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Experimental Investigation of Coconut Oil as a Surfactant for Chemical Enhanced Oil Recovery

Anthony Ogbaegbe Chikwe, Christian Emelu Okalla*, Young-Dede Steven Boloinyofa, and Ndubuisi Uchechukwu Okereke

Department of Petroleum Engineering, Federal University of Technology, Owerri, Nigeria.

*Corresponding author: christian.okalla@futo.edu.ng

Abstract— This study presents a comprehensive analysis of the efficacy of coconut oil as a natural surfactant in Chemical Enhanced Oil Recovery (CEOR) processes. This study evaluates the effectiveness of coconut oil as a surfactant in Chemical Enhanced Oil Recovery (CEOR). The results indicate that coconut oil is a highly effective and sustainable alternative to synthetic surfactants, with an average oil recovery improvement of up to 20% compared to a water-only injection scheme. The study compares the performance of coconut oil to conventional synthetic surfactants and highlights its potential as a sustainable and cost-effective alternative in CEOR operations. The results demonstrate that coconut oil effectively reduces Interfacial Tension (IFT) between oil and water, with an average IFT reduction of up to 50% across a range of salinities and temperatures. The experimentally determined IFT values were used to model the displacement process in a micro fluidic system, providing insights into the oil recovery mechanisms associated with coconut oil injection. Additionally, the study investigated the influence of different concentrations of coconut oil on the stability and adsorption of the surfactant in various reservoir conditions, revealing its compatibility and applicability in a wide range of CEOR applications.

Keywords— Bio-material, Eco-friendly, IFT, Coconut Oil, Micro Fluidic.

1. INTRODUCTION

There has been a growing interest in renewable and environmentally friendly surfactants use for enhanced oil recovery (EOR) processes [1]. Among the various types of renewable surfactants, coconut oil has received attention due to its availability and biodegradability [2]. Coconut oil is non-ionic surfactant that has been shown to have good compatibility with crude oil and formation water. Coconut Oil has been identified as a source of surfactants for EOR due to their natural abundance in tropical regions and their high content of lauric acid and natural surfactants [3]. The use of coconut oil as surfactants offers several advantages, including cost-effectiveness, environmental friendliness, and enhanced biodegradability [4]. Hence, the oil and gas industry place a high priority on oil recovery, as it is a vital aspect of the extraction process. Enhanced Oil Recovery (EOR) techniques, such as Chemical Enhanced Oil (CEOR), have been developed to increase the volume of oil extracted from underground reservoirs [5]. CEOR uses surfactants, which reduce the interfacial tension (IFT) between oil and water, leading to increased oil production [6]. The growing importance of EOR techniques in the oil industry is further highlighted by the need to maintain a stable and secure energy supply. As conventional methods of oil extraction become less viable, it is essential to explore alternative methods to extract remaining oil from mature fields, in order to maintain production and meet global energy demands. Moreover, the development and utilization of EOR techniques can help to prolong the lifespan of these mature fields, thereby extending the economic benefits they provide to their host countries and the global economy. Over time, the development and production of crude oil has progressed through a series of phases, with each phase utilizing different methods to extract oil from the reservoir. These phases are known as Primary, Secondary, and Tertiary or Enhanced Oil Recovery (EOR).

Primary recovery. This is the initial phase of production, where the inherent energy sources within the reservoir, including solution gas drive, gas-cap drive, natural water drive, and fluid and rock expansion, are utilized to displace the oil towards the producing wells. Primary recovery typically only yields a relatively low recovery factor, with an average of 5 to 30% of the original oil in place being recovered [7]. This low recovery factor is attributed to the limited displacement efficiency of the inherent energy sources, which can only move the oil toward a limited extent before the pressure and energy decline.

In the second phase, known as Secondary recovery, techniques like water flooding or gas injection are employed to enhance the existing reservoir energy. sources and displace additional oil. This phase can result in increased recovery of up to 50% of the original oil in place. Secondary recovery, referred to as pressure maintenance, begins once primary recovery methods become insufficient to maintain economic production rates. As the inherent energy sources within the reservoir are depleted, fluids such as water or gas are injected from the surface to maintain reservoir pressure and drive more oil towards the production wells. The most commonly employed secondary recovery process is water flooding, in which water is injected into the reservoir, displacing oil and sweeping it towards the production wells. The recovery factor achieved through primary production and subsequent water flooding can be between 35 and 50% of the initial oil in place [8]. Additionally, water flooding, other secondary recovery processes include gas injection, which can involve injecting gas that is either miscible (i.e., capable of mixing with the oil in the reservoir) or immiscible (i.e., not capable of mixing with the oil). Miscible gas injection is typically used in reservoirs with high oil saturation, while immiscible gas injection is more commonly employed in reservoirs with low oil saturation. When employing water flooding, it is necessary to carefully control the injection rate and pattern for effective oil recovery.

Tertiary recovery, referred to Enhanced Oil Recovery (EOR). This is the third and final phase in oil production. This phase is employed once secondary recovery methods become uneconomical and involve the injection of extra fluids or energy sources into the reservoir to displace and mobilize additional oil. EOR techniques are typically more expensive than primary and secondary recovery methods, but they can significantly increase the recovery factor from the reservoir. EOR utilizes various techniques, including miscible gases (such as carbon dioxide), chemicals (including surfactants and alkalis), and thermal energy (e.g., steam injection), to extract residua l oil from the reservoir after conventional primary and secondary recovery methods become uneconomical [9].

Chemical methods: It comprises of the use of polymers, surfactant, alkaline flooding and foam flooding. The mechanisms of chemical methods vary, depending on the chemical materials added into the reservoir. The chemical methods may provide one or several effect to reduce interfacial tension (IFT), wettability alteration, mobility control and emulsification. The chemical methods include;

i. Polymer flooding: Polymer flooding involves the injection of polymer solutions into the reservoir to improve the effectiveness of water flooding [10]. Polymers, which are high molecular weight molecules, are added to the injected water in concentrations ranging from 250-2000ppm. This results in a viscosity increase, altering the mobility ratio between the injected fluid and the reservoir fluid. The improved mobility ratio leads to better sweep efficiency, resulting in higher oil recovery.

ii. Surfactant flooding: This is an EOR technique that uses surfactants, such as soap or detergent, to reduce the interfacial tension between injected water and reservoir oil. By decreasing the interfacial tension, the injected water becomes more effective at displacing the immobilized oil from the rock’s pores, leading to improved oil extraction.

iii. One advantage of surfactant flooding is that it allows the oil to be extracted from reservoirs where the natural energy has already been depleted by primary and secondary recovery methods. However, the surfactant solution used must be tailored to the specific characteristics of the reservoir, including the rock and crude oil properties, to be effective.

iv. Alkaline flooding: This enhanced oil recovery (EOR) method involves injecting alkaline chemicals like sodium hydroxide, sodium orthosilicate, or sodium carbonate into the reservoir [11]. The alkaline chemicals interact with specific oil types to generate surfactants, which lower the interfacial tension between oil and water. This results in enhanced oil recovery by facilitating the displacement of crude oil from the reservoir. The alkaline agents raise the pH of the flooding water, resulting in a reaction between alkaline and acidic components in crude oil. In carbonate reservoirs, alkaline flooding may not be recommended due to the formation of calcium hydroxide, which can cause precipitation and damage to the formation [12]. Alkaline flooding in mixed-wet carbonates with natural fractures may result in oil recovery through mechanisms beyond interfacial tension reduction, such as emulsification and wettability alteration [13].

v. Surfactant flooding: A Surfactant Flooding is a type of enhanced oil recovery (EOR) method where surfactants are injected into the reservoir to mobilize residual oil and enhanced oil production by reducing the interfacial tension of the oil and water. The injection regulates the phase behavior properties within the reservoir, facilitating the movement of trapped crude oil by reducing the interfacial tension (IFT) between the injected fluid and the oil.

Surfactant systems typically comprise both surfactants and co-surfactants. However, in practice, the combination of multiple components in the surfactant solution often leads to chromatographic separation within the reservoir, causing a rapid shift in solution concentration from its optimal level. The primary goal of surfactant flooding is to maximize oil recovery while minimizing chemical costs. Although achieving low interfacial tension (IFT) is important, solely focusing on IFT reduction does not always ensure optimal oil recovery. Other critical factors, such as maintaining optimal salinity, must also be considered for effective and efficient oil extraction [14]. In enhanced oil recovery (EOR) processes, sulfonated hydrocarbons such as alcohol propoxylate sulfate and alcohol propoxylate sulfonate are commonly used as surfactants. To optimize surfactant flooding for a specific reservoir, both surfactants and polymers are often incorporated into the flooding mixture. While surfactants primarily reduce the interfacial tension (IFT) between oil and water, polymers enhance sweep efficiency by improving fluid mobility control [15].

The effectiveness of surfactant flooding depends on several factors, including:

i. Surfactant stability: The ability of the surfactant to maintain its performance under reservoir conditions, such as high temperature and pressure, is crucial for sustaining low IFT throughout the flooding process.

ii. Surfactant adsorption: The extent to which surfactants adhere to reservoir rock surfaces influences their availability and overall effectiveness.

iii. Surfactant dosage: The amount of surfactant injected must be carefully managed to ensure optimal oil recovery while maintaining cost efficiency.

From a fundamental perspective, enhanced oil recovery (EOR) refers to techniques that involve the introduction of external energy and materials into a reservoir to regulate key factors such as wettability, interfacial tension (IFT), and fluid properties. These methods also help establish the necessary pressure gradients to overcome retaining forces, facilitating the controlled movement of residual crude oil toward production wells.

1. Interfacial Tension (IFT): Laboratory evaluation of surfactant for IFT reduction involves measuring the reduction in interfacial tension between oil and water phase in the presence of the surfactant. IFT influence the ability of the surfactant to mobilize oil from the reservoir rock. However, these studies have shown that sulphonated coconut oil surfactants can reduce interfacial tension to as low as 0.001mN/m or less, depending on the surfactant concentration and other factors. This reduction in interfacial tension is crucial for enhanced oil recovery, as it allows the oil to move more easily through the reservoir rocks and towards production wells. Low interfacial tension also helps to stabilize emulsions of oil and water, preventing them from separating during transportation and processing.

2. Wettability alteration: The laboratory evaluation of wettability of sulphonated coconut oil involves several tests to determine how well the surfactant alters the wetting behavior of reservoir rocks. During Contact angle measurement, a drop of sulphonated coconut oil is placed on the surface of a reservoir rock sample. The contact angle of the drop is then measured using a goniometer, which can provide information on the degree of wettability.

3. Phase Behavior. The phase behavior of surfactant/oil/water mixtures is the most crucial factor influencing the effectiveness of a chemical flood, as it directly impacts oil recovery efficiency, [16]. However, in the laboratory evaluation of the phase behavior cloud point test is conducted to determine how the sulphonated surfactant (coconut oil) affects the stability and miscibility of different phases (oil, water and surfactant). The cloud point test determine the temperature at which a clear solution of sulphonated coconut oil becomes cloudy, which provides information on the surfactant's ability to reduce the interfacial tension between oil and water phases.

4. Effect of Temperature and Pressure. Understanding the influence of temperature on various EOR parameters, such as wettability, IFT, oil viscosity, imbibitions rates, and phase behavior of surfactant/oil/water systems, is crucial for designing effective EOR strategies. However, the complex nature of these systems often leads to contradictory findings, making it challenging to develop general rules. For instance, [16] demonstrated that higher temperatures resulted in higher optimal salinity, while [17] observed that for many surfactants, optimal salinity decreased or remained unchanged with increasing temperature.

5. Phase Equilibrium. In surfactant-based EOR processes, phase equilibrium and phase behavior of the displacing and displaced fluids play a significant role in determining the recovery efficiency. Three types of surfactant systems have been identified based on their phase behavior characteristics. As shown in Figure 3, Winsor I systems consist of a lower-phase microemulsion in equilibrium with excess oil, while Winsor II systems contain an upper-phase microemulsion in equilibrium with excess water or brine. Winsor III are systems that have a middle-phase microemulsion. Winsor I and Winsor II systems can reach a maximum of two equilibrium phases, whereas the Winsor III system can achieve three-phase equilibrium, incorporating both Type I and Type II regions. This indicates the complexity and versatility of surfactant systems in achieving different phase equilibria and the corresponding interfacial tension behaviors.

2. MATERIALS AND METHODS

2.1 Materials

The following materials were used to achieve the study's objective;

i. Core sample
ii. Coconut Oil
iii. Brine solution
iv. Coconut Oil Slug
v. Crude Oil
vi. Core flooding apparatus
vii. Measurement equipment

2.2 Methods

2.2.1 Preparation of the Core Sample

Unconsolidated sand was collected from Nembe Creek of the River Nun in Niger Delta. The sand sample was dried and free from any contaminants. The sand sample was cleaned a gentle cleansing (e.g. diluted aceric acid) to remove any residual oil and water. After cleaning, the sample was allowed to dry completely. The sand sample was weighed with weighing balance. The sand sample was then saturated with brine in a saturator container for 48 hours. The saturated sand samples were weighed and mass recorded. The difference in weight between the brine saturated sand sample and dried sand was used to determine the porosity of the unconsolidated sand. The sample was then stored in an air tight container (a plastic bag) to prevent contamination or degradation. The container was labeled with the date and the contents of the solution (i.e. Sand sample) and kept in a cool and dry place.

2.2.2 Preparation of the Coconut Oil

Coconut (mature) is obtained from Tubopiri and Orupiri. Coconuts were opened with matchet and the coconut meat was thoroughly removed from the coconut shells with a knife. A food processor was used to shred the coconut meat. Coconut meat was processed to make a coconut milk Blend the coconut meat with water for 2-4 minutes or until the mixture is thick and creamy. Then strain the coconut meat from the coconut milk with a nut milk bag or fine mesh strainer and then thoroughly pour the coconut milk into a large pan. Warm the coconut milk over low heat. Ensuring that the milk temperature lower and to simmer the coconut milk lightly, as the milk heats, the coconut oil will rise to the top. This process will take between one to two hours. Note, as the coconut milk cook down the colour of the coconut milk will darken and the coconut oil will begin to solidify and start to separate at the top of the coconut milk. Once the oil has separated from the milk, you will strain the oil. I used a metal mesh strainer to do this. The sieved coconut oil was stored in an air tight container (a glass jar). The container was labeled with the date and the contents of the solution (i.e. **"coconut oil)** and kept in a cool and dry place.

2.2.3 Preparation of Brine Solution

40 g of NaCl (sodium chloride) was measure out using volumetric flask.1000 ml of distilled water was also measured out using a measuring cylinder. The 40 g of NaCl was added to the 1000 ml of distilled water in the measuring cylinder. The mixture was stirred until it is completely dissolved using a mixer rotating at 2 rpm for several minutes. Once the NaCl is dissolved, the solution was filtered to remove impurities or undissolved particles. This ensures that the solution is clean and free of contaminants that could affect the core flooding tests. The pH was checked and adjusted to meet the specific pH required for the experiment which was determined by the experimental design and properties of the core sample, although the typical pH for brine solution is slightly alkaline (pH 7-8). The brine solution was stored in an air tight container using a plastic jar. The container was labeled with the date and the contents of the solution (i.e. "Brine solution). The brine solution should be and kept in a cool and dry place.

2.2.4 Preparation of the Surfactant Slug

The desired concentration of coconut oil (35 cl) was obtained. 5cl was measured out into volumetric a beaker. 1.5 g of sulfur powder was then added to the 5cl of coconut oil in the volumetric flask and mix properly by subjecting the mixture on a mixer rotating at 2rpm for five minutes. The mixture was then filtered to remove the undissolved solute. A viscometer was then used to check the viscosity of the mixture. If the viscosity is too high, add more brine solution to lower the concentration and reduce the viscosity. The slug was stored in an air tight container using a plastic jar. The container was labeled with the date and the contents of the solution (i.e. "Coconut oil slug). The brine solution should be and kept in a cool and dry place.

2.2.5 Flooding procedure

Drainage Process: Brine in the core samples was displaced with crude oil to simulate the original migration process of crude oil. The volume of brine displaced indicated the original oil in place. Secondary Recovery: Brine was pumped into the core sample to displace the oil, and the recovered oil volume was recorded. Tertiary Recovery: The developed Surfactants solution was pumped in to displace the remaining crude oil, and the recovered oil volume was recorded.

2.2.6 Concentration Increase

The concentration of the surfactants solution was increased, and the above process was repeated. Toluene, an aromatic compound, was used to cleanse the core sample between tests. Brine was flooded to create a suitable environment for the migration process. Crude oil was pumped to displace the brine, simulating the drainage process. The volume of brine recovered indicated the initial oil in place. Brine was pumped to displace oil, recording the recovered volume. The surfactants solution was pumped in to displace the remaining crude oil, recording the recovered volume. The process was repeated for another concentration increase.

2.2.7 Porosity Determination

The pore volume of the sand sample was determined by following these steps: The dried weight of the sand sample (filled with sand samples) was recorded. The sand sample was then saturated with brine for a period of 42 hours, after which the weight was again recorded. The density of the brine used was determined in the laboratory using a density bottle of 50 ml and recorded.

The following calculations were made from the recorded values:

$$Pore\ volume = \frac{Saturated\ weight\ of\ sand - Dry\ weight\ of\ sand}{Density\ of\ Brine} \quad (1)$$

$$Bulk\ Volume = \pi r^2 h \quad (2)$$

Where,

r = radius of the sand sample
h= height/length of the sand sample

Therefore

$$Porosity = \frac{Pore\ Volume}{Bulk\ Volume} \quad (3)$$

2.2.8 Viscosity Determination

The viscosity of all the solution (various crude oil samples, surfactant solution, brine) were determine using cannon glass viscometer. The particular solution whose viscosity is to be determined were drawn into the upper bulb by suction, and then allowed to flow down through the capillary into the inner bulb. There are two marks to indicate the fluid volume. The time taken for the level of the fluid to pass between these marks is proportion to the kinetic viscosity.

Kinematic Viscosity = Efflux time × Viscometer constant
Dynamic Viscosity = Kinematic Viscosity × Density
Dynamic Viscosity = Fluid density × Efflux Time × Viscometer Constant

2.2.8 Displacement Efficiency

The displacement efficiency by the local materials was determined by the following equation:

$$Displacement\ Efficiency = \frac{Tertiary\ Recovery}{OOIP} \times 100 \quad (4)$$

Residual Oil Saturation = OIIP - (Secondary + Tertiary Recovery)

(Irreducible Water Saturation = Pore Volume – Displaced Water)

2.2.9 Oil Recovery Efficiency

The oil recovery efficiency was determined by the following equations:

Cumulative Oil Recovery = secondary recovery + Tertiary recovery

$$\%\ Recovery = \frac{Cumulative\ Oil\ Recovery}{OIIP} \times 100 \quad (5)$$

2.2.10 FTIR Spectroscopy on coconut oil

4g was weighed out of the sample of coconut oil and remove any impurities or contaminants that might interfere with the analysis. The 4g of the coconut oil sample was placed in the sample compartment of the FTIR spectrometer using an ATR crystal or by pressing it into a KBr disk. The parameters of the FTIR spectrometer were adjusted to optimize the sensitivity and resolution of the spectra. Then, the infrared spectrum of the coconut oil sample was acquired. After acquiring the infrared spectrum, the data imported into a computer for analysis. Then a software (Spectrum) was used to process and interpret the data, comparing the spectrum of the sample (sulphonated coconut oil) to reference spectra of pure coconut oil. The FTIR spectra were analyzed to identify the peaks associated with specific functional groups and compounds in the coconut oil. The data was interpreted to determine the purity and quality of the oil.

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3. RESULT AND DISCUSSION

3.1 Results

The experimental result which was carried out with varying properties.

Table 1: Different Properties of the Test Fluid

SAMPLE	EFFLUX TIME	VISCOMETR CONST	DENSITY (g/cm^3)	KINEMATIC VISCOSITY (cm^3/s)	DYNAMIC VISCOSITY (cp)
Surfactant (Coconut Oil) (0.2%)	27	0.0364099	1.0412	0.9831	1.0236
Surfactant (Coconut Oil) (0.5%)	27	0.0364099	1.0412	0.9831	1.0236
Surfactant (Coconut Oil) (1%)	27	0.0364099	1.0412	0.9831	1.0236
Crude oil	293	0.0364099	0.8909	10.668	9.5049
Brine	27.1	0.0364099	1.0238	0.9867	1.0102
SDS	-	-	-	1.0210	-

Table 2: Properties of Core Samples Used

NO	LENGTH (cm)	DIAMETER (cm)	DRY-WEIGHT (g)	WET WEIGHT (g)	BULK VOL (cm)	PORE VOL (cm)	POROSITY
A	5.9	3.65	130.44	143.54	61.73	12.84	20.80%
B	5.9	3.7	135.34	149.6	63.44	13.98	22.03%
C	5.35	3.8	125.49	139.15	60.683	13.39	22.06%

Table 3: Core Samples Used

NO	LENGTH (cm)	DIAMETER (cm)	DRY-WEIGHT (g)	WET WEIGHT (g)	BULK VOL (cm)	PORE VOL (cm)	POROSITY
A	5.9	3.65	130.44	143.54	61.73	12.84	20.80%
B	5.9	3.7	135.34	149.6	63.44	13.98	22.03%
C	5.35	3.8	118.49	124.15	60.683	5.549	9.1%

Table 4: Results from the experiment at different concentrations of the EOR agents at 0.2% concentration

Concentration	OOIP	Water flooding (Secondary recovery)	% Recovery	Tertiary Recovery using Local EOR agents	% Recovery	Total recovery	% Recovery
Coconut Oil	11	6ml	54.54	3ml	27.27	9ml	81.81
SDS	11ml	4ml	36.4	4ml	36.4	8ml	73

Table 5: Results from the experiment at different concentrations of the EOR agents at 0.5% Concentration

Concentration	OOIP	Water	%	Tertiary	%	Total	%

		flooding (Secondary recovery)	Recovery	Recovery using Local EOR agents	Recovery	recovery	Recovery
Coconut Oil	10ml	5ml	50	3.8ml	38	8.8ml	88
SDS	11ml	6ml	54.5	3.1ml	28.2	9.1ml	82.7

Table 6: Results from the experiment at different concentrations of the EOR agents at 1% Concentration

Concentration	OOIP	Water flooding (Secondary recovery)	% Recovery	Tertiary Recovery using Local EOR agents	% Recovery	Total recovery	% Recovery
Coconut Oil	10ml	6ml	60	3.8ml	38	9.8ml	98
SDS	11ml	5.5ml	50	4.2ml	38.2	9.7ml	88.2

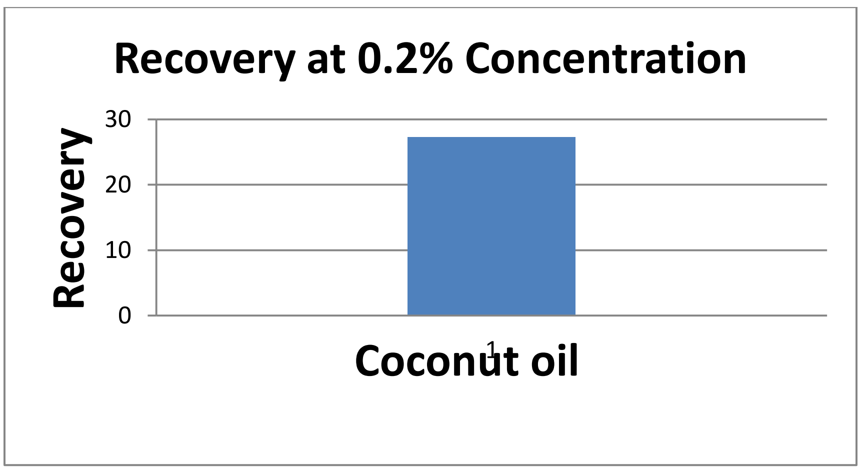

Figure 1: Recovery at 0.2% concentration of selected surfactant

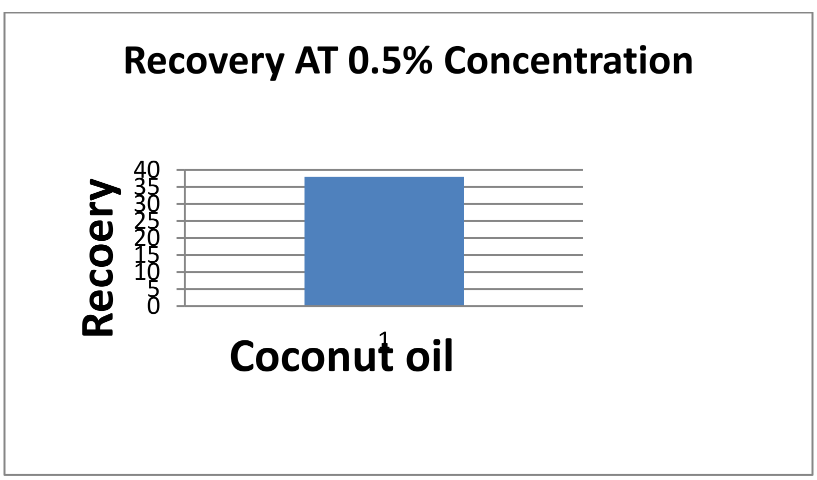

Figure 2: Recovery at 0.5% concentration of selected surfactant

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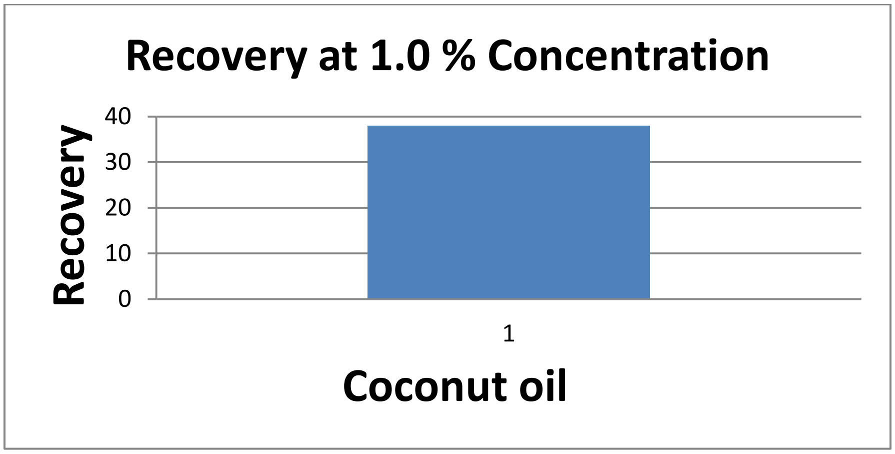

Figure 3: Recovery at 1.0% concentration of selected surfactants

For Conventional Agent

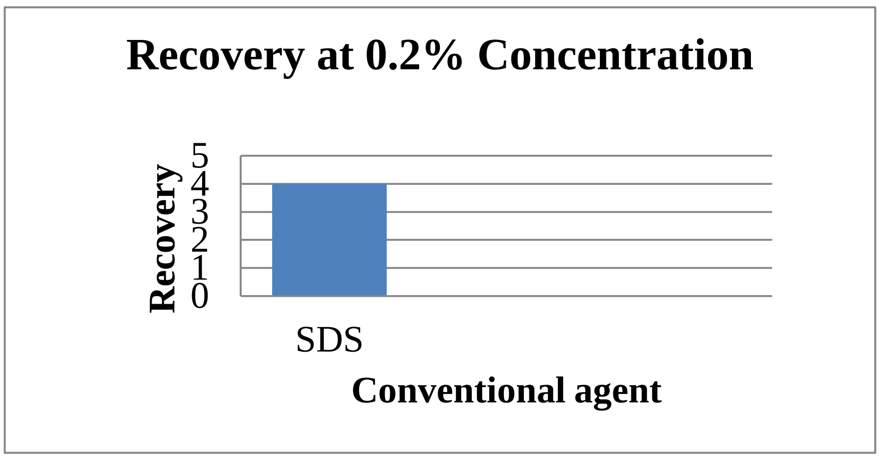

Figure 4: Recovery at 0.2% concentration of conventional agent

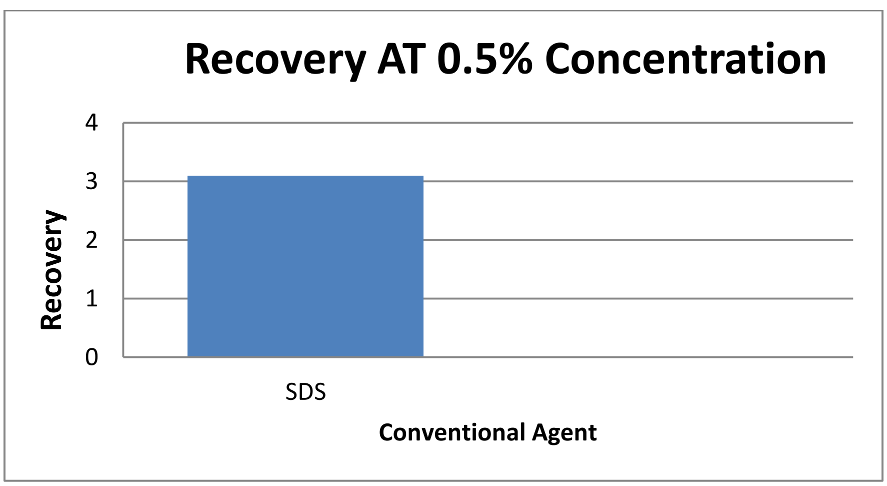

Figure 5: Recovery at 0.5% concentration of conventional agent

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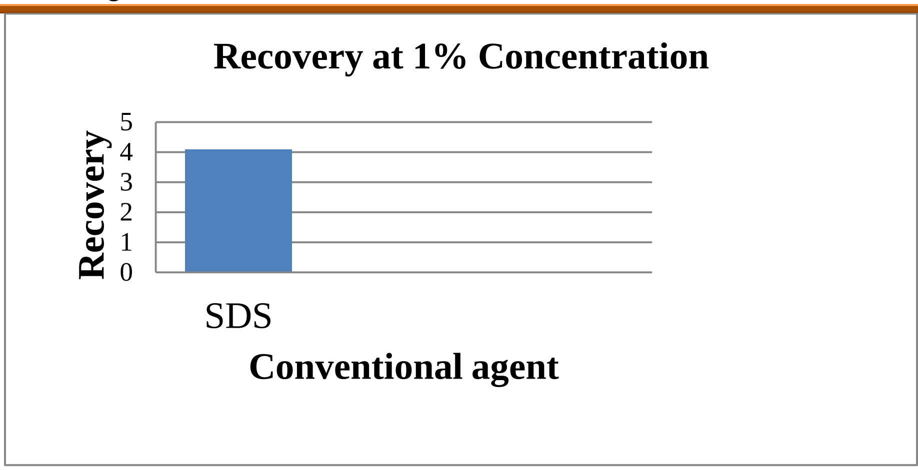

Figure 6: Recovery at 1.0% concentration of conventional agent

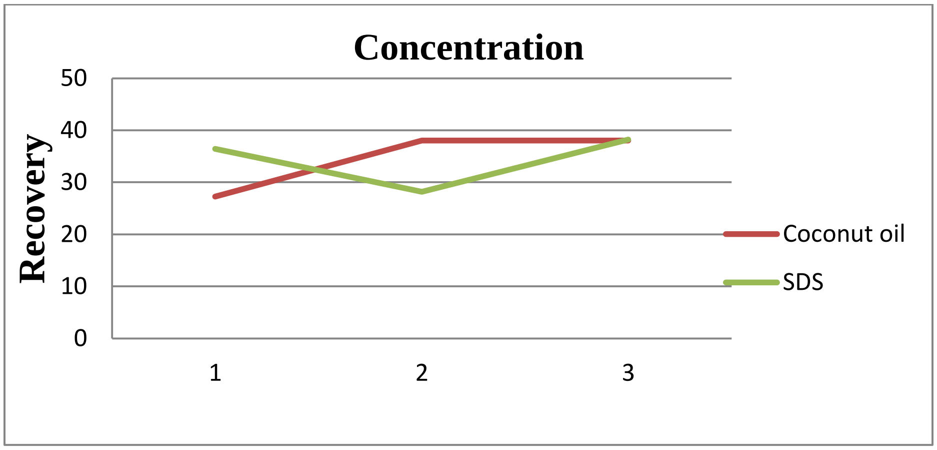

Figure 7: A graph of recovery against concentration

FTIR Characterization of Pure Coconut Oil and Sulphonated Coconut Oil

Table 7: Sulphonated coconut oil

S/N	Absorbance	Characteristic peaks (Wavelength) cm^{-1}	Functional group	Compound name
1	0.5-2.0	2400-2600	S-H Stretching band	Thiols (RSH)
2	0.1-0.5	800-1000	C-S Stretching band	Sulphonate (S=O)
3	0.1-0.2	400-600	S-S Stretching band	Disulphide (S-S)
4	0.1-0.2	Absent	C-H Stretching band	Coconut oil (Natural)

Table 8: Pure coconut oil

S/N	Absorbance	Characteristic peaks (Wavelength) cm^{-1}	Functional group	Compound name
1	1.0-2.0	3050-2800	C-H Stretching band	Triglycendae
2	0.5-1.0	1400-900	C-H bending band	Methylene C.
3	0.2-0.5	1680-1500	C=C Stretching band	Oleic acid
4	0.2-0.5	1228-1155	C-O Stretching band	Fatty acid
5	0.5-1.0	1050-800	C-O-C Stretching band	Ester

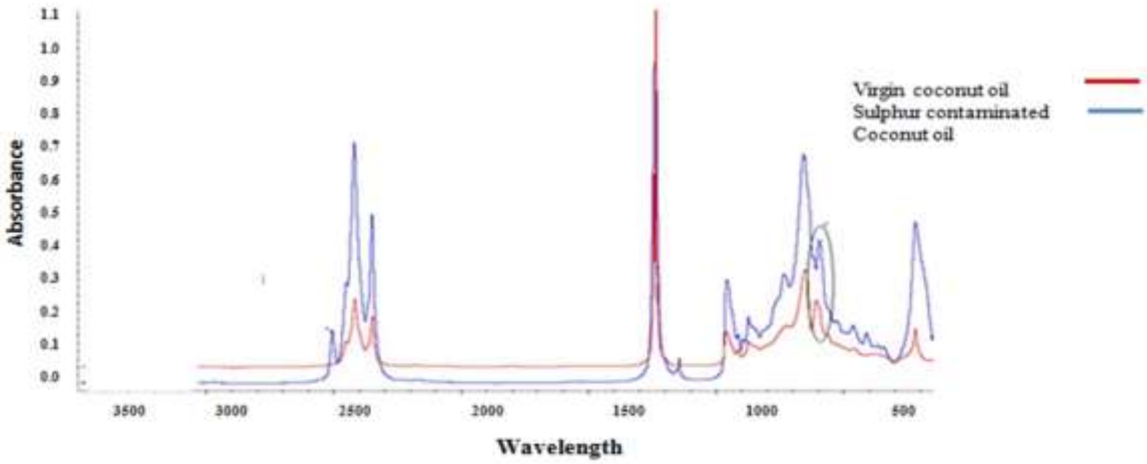

Figure 8: FTIR spectra of virgin coconut oil (VCO) and adulterated coconut oil

3.2 Discussion

The surface tension of coconut oil solutions showed a decrease with increasing oil concentration, indicating surfactant properties. The emulsion stability of the coconut oil-water mixtures was tested using the centrifuge test method. Coconut oil showed better emulsification properties at a higher concentration. The interfacial tension between oil and brine was measured using the spinning drop method. The interfacial tension decreased with increasing concentration of coconut oil, indicating a surfactant effect. The viscosity of the surfactant solutions was measured using a rotational viscometer. The viscosity increased with increasing concentration of coconut oil, which is an important consideration for CEOR applications. Core flooding tests were carried out to evaluate the potential of coconut oil for CEOR applications.

The presence of sulphonated functional groups (sulphates or sulphonates) in the coconut oil indicates successful sulphonation. The presence of new peaks at 2400-2600 cm^{-1} (S-H Stretching Band) and 800-1000 cm^{-1} (C-S Stretching Band) confirms the incorporation of sulphur into the coconut oil.

The FTIR spectrum of virgin coconut oil should show the characteristic peaks of triglycerides, such as CH Stretching Band (3050–2800 cm^{-1}), C-H Bending Band (1400–900 cm^{-1}), C=C Stretching Band (1680–1500 cm^{-1}), C-O Stretching Band (1050–800 cm^{-1}). The presence of these peaks indicates the presence of pure triglycerides in the coconut oil, without adulterants or contaminants.

4. Conclusion

Coconut Oil shows promise as sustainable and effective surfactant for enhanced oil recovery, particularly in high-viscosity and high-temperature reservoirs. The literature review highlights the positive impact of coconut oil on interfacial tension, emulsifying properties, and oil recovery factors. However, further research and testing are necessary to fully understand the properties and behavior of coconut oil as a surfactant under different reservoir conditions.

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Authors

Anthony Ogbaegbe Chikwe, is a senior lecturer in the department of Petroleum Engineering, Federal University of Technology, Owerri. He holds both BSc. and MSc. degree in Petrochemical Engineering from the University of Oil and Gas Moscow. He also holds Post graduate certificate in advance studies in academic practice from Newcastle University upon Tyne, UK and Ph.D degree in Petroleum Engineering from the Federal University of Technology, Owerri. His research interests are in Production, Reservior, Natural Gas and Drilling Engineering. He is also a fellow of the Higher Education Academy, UK.

Christian Emelu Okalla, is a Technologist and Researcher at the Department of Petroleum Engineering, Federal University of Technology Owerri, Nigeria. He holds both B.Eng and M.Eng in Petroleum Engineering from the Federal University of Technology Owerri. His research interests are in drilling engineering, production engineering, natural gas engineering, reservoir engineering, and reservoir simulation.

Young-Dede Steven Boloinyofa holds degrees in Mechanical Engineering and Petroleum Engineering. His research interests include thermal–fluid and energy engineering, drilling engineering, reservoir engineering, and production engineering. He received his academic training from the Petroleum Training Institute (PTI), Effurun, and the Federal University of Technology, Owerri.

Ndubuisi U. Okereke has over 15 years combined industry and academia experience, cutting across; subsea engineering and deepwater oil field development, process and flow assurance studies, project management and tutoring on courses related to Petroleum production, reservoir engineering, rock mechanics etc. Some of the major projects he has been involved in includes: Review of Severe Slugging Mitigation Strategy for Chevron's Agbami Oil Field, Swamp dredging/work-over operations of typical swamp oil wells: such as Belema Oil wells 8, 9, and 10 for SPDC, Chobiekiri Capital Dredging project (SPDC), Alakiri Gas Plant Access Dredging (SPDC). He is a member of SUT (Society for Underwater Technology) and SPE (Society of Petroleum Engineers). He has also been involved in a Pre-FEED project for Santos basin in Brazil, where he worked with the Flow Assurance team to develop a Flow Assurance strategy for an oil field with inherent wax problem. He is very competent in the deployment of OLGA.