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Designing for the Future – A Review of the Design, Development and Testing of a Novel, Inhibitive Water-Based Drilling Fluid

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Abstract

The search for a highly inhibitive water-based drilling fluids system, which would perform like an oil-based drilling fluid, has been a continuous endeavor in the drilling-fluid industry. Many approaches have been tried with only limited success. We have systematically designed and developed a new highly inhibitive water-based drilling fluid, which has performance characteristics of an oil-based mud for inhibiting and drilling highly reactive water-sensitive shales. The newly developed high performance water-based drilling fluid offers superior shale stability, excellent lubricity, high ROP, and less risk of stuck pipe.

The new system consists of four basic components: a shale inhibitor, encapsulator, anti-accretion/lubricant agent, and fluid-loss-control additive. The system components are uniquely designed for high performance. Unlike other high performance water-based drilling fluids, this newly designed drilling fluid is versatile and can be formulated with fresh water, seawater or saltwater providing a flexibility for a variety of drilling fluid formulations and applications.

This paper will discuss the systematic design criteria and development of the system. Insight into the unique chemistry and molecular modeling of the shale inhibitor will be highlighted. The paper will compare the performance of previous high performance water-based muds with the newly developed high performance water-based drilling fluid. Formulations and applications of the drilling fluid will be presented.

Introduction

Invert emulsion drilling fluids, more commonly referred to as "oil-based muds" (OBM), 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), a fluid which is capable of insuring high rates of penetration (ROP), coupled with good lubricity and low potential for stuck pipe. The development of a water-based drilling fluid (WBM) 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 OBM would have been used. The application of such water-based fluids has generally been carried out when concerns are associated with the use of invert emulsion fluids such as poor logistics, high risk of lost circulation, and environmental compliance concerns, and economics. Even allowing for the successes of a number of these fluids, invert emulsion drilling fluids are still universally recognized as being the most efficient fluids to drill with. This is primarily 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 documented many times: - the main points can be summarized as:

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

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

- High unit cost of base fluid(s)
- 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 OBM, some of these disadvantages have been successfully dealt with, 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 OBM.[1-10] A few of the more successful were as follows: -

- Potassium/PHPA fluids
- Salt/glycol fluids
- Cationic fluids
- $CaCl_2$/polymer fluids
- Silicate 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. For example, potassium/polymer fluids cannot reach the inhibition levels of an OBM, thus in highly water-sensitive shales, bit balling, accretion, wellbore instability and poor ROP can result. Cationic polymer systems give a more OBM-like inhibition, however, the cost of running the system, toxicity of cationic polymers, and their incompatibility with other anionic drilling fluid additives have resulted in only limited success. CaCl2/polymer fluids have limitations with respect to polymeric control over fluid properties, logistics, and fluid density. Silicate fluids exhibit highly inhibitive properties, however, they 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 OBM performance in a particular geographic area, with detailed knowledge of area geology and requirements. Custom-designed lubricants and lubricant blends, specific surfactants for ROP enhancement, and more efficient filtration-control polymers are some examples.

These developments have all resulted in various WBM's which are relatively finely tuned to perform in certain areas while drilling through specific shale types. The newly developed high-performance water-base mud (HPWBM) addresses these issues.

Research and Development

A research and development commitment was taken to look into the potential for radically improving upon existing WBM technologies. Given the goals of the development project – to find a WBM that would give similar performance characteristics to that of an OBM – 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 the shortcomings of previously developed WBM, it was deemed critical that throughout the development, focus was maintained on the entire performance spectrum of an OBM, and did not focus in on only one aspect of OBM performance. The following were determined to be the key criteria.

- Highly inhibitive system
- 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
- Highly solids tolerant

To this end, a development project matrix was set up involving three technical centers in different geographical locations. Test procedures, samples, and test substrates were shared between these centers for uniformity in testing, as well as quality control checks on the test results. The selection of the most appropriate chemistry groups was chosen from previous research work involving molecular modeling of shale inhibition, and from both field and laboratory testing experiences. The test matrix involved the combination of 9 novel shale inhibition chemistries, coupled with testing in three different base fluids (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) 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 – a mineral oil-based drilling fluid, NaCl/PHPA, and KCl/Silicate water-based drilling fluids. Generalized formulations for the HPWBM, and formulations for the three baseline fluids are shown in **Tables 1a-d.**

As the final selection of the materials for this new HPWBM became clearer, more complex testing was conducted. Molecular modeling of inhibitor chemical behavior in shale substrates, shale membrane testing, large-scale accretion testing, and ROP testing were performed to confirm the research project findings and to develop a better understanding of the likely fluid performance.

The final result of this broad 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, and far exceeded those exhibited by other water-based fluids. 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 the shale inhibitors and formulated HPWBM. The shale substrates used were of 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 **Fig. 1**, with CEC and clay breakdown in **Fig. 2**. The inhibition methods used are described below.

Bentonite Inhibition

The ability of a chemical to prevent bentonite from yielding and to maintain 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 was treated with 10-lb/bbl bentonite every day. After heat aging at 150°F for 16 hours, the rheological properties were measured before adding another portion of bentonite. These daily additions of bentonite and aging were continued until the sample became too viscous to measure.

The performance of the selected shale inhibitor in the HPWBM, compared with potassium chloride and a commercial quaternary amine shale inhibitor, is shown in **Fig. 3**.

Hot Roll/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.

The test results obtained from some of the potential candidate chemistries for the HPWBM are shown in **Fig. 4,** being compared to OBM and a 20% NaCl/PHPA fluid.

Slake Durability Test

This test is similar in design to the hot rolling dispersion test, but provides a harsher, more abrasive environment. **Fig. 5** shows the Slake durability tester. 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 for a 4-hr 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° and re-weighed. The moisture content of the shale and the percentage recovery of the shale are determined.

The test results obtained from some of the potential candidate chemistries for the HPWBM are shown in **Fig. 6**, being compared to OBM and a 20% NaCl/PHPA fluid.

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 that exhibits a tendency to imbibe 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 and then placed into the bulk hardness tester (**Fig. 7**). Using a torque wrench, the shale is extruded through a perforated plate, 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.

The test results obtained from some of the potential candidate chemistries for the HPWBM are shown in **Fig. 8**, being compared to OBM and a 20% NaCl/PHPA fluid.

Accretion Test

One of the primary failings of previous highly inhibitive WBM has been a tendency for accretion (or bit balling), where partially hydrated shales are compressed 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.

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. The percent weight of the cuttings adhering to the bar is determined after removing, washing the cuttings, and drying the sample.

The test results obtained from some of the potential candidate chemistries for the HPWBM are shown in **Figs. 9a-b** being compared to a CaCl2/polymer and a 20% NaCl/PHPA fluid.

New Fluid Formulation

From the final results of this extensive matrix of testing, three newly developed chemistries were chosen as components of the new drilling fluid developed. The final HPWBM consists of five synergistic products; a brief description of these key components follows. A typical formulation for this fluid for a Gulf of Mexico well is given in **Table 2**.

Hydration Suppressant

This is a multi-functional complex amine-based molecule, which is fully water-soluble and exhibits low marine toxicity. 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 structure of this compound fits perfectly 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

This is a novel, 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 allow superior inhibition by limiting water penetration into the clays and binding clay platelets together via the end charges. The molecular weight of the polymer allows rheological flexibility over a wide range of fluid densities and 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.

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 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 high solids-laden (high mud weight) fluids. The component exhibits low marine toxicity. The accretion suppressant agent aids in preventing any buildup of drill solids on the drillstring and below the bit, allowing the cutters good contact with the new formation for improved rate-of-penetration. The component also lowers torque and drag by reducing the coefficient of friction.

Rheology Controller

Xanthan gum was chosen as the optimal 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 optimal rheological control at temperatures up to 300°F. The high low-shear-rate viscosity and efficient carrying capacity of the polymer allows for optimized rheological control to improve fluid performance in extended reach and deepwater environments.

Filtration Controller

An ultra-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).

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 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 criterias required in most areas of the world.

New Fluid Performance

Extracts from the laboratory test results obtained from the new HPWBM are shown in **Figs. 10-16**.

Fig. 10 shows the comparative shale inhibition results using the hot roll dispersion test method.

Fig. 11 shows the comparative shale inhibition results using the Slake durability test method.

Fig. 12 shows comparative shale inhibition using the cuttings hardness test method.

Fig. 13 shows the comparative performance of the fluids with respect to cuttings accretion using the rolling bar test method.

From the above, it can be seen that the HPWBM significantly outperforms the NaCl/PHPA fluid with respect to shale inhibition, and is a close equivalent to the KCl/Silicate and OBM fluids.

Fig. 14 shows the comparative lubricity measured using the Fann metal/metal lubricity test at two different loadings.

Fig. 15 shows the comparative effect of solids loading using OCMA bentonite as the contaminant.

Fig. 16 shows the rheological parameters of the fluid over a wide temperature range.

From these tests, it can be seen that the HPWBM significantly outperformed both the NaCl/PHPA and the

KCl/Silicate water-based fluids, and could be compared directly with the performance of the OBM. The stability of the rheology with temperature will allow the fluid to be also suitable for drilling in deepwater environments.

The flexibility in the fluid is also demonstrated in **Fig. 17** where the inhibition characteristics of the HPWBM are measured using different base fluids of seawater, 10% KCl brine, and 20% NaCl brine. In each case the fluids had 3% vol hydration suppressant, 2-lb/bbl dispersion suppressant, and 1.5% vol accretion suppressant.

Additional Test Procedures

Molecular Modeling

The newly developed hydration suppressant was theorized to function by fitting between clay platelets and binding the plates together thereby greatly diminishing the clay's tendency to imbibe water from an aqueous environment. Molecular modeling and x-ray diffraction studies of this molecules unique chemical structure were carried out using a hydration suppressant-water mixture with a model montmorillonite clay layer using a combination of Monte Carlo and molecular dynamics methods.

The studies show evidence that the newly developed molecule inhibits shale swelling by a mechanism different from the polyglycols. This mechanism involves specific binding of the amine groups of the hydration suppressant onto the shale interfaces rather than the entropically driven exclusion of water from the interlayer space as was the case for glycols. The actual mechanism involves a neutral amine molecule binding to the clay via metal cations, or an amine molecule in the protonated form binding in place of metal cations involving an ion exchange mechanism. X-ray diffraction measurements on montmorillonite samples soaked in solutions of the hydration suppressant show a decrease in layer spacing with increasing shale inhibitor concentrations. This is a reverse of the trend observed for glycols. These measurements also provided evidence that the degree of protonation of the shale inhibitor is important to the binding mechanism and that the shale inhibitor molecule is indeed present in the interlayer space. These studies were also carried out on complex amines of similar molecular structure, with varied molecular size, the optimum product being chosen for the new HPWBM. The results from interlayer spacing analysis using the hydration suppressant at various concentrations in differing salts are shown in **Fig. 18**, with representation of the binding mechanism model being shown in **Fig. 19**.

Shale Membrane Testing

Using the shale membrane tester,[11] the effects of both the hydration suppressant and the formulated HPWBM have been tested. The shale-membrane tester evaluates the effect(s) of fluid chemistry on the transmission of pore pressure through a disk of shale, under high-pressure conditions. The shale used in these analyses was Pierre 1e shale, and the results were compared against those obtained from conventional mineral oil-based drilling fluids and silicate-based drilling fluids. Exposure of the shale to the hydration suppressant in these tests generated a reduction in permeability of the shale, further supporting the molecular model theory of selective binding of the molecule in the shale interlayers and collapsing of the hydratable shale structure.

Full-Scale Accretion and ROP Testing

The newly developed HPWBM was tested on a full-scale drilling tester, where a block of shale (Pierre 1e) was drilled under controlled conditions of rotation (rpm) and weight on bit (WOB) while circulating the drilling fluid under high pressure. In addition to observing the effect(s) of the fluid on the shale while drilling, and observing the condition of the drilled "cuttings", the effect of addition of the accretion suppressant on rate of penetration (ROP) was monitored. A summary of the results from these tests is shown in **Table 3** and documented in the photographs in **Figs. 20a-c**.

A series of three tests were performed, following the modified DEA 90 protocol. The first was a baseline 12-lb/gal 20% NaCl/PHPA fluid to test the effectiveness of the accretion suppressant by itself in improving rate of penetration, and to obtain baseline drilling performance data. The addition of 3% volume of the accretion suppressant increased the average ROP by 474%.

The second run used the new HPWBM formulation at a density of 12 lb/gal, evaluating performance both with and without the accretion suppressant. At 10,000 lb WOB and 75 rpm the 3% vol of the accretion suppressant was added, increasing the ROP by 274%, with no indications of accretion or bit balling being seen. The cuttings from this run were harder and termed as crisp and similar to those from OBM. When the 1.5- to 2.0-in. cuttings were broken by hand, there was a positive snap compared to the softer more pliable cuttings produced from the PHPA mud run in Test #1. The borehole caliper measured 6.599 in. at the top and 6.602 in. at the bottom with the HPWBM. The difference in the upper and lower borehole size in the PHPA muds was 0.14 in. in Test 1.

The third run was used to test the effectiveness of the accretion suppressant in a high-density fluid, as such products are normally ineffective in high solids. In this test the HPWBM from the second run was weighed to 16.0 lb/gal and over the last 18 inches of the shale the hydration suppressant was injected at 3% vol of the circulating flow rate. The ROP increased by 45.8%.

HSE testing

All components of the new HPWBM, and the fully formulated fluid itself, were screened from both a health and safety, and an environmental hazard (HSE) standpoint. Testing protocols from the guidelines for the Gulf of Mexico, North Sea, and Canada have been followed to gain sufficient test data for the HPWBM and its components. The formulated HPWBM far exceeds the toxicity discharge requirements for the United States Gulf of Mexico, and the Microtox screening requirements for Canada land operations. Individual component testing carried out for the North Sea allows the formulated fluid to be discharged with no restrictions.

By reducing the alkalinity of the hydration suppressant during manufacture, this material was made safe to handle with normal health and safety precautions, and the buffering action of the product has minimized the amount of caustic soda at the rig site, further improving the safety aspects of using WBM.

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 HPWBM has been utilized in the Gulf of Mexico for drilling five wells, both shelf and deepwater, through sections primarily composed of highly reactive shales. A more detailed performance analysis of the fluid in the field will be the subject of a later paper. As a brief summary, the fluid has performed exceptionally well over the first five wells. Levels of wellbore stability have been excellent in areas where previous WBM's have failed, and rates of penetration have been higher than offset WBM wells, with no evidence of bit balling – a common problem in the areas where the HPWBM was tested.

From a practical standpoint, the HPWBM has proven to be easily and rapidly mixed both in shore-based fluid plants and at the rig site. 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 WBM's, making the fluid properties easier to engineer and maintain. 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 removed from the fluid during the initial pass over the shale shaker screens (**Fig. 21**). The low levels of contamination of the fluid which result from its high performance and inhibition have allowed the fluid to be recovered and used on subsequent wells, thus treating the fluid more as an OBM than a WBM.

Conclusions

A new, highly inhibitive, water-based fluid system has been developed. Extensive laboratory results show that the system significantly reduces clay dispersion, hydration, and accretion, outperforming previous highly inhibitive WBM and reaching into the realm of OBM. The inhibitive components of the HPWBM have been specifically designed to impart maximum chemical stabilization to both swelling and dispersive clay formations.

The 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. Unlike previous inhibitive water-based fluids, the HPWBM is extremely flexible within its design, having been successfully formulated with a variety of base brines from freshwater to saturated NaCl and at densities ranging from 8.6 to 16 lb/gal. The fluid can be designed to meet global HSE requirements.

Initial field trials have proven that the 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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Table 1a Typical Composition of HPWBM (20% NaCl)		
Seawater	(mL)	293.0
NaCl	(g)	80.4
Filtration controller	(g)	4.0
Polymer viscosifier	(g)	0.5
Dispersion Suppressant	(g)	4.0
Hydration Suppressant	(g)	10.5
Accretion Suppressant	(g)	17.5

Table 1b Typical Composition of Silicate Mud		
Freshwater	(mL)	290.0
Sodium Silicate	(mL)	42.0
Soda ash	(g)	0.5
KCl	(g)	30.0
Fluid loss agent	(g)	5.0
Polymer Viscosifier	(g)	1.0

Table 1c Typical Composition of PHPA/NaCl Mud		
Freshwater	(mL)	323.0
NaCl	(g)	73.2
NaOH	(g)	0.5
Bentonite	(g)	5.0
Fluid Loss Agent	(g)	3.0
PHPA	(g)	1.0
Polymer viscosifier	(g)	0.5

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% CaCl2 Brine	(mL)	75.0

Table 2 Typical Gulf of Mexico Composition of HPWBM		
Water	(bbl)	0.84
NaCl	(lb/bbl)	74
Hydration Suppressant	(lb/bbl)	10.5
Dispersion Suppressant	(lb/bbl)	2.5
Fluid Loss Reducer	(lb/bbl)	2.0
Viscosifier	(lb/bbl)	1.25
Accretion Suppressant	(lb/bbl)	10.5
Barite	(lb/bbl)	23.5

Table 3 Drillability Results from Full Scale Drilling tests on Pierre 1E Shale ROP at 10,000 lb WOB and 75 rpm		
12 lb/gal NaCl/PHPA	(0)	3.4
12 lb/gal NaCl/PHPA	(+3%)	32.4
12 lb/gal HPWBM	(0)	12.8
12 lb/gal HPWBM	(+3%)	47.9
16 lb/gal HPWBM	(2%)	21.6
16 lb/gal HPWBM	(3%)	31.5
(Additions of accretion suppressant in %volume		

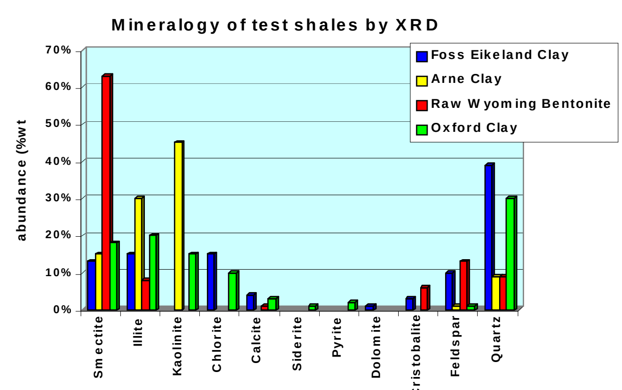

Fig. 1 – Mineralogy by semi-quantatative XRD of the four shale substrates used in laboratory development

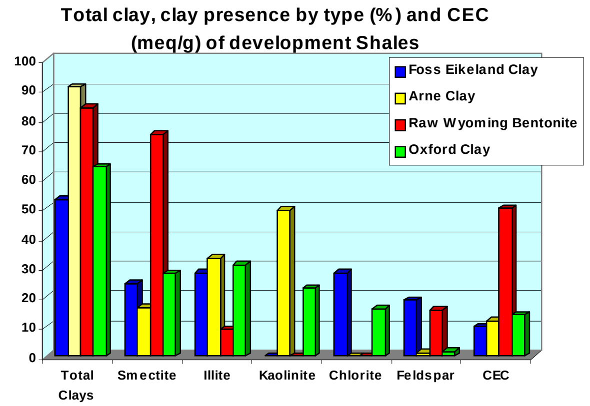

Fig. 2 –Clay content, clay type and reactivity of the four shale substrates used in laboratory development.

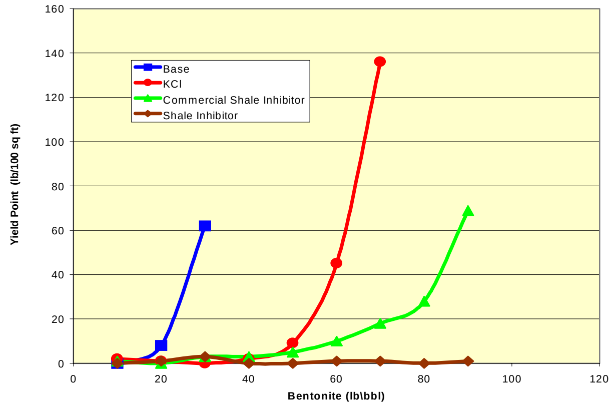

Fig. 3 –Bentonite Inhibition Test comparing the yield point of three shale inhibitors and the base fluid.

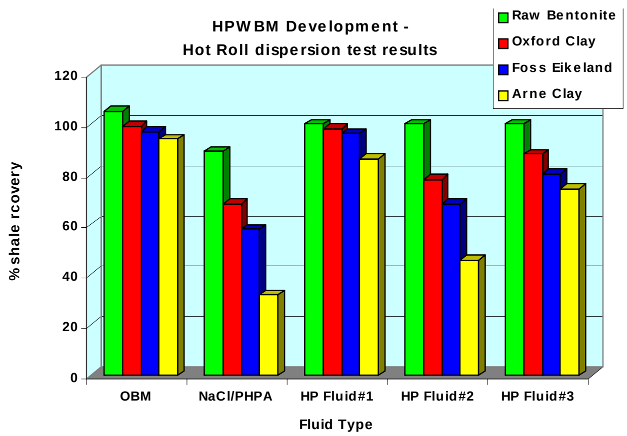

Fig. 4 –Hot Roll Dispersion Test results from HPWBM Development.

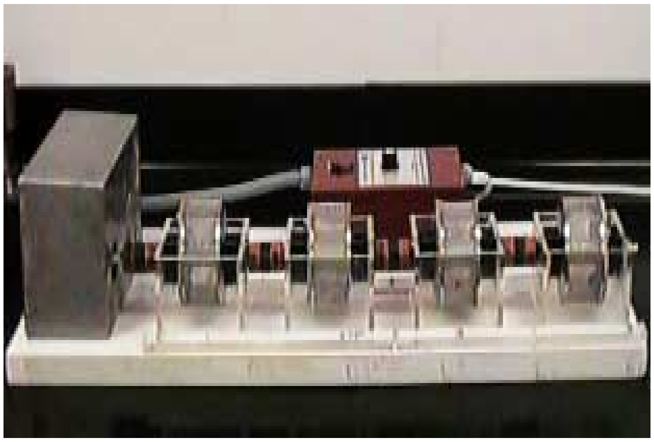

Fig.5 – The Slake Durability apparatus

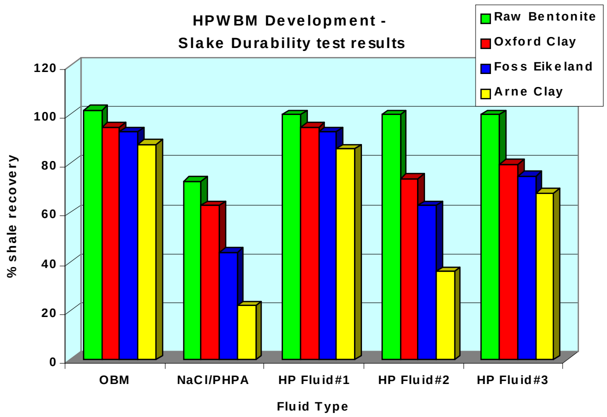

Fig. 6 – Slake Durability Test results from HPWBM development

Fig. 7 – Bulk Hardness Tester.

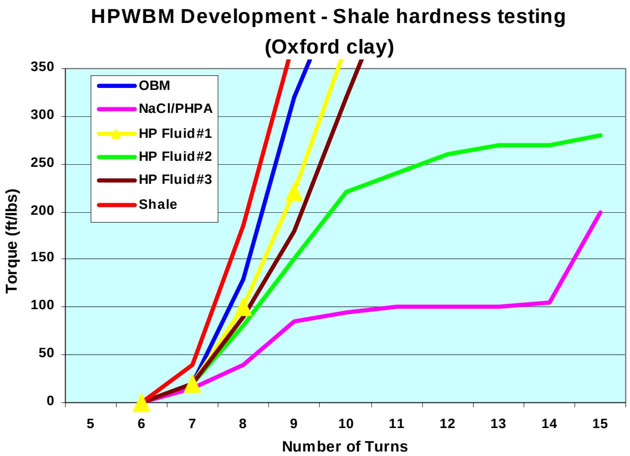

Fig. 8 – Bulk Hardness Test results from HPWBM Development.

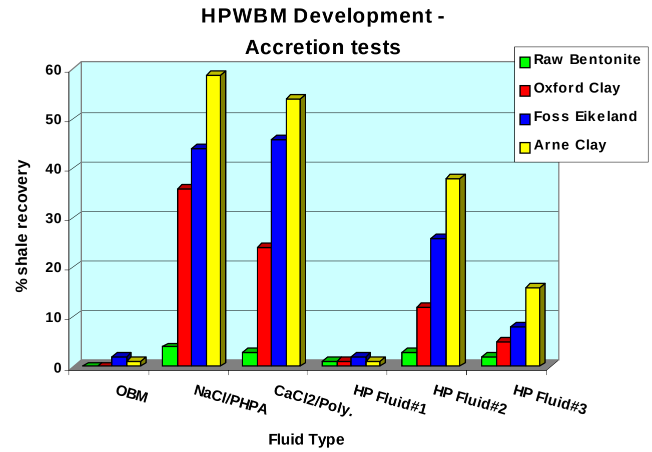

Fig. 9a – Accretion Test results from HPWBM Development.

Fig. 9b – Accretion Test pictures from HPWBM development.

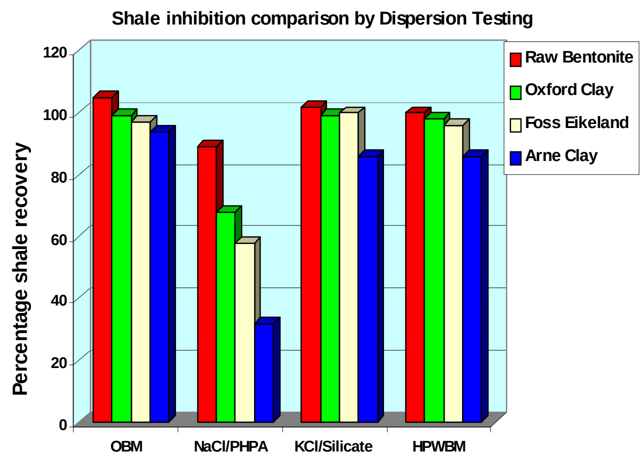

Fig 10 – Results from Hot Roll Dispersion Test on new HPWBM

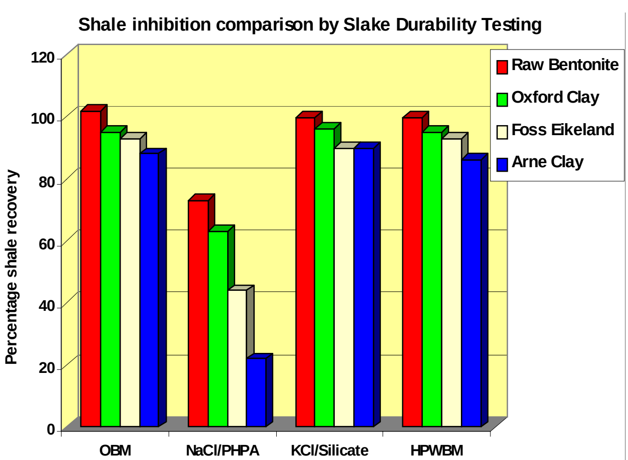

Fig 11 – Results from Slake Durability Test on new HPWBM.

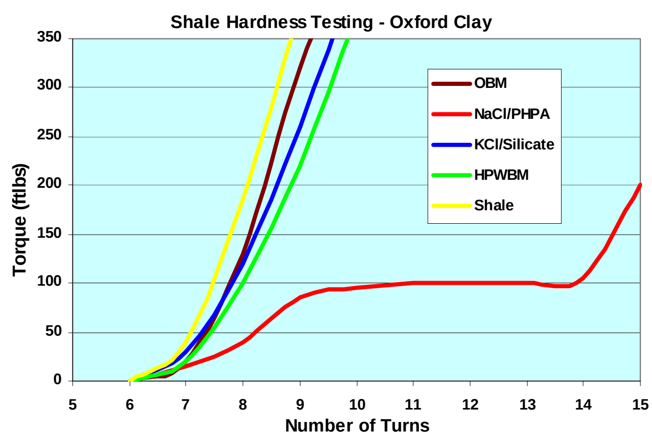

Fig 12 – Results from Shale Hardness Test on new HPWBM.

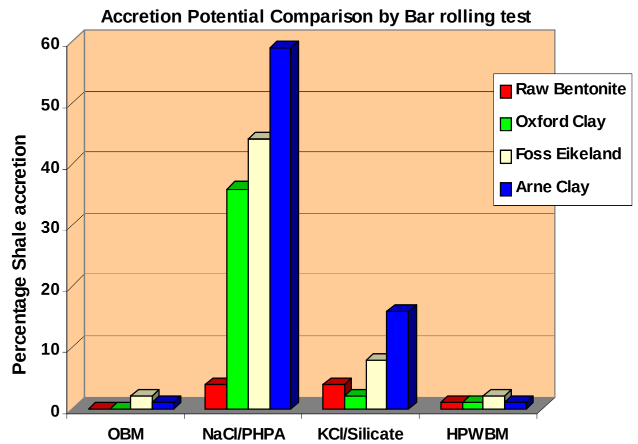

Fig 13 – Results from Rolling Bar Accretion Test on new HPWBM.

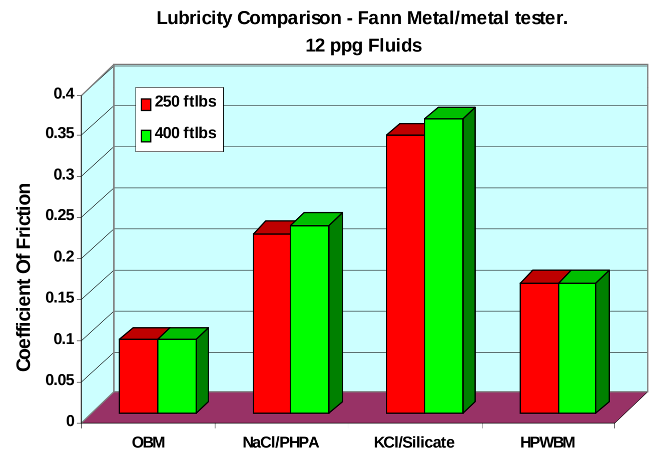

Fig 14 – Lubricity Test results (metal/metal) on new HPWBM.

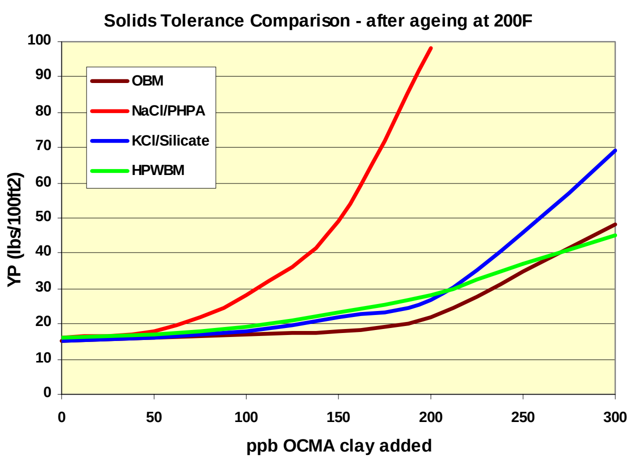

Fig 15 – Results from Solids Tolerance Test on new HPWBM.

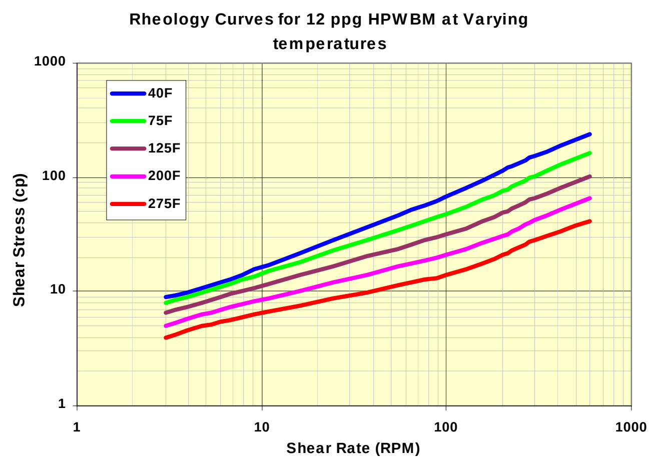

Fig 16 – Rheology curves of new HPWBM over cold-warm temperature range.

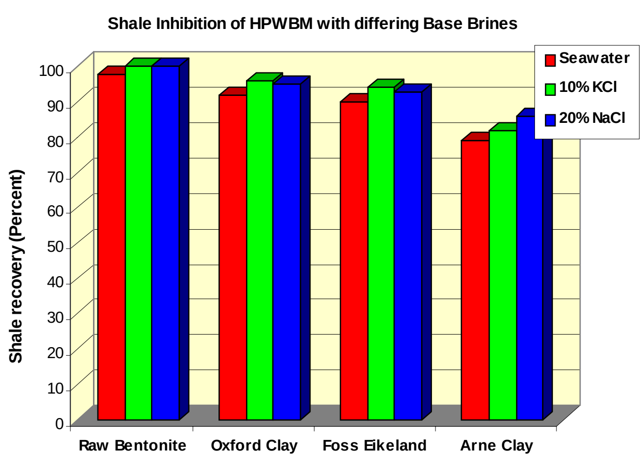

Fig 17 – Inhibition results from new HPWBM formulated in differing base fluids.

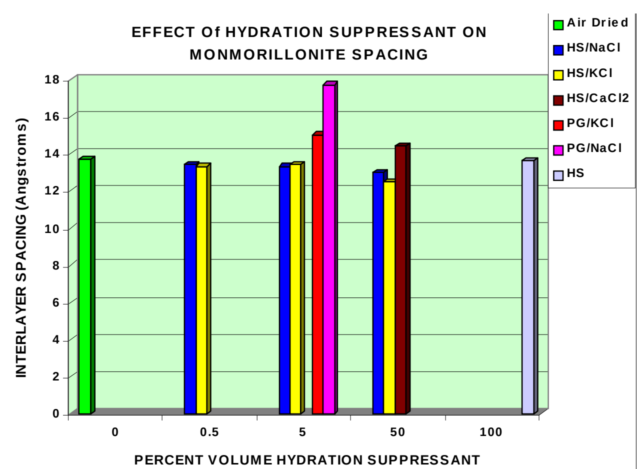

Fig 18 – X-ray diffraction results of clay/salt mixes with hydration suppressant showing interlayer spacing.

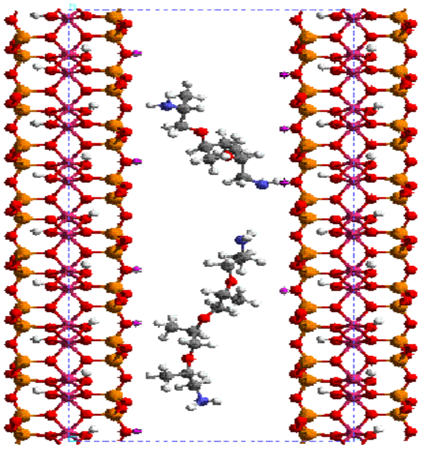

Fig 19 – Molecular modeling results showing binding of hydration suppressant to shale interface.

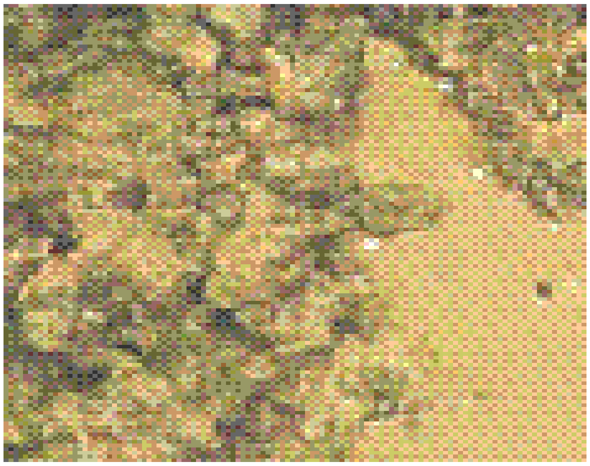

Fig 20a –Full scale accretion and ROP test results - Photos of cuttings recovered from NaCl/PHPA fluid.

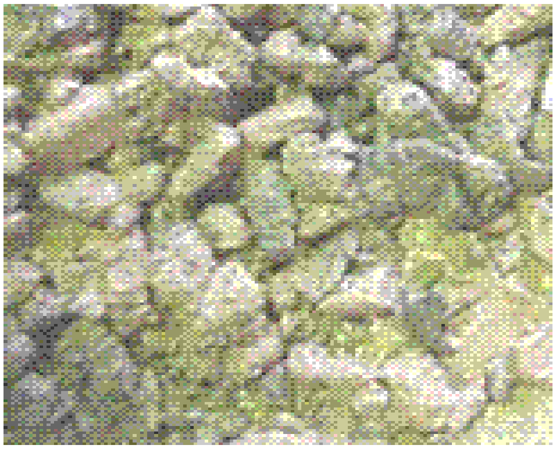

Fig 20b – Full-scale accretion and ROP test results - Photos of cuttings recovered from HPWBM.

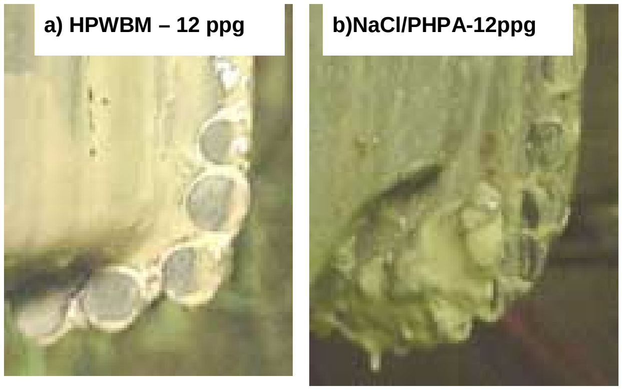

Fig 20c –Full-scale accretion and ROP test results - Photos of bits after a) HPWBM and b) NaCl/PHPA, showing clean cutters in a) and balled cutters in b).

Fig 21 – Cuttings from highly reactive shale section in GOM drilled with HPWBM.