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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 on 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. Therefore, this study was conducted with the aim of carrying out core flooding experiments to evaluate the efficiency of the synergy of polymer-surfactant flooding and low salinity water for enhanced oil recovery in dolomite reservoirs using local and synthetic polymers. In this research, a certain local polymer okro (*Abelmoschus esculentus*), a commonly used synthetic polymer Partially Hydrolyzed Polyacrylamide (HPAM) and a surfactant, C12TAB (dodecyl trimethyl ammonium bromide in tertiary mode were evaluated in the laboratory at reservoir conditions in the presence of divalent ions and were used to determine and optimize its effectiveness in increasing oil production. The polymer slug was injected directly after the surfactant slug in order to maintain a stable displacement front behind the surfactant in all the six cores (aged and unaged); Comparison of tertiary low salinity surfactant and polymer slugs injection in aged and unaged cores - the low salinity surfactant and polymer slugs injection in aged and unaged cores was compared to determine the effect of wettability on the performance of tertiary recovery. The pressure profiles were determined to monitor the pressure behavior of the injected fluids in the cores. Also, the capillary number, *Nc* was calculated for both surfactant and the two polymer slugs (HPAM and Okro) for the trapped oil in the porous media after secondary waterflooding. The results of tertiary low salinity surfactant and polymer slugs injection in all six cores revealed that the slug injection has mobilized and produced different amount of oil from the cores using okro and HPAM polymers. Cores D1, D2, D3, D4, D5, and D6 gave 5.81, 4.70, 2.95, 6.00, 13.00 and 14.50 % OIIP respectively when okro was injected, while cores D1, D2, D3, D4, D5, and D6 gave 5.00, 4.12, 2.50, 5.87, 10.00, and 11.8 % OIIP respectively when HPAM polymer was injected. In the comparison of tertiary low salinity surfactant and polymer slugs injection in aged and unaged cores, the unaged cores D1 and D2 gave a tertiary recovery of 19.0 and 15.03 % of residual oil respectively while the aged core D5 flooded with same slug size produced 50.05 % of residual oil when okro polymer solution was injected. While the unaged cores D1 and D2 yielded tertiary recovery of 15.70 and 12.00 % of residual oil respectively and the aged core D5 flooded with same slug size produced 42.00 % of residual during HPAM polymer slug injection. 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. Generally, the pressure across the cores increased with surfactant and polymer slugs injection as oil production increased. The cores continued producing oil during low salinity injection until the oil production stopped. In this study, the tertiary slugs injection has reached a capillary number of 2.03 x 10^{-4} and 1.18 x 10^{-4} when okro and HPAM polymers were injected respectively, and this has decreased the residual oil saturation. 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.

Keywords:- *(Polymer, Surfactant, Natural Polymer, Water Flooding, Wettability Alteration, Low Salinity Water. Abelmoschus Esculentus (Okro), HPAM, C12TAB).*

I. INTRODUCTION

Oil and gas resources remain the world's major contributor to energy supply even with the recent energy generation from renewable sources. As global energy demand increases in juxtaposition to dwindling energy resources, maximizing oil recovery from previously under-exploited reserves becomes crucial to meet the ever increasing energy demand (Gbadamosi, *et al*., 2019). The processes of oil recovery are majorly in three stages namely: primary,

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secondary and tertiary (EOR) stages. After the application of primary and secondary oil recovery techniques, two-third of the original oil in place (OOIP) remains in the reservoir. This is either because the oil is trapped by capillary forces (residual oil) or bypassed in some other way. The bypassed oil arises due to reservoir heterogeneities or because of unfavorable mobility ratio between the aqueous and oleic phase. On the other hand, the residual oil is made up of discrete ganglia that are produced when a finger-like protrusion of the oleic mass forms a narrow neck by the combined effects of local pressure gradient and interfacial tension (IFT).

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 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 mechanisms 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 (Uzoho, 2019).

Low salinity waterflooding has received increasing attention. However, the increased oil recovery by low salinity waterflooding in most cases is very limited. Combining low salinity water 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) 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 used 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 tension 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 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 industry, the synthetic polymer polyacrylamide in hydrolyzed 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 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 battle 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 (Azza *et al*., 2023). Also, the surfactant C12TAB, has the capacity to reduce the interfacial tension between the crude oil and injected brine. With the application of EOR (Enhanced Oil Recovery) using Okro (*Abelmoschus esculentus*) as natural polymer and C12TAB as surfactant, additional oil will be recovered from the oil fields. Farmers can now venture into monumental cultivation of *Abelmoschus esculentus*, thereby leading to job creation and elating the nation’s local content. Also, this research work will translate into economic boom to the oil industries, more job creation, and increase in the nation's GDP (Gross Domestic Product).

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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 water flooding.

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 geologic 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 ($SO4^{2-}$) 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 $SO4^{2-}$ on the oil recovery from chalky limestone of low water wetness in a spontaneous imbibition process. The results clearly demonstrated that increasing $SO4^{2-}$ 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 suggested 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 via an intermediate, such as divalent ion calcium. Berg *et al.* (2009) provided direct experimental evidence 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 via 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 deflocculation 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 Y.

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 *et al.* (2020) 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

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^{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 27 bar was applied to the core and the pressure reading was checked for stabilization after 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 to saturate the core, the pump was set to hold a pressure of 5 bar which was 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.

$$\emptyset = {}^{V_P}/_{V_b} \quad X \quad 100 \qquad (1)$$

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.

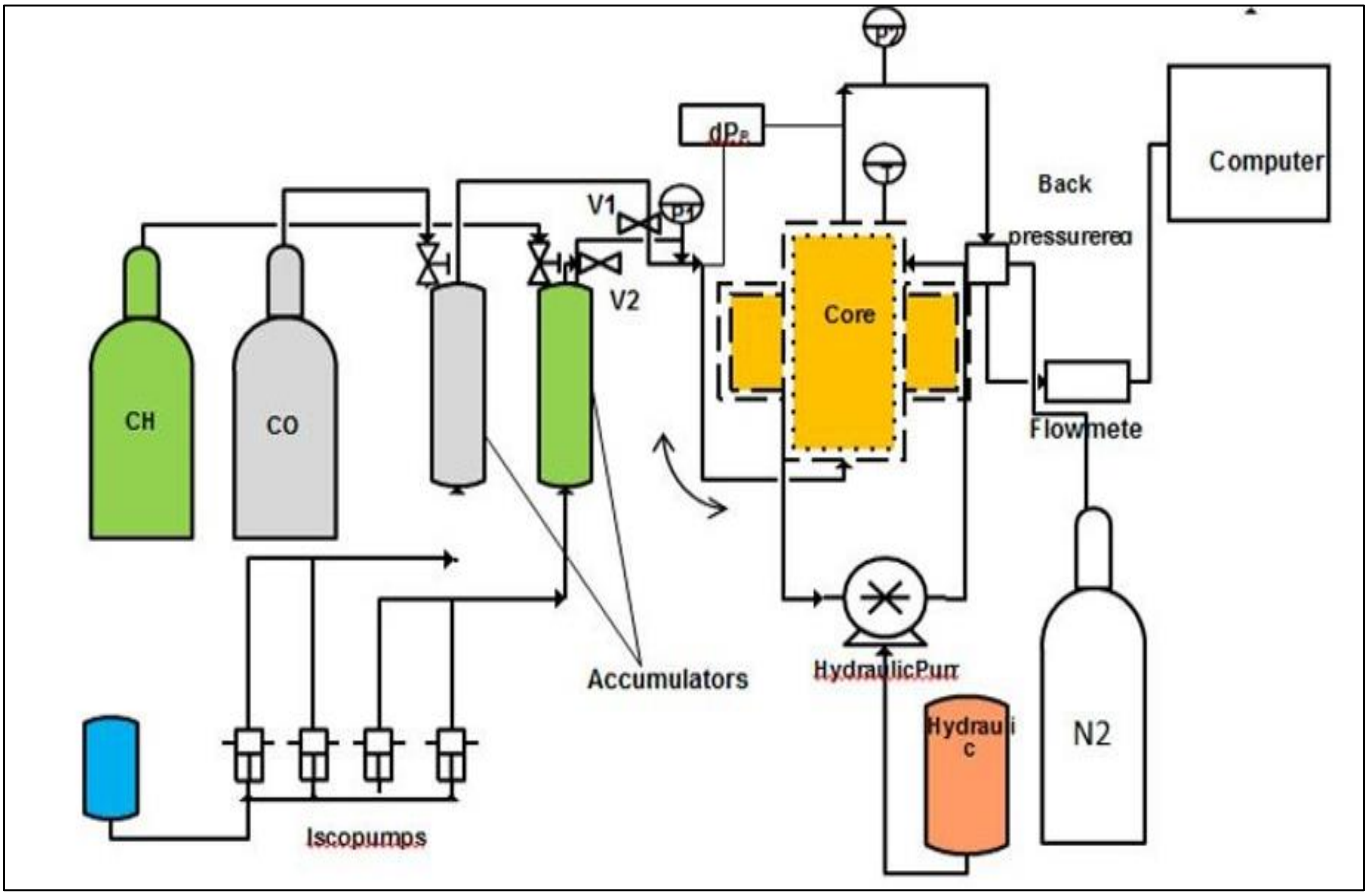

Fig. 1: Core Flooding Experimental Set-up

VI. EXPERIMENTAL DESCRIPTION

A. Permeability Measurements:

The permeability measurements were carried out using the Darcy's law equation and the experimental set-up is as shown in figure 1. 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 absolute, effective and relative permeability measurements were conducted before aging and after aging according to the procedure of Avinoam *et al.* (2019) with slight modification. Table 6 shows the initial parameters of the cores before flooding process.

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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 NaCl brine). 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.

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.

A. 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. The brine was placed on a magnetic stirrer to dissolve the salts properly and then filtered using 0.45μm 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	$MgCl_2.6H_2O$	2.375×10^{-2}	4.821
Calcium Chloride	$CaCl_2.2H_2O$	9.920×10^{-3}	1.458
Strontium Chloride	$SrCl_2.2H_2O$	8.689×10^{-5}	0.017
Magnesium Sulphate	$MgSO_4.7H_2O$	2.725×10^{-2}	6.704

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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 using anhydrous and hydrated salts in accordance with the composition indicated in the work of Kerunwa (2020) and the concentration is similar to the study of Cuenca and Serna (2021).

The synthetic sea water was diluted 22 times to make low salinity brine used for injection in the unaged cores according to the procedure of Saw and Mandal (2020) with little modification.

B. 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. The brine made was put on a magnetic stirrer to dissolve the salts properly and then filtered 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 Y 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 analyzed. 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 3: Chemical Composition of Low Salinity Water

Salt	**(g/kg solution)**	**Producer**
NaCl	3.000	Qualikems

Table 4: 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

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 filtered 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 2h 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 sample – natural polymer (*Abelmoschus esculentus*) was sliced, dried, pulverized and the powdered fruit was then passed through sieve no. #22 to obtain fine granules (Pratibha, 2020). A stock polymer solution with a concentration of 20,000 mg/l was prepared by dissolving 10g of powdered okro sample in 0.5 liter of distilled water at 60 °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 sieved out to obtain a clear solution. In determining the absorbance of the polymer at different concentrations, the stock polymer solution (20,000 mg/l) was further diluted to concentrations of 2200, 2000, 1600, 1200, 800, and 400 mg/l which was achieved by using 1.1, 1.0, 0.8, 0.6, 0.4 and 0.2 g of okro sample respectively in line with the procedure of Uzoho *et al*. (2022) with little adjustment.

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XI. PREPARATION OF POLYMER SOLUTION (HPAM)

The type of polymer used in this study is the partially hydrolyzed polyacrylamide (HPAM). A 5000 ppm stock solution was prepared by measuring 0.30 wt % NaCl brine in a beaker. The beaker was placed on a magnetic stirrer and the speed was set to 150 rpm at 26 ^{O}C to create a vortex which extends about 75 % towards the bottom and to ensure full hydration of the polymer powder. An amount of 3 g of HPAM polymer weighted in a tray was added to the brine by carefully sprinkling the polymer powder just below the vortex shoulder. The speed of the magnetic stirrer was reduced to the lowest speed where polymer particles still float in the solution and the beaker was covered with perforated parafilm. The solution was left on the magnetic stirrer overnight and then transferred to Duran flask with a cork and sealed with parafilm. The polymer stock solution (5000 ppm) was further diluted to concentrations of 1000, 600, 300 and 100 ppm; and then filtered using 40 µm filter and vacuum apparatus before using it for viscosity measurements and flooding process. This method was according to the procedures proposed by Lizcano *et al.* (2020) with slight modifications. In the work of Lizcano *et al.* (2020), a 5000 ppm stock solution using the magnetic stirrer vortex method was prepared, and from it, HPAM solutions of 2000, 1000, 500, 100, and 50 ppm were diluted, while in the current study, a 5000 ppm stock solution was prepared and diluted to concentrations of 1000, 600, 300 and 100 ppm; and then filtered using 40 µm filter and vacuum apparatus before using it for viscosity measurements and flooding process. 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 analyzed 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 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}.

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

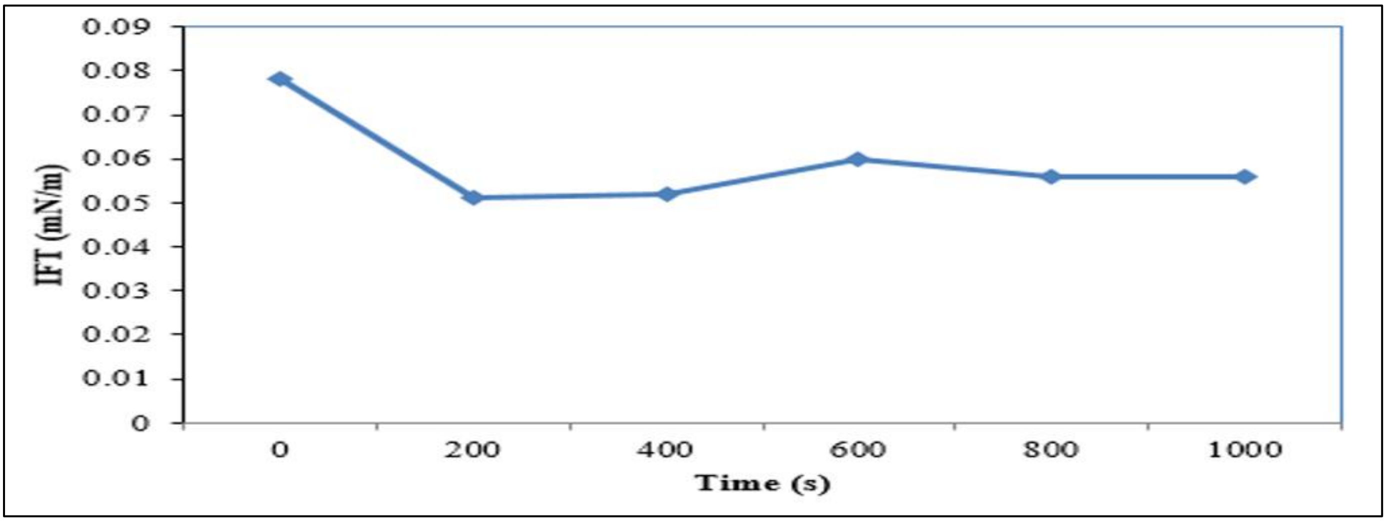

Fig 2: IFT Measurements of Equilibrated C12TAB Surfactant Solution with Diluted Crude Oil

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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 tomaintain 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**). The surfactant is a very efficient wettability modifier in carbonates, but does not decrease 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 7 and 8 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)	5.81	4.70	2.95	6.00	13.00	14.50
RF (% of Sor after LS)	19.00	15.03	18.50	34.05	50.05	63.00
Sor @ LS-S-P (% PV)	23.90	21.65	11.21	12.77	12.68	15.0

*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
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	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	4.12	2.50	5.87	10.00	11.80
RF (% of Sor after LS)	15.70	12.00	16.00	30.00	42.00	52.50
Sor @ LS-S-P (% PV)	27.95	24.15	11.94	14.80	15.74	17.50

* 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 Tables 7 and 8, core D3 was flooded by 0.3 PV of surfactant followed by 0.5 PV of polymer, and this showed low tertiary recovery of 2.95 % of OIIP compared with the other aged cores when okro was used as polymer,

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while 2.5 % 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. When core D4 was flooded by 0.5 PV of surfactant followed by 1 PV of polymer, the response was moderate and it yielded a tertiary recovery of 6.00 % of OIIP during okro polymer injection.

However, there was a consistent increase in the % oil recovery from Cores D3, D4 and D5 from 2.95 % to 14.50 % 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.

When cores D5 and D6 were flooded with 1 PV and 2 PV of surfactant respectively and then followed by 1 PV of polymer, the tertiary recovery were 13.0 and 14.5 % of OIIP from core D5 and D6 during okro polymer injection while the recoveries were 10.0 and 11.80 % of OIIP respectively when HPAM polymer was injected. This high recovery compared to the other two cores is due to increase in the surfactant slug size injected.

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 injected respectively. When okro was used as the polymer, the lowest tertiary recovery is 15.03 % of residual oil which is obtained by injecting 1 PV of surfactant in core D2.

The highest tertiary recovery is 63.0 % of residual oil obtained by injecting 2 PV of surfactant in core D6, while the value of 52.5% was obtained in core D6 when HPAM polymer solution was injected.as shown in Tables 7 and 8.

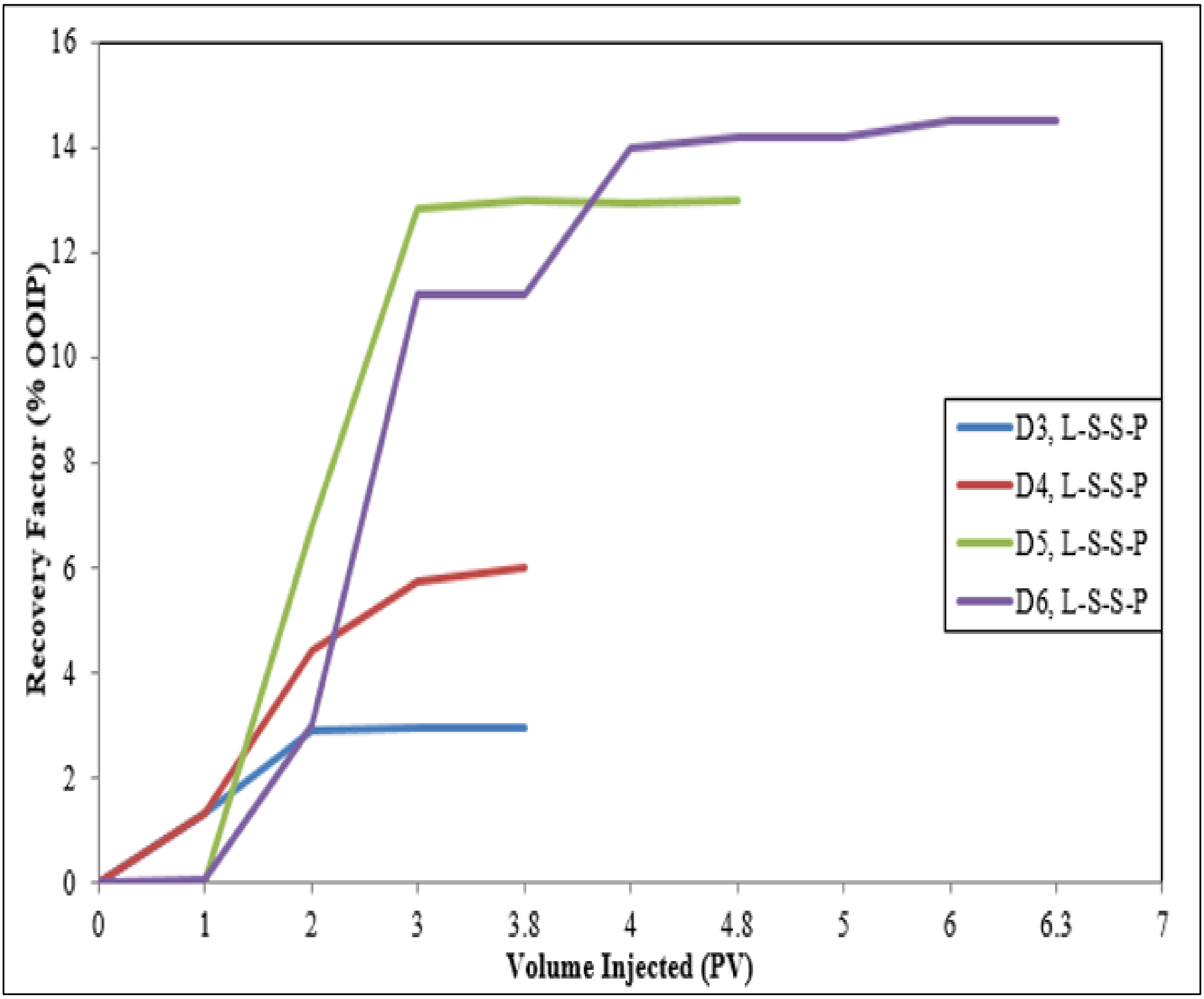

Fig 3: Oil Recovery of Tertiary Low Salinity Surfactant and Polymer Slugs Injection Based on % of OIIP Done in the Aged Cores Using Okro

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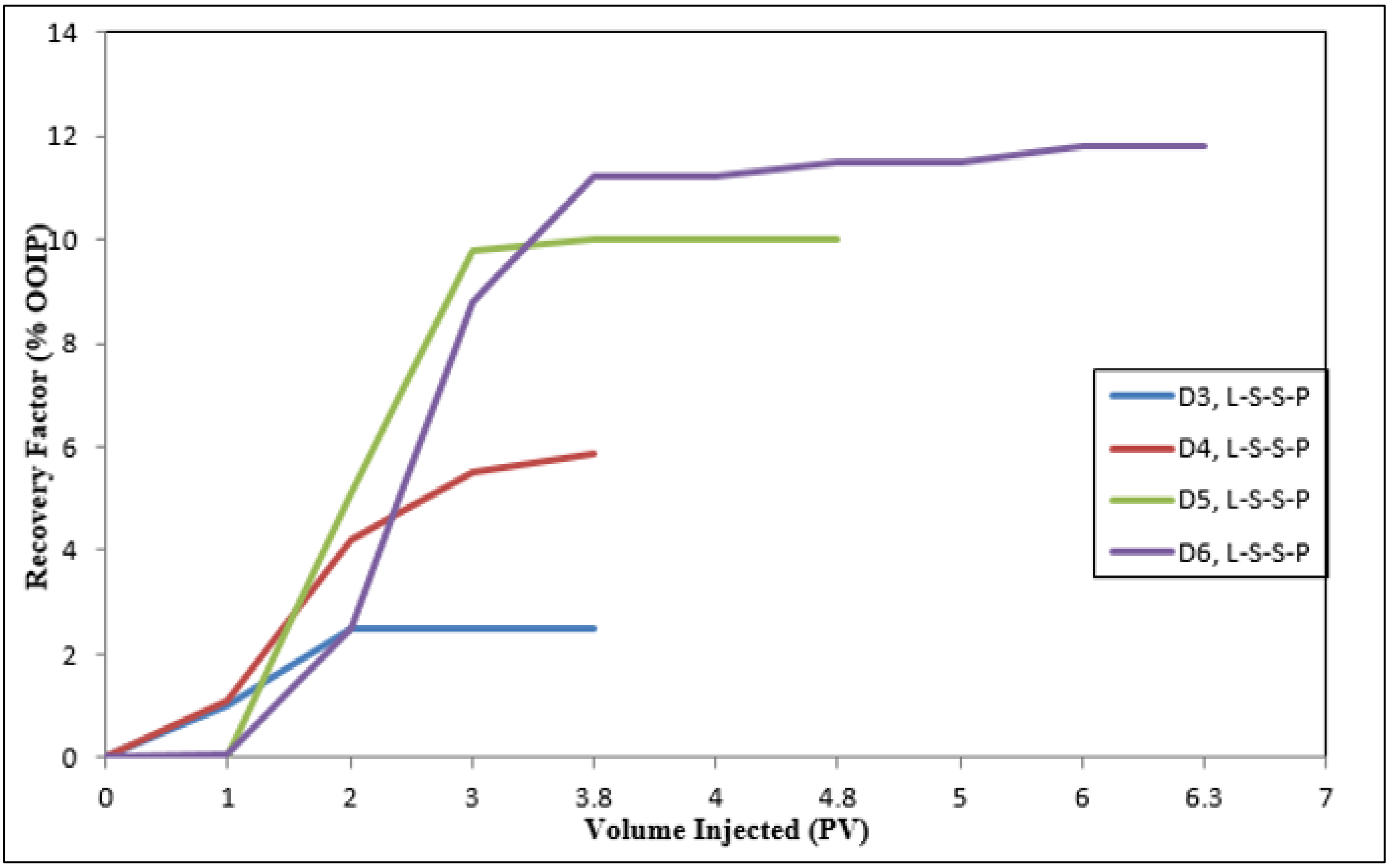

Fig 4: Oil Recovery of Tertiary Low Salinity Surfactant and Polymer Slugs Injection based on % of OIIP Done in the Aged Cores Using HPAM.

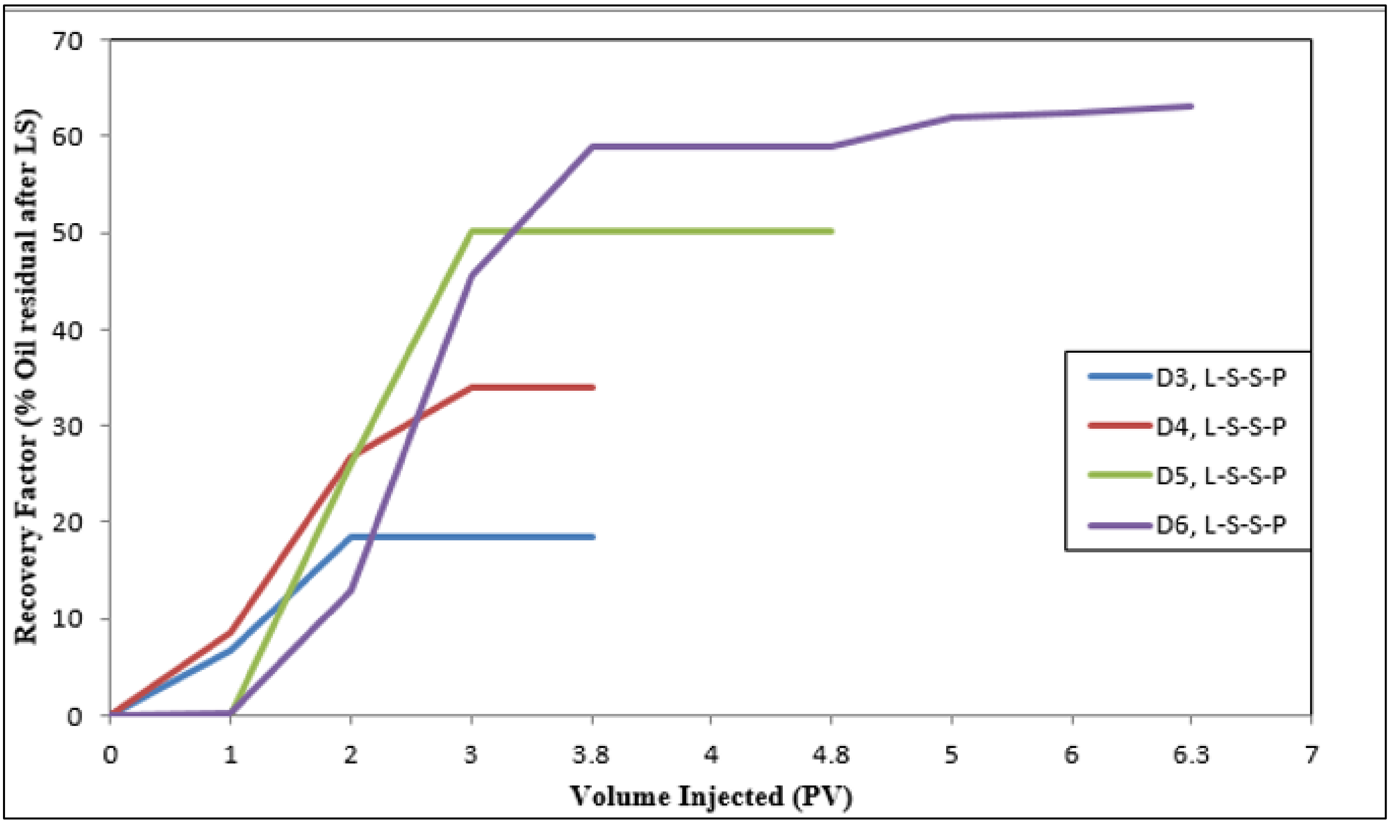

Fig. 5: Oil Recovery of Tertiary Low Salinity Surfactant and Polymer Slugs Injection Based on the Residual Oil After Secondary Low Salinity Water Flooding Using Okro.

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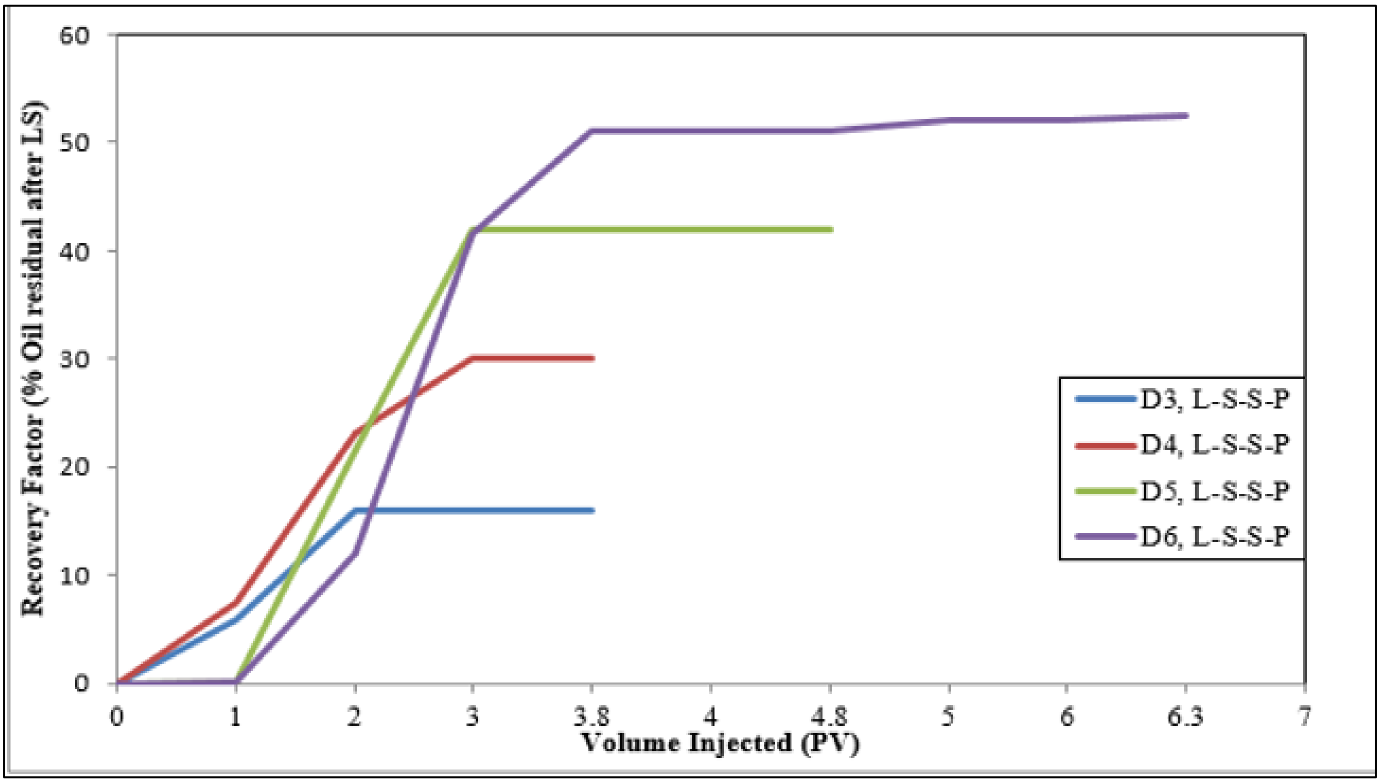

Fig 6: Oil Recovery of Tertiary Low Salinity Surfactant and Polymer Slugs Injection Based on the Residual Oil After Secondary Low Salinity Water Flooding Using HPAM

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. This was also corroborated by the previous studies conducted by Xiao *et al.* (2021), where they noted that oil recovery factor has increased by the increase of surfactant slug sizes from 0.05 PV to 0.15 PV. 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 Osama & Ahmad (2020). 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.

B. 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 cores D3 and D4. The pressure profile in all the aged cores increased until it reached the peak value during surfactant injection. Nevertheless the significant oil production from the core D6 started after 1.9 PV injection of surfactant. During okro polymer injection core D3 was flooded by 0.5 PV of polymer and the pressure profile was increasing without any sign of polymer breakthrough.

The pressure across the cores increased substantially because of ncreasing the viscosity of the injected brine when okro and HPAM polymer slugs were injected. When core D3 was flooded by 0.5 PV of polymer the pressure profile was increasing without any sign of polymer breakthrough during okro polymer injection. In the remaining cores D4, D5, and D6, which were flooded by 1 PV of polymer the pressure profile increased until the polymer breakthrough occurred and then stabilized or started to drop.

The breakthrough of the polymer occurred after 0.45 and 0.95 PV of polymer injection during okro and HPAM polymer injection in cores D4 and D6. All the cores showed an increase in oil production during the polymer flooding. Broadly speaking the polymer flooding improves the

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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 declined once the low salinity waterflooding started and then stabilized. The cores continued producing oil during low salinity injection until the oil production stopped.

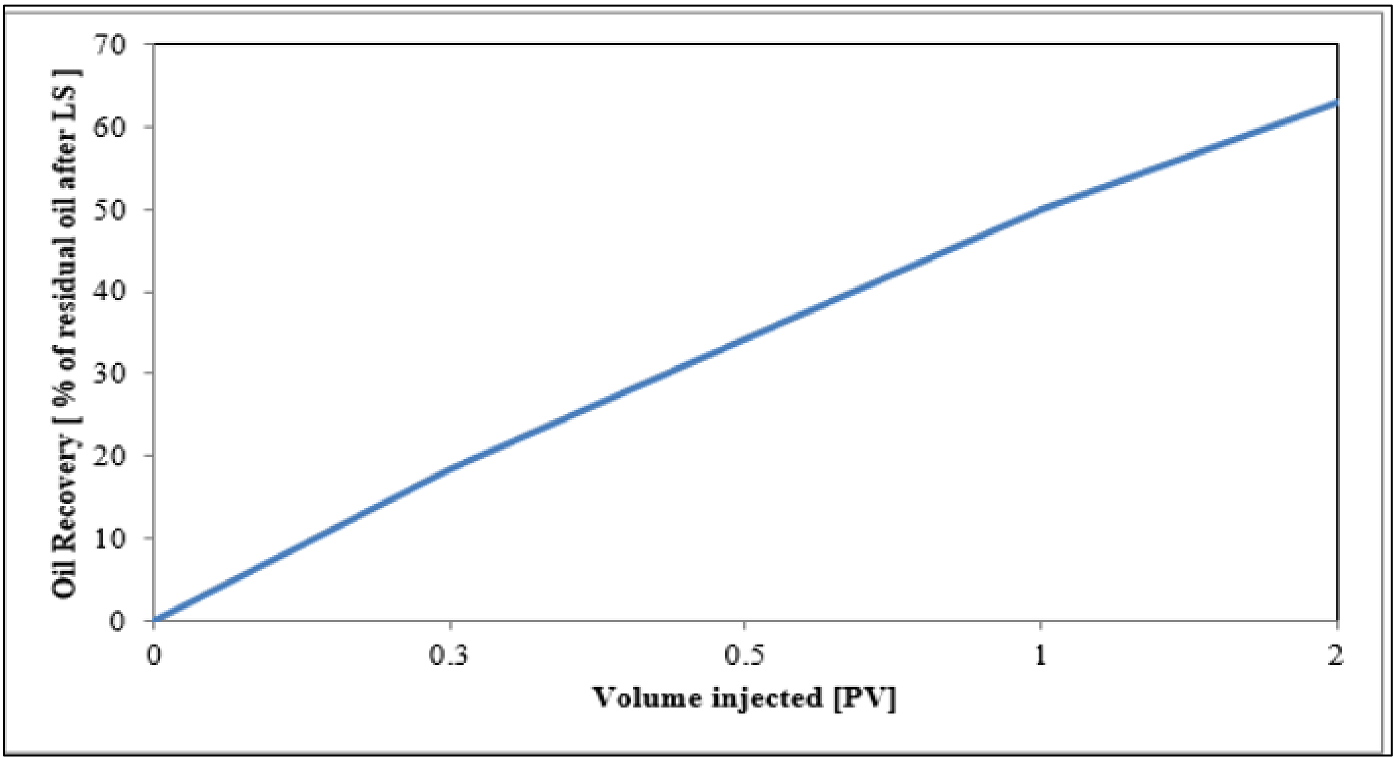

Fig 7: Relationship between Oil Recovery and Surfactant Slug Size Injected at Constant Surfactant Concentration Using Okro

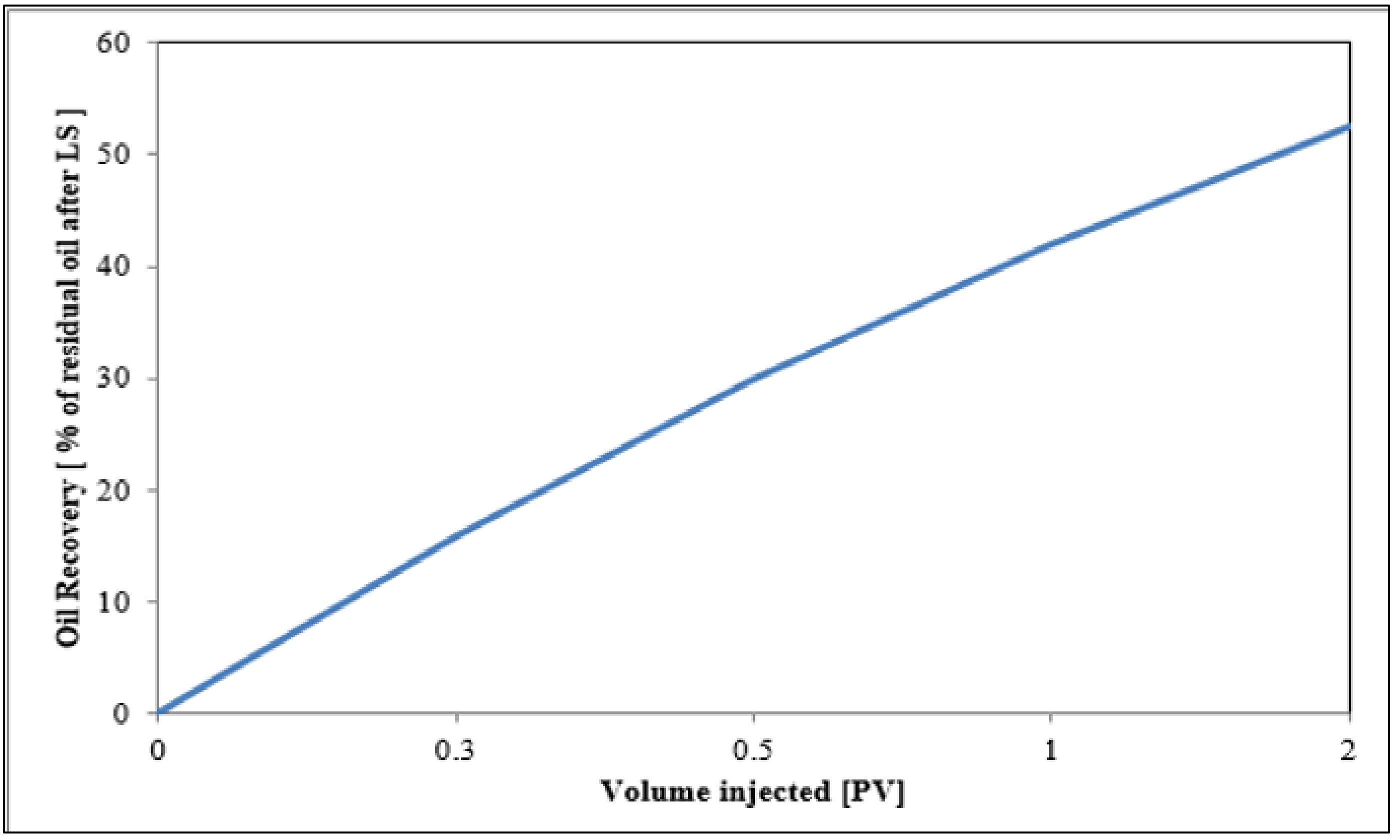

Fig 8: Relationship between Oil Recovery and Surfactant Slug Size Injected at Constant Surfactant Concentration using HPAM.

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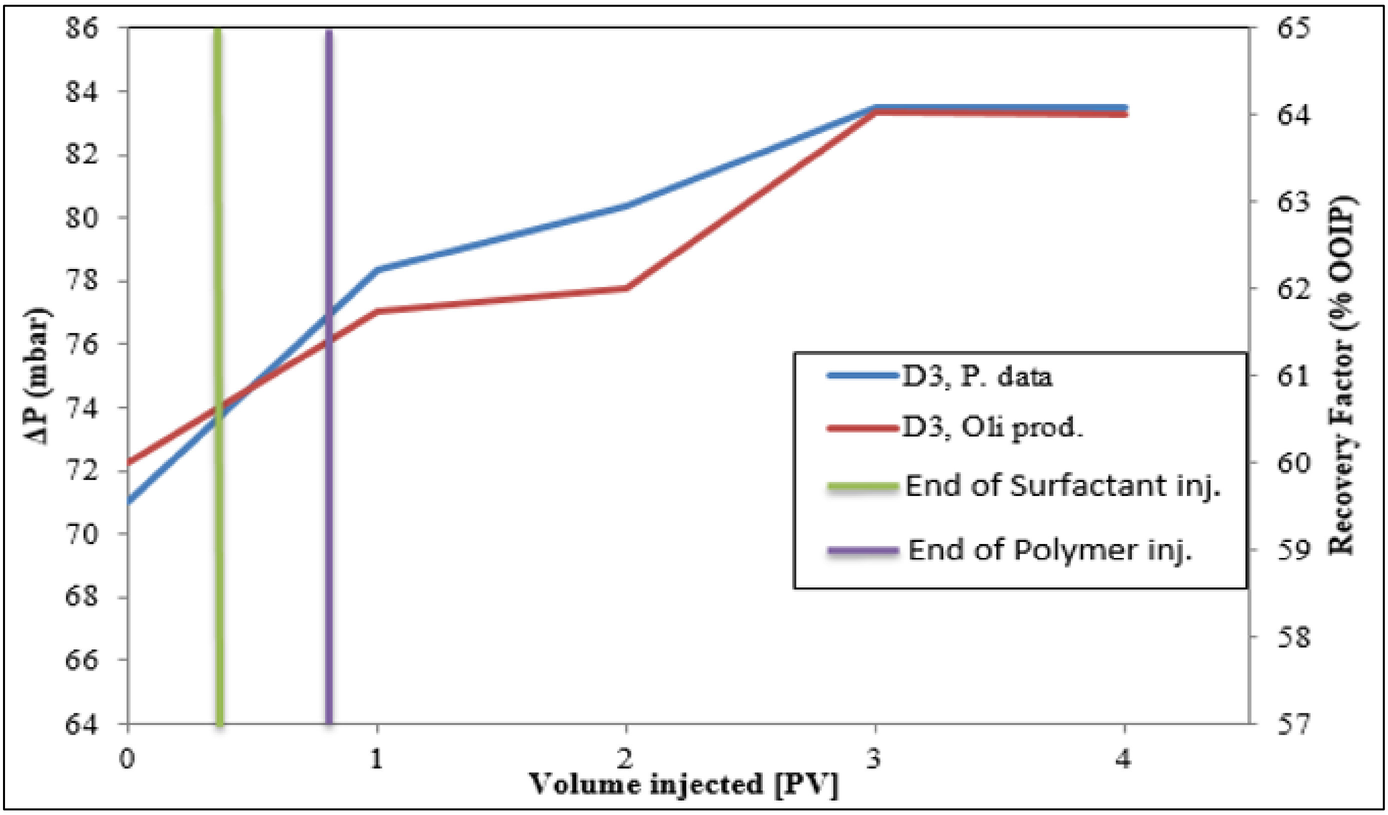

Fig 9: Pressure and Production Profile of LS-S-P Flooding in Core D3 using Okro

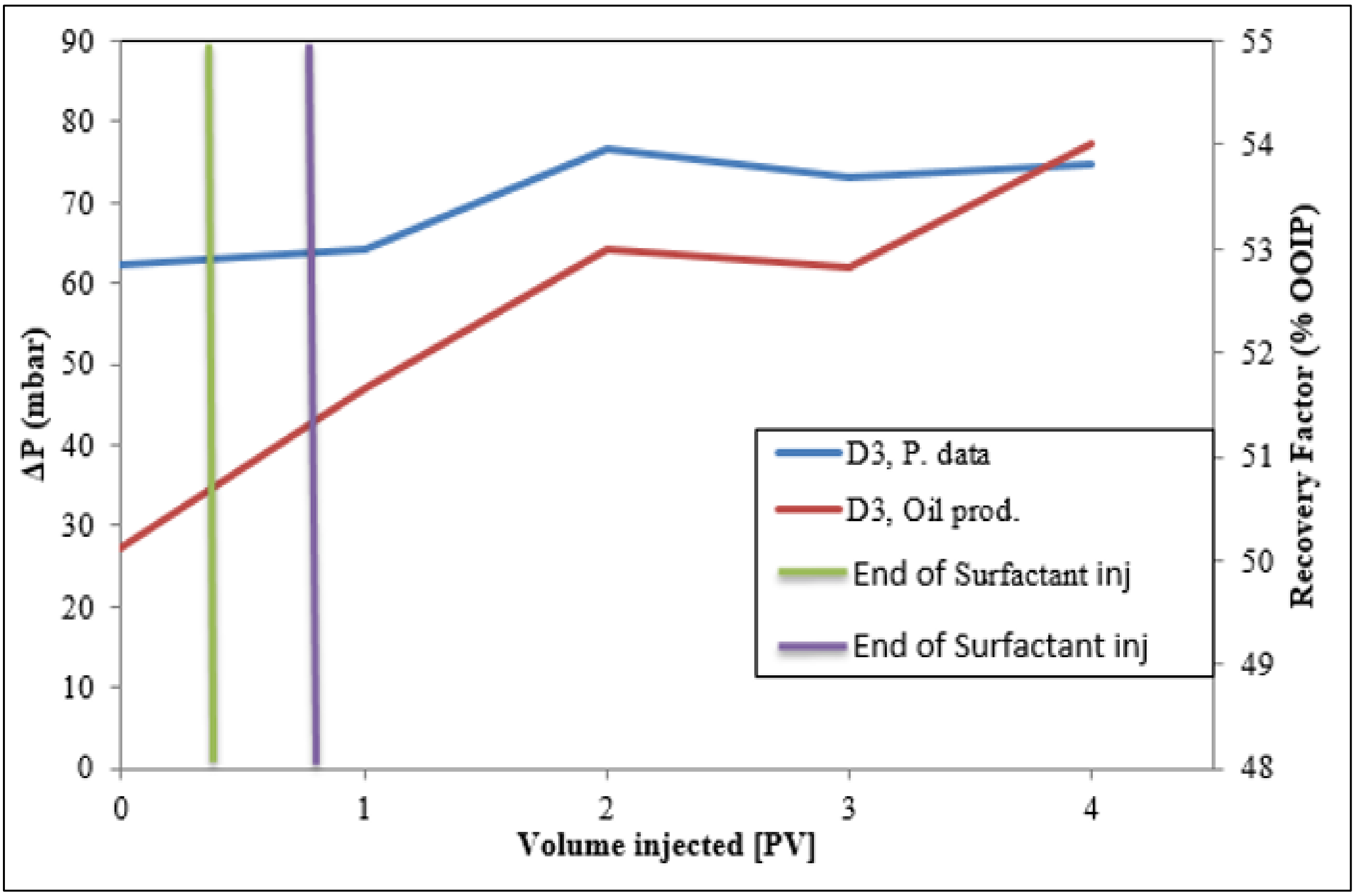

Fig. 10: Pressure and production profile of LS-S-P flooding in core D3 using HPAM.

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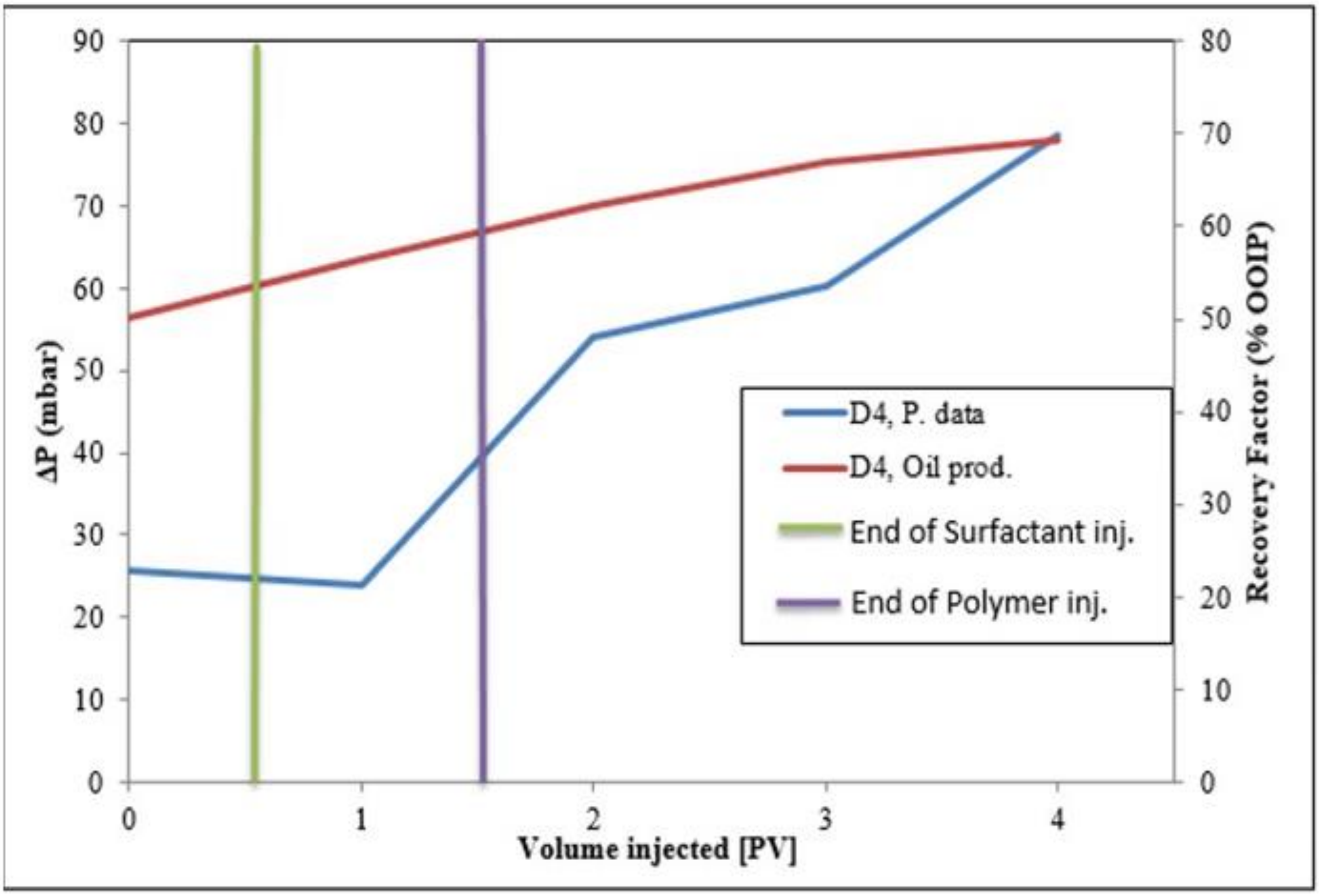

Fig 11: Pressure and Production Profile of LS-S-P Flooding in Core D4 Using Okro

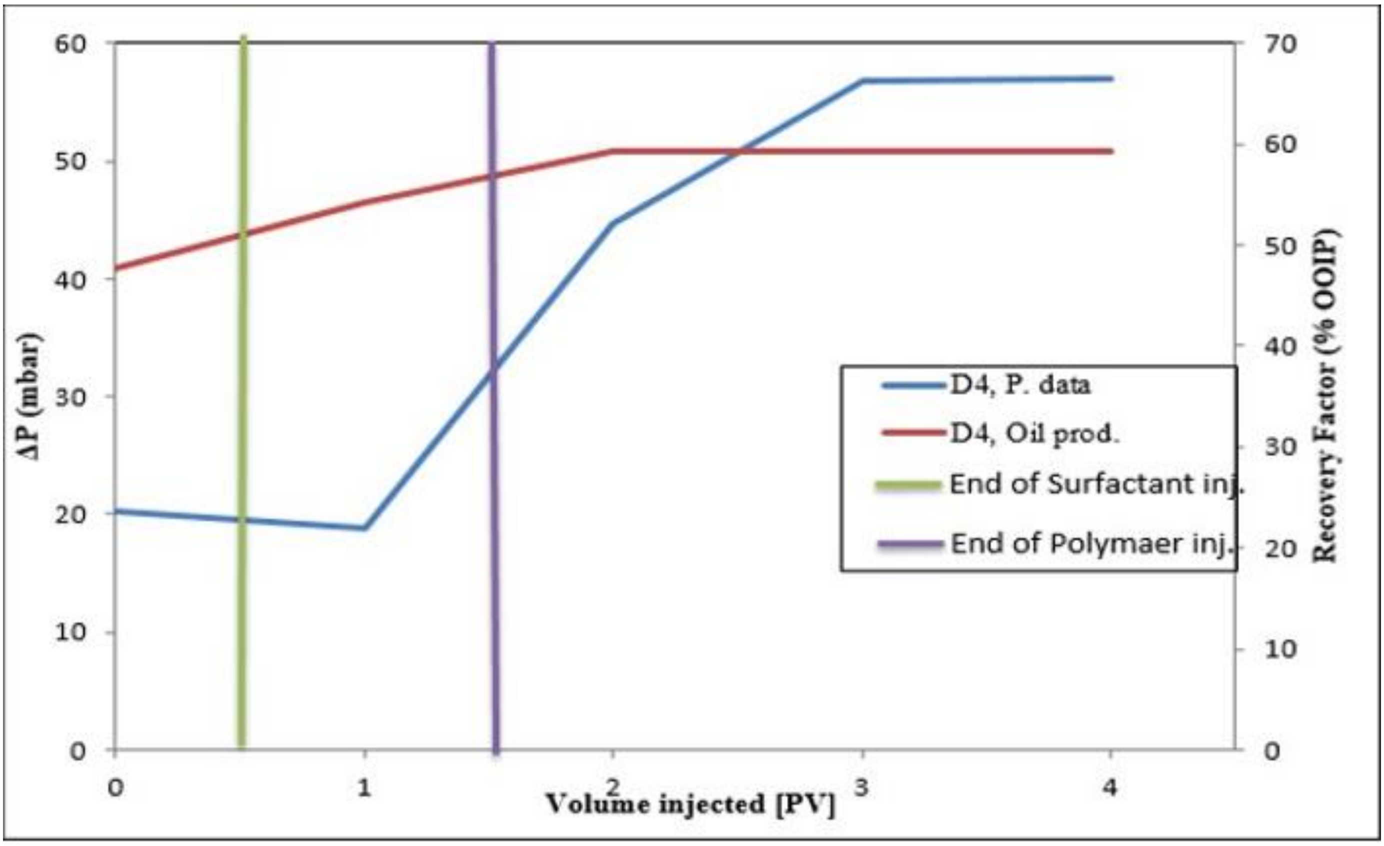

Fig 12: Pressure and Production Profile of LS-S-P Flooding in Core D4 using HPAM

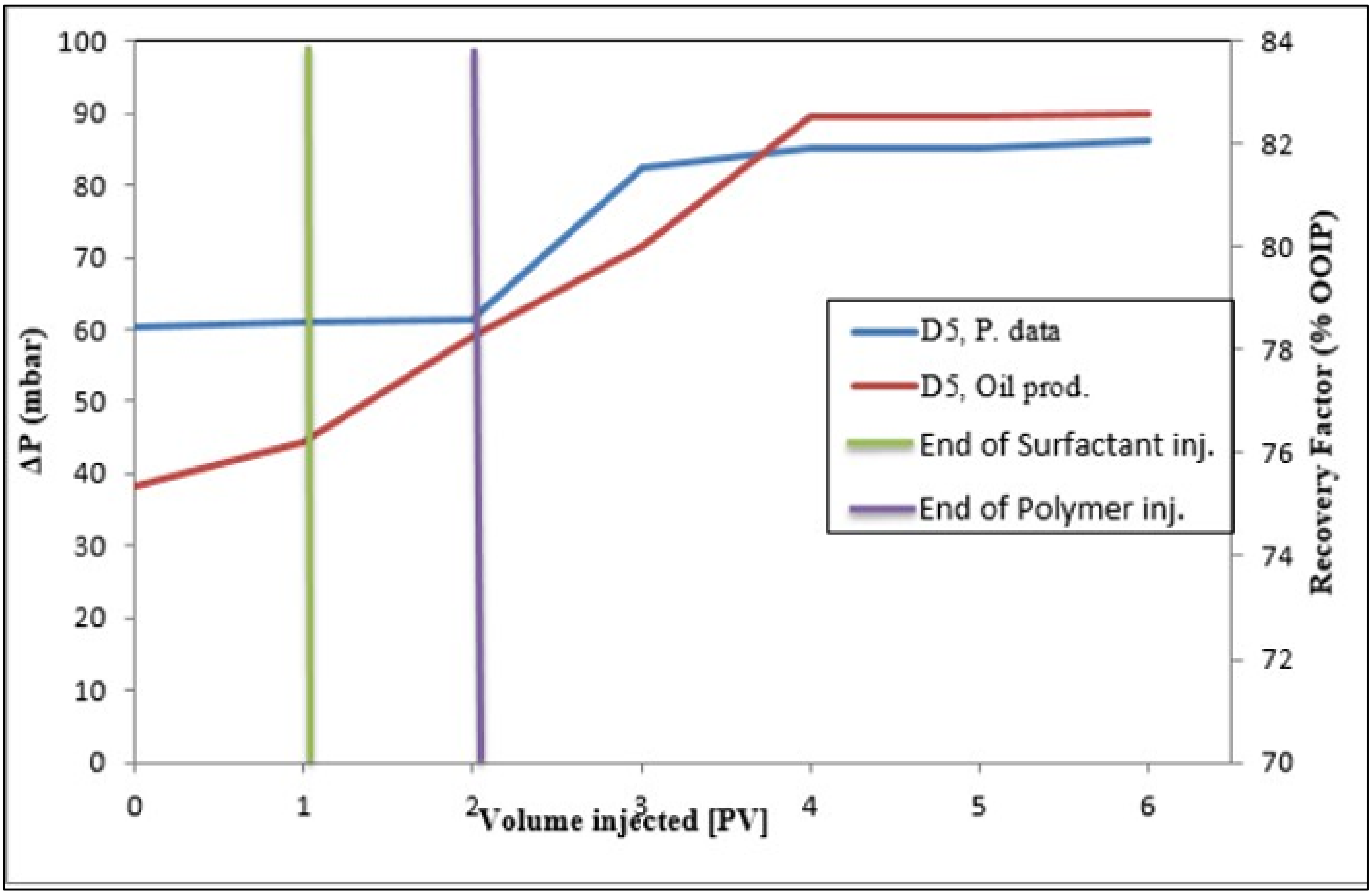

Fig 13: Pressure and Production Profile of LS-S-P Flooding in Core D5 using okro.

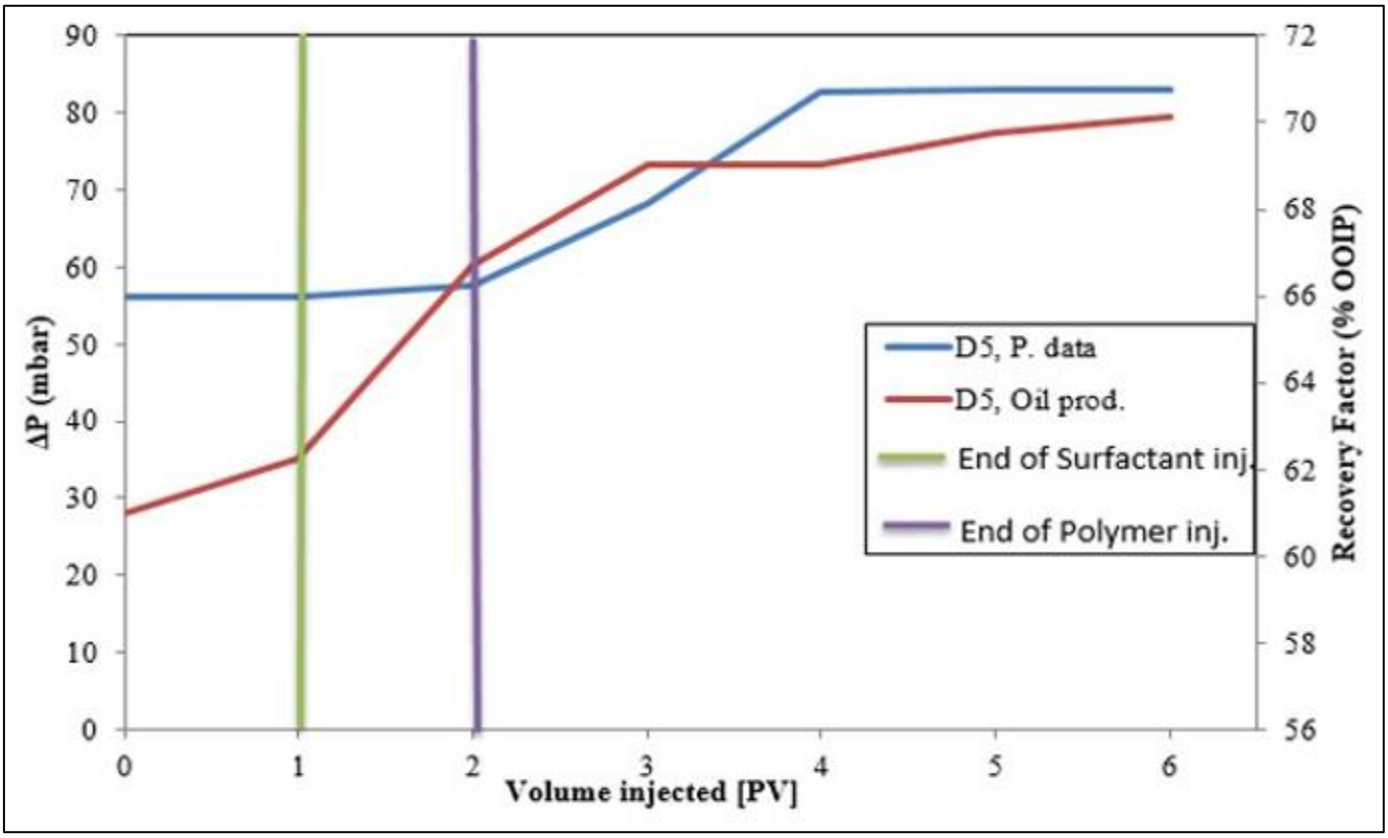

Fig 14: Pressure and Production Profile of LS-S-P Flooding in Core D5 using HPAM.

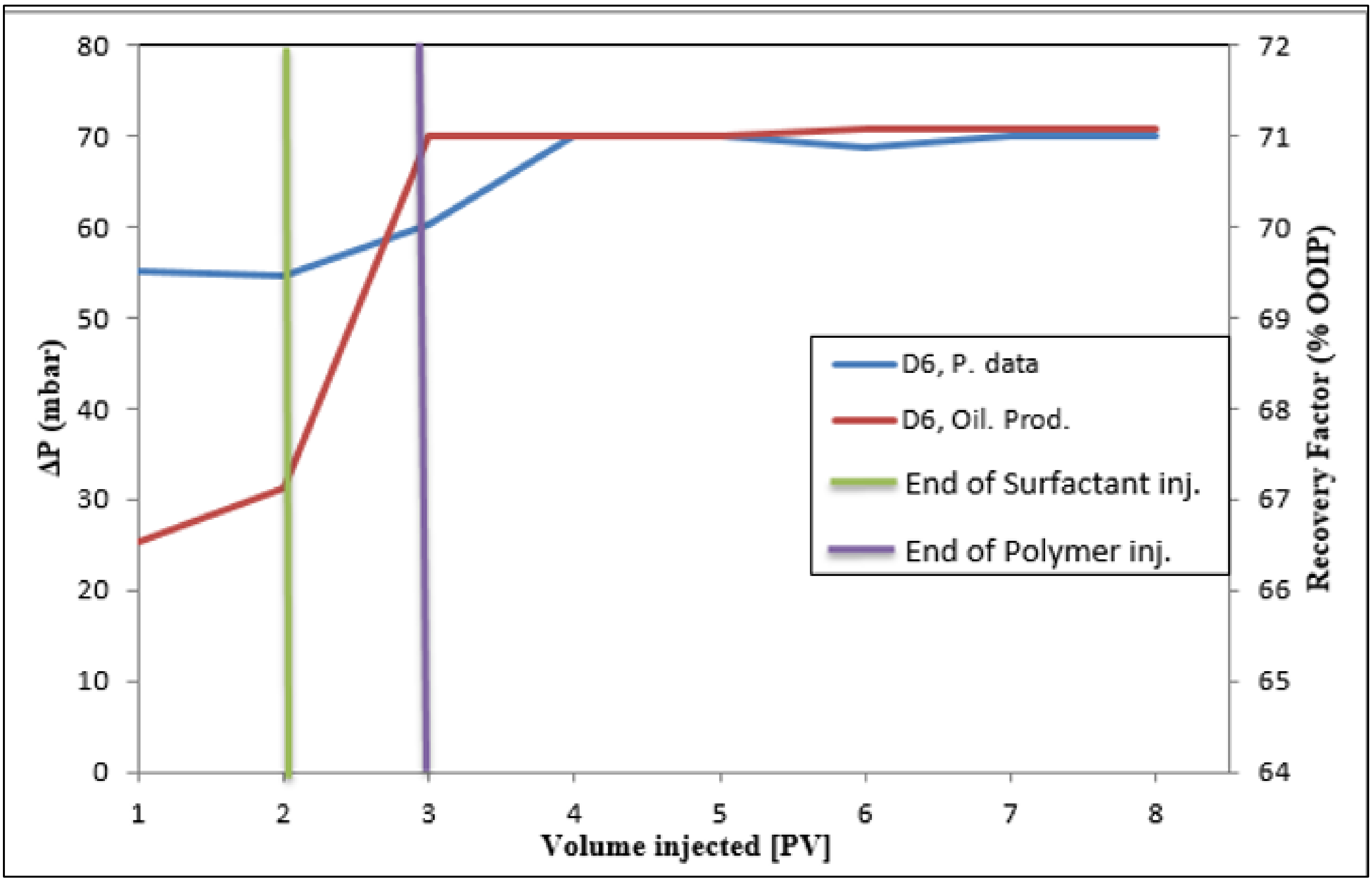

Fig 15: Pressure and Production Profile of LS-S-P Flooding in Core D6 using okro.

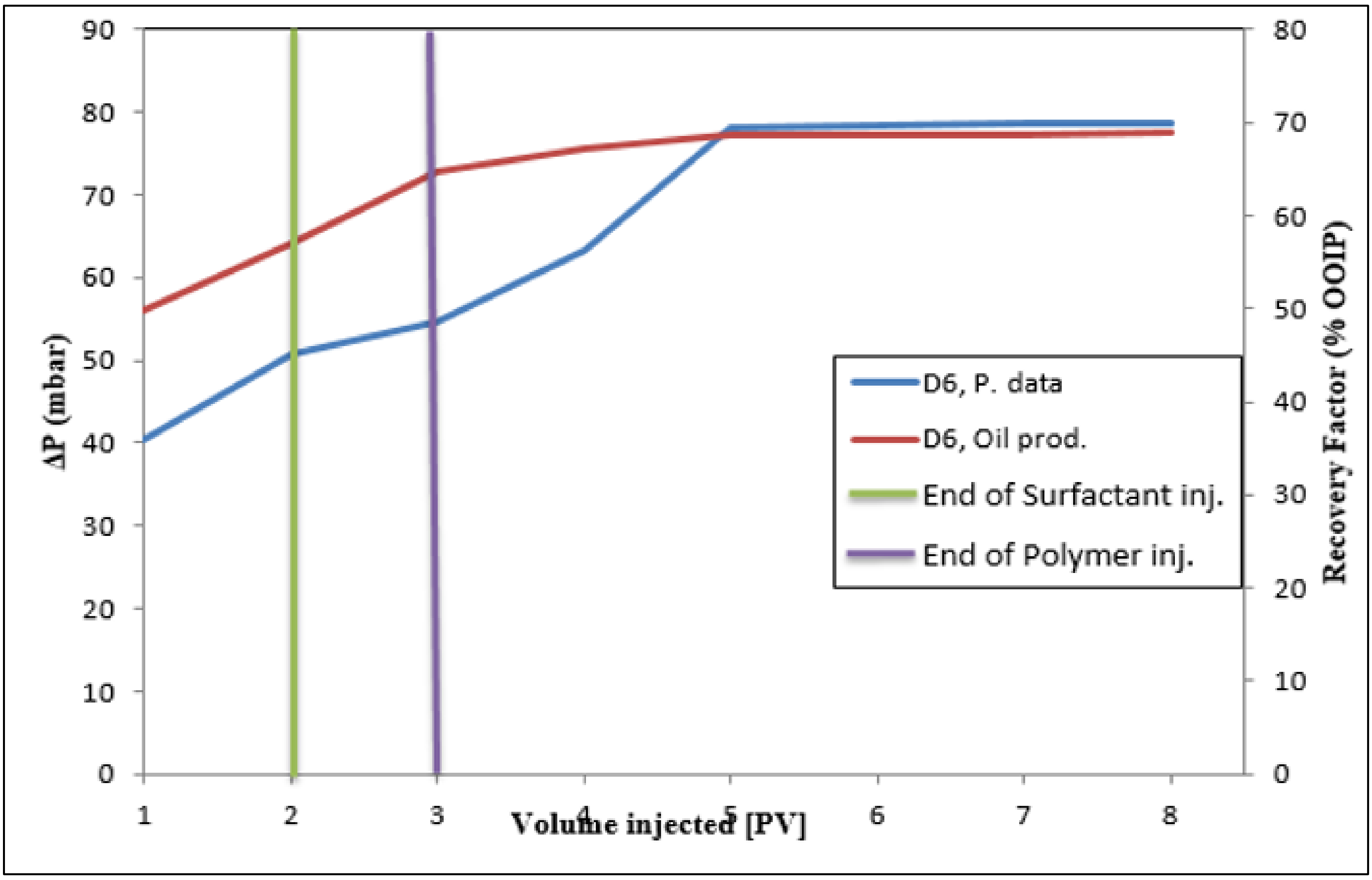

Fig. 16: Pressure and Production Profile of LS-S-P Flooding in Core D6 using HPAM

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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. The 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.

From the figures below, 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 50.05 % and 42.00 % 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 15.03 % of residual oil for okro, and 15.70 and 12.00 % 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 consequence 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.

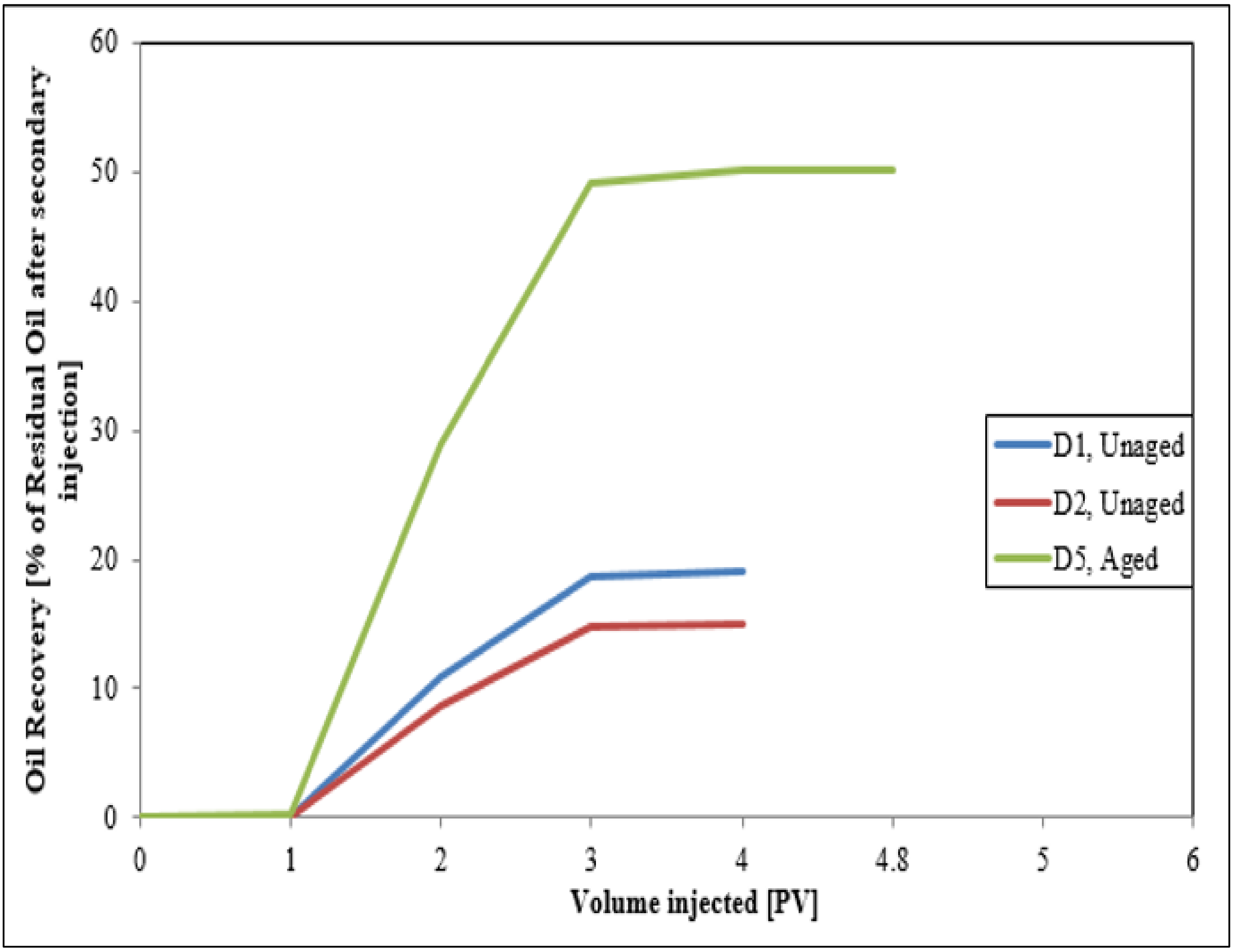

Fig 17: Recovery Profiles of Cores D1 (Unaged), D2 (Unaged), and D5 (Aged) Using Okro

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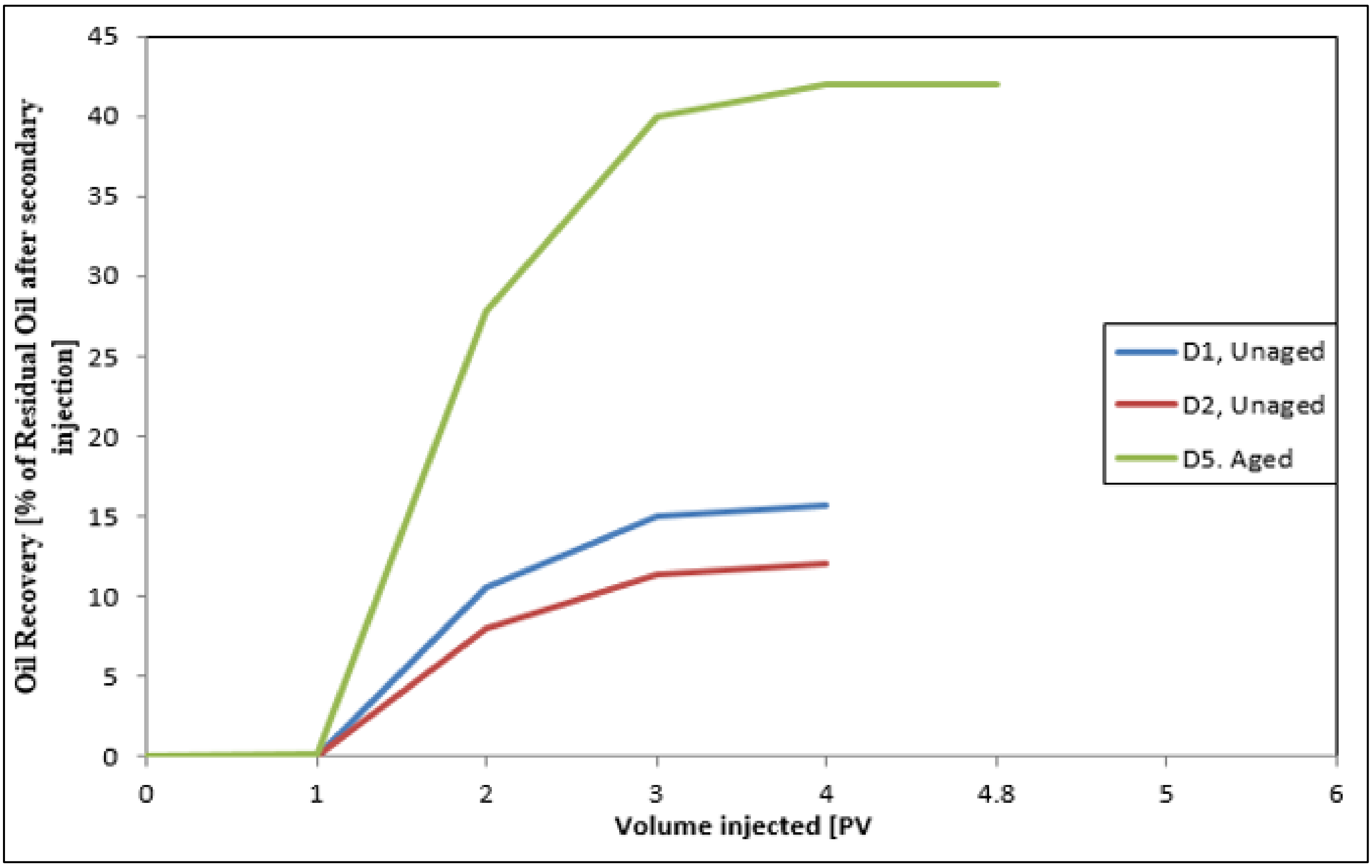

Fig 18: Recovery Profiles of Cores D1 (Unaged), D2 (Unaged), and D5 (Aged) Using HPAM.

➢ *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:

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

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 **9**.

Table 9: 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	4.85×10^{-6}	4.85×10^{-6}	4.88×10^{-6}	4.87×10^{-6}	4.85×10^{-6}	4.85×10^{-6}
Nc of 300 ppm HPAM Polymer	1.18×10^{-4}	1.18×10^{-4}	1.18×10^{-4}	1.18×10^{-4}	1.18×10^{-4}	1.18×10^{-4}
Nc of 600 ppm HPAM Polymer	1.62×10^{-4}	1.62×10^{-4}	1.63×10^{-4}	1.62×10^{-4}	1.62×10^{-4}	1.63×10^{-4}
Nc of 300 ppm Okro Polymer	2.00×10^{-4}	2.00×10^{-4}	2.04×10^{-4}	2.00×10^{-4}	2.00×10^{-4}	2.03×10^{-4}
Nc of 600 ppm Okro Polymer	2.57×10^{-4}	2.57×10^{-4}	2.50×10^{-4}	2.57×10^{-4}	2.57×10^{-4}	2.50×10^{-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 9). The capillary force is responsible for trapping oil in the porous media after secondary waterflooding. It has been shown that the capillary number and ROS are related such that a greater capillary number leads to a lower ROS (Zivar *et al.*, 2021). 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.

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XVI. SUMMARY

It was expected 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 injected were 0.3, 0.5, 1, and 2 PV and the recovery increased from 15.03 % to 63.0 % and from 12.0 % to 52.5 % 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 15.03 % of residual oil respectively while the aged core D5 which flooded with same slugs size gave 50.05 % of residual oil during okro polymer injection. Also when HPAM polymer was injected the unaged cores D1 and D2 gave a tertiary recovery of 15.07 and 12.0 % of residual oil respectively while the aged core D5 which flooded with same slugs size gave 42.0 % of residual oil.

Figures 19 and 20 present a schematic of the CDC (Capillary Desaturation Curve) (adapted from Mirzaie *et al.*,2019), 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. Siyal *et al.* (2021) noted that the critical capillary number for mixed-wet rocks is one order of magnitude higher than water-wet rocks. They reported a critical capillary number of 10^{-6} for water-wet rocks. Zivar *et al.* (2021) showed that the capillary number and ROS are related such that a greater capillary number leads to a lower ROS. They concluded that the most practical technique of increasing the capillary number is the reduction of the IFT (Interfacial tension). 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 their studies, Mirzaie *et al.* (2019) acknowledged the use of capillary number for mobilization and capillary number for prevention of entrapment, (NC)c and (NC)max respectively during core flooding. They also observed that in principal, the (NC)c is much higher than the capillary number at normal water flooding conditions. The residual saturations start to decrease at the critical capillary number as the capillary number is increased, and cannot be decreased further at (NC)max.

In this research, the tertiary slugs injection has reached a capillary number of 2.03 x 10^{-4} and 1.18 x $10^{-4}$when okro and HPAM polymers were injected respectively, and this has decreased the residual oil saturation (see tables 10 and 11). The obtained results were compared with the CDC measured by the work of Mirzaie *et al.* (2019) 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 / Sor-LS in the range of 0.47 and 0.58 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. This suggests that more surfactant is needed to be injected in order to gratify surfactant retention and attain lower residual oil saturation.

Cores D5 and D6 which flooded by 1 and 2 PV of surfactant respectively gave a reasonable decrease in the residual oil saturation which are consistent with the CDC curve. However injection of 2 PV of surfactant resulted in higher tertiary recovery.

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 10: 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	10.01
Sor-LS-S-P / Sor-LS	0.75	0.68	0.71	0.68	0.62	0.47
NC of LS-S-P	2.00×10^{-4}	2.00×10^{-4}	2.04×10^{-4}	2.00×10^{-4}	2.00×10^{-4}	2.03×10^{-4}

*Unaged Cores

Table 11: Parameters of Tertiary Slugs Injection in the Cores using HPAM.

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 (HPAM)	1	1	0.5	1	1	1
Sor@ LS-S-P (% PV)	27.95	24.15	11.94	15.74	14.80	12.50
Sor-LS-S-P / Sor-LS	0.88	0.76	0.76	0.84	0.73	0.58
NC of LS-S-P	1.18×10^{-4}	1.18×10^{-4}	1.18×10^{-4}	1.18×10^{-4}	1.18×10^{-4}	1.18×10^{-4}

*Unaged Cores

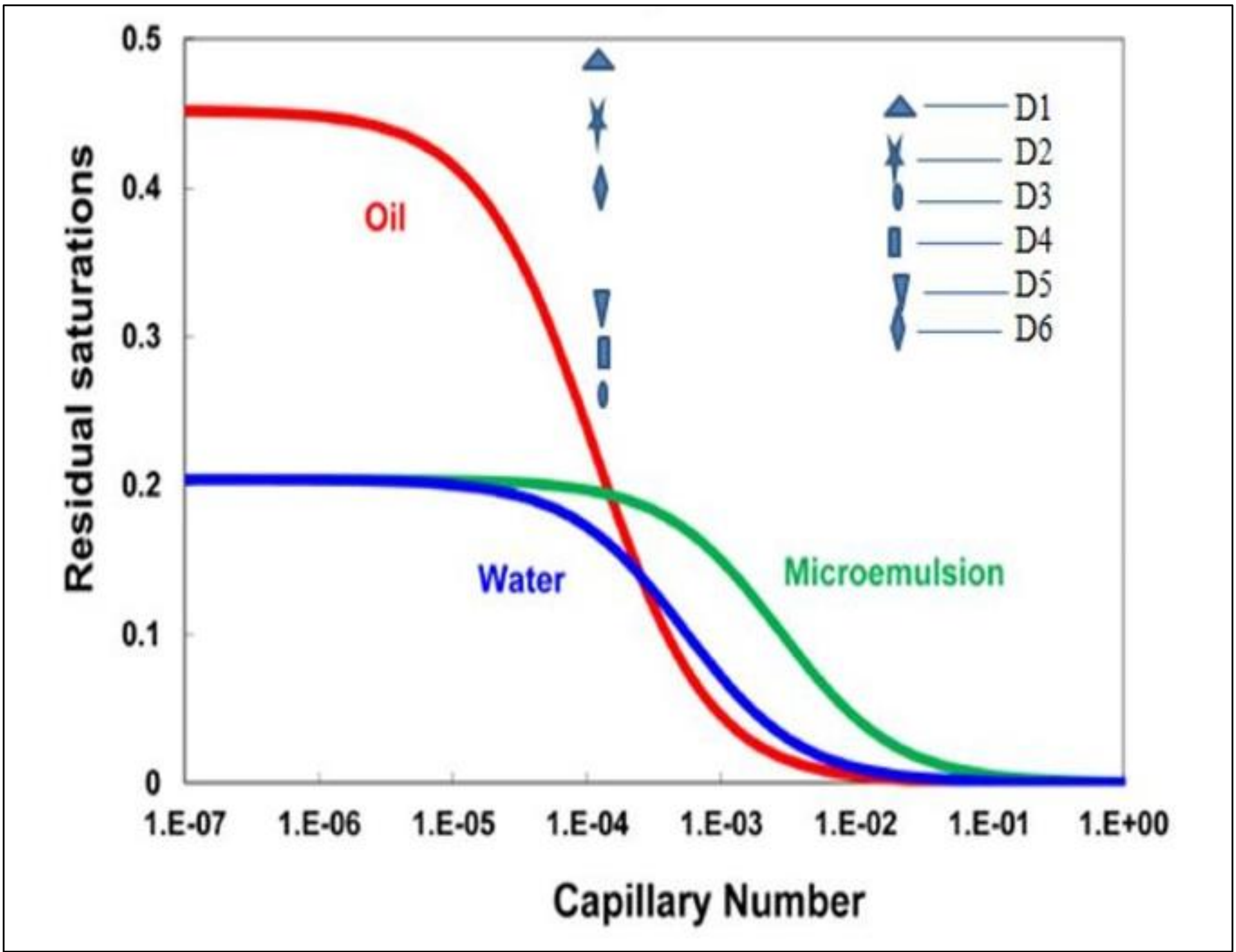

Fig 19: Schematic of the Capillary Desaturation Curve (Adapted from Mirzaie *et al*., 2019) for the Six Dolomite Cores when okro Polymer Solution was Injected.

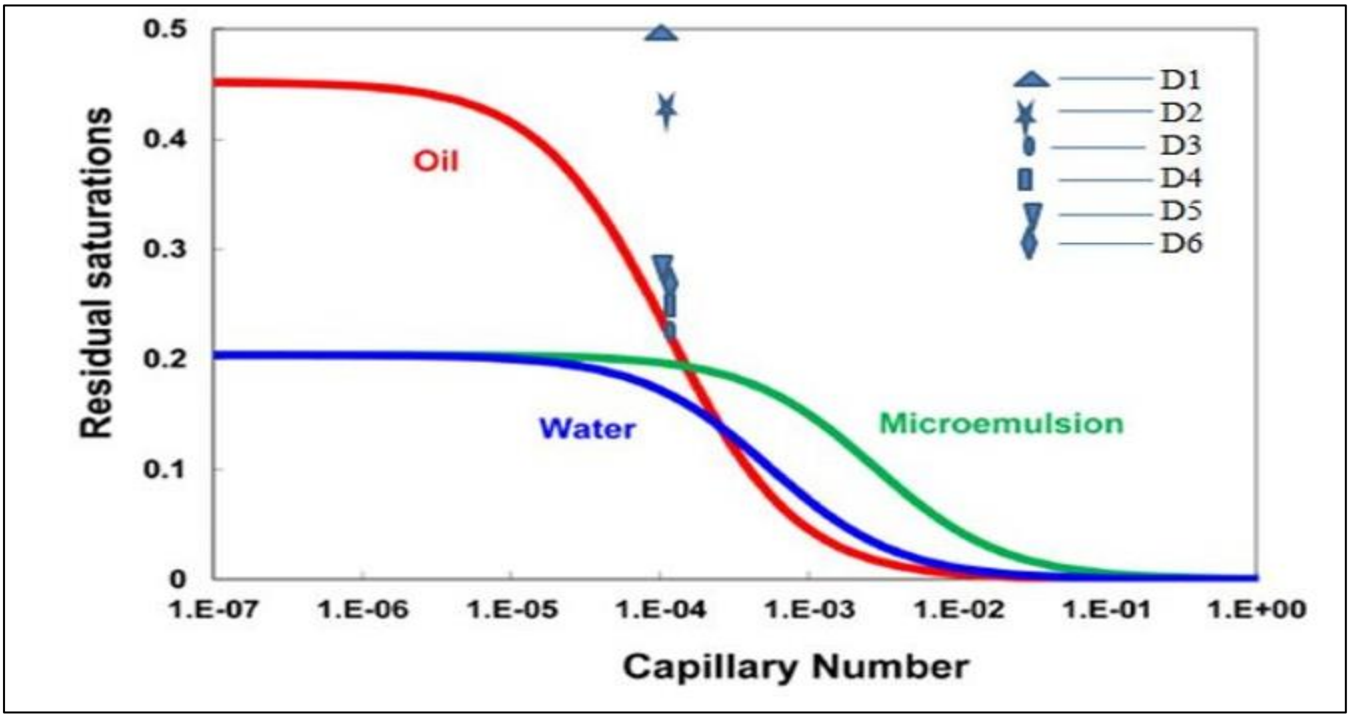

Fig 20: Schematic of the Capillary Desaturation Curve (Adapted from Mirzaie *et al*., 2019) for the Six Dolomite Cores when HPAM Polymer Solution was Injected

XVII. CONCLUSION

Core flooding experiments have been conducted 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 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. 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.

Tertiary low salinity surfactant and polymer slugs injection was conducted in all the six cores using HPAM and okro polymers. Cores D1, D2, D3, D4, D5, and D6 gave 5.81, 4.70, 2.95, 6.00, 13.00 and 14.50 % OIIP respectively when okro was injected, while cores D1, D2, D3, D4, D5, and D6 gave 5.00, 4.12, 2.50, 5.87, 10.00, and 11.8 % OIIP respectively when HPAM polymer was injected.

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. The capillary number achieved by tertiary slugs injection was high enough to mobilize a significant amount of residual oil after water flooding. 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 15.03 % of residual oil respectively while the aged core D5 flooded with same slug size produced 50.05 % of residual oil when okro polymer solution was injected. While the unaged cores D1 and D2 yielded tertiary recovery of 15.70 and 12.00 % of residual oil respectively and the aged core D5 flooded with same slug size produced 42.00 % of residual during HPAM polymer slug injection.

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XVIII. 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 analyzed, 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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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, mg/l (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