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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

Abstrakt:

Povrchově aktivní látky jsou dnes považovány za součást technik zvýšené těžby ropy (EOR) díky své vynikající účinnosti při snižování mezifázového napětí (IFT) a kontaktního úhlu. V důsledku toho se tento výzkum zaměřuje na použití povrchově aktivní látky SDS v EOR. Kritická micelární koncentrace (CMC) povrchově aktivních látek SDS byla zjištěna měřením vodivosti a zákalu, aby se zjistilo, kde se molekuly povrchově aktivních látek nacházejí v objemové fázi a kde nedochází k jejich agregaci. Bylo provedeno několik studií IFT a kontaktního úhlu (CA) systémů kapalina/kapalina a kapalina/kapalina/kamenivo v přítomnosti povrchově aktivních látek SDS o koncentracích 500, 1000, 2000, 3000 a 4000 ppm v destilované vodě (DW) a v útvarové vodě. Po přidání 3000 ppm SDS do DW a formační vody se IFT snížila z 29,5 a 22,22 na 5,28 a 2,35 mN/m v uvedeném pořadí. Navíc při existenci SDS3000 na bázi DW a SDS2000 na bázi formovací vody byly nejnižší CA olejových kapek na povrchu karbonátové horniny 29° a 96,2°. A konečně, vytěsňování ropy pomocí karbonátových jádrových vložek vykazovalo 44% a 56,8% zlepšení OOIP v případě faktoru výtěžnosti při použití roztoků formační vody a SDS 500 ppm.

Abstract:

Surfactants are now deemed part of enhanced oil recovery (EOR) techniques due to their excellent performance in reducing interfacial tension (IFT) and contact angle. As a result, the emphasis of this research is on the use of SDS surfactant in EOR. The critical micelle concentration (CMC) of SDS surfactants was found by measuring conductivity, and turbidity to establish where surfactant molecules are in the bulk phase and away from aggregation. Several IFT and contact angle (CA) studies of fluid/fluid and fluid/fluid/rock systems were performed in the presence of SDS surfactants at concentrations of 500, 1000, 2000, 3000, and 4000 ppm in distilled water (DW) and formation water. When 3000 ppm SDS was added to the DW and formation, the IFT decreased from 29.5 and 22.22 to 5.28 and 2.35 mN/m, respectively. Furthermore, with the existence of the DW-based SDS3000 and the formation water-based SDS2000, the lowest CAs of the oil droplets on the surface of the carbonate rock were 29° and 96.2°, respectively. Lastly, the oil displacements using carbonate core inserts demonstrated 44% and 56.8% OOIP improvements in recovery factor when using formation water and SDS 500 ppm solutions, respectively.

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, March 27, 2023 ………………………………………………

Rebaz Jamel Anwar

Acknowledgment

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List of Abbreviations

Abbreviation	Meaning
SDS	Sodium dodecyl sulfate
DW	Distilled water
PV	Pore volume
CA	Contact angle
IFT	Inter facial tension
EOR	Enhanced oil recovery
CMC	Critical micelle concentration

1. Introduction

Field and laboratory experiments revealed that more than 60% of the original oil in place (OOIP) remains trapped or upswept in the reservoir after both primary and secondary processes. Thus, researchers and businesses attempt to raise the recovery factor to a higher level by employing tertiary methods such as chemical and thermal processes. Surfactant flooding is recognized as one of the effective approaches for increasing oil recovery by improving the microscopic sweep efficiency and lowering the interfacial tension between the injected fluid and the crude oil in the porous medium, based on field experience and a number of published research articles (Dashtaki et al., 2022).

Most reservoirs across the globe use enhanced oil recovery (EOR) procedures to recover additional volumes of oil that would otherwise be lost during secondary recovery by waterflood or gas injection. Worldwide petroleum reserve figures show that, despite being identified and measured, a large fraction of oil and gas is left underground following primary and secondary recovery due to a lack of accessible technology and bad economics. Unrecovered oil in a typical reservoir, even if the reservoir is of high grade, frequently surpasses half of the amount of petroleum initially there (PIIP). Furthermore, recovery from heavy oil reservoirs and unconventional reservoirs, such as tight shale formations, is relatively poor. The Energy Information Administration estimates that 300 billion barrels of oil remain untapped. Therefore, EOR procedures are used as a tertiary recovery process to recover unexploited resources to the greatest degree possible in terms of technology and economics (Satter and Iqbal, 2016). Chemical EOR uses a wide range of chemical agents, including surfactants. Surfactants are widely used in the petroleum industry because of their ability to influence the water/oil interface as well as the properties of the rock surface. Before being used in oil recovery applications, Surfactant formulations should be optimized under reservoir conditions. Surfactant screening is typically used for this, which is still a time-consuming and resource-intensive process. There are two major reasons why surfactant screening is difficult. First, most surfactants are heavily influenced by the conditions in the oil reservoir, as well as the type of reservoir rock (Massarweh and Abushaikha, 2020). EOR with surfactants is a fundamental method. Surfactants' primary functions are to reduce interfacial tension and to alter wettability (Sheng, 2015). Surfactants, in general, have a hydrophilic head (polar) and a hydrophobic tail (nonpolar). Surfactants can form an interface between two immiscible phases of oil and water, increasing the solubility of a hydrophobic compound in water. As a result, the surfactants will cause the crude oil to separate from the water phase and become mobile. Depicts surfactant molecules with a hydrophilic tail (attracted to water) and a hydrophobic head (repelled by water). When the surfactant is injected into the reservoir, the head of the surfactant molecules is drawn to water, while the tail is drawn to crude oil. As a result, the crude oil will be surrounded by surfactant molecules and will be available for production (Dashtaki et al., 2022). SDS, an anionic surfactant with a molecular weight of 289 g/mol, is a common surfactant. have conducted an experimental study on it and discovered that using the surfactant improves EOR (Ben Mahmud et al., 2021).

1.1.*Objectives*

The main objective of this study is to study the impact of SDS Surfactant in enhanced oil recovery, which covers the following sub-objectives:

- Study the impact of SDS Surfactant on IFT reduction.
- Study the impact of SDS Surfactant wettability alteration.
- Study the impact of SDS Surfactant on recovery factor.

1.2.*Report outlines*

Chapter one covers the introduction to the project, including research objectives and the outline. Chapter two describe the background, which includes the Petroleum reservoir, Rock properties, Oil Recovery mechanism, and Chemical EOR. Chapter three covers materials and methods, and Chapter four covers results. The last chapter which is chapter five, covers the Conclusion and recommendation.

2. Background

2.1. Petroleum reservoir

Petroleum reservoirs may contain oil, natural gas, or both. Their important properties include pay zone thickness, lithology, rock porosity, total rock compressibility, and rock permeability. These properties affect fluid flow within the reservoir and, thus well productivity (Properties of Petroleum Reservoirs, 2008). Normally, petroleum reserves are located in sedimentary rocks. Petroleum is only discovered on rare occasions in cracked igneous or metamorphic rocks. Igneous and metamorphic rocks occur in high-pressure and high-temperature environments that are not conducive to the creation of petroleum reserves. They often lack the linked pore space or permeability required to construct a conduit for petroleum to flow to a wellbore. While a metamorphic rock may have started out as sandstone, it has been altered by heat and pressure. Any petroleum fluid that may have previously filled the pores is roasted away. As a result, sedimentary rock is the most probable form of rock to hold economic quantities of petroleum (Integrated Reservoir Asset Management, 2010).

A hydrocarbon reservoir can only form if many crucial elements are present. First, a source rock for the hydrocarbon must be present. It is usually assumed that hydrocarbons develop from the leftovers of aquatic life. The remnants aggregate in a sedimentary environment, such as shale, and constitute a source rock. Second, the pressure and temperature of the source rock should be adequate for the production of oil or gas from the organic combination. The production of oil or gas may not be ideal if the circumstances are not favorable. For example, if the temperature is too high, decomposing organic material might be overdone. As a result, gas and carbon residue might be produced. The presence of a reservoir rock and a conduit from the source rock to the reservoir rock is a third component. If fluids can be confined in a volume of rock and the rock can support economic flow rates, the rock is termed reservoir rock. Hydrocarbons are often generated in rocks that are not conducive to contemporary manufacturing processes. Hydrocarbons must be able to flow into wells in order to be produced. The flow rate must be high enough to make the wells profitable (Integrated Reservoir Asset Management, 2010). Figure 1 shows the petroleum reservoir. Figure 1 shows the petroleum reservoir.

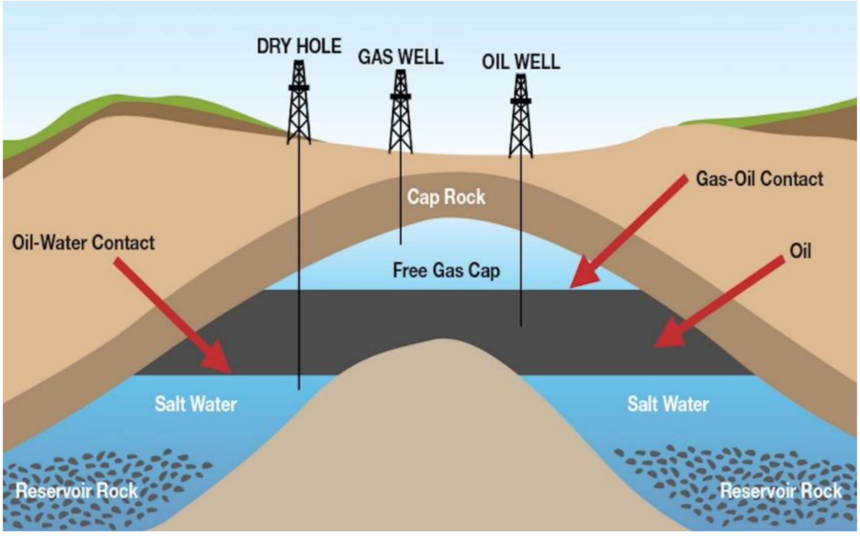


Figure 1 petroleum reservoir(Bjørnland, Nordvik and Rohrer, 2021).

2.2. *Rock properties*

A reservoir rock is a type of rock that allows oil to be trapped in porous medium. The reservoir rock has pores and throats that create a flow channel and an accumulation system for hydrocarbons, as well as a sealing mechanism that prevents hydrocarbon penetration to the surface layers. The reservoir rock has several forms, ranging from loose sands to thick and tight boulders. Reservoir rocks are divided into two types: conventional and unconventional rocks. In the case of traditional type, the rock is made up of grains that are held together by a variety of materials like as silica, calcite, and clay. These rocks have adequate storativity and conductivity for the accumulation and movement of hydrocarbons. Reservoir rock qualities must be studied in order to analyze and understand reservoir behavior and to enhance reservoir performance (Alamooti and Malekabadi, 2018).

The majority of reservoir rock qualities are evaluated in laboratories. The reservoir rock should be sampled in order to conduct experimental experiments. Rock properties analysis is divided into two categories: advanced core analysis or special core analysis (SCAL) and routine core analysis (RCAL). SCAL determines all saturation-dependent or multiphase flow characteristics such as relative permeability, capillary pressure, compressibility, and wettability, whereas RCAL characterizes additional factors such as porosity, permeability, saturation, and lithology. Because the aforementioned qualities have a substantial impact on hydrocarbon dispersion through reservoirs, a thorough understanding of reservoir rock properties is very necessary, particularly when selecting EOR technologies (Alamooti and Malekabadi, 2018).

2.2.1. Porosity

Porosity is a measure of the amount of empty space in a substance. Two essential characteristics that determine porosity are the volume of void spaces and the distribution of pore size. The interconnectivity of the pores is very important in tissue engineering. The majority of investigations have concentrated on the influence of pore size (Kun et al.,2009).

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. An interconnected network of pores between the solid mineral grains (intergranular porosity) accounts for a major amount of the overall porosity in granular materials such as silts, sands, gravels, and porous sandstones. Fractures across the medium, in addition to matrix porosity, are an essential component of porosity in clayey unconsolidated deposits and many rocks. The quantity of fracture porosity in porous sandstones or clays is generally minor in comparison to the matrix porosity. In contrast, fracture porosity accounts for the majority of total porosity in many crystalline and carbonate rocks. Even if the cracks constitute a little portion of the total porosity, they can take the lead in directing groundwater flow. The fracture porosity in fissured clay may be small in comparison to the matrix porosity, but the majority of groundwater flow may occur in the fractures rather than the matrix (Fitts, 2013). Figure 2 shows the porosity.

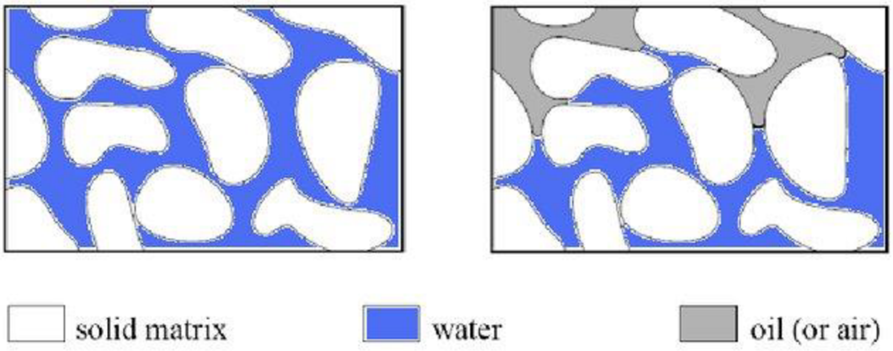


Figure 2 Porosity (Abdussamie, 2009).

2.2.2. Permeability

A rock's permeability is a measure of its ability to transport liquids. The coefficient of permeability (or hydraulic conductivity) is defined as the discharge velocity across a unit area under a unit hydraulic gradient, and it is affected by medium qualities as well as fluid viscosity and density. The permeability coefficient of a rock changes based on the density and viscosity of the fluid. Because of the presence of discontinuities in a rock mass, permeability is governed not only by an unbroken rock but also by the discontinuities between intact rock blocks. This chapter offers typical permeability values for various rocks and covers several methods for calculating the permeability of the rock. The chapter also discusses the elements that influence rock permeability. The permeability of an undamaged rock is known as its "primary permeability." Porosity governs intact rock permeability, which varies depending on factors such as rock type, geological history, and in-situ stress conditions (Zhang, 2006).

Permeability is a key factor in determining how fluids flow through a porous media, and it may be assessed using a variety of approaches. Darcy's law and the Kozeny-Carman equation are two of the most often used permeability estimation methods. Permeability may be estimated using Darcy's law by creating a pressure gradient between opposing sides of an inlet-outlet in a certain direction. The permeability is then determined by the fluid viscosity and flow rate. (Winardhi, Maulana and Latief, 2016). Figure 3 shows the permeability of rocks.

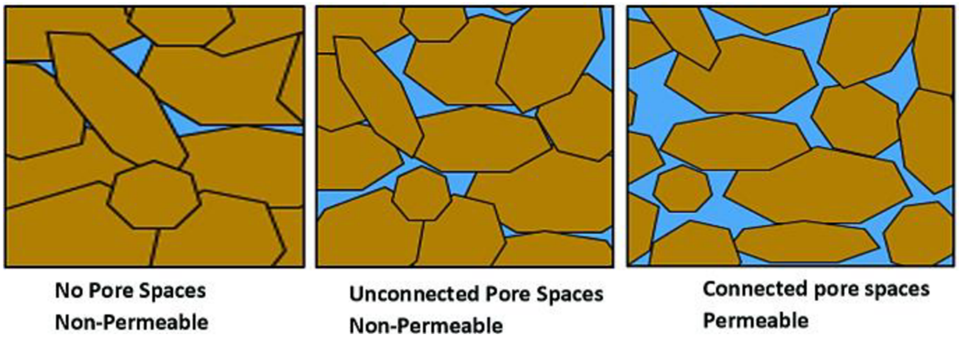


Figure 3 Permeability (Ganat, 2019)

2.2.3. Interfacial tension

Interfacial Tension (IFT) is the buildup of energy and the imbalance force at the interface of two distinct phases, such as liquid-solid (Gholami and Fakhari, 2017). The force of attraction between molecules at the interface of two fluids is referred to as interfacial tension. This force is frequently referred to as surface tension at the air-liquid contact. Millinewtons per meter (mN/m) is the SI unit for interfacial tension. These are the same as the previous units of dynes per centimeter (dyne/cm). The surface tension and viscosity of crude oil (or a crude oil product) influence the rate at which an oil spill spreads (Speight, 2020).figure 4 showes the interfacial tension.

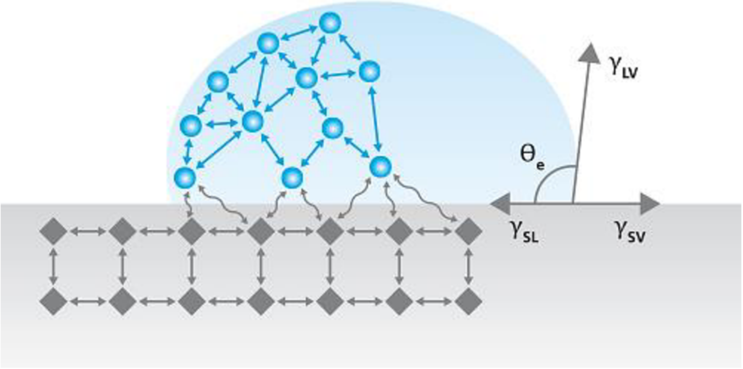


Figure 4 interfacial tension (Ghamartale et al., 2021).

2.2.4. Wettability

Wettability is the ability of a liquid to disseminate across a surface. It is determined by the contact angle between the substance and the surface. The contact angle and surface energy have a direct connection, which means that the contact angle reduces as the surface energy increases (Praveen et al., 2019). The surface is said to be water-wet if the water contact angle is 90° or higher. The surface is said to be oil-wet if the water contact angle is higher than 90° as showen in figure 5(ShamsiJazeyi et al., 2014).

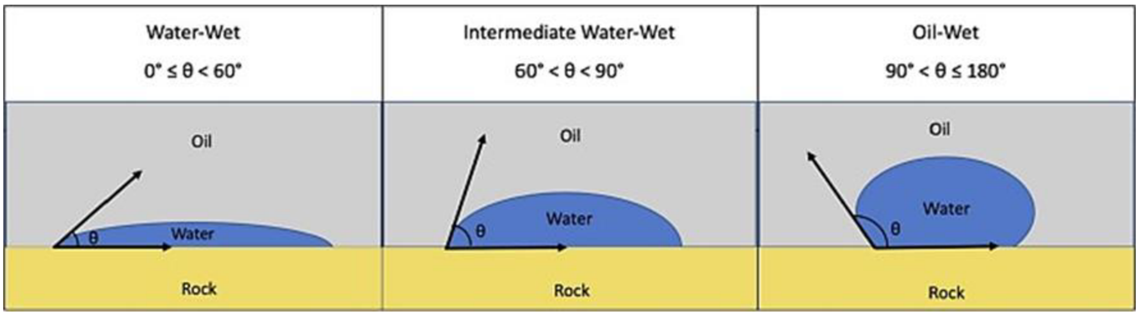


Figure 5 contact angle (Tavakkoli et al.,2022).

2.3. *Oil recovery mechanism*

Oil reservoirs can include up to three distinct phases: primary, secondary, and tertiary (or enhanced) recovery. During primary recovery, the natural pressure of the reservoir or gravity drives oil into the wellbore, combined with artificial lift techniques (such as pumps) which bring the oil to the surface. But only about 10 percent of a reservoir's original oil in place is typically produced during primary recovery. Secondary recovery techniques extend a field's productive life generally by injecting water or gas to displace oil and drive it to a production wellbore, resulting in the recovery of 20 to 40 percent of the original oil in place.

Thermal recovery technologies include cyclic steam injection, steam flooding, and in-situ combustion. In terms of field experience, steam processes are the most advanced of all enhanced oil recovery systems and consequently have the least uncertainty in projecting performance, assuming that a good reservoir description is available (Speight, 2019).

2.3.1 Primary recovery

Primary oil production is the early stage of reservoir recovery in which oil is brought to the surface using natural energy or artificial lift tools such as gas lifts or pumps (Alamooti and Malekabadi, 2018). Primary oil recovery refers to the production of hydrocarbons using the reservoir's inherent driving processes without the assistance of injected fluids such as gas or water. However, the lack of sufficient natural drive in most reservoirs has led to the practice of supplementing natural reservoir energy with some type of artificial drive, the most basic of which is gas or liquid injection (Vishnyakov et al., 2020).

2.3.2. Secondary recovery

Secondary recovery is used to maintain reservoir pressure by injecting water or gas into the aquifer or gas cap, respectively. Secondary recovery is often initiated immediately after primary production in many reservoirs (Alamooti and Malekabadi, 2018). When primary recovery procedures fail to generate oil naturally, secondary recovery methods will be used to generate oil from the reservoir and bring it to the surface. Pumping extra energy sources supplemental energy into the reservoir in order to maintain and improve reservoir pressure is essentially what these procedures entail. These artificial techniques include natural gas reinjection, water injection, and CO2 injection, as shown in Figure 6. Because the leftover heavy oil is extremely viscous to flow and is held back by sandstone in the reservoirs, the artificial pressure loses effectiveness over time. The overall recovery factor of heavy oil will be in the 10–25 percent range, including primary recovery procedures (Ganat, 2019). Figure 6 shows the secondary recovery.

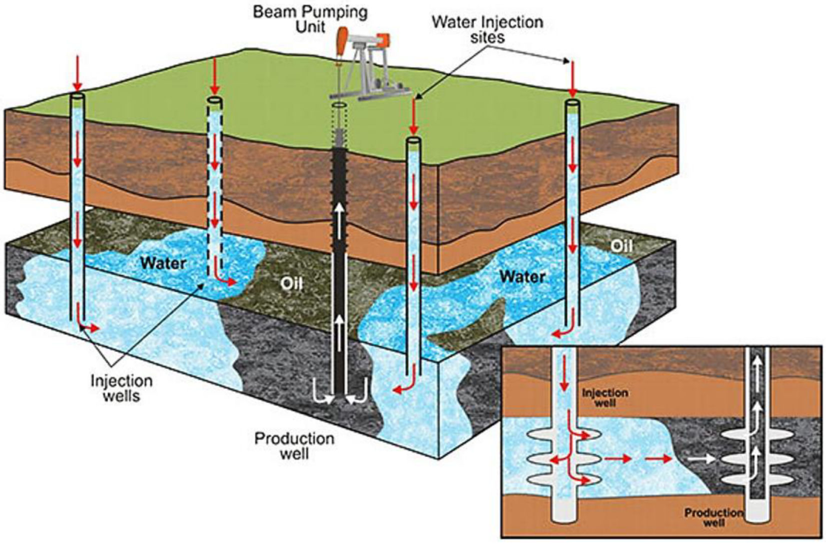


Figure 6 secondary recovery (Patel, Mehta and Patel, 2011).

2.3.3. Tertiary recovery

Tertiary oil recovery aims to recover more crude oil that could not be recovered during secondary oil recovery, such as remaining oil and residual oil. The term "remaining oil" refers to crude oil that cannot be swept due to formation heterogeneity. While residual oil refers to the crude oil residue in reservoir pores that cannot be displaced even after flooding with water. Oil recovery can be improved in two ways. Increasing the sweep efficiency of the injection fluids in the oil reservoir is one aspect (Dai, 2018). Tertiary methods can extract between 30 and 60 percent of the remaining hydrocarbon through various applications (Jain et al., 2022).

The most commonly used method is to reduce the effects of oil reservoir heterogeneity by improving the mobility-control of the displacing phase, which can be accomplished primarily by increasing the viscosity of the displacing phase to reduce the remaining oil. Another consideration is to improve oil displacement efficiency, which is accomplished by altering the wettability of the rock surface and lowering the oil-water interfacial tension (IFT), thereby lowering residual oil saturation. Tertiary oil recovery technologies are broadly classified into four types: chemical flooding, thermal recovery, gas flooding, and microbial flooding. Chemical flooding, for example, refers to the method of improving oil recovery by injecting chemical agents that can increase sweep efficiency or displacement efficiency, such as polymer flooding, surfactant flooding, alkaline flooding, foam flooding, and combination flooding. Combination flooding encompasses both binary (surfactant/polymer flooding, alkaline/polymer flooding, etc.) and ternary (alkaline/surfactant/polymer flooding, etc.) flooding. Polymer flooding, surfactant/polymer binary combination flooding, and alkaline/surfactant/polymer ternary combination flooding are commonly used in oilfields today (Dai, 2018). Figure 7 shows the tertiary recovery.

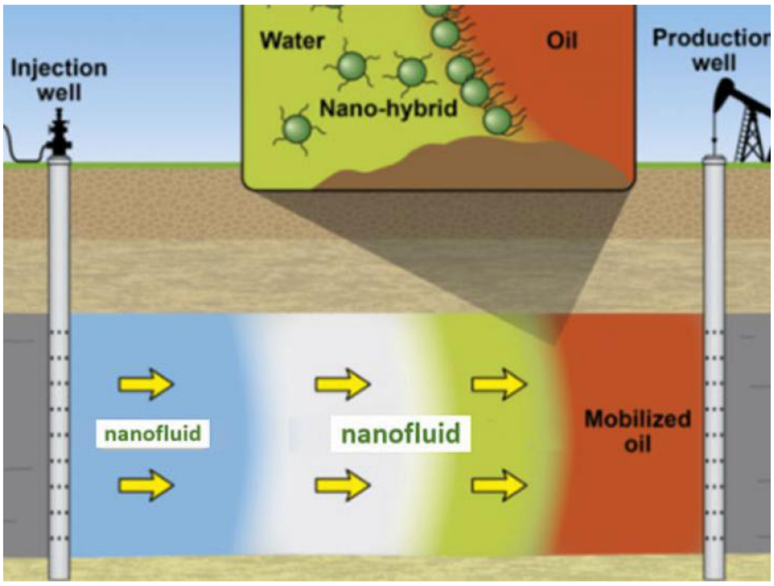


Figure 7 Tertiary recovery (Alam and Ahammad, 2014).

2.4. *Chemical EOR*

Chemical EOR, a non-thermal EOR method, has been deemed the most promising of all EOR techniques due to its higher efficiency, technical and economic feasibility, and low capital cost. Because of higher oil prices and technological advancements that allow understanding of their mechanism, the use of this EOR method became popular in the 1980s. Chemical EOR methods improve oil recovery by increasing the efficacy of water injected into the reservoir to displace the oil. Chemicals injected with the water slug change the fluid–fluid and/or fluid–rock interaction in the reservoir, depending on the type of chemical EOR process used. This includes lowering the IFT between the imbibing fluid and the oil or increasing the injectant's viscosity to improve mobility and conformance control. Furthermore, the injected chemicals alter the wettability of the rock, increasing oil permeability (Gbadamosi et al., 2019).

2.5. ***EOR mechanisms***

2.5.2. IFT reduction

Interfacial tension (IFT) is a measurement of the energy required to maintain the two-phase contact stable during separation. When IFT is lowered, the two-phase interface becomes easier to break. Surfactant studies demonstrate that efficient surfactants may considerably lower IFT and combine two phases to generate a microemulsion phase. The IFT between the oil and water phases is an essential element in EOR operations that impacts oil recovery. IFT reduction is the most applicable way to increase the capillary number by 3–4 orders to make oil flow much easier. (Deng et al., 2021). Low IFT can minimize capillary pressure, which is a favorable factor for water flow to displace oil when the capillary force is an unfavorable flow force. Meanwhile, oil in a low IFT environment deforms more quickly and becomes a thin thread, which enhances oil output (Qi et al., 2022). Surfactant has long been thought to be a reliable solution for improved oil recovery by lowering oil-water interfacial tension (IFT) (Aslam, 2021). The main advantage of using it is that it can mobilize residual oil saturation by establishing an interfacial tension (IFT) between crude oil and water that is low enough to overcome capillary forces and allow the oil to flow (Jain et al., 2022).

2.5.3. 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 particular rock-fluid system is affected by salinity, pressure, formation type, and temperature (Nazarahari et al., 2021). Changing the wetting condition of materials is a growing subject of study in many branches of engineering and science. The technique of making reservoir rock more water-wet is commonly referred to as wettability modification in the oil business. This is especially true in naturally hydrophobic carbonates, fractured rocks, and heavy-oil systems. This change in wettability improves oil recovery in oil-wet and weakly water-wet reservoirs, thus increasing final oil recovery. Thermal and chemical approaches have typically been employed to modify wettability (Mohammed and Babadagli, 2015). Oil can be recovered more readily from the water-wet rock than from oil-wet rock, and one method for improving oil recovery is to change the wettability of the reservoir rock from oil-wet to water-wet. If the water contact angle is 90° or greater, the surface is said to be water-wet. If the water contact angle is greater than 90°, the surface is said to be oil-wet (ShamsiJazeyi et al., 2014). Figure 8 shows the wettability alteration.

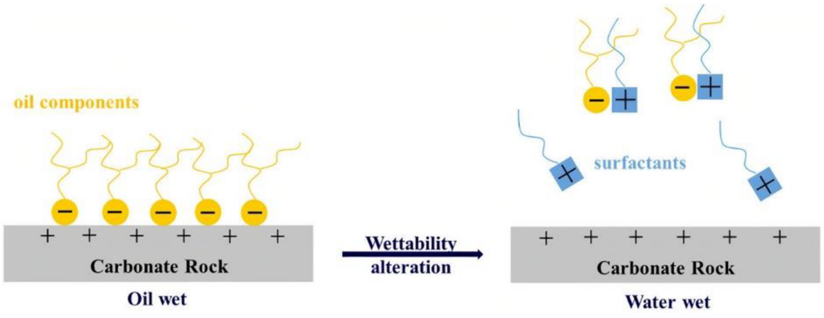


Figure 8 wettability alteration by surfactant (Yao, Wei and Kang, 2021).

2.5.4. Mobility control

Mobility control is a critical element in any enhanced oil recovery (EOR) process. It can be accomplished by chemical injection to change displacement fluid viscosity or preferentially diminish particular fluid relative permeability using foam injection or even chemical injection to adjust wettability (Sheng, 2011). According to the usual mobility control requirement, the displacing phase mobility (e.g., polymer) should be equal to or less than the total of the mobilities of numerous displaced phases (e.g. water and oil). When the oil mobility is substantially lower than the water mobility, the total of the displaced phase mobilities is almost equal to the water mobility. The displacing polymer mobility is thus practically the same as the water mobility, according to the demand. As a result, the polymer solution will flow preferentially through water channels, leaving the oil alone (Sheng, 2012).

2.6. Surfactant Flooding

Surfactant flooding is a promising chemical EOR technique used to reduce residual oil saturation in which a surfactant solution is injected into the reservoir to reduce the IFT between the crude oil and reservoir brine, change the wettability of the reservoir rocks, and thus improve the overall sweep efficiency of crude oils from reservoirs. Numerous studies on various types of surfactants have been conducted in order to improve crude oil recovery from petroleum reservoirs. Numerous studies on various types of surfactants have been conducted in order to improve crude oil recovery from petroleum reservoirs (Anto and Bhui, 2022).

Because high interfacial energy exists between oil and water, the most stable thermodynamic state for an oil-water system is phase separation, which means that oil-water emulsions are only metastable. The addition of surfactants and co-surfactants improves the stability of these emulsions by lowering the interfacial energy. Depending on the physicochemical condition of formation, the addition of emulsifying agents, such as surface-active agents (surfactants), results in either an opaque stable emulsion or a clear microemulsion. Microemulsion systems, on the other hand, maybe thermodynamically stable because the interfacial energy tends to be zero (Anto and Bhui, 2022). As shown in figure 9.

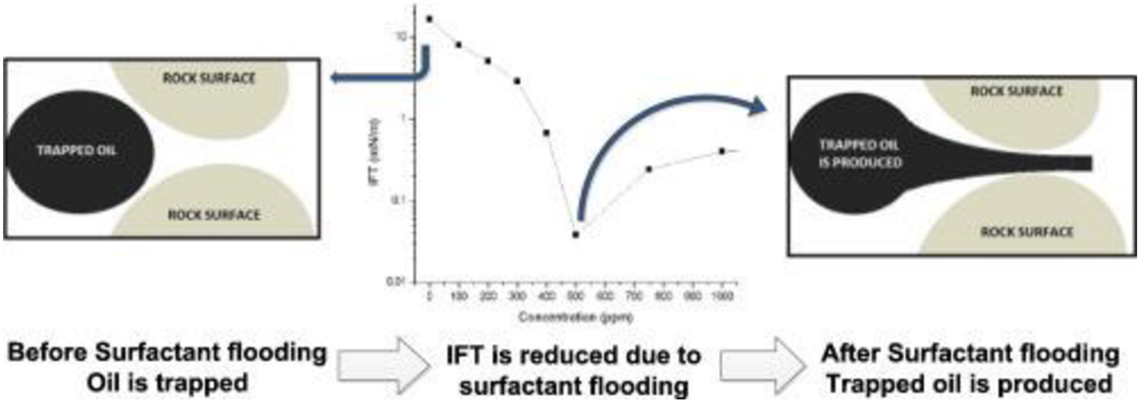


Figure 9 impact of surfactant on IFT (Synthesis and physiochemical characterization of zwitterionic surfactant for application in enhanced oil recovery, 2017).

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

3.3.2. Rock

Generally, this work focused on carbonate rock. Samples of carbonate rocks were collected from the carbonate outcrop as shown in Figure 10.

Figure 10 core plug sample.

3.3.3. Water

Distilled water and formation water that is taken from Field X in the Kurdistan Region were used.

3.3.4. SDS Surfactant

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

3.3.5. Crude oil

Crude oil with a density of 0.865 gm/cm3, (°API) of 32.6, and viscosity of 1.14 cP was collected from X oilfield in Iraq. The crude oil's density and viscosity were determined using the PAAR density meter and the Brookfield viscometer.

Table 1 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 core samples utilized in this investigation were meticulously cut to the necessary lengths and with a 1.5in diameter. The plug was cleaned using a Soxhlet extraction with ethanol and toluene at a temperature of 60-80°C for 24 hours to remove any remaining water, oil, or residues. After that, the core sample was dried in a 70°C oven for 6 hours. Then, the porosity and permeability of core samples were determined using the helium porosity meter and gas permeameter (GP- R20) illustrated in Figure 11.

To create the saturation profiles inside the prepared cores, each core sample was put inside the core holder, and the brine accumulator was connected to the core holder, before applying a confining pressure 1000 psi greater than the injection pressure. After connecting the core flooding system, the brine was injected at a rate of 0.25 cm3/min using a fluid injection pump. The dead volume of the core holder and tubes was measured before inserting the cores into the core holder. When the core produced brine and injection was ceased, the cores were saturated. The weight and pore volume of the saturated cores were measured to determine the pore volume. Instead of the brine accumulator, an oil accumulator is linked to the core holder, and restricting pressure is provided to the core. Then, crude oil was injected at varied rates ranging from 0.1 to 4.2 cm 3 /min into the core samples, and the generated water was measured in a graduated flask. Following the breakthrough, an additional 2 pore volumes (PVs) of crude oil were injected to finish the saturation process. The initial water saturation (Swi) of the water collected in the graduated flask was determined. The saturated cores were then stored for one week to create a full and stable oil-wet condition.

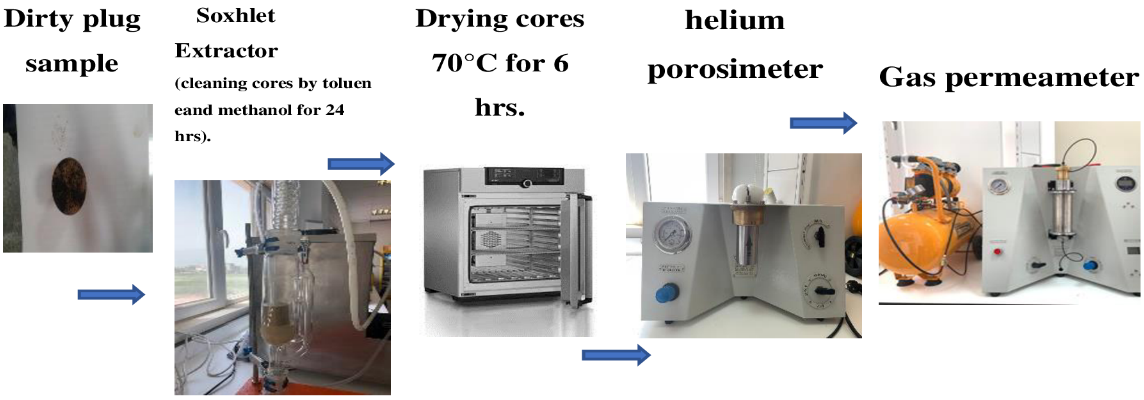


Figure 11Procedural steps of the aging and preparation of core samples for core flooding.

3.2.2. Preparation of thin sections

The procedure began with the preparation of 2 mm rock plates from carbonate outcrop samples. Following the acquisition of the smooth plates, they were cleaned using toluene and distilled water. The smooth and cleaned parts were then immersed in crude oil for 12 days at 70 °C to create an oil-wet condition (Figure 12). Following that, the aged rock slices were placed into enclosed containers filled with SDS surfactant under static conditions for three days to evaluate the wettability alteration.

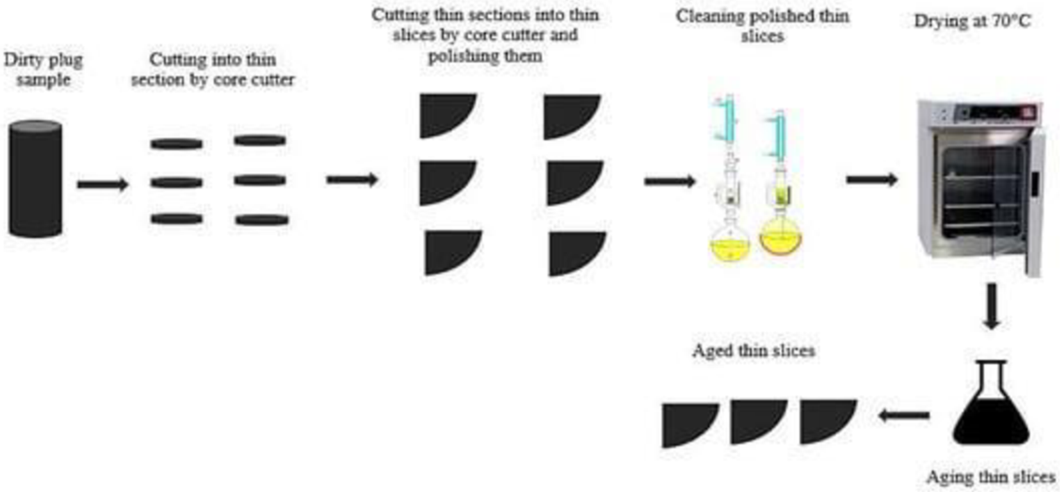


Figure 12 Procedural steps of the preparation and aging of rock Plates used in measuring contact angle (Javad Nazarahari et al., 2020).

3.2.3. Prepare fluid solutions

The surfactant solution was prepared from SDS surfactant, distilled water, and formation water. It is mixed by Hotplate Stirrer as shown in figure 13. The SDS surfactant was mixed at concentrations of 500, 1000, 2000, 3000, and 4000 ppm in distilled water (DW) and formation water.

Figure 13 hotplate stirrer.

3.2.4. IFT and contact angle measurements

IFT and contact angle measurements of the oil/surfactant and oil/surfactant/rock were performed using the pendant and spinning drop procedures described in Figure 14. The VIT-6000 measuring apparatus is made up of two sample containers, a pump, valves, and an HD camera. The camera is linked to a computer, which contains software for analyzing the images of oil droplets.

In addition, the wettability of the carbonate rock samples was assessed using the spinning drop concept when the oil droplet came into contact with the aged surface of the thin section in the presence of surfactant solutions. For 12 days, the prepared thin portions of carbonate rocks were immersed in crude oil. All IFT and contact angle measurements were taken at room temperature.

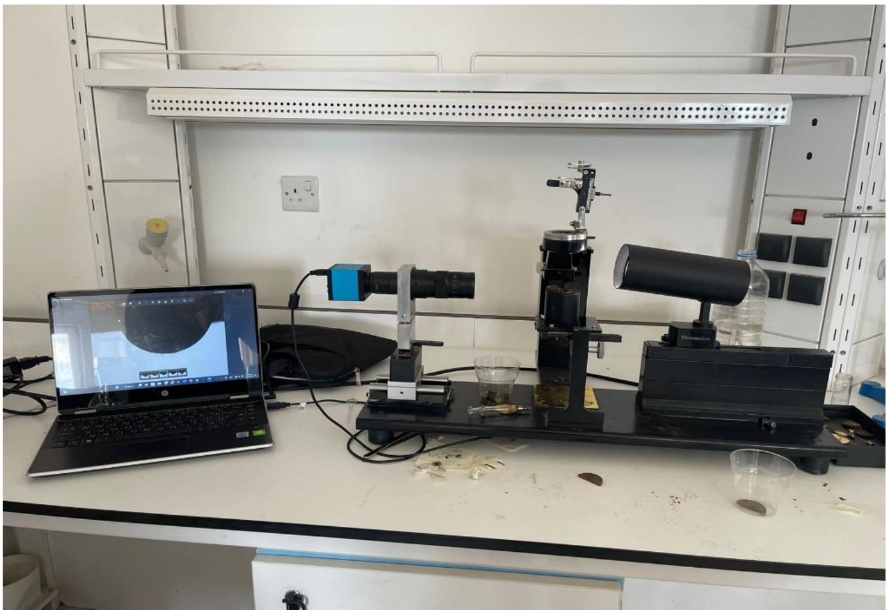


Figure 14 Schematic representation of a VIT-6000 apparatus used to measure IFT and contact angle.

3.2.5. Oil displacement

The schematic layout of the core flooding apparatus utilized for displacement experimental testing is shown in Figure 14. The system comprises of a core holder, pumps, tanks, a collecting vessel, valves, and gauges. Using pumps and an oven, the temperature and pressure of the experiments were kept at approximately 70 °C and 2000 psi, respectively. This study employed carbonate rock taken from an outcrop.

This research made use of carbonate rock taken from an outcrop. A block with a porosity of 17.8% and a permeability of 9.8 mD was created. The prepped core pieces were cleaned with toluene in a Soxhlet for 24 hours before drying. The saturation of the core plugs was accomplished using the core flooding device by pouring brine into the core plugs at a rate of 0.2 cm3/min to determine the dead volume. The crude oil was then pumped into the core plugs at a rate of 0.1-0.5 cm3 / min until the breach occurred, and two additional PVs were inserted. Furthermore, the displacement of the saturated core plugs was achieved as a secondary recovery by injecting 2.5 PVs of formation taken from a field at a rate of 0.5 cm3 /min. Following that, 2.5 PVs of SDS 500 were introduced into the core plugs as surfactant flooding at the same injection rate as the formation water. The displaced amount of crude oil was gathered in order to calculate the recovery factor obtained from all displacements.

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 can 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 distilled water, the conductivity of SDS-surfactants was raised from 6 to 96.7 µs/cm. With rising concentration up to 4000 ppm, the conductivity of the SDS surfactant with formation water rose from 12 to 65.2 µs/cm. The surfactant molecules behaved differently depending on the quantity of surfactant. Surfactant molecules had a significant pull on the interface between oil and water before CMC. The collected surfactant molecules were separated from the oil droplets after the CMC threshold, resulting in a reduced absorption behavior.

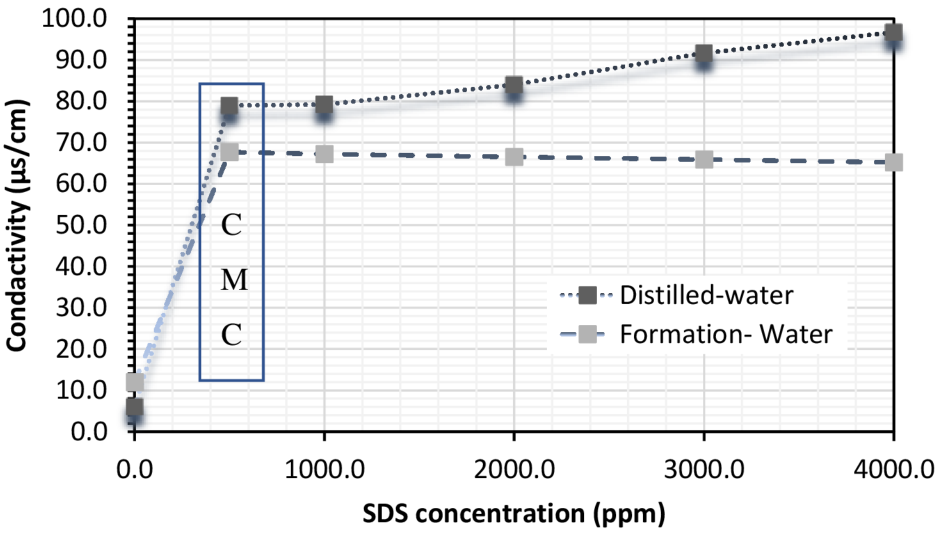


Figure 16 CMC ranges of the SDS surfactants estimated using conductivity

Figure 16 illustrates the turbidity of the surfactants used at various amounts. 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 distilled water, the turbidity of the SDS surfactant increased from 1.0 to 39.3 NTU at 4000 ppm.

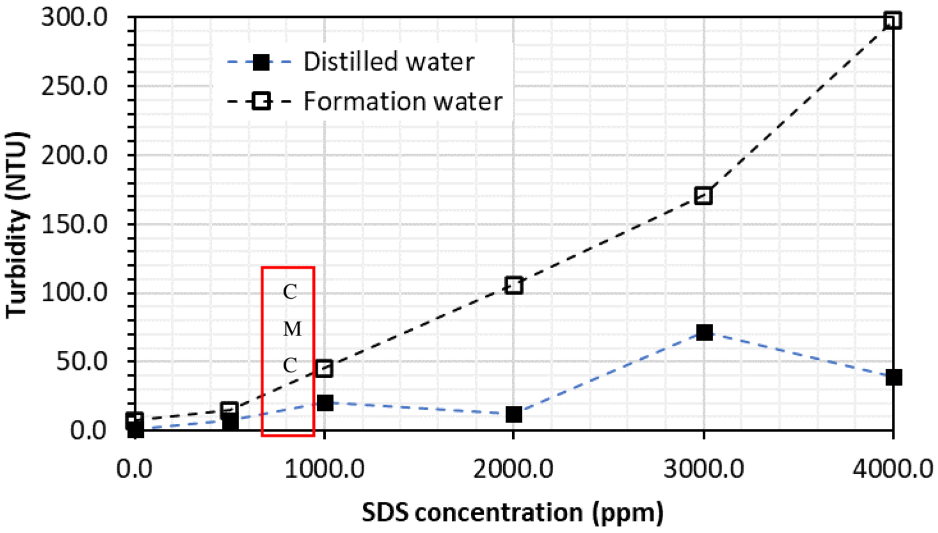


Figure 17 CMC ranges of the SDS surfactants estimated using turbidity.

4.2.Interfacial tension

The pendant method was used to quantify the IFT of crude oil droplets in the presence of surfactant solutions made by mixing SDS surfactant with distilled water and formation water. The IFT values measured between crude oil and surfactant solutions made from SDS surfactant with distilled water and formation water at various concentrations ranging from 500 to 4000 ppm are shown in Figure 19. As can be seen, the IFT of the crude/water system without detergents was between 22.22 and 29.5mN/m. In general, the lowest IFT was obtained by using a formation water solution at 3000 ppm, which is approximately 82.10%. When SDS surfactant was combined with purified water at 3000 ppm, the IFT of the DW decreased from 29.5 to 5.28 mN/m. However, the SDS surfactant worked better when used within the structure, reducing the IFT by 89.42% from 22.22 to 2.35 mN/m. However, the SDS surfactant fared weaker in the reduction of the IFT in both instances of distilled water and formation water. The IFT was reduced by 77.0% with the distilled water at 4000 ppm and by 77.4% with the formation water at 4000 ppm. The IFT was initially high with 0% surfactant concentration and decreased considerably when the concentration of the used surfactants was raised to the CMC limit. Furthermore, Figure 18 shows the dynamic IFT curves of crude oil/surfactant systems at various ratios. The IFT was gradually reduced as the test duration lengthened, from its maximum to its minimum number. As shown in figure 18 the CMC threshold is reached when the SDS surfactant is introduced to the solution at a quantity of 500 ppm in both distilled and formation water.

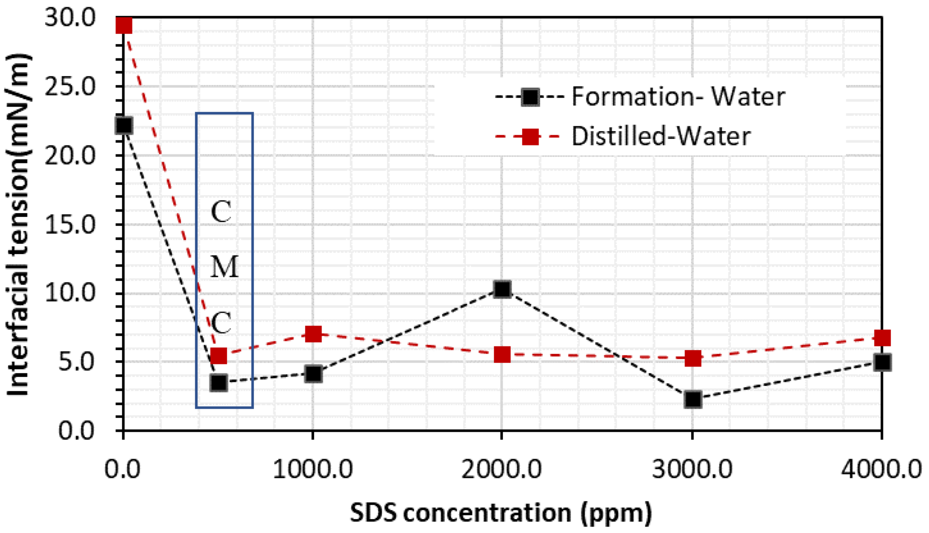


Figure 18 IFT values of oil/surfactants (SDS) at different concentrations.

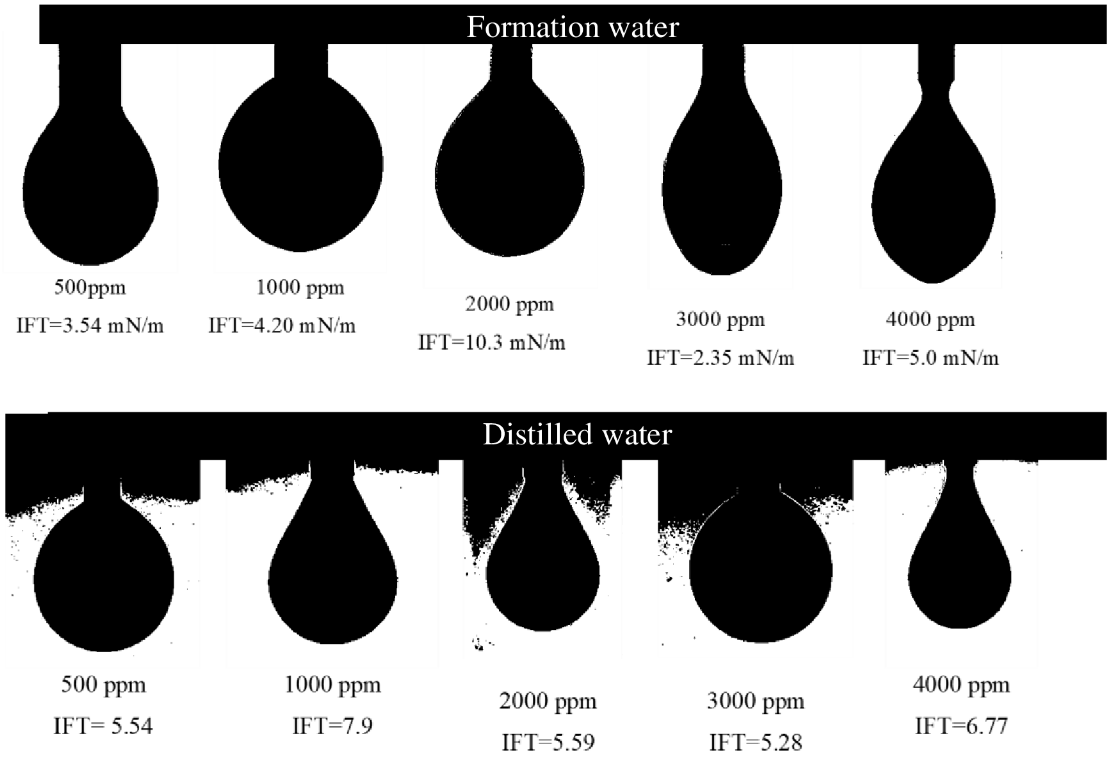


Figure 19 impact of formation water and distilled water with SDS surfactant on IFT at various concentrations.

4.3. Wettability alteration

The wettability of the used rock samples was determined by measuring the contact angles of oil drops on the surface of carbonate rock in the presence of various surfactant-based solutions. The contact angles measured for various solutions of SDS surfactant combined within distilled water and the formation water at varying amounts range from 500 to 4000 ppm are shown in Figure 21. Overall, SDS showed the greatest efficacy, lowering the CA to 29° when 3000 mg of SDS surfactant was combined with distilled water. This verifies the system's water-wet behavior. However, when the formation water-SDS4000 ppm solution was used, the highest CA ranges 114.8° of the oil droplet on the surface of the thin section was measured, indicating a strong oil-wetting condition. As can be seen, the SDS surfactant used was more active in the distilled water than in the formation water. At the CMC concentration, SDS surfactants demonstrated the greatest efficacy in changing the wettability of the carbonate rock towards a water-wet condition. The contact angles found with the DW-based SDS surfactants seem to be 44.4°, respectively, at 500 ppm. Furthermore, Figure 20 depicts the recorded forms of crude oil droplets on the surface of carbonate thin sections in the presence of DW-based and formation water solutions. When encircled by the DW-SDS3000 surfactant solution, the oil droplet with CA of 29° is almost free on the surface of the thin section. When 4000 ppm of SDS surfactant was combined with the formation water, the oil particle was strongly attracted to the solid surface (see Fig. 20).

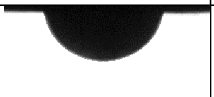
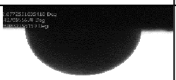
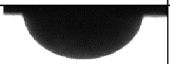
name	500 ppm	1000 ppm	2000 ppm	3000 ppm	4000 ppm
Formation water	 average angle=107°	 average angle =107.6°	 average angle =96.2°	 average angle= 98.15°	 average angle =114.8°
Distilled water	 average angle =44.5°	 average angle =54°	 average angle =45.8°	 average angle=29°	 average angle =38.7°

Figure 20 The shapes of the oil droplets on the carbonate thin section with the presence of SDS surfactant solutions at different concentrations ranged from 500 to 4000 ppm with the DW and formation water.

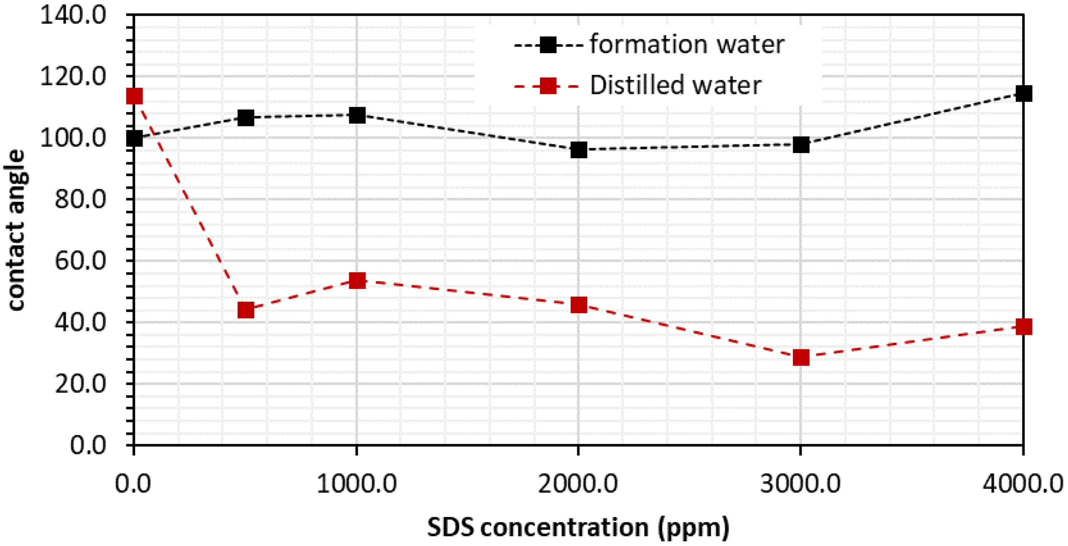


Figure 21 Contact angle values of oil/surfactants (SDS) at different concentrations.

4.4.Oil recovery

Oil displacement experiments were used to assess the improvement in the oil recovery factor. According to the findings of the CMC readings, surfactant solutions made by mixing 500 ppm of SDS surfactant within the formation water were chosen to be used 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 an x field in Iraq. The original oil content of the Core plug is 37%, and the pore capacity is 9.31 cm3. At first, formation water was introduced into the core plug at a rate of 0.1 cm3/min for up to 2 PVs (see Figure 22). As a result, the recovery factor from this shift was 44% OOIP. Following that, the oil recovery factor was increased to 44% OOIP by introducing 2 PVs of SDS500 surfactant solution at the same rate as the formation water input. By introducing 3 PV of SDS500 the oil recovery reaches 51.0% OOIP. The oil recovery rose to 56.8% OOIP after injecting the core plug with 4 PVs of SDS500.

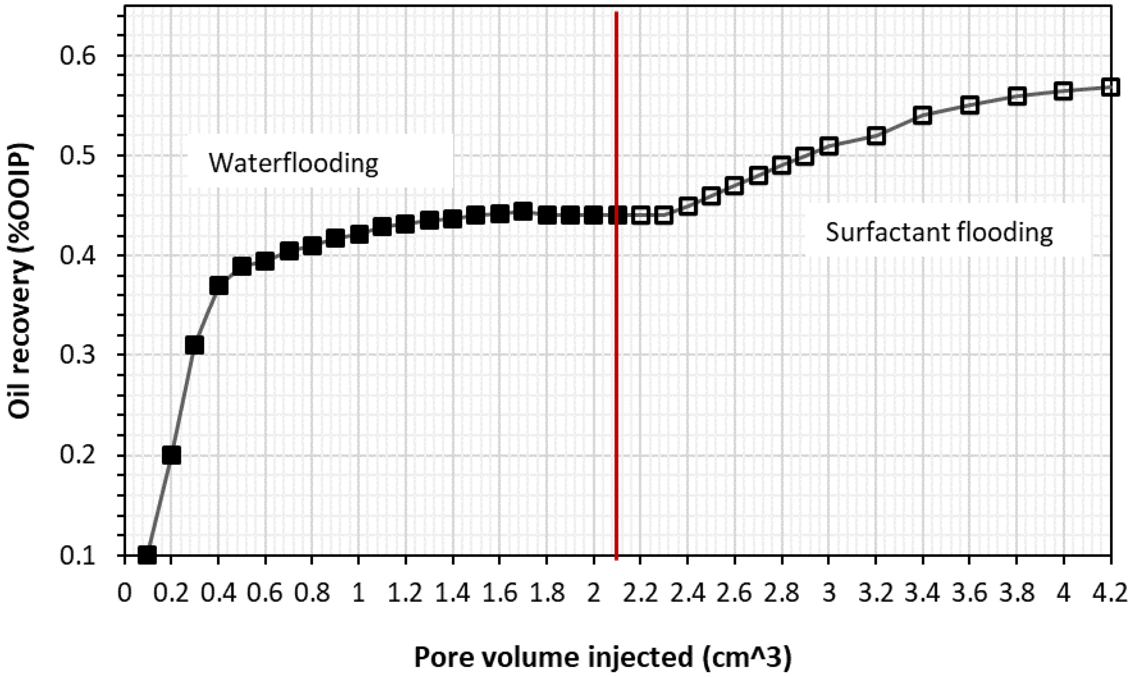


Figure 22 Oil recovery profile of water injection, SDS surfactant flooding into the prepared carbonate core plugs. The displacement was conducted by injecting 4 PVs of formation water and the surfactant solutions in core plug.

5. Conclusion and recommendation

5.1. *Conclusions*

This research concentrated on the use of SDS surfactant extracts in IFT decrease, wettability alteration, and improved oil recovery. The CMC point of the SDS surfactant was determined using the IFT and conductivity readings. When compared to DW-based SDS3000 ppm instances, the formation water-based SDS3000 ppm was more effective in reducing the IFT to its minimum of 2.35 mN/m. When pure water containing SDS3000 ppm surfactant was used, the lowest contact angle was 29°. The oil-wet condition was changed to a water-wet state by using an SDS surfactant based on distilled water. Furthermore, after waterflooding, SDS surfactants were able to recover an additional 56.8% OOIP.

5.2. ***Recommendation:***

I wish researchers in the future to use SDS surfactants with different types of rocks to know more about the role of SDS surfactants in oil recovery.

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