2018; Gul et al., 2019). Figure 2 and 3 show the measured frictional pressure losses as function of flow rate at the highest test temperature of 230°F (110°C) for the ⅜-in (0.9525 cm) and the ½-in (1.270 cm) OD pipes respectively.

As can be seen from the results, fluids with higher polymer concentration show larger pressure losses in laminar flow, as expected, but smaller pressure losses in turbulent flow regime due to the drag reducing effect of the polymers. The drag reduction effect was shown to be significant, especially in the smaller diameter pipe, where a reduction in frictional pressure losses of up to 65% could be measured in the fluid with the highest concentration of xanthan. In this smaller pipe, the polymers shifted their role completely, from viscosifiers in the laminar flow range to drag reducers in the transitional and turbulent flow ranges. The expectation was that at sufficiently high polymer loading, the high viscosity of the fluid would start dominating the pressure losses again. In the larger diameter (½ in) pipe about 50% reduction in frictional pressure losses could be measured for the best performing polymer concentration, which was 1.25 lb/bbl (3.57 kg/m³).

Testing with Alternative Biopolymeric Additive

The remarkable finding from the rheological test performed with the smallest (⅜ in) pipe, i.e. that xanthan gum continued to decrease frictional pressure losses with increasing polymer loading in the entire concentration range up to the highest polymer loading, triggered the interest in increasing the polymer concentration even further. However, due to the gelling problems with xanthan in buffered formate brines at high polymer concentrations, as described above, the previously described alternative biopolymeric viscosifier was tested instead. This additive can be added to buffered formate brines in higher concentrations with significantly less gelling.

A polymer concentration of 3.0 lb/bbl (8.57 kg/m³) was selected, which displays very similar rheological properties to the fluid containing 1.5 lb/bbl xanthan (4.29 kg/m³) xanthan gum when measured with a rotational viscometer at 150°F (66°C), cf. Figure 4. It can be observed that this alternative viscosifier also appears to be less temperature thinning than xanthan gum.

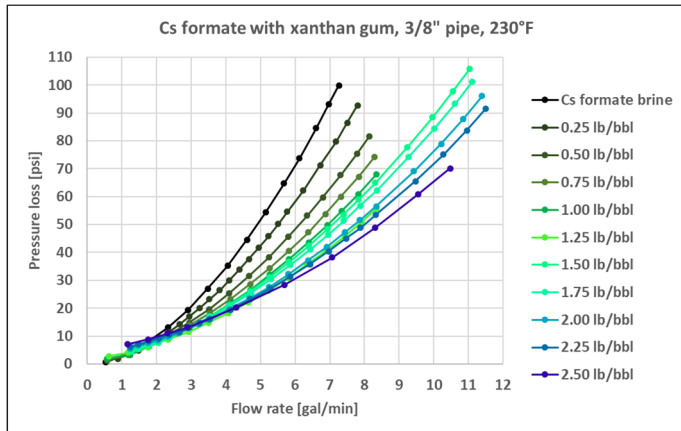


Figure 2 – Results of flow loop testing in test section with the smallest pipe diameter (3/8 in (0.9525 cm) OD). Mostly transitional and turbulent flow regimes were experienced in this tubing size.

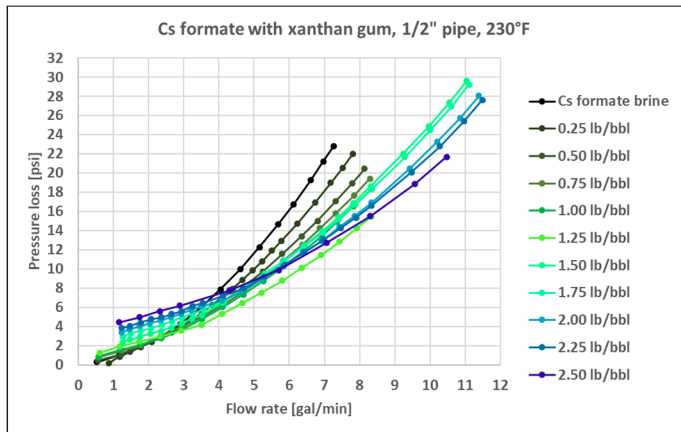


Figure 3 - Results of flow loop testing in test section with the largest pipe diameter (1/2 in (1.270 cm) OD). Laminar, transitional, and turbulent flow regimes were experienced in this tubing size.

Unfortunately, differential pressure losses were only measured in the large (1/2 in) pipe section. The results of the testing are shown in Figures 5 to 7 for the three temperatures respectively. The pressure losses are plotted together with those for the fluid with 1.25 lb/bbl xanthan gum, which was the best performing xanthan fluid in the 1/2-in pipe, and with the 1.50 lb/bbl xanthan fluid, which has the most compatible rheology (see Figure 4). Reduction in frictional pressure losses of up to 74% was measured, which can be compared with about 50% for the best performing xanthan gum fluid in the 1/2-in diameter pipe.

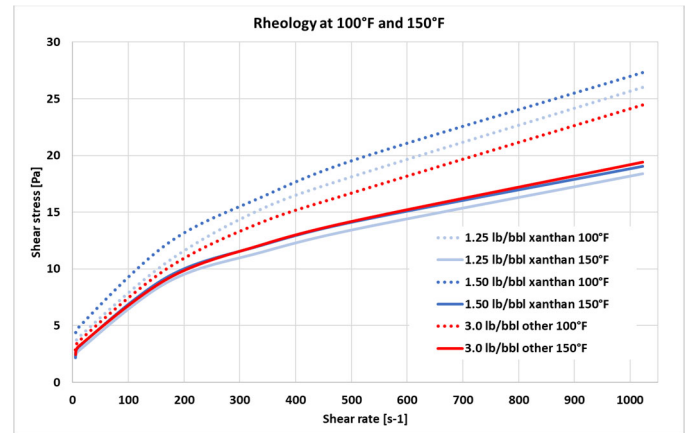


Figure 4- Shear stress versus shear rate for cesium formate brine with 3.00 lb/bbl (8.57 kg/m³) other biopolymeric viscosifier compared to cesium formate brines with 1.25 and 1.50 lb/bbl (3.57 and 4.29 kg/m³) xanthan gum respectively.

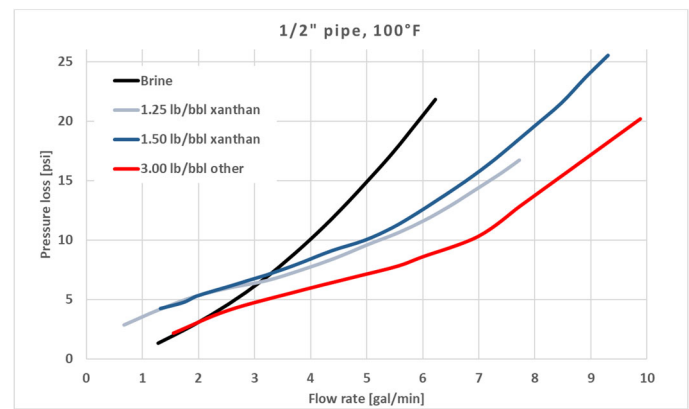


Figure 5 – Frictional pressure losses as function of flow rate for cesium formate brine with two concentrations of xanthan and with an alternative biopolymeric additive measured in the 1/2-in pipe at 100°F (38°C).

Temperature dependence

Figure 8 shows the temperature dependence of the frictional pressure losses for cesium formate brine with 1.50 lb/bbl xanthan gum and with 3.00 lb/bbl alternative biopolymeric viscosifier. These fluids have similar viscosity at 150°F (66°C) (see Figure 4). As can be seen, the drag reduction performance varies very little with temperature and both xanthan gum and the alternative viscosifier have excellent drag reduction properties in the whole test temperature range (100 – 230°F (38 – 110°C)). As neither of these two polymers are very temperature thinning, one can expect this to be the case also at higher temperatures.

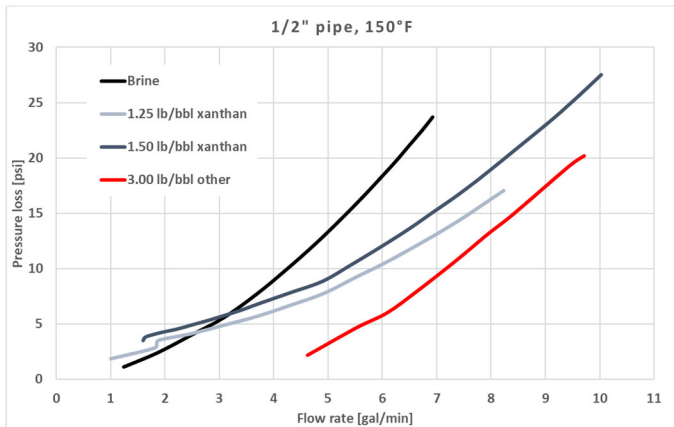


Figure 6 - Frictional pressure losses as function of flow rate for cesium formate brine with two concentrations of xanthan and with an alternative biopolymeric additive at 150°F (66°C).

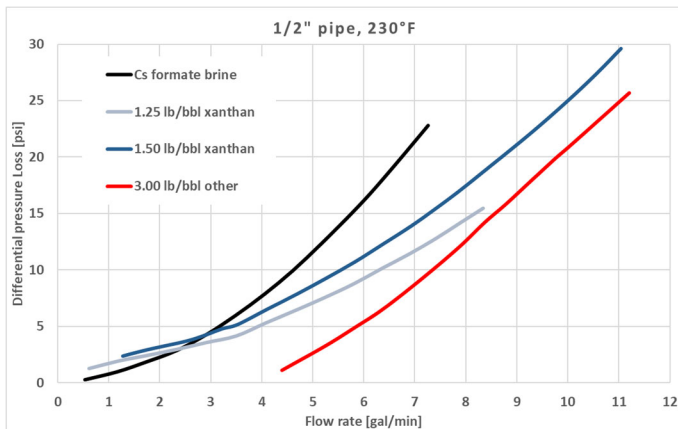


Figure 7 - Frictional pressure losses as function of flow rate for cesium formate brine with two concentrations of xanthan and with an alternative biopolymeric additive at 230°F (110°C).

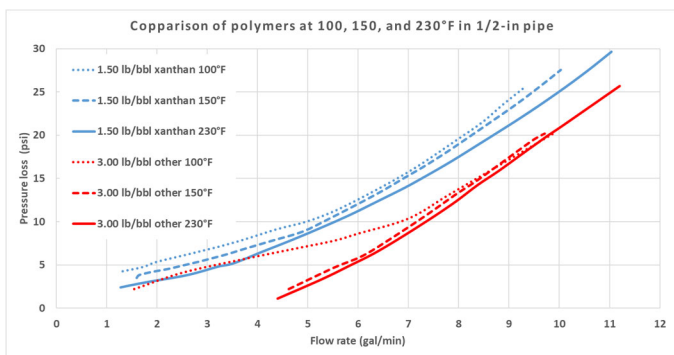


Figure 8 - Frictional pressure losses as function of flow rate for cesium formate with 1.50 lb/bbl (4.29 kg/m³) xanthan gum and with 3.00 lb/bbl (8.57 kg/m³) alternative biopolymeric viscosifier at all three test temperatures in the 1/2-in pipe section. These polymer concentrations have similar viscosity measured on a rotational viscometer.

Hydraulic Model with Drag Reduction

The full set of flow loop data has been compiled and used

to build a predictive model for frictional pressure prediction in transient and turbulent flow using advanced machine learning techniques (Johnson et al. 2018; Gul et al., 2019). Two machine-learning regression algorithms (random forest and XGBoost) were trained using the experimental data-set to estimate a correction factor to the commonly used Dodge and Metzner's friction factor correlation. A regressor was trained with the features of fluid rheology properties and the Reynolds number. Using this approach, the friction factor estimation error was decreased to only 1.28%. Details of this work are described by Gul et al. (2019).

Qualifying Fluid for a Challenging HP/HT Slim Hole Drilling Application

An operator considered the use of a low-solids cesium formate based drilling fluid for a challenging ultra-HP/HT re-entry drilling application. A 19.2 lb/gal (2.30 g/cm³) drilling fluid was required, which would give an equivalent static density (ESD) of 18.7 lb/gal (2.24 g/cm³) and a bottom-hole pressure of 13,390 psi (923 bar).

The preferred solution was to drill 1,634 ft (498 m) 3½-in open hole from the base of the currently installed 4½-in liner. (see well configuration in Figure 9). The BHST (bottom-hole static temperature) was 385°F (196°C). Due to a narrow margin between pore pressure and fracture pressure gradient, the fluid needed to provide strict control on maximum allowable ECD value. The fluid was also required to be thermally stable, have low solids content, low viscosity, limited sag potential, and good hole cleaning capability.

The fluid strategy for the well was to utilize a solids-free cesium formate fluid only containing the lowest possible amount of xanthan gum to allow for enough cuttings transport and fluid loss control. The operator already had positive experience with using cesium formate brine in a well in the same area with similar ultra-HP/HT conditions. As the fluid density was approaching the limit, true crystallization temperature (TCT) was critical, and the option of adding a small amount of micronized weighting solids had to be left open. Micronized weighting solids were also required on the rig as no higher density compatible kill-weight fluid was available. A certain amount of xanthan gum was therefore required to suspend any micronized solids.

Two conventional hydraulics software packages were used to evaluate the feasibility of drilling the required section with a xanthan-viscosified cesium formate fluid. The 19.2 lb/gal (2.30 g/cm³) drilling fluid was formulated based on a very concentrated cesium formate brine, containing 0.75 lb/bbl xanthan gum, some high temperature starch, and a small amount of calcium carbonate bridging solids was used for fluid loss control. The simulations were run for the scenario of drilling ahead from 12,122 ft (3,695 m) to 13,800 ft (4,200 m) with 60 rpm, an ROP of 8.2 ft/hr (2.5 m/hr), and a pump-rate of 100 gal/min (455 l/min). Both software packages concluded that the application would be unfeasible due to ECD values exceeding fracture gradient limits.

This opportunity has now been revisited with the new

software package to verify whether drag reduction is significant enough in this application to change the ECD behavior.

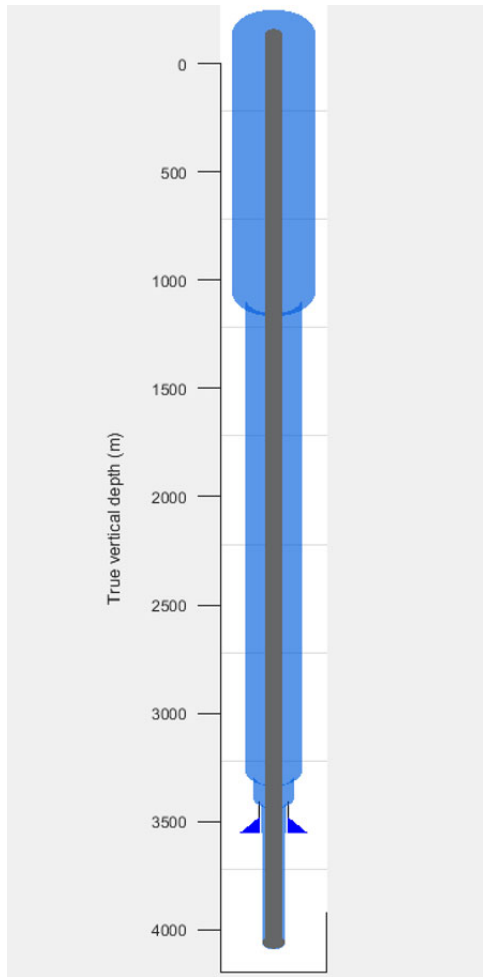


Figure 9 – Well configuration of ultra-HP/HT slim-hole re-entry drilling application.

Assuming no drag reduction, and by using the Dodge & Metzner model, the bottom-hole ECD at the end of drilling was determined to be 19.57 lb/gal (2.35 g/cm^3). By using the user-defined friction model, assuming a xanthan concentration of 0.75 lb/bbl (2.14 kg/m^3), the ECD was reduced to 19.26 lb/gal (2.31 g/cm^3), see Figure 10.

Further fluid optimization work was then done to achieve the lowest possible ECD using more advanced simulation. Several fluids were considered, each containing only xanthan gum as primary viscosifier and drag reducer (i.e. no starch or calcium carbonate used). Xanthan concentrations of 1.25, 1.50, 1.75, and 2.00 lb/bbl ($3.57, 4.29, 5.00, \text{ and } 5.71 \text{ kg/m}^3$) were assumed. The simulation results are shown in Figure 11. Based on these results, it appears that for this well the lowest ECD can be achieved with a xanthan concentration of 1.75 lb/bbl (5.00 kg/m^3). When circulating at 100 gal/min (379 L/min) the ECD value modeled with the Dodge & Metzler model was shown to be approximately 0.2 lb/gal too high, and it could be reduced by

another 0.11 lb/gal by optimizing the fluid. The corresponding reductions when circulating at the highest rate (150 gal/min) were 0.50 and 0.23 lb/gal ($0.06 \text{ and } 0.03 \text{ g/cm}^3$) respectively. Although this ECD modification may at first appear to be modest, it basically turns an “impossible to drill” scenario into a feasible scenario. Note that this concentration of xanthan is also expected to yield the required fluid loss control (Howard et al., 2017) for the intended application, such that any other additives can be kept to an absolute minimum.

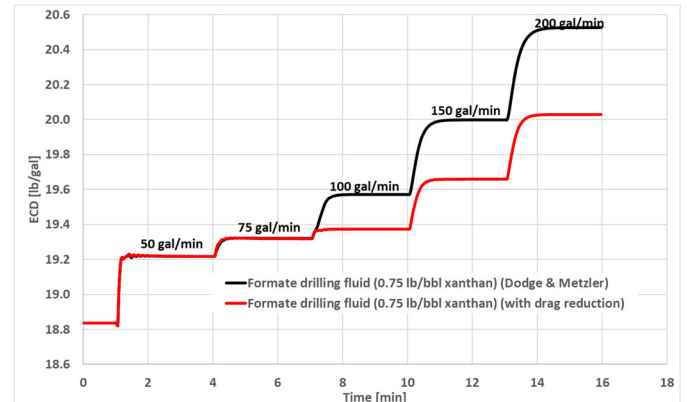


Figure 10 – Bottom-hole ECD as function of circulating rate for a standard 19.2 lb/gal cesium formate drilling fluid containing 0.75 lb/bbl xanthan gum. The hydraulic simulation has been performed at five different circulating rates using the Dodge & Metzler model (black line) and the user-defined friction model (red line).

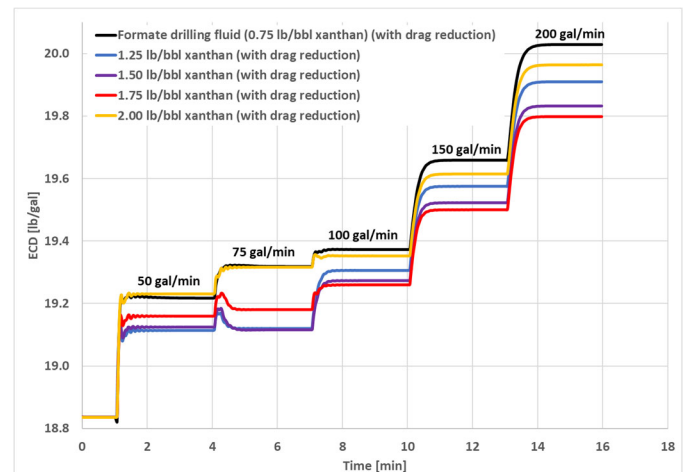


Figure 11 - Bottom-hole ECD as function of circulating rate for a standard 19.2 lb/gal (2.30 g/cm^3) cesium formate drilling fluid containing 0.75 lb/bbl xanthan gum compared with cesium formate brine of the same density containing various amounts of xanthan gum. All simulation have been performed at five different circulating rates using the user-defined friction model.

Discussion

The inclusion of drag reduction in a hydraulics software package has been a very useful exercise and has clearly demonstrated the importance of considering drag reduction in challenging applications. However, only a relatively limited dataset specific to cesium formate brine and xanthan gum was

used for modeling. Before the software is used more generally for all formate brines, the following should be investigated:

- **Effect of formate brine type.** All three formate brines, i.e. sodium formate, potassium formate, and cesium formate have a very similar effect on biopolymers in that they are all good water-structure makers. The xanthan polymers are therefore expected to have a similar configuration in the three brines, and the model is expected to be valid for all three brines. Flow-loop tests with sodium and potassium formate brines are recommended to confirm this.
- **Effect of polymer type.** It was unexpected that the alternative biopolymeric viscosifier that was added in one 'arbitrary' concentration performed even better than xanthan, which was known to be an excellent drag reducer. This alternative polymer, which is also a combined pseudoplastic viscosifier and drag reducer, should be tested at various concentration in both diameter pipes.
- **Temperature dependence.** Formate fluids viscosified with xanthan are not very temperature thinning, so it is expected that good drag reduction is provided by these fluids up to the transition temperature of the polymer (Figure 1). The performance is expected to decline above the transition temperature, where polymers also readily degrade. The alternative biopolymer that was tested is even less temperature thinning, so it is also expected to perform well at higher temperature. This polymer doesn't have a transition temperature, which means that its performance could be less affected by higher temperature. However, both polymers degrade quickly in this high temperature range, and would most likely not maintain drag reduction properties if exposed for a long time. High temperature flow-loop testing would be recommended to investigate the effect of very high temperatures on drag reduction performance of both polymers.
- **Effect of solids.** Some solids are normally present in formate drilling fluids in the form of CaCO_3 , added as bridging material, or drilled solids, picked up during use. Solids impact the rheology of the fluids, but it is uncertain to what extent the low concentration of any solids present in formate brine have any impact on drag reduction. Flow-loop testing with solids is therefore recommended.
- **Field Fluid:** Any fluid that is used in the field will change properties over time. Polymer degradation over time by shear and temperature leads to degradation of the fluid's drag reducing properties. Rotational viscometers are not suitable for determination a fluid's drag reducing properties. Johnson et al. (2018) recommend the use of automated real-time measurement of the friction factor using a pipe viscometer method. This method utilizes pressure vs. flow rate data to calculate rheological parameters for the fluid under investigation, as was done in characterizing the drag reduction properties of the fluids described here.

Conclusions

The inability of conventional hydraulics modeling software to consider drag reduction is thought to be an important reason for the lagging uptake of biopolymer viscosified formate brines for challenging CT and slim hole applications in the field. Triggered by this, a flow-loop study was conducted, and advanced machine learning techniques were utilized to implement drag reduction in an existing hydraulics modeling software package. The software was used to qualify a cesium formate / xanthan gum fluid system for a very challenging HP/HT slim-hole drilling application that had previously been deemed extremely challenging by two conventional hydraulics software packages. The following conclusions are drawn from this study:

- Drag reduction has a significant impact on frictional pressure losses in formate brine/biopolymer fluid systems and should not be ignored. This doesn't only apply to CT applications where drag reducers are specifically added to reduce frictional pressure losses, but to all applications where transient and turbulent flow is experienced.
- Extensive flow-loop testing has confirmed that cesium formate brine viscosified with xanthan gum exhibits significant drag reduction when circulated in transient and turbulent flow. Up to 65% reduction was measured in the smallest ($\frac{3}{8}$ in) pipe section.
- The use of a newly developed software package to model a slim hole HP/HT drilling application, which was deemed impossible by two conventional software packages, confirmed that the effect of drag reduction can be significant and should not be ignored. A reduction in ECD from 19.57 to 19.26 lb/gal (2.35 to 2.31 g/cm^3) was achieved at a circulating rate of 100 gal/min (379 L/min) when drag reduction was considered and the xanthan concentration was optimized. Significantly higher reductions were predicted for higher circulating rates.
- A single flow-loop test was also performed with an alternative biopolymeric viscosifier in the $\frac{1}{2}$ -in pipe section. This viscosifier, although tested at only one concentration, showed better drag reduction performance than any of the 10 xanthan concentrations that were tested. Up to 74% reduction in pressure losses was measured in the $\frac{1}{2}$ -in pipe compared with up to 50% for the best xanthan viscosified fluid. It is recommended to test this biopolymer at more concentrations to confirm its superior performance and generate data that can be integrated into the hydraulic modeling software package.
- The testing was performed in a concentrated cesium formate brine. However, all formate brines are compatible with biopolymers, and stabilize them at high temperatures. High-temperature flow-loop tests should be performed to determine drag reduction properties of biopolymeric viscosifiers in all formate brines up to their temperature limits of about 400°F (204°C).

- The newly developed hydraulics software package also provides a new tool for drilling fluid formulation. Today, when formulating and evaluating drilling fluids based on formate brines, the operators demand strict specs for parameters such as PV, YP, and fluid loss, which typically have been optimized for oil-based muds to avoid differential sticking and barite sag problems. Optimization for differential sticking and sag is irrelevant for low-solids drilling fluids based on formate brines with biopolymeric viscosifiers, which generate thin filter cakes and do not suspend weighting solids. With the new software, such fluids can now be optimized based on parameters that matter, such as reduced pressure losses and improved ECD.
- The high drag-reducing effect that was found in formate brine with commonly used biopolymeric viscosifiers suggests that these fluid systems are quite suitable for many applications where transient and turbulent flow is experienced. In addition to CT and slim hole drilling, examples of such applications are CTCO, other CT interventions, open-hole gravel packing (OHGP), including extended reach and HP/HT applications.

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Nomenclature

<i>BHCT</i>	= Bottomhole circulating temperature
<i>BHST</i>	= Bottomhole static temperature
<i>CaBr₂</i>	= Calcium bromide
<i>CaCl₂</i>	= Calcium chloride
<i>CT</i>	= Coiled tubing
<i>CTCO</i>	= Coiled tubing cleanout
<i>ECD</i>	= Equivalent circulating temperature
<i>HEC</i>	= Hydroxyethyl cellulose
<i>HP/HT</i>	= High pressure high temperature
<i>KHCO₃</i>	= Potassium carbonate
<i>K₂CO₃</i>	= Potassium bicarbonate
<i>LSRV</i>	= Low shear rate viscosity
<i>NaBr</i>	= Sodium bromide
<i>NaCl</i>	= Sodium chloride
<i>OBM</i>	= oil-based mud
<i>PEG</i>	= Polyethylene glycol
<i>PHPA</i>	= Partially hydrolyzed polyacrylamide
<i>TCT</i>	= True crystallization temperature
<i>T_m</i>	= Transition temperature
<i>YPL</i>	= Yield-power-law

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