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Coupling of Technologies for Concurrent ECD and Barite Sag Management

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Abstract

Drilling fluid viscosity has a significant impact on circulating pressure losses and solids suspension characteristics of the fluid. Viscosity levels required for managing dynamic barite sag and optimizing hole cleaning efficiency are frequently at odds with those needed for reducing circulating pressure losses. Ideally, viscosity levels should be maximized at ultra-low shear rates for controlling dynamic barite sag, and minimized at high shear rates to reduce drill string and annular circulating pressure losses. Frequently, there is a narrow operating window between fracture pressures and circulating density, which can be compounded by a high potential for dynamic barite sag. The drilling operation is at risk in these situations from pressure-related viscosity effects arising from dynamic sag and equivalent circulating density (ECD), however, the proposed solution to one problem generally has a negative impact on the other.

This paper presents technology for managing dynamic barite sag while minimizing the corresponding effect on downhole pressure losses in invert-emulsion drilling fluids. Data presented will demonstrate the ability to control dynamic barite sag while minimizing the effect on ECD, thus reducing the frequency of drilling fluid related non-productive time.

Introduction

Barite sag in drilling fluids is defined as the variation of mud density normally seen when circulating bottoms-up. This phenomenon is usually observed when drilling highly deviated wells with invert emulsion drilling fluids and has been associated with lost circulation, stuck pipe, stuck casing and in some instances complete loss of the well bore. Hanson et al.[1] concluded that barite sag was more likely to occur under dynamic conditions rather than static conditions. Bern et al.[2] concluded that the highest levels of barite sag occurred under low annular velocity and at wellbore angles between 60° and 75°. Dye et al.[3] performed a study that substantiated Hanson's and Bern's results and went on to further delineate the dynamic condition at which barite sag would occur. From this work, technology was developed for rig site monitoring of invert emulsion drilling fluids towards barite sag management.

High profile wells are generally associated with deepwater, extended reach drilling (ERD) and high temperature high pressure (HT-HP) operations. These wells are usually drilled with synthetic-based mud (SBM) or oil-based mud (OBM) for a number of reasons including high day rates, shale inhibition, hydrate suppression, improved thermal stability, lubricity characteristics and high rates-of-penetration (ROP). While the advantages of invert emulsions are many there are some disadvantages including environmental issues, lost circulation and a relatively high cost per barrel. Downhole losses associated with invert emulsion drilling fluid generally arise from high ECD's. Downhole pressures and temperatures are related to increased ECD in an invert fluid above which similar water based mud (WBM) would generate.

Barite Sag Management

Dynamic barite sag cannot be effectively managed without an awareness and appropriate control of all variables effecting barite sag. A new and simplistic technology is available to manage the drilling fluid variables effecting dynamic barite sag. This tool was derived from flow loop tests using analytical techniques and correlates well with field observations of barite sag. When developing this model, flow loop tests were conducted concurrently with field operations, presenting a unique opportunity to correlate laboratory and field results. Dynamic sag and rotational viscosity were measured at equivalent shear rates using a low shear rate field viscometer capable of measuring shear rates as low as 0.001 rpm ($0.0017 s^{-1}$). A relationship between drilling fluid viscosity and dynamic sag was discovered such that one could accurately predict flow loop results from simple ultra-low shear rate viscometer measurements. This predictive technology possesses the technical relevance of flow loop tests but is simpler and less time-consuming to perform. In most cases this technology is used instead of flow loop tests, which makes it uniquely suited for field use.

This technology predicts dynamic barite sag potential through direct measurement of ultra-low shear rate viscosity and comparison to the barite sag "Prevention Window" (PW) shown in Figure 1. Viscosity levels below the Lower Limit correlate with severe dynamic barite sag observed in the field and laboratory tests, and correspond to a high potential for dynamic barite sag. Conversely, viscosity levels above the Upper Limit indicate a low potential for dynamic barite sag, but are excessive in terms of requirements for barite sag management. Finally, viscosity levels within the Limits of the PW are preferred, and indicate a low potential for dynamic barite sag. In terms of balancing barite sag and ECD management, the viscosity profile of the drilling fluid is optimized within the PW. For details and case histories on development of the barite sag PW see references from Dye et al.[3,4]

ECD Management

ECD is influenced by flow rate, mud properties, rate-of-penetration, cuttings density and size and geometrical constraints. Pressure subs are usually used on critical wells with tight operating windows to monitor and manage ECD trends. Accurate hydraulics models are useful for establishing an "expected" trend for comparison against measured tool pressures. When tool data deviates from expected trends, remedial action such as controlling ROP, sweeps and short trips can be taken to prevent loss circulation, stuck pipe and pack-offs.

Mud properties, to some extent, can be maintained within set specifications at the rig site. For instance density, Plastic Viscosity (PV), Yield Point (YP), as well as ten second and ten minute gel strengths are typically monitored at ambient pressure at 120°F or 150°F and adjusted according to the drilling fluids program or operational conditions. Invert emulsion fluids generally exhibit much greater fluctuations in rheological behavior with temperature and pressure than do water-based drilling fluids.[5] In addition, invert emulsion drilling fluids compress under pressure and expand with temperature; therefore the downhole density may be significantly different than density measured at surface. For consistent and accurate ECD modeling of invert emulsion drilling fluids, rig site rheological measurements are not adequate. Thus the need for characterizing the fluid rheological properties coupled with base fluid density corrections that reflect downhole pressure and temperature conditions.

Study Fluids and Test Methods

For this study five fluids were selected for characterization on the barite sag PW followed by a detailed hydraulics analysis. The test fluids consisted of a baseline fluid and the baseline fluid treated with two types of rheological modifiers to identify; 1) the chemistry best suited to manage barite sag and 2) the impact of treatment on downhole pressure losses. Table 1 lists fluid compositions and properties. All fluids were characterized over the standard six speed viscometer shear rate range at 120° F for PV, YP and gel strengths and the ultra-low shear rate range for dynamic barite sag tendencies. In addition, each fluid was tested on a Fann® Model 75 HT-HP viscometer at downhole pressure and temperature. Finally each fluid was characterized on a stress controlled rheometer, Rheometrics SR-5000, using dynamic oscillatory techniques to determine linear viscoelastic properties.

Baseline Fluid

The baseline fluid (Fluid #1) was intentionally designed so that the viscosity profile would fall below the Lower Limit of the PW. See Table 1 for fluid composition and properties. Figure 2 illustrates the baseline fluid used in this study compared to a fluid known to have sagging potential. See reference from Dye et al.[3,4] for details on the dynamic barite sag PW and the details on the fluid used here for comparison purposes. The baseline fluid in this study has a high potential for severe dynamic barite sag.

Treated Fluids

Fluid #1 was treated with two types of rheological modifiers: high performance organophilic clay (HPOC), or fatty acid rheological modifier (FARM). Each product was added in small quantities to achieve a viscosity profile within the PW (optimized for barite sag management) and subsequently adjusted to within or slightly above the PW. Treatment levels were selected in order to determine the impact of increased concentrations on barite sag and circulating pressure loss.

Figure 3 illustrates the results on viscosity profiles of additions of FARM at two concentrations. An increased, upward shift, in overall viscosity is evident with treatment of the baseline fluid with FARM. In fact, the flow curve for Fluid # 4 was below the Lower Limit. It was decided, based on the amount of treatment, to use Fluid #4 for ECD comparison even though it would likely exhibit dynamic barite sag. The viscosity curve of Fluid #5 did fall within the window; however, it did not remain within the window limits over shear rate region.

Figure 4 illustrates the viscosity profiles of HPOC treated fluid (Fluids #2 & #3). Both levels of treatment shifted the viscosity curve upwards into and slightly above the window. A minimal treatment level of HPOC was required to shift the viscosity curve into the barite sag PW limits.

HPOC and FARM Treatment Comparison

Both the HPOC and FARM rheology modifiers increased the ultra-low shear rate viscosity of the treated fluids. In addition to monitoring ultra-low shear rate viscosity, the analytical tools mentioned earlier were used to better understand which type of treatment would optimize drilling fluid viscosity for management of both dynamic barite sag and overall circulating system pressure losses.

Figure 5 shows results on a typical six speed viscometer shear rate range coupled with ultra-low shear rate data on Fluids #3 and #5. Properties were measured at 120°F at ambient pressure. The flow properties of these fluids are similar within the shear rate range of 3 rpm to 600 rpm. However, Fluid # 5 (FARM-treated) begins to change slope below the 3rpm region and tends towards Newtonian behavior, whereas Fluid #3 (HPOC-treated) maintains a relatively constant slope over the entire shear rate range. All fluids in this study treated with the FARM additive exhibited a lower Newtonian region (Figure 6).

Figure 7 shows the PV, YP, 6 and 3rpm readings and Low Shear Rate Yield Point (LSYP or YZ) values for Fluids #3 & 5. Not surprisingly, these values are similar since they are derived form measurements taken from the six speed viscometer readings in Figure 5.

Dynamic oscillatory measurements were used to provide insight into the differences observed at ultra-low shear rates and delineate the performance characteristics of the HPOC and FARM-treated fluids. While normal rotational viscometer tests apply a force or a strain in a constant direction, oscillatory tests move the measuring geometry through a short distance in one direction, then reverses its motion until it passes though its starting point. The movement of the geometry is small enough that it will not disturb the overall structure of a sample but will allow measurement of rheological properties. This oscillatory motion is repeated indefinitely, usually following a sinusoidal pattern of movement, allowing for long-term measurement of a sample under set stresses or strain rates without destroying the structure of the sample.

Before discussion of oscillatory measurements a short discussion on viscoelasticity is necessary. A Newtonian fluid will manifest a pure fluid-like response and a material such as steel will manifest a solid-like response to an applied stress. Most materials have some fluid-like (viscous) characteristics as well as solid-like (elastic) characteristics. It is desirable for drilling fluids to manifest both behaviors depending on the operational conditions. For instance at very low shear rates it is desirable for the solid-like characteristics to be dominant for suspension of cuttings and weighting material. At high shear rates the fluid-like or viscous characteristic is desirable for transfer of hydraulic horsepower down the drill string and bit.

One of the most common methods of quantifying the viscoelastic properties of fluids is by measurement of their elastic modulus (G') and viscous modulus (G").[6,7] Two oscillatory tests are performed in order to quantify G' and G". The first test, the Strain Sweep, is a destructive test used to determine the extent of linear viscoelastic region. After determining the linear viscoelastic region, a non-destructive Dynamic Frequency Sweep is performed to quantify G' and G" moduli of the static gel. From the measured moduli, an undisturbed viscosity (η^*), or dynamic viscosity is calculated. In addition, tan (δ), ratio of G"/G', is calculated and used as an indicator of solid-like behavior. A ratio tending towards zero is indicative of purely elastic (solid-like) behavior, whereas, a ratio tending towards one (or higher) indicates viscous (liquid-like) behavior. The dominance of G' over G" is an indicator that a networked, 3-dimensional structure exists.

Dynamic oscillatory tests were performed to identify the relative performance differences between HPOC and FARM rheological modifiers. Results are presented for Fluids #3 and #5 in Figures 8 thru 11. Figure 8 shows results on Fluid #3 (HPOC treated). Here, the elastic modulus (G') is virtually flat over the frequency region (frequency independent), which indicates that the elastic response has little dependence on strain rate. The tan (δ) value, approximately 0.2 to 0.3, was also fairly flat, but slightly increasing at higher frequencies, indicating that the viscous nature of the mud increases its impact at higher strain rates. The dynamic viscosity exhibits a high degree of shear-thinning over the test region and has a constant slope.

Figure 9 shows results on Fluid #5 (FARM-treated). This fluid exhibits frequency dependency of G' and has little separation between the elastic and viscous moduli. The tan (δ) value for Fluid #5 is fairly constant, 0.4 to 0.5, over the frequency range, and is higher than that of Fluid #3. Finally, the dynamic viscosity exhibits a lower degree of shear-thinning over the test region and the slope approaches that of a Newtonian fluid at low frequencies (lower Newtonian region). The lower Newtonian region was also observed in the ultra-low shear rate region in Figure 6 for all FARM-treated fluids. Another observation from Figures 8 and 9 are the differences in magnitude of G'. With Fluid #3, the elastic modulus (G') is an order of magnitude higher that that of the Fluid #5, indicating a stronger network exists in Fluid #3 (HPOC) compared to Fluid #5 (FARM).

Figures 10 and 11 illustrate the results from Dynamic Time Sweeps. The Dynamic Time Sweep is a non-destructive test, where the timed response of gel growth can be observed. This test gives useful information about the growth of gel structure in a near-static fluid. The fluid structure is initially broken by shearing for two minutes at 1022 s^{-1} (equivalent to 600 rpm). Then, the test begins with an oscillating strain in the linear viscoelastic region while G', G" and dynamic viscosity are continually monitored. As the gel structure grows, the structural dominance of the mud increases (G' growth and tan (δ) decrease) while the gel has an additive effect on the dynamic viscosity measured over time.

In Figure 10, Fluid #3 exhibits an initial sharp decrease in tan (δ), corresponding to increases in η^*, G', and G", indicative of gel growth (structured network) in the fluid. After ~10 minutes, the gel growth levels out and remains constant after ~20 minutes. Afterwards, G', G", η*, and tan (δ) are flat over time, also exhibiting a large G'/G" separation. This indicates retention of structure within the mud over time.

From Figure 11, Fluid #5 exhibits no initial gel growth period. Instead, after ~10 minutes, η*, G', and G" all begin to decrease steadily over time while tan (δ) slowly increases with time. This indicates that the structure in the mud breaks down with time and the system moves toward viscous (G") behavior. In comparing Figures 10 and 11, the value of G' in the HPOC-treated fluid is an order of magnitude higher than that of the FARM-treated fluid.

Hydraulics Analysis

The treated fluids were compared to the baseline fluid for overall impact on downhole pressure losses. The pressure loss analyses were made using an advanced hydraulics model, Advantage Engineering Hydraulics. Advantage is an HT-HP model which applies appropriate corrections to rheology based on Fann 75 data and base fluid density based on PVT data.[8]

Additional analysis on the drilling fluid was required in order to perform an accurate hydraulics analysis. It has been well documented that synthetic and oil-based drilling mud rheology, as well as density, change under pressure and temperature conditions experienced at downhole conditions. HT-HP, as well as conventional 6-speed viscometer data were generated on each mud and used for an extensive hydraulics analysis for each mud. HT-HP rheology corrections were based on temperatures and pressures that the fluids would experience in deepwater wells.

Two deepwater wells were modeled: 1) a vertical deepwater well in the Gulf of Mexico and 2) a deepwater horizontal well located in West Africa. For each well type, drilling parameters such as flowrate, ROP, cutting density/size were kept constant.

Figure 12 presents ECD results from the vertical deepwater well. In this case a 12 ¼" open hole section was modeled below 11 7/8" casing from approximately 15,600 to 18,000 feet TVD. The surface mud weight for this well was 12.0 ppg, measured at 60°F and atmospheric pressure. When circulating, the ECD (at bit) from Fluid #1 (baseline fluid) was 12.56, which is 0.56 ppg above surface mud weight. The bottom hole ESD at downhole conditions was 12.21 ppg, so a ~ 0.35 ppg increase in density resulted from annular pressure losses. With Fluid #3 (HPOC), the ECD increased 0.06 ppg above Fluid #1, whereas ECD increased 0.23 ppg with Fluid #5 (FARM).

Figure 13 illustrates results on a deepwater horizontal well. In this scenario a horizontal 8 ½" section was modeled below 9 5/8" casing from ~ 8,000 feet to 9,000 feet measured depth. In this well Fluid #1 had an ECD of 12.75 ppg and an ESD of 12.09 ppg, indicating a net increase in density due to annular pressure loss of 0.66 ppg. Fluid #3 had an ECD increase of 0.16 ppg compared to Fluid #1, while the increase in ECD for Fluid #5 was 0.80 ppg as compared to Fluid #1.

From the results above it is apparent that the choice of rheological modifiers can have a dramatic effect on pressure loss in the circulating system. Recalling the data presented in Figures 5 and 7, the six speed viscometer readings of the two fluids had similar viscosity profiles and therefore, had similar PV, YP, 6 and 3rpm readings. In reviewing these data it is not clear why there would be significant differences in the hydraulics of the two fluid systems.

The two rheological modifiers (HPOC and FARM) provide completely different mechanisms for viscosity modification. Insight into the mechanisms was provided from results in dynamic oscillatory tests presented in Figures 8 – 11. Similarly, the differences are apparent in HT-HP viscometer test data shown in Figures 14 and 15. In Figure 14, the solid lines are the viscosity profiles of three HT-HP viscometer tests on Fluid #5 (FARM-treated) while the dashed lines are from Fluid #3 (HPOC-treated). From Figure 14 it is apparent that the rheological modifiers behave differently when measured under temperature and pressure. Fluid #5 is more viscous compared to Fluid #3 under simulated downhole conditions. Figure 15 compares the HT-HP viscometer test data from Fluids #1 and #3. Neither of these fluids contains the FARM rheological modifier and it is shown that the flow profiles of these fluids are very similar at high shear rates.

Table 2 lists the entire circulating system pressure loss breakdown for both chemistries on the example wells. The impact of the FARM-treated fluid on downhole rheology is evidenced by higher circulating pressure losses compared to HPOC-treated fluid. In the deepwater horizontal case, Fluid #5 (FARM) had an 80% increase in annular pressure losses and in the vertical case a 40% increase compared to Fluid #3 (HPOC).

Conclusions

Conclusions are based on an investigation of two drilling fluid treatment approaches to counter severe barite sag while simultaneously managing circulating pressure losses.

- Ultra-low shear rate viscosity measurements can delineate performance differences that are not apparent from conventional 6-speed viscometer data.
- Viscoelastic measurements provide insight into the mechanisms of rheology modifications that are not apparent from viscometer measurements.
- Significant differences in drilling fluid rheological behavior are observed when comparing properties measured at surface versus downhole conditions. These differences can become more pronounced when using rheological modifiers.
- The impact on drilling hydraulics can vary significantly depending on the type of chemistry chosen for rheology modification.
- HPOC chemistry is preferred over FARM chemistry for concurrently managing ECD and dynamic barite sag.
- Corrective action for problems such as barite sag and ECD management should not be made in isolation from one another. The solution to one problem may compound or increase the risk of the other.
- Technologies are available to optimize drilling fluid properties for managing barite sag and ECD.

Acknowledgments

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Nomenclature

PW = Prevention Window
ECD = Equivalent Circulating Density
ROP = Rate of Penetration
ESD = Equivalent Static Density
ROP = Rate of Penetration
PV = Plastic Viscosity
YP = Yield Point
LSRYP or YZ = (2 x 3 rpm) - 6 rpm dial reading
G' = Storage Modulus
G" = Loss Modulus
*h * = Dynamic Viscosity*
tan (d) = G"/G'

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Table 1

Additive \ Fluid #	1	2	3	4	5
Base Fluid, bbl	0.616	0.615	0.616	0.615	0.615
HPOC, ppb	2.4	2.5	2.65	2.4	2.4
Emulsifier ppb	10	10	10	10	10
$CaCl_2$ Brine, bbl	0.175	0.175	0.175	0.175	0.175
Barite, ppb	214.4	214.1	214.1	214.1	214.1
Drill Solids, ppb	27	27	27	27	27
FARM, ppb				0.25	0.85
Heat Aged 16 hours @ 150°F					
Mud weight, lb/gal	12.0	12.0	12.0	12.0	12.0
T 600 rpm @ 120°F	47	54	58	49	56
T 300 rpm	28	32	35	29	34
T 200 rpm	20	22	27	21	27
T 100 rpm	13	14	17	14	19
T 6 rpm	4	5	8	5	8
T 3 rpm	3	4	7	4	7
Plastic viscosity, cP	19	22	23	20	22
Yield point, lb/100 ft^2	9	10	12	9	12
YZ lb/100 ft^2	2	3	6	3	6

Table 2

Deepwater Horizontal Well						
System Pressure Loss						
					Drill	Motor
Fluid	SPP	Surface	Bit	Annulus	String	MWD
1	2480	62	93	193	821	1311
2	2523	61	93	227	831	1311
3	2569	64	93	237	864	1311
4	2535	59	93	265	807	1311
5	2767	63	93	427	873	1311
Deepwater Vertical Well						
System Pressure Loss						
					Drill	Motor
Fluid	SPP	Surface	Bit	Annulus	String	MWD
1	3017	238	188	327	1381	883
2	3109	231	188	344	1463	883
3	3174	247	188	383	1473	883
4	3020	217	188	368	1364	883
5	3284	227	188	536	1450	883

Figure 1

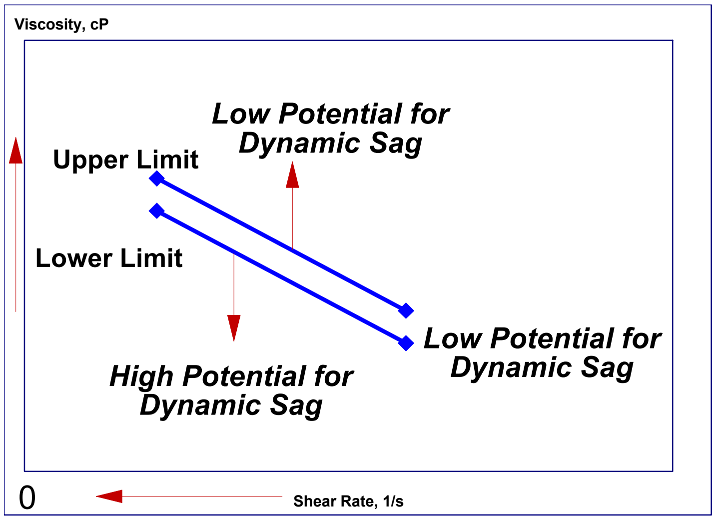
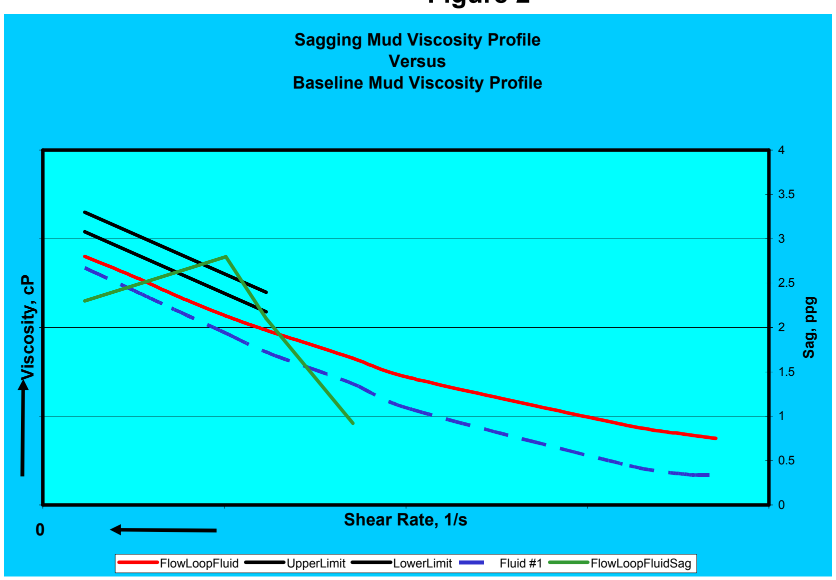


Figure 2



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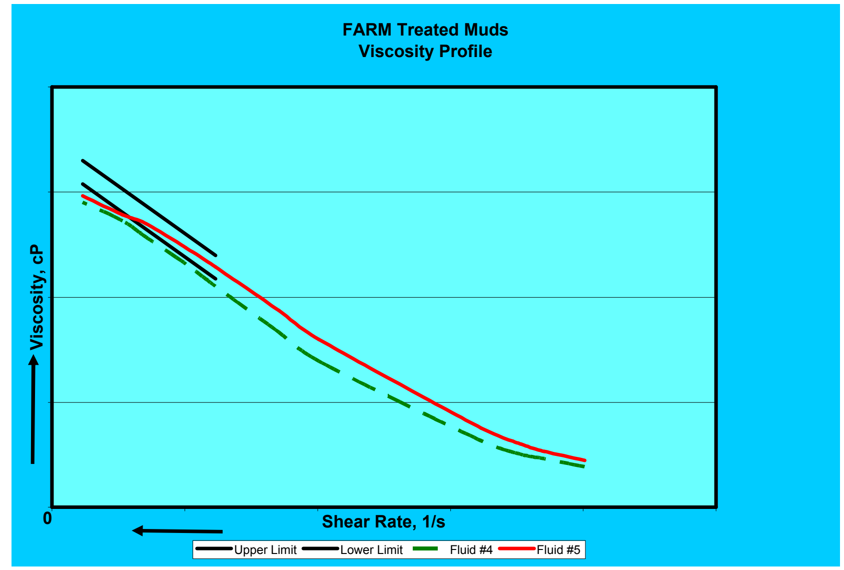

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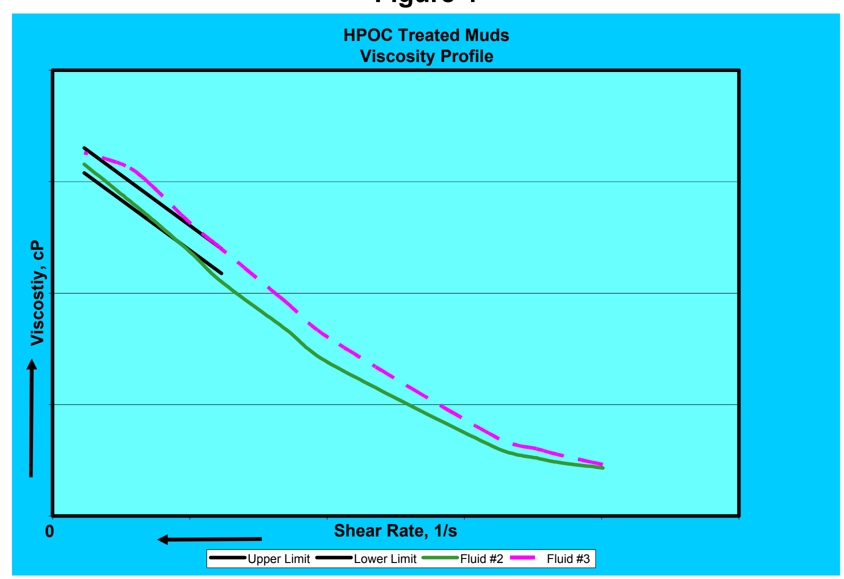

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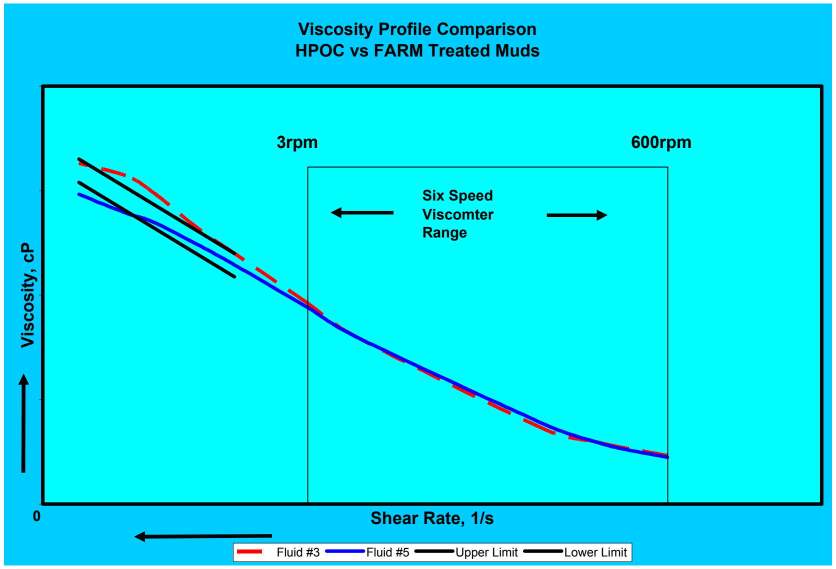

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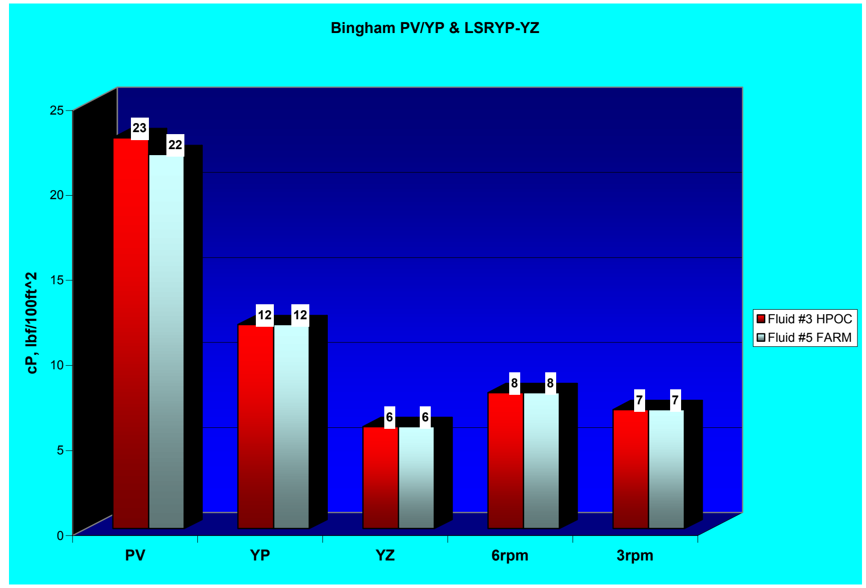

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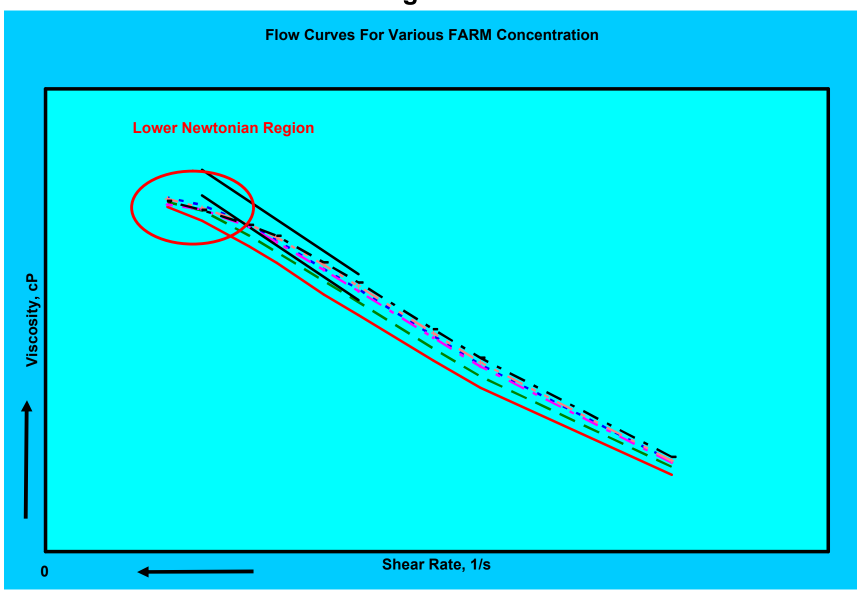

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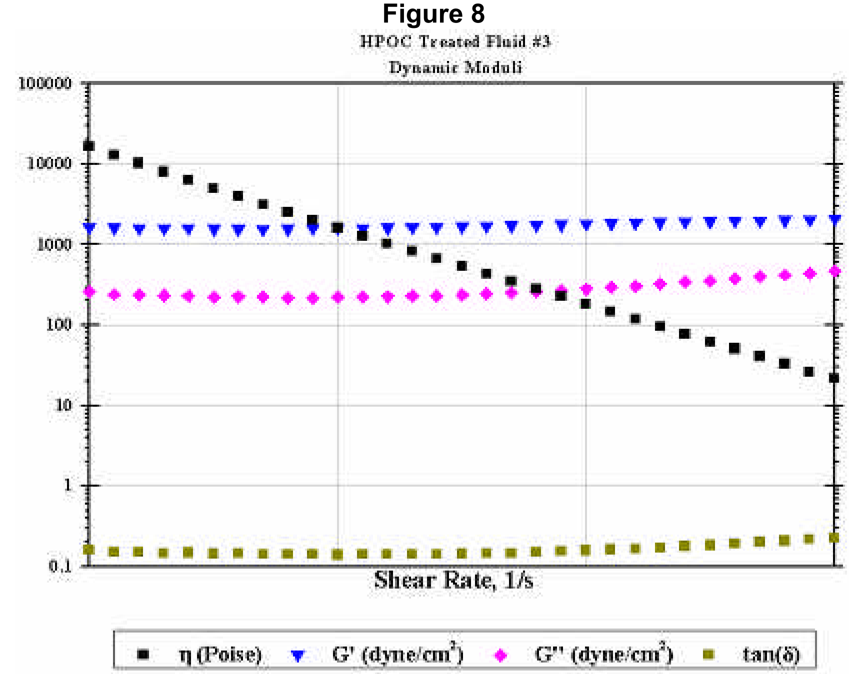
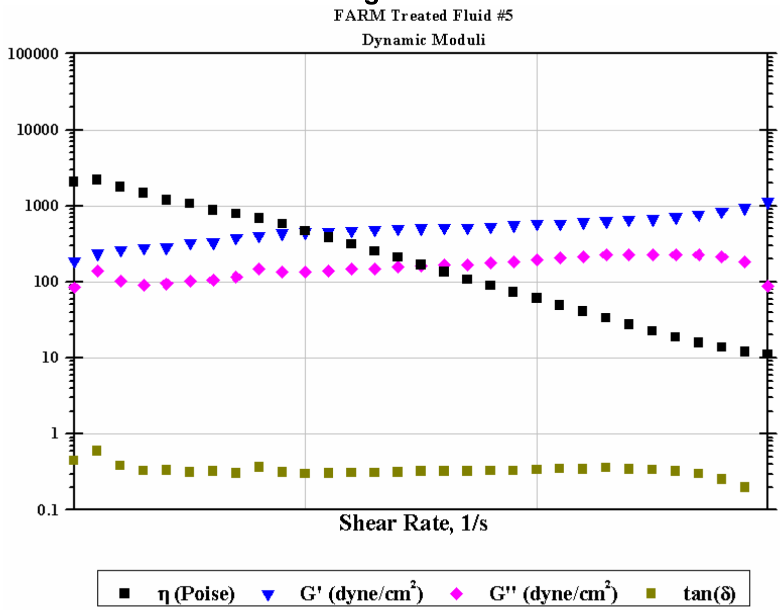


Figure 9



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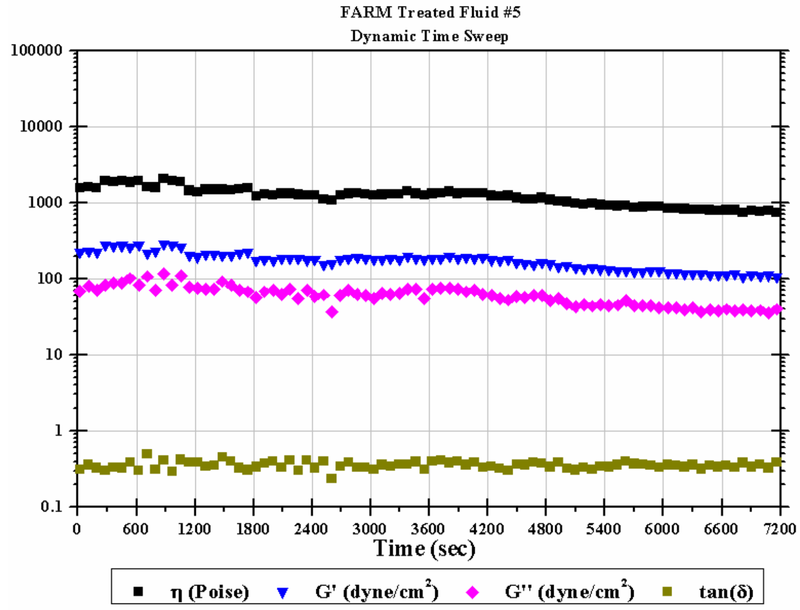

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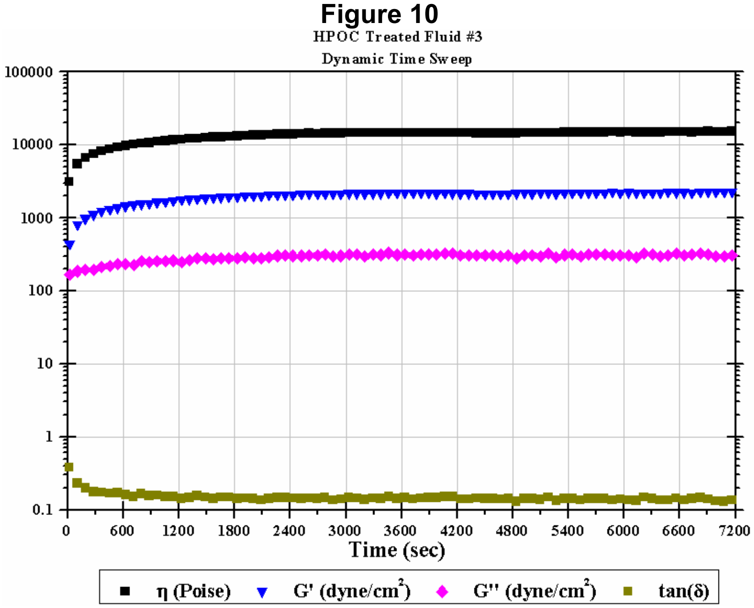

Figure 12

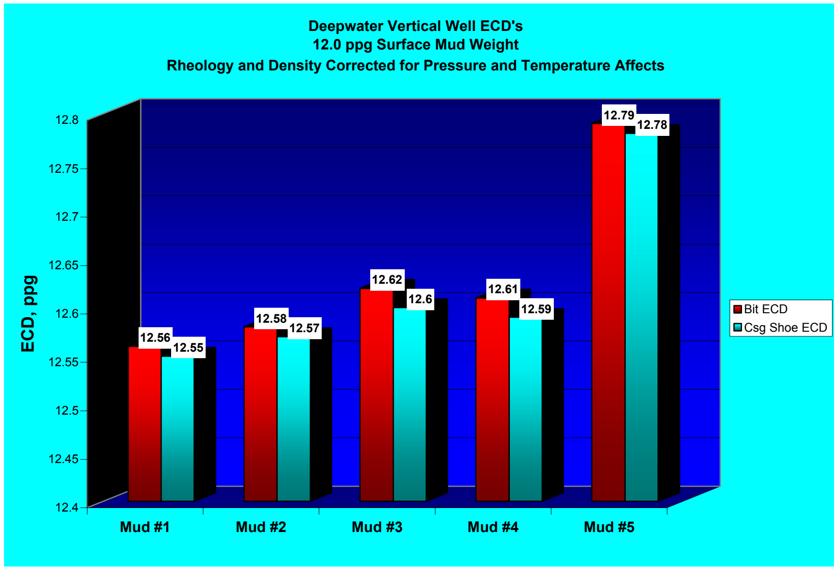

Figure 13

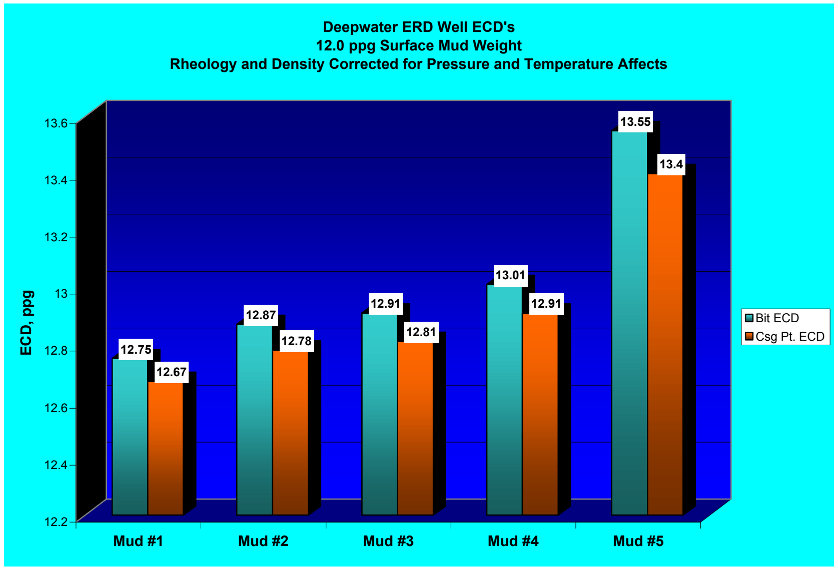

Figure 15

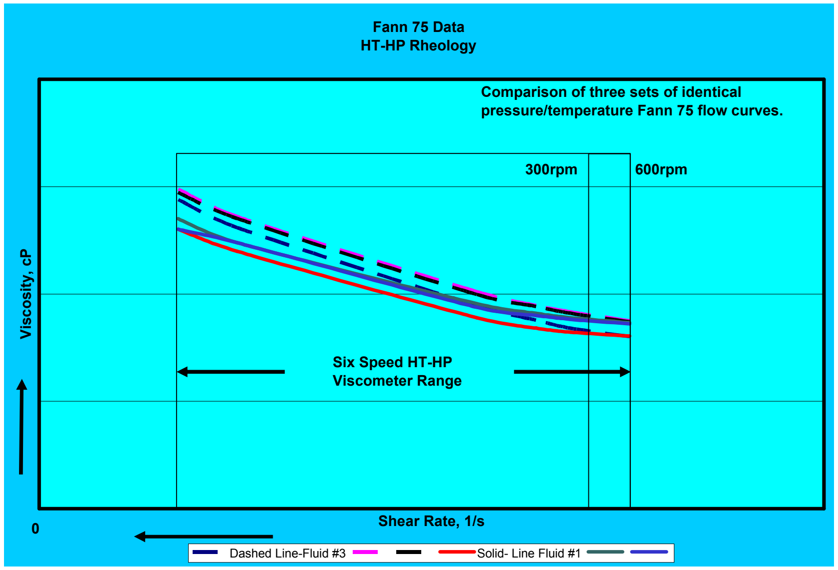

Figure 14