WJAETS

World Journal of Advanced Engineering Technology and Sciences

World Journal Series INDIA

(RESEARCH ARTICLE)

Check for updates

Spontaneous imbibition and core flooding analysis of pH adjusted alkali and surfactant system in high salinity sandstone reservoir

Amalate Ann Obuebite [1, 2, *], Digieneni Yousuo [1] and Obumneme Okwonna [2, 3]

[1] Department of Petroleum Engineering, Niger Delta University, PMB 071, Wilberforce Island, Bayelsa State, Nigeria.
[2] Africa Centre of Excellence for Oilfield Chemicals Research (ACE-CEFOR), University of Port Harcourt, PMB 5323, Port Harcourt, Rivers State, Nigeria.
[3] Department of Chemical Engineering, University of Port Harcourt, PMB 5323, Port Harcourt, Nigeria.

Abstract

Some of the limitations of a cost-effective alkaline surfactant flooding method include chemical precipitation and other formation damage issue which has greatly affected the application of chemical flooding especially in high salinity reservoirs. This study ascertains the chelating attributes of Ethylene-diamine-tetracetic Acid-(EDTA/NaOH), investigates the ability of EDTA/NaOH and an anionic surfactant to improve oil recovery in heavy oil sandstone formation. Petrophysical analysis of the crude oil and core samples were performed. Hard brine at 5.1% optimal salinity and 0.2 wt.% surfactant imbibition were performed on the sandstone core plug for over 240 hrs. and the volume of oil recovered was determined using Amott imbibition cells. Sandstone core flooding test was thereafter conducted using the alkaline -surfactant solution at optimal salinity. Spontaneous imbibition results showed that surfactant imbibition (26.6%) produced a higher recovery than hard brine recovery (18.7%) after 240hrs. Sandstone core flooding results showed increased heavy oil recovery of 37% OOIP with alkaline-surfactant solution and additional 8% recovery was achieved by performing a final chase brine flooding, totaling 45% indicating that traces of alkaline-surfactant, in the core, aided the final imbibition process. This study underpins and complements several research solutions concerned with flooding in harsh oilfield terrains, thus making the overall process cost-effective and less time- consuming.

Keywords: Chemical flooding; Imbibition process; Solubilization; Salinity; Divalent ions

1. Introduction

The huge contribution of fossil fuels to emission of greenhouse gases especially carbon dioxide and its adverse effect on the climate has resulted in a gradual shift of the global energy market to renewable energy sources [1], however, due to the ever-increasing energy demand globally, the non-renewable energy sources such as oil and gas will still constitute a huge percentage (74%) of the global energy mix by 2050 [2], this calls for an additional oil recovery from green fields and brownfields. There are several EOR methods such as thermal recovery, miscible gas injection, gas injection, chemical flooding and microbial enhanced oil recovery method etc. These oil extraction methods can greatly optimised oil production to the surface. Traditionally, these methods are mostly employed after secondary recovery (water flooding, gas injection) has been conducted to further improve reservoir productivity and recover residual oil bypassed during secondary flooding [3]. As production takes place in a reservoir, fluids move to the surface (primary recovery) by the reservoir's natural energy such as solution gas, rock and fluid expansion, this accounts for about 5-25%. Over time, pressure draw down occurs resulting in production decline, thus the need to maintain pressure and increase production. Most large oil fields are produced with some secondary pressure maintenance scheme, such as gas and/or water flooding (due to its abundance) which improves oil recovery between 25-40%, still leaving about 40% of residual

---

oil due to the inability of the reservoir pressure to surpass the capillary forces that inhibit oil flow. Enhanced (Tertiary) oil recovery is an improved recovery mechanism that aims to improve displacement efficiency and recover the residual oil at the swept zones. Non-reservoir materials (e.g., steam, chemicals) capable of changing the oil-brine-rock interactions are introduced into the reservoir thus, improving oil production to about 50% [4]. Chemical flooding which entails the addition of certain chemicals such as alkaline, surfactants, polymers accounts for above 20% residual oil recovery. The synergy between the alkaline and surfactant chemicals produces an ultra-low interfacial tension and reduces surfactant adsorption due to the presence of low-cost alkaline [5]. However, this widely accepted and effective method has certain limitations such as excessive chemical precipitation, formation damage issues such as corrosion, silicate scales formation and emulsion formation.

Formation damage occurrences have the tendency to impede the efficiency of oil recovery and bring about increased expenditure and technical challenges to oilfields operations and facilities [6]. For example, the use of surface-active agents which produces Type I or Type II microemulsions causes serious blocking of the pore spaces in reservoirs with low permeability such as carbonate reservoirs. Moreover, surfactant retention caused by the interaction of surfactant chemicals with minerals on the rock surfaces also results in pore throat constriction leading to reduced permeability [3].

Similarly, the deposition of scales (due to the incompatibility of alkali chemicals and connate water) on the pore spaces of reservoir formation also causes permeability impairment [6].

Additionally, the implementation of chemical EOR especially surfactant chemicals (which are expensive) on a field scale result in an overall increasing operating cost due to the high cost and huge quantity of chemicals required and the basis for adjudging an effective chemical EOR process during the method selection is hinged on both oil recovery efficiency and cost-effectiveness. The mechanism posited for the efficiency of chemical EOR is the use of sacrificial agents (alkali) which can form complexes with monovalent, divalent cations present in the formation brine, thus reducing the number of cations that could affect the performance of these chemicals. In this study, the performance of a chelating acid agent in acting as an alkali chemical alongside an anionic surfactant was evaluated in a high salinity hard brine-saturated sandstone core plug and its displacement efficiency of heavy oil under reservoir conditions was determined.

2. Material and methods

2.1. Materials

Reagents such as Alcohol alkyl sulphate, sodium hydroxide, ethylenediaminetetraacetic acid (EDTA), deionized water, toluene, propanol-2, potassium hydrogen phthalate, sodium chloride, calcium chloride, potassium hydroxide and magnesium chloride were purchased from a local supplier. These chemicals did not undergo further processing due to their high analytical grade. The apparatus used include water bath, viscometer, potentiometer, filter paper, volumetric flask, funnels, beakers, weighing balance, vacuum saturator, magnetic stirrer, pH indicator, Amott cells, core samples and core flooding equipment (AFS-300)

2.2. Brine Preparation

Brine was formulated to simulate formation water that was produced from the well where cores were collected using deionized water and reagent- grade salts each having concentration and salinity typical of the reservoir connate water. The brine contained varied concentrations of sodium chloride, calcium chloride and magnesium chloride having a total dissolved solids (TDS) of 72,322 g/L at a salinity of 7.23%, with 14,9832 g/L being concentrations of the divalent ions: Ca^{2+} and Mg^{2+}.

Table 1 Composition of formulated brine

Components	Concentration (g/L)
NaCl	56.777
KCl	0.563
$MgCl_2$	6.824
$CaCl^2$	8.157
T.D. S	72.3224 (7.23%)

The brine solution was prepared as reported by [7] using a magnetic stirrer at 20 °C temperature until the solution was completely dissolved. The brine solution was filtered, stored in an airtight vacuum flask and labelled 'hard brine'. The brine components and their concentration are outlined in Table 1.

2.3. Core Samples preparation

Sandstone core plug, A40 obtained from water wet sandstone reservoir were analyzed to determine their petrophysical properties such as porosity, pore volume etc. The core samples were measured using a measuring scale to determine the dry weight, thereafter, to attain complete saturation of the core plug, it was immersed in the prepared brine for 48 hrs and the weight difference was used to calculate the pore volume (PV). Secondary data obtained from XRD analyses showed the mineralogy of the core sample as containing mainly quartz, clay minerals and feldspar.

2.4. Crude oil characterization

The crude sample was obtained from an oil well in Field X, South-south Nigeria, it was characterised to determine some physical properties of the crude oil such as API gravity, viscosity etc. The apparent pH of the oil was conducted to determine the corrosiveness of the oil sample while the TAN test was conducted to determine the corrosiveness of the oil, the acid content of the oil and its soap forming ability. Studies have shown that crudes with high acid number, have high acidic content producing high amount of petroleum soap (in-situ surfactant) when reacting with oil.

2.5. Total Acid Number (TAN) test

The non-aqueous phase potentiometric titration method was used to determine the acid number of the crude oil sample used in this study using the standard method, ASTM D664. The solvent solution of Toluene, Propanol-2 and water in this ratio; 500:495:5ml under a film cupboard was prepared and placed in a well-labelled volumetric flask. A titrant solution of 0.1mol/litre of potassium hydroxide (KOH) in Propanol 2 was prepared and allowed to boil for 10mins, then stored in a volumetric flask, allow to stand for 48 hrs and then filtered. A titrant solution of 0.1 mole/litre potassium hydrogen phthalate (KHP+) in 1 litre of distilled water was standardized. An aqueous buffer solution with pH adjusted to 11 was prepared. Oil sample weighing 20 grams was sieved using a mesh and turned into the potentiometer and the solvent solution was measured in. In a different vessel, the titrant solution was filled to line, and titration commenced. Afterwards, the value of B was recorded as the volume of titrant for the last endpoint and used in calculating the mole/L of KOH and the acid number as shown in Equations 1 and 2.

$$KOH\ vol. \left(\frac{mol}{l}\right) = \frac{(KHP\ solution.grams) * (KHP\ concentration)}{KOH\ Concentration} \quad \ldots\ldots\ldots..[1]$$

$$Acid\ number = (A - B) * M * \frac{56.1}{W} \quad \ldots\ldots\ldots\ldots\ldots\ldots..\ [2]$$

Where,

A = volume of KOH solution used in titration to the last inflection endpoint, ml
B = Volume corresponding to A for blank titration, ml
M = KOH Concentration, mole/L
W = Mass of oil Sample, grams.

2.6. Imbibition test

Spontaneous imbibition test was performed using the formulated hard brine at a salinity of 7.2 wt.% and 0.2 wt. % alcohol alkoxyl sulphate (anionic surfactant) to displace fluid. The value of the surfactant's critical micelle concentration (CMC) was obtained from [7]. The core sample was first vacuumed for 24 hrs to remove air from the core completely. The core sample was later immersed in the crude oil and allowed to be fully saturated for about 10 days at a constant pressure of 148 atm. Using the formation brine, the sandstone cores were placed at the bottom of the Amott cells to displace fluid and ascertain if formation water can displace oil trapped in the sandstone cores. The displaced oil volume was recorded as a function of time until no oil was further displaced. The experiment was conducted over a period of 10 days and temperature at 80 °C. The amount of oil recovered is calculated as

$$R = \frac{V_{or}}{V_{oi}} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ [3]$$

Where

R = Oil recovery expressed in (%)
V_{or} = Volume of oil recovered (ml)
V_{oi} = Volume of oil initially in place (ml)

2.7. Chemical enhanced oil recovery test

Oil displacement test was conducted to assess the benefits of alkaline-surfactant flooding on residual oil recovery from sandstone core sample. The core flood equipment as shown in Fig. 1 consists of cylinder injection pump, three fluid accumulators, pressure tapped core-holder, pump to hold confining pressure on the core, a backpressure regulator, stopwatch, thermostat, pressure measurement system, and computer systems (monitors) for data acquisition.
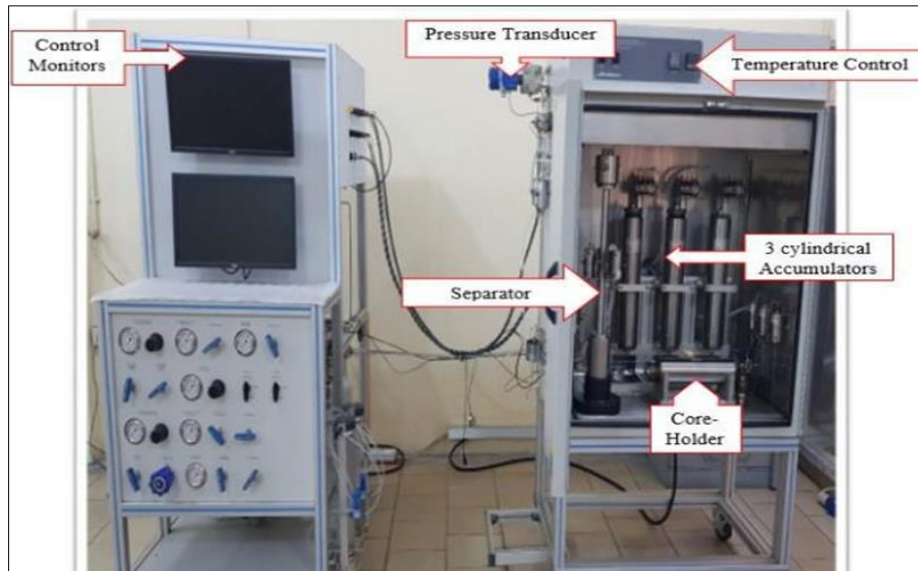
Figure 1 Core flooding equipment (Laser Engineering Core lab)

The core sample was inserted into the core holder while the three accumulators were filled with each of these fluids: oil, brine, alkaline/surfactant chemical. Liquid permeability at different flowrates were measured. Brine displacement by oil was performed to determine S_{wir} and relative permeability to oil at S_{wir}.

Secondary recovery using hard brine was conducted to determine residual oil saturation, this was followed by chemical flooding and chase brine flooding as tertiary recovery method to determine additional recovery.

2.7.1. Liquid Permeability

Hard brine at 8.5 PV was injected at ambient temperature into the core at increasing flowrate (1-6 ml/min). As the flooding continued, pressure data (P1 & P2) measured by pressure transducer were recorded, as the pressure stabilised, the flow rate was increased, and the effluent was collected in burettes. At flow rate of 6ml/min, it was evident the core was fully saturated having a stabilized pressure profile. Absolute brine permeability was estimated using Darcy's equation.

$$q = \frac{KA}{\mu}\frac{\Delta P}{L} \ \dots\dots\dots\dots\dots\dots \ [3]$$

Where,

k = Brine permeability
q = Flow rate during the brine flood (steady state)
μ = Viscosity of the brine
L = Length of the core
A = Area of the core
ΔP = Pressure drop across the core (at steady state)

2.7.2. Drainage

Prior to the drainage experiment, the system was allowed to run at constant flow rate of 0.107ml/min to overcome the backpressure of 50psi. Oil as the displacing fluid displaced brine until no more was produced. As brine displacement continued, pressure data (P1 & P2) were recorded. Volume of brine displaced was collected into burettes. The experiment continued until the first drop of oil was seen and a stabilized pressure profile obtained. Initial oil saturation was determined. The volume of water collected was measured, effective and relative oil permeability alongside irreducible water saturation was calculated using Equations 4, 5 and 8.

2.7.3. Secondary recovery (Hard Brine Flooding)

Brine was used to displace oil which was collected into burettes and measured at the end of the experiment when oil was no longer recovered, and a stabilized pressure profile obtained. Collected oil volume was measured, effective and relative water permeability was calculated as well as residual oil saturation using Equations 6, 7 and 9.

2.7.4. Alkaline + Surfactant Flooding

Solution of EDTA/NaOH and alcohol alkoxyl sulfonate was injected into the slug and used as a displacing fluid to enhance oil recovery. At a constant flow rate of 0.107ml/ min, alkaline+ surfactant solution at CMC was used to displace residual oil left after brine flooding. As displacement continued, pressure data (P1 & P2) measured by pressure transducer were recorded. The experiment continued until an oil cut of less than 1% and a constant pressure profile was obtained. Recovery factor was calculated using equation 9.

2.7.5. Chase Brine Flooding

Hard brine was used to completely displaced the alkaline + surfactant solution ensuring an effective displacement of residual oil from the core. Similar procedures were conducted and at constant pressure readings with no drop of oil left, the experiment ended. Several calculations to determine permeability, initial oil saturation, residual oil saturation, recovery factor etc. were estimated, their definitions and mathematical formulas are presented in Equations 4 to 9.

2.7.6. Oil Permeability

Oil permeability at connate water saturation was calculated from pressure drop and flow rate data using Darcy's law. The oil permeability is given by,

$$K_O = {q\mu L}/{\Delta P} \quad …………… \quad [4]$$

Where,

K_o =Oil permeability at connate water saturation
Q = Flow rate at steady state
μ = Viscosity of oil.
 L = length of the core sample

2.7.7. Oil Relative Permeability

The ratio of the oil permeability at connate water saturation to the brine permeability is:

$$K_{ro} = \frac{K_O}{K} \quad ……….. \quad [5]$$

Where,

K = Brine permeability
K_{ro}= Oil relative permeability
K_o= Oil permeability

2.7.8. Water permeability

Darcy's law valid for steady state flow was used in calculating permeability from pressures and flow rate data gotten during brine flooding. At water saturation of one, permeability is expressed as:

$$q = \frac{KA}{\mu} \cdot \frac{\Delta P}{L} \quad \ldots\ldots\ldots\ldots \text{[6]}$$

Where,

K_w = Water permeability
Q = Flow rate at steady state
μ = Viscosity of water
L = length of the core sample

2.7.9. Water Relative Permeability

The ratio of water permeability at residual oil saturation to brine permeability.

$$K_{rw} = \frac{K_w}{K} \quad\quad \ldots\ldots\ldots\ldots\ldots. \text{[7]}$$

Where,

K_{rw} = Water relative permeability
K_w = Water permeability
k = Brine permeability

2.7.10. Initial Oil Saturation

The ratio of the volume of oil initially present in the reservoir (rock) to the pore volume of that rock. During the drainage experiment, initial oil saturation was estimated from the volume of water recovered in the burette and calculated as:

$$S_{oi} = \frac{V_w}{V_p} \quad \ldots\ldots\ldots\ldots\ldots.. \text{[8]}$$

Where,

S_{oi} = Initial Oil Saturation
V_w = Volume of water in the effluent
V_p = Core Pore Volume

2.7.11. Residual Oil Saturation

This was calculated during the brine flooding as the total volume of oil recovered in the burette and expressed as:

$$S_{or} = {V_o}/{V_P} \quad \ldots\ldots\ldots\ldots. \text{[9]}$$

Where,

S_{or} = Residual Oil Saturation
V_o = Volume of oil recovered during brine flooding)
V_p = Core Pore Volume

3. Results and discussion

This section presents and analyzes all results, analytical graphs, pictures and tables derived from this study.

3.1. Crude oil characterization

Table 1 depict the properties of crude oil sample. The classification of crude oil using the API gravity considers crude oil within the range of 15-25 API as heavy crude, thus the crude oil used in this study with an API gravity of 20 is classified as a heavy oil. The dynamic viscosity of the crude (56 cP) is less than 100 cP, this implies that it is suitable for surfactant flooding as reported by [3].

Table 1 Properties of crude oil

Input	Value	Unit
API of crude oil (˚)	20.03	˚API
Oil specific gravity (Sg)	0.933	
Density @27˚C	0.931	g/cc
Oil viscosity (μo) @30 ˚C	70.50	cst
Oil viscosity (μo) @30 ˚C	56.42	cP
pH value	6.8	

3.2. Results of crude oil TAN

The total acid number of the crude oil sample was estimated as 0.42 mg KOH/g. This implies that the level of corrosiveness of the oil is minimal as such does not pose a corrosion risk, as crude oils with total acid number above 0.5 mg KOH/g are considered high as suggested by [8] and may result in severe corrosion damage to production facilities. Furthermore, the acid content present in the oil sample will react with the alkali chemical (EDTA/NaOH) to produce an insitu surfactant via the saponification process, this will reduce the viscosity of the crude and improve the oil/water solubilization process [9].

3.3. Core sample characterization

The lithological description of the core sample shows that they range from very fine to fine grained, well-sorted, well cemented sandstones obtained at an average well depth of approximately 8,805ft and an initial reservoir pressure of 6500 psi with a horizontal air permeability (k_{air}) of 383 mD. The reservoir temperature falls within the range of 70 ˚C to 100 ˚C. Table 2 shows the calculated properties of the sandstone core plug with a pore volume and absolute porosity of 8.5 cm^3 and 21.2% respectively, this is in line with the findings of [10] for the range of porosity values of Niger Delta reservoirs which indicates a good reservoir quality.

Table 2 Calculated properties of Core sample

Core Length (cm)	Core Plug Diameter (cm)	Bulk Volume (cm3)	Dry Sample mass (g)	Saturated Sample mass (g)	Mass of Brine (g)	Brine density (g/cm3)	Pore Volume Vp (cm3)	Porosity (%)
5.68	3.0	40.15	124.39	133.15	8.76	1.02	8.5	21.17

3.4. Recovery by Imbibition

Spontaneous imbibition test conducted at an optimum brine salinity of 5.1 wt.% refer to [7] and subsequently 0.2 wt. % surfactant resulted in an oil recovery factor of 18.7% and 26.6% respectively after 10 days (240 hrs.) as shown in figure 2. It was observed that after 120 hrs. of the imbibition test, the oil recovery rate using both brine and surfactant began to reduce gradually. This is because the increased pore spaces (21% porosity) and permeability of the sandstone plug allowed for improved oil recovery and overtime with reduced pressure, the recovery began to drop.

The recovery factor of the sandstone core when imbibed with surfactant resulted in a higher recovery than when it was imbibed with formation brine. This high recovery is attributed to the mechanism of surfactant flooding: wettability alteration from oil-wet to water-wet arising from the surfactant adsorption at the rock surface and a reduction in interfacial tension.
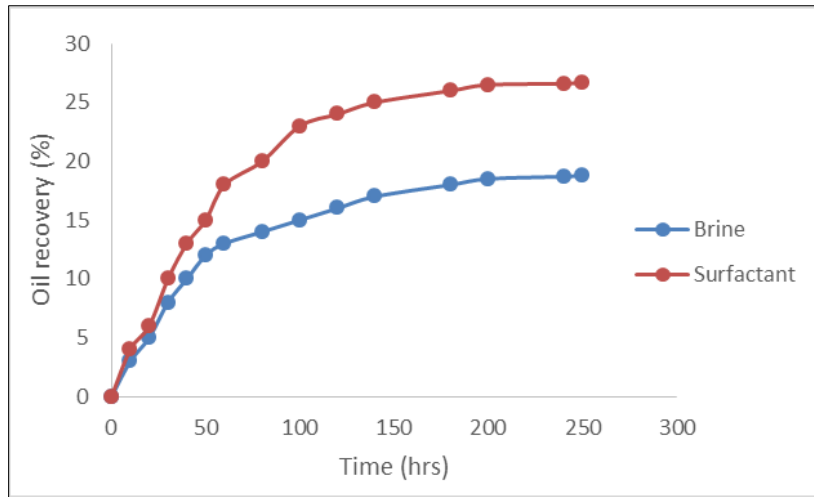
Figure 2 Recovery factor during spontaneous imbibition test

3.5. Chemical Recovery

Table 3 Calculated value for absolute permeability

	Absolute Permeability	
Input Parameter	**Value**	**Unit**
Water viscosity (μ)	1.000	cP
Length (L)	5.68	Cm
Diameter (d)	3.0	Cm
Slope (m)	4.73	
Permeability (k)	448.11	mD

The chemical slug composed of 1.5 wt.% ethylene-diamine-acetic acid and sodium hydroxide (EDTA/NaOH) at pH value of 9 serving as the alkaline with 0.2 wt.% alcohol alkoxyl sulfonate as surfactant, at an optimal brine salinity of 5.1%, which resulted in a low IFT value of 1.6 mN/m as reported by [7]. The calculated values of permeability, oil and water saturations, recovery factor after brine and chemical flooding for the floods are represented in the tables below. Table 3 shows values of absolute permeability to oil at S_{wi} calculated from Darcy's equation and ΔP derived from the plot in figures 3a and 3b.
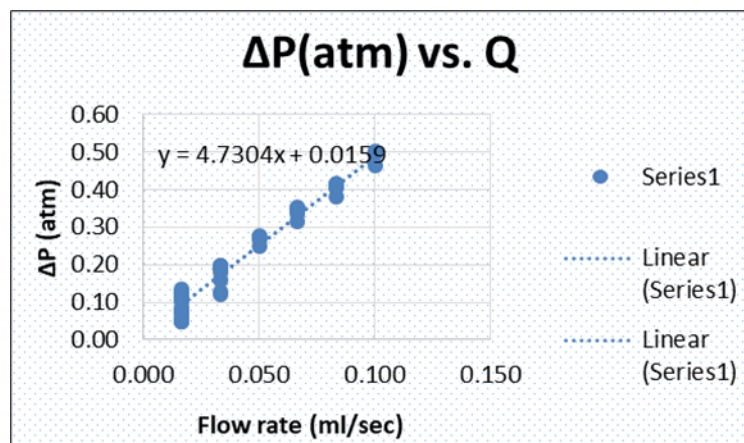

Figure 3a Plot of Pressure gradient versus flow rate

$$q = \frac{kA}{\mu}\frac{(P_1 - P_2)}{L} = \frac{kA}{\mu}\frac{\Delta P}{L}$$

$$\Delta P = \left(\frac{\mu L}{kA}\right) q$$

$$y = m\,x + c$$

slope: $\qquad m = \frac{\mu L}{kA}$

Permeability (Darcy): $\qquad k = \frac{\mu L}{mA}$

1 Darcy = 1000 mD

Figure 3b Darcy's equation for permeability

Table 4 Calculated Drainage values

Input	Value	Units
Pore volume	8.5	ml
Dead volume	8.1	ml
Total volume	16.6	ml
Irreducible water saturation (Swi)	1.0	ml
Irreducible water saturation (Swi)	11.765	%
Original Oil in place (OOIP)	7.5	ml
Irreducible water saturation (Swi)	0.1176	ml

Core flood at a flow rate of 0.107 ml/min produced an irreducible water saturation of 0.11ml or 11.76% and oil originally in place (OOIP) of 7.5 ml at the start of the test as seen in Table 4. Oil effective and relative permeability were calculated to be 202.1mD and 0.45mD while water permeabilities were 0.03mD and 12.07mD respectively as shown in Tables 5 and 6. This shows a higher effective and relative permeability for oil than water.

Table 5 Calculated values of relative and effective oil permeability

Calculated Terms for Drainage Test		
Input	Value	Unit
Oil relative permeability (K_{ro})	0.45	mD
Oil effective permeability (K_{eo})	0.2020874	Darcy
	202.09	mD

Table 6 Calculated value for relative and effective water permeability

Calculated Terms for Imbibition process		
Input	Value	Unit
Relative water permeability (Krw)	0.03	mD
Effective water permeability (Kw)	0.012	Darcy
	12.07	mD

Oil recovery during secondary flooding with 8.5 PV was high and produced 2.9 ml of oil at a recovery factor of 38.6% OOIP. 61.4% of residual oil was left unrecovered in the reservoir (see Table 7). It was observed that the use of brine during the imbibition process of the core flooding experiment resulted in a higher oil recovery as opposed to using the same formation brine during spontaneous imbibition.

Table 7 Calculated Imbibition values (Secondary flooding)

Imbibition Data	Value	Units
Pore volume	8.5	ml
Dead volume	8.1	ml
Total volume	16.6	ml
OOIP	7.5	ml
Brine recovery	2.9	ml
Recovery factor	38.6	%
Irreducible oil saturation (Soi)	61.4	%
Residual oil after brine flooding	4.6	ml

Results of Alkaline-surfactant flooding using EDTA/NaOH 1.5wt % concentration and 0.2wt % surfactant at salinity of 5.1 wt. % resulted in a recovery factor of 37.3% (see Table 9). Final chase brine flooding produced an additional 8.0% residual oil recovery, totaling 45.3% incremental recovery (see Table 8). In the case of chemical flooding, an increase in recovery factor during the core flooding test was noted as compared to spontaneous imbibition test. The synergistic use of alkaline and surfactant also played a vital role leading to higher recovery (37.3%) compared to using surfactant alone (26.6%) as noted by [6, 11]. Furthermore, the use of a strong acid (EDTA) whose pH was adjusted using sodium hydroxide underpins the fact that the pH value of a chemical plays an important role in oil recovery as noted by [5,12]. The result obtained is in line with the findings of [13], where they noted that certain chemicals capable of chelating divalent cations are excellent candidates for chemical flooding under harsh conditions. EDTA/NaOH sequestered the divalent metals and effectively recovered residual oil, thus making it an effective recovery and cost-effective agent as its application erases the need to soften produced water which is expensive.

Table 8 Residual oil recovery factor

Tertiary Recovery	Recovery factor (R.F) after chemical flooding	
OOIP	7.5	ml
Residual Oil saturation	4.6	ml
Alkaline-surfactant flooding (EOR)	2.8	ml
Final chase flooding with hard brine	0.6	ml
Oil displacement efficiency	0.73	ml
Oil displacement efficiency	73.9	%
Recovery factor	0.45	ml
Recovery factor	45.33	%

Alkaline- surfactant flooding also increased the relative and effective oil permeability (see Table 10) from 0.45 mD and 202 mD to 2.61 mD and 1170 mD due to increasing capillary number and ultra-low interfacial tension (IFT), as noted by [14] thus increasing recovery typical of water-wet system where capillary forces aid water breakthrough.

Table 9 Residual Oil Recovery without final Imbibition

Recovery without chase water	Recovery factor calculation	
Total volume of oil recovered	2.8	ml
OOIP	7.5	ml
Recovery factor	0.37	ml
Recovery factor	37.33	%

**Table 10** Calculated value for effective and relative permeability

Calculated Terms for chemical flooding process		
Input	Value	Unit
Relative oil permeability (K_{ro})	2.61	mD
Effective oil permeability (K_o)	1.17	Darcy
	1170	mD

Relative permeability measured across varied fluid saturations were used to construct the permeability plot as seen in figure 4. Endpoints were taken as indicated in Table 11.

In figure 4, point A represents the start of oil permeability while point B, represents start of irreducible water. Water permeability increases along curve BC as oil permeability reduces to zero along curve AD, thus point D is the point of irreducible oil saturation.

Table 11 Endpoint value for relative permeability curve

Endpoint	Values	Unit
K_{rw}	0.03	mD
S_{wi}	0.11	mD
K_{ro}	0.46	mD
S_{or}	0.57	mD
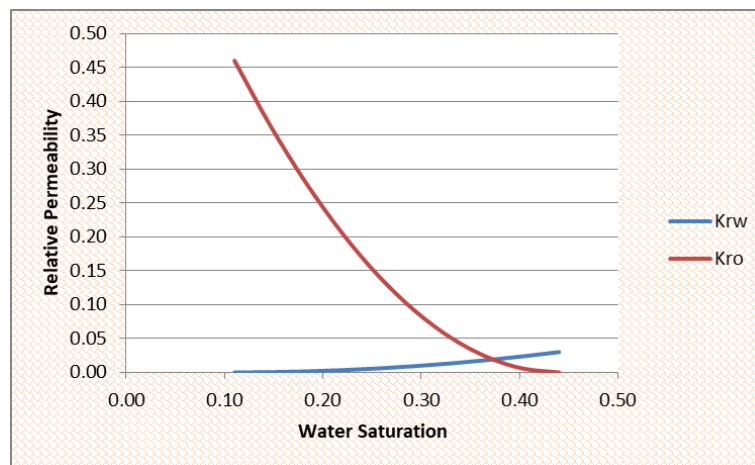
Figure 4 Relative Permeability Curve

4. Conclusion

Based on the outcome of this study, a chemical slug composed of alkali chemical; 1.5 wt.% ethylene-diamine-acetic acid and sodium hydroxide (EDTA/NaOH) at an adjusted pH value of 9 and surfactant chemical; 0.2 wt.% alcohol alkoxyl sulfonate at optimal brine salinity of 5.1% showed increased solubility, reduced interfacial tension and improved heavy oil recovery to 45.3% OOIP at reservoir temperature of 80 °C. This implies that the EDTA/NaOH can sequester the divalent ions resulting in increased oil recovery in the presence of divalent ions. Results from spontaneous imbibition experiments indicates that flooding with surfactant resulted in a higher recovery factor (26.6%) as compared to brine flooding with a recovery factor of 18.7% due to the mechanism of surfactant flooding; wettability alteration from oil-wet to water-wet arising from the surfactant adsorption at the rock surface and a reduction in interfacial tension. However, a higher recovery was obtained during the core flooding experiment for both brine flooding and chemical flooding owing to the synergy between the alkali and surfactant chemical. This study underpins the important role, pH plays in chemical oil recovery especially when flooding with hard waters. It further reduces the limitations of a cost-effective alkaline surfactant flooding method including chemical precipitation and other formation damage issue.

Compliance with ethical standards

Disclosure of conflict of interest

The authors declare that there is no conflict of interest.

References

[1]   N. Abas, A. Kalair, and N. Khan, Review of fossil fuels and future energy technologies. Futures, vol. 69, 2015, pp. 31-49.

[2]   International Energy Agency, IEA, World Energy Outlook. Retrieved from: http://www.iea.org. 2022. Accessed 20th March 2023.

[3]   J. Sheng, Modern chemical enhanced oil recovery: theory and practice. Gulf Professional Publishing. 2011, pp. 239-330.

[4]   V. Vladimir, S. Baghir, S. Ahmad, Z. Eldar, Oil recovery stages and methods, Primer on Enhanced Oil Recovery. Gulf Publishing. 2020, pp. 53-63

[5]   A. A. Obuebite, O. Okwonna, M. Onyekonwu, O. Akaranta, Chemical Flooding Using Natural Recovery Agents at Reservoir Conditions. International Journal of Engineering and Technical Research, vol.11, No. 5, 2021.

[6]   J. J. Sheng, Formation damage in chemical enhanced oil recovery processes. Asia-Pacific Journal of Chemical Engineering, vol. 11, No. 6, 2016, pp. 826-835.

[7]   A. A. Obuebite, O. O. Okwonna, J. R. Gbonhinbor, Design of salinity tolerant in alkaline surfactant systems for high salinity reservoirs. GSC Advanced Research and Reviews, vol. 14, No. 3, 2023, pp. 193-208.

[8]   H. S. Salim, I. M. Ahmed, and M. A. Mustafa, Compositional Analysis of High-TAN Sudanese Crude oil using High Resolution Mass Spectrometry and study of the Effect of Temperature and Catalyst on Acidic Composition. ACS Omega, vol. 7, 2022, pp.17472-17482.

[9]   A. Obuebite, M. Onyekonwu, O. Akaranta, C. Ubani, and C. Uzoho, An Experimental Approach to Low cost, High-performance Surfactant Flooding. Scientific African, vol. 8, No. e00361, 2020, pp. 2468-2276. https://doi.org/10.1016/j.sciaf.2020.e00361

[10]   C. S. Orji, E. D. Uko, and I. Tamunobereton-ari, Permeability-Porosity Trends In Cawc Reservoir Sands In the Niger Delta Nigeria Using Well-Log Data. Malaysian Journal of Geosciences, vol. 3, No. 2, pp. 33-42.

[11]   A. A. Obuebite, M. O. Onyekonwu, O. Akaranta, C. E. Ubani, Phase Behaviour of Local Alkaline and Surfactants during Flooding. Paper presented at the Nigeria Annual International Conference and Exhibition, Lagos, Nigeria. 5-7 August 2019.

[12] O. Massarweh, and A Abushaikha, The use of surfactants in enhanced oil recovery: A review of recent advances, Energy Reports, vol. 6, 2020, pp. 3150-3178. https://doi.org/10.1016/j.egyr.2020.11.009

[13] A. Flaaten, Q. Nguyen, J. Zhang, H. Mohammadi, G. Pope, Chemical Flooding Without the Need for Soft Water. SPE Journal, vol. 15, No. 1, 2008, pp.184-196.

[14] L. Zhao, J. Wang, X. Zhang, X. Guo, L. Chen, A. Zhang, K. Cao, J. Li, Experimental study on the evaluation of surfactant/polymer flooding for enhancing oil recovery in Kumkol Oil Field. Journal of Petroleum Exploration and Production Technology, vol. 13, 2023, pp. 853-864.