

## Organoclay Role On Drilling Fluid Stability And Effect On Formation Damage

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### Abstract

This work tends to link the role of organoclay used in OBM system on formation damage issues. This role was investigated at different concentrations in the framework to study emulsion fluid stabilization mechanisms and filtration properties. In the present work, drilling fluid rheology and filtration properties correlation of clay mineral invert emulsion is investigated. In these complex systems, the experiments will allow to establish if the rheological properties are governed rather by the water in oil emulsion characteristics or by the structural properties of the dispersed organoclay in the continuous oil phase. Rheology, SAXS, X-Ray, Size Distribution, Microscopy, and Displacement test are used to evaluate drilling fluid stability and formation damage Caused by organoclay additive.

The preparation of drilling fluid with different ratio of dispersed water and different organoclay shows that the nature of this product has a large impact on viscosity and emulsion stability. Organoclay minimize interaction of Oil-Based drilling fluid system with the bearing rocks by forming a low permeability protective cake on the wellbore and by developing adequate physicochemical characteristics.

Surfactant type and concentration used for organoclay preparation can affect rock reservoir-drilling fluid interactions. Displacement test under reservoir conditions performed with using different additives and three (03) types of organoclay shows that filtration and return permeability damage ratio are affected seriously by type and organoclay concentration. Our work attempts to use other complementary analyzes as cited above for possible links between the additives nature, concentration and filtration properties of fluids through the reservoir

### 1. Introduction

#### 1.1 Overall review on the filtrate drilling and wellbore damage

Oil drilling is the set of operations to achieve the porous and permeable rocks of the basement may contain oil and gas. It represents the key step in the process of operating an oil or gas field. Pass an oil drilling requires a good understanding of

geological formations traversed and in situ reservoir conditions such as temperature, pressure and geodynamic constraints on the one hand and a good formulation of the drilling fluid on the other hand . This represents 15% to 18% of the total cost of drilling [39, 37 and 36].

These fluids used in rotary drilling to perform all necessary functions during drilling operations, such as the rise of material from the bottom of the well to the surface, Keep the cuttings in suspension during a judgment of circulation, cool and lubricate the drill bit and maintain the walls of the stable wells. They are composed of different liquid components (water, oil) and / or gaseous (air or natural gas) containing suspended mineral and organic additives (clays, polymers, surfactants, cuttings, cement etc ...) [21, 11, 23 and 24]. These inverse emulsion fluids are composed of an oily phase (90 %) and an aqueous dispersed phase (10 %) viscosified by organoclay, materials added to drilling fluids to improve their rheological properties as well as affinity for the organic medium. Fluids governed by 03 component interaction (water/oil/OC) and are affected by several parameters such as phase's ratio (water/oil), organoclay quantity, droplets size and deformation [41, 4, 16, 28 and 43].

These fluids have thixotropic behavior and develop a gel which retains the material behavior in suspension when the drilling is stopped, as they help maintain the rheological properties of the mud at various depths i.e. d at different temperatures [26, 35, 18, 25, 42, 9 and 22].

The stability of these complexes drilling fluids is governed by several factors, namely quantity of water, the state of organoclay particle dispersion and the interactions between the main components water/oil/AO [27, 47, 15, 48, 13, 44, 9]. During the drilling process of an oil well, the movement of such fluids creates a filter cake on the well walls to minimize the maximum invasion of the filtrate fluid and the fine particles of the drilling fluid and those from debris drilled during the drilling tool rotation. If these fluids are not stable or do not conform to API, this will cause severe damage to the reservoir rock which will affect the productivity of oil well [7, 5, 17, 17].

The objective of this study is to show, first, a W / O (90/10) invert emulsion drilling fluid stability containing

organoclay and, secondly, Hassi Messaoud (Algeria southern field) rock reservoir damage during drilling fluids movement.

### 1.2. Problem statement

As noted above, the oil industry uses different drilling fluids to perform oil well drilling. There are composed of numerous additives, making the fluid able to circulate in different geological formations providing functions for a suitable drilling well. However, while circulating in the well at high pressure, this will cause a filtration of the drilling fluid liquid phase and the added fine particles as viscosifiers and other drilled particles that may lead to severe formation damage represented by a drastic reduction of the permeability and porosity formation. This damage is a function of several parameters, such as type and injection conditions of drilling fluid, and the properties of the rock itself such as permeability and porosity.

To answer our problem, we have combined two approaches, one is based on the study of emulsion stability over time as well as the dispersion of organoclay in these emulsions (Rheo-SAXS), and the second is to evaluate the damage on Hassi-Messaoud samples with the same formulations used on field to drill the well. The drilling fluid was formulated with different organoclay used as viscosifiers.

### 1.3. Paper highlights

The main objective of this study is, at first, to study the stability of the various drilling fluids at different ingredients, especially the effect of different organoclay. This first phase is to present the state of organoclay dispersion in various fluids used and the role of different ingredients on the rheological and filtration behavior (HTHP) for the different fluids.

The second section is to study the damage on different rocks samples (Hassi Messaoud well and Berea sandstone, USA), following the flow of drilling fluids formulated above. In this section, we try to combine the Rheo-SAXS results with those obtained in the clogging of different rocks with different fluids in order to investigate how the AO will cause damage.

## 2. Drilling fluid preparation

### 2.1. Materials and methods

In our work, we used three types of commercial organoclay, called VG69, Bentone 38 VCG and Geltone. These clays act as viscosifiers and control the dispersions properties of oil-based drilling fluids. The Bentone 38 is an hectorite (trioctahedralsmectite) modified by cation exchange with dialkyl dimethylammonium surfactant and VG69 and Geltone are organophilic montmorillonite (a dioctahedral smectite). In a first step, the clay structure was characterized by XRD technic, using a powder diffractometer (Philips) in reflection mode with a Cu anode ( $K\alpha = 1 : 54\text{\AA}$ ).

As a second step, the inverse emulsions in drilling fluids were formulated on the basis of the fluids used on Hassi Messaoud wells southern Algeria. These emulsions (W/O) are formulated using an emulsifier and a wetting agent, namely a commercial nonionic surfactant (Versacoat) and a cationic

surfactant (Versamul). These products used in drilling fluids formulation are provided by MI Swaco Company. The preparation procedure is the following:

The emulsifier and wetting agent were added gradually with Ultra Turrax stirring in the continuous phase (diesel or dodecane), then an amount of mixture surfactant (anionic and cationic surfactant) is added and stirred for twenty minutes (20min) followed by an amount of clay, all stirred for forty minutes (40 min). A quantity of distilled water (10 % by volume) was added drop wise over 30 minutes of stirring. After stirring for 5 min at 7200 rev / min, stability was recorded after 30 min of rest. The emulsions were prepared with mass ratios of AO/variable liquid phase mass ratio of 0.5, 0.75, 1, 1.5, 2.5, 3.75 and 4.5 %.

These drilling fluids are then subjected to rheological characterization in order to obtain certain properties such as shear stress and yield value using a Fann 35 viscometer with coaxial cylinders designed under the Couette principle with different rotation speed (600, 300, 200, 100, 6 et 3 Tr/min). The filtrate measurements are performed according to API specifications, at a temperature of 250° F and a pressure of 500 psi. The instrument is a filter press HPHT (high pressure, high temperature), composed of a heating temperature enclosure, a filtration cell with two pressure units, gaskets resistant to high temperature and a thermometer. The filtration process begins when the filter presse conditions reached 500 Psi 250 °F. The evolution of the filtrate is monitored for 30 minutes.

The third step is to circulate the above formulated drilling fluids through Hassi Messaoud reservoir rocks samples according to the universal protocol generally used to measure the extent of damage. The experimental protocol used is described in the damage section.

### 2.2. DRX characterization

Through the XRD results, we notice that the three used organoclay show two periodicities  $d_1$  and  $d_2$ . These values correspond to those observed in the organo-modified clays for  $d_1$  and hydrophilic for  $d_2$ . The distance  $d_1$  corresponding to the surfactant intercalation in the interlayer space. This space is 20Å for VG69, 21.1 Å for Bentone and 23.8 for Geltone compatible with paraffinic structure of the added surfactant, referring to the thickness of a sheet which is 10 Å. However, the observation of a periodicity of  $d_2$  around 12 Å, shows that the exchange is not complete, there remains hydrophilic regions. These clays are partially modified (Figure 1).

### 2.3. Emulsions stability studies

Stability tests performed on mixtures of W/O (Water in Oil) with surfactant but without addition of organoclay (OC) have shown that the phase mixture is unstable when agitation is stopped. The OC dispersions in gasoil are not stable either, OC particles settled rapidly. The W/O emulsions loaded OC but without surfactant are not stable either as shown in Table 1.

The stability of the dispersions and emulsions is possible only with the addition of a mixture of surfactant and a minimum amount of OC estimated 3% in our study whatever the OC nature used in this study. The surfactant addition provides a more uniform OC dispersion in the organic phase. The presence of micrometer size water droplets in the emulsion further improves the stability of the clay dispersion in the organic phase [27, 10, 1].

## 2.4. Rheo-SAXS studies for OC dispersion in the emulsions

Small Angle X-Ray Scattering measurements were carried out under shear to study the relationship between the emulsions viscosity obtained and the OC structure and orientation in the dispersed organic phase. The experiments were carried out on the experimental line SWING SOLEIL synchrotron (France) using a Rheo-SAXS equipment consisting of a rheometer (Paar Antoon MC 501) placed in the X-ray path beam (Energy 11 keV).

The obtained results shows that the first maximum  $q = 0.1 \text{ \AA}^{-1}$  correspond to the swelling of the OC interlamellar spaces, due to dodecane carbon chain insertion. The second maximum ( $q \approx 0.2 \text{ \AA}^{-1}$ ) corresponds to the surfactant molecules insertion used to render the clay organophilic. The last ( $q \approx 0.45 \text{ \AA}^{-1}$ ), visible only with Geltone correspond to the spacing in the hydrophilic clay so on clay unmodified regions Figure 2.

As demonstrated by Akkal et al [2], for powder, in the  $0.04 < q < 0.4 \text{ \AA}^{-1}$  region, surfactant forms a 2D thickness =  $20 \text{ \AA}$  for VG69 and Bentone and  $2D = 24 \text{ \AA}$  for Geltone. After dispersion in dodecane,  $d$  is 2 times greater (VG69 and Bentone) or three times (Geltone) higher than in the OC and thus the mixture (TA + dodecane) occupies a space between sheet  $2D = 54 \text{ \AA}$ ,  $64 \text{ \AA}$  and  $58 \text{ \AA}$ , for VG69, Bentone and Geltone respectively. The emulsion containing bentone shows that the dispersion of sheets is strongest: the basal spacing is highest ( $d(001) = 74 \text{ \AA}$ ) and the number of the layers lowest ( $\langle N \rangle = 1.3$ ) (after the results of SAXS) [2].

## 2.5. Fluids characterization

### 2.5.1. Fluids preparation

Drilling fluids containing different chemical compounds are formulated in order to be used for damage tests. These fluids are composed of organoclay, a continuous phase (diesel or n-dodecane), a discontinuous phase (water), a wetting agent and dispersant, and other additives such as fluid loss, lime and calcium carbonate  $\text{CaCO}_3$ . All fluids are prepared according to API specifications and characterized by different measures (viscosity, yield stress, density and H/E ratio) after 16h ageing before being injected to simulate borehole circulation conditions and to chemically stabilize the emulsion. In this work, six drilling fluids were prepared whose compositions are given in Table 2

### 2.5.2. Rheology studies

Rheological parameters such as shear stress, shear rate of all prepared fluids were measured using a Fann35 viscometer

with imposed speed (600, 300, 200, 100, 6 and 3 [rpm]). The apparent viscosity, plastic viscosity and yield stress are calculated. The density is measured using a densimeter apparatus. We calculate the rheological parameters represented by the plastic viscosity (slope of Bingham model), the yield stress (y-intercept) and the apparent viscosity (viscosity read at 600 [rpm] divided by 2).

The rheological results of simplified muds (Table 3) are obtained in the first step at different concentrations of surfactants (wetting and dispersing agents) as indicated by the Figure 3 and Table 4. These measurements are performed before and after aging. The sample containing twain equally surfactant (versamul-versacoat) with a ratio of (1/1%) requires high stress to flow (case of sample 4), the sample 3 requires a less important constraint to begin to flow, while samples 1 and 2 show a rheological behavior very close Figure 3. This is explained by the fact that the rheological properties: apparent viscosity (VA), plastic viscosity (VP) and yield value (YA) increase with the amount of added surfactant. A significant amount of surfactant reduces the attractions forces between particles and have a greater influence on the rheological properties, due to hydrophilic parts by improving fluid stability [2] and lowering the interfacial tension between the two phases [23, 9, 45].

Figure 4 shows a simplified mud rheogram with different ingredients. Adding versatrol showed an invert effect on the rheological properties by reducing the viscosity and yield stress. On the other side the addition of lime and calcium carbonate  $\text{CaCO}_3$  changed the rheological properties of the fluid by increasing the apparent and plastic viscosities and thereafter the yield stress, this is due to emulsion particles stabilization and increase in specific density [9, 20]. To investigate the clay nature effect on the drilling fluid stability Table 5, we carry on the same curve of different formulated fluids (Figure 5). Fluid 3 containing Bentone shows a rheological behavior characterized by a high yield stress ( $Y_P = 13 : 5 \text{ Pa}$ ) compared to that containing VG69 having a yield stress ( $Y_P = 10 \text{ Pa}$ ). This is explained by the fact that bentone exhibits good dispersion in solvent leading to a better stability of the fluid. These fluids after aging show a more viscous behavior marked by an increase in rheological parameters. Aging also seems crucial for the stability of the system. Based on the rheology results presented above, the basics of fluids can not be stable with only a surfactant ratio 1:1 of versamul and versacoat. The addition of other ingredients (lime and  $\text{CaCO}_3$ ) has increased the rheological parameters. It should be noted that similar content of the Bentone increases different rheological parameters  $V_p$ ,  $V_A$  and  $Y_P$  with respect to the OC VG69. This confirms the interesting experiments results (SAXS) found by Akkal et al [2].

### 2.5.3. Filtration measurements

Filtration results of simplified drilling fluid prepared in laboratory are given in Figure 6. According to these results, an equal parts (1%) of twin surfactants gives a reasonable filtration around (25 mL). A decrease in the concentration of

one of the two surfactants increased the volume of filtrate because the fluid is less viscous. This result is explained by the fact that less surfactant leads to fluid instability and phase separation. For this purpose, the dense particles are retained on the paper filter as the fluid passes.

To investigate the role of other additives on the filtration properties, we plotted the API filtration curve for various fluids by adding an additive to each step as shown in Figure 7. The base fluid (fluid 1 containing 1 % of versamul and 1 % versacoat) shows a low filtration around (5ml) during the first 15 minutes before increase rapidly to 30 ml at the end test. Adding versatrol, has limited the filtrate at about 18 ml. Lime addition was also used to obtain a filter volume stabilizes at about 20 ml. The addition of calcium carbonate shows a filtration smaller than previous fluid (fluid 4 and fluid 2). Calcium carbonate makes the dense fluid stabilizes the filtration for 18 min.

To study the influence of clay on filtration tests, a fluid were prepared (fluid 3) with replacement of bentone by VG69 clay. Note that the filtration volume dropped to 8 mL after 30 min Figure 9, we also note that the reduction of the surfactant concentration (0.5%) of one or the other (versacoat and versamul) has given less than the fluid 3 filtrate Figure 8.

### 3. Damage formation experiments

#### 3.1. Materials and methods

The experimental study of the reservoir formation damage afterpart to the drilling mud circulation can be investigated with equipment specifically designed for this type of testing. Several parameters are to be considered carefully during the simulation such as the confining pressure, the pressure injection and deformation of the natural clays structure at high temperature. The plugs transfer from saturation step towards dynamic filtration and vice versa, should be done with caution to avoid damaging the cake formed on the sample surface. Achieving the damage tests with circulating of the drilling mud must be undertaken with great caution. Conducting experimental tests is done in six basic steps:

1. Petrophysical characterization of samples by determining parameters such as air permeability, porosity, and the density
2. Sample saturation with brine
3. Injecting Soltrol 130 solvent to measure initial permeability
4. Drilling fluid preparation and injection into the sample
5. Injection of Soltrol 130 in the opposite direction to measure final permeability.

##### 3.1.1. Samples preparation and description

In this work, two sets of samples were selected Berea sandstone that is relatively homogeneous and heterogeneous Hassi Messaoud samples. The selected samples were washed by Soxhlet extraction with a solvent mixture of methanol/acetone/toluene 15/15/70, to extract the organic material (hydrocarbon fluids) and impurities. It is followed by a second wash with methanol alone to dissolve the salts. After washing, the samples were brought to the oven at 65 °C for

drying to stabilize the weight of the samples, the porosity and permeability are then determined. The sample saturation procedure is performed with API brine water (8.5% NaCl and 2.5% KCl). This core saturation operation is performed under vacuum for more than 24 hours to implement the irreducible water saturation.

#### 3.1.2. Experimental device and test procedures

The equipment is composed of a sample holder that keeps it sample under reservoir conditions such as pressure and temperature and two fluid cells. A rubber sleeve is placed inside the sample holder to prevent any leakage. Then the sample is placed inside the sleeve. A pump is connected to the port of the sample to force fluids (solvents and drilling fluids) through the sample according to Figure 9.

Working conditions are fixed in the beginning of the tests such as temperature 80 °C, an injection pressure of 2500 psi and confining pressure of 450 psi. Cells A and C provided with a piston, are filled with a reference fluid, the cell B is filled with drilling mud. To measure the initial permeability ( $K_i$ ) by injecting the soltrol 130 through the sample in the production direction with applying a pressure and against pressure upstream and downstream of the sample during 2 hours. After the damaging stage, we proceed to unclogging by passing soltrol 130 oil in the production direction until a stabilised pressure. Final permeability is thus determined ( $K_f$ ) according to figure 10.

#### 3.2. Results and discussion

The damage represents the permeability reduction before and after the drilling fluid circulation calculated by the above formula 1.

$$DR = K_i - K_f / K_i \quad (1)$$

where  $k_i$  and  $k_f$  are the initial and final permeability.

The damage ratio and other parameters that have a significant influence on the damage mechanisms such as drilling fluid flow rate, absolute permeability, porosity and differential pressure are given in Table 5.

##### 3.2.1. Effect of the rock properties on the damage ratio

The formation damage is closely related to the rock petrophysical properties. However, the most permeable rocks show significant damage compared with those that are less. This phenomena is observed on Hassi Messaoud samples B1 and A1 having upper permeabilities 380 mD. These samples have given a damage ratio of 69% and 90.48 %, compared with low permeabilities ones ( $\approx 85$  mD) (Figure 11)

##### 3.2.2. Pressure effect on the damage ratio

This damage is treated in terms of permeability reservoir reducing that expresses the difference between the initial and final permeability divided by the initial permeability and results shows that the damage ratio increases with increasing differential pressure. This is observed for Hassi Messaoud

sample #6, sample #5 and sample #4 respectively. These samples are plugged with drilling fluid #1. At differential pressure  $\Delta P$  of 2.70 [MPa], 1.08 [MPa] and 0.79 [MPa]. A damage ratio of 90.48%, 69% and 62.72% was respectively obtained (Table 6). One possible reason for this decrease is that with the increase in  $\Delta P$ , more forces are acting on the drilling fluid solid particles when penetrating into the pores and travelling through the formation.

For low pressure  $\Delta P$ , the solids are held firmly because less forces acting on them and they flow relatively easily during the return flow compared with the previous case. The high permeability can be seen due to the high porosity which are larger than the particle size in the drilling fluid, this will allow relatively free movement of the fluid including particles which leads to a smaller damage.

### 3.2.3. Filtration volume effect on damage ratio

Damage ratio decreases with increasing drilling fluid flow rate. This is observed for Hassi Messaoud sample #2 and Berea sandstone samples GB#11 and GB#9, respectively damaged by drilling fluid 2 (Figure 12). As explained above, this is strictly related to the differential pressure. For high pressures, the larger particles are retained on the sample face as a result a large volume of drilling fluid filtrate can circulate easily through the formation [30][31].

### 3.2.4. Surfactant type and concentration effect on damage ratio

Damage ratio varies with type of rock even though they have same petrophysical parameters. In this part samples were selected with similar petrophysical properties and damaged with same drilling fluids composition but containing different surfactant concentration. Berea sandstone sample GB #11 damaged by drilling fluid 2 containing two surfactant (Versamul and Versacoat) with a ratio of 2% gave 8.01% damage ratio compared with Berea sandstone GB#5 and GB#1-1 clogged with the same drilling fluid with similar surfactant of 1.5% concentration showed respectively 47.1% and 29.33% damage ratio. This may be explained by the fact that fluid 2 is more stable over time and contains less free surfactant compared with the two fluids 3 and 4 containing less surfactant which leads to phase separation. These free surfactant will be deposited preferentially and adsorbed on the rock surface increasing damage ratio [6, 40, 3].

Berea sandstone GB#5 has been clogged with drilling fluid 3 containing 1% of Versamul and 0.5% of Versacoat gave 47.1% damage ratio higher than Berea sandstone #1-1 clogged with fluid 4 which records 29.33%. This may be explained by the fact that less amount of Versamul leads to increase interparticle repulsion force and led to the drilling fluid instability. More amount of wetting agent leads to wettability change and altered the formation [49] and increases in damage ratio Figure 13.

### 3.2.5. Organoclay effect on the damage ratio

Our conclusions are based on the SAXS technics results presented in the technical work Akkal et al [2]. For this

purpose, damage tests are achieved using drilling fluids of similar composition but differ in the added viscosifants agents : VG69 or bentone clays (composition according to fluid 3). Clogging the two Hassi messaoud samples #1 and #3 with fluid 3 containing Bentone and VG69 clays respectively led respectively to 31.88 % and 67.61% damage ratio (Figure 14).

Results showed that Bentone has the best stability to swelling (high interlayer space  $\langle d \rangle$ ) and dispersion (low number of sheets  $\langle N \rangle$ ) in the emulsion compared to that of VG69 clay [2]. According to the porous network distribution, the large particles are deposited in the pores (the case of Bentone), whereas those smaller infiltrate deeper into the formation and block the pores connection (VGA OC case) [20, 19, 38] [8, 14, 12, 29]. During back flow phase of damage tests, fluid containing Bentone has been easily cleaned compared to that containing VG69 clay. This explains the high clogging rate. The same remark is noticed for Berea sandstone samples GB#29 and GB#9 clogged with fluid 2 viscosified with VG69 and bentone clays with respectively 33.86 % and 48.67 % damage ratio (Figure 14).

### 3.2.6. Carbonate calcium effect on the damage ratio

To study the effect of solid particles on the filter cake, the evolution of relative permeability over time for the samples #1 and #2 clogged with drilling fluid #2 and 3 with and without  $\text{CaCO}_3$  (Figure 15) shown that the solid particles addition increases damage ratio during the displacement tests and influence rock physical properties such porosity and permeability.

## 4. Conclusion

This work was conducted to understand the relationship between the composition of a fluid model of reverse-type (W/O) loaded organoclay, on one hand, and the influence of these fluids, their compositions, their stabilities over time and also the rheology on the reservoir damage due to the drilling fluid flow. It appears that three major problems are directly related to reservoir formation damage. It has been established that the concentration of 3% and 1% for organophilic clay VG69 and surfactant (Versamul and Versacoat), respectively are sufficient to provide rheological properties. These drilling fluid are stable over time and have given a damage ratio about 20% - 40%.

This damage increases with pressure differential  $\Delta P$ . It has been concluded also that for highly porous samples around 20% gave high damage ratio (57%) compared with low porosity samples (12%) which recorded 20% - 40% damage ratio. The effect of calcium carbonate investigation on the damage showed an increase of 70%. We also found that the emulsions are stable for 3% organoclay, 1% emulsifier and 1% wetting agent. These

Emulsions exhibit non-Newtonian fluids with shear-thinning behavior explained by the structural study (SAXS technology in combination with modeling) that showed the existence of junction zones between particles whose failures are responsible for the fall sub increasing shear viscosity.

We also thought that the increased droplet deformation when the shear increases also contributed to the decrease in viscosity. Among the studied clays, we obtained better results with Bentone which gives a more significant swelling with a smaller number of layers.

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## Nomenclature

*DR*= Damage ratio [%]

*Ki*: Initial permeability [mD]

*Kf*= Final permeability [mD]

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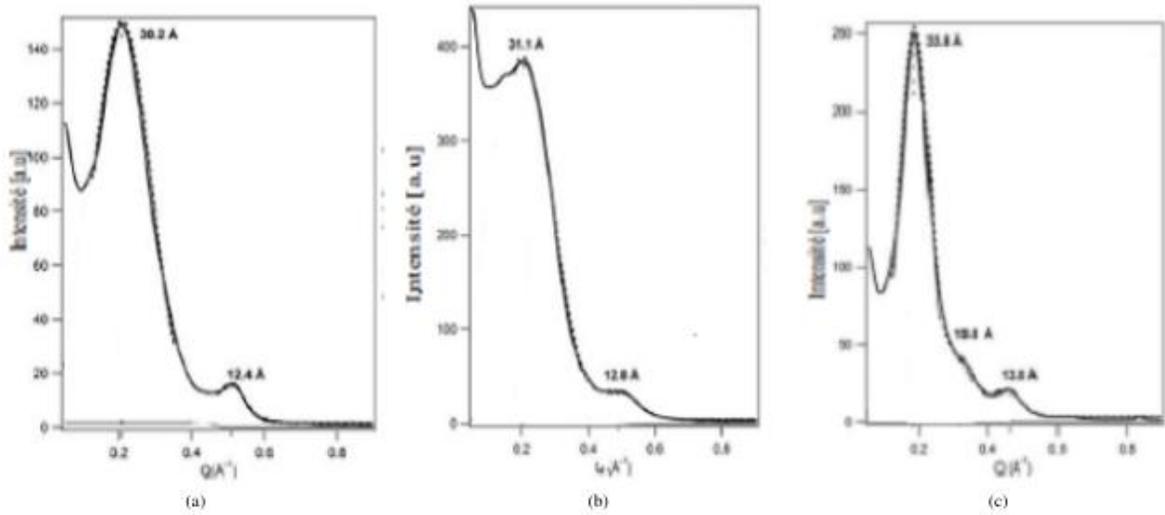


Figure 1. XRD results for the three organophilic clays

Table1. Emulsions stability results

VG69(%)	Tensio-actif(%)									
	0.4 / 0.4	0.4 / 1	0.7 / 0.7	0.195 / 0.7	1.2 / 0.7	0.7 / 0.195	0.7 / 1.2	1 / 0.4	1 / 1	
0.3			■							
1.0	■	■						■	■	
2.0			■	■	■		■	■		
3.0	■	■	■	■	■	■	■	■	■	
3.6	■	■	■	■	■	■	■	■	■	

■ : Emulsion stable  
 ■ : Emulsion moins stable  
 ■ : Emulsion non stable

Table 2. Drilling fluid preparation protocol.

Product name	Fluide 1	Fluide 2	Fluide 3	Fluide 4	Fluide 5		Fluide 6		Agitation time (min)
					(0.5%versamul +1% versacoat)	(1%versamul + 0.5% versacoat)			
Gas-oil	■	■	■	■	■		■		
Versamul (Emulsifier)	■	■	■	■	■		■		
Versacoat (Wetting agent)	■	■	■	■	■		■		20
Organoclay	■	■	■	■	■		■		40
Brine	■	■	■	■	■		■		30
Versatrol (Filtrate reducer)		■	■	■	■		■		15
Lime			■	■	■		■		15
CaCO <sub>3</sub> (Weighting agent)			■						40

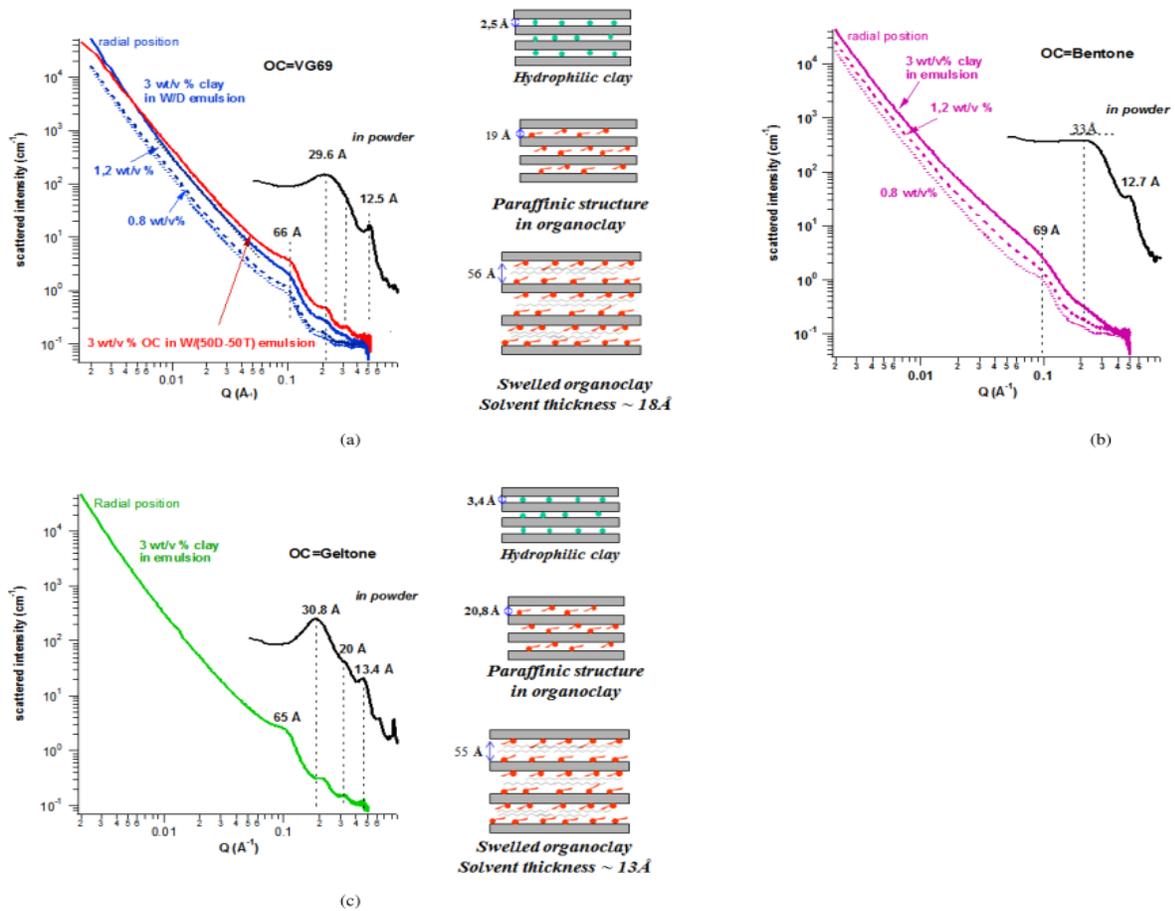


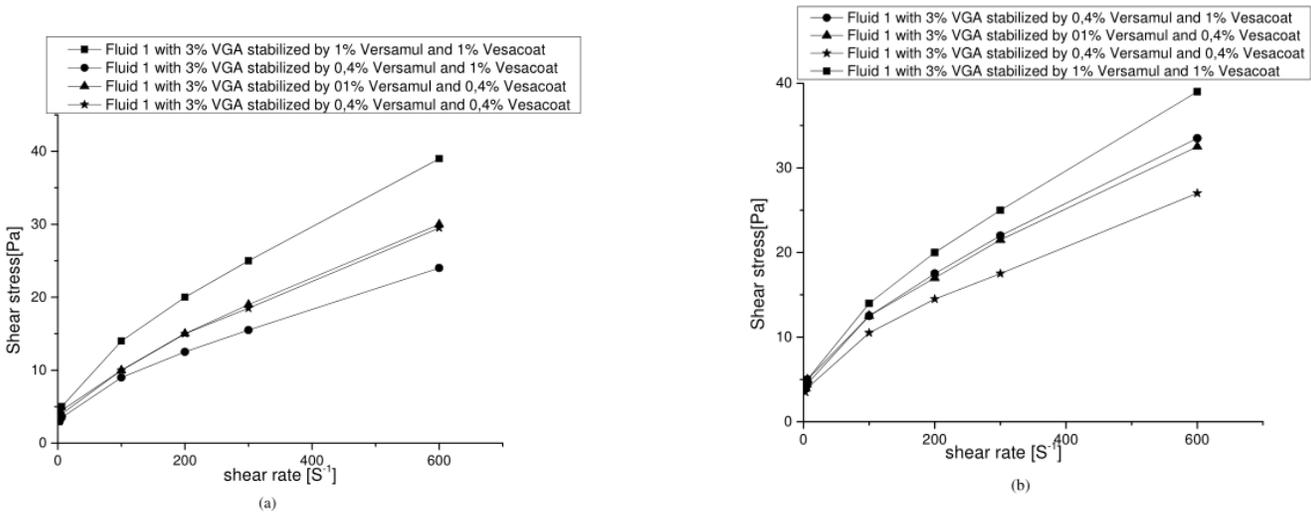
Figure 2. Rheo-SAXS studies for OC dispersion in the emulsions ,a)VGA, b)Bentone and c)Geltone.

Table 3. Simplified drilling fluid

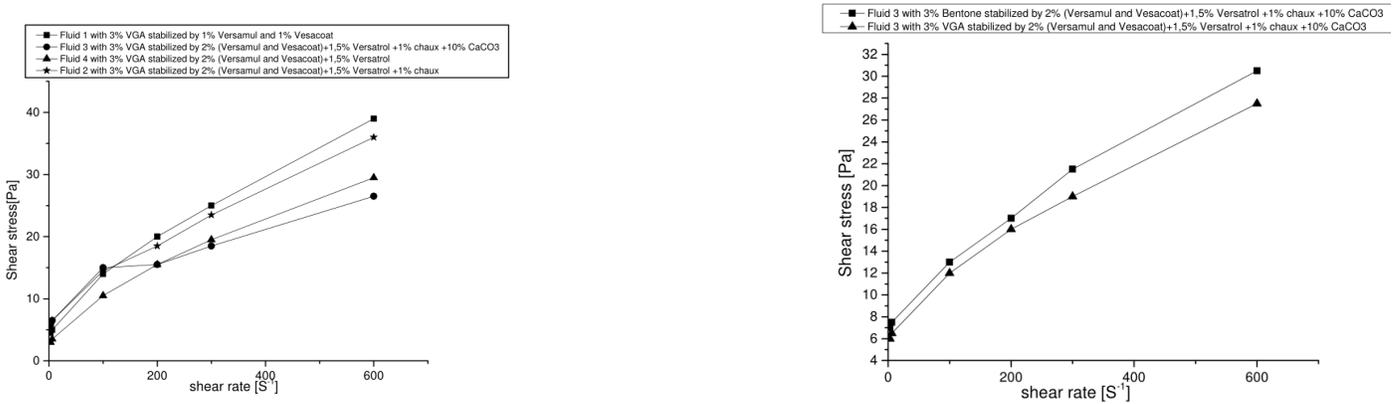
Product name	Quantity (%)				Agitation time in [min]
	Fluid 1	Fluid 2	Fluid 3	Fluid 4	
Gas-oil	90	90	90	90	N/A
Versamul (emulsifying agent)	1	1	0.4	0.4	N/A
Versacoat (wetting agent)	1	0.4	1	0.4	20
Brine	10	10	10	10	30
Organophilic clay VG69	3	3	3	3	40

**Table 4. Fluid 1 with different concentrations of surfactant**

Fluids	Clay type	Surfactant type(%)		Rheological parameters Before aging				Rheological parameters After aging		
		VG69(%)	Versamul	Vesacoat	Density	Va	Vp	Yp	Va	Vp
Fluid 1	3	0.4	0.4	0.88	13.5	10.5	6	14.75	11.0	7.5
Fluid 2	3	0.4	1	0.87	12.0	8.5	7.0	16.75	11.5	10.5
Fluid 3	3	1	0.4	0.86	15.0	11.0	8.0	16.25	11.0	10.5
Fluid 4	3	1	1	0.88	16.0	11	100	19.5	14	11



**Figure 3. Rheology measurement for simplified mud a) before aging, b) after aging.**



**Figure 4. Rheology measurement for simplified mud**

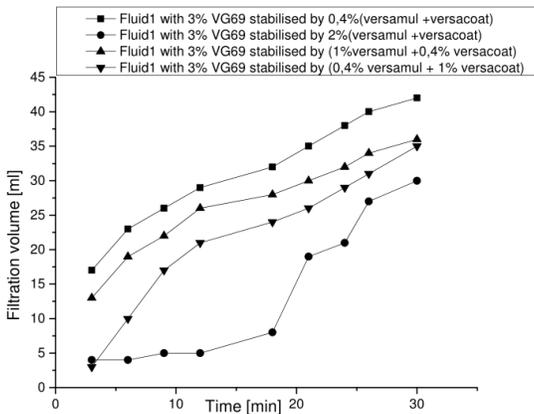
**Figure 5. Orgno-clay effect on the drilling mud Rheology**

**Table 5. Fluid composition in function of the surfactant concentration of organoclay type.**

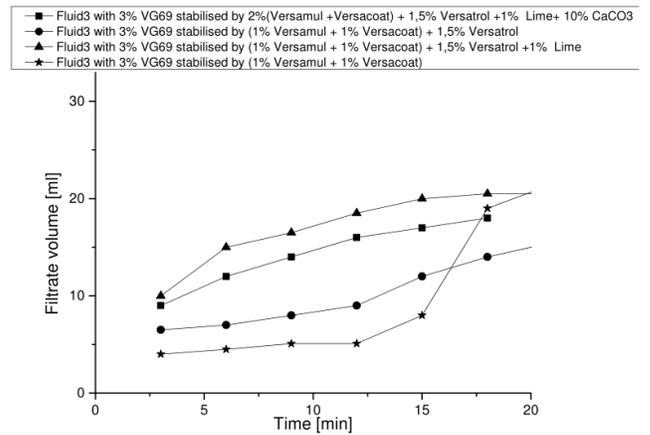
Fluid name	Argile (3%)	Surfactant(%)		Rheological parameters			
		Versamul	Versacoat	Density	$\gamma_p$	$V_A$	$V_P$
Fluid 3	VG69	1	1	0.93	16	11	10
Fluid 3*	Bentone	1	1	0.91	17.75	11	13.5

**Table 6. Experiment parameters.**

Description	Fluid No.	Flow rate Q in [m <sup>3</sup> /s]	Permeability formation $k_f$ in [m <sup>2</sup> ]	Porosity $\phi$ in [%]	Damage ratio DR in [%]	Differential pressure $\Delta P$ in [MPa]
Hassi Messaoud Sample #1	1	$26.70 \times 10^{-9}$	$9.04 \times 10^{-14}$	12.45	67.61	0.128
Hassi Messaoud Sample #2	2	$3.10 \times 10^{-9}$	$6.32 \times 10^{-14}$	11.60	20.40	2.36
Hassi Messaoud Sample #3	1(Ben)	$3.10 \times 10^{-9}$	$1.65 \times 10^{-14}$	9.76	31.88	0.49
Hassi Messaoud Sample #4	1(Ben)	$5.08.10 \times 10^{-9}$	$1.65 \times 10^{-14}$	17.39	62.72	0.79
Hassi Messaoud Sample #5	1(Ben)	$8.6.10 \times 10^{-9}$	$1.65 \times 10^{-14}$	24.15	69	1.08
Hassi Messaoud Sample #6	1(Ben)	$2.37.10 \times 10^{-9}$	$1.65 \times 10^{-14}$	15.97	90.48	2.70
Hassi Messaoud Sample #7	1(Ben)	$1.65.10 \times 10^{-9}$	$1.65 \times 10^{-14}$	14	53.3	1.64
Berea sandstone sample GB#29	2(Ben)	$7.67 \times 10^{-9}$	$10.9 \times 10^{-14}$	18.40	33.33	0.77
Berea sandstone sample GB#11	2	$1.14 \times 10^{-9}$	$9.84 \times 10^{-14}$	18.40	33.33	0.48
Berea sandstone sample GB#9	2	$0.26 \times 10^{-9}$	$7.58 \times 10^{-14}$	19.84	57.35	0.24
Berea sandstone sample GB#05	3	$1.39 \times 10^{-9}$	$6.92 \times 10^{-14}$	18.90	42.86	0.96
Berea sandstone sample GB#1-1	4	$0.64 \times 10^{-9}$	$8.27 \times 10^{-14}$	19.54	83.33	0.88



**Figure 6. Filtration curves for drilling fluid1 with different concentration of surfactant.**



**Figure 7. Filtration curves for different drilling fluid.**

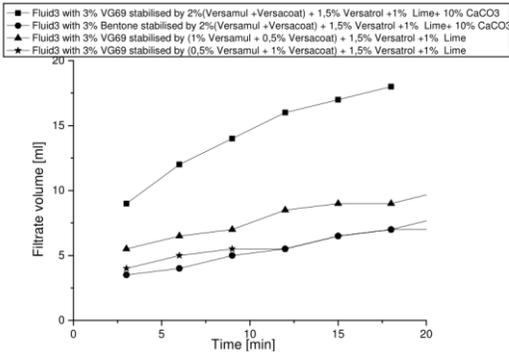


Figure 8. Filtration curves shows the organoclay type and surfactant quantity on the filtration volume.

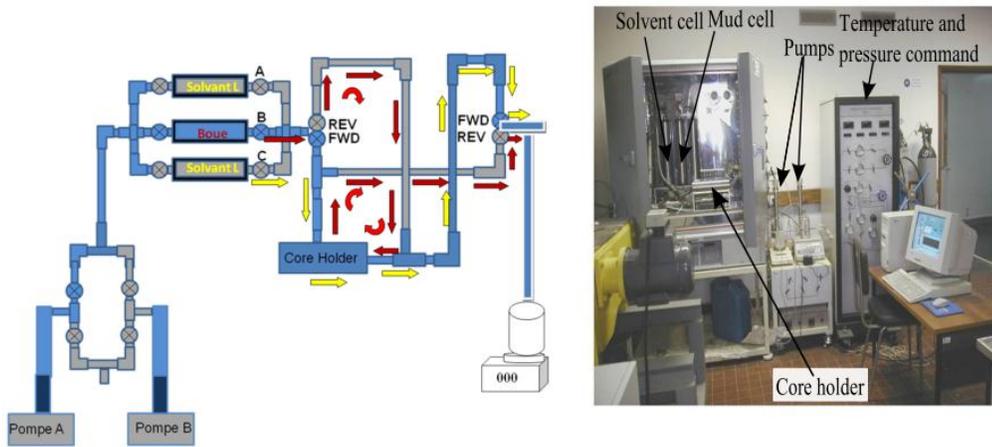


Figure 9. Sample core holder, a) schematic core holder and b) Hasler cell.

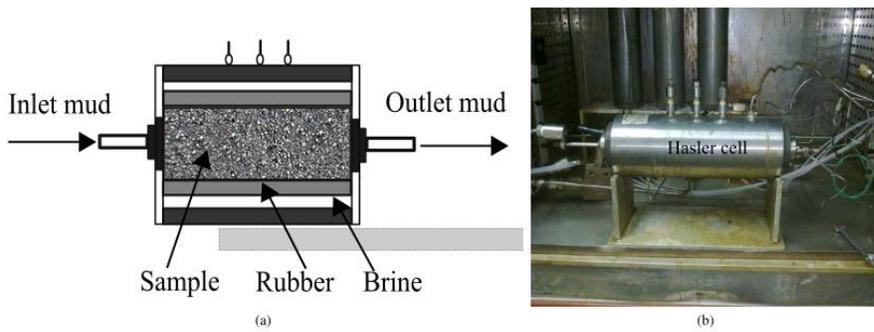
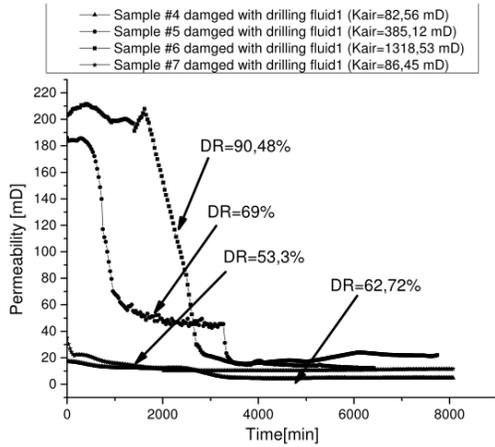
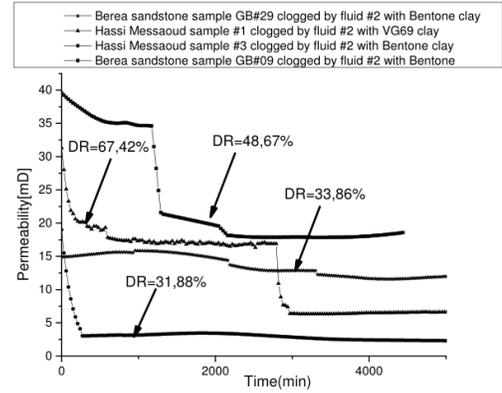


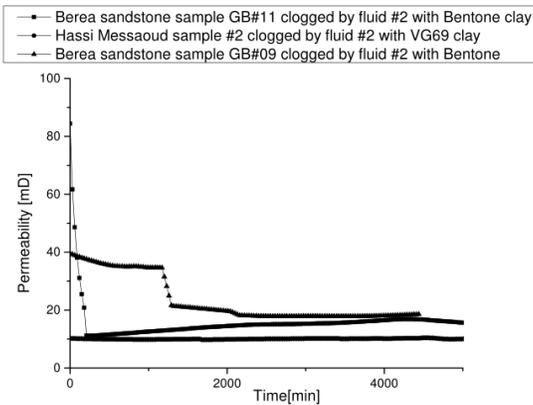
Figure 10. a) Diagram flow for initial and final permeability estimation and b) Apparatus used in this work.



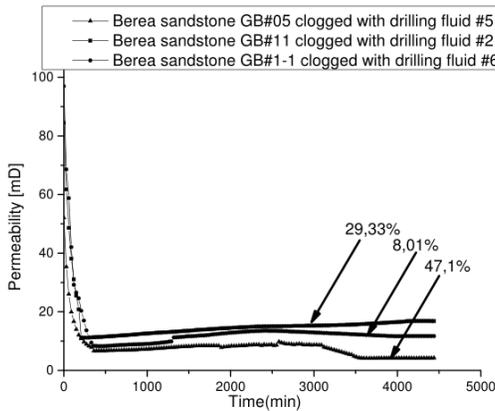
**Figure 11. Damage results on the OKJ and OKN samples.**



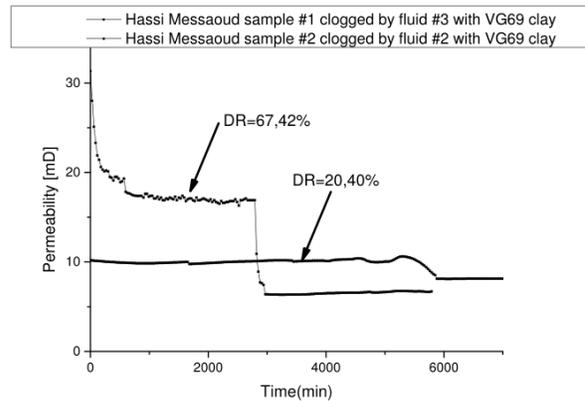
**Figure 14. Damage results of the samples clogged with VG69 and Bentone clays**



**Figure 12. Volume filtrate effect on the damage ratio**



**Figure 13. Damage results on the Hassi Messaoud samples clogged with different surfactant**



**Figure 15. Damage results of the samples damaged with and without CaCO<sub>3</sub>**