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Successful Application of Direct Emulsion Fluid in Oklahoma Shale and the Delaware Basin

Josh Harton and Mike Redburn, Newpark Drilling Fluids

Abstract

Two operators drilling in South Central Oklahoma and the Delaware Basin of Southeast New Mexico sought a viable replacement to the traditional drilling fluids intrinsic to their regions for both a cost-effective and performance-based approach to drilling.

In Oklahoma, the issue was the increased well costs related to lost circulation and the use of traditional oil-based invert drilling fluids. Conventional use of these fluids in depleted zones have known issues with lost fluid and require the use of LCM to maintain circulation. In New Mexico, the success criteria required drilling through the thick evaporite deposit covering much of the Delaware Basin. Customary under-saturated water-based drilling fluids affect the wellbore with significant washout and the leaching of salt into the fluid, which leads to increased fluid density as well as affecting fluid characteristics. To compound the issue, lost circulation events below the evaporite zone, due to a lower fracture gradient, require a lower fluid density.

The increased well costs due to these issues demanded solutions. This paper investigates the formulation and field use of a direct emulsion drilling fluid that utilizes diesel as the internal phase. Development was initiated by conceptualizing the customer's operational criteria and identifying a robust suite of products. Lab testing began on emulsifiers and products that would perform under the operational standards for both performance and cost. The results of this study offer operators an operationally successful and cost-effective replacement drilling fluid that is challenging regional fluid traditions.

Introduction

Operators drilling in two separate, and different, regions required solutions to issues endemic to their drilling processes. The challenges are separate and varied, however, the solution is the same – direct emulsion drilling fluid.

In South Central Oklahoma, drilling through the Arkoma Woodford shale can be both challenging and cost prohibitive due to the propensity for lost circulation. Use of traditional oil-based invert drilling fluids commonly results in higher fluid-related costs and also extended days until rig release.

In Southeast New Mexico, a two-fold problem exists. First, the salt formation must be drilled with borehole integrity. Second, below the salt formation a plan is required for dealing with fluid losses associated with a low fracture gradient. In the past, drilling practices have either set a protective string of casing after drilling through the salt zone, or have drilled to TD below the salt zone experiencing losses while continuously pumping LCM in order to maintain circulation. The latter drilling practice commonly results in large wastewater volumes as large dilutions are required to maintain the lower fluid density vital for drilling. Additionally, issues related to the use of a traditional water-based fluid have resulted in wellbore washout of the evaporite deposit and the added cost of excess cement due to permits requiring cement to surface.

Fluid Design

Direct emulsion drilling fluids – brine or water being the external phase – are a technology that has been known to the industry for decades. In the late 1990's and early 2000's, Newpark Drilling Fluids developed a direct emulsion fluid for use in the Delaware Basin. The fluid performed well, however, emulsion stability required the use of additional products, such as attapulgite clay, to maintain a stable emulsion for a period of several hours.

Using lessons learned from past ventures, the current fluid design would not contain commercial clays and possess a more robust emulsifier package that would stabilize the emulsion for a period of days to accommodate time out of the hole or fluid storage between wells.

Interpreting the combined needs of the operators, combining fluid design with specific well requirements, and using past lessons learned, has resulted in the development of a fluid system that both meets the demands of drilling in each region and results in cost savings for the customers. Specific design criteria for the fluid consisted of the following:

- Maintain inhibitive properties through the brine external phase or with the additional use of inhibitors
- Perform as a density-reduction fluid using a saturated or near-saturated brine
- Maintain borehole integrity while drilling through salt zones
- Provide competitive performance including increased drilling rate or ROP
- Reduce the cost per barrel to less than half that of a

traditional oil-based invert fluid

- Possess emulsion stability at relatively low concentrations of emulsifier at ambient temperature and low shear
- Remain commercial clay-free
- Possess fluid-loss-control properties when required
- Tolerate storage under controlled conditions

The aforementioned goals would require a robust emulsifier capable of remaining stable under certain conditions of time, heat, and water activity.

Laboratory testing began on a variety of suitable emulsifiers using emulsification principles such as HLB and emulsifier packing theory[4] as informative guides. Once several emulsifier packages were identified, additional laboratory testing was implemented with a sodium chloride brine-based fluid to narrow down the list and find a best fit candidate.

The chosen emulsifier package has shown to perform to the criteria required and provide a stable emulsion under conditions modeled in both the Delaware Basin and the Arkoma Woodford shale. Table 1 and Table 2 show both the product type used and the properties of the lab-built fluid tested using API 13B-1 standard.

Table 1: Lab-Built Direct Emulsion Fluid Components

Product	Function
9.9-lb/gal Field Brine	External Phase
Soda Ash	pH Buffer
Novel Emulsifying Agent	Emulsifier
Novel pH Buffer	pH Buffer
Polymer	Viscosifier
Diesel	Internal Phase

Table 2: Lab-Built Direct Emulsion Fluid Properties

Fluid Properties	Pre-Hot Roll	Post Hot Roll (16 hr @ 180°F)
Fluid Density (lb/gal)	8.8	8.8
600-rpm Dial Reading	30	30
300-rpm Dial Reading	20	19
200-rpm Dial Reading	16	14
100-rpm Dial Reading	11	9
6-rpm Dial Reading	4	3
3-rpm Dial Reading	3	2
PV (cP)	10	11
YP (lb/100 ft^2)	10	8
Gel Strength: 10-s, 10-min,30-min (lb/100 ft^2)	4,5,6	3,4,5
pH	9.91	9.77
API Fluid Loss (mL/30 min)	25	27

Results from lab testing proved the stability of the direct emulsion fluid before and after hot rolling for 16 hours. The initial testing formulation (Table 1) did not require a target for API fluid loss, however, later formulations were constructed with the addition of either a modified starch or polyanionic cellulose to reach this target.

The simplicity of the system is evident from the few products required in the base formulation. Direct emulsion fluids used in the past have typically required additions of attapulgite clay to both provide viscosity and help stabilize the emulsion. As mentioned earlier, the choice of emulsifier eliminated this requirement. A testament to the success of the current emulsifier package is the ability to maintain a stable emulsion without the need for additional solids.

To further test the limits of the fluid and its emulsion stability, an image analyzing device was utilized in the lab at different intervals of timed static testing. The purpose of this exercise was to test for coalescence at the micron (µm) level. Image analyzing devices work on the principal of dynamic image analysis to optically identify particle size. This method of analysis proved especially useful in detecting the micelle structures in contrast to a traditional laser diffraction particle size analyzer, which uses principles of light diffraction as the laser beam passes through dispersed particulate samples. Figures 1 - 3 display the results of the post – mixing and static age testing. Success criteria for an effective emulsifier is the ability to maintain separation between micelle structures, therefore deterring coalescence, after the post – mixing period. The data display the bulk of the micelle structures consistently remaining less than 30 microns in diameter from the post – mixing period through the 48 hour static age interval. A total of three tests were conducted for each testing interval and the data then averaged.

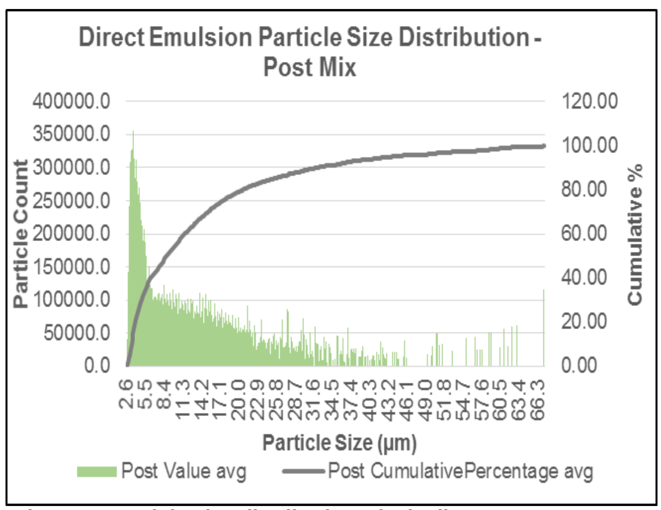

Figure 1: Particle size distribution of micelle structures, post - mixing

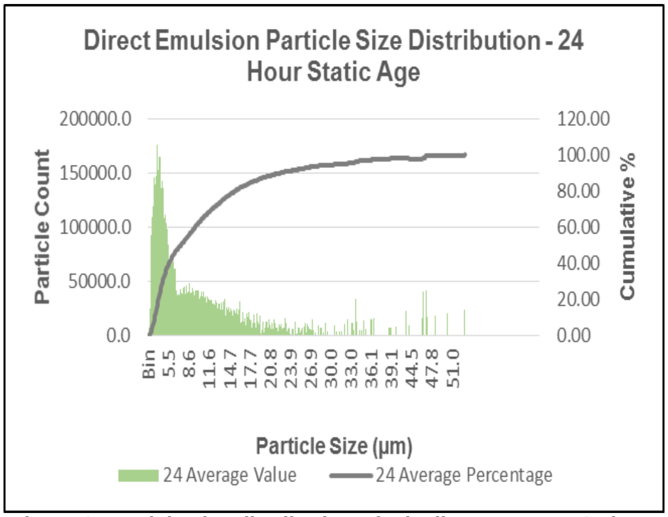

Figure 2: Particle size distribution of micelle structures, 24 hour static age

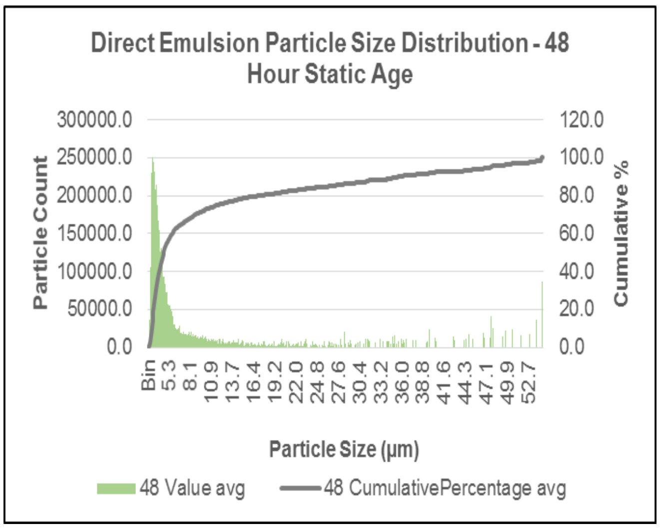

Figure 3: Particle size distribution of micelle structures, 48 hour static age

Fluid Considerations in the Field

Developmental work done with direct emulsion fluids began as a way to control density. Prior versions used large additions of sepeolite or attapulgite clay requiring large amounts of product on location. The new approach was to develop the system without commercial clays, thereby limiting the amount of products on location. In doing so, not only were product concentrations reduced, but the fluid properties remained much more stable. This was only capable due to the novel emulsifier blend. Having this simplistic approach also leads to easier maintenance from the rig site both with mixing and process control.

Economics being a major factor in fluid design, it is important to note these additional points regarding fluid maintenance and cost saving measures:

- Rig requirements for the fluid are similar to any brine-based fluid
- Fluid can be recovered and reused from well to well
- Additions of a biocide are recommended for storage between wells
- Based on results showing less fluid retained on cuttings, solids control equipment should still be optimized
- A centrifuge is required at the rig site to aid in controlling fluid density

Taking the above-mentioned principals into account, the fluid system was ready for field trials. Regions requiring an immediate need were identified and steps taken to initiate the trial process.

Fluid Implementation in the Arkoma Woodford Shale

Operations in the Arkoma Woodford Shale centered in the South Central portion of Oklahoma. The play has been active since 2003 with 2004 seeing its first lateral operations. Common issues with the shale play pertain to fractured intervals as well as shale reactivity in the upper hole sections. Slow ROP and bit degradation are also experienced. Bit issues are especially evident in the southern-most parts of the formation where the composition consists of alternating bands of chert-like amorphous silica[6]. The implications of these combined issues result in frequent bit trips, stuck pipe, as well as the high costs associated with fluid lost downhole.

Operators in the area have traditionally drilled with oil-based invert fluids due to the reactive upper sections. However, the high cost incurred from fluid losses has forced them to look for alternatives without sacrificing performance.

A density-reduced, brine-based, direct emulsion fluid tailored further to meet this specific requirement for inhibition would satisfy drilling operations effectively and would add value. The recommended fluid was customized with specific products for the downhole reactive formations. A formulation containing both potassium chloride and a modified starch was chosen to meet the specified geologic requirement of the area. The potassium would provide the additional inhibition required by the operator for shale swelling of the clay matrix. The addition of a modified starch for the required API fluid loss would aid in reaching the identified target.

Table 4 and Table 5 outline the component product types and properties of the direct emulsion drilling fluid used in the Arkoma Woodford formulation. The average properties were taken over three wells. The properties tested included MBT which indicates the amount of clay present. The goal was to keep the clay content “as low as possible” (ALAP) whereby only native clays are incorporated during the drilling process.

Table 4: Direct Emulsion Fluid Components Arkoma Woodford Shale	
Product	**Function**
9.4-lb/gal Field Brine	External Phase
Potassium Chloride	Inhibition
Soda Ash	pH Buffer
Novel Emulsifying Agent	Emulsifier
Novel pH Buffer	pH Buffer
Polymer	Viscosifier
Diesel	Internal Phase
Modified Starch	Fluid Loss Additive

Table 5: Direct Emulsion Fluid Arkoma Woodford Shale Average Properties	
Fluid Properties	**Average Properties Over 3 Wells**
Fluid Density (lb/gal)	8.8 – 9.2
PV (cP)	15 - 20
YP (lb/100 ft^2)	14 - 20
pH	8.5 – 9.0
API Fluid Loss (mL/30 min)	4.0 – 6.0
MBT	ALAP from Native Clays

A six-well trial has been successfully completed in the Arkoma Woodford Shale region. Improvements have been seen both in days spent on well and in the overall cost associated with fluid lost downhole. Figure 4 depicts the savings experienced verses a traditional oil-based invert fluid in relation to days until rig release and total fluid losses.

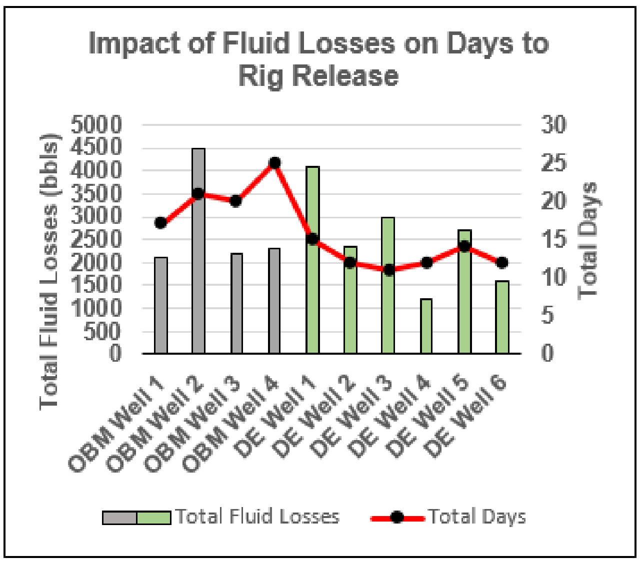

Figure 4: Downhole fluid loss impact on days until rig release.

The implications of the cost benefits from Figure 4 are wide ranging. For example, the average number of days until rig release for an oil-based invert fluid over four wells was approximately 21 days. This same average over six wells for a direct emulsion fluid equates to 12.75 days. Depending on daily rig rates, this amount could easily eclipse $100,000 per well in savings. Figure 5 represents the percent reduction in fluid cost when losses are experienced with a direct emulsion fluid verses an oil-based invert fluid.

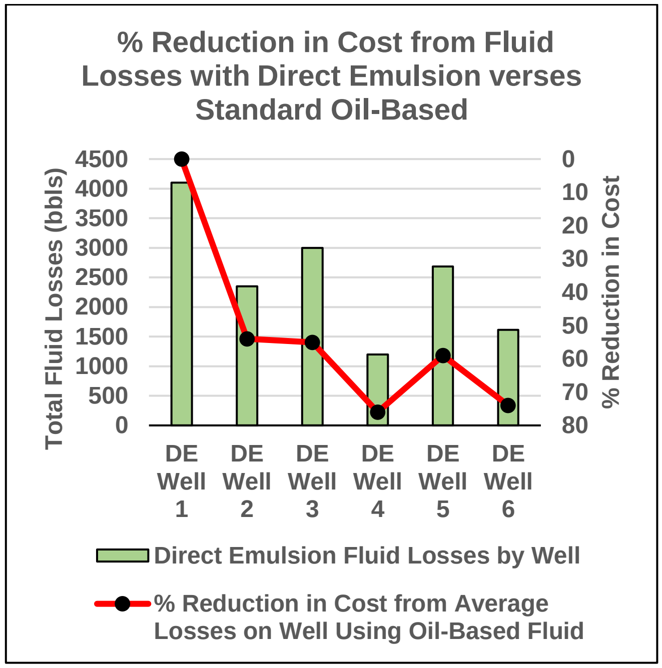

Figure 5: Cost reduction from fluid losses with direct emulsion fluid verses standard oil-based fluid.

Numerous additional advantages have been experienced in this region using a direct emulsion fluid in lieu of an oil-based invert. They include:

- Fluid can be mixed on location, which reduces costs related to trucking as compared to oil base invert fluids requiring a liquid mud plant for adequate mixing time and shear
- A wider variety of LCM can be used in contrast to an oil-based invert fluid due to the external phase being brine or water
- Brine is easily available from nearby salt-water disposal wells
- Provides improved hole stability in curve and lateral sections of wells leading to slick trips
- Fluid can be reused from well to well just as conventional invert emulsion fluids

The impact of fewer days spent on location combined with savings experienced from reduced/cheaper total fluid losses along with the aforementioned advantages have resulted in a dramatic impact on drilling costs for the customer.

Fluid Implementation in the Delaware Basin

Drilling in the Delaware Basin of Southeast New Mexico involves a different set of challenges. Objectives for successful operations in this region include the following:

- Drill with borehole integrity and the absence of washout through the thick salt deposit that covers much of the basin

- Drill with a reduced fluid density after the salt section to avoid loss circulation events in subsequent formations that possess a lower fracture gradient

Using knowledge gained from the service company's past experience with operators in the region, a direct emulsion fluid redesigned with a different emulsifier package would improve aspects of both performance and cost. As previously stated, the focus now would be on achieving emulsion stability over a longer time period without the use of commercial clay products.

Conventional fluid operations have commonly drilled the salt section using either a saturated sodium chloride brine or a pre-hydrated bentonite water-based fluid.

Traditionally at TD of the salt zone, one of two operations has been performed – either set a protective string of intermediate casing to shield the section from subsequent operations, or displace the saturated brine in the active system to the pre-hydrated bentonite fluid in an effort to cake off the salt section and drill to the ensuing casing point. Both the above methods have issues related to cost. The issue inherent with using a pre-hydrated bentonite fluid is that washout and salt leaching continue as the interval is drilled. As a result, fluid weight increases. This poses additional issues with lost circulation events as formations following the salt zone possess a lower fracture gradient and require a less dense fluid.

This method of dump-and-dilute drilling has widespread implications on ancillary operations related to drilling. Charges accrue both from LCM usage as well as the large volumes of wastewater that must be hauled off due to dump-and-dilute practices. Extra expenses accumulate to deal with operations of this type such as the cost of make-up water and product to maintain volume in the active system, increased amounts of trucking for haul-off, and disposal of the wastewater. Excessive trucking also lends to a higher possibility of HSE events due increased road exposure for trucks.

A direct emulsion drilling fluid containing a saturated sodium chloride brine external phase reduced with diesel to a specified fluid density met the operational criteria successfully.

Following the successful three-well trial in the region, three additional wells are planned. Table 6 displays the product types used and Table 7 the average properties of the direct emulsion fluid used in the Delaware Basin.

Table 6: Direct Emulsion Fluid Delaware Basin Components

Product	Function
9.9-lb/gal Field Brine	External Phase
Novel Emulsifying Agent	Emulsifier
Novel pH Buffer	pH Buffer
Polymer	Viscosifier
Diesel	Internal Phase

Table 7: Direct Emulsion Fluid Delaware Basin Average Properties

Fluid Properties	Average Properties Over 3 Wells
Fluid Density (lb/gal)	8.7 – 9.2
PV (cP)	10 – 15
YP (lb/100 ft^2)	8 – 12
pH	8.5 – 9.5
API Fluid Loss (mL/30 min)	10 – 15

In contrast to the Arkoma Woodford Shale fluid, API fluid loss was not a concern in this area. Operational concerns mainly centered on fluid density, borehole washout, and lost circulation in contrast to shale reactivity. All completed wells have seen performance gains using the direct emulsion fluid over the traditional saturated sodium chloride brine-based drilling fluid.

A major benefit obtained by customers is the elimination of a protective string of casing traditionally set after the salt zone. Cost saving estimates run in the range of $85,000 for casing in addition to the time saved from operations spent on the casing run, as well as charges for cementing and trucking.

Figure 6 illustrates the gains in performance experienced after converting to a direct emulsion drilling fluid. Based on data from Figure 6, a direct emulsion fluid out-performed the sodium chloride brine drilling fluid by an average of 9.67 hours in drilling to TD of the salt section. Figure 7 illustrates the reduction in LCM usage based on averaging over the three wells.

Further benefits included a gauged or near-gauged wellbore and also the absence of lost circulation events in formations below the salt deposit. Fluid weight was easily maintained due to the absence of salt leaching.

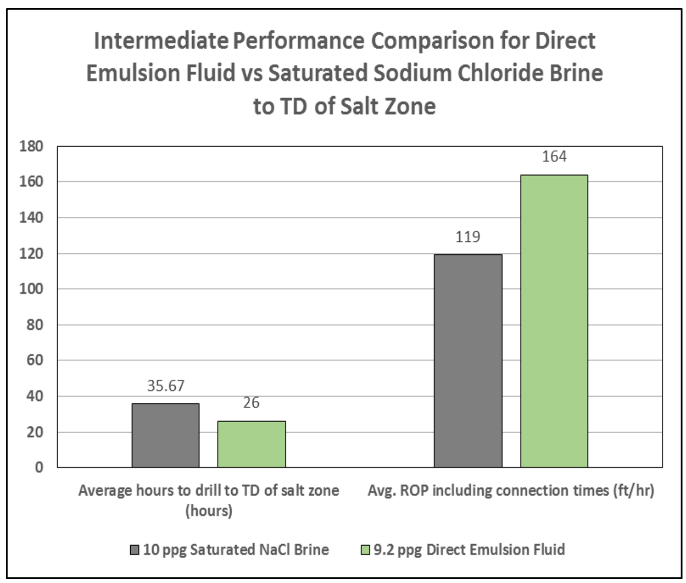

Figure 6: Performance gains when using a direct emulsion fluid verses a saturated sodium chloride brine.

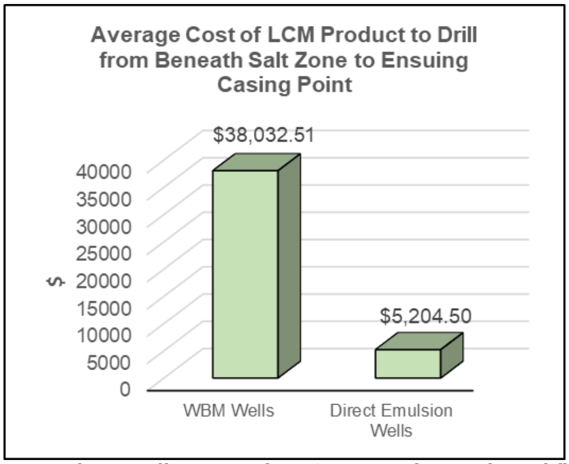

Figure 7: Three-well average for LCM cost of water-based fluid verses direct emulsion fluid when drilling from beneath salt zone to ensuing casing point.

Table 8 displays how well the direct emulsion stabilized the wellbore when drilling through the evaporite environment. The average hole size was calculated using fluid caliper pills pumped at TD.

Table 8 – Comparison of Bit Size to Average Hole Size

Well	Bit Size (in.)	Average Hole Size* (in.)
1	12.25	12.5
2	8.75	8.75
3	8.75	8.75
** as measured with fluid caliper pills*		

A reduction in lost circulation events, elimination of a casing string, less wastewater haul-off, reduced LCM product usage, and improved performance have all aided in diminishing the cost burden on the customer. Based on the data, a density-reduced, direct emulsion fluid has effectively usurped past fluid practices in the Delaware Basin and has increased customer confidence.

Conclusions

Newly available emulsifiers have made possible the revival and improvement of technologies used in the industry several decades ago. Focused laboratory research has resulted in an emulsifying package for a direct emulsion drilling fluid that does not require the additional use of commercial clay products and still maintains a stable emulsion for a period of days. Furthermore, the system can be engineered to fit a wide range of operator requirements with respect to parameters such as inhibition, fluid loss control, rheology, and fluid density.

Successful field trials with the fluid system used in two separate and geologically diverse environments has shown added value to operators seeking a more cost-effective approach to their drilling operations.

Based on the data collected to this point, operations in the Arkoma Woodford shale of South Central Oklahoma have seen dramatic gains in performance and cost savings over the customary oil-based invert fluid used in the area.

Similarly, in the Delaware Basin of Southeast New Mexico, the fluid system has proved its validity over the traditional fluids used in the region by effectively eliminating a casing string and also allowed operators to drill to the ensuing casing point while accruing less expenses due to lost circulation issues.

Both customers plan to continue their operations with the direct emulsion fluid as a part of their drilling programs.

Acknowledgments

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Nomenclature

HLB = hydrophilic lipophilic balance
HSE = health safety environmental
LCM = lost circulation material
LGS = low gravity solids
MBT = methylene blue test
PV = plastic viscosity
ROP = rate of penetration
TD = total depth
YP = yield point

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