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Combined Polymer-Surfactant Flooding and Low Salinity Water for Enhanced Oil Recovery in Dolomite Reservoirs using Local and Synthetic Polymers

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Abstract:-In last years, there has been a growing interest in the effect of reducing salinity of injected water in oil recovery. Numerous studies have demonstrated that low salinity water flooding is a promising method that can lead to a significant reduction in residual oil saturation compared to traditional water flooding. The mechanisms behind improved oil recovery by low salinity water flooding are not fully understood, but many researchers have claimed wettability alteration. Investigation has been carried out to characterize the polymers and surfactant solutions in terms of their ability to improve oil recovery in their aqueous solutions. A series of flooding experiments have been conducted to find the additional recovery using polymer and surfactant slugs. In this research, the effect of low salinity water flooding on improving oil recovery is investigated in six dolomite cores. In addition, a combined low salinity and polymer-surfactant slugs injection were conducted in tertiary mode to determine and optimize its effectiveness in increasing oil production. The tertiary low salinity surfactant-polymer slugs injection showed an increase in oil recovery with increasing size of surfactant slug injected at constant surfactant concentration. The wettability of the cores had impact on the efficiency of the slugs injected to improve oil recovery.

Keywords:- *(Polymer, surfactant, Natural polymer, water flooding Abelmoschusesculentus (Okro), HPAM, C12TAB).*

I. INTRODUCTION

A large amount of oil is still trapped in reservoirs after the traditional primary and secondary oil recovery processes. To recover these huge amounts of residual oil, the true understanding of subsurface characteristics especially the interfacial interactions between crude oil, brine and rock is essential. The surface chemistry involved in the equilibrium of capillary, viscous and gravitational forces is very important in oil recovery enhancement.

Water-flooding is the commonly used method among fluid injection procedures to improve recovery from oil reservoir. The purpose of waterflooding is to maintain the reservoir pressure and sweep the mobilized oil toward the producing wells. The residual oil trapped in the reservoir after waterflooding can be mobilized by using enhanced oil recovery (EOR) techniques. The EOR is defined as oil recovery by injection of materials that are not normally present in the reservoir such as surfactants and polymers (Skarestad and Skauge, 2007). Some of the goals of the EOR (Enhanced Oil Recovery) methods are to increase the volumetric displacement efficiency and/or to remobilize oil that is capillary trapped in the water flooded zones therefore reducing the residual oil saturation. This recovery method is possible due to certain displacement mechanism like reduction in interfacial tension between oil and formation water, reduction in capillary pressure, emulsification of oil, wettability alteration of rock surface and mobility control (Laura, 2011).

Low salinity waterflooding has received increasing attention. However, the increased oil recovery by low salinity is in most cases very limited. Combining low salinity with other EOR methods has been the focus in recent years. Many papers have been presented in the literature dealing with and discussing the mechanism of possible enhanced oil recovery by low salinity injection. The low salinity effect LSE (Low Salinity Effect) seems to be consistent better when LS (Low Salinity) is injected in a secondary mode compared to tertiary injection (Morrow and Buckley, 2011). Also combination of LS with surfactant or polymer shows increased recovery in secondary mode (Alagic and Skauge, 2010; Shaker and Skauge, 2013).

Chemical flooding methods are classified into a special branch of EOR processes to produce residual oil after water flooding. These methods are utilized in order to reduce the interfacial tension, to increase brine viscosity for mobility control and to increase sweep efficiency in tertiary recovery. Surfactants are deemed good EOR agents since 1970s (Samanta*et al*., 2012), as they can remarkably reduce the interfacial tensions and alter wetting properties.

Displacement by surfactant solutions is one of the important tertiary recovery processes by chemical solutions. The addition of surfactant decreases the interfacial tension between crude oil and formation water, lowers the capillary forces, facilitates oil mobilization and enhances oil recovery. The surfactant is dissolved in either water or oil to form micro-emulsion which in turn forms an oil bank (Bera*et al.*, 2011). The formation of oil bank and subsequent maintenance of sweep efficiency and pressure gradient by injection of polymer and chase water increase the oil recovery.

A surfactant molecule is amphiphilic, that has a polar water-soluble portion, or moiety (hydrophilic component) attached to a non-polar insoluble hydrocarbon chain (lipophilic component). This double nature of the surfactant makes it reside at the interface between aqueous and organic phases thereby lowering the interfacial tension.

When an aqueous phase with the dissolved surfactant contacts an oleic phase the surfactant, due to its dual nature tends to align at the interface so that the hydrophilic parts (heads) are in the water phase and lipophilic parts (tails) are in the oleic phase. As the concentration of the surfactant increases at the interfaces, the IFT (Interfacial Tension) between the two phases reduces impressively. However, this process leads to the alteration of the solubility of the surfactant in the bulk oleic and aqueous phases which, in turn, might affect the interfacial tension. Thus, exploring the properties of surfactant – oil – brine behavior enables us to predict and to optimize the flood process.

In this research, an experimental investigation has been carried out to study the effect of reducing salinity of the injected water and to determine and optimize the effectiveness of a combined process of low salinity surfactant and polymer slugs injection as tertiary mode.

II. SIGNIFICANCE OF THE RESEARCH

When a reservoir is flooded with polymer, the mobility ratio between the displaced fluid and the displacing fluid become favorable compared to the conventional water flooding. In the oil and gas industry, the synthetic polymer polyacrylamide in hydrolyzed form and the biopolymer xanthan are being used for this purpose. However, the polyacrylamide is susceptible 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 and 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 combat these problems. Natural polymers from agricultural and forest produce are abundant 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 harsh reservoir conditions (Agi*et al.*, 2018).

With the application of EOR (Enhanced Oil Recovery) using Okro (*Abelmoschusesculentus*) as natural polymer, additional oil will be recovered from the oil fields. Also this research work will result in economic boom to the oil and gas industries, job creation, and increase in the nation's GDP (Gross Domestic Product).

III. LITERATURE REVIEW

Water flooding has for a long time been employed to improve oil recovery in many oil fields. Formation damage due to water injection was the main issue of water flooding design process for many years and oil companies conducted different compatibility tests between injection water and formation water to eliminate any possibility of formation damage (Abdulrazagy and Zaid, 2015). In recent years, the results of extensive research work demonstrated that alteration of water salinity concentration and composition improves significantly the ultimate oil recovery of water flooding. Up to date there is no universal agreement among the researchers on the mechanism of low salinity flooding. Different mechanisms are proposed in the literature such as wettability modification, fine migration, interfacial reduction, emulsion, and ionic exchange.

In most of the oil reservoirs, the sources used for water-flooding were mainly aquifer water and seawater which are high salinity water. In the last decade, a consideration has been given to the effect of water chemistry; the amount and composition of salt in the water used for flooding in the oil recovery. Several studies were considered to investigate the effect of decreasing the salinity of the injected brine in improving the performance of waterflooding.

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.

A number of research work has been published that indicated that calcium ion (Ca^{2+}), magnesium ion (Mg^{2+}) and sulfate ion (SO_4^{2-}) are the responsible ions for the alteration of wettability in brine injection process (RezaeiDoust*et al.*, 2009). The alteration activity of these ions increases with increasing the temperature above 100 ^{O}C. Zhang et al., (2007) have studied the impact of Ca^{2+}, Mg^{2+} and SO_4^{2-} on the oil recovery from chalky limestone of low water wetness in a spontaneous imbibition process. The results clearly demonstrated that increasing SO_4^{2-} in the presence of Mg^{2+} at higher temperatures improves the oil recovery significantly. No significant improvement in oil recovery was observed at both 70 and 100 ^{O}C in the presence of NaCl, therefore they concluded that sulfate could not change the wettability to improve the spontaneous imbibition at low temperature (Zhang *et al.*, 2007). On the other hand in the presence of Ca^{2+} and/or Mg^{2+} with sulfate significant improvement in the imbibition of water was observed and this was attributed to the change of wettability of the system to more water wet. Zhang *et al.*, (2007) proposed a chemical mechanism for alteration of wettability. They suggest that if injected water contains Ca^{2+} and SO_4^{2-}, sulfate ions will adsorb onto the positively charged chalk surface, and a reduction of the positive surface charge will prevail. The electrostatic repulsion will decrease in this case and more of Ca^{2+} can be attracted to the surface (RezaeiDoust*et al.*, 2009). RezaeiDoust*et al*.,(2009) suggested that Mg^{2+} is able to displace the Ca^{2+} which is connected to the carboxylic group, in the same way as Mg^{2+} is able to displace other Ca^{2+} ions from the surface lattice of the chalk. Frontiers BP (2009), presented a hypothesis for low salinity effect in the presence of clay. They suggested that the negatively charged clay particles produce a diffuse double layer; whereas in the aqueous phase in the vicinity of clay is positively charged. The thickness of the double layer increases with decreasing salinity. Water molecules within the double layer are rigid or "quasi-crystalline" and that will result in an increase of oil phase relative permeability as medium becomes more water wet. On the other hand if hardness (Ca^{2+} and/or Mg^{2+}) is present in the system, negatively charged oil surface can bind with the clays through an intermediate, such as divalent calcium ion. Berg *et al.*, (2009) provided direct experimental evidence, and indicated that wettability modification of clay surfaces was a microscopic mechanism for low salinity flooding. They ruled out emulsification, interfacial tension reduction, fines migration and selective plugging of water-bearing pores through clay swelling as most relevant mechanisms. They have confirmed wettability modification as the relevant mechanism, and they have indicated that they are trying to distinguish between double layer expansion and cation exchange or if a layer of clay detaches together with each oil droplet. They stated that oil has been released in low salinity system where also clay de-flocculation and formation damage has taken place, and at least for Montmorillonite clays there was a range of salinity where oil can be removed with no damage.

IV. 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 investigation, 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 (*VP*), of the core used. The bulk volume (*Vb*) 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.

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

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

V. EXPERIMENTAL SETUP

The experimental setup for the displacement experiments in this research is shown in figure **1** below.

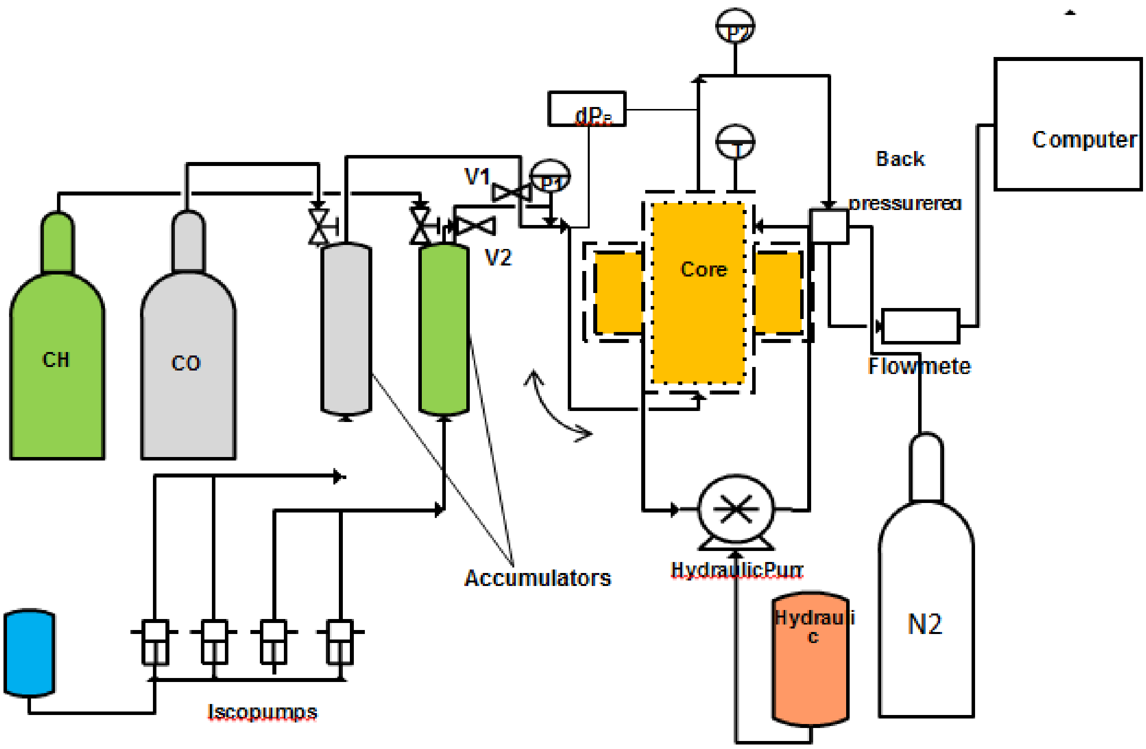

Fig. 1: Core flooding Experimental set-up.

VI. EXPERIMENTAL DESCRIPTION

A. Permeability Measurements:

The permeability measurements were carried out using the Darcy's law equation. For the absolute permeability, the core was first flushed with 2 PV of synthetic sea water before conducting the permeability measurements. After that the differential pressure across the core was recorded for five different flow rates applied for injection. The permeability is calculated by finding the slope of the relationship of the flow rate versus the differential pressure and by knowing the viscosity of the injected brine and the sizes of the core. The effective and relative permeabilities were measured in this study using the same procedure and the measurements were conducted before aging, after aging, after low salinity flooding, and after the surfactant and polymer flooding.

B. Drainage

The primary drainage process for the cores was established by using high viscous crude 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 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.

After aging, 3 PV of the diluted medium crude oil was used to flush the cores and displace the high viscous crude oil sample X. The diluted medium crude oil was used in order to have a better mobility ratio since its viscosity would have been reduced. The effective permeability measurements of the cores after flushing with diluted crude oil was conducted and compared with the measurements before aging to study the wettability alteration.

D. Low Salinity Surfactant and Polymer Slugs Injection:

The tertiary low salinity surfactant and polymer slugs injection was performed in all six cores used in this investigation. The six cores were flooded by 3000 ppm NaCl brine (low salinity brine). This was done so as to use the unaged cores for low salinity surfactant and polymer slugs injection and compare their recoveries with the aged cores. The size of the slugs injected was nevertheless varied. In the aged cores the different size of surfactant slug injected was in order to determine the optimum slug size that gives high oil recovery. The unaged cores were flooded with same surfactant slug size and compared with the aged core to ascertain the effect of wettability. The polymer slug was injected directly after the surfactant slug in order to maintain a stable displacement behind the surfactant. The slug size injected in each core is presented in table **1**. The surfactant solution used was made of 1 wt % of active surfactant mixed with low salinity brine (i.e 3000 ppm NaClbrine). The type of polymer used was partially hydrolyzed polyacrylamide (HPAM) with concentration of 300 ppm.

Table 1: The sizes of the surfactant and polymer slugs injected in each core

Core ID	Surfactant slug size [PV]	Polymer slug size [PV]
D1*	1	1
D2*	1	1
D3	0.3	0.5
D4	0.5	1
D5	1	1
D6	2	1

* unaged cores

The cores were flooded with continuous low salinity brine after the injection of the slugs, until the oil production stopped. The unaged cores D1 and D2 were flooded with same slug size as the aged core D5 in order to investigate the effect of wettability on the performance of oil recovery. The flow rate during the flooding processes was set to 0.1 ml/min and production samples were collected by fraction collector. The experimental setup is as shown in figure **1**. The production profiles and saturation were calculated and the pressure drop was continuously monitored during the flooding processes.

E. Low Salinity Polymer Slug Injection:

All the six cores were flooded by a slug of polymer with higher concentration after low salinity surfactant and polymer slug injection. This was done so as to observe if additional oil recovery can be obtained from the cores. The slug size in the entire core was 1 pore volume and the concentration of the HPAM polymer injected was 600 ppm. A continuous injection of low salinity brine (3000 ppm NaCl) was preformed after the polymer slug until the oil production ceased. The flow rate was set to 0.1 ml/min during the flooding process and production samples were collected to calculate the production profile and saturations. The pressure drop was continuously monitored during the flooding processes

VII. 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 measurements 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 **2** 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.

Table 2: 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 tomake 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 **3** below.

Table 3: 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.

VIII. CRUDE OILS

Three types of the oils were used in this procedure either for displacement process or for aging. These oils are high viscous crude oil sample X, medium crude oil and the diluted medium crude oil. 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 **4** shows the properties of the test fluids used for this experiment .

Table 4: Crude Oil Properties

Oil Sample	AN Mg KOH/ g oil	BN Mg KOH/g oil	Density g/cm^3	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

The high viscous oil was used for drainage process to establish initial water saturation, $S_{wi,}$ in the cores. Then it was miscible replaced by injecting the medium crude oil sample into the cores. After that the cores were aged with the medium crude oil sample in order to alter the wettability of the cores during the aging. The medium crude oil was then diluted. After the aging, the medium crude oil sample was also miscible replaced by diluted crude oil to get lower oil viscosity inside the cores before starting the flooding experiments. The medium crude oil sample was filtrated using 0.5 µm in-line filter before it was used for either injection or making the diluted crude oil. The filtration was done to remove any unwanted particles and/or wax contents.

IX. SURFACTANTS SOLUTION

The surfactant used in this study was C12TAB (Dodecyl trimethyl ammonium bromide).

Table 5: Average value of IFT measurements for the surfactant solution

Surfactant	C12TAB
IFT of Equilibrated sample (mN/m)	0.058

The surfactant solution was made of 1 wt % of active surfactant mixed with low salinity brine (i.e 3000 ppm NaCl brine). The solution was put on the magnetic stirrer for 2 h to homogenously mix the surfactant before using it for samples preparation. Sample of surfactant solution was equilibrated with diluted crude oil in 1:1 ratio before conducting the interfacial tension measurements.

X. 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 *(Abelmoschusesculentus*). The sample was dried, pulverized and sieved to obtain fine granules, and this okro sample was characterized(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.

XI. 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); and 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.

The most important aspects should be avoided for polymer solution. These are unnecessary exposition to air, sample homogeneity, creation of microgels, 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 B.

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.

XII. 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 analysed and these measured properties include density, viscosity, and interfacial tension. The surfactant used for the tertiary injection was chosen on the basis of the interfacial tension measurements while the polymer concentration was chosen based on the viscosity measurements. Low salinity surfactant and polymer slugs injection was conducted in this research to determine its effectiveness as tertiary injection mode in all six cores. The procedure of tertiary injection was executed by injecting a surfactant slug followed by a polymer slug and then a continuous injection of low salinity brine. All the aged cores were flooded with a different size of surfactant slug but with constant concentration so as to determine the optimum slug size that gives high oil recovery. The polymer slug was injected immediately after the surfactant slug in order to maintain a stable displacement front behind the surfactant. The production profile and parameters of the cores are hashed out and compared. Finally, the cores were flooded by 1 PV of low salinity polymer with higher concentration followed by continuous low salinity brine injection to observe any further production.

XIII. INTERFACIAL TENSION MEASUREMENTS

The interfacial tension measurements of the surfactant solution used in this procedure was carried out at temperature of 23 ^{O}C. The surfactant was equilibrated with the crude oil. Figure **2** below shows the measurements of equilibrated surfactant solution with diluted medium crude oil sample for two weeks and the value of the obtained interfacial tensions was listed in table **5**. The uncertainty of the measurements is estimated to be 20 % of the obtained value.

As seen in figure**2**, the IFT (Interfacial Tension) measurements of the equilibrated surfactant solution started to stabilize after almost 3 min. From table **5**, it is evident that the surfactant solution reduced the interfacial tension to the order of 10^{-2}.

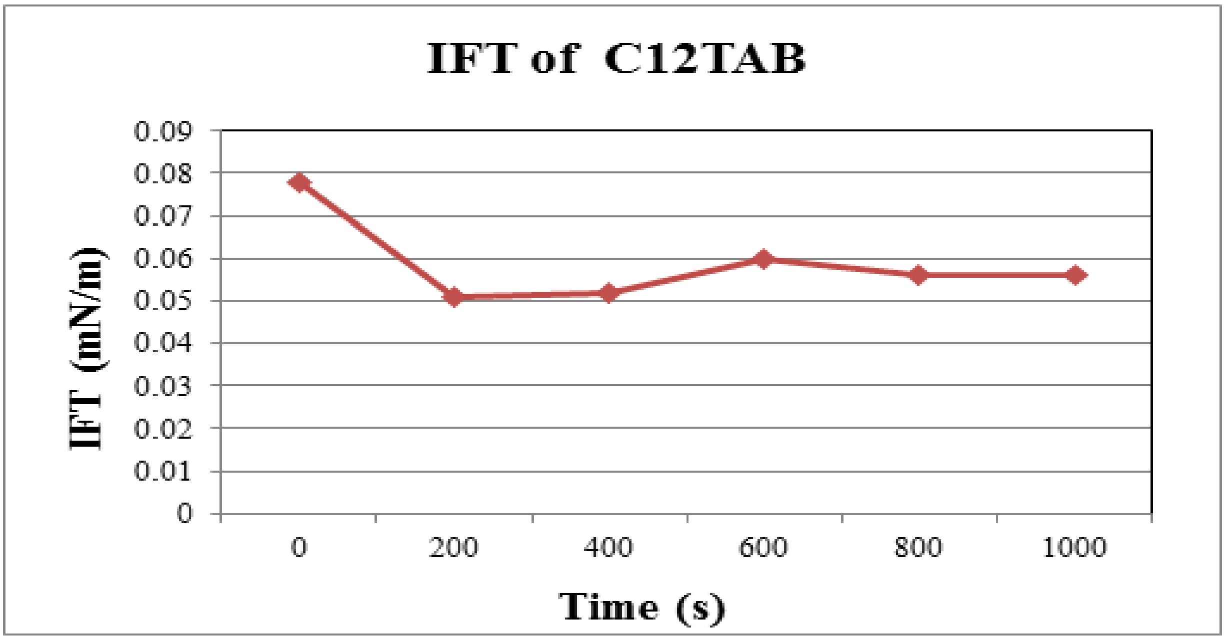

Fig. 2: IFT measurements of equilibrated C12TAB surfactant solution with diluted crude oil.

The six dolomite cores used in this research were assigned D1, D2, D3, D4, D5, and D6. The Dolomite core samples were obtained from OrekeIfelodun Local Government Area of Kwara State of Nigeria.

Table 6: 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 **6**.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 reduction in permeability is more pronounced in the cores D5, and D6 while cores D3 and D4 showed about 23 % and 24 % reduction in permeability respectively.

XIV. LOW SALINITY SURFACTANT AND POLYMER SLUGS INJECTION

In this procedure, the combined process of low salinity surfactant and polymer flooding was investigated in order to determine its effectiveness as tertiary injection mode. A surfactant slug was injected followed by a polymer slug and then a continuous injection of low salinity brine.

Each of the aged cores has been flooded with a different size of surfactant slug at a constant concentration so as to determine the optimal slug size that produces high oil recovery. The polymer slug was injected directly after the surfactant slug in order to maintain a stable displacement behind the surfactant.

The surfactant used in this study is dodecyl trimethyl ammonium bromide, C12TAB. 1 wt % surfactant C12TAB was added to the low salinity brines. Its choice was predicated on interfacial tension measurements (see section **XIII**). This surfactant is able to change wetting properties of dolomites without decreasing substantially the IFT (Strand, 2005). The surfactant was added to observe if it is possible to improve the water wetness even further after using low salinity water. The composition of the surfactant system was always kept at constant 1:1 surfactant to mixed-oil ratio.

The polymer solutions used in this research were prepared by using okro and HPAM and the concentration was chosen based on the viscosity measurement. The concentration of 300 ppm of okro and HPAM was chosen since it gives a viscosity of 3 cp which is close to diluted oil viscosity, therefore the viscosity ratio is about 1.

In the tables below is depicted a summary of the experimental parameters of low salinity surfactant and polymer slugs injection and will be discussed in this section.

Table 7: Experimental Parameters of Low Salinity Surfactant and Polymer Slugs Injection for Medium Oil using Okro

Core ID	**D1***	**D2***	**D3**	**D4**	**D5**	**D6**
Sor @ LS (% PV)	31.92	31.74	15.80	18.65	20.32	21.41
PV inj. of Surfactant	1	1	0.3	0.5	1	2
PV inj. of Polymer (**Okro))**	1	1	0.5	1	1	1
PV inj. of LS	2.0	2.0	3.0	2.3	2.8	3.3
RF (% of OIIP)	3.95	4.12	5.81	26.00	30.00	14.00
RF (% of Sor after LS)	19.0	12	6.20	48.50	53.50	23.50
Sor @ LS-S-P (% PV)	23.90	21.65	11.21	12.77	12.68	17.50

*Unaged cores

Table 8: Experimental Parameters of Low Salinity Surfactant and Polymer Slugs Injection for Medium Oil using: HPAM

Core ID	**D1***	**D2***	**D3**	**D4**	**D5**	**D6**
$S_{or\ @\ LS}$ (% PV)	31.92	31.74	15.80	18.65	20.32	21.41
PV inj. of Surfactant	1	1	0.3	0.5	1	2
PV inj. of Polymer**(HPAM)**	1	1	0.5	1	1	1
PV inj. of LS	2.0	2.0	3.0	2.3	2.8	3.3
RF (% of OIIP)	5.00	2.75	4.80	34.0	31.50	15.00
RF (% of Sor after LS)	15.00	11.50	6.50	62.0	60.5	28.50
$Sor_{@\ LS\text{-}S\text{-}P}$ (% PV)	27.95	24.15	11.94	14.80	15.74	15.00

* Unaged cores

A. Oil Recovery in Aged Cores (LS-S-P):

The oil recovery of tertiary low salinity surfactant and polymer slugs injection has been conducted in the aged cores and the results are presented in figures **3** and **4**.

The slugs injection have mobilized and produced oil from the cores as tertiary recovery after the secondary low salinity flooding, as it is evident from the figures. The amount of produced oil varies in cores depending on the size of the surfactant slug injected. From table **7** above, core D3 was flooded by 0.3 PV of surfactant followed by 0.5 PV of polymer, and this showed low tertiary recovery of 5.81 % of OIIP compared with the other aged cores when okro was used as polymer, while 4.8 % of OIIP was recorded when HPAM was used while keeping the PV of surfactant and polymer injected constant (see table **8**).

This observation would be explicated by retention of surfactant due to adsorption, precipitation, and phase trapping; therefore the efficiency of surfactant flooding will be reduced.

However, there was a consistent increase in the % oil recovery from Cores D3, D4 and D5 from 5.81 % to 30.00 % during okro injection.

This increment in recovery is in keeping with increase in the surfactant slug size which means that more oil has been mobilized by surfactant.

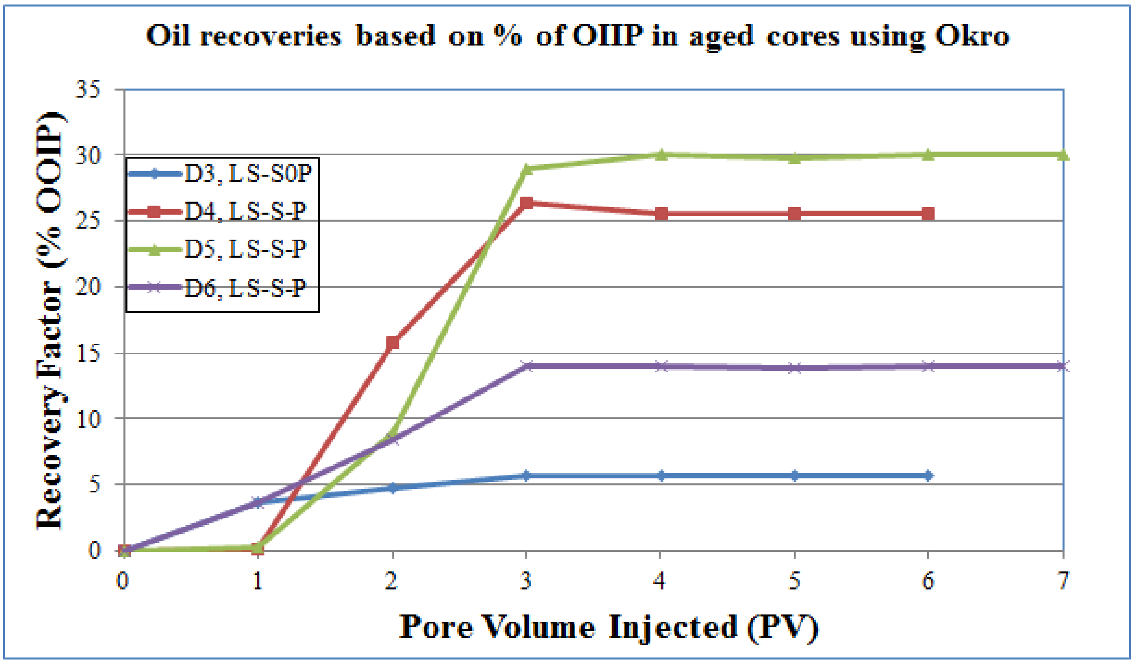

Fig. 3: Oil recovery of tertiary low salinity surfactant and polymer slugs injection done in the aged cores

Core D6 is flooded with 2 PV of surfactant and then followed by 1 PV of polymer. The tertiary recovery is 14.0 % OIIP when okro was used as polymer. Core D5 notwithstanding showed higher recovery 30.0 % of OIIP compared to core D6 when okro was used even though the latter was flooded with larger slug size.

In figures **5** and **6** are depicted the oil recovery of tertiary low salinity surfactant and polymer slugs injection based on the residual oil after secondary low salinity waterflooding when okro and HPAM were used respectively. When okro was used as the polymer, the lowest tertiary recovery is 6.2 % of residual oil which is obtained by injecting 0.3 PV of surfactant in core D3.

The highest tertiary recovery of residual oil obtained by injecting 1 PV of surfactant in core D5 was 53.5% and 60.5 % when okro and HPAM polymer solutions were injected respectively as shown in tables **7** and **8.**

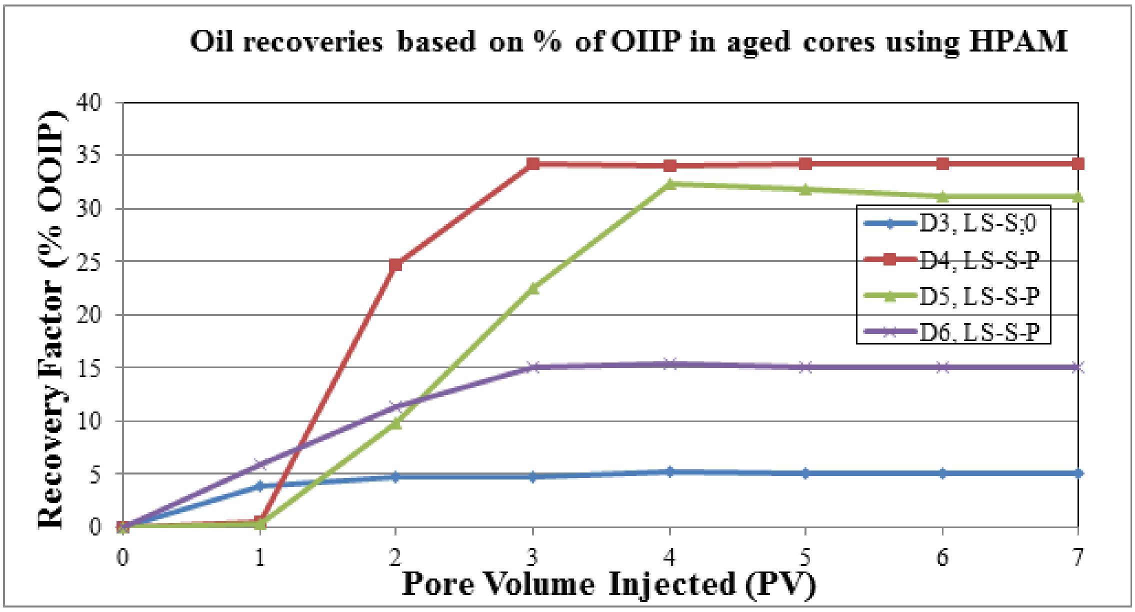

Fig. 4: Oil recovery of tertiary low salinity surfactant and polymer slugs injection done in the aged cores using HPAM.

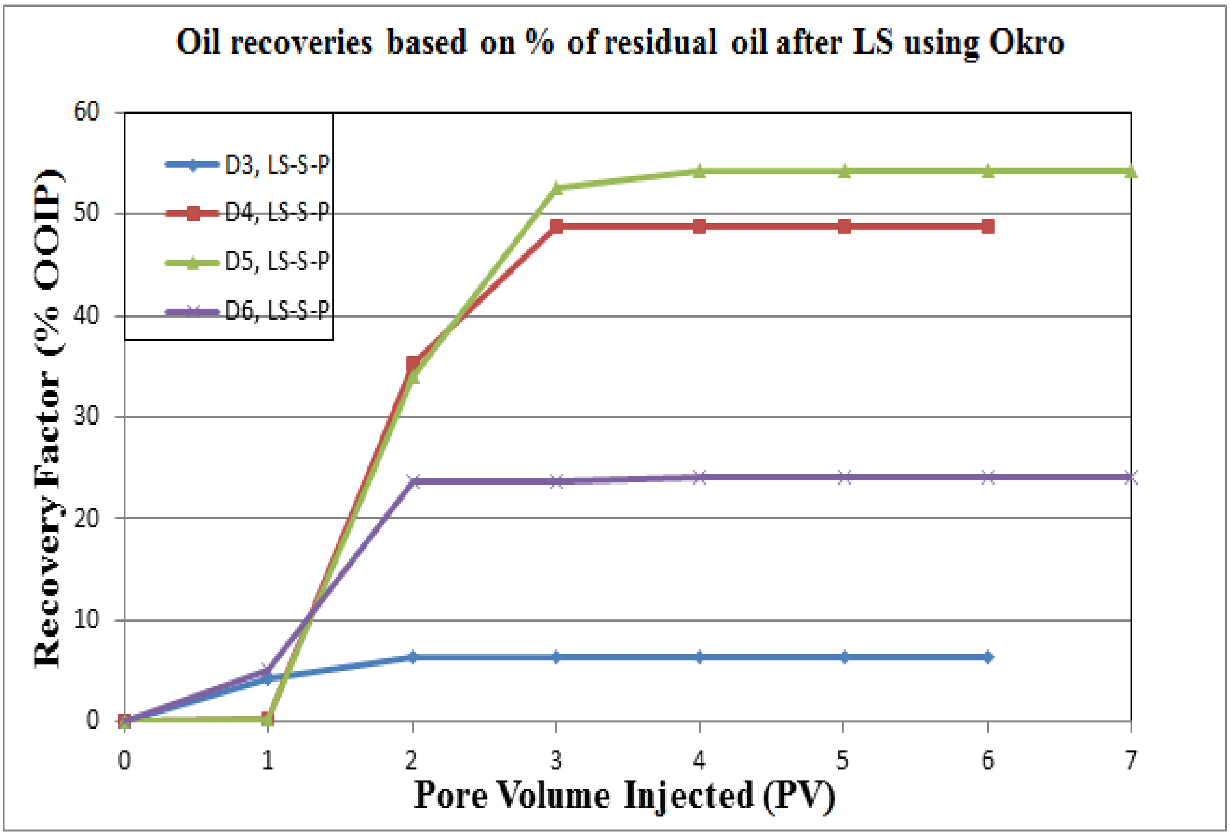

Fig. 5: Oil recovery of tertiary low salinity surfactant and polymer slugs injection based on the residual oil after secondary low salinity water flooding using okro.

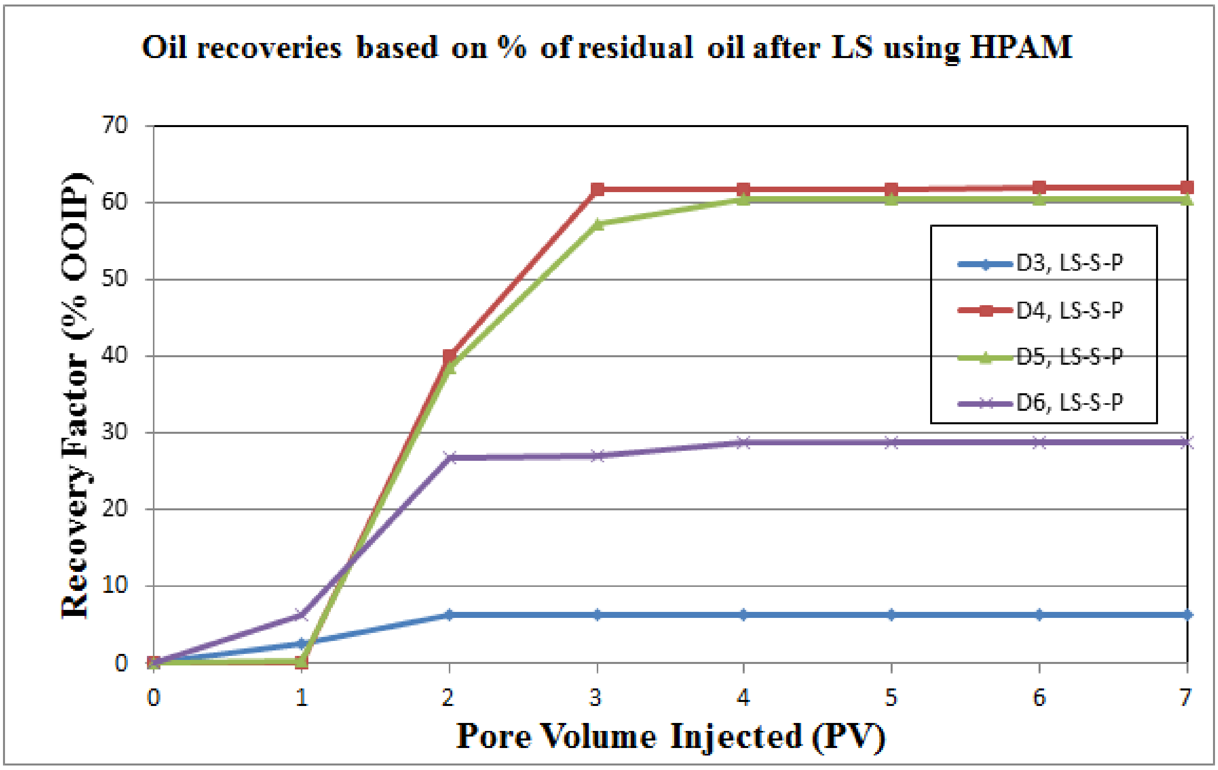

Fig. 6: Oil recovery of tertiary low salinity surfactant and polymer slugs injection based on the residual oil after secondary low salinity waterflooding using HPAM.

The relationship between the surfactant slug size injected and the final tertiary recovery factor based on the secondary residual oil is displayed in figures **7** and **8**. The tertiary recovery increases with increase in the size of the surfactant slug injected as shown in the figures.

The injection of larger surfactant slug than 2 PV nonetheless could result in the production of more oil and increase the recovery factor. Therefore the optimum surfactant slug size would be achieved when there is no more increase in the recovery factor with further increase in the surfactant slug size at constant surfactant concentration.

The residual oil saturation would most probably be caused by capillary force which is responsible for trapping oil after the low salinity waterflooding. Experimental investigations have revealed that the surfactant flooding can improve the recovery after immiscible displacement by reducing the interfacial tension between oil and water which leads to higher capillary number and mobilize the trapped oil in line with the observations of Skauge*et al*., (2011). In this research, the interfacial tension of the surfactant used is 5.8 x 10^{-2} mN/m which is low enough to mobilize the trapped oil and improve recovery.

The polymer slug injected after the surfactant slug could also conduce to increase in the tertiary recovery by improving the volumetric sweep efficiency. But the main use of the polymer slug in this procedure was to maintain a stable displacement behind the surfactant and therefore having a better mobilization of oil.

Pressure Profiles

For all the aged cores, the pressure profile of low salinity surfactant and polymer slug injections have been deployed against the oil production profile and the results are presented in figures **9-16**. In all the four aged cores, the pressure across the cores started increasing with injection of surfactant slug both when okro and HPAM polymer solutions were injected. During surfactant injection cores D5 and D6 exhibited an early response by producing oil; however the produced volume was not significant from both cores. In cores D3 and D4 there was no sign of any oil production during surfactant injection despite being flooded by 1 PV of surfactant. The pressure profile in core D6 which is flooded by 2 PV increased until it reached the peak value and then started declining. Substantial oil production from the core however commenced after about 2 PV injection of surfactant.

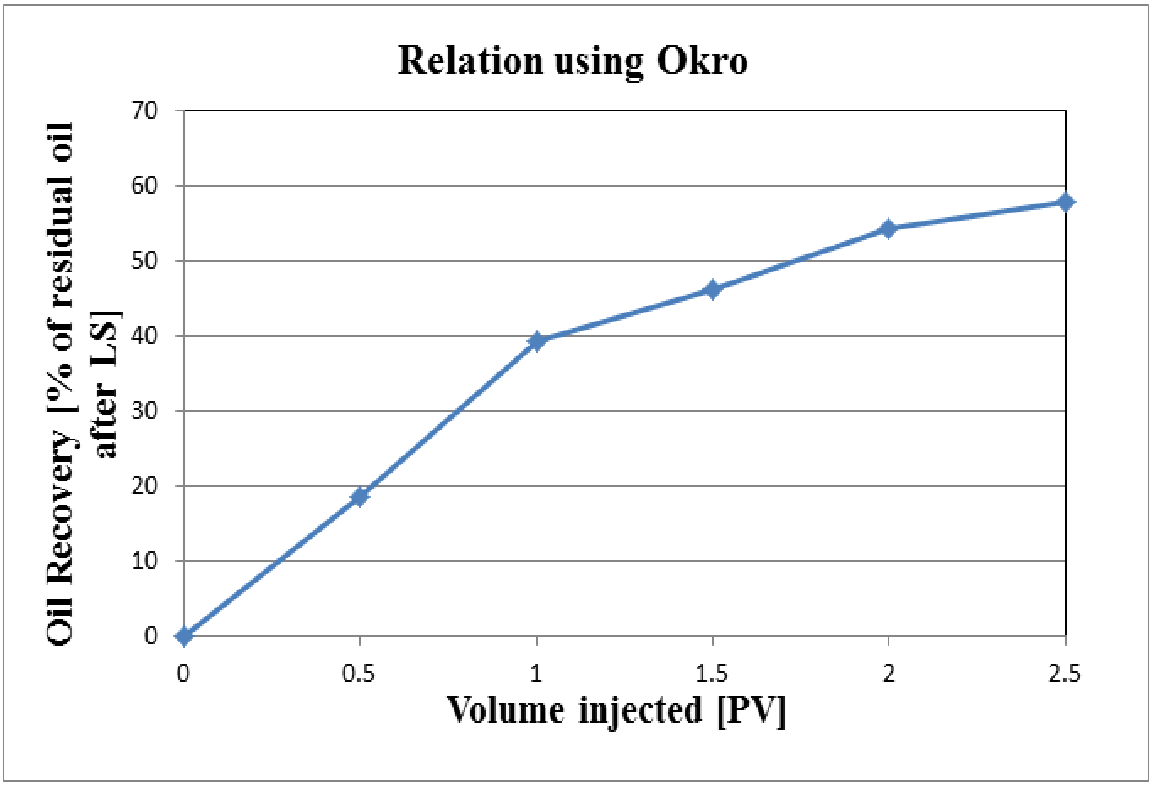

Fig. 7: Relationship between oil recovery and surfactant slug size injected at constant surfactant concentration using okro.

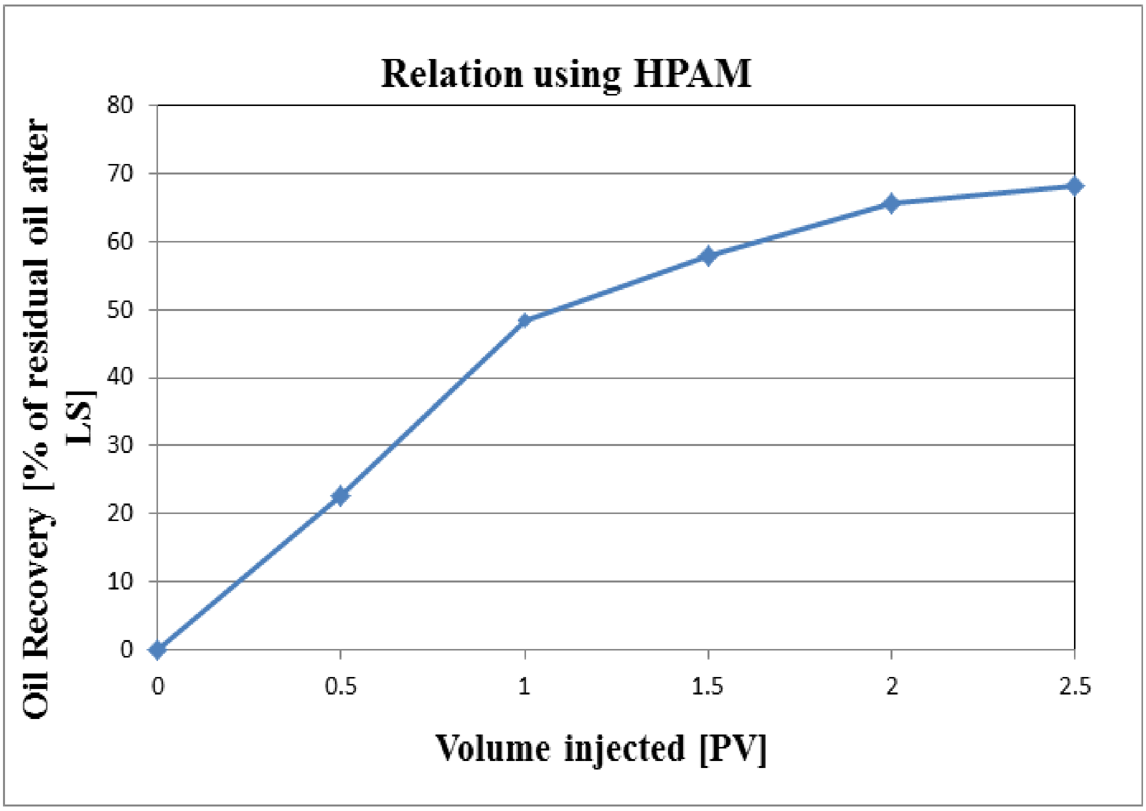

Fig. 8: Relationship between oil recovery and surfactant slug size injected at constant surfactant concentration using HPAM.

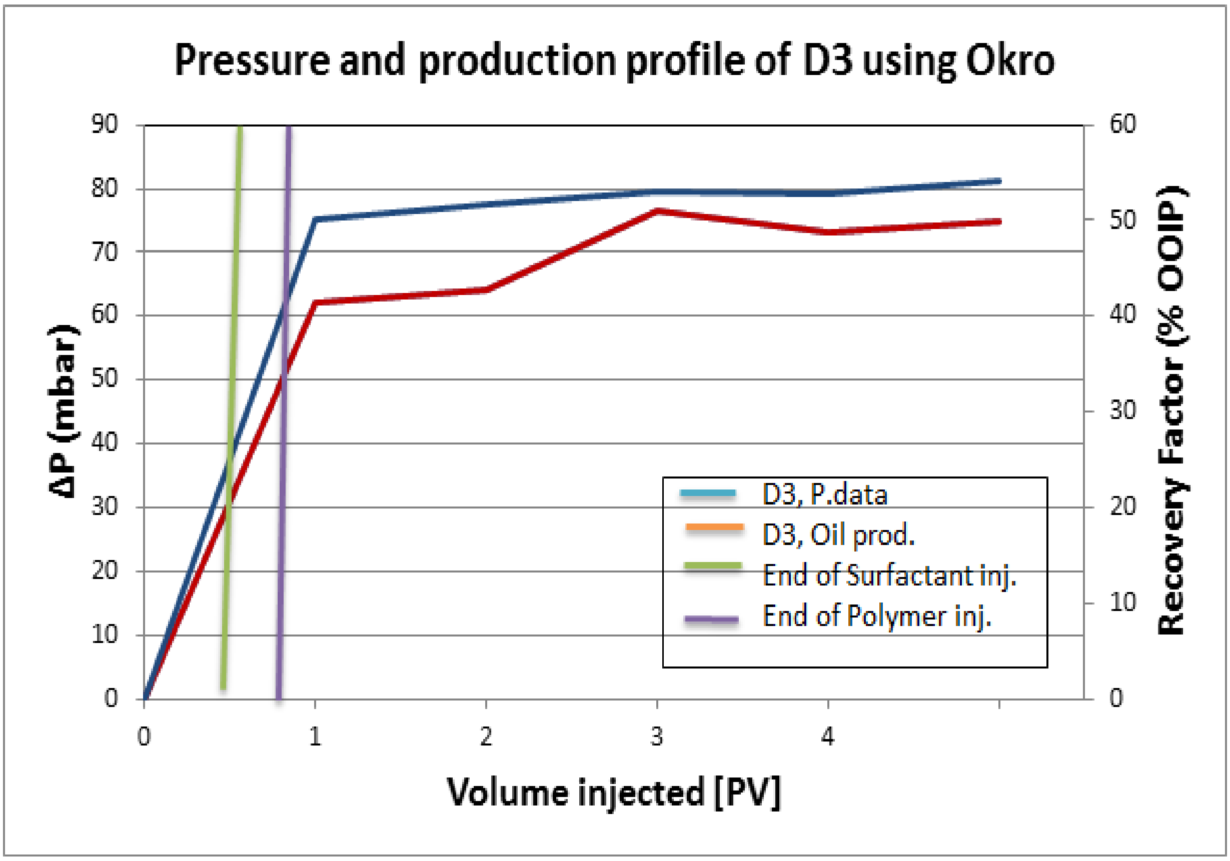

Fig. 9: Pressure and production profile of LS-S-P flooding in core D3 using okro.

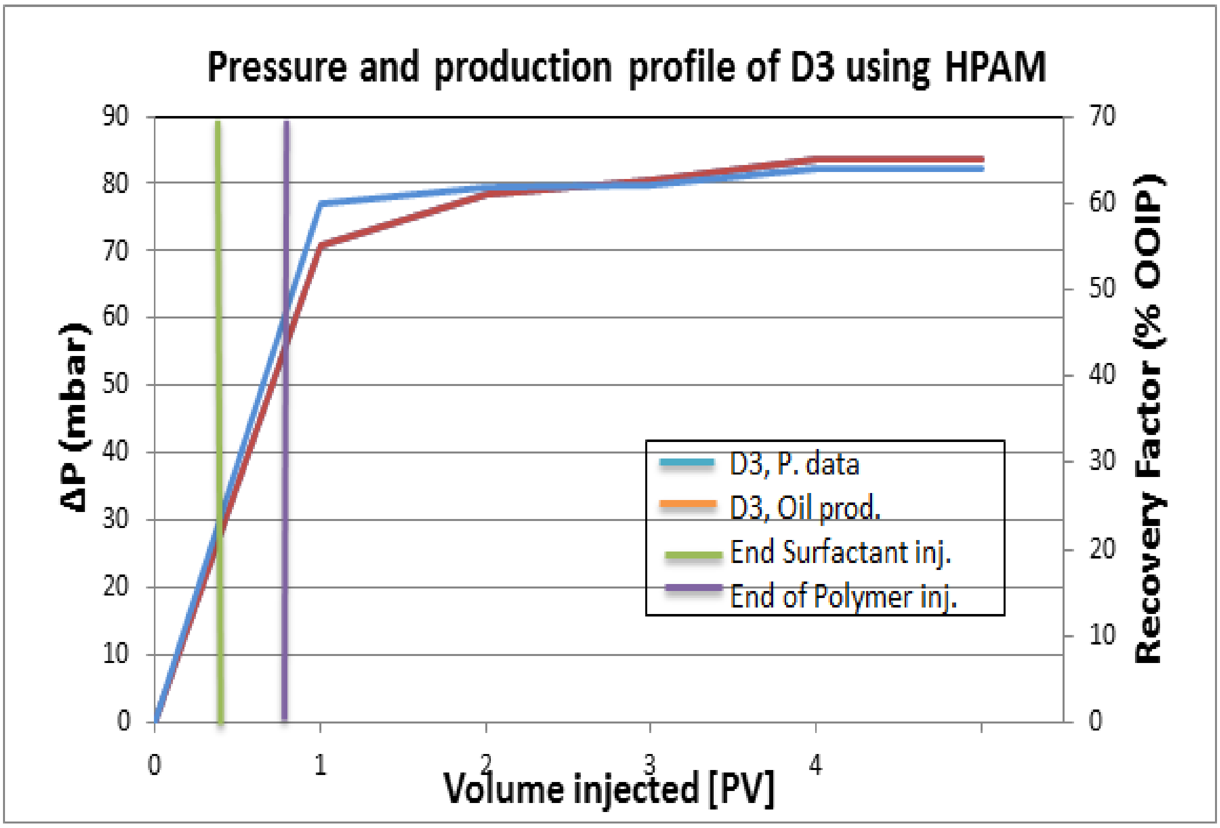

Fig. 10: Pressure and production profile of LS-S-P flooding in core D3 using HPAM.

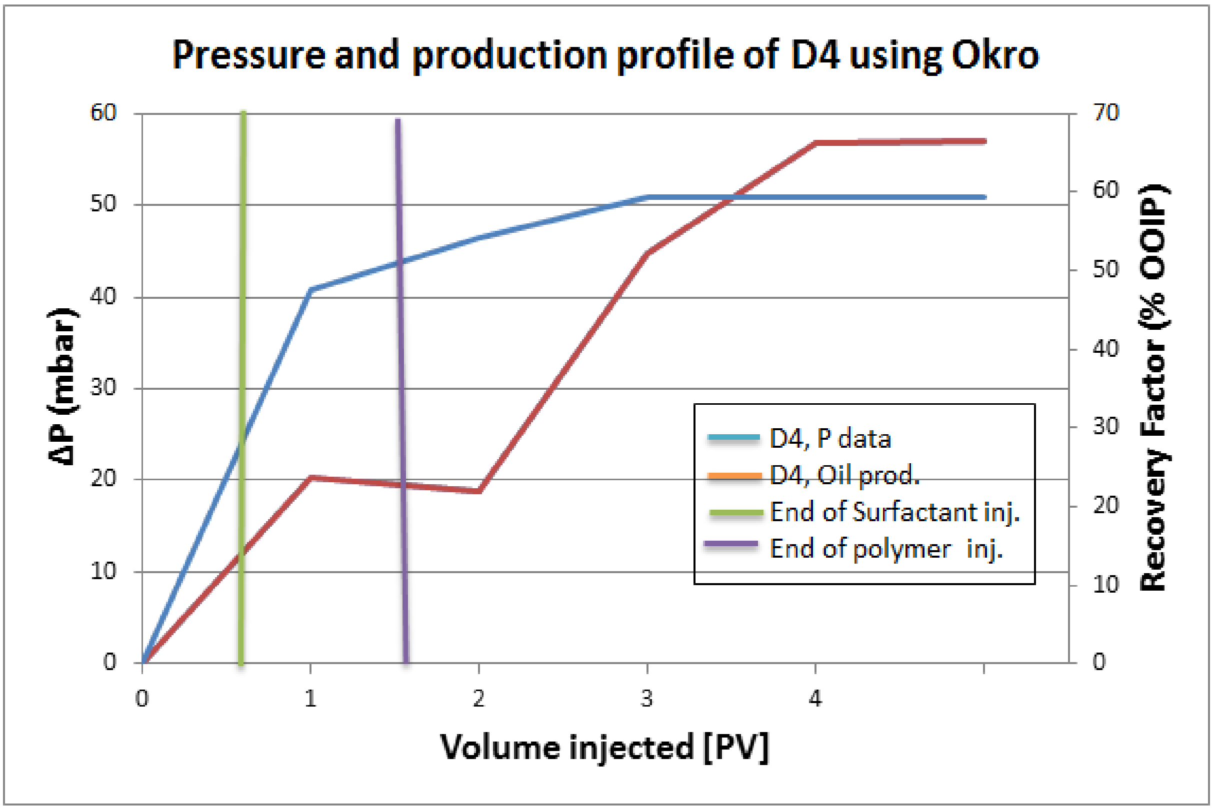

Fig. 11: Pressure and production profile of LS-S-P flooding in core D4 using okro.

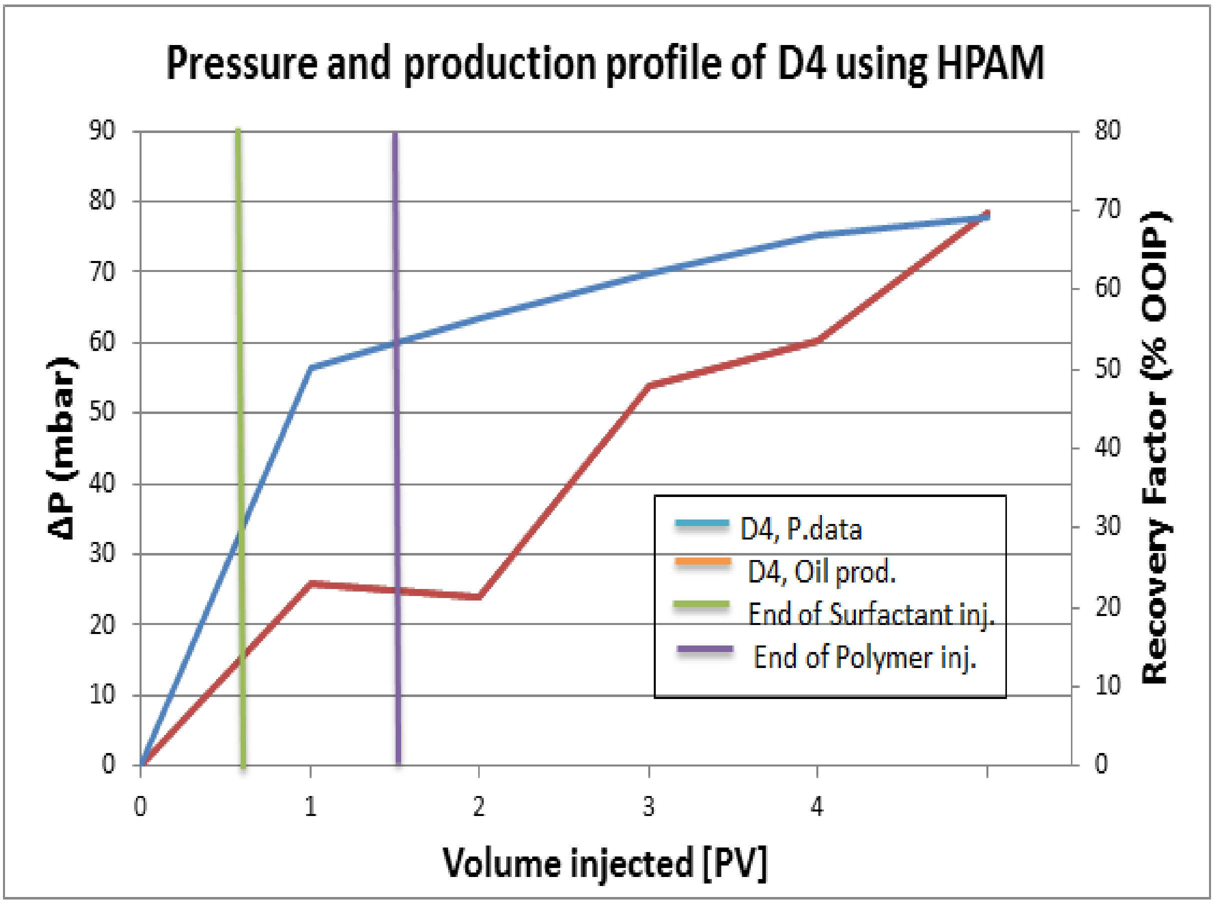

Fig. 12: Pressure and production profile of LS-S-P flooding in core D4 using HPAM.

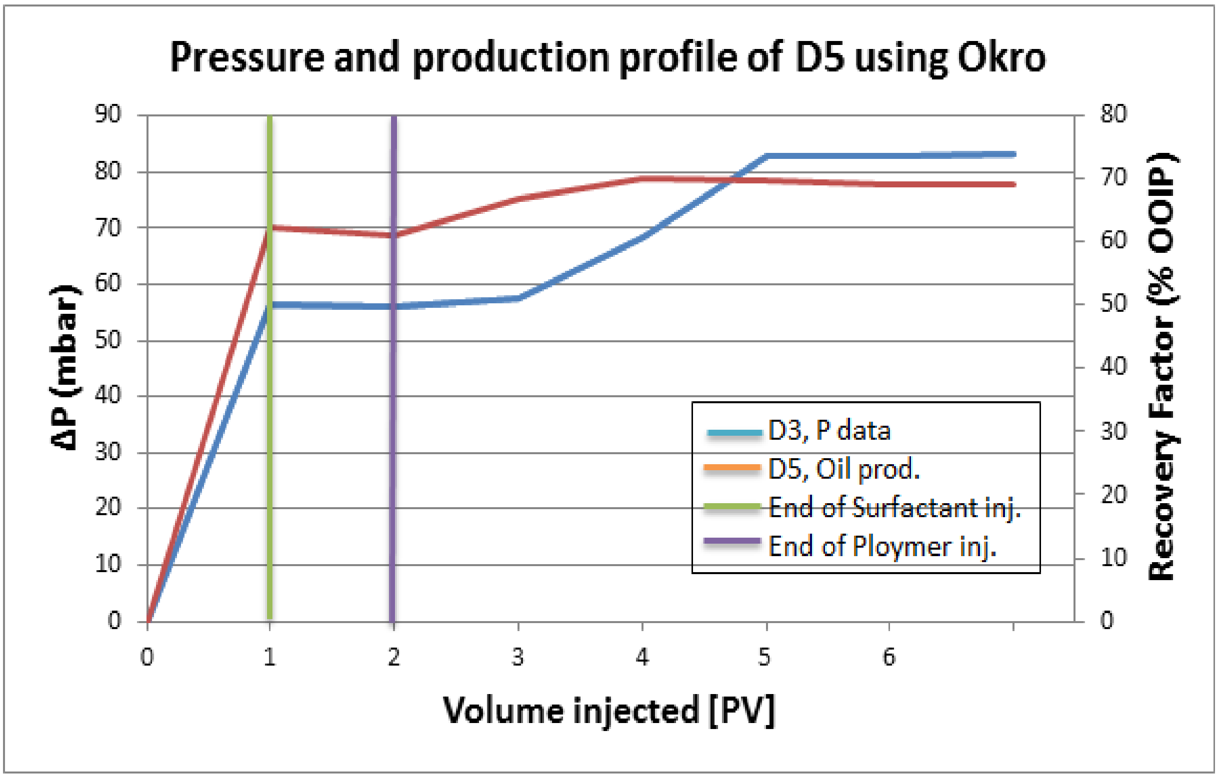

Fig. 13: Pressure and production profile of LS-S-P flooding in core D5 using okro.

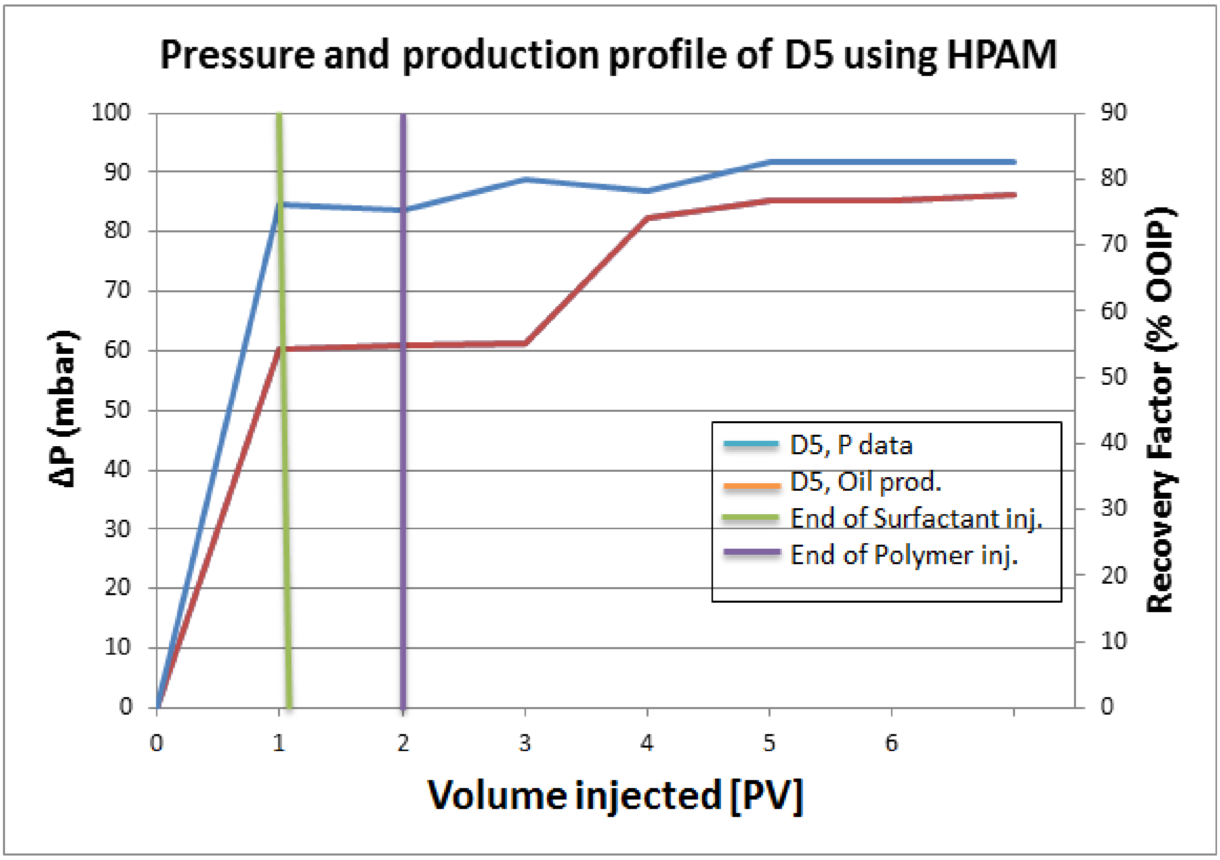

Fig. 14: Pressure and production profile of LS-S-P flooding in core D5 using HPAM.

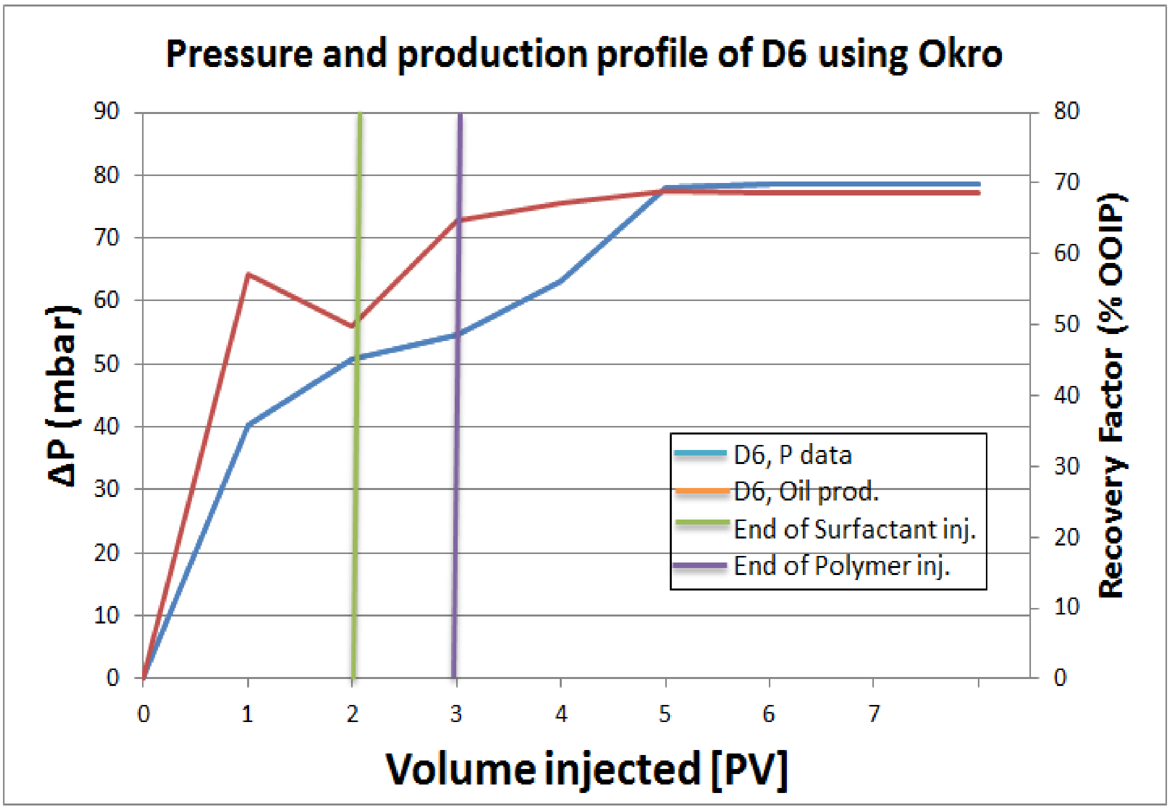

Fig. 15: Pressure and production profile of LS-S-P flooding in core D6 using okro.

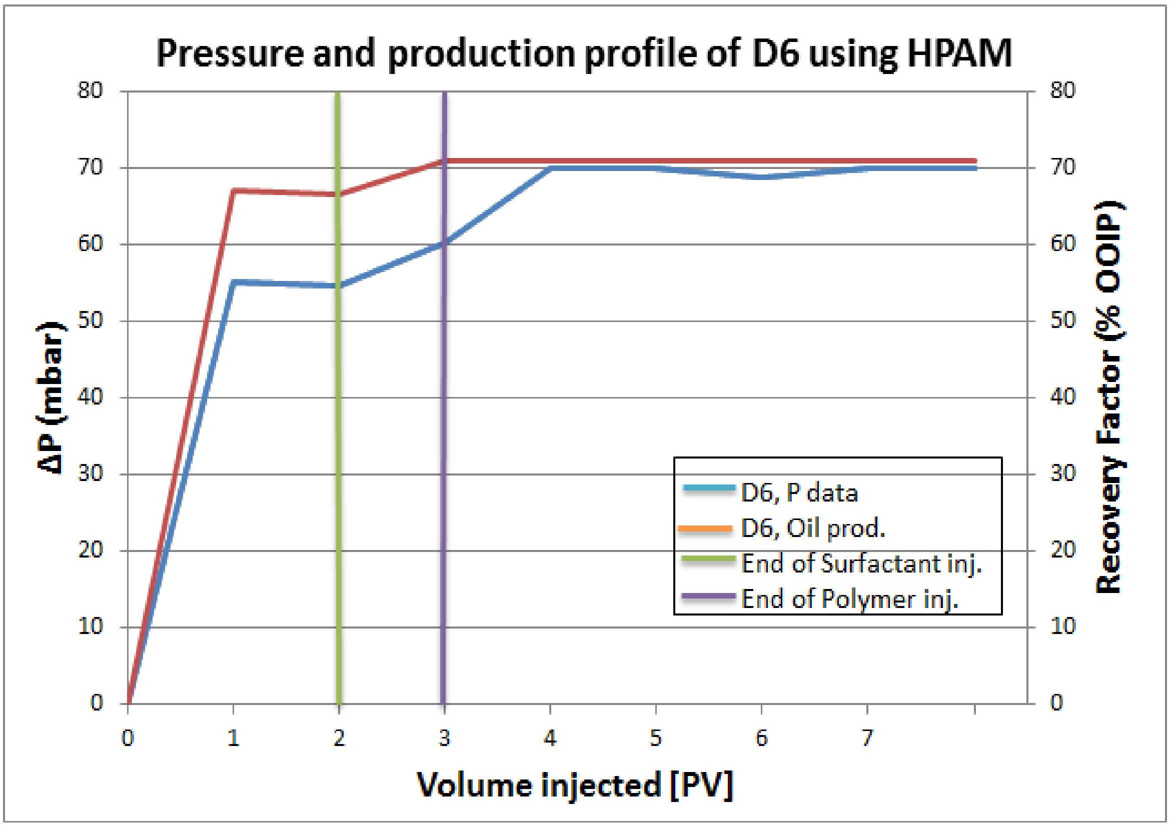

Fig. 16: Pressure and production profile of LS-S-P flooding in core D6 using HPAM.

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When the polymer slug was injected following surfactant injection, the pressure across the cores increased significantly because of increasing the viscosity of the injected brine. Core D3 was flooded by 0.5 PV of polymer and the pressure profile was increasing without any sign of polymer breakthrough when okro and HPAM were used as polymer.

When the other cores D4, D5 and D6, were flooded by 1 PV of polymer the pressure profile increased until the polymer breakthrough occurred and then leveled off or started to fall down.

The breakthrough of the polymer occurred after 0.5 PV of polymer injection in the cores D4 and D6 when okro was injected as polymer. In all the cores there was an increase in the oil production during the polymer flooding. Polymer breakthrough took place after 0.5, 0.1, and 0.1 PV of polymer injection in the cores D4, D5, and D6 respectively during okro and HPAM polymer injection. All the cores showed an increase in the oil production during the polymer flooding. In general the polymer flooding more often than not improves the volumetric sweep efficiency therefore increasing oil recovery.
All the cores were flooded by continuous low salinity brine (3000 ppm NaCl) after the polymer slug injection. The pressure profile in all cores waned once the low salinity waterflooding started and then stabilized. The cores kept on producing oil during low salinity injection until the oil production stopped.

XV. COMPARISON OF TERTIARY LOW SALINITY SURFACTANT AND POLYMER SLUGS INJECTION IN AGED AND UNAGED CORES

The tertiary low salinity surfactant and polymer slugs injection was also investigated in the unaged cores D1 and D2. 1 PV of surfactant was injected followed by 1 PV of polymer, and then a continuous injection of low salinity brine. This slug size and injection procedure in the unaged cores is identical with the slug size and injection procedure in the aged core D5.The low salinity surfactant and polymer slug injection in these three cores is compared and presented in figures**17** and **18** to determine the effect of wettability on the performance of tertiary recovery

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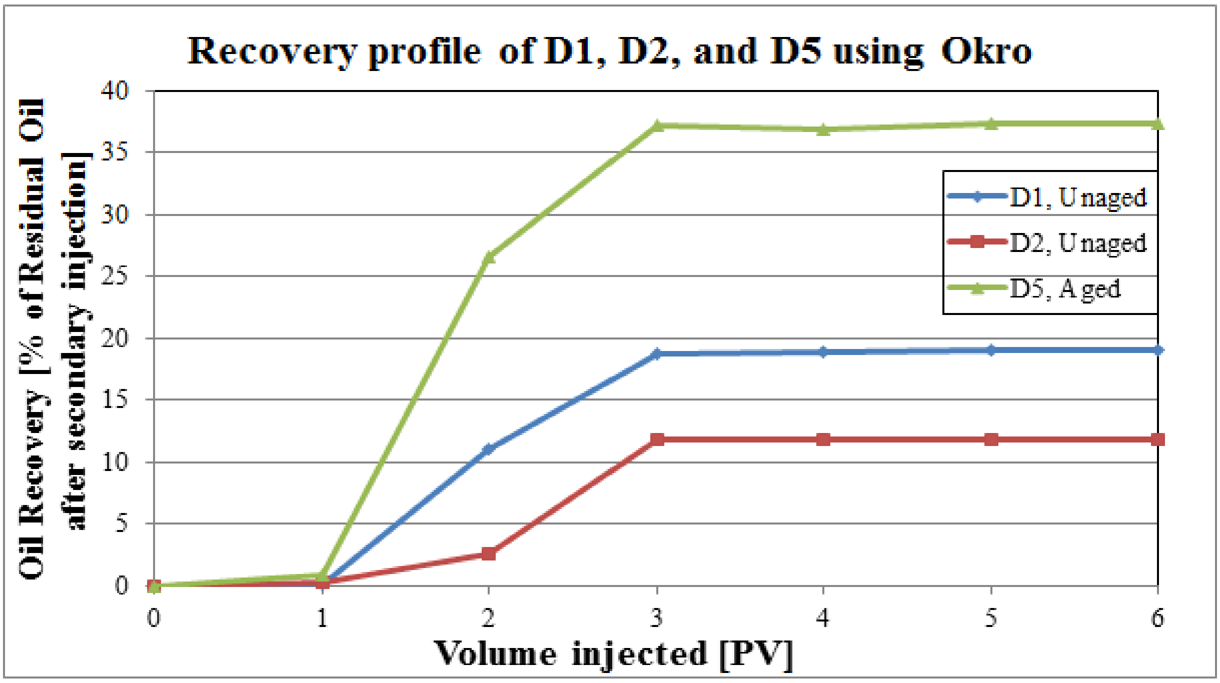

Fig. 17: Recovery profiles of cores D1(unaged), D2 (unaged), and D5 (aged) using okro.

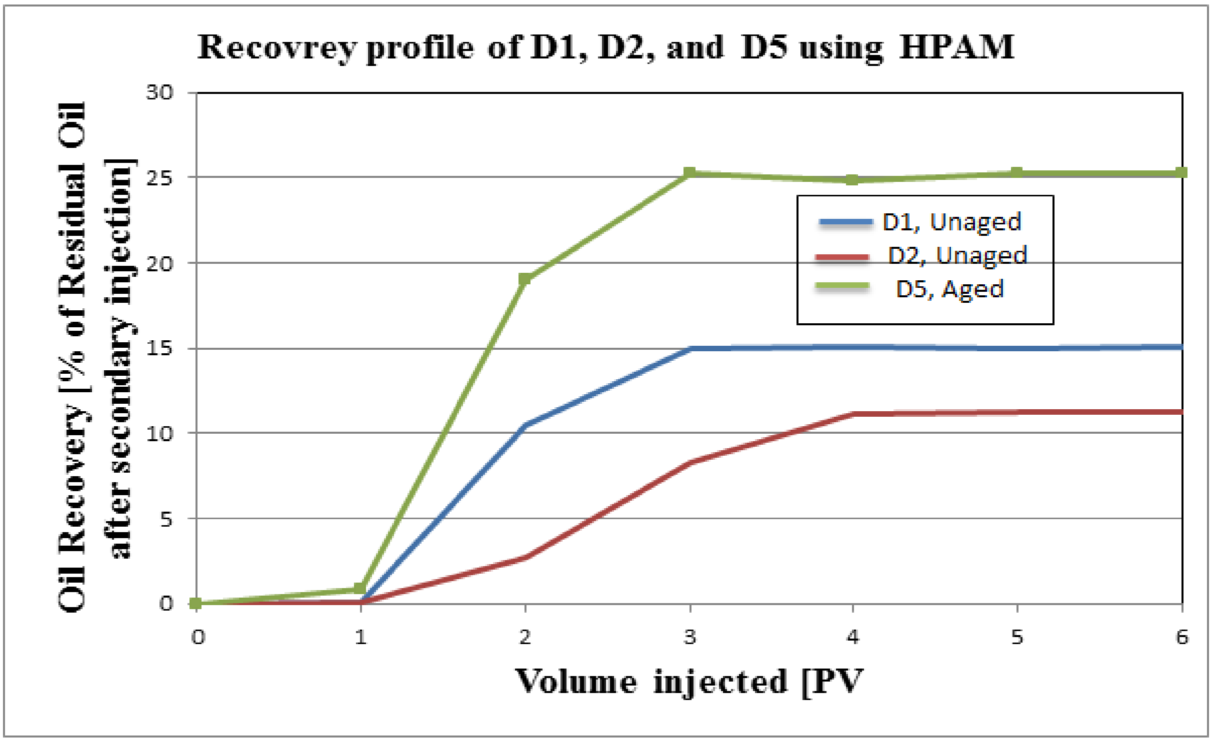

Fig. 18: Recovery profiles of cores D1 (unaged), D2 (unaged) and D5 (aged) using HPAM.

From the above figures, it is evident that the response of tertiary slug injection in all the three cores started during the polymer injection. The aged core D5 yielded tertiary recovery of 37.5 % and 25.0 % of residual oil during okro and HPAM polymer injection respectively which are much higher than the unaged cores D1 and D2 that produced a tertiary recovery of 19 and 12 % of residual oil for okro, and 15 and 11.5 % for HPAM respectively.

It has been ascertained that the unaged cores has a strongly water-wet behavior, while the wettability of core D5 was altered during the aging period to less water-wet state. This huge disparity in the tertiary recovery between aged and unaged cores suggests that the wettability of the core has a great effect on the performance of low salinity surfactant and polymer slugs injection. As shown in tables **7** and **8** whilst the strongly water-wet cores has a much higher residual oil after secondary low salinity waterflooding, their response to the tertiary injection was much lower than the less water-wet core.

XVI. 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 which is two times the one used in the low salinity surfactant and polymer slugs injection stage. 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

XVII. CAPILLARY NUMBER, NC

The ratio between the viscous force and capillary force is called the capillary number, *Nc*, and it is given by the following equation:

$$N_C = \frac{Viscous\ force}{capillary\ force} = \frac{u.\mu}{\sigma} \text{---------------}2$$

This has been calculated for both surfactant and the two polymer slugs (HPAM and Okro) used in this study and the results are presented in table **11** below.

Table 11: Calculated capillary number (*Nc*) for Surfactant and the Two Polymers (HPAM and Okro) injected

Core ID	D1	D2	D3	D4	D5	D6
Nc of Surfactant	4.85 x 10^{-6}	4.85 x 10^{-6}	4.88 x 10^{-6}	4.87 x 10^{-6}	4.85 x 10^{-6}	4.85 x 10^{-6}
Nc of 300 ppm HPAM Polymer	2.00 x 10^{-4}	2.00 x 10^{-4}	2.04 x 10^{-4}	2.00 x 10^{-4}	2.00 x 10^{-4}	2.03 x 10^{-4}
Nc of 600 ppm HPAM Polymer	2.57 x 10^{-4}	2.57 x 10^{-4}	2.50 x 10^{-4}	2.57 x 10^{-4}	2.57 x 10^{-4}	2.50 x 10^{-4}
Nc of 300 ppm Okro Polymer	1.18 x 10^{-4}	1.18 x 10^{-4}	1.18 x 10^{-4}	1.18 x 10^{-4}	1.18 x 10^{-4}	1.18 x 10^{-4}
Nc of 600 ppm Okro Polymer	1.62 x 10^{-4}	1.62 x 10^{-4}	1.63 x 10^{-4}	1.62 x 10^{-4}	1.62 x 10^{-4}	1.63 x 10^{-4}

The surfactant gave a capillary number in order of 10^{-6} while the polymer solutions gave a capillary number in order of 10^{-4} (see table **11**). The capillary force is responsible for trapping oil in the porous media after secondary waterflooding. Numerous studies have demonstrated that the residual oil saturation is related to the capillary number and in order to achieve low, S_{or}, after water-flood, a high capillary number, *Nc*, is needed (Lake, 1989). The surfactant results in the reduction of the interfacial tension between oil and water therefore increasing the capillary number from equation **2**. The polymer increases the capillary number through increasing the viscosity of the injected brine.

From this study, it has been shown in the preceding sections that the surfactant and polymer slugs injected have mobilized and produced oil from the cores which resulted in lower residual oil. While calculating the capillary number for polymer injection in this research, the interfacial tension between oil and injected brine is assumed to be constant after the surfactant slug injection. Therefore the capillary number of polymer injection is higher than the surfactant injection because of higher polymer viscosity.

XVIII. SUMMARY AND DISCUSSION

It was anticipated in this research 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 injection of surfactant was considered to mobilize the trapped oil after waterflooding by substantially reducing the interfacial tension. Notwithstanding the amount of the mobilized oil will depend on the size of the surfactant slug injected at same surfactant concentration.

When tertiary low salinity surfactant and polymer slugs injection was conducted on the aged cores, it showed additional oil production and the oil recovery increased with increased surfactant slug size injected. The sizes of surfactant slugs were 0.3, 0.5, 1, and 2 PV and the recovery increased from 6.2 % to 53.5 % and from 6.5 % to 62.0 % of residual oil after secondary flooding when okro and HPAM polymer solutions were injected respectively.

Finding the optimum surfactant slug size demands the injection of larger than 2 PV of surfactant with same concentration in order to observe the recovery performance. The comparison between aged and unaged cores flooded with same surfactant and polymer slugs size proved that the wettability of the cores affects the performance of slugs injection in the recovery of trapped oil. The unaged cores D1 and D2 gave a tertiary recovery of 19.0 and 12.0 % ; 15.0 % and 11.5 % of residual oil respectively whereas the aged core D5 which flooded with same slugs size gave 37.5 % and 25.0 % of residual oil during okro and HPAM injection respectively.

Figures 19 and 20 present a schematic of the CDC (Capillary Desaturation Curve), where the logarithmic x-axis is representative of the capillary number, and the normal y-axis shows the residual saturation of the non-wetting phase when okro and HPAM polymer solutions were injected respectively. In these figures, there is a normal range of capillary numbers for water flooding, where the ROS (residual oil saturation) is usually high in this range. After passing the critical capillary number using an EOR (Enhanced Oil Recovery) method, a reducing trend can be observed for ROS. Garnes*et al*., (1990) reported 4×10^{-6} as the critical capillary number of water-wet Berea sandstones. Since the capillary number has a significant impact on the amount of trapped fluid, the ROS is commonly measured experimentally as a function of the capillary number to obtain the CDC as described in the previous study conducted by Sahimi, (1993). On the other hand, a large change in the capillary number is required to significantly change the ROS due to the logarithmic x-axis of CDC.

In this research, the tertiary slugs injection has reached a capillary number of 1.18 x 10^{-4} and 2.03 x 10^{-4} when okro and HPAM polymers were injected respectively, and this has decreased the residual oil saturation (see tables 9 and 10).

Figures 19 and 20show a comparison of the obtained results with the CDC measured by the work of Lake (1989). The obtained results were compared with the CDC measured by the work of Zivar*et al.,* (2021), and these are presented in figures 19 and 20.

The attained capillary number in this investigation should reduce the residual oil saturation and give values of Sor-LS-S-P in the range of 12.68 and 15.74 when okro and HPAM were used .respectively. Nevertheless, in this study the reduction in the residual oil saturation is extremely dependent on the size of the surfactant slug injected at constant surfactant concentration.

The cores D3 and D6 which were flooded by 0.3 and 1 PV of surfactant respectively, and demonstrated a marked deviation from the curve when okro was injected.Similar deflection was noticed when cores D3 and D4 were flooded by HPAM.

This suggests that more surfactant is needed to be injected in order to gratify surfactant retention and attain lower residual oil saturation.

A satisfactory decrease in the residual oil saturation which is consistent with the CDC was obtained when cores D4 and D5 were flooded by 0.5 and 1 PV and when cores D5 and D6 were flooded by 1 and 2 PV of surfactant during okro and HPAM polymer solutions injection respectively.

Whilst the unaged cores D1 and D2 have high residual oil saturation after waterflooding, the tertiary slugs injection did not demonstrate a significant decrease in the residual oil saturation. The unaged cores have a strongly water-wet state and this indicates that the wettability affects the performance of tertiary recovery.

Table 12: Parameters of tertiary slugs injection in the cores using:
Okro

Core ID	**D1***	**D2***	**D3**	**D4**	**D5**	**D6**
Sor @ LS (% PV)	31.92	31.74	15.80	18.65	20.32	21.41
PVinj.of Surfactant	1	1	0.3	0.5	1	2
PVinj.of Polymer(**Okro)**)	1	1	0.5	1	1	1
Sor @ LS-S-P (% PV)	23.90	21.65	11.21	12.77	12.68	17.50
Sor-LS-S-P / Sor-LS	0.81	0.68	0.71	0.68	0.62	0.82
N_C of LS-S-P	1.18 x 10^{-4}	1.18 x 10^{-4}	1.18 x 10^{-4}	1.18 x 10^{-4}	1.18 x 10^{-4}	1.18 x 10^{-4}

Table 13: Parameters of tertiary slugs injection in the cores using:
HPAM

Core ID	**D1***	**D2***	**D3**	**D4**	**D5**	**D6**
$S_{or\ @\ LS}$ (% PV)	31.92	31.74	15.80	18.65	20.32	21.41
PV inj. of Surfactant	1	1	0.3	0.5	1	2
PV inj. of Polymer (HPAM)	1	1	0.5	1	1	1
$Sor_{@\ LS\text{-}S\text{-}P}$ (% PV)	27.95	24.15	11.94	14.80	15.74	15.00
Sor-LS-S-P / Sor-LS	0.88	0.76	0.76	0.79	0.77	0.70
N_C of LS-S-P	2.00 x 10^{-4}	2.00 x 10^{-4}	2.04 x 10^{-4}	2.00 x 10^{-4}	2.00 x 10^{-4}	2.03 x 10^{-4}

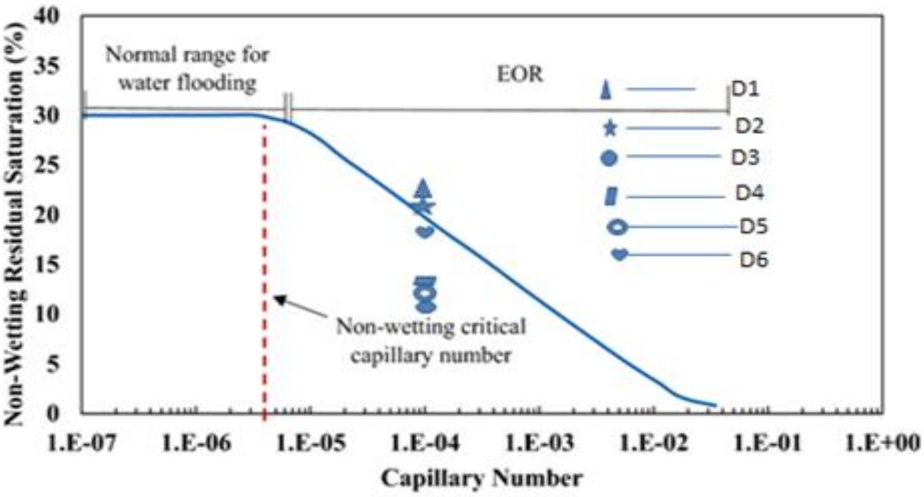

Fig. 19: Schematic of the capillary desaturation curve (adapted from Lake (1989)) for the six dolomite cores when okro polymer solution was injected.

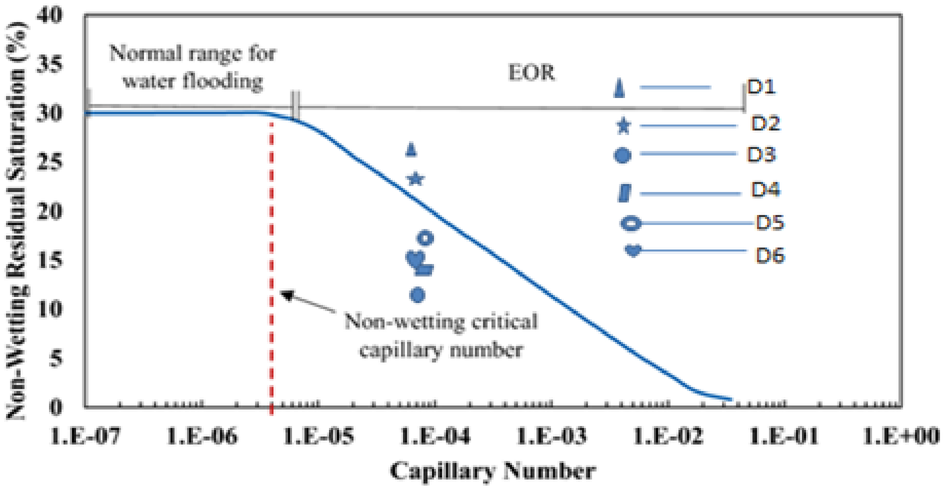

Fig. 20: Schematic of the capillary desaturation curve (adapted from Lake (1989)) for the six dolomite cores when HPAM polymer solution was injected.

XIX. CONCLUSIONS

Core flooding experiments have been carried out on six Dolomite cores to study the effect and different aspects of low salinity waterflooding followed by combined low salinity polymer and surfactant slugs injection. Two out of the six cores were unaged and these were tested for effect of reducing salinity of injected brine in both secondary and tertiary mode. The two cores did not display 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 ppm NaCl brine as a secondary mode.

The aging period modified the wettability of the cores to less water-wet state which was corroborated by reduction in the oil permeability after aging (see table **6**). The oil recovery from these aged cores was superior to that of the unaged cores which indicates the effect of initial wettability state on performance of low salinity waterflooding. This confirms the fact that the rock should be exposed to crude oil to create mixed-wet conditions in order to observe the effect of low salinity waterflooding. Fines particles were not noticed in the effluent during the coreflooding experiments and the pressure profiles were stable and increased only as a response to increasing the flow rate.

Generally, the results of tertiary low salinity surfactant and polymer slugs injection in all six cores indicated that the slug injection has mobilized and produced different amount of oil from the cores. The aged cores were flooded with different surfactant slug size and the oil recovery increased with increasing the size of the surfactant slug injected at constant surfactant concentration.

However the reduction in the residual oil was highly dependent on the surfactant slug size injected. The injection of 0.3 and 0.5 PV of surfactant did not decrease the residual oil saturation sufficiently which suggests that more surfactant should be injected to satisfy retention and achieve low residual saturation.

The injection of 1 PV and 2 PV of surfactant produced an increasing change in residual oil saturation. The optimization of surfactant slug size demands injection of more than 2 PV of surfactant with same concentration to observe the recovery performance. The comparison between aged and unaged cores flooded with same surfactant and polymer slugs size established the fact that the wettability of the cores impacts the performance of slugs injection in the recovery of trapped oil.

The unaged cores D1 and D2 gave a tertiary recovery of 19.0 and 12.0 % of residual oil respectively while the aged core D5 flooded with same slug size produced 37.5% of residual oil when okro polymer solution was injected. While the unaged cores D1 and D2 yielded tertiary recovery of 15.00 and 11.5 % of residual oil respectively and the aged core D5 flooded with same slug size produced 25.0 % of residual during HPAM polymer slug injection.

The low salinity polymer slug injection performed at the end with higher concentration resulted in producing additional oil from the cores. However the performance of this injection varied because of different residual oil obtained after tertiary low salinity surfactant and polymer slugs injection.

XX. FURTHER WORK

Chemical analysis should be carried out on the effluent sample so as to afford an improved understanding on how the low salinity waterflooding works and the mechanisms behind it that lead to improved oil recovery. These analyses should comprise the concentration of the cations present in the effluent as well as the effluent pH, and these should be compared to the injected brine.

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.

Additionally, the optimization of the surfactant slug size that gives high oil recovery would necessitates more experiments with larger slug size at same surfactant concentration to determine the optimum slug in term of oil recovery. Effluent from the tertiary low salinity slugs injection should be analysed, as this will assist in identifying the factors that affect the performance of the surfactant injection such as retention.

Whilst the surfactant concentration was kept constant in this research, the surfactant solution should be made with different concentrations and tested for interfacial tension measurements to obtain the optimum concentration that give low IFT with smaller amount of surfactant used.

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APPENDIXES

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

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APPENDIX B

Table B1: 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 B2: 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 B3: 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 B4: 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