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Comparative Assessment of Conventionally and Locally Sourced Surfactants for Enhancing Steam Flooding Techniques for Heavy Oil Recovery in Niger Delta

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Authors' contributions

This work was carried out in collaboration among all authors. All authors read and approved the final manuscript.

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ABSTRACT

The recovery of heavy oil reserves presents a significant challenge in the petroleum industry due to its high viscosity and poor mobility characteristics. Steam flooding, as a thermal Enhanced Oil Recovery (EOR) technique, has shown promise in mobilizing heavy oil deposits. However, the limited success of conventional steam flooding in heavy oil reservoirs necessitates innovative

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approaches. This study explores the utilization of conventional and locally sourced surfactants in surfactant-enhanced steam flooding (SESF) for heavy oil recovery in the Niger Delta region. The study examines the selection, formulation, and injection of surfactants specifically tailored for heavy oil reservoir conditions. Laboratory experiments, core flooding tests, and numerical simulations are conducted to evaluate the impact of surfactants on interfacial tension reduction, wettability alteration, and improved oil mobility in heavy oil reservoirs subjected to steam flooding. The project's findings demonstrate the significant potential of (SESF) for heavy oil recovery. The synergistic effects of surfactants and steam, including the reduction of oil-water interfacial tension, lead to increased oil production rates, reduced steam consumption, and enhanced sweep efficiency. Furthermore, economic assessments are conducted to evaluate the feasibility of implementing this approach on a field scale, considering both technical and economic aspects. This study not only contributes valuable insights to the field of heavy oil recovery but also underscores the practicality of surfactant-enhanced steam flooding as an environmentally responsible solution for unlocking the vast heavy oil reserves worldwide. The research bridges the gap between laboratory findings and real-world applications, offering a promising path forward for the sustainable development of heavy oil resources.

Keywords: Paw-paw leaf extract; sodium lauryl sulphate; Enhanced oil recovery; core flood experiments.

1. INTRODUCTION

In the pursuit of efficient methods for recovering heavy oil reserves, the fusion of steam flooding and surfactant application stands out as a groundbreaking approach. The utilization of steam flooding, coupled with surfactant agents tailored for heavy oil characteristics, has the potential to revolutionize the recovery process by optimizing reservoir conditions, viscosity reduction, and interfacial tension modification. As we embark on this chapter, we aim to dissect the intricate interplay between steam, surfactants, and heavy oil properties.

In the past four decades, Nigeria produced oil from conventional oil reservoirs with an average of about 37.2 billion barrels. However unconventional oil reservoirs within Nigeria are about 42 billion barrels [1]. In recent years there has been a significant decline in conventional reserves at present, this has necessitated the drive towards searching for unconventional reserves. Heavy crude oil is a kind of formation oil which does not run easily in the reserve. because of its higher density and viscosity compared to medium or light oil. Heavy oil is defined as any kind of liquid petroleum with API gravity less than 22ºAPI, and a reservoir viscosity of 10-5000 cp. The oil becomes heavier only after substantial degradation during migration and after entrapment. The degradation can occur through a variety of biological, chemical, and physical processes. Table 1 gives a summary of the differences between light oil, heavy oil, extra heavy oil and tar sand/bitumen Heavy oil reservoirs are mostly located at shallow depth ranges around 1,000 ft. The porosity and the permeability are usually around 30% and greater than 1,000 md, respectively.

Heavy oil is an important energy source presently making an important contribution to the general energy supply. The world's total heavy oil reserve and bitumen reserve are estimated around 5.6 Trillion barrels [2]. Most heavy oil deposits in Nigerian basin is due to past flaring activities causing a decrease in the viscosity of oil, or can be attributed to a biodegradable process in which micro-organism on a geological time scale degrade. The increasing demand for energy and the depletion of conventional oil reserves has prompted the exploration of heavy crude oil reserves. Tremendous sources of heavy oil exist throughout the world. However, condition upon which the heavy oil occur vary significantly [3]. Heavy crude oil is characterized by high viscosity and density, which makes it difficult to extract using conventional methods.

1.1 Enhanced Oil Recovery

The phrases EOR and IOR are used interchangeably a lot of the time. The primary and secondary Recovery are mostly used for conventional oil recovery.

The thermal and chemical EOR are mostly used for the extraction of un-conventional heavy crude oil/light crudes as illustrated in the figure below.

Table 1. Crude oil classification of fluid density, viscosity and mobility

Type	*Density, API*	*Viscosity, cp*	Behaviour at reservoir condition
Light oil	>22	1-100	mobile
Heavy oil	15-22	100-1000	Mobile
Extra heavy oil	10-15	1000-10000	Slightly mobile
Tar sand	7-12	>10000	immobile

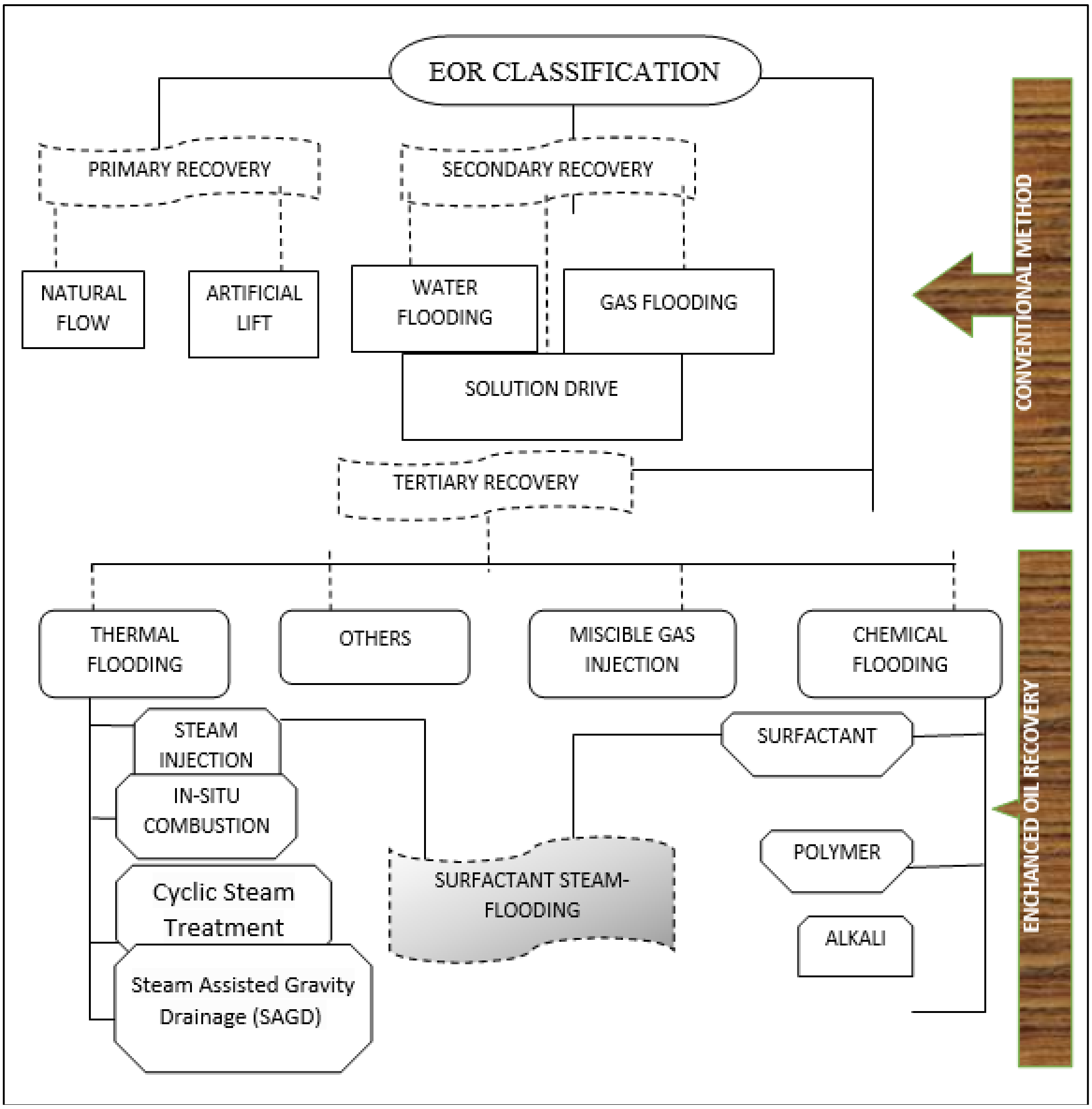

Fig. 1. Enhanced oil recovery of surfactant-steam-flooding

1.2 Chemical Flooding

Chemical enhanced oil recovery (CEOR) uses alkali, surfactant, polymer, or mixtures of these in order to improve oil recovery. To lessen the interfacial tension between the oil and the reservoir rock's surface, surfactant and alkaline are utilised. Additionally, alkaline creates soap in-place, which reduces the adsorption of surfactants. To improve the reservoir's microscopic sweep efficiency, alkaline and surfactants are both utilised [4]. The front of the displacing fluid is stabilised by the addition of polymer. By achieving a favourable mobility ratio between the fluids being displaced and being displaced, polymer injection aims to increase the reservoir's macroscopic sweep efficiency.

1.3 Thermal Method

Since the middle of the 1950s, thermal technologies have increasingly been applied in the sector. Thermal methods are primarily used for heavy oils and tar sands, although they are applicable to light oils in some special cases. Other non-thermal methods are normally used for light crudes. Some of these methods have been tested for unconventional heavy oils, however, have had limited success in the field. They are, without a doubt, the most sophisticated EOR techniques in terms of both technology and expertise. In order to raise the temperature of the remaining oil and thus reduce its viscosity, this approach entails adding thermal energy or heat into the reservoir. This increases the oil's mobility and capacity to flow through the reservoir. For recovering heavy oil with an API of 10–20°, thermal techniques are primarily used. Popular thermal methods are: Steam flooding (or hot water) injection, in situ combustion, Cyclic Steam Treatment (huff and puff), and Steam Assisted Gravity Drainage (SAGD)

1.4 Worldwide EOR oil production

In comparison to the 85 million barrels produced daily, or around 3.5% of the daily production, the total global oil production from EOR has remained relatively stable over time, providing roughly 3 million barrels of oil per day from Fig. 2.

Two (2) million barrels of oil are produced each day via thermal techniques, which account for the majority of this production. Included in this are Venezuela, Indonesia, Oman, China, Venezuelan heavy oil (Alberta), Californian heavy oil (Bakersfield), and other countries [5]. About a third of a million barrels of oil are produced daily by CO2-EOR, which has been increasing recently. These barrels come primarily from the Weyburn field in Canada and the US Permian Basin. Another 0.3 million barrels per day come from hydrocarbon gas injection operations in Venezuela [6].

Based on the number of projects performed EOR for heavy oil worldwide, thermal Method still remain the most effective for the production of EOR, this can be seen from the Fig. 3.

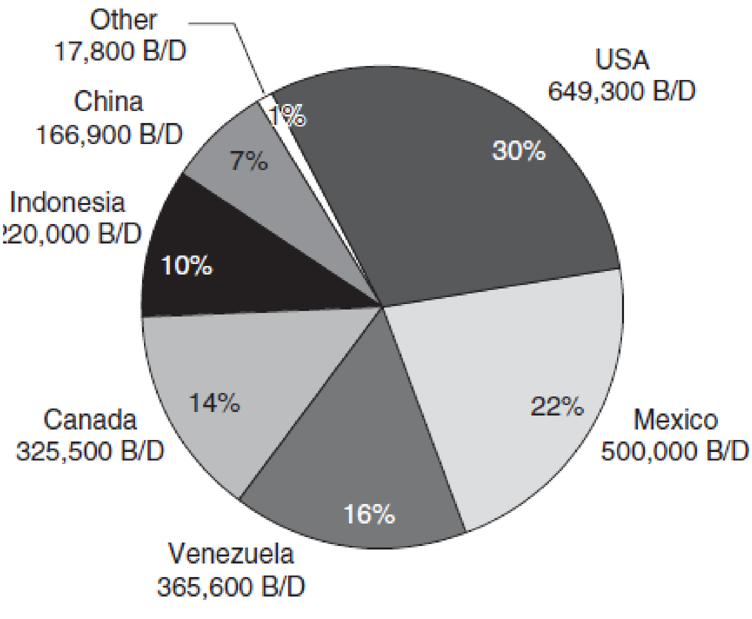

Fig. 2. Current EOR from contributing countries [6]

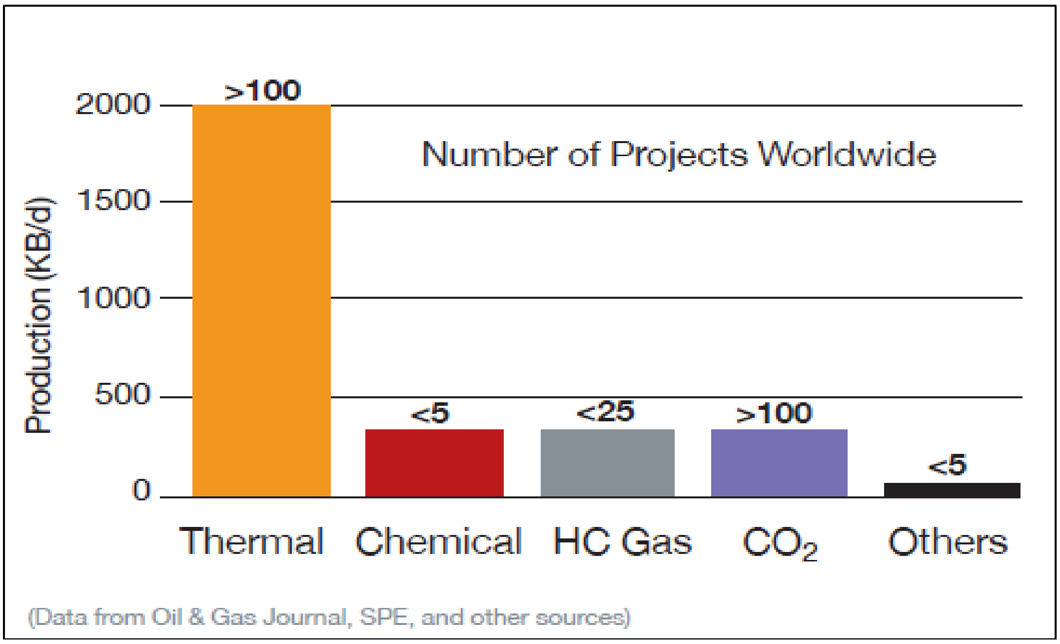

Fig. 3. EOR production (KB/d) worldwide [6]

Recent advancements in technology and the current economic climate have resulted in a renewed interest in EOR. Future growth of EOR will depend on both technology and oil price. Long term commitments in capital and human resources, as well as in R&D, are essential for success in EOR practice. While EOR screening methods are useful tools, recovery methods that are considered unattractive in most reservoirs can be applicable in specific situations [6].

1.5 Steam Flooding

This method involves the first injection of wet saturated steam into a well at a high temperature and pressure. The well is kept closed for a few days to allow the steam to soak after it has been injected sufficiently to heat the reservoir's oil. Oil is then produced by reopening the well (hot-oil puffing) [7]. In reservoirs with high viscosities, the inter-well flow resistance is very strong. If steam flooding is used directly, the steam cannot be injected at an appropriate rate, which reduces the injection rate, enhances the reservoir pressure, and finally prevents the steam from being injected, resulting in a reduced oil-production rate. As a result, the effective time of steam flooding is delayed, poor economic efficiency and causing low GOR. For this reason, steam huff and puff is often used to heat the reservoirs. After a heat connection is built between wells, steam flooding is then used to produce oil

Steam flooding involves the injection of steam into the reservoir for a long period of time to heat the heavy crude oil and reduce its viscosity, which allows it to flow to the production wells [8]. Steam is continually injected into fixed well designs during steam flooding, creating a hot zone that moves continuously throughout the reservoir and facilitating an oil sweep with a potential recovery factor of 50-70% OOIP. Steam flooding has several advantages over other EOR techniques such as low chemical usage, low environmental impact, and high recovery efficiency. The performance of the steam flooding process oil production is significantly impacted by several major aspects, including mineral dissolution, sand formation, and the resulting permeability variance [9].

Steam-flooding surfactant oil recovery investigation shows the effects of temperature, pressure, and oil viscosity on oil recovery process. At higher temperatures and pressures resulted in greater oil recovery, and heavy oil with higher viscosity required higher temperatures and longer steam injection periods to achieve optimal recovery.

In a recent study, Wu et al. [10] used a simulation model to investigate the effect of steam injection rate on heavy oil recovery. They found that a higher steam injection rate resulted in higher oil recovery, but also led to greater steam

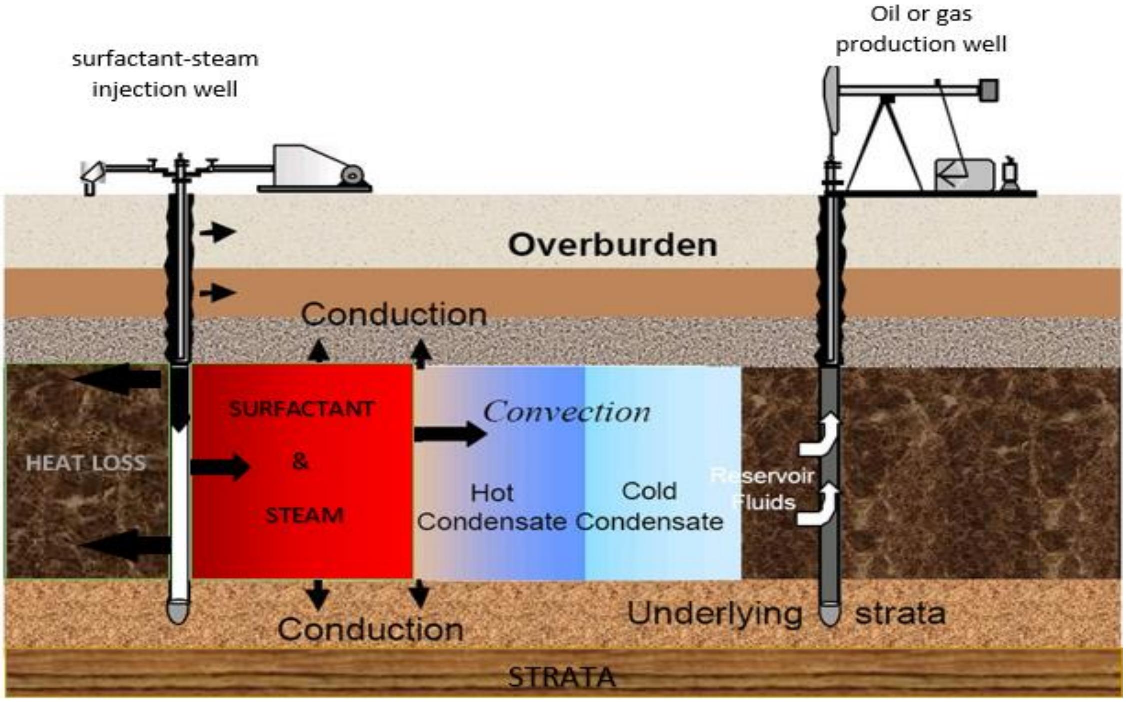

Fig. 4. Steam-Drive oil recovery mechanism

channelling behaviour, which reduced the overall efficiency of the process. This channelling behaviour hinder the further development of heavy oil reservoirs. Considering these serious problems like fingering, channelling, steam overlap. One of the most significant causes of steam flooding's low horizontal sweep efficiency is steam fingering. The phenomena of unstable displacement fronts brought on by steam's great mobility and low viscosity is referred to as "steam fingering." It makes steam flooding worse. Steam flows far more quickly than crude oil during steam flooding.

Another study investigated the impact of steam quality on heavy oil recovery [11]. They found that higher steam quality resulted in greater oil recovery due to more efficient heat transfer and reduced steam channelling. Also, a reduction in the wellbore heat loss rate also indicates an increase in steam quality. For a profile control process in heavy oil reservoirs, a dual-pipe wellbore configuration is one of the most often employed configurations. Compared with other steam injection parameters at the wellhead conditions, changes in an injection pipe size are more acceptable. To obtain higher steam quality under well bottom hole conditions, a steam injection pipe with a smaller size is recommended during steam injection processes.

In addition to experimental and simulation studies, several reviews have been conducted which showed that steam flooding was most effective in sandstone reservoirs with high permeability. Overall, the literature suggests that steam flooding can be an effective method for recovering heavy oil, but its success depends on several factors, including reservoir characteristics, temperature and pressure conditions, and steam injection rate and quality

1.6 Steam Flooding Surfactants

The term surfactant comes from short for surface-active-agent that is utilized to diminish the IFT between two different phases such as two liquids or between a liquid and a solid. Surfactants are considered as good EOR substances since 1970s because they can meaningfully reduce the IFTs and change wetting characteristics.

Surfactant flooding is regarded as one of the most effective and widely used enhanced oil recovery (EOR) processes. Surfactant flooding oil contributed greatly to daily EOR production. Because of the reasonable oil recovery achieved through surfactant flooding, efforts have been concentrated on continual sourcing for alternatives and enhancements to existing oilfield surfactants.

There are 4 major types of surfactants used whose head-groups might produce charges after interaction with water, these are;

1) The anionic-surfactants (-ve polar-head group).
2) Cationic-surfactants (+ve).
3) non-ionic surfactants (no charge).
4) zwitterionic surfactants (both negative and positive-ions).

In EOR processes, surfactants can be used to alter the interfacial tension between oil and water, improving oil recovery from reservoirs. In general, surfactant addition to steam flooding not only reduced the water-in-oil emulsion content of the extracted oil samples but also increased the oil recovery. So from the experiment conducted anionic surfactant (Sodium Dodecyl Sulfate) and (Sodium Octyl Sulfate) resulted in the greatest asphaltene precipitation and oil recovery among all anionic surfactants...

Squeezing every last bit of efficiency becomes necessary as the world's energy needs and drilling costs climb. One of the tertiary recovery methods uses chemical processes, which use synthetic compounds like alkali, surfactants, and polymers to increase oil recovery but are imported and expensive. Through a combination of the beneficial effects of these three different types of Enhanced Oil Recovery (EOR) agents, some researchers have demonstrated that Alkaline-Surfactant-Polymer (ASP) blends have a great potential to boost oil recovery. Local elements in our surroundings can improve oil recovery some of which are paw-paw leaf extract [12].

1.7 Surfactant Performance Dependent Factors

A few elements that influence how well surfactants operate when in use consist of the following:

1.7.1 Temperature

A surfactant's performance is significantly influenced by temperature. IFT and critical micelles concentration (CMC) of a surfactant are both influenced by temperature. Anionic surfactants make this more apparent. The majority of surfactants have a cloud point, past which the solution gets foggy and IFT and other parameter measurements are rendered impossible. An ionic surfactant's Krafft point temperature determines when it will start to precipitate, lose its effectiveness, and eventually separate from the aqueous solution. Depending on the surfactant's structure, the cloud point can range from 60°C to 160°C. Following CMC, the behaviour of the surfactant, in particular the surface tension, stabilises and doesn't change no matter how much the concentration is raised. According to studies, most surfactants either become less active or precipitate at temperatures exceeding 120°C.

1.7.2 Interfacial tension (IFT)

Is the force that exists between the interfaces of two fluids. The force is responsible for the formation of capillary forces in porous media. The reduction of this force leads to an increase in oil recovery. Surfactants are mostly employed in chemical EOR to minimise this force. It is affected by temperature, pressure, and the phase composition. It is measured in dynes per centimetre. As interfacial tension falls, so does oil recovery. In their experimental work, Youyi Zhu et colleagues (2013) discovered that when the oil/water interfacial tension was reduced to 5 ×10^3 c, the near maximum incremental oil recovery was reached.

1.7.3 Optimal salinity

Salinity is a crucial factor in influencing surfactant performance. Chou and Shah (1981) observed the maximum oil recovery when the salinity of connate water and chemical slug was kept at the ideal level for the selected surfactants in their experimental study.

1.7.4 Divalent ions

The value of divalent salts like Ca^{2+} and Mg^{2+} must be maintained very low. A higher concentration of these salts may cause surfactant precipitation and, as a result, pore space clogging.

1.7.5 Pressure

The effects of pressure on surfactant behavior have not been thoroughly studied to yet. According to the information available, pressure can affect on the CMC.

2. MATERIALS AND METHODS

As we delve into the pivotal aspects of this research a comprehensive overview of the materials and methods employed in our study. This section is pivotal as it offers a detailed insight into the tools and techniques we harnessed to gather data, perform analyses, and attain the objectives of this research.

2.1 Experimental Apparatus/Materials

2.1.1 Apparatus

Ostwale Viscometer/U-tube, Weighing Balance, 4 Core Sample, Aluminium Foil, Sharp Sand, Spatula, Mesh, Bowl, Laboratory Test Sieve-(sized sieves-63ml,125ml&250ml), Pen, Conical Flask, Oven, Retort Stand, Density Meter, Measuring Cylinder, Flat Bottom Flask, Beaker, Heskel Flow-Rate Pump, Accumulator, Core Holder, Pressurizer, Saturator.

2.1.2 Materials

Industrial Salt (5000ppm), Heavy Crude Oil-(400ml), Tap Water, Sodium Lauryl Sulphate (SLS)-300ppm, Brine-(density-1.031g/cm3), Paw-Paw Leaf Extract (PLE)-300ppm, polymer (xanthan 100ppm).

2.1.3 PAW-paw leaf extract

This is a locally made surfactants used in the experiment together with steam to reduce the interfacial tension bond between the crude and the rock surface.

2.1.4 The core flooding system

This system simulates reservoir fluids and is utilized in the enhanced oil recovery process. Additionally, it is used to determine the rate at which permeability, displacement efficiency, and oil recovery changes. It is composed of the following components: the flowrate pump, the accumulator, the saturator, the core holder, and the pressurizer.

2.1.4.1 Encapsulated Plug Preparation

Saturating a core sample with brine is a crucial step in understanding reservoir behavior and rock properties. A representative core sample that accurately reflects the reservoir's properties was selected, and thoroughly cleaned to remove any drilling fluids, mud, or contaminants that might affect the saturation process. It was then allowed to dry, after which the weight of the core was determined using a weighing balance as well as its diameter and height using a Calliper.

A Prepared brine solution of 400ml with the desired salinity and composition (brine density of 1.031g/cm3) was poured into the saturator. The core was then placed in the core holder which was connected to the pressurizer to generate an Overburdened pressure of 1100psi. Brine was then displaced into the core using the flow pump until it was saturated. In order to accurately replicate the core's natural saturation in the reservoir, this was held for 48 hours to allow for full saturation. The weight of the saturated core was then recorded, the values gotten at wet and dry is then used to calculate the porosity

Fig. 5. Paw-paw leaf extract

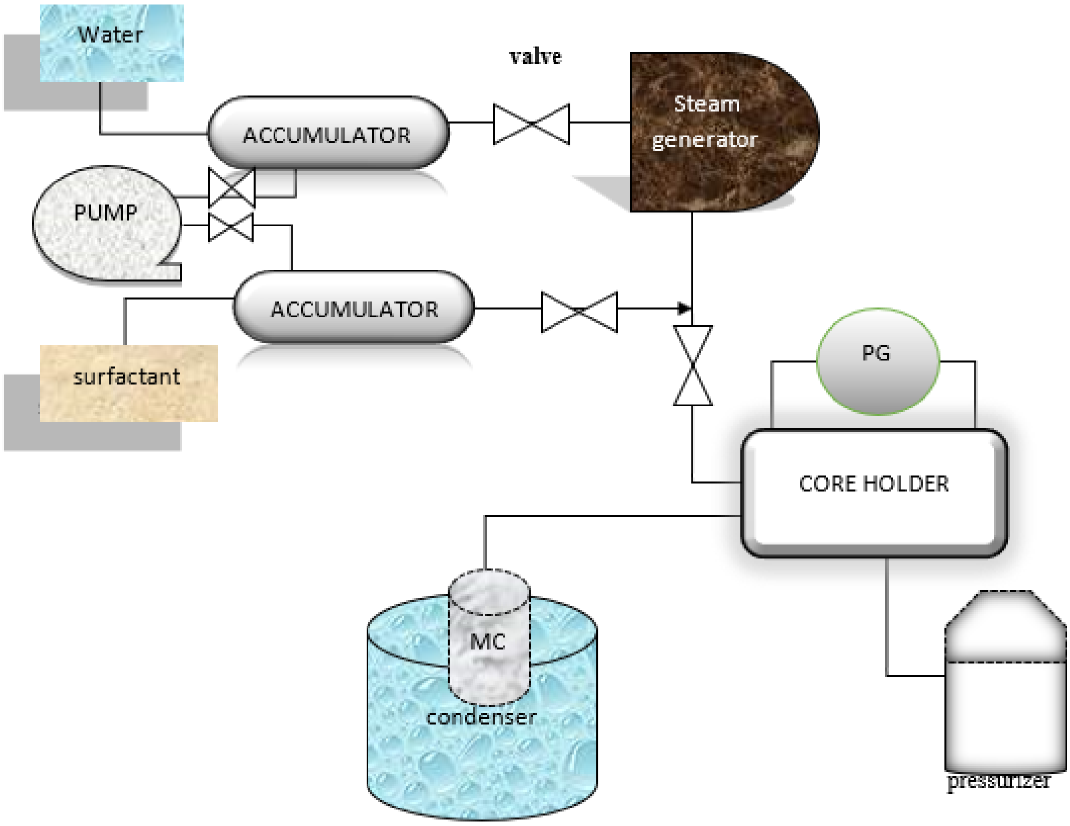

Fig. 6. Core Flooding Schematic diagram of experimental setup

2.1.4.2 Evaluation of Heavy-Oil Petro-Physica Properties

To determine the viscosity using ostwale/u-tube viscometer The certain procedures were taken

1. The U-tube viscometer was clamped on a level surface using a retort stand
2. It was then Calibrated using water which is standard fluid of known viscosity to verify its accuracy.
3. One side of the U-tube was filled with the heavy crude to a specific level.
4. Carefully releasing the fluid from the filled side of the U-tube.
5. Start a stopwatch or timer as soon as the fluid flows past a certain level. As soon as the movement of the fluid reaches a predetermined level in the empty arm of the U-tube, the stopwatch or timer was stopped and the Effluent Time was then recorded.
6. Repeat the experiment multiple times with the same fluid and calculate the average Efflux time it takes for the fluid to flow through the U-tube.
7. Clean the U-tube viscometer thoroughly after each measurement to prevent cross-contamination. After which the viscometer was stored properly to maintain its accuracy for future measurements.

$$\boldsymbol{Viscosity_{kinematic} = Effluent\ time \times constant} \qquad \mathbf{1}$$

$$\boldsymbol{Viscosity_{kinematic} = \frac{dynamic\ viscosity}{density\ of\ oil}} \qquad \mathbf{2}$$

To determine the permeability of the core samples, the certain procedures were taken

1. The core plug sample was placed inside the rubber butt (core holder) and both ends were capped with stem heads.
2. One end was attached to the (brine) reservoir, and the other to the receiving point or beaker.
3. The flowrate pump was turned on, and the flow rate was measured, as well as the

differential pressure (P), which was measured and recorded in (psi).

4. The real length of the plug, brine viscosity, and plug area, A were determined.
5. Permeability was calculated using Darcy's law for incompressible fluid equation.

$$\boldsymbol{permeability, K = \frac{QuL}{Adp}} \quad \textbf{3}$$

Where;

Q is flow rate (gpm), u= viscosity of brine, L is length of plug (cm), A is cross sectional area of plug, dp is differential pressure (atm), I inch, K is permeability (D)

2.2 Surfactant Preparation (Paw-paw Leaf Extract)

The paw-paw leaf was first gotten, washed and kept in the sun to dry. It was then shredded to pieces, putted in a mortar and pounded to paste. After which the meshed paw-paw leaf was then placed in a sieve and squeezed to extract the liquid, the process was continued until the sufficient quantity required was gotten.

2.2.1 Primary recovery (Diagenetic process)

In this process, the hydrocarbon fluid first migrates from the source rock where it was produced to the reservoir, in this example, the core sample. The following methods were used to record this process:

1. The core plug soaked in brine was inserted into the core holder.
2. A 400ml sample of heavy crude was added to the accumulator.
3. The flowrate pump and core holder were both connected to the accumulator.
4. The pressurizer created a pressure differential across the core holder which was recorded.’
5. The overburden pressure was also recorded.
6. The accumulator displaced oil into the core holder and to the core after the flow rate pump was turned on.
7. Oil and brine were both displaced and collected into a beaker.
8. The volume of brine displaced was recorded and deducted from the volume of oil injected. This value was recorded as the OIIP (the original oil in place).

In order to calculate the irreducible water saturation, the amount of brine that was displaced was also measured and subtracted from the volume of brine that was initially in the core holder.

2.2.2 Secondary recovery/water flooding [Imbibition process]

This process simulates the use of water flooding to improve the recovery efficiency

1) 400 ml of Water was injected into the accumulator.
2) This is an imbibition process where water is displaces the oil in the core
3) The amount of oil produced by the water flooding are measured.
4) Also note the pressure difference across the core holder.

2.2.3 Tertiary recovery

Determination analysis of the recovery efficiency of steam flooding with steam flooding surfactants (using local and conventional)

This is usually carried out after secondary recovery, so as to increase the recovery.

Table 2. Flooding the cores with low salinity steam at different temperatures to determine the optimum temperature

S/N	Low salinity steam@ 5000ppm	injection temperature
1	Core A	100°c
2	Core B	90°c
3	Core C	80°c
4	Core D	70°c
5	Core E	60°c
6	Core F	50°c

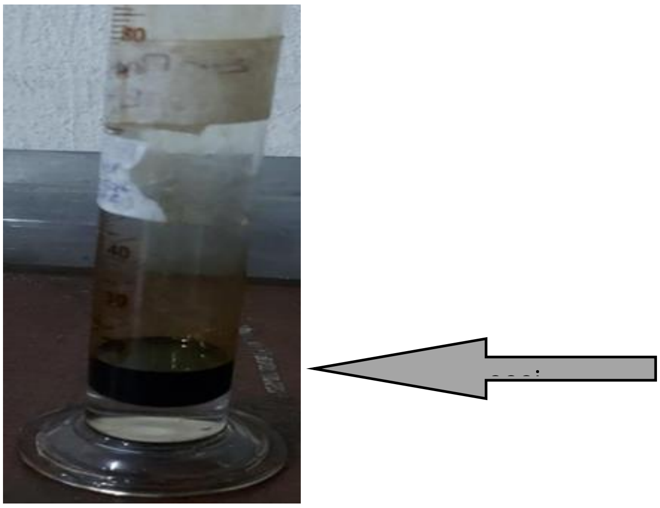

Fig. 7. Cylinder showing Original Oil in Place

2.3 Conventional & Local Surfactant-Steam-Flooding Eor Process

2.3.1 Sls-sodium lauryl sulphate

(i) The Surfactant steam flooding is injected first at the various temperatures obtained from the first experiment until oil recovery can no longer be recovered from the core samples
(ii) Optimum concentration of Surfactant (SLS), (PLE) was injected in the design at various temperatures as shown in the table 3.
(iii) Optimum concentration of Surfactant (PLE) were injected in the design as shown in the table 4 (1ml of PLE to 99ml of water)
(iv) Salt concentration was 5000ppm or 0.5g

2.4 Polymer added to the Optimum Recovery Obtained from Experiment I, Ii And Iii

The optimum recovery gotten from the 3 experiment from the Steam-flooding, Steam-flooding with conventional surfactant and the Steam-flooding with local surfactants are injected with Polymer to create a stable front to push the oil to obtain maximum recovery.

Table 3. Conventional and local surfactants core flooding at optimum temp

S/N	CORE SAMPLES	Surfactants		
		Steam temp	**Conventional (%Conc)**	**Local (%Conc)**
1	Core A	100°c	SLS (0.3%)	PLE (0.3%)
2	Core B	90°c	SLS (0.3%)	PLE (0.3%)
3	Core C	80°c	SLS (0.3%)	PLE (0.3%)
4	Core D	70°c	SLS (0.3%)	PLE (0.3%)
5	Core E	60°c	SLS (0.3%)	PLE (0.3%)
6	Core F	50°c	SLS (0.3%)	PLE (0.3%)

Table 4. Addition of steam flooding-surfactant with polymer at optimum recovery

S/N	Cores samples	Optimum temperature values from experiment I,II &III	Polymer + the optimum recovery obtained from experiment I,II AND III
1	Core A	Optimum temp	Steam flooding +POLYMER
2	Core B	Optimum temp	Steam-flooding Surfactant(SLS)+POLYMER
3	Core C	Optimum temp	Steam-flooding Surfactant(PLE)+POLYMER

3. RESULTS AND DISCUSSION

In the pursuit of efficient methods for recovering heavy oil reserves, the fusion of steam flooding and surfactant application stands out as a groundbreaking approach. This chapter delves into the intricacies of this innovative strategy, which offers a compelling solution to the challenges posed by the extraction of heavy crude. The utilization of steam flooding, coupled with surfactant agents tailored for heavy oil characteristics, has the potential to revolutionize the recovery process by optimizing reservoir conditions, viscosity reduction, and interfacial tension modification. As we embark on this chapter, we aim to dissect the intricate interplay between steam, surfactants, and heavy oil properties.

3.1 Results

HEAVY-OIL PETRO-PHYSICAL PROPERTIES

Density of oil=0.9456
Density of bottle/ pycnometer= 22.88g/cm3
Temperature of oil=28°c
Viscometer constant at 28°c=0.03641743
Effluent Time=7276 secs

$$\mu_{kinematic} = Efflux\ time \times constant \quad \mathbf{4}$$

Kinematic viscosity =264.97cp

$$\mu_{kinematic} = \frac{dynamic\ viscosity}{density\ of\ oil} \quad \mathbf{5}$$

Dynamic viscosity =250.56cm2/sec
Bulk volume=61.74cm3
Wet weight=143.84g
Dry Weight =130.44g

$$V_{pore} = \frac{[wet\ weight - dry\ weight]}{[density\ of\ brine]} \quad \mathbf{6}$$

$$V_{pore} = 12.997cm3$$

$$Porosity = \frac{Pore\ volume}{Bulk\ volume} \quad \mathbf{7}$$

$$Porosity\ = 21.05\%$$

$$Permeability, K = \frac{QuL}{Adp} \quad \mathbf{8}$$

Where;

Q is flow rate (gpm), U is viscosity of brine, L is length of plug (cm), A is cross sectional area of plug, Dp is differential pressure (atm), I inch, K is permeability (mD).

3.2 Tertiary Recovery

Overburdened pressure =1100psi

$$RF = \frac{VOLUME\ OF\ OIL\ RECOVERED}{ORIGINAL\ OIL\ IN\ PLACE} \times 100 \quad \mathbf{9}$$

3.3 Analysis of Result

In the course of conducting experiments involving steam flooding and steam-flooding with surfactants for local and conventional, a critical finding emerged regarding the influence of temperature on recovery efficiency. The experiments were conducted at varying temperature levels, and the analysis of the results reveals a distinct trend in recovery performance.

Table 5. Effect of Steam-flooding Surfactant on permeability

$TEMP$	$Permeability, k$		
	Steam-flooding	**Steam-flooding +conventional surfactant (sls)**	**Steam-flooding +local surfactant (ple)**
100°c	389.89md	487.37	649.83md
90°c	433.22md	482.73md	623.84md
80°c	487.37md	556.26md	740.8md
70°c	557md	636.83md	617.34md
60°c	649.8md	970.4m	779.80md
50°c	779.7md	1728.5m	1130.71md

Table 6. Effect of temperature on the Recovery efficiency of Steam-flooding and Steam-flooding Surfactant

Temp	Recovery Factor (%)		
	Steam-flooding	Steam-flooding +conventional surfactant (sls)	Steam-flooding +local surfactant (ple)
100°c	94.5	97.5	96
90°c	78	96.4	87
80°c	77	94.1	83.3
70°c	75	84	80
60°c	72	83	78.6
50°c	60	87.5	75

Table 7. Recovery Factor (%) At Optimum Temp of at Optimum Temp 90°C

	Recovery factor (%) at optimum temp of at optimum temp 90°C		
Polymer	Steam-flooding	Steam-flooding + conventional(sls)	Steam-flooding +local (ple)
Without Polymer	78	96.4	87
With polymer (xanthan)	79	97.4	88

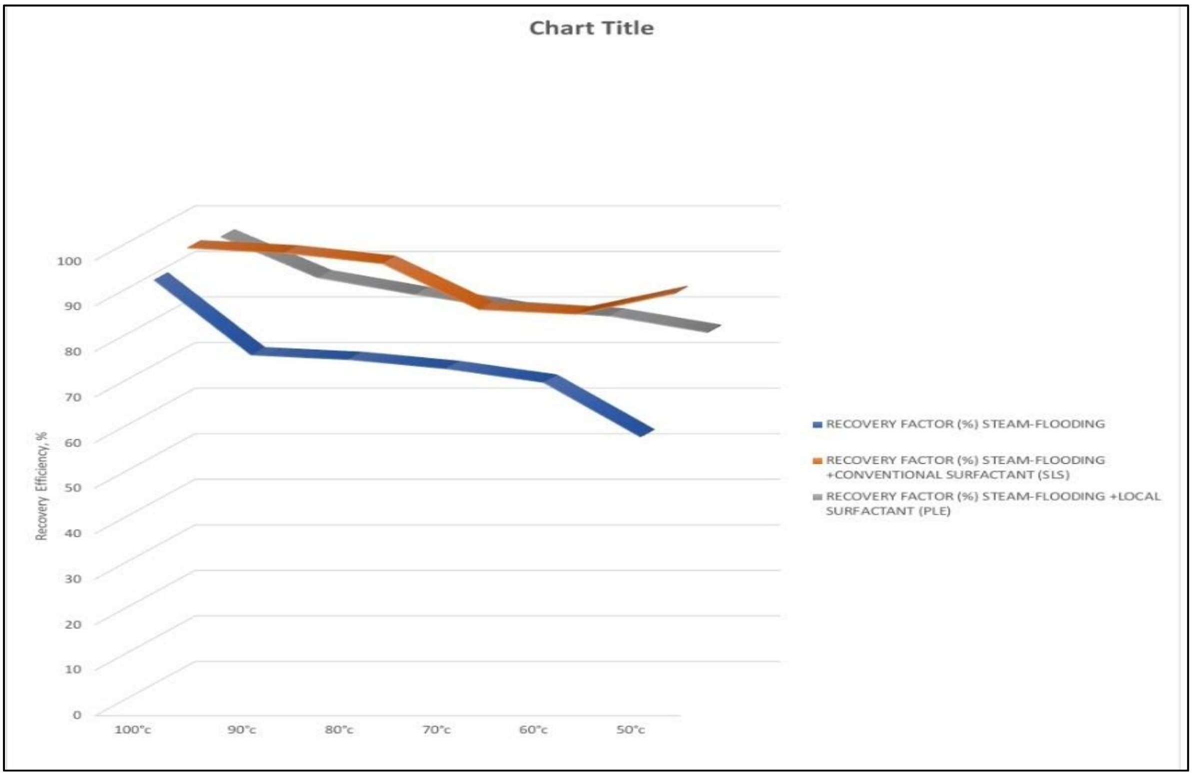

Fig. 8. Chart showing a comparison of the effect of temperature of the recovery efficiency of steam-flooding with the Steam-flooding Surfactant

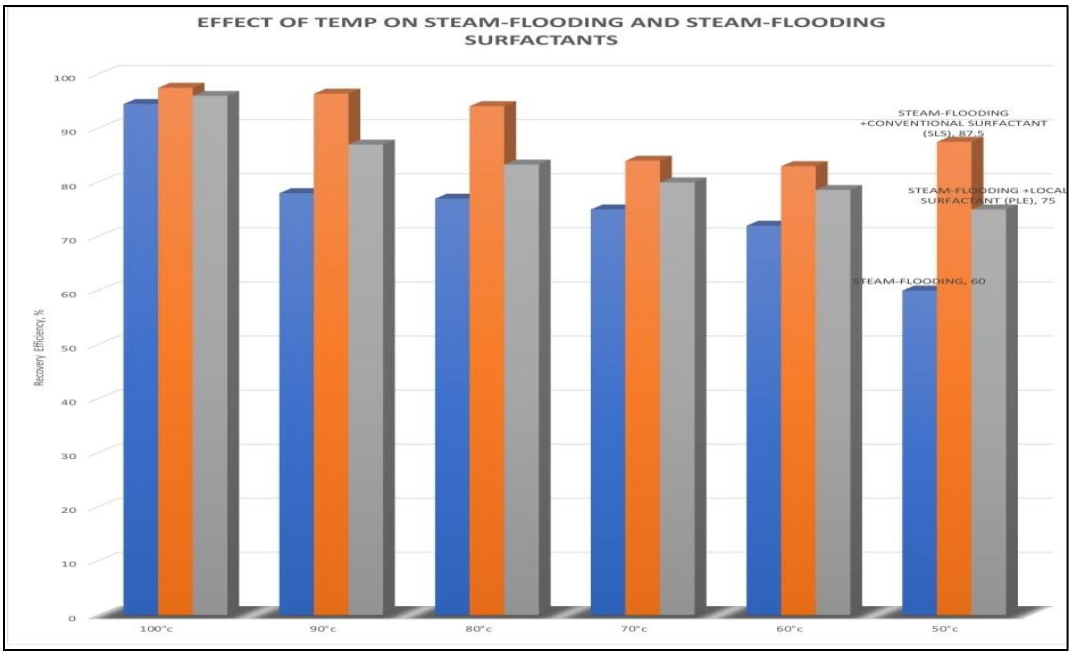

Fig. 9. Comparison of the effect of temperature of the recovery efficiency of steam-flooding with the Steam-flooding Surfactant

Table 8. The various differential pressure on Steam-flooding and Steam-flooding Surfactant

TEMP	**Differential pressure**		
	Steam-flooding	**Steam-flooding +conventional surfactant (sls)**	**Steam-flooding +local surfactant (ple)**
100°c	10psi	8psi	6psi
90°c	9psi	7psi	5psi
80°c	8psi	5psi	4psi
70°c	7psi	4psi	4psi
60°c	6psi	3psi	3psi
50°c	5psi	2psi	2psi

The temperature ranges of 90-100 degrees Celsius emerged as the optimal range for achieving enhanced recovery in both steam flooding and steam-flooding with surfactants scenarios as shown in Fig. 3. This trend could be attributed to several underlying factors:

I. Enhanced Fluid Mobility: At higher temperatures, the viscosity of both steam and surfactant solutions tends to decrease, leading to improved fluid mobility within the porous medium. This, in turn, facilitates a more effective displacement of trapped hydrocarbons.
II. Surfactant Performance: In the case of steam-flooding with surfactant, higher temperatures might have positively impacted the interfacial tension reduction between water, oil, and rock surfaces. This effect could have further aided in the release and displacement of trapped oil, resulting in improved recovery.
III. Improved Rock Permeability: The elevated temperature may have contributed to increased rock permeability, enabling a greater flow of fluids through the reservoir rock. This improved connectivity could have played a role in enhancing recovery rate.

3.3.1 Surfactant steam flooding vs. normal steam flooding

The observation that surfactant steam flooding outperforms normal steam flooding highlights the significance of chemical agents in improving oil recovery. Surfactants are known to reduce interfacial tension between oil and water, thereby facilitating the displacement of trapped oil. At higher temperature, it is likely that the surfactant's enhanced wetting properties promote improved oil mobilization and subsequent recovery. This result validates the potential of surfactant steam flooding as a viable method for enhanced oil recovery.

3.3.2 conventional SLS vs. locally made surfactants

The stark contrast between the recovery rates achieved with conventional SLS and locally made surfactants raises important considerations. The significantly higher recovery achieved with conventional SLS suggests that its well-established formulation and properties have a strong impact on oil recovery. This could be attributed to factors such as consistency in chemical composition, known efficiency, and established performance metrics. On the other hand, the lower recovery observed with locally made surfactants could be due to variations in formulation, purity, or compatibility with the reservoir conditions. This underlines the need for thorough research and quality control when developing custom surfactants for oil recovery applications

4. CONCLUSIONS

My finding suggest that surfactant steam flooding is more effective than normal steam flooding from the Table 3 or Fig 3 above. At an optimum temperature of 90°c gives me almost the same recovery as that of 100°c, so as to save cost of heating the steam to 100°c and above, which is more expensive due to the energy requirements need to reach steam at 100°c.

In conclusion, the results of this experiment shed light on the effectiveness of surfactant steam flooding and conventional SLS in enhancing oil recovery. The observed differences between the techniques underline the importance of understanding chemical properties, formulation, and operational dynamics. As the industry strives for more efficient and sustainable oil recovery methods, the insights gained from this study contribute to the ongoing dialogue on optimizing reservoir operations and economic outcomes.

5. RECOMMENDATIONS

The experimental results provide a foundation for potential practical applications in reservoir management. To translate these findings into successful field operations, a multi-faceted approach is recommended. This includes comprehensive reservoir simulations, economic assessments, and thorough analyses of operational challenges associated with both surfactant steam flooding and the use of custom-made surfactants. Collaborations between chemical engineers, geologists, and reservoir engineers are crucial to fine-tune the application of these techniques to diverse reservoir conditions.

COMPETING INTERESTS

Authors have declared that no competing interests exist.

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