# Impact of Natural Surfactants from *Vernonia Amygdalina* On Petrophysical Properties of Niger Delta Sandstone Reservoirs: Implications for Enhanced Oil Recovery

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***Abstract***
*This study evaluates the effectiveness of natural surfactants derived from Vernonia Amygdalina in enhancing oil recovery from sandstone reservoirs in the Niger Delta. The research focuses on the surfactant's impact on critical petrophysical properties, specifically porosity and hydraulic conductivity. Various concentrations of the surfactant were tested to determine their influence on solution viscosity, pH, and density, along with the critical micelle concentration (CMC). Core flooding experiments were conducted to analyze the porosity and permeability changes in reservoir samples. Results indicated that the addition of Vernonia Amygdalina surfactants reduced pH levels while increasing viscosity and density. However, increased surfactant concentration correlated with reduced porosity, and the permeability exhibited a partial sinusoidal effect. This study provides insights into the potential of natural surfactants as effective agents for enhancing oil recovery while addressing formation integrity.*

***Keywords: Natural surfactants, oil recovery, formation damage, Vernonia Amygdalina, Niger Delta, sandstone reservoirs.***

## I. INTRODUCTION

The Niger Delta region of Nigeria is one of the most prolific oil-producing areas in Africa, contributing significantly to the country's economy. However, as conventional oil reserves become depleted, there is an urgent need for enhanced oil recovery (EOR) techniques that are both effective and environmentally sustainable (Alvarado & Manrique: Abramova *et al.*, 2014:). Among various methods of EOR, surfactant flooding has emerged as a promising approach, utilizing surface-active agents to improve oil mobilization from reservoir rocks (Gbadamosi *et al.*, 2019).

Natural surfactants, particularly those sourced from local plants, have garnered interest due to their biodegradable nature and lower toxicity compared to synthetic alternatives (Kumar *et al*, 2021: Abdulrahman *et al.*, 2023). *Vernonia Amygdalina*, commonly known as bitter leaf, is rich in phytochemicals that exhibit surfactant properties, making it a viable candidate for application in oil recovery (Imuetinyan *et al*., 2022). Understanding how these surfactants influence the petrophysical properties of reservoir rocks, specifically porosity and permeability, is critical for optimizing oil recovery processes in the Niger Delta.

Surfactants function by reducing the interfacial tension between oil and water, which facilitates the mobilization of trapped oil within porous media (Chowdhury *et al.*, 2022). They also alter the wettability of reservoir rocks, promoting a shift from oil-wet to water-wet conditions, further enhancing oil displacement (Alvarez & Schechter, 2017: Nwidee *et al.*, 2017). The application of surfactants in EOR is not without challenges; improper selection or application can lead to formation damage, such as clay swelling and pore blockage, which ultimately affect reservoir performance (Bahrami, 2013: Rigi*et al.*, 2023).

The introduction of natural surfactants into oil recovery strategies is particularly relevant in the Niger Delta, where the unique geological and chemical conditions require tailored approaches to enhance oil extraction (Odo *et al*., 2024). Previous studies have documented the effectiveness of synthetic surfactants in various geological settings; however, limited research has been conducted on the application of natural surfactants, especially *Vernonia Amygdalina*, in the context of the Niger Delta reservoirs.

Despite the recognized potential of natural surfactants like Vernonia Amygdalina in enhancing oil recovery, there is limited empirical evidence regarding their influence on key petrophysical properties such as porosity and permeability in Niger Delta sandstone reservoirs. Previous studies have indicated that surfactants can alter the physical and chemical properties of reservoir fluids Olayiwola $ Dejam, 2019: Isaac *et al*, 2022); however, the specific impacts of locally sourced surfactants on the reservoir characteristics and subsequent oil recovery efficiency remain inadequately explored. Furthermore, the interplay between surfactant concentration and the resultant changes in reservoir properties presents a gap in understanding that needs to be addressed.

This paper aims to evaluate the impact of natural surfactants derived from *Vernonia Amygdalina* on the petrophysical properties of Niger Delta sandstone reservoirs, focusing on porosity and hydraulic conductivity. Key objectives: To determine the effect of varying concentrations of *Vernonia Amygdalina* surfactant on the viscosity, pH, and density of saline solutions. To analyze the critical micelle concentration (CMC) of the natural surfactant and its relationship with oil displacement efficiency. To assess the impact of surfactant flooding on the porosity of sandstone core samples through saturation tests. To investigate the effect of surfactant concentration on the permeability of sandstone core samples using constant head permeability tests.
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## II. LITERATURE REVIEW

Surfactants are compounds that reduce surface tension between two immiscible phases, such as oil and water, and play a crucial role in enhanced oil recovery (EOR) (Alvarado & Manrique, 2010: Gbadamosi *et al*., 2019). Studies have highlighted the effectiveness of both synthetic and natural surfactants in improving oil recovery from depleted reservoirs (Massarweh & Abushaikha, 2020: Atta *et al*., 2021)

Natural surfactants, derived from plant and animal sources, have gained attention as environmentally friendly alternatives to synthetic surfactants (De *et al.*, 2015: Rai *et al.*, 2021 Atta, *et al*., 2021). *Vernonia Amygdalina*, commonly known as bitter leaf, is a promising source of natural surfactants due to its unique phytochemical composition. Kumar *et al.*, (2021) demonstrated that natural surfactants exhibit lower toxicity and are biodegradable, making them suitable for use in sensitive environments such as oil reservoirs. The primary mechanisms by which surfactants enhance oil recovery include

**Reduction of Interfacial Tension:** Surfactants reduce the interfacial tension between oil and water, facilitating the mobilization of trapped oil (Ayirala *et al*., 2021: Kesarwani *et al.*, 2021).
**Wettability Alteration:** Surfactants can shift the wettability of reservoir rocks from oil-wet to water-wet, promoting oil displacement (Mohammed & Babanginda, 2015: Kamal *et al.*, 2017: Ahmadi *et al*., 202: Alvarez & Schechter, 2017: Zhang *et al.*, 2021)
**Micelle Formation:** At concentrations above the critical micelle concentration (CMC), surfactants form micelles that can solubilize oil, further enhancing recovery (Bera & Mandal, 2015: Negin & Xie, 2017: Afolabi *et al.*, 2022).

The application of surfactants in EOR can result in several formation damage mechanisms, which include:
**Clay Swelling:** Many sandstone formations contain clay minerals that can swell in the presence of water. Surfactants may exacerbate this issue by promoting clay swelling, which can block pore throats and reduce permeability (Yuan & Wood, 2018: Nguyen & Sanders, 2022: Sikiru *et al.*, 2023)
**Pore Blockage:** The adsorption of surfactant molecules onto the pore surfaces can lead to pore blockage, limiting fluid flow. This phenomenon can significantly impact the reservoir's ability to produce hydrocarbons efficiently (Pal, *et al.*, 2018: Groenendijk & van Wunnik, 2021).
**Chemical Reactions:** Surfactants can react with reservoir fluids and minerals, leading to the precipitation of solids that can clog pore spaces. These reactions can decrease permeability and hinder oil flow (Gbadamosi *et al*., 2019: Raza *et al*., 2023).
**Microbial Activity:** The introduction of surfactants can stimulate microbial growth, which may result in biofilm formation that can further obstruct fluid pathways in the reservoir (Banat *et al.*, 2010: Can, 2018: Niu et al., 2021).

Understanding these mechanisms is critical for optimizing surfactant application while minimizing formation damage in oil reservoirs.

Limited research has specifically focused on the application of *Vernonia Amygdalina* as a natural surfactant in oil recovery. Preliminary studies indicate its potential to enhance oil displacement efficiency while posing less risk of formation damage compared to synthetic alternatives (Imuetinyan *et al*., 2022: Adenutsi *et al*., 2023)

## III. MATERIALS AND METHODS

The success of the experimental investigation relied on several laboratory materials and equipment, including a simple separation setup, electronic weighing balance, Soxhlet extractor, 30 × 100 mm thimbles, heating element (electric cooker), filter paper, calibrated beakers, measuring cylinders, conical flasks, spatula, mercury thermometer, magnetic stirrer, viscometer, density bottle, valves, accumulators, micro-pump, Vernier caliper, pipette, and U-tube manometer.

The chemical reagents utilized included laboratory distilled water ($H_2O$), ethanol, and natural surfactant extracted from *Vernonia Amygdalina*, sourced locally from Amassoma, Bayelsa State, on June 15, 2023. The leaves were sun-dried for about one week before being ground into fine particles and stored in an airtight container. Two cylindrical core samples were obtained from the Niger Delta sandstone formation.

**Brine Preparation**: A 1.5% brine solution was prepared by dissolving 15 g of sodium chloride (NaCl) in 1000 ml (1 L) of distilled water. The mixture was stirred with a spatula and magnetic stirrer at room temperature (29-31 °C) for approximately 60 minutes, ensuring a homogenous mixture, which was then filtered to remove any particulates. The density, viscosity, and pH of the saline solution were measured using a density bottle, Ostwald viscometer, and pH digital meter respectively. This prepared saline solution served as the control sample.

**Extraction of Surfactant from *Vernonia Amygdalina*:** An extraction apparatus was constructed using stands and clamps to support the setup. A round-bottom flask containing 250 ml of ethanol was connected to a Soxhlet extractor and condenser, which was mounted on a heating element. The pulverized leaves were placed in a 30 × 100 mm cellulose thimble and inserted into the extractor. The ethanol was heated, vaporized, and passed through the condenser, collecting in the thimble. This process continued until pure ethanol was obtained. The mixture of ethanol and minerals was then separated using a simple distillation setup.

**Critical Micelle Concentration (CMC):** The CMC of the natural surfactant was determined using the electrical conductivity method. The conductivity detector was calibrated with a standard solution, followed by washing the probe with distilled water. The CMC was identified from the inflection point of a plot of conductivity against surfactant concentration. A 1000 ppm brine solution was prepared, and varying concentrations of the natural surfactant were tested to establish the relationship between conductivity and concentration.

**Preparation of Surfactant-Brine Solutions**: The 1.5% saline solution was used to prepare five different surfactant-brine solutions with concentrations of 0.05%, 0.1%, 0.2%, 0.4%, and 0.6%. The viscosity, density, and pH of these solutions were measured at 30 °C.

**Macroscopic Core Flooding**: A constant head permeability test assembly was set up as shown in figure 1, with the core sample saturated with a 20,000-ppm brine solution for 5 minutes at 29-31 °C. The sample was placed in the core holder, and the flow rate of the injected brine was calibrated. The pressure drop across the core was recorded at various flow rates for different surfactant-brine solutions.

**Data Analysis**: To measure the density of the solutions, the mass of both an empty and a liquid-filled density bottle was recorded. The density was calculated using the difference in mass divided by the volume of the bottle. The viscosity of the brine and surfactant-brine solutions was measured by timing the efflux of the liquid through a capillary tube and calculating the dynamic and kinematic viscosity using Poiseuille’s law.

The core samples were weighed and saturated in the 1.5% brine solution for 20 minutes. The pore volume was calculated using the following equations:

$$v_p = \frac{w_{sat} - w_{dry}}{p_{brine}} \dots\dots\dots\dots\dots\dots (1)$$

$$v_b = \frac{\pi d^2}{4} \dots\dots\dots\dots\dots\dots\dots\dots\dots.. (2)$$

$$\emptyset = \frac{v_p}{v_b} \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots (3)$$

Were,

$v_p$ = pore volume (cc)

$v_b$ = bulk volume of the core sample (cc)

$w_{dry}$= dry weight of the core sample (g)

$w_{sat}$= saturated weight of the core sample (g)

$p_{brine}$= density of the brine (g/cc)
$\emptyset$= porosity of the sample (%)

The permeability was calculated using the flow rate and pressure difference across the core samples, employing the equation:

$$k = \frac{q\mu L}{A\Delta \text{p}} \dots\dots\dots\dots\dots\dots\dots\dots\dots (4)$$

$k$ = absolute permeability (D)
$q$= flow rate (cc/s)
A = cross-sectional area ($cm^2$)
$\mu$= viscosity of the fluid (cp)
Δp = pressure drop (atm)
L = length of the core sample (cm)

## IV. RESULT AND DISCUSSION

The viscosity, pH values, and specific mass (density) of the prepared brine and surfactant-brine solutions are summarized in Table 1 below.

Table 1: Properties of the Prepared Solutions

| Concentration (%) | Density (g/cc) | pH | Viscosity (cp) |
|---|---|---|---|
| 1.5-B | 1.0895 | 6.5 | 0.0887 |
| 0.05-SB | 1.0906 | 6 | 0.0931 |
| 0.1-SB | 1.091 | 5.5 | 0.09422 |
| 0.2-SB | 1.0943 | 5.3 | 0.0973 |
| 0.4-SB | 1.0952 | 5.1 | 0.0988 |
| 0.6-SB | 1.1008 | 4.9 | 0.1005 |

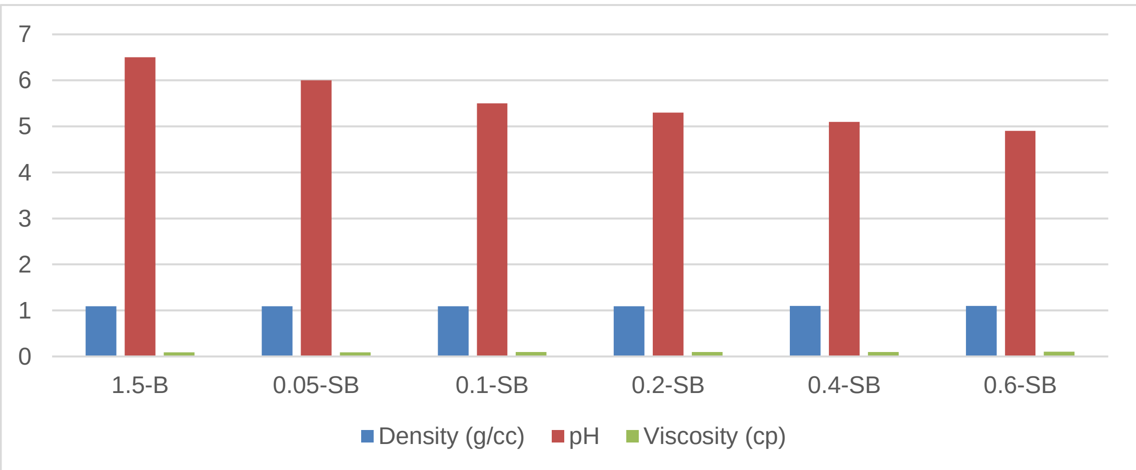


Figure 1: A Cluster Chart Representation of The Properties of The Prepared Solutions.

The data presented in Table 1 and Figure 1indicate a decrease in pH values alongside increases in viscosity and density as surfactant concentration rises. This suggests that the incorporation of surfactants into saline solutions significantly enhances the properties of the prepared solutions. The critical micelle concentration (CMC) of the natural surfactant is illustrated in Figure 2, where the CMC was determined to be 0.25%. Conductivity increases linearly with surfactant concentration until a specific point is reached, beyond which the slope decreases. This inflexion point indicates the CMC for the surfactant.
As shown in the Figure 2, an increase in solution concentration leads to the aggregation of surfactant monomers, forming micelles. This aggregation can

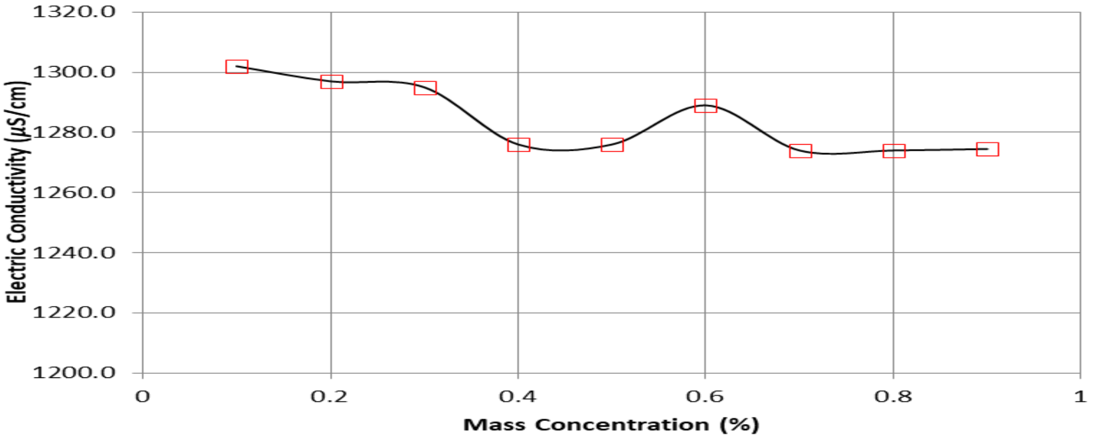


Figure 2: Critical micelle concentration for Vernonia Amygdalina

consist of one or more layers, where hydrophobic interactions among surfactant molecules increase adsorption levels (Clint., 2012; Chang *et al*., 2018).
According to Belhaj *et al.* (2020), properties such as pH, ionic strength, temperature, and surfactant concentration can influence adsorption behaviors and affect mineral dissolution and surfactant precipitation.
The absolute porosities of the Niger Delta reservoir core samples were calculated after being fully saturated in a vacuum saturation assembly with control (15,000 ppm brine) and various surfactant-brine solutions. The porosity was derived from the difference between the wet and dry masses of the core plug, normalized by the bulk volume (volume of the cylindrical core). The results are summarized in Table 2

Table 2: Porosity and Core Sample Characterization

| C (%) | P (g/cc) | Niger delta reservoir sandstone core sample L = 6.94cm D = 3.83cm | | | | |
|---|---|---|---|---|---|---|
| | | **$M_{dry}$ (g)** | **$M_{we}$ (g)** | **Vp (cc)** | **Vb (cc)** | **Φ (%)** |
| 1.5-B | 1.0895 | 146.17 | 160.55 | 13.20 | 79.99 | 16.5 |
| 0.05-SB | 1.0906 | 146.17 | 159.42 | 12.15 | 79.99 | 15.19 |
| 0.1-SB | 1.0910 | 146.17 | 159.26 | 12.00 | 79.99 | 15 |
| 0.2-SB | 1.0943 | 146.17 | 158.56 | 11.32 | 79.99 | 14.16 |
| 0.4-SB | 1.0952 | 146.17 | 158.42 | 11.19 | 79.99 | 13.98 |
| 0.6-SB | 1.1008 | 146.17 | 157.22 | 10.04 | 79.99 | 12.55 |

Figure 2 illustrates the relationship between various solutions and the ability of the Niger Delta reservoir core sample to retain hydrocarbons. The laboratory results confirm that surfactant-saline solutions have a negligible impact on the porosity of the Niger Delta's porous and permeable formations.

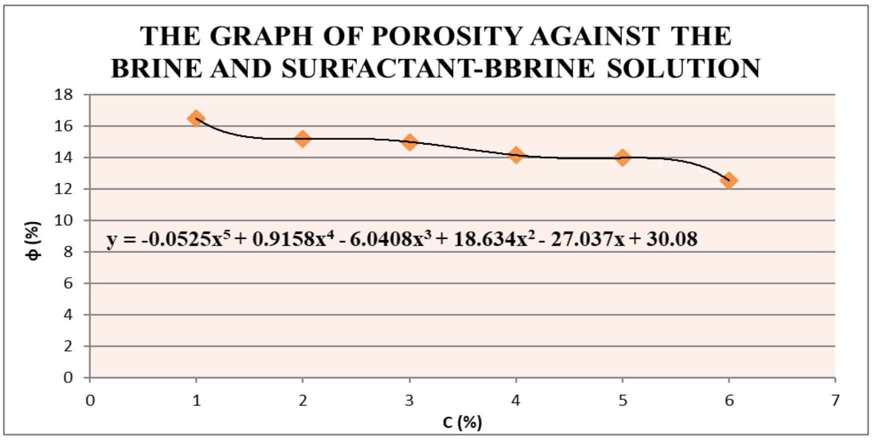


Figure 2: Graphical representation of porosity against the prepared concentrations.

The hydraulic conductivity test measures absolute permeability by injecting brine and surfactant-brine solutions with known viscosity through the cylindrical core sample. The flow rate was maintained, and the corresponding pressure differences between the inlet and outlet were recorded in Figure 3. Darcy's equation was used to deduce the absolute permeability.

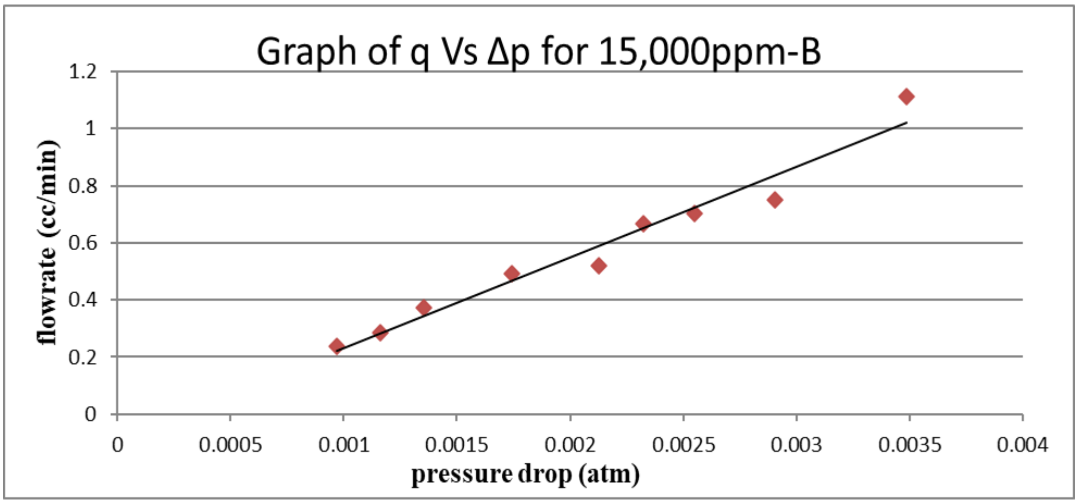


Figure $: Graph of flow rate against pressure drop when 15,000 ppm brine was injected into the core sample.

The hydraulic conductivity test results for different surfactant-brine solutions, such as 500ppm, 1000 ppm, and 2000 ppm, are also included, showing varying effects on permeability

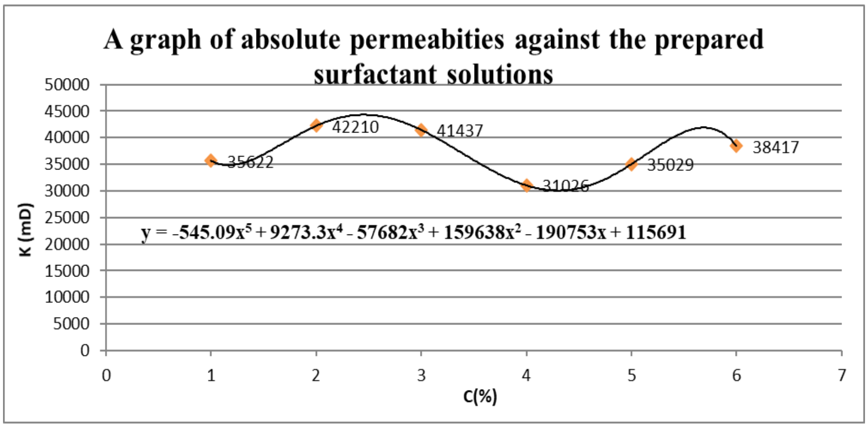


Figure 4: Graphical representation of the hydraulic conductivities against brine and surfactant-brine solutions.

The analysis indicates that surfactant-brine solutions minimally affect the permeability of the subsurface sandstone core sample. Figure 4 reveals a partial sinusoidal relationship between surfactant-brine concentration and permeability, This suggests that the formation particles in the sandstone core interact with the injected fluids, promoting particle migration and trapping.

## CONCLUSION

The investigation into permeability and porosity was conducted experimentally to evaluate the effects of natural surfactant on sandstone core samples. Based on how important the results of this research work, a series of experiments, such as saturation tests and constant head permeability tests, were conducted at surface conditions to verify the distinctive petrophysical impairment. The following conclusions can be drawn from the test results:

1. The addition of natural surfactant (*Vernonia amygdalina*) to a saline solution decreases the pH of the solution.
2. The viscosity and density of saline solutions increase as the concentration of natural surfactant (*Vernonia amygdalina*) increases, indicating a direct proportionality.
3. The presence of *Vernonia amygdalina* surfactant extract in Niger Delta reservoir core samples reduces the porosity of the sandstone core plug as the concentration increases. Surfactant flooding has a partial sinusoidal effect on the permeability of the core sample

## Recommendations

1. Future studies should focus on long-term impacts and field trials of *Vernonia amygdalina* surfactants to better understand their effectiveness in real-world oil recovery scenarios.
2. Further experimentation should be conducted to optimize surfactant concentrations for minimizing formation damage while maximizing oil recovery
3. Comprehensive Studies on Formation Damage: Detailed studies on formation damage mechanisms due to surfactant flooding should be undertaken to develop strategies for mitigating adverse effects.

## Conflict of Interest

No conflict of interest

## Author Contributions

E. Omuso-Wilson conducted the research; E.D Goodluck analyzed the data; Both authors wrote the paper; all authors had approved the final version.

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