

New Technology of the Past: Optimizing Water-Based Drilling Fluid to Match Unconventional Drilling Challenges

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Abstract

Since the advent of the United States shale revolution, drilling fluid requirements for unconventional well development have been refined through drilling activity and rig limitations. Transitioning to longer laterals led to a preference for invert emulsion fluids, but as rig technologies advance, opportunities for water-based drilling fluids returned. In the right application, water-based drilling fluids offer significant cost and environmental benefits. Aligning risk, experience, laboratory data, and robust data sets creates the opportunity to tailor products to specific risks, eliminating unnecessary costs encountered with broad solutions like high-performance water-based and invert emulsion drilling fluids.

An optimized water-based drilling fluid system (OWBDF) was developed to address these drilling risks without the additional costs of invert emulsions or high-performance water-based drilling fluids (HPWBDFs). The OWBDF is tailored to minimize torque and drag, maximize rate of penetration, and control water usage while eliminating the need for base oil.

A new family of lubricants was designed to lower coefficient of friction and extend pipe life. In addition, a single-sack wall cake blend of additives provides supplemental lubricity and improves wellbore quality through improved filtration control. Finally, a versatile dewatering flocculant minimizes solids to reduce dilution and maximize the spurt loss at the bit for higher rate of penetration. This paper will discuss the development of these products and the resulting field success since deployment. In some cases, the selective transition to this OWBDF has resulted in cost savings of over \$100,000 per well in base oil alone.

Introduction

Over the past decade, unconventional oil and gas remains the primary driver of production in the United States. Post-pandemic, activity has returned with boosted oil recovery and a decline in drilled but uncompleted (DUC) well inventory.

Before the shale revolution, most wells drilled in unconventional shale basins were vertical – and many were shallower conventional reservoirs. Over time well designs transitioned to horizontal profiles with aggressive build sections. The lateral length per well continues to grow (Figure 1) from less than a mile in 2010 to nearly two miles in 2022

(Phinds 2022). Many lateral sections exceed three miles with current records exceeding four miles.

Permian Basin: Average Lateral Length by Year

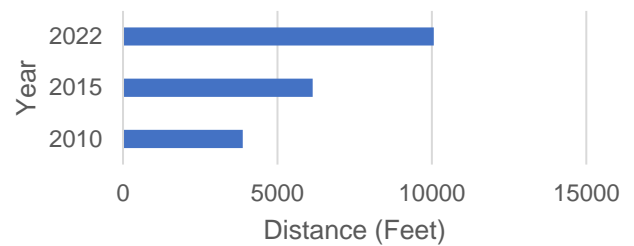


Figure 1: Average Permian Basin lateral length by year

Technological advances, cost reduction efforts, and consolidated acreage have allowed operators to drill further, increasing production section exposure on each well. Enhanced drilling rig capabilities (Table 1) is essential for longer laterals, including 7500 psi circulating systems for higher circulating rates, which improves hole cleaning through turbulent flow (Parsons, Strickland, and Offenbacher 2018).

Table 1: Select drilling rig advancements over past decade

	Typical Rig Specs Year 2010	Typical Rig Specs Year 2020+	Improvement Impact
Mast Rating	250,000 to 350,000 lb	Up to 750,000 lb.	Max pick up weight increased to handle longer drill strings
Mud Pump System	3500 to 5000 psi	Up to 7500 psi	Handles increased downhole pressures and improves hole cleaning as laterals extend further
Skidding	X-Y Direction	360° walking systems	Reduce cycle time and cost of rigging up/down

Water-based drilling fluids were used in many of the early vertical and short horizontal wells across most unconventional basins. As well complexity increased, invert emulsion drilling fluids (IEFs) became the preferred fluids to lower torque and improve rate of penetration with the original drilling rig limitations.

HPWBDFs were designed to replace IEFs with lower cost-per-barrel while claiming IEF performance. The definition of HPWBDFs has become a highly subjective term, but traditionally consists of a suite of materials including an anti-accretion surfactant (ROP enhancer), an encapsulating polymer, and an amine shale inhibitor to provide superior shale inhibition in highly reactive formations where an IEF is traditionally required.

In almost every unconventional lateral, none of these components are necessary. Unconventional shale reservoirs generally feature limited reactivity – the ultimate driver for IEFs was lubricity as lateral length increased. A comprehensive review of formation characteristics, advancing rig capabilities, and proper application of fluid technologies reveals numerous areas of major shale basins can be drilled with simple drilling fluids optimized to the known risks by merging data analytics and fluids technology, resulting in the OWBDF.

Well Characterization Through Data Analytics

Historical data and experience are key to preparing for upcoming wells, particularly when the service provider has experience where the operator does not (Welker, Offenbacher, Snell, Provada 2018). An in-house data analytics platform contains drilling fluids-related data gathered from ~2014 to date across major U.S. basins – data volumes amounting to >20,000 wells. Well data and formation properties are aggregated to align well risk with fluid requirements.

In the data analytics dashboard, risk events are filtered by a multitude of factors including target reservoir, geographical location, and likelihood of a fluids-related drilling issue. An offset mapping tool aids to identify nearby wells and the associated challenges or properties (Figure 2).

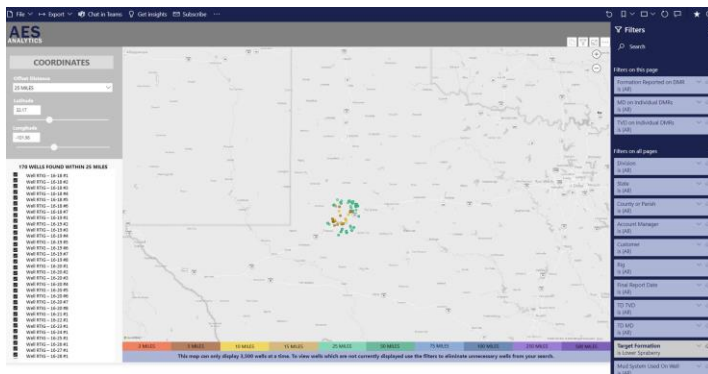


Figure 2: Offset mapping tool filters drilling fluid properties

Unconventional Shale Properties

Formation reactivity is a fundamental consideration during the drilling fluid selection process. Reactive shales present substantial drilling risk through lost rate of penetration via balling, washout, sticking from under-gauge hole, and formation collapse.

Where reactive shale is present, supplemental additives including salts, polymers, amines, and other chemicals aid to limit interactions with water. Testing processes aid to identify the type and concentration of different additives, which require monitoring and maintenance in the field. Oil-continuous IEFs eliminate most interactions with these shales, providing simplicity and performance at a higher per-barrel cost offset by rig time savings.

Shale characterization is complex, but basic indicators of reactivity aid to identify reactive clays prior to additional testing. Cation exchange capacity (CEC) is a measure of cations on clay surfaces that may be exchanged for other cations. A higher CEC is indicative of a more reactive formation.

Sandstone and limestone are nonreactive and have CEC values of less than 1 meq/100g. Formations with CEC values of <10.0 have very little reactivity. Moderately reactive shale has a CEC value from 10 to 20 meq/100 g, while highly reactive shale has a CEC value greater than 20 meq/100g (Stephens 2009).

CEC measurements of formation cuttings samples collected across the Marcellus, Utica, and multiple benches of the Permian Basin demonstrate minimal reactivity. Figure 3 presents CECs measured from these formations alongside select reactive clays found across the globe. Arne clay is a highly dispersive clay, whereas Green and Oxford clays are highly swelling in nature (Cliffe 2008).

For greater detail, X-ray diffraction (XRD) provides the mineral abundance within a formation. Smectite, for example, is a highly reactive clay known to present drilling challenges if untreated. Table 2 compares a troublesome reactive formation sample from Oklahoma with a typical unconventional reservoir section.

These data sets indicate that shale inhibitors, particularly the combination used in HPWBDFs, are unnecessary. This was confirmed when early laterals were drilled with water-based fluids and again with the OWBDF.

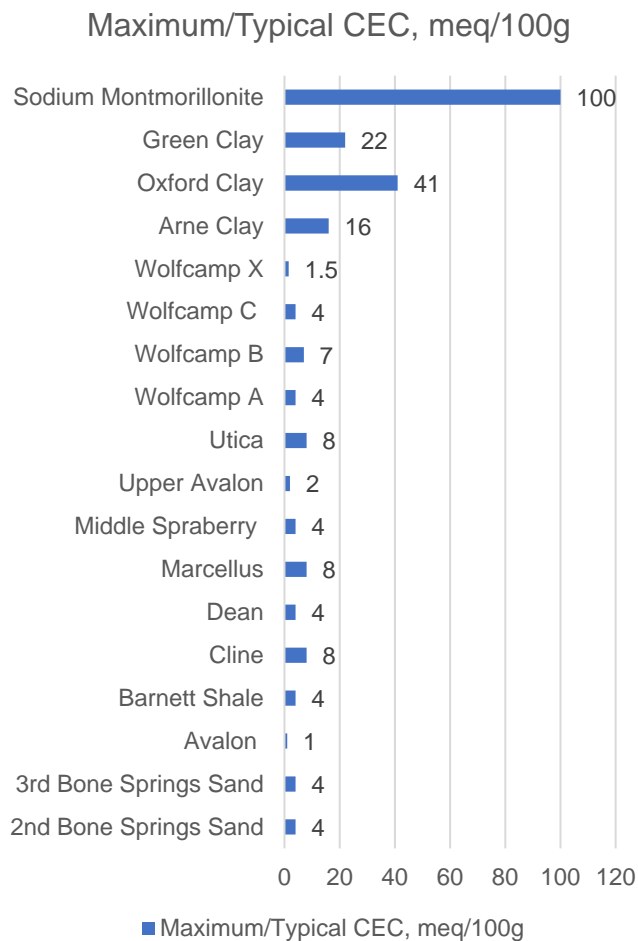


Figure 3 – CEC Values of select unconventional formation cutting samples & standard clay types

Table 2: XRD results comparison

Mineral Type		Oklahoma Sample 6,100' MD, WT%	Permian Basin Sample 15,900' MD, WT%
Silicate	Quartz	34.5	48.1
	Kaolinite	7.6	0.2
	Smectite	22.2	-
	Illite-Mica	5.0	15.4
	Mixed Layer Illite / Smectite	28.2	6.4
	Feldspar	0.9	5.6
Carbonate	Calcite	0.5	6.6
	Dolomite / Ankerite	0.0	16.6
Iron Sulfide / Oxide	Pyrite / Goethite	1.1	0.8
Sulfate	Barite	0.3	-

Optimized Water-Based Drilling Fluid

The OWBDF aligns the drilling performance needs of many unconventional shales with cost and operational efficiency. To achieve this task, a properly designed OWBDF eliminates additives designed to address very low risks and features additives to address primary performance goals and contingencies. Table 3 lists fluid requirements for the lateral versus the requirements met by the OWBDF and traditional HPWBM.

Table 3: OWBDF matches lateral section requirements

Selection Criteria	Lateral Section Requirements	OWBDF	Traditional HPWBM
Lubricity	✓	✓	✓
Corrosion Mitigation	✓	✓	✓
Environmental Sensitivity	✓	✓	✓
Cost Appropriate	✓	✓	✗
Simplicity	✓	✓	✗
Shale Inhibition	✗	✗	✓
Anti-Accretion	✗	✗	✓
Supplemental Polymers	✗	✗	✓
HPHT Performance	✗	✗	✓

Key system components include a series of lubricant options to reduce torque and drag, a flocculant to enhance drilled solids removal, a corrosion inhibition package, and an optional wall cake additive.

An unviscosified brine – typically freshwater, sodium chloride, or other field brine sources – serves as the base fluid. Table 4 presents a typical formulation and properties.

Table 4: Typical OWBDF Formulation

Additive	Concentration
Freshwater, NaCl, or Field Brine bbl/bbl	0.92 – 0.99
Lubricant, % v/v	1 – 5
Flocculating Polymer	As needed
Corrosion Inhibitor Package, % v/v	0.05-1 or as monitoring dictates
Sodium Hydroxide or similar	As needed for pH
Wall Cake Additive / Wellbore Stabilizer, lb/bbl	1 – 4
Properties	Value
Density, lb _m /gal	8.4 – 10
Plastic Viscosity, cP	1 – 4
Yield Point, lb/100 ft ²	1 – 3
API Filtrate, cc/30'	No Control
pH	9 – 10.5

Clear Fluid Benefits

Where fluid interaction with the wellbore is limited, high spurt loss fluids maximize rate of penetration. Originally,

enhanced rate of penetration from clear fluids was believed to originate from eliminated “chip hold down” where minimal viscosity allowed cuttings to clear the cutter face in rock bits quickly (Doty 1986).

Ledgerwood (2018-2019) explains the phenomenon as dilational hardening, where the extruded cutting is stronger than the rock itself due to a pressure imbalance. High spurt loss fluids are slow to form a seal at the extruded cutting, preventing the pore pressure in the cutting from dropping and limiting the pressure differential between it and the borehole (Figure 4).

Clear fluids are mostly Newtonian in flow characteristics, promoting turbulence for hole cleaning.

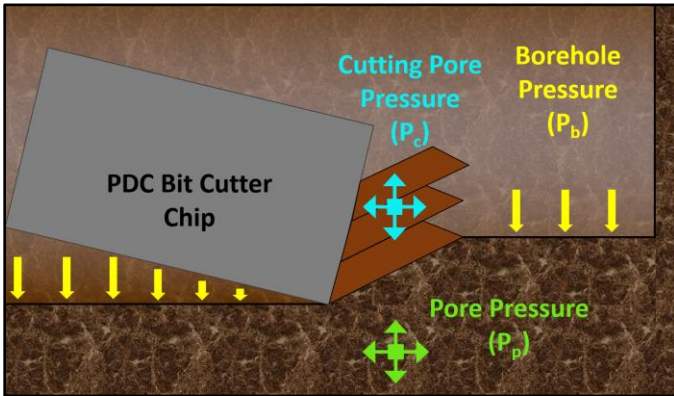


Figure 4 – Dilational hardening is limited when cuttings pore pressure is more rapidly equalized to borehole pressure – leading to faster chip clearance

Base Fluid Options

Other unconventional fields, such as the Montney and Duvernay formations in Canada or the Bakken, may use more exotic clear fluids to benefit from enhanced rate of penetration, but the cost of higher density brines increases dramatically (Dubberley and Magill 2020). Figure 5 shows the maximum achievable density of common clear fluids.

Areas with high risk of losses, such as many parts of the Permian Basin, remain cost-inefficient for high density clear fluids. The OWBDF uses freshwater and sodium chloride because of their availability, compatibility, and low cost. Calcium chloride is an option, but cation-tolerant corrosion inhibitors and lubricants significantly increase the overall cost of a system.

Maximum Ambient Density by Brine Type (lbm/gal)

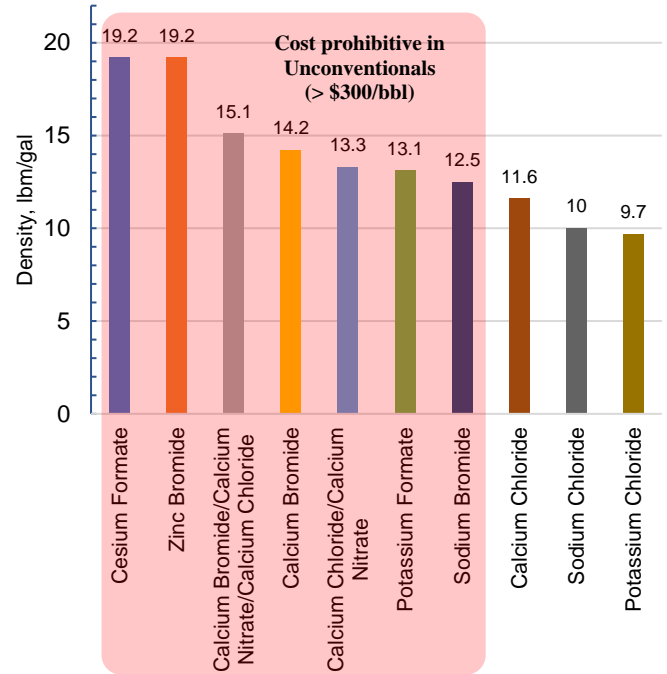


Figure 5 – Common brine options sorted by maximum ambient density (lbm/gal)

Lubricity / Torque Mitigation

Lubricants aid to reduce the coefficient of friction, sustaining energy at the bit and keeping the drilling assembly below torque limits. In many cases, friction factor analysis demonstrates water-based lubricant performance matching the lubricity of IEFs.

HPWBMs feature an anti-accretion agent, composed of a blend of surfactants and lubricants. While their primary function is to limit accretion on the drilling assembly, their lubricating properties are another important benefit.

For the OWBDF, the fluid development team focused on lubricating properties alone. This simplified the chemistry to reduce the risk of incompatibilities encountered with complex surfactant blends.

Lubricant Options

Lubricant additives consist of mechanical and chemical mechanisms. Mechanical additives reduce the surface contact area between surfaces while chemical additives create a film across surfaces to lower their coefficient of friction.

Mechanical lubricants include nut shells, glass or co-polymer beads, or graphite. Nut shells are low-cost, but they must be re-introduced into the circulating system regularly as they are removed by solids control equipment. Glass or polymer beads can include separate recovery units, but they have significant cost and personnel requirements that limit their adoption. Graphite reduces friction as the layers slide against one another under compression.

Other mechanical lubricant options include nanoparticles, such as iron oxide and titanium dioxide, where the ultra-fine particles are designed to smooth surfaces by filling imperfections in steel. While a novel concept, testing did not reveal differentiated performance to justify the cost.

Liquid chemical additives, usually surfactants, remain mixed in the fluid across multiple circulations, limiting treatment requirements. Drilling fluid compatibility is a primary concern, particularly given the number of different factors that can cause incompatibility.

Surfactants can grease and/or cheese, which can create screen blinding and loss of torque reduction. Greasing occurs when the lubricant chemistry oil-wets solids instead of metal or formation, creating clumps of lubricant and solids. Cheesing is an emulsion formed when cations interact with the lubricant, creating white chunks that neutralize the lubricant (Figure 6).

Cheesing and greasing tendency is an important screening test to identify effective lubricants. Cheesing and greasing tendency is a factor of pH, hardness, solids, time, and temperature. Many promising chemistries have high cheesing/greasing tendencies that limit their field use.

Other risks include high foaming tendency and hydrocarbon contamination.



Figure 6 – Incompatibility examples of experimental lubricants cheesing (left) and greasing (right)

Lubricant Development

Lubricant development follows two key steps: compatibility screening and coefficient of friction reduction. There are many additives that provide coefficient of friction reduction, but they are incompatible with common fluid conditions, eliminating them from consideration. Fluids that meet standard stress tests are then screened for performance properties.

Compatibility testing includes exposure of brine/lubricant solutions to different conditions, including elevated pH, low and high salinity, elevated cations, and fine solids. Jars of each sample are placed in a rolling oven at 150°F for 16 hours. Visual analysis for greasing, cheesing, or other signs of incompatibility determines passing and failing additives (Figure 7).



Figure 7 – Jar testing of various lubricants after hot rolling at 150°F

Lubricity testing was performed on a Lubricity Evaluation Monitor (LEM). The LEM features a bob that presses against a surface (usually metal). The entire assembly is immersed in a circulating cell which improves testing consistency with dispersible additives.

Lubricity values do not translate directly to the field. It is not uncommon for a brine lubricant to have much lower coefficient of friction readings than invert emulsion fluids on the lubricity meter, yet this effect is not observed at the rig. Instead, coefficient of friction readings are compared as a relative percent reduction to their baseline (untreated) fluid values.

The LEM is equipped with a syringe pump to add additional lubricant in set increments over time. The fluid design team uses a standard set of 0% (baseline), 1%, 2%, 4%, and 6% v/v readings. Most lubricants reach their maximum reduction at or before 3% v/v. The output graph helps to identify when additional lubricant does not contribute to an overall reduction in coefficient of friction.

Compatible chemistry components were tested in freshwater, 9.5 lb_m/gal sodium chloride brine, 10.0 lb_m/gal sodium chloride brine, and several sodium chloride-based field brines. Of the chemistries evaluated, one blend (EXPL 7600) was compatible across all screening tests and had the highest coefficient of friction reduction versus baseline readings.

Results of EXPL 7600 testing are shown in figures 8 and 9. In figure 8, the lab brine and field brine 2 reached a maximum reduction of 38% and 49% (relative to 0% baseline) at 1% v/v, respectively. Field brine 1 required additional lubricant, reaching its maximum reduction of 58% relative to baseline at 2% v/v. It is suspected that cations in Field Brine 1 reduced lubricant performance until sufficient lubricant was present to overcome them. In figure 9, similar reductions occur between tap water and cut brine, 71% and 60% respectively.

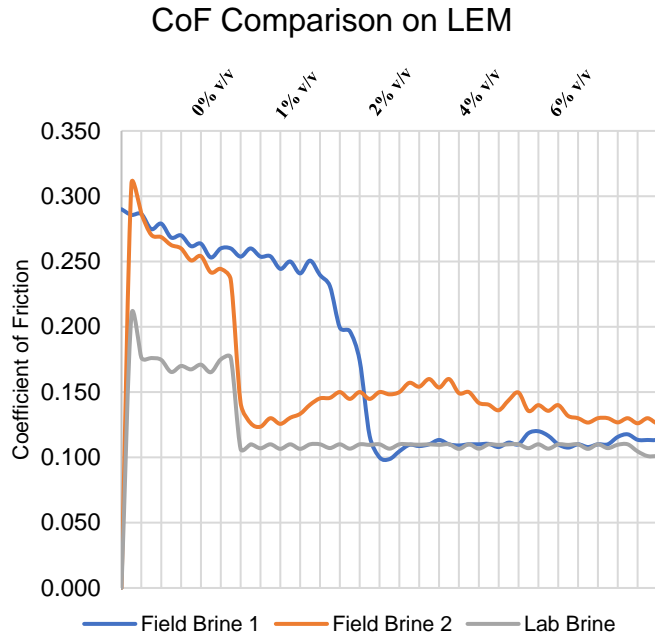


Figure 8: LEM results of EXPL 7600 lubricant on several field and lab brines – sodium chloride based

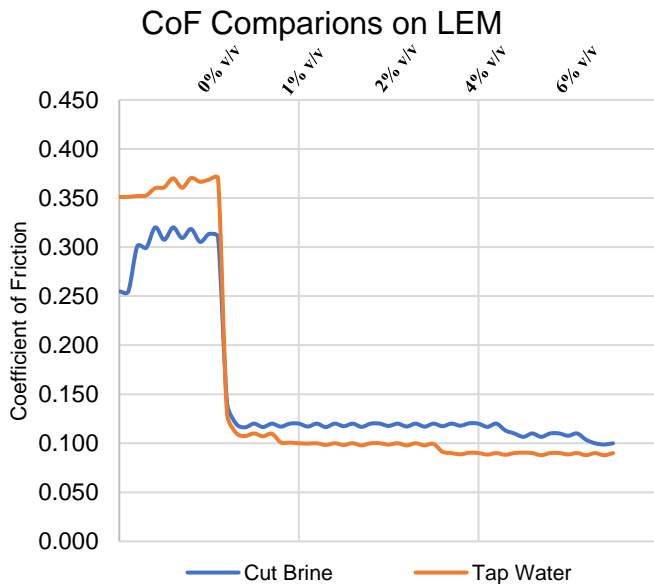


Figure 9: LEM results of EXPL 7600 lubricant in tap water and a 9.5 lb_m/gal cut brine (sodium chloride)

Flocculation and Solids Removal

Flocculation uses polymers to agglomerate fine solids into larger “flocs” that separate more easily in solids control equipment. It is long-proven method to maximize well economics by reducing dilution requirements, waste volumes, and water usage (Gallus, Lummus, and Fox 1958, Nordquist and Faucher 1988).

The process, often called dewatering, requires a

combination of a compatible flocculant and proper product application (Wojtanowicz 1988). Over-treatment of a flocculant causes residual polymer to viscosify the circulating system, which can reduce rate of penetration and limit solids separation.

The new flocculant was designed to perform across a wide range of salinities, from freshwater to saturated sodium chloride. For screening, jars of bentonite-laden fluids were placed on a laboratory bench and treated at different polymer concentrations. Testing was repeated using solids-laden field brine. Performance was evaluated by visual separation.

Tables 5 and 6 provide an example of the flocculant evaluation process. 30 lb/bbl of fresh bentonite gel is hydrated in fresh water. Brine fluid is added to increase chlorides, and the solution is dosed with a treatment of flocculant. Samples are then centrifuged at different speeds. Reduced effluent density and lower MBT values relative to the control are observed. Results show Exp Flocc #2 provides superior flocculation to Exp Flocc #1.

Table 5 – Flocculant testing formulations

Additive	Control	Exp Flocc #1	Exp Flocc #2
Freshwater (mL)	260	260	260
Bentonite Gel (lb/bbl)	30	30	30
10.0 lb/gal Field Brine (mL)	78.4	78.4	78.4
0.5% (wt.) Exp Flocc #1 (mL)	-	3.5	-
0.5% (wt.) Exp Flocc #2 (mL)	-	-	3.5
Density (lbm/gal)	9.13		
Chlorides (mg/L)	40,000		
MBT (lb/bbl)	30		

Table 6 – Flocculant testing results

Fluid Set	Centrifugal G-Force (RPM)	Effluent Density (lbm/gal)	MBT (lb/bbl)
Control	1000	9.03	22.5
Exp Flocc #1	1000	8.95	16.5
Exp Flocc #2	1000	8.88	12
Control	2000	8.99	20
Exp Flocc #1	2000	8.91	14
Exp Flocc #2	2000	8.87	11

The new flocculant is delivered as a liquid so that the polymer is hydrated and ready to use (Figure 10). This eliminates delays due to improper mixing or insufficient hydration time at the rig site. The flocculant can be injected directly from the bulk tote using an injection pump or gravity-fed where desired.



Figure 10 – Experimental flocculant in dry and liquid form

Flexible Additives

Flexibility is a key OBWBDF characteristic. Additives are only used as necessary to minimize costs and focus on risks. The nuances of unconventional basins require special attention where permeable streaks or mechanical instability risk is high – and quick response when issues occur. To address these concerns, a single sack concept was identified to reduce materials on location, reduce mixing times, and limit trucking requirements. In the field, this material is pumped in sweeps as needed, but it is also a fast option to “mud up” if conditions require it.

The blend of materials, also called a “wall cake additive” was developed containing sealing and plugging agents to stabilize the wellbore, reduce differential sticking risk, and enhance lubricity. In higher risk areas, larger supplemental particles are available through other single-sack blends to limit accumulation of fine solids in the permeable zone (Dupriest et al 2011).

The blend was developed by optimizing key additives to promote fluid loss and wellbore stability. Table 7 shows select blends tested during the optimization process. Blend #4 provided optimal fluid loss reduction.

Table 7: Optimized blend for wall cake additive

Experimental Blend No.	Blend #1	Blend #2	Blend #3	Blend #4
Exp additive #1, % wt.	29%	29%	33%	29%
Exp additive #2, % wt.	-	-	9%	13%
Exp additive #3, % wt.	29%	-	-	33%
Exp additive #4, % wt.	42%	42%	58%	25%
Exp additive #5, % wt.	-	29%	-	-
API Fluid Loss, cc/30 min	11.3	No control	7.5	6.1

*Base test fluid consisted of 9.2 lb/gal NaCl brine, 0.25 lb/bbl soda ash, 0.25 lb/bbl caustic soda

Additional solid materials risk undermining lubricant performance if the surfactant additive adheres to solids instead of surfaces. Blend #4 was tested to confirm complementary lubricity with EXPL 7600 lubricant. Figure 11 shows improved coefficient of friction values (~0.23) with 6 lb/bbl of Blend #4 compared to the baseline 9.5 lbm/gal cut brine solution (~0.3-0.35). This resulted in a 29% decrease relative to the base line coefficient of friction. When combined with EXPL 7600, coefficient of friction is reduced over 80% relative to the base line reading. Figure 12 show images of the filter cake formed by Blend #4 at 6 lb/bbl on a 3-micron disk.

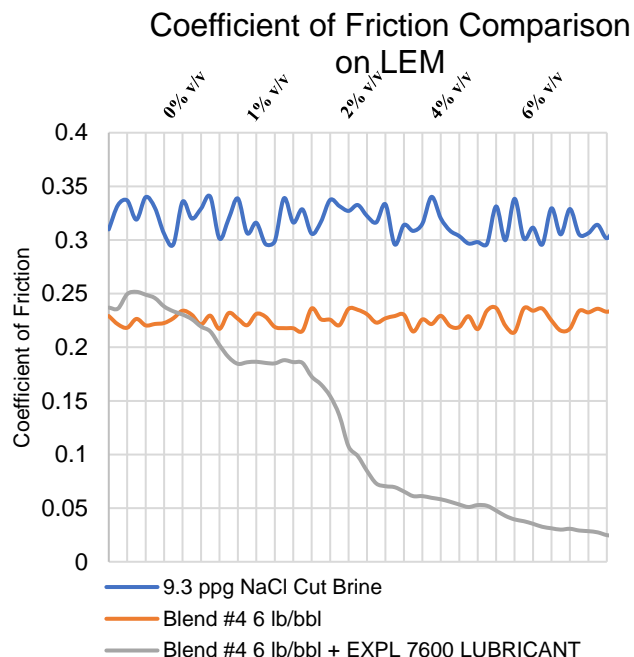


Figure 11: LEM results of Blend #4 with and without EXPL 7600 lubricant in 9.5 lbm/gal cut brine (sodium chloride)



Figure 12 – Filter cake generated with 6 lb/bbl of Blend #4 on a 3-micron aloxite disk, resulting in 9 cc/30min filtrate

Corrosion and Drill Pipe Life

Between 2021 and 2022, the price of drill pipe increased 90% due to the pandemic-induced supply chain crisis (Blas 2022). While prices have moderated, pipe preservation remains a focus for operators.

Oil-continuous IEFs are non-corrosive, requiring no additional treatment to mitigate corrosion while drilling. Aqueous fluids require a corrosion control program to limit

metal loss by general corrosion and possible catastrophic failure from pitting corrosion.

A basic corrosion control program provides many of the critical corrosion mitigation measures, including chemicals and corrosion ring monitoring. Fluid additives, including lubricants, are qualified for compatibility at basic pH levels above 9.0 as part of the corrosion control strategy.

Chemical treatments include an oxygen scavenger, biocide, and scale inhibitor. Where possible the treatment is added via dosing pumps to maintain inhibitor levels as they are consumed during drilling. Additional treatment includes a hydrogen sulfide scavenger, which mitigates corrosion and hydrogen sulfide safety risks.

The corrosion ring program requires continuous monitoring and education to confirm corrosion rings are properly installed, documented, and preserved for laboratory analysis. Treatment levels are adjusted when corrosion rates or scale are observed during the monitoring process.

Field Success

Well candidates were identified utilizing the data analytics platform to match well risks to applications in the Midland Basin. Offset performance indicators and clay characterization data confirmed torque – not reactive shale – was the primary well challenge.

A 7 7/8" lateral section was planned using water as the base fluid with a standard corrosion program. After drilling out the intermediate casing shoe, drilling commenced as torque was closely monitored. When torque reached programmed limits, sweeps of EXPL 7600 lubricant were introduced. The total active system concentration was increased to 1.5% v/v. A 50% increase in weight-on-bit was realized along with a 50% increase in rate of penetration.

Sweeps of Blend #4 was pumped at 2-4 lb/bbl every 90 ft. stand to provide supplemental torque reduction and to seal any permeable zones. Sweep returns were diverted to limit the introduction of solids.

To maintain rate of penetration, solids were controlled through dewatering using the flocculant product, limiting dilution requirements and water usage. At total depth of the 14,000 foot interval, a pill containing the EXPL 7600 lubricant was spotted before running casing. No issues were encountered when running casing to bottom or cementing.

Base oil savings exceeded US \$100,000, while environmental impact and carbon intensity was reduced. The optimized water-based drilling fluid is now used in areas throughout West Texas where IEFs were the standard (Figure 13).

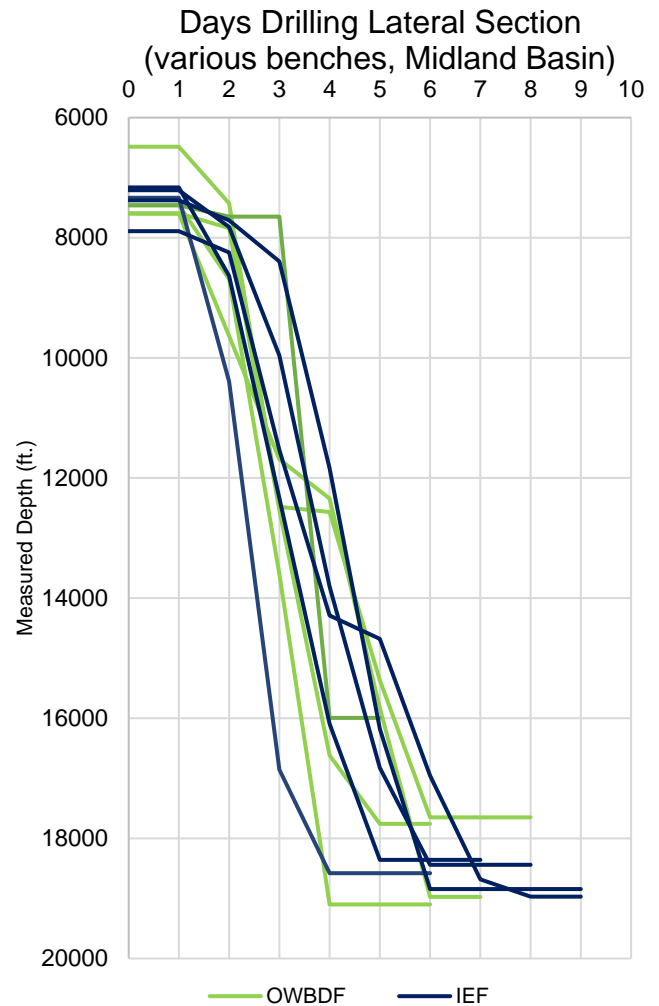


Figure 13 – Days vs. depth chart comparing OWBDF and IEF fluid sets used to drill various lateral section in the Midland basin

Conclusions

Drilling technology – including drilling rigs, drilling fluids, and data systems – continue to advance. Aligning complementary advances demonstrates:

- Rig capabilities enable a return to aqueous fluids where IEFs were previously required for lubricity
- Data analytics provides improved risk analysis to identify appropriate wells where an OWBDF offers the best economics
- OWBDFs provide similar performance to IEFs, eliminating base oil use, reducing waste volumes, and lowering chemical requirements to drill numerous wells

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