Palacký University Olomouc

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Experimental Investigation of SDS Surfactant on Oil Recovery

Bachelor thesis

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Experimental Investigation of SDS Surfactant on Oil Recovery

Anotace:

Vzhledem k jejich mimořádné účinnosti při snižování mezifázového napětí (IFT) a kontaktního úhlu (CA) jsou povrchově aktivní látky v současnosti považovány za součást metod zvýšené těžby ropy (EOR). Cílem této studie je proto studovat a zkoumat použití povrchově aktivní látky dodecylsulfátu sodného (SDS) při EOR. Kritická micelární koncentrace (CMC) povrchově aktivní látky SDS byla stanovena měřením vodivosti a byl proveden test zákalu, aby se zjistilo, kde se molekuly povrchově aktivní látky nacházejí v objemové fázi a kde nedochází k jejich agregaci. V přítomnosti povrchově aktivních látek SDS o různých koncentracích 500, 1000, 2000, 3000 a 4000 ppm v destilované vodě (DW) a v útvarové vodě bylo provedeno několik experimentů IFT a CA systémů kapalina/tekutina a kapalina/tekutina/hornina. Výsledky studie ukázaly, že IFT se snížila z 29,5 na 5,28 mN/m a 22,22 na 2,35 mN/m, když bylo do DW a formovací vody přidáno 3000 ppm SDS.l/l vdxzwa v uvedeném pořadí. Kromě toho byly nejnižší CA olejových kapiček na povrchu tenkých řezů 29° a 96,2° při přítomnosti SDS na bázi DW v koncentraci 3000 ppm, respektive SDS na bázi formovací vody v koncentraci 2000 ppm. A konečně při použití roztoků formační vody a SDS o koncentraci 500 ppm se při vytěsňování ropy pomocí karbonátových jádrových zátek projevilo 44%, resp. 56,8% zvýšení faktoru výtěžnosti OOIP.

Annotation

In light of their exceptional effectiveness in decreasing interfacial tension (IFT) and contact angle (CA), surfactants are now considered part of enhanced oil recovery (EOR) methods. As a result, the objective of this study is to study and investigate the application of sodium dodecyl sulfate (SDS) surfactant in EOR. SDS surfactant critical micelle concentration (CMC) was determined by measuring conductivity, and the turbidity test was carried out to determine where surfactant molecules are in the bulk phase and away from aggregation. In the presence of SDS surfactants at different concentrations of 500, 1000, 2000, 3000, and 4000 ppm in distilled water (DW) and formation water, multiple IFT and CA experiments of fluid/fluid and fluid/fluid/rock systems were conducted. The results of the study showed that the IFT reduced from 29.5 to 5.28 mN/m and 22.22 to 2.35 mN/m when 3000 ppm SDS was introduced to the DW and formation water.

respectively. Furthermore, with the addition of the DW-based SDS at a concentration of 3000 ppm and SDS at 2000 ppm with the formation water, the minimum CAs of the oil droplets on the surface of the thin slices were 29° and 96.2°, respectively. Finally, oil displacements using the core plugs displayed 44% and 56.8% OOIP increases in recovery factor when formation water and SDS at 500 ppm solutions, respectively, were used.

Klíčová slova: SDS, kontaktní úhel, IFT, smáčivost, destilovaná voda a formovací voda.

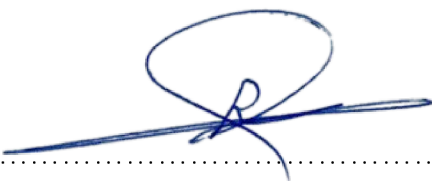**Keywords:** SDS, contact angle, IFT, wettability, distilled water, and formation water.

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Declaration

I declare that I have prepared the bachelor's thesis myself and that I have stated all the used information resources in the thesis.

In Olomouc, June 6th, 2023   …………………………………………

                                                          Rebaz Jamel Anwar

Acknowledgment

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List of Abbreviation

Abbreviation	Meaning
CA	Contact angle
CMC	Critical micelle concentration
DW	Distilled water
EOR	Enhanced oil recovery
IFT	Inter facial tension
NTU	Nephelometric Turbidity Unit
OOIP	Original Oil in Place
PV	Pore volume
RCAL	Routine Core Analysis
SDS	Sodium dodecyl sulfate
SCAL	Special Core Analysis
SWI	Initial Water Saturation

1. Introduction

According to field observations and laboratory experiments, over 60% of the original oil in place (OOIP) is still trapped or upswept in the reservoir following both primary and secondary processes. Therefore, by using tertiary techniques, like chemical and thermal processes, researchers as well as oil companies try to increase the recovery factor to a higher level. Based on field observations and a number of previously published studies, surfactant flooding is acknowledged as one of the efficient methods to boost oil recovery by enhancing microscopic sweep efficiency and reducing the interfacial tension (IFT) between the crude oil present in the porous medium and the injected fluid (Dashtaki et al., 2022).

In order to recover greater amounts of oil that might not have been recovered during secondary recovery by waterflood or gas injection, the majority of reservoirs throughout the world apply enhanced oil recovery (EOR) techniques. According to statistics on the world's petroleum reserves, despite being found and determined, a substantial amount of oil and gas is left underground after primary and secondary recovery because of a lack of readily available technology and poor economics. The amount of unrecovered oil in a typical reservoir typically exceeds half of the petroleum initially in place (PIIP) even if the reservoir oil has a high API grade. In addition, recovery from heavy oil reservoirs and unconventional reservoirs is generally subpar. Satter and Iqbal (2016) report that according to the Energy Information Administration, there are still 300 billion barrels of untapped oil. In order to recover oil resources that are underutilized to the greatest feasible extent from the standpoint of technology and economics, EOR processes are used as a tertiary recovery process. Surfactants are among the several chemical agents used in chemical EOR. In light of their ability to affect both the qualities of the rock surface and the water/oil contact, surfactants are extensively used in the petroleum sector. Surfactant mixtures need to be optimized in reservoir conditions prior to being employed in hydrocarbon recovery applications. This is usually accomplished through surfactant screening, which is a time- and resource-consuming procedure. The difficulty of surfactant screening can be attributed to two main factors. First, the conditions in the oil reservoir and the kind of reservoir rock have a significant impact on most surfactants (Massarweh and Abushaikha, 2020). Surfactant-based EOR is a crucial technique.

Reduced interfacial tension and altered wettability are the main effects of surfactants (Sheng, 2015). Generally, surfactants are composed of a hydrophilic (polar) head and a hydrophobic (nonpolar) tail. A hydrophobic chemical can become more soluble in water through the formation of contact between two immiscible phases of oil and water with the help of surfactants. The effect addition of surfactants will be that the crude oil will become mobile and separate from the aqueous phase. The head of the surfactant molecules is attracted to water when the surfactant is introduced into the reservoir, whereas the tail is attracted to crude oil. As a result, surfactant molecules will surround the crude oil, making it ready for production (Dashtaki et al., 2022). A typical surfactant is sodium dodecyl sulfate (SDS), an anionic surfactant, which has a molecular weight of 289 g/mol. Ben Mahmud et al. (2021) investigated SDS experimentally and found that the use of the surfactant enhances oil recovery.

1.1. *Objectives*

The primary objective of this research is to examine how Sodium dodecyl sulfate surfactant affects enhanced oil recovery. The secondary objectives of the research include:

- Research the effect of SDS surfactant on lowering IFT,
- Investigate the effects of SDS surfactant on altering wettability, and
- Examine how SDS surfactant affects the recovery factor.

1.2. *Report Outline*

This bachelor's thesis is divided into five chapters. Each chapter's purpose and goal are briefly outlined below. The first chapter is the introduction to the research, which comprises a brief introduction to the primary topic of the research, the research objectives, and the research outline. The second chapter is the research background, which includes some useful background information on petroleum reservoirs, reservoir rock features, and oil recovery processes such as chemical EOR. The third chapter discusses the research materials and methodologies. The fourth chapter displays and interprets the obtained

results. The fifth and final chapter discusses the main conclusions of the acquired results and makes some recommendations for further research.

2. Background

2.1. Petroleum reservoir

Natural gas, oil, or both may be found in petroleum reservoirs. Lithology, total rock compressibility, rock porosity, rock permeability, and pay zone thickness are some of the crucial characteristics of petroleum reservoirs. These characteristics influence reservoir fluid flow and well productivity (Guo et al., 2008). Petroleum deposits are typically found in sedimentary rocks. Rarely, petroleum has been found in fractured igneous or metamorphic rocks. High-temperature and high-pressure settings that do not favor the formation of petroleum reservoirs are where igneous and metamorphic rocks are found. They frequently lack the connected pore space or permeability needed to build a path to carry petroleum to a wellbore. A metamorphic rock may have originated as sandstone, but heat and pressure have changed it. The pores have been rendered clean of any petroleum fluid that may have ever occupied them. Therefore, sedimentary rock is the type of rock that is most likely to contain economically significant amounts of oil and gas (Fanchi, 2010).

Only under certain specific conditions can a hydrocarbon reservoir emerge. A source rock is essential for the hydrocarbon. Hydrocarbons are typically thought to form from the remains of aquatic life. The leftovers accumulate in a sedimentary setting, like shale, and form a source rock. The source rock's pressure and temperature must be suitable for extracting oil or gas from the organic materials and compounds. If the conditions are unfavorable, the extraction of oil or gas might not be optimal. For instance, excessive decomposition of organic materials may occur if the temperature is excessively high. Gas and carbon residue could emerge as a result. The existence of a reservoir rock and a passageway leading from the parent rock to the reservoir rock is also essential. Rock is referred to as reservoir rock if fluids can be contained within a volume of it and the rock can sustain reasonable flow rates. To be produced, hydrocarbons need to be able to flow and enter wells. To make petroleum wells profitable, the flow rate must be high enough to produce a large amount of hydrocarbons (Fanchi, 2010). Figure 1 depicts the oil reservoir.
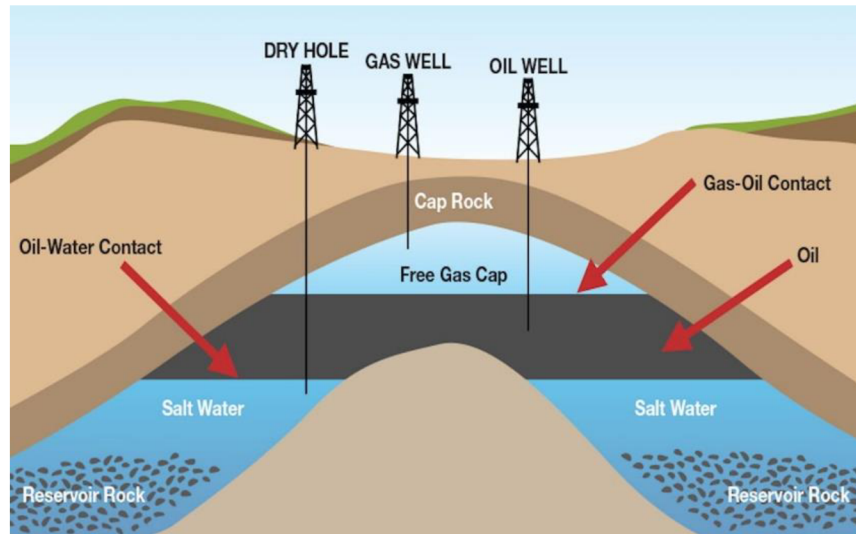
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Figure 1 Petroleum reservoir (Bjørnland et al., 2021).

2.2. *Rock properties*

A reservoir rock permits the oil to be entrapped in porous media. The holes and throats in the reservoir rock act as a flow channel, an accumulation system, and a sealing system that keeps hydrocarbons from penetrating the surface layers. The reservoir rock comes in a variety of shapes, from loose sands to dense and compact rocks. There are two categories of reservoir rocks: conventional reservoir rocks and unconventional reservoir rocks. When a rock is of the conventional type, it is composed of tiny grains that are bound together by a number of substances, including silica, calcite, and clay. These rocks offer sufficient conductivity and storage properties for accumulating and transiting hydrocarbons. For the purpose of studying and comprehending reservoir behavior and improving reservoir performance, reservoir rock properties must be looked into and investigated properly (Alamooti and Malekabadi, 2018).

Most reservoir rock characteristics are assessed in laboratories. To conduct tests, a sample of the reservoir rock must be taken. Advanced core analysis, also known as special core analysis (SCAL), and routine core analysis (RCAL), are two types of rock characteristics analysis. Relative permeability, rock compressibility, capillary pressure, and wettability are all saturation-dependent or multiphase flow properties that are determined by SCAL, whereas lithology, saturation, porosity, permeability, and some

other characteristics are characterized by RCAL. In-depth knowledge and comprehension of reservoir rock properties are crucial, especially when choosing EOR technologies because the above-mentioned characteristics have a significant effect on hydrocarbon distribution in reservoirs (Alamooti and Malekabadi, 2018).

2.2.1. Porosity

Porosity is a measure of the amount of empty space in a rock. Two essential characteristics that determine porosity are the volume of void spaces and the distribution of pore size. The majority of investigations have concentrated on the influence of pore size (Kun et al., 2009). A porous rock has blank spaces where fluids like compressed air can be stored. The fraction of a rock that is vacant and may be utilized for storage is described as porosity. Porosity manifests itself differently in different geologic materials. In granular materials like silts, sands, gravels, and porous sandstones, a significant portion of the total porosity is accounted for by an interconnected network of pores between the grains of the solid mineral. This interconnected network of pores is called intergranular porosity. In addition to matrix porosity, in clay-rich unconsolidated deposits and numerous rocks, fractures in the medium are a crucial part of porosity. In porous sandstones or clays, the percentage of fracture porosity is typically insignificant compared to the matrix porosity. On the contrary, many crystalline and carbonate rocks have fracture porosity that makes up the bulk of the total porosity. Even though they only make up a small portion of the total porosity, the cracks can play a major role in controlling how groundwater flows. In fissured clay, the fracture porosity might be less than the matrix porosity, nevertheless, the majority of groundwater flow may take place in the fractures as opposed to the matrix (Fitts, 2013). Figure 2 shows the porosity of a rock.
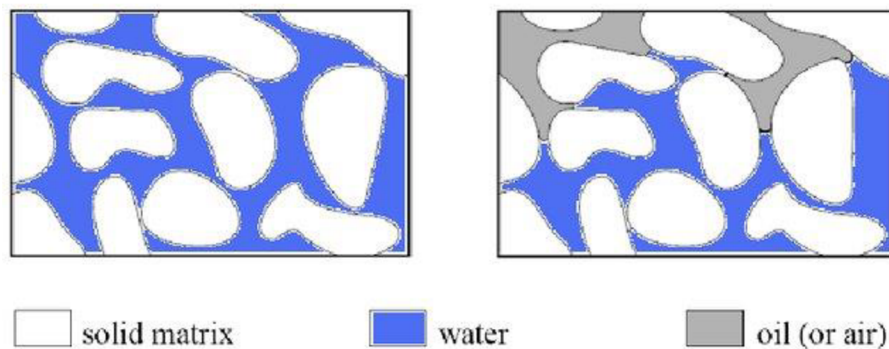

Figure 2 Rock porosity (Abdussamie, 2009).

2.2.2. Permeability

Permeability is defined as a measure of a rock's ability to move fluids. The discharge velocity over a unit area at a unit hydraulic gradient is termed as the coefficient of permeability or sometimes called hydraulic conductivity. The coefficient of permeability depends on the medium (the reservoir rock) properties along with the viscosity and density of the existing fluid. Due to the existence of discontinuities inside a rock mass, permeability is controlled by both the discontinuities within complete rock blocks and the unbroken rock as well. This part of the study discusses numerous techniques for determining the permeability of rocks as well as typical permeability values for different types of rocks. This part also goes through the factors that affect the permeability of rocks. Primary permeability refers to a rock's permeability in its undamaged state. According to several parameters, including the type of rock, geological history, and in-situ stress conditions, porosity controls intact rock permeability (Zhang, 2006).

The movement of fluids through a porous medium is significantly influenced by permeability, which can be measured in a number of ways. The Kozeny-Carman equation and Darcy's law are two of the most popular techniques for estimating permeability. By establishing a pressure gradient across opposing sides of an inlet-outlet in a particular direction, permeability can be calculated using Darcy's law. The viscosity of the fluid and the fluid flow rate are then used to work out the permeability (Winardhi et al., 2016). Figure 3 shows the permeability of rocks.
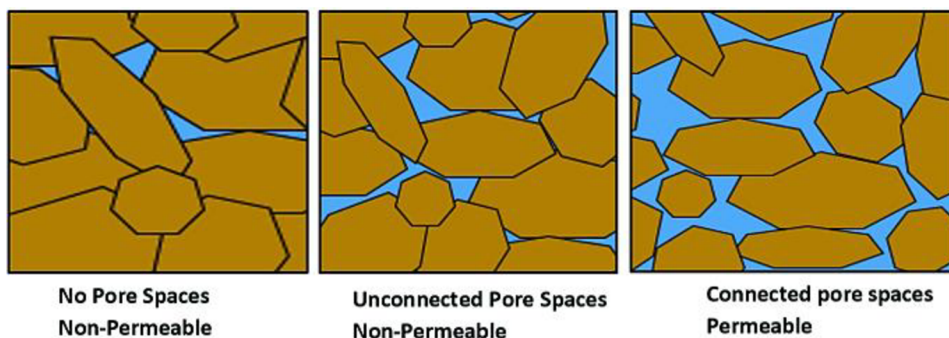

Figure 3 Permeability (Ganat, 2019)

2.2.3. Interfacial tension

According to Gholami and Fakhari (2017), interfacial tension is the accumulation of energy and the imbalance of force at the contact point, or contact line, of two different phases, like liquid-solid. Interfacial tension is the term used to describe the force of attraction between molecules at the contact point, or contact line, of two fluids. At the air-liquid interface, this force is usually referred to as surface tension. Generally, IFT is measured in the SI units of millinewtons per meter (mN/m). These are similar to the dynes per centimeter (dyne/cm) measurements from earlier. The velocity at which an oil spill spreads is influenced by the surface tension and viscosity of crude oil (Speight, 2020). Figure 4 depicts the tension between surfaces (IFT).
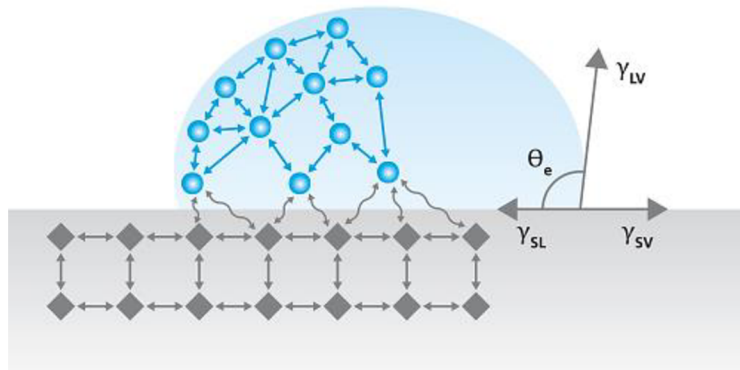
Figure 4 Interfacial tension (Ghamartale et al., 2021).

2.2.4. Wettability

The tendency of a liquid for spreading across a surface is known as wettability. The angle of contact between the material (oil or water) and the surface controls it. Surface energy and contact angle (CA) are related and affect one another. As the surface energy rises, the CA decreases (Praveen et al., 2019). If the water CA is less than 90°, the surface is referred to as water wet. If the water CA is greater than 90°, as shown in Figure 5, the surface is considered to be oil-wet (ShamsiJazeyi et al., 2014).

Water-Wet	Intermediate Water-Wet	Oil-Wet
$0° \leq \theta < 60°$	$60° < \theta < 90°$	$90° < \theta \leq 180°$

Figure 5 Contact angle and wettability relationship (Tavakkoli et al., 2022).

2.3. Oil recovery mechanisms

Primary, secondary, and tertiary recovery are the three separate phases that a petroleum reservoir may go through. Tertiary recovery is usually referred to as enhanced oil recovery. In primary recovery, oil is pumped into the wellbore by gravity or the natural pressure of the reservoir, and then th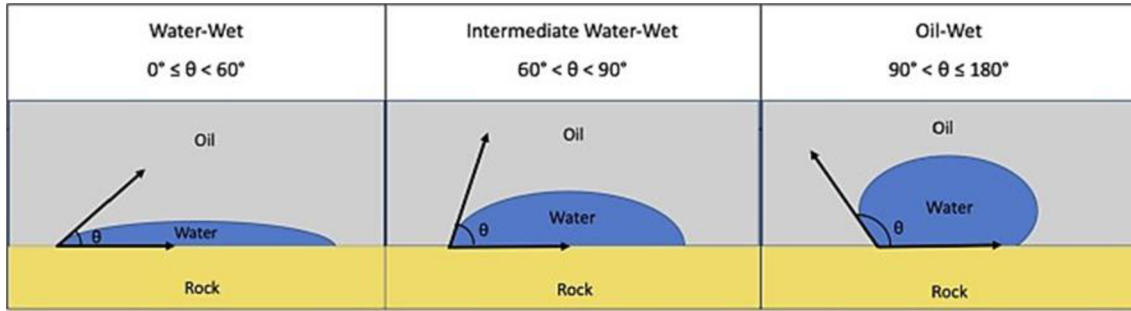e oil is raised to the surface using artificial lift methods. However, only about 10% of the OOIP is usually produced at the primary recovery phase. By commonly injecting water or gas to replace the oil and moving it to a producing well, secondary recovery methods prolong the productive lifespan of a field and enable the recovery of 20 to 40% of the OOIP. Thermal EOR methods include in-situ combustion, steam flooding, and cyclic steam injection. If an effective reservoir description is provided, steam processes, which are the most developed and sophisticated enhanced oil recovery methods in terms of field experience, will have the least uncertainty in performance projections (Speight, 2019).

2.3.1 Primary recovery

According to Alamooti and Malekabadi (2018), primary oil recovery is the initial phase of reservoir recovery during which oil is lifted to the surface either naturally by the natural pressure of the reservoir or artificially using artificial lift equipment, including gas lifts or pumps. Primary oil recovery is the process of producing hydrocarbons without the aid of injected fluids, like gas or water, and only by utilizing the reservoir's driving forces. Due to the fact that most reservoirs do not have enough

natural drive, some artificial drive is practiced along with the natural drive. The most fundamental artificial drive is gas or liquid injection (Vishnyakov et al., 2020).

2.3.2. Secondary recovery

Secondary recovery methods maintain reservoir pressure. This is done by injecting gas or water into the gas cap or aquifer, respectively. In many reservoirs, secondary recovery frequently begins right after primary production (Alamooti and Malekabadi, 2018). Secondary recovery techniques are used to produce oil from the oil reservoir and deliver it to the surface when the primary recovery methods are unable to produce oil naturally. Secondary recovery approaches essentially involve pumping supplemental energy from additional energy sources into the reservoir for the purpose of keeping and raising reservoir pressure. As depicted in Figure 6, these artificial approaches include the reinjection of natural gas, the injection of water, and the injection of carbon dioxide. The artificial pressure gradually becomes ineffective because the residual heavy oil is exceedingly viscous to flow and is resisted by sandstone in the reservoir. Including primary recovery techniques, the heavy oil recovery factor will range from 10% to 25% (Ganat, 2019).
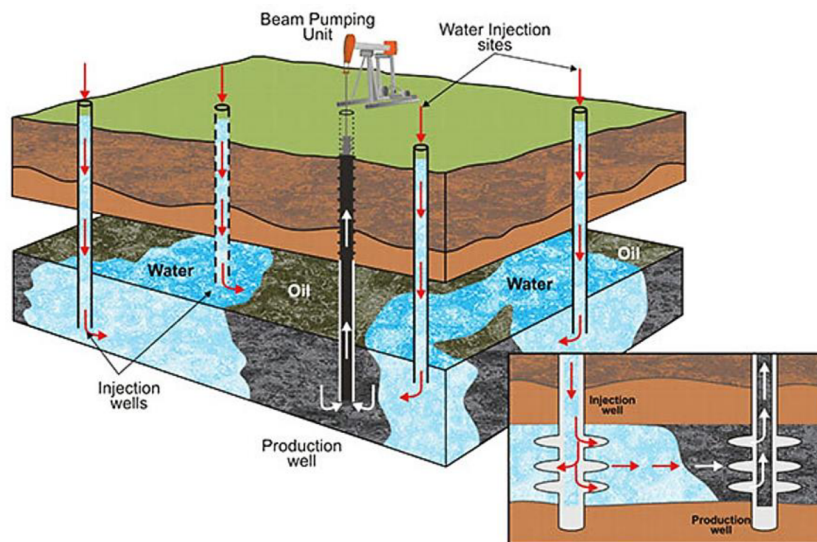

Figure 6 Secondary recovery (Patel et al., 2011).

2.3.3. Tertiary recovery

Tertiary oil recovery attempts to retrieve and recover extra crude oil, such as residual oil and remaining oil, that was not able to be recovered during the primary and secondary

oil recoveries. Crude oil that is unable to be swept because of formation heterogeneity is referred to as remaining oil. Residual oil describes the oil residue in reservoir pore spaces that is immobile even after being flooded with water. There are two approaches to increasing oil recovery. One element is to increase the oil reservoir's sweep efficiency (Dai, 2018). Through a variety of applications, tertiary recovery methods are capable of recovering between 30 and 60% of the remaining hydrocarbon (Jain et al., 2022).

The most prevalent technique is to enhance the mobility control of the displacing fluid in order to lessen the impacts of oil reservoir heterogeneity. This can be done mostly by making the displacing fluid more viscous in order to displace the residual oil. Enhancing oil displacement efficiency is another factor to take into account. This is done by modifying the rock surface's wettability and lowering the oil-water IFT, which reduces residual oil saturation. The four main categories of tertiary oil recovery technologies are thermal recovery, chemical flooding, gas flooding, and microbial flooding. Chemical flooding, for instance, is a technique for boosting oil recovery that involves injecting chemicals that can boost sweep or displacement efficiency, such as polymer, surfactant, alkaline, foam flooding, or combination flooding. Binary flooding (surfactant/polymer flooding, alkaline/polymer flooding, etc.) and ternary flooding (alkaline/surfactant/polymer flooding, etc.) are both included in combination flooding. Today's oilfields frequently use polymer flooding, alkaline/surfactant/polymer ternary combination flooding, and surfactant/polymer binary combination flooding (Dai, 2018). The tertiary recovery is depicted in Figure 7.
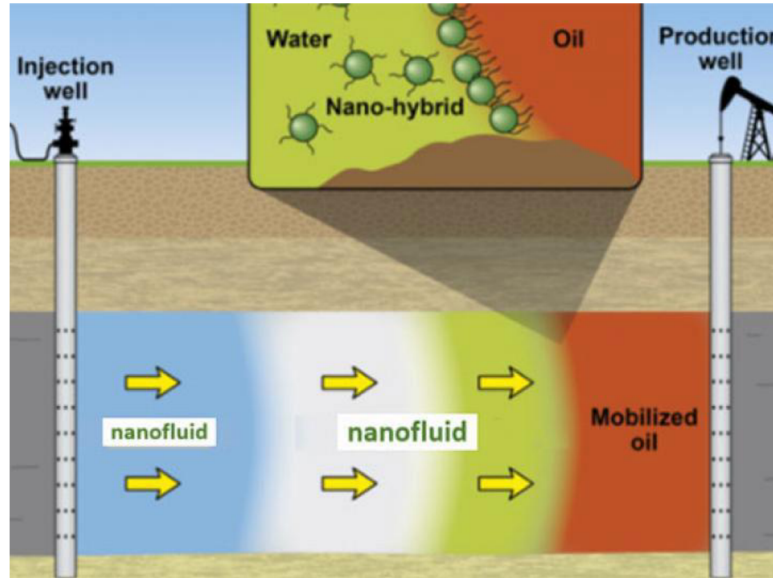
Figure 7 On of the Tertiary Recovery Ways (Alam and Ahammad, 2014).

2.4. *Chemical EOR*

A combination of its higher efficiency, technical and financial viability, and low capital cost has led chemical EOR to be regarded as the most promising EOR method. Chemical EOR is a non-thermal EOR technique. Chemical EOR approaches became more popular in the 1980s as oil prices rose and technological advances allowed for a better understanding of their process. Chemical EOR technologies improve the effectiveness of injected water in the displacement of oil, resulting in greater oil recovery. Regarding the type of chemical enhanced oil recovery technique employed, the chemicals injected with the water slug modify the fluid-fluid and fluid-rock interactions inside the reservoir. This might entail lowering the IFT between the imbibing fluid and the oil or increasing the viscosity of the pumping solution to improve mobility and conformity control. Furthermore, the chemicals injected have the ability to change the wettability of the rock, increasing oil permeability. (Gbadamosi et al., 2019).

2.5. EOR mechanisms

2.5.1. IFT reduction

The amount of energy needed to keep the two-phase interface steady during dissociation is termed interfacial tension. The two-phase contact gets simpler to break when IFT is reduced. Studies on surfactants show that effective surfactants can significantly reduce IFT and merge two phases to create a microemulsion phase. In EOR activities, the IFT between the water phase and the oil phase is a crucial component that affects oil recovery. The most practical method for boosting the capillary number by 3–4 orders to greatly facilitate oil flow is IFT reduction (Deng et al., 2021). Whenever the capillary force is an undesirable flow force, low IFT may reduce capillary pressure, which is an asset for water flow to replace oil and move it to the wellbore. On the other hand, oil deforms faster and thins down in a low IFT environment, increasing the production of oil (Qi et al., 2022). By reducing the oil-water IFT, surfactants have long been considered to be a dependable remedy for enhanced oil recovery (Aslam, 2021). Surfactants can mobilize residual oil saturation. By creating a low enough IFT between crude oil and water that can overcome capillary forces and enable the oil to move freely (Jain et al., 2022).

2.5.2. Wettability alteration

Wettability is a critical characteristic that governs fluid adherence into pore spaces and impacts the recovery capability of any hydrocarbon resource. However, the wettability of any specific rock-fluid system is affected by salinity, pressure, formation type, and temperature (Nazarahari et al., 2021). In many areas of science, engineering, and research, the study of altering the wetting state of materials is growing. In the oil sector, the process of increasing reservoir rock's water-wettability is known as wettability alteration. This is particularly true for carbonates that are naturally hydrophobic, and fractured rocks, as well as heavy-oil systems. This alteration in wettability increases final oil recovery through increasing oil recovery in reservoirs that are oil-wet and/or weakly water-wet. To alter wettability, generally thermal or chemical methods have been used (Mohammed & Babadagli, 2015). Changing the wettability (from oil-wet to water-wet) of the reservoir rock is one way to improve oil recovery since oil can be produced more easily from a water-wet reservoir rock than from an oil-wet reservoir rock. It is said that

a surface is water wet if the water CA is less than 90°. The surface is regarded as oil-wet if the water CA is more than 90° (ShamsiJazeyi et al., 2014). Figure 8 shows the wettability alteration using surfactants.
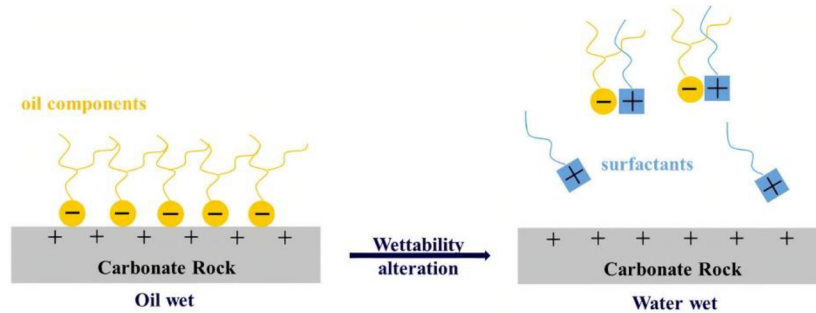

Figure 8 Wettability alteration by surfactants (Yao et al., 2021).

2.5.3.   Mobility control

A crucial component of any EOR technology is mobility control. It can be achieved through injecting chemicals to alter the viscosity of the displacing fluid, foam injection to preferentially decrease a specific fluid's relative permeability, or chemical injection to modify wettability (Sheng, 2011). The standard criterion for mobility control suggests that the mobility of the displacing phase (such as a polymer) needs to have the same or smaller value than the sum of the mobilities of all the displaced phases (such as water and oil). The sum of the mobilities of the displaced phase is essentially equal to the water mobility when the oil mobility is significantly less than the water mobility. Therefore, according to the criterion, the mobility of the displacing polymer is nearly identical to the water mobility. As a result, the oil will not be affected by the polymer solution, which will flow preferentially through water channels (Sheng, 2012).

2.6. Surfactant Flooding

A surface-active agent (surfactant) solution is pumped into the reservoir to lower the IFT between the oil and the brine, alter the reservoir rock's wettability, and thereby increase the overall sweep efficiency of the reservoirs' crude oils. Surfactant flooding is an excellent chemical EOR technology employed for minimizing residual oil saturation.

The recovery of crude oil from petroleum reservoirs has been improved by a number of experiments on multiple kinds of surfactants (Anto and Bhui, 2022).

Oil-water emulsions are only metastable because phase separation is the most thermodynamically stable condition for an oil-water system due to the presence of significant interfacial energy between crude oil and water. By reducing the interfacial energy, the inclusion of surfactants and co-surfactants enhances the stability of such emulsions. The inclusion of emulsifying agents, such as surfactants, produces either a stable emulsion that is opaque or a transparent microemulsion, based on the formation's physicochemical conditions. The interfacial energy of microemulsion systems, on the other hand, is typically negligible (tending to be zero), making them potentially thermodynamically stable (Anto and Bhui, 2022). Figure 9 illustrates the effect of surfactant flooding on reducing IFT and oil production.
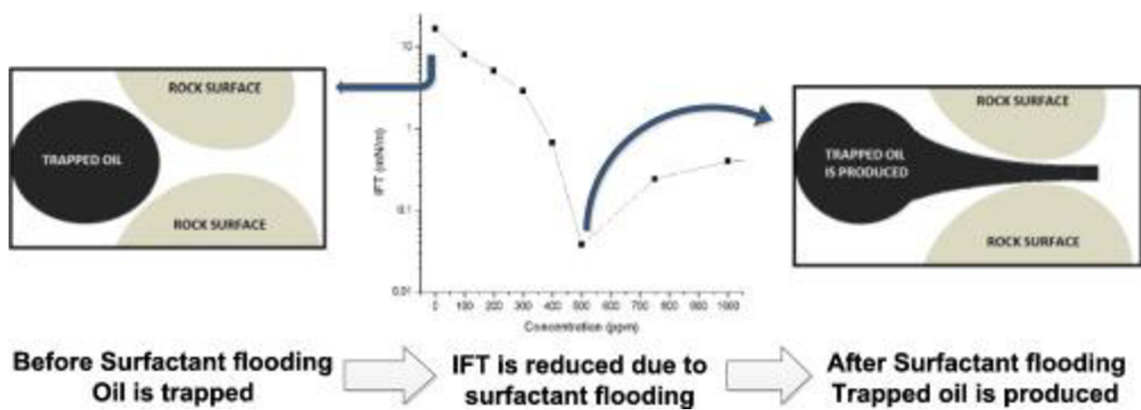

Figure 9 Impact of surfactant on IFT (Kumar and Manda, 2017)

3.   Materials and methods

This chapter shows and describes in detail the materials utilized in the experimental testing of this study, including chemical reagents, water, crude oil, and rocks, as well as the apparatus employed.

3.1 Materials

3.1.1. Rock

Generally, this work focused on carbonate rock. Samples of carbonate rocks were collected and retrieved from the carbonate outcrop (Figure 10).

Figure 10 Core plug sample.

3.1.2. Water

Distilled water (DW) and formation water were used. The formation water is taken from Field X in the Kurdistan Region.

3.1.3. SDS Surfactant

Sodium dodecyl sulfate (SDS) with the formula $CH_3(CH_2)_{11}OSO_3Na$ and structure $H_3C-(CH_2)_{11}-O-S(=O)_2-O^-Na^+$ was used in this study. Sodium dodecyl sulfate is an anionic surfactant.

3.1.4. Crude oil

The X oilfield in Iraq yielded crude oil with the following properties: density of 0.865 g/cm^3, API gravity of $32.6°$, and viscosity of 1.14 cP (Table 1). A sample of this field's crude oil was taken. The density and viscosity of the crude oil were calculated and measured by the PAAR density meter and the Brookfield viscometer, respectively.

Table 1 Properties of the crude oil properties.

Properties	Value
Density (g/cm^3)	0.865
Viscosity (cP)	1.14

3.2. Experimental work

3.2.1. Preparation of core plugs

All of the examined core samples had a 1.5-inch diameter and were properly trimmed to the proper size. The core plugs were cleansed for about a day with a Soxhlet extractor using toluene and ethanol at a temperature of 60-80°C to remove any leftover water, oil, or residues. The samples were then dried out in an oven for six hours at 70°C. The porosity and permeability of samples were then determined using the helium porosimeter and gas permeameter (GP- R20), respectively (see Figure 11).

Each sample was placed in the core holder, the brine accumulator was connected to the core holder, and a confining pressure of 1000 pascals per square inch (psi) greater than the injection pressure was delivered to the samples to establish the saturation profiles. After the core flooding system had been attached, a fluid injection pump was activated for introducing the brine at a rate of 0.25 cm^3/min. The dead volumes of the tubes and core holder were measured before inserting the cores into the core holder. As the brine production and injection ceased, the samples became saturated. The weight and pore volume of the saturated samples were recorded in order to calculate the pore volume. instead of using the brine accumulator, this time an oil accumulator is attached to the core holder, and confined pressure is given to the core. After crude oil was poured into the cores at different flow rates ranging from 0.1 to 4.2 cm^3/min, the produced water was measured in a graduated flask or measuring cylinder. Following the breakthrough, two more pore volumes (PVs) of crude oil were injected in order to complete the saturation operation. The initial water saturation (Swi) of the water obtained in the measuring cylinder or graduated flask was measured. After a week, the saturated cores were completely and persistently oil-wet.
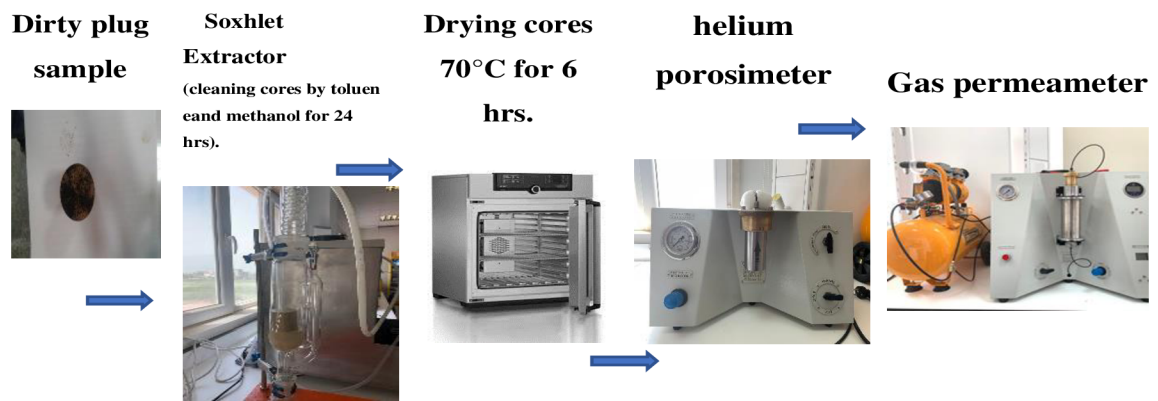
Figure 11 The aging process and the preparation of core samples for core flooding.

3.2.2. Preparation of thin sections

The thinning procedure began with the fabrication of 2-mm thin sections from the samples using a core cutter. The thin sections were then thinly sliced using the core cutter. After that, they were cleansed with DW and toluene. To create an oil-wet condition, the cleaned thin slices were immersed in crude oil for 12 days at 70°C. Then in order to assess how the wettability had changed over time, the aged thin slices were put into sealed containers filled with SDS surfactant and left there for three days under static conditions. Figure 12 shows the slicing and aging processes of the core plugs.
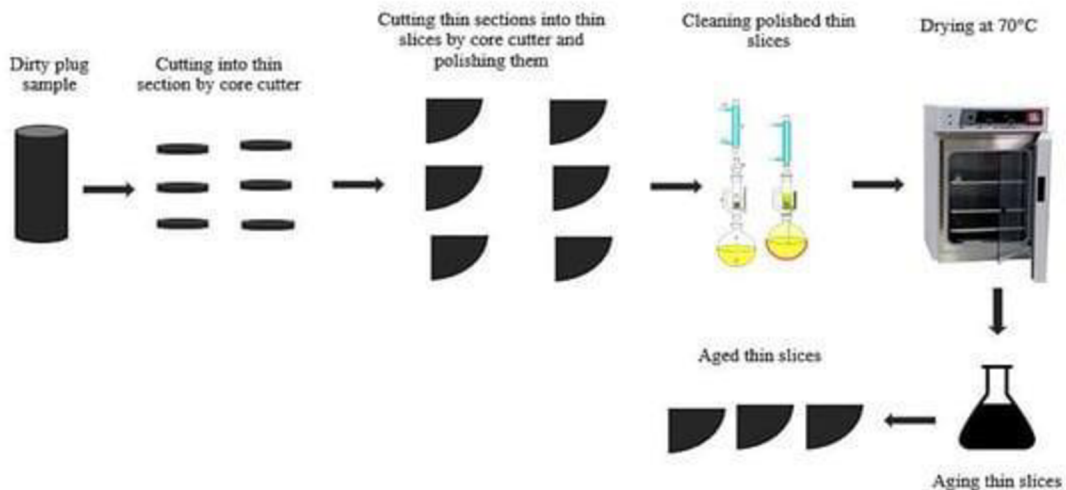

Figure 12 Steps of the preparation of thin sections and slices and the aging process of the thin slices used in measuring CA (Nazarahari et al., 2020).

3.2.3. Prepare fluid solutions

Distilled water, formation water, and SDS surfactant were used to prepare the surfactant solution. A hotplate stirrer is used to mix the ingredients together, as seen in Figure 13. The SDS surfactant was added at different concentrations of 500, 1000, 2000, 3000, and 4000 ppm with the formation water and DW.

Figure 13 Mixing the SDS solution by Hotplate stirrer.

3.2.4. IFT and contact angle measurements

The pendant and spinning drop techniques shown in Figure 14 were used to measure the IFT and CAs of the oil/surfactant and oil/surfactant/rock systems. A high-definition (HD) camera, a pump, valves, and two sample containers make up the VIT-6000 measurement device that is used in this process. The computer that has the software to analyze and evaluate the photos of the oil droplets is connected to the HD camera.

Additionally, when the oil droplet made contact with the thin section's aged surface while being surrounded by surfactant solutions, the spinning drop concept was used to evaluate and measure the samples' wettability. The thin carbonate rock pieces were submerged in crude oil for 12 days. At room temperature, all of the CA and IFT measurements were made.

Figure 14 The VIT-6000 apparatus employed to measure CA and IFT.

3.2.5. Oil displacement

Figure 14 depicts the schematic arrangement of the core flooding equipment employed for displacement experimental testing. A core holder, tanks, pumps, valves, a collecting vessel, and gauges make up the apparatus. The tests' temperature and pressure were maintained at around 70°C and 2000 psi using an oven and pumps, respectively.

The obtained sample from the carbonate outcrop had a permeability of 9.8 mD and a porosity of 17.8%. The prepared core pieces were washed in a Soxhlet with toluene for 24 hours and then dried out. By flooding the core plugs with brine at a rate of 0.2 cm3/min, the saturation of the core plugs was achieved, allowing the dead volume to be calculated. Then, two more PVs were inserted, and the crude oil was injected into the core plugs at a rate of 0.1 cm^3/min to 0.5 cm^3/min until the breach happened. Furthermore, a 2.5 PVs injection of formation water from a field at a rate of 0.5 cm3/min led to the achievement of the displacement of the saturated core plugs as a secondary recovery. Then, at the same injection rate as the formation water, 2.5 PVs of SDS at a concentration of 500 ppm were injected as surfactant flooding into the core plugs. For the purpose of calculating the recovery factor derived from all displacements, the displaced volume of crude oil was collected.

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Figure 15 The core-flooding apparatus.

4. Results and discussions

4.1. Characterization of surfactant solution

One of the most well-known properties of a surfactant is its critical micelle concentration (CMC). Surfactants exhibit their finest efficacy with the greatest absorption at the CMC point. Conductivity and turbidity could be used to calculate the CMC as an important measure. Figure 15 depicts the conductivity of the surfactant used at various amounts. As can be seen, the CMC of the SDS surfactant was determined to be 500 ppm. With DW, the conductivity of SDS-surfactants was raised from 6 to 96.7 µs/cm. The SDS surfactant with formation water's conductivity increased from 12 to 65.2 s/cm as concentration increased up to 4000 ppm. The amount and concentration of surfactant had an impact on how the surfactant molecules behaved. Before CMC, surfactant molecules exerted an immense pull on the oil-water contact. After the CMC threshold, the gathered surfactant molecules were dissociated from the oil droplets, which caused a reduction in the absorption behavior.
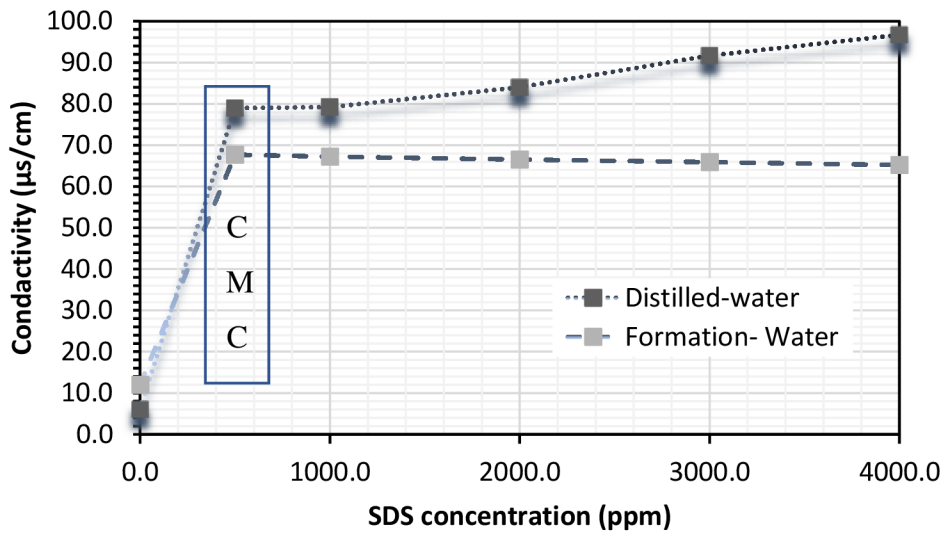
Figure 16 Estimated SDS surfactant CMC ranges via conductivity.

Figure 17 illustrates the turbidity of the surfactants used in various concentrations. As can be seen, the CMC of SDS surfactants was determined to be 500 ppm. The turbidity of the SDS surfactant with formation water rose constantly from 7.25 to 298 NTU (Nephelometric Turbidity Unit) at 4000 ppm. With DW, the turbidity of the SDS surfactant increased from 1.0 to 39.3 NTU at 4000 ppm.
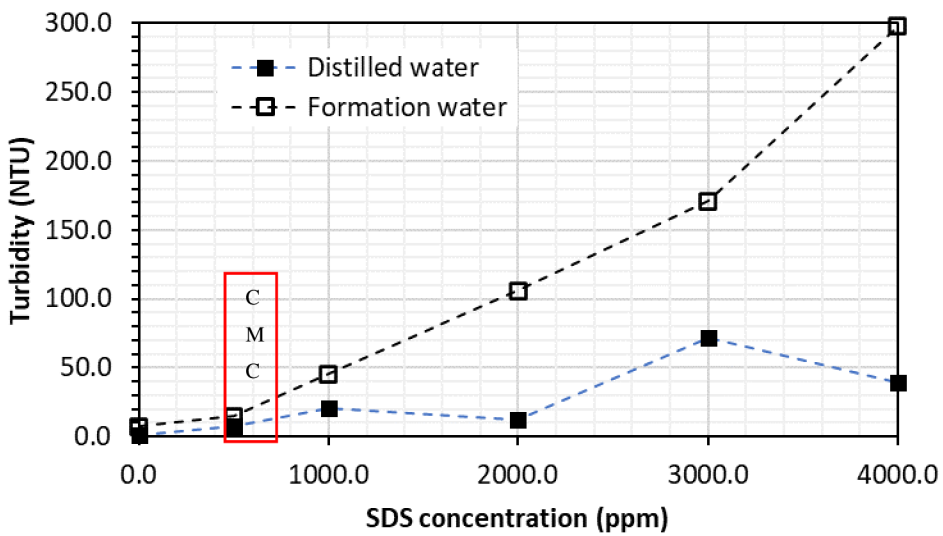

Figure 17 Estimated SDS surfactant CMC ranges via turbidity.

4.2.Interfacial tension

The IFT of crude oil droplets with the surfactant solutions formed by blending SDS surfactant with both DW and formation water was measured using the pendant technique. Figure 18 displays the interfacial tension values of oil-surfactants (SDS) at various concentrations. Furthermore, Figure 19 displays the IFT values between crude oil and SDS surfactant solutions prepared with DW and formation water at different concentration ranges from 500 to 4000 ppm. The crude-water system with no detergents had IFT values from 22.22 to 29.5 mN/m. In general, a formation water solution of 3000 ppm, or around 82.10%, was used to achieve the lowest IFT. The IFT of the DW reduced from 29.5 to 5.28 mN/m when SDS surfactant was added to purified water at 3000 ppm. Furthermore, when applied inside the structure, the SDS surfactant performed better, lowering the IFT from 22.22 to 2.35 mN/m (89.42%). However, in both cases of DW and formation water, the SDS surfactant performed less effectively in the reduction of the IFT. With DW at 4000 ppm and formation water at 4000 ppm, the IFT decreased by 77.0% and 77.4%, respectively. When the used surfactant concentration was increased to the CMC limit, the IFT significantly reduced from its initial high level at 0% surfactant concentration. The crude oil-surfactant systems' dynamic IFT curves at different ratios are also shown in Figure 18. As the test time grew for a longer period, the IFT steadily decreased from its highest to its lowest number. The SDS surfactant is added to the solution at a concentration of 500 ppm in both distilled and formation water, as illustrated in Figure 18, and at this point, the CMC threshold is earned.
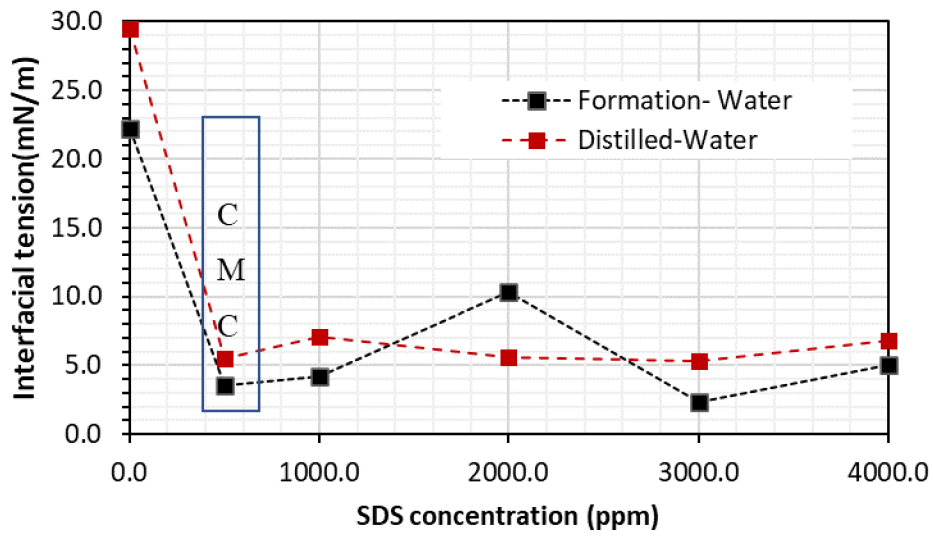
22

Figure 18 IFT values for various concentrations of oil and surfactants (SDS).
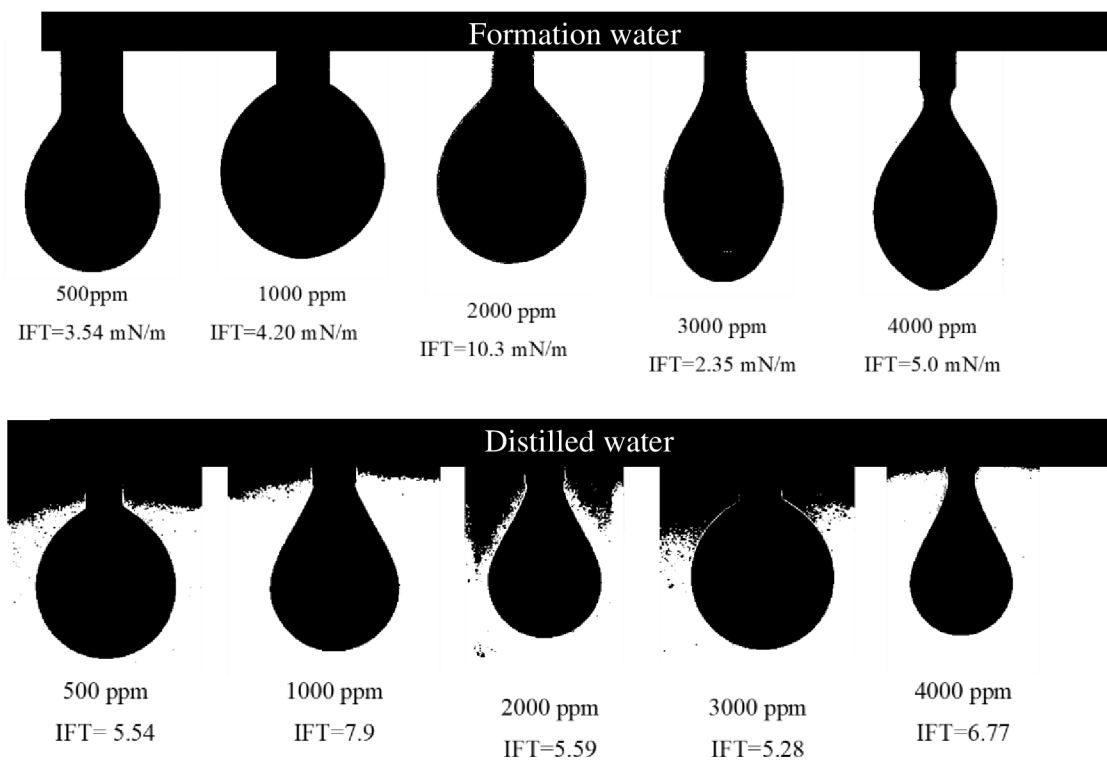

Figure 19 The effect of formation water and DW containing SDS surfactant on IFT at different concentrations.

4.3. Wettability alteration

In order to test the wettability of the used rock samples, the CAs of oil droplets on the thin slices in the presence of various surfactant-based solutions were determined. Figure 20 depicts various kinds of oil droplets on the thin sections in the presence of SDS containing DW and formation water at a variety of concentrations. The CAs for numerous SDS surfactant solutions combined with varying concentrations of DW and formation water ranging from 500 to 4000 ppm are shown in Figure 21. The SDS surfactant was most effective when an amount of 3000 mg of it was mixed with DW causing the CA to lower to 29°. The system's water-wet behavior is confirmed by this. On the other hand, the largest CA value (114.8°) for the oil droplet on the surface of the thin section was observed when the formation water-SDS 4000 ppm solution was utilized, suggesting a strong oil-wetting situation. As can be observed, the formation water had less of the SDS surfactant's active ingredient than the DW did. The SDS surfactants showed the best effectiveness in converting the wettability of the carbonate rock to a water-wet state at the CMC concentration. At 500 ppm, the CAs for the DW-based SDS surfactants appeared to be 44.4°. Figure 20 shows the obtained forms of oil drops on the carbonate thin sections' surfaces when DW-based and formation water solutions are present. The oil droplet with a CA of 29° is nearly free on the thin section surface when it is surrounded by the DW-SDS 3000 ppm surfactant solution. As shown in Figure 20, the oil droplet was firmly attracted to the solid surface when the formation water and 4000 ppm of SDS surfactant were added together.
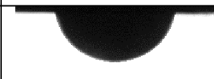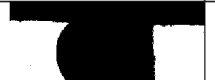
name	500 ppm	1000 ppm	2000 ppm	3000 ppm	4000 ppm
Formation water	average angle=107°	average angle =107.6°	average angle =96.2°	average angle= 98.15°	average angle =114.8°
DW	average angle =44.5°	average angle =54°	average angle =45.8°	average angle=29°	average angle =38.7°

Figure 20 The various forms of oil droplets on thin sections in the presence of various concentrations of SDS surfactants with DW and formation water.

Figure 21 CA values for oil-SDS at various concentrations.
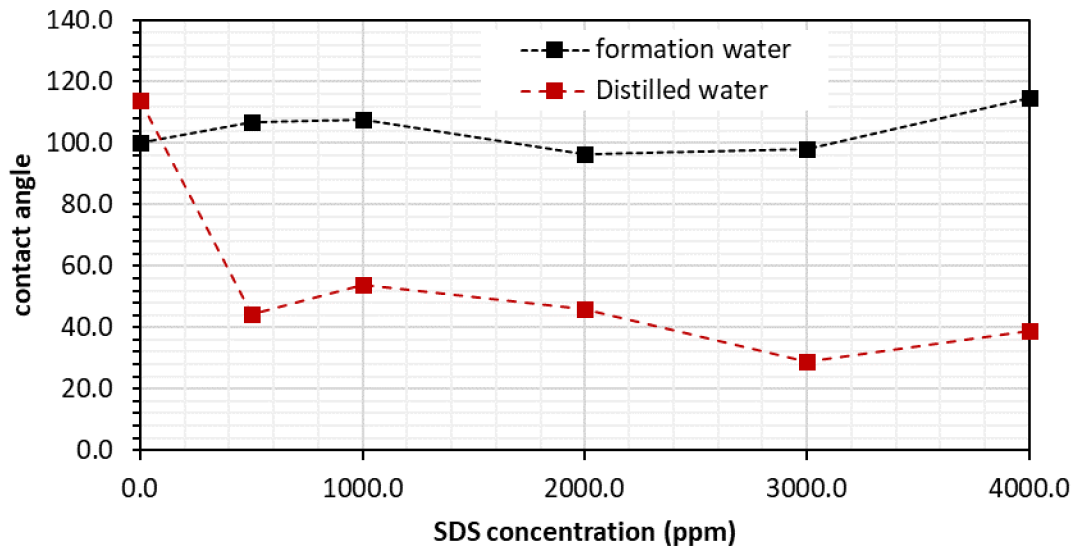
4.4.Oil recovery

To evaluate the increase in the oil recovery factor, oil displacement tests were conducted. According to the results of the CMC readings, surfactant solutions made by mixing 500 ppm of SDS surfactant within the formation water were chosen to be employed as EOR injection fluids. In the displacement experiments, a plug with a porosity of around 17.8% and a permeability of around 9.8 mD was chosen from a carbonate rock in Field X in Iraq. The core plug's initial oil content was 37%, and the pore capacity was 9.31 cm^3. Figure 22 depicts an oil recovery curve produced by water injection and SDS flooding into the core plugs. Four PVs of formation water and surfactant solutions were injected into the prepared core plugs to do the displacement. Formation water was originally introduced into the core plug at a volumetric flow rate of 0.1 cm^3/min during the first two PVs (see Figure 22). As a result, the recovery factor obtained was 44% of OOIP. The oil recovery factor was increased to 49% of OOIP by injecting two PVs of 500 ppm SDS solutions at the same flow rate as the formation water. Oil recovery was enhanced by three PV of SDS at 500 ppm, bringing it to 51.0% of OOIP. The oil recovery increased to 56.8% of OOIP after injecting four PVs of SDS at a concentration of 500 ppm into the sample.
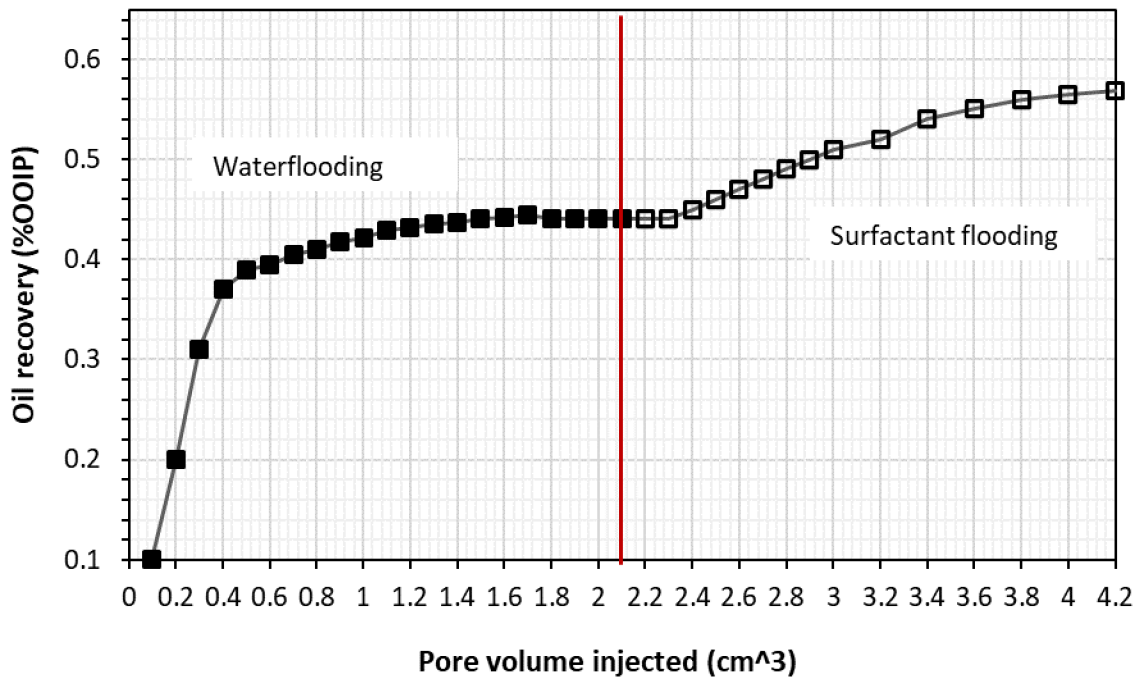
Figure 22 Water injection and SDS surfactant flooding oil recovery profile.

5. Conclusions and recommendations

5.1. *Conclusions*

This study focused on the application of SDS surfactant solutions in IFT reduction, wettability alteration, and improved oil recovery. Using the IFT and conductivity values, the CMC point of the SDS surfactant was determined. In comparison to DW-based SDS at 3000 ppm instances, formation water-based SDS at 3000 ppm was more effective in lowering the IFT to its minimum of 2.35 mN/m. The lowest CA was 29° when DW with SDS at 3000 ppm surfactant was utilized. By applying an SDS surfactant based on DW, the oil-wet condition was converted to a water-wet state. Furthermore, SDS surfactants were able to recover an additional 56.8% of OOIP after waterflooding.

5.2. Recommendation

The author recommends that SDS surfactants be used at various other concentrations to further investigate the effect of SDS surfactants on wettability alteration, IFT reduction, and hence oil recovery. The author also

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recommends researchers use SDS surfactants with other types of reservoir rocks to learn more about the effect of SDS surfactants in oil recovery. Another recommendation the author would like to suggest is that other researchers carry out investigations on the effect of other surfactants on carbonate reservoir rocks and oil recovery factor.

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