

**APPLICATION OF OIL PALM MILL EFFLUENT AND PALM BUNCH  
EMULSION AS CHEMICALS IN ENHANCED OIL RECOVERY**

**BY**

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**A THESIS SUBMITTED TO THE DEPARTMENT OF PETROLEUM ENGINEERING,  
SCHOOL OF POSTGRADUATE STUDIES  
FEDERAL UNIVERSITY OF TECHNOLOGY OWERRI**

**IN PARTIAL FULFILMENT OF THE REQUIREMENTS FOR THE AWARD OF  
DOCTORATE DEGREE (PhD) IN PETROLEUM ENGINEERING**

**JULY, 2025**

**CERTIFICATION**

This is to certify that this research project proposal " **APPLICATION OF OIL PALM MILL EFFLUENT AND PALM BUNCH EMULSION AS CHEMICALS IN ENHANCED OIL RECOVERY**" was carried out by **DANIEL OJI NDEM** (Reg. No: 201743233938) in partial fulfillment for the Award of Doctor of Philosophy in Petroleum Engineering Federal University of Technology Owerri.



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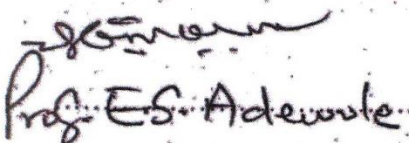
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## **DEDICATION**

This research work is dedicated to God Almighty, to my loving wife and children, to my supervisors for their immense contributions.

## **ACKNOWLEDGEMENTS**

I would like to express my heartfelt gratitude to Almighty God for granting me the grace and strength to complete this dissertation. His divine intervention made everything possible, and I am forever grateful. I extend my deepest appreciation to the individuals who have played a significant role in my academic journey. First and foremost, I am indebted to my dedicated supervisor, Engr. Prof. S. I. Onwukwe whose support and guidance throughout the entire writing process have been valuable. I would also like to express my sincere thanks to my two other supervisors, Engr. Dr. Angela Nwachukwu and Dr. U. I. Duru for their expert advice and constant encouragement.

My heartfelt appreciation goes to the HOD of Petroleum Engineering, DR. A Kerunwa and the entire staff of the department for their strong support in preparing me for this research work. I would like to acknowledge other lecturers and non-academic staff of the Department of Petroleum Engineering for their professional guidance and support throughout the process of writing this research work

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## ABSTRACT

Chemical enhanced oil recovery is one of the popular techniques used in the petroleum industry, and most of the chemicals are imported and expensive. Therefore, it is important to develop cheaper and indigenous chemicals for enhancing oil recovery from Nigerian oil reservoirs. This research focused on the formulation of emulsions for emulsion flooding of residual oil from oil reservoirs using locally available agricultural waste materials from palm oil mill. Oil was extracted from palm oil mill effluent using a centrifuge; alkaline solution was prepared with distilled water and ash from burnt empty fruit bunch. Oil/Alkali solution emulsions were formulated using different ratios of oil/palm bunch ash solution (5/95, 10/90, 15/85, 20/80, 25/75, 30/70, 35/65, 40/60, 45/55). Nine core samples of determined dimensions were initialized at reservoir conditions by flooding them with brine of salinity of 30000ppm until the differential pressure became stabilized. To produce the brine upon pressure stabilization, and determine the original oil in place, the brine- saturated core samples were flooded with crude oil (32.9 API). Then the crude oil-saturated core samples were firstly flooded with water till oil production ceased with 58.3% of oil recovered. Lastly, to produce the oil-in-place, the previously water flooded core samples, were respectively flooded with the formulated emulsions of 15/85, 25/75, 30/70, 35/65, 40/60 and Oil/Alkali solution ratios due to their stability performance. The results revealed that water flooding yielded 32.5% of the oil in the respective core samples while different ratios of formulated emulsion (15/85, 25/75, 30/70, 35/65, 40/60) yielded incremental oil recovery of 30.4%, 32.8%, 35.2%, 51.6%, and 55.2% ..The experiments suggest that certain emulsion compositions enhance the mobilization and displacement of oil better, leading to high reservoir sweep efficiency.. The economic analysis shows that investment in the production of conventional emulsion sample has negative net present value of -499,507,552,185.00 Naira throughout a 10-year period, while investment in the production of 30/70 emulsion sample with oil extracted from palm oil mill effluent and palm bunch ash solution has positive net present value of 26,940,828,073.20 Naira. A mathematical proxy model developed for oil recovery efficiency prediction gave an R-square of 95.2%. This work has established that these emulsion samples can yield encouraging oil recoveries when used in enhanced oil recovery

**Keywords:** Palm oil mill effluent, Empty palm fruit bunch, Emulsion flooding, Core Flooding, Recovery Efficiency, Palm Bunch Ash.

# CHAPTER ONE

## INTRODUCTION

### 1.1 Background Information

Emulsion flooding of the petroleum reservoir is a facet of chemical enhanced oil recovery method whereby slug comprised of stable solution of hydrocarbon, brine, and emulsifying agent are injected into the reservoir to help mobilize and produce trapped oil that are by passed in the reservoir due to viscous, gravity and capillary forces thereby ultimate recovery is optimized.

One of the demerits of chemical enhanced oil recovery method is the high cost of the chemicals which makes the process viable only when there is rise on price of crude oil (Uzoho., Onyekonwu, & Akaranta 2019). Many Niger Delta oil fields in Nigeria are approaching tertiary recovery stage. It is therefore imperative to introduce local contents as substitutes for costly chemicals in sustaining the process.

Research has revealed that some indigenous materials in Nigeria contain chemical composites that can *serve* as alkali, surfactant and polymer for chemical flooding, (Obuebite , 2023; Onwukwe, et al., 2022; Gbadamosi, et al., 2022; Uzoho., Onyekonwu, & Akaranta, 2019; Akpoturi and Ofesi, 2017; Oduola and Oriji, 2017; Ogolo., Ogiriki., Onyiri., Nwosu.& Onyekonwu 2015; Ikeagwu and Adetila, 2015). Emulsion flooding is an effective chemical flooding method; the performance of this technique is strongly dependent on the formulation of the emulsion slug. They are kinetically stable and are not formed spontaneously; they require external energy to be produced. The unrefined palm oil mill effluent is a thick brownish sticky and colloidal substance which contains: water, suspended solids and oils (Ng, Goh, and Tay 1987). The empty palm fruit bunches ash contains potassium oxide

and sodium oxide (Ogunsuyi and Akinnawo 2012). These substances and compounds are common in the Niger Delta region and have potentials in formulating cost effective and environmentally friendly emulsion flood fluid for emulsion flooding operation in oil reservoir.

The majority of the world's current oil production comes from mature fields. Oil corporations and governments are concerned about increasing oil recovery from aged resources. Furthermore, the rate of replacement of produced reserves by fresh fields has been progressively declining in past decades. As a result, increasing the recovery factors from mature fields under primary and secondary production will be important in the coming years to fulfill the growing energy demand. The oil industry is always researching new, efficient, and cost-effective methods of recovering every drop of oil from mature or existing oil fields. Accordingly, crude oil development and production have progressed through three separate phases: primary, secondary, and tertiary or enhanced oil recovery. The rock in the reservoir has a high affinity for oil in the reservoir, which means that oil is the wetting phase of reservoir rock. After primary and secondary oil recovery techniques are no longer effective for fluid mobility in the reservoir, tertiary recovery, also known as Enhanced Oil Recovery is then introduced. There are different types of enhanced oil recovery methods and chemical flooding is one of them; It entails the use of chemicals in the form of alkali, surfactant and polymer to produce more oil beyond that recoverable by secondary recovery method Mandal (2015).

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 Laura (2011).

## **1.2 Problem Statement**

In Nigeria, the use of oil field chemical in enhancing oil recovery from the reservoir is a capital-intensive program due to high foreign exchange required to import the oil field chemicals. Hence a significant percentage of the residual oil in the mature fields are being shut-in or underproduced. Therefore, it is pertinent to improvise local chemicals which are cost effective, user friendly and eco-friendly to reactivate and prolong the producing life of these oil fields.

## **1.3 Objectives of the Study**

The main objective of the research is to investigate the effectiveness of local materials, using agricultural waste of palm oil mill to enhance oil recovery from oil reservoirs:-

### **The specific objectives are:**

1. Characterization of burnt palm oil fruit bunch and palm oil mill effluent.
2. Investigation of exact mechanism of recovery action.
3. Provide reservoir system (reservoir and wellbore) screening guide for use of product.
4. Formulation of emulsion flood fluid using burnt palm oil fruit bunch and palm oil mill effluent emulsifying agent.
5. Carry out core sample flooding experiment to determine oil recovery potential of burnt empty palm oil fruit bunch-and palm oil mill effluent emulsifying agent in emulsion flooding
6. Develop a numerical model to determining the recovery efficiency of the formulated emulsion flood fluid.

#### **1.4 Justification of the Study**

Due to the high cost of imported chemicals, the use of local chemical in enhanced oil recovery is taken into consideration (Uzoho, Onyekonwu, & Akaranta, 2019; Hosseini, Hosseini & Sarmadivaleh 2021). High viscosities oil-in-water emulsions can be applied in displacing oil from a petroleum reservoir, thereby increasing oil recovery factor. Zohoorparvaz, Arastoo, and Sahraei (2013)

#### **1.5 Scope of the Study**

This work will be limited to a laboratory experiment on the investigation of the use of emulsion derived locally from palm oil fruit bunch and palm oil mill effluent, therefore, it does not involve field testing.

## CHAPTER TWO

### LITERATURE REVIEW

#### 2.1 OVERVIEW OF CHEMICAL ENHANCED OIL RECOVERY (CEOR)

More than two-thirds of the fields in the Niger Delta are mature fields, therefore primary recovery mechanisms are no longer imperative for the withdrawal of hydrocarbons from these Brownfield (Onwukwe, Izuwa, Ileaboya & Ihekoronye 2019). The global decline in petroleum reserve and the subsequent rise in the yearning for oil have drawn a lot of interest in recovering the residual oil trapped within the pores of the reservoir after primary and secondary techniques are unable to yield additional recovery of oil from the reservoir (Nguyen, Carey, Viswanathan & Porter 2018). About 60% of the Original Oil In Place (OOIP) are withdrawn after the application of primary and secondary recovery processes in producing oil from petroleum reservoirs, this is as a result of the early breakthrough of the displacing fluids used in secondary recovery technique, therefore other techniques are needed to harness the remnant 40% of the Original Oil In Place (Bornae, Manteghian, Rashidi, Alaei, & Ershadi 2014).

Globally, more than Four trillion barrels of crude oil are left untapped in the petroleum reservoirs at the expiration of primary and secondary recovery drive mechanisms application in withdrawing hydrocarbons from porous media. To improve the mobility of the circumvented or trapped oil in the formation, there has been in practice the application of secondary and tertiary oil recovery methods to harness the remaining 40% of oil in the reservoirs. Numerous researches have been carried out to recommend satisfactory methods to produce adequate volume of residual oil from the reservoir formation (Yun, et al., 2020)

Enhanced oil recovery (EOR), is a compendium of streamlined techniques applied in recovering residual oil from a hydrocarbon formation. The expression “Improved oil recovery” (IOR) has been often substituted for “Enhanced Oil Recovery” (EOR). Improved oil recovery (IOR), broadly applies the improvement of hydrocarbon recovery by any method found capable. For instance, operational approaches such as horizontal wells and infill drilling, advance vertical and areal displacement are IOR applicable methods which can result to a boost in recovery of hydrocarbons. The major objective of Enhanced oil recovery is the reduction of hydrocarbon saturation below the residual oil saturation ( $S_{or}$ ) which is the saturation of oil retained in the reservoir after water flooding process due to capillary forces, and high viscosity (Thomas 2008).

Mobilizing the trapped oil droplets into a flowing oil bank invariably reduces the amount of residual oil saturation thus accounting for additional oil recovery of about 20%. Nevertheless, the economic implication of surfactant agents has rendered surfactant flooding less striking. fascinatingly, topical experimental investigations have established that certain materials obtained locally have the ability of surface-active agents in the efficient recovery of oil trapped in the petroleum reservoirs. This has attracted more interest due to their low cost, availability and eco- friendly nature (Obuebite, Onyekonwu, Akaranta, Ubani, & Uzoho 2020).

## **2.2 Current Research on the Use of Local Resources in Oil Flooding**

Azdarpour, Noroupour, Santos & Mohammadian (2023) examined the efficiency of a green surfactant extracted from the *Avena sativa* (Oat plant) in boosting oil recovery when these three sodium salts; Sodium chloride (NaCl), Sodium carbonate ( $\text{Na}_2\text{CO}_3$ ), and Sodium sulphate ( $\text{Na}_2\text{SO}_4$ ) were respectively added to it. Secondly the researchers investigated the effectiveness of Sodium hydroxide (NaOH) as an additional chemical to the green surfactant in enhancing oil recovery. During the experiment, the core sample was first flooded with NaOH, and then followed by the green surfactant

extract from *Avena sativa* at a critical micelle concentration (CMC) value of 4,000 ppm, and respective injections of  $\text{Na}_2\text{CO}_3$ ,  $\text{NaCl}$ , and  $\text{Na}_2\text{SO}_4$ . However, the researchers observed that the addition of Sodium hydroxide ( $\text{NaOH}$ ) improved the effectiveness of the green surfactant by increasing the recovery factor due to reduction in the interfacial tension of the reservoir formation. The result showed recovery factors of 88.45%, 80.87%, and 7.98% using  $\text{Na}_2\text{CO}_3$ ,  $\text{NaCl}$ , and  $\text{Na}_2\text{SO}_4$  respectively.

Rad, Alizadeh, Takassi & Mokhtary (2023) due to growing need for eco-friendly chemical additives in the oil industry and legislative policies synthesized a fresh eco-friendly surfactant and evaluated its applications in surfactant-stabilized foam. The experiment was carried out in two stages: formulation of surfactant and feasibility study of its performance in enhanced oil recovery operation. The surfactant molecules were made through chemical reactions, and then tested for properties such as FT-IR,  $^1\text{H}$  NMR, and CHNSO to categorize surfactant structure and validate the formulations procedure. The critical micelle concentration (CMC) of the surfactant was noted to be 2521 ppm, and at different oil types and salinity values. The performance of the formulated surfactant in the fluid–fluid interface was evaluated during the second stage the ability of the surfactant to foam was also evaluated in various surfactant concentration, oil forms, pH and salinities. The researchers examined the effect of these factors with temperature. Using four sand sample flooding experiment, the behavior of surfactant foam in oil reservoirs was ascertained and the outcome indicated that formulated surfactant can be applied in field test operations because the surfactant can produce additional 15% oil from water-wet reservoir and additional 11% from oil-wet reservoir formation.

Onwukwe et al., (2022) investigated the effectiveness of nanofluids formulations from a blend of nanoparticles and oil extract from *Irvingia gabonensis* (bush mango) in boosting recovery from oil porous media. This empirical assessment engaged the use of sand face flooding operation, brine,

crude oil, nano-particles, and *Irvingia gabonensis*. The researchers synthesized nano-fluids using nano-particles of aluminum oxide ( $\text{Al}_2\text{O}_3$ ) and zinc oxide ( $\text{ZnO}$ ) and applied them respectively in flooding oil –wet sand face samples after having flooded the sandstone cores with water. Lastly, oil extract from *Irvingia gabonensis* which served as organic polymer was blended with the nano-fluids of  $\text{Al}_2\text{O}_3$  and  $\text{ZnO}$  respectively, the combination of the respective nano-fluids and the organic polymer was used in flooding the crude oil-wet core samples, its effects on oil recovery from the core samples were obtained. The outcome from nano-fluids flooding with the nano-particle of aluminum oxide and zinc oxide showed oil recoveries of 38.9% and 42.8% correspondingly. Nonetheless, as the respective nanofluids mixed with the organic polymer were injected into the core samples, the oil recovery significantly enhanced to 47.7% and 52.7% for the  $\text{Al}_2\text{O}_3$  and  $\text{ZnO}$  nano-fluid flooding respectively. This evaluation revealed that nano-particles of  $\text{Al}_2\text{O}_3$  and  $\text{ZnO}$  can boost oil recovery from the porous media, however, the addition of *Irvingia gabonensis* to the nanofluid of  $\text{Al}_2\text{O}_3$  and  $\text{ZnO}$  promoted oil recovery from oil-wet core samples. Consequently, the researchers concluded that *Irvingia gabonensis* has proven its ability to optimize oil recovery through the mechanisms of viscosity increase and mobility decrease of the flooding fluid.

Abbas, Abd-alsaheb & Abdullah (2023) carried out a research to prove the environmental friendliness, and low cost of locally synthesized surfactants in chemical enhancement of oil recovery from porous media. In this research, saponin extract from various natural materials in the Middle East were tested for their behavior with quartz sand, the adsorption isotherm models were pinpointed in evaluating the saponin behavior with reservoir formations. Three local materials evaluated were fenugreek, sugar beet leaves and chickpeas. The major mode of extraction applied was chemical extraction using the Soxhlet UV Vis spectrometer was used to study the behavior of the solution and the resulting adsorption on quartz sand. All the samples were dominated by glycosides (triterpenoid

saponin) with difference in purity, and intensity corresponding to the source of the local material. The entire sample exhibited close critical micelle concentration (CMC) range of 45.5 wt%. The researchers noted that sugar beet leaves gave the greatest adsorption level at 192 g/kg, about 25% and 37% above the Fenugreek and chickpeas, correspondingly. When the researchers increased the salinity, the outcome was a decrease in adsorption ranging from 2% and 56%. However, they observed that the adsorption isotherms conformed to the Langmuir model fitting and the sugar beet leaves model appears to validate Freundlich and Halsey isotherms

Haq (2021) investigated the efficiency of a local surfactant –Polymer (SP) solution in enhancing recovery of oil from a carbonate formation using core samples. The researchers combined laboratory, and simulation in this study. Several formulations of Surfactant-Polymer from alcohol, ketone, and natural acid were made after analyzing their abilities to reduce interfacial tension (IFT) and their behavior in response to temperature and pressure changes. Surfactant-polymer mixture of xanthan gum (XG), alkyl polyglucoside (APG), and butanone displaced 22% trapped oil from the carbonate core samples. The researchers noted that this formulation produced more than twice of the trapped oil. Likewise, a mixture of XG, APG, acrylic acid, and butanol recovered more considerable oil volume than the respective use of APG, XG, and acrylic acid formulation. Therefore, they concluded that APG, XG, and butanone mixture are more effective in boosting recovery from the carbonate porous media

Uzoho, Onyekonwu, & Akaranta, (2019) carried out a core sample flooding experiments using fourteen local resources of diverse concentration based on laboratory provisions. These researchers screened the following local resources for chemical flooding operations of the Niger Delta oil reservoirs: *Elaeis guineensis* (Palm oil), *Musa sapientum* (Banana), Potash, *Khaya ivorensis* (African Mahogany), Nkankan (a native plant), *Carica papaya*'s leaves (Pawpaw Leave), *Cocos nucifera*

(Coconut), kai-kai (Local Gin), Vernonia amygdalina (bitter leaf), Abelmoschus esculentus (Okro), Brachystegia eurycoma (Achi), Detarium microcarpum (Ofor Seed), Irvingia gabonensis (Ogbono Seed) and Mucuna flagellipes (Ukpo). Firstly, the researchers used each of the local materials separately in flooding the oil wetted core sample and observed that Alkali performed well with additional oil displacement efficiency of 17.3%. Surfactant and Polymer produced additional recovery efficiency of 5.2% and 18.7% respectively. Secondly, the local materials were combined in formulating Alkaline-Polymer, Alkaline-Surfactant, Surfactant-Polymer and Alkaline-Surfactant-Polymer solutions. The solutions were respectively used to flood oil core samples to produce further oil displacement efficiencies of 96.7%, 93.5%, 95.2% and 90% accordingly. The researchers observed that alkali and polymer local materials gave better recovery efficiencies when used independently, they concluded that the local materials are efficient in flooding oil reservoirs and can be used instead of synthetic materials though refining and modifications will improve the effectiveness of the local materials.

Oyatobo, Muoghalu, Ikeokwu & Ekpotu (2021) in search of better method of improving chemical flooding operations of oil reservoirs used locally sourced polymers to enhance oil recovery from sandstone reservoirs through viscosity increase of the flooding fluid and secondly to reduce the cost of accrued from using imported synthetic polymers such as Floppan. The researchers experimented on Starch, Ewedu, and Gum Arabic. The optimum efficiency of these polymers was evaluated in oil wetted core samples flooding. The researchers found out that starch produced the utmost oil recovery as a result of viscosity increase of the displacing fluid as compared to Ewedu and Gum Arabic. In conclusion, they suggested an increase in the concentration of Starch and Gum Arabic for maximum displacement efficiency

Obuebite, et al.,(2020) carried out a research on Surfactant flooding based on its ability to reduce interfacial tension between the displacing and displaced fluids. The research reviewed the oil displacement efficiency of different local surfactant in comparison with synthetic surfactant. Commonly used synthetic surfactant, Sodium dodecyl sulphate (SDS) and three different local surfactant namely AlkaSurf X (a hibiscus plant extract), Palm kernel oil (*Elaeis guineensis*) and Moringa leaf (*Moringa oleifera*) was evaluated in the laboratory using various concentration in a bid to compare their performance, however only two local surfactant; Moringa leaf (*Moringa oleifera*) and AlkaSurf X were used as Palm kernel oil (*Elaeis guineensis*) failed the initial compatibility test. To simulate actual formation brine, brine samples were prepared in the laboratory using sodium chloride and Potassium chloride with Total dissolved solids (TDS) of 30,000 ppm. Critical micelle concentration (CMC) was calculated to ascertain the right concentration to flood with. Sandstone oil displacement experiments using core plugs with porosity values ranging from 22%-23% was carried out on medium crude oil to ascertain the effectiveness of the selected local surfactant in recovering oil. Results showed high compatibility of the brine with all the selected local surfactant. As the brine salinity increased, the pH of the surfactant concentration increased. In line with the results obtained from the CMC plot, the synthetic surfactant performed best at 0.2 wt. % while the local surfactant performed best at a higher concentration of 0.4 wt% of the two-local surfactant, AlkaSurf X gave the highest additional recovery of 22.7% OOIP while the synthetic surfactant gave an additional recovery of 20% OOIP. This study underpins the oil displacement efficiency of these local surfactant. Moreover, Alka-surf X can be considered as a novel, low-cost, high performing surfactant capable of enhancing oil recovery.

Peter and Onyekonwu (2018) formulated Alkaline-Surfactant-Polymer (ASP) fluids from local materials such as: burning of palm bunch, plantain back, archi and prepared displacing fluids from

solution of foreign polyenoic cellulose polymer. Several core flooding tests were carried out in the laboratory using different compositions of the fluids in flooding the core samples to determine the compositions that would push out more oil. Result obtained showed that highest recovery of oil 3.5ml was obtained when the ASP fluid has a composition of 0.6 Alkaline and 0.4 Polymer, displacing about 64.07%. The displacing fluids from the foreign materials recovered 4.0ml (78.13%). The residual oil saturation after flooding with the local alkaline-polymer fluid was about 24%.

Onyemachi, Onwukwe, Duru, Chikwe & Uwaezuoke (2020) observed that the application of nanofluids flooding in the oil and gas industry is recently emerging as enhanced oil recovery methods and nanoparticles have the ability to alter the rock formation in order to recover oil trapped in the pores of the rock to improve oil recovery. Therefore, in this study, the researchers used core plug samples in the laboratory to investigate the effect of nanoparticles on oil recovery. The core samples were saturated with low salinity brine considering its ability to alter rock wettability. After core flooding with brine for secondary recovery process, extracted oil from *Irvingia gabonensis* was pumped into the formation to investigate the its effect on oil recovery. The result of the study showed that magnesium oxide, silicon oxide, aluminum oxide, and zinc oxide had oil recovery of 38.1%, 45.6%, 47.7% and 35.1%, respectively. However, when the nanofluids with *Irvingia gabonensis* were injected into the formation as a displacing agent, the oil recovery greatly improved to 50.3%, 52.0%, 53.2% and 52.4% for (MgO, SiO<sub>2</sub>, Al<sub>2</sub>O<sub>3</sub> and ZnO). The result of the study showed that nanofluid flooding is a promising potential to improve oil recovery in the Niger Delta.

Ojukwu, Onyekonwu, Ogolo & Ubani (2013) believed that alkaline-surfactant-polymer (ASP) designed from local materials has great potential in enhanced oil recovery (EOR) considering the cost. The researchers therefore evaluated the following materials in formulating polymer floods; *Irvingia Gabonensis*, Lecithin and Palm Bunch Ash (PBA). Granulated *Irvingia Gabonensis*, and wild mango

seeds (Ogbono, a biopolymer). It was noted that it has comparable properties with the xanthan gum that is already in use. Lecithin, a surfactant extract from soya bean, and PBA, an alkali was respectively simultaneously used to flood the core samples, resulting to the recovery of more 25 % of oil-in-place due to the reduction of interfacial tension by the alkali. The surfactant recovered 23.3% OIP. The polymer used increased recovered 22.7% OIP. A blend of the reagents recovered 27.7% trapped oil-in-place and an incremental oil recovery of 17.9% above water flooding. . They posited that the technique can be successfully applied in producing oil left in reservoirs after primary and secondary recovery process has been exhausted

Eseimokumoh, Woyintonye, Eniye, Preye & Young (2021) studied the ability of cornstarch (local polymer) to recover additional oil after conventional water flooding. This research was conducted by injecting four different unconsolidated samples (sand pack) with cornstarch solution at varying concentration of 500ppm, 1000ppm, 3000ppm, and 9000ppm. From the results of the experiment conducted, it was deduced that Cornstarch has the ability to recover an additional volume of oil about half the volume of oil recovered during conventional water flooding (i.e. if 50% of oil initially in place was recovered during water flooding, cornstarch can recover an additional 25% of the residual oil after water flooding). Also, higher concentrations of cornstarch reduce the recovery factor due to polymer adsorption on the rock surfaces which alters the rock wettability. To reduce the adsorption effect of Cornstarch, the researchers recommended that the concentration of Cornstarch be measured after the flooding experiments for a better understanding of the adsorption mechanism of cornstarch.

Daud et al. (2021) studied the application of lignosulfonate (LS) from coconut husk as a surfactant agent to increase the efficiency of surfactant flooding. Lignin was extracted from coconut husk before sulfonation using sodium sulphite,  $\text{Na}_2\text{SO}_3$  to form lignosulfonate. FTIR was used to characterize the lignin and lignosulfonate and compare them with the commercial product. The oil (paraffin)

displacement experiment was then conducted using 5% lignite and 95% sand to simulate Malaysia's sandstone reservoir mineral composition. Two types of surfactant were studied; anionic (Sodium Dodecyl Sulfate-SDS) and nonionic (4-octylphenol polyethoxylate-TX100). The percentage of oil recovery was calculated based on the volume of oil recovered from the original oil in place (OOIP). The displacement tests show that oil recovery was increased from 2.52% to 3.10% for SDS after the preflush and from 1.36% to 2.00% for TX100 after initial flooding with LS. This increase corresponds to 23.6% and 47.1% increments in oil recovery from the test without LS flooding respectively. These results have shown that the LS have the potential to be used as a surfactant agent to increase the efficiency of surfactant flooding.

Fadairo, et al., (2021) reported the extraction and performance evaluation of two locally formulated polymers for enhanced oil recovery applications. The oil displacement processes were conducted using six (6) sandstone core samples. Reservoir permeability tester was used to simulate real reservoir conditions in order to evaluate the suitability of the formulated biopolymers for oil displacement applications at laboratory conditions. The experimental results indicate the effectiveness of the local polymer solutions in enhancing oil recovery better than the traditional water flooding with percentage oil recovery of 30.9–39.3% for banana peel derived polymer and 40.6–50.8% for mango kernel derived polymer compared to the traditional water-flooding with percentage recovery of 16.2–32% of the initial oil in place. This work identified the potential suitability and use of local polymers for enhanced oil recovery.

Akpoturi and Ofesi (2017) conducted a flooding experiment in the laboratory to study the use of locally derived alkaline in optimizing recovery of oil from Niger Delta reservoir using core samples prepared and saturated with formation brine of 30, 000ppm salinity, crude (light and medium) were then flowed through sand samples. The samples were individually flooded with brine for secondary

recovery process where an average of 55% of initial Oil in place was recovered. Each sample was flooded with different alkaline (local and conventional) for the tertiary recovery stage. The result obtained during flooding on samples saturated with light crude showed that KOH recovered 74%, NaOH recovered 66%, and palm bunch ash recovered an average of 64% while  $\text{Na}_2\text{CO}_3$  recovered 59%. The research concluded that the use of local content which is relatively cheaper can enhance oil recovery in the Niger Delta and this will in turn increase the local content drive of the Nigerian government in the oil and gas industry.

Oduola and Oriji (2017) due to the quest for techniques to recover the remaining 60–80% of the original oil in place (OOIP) left after conventional oil recovery delved into the application of an appropriate formulation of an ASP composite substance that can recover more oil from mature reservoirs using Ogbonor seeds, *Irvingia gabonensis*, potash, and salt). The study showed that the best level of salinity needed for the retention of the polymer gel viscosity is 30g/l and the maximum viscosity of the polymer solution is 1.086, in the absence of additives. In conclusion, the researcher stated that the chosen additive (potash) does not have a significant effect on the polymer solution that will result in highest viscosity which enhances a good percentage of oil recovery. Polynomial models relating the resulting polymer viscosity with concentration and salinity have been developed, applicable for predicting polymer viscosity at different concentrations of salt and additive.

### **2.3 Emulsion Flooding**

Emulsion flooding is a form of enhanced oil recovery process characterized by the pumping of an emulsion into a petroleum reservoir to raise the volume of oil recovery from the reservoir (Alvarado, Wang & Moradi, 2011). It is specifically formed by the combination of water, oil, and a surfactant which contributes to the stability of the mixture (Farajzadeh, Wassing & Lake 2019).

Emulsion flooding of the petroleum reservoir is an aspect of chemical enhanced oil recovery method whereby slug comprised of stable solution of hydrocarbon, brine, and emulsifying agent are injected into the reservoir to help mobilize and produce trapped oil that are by passed in the reservoir due to viscous, gravity and capillary forces thereby ultimate recovery is optimized. There are various emulsion formulations, including water-in-oil (W/O) emulsions and oil- in-water (O/W) emulsions (Zhao, Torabi, & Yang 2022).

Emulsions are mixtures of at least two liquids that are immiscible. In emulsions obtained from two such liquids, one of the liquid phases consists of droplets dispersed inside the other, continuous, liquid phase. The flow of emulsions through porous media is very important in enhancing oil recovery (Arhuoma, Yang, Dong, Li, & Idem 2009; Mandal, Samanta, Bera, & Ojha 2010a; McAuliffe, 1973a). As the population of the world increases, the need for energy, especially fossil fuels increase. Since the costs of exploring new reservoirs and drilling new wells are very high, most reservoirs have passed their first and second stages of production, and it is crucial to employ EOR methods.

Emulsions are commonly described as a blend of two dissimilar immiscible fluids that are dispersed in each other consisting of two divergent phases, the dispersed or internal phase, and the continuous or external phase (Maaref, Ayotollahi, Rezaei, & Masihiet 2017). Generally, two types of emulsions are used in emulsion flood technique, which are O/W and W/O emulsions; between these two, O/W emulsions have shown a better performance and higher oil recovery in the literature (Gogarty 1967). These emulsions can improve water injection profile through the selective plugging process. This means that they can prevent water from passing through areas with lower moveable oil saturation and reduce water cut, while the oil recovery factor is increasing (Zohoorparvaz and Arastoo 2013; Yu, Dong, Ding & Yuan 2018). There have been numerous experimental studies and hypothetical exactness underscoring the introduction of emulsion flooding as an efficient method in flooding oil

reservoirs. (Demikhova, et al., 2016; Kumar, Dao & Mohanty 2012; Usman and Jimme, 2016; Yang and Wan Fen, 2020).

Wei, Lu, Li, Li & Ning (2018) noted that the global economic impasse has rendered the use of imported chemicals for chemical enhanced oil recovery unrewarding. Therefore, their research proposed a chemical flooding process that will use mild oil-water emulsion formulated by saponification of low-cost alkali and petroleum acid-rich oil. The result established that oil-water emulsion flooding can increase the sweep efficiency and enhance recovery from oil reservoirs

Emulsion flooding technique has been adjudged one of the efficient and effective tertiary recovery methods, the success of this method lies on the formation of the emulsion slug. McAuliffe (1973b) reported the first application of emulsion flooding in an oil field. The emulsion with normal droplet diameter of 3 microns and viscosity in 200 cp were pumped into the well. In the 2-year period, three emulsion injection wells showed lower water cut and increased oil recovery, the studies indicated an improvement in sweep efficiency. The injection of 3% of the 33,000 bbl crude oil emulsion resulted to a production of 55,000 bbl of additional oil. To improve the dislodgement of trapped oil in the formation demands that the mobility of the displacing fluid be made smaller than the mobility of the remaining oil in the reservoir, the achievement of this objective calls for the injection of emulsions as prospectively useful technique (Kumar et al., 2012; Rocha De farias, De Souza, Da Silveira, Hirasaki & Miller 2012).

The efficiency of emulsion in enhancing recovery of oil from various geological reservoirs such as carbonate and sandstone formations has been established (Kumar and Mandal 2019). Regrettably, the commonly applied water flooding recovery technique is characterized by low displacement efficiency due to unfavorable mobility ratio resulting to viscous fingering and early water breakthrough occasioned by reservoir heterogeneity (Rocha de Farias, et al., 2012; Jamaloei, Babolmorad & Kharrat

2016; Liu, Bai & Wang 2010;). To solve the problem of early breakthrough of water used in water flooding, water management skills become necessary and one of those skills is the employment of emulsions injection into the hydrocarbon formation (Taylor, Zohoorparvaz, Arastoo & Sahraei 2015)

### **2.3.1 Mechanism of Emulsions Formulations**

Emulsion formation in the petroleum reservoir is a complex physical and chemical development which is subjective to many parameters, such as; wettability of the rock, structure of the pore-throat structure, crude oil properties, the volume of trapped oil, and the distribution type of the trapped oil. Compared with emulsions formed by mechanical stirring, the formation mechanism is more complex. There are few studies on the formation mechanism of emulsions in porous media, and they have been mostly carried out through visualization tests or microfluidic devices.

Microfluidic devices can be used to simulate the formation process of emulsions, (Galooyak, Dabir & Zolfaghari 2015)

Kokal and Al-Dokhi (2007) reported a novel method to observe and study the characteristics of emulsions in a high-pressure and high-temperature environment. The study was conducted in a special visual pressure/volume/temperature (PVT) cell. The results showed that emulsions can form under reservoir conditions, especially if the crude oil has a tendency to precipitate asphaltenes. The formation of emulsions mainly depends on the composition of crude oil, especially the content of gelatin and asphaltene (Ortiz, Baydak & Yarranton, 2010)

The snap-off of residual oil depends on the capillary number, velocity, viscosity ratio, and pore-throat ratio. Hoyer, Alvarado and Carvalho (2016) reported the snap-off process in a constricted capillary with an elastic interface, suggesting that interface rheology greatly influences the snap-off of drops and that a reasonable viscoelastic behavior at the interface may lead to optimal interfacial stability against snap-off.

Zhou, Yin, Cao & Zhang (2018) studied the stability of emulsion used in displacing reservoir oil through the formation pore spaces by determining the zeta potential of various emulsifier concentration in the emulsions, the viscosity variation at respective water cut were also investigated. The results indicated that the zeta potential increases with increase in concentration of the emulsifier in the emulsion showing that oil recovery efficiency is 9.8% at emulsifier concentration of 0.4%. Kim, Jeong & Kim (2008) simulated the droplet formation in a cross-junction micro-channel using the lattice Boltzmann method, and the surface tension affecting the droplet length and the interval between droplets were investigated. The results indicated that the droplet length and the interval between droplets were increased with increased surface tension.

Fu, Zhao, Bai, Jin & Cheng (2016) simulated the emulsion formation by a ternary Lattice Boltzmann method, and the simulation results showed favorable agreement of emulsion formation with the experimental data. The results showed that the flow rate of outer fluid supplied viscous shear force against interface tension, which made the droplet pinch-off occurred near the exit orifice. As the fluid viscosity increased, the droplet pinch-off was delayed

### **2.3.2 Types of Emulsions**

Emulsions can be classified into two types namely: micro-emulsion and macro-emulsion. Micro-emulsions are thermodynamic stable (from high energy to low energy), transparent or translucent, isotropic liquid mixtures of oil, water, and an emulsifier. They have a droplet size of 100nm and are

characterized by their low interfacial tension and high power of solubility. Macro-emulsions have larger droplet size, typically greater than 100nm, and are kinetically stable (the emulsion forms slowly, from low energy to high energy) for three components of the emulsion system, the micro-emulsion is the counterpart of the macro-emulsion since they both belong to the system but with different characteristics. The study of micro-emulsion began in the late 1960s, encouraged by the long emulsion stability and ultra-low interfacial tension of the micro-emulsion. The petroleum industry started research into the tertiary micro-emulsion recovery method EOR research in the 1970s. (Healy, Reed & Carpenter 1975).

Table 2.1: Comparison between Micro-emulsion and Macro-emulsion source Healy et al., (1975)

	Macro-emulsion	Micro-emulsion
Stability	Kinetically	Thermodynamically
Transparent	No, milky white	Yes or low turbidity
Size	Mainly 0.1-10 mm	10-200 nm
Formation	No	Spontaneous
Type	o/w, w/o, w/o/w, o/w/o	o/w, w/o, cylinder

Source: Healy et al. (1975)

Healy et al. (1975) carried out a laboratory experiment on micro-emulsion core flooding. He projected that the micro-emulsion flooding is concerned with miscible and immiscible aspects which are affected by injection rate. Residual oil saturation reduction is a consequence of increased surfactant concentration. Willhite, et al., (1980) executed a laboratory study on the micro-emulsion oil recovery mechanisms by investigating the phase behavior and conducting core flooding experiments. The authors reported that a milky white macro-emulsion effluent was observed and are of the opinion that the single pseudo three phase charts may be not enough due to the variation of the concentration of the surfactant to the oil phase ratio.

Bennet, Davis, Macosko & Scriven (1981) scrutinized the rheological properties of the micro-emulsion and established the Newtonian and Non-Newtonian behavior.

Bouabboune, Hammouch & Benhadid (2006) evaluated micro-emulsion flooding and surfactant flooding effectiveness in a low-viscous oil reservoir. The authors explained that the micro-emulsion flooding technique is the exceptional and effectual technique for brown fields, and established a critical surfactant concentration, and micro-emulsion viscosity for flooding programs.

Binder, Clark & Russel (1965) raised the idea to inject an oil-in water emulsion to improve the heavy oil recovery in his patent. They recognized the necessity to increase the displacing fluid viscosity to tune the mobility ratio during the viscous oil reservoir water flooding. They mentioned that the oil-in-water emulsion might make up the whole driving fluid body or a portion of the driving fluid. The core flooding results indicated that 78% of the oil in place was recovered at the breakthrough and 83% recovery factor was reached by injecting one pore volume emulsion. And the produced emulsion was very similar in characteristics to the emulsion injected.

Bousaid (1978) projected a surfactant stabilized solvent in water emulsion flooding to enhance recovery from low-API gravity oil reservoir. The surfactant concentration may vary during the sixteen-injection processes and different hydrocarbon as solvent could be used in making the emulsion.

Sarma, Maini & Jha (1995) summarized the mechanism of the solvent in water emulsion flooding including mobility control, viscosity reduction by solvent dissolution, oil mobilization by in situ emulsification and phase interfacial tension reduction. The viscosity reduction improved but mobility control worsened with the surfactant concentration decreasing. The economical evaluation of solvent in water emulsion flooding shows that the continuous injection is not economical.

Bryan and Kantzas (2007) investigated the potential application of the alkali-surfactant flooding in heavy oil reservoir. The in-situ emulsification is the main mechanism for this process due to both alkaline and surfactant could lower the interfacial tension between water and oil phase. The experiment results suggest the water-wet rock and oil in water emulsion are preferred because the low viscosity character of the O/W emulsions could facilitate the production.

(Flaaten, Nyugen, Pope & Zhang 2008; Zhang, Roberts, Bryant & Huh 2009) discussed the potential application of the nanoparticles stabilized emulsion system in petroleum industry. The toluene in water

emulsions are generated with assistant of a bit of nano-particles. The study of the emulsion stability and phase behavior are reported and the emulsion`s piston-like front flooding is observed.

### **2.3.3 Rheological property of emulsions**

The rheological properties of emulsions affect seepage characteristics in porous media, such as deformation, migration, coalescence, and blocking of the throat. They are also important factors affecting the swept volume and displacement efficiency. The emulsion behaviors include different characteristics such as Newtonian fluid, expansion fluid, pseudo-plastic fluid, and visco-elastic fluid. (Yang, Tchoukov, Pensini, Czarnecki, Masliyah & Xu 2014).

The interfacial rheological method is the most common method for measuring the rheological properties of emulsions. It includes a shear test and an expansion test, and they are used to measure the shear rheological property and expansion rheological property, respectively. The shear test method utilizes a stress rheometer with a double-wall ring geometry (Pensini, Harbottle, Yang, Tchoukov, Li, Kailey, Behles, Masliyah & Xu (2014)

### **2.3.4 Emulsifying Agents.**

The emulsifying agents are developed to stabilize emulsions. They are classified into two types; namely, finely divided solids and surface-active agents, Fine solids generally stabilize an emulsion mechanically, these materials which are wet by both water and oil, should be smaller than emulsion droplets and should accumulate at the water/oil interface. The effectiveness of these particles in stabilizing emulsions are strongly dependent on various factors such as inter-particle interactions, particle size, and wettability of the material, (Dalmazzone, Noik, Glenat & Dang, 2010). Fine solid materials existing in the produced oil include clay particles, sand, asphaltene/ wax, silt, and mineral scales deposited on the water/oil interface, (Kokal and Al-Juraid, 1998; Menon and Wasan, 1987).

Surface-active agents or surfactant are the particles which are soluble in both oil and water phases. They have a hydrophilic branch, which has tendency to interact with oil and there is a hydrophobic branch that has an affinity towards water. Due to their special chemical structure, surfactant tend to create an interfacial film at the oil-water interface. (Binks, Dong & Rebolj, 1999).

This phenomenon generally leads to a reduction in the interfacial tension (IFT) and consequently enhances droplets dispersion and emulsification. Naturally acting surfactants such as asphaltenes and resins in the heavy oil have high boiling-temperature fractions. These materials appear to be the main components of intervening films that form between the water and oil droplets in the field emulsions. Other emulsifying agents might come from the injected chemicals including asphaltene control agents, wax, stimulation chemicals, corrosion inhibitors, scale inhibitors, and drilling fluids to the wellbores or formation. (Kokal 2005).

### **2.3.5 Stability of Oil Emulsions**

From a thermodynamic perspective, an emulsion is an unstable system due to its natural tendency for a liquid/liquid mixture to minimize its inter-facial interactions (or/and inter-facial energies). (Kilpatrick 2012). However, most emulsions demonstrate a kinetic stability after a period of time. Oilfield emulsions are usually categorized based on their degree of kinetic stability. The interactions between the surface-active agents and water/oil interfaces are primarily responsible for emulsion stability. During emulsification, emulsifying agents are adsorbed to the freshly formed inter-facial film, which weakens the inter-facial forces and allows the immiscible phases to be partially mixed. Following the first drop formation, the former emulsion begins to be altered because of different time-dependent processes, which are Ostwald ripening, coalescence, flocculation, sedimentation, and creaming as the most controversial processes, (Urbina-Villalba, 2009).

### 2.3.6 Factors Affecting the Viscosity of Emulsions

The viscosity of Emulsion flooding plays a crucial role in determining its effectiveness in flooding petroleum reservoirs. The composition of the emulsion greatly influences its viscosity, emulsions typically consist of water, oil, emulsifying agents. The choice of oil and water phases, along with the surfactants used as emulsifying agent impacts the interfacial tension and stability of the emulsion. The viscosity of emulsion is generally affected by temperature, shear rate, salinity and pH, particle contamination and emulsification techniques such as mechanical stirring, homogenization, and ultrasonic method. (Masalova, Kapiamba, Tshilumbu, and Malkin 2018).

Shafiei, Kazemzadeh. Shirazy & Raizi (2022) took a stage by stage investigation of the parameters influencing the stability and viscosity of the emulsion. In the initial stage, 50% volume of water was elected as the best water cut. The second stage saw the appraisal of salt type and its most excellent concentration by measuring the average droplets size. The third stage investigated the outcome of SiO<sub>2</sub> nano-particles and nonionic surfactant (polysorbate 80) on emulsion stability and viscosity. According to the results, the best amount of water cut was 50% due to the maximum viscosity. In salts the yield was as follows: MgCl<sub>2</sub> > CaCl<sub>2</sub> > MgSO<sub>4</sub> > Na<sub>2</sub>SO<sub>4</sub> > NaCl. The best yield was related to MgCl<sub>2</sub> at a concentration of 10,000 ppm. Finally, it was shown that the synergy of nano-particles and surfactant resulted in higher stability and viscosity than in the case where each was used alone. The work observed that the optimal concentration of nanoparticles is equal to 0.1% (w/w), and the optimal concentration of surfactant is equal to 200 ppm. In general, a stable state was obtained in 50% water-cut with MgCl<sub>2</sub> salt at a concentration of 10,000 ppm and in the presence of SiO<sub>2</sub> nanoparticles at a concentration of 0.1% and span 80 surfactant at a concentration of 200 ppm. The results obtained from this study provide important insights for optimal selection of the water-based EOR operation parameters.

Zhang and Xu (2016) studied the rheological performance of oil-water emulsion using Haake RS6000 rheometer with a laboratory scale flow ring. The non-natural emulsion was subjected to characterization at volume fractions from 0.1 to 1.0 L/L and shear rates ranging from  $0.001-1000\text{s}^{-1}$  at a temperature of  $20^{\circ}\text{C}$ . as the emulsion flow was observed by the static mixer in the 2-m long horizontal pipes of 25mm and 50mm inside diameters at diverse mixture flow rate ranging from 0.01- 7.00m<sup>3</sup>/h. A comparison between rheological measurements and laminar flow data shows that the values of the Sauter mean droplet diameters formed by the SMV static mixer are approximately one order of magnitude bigger than those measured by the rheometer. For oil-in-water emulsions with low oil content, the stress-strain relationships obtained in the rheometer are more suitable for predicting the transport characteristics of the emulsions with a large pipe diameter than those with a small pipe diameter. In addition, the phase inversion points in the pipe flow are closer to those measured at high shear rates in the rheometer. Therefore, the apparent viscosity obtained by the rheology measurements at high shear rates could be introduced for accurate calculations of the mixture Reynolds number and the friction factor in emulsions flow.

### **2.3.7 Droplet Size Distribution Techniques**

Droplet size distribution is one of the most important characteristics of the emulsions since it determines the potential destabilization processes. (Sjöblom et al., 2003).

Zhou and Kresta (1998) conducted an extensive review on the correlations and measurement techniques (light transmission, image analysis, and coulter counter) employed for determination of droplet size in the oil/water emulsions. Sprow (1967) established that in the case of oil/ water emulsions, the inertial effects dominate the viscous energies as the continuous phase has a low viscosity than the suspended phase. Hinze (1955) found that if the water drops exist in the oil emulsion phase, the viscous forces override the inertial forces in this type of emulsion. Although there are

methods such as Nuclear Magnetic Resonance (NMR), and video enhanced microscopy to measure the droplet size distribution in water/oil emulsions

Aichele, Flaum, Jiang, Hirasaki, & Chapman (2007) posited that sampling is generally required before conducting measurements. Among the measurement tools, particle video microscope (PVM) and focused beam reflectance measurement (FBRM) particle size analysis probes offer an in-situ droplet size measurement (Kokal 2005).

Sprow (1967) concluded that the mean droplet diameter is directly proportional to the maximum measured value for droplet size of the aqueous fluid as the continuous phase. This finding has been confirmed by several researchers (Lemenand, Della Valle, Zellouf & Peerhossaini 2003).

Boxall, Koh, Sloan, Sum & Wu, (2009) also obtained a relationship between the mean and maximum droplet size for a water droplet in oil emulsions. Droplet measurements are usually carried out in a mixing cell with a six-blade turbine impeller. Two droplet size analysis probes are normally installed at 45 degrees in the cell, oriented in front of each other; namely, a focused beam reflectance measurement (FBRM) probe and a particle video microscope (PVM) probe. They are placed at an equal level to the top of impeller to facilitate measurements and make the most of the flow passing the window. The turbine blade mixes all the materials to produce steady droplet size which can be achieved when there is a minor variation in FBRM distribution (Calabrese, Chang, & Dang 1986).

An optical rotating lens, which is placed at the top of the probe and is responsible for deflecting the laser, will reflect a laser beam, when the probe is inserted into an emulsion system. This occurs only when the beam scans the surface of a particle. The probe is responsible to determine the reflection time and to measure the chord length which is time multiplying by the speed of laser scan (Boxall, Koh, Sloan, Sum & Wu, 2009). Particle video microscope (PVM) is a complementary droplet size

analysis tool. The probe takes images of the lightened area and identifies droplets. Particles smaller than 20  $\mu\text{m}$  cannot be identified by the PVM probe as individual droplets (Boxall, et al. 2009).

Once a steady-state distribution is reached, the PVM probe takes random images for different distributions and the droplets are counted to calculate the droplet size distribution. Supplementary information on the PVM and FBRM can be found in the literature (Boxall, Koh, Sloan, Sum & Wu 2011).

Nuclear magnetic resonance (NMR) is one of the reliable and popular methods to measure the droplet size distribution (DSD) in both water/oil and oil/water emulsions so that a simple sample preparation is needed and an acceptable accuracy is attained. Emulsion stability analysis by the NMR method is based on the signal attenuation which is a result of random movements of droplets when the sample is imposed to two magnetic fields, since the intensity of NMR signal is related to the number of nuclei which are produced (Alvarado, Wang & Moradi 2011).

Hollingsworth, Sederman, Buckley, Gladden & John (2004) proposed a new method to calculate DSD by NMR which significantly reduced the experiment time. Amani, Nazar, Reza, Sabzyan & Azimi (2016) combined the previous approaches and introduced a fast strategy. Ernst (2010) used the Van der Tuuk model to obtain the droplet variation. Depending on the size range of droplets, two different methods were employed to determine DSD. A Fourier-Transform NMR Spectroscopy ordered from Bruker Company was used for DSD measurements. The samples are placed inside the machine right after preparation for conducting spectroscopy measurements. The experimental design and interpreting the results can be made using Taguchi method. A simple schematic of DSD measurement tool made of (a) PVM probe, (b) FBRM probe, (c) magnetic agitator, (d) impeller, and (e) baffle (Boxall et al. 2009). Another approach to determine the droplet size distribution is through the combination of a microscopic equipment, a digital image processing software, and a statistical tool,

the combined tools were used to investigate the effect of process conditions on the settling velocities of emulsions. Digital pictures were taken by a charge-coupled device (CCD) from an optical microscope. The droplet size distribution was determined by the AxioVision software. Different modules of this software enable us to perform systematic analysis on the phase distribution of the samples. The module can classify the particles by area or diameter. The research outputs included the droplet diameters and number of particles for each sample. The researchers took several pictures and scrutinized them to obtain  $d_{4.3}$  diameter. The  $d_{32}$  or Sauter 16 diameter is the volumetric average diameter of a spherical droplet similar to the mean diameter of particle system (Souza et al 2015).

Laser diffraction is another widely used technique to obtain the particle size distribution. Malvern diffractometer is one of the experimental apparatuses to determine the particle diameter, based on the optical properties of light. When a laser beam passes through a droplet, the sensors detect the angular variation in the scattered light intensity. Small particles scatter the light at big angles, whereas small deviations were reported for large particles. The angular deviation intensity of the scattered light is then studied to estimate the particle size where the Mie theory is used to analyze the scattered light (Binks, Dong & Rebolj 1999). One of the widely used methods for determining the emulsion stability is bottle test (Kokal 2005). This method relies on the water resolution so that the procedure involves diluting emulsion with a solvent, adding emulsifier, shaking, and monitoring phase separation by time. The test is normally conducted at a specific temperature and may be performed using a centrifuge to accelerate the separation process. ASTM (American Society for Testing and Materials) method is a broadly accepted strategy to specify the sediment and emulsion stability. This method is also applicable to examine the effect of different emulsifiers on emulsion stability. Turbiscan™ LAB is an appropriate equipment to fully characterize different types of dispersions such as emulsions or suspensions in terms of properties, type, and stability Turbiscan™ LAB Stability Analyzer. It is used

to perform the aging tests to provide adequate information on destabilization mechanisms (e.g., sedimentation, coalescence, flocculation, and creaming). Turbiscan Lab Expert offers more useful information, compared to the typical experimental approaches. For instance, it is possible to determine the stability of both concentrated and opaque colloidal dispersions with single equipment. The instability phenomena are also observed much quicker and simpler through using this tool, compared to the classical techniques (Celia, Trapasso, Cosco, Paolino & Fresta 2009).

Xu, Kang, Wang, & Meng (2013) performed electrical Microscope Analysis to investigate the stability of water/oil emulsions. The emulsion behaviors were monitored by an electrical microscope to take the amplified images of microscopic configuration and to determine the type of created emulsions. A proper statistical software was employed to obtain the average droplet size. Measurements through Turbiscan Lab Expert Stability Analysis were conducted by a pulsed near infrared LED. Two separate optical sensors captured and detected the light transmitted and back-scattered by the samples, for water/oil emulsions, only the back scattering (BS) light was investigated since this type of dispersion was opaque and the transmission light was weak or/and almost negligible (Ernst 2010).

### **2.3.8 Current Status of Emulsion Flooding for Enhanced Oil Recovery**

Pang et al., (2019) investigated the use of w/o emulsions for heavy oil recovery in a laboratory study and noted that the reservoir oil viscosity is significantly reduced by the emulsion and the oil recovery factor is thus improved. Alomair, Matar & Alsaeed (2015) carried out a field research in a Canadian heavy oil reservoir and established an increment of up to 20% in oil recovery factor by the application of almost 10% recovery

McAuliffe (1973a) pioneered the study of Oil-in-Water emulsions flooding as an EOR method by injecting emulsion into two similar cores and stated that emulsions drops have been trapped in layers

with high permeability and created an obstruction against water flow. Li, Zhang, Lau & Fu (2020) conducted a case study for heavy oil reservoir in a China. The authors noted that emulsion flooding increased oil recovery factor by ed this finding to the larger drop size of emulsion oil compared to the pore throat size. Various experiments have worked on plugging agents such as gels, cement and polymers to control water cut in production wells (Bai and Zhang 2011; Liu, Li, Lv, Li & Chen 2017; Stavland, Andersen, Sandoe, Tjomsland & Mebratu 2006) revealed that emulsion flooding can improve oil recovery factor more than gel flooding caused by the formation damage it imposed on marked regions and the absence of discrimination in selecting plugging process during the gel injection. The group developed a high-water content emulsion and introduced it in a North Sea oil reservoir to moderate water production.

Taylor, Zohoorparvaz, Arastoo & Sahraei (2015) verified the capability of using oil in water emulsions in managing water production from water flooding program of hydrocarbon reservoirs and accepted that decline in permeability of the high permeability layers resulted up to 30% enhanced oil extraction). Mandal, Bera & Ojha, (2010a) experimented to ascertain the effect of different values of oil content (5, 10, 20 and 30%) in Oil/Water emulsions will impose on reservoir formation when injected into it. They made oil –water emulsions using gear oil and injected them into core samples. The outcome of the flooding trials demonstrated that the emulsion with 10 % content gave the optimum oil recovery.

Pei, et al. (2017) enforced O/W emulsions by using few quantities of HPAM and noticed more stable emulsions with higher shear viscosity. The researchers experienced improved sweep efficiencies and more than 30% enhancement in oil recovery when the emulsion was injected into sand pack models to displace oil. Currently, emulsion flooding is still in the experimental laboratory stage. The design of field applications requires full understanding of the above aspects. There are scanty recorded field

test cases of emulsion flooding, and the most thriving case is the field test at Section 5K of the Midway-Sunset Oil Field.

However, an obvious emulsification phenomenon appeared in the ASP flooding field test (Crafton, Penny & Borowski 2009) which resulted in the development of reference values for laboratory studies and field tests of emulsion flooding.

The midway-sunset oil field is a humongous oil reservoir in Kern county, San Joaquin valley, California in the United States. The field was discovered in 1894, since then till 2006, it has produced 3 billion barrels of oil California Oil and Gas fields. 1998), Section 5K of the Midway-Sunset Oil Field is near Taft, California. The sands under the flood are the Top Oil sands and the Kinsey Oil sands. The sand thickness of Top Oil sands ranges between 3.05 and 6.10 m, and the thickness of Kinsey Oil sands ranges between 1.83 and 3.66 m. The porosity ranges from 33% to 35%. The average permeability of the Top Oil and Kinsey Oil sands is  $450 \times 10^{-3} \mu\text{m}^2$ . The oil saturation is approximately 40%, the residual oil saturation ranges from 30% to 33% after core water flooding, and the movable oil is very low. The oil gravity is approximately 20° API for the Top Oil sands, and it is approximately 25° API for the Kinsey Oil sands. The salinity is approximately 14000-15000 mg/L. Water flooding was started in September 1962. The water cut increased from approximately 25% to approximately 92% from the end of 1965 to mid-1970. The emulsion used to recover oil from this field was prepared using 70% Midway-Sunset Section 26C crude oil (14° API) and 30% fresh water phase containing 1% sodium hydroxide. The average droplet diameter of the emulsion was 3  $\mu\text{m}$ , and the viscosity was approximately 200 mPa·S. The emulsion was injected into three wells in April 1967. The field test indicated that the emulsion did not migrate with the water from the injection wells to the oil wells. Oil well 6-1 is 60.96 m away, which is the closest well to injection well 35. No emulsion was observed in the produced fluid from oil well 6-1, and no decrease in API gravity was found in the

produced oil. The API gravity of the produced oil was 24°, while the API gravity of emulsion was 14°. After the emulsion was injected for 4 months, the oil production of oil wells surrounding emulsion-treated injectors increased significantly and the water cut decreased compared with that resulting from water flooding. In all, 33 040 t of 14-% emulsion (4620 t of crude oil) was injected, and the volume of the emulsion was approximately 0.04 pore volume at Section 5K. The total produced fluid remained approximately constant, and the oil production increased. The oil production was approximately 7700 t by May 1970, which was greater than the extrapolated value. The produced water salinity increased after emulsion injection, indicating that more formation water was produced, and the sweep efficiency was also improved. (Zhou, Y., Yin, D., Chen, W., Liu, B & Zhang, X 2019)

Xing-V is an ASP flooding field test area in the Daqing Oilfield. The average net pay thickness is 6.8 m, the permeability is  $589 \times 10^{-3} \mu\text{m}^2$ , and the viscosity of the crude oil is 6.1 m Pa·S in the reservoir. There are five wells, including one injection well and four oil wells. The five-point well pattern was thus adopted, and there are five wells with one injection well and four oil wells in the test. The formulation of the ASP flooding system consists of NaOH with a concentration of 1.2%, ORS-41 with a concentration of 0.3%, and polymer with a concentration of 1200 mg/L. When the injecting liquid was approximately 0.08 PV (pore volume), the oil production was successively increased in the four oil wells. When the injecting liquid was approximately 0.7 PV, the water cut decreased from 96.9% to 80.7% (16.2% decrease). The cumulative oil production increased by 13 102 t. Different degrees of emulsification were observed in the fluids produced by the four oil wells, and more emulsion was observed in oil wells Y5-S3-2 and Y5-S1-1 with a viscosity of 40 mPa·S. To study the emulsification characteristics and their influence on the recovery in ASP flooding, the oil color, water color, and emulsification of the produced liquid were observed in well Y5-S3-2 (Zhou et al. 2019)

The area of Xing-II is also in the Daqing Oilfield. The average net pay thickness is 5.8 m, the permeability is  $675 \times 10^{-3} \mu\text{m}^2$ , and the inverted five spots well pattern was adopted in this area, including four injection wells and nine oil wells. Different degrees of emulsification were observed in the nine oil wells after injecting chemical fluid. The emulsion is greatest in the produced liquid of center well Y2-2-S1. In addition, the incremental oil production is highest in well Y2-2-S1. The water cut remained 100% for nine months before injecting chemical fluid. The minimum water cut was 50.7% and decreased by 49.3%. The average incremental oil production was 29 t/d, and the water cut stabilized between 50% and 80% for 16 months. The oil recovery was enhanced by more than 20%.

In addition, the ASP flooding field test was carried out in other areas, and the emulsification appeared. The emulsification was found in the field test, namely the more uniform the oil layer and the larger the injection-production well spacing, the more emulsion that appeared in the produced liquid. It is easier to emulsify residual oil by adding strong alkali than by adding weak alkali. After the residual oil emulsified, the viscosity of the displacing fluid increased, and its flow resistance increased. Thus, the amount of produced liquid greatly decreases, but the water cut also decreases, and the oil production rate greatly increases. The water cut decreases significantly when more emulsion appears in the produced liquid, which indicates that the emulsion can effectively adjust the displacement liquid mobility ratio and enhance the recovery. It was also found in surfactant flooding field tests that, although the oil-water interfacial tension is low, the oil recovery is not high if little or no emulsion is produced. Therefore, the research emphasis on the surfactant is important to increase the emulsifying performance (Son, Kim, Lee, Kim & Sung 2014)

Sofla, Sharifi, & Sarapardeh (2016) developed a green surfactant to improve the emulsifying property of surfactant based on the existing green surfactant. Therefore, accelerating the

development of a green surfactant with high efficiency, low-cost, and good emulsifying properties and the environmental friendliness of chemical flooding in field applications.

### **2.3.9 Advantages of Emulsion Flooding**

One of the advantages of O/W of emulsion flooding are its accessibility and lower cost of transportation as well as its exhaustively coverage in the hydrocarbon formation and so its simple injection (Kumar and Mahto 2016; Yu et al. 2018).

Romero et al., (1996) studied the consequence of fracture plugging of in situ O/W emulsions by injection of an optimum amount of water/oil ratio into reservoir core samples and observed a huge reduction of 90% in water relative permeability. According to Starvland, et al., (2006), the reduction in permeability varies from layer to layer, with regard to the fluid's saturation. Demikhova, et al., (2016) ascribed this issue to retention of dispersed oil droplets of O/W emulsions in the pore throat as a result of two mechanisms: (1) size exclusion and (2) droplets/pore walls interactions in porous media.

Yu et al., (2018) declared that permeability reduction of their core sample experiment models was a function of the volume of emulsion slug, oil and water fraction in emulsions, injection flow rate and the absolute permeability of the models. Emulsions are beneficially applied in the oil industry, but may exhibit some other detrimental behaviors. Textually, traditional water injection into petroleum formations known for high permeability has resulted to water coning and early water breakthrough, because of this adverse effect of water flooding.

Sadati and Sahraei (2019) introduced the injection of Oil in Water emulsions as a corrective technique in enhancing recovery from Iranian oil reservoirs, a succession of flooding trials was demonstrated in an Iranian oil formation with reservoir descriptions of 75°C and 2000 psi. An anionic surfactant Sodium Lauryl Sulphate was used in dispersing the oil in water emulsion and the stability description

of the formed emulsion was noted through visual stability measurements, furthermore emulsions with various water percentage ranging from 90, 80, 70 and 60 were consecutively injected into the porous media of the petroleum reservoir to ascertain the oil in water emulsion formulation that can produce extra oil. The test proved that emulsion with 80% water-base produced more oil and generally traditional water flooding accompanied by emulsion injection can enhance recovery to almost additional 20%. Finally, the outcome of the stability test showed that the addition of the surfactant formed a stable emulsion for a period of 182 days (one hundred and eighty-two days). Water /oil emulsion has the ability to usefully advance the sweep efficiency and impact positively on the volume of oil recovery from a petroleum reservoir as a result of its capability to manage mobility and it is ideal for oil reservoirs with API gravity between 10 and 22.3

Zigi, Wanfen, Renbao & Sheshi (2022) investigated the emulsion stability, dispersion of droplet size and other emulsion performances at diverse water content and salinity. The displacement efficiency and mechanisms of water/oil emulsion injection were studied through core flooding trials and monitored using etched transparent glass networks of pores and constriction. The results disclosed that: emulsions viscosity decreases with increasing shear rate, stability and droplet size dispersion decrease with increase in percentage of water in the emulsion, emulsion stability was inversely proportional to salinity. However, the viscous fingering, early water breakthrough due to petroleum reservoir heterogeneity were managed very well with emulsion flooding.

Wang, Xu, Liu, Jiang & Wu (2023) conducted a core sample experiment to evaluate the characteristics of emulsion flow and means by which emulsion flooding can displace oil in reservoir pore throat. The outcomes of the research showed that emulsion flooding can recover up to 6 % additional oil by efficiently and effectively sweeping the residual oil from the reservoir porous media to the production well and could achieve this feat through two mechanisms: (1). Reduction of viscous fingering by

mobility control and plugging of high permeability zones as well as thief zones. (2). Effect of the forces of extrusion as emulsions are transported through the pore throats.

Guillen, Carvalho & Alvarado, (2012) carried out pore scale flow visualization experiments as well as core flooding tests in parallel sandstone core samples having different permeability, to understand the mechanisms of incremental oil recovery achieved by emulsion injection. The results showed emulsion flooding offers multi-scale mechanisms which are microscopic displacement efficiency, and conformance sweep efficiency.

Guillen et al., (2012) introduced a selective mobility control mechanism of emulsion droplets driven by capillary forces so that strong interfacial forces (low capillary number) have significant effect in lowering down the mobility of emulsion containing larger drops compared to the diameter of pore throats. On the other hand, displacing fluid mobility is only slightly influenced by emulsion drops in high capillary numbers. In this study, O/W emulsions with different ratios of water volume to oil volume of 90/10, 80/20, 70/30 and 60/40 were created. Gas-oil and double-distilled water were used as internal and external phase, respectively. Minimizing interfacial tension between gas-oil and distilled water is the most important mechanism for dispersing oil drops in the water and making stable emulsions. To achieve this, the surfactant of SDS was dissolved in the water at a specific concentration before adding the oil phase. The surfactant concentration in the emulsions has been chosen around twice the critical micellar concentration of SDS.

Xiaoyan, et al., (2021) used one-dimensional homogeneous core flooding experiments and parallel core flooding experiments to examine the effect of emulsification on the oil recoveries in the SP flooding process. 0.3 pore volume (PV) of emulsions which are prepared using ultra-low interface tension (IFT) SP solution and crude oil with stirring method was injected into core models to mimic the emulsification process in SP flooding, followed by 0.35 PV of SP flooding to flood emulsions and

remaining oil. The other experiment was performed 0.65 PV of SP flooding as a contrast. We found SP flooding can obviously enhance oil recovery factor by 25% after water flooding in both homogeneous and heterogeneous cores. Compared to SP flooding, emulsification can contribute an additional recovery factor of 3.8% in parallel core flooding experiments. But there is no difference on recoveries in homogeneous core flooding experiments. It indicates that the role of emulsification during SP flooding will be more significant for oil recoveries in a heterogeneous reservoir rather than a homogeneous reservoir

Wang, et al., (2021) analyzed the oil displacement efficiency and sweep efficiency for the surfactant-polymer flooding by using a heterogeneous micro-fluidic model. The authors studied the influence of salinity and water content on the W/O emulsion rheological behaviors, stability, and DSD were studied. Besides, core flooding experiments were conducted to investigate the displacement efficiency of the emulsion formed in different water content conditions. Furthermore, a visual micro-fluidic device was designed with different diameter particles to simulate heterogeneous formation. The blue-dyed emulsion was injected into a micro-model device, followed by emulsion and water to displace the red-dyed oil. The displacement process was recorded with a camera, these were then analyzed to study the displacement behaviors and oil recovery mechanisms of W/O emulsion flooding at the pore scale. This study provides significant information for the key mechanisms of W/O emulsion flooding, which is useful for the optimum field application of W/O emulsion.

### **2.3.10 Rheological Property of Emulsions**

Several experiments to analyze the effectiveness of the emulsion injection have been executed; however, literature is still limited about this method. One of these experiments was carried out by Demikhova et al., (2014) flooding Ottawa quartz sand pack with two oil-in-water emulsions prepared separately EM1 and EM2. The dispersed phase was represented by two ionic liquids (called IL1 and IL2) used in each emulsion respectively. An emulsifying agent was used in aqueous phase. Ninety percent of emulsion droplet size had 5  $\mu\text{m}$ . Additional properties of the components of the emulsion

may be found in the paper. A total of nine displacement tests were carried out, varying parameters such as temperature, water salinity, permeability, porous media and emulsion concentration. Emulsion flooding was considered as tertiary recovery followed by water displacement; secondary recovery was covered by water flooding. Results showed that in all cases both emulsions EM1 and EM2 lead to increase the oil recovery obtained by water flooding after emulsion entrapment. Additionally, was found that the use of an organic or inorganic anion in the dispersed phase of the emulsion will impact the recovery results. Although it is not clearly indicated which one generated the best results, it is stated that the emulsion that used the IL2 showed better results with recovery increasing up to 17%. Moreover, at reservoir conditions including sandstone representative sample and reservoir temperature up to 79°C it was obtained 29% additional recovery by the tertiary recovery with emulsion displacement

#### **2.4 Other Methods of Enhanced Oil Recovery**

There are several methods employed in enhancing recovery of residual oil, methods such as: thermal method, chemical method, microbial method, miscible and immiscible method, and chemical are the most common enhanced oil recovery techniques. These processes are effective methods of reducing residual oil saturation, and are thus considered Enhance Oil Recovery methods which are typically appropriate after secondary recovery drive mechanisms have been exhausted.

It is evident that low API gravity oil reservoirs and high API gravity oil reservoir are poorly recovered through primary and secondary withdrawal methods, thus the bulk of the recovery from these reservoirs is from EOR methods which targets a recovery factor of about 45% of the original oil in place (OOIP). The selection criteria for a particular method lies on the reservoir rock and fluid properties Thomas (2008).

### **2.4.1 Thermal Methods**

Thermal recovery techniques basically involve heating the reservoir oil to reduce the viscosity and improve mobility of the oil (Hascakir 2017). It is mainly proposed for highly viscous oil reservoirs heavy oils and asphalts, though in special cases can be extended to light oils reservoirs. Considerable industry interest in the application of heat to petroleum reservoirs as a means of increasing oil recovery has been evident in the past few years. Three thermal methods which have attracted interest are (1) steam injection, in-situ combustion, and combination of steam and in-situ combustion. Thermal injection can increase oil recovery by almost 30-50% when compared to water flooding method; it can cause reservoir damage and plugging if the process is mismanaged. (Alvarado and Manrique 2010).

Since 1950's, thermal methods have been candidates in enhancing oil recovery for heavy, and extra heavy oil reservoirs through the provision of heat to the reservoir, and consequent oil viscosity reduction. However other mechanisms, such as rock and fluid expansion, compaction, steam distillation may play a role. Thermal methods have been highly successful in Canada, USA, Venezuela, Indonesia and other countries (Gomaa, Salem, & El-hoshoudy 2023).

Several types of thermal flooding are mentioned below:

### **2.4.2 Steam Flooding**

Steam flooding is a thermal-based enhanced oil recovery method that applies injected steam into the reservoir to reduce the viscosity of heavy oil and increase its mobility (Dong, et al.,2019). It is a broadly applied thermal EOR technique on a commercial scale, it is done by introducing steam into a petroleum reservoir to warm up the oil and decrease its viscosity thereby mobilizing the oil, as the steam heats the oil, the oil expands and flow towards the production wells, latent heat is released as a result of the condensation of steam (Alvarado & Manrique 2010). Usual recovery factors range

between 50-60% of the oil-in-place (OIP). The advantages of steam injection are: High oil recovery factor, and reduced environmental impact, steam injection produces fewer greenhouse gas emissions compared to other thermal EOR methods such as in-situ combustion. The challenges faced by steam flooding are: high energy requirements, water consumption, reservoir heterogeneity, equipment and maintenance cost. There are several forms of steam flooding.

### **2.4.3 Cyclic Steam Stimulation (CSS)**

Steam is pumped into a reservoir production well at a temperature of 572-644 °F (300-340°C) for a given length of time considerably weeks or months. The well is then shut-in and the oil is soaked by the steam for a length of time (days –weeks) to reduce the oil viscosity before production is restarted, when oil production declines, the cycle is reiterated (Hascarki, 2017).

(Li, Li, Zhang, Li, & Yang 2018; Zhang, Liu, Ta, & Zou 2020) Observed that oil rate increases quickly to a high rate, and stays at that level for a Steam-oil ratio is initially 1:2 or lower, and it increases as the number of cycles increase. Near-well bore geology is important in cyclic steam stimulation for heat distribution as well as capture of the mobilized oil. CSS is mainly desired because it has quick payout, however, recovery factors are low (10-40% OIP). Figure 2.4.3 below showed the stages steam injection

### CYCLIC STEAM STIMULATION

Steam, injected into a well in a heavy-oil reservoir introduces heat that, coupled with alternate "soak" periods, thins the oil allowing it to be produced through the same well. This process may be repeated until production falls below a profitable level.

*Schematic portrays one well during the 3 phases of this process. Flow pattern is stylized for clarity.*

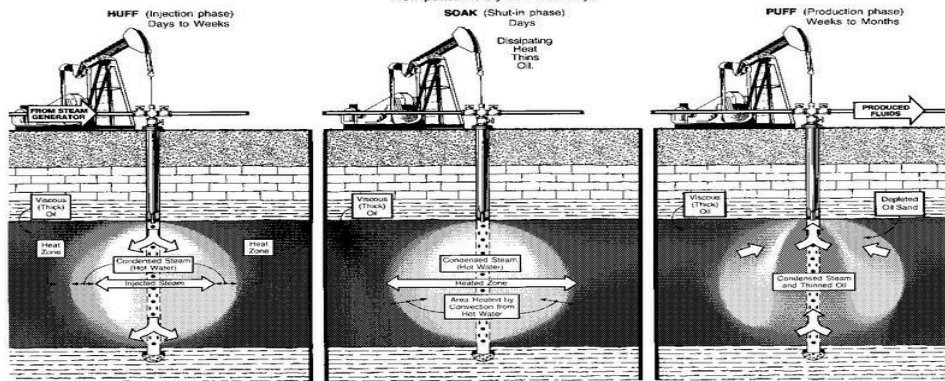


Plate 2.1: Continuous cyclic steam flooding processes courtesy of (Department of energy, United State of America)

#### 2.4.4 Steam Assisted Gravity Drainage (SAGD)

SAGD method entails the pumping of steam into a well bore located below a producing well bore. The steam heats the oil, reducing the viscosity of the heavy oil and bitumen and allowing the oil to flow through the reservoir towards the producing well bore due to gravity. The steam and heated oil are then produced from the producing well and separated at the surface (Butler 1994). Some of the advantages of this method are: high recovery rate of about 60% of the oil-in-place which renders it one of the most efficient recovery method for heavy oil and bitumen, it has low negative environmental impact because it reduces greenhouse gas emissions when compared to other thermal methods such as steam flooding, it reduces surface disturbance and requires fewer well pads (Bera, Achinta & Babadagli 2015). Despite the advantages of SAGD, it has some notable limitations such as high cost of operation, geological dependence because it is not effective when applied to all reservoirs; the water requirement for the success of this method is very high. Babadagli (2007).

Butler (1994) developed an SAGD intervention for the recovery of the Alberta bitumen. The development depended on the gravity segregation of steam, employed two parallel horizontal wells,

and located 500 cm apart within same vertical line. The schematic is shown in Fig. 2.4.4 The injection well is at the top and the producer was situated close the base of the reservoir, as steam ascended the top of the reservoir to form a steam chamber, the bitumen was mobilized due to a high decrement in its viscosity, and pushed down by gravity to the producer placed near the base of the reservoir. Continuous injection of steam resulted to the expansion of the steam chamber and tangential spread in the reservoir. The author noted the following facts: high vertical permeability is quite critical for the effectiveness of SAGD, SAGD is highly energy intensive Large volumes of water are required for steam generation, and the natural gas consumption for steam generation ranges between 200- 500 tons/sm<sup>3</sup> of bitumen. Other variations of SAGD are Expanding Solvent-SAGD and Vapor Extraction, the mechanisms of these processes depend primarily on molecular diffusion and mechanical dispersion for the transfer of solvent to the bitumen for viscosity reduction. Dispersion and diffusion are inherently slow, and therefore, are much less efficient than heat for viscosity reduction. The Expanding- Solvent-SAGD process is a variation, where the addition of about 10% steam to the solvent mixture has been suggested to gain a 25% gain in the energy efficiency of VAPEX-SAGP Steam flooding.

Vaporized Extraction (VAPEX) entails the injection of vaporized hydrocarbon solvents into heavy oil and bitumen reservoir, the advantages of VAPEX over SAGD lies on its energy consumption efficiency, eco-friendly and low capital required for introducing this method to the reservoir. It is applicable in thin-oil reservoirs. (Das and Butler 1998). VAPEX is a non-thermal version of SAGD, and it operates on the same mechanisms as SAGD. A solvent gas replaces the steam in SAGD, or a mixture of solvents, such as ethane, propane and butane is pumped down with a carrier gas such as N<sub>2</sub> or CO<sub>2</sub>. Solvent selection is based upon the reservoir pressure and temperature. The solvent gas is injected at its dew point. The carrier gas is intended to raise the dew point of the solvent vapor so that

it remains in the vapor phase at the reservoir pressure. A vapor chamber is formed and it propagates laterally. The main mechanism is viscosity reduction. (Das and Butler 1998)

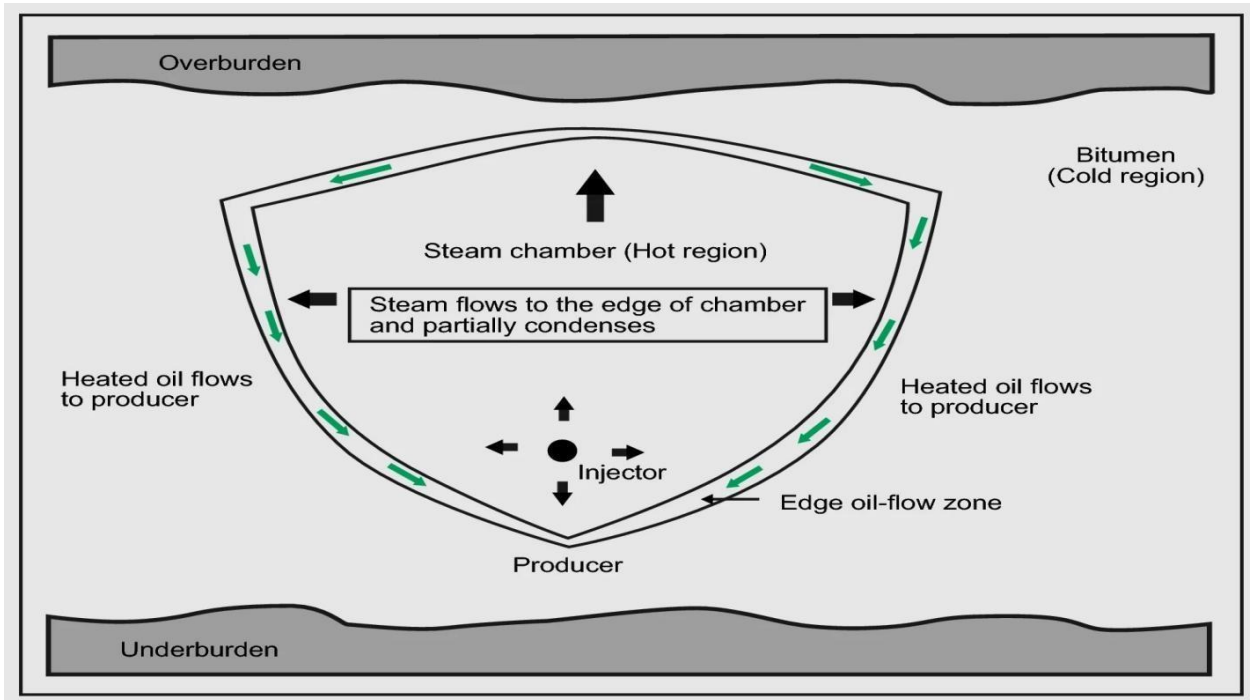


Plate 2.2: Schematic of SADG (Steam assisted gravity drainage flooding) source, Ghasemi and Whitson (2015).

## 2.4.5 IN-SITU COMBUSTION

Another term for this method is fire flooding where air or oxygen is introduced to the hydrocarbon reservoir to burn a segment of the oil- in-place to produce heat by raising the very temperatures to a range of 450-600°C in a narrow zone. High reduction in oil viscosity occurs near the combustion zone. The process has high thermal efficiency is witnessed due to moderately small amount of heat loss to the overburden or under-burden formation with no well bore heat loss. In some cases, additives such

as water or a gas is used along with air, primarily to improve heat recovery (Antolinez, Miri & Nouri 2023).

Rigorous corrosion, toxic gas production and gravity override are common problems. The main types of in-situ combustion are:

- Forward combustion. In forward combustion, ignition occurs near the injection well, and the hot zone moves in the direction of the air flow, whereas in reverse combustion, ignition occurs near the production well, and the heated zone moves in the direction counter to the air flow
- Reverse combustion. Reverse combustion has not been successful in the field because of the consumption of oxygen in the air before it reaches the production well
- High pressure air injection. High pressure air injection involves low temperature oxidation of the in-place oil. There is no ignition. The process is being tested in several light oil reservoirs in the USA. (Chu 1983).

## **2.5 Other Types of Thermal Flooding**

### **1. Electromagnetic Heating**

It is one of the relatively novel thermal flooding techniques where electromagnetic waves are transmitted to heat the oil in the reservoir and mobilize it for recovery; the inherent mechanism of electromagnetic heating is viscosity alteration of the oil (Sivakumar, Krishna, Hari & Vij 2020).

### **2. Microwave Heating**

This method is also relatively new in thermal enhanced oil recovery methods, it makes use of the microwave radiation to heat up the petroleum reservoir oil, the mechanism employed by this method are viscosity reduction and mobility increase of the oil. A number of factors influence the selection of

an EOR method suitable for a given reservoir; some of these factors are functions of the formation geology, technology, and economic considerations. The oil and gas operators have been applying the thermal technique to produce oil from the hydrocarbon such like cyclic (Chen, et al.,2023)

### **2.5.1 Miscible Flooding Process**

Miscible flooding is a form of enhanced oil recovery method that is currently receiving substantial amount of attention due to its potential to recover additional residual oil from a petroleum reservoir. The principle of this method is the injection of hydrocarbon solvent into the formation to mix with the reservoir oil and dissolve it, thereby generating a miscible mobilized fluid. The mechanisms of this method are; solvent-oil miscibility and improvement in reservoir sweep efficiency. The solvent-oil miscibility is governed by the solubility parameter of the solvent and the oil, which is a measure of the energy needed to dissolve a certain component in the solvent, for the oil and solvent to form a single phase, the solubility parameters of the two must be close enough. (Kumar, Sampaio, Ojha, Hoteit & Mandal, 2022)

The displacing fluid and residual oil mix to form a single phase. Here the interfacial tension is zero and the capillary number turns infinite, and the microscopic displacement efficiency is maximized. This process maintains reservoir pressure and improves oil displacement because the interfacial tension between oil and water is reduced due to the introduction of miscible gases into the reservoir. Miscible process can be categorized into two types: single contact and multi contact miscible flooding. Liquefied petroleum gas or alcohols is injected fluids in single contact miscible flooding. The injected fluid is miscible with residual oil immediately in contact. While in multiple contact or dynamic miscible process the injected fluids are usually methane, inert fluids, or an enriched methane gas supplemented with C2 - C6 fractions (Shah et al.,2010)

Miscible Flooding Miscible flooding implies that the displacing fluid is miscible with the reservoir oil either at first contact (SCM) or after multiple contacts (MCM). A narrow transition zone (mixing zone) develops between the displacing fluid and the reservoir oil, inducing a piston-like displacement. The mixing zone and the solvent profile spread as the flood advances. Interfacial tension is reduced to zero in miscible flooding, therefore,  $N_c = \infty$ . Displacement efficiency approaches 1 if the mobility ratio is favorable ( $M < 1$ ). The various miscible flooding methods include: – miscible slug process, – enriched gas drive, – vaporizing gas drive, – high pressure gas (CO<sub>2</sub> or N<sub>2</sub>) injection. Miscible Slug Process is a “single contact miscible” type process, where a solvent, such as propane or pentane, is injected in a slug form (4-5% HCPV). The miscible slug is driven using a gas such as methane or nitrogen, or water. This method is applicable to sandstone, carbonate or reef-type reservoirs, but is best suited for reef-type reservoirs. Gravity segregation is the inherent problem in miscible flooding. Viscous instabilities can be dominant, and displacement efficiency can be poor. Reef-type reservoirs can afford vertical gravity stabilized floods, which can give recoveries as high as 90% OOIP. Several such floods have been highly successful in Alberta, Canada. Availability of solvent and reservoir geology is the deciding factors in the feasibility of the process. Hydrate formation and asphaltene precipitation can be problematic. Stalkup (1983)

### **2.5.2 Vaporizing Gas Drive**

This also is a Multiple Contact Miscible type process, and involves the continuous injection of natural gas, flue gas or nitrogen under high pressure (10-15 MPa). Under these conditions, the C<sub>2</sub>-C<sub>6</sub> fractions are vaporized from the oil into the injected gas. A transition zone develops and miscibility is achieved after multiple contacts. A limiting condition is that the oil must have sufficiently high C<sub>2</sub>-C<sub>6</sub> fractions to develop miscibility. Also, the injection pressure must be lower than the reservoir saturation pressure

to allow vaporization of the fractions. Applicability is limited to reservoirs that can withstand high pressures (Du and Nojabaei 2019).

CO<sub>2</sub> Miscible method has been gaining prominence in recent years, partly due to the possibility of CO<sub>2</sub> sequestration. Apart from environmental objectives, CO<sub>2</sub> is a unique displacing agent, because it has relatively low minimum miscibility pressures (MMP) with a wide range of crude oils. CO<sub>2</sub> extracts heavier fractions (C5-C30) from the reservoir oil and develops miscibility after multiple contacts (Du and Nojabaei 2019)

## **2.6 Chemical Flooding**

There are different types of enhanced oil recovery methods and chemical flooding is one of them; it entails the use of chemicals in the form of alkali, surfactant and polymer to produce more oil beyond that recoverable by secondary recovery method (Mandal 2015).

Chemical flooding is a technique used in enhanced oil recovery (EOR) to improve the recovery of hydrocarbons from the reservoir. The method involves the injection of chemicals into the porous media to enhance the mobility of oil and sweep it towards the production wells (Kumar, et al., 2019). The chemicals used for this method can be classified into three types or categories based on their functions: surfactant are used to reduce the interfacial tension between oil and water, which improves the ability of oil to flow easily through the reservoir. Polymers are used to increase the viscosity of the displacing fluid, which helps to push the oil towards the producing well. Alkaline are used to alter the pH level of the reservoir, which enhances recovery by the reduction of the adsorption of oil onto the reservoir rock surface (Zhang, et al., 2016).

Chemical flooding has many advantages over other enhanced oil recovery methods, one of the most significant advantages is that chemical flooding can be applied in a wide range of reservoirs, including

those with high permeability and low oil saturation, it can also be used in combination with other EOR methods, such as thermal recovery, to enhance the recovery efficiency. Its limitations are that it demands a substantial amount of chemicals, this can be expensive, especially for marginal fields, it is time consuming as the injected chemicals take a very long time to produce appreciable results. Since the properties of reservoirs can vary widely, it is difficult to predict the performance of chemical flooding (Kumar, et al., 2020).

Chemical flooding has been used in many parts of the world; one prominent case in point is the Daqing oil field in China, which is one of the largest oil fields in the world. Chemical flooding was first introduced in Daqing in the 1970`s, and it has since become the practical EOR method used in this field. The chemical flooding process in this field is the Alkaline-Surfactant-Polymer flooding type. Daqing oil field is still producing oil till date. Another example is the Prudhoe Bay oil field in Alaska, which is the largest oil field in North America. The introduction of chemical flooding commenced in this field since 1980s and till date is a major part of the enhanced oil recovery program in the field. The efficiency of chemical flooding is deeply affected by reservoir heterogeneity, fluid properties, such as viscosity and interfacial tension, injection strategies, such as the injection rate and the injection sequence, chemical interactions, such as adsorption and precipitation (Zhang, et al., 2016).

## **2.7 Alkaline Flooding**

Alkaline flooding is a technique employed in the oil and gas industry to enhance recovery of residual oil from the reservoir, the method entails pumping an alkaline solution into the porous media to increase the pH level of the oil and alter the rock and fluid properties (Alvarado and Manrique 2010). The alkaline chemical reacts with the acid components of the reservoir rock, generating soap-like compounds that can reduce the oil viscosity and increase mobility. (Zhang et al., 2016). IFT reduction

is the main mechanism. Spontaneous emulsification may also take place. Drop entrainment or drop entrapment may occur depending on the type of emulsion formed, which may enhance or diminish the recovery. Alkali can cause changes in wettability (Froning and Leach 1967).

However, large concentrations are required for wettability alterations. Field results have been discouraging, giving a recovery factor of (0-3% OIP). The process is complex to design due to the various reactions that take place between the alkaline chemical and the reservoir rock and fluids. Alkali flooding is an enhance oil recovery (EOR) technique that utilizes an alkali (an alkali is a basic compound which may be an ionic salt of an alkali metal or alkaline earth metal) in improving oil recovery factor (Kurmar, et al.,2019).

Experimental Study carried out by (Alvarado and Manrique 2010) on enhanced oil recovery using alkaline and organic acid. The organic acid is obtained from the acidic component of the crude oil. The generated soap acts as an in-situ surfactant to reduce interfacial tension between oil and gas, reduce capillary pressure, alters wettability and emulsify the crude oil, thereby, improving oil recovery. The injection of alkaline into the reservoir makes the reservoir more water wet, thus increasing the flooding effectiveness. These alkalis include Sodium Metaborate ( $\text{NaBO}_2$ ), Sodium Carbonate ( $\text{Na}_2\text{CO}_3$ ), Sodium Hydroxide ( $\text{NaOH}$ ), Sodium Bicarbonate ( $\text{NaHCO}_3$ ), plantain peel ash, potash and palm bunch ash.

### **2.7.1 Surfactant Flooding**

Surfactant Flooding is process which involves the pumping of surfactant into the reservoirs to reduce the inter facial tension between the porous media and oil (Demirbas, Alsuami, & Hassanein, 2015). Surfactant are molecules that have both hydrophobic and hydrophilic properties, which are effective in lowering interfacial tension between oil and water. Petroleum sulfonate or another commercial

surfactant are often used. Surfactant are known to be surface active agents like soap and detergent. Their hydrophilic and hydrophobic nature reduces the interfacial tension between the oil and water. Surfactant flooding has been proven as the EOR technique used for mobilizing residual oil trapped in the reservoir. The purpose of surfactant injection into reservoir for improving oil recovery factor is to alter the fluid/fluid interaction by reducing (IFT) interfacial tension between the oil and brine, and fluid/rock properties via wettability alteration of the porous medium. (Maia, Francisco, Moreira, Nascimento & Grasseschi 2024)

There are four types of surfactant namely: 1. Anionic- they have negatively charged head group, and are generally used in enhanced oil recovery programs to reduce interfacial tension. 2. Cationic- these types have positively charged head group and can be used to alter wettability by adsorbing onto the reservoir sandstone. 3. Non-ionic- this type has no charged head group and are always used together with other surfactants to enhance their efficiency. 4. Amphi-philic- these types have both hydrophobic and hydrophilic zones in the same molecule and they are used in enhanced oil recovery to alter wettability and interfacial tension (Hirasaki, et al.,2011)

### **2.7.2 Polymer Flooding**

Polymer Flooding is a broadly applied chemically enhanced oil recovery method characterized with pumping polymer solution into the petroleum reservoir to increase the viscosity of the displacing fluid and increase sweep efficiency which reduces the mobility ratio between the displacing fluid and the reservoir oil. There are various aspects of polymer flooding such as polymer selection, injection strategies, and field applications (Mohammadi, Khodapanah & Tabatabaei-Nejad, 2019)

Hassan, Al-Shalabi & Ayoub (2022), discussed among others, polymer selection, injection strategies, mechanisms of oil recover and field applications as well as the challenges associated with polymer

flooding, such as polymer degradation and injection issues. Water soluble polymers, such as polyacrylamide and polysaccharide are effective in improving mobility ratio and reducing permeability contrast. In most cases, polymer flooding is applied as a slug process (20-40% PV) and is driven using dilute brine. Polymer concentration is between 200-2000 ppm. One of the common reasons for the failure of polymer floods in the past was that it was applied too late in the water flood, when the mobile oil saturation was low. The process will be more effective if applied earlier during water flooding before water breakthrough, the increment in viscosity of the injected fluid gives room for the mobility and conformance control of the injected slug and eradicates viscous fingering phenomena (Kamal, Sultan, Al-Mubaiyedh, & Hussein 2015). Consequently, early water breakthrough generally met in water flooding process is withheld and an increase in oil recovery factor is realized. Polymer flooding has been implemented successfully in many oilfields either on a pilot scale or commercial scale for several decades. Additionally, polymer flooding has maintained an increasing importance to the current energy market. The most notable contribution is the reported increase in oil production of 300,000 bbl /day from Daqing oil field in China. Generally, two major classifications exist for polymers used during polymer flooding recovery operations, namely, synthetic polymers and bio-polymers.

Typical examples of synthetic polymers are polyacrylamide and its derivatives such as partially hydrolyzed polyacrylamide (HPAM), hydrophobic associating polyacrylamide (HAPAM), and copolymers of acrylamide. On the other hand, biopolymers include xanthan gum, scleroglucan, hydroxyethylcellulose, carboxymethylcellulose, welan gum, guar gum, schizophyllan, mushroom, polysaccharide, cellulose, and lignin, (Gbadamosi, et al., 2022)

### 2.7.3 Surfactant-Polymer (SP)

Surfactant-Polymer flooding is a vital enhanced oil recovery (EOR) technique for the high-water cut mature oilfield. An aqueous surfactant slug is followed with a polymer slug, and the two chemical slugs are driven through the injector using water, it is a widely used enhanced oil recovery technique. The use of SP flooding can result to increase oil recovery through the reduction of interfacial tension between the oil and water phases. Polymers used in SP flooding are basically water soluble and can be classified into two categories: hydrophilic and hydrophobic. Hydrophilic polymers are water soluble and are generally used in SP flooding to increase the viscosity of the injected water. (Al-Sabagh, Kandile, El-Ghazawy, Noor El-Din & El-Sharakly 2016). The formation of emulsion is common during surfactant-polymer flooding and is critical for the success of SP flooding. The emulsions act as a carrier for surfactant and polymer, allowing them to effectively displace the trapped oil. The formation of emulsions is influenced by several factors, including the type and concentration of surfactant and polymers, the salinity and pH of the reservoir water, and the temperature of the reservoir. The emulsion formation process involves the adsorption of surfactant onto the oil-water interface, followed by the formation of surfactant particle. The polymer molecules then adsorb onto the surfactant particle, forming a complex network that stabilizes the emulsion. The size and stability of the emulsion lies on the attractive and repulsive forces between the surfactant and polymer molecules. The type and concentration of surfactant and polymers used can significantly affect the emulsion formation process. Surfactant with low critical micelle concentration (CMC) values are preferred as they can form micelle at lower concentrations, which reduces the amount of surfactant required for emulsion formation. Polymers with high molecular weights and high charge densities are also preferred as they can form more stable networks with the surfactant micelle. High salinity and pH level of the reservoir water can also affect the emulsion formation process by reducing the

effectiveness of the surfactant and polymer to form stable emulsion. High temperature will increase the mobility of the surfactant and polymer molecules resulting to a decrease in emulsion stability. (Al-Saleh, Yussuf, Jumaa, Hammoud & Al-Shammari 2019).

Xiaoyan, et al., (2021) investigated the use of one-dimensional homogeneous core flooding experiments and parallel core flooding experiments to examine the effect of emulsification on the oil recoveries in the SP flooding process. 0.3 pore volume (PV) of emulsions which are prepared using ultra-low interface tension (IFT) SP solution and crude oil with stirring method was injected into core models to mimic the emulsification process in SP flooding, followed by 0.35 PV of SP flooding to flood emulsions and remaining oil. The other experiment was preformed 0.65 PV of SP flooding as a contrast. The authors observed that SP flooding can evidently enhance oil recovery factor by 25% after water flooding in both homogeneous and heterogeneous cores. Compared to SP flooding, emulsification can contribute an additional recovery factor of 3.8% in parallel core flooding experiments. But there is no difference on recoveries in homogenous core flooding experiments. It indicates that the role of emulsification during SP flooding will be more appreciative for oil recoveries in a heterogeneous reservoir rather than a homogeneous reservoir.

#### **2.7.4 Alkaline-Surfactant-Polymer (ASP) Flooding**

Alkaline-Surfactant-Polymer flooding is a intricate program that uses the synergistic interaction between the alkaline agents, surfactant and polymers with the ability to change the reservoir rock and fluid properties. The efficacy of ASP flooding in maximizing recovery factor depends on the petroleum reservoir rock and fluid properties, injection strategies, and operational framework (Li, et al.,2024). The mechanisms involved in ASP flooding are the reduction in interfacial tension, wettability alteration, mobility control (Arsad, et al., 2022)

Shakeel, Samanova, Pourafshary & Hashmet (2021) observed that ASP flooding is specifically effective in carbonate reservoirs due to their sensitivity to pH alterations and the prospect for mineral suspension and precipitation effect. The method utilizes mainly three chemical formulations: – alkali, surfactant and polymer solutions. The chemical slugs may be pumped in succession or probably as a premixed single slug. The major recovery mechanisms are Interfacial tension reduction, and enhancement of mobility ratio. Similar to other chemical EOR, alkaline-surfactant-polymer is used to advance the mobility ratio and increase the capillary number.

This type of flooding combines chemicals that are considered perfect solution to improve the mobility ratio and capillary number. One of the functions of polymers is to increase the viscosity of the displacing fluid thereby, improve the sweep efficiency. Furthermore, polymer can also ensure the control of a good mobility for the flooding thus increasing the sweep efficiency. The elastic viscosity is a special property possessed by ASP flooding where it exerts a larger pulling force on oil droplets or oil films due to the stress at the surface between oil and polymer. Over time, the force increases until it reaches a point where the force generated is powerful enough to recover oil from unrecoverable pore thus, residual oil saturation decreases. Overall, ASP flooding is expected to recover between 16 to 19 % from the original oil in place (Chang, et al.,2006).

## **2.8 Micellar Flooding**

Micelle flooding is a category of enhanced oil recovery technique that involves the injection of a fluid especially hydrocarbon solvent into the reservoir to mix with and dissolve the oil, thereby creating a miscible fluid that can flow easily through the reservoir and push the residual oil towards the producing well (Das, Gogoi & Mech 2017).

Das et al. (2017) used black liquor, a waste product of paper mills as micelle in upper Assam basin for enhancing oil recovery. The research compared the efficiency of flooding two respective oil wells with micelle and surfactant, the result indicated that micellar flooding was more efficient in mobilizing the trapped oil from the reservoir than surfactant flooding due to its ability to alter interfacial tension

## **2.9 Microbial Enhanced Oil Recovery (MEOR)**

Microbial flooding is a method of enhancing oil recovery from a hydrocarbon reservoir, it applies the injection of microorganisms to advance the recovery of oil. This method can increase oil recovery through wettability of the reservoir rock. There have been several researches on Microbial EOR since the 1960's. A few field tests have also been carried out in the USA and other countries. Microbes react with a carbon source, such as oil and produce surfactant, polymers, biomass and gases such as CH<sub>4</sub>, CO<sub>2</sub>, N<sub>2</sub> and H<sub>2</sub> as well as solvents and certain organic acids. Oil recovery mechanisms in microbial EOR are those of the classic chemical methods, which include IFT reduction, emulsification, wettability alteration, improved mobility ratio, selective plugging, viscosity reduction, oil swelling and increased reservoir pressure due to the formation of gases. Increase in permeability can result from the acids formed. Microbes can be indigenous or introduced. Imported microbes must adapt to reservoir temperature, salinity and hardness (Xiao, Amir & Junaidi 2023)

Microbial flooding can also enhance oil recovery by producing bio-surfactant which reduces the interfacial tension between the oil and water phases and mobilize trapped. The microorganisms used in this type of flooding can either be originally in the reservoir or injected into the reservoir. The efficacy of microbial flooding depends on factors such as the composition of the reservoir, the type of microorganism used, the reservoir conditions. while the cost effectiveness of this method lies on the

price of oil, the cost of microbial inoculation, and cost of maintaining optimal environmental reservoir conditions. (Al-Saleh, et al., 2019).

## **2.10 Foam Flooding**

This is a method of enhanced oil recovery where gas-liquid foam is injected into the petroleum reservoir to increase the sweep efficiency of the displacing fluid, reduce gas mobility and reduce gravity segregation to recover more oil from the porous media (Al-Saleh, et al., 2019)

It is a multifaceted non-Newtonian fluid with properties and characteristics managed by many variables. Foam is a dispersion of a liquid containing surfactant in a gas such as carbon dioxide (CO<sub>2</sub>), air, nitrogen (N<sub>2</sub>), steam or natural gas. Simultaneous injection of a gas and surfactant solution, or the injection of a gas into the porous medium containing a surfactant solution, generates foam in situ. Foam forms, breaks and re-forms in the pore throats as fluids advance in the porous medium. The presence of oil inhibits the formation of foam, and is therefore not effective in mobilizing residual oil. Mobility of foam is lower than that of gas or steam, and it acts as a viscous fluid. Foam has been used (with limited success), as a mobility control agent or blocking agent, with steam and CO<sub>2</sub> in some reservoirs (Guo and Aryana 2016).

## **2.11 Factors Affecting Mobility**

The mobility ratio and capillary number play a vital role in determining the mobility of the reservoir oil during enhanced oil recovery processes. The mobility ratio is defined as the ratio between the mobility of the displacing fluid (primarily water) and the mobility of the displaced fluid (oil). When mobility is greater than unity, then the injected fluid will tend to move faster than the displaced fluid leading to a phenomenon called viscous fingering which will give rise to the early breakthrough of the

displacing fluid, thereby leaving pockets of immobilized oil behind. On the other hand, when mobility ratio is less than one, the injected fluid tends to flow slower than the displaced fluid, resulting to a situation where the injected fluid will sweep more oil from the reservoir (Sheng, 2011).

The capillary number is another reservoir oil mobility determinant; it is the ratio of viscous forces to capillary forces. Capillary forces arise due to the surface tension of the fluids and tend to hold the oil in place, viscous forces, on the other hand arise due to the flow of fluids and tend to move the fluids. If capillary number is high, then capillary forces are dominating the viscous forces, the oil will be held in place, making it difficult for recovery. General a capillary number close to one is desirable for effective oil recovery:

Capillary Number ( $N_c$ )

Mobility Ratio ( $M$ ).

Capillary Number is mathematically described as:

$$N_c = v\mu/\sigma \quad 2.$$

where

$V$  is the Darcy velocity (m/s),

$\mu$  is the displacing fluid viscosity (Pa.s)

$\sigma$  is the interfacial tension (N/m).

Mobility ratio is mathematically defined as  $M = \lambda_d / \lambda_D$ , where  $\lambda_d$  is the mobility of the displacing fluid (e.g. water), and  $\lambda_D$  is the mobility of the displaced fluid (oil). ( $\lambda = k/\mu$ , where  $k$  is the effective permeability, (md) and  $\mu$  is the viscosity (Pas) of the fluid concerned). Mobility ratio controls the

microscopic and macroscopic displacement efficiencies. If  $M > 1$ , it is considered unfavorable, If  $M < 1$ , it is considered favorable (Amoli, 2011)

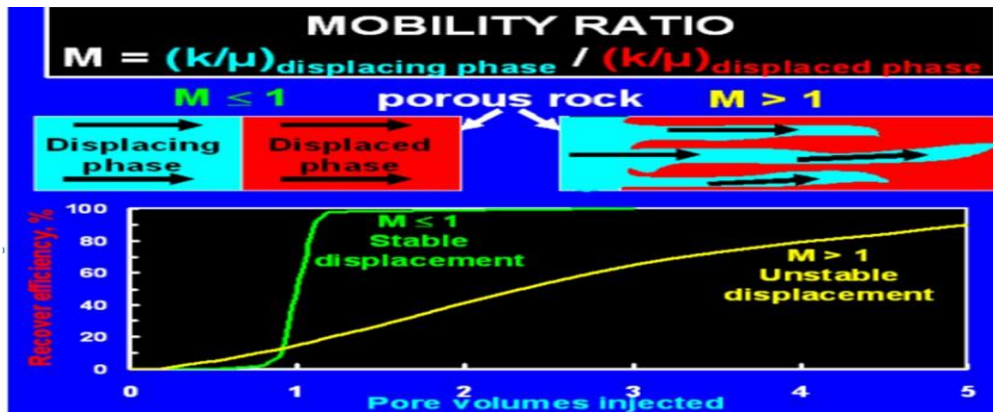


Plate 2.3: Comparisons between the two cases of Mobility Ratio courtesy of Amoli, (2011)

## 2.12 Knowledge Gap

From the literature review, it can be posited that more than ninety percent of these local materials used in the previous research experiments are not waste materials and therefore applying them in enhanced oil recovery will increase the cost of production because of their competing use in the such food chain. Because of this fact, they cannot be adjudged cheap, and quantitative availability for flooding operations is not guaranteed.

Secondly, none of the researchers has used any of the local materials for macro-emulsion flooding operations except in surfactant flooding operations where micro-emulsion is formed at the interface between oil and water phases and is not formed ab initio as a flooding fluid. It thus becomes viable to conduct this research using agricultural waste of palm oil mill in the formulation of emulsion fluid for reservoir flooding operations.

## **CHAPTER THREE**

### **MATERIALS AND METHODS**

The materials and methods to be used to achieve the objective of formulating an emulsion using the waste materials from palm oil mill industry will be explained in details in this chapter.

#### **3.1 MATERIALS**

This research made use of many materials in other to achieve the aim and objectives of this work. The materials employed in this researched are itemized below;

**i. Empty Palm Fruit Bunch**

Empty palm fruit bunch is the fibrous residue remaining after the fruit bunch has been stripped of its fruits during pal oil extraction process.it accounts for more than 22% of the total solid waste generated from palm oil mills. It is rich in cellulose, heme-celluloses and lignin rendering it a potential source of natural polymers and fibers for various application, including formulation of flooding fluids (Ng et al., 2015)

**ii. Palm Oil Mill Effluent**

Palm oil mill effluent also known as palm oil sludge is huge liquid waste produced from the production of of palm oil as a result of sterilization and clarification processes in the palm oil mill.

**iii. Core Samples**

Core samples are cylindrical shaped rock section obtained with a hollow steel tube known as core drill

**iv. Crude Oil**

Crude oil is a yellowish black liquid mixture of hydrocarbons found in oil reservoir formations.

**v. Brine**

Brine is a high concentrated solution of salt (usually sodium chloride) in water. In different contexts, brine may refer to solutions used for preserving foods. Lower levels of concentration are called by different names: fresh water, brackish and saline water. Other materials used for this work include:

**vi. Centrifuges**

A centrifuge is a device that is used to separate particles suspended in a fluid in terms of the particle size, medium viscosity, density and rotor speed. It applies the centrifugal force within a solution, gravitational force then causes denser particles than the solvent to sink below while particles less dense than the solvent float to the top of the centrifuges

**vii. Separating Funnel**

A separating funnel is used to separate two immiscible liquids, oil and water due to the insolubility of oil in water. The principle of the separating funnel is the uneven density of the particles of the mixture

**viii. Analytical Sieve of mesh size 170 mesh size of 88 microns.**

This is a device with perforations for the separation of finer particles of a sample with varying sizes of particles.

**ix. Electric Mixer**

The electric mixer uses high speed eccentric rotation to make the liquid in a container homogenize fully.

**x. Atomic Absorption Spectrophotometer (AAS)**

Atomic Absorption Spectrophotometer is a tool used in the evaluation of the quantitative and qualitative mineral compositions of liquid samples. It applies the principle of light absorption by atoms and ions at a particular and unique wavelength. Once the specific wavelength is made available, the atom absorbs the light as electrons in the atom are excited. AAS consists of four components: the Sample introduction part, the Radiation source that matches the narrow light bands absorbed by a particular atom (a hollow cathode lamp), a graphite furnace to heat the sample, the mono-chromator or poly-chromator select the wavelength of light and a photo detector. The reason for heating the sample is partly to free the atoms from the liquid and form salts and provide energy that can lift the atom from ground state to excited energy level, as the atoms fall back to ground energy level, light is emitted at particular wavelengths. The more the light that the AAS detector catches at that wavelength, the more of the element that is present in the sample



**Plate 3.1.** Graphite Furnace AA-680 Atomic Absorption Spectrophotometer

Other materials are:

- i. Density bottle
- ii. Liquid Permea-meter flow loop

- iii. Beaker
- iv. Measuring cylinders
- v. Thermometer
- vi. Flooding apparatus
- vii. Stop watch
- viii. Pump
- ix. Electronic Vernier caliper
- x. Hydrometer
- xi. Retort stand
- xii. Magnetic stirrer

### 3.2 Methods

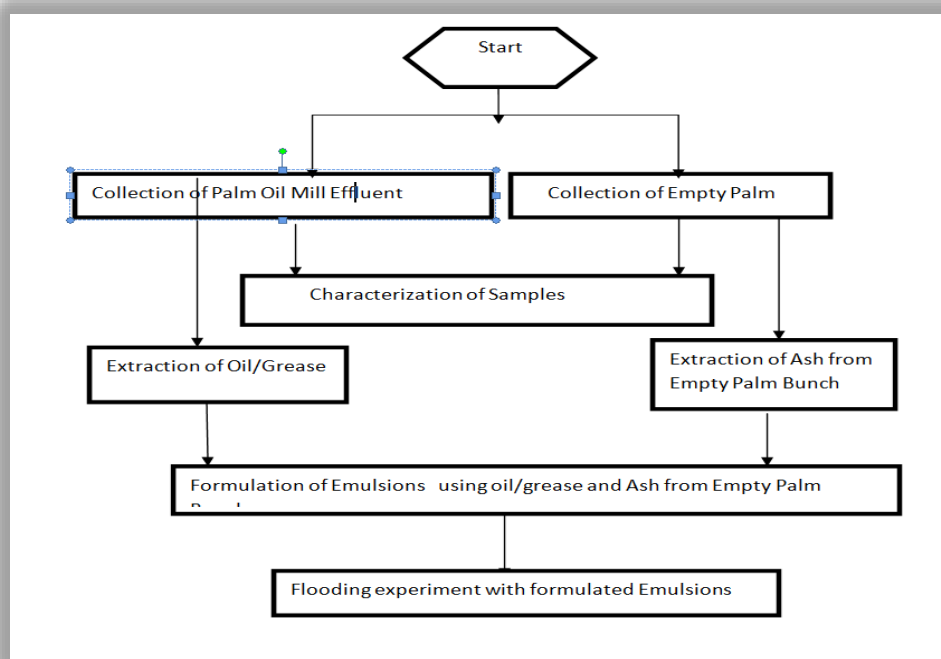


Figure 3.1: Experimental Study Flow Chart

The palm oil mill effluent (POME) used in this research was collected from a palm oil mill in Elebele Town in Ogbia Local Government Area of Bayelsa State, Nigeria. The effluent was collected in four-liter plastic containers from effluent storage tank in the mill, and was placed in ice cooler to maintain temperature during transportation to the laboratory. The effluent was filtered using a separating funnel to remove the solid particles, and the resultant filtrate went through analysis for chemical properties using Atomic Absorption Spectrophotometer (AAS). The palm oil mill effluent was filtered with a 170-mesh sieve to remove solid particles; the elements (oil, sodium, potassium, magnesium, phosphate, calcium, and ammonium) in the samples to be measured were selected. The conventional technique of quantitative chemical analysis of heating the sample in a water bath to a temperature 60°C was done by making the sample suitable for AAS analysis.

10 milliliters of the sieved palm oil mill effluent were injected into the graphite furnace cuvette, controlled electrical heating process of the cuvette dried the sample and removed the matrix before atomization. The hollow cathode lamps provided exact elemental output of light focused through the center of the graphite furnace cuvette to activate measurement as atomization was ongoing.

### **3.2.1 Laboratory Extraction of oil from Palm Oil Mill Effluent (POME)**

The solids in the effluent were removed using a centrifuge, the centrifuge was put on a leveled table, the palm oil mill effluent was poured equally into the centrifuge tubes and capped with lids while placing the tubes opposite each other in the centrifuge, the tube was balanced correctly, the lid of the centrifuge closed, then placed in a rotor and spun at a speed of 1200 RPM for 15 minutes until the timer shut off the motor. Oil and water from the collected palm oil mill effluent were extracted using Centrifugal method. The solids and heavier components settled at the bottom while the oil and water moved towards the outer edges of the centrifuge. Furthermore, the effluent comprising oil, and water was poured into a separating funnel with its stopcock, the stopper was closed, and the separating funnel

fixed firmly on a stand. The effluent was left undisturbed in the funnel closed for thirty minutes (30 Min.). The water remained below and the oil floated on it, the stopper was removed without shaking the funnel, then the stopcock was opened to collect the water at the bottom of the funnel with a container. The stopcock was closed when all the water has been removed and the oil collected separately for rheological analysis

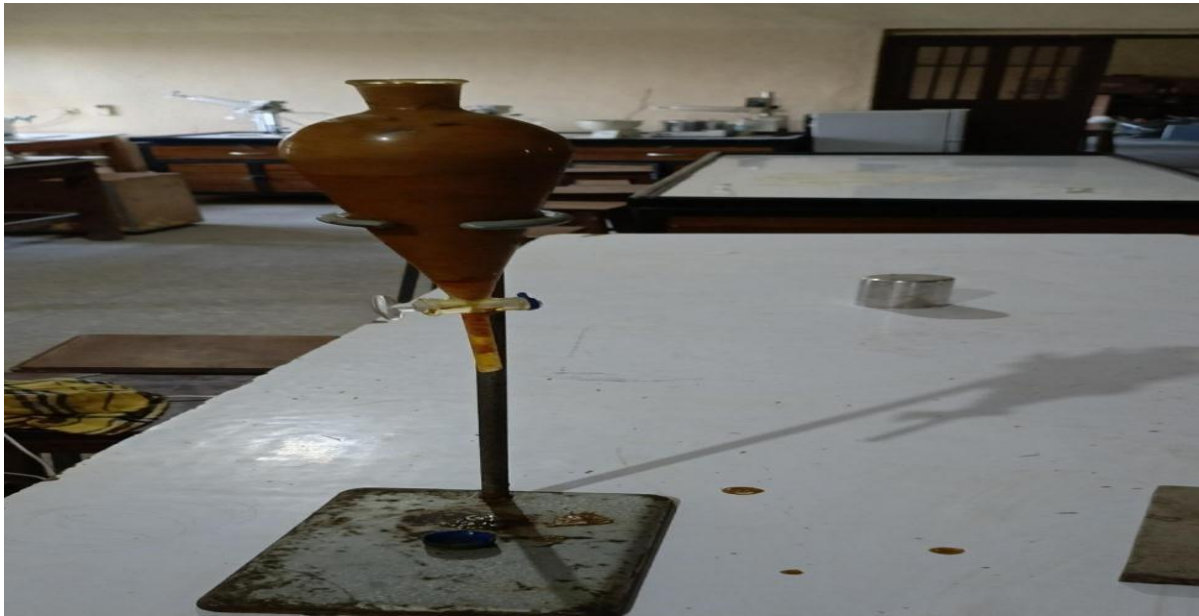


Plate 3.2: Separating Funnel (used to separate oil from sludge)

### 3.2.1.1 Specific gravity determination of the oil

A hydrometer was used to determine the specific gravity of the oil/grease extracted from the palm oil mill effluent, the oil was poured into a 100cc of graduated cylinder, the hydrometer was inserted into the graduated cylinder until the principal floatation was observed. Once the hydrometer became stable, the specific gravity was read from the graduations of the measuring cylinder, and the API gravity was computed using the formula below

$$API = \frac{141.5}{S.G} - 131.5 \quad 3.1$$

### 3.2.1.2 Viscosity determination of the oil

A viscometer was used to determine the viscosity of the oil extracted from palm oil mill effluent. The oil was sucked into the viscometer at a certain marked level, and was now allowed to flow down from the marked level at the recording of a stop watch as  $T_1$  in seconds. The process was repeated to get the second Time reading required in flowing down as  $T_2$  in seconds. The mean of the two times was recorded and multiplied with the viscometer constant  $C$  which is 0.1 to get the actual viscosity

### 3.2.1.3 Determination of the Density of oil.

An empty calibrated density bottle(50cc) was weighed and the weight was recorded as  $W_1$ , then the density bottle was filled with the oil to its capacity and reweighed as  $W_2$

The mass of the oil was calculated by subtracting  $W_2$  from  $W_1$ . The density of crude oil was obtained using the formula below:

$$\rho_{oil} = \frac{M}{V} \quad 3.2$$

Where  $m$  = mass of crude oil

$V$  = volume of the bottle, 50cc

### 3.2.1.4 Temperature and pH determination of the oil

The oil was poured in a cylindrical beaker 100cc. A thermometer was inserted into the beaker of oil and observations were made to where the mercury level stopped. The temperature was recorded as  $T$ . The pH value was determine using a pH meter

### 3.2.2 Preparation of Ash Solution from Empty Palm Bunch

Empty palm bunch fruit were gathered from the palm oil factory and dried under the sun for 7 days to remove any trace of moisture, thereafter, it was burnt without any petroleum related product in open air and allowed to cool. The burnt ash was then packed in a bag for use, and sieved with size 180mm sieve used to obtain fine homogeneous ash particles. After the sieving, the ash was weighed in a balance, 350g of ash was dissolved in 1000ml of water. The solution was stirred gently using a spatula and allowed to settle for 24 hours. The solution was then sieved to separate insoluble ash particle from the solution, lastly the sieved solution was stored in a beaker for use. A portion of the Ash solution was taken for chemical characterization.



Plate 3.3: Burning empty palm bunch



Plate 3.4: Palm Bunch Ash



Plate 3.5: Homogenized palm bunch Ash



Plate 3.6: weighing of the Ash sample

### **3.2.3 Formulation of Emulsion using Ash Solution from Burnt Empty Palm Bunch and Oil Extracted from Palm Oil Mill Effluent**

The extracted oil was mixed with the ash solution at room temperature in a ratio of 5/95, 10/90, 15/85, 20/80, 25/75, 30/70, 35/65, 40/60, 45/55 in milliliters by placing the oil extracted from palm oil mill effluent in respective beakers and different volumes of ash solution was added to it in the ratios (5/95, 10/90, 15/85, 20/80, 25/75, 30/70, 35/65, 40/60, 45/55 ) and labeled accordingly. An electric mixer was used in homogenizing the mixtures in order to create smaller droplets of the oil within the surfactant solution for increase of emulsion stability. By placing the emulsions formulated respectively in a Biobase Bk-VX1 electric mixer. The samples were put into the tube and put in place through the test tube holder rod by pressing into the mixing head.

The speed control knob was initialized by placing it at the lowest position, and later set at speed of 1200RPM for 5 minutes, and the process was repeated. The emulsions thus formed in the respective tubes were then evaluated for stability. The emulsion samples were evaluated

### **3.2.3.1 Density Test on Emulsion Samples**

The samples prepared were weighed using a density bottle. Initially, the empty bottle was weighed and the weight was recorded as  $W_1$ . Then the bottle was filled with the oil to its capacity and reweighed as  $W_2$ . finally, the mass of the oil was calculated by subtracting the  $W_1$  from  $W_2$ . The density of emulsion samples oil was obtained by using the relationship

$$\rho_{oil} = \frac{M}{V} \quad 3.3$$

Where  $m$  = mass of emulsion

$V$  = volume of the bottle, 50cc

### **3.2.3.2 Viscosity Test on Emulsion Samples**

The determination of the viscosity of the emulsion sample was carried out using the method in 3.2.3

### **3.2.3.3 Evaluation of Emulsion Stability**

#### **3.2.3.4 Visual Observation**

The formulated Emulsions` stability was evaluated by allowing the emulsions to stay seven days (7 days) to observe any signs of separation, creaming or sedimentation

#### **3.2.3.5 Centrifugal Test for Stability of Formulated Emulsion**

Centrifugal applies the force of gravity to accelerate separation of liquid phase in an emulsion. 40ml of the formulated emulsions were respectively poured into the centrifuge tubes and capped with lids while placing the tubes opposite each other in the centrifuge, the tube was balanced correctly, and the lids closed, then placed in a rotor, varied centrifugal temperature of 30°C to 100°C were used to test the thermodynamic effect on emulsion stability, thereafter, the experiment was repeated to observe the

effect of varied RPM (1200rpm) on the formulated emulsion samples while observing the time it took for phase separation.

A centrifuge machine was brought and cleaned for use, the machine was connected to a power source and the emulsion samples were poured into the glass wares in the spinning centrifuge and cocked. The centrifuge operation was carried out first at 1200rpm varied in different temperatures of 30<sup>0</sup>C, 40<sup>0</sup>C, 50<sup>0</sup>C, 60<sup>0</sup>C, 70<sup>0</sup>C, 80<sup>0</sup>C, 90<sup>0</sup>C, and 100<sup>0</sup>C at time interval 6minute. The separation between the oil, water was then noted and the emulsion sample stability was calculated using ratio data method:

$$\frac{1 - \text{volume of seperated phase}}{\text{volume of emulsion sample}} * 100 \quad 3.4$$



Plate 3.7: Emulsion samples



Plate 3.8: Centrifugal test of formulated emulsion sample

### **3.2.3.6 Determination of Interfacial Tension Between oil and Ash Solution**

Spinning drop tensiometer (SDT) is a technique for measuring the interfacial tension between two fluids. In this work, spinning drop tensiometer (Kruss Data Physics) was used to determine the interfacial tension between oil/grease and ash solution used in formulating the emulsion samples. The densities of these fluids have been initially measured in section 3.2.7.1.

The rotating cylinder and drop information system of the tensiometer were appropriately cleaned and dried, the rotating cylinder was filled with the heavier fluid (Ash Solution) and then a drop of oil was created using the drop information system. The cylinder was rotated at constant speed of 1000RPM, the images of the drop was captured by a high-speed camera. Finally, the drop length (L), drop width (W), and the ratio aspect (L/W) were measured, then the interfacial tension (IFT) were calculated using Vonnegut equation:

$$\text{IFT} = \left( \frac{\rho \Delta \omega^2 L^3}{4\pi^2} \right) \quad 3.5$$

### 3.2.3.7 Determination of shear stress of emulsion samples

The capillary viscometer method measures shear stress by analyzing the flow of fluids through a narrow capillary tube. In this work the (Ubbelohde viscometer) was used to determine the shear stress of the emulsion samples. This viscometer consists of a narrow cylindrical glass tube (capillary tube), with a uniform diameter (R) and the length (L) a reservoir container to hold fluids and the stop watch to measure flow rate (Q) and a manometer to measure pressure difference ( $\Delta P$ ).

The reservoir was filled with the emulsion samples respectively and connected to the capillary tube, the pressured drop, flow rate and temperature were measured. The fluid density was also observed.

Finally shear rates were calculated using the equation 3.3.7

$$\tau = \frac{R\Delta P}{4L} \quad 3.6$$

### 3.2.3.8 Preparation of the control emulsion using the works of Mandal (2010)

A standard emulsion was prepared in line with the works of Mandal et al (2010). In his preparation of the emulsion, gear oil was used with sp. gravity of 0.905, and kinematic viscosity 197 cst. Detergent was equally added to it to improve its recovery efficiency as a surfactant then distilled water. The entire mixture was mixed in a three-blade propeller at room temperature.

In this present work, we used sodium lauryl sulphate which is an industrial standard surfactant. An oil-in-water emulsion sample of 30/70 ratio was prepared in accordance to Mandal, (2010). the choice

of this ratio is because the works of Mandal (2010) highlighted this ratio as producing the best oil recovery from a core flooding experiment.

A 1000ml beaker was cleaned and distilled water of 700ml was poured into it. The sodium lauryl sulphate was weighed in a balance, then 0.1g of sodium lauryl sulphate was dissolved in 100ml of water, so 0.7g of the surfactant was dissolved in 700ml of water. 300ml of the lubricant oil bought from a fuel station oil was measured into the same beaker. A magnetic stirrer was applied in mixing the emulsion. The sample was evaluated using the same method applied to the emulsion samples formulated with oil/grease extracted from palm oil mill effluent and ash solution from palm bunch.



Plate 3.9: Sodium lauryl Sulphate for control emulsion sample



Plate 3.10: Lubricant for Control Emulsion



Plate 3.11: Formulated control emulsion sample

### **3.2.3.9 Formation Water Analysis for Compatibility with Formulated Emulsion**

The reservoir formation water of a mature well was obtained from a separation tank in one of the oils and gas production facilities in Port-Harcourt; It was properly labeled and stored to prevent contamination. Test for the presence of some elements which are known to give rise to scaling during enhanced oil recovery process were carried out. The ionic composition, total dissolved solids, pH value and langelier saturation index were determined for the formation water sample. The test followed the guidelines of American Society for Testing and Material (ASTM). Electrometer was used for pH, salinity and TDS, digital scale instrument for titration was also employed to determine the carbonate and bicarbonate contents. Sulphate content determination was done using ultraviolet visible spectrophotometer (HACH DR 6000) Model.

### **3.2.4 Core flooding experiment.**

A core flooding experiment was conducted using encapsulated cores 111. The cores were prepared as follows: Sand grains (Niger Delta formation) were washed, dried using a desiccator and sieved using a shale shaker to four different grain sizes. A= 850, B= 600, C= 425, D=212. The sand was packed (compressed) into a cylindrical aluminum foil using different grain sizes to form uniform core plug (samples) with cotton screen at the top and bottom of the cylindrical plug respectively. The plug samples were further dried in the conventional oven at the temperature of (90-100) °C The weight, length and diameter of each plug were determined using weighing balance and vernier caliper. The petrophysical properties of the core samples were determined on the following properties:

### 3.2.4.1 Determination of core sample porosity

The following procedure was used in determining the porosity of plug; The length and diameter (internal) of the plug samples were measured using a veneer caliper and the bulk volume was calculated using

$$BV = \pi r^2 L \quad 3.7$$

Where: r = radius, L = length of plug sample.

The weight of the dry core from the conventional oven was weighed and recorded. The plugs were properly saturated with brine of concentration 30000ppm in a beaker under atmospheric condition for over 24hrs and the weight of saturated plug samples were measured and recorded. Weights of the dried sample were subtracted from that of the saturated sample; this will give the weight of the brine in the pore space of the sample. To obtain the pore volume; the formula below was applied;

$$PV = \frac{W_{satPlug} - W_{dry Plug}}{\rho_{NaCl}} \quad 3.8$$

Where;

$W_{sat.plugin}$  = weight of saturated plug

$W_{dryplugin}$  = weight of dry sample

$\rho_{NaCl}$  = density of NaCl

The porosity was calculated using the results obtained in s above and the formula below;

$$\text{Porosity, } \emptyset = \frac{P.V}{B.V} \times 100\% \quad 3.9$$

### 3.2.4.2 Determining the permeability of core samples

The plug sample was inserted inside a rubber butt (core holder) and both ends were capped with stem head. One end of the assembly was connected to the reservoir containing brine and the other to the receiving point. The liquid permeameter was switched on and the pump was regulated to a gauge of 30% using the pressure regulator. The pressure differential was recorded as  $\Delta P$  in 'inch water', the length of the plug, ( $L_{\text{plug}}$ ), viscosity of brine, ( $\mu_{\text{NaCl}}$ ), and area, ( $A$ ), were computed.

The permeability was calculated using Darcy's law for in-compressible fluid.

$$K = \frac{Q \cdot \mu_{\text{NaOH}} \cdot L_{\text{plug}}}{A_{\text{plug}} \Delta P} \quad 3.10$$

Where

$Q$  = flow rate, cc/sec

$\mu_{\text{NaOH}}$  = viscosity of sodium hydroxide, cp

$L_{\text{plug}}$  = length of plug, cm

$A_{\text{plug}}$  = cross sectional area of plug, cm<sup>2</sup>

$\Delta p$  = differential pressure, atm

$K$  = permeability, d

**Note:** 100% = 1.5 gpm = 94.635 cc/sec

1 gal = 3785.412 cc

1 gpm = 63.09 cc/sec

1-inch water =  $2.46 \cdot 10^{-3}$  atm



Plate 3.12: Conventional oven (drying of plug samples)



Plate 3.13: Liquid Permeameter flow loop

#### **3.2.4.3 Properties of the crude oil sample.**

The following procedures were used in determining the specific gravity of the crude oil: Crude oil was poured into a 1000cc of graduated cylinder and a hydrometer was inserted into the graduated cylinder until the principal of floatation was observed. Once the hydrometer was stable, the specific gravity was read off from the graduations on the measuring cylinder.

The API gravity was computed using equation 3.2.2

#### **3.2.4.4 Determination of crude oil Density.**

An empty calibrated density bottle(50cc) was weighed and the weight was recorded as  $M_1$ , the bottle was filled with the crude oil to its capacity and reweighed, and the weight was recorded  $M_2$ , the mass of crude oil was calculated as:  $m = M_2 - M_1$ . The density of crude oil  $\tau_0$  was obtained using the equation 3.2.1

#### **3.2.4.5 Determination of crude oil Viscosity**

A viscometer was used to measure the viscosity crude oil used in the core flooding experiment. The oil sample was sucked into the viscometer at a certain marked level. It was allowed to flow down from the marked level at the recording of a stop watch as  $T_1$  in seconds. The process was repeated to get the second reading of time required in flowing down as  $T_2$  in seconds. The mean of the two times was recorded. The viscometer constant  $C$  which is 0.1 to get the actual viscosity mean time was multiplied with the time to get the viscosity

#### **3.2.4.6 Preparation of sodium chloride solution (brine)**

The concentration of the sodium chloride (NaOH) used in this experiment was 30,000ppm and it was prepared as follows: 30g of NaCl was weighed into a beaker (1000ml) using a weighing balance and dissolved with water. it was mixed thoroughly using magnetic stirrer and transferred to a different graduated cylinder (1000ml). Water was added into the graduated cylinder to the mark 1000ml to obtain 30,000ppm concentration. The density and viscosity of the sample was obtained by using the same procedure given 3.2.4 and 3.2.5



Plate 3.14: weighing of sodium chloride

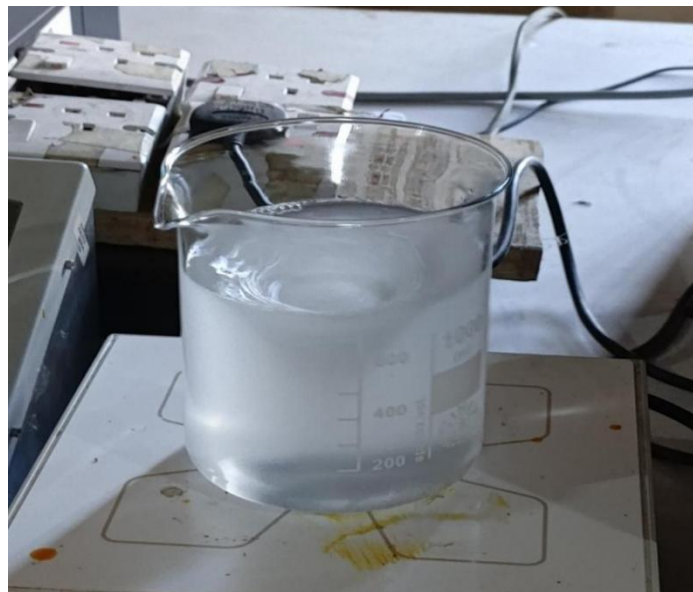


Plate 3.15: formulated brine solution

### 3.2.4.7 Laboratory Core Flooding Experiment

The flooding process took place in a flood scheme apparatus that housed the core, accumulator, core scheme injector etc. For the purpose of this flooding exercise, our prepared emulsions of 15/85, 25/75, 30/70, 35/65, and 40/60 oil-in-water emulsions were used in addition to the control prepared. Prior to the secondary flooding process with water, original oil in place was obtained by saturating the core with brine and then injecting oil to displace the brine water in the core sample. The oil that settled at the top of the beaker containing both oil and water then formed our primary recovered oil.

The saturated sample was inserted into a core holder (rubber butt) and the weight ( $M_1$ ) was obtained. The end of the two sides of the core holder was capped with stem heads and one end was connected via tubing to the electrical pump. The plug was flooded thoroughly using crude oil at a flow rate of 2cc/60sec until crude oil was being produced at the receiving end. The stem heads were removed from the rubber butt, and the volume of the brine was read off from the cylinder. The volume of the brine obtained is the volume of the oil originally in place.

The stem heads were reconnected to the rubber butt containing the saturated plug and the reservoir was replaced with a known volume of water. The water was injected using the electrical pump into the core holder at a flow rate of 2cc/60secs until brine breaks through at the receiving end, then the oil recovered were recorded appropriately. Sequentially, the emulsions were used in flooding the core samples with the Control emulsion added. The emulsion sample were injected into the core holder at a flow rate of 2cc/60sec to recover the oil that was not recovered using water-flooding. The injection was continued until there was emulsion breakthrough at the receiving end

The volume of oil recovered from each core sample using respective emulsion sample was recorded and observations were noted. This process was repeated using the other emulsions prepared respectively and the corresponding observation recorded.

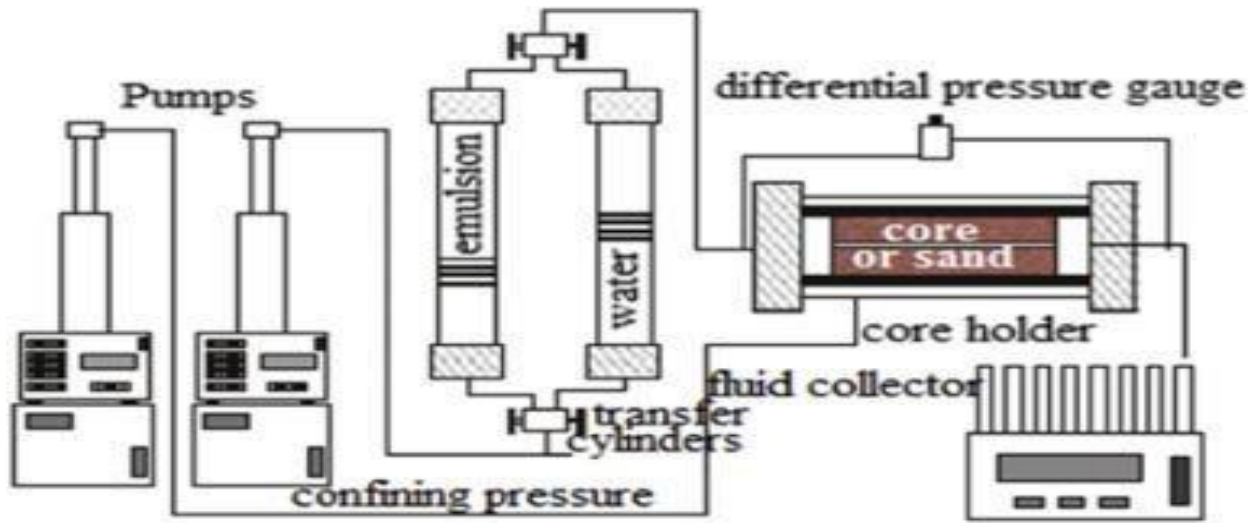


Fig. 3.2: Core Samples Experimental Setup

### 3.2.5 Generation of Proxy Model for the Prediction oil Recovery efficiency

A correlation using reservoir fluid parameters sensitive to oil recovery efficiency was developed by applying linear regression analysis. Regression models are widely used to establish relationships between variables. Linear regression is a statistical method for modeling the relationship between a dependent variable (target variable), and one or more independent variables (predictor variables). the objective is to create a linear equation that best predicts the value of the target variable based on the values of the predictor variables. The model was done through historical gathering of variables of interest, and laboratory experiments. The data-set is organized in excel with independent and dependent variables in separate columns. The proxy model was developed by constructing the linear equation using intercept and coefficients. The experiment revealed that the recovery efficiency depends greatly on oil and emulsion viscosities ratio, reservoir fluids and injection fluid viscosity, therefore, the proxy model is based on these factors. The general form of polynomial regression is;

$$Y = \alpha + \beta_1 X_1 + \beta_2 X_2 + \beta_3 X_3 \dots + \beta_n X_n \quad 3.11$$

Where

Y is the dependent variable (response variable)

X is the independent variable (predictor variable)

$\beta_1, \beta_2 \dots \beta_n$  are coefficients

n is the degree of the polynomial (order of regression)

$\xi$  is the error term (residual)

### **3.2.5.1 Validation of proxy Model**

The developed proxy model was validated by initially applying it in the prediction of recovery efficiency using the parameters obtained from the experiment. This predicted recovery efficiency was compared to the recovery efficiency derived from core flooding experiments performed earlier. Then, the proxy model was also validated by scaling up the model through application of Plackett-Burman range of parameters matrix to design reservoirs with combination of different value range of the sensitive parameters. Lastly the model was validated by comparing it to already published model in the field of enhanced oil recovery. On this last note, the correlation model developed by (Balhasan, Jumaa & Elbagir 2017) published in International Journal of Applied Engineering Research was compared to the proxy equation developed from this work since the two are characterized by same parameters.

## CHAPTER FOUR

### RESULTS AND DISCUSSIONS

#### 4.1 Results

The results from the experiment are presented and analyzed in this section.

##### 4.1.1 Chemical Analysis of Palm Oil Mill Effluent and Palm Bunch Results

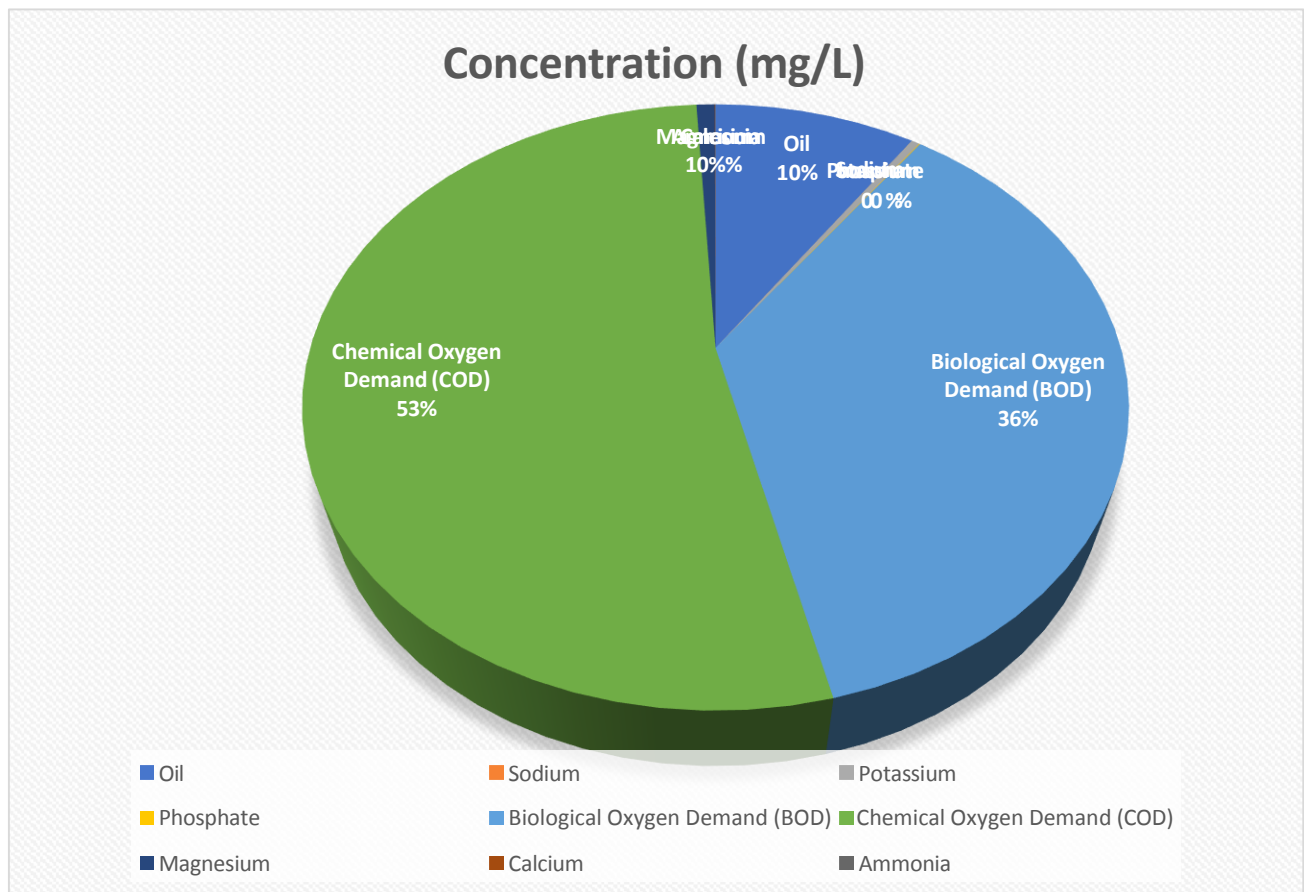


Figure 4.1: Characterization of palm oil mill effluent

#### 4.1.2 Chemical characterization of burnt Empty Palm Fruit Bunch

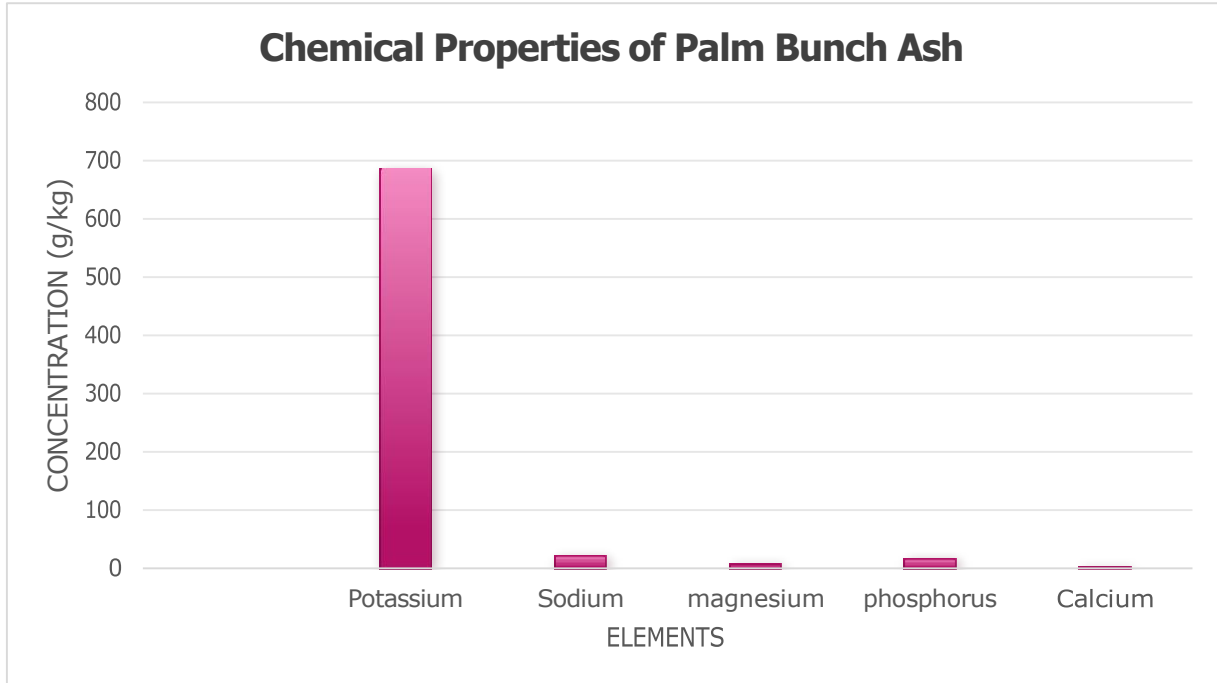


Figure 4.2: Chemical characterization of burnt empty palm fruit bunch

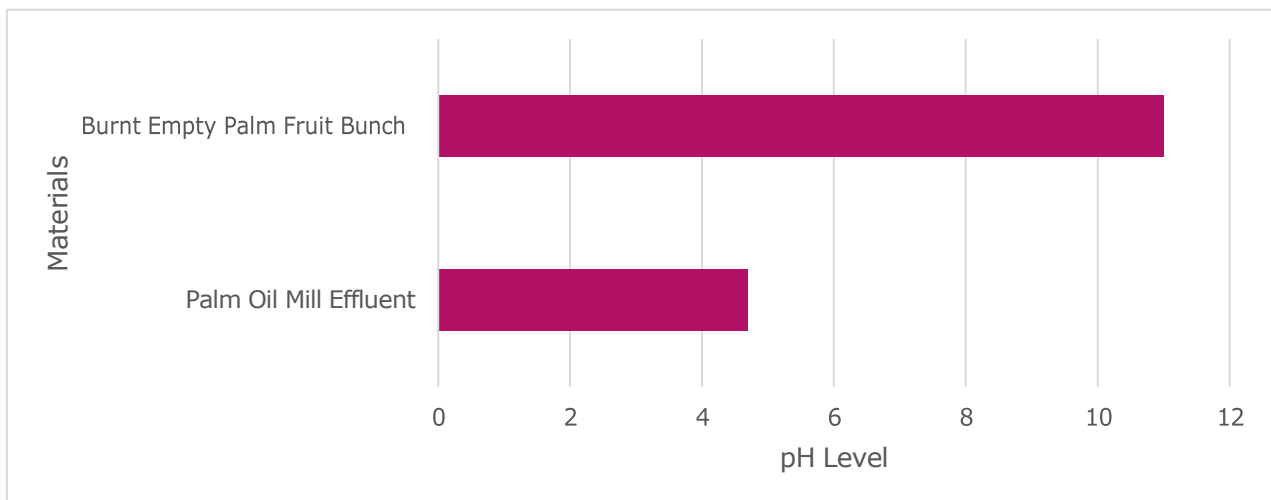


Figure 4.3: pH levels of Palm Oil Mill Effluent and Burnt Empty Palm Fruit Bunch

### 4.1.3 Formulated Emulsion Results

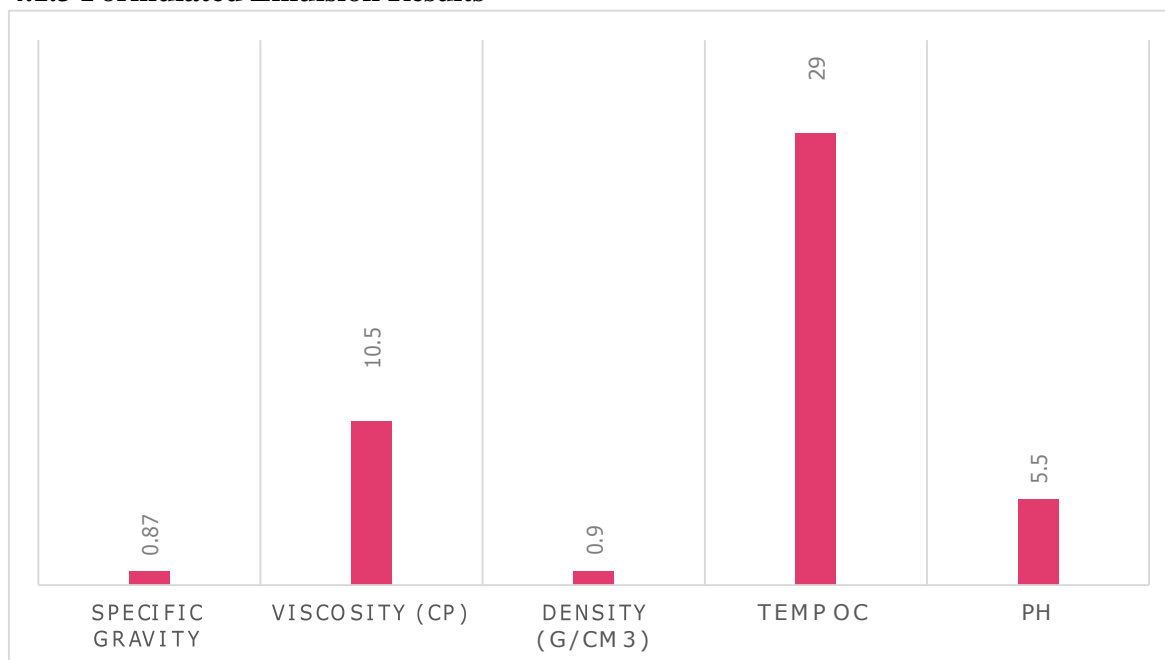


Figure 4.4: Properties of the Oil Extracted from Palm Oil Mill Effluent

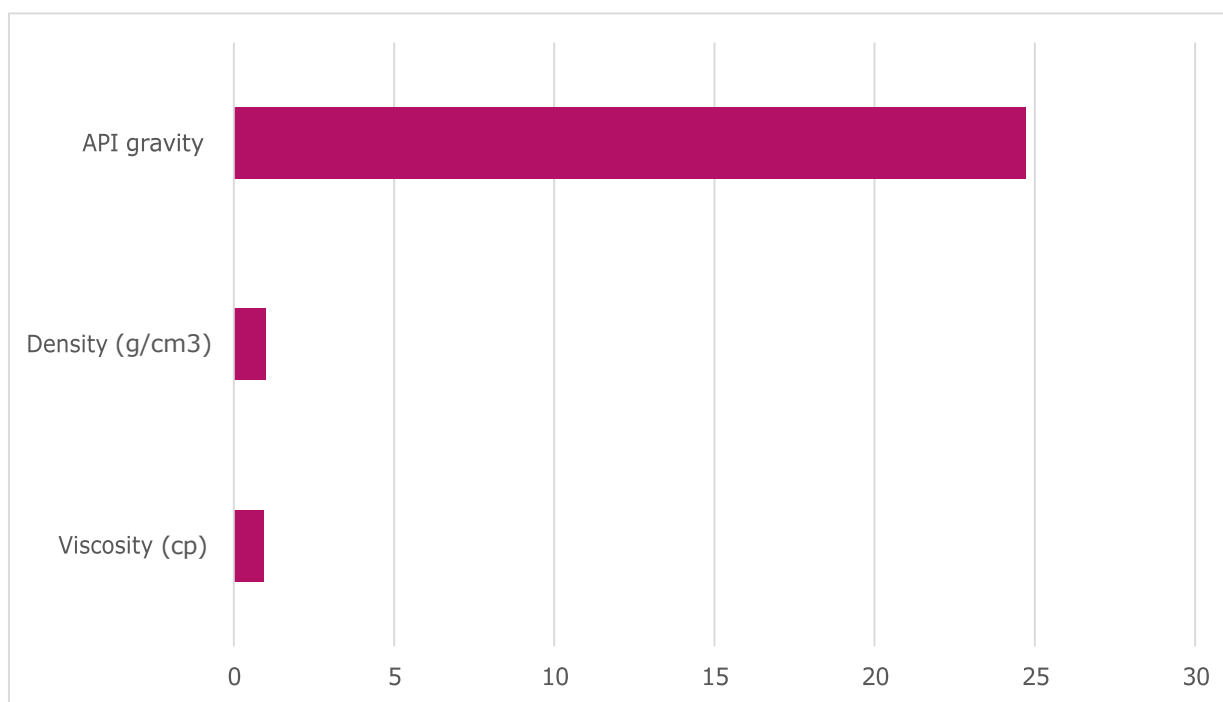


Figure 4.5: Property of Palm bunch Ash solution

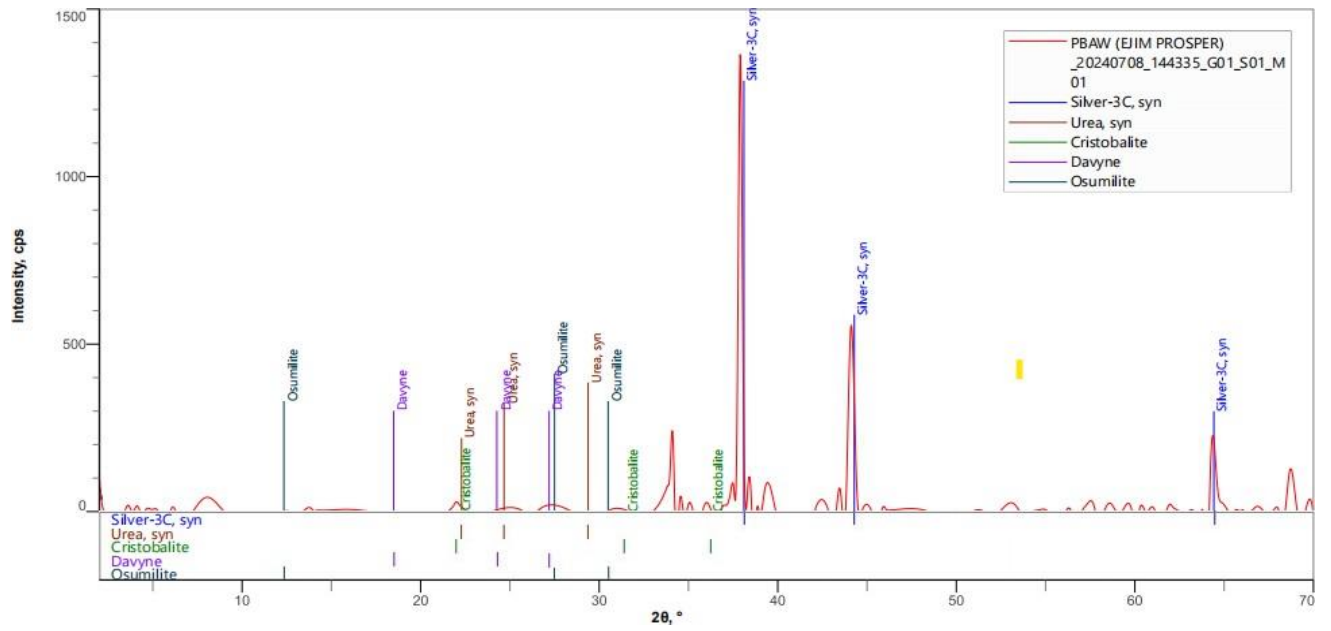


Figure 4.6: Phase Identification of Ash solution formulated with burnt palm bunch

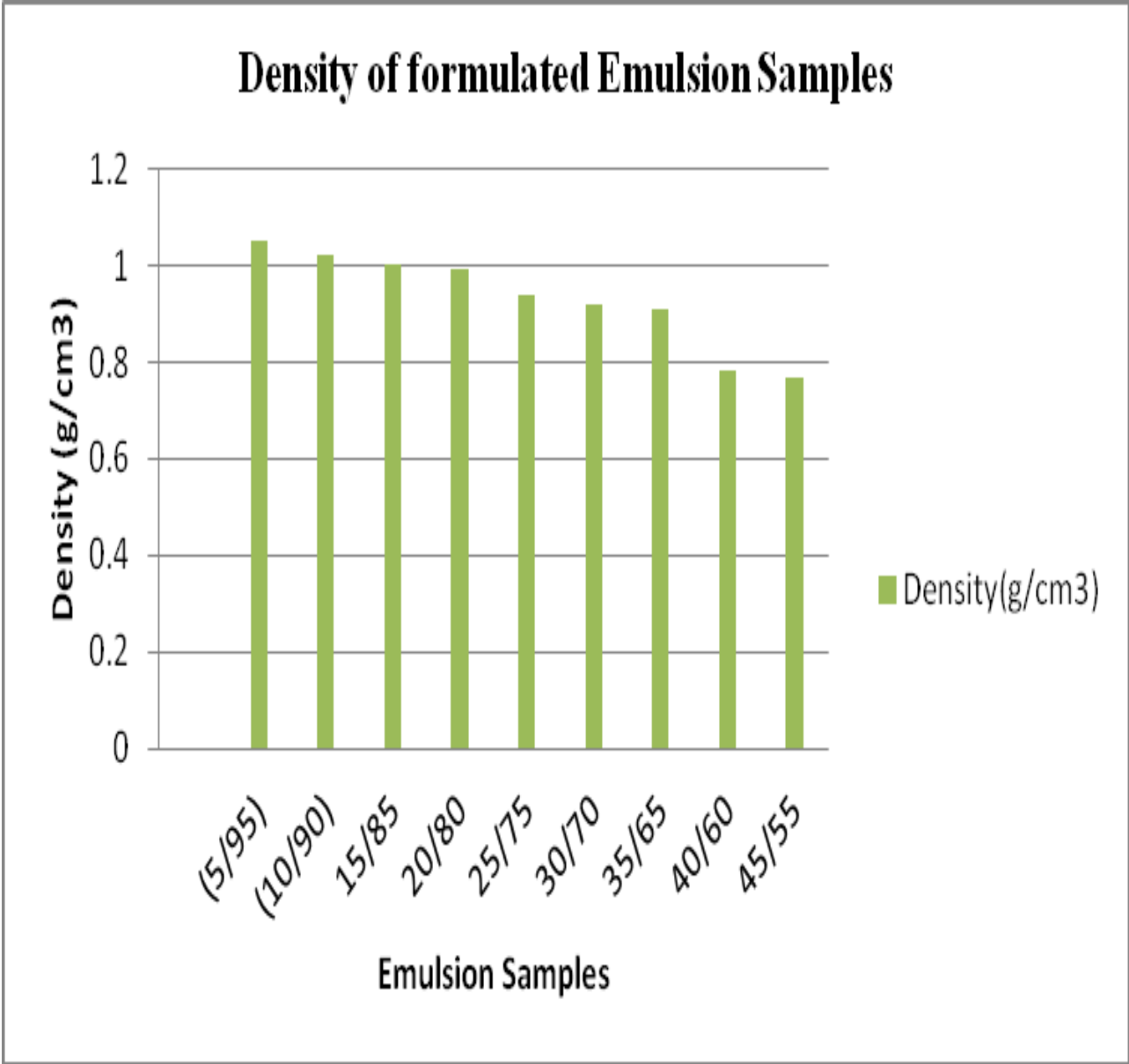


Figure 4.7: Density of Formulated Emulsion Samples

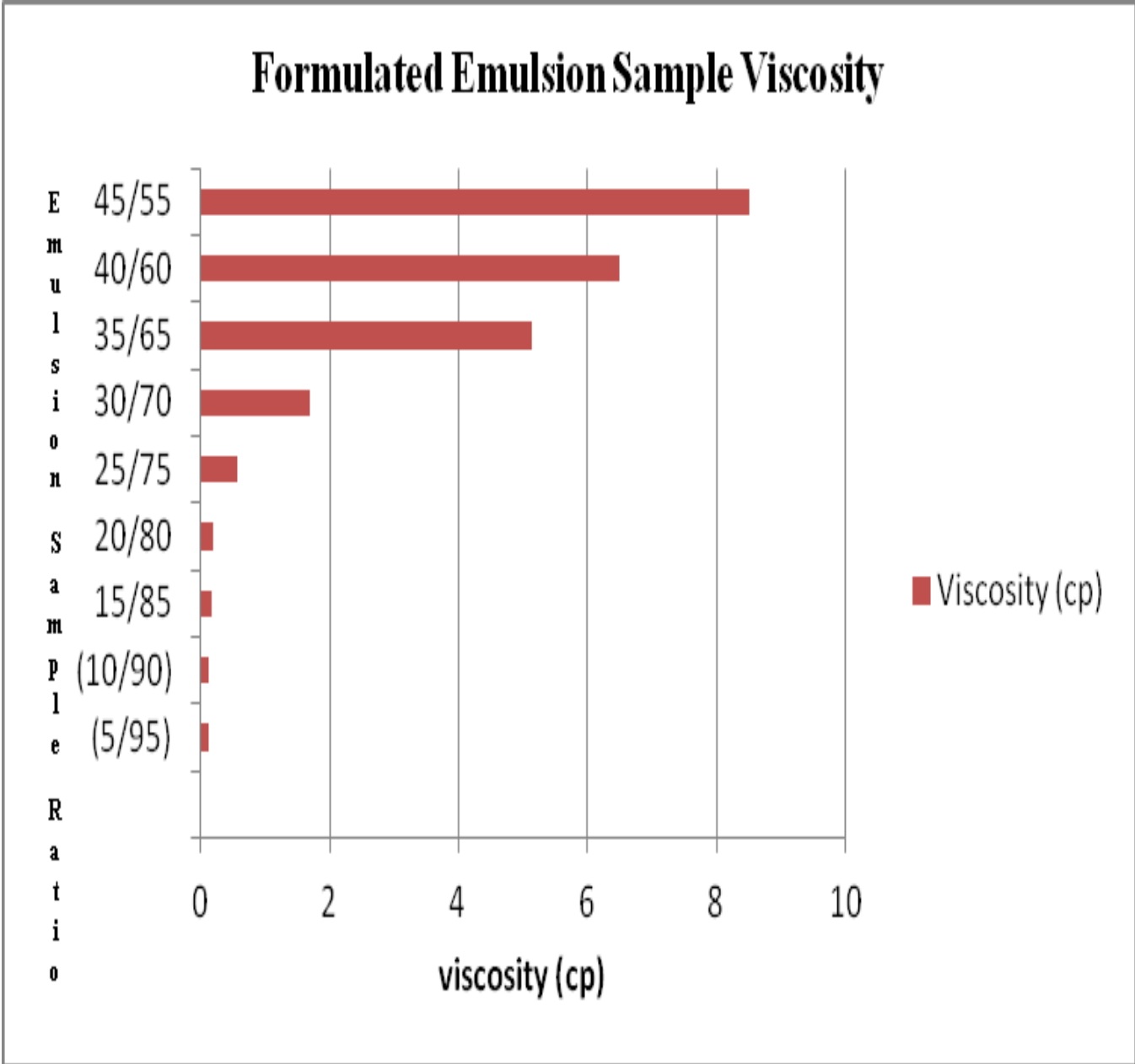


Figure 4.8: Viscosity of formulated Emulsion samples

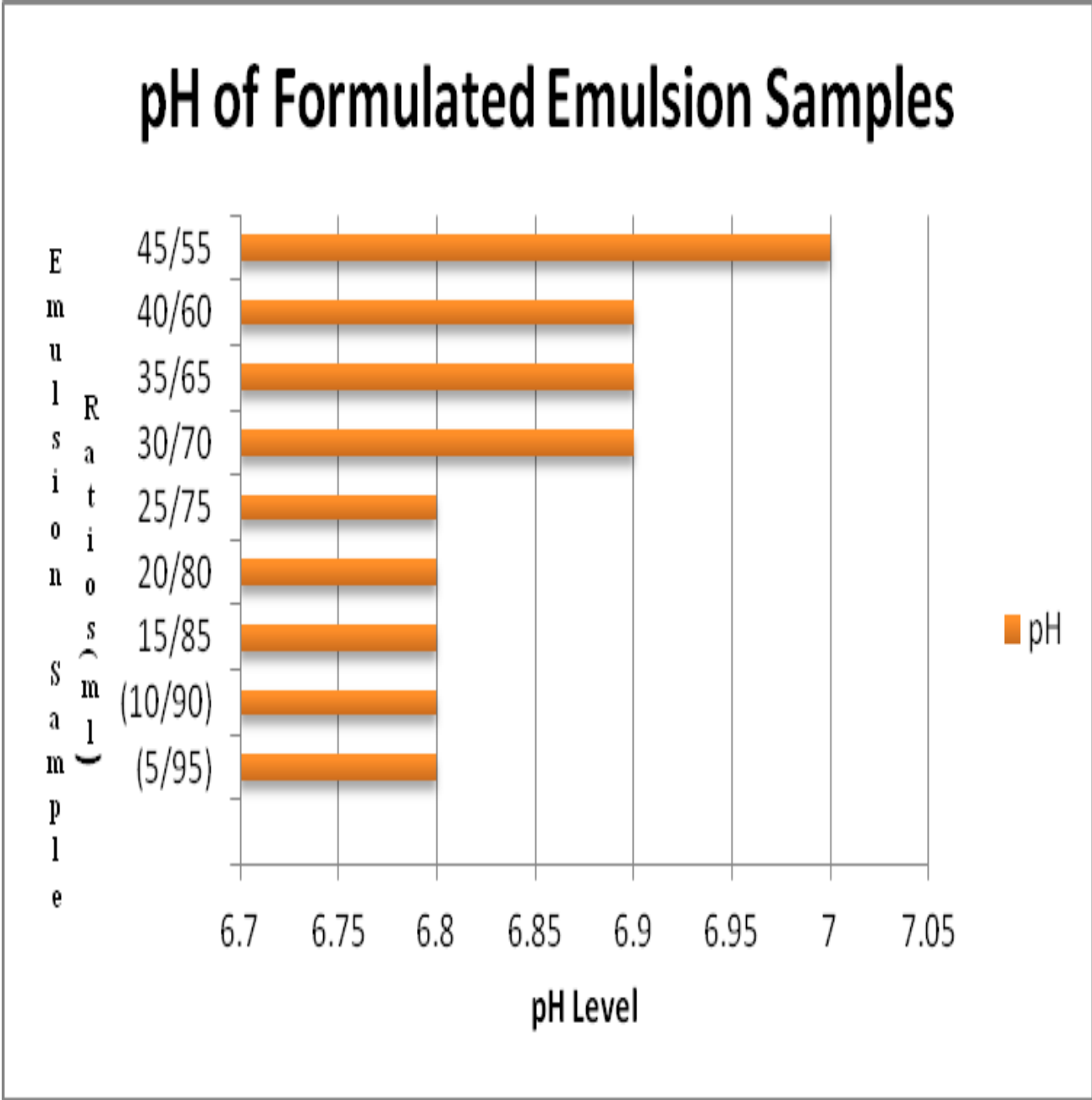


Figure 4.9: pH Levels of formulated Emulsion samples

## 4.1.4 Emulsion Stability Results

### 4.1.4.1 Centrifugal Test

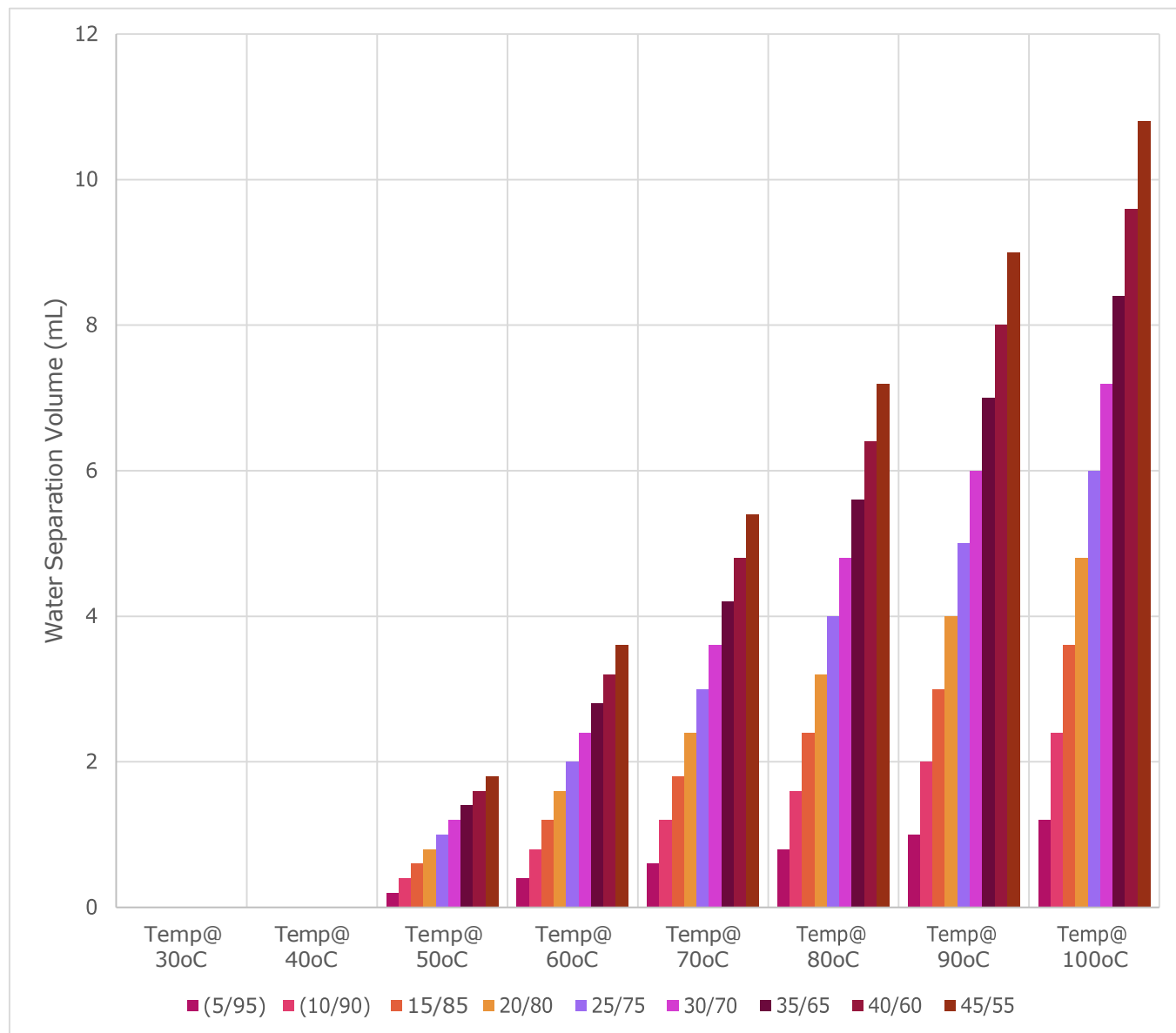


Figure 4.10: Centrifugal Test for Phase Separation

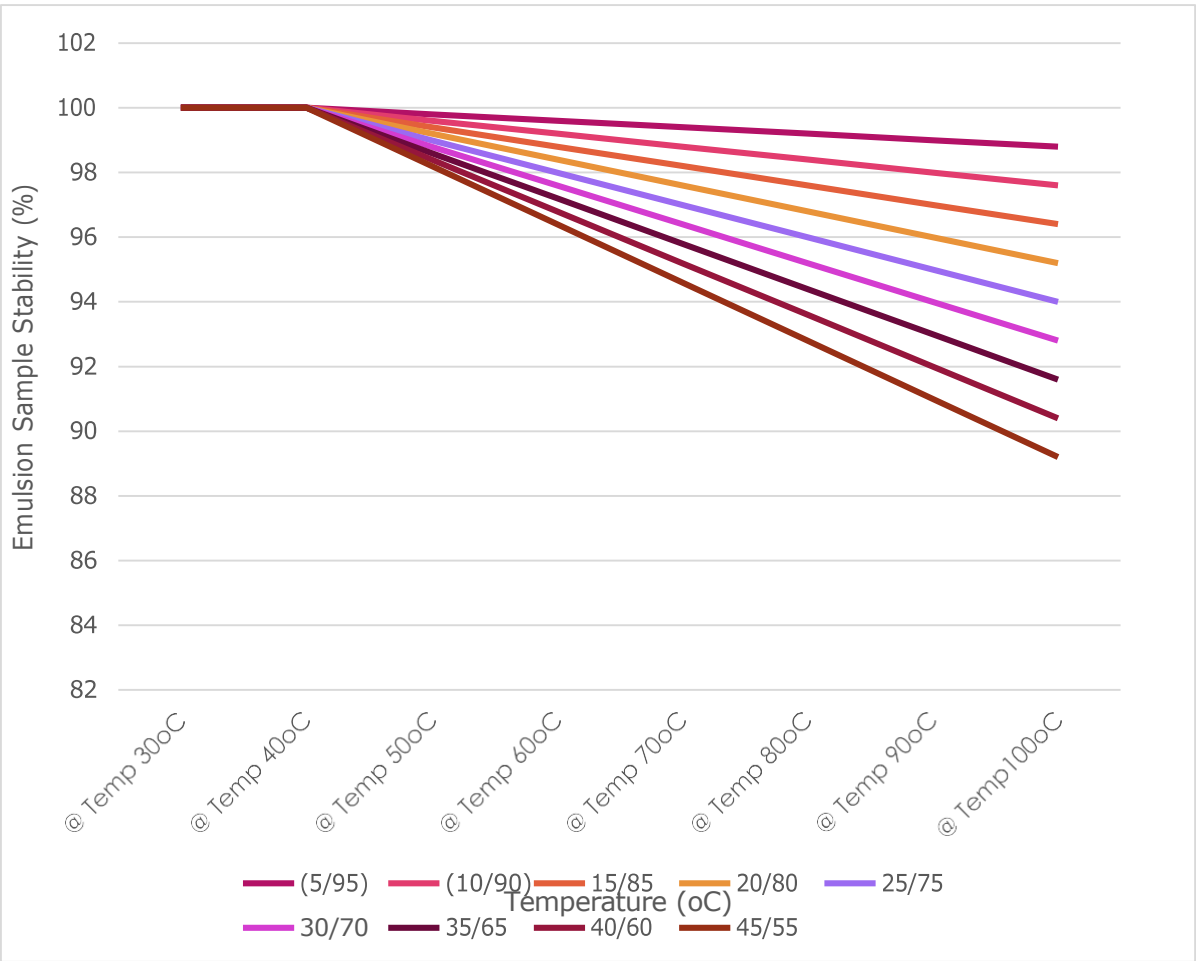


Figure: 4.11: Stability of emulsion samples (%) at different temperatures using Ratio Data Method

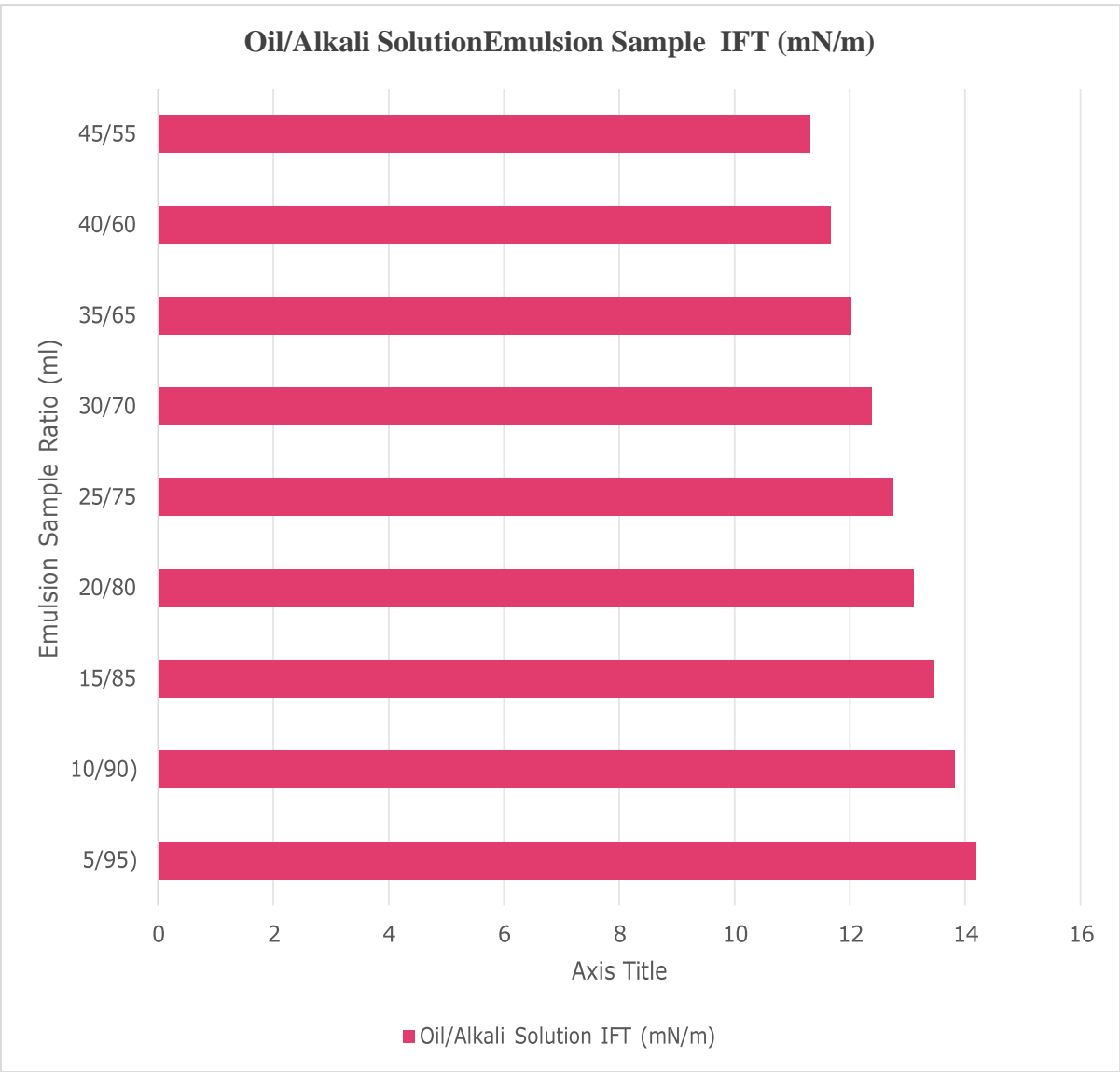


Figure. 4.12: Inter-Facial Tension between oil and alkali solution of Emulsion Sample

#### 4.1.4.2 Droplet Size Distribution

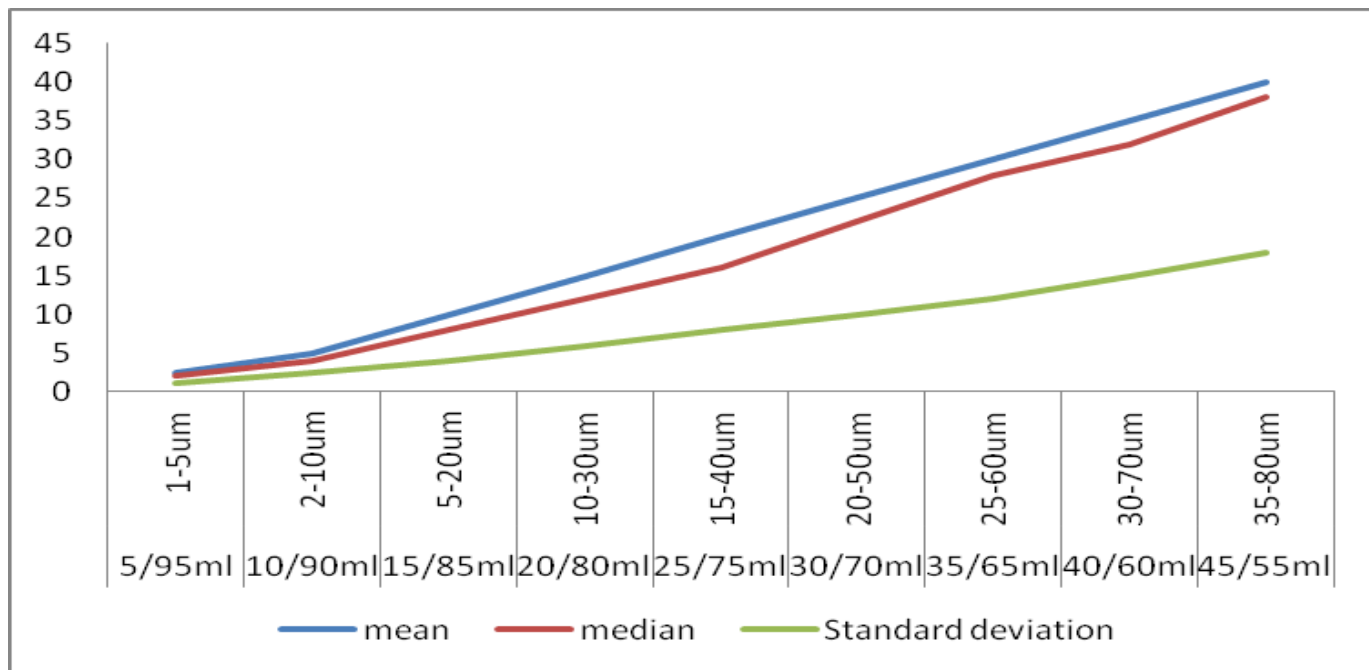


Figure 4.13: Droplet size distribution with mean, median and standard deviation of the Emulsion Samples

### 4.1.4.3 Shear Stress of Emulsion Sample

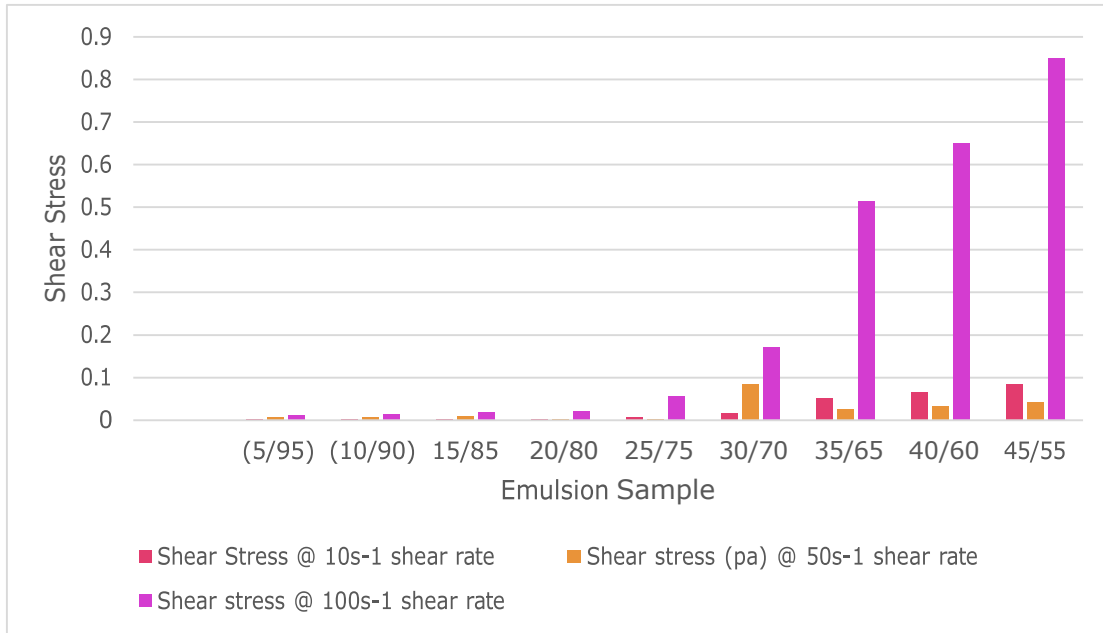


Figure 4.14: Shear Stress of Emulsion Samples at different shear rates

### 4.1.5 CORE FLOODING ANALYSIS

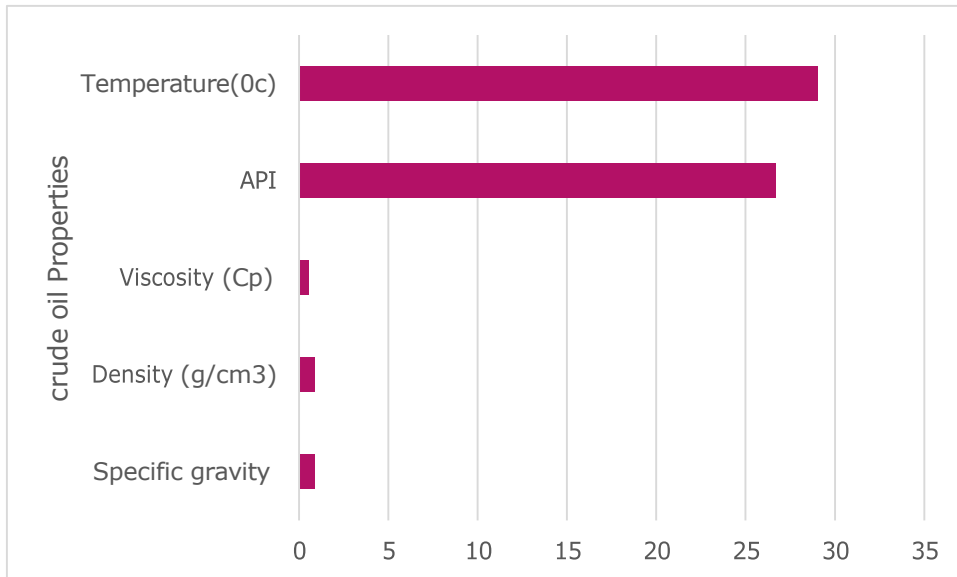


Figure 4.15: Property of crude oil used in the flooding experiment

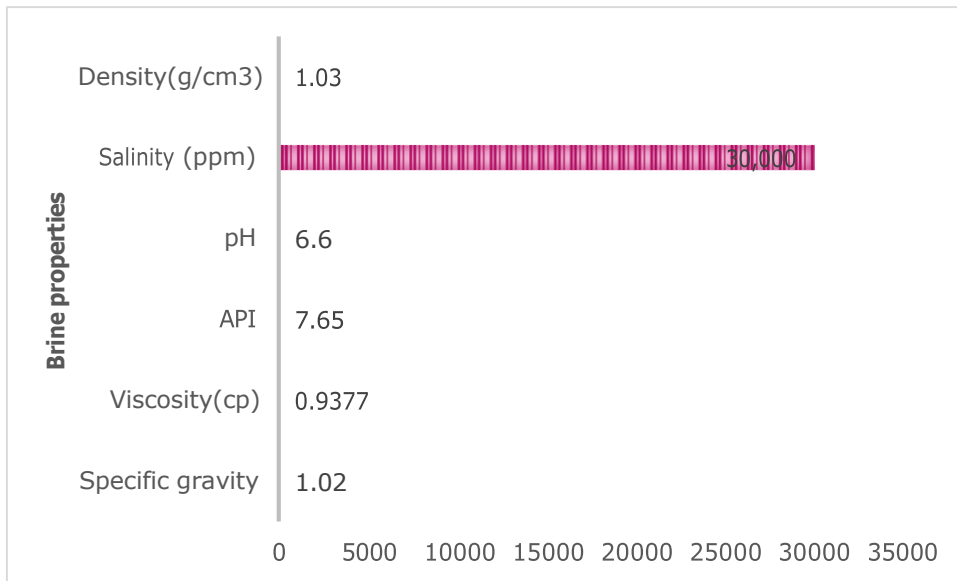


Figure 4.16: Properties of brine used in the flooding experiment

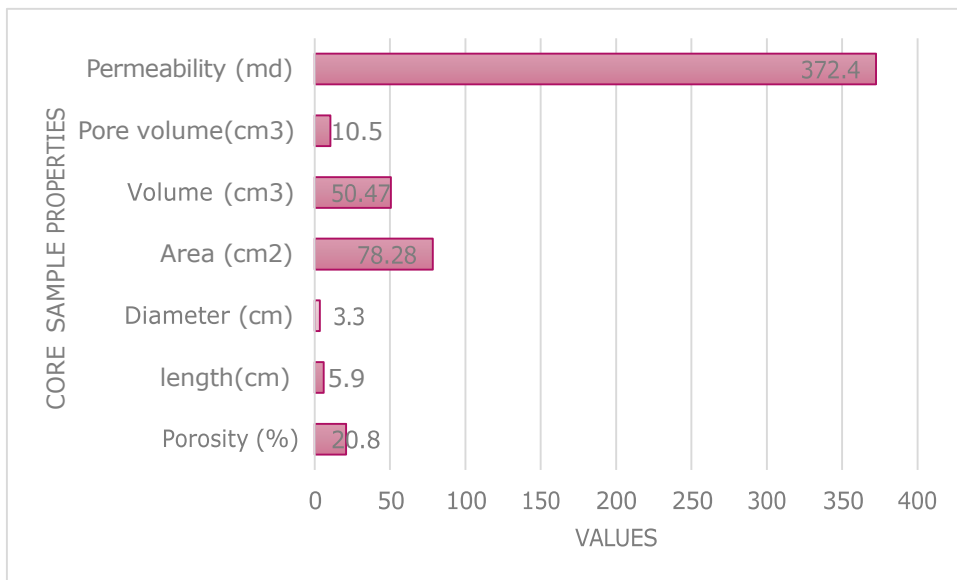


Figure 4.17: Properties of core samples

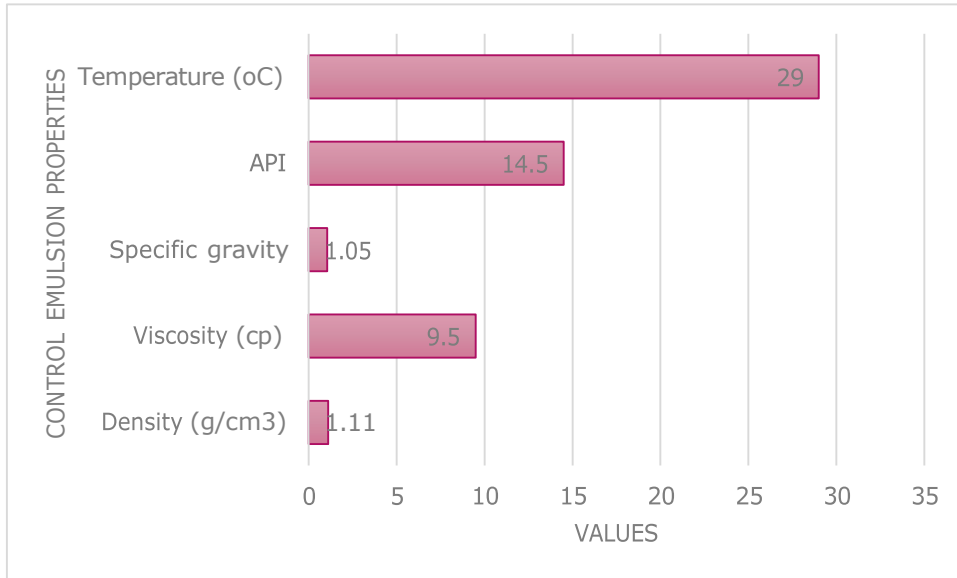


Figure 4.18: Properties of the control emulsion prepared using engine oil and sodium Lauryl Sulphate

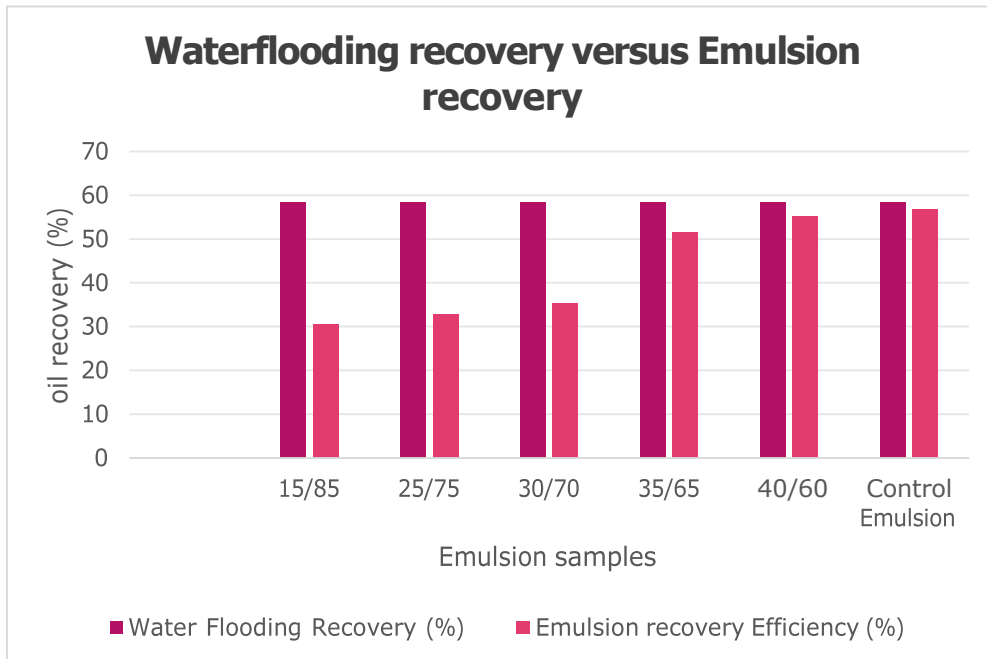


Figure 4.19: Recovery with Water Flooding and Formulated Emulsion flooding

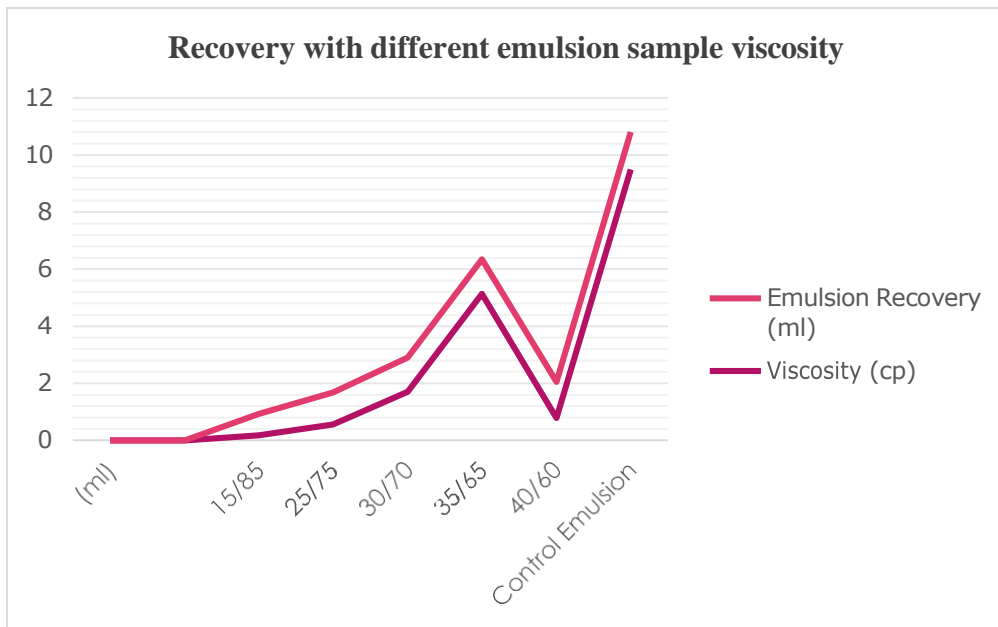


Figure 4.20: Recovery with different emulsion viscosity

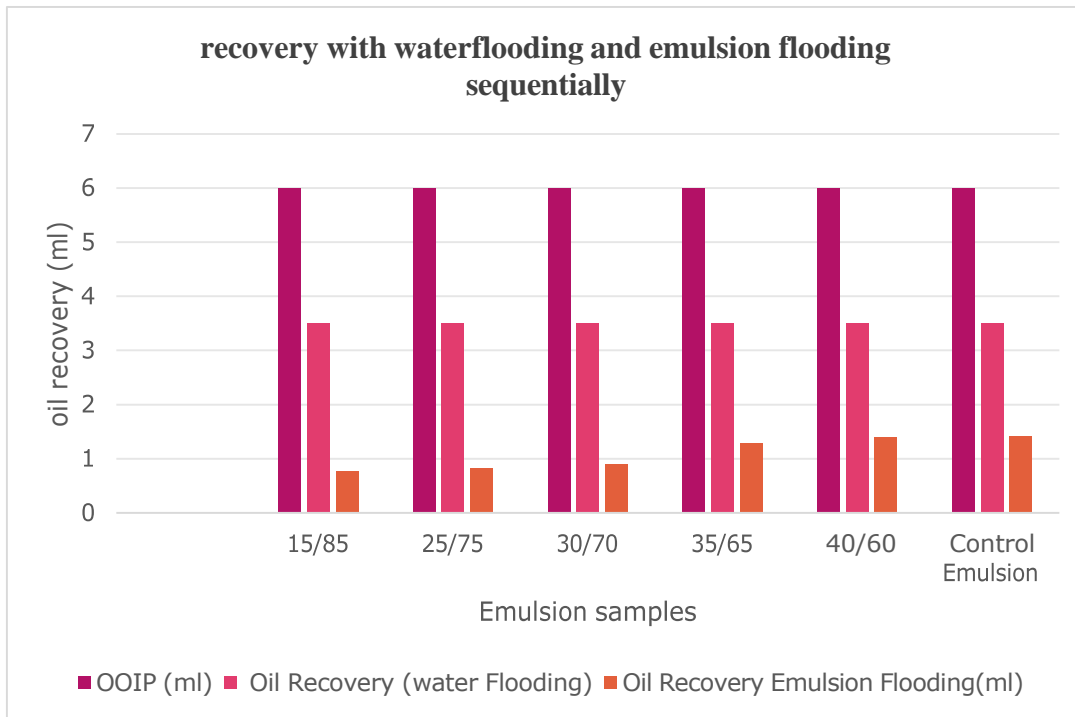


Figure 4.21: Comparison of results of recovery from formulation Emulsions and Control Emulsion

#### 4.1.6 Developed Proxy Model through Application of Regression Analysis

$$RE = 0.288 Tr + 0.063\mu + 0.051\mu e - 0.046yo - 0.00004Ts \quad 4.1$$

#### Validation of Proxy Model

The proxy model was validated and tested by firstly comparing the recovery efficiency predicted with the model to the recovery efficiency obtained from the laboratory core flooding experiment.

Then the proxy model was compared with the proxy model by (Balhasan, Jumaa & Elbagir 2017)

$$RE = 0.165 \ln\left(\frac{T_r}{T_s}\right)^{0.88} + 0.0066 \ln\left(\frac{\mu_o}{\mu_w}\right) + 0.28 \left(\frac{1}{y_o}\right)^{1.55} + 0.264 \quad 4.2$$

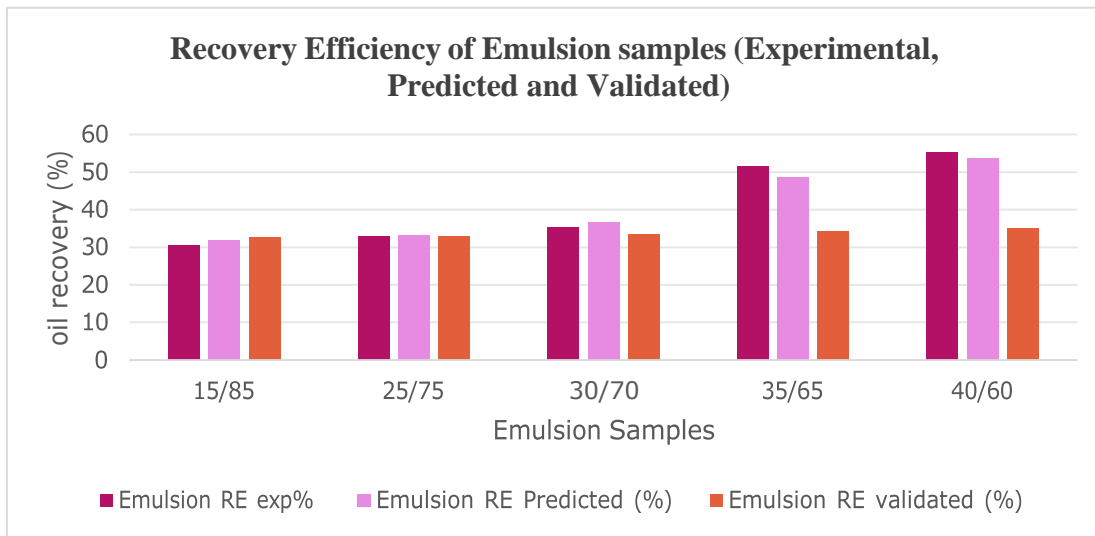


Figure 4.22: Recovery Efficiency (Experimental, Predicted and Validated)

#### 4.1.6.1 Application of Plackett-Burman in the Scaling-up of the Proxy Model

Table 4.1: Range of investigated Factors Influencing Emulsion flooding

Parameter	Lowest	Median	Highest
Reservoir Temperature °F	122	189	250
Oil Viscosity, $\mu_o$ (cp)	0.4	1	2
Emulsion Viscosity, $\mu_e$ (cp)	0.5	5	10
Surface temperature °F	75	84.2	90
Oil specific Gravity	0.97	0.86	0.78

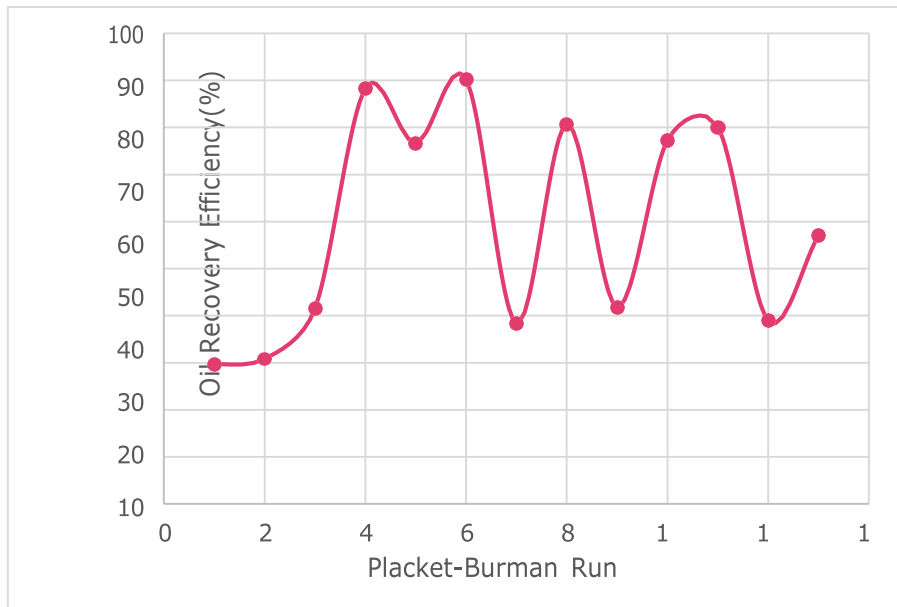


Figure 4.23: Recovery Efficiency of each Plackett-Burman run (%)

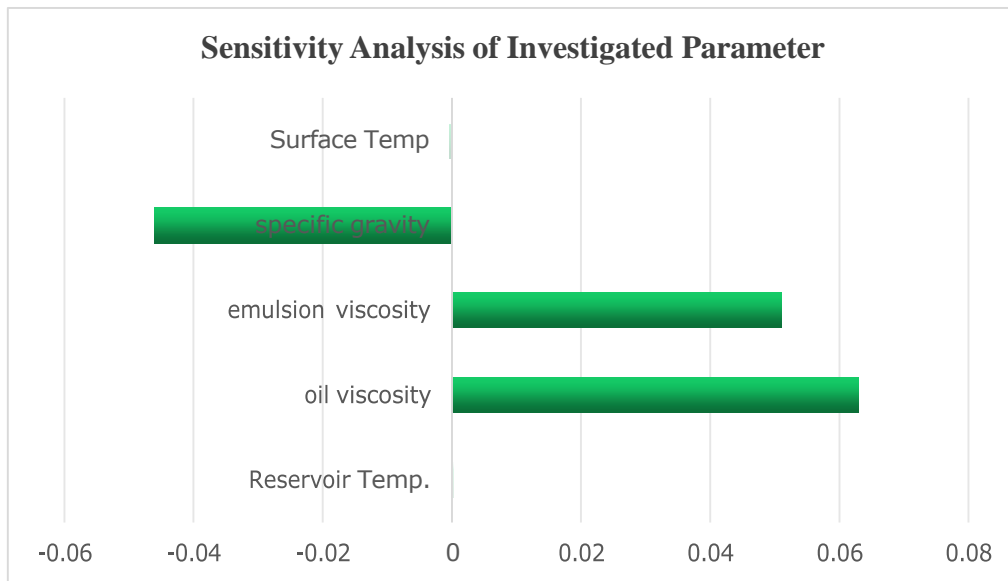


Figure 4.24: Sensitivity analysis of factors affecting emulsion flooding of oil reservoir

#### 4.1.7 Economic Analysis of Formulated Emulsion versus Conventional Emulsion

Table 4.2: Assumptions for Economic Analysis

Annual oil Production (bbl)	Oil Price \$	Annual Revenue \$	Annual Revenue =N= (1 \$ = 1,500=N=)	Discount Rate %	Oil Production Life Span (yr)
100,000	66	6,600,000	9,900,000,000.00	10	10

Table 4.3: Cost estimate of Emulsion formulation with conventional Material

Materials	Unit	Unit price (=N=)	Quantity	COST (=N=)
Engine Oil	1liter	9500	15,900,000	105,735,000,000.00
Sodium Lauryl Sulphate	1kilogram	4.000	4,770	19,080,000.00
Distilled Water	1 liter	600	4,770,000	2,862,000,000.00
			TOTAL	108,616,080,000.00

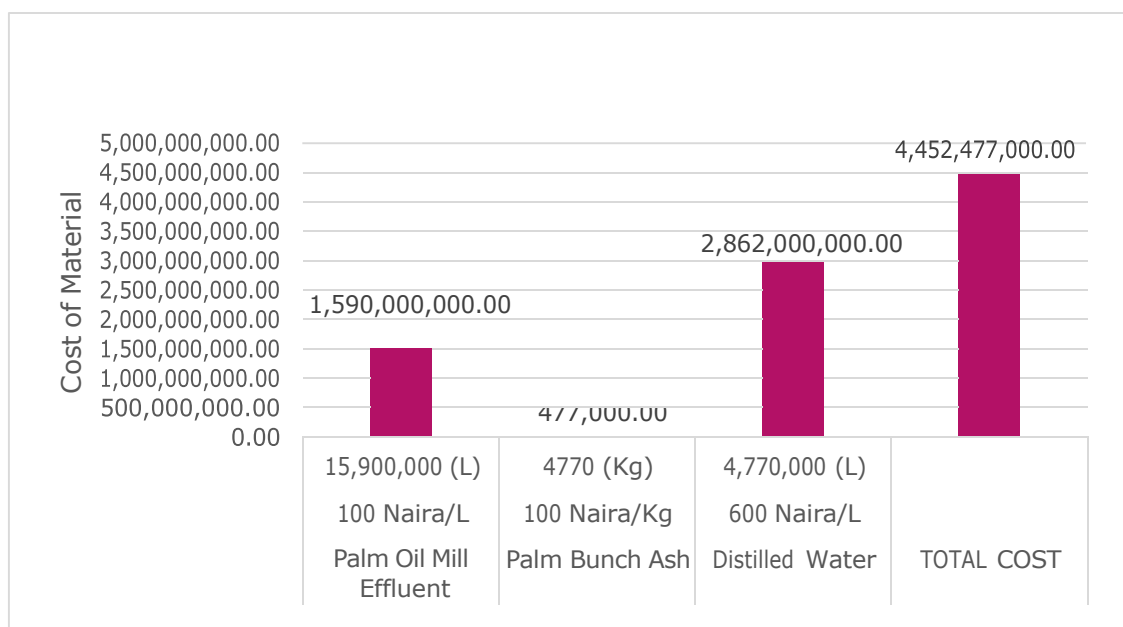


Figure 4.25: Cost estimate of Emulsion formulation with Palm Oil Mill Effluent and Palm Bunch Ash

**Table 4.4: Cost estimate of Emulsion formulation with Palm Oil Mill Effluent and Palm Bunch Ash**

Materials	Unit	Unit price (=N=)	quantity	COST (=N=)
Palm Oil Mill Effluent	1liter	100	15,900,000	1,590,000,000.00
Palm Bunch Ash	1kilogram	100	4,770	477,000.00
Distilled Water	1 liter	600	4,770,000	2,862,000,000.00
			<b>TOTAL COST</b>	<b>4,452,477,000.00</b>

**Table 4.5: Cash flow and Present Value of conventional Emulsion at a discount rate of 10%**

<b>Year</b>	<b>Investment</b>	<b>Annual Revenue (=N=)</b>	<b>Discount factor</b>	<b>Net Cash Flow</b>	<b>Present Value</b>
0	-108,616,080,000.00	0	1.0000	-108,616,080,000.00	-108,616,080,000.00
1	-108,616,080,000.00	9,900,000,000.00	0.9091	(98,716,080,000.00)	(89,846,272,727.00)
2	-108,616,080,000.00	9,900,000,000.00	0.8264	(98,716,080,000.00)	(80,649,211,099.00)
3	-108,616,080,000.00	9,900,000,000.00	0.7513	(98,716,080,000.00)	(72,959,486,111.00)
4	-108,616,080,000.00	9,900,000,000.00	0.6830	(98,716,080,000.00)	(66,539,320,579.00)
5	-108,616,080,000.00	9,900,000,000.00	0.6209	(98,716,080,000.00)	(60,972,838,497.00)
6	-108,616,080,000.00	9,900,000,000.00	0.5645	(98,716,080,000.00)	(55,993,181,870.00)
7	-108,616,080,000.00	9,900,000,000.00	0.5132	(98,716,080,000.00)	(51,458,365,111.00)
8	108,616,080,000.00	9,900,000,000.00	0.4665	(98,716,080,000.00)	(47,235,544,990.00)
9	108,616,080,000.00	9,900,000,000.00	0.4241	(98,716,080,000.00)	(43,207,672,039.00)
10	108,616,080,000.00	9,900,000,000.00	0.3855	(98,716,080,000.00)	(39,261,739,162.00)
<b>Total</b>	<b>1,086,160,800,000.00</b>	<b>99,000,000,000.00</b>		<b>980,716,080,000.00</b>	<b>(608,123,623,185.00)</b>

**NPV =N= (-499,507,552,185.00)**

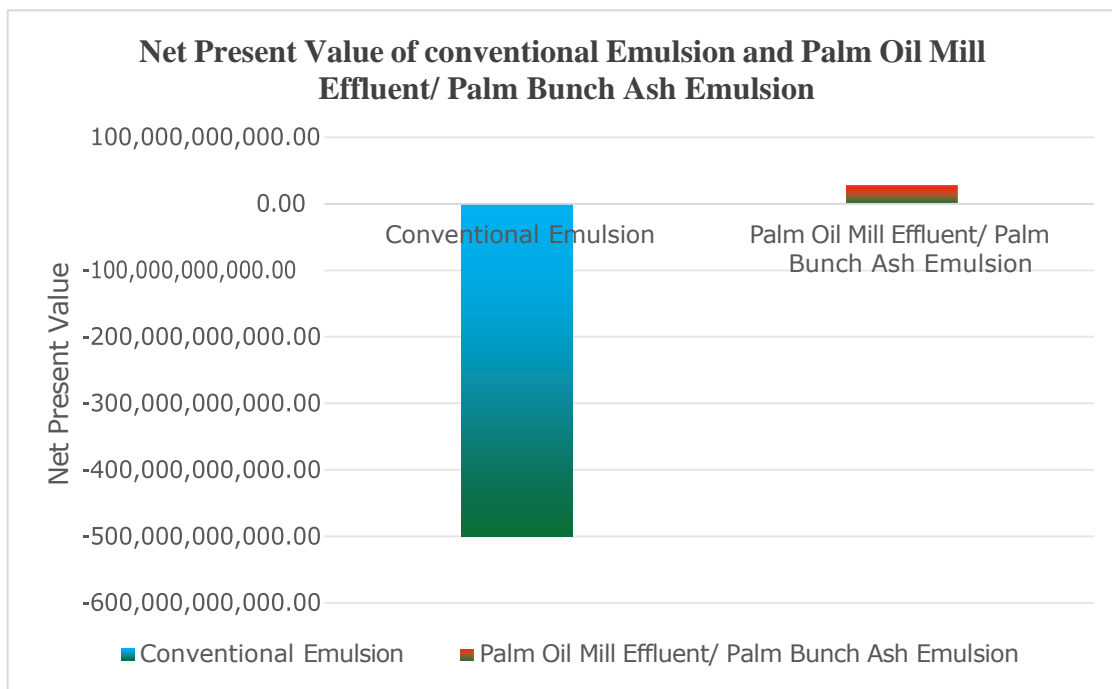
**Table 4.6: Cash Flow Analysis of Emulsion Formulation with Palm Oil Mill Effluent and Palm Bunch Ash at Discount rate of 10%**

Year	Investment	Revenue	Discount factor	Net Cash Flow	Present Value
0	-4,452,477,000.00	0	1.0000	-4,452,477,000.00	-4,452,477,000.00
1	-4,452,477,000.00	9,900,000,000.00	0.9091	5,447,523,000.00	4,952,343,159.00
2	-4,452,477,000.00	9,900,000,000.00	0.8264	5,447,523,000.00	4,501,833,007.20
3	-4,452,477,000.00	9,900,000,000.00	0.7513	5,447,523,000.00	4,092,724,029.90
4	-4,452,477,000.00	9,900,000,000.00	0.6830	5,447,523,000.00	3,720,658,209.00
5	-4,452,477,000.00	9,900,000,000.00	0.6209	5,447,523,000.00	3,382,367,030.70
6	-4,452,477,000.00	9,900,000,000.00	0.5645	5,447,523,000.00	3,075,126,733.50
7	-4,452,477,000.00	9,900,000,000.00	0.5132	5,447,523,000.00	2,795,668,803.60
8	-4,452,477,000.00	9,900,000,000.00	0.4665	5,447,523,000.00	2,541,269,479.50
9	-4,452,477,000.00	9,900,000,000.00	0.4241	5,447,523,000.00	2,310,294,504.30
10	-4,452,477,000.00	9,900,000,000.00	0.3855	5,447,523,000.00	2,100,020,116.50
<b>Total</b>	<b>44,524,770,000.00</b>	<b>99,000,000,000.00</b>		<b>54,475,230,000.00</b>	<b>31,393,305,073.20</b>

**Net Present Value = N=26,940,828,073.20**

**Table 4.7: Table 4.Net Present Value of conventional Emulsion and Palm Oil Mill Effluent/ Palm Bunch Ash Emulsion**

<b>Investment</b>	<b>Conventional Emulsion</b>	<b>Palm Oil Mill Effluent/ Palm Bunch Ash Emulsion</b>
<b>Net Present Value</b>	=N= (- 499,507,552,185.00)	=N=26,940,828,073.20



**Figure 4.26: Net Present Value Conventional Emulsion and Palm Oil Mill Effluent/ Palm Bunch Ash Emulsion**

Table 4.8: Investment analysis in formulating conventional and palm oil mill effluent emulsion

<b>Investment</b>	<b>Net Present Value (-N-)</b>	<b>Payback Period (year)</b>	<b>Return on Investment (%)</b>
Conventional Emulsion	=N= (-499,507,552,185.00)	-	-90.89
Palm Oil Mill Effluent/Palm Bunch Ash Emulsion	=N= 26,940,828,073.20	8.17	122.35

## 4.2 Discussion

### 4.2.1 Chemical analysis of palm bunch ash and palm oil mill effluent

Prior to the application of alkaline solution as one of the emulsion formulation chemicals, the ash obtained from the burnt empty palm fruit bunch was characterized to ascertain its suitability as an emulsifier, the pH level indicated 11.0 as shown in figure 4.1, and Table 4.1. It proves that it is a base which can neutralize any acidic components in the system, the alkaline nature creates a stable emulsion. The potassium content (68.4%) of the ash is the principal component in the ash solution which acts as an emulsifier. Potassium ions ( $K^+$ ) are known to possess emulsifying properties, which help to stabilize emulsions by reducing the interfacial tension between the oil and water.

The sodium ions ( $Na^+$ ) contained in the ash solution contribute to emulsion stability though to a lesser extent compared to potassium. The calcium ( $Ca^{++}$ ) and magnesium ( $Mg^{++}$ ) ions content have the potential of destabilizing emulsions but due to the low content of these components (0.08% and 0.62%) in palm bunch ash, the above-mentioned adverse effects of calcium and magnesium are negligible. Phosphorus (P) can help to improve the stability of emulsions by forming complexes with metal ions and reduction of interfacial tension.

Figure 4.2 shows the components of palm oil mill effluent, the high oil content indicates significant beneficial utilization as a natural emulsifier, reducing the need for synthetic additives in emulsion formulation for enhanced oil recovery. The low pH of 4.7 indicates acidic conditions, which may require neutralization or buffering to stabilize emulsions. Murtado, M.M et al (2020)

The high oil content and divalent ion levels are advantageous, but its acidic pH and high BOD/COD were treated before use. Figure 4iii shows the characterization of oil extracted from the palm oil mill

effluent, the specific gravity of the oil (0.87) indicates that the extract is less dense than water and is beneficial for emulsion formulation because it can easily mix with water. The viscosity at 10.5 is relatively low, which is suitable for emulsion formulation because it allows for easy mixing and flow.

The density (0.90g/cm<sup>3</sup>) of the oil extract from palm oil mill effluent indicates that it is less dense than water, therefore suitable for emulsion formulation chemical Abhijit, S., Ojha, K., Mandal, A., Sarkar, A (2013). The temperature (29°C) is within the optimal range for emulsion formulation because it allows for easy mixing and stability. The pH value (5.5) of the oil extracted from Palm oil mill effluent is slightly acidic, and higher than the pH value of palm oil mill effluent (4.7) which can affect the stability of the emulsion.

#### **4.2.2 Properties Analysis of Oil Extracted from Palm Oil Mill Effluent**

The Specific Gravity (0.87) indicates that the oil is lighter than water, which is beneficial for emulsion formulation as it will help in creating a stable mixture. The viscosity (10.5 cP) which is relatively low viscosity suggests that the oil has good fluidity, and can be easily mixed with other components. This is advantageous for emulsion formulation. The density (0.90 g/cm<sup>3</sup>), confirms that the oil is lighter than water, supporting its suitability for emulsions. The pH Value (5.5) indicates slight acidity which may affect the stability of the emulsion, but is neutralized by palm bunch ash solution with pH level of (11.0). The implications for emulsion formulation as established by the properties of the oil extracted from palm oil mill effluent are: it can form stable emulsions, especially when combined with a suitable emulsifier, the relatively low viscosity and density indicate good flow-ability, making it easy to mix and apply. considering these factors, it indicates that there can be effective formulation of a stable and efficient emulsion using the extracted oil from Palm Oil Mill Effluent and Palm Bunch Ash solution.

### 4.2.3 Properties of a palm bunch ash (PBA) solution.

Figure 4.4, and 4.5 show that the potential effects of palm bunch ash solution when mixed with oil extracted from palm oil mill effluent (POME) for emulsion formulation in enhanced oil recovery of mature fields in the Niger Delta are based on the properties which can positively influence the behavior of the emulsion, they include:

- (1). Emulsion stability: - The relatively low viscosity of the palm bunch ash solution can help stabilize the emulsion by reducing the likelihood of phase separation.
- (2). Fluidity: - The low viscosity and similar density to water can facilitate injection and flow through the reservoir. The PBA solution's surface properties may improve the wettability of the oil, enhancing the emulsion's ability to interact with the reservoir rock. The low viscosity of the PBA solution can facilitate injection into the reservoir. The emulsion's viscosity and density will influence its ability to displace oil from the reservoir rock.
- (3). Stability: - The emulsion's stability will impact its ability to maintain contact with the oil and rock surfaces. Analysis of formulated emulsion samples with oil extracted from palm oil mill effluent (POME) and palm bunch ash solution.

Figure 4.5 shows the presence of compounds suggesting that palm bunch ash solution is a complex mixture of Silica ( $\text{SiO}_2$ ) and alumino-silicates (Davyne, Osumilite), which can contribute to its emulsifying properties. Organic matter (Urea), indicating some degree of organic content., and alkali metals (K, Na, Ca) and magnesium, which can help stabilize emulsions.

The combination of silica, alumino-silicates, and organic matter in palm bunch ash solution can help to stabilize emulsions by forming a protective film around droplets. The presence of organic matter (Urea) and alkali metals can contribute to surface tension reduction, facilitating emulsion formation.

The complex mixture of compounds may help maintain emulsion stability over time. Using palm bunch ash as an emulsifier for oil extracted from palm oil mill effluent (POME) emulsion samples offers the advantages of mobilizing trapped oil, and increasing recovery efficiency. The natural emulsifying properties of palm bunch ash minimized the need for additional surfactant. Utilizing palm bunch ash, a waste product, reduces waste disposal issues and promote sustainability.

#### **4.2.4 Formulated Emulsion Samples Analysis**

Figure 4.6 represents the density of emulsion samples formulated by using oil extracted from palm oil mill effluent and palm bunch ash solution. The density of the emulsion samples decreases as the proportion of palm bunch ash solution component of the emulsion decreases, from 1.05 g/cm<sup>3</sup> (5/95) to 0.77 g/cm<sup>3</sup> (45/55) indicating that the palm bunch ash solution is denser than the oil extracted from palm oil mill effluent. Figure 4.7 shows that the viscosity of the emulsion samples increases significantly as the proportion of palm bunch ash solution decreases, from 0.12 cP (5/95) to 8.5 cP (45/55) suggesting that the palm bunch ash solution contributes to increase flowability of the emulsion. The pH level of the emulsion samples remains relatively stable and neutral ranging from 6.8 to 7.0.

#### **4.2.5 centrifugal test for emulsion samples stability**

Figure 4.9 and 4.10 shows that the more water separated from the emulsion samples as the ratio of the palm bunch ash solution decreases, therefore, the stability of the samples decreases with increasing oil content, from 98.8% (5/95) to 89.2% (45/55). Higher stability is desirable for enhanced oil recovery operations, but the decrease in stability with increasing oil content is expected. As shown in figure 4.9 and 4.10, it is noteworthy that viscosity increases with increasing oil content, which can be beneficial for mobility control but may hinder injection. Interfacial Tension (IFT) decreases with increasing oil content, which is favorable for enhanced oil recovery. The droplet size distribution shifts towards

larger droplets with increasing oil content. Considering the trade-offs between stability, viscosity, IFT, and droplet size distribution, the samples 5/95, 10/90, and 15/85 show higher stability but the low viscosity property of these samples can lead to early breakthrough due to their inability to mobilize more oil. 25/75 emulsion sample is the optimal choice for enhanced oil recovery because this sample offers a relatively high stability of 96.3%, a moderate viscosity of 0.00056 Pa·s, which balances injectivity and mobility control, a relatively low IFT of 12.75 mN/m, which enhances oil displacement efficiency, a droplet size distribution of 15-40 mL, which is suitable for EOR applications. While the 45/55 sample has the lowest IFT, its lower stability and higher viscosity may compromise its overall performance. The 25/75 sample offers a better balance of properties, making it a more suitable choice for enhanced oil recovery in the Niger Delta.

Figure 4.9 shows the centrifugal test on the emulsion samples formulated with various ratios of oil and palm bunch ash solution. All the emulsions samples (5/95 to 45/55) show excellent stability, with no oil separation at 30°C and 40°C. As temperature increases from 50°C to 100°C, oil separation increases, indicating that emulsion stability is temperature-sensitive. Emulsions with higher oil content (25/75 to 45/55) exhibit increased water separation, suggesting decreased stability.

The 25/75 ratio appears to be a threshold, beyond which water separation increases significantly and this can be termed the critical ratio. The emulsion samples with lower oil content ( $\leq 20\%$ ) such as 5/95, 10/90, 15/85, and 20/80 are more stable, indicating suitable surfactant concentration and/or effective emulsification technique, but the increase in water separation with temperature increase suggests that the 5/95, 10/90, 15/85, and 20/80 emulsion samples may be sensitive to thermal stress, potentially leading to phase separation, and higher oil content ( $>25\%$ ) in emulsion samples of 30/70, 35/65, and 40/60 may require additional surfactant or modified emulsification techniques to maintain stability.

#### **4.2.6 Interfacial Tension (IFT) between Oil and palm bunch ash solution of Emulsion Samples**

Figure 4.11 indicates that the interfacial tension (IFT) decreases consistently as palm bunch ash solution ratio increases, the rate of decrease in IFT slows down as the ratio of palm bunch ash solution increases, as the palm bunch ash ratio increases, the IFT between oil and palm bunch ash solution decreases. This is beneficial for oil recovery, as lower IFT facilitates easier displacement of oil by the injected fluid. The data suggests that increasing the palm bunch ash solution ratio beyond 25/75 (oil/palm bunch ash solution) may not yield significant reductions in IFT, this indicates an optimal palm bunch ash solution ratio range for effective oil recovery. Lower IFT values generally indicate more stable emulsions. The formulations with higher palm bunch ash solution ratio (25/75, 30/70, 35/65) may produce more stable emulsions. Therefore, it is evident that the optimal emulsion sample ratio for minimal IFT is between 25/75 and 35/65. IFT reduction becomes less significant beyond 25/75 oil/palm bunch ash solution ratio. Emulsion stability is expected to increase with higher palm bunch ash solution ratio

#### **4.2.7 Droplet size distribution of emulsion samples.**

Figure 4.12 reveals that the droplet sizes range from 1-80 microns, show relatively broad distribution. The mean droplet sizes range from 2.5 to 40 microns, while the median values range from 2 to 38 microns. Standard deviation ranges from 1.2 to 18 microns, indicating varying levels of dispersion. A broader droplet size distribution such as the one shown in figure 4xi can improve mobility control during enhanced oil recovery program by allowing better sweep efficiency and oil displacement. A smaller mean droplet size (e.g., 5/95 sample) may enhance emulsion stability, reducing coalescence and improving oil transport. Larger droplet sizes (e.g., 45/55 sample) may increase viscosity, potentially improving oil displacement efficiency. The 10/90 to 30/70 samples have suitable droplet sizes for optimal capillary number, facilitating oil displacement in porous media. The optimal droplet

size range for enhanced oil recovery typically falls between 10-30 microns. Samples (20/80, 25/75, and 30/70) with droplet sizes within this range exhibit better performance in terms of oil displacement efficiency and mobility control.

#### **4.2.7.1 Shear Stress in Emulsion Samples**

Figure 4.13 represents the shear stress of various emulsion samples (5/95 to 45/55) at different shear rates (10 s<sup>-1</sup>, 50 s<sup>-1</sup>, and 100 s<sup>-1</sup>). Most emulsions exhibit shear thinning behavior, where shear stress increases with shear rate but at a decreasing rate, (Derkach 2010; Dickinson 2015). This is beneficial for enhanced oil recovery, as it allows the emulsion to maintain its viscosity and flow easily through porous rock formations. Emulsions with higher viscosity tend to have higher shear stresses, indicating stronger resistance to flow. The 5/95 and 10/90 emulsions show relatively low shear stresses, indicating potential instability or breakdown during flooding operations. In contrast, emulsions with higher concentrations (25/70 to 45/55) exhibit significantly higher shear stresses, suggesting improved stability.

Emulsion sample with ratio 25/75 appear to offer a balance between viscosity and shear stress, making it the optimal emulsion ratio suitable for enhanced oil recovery operation.

#### **4.2.8 Core flooding experiments using different emulsion samples to recover oil.**

Figure 4xviii shows that crude oil recovery using water flooding recovered 58.33% of the oil-in-place from all crude oil saturated core samples, indicating that water flooding alone is not very effective in recovering oil from the mature fields as represented by the core samples. Emulsion flooding increases oil recovery when compared to water flooding. Though the highest oil recovery is achieved with waterflooding, and the control emulsion sequentially (95.83%) and waterflooding with the 40/60 emulsion sample sequentially (95.63%), however the 25/75 emulsion sample with waterflooding

sequentially recovered 91.13% of the oil. It is noteworthy that the optimal ratio in recovering oil from the core sample when the viscosity, and stability of the emulsion samples are compared is 25/75 emulsion sample because an extra cost is needed to increase the viscosity from 0.56cp of 25/75 ratio to 6.5 cp of 40/60 ratio. Emulsion flooding shows significant improvement in oil recovery compared to water flooding, indicating the potential benefits of using emulsion flooding in enhanced oil recovery (EOR) operations.

#### **4.2.8.1 Plackett-Burman runs of parameters effecting emulsion flooding**

Figure 4.21 and 4.22 show that as the emulsion oil/palm bunch ash solution ratio increases from 15/85 to 40/60, the cumulative oil produced ( $N_p$ ) also increases. This suggests that as the viscosity of the emulsion sample increases, oil recovery increases too. Both experimental and predicted recovery efficiency values increase with increasing oil ratio and decreasing palm bunch ash solution ratio. This indicates that the enhanced oil recovery process becomes more efficient as less water is injected.

The predicted recovery efficiency values are generally close to the experimental Recovery Efficiency values, indicating a good match between the model predictions and actual experimental results. R-squared value (0.952) is close to unity, indicating a strong correlation. The model explains approximately 95.2% of the variability in the experimental recovery efficiency indicating a very strong positive linear relationship between the experimental and predicted recovery efficiencies, suggesting that the model is accurately predicting the recovery efficiency

Cumulative oil production ( $N_p$ ) varies widely across runs, indicating a strong dependence on the input parameters. Higher oil emulsion viscosity tends to result in higher recovery efficiency, especially with low oil viscosity. Higher reservoir temperature affects the viscosity of the oil more than it affects the viscosity of emulsion. Run 6 yielded higher recovery efficiency because the high temperature

mobilizes the oil, therefore supports the mobility of oil. Higher recovery efficiency is associated with mobility ratio, placket-burman run numbers where the oil viscosity is higher than emulsion viscosity experience lower recovery efficiency.

Emulsion /crude oil viscosity ratio (2/10) appears to favor higher recovery factor, therefore it is the optimal mobility ratio for higher recovery efficiency as shown in Table 4.19. The most sensitive parameter is oil viscosity, followed by viscosity of emulsion as shown in figure 4.23

#### **4.2.9 Economic Analysis of formulating Mandal, (2010) 30/70 conventional emulsion sample and 30/70 emulsion with POME/PBA solution**

The yearly investment in the production of the conventional emulsion sample of 30/70 oil/water emulsion requires a significantly higher yearly investment of (=N= 108,616,080,000) compared to investment in the production of 30/70 emulsion sample of oil/palm bunch ash solution of (=N= 4,452,477,000).

Investment in the production of conventional emulsion sample has negative cash flows throughout the 10-year period, while investment in the production of 30/70 emulsion sample with oil extracted from palm oil mill effluent and palm bunch ash solution has yearly positive cash flows because the expenses made in formulating the emulsion is far less than the income made from the sales of produced oil.

Net Present Value (NPV) of investment in the conventional 30/70 emulsion sample has a negative NPV =N= (- 499,507,552,185.00)), while investment in the production of 30/70 emulsion sample with oil extracted from palm oil mill effluent and palm bunch ash has a positive NPV (=N= 26,940,828,073.20).

Investment on the production of conventional emulsion of 30/70 ratio appears non-viable, as it requires a substantial initial investment and generates consistent negative cash flows, leading to a

significant loss of 90.89%, but investment in the production of 30/70 emulsion ratio with oil extracted from palm oil mill effluent and palm bunch ash appears viable, with a relatively small yearly investment, positive cash flows for the 10year period, and a substantial positive NPV with payback period of 8.17 years and a Return on investment of 122.35%

## CHAPTER FIVE

### CONCLUSION AND RECOMMENDATIONS

#### 5.1 Conclusion

This experiment successfully demonstrated the potential of using palm oil mill effluent and palm bunch ash solution from burnt empty palm fruit bunch to formulate stable emulsion. The results showed that

- The combination of these two agricultural waste materials can produce an emulsion with stable characteristics for recovery of trapped oil from mature fields.
- The emulsion stability, and viscosity were influenced by factors such as temperature, mixing ratio, and time. These findings suggest conclusively that this emulsion could be valuable.
- The 40/60 emulsion sample gave the highest recovery. The emulsion formulated with oil extracted from palm oil mill effluent and palm bunch ash solution offers an alternative to conventional emulsifiers.
- Characterization of burnt palm oil fruit bunch and palm oil mill effluent revealed their chemical viability in formulating emulsion flooding fluid.
- The experiment showed that the emulsion samples enhanced oil recovery through interfacial tension reduction and wettability alteration mechanisms.
- Burnt palm fruit bunch can be used as emulsifying agent.
- Core sample flooding experiment determined oil recovery potential of burnt empty palm oil fruit bunch and palm oil mill effluent
- Developed numerical model helped to validate the recovery efficiency of the formulated emulsion flood fluid.
- Increasing the emulsion formulation ratio beyond 25/75 (oil/palm bunch ash solution) may not

yield significant increase in oil recovery

- Investment in the production of the local emulsion has a positive net present value, therefore be economically beneficial and sustainable
- Emulsion flooding increases oil recovery when compared to water flooding.
- Emulsions with higher concentrations (25/70 to 45/55) exhibit significantly higher shear stresses, showing improved stability.
- Emulsion sample with ratio 25/75 appear to offer a balance between viscosity and shear stress, making it the optimal emulsion ratio suitable for enhanced oil recovery operation.
- The stability of the samples decreases with increasing oil content, from 98.8% (5/95) to 89.2% (45/55).

## **5.2 Recommendations**

- Based on the results of this research, the stability of the formulated emulsions should be further improved for reservoirs with higher temperature because high temperatures can cause emulsions to degrade, leading to reduced mobility control
- Field tests should be performed to assess the feasibility of large-scale oil recovery production in field application using this emulsion formulated with palm oil mill waste materials
- Therefore, the sample's low density which may lead to instability of the sample should be looked into. Furthermore, the high viscosity which can cause injectivity challenges should be addressed

### 5.3 Contribution to knowledge

- This study explores the application of palm oil mill waste, specifically oil palm mills effluent and palm bunch, to formulate an emulsion fluid, NGU1, designed to enhance oil recovery
- The use of local materials in enhanced oil recovery (EOR) has been extensively researched;
- Waste recycling: The development of NGU1 demonstrates a practical approach to recycling waste materials, converting them into a valuable resource that generates income and supports sustainable practices.
- Correlation for oil recovery efficiency of a Niger delta well under emulsion flooding operations: A core sample analysis International Journal of Petroleum and Engineering Gas Research 8(1), 76-84, 2025
- Evaluating the stability of emulsion fluids synthesized with palm oil mill waste for enhancement of hydrocarbon withdrawal from Niger delta oil fields. Journal of Oil, Petroleum and Natural Gas Research 2(10), 1-5, 2025
- Economic evaluation of oil reservoir emulsion fluid formulated with palm oil mill effluent and empty palm bunch. International Journal of Petroleum and Engineering Gas Research, 7(2), 49-62, 2024
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## APPDENDIX

**Table 4.1: Chemical characterization of palm oil mill effluent**

PARAMETER	Oil	Na	K	PO <sub>4</sub>	BOD	COD	Mg	Ca	NH <sub>3</sub>	pH
Concentration (mg/L)	7600	1.26	309	28.0	28950	42200	688	15.2	14.9	4.7

**Table 4.2: Chemical characterization of burnt empty palm fruit bunch**

ELEMENTS	CONCENTRATION (g/kg)	CONCENTRATION (%)	pH
Potassium	684.35	68.4	11.0
Sodium	20.16	2.02	
magnesium	6.18	0.62	
phosphorus	15.59	1.59	
Calcium	0.84	0.08	

**Table 4.3: Phase Identification of Ash solution formulated with burnt palm bunch**

COMPOUND	CRISTOBALITE	DAVYNE	UREA	SILVER-3C	OSUMILITE
FORMULA	SiO <sub>2</sub>	K <sub>2</sub> Na <sub>4</sub> Ca <sub>2</sub> Al <sub>6</sub> Si <sub>6</sub> O <sub>24</sub>	CH <sub>4</sub> N <sub>2</sub> O	Ag	K-Na-Ca-Mg-Al-Si

**Table 4.4: Properties of the Oil Extracted from Palm Oil Mill Effluent**

PROPERTY	Specific Gravity	Viscosity (cp)	Density (g/cm <sup>3</sup> )	Temp oC	pH
VALUE	0.87	10.5	0.90	29	5.5

**Table 4.5: Property of Palm bunch Ash solution**

Viscosity (cp)	Density (g/cm <sup>3</sup> )	API gravity
0.9436	1.0016	24.71

**Table 4.6: Properties of formulated emulsion samples**

Sample	Density(g/cm <sup>3</sup> )	Viscosity (cp)	Specific Gravity (s.g)	API	Temp °C	pH
5/95	1.05	0.12	0.91	23.99	28	6.8
10/90	1.02	0.13	0.90	25.72	28	6.8
15/85	1.00	0.18	0.89	27.49	28	6.8
20/80	0.99	0.20	0.87	31.14	28	6.8
25/75	0.94	0.56	0.86	33.03	28	6.8
30/70	0.92	1.70	0.85	34.38	28	6.9
35/65	0.91	5.14	0.84	36.95	28	6.9
40/60	0.78	6.5	0.83	38.98	28	6.9
45/55	0.77	8.5	0.80	45.38	28	7.0

**Table 4.7: Centrifugal Test for Phase Separation**

Sample	Temp@ 30°C	Temp@ 40°C	Temp@ 50°C	Temp@ 60°C	Temp@ 70°C	Temp@ 80°C	Temp@ 90°C	Temp@ 100°C
	Water Separation (mL)	Water Separation (mL)	Water Separation (mL)	Water Separation (mL)	Water Separation (mL)	Water Separation (mL)	Water Separation (mL)	Water Separation (mL)
5/95	0	0	0.2	0.4	0.6	0.8	1.0	1.2

10/90	<b>0</b>	<b>0</b>	0.4	<b>0.8</b>	<b>1.2</b>	<b>1.6</b>	<b>2.0</b>	<b>2.4</b>
15/85	<b>0</b>	<b>0</b>	0.6	<b>1.2</b>	<b>1.8</b>	<b>2.4</b>	<b>3.0</b>	<b>3.6</b>
20/80	<b>0</b>	<b>0</b>	0.8	<b>1.6</b>	<b>2.4</b>	<b>3.2</b>	<b>4.0</b>	<b>4.8</b>
25/75	<b>0</b>	<b>0</b>	1.0	<b>2.0</b>	<b>3.0</b>	<b>4.0</b>	<b>5.0</b>	<b>6.0</b>
30/70	0	0	1.2	2.4	3.6	4.8	6.0	7.2
35/65	<b>0</b>	<b>0</b>	1.4	<b>2.8</b>	<b>4.2</b>	<b>5.6</b>	<b>7.0</b>	<b>8.4</b>
40/60	<b>0</b>	<b>0</b>	1.6	<b>3.2</b>	<b>4.8</b>	<b>6.4</b>	<b>8.0</b>	<b>9.6</b>
45/55	<b>0</b>	<b>0</b>	1.8	<b>3.6</b>	<b>5.4</b>	<b>7.2</b>	<b>9.0</b>	<b>10.8</b>

**Table 4.8: Stability of emulsion samples (%)at different Temperatures using Ratio Data Method**

<b>Sample</b>	<b>Emulsion Stability (%) @ Temp 30°C</b>	<b>Emulsion Stability (%) @ Temp 40°C</b>	<b>Emulsion Stability (%) @ Temp 50°C</b>	<b>Emulsion Stability (%) @ Temp 60°C</b>	<b>Emulsion Stability (%) @ Temp 70°C</b>	<b>Emulsion Stability (%) @ Temp 80°C</b>	<b>Emulsion Stability (%) @ Temp 90°C</b>	<b>Emulsion Stability (%) @ Temp100° C</b>
5/95	<b>100</b>	<b>100</b>	99.8	<b>99.6</b>	<b>99.4</b>	<b>99.2</b>	<b>99.0</b>	<b>98.8</b>
10/90	<b>100</b>	<b>100</b>	99.6	<b>99.2</b>	<b>98.8</b>	<b>98.4</b>	<b>98.0</b>	<b>97.6</b>
15/85	<b>100</b>	<b>100</b>	99.4	<b>98.8</b>	<b>98.2</b>	<b>97.6</b>	<b>97.0</b>	<b>96.4</b>
20/80	<b>100</b>	<b>100</b>	99.2	<b>98.4</b>	<b>97.6</b>	<b>96.8</b>	<b>96.0</b>	<b>95.2</b>
25/75	<b>100</b>	<b>100</b>	99.0	<b>98.0</b>	<b>97.0</b>	<b>96.0</b>	<b>95.0</b>	<b>94.0</b>
30/70	<b>100</b>	<b>100</b>	98.8	97.6	96.4	95.2	94.0	92.8
35/65	<b>100</b>	<b>100</b>	98.6	<b>97.2</b>	<b>95.8</b>	<b>94.4</b>	<b>93.0</b>	<b>91.6</b>
40/60	<b>100</b>	<b>100</b>	98.4	<b>96.8</b>	<b>95.2</b>	<b>93.6</b>	<b>92.0</b>	<b>90.4</b>
45/55	<b>100</b>	<b>100</b>	98.2	<b>96.4</b>	<b>94.6</b>	<b>92.8</b>	<b>91.0</b>	<b>89.2</b>

**Table 4.9: Inter-Facial Tension between oil and alkali solution of Emulsion Samples**

<b>Emulsion Sample Ratio (mL)</b>	5/95	10/90	15/85	20/80	25/75	30/70	35/65	40/60	45/55
<b>Oil/palm bunch ash solution IFT (mN/m)</b>	14.19	13.83	13.47	13.11	12.75	12.39	12.03	11.67	11.31

**Table 4.10: Droplet size distribution with mean, median and standard deviation of the Emulsion Samples**

samples	Droplet size distribution (mL)	Mean (mL)	Median (mL)	Standard deviation (mL)
5/95	1-5	2.5	2	1.2
10/90	2-10	5	4	2.5
15/85	5-20	10	8	4
20/80	10-30	15	12	6
25/75	15-40	20	16	8
30/70	20-50	25	22	10
35/65	25-60	30	28	12
40/60	30-70	35	32	15
45/55	35-80	40	38	18

**Table 4.11: formulated emulsion samples shear stress at different shear rate**

Sample	Viscosity (pa. s)	Shear Stress @ 10s <sup>-1</sup> shear rate	Shear stress (pa) @ 50s <sup>-1</sup> shear rate	Shear stress @ 100s <sup>-1</sup> shear rate
5/95	0.00012	0.0012	0.006	0.012
10/90	0.00013	0.0013	0.0065	0.013
15/85	0.00018	0.0018	0.009	0.018
20/80	0.0002	0.002	0.001	0.02
25/75	0.00056	0.0056	0.0028	0.056
30/70	0.0017	0.017	0.085	0.17
35/65	0.00514	0.0514	0.0257	0.514
40/60	0.0065	0.065	0.0325	0.65
45/55	0.0085	0.085	0.0425	0.85

**Table 4.12: Properties of Emulsion Samples for Stability and EOR suitability Analysis**

Sample	Emulsion Stability (%) @ Temp 100°C	Viscosity (pa. s)	Shear stress @ 100s-1 shear rate	Droplet size distribution (mL)	Oil/palm bunch ash solution IFT (mN/m)	Density (g/cm <sup>3</sup> )	pH	API
5/95	98.8	0.00012	0.012	1-5	14.19	1.05	6.8	23.99
10/90	97.6	0.00013	0.013	2-10	13.83	1.02	6.8	25.72
15/85	96.4	0.00018	0.018	5-20	13.47	1.00	6.8	27.49
20/80	95.2	0.0002	0.02	10-30	13.11	0.99	6.8	31.14
25/75	94.0	0.00056	0.056	15-40	12.75	0.94	6.8	33.03
30/70	92.8	0.0017	0.17	20-50	12.39	0.92	6.9	34.38
35/65	91.6	0.00514	0.514	25-60	12.03	0.91	6.9	36.95
40/60	90.4	0.0065	0.65	30-70	11.67	0.78	6.9	38.98
45/55	89.2	0.0085	0.85	35-80	11.31	0.77	7.0	45.38

**Table 4.13: Property of crude oil used in the flooding experiment**

Property	Specific gravity	Density (g/cm <sup>3</sup> )	Viscosity (Cp)	API	Temperature( <sup>0</sup> c)
Values	0.89	0.84	0.55	26.7	29

**Table 4.14: Properties of brine used in the Flooding Experiment**

Property	Specific gravity	Viscosity(cp)	API	pH	Salinity (ppm)	Density(g/cm <sup>3</sup> )
Values	1.02	0.9377	7.65	6.6	30,000	1.03

**Table 4.15: Properties of core sample**

Porosity (%)	length(cm)	Diameter (cm)	Area (cm <sup>2</sup> )	Volume (cm <sup>3</sup> )	Pore volume(cm <sup>3</sup> )	Permeability (md)
20.8	5.9	3.3	78.28	50.47	10.50	372.4

**Table 4.16: Properties of the control emulsion prepared using engine oil and sodium Lauryl Sulphate**

Property	Value
Density (g/cm <sup>3</sup> )	1.11
Viscosity (cp)	9.5
Specific gravity	1.05
API	14.5
Temperature	29°C

**Table 4.17: Recovery with water flooding and formulated emulsion samples flooding**

Emulsion Sample (ml)	OOIP (ml)	Oil Recovery (water Flooding) (ml)	Oil Recovery Emulsion Flooding(ml)	Total Recovery (ml)	Water Flooding Recovery (%)	Emulsion recovery Efficiency (%)
15/85	6.00	3.50	0.76	4.26	58.33	30.4
25/75	6.00	3.50	0.82	4.32	58.33	32.8
30/70	6.00	3.50	0.89	4.38	58.33	35.2
35/65	6.00	3.50	1.29	4.79	58.33	37.1
40/60	6.00	3.50	1.39	4.88	58.33	37.3
Control Emulsion	6.00	3.5	1.41	4.92	58.33	37.5

**Table 4.18: Recovery Efficiency from Emulsion core flooding, Predicted model, and Validated model**

Sample	Q (ml/min)	$\Phi$ (%)	K (mD)	$\mu_o$ , (cp)	$\mu_e$ , (cp)	L (cm)	D (cm)	O OI P (ml)	Np (ml)	Emulsion Experimental RE exp%	Emulsion RE Predicted (%)	Emulsion RE validated (%)
15/85	2	0.208	372.4	0.55	0.18	5.9	3.3	6	4.26	30.4	31.8	32.7
25/75	2	0.208	372.4	0.55	0.56	5.9	3.3	6	4.32	32.8	33.0	32.8
30/70	2	0.208	372.4	0.55	1.70	5.9	3.3	6	4.38	35.2	36.7	33.5
35/65	2	0.208	372.4	0.55	5.14	5.9	3.3	6	4.79	51.6	48.7	34.3
40/60	2	0.208	372.4	0.55	6,50	5.9	3.3	6	4.88	55.2	53.7	35.0

**Table 4.19: Recovery Efficiency with Proxy Model in Scale-up using Plackett-Burman Design of Experiment**

Run No.	$T_{res}$ (°F)	$\mu_o$ (cp)	$\mu_e$ (cp)	$T_{sur}$ (°F)	$y'_o$	RE (%)
1	122	0.4	0.5	75	0.78	29.7
2	250	0.4	0.5	90	0.97	30.8
3	250	2.0	0.5	75	0.97	41.5
4	122	2.0	10	75	0.78	88.3
5	122	0.4	10	90	0.97	76.7
6	250	2.0	10	90	0.78	90.2
7	122	2.0	0.5	90	0.97	38.3
8	250	0.4	10	75	0.78	80.7
9	250	2.0	0.5	90	0.78	41.8
10	122	0.4	10	75	0.87	77.3

<b>11</b>	250	0.4	10	90	0.78	80.1
<b>12</b>	122	2.0	0.5	75	0.97	38.9
<b>13</b>	189	1.0	5.0	84.2	0.86	57.1

**Table 4.20: Statistical data of the developed proxy model**

R-Squared
0.9520

**Table 4.21: Cost estimate of Emulsion formulation with Palm Oil Mill Effluent and Palm Bunch Ash (April 2025)**

<b>Materials</b>	<b>Unit</b>	<b>Unit price (=N=)</b>	<b>quantity</b>	<b>COST (=N=)</b>
Palm Oil Mill Effluent	1liter	100	15,900,000	1,590,000,000.00
Palm Bunch Ash	1kilogram	100	4,770	477,000.00
Distilled Water	1 liter	600	4,770,000	2,862,000,000.00
			<b>TOTAL COST</b>	<b>4,452,477,000.00</b>