The Effect of Salinity on the Rheological Properties of Water Based Mud under High Pressures and High Temperatures for Drilling Offshore and Deep Wells

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Abstract

The significance of exploring deep and ultra-deep wells is increasing rapidly to meet the escalating global demands on oil and gas. Drilling at such depth introduces a wide range of difficult challenges. One of these challenges is the negative impact on the drilling fluids rheological properties when exposed to high pressure high temperature (HPHT) conditions and/or becoming contaminated with salts, which are common in deep drilling or in offshore operations.

The drilling engineer must have a good estimate for the values of rheological characteristics of a drilling fluid, such as viscosity, yield point and gel strength, and that is extremely important for a successful drilling operation. In this research work, experiments were conducted on water-based muds with different salinity content, from ambient conditions up to very elevated pressures and temperatures.

In these experiments, water based drilling fluids containing different types of salt (NaCl and KCl) at different concentrations were tested by a state-of-the-art high pressure high temperature viscometer. In this paper, the effect of different electrolysis (NaCl and KCl) at elevated pressures (up to 35,000 psi) and elevated temperatures (up to 450 ºF) on the viscosity of water based mud has been investigated.

Conducting this study led to the conclusion NaCl contaminated samples had higher shear stress-shear rate curves than water based mud; whereas, KCl contaminated samples had lower shear stress-shear rate curves than water based mud. Also, the study showed that Hershel-Bulkely model provides a good fit for the experimental data and well predicts the observed muds behavior.

Keywords: rheology, water-based mud, HPHT, salinity, deep wells, drilling fluids, NaCl, KCl

1. Introduction

High demands on oil and gas and increased depletion rate of near surface reservoirs around the world require industry to look for oil in deeper and more challenging reservoirs. One of the challenges associated with drilling deep and ultra-deep wells is to maintain desirable rheological properties of the drilling fluids.

Those properties can be highly influenced and altered by many factors in deep/ultra-deep drilling. Elevated temperature and pressure are among the most significant factors, in addition to ageing and electrolysis contamination. Elevated temperature might be introduced from geothermal source. Hydrostatic pressure, which is a function of depth, increases with drilling depth. Salts can be present in drilling fluids from several sources. These fluids can be contaminated during drilling of salt beds and the probability to encountering such type of layer during drilling operation is higher for deep wells. Salts also can be present by design such as salts added to the drilling fluid system to have a salt saturated water based mud, or in offshore operations where seawater is used in preparing the drilling fluids.

The effect of these fluids has been studied in depth for certain ranges of each factor. Bartlett (1967) has studied the effect of temperature on the flow properties of drilling fluids for temperatures up to 320 ºF. N. J. Alderman, Gavignet, and Mailand (1988) studied rheology of WBM under HPHT conditions where temperature reached up to 266 ºF and exceeding pressure of 8700 psi. Ali and Al-Marhoun (1990) have studied the effect of three variables, pressure, temperature and aging on the rheology of WBM. Rossi, Luckham, Zhu and Briscoe (1999)

have investigated the HPHT rheology of bentonite clay suspensions with different electrolytes such as NaCl, KCl and LiCl. A recent paper by Lee, Shadravan and Young (2012) discussed the rheological properties of invert emulsion drilling fluid under extreme HPHT conditions. Amani and Al-Jubouri (2012) studied the effect of high pressures and high temperatures on the viscosity of both oil based muds and water based muds. All these studies showed that changes and alterations occurred in the fluid rheological properties when they were subjected to these conditions, and these changes will negatively impact the functionality of drilling fluids.

Drilling fluid has an important role during the drilling operations. It serves as medium of carrying the cuttings from the bottom hole to the surface. It provides pressure on the well walls and prevents the walls from collapsing and the formation fluid from entering the wells. Moreover, it acts as a lubricant for the bit and the drilling string.

For drilling operations under HPHT conditions, the industry prefers to use oil based mud (OBM), which has advantage over water based mud (WBM) since it can maintain its rheological properties at high range of temperatures. However, this is not always feasible due to logistic, environmental regulation or cost, which makes the WBM preferable (Elward-Berry & Darby, 1997).

Controlling rheological properties in water based mud is achieved by adding special additive which provides the viscosity and gel-strength properties. This additive is mainly Na+-Montmorillonite, which is also known as bentonite. This additive serves a secondary function as well; it is capable of controlling fluid loss.

This paper discusses the contamination of two salt types, namely, NaCl and KCl, at three levels of concentration and the observed shear stress-shear rate relation at extreme HPHT conditions.

2. Mathematical Models

By definition, viscosity is the fluid's resistance to flow. Understanding the viscosity and the fluid behavior can be achieved by measuring the shear stress, τ, at given range of shear rates, $\dot{\gamma}$. In the oil and gas industry today, there are several models used to describe the viscosity behaviour of fluids and muds (Bartlett, 1967; Alderman et al., 1988; Okafor & Evers,1992).

The first model is Newtonian fluids model which assumes that the shear stress has a linear relation with the shear rates and the apparent viscosity. Thus, the ratio between shear stress and shear rate is constant:

$$\tau = k\dot{\gamma} \tag{1}$$

Where k is the proportionality constant.

The second model is the Power-low model. In this model, the non-linearity of the fluid is associated with addition of power exponent, n, which is also known as flow behavior index:

$$\tau = k\dot{\gamma}^n \tag{2}$$

Note that the Newtonian fluid equation is a special case where the exponent component is 1. If the exponent is less than 1, the fluid is classified as pseudoplastic, and, if the exponent is higher than 1, it is dilatant.

Both previous models assume that fluid will start flowing once shear stress is applied. Many fluids, however, requires a minimum applied force to flow and overcome the friction between the fluid layers. This can be modeled using Bingham model where it has an offset and the fluid behaves linearly:

$$\tau = \tau_0 + \mu_\infty \dot{\gamma} \tag{3}$$

Where τ_0 is the yield point and μ_∞ is plastic viscosity.

However, for some fluids, in addition to the initial stress to so start flow, the fluid does not have a linear relationship between the shear stress and shear rate. A more general model, which accounts for all rheological properties described earlier, is Herschel-Bulkley model. This model consists of three parameters.

$$\tau = \tau_0 + k\dot{\gamma}^n \tag{4}$$

3. Experimental Set-up

3.1 Material

The drilling fluid used in this experiment was a water based mud. The chemical composition of the mud is summarized in Table 1.

Besides water, a major contributor to the chemical composition is M-I Gel supreme, which is a treated Sodium-Montmorillonite. It provides viscosity and fluid loss control. Other additives added to improve the drilling fluid are:

- Caustic Soda and Lime to act as pH-modifier

- Asphasol Supreme, Black Fury (Gilsonite in Glycol) and POROSEAL (Co-polymer) to provide shale stability.

- XP-20 (Chrome lignite) to serve as deflocculant.

- SAFE SCAV HS to serve as a hydrogen sulfide scavenger

- Driscal D (synthetic polymer) to improve fluid properties under HPHT condition.

- Barite as to serve as a weighing additive

The material described above is the basic mud unit, or No-salt mud. From this basic mud, another six mud samples were prepared by adding two type of salts, namely, Sodium-Chloride (NaCl) and Potassium-Chloride (KCl). Each salt mud samples was prepared at three levels of concentrations: 3%, 5% and 7%.

3.2 Instrumentation

The experiment was conducted using Chandler (Model 7600) Ultra HPHT Viscometer. The viscometer is capable of testing the drilling fluid's properties, such as viscosity and gel strength, under severe conditions. The device is capable of reaching a temperature up to 600 ºF (316 ºC) and a pressure up to 40,000 psi (276 MP).

Table 1. Chemical composition of WBM

Additives	[PPB]
Water	268.61
M-I Gel Supreme	8.00
Caustic Soda	1.00
Asphasol Supreme	5.00
XP-20	5.00
Black Fury	5.00
Lime	2.00
DRISCAL D	5.00
POROSEAL	10.50
SAFE SCAV HS	0.40
Barite	214.49

3.3 Pressure and Temperature Schedule

Ideally, to study the effect of pressure and temperature on a given sample, a full factorial design would be applied. However, this tends to be impractical and proves difficult for limited resources. Therefore, choosing conditions which represent the well environment and what the drilling fluid will experience is critical.

For this study, eight conditions have been determined. Table 2 summaries the pressure and temperature combination for each condition.

Table 2. Pressure and temperature schedule

	Pressure [psi]	Temperature [F]
Case 1	0	Ambient
Case 2	5,000	126
Case 3	10,000	180
Case 4	15,000	234
Case 5	20,000	288
Case 6	25,000	342
Case 7	30,000	396
Case 8	35,000	450

4. Results and Discussion

4.1 Effect of Pressure and Temperature on Samples

There are seven water-based mud samples that were tested, one sample with no salt contamination, three samples with NaCl salt contamination at 3%, 5% and 7%, and three samples with KCl at concentrations similar to NaCl samples. The rheograms of the no-salt, 7% of NaCl and 7% of KCl are shown in Figure 1 to Figure 3.

Figure 1. Shear Stress vs. Shear Rate for WBM with no salt at different pressures and temperatures

For the no-salt sample at low pressure and temperature, the relation between the shear stress and shear rate has followed the power low model. However, once the pressure and temperature goes above 35,000 psi and 450 ºF (Case 8), the fluids begins to follow Bingham model.

Samples with salt behave slightly different. For the NaCl (Figure 2), at room conditions and at slight increase in pressure and temperature, (Case 1 and 2), the fluid maintained the same behavior. In case 3, the fluids had lower shear stresses at middle to low range of shear rate. In case 4, the shear stress dropped significantly and the relationship was linear with the shear rate. Case 5 and 6 had the lowest shear stress for given shear rates among all the cases and they were almost identical. Additional increase in pressure, above 30,000 psi, and temperature, above 450 ºF, resulted in higher yield points.

Figure 2. Shear Stress vs. Shear Rate for WBM with 7% NaCl salt at different pressures and temperatures

The effect of pressure and temperature on the second type of salt sample, KCl, was generally similar to the NaCl (Figure 3). At low temperatures and pressures the fluids had power low properties (Case 1 and 2). When the pressure and temperature increased the shear stresses at high shear rates dropped down significantly and it started to show a linear curve (case 3 and 4). No apparent changes were observed on the shear stress between the conditions of case 5 and 6. After the condition of case 7, the yield point of the curves start increases in a large step.
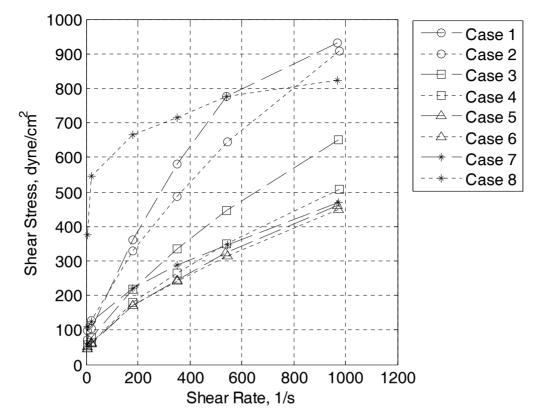
Figure 3. Shear Stress vs. Shear Rate for WBM with 7% KCl Salt at Different Pressures and Temperatures

4.2 Effect of Salinity

To have better understanding and to simplify the comparison between different samples at a given condition, the data was fitted to a 3-parameters viscosity model, Hershel-Bulkely Model. The fitted curves are plotted in Figure 4 to Figure 11. From a statistical perspective, the Hershel-Bulkely model has provided a good fit for all curves with coefficients of determination, R2, ranging between 0.999 and 0.918 and an average of 0.986.

For case 1, which is at ambient conditions (Figure 4), the samples with NaCl contamination had a higher sheer stress at a given shear rates than the corresponding sheer stresses of KCl contaminated samples. For the sample with no salt, the shear stress had middle values between the NaCl and KCl samples, specifically at shear rates lower than 400 1/s. In addition, among the NaCl samples, it is observed that the 5% contamination resulted in the highest stress, while the 3% and 7% had almost the same stress at a given shear rate. The deviation in the curve due to the concentration was not observed for the KCl samples at the mentioned condition.

Once the temperature and pressure elevated for case 2 (Figure 5) the effect of salts on the rheology became more apparent. The magnitude of the shear stresses, for given shear rates, is in this order: NaCl 5% > NaCl 7% > NaCl 3% > No Salt > KCl 5% > KCl 7% > KCl 3%.
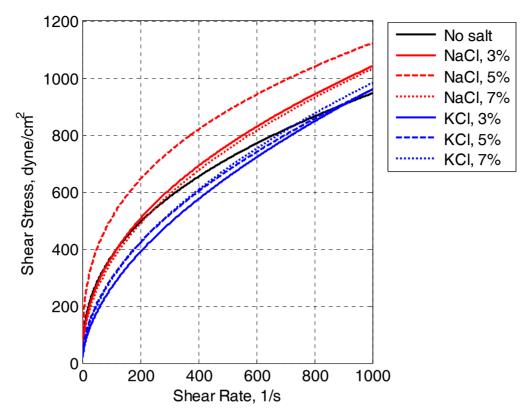
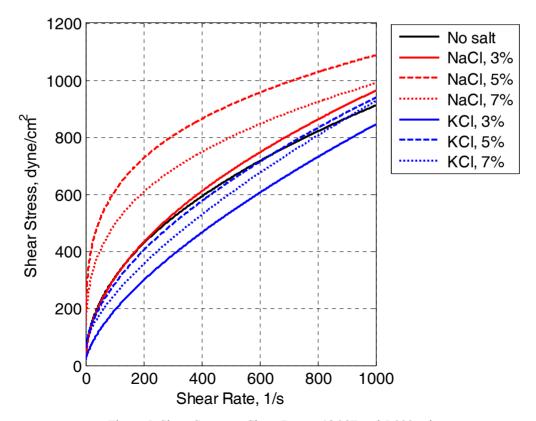Figure 4. Shear Stress vs. Shear Rate at ambient temperature and pressure

Figure 5. Shear Stress vs. Shear Rate at 126 °F and 5,000 psi

Higher increase in the temperature and pressure (Figure 6) resulted in reduction of stresses, particularly at high shear rates. Moreover, yield points of the higher NaCl concentration samples were reduced. Another observation noted in all salt samples was that the exponent component of the model increased and became more linear.
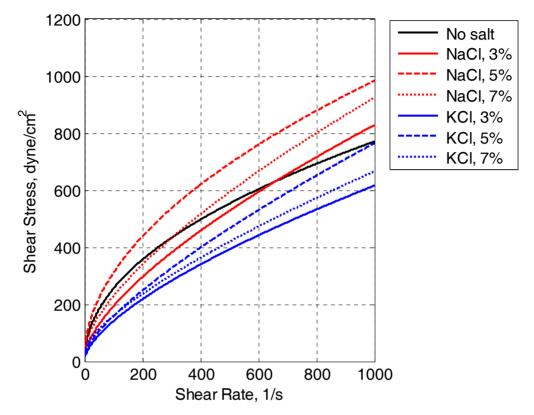

Figure 6. Shear Stress vs. Shear Rate at 180 °F and 10,000 psi

At a pressure of 15,000 psi and a temperature of 234 ºF, shear stresses kept decreasing (Figure 7) and, in similar manner, NaCl mud had higher stress at high shear rates followed by no-salt mud and KCl mud. For the KCl mud, there is significant difference among all the different concentrations.

Next condition was at a pressure of 20,000 psi and temperature of 288 ºF (Figure 8). It is noticed that all salt muds, except NaCl 5%, had lower shear stresses at high shear rate than the no salt mud.

For pressure of 25,000 psi and temperature of 342 ºF (Figure 9), similar behavior was observed as in the previous condition. However it can be noticed that, in the KCl mud, the values of shear stress at high shear rate began to vary and were in order of the concentration level of the KCl salt.

After 30,000 psi and 396 ºF (Figure 10), the yield points off the muds start increasing. NaCl muds (5% and 7%) have the highest yield point compared with the rest. Also, it is noticed that the shear stress at high shear rate starts to increase.

The last condition was with a pressure of 35,000 psi and a temperature of 450 ºF (Figure 11). In this condition a large shift in the mud behavior was observed. While in general the order of the shear stress of the mud was NaCl, No salt then KCl, the order in this condition has changed. KCl samples with 5% and 7% concentrations had higher values compared with NaCl. No big changes were observed in the KCL 3% is observed.
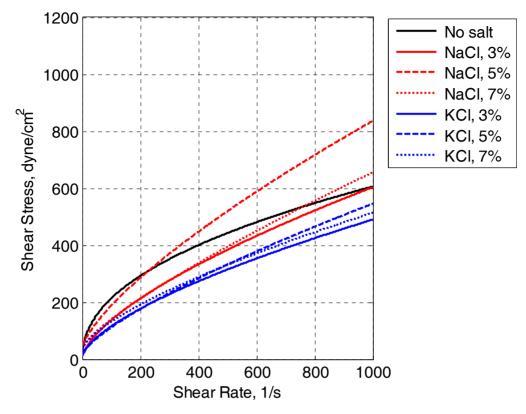
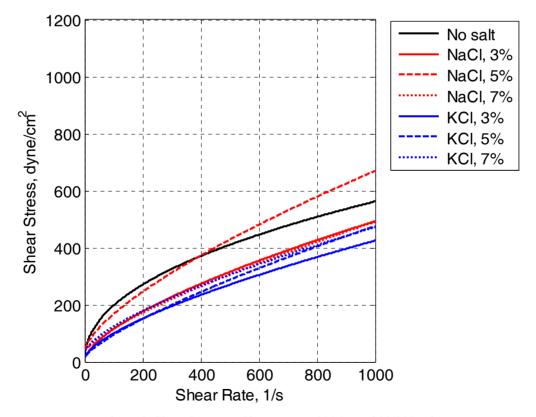Figure 7. Shear Stress vs. Shear Rate at 234 °F and 15,000 psi

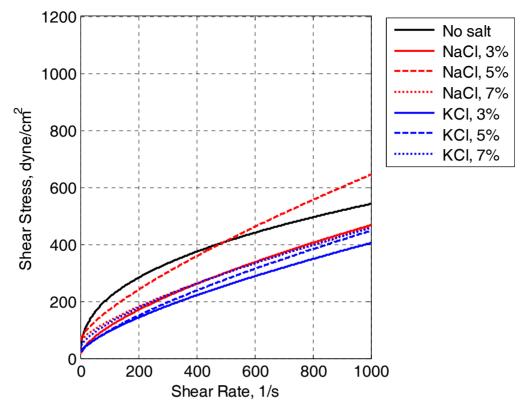Figure 8. Shear Stress vs. Shear Rate at 228 °F and 20,000 psi

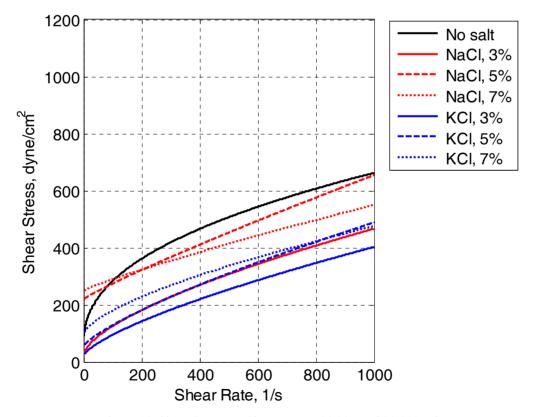Figure 9. Shear Stress vs. Shear Rate at 342 °F and 25,000 psi

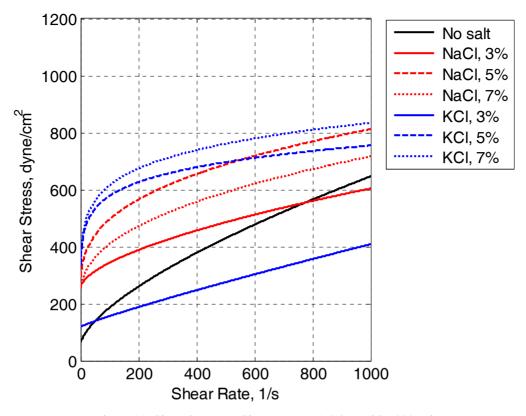Figure 10. Shear Stress vs. Shear Rate at 396 °F and 30,000 psi

Figure 11. Shear Stress vs. Shear Rate at 450 °F and 35,000 psi

5. Conclusion

1) For No-Salt water based mud, increase in temperature and pressure resulted in lower shear stresses at high shear rates. Shear stress, however, started to increase when the temperature and pressure exceeded 396°F and 30,000 psi respectively.

2) Water based mud generally followed the power low model although small values of yield point were observed.

3) Muds with NaCl and KCl contamination followed the general behavior of water based muds at elevated pressures and temperatures. These fluids, however, followed Bingham plastic model when the pressure and temperature exceeded 20,000 psi and 288 ºF respectively.

4) In general, NaCl contaminated samples had higher shear stress-shear rate curves than water based mud. On the other hand, KCl contaminated samples had lower shear stress-shear rate curves than water based mud.

5) A sharp increase was observed in shear stress-shear rate curves of high KCl concentration samples at a pressure of 35,000 psi and temperature of 450ºF compared to corresponding curves of the water based mud.

6) Hershel-Bulkely model provided a good fit for the experimental data and it well predicted the observed behavior.

Acknowledgement

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