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INVESTIGATION OF THE IMPACT OF WEIGHTING PARTICLES ON DRILLING MUD RHEOLOGY AND DAMAGE TO RESERVOIR FORMATION

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ABSTRACT

The effect of calcium carbonate on drilling fluid densities after damage to the reservoir during the liquid flow was considered in the present paper. To test the initial / final permeability and fluid flow rate as well as the damage ratio, the damage tests have been completed and several Binghamian drilling formulation that were carefully prepared in the laboratory are used. Based on the obtained results, there is a minimal quantity of surfactant and the DR significantly changes beyond this limit. The drilling fluids containing 3 % of calcium carbonate and 2-3 % of the emulsifiers and wetting agent show a high flow pressure and display an immense damage ratio of about 43 %. It is also that these drilling fluids containing calcium carbonates provide the rheological properties close to those used in the field level. Such drilling fluids are stable over time, giving the yield stress beteween 5-10 Pa to allow the fluid flow.

Keywords: Weighting agent; rheology;damage ratio; water-oil mud; permeability reduction.

1. INTRODUCTION

Damage to the formation of the reservoir results in a significant reduction in productivity in different oil and gas fields. Such damage can be caused by mechanical effects such as fines movement, intrusion of solids and emulsion forming and chemical effects of clay swelling, solid precipitation and wettability changes [1–3]. Nonetheless, the use of stimulation techniques to repair formation damage is costly, which involves the use of well-designed laboratory programs that can allow those involved in designing and performing drilling, completion or stimulation programs to assess the effectiveness of specific programs prior to their deposit implementation [1,4] . In particular, this damage is mainly due to the circulation of the drilling fluid to perform ceratin functions such as raising debris, maintaining stable walls, cooling the drilling device and forming a protective layer on well walls called the cake [5–7] . These can be either water based mud (WBM), oil based mub (OBM) or faom based mud (FBM). The use of one or the other is closely based on the design of the crossed formations. These drilling fluids consist of two phases water/oil that are stabilized by surfactants (wetting agents and emulsifiers) and viscosified by organophilic clays and display non-Newtonian behavior decried by a thixotropic model which needs a yield stress to flow [8,9] . These fluids are circulated by a high pressure higher than the geodynamic pressure of the reservoir formation in order to prevent the fluids from the reservoir formation entering to the oil well. The drilling fluid filtrate and fine molecules, however, penetrate the structure of the reservoir by reducing its permeability, causing severe damage and reducing the annual efficiency of the well [10,11]. As described above, the severity of this damage depends on several factors, including the amount and form of surfactants used to stabilize the drilling fluid [12] . The interaction of surfactants with the fluids and pores of the reservoir formation results in altered wettability and makes the rock wettable only with oil rather than water [13–15]. Other studies have shown that the damage is also caused by the contact between the surfactants and the clays found in the reservoir, which are very sensitive to the fluids that invade the structure [16,17]. The effectiveness of these fluids depends on the stability of the emulsion during the drilling process and the interfacial properties arising from the interaction of the fluid with the crude oil and the rock formation whose their choice which determines the stability of the fluid emulsion [18–20]. The criteria used in surfactant choice are as follows: 1)

required HLB, (2) oil type (mineral, paraffin, ester or diesel), (3) bottom temperature, (4) salinity, and (5) ionic type [21,22]. Generally, proper use of anionic-nonionic surfactant mixture must fulfill emulsion stability criteria under a wide range of conditions, including temperatures up to about 150 C. These surfactants interacted with clays added to the drilling mud as a viscosifier and calcium carbonates ($CaCO_3$) as a densifier, leading to severe damage to the reservoir formation. The present work focus on the damage caused by the deposition of calcium carbonates ($CaCO_3$) applied to the various liquids formulated at the laboratory scale in order to increase the density of these fluids and to see their effects on the damage caused to the reservoir rock in terms of permeability reduction before and after the injection of these fluids. In this study, we used common additives in water in oil based mud containing surfactants, organophilic clay, filtrate reducer, inorganic salts and also calcium carbonates as densifier agent. The damage was measured in terms of permeability reduction before and after the circulation of these fluids through the reservoir rock.

1.1. Materials and methods

In the laboratory, the drill fluid damage experiment must accurately replicate the operation to be done on an oil well deposit. This experiment is conducted under static conditions using a "TEMCO-Inc" tool. The damage tool is a system designed in the well bottom conditions for movement, clogging and stimulation tests on reservoir rocks i.e. at high temperature and high pressure. Displacement experiments are carried out with different fluid types whose the continuous phase is oil with dispersed water droplets. This device allows the liquid to be pumped in two directions namely production and injection directions : a production direction simulating the recovery of the crude oil from the well and a injection direction simulating the mud injection during a drilling process (see Figure 1a an 1b). The samples selected to perform the damage tests are from Berea sandstones, which are relatively homogeneous, whose air permeabilities and porosities are of the order of 70 mD and 11% respectively. These samples are saturated under vacuum with an API brine (8.5 % NaCl and 2.5 % KCl) in order to sut up the irreducible water. This operation is completed by a soltrol 130 displacement at low flow rate (injection of about 20 pore volumes).

a
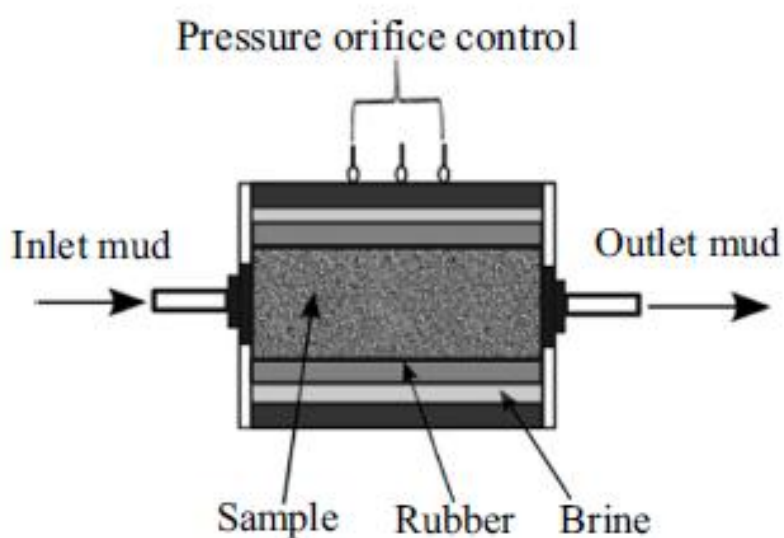
b

Fig.1. a) Applied apparatus to achieve the tests. and b) sample core holder

1.2 Initial and final permeability assessment (Ki)

The saturated sample is placed in a Hassler cell and then confined to 2500 psi and heated to 80 °C. Once these two parameters have been stabilized, a soltrol 130 (inert oil) drainage is carried out in the direction of production, (figure 1a). During the process, the differential pressure is recorded for a fluid chosen in laminar flow to verify the permeability evolution. The initial permeability (named reference permeability) is reported once these parameters are

stabilized before being inserted into the system, then the prepared and characterized mud must be fully homogenized. The drilling fluid is pumped into the injection path through the sample under the same pressure and temperature conditions listed above by maintaining a constant differential pressure of 20 KgF/cm^2 for three hours. The final permeability is carried out with circulation of soltrol 130 agents in the production direction to clean the sample until it reaches a clear and stable flow of the sweeping oil. Under the same initial conditions, the damage ratio (DR) is calculated as follows:

$$DR = \frac{k_i - k_f}{k_i}$$

Where k_i and k_f are the initial and final permeabilities, respectively.The damage ratio and other parameters that have a significantinfluence on the damage mechanisms such as drilling fluid flowrate, absolute permeability, porosity and differential pressure arealso derminated.

1.3 Rheology tests

The drilling fluids containing different chemical compounds are formulated to be injected through the selected cores. These fluids are inverse emulsions of water in oil (10% water and 90% oil), stabilized with surfactant (emulsier and wetting agent) and organo-clay (OC) particles. The other compounds are added to adjust the density and the fluids filtrate such as calcium carbonates ($CaCO_3$) and lime. All drilling fluids are prepared according to API (American Petroleum Institute) specications and are characterized by different rheological measurements (viscosity and yield stress), density and distillation (API, 1988, 2005). These fluids are kept at rest for 16 h before being injected to simulate circulation conditions in a wellbore and to chemically stabilize the emulsion. In this work, four types of drilling fluids are prepared whose compositions are given in Tables 1. A viscometer known as Fann35 including the coaxial cylinders is used to perform the rheological characterizations herein.

Table 1. Drilling fluid composition with and without carbonate calcium $CaCO_3$ for drilling fluids A, B and C #2)

Fluid A	Fluid A	Fluid A$_1$	Fluid B	Fluid B$_1$	Fluid C	Fluid C$_1$
Continue phase	0.89 m^3	0.674 m^3	0.866 m3	0.654 m3	0.880 m^3	0.700 m^3
Dispersed phase	0.047 m^3	0.073 m^3	0.055 m3	0.088 m3	0.050 m^3	0.088 m^3
Emulsifier I	5 kg/m^3	8 kg/m^3	10 Kg/m3	11 Kg/m3	1.49 kg/ m^3	2.86 kg/ m^3
Emulsifier II	-	-	10 Kg/m3	11 Kg/m3	6.86 Kg/m3	7.14 Kg/m3
Wetting agent	2.5 kg/m^3	5 kg/m^3	25 Kg/m3	20 Kg/m3	1.49 kg/ m^3	7.14 kg/ m^3
Viscosifier I	45 kg/m^3	25 kg/m^3	40 Kg/m3	10 Kg/m3	34.32 kg/ m^3	18.60 kg/ m^3
Viscosifier II	-	-	10 Kg/m3	15 Kg/m3	-	-
Filtrate reducer	25 kg/m^3	20 kg/m^3	35 Kg/m3	20 Kg/m3	27.18 kg/ m^3	25 kg/ m^3
Activating agent	19.95 kg/m^3	20 kg/m^3	25 Kg/m3	20 Kg/m3	20 kg/ m^3	20 kg/ m^3
Salt	16.36 kg/m^3	26.30 kg/m^3	18 Kg/m3	-	16.30 m^3	31.20 m^3
Weighting agent	-	524.10 kg/m^3		518 kg/m^3	--	392 kg/m^3

Index 1 indicates that the fluid is weighted by calcium carbonates.

2. RESULTS AND DISCUSSION

2.1 Rheology results

The rheograms of the various drilling fluids used in the rock damage process of the reservoir are shown on the Figure 1. These rheograms exhibit a non-Newtonian behavior that shows the flow of an ideal plastic fluid (Bingham) that they exhibit a yeild stress that ranges from 5-10 Pa based of the used formulation. By adding the weighting agent ($CaCO_3$) to the drilling mud, a flow stress is observed as it shows the shear stress as a function of the shear rate. This behavior is due over a critical volume fraction of particles to the creation of a gel-like structure [23–25]. A Shear thinning behavior is expected to occur for viscosifying by clay particle dispersions as well as for $CaCO_3$ particles exceeding yield strength due to gel-like structure break [26,27]. A $CaCO_3$-weighted fluids show low stress at low shear rates for all formulations and this stress increases with increasing shear level (Figure 1) [28]. The drilling fluid (rheol5) thus shows a more significant rheological behavior than the other two fluids (rheol1 and rheol2) (not having a weighting agent ($CaCO_3$)). The same behaviour is found after adding the weighting agents showing that adding local $CaCO_3$ has a better rheological behavior compared to the imported one.
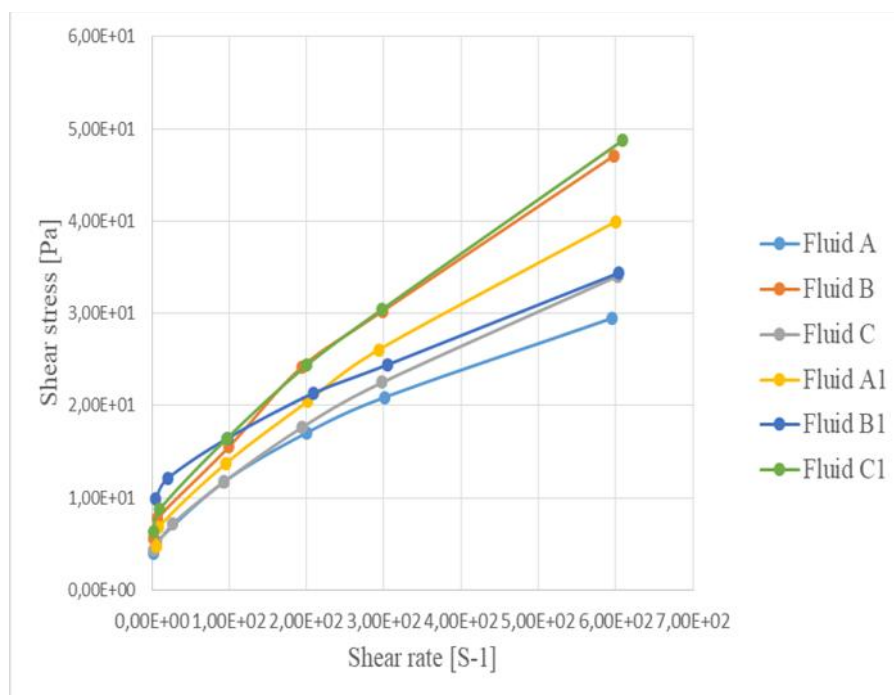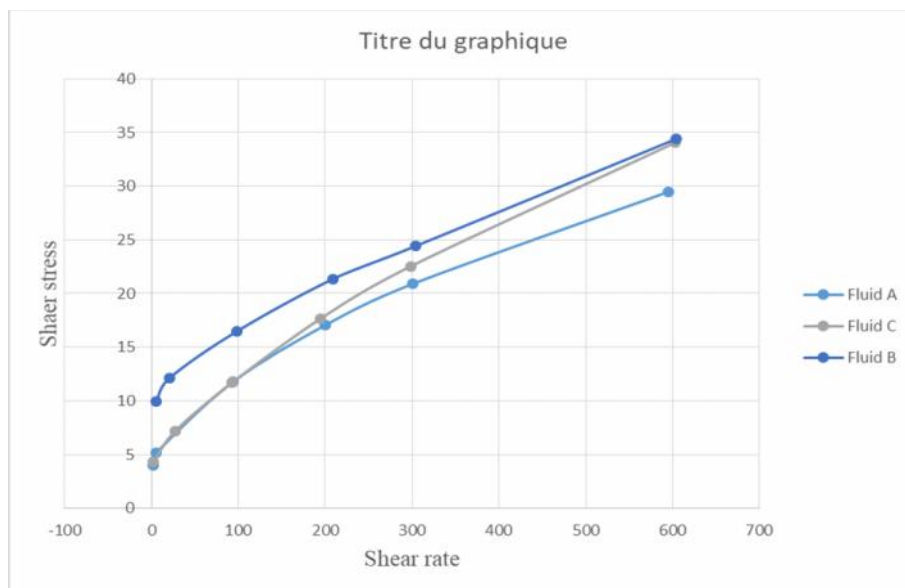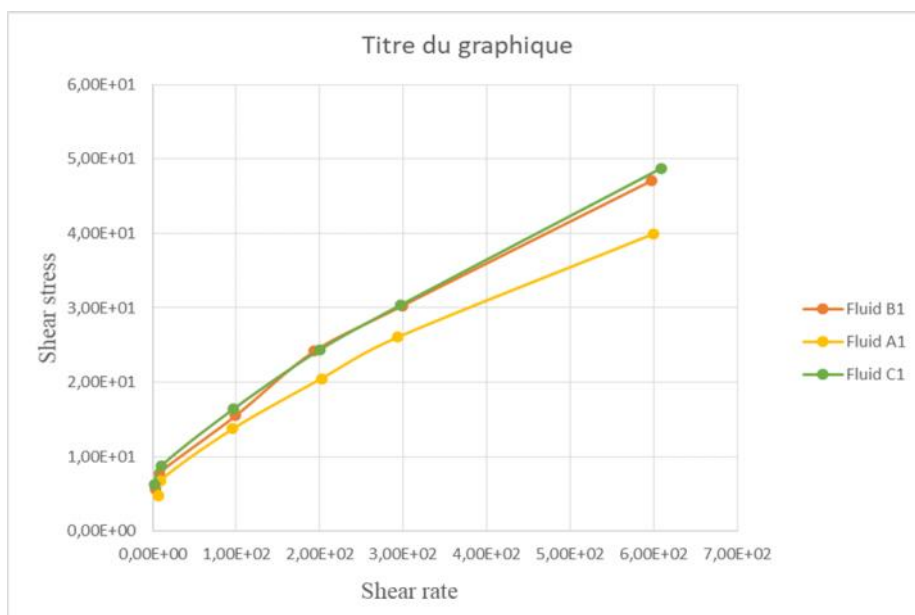
Fig.2. Rheogram highliting the Bingham behaviour of the prepared fluids for the damage samples   .

2.2. Effect of calcium carbonate on the rheological properties

To investigate the effect of calcium carbonate particles as weighting agent on the rheological behavior of the three fluids prepared in the laboratory in the way that they were used later in reservoir rock damage studies, we drew the shear stress rheograms according to the shear level as shown on the figures (fluids rehograms named A to C). The results show that the drilling fluid not containing calcium carbonate ($CaCO_3$) has a lower rheological behaviour than the other two fluids even increases the shear rate and is also present a low threshold stress. Fluid A has a similar rheological behaviour to fluid C for low shear rates. This behaviour changes at high shear rates. Fluid B shows a significantly better rheological behaviour compared to the other two fluids A and fluid C with a higher threshold stress. Fluids weighted with calcium carbonates exhibiting Binghamb behavior have yield strength about 10 Pa. Flow diagrams, which indicate a plastic flow, have a yield strength due to bond formation between aggregated clay particles (elastic flocs) and weighting agent, which thus form a network [29-31].

a

b

Fig.3. Rheogram highliting the Bingham behaviour of the prepared fluids for a) without adding weighting agent and b) with weighting agent

3. Experimental outcomes for damage tests

Results relating to the damage caused by the flow of drilling fluids to the reservoir formation are obtained by the equipment assigned to damage assessments as mentioned above. The
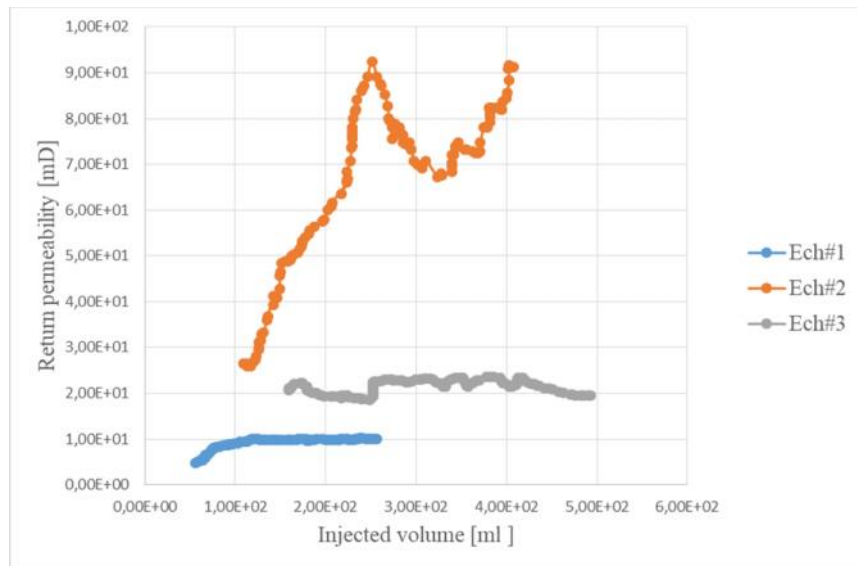
movement of the drilling fluid through the sample causes damage by reducing its annual production and raising the permeability and porosity of the reservoir. Consequently, the damage ratio is given by the above formula 1.

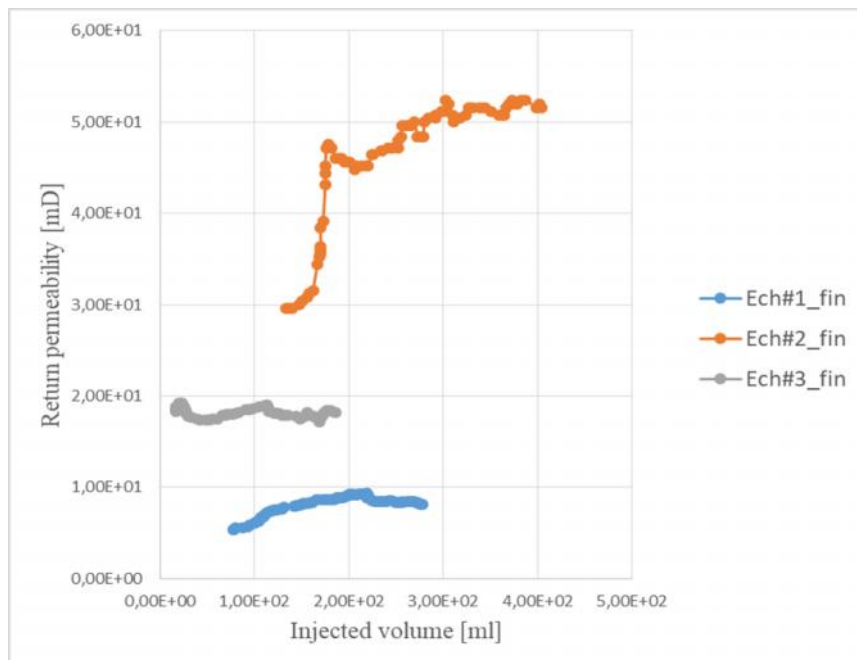### 3.1. Effect of CaCO$_3$ carbonates on the rock damage

To study the effect of adding calcium carbonate weights (CaCO$_3$) on plug damage from berea sandstone, we selected two drilling fluid types that differ in the amount of calcium carbonate added to the drilling fluid (see formulation tables). Figures (quoted in the figures) and the table 1 show the results of the damage tests. These results show that higher density drilling fluids (d=1,25 SG) show a higher damage of 33,37% compared to density fluids of d=0,88% SG (Table 4 and Figure 5) whose the damage ratio is about of 13.11%. The drop in permeability following the fluid injection is in fact due to the composition of the drilling fluid, in addition to organo-philic clays as a viscosifier and surfactants as a satbilizer, contains calcium carbonates which, when deposited on the pores of the reservoir formation, lead to a severe damage, which in turn leads to a drop in the production of an oil well [32-34].

Table 1. Description of the experimental results including the sample name, applied fluid, air permeability, initial and final permeability and damage ratio.

Mud type	Density (SG)	Sample	Air permeability Kair (mD)	Initial permeability Ki (mD)	Final permeability Kf (mD)	Damage (%) C	Medium damage (%) Cm
Fluid (A)	0.88	1	41.88	7.78	8.50	13.09	13.11
		3	96.19	20.70	17.99	13.13	
	1.25	2	40.65	14.19	9.92	30.09	30.09

a

b

Fig.3. Effect of calcium carbonates $CaCO_3$ on the rock damage indicatin a) the initial and b) final permeability for samples #1, #2 and #3

3.2. Pressure effect on the reservoir rock damage

As described above, the damage to the oil well formation expresses the difference between the initial permeability and the final permeability divided by the initial permeability in terms of reduced permeability. Based on this, the relation 1 should be used to describe the variation in permeability: there will be little damage for small variations in permeability; hence the

production of an oil well will be higher than the large variations in permeability. According to the obtained results, the pressure has a significant effect on the reservoir formation damage that is directly related to the type and composition of the used drilling fluid. As shown on the Figure 6, during the first seconds of drilling fluid injection, the pressure decreases rapidly and then stabilizes by creating a plateau. The reduction in pressure was stronger after damaging the sample with drilling fluid containaing the calcium carbonate ($CaCO_3$) [14,15].
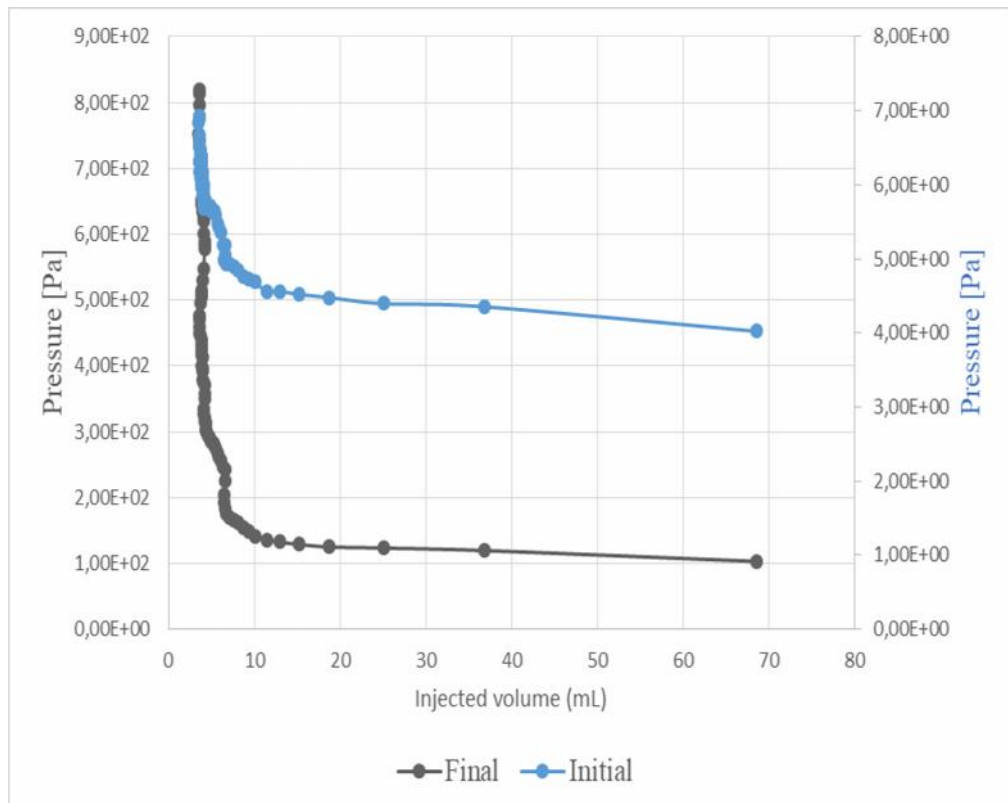

Fig.4. Pressure effect vs injected volume hilightinh the initial and final pressure during the drilling fluid circulation through the reservoir rock

3.3. Effect of flow rate

To investigate the effect of flow rate on the pressure and permeability reduction a sets of tests are performed. These tests are performed on the plugs from Berea sandstone characterized with homogenious permeability and porosity of order of 70 [mD] and 12 % respectively. The obtained results are shown on the Figure 7. For the permeability, during the first second of injection, it decreases as the fluid at this time begins to create its path, then this permeability increases to its maximum and relapses again following the injection of the drilling fluid

containing calcium carbonates. These will settle on the porosity of the rock which leads to a sever reduction in permeability. On the other hand, there will be a significant increase in the injection pressure following the closure of the fluid circulation channels [35–37]. The pressure injection, increases as the fluid injection increases, it is low at the first second of injection, then this pressure increases and reaches its maximum following continuous damage by the calcium carbonates particles [38–40].
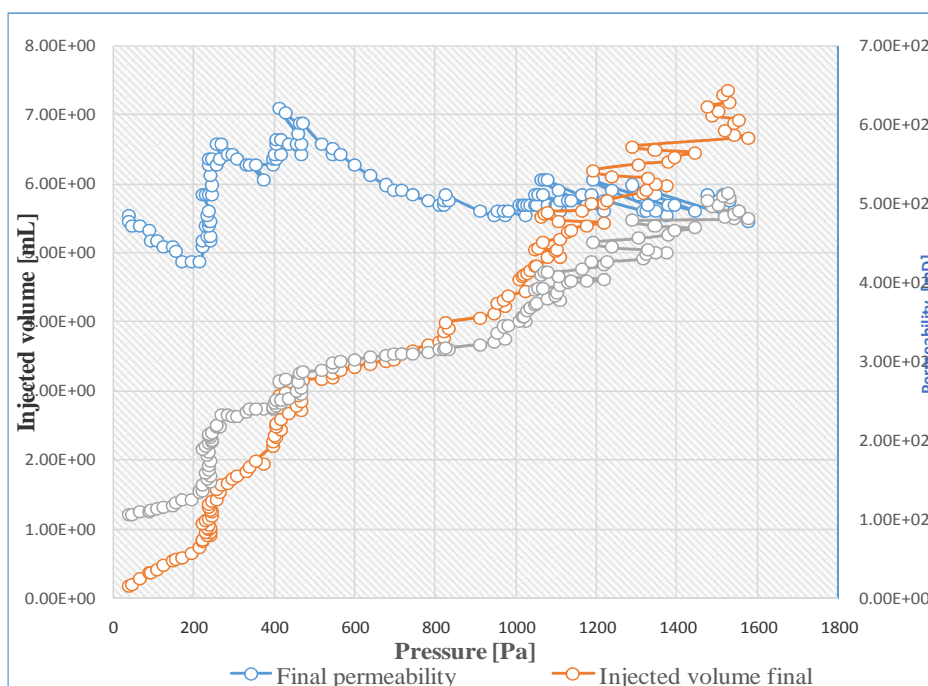

Fig.5. Pressure effect vs injected volume hilightinh the initial and final pressure during the drilling fluid circulation through the reservoir rock

3.4. Effect of surfactant

Basically, the DR differs from one rock to another even though they have the same petro-physical parameters.This issue is pretty well known in the petroleum society. The samples with similar petrophysical properties have been chosen in this sub-subsection.These samples have been damaged with drilling fluids with the same composition but containing different surfactant ratios called fluids #2,#3 and #4 (see Table1). It is well worth indicating that the Berea sandstone samples are well known as the homo-geneous rocks.That is why these samples are considered in this work. According to the damage test results, the Berea sandstone sample #1 damaged by a drilling fluid C1 containing two surfactants as emulsifier

and wetting agent (3 %) has given a damage ratio about 43.81%. This damage ratio is greater than the value obtained by the fluid #2 (27.43 %) which contains 1.5 % as emulsifiers. This sustains a weakly filtrate invasion compared to fluid #1.This would be due to the differential pressure as signified before and the excess of cationic surfactant in fluid #1 which has led to more permeability alteration [41,42]. Sample#4 clogged with drilling fluid C1 which contains a greater emulsifier and wetting agent (3 %) provides more formation permeability changes about 24.23 %. As aresult, a higher damage ratio can be seen (24.33 %) compared with sample #5 clogged with drilling fluid C containing emulsifier and wetting agent of about 1.5 % showing a damage ratio of about 16.52 % value lower to the sample #4. Besides the effects of emulsifiers and the weighting agent used in the drilling fluid composition, there is also the effect of the various samples air permeability, where the damage increases when the permeability is greater. It has been demonstrated that a greater differential pressure concludes a significant particles deposition on the throat pores during spurt injection. As a result further damage is caused by the most permeable rocks.
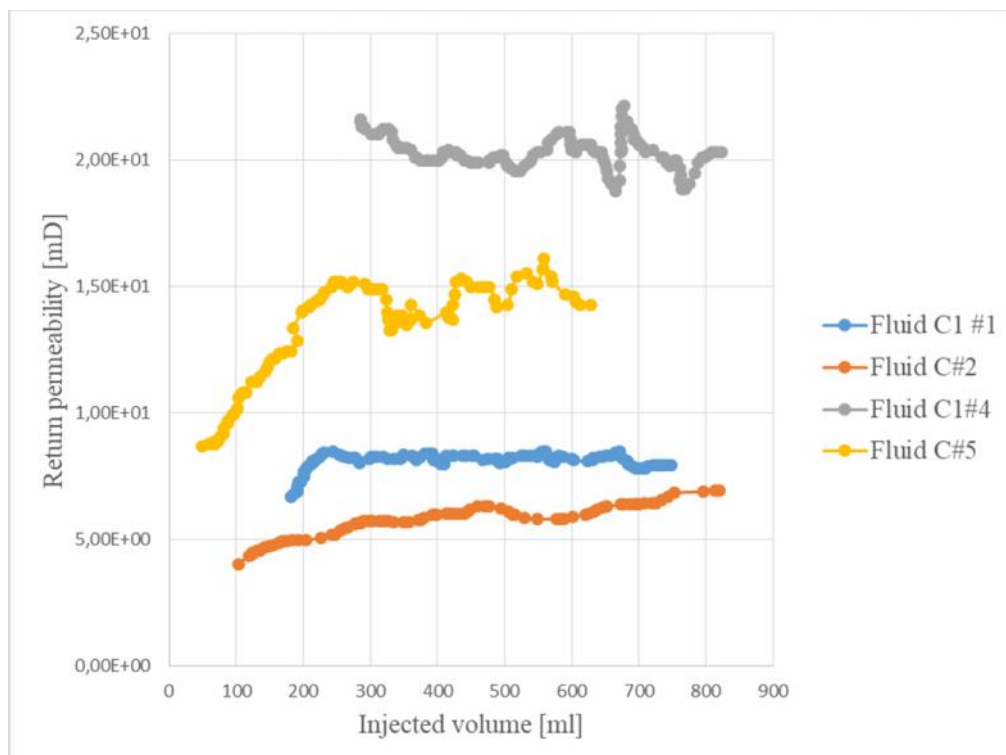

Fig.6. Pressure effect vs injected volume hilightinh the initial and final permeability during the drilling fluid circulation through the reservoir rock for the samples #1, #2,#4 and #5 with drilling mud C

4. CONCLUSION

According to the rheological properties on the fluid flow invasion through the reservoir rock samples, the effect of the liquid composition and their stability over time were studied and understood. According to the results obtained, the concentrations of 2-3% and 3% for organoclay VG69 and emulsifiers and weighting agent are sufficient to provide the rheological properties close to those used in the field level. Such drilling fluids are stable over time, giving the yield stress beteween 5-10 Pa to allow the fluid flow. It was also found that there is a more significant rheological behavior in the densifying fluids with the weighting agent ($CaCO_3$). For the clogged Berea sandstone specimens with two drilling fluids (with and without calcium carbonate), the impact of calcium carbonate on the damage ratio is also studied. Consequently, the introduction of local calcium carbonate produces the DR up to approximately 43%. The extent of the filtrate intrusion also decreases with the pressure and permeability. Based on the obtained results, there is a minimal quantity of surfactant and the DR significantly changes beyond this limit.

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