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Novel Inhibitor Chemistry Stabilizes Shales

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Abstract

Historically, while water-based drilling fluids intrinsically offer environmental advantages over their invert emulsion counterparts, the performance deficiencies of conventional aqueous systems have restricted their application in more technically demanding applications. This shortcoming is particularly evident when encountering complicated and highly reactive shale formations, where ensuing low rates of penetration and the risk of serious hole problems can jeopardize the economics of a drilling program.

This paper describes the development and application of a uniquely engineered water-based drilling fluid that demonstrates enhanced shale stabilization properties across an extensive variety of shale types, thus allowing water-based fluids to be used in applications previously reserved for invert emulsion systems. The drilling fluid is composed primarily of a novel chemistry shale stabilizer that minimizes fracturing in unstable shales and a novel claystone encapsulator to maintain cuttings integrity. The novel drilling fluid allows tolerance to high levels of contamination and a flexible formulation approach to optimize both drilling performance and economics.

The authors describe the development of the drilling fluid and demonstrate its unique properties, presenting unique laboratory test data and initial data from the first field wells using the new system.

Introduction

Invert emulsion drilling fluids (IEM), have traditionally been the fluids of choice when drilling demanding wells. Such wells require a highly inhibitive fluid to minimize interactions between the fluid and water-sensitive formations (mainly claystones and shales), ensure high rates of penetration (ROP), coupled with good lubricity and low potential for stuck pipe. The development of a water-based drilling fluid (WBF) which could exhibit similar drilling characteristics to an invert emulsion drilling fluid has been an ongoing endeavor of the drilling fluids industry for some time. A number of fluids research and development projects have reached fruition over the last few years and these water-based fluids have been applied in the field on wells where traditionally IEM would have been used. The decision to utilize such water-based fluids has generally been taken when risks associated with the use of IEM such as poor logistics, high levels of lost circulation, environmental compliance concerns and economics are deemed to be unacceptable. Even allowing for the successes of a number of these fluids, invert emulsion drilling fluids are still universally recognized as being the most efficient drilling fluids. This is primarily due to the absence of contact between the drilled formations and water, and due to the inherent lubricity characteristics of these fluids.

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

- High levels of wellbore stability
- High levels of contamination tolerance
- High rates of penetration
- Low coefficient of friction
- Thin, lubricated filter cake
- Low dilution rates and ease of engineering
- High levels of re-usability

The disadvantages of invert emulsion drilling fluids have also been well documented and can be summarized as:

- High unit cost of fluid
- High cost of environmental compliance
- High viscosity variation with temperature
- Potential elastomer compatibility issues
- Logistical requirements for bulk fluid transfers

With the long-term usage of IEM, many of these disadvantages have been successfully overcome by improvements and changes in engineering practices; however increasing concerns over the long-term environmental effects of discharging cuttings contaminated with invert emulsion fluids have increased the demand for a true water-based alternative.

Several water-based drilling fluid systems have been developed over the past ten years with the goal of approaching the drilling performance of an IEM.[1-9] A few of the more successful were:

- Potassium/PHPA fluids
- Salt/Glycol fluids
- Cationic Fluids
- $CaCl_2$/Polymer fluids

- Silicate fluids
- Polyamine fluids

The approaches taken with these fluids have not, however, always been completely successful in inhibiting the hydration of highly water-sensitive clays.

In addition many of these fluids have other performance limitations, *e.g.* Potassium/PHPA 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 give a more IEM-like inhibition, 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. $CaCl_2$/polymer fluids have limitations with respect to polymeric control over fluid properties, logistics, and fluid density. Silicate fluids exhibit highly inhibitive properties, but have problems related to logistics, tool compatibility and flexibility in mud formulations.

Over and above these system developments, there have been a number of developments of individual products, designed to further enhance the performance characteristics of these systems. Many of these products have been designed to try to bring these fluids closer to IEM performance in a particular geographic area, combining the development with a detailed knowledge of area geology and requirements. Custom-designed lubricants and lubricant blends, specific surfactants for ROP enhancement, alternate shale encapsulators, and more efficient filtration-control polymers are some examples.

These developments have all resulted in various WBF's which are relatively finely tuned to perform in certain areas while drilling through specific shale types. The recently developed polyamine fluids have certainly come closest to the overall performance of an IEM with their custom-designed triple inhibition mechanism, and anti-accretion performance. It was with these fluids in mind, and with a knowledge of the small failings in the polyamine fluid performance, that the development of a new high-performance water-based drilling fluid was approached.

Research and Development

A research and development commitment was taken to look into the potential for improving upon existing polyamine-based (and other) high-performance water-based drilling fluid (HPWBM) technologies. Given the goals of the development project – to find a WBM that would give similar performance characteristics to that of an IEM – it was believed that development of individual products, which could enhance existing systems, would be insufficient to achieve the goal. With this in mind, a complete systems approach was taken.

Learning from previously developed HPWBM it was deemed critical that throughout the development, focus should be maintained on the entire performance spectrum of an IEM, and not limited to only one aspect of IEM performance. The following were determined to be the key criteria:

- Highly inhibitive across a wide range of shale types
- Significant reduction in clay dispersion and hydration compared to existing state-of–the-art inhibitive systems
- Lower risk of accretion and cuttings agglomeration related problems
- Environmentally acceptable
- Highly flexible in formulation – easily controllable filtration and rheology profiles, and usable with various base brines
- Highly solids tolerant

The test matrix involved testing in four different base fluids (freshwater, seawater, 10% KCl, and 20% NaCl). Testing was conducted on four differing shale substrates (from highly swelling to highly dispersive), and used a variety of inhibition test methods (shale dispersion, bentonite tolerance, shale swelling, shale hardness, shale accretion and unconfined shale fracture development) which are briefly described later. In addition to the above, the formulated fluids were also subject to fluids performance testing (lubricity, filtration, rheology, contamination tolerance, thermal stability etc.) to evaluate their overall performance. The test results achieved were compared to three baselines of a mineral oil-based fluid, a KCl/Glycol water-based fluid, and a polyamine high-performance, water-based fluid. Generalized formulations for the novel HPWBM, and formulations for the three baseline fluids are shown in **Tables 1a-d.**

The final result of this research and development project was a new water-based drilling fluid which exhibited laboratory performance characteristics which were in the realm of those achieved by invert emulsion fluids, far exceeded those exhibited by other water-based fluids, and were superior to those exhibited by the polyamine high-performance WBM. This fluid was then taken to the field test stage.

Shale Inhibition

As discussed above, several test methods were utilized to evaluate the inhibitive properties of both the shale inhibitors and the formulated new HPWBM. The shale substrates used were of both outcrop shales, which spanned the range from highly swelling (Wyoming Bentonite) to highly dispersive (Arne Clay), and included two mixed shales (Foss Eikeland and Oxford Clay). XRD mineralogy for these shales is shown in **Figure 1**, with CEC and clay breakdown in **Figure 2**. In addition problematic field shales were evaluated – cores of "Nahr Umhr" shale from the Middle East and large cavings from the “Los Monos” shales of southern Latin America were utilized for the unconfined shale fracture testing and inhibition testing. The inhibition test methods used are described in detail in Appendix A,

The HPWBM shale inhibitor was tested in these various tests and the performance compared with various competitive products. **Figure 3** shows the Bentonite shale inhibition test results comparing the yield point of three shale inhibitors and seawater. **Figure 4** shows the comparative shale inhibition results using the hot roll dispersion test method. **Figure 5** shows the comparative shale inhibition results using the Slake durability test method. Results of the cuttings hardness test on both Oxford Clay (**Figure 6a**) and Foss Eikeland Clay (**Figure 6b**) are shown. **Figure 7a and 7b** show the accretion test results. **Figure 8a** shows the linear swelling tests results and **Figure 8b** the steady linear swelling rate on Nahr Umhr Shale. **Figure 9a** and **Figure 9b** are unconfined shale fracture testing results from Nahr Umhr Shale. **Figure 10** shows the comparative lubricity measured using the Fann metal/metal lubricity tester**.** **Figure 11** shows the comparative effect of solids loading using OCMA bentonite as the contaminant.

New Fluid Formulation

From the final results of our extensive matrix of testing, a final novel HPWBM emerged consisting of four synergistic basic products; a brief description of these key components follows. Typical formulations for this fluid for a Gulf of Mexico well and a Western US land well are given in **Table *2***.

Hydration Suppressant

This is a multi-functional complex substituted cyclic hydrocarbon blended material, which is partially water-soluble. The compound is compatible with other common drilling fluid additives used in WBM, exhibits a pH buffering effect, and has no hydrolyzable functionality. The unique molecular structural blend of these components allows adsorption onto the shale surface resulting in a solubility change which blocks access to the shale by water. In addition, parts of the molecular blend can fit between clay platelets, tending to collapse the clays hydrated structure and greatly reduce the clay’s tendency to imbibe water from an aqueous environment. The material requires minimal salinity for maximum functionality and is equally stable in high salinity and hardness environments.

Dispersion Suppressant

This is a novel, low-molecular-weight, fully water-soluble copolymer and exhibits good biodegradability and low marine toxicity. The polymeric additive is designed to have a molecular weight and charge density that promotes superior inhibition by limiting water penetration into the clays and binding clay platelets together via the end charges. The molecular weight and charge of the polymer allows rheological flexibility over a wide range of fluid densities while tolerating high salinity and hardness. The compound has the ability to control both dispersion and accretion of water-sensitive clays.

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 both salinity and hardness. The high LSRV and efficient carrying capacity of the polymer optimizes rheological control to improve fluid performance in extended reach and deepwater environments.

Filtration Controller

A low viscosity, cellulosic 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).

Accretion Suppressant

This component is a unique blend of surfactants and lubricants which is designed to coat drill cuttings and metal surfaces to reduce the accretion tendency hydrated cuttings on the surface of metals and 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 accretion suppressant aids in preventing any buildup of drill solids below the bit, allowing the cutters good contact with new formation for improved rate-of-penetration. The component also lowers torque and drag by reducing the coefficient of friction.

The design, selection, and concentrations of each of the above components were fine-tuned to optimize upon the synergies of the compounds and to improve the flexibility of the overall system design. The net result being a high-performance, water-based fluid which will perform in a wide variety of base fluids and over a wide density and temperature range.

New Fluid Performance

From these results of laboratory testing (Figures 3-11), it can be seen that the new HPWBM significantly outperforms the KCl/Glycol fluid with respect to shale inhibition, and is a close equivalent to the KCl/Silicate, polyamine and IEM fluids.

It is also evident that the new HPWBM significantly outperformed the NaCl/PHPA and was better than the KCl/Silicate and polyamine water based fluids in overall performance, being closely compared directly with the performance of the OBM.

The flexibility in the fluid is also demonstrated in **Figure 12** where the inhibition characteristics of the new

HPWBM are measured using different base fluid of Freshwater, Seawater, 10%KCl brine, and 20% NaCl brine using 4 types of clay.

Field Testing

The true test of the success of any fluid development is an evaluation of the fluid performance over a range of operating parameters and areas during drilling. To date the new HPWBM has been utilized in the western Rocky Mountain area of the United States for drilling two wells through sections primarily composed of reactive shales. The fluid has performed well over the first two wells. Levels of wellbore stability have been excellent in areas where previous conventional WBF's have failed, and drilling rates have been above average and maintained with no wellbore instability issues resulting in some of the fastest and most economical wells drilled in this area (**Figure 13)**.

From an engineering standpoint, the new HPWBM has proven to be easily and rapidly mixed at the rigsite. The polymers chosen for the system yield rapidly under low shear, minimizing any tendency for shaker-screen blinding with the new fluid. Initial evaluations of inhibitor depletion, indicate lower depletion rates than those experienced by previously used WBF's, making the fluid properties easier to engineer and maintain. Field tests developed to allow the engineer to directly determine the concentration of both hydration suppressant and encapsulator have proven accurate and beneficial in optimizing engineering of the system. The high levels of inhibition have also translated into low dilution rates for the fluid, as cuttings from even the most reactive of claystones are readily removed from the fluid during the initial pass over the shale shaker screens (**Figure 14**).

A more detailed performance analysis of the fluid in the field will be the subject of a later paper as further field trials are completed.

Conclusions

A new, high-performance, inhibitive, water-base fluid system has been developed. Extensive laboratory results show that the system significantly reduces clay dispersion, hydration, and accretion, outperforming previous highly inhibitive WBF and reaching into the realm of invert emulsion fluids. The inhibitive components of the new HPWBM have been specifically designed to impart maximum chemical stabilization to both swelling and dispersive clay formations as well as older, more easily fractured, shales.

The new HPWBM has been designed with a total-system approach. Products have been specifically chosen to satisfy the requirements of both a highly inhibitive fluid and a high-performance fluid. The new HPWBM is extremely flexible within its design, being successfully formulated with a variety of base brines from freshwater to saturated NaCl, at densities ranging from 8.6 to 16 lb/gal and at temperatures to 275°F.

Initial field trials have proven that the new HPWBM can be easily prepared, has good screenability and exhibits outstanding drilling performance. The use of this fluid to drill highly reactive shales confirmed the laboratory predictions for cuttings integrity and wellbore stability. The overall performance and user-friendliness are two attributes that bring this drilling fluid close to the goal of matching an OBM.

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Appendix A

Bentonite Inhibition

The ability of a chemical to prevent bentonite from yielding while maintaining a low rheological profile is the simplest of tests for the evaluation of shale inhibitors. This inhibition evaluation procedure was designed to simulate the incorporation of high-yield clays into a drilling fluid, as occurs while drilling water-sensitive shales in the field.

The test method determines the maximum amount of API bentonite that can be inhibited by a single (8.0 lb/bbl) treatment of shale inhibitor over a period of several days. 350 mL of fresh water containing 8.0 lb/bbl of shale inhibitor is treated with 10-lb/bbl bentonite every day. After heat aging at 150°F for 16 hours, the rheological properties are measured before adding another portion of bentonite. These daily additions of bentonite and aging are continued until the sample becomes too viscous to measure.

Hot Rolling Dispersion Test

This test involves exposing a weighed quantity of sized shale pieces to a formulated fluid in a conventional roller oven cell. The test provides a long-term exposure of the shale to the fluid under mild agitation conditions. Under such conditions, dispersion of the shale into the fluid will occur depending on the tendency of the shale to disperse and the inhibitive properties of the fluid. The rheological characteristics of the fluid can also influence the test results by altering the amount of agitation in the rolling phase. For these tests the rheological parameters of each fluid tested are designed to be similar to minimize any inaccuracies in cross-fluid comparisons.

The fluid and shale are rolled together in a roller oven for 16 hours at 150°F. Following cooling to room temperature, the fluid is poured out over a 1-mm sieve, and the shale pieces remaining are recovered, washed, weighed, dried overnight at 210°F and re-weighed. The moisture content of the shale and the percentage recovery of the shale are determined.

Slake Durability Test

The Slake Durability Test is similar in design to the hot rolling dispersion test, but provides a harsher, more abrasive environment. This test is designed to simulate exposure of cuttings to the fluid in a well annulus, and subsequent removal at the shaker screens.

The evaluation consists of placing a weighed quantity of sized shale pieces in a round cage semi-immersed in the test fluid. The cage with cuttings is rotated through the fluid for a 4-hour period at room temperature. During rolling, any sensitive shale will tend to hydrate, break up, and disperse, passing through the cage screen. The shale pieces remaining in the cage after the test period are recovered, washed, weighed, dried overnight at 210°F and re-weighed. The moisture content of the shale and the percentage recovery of the shale are determined. For some of the less water-sensitive clays, the testing period was extended to eight hours.

Bulk Hardness Test

This test is designed to give an assessment of the hardness of shale following exposure to a test fluid. The hardness of the shale can be related to the inhibitive properties of the fluid being evaluated. Shale which exhibits a tendency to adsorb liquid from a test fluid will become softer, and this can translate into a weaker wellbore during drilling and/or increased tendency for drilled shale to compact/accrete.

In this test, sized shale pieces are hot rolled in the test fluid for 16 hours at 150°F. After hot rolling, the shale pieces are recovered on a 1-mm sieve, washed with brine to remove excess fluid and then placed into the bulk hardness tester (**Figure A**). The shale is extruded through a perforated plate using a torque wrench which permits measuring the maximum torque required for each turn in compression. Depending upon the condition of the cuttings, the torque may reach a plateau region or may continue to rise during the extrusion. Harder, more competent shale pieces will give higher torque readings.

Accretion Test

One of the primary failings of many inhibitive WBM has been a tendency for accretion (or bit balling), where partially hydrated shales are conglomerate onto the drilling assembly, resulting in poor drilling performance. This is a complex process, being very dependent on shale type, drilling parameters, and fluid type and properties.

The simple laboratory accretion test consists of placing a steel bar in a hot rolling cell containing the test fluid. Sized shale pieces are placed evenly around the centralized accretion bar. The cell is closed and rolled at room temperature for a specific period of time. After rolling, the bar is removed and a photo is taken for visual documentation. The percent weight of the cuttings adhering to the bar is determined after removing, washing the cuttings, and drying the sample.

Linear Swelling Test

The tendency for a shale to adsorb fluid from a water-based drilling fluid can lead to a swelling of the shales which can translate to decreased wellbore size and wellbore instability issues as well as swollen cuttings which tend to be more adhesive in nature and can, in turn, lead to bit balling and poor rate of penetration.

The amount of fluid adsorbed by shale over time can be determined in the laboratory using the linear swellmeter. In this test, the shale to be tested is ground into a powder, then compressed into a sized shale pellet which is placed between a metal plate and a linear transducer. The pellet is immersed in the test fluid and the change in length of the pellet is measured over time by the transducer. Both the total change in length over a given time period and the constant rate of change can be determined.

Unconfined Shale Fracture Development Test

The tendency for consolidated, older, shales to adsorb fluid from water-based drilling fluids can lead to both an extension and widening of existing natural fractures within the shale and to the development of new and possibly interlinked fractures within the shale. This can translate to spalling shale and chemically induced wellbore instability.

The effect of a fluid on consolidated shales can be qualitatively and quantitatively determined using the unconfined shale fracture development test. In this test an approximately 1-inch square block of shale (preferably from a core, although large cavings can also be used) is immersed into the test fluid after a microscopic thin section has been cut from the block. Time-lapse photography is then used to qualitatively evaluate the effect of the fluid on the shale over a 24-hour time period. Following exposure, a further microscopic thin section is taken from the block and fracture number and size are directly measured under the microscope. The thin sections also allow a qualitative measure of fracture interconnectivity and fracture mineralogy to be determined.

Table 1a Typical Composition of New HPWBM	
Seawater (mL)	330.0
Filtration controller (g)	3.0
Polymer viscosifier (g)	1.0
Dispersion suppressant (g)	3.0
Hydration suppressant (mL)	8.0
Accretion suppressant (mL)	7.0

Table 1b Typical Composition of Polyamine Mud	
Seawater (mL)	327.0
Polyamine inhibitor (mL)	10.5
Polymeric encapsulator (g)	2.5
Anticrete (mL)	7.0
Fluid loss agent (g)	3.0
Polymer viscosifier (g)	1.0

Table 1c Typical Composition of KCl/Glycol Mud	
Seawater (mL)	323.0
KCl (g)	30.0
Soda ash (g)	0.5
Polyglycol (mL)	10.5
Fluid loss agent (g)	3.0
PHPA (g)	1.0
Polymer viscosifier (g)	0.75

Table 1d Typical Composition of Oil Based Mud	
Mineral oil (mL)	255.0
Primary emulsifier (mL)	9.0
Secondary emulsifier (mL)	4.0
Lime (g)	7.5
Fluid loss agent (g)	2.0
Organoclay viscosifier (g)	6.0
25% $CaCl_2$ Brine (mL)	75.0

Table 2a Typical GOM Composition of New HPWBM	
Seawater (bbl)	0.92
Hydration suppressant (lb_m/bbl)	8.0
Dispersion suppressant (lb_m/bbl)	2.5
Fluid-loss reducer (lb_m/bbl)	2.5
Viscosifier (lb_m/bbl)	1.25
Accretion suppressant (lb_m/bbl)	7.0
Barite (lb_m/bbl)	43.5

Table 2b Typical Land Composition of New HPWBM	
Freshwater (bbl)	0.925
Na_2SO_4 (lb_m/bbl)	2.0
Hydration suppressant (lb_m/bbl)	8.0
Dispersion suppressant (lb_m/bbl)	3.0
Fluid-loss reducer (lb_m/bbl)	3.0
Viscosifier (lb_m/bbl)	1.0
Barite (lb_m/bbl)	50.0

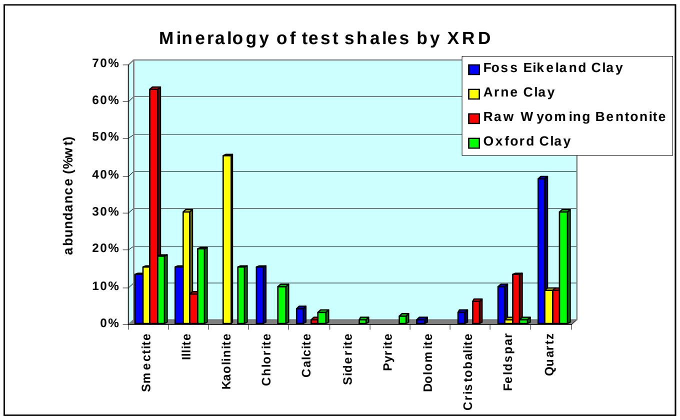

Figure 1 – Mineralogy by semi-quantatative XRD of the four shale substrates used in the new HPWBM development.

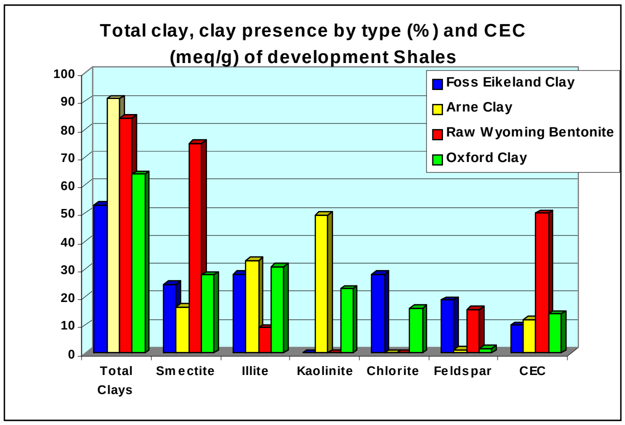

Figure 2 – Clay content, clay type and reactivity of the four shale substrates used in laboratory development.

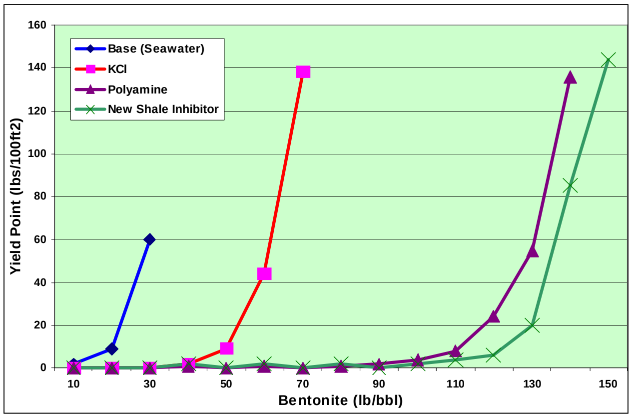

Figure 3 – Bentonite inhibition test comparing the yield point of three shale inhibitors and the base fluid.

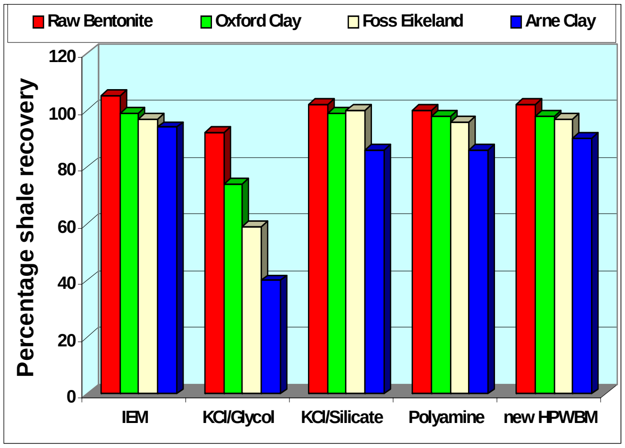

Figure 4 – Results from hot roll dispersion testing on new HPWBM.

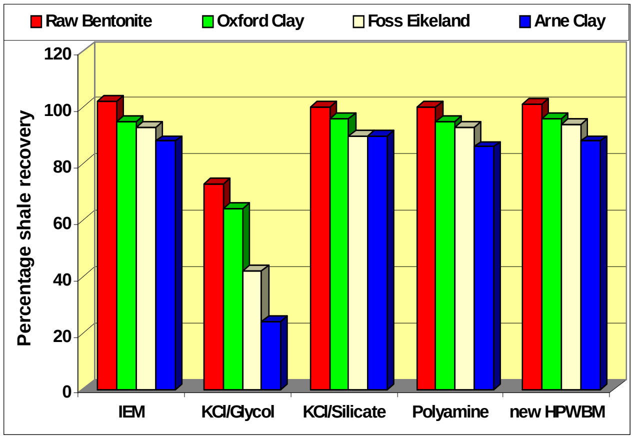

Figure 5 – Results from Slake durability testing on new HPWBM.

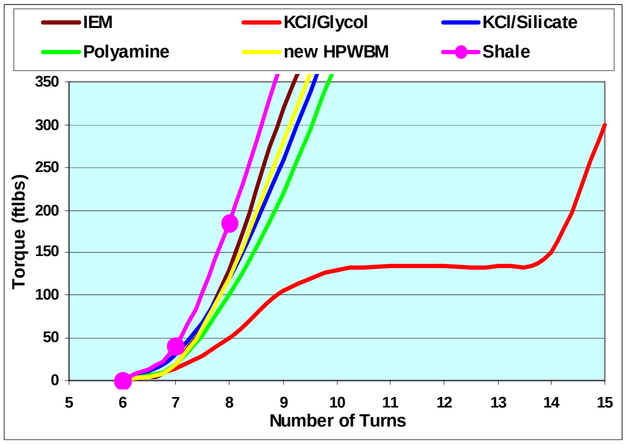

Figure 6a – Results from shale hardness testing on new HPWBM (Oxford Clay).

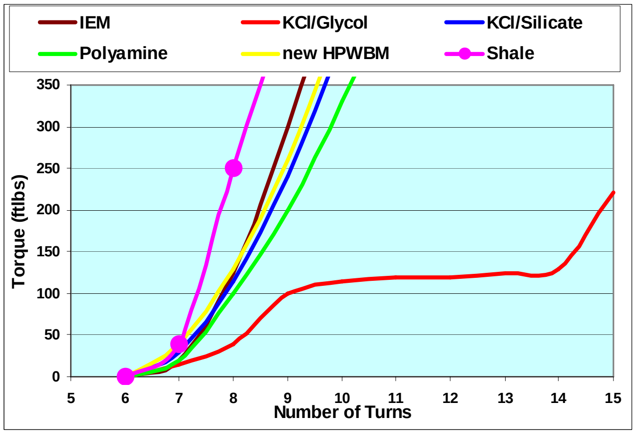

Figure 6b – Results from shale hardness testing on new HPWBM (Foss Eikeland Clay).

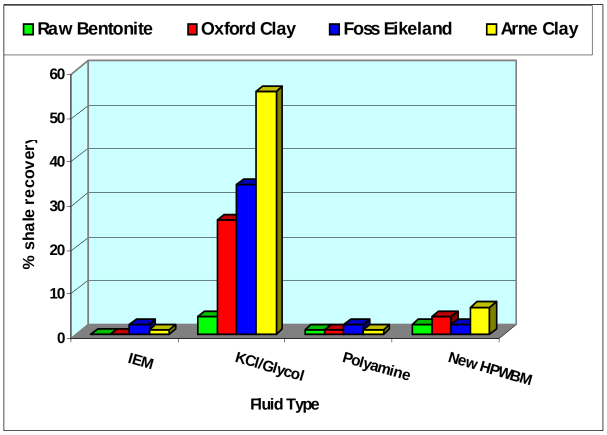

Figure 7a – Accretion test results from the new HPWBM.

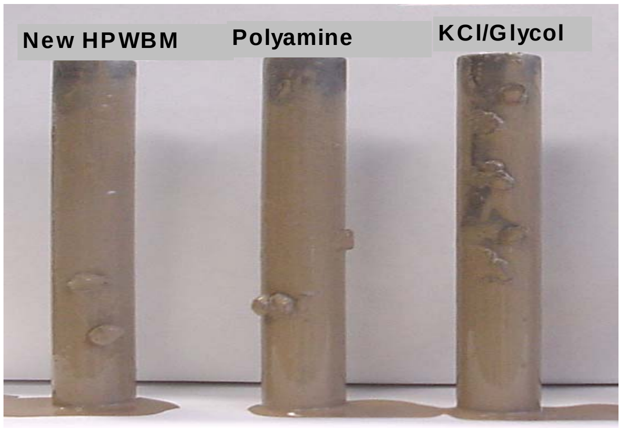

Figure 7b – Accretion test pictures from the new HPWBM.

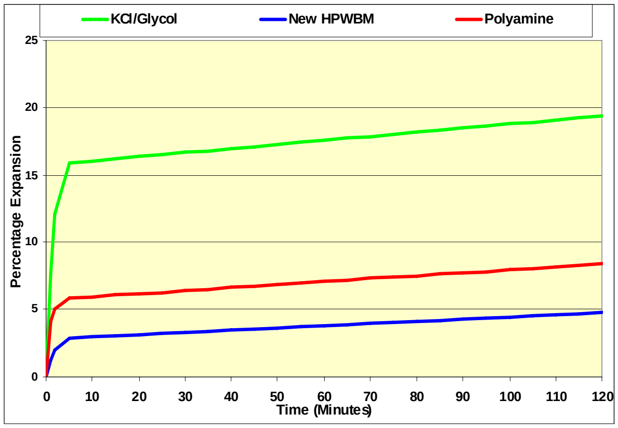

Figure 8a – Linear swelling test results from the new HPWBM (Nahr Umhr Shale).

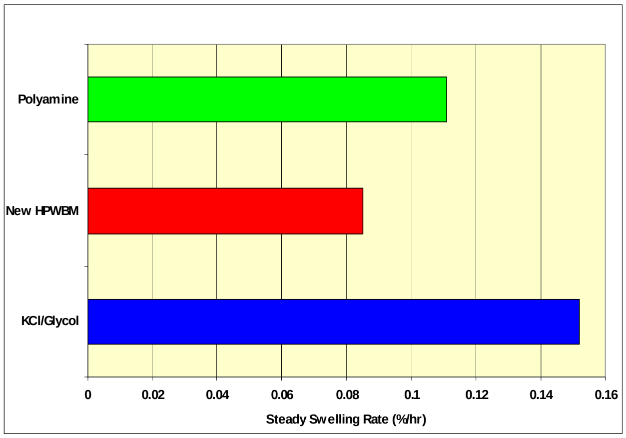

Figure 8b – Steady Linear swelling test rates from the new HPWBM (Nahr Umhr Shale).

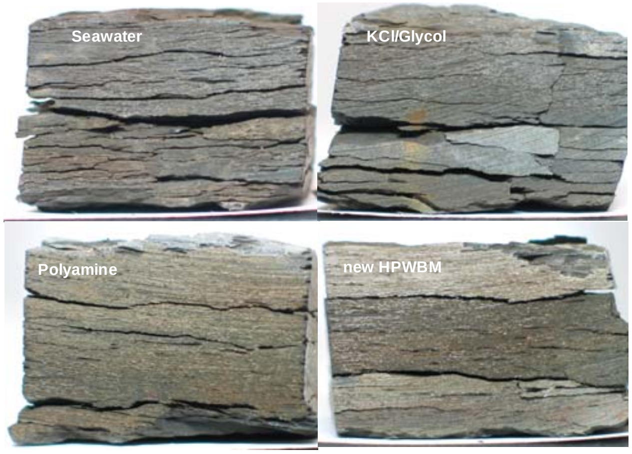

Figure 9a – Results from unconfined shale fracture testing on the new HPWBM (Nahr Umhr shale).

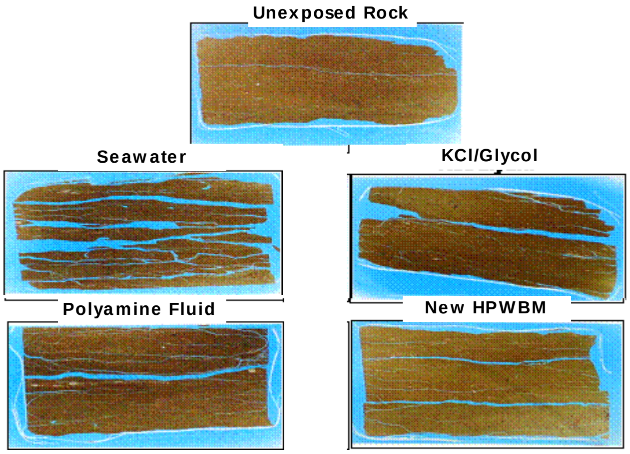

Figure 9b – Results from unconfined shale fracture testing on the new HPWBM (Nahr Umhr shale).

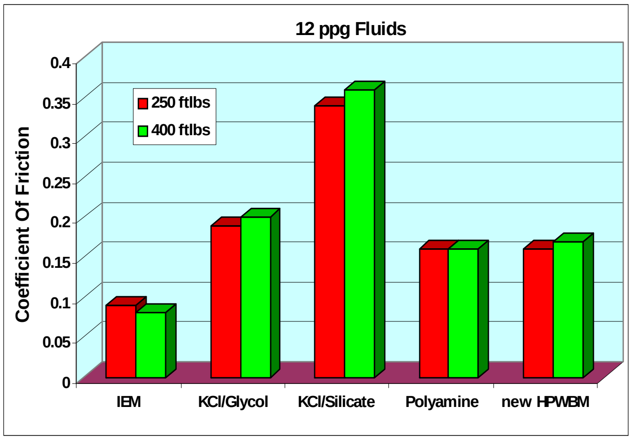

Figure 10 – Results from comparative metal/metal lubricity tests on new HPWBM.

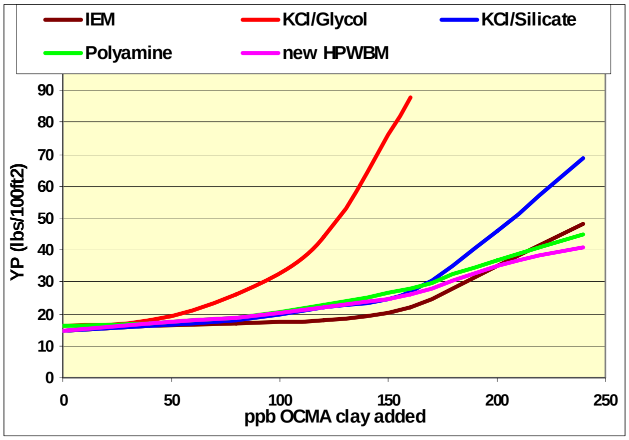

Figure 11 – Results from solids tolerance testing on new HPWBM.

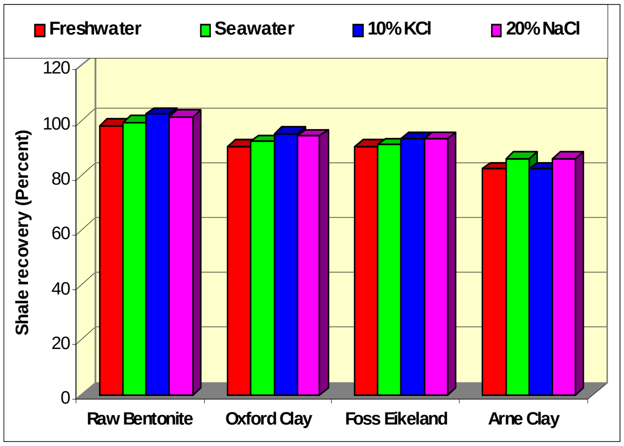

Figure 12 – Inhibition results from new HPWBM formulated in differing base fluids.

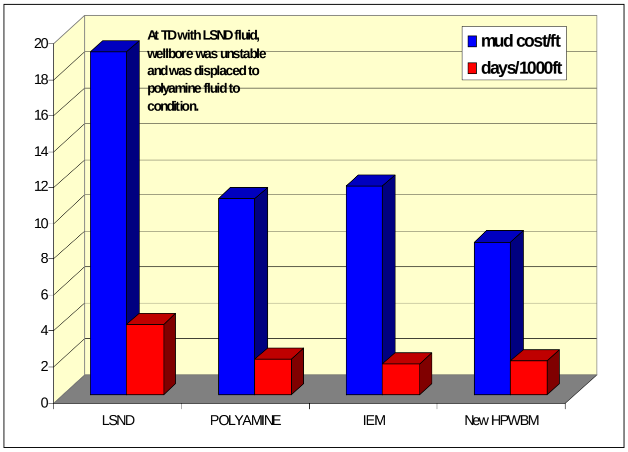

Figure 13 – Drilling and economic performance comparing initial field trial of HPWBM to offset data.

Figure 14 – Images from initial field trial showing high levels of shale inhibition and cuttings quality.

Fig A – Bulk hardness tester.