ROP Enhancement in Shales through Osmotic Processes
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Abstract
70%-80% of all formations drilled globally are identified as shales, i.e. argillaceous rocks that contain significant amounts of clays. In addition, the US Energy Information Administration conservatively estimates that 26% of recoverable oil and gas resources of the United States alone are contained in shale formations (EIA Annual Energy Outlook, 2014). Accordingly, there has been an increasing focus on efficient drilling of tight shaly formations, as encountered for instance in long horizontal laterals of unconventional wells. Improvements in PDC bit design and low friction cutter technology need to be mentioned in particular, which have made PDCs the bits of choice in all but the hardest formations.

The question now arises where the next step change in rate-of-penetration (ROP) improvement for PDC bits is going to come from. The answer lies in optimizing the intricate relationship between bit, intact and failed rock, and the drilling fluid. When shales are drilled with PDC cutters, a built-up “detritus” edge of failed rock will temporarily adhere to the cutter and prevent it from cutting new rock effectively. Disrupting this detritus may significantly reduce friction at the bit and improve PDC cutting efficiency. This appeared to be the case when testing high salinity formate muds in the Deep Trek downhole drilling tests. The merits of high salinity formate muds, which significantly out-drilled even oil-based mud at high densities during Deep Trek, were duly noted but never fully explained.

In this paper, it is proposed that the mechanism responsible for the Deep Trek ROP results with formate mud is chemical osmosis, which effectively draws water from the drilled shale and generates a lubricating layer between the cutter and the shale that disrupts the detritus and allows the bit to be cleaned more effectively through the hydraulic nozzle flow, thereby enhancing ROP. Support for the proposed mechanism is provided by an extensive set of laboratory tests, ranging from simple hot-rolling tests that measure accretion tendencies of shale on steel to realistic drilling tests on full-scale equipment and actual PDC bits under downhole conditions. The results show unequivocally that high salinity muds yield consistently lower accretion tendency and 50-60% higher ROP in shales, and that the underlying mechanism appears to be chemical osmosis. Moreover, results of positive field trials with formate muds for ROP enhancement in Canada, which significantly exceed oil/synthetic mud drill rates, further support the hypothesis of the merits of chemical osmosis for ROP enhancement. The osmosis phenomenon is well-known for borehole stabilization in oil/synthetic muds and high salinity water–based muds, but has never been deliberately deployed for ROP enhancement in shales. The latter is the topic of the present paper.

Introduction
The majority of rock formations drilled globally qualifies as shale, and shale drilling offers a variety of unique challenges. Among them is the tendency for bits to ball up and ROP to slow down accordingly, particularly when water-based muds (WBM) are used. As a result, operators around the world have flocked to oil-based / synthetic-based muds (OBM/SBM) to do the heavy lifting on their shale drilling. But the superior shale drilling characteristics of OBM/SBM come at a cost. Among the downsides of OBM/SBM are high per barrel cost, difficulties obtaining high-quality electrical/resistivity logs, oil emulsion blocks in (tight) gas sands, sensitivity to severe lost circulation, incompatibility to cement that may result e.g. in poor cement bonds, making early gas kick detection more difficult, difficulty finger-printing hydrocarbons, creating a messy work environment with potential fume and fire hazards, and last-but-not-least high waste disposal costs. The quest to find high-performance WBMs that are technically, economically and environmentally viable alternatives to OBM/SBM is therefore by no means in vain. A first and key hurdle that must be overcome, however, is to formulate WBMs that drill at least as fast as OBM/SBM, given the overriding importance usually given to unit drilling costs.
Effect of Osmosis on Bit-Balling and ROP
Table 1 gives an overview of direct and coupled flows that may occur in shales under the influence of various gradients. The direct flows are shown on the diagonal in the table, and include such well-known flows as hydraulic flow driven by a pressure gradient described by Darcy’s law and diffusion of ions driven by a chemical potential gradient described by Fick’s law. Coupled flows are shown off the diagonal in the table, and include the flow of water driven by electrical potential gradients and chemical potential gradients, processes known more popularly as electro-osmosis and chemical osmosis respectively. These processes, in particular chemical osmosis, will be topic of study in the remainder of this paper.

<table>
<thead>
<tr>
<th>Flow / Driving Force</th>
<th>Hydraulic Gradient $\Delta P$</th>
<th>Chemical Potential Gradient $\Delta \mu$</th>
<th>Electric Potential Gradient $\Delta E$</th>
<th>Temperature Gradient $\Delta T$</th>
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<td>(Darcy’s Law)</td>
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<td>Dufour Effect</td>
<td>Peltier Effect</td>
<td>Thermal Conduction (Fourier’s Law)</td>
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Table 1 – Overview of direct and coupled flows (see van Oort et al., 1996). Well-known flow laws for direct flows are shown on the diagonal. Coupled flow are off-diagonal, including electro-osmosis and chemical osmosis (shaded in gray) discussed here.

In a series of papers, George Cooper and his co-workers showed the potential benefits of electro-osmotic processes to well construction. Applications included improving the in-situ load-bearing capacity of a jet- or pile-driven casing string in offshore environments (Wrixon and Cooper, 1997; see also Esrig, 1978, and Rose and Gribbs, 1979) through clay dehydration, as well as the reduction of bit-ballng and improvement of ROP in clay-rich shales (Cooper and Roy, 1994; Hariharan, Cooper and Hale, 1998). Figure 1, adopted from Cooper and Roy, 1994, shows that placing a negative charge on a PDC bit (i.e. making the bit the cathode = negative pole) approximately doubled ROP in Pierre (Wellington) Shale, by avoiding balling of the bit.

![Figure 1](image)

**Figure 1** – Rate of penetration as a function of WOB for a PDC bit with - and without - a negative charge of 10 V, 0.5 – 1.5 A (Figure adopted from Cooper and Roy, 1994, Figure 8). Note the improvement in ROP when the negative charge is applied, e.g. at 6000 N WOB where ROP improves from 10 ft/hr to 18 ft/hr.

Bit-ballng is a well-known limiter of ROP (Dupriest and Koederitz, 2005; Remmert et al., 2007), caused by adherence of rock material onto the bit cutters, which interferes with effective cutting of the rock. As shown clearly by e.g. Ledgerwood (2007), adherence of failed rock material (also known as “detritus”) to the cutters may only be temporary without permanent attachment, but may still interfere at any particular drilling instant with optimum action of the bit cutters, thereby lowering ROP. Bit-ballng typically occurs in drilling environments:
where hydraulic horsepower at the bit (HSI) is low (e.g. HSI less than 2.5),

when open-face volume at the bit is limited (Pessier and Fear, 1992),

where depth-of-cut is high (due to maintaining high WOB / low RPM),

when water-based mud (WBM) is used (although bit-ballling in oil- or synthetic based mud (OBM/SBM) is possible also in cases where the conditions mentioned above apply)

when clay-rich shales are drilled (although bit-ballling is by no means limited to shales exclusively)

Electro-osmosis with a cathodic (i.e. negatively-charged) bit can help prevent bit-ballling by drawing hydrated cations (i.e. positive ions) such as Ca\(^{2+}\), Mg\(^{2+}\), Na\(^{+}\) etc., which are present in abundance within the clay-rich shale formations, towards the bit. The water mobilized with the migrating cations may generate a lubricating water layer between the bit cutters and the shale that minimizes any potential sticking of the shale material to the bit. This then allows the cutters to be cleaned more effectively with the available hydraulic horsepower. This mechanism of clay dehydration by an applied electrical potential is well-known in civil engineering, where it is exploited for various soil- and foundation stabilizing purposes.

After Cooper’s pioneering work, an attempt was made to develop commercial applications of electro-osmotic bits for bit-ballling mitigation and ROP enhancement purposes. These were only partially successful, with the best-known application being the development and field testing of an electro-osmotic “anti-ballling coating (ABC)” by Smith et al., 1996. Failure was primarily associated with the engineering challenge of generating and sustaining a negative charge of sufficient magnitude at the bit under challenging downhole conditions. Field application of electro-osmosis for ROP enhancement purposes thereby remains largely an unexplored territory. However, the historical work done on it clearly points to the potential benefits of osmotic processes for ROP enhancement.

An indication that ROP enhancement might also be achieved through chemical osmosis was obtained in large-scale drilling tests reported on by Ramsay et al., 1996, and later in the Deep Trek investigation (Judzis et al., 2007; Black et al., 2008), a study co-sponsored by the US Department of Energy (DOE) and industry partners into the drilling behavior of advanced PDC bits and high-pressure/high-temperature (HPHT) drilling fluids. Significant conclusions from the earlier the earlier study (Ramsey et al., 1996) include:

- ROP’s in Mancos shale with solids-free 18.5 ppg cesium formate brine were 2-4 times higher than in the water-based mud used as a standard. Lack of bit balling in the cesium formate brine was proposed as one of the reasons for the higher ROPs.
- The ROP versus torque and horsepower data suggested that cesium formate would give a longer bit life and extended mud motor life. The significance of this observation will become clear when discussing Canadian field trials below.
- Adding solids to the formate brine decreased ROPs significantly. The ROPs decreased in a straight line relationship with increasing Fann 600 readings signaling increased viscosity due to solids.

The Deep Trek investigation employed high-pressure drilling tests (with 10,000 psi fluid pressure, 12,000 psi and 13,000 psi confining and overburden pressure respectively) conducted in full-scale drilling test equipment to delineate the influence of various drilling-, bit- and mud parameters on ROP. Figure 2 show results of Deep Trek tests conducted using the same 7-bladed PDC bit while drilling Mancos shale samples with various mud formulations, including base oil, 16 ppg OBM weighted with barite and Manganese Tetroxide (Mn\(_3\)O\(_4\)), and 16 ppg cesium formate mud with 20 ppb calcium carbonate with and without 20 ppb simulated drill solids (Revdust). The results of these tests were as follows:

- The 16 ppg cesium formate mud increased ROP by more than 100% compared to the 16 ppg OBM in Mancos shale (and in Carthage limestone). The ROP increase was attributed to cesium formate improving both drilling efficiency (as characterized using Mechanical Specific Energy, MSE) and bit aggressiveness. As can be seen from Figure 2, the cesium formate mud basically drilled as fast as unweighted base oil. The ROP improvement by cesium formate mud was seen primarily in conjunction with PDC bits.
- Largely unnoticed was the fact that the cesium formate mud maintained its high ROP even when 20 ppb of simulated drill solids were added (raising the total number of solids to 40 ppb given the concentration of 20 ppb of Calcium Carbonate in the base mud). As shown in Fig.2, the ROP values achieved in cesium formate mud with simulated drilled solids were somewhat reduced compared to the mud without such solids (particularly at higher WOB values), but the mud still outdrilled OBM by a considerable amount.

These conclusions are very significant. First of all, there are few WBM systems that can claim the ability to outdrill OBM by 100+% in a heads-up comparison. Furthermore, the last observation seems to indicate that the improvement in ROP offered by cesium formate mud goes beyond that of a clear, low-no-solids drilling fluid, which are well-known to improve ROP (see e.g. Darley and Gray, 1988), given that high ROP was maintained even when the mud was loaded with solids. Some other mechanism therefore must be acting to uphold the higher ROP even in the presence of solids, and it is our contention that this mechanism is chemical osmosis. There is an important caveat, however. As can be seen from Table 2, the Deep Trek tests on cesium formate mud were conducted at higher horsepower, and therefore higher HSI, at the bit than those done on OBM, which could partly explain the better formate mud results given the important impact of HIS on bit cleaning and ROP. In the work presented here, we have conducted our drilling tests at constant HSI to level the playing field for all muds tested.
Figure 2 – The effect of various drilling fluid formulations on ROP with a 7-bladed PDC bit on Mancos shale. Note the elevation of ROP compared to 16 ppg OBM (weighted with either barite of Manganese Tetroxide (Mn$_3$O$_4$) when using 16 ppg cesium formate (CsFo) mud (light blue triangles), which remains equal to the high ROP measured with unweighted base oil (green squares) even when 20 ppb of simulated drill solids are added (dark blue triangles). Figure adopted from Black et al., 2008, figure 18.

<table>
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<tr>
<th>Test Deep 21 - 16 ppg CsFo fluid (with 20 ppb CaCO$_3$)</th>
<th>Test Deep 30 - 16 ppg OBM</th>
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Table 2 – Experimental parameters of the Deep Trek tests shown in Figure 2 for 16 ppg cesium formate (CsFo) mud and 16 ppg OBM. Note the evident increase in ROP when using CsFo mud, but also the higher hydraulic horsepower used in the CsFo tests.

Chemical osmosis, i.e. the flow of water driven by a chemical potential gradient often expressed as a difference in water activity between two systems in contact with each other, is a well-known process in the oil and gas industry. It forms the basis for invert oil emulsion muds (IOEM) and in particular for balanced activity oil muds (Chenevert, 1970). In IOEMs, the continuous oil or synthetic phase constitutes a near-perfect semi-permeable membrane that allows osmotic transport of water between the water-based invert phase and the rock. Use of elevated salt concentrations (typically CaCl$_2$) in the invert phase usually lower water activity in this phase sufficiently to either balance the water activity of the brine in the rock pore spaces or direct net osmotic transport of water from the rock to the invert phase. This, in turn, avoids near wellbore hydration and pore pressure elevation, thereby averting reduction of effective rock stresses that can cause wellbore instability. Note that the dynamics of water transport in OBM/SBM systems in generally slow, as water molecules need to be transported across the semi-permeable oily membrane through the aid of surfactants.

For a shale formation with water activity $a_{w,\text{shale}}$ exposed to a drilling fluid with water activity $a_{w,df}$ the osmotic pressure $\Delta \Pi_{osm}$ can be written as:

$$\Delta \Pi_{osm} = \frac{RT}{V_w} \ln \left( \frac{a_{w,\text{shale}}}{a_{w,df}} \right)$$  

(1)
where \( R \) is the gas constant, \( T \) is temperature, and \( \bar{V}_w \) is the molar volume of water.

The action of the osmotic pressure is attenuated by a membrane efficiency \( \sigma \), which indicates how selective the system is to osmotic transport of water, with \( \sigma = 1 \) indicating a perfect semi-permeable membrane (only flow of water is allowed, no flow of solutes / ions across the membrane system is permitted) and \( \sigma = 0 \) representing no membrane and therefore absence of any osmotic phenomena. The flow \( J_V \) in- and out of the shale system can be written as:

\[
= \Delta P - J_V \sigma \Delta \Pi
\]  

with \( \Delta P \) representing the hydraulic mud overbalance compared to the formation pore-pressure.

Chemical osmotic transport may also occur in shales exposed to high-salinity WBM systems (van Oort et al, 1995, 1996, 1997). In this case, however, there is no perfect semi-permeable membrane supporting osmotic water flow. Rather, in an intact shale with narrow pores (pore diameters on the order of tens of nanometers), there is a marked difference in mobility between (small) water molecules and (large) hydrated ions that will support selective transport of water in case a chemical potential difference is applied. When a shale is contacted by a high-salinity WBM with a water activity that is lower than the water activity of the shale pore fluid, the larger mobility of water molecules compared to hydrated ions results in a net flow of water (and thereby a net mass transfer) from the shale to the mud (see Figure 3). This process is also referred to as osmotic transport across an imperfect, “leaky” membrane system. The efficiency \( \sigma \) of a leaky membrane is usually significantly less than that of a perfect semipermeable system, and was measured for several high salinity systems to be on the order of 0.01 – 0.1 (i.e. 1%-10% efficiency). However, coupled with a large osmotic driving force, represented by the osmotic pressure \( \Delta \Pi \) which can easily reach 1000’s of psi in high-salinity WBM systems, it is still possible to generate an effective osmotic force \( \sigma \Delta \Pi \) that draws water from the shale even when a significant hydraulic overbalance \( \Delta P \) is applied. Note that the dynamics of water transport in WBM will be much faster than in OBM/SBM, as the water phases of the mud and shale are in direct contact with each other.

In analogy to the electro-osmotic process, the ability of high-salinity WBM systems, which can generate significant effective osmotic pressures, to quickly draw water from shales now offers a mechanism by which bit-ballung may be minimized and ROP may be improved. Water drawn from the shale may improve cutter lubrication and minimize instantaneous sticking of clay material / detritus to the bit, allowing the material to be effectively evacuated from the cutters and the bit face by hydraulic action. Note that water drawn from the outer layers of clays may also harden them and make them less prone to sticking. The relationship between shale water content and strength was studied in detail by e.g. Hale et al., 1993, who found that even modest reductions in shale water content could significantly increase shale strength. A strengthened, dehydrated outer layer of a shale cutting may be less prone to sticking and behave less plastically than the fully hydrated shale material. As indicated by van Oort, 2003, there may be a relationship here with the Atterberg limits in soil mechanics, which delineate a zone in soil water content where such a soil is most likely to exhibit maximum plasticity. Through chemical osmosis, it may be possible to take the outer shale layers from the plastic zone to a dryer, more dehydrated zone where the clays exhibit less likelihood to stick to PDC cutters. This evidently warrants further study.

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**Figure 3 – Osmotic transport of water across a leaky membrane system, in this case represented by a high water-activity shale contacted by a low water-activity cesium formate mud. Negation of the chemical potential imbalance favors the net transport of water molecules out of the shale versus the transport of hydrated ions (only cesium cations shown here) into the shale.**

Driving Force = \( \Delta P - \sigma \Delta \Pi \)
Formate Muds
In our experimental investigations to date we have focused exclusively on the application of formate muds. Prime motivations for doing so were: (1) to achieve continuity with previous work such as the Deep Trek investigation; (2) the fact that formate salts are extra-ordinarily soluble and thereby can generate very low water activities, which translate into high osmotic pressures that are very suitable for the purpose of our study; (3) formates offer a range of other benefits that make them good candidates for application in drilling fluids. The properties of formate muds have been extensively studied and catalogued (see Howard, 2014; Downs, 1992, 1993, 1994, 2005, 2006, 2010), and the reader is referred to these publications for further details. Formate muds have found considerable industry acceptance in particular because of their excellent HPHT fluid characteristics, making them very suitable for HPHT drilling and completion applications, as well as low reservoir damage characteristics, making them deliver superior performance as reservoir drill-in fluids and completion brines. Wide scale acceptance of formate muds for drilling purposes, however, has not yet occurred (with the exception of unconventional shale drilling applications in Canada, discussed below). Possible reasons for this are:

- Formate muds are often directly – and unfairly - associated with (or mistaken for) 100% cesium formate mud, which comes at a premium cost because of the rarity of cesium ore. It is, however, quite possible to formulate more cost effective mud systems using such readily available and low cost salts as sodium formate and potassium formate, or mixes of sodium-, potassium-, and formate. Moreover, even though low solids muds are generally preferred with mud density generated primarily by the dense base brines themselves, it has been shown that excellent formate mud formulations can be created using Manganese Tetroxide (Mn$_3$O$_4$) as a weighting agent (see e.g. Al-Bagoury and Steele, 2014).

- Inconsistency in global environmental regulations, as pointed out by Gilbert et al., 2007. Concentrated cesium and potassium formate brines do not meet the requirements of the US Environmental Protection Agency (EPA) Solid Particular Phase (SPP) LC-50 test that pertain to use and disposal of drilling fluids e.g. in the Gulf of Mexico (GOM), primarily due to the extra-ordinary sensitivity of the particular test organism, Mysis bahia (also known as Americamysis bahia), to elevated concentrations of cesium and potassium salts. In stark contrast to this, cesium and potassium formate brines carry a low hazardousness assessment under OSPAR for use in the North Sea. Unless this inconsistency gets resolved, cesium and potassium formate muds will have to be used under zero-discharge conditions in the GOM (note that this restriction does not apply in other offshore environments around the world, and does not apply to sodium formate possibly combined with low levels of potassium formate). For deep GOM drilling in small hole sizes where cuttings volumes are relatively small and manageable, however, the use of cesium/potassium/sodium formate systems should not be rejected a priori, as the potential benefits may greatly outweigh the inconvenience.

Experimental
In the experimental investigations, two test methods were used. The simple and cost-effective accretion test was used to pre-screen various mud formulations with and without solids for their tendency to cause clay sticking on steel, and to select formulations for more sophisticate downhole drilling simulator tests. Even though the accretion test is a crude and unsophisticated tool, it does quantify the tendency of mud systems to cause accretion, and its results generally extrapolate well to field practice. These tests were followed by a series of realistic downhole drilling simulator tests drilling large blocks of shale and limestone under realistic downhole conditions using full mud formulations. A series of micro-bit drilling tests to complete the trifecta of drilling optimization tests is currently ongoing and will be reported on in future reports.

Accretion Test Procedure
Accretion was studied in the laboratory using a rolling bar accretion test method. Tests were conducted for a variety of cesium and potassium formate salt concentrations, and at different solids content. Details of the studied fluids are given in Table 3. Concentrated solutions of cesium and potassium formate had water activities of 0.326 (with a density of 18.36 ppg) and 0.260 (with a density of 13.10 ppg) respectively. Higher water activity solutions were prepared by dilution of these concentrated solutions with water. Formate brines were viscosified by adding XC polymer (Xanthan gum). The concentration of XC was varied among the different solutions to obtain roughly the same non-Newtonian viscosity, as characterized using a Plastic Viscosity (PV) and a Yield Point (YP), for each solution. This was intended to avoid any viscosity artifacts that tend to plague cuttings dispersion and accretion tests (see Hale, 1991). The target viscosity parameters (PV ~ 10 cP, YP ~ 25 lb/100ft$^2$) were achieved in all but the most concentrated formate solutions. Calcium carbonate was added in concentrations of 0 ppb, 15 ppb, 30 ppb and 40 ppb to simulate the effect of solids in drilling fluid. The tests were carried out in one laboratory barrel (350 ml) of each drilling fluid. Following steps were followed:

1. Place a clean hollow steel bar in a mason jar containing drilling fluid.
2. Add 25 grams ($W_1$) of shale cuttings to the jar. 1/4" bentonite tablets, equilibrated to a water activity $a_w^{shale} = 1.0$, were used to simulate the effect of reactive shale cuttings.
3. Seal the lid of the jar and place it horizontally in a roller oven at 120 °F for 30 minutes.
4. Carefully remove the bar from the jar and gently rinse off any extra mud.
5. Scrape off adhered solids from the bar and measure its weight ($W_3$).
6. Allow the accreted solids to dry to a constant weight ($W_1$) at 220 °F.

Quantitatively, the percentage accretion was calculated from the dry weight of accreted solids using the following relation (De Stefano and Young, 2009):

$$\% \text{ Accretion} = \frac{W_3}{(100 - M_1)/100} \times W_1$$

Where $M_1$ is the water content of the unexposed bentonite tablets and $W_1$ is the weight of cuttings added to the jar.

Similarly, moisture content of agglomerated solids was calculated from:

$$\% \text{ Moisture} = \frac{(W_3 - W_2)}{W_2} \times 100$$

<table>
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<tr>
<th>Water Activity (@ 25°C)</th>
<th>Osmotic Pressure (MPa)</th>
<th>Density (ppg)</th>
<th>PV (cp)</th>
<th>YP (lbf/100ft²)</th>
<th>Measured Accretion (%)</th>
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<td>16.1</td>
<td>20.5</td>
<td>25.9</td>
<td>0.0</td>
</tr>
<tr>
<td>0.326</td>
<td>154.28</td>
<td>18.5</td>
<td>25.0</td>
<td>16.0</td>
<td>0.0</td>
</tr>
</tbody>
</table>

| Potassium Formate Solutions |
|-----------------------------|------------------------|---------------|---------|------------------|------------------------|
| 0 ppb solids                |
| 1                           | 0.00                   | 8.3           | 7.5     | 26.0             | 36.4                   |
| 0.956                      | 6.19                   | 8.8           | 8.5     | 30.0             | 18.7                   |
| 0.907                      | 13.44                  | 9.2           | 9.0     | 27.2             | 0.0                    |
| 0.85                       | 22.37                  | 9.6           | 9.2     | 26.0             | 0.0                    |
| 40 ppb solids               |
| 1                           | 0.00                   | 8.9           | 7.3     | 25.0             | 58.2                   |
| 0.956                      | 6.19                   | 9.4           | 9.8     | 31.0             | 22.7                   |
| 0.907                      | 13.44                  | 9.8           | 8.9     | 26.9             | 16.4                   |
| 0.85                       | 22.37                  | 10.1          | 11.0    | 31.0             | 4.0                    |

Table 3 – Water activities, theoretical osmotic pressures (assuming $a_w$ = 1.0), mud rheological properties and accretion results for cesium formate and potassium formate mud formulations used in accretion tests with and without addition of solids (0 ppb, 15 ppb, 30 ppb and 40 ppb calcium carbonate).

**Downhole Simulation Test Procedure**

Full scale drilling tests were conducted using a high pressured drilling simulator, shown in Figure 4. 15 ½” x 36 ¼” cylindrical rock samples of Mancos Shale and Carthage Limestone were drilled with a 5 bladed 8 ¾” PDC bit (Figure 5) at the bottomhole pressure of 6,000 psi. Drilling fluid was circulated at 460 gpm and HSI was maintained around 2.0 to align closely with the Deep Trek test protocol. The test matrix for the series of tests conducted is given in Table 4.

Low- and high water-activity formate brines (which were based on a blend of cesium and potassium formate) at approximately 50 bbl per test were used during the drilling tests. Brines were viscosified by adding Xanvis. Calcium carbonate was again used to simulate the effect of solids, similar to the Deep Trek tests. In each drilling test cycle, Carthage Limestone was tested first, followed by Mancos Shale. Drilling was always initiated at lower WOB, which was progressively increased as long as torque values produced in the drilling assembly remained within operational limits. 30” of the core was drilled in each test and parameters such as ROP, weight-on-bit (WOB), torque and specific energy were continuously recorded during drilling.
Table 4 – Cycles of testing with mixed cesium / potassium mud used at low and high water activity (\(a_{\text{w}}^{\text{DF}}\)) and at low (10 ppb) and high (40 ppb) solids content. Indicated are theoretical osmotic pressure for shale test (assuming \(a_{\text{w}}^{\text{Shale}} = 1.0\)), hydraulic horsepower and HSI, which was kept to a value close to 2.0 for all test.

<table>
<thead>
<tr>
<th>Cycle</th>
<th>Base Fluid</th>
<th>Mud Type</th>
<th>Water Activity</th>
<th>Solids Content (ppb)</th>
<th>Density (ppg)</th>
<th>Osmotic Pressure (M Pa)</th>
<th>Hydraulic Horse Power</th>
<th>HSI</th>
<th>Rock Type</th>
<th>Test</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Fresh Water</td>
<td>Low Mud Weight</td>
<td>1</td>
<td>-</td>
<td>9.5</td>
<td>0.000</td>
<td>120.596</td>
<td>2.005</td>
<td>Carthage</td>
<td>1</td>
</tr>
<tr>
<td>2</td>
<td>Formate Mud</td>
<td>Low aw - Low Solids</td>
<td>0.25</td>
<td>10</td>
<td>15.7</td>
<td>190.814</td>
<td>122.509</td>
<td>2.037</td>
<td>Carthage</td>
<td>3</td>
</tr>
<tr>
<td>3</td>
<td>Formate Mud</td>
<td>Low aw - High Solids</td>
<td>0.25</td>
<td>40</td>
<td>15.7</td>
<td>190.814</td>
<td>122.509</td>
<td>2.037</td>
<td>Carthage</td>
<td>5</td>
</tr>
<tr>
<td>4</td>
<td>Formate Mud</td>
<td>High aw - Low Solids</td>
<td>0.825</td>
<td>10</td>
<td>11.2</td>
<td>26.479</td>
<td>120.375</td>
<td>2.001</td>
<td>Carthage</td>
<td>7</td>
</tr>
<tr>
<td>5</td>
<td>Formate Mud</td>
<td>High aw - High Solids</td>
<td>0.825</td>
<td>40</td>
<td>11.2</td>
<td>26.479</td>
<td>120.375</td>
<td>2.001</td>
<td>Carthage</td>
<td>9</td>
</tr>
<tr>
<td>6</td>
<td>Fresh Water</td>
<td>High MW - Kill Mud</td>
<td>1</td>
<td>-</td>
<td>16.0</td>
<td>0.000</td>
<td>124.850</td>
<td>2.076</td>
<td>Mancos</td>
<td>12</td>
</tr>
</tbody>
</table>
Downhole drilling tests were conducted in 6 cycles. Cycles 1 and 6 in Table 4 refer to reference baseline tests that were run in low- and high mud weight freshwater WBMs. Results from these reference tests were then used for comparison with the formate mud test results. Cycle 1 tests on 9.5 ppg WBM served as a reference for Cycle 4 and 5 tests on 11.2 ppg mixed cesium/potassium formate muds, Cycle 6 tests on 16 ppg WBM served as a reference for Cycle 4 and 5 tests on 15.7 ppg mixed cesium/potassium formate mud. Cycle 2 represents a low water activity (high salinity) formate blend test obtained with 10 ppb calcium carbonate. After the completion of Cycle 2, an additional 30 ppb of calcium carbonate was added to the mud and Cycle 3 was carried out with low water-activity, high solids concentration mud. Once low water activity cycles were completed, the whole fluid system was switched out to a high water-activity (low salinity) formate blend. Drilling was then carried out with this new fluid with low solids content (10 ppb) and subsequently with high solids content (40 ppb) in Cycles 5 and 6 respectively. Raw test data was processed, and moving averages of ROP vs. WOB behavior were fitted to trend lines which were used for performance comparisons. WOB values selected for Carthage Limestone were 10, 20, 30, 40, and 50 klbs, and those for Mancos Shale were 5, 15, 25, and 35 klbs.

**Results**

**Accretion Tests**

Table 3 (left hand side) shows accretion results for concentrated cesium formate formulations. Regardless of the amount of solids, no accretion was observed for these concentrated formulations. Next, the accretion effect was studied in more diluted brine solutions (right hand side of Table 3). Figure 6 shows the actual photographs of the steel bars after the tests. The steel bar on the left side of every picture shows the (high) accretion tendency of freshwater WBM. The concentration of cesium formate increased from left to right in the picture, with the picture on the far right representing the most concentrated cesium formate formulation. The magnitude of accretion measured for cesium formate mud is represented in the bar chart in Figure 7. Results again clearly show that accretion tendencies are largely eliminated when cesium formate concentration was increased, but some accretion is now seen for the more dilute concentrations (\(a_w^{DF} > 0.97\)), which gets slightly worse when solids were added: the amount of accreted solids was slightly higher in high solids content mud (40 ppb) as compared to the low solids mud (10 ppb). Note that the addition of solids also worsened the accretion in freshwater mud (\(a_w^{DF} = 1\)), and that this effect persisted in the results with the diluted cesium formate mud formulations.

The results for accretion in potassium formate muds are shown in Table 2, and in Figures 8 and 9. Trends similar to those observed for the cesium formate muds are observed in the potassium formate muds, i.e. accretion is strongly suppressed with increasing potassium formate concentration and lower water activity, whereas addition of solids exacerbates the accretion tendency. The latter effects appear to persist more when increasing potassium formate concentration compared to the cesium formate solutions, which may be caused by differences in clay inhibition tendency (see Discussion below).
I. Zero concentration of solids

II. 40 ppb concentration of solids

Figure 6 – Photographs of shale accretion on steel in more diluted, higher water-activity cesium formate muds, with the results for zero solids concentration on the left and those obtained for 40 ppb of solids on the right. Note that some accretion is observed for mud formulations at a water activity of 0.97. The amount of accretion is slightly higher in the mud with higher (40 ppb) solids content.

Figure 7 – Results of cesium formate accretion tests on diluted muds, showing a slight influence of solids content.

Figure 8 – Photographs of accretion results obtained for potassium formate muds at diluted conditions, with the results for zero solids concentration on the left and those obtained for 40 ppb of solids on the right.
Figure 9 – Results of Potassium formate accretion tests on diluted muds, showing more pronounced influence of solids content than observed for the cesium formate muds (cf. Fig. 7).

Downhole Simulation Test Results

Figure 10 compiles the entire set of fitted data for all test cycles, for 9.5 ppg WBM base mud (Figure 10a), 15.7 ppg mixed formate mud with 10 ppb calcium carbonate (Figure 10b), 15.7 ppg mixed formate mud with 40 ppb calcium carbonate (Figure 10c), 11.2 ppg mixed formate mud with 10 ppb calcium carbonate (Figure 10d), 11.2 ppg mixed formate mud with 40 ppb calcium carbonate (Figure 10e), and 16 ppb WBM base mud (a bentonite-barite kill mud formulation, Figure 10f).

Figure 11 shows the comparison of the trend lines obtained for 9.5 ppg WBM base mud and 11.2 ppg mixed formate mud with low and high solids content while drilling Mancos Shale. The formate mud with low solids drills on average ~ 60% faster than the base mud (e.g. at 24 klbs WOB, formate mud drills at 82 ft/hr vs. 51 ft/hr for the base mud). This ROP improvement is reduced to ~ 15% when the system is loaded up with solids (e.g. at 26 klbs WOB, formate mud drills at 71 ft/hr vs. 61 ft/hr for the base mud).

Figure 12 shows the comparison of the trend lines obtained for 16 ppg base mud and 15.7 ppg mixed formate mud with low and high solids content while drilling Mancos Shale. The formate mud with low solids drills on average ~ 50% faster than the base mud (e.g. at 30 klbs WOB, formate mud drills at 93 ft/hr vs. 61 ft/hr for the base mud). This ROP improvement is reduced to ~ 20% when the system is loaded up with solids (e.g. at 30 klbs WOB, formate mud drills at 73 ft/hr vs. 61 ft/hr for the base mud).

The drilling results for Carthage Limestone were all bound within a tight band and appeared to be largely identical within the experimental error. Hence, no clear ROP enhancement effect was seen for this formation. Note, however, that the blocks of Carthage that were drilled in this investigation were dry samples for which no ROP enhancement effects were expected. This result is distinctly different, however, from the results obtained during the Deep Trek investigation, where an increased ROP was observed with cesium formate mud compared to OBM in Carthage Limestone (although again achieved at a higher hydraulic horsepower / HSI, see Black et al., 2008). The potential merits of formate muds and other high-salinity muds for increasing ROP in formations other than shales is therefore unresolved at the present time and requires further study.
Figure 10a – Cycle 1: 9.5 ppg WBM Simulator Data

Figure 10b – Cycle 2: 15.7 ppg formate mud with 10 ppb solids

Figure 10c – Cycle 3: 15.7 ppg formate mud with 40 ppb solids

Figure 10d – Cycle 4: 11.2 ppg formate mud with 10 ppb solids

Figure 10e – Cycle 5: 11.2 ppg formate mud with 40 ppb solids

Figure 10f – Cycle 6: 16 ppg WBM
Figure 1 – Drilling simulator results for low(er) salinity, 11.2 ppg formate mud in Mancos Shale compared to 9.5 ppg WBM base mud, showing a 60% improvement for low solids (10 ppb) mud and 15% improvement for high solids (40 ppb) mud.

Figure 2 – Drilling simulator results for high salinity, 15.7 ppg formate mud in Mancos Shale compared to 16 ppg WBM base mud, showing a 50% improvement for low solids (10 ppb) mud and 20% improvement for high solids (40 ppb) mud.
Field test results
The first purposeful use of formate as a drilling fluid was reported in 2001 for the drilling of two exploration wells in the Barents Sea (Offshore Magazine, August 2001). A mixed sodium/potassium formate system was selected, primarily because its excellent health, safety and environmental (HSE) profile was considered a good match for the fragile ecosystem of the Barents Sea (the mud system contained only Plonor List Category "A" chemicals, which the Norwegian Pollution Control Authority and European Standard defines as naturally occurring material) and the mud minimized the risk of reservoir impairment. The wells were drilled ahead of the planned drilling curve with minimized waste generation and low dilution rates. Problems with a fluid loss additive (polyanionic cellulose, PAC) on the first well (Goliath) were overcome and the well was drilled 11.8 days ahead of schedule with a penetration rate in largely shale-based formations of 49 – 82 ft/hr (i.e. very comparable with the results of our drilling simulator tests). The second well (Gamma) was drilled 5 days less than the expected time frame, with no drilling fluid-related trouble time. Despite the slower drilling in hard rock through much of the 8 1/2-in. section, penetration rates in the clay-rich intermediate and reservoir zones reached as high as 107 ft/hr (including connection time). The quality of the cuttings was noted to be similar to those generated by OBM, and the mud facilitated a high core recovery of 97%. It was noted that the mud system exhibited a superb rheological profile, excellent hole cleaning and wellbore stability properties, and reduced dilution rates significantly compared to more conventional WBM systems. The Barents Sea field case leaves one to wonder why, despite the evident drilling success achieved with a cumulative time-savings reported to amount to 16.8 days on two wells, it has taken so many years for more drilling applications of formate muds to materialize.

However, since June of 2013, over 120 wells have been drilled with potassium formate in Western Canada. The formulation used on all of these projects was designed and maintained as an unviscosified solids-free brine. Many iterations of this system in a variety of different areas and formations have been implemented, but the fluid base design remains consistent. Most of the successful projects are in tight, historically slow-drilling formations with the formate system run as clean and solids-free as possible. Polymer additions are minimized and additions are only as needed to flocculate cuttings, as any type of excess polymer in the system will lead to the eventual buildup of solids. Since most of the shale formations are tight rock with little porosity, the system is run with relaxed fluid loss and no LCM or bridging materials. Longer lateral reaches require the addition of chemical lubricants, especially in the areas where the brine is heavily diluted.

First application formate brine was in the “Montney Field A” (See Figure 13). The fluid was initially introduced to try and increase the ROP in the lateral section. Typically, the Montney laterals were drilled with a weighted invert system and suffered from slower ROP and multiple bit runs were required to reach TD. A high-density, solids-free brine was proposed to help increase ROP in the horizontal and potassium formate brine was eventually selected based on its favorable low-corrosive nature. Once the brine was implemented, positive results were instantaneously realized. There was an immediate increase in observed ROP (30-50%) and average bit life was more than doubled versus OBM. This brine exhibited excellent wellbore cleaning in the horizontal section due to its near-Newtonian rheology, maintaining a turbulent flow profile at basically any pump rate. Due to its success, the operator implemented it in all of their Montney wells in the area and has since drilled over 45 laterals with formate with a substantial reduction in drilling days. The wells are typically drilled with a diluted potassium formate brine (1.25 – 1.30 SG) which is overbalanced for the reservoir; however, losses are minimal in most areas due to it being a very tight formation. Note that the Montney formation is composed of siltstone and shale with fine-grained sandstone towards the top. It has been observed that when the upper, more sandier Montney is drilled, substantially lower ROP are achieved than drilling the more clay-rich middle and lower Montney wells. This point seems consistent with the fact that the benefits of formate fluids for ROP enhancement are primarily achieved in shales.

After the success with the formate fluid in the “Montney Field A”, another operator in a nearby area conducted a trial. A four well pad was selected that had two Montney horizontals that were previously drilled with OBM. Trial well #1 saw the average ROP nearly double (8.5m/hr vs 16.4m/hr) and the average bit run triple (846m vs 284m). The previous laterals were drilled with an OBM system with an average of 8 bits in the lateral, whereas the first well TD’d a longer lateral with only 3 bits (See Figure 14). For a direct comparison, the first formate well was displaced to OBM for the last 86 m of the horizontal and the ROP was instantly cut in half. WOB was increased but it proved impossible to match the ROP of the formate brine with the same bit and BHA. The second trial well on the pad was also a success with only two bit runs with an average of 1144 m per run (See Figure 15). Since this pad, 30 more wells have been drilled in the area with great success and have seen bit runs larger than 2000 m and lateral lengths up to 3250 m. After seeing the reduced drilling days in the horizontal, the benefits of drilling with formate brine to the intermediate well sections was explored. Currently, wells are drilled with surface casing using Floc-Water with displacement to potassium formate brine when elevated density is required, completing the intermediate and main hole sections with formate for a 10-15+ days savings versus OBM (See Figure 16).

The success of the use of formate fluids on Canadian shale wells has been reported by an independent operator (Siemens and Wiesel, 2014). Highlighting the various benefits of use of formate muds for their operations (i.e. elevated, no-solids brine density, low corrosion tendency, high lubricity, formation compatibility, etc.) this operator also notes a 30-40% average savings in drilling time, 17-27% fluid cost savings, and, most importantly, a 27% total drilling well cost savings.
Figure 13 – Potassium formate brine drilling performance (blue lines) compared to invert mud (red lines) in Montney Field A.

Figure 14 – Potassium formate brine drilling performance (blue line) compared to invert mud (red lines) in Montney Field B trial #1.
Figure 15 – Potassium formate brine drilling performance (blue line) compared to invert mud (red lines) in Montney Field B trial #2.

Figure 16 – Potassium formate brine drilling performance (blue lines) compared to invert mud (red lines) in Montney Field B.
Discussion
Accretion tests show cesium formate and potassium formate muds to have excellent “anti-accretion” tendencies. Accretion tendency reduces with increasing salinity and lowering of water activity, which coincides with increasing osmotic pressures. It is tempting therefore to ascribe the accretion results to the action of chemical osmosis, but the differences between cesium and potassium formate show that inhibition effects appear to play a role as well. Inhibition is defined in this context as the inherent swelling pressure acting between clay platelets. Cesium ions are some of the most powerful inhibitors of clay swelling, and are even better in this task than potassium ions. Lower hydration and swelling in cesium formate compared to potassium formate may explain the (slight) difference in accretion tendency that is observed in cesium formate fluids for equivalent osmotic pressure. Introduction of solids (in the form of calcium carbonate) clearly interferes with avoidance of accretion, and the trends observed in the simple accretion test extend all the way to the large scale drilling simulator tests and earlier large scale drilling tests (Ramsey et al., 1996, black et al., 2008).

Downhole drilling simulator tests showed improvements on the order of 50%-60% of formate muds compared to base muds (11.2 ppg formate mud compared to 9.5 ppg base mud, 15.7 ppg formate mud compared to 16 ppg base mud) in Mancos Shale. Note that these tests were conducted at lower pressure and more consistent HSI values than the Deep Trek investigation (6,000 psi vs. 10,000 psi fluid pressure, HSI ~2), where improvements on the order of 100% were seen. Introduction of solids interfered with ROP improvement, and to a much larger extent than observed in the Deep Trek tests, although a net improvement was still evident in the formate muds even at high solids concentration. It is postulated that high concentration of fine / colloidal solids present at the interface between the cutter and the shale formation interfere with obtaining benefits from the water layer(s) extracted from the shale through osmosis. This clearly underlines the need to keep drilling fluids as clean as possible, an import point that is well-illustrated by the Canadian field experience as well. The ROP enhancement results obtained to date appear fully consistent with proposed mechanism of chemical osmotic dehydration of the clay fabric to provide better lubrication and cleaning on the cutter faces, and possibly strengthening of the outer layers of the shale making it less prone to sticking. It could be argued that the benefits observed in the experiments are due to clay inhibition, i.e. suppression of hydration of clay minerals in the shales. As already stated, both cesium and potassium cations are excellent “inhibitors”, although even they do not reduce clay hydration to zero (van Oort, 2003). But this raises questions about why formates would outdrip OBM/SBM both in the Deep Trek tests as well as the Canadian field tests, given that OBM/SBM provides the ultimate “inhibitive” action by not allowing any shale hydration. Moreover, ROP benefits like those observed with the formate fluids have not been seen e.g. in KCl/polymer muds which usually employ levels of potassium ions that tend to maximize inhibitive benefits (note that KCl/polymer muds usually do not provide significantly low water activities, such that their potential osmotic benefits are minimal). Clearly, something more than simple “inhibition” must be at play to facilitate the ROP enhancement. The analogy with electro-osmosis, for which ROP enhancement was clearly demonstrated and explained, adds further support for the chemical osmotic origins of the ROP enhancement discussed here.

An interesting observation from the Canadian field trials is that formate brines appear to extend bit life. A straightforward explanation for this it would be that at equal RPM values, a bit with a higher ROP will require fewer revolutions than a bit with lower ROP. Fewer revolutions simply means less wear. The increased depth-of-cut due to the higher ROP translates into less lateral / whirl vibration and impact damage to the bit. Alternatively, if the osmotic mechanism indeed lubricates cutters better, than this could keep cutters cooler while drilling by reducing friction at the bit. Bit friction, torque on bit and high depth-of-cut also play an important role in excitation of torsional drillstring vibrations (also known as stick slip), which are very harmful to bits and downhole BHA components such as MWD/LWD tools and downhole motors (see e.g. Dupriest and Koederitz, 2005). The potential to extend the life of bits and downhole tools through favorable rock-bit-fluid interaction should be studied further, given the profound implications for minimizing drilling time and cost.

Conclusions
This paper presents a follow-up to the pioneering work by Cooper on electro-osmosis and the Deep Trek investigation dedicated to studying the ROP behavior of mud formulations in high-pressure drilling tests, in order to further delineate the use of osmotic processes for ROP enhancement purposes. Results of accretion tests and full-scale downhole simulation tests appear to confirm the benefits of high salinity formate mud formulations for ROP enhancement in shales. It appears that the ROP benefits of these high salinity, low water activity systems go beyond that of a mere low solids drilling fluid. The ROP enhancing mechanism is attributed to chemical osmosis, which pulls water from the clay-rich rocks under the influence of a chemical potential gradient. This, in turn, forms a lubricating layer that interferes with intact and failed rock from building up on the cutter edges and sticking to the cutter body. An additional benefit could come from strengthening of the outer shale layers due to this dehydration effect, making cuttings / failed rock less prone to adhere to the cutters. The process is analogous to the ROP enhancing effect of electro-osmosis.

Extensive field drilling results with formate muds are very much aligned with the lab study presented here, with formate muds consistently out-drilling invert systems (OBM/SBM). Such results are very significant, given the premium usually paid for OBM/SBM use, both in direct cost as well as costs associated with waste handling and cleanup. Formate muds should be seriously considered as superior WBM drilling formulations, and the stigma associated with high perceived cost (primarily associated with the use of pure cesium formate) should be abandoned.
To fully validate the proposed osmotic mechanism, it would be useful to study other high-salinity, low water-activity mud systems as well. Further investigation should focus on the development of formates and other high salinity muds as superior shale drilling fluids and potential OBM/SBM replacements, as well as potentially harnessing the benefits of electro-osmosis for ROP enhancement that could potentially be used in a large variety of different mud formulations.

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