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Field Trial of a Unique High-Density Drill-In Fluid

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Abstract

A new biopolymer-free, high-density drill-in fluid was successfully used for horizontal drilling and open-hole completion in the Gulf of Mexico. The drill-in fluid consisted of a 13.7-lb/gal $CaBr_2$ brine, a dual-function starch, a pH-buffering compound, and a blend of calcium carbonate.

The 1500-ft horizontal section was drilled in approximately 30 hours without encountering any problems. During the drilling operation, very stable rheology and excellent fluid loss control properties were observed. Only a minor treatment with small amounts of the pH-buffering compound was required for rheology maintenance. The unique rheological profile resulted in minimal ECD increases and allowed more efficient hydraulics for hole cleaning.

The production section was completed with a pre-packed screen and gravel pack. Weighted acid was pumped for filtercake clean up and stimulation. The production was found to be at least 1.5 times that predicted. The skin factor was determined to be around 2 – 4. The remaining drill-in fluid system was sent in for brine reclamation.

Introduction

Designing a water-based drill-in fluid for subsea completion applications requires the consideration of several factors, such as mud weight, rheology, fluid-loss control, lubricity, formation damage, aquatic toxicity, TCT, compatibility with completion fluid, etc.

For conventional high-density drill-in fluid design, one often can choose an appropriate makeup brine for density, a suitable biopolymer for viscosity, a starch for fluid-loss control, a secondary rheology viscosifier or stabilizer, and some sized calcium carbonate for bridging and filtercake building. The viscosifying capability of biopolymers, however, usually varies with type of makeup brine used and tends to deteriorate rapidly with increasing salinity and concentration of divalent species in the base brine, especially in generating low-shear-rate viscosity for effective hole cleaning. Innovative but more complicated systems have been developed to improve the performance of the drill-in fluids for deepwater operations.[1]

A more recent development in drill-in fluid technology revealed a simple, biopolymer-free, high-density drill-in fluid, which is characterized with exceptional low-end rheology and particularly suitable for deepwater operations.[2] Unlike the conventional drill-in fluid, this new system relies on a single starch additive for both viscosity and fluid-loss control. The desired suspension quality and carrying capacity are generated from the interactions of the starch with a pH-buffering agent, such as MgO, in brines rich in divalent cations such as calcium. The starch and calcium carbonate can be easily removed later with acid breakers during completion to enhance production.

A 13.9-lb/gal biopolymer-free drill-in fluid system was successfully formulated in the lab and subsequently used in the field to drill a horizontal well for subsea completion in the Gulf of Mexico. This paper discusses the laboratory testing and field trial of the high-density biopolymer-free drill-in fluid.

Fluid Design and Mud Properties

The main factors considered for the high-density biopolymer-free drill-in fluid system were the rheological property of the fluid, its impact on ECD, fluid-loss control, and aquatic toxicity.

Before the well was started, seismic data indicated that the projected well path would pass through a fault that could have stratigraphically served as a seal and isolated a virgin-pressured sand from depleted sands that now could have a reduced fracture gradient. More detailed well data is listed in Table 1.

Based on offset well information, a minimal equivalent static density (ESD) of 14.0 – 14.2 lb/gal is necessary to provide pressure control and a slightly higher density may be needed to maintain wellbore stability in shales. This minimal mud weight creates an overbalance of at least 1500 psi over the depleted sand that is to be exposed at drill out.

With the expected high mud weight and low fracture gradient, the drill-in fluid therefore, must be designed to have a rheological profile that is sufficient to clean the hole but not excessive enough to initiate fractures in the depleted sands. In order to obtain this rheology, a 13.7 – 13.8-lb/gal $CaBr_2$ brine was used as the makeup fluid and the primary source for density. A small amount of sized calcium carbonate (20 lb/bbl) was incorporated as the bridging agent as well as a secondary weighting agent. In this combination, the plastic viscosity (PV) of the fluid can be controlled as low as possible, preferably in the mid-twenties.

The 13.7 – 13.8-lb/gal $CaBr_2$ makeup brine also produced an LC_{50} value greater than the 30,000 limit, creating a likelihood of dischargable cuttings.

Despite the relatively low concentration of calcium carbonate, the drill-in fluid was formulated to provide good fluid-loss control over the depleted sands using the unique starch. Based on preliminary tests, 7-lb/bbl starch was required for optimal fluid-loss-control performance.

Rheology

Shown in Table 2 are composition and rheological properties of two 13.9-lb/gal drill-in fluid systems, one biopolymer-free and one conventional, for comparison. Both systems were also weighted up to 14.5 lb/gal using calcium carbonate as the weighting agent to evaluate rheology under high solids loading.

The biopolymer-free system displayed fairly consistent rheological properties even after the mud weight was raised to 14.5 lb/gal. This consistent rheology was partially attributed to a lower density of the makeup brine and partially to the lack of biopolymer in the system. In contrast, the rheology of the conventional system was similar to the biopolymer-free system at 13.9 lb/gal, but a higher rheology was observed after the mud weight was increased to 14.5 lb/gal. This higher rheology probably would induce fractures and lost circulation problems (Table 2).

A more distinct difference between the two systems lies in the low-end rheology and low-shear-rate viscosity (LSRV) which was measured at 0.0636 sec^{-1} using a Brookfield viscometer. The biopolymer-free system consistently showed low-end rheology and LSRV readings higher than the conventional system. This difference was attributed to the unique starch in the biopolymer-free system and was expected to positively affect hole cleaning and penetration rate.

During the laboratory testing of the biopolymer-free system, it was also noticed that its rheological property can be profoundly affected by temperature and shearing. Laboratory testing showed that temperature tends to cause an increase in the rheology, especially when temperature is provided during and/or after mixing of fluid. This increase seems to result from a temperature-promoted yield of the starch and/or a temperature-induced interaction between the starch and the MgO. After exposure to elevated temperature, the rheological property stabilizes quickly.

On the other hand, shearing tends to reduce the rheology of the fluid resulted from a mechanical interruption of the starch-MgO interaction. This reduction in rheology can be restored with a single treatment or combination of MgO, starch, and temperature.

Figure 1 shows the rheological property of a 14.5-lb/gal biopolymer-free fluid after being subjected to temperature and shearing treatments. The effects of temperature and shearing on rheology were also observed during the field trial of the biopolymer-free system.

Fluid Loss Control

The fluid-loss-control property was evaluated using regular HTHP fluid loss cells fitted for testing with ¼-in. thick aloxite disks. The fluid-loss tests were conducted at the static bottomhole temperature (SBHT) of 150°F with a 500-psi differential pressure. Ceramic disks of 5-micron pore-throat sizes were used as the filtration media.

The biopolymer-free system was found to have fluid-loss-control property similar to the conventional drill-in system. Figure 2 shows the 24-hr fluid losses of three biopolymer-free fluids with differing amounts of calcium carbonate. The actual fluid losses varied from 20 to 24 mL in 24 hours.

As the amount of calcium carbonate in the fluid increased, the fluid loss also increased slightly. Despite this increase, the fluid-loss control was considered sufficiently low to minimize the invasion of filtrate and solids. The filter cakes formed after 24 hours were about 2/32 – 3/32-in. thick, suggesting the possibility of having differential sticking could be greatly minimized.

Lubricity

Lubricity is considered an important property for drill-in fluid to minimize torque and drag during horizontal drilling. Because of the high differential pressure to be encountered when drilling the depleted sands, sliding the drillstring may become an issue, when initial filtercake building is less effective. Improving the lubricity character of drill-in fluid may alleviate this kind of problem.

Since the biopolymer-free system consists of mostly 13.7-lb/gal $CaBr_2$ brine, and high-density brines are known to have coefficients of friction (CoF) 30-40% less than that of water, the biopolymer-free system was expected to exhibit lubricity sufficient for the operation.

Using a specially designed lubricity tester,[3] the coefficients of friction of the biopolymer-free drill-in fluid have been measured to be in the range of 0.18 – 0.19 when tested on a drillpipe-casing interface (Table 3). The coefficient of friction did not seem to be strongly affected by the content of calcium carbonate in the fluid; however, a glycol-based lubricant was found to improve the CoF more effectively at the lower carbonate content.

Filtercake Clean Up

Depending on the type of completion method to be employed, filtercake clean up can be a critical process affecting the productivity of the well.

The planned subsea completion with gravel pack requires the filter cake be completely removed so that neither flow of hydrocarbon would be restricted nor plugging of the production screen would occur.

The filtercake removal can be achieved by using weighted acid, a blend of high-density brine and HCl acid, as a breaker for destroying calcium carbonate and starch. The effectiveness of the weight acid was evaluated by conducting return permeability tests.

The water permeability of 5-micron ceramic disks was individually established in a double-ended HTHP fluid-loss cell by flowing water from both directions of the disk, one side at a time, at room temperature and 5-psi pressure. A static filter cake was then built on the disk at 150°F, 300-psi differential for 39 hours with the cell in an up-side-down position. After building the filter cake, the drill-in fluid was decanted and 60 mL of weighted acid was poured into the cell and the cell was re-assembled. The filter cake was allowed to soak in the acid for 6 hours at 150°F, 300 psi. After the 6-hr soaking, about 55-60 mL of the acid was carefully drained without blowing air through the disk. The cell was allowed to cool down to room temperature and the water permeability of the disk was re-determined in both directions (production and injection) as the return permeability.

Because of the brine density restriction, the HCl concentration in the weighted acid was limited to about 8%. This strength of acid was enough to dissolve all the carbonate and break down all the starch in the filter cake after 6 hours of soaking at 150°F.

Return permeability measurements carried out after the acid soakings showed that 80-90% of the original permeability from the production side and 70-80% from the injection side could be re-established.

Toxicity

The LC_{50} value of the biopolymer-free mud system was evaluated by conducting aquatic toxicity tests using mysid shrimps. Test results indicated LC_{50} values varied from 40,000 to 50,000 ppm. Although the LC_{50} values are greater than EPA's 30,000 ppm limitation, zero discharge setup was recommended for the rig to retain cuttings.

Field Application

From Mixing Plant to the Rig

Based on the well test data obtained from the reservoir sand at the previous casing point and hydraulic modeling, a mud weight of 13.9 lb/gal was determined to be the drill-out mud weight. This would give an equivalent static density (ESD) of 14.1 lb/gal and an overbalance of at least 1,400 psi over the depleted sand.

The 13.9-lb/gal biopolymer-free drill-in fluid was mixed in 500-barrel batches at a mixing plant. To ensure proper mixing and shearing of polymer, a hopper equipped with a specially designed jet and a radial premixer was used. The base brine was first blended and pre-heated to 110 – 120°F before mixing to enhance the starch yield and promote stability of the rheology.

A sample of each batch was collected and its rheology measured at 75, 120, and 150°F along with a HTHP fluid-loss measurement at 150°F, 500 psi over 5-micron disk. The average fluid composition and properties after mixing are shown in Table 3. The higher rheology of the plant mud, when compared with the lab mud, was attributed to the better shearing and pre-heating given at the mixing plant.

After mixing, the drill-in fluid was pumped into storage tanks awaiting transportation to the rig. No biocide was added for this temporary storage, as the salinity of the fluid was considered high enough to prevent biodegradation of the starch.

A total of 5000 barrels of the drill-in fluid was delivered to the rig in a single boat trip. The fluid was sheared every two hours during the boat ride. Once the fluid was off-loaded to the pit system, a basic property check was conducted to make sure the density, rheology and fluid-loss control were still acceptable.

The fluid was found to have a lower rheology but the same fluid-loss-control value (Table 4). The reduction in rheology was attributed to the shearing of fluid during transportation. The fluid system was not treated further until displaced and cement drilled.

Displacement

Because of leaky cement plug and rig limitations, a direct displacement inside the casing was carried out first through the choke line. The riser was then displaced to seawater and circulated clean before being displaced with the drill-in fluid. Specially designed spacers and chemicals were used during the displacement to make sure residues from the previous mud systems would be cleaned off the interior surfaces of the casing, riser, and mud lines.

The well was displaced to the biopolymer-free system without encountering any problems. The pumping schedule for the displacement was hydraulically modeled before the displacement and tracked very well during the actual displacement.

Drilling

Drilling of the cement and new formation for Formation Integrity Test (FIT) started after the displacement. While drilling cement, the system was lightly treated with 0.25 lb/bbl of magnesium chloride for cement contamination, although previous lab tests indicated that cement contamination would exert little impact on fluid properties.

A slight adjustment in brine density using dry $CaBr_2$ was also performed as a certain degree of fluid contamination had occurred during displacement, which reduced the mud weight slightly. The surface mud weight was adjusted to obtain a consistent ESD of 14.0 – 14.1 lb/gal with the Pressure-While-Drilling (PWD) tool. For accuracy, the mud weight was measured using a pressurized balance and adjusted with the temperature correction factor to density at 70°F.

From the FIT test, an equivalent mud weight of 14.8 lb/gal for the depleted sand was achieved. This value was considered as the upper limit for ECD, although it was never exceeded during the drilling operation.

Drilling started at about 17,465 ft and reached total depth (TD) at about 18,975 ft. Total footage drilled was 1,510 ft and the total time of bit spent on bottom drilling was about 21 hours. This gives an average rate of penetration (ROP) of 72 feet per hour. No unusually high torque or drag was observed during drilling or sliding in the depleted sand, suggesting instantaneous filtercake building and good fluid lubricity.

During the drilling operation, certain mud properties were monitored at 250-ft intervals.

The rheology of the fluid system was found to be very stable throughout the drilling operation (Figure 3). Only a small amount of MgO was added for maintenance of the rheology. The low-shear-rate viscosity (LSRV) of the system, as measured using a Brookfield viscometer, showed a gradual decrease as drilling operation proceeded (Table 4 and Figure 4). The decreasing trend, however, did not seem to have impacted the hole-cleaning efficiency. Depletion and degradation through shearing were responsible for the decrease in LSRV.

The biopolymer-free system exhibited an interesting behavior in the LSRV at elevated temperatures. Instead of decreasing with increasing temperatures, the LSRV tended to stay the same or often times increased with increasing temperatures (Figure 5). This property was considered extremely beneficial for hole cleaning during horizontal and extended-reach-drilling operations.

The fluid-loss property remained very stable throughout the whole drilling operation (Figure 6). The HTHP fluid-loss test conducted on the rig using water-saturated ceramic disks as the filtration media assured the optimal performance of the fluid-loss-control polymer and bridging material. However, instead of running for 24 hours, the test was only conducted for 1 hour. The 1-hr fluid-loss data was then compared with the 24-hr lab data to evaluate if there was a change in the trend of the fluid-loss control. Shearing the fluid through the bit and incorporating a small amount of drill solids seemed to have improved the fluid-loss-control property a little bit, as indicated by the 1-hr fluid-loss test results. The solids content of the drill-in fluid was monitored on the rig to ensure the fluid system would not contain more than 3% by volume of drill solids, which was considered detrimental to the completion and production of the well.

A quick method was devised for determining the content of calcium carbonate and acid-insoluble material in the fluid (Appendix). Throughout the course of the drilling operation, the calcium carbonate content fluctuated somewhat, partially due to the use of calcium carbonate-based pills to slug the drillpipe prior to trips (Figure 7).

The amount of acid-insoluble material in the fluid increased with increasing depths, as expected (Figure 7). The total amount of acid-insoluble material in the system was less than 2% by volume at the end of the well, which was considered acceptable for the operation. Most of the acid-insoluble materials were believed to be fine-grained clays; however, MBT values suggested there was less than 1 lb/bbl of bentonitic clays in the fluid at the end of the well.

Mud samples were collected after the displacement and at the end of the well for toxicity tests. They showed LC_{50} values less than 30,000 ppm, which prevented the discharge of the cuttings. The low LC_{50} values were related to a possible minor contamination from the displacement chemicals and/or crude oil, which could have easily reduced the LC_{50} values from 40,000 – 50,000 ppm range to less than 30,000 ppm. The drilling operation was not hampered by the low LC_{50} values as the rig was set up for zero discharge.

At the end of the well, the drill-in fluid was sent in for brine reclamation. Approximately 70% of the 13.7-lb/gal $CaBr_2$ base brine was successfully reclaimed for other uses.

Completion and Production

After drilling to total depth, a short trip was made to condition the wellbore. The well was then displaced with a solids-free pill to the shoe and clear brine up in the casing for running pre-packed production screen in a non-damaging environment. The plan was then to displace to filtered completion brine and gravel pack. However, after the screen was run to the bottom and the open hole displaced, the rig had to shut down for nine days due to hurricane. A storm packer had to be run so the riser could be disconnected.

During this shut down, the hydrostatic pressure was removed from the wellbore as the clear brine leaked into the depleted sand in the heel section. This could result in a complete collapse of the well hence a re-drill, or a partial collapse of the shale on the screen preventing a complete gravel pack.

After the hurricane, the wellbore was found open. A gravel pack was successfully conducted, but only the heel part of the open hole extending to the shale break was gravel packed. The shale break in the middle of the well had indeed closed in around the screen and prevented the gravel pack from progressing to the toe.

After gravel packing, the filter cake left behind was destroyed with the application of a 13.8-lb/gal acid package containing 7.5% of HCl through wash cups. The well was then shut in while tying to the subsea flowline. Production was brought on and the well was produced back to the host platform. Initial production data showed a peak rate at about 1.5 times the expected rate with a skin factor of 2 – 4.

Conclusions

Based on the field trial of a biopolymer-free high-density drill-in fluid, the following conclusions have been reached.

- The biopolymer-free drill-in fluid has very stable rheological and fluid loss control properties.
- Maintenance of the system is very simple because of this stability.
- Its high low-shear-rate and low high-shear-rate rheological profile contributed to good hole cleaning, minimal ECD increase, and fast ROP.
- The system has minimal productivity impairment when its filter cake is properly removed using acid.
- Base brine used for mud weight can affect aquatic toxicity of the system, and as a precaution, zero discharge may be needed for drilling operation.,
- The drill-in fluid can be returned for brine reclamation thus reducing fluid cost.

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References

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3. Dzialowski, A., Hale, A.H., and Mahajan, S.: “Lubricity and Wear of Shale: Effects of Drilling Fluids and Mechanical Parameters,” SPE/IADC 25730, 1993 SPE/IADC Drilling Conference, Amsterdam, The Netherlands, Feb. 23-25, 1993.

Appendix - Procedure for Determination of Methylene Blue Capacity, $CaCO_3$ and Acid-Insoluble Solids in Drill-In Fluids (DIF)

I. Equipment and Chemicals

a. One 150-mL beaker
b. One hot plate with magnetic stirrer and magnetic bar
c. 5-mL and 10-mL graduated pipettes
d. 5-mL and 10-mL syringes
e. One 25-mL graduated cylinder
f. Filter papers and one glass funnel
g. One electronic balance to 0.01-g accuracy
h. 250-mL 3% hydrogen peroxide solution
i. 100-mL 15% HCl solution
j. 0.01-meq Methylene Blue solution

II. Procedure

a. To a 250-mL beaker, add 5 mL of DIF sample and 25 mL of 3% hydrogen peroxide solution. Cover the beaker with a watch glass.
b. Gently boil the fluid for 10 min on a hot plate. Add small amounts of distilled water for volume if necessary.
c. Let the fluid cool down a little. Titrate the warm fluid sample drop-wise with 15% HCl solution until all the carbonate has dissolved. The amount of $CaCO_3$ can be calculated using the following equation:

$CaCO_3$ in lb/bbl = (mL of 15% HCl) x 14.58

d. To the remaining fluid sample, titrate with Methylene Blue solution to end point. This is the MBT value in lb/bbl.
e. Filter out the solids left in the fluid sample using a filter paper and glass funnel. Rinse the solids on filter paper with freshwater to remove salts. Dry the solids and filter paper to a constant weight. Weigh the solids and calculate acid-insoluble using the following equation:

Acid-Insoluble in % Vol = (Dry wt) x 7.69

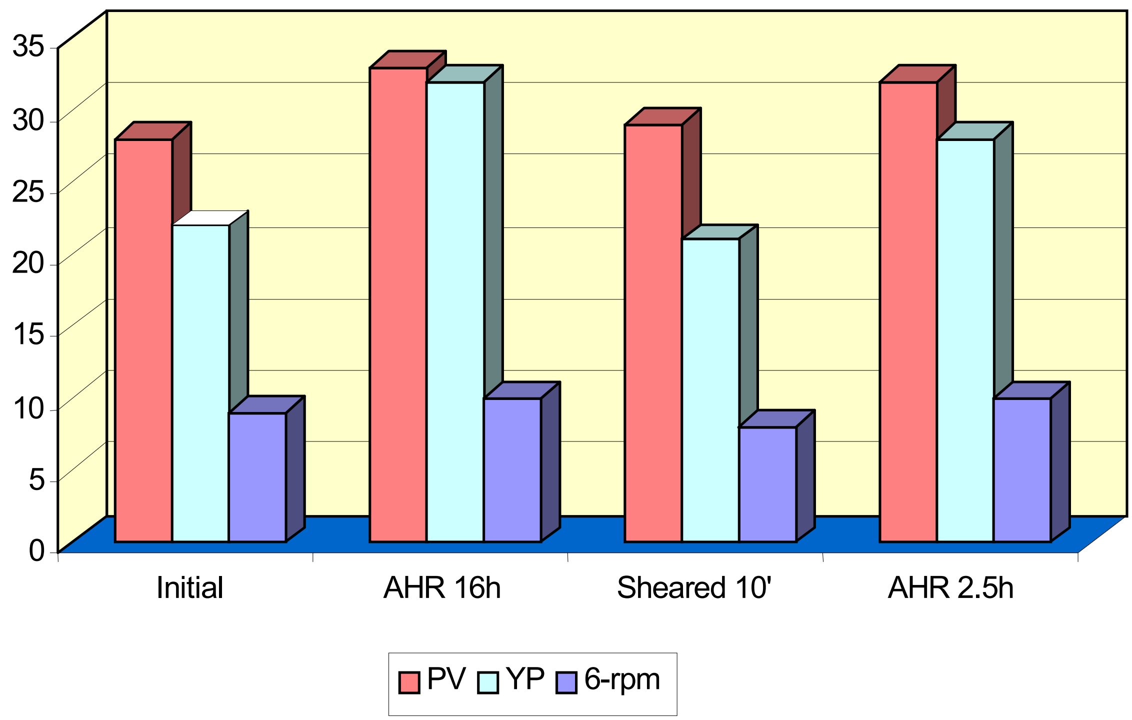

Fig. 1 – Effects of temperature and shearing on rheology of biopolymer-free drill-in fluid.

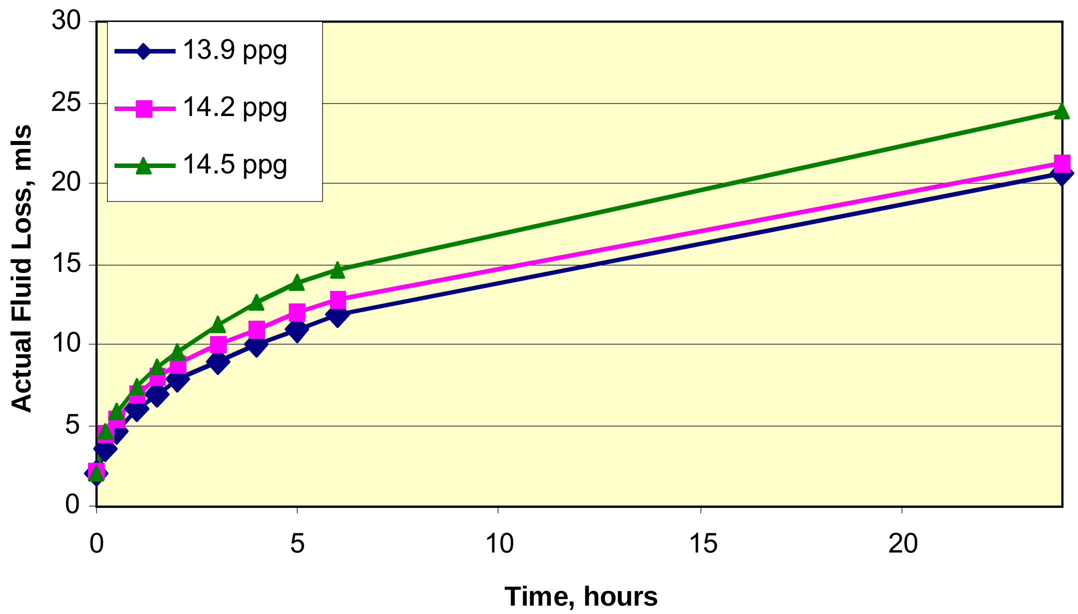

Fig. 2 – 24-hr fluid losses of biopolymer-free drill-in fluids with differing amounts of calcium carbonate as bridging material and weighting agent.

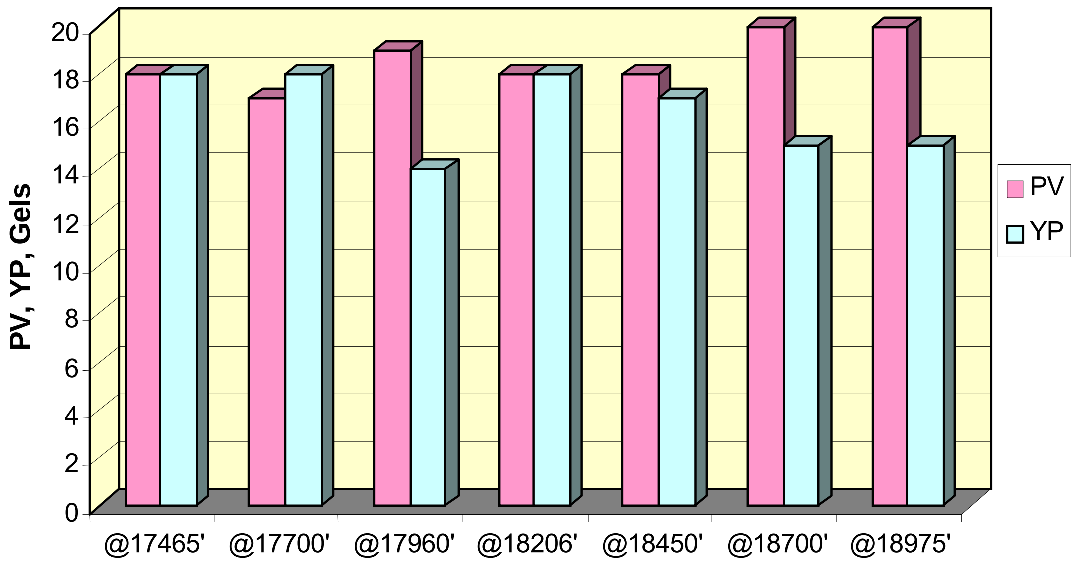

Fig. 3 - Rheology of biopolymer-free field mud measured at 120°F during the drilling operation.

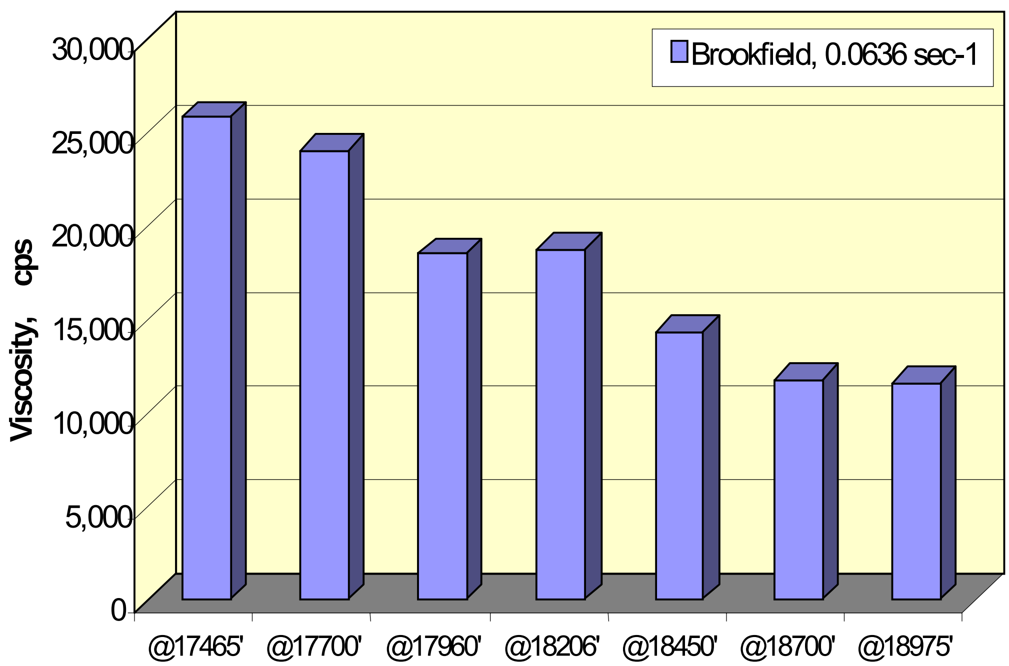

Fig 4 - Low-shear rate viscosity (LSRV) measured during the field trial of the biopolymer-free drill-in fluid. Notice the gradual decrease in LSRV with drilling. Shearing through the bit was believed to have contributed to the decrease.

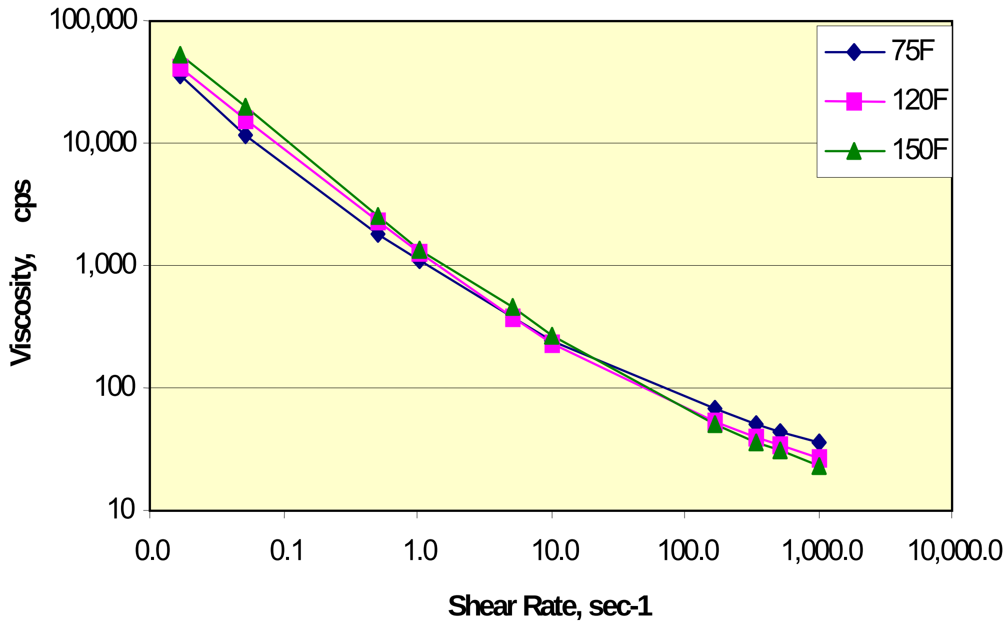

Fig 5 - A typical example of the rheological profile of the biopolymer-free drill-in fluid showing an increase of LSRV at elevated temperatures. The mud sample was collected from 17,960 ft.

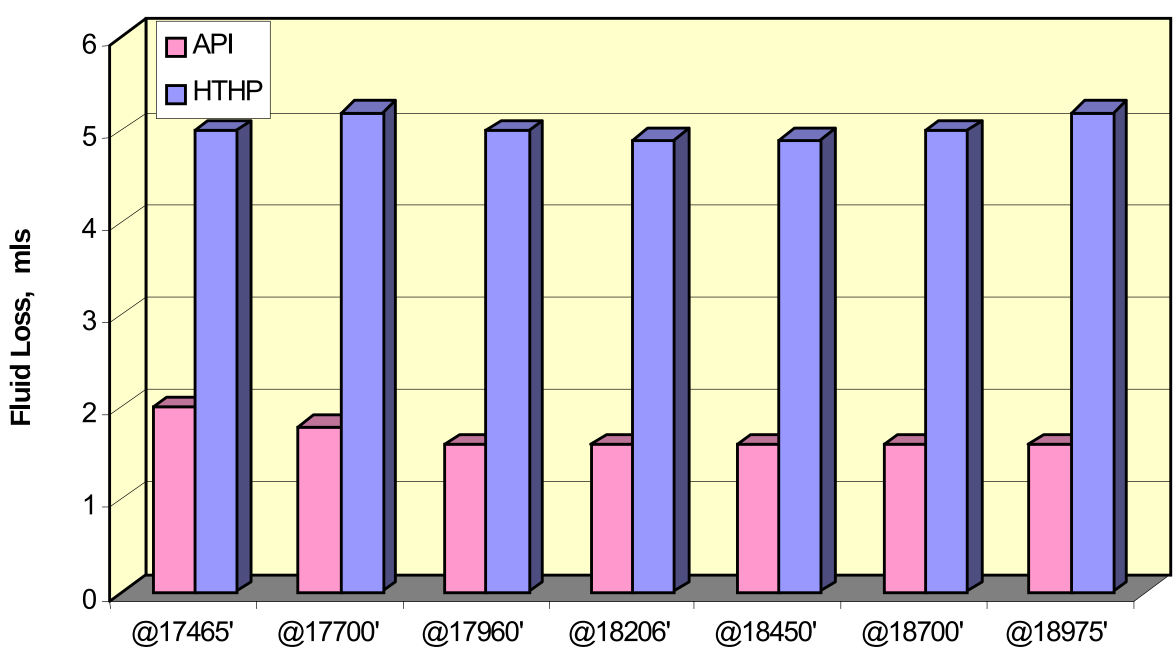

Fig. 6 - Fluid loss properties of a biopolymer-free drill-in fluid from the field trial. The fluid loss was measured at 150°F with 500 psi differential pressure over water-saturated 5-micron disk for 1 hour.

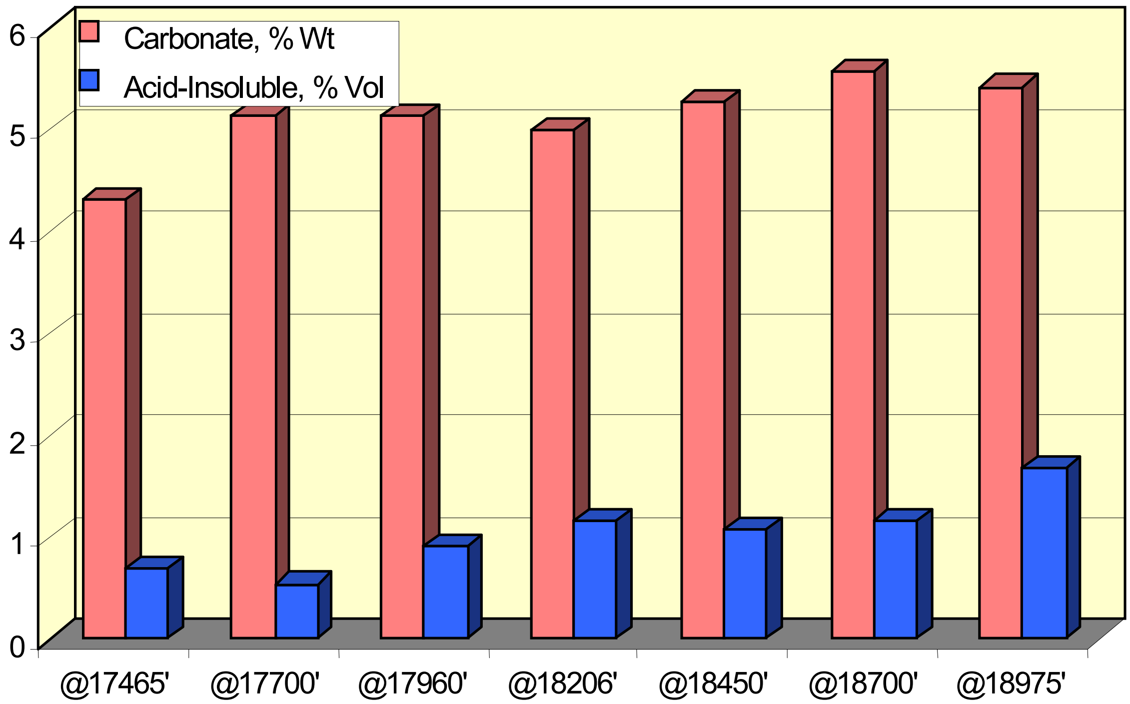

Fig. 7 - Variation of the content of calcium carbonate and acid-insoluble materials in field mud samples. The gradual increase in calcium carbonate was related to the use of carbonate-based pills. The increase in acid-insoluble was related to the incorporation of drill solids from shale.

Table 1. Drilling Parameters and Well Information	
Mud weight	13.9 – 14.5 lb/gal
Pore pressure	12.5 – 13.7 lb/gal
Casing size	7⅝ in.
Bit size, Type	6.5in. rock bit
Open hole section	1,500 ft
Hole angle	90 – 91 degrees
Formations	Sand, Shale, with fault
Completion	Open hole gravel pack
TCT of brine	20°F

Table 2 – Comparison of 13.9-lb/gal drill-in fluids Before and after weight-up to 14.5 lb/gal using calcium carbonate

	Biopolymer-Free		Conventional	
Mud weight (lb/gal)	**13.9**	**14.5**	**13.9**	**14.5**
14.2-lb/gal $CaBr_2$ (bbl)	0.886	0.777	0.886	0.777
Freshwater (bbl)	0.08	0.109	0.08	0.109
Starch lb/bbl)	7	7	3.75*	4.5*
Biopolymer (lb/bbl)	-	-	1.2	0.85
MgO (lb/bbl)	1.5	1.0	1.0	1.5
Calcium Carbonate (lb/bbl)	20	100	20	100
	Rheology at 120°F			
600-rpm	74	83	79	111
300-rpm	48	54	55	76
200-rpm	38	42	45	59
100-rpm	26	29	32	38
6-rpm	8	9	8	6
3-rpm	7	8	6	3
PV (cP)	26	29	24	35
YP (lb/100 ft^2)	22	25	31	41
10-sec/10-min Gels (lb/100 ft^2)	6/7	7/11	6/6	3/4
Calculated ECD (lb/gal)	14.9	15.6	15.0	15.9
LSRV at 75F (cP)	23,000	-	7,000	-
LC_{50} (ppm SPP)	40,000 – 50,000			

*A different type of starch was used with the conventional drill-in fluids

Table 3 – Coefficients of Friction

	13.9 lb/gal	14.5 lb/gal
Base Mud	0.195	0.184
Base Mud with 3% Glycol-Based Lubricant	0.176	0.189

*Testing performed on a pipe-casing interface using a specially designed lubricity tester.

Table 4 – Composition and Properties
13.9-lb/gal Biopolymer-Free Drill-In Fluid

	Average Fluid Composition and Properties		
14.2 lb/gal CaBr2 brine (bbl)	0.886		
Freshwater (bbl)	0.08		
Starch (lb/bbl)	7		
MgO (lb/bbl)	0.6 – 0.8		
Calcium Carbonate (lb/bbl)	17 – 20		
	From Mixing Plant	**Before Drilling Started**	**During Drilling Operation**
Mud Weight (lb/gal)	13.9+	13.9	13.8+
PV (cP)	21	19	19
YP (lb/100 ft^2)	26	17	16
10-sec/10-min Gels (lb/100 ft^2)	8/11	4/6	3/5
3-rpm Reading	8	4	3
Equivalent Circulating Density (ECD) (lb/gal)	-	-	14.4 – 14.5
1-hr HTHP fluid loss at 150°F, 500-psi over 5-micron disk (mL)*	6.3	6.2	5.2

* Rheology tested at 75, 120 and 150°F, only the 150°F data is shown.