AADE-06-DF-HO-08

Salt-Free Internal Phase Oil Mud Provides Improved Performance

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Abstract

Water-in-oil emulsions have been used as drilling fluids since the 1950s. As these systems were developed, it was found that emulsified calcium chloride brine provided optimal properties and excellent shale stability when used as the internal water phase. Concern over the environmental acceptability of the calcium chloride has led to the investigation of alternative materials that can be used in the internal phase. Using a non-ionic polyol consisting of polyglycerol as a component of the internal phase instead of calcium chloride addresses these concerns.

The field performance of systems containing the polyglycerol as an internal phase has been measurably better than similarly formulated oil-based mud using calcium chloride. This result was unexpected. In the 40+ wells where the polyglycerol internal phase oil-based mud has been utilized, large improvements in rate of penetration (ROP) and wellbore stability have been noted. On these wells in western Canada and the U.S. Rocky Mountains, a consistent trend of increased ROP and improved wellbore stability (allowing lower mud densities) has shown that the polyglycerol functions differently than calcium chloride in the mud. Shale stability testing using a downhole simulation cell illustrates this.

Introduction

Use of non-aqueous drilling fluid has increased substantially in many drilling regions since the 1980s. There are a number of reasons for using them rather than water mud. Improved wellbore stability and increased drilling rate have provided ample economic benefits by reducing overall drilling costs.[1]

The major breakthrough that provides the wellbore stability benefits was the development of the controlled activity concept by Chenevert.[2] This concept prevents hydration of troublesome shale formations by maintaining the drilling fluid aqueous activity less than or equal to the aqueous activity of the shale. Historically, the control of aqueous activity has been accomplished using salts. In most regions of the world, calcium chloride is the preferred salt for this purpose, although sodium chloride and magnesium chloride have also been utilized[3].

The use of non-ionic polyols as an agent for activity control is a relatively recent development for water-based drilling fluids[4] and non-aqueous emulsion fluids. Patent literature lists polyols like glycerol and polycyclicpolyetherol (PECP) as emulsified phase components in a non-aqueous emulsion fluid[5]. Earlier work shows that polyols like glycerol could be used to enhance the thermal stability of non-aqueous emulsion drilling fluid[6]. The addition of these materials for activity control in oil-based and synthetic-based non-aqueous fluid to achieve a desired activity had not been practiced in field operations until Newpark Canada began using polyglycerol for activity control in the 3rd quarter of 2001. Although the practice improved environmental acceptability without sacrificing the benefits of aqueous activity control, improvements in drilling performance encouraged the use of the fluid in more general circumstances[7].

Exploring the differences between polyols and salts gives insight into the reasons that polyglycerol internal phase fluids have benefits over conventional salt-based fluids. Laboratory testing that demonstrates the effectiveness of polyglycerol for activity control has helped to develop techniques for field application. As with all drilling fluids, a consistent approach to engineering the fluid is the key to successful use. Examples of operational improvement to reduce drilling costs and increase drilling performance demonstrate the practical application of polyglycerol internal phase fluids.

Differences between salts and non-ionic polyols

Ionic salts dissolve in water by separating into positively charged cations and negatively charged anions. These ions attract associated water molecules that move with the ions. This attraction lowers the aqueous activity of the solution, with activity decreasing at higher dissolved salt content. Figure 1 gives a plot of the activity of calcium chloride solutions versus the concentration of salt up to a 40 wt% concentration. Most non-aqueous drilling fluids utilize activities of 0.75 Aw (25 wt% calcium chloride brine) to 0.50 Aw (36 wt% calcium chloride brine).

Non-ionic polyols solubilize in water by the association of water molecules with hydroxyl groups present on the polyol molecule. Typically, lower molecular weight polyols with high concentrations of hydroxyl groups exhibit activity reduction in water solutions. For polyol compounds that exhibit activity reduction, activity versus concentration curves are similar to the activity plot for commercial polyglycerol in Figure 2. The commercial polyglycerol provided for use in drilling fluids consists of primarily di- and tri-glycerol with glycerol and some water with a small amount of sodium chloride. Table 1 gives typical analysis of commercial polyglycerol. Comparing Figures 1 and 2 shows that higher concentrations of polyol are required for the same activity when compared to calcium chloride. For example, to achieve a 0.70 Aw; a concentration of 70 vol% of the polyglycerol with 30 vol% fresh water is required as compared to 27.5 wt% calcium chloride.

The ability to achieve activity reduction is only a part of the process of stabilizing shale with balanced activity non-aqueous fluid. The other part of the process is to establish an osmotic membrane by the efficient emulsification of the low activity aqueous phase. Testing has been conducted to show that the low activity emulsified phase consisting of polyglycerol and water works as well as conventional calcium chloride brine.

Downhole simulation testing

Shale stability testing using preserved shale can demonstrate osmotic phenomena associated with controlled activity fluids. The continuing downhole simulation cell project conducted by Newpark Drilling Fluids has the capability to return a shale specimen to *in situ* conditions and, by drilling with a small bit under downhole conditions, duplicates the environment experienced in an actual wellbore[8]. When fluid flow between the shale and the drilling fluid is measured, the formation of an osmotic membrane can be demonstrated. Two different test series were conducted with commercial polyglycerol internal phase compared to calcium chloride brine internal phase.

Gulf of Mexico Shale - West Delta 109

Several projects have been conducted using a shale core obtained from West Delta Block 109 in the Gulf of Mexico at a depth of approximately 4,200 ft[8,9]. In a project for the Gas Research institute[8], a 0.89 Aw (16 wt% calcium chloride brine) mineral oil-based fluid was used in testing to determine the downhole activity of this shale. At downhole conditions and with no differential pressure between the drilling fluid and the shale, water was removed from the shale at a rate of 0.064 mL/hr (see Figure 3). As a comparison, an identically formulated fluid with similar properties was prepared using 40 vol% commercial polyglycerol and 60 vol% fresh water that resulted in a 0.89 Aw internal phase. When the polyglycerol internal phase system was tested, water was removed from the shale at a rate of 0.060 mL/hr (see Figure 4). Similar values for the shale moisture content were also found on comparison of the two tests. The test specimens also appeared to be almost identical as seen in Photographs 1 and 2.

Atoka Shale - Oklahoma

Two samples from an Atoka shale core from a depth of approximately 3,700 ft (see mineralogical analysis Figure 5) were tested using non-aqueous fluids with 0.64 Aw (30 wt% calcium chloride brine and 75 vol% polyglycerol). After equilibrating to conditions of stress and temperature, the shale was drilled with no differential pressure. Every 48 hr the differential pressure was increased by 500 lb/in^2 until the differential pressure reached 3,000 lb/in^2. In the two tests using each fluid, the results showed similar ability to form an effective membrane at differential pressures up to 2,000 lb/in^2. This was indicated by fluid flow from the shale into the drilling fluid at 500, 1,000, 1,500, and 2,000 lb/in^2. At 2,500 and 3,000 lb/in^2 differential pressures, flow reversed and fluid began flowing into the shale from the drilling fluid for both the calcium chloride brine internal phase and the polyglycerol internal phase. This result suggests that the fluids have similar performance when considerable differential pressure exists between the wellbore and the formation. Additional testing is underway to further quantify the performance of the fluid in the Atoka shale at high differential pressures.

Non-aqueous fluid formulation and engineering using polyglycerol

Non-aqueous fluids using a polyglycerol internal phase formulated with conventional emulsifiers and organoclay normally minimize the polyglycerol content. Typical formulations use oil/water ratios of 98/2 or 97/3. This is done for several reasons. Since the polyglycerol is higher cost than calcium chloride, minimizing the amount in the fluid results in the lowest cost fluid. Also, as the polyglycerol content of the fluid increases, larger amounts of emulsifiers are required for equivalent properties of electrical stability and high temperature/high pressure filtration. This tendency is much more pronounced in laboratory and newly mixed field mud. Finally, the amount of polyglycerol required to achieve the desired activity can double or triple the volume of the emulsified phase as compared to calcium chloride brine, but this volume is not totally distilled in the retort test.

Engineering fluids using a polyglycerol additive for activity control has required the development of a reliable means of measuring fluid activity. Conventional humidity sensors are extremely sensitive to temperature and the apparatus customarily used is prone to error. For that reason, a robust, automated instrument has been used to measure the fluid activity. Because it records the readings and confirms that the sample temperature is constant, the activity measurement is more accurate and reliable than achieved in the past[10]. Photo 3 shows the instrument currently in use in the field and laboratory.

With the more costly polyglycerol internal phase, undesirable water can cause an increase in the fluid activity to an unacceptable value. For this reason, a means of removing water is needed. Magnesium sulfate is a compound that complexes with water to form magnesium sulfate heptahydrate[11]. This can be used to remove undesirable water from the fluid.

Case History 1: Minehead Field, Canada

A development well drilled by a major Canadian operator in Alberta's Minehead Field provides an excellent opportunity to gauge field performance of the salt-free system versus that of conventional non-aqueous fluid. In this example, the operator had drilled numerous wells in the field, systematically optimizing various operational factors along the way to achieve a high degree of cost-effective efficiency while utilizing various oil-based formulations. Prior wells in the field had utilized conventional calcium chloride inverts, potassium formate inverts and all-oil systems.

All-oil systems had been utilized exclusively on a series of most recently drilled wells in the field.

Typical Minehead Field wells are drilled to total depth of 11,200 ft utilizing two strings of full-bore casing. The surface interval is drilled to about 2,050 ft with a simple bentonite slurry, where 9 5/8-in casing is set. The 8 ¾-in production interval is drilled to about 11,200 ft. Multiple wells utilizing the all-oil system averaged 31 days from spud to rig release with typical total drilling costs of $2.5-2.6 million. The pacesetting well drilled with an all-oil fluid system was completed in 27 days with total well cost of $2.4 million.

Salt-Free System Results

In January, 2005, the salt-free internal phase system was selected to drill two wells in the Minehead area. The first well was planned for a total cost of $2.56 million, and was projected to be drilled to 11,200 ft in 30 days, spud to rig release, including one logging run.

The salt-free system represented the only operational variance as compared to previous projects in the field. The system was employed in the 8 ¾-in production interval.

Fluid activity was maintained at 0.55 Aw with additions of the polyglycerol additive. A high oil/water ratio was maintained in the range of 97/3 to 98/2. Rheological properties for optimal hole cleaning were achieved via organophillic clay additions. Good wellbore stability and easily maintained low gravity solids content indicated the superior inhibitive characteristics of the salt-free fluid.

The well was drilled to total depth at 11,222 ft with an average ROP of 510 ft/day. The well was drilled, logged and cased in 26.7 days, including non-productive time (NPT). Bit selection issues in highly developed sandstone formations cost 3.2 days of NPT.

Drilling fluid cost was $251,369 ($22.40/ft drilled). Total well cost was $1.93 million in 26.7 days, versus projected cost of $2.56 million in 30 days. This also beat the previous pacesetting performance by nearly $500,000 in total well cost. Total savings to the operator on this well were estimated at $600,000—and were attributed to outstanding ROP and wellbore stability provided by the inhibitive fluid properties.

Case History 2: Wildhay Field, Canada

Typical well designs in this field feature 9 5/8 in casing set at about 1,320 ft, and 7 7/8 in production interval drilled to about 10,300 ft, where 4 ½ in casing is set.

A variety of fluids have been utilized to drill wells in the field, including both water- and oil-based systems. Among offsets, one operator had drilled a series of wells utilizing a conventional calcium chloride invert system. These wells were drilled, on average, in 24-26 days with total well cost of $2.5-2.6 million.

Salt-Free System Results

The subject well, utilizing the salt-free invert system, was spudded on November 26, 2005. The 12 ¼ in surface hole was drilled with a basic bentonite slurry to 1,200 ft in 3.5 days. Massive fluid losses and sand were problematic throughout the interval, costing the operation 0.5 days in NPT.

The 7 7/8 in production interval was drilled in 10 days with the salt-free invert system. Fluid density for the interval was gradually increased from 8.2 lb/gal to 10.3 lb/gal while drilling the interval. A high oil/water ratio was maintained from 97/3 to 98/2.

Good hole cleaning was ensured through close attention to rheology, and was adjusted with additions of quality organophillic clay and a rheology modifier. The polyglycerol additive was employed to control the activity of the interval phase less than 0.55 Aw. Wellbore stability was credited for trouble-free tripping and improved penetration rates.

The well reached total depth of 10,300 ft in 15 days with ROP averaging 606 ft/day. Total drilling fluid cost was $223,390, or $21.70/ft drilled. The well was drilled, logged and cased in 16 days with total well cost of $1.51 million. Total well cost savings estimated by the operator were $300,000.

Case History 3: Table Rock, Wyoming

Operational demands in this active drilling basin dictated an oil-based fluid with the lowest density achievable and appropriate activity control to drill the production interval (16,000-18,000+ ft) through the Weber formation.

The salt-free invert system was recommended, since it could be formulated at the lowest possible density (7.4

lb/gal). This resulted from the use of polyglycerol to replace calcium chloride to achieve activity control while saving 0.2 lb/gal in final density.

As compared to earlier wells drilled in the field with conventional calcium chloride invert systems, the polyglycerol invert wells achieved a 73% increase in ROP in the hard rock drilling environment at Table Rock. ROP increased from 2.6 to 4.5 ft/hr.

Further, when trace elements of H_2S were detected in the upper Weber and additional density was required, ROP remained virtually the same at the increased mud density.

Interval results, coupled with operational improvements in intermediate sections, resulted in measurable efficiency improvements for the operator. Figure 6 gives the days versus depth for 5 wells. The two fastest wells for this interval, TRU 135 and TRU 134, utilized the polyglycerol internal phase system.

Summary and Conclusions

The use of polyglycerol as an activity control agent in non-aqueous fluid's internal phase has proven successful over the past 4 ½ years. In field operations, an improvement in drilling performance and reduction in wellbore instability has justified the continued use of the system.

Utilization of an accurate, automated electrohygrometer has improved the monitoring and treating of the system. This has allowed for consistent treating practices for polyglycerol additions and water scavenger treatments.

Continued studies are underway to understand the differences in fluid performance that result in the improvements observed. The emulsification of a polyglycerol-based internal phase may be different from the emulsification of ionic salts like calcium chloride.

Acknowledgments

The authors would like to acknowledge their respective companies for permission to publish this paper. The contributions of numerous drilling supervisors and mud engineers to the successful application of the polyglycerol based fluid are also recognized.

Nomenclature

Aw	=	*water activity expressed as a decimal fraction (fresh water = 1.00 Aw)*
Polyglycerol	=	*compounds consisting of repeating glycerol units - di- and tri-glycerol*
Polyol	=	*organic compound with one or more hydroxyl (OH) groups*

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Table 1 - Typical Composition of Commercial Polyglycerol

Glycerol	30 wt%
Di-glycerol	30 wt%
Tri-Glycerol	15 wt%
Higher order polyglycerols	10 wt%
Water	15 wt%
Sodium chloride	15,000 mg/L

Figure 1 - Activity of Calcium Chloride Solutions (in Fresh Water)

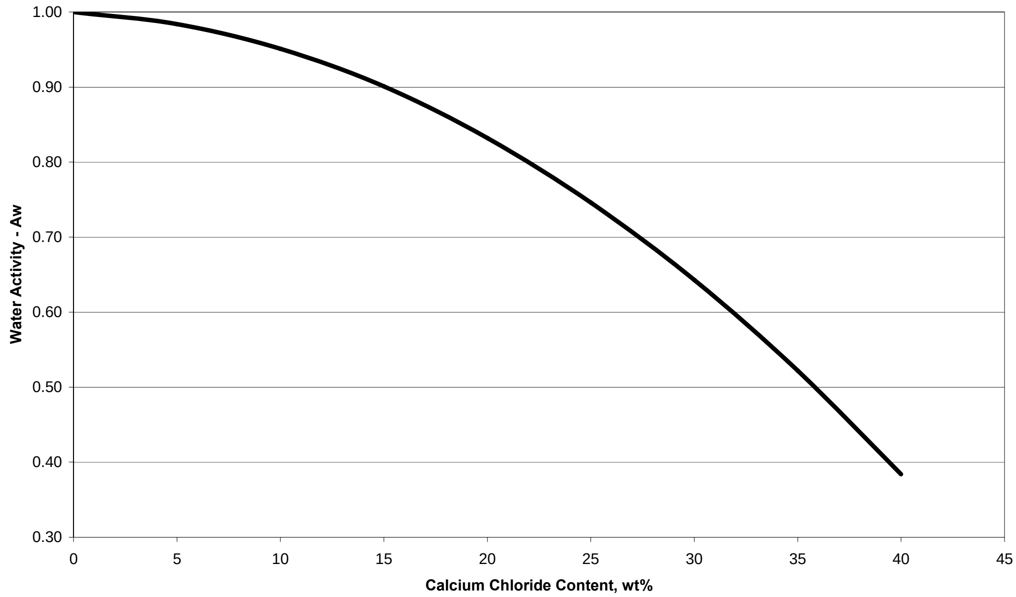


Figure 2 - Activity of Commercial Polyglycerol Solutions (in Fresh Water)

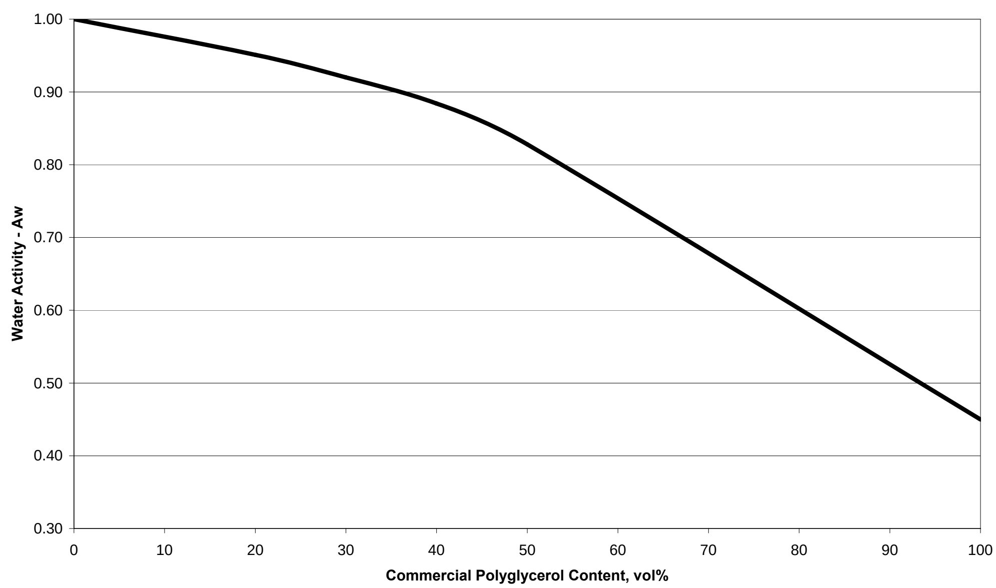


Figure 3

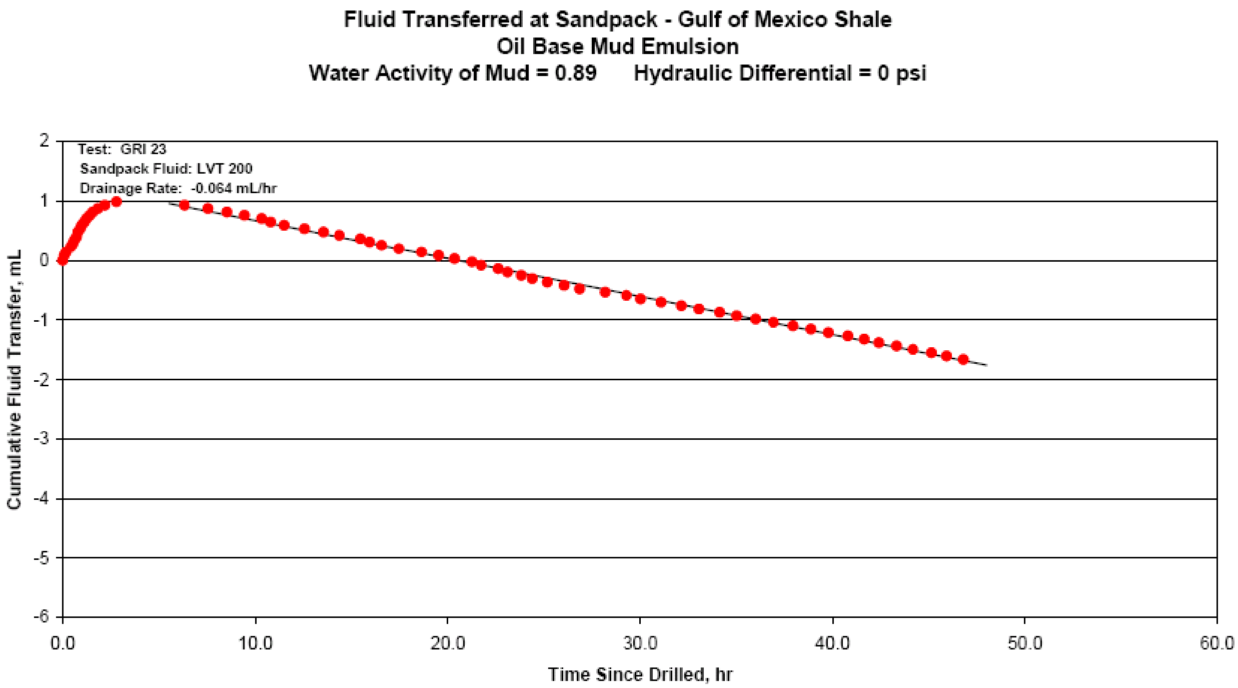


Figure 4

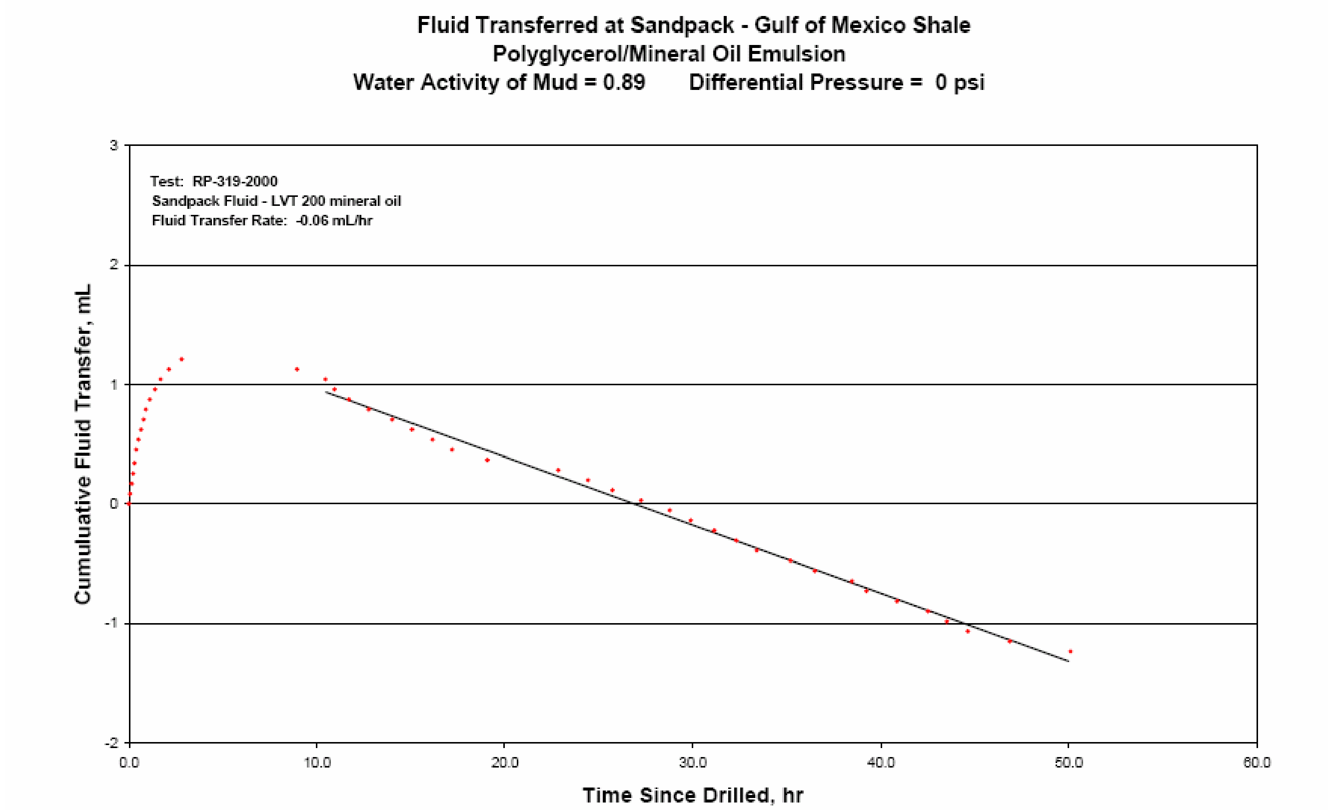
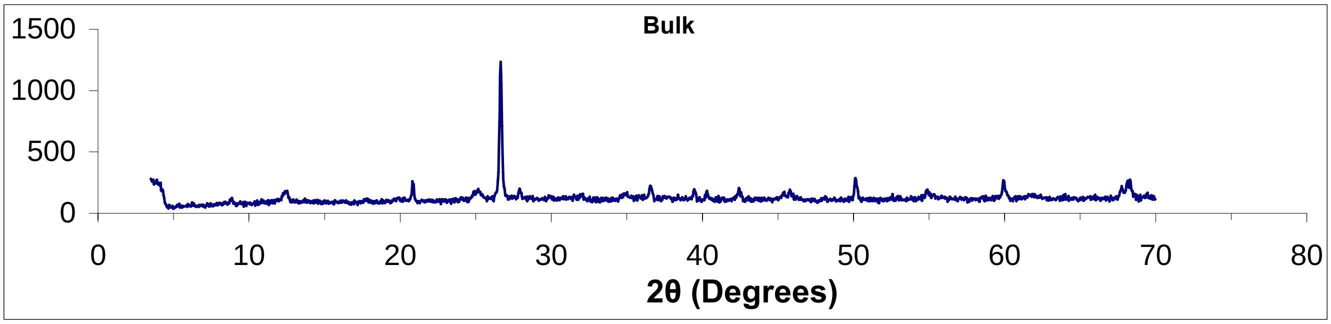
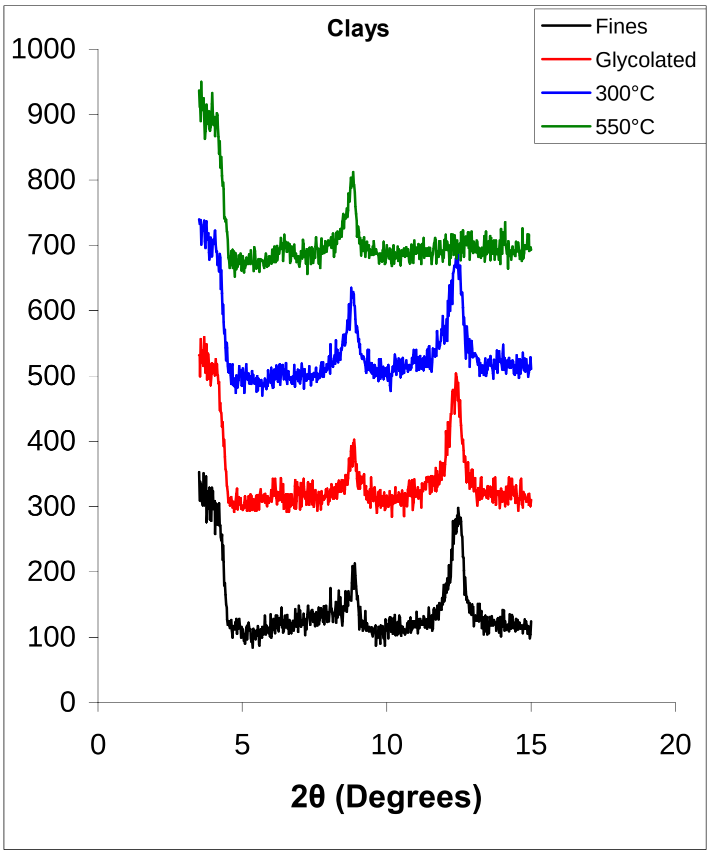


Figure 5 - Mineralogical Analysis - Atoka Shale





Interstitial Cations and Anions -			**meq/100 g**
Sodium	2.6	Chloride	0.2
Potassium	1.0	Sulfate	0.7
Magnesium	0.0	Carbonate	0.9
Calcium	0.0	Bicarbonate	1.2

Bulk Composition -	**wt%**
Quartz	52
Feldspar	15
Calcite	0
Dolomite	0
Siderite	0
Pyrite	0
Halite	0
Barite	0
Total Clay	33

Clay Composition -	**wt%**
Kaolinite	32
Chlorite	7
Illite	31
Smectite	19
Mixed-layer	11
Illite/smectite	19 / 81

CEC -	**meq/100 g**
	13.5

Moisture -	**wt%**
	2.0

Hardness -	**Duro 'C'**
	95

Specific Gravity -	**Air Pyc.**
	2.56

Shale Equivalent Water Activity -	**A_s**
	0.660

Exchangeable Bases -	**meq/100 g**
Sodium	3.6
Potassium	1.2
Magnesium	1.2
Calcium	4.8

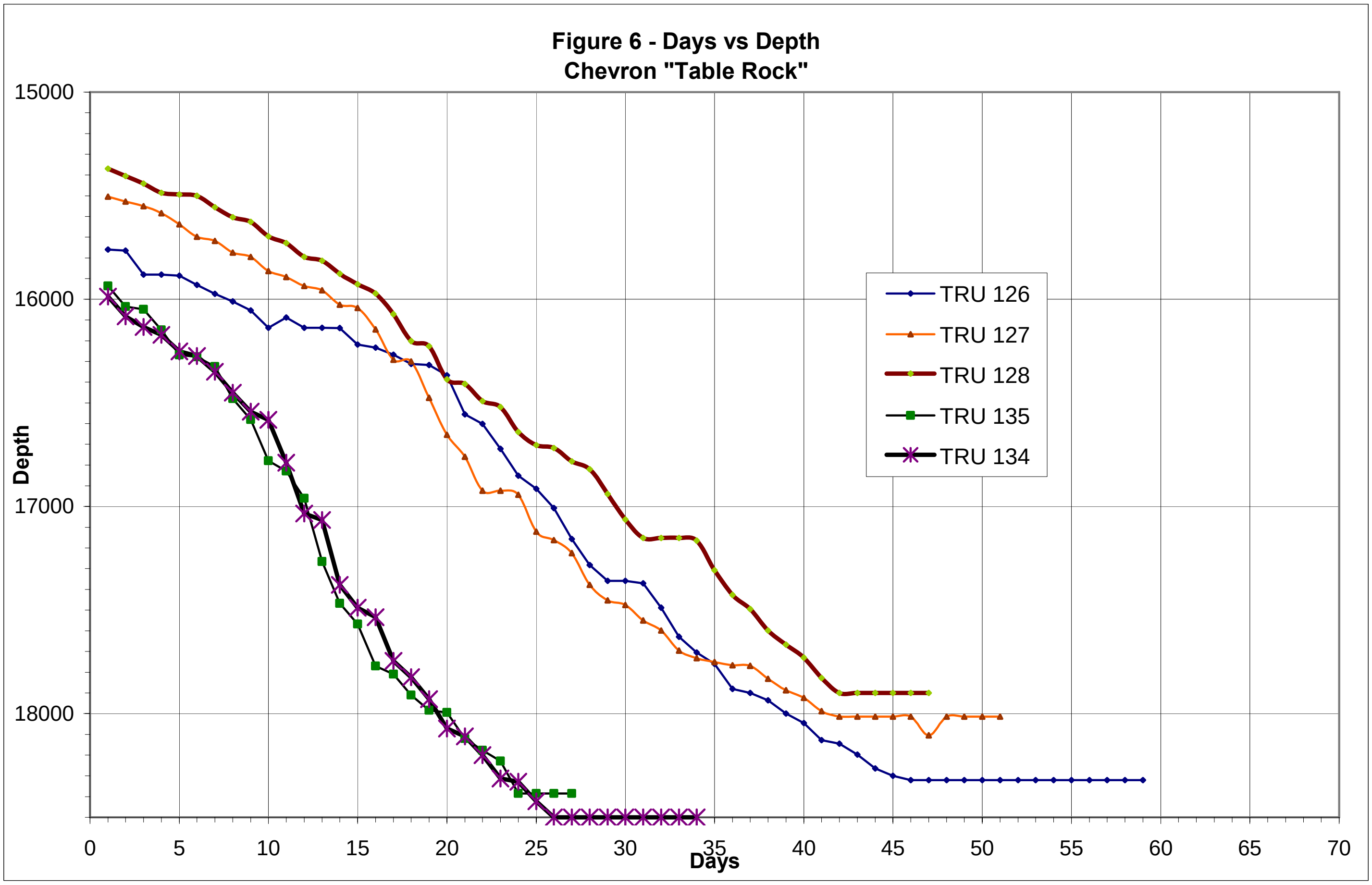


Figure 6 - Days vs Depth
Chevron "Table Rock"
Depth
Days
15000
16000
17000
18000
0
5
10
15
20
25
30
35
40
45
50
55
60
65
70
TRU 126
TRU 127
TRU 128
TRU 135
TRU 134

Photo 1 - Shale after exposure to calcium chloride brine internal phase mud

Photo 2 - Shale after exposure to polyglycerol internal phase mud

Photo 3 - Automated activity measurement system