

New XHPHT Drilling Fluid Used to Successfully Drill Deep Bossier Sands in Central Texas

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Abstract

The challenges of drilling in ultra HPHT environments are many and varied. From the early planning phase to well completion, technical challenges encountered are extreme and can be very costly. One area where extreme temperatures and pressures are encountered is the deep Bossier trend located in Central Texas, which has experienced a recent increase in drilling activity. As in all projects, the selection and use of the proper drilling fluid is paramount to the success of the overall operation. The extreme temperature and pressure gradients encountered in this trend can lead to a multitude of problems including loss of circulation, well control issues, and difficulties logging due to high temperature fluid gellation. This paper compares and contrasts the types of drilling fluids used, highlighting the recent successful use of a new Extreme High Pressure, High Temperature (XHPHT) drilling fluid in this trend.

This paper summarizes portions of the planning and drilling challenges associated with this trend. Aspects covered and the technologies employed to successfully drill to total depth include:

- Pore pressure, fracture gradients, casing seat selection, logging
- Drilling fluids selection, monitoring and maintenance relative to depth and temperature

Operational highlights and key lessons learned will also be addressed.

Introduction

The Cotton Valley has long been a highly productive formation onshore in Texas and Louisiana. The majority of Cotton Valley wells drilled are located in Northeast Texas and Northwestern Louisiana where the formation is encountered at relatively shallow depths in comparison to those required to penetrate the formation in the Central Texas area. Cotton Valley wells in Leon and Robertson counties will approach depths of 20,000 ft and experience associated bottomhole temperatures and pressures of 425° F and 20,000 psi, respectively. In addition to the extreme temperatures and pressures encountered, potential drilling problems include slow rates of penetration, wellbore stability and deviation, loss

of circulation, and influxes of carbon dioxide (CO₂) and hydrogen sulfide (H₂S) gases. Many of the recently drilled wells have used oil-based mud (OBM) to either help eliminate or overcome these problems.

Several wells have recently been drilled with no mud related problems by utilizing a new oil-based drilling fluid designed for use in extreme high pressure, high temperature applications. The XHPHT system has been used on several Gulf of Mexico deep shelf gas wells, but until recently, has not been used on any land applications. The new system employs new fluid loss additives, viscosifiers, and emulsifiers to provide enhanced rheological and fluid loss control in extreme operating environments.

Well Design

A sound well design with accurately planned casing points is crucial to drill a successful deep Bossier well. There are a number of potential problems and considerations that should be taken into account in the planning stage.

These include but are not limited to:

- High temperatures & pressure gradients
- Lost circulation potential
- Large quantities of CO₂ gas
- H₂S potential
- Rates of penetration

This is not to say that problems will not be encountered regardless of how good the planning and design might be. A number of different casing point selections have been tried with varying degrees of success. Casing points have typically been based on the desired casing sizes. One casing program that has been successful through the trend was identified by Tubbs and Wallace.¹ The program calls for setting a first string of intermediate casing, usually 13 3/8 inch, into the top of the Georgetown formation isolating problematic zones previously drilled after setting casing at conventional surface casing depths. A second intermediate string is then set through the Travis Peak and Knowles Lime into the top of the Bossier shale. This requires drilling through the Travis Peak with a 12 1/4 inch bit, which tends to be very slow. Drilling can then proceed to total depth as sufficient fracture gradient exists at the second casing shoe to accommodate the fluid densities that will be needed.

The majority of deep Bossier wells in the trend drill a

17 1/2" surface hole to between 2,450 ft and 2,800 ft true vertical depth (TVD), setting 13 3/8" surface casing into the Midway Shale. The intermediate section is typically drilled with a 12 1/4" bit to the top of the Travis Peak. At this point, a 10 5/8" bit will be used to complete the intermediate section to the top of the Knowles Lime. The 10 5/8" bit will outperform the 12 1/4" bit and still allow 9 5/8" casing to be run and cemented. Drilling will then resume with an 8 1/2" bit to the upper Bossier shale where a 7 5/8" liner is set. The shoe will be drilled out and tested to ± 19.0 lb/gal mud weight equivalent. In this section, drilling will resume with a 15.5 – 16.0 lb/gal OBM. The fluid density will gradually increase as background gas increases. Depending on geology and formation development the expected mud weight at total depth (19,000 ft - 20,000 ft) will be ± 18.7 lb/gal.

Drilling Fluid Selection

Most of the deep Bossier wells utilize a water-based system to the top of the Bossier where either the second intermediate string or drilling liner is set. The drilling environment to this depth is more normally pressured (Figure 2) and moderate in the temperature gradient encountered (Figure 1). After setting casing at the top of the Bossier, the water-based system is displaced from the hole with OBM which is used to drill the remainder of the well.

Water-based mud (WBM) is used to drill the upper section for several reasons. There is a high potential for whole mud losses while drilling the Pecan Gap, Rodessa, and Woodbine formations. The intermediate section will encounter a long section of Travis Peak and will drill relatively slow. Historically, WBM has out performed OBM in hard rock drilling. This is due to the micro-fracturing that occurs ahead of the bit with WBM that does not occur with OBM. Additionally, to control the density and drill solids, excessive dilution with base oil would likely be necessary, increasing the cost of the fluid.

The fluid density should be maintained below 10.2 lb/gal while drilling the Travis Peak. Depending on faulting and formation development, the potential exists for pressured sand just below the Travis Peak. In the lower portion of the intermediate section, CO₂ should be expected. Significant lime additions will be necessary to treat the CO₂ while drilling the Knowles Limestone. As should be expected, daily treatment of the WBM in the liner section will increase as temperatures increase. HPHT additives will be necessary in this section to help prevent high temperature gelation.

After setting casing into the top of the Bossier, the well is displaced with a diesel OBM. These wells can be successfully drilled with a high performance XHPHT WBM, but the cost of these systems would be 30-40% higher.

An OBM is ideal for drilling the remainder of the well versus a water-based fluid for the following reasons:

- Increased thermal stability³
- Superior wellbore stability³
- Enhanced solids tolerance
- Generally higher rates of penetration

- Ease of treatment for acid gases

The OBM system is treated conventionally until bottomhole temperatures approach 385° F. The system is then converted to the new XHPHT OBM. The new system employs new fluid loss additives, viscosifiers, and emulsifiers.

The need to convert at these bottomhole temperatures is necessary for several reasons. First, not only does the temperature gradient continue to increase, but second, the formations encountered are hard and abrasive leading to ROP's less than 4 fph and promoting the build up of fine solids in the system.

In addition to increasing the emulsion stability, the new emulsifier employed in the XHPHT system helps enhance the solids tolerance of the system. This is needed since the types of bits employed to drill this section can lead to a buildup of fine drill solids. Diamond impreg or PDC bits are often used to drill this section. The cutting mechanism of impreg bits is best described as "grinding" as compared to fixed cutter bits that "shear" the formation. Impreg bits take a very small depth of cut (DOC) compared to conventional fixed cutter bits. The DOC is the length of forward progress made during one revolution of the drill bit. The DOC of an impreg bit can be as small as 0.005" (0.13 mm). In normal fixed cutter drill bit applications, the DOC is greater than 0.050" (1.3mm).² As can be seen, the size of a cutting from an impreg bit can be less than 10% the size of a conventional cutting, resulting in an increase of fine drill solids in the system.

It has been well documented that oil-based muds are also heavily affected by temperature and pressure.³ The density of OBM's will vary in proportion to the amount of oil, water, and solids in the fluid. In general, their density will decrease with increasing temperature and increase with increasing pressure. It is also known that at a certain point the increased pressure component will dominate the thermal expansion resulting in a higher downhole density than what is observed on the surface. Not only will the compressed fluid have a higher density, it may also have a higher viscosity and exhibit excessive gel strengths if the low gravity solids are not controlled to an acceptable level.

This in turn can lead to high temperature gelation problems during trips, logging, and running casing. This increased gel structure can cause excessive swab and surge pressure, inhibit the ability to get logs to bottom, and increase the potential for loss circulation to occur.

XHPHT System

The new XHPHT system used on the Case History well is comprised of several high temperature viscosifiers, fluid loss additives, and a new high temperature emulsifier. The system is flexible in the sense that all the additives are compatible with their conventional additives. Depending on the drilling environment and circumstances, each product can be used as a singular solution or formulated as an integrated system.

Viscosifiers

The system has two new viscosifiers, an extended high temperature organoclay and a high temperature polymer. The

clay is a highly refined organophilic hectorite used for suspension and supplemental fluid loss control. Typically, standard organophilic clays have temperature stabilities ranging from 350°F to about 400°F. The chemistry of the new clay has been modified to increase the temperature stability to >450°F.

The second viscosifier is a surfactant treated, finely-ground, inorganic compound. It is used to modify the fluid's rheological properties and is effective in reducing syneresis. Factors that determine its use include the characteristics of the base oil, the emulsifier package, and the physical application parameters.

Fluid Loss Additives

The first of two new fluid loss additives is an amine treated lignite (ATL). Similar to organophilic clays, the quaternary amines used in the manufacture of ATL have a tendency to dissociate from the lignite at elevated temperature and particularly in the presence of divalent cations, resulting in a lack of thermal stability above 425°F. The new ATL has a temperature stability of 475-550°F and is environmentally compliant for North Sea use and since it will not interfere with the Reverse Phase Extraction (RPE) or sheen test, it is a viable fluid loss additive for Gulf of Mexico (GoM) compliant systems.

The second fluid loss additive is a synthetic polymer used primarily as for XHPHT fluid loss control. The temperature stability of the product is in excess of 900°F. Due to the product's secondary viscosity effect, it contributes to controlling barite sag. It will also stabilize HPHT viscosity well beyond the temperature limit of organophilic clays and will therefore compliment the HPHT organoclay at temperatures above 430°F.

Emulsifier

The new high-temperature emulsifier and wetting agent is a high-performance, environmentally safe product, used as a supplementary emulsifier in conjunction with conventional products. The new emulsifier readily stabilizes fluids, requiring minimal shear to perform and is compatible with a wide range of internal phase salinities. Drilling fluids made from low aromatic content base fluids and treated with the new emulsifier show increased solids tolerance and exhibit a more stable emulsion above 400°F. It has been recognized that additions of lime with the new emulsifier will enhance the temperature stability of the system with respect to viscosity.

Case History

The first land use of the XHPHT system was on a deep Bossier well with a target depth greater than 20,000 ft. The expected temperatures and pressures at total depth were 440°F and 22,000 psi, respectively. A large casing program was chosen to provide a contingency liner option at 19,000 ft.

Water-Based Section

The well was spudded with a conventional water-based fluid. The section was drilled without problems and surface casing was set at approximately 4,500 ft, reaching casing point with a 9.2 lb/gal mud.

The first intermediate section was drilled with a lignite/lignosulfonate system. The section reached a total depth at 12,811 ft with 10.0 lb/gal mud weight. Casing was set into the top of the Travis Peak without problems. The rate of penetration through this section averaged nearly 15 ft/hr.

The second intermediate section continued with the use of the lignite/lignosulfonate system drilling to the top of the Knowles Lime. This section was drilled with a 10-5/8" bit to just below 17,200 ft, logged, and casing run and cemented with no problems.

Invert Emulsion Section

Prior to drilling out and testing the casing shoe, the hole was displaced with a 16.0 lb/gal OBM. Initial fluid properties are listed in Table 1. Drilling fluid considerations for drilling this interval were:

- rapid increase in pore pressure
- bottomhole temperatures in excess of 400°F
- potential for CO₂ and H₂S
- slow ROP's

Drilling resumed at an average ROP of 6 ft/hr. As expected the pore pressure quickly increased as evidenced by increasing temperatures and background and connection gas. Within 1,100 ft of drilling out of the second intermediate string, an 18.4 lb/gal fluid density was needed to control formation pressures. Large quantities of lime additions were needed to treat the CO₂ encountered in the Knowles Limestone. To maintain an excess lime concentration of 3.0 lb/bbl, daily additions of nearly 2,200 lbs of lime were needed. The average daily addition of lime for this section was 1,500 lbs, indicating that significant amounts of CO₂ were continually being encountered (Figure 6).

At 19,275 ft, bottom hole temperatures were approaching 400°F. Although the fluid remained stable, increasing concentrations of conventional emulsifier were required to maintain the desired emulsion stability (ES). Figure 3 shows the emulsion stability and the erratic behavior of the ES until the new emulsifier was introduced to the system. ES readings averaged 800-900 mV and were in a decreasing trend. After an initial treatment was made the concentration was increased and the ES steadily improved. Additions of the new high temperature emulsifier were begun at an initial concentration of 0.5 lb/bbl. This concentration was gradually increased to just over 4 lb/bbl and maintained. Just prior to reaching total depth, the concentration was increased to 5.5 lb/bbl.

A second benefit of the new emulsifier was realized with the decrease in plastic viscosity (PV) readings. As can be seen in Figure 7, the PV gradually increased with increasing depth. Plastic viscosity is affected by the size, shape, distribution, and quantity of solids, and the viscosity of the liquid phase. Therefore it is affected by all solids, including low gravity

solids. As previously discussed, bit type and dilution rates can negatively affect the percentage of low gravity drill solids in a drilling fluids system. As can be seen in Figure 5, this is precisely what happened. The percentage of low gravity solids increased from an average of 6% to near 10% as drilling progressed. Prior to the XHPHT emulsifier additions, the PV was running over 60 centipoises (cP). After the additions were started, the PV decreased to ± 50 even though the percentage of low gravity solids was increasing.

The HPHT fluid loss was initially maintained with a combination of conventional fluid loss additives such as gilsonite and asphalt along with emulsifiers. As can be seen in Figure 4, the fluid loss was being controlled at ± 1.0 ml but showed an increasing trend from just below 19,000 ft to about 21,000 ft. An initial treatment of 0.5 lb/bbl of the high temperature fluid loss additive was made to the system and maintained to total depth. Figure 4 shows the decreasing trend in the HPHT fluid loss after the fluid loss material was added. The HPHT fluid loss was measured at 350°F from the initial displacement depth of 17,233 ft. to 19,275 ft. At this depth, due to safety considerations, the decision was made to reduce the HPHT measurement temperature to 300°F. Fluid samples were sent to the Houston laboratory on a weekly basis where the HPHT was tested at 350°F. In addition to providing superior HPHT fluid loss control, the fluid loss additive also enhances the rheology and suspension characteristics of the drilling fluid. This secondary effect of the product is important at elevated temperatures due to the fact that very few organophilic clays can withstand temperatures in excess of 385° F for prolonged periods of time without being replaced.

A 20.0 lb/gal formation integrity test (FIT) was performed at 19,275 ft to determine if enough fracture gradient existed at the 9 5/8" casing shoe to drill to total depth without an additional drilling liner. The test was successful and drilling continued to total depth with no fluids related problems. The bottom hole temperature and pressures fell just short of what was expected at total depth. The final temperature and pressure was 430°F and just over 21,000 psi., respectively.

Best Practices

Experience with these types of wells has led to several best practices. One practice that has been very successful has been the mixing and spotting of a pill prior to logging. The objective is to reduce the percentage of low gravity solids to less than 6, ensuring that the HPHT fluid loss in the open hole is 2.0 ml or less and sufficient excess lime is present to manage any CO₂ influx. Other wells in this trend that have not spotted logging pills have had to make multiple wiper trips prior to getting logs to bottom.

A number of the deep Bossier wells have been directionally drilled with an S-curve profile. It has been observed that when drilling directionally in the 12 1/4" section, weighted sweeps will be necessary to avoid cuttings bed formation. High viscosity sweeps are not generally recommended as they tend to channel to the high side of the

wellbore.

Periodic laboratory analysis of the drilling fluid is necessary to make certain the rig site analysis is accurate. Rheological properties of the fluid should be measured at anticipated downhole temperatures and pressures. If the fluid is not stable at the temperatures and pressures currently or soon to be experienced, pilot testing should be conducted to determine treatments to achieve stability.

Conclusions

- The new XHPHT additives increased the temperature stability and stabilized the system enhancing the overall drilling operation
- Benefits of the XHPHT emulsifier were not only high temperature emulsion stability, but also included increased solids tolerance of the system
- The use of XHPHT logging pills to reduce high temperature gelation was instrumental in successful logging of the well on the first attempt
- Additional benefits from use of the XHPHT system include reduction in mud-related non productive time (NPT) and overall well costs

Acknowledgments

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Nomenclature

Define symbols used in the text here unless they are explained in the body of the text. Use units where appropriate.

<i>BHA</i>	= Bottomhole assembly
<i>ROP</i>	= Rate of Penetration
<i>OBM</i>	= Oil Base Mud
<i>H₂S</i>	= Hydrogen Sulfide
<i>CO₂</i>	= Carbon Dioxide
<i>XHPHT</i>	= Extreme High Pressure High Temperature
<i>TVD</i>	= True Vertical Depth
<i>FIT</i>	= Formation Integrity Test
<i>PV</i>	= Plastic Viscosity
<i>WBM</i>	= Water Based Mud
<i>F</i>	= Temperature, degrees Fahrenheit
<i>NPT</i>	= Non-productive Time
<i>Lbs/gal</i>	= Density, pounds per gallon
<i>Psig</i>	= Pressure, pounds per inch ² (gauge)
<i>YP</i>	= Yield Point, lbf/100 ft ²
<i>Lb/bbl</i>	= Concentration, pounds per oilfield barrel

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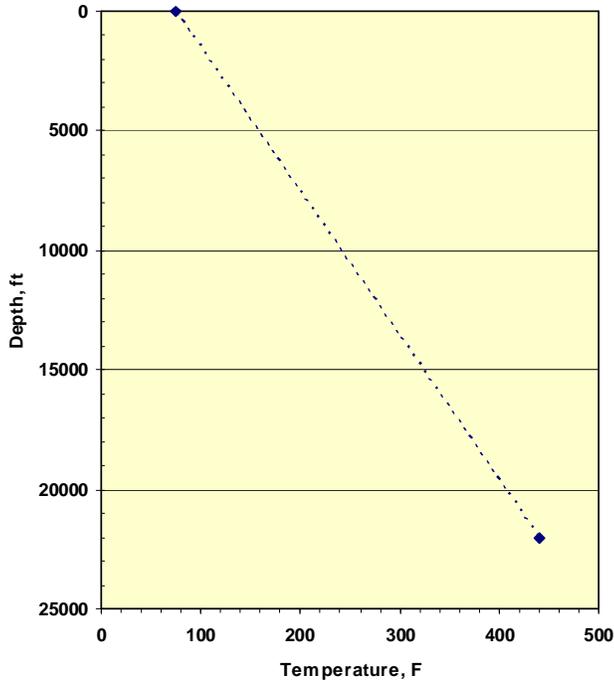


Figure 1 – Deep Bossier Temperature Gradient

Table 1
Initial OBM Properties

Density, ppg	16.0
Plastic Viscosity, cp	29
Yield point, lb/100 ft ²	10
10 sec. Gel, lb/100 ft ²	11
10 min. Gel, lb/100 ft ²	19
HTHP Filtrate, cc	5.8
HPHT Temperature, °F	350
Solids, %	30
Oil, %	60
Water, %	10
OWR	86/14
E.S., nV	979
CaCl ₂ , % wt	21

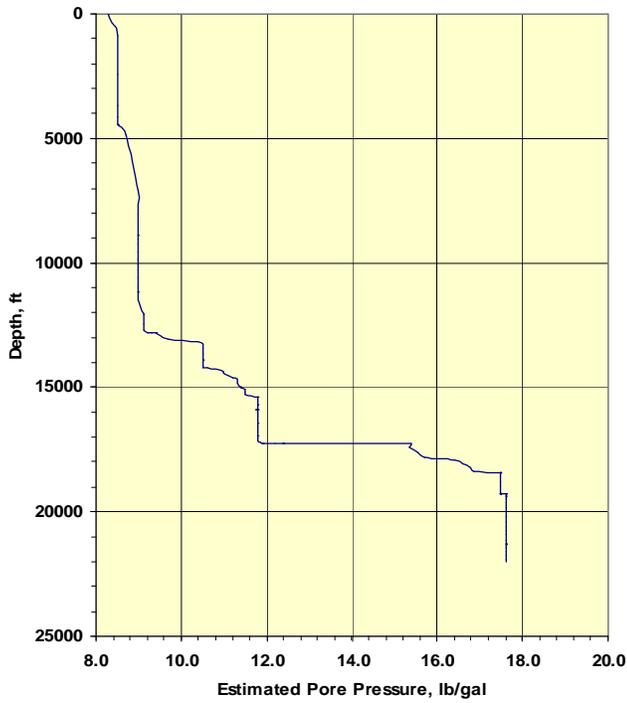


Figure 2 – Estimated Pore Pressure

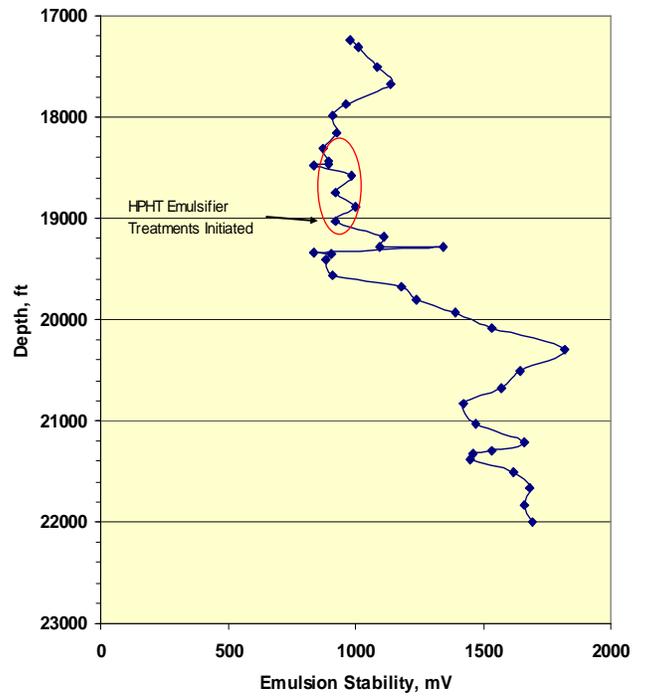


Figure 3 – Emulsion Stability @ 150° F

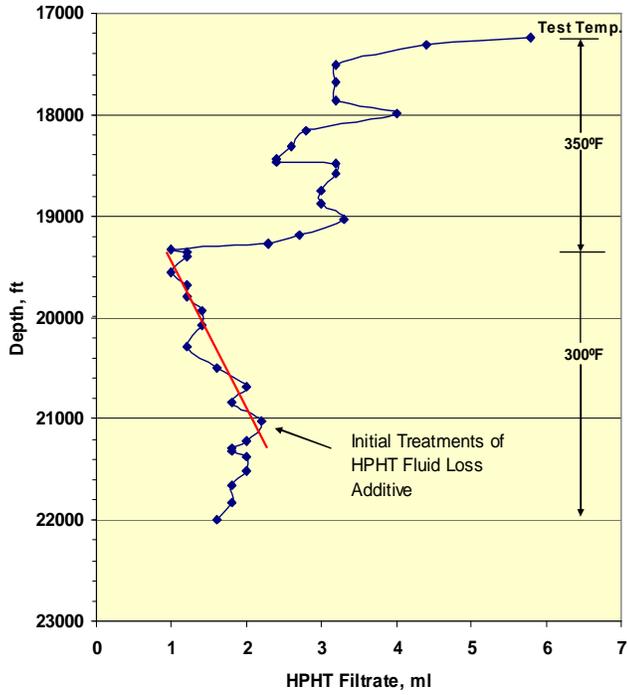


Figure 4 – HPHT Fluid Loss

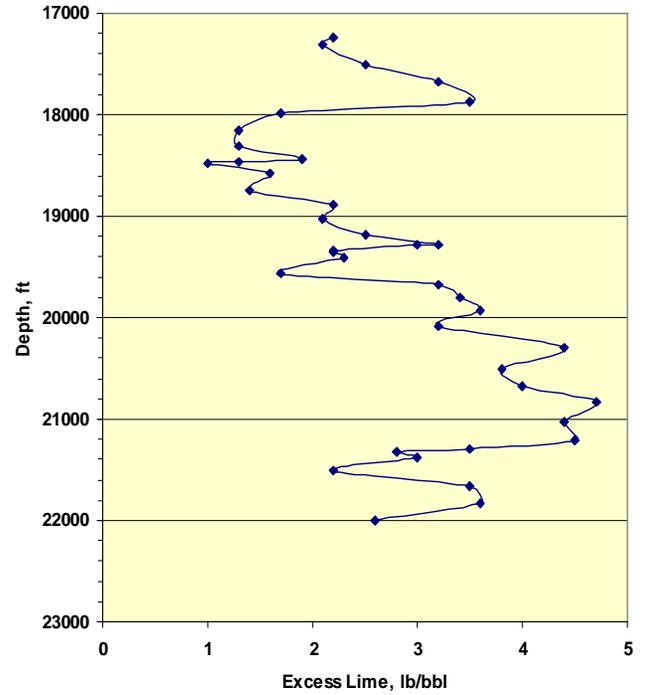


Figure 6 – Excess Lime Concentration

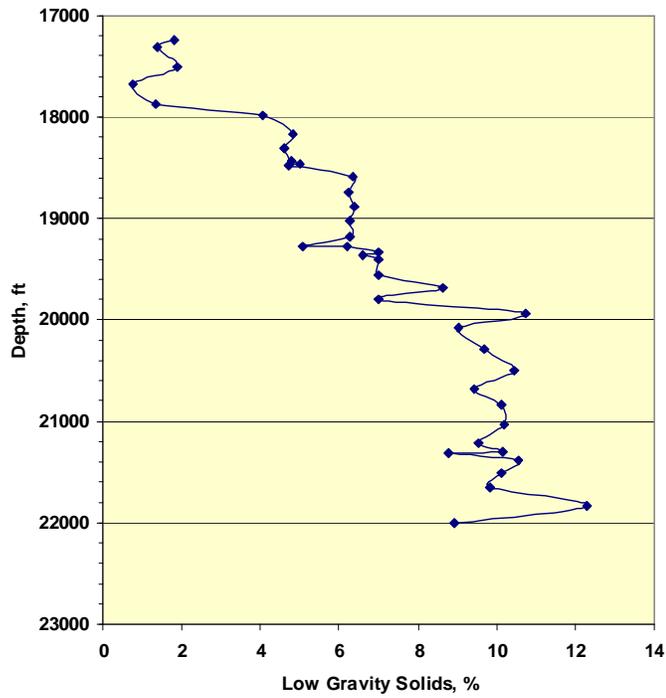


Figure 5 – Percent Low Gravity Solids

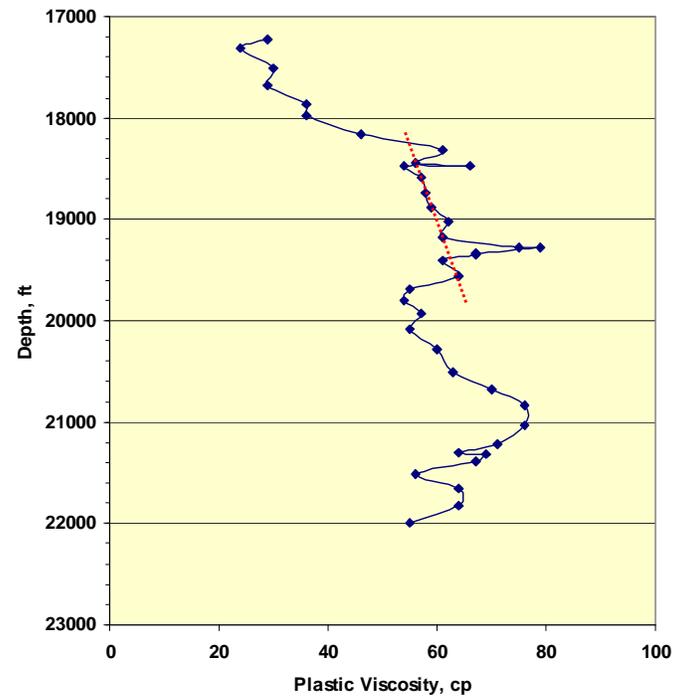


Figure 7 – Plastic Viscosity @ 150° F