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A Technical Review of Solids Free Brine-Based Drilling Fluids

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Abstract

This paper will provide a broad high-level technical review of solids free brine-based drilling fluids (SFB). The goal is to explain the advantages and disadvantages of SFB over conventional drilling fluids. Solids free brine-based drilling fluids differs from conventional drilling fluids in several key aspects:

- Solids Free
- No Fluid Loss Control Additives
- Low Viscosity

The key advantage of SFB over conventional (weighted) water-based (WBM) or oil-based (OBM) drilling fluids is that they can significantly increase drilling speeds when utilized on suitable wells. However, SFB pose a series of unique technical challenges which must be addressed in order obtain maximum performance. This paper will discuss the following topics:

- Selection of Suitable Wells for SFB Technology
- Brine Properties and Selection Guidelines
- Health and Safety
- Corrosion Control
- Fluid Loss Control
- Solids Removal Process
- Hole Cleaning
- Wellbore Stability
- Formation Damage
- Lubricant Design and Selection

Introduction

Solids free brines have been used as completion fluids for many years as they can provide density for well control while eliminating solid weighting materials which are potentially formation damaging (Caenn et al. 2011). Similarly, solids free water-based drilling fluids have been used for several decades to deliver high rates of penetration (ROP) in intervals that do not require drilling fluid density for well control (Caenn et al. 2011). Solids free brine-based drilling fluids (SFB) are simply a combination of these technologies: high density drilling fluids that enable fast drilling. This increase in drilling efficiency is achieved via two complimentary mechanisms: a higher rate of penetration (ROP) and improved drill bit life. The higher ROP achieved with SFB is due to the solids free nature of the system and the improved drill bit life is believed to be a consequence of improved drill bit cooling in SFB vs OBM (Doty 1986 and Redburn et al. 2017).

In recent years, the use of SFB drilling fluids has witnessed a significant increase in Western Canada. The data in Figure 1 plots the number of wells utilizing SFB drilling fluids over the period 2014 - 2019. (Data provided is for wells serviced by Secure Energy Services).

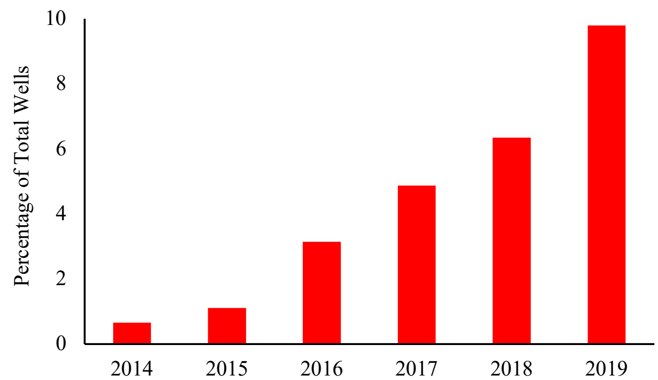

Figure 1: Wells Utilizing SFB Drilling Fluids

The objective of this paper is to provide a broad high-level technical review of solids free brine-based drilling fluids (SFB) with a focus on the high density calcium chloride brines currently being utilized in Western Canada.

Selection of Suitable Wells for SFB Technology

It appears that formations with low matrix permeability and limited natural fractures are potential candidates for SFB drilling fluids (see fluid loss section below for more details). In Western Canada the majority of SFB wells are currently being drilled in the Montney formation which is a low permeability (microdarcy) unconventional oil and gas reservoir.

However, it should be noted that a considerable number of Montney wells continue to be drilled with conventional oil-based drilling fluids (Figure 2) and that the overall advantage / disadvantage of SFB vs OBM depends on numerous factors which are frequently operator dependent. (Data provided is for wells serviced by Secure Energy Services).

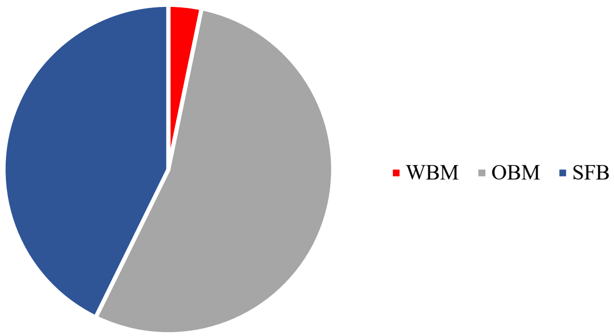

Figure 2: Drilling Fluids in Montney Formation (2019)

Brine Properties and Selection Guide

The primary factor influencing brine selection for a specific SFB project is the brines working density range. It is essential that the brine can provide sufficient density for well control and mechanical stabilization of the wellbore. Secondary factors include commercial (cost / logistics), physical (crystallization temperature) and chemical (corrosion / additive compatibility) considerations. The data provided in Table 1 summarizes the properties of some common drilling fluid brines.

Table 1: Properties of Common Drilling Fluid Brines

Brine	Maximum Density	Relative Cost
Potassium Chloride	1162 kg/m^3	$
Sodium Chloride	1197 kg/m^3	$
Sodium Formate	1330 kg/m^3	$$
Calcium Chloride	1396 kg/m^3	$
Potassium Formate	1580 kg/m^3	$$
Sodium Bromide	1530 kg/m^3	$$$
Cesium Formate	2200 kg/m^3	$$$$

In Western Canada, candidate SFB wells typically require brine densities in the 1200 - 1400 kg/m^3 range. This narrows the brine options down to formate salts, sodium bromide and calcium chloride. The significantly lower cost of calcium chloride means that it is generally the preferred option. However, divalent calcium chloride brines are technically more challenging to run than monovalent brines.

While the maximum density of calcium chloride brine is approximately 1400 kg/m^3 the working range can be extended to approximately 1600 kg/m^3 by mixing with calcium nitrate as detailed in Table 2.

Table 2: Calcium Chloride and Calcium Nitrate Brines

Brine	Maximum Density	Relative Cost
Calcium Chloride	1396 kg/m^3	$
Calcium Nitrate	2300 kg/m^3	$$
$CaCl_2 + Ca(NO_3)_2$	1600 kg/m^3	$

Health and Safety

The toxicity of an SFB drilling fluid system will depend on the specific brine and any additional additives used in the fluid system. A simplified summary of various base fluid toxicities is provided in Table 3.

While the data provided in Table 3 is highly simplified it illustrates that the toxicity of common drilling fluid brines generally falls between water and hydrocarbon base fluids. This intermediate toxicity is illustrated by calcium chloride brine: while it is a skin / eye irritant it does not contain the carcinogenic species present in diesel and certain mineral oils.

It is important to remember that even when a non-hazardous brine such as sodium chloride is being used, common SFB additives such as corrosion inhibitors and oxygen scavengers are typically hazardous and this must be considered when assessing the systems overall health and safety requirements.

Table 3: Base Fluid Toxicity

Base Fluid	GHS Classification System		
	Hazardous	Irritant	Carcinogen
Water	No	No	No
Diesel	Yes	Yes	Yes
Mineral Oil	Yes	Yes / No	Yes / No
Synthetic Oil	Yes	Yes / No	No
Sodium Chloride	No	No	No
Potassium Chloride	No	No	No
Sodium Formate	No	No	No
Potassium Formate	No	No	No
Cesium Formate	No	No	No
Sodium Bromide	No	No	No
Potassium Sulfate	No	No	No
Calcium Chloride	Yes	Yes	No
Calcium Nitrate	Yes	Yes	No

Corrosion Control

The primary concern with brine based drilling fluids is the potential for elevated corrosion rates. In order for corrosion to occur four key components must be present:

- Cathode Site
- Anode Site
- Electrolyte Solution
- Conductive Bridge

Corrosion does not occur in OBM fluid systems since the base oil (continuous phase) is non-conductive. However, all four requirements are satisfied when a steel-alloy drill pipe is submerged in a water based drilling fluid. The dissolved ions present in brines increase the electrical conductivity of the fluid which can significantly increase corrosion rates. It is therefore essential that brine-based systems incorporate a suitable corrosion control package. The corrosion control package will typically consist of three or four key components:

- Corrosion Inhibitor
- Oxygen Scavenger
- pH Control
- (H_2S Scavenger)

The selection of a suitable corrosion inhibitor is essential when drilling with SFB systems (Bush 1974). Unfortunately, extensive laboratory testing has shown that many "off-the-shelf" corrosion inhibitors provide only limited performance in brine based drilling fluids - especially high density calcium chloride brines. For example, phosphate ester based inhibitors generally exhibit poor solubility and low performance in calcium chloride brines. We have found that amine based inhibitors can perform well but fine tuning of the chemistry is essential in order to avoid foaming in drilling fluid applications.

When evaluating corrosion inhibitors in the laboratory we have found that the rotating cylinder electrode (RCE) test method provides the best results as it is able to mimic the high shear rate conditions (turbulent flow) occurring downhole while drilling (Gabe et al. 1981). This is demonstrated in the corrosion inhibitor testing summarized in Table 4: While "Inhibitor A" provides acceptable performance under static conditions its performance drops significantly under high shear conditions.

Table 4: Corrosion Inhibitor Testing

Calcium Chloride Brine (1300 kg/m^3)	Shear Rate (rpm)	
	0	2500
	Corrosion Rate (mpy)	
Corrosion Inhibitor		
None (Control)	~ 50	~ 50
Inhibitor A @ 10 L/m^3	~ 10	~ 50

A high performance oxygen scavenger is also required as part of the corrosion package in an SFB system (Bush 1974). Sodium sulfite is a cost-effective oxygen scavenger in tradition water based drilling fluids. However, the solubility of sodium sulfite in high density calcium chloride brines is low and this negatively impacts field performance. We have developed a proprietary scavenger which exhibits high solubility and oxygen scavenging performance in calcium chloride brines.

Maintaining an elevated pH is a well established and cost-effective method for reducing corrosion rates in water based drilling fluids (Bush 1974). However, this approach is somewhat complicated in high density calcium chloride brines. The data in Figure 3 plots brine density vs maximum obtainable pH in calcium chloride brine treated with excess calcium hydroxide (lime). As can be seen, the maximum achievable pH of the brine drops as brine density increases. An in-depth explanation of this phenomenon is beyond the scope of this article but is believed to be a consequence of two complimentary mechanisms: a reduction in ion activity as brine density is increased and a complementary reduction in $Ca(OH)_2$ solubility as brine density increases. It should be noted that this pH limit is independent of the base used to raise pH (sodium hydroxide / calcium hydroxide / monoethanolamine).

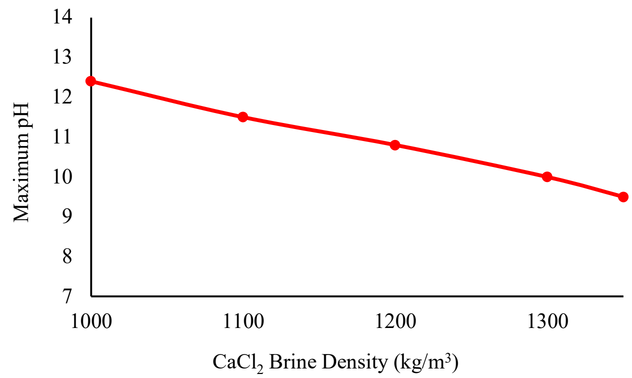

Figure 3: Maximum pH in Calcium Chloride Brine

The practical implications of this phenomenon can be important. For example, drilling regulations in Canada (Industry Recommended Practice 1: Critical Sour Drilling) stipulate that the pH of water based drilling fluids should be maintained at ≥ 10.5 when drilling critical sour wells. When using calcium chloride brines in such applications it is important to check that this pH can be obtained at the fluid density required for well control.

The complexity of measuring pH in high density brines is addressed in API Recommended Practice 13J. This document indicates that pH test papers are inaccurate in such brines and that the preferred test method is a double junction digital pH meter with a high salinity electrolyte solution. Interestingly, the document provides two options for measuring pH in high salinity brines:

- Measurement on Neat Sample
- Measurement on 1:1 Diluted Sample

However, in a filtered 1300 kg/m^3 density calcium chloride brine at maximum pH these two methods give significantly different results (Table 5) This situation is obviously not ideal, and the authors hope to work with the API to provide clarity on this issue.

Table 5: Measured pH in 1300 kg/m^3 Calcium Chloride Brine

API Testing Method	Measured pH (Double Junction pH Meter)
Neat sample	10.0
1:1 Dilution	10.8

It should be noted that corrosion control packages are primarily designed and tested to minimize corrosion on the steel alloys used in drill pipe construction. The compatibility of other metals with the brine in question should be carefully examined in order to prevent corrosion issues. For example, common grades of stainless steel are susceptible to pitting corrosion in high density calcium chloride brines. If stainless steel components are required (typically in downhole tools) when drilling with such brines it is important to consult with the manufacturer and switch to a (higher grade) pitting resistant stainless steel.

In addition to the selection of suitable corrosion control additives it is important to accurately monitor the real-time performance of these additives in field operations. Oxygen levels in the SFB should be measured using a digital dissolved oxygen meter and these results used to adjust to loading of oxygen scavenger in this system.

Ideally, real-time corrosion rates would also be measured using a portable LPR (linear polarization resistance) corrosion meter. However, attempts to use this methodology in the field have so far failed to provide accurate results. The development of a suitable measurement technique is an active area of research within our technical team.

In addition to dissolved oxygen and corrosion rate measurements it is also desirable to have simple chemical tests available to measure corrosion inhibitor and oxygen scavenger levels in the drilling fluid system. This is technically challenging, but we have recently developed two test methods that are now entering field trails.

The final “piece of the puzzle” relates to how these corrosion control additives are added to the fluid system. Extensive field results have indicated that maintaining constant additive concentrations in the fluid provides optimum performance. In order to achieve this goal, we have developed chemical addition trailers which allow corrosion control additives to be continuously added to the drilling fluid system at controlled rates (Figure 4). (These units can also be used for the addition of chemical lubricants).

Figure 4: Chemical Addition Trailer for Liquid Additives

The standard method (API Recommended Practice 13B-1) for measuring drilling fluid corrosion rates involves the placement of steel corrosion coupons within the drill pipe. The corrosion coupons are weighed before and after exposure to the drilling fluid and the corrosion rate calculated. These corrosion rates can then be used to measure the performance of the corrosion control package being utilized (Table 5).

Table 5: Corrosion Rates from Drill Pipe Corrosion Rings

Corrosion Rate (mpy)	Interpretation
< 25	Low
25 - 75	Moderate
75 - 125	High
> 125	Severe

Third party corrosion ring analysis is performed on all SFB wells serviced by Secure Energy Services. The data in Table 6 summarizes corrosion ring results for a series of wells (> 150) drilled with calcium chloride brine (2014 - 2019).

Table 6: Corrosion Ring Analysis on SFB Drilling Fluids

Brine Type	Corrosion Rings	Average Corrosion Rate (mpy)
Calcium Chloride	491	23

The data in Table 6 demonstrates that excellent corrosion rates can be maintained in brine-based drilling fluids when running a fully optimized corrosion inhibitor package.

Fluid Loss Control

The absence of fluid loss control additives in SFB systems can potentially result in significant volumes of drilling fluid invasion into the formation. This fluid invasion has the potential to lead to three undesirable consequences:

- High Drilling Fluid Costs
- Wellbore Instability
- Formation Damage

The cost of drilling fluid seepage losses will depend on the specific brine being utilized and the formation being drilled. For example, when drilling horizontal intervals in the Montney formation seepage losses typically fall in the 1 - 2 m^3 / 100m range. When drilling with calcium chloride brine this seepage loss cost is deemed acceptable as it is covered by cost-savings from increased drilling speeds. However, when drilling higher permeability formations or using higher cost brines these seepage loss costs can eliminate the advantage of SFB over conventional drilling fluids.

It also important to consider wellbore stability when drilling with SFB drilling fluids. The stability of a wellbore is determined by both mechanical and chemical factors – both of which can be strongly influenced by the drilling fluid system.

In conventional systems, a low permeability filter cake is deposited on the wellbore when drilling through formations with significant permeability. This low permeability filter cake allows the drilling fluids hydrostatic pressure to mechanically stabilize the wellbore. However, no significant filter cake is deposited when drilling with SFB systems so drilling through permeable formations that require mechanical stabilization (hydrostatic pressure) can result in wellbore instability issues. This is not typically a problem as SFB drilling fluids are usually used in low permeability (microdarcy) formations. However, this type of wellbore instability has been encountered when attempting to drill through coal zones using SFB drilling fluids. In this case it is usually necessary to add conventional fluid loss additives (solids) to the SFB in order to safely drill through the unstable zone. (The addition of such solids is undesirable since they can negatively impact the drilling rate).

One additional advantage of SFB drilling fluids is that they provide chemical stabilization when drilling water sensitive shales. This stabilization is achieved through two potential mechanisms: reduced water activity and cation exchange with reactive clays (Yew 1992). The reduced water activity mechanism will operate in all high density brines while cation exchange occurs only in brines containing exchangeable cations (generally potassium).

When drilling production intervals, high volumes of drilling fluid invasion can potentially lead to formation damage. This is generally not a concern in SFB wells since the production intervals are typically very low permeability formations that will undergo post-drilling stimulated by hydraulic fracturing. However, formation damage should be carefully reviewed if attempting to drill higher permeability reservoirs or open-hole completions with an SFB drilling fluid (Masikewich 1999).

Solids Removal Process

As discussed above, SFB can potentially drill significantly faster than conventional drilling fluids. This overall increase in drilling efficiency is primarily a consequence of improved ROP but extended drill bit life is another contributing factor.

In order to maximize ROP it is important to maintain the concentration of solids in the drilling fluid at ≤ 0.5 % by volume. This is achieved by a combination of chemical and physical methods. A suitable synthetic polymer is used to flocculate drilled solids in the SFB as the fluid returns to surface. Once the drilled solids have been successfully flocculated the fluid is injected into a high performance centrifuge in order to remove the solids from the fluid.

The flocculation polymers used in SFB drilling fluids are typically hydrolyzed polyacrylamides (HPAM). The synthetic nature of these polymers allows molecular weight, charge and charge density to be systematically varied resulting in a vast array of potential polymers. The flocculation performance of a given polymer will depend on the chemical and physical properties of both the drilling fluid and formation solids to be removed. While certain polymers generally provide a good "starting point" in a specific brine we have found that polymer optimization is best achieved by simple field level pilot testing. Interestingly, we have found that lubricant additives can have a significant impact on the efficiency of this solids removal process and this will be covered in more detail in the lubricants section.

As would be expected, centrifuge performance also has a significant impact on the solids removal process. We have found that retention time and g-force must be carefully balanced in order to obtain maximum solids removal efficiency. (Care must be taken to avoid mechanically breaking down the flocculated drilled solids with excessive g-forces). We therefore recommend a minimum of two fully variable, large diameter, long scroll centrifuges for use on all SFB projects.

Hole Cleaning

In order to maximize ROP and improve solids removal SFB drilling fluids are designed with the lowest possible viscosity. They are essentially Newtonian fluids with no capacity to suspend solids under static conditions. Hole cleaning is achieved by maintaining the maximum allowable flow rate (turbulent flow in annulus) and solids settling under static conditions is managed by appropriate drilling practices.

It is important to run detailed hydraulics analysis on proposed SFB wells in order to ensure satisfactory hole cleaning can be achieved. Using this approach, we have successfully drilled a 6950 m Montney well with a lateral interval over 3800 m in length. The lateral was drilled with a calcium chloride based SFB fluid system (1270 kg/m^3) using polymer beads (2 - 4 % by volume) as mechanical lubricant.

Lubricants

The coefficients of friction (COF) of some common drilling fluid systems are provided in Figure 6 (brine samples were tested at maximum density). While the exact COF value will depend on brine chemistry and density it has been found that SFB systems typically exhibit COF values that fall between WBM and OBM drilling fluids. We have found that chemical and physical lubricants can both perform well in SFB drilling fluids.

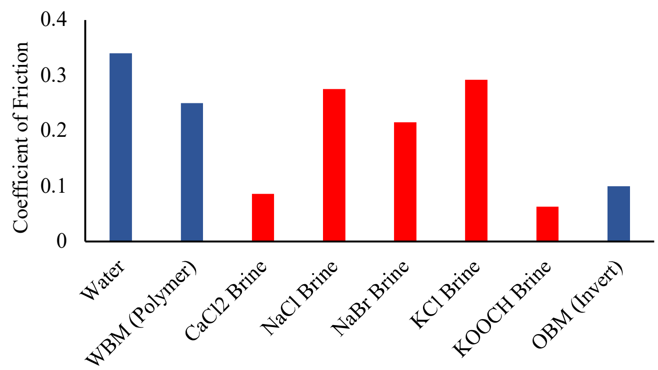

Figure 6: Drilling Fluid Coefficients of Friction (COF)

Physical lubricants are essentially inert and can be used in all common SFB drilling fluids - they range from simple nut shells to engineered beads (polymer / ceramic / glass). Optimum performance is generally obtained from polymer beads as they offer an improved life-span due to increased crush resistance. Results from the field indicate that a concentration of 2 - 4 % (volume) is generally required for maximum performance. In order to maintain this concentration in the active system a mechanical bead recovery unit is generally required.

Mechanical lubricants can not be routinely evaluated in the laboratory using a standard lubricity meter (Skalle 1999). However, the field performance of mechanical lubricants in SFB drilling fluids is well established - as evidenced by the 6950 m Montney well successfully drilled with a calcium chloride based SFB (see previous section for details).

Chemical lubricants typically incorporate a surfactant package to aid lubricant dispersion in the drilling fluid. However, surfactant performance is strongly influenced by salinity and so custom lubricants need to be designed for SFB drilling fluids. The situation is further complicated in divalent brines such as calcium chloride.

We have found that extensive laboratory testing is required when designing lubricants for brine-based drilling fluids:

- Lubricity Performance (Reduction in COF)
- Lubricant Dispersion
- Chemical Stability
- Thermal Stability
- Wettability Modification on Drilled Solids

Lubricant performance is the most obvious parameter and this is traditionally measured using an OFITE lubricity meter (although more advanced instruments are also available). When running these tests, engineering calculations should be performed in order to ensure that the testing is being performed under realistic downhole conditions.

In order to obtain maximum performance it is important that the lubricant is uniformly dispersed within the drilling fluid. This parameter is typically measured by simple visual inspection of the drilling fluid - lubricant mixture.

It is also critical to ensure that the lubricant is chemically stable in the brine-based drilling fluid. This is a particular concern in calcium chloride brines as the combination of elevated pH and divalent cations can lead to chemical deactivation of fatty acids in the lubricant package. This type of deactivation typically results in the formation of insoluble waxes (calcium salts of organic acids) that can be detected by visual inspection.

Drilling fluid lubricants function by forming a low COF (hydrophobic) coating on the drill pipe surface. However, a similar coating can also be formed on drilled solids. While the coating of drilled solids with lubricant does not negatively impact COF reduction, it can lead to elevated lubricant costs (depletion) and a reduction in the solids removal efficiency at surface. We believe this effect is caused by the lubricant coating preventing flocculation polymers from binding to the drilled solids surface (Figure 7). This decrease in solids removal efficiency is particularly undesirable in SFB as it can significantly reduces the rate of penetration.

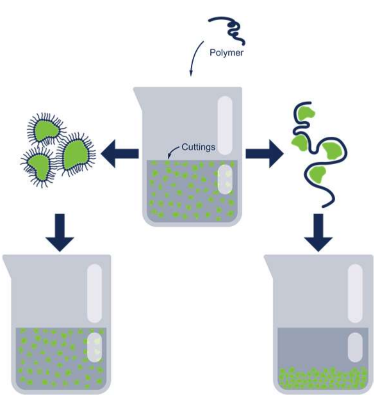

Figure 7: Impact of Lubricant on Solids Flocculation

Finally, the thermal stability of the lubricant must be evaluated by remeasuring all the above properties after aging the drilling fluid - lubricant mixture under downhole conditions.

By following this lubricant development process we have been able to build a family of high performance lubricants for SFB drilling fluids. These lubricants offer excellent COF reduction, high chemical and thermal stability and they do not impact the solids removal process (Figure 8).

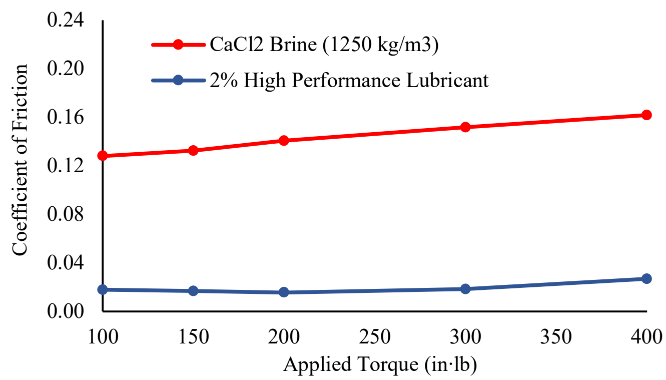

Figure 8: Performance of Chemical Lubricants

Conclusions

When drilling suitable (low permeability) formations, solids free brine-based drilling fluids (SFB) can provide significantly faster drilling rates than conventional WBM or OBM drilling fluids. The key components of an SFB drilling fluid include:

- Inorganic Salt (Brine)
- Corrosion Control Package
- Solids Removal Package
- Lubricant (Optional)

With a suitable corrosion package, corrosion levels in SFB drilling fluids can comfortably be maintained within acceptable levels. In addition, a carefully designed solids removal system (flocculation polymer + centrifuge) will allow drilled solids to be routinely maintained at less than 0.5% (volume) and high drilling speeds to be achieved. When required, both physical and chemical lubricants can be utilized in SFB drilling fluids. (Physical lubricants are generally “universal” while chemical lubricants provide brine specific performance).

The Montney formation in Western Canada has proven to be an excellent candidate for calcium chloride based SFB drilling fluids. It is anticipated that the popularity of this class of drilling fluids will continue to increase in coming years.

Acknowledgments

The authors would like to thank all members of the technical and operations teams at Secure Energy Services.

Nomenclature

SFB = *Solids Free Brine Based Drilling Fluid*
OBM = *Oil Based Drilling Fluid*
WBM = *Water Based Drilling Fluid*
ROP = *Rate of Penetration*

RCE = *Rotating Cylinder Electrode*
HTHP = *High Temperature and High Pressure*
mpy = *Mils Per Year*
LPR = *Linear Polarization Resistance*
COF = *Coefficient of Friction*

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