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An Experimental Investigation of Formation Damage Caused by Commonly Used Water-Based Drilling-Mud Onshore Trinidad

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Abstract: *During drilling operations, formation damage occurs within the vicinity of the well bore. Unless appropriate steps are taken, well productivity can be drastically affected. The severity of this damage depends on the degree of underbalanced or overbalanced pressures between the drilling-mud and formation fluids during drilling operations; the compositions of the commonly used drilling-mud; the amount and types of clay present in the reservoir; fluids compatibility; and the amount of fines migration that occurs during the drilling and well clean-up operations. The end result is a decrease in permeability which is usually expressed by a dimensionless parameter referred to as "skin". In this study, rock samples from four of the main oil producing reservoirs onshore Trinidad (Cruse, Forest, Morne L'Enfer and Herrera) were treated with six commonly used drilling-mud samples. Permeability measurements before and after treatment of the reservoir samples were conducted to determine the extent of formation damage. X-Ray Diffraction tests were performed to determine the type and percentage of clay present and scanning electron microscope images were obtained to show how the clays were distributed in the formations. The results from these tests gave valuable information in the selection of suitable drilling-mud for the onshore oil reservoirs in Trinidad. This information can benefit other regions as well that have similar shaly sandstone oil and gas reservoirs.*

Keywords: *Drilling mud, clay, formation damage, reservoir, permeability, experimental*

1. Introduction

Formation damage to productive reservoirs is caused by the swelling of clays and by the blockage of pore throats and is of a major concern during drilling operations (Bennion et al., 1995; Bennion et al., 2002). The severity of this damage depends on the choice of drilling-mud, the presence and type of clays present in the reservoir, the mud salinity and the depth of mud filtrate invasion (Civan, 2007). The drilling-mud to be used has to be carefully selected so as to control and minimise fluid losses. The approach taken is to use bridging agents (e.g., calcium carbonate) and high polymer loadings (e.g., xanthan-gum) in drilling-mud so as to reduce fluid losses. However these additives themselves and others (for mud weighting, clay dispersants and various dissolved salts) can contribute to formation damage (Navarrete et al., 2000). The presence of clay minerals is probably the most important and complex aspect relating to formation damage (Carney and Taylor, 1978). However the invasion of mud filtrate can also cause damage in formations which are void of clays (Jones and Neil, 1960).

Problems associated with the presence of clays in drilling productive formations have been well documented (Halbouty and Kalden, 1938). In general the clays in reservoir are classified as *swelling* or *non-swelling* (Carney and Taylor, 1978). Montmorillonite is the only clay that swells and the degree of swelling depends upon the cation which is associated with the clay and the amount of dissolved salts in the water contacting the clay. Mixed-layers clay contains montmorillonite which will also swell with water, but the illite portion of this clay is relatively non-water swelling. Kaolinite and chlorite, as well as illite are classified as non-water swelling clays (Alymore and Quirk, 1966). They do not build viscosity in water as effectively as montmorillonite, since their crystals tend to remain in packets rather than disperse, as is typical for montmorillonite.

A fair degree of clay inhibition (stabilisation) can be obtained by the use of inorganic salts (such as potassium chloride, ammonium chloride and zirconyl chloride) when added to the fluid phase of water-base mud (Carney and Taylor, 1978). In addition, the use of polymers for encapsulation has proved valuable for these same fluids, as they will reduce the mobility of water into the clay lattice structure, thus retarding its adsorption by the clay (Carney and Taylor, 1978). The merits of a low pH filtrate have been also substantiated (Mungan, 1965). However an increase in pH allows increased hydration of clays, and their subsequent dispersion followed by migration until they are stopped by a natural choke in a flow channel. This migration can contribute to the blockage of many productive zones (Carney and Taylor, 1978).

Formation damage also occurs in water sensitive reservoirs, with and without the presence of clays, by a phenonmenon called *Aqueous Solution Salinity Shock* (Civan 2007). This occurs when the salinity of the mud filtrate is lower than the critical salt concentration (CSC) (Khilar and Fogler, 1985). This causes particles of clays or other finely divided minerals to become loosened from attached sand grains which will eventually move to bridge pores and flow channels. Experimental studies on cores of unconsolidated sand have been found to be water sensitive if' an amount of fine-grained sand (less than 350 mesh) was present (Jones and Neil, 1965). Clays (including montmorillonite) on the other hand are believed to disperse, chiefly because of the development of negative electrical charges on the clay particles which cause the particles to repel one another and overcome attractive forces. Aggregates weaken and fragments become detached which may move and eventually form obstructions in flow channels (Jones and Neil, 1965).

During drilling operations, mud-filtrate invades near the well bore region, often called the flushed and transition zones. The flushed zone is perforated and partially cleaned-up in the well completion phase to improve flow. Very often the zone invaded by the mud filtrate known as the transition zone is often too deep for penetration. The mud filtrate in the flushed and transition zones contains materials used for fluid loss control, mud weighting, pore blocking/ bridging particulates. Clay dispersants and various dissolved salts would interact with the formation and cause formation damage (commonly referred to as *skin*). In this study mud-filtrate from six commonly used drilling- mud onshore Trinidad was obtained and their effect on the four (4) main oil-producing reservoirs onshore Trinidad was experimentally investigated. The objective was to recommend a suitable drilling-mud for future drilling operations onshore Trinidad.

2. Description of Trinidad Onshore Oil Reservoirs

The reservoirs in Trinidad are sedimentary in origin. The main oil bearing stratigraphic sequence of the onshore reservoirs consists of the Upper and Lower Morne L'Enfer (UMLE, LMLE), Forest and Cruse formations of Pliocene age and the Wilson/Herrera of the Middle Miocene age (Wach and Archie 2008). The lithological framework of these reservoirs consists of sand with varying degrees of silt and dispersed clays which were deposited within a deltaic setting. The reservoirs themselves are poorly consolidated, often with exceptionally high porosities in the 20 to 40 % range and with permeabilities in the range of 10-1,500 millidarcy (mD). Porosities within the 8 to 20% range and permeabilities of less than 10 mD are encountered in the deep Cruse and deep Herrera formations (Ramkhalawan et al., 1995). This wide variation in permeability has led the experienced geologists and engineers in Trinidad to describe these onshore reservoirs as being"very heterogeneous".

3. Distinguishing features of the commonly used water based drilling mud onshore Trinidad

The composition of a particular drilling-mud is tailored from experience so as to provide appropriate parameters for drilling a reservoir and with minimum damage to the reservoir. The compositions of the six commonly used water- based drilling-mud onshore Trinidad can be seen in Table 1. The distinguishing feature(s) for each mud sample are as follows:

3.1 Gel Polymer Neutral (7.5 pH) and High (11 pH) pH Mud Systems

The basic polymer mud systems are often used for the drilling of low budget on-land wells. These mud comprises of bentonite, for mud viscosity and filter cake development; Poly Anionic Cellulose (PAC), for filter cake enhancement and fluid loss control so as to minimise formation damage; and a zanthan based viscosifier, for increasing viscosity and yield point. Barite is commonly used to increase density to the required amount. These mud additives perform best under an alkali condition and some mud companies prefer to maintain a pH greater than 7.5 for maximising performance.

However the free hydroxyl ions within the mud at higher pH, often cause clay related drilling problems such as bit balling, mud rings and sloughing of clays. The increase in pH causes increased hydration of clays, and their subsequent dispersion followed by migration until they are stopped by a natural choke in a flow channel (Carney and Taylor, 1978). For this reason, some companies prefer to maintain a neutral pH so as to eliminate these problems, although the performances of these additives are reduced.

3.2 15% NaBr/NaCl Saltwater Based and KCl Polymer Mud Systems

The 15 % NaBr/NaCl saltwater and KCl Polymer mud systems are both additives used to minimise formation due to clay swelling and prevent clay related problems mentioned above (Jones and Neil, 1965). Since sodium is not as effective as potassium, a larger percentage of sodium is required to achieve the same level of inhibition. The saltwater-based mud (i.e., 15% NaBr/NaCl) requires polymers that can function under high salinity conditions such as Flo Vis NT, Dual Flo HT and Mag OR for viscosity and fluid loss control. Major considerations when using salt-based fluids are corrosion control on surface and down-hole equipment, cost and treatment/disposal of fluid after drilling.

Table 1. Composition of Commonly used Drilling Mud Onshore Trinidad

Mud Additives	Concentration of Mud Additive in Drilling Mud Samples					
	Gel Polymer (7.5 pH)	Gel Polymer (11 pH)	Saltwater Based Mud (15% NaBr/NaCl)	Lignite / Lignosulfonate	HiDrill Polymer	KCl Polymer
Gel	10 ppb	10 ppb		15 ppb	10 ppb	10 ppb
Duotech	2 ppb	2 ppb				
PAC	1 ppb	1 ppb		0.5 ppb	1.5 ppb	2 ppb
Caustic Soda	0.25 ppb	1 ppb				
Barite	85 ppb	85 ppb		85 ppb	85 ppb	65 ppb
NaBr/NaCl Brine			15%			
FloVis NT			1 ppb			
Dual Flo HT			5.5 ppb			
Mag OR			0.75 ppb			
Myacide GA25			1%			
SafeCarb			35 ppb			
Spersene				2 ppb		
Tannathin				5 ppb		
FedZan				2 ppb	2 ppb	
Rheosmart					0.5 ppb	
MSA Drill-in					0.5%	
HiDrill					1.5%	
Duovis						1 ppb
KCl						5%
KOH						1 ppb
Soda Ash						0.5 ppb

3.3. Lignite-lignosulfonate mud system

The highly dispersed lignite-lignosulfonate mud system is frequently used throughout Trinidad. The advantage of this mud system is the ability to achieve low fluid loss and tough filter cake. Also a highly dispersed fluid can eliminate rheology problems, often caused by increase in solids or temperature, which results in increased yield point and gel strengths. These problems are commonly encountered when using non-dispersed polymer fluids. Both lignite (Tannathin) and lignosulfonate (Spersene) will require a pH greater than 9.5 to be effective as a dispersant. Some of these particles assist in building the wall cake but due to their small particle size a significant amount is present in the mud filtrate.

3.4 HiDrill Polymer mud system

The HiDrill Polymer mud system is similar to the basic polymer system, except that it contains the additive Rheosmart, which is a deflocculant that is effective at neutral pH; and HiDrill, which is an anionic clay inhibitor. These additives make this mud system more effective at reducing the clay related drilling problems than the basic polymer system. However the cost of this mud system is high.

4. Experimental Study

In the laboratory, formation damage by drilling mud is investigated by circulating mud and allowing it to contact the core face. This procedure simulates the formation of a mud filter cake at the wall of the borehole in productive formation and the entering of mud filtrate into the formation. However, due to a lack of equipment and samples, small core plugs from the onshore reservoirs in Trinidad were treated with mud filtrate by soaking under vacuum so as to determine the extent of formation damage in the flushed and transition zones which are partially perforated and cleaned up.

4.1 Core Preparation

Reservoir rock samples from the Morne L'Enfer, Cruse, Forest and the Herrara formations were obtained from the local oil company of Trinidad and Tobago, Petrotrin. These are the major oil reservoirs onshore Trinidad where drilling operations take place regularly. Six core plugs of dimension 1-inch diameter by about 2 inches in length were prepared from each formation by a commercial core company based in Trinidad. The core samples were placed in a Soxhlet apparatus and treated with toluene to remove oil and then with methanol to remove toluene and water from the cores. The cores were then dried in an oven at 40°C.

Porosity and permeability measurements were made. The cores were then placed in labeled containers (see Figure 1) and transported to the UWI Chemical laboratory. Table 2 shows the permeability of formation core samples before and after treatment with mud filtrate (soaking under vacuum).

Table 2. Permeability of Formation Core Samples before and after treatment with Mud Filtrate

Mud Type	Morne L'Enfer		Forest		Cruse		Herrera	
	Avg. Ø=39.9 %		Avg. Ø = 27.9 %		Avg. Ø = 8.9 %		Avg. Ø = 15.9 %	
	Permeability, md		Permeability, md		Permeability, md		Permeability, md	
	Before	After	Before	After	Before	After	Before	After
Gel Polymer (7.5 pH)	820	778	267	186	0.08	0.06	23.3	17.4
Gel Polymer (11 pH)	782	789	169	153	8.42	1.54	7.6	6.3
NaBr/NaCl Saltwater Based Mud	1500	1203	229	101	13.9	3.92	10.3	3.8
Lignite/Lignosulfonate	791	23	226	175	7.41	5.19	5.2	1.2
HiDrill Polymer	1060	450	273	162	16.1	5.26	1.7	1.9
KCl Polymer	1260	490	266	202	19.5	6.53	5.4	4.7

Figure1. Core samples

4.2 X-Ray Diffraction (XRD) Analysis

X-Ray Diffraction (XRD) analyses were conducted on samples from each formation by a commercial lab in Houston. A summary of the clay type, quartz and calcite content present can be seen in Table 1.

4.3 Mud Filtrate Preparation

Six mud samples that are commonly used in drilling of the above formations were obtained from drilling-- mud companies based in Trinidad. The compositions of these samples are shown in Table 1 (and a description of the distinguishing features for each sample was discussed earlier). Standard API filter press tests were conducted until about 200 cc of mud filtrate was obtained from each of the mud samples. The core samples were then soaked with the mud filtrate samples as described below.

4.4 Core treatment with Mud Filtrate

The apparatus that was setup for soaking of the core samples can be seen in Figure 2. It consists of a thick walled glass bottle (soak bottles) with a rubber bung stopper and two short pieces of quarter inch diameter stainless steel tubing which were bent at right angles. One of the stainless steel tubing was connected to a vacuum pump using a piece of clear, thickwalled plastic tubing. Another piece of clear plastic tubing, a quarter inch in diameter, was inserted into the glass bottle containing the mud filtrate and the other end was connected to the second stainless steel tubing. Two pinch valves were also installed on each of the plastic tubing. Six (6) of the apparatus described above were setup--one for each mud filtrate sample.

In each setup, a properly labeled core sample from each of the four formations was placed in the soak bottle. The valve at the vacuum pump end was opened and the valve at the mud filtrate end was closed. Each soak bottle was evacuated to remove air from the soak bottles and core samples. After vacuuming for about one hour, the valve at the vacuum pump end was closed and the vacuum pump was switched off. The valve at the filtrate end was then opened. Mud filtrate of sufficient quantity was allowed to enter the soak bottles, so as to completely immerse and saturate the cores (see Figure 3).

Figure 2. Apparatus for soaking cores

Figure 3. Cores covered with mud filtrate

The valve at the filtrate end was closed, and the cores were left to soak for a period of seven days (see Figure 4). The cores were removed and taken back to the commercial core labs where they were cleaned to remove mud filtrate. They were then dried and air permeability measurements were again made.

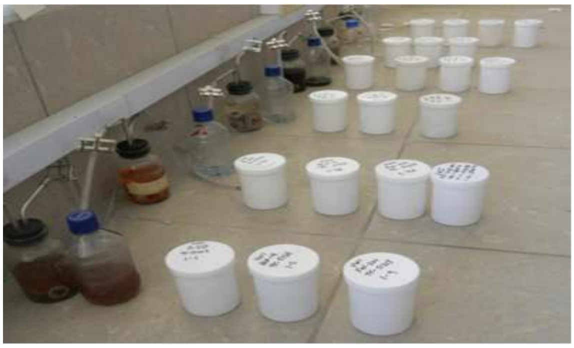

Figure 4. Cores soaking in mud filtrate

5. Reservoir Rock Properties

5.1 Porosity and Permeability Measurements

Porosity and permeability measurements of each core sample were conducted using the same commercial core lab (that prepared the core samples). Porosity was determined using a helium porosimeter before soaking of the core samples. Air permeability measurements were made before and after soaking of the core samples. Table 2 shows the results obtained for each formation.

5.2 Scanning Electron Microscope Images

Scanning electron microscope images shown in Figure 5 were taken of samples from each formation before and after mud filtrate treatment. These images were taken by the UWI medical facilities at Mount Hope, Trinidad.

6. Results and Discussions

Although this study was faced with two major difficulties—sample size and lack of equipment, the samples studied derive from real specific points in the reservoirs that are encountered during drilling operations,which are t subject to mud filtrate invasion and formation damage. Each of the measured permeability in Table 2, although specific to a reservoir depth at which a core sample was taken is either close to or within the range of values mentioned earlier before the soaking period. The same trend is expected for the clay and other mineral content. However, no data were found in the open literature for making a similar comparison.

6.1 Clay and Other Mineral Content

Table 3 shows the weight % of the clay type and other main minerals present in core samples from each formation as determined from the XRD tests. The Morne L'Enfer, Forest and Herrara samples have total clay content of about 8 % by weight, whereas in the Cruse sample it was about 3 %. The clays are dispersed and in small clusters as can be seen by the white patches in the SEM images in Figure 5. The XRD tests also show that the Cruse sample has a high calcite content of about 23 % by weight.

6.2 Core Permeability before and after Mud Filtrate Treatment

Table 4 shows the percent reduction in permeability which was determined for each core sample from the various formations as follows:

% Reduction in Perm.

$$= \frac{\text{(Perm. before treatment} - \text{Perm. after treatment)}}{\text{Perm. before treatment}} \times 100$$

Where,

Perm. = Permeability

Table 3. Clay and Other Mineral Content from X-Ray Diffraction (XRD) Tests on Formation Core Samples

Formation	Clay Content, Wt. %				Wt. %	Wt. %
	Chlorite	Kaolinite	Illite	Mx I/S*	Quartz	Calcite
Morne L'Enfer	1	Tr	3	4	64	Tr
Forest	1	1	3	2	66	1
Cruse	1	Tr	2	Tr	58	23
Herrera	2	2	4	1	78	4

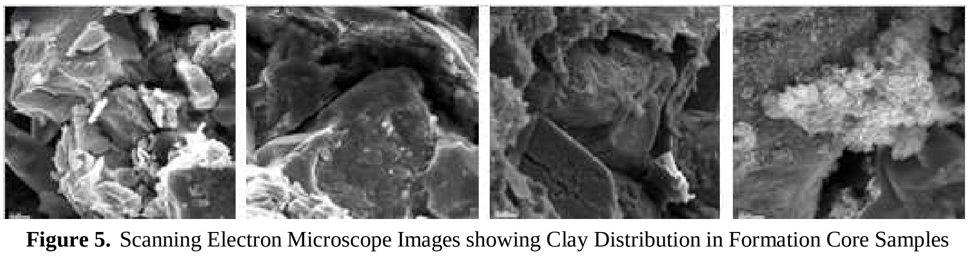

Figure 5. Scanning Electron Microscope Images showing Clay Distribution in Formation Core Samples

Table 4. % Reduction in Permeability after treatment of Formation Core Samples with Mud Filtrate

Mud Type	% Reduction in Permeability after Treatment			
	Morne L'Enfer	Forest	Cruse	Herrera
Gel Polymer (7.5 pH)	5.1	30.4	27.6	25.1
Gel Polymer (11 pH)	0.0	9.2	81.7	16.2
NaBr/NaCl Saltwater Based	19.8	56.1	71.8	62.9
Lignite/Lignosulfonate	97.1	22.5	30.0	77.6
HiDrill Polymer	57.5	40.5	67.3	0.0
KCl Polymer	61.1	24.2	66.5	12.2

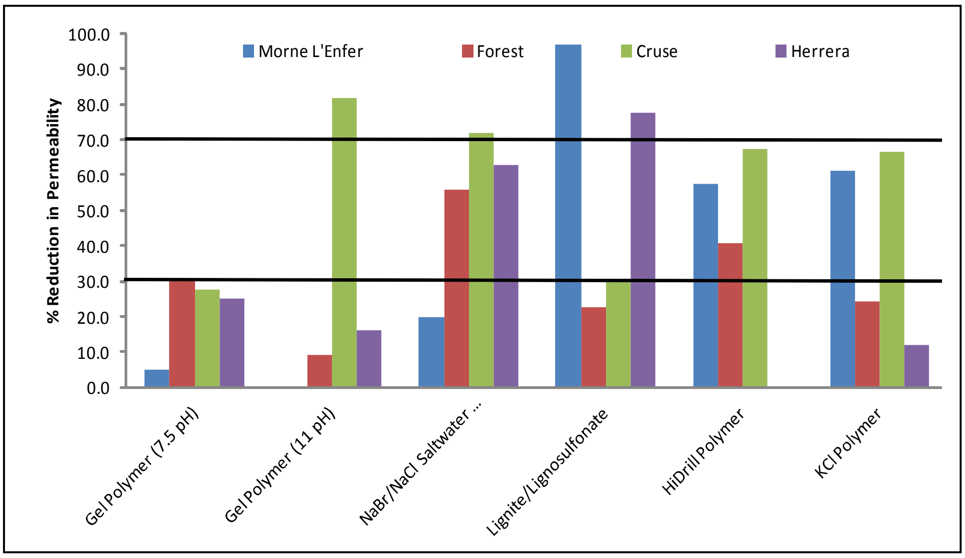

Figure 6. % Reduction in Permeability after treatment of Formation Core Samples with Mud Filtrate

6.3 Drilling Mud Selection

Based on the above assumption, Tables 5 and 6 were derived from Figure 6. They can be used for selecting a drilling-mud that is suitable for drilling single and multiple formations onshore Trinidad and with minimum damage to the formation in the mud filtrate flushed and transition zones. Low cost neutral Gel Polymer (7.5 pH) mud system is the single best selection for the drilling of both single and multiple formations.

6.4 Observations of Interest

Table 3 shows that the Morne L'Enfer has the highest weight % mix of Illite-Smectite (i.e., 4%) and the highest total clay content (8 % by weight). High alkaline mud such as the Gel Polymer (i.e., 11 pH) mud causes increased hydration (swelling) of smectite; and the dispersion of all clays present, followed by migration until they are stopped by a natural choke in a flow channel. However, as showed in Table 4 and Figure 6, there was no change in the permeability for the Morne L'Enfer core sample after treatment with the high alkaline Gel Polymer (i.e., 11 pH) mud filtrate. It is possible that:

1) The clay content is too small for formation damage by clay swelling to be noticeable.
2) Airflow permeability could not provide the drag force needed for fines migration until they are stopped by a natural choke in a flow channel. Perhaps permeability measurement by flowing mud filtrate would have shown the expected results.

Table 4 and Figure 6 show that the percent reduction in permeability in cores from the Cruse formation, that were treated with the high alkaline Gel Polymer (i.e., 11 pH) mud filtrate and the 15% NaBr/NaCl saltwater- based mud filtrate, were greater than 70 %. As showed in Table 3, the sample from the Cruse formation has a high calcite concentration of 23 weight %. Moreover, the percent reduction in permeability in cores from the Morne L'Enfer and Cruse formations that were treated with Lignite/Lignosulfonate mud filtrate was greater than 70 % (see Table 4 and Figure 6).

6.4 Limitations

The use of one core sample from each formation was not

Table 5. Drilling Mud that cause a Permeability change of less than 30 % on Core Samples from Single Formations

Formations	Drilling Mud Selection			
Single	**First Choice**	**Second Choice**	**Third Choice**	**Fourth Choice**
Morne L'Enfer	Gel Polymer (11 pH)	Gel Polymer (7.5 pH)	NaBr/NaCl Saltwater	
Forest	Gel Polymer (11 pH)	Lignite/Lignosulfonate	KCl Polymer	Gel Polymer (7.5 pH)
Cruse	Gel Polymer (7.5 pH)	Lignite/Lignosulfonate		
Herrera	HiDrill Polymer	KCl Polymer	Gel Polymer (11 pH)	Gel Polymer (7.5 pH)

Table 6. Drilling Mud that cause a Permeability change of less than 30 % on Core Samples from Multiple Formations

Formations	Drilling Mud Selection	
Multiple	**First Choice**	**Second Choice**
Morne L'Enfer and Forest	Gel Polymer (11 pH)	Gel Polymer (7.5 pH)
Forest and Cruse	Lignite/Lignosulfonate	Gel Polymer (7.5 pH)
Cruse and Herrera	Gel Polymer (7.5 pH)	
Morne L'Enfer, Forest and Cruse	Gel Polymer (7.5 pH)	
Morne L'Enfer, Forest and Herrera	Gel Polymer (11 pH)	Gel Polymer (7.5 pH)
Morne L'Enfer, Forest, Cruse and Herrera	Gel Polymer (7.5 pH)	

possible, since it is impossible to restore the sample to its original state for each mud filtrate test. On the other hand, the use of six core-plugs from the same formation would not have the same permeability, clay and other mineral content and formation fines present. There is a lack of equipment for the circulation of mud filtrate into the core. Another limitation was the inability to provide the drag force needed for fines migration until blocked.

Due to limitations in sample size, perhaps the one small core plug from each formation (and not whole cores) that was sent for XRD test did not provide a true representative of the clay content. These limitations made it difficult to explain 1) the reduction in permeability and 2) the cause of formation damage by the various mud filtrates. Perhaps the change in permeability was due to fines from the mud filtrate entering the core and the dispersion of fines present in the core during the vacuum soaking period.

7. Conclusions

Based on the core samples studied, several conclusions can be made:

1) The total clay content in Trinidad onshore reservoirs are less than 8 % by weight; are dispersed; and in small clusters.
2) The clay content is too small for formation damage by clay swelling to be noticeable by permeability measurements.
3) The low cost neutral Gel Polymer (i.e., 7.5 pH) mud system is the single best selection for the drilling of both single and multiple formations onshore Trinidad.

It is recommended that XRD should be done on whole core samples to provide a true representative of the clay content in formations. Besides, drilling-mud should be circulated and allowed to contact the core face and enter the core and provide the drag forces required for migration and blockage of dispersed fines.

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