Investigation of Combined Polymer Flooding and Low Salinity Water for Enhanced Oil Recovery in Dolomite Reservoir using Okro (*Abelmoschusesculentus)*

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Abstract:- The major objective of the present investigation was to study combined polymer flooding with low salinity water for enhanced oil recovery in dolomite reservoirs using okro (*Abelmoschusesculentus*) with the formulation of saline water and synthetic sea water, to conduct displacement experiments on six (6) dolomite core samples as well as studying the effect of concentration of Okro polymer, HPAM and saline water on oil recovery.When a reservoir is flooded with polymer, the mobility ratio between the displaced fluid and the displacing fluid become favourable compared to the conventional water flooding. In the oil and gas industry, the synthetic polymer polyacrylamide in hydrolysed form and the biopolymer xanthan are being used for this purpose. However, the polyacrylamide is vulnerable to high temperature and salinity. Also, its synthetic nature makes it harmful to the environment. The biopolymer xanthan has the problem of degradation and both are very expensive. With the shortfall in crude oil price coupled with the high cost of exploitation and drilling new wells, there is need to look inward and think out of the box in formulating new improved polymers that can battle these problems. Natural polymers from agricultural and forest produce are rampant in nature, cheap and environmentally friendly. These agricultural and forest produce contain starch and cellulose which are known to have rigid and long polysaccharide chains that can withstand the rough reservoir conditions. This study, therefore investigate the use of *Abelmoschusesculentus* (Okro) as a natural polymer that can be used for enhanced oil recovery applications. It was observed that this polymer exhibits non-Newtonian, pseudoplastic and shear-thinning behaviours. Various experiments conducted in this research indicate that natural polymers can recover additional oil from an oil field.

Keywords:- *(Reservoir, Natural polymer, mobility ratio, Abelmoschusesculentus (Okro), biopolymer xanthan HPAM).*

I. INTRODUCTION

More than half of the world's oil reserves are stored in carbonate reservoirs (Al-Shalabi*et al.*, 2014). Due to heterogeneity, the complexity of minerals (limestone, chalk, and dolomite), low permeability, and wettability condition, enhanced oil recovery (EOR) methods for such reservoirs are challenging. Because of the inherent oil-wet nature of the carbonate rock, a large volume of oil remains in the matrix with injected water failing to flush most of the oil from the pore spaces (Shehata and Nasr-El-Din, 2014). Hence, it is necessary to increase the potential of oil production through wettability alteration by EOR methods such as additive chemicals, nano-materials, and low-salinity water.

Water injection to improve the oil recovery has been employed for many years. The effect of injection brine composition and concentration on the displacement efficiency has been ignored in the design of water flooding in the past. Historically avoiding formation damage by making sure no interaction between injected brine and indigenous brine will take place during water flooding was the main design parameter of water flooding (Abdulrazagy and Zaid, 2015). Morrow *et al*., (1996) concluded that oil recovery optimization during water flooding requires alteration of injection water brine composition. Tang and Morrow (1999) and McGuire *et al*., (2005) concluded that decreasing brine salinity results in an improvement of oil recovery.

Polymer flooding is an EOR method that uses polymer solutions to increase oil recovery by decreasing the water/oil mobility ratio thus increasing the viscosity of the displacing water. Polymer flooding is used under certain reservoir conditions that lower the efficiency of a regular waterflood, such as fractures or high-permeability regions that channel or redirect the flow of injected water, or heavy oil that is resistant to flow. Adding a water-soluble polymer to the water flood allows the water to move through more of the reservoir rock, resulting in a larger percentage of oil recovery.

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It is a well acknowledged fact that the use of polymer increases the viscosity of the injected water and reduces permeability of the porous media, allowing for an increase in the vertical and areal sweep efficiencies, and consequently, higher oil recovery (Samanta*et al.,* 2011). The main objective of polymer injection is for mobility control, by reducing the mobility ratio between water and oil. The reduction of the mobility ratio is achieved by increasing the viscosity of the aqueous phase. Another main accepted mechanism of mobile residual oil after water flooding is that there must be a rather large viscous force perpendicular to the oil-water interface to push the residual oil. This force must overcome the capillary forces retaining the residual oil, move it, mobilize it, and recover it (Guo and Huang, 1990).

Low salinity waterflooding process involves injecting brine with a lower salt content or ionic strength. The ionic strength is typically in the range of 1000–5000 ppm which is much lower than that of the formation water or seawater. The low salinity waterflooding causes a shift in the thermodynamic equilibrium between crude oil, brine and rock system that has been established during the geological time, which tends to favor improved oil recovery. Several laboratory studies demonstrated the potential of low salinity water-flooding to improve oil recovery where the core flood experiments showed increase in oil recovery in both secondary and tertiary mode (Filoco and Sharma, 1998; Zhang and Morrow, 2006; Yildiz*et al.,* 1999). In addition, field trial of low salinity water-flooding has been carried out and showed significant success (Lager *et al.,* 2008).

A. Problem Statement

Primary recovery can recover from zero to over 50% of the original oil in place (OOIP), and the secondary recovery can recover from 30 to 50 % of the original oil in place. Since oil production grows at a rate greater than reserve addition, there is a need to boost the reserve, and this lies with the application of tertiary recovery (EOR) which targets what is left (> 50 % OOIP).Hence there is need for the use of natural polymer.

In this research, investigation of combined polymer flooding and low salinity water for enhanced oil recovery in dolomite reservoir using okro (*Abelmoschusesculentus*), polymer flooding tests were systematically performed using polymer concentrations less and higher than 300 ppm (Shiran, 2014). The effect of this was examined on increased oil recovery at lower residual oil saturations similar to the cases in Shiran's work (Shiran, 2014) in which 300 ppm was used.

B. Scope and Limitations

This experimental research was devoted to investigating the mechanism(s) behind the low salinity effect with emphasis on wettability alteration mechanism. Furthermore, the examination of the combined effect of low salinity polymer solution on increased oil recovery was the matter of interest in this research. Studies were made to test if the combination of low salinity water and polymer has synergistic effect on increased oil recovery, and if so to investigate the oil mobilization and fluid flow properties for low salinity polymer.

II. LITERATURE REVIEW

Historically, avoiding formation damage by making sure no interaction between injected brine and indigenous brine will take place during water flooding was the main design parameter of water flooding. Morrow *et al*., (1996) concluded that oil recovery optimization during water flooding requires alteration of injection water brine composition. Tang and Morrow (1999) and McGuire *et al*., (2005) inferred that decreasing brine salinity results in an improvement of oil recovery. Jerauld *et al*., (2008) indicated that low salinity flooding of more than 20 sandstone cores at reservoir conditions in secondary and tertiary modes had been conducted as reported in the literature. They also reported an improvement of recovery efficiency of 5 to 38 % and 3 to 17 % reduction of residual oil saturation as a result of low salinity flooding. Several laboratory studies demonstrated the potential of low salinity water-flooding to improve oil recovery where the core flood experiments showed increase in oil recovery in both secondary and tertiary mode (Filoco and Sharma, 1998; Zhang and Morrow, 2006; Morrow *et al.*, 1996). In addition, field trial of low salinity water-flooding has been carried out and showed significant success (Lager *et al*., 2008).

McGuire *et al.,* (2005) reported BP experience with low salinity flood. They indicated that BP tested four areas using water injection salinity ranges between 1500 to 3000 ppm and the benefits of its LoSal EOR ranged from 6 to 12 % OOIP, resulting in an increase in waterflood recovery of 8 to 19 %. It is well known that low salinity flood has the following advantages: high EOR potential, environmentally friendly, and combination with other recovery methods possible (such as polymers, alkaline, surfactant, etc.). Robertson (2007) showed that using data obtained from three oilfields, oil recovery increases as the salinity ratio of the waterflood decreases.

Kumar *et al.,* (2010) concluded that oil recovery from Berea by traditional flooding is accompanied by fine migration in quantities sufficient to have some bearing on oil-brine interfacial stability, and that low salinity flooding increases this tendency. Wideroee*et al*., (2010) employed NMR relaxation/diffusion measurements and CryoESEM Imaging for detecting wettability changes during low salinity flooding of sandstone cores. They concluded that the responses in the data from low salinity flooding experiments may be attributed to wettability changes.

Wettability has in many papers been discussed as a key parameter for the LSE. However, the shift in wettability is not well documented. Wettability tests before and after shift in salinity are rare, and most indications are based on end point water relative permeability or the shape of the oil production curve. Tang and Morrow (1999) showed that properties of the crude oil and the rock and the presence of connate water all play an essential role in the sensitivity of oil recovery to brine composition.

Among other mechanisms that have been suggested for explaining LSE during the last 10 years, are in addition to fines migration, impact of alkaline flooding (McGuire *et al*., 2005), multicomponent ion exchange (Lager *et al*.,2007), microscopically diverted flow (Skauge, 2008), double-layer expansion (Ligthelm*et al*.,2009) and pH driven wettability change (Austad*et al.,* 2010). Injection of low salinity brine can give rise to a moderate improvement in oil recovery compared to traditional high salinity waterflooding.

According to Lager and Webb (2008), a hydraulic unit was converted to inject low salinity brine into an Alaskan reservoir in 2005 by switching a single injection pad from high salinity produced water to low salinity water. An injector well and two close production wells were selected within a reasonably well constrained area. The detailed analysis of the production and the chemical composition of the produced water showed the effect of injection brine composition in improving recovery at reservoir scale. The salinity of the produced water used for injection was 16640 ppm of total dissolved solids, while the low salinity brine used has a salinity of 2600 ppm of total dissolved solids. The production data indicated that the process was successful where the oil production increased and the water cut dropped from 92 to 87 %.

III. MATERIALS

A. Sample collection and analyses

The crude oil sample was collected from the Research and Development Division of the Nigerian National Petroleum Corporation (NNPC). The characterization of the crude oil was done by analyzing the physical properties such as Color/appearance; Density, specific gravity, API Gravity; Cloud point; Pour point; Flash point; Kinematic and Dynamic viscosities. These oils were of two types. These oils were used either for displacement process or for aging. These oils are a high viscous crude oil sample X, and a medium crude oil sample.

B. Core Preparation

Six dolomite cores were used in the course of this research, and these core samples were characterized in order to know their mineralogical composition. To avoid any experimental error, cores were prepared very carefully. The core restoration/mild cleaning were carried out using the technique in line with the procedure described by Springer *et al.,* (2003) and Ivan (2017) with a little modification.

Before starting to carry out any measurement, the cores were cleaned with a brush to remove possible dust particles attached to the surface of the samples. Afterwards, they were inserted inside Soxhlet apparatus to be extracted with toluene for 24 h. The cores were put in the oven at temperature of 90 ^{O}C for couple of days to dry them properly and then the length and diameter of the cores were measured. The dead ends volumes were measured before mounting the core into the core holder to make correction for later calculations. Then a confining pressure of about 27 bar was applied to the core and the pressure reading was checked for stabilization about half an hour to ensure there is no leakage in the core holder. Afterwards the core was connected to a computer-aided pump through a piston cylinder filled with synthetic sea water. Before starting saturating the core, the pump was set to hold a pressure of 5 bar which will be the pressure in the cylinder and lines as well. After the pressure was stabilized in the system, the inlet valve of the core-holder was opened and the brine was sucked into the core. The pump has to deliver more synthetic sea water to fill the pore volume of the core and to maintain the pressure of 5 bar. This was maintained until there was almost no change in the cumulative volume of added brine which represents the pore volume (V_P), of the core used. The bulk volume (V_b) of the core was calculated based on the geometrical measurements done during the core preparation. The porosity of the core was then measured using equation 1.

$$\emptyset = {}^{V_P}\!/_{V_b} \qquad \text{-----------------------1}$$

The core was put aside for one week after saturation to allow synthetic sea water to attain ionic equilibrium with the core.

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Fig. 1: Porosimeter

The Porosimeter was used to measure the porosities of dolomite core samples. The core flooding was carried out using an experimental setup.

IV. EXPERIMENTAL DESCRIPTION

A. Permeability Measurements:

The permeability measurements were carried out using the Darcy's law equation. The absolute, effective and relative permeability measurements were conducted before aging, after aging, after low salinity flooding and polymer flooding.

B. Drainage

The primary drainage process for the cores was established by using high viscous oil sample X. The process was done with the core oriented vertically to make use of the gravitational force.

C. Aging:

After the primary drainage process the cores were aged using aging cell in an oven for about 4 weeks at a temperature of 85 ^{O}C to alter the wettability of the cores. Cores D3, D4, D5, and D6 were aged for 4 weeks while cores D1 and D2 were not aged to watch the effect of aging on the performance of displacement experiments.

D. Synthetic Sea Water and Low Salinity Water flooding:

The effect of reducing salinity of the injected brine was inspected in the unaged cores in both secondary and tertiary mode. The synthetic sea water was injected first in core D1 as secondary mode then followed by 22 times diluted sea water as tertiary mode. Core D2 was flooded directly from the beginning by 22 times diluted sea water. The aged cores D3, D4, D5, and D6 were flooded by 3000 ppm NaCl brine (low salinity brine) as secondary injection. During the flooding experiments all the cores were subjected to a confining pressure of 25 bar. Before starting the flooding in each core the system was pressurized to 8 bar by using the back pressure regulator to prevent the development of air bubbles.

The flooding process commenced with slow flow rate of 0.1 ml/min in order to forestall the fingering displacement that causes the early water break-through. When the oil production was stopped, the injection was continued at same rate for 2 more pore volume. After that the flow rate was increased in order to observe the effect of increasing the viscous force on the oil recovery. Also the injection continued for almost 2 pore volume after the oil production was ceased. The flow rates used in the experiments were 0.1, 0.5, and 1 ml/min. During the flooding, samples of production were collected using the fraction collector. The volume of oil and water produced in each tube was measured volumetrically and the calculations of the production profiles and saturations were carried out. The pressure profile during the displacement was continuously monitored.

A. Samples Preparation

The fluid samples used in this study are described and presented in this section. In addition the chemical composition and the preparation procedures are explained for each fluid. These fluids were either used for displacement experiments or for other measurement during the study.

➢ *Synthetic Sea Water (SSW)*

Synthetic sea water was used to saturate all the cores. The chemical composition of the synthetic sea water is listed in table **1** below. The brine was prepared by mixing distilled water and the salts. The brine was placed on a magnetic stirrer to dissolve the salts properly and then filtrated using 0.45 µm vacuum filter.

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Table 1: Chemical Composition of Synthetic Sea Water (SSW)

Salt	Formula	H_2O, Mol kg^{-1}	(g/kg) Solution
Sodium Chloride	NaCl	4.504×10^{-1}	26.348
Potasium Chloride	KCl	9.022×10^{-3}	0.672
Sodium Hyrogen Carbonate	$NaHCO_3$	1.979×10^{-3}	0.166
Pottasium Bromide	KBr	8.110×10^{-4}	0.096
Boric acid	H_3BO_4	3.186×10^{-4}	0.025
Sodium Fluoride	NaF	6.754×10^{-5}	0.003
Magnesium Chloride	$MgCl_2.6\ H_2O$	2.375×10^{-2}	4.821
Calcium Chloride	$CaCl_2.2\ H_2O$	9.920×10^{-3}	1.458
Strontium Chloride	$SrCl_2.\ 2\ H_2O$	8.689×10^{-5}	0.017
Magnesium Sulphate	$MgSO_4.\ 7\ H_2O$	2.725×10^{-2}	6.704

The anhydrous salts were procured from Sigma-Aldrich (USA) and the hydrated salts were purchased from Quali-Tech Chem (Indian).The synthetic seawater was prepared in accordance with the composition indicated in the work of Berkowitz*et al*., (2001) and the concentration is similar to the studies of Petrov*et al.,* (2011); Cuenca and Serna (2021). The synthetic sea water was diluted 22 times to make low salinity brine used for injection in the unaged cores.

A. Low Salinity Water (LSW):

The low salinity water used for secondary waterflooding in the aged cores was made by mixing distilled water and sodium chloride (NaCl). The brine contains 0.30 wt % of NaCl and the composition is listed in table **2** below.

Table 2: Chemical composition of low salinity water

Salt	(g/kg solution)	Producer
NaCl	3000	Qualikems

The brine made was put on a magnetic stirrer to dissolve the salts properly and then filtrated using 0.45 µm vacuum filter.

B. Crude Oils

During the drainage and flooding experiments, high viscous crude oil sample X was used to establish the minimum value of initial water saturation, S_{wi}, for all cores. Crude oil densities and viscosities were measured at 20 °C, 23 °C and 26 °C. Acid Number (AN) and Base Number (BN) were analysed. Crude oil was also used in aging the cores before the main flooding experiments. Composition and some of the important properties of crude oil were noted. Table **3** shows the properties of the test fluids used for this experiment.

Table 3: Crude oil properties

Oil Sample	AN Mg KOH/ g oil	BN Mg KOH/g oil	Density g/cm³	Viscosity cP	API gravity	pH	Color
High viscous crude oil sample X	3.91	1.29	0.9226	4.28	21.87	7.30	Black
Medium crude oil	0.23	1.17	0.8954	3.15	26.53	7.60	Dark brown

C. Preparation of Okro (Natural Polymer) Sample

The okro polymer solution was prepared with a concentration of 2000 mg/l. Fresh water was used for the preparation of Okro samples – Natural polymer *(Abel moschusesculentus*). The sample was dried, pulverized and sieved to obtain fine granules (Gemede*et al*., 2016). The okro sample was further dissolved with fresh water at 60 ^{O}C and stirred vigorously for proper dissolution. However, the dissolution was incomplete as there were undissolved particles still floating in the solution. These particles were carefully sieved out to obtain a fairly clear solution. In determining the absorbance of the polymer at different concentrations, a stock polymer solution, 20,000 mg/l was prepared and further diluted to concentrations of 2200, 2000, 1600, 1200, 800, and 400 mg/l respectively with a 100 ml conical flask.

D. Preparation of Polymer Solution (HPAM)

The type of polymer used in this study is the partially hydrolyzed polyacrylamide (HPAM). The diluted polymer solutions were prepared using the following steps:

- A coated magnet was put in a Duran flask and then about half of the 0.30 wt % of NaCl brine was added.
- Polymer from the stock solution was added by weight to the Duran flask.
- The rest of the brine was added so that the concentration of the polymer matches the final concentration wanted.
- The solution was put on a magnetic stirrer at low speed (< 100 rpm), then sealed by cork and parafilm and left to stand overnight.
- The solution was then filtered using 40 µm filter and vacuum apparatus before using it for viscosity measurements and flooding process.

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The most important aspects should be avoided for polymer solution. These are unnecessary exposition to air, sample homogeneity, creation of micro gels, shear degradation, and iron contamination. The concentrations of the polymer stock solution and the diluted polymer solutions made in this investigation for both okro and HPAM are presented in Appendix C.

The viscosity and shear rate measurements were carried out on all the okro and HPAM polymer solutions made and the solution that gives the desired viscosity for flooding was chosen for tertiary slug injection.

V. RESULTS AND DISCUSSION

Below are presented the various measurements and displacement experiments conducted during this research, and they are discussed. The measured properties of different liquids used or prepared are stated and analyzed and these measured properties include density, and viscosity. The polymers concentration used for the tertiary injection was chosen on the basis of the viscosity measurements. Also the basic physical and petrophysical properties of the six dolomite cores used for displacement experiments are stated and discussed. These cores are assigned D1, D2, D3, D4, D5, and D6. Cores D1 and D2 were not aged while the remaining four cores were aged for four weeks at 85 ^{O}C.

Core D1 was first flooded with synthetic sea water, and then followed by 22 times diluted synthetic sea water. This was done in order to observe the effect of the low salinity waterflooding as tertiary mode. Core D2 was flooded directly by the 22 times diluted synthetic sea water as secondary mode and compared with core D1.

The aged cores were flooded by low salinity brine which is 3000 ppm NaCl brine and the oil recovery and pressure profiles are presented. The wettability state as well as the recovery parameters of the cores are discussed and compared with the unaged cores to determine the effect of aging and low salinity waterflooding.

A. Mensuration of Liquids Properties

In this section, the measured properties of the fluids used in this research are portrayed and discussed. The fluids were used during this investigation either for displacement experiments or for testing purposes.

➢ *Density:*

The density measurements of the fluids used in this study are recorded in Appendix B. The measurements for brines and oils were carried out at three different temperatures. The results indicate that the density of brines and oils decreases with increase in the temperature.

➢ *Viscosity*

The viscosity measurements of brines and types of oil used in this study were conducted at three different temperatures and the results are showcased in Appendix C. The fluid viscosity mainly depends on the temperature and the results demonstrate that the viscosity of brines and oils used decreased with increasing temperature. The displacement experiments in this study were conducted at room temperature and the measured temperatures during the experiments were between 20 and 26 ^{O}C.

The viscosity measurements of the polymer solutions were conducted at temperature of 20 ^{O}C, 23 ^{O}C, and 26 ^{O}C and they are depicted in Appendix C. The concentration of the polymer solutions used was chosen based on the viscosity measurements (see Appendix C). In the low salinity polymer slug injection which is the last flooding process, the concentration chosen for polymer slug was 600 ppm and that was in order to notice if any additional oil can be produced by further improving on the viscosity ratio between oil and polymer solution.

B. Basic Physical and Petrophysical Properties of the Rocks:

The six dolomite cores used in this research were assigned D1, D2, D3, D4, D5, and D6. The basic properties of these cores are presented in table **4** below. The Dolomite core samples were obtained from OrekeIfelodun Local Government Area of Kwara State of Nigeria.

Table 4: Physical properties of the Dolomite core samples

Core ID	**Length (cm)**	**Diameter (cm)**	**PV (ml)**	**Porosity φ (%)**	**Absolute K (mD)**	**Swi (%)**
D1	4.50	3.4	6.68	16.35	213.22	19.00
D2	4.26	3.4	6.32	16.34	217.30	20.50
D3	4.75	3.38	6.75	15.83	219.81	19.50
D4	4.20	3.5	6.30	15.59	219.17	22.00
D5	4.80	3.5	8.41	18.21	223.08	21.50
D6	4.80	3.38	7.81	18.13	221.39	23.00

As seen from table **4** the dolomite cores have porosities ranging from 15.59 – 18.21 % while the absolute permeabilities varies between 213.22 and 223.08 mD. The mutation in the absolute permeabilities of the cores could be as a result of the interactions between the SSW used for measurement and the rock minerals during saturation. In addition the differences in the pore structure of the cores could also conduce to the permeabilities variation. Initial parameters of the cores after the drainage process and also the permeability measurements conducted before and after the aging period are presented in table **5**.

Table 5: The initial parameters of the cores before flooding process

Core ID	D1	D2	D3	D4	D5	D6
Swi[% PV]	18.70	19.00	19.50	22.50	21.50	23.00
Soi [%PV]	81.30	81.00	80.50	77.50	78.50	77.00
Keff [mD] before aging	262.26	268.27	273.05	282.80	287.85	287.52
Keff [mD] after aging	NA*	NA*	210.43	215.02	212.90	205.93

NA* implies not aged

The initial water and oil saturations of the unaged cores D1 and D2 are nearly the same as shown in table **5**. The other four cores that were aged for four weeks at 85 ^{O}C demonstrated a decrease in the effective permeability which indicates that the wettability of the cores has been altered during aging period. The diminution in permeability is more marked in the cores D5, and D6 while cores D3 and D4 showed about 23 % and 24 % reduction in permeability respectively.

C. Synthetic Sea Water (SSW) and Low Salinity (LS) WaterfloodingIn Unaged Cores:

In this procedure, the effect of decreasing the salinity of injected brine on the oil recovery of two unaged cores was first examined. The brines used were synthetic sea water and 22 times diluted synthetic sea water and the experiments were carried out in secondary and tertiary mode. Core D1 was flooded first with synthetic sea water; then followed by 22 times diluted synthetic sea water so as to observe the effect of the low salinity waterflooding as tertiary mode. But core D2 was flooded directly by the 22 times diluted synthetic sea water as secondary mode and compared with core D1.

➢ *Production Profiles of Secondary Injection*

The production profiles of secondary waterflooding of the unaged cores D1 and D2 are depicted in figure **2**. Core D1 was flooded with synthetic sea water while core D2 was flooded by the 22 times diluted synthetic sea water.

D. Comparison between the Synthetic Sea Water (SSW) and Low Salinity (LS) Waterflooding as Secondary Mode:

The production recovery parameters of synthetic sea water and low salinity water flooding were done as secondary mode water flooding in unaged cores D1 and D2 and the results are presented in table **6** below. The flooding process in both cores was similar and the flow rate was increased when the oil production ceased so as to observe the effect of increasing the viscous force. It is apparent from the table that the two flooding cases gave almost same oil recovery where synthetic sea water gave 48.54% of oil recovery factor and the 22 time diluted synthetic sea water gave 47.96% of oil recovery factor.

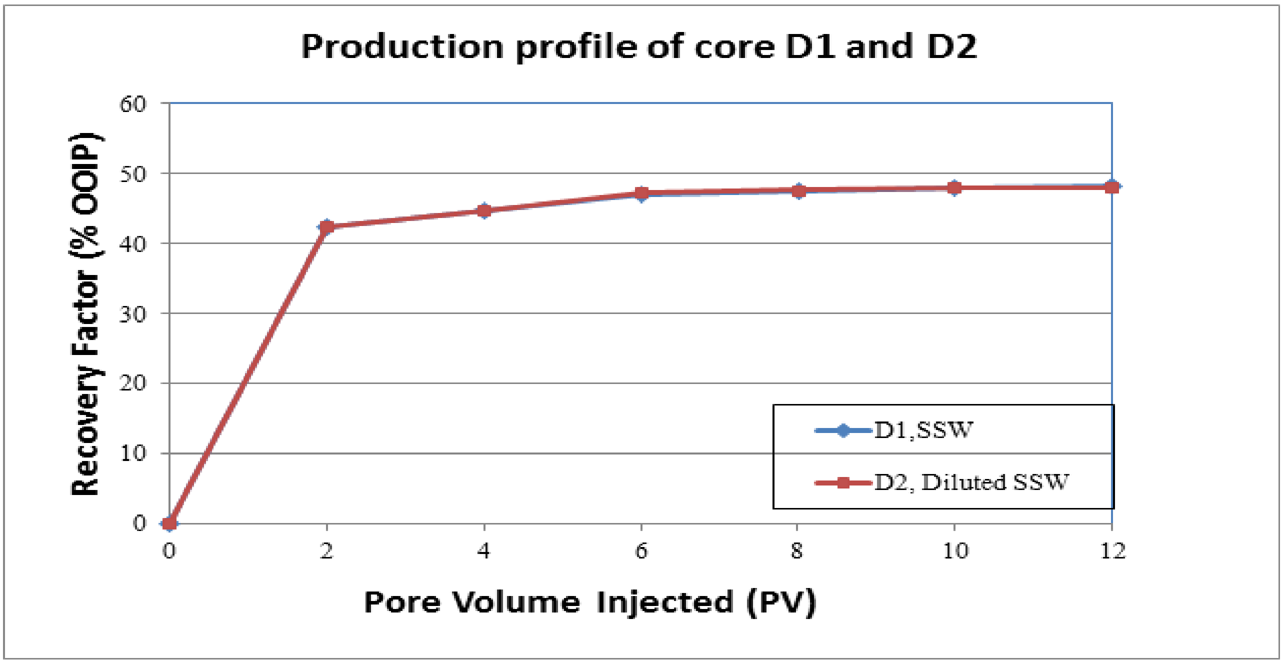

Fig. 2: Production profile of SSW and DSSW in unaged cores D1 and D2.

Table 6: Production recovery parameters of SSW and LS water flooding as secondary mode

Core	D1 (Secondary SSW)	D2 (Secondary LS)
PV Injected	9.7	7.0
RF (% of OIIP)	48.54	47.96
WBT (PV)	0.48	0.41
S_{or} (%PV)	31.92	31.74
K_{effe}atS_{or}	32.18	32.08

It was noticed in both experiments above that oil production was stopped or continued at a high water/oil ratio once the water break-through happened. This type of production shows that both cores have strongly water-wet conditions as observed in the work of Jadhunandan and Morrow (1995). Besides, the high residual oil left after the flooding process which is 31.92 and 31.74 % PV for cores D1 and D2 respectively reflects that the cores are at strongly water-wet state.

Numerous researchers have demonstrated that the reduction in the salinity of the injected brine gives higher oil recovery compared to high salinity brine. These studies notwithstanding were conducted in aged cores where the aging period affected the crude oil/brine/rock (COBR) interaction and altered the wettability of the core to reveal the reservoir state. This change in wettability influences the performance of the waterflooding using different brine salinityin line with the result of Tang and Morrow (1997); Winoto(2012). A stated essential condition for observing the effect of low salinity waterflooding is setting up the mixed wettability by exposing the rock to crude oil (Morrow and Buckley, 2011).

E. Low Salinity (LS) Water flooding in Aged Cores:

Here, the secondary low salinity waterflooding process was conducted in the aged cores (aged for 4 weeks at a temperature of 80 ^{O}C), and the results obtained are presented and discussed. The aged cores are D3, D4, D5, and D6 and the low salinity brine used for flooding is 3000 ppm NaCl brine. In this procedure the flow rate was increased when the oil production stopped so as to observe the effect of increasing the viscous force. The effect of aging period in modifying the wettability of the cores is discussed and the pressure profiles are shown below.

- *Oil Recovery of Low Salinity Waterflooding*

The four aged cores were flooded with low salinity (3000 ppm NaCl) brine as secondary mode, and the results are presented in figure **3**. The recovery parameters of the cores are also shown in table **7** below.

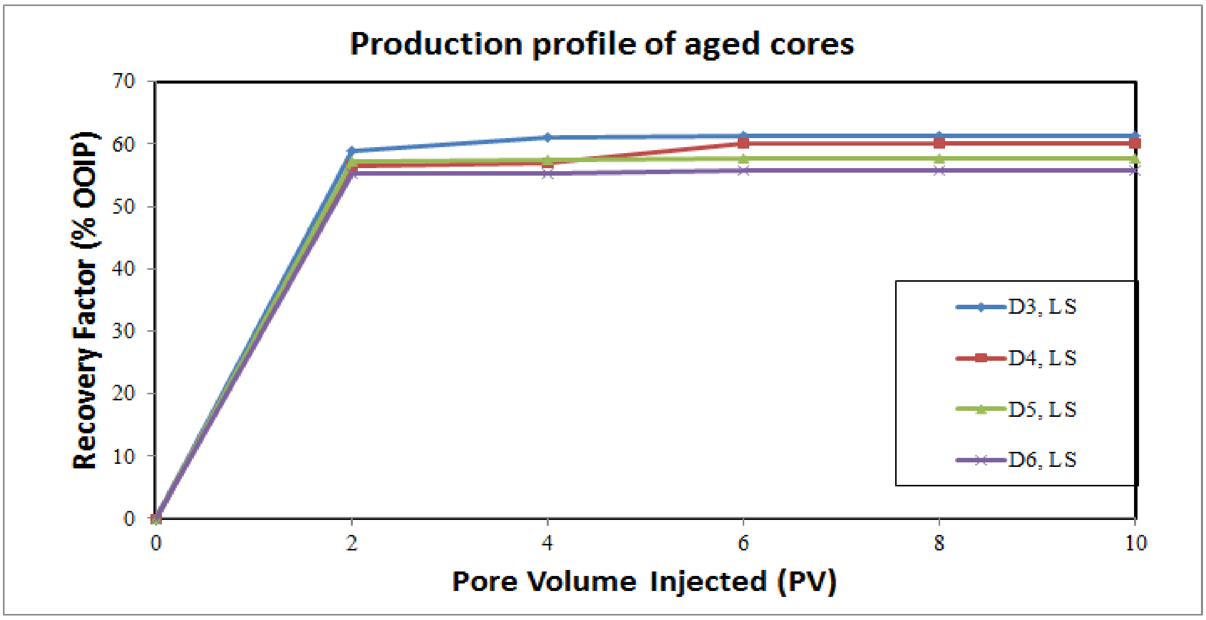

Fig. 3: Production profiles of low salinity waterflooding in aged cores.

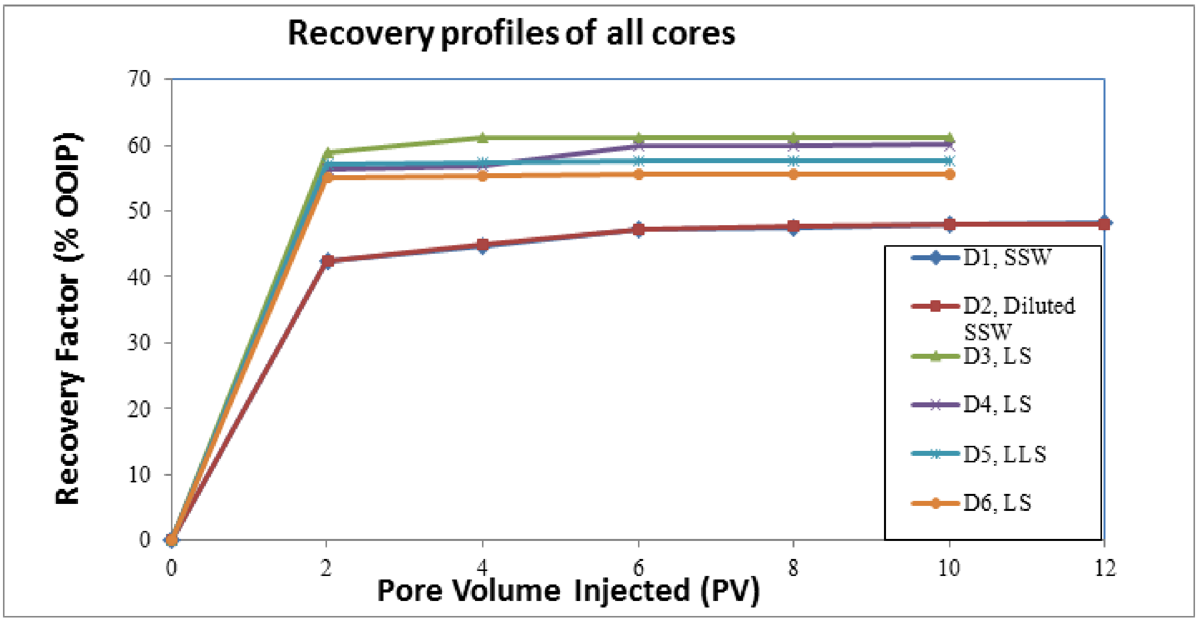

Fig. 4: Recovery profiles of secondary waterflooding for all six cores.

Table 7: The recovery parameters of low salinity waterflooding for the Aged Cores

Core ID	D3	D4	D5	D6
S_{wi} (% PV)	19.50	22.50	21.50	23.00
S_{oi}(% PV)	80.50	77.50	78.50	77.00
Pore volume injected([PV)	7.40	8.30	7.60	7.20
RF (% OIIP)	61.21	60.00	57.44	55.70
WBT([PV)	0.38	0.40	0.37	0.36
Sor,LS (% PV)	15.80	18.65	20.32	21.41
Keff at Sor (mD)	60.83	72.92	61.00	70.53

As presented in table **7**, the recovery factors obtained for low salinity water flooding in the four aged cores are ranging between 55.70 – 61.21 ± 2 % OIIP with highest recovery recorded in core D3**.** It was noted that the four cores have nearly the same initial oil saturations, Soi, in the range of 77.00 – 80.50 % PV, and the flooding processes were similar, the recovery factors and residual oil differ among the cores. The wettability of the cores could be modified during the aging period at different scale which led to this variation in oil recovery. The level of interaction between surface-active constituents in the oil and the rock surface in a crude oil/brine/rock (COBR) system is determined by many factors, such as fluid content, oil composition, rock mineral composition, brine composition, temperature, and pressure. A study conducted by Anderson, (1986); Tang and Morrow, (1997) revealed that this COBR interaction controls wettability and the efficiency of oil recovery by a variety of possible mechanisms.

Considering figure **4,** the results of secondary injection in both aged and unaged cores clearly show that the low salinity (3000 ppm NaCl brine) injection in aged cores gives higher recovery when compared to injection of synthetic sea water and 22 times diluted sea water in the unaged cores. The obtained results reveal that the aging period of the cores had a positive effect in altering the wettability of the cores toward less water wet conditions which is evident in higher oil recovery. Literatures have it that both the aging time and aging temperature of cores affect the oil recovery where the oil recovery by waterflooding increases with increasing aging time and temperature (Jadhunandan and Morrow, 1995).

The noticed reduction in the oil permeability at initial water saturation before and after aging also could be a qualitative indication of alteration in the wettability of the aged cores to less water wet state compared to the unaged (strongly water wet) cores. In strongly water wet cores the oil occupies the large pores and therefore will flow easily with minimal resistance having high oil permeability. As the wettability changed towards less water-wet conditions the flow resistance of oil will increase leading to decrease in the oil permeability at initial water saturation. The cores D3, D4, D5, and D6 showed 24 – 28 % reduction in the oil permeability after aging, (see table **5**).

F. Wett ability

The performance of water flooding is greatly affected by the wettability state of the COBR system. A study conducted on different COBR systems revealed that the oil recovery by water flooding increased with change in the wettability from strongly water-wet to a maximum at close to neutral wettability (Jadhunandan and Morrow, 1995). A comparison of the oil recovery gotten from all the six cores used in this research flooded in secondary stage is depicted in Figure **4.**

As reported in the literatures, during the low salinity water flooding the wettability of the cores changes towards a more water wetness and thisresults in increased oil recovery (Skrettinglande*t al.,*2010).The pore scale network modeling and the percolation theory have been used to discuss and physically explain this mechanism where the low salinity injection has been concluded to alter the wettability of the mixed wet cores towards more water wet conditionsas noted by Sorbie and Collins (2010).

The relative permeability values to water, K_{rw}, can be obtained as a ratio of the endpoint permeability to water, K_{eff}, to the absolute permeability, Kabs, for the corresponding cores. After the low salinity waterflooding in the aged cores, these relative permeability values could indicate cores wettability.

These values are compared with the values of the unaged cores D1 and D2 (strongly water-wet cores).The residual saturation after secondary waterflooding and the relative permeability values of the six cores are depicted in table **8** below.

Table 8: Residual saturation and relative permeability values of all cores

Core	**D1**	**D2**	**D3**	**D4**	**D5**	**D6**
S_{or}	31.92	31.74	15.80	18.65	20.32	21.41
K_{rw} after LS	0.12	0.14	0.21	0.17	0.20	0.18

The unaged cores D1 and D2 are strongly water wet with their values of relative permeabilities being 0.12 and 0.14 respectively. However the typical values of the relative permeability for strongly water wet system is in the range of 0.05 to 0.1. The aged cores were flooded by low salinity brine, and show relative permeability values between 0.17 **-** 0.21 which are in the range of the typical weakly water wet systems (the relative permeability of 0.1 – 0.3 is determined as weakly water wet). The intermediate water wet system has generally relative permeability of greater than 0.3.

Due to aging the wettability of cores D3, D4, D5 and D6 has been modified to less water wet state, and this was reflected in the reduction in the oil permeability after the aging. There is that tendency that during the low salinity flooding the wettability of the cores might be changed toward more water wet leading to the release of oil from the rock surface and increase recovery.

➢ *Pressure Profiles:*

The pressure and production profile of the low salinity waterflooding in the aged cores have been combined, and are depicted in figures **5-8**. The pressure development of the cores has rather similar trends, as evident from the figures. The pressure profile started increasing at the beginning of the low salinity injection until the peak value was reached just before the water break-through, and then decreased and leveled off. The flooding started with injection rate of 0.1 ml/min to have a kind of stable displacement and avoid the fingering phenomena which cause early water break-through. The observed pressure peak at water break-through of the cores was in the range of 30 mbar and the volume of water produced at the breakthrough were 0.54, 0.56, 0.58, and 0.53 PV from D3, D4, D5, and D6 respectively. The pressure stabilized at the breakthrough with minor perturbation in the profile.

There was a slight increase in the differential pressure profile of the cores after about 3 PV injection occasioned by the increase in the injection rate.

After the oil production ceased, the injection rate was increased to 0.5 ml/min and then increased further to 1 ml/min as evident from the increase in the pressure profile. There was a noticeable response of this increase in the injection rate in the production profiles of core D3, while cores D4, D5 and D6 produced less oil as the injection increased.

The increase in recovery resulting from the rising flow rate is one of the indications that the wettability of the core is less water wet.

In some dolomite formations that contain fine particles; these could migrate in the porous medium and cause a reduction in the permeability of the formation by plugging the interconnecting pore throats. Also, fine migration has been proposed to provide a mobility control to improve the performance of the waterflooding by diverting the flow from the water swept zones to un-swept zones. The pH, temperature, salinity of the injected brine, and flow rate have been found to be important factors contributing to the fine migration process (Lemon *et al.*, 2011).

Fine migration also has been noticed and suggested in the literatures as one of the mechanisms that causes an increase in the oil recovery by low salinity waterflooding (Zhang *et al.,* 2007).

Nevertheless, core flood experiments conducted by BP have shown neither fines were produced in the effluent nor reduction in permeability (Lager *et al.,* 2008). Fine particles have not been visually noticed in this research in the produced effluent during the core flood experiments of secondary low salinity water flooding.

As noticed in the pressure profiles of the cores shown in figures **5-8**, it seems to be stable during the low salinity injection and increased only as a response of raising the flow rate.

Therefore this indicates that the swelling of clay in the dolomite sample used is not pronounced, otherwise it will be observed as a noticeable increase in the pressure profile.

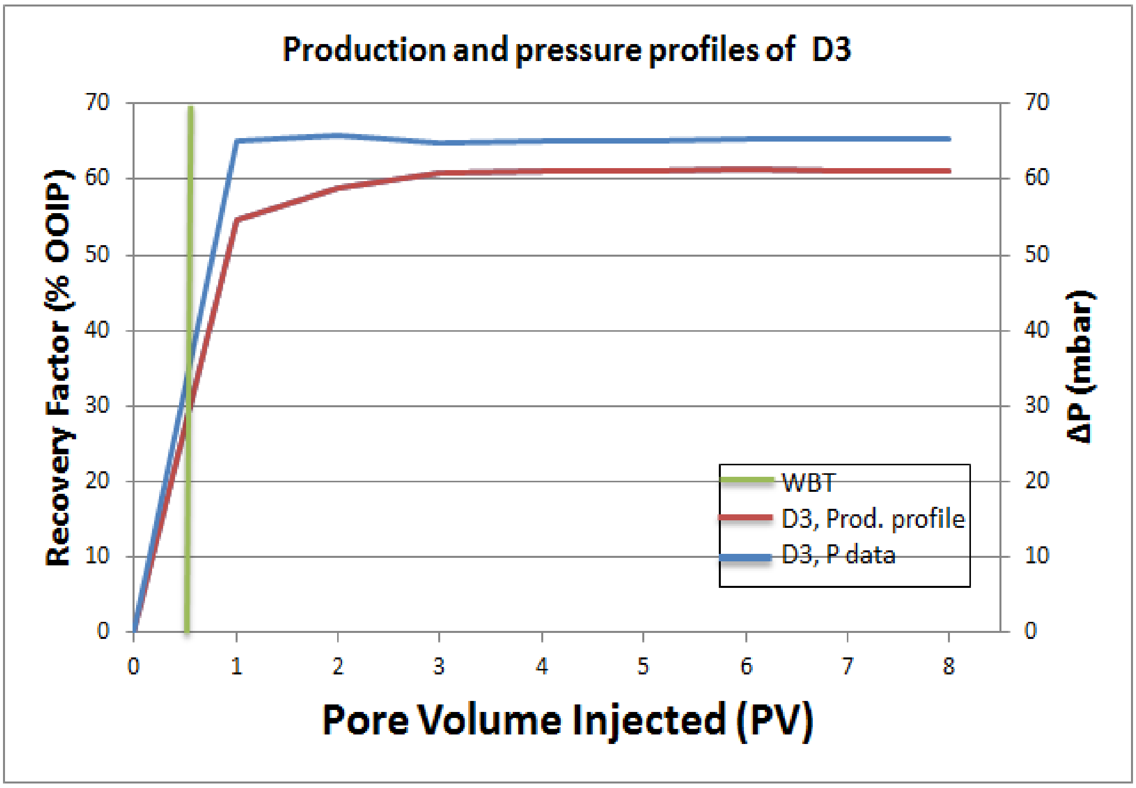

Fig. 5: Production and Pressure profiles of LS waterflooding in core D3.

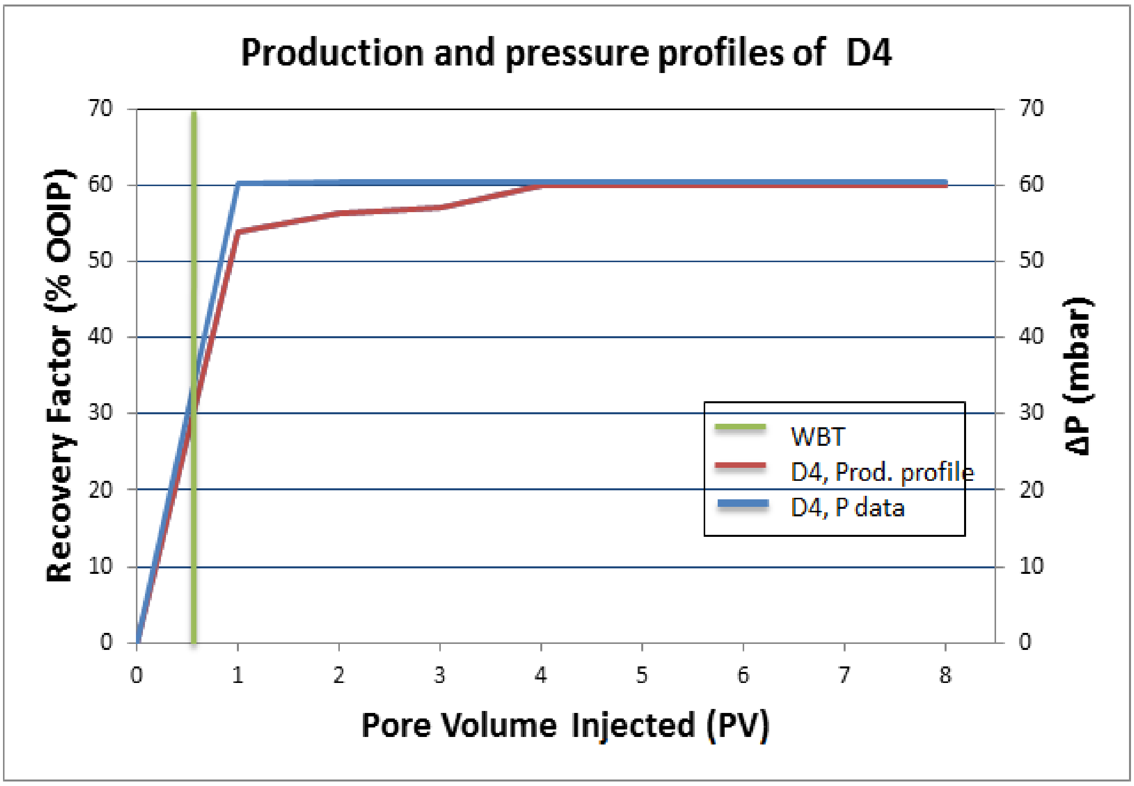

Fig. 6: Production and pressure profiles of LS waterflooding in core D4.

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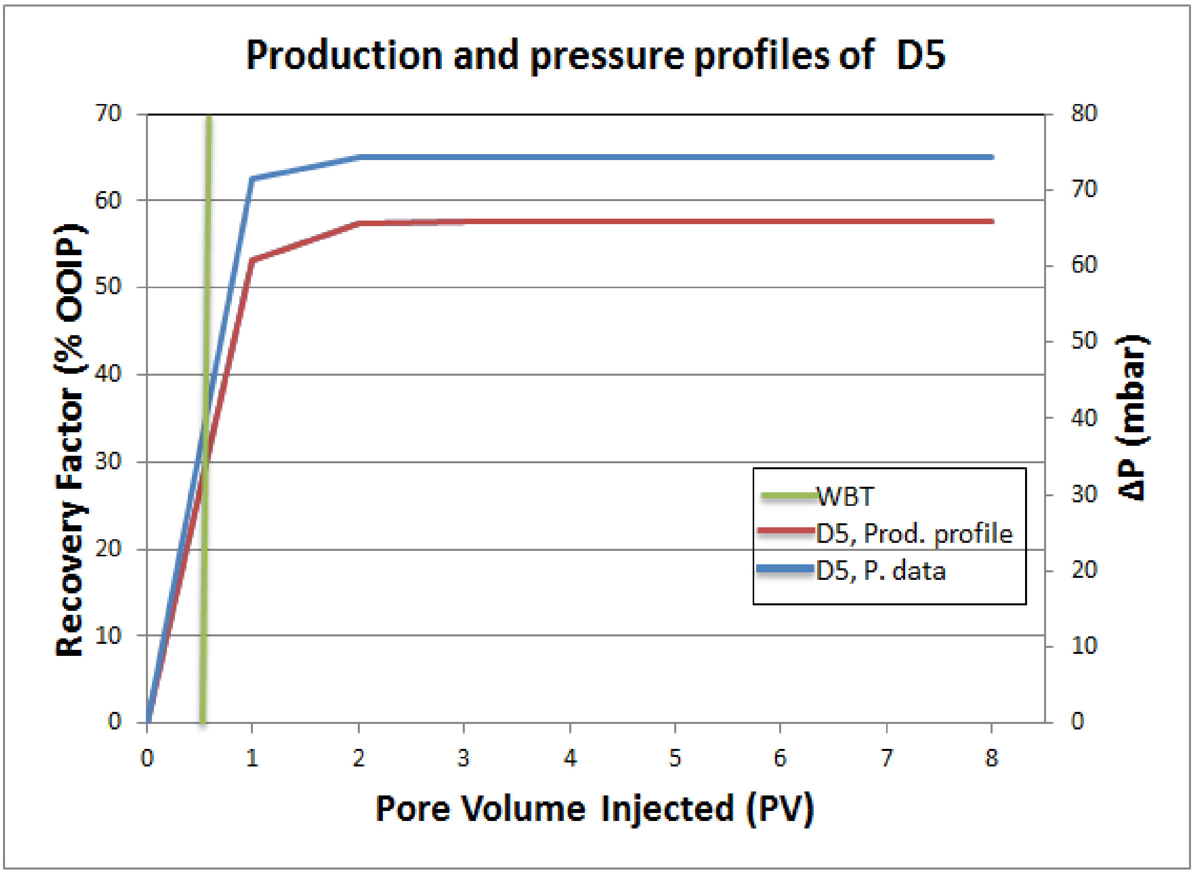

Fig. 7: Production and pressure profiles of LS waterflooding in core D5.

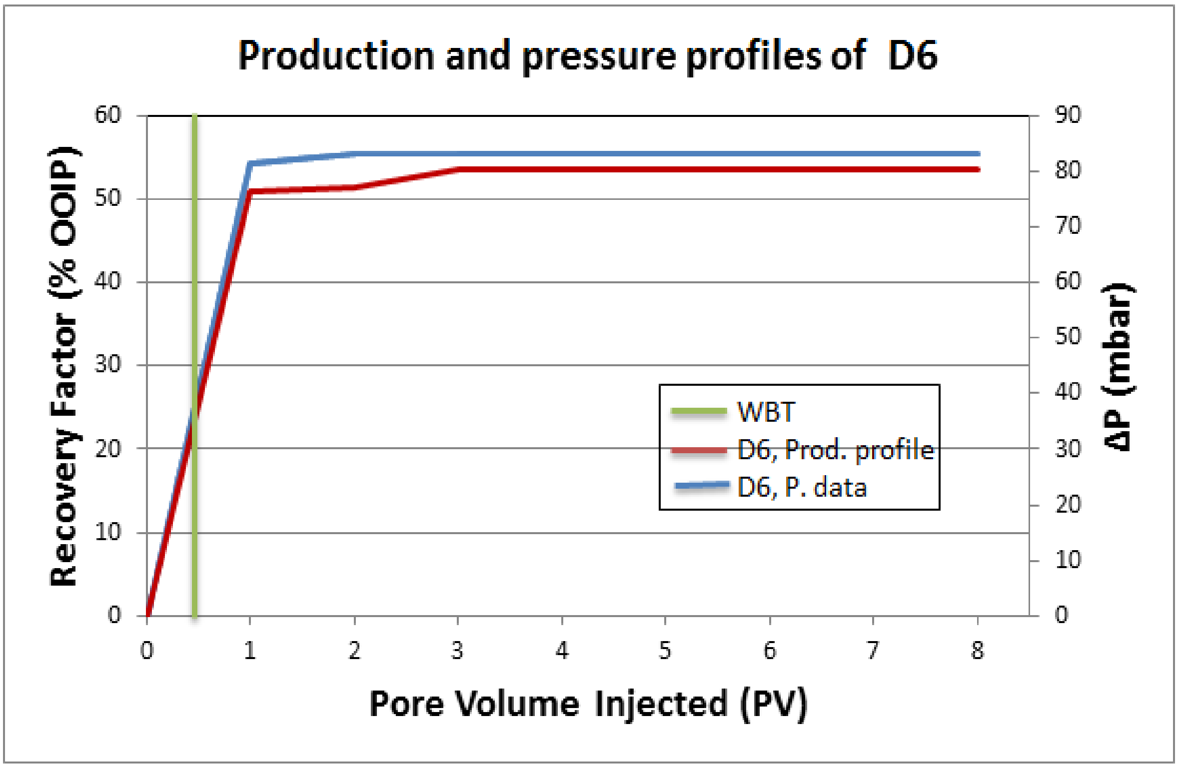

Fig. 8: Production and pressure profiles of LS waterflooding in core D6.

G. Low Salinity Polymer Slug Injection:

All the cores were flooded by 1 PV of polymer followed by continuous low salinity brine injection after the tertiary low salinity surfactant and polymer slugs injection, to observe any further production. The concentration of the polymer solution used in this stage is 600 ppm. The recovery parameters of the cores are presented in tables **9** and **10**.

Table 9: Recovery Parameters of Low Salinity Polymer Injection using Okro

Core ID	**D1**	**D2**	**D3**	**D4**	**D5**	**D6**
Sor after LS-S-P	23.90	21.65	11.21	12.77	12.68	17.50
PV inj	3.5	3.7	5.2	3.7	3.6	4.7
RF (Soi)	0.74	0.60	1.15	1.62	3.08	2.29
Sor after LS-P	23.48	20.68	10.42	9.91	10.00	16.49
ΔSor	0.42	0.97	0.79	2.88	2.68	1.01

Table 10: Recovery Parameters of Low Salinity Polymer Injection using HPAM

Core ID	**D1**	**D2**	**D3**	**D4**	**D5**	**D6**
Sor after LS-S-P	27.95	24.15	11.94	14.80	15.74	15.00
PV inj	3.5	3.7	5.2	3.7	3.6	4.7
RF (Soi)	0.49	0.58	1.00	1.50	3.00	2.25
Sor after LS-P	26.98	22.15	10.00	11.21	12.70	13.92
ΔSor	0.97	2.00	1.94	3.59	3.04	1.08

- *Oil Recovery*

The six cores were flooded by 1 PV of 600 ppm okro and HPAM polymer solutions in order and the oil recovery is presented in figures **9** and **10**.The results clearly show that the polymer slug injection has mobilized some oil from the cores. However, there is variation in the quantity of produced oil among the cores as depicted in the figures. When okro polymer solution was used, cores D1, D3, and D4 recorded oil production of less than 3 % of OIIP while cores D2 and D5 demonstrated a substantial amount of oil recovery of 8.6 and 8.9 % of OIIP. The two cores with highest recovery reacted early to the okro polymer slug injection by starting oil production after injecting around 0.2 and 0.3 PV of polymer slug into core D2 and D5 respectively.

When HPAM polymer solution was injected, cores D1, D3, and D4 also produced less than 3 % of OIIP while cores D2 and D5 showed an improved oil recovery of 11.8 and 11.2 % of OIIP. The two cores with highest recovery responded early to the HPAM polymer slug injection by starting oil production after injecting around 0.2 and 0.3 PV of polymer slug into core D2 and D5 respectively.

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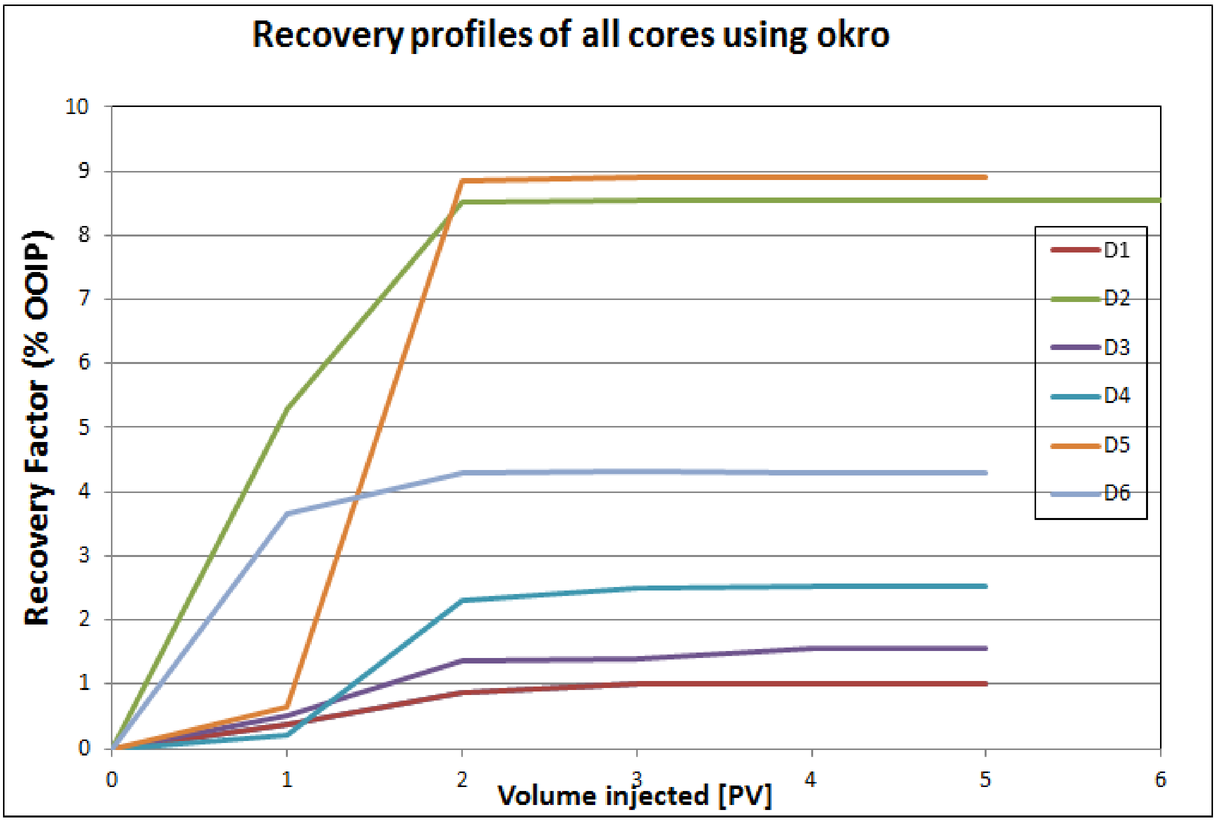

temperature.Fig. 9: Oil recovery of low salinity polymer slug injection using okro.

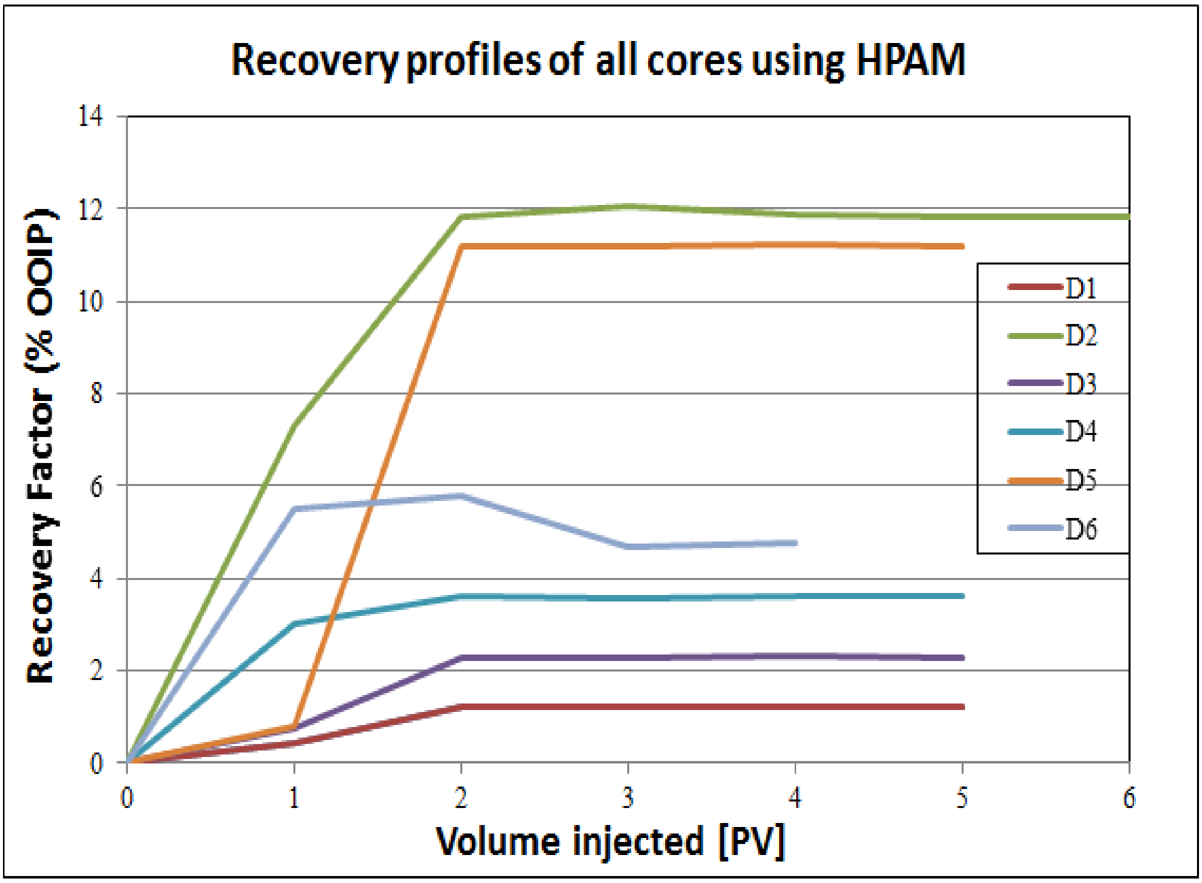

Fig. 10: Oil recovery of low salinity polymer slug injection using HPAM.

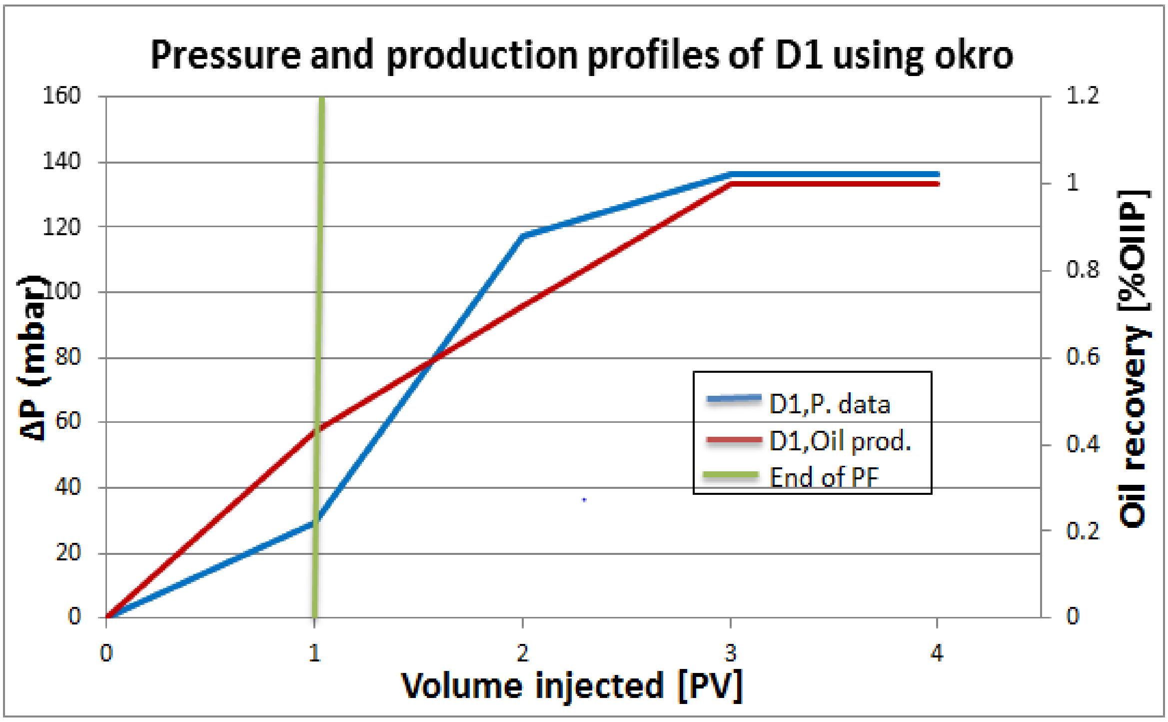

Fig. 11: Pressure and production profiles of LS-P flooding in core D1 using okro.

The consequence of polymer solution in improving oil recovery is mainly due to increasing the viscosity of the injected brine which conduces to improving the volumetric sweep efficiency. Increasing the viscosity of the injected water, µw, essentially causes an increase in capillary number, N_C and therefore affords lower residual oil, Sor. However, the reduction is small since it takes a major change (order of magnitudes) in order to affect Sor dramatically as observed by Skarestad and Skauge (2007).

The recovery performance of the cores does not reflect the effect of wettability on the performance of the polymer slug injection particularly when okro polymer solution was used. The strongly water-wet core D2 gave the second largest recovery when okro was injected while the other strongly water-wet core D1 gave the lowest recovery. Also when HPAM was injected the strongly water-wet core D2 gave the highest recovery while the other strongly water-wet core D1 gave the lowest recovery.

➢ *Pressure Profiles*

The pressure profile of low salinity polymer slug injection performed in all the cores is deployed against the oil production profile and the results are presented in figures **11–22.** During the polymer slug injection, the pressure across the cores increased in reaction to increasing the viscosity of the injected brine. The pressure profile in all the cores decreased during the low salinity brine injection that followed the polymer injection, and stabilized afterwards. All the cores commenced production of oil during the polymer slug injection and continued producing during low salinity flooding until the oil production stopped.

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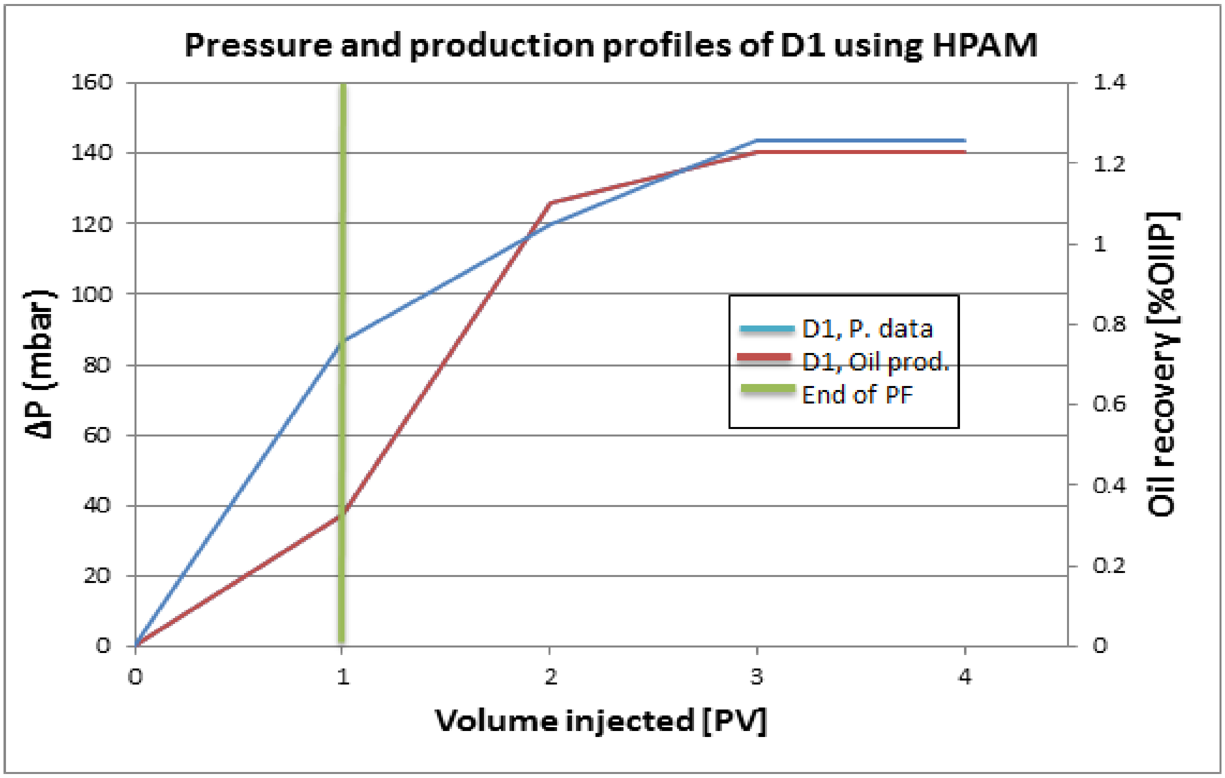

Fig. 12: Pressure and production profiles of LS-P flooding in core D1 using HPAM.

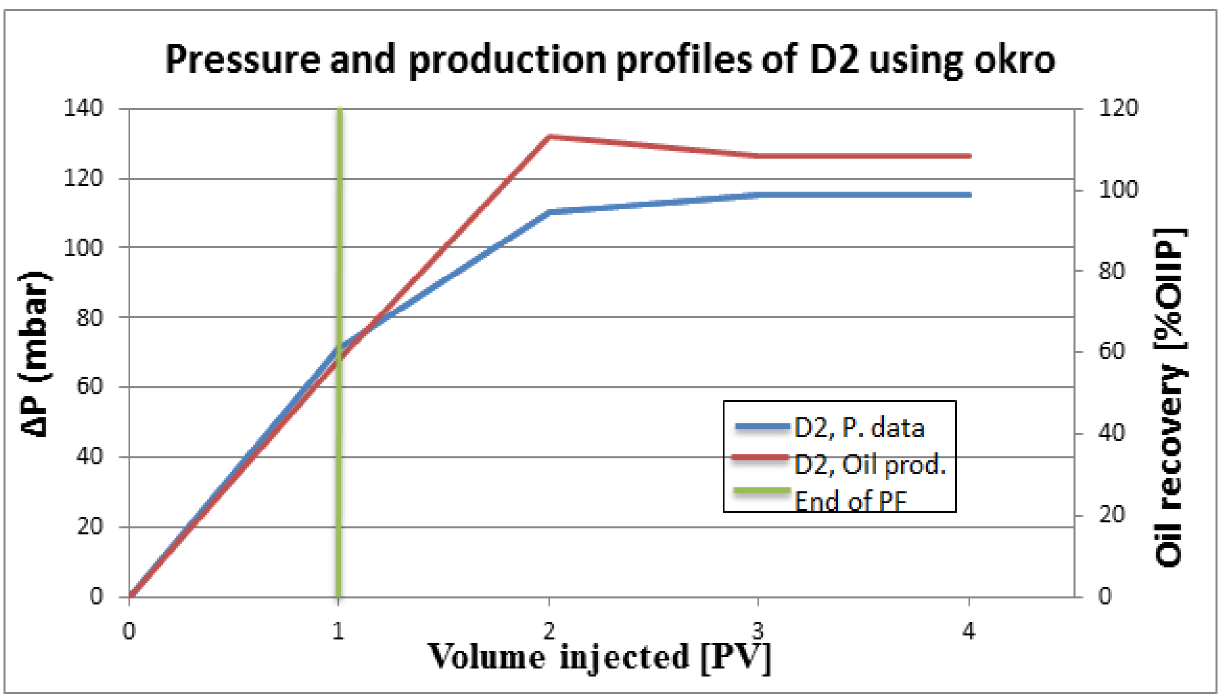

Fig. 13: Pressure and production profiles of LS-P flooding in core D2 using okro.

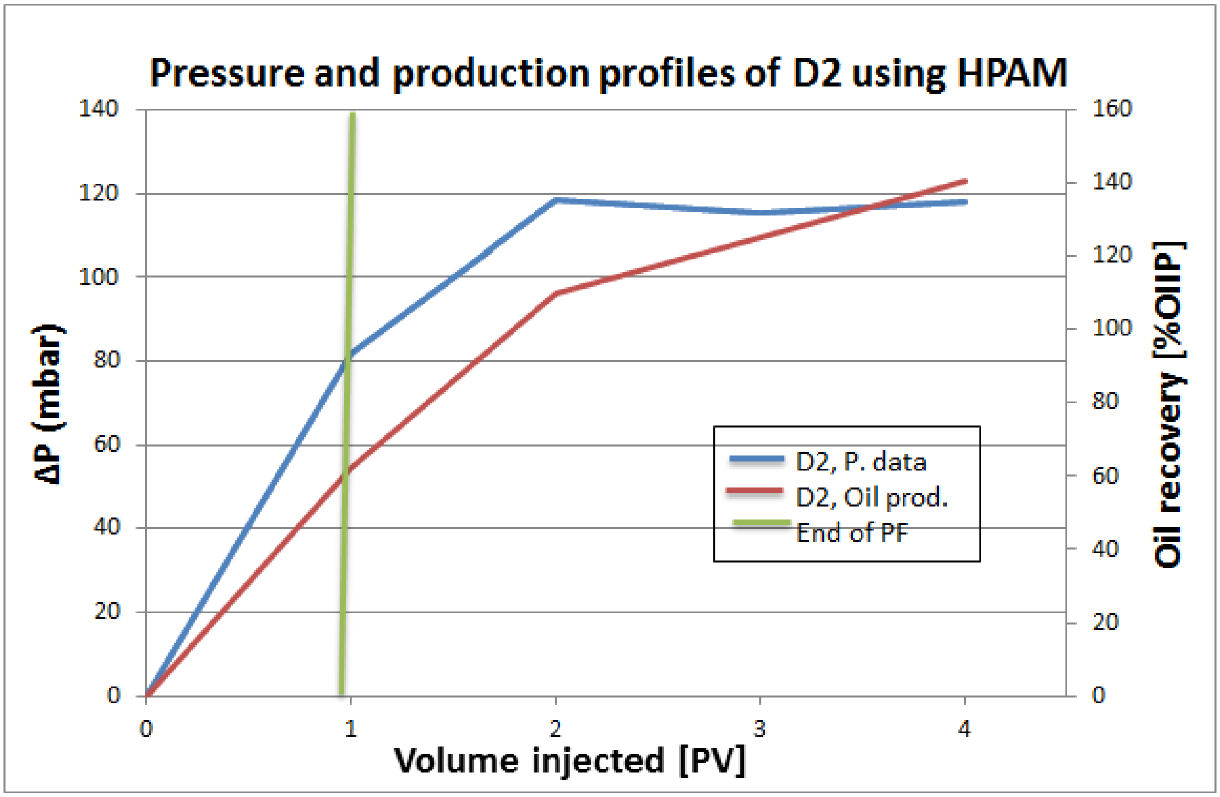

Fig. 14: Pressure and production profiles of LS-P flooding in core D2 using HPAM.

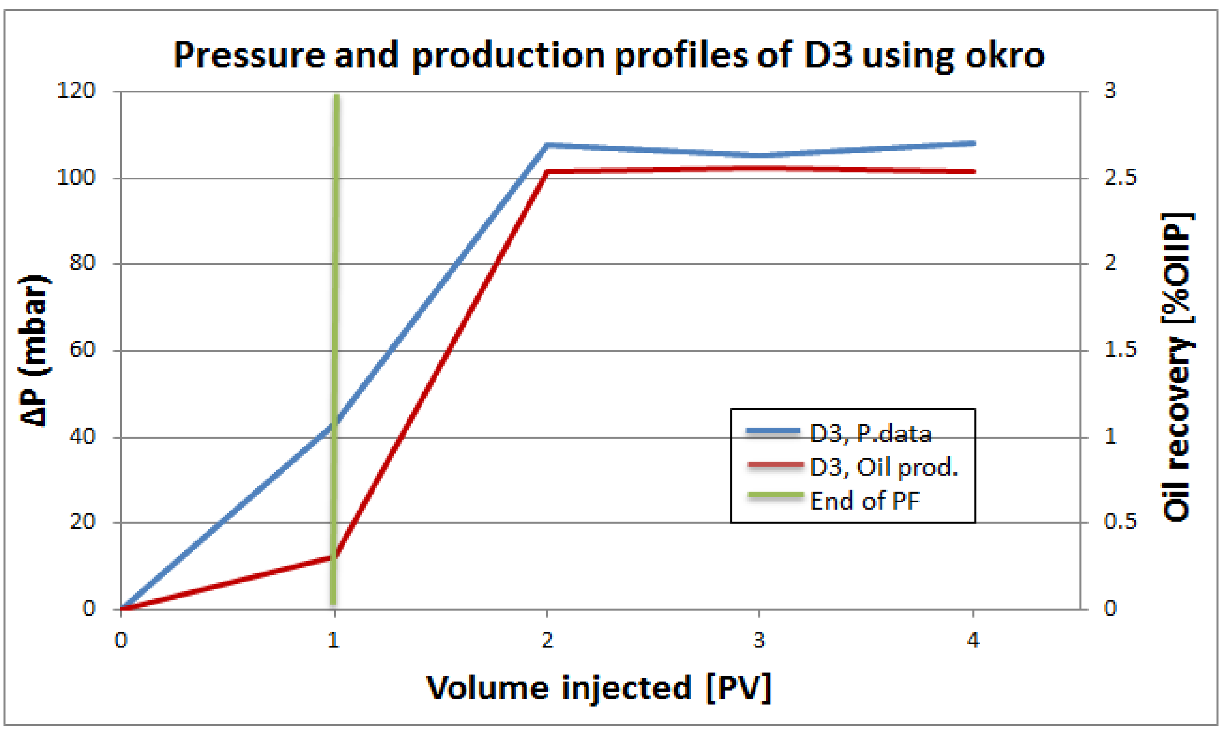

Fig. 15: Pressure and production profiles of LS-P flooding in core D3 using okro.

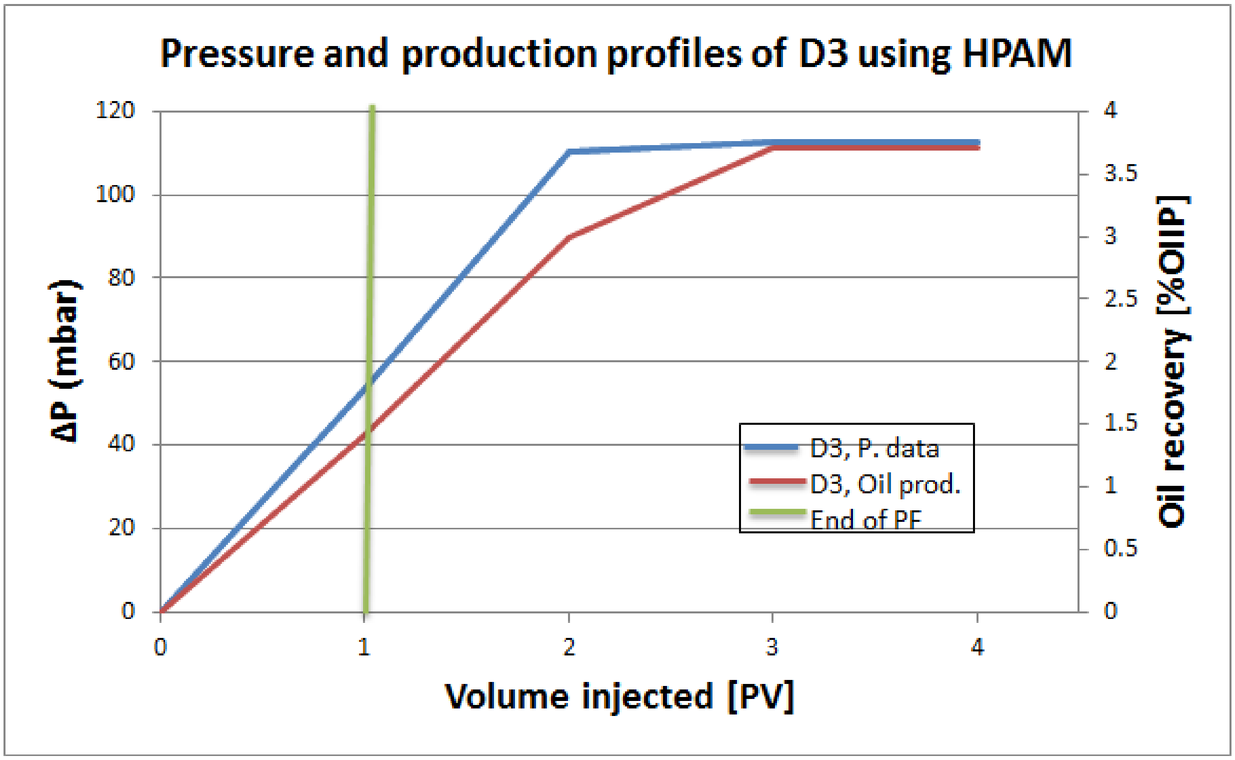

Fig. 16: Pressure and production profiles of LS-P flooding in core D3 using HPAM.

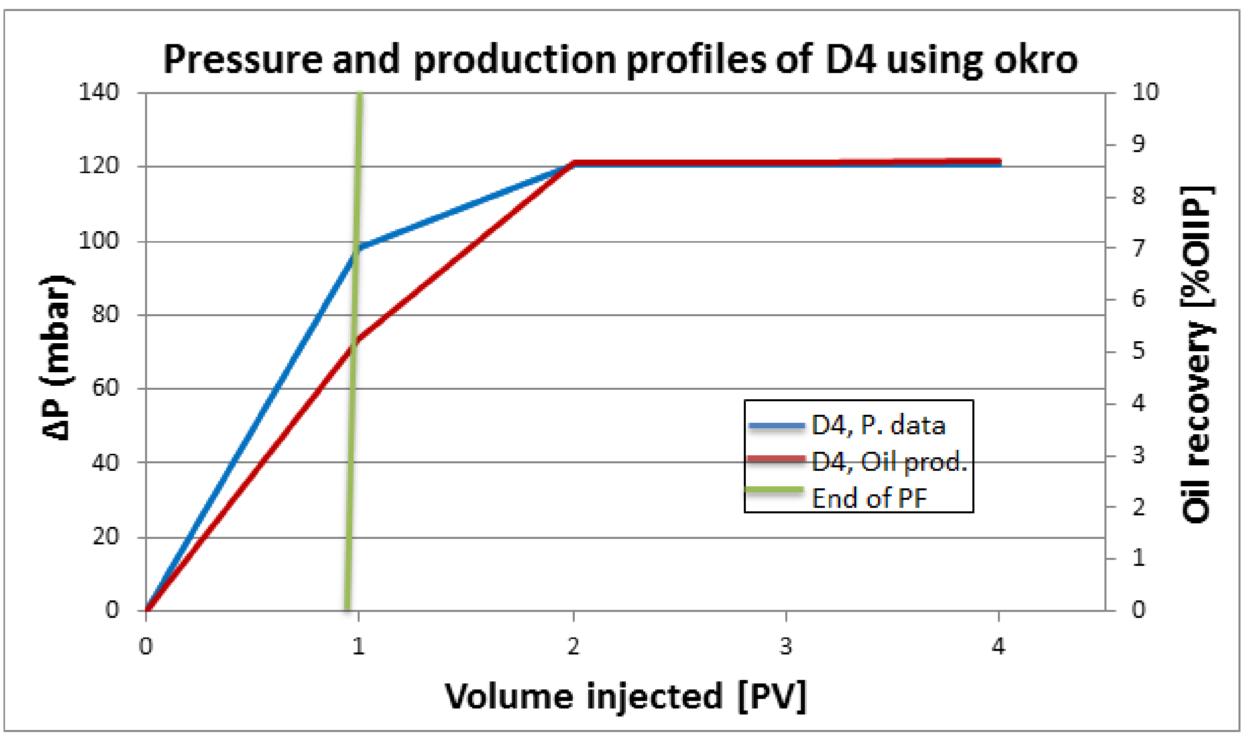

Fig. 17: Pressure and production profiles of LS-P flooding in core D4 using okro.

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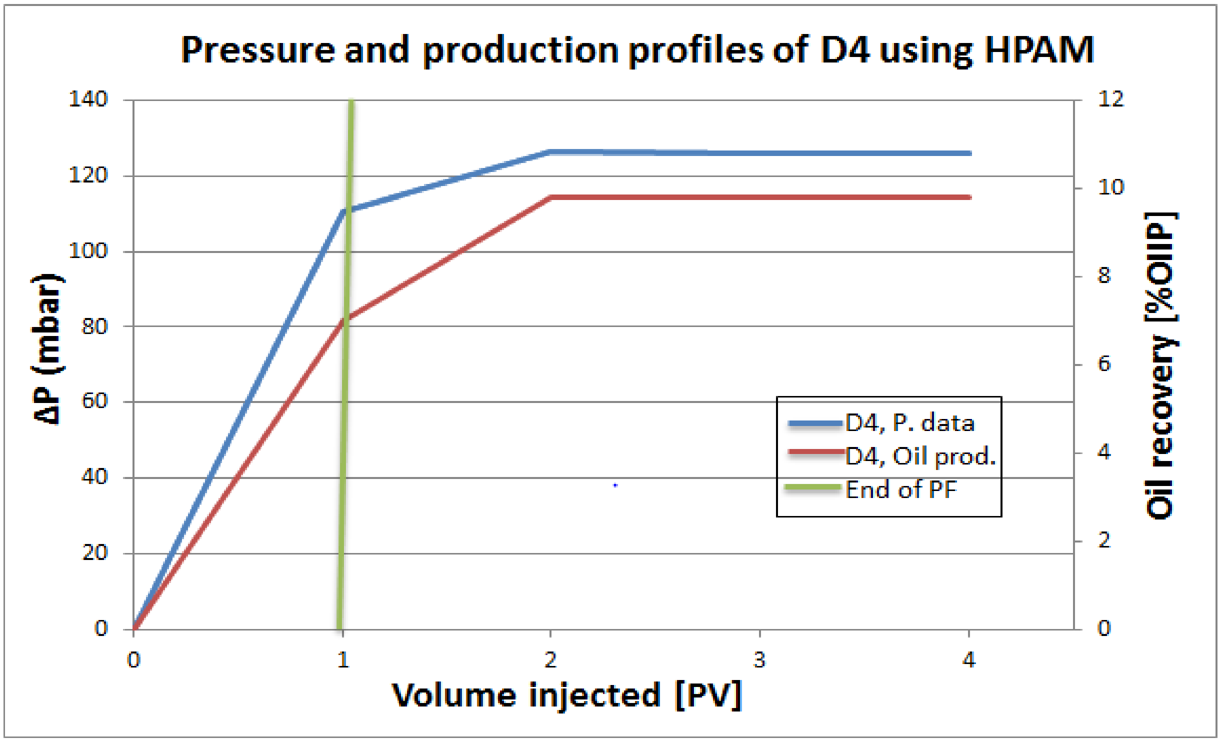

Fig. 18: Pressure and production profiles of LS-P flooding in core D4 using HPAM.

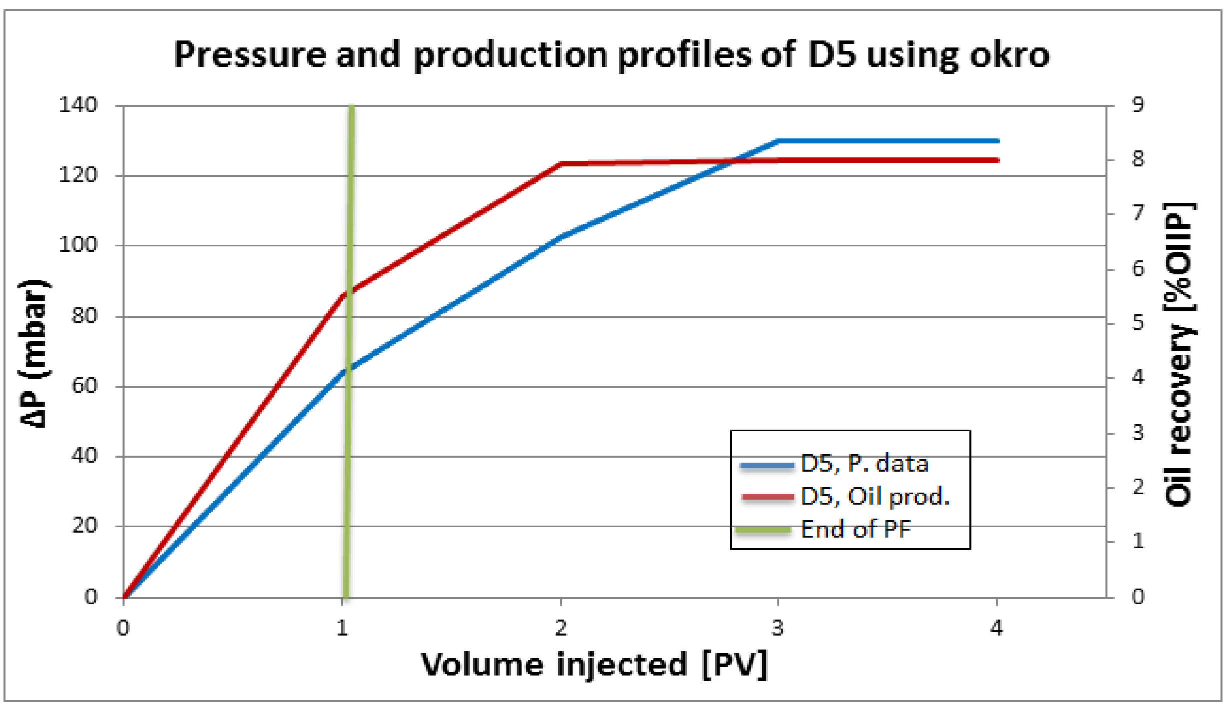

Fig. 19: Pressure and production profiles of LS-P flooding in core D5 using okro.

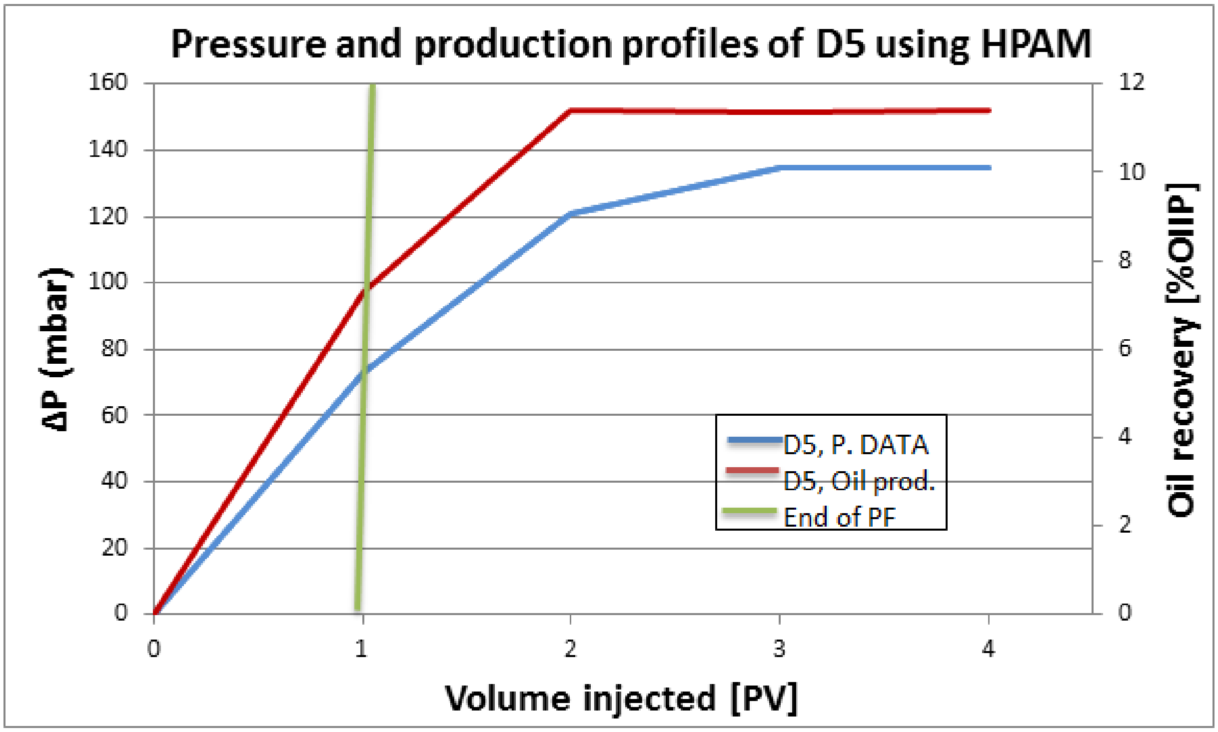

Fig. 20: Pressure and production profiles of LS-P flooding in core D5 using HPAM.

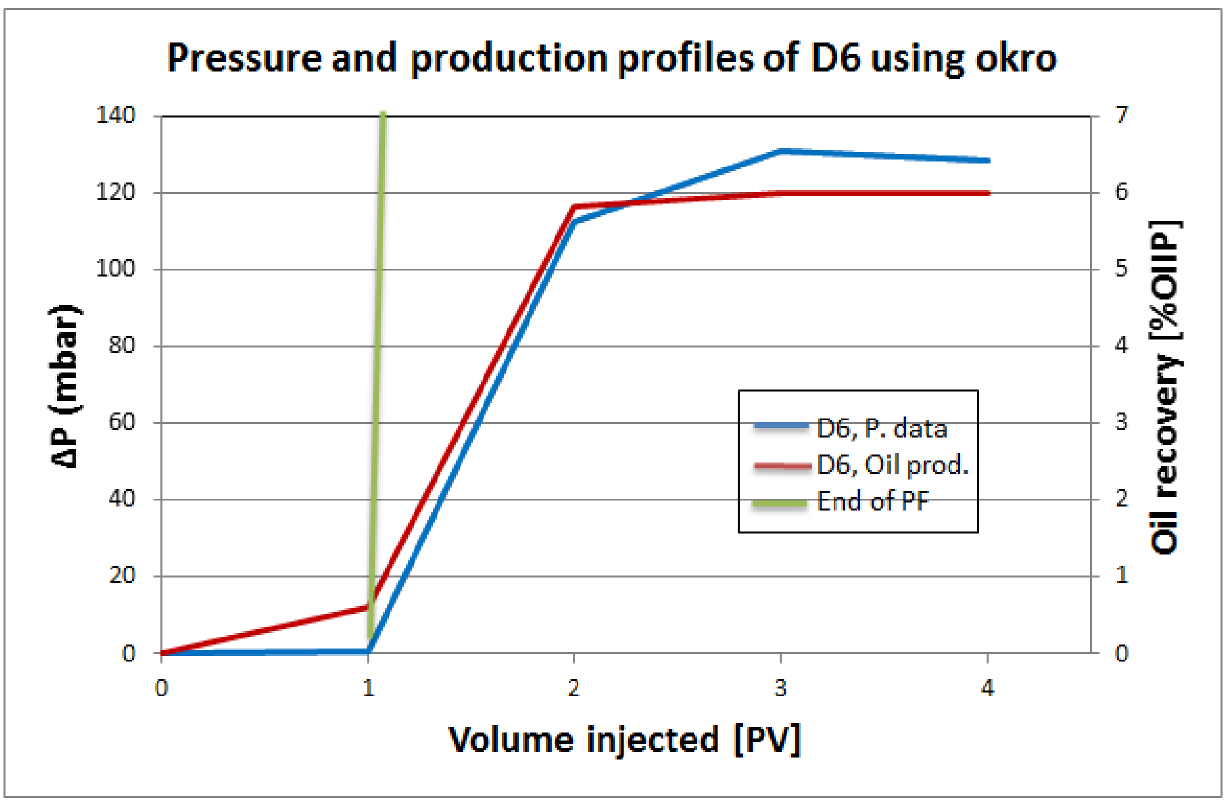

Fig. 21: Pressure and production profiles of LS-P flooding in core D6 using okro.

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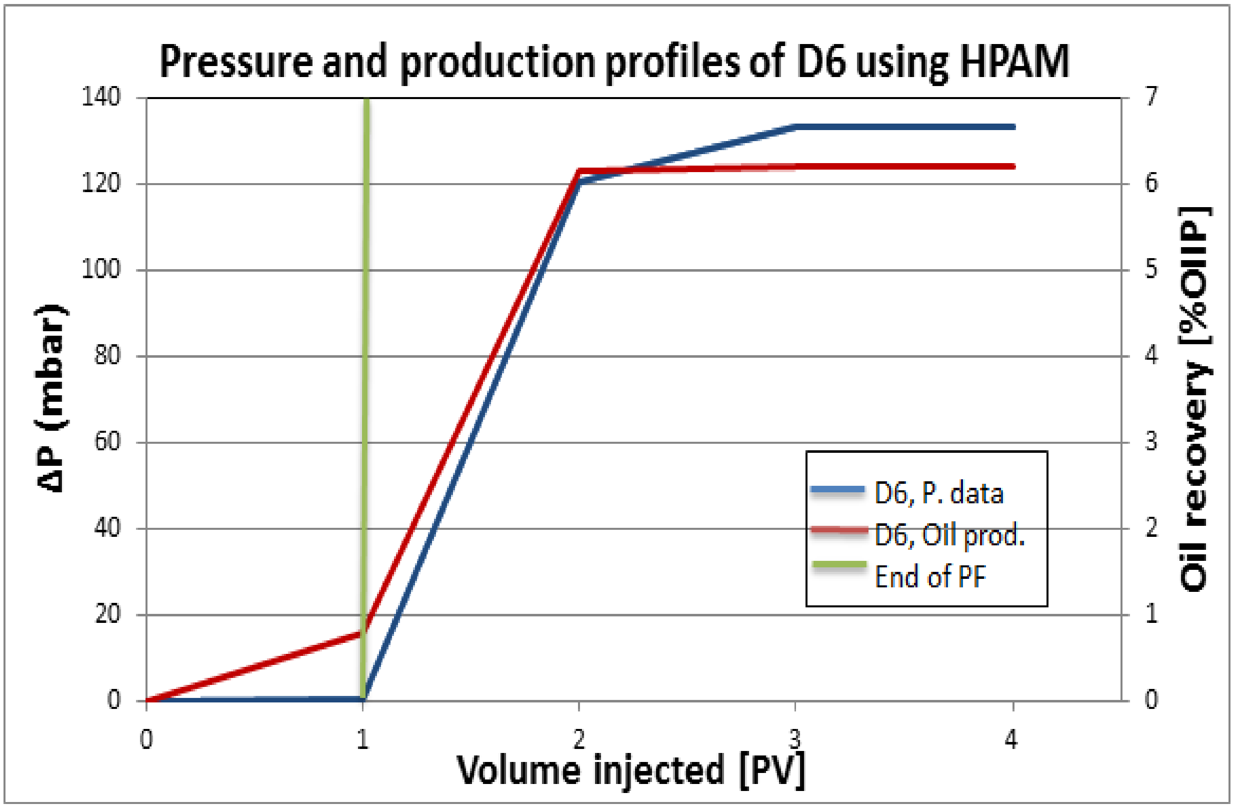

Fig. 22: Pressure and production profiles of LS-P flooding in core D6 using HPAM.

VI. SUMMARY AND DISCUSSION

It was anticipated in this investigation that lowering the salinity of the injected brine could conduce to increasing oil recovery from dolomite cores. Conditions necessary for improving oil recovery by low salinity waterflooding include significant clay fraction, initial formation water which contains divalent cations, crude oil which contains polar components, and exposure of the rock to crude oil to create mixed-wet conditions. The experiments carried out on the two unaged cores established lack of dependence of oil recovery on the salinity of the injected brine either in secondary or tertiary mode. The recovery factors of secondary synthetic sea water flooding and low salinity water-flooding were48.54% and 47.96 % respectively. There was not any increment in the oil recovery in the unaged cores during the tertiary low salinity waterflooding. Although the secondary low salinity waterflooding in the aged cores gave a recovery factor in the range of 55.70 – 61.21 ± 2 % which is higher than the unaged cores. This emphasizes the importance of initial wettability state of the core to observe the effect of low salinity waterflooding.

VII. CONCLUSIONS

An experimental investigation was performed to improve the oil recovery and extraction of residual oil from highly abundant oil-wet carbonate rocks. The synergy between polymer and low-salinity water has tremendous potential in maximizing oil reserves recovered, extend the life of fields, and increase the recovery factor.The experimental work was conducted on six Dolomite cores. Two out of the six cores were unaged and were tested for effect of reducing salinity of injected brine in both secondary and tertiary mode. The two cores did not demonstrate any increase in oil recovery by low salinity waterflooding compared to high salinity water in both secondary and tertiary mode. The unaged cores showed a strongly water-wet behavior. The other four cores were aged with crude oil and flooded by low salinity brine which is 3000 ppmNaCl brine as a secondary mode. The aging period altered wettability of the cores to less water-wet state which was confirmed by reduction in the oil permeability after aging.

Overall, the results of low salinity and polymer slugs injection in all six cores showed that the slug injection has mobilized and produced different amount of oil from the cores. The oil recovery for both okro and HPAM polymers from the aged cores was higher than that of the unaged cores which indicates the effect of initial wettability state on performance of low salinity waterflooding. This confirms that

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the rock should be exposed to crude oil to create mixed-wet conditions in order to observe an effect of low salinity waterflooding.

Fines particles were not been observed in the effluent during the corefiooding experiments and the pressure profiles were stable and increased only as a response of rising the flow rate.

In comparison, okro *(Abelmoschusesculentus)*gave the higher recovery of oil than the HPAM polymer. These results validate the use of okro polymer as an alternative to synthetic polymers under reservoir conditions for enhanced oil recovery (EOR) applications in the oil industry. Other merits for the use of Okro are its availability, cheap, biodegradable, does not cause any adverse effect to the reservoir and its fluids; and poses no environmental problem.

VIII. FURTHER WORK

Large Sor is normally recorded in water-wet reservoirs due to increased capillary entrapment of oil. By optimizing the ion composition, it may be possible to find a brine composition that modifies the reservoir wettability toward less water-wet conditions than what was obtainable in this investigation, thus effecting further Sor reduction.

The comprehension of aspects behind the effect of low salinity waterflooding in increasing the oil recovery demands extensive researches to ascertain the different variables that conduce to the performance of the process.

Quantitative methods such as USBM and Amott-Harvey should be employed in the determination of initial wettability state and the changes in the wettability of the cores during the low salinity water flooding, as this will assist in describing the improvements in the recovery.

The consequence of reducing salinity of the injected brine should be conducted in aged cores where the initial wettability of the cores reflects the reservoir wettability and the experiments should be performed in both secondary and tertiary mode.

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APPENDIX A

Table A1: Drainage Data Of Cores D1 And D2

Core ID	Volume of high viscous oil Injected X (PV)	Volume of produced water (ml)	Swi (%)	Soi (%)
D1	15.00	2.61	17.4	82.6
D2	18.00	3.44	19.1	80.9

Table A2: Drainage data of core D3

Rate (ml/min)	Volume of high viscous oil Injected X (PV)	Volume of produced water (ml)	Swi (%)	Soi (%)
0.1	2.0	0.41	20.70	79.30
0.5	2.0	0.44	22.13	77.87
1.0	4.0	1.38	34.58	65.42
1.5	3.0	0.93	31.00	69.00
2.0	3.5	0.96	27.53	72.47

Table A3: Drainage data of core D4

Rate (ml/min)	Volume of high viscous oil Injected X (PV)	Volume of produced water (ml)	Swi (%)	Soi (%)
0.1	2	0.44	21.96	78.04
0.5	1.5	0.38	25.62	74.38
1.0	4	1.33	33.17	66.83
1.5	3	0.90	30.00	70.00
2.0	4	1.13	28.32	71.68

Table A4: Drainage data of core D5

Rate (ml/min)	Volume of high viscous oil Injected X (PV)	Volume of produced water (ml)	Swi (%)	Soi (%)
0.1	2	0.38	19.01	80.99
0.5	2	0.38	18.73	81.27
1.0	2	0.38	19.16	80.84
1.5	4	0.99	24.75	78.25
2.0	3	0.86	28.50	71.50

Table A5: Drainage data of core D6

Rate (ml/min)	Volume of high viscous oil Injected X (PV)	Volume of produced water (ml)	Swi (%)	Soi (%)
0.1	2	0.40	20.00	80.00
0.5	2	0.39	19.70	80.30
1.0	3.5	0.82	23.28	76.72
1.5	2.5	0.47	18.94	81.06
2.0	5	1.55	31.00	69.00

APPENDIX B

Table B: Density Measurements of Fluids with Uncertainty Of +/- 0.0001

Density (g/cm^3)			
Temperature [^{O}C]	20 ^{O}C	23 ^{O}C	26 ^{O}C
Fluids			
Synthetic sea water	1.0472	1.0310	1.0192
Low salinity water	0.9987	0.9901	0.9835
High viscous Sample X crude oil	0.9418	0.9305	0.9226
Medium crude oil	0.9039	0.9008	0.8954
3000 ppm NaCl brine	1.003	0.8901	0.7950
C12TAB	0.9989	0.9921	0.9830

APPENDIX C

Table C1: Viscosity Measurements of Brines and Oils

Viscosity (cP)			
Temperature [^{O}C]	20 ^{O}C	23 ^{O}C	26 ^{O}C
Fluids			
Synthetic sea water	1.09	1.02	0.98
Low salinity water	1.02	0.93	0.87
High viscous Sample X crude oil	4.37	4.31	4.28
Medium crude oil	3.40	3.27	3.15
3000 ppm NaCl brine	0.96	0.84	0.79
C12TAB	1.02	0.86	0.81

Table C2: Concentration of OKRO polymer solutions: Viscosity measurements

Polymer solution	**Concentration mg/l (ppm)**	**Viscosity (cP)**		
		20 ^{O}C	**23 ^{O}C**	**26 ^{O}C**
Stock polymer solution	20.000	72.32	69.14	57.26
Diluted polymer solution	2200	64.63	60.21	50.98
Diluted polymer solution	2000	50.05	43.53	38.72
Diluted polymer solution	1600	42.97	40.22	31.54
Diluted polymer solution	1200	39.01	32.68	23.82
Diluted polymer solution	800	33.52	27.21	18.30
Diluted polymer solution	400	28.30	21.73	14.61

Table C3::Concentration of HPAM polymer solutions

Polymer solution	**Concentration (ppm)**	**Viscosity (cP)**		
		20 ^{O}C	23 ^{O}C	26 ^{O}C
Stock polymer solution	5000	40.00	37.08	30.75
Diluted polymer solution	1000	33.41	23.91	18.90
Diluted polymer solution	600	24.57	16.25	11.53
Diluted polymer solution	300	15.16	12.08	9.03
Diluted polymer solution	100	11.28	9.24	6.76

Table C4: Shear Rate of Polymer Solution for HPAM

Viscosity (mPa.s)	**Shear rate (1/S)**				
	100 ppm	**300 ppm**	**600 ppm**	**1000 ppm**	**5000 ppm**
0	23.09	159.56	618.98	1546.05	10482.69
10	17.32	116.42	459.49	1282.02	9620.67
20	15.39	104.78	306.32	964.01	7696.54
30	11.54	69.99	229.75	769.21	6413.78
40	7.70	52.50	183.80	641.01	5497.53
50	5.77	42.91	153.16	549.44	4810.34
60	4.62	34.93	131.28	480.76	4275.85

Table C5: SHEAR RATE OF POLYMER SOLUTION FOR OKRO

Viscosity (mPa.s)	**Shear rate (1/s)**				
	1200 ppm	**1600 ppm**	**2000 ppm**	**2200 ppm**	**20,000 ppm**
0	47.21	186.34	634.15	1210.62	11675.38
10	18.74	76.59	226.84	603.54	4891.79
20	10.80	37.27	105.69	201`.77	1459.42
30	9.44	31.06	90.59	151.33	11297.26
40	7.87	26.62	79.27	134.51	1167.54
50	6.74	23.29	70.41	121.06	1061.40
60	5.90	20.70	63.42	110.06	973.20

APPENDIX D

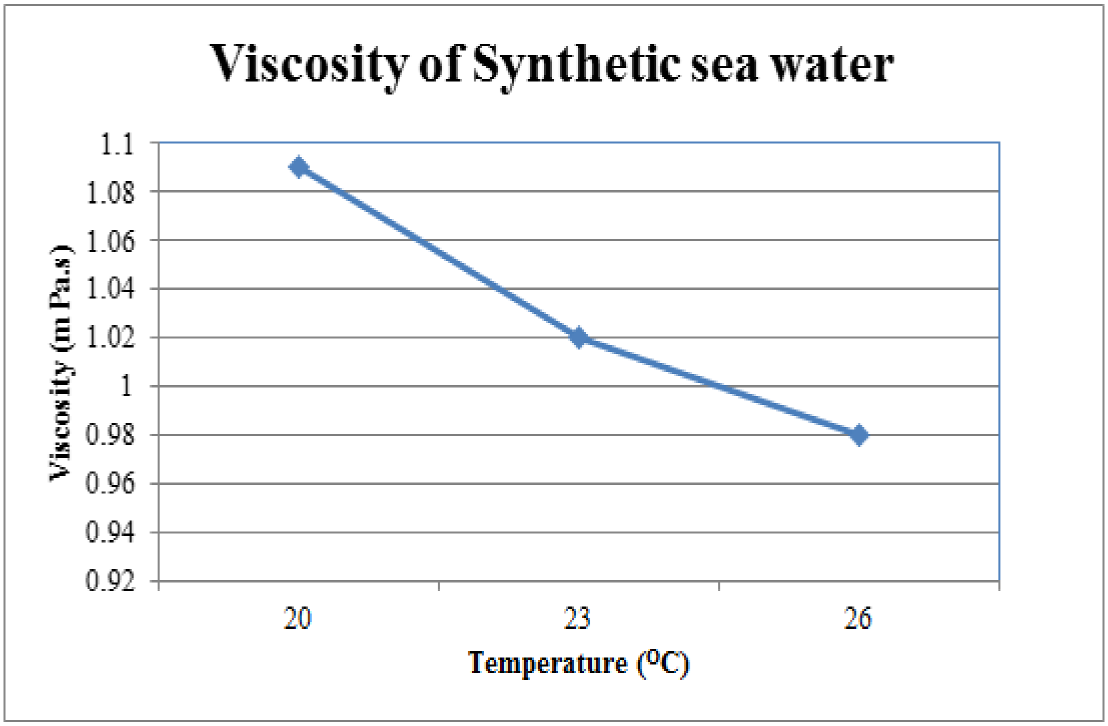

Fig. 23D1: Viscosity of Synthetic sea water measured at different temperature.

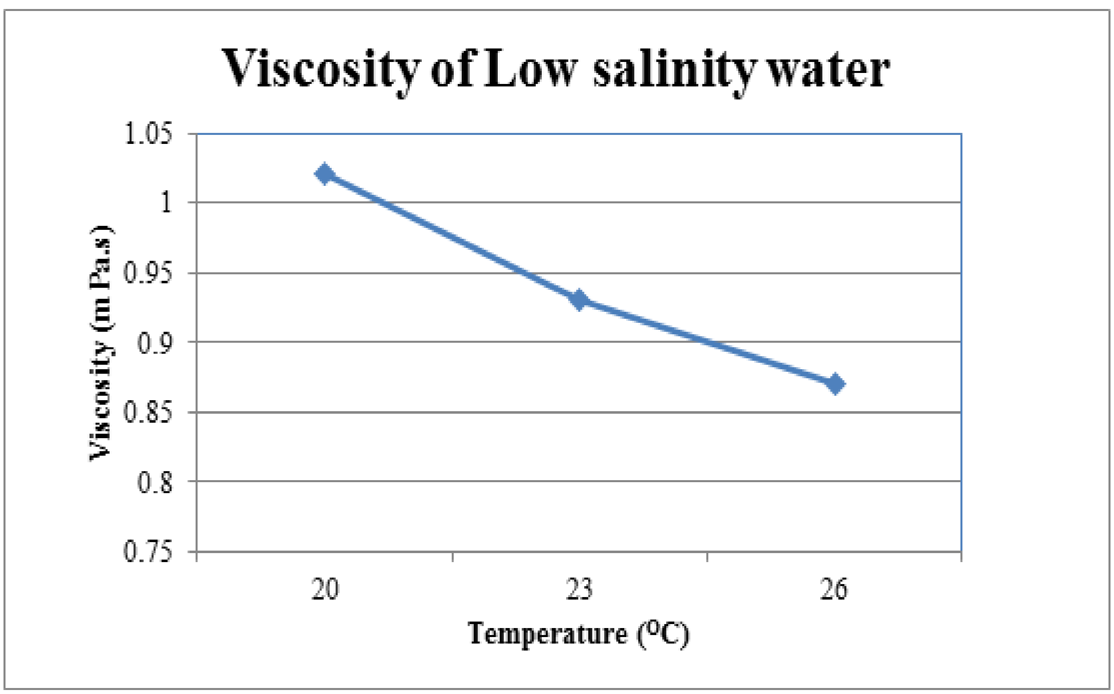

Fig. 24D2: Viscosity of Low salinity water measured at different

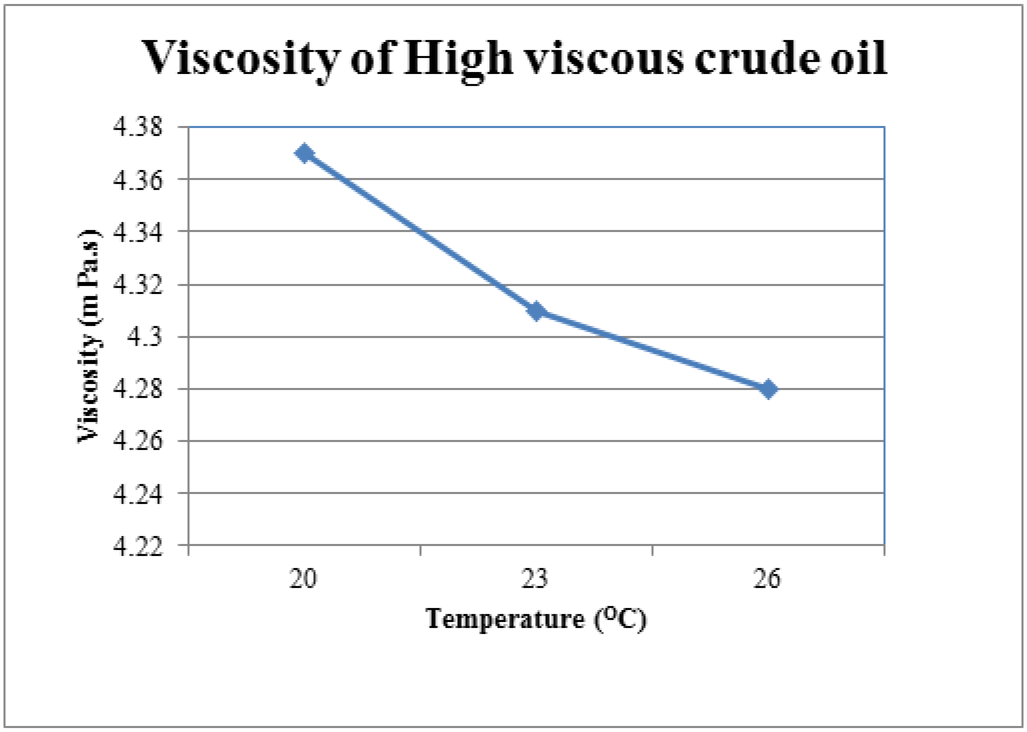

Fig. 25D3: Viscosity of High viscous crude oil Sample X measured at different temperature.

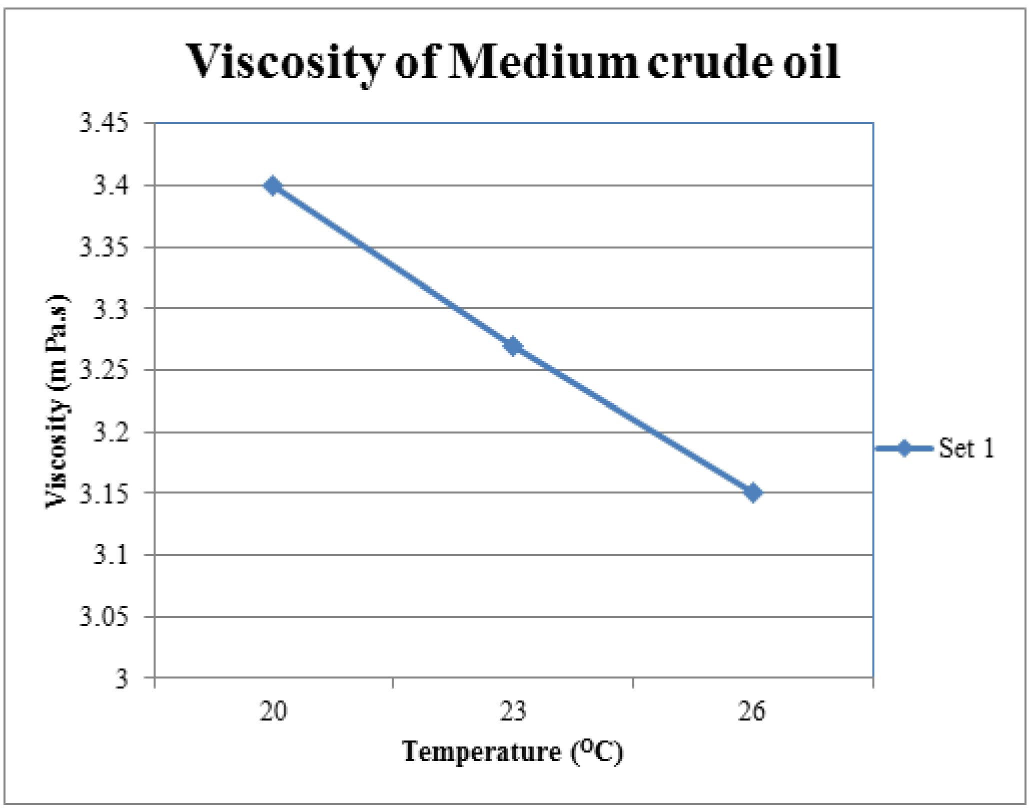

Fig. 26D4: Viscosity of Medium crude oil measured at different temperature.

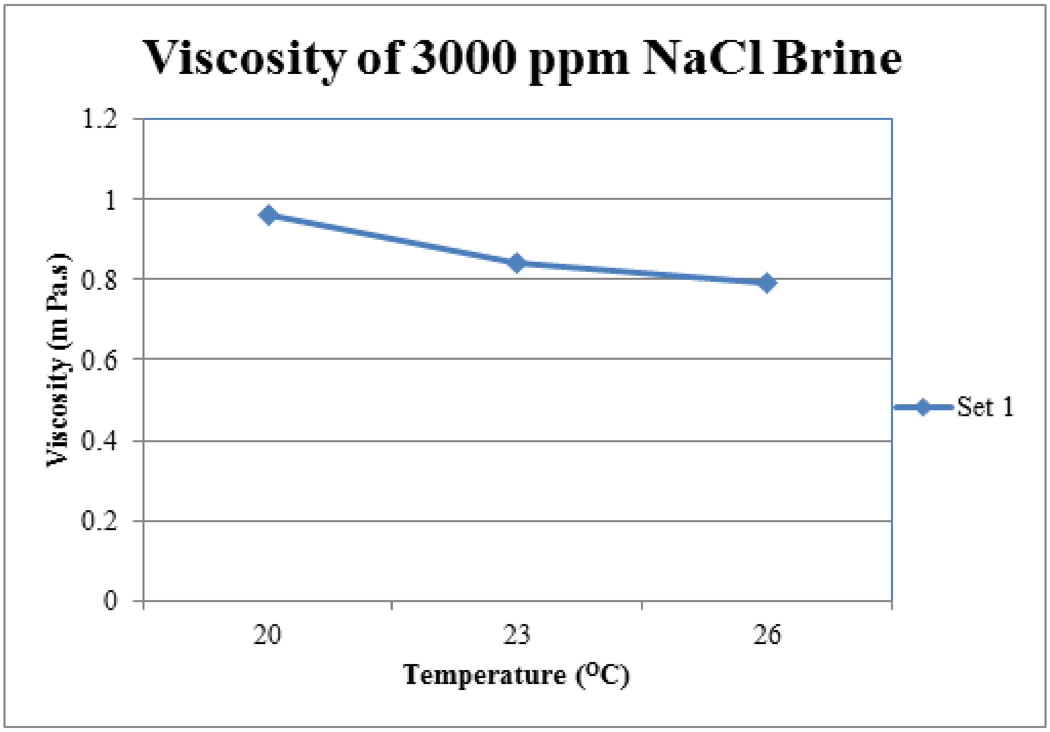

Fig. 27D5: Viscosity of 3000 ppm NaCl Brine measured at different temperature.

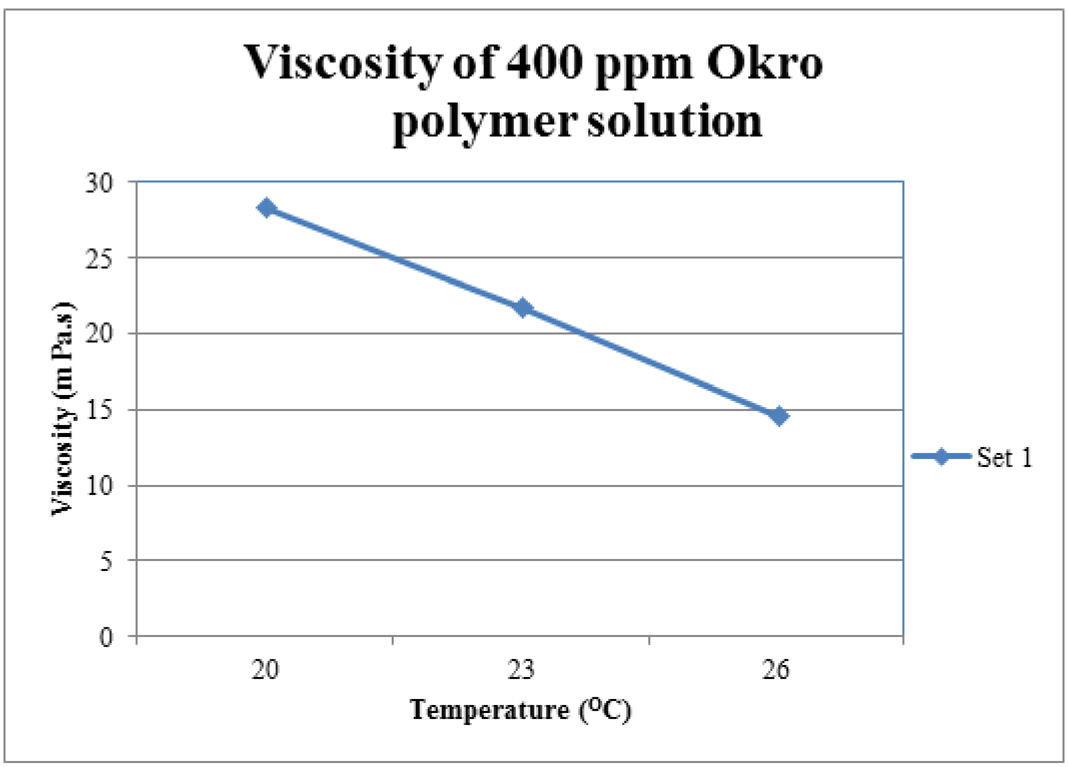

Fig. 28D6: Viscosity of 400 ppm Okro polymer solution measured at different temperature.

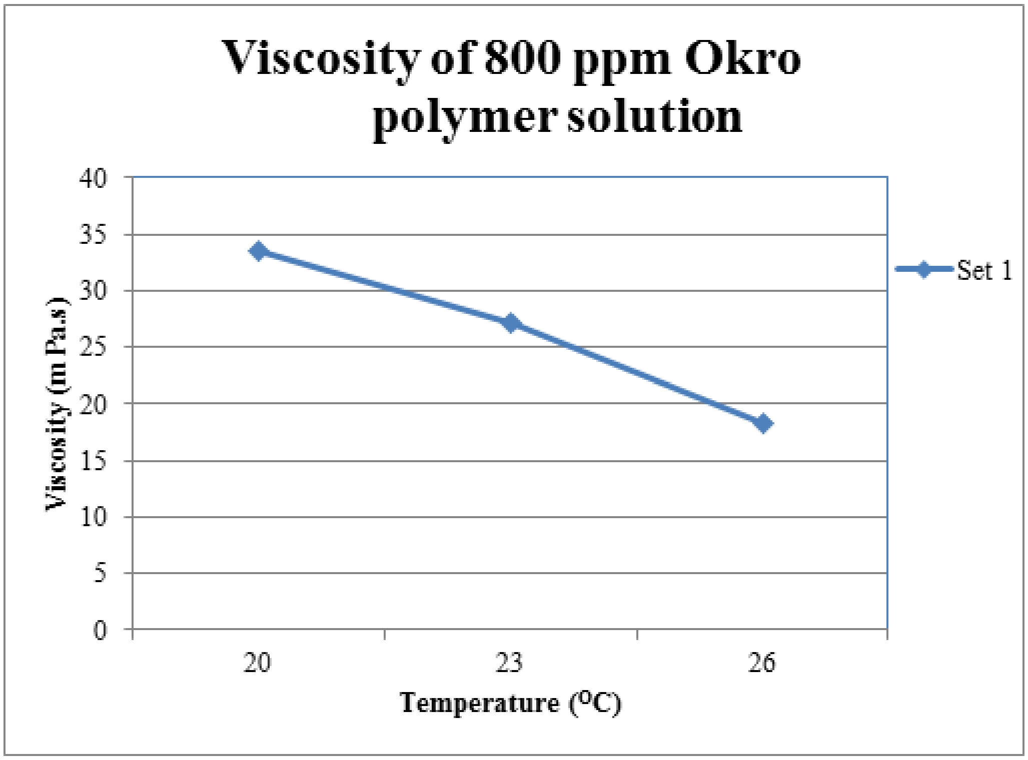

Fig. 29D7: Viscosity of 800 ppm Okro polymer solution measured at different temperature.

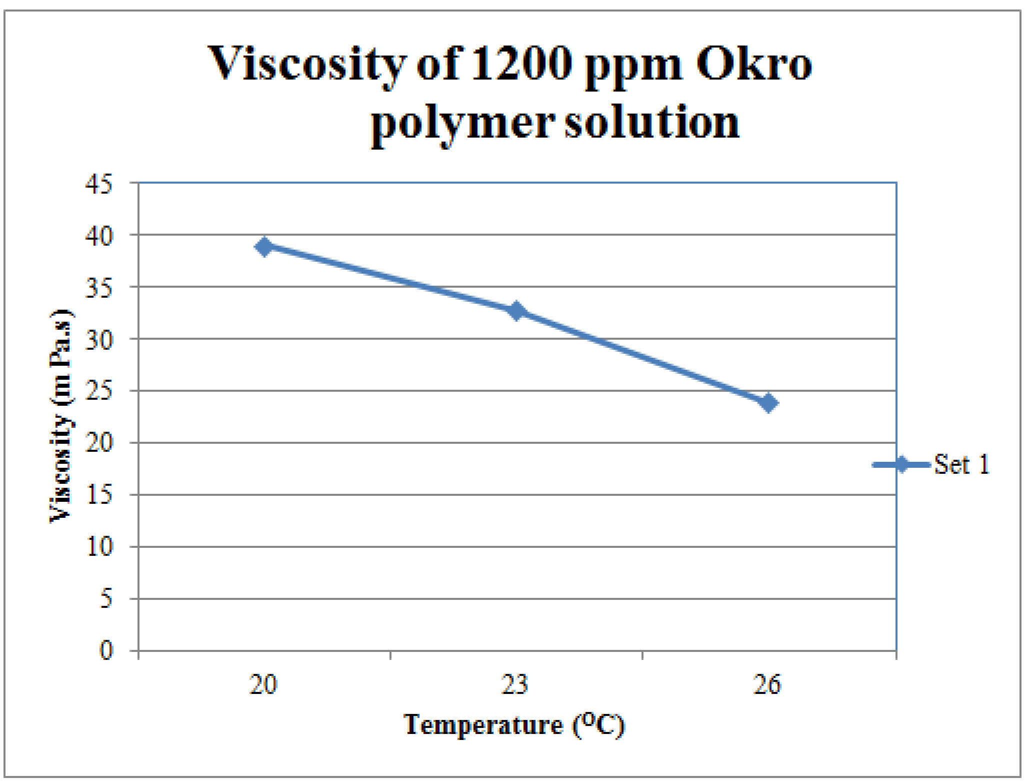

Fig. 30D8: Viscosity of 1200 ppm Okro polymer solution measured at different temperature.

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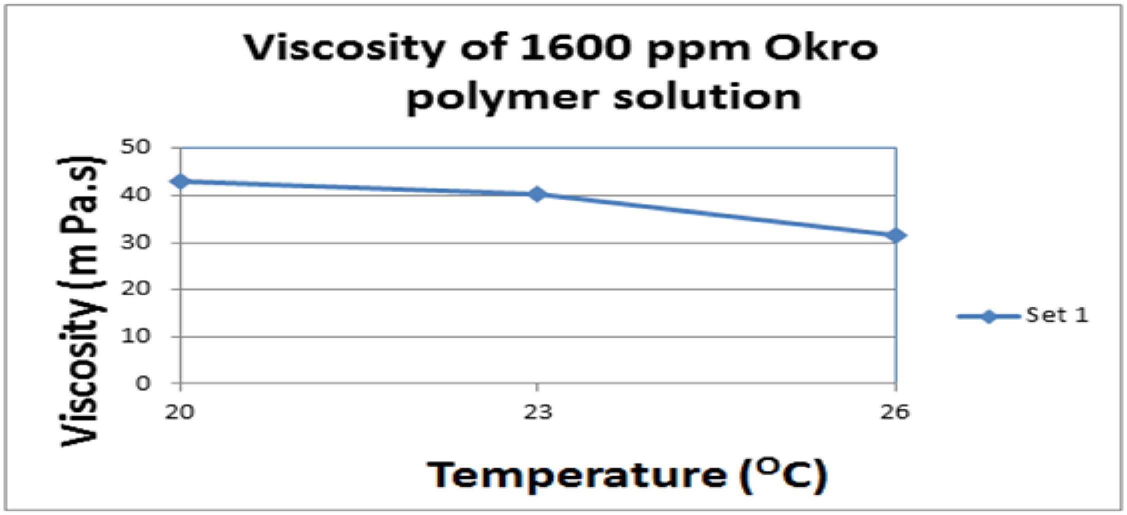

Fig. 31: D9: Viscosity of 1600 ppm Okro polymer solution measured at different temperature.

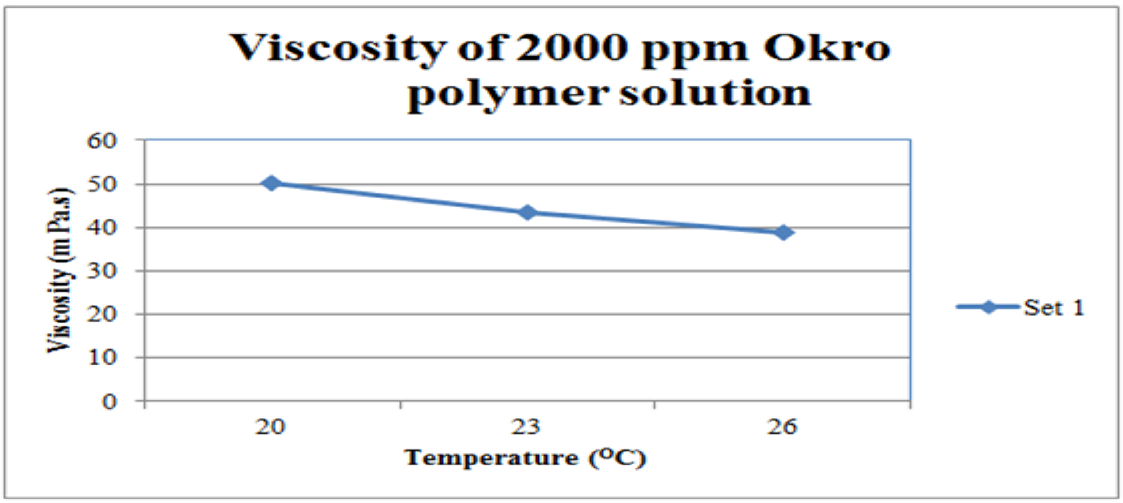

Fig. 32: D10: Viscosity of 2000 ppm Okro polymer solution measured at different temperature.

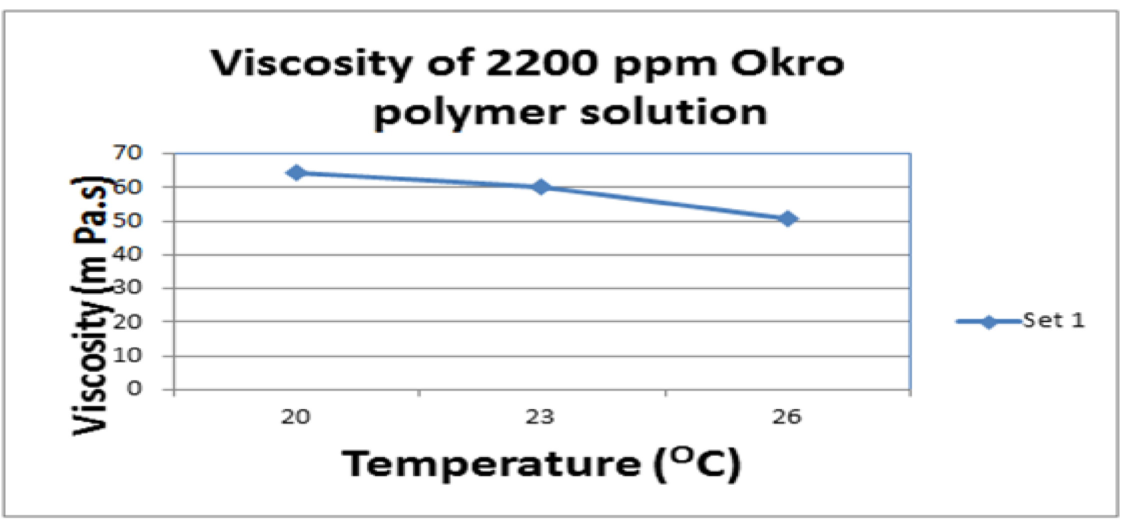

Fig. 33D11: Viscosity of 2200 ppm Okro polymer solution measured at different temperature.

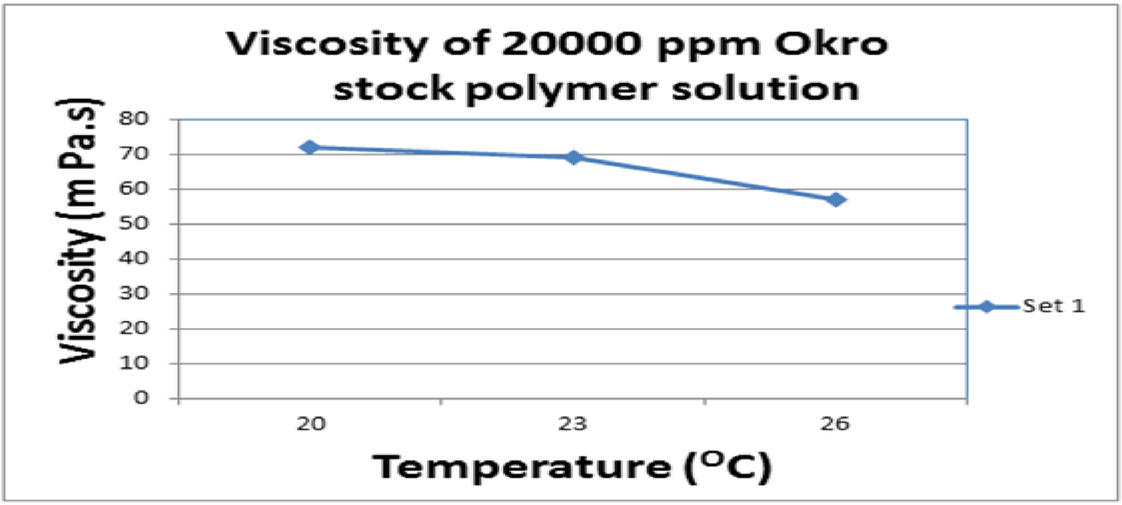

Fig. 34D12: Viscosity of 20000 ppm Okro polymer solution measured at different temperature.

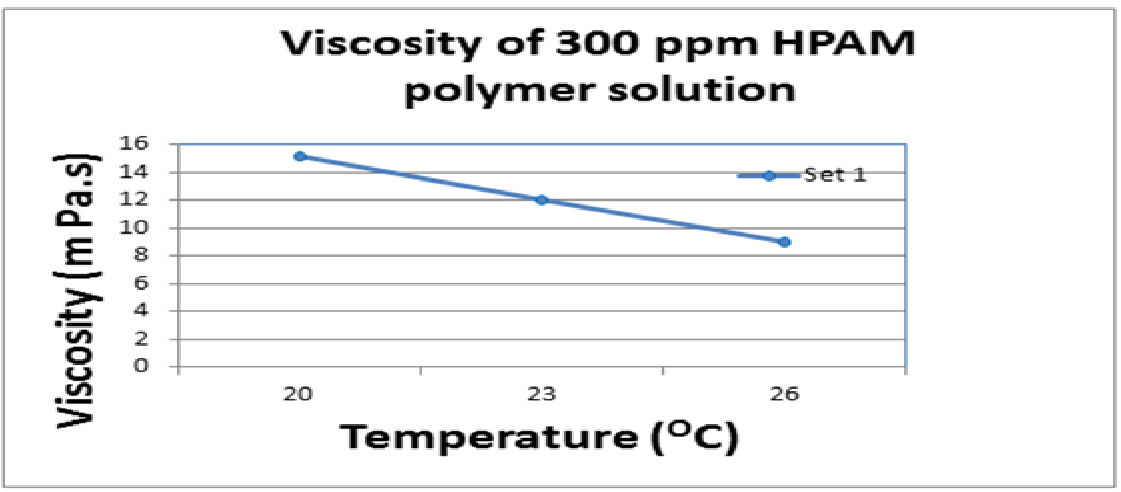

Fig. 35D13: Viscosity of 300 ppm HPAM polymer solution measured at different temperature.

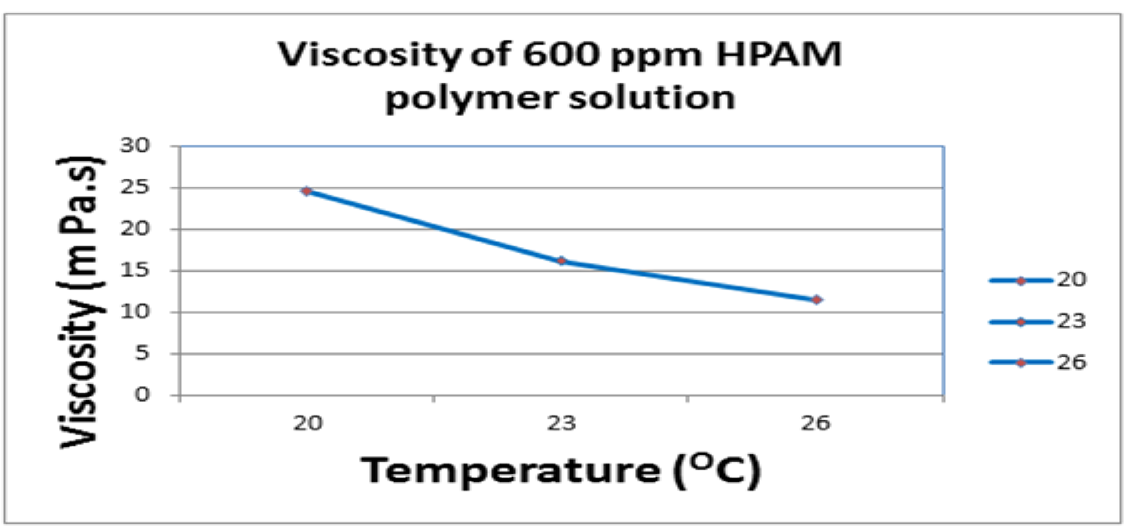

Fig. 36D14: Viscosity of 600 ppm HPAM polymer solution measured at different temperature.

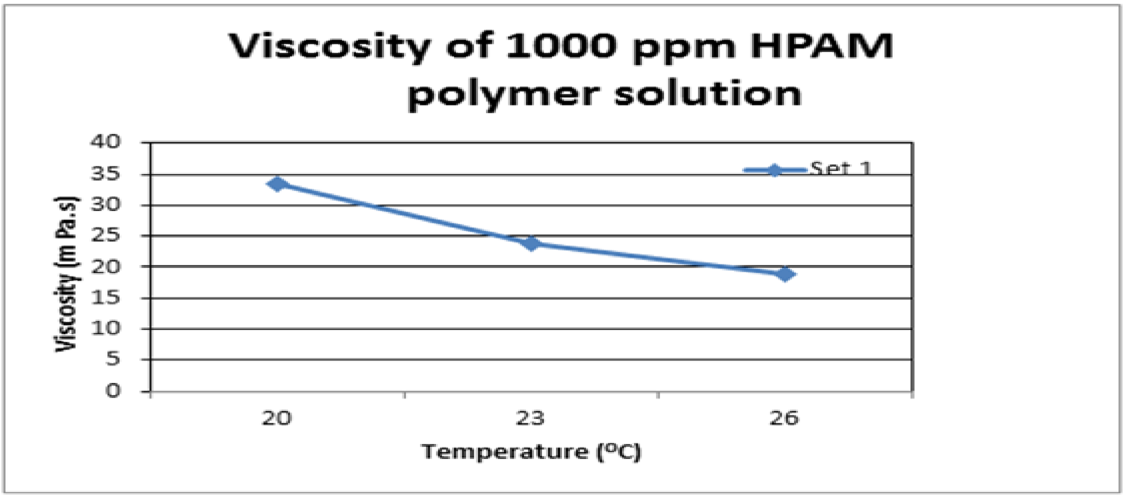

Fig. 37D15: Viscosity of 1000 ppm HPAM polymer solution measured at different temperature

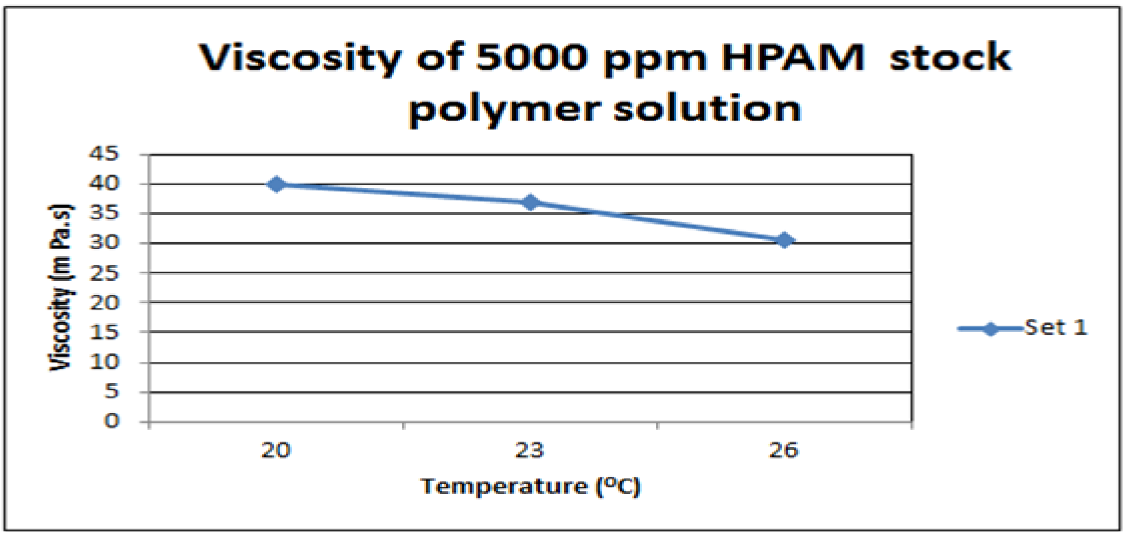

Fig. 38D16: Viscosity of 5000 ppm HPAM polymer solution measured at different temperature.

APPENDIX E

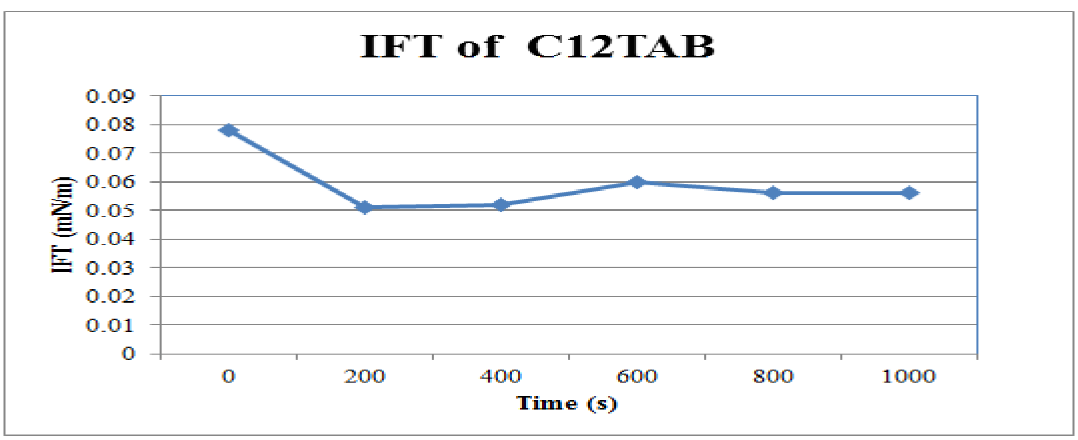

Fig. 39: IFT measurements of fresh sample of C12TAB surfactant with diluted crude oil.