

New Polymer Chemistry Water-Based Drilling Fluid Performance Exceeds Baseline Drilling Metrics in The Delaware Basin

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Abstract

With the ever-present effort to deliver wells faster, cheaper, and more efficiently, operators have looked to fluid providers to offer solutions in support of these objectives. Non-aqueous drilling fluids have become the standard choice for drilling horizontal wells under the perception that such fluids provide improved rates of penetration and reduced torque and drag. However, numerous disadvantages exist with the use of non-aqueous drilling fluids.

In many geographical regions, water-based drilling fluids provide benefits and cost efficiencies that cannot be obtained through the use of non-aqueous fluids. Recent advancements in polymer chemistry have proven renewed relevance in the use of water-based drilling fluids to deliver wells faster and with lower cost.

In the Delaware Basin, countless wells have been drilled over the past decades. Challenges in this area include shallow evaporite salt zones with adjacent unconsolidated formations. These formations must be drilled and cased off prior to drilling horizontal reservoirs such as Bone Springs and Wolfcamp. The 2nd Bone Springs' composition of heterogenous siliceous fine-grained sandstone creates torque and drag challenges that demand a high level of fluid lubricity to maintain desired rates of penetration. Running and cementing of production casing pose additional difficulties.

Comparing a 13-well cluster of 2-mile extended-reach horizontal wells in the 2nd Bone Springs sand, this paper will demonstrate the exceptional progression of performance by transitioning away from the conventional approach of basic water-based drilling fluid followed by non-aqueous drill-in fluid or diesel-brine emulsions (direct emulsions) for the reservoir section. New polymers used in conjunction with high-performance water-based drilling fluids allow the operator to cut the average well delivery times in half, dramatically reduce the occurrence of downhole losses, reduce drilling fluids cost while using produced water as the base fluid, and dramatically improve casing operations for the reservoir interval.

Introduction

Countless wells have been drilled in the Delaware Basin over the past century. Improvements in technology have seen longer, deeper horizontal wells become the standard design. Shallow halite formations are common in the Ochoan series

typically requiring the first intermediate casing string to be set just below the salt.

Throughout the years, numerous types of fluid systems have been used during the construction of Delaware Basin wells. Water-based drilling fluids (WBM), oil-based drilling fluids (OBM), direct emulsions, water, prepared brines, and produced brines have all been used with varying levels of success. In recent years, operators have migrated to selecting fluids deemed to provide the most economical means of drilling a given interval. However, fluid economics are often independent of the greater overall well delivery economics.

This paper will detail the operational history of one operator drilling a series of consecutive wells targeting the 2nd Bone Springs sands over an approximate two-year period in the Delaware Basin. Also documented is the introduction of new polymer chemistry, used in both direct emulsion and high-performance water-based fluids (HPWBM), which helped the operator overcome recurring challenges and cut well delivery times by more than half.

Background

A baseline for well delivery performance was established using the most recent operator wells in the immediate area. All the wells were targeting the same Bone Springs production zone at similar depths. The historical fluids strategy included the use of brines and direct emulsion fluids to drill the salt-bearing formations. Typically, generic water-based fluid was used to drill the intermediate build section. Oil-based drilling fluid had also been employed on earlier wells.

In the most recent wells prior to introduction of new fluid solutions, a surface casing string was set for water protection. Thereafter, a direct emulsion water-based drilling fluid was used to drill the halite formations. Generic water-based fluid was then used to drill any subsequent intermediate intervals and the horizontal production interval.

The operator was facing some recurring challenges with these wells. The most notable challenge for the customer was excessive time and difficulty associated with running and cementing the 5½-in. production casing. Casing operations were requiring between approximately 40 and 60 hours (average of 49.2 hours). Typically, the drilling team would need to work the casing string to bottom by some measure of circulation, rotation, and reciprocation. These mitigation

actions were balanced with a risk of damaging the casing string. In some cases, the production casing was not landed at the total target depth leaving 200 to 300 feet of rathole below the casing shoe.

Further challenges were encountered during cementing operations. During the most recent 5 wells, little or no returns were observed while cementing.

The customer sought to improve upon the time associated with running and cementing the production casing. An additional goal was to eliminate the fluid losses encountered while cementing as well as the requirement of a two-stage operation.

Results from Previous Wells

The customer was averaging 29.6 days to construct the Bone Springs wells. This equated to 19.76 days per 10,000 feet. These well delivery metrics were comparable to peer operators drilling similar wells and production targets in the surrounding Lea County.

Fluid system economics were considered “fair to inexpensive” and in line with similar wells in the area. Drill water was hauled to location for use in the water-based drilling fluid used to drill the final interval.

Perceived Benefits of OBM

During the modern development of unconventional plays across US land operations, the low cost of OBM rental has driven it’s widespread use for horizontal drilling. For many drilling engineers, there are perceived benefits to using OBM. These include:

- Faster rates of penetration (ROP)
- Reduced torque and drag (lubricity)
- Improved formation stability
- Higher temperature stability
- Ease in running casing and liners

In reality, oil-based drilling fluids have numerous potential deficiencies when compared to water-based drilling fluids:

- Increased occurrence of lost circulation
- Higher equivalent static density (ESD)/equivalent circulating density (ECD)
- Reduced flow rates
- Potential formation damage due to wettability changes
- Complicates cementing
- Increased environmental and health impacts

When properly designed and implemented, modern WBM can not only match but exceed the performance of oil-based drilling fluids. (Patel et al. 2007)

In US land operations, many OBMs have been recycled and reused to an extent that has further diminished the perceived benefits from their use. These overworked fluids are loaded with ultra-fine, low-gravity solids (LGS) or “fines”. Plastic viscosities (PV) exhibited in these fluids far exceed those

typically achieved with clean, well-maintained fluids of similar density and oil-water ratio (OWR). Higher solids content and plastic viscosity result in reduced allowable flow rates within a given surface pressure limit. This in turn can limit drilling performance and reduce cuttings transport efficiency.

Another consequence of high solids is that the lubricity benefits associated with OBM are greatly diminished. Diesel itself is not a lubricant, a point that is often overlooked. The lubricating characteristics of OBM are primarily derived from the emulsifiers, wetting components, and even the salinity in the brine phase.

Figure 1 below demonstrates the ineffectiveness of diesel as a lubricant. The use of diesel and/or mineral oil (white oil) as a lubricant in water-based muds is a common practice during drilling operations. Field testing and laboratory testing have demonstrated that diesel and mineral oils are not effective lubricants for use in drilling fluids.

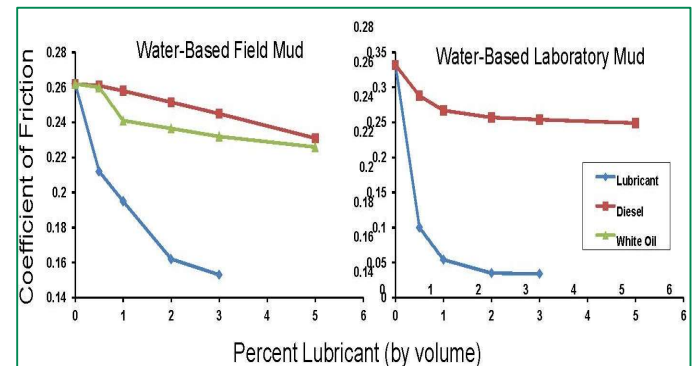


Figure 1 – Lubricant comparison showing coefficients of friction for different lubricants vs diesel or white oil in laboratory and field water-based drilling fluids.

Figure 2 below shows the coefficient of friction (COF) of several lubricants commonly used in drilling operations. Despite being hydrocarbon based, diesel and white oils do not make effective lubricants because of their solvent-like properties. Water-based lubricants consistently perform significantly better than diesel or mineral oil.

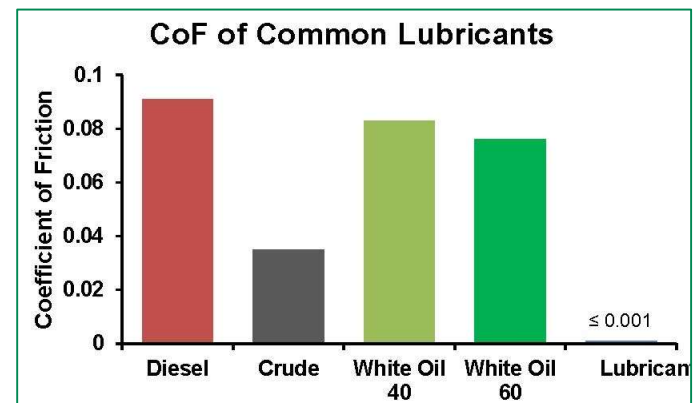


Figure 2 – Lubricant comparison showing coefficients of friction for a WBM utilizing lubricant, diesel or mineral oil (white oil).

As discussions involving Environmental, Social, and Governance (ESG) criteria become more routine, the continued use of diesel-based OBM is likely to be a common topic. For many drilling applications, HPWBM not only perform better but minimize exposure risks for personnel and the environment alike.

New Polymer Chemistry

As the industry strives for continued improvements in cost, efficiency, and ESG impact, water-based alternatives are continuing to become the preferred choice over traditional OBM. New water-based polymer chemistry has emerged as a viable fluid to replace non-aqueous with aqueous drilling fluids. Traditionally, HPWBM employ separate polymeric constituents to provide viscosity, fluid-loss control, and cuttings encapsulation. Various limitations exist with commonly used polymeric additives which can render them unusable under conditions of:

- High monovalent salinity
- Divalent salinity
- Hardness from Ca⁺⁺ or Mg⁺⁺

The above limitations generally limit the use of produced water, thus requiring transportation of fresh water to the drilling location.

Fluid-loss control and encapsulation polymers such as polyanionic cellulose (PAC) and partially-hydrolyzed polyacrylamide (PHPA) often conflict with the desirable rheological profile generated with xanthan gum (Nwousu et al. 2014).

Figure 3 compares the rheology of the new polymer chemistry with other rheology modifiers.

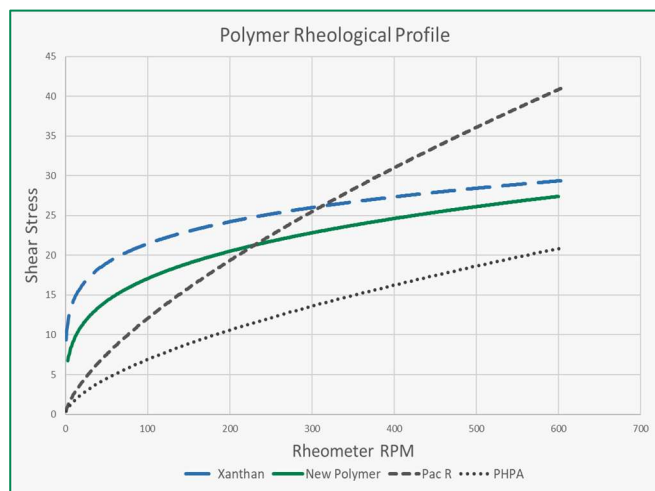


Figure 3 – Rheological comparison of the new polymer chemistry with other common polymeric additives.

New polymer chemistry is now being employed to overcome prior limitations and simplify fluid formulations. This polymer replaces the functions normally performed by multiple additives. Offered in two viscosity grades (regular and low-viscosity), the new polymer chemistry provides an excellent shear-thinning, low-shear-rate viscosity profile while

also serving as the primary fluid-loss control agent (Figure 4). Additionally, the polymers encapsulate cuttings as well as or better than premium PHPA (Figure 5).

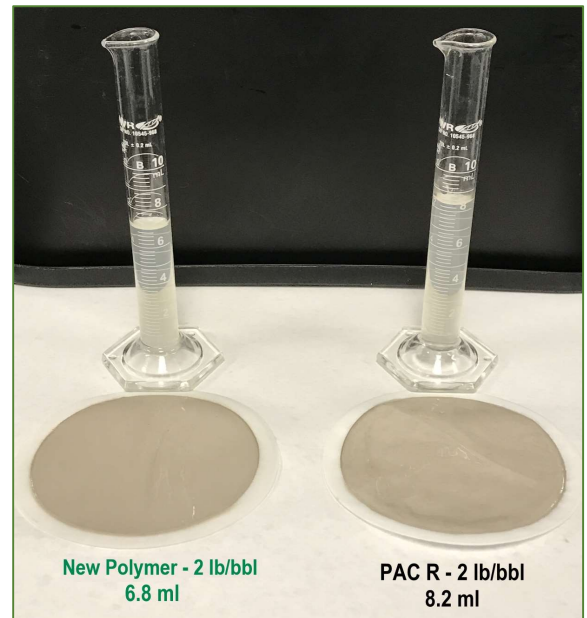


Figure 4 – Fluid-loss control of new polymer compared with PAC R using 2 lb/bbl of each mixed in fresh water with 35 lb/bbl of API standard evaluation clay #7, pH adjusted to 9.8.

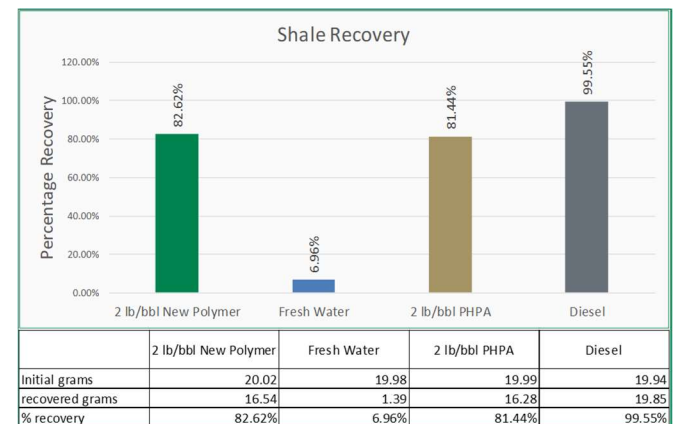


Figure 5 – Shale recovery comparison using Midway Shale, demonstrating encapsulation performance.

Performance of this new polymer chemistry is not stifled by high hardness nor salinity. The polymers remain usable in saline base fluids up to saturation in monovalent brines and approximately one third of saturation in divalent brines. For this reason, their use in produced field brines is possible.

An additional unique characteristic of the new polymer chemistry is its ability to consistently form an exceptionally thin, durable filtercake (Figure 6). Whether in high-performance water-based drilling fluid or direct emulsion WBMs, API filtercakes are routinely less than 2/32 inch thick HTHP filtercakes are routinely less than 3/32 inch thick. The resulting fluid-loss control rivals that of any established polymers on a pound-for-pound basis.

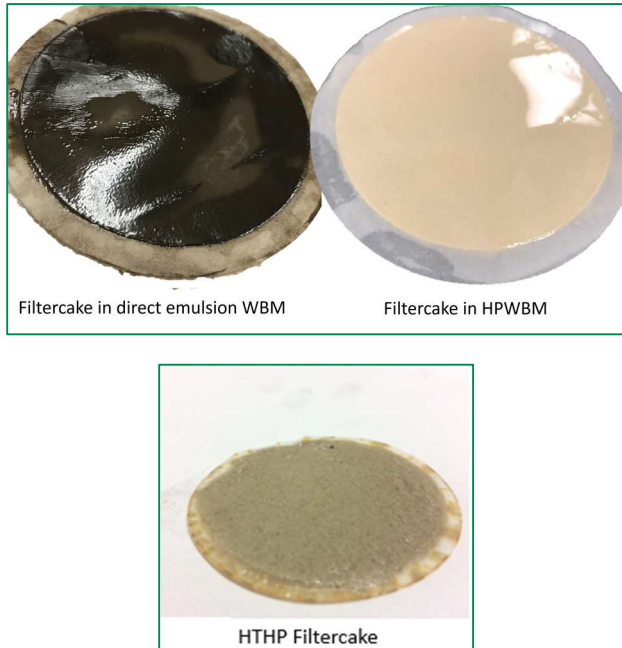


Figure 6 – API filtercakes measuring little more than film in thickness. HTHP filtercake (225°F) less than 2/32-in. Obtained from field muds.

Field Application

In an effort to reduce operational time associated with production casing operations, the customer sought changes in the established drilling fluids strategy. The new polymer chemistry was initially introduced into a direct emulsion fluid. Performance improvements were immediately realized. Drilling times were reduced as was operational time associated with running the 5½-inch production casing.

Continuing with the success achieved with the new polymer chemistry in a direct emulsion system, further efforts were made to improve performance and reduce cost. The continued use of a direct emulsion fluid was required for successful drilling of the halite formations. The direct emulsion fluid delivers a low density while maintaining salt-saturation. This allow continued drilling of a single interval down to the top of the start of the trajectory build depth ensuring the elimination of a casing string.

However, the benefits provided by a direct emulsion fluid containing new polymer chemistry were deemed unnecessary for drilling the final interval comprised of the trajectory build and horizontal production zone. Following completion of the intermediate interval, the direct emulsion fluid was stored on site to be used for subsequent wells.

The last 5 wells studied in this paper used a HPWBM formulated with the new polymer chemistry to drill the final production interval. This system continued to make use of produced water as the base fluid. Modest concentrations (target concentration of 2 lb/bbl) of the new polymer chemistry and approximately 2% by volume of a proven lubricant comprised the remainder of the unweighted system. Transition from direct emulsion fluid to high-performance water-based fluid for the

production interval greatly reduced the overall fluid cost by eliminating the diesel otherwise required for dilution and maintenance of the system.

Figure 7 illustrates the progression in well delivery performance in days per 10,000 ft. The first 5 wells were the most recent 2nd sand Bone Springs wells drilled prior to introduction of the new polymer chemistry WBM. The next 3 wells represent the use of the new polymer chemistry in direct emulsion WBM. The last 5 wells employed a HPWBM with new polymer chemistry and approximately 2% of a proven lubricant.

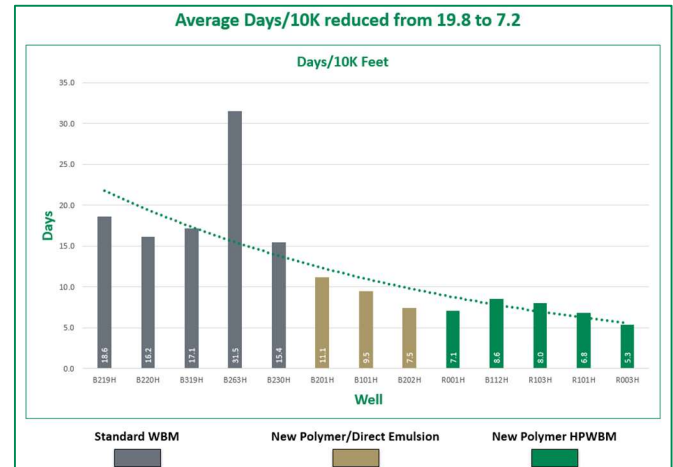


Figure 7 – Performance progression measured in days/10,000 feet.

Conclusions

The use of the high-performance water-based drilling fluid (HPWBM) containing the new polymer chemistry addressed the customer's primary goal of reducing production casing operational time. Losses while cementing were eliminated or dramatically reduced.

- Reduced the average total days on well from 29.6 to 18.5 (37.5% reduction).
- Saved an average 11.1 days as compared to the traditional fluid strategy. The equated to an approximate monetary savings of over \$720,000 per well based on a daily spread rate of \$65,000.
- Reduced the average days/10,000 feet by 63.7%, from 19.8 days to 7.2 days when compared to the historical fluid strategy.
- Reduced the average days/10,000 feet by 23.5% compared to the interim use of direct emulsion fluid with new polymer chemistry for the intermediate and production intervals.
- Reduced the average time to run and cement production casing from 49.2 hours to 26.3 hours (46.5% improvement) while eliminating the need for rotating casing to bottom.
- Cementing of production casing transitioned from consistent complete loss of returns to full returns on 7 of 8 wells and full returns for most of the 8th (losing partial returns after ~65% of the cement was in place).

- Interim fluids cost while using direct emulsion was higher but offset by time savings. Ultimately, the fluids cost using HPWBM with the new polymer chemistry was reduced to be slightly cheaper on average than the original generic WBM.

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