

**PORE-SCALE INVESTIGATION OF EMULSION
FORMATION AND ITS IMPACT ON OIL
DISPLACEMENT EFFICIENCY IN MICROMODELS**

by

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ORIGINALITY STATEMENT

I, Olzhas Bakhtygereyev, hereby declare that this submission is my own work and to the best of my knowledge it contains no materials previously published or written by another person, or substantial proportions of material which have been accepted for the award of any other degree or diploma at Nazarbayev University or any other educational institution, except where due acknowledgment is made in the thesis.

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ABSTRACT

After conventional water flooding, most portion of oil remains trapped in porous media due to poor mobility ratio, capillary forces and reservoir heterogeneity. To address this issue, chemical enhanced oil recovery (EOR), particularly surfactant flooding, has become commonly used to improve oil displacement efficiency by IFT reduction and wettability alteration. However, mechanisms of in-situ emulsification at pore scales and their impact on oil recovery under varying reservoir conditions require further research. This study investigated pore-scale mechanisms of emulsification and their impact on oil displacement efficiency using micromodel experiments. Three tests were conducted to evaluate the effects of oil viscosity, salinity, and heterogeneity: (i) low-viscosity oil in a heterogeneous micromodel with Caspian Sea water, (ii) high-viscosity oil under the same conditions, and (iii) high-viscosity oil in a complex heterogeneous micromodel using NaCl brine (10,000 ppm).

The pattern of the micromodel was monitored in real-time using a digital camera to observe oil displacement and in-situ emulsification mechanism. In Test 1, which used low-viscosity oil with Caspian Sea water, showed the highest recovery factors among all three tests: secondary waterflooding achieved a recovery factor of 0.345, secondary surfactant flooding reached 0.366, and tertiary surfactant flooding yielded 0.528. Despite these recovery results, in-situ emulsification was limited. In contrast, Test 2 with high-viscosity oil showed significantly more and stable O/W droplets. In Test 3, NaCl brine produced unstable droplets that coalesced rapidly rather than contributing to flow diversion, while the complex heterogeneous micromodel promoted localized droplet generation at pore constrictions. Overall, the results demonstrate that oil viscosity, water composition, and micromodel heterogeneity produce in-situ emulsions and improve displacement efficiency. These findings highlight the importance of considering such injection strategies and reservoir specific conditions when designing surfactant flooding for mature reservoirs with high water-cut.

DEDICATION

The dedication of my thesis goes to my dear parents because their continuous support, multiple sacrifices and constant motivation have built the path which I followed through my academic journey. The strength which your belief in me provides enables me to progress through life when I face my most difficult challenges.

I want to express my gratitude to my grandparents because they have provided me with their knowledge and their prayers and their limitless affection. The way you have always been part of my existence brings me peace while also motivating me to achieve greatness.

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1. INTRODUCTION

Primary and secondary recovery methods typically leave 50–70% of the original oil in place unrecovered. Capillary forces, unfavorable mobility ratios, and reservoir heterogeneity all contribute to trapping oil within porous media, and as easily accessible reserves continue to decline, there is growing pressure to improve recovery from existing fields through enhanced oil recovery (EOR) techniques (Gbadamosi et al., 2019).

Surfactant flooding is the most interesting method of chemically enhancing oil recovery. Surfactants reduce the interfacial tension (IFT) between oil and water, and capillary forces that hold oil on the rock's surface are decreased respectively. Oil displacement is enhanced by their ability to alter wettability and emulsify fluid in the system (Jinmei et al., 2025; Yang et al., 2021).

Emulsification is the dispersion of one immiscible liquid in another in the form of droplets—is particularly important in surfactant flooding. Emulsified oil droplets block highly permeable zones, leading to fluid migration to upswept areas after water flooding, thereby increasing both microscopic displacement and macroscopic sweep efficiency (Jiang et al., 2021; Y. Li et al., 2022). Emulsification and IFT reduction demonstrate the importance of surfactant injection in oil recovery, particularly in heterogeneous reservoirs (J. Li et al., 2022; Z. Liu et al., 2024).

Now researchers can observe these processes at the pore scale using micromodels and microfluidic technologies. Micromodels allow scientists to observe fluid-fluid and fluid-rock at pore level, where the effect of droplets on oil displacement by their formation, coalescence and transportation is visible (Gogoi & Gogoi, 2019; Yang et al., 2021).

The emulsification process depends on the properties of the oil and the salinity of the water (Shafiei et al., 2022). The presence of natural surfactants such as asphaltenes and resins in crude oil, leads to the formation of stable emulsions, as these compounds create stronger interfacial films, controlling oil spreading and migration during emulsion formation (Pu et al., 2023). Water with different divalent ionic compositions and concentrations influence on oil displacement by changing interfacial tension and the formation of emulsion (Mansouri et al., 2025).

Important areas of this research remain unexplored because most pore-level studies consider synthetic fluids and homogeneous porous media, as these materials do not mimic real reservoir conditions. The combined effects of oil viscosity, water salinity, and pore structure heterogeneity on emulsification, oil displacement and surfactant performance have not been systematically studied.

This study addresses these gaps using micromodel experiments that incorporate two crude oils of different viscosity, two water types (synthetic NaCl brine and natural Caspian Sea water), two injection strategies (secondary and tertiary surfactant flooding), and two micromodels with different heterogeneity and permeability characteristics. For regional EOR operations, the usage of Caspian Sea water is cost-effective and adds realistic ionic complexity. Controlled laboratory conditions and high-resolution pore scales are managed to investigate emulsion formation mechanism during IFT reduction and impact of in-situ emulsions on oil displacement efficiency, with the broader objective of optimizing chemical enhanced oil recovery (EOR) methods in heterogeneous reservoirs.

1.1 Problem statement

The oil and gas industry are the main part of the economy in Kazakhstan. Most mature oil fields face declining production due to high-water-cut. Large oil fields in Mangystau and Kyzylorda regions, including Zhetybai, Uzen, Kalamkas and Kumkol possess water cuts ranging from 90 to 95% (Alisheva et al., 2025). It means mostly water is produced to surface, with a small portion of usable oil. Despite this, a significant volume of oil remains trapped in the reservoir due to the capillary forces, low displacement efficiency, and reservoir heterogeneity.

Currently, conventional waterflooding has reached operational limits of these fields. Injecting water flows through highly permeable zones, bypassing a significant portion of the oil, leaving it untouched. Modern oil production requires effective management of injection strategies to improve oil recovery from mature reservoirs.

Surfactants enable oil extraction because they reduce interfacial tension and produce oil by generating in-situ emulsions which directs oil flow toward unswept zones. Implementing surfactant flooding methods in mature fields in Kazakhstan requires a comprehensive study of

the emulsification processes occurring at the pore level under operating conditions, including local Caspian Sea waters and the typical heterogeneous pore structures of these reservoirs.

This is precisely the problem this study addresses. By investigating emulsification mechanisms at the pore scale through micromodel experiments, the work aims to generate mechanistic insight that is directly applicable to improving chemical EOR performance in mature, high water-cut fields in Kazakhstan.

1.2 Objectives of the Thesis

1.2.1 Main Objective

The main objective of this study is to investigate pore-scale in-situ emulsion formation mechanisms and evaluate their impact on oil displacement efficiency through micromodel experiments under varying injection fluid and operational conditions.

1.2.2 Specific Objectives

The specific objectives of this research are:

1. To analyze the effect of oil viscosity on emulsion formation and displacement efficiency using different crude oil samples
2. To investigate the influence of water composition, including brine and Caspian Sea water, on surfactant performance and emulsion behavior
3. To compare the effectiveness of different injection strategies, including secondary and tertiary surfactant flooding
4. To study the role of reservoir heterogeneity on fluid flow patterns and oil recovery using micromodels with varying permeability distributions
5. To evaluate the relationship between emulsification and oil displacement efficiency at the pore scale

1.3 Hypotheses

This study is based on the following hypotheses:

1. In-situ emulsification significantly contributes to oil displacement efficiency beyond the effect of interfacial tension reduction alone
2. Higher oil viscosity leads to more stable emulsions and improved sweep efficiency
3. Water composition, particularly the presence of divalent ions, affects emulsion formation and stability
4. Injection strategy influences the extent of emulsification and overall oil recovery

1.4 Justification of the R&D

The study is based on three main foundations: surfactants design, ionic composition of water and heterogeneity of the micromodel.

Successful surfactants design requires understanding how emulsification occurs under specific fluid flow conditions in order to reduce IFT. The study provides pore scale data that helps researchers choose the proper composition of surfactants, optimal concentrations, and the injection strategy. Engineers will gain practical knowledge about surfactant flooding, whether in-situ emulsification stronger under secondary or tertiary recovery, or effectiveness of surfactant at various viscosity.

The study is of particular importance for the Mangystau region where Caspian Sea water is vital in daily-life and cost-effective as injection source. The ionic composition of the Caspian Sea water differs from synthetic salt brines which used in laboratory studies, with the high levels of divalent ions, including Ca^{2+} and Mg^{2+} , and these ions affect the adsorption of surfactants, interfacial tension, and stability of the emulsion (Al-Sakkaf & Onaizi, 2024).

The heterogeneous micromodels in this study serve as an important link between laboratory tests and the realistic characteristics of the reservoir. Real reservoirs are heterogeneous, since the distribution of their permeability varies throughout the pore network, which leads to the formation of specific flow paths that cannot be overcome by water flooding. The study demonstrates how heterogeneity of pore size, effect on capturing flow diversion, droplet trapping and improvement of sweep efficiency, which does not appear in homogeneous reservoirs. The results of the study can be applied to complex reservoir systems that operate in several layers and exist in mature oil fields in Kazakhstan.

1.5 Scope of Work

The study examines the effect of in-situ emulsification on oil displacement through controlled-pore experiments using micromodels during surfactant flooding. During the test, two injection strategies were used: surfactant flooding as secondary and surfactant flooding after water flooding as tertiary recovery. A comparison of these two methods shows how different injection times affect liquid interactions, emulsion formation, and the efficiency of oil displacement. Two crude oils with different viscosities, two water types (synthetic NaCl brine and natural Caspian seawater), and two micromodels with different permeabilities will be used in this study. Obtaining high-resolution images makes it possible to fully observe the processes at the pore scale, including droplet formation, coalescence, and transportation during all experiments. The main advantage of micromodel test is that it allows researchers to observe the all processes inside of micromodel, while core flooding tests are limited in this case.

However, the study contains clear limitations that need to be considered. The experiments, which were conducted in the laboratory, can only show two-dimensional results, since our testing method could not reflect the three-dimensional behavior of the flow in the reservoir and gravitational forces due to the significant natural fluctuations present. The results are also specific to the surfactant system and liquid properties tested here, and should not go beyond these limits without further investigation. This study provides insight into the mechanical properties of pores, which are necessary for researchers to improve surfactant flooding methods used in field work.

2. LITERATURE REVIEW

2.1 Enhanced Oil Recovery (EOR): Overview and Challenges

Oil recovery from subsurface reservoirs is conventionally achieved through three sequential stages, as illustrated in Figure 1. Primary recovery relies on natural reservoir energy - including solution gas drive, water drive, and gravity drainage - and typically yields only 5–15% of the original oil in place (OOIP) (Kumar et al., 2021). Secondary flooding methods, which use water flooding and gas injection, are used to maintain pressure when oil is supplied to production wells, resulting in total production reaching approximately 20-40 % of OOIP (Kumar et al., 2021; Sheng, 2015).

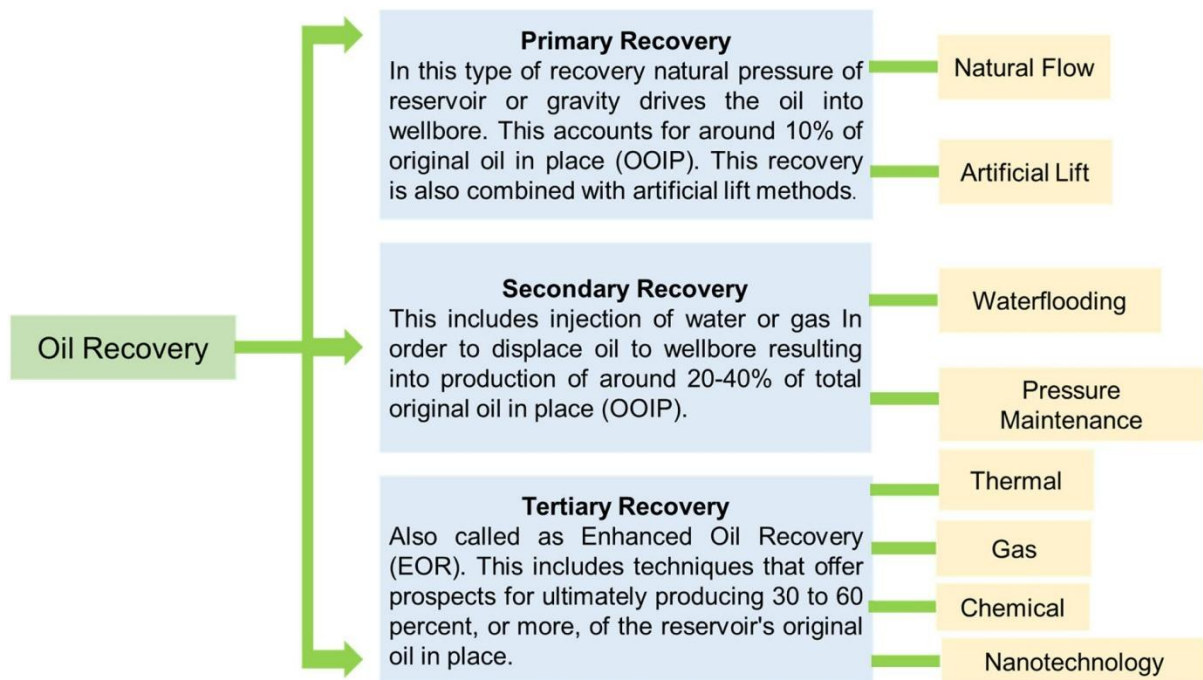


Figure 1 Classification of oil recovery methods showing primary, secondary, and tertiary (EOR) processes.
(Kumar et al., 2021)

Mostly trapped oil remains in reservoirs after traditional secondary recovery due to capillary forces, unfavorable mobility ratios, and reservoir heterogeneity. The flooding process shows that water passes through areas with high permeability, which creates an unstable displacement front, which scientists call viscous fingering (Fig. 2). The displacing liquid moves at a higher speed than the displaced oil due to high mobility ratio which exceeds 1 ($M > 1$), and

this situation leads to early water breakthrough, leaving large amounts of oil in low permeability areas (J. Li et al., 2019; Sheng, 2013).

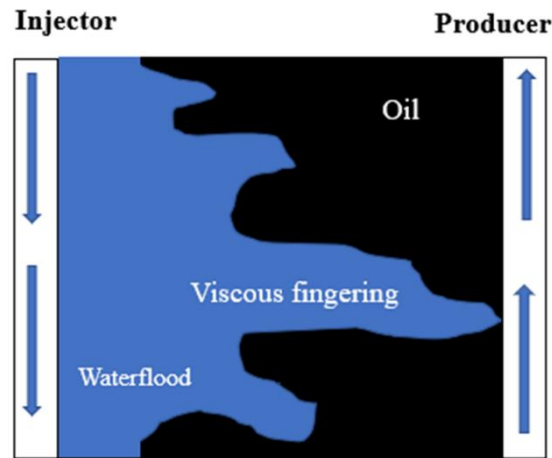


Figure 2 Schematic illustration of viscous fingering during waterflooding, leading to bypassed oil and poor sweep efficiency (Gbadamosi et al., 2022).

To address these issues, Enhanced Oil Recovery (EOR) techniques are presented to recover the remaining oil in reservoir by increasing displacement efficiency at both microscopic and macroscopic levels. EOR methods are broadly divided into thermal, gas, chemical and nanotechnology methods (Sheng, 2013). Thermal methods, including steam injection and in-situ combustion, allow operators of heavy oil fields to reduce viscosity, but they face operational difficulties due to heat losses in the reservoir and technical problems related to environmental protection (Kovscek, 2012). Gas injection methods improve recovery by oil swelling, viscosity reduction of oil, and creating a miscibility effect. However, their effectiveness is limited due to gravity override and poor conformance (Du & Nojabaei, 2019).

Chemical EOR includes polymers, surfactants, alkalis, or their combinations. The formulations shown in Figure 3 contain the surfactant–polymer (SP) and alkali–surfactant–active substance (A) systems, as well as the alkali–polymer (AP) and alkali-surfactant-polymer (AP) systems, which combine together, modifying liquid and changing interfacial properties. Polymers improve sweep efficiency by increasing the viscosity of the injected liquid and reducing the mobility ratio, which leads to suppression of viscous fingering (Gbadamosi et al., 2019). However, their abilities are affected by reservoir salinity, temperature and mechanical degradation. Alkalis increase the effectiveness of surfactants by in-situ soap generation and reducing losses during adsorption of surfactants. Surfactants contribute to the mobilization of

capillary-trapped residual oil, which persists after flooding, as they interact with the pores, reducing IFT and changing wettability (Al-Azani et al., 2022; Sheng, 2015).

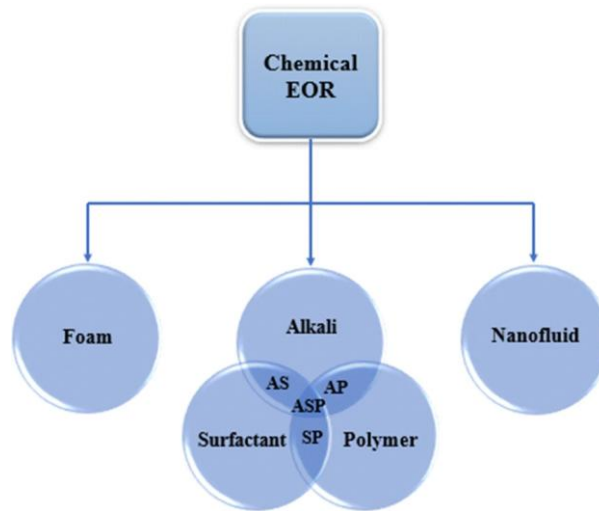


Figure 3. Chemical EOR classification (Gbadamosi et al., 2019)

Despite significant potential of the Chemical EOR, the practical application faces numerous obstacles: surfactants adsorb on the surface of rocks, chemicals could be destroyed under the influence of high temperatures and salinity, and the technology is too expensive to implement in real field conditions (Bazazi et al., 2019). Understanding these obstacles requires scientists to study how fluids move through pore spaces at a fundamental level. Surfactant flooding has become a successful method because it directly affects the oil trapped in the capillaries, and the next section will provide a detailed analysis of its work processes.

2.2 Surfactant Flooding

The process of surfactant flooding where surfactant solution is pumped through injection wells, which move through the formation to push the oil reservoir towards the producing wells, as shown in Figure 4.

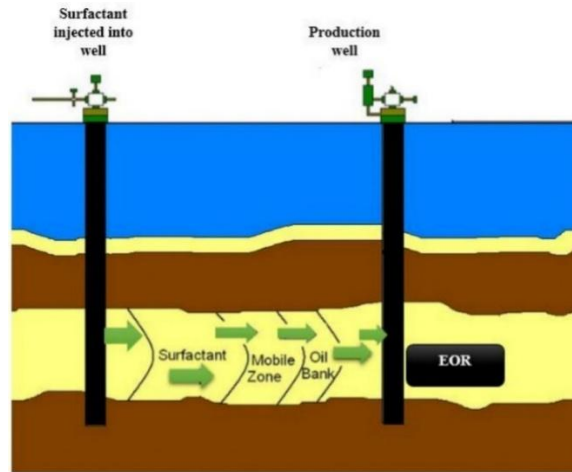


Figure 4. Schematic illustration of the surfactant flooding process in an oil reservoir (Isaac et al., 2022)

This method increases oil recovery on two scales: on the pore scale by mobilizing trapped oil droplets (microscopic efficiency) and on the reservoir scale by improving contact between the injected liquid and unswept zones (macroscopic efficiency) (Elmuzafar Ahmed et al., 2022; Massarweh & Abushaikha, 2020).

2.2.1 Interfacial Tension Reduction and Wettability Alteration

Surfactants are amphiphilic molecules that have a hydrophilic head that binds to water and a hydrophobic tail that binds to oil. The compound's ability to exist in two different forms, allows surfactants to adsorb on the oil-water interface, which leads to IFT and capillary forces reduction. High displacement of trapped oil is achieved, when droplets deform and flow easily under ultra-low IFT conditions, decreasing from 20-30 mN/m to 10^{-3} mN/m (Massarweh & Abushaikha, 2020).

Wettability describes how strongly a rock surface prefers contact with one liquid to another in multiphase system(Isaac et al., 2022). In Figure 5, reservoir rock initially was oil-wet, then surfactant interacted with surface of the rock and removed oil, making it water-wet Figure 5.

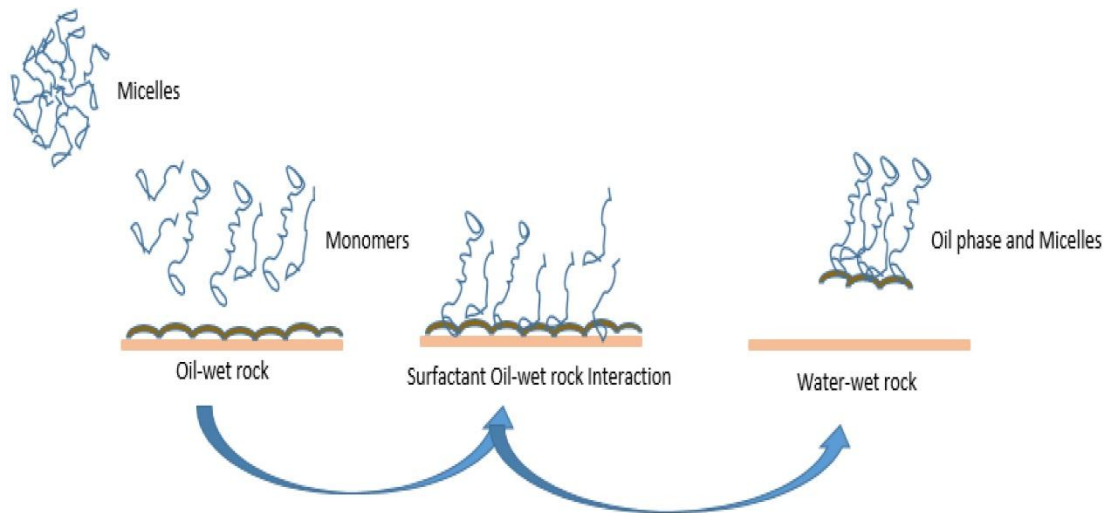


Figure 5. Wettability alteration mechanism from oil-wet to water-wet conditions due to surfactant adsorption (Isaac et al., 2022)

This process allows the injected water to separate the oil from the pore walls before it enters production wells. The combination of IFT reduction and wettability alteration leads to spontaneous absorption and improves oil recovery according to experiments on micromodels (Mejia et al., 2019). Besides of these mechanisms, oil recovery in heterogeneous reservoirs additionally require in-situ emulsification and flow diversion, to achieve high production (An et al., 2026)

2.2.2 Types of Surfactants and Their Applications in EOR

The five categories of surfactants used in EOR are based on the content of their main group, which includes anionic surfactants, cationic surfactants, nonionic surfactants, zwitterionic surfactants, and biosurfactants. The right choice depends on the reservoir characteristics — rock type, water salinity and temperature (Kamal et al., 2017)

Anionic Surfactants

Anionic surfactants represent the dominant category of surfactants used to improve the efficiency, mostly in sandstone reservoirs. The negatively charged upper groups of these substances reduce adsorption on sandstone surfaces that have the same negative charge, which ensures better permeability of the reservoir. This surfactant is low cost and effective at reducing interfacial tension. Figure 6 shows sodium dodecyl sulfate (SDS) as a standard example, which contains a head sulfate group and a hydrocarbon tail. The main disadvantage of these

compounds is related to their sensitivity to high salinity and the concentration of divalent ions, which reduces their effectiveness in specific reservoir waters (Kamal et al., 2017)

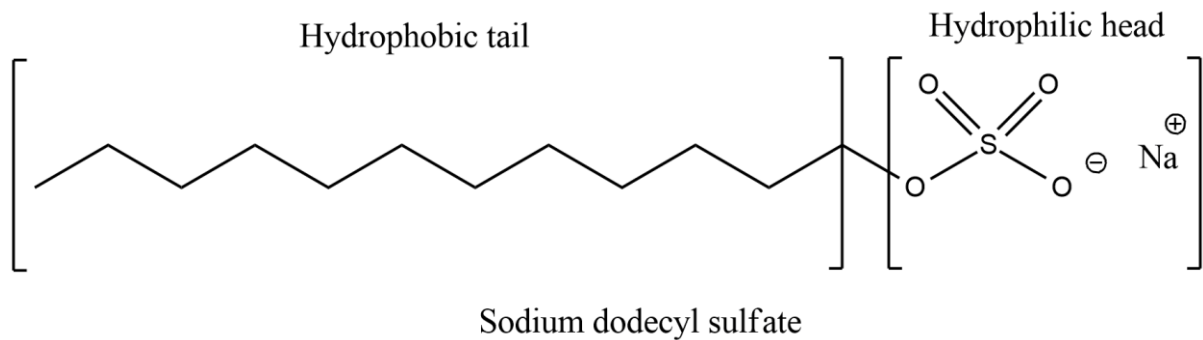


Figure 6. Chemical Structure of SDS

Cationic Surfactants

Cationic surfactants have a positive charge and are mainly used in carbonate reservoirs. This surfactant acts as a wetting agent between oil and water, and adheres to negatively charged carbonate surfaces. Figure 7 shows cetyltrimethylammonium bromide (CTAB) as a typical example. The strong surface affinity of the surfactant leads to significant losses during adsorption, and their high costs, prevent wider application (Kamal et al., 2017)

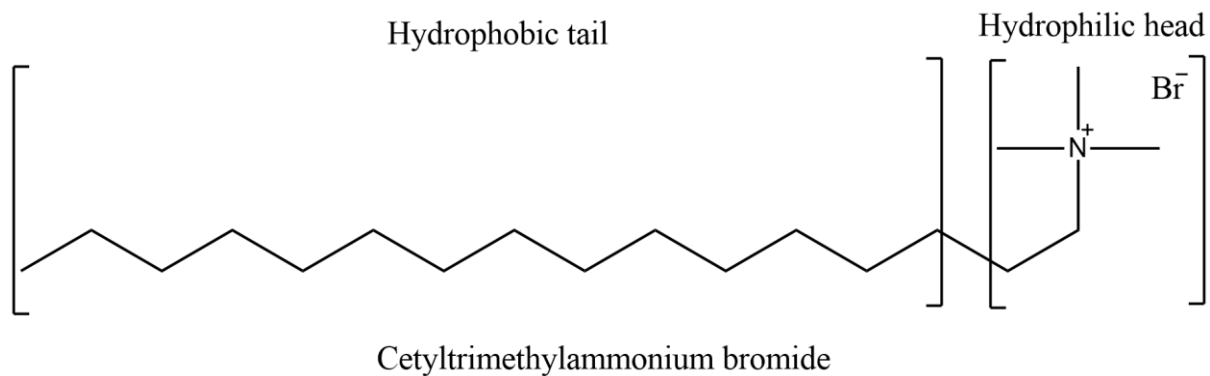


Figure 7. Chemical Structure of CTAB

Nonionic Surfactants

Nonionic surfactants do not carry any charge and are usually used as co-surfactants with along with ionic types. The absence of electrostatic interactions provides them with good resistance to salinity and temperature fluctuations. Figure 8 shows Laureth-1 as an example,

where the ethoxylated group creates hydrophilicity. Their main limitation is related to their lower ability to reduce interfacial tension compared to ionic surfactants (Kamal et al., 2017)

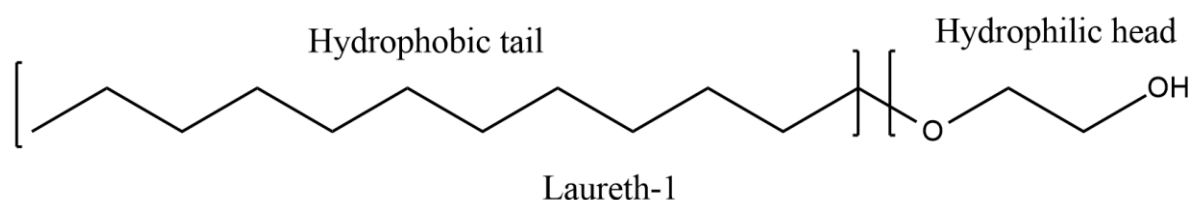


Figure 8. Chemical Structure of Laureth-1

Zwitterionic Surfactants

Zwitterionic surfactants stabilize their molecular structure because they contain both positive and negative charges that protect them from extreme conditions such as high salinity and high temperature. Cocamidopropyl Betaine (CAPB) demonstrates compatibility with various reservoir fluids, making it a well-studied example in Figure 9. The researchers found that the market potential of the product is limited due to the cost of its production (Kamal et al., 2017). The researchers found that the market potential of the product is limited due to the high production cost.

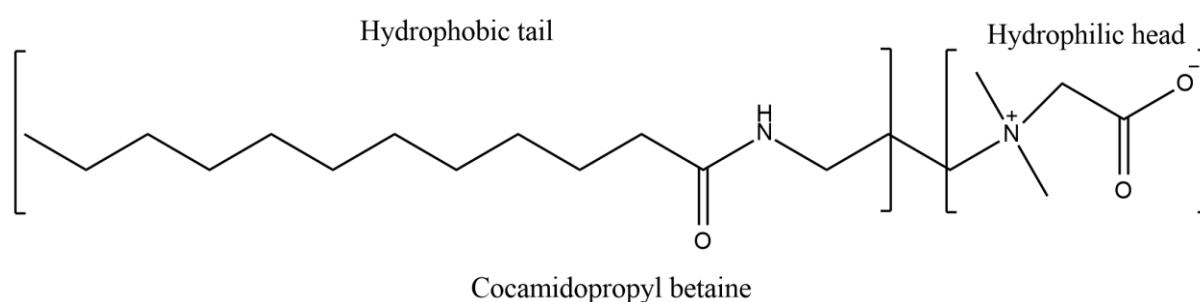


Figure 9. Chemical Structure of CAPB

Biosurfactants

Biosurfactants are environmentally friendly compounds to enhance oil recovery, because they are produced by microorganisms as a result of the natural process of surfactants formation. Rhamnolipids C14 is shown in Figure 10, consists of a sugar-based hydrophilic head

and a hydrocarbon tail. The product is completely biodegradable, as it has low toxicity and at the same time provides acceptable performance characteristics in specific application conditions. The main disadvantages are high production costs and stability issues that limit their widespread application (Kamal et al., 2017).

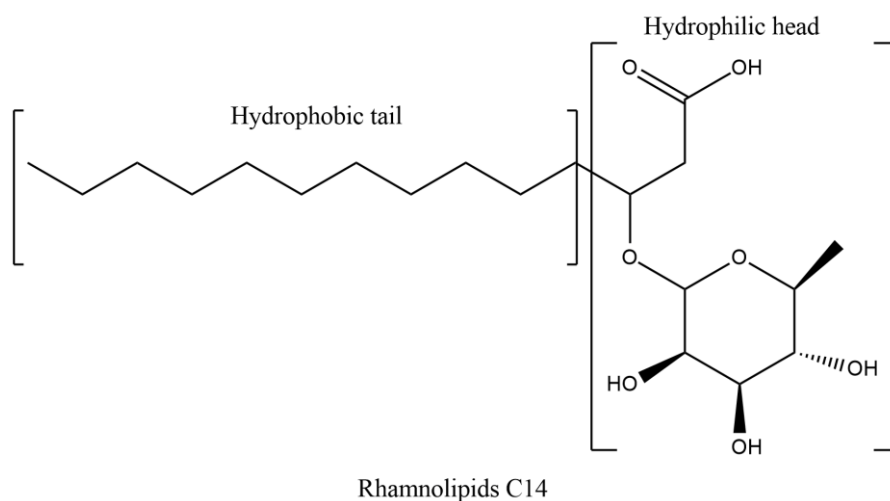


Figure 10. Chemical Structure of Rhamnolipids C14.

The table 1 provides a complete comparison of the five types of surfactants based on their types, charge, typical application, reservoir conditions, advantages, disadvantages, and their main representative examples.

Table 1. Summary of Surfactant Types in EOR

Surfactant Type	Charge	Typical Application	Suitable Reservoir	Key Advantages	Limitations	Examples
Anionic	Negative	EOR flooding (most common)	Sandstone	Strong IFT reduction, low cost	Sensitive to high salinity and hardness	SDS, AOS
Cationic	Positive	Wettability alteration	Carbonate	Strong adsorption on carbonate	High adsorption loss, expensive	CTAB
Nonionic	Neutral	Co-surfactant systems	Sandstone and carbonate	Salt tolerance, thermal stability	Weaker IFT reduction	Laureth-1, Tween 80
Zwitterionic	Both (+/-)	Harsh conditions EOR	Carbonate and high salinity reservoirs	Excellent salt and temperature tolerance	Higher cost	CAPB
Biosurfactants	Variable	MEOR / green EOR	Both	Environmentally friendly	Limited large-scale application	Rhamnolipids, Sophorolipids

While IFT reduction and wettability alteration are well-established mechanisms in surfactant flooding, growing evidence suggests that in-situ emulsification plays an equally important role, particularly in heterogeneous and low-permeability reservoirs. This mechanism is discussed in detail in the following section.

2.3 Emulsification in Surfactant Flooding

Emulsification is one of the key processes occurring during surfactant flooding, where oil droplets disperse into the aqueous phase to produce oil-in-water (O/W) or water-in-oil (W/O) emulsions, as shown in Figure 11.

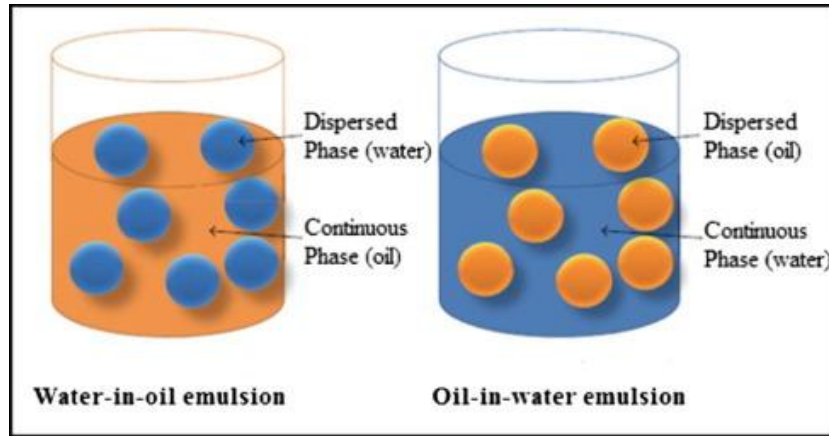


Figure 11. Schematic figure of O/W and W/O emulsions ((Vellaiyan & Amirthagadeswaran, 2016)

Emulsification is facilitated by surfactant adsorption at the oil–water interface, which reduces interfacial tension and enables the breakup of liquid phases into dispersed droplets. The resulting emulsion droplets influence multiphase flow behavior of pore space, contributing oil recovery improvement by enhancing both microscopic displacement and increased macroscopic sweep efficiency (J. Liu et al., 2023). A clear understanding of emulsification mechanism at pore scale, allows us to properly design and optimize surfactant flooding.

2.3.1 Emulsification Mechanism

The formation of emulsions at the pore scale occurs through two main mechanisms: snap-off and shear-induced breakup, which are presented in Figure 12. The snap-off mechanism (Figure 12A-B) leads to the fact that trapped oil deforms during surfactant solution moves along the surface, and IFT decreases. The structure of oil ganglia becomes unstable under the influence of an increasing pressure gradient and eventually breaks up into droplets that move forward through the network of pores. This mechanism acts mainly in narrow pores, where capillary instability controls the breakup process.

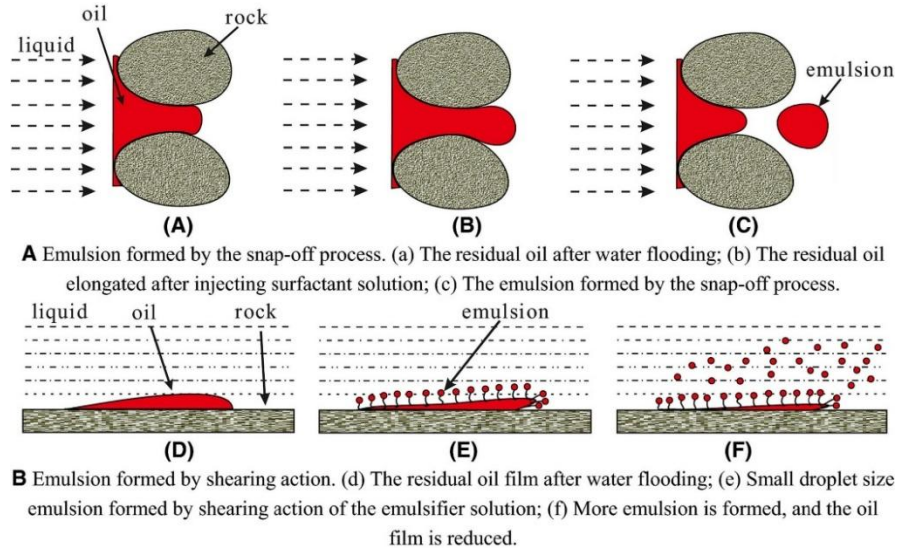


Figure 12. Schematic illustration of emulsification mechanisms in porous media: (A–C) snap-off mechanism and (D–F) shear-induced emulsification (L. Liu et al., 2024)).

Shear-induced emulsification (Fig. 12D-F) occurs when the current aqueous phase creates sufficient shear stress at the oil–water interface. The molecules of surfactants quickly adsorb to new interfaces, splitting thin oil films into smaller droplets with greater stability. The effectiveness of this mechanism depends on the magnitude of the shear forces and the emulsifying ability of the surfactant system (J. Liu et al., 2023).

Micromodel and microfluidic studies demonstrate direct experimental confirmation of these mechanisms, and they are summarized in Table 2. The researchers used transparent porous media to study emulsification during surfactant flooding, and visually see how droplet formation occurs caused by snap-off and shear-induced mechanisms. Zhao et al., 2020 have shown how they tracked the formation of droplets and their movement through the pore grid, as emulsification occurs during active flow. Mejia et al., 2019 used micromodel systems to show how oil breaks into smaller parts and spreads through the pores, which proved that emulsification occurs using real mechanisms, not just scientific theories. (Ramatou et al., 2026) demonstrated that emulsification become apparent from the synergy of ultra-low IFT and pore-scale hydrodynamic forces, including shearing, stretching, and breakup

Table 2. Summary of micromodel and microfluidic studies on pore-scale emulsification mechanisms

Study	Experimental System	Key Observations	Mechanisms Identified	Key Contribution
(Zhao et al., 2020)	Microfluidic porous media	Real-time droplet generation and transport	Snap-off, shear-induced breakup	Direct visualization of in-situ emulsification
(Mejia et al., 2019)	Oil-wet fractured micromodel	Oil mobilization from matrix to fracture	Capillary + viscous + emulsification effects	Demonstrated role of low IFT and viscous forces
(Ramatou et al., 2026)	Glass micromodel (sandstone-like)	Droplet breakup, deformation, and redistribution	Shearing, stretching, breakup	Coupled chemical (IFT) + mechanical mechanisms

The interfacial film that forms around the dispersed droplets determines the stability of the emulsion systems. The combination of surfactant molecules and crude oil components, including asphaltenes and resins, forms a viscoelastic protective layer that prevents coalescence. The rheological properties of oil film determine droplet deformation, transportation and resistance. (Al-Sakkaf & Onaizi, 2024; Y. Zhou et al., 2023).

System parameters, including the concentration of surfactants, salinity, temperature, and oil composition, also play an important role. The concentration of surfactants increases, resulting in better coverage of the interface and a decrease in droplet size, while changes in salinity and temperature affect the phase behavior of surfactants and the stability of emulsions (Hu et al., 2024; Z. Li et al., 2020)

The mechanisms of snap-off and shear-induced breakup depend on the geometry of the pores and flow conditions, while the stability and movement of droplets are determined by the

physico-chemical characteristics of the liquid. Their impact on oil recovery depends on how these droplets modify flow behavior, mobility control, and displacement efficiency within the porous medium. The following section provides a complete explanation of these aspects.

2.3.2 Role of In-situ Emulsification in Oil Recovery

The injected surfactant in the system begins to spread through the pore network and contacts the trapped oil, producing and transporting droplets to the production well as shown in Figure 13. The mobilization of trapped oil occurs mostly through interfacial tension reduction, while emulsification contributes by producing smaller oil droplets that move through the pore network (Al-Sakkaf & Onaizi, 2024; Y. Zhou et al., 2023).

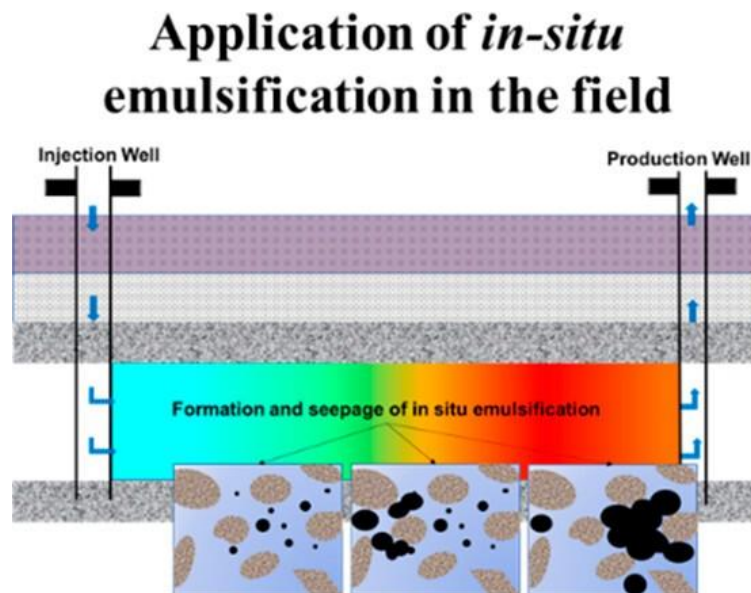


Figure 13. Schematic illustration of in-situ emulsification during surfactant flooding in porous media (J. Liu et al., 2023)

The flow behavior of porous media shows that in-situ emulsification modifies their transport properties. The dispersed droplets in the system create additional flow resistance, which changes the relative permeability, resulting in better mobility control and stable displacement front. In addition, in-situ emulsification temporarily blocks high-permeability zones, redirecting injected fluid to the low-permeable zones, pushing untouched residual oil to the production well. This process is called jamming effect, which is shown in Figure 14, and by path blockage this process improves macroscopic sweep efficiency (J. Liu et al., 2023; Y. Zhou et al., 2023)

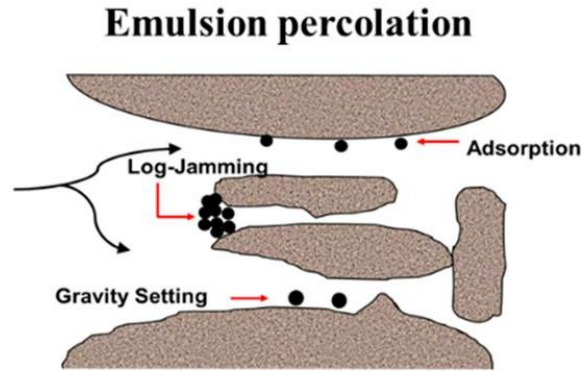


Figure 14. Mechanism of emulsion transport and pore-throat blocking (Jamin effect) in porous media (J. Liu et al., 2023)

The deformation and transportation of oil droplets through narrow pores is very important in heterogeneous reservoirs, where various permeabilities can affect fluid distribution in porous media (Al-Sakkaf & Onaizi, 2024; G. Zhou et al., 2023). The emulsification process mostly depends on the properties of fluids, especially oil viscosity which controls how droplets deform, breakup and move through the porous media. The better performance of surfactant flooding needs optimization through research that investigates how emulsification processes are affected by viscosity.

2.4 Effect of Viscosity on Emulsification

The viscosity of oil provides a fundamental basis for evaluating how liquids move through pipes, how emulsions behave, and how two-phase systems work. It shows oil resistance to flow and deformation, controlling the mobility ratio during EOR. The high viscosity of the oil creates an unfavorable mobility ratio, which leads to instability of the displacement front and reduces sweep efficiency, while oil with low viscosity flow more easily, but their flow are prone to early breakthrough and channeling.

Viscosity governs the viscosity forces of emulsions which drive droplet deformation and breakup. A higher viscosity increases the resistance to deformation and changes break up dynamics of emulsions, by producing large droplets. However, emulsions gain stability, with the film drainage rate reduction and preventing coalescence. Low-viscosity oils are dispersed into smaller droplets, but form unstable emulsions because their surface films are weak and faster coalescence (Isaac et al., 2022; J. Liu et al., 2023).

These effects are confirmed by direct data from microfluidic studies. (Yao et al., 2019) investigated droplet formation in a T-junction microfluidic device and found that increasing the viscosity of the oil from 5 to 15 cSt reduces the droplet size by about 32% due to stronger shear forces of viscosity acting on the dispersed phase. The results showed that the rate of droplet formation decreases with increasing viscosity at constant pressure in accordance with all pressure ratios shown in Figure 15.

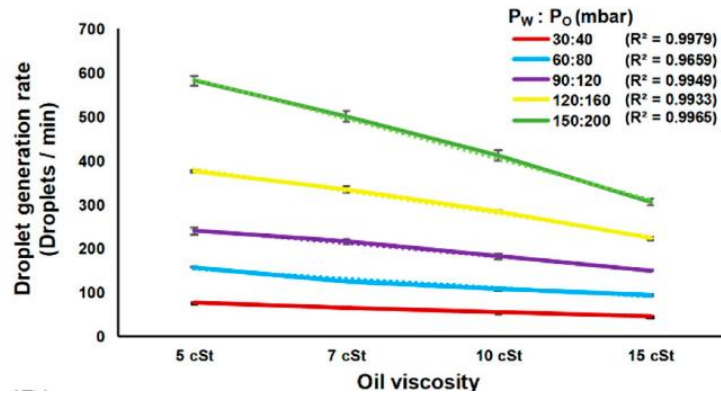


Figure 15. Effect of oil viscosity on droplet generation rate under different pressure conditions (Yao et al., 2019)

The behavior of droplets and the interaction with the pore structure at the pore level depend on the viscosity. Droplets with high viscosity resist deformation, and a higher-pressure drop is required to pass through the pore channels, increasing resistance to flow and spread injected liquid over unswept areas. The lower viscosity of the droplets makes it easier to move them, but leads to less efficient displacement. Viscosity is a significant factor that links the activity at the interface with the flow pattern at the pore level, and this relationship directly affects the efficiency of oil production (Isaac et al., 2022; J. Liu et al., 2023).

2.5 Effect of Salinity on Emulsification

Salinity is one of the influential controlling emulsification and interfacial properties in surfactant-based systems. Figure 17 demonstrates that an increase in the salinity level leads to a gradual transition from one Winsor type to another, which begins with I, passes through III and ends at II, and each of them has different emulsion properties (Hou & Sheng, 2022; Massarweh & Abushaikh, 2020)

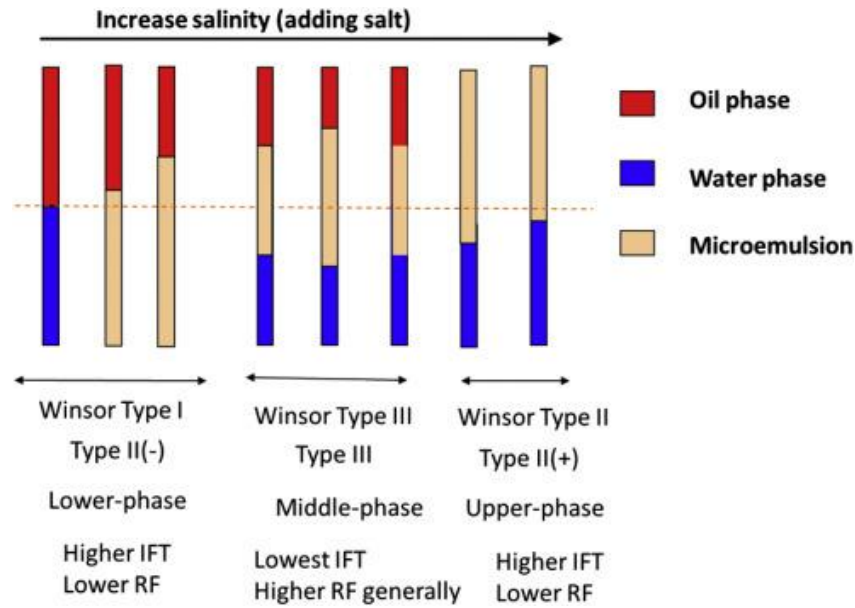


Figure 16. Influence of salinity on Winsor phase behavior (Type I–III–II) and microemulsion formation in surfactant systems (Sheng, 2015).

In Winsor type I, at the low salinity, surfactant prefers the aqueous phase, forming oil-in-water microemulsion, in equilibrium with excess oil, which promotes the formation of oil-in-water (O/W) emulsions with high interfacial tension and limited stability. The system reaches the Winsor Type III level when the salinity reaches an optimal level, as the system produces a medium-phase microemulsion that provides ultra-low interfacial tension. Under optimal conditions, tiny stable droplets are formed, which provide the best performance for enhanced oil recovery techniques. At a high salinity level, reaching the Winsor Type II level, the surfactant tends to split into two phases, which leads to the formation of water-in-oil (W/O) emulsions, which have increased interfacial and reduced emulsification efficiency (Isaac et al., 2022)

Salinity affects emulsion stability are affected by the ionic strength, surfactants concentration, and interfacial films. The higher salinity compresses the double electric layer at the oil-water interface and promotes the adsorption of surfactants, improving interfacial film, reducing droplet coalescence. (Ling et al., 2018). At the same time, the presence of divalent ions-such as Ca^{2+} and Mg^{2+} -can further alter the interfacial properties by interacting with both surfactant molecules and crude oil components, by improving emulsion stability. Effect of divalent ions are particularly relevant when using natural water sources such as Caspian Sea water, where the ionic complexity could produce more droplets than synthetic NaCl brine.

2.6 Reservoir heterogeneity

Reservoir heterogeneity describes how permeability levels, pore structure and geometry are different in the reservoir. Differences in pore sizes change capillary pressure and resist flow in reservoir, due to the oil trapping. At the large scales, due to the channeling and viscous fingering fluid moves to the high-permeable zone, bypassing significant portion of oil in the heterogeneous reservoirs. (Wang et al., 2024).

The effects of this phenomenon have been proven in several experimental studies with micromodels. A study conducted by (Wang et al., 2024) showed that a higher degree of heterogeneity increases instability of the flow, and alters displacement behavior. The study shown in Figure 17 shows that oil recovery rates depend on two main factors: the number of capillaries and the level of heterogeneity present in the system. Homogeneous group archive highest oil recovery more than 80%, owing to uniform sweep efficiency, while highly heterogeneous systems provide lower oil extraction, less than 60%, due to the channeling and flow bypassing.

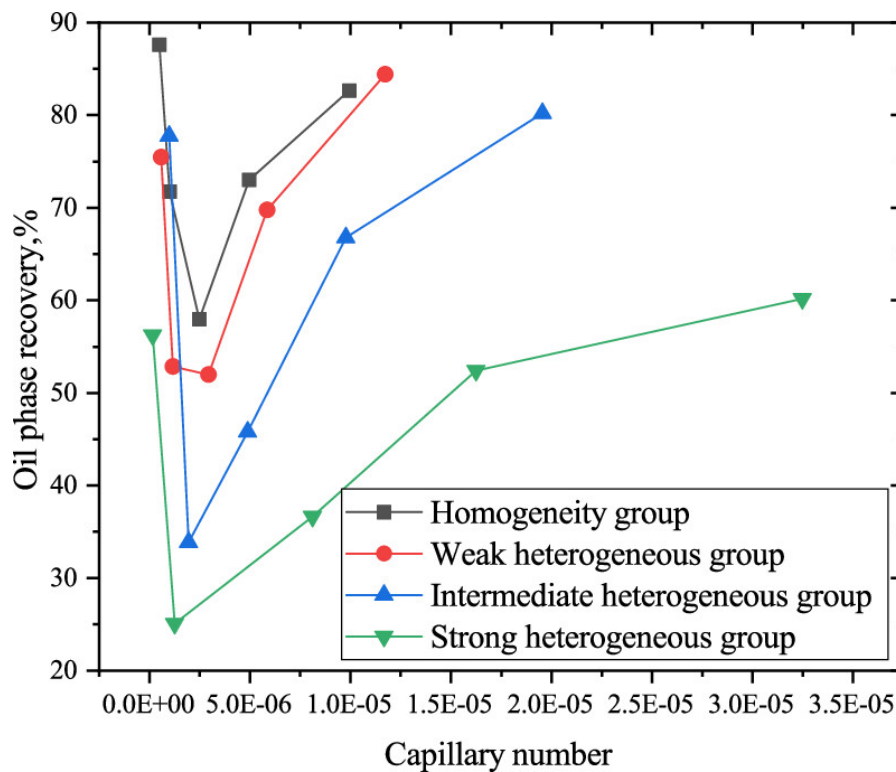


Figure 17. Effect of reservoir heterogeneity on oil recovery as a function of capillary number (Wang et al., 2024).

Increasing capillary number leads to better oil recovery in all systems, by rising viscous forces that help overcome capillary trapping. However, oil recovery and capillary numbers varies depending on the heterogeneity degree. Systems with weak or intermediate heterogeneity show significant recovery improvement when viscous forces take effect, while systems with high heterogeneity show slow recovery progress because their flow distribution remains concentrated in areas with high permeability and limited contact with areas with low permeability(Wang et al., 2024)

The heterogeneity in composition affects the in-situ emulsification at the pore level. The combination of different pore sizes and local velocity gradient generates droplets by promoting snap-off and shear-induced breakup effects. The mechanisms of formation of these systems depend on the specific pore structure and flow conditions (J. Liu et al., 2023).

The heterogeneity of the reservoirs acts as the main element that controls both the fluid displacement and in-situ emulsification in the porous media. The influence of the heterogeneity of the reservoir should be fully taken into account when researchers analyze pore level data and develop surfactant flooding strategy. Micromodel experiments allow to study the interaction of porous structures in controlled environments that simulate real heterogeneous reservoir conditions.

2.7 Micromodel studies

Micromodels are transparent, microfabricated porous media systems that mimic the pore structure and reservoir conditions, enabling to visually see multiphase flow at the pore level. The devices that researchers create using photolithography of glass and silicon materials can be configured to display different pore shapes, types of wettability, and different levels of material distribution (Mejia et al., 2019). The standard micromodel system shown in Figure 18 contains inlet and outlet openings that connect to a two-dimensional porous region that uses pore and grain structures to determine how liquids flow through the system.

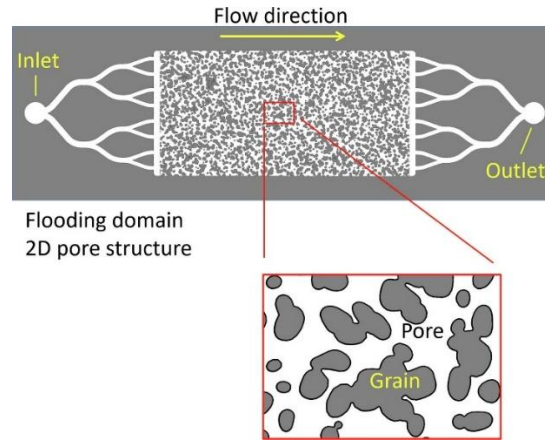


Figure 18. Schematic representation of a micromodel used for pore-scale visualization of multiphase flow (Kharrat et al., 2022).

The main advantage of micromodels over traditional core flooding experiments is the ability to directly observe the mechanisms of pore displacement. Core flooding experiments provide researchers with general extraction results, but do not show microscopic displacement, while micromodels allow researchers to observe capillary trapping, viscous fingering, phase redistribution, and fluid-rock interaction. The visualization possibility of in-situ emulsification during surfactant flooding by micromodel allows researchers understand deeply generation mechanisms of O/W and W/O emulsions through snap-off at pore throats and shear-induced breakup (Zhao et al., 2020).

However, micromodels have some constraints, regarding the design of micromodel. Mostly micromodels are two-dimensional and they cannot replicate three-dimensional natural reservoirs due to complexity of pore geometry, which may give inaccurate assessment of field conditions. Nevertheless, this technology remains one of the most effective tools for studying the EOR processes at the pore level. This equipment allows researchers to capture in-situ emulsification, droplet movement and flow distribution making it ideal for studying oil displacement efficiency under microscopic conditions (L. Liu et al., 2024).

2.8 Research Gap

Current research on surfactant flooding and emulsification through micromodel has been extensively studied. However, researchers conduct their research under simplified conditions that use a single type of oil, synthetic brine, and homogeneous porous media. Specific gaps in research appear as three distinct areas of scarcity.

The effect of oil viscosity on in situ emulsification remains poorly understood. The researchers did not establish a relationship between viscosity and emulsification strength due to the lack of comparative pore-scale studies in which low- and high-viscosity oils were tested under similar experimental conditions. Most studies use synthetic brines that are unable to fully reproduce the ionic composition present in real commercial waters. The specific effect of seawater on the properties of surfactants and emulsions remains unexplored in the Caspian Sea region, as seawater serves as a reliable source for injection. In addition, reservoir heterogeneity effect has not explored yet, as they are conducting tests using micromodels that show different permeability characteristics, demonstrating how the pore structure affects droplet formation, movement, and flow redirection. There is no information in the existing knowledge base on how various injection methods, including combined injection of water with a surfactant and sequential flooding with water and flooding with a surfactant, affect the nature of emulsification and extraction results.

This study addresses these gaps by simultaneously accounting for oil viscosity, water composition, injection strategy, and micromodel heterogeneity within several experiments. High-resolution visualization enables real-time monitoring of the in-situ emulsification process and controlling recovery factor based on the leaving oil after injection in the micromodel.

3. METHODOLOGY

3.1 Materials

The materials used in this study include brines (NaCl solution and Caspian Sea water), 2 oil samples, surfactant solution, food coloring, 2 micromodels, and a camera for imaging. A synthetic NaCl solution at 10,000 ppm, was prepared to represent typical formation water and injection fluid. A natural Caspian Sea water is the second injection fluid, used to examine how more complex divalent ions affect in-situ emulsification and displacement behavior. The Caspian Sea water sample was obtained from the KMG Engineering branch in Aktau, where its ionic composition had been previously analyzed. The full ionic composition is provided in Table 2, which confirms the representativeness of the sample used in the experiments.

Table 3. Ionic Composition of Caspian Sea Water

Parameter	Unit	Caspian Seawater
pH	–	8
Density	g/cm ³	1.009
Calcium (Ca ²⁺)	mg/L	450.9
Magnesium (Mg ²⁺)	mg/L	881.6
Sodium + Potassium (Na ⁺ + K ⁺)	mg/L	2863.8
Chloride (Cl ⁻)	mg/L	5583.4
Sulfate (SO ₄ ²⁻)	mg/L	2979.2
Carbonate (CO ₃ ²⁻)	mg/L	Not detected
Bicarbonate (HCO ₃ ⁻)	mg/L	292.8
Total Dissolved Solids (TDS)	mg/L	13051.7
Water Type (Sulin)	–	Cl–Mg
Total Hardness	mg- eq/L	95.0

Two crude oil samples, designated Sample 1 and Sample 2, were used in the study. Sample 1 has a significantly higher viscosity (about 20 times) than Sample 2, resulting in a significant difference between the two samples. The complete physicochemical properties of both samples are presented in Table 3.

Table 4. Properties of Oil Samples 1 and 2

Property	Unit	Sample 1 (High viscosity)	Sample 2 (Low viscosity)
Density	g/cm ³	0.914	0.891
Dynamic Viscosity	mPa·s	558.58	32.21
Kinematic Viscosity	mm ² /s	611.35	36.15
Temperature	°C	20.0	20.0
API Gravity	°API	22.7	26.5

Sodium dodecyl sulfate (SDS) at a concentration of 0.1 wt% was chosen as the surfactant, as it has been shown to reduce interfacial tension and produce in-situ emulsions. SDS of analytical grade $\geq 99\%$ was used as is, without further purification. Standard laboratory glassware, including 100 mL beakers, was used to prepare the brine and surfactant solutions.

Two glass micromodels were used in the study, shown in Figures 19a and 19b. The first model is a heterogeneous, measuring $7.5 \text{ cm} \times 7.5 \text{ cm}$ with a channel thickness of $150 \text{ }\mu\text{m}$. The second micromodel is also heterogeneous and consists of two distinct permeability zones (low and high permeability regions) measuring approximately $4.5 \text{ cm} \times 8 \text{ cm}$ and $150 \text{ }\mu\text{m}$ thickness, enabling the study of flow patterns in complex and heterogeneous porous media. These micromodels allow the researchers to visualize how fluids move through the small pores.

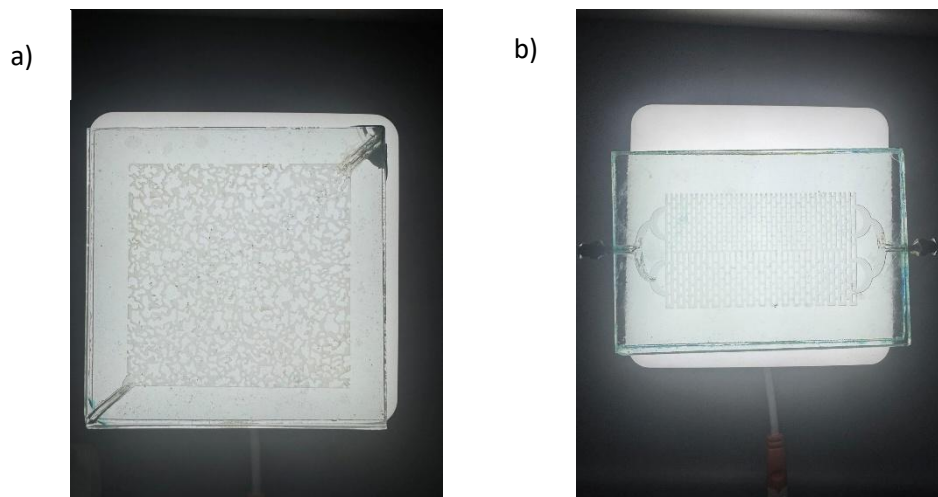


Figure 19 (a-b). Micromodel 1(a) and Micromodel 2 (b)

The fluid was injected using a high-precision syringe pump (KD Scientific, USA), shown in Figure 20, which made it possible to precisely control the flow rate throughout the experiment. The pump was connected to disposable syringes and flexible tubes and supplied liquid directly to the inlet and outlet openings of the micromodel with a consistently low flow rate suitable for pore-scale studies.

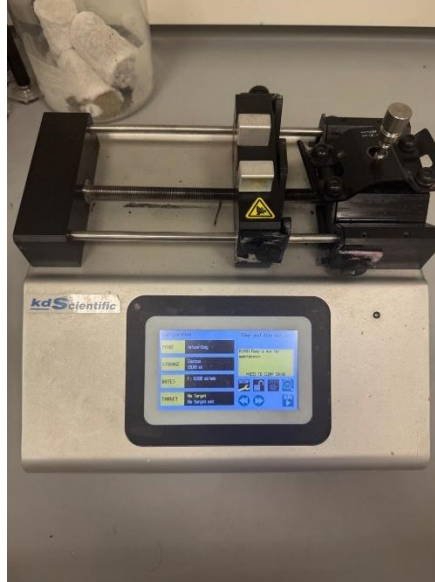


Figure 20. Syringe-pump kdScientific

The movement of the fluid was recorded using a digital camera, as shown in Figure 21, which provided optical visualization of the flow behavior inside the micromodel in real time throughout the experiment.



Figure 21. Digital Camera

3.2 Experimental Setup

Micromodel experiments were conducted to examine pore-scale fluid flow and in-situ emulsion formation. The experimental setup, shown in Figure 22, consisted of three main components: a syringe pump, micromodel, and an optical imaging system.

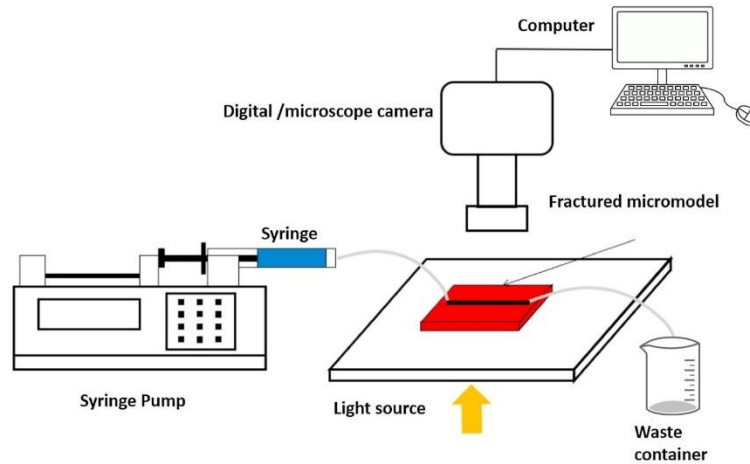


Figure 22. Experimental Set-up

A syringe pump (KD Scientific, USA) controlled the injection of liquid by connecting it to both disposable syringes and a flexible tube. The micromodel received liquid through an inlet, and the outlet was connected to a waste container. Sealed tube connections were used to prevent leaks that occurred during injection. During the experiments, the flow rate remained constant and was $0.002 \text{ cm}^3/\text{min}$. The pressure was not considered, because the objective of this work was to achieve direct visualization of the emulsification process and oil displacement at the pore scale using transparent micromodels, and specialized equipment that could provide accurate measurements of pressure drop at the micromodel scale was not available in our laboratory.

The micromodel was positioned horizontally on a flat support to ensure uniform flow distribution and eliminate the effects of gravity. A backlight was used beneath the micromodel to ensure uniform illumination and enhance the contrast between the liquid phases.

Displacement behavior and emulsion formation were recorded in real time using a high-resolution digital camera mounted above the micromodel. Images were continuously transmitted to a connected computer for monitoring and subsequent analysis.

All experiments were performed in the laboratory at room temperature, approximately 20–25 °C, without active temperature control, in a well-ventilated area to ensure safe handling of the liquid.

3.3 Experimental Procedure

For each experiment, the micromodel was initially saturated with brine (10,000 ppm NaCl) at an injection rate of 0.02 cc/min. The brine solution was prepared by dissolving 4 g of NaCl in 0.4 L of distilled water and mixing using a magnetic stirrer (Figure 23) to ensure complete dissolution and homogeneity.



Figure 23. Magnetic stirrer

Following brine saturation, crude oil was injected at the same flow rate to establish initial oil saturation conditions within the micromodel.

Surfactant/Water flooding was then performed by syringe-pump as a secondary recovery process using either synthetic brine or Caspian Sea water at a reduced injection rate of 0.002 cc/min. This was followed by surfactant flooding (after water flooding) as a tertiary recovery method at the same flow rate. Color of surfactant and water should be changed by food coloring (Figure 24) in order to distinguish present of injector in macroscopic condition.



Figure 24. Food colorings

The surfactant solution (0.1 wt%) was prepared by dissolving 0.04 g of Sodium dodecyl sulfate (SDS) in 40 mL of the prepared brine, followed by mixing to obtain a homogeneous solution.

To evaluate the effect of injection strategy, surfactant solution was injected directly as a secondary recovery method and for comparison, water injected as secondary and surfactant as tertiary recovery methods.

For 2 experiments involving Sample 1 and 2, the same procedure for surfactant as secondary recovery was followed. In addition, Caspian Sea water was used as the secondary injection fluid to investigate the influence of divalent ions on emulsion generation, followed by surfactant flooding as tertiary recovery.

For the second micromodel with dual heterogeneity (low and high), experiments were conducted using Sample 1 due to its higher viscosity and stronger tendency to form emulsions. Same procedure with surfactant as secondary recovery, but for the second injection strategy Synthetic NaCl 10000 ppm was applied as secondary recovery, followed by surfactant flooding as tertiary recovery.

During each experiment, fluids were injected continuously, and displacement processes, flow patterns, and emulsion formation were monitored and recorded in real time. Images were to observe how fluid distribution changed within the micromodel at specific time

intervals. During secondary injection, images were captured at 1, 5, 10, 30, 60, and 120 minutes, and during tertiary surfactant injection, images were captured at 120, 121, 127, 150, 180, and 240 minutes. The recorded images were processed in MATLAB to determine porosity and oil saturation (S_o).

A combination of manual and automated methods was used in the image processing process in the MATLAB. Grayscale conversion and filtering was applied to take original images as the first step in image preprocessing to improve contrast. First of all, the RGB (Red, Green, Blue) graphics application and threshold values were used, to divide each image into three separate parts, which included components of oil, water, and a solid matrix. Thresholds were set to control pixel intensity ranges and analyze all the images within each experiment. Porosity was calculated by dividing the number of pore pixels to the total number of image pixels, which included all areas of the solid matrix. Oil saturation was defined as the ratio of the number of pixels containing the oil phase to the total number of pixels in the pore space. Dimensions of the micromodel were known to determine the scale of the image, while manual verification showed correct phase identification in areas with low contrast and overlapping color intensity.

The uncertainty of saturation values emerges from three factors which include image resolution and illumination changes and threshold selection. The oil saturation measurements have an estimated uncertainty of ± 3 to 5% based on multiple tests and sensitivity assessments. The method delivers dependable quantitative fluid distribution data which can be used for comparison throughout all tests.

The analysis began with a plot of oil saturation (S_o) against injection time to assess the efficiency of the injection fluid. Recovery performance was evaluated through the recovery factor (RF) plot which showed the relationship between recovery factor and injected pore volume (PV). The recovery factor was calculated using the expression: $RF = (S_{oi} - S_o)/S_{oi}$, where S_{oi} is the initial oil saturation and S_o is the oil saturation at a given time. The injected pore volume was determined from $PV = (q \times t)/V_{bulk}$, where q is the injection rate and t is the injection time. The bulk pore volume of the micromodel was calculated based on its geometrical properties and porosity using $V_{bulk} = h \times w \times thickness \times \phi$ where h , w , and $thickness$ represent the micromodel dimensions and ϕ is the porosity obtained from MATLAB image analysis.

The properties of the micromodels used in different tests are summarized as follows. For Test 1, the micromodel dimensions were $h=7.5=7.5=7.5$ cm, $w=7.5=7.5=7.5$ cm, thickness = 150 μm , with a porosity of 0.4985, resulting in a bulk volume of 0.42 cc, and an injection rate of 0.002 cc/min. For Test 2, the micromodel had the same dimensions ($h=7.5=7.5=7.5$ cm, $w=7.5=7.5=7.5$ cm, thickness = 150 μm), with a porosity of 0.4648 and a bulk volume of 0.39 cc, while the injection rate remained 0.002 cc/min. For Test 3, a different micromodel geometry was used with $h=4.5=4.5=4.5$ cm, $w=8=8=8$ cm, thickness = 150 μm , and porosity of 0.4560, resulting in a bulk volume of 0.24624 cc, with the same injection rate of 0.002 cc/min.

3.4 Experimental Design

A series of experiments were designed to evaluate the effects of oil viscosity, injection strategy, water composition, and porous media heterogeneity on emulsion formation and oil displacement efficiency.

The experimental variables include:

1. Oil type (Sample 1 vs Sample 2)
2. Injection strategy (surfactant vs water + surfactant)
3. Water composition (NaCl brine vs Caspian Sea water)
4. Micromodel heterogeneity (Micromodel 1 vs Micromodel 2)

3.5 Measurement and Analysis

Results of the experiment were analyzed by using two methods, which included qualitative pore-scale studies and quantitative image analysis methods. Full information on image processing methods and procedures for calculating oil saturation (S_o), extraction coefficient (RF) and volume of injected pores (PV) is provided in Section 3.3.

Qualitative analysis studies the patterns of micromodel displacement, flow behavior, and in-situ emulsion formation, assessing the uniformity of the flow and the distribution of liquid across sites with different levels of permeability. The assessment of emulsion formation was based on three criteria, which included droplet generation, distribution, and time of stability. The O/W emulsions are dispersed oil droplets that exist in the aqueous phase, while

the oil emulsions show water droplets that exist in the W/O phase. The emulsions reached a stable state when their droplets retained their original shape, which led to their continuous dispersed state. The emulsions became unstable due to rapid coalescence, which led to a change in the shape of the droplets or their reattachment to the pore walls.

Quantitative analysis measures trends in oil saturation (S_o vs injection time) and recovery coefficient (RF vs injection pore volume), which allowed them to evaluate the effectiveness of displacement in various experiments. The process of general analysis is used to combine numerical results with a visual assessment of the mechanisms of displacement. The main source of errors in measuring oil saturation is image segmentation and lighting conditions, which, according to Section 3.3, are estimated at $\pm 3\text{-}5\%$.

The experimental design test only one specific variable at a time. The secondary and tertiary methods differ in that the injection sequence determines their functions: the surfactant flooding as secondary recovery is used to displace initial oil, while the surfactant flooding as tertiary recovery is used after water flooding to extract the remaining oil reserves. Test 1 examines the effect of the injection strategy of Caspian Sea water as secondary recovery on low-viscosity oil (Sample 2), Test 2 evaluates a similar effect for higher-viscosity oil (sample 1), and Test 3 examines the effect of complex heterogeneity and synthetic NaCl brine using a double permeability micromodel. Oil Sample 1 was selected for Test 3 because higher viscosity makes it more suitable for emulsification, which helps researchers control pore-scale emulsification processes under difficult flow conditions.

Table 5. Summary of Experimental Conditions

Test	Oil	Brine	Injection strategy	Micromodel model	Objective
T ₁	Sample 2	Caspian Sea	Surfactant injection	Model 1	To evaluate low-viscosity oil displacement using Caspian Sea water in a heterogeneous micromodel.
			Water flooding+ Surfactant injection		
T ₂	Sample 1	Caspian Sea	Surfactant injection	Model 1	To study high-viscosity oil displacement using Caspian Sea water under heterogeneous conditions.
			Water flooding+ Surfactant injection		
T ₃	Sample 1	NaCl	Surfactant injection	Model 2	To assess high-viscosity oil displacement using NaCl brine in a complex heterogeneous micromodel.

3.6 Data Processing and Preliminary Tests

Several preliminary testing and experiments with both oil samples were conducted before starting the main experiments. Pilot tests were need to determine the best experimental conditions, pipe connections, image pre-processing and fixed flow rate because higher flow rate lead to system failures and micromodel leaks.

Pilot tests show that the image acquisition and processing successfully reflect the patterns of oil saturation and displacement. The full image processing procedure is described in detail in Section 3.3, which does not need to be repeated here. These initial steps were designed to

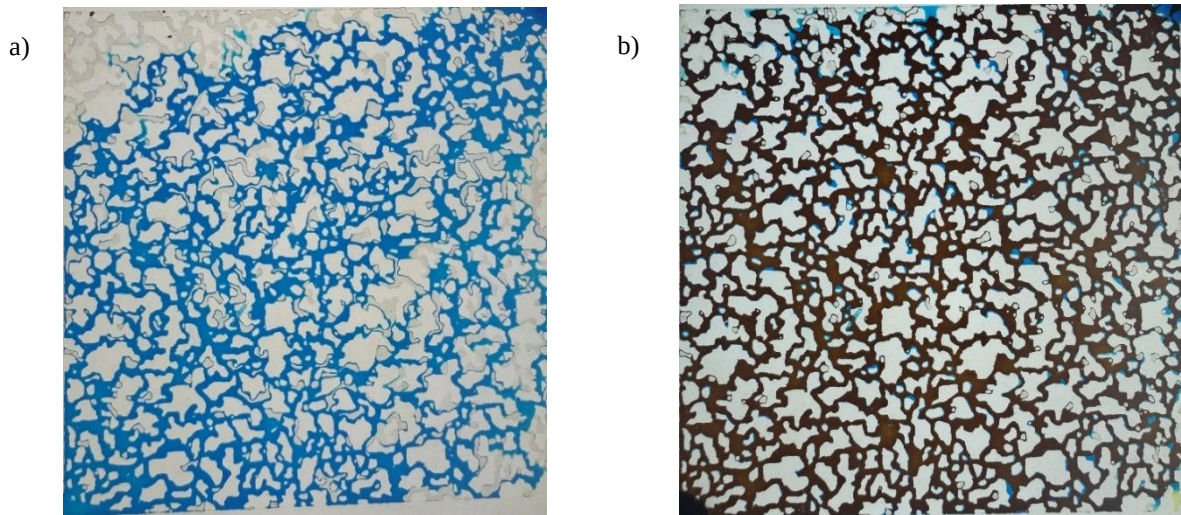
create best testing conditions that could be accurately replicated during the main testing process.

4. RESULTS

4.1 Micromodel Saturation with Oil Sample 2

4.1.1 Macroscopic Saturation Behavior

The micromodel was initially saturated with NaCl 1000 ppm brine (blue) at 0.1 cc/min to simulate formation conditions, then oil was injected at same rate to mimic reservoir conditions. As shown in Figures 25 (a-b), water reached breakthrough at approximately 3 min and could not fully displace the air initially present within the micromodel, however oil saturation of micromodel took about 5 mins and displaced all air inside of micromodel after water flooding.



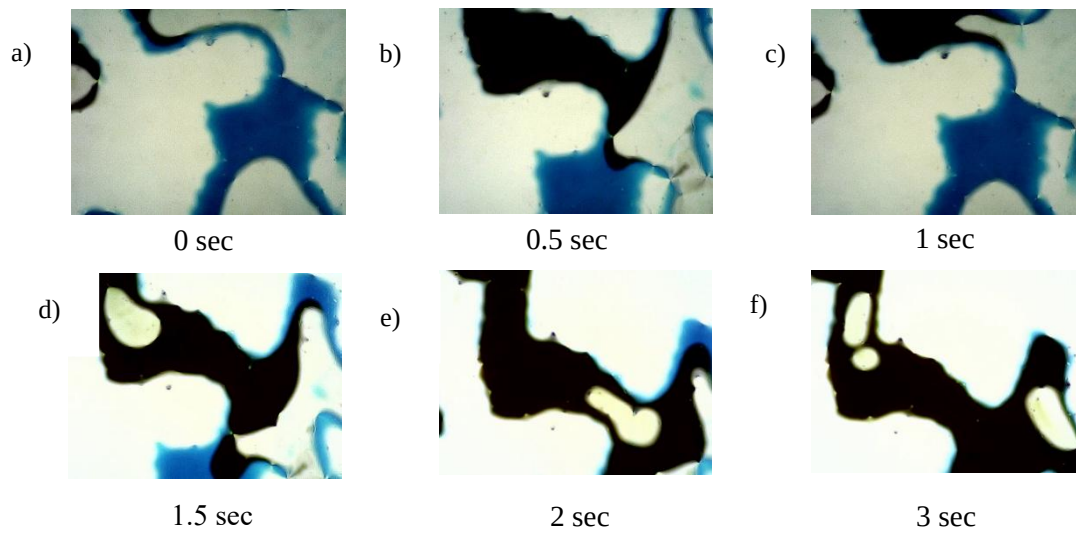
Figures 25 (a-b). Saturated Micromodel by water (a) and oil (b)

The high mobility of water, which caused preferential flow and left some air trapped within the pore network of micromodel. Subsequent oil injection proved more effective, displacing the remaining air and filling both large pores and smaller pore throats. By the end of oil injection, a nearly fully oil-water saturated condition was achieved within the micromodel.

4.1.2 Pore-Scale Behavior of Saturation

The Figures 26 (a-f) show a microscopic analysis of the displacement of air by oil during injection. Air fills the pore spaces of the irregularly shaped material, but remains in the

corners of the pores due to capillary forces. The oil injection process begins when oil enters the pore system and uses capillary forces to displace trapped air.



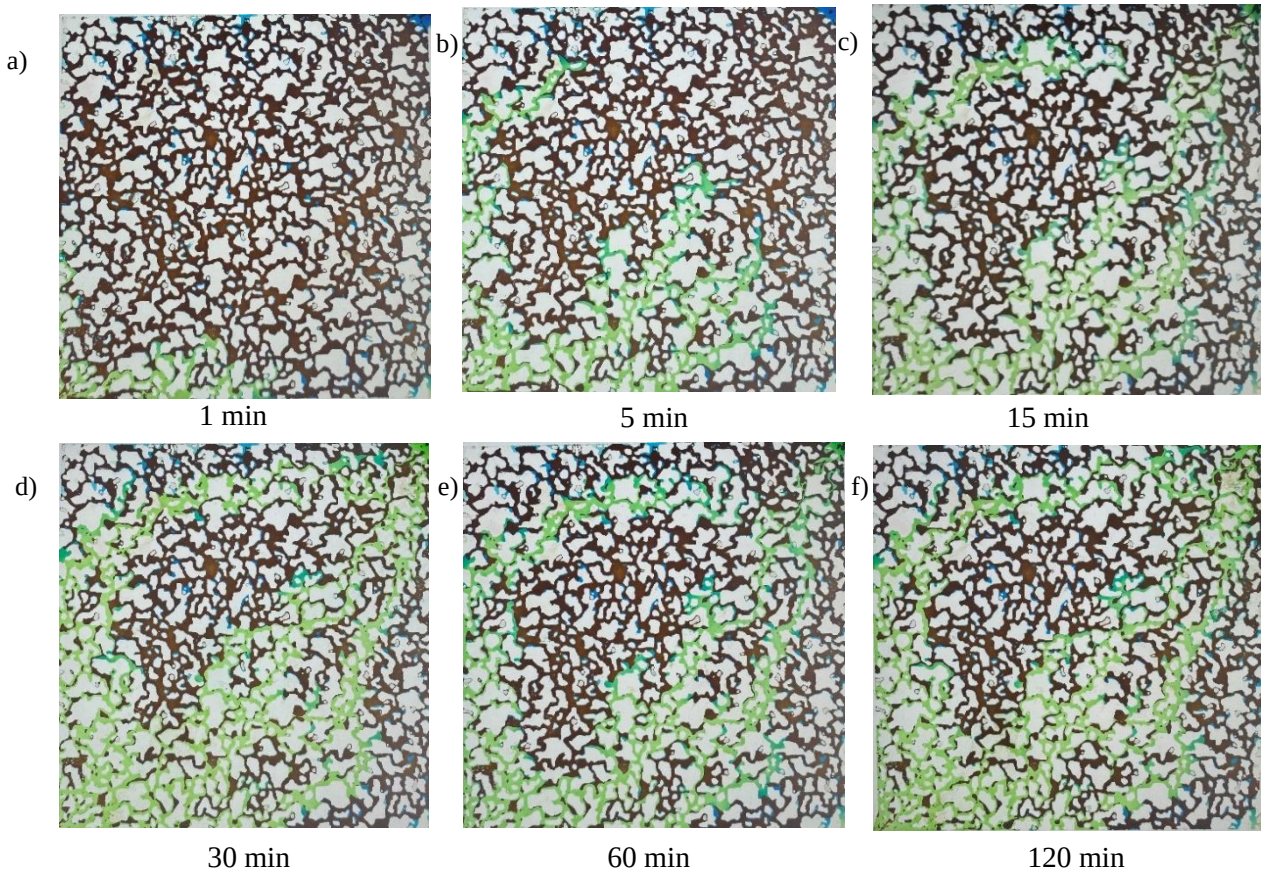
Figures 26 (a-f). Pore-Scale Analysis of air displacement

The oil passes through narrow openings in the pore system, after which it spreads along the walls due to its strong attraction to a hard surface. The isolated air bubbles present in the system lose volume until they disappear completely as the oil passes through the entire pore structure. The oil phase forms compounds throughout the micromodel that create the necessary initial saturation conditions for upcoming flooding experiments.

4.2 Test 1: Surfactant Flooding as Secondary Recovery

4.2.1 Macroscopic Displacement

Figures 27 (a-f) show the changes in fluid distribution that occur after secondary flooding constant flow rate $0.002 \text{ cm}^3/\text{min}$. Images were taken at multiple time intervals, including 1, 5, 15, 30, 60 and 120 minutes, to observe the progress of macroscopic displacement.



Figures 27 (a-f). Macroscopic displacement during surfactant flooding as secondary recovery with oil sample 2

During the initial injection period, which lasts from 1 to 5 minutes, the surfactant begins to penetrate the pore network, moving along the preferred flow paths that exist due to the heterogeneity of the micromodel. The front of the surfactant reaches the outlet after 15 minutes, which means the beginning of a breakthrough. The remaining oil is present in significant quantities, as it remains in areas with low permeability and in the corners of the pores.

Oil production continued from 15 to 60 minutes, as the surfactant retains its oil extraction functions by reducing interfacial tension and creating an emulsion.

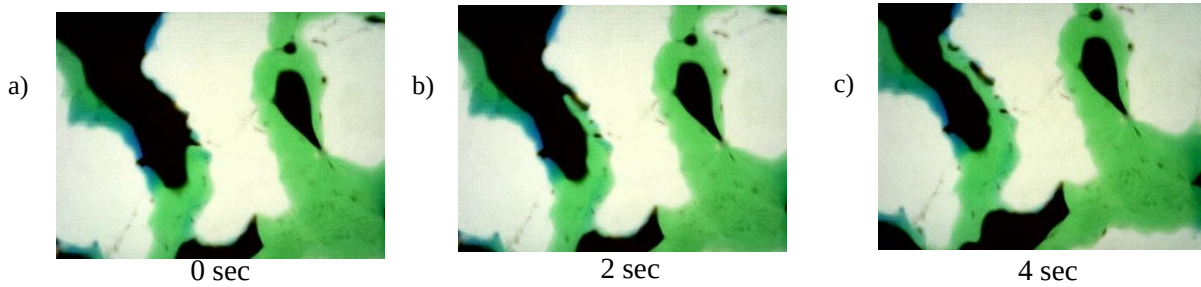
The period between 60- and 120-minutes results in minimal changes in the distribution of fluids in the system. There is only a small additional displacement of oil, which indicates that the system is approaching residual oil saturation. The 60-minute and 120-minute images show similar results, as most of the recoverable oil has already been extracted.

The test results show that the method of direct injection of a surfactant requires mandatory rinsing with water, since it does not allow to increase the efficiency of macroscopic

cleaning due to this process. The injected liquid mainly passes through the existing preferred channels, leaving significant areas of the micromodel unswept.

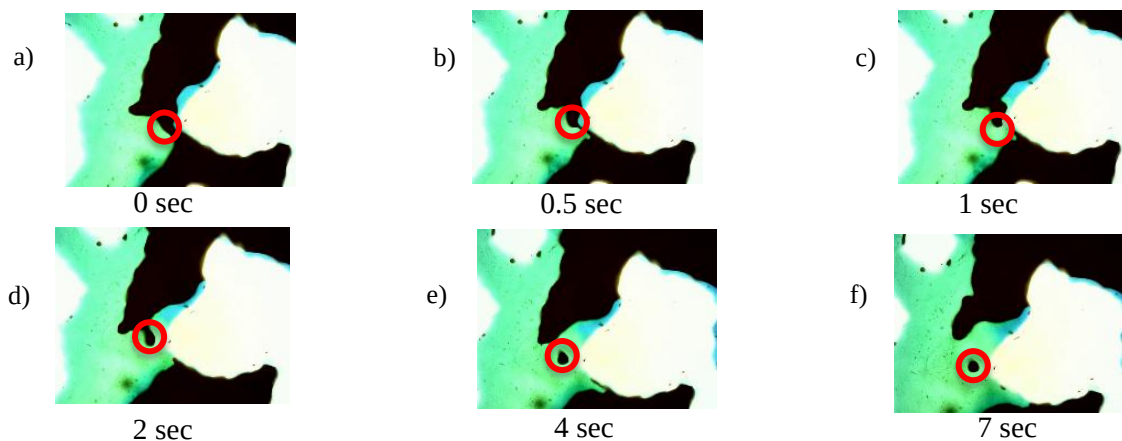
4.2.2 Pore-Scale Behavior

Pore-scale images show the mechanisms of the oil mobilization when surfactants are injected. Figures 28 (a-c) demonstrate 2 main processes surfactant invasion and oil breakdown by surfactant mobilization.



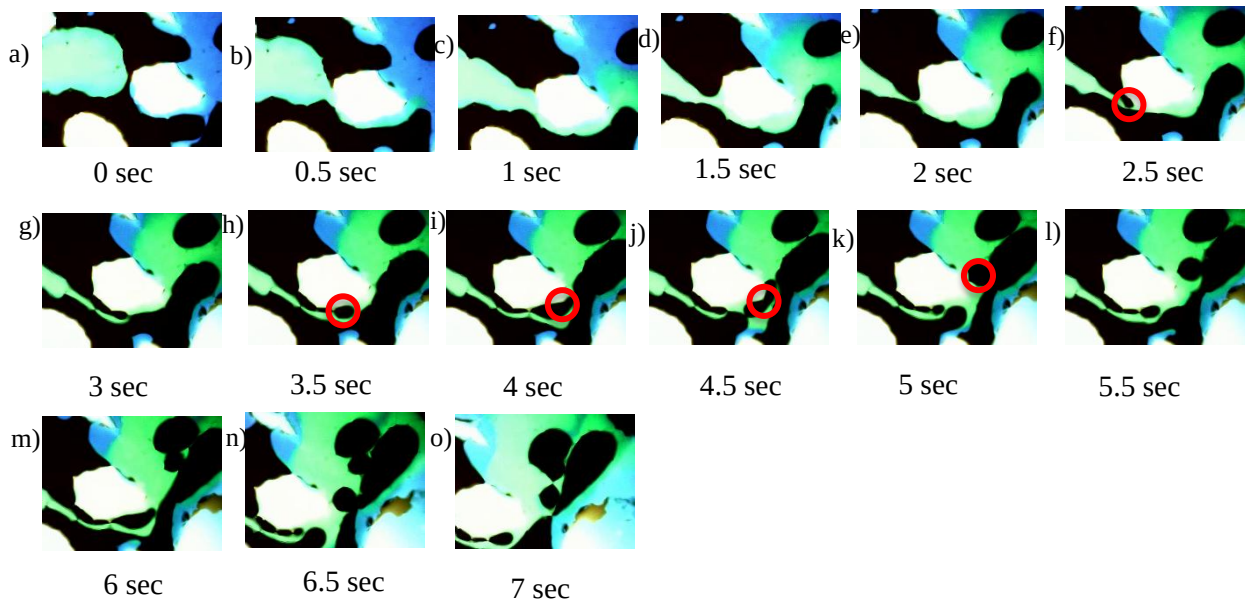
Figures 28 (a-c). Microscopic displacement during surfactant flooding as secondary recovery.

In Figures 28 (a-c), injected surfactant solution (green) passes through the pore space and comes into contact with oil (black). The process of liquid displacement occurs in two ways: it moves along the walls of the pores and passes through the pore throats in accordance with the capillary flow. The surfactant's front deforms the oil phase, which separates from solid surfaces, since SDS adsorption reduces the IFT at the oil-water interface.



Figures 29 (a-f). Oil ganglia separation into droplet during surfactant flooding as secondary recovery.

The emulsified droplets are shown in Figures 29 (a-f). Oil broke up into small W/O droplets, and temporarily stabilized by a surfactant to ensure their passage through narrow pores to the outlet.



Figures 30 (a-o). Transition of oil droplets during secondary recovery

The oil phase continuously transforms into oil films and ends with the formation of individual oil droplets, as shown in Figures 30 (a-o). The aqueous phase carries isolated droplets formed from destabilizing thin oil films, which turn into individual droplets. The system of narrow pores facilitates the movement of droplets, as this reduces the resistance of the capillaries.

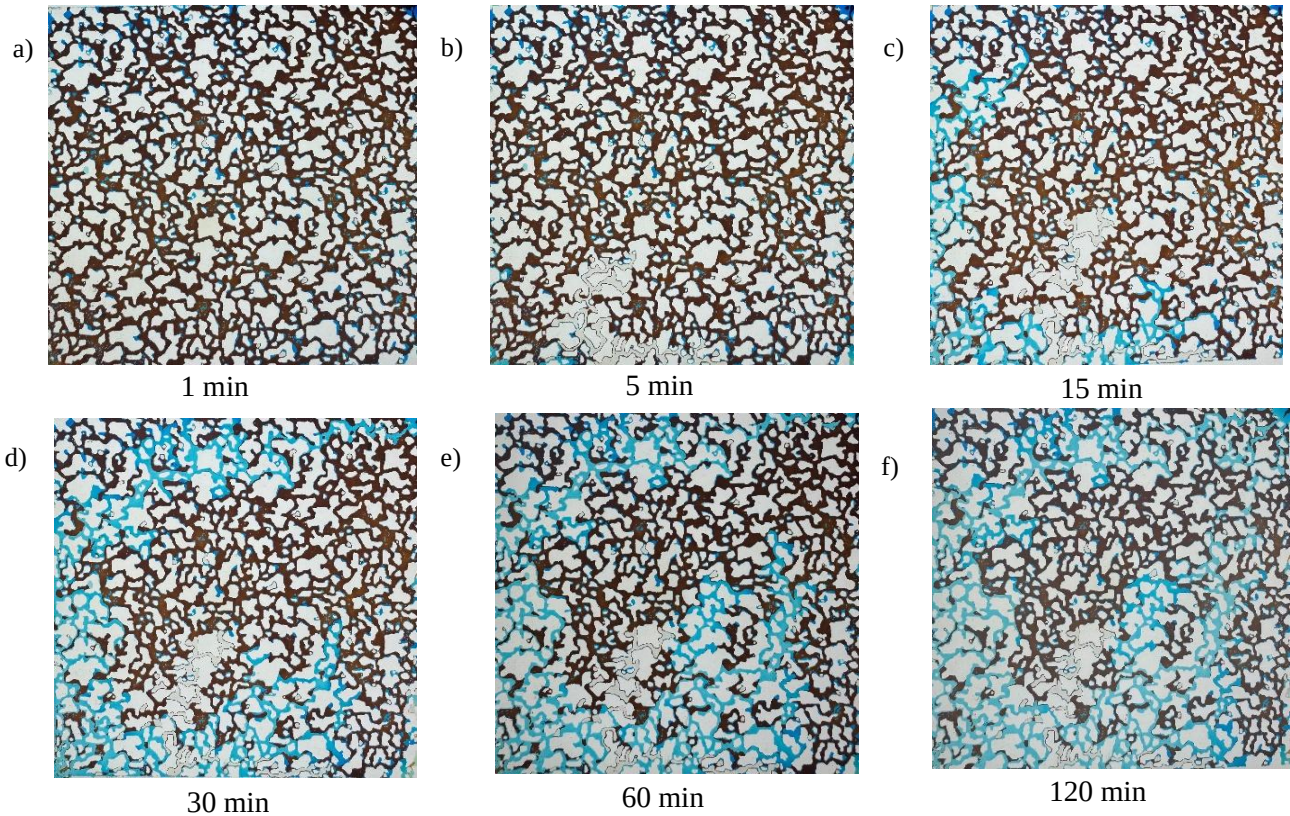
The films of surfactants visible around the oil droplets show that the pore walls now have improved wettability, which helps to separate the oil and move the droplets towards the outlet.

Improving the pore level has not completely solved the problem, as some oil still remains in the corners of the pores and dead ends. The surfactant injection increases displacement efficiency at the microscopic level, but this method does not allow to increase the overall displacement efficiency, since the direction occurs through channels with high permeability, which could not produce the residual oil zones of the micromodel.

4.3 Test 1: Caspian Sea and Surfactant flooding

4.3.1 Macroscopic Displacement of Caspian Sea flooding as secondary recovery

Figures 31 (a-f) show how the fluid distribution changes when water from the Caspian Sea at a flow rate of $0.002 \text{ cm}^3/\text{min}$ is injected. The images correspond to the upload time equal to 1, 5, 15, 30, 60, and 120 minutes.



Figures 31 (a-f). Macroscopic displacement during Caspian Sea flooding as secondary recovery

During the first (1-5) minutes after the start of water injection, the Caspian Sea water moves easily along the micromodel. The displacement front is non-uniform because of the surface heterogeneous structure that creates channeling.

Water passes through areas with high permeability after 15-30 minutes, forming distinct structures similar to fingers. The ratio of the mobility of water and oil creates unfavorable conditions that lead to premature breakthrough of the system, while providing ineffective coating.

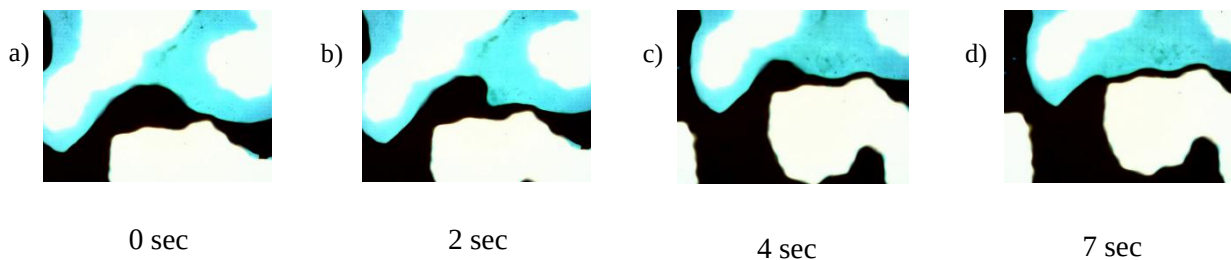
The injected water reaches the outlet after 30 minutes, which indicates that a breakthrough has occurred.

The water supply system operates through the same channels for 30-60 minutes and enters uncovered areas. Due to the heterogeneity of micromodel, oil movement during the process is minimal.

The system reaches maximum stability after 120 minutes, which makes further injection actions useless for oil changes. The remaining oil remains in place due to the capillary forces, requiring tertiary recovery to produce residual oil.

4.3.2 Pore-Scale Behavior of Caspian Sea flooding as secondary recovery

Pore-scale images provide a better understanding of the mechanisms of displacement during flooding. The injected water moves through the pore network, displacing the oil phase, while maintaining its structural appearance, as shown in Figures 32 (a-d).

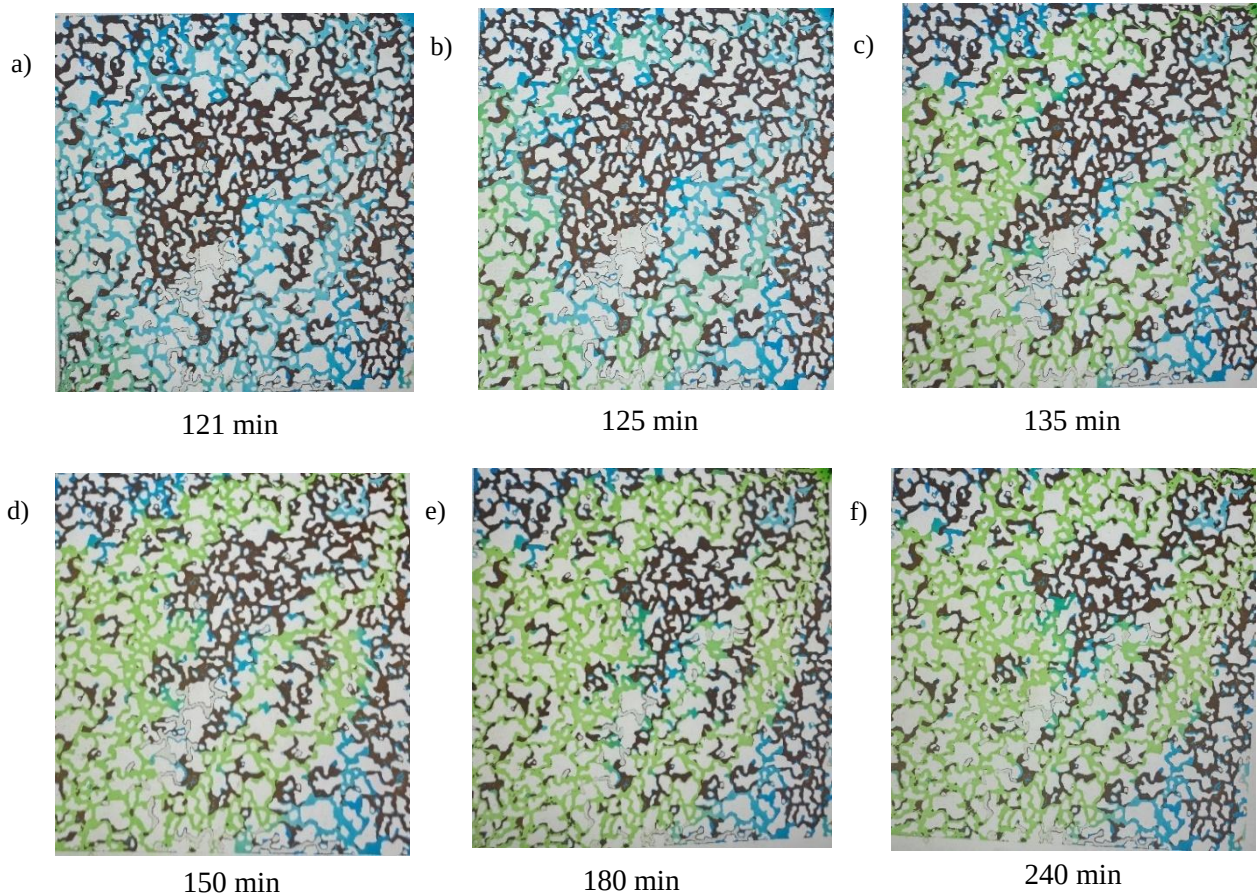


Figures 32 (a-d). Oil Displacement by Caspian Sea

The Caspian Sea water injection does not form visible droplets or emulsification; however, oil phase was pushing by water. The water-oil interface looks smooth, indicating low interfacial activity. Strong capillary retention occurs due to the fact that the interfacial tension remains unchanged, which prevents the movement of oil residues.

4.3.3 Macroscopic Displacement of Surfactant flooding as tertiary recovery

The distribution of the surfactant injection during tertiary recovery after injection of water, is shown in Figures 33 (a-f). The injection system maintained a constant flow rate of $0.002 \text{ cm}^3/\text{min}$, while the recorded images showed different times, including 121, 125, 135, 150, 180, and 240 minutes.



Figures 33 (a-f). Macroscopic displacement during Surfactant flooding as tertiary recovery. (Green - surfactant, blue – Caspian Sea water, brown - oil)

The surfactant enters to the micromodel during the injection process in the initial period, from 121 to 125 minutes. The initial stage of injection of the surfactant provides a more uniform displacement compared to the secondary injection of the surfactant.

Within 135-150 minutes, the surfactant penetrates deeper into both those areas that have been displaced and those that remain intact. The displacement front forms a more uniform pattern, which is less active when applied with fingers compared to water application. This result shows that the system provides better flow distribution, which allows for more effective mobility control.

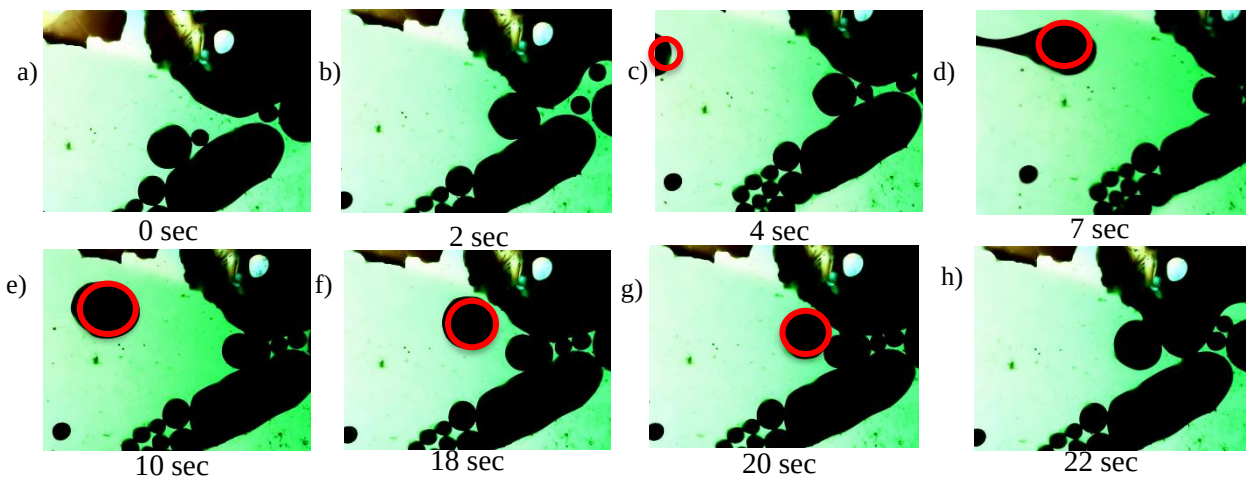
The surfactant reached the outlet after 150 minutes. In the second case, the results are different, since greater contact with the surface of the micromodel leads to better overall movement.

The oil flow continues to spread over a larger area, from 150 to 180 minutes. The surfactant penetrates into previously inaccessible areas, as the flow distribution and pore formation effect are improved.

A time period of 180 to 240 minutes ensures an even distribution of displacement, while the level of residual oil is reduced to a higher level than during water flooding and injection of secondary surfactant. The system has become a more effective method of displacement.

4.3.4 Pore-Scale Behavior of Surfactant flooding as tertiary recovery

Pore images clearly demonstrate enhanced oil mobilization during surfactant injection as a tertiary recovery method. As shown in Figures 34 (a–h), a large oil droplet separates from the continuous oil phase and is transported within the aqueous phase flow.



Figures 34 (a-h). Oil Displacement by Surfactant as tertiary recovery

This detachment occurs due to a reduction in IFT caused by sodium dodecyl sulfate, which weakens the adhesion between the oil and the solid surface. As a result, the oil structure becomes unstable and breaks up into smaller, discrete droplets.

Then the separated droplet moves through the porous network and directly contributes to the production of oil. The movement of the droplets helps to displace the surrounding oil, while pushing excess oil towards the outlet. The demonstration shows how droplet mobilization and improved displacement work together to create a common effect.

The images also show that oil now exists as individual droplets of different sizes, rather than as solid aggregates. The study shows a better displacement efficiency at the microscopic level due to flooding and the introduction of a secondary surfactant compared to both methods.

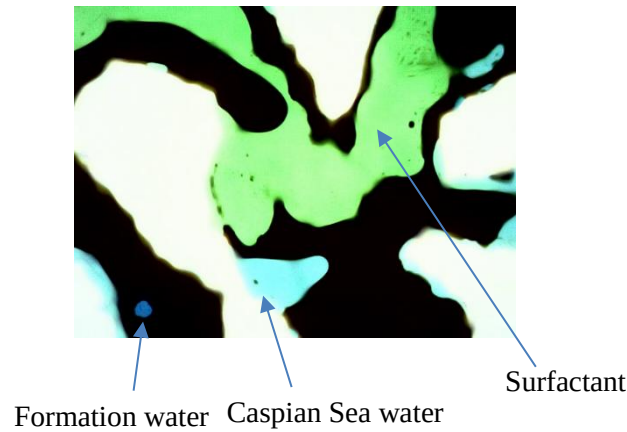


Figure 35. Visualization of fluid phases in the micromodel using color differentiation

For clarity, Figure 35 uses colors to differentiate the different liquids: the surfactant solution is shown in green, the oil phase in black, the Caspian Sea water in light blue, and the formation water in a darker blue.

Quantitative Analysis and Comparison (Test 1)

The change in oil saturation (S_o) over injection time for various injection methods is shown in Table 5. The surfactant injection as secondary recovery, achieves a 0.6208 reduction in oil saturation, while water injection as secondary recovery reached 0.64. Differences in 2 secondary methods are insignificant due to the low viscosity of the Oil Sample 2.

According to the results of Test 1, surfactant flooding as tertiary recovery after water injection led to a significant decrease in oil saturation, producing remaining oil and reached the lowest S_o about 0.46.

Table 6. (Oil Saturation vs Time for Test 1)

Test 1	Surfactant secondary	Water secondary	Surfactant tertiary
Time	So	So	So
0	0.98	0.98	-
1	0.92	0.93	-
5	0.78	0.81	-
30	0.70	0.78	-
60	0.65	0.70	-
120	0.62	0.64	0.64
121	-	-	0.60
125	-	-	0.58
135	-	-	0.57
150	-	-	0.56
180	-	-	0.49
240	-	-	0.46

Table 6 shows the recovery factor (RF) versus injected pore volume (PV) of different injection methods. The surfactant flooding as secondary recovery has shown that injection of a surfactant yields better displacement results due to higher RF values. Water injection showed a slower and more gradual increase in RF, suggesting a limited ability to mobilize trapped oil. When a surfactant was injected after water injection (tertiary recovery), a clear increase in recovery was observed, especially at larger pore volumes. This demonstrates that the surfactant can effectively recover additional oil remaining after water injection. Overall, the results highlight the advantage of surfactant injection, particularly when used as a tertiary recovery method.

Table 7. RF vs PV injected for Test 1

PV injected	RF ₁ (surfactant secondary)	RF ₂ (water secondary)	RF ₃ (surfactant tertiary)
0.004	0.054	0.049	-
0.033	0.200	0.169	-
0.071	0.261	0.209	-
0.142	0.290	0.205	-
0.285	0.331	0.286	-
0.570	0.367	0.345	-
0.575	-	-	0.387
0.594	-	-	0.399
0.575	-	-	0.387
0.604	-	-	0.399
0.713	-	-	0.430
0.855	-	-	0.502
1.141	-	-	0.529

Figure 36 demonstrates the changes in oil saturation (S_o) through injection time which three different injection methods: surfactant injection as secondary recovery, water flooding, and surfactant injection following water flooding for tertiary recovery.

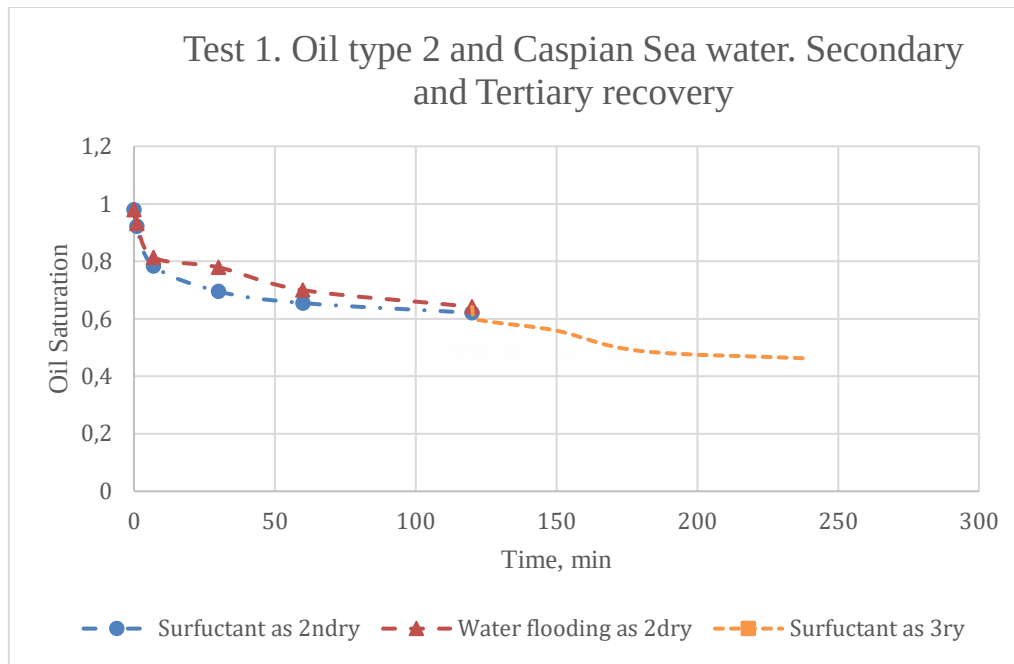


Figure 36. Oil saturation vs time for Test 1

The initial oil saturation was approximately 0.98 in all cases. During secondary recovery, both injection methods (water and surfactant) rapidly reduced oil saturation during the initial period. Waterflooding showed higher oil saturation than surfactant flooding, which showed lower displacement efficiency. Oil saturation for surfactant flooding as secondary decreased to approximately 0.62 after 120 minutes, while waterflooding reached 0.6419, demonstrating the superiority of surfactant injection over water in oil mobilization. During tertiary recovery, surfactant injection after water flooding resulted in a reduction in oil saturation from 0.64 to approximately 0.46. The additional oil recovery was due to both greater displacement efficiency and improved microscopic displacement.

The graph in Figure 37 shows the recovery factor (RF) against injection pore volume (PV), at varies depending on different injection methods.

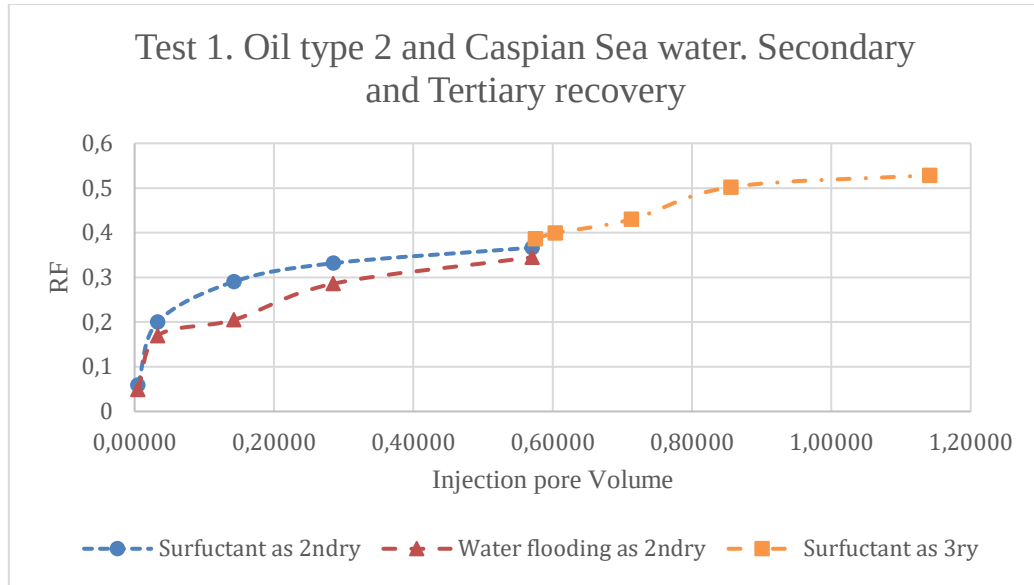


Figure 37. RF vs Injected Pore Volume for Test 1

During surfactant flooding as secondary recovery, recovery factor reaches 0.37 at 0.57 PV injection, while water flooding reaches 0.34 at same injection pore volume.

The most significant improvement occurs in the tertiary recovery. The RF begins to increase after switching to the injection of surfactants, which shows a jump from 0.35 to 0.52 with the 1.14 injection PV. The results show that tertiary surfactant flooding achieves highest recovery among other injection methods.

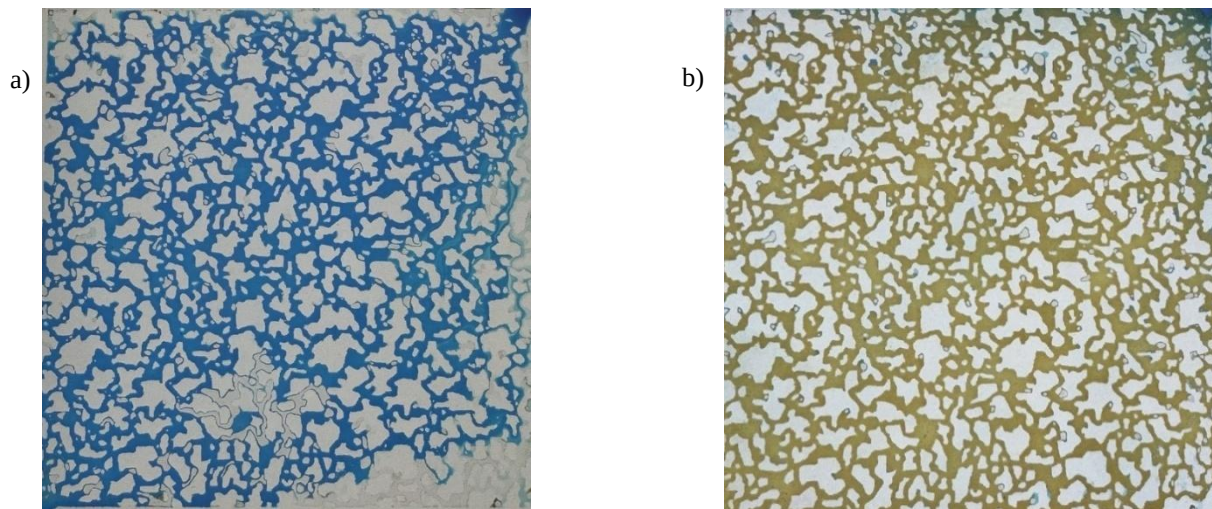
The combination of water flooding and surfactant injection shows better results when comparing oil saturation and recovery rate. Surfactant flooding is a secondary method that enhances microscopic displacement by reducing IFT, but its effectiveness is limited due to early breakthrough. Flooding with water provides better macroscopic cleaning results, but does not allow efficient movement of trapped oil at the pore level.

The tertiary method combines the positive features of both existing methods. The process uses water flooding to create flow paths that increase cleaning efficiency, before surfactants to improve microscopic displacement through emulsification and droplet mobilization. The combined approach provides the highest recovery rate with the lowest residual oil saturation.

4.4 Micromodel Saturation with High-Viscosity Oil (Sample 1)

4.4.1 Macroscopic Saturation Behavior

Figures 38 (a–b) show the initial saturation of the micromodel with water from the Caspian Sea, followed by the addition of highly viscous crude oil (Sample 1). The micromodel was created with full saturation of water and oil in order to create conditions corresponding to the real behavior of the reservoir. The initial oil saturation was determined by pumping oil into the system at 0.1 cc/min rate.

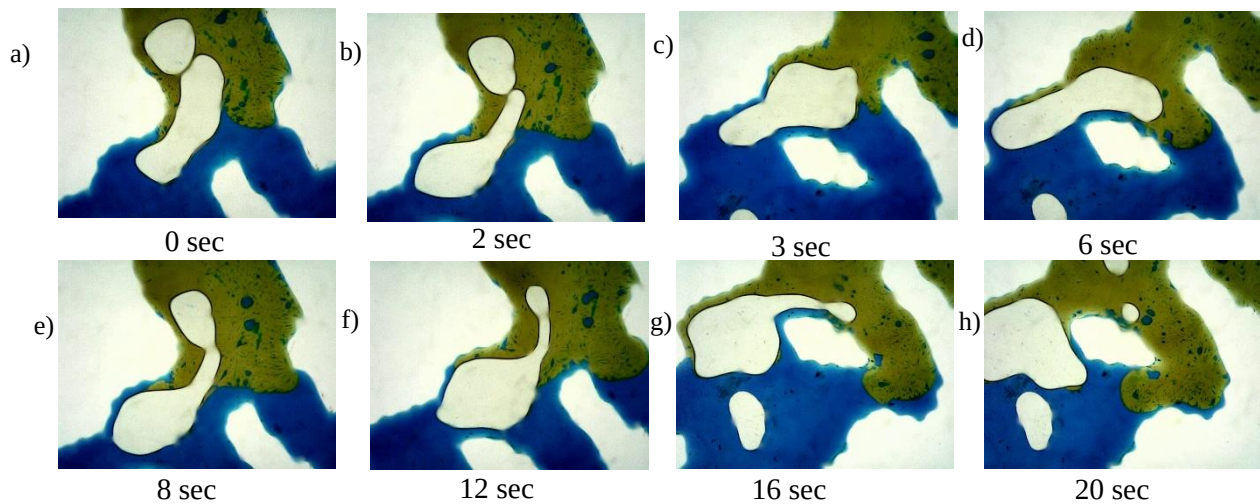


Figures 38 (a-b). Saturation of micromodel by Oil Sample 1.

The saturation process for sample 1 took about 10 minutes longer than for sample 2 with low oil viscosity, since sample 1 had a higher viscosity and slower displacement. The injected yellow oil shows how it displaces water, occupying most of the pore space, creating conditions reminiscent of the initial saturation with oil.

4.4.2 Pore-Scale Behavior

Observations of the pore scale show that highly viscous oil exhibits various patterns of displacement. The injected oil, shown in yellow, in the process shown in Figures 39 (a–h), is the main component that displaces the aqueous phase, shown in blue, from the pore network.



Figures 39 (a-h) Macroscopic displacement during surfactant flooding as secondary recovery with oil sample 2

The oil can penetrate into smaller pores and into areas inaccessible to the water phase. The presence of a higher viscosity causes the displacement front to become more stable, which prevents the formation of a flow structure.

Figure 40 shows the unstable formation of water droplets that occurs in the oil phase. The spreading oil causes the continuous aqueous phase to break up into smaller isolated areas, which leads to the formation of droplets. The presence of these droplets demonstrates that the displacement process is carried out using two separate mechanisms that combine viscous and capillary forces.



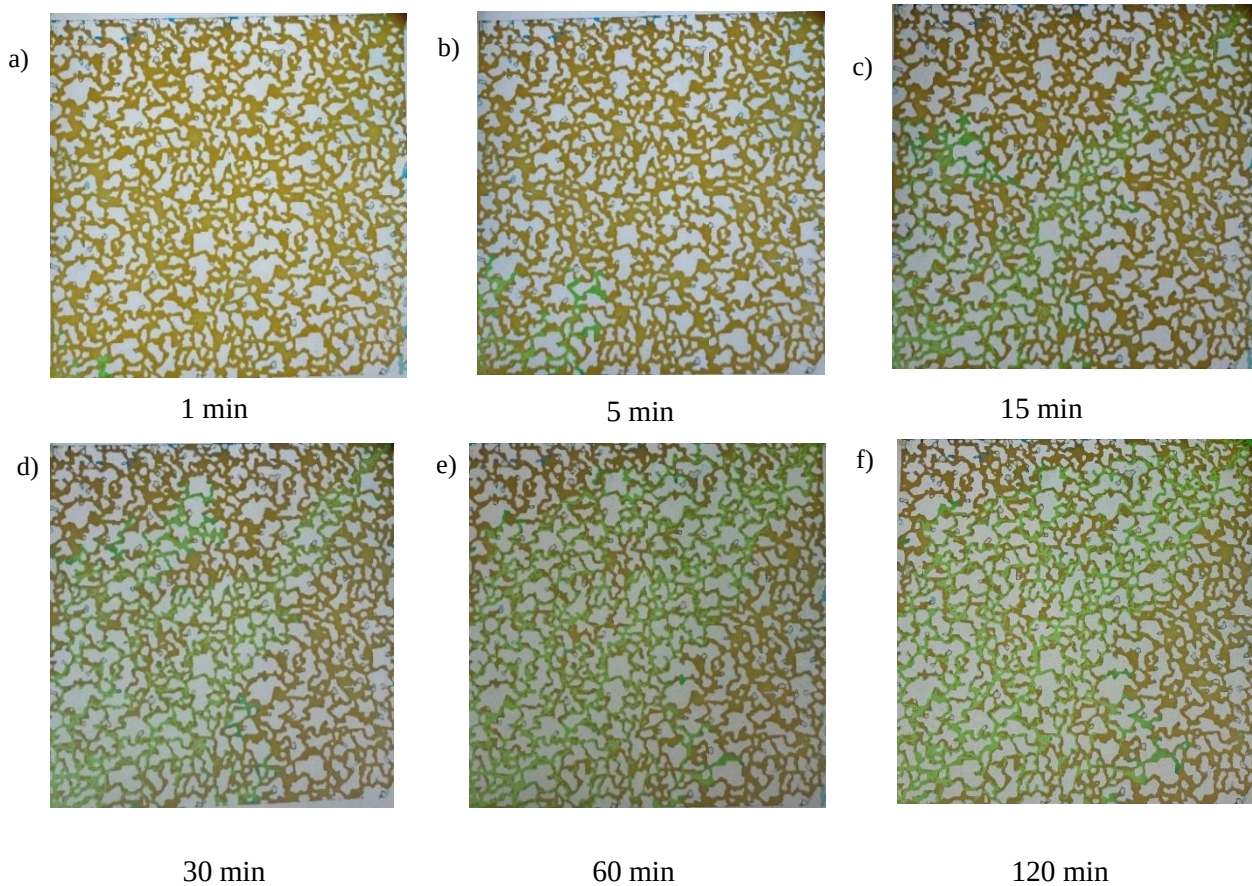
Figure 40. Unstable W/O droplets observation during Sample 1 oil flooding

Overall, high-viscosity oil has a better ability to displace liquid and air from the pores than low-viscosity oil because it can access smaller pores while moving trapped liquids.

4.5 Test 2 Surfactant Flooding as Secondary Recovery

4.5.1 Macroscopic Displacement

The surfactant injection process used for the secondary flooding of high-viscosity oil (Sample 1) shows changes in the distribution of fluid in the time sequence shown in Figures 41 (a–f). The injection occurred at a rate of $0.002 \text{ cm}^3/\text{min}$ for 1, 5, 15, 30, 60, and 120 minutes.



Figures 41 (a-f). Macroscopic displacement during Surfactant flooding as secondary

The injected surfactant begins to penetrate the micromodel during the first 5 minutes of the test and begins to interact with the highly viscous oil. In the case of highly viscous oil, the displacement front moves more evenly because there is less slippage, which is the result of both cases having different mobility coefficients.

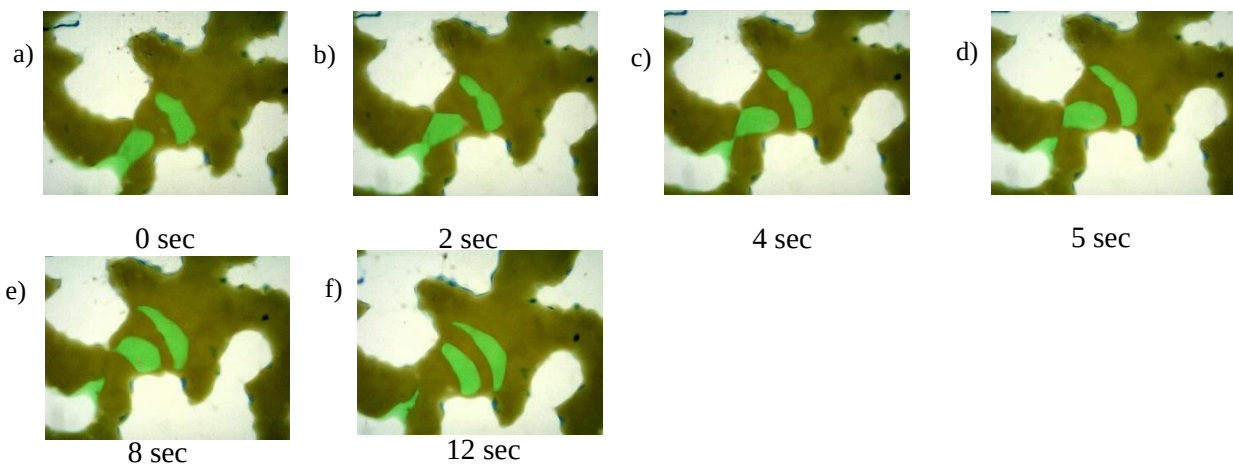
Over a period of 15 to 30 minutes, the surfactant flow moves through the porous media at a more uniform rate. The injected liquid spreads over all parts of the micromodel, while the distribution occurs at a lower level than when estimating low viscosity.

The surfactant front reaches the outlet after 30 minutes of testing, but the breakthrough through sample 2 shows a lower intensity than expected. The displacement distribution remains more uniform, which indicates that better performance has been achieved in the process in terms of macro-displacement.

For 30-60 minutes, the oil continues to be displaced over a large area. The surfactant interacts with viscous oil, which leads to improved oil mobilization and reduced oil leakage. The period from 60 to 120 minutes shows that oil displacement becomes more uniform and leads to a noticeable decrease in oil saturation. The displacement efficiency increases with high viscosity because the displacement front is more stable.

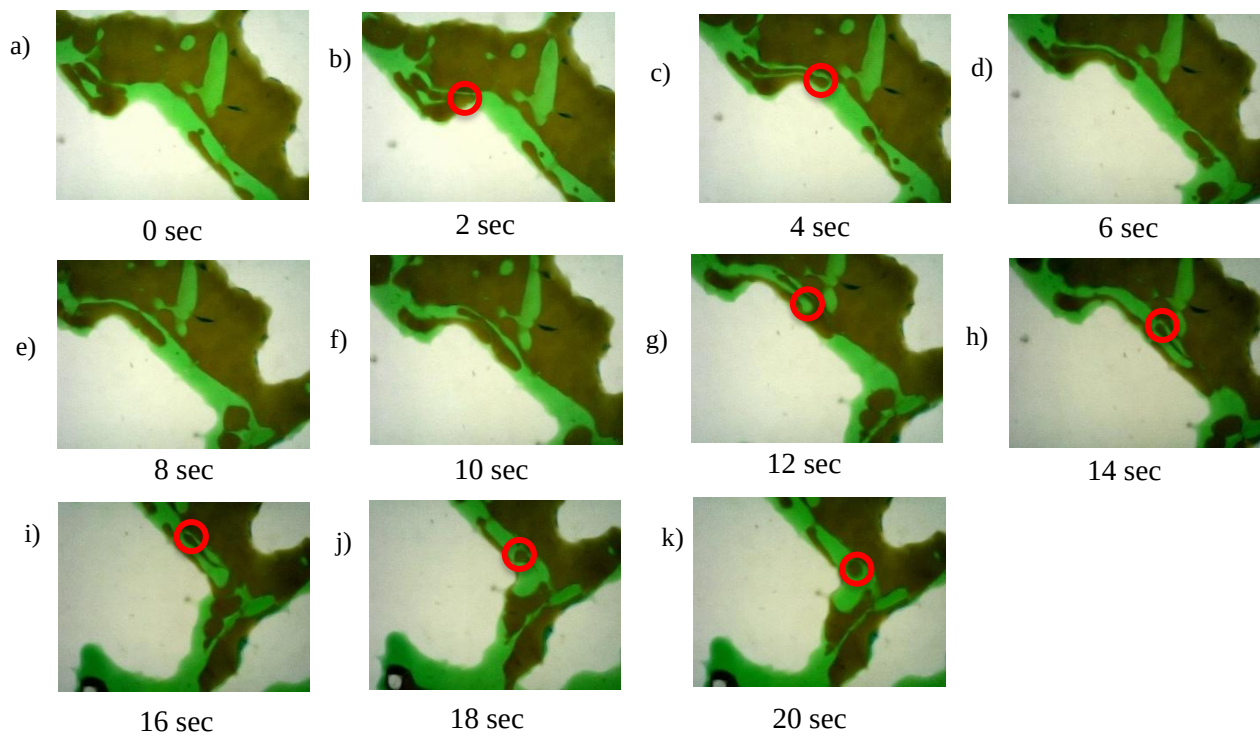
4.5.2 Pore-Scale Behavior

Unstable generation of the W/O emulsions was presented in Figure 42 (a-f). The droplets exhibit instability because they are constantly changing their shape, which indicates that the viscous oil phase dominates the flow, while only a few stable emulsions can form.



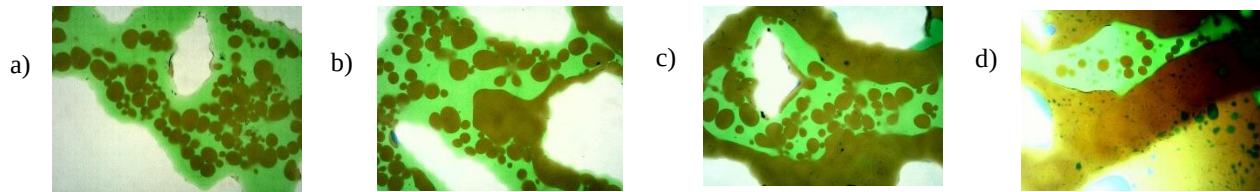
Figures 42 (a-f). W/O droplets generation and destabilization

The oil-in-water (O/W) emulsions shown in Figures 43 (a-j) are at the initial stage of formation. Thin oil films begin to break up into smaller droplets as SDS reduces IFT, which leads to their stretching. The droplets leave the primary oil phase and begin to move through the aqueous phase, which provides better microscopic displacement.



Figures 43 (a-k). O/W generation

In the production area, there are oil droplets that accumulate in the pore network, as shown in Figures 44 (a–d).



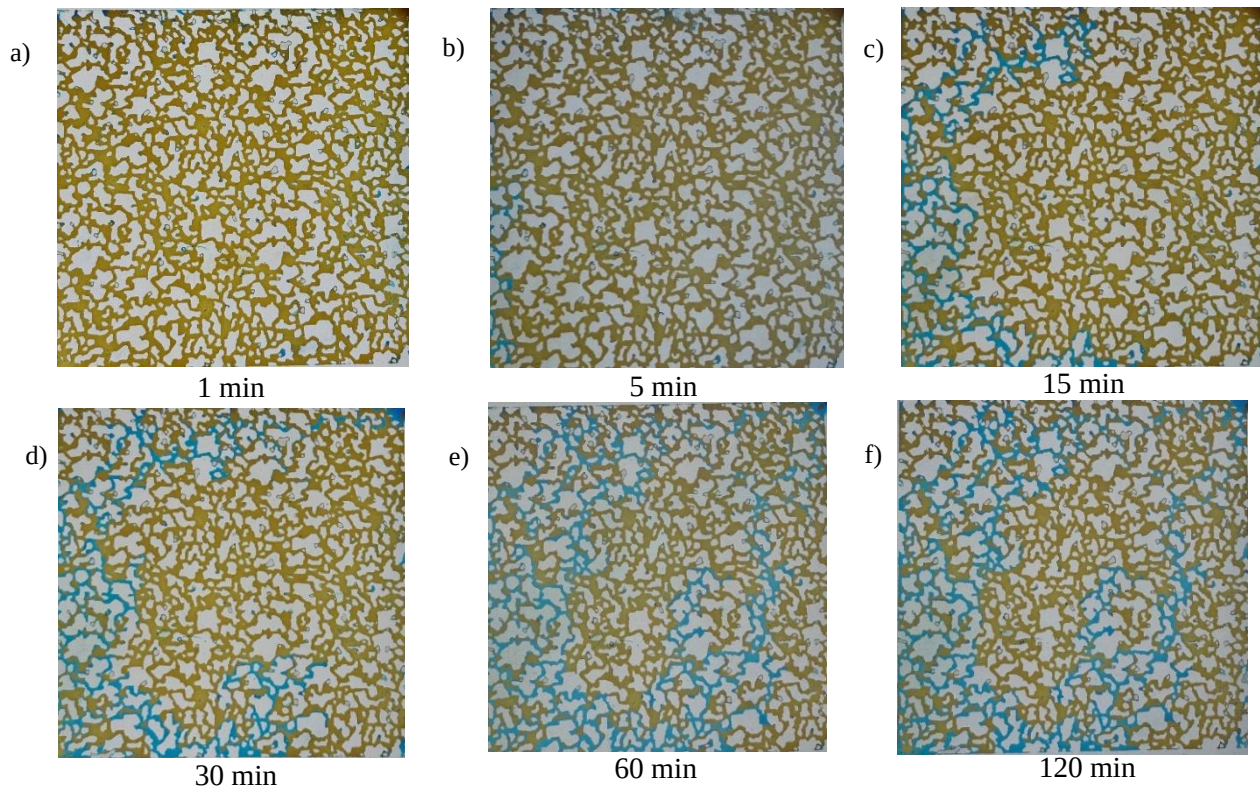
Figures 44 (a-d). Production site

The droplets move through the pore space, changing in size, forming a dense dispersed phase. The system moves a significant amount of oil, which reaches the exit point due to efficient transportation.

4.6 Test 3 Caspian Sea and Surfactant flooding

4.6.1 Macroscopic displacement of Caspian Sea as secondary recovery

The Figures 45 (a–f) show the water injection process, which causes macroscopic displacement from the Caspian Sea. Test 3 was examined like previous tests with six different injection times: 1, 5, 15, 30, 60, and 120 minutes, maintaining a steady flow of $0.002 \text{ cm}^3/\text{min}$.



Figures 45 (a-f). Caspian Sea flooding during secondary recovery

The first 5 minutes demonstrate initial water penetration into the micromodel, which creates initial flow paths. The displacement front exhibits an uneven pattern because water and high-viscosity oil move at different speeds, which causes the initial development of channeling.

The water flow during the next 15 to 30 minutes through the larger pores creates distinct finger-like structures. The "fingering" of water movement through the oil-filled space, particularly in narrower areas, result in significant oil bypassing. The displacement front shows instability while the sweep efficiency remains at low levels.

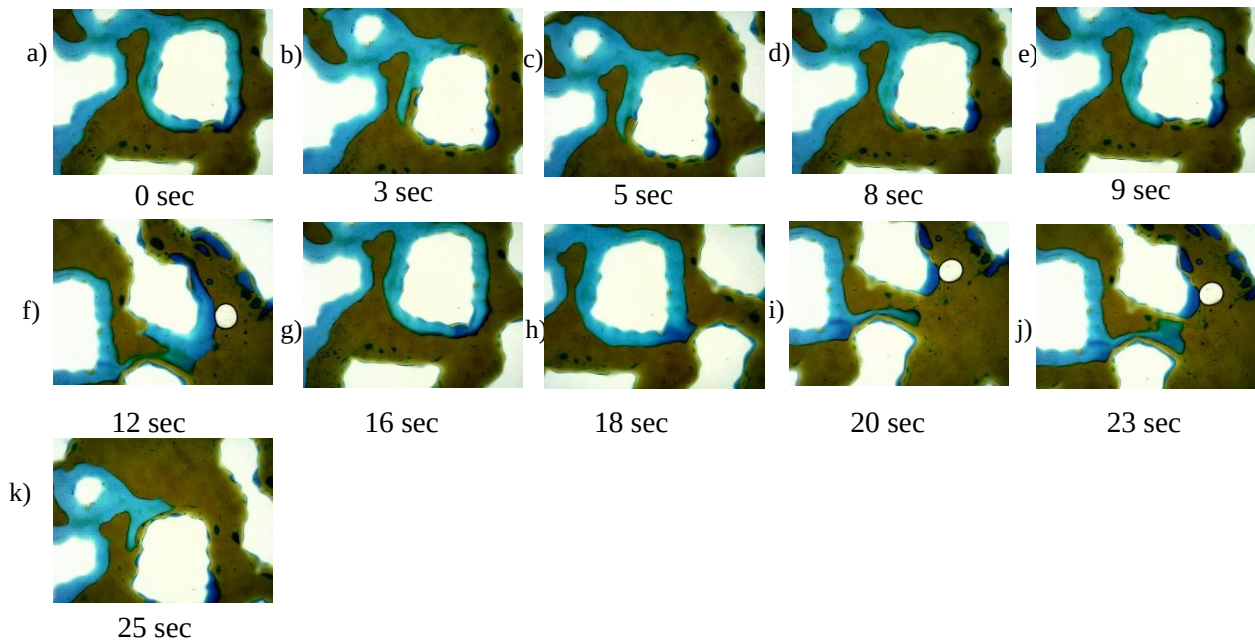
Most pore space becomes occupied by water at the 30-to-60-minute. The main flow channels create inaccessible regions, which leave behind scattered oil clusters that remain trapped.

The micromodel shows water distribution after 120 minutes, but the displacement process proves ineffective. The widespread oil distribution demonstrates both poor displacement performance and high bypass flow rates.

The study results show that waterflooding in the Caspian Sea requires finger-like and channel-like structures which result in incomplete oil displacement and high residual oil saturation.

4.6.2 Pore-Scale Behavior of Caspian Sea as secondary recovery

The pore-scale images (Figures 46 (a-k)) show the displacement mechanisms during flooding by the Caspian Sea.



Figures 46 (a-k). Pore-scale displacement by Caspian Sea

At the pore level, the injected water (light blue) flows mainly along the pore walls, while the oil phase (dark yellow) remains concentrated in the pore centers. This indicates a water-wet system in which water prefers hard surfaces and forms thin films along the boundaries of the pores.

As the injection continues, water constantly enters and exits the same pore openings, indicating unstable displacement and insufficient displacement. Instead of evenly displacing the oil, the water partially bypasses it, leaving the oil in the center of the pores and dead-end zones.

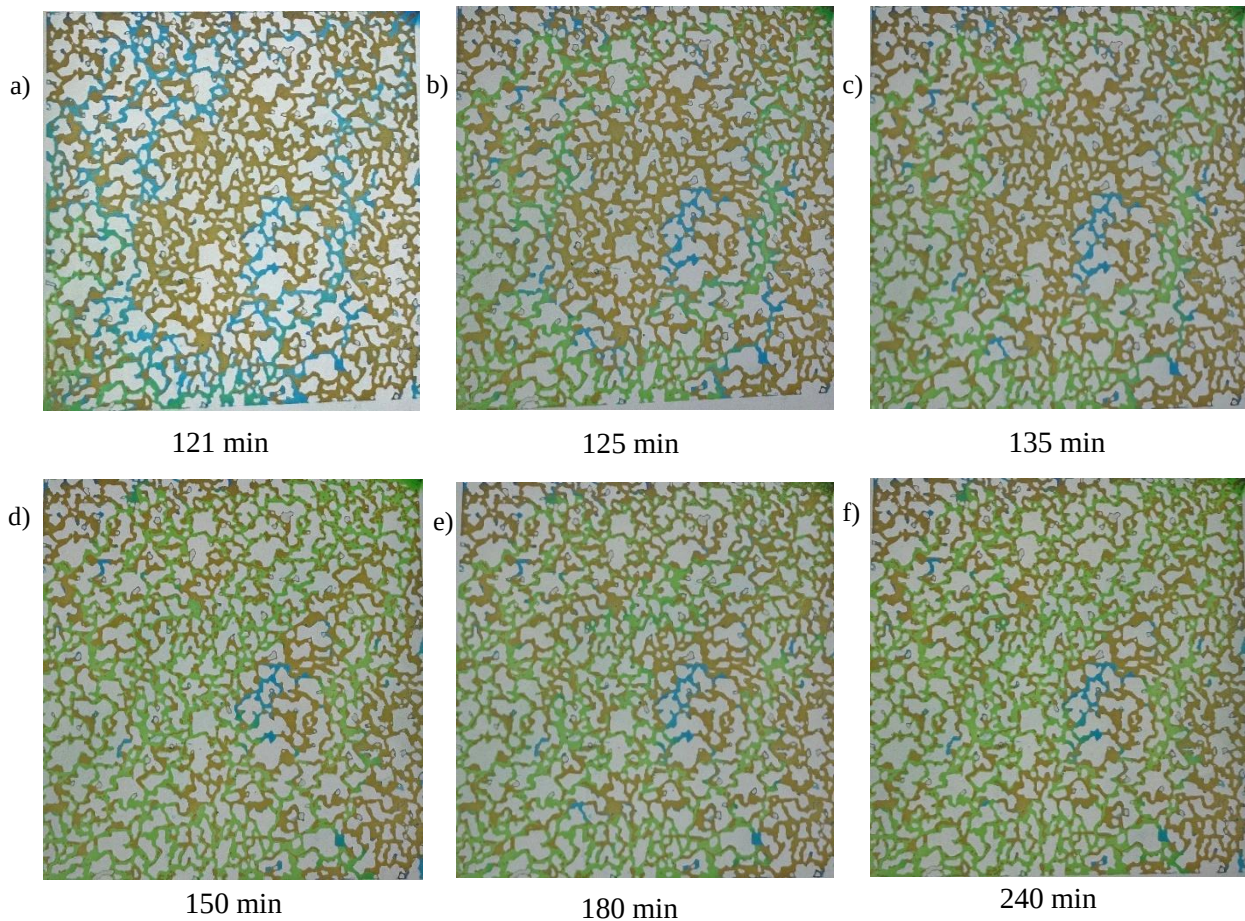
There is no emulsification in these images. The oil remains homogeneous, without the formation of clear droplets or their coalescence. This confirms that displacement is controlled primarily by the effect of viscosity and wettability, rather than by reducing IFT. This behavior

also reflects the existing nature of the micromodel, in which water spreads over the walls, while oil remains inside. This does not indicate a significant change in wettability caused by the injection itself.

In general, observations of the pore scale show that water injection from the Caspian Sea is ineffective for mobilizing trapped oil, as it mainly flows around the oil rather than breaking it into mobile droplets.

4.6.3 Macroscopic displacement of Surfactant as tertiary recovery

Figures 47 (a–f) show the macroscopic displacement during the surfactant flooding as tertiary recovery. The surfactant was injected after water injection at a rate of $0.002 \text{ cm}^3/\text{min}$, and images were obtained through 121, 125, 135, 150, 180, and 240 minutes.



Figures 47 (a-f). Surfactant flooding as tertiary

The surfactant, which was injected into the system (121-125 minutes), begins to penetrate through the network of pores, following the pre-existing flow paths created by

flooding with water. The displacement front provides greater stability when water is injected, as it moves at a lower speed without exhibiting any uneven flows.

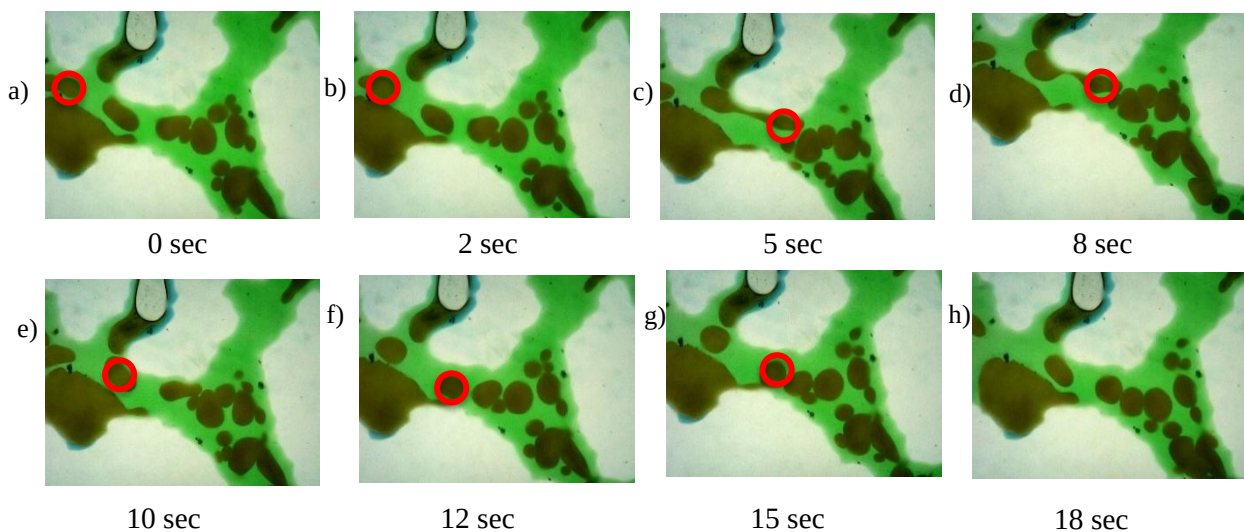
At 135 and 150 minutes, the surfactant begins to penetrate into zones that were previously untouched. The surfactant successfully penetrates the untouched territory that existed after the flooding in its current state, which leads to an increase in the efficiency of surface production.

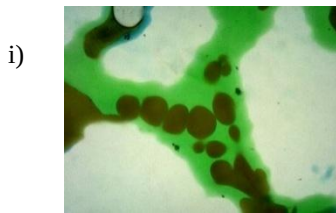
The displacement scheme of the micromodel reaches a maximum degree between 150 and 180 minutes of the experiment. The surfactant expands its movement beyond the main flow paths, which ensures better contact with oil and effectively reduces mobility due to the presence of oil.

By the time the duration of the experiment reaches 240 minutes, the surfactant occupies a large area of the micromodel. The distribution is more uniform than when filling with water, as the amount of remaining oil has decreased to a lower level.

4.6.4 Pore-Scale Behavior of Surfactant as tertiary recovery

The pore-scale images in Figure 48 (a–i) demonstrate all the basic mechanisms that enhance oil recovery through the injection of surfactants, showing how droplets form, coalesce, and accumulate in the system.





20 sec

Figures 48 (a-i). O/W droplet generation.

The surfactant is colored green and injected to reduce the IFT between oil and water. The oil phase begins to form smaller droplets, resulting in oil-in-water emulsions. Figure 48 (a-i) shows that the oil separates from the oil film due to capillary instability and shear forces that create mobile droplets passing through the pores.



0 sec



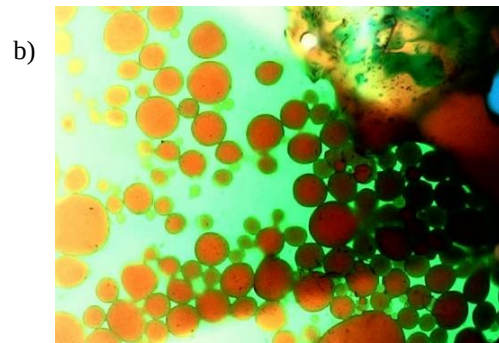
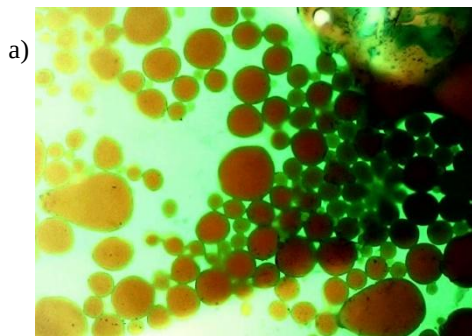
2 sec



4 sec

Figures 49 (a-c). Coalescence

Figure 49 (a-c) shows how these droplets move through spaces, starting to contact each other. Small droplets were combined to form larger ones, especially in wider pores. The emulsion system exhibits dynamic behavior because the droplet sizes are constantly changing throughout the feeding process.



Figures 50 (a-b). Production site O/W droplets accumulation.

The movement of droplets to the outlet occurs at the final stage of removal. Figures 50 (a-b) show that many droplets have accumulated near the production site, which proves that oil can move through a porous medium during transportation.

A change in the pore structure indicates that a continuous flow of oil is transformed into a moving emulsion system. The oil recovery process is improved by droplet formation and coalescence, as these processes transform trapped oil into a form that can move through a network of pores.

Quantitative Analysis and Comparison (Test 2)

Table 7 and Figure 51 show the changes in oil saturation (S_o) that occur over injection time with injection methods. The study compares three displacement methods, which include injection of a surfactant used as a secondary recovery method, water flooding as secondary, and surfactant as tertiary recovery method after water flooding

Table 8. Comparative analysis for Test 2

Test 2	Surfactant secondary	Water secondary	Surfactant tertiary
Time	S_o	S_o	S_o
0	0.98	0.98	-
1	0.95	0.96	-
5	0.92	0.93	-
15	0.87	0.91	-
30	0.78	0.85	-
60	0.68	0.81	-
120	0.61	0.80	0.80
121	-	-	0.80
125	-	-	0.78
135	-	-	0.75
150	-	-	0.71
180	-	-	0.60
240	-	-	0.54

The initial conditions of the oil saturation for both the surfactant and the water injection, were 98%. The difference between 2 methods becomes obvious from the very beginning, which shows their different effectiveness. The first five minutes of injection of the surfactant show a faster decrease in oil saturation at $S_o = 0.92$ compared to the water injection rate at $S_o = 0.93$.

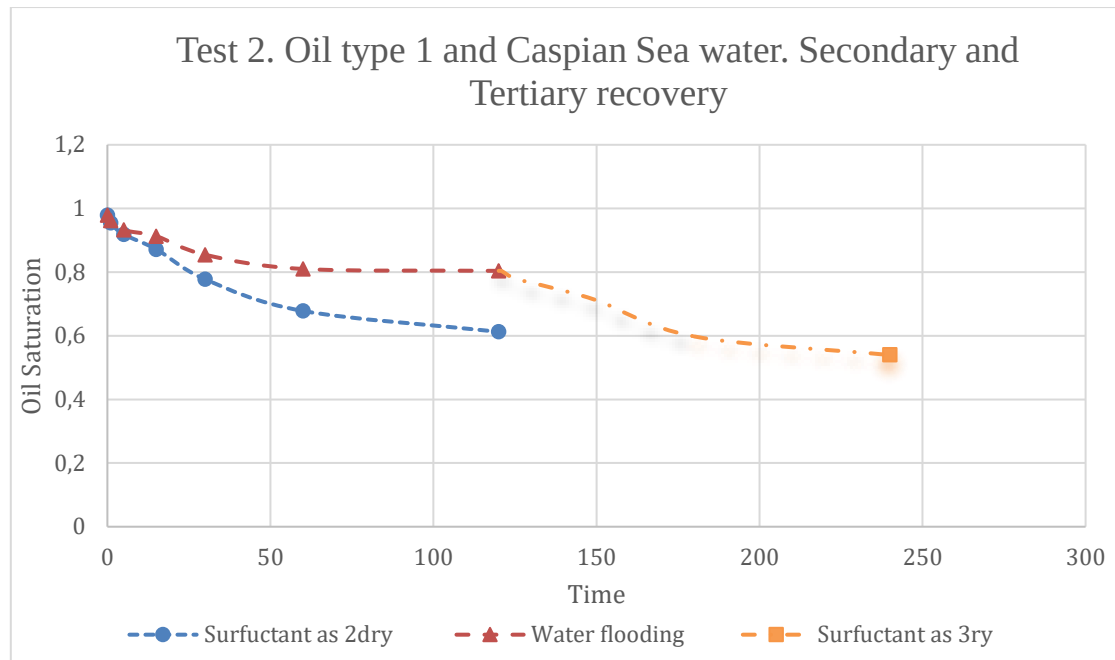


Figure 51. S_o vs Time for Test 2.

The oil saturation level after 30 minutes shows that when the surfactant is injected, a lower oil saturation level is achieved - 0.78 compared to the water injection method, in which the saturation level remains higher - 0.85. 2 injection methods demonstrate the differences in the methods of oil displacement from the formations. Water injection are controlled by viscous forces, which leads to the formation of channels and bypassing the reservoir. The injection process of the surfactant leads to a decrease in interfacial tension, which allows the oil to pass through the pores.

Water injection operations in the later stages, lasting from 60 to 120 minutes, reach a stable state at $S \approx 0.80$, indicating that all easily recoverable oil has been removed and the remaining oil has become unavailable. The surfactant injection process continues to reduce the oil saturation until it reaches 0.61, which demonstrates its effectiveness in extracting oil that remains stuck after water injection.

The surfactant flooding as tertiary recovery decreases oil saturation from 0.81 to 0.54. This decrease is an important event, as it demonstrates the amount of residual oil that could not be extracted during flooding.

Table 8 and Figure 52 show the recovery factor based on the volume of injected pores, which allows for a better understanding of the displacement efficiency.

Table 9. Calculation RF and PV injected for Test 2

PV injected	RF ₁ (surfactant secondary)	RF ₂ (water secondary)	RF ₃ (surfactant tertiary)
0.005	0.025	0.018	-
0.025	0.062	0.048	-
0.076	0.110	0.068	-
0.153	0.206	0.127	-
0.306	0.308	0.173	-
0.612	0.374	0.179	-
0.617	-	-	0.180
0.637	-	-	0.204
0.689	-	-	0.230
0.765	-	-	0.273
0.918	-	-	0.389
1.224	-	-	0.449

With small volumes of injection into the pores ($PV < 0.1$), both the surfactant and the water injection exhibit similar recovery rates, since displacement is mainly controlled by the volumetric flow. After that, the two methods begin to show different results.

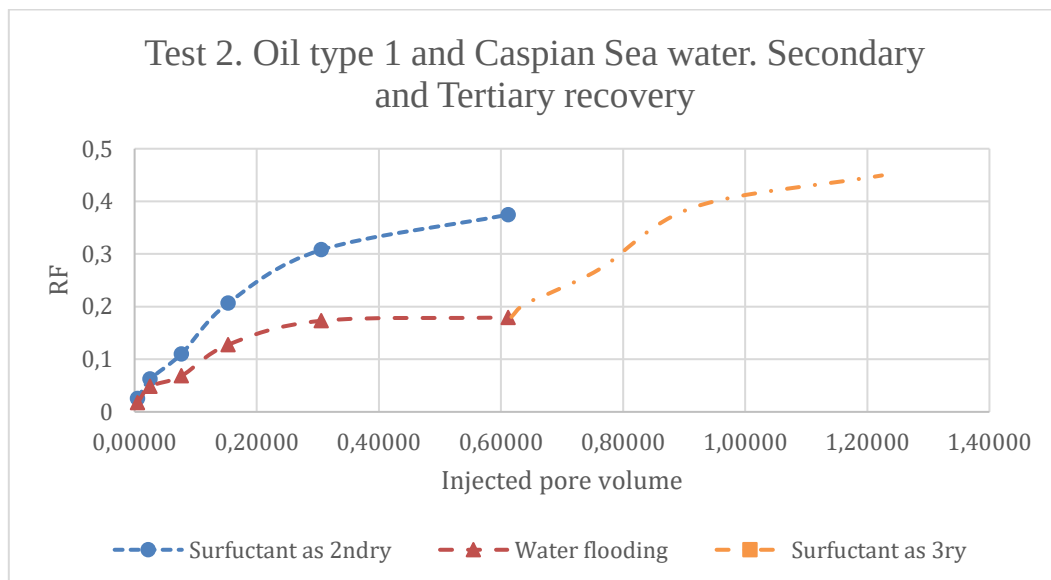


Figure 52. RF vs Injected Pore Volume for Test 2

Recovery factor of surfactant injection as secondary recovery (RF_1) demonstrates a much faster increase in oil recovery compared to water flooding. The RF_1 reaches approximately 0.31 with a pore volume of about PV 0.30, while RF_2 of water flooding reaches approximately 0.17. The results show that when the surfactant is injected, the oil recovery coefficient doubles compared to other methods with the same amount of injection.

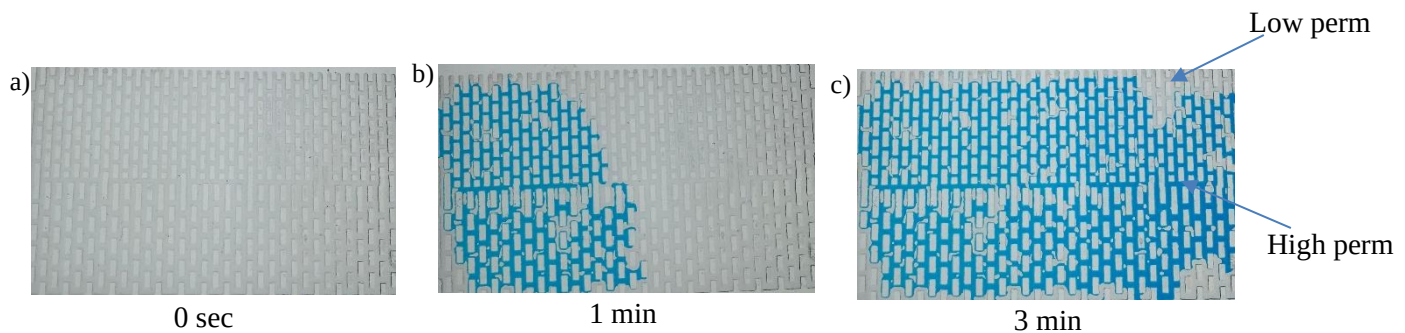
The difference becomes more noticeable with an increase in pore volume, which reaches approximately PV=0.6. When the surfactant is injected as secondary, RF_1 reaches approximately 0.37, RF_2 reaches approximately 0.18, which shows different saturation points.

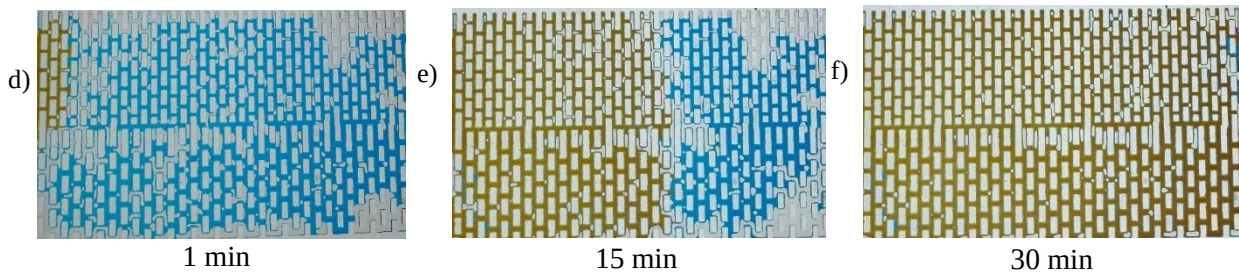
The surfactant flooding as tertiary recovery increased RF after water flooding from 0.18 to 0.45 with increasing PV. A significant spike indicates that a significant amount of oil remains in the reservoir after water flooding, however surfactant as tertiary improved oil recovery by IFT reduction, wettability alteration and emulsification process.

4.7 High-Heterogeneity Micromodel Saturation

4.7.1 Macroscopic displacement

The saturation experiment was conducted using a heterogeneous micromodel with two regions (left and right), both of which exhibited heterogeneity, but at different levels, as shown in Figures 53 (a–f). The right side exhibits a higher degree of heterogeneity, with a more uneven pore distribution and less uniform liquid filling. This structural difference significantly affects the distribution and displacement of liquid during saturation.





Figures 53 (a-f). Saturation process in a heterogeneous micromodel with two regions (left: lower heterogeneity; right: higher heterogeneity) during water and oil injection.

To prevent leakage on micromodel, lower injection rate of $0.02 \text{ cm}^3/\text{min}$ was performed for micromodel saturation due to the complex heterogeneity. It took longer to complete the saturation process, as the system demonstrated greater design complexity and lower injection rate than previous tests were performed. The process of achieving water saturation took 3 minutes, while the oil injection process took about 30 minutes, which showed that higher flow resistance was observed in some pore areas while maintaining limited connectivity.

The macroscopic images in Figures 53 (a–f) show clear visual differences between the two studied areas. The left side shows a uniform distribution of the liquid, while the saturation front moves more continuously. The right side shows an uneven pattern, which causes the penetration of liquid to be uneven. There are several areas in this area that contain either weakly saturated or non-displaced areas that show more pronounced changes in the material. The process of pumping water ensures the movement of liquid along preferred paths, while sections of the porous network remain unfilled. The yellow phase of oil injection displaces water through larger channels, but the water remains stuck in small pores and thin areas in the form of separate accumulations.

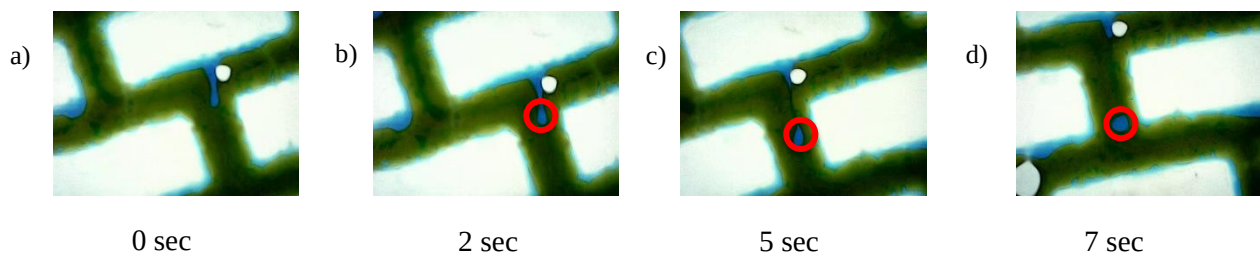
Capillary forces and pore size distribution control the movement of liquid at the pore level. Heterogeneous areas experience increased capillary resistance, since the smaller pore diameter prevents the movement of liquid, which slows down the penetration of fluid. As a result of the process, scattered groups of liquid are formed, which create an uneven movement pattern. An area with less material variability ensures the movement of the liquid, since its pores are better interconnected, which facilitates the flow process. This experiment was conducted using oil sample 1 and NaCl brine. Compared to previous tests, sample 1 performed better in the heterogeneous micromodel. It has higher viscosity and droplet formation ability facilitate more efficient displacement in heterogeneous system. Using NaCl brine provides

more controlled conditions for comparison, as the lack of additional ions can affect interfacial behavior and wettability.

Overall, the results show that increasing heterogeneity leads to lower saturation, uneven liquid distribution, and higher liquid holdup. These conditions are expected to impact subsequent waterflooding processes, reducing waterflood efficiency and increasing the importance of surfactant-assisted recovery.

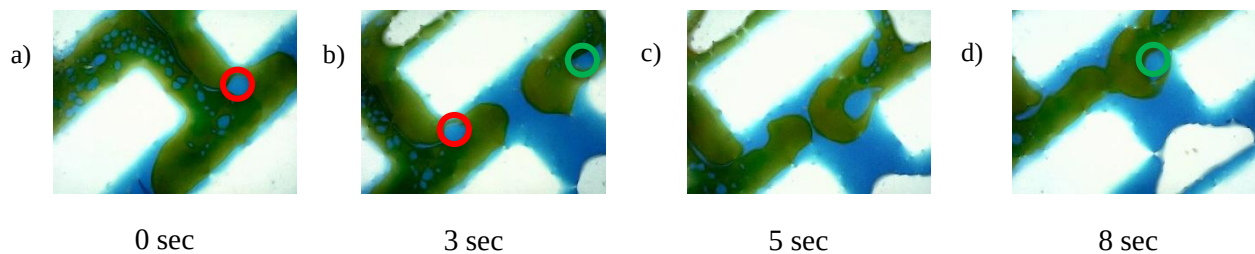
4.7.2 Pore Scale Behavior

The results show that an increase in heterogeneity leads to three effects, which include lower saturation, uneven fluid distribution, and increased fluid retention. These conditions will affect the flooding processes, as they will reduce the effectiveness of flooding, while at the same time increasing the need for recovery with surfactants.

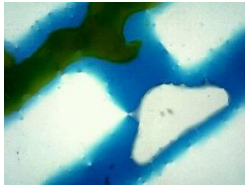


Figures 54 (a-d). Droplet generation

Observations of the pore scale at Figures 54 (a-d), during oil injection show that heterogeneous micromodels in both areas create small droplets that form inside their pore network (highlighted by red circle). Oil displaces the aqueous phase, forming droplets that form in the necks of pores and narrowed areas where capillary forces prevail. The left and right sides exhibit this behavior, as droplet formation occurs at all levels of heterogeneity.



e)



10 sec

Figures 55 (a-e). Demulsification

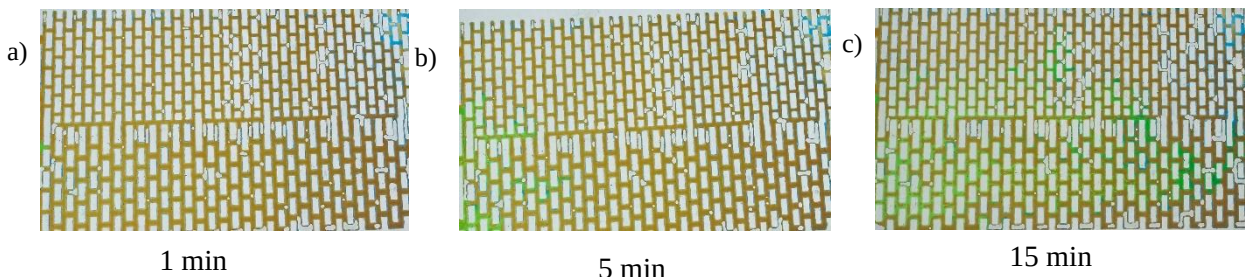
The highly heterogeneous region on the right side at Figures 55 (a-e), shows increased accumulation and coalescence of droplets (highlighted by red and green circles) due to an irregular pore structure and limited local flow. The system experiences short-term droplet retention, which causes them to merge, resulting in the formation of larger oil channels. The left side of the area shows smoother droplet movement, as improved pore connectivity reduces the number of droplets accumulating.

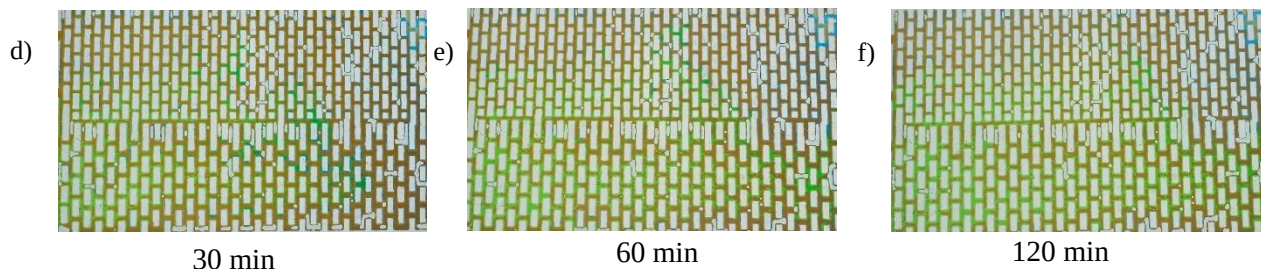
The results show that oil displacement in heterogeneous systems requires both droplet formation and their fusion. The movement of liquids depends on how these droplets maintain their stability and mutual attraction. The extraction phase affects the movement of the liquid and the effectiveness of oil extraction methods by affecting the liquids that get trapped.

4.8 Test 3 Surfactant Flooding as Secondary Recovery

4.8.1 Macroscopic displacement of Surfactant as secondary recovery

The procedure for introducing a surfactant into a heterogeneous micromodel Figure 56 (a-f) demonstrates its development over six different time intervals, which include 1, 5, 15, 30, 60 and 120 minutes. The images demonstrate that the nature of the displacement strongly depends on the heterogeneity, which creates an uneven distribution of surfactants between the left area with lower permeability and the right area with higher permeability.





Figures 56 (a-f). Surfactant flooding as secondary

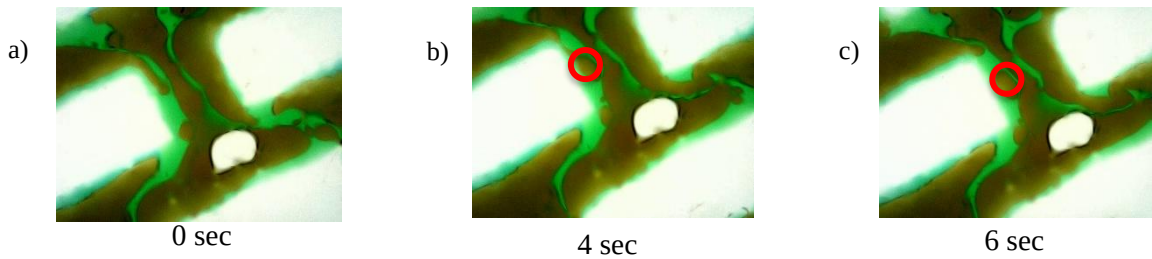
The injected surfactant begins to flow into the micromodel during the first 5 minutes of injection. The surfactant passes through an area with high permeability, which is located on the right side of the area and moves along the easiest flow paths, since the displacement front is extremely uneven. The area with low permeability (the left side) remains largely unplaced, which indicates a strong influence of permeability on the distribution of liquid.

The surfactant penetrates deeper into the pore network within 15-30 minutes. The right side is largely injected, while the left side still has limited penetration. The displacement front has an uneven structure, since the surfactant moves through special channels that avoid oil entering the areas. The unevenness in the micromodels leads to a decrease in the displacement efficiency, which affects to a greater extent than on standard micromodels. The surfactant reaches most of the micromodel after 30 minutes, moving through channels with high permeability. The dominant channels control the breakthrough, as a result of which oil enters a zone with low permeability. Macroscopic displacement occurs due to permeability contrast, which has a greater impact than interfacial effects.

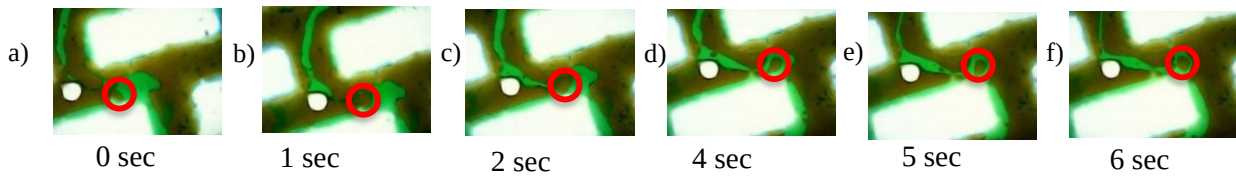
The surfactant begins to penetrate into previously upswept areas 30-60 minutes after continuous injection, but progress is negligible. The right area appears to have been largely removed, while the left area still contains a significant amount of residual oil. The remaining oil is retained because the displacement process slows down as less accessible pore spaces are filled.

4.8.2 Pore scale Behavior of Surfactant as secondary recovery

Pore-level research demonstrates that displacement patterns show distinct emulsion-based mechanisms which control oil movement through areas with both low and high permeable materials.

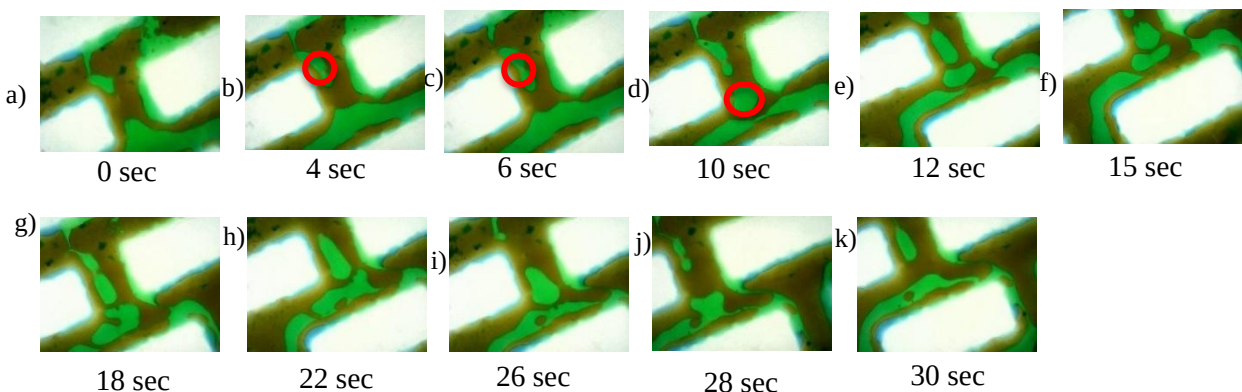


Figures 57 (a-c). O/W emulsion observation at low permeability zone



Figures 58 (a-f) O/W emulsion observation at high permeability zone

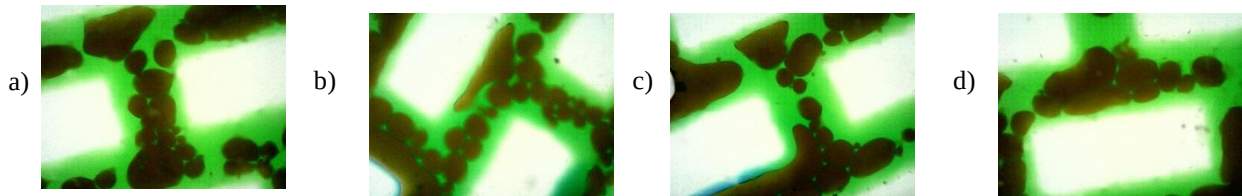
The 2 sides of the micromodel depict oil-in-water emulsions by red circle, as shown in Figures 57 (a-c) and 58 (a-f). The surfactant phase (green) penetrates into the oil phase (yellow), as a result of which small oil droplets are separated from the oil ganglia. The oil breaks down into oil droplets due to the IFT reduction. The same behavior is observed in both areas with low and high permeability, since the interaction of surfactants with oil determines the effects at the pore level to a greater extent than changes in permeability.



Figures 59 (a-k). W/O emulsion generation observation at high permeability zone

Generation of the (W/O) emulsions are also shown in Figures 59 (a-k) by red circle, corresponding to the area with high permeability. The droplets remain unstable as they

constantly change their shape, coalesce with each other and creating larger oil structures. Liquid emulsions act as temporary components throughout the displacement process, as they do not contribute to stable oil transportation.



Figures 60 (a-d). Production site at both permeability zones.

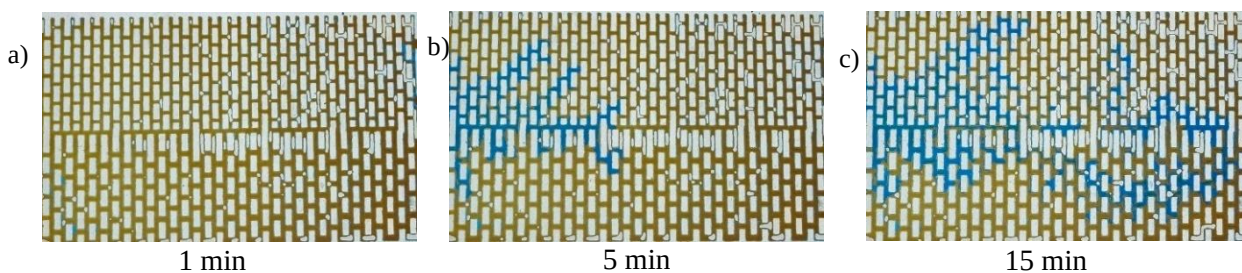
The production area shown in Figures 60 (a-d) displays an accumulation of oil droplets. The existing oil-in-water droplets move through the pore system until they reach the outlet area. The droplet snap-off process and droplet transportation functions are the primary method that facilitates oil recovery during surfactant injection in heterogeneous systems.

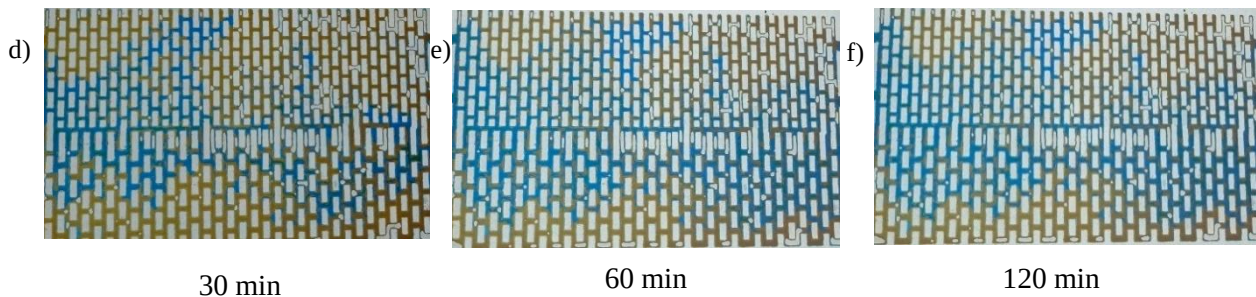
The findings demonstrate that oil-in-water emulsions help increase oil recovery while water-in-oil emulsions provide only temporary results which decrease their effectiveness. The different displacement patterns caused by heterogeneity do not affect the basic pore-level functions which operate the same way in both areas.

4.9 Test 3 Water and Secondary as Tertiary flooding

4.9.1 Macroscopic Displacement during water as secondary recovery

The NaCl brine was injected at 0.002 cm³/min rate to produce macroscopic displacement at different time intervals of 1, 5, 15, 30, 60 and 120 minutes. The results demonstrate that the micromodel inhomogeneity critically affects the displacement behavior.





Figures 61 (a-f). Macroscopic displacement by water flooding

The injected brine begins to penetrate the micromodel through its highly permeable area at 1-5 minutes. The blue injected water and yellow oil have an unfavorable mobility ratio, which leads to uneven displacement of the displacement front and the appearance of the first signs of channel formation.

During the intermediate time periods (15-30 minutes), the brine moves further into the system, continuing to move through channels with high permeability. These two areas differ from each other more clearly because access to the low permeability area is limited. This indicates that the flow is highly dependent on permeability, as water passes through large areas of oil.

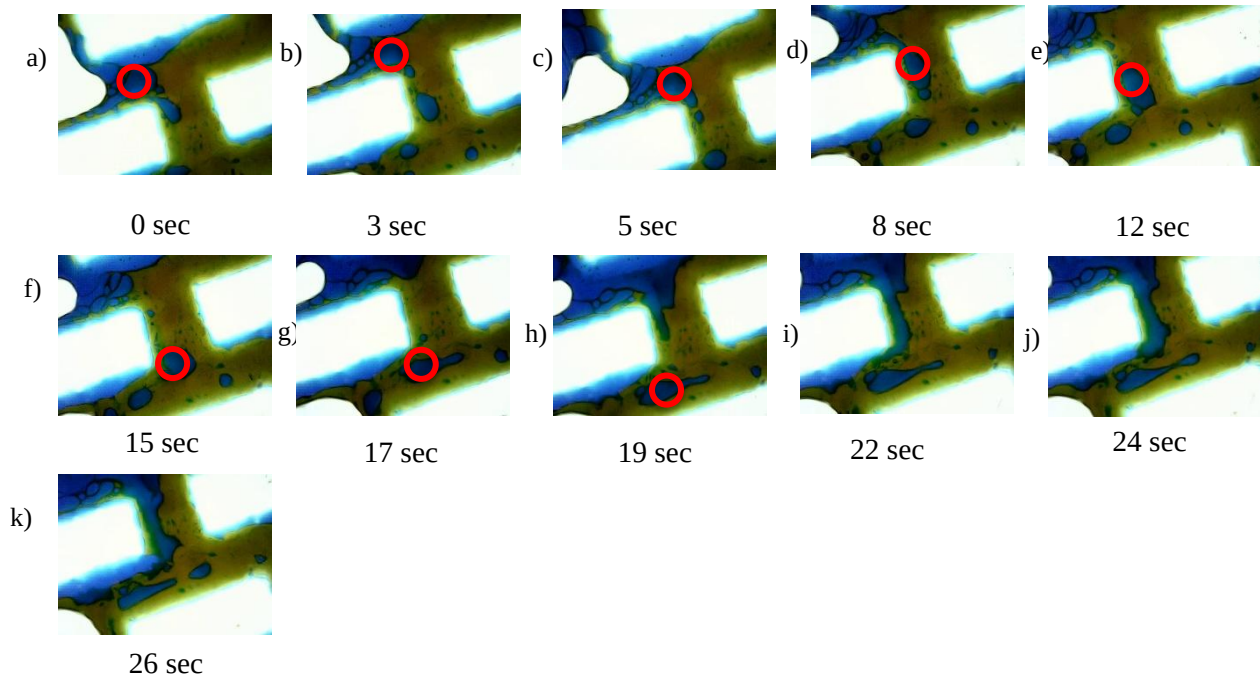
In the high-permeability zone, the first breakthrough occurs after 30 minutes, while in the low-permeability zone, most of the oil reserves remain. The displacement front remains uneven, as the laying of channels reduces the cleaning efficiency. The brine continues to spread through the already untouched areas between 30 and 60 minutes of injection. The low permeability zone has limited contact with the reservoir, as the flood has not been able to change the pattern of flow distribution.

The system reaches a near-stationary mode after 60-120 minutes, since any additional injection leads only to a minimal increase in oil recovery. The remaining oil in the low permeability zone indicates that the displacement efficiency remains at a low level, as a significant amount of oil remains in it.

During NaCl brine flooding, an early breakthrough is observed in combination with intensive channel distribution and low transfer efficiency. The system does not provide effective movement, since it lacks both IFT reduction and low mobility control.

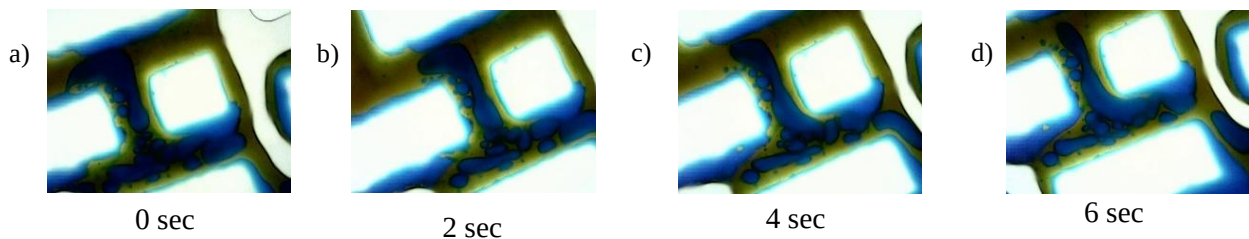
4.9.2 Macroscopic Displacement during water as secondary recovery

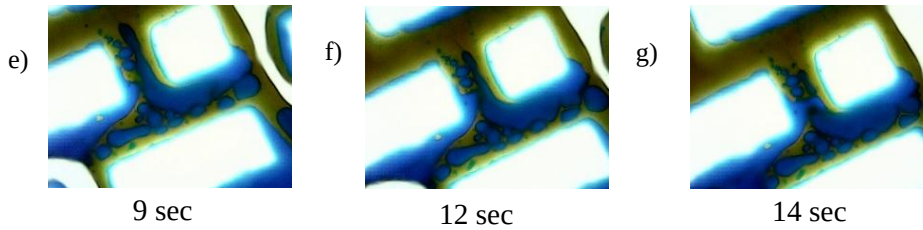
The pore scale investigation demonstrates that NaCl brine flooding generates only minimal emulsification which occurs through direct displacement mechanisms.



Figures 62 (a-k). Water flooding at high permeability zone

The red circle in the high permeability region in Figures 62 (a–k) shows that when NaCl is injected, unstable W/O droplets are formed. Droplets exhibit extreme instability as they constantly change shape, combining with neighboring droplets to coalesce. The IFT of the system remains high, which prevents the formation of stable emulsions. There is piston movement in this area, as the movement of the water pushes the oil forward, preventing it from becoming movable droplets.



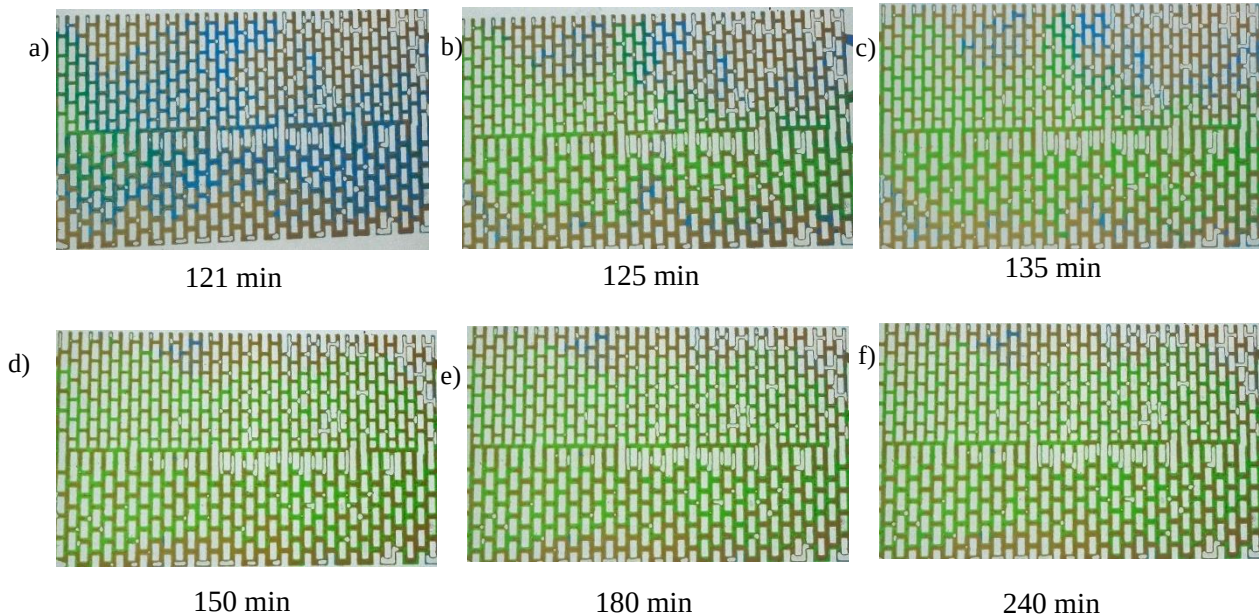


Figures 63 (a-g). Water flooding at low permeability zone

The area with low permeability is shown in Figures 63 (a-d), which show the formation of unstable water droplets in the oil system. A thin film of water makes its way through the walls of the pores and collects small droplets together and create big water film. This process improves the local connection with the brine, but it does not lead to better oil movement. The oil retains its continuous state, while the displacement process continues by gradually releasing the oil rather than separating the droplets.

4.9.3 Macroscopic Displacement of Surfactant Flooding as Tertiary Recovery

The dynamics of displacement during the introduction of a surfactant as a method of tertiary reduction at a rate of $0.002 \text{ cm}^3/\text{min}$ is shown in Figure 64 (a-f), at six recorded time points: 121, 125, 135, 150, 180 and 240 minutes.



Figures 64 (a-f). Surfactant flooding as tertiary

The injected surfactant first begins to penetrate the micromodel at the 121-125 minutes, moving through areas that were previously displaced by water. The surfactant is distributed

more efficiently than when rinsed with water, as it begins to penetrate into areas that have not been previously swept.

The front of action of the surfactant moves in both high and low permeability areas after 135 minutes. In the process of displacement, a more uniform distribution is achieved, while previously untested areas begin to interact with existing ones. The process of reducing the interfacial tension allows the oil to separate from the pore walls, resulting in improved displacement characteristics.

A significant increase in oil production becomes apparent after only 150 minutes. The surfactant ensures effective removal of oil from the reservoir by reducing capillary forces and makes oil accumulations available for extraction. The displacement front shows a more stable structure of the flow, which moves through the system without forming channels, in contrast to the period of flooding.

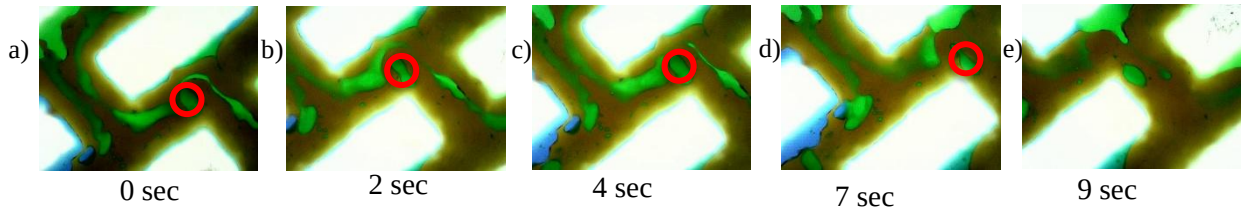
The surfactant continues to spread through the micromodel for 150-180 minutes, resulting in increased displacement performance. The liquid moves through a porous network, which leads to a better distribution of liquids between areas with different levels of permeability and provides more stable displacement results.

The system begins to reach a state of uniform saturation in the final stages, which last from 180 to 240 minutes. In the process, most of the remaining oil is displaced, which leads to a decrease in the level of residual oil, which becomes lower than the level remaining after filling.

The tertiary surfactant flooding method shows better results than water flooding, as it provides higher displacement efficiency, reduces channel formation, and increases recovery of previously trapped oil.

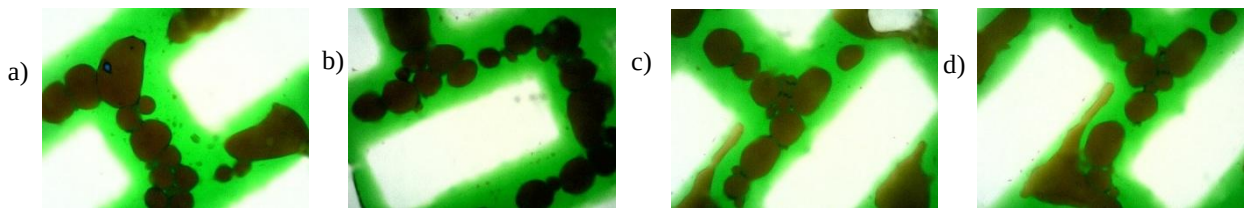
4.9.4 Pore-Scale Observation of Surfactant Flooding as Tertiary Recovery

The study shows that the surfactant flooding as tertiary recovery leads only to minimal emulsion formation at the pore level compared to previous tests, which revealed a distinct pattern of displacement that occurs during post-treatment experiments.



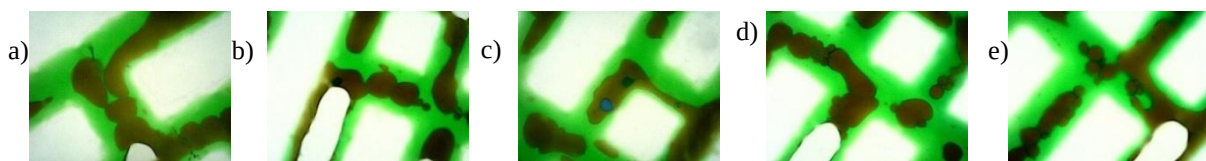
Figures 65 (a-e). W/O emulsion generation at high permeability zone

In the high permeability section of Figure 65 (a-e), emulsions of the W/O are shown in red circle, water droplet detached from oil ganglia however, shape of this droplets were deformed and unstable.



Figures 66 (a-d). O/W emulsions observation at high permeability zone

The area with high permeability in Figures 66 (a-d) shows oil-water emulsions. The surfactant solution contains dispersed oil droplets that separate from the primary oil phase. Oil droplets appear more often than water droplets because the decomposition and mobilization of oil occur during IFT reduction.



Figures 67 (a-e). O/W emulsions observation at low permeability zone

Figure 67 (a-e) shows oil-water emulsions in the form of five images that represent an area with low permeability, and at the same time show fewer droplets than an area with high permeability. The process of droplet formation and movement through the system becomes less efficient, due to the ability of surfactants to penetrate into the low permeability zone and produce more droplets are limited.

The formation of an emulsion during the surfactant flooding as tertiary demonstrates a the increased number of oil droplets in areas with high permeability shows that emulsification

depends on the flow direction, while in areas with low permeability, droplet formation is limited, making it difficult to extract residual oil from complex systems.

Quantitative Analysis and Comparison (Test 3)

Table 9 displays the oil saturation changes that occurred throughout time when different methods were used.

Table 10. Analysis and Comparison for Test 3

Test 3	Surfactant secondary	Water secondary	Surfactant tertiary
Time	S_o	S_o	S_o
0	0.90	0.90	-
1	0.89	0.89	-
5	0.82	0.88	-
15	0.74	0.86	-
30	0.68	0.79	-
60	0.58	0.76	-
120	0.54	0.72	0.72
121	-	-	0.70
125	-	-	0.68
135	-	-	0.65
150	-	-	0.48
180	-	-	0.46
240	-	-	0.45

Figure 68 shows how oil saturation changes over time for water flooding secondary surfactant flooding and tertiary surfactant injection.

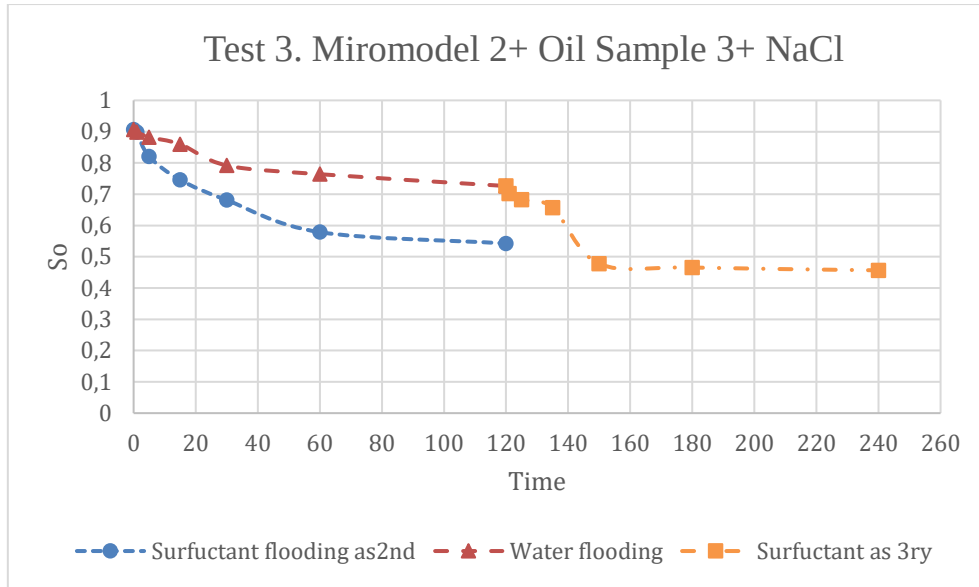


Figure 68. S_o vs Time for Test 3.

Both methods of oil extraction initially show identical results, since both water flooding and surfactant flooding begin with the same level of oil saturation ($S \approx 0.906$). After the initial testing period, the results of the two oil extraction methods begin to differ. The surfactant filling method shows better oil extraction results than other methods during the first five minutes of testing. The value of S_o for flooding with a surfactant drops to 0.82 after 5 minutes, while when injection with water, the value of S_o is higher and amounts to 0.88. The early stages of oil extraction using surfactants show increased efficiency, as surfactants reduce the interfacial tension.

The period from 15 to 30 minutes shows a higher degree of separation of the two methods. During the surfactant flooding as secondary, the S_o reaches 0.68 after 30 minutes, while during the water flooding, the S_o level is maintained at 0.79. The results show that in a heterogeneous micromodel, flooding with water faces obstacles associated with channeling and bypass, while flooding with a surfactant increases the efficiency of reservoir cleaning.

The existing gap continues to persist for a period of 60 to 120 minutes. In the process of surfactant flooding as secondary, S_o reaches 0.54, while when injection with water, S_o remains much higher - 0.73, which indicates a decrease in cleaning efficiency.

The injection of a surfactant for tertiary recovery begins when the water flooding ends at a value of $S_o=0.73$. The period between 135 and 150 minutes shows a significant decrease

in oil saturation, as the value of S_o drops from 0.65 to 0.47. The value reaches 0.45 at the final stage, which occurs after 240 minutes. The results show that surfactants are effective in extracting oil that remains after flooding.

The S_o vs injection time results demonstrate that surfactant injection delivers greater efficiency for both secondary and tertiary operations when compared to water injection. The corresponding RF results, depending on the injected pore volume, are presented in Table 10.

Table 11. PV injected vs RF for test 3

PV injected	RF ₁ (surfactant secondary)	RF ₂ (water secondary)	RF ₃ (surfactant tertiary)
0.008122	0.008	0.008	-
0.040611	0.095	0.026	-
0.121832	0.177	0.051	-
0.243665	0.248	0.126	-
0.487329	0.361	0.157	-
0.974659	0.401	0.199	-
0.982781	-	-	0.225
1.01527	-	-	0.247
1.096491	-	-	0.274
1.218324	-	-	0.472
1.461988	-	-	0.486
1.949318	-	-	0.496

Figure 69 shows the relationship between the volume of injected pores (PV) and the extraction coefficient (RF). With small pore volumes, the injection of surfactant (RF₁) occurs much faster than the injection of water (RF₂). The results show that injection of a surfactant provides higher oil production at an early stage, since at $PV \approx 0.24$ RF₁ reaches approximately 0.25, while RF₂ is only about 0.13.

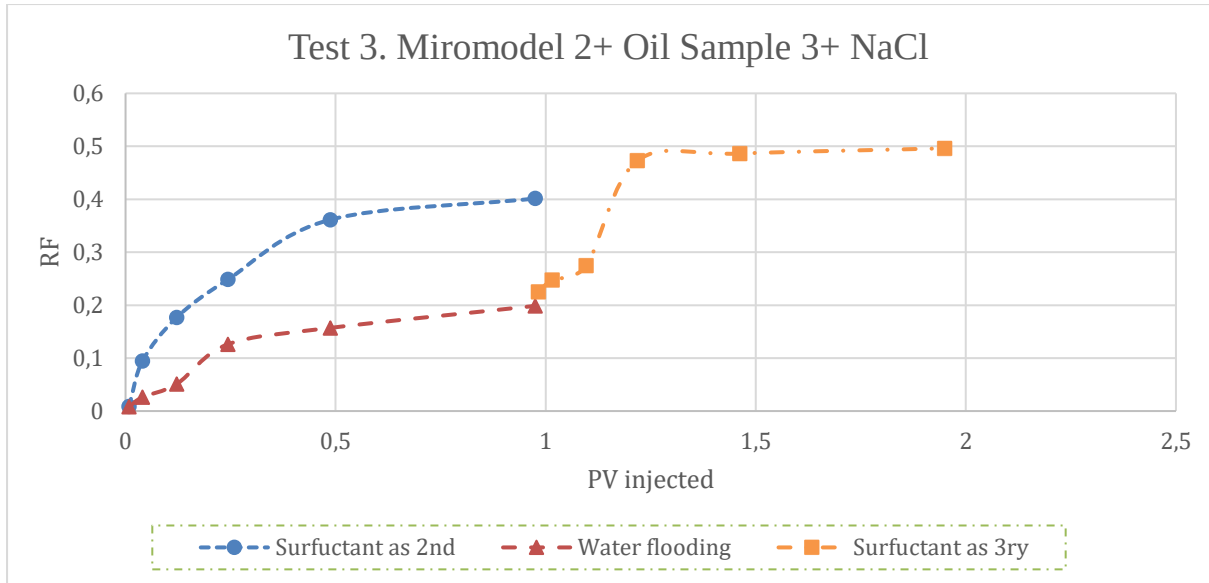


Figure 69. RF vs PV injected for Test 3

During the injection process, RF_1 steadily increases until it reaches a maximum value of 0.40, when the pore volume reaches 1.0, which proves the effectiveness of the secondary surfactant filling process. The water filling process shows a slower increase in RF_1 , which remains at lower levels until it reaches 0.20, when the pore volume reaches an equivalent level. This discovery demonstrates that filling with water has a low efficiency for displacing liquids and causes an immediate breakthrough of the liquid.

The recovery process begins at the end of water flooding, when tertiary surfactant flooding begins, and significant progress is being made. The RF_3 value begins to increase slowly until the period between PV 1.1 and 1.2, which shows a rapid increase as the residual oil begins to exit its trapped state. The final RF_3 value reaches 0.496, which exceeds the recovery level achieved by flooding with water.

The combination of S_o -time and RF-PV results clearly demonstrates the advantage of surfactant filling. This process produces better results because the lower IFT allows the oil to separate and form droplets that move through the pore space, as shown in image studies. The surfactant applications allow to change the properties of wettability, which improves fluid displacement in both areas with high and low permeability.

Flooding operations depend on the presence of non-uniform surfaces, which create paths that allow fluids to pass through areas with high permeability, while at the same time retaining oil inside areas with low permeability. Due to this, the system provides increased residual oil saturation with reduced production.

The tertiary stage of the application of surfactants is especially important for the mobilization of this trapped oil. The RF_3 level shows a sharp increase, while the oil saturation level decreases sharply, which confirms the data on droplet formation and transport that occur at the pore level. This method works better than the secondary application of surfactants, but its effectiveness is reduced due to previous water penetration and limited access in certain areas.

The results of test 3 demonstrate that surfactant flooding achieves high efficiency in heterogeneous systems when it is used as an additional method of extracting the remaining oil after water flooding.

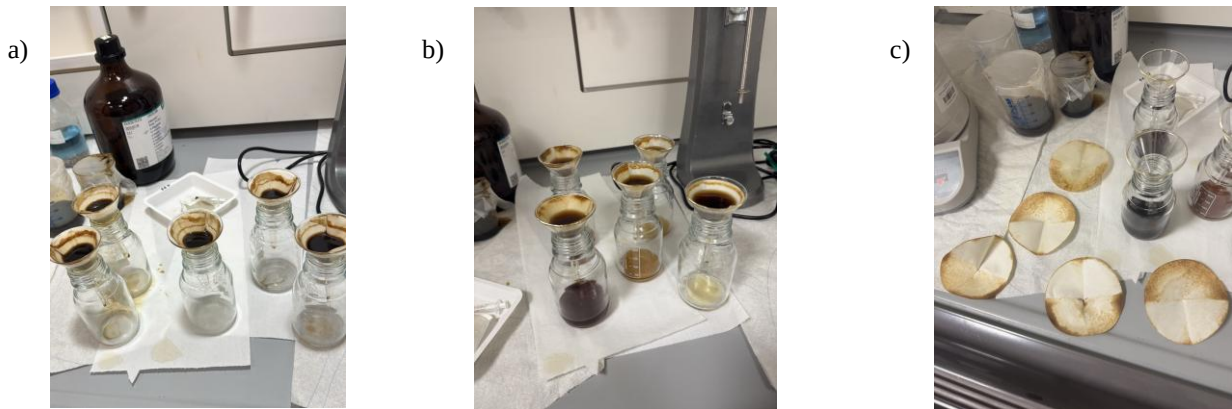
5.DISCUSSION

The study examined how oil viscosity, water composition, injection strategy, and heterogeneity effect on pore-scale emulsion formation and oil displacement efficiency through micro-model tests.

5.1 Effect of Asphaltene content

The process of emulsification depends on its viscosity, density, and asphaltene content. To evaluate asphaltene content, filtration method was used to extract the asphaltenes from the two oil samples.

The filtration process of sample 1 did not reveal the presence of asphaltenes, as shown in Figures 70 (a-c). According to the filtration results, the sample 1 does not contain asphaltenes or contains them in small quantities.



Figures 70 (a-c). Asphaltene extraction results for Sample 1 (no visible asphaltenes)

A small amount of asphaltenes was found in Sample 2, shown in Figure 71 (a-c). This amount was too small to make any significant changes to the emulsification process.

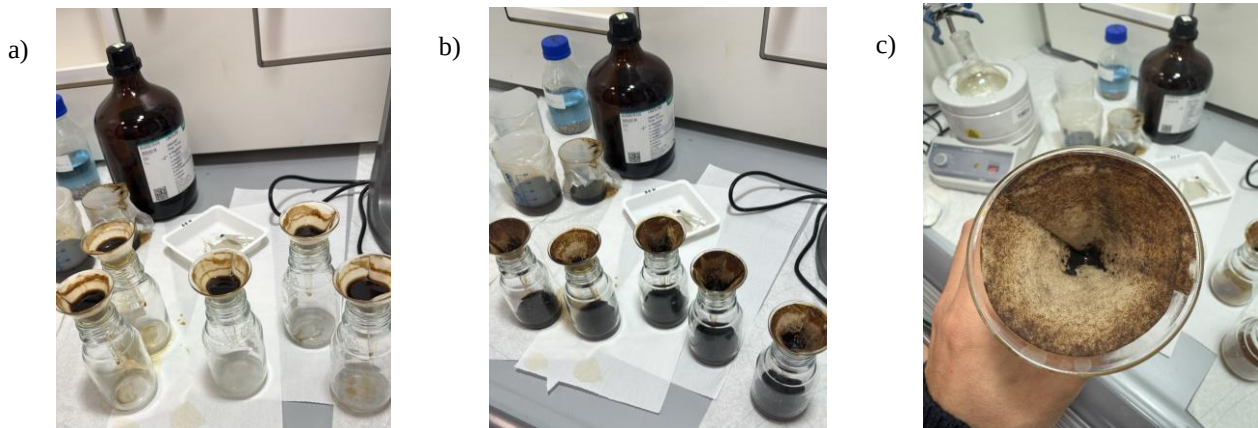


Figure 71 (a-c) Asphaltene extraction results for Sample 2 (presence of asphaltenes)

Based on these observations, the differences in emulsification and displacement behavior observed in this study are primarily attributed to viscosity effects rather than asphaltene content.

5.2 Effect of Oil Viscosity

In this study, viscosity was chosen as the main parameter because it controls fluid mobility, flow stability, and ability of oil phase to deform and break into droplets at the pore scale. The asphaltenes content was not considered, because they were neglected or small quantities of asphaltenes were extracted from oil samples 1 and 2.

Viscosity affects both macroscopic displacement and microscopic mechanisms. The viscosity property determines how the injected liquid and oil will move through the system, resulting in efficient channel movement and forcing. Viscosity is an important factor determining the behavior of droplets at the pore level, as it regulates the formation, deformation and stability of droplets in emulsions.

In this study 2 oil samples are presented. Sample 1 highly-viscous and Sample 2 low-viscous oil with 20 times difference in viscosity were used to find out how viscosity affects oil displacement and emulsification processes.

The viscosity of the oil samples play a crucial role in displacement behavior and the emulsification process. The highly viscous oil (Sample 1) showed a greater tendency to droplet formation, which led to increased oil production by movement of droplets and ability to block high permeable zones. The droplets that formed in this situation maintained their stability for a long period of time. In complex systems, the system performed better because the displacement stability improved, even though emulsification occurred at a lower intensity.

Low viscosity oil (Sample 2) demonstrated a more stable displacement front movement and stable droplets however their number was less compared to Sample 1. This can be explained by the significant viscosity difference between the two samples (approximately 20 times), which allowed Sample 2 to be mobilized more easily and produced droplets more efficiently.

5.3 Effect of Water salinity

The behavior of emulsion generation during surfactant flooding as tertiary recovery was influenced by the composition of the water in the system. In this study, 2 different brines were used for secondary injection: a synthetic NaCl brine with a concentration of 10,000 ppm and natural Caspian Sea water with an approximate salinity of 13,000 ppm. This range of salinity was chosen because it reflects the moderate to low salinity levels. Bartels (2016) and other researchers demonstrated that a low brine salinity at 10000-13000 ppm can significantly change wettability and behavior of the interface at the pore scale. The selected range allows us to study the emulsification processes along with the displacement mechanisms that occur during real low-salinity flooding operations.

During the secondary flooding tests 1 and 2, the water of the Caspian Sea was used as an injector. The tests showed that the displacement process remained stable, and significant emulsification and droplet formation occurred during surfactant as tertiary recovery, indicating successful mobilization of residual oil. The use of the Caspian Sea water is also justified by its practical importance, as it is an easily accessible and cost-effective source of injected water for oil fields in the Mangystau region.

In test 3, synthetic NaCl brine was used as an injector. The effectiveness of the natural brine system had to be evaluated by direct comparison with a synthetic controlled system. NaCl brine with a concentration of 10,000 ppm was chosen, because of consistence with core flooding experiments that had been conducted previously by Muh Naim, who is the part of our research team and this core flood experiments were done in his thesis titled: “*Core Flood Investigation of Surfactant-Induced Emulsion Effects on Kazakhstani Oil Recovery*”. These experiments with micromodels were designed to provide insights into the mechanisms observed at the core scale. During secondary water flooding, NaCl brine produced more visible droplets than Caspian Sea water, however, these droplets were unstable and quickly coalesced. In contrast, Caspian Sea water showed very limited emulsion formation during water flooding. This difference can be explained by the presence of divalent ions (Ca^{2+} and Mg^{2+}) in Caspian Sea water, which stabilize the oil–water interface and suppress droplet breakup. As a result, displacement in this case is dominated by film flow and bypassing rather than emulsification.

During surfactant flooding as tertiary recovery, the effect of water composition became less dominant, as surfactant action controlled interfacial behavior. However, Caspian Sea water

produced more oil droplets compared to NaCl brine during tertiary surfactant injection. This suggests that its ionic composition still influences emulsification behavior, even in the presence of surfactant.

5.4 Effect of Injection Strategy

This study investigates injection methods: surfactant as secondary, and surfactant as tertiary after water flooding, had the greatest impact on the effectiveness of the production. The water flooding method was unable to achieve high oil recovery due to early breakthrough, channeling and was highly dependent on the heterogeneity of micromodels. The recovery factors of water flooding showed low values throughout all 3 tests, 0.34, 0.18, 0.19.

The surfactant flooding as secondary recovery provided better results because it improved oil displacement by reducing IFT, wettability alteration and emulsification. The results of all tests showed that surfactant flooding as secondary injection method, reached recovery factors of 0.36 for the 1st test, 0.37 for the 2nd test, and 0.40 for the 3rd test. These results, showed that the performance of surfactant flooding is better than water flooding as secondary recovery.

The use of surfactant flooding as a tertiary recovery method has yielded the best experimental results. This method produces fewer droplets than surfactant as secondary recovery, because the injected water as secondary recovery, created flow pathways and displaced large part of oil, and amount of remaining oil which trapped in low-permeability regions was available to generate more droplets. The recovery factor reached 0.53 in test 1, 0.45 in test 2, and 0.50 in test 3.

This study shows that surfactant flooding as tertiary recovery effectively combines improved sweep efficiency from water flooding and enhances microscopic displacement.

5.5 Effect of Heterogeneity

In this study, 2 micromodels with various heterogeneity were selected. 1st is ordinary heterogeneous porous media and 2nd is complex heterogeneous porous media with dual permeabilities, to see the influence of heterogeneity of porous media on oil production and emulsification.

Tests 1 and 2 were conducted by using micromodel 1, and 2nd test with high-viscosity oil showed that the recovery factors were $RF \approx 0.18$ for water flooding, $RF \approx 0.37$ for secondary surfactant flooding, and $RF \approx 0.45$ for tertiary surfactant injection. Initially, all tests were to be performed with the 1st micromodel, however, during the following experiments, micromodel 1 was damaged, and could not be reused. Then we decided to use second micromodel that contained double permeability parts (low and high) to conduct test 3, which examined how stronger heterogenous system affects the displacement results.

Test 3 showed that the heterogeneity of the dual-permeability affects the movement of fluid through porous media and emulsification. Water flooding again showed low recovery factor ($RF \approx 0.20$), as water moved through the system through channels with high permeability. The use of surfactant flooding showed higher recovery coefficient, which reached $RF \approx 0.40$ for secondary recovery and $RF \approx 0.50$ for tertiary flooding. These results surpassed the results of micromodel 1, because performance of emulsification and sweep efficiency were better done under more complex heterogeneity system.

The dual permeability Micromodel 2 design provides better interaction between injection fluid and with different levels of permeability. During the injection of the surfactant, oil-in-water emulsions are formed, which allow the trapped oil to flow into the main channels, thereby increasing oil recovery.

Wang et al. (2024) found that an increase in heterogeneity leads to an increase in viscosity forces, which increases the efficiency of oil displacement in all areas. The study showed that the complex heterogeneity improves emulsification and fluid redistribution, resulting in higher recovery factor compared to micromodel 1.

The effectiveness of water flooding is reduced due to heterogeneity, but it increases the effectiveness of surfactants, providing better access to the trapped oil.

5.6 Pore-Scale Mechanisms

During experiments with surfactant flooding, at pore scale conditions, W/O (water-in-oil) emulsions were generated and improved oil recovery. The process begins with the oil forming droplets that separate from the pore walls and move through an interconnected pore system.

Surfactant flooding also generated (W/O) water-in-oil emulsions, however they were unstable, which limits their ability to improve oil recovery. Secondary surfactant flooding generated more droplets, while tertiary flooding was more effective in mobilizing previously trapped oil.

6.CONCLUSION AND RECOMENDATIONS

The study showed that pore-scale emulsification is a significant mechanism that increases oil recovery under various experimental conditions. Four key parameters were investigated in this study: oil viscosity, water composition, injection strategy, and micromodel heterogeneity.

The behavior of oil displacement depends on its viscosity. High-viscosity oil promotes droplet formation, while low-viscosity oil provides a more stable displacement front and improved sweep efficiency in heterogeneous systems.

The composition of the water affects the emulsification process that occurs during surfactant flooding after water injection. The use of NaCl brine leads to the formation of extremely unstable droplets, while the Caspian Sea water prevents emulsification due to its ionic composition. However, during surfactant flooding after water injection, Caspian Sea water produced more stable droplets than synthetic NaCl, and oil displacement efficiency of Caspian Sea water slightly higher than NaCl.

The most important element of the process is the injection method. In all tests, surfactant flooding as secondary recovery gives better results than water flooding. The secondary method helps to produced more visible droplets and increased oil recovery. With the tertiary method, maximum oil recovery is achieved by extracting the remaining oil after water flooding. The extraction coefficients for tests 1, 2, and 3 reached values of 0.53, 0.45, and 0.50.

Heterogeneity affects the sweep efficiency, since both channeling and bypassing are happened when injection agent is flooded. The increased heterogeneity of the system enhances the interaction between the pores, which leads to the formation of more droplets and better movement of oil during surfactant flooding.

Overall, Surfactant flooding is better than conventional water flooding methods in terms of displacement efficiency, emulsification and recovery factor.

Recommendations

Based on the results of this study, the following recommendations are proposed:

- Investigate the performance of different types of surfactants (non-ionic, cationic) under similar conditions
- Study the effect of salinity and ionic composition in a more controlled and systematic way
- Perform quantitative analysis of droplet size distribution and emulsion stability
- Investigate oil droplet size distribution in more detail to better understand emulsification mechanisms
- Evaluate the effect of injection rate and pressure on emulsification and recovery
- Investigate wettability alteration in more detail to better understand displacement mechanisms
- Study combined chemical EOR methods (e.g., surfactant–polymer flooding) in heterogeneous systems

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