AADE-24-FTCE-047

Formulating High-Performance Well Construction Fluids Based on Formate Brines — Lessons Learnt Over 30 Years

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Abstract

Well construction fluids based on high-density sodium, potassium, and cesium formate brines have been successfully used for reservoir drilling, shale drilling, managed-pressure drilling, slim-hole/coiled-tubing applications, perforating, screen-running, gravel-packing, workover, and upper completion installation since the 1990s. The exceptional performance of a single fluid type across so many various applications is truly remarkable, and the use of the same formate base fluids for all operational stages of a well construction has been proven to streamline the transition between them, while also ensuring that the reservoir is exposed to only one, nondamaging filtrate.

After 30 years of deploying formate fluids in the field, one would think that fluid service companies would be skilled in the formulation of high-performance fluids based on formate brines, but unfortunately, that is not always the case. A formate fluid formulation that should ideally contain just a few essential components is often formulated with a long list of redundant additives.

The concentrated formate brines have many inherent beneficial properties that make most additives unnecessary. However, one essential additive must always be included: the carbonate/bicarbonate pH buffer. This helps maintain a slightly alkaline pH and protects metals against corrosion, even after a large influx of reservoir gases.

Xanthan gum is an additive that is exceptionally compatible with formate brines and provides the fluid with many favorable properties. It has the benefit of being stable at high temperature in the formate brine and simultaneously self-break over time. Its shear-thinning rheology and drag reduction properties make the fluid ideal not only for applications with narrow pressure windows but also for slim-hole and coiled-tubing applications. Cellulose nanofibrils, another shear thinning viscosifier that is stabilized at high temperatures in formate brines, is an excellent xanthan replacement for higher-temperature applications, but it lacks drag-reducing properties.

A simple buffered formate brine viscosified with xanthan gum is the perfect fluid for most applications. The unique rheological properties of xanthan gum provide excellent solids suspension and fluid loss control properties, which have been proven in many field applications.

For applications where fluid loss control is the primary driver, there exists a wide range of self-breaking, starch-based products that are fully compatible with formate brines and are also stabilized at high temperatures by the formate ion.

Sized calcium carbonate is the recommended bridging material in formate fluids and should be used at the lowest possible concentration whenever a thin, acid-soluble filter cake is desired.

Many other additives, such as some synthetic polymers and thermal extenders, have been found to be compatible with formate brines. These should be used only if strictly necessary and always at the lowest possible concentrations.

Even with a simple high-performance formate formulation and minimum additives, problems are often encountered when trying to mix these fluids in the laboratory and in the field. Polymeric additives need shear, temperature, and time to hydrate in formate brines. Special laboratory mixing procedures have evolved over the years, and many useful recommendations are available for preparing formate fluids for use in the field.

The number one rule when formulating formate fluids is ‘less is more’, and when mixing, ‘patience is a virtue’.

This paper shares useful knowledge about formulating, mixing, and testing formate fluids, which has been gained over more than 30 years both in the laboratory and in the field.

Introduction

Well construction fluids based on sodium (Na), potassium (K), and cesium (Cs) formate brines have been successfully utilized in the field for more than 30 years. Their use has included reservoir drilling (Hands et al., 1998; Bungert et al, 2000; Saasen et al., 2002; Berg et al, 2007, 2009, Jøntvedt et al., 2018; Nilsen et al., 2023a, 2023b), shale drilling (Zuvo and Askø, 2001; van Oort et al., 2015), managed-pressure drilling (MPD) (Syltøy et al., 2008; Carnegie et al., 2013; Nilsen et al., 2023a, 2023b), perforating (Roy et al., 2008), slim-hole (SH) and coiled-tubing (CT) applications, screen-running (Saasen et al., 2002; Berg et al, 2007, 2009, Jøntvedt et al., 2018; Nilsen et al., 2023a, 2023b), gravel-packing (Tahirov et al., 2019; Nilsen et al., 2023a; Nilsen et al. 2023b), workover (Brangetto et al., 2007), and upper-completion installation.

Formate-based well construction fluids were developed by Shell Research in the 1990s. In addition to xanthan gum viscosifier and sized calcium carbonate bridging material, Shell's early laboratory formulations, which were designed for deep high-pressure/high-temperature (HP/HT) drilling applications, included a blend of ultralow molecular weight (ULMW) polyanionic cellulose (PAC) and an alkyl acrylate-AMPS (2-acrylamido-2-methyl-propane sulfonic acid) polymer for tight fluid loss control under hydrothermal conditions (Downs, 1992, 1993). In Shell's later laboratory prototype formulations, the AMPS polymer was replaced with modified starch (Howard, 1995), which was found to be stable in formate brines up to at least 150°C (302°F). This latter formulation was used in Shell's first published formate drilling application (Hands, et al., 1998) and in Exon-Mobil's deep gas well drilling campaign in Germany in the late 1990s (Bungert et al., 2000).

Moving into the 2000s, Equinor was the primary user of formate drilling fluids in their Huldra, Kristin, Kvitebjørn and Vega fields. The six Huldra wells were drilled with the same simple formulation containing xanthan gum, PAC, and modified starch (Saasen et al., 2002). Due to the higher temperature of 172°C (342°F) in the Kristin reservoir, xanthan was substituted with a cellulose nanofibril (CNF) viscosifier and AMPS polymer was added for fluid loss control. This formulation was adapted for the first Kvitebjørn wells, although several variations of the fluid formulation were used during the Kvitebjørn drilling and completion campaign. The concentration of AMPS polymer was reduced for environmental reasons, and PAC and modified starches were tested at different concentrations. Initially, it was thought that the use of PAC was critical for good fluid loss control, which was later proven wrong when it was discovered that good fluid loss control could be obtained without PAC when proper pH and buffer management was introduced.

In the 2010s, a large effort was invested in the formulation of a combined drilling and screen-running fluid for TotalEnergies' 145°C (293°F) Martin Linge field, where compatibility with both the Darcy-permeability formation and the 250-µm sand screen had to be met. A simple drilling fluid formulation, free from both PAC and AMPS polymers, was used for the first time to drill in the challenging Martin Linge reservoir (Jøntvedt et al., 2018). This simple fluid, consisting of only buffered formate brine, xanthan gum, high-temperature modified starch, and sized calcium carbonate, was used to great success and even outperformed oil-based mud in terms of both drilling performance and shale-stabilizing properties. Important for this success was the maintenance of the pH and buffer concentrations throughout the operations. Since then, Equinor has acquired the Martin Linge field and drilled five additional reservoir sections with the same simple formulation without experiencing any fluid-related problems (Nilsen et al., 2023a, 2023b).

Other lessons have also been learned in the field over the years. Inexperienced users of formate drilling fluids have typically overdosed the fluid on excess polymers owing to lack of immediate polymer hydration. Patience is the virtue here, and the use of fine shaker screens should always wait until the fluid has made a couple of circulations through the drill bit for extra shear. For other fluid applications, such as screen-running and perforating where there is no bit involved, it is essential that the fluid be properly sheared before it is circulated into the well.

The introduction of formate fluids has also been slowed down by the fact that API and ISO have lagged behind in the development of formate-specific procedures for mixing and testing formate fluids. Although several formate-specific test methods have recently been published in ISO 13503-3 (ISO, 2022), additional work is needed. In certain instances, suggestions have been made to dilute the brines with water for better hydration, resulting in loss of some of the many inherent, beneficial properties of the concentrated formate brine.

With up to 30 years of experience with formulating and mixing formate-based fluids in the laboratory and in the field, the authors of this paper wish to share their knowledge with all potential users of formate-brine-based fluid systems. This paper presents optimized, mostly field-proven, formulations for reservoir applications, high- and low-temperature environments, shale drilling, screen-running, perforating, and slim-hole/coiled-tubing applications in. It also includes best practices for hydrating various types of polymers in the laboratory and the field.

Common Pitfalls

Despite the long history of deploying formate fluids in the field, mostly in HP/HT applications, some fluid service companies overcomplicate the design of their formate fluids. A fluid formulation that should ideally contain just a few essential components may ultimately contain a long list of redundant additives. The reasons for this are as follows:

- Many fluid designers are unaware of the many inherent beneficial properties of the formate brine itself, which make many additives superfluous. Unnecessary products such as shale stabilizers, corrosion inhibitors, biocides, and antioxidants are frequently found in formate formulations.
- Many fluid designers use oil-based mud performance criteria for qualifying formate fluids. Oil-based muds require low fluid loss to prevent the damaging oil-wetting filtrate from entering the reservoir. A formate fluid on the other hand, performs the best with a high spurt loss. A high spurt loss provides the best drilling performance, including the surprisingly high rate of penetration (ROP) that is frequently reported in the field. The monovalent formate filtrate is nondamaging to the reservoir, and striving to keep the fluid loss low typically results in fluids being overdosed with solids and fluid loss control agents with unwanted Newtonian rheology profiles.
- Although the best formate formulations are inherently simple in design, the mixing procedure for hydrating polymers in formate brines is not intuitive. Inexperienced users of formate brines may assume that polymers are destroyed when too much heat and shear are applied during mixing, but in the polymer-protective environment of formate brines, the input of thermal and mechanical shear energy over an extended time during mixing is highly desirable. The typical response to slow biopolymer hydration in formate

brines is to add more polymers or replace the polymers with other additives that may not have the same beneficial properties.

Base Brine Composition

The three formate brines that are currently used in drilling and completion fluid formulations are sodium formate, potassium formate, and cesium formate brines. The solubilities and densities of these three saturated formate brines are shown in Table 1.

Table 1 – Properties of saturated sodium, potassium, and cesium formate brines at 20°C (68°F).

Brine type		Maximum Molar Concentration		Maximum Density	
		[mol/L]	[wt%]	[g/cm³]	[lb/gal]
Sodium formate	NaCHOO	9.1	46.8	1.33	11.1
Potassium formate	KCHOO	14.5	75.0	1.59	13.3
Cesium formate	CsCHOO	10.7	83.0$^{1)}$	2.30	19.2

$^{1)}$ Applicable to cesium formate monohydrate

Cesium formate can reach the highest density of approximately 2.30 g/cm³ (19.2 lb/gal). By adding water to cesium formate brine, any required density can be reached. However, water dilution is detrimental to many of the beneficial properties of formate brines, so brines in the density range of 1.57–2.20 g/cm³ (13.3–18.3 lb/gal) are preferably formulated with as much potassium formate as possible, which is also beneficial from a cost point of view. Regarding lower-density brines, there are no known performance benefits to gain from replacing potassium formate with sodium formate, so cost is the biggest driver for blending sodium and potassium formate brines.

When blending formate brines, it is important to consider the crystallization temperature of the resulting brine. When the crystallization temperature or pressurized crystallization temperature is critical for the application, cesium formate may be needed to formulate brines with densities significantly lower than 1.57 g/cm³ (13.1 lb/gal) to lower the crystallization temperature. Adding cesium formate and water to a concentrated potassium formate brine lowers the crystallization temperature without altering the brine density. Measuring the crystallization temperature of formate brines is challenging due to extreme supercooling and the existence of a metastable potassium formate crystal. The recommended method for performing these measurements has been published in ISO 13503-3 (ISO, 2022).

There are also other properties of blended brines that depend on the formate brine type and water content and can be altered by careful consideration of brine composition. Water removal from the brine typically improves properties such as shale stability, polymer temperature stability, and lubricity at the cost of increased viscosity and crystallization temperature. Potassium formate has been found to be more effective at stabilizing biopolymers at high temperatures than sodium and cesium formate, and high-temperature formulations therefore benefit from the highest possible potassium formate content and the lowest possible water content.

Compatible Additives

Unlike most oil- and water-based drilling and completion fluids, formate-based fluids are simple and contain only a few key additives. The reason for this difference is that the formate brine itself has many inherent beneficial properties, and the fluid therefore needs few additives to improve its performance.

The formate ion is an antioxidant, so additional antioxidants are rarely needed. Formate brines are naturally dense and do not require solid weighting agents. Biocide additions are not generally needed because the low water activity of concentrated formate brines discourages the growth of microorganisms. Low water activity also provides formate brines with strong osmotic pressure benefits that not only assist in stabilizing reactive shales but can also strengthen them (van Oort and Howard, 2017). Formate brines are also naturally lubricious, which means that lubricants are rarely needed. Finally, formate brines are not significantly corrosive to metals and do not require the addition of corrosion inhibitors (Leth-Olsen, 2004).

An additive that is **always required** in all formate fluid formulations is the carbonate/bicarbonate pH buffer. This should never be omitted. One additive that is **recommended** for use in formate drilling fluids, screen-running fluids, perforating fluid, and various pills is a shear-thinning viscosifier for rheology modification. Fluid loss polymers, bridging materials, and thermal extenders are **optional**, depending on the application.

Biopolymers are exceptionally compatible with formate brines as they are stabilized at high temperature by several key properties of these brines (Downs, 1991; Howard, 1995; Howard et al., 2015; Anderson et al., 2023; Howard, 2024). Figure 1, taken from Howard (1995), compares the 16-hour temperature stability of three commonly used biopolymers in different brine systems. Similar behavior has been found for CNF.

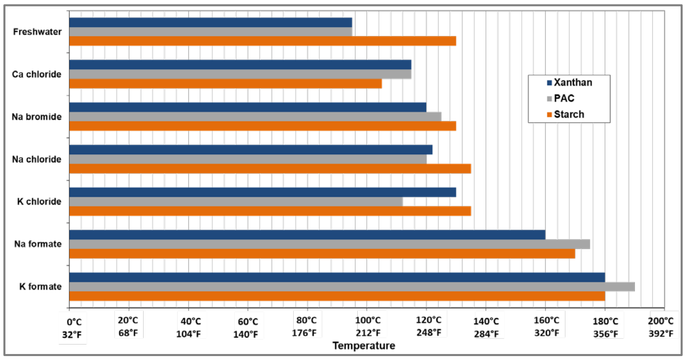

Figure 1 – 16-hour stability temperature for xanthan gum, PAC, and a modified starch in concentrated oilfield brines. For xanthan and PAC these temperatures are determined as the temperature at which the fluid loses half of its viscosity. For the modified starch, where the viscosity was too low to measure, API fluid loss measurements were used. The data are taken from Howard (1995).

Many biopolymers that are used in formate fluid formulations are supplied in both powder and liquid forms. Liquid additives typically contain active ingredients dispersed in a glycol-type dispersant. Our experience with these products when tested in the laboratory is as follows:

- **Density loss** – A density reduction occurs when these are added to the heavy formate brine, which needs to be compensated for in the brine composition.
- **Inhomogeneity** – The concentration of the active ingredient appears to vary not only between batches but also inside the batches.
- **Unwanted suspension agent** – The dispersing glycol may have a positive or negative effect on fluid properties. Unfortunately, the addition of glycol to formate fluids results in increased fluid loss.
- **Loss of modularity** – The fact that the added glycol cannot be separated from the active ingredient means that the fluid formulation is no longer modular.

It is recommended that dispersed additives be used only if the powder version is unavailable or for other reasons cannot be used.

Notably, the viscosifier hydroxyethyl cellulose (**HEC**), which is commonly used in high-density halide brines, is **not** compatible with formate brines. Fortunately, there are better alternatives such as xanthan gum and CNF.

Some of the additives that have been found to be compatible with formate brines are described here.

Carbonate/Bicarbonate pH Buffer

The carbonate/bicarbonate pH buffer is the most important additive in all formate fluid formulations (Howard and Downs, 2009). Although formate salts, when dissolved in water, exhibit a naturally slightly alkaline pH (8–10), it is important that carbonate/bicarbonate pH buffer is added, as this allows the pH to remain stable over time in the case of an acid gas influx from the reservoir.

The amount of carbonate /bicarbonate pH buffer to be added depends on the application, but as a rule-of-thumb, maintaining a buffer concentration of approximately 11–23 kg/m³ (4–8 lb/bbl) of sodium and/or potassium carbonate/bicarbonate is recommended for most well construction applications. For applications where there is a risk of incompatibility between the pH buffer and the formation water, lower concentrations may be considered. It is recommended that a concentration within the higher end of this range be used for the following applications:

- Long-term exposure to high temperatures (~150°C (302°F) and above).
- Exposure to high amounts of acid gas

When buffering formate brine, it should be considered that some suppliers prebuffer the brine, while others do not. The buffer concentration should therefore be measured before and after the buffer is added.

Xanthan Gum

Xanthan gum is a polysaccharide biopolymer that imparts shear-thinning (pseudoplastic) rheological properties to water-based drilling and completion fluids over a wide range of temperatures, pH values, and salinities and has been used in formate-based drilling and completion fluids since their introduction in the 1990s (Downs 1991; Howard 1995; Howard et al., 2015).

The unique ability of formate brines to stabilize xanthan at high temperature by increasing its transition temperature was discovered by Shell scientists in the 1980s (Clarke-Sturman and Sturla, 1988). This is illustrated in Figure 2. Although the transition temperature is not directly linked to the longer-term stability of xanthan in these brines, the figure is a good illustration of how both brine type and brine concentration affect the temperature stability of xanthan. For the maximum temperature stability of xanthan, it is advised to optimize the concentration of potassium formate and minimize water dilution.

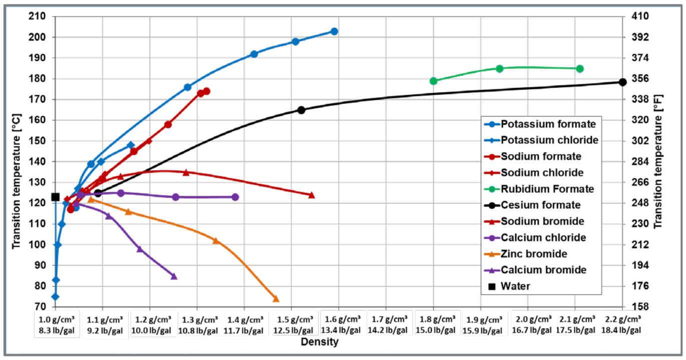

Figure 2 – Transition temperature of xanthan gum in various oilfield brines as a function of brine density. The cesium and rubidium formate data are taken from Kaminski (2013) and the others from Howard (1995).

Another unique property of xanthan when used in formate brine is that although it is stabilized at high temperatures by the formate brine system, it degrades over time. Therefore, unlike synthetic viscosifiers, which are needed in other fluid systems, highly temperature-stable fluids can be formulated that fully break down over time and therefore do not cause permanent damage to the formation (Anderson et al., 2023; Howard, 2024).

In addition to providing shear-thinning rheology to formate-based fluid systems, xanthan is an excellent drag reducer (Johnsen et al., 2018; Gul et al., 2019; Howard et al., 2019). Several studies have shown that of all the biopolymers used in oilfield brines, xanthan gum is the most effective drag reducer (Fryzowicz and Maas, 2011; Shah and Zhou, 2003; Ahn, 2015).

When added at higher concentrations, xanthan also provides fluid loss control by means of viscoelastic, time-independent pseudoplastic rheological behavior (Powel et al., 1995; Howard et al., 2017).

Proprietary Starch-Based Polysaccharide Viscosifier

A proprietary starch-based product has been identified that behaves similar to xanthan gum when hydrated in formate brines. This product, which is commercially available from the supplier, has been extensively tested in formate fluid formulations in the laboratory, and it has also been used in blended cesium/potassium formate displacement pills in BP's Raven field (Tahirov et al., 2019). Compared with xanthan, this additive, which has a similar shear-thinning rheology profile and temperature stability, has the following two advantages:

- It appears to be easier to hydrate (requires less heat and shear) in formate fluids.
- When used at high concentrations, gels are less prone to form in formate brines rich in carbonate/bicarbonate pH buffer.

To obtain the same rheology as that of xanthan, the addition of approximately twice the weight of xanthan (dry product) is needed. This viscosifier has been shown to have drag-reducing properties similar to or possibly better than those of xanthan (Howard et al., 2019).

Cellulose Nanofibrils (CNF)

Different types of CNF products have been evaluated for their compatibility with and performance in formate fluids (Howard et al., 2022). The CNF products were found to be exceptionally compatible with formate brines, and like other biopolymers, they appear to be stabilized at high temperature in the formate-rich environment. Rheology testing has also shown that CNF is unique when hydrated in formate brine, as it exhibits a rheological profile that is more shear-thinning than that of xanthan gum (Howard et al., 2022).

The exact temperature at which CNF can be used in formate brine depends on the duration that it needs to remain stable and the type and concentration of formate brine. However, its shear-thinning rheology was found to persist after seven days of exposure to temperatures up to 195°C (383°F) and after at least 16 hours at 200°C (392°F) in a cesium/potassium formate drilling fluid. CNF has also been shown to hydrate significantly more easily than xanthan and starch-based additives in formate brine.

Although CNF has been found to be more shear-thinning than xanthan gum and significantly easier to hydrate, it does not exhibit drag-reducing properties and is therefore not suitable as a xanthan replacement in SH/CT applications. Additionally, it does not biodegrade as readily as xanthan or the proprietary starch-based viscosifier.

Fluid Loss Control Starches

There are many starch-based fluid loss control additives available on the market. All the products that have been tested are compatible with formate brines, and they are stabilized at high temperature in the formate environment, as shown in Figure 1 (Howard, 1995). Some of these starches have also been modified to tolerate higher-temperature environments. One interesting observation that was reported by Howard (2024) is that these starches appear to hydrate and break down at very different rates when they are added to formate brine (Howard, 2024). Figure 3 shows that some of these starches, including one high-temperature starch, continue hydrating for an extended time during static exposure to 135°C (275°F) in a blended cesium/potassium formate brine. As the hydrating and self-breakage rates of all biopolymers are dependent on brine type and concentration, these should always be considered when fluid systems are designed for specific temperatures and exposure times.

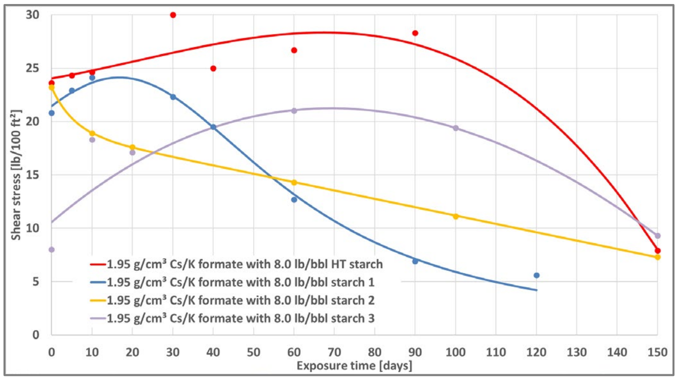

Figure 3 – Hydrating and self-breaking rates of four proprietary starch-based fluid loss control polymers at 135°C (275°F). All the starches were added to 1.95 g/cm³ (16.3 lb/gal) cesium/potassium formate brine at a concentration of 23 kg/m³ (8.0 lb/bbl). The viscosity (300 rpm-reading), measured at 49°C (120°F), is plotted as a function of time after subtracting the brine viscosity. The figure is taken from Howard (2024).

Although these products are designed to provide fluid loss control and exhibit minimal viscosity, they all provide some unwanted Newtonian rheology. It is therefore advised to minimize their concentration to just what is needed for the required fluid loss control and to use xanthan gum or other shear-thinning viscosifiers to build the rheology.

Polyanionic Cellulose (PAC)

PAC is a fluid loss control agent that is stabilized at high temperatures in formate brines, similar to xanthan gum and starch (see Figure 1).

In the past, PAC was routinely used in the field when drilling with formate fluids (Hands et al., 1998; Bungert et al., 2000; Berg et al. 2007, 2009). Equinor reported that drilling fluids had better fluid loss control and shale-stabilizing properties when PAC was present in the formulation (Berg et al., 2007, 2009). Subsequent experiences with PAC-free formulations showed that the problems with these formulations could be eliminated by introducing better maintenance of the carbonate/bicarbonate pH buffer. After new routines for measuring and controlling carbonate/bicarbonate buffer levels were introduced (ISO, 2022), PAC was successfully eliminated from formate drilling fluid formulations (Jøntvedt et al., 2018; Nilsen et al., 2023a, 2023b).

One of the drivers for eliminating PAC from the most recent formulations was that it became difficult to source good quality ULMW PAC that was able to pass the production screen test on 250-µm screens. This problem may no longer exist, but recent drilling experience with cesium/potassium formate fluids clearly indicates that PAC is not needed, at least not for reservoir temperatures below 160°C (320°F).

Proprietary Synthetic Fluid Loss Control Polymer

Introduction of CNF into formate fluid formulations not only extends the temperature window of shear-thinning rheology but also extends the duration at which the fluid can maintain good fluid loss control at higher temperatures. However, CNF does not appear to increase the temperature ceiling for fluid loss control. A better high-temperature fluid loss control agent is therefore needed for certain high-temperature applications.

An extensive study was conducted to identify synthetic fluid loss control polymers that are compatible with formate brines (Anderson, 2013; Kaminski, 2013). The study identified one synthetic polymer that outperformed all the others, including the AMPS polymer that was used in all early formulations, and was able to provide formate fluids with good fluid loss control at elevated temperatures without adding unacceptable levels of Newtonian rheology. This additive, which is commercially available, is a proprietary white, free-flowing synthetic polymer designed for high-temperature drilling environments. It is said to be compatible with all commonly used materials in water-based drilling fluids.

It should be noted that synthetic polymers are even more difficult to hydrate in formate brines than biopolymers are, and an excessive amount of time and temperature are needed. It is therefore recommended that this additive be used in combination with starch-based fluid loss control additives so that it starts to take over control when the starch gives up. It should also be considered that the hydration rate of this polymer is temperature dependent, which means that there may be temperature pockets where the starch loses its functionality before this additive takes over.

Synthetic Viscosifiers

Several synthetic viscosifiers have been tested in formate brines (Anderson, 2013; Kaminski, 2013). Although a few additives were found to hydrate in formate brine, they all exhibited Newtonian, or even shear-thickening rheology.

Since the abovementioned proprietary synthetic fluid loss control additive introduces some Newtonian rheology to the fluid, it is doubtful whether a synthetic viscosifier could have anything more to contribute. To date, all rheological challenges we have been faced with have been solved by the combination of CNF and the abovementioned synthetic fluid loss control additive.

Sized Calcium Carbonate

Sized calcium carbonate is the recommended bridging material for all formate fluids. Since formate fluids are free of solid weighting material, an exceptionally thin filter cake is formed that easily lifts off. Although calcium carbonate can be fully removed with acid, no acid treatment has ever been needed in the field. We are aware of only one published occasion where acid has been applied in a well (Carnegie et al., 2013). After one of two Kanowit wells was treated with acid, multi-rate well testing revealed that both wells could produce at an absolute open-flow rate greater than 150 MMscf/day, which is 50% higher than the original technical potential estimated in the field development plan.

Thermal extenders

Thermal-extender additives are typically not needed in formate-brine-based fluids because of the temperature-protection provided by the formate ion itself. The formate ion protects polymers by being:

- a water structure maker – it increases the transition temperature of xanthan, as shown in Figure 2.
- an antioxidant – it provides antioxidant properties in the same way as other antioxidants commonly used as thermal extenders. With up to 14 mol/L formate ions in the brine, this antioxidant will never deplete.

To determine whether it is possible to further improve the temperature stability of biopolymers above what can be achieved with the formate brine itself, a study was conducted to test various thermal extenders in a potassium formate brine viscosified with xanthan gum (Kaminski, 2013; Howard et al., 2015). Several thermal extenders were found to have some positive impact on the temperature stability of xanthan gum in potassium formate brine, but the preferred additive package was a combination of magnesium oxide and polyethylene glycol (PEG). The ability of PEG to stabilize biopolymers is in full agreement with the findings of an old study by van Oort et al. (1997).

Further testing of magnesium oxide in formate fluids has shown that this additive is also beneficial for stabilizing CNF and starch-based fluid loss additives in high-temperature formate formulations, but as it increases pH in the fluid, the pH must be adjusted back to the desired value with formic acid after magnesium oxide is added. It is important to consider that the pH increase from magnesium oxide is a slow process occurring during its dissolution, and when acid is used to reduce the pH, enough time must be given for the pH to stabilize.

For PEG, the situation is different. Although PEG has been shown to protect xanthan gum and other polymers at high temperatures, its use is not always beneficial. Like other glycols, PEG has an adverse effect on fluid loss control in formate fluids and is therefore not recommended for use in fluids that require good fluid loss control. However, it can be beneficial in applications where fluid loss control is not critical, such as e.g., viscous pills. It should be noted that since PEG is a liquid product, the addition of 5 vol% PEG-200 to a formulation dilutes the fluid, something that must be rectified by altering the formate brine composition.

Further testing was conducted on stabilizing CNF with sodium erythorbate. Although the addition of sodium erythorbate was successful at increasing the thermal stability of CNF in a high-temperature drilling fluid formulation, its presence resulted in higher fluid loss.

Proprietary blend of cellulosic products

This commercially available ‘free-flowing powder’ is not normally recommended for use in formate formulations, but it was found to be essential for controlling fluid loss in the ultrahigh-temperature formulation, described below. It is the finest grade of a series of products described as a blend of cellulosic (modified polymers and solids) and other materials. It is said to have a broad particle size distribution with a d50 of 55–70 µm and a temperature stability above 204°C (400°F).

Solid Weighting Material

Solid weighting material is not recommended for use in formate formulations except for in emergency situations because it significantly reduces the many benefits of these solids-free/low-solids fluid systems. One exception to this is to weigh up potassium formate-based spacer fluids. The good options are ilmenite, hematite, and manganese tetraoxide. Barite should never be used in formate brines due to its high solubility in formate brines containing potassium and carbonate pH buffer (Howard et al., 2016).

Formate Fluid Laboratory Mixing and Testing

The high salinity of formate fluids makes them quite different from traditional water-based fluids. Therefore, formate fluid mixing and testing procedures differ from standard water-based mud mixing and testing procedures.

Formate Fluid Laboratory Mixing

In the laboratory, it is recommended that formate fluids be prepared in batches of 1,400 mL (4 lab barrels) in 2-liter stainless steel jugs with a Silverson high-shear mixer with a water-based mud shearing head and shear-speed setting of 6,000 rpm. A mixing time of 45 minutes is recommended.

Any pH or buffer adjustments should be made before mixing. For better polymer hydration, the brine should be heated to 40°C (104°F) prior to mixing, and no temperature buildup should be restricted during mixing. During mixing, the additives should be added at 5-minute intervals in the following order:

- Xanthan gum, or alternative viscosifier.
- Starch-based fluid loss control agent.
- PAC if needed.

If thermal extenders are used, these should be added five minutes before the end of the high-shear mixing procedure.

Solid bridging materials should be added after the high-shear mixing procedure with the shear head removed or by use of a paddle mixer to avoid breaking the bridging material and thereby reduce its particle size.

If synthetic polymers are needed, they should be added at the beginning to maximize their hydration time. It should be noted that synthetic polymers are even more difficult to hydrate in formate brines than biopolymers are, and an excessive amount of time and temperature are needed. It is therefore recommended that such additives be used in combination with biopolymers such as xanthan and starch so that they start to take over control when the biopolymers give up.

Formate Fluid Testing

With a few exceptions, laboratory test methods for formate fluids are identical to those for other water-based fluids and heavy brines. The exceptions are the measurements of pH, crystallization temperature, and carbonate/bicarbonate pH buffer concentration, which are all detailed in ISO 13503-3 (ISO, 2022). The most important formate fluid properties to be measured are as follows:

- The **pH** of the formate brine or filtrate should be measured on a sample diluted with nine parts deionized water as detailed in ISO 13503-3 (ISO, 2022).
- The **carbonate/bicarbonate buffer concentration** of formate brine should be measured according to the method detailed in ISO 13503-3 (ISO, 2022).
- The **rheology** of formate fluids should be measured with a rotational viscometer at 49°C (120°F). The procedure detailed in API RP 13B-1 (API, 2019) is fully applicable for formate fluids.
- **HP/HT fluid loss** testing of formate fluids should be conducted with industry-recognized commercial filter paper or ceramic discs as the filter medium and high-purity nitrogen gas as the pressure source. The procedure detailed in API RP 13B-1 (API, 2019) is fully applicable for formate fluids. However, it is important to note that CO_2 should not be used for pressurizing if the HP/HT filtrate is to be used for pH measurement and/or carbonate/bicarbonate buffer determination, as CO_2 interferes with these properties. nitrogen is the preferred pressurizing gas.
- The **crystallization temperature** of formate brine should be measured according to the method specified in ISO 13503-3 (ISO, 2022).
- **Sag testing** is not required for formate fluids because there is nothing in them that can sag. If customers require that sag testing be performed for fluid qualification purposes, then any common method can be used to show that formate fluids do not sag.
- **Production screen testing** is recommended for use on screen-running fluids. The recommended test method is described by Sorgard et al. (2001).
- **Bottle testing** can be performed to verify the compatibility between the formate brine filtrate and reservoir water. This is done by mixing brine and formation water together across a range of different blend ratios in a bottle at a temperature as close as possible to that of the reservoir. It is important to include a bottle with 100% reservoir water and one with 100% brine for the following reasons:
  - 100% Reservoir water – This indicates if any self-scaling occurs.
  - 100% brine – A white precipitate may be observed in this bottle because silicate leaches out of glass when in contact with concentrated formate brine. At temperatures above 100°C (212°F), such a precipitate may be observed within a few hours. If such a precipitate appears, which is a laboratory artifact, it could also have happened in other bottles.
- **Scrape testing** is recommended for testing the ability of a screen-running fluid to repair damage to the filtercake. This is a standard HP/HT fluid loss control test performed on a screen-running fluid on a ceramic disk with a drilling fluid filtercake that has a center section scraped off. An example is shown in Figure 4.

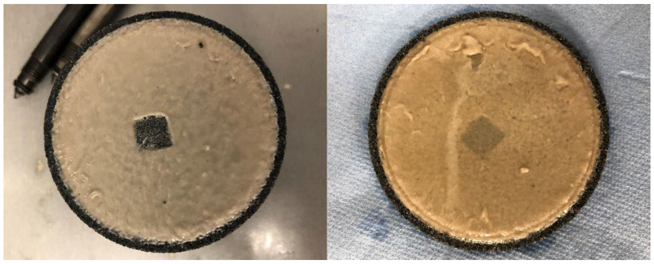

Figure 4 – Example of a scrape test on a 120-µm disk before and after the HP/HT fluid loss test with a screen-running fluid. Taken from Nilsen et al. (2023a, 2023b).

Formulations

Rule number one when formulating fluids with formate brines is ***'less is more'***. The formate base formulation is simple, as the brine itself provides most of the essential properties required in a well construction fluid. The ideal fluid formulation is modular, meaning that each component has only one function, and when any additive concentration is altered, it should only affect one fluid property.

The base formulation of all formate fluids that require shear-thinning rheology and fluid loss control is shown in Table 2.

Table 2 – BASE FORMULATION for formate fluids that require shear-thinning rheology and fluid loss control.

Component	Concentration [lb/bbl]	Function
Formate brine		Density Antioxidant Thermal extender Lubricant Shale stabilizer Corrosion Protection Biocide
$K_2CO_3/KHCO_3$		pH control Corrosion protection
Xanthan gum	0.5–0.8	Rheology Fluid loss control
Modified starch	3.0–6.5	Fluid loss control
Sized $CaCO_3$	14–35	Filter cake material

Reservoir Drilling Fluid Formulations

Historically, there have been two main drivers for choosing low-solids formate reservoir drilling fluids:

- Increased well productivity – from low solids content and monovalent, nondamaging filtrate.
- Low ECD – enabling drilling in reservoirs with a narrow pressure window between the reservoir pore pressure and fracture gradient.

Another benefit that has been recognized is the ability to use the same formate base fluids for all operational stages, which reduces the complexity of transitioning between them and guarantees that the reservoir is exposed only to one. nondamaging filtrate.

There are no known incompatibilities between any reservoir fluids and formate brines. The only known potential issue is incompatibility between the carbonate pH buffer and formation waters that are rich in divalent cations, such as calcium and magnesium. This can easily be tested with a simple bottle test as described above, and if incompatibility is confirmed, the carbonate concentration can be reduced. However, the carbonate/bicarbonate pH buffer should never be eliminated completely.

When formulating drilling fluids to be used in the reservoir, the base formulation, shown in Table 2, is always the best starting point, and in most cases, it also ends up as the final formulation. The exact temperature limit for this basic formulation depends on the formate brine type, brine composition, and exposure time.

It is out of the scope of this publication to list all historic reservoir drilling fluid formulations that have been used, so it is limited to some representative examples.

Martin Linge Reservoir Drilling Fluid

The most recent example of a simple reservoir drilling fluid formulation is the 2.07 g/cm³ (17.3 lb/gal) fluid that was used in the 145°C (293°F) gas/condensate reservoir in the Martin Linge field in the Norwegian sector of the North Sea.

TotalEnergies chose to use a formate fluid when drilling the fourth Martin Linge reservoir section after having failed three times with oil-based mud (Jøntvedt et al., 2018). The oil-based mud not only plugged the 230-µm expandable sand screens but also caused several unexpected challenges during drilling. While drilling in overbalance with oil-based mud loaded with 1,400 kg/m³ (490 lb/bbl) barite, problems were encountered with low ROP, a stuck-pipe incident, and several occurrences of hole instability. This was particularly evident through coal sections, with one well suffering collapse and subsequent side tracking. Despite additional cleanup operations, initial production tests on these wells delivered PI values lower than half of those expected.

An extensive design program was conducted to optimize a 2.07 g/cm³ (17.3 lb/gal) cesium/potassium formate reservoir drilling fluid by adopting the 'less is more' philosophy. The formulation contained xanthan gum, modified starch, and a sized calcium carbonate bridging package in a suitably buffered formate base brine. The concentrations of each additive were kept to a minimum apart from a slightly higher than the desired concentration of calcium carbonate bridging solids of 100 kg/m³ (35 lb/bbl). This approach was required for the fluid to provide effective bridging over a wide sandstone permeability range while still being fully compatible with the 250-µm stand-alone screens (SAS). The fluid formulation is shown in Table 3, and the fluid properties are shown in Table 4.

Table 3 – Reservoir drilling fluid formulation used by TotalEnergies and Equinor to drill the Martin Linge gas wells.

Component	Concentration	
	[kg/m³]	[lb/bbl]
Cs/K formate brine		
Xanthan	1.57	0.55
High-temperature modified starch	15.7	5.5
Sized calcium carbonate	100	35

This simple formate drilling fluid outperformed oil-based mud in terms of all the criteria, delivering significant benefits such as increased ROP, improved drilling dynamics, wellbore stability, and increased PI (Jøntvedt et al., 2018). It was also reported that during drilling, the average fluid loss was 7 mL/30 minutes, with a spurt loss of 2.8 mL, which was much lower than what was measured on the laboratory sample. A photo of the filter cake is shown in Figure 5.

Table 4 – Properties of 2.07 g/cm³ (17.3 lb/gal) reservoir drilling fluid before hot rolling (BHR) and after hot rolling (AHR) 16 hours of hot rolling at 135°C (275°F).

Rheology measured at 49°C (120°F)		
	BHR	**AHR**
Plastic Viscosity	28	29
Yield Point	21	23
Gels (10 sec)	4	4
Gels (10 min)	8	6
3-RPM reading	3	3
HP/HT Fluid Loss at 135°C (275°F) at 500 psi		
	AHR 50 µm disk (OFITE 170-53)	**AHR 120 µm disk (OFITE 170-53-4)**
Fluid loss (30 min) [mL]	9.5	9.0
Spurt loss [mL]	4.2	5.5

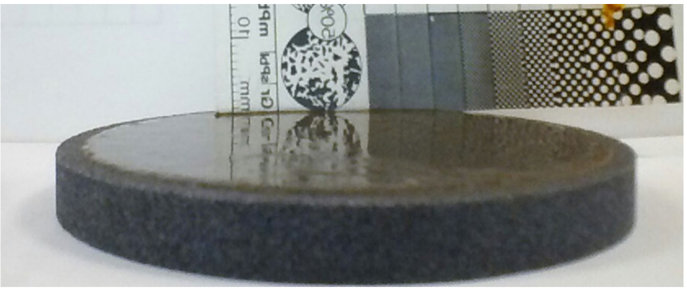

Figure 5 – Photo of the filter cake from the Martin Linge field mud after an HP/HT fluid loss test on a 50-µm disk at 135°C (275°F).

Equinor has since acquired the Martin Linge field and successfully drilled five additional reservoir sections in MPD mode with the same simple, reduced-density, fluid formulation, delivering the same good drilling performance. Four of these wells were completed with openhole gravel pack and one was completed with SAS. All the wells have proved to have good initial productivity and a high well productivity index (Nilsen et al., 2023a, 2023b).

Huldra Reservoir Drilling Fluid

Drilling of the Martin Linge reservoir sections was not the first time that Equinor used cesium/potassium formate drilling fluid in the reservoir. A similar 1.94 g/cm³ (16.2 lb/gal) fluid was used to drill six reservoir sections in the 150°C (302°F) Huldra HP/HT gas field in the early 2000s. As a result of well control problems occurring in the first well when attempting to run screens in oil-based mud, Equinor chose to use a cesium/potassium formate combined drilling and screen-running fluid because of its insignificant sag potential. This was the first worldwide use of cesium formate brine in a drilling fluid (Saasen et al., 2002). The formulation, shown in Table 5, utilized a biopolymer package consisting of xanthan gum, PAC, and modified starch. Sized calcium carbonate was selected to provide a suitable particle size distribution for the reservoir while being compatible with the 300-µm SAS. The properties of this fluid are similar to those of the Martin Linge fluid, which contains no PAC (Table 4) but has slightly higher gel values.

Table 5 – Reservoir drilling fluid formulation used by Equinor to drill the Huldra HP/HT gas wells.

Component	**Concentration**	
	[kg/m³]	**[lb/bbl]**
Buffered Cs/K formate brine		
Xanthan	3.0	1.05
PAC	13	4.6
Modified starch	7.0	2.45
Sized calcium carbonate	60	21

Notably, PAC was included in this formulation because of difficulties in controlling fluid loss when it was eliminated, which was subsequently diagnosed as caused by incorrect pH and buffer treatments. This was prior to the development of a good method to measure and maintain carbonate/bicarbonate buffer concentrations (see section above on PAC). Currently, PAC is not considered necessary in this formulation.

All Huldra wells cleaned up naturally during production startup, with skins at the low end of the expected range for the screen completions (Downs and Fleming, 2018).

Kristin and Kvitebjørn Reservoir Drilling Fluids

In the early 2000s, Equinor faced a high-temperature challenge when drilling the reservoir section of the Kristin gas/condensate field. A 2.09 g/cm³ (17.4 lb/gal) drilling fluid was required that could withstand the Kristin reservoir temperature of 172°C (342°F). At this temperature, the fluid formulation that was previously used for drilling in the 150°C (302°F) Huldra reservoir was not temperature resistant enough.

Since the critical properties, such as shale stability and sag-free density, which are provided by the inherent properties of the buffered cesium/potassium formate base brine, are temperature-independent, additional consideration was needed only for the performance properties: rheology and fluid loss control. High-temperature additives such as AMPS polymer and CNF were combined with modified starch and a calcium carbonate bridging package. The formulation is shown in Table 6. Due to misunderstood artifacts encountered during coreflood testing, PAC was not included (see section above on PAC).

As this fluid formulation performed well in Kristin, the same fluid was used when Equinor subsequently started drilling in the Kvitebjørn HP/HT gas/condensate reservoir, which had a similar density requirement of up to 2.09 g/cm³ (17.4 lb/gal) but had a lower reservoir temperature of 155°C (311°F) (Berg et al., 2007, 2009).

Despite successful deployment of the original formulation, continuous efforts were made to improve upon it. Particularly important was reducing the concentration of the AMPS polymer, which was not only classified as a red chemical in the Norwegian HOCNF system but also proven to be difficult to hydrate, which caused it to string out on the shaker unit. The reformulation exercise resulted in a reduction in the AMPS polymer concentration by 87.5% and in the modified starch concentration by approximately 50%. The fluid loss control properties were improved by reintroducing ULMW PAC, which then had been requalified for use. The redesigned fluid improved the performance properties, increased the environmental suitability, and reduced the total polymer loading by almost 20% (Berg et al., 2007, 2009).

Today, with good routines for monitoring and controlling the carbonate/bicarbonate buffer concentration, this fluid would likely be formulated without PAC. Based on newer experience from Kvitebjørn MPD (see below), neither CNF nor AMPS polymer is needed in this 155°C (311°F) formulation.

Table 6 – High-temperature reservoir drilling fluid originally used in the early Kvitebjørn wells. This formulation was originally designed for the much warmer, 172°C (342°F), Kristin reservoir.

Component	Concentration	
	[kg/m³]	[lb/bbl]
Buffered Cs/K formate brine		
CNF[1)] partially hydrated in potassium formate	54.5	19.1
AMPS polymer	11.4	4
Modified starch	11.4	4
Sized calcium carbonate	57	20

1) this is an old CNF product, and not the same as described above

Kvitebjørn MPD Stress-Caging Drilling Fluid

By 2007, the fracture gradient of the Kvitebjørn reservoir had decreased due to pore pressure depletion from early production. In addition to introducing MPD, a range of synergistic technologies were introduced, including wellbore-strengthening technology enabled by a reduced-density, low-ECD cesium/potassium formate fluid with a controlled- particle size-distribution blend of calcium carbonate and graphite-coated calcium carbonate (Syltøy et al., 2008). A polymer package similar to that used in Huldra was adapted, albeit with a concentration increase from 60 to 100 kg/m³ (21 to 35 lb/bbl) of the bridging material. This was the result of the wellbore-strengthening additive integration. The formulation is shown in Table 7.

Table 7 – Stress-caging drilling fluid used with MPD to drill the 155°C (311°F) Kvitebjørn reservoir. The fluid density ranged from 1.79 to 1.83 g/cm³ (14.9 to 15.2 lb/bbl).

Component	Concentration	
	[kg/m³]	[lb/bbl]
Buffered Cs/K formate brine		
Xanthan	2.0	0.70
Modified starch (HT)	15.0	5.26
PAC	11.0	3.86
Sized calcium carbonate	65.0	22.8
Graphite-coated calcium carbonate	35.0	12.3

Kanowit MPD Reservoir Drilling Fluid

Kanowit is a gas/condensate field offshore Sarawak in Malaysia. The fractured carbonate reservoir has a temperature of 112°C (234°F). The development plan required low-solids well construction fluids to minimize formation damage, ensure maximum gas production rates, and restrict solids passing through gas processing facilities during production startup. To minimize the risk of losses, Petronas Carigali used a 1.52 g/cm³ (12.7 lb/gal) underbalanced formate drilling fluid in combination with MPD technology. A sodium/potassium formate-based low-solids drilling fluid was designed to meet the project challenges, which marked the first-ever deployment of an underbalanced formate brine system for drilling a carbonate reservoir in MPD mode. The fluid formulation, shown in Table 8, required a slightly higher xanthan gum concentration than recommended, as the viscosity yield in a sodium/potassium base brine is lower than in a more concentrated cesium/potassium formate brine. An ammonium bisulfite oxygen scavenger was added to the brine, although at such low temperatures, an oxygen scavenger is not needed.

Table 8 – Fluid formulation for the Petronas Kanowit drilling fluid.

Component	Concentration	
	[kg/m³]	[lb/bbl]
Buffered Na/K formate brine		
Xanthan	3.7	1.3
Modified starch	17.1	6.0
Sized calcium carbonate	57	20

Both Kanowit wells were drilled successfully with the formate fluid and produced at an absolute open-flow rate greater than 150 MMscf/day, which is 50% higher than the original technical potential estimated in the field development plan (Carnegie et al., 2013).

Ultrahigh-Temperature Formulations

Ultrahigh-temperature formate drilling fluid formulations have been the biggest formulation challenges throughout the years.

Although a successful fluid was formulated for the 172°C (342°F) Kristin reservoir (see above), it is unclear whether this fluid can reach much higher temperatures, and the AMPS polymer that was added did not appear to hydrate easily. With the new CNF product in use today, combined with high-temperature starch and magnesium oxide thermal extender, fluids with good shear-thinning rheology and good fluid loss control can be formulated at higher temperature without the use of any synthetic polymers. The exact temperature limit, however, depends on the brine composition and exposure time.

Fortunately, CNF maintains good shear-thinning rheology up to temperatures significantly above 170°C (338°F) in formate brines, but the use of starch-based additives for fluid loss control has proven to be challenging. Depending on the formate brine composition and the required exposure time, the commercially available proprietary synthetic fluid loss polymer, described above, may be needed for fluid loss control. The use of a thermal extender has also proven favorable for further protecting polymers from degradation at higher temperatures.

Multiple studies, including two MSc projects (Anderson, 2013; Kaminski, 2013), have been conducted to find the best additives. Another large study was subsequently conducted to determine the best combination of these additives for an ultrahigh-temperature cesium/potassium formate drilling fluid. After testing various types and concentrations of fluid loss control additives, thermal extenders, and bridging packages, a high-temperature formulation was achieved. The formulation is presented in Table 9, and the properties before and after hot rolling can be found in Table 10.

Table 9 – Ultrahigh-temperature fluid formulation.

Component	Concentration [kg/m³]	Concentration [lb/bbl]
Buffered Cs/K formate brine$^{1)}$		
Magnesium Oxide (MgO)	2.86	1.00
Formic acid 50%	11.9	4.18
Synthetic fluid loss polymer	17.1	6.00
CNF (active ingredient)	4.49	1.57
High-temperature modified starch	17.1	6.00
Proprietary blend of cellulosic products	11.4	4.00
Sized $CaCO_3$	114	40

1) The brine, which was 1.89 g/cm³ (15.8 lb/gal) 50/50 (vol) blend of cesium and potassium formate brine, was buffered with 5 lb/bbl $K_2CO_3/KHCO_3$ pH buffer

The fluid rheology before and after hot rolling at 185°C (365°F) is shown in Figure 6. The fluid has a high, shear-thinning rheology before hot rolling, which is provided by CNF and the modified starch. Over time, the modified starch breaks down, and the synthetic fluid loss control agent starts hydrating. The fluid displays the highest viscosity on day 5, but the shear-thinning properties of the fluid improve after this, and on day 7, it still has very good rheological properties, which must come from the combination of CNF and the synthetic fluid loss control agent. Unfortunately, the fluid was only tested for seven days at this temperature. The fluid was also tested for seven days at 195°C (383°F) and 16 hours at 200°C (392°F) and was shown to maintain both rheology and fluid loss control in all tests. At 195°C (383°F), the fluid maintained its shear-thinning rheology during the seven days but not to the same extent as at 185°C (365°F).

Table 10 – Properties of the 1.89 g/cm³ ultra-high-temperature fluid formulation before and after hot rolling at three different temperatures. The HP/HT fluid loss was measured at the same temperature as the fluid was hot rolled. FL = fluid loss.

	BHR	AHR 185°C (365°F)					
		16 h	2 d	3 d	4 d	5 d	7 d
Plastic Viscosity	40	34	40	63	49	56	41
Yield Point	78	40	36	18	36	39	38
Gel (10 sec.)	27	8.9	7.7	8.7	7.1	7.5	5.7
Gel (10 min.)	28	11	10	11	8.1	10	6.7
3-RPM reading	27	8.1	7.5	7.8	7.7	7.4	6.0
HP/HT FL10-µm 500-psi [mL]	7.8	16	24	21	17	25	27
pH	10.4	9.3	8.6	8.4	8.4	8.3	8.3

	BHR	AHR 195°C (383°F)				AHR 200°C (392°F)
		16 h	3 d	5 d	7 d	16 h
Plastic Viscosity	40	45	77	77	41	44
Yield Point	91	38	2	2	36	27
Gel (10 sec.)	32	6.7	3.5	3.5	3.8	8.7
Gel (10 min.)	34	8.5	3.4	3.4	4.5	10.1
3-RPM reading	33	6.4	3.2	3.2	3.5	7.2
HP/HT FL10-µm 500-psi [mL]	8.4	26	21	21	22	34
pH	10.2	8.5	8.3	8.3	8.3	8.8

This high-temperature formulation was also tested with a lower concentration of the synthetic fluid loss control polymer, which resulted in worse fluid loss control, from the initial spurt loss to the total filtrate loss. A higher concentration was also tested, but the fluid developed a stringy appearance after 16 hours of hot rolling, and the fluid loss control did not improve.

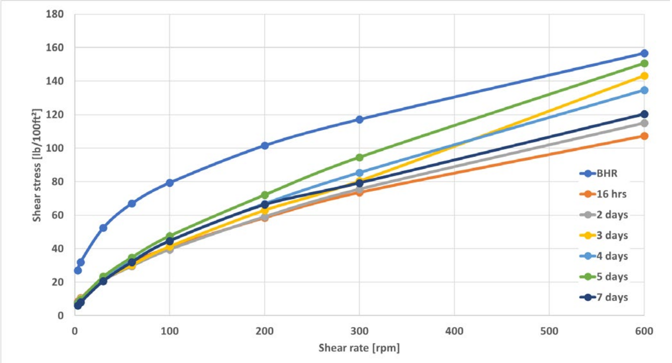

Figure 6 – Rheological properties of the high-temperature formulation before and after hot rolling at 185°C (365°F).

For temperatures above 200°C (392°F), a synthetic viscosifier may be needed, depending on the base-brine composition. Lower-density cesium/potassium formate blends with more potassium formate are expected to tolerate somewhat higher temperatures. To date, none of the synthetic viscosifiers that have been found to be compatible with formate brines have exhibited shear-thinning rheology.

Shale Drilling Fluid Formulations

Fluids based on potassium and cesium formate brines are among the best shale-stabilizing water-based drilling and completion fluids currently available (van Oort and Howard, 2017). A recent study has also shown that under the right circumstances, high-salinity formate drilling fluids can out-drill oil- and synthetic-based mud when drilling shale (van Oort et al., 2017).

Equinor reported that reservoirs with significant amounts of shale have been successfully drilled with formate-based drilling fluids in the Huldra field (Saasen et al., 2002), the Kvitebjørn field (Berg et al., 2007, 2009), and the Martin Linge field (Nilsen et al., 2023a, 2023b), and TotalEnergies explained how a formate-based drilling fluid outperformed oil-based mud when drilling through shale sections in the Martin Linge reservoir (Jøntvedt et al., 2018).

The first purposeful use of formate for drilling a shale section was reported in 2001 for drilling two exploration wells in the North Sea (Zuvo and Askø, 2001). The mud system exhibited a superb rheological profile, excellent hole cleaning and wellbore stability properties, and both wells were drilled ahead of schedule. Van Oort et al. (2015) also reported that 120 wells were drilled with potassium formate brine, with only lubricant added, through shale sections in Western Canada. The wells were drilled with unviscosified solids-free potassium formate brine to avoid building up solids. Van Oort et al. explained that the high-salinity potassium formate fluid yielded a consistently lower accretion tendency and a 50–60% higher ROP in shales than oil-based mud.

Unlike other water-based drilling and completion fluids, formate fluids have shale-stabilizing properties that are attributable to the inherent properties of the formate brine itself rather than to additives. In addition to simplifying the formulations, this has the great advantage that the shale-stabilizing constituents are not depleted with time, and no complicated or expensive maintenance is needed. Therefore, when formulating shale drilling fluids based on formate brines, no additional considerations need to be taken, and the fluid formulation can be optimized based on other desired fluid properties.

It should be noted, however, that the properties of the formate brines that are responsible for the excellent shale-stabilizing properties of the fluid are the osmotic effect resulting from the low water activity of the brine and the high viscosity of the filtrate compared with that of typical water-based mud filtrates. Therefore, care should be taken when formulating lower-density fluids based on diluted formate brines. Although good performance has been reported in very dilute potassium formate brines (Hallman et al., 2002), the excellent performance of these fluids when drilling these shale sections is not fully understood, and the same good performance may not be experienced in other shale environments.

Screen-Running Fluid Formulations

The low-solids/solids-free nature of formate screen-running fluids makes them ideal for preventing plugging of screens. There are many published cases of screens being plugged by running them in oil-based muds. Examples include Equinor's Kristin field (Zaostrovski, 2011), BP's Marnock field (Munro et al., 2002), and TotalEnergies' Martin Linge field (Jøntvedt et al., 2018). Conversely, there have been no documented instances of screen plugging with formate fluids. In fact, the use of formate fluids has been reported to be highly successful when installing expandable sand screens with very fine screen sizes ≤230 µm (Weekse et al., 2002; Simpson et al., 2009; Oswald et al., 2006).

When using low-solids/solids-free formate-based screen-running fluids, no compromise is required when selecting production screen size, as no screen-plugging solid weighting material is involved. This provides an ideal 'clean' environment for an optimized completion strategy.

In most of the cases where screens have been run in formate fluids, this has been the drilling fluid, which at total depth typically passes the production screen test, described above, without any treatment or conditioning needed. In other cases, often due to a required density different from that of the drilling fluid, a separate screen-running fluid is needed. The design of this fluid should be based, where possible, on the drilling fluid formulation. Any alteration in density should be accommodated by adjusting the formate brine composition. All pH and buffer requirements established for the operation must be maintained. The polymer concentration should remain the same or preferably be reduced. As the filter cake is already established at the time this fluid is used, a low solids content is desired, just enough to repair any damage to the filter cake, which can be established by performing the scrape test described above. Special consideration must be given to ensure that the particle size distribution of the bridging material is compatible with the programmed screen size.

An example of a screen-running-fluid formulation is shown in Table 11, with typical properties shown in Table 12. A thorough review of the well conditions and completion methodology should be performed to establish any specific properties and specifications.

Table 11 – Typical screen-running fluid formulation.

Component	Concentration [kg/m³]	Concentration [lb/bbl]
Buffered formate brine		
Xanthan gum	1.4–2.3	0.5–0.8
Modified starch	8.6–18.6	3.0–6.5
Sized $CaCO_3$	40–57	14–20

Table 12 – Example of typical screen-running fluid properties.

Rheology measured at 49°C (120°F)		
	BHR	**AHR**
Plastic Viscosity	24	31
Yield Point	12	22
Gels (10 sec)	1.5	3.9
Gels (10 min)	2.5	4
3-RPM Reading	1.3	3.8
HP/HT Fluid Loss (Filtercake Scrape test) at 135°C (275°F) at 500 psi		
	AHR 50-µm disk (OFITE 170-53)	**AHR 120-µm disk (OFITE 170-53-4)**
Fluid loss Total [mL]	3.2	3.2
Spurt loss [mL]	0	0.2

Slim-Hole/Coiled-Tubing Fluid Formulations

Ideal fluids for use in SH/CT applications are those with shear-thinning rheology and drag-reduction properties. Low-solids or solids-free formate brines viscosified with xanthan gum tick both boxes. In addition to being exceptionally compatible with formate brines in a wide temperature range, xanthan gum has both shear-thinning and drag-reducing properties (see section above on xanthan gum).

The phenomenon of drag reduction, also referred to as friction reduction, is the reduction of frictional pressure losses under turbulent or transient flow by the addition of a small quantity of high-molecular-weight polymers, fibers, or surfactants to the fluid. These additives are referred to as drag reducers or friction reducers. The phenomenon of drag reduction is not fully understood and therefore not considered in the hydraulic modeling software packages used for drilling and completion fluids (Howard et al., 2019).

All the known applications of formate brines with xanthan gum in SH/CT applications have been successful. The published applications are as follows:

- Shell's first use of a formate drilling fluid to re-enter a well in the Berkel field in the Netherlands occurred in 1993 with coiled tubing (Simmons and Adam, 1993). As the first formate drilling fluid ever used, the fluid contained several unnecessary additives in addition to xanthan gum.
- Shell Expro used a potassium formate CT drilling fluid to drill a CT sidetrack in the North Cormorant Field after oil-based mud failed the surface pumping test (Lord et al., 1997).
- In the 1990s, Prudhoe Bay operators in Alaska drilled many horizontal wells with coiled tubing (Beck et al., 1993; Powell et al., 1995). The wells were drilled with

drilling fluids consisting of only xanthan gum in monovalent brines, and potassium formate brine was used for some of the higher-density applications. Solids-free fluids, with only xanthan gum added, were formulated for optimum drag reduction and shear-thinning rheology.

- Equinor, inspired by the success in Prudhoe Bay, reported the successful use of a solids-free potassium formate fluid to drill a well with a challenging well path with coiled tubing (Samsonsen et al., 1998). It is uncertain what type of polymers were used in this fluid.
- BP performed a very challenging CT milling operation in the Tuscaloosa 204°C (400°F) reservoir (Messler et al., 2004). The xanthan-viscosified potassium formate fluid enabled the CT milling application to progress as planned after two unsuccessful attempts with unviscosified halide brine. The authors of the paper claimed that the development of this milling fluid had broken new ground in CT fluid technology for deep hot wells.

To formulate formate-based fluids for such applications, the ideal fluid should be solids-free, with xanthan gum being the only additive. The higher the concentration of xanthan gum is, the better the drag-reducing properties are (Johnson et al., 2018; Gul et al., 2019; Howard et al., 2019). It is known that Powell et al. (1995) used xanthan concentrations as high as 2.5 lb/bbl in their formulations. Considering that solids-free formate brines viscosified with xanthan gum can provide excellent fluid loss control properties (Powell et al., 1995; Howard et al., 2017), ideally, no other additives are needed.

The use of high concentrations of xanthan gum in buffered formate brines can be challenging due to the buildup of some gels when the fluid is left static at ambient temperature conditions. The alternative commercially available proprietary starch-based polysaccharide viscosifier described above may therefore be a better choice. In laboratory testing, this additive has been shown to have the same good shear-thinning properties as xanthan gum, drag-reducing properties as good or better than xanthan gum (Howard et al., 2019), and the ability to control fluid loss in solids-free fluids (Howard et al., 2017). It also appears to be easier to hydrate in formate brines.

If other additives, such as starch or calcium carbonate bridging solids, are desired for fluid loss control, their concentrations should be kept at an absolute minimum because they do not provide shear-thinning rheology or drag reduction.

Perforating-Fluid Formulations

There is a long history of formate-based formulated fluids being designed for and used as perforating pills in gas wells (Olsvik et al., 2013). A comprehensive review of the successful qualification and field use of a cesium formate perforating pill in BP's Rhum field was published in 2008 (Roy et al., 2008). This paper discusses the requirements for a fluid that provides an effective solution for minimizing health, safety, and environment (HSE) exposure and maximizes productivity during a drill-pipe-conveyed dynamic-underbalanced perforating application. Roy et al. demonstrated that the unique synergy of the perforating methodology and the selected low-solids, high-density cesium formate perforating fluid provided the best compromise and delivered significant HSE benefits by:

- Allowing the well to remain in an overbalanced condition until the tubing hanger is landed.
- Facilitating safe overbalanced or dynamic underbalanced perforating on drill pipe in long reservoir intervals.
- Eliminating complicated surface rig-ups, rig modifications, and multiple wireline/coiled-tubing runs.

Tubing-conveyed perforating in overbalanced fluid not only reduces HSE risk compared to underbalanced perforating on coil tubing or wireline but also significantly reduces rig-time. For an average North Sea HP/HT well, a study revealed that a typical overbalanced perforating job on drill pipe takes three days, compared to ten days for a wireline or CT perforating job, corresponding to a full week of rig-time savings (Larsen and Hatland, 2016).

To date, high-density cesium/potassium formate perforating pills have been used in almost 50 perforating applications in 20 different fields around the world. Most of these applications are tubing-conveyed perforating in dynamic underbalance.

There are also many instances where both overbalanced and underbalanced perforating have been performed safely in clear formate completion brine at densities up to 2.06 g/cm³ (17.2 lb/gal) at temperatures of approximately 200°C (392°F) while delivering effective fluid loss control and minimal seepage losses. In these cases, a formate fluid-loss control pill was often spotted above the perforation interval or on standby at service for deployment if losses would occur.

Formate perforating fluids are recommended to be formulated with the same design methodology as reservoir drilling fluids, i.e., with only a small amount of carefully selected additives, which are included to perform a specific function. For most applications, these fluids are built with additives such as xanthan gum, modified starch, and calcium carbonate bridging material, albeit at higher concentrations than in a drilling fluid. A typical formate perforating fluid is shown in Table 13.

Table 13 – Typical formate perforating fluid formulation.

Component	Concentration	
	[kg/m³]	[lb/bbl]
Buffered formate brine		
Xanthan gum	1.4–3.0	0.5–1.05
Modified starch	8.6–23	3.0–8.0
Sized $CaCO_3$	100–250	35–88

Understanding the core functions of the fluid on an application-to-application basis is important in the design process. It is important to remember that the primary function of a perforation is to penetrate beyond any skin/formation damage incurred during drilling and create a virgin production surface area. Since the perforating pill will be the first fluid to contact this newly exposed formation, it is crucial to fully assess its compatibility with the reservoir, as is the case for a reservoir drilling fluid.

Perforating pills are often subjected to extended static periods at reservoir temperatures and should be designed to maintain reasonably stable properties under such conditions. For formate perforating pills, this mostly applies to viscosity and fluid loss control, as the fluid density is mostly rovided by the sag-free base brine. A careful design must be used for the bridging package to minimize initial losses and ensure low seepage losses post perforating. As such, the calcium carbonate concentration is typically higher in these fluids than in drilling fluids because they are a one-shot deployment rather than being continually refreshed during fluid circulation. To enhance stability and durability, especially in high-temperature applications, the polymer concentration is often higher than in drilling fluids.

In cases where a perforating pill is required to maintain stable properties for extended time periods under static HP/HT conditions, additional additive(s) may be considered. Table 14 shows a fluid formulation in which 7.1 kg/m³ (2.5 lb/bbl) CNF was added to improve the rheology and fluid loss control properties during 7 days of static aging at 157°C (315°F). The properties are shown in Table 15.

Table 14 – HP/HT long-term perforating pill formulation.

Product	Concentration	
	[kg/m³]	[lb/bbl]
Buffered Cs/K formate brine		
Xanthan	1.86	0.65
CNF	7.1	2.5
Modified starch	18.6	6.5
Sized calcium carbonate	114	40

Table 15 – HP/HT long-term perforating pill properties before and after static aging at 157°C (315°F) for up to 7 days.

	BHR	After Static Aging 157°C (315°F)			
		16 h	5 d	6 d	7 d
Plastic Viscosity	54	63	52	43	45
Yield Point	46	61	48	34	42
Gel (10 sec.)	9.6	14	12	7.3	8.4
Gel (10 min.)	11	15	12	7.5	12
3-rpm reading	10	16	12	7.5	8.2
HP/HT fl. loss 50 µm 500 psi [mL]	7	6.5	8	11	9.5
Spurt [mL]	2.5	3	3	4	3.5

Another thing to consider in cases where the perforating pill is spotted in a cooler area above the perforation zone or even at the surface is the avoidance of excessive or progressive gels. High gels developing over time can cause difficulty when pumping the fluid. This again highlights the need to employ a "less is more" approach to the design, where it is ensured that additives and their concentrations are carefully selected, tested, and qualified to provide controlled properties, while avoiding unnecessary additions.

Field Mixing

Before mixing fluids for field use, the brine composition needs to be carefully designed and critical properties such as density, pH, carbonate/bicarbonate buffer concentration, and crystallization temperature need to be measured and verified with a focus on fluid quality control.

Extensive fluid preparation experience from the laboratory has established the critical parameters and requirements for effective formate fluid mixing. Particularly, in the case of polymer yield, it is essential to impart time, temperature (ideally up to 100°C (212°F)), and high shear to achieve the programmed properties. However, there can be some limitations in mixing capabilities, such as the maximum temperature at which it is possible to heat the fluid during mixing. These limitations must be assessed and mitigated. This can in many cases be done by extending one of the other critical parameters to compensate for the limitation. It is recommended that regular sampling and pilot testing be conducted throughout.

The extent to which the polymers are fully hydrated before the fluid is shipped to the rig depends on the application. As described by Howard et al. (2022), full hydration of xanthan gum in formate brines is challenging because these fluids have salt concentrations of 75–80 wt%, and their water activity is very low. Ideally, a temperature of approximately 90°C (197°F) should be used, in combination with high shear (Howard et al., 2022, Nilsen et al., 2023a, 2023b).

For applications such as drilling, where the fluid circulates through the drill bit, full hydration of polymers before the fluid is shipped to the rig is not critical, as the drill bit is a powerful high-shear mixer. Berg et al. (2007, 2009) recommend that the finest shaker screens not be installed before the fluid has made a couple of circulations through the bit. It is also important not to add any extra polymers before one has ensured that the polymers are fully hydrated.

Conclusions

After more than 30 years of formulating well construction fluids based on sodium, potassium, and cesium formate brines in the laboratory and using these fluids in the field, valuable lessons have been learned:

- 'Less is more' – The formate brine has many inherent beneficial properties, making many traditional additives superfluous.
- The carbonate/bicarbonate pH buffer is an essential additive that should never be omitted. All the other additives are optional.
- Formate brines stabilize biopolymers at high temperature. As their stabilizing performance varies depending on brine type and concentration, brine composition is important not only for properties such as density, crystallization temperature, and brine viscosity, but also for the temperature stability of the fluid.
- Biopolymers should be used whenever possible in formate brines, not only because they are stabilized at high temperature but also because they break down over time and thereby protect the reservoir from formation damage.
- For formate fluids that require shear-thinning rheology and/or drag reduction properties, xanthan gum or an alternative starch-based polysaccharide additive is a

key ingredient.

- CNF provides exemplary shear-thinning rheology in formate brines at temperatures above what can be reached with xanthan gum. However, CNF does not provide drag reduction properties.
- Modified starch is highly compatible with formate brines and provides good fluid loss control. However, it does contribute to undesired Newtonian viscosity, so its concentration should be kept at a minimum when optimum rheology is essential.
- Formate fluids are highly compatible with acid-soluble, sized calcium carbonate, making this the preferred choice if bridging material is needed.
- Magnesium oxide is a useful thermal extender for formate fluids when needed. Proper control of pH is crucial for ensuring good performance.
- When fluid loss control is not a priority, PEG can be a valuable thermal extender in formate fluids. Its ability to protect biopolymers at high temperatures has been proven, however, it has a negative impact on fluid loss control.
- Solid weighting materials should never be used in formate fluids unless needed for emergencies or in spacer fluids.
- Additives in powder form are preferred over additives dispersed in glycol due to the negative impact glycol has on fluid loss control.
- Hydrating polymers in concentrated formate brines is difficult in the laboratory and in the field. High shear, high temperature, and time are needed. The drill bit is the best performing high-shear mixer for formate fluids.
- Most API- and ISO-recommended measuring methods are suitable for formate fluids. However, separate methods have been developed for determining the pH, crystallization temperature, and carbonate/bicarbonate buffer concentration. These are available in ISO (2022).

Acknowledgments

The authors would like to thank Sinomine Specialty Fluids Ltd. for giving their permission to publish this paper. A special thank you to Bob Frost and the entire team at the Sinomine Specialty Fluids Laboratory in Aberdeen for their invaluable support. None of this would have been possible without the good service provided by Bob and his team.

Nomenclature

AHR = *after hot rolling*
AMPS = *2-acrylamido – 2-methyl-propane sulfonic acid*
BHR = *before hot rolling*
CNF = *cellulose nano fibrils*
Cs = *cesium*
CT = *coiled tubing*
HP/HT = *high-pressure/high-temperature*
HEC = *hydroxyethyl cellulose*
HSE = *health, safety, and environment*
K = *potassium*
MPD = *managed-pressure drilling*
Na = *sodium*
PAC = *polyanionic cellulose*
PEG = *Polyethylene glycol*
ROP = *rate of penetration*
SAS = *stand-alone sand screen*
SH = *slim hole*
ULMW = *ultralow molecular weight*

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