DEVELOPMENT AND TESTING OF A WATER-BASED DRILLING FLUID THAT GIVES OBM-TYPE PERFORMANCE

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ABSTRACT

It has long been recognized that there exists a significant technology gap between the performance of the best water-based drilling fluids (WBF) and invert emulsion fluids. WBF fall behind with respect to shale inhibition, wellbore stability, rate of penetration (ROP), and fluid stability. Strengthening of restrictions regarding use and discharge of invert emulsion fluids, coupled with the challenges of extended reach and deepwater drilling – low fracture gradients, narrow equivalent circulating density (ECD) windows, and high lost circulation risk – have challenged WBF development.

The results of several research and development projects into shale inhibition, cuttings accretion, lubricity, cuttings encapsulation and rate of penetration with WBF allowed the stepwise generation of a new WBF designed to approach invert emulsion fluid performance.

This paper describes the development of a these inhibitive water-based fluids and field performance results obtained from these fluids which show the invert-emulsion-like performance. The paper also discusses the engineering of the new drilling fluid.

INTRODUCTION

Invert emulsion drilling fluids (IEM) have always been the first choice in fluids when drilling demanding wells that require a highly inhibitive fluid, capable of guaranteeing high rates of ROP, good lubricity and the lowest potential for stuck pipe. The development of a water-based drilling fluid which would give drilling characteristics similar to an IEM has long been seen as the ultimate goal of drilling fluids research and development. Invert emulsion drilling fluids are universally recognized as being the most efficient fluids to drill with, due to the absence of contact between the drilled formations and water and the inherent oil-wetting and lubricity characteristics of these fluids.

The advantages of invert emulsion drilling fluids have been well documented; the main points can be summarized as:

a) Improved wellbore stability
b) High degree of contamination tolerance
c) Improved ROP
d) Low coefficient of friction
e) Thin, lubricious filter cake
f) Low dilution rates and ease of engineering
g) High degree of re-usability

Several water-based drilling fluid systems have been developed and used in the field over the past 10 years with the goal of approaching the drilling performance of an IEM. [1-8] A few of the more successful were as follows:

a) Potassium/polyacrylamide (PHPA) fluids
b) Salt/glycol fluids
c) Silicate fluids
d) $CaCl_2$/Polymer fluids
e) Cationic fluids

Despite these field successes, however, the use of these fluids has not been completely successful in inhibiting the hydration of highly water-sensitive clays and these fluids have various inherent limitations, such as:

- Potassium/Polymer fluids cannot reach the inhibition levels of an IEM, thus in highly water-sensitive shales, bit balling, accretion, wellbore instability, and poor ROP can result.
- Cationic polymer systems can be almost as inhibitive as an IEM; however, the cost of running the system, toxicity of cationic polymers, and their incompatibility with other anionic drilling fluid additives has resulted in only limited success in the field.

- Silicate fluids exhibit highly inhibitive properties but have limitations related to density, salinity, lubricity, and logging tool compatibility.

In addition to these generalized system developments, there have been a number of individual product developments that have allowed the performance of such systems to be pushed closer to that of an IEM. Effective lubricants, ROP enhancers, and more efficient filtration-control polymers are some examples. These developments have all resulted in various WBFs, which are relatively fine tuned to perform in certain areas while drilling through specific shale types. A WBF, which is as flexible in its performance as IEM, had not, as yet, been developed.

RESEARCH AND DEVELOPMENT

A research and development commitment was taken to look into the potential for vastly improving existing WBF technologies. Given the goals of the development project – to find a WBF that could give similar performance to an IEM – it was felt that development of individual products, which could enhance existing systems, would be insufficient to achieve the goal; therefore a complete systems approach was taken.

It was also critical that throughout the development phase that, focus was maintained on the entire performance spectrum of an IEM and not solely on one aspect of IEM performance. Testing was conducted in differing base fluids (from seawater to saturated NaCl), on differing shale substrates (from highly swelling to highly dispersive), and used a variety of test methods (shale dispersion, shale swelling, shale hardness, accretion, lubricity, filtration, rheology, contamination tolerance, thermal stability, etc.) to evaluate overall performance. Results were compared to three baselines – mineral oil-based fluid (MOBM), NaCl/PHPA WBF and KCl/Silicate WBF.

In addition to the above, more complex testing such as molecular modeling of inhibitor chemical behavior in shale substrates, shale membrane testing, large-scale accretion testing, and ROP testing were conducted. The final result of this broad research and development project was a new, high-performance water-based drilling fluid which exhibited laboratory performance characteristics in the realm of those achieved by invert emulsion fluids, and far exceeded those exhibited by other water-based fluids.

NEW FLUID FORMULATION

The new drilling fluid developed from the project consists of five synergistic products, three of which were newly developed. A brief description of these key components follows.

Hydration Suppressant. **A** multi-functional complex amine-based molecule, this component is completely water-soluble and exhibits low marine toxicity. The compound is compatible with other common drilling fluid additives used in WBF, exhibits a pH buffering effect, and has no hydrolyzable functionality. The unique molecular structure of this compound has been shown by molecular modeling techniques to provide a perfect fit between clay platelets, tending to collapse the clay's hydrated structure and greatly reduce the clay's tendency to imbibe water from an aqueous environment. The compound requires minimal salinity for maximum functionality, and is equally stable in high-salinity and hardness environments.

Dispersion Suppressant. A novel, amphoteric, low-molecular-weight copolymer, this component is fully water soluble and exhibits good biodegradability and low marine toxicity. The polymeric additive is designed to have a molecular weight and charge density that imparts superior encapsulation by limiting water penetration into the clays. The molecular weight of the polymer allows significant flexibility in a wide range of mud densities and mud formulations; the charge density provides improved clay surface binding of the polymer and high salinity and hardness tolerance. The compound has the ability to control both swelling and dispersion of water-sensitive clays without having significant adverse effects on rheological properties. As a secondary function, the polymer imparts some anti-accretion properties to the fluid.

Accretion Suppressant. This component is a unique blend of surfactants and lubricants designed to coat drill cuttings and metal surfaces to reduce the accretion tendency of hydrated solids on the surface of metals, and to reduce the agglomeration tendency of hydrated cuttings with each other. This blended component is designed to exhibit stability in low- to high-salinity environments, and be compatible with highly solids-laden (high-mud-weight) fluids. The component exhibits low marine toxicity. The accretion suppressant agent aids in preventing any buildup of drill solids below the bit, allowing the cutters good contact with new formation for improved ROP. As a secondary functionality the component also lowers torque and drag by reducing the coefficient of friction.

Rheology Controller. Xanthan gum was chosen as the optimum rheology-control agent for the fluid, based on the high efficiency of the polymer and its tolerance to salinity and hardness. The presence of the hydration suppressant stabilizes the Xanthan gum in solution, giving optimum rheological control at temperatures to 150°C (300°F). The high low-shear-rate viscosity (LSRV) and efficient carrying capacity of the polymer allows for optimized rheological control to improve fluid performance in extended-reach and deepwater environments.

Filtration Controller. A low-viscosity, highly modified, polysaccharide polymer was chosen as the optimal filtration-control agent for the system. This polymer is stable in low to high salinities, and at high hardness levels. The low viscosity contribution of the polymer allows for optimal filtration control to be achieved even at high solids loading (high mud weights). The polymeric substitution allows the polymer to interact with the Xanthan gum, providing improved LSRV for more optimized hydraulics behavior.

The design and selection of each of the above components were fine-tuned to optimize on the synergies of the compounds, and improve the flexibility of the overall system design. The net result is a novel high-performance water-based fluid which will perform in a wide variety of base fluids, over a wide density and temperature range, and will meet the environmental acceptance criteria required in most areas of the world.

LABORATORY TESTING RESULTS

Summaries of some of the laboratory test results are shown as Figures 1 to 7. Testing was carried out on four outcrop shale substrates which were used in their native state:

- Raw Bentonite – This was Wyoming bentonite ore, a predominantly sodium montmorillonite with high swelling characteristics.
- Foss Eikeland Shale – An outcrop shale from Norway with ~15% sodium montmorillonite and exhibiting high tendency to dispersion and accretion.
- Oxford Clay –An outcrop shale from the UK with ~10% sodium montmorillonite and showing a tendency to both swell and disperse.
- Arne Clay – Outcrop clay from the UK composed predominantly of kaolinite; the material is fragile and has a very high tendency to disperse and accrete.

Four drilling fluid systems are shown in these comparisons:

- MOBM – A mineral oil-based fluid, Oil/Water Ratio 80/20, yield point (YP) = 15, electrical stability (ES) ~1000 v, and density 12 lb/gal.
- NaCl/PHPA – An example of a WBF typically used in the US Gulf of Mexico (GOM) with 20% wt NaCl and 1-lb/bbl PHPA polymer. YP = 15, weighted to 12 lb/gal with barite.
- KCl/Silicate – An example of one of the most inhibitive WBF with 10% KCl and 8% sodium silicate. YP = 15, weighted to 12 lb/gal with barite.
- NWBF – The formulated new water-based fluid, which was weighted to 12 lb/gal, YP = 15. The formulation is given in Table 1.

These figures summarize the test data:

Figure 1 – Comparative shale inhibition results using the hot-roll dispersion test method.
Figure 2 – Comparative shale inhibition results using the Slake durability test method.
Figure 3 – Comparative shale inhibition using the cuttings hardness test method.
Figure 4 – Comparative cuttings accretion using the rolling-bar test method.
Figure 5 – Comparative lubricity using the Fann metal/metal lubricity test at two different loadings.
Figure 6 – Comparative effect of solids loading using OCMA bentonite as the contaminant.
Figure 7 – Inhibition characteristics of the new water-based fluid using different base fluids of seawater, 10% KCl brine, and 20% NaCl brine. In each case, the fluids had 3% hydration suppressant, 2-ppb dispersion suppressant, and 1.5% accretion suppressant.

From these test results it can be readily seen that the NWBF significantly outperformed both the NaCl/PHPA and the KCl/Silicate water-based fluids, and could be compared directly with the performance of the MOBM. Based on these and many other test results, the new water-based drilling fluid was considered, from a laboratory standpoint, to be a significant improvement over existing water-based fluids and to have the potential to be a true performance equivalent to invert emulsion drilling fluids. It was with this background that the system was taken for field trials.

FIRST FIELD TRIAL

The NWBF was put forward for an initial field trial in the GOM, where the high inhibition characteristics (without resorting to use of potassium ion which creates a toxicity issue) were uniquely required. Inhibition testing carried out on "gumbo" clays from the potential field trial area highlighted the performance potential of the NWBF. The NWBF system was chosen for a well drilled in the deepwater GOM at 3,797-ft water depth. The new system was used to drill the 17-in. pilot hole and to open it to 22 in. from 6,125 to 7,360 ft. This interval is characterized by highly reactive shales and sand and is typically drilled with a 20% NaCl water-based mud containing partially hydrolyzed PHPA. On the previous offset wells, the problems encountered were shaker screen blinding, rapid depletion of the encapsulator, and high dilution rates. Some operators have used significantly more expensive synthetic-based drilling fluids to overcome all the above-mentioned problems when drilling similar sections in this area.

Fluid Mixing. One of the main advantages of the NWBF system is the ease of the mixing process. The products can be added relatively quickly, and the fact that two products are liquid saves even more time. Table 2 shows the formulation of the 10-ppg NWBF mixed and used. The mixing was done using a high-power hopper, which improved the mixing speed.

Drilling Performance. The well was displaced inside casing (using a 100-bbl viscosified seawater spacer) from the gel mud used previously to a 10-ppg NWBF. After drilling the cement plug (without fluid treatment), the pH increased from 9.5 to 10 and total hardness from 400 to 1000 mg/L; this did not affect fluid properties. This was attributed to the fact that the system was formulated bentonite-free and that the dispersion-suppressing polymer is calcium tolerant.

Rigsite test procedures to monitor the product concentrations of the clay dispersion inhibitor and the clay hydration inhibitor were developed before the field trial. These were run to ensure that optimized engineering control over the system could be readily maintained. The clay hydration inhibitor is also the only alkalinity source in the drilling fluid, generating high measured filtrate and mud alkalinities (P_f, M_f, and P_m). A decrease in the inhibitor concentration can also be crudely monitored by a drop in alkalinities.

When drilling began, the cuttings observed at the shakers were dry, firm, and very well encapsulated, indicating that the system provides outstanding inhibition. Another indication was when, after taking a survey for more than two hr without circulation or moving the drill pipe, the string was picked up without any overpull and the drilling resumed. Dilution premix was continuously added to the system to maintain the active volume along with the desired concentrations. The ROP averaged 150 ft/hr, but it was as high as 300 ft/hr. (On offset wells drilled with the 20% NaCl/PHPA fluid, the ROP averaged only 95 ft/hr). This was a good test of the inhibitive characteristics of the fluid, which showed good cuttings integrity and encapsulation as can be seen in Figure 8.

The interval was drilled to 7,366 ft using higher flow rates (1,350 – 1,400 gal/min) and the fluid properties remained very stable. It was necessary to add viscosifying polymer to the premix to maintain the rheology, as the mud would only incorporate a minimum amount of drill solids. After reaching 7,366 ft, a 100-bbl sweep was pumped and the fluid was weighted to 10.3 lb/gal. The bit and the bottomhole assembly (BHA) were pulled out of hole completely free of gumbo shale as can be seen in Figure 9. This was almost unheard of in previous wells drilled with WBF, proving that the NWBF has a minimum accretion tendency.

Due to the excellent fluid screenability observed during the 17-in bit run, finer screens were run while opening the hole to 22 in. Two primary shakers were equipped with 140/110/110-mesh screens and three were dressed out with 110/110/110-mesh screens. This hole opening section was equivalent to drilling a new 14-in section. The cuttings generated had the same good integrity and were observed to be firmer and dryer than typical WBF cuttings. A steady rate of penetration averaging 120 ft/hr was maintained throughout the interval and there were no problems associated with excessive amounts of cuttings. Dilution premix was added to maintain volume and fluid properties remained very stable.

FIRST FIELD INVERT EMULSION FLUID REPLACEMENT

The NWBF was chosen for a land application in Canada where invert emulsion fluids had been the drilling fluid system of choice based on low density requirement, highly reactive and sensitive shale sections, and the inability of previously tried WBF to meet performance and environmental targets.

The requirement in this well was to drill an 8¾-in. high angle (47°) wellbore for 7,250 ft through a complex mix of silts, sand, and shales, including the Blackstone shale formation which had proven problematic with all previously used WBF. Density needed to be maintained in the range of 8.4 to 9.1 lb/gal, with an environmental requirement for disposal that there be low conductivity and no chlorides in the waste water and cuttings.

With no shearing unit and one standard venturi-type hopper, fluid mixing was carried out without incidents. After displacement and drilling out the cement and shoe with an 8.5-lb/gal NWBF, drilling commenced with average ROPs in the range of 74 to 150 ft/hr. This was directly comparable to offset wells drilled with invert emulsion fluids, and was significantly higher than the penetration rates seen with offset wells where WBF had been used (average ROP 20 to 50 ft/hr). Density was controlled easily in the desired range with minimal dilution, despite only having one shale shaker and one centrifuge for solids control. No issues were experienced during the drilling of the section. Wiper trips were typically a little tight on the first pull and thereafter were clean. When tripped out of hole, and at total depth, the bit and BHA were noticeably clean, with no adhered shale or cuttings – a scenario that had been commonly seen on offset wells drilled with WBF. The entire section was drilled and logs were run with no indications of the wellbore instability seen in the blackstone shales with previously used WBF. Caliper logs run after the section showed an average hole size that was 22% overgauge, compared to 19% for offset wells drilled with IEM and 65-75% for offset wells drilled with WBF.

The low dilution and gauge hole led to minimal fluid and cuttings that were sent for disposal at the end of the well. In addition the low toxicity of the fluid, and the chloride/low conductivity nature of the fluid waste allowed disposal without transportation to a special waste site. The net result was a successful field trial that was completed at a well fluid and fluid disposal cost significantly lower (28 – 182%) than all other offset wells. Based on this performance the fluid system was recommended for future usage in place of IEM.

FURTHER FIELD USAGE

The NWBF has since been utilized on over 300 wells on a global basis. In >60% of the applications, the NWBF selection has been on the basis of replacing either existing or planned usage of IEM. A breakdown of these applications by well type, and by well geographic location, are shown in Figures 10 and 11.

The NWBF has been used in a variety of difficult situations, some of the highlights of its usage are:

- Deepwater record: 9,472 ft water depth offshore Brazil
- Maximum mud weight: 17.2 lb/gal, Wyoming US
- Maximum angle built: 90°, United Arab Emirates and Brazil
- Maximum number of intervals in one well: five (20, 17, 14.5, 12.25, 8.5-in.), GOM
- Longest interval: 9,384 ft, South China onshore
- Largest directional interval: 8,900 ft, 17½ in., 65° angle, North Sea

Benchmarks against mineral oil-based fluids, synthetic invert fluids, and other water-based fluids have been conducted evaluating the performance of the NWBF in the field. In all of the areas used, the NWBF has proven itself to far exceed the performance of other WBFs in terms of improved wellbore stability, improved ROP, ease of maintenance of fluid properties, lower dilution rates, and improved economics of the drilling operation. In addition, the NWBF has proven in many cases to show equivalent drilling performance to invert emulsion fluids with respect to wellbore stability and drilling rates. Figure 12 shows a comparison of drilling performance over a range of fields in the deepwater area of the GOM. The wells that used NWBF for the upper reactive shale sections, then SBM in the lower sections showed drilling performance as good as, and often better than, those wells that used SBM for all of these hole sections. Figure 13 compares offset wells with the NWBF for two fields in the GOM.

The enhanced shale inhibition and low risk of accretion seen from the NWBF has allowed the use of high performance PDC drill bits to achieve optimal drilling rates even through some extremely reactive shale formations. The use of the NWBF has been characterized by large, well-defined, cuttings as can be seen in Figure 14, which are readily removed by the primary solids-control equipment on the first pass, ensuring that the fluid does not become rapidly contaminated by drill solids, and that dilution rates to maintain drilling fluid parameters is low.

CONCLUSIONS

The NWBF is a new high-performance water-based drilling fluid designed with a total-system approach. It contains products specifically chosen to satisfy each of the requirements of a highly inhibitive fluid.

The NWBF is extremely flexible and easy to run under various conditions. Laboratory and field tests have demonstrated that the system could be successfully formulated with a variety of base brines and at densities ranging from 8.6–17 lb/gal.

The field usage has proved that the fluid can be easily prepared, has good screenability through fine shaker screens, and has outstanding drilling performance approaching that of an IEM.

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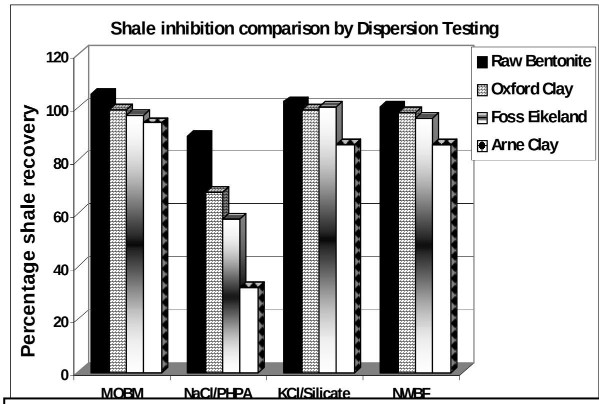
Table 1
Composition of NWBF Used in Laboratory

20% NaCl Brine (bbl)	0.86
Hydration Suppressant (lb_m/bbl)	10.5
Dispersion Suppressant (lb_m/bbl)	2.0
Fluid Loss Reducer (lb_m/bbl)	4
Viscosifier (lb_m/bbl)	1.0
Accretion Suppressant (lb_m/bbl)	5.0
Barite (lb_m/bbl)	120

Table 2
Composition of NWBF Used in Field Trial

Water (bbl)	0.84
NaCl (lb_m/bbl)	74
Clay Hydration Inhibitor (lb_m/bbl)	10.5
Clay Dispersion Inhibitor (lb_m/bbl)	2.5
Fluid Loss Reducer (lb_m/bbl)	2
Viscosifier (lb_m/bbl)	1.25
Accretion Inhibitor (lb_m/bbl)	10.5
Barite (lb_m/bbl)	23.5



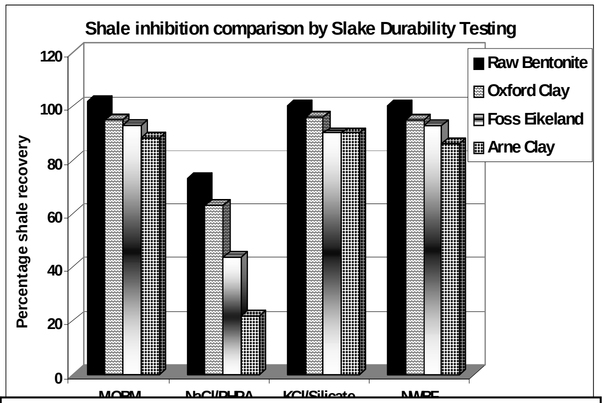


Figure 1 - Comparative shale inhibition results using the hot-roll dispersion test method.	Figure 2 - Comparative shale inhibition results using the Slake durability test method.

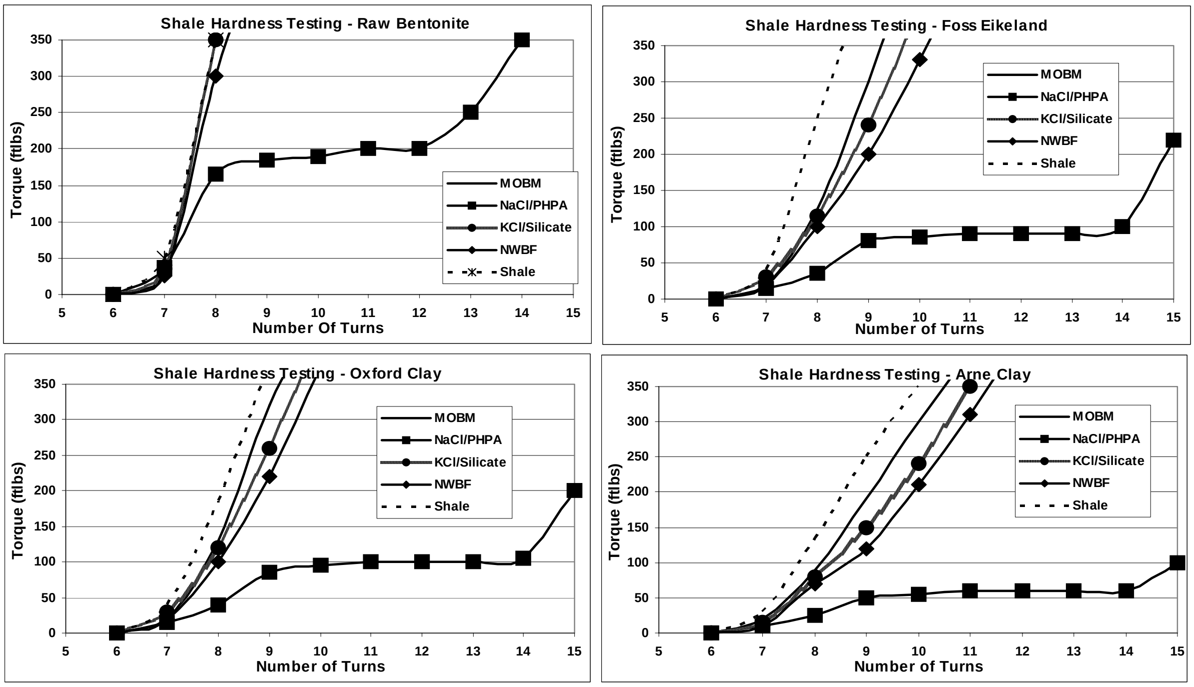
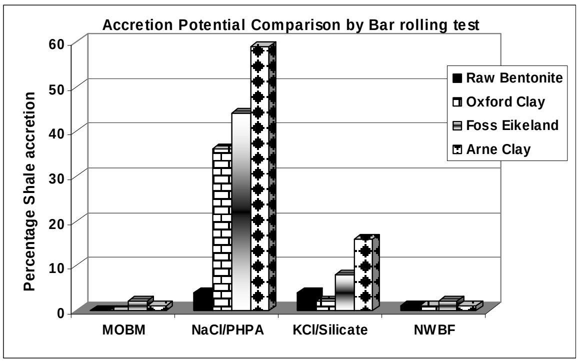


Figure 3 – Comparative shale inhibition using the cuttings hardness test method.



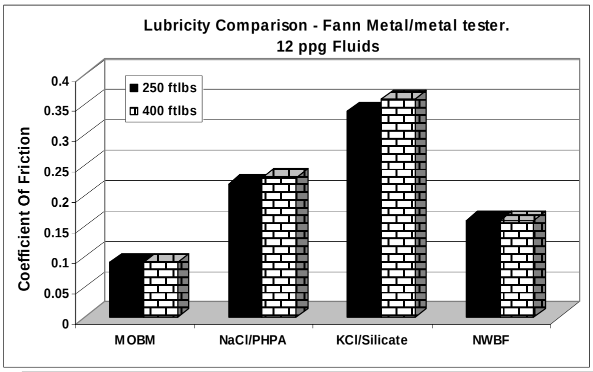
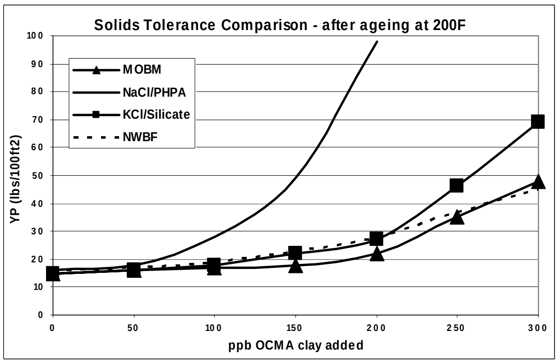


Figure 4 - Comparative cuttings accretion using the rolling-bar test method.

Figure 5 - Comparative lubricity using the Fann metal/metal lubricity test at two



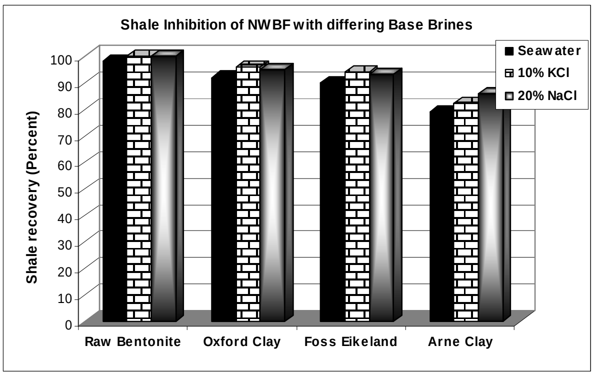


Figure 6 - Comparative effect of solids loading using OCMA bentonite as the contaminant.

Figure 7 - Inhibition characteristics of the new water-based fluid using different base

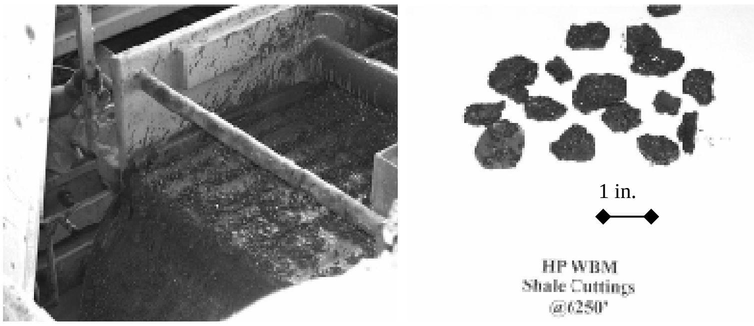


Figure 8 – Good cuttings condition and ready removal at shale shakers as seen on first field trial.

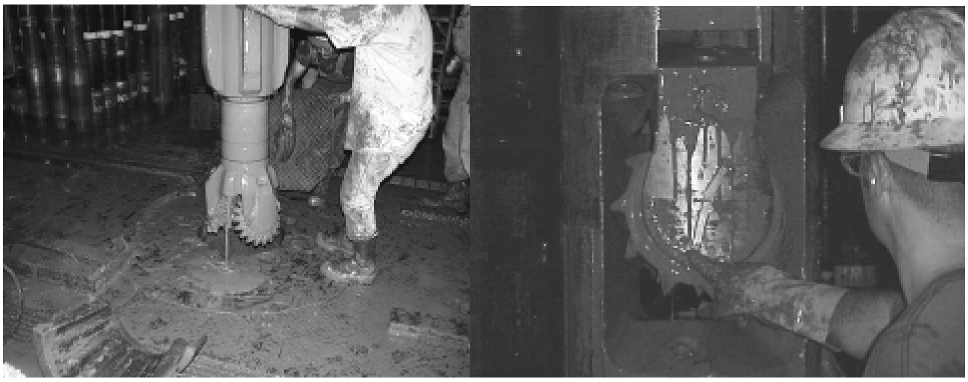
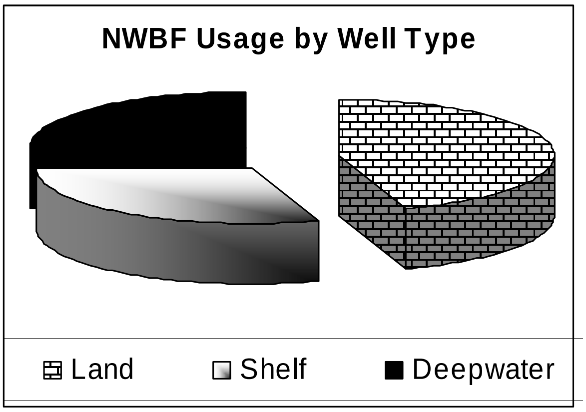


Figure 9 – Clean drilling and hole-opening BHAs as seen on the first field trial.



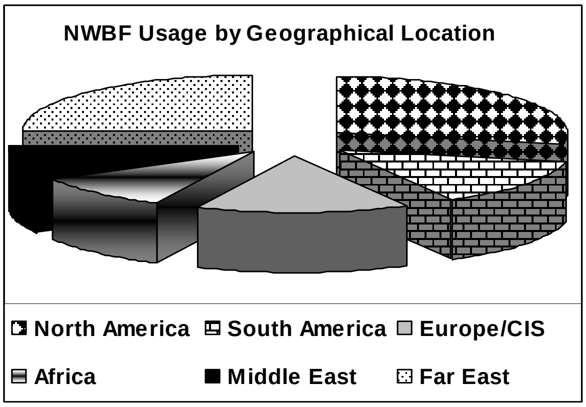
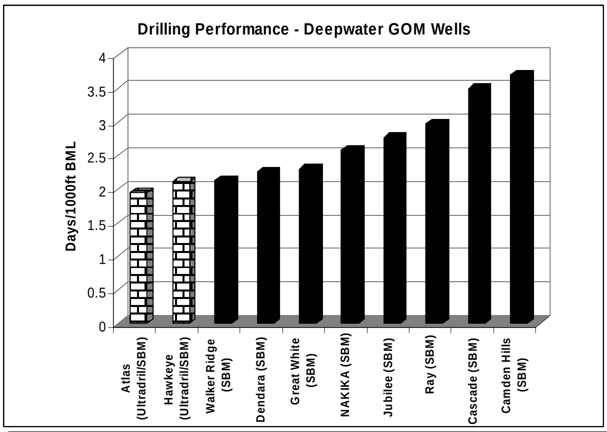


Figure 10 – Breakdown of field use of NWBF by type of well drilled.

Figure 11 – Breakdown of field use of NWBF by geographical location of well drilled.



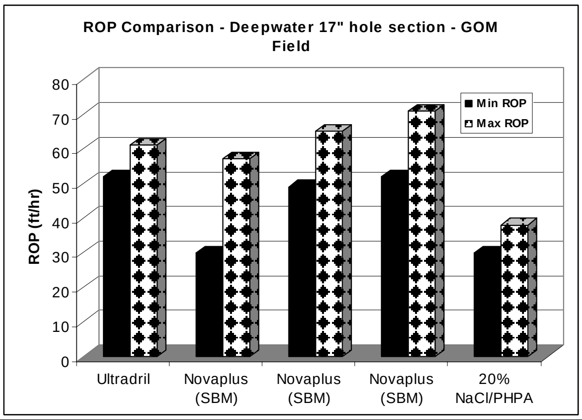


Figure 12 – Drilling performance comparison for GOM deepwater fields.

Figure 13 – Drilling rate comparison for offset wells on deepwater GOM development.

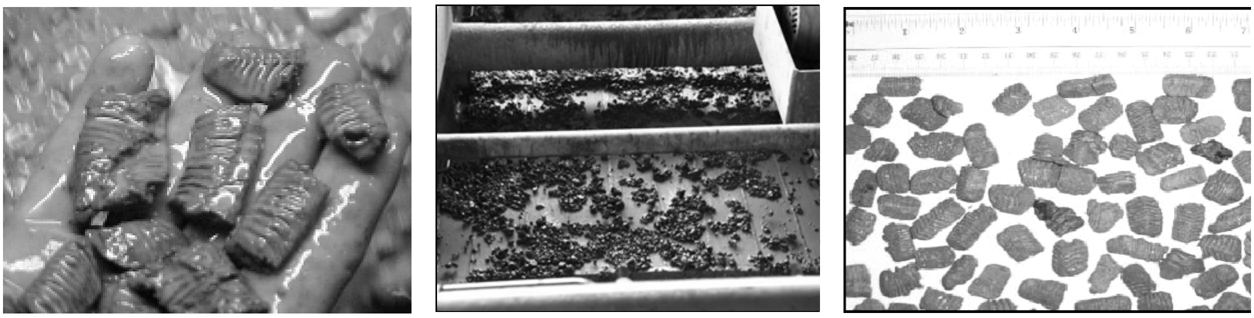


Figure 14 – Cuttings condition typified by use of NWBF (coupled with PDC bits) through reactive shales.