Experimental Investigation of Foam Stability under Various Salinity Levels, Oil Types, and Surfactant Conditions: Effect of Natural Polymer Lignin

Amir Hossein Saeedi Dehaghani[1*] **,Mohammad Amin Behnam Motlagh**[2]

1- Department of Petroleum Engineering, Faculty of Chemical Engineering, Tarbiat Modares University, Tehran, Iran, asaeedi@modares.ac.ir, +989122892230

2- Department of Petroleum Engineering, Faculty of Chemical Engineering, Tarbiat Modares University, Tehran, Iran, m_behnammotlagh@modares.ac.ir, +989120237573

Abstract

Gas injection is a widely applied enhanced oil recovery (EOR) technique, but its efficiency is often limited by gas channeling and gravity override in high-permeability zones. To address these issues, this study explores the use of natural polymer lignin as a novel foam stabilizer in gas-injected EOR systems. Lignin's amphiphilic nature enables it to improve foam stability under harsh conditions, including high salinity and oil contamination. Laboratory experiments were conducted using two surfactants (CTAB and SDS), three oil types (heptane, toluene, heptol), and aqueous systems with varying salinity (distilled water and synthetic seawater). Surface tension measurements, static foam generation, and foam stability assessments were performed. Results showed that lignin significantly enhances foam stability, particularly when combined with CTAB. In distilled water, increasing lignin concentration from 100 to 2000 ppm led to a more than threefold increase in foam half-life, from 241 to 801 minutes. Moreover, CTAB–lignin systems showed superior performance compared to SDS or lignin alone, especially under saline and oily conditions. These findings suggest that lignin-enhanced foams are promising, cost-effective, and environmentally

---

[*] Corresponding author. Tel: +989122892230 E-mail address : asaeedi@modares.ac.ir

friendly candidates for improving gas mobility control in EOR operations, particularly in complex reservoirs.

Keywords: Gas injection, lignin, Surfactants, Oil types, Salinity, Foam stability

1. Introduction

With the growing global demand for oil and the depletion of natural reservoir productivity, the need for enhanced oil recovery (EOR) techniques has become increasingly apparent[1]. EOR methods are essential to extract the maximum amount of oil from existing reservoirs, extending their productive life[2],[3]. Among these techniques, gas injection has been widely adopted over the past five decades[4]. This process involves injecting gases—either hydrocarbon-based (e.g., methane, ethane) or non-hydrocarbon gases (e.g., carbon dioxide, nitrogen)—into the reservoir to increase displacement efficiency and reduce residual oil saturation[5],[6]. One of the advantages of gas injection is its ability to improve microscopic displacement efficiency, as the injected gas can interact with the reservoir oil, potentially leading to immiscible, partially miscible, or fully miscible conditions[7]. However, despite these advantages, the method faces several challenges. Gas has a lower viscosity and density than oil, which leads to gas "fingering" and gravity override. These phenomena result in poor volumetric sweep efficiency, leaving significant amounts of oil unrecovered in lower permeability zones[8]. Foams have been introduced as a viable solution to these challenges. A foam is essentially a gas-liquid dispersion stabilized by surfactants, which increases the apparent viscosity of the gas phase, reducing its mobility[9]. By improving gas viscosity and entrapping gas bubbles in the porous media, foams offer better control over gas movement and prevent gas channeling through high-permeability zones[10]. This improves the overall sweep efficiency, allowing for more uniform and effective oil recovery[11]. One of the critical challenges of foam injection is ensuring the stability and longevity of the foam under various reservoir conditions, including high salinity, varying temperatures, and the presence of oil[12]. Surfactant-stabilized foams tend to degrade when exposed to harsh reservoir conditions, especially in the presence of crude oil[13]. The interaction between the foam and oil leads to the destabilization of the foam lamellae, reducing its efficiency[14]. To address these challenges, the use of natural polymers, such as lignin, has emerged as a promising area of research[15]. Lignin is a biopolymer derived from plant cell walls and is one of the most abundant natural polymers in the world. It has both hydrophilic and hydrophobic properties, making it an excellent candidate for stabilizing foams in gas injection EOR applications[16].

A growing body of literature has addressed the role of polymers in foam stabilization for EOR. Polymer-stabilized foams have attracted increasing attention due to their ability to form interfacial structures that can significantly enhance foam film stability, particularly through mechanisms such as steric hindrance and reduced drainage[17]. Nguyen et al. (2000) and Xu, Saeedi, and Liu (2016) emphasized the importance of surfactant-polymer synergy in stabilizing foams under high salinity and temperature[18], [19]. Srivastava et al. (2017) and Osei-Bonsu, Grassia, and Shokri (2017) showed that polymer addition reduces liquid drainage and enhances foam structure in porous media [20], [21]. Telmadarreie and Trivedi (2018) conducted a comprehensive study comparing conventional foams and polymer-enhanced foams (PEF) under static and dynamic conditions in the presence of heavy crude oil. Their results demonstrated that while heavy oil severely reduced the foamability and stability of conventional foams—especially for nonionic surfactants—adding polymer significantly improved foam longevity and propagation within porous media. Notably, N85-based PEF achieved up to 98% oil recovery compared to only 57% for foam alone. The study emphasized the critical role of polymer addition in mitigating foam collapse due to oil and in enhancing sweep efficiency during CO_2 foam flooding in heavy-oil-saturated reservoirs[22]. Ahmed et al. (2019) demonstrated that polymer-free CO_2 foams can achieve comparable stability and viscosity to polymer-stabilized foams under high-pressure, high-temperature (HPHT) conditions, while avoiding issues like polymer degradation and pore plugging. Their findings emphasize the importance of optimized surfactant formulations for generating strong foams without the drawbacks associated with conventional polymers[23]. Zhang et al. (2020) designed foam systems based on anionic (SDS), nonionic (APG), and cationic (CTAB) surfactants stabilized with lignin–cellulose nanofibrils (LCNFs) to improve foam stability for EOR applications. Their results showed that the synergistic interactions between CTAB and LCNFs significantly enhanced both initial foam volume and drainage half-life. The SDS/CTAB/LCNF system, at an optimal 3:1 ratio, doubled the foam index (FCI) compared to SDS alone. In oil-contaminated systems, the presence of LCNFs improved foam stability by reducing liquid drainage and thickening the foam film, mainly through electrostatic attraction and hydrogen bonding mechanisms. These findings confirm the potential of lignin-based nanomaterials as environmentally friendly stabilizers in complex reservoir environments[24]. Hanamertani and Ahmed (2021) reported that the addition of associative polymers not only doubled the foam half-life in bulk experiments but also improved the apparent viscosity and mobility reduction factor in porous media by up to 2.5 times compared to polymer-free foams. Moreover, the associative polymer-stabilized foam demonstrated higher oil tolerance and achieved a 28% incremental oil recovery, highlighting its potential as a robust mobility control agent in harsh reservoir environments[25]. Emami et al. (2022) conducted a comparative experimental study on anionic (SDS) and nonionic (LA-7) surfactants to evaluate the influence of salinity and pH on foam stability and foamability. Their results demonstrated that foam stability and water recovery in porous media are highly dependent on both surfactant type and salinity level. Notably, SDS-based foams showed higher initial foam height but were more sensitive to divalent salts, while LA-7 demonstrated better performance at near-neutral pH. The study highlighted that foam stability had a more significant impact on fluid recovery than foamability, emphasizing the need for carefully optimized formulations in EOR applications[26]. Ju et al. (2022) systematically studied the effects of hydroxypropyl guar (HPG) as a foam stabilizer and SDS/CTAB as foaming agents on the rheological and stability behavior of foam fluids for coalbed methane stimulation. Their results showed that increasing HPG concentration significantly enhanced foam viscosity and half-life, while the presence of inorganic salts and coal particles had complex interactions depending on surfactant type. Notably, SDS-based foams exhibited greater stability and smaller bubble size compared to CTAB, and the foam half-life increased with decreasing bubble diameter. These findings confirm the critical role of polymer concentration and interfacial film structure in determining foam performance under varying reservoir-like conditions[27]. Sheng et al. (2023) investigated the oil resistivity and stability of foams formed by mixtures of short-chain fluorocarbon and various hydrocarbon surfactants in the presence of n-heptane. Their results showed that foamability and foam stability were significantly reduced by oil, especially for SDS and CTAB-based foams. Among all tested systems, the mixture of APG-0810 and FS-50 exhibited the best oil resistivity and foam film stability due to the formation of pseudoemulsion films and better interfacial interaction with oil. These findings highlight the critical role of surfactant structure in designing foam systems for oil-contaminated environments[28]. Wen et al. (2024) demonstrated that the adsorption of alkyl polyglycoside (APG-0810) surfactants at the CO_2–water interface is strengthened with salinity, leading to enhanced interfacial activity and liquid film stability. These findings highlight the importance of optimizing interfacial interactions in saline environments to design robust CO_2 foam systems[29].

Wu et al. (2024) demonstrated that the incorporation of a temperature-resistant polymer (Z364) into betaine-based foams significantly enhanced foam stability under high-temperature and high-salinity conditions. The polymer improved the viscosity of the liquid film and formed stable polymer–surfactant complexes at the gas–liquid interface, resulting in up to a 325% increase in foam half-life and improved fluid diversion in heterogeneous porous media[30]. Ahmed et al., (2025) showed that hydrophobically modified polymers (HMPs) have demonstrated remarkable potential in enhancing foam stability and CO_2 mobility control by improving interfacial film strength, viscosity, and drainage resistance—particularly under high salinity and temperature conditions[31].

This research is driven by the growing need for more efficient and sustainable EOR methods, especially in light of increasing global energy demand and the declining productivity of conventional reservoirs. Although gas injection is widely utilized in EOR, its effectiveness is often limited by poor gas mobility control. Foam injection offers a viable solution to this issue, but conventional surfactant-based foams frequently suffer from poor stability under harsh reservoir conditions, including high salinity, elevated temperatures, and the presence of crude oil. Natural polymers such as lignin have emerged as promising alternatives to synthetic stabilizers due to their amphiphilic structure, environmental friendliness, and widespread availability. Lignin's ability to interact with both aqueous and oil phases makes it particularly suitable for enhancing foam film stability and resisting foam collapse under challenging conditions. Thus, lignin-stabilized foams present a compelling option for improving gas mobility control in EOR applications. In this study, we investigate the stabilizing effect of lignin in foam systems under various reservoir-relevant conditions. A comprehensive set of laboratory experiments was conducted using different surfactants (CTAB and SDS), oil types (heptane, toluene, and heptol), and aqueous phases with varying salinity levels (distilled water and synthetic seawater). Key performance metrics—such as foam half-life, total stability duration, surface and interfacial tension—were evaluated through static foam tests and physicochemical characterization. The goal is to assess the synergistic behavior of lignin–surfactant systems and establish their viability as sustainable, high-performance agents for enhancing foam-based gas injection in EOR.

2. Experimental section and approaches

This section details the materials, experimental setup, and methods used to evaluate the stability of foam generated using natural polymer lignin and surfactants under various reservoir conditions. The primary aim of the experiments was to analyze foam stability, considering factors such as oil type, salinity, and pH, and to compare the performance of lignin-stabilized foam with that of surfactant-only foam.

2.1. Materials

The following materials were used in the experimental setup:

- **Cationic Surfactant (Cetyl Trimethyl Ammonium Bromide - CTAB):** CTAB ($C_{19}H_{42}BrN$), purchased from MERCK in powder form, was used as the primary cationic surfactant. The molecular structure of CTAB is represented as $(C_{16}H_{33})N(CH_3)_3]Br$, with a molecular weight of 364.46 g/mol and a critical micelle concentration (CMC) ranging from 0.92 to 1 mM, and its molecular structure is represented in Fig. 1. This figure illustrates the chemical structure of CTAB, featuring the long hydrophobic alkyl chain (C_{16}) attached to a central trimethylammonium group (N^+) with a bromide ion (Br^-) as the counterion[32].
- **Anionic Surfactant (Sodium Dodecyl Sulfate - SDS):** SDS ($C_{12}H_{25}OSO_2ONa$), also purchased from MERCK, was used as the anionic surfactant. Its molecular weight is 288.38 g/mol, and it has a CMC of 7-10 mM. Fig. 2 illustrates the molecular structure of SDS. SDS is an anionic surfactant composed of a hydrophobic 12-carbon alkyl chain (C_{12})connected to a hydrophilic sulfate group (SO_4^{2-}). The sulfate head is negatively charged, and it is paired with a sodium ion (Na^+)as the counterion. This structure allows SDS to reduce surface tension in solutions, making it highly effective in detergents and for solubilizing lipophilic substances in aqueous environments[33].
- **Deionized Water**: Deionized water with conductivity less than 1 µS/cm, a pH between 6.5 and 7.5, and undetectable levels of $CaCO_3$, Cl^-, or Fe^{2+}, was obtained from Zolal Company.
- **Mineral Salts**: NaCl, $MgCl_2$, $CaCl_2$, and KCl, all obtained from MERCK, were used to simulate reservoir salinity. These salts possess high solubility at room temperature.
- **Natural Polymer Lignin**: Lignin ($C_9H_{10}O_2C_{10}H_{12}O_3C_{11}H_{14}O_4$), a biopolymer, was sourced from MERCK in powder form. It is used to stabilize the foam in combination with surfactants. Fig. 3 shows the molecular structure of natural polymer lignin. Lignin is a complex, highly

branched, and cross-linked polymer composed of various phenolic units, primarily p-coumaryl alcohol, coniferyl alcohol, and sinapyl alcohol. These units are connected by different types of bonds, including carbon-carbon and ether bonds, forming a three-dimensional structure. Lignin's irregular and highly branched architecture contributes to its role in providing rigidity and resistance to degradation in plant tissues[34].

- **Asphaltene**: The asphaltene sample used in this study was extracted from a heavy crude oil obtained from the Rag Sefid oil field, located approximately 150 kilometers southeast of Ahvaz, Iran. The asphaltene was isolated following the standard ASTM D6560-12 method using n-heptane as the precipitating agent. Crude oil was diluted with excess n-heptane at a 40:1 volume ratio and stirred at room temperature for 24 hours to facilitate precipitation. The resulting precipitate was filtered and thoroughly washed with hot n-heptane to remove maltenes and other soluble fractions. The purified asphaltene was then dried under vacuum at 60°C for 24 hours and stored in airtight containers. For interfacial tension measurements, a stock solution was prepared by dispersing the asphaltene in toluene and sonicating the mixture for 30 minutes to ensure full dissolution. Figure 4 illustrates the apparatus used for asphaltene extraction during this procedure.

Moreover, CO_2 and air were used as the gas phases for foam generation, simulating common gas injection processes in EOR. Furthermore, three types of oils were tested to study their impact on foam stability: heptane, toluene, and a heptol (mixture of heptane and toluene). Fig. 5 and 6 depict the molecular structure of heptane and toluene. Heptane is a linear alkane hydrocarbon with the molecular formula C_7H_6 .It consists of a chain of seven carbon atoms, where each carbon atom is single-bonded to hydrogen atoms. The structure is simple and linear, with no branching, and all bonds between carbon atoms are single bonds, which is characteristic of alkanes. Heptane is commonly used as a reference compound in octane ratings for fuels and has applications in organic solvents[35],[36].

Seawater was one of the essential components used in the tests conducted, being utilized as the base solution. The ion concentrations present in the seawater are shown in Table 1.

2.2. Foam stability experiments

Foam stability was assessed through a series of controlled laboratory experiments using a static foam generation approach, which was consistently applied throughout the study. This method was selected for its reproducibility and its ability to isolate foam decay behavior under static (non-flowing) conditions, making it suitable for comparative analysis across different formulations. The experiments were designed to simulate enhanced oil recovery (EOR) conditions by varying the type of surfactant (CTAB and SDS), natural polymer (lignin), type of oil (heptane, toluene, heptol), and salinity levels (distilled water and synthetic seawater). For each test, the foam was generated once and allowed to decay naturally over time. Foam height was recorded at regular time intervals using a calibrated measuring column, and two main indicators of stability were analyzed: foam half-life (the time it takes for the foam to reduce to half its initial height) and total stability duration (the time until complete foam collapse).

2.2.1. Static foam generation method

The static foam method was the only technique employed in this study for foam generation and evaluation. In this method, foam is generated at the beginning of the experiment and left undisturbed for observation of its natural decay behavior. This technique is particularly useful for isolating the effect of variables such as surfactant type, salinity, and oil content on foam longevity, without the interference of continuous gas flow. Foam generation was conducted inside a custom-designed medium-pressure foam column, where a fixed volume of the surfactant solution was introduced, followed by controlled gas injection (air or CO_2)through a porous diffuser at the base of the column. The gas flow was regulated using a precision flow meter (mL/min), ensuring accurate and repeatable foam formation conditions. Once foam was formed, the gas input was stopped and the decay process began. The foam height was monitored and recorded using a scale marked on the column wall, and environmental variables such as temperature and ambient pressure were kept constant to ensure test consistency. This method allows for reliable assessment of how formulation components affect foam structure and durability.

2.2.1.1. Mixing method

In preparation for foam generation, the surfactant solutions were mixed using a magnetic stirrer at 1400 rpm for 5 minutes to ensure complete dissolution and homogeneity. This step is essential to prevent inconsistencies in foam formation due to undissolved particles or phase separation. It is important to clarify that this mixing step is not a method of foam generation itself, but a preparatory procedure that ensures consistency before the gas injection process. Unlike the shaking method, which uses mechanical agitation to create foam, the mixing process is solely for solution preparation. It should be stated that although the shaking method is commonly referenced in literature as a basic test for foamability, it was not applied in this study. This method typically involves manual shaking of a sealed container with a surfactant solution to create foam, but due to its low reproducibility, lack of control over gas volume, and limited applicability to EOR-relevant conditions, it was excluded from our methodology.

The medium-pressure foam chamber used in this study is rated for a maximum operating pressure of 5 bar. However, all foam generation and stability experiments in this work were conducted under atmospheric pressure conditions (approximately 1 bar). The medium-pressure capacity of the apparatus is intended to allow for future testing under higher pressure conditions, but was not employed in the present experiments. The experimental setup used for foam generation and stability testing is illustrated in Fig. 7, which is corresponded to the static foam generation method. The column allows for precise monitoring of foam height under medium-pressure conditions, enabling the evaluation of foam performance under various salinity and oil contamination scenarios.

2.4. Critical micelle concentration (CMC) determination

The critical micelle concentration (CMC) is a key physicochemical property of surfactants, defined as the concentration at which surfactant molecules begin to self-assemble into micelles in solution. Below this threshold, surfactants predominantly exist as monomers, while above the CMC, micelle formation alters the bulk and interfacial properties of the solution, including surface tension and foam stability[37]. Accurate determination of the CMC is essential in foam studies, as surfactant concentrations below the CMC typically result in weak and unstable foam. In contrast, surfactant concentrations at or above the CMC promote micelle formation, which enhances foam structure by strengthening the lamellae and reducing liquid drainage. This is particularly important for applications such as gas injection in enhanced oil recovery (EOR), where surfactants must maintain foam integrity in saline or oil-contaminated environments. In this study, the CMC values were determined to ensure that all foam stability experiments were conducted at concentrations above this threshold. This helped optimize surfactant performance and ensured the reliability of the foam stability assessments.

2.4.1. Surface tension measurement

Surface tension measurements were used to determine the CMC of the surfactant solutions. Surfactants reduce surface tension by adsorbing at the air–water interface. As surfactant concentration increases, surface tension decreases until it reaches a plateau—the CMC point—beyond which further increases in concentration do not significantly affect surface tension, as excess surfactant molecules begin forming micelles in the bulk solution rather than accumulating at the interface. The CMC was identified as the concentration at which this transition occurs. This method is widely accepted and provides a reliable indication of the optimal concentration range for surfactant use in foam applications[38].

2.5. Foam stability measurement

Foam stability is a critical parameter in applications like EOR, where foams are used to improve the sweep efficiency of gas injection by preventing gas channeling in porous media. The stability of foam is largely influenced by the surfactants used, the presence of oil, salinity, and other reservoir conditions. Two key parameters were employed in this study to quantitatively evaluate the foam stability: foam half-life and foam volume decay. These parameters help assess how well the foam resists collapse over time under static condition, providing insights into its long-term effectiveness in various industrial applications.

2.5.1. Foam half-life

The foam half-life is defined as the time it takes for the foam height to reduce to half of its original value. This measurement is widely used as an indicator of foam stability because it provides a simple yet effective way to compare the performance of different surfactants and conditions. A longer foam half-life indicates that the foam is more stable and can resist breakdown for a more extended period, which is critical in applications like EOR, where foams must maintain their structure to effectively block high-permeability zones. The half-life is affected by factors such as the surfactant concentration, the type of oil present, and the salinity of the solution.

2.5.2. Foam volume decay

Foam volume decay refers to the reduction in foam volume over time, and it provides a more detailed understanding of foam stability by capturing the rate at which the foam collapses. The foam volume decay is measured continuously during the experiments, and the stability of the foam is calculated using the following formula:

$$s = \frac{v'_s - v_s}{v'_s} \qquad (1)$$

Where S is the foam stability, V_s' is the initial foam volume, V_s is the foam volume after a specified time. This equation allows for the comparison of foam stability across various time intervals during the experiments. A higher value of S indicates greater foam stability, as the foam retains more of its original volume over time. Conversely, a lower value of S suggests that the foam is collapsing more rapidly, indicating poor stability[39].

3. Results and discussion

The primary aim of this research is to assess the impact of a biopolymer, lignin, on the stability of foam in gas injection processes. Traditional surfactants often exhibit poor performance in challenging reservoir conditions, including high salinity, temperature, pressure, and the presence of oil. Therefore, finding a stabilizing agent that can improve foam performance is crucial. Lignin, a natural polymer with both hydrophilic and hydrophobic components, serves as an ideal candidate for enhancing foam stability. This section discusses the experimental results and analyzes the foam stability under various conditions, including the presence of CTAB and SDS surfactants, different salts, and oil. Additionally, the role of CO_2 injection in foam stabilization is evaluated.

3.1. Surface tension variation

Surface tension is a critical parameter in understanding the interfacial behavior of surfactants and their effectiveness in foam stabilization. The variation of surface tension with increasing concentrations of two widely used surfactants (CTAB and SDS) was investigated in both deionized water and synthetic seawater. Surface tension measurements were conducted using the pendant drop method to determine the CMC for each surfactant under the respective conditions. Fig. S1 (See supplementary file) illustrates the changes in surface tension as a function of increasing concentrations of the two surfactants in different aqueous media, highlighting the distinct behavior of each system. Fig. S1 (Supplementary data) illustrates the changes in surface tension as a function of increasing concentrations of the two surfactants in different aqueous media, highlighting the distinct behavior of each system. Overall, CTAB demonstrated a more rapid and effective reduction in surface tension at lower concentrations compared to SDS, in both deionized water and seawater. The cationic structure of CTAB allows for better adsorption and micelle formation, making it a more efficient surfactant for reducing surface tension. The presence of salts in seawater consistently resulted in a higher initial surface tension but facilitated micellization, likely due to ionic screening effects that support aggregation at lower interfacial free energy. It is also worth noting that the densities of the prepared surfactant solutions across all tested concentrations showed minimal variation, ranging from 0.998 to 1.012 g/cm³. These small changes are typical for aqueous surfactant systems and are not expected to significantly affect interfacial behavior. These surface tension behaviors are important in the context of foam formation and stability, as they directly influence the surfactant's ability to form stable foam films. Efficient surface tension reduction and timely micelle formation are essential characteristics of a good foaming agent, particularly in enhanced oil recovery applications where stability under varying salinity conditions is critical.

Fig. S2 (See supplementary data) illustrates how the surface tension of deionized water and seawater changes with increasing concentrations of lignin, in the presence and absence of CTAB. Surface tension profiles show that lignin alone has a concentration-dependent effect that varies between deionized water and seawater due to ionic interactions. The presence of CTAB significantly lowers surface tension in both media, and lignin's additional contribution becomes more evident only at higher concentrations. Notably, the initial increase in surface tension in seawater without CTAB highlights the competing interactions between lignin and salts.

Fig. S3 (See supplementary data) illustrates the interfacial tension (IFT) between distilled water and heptol under two experimental conditions: (i) varying asphaltene concentrations alone, and (ii) increasing lignin content at a fixed asphaltene concentration of 500 ppm. In the asphaltene-only system, IFT initially decreases due to interfacial adsorption but rises at 1000 ppm due to aggregation, before declining again at higher concentrations. In contrast, the asphaltene–lignin system shows a more stable and consistent reduction in IFT, suggesting synergistic interactions that enhance interfacial packing and minimize energy.

3.2. Determination of optimal CTAB and SDS concentrations for foam stability

Fig. S4 (See supplementary data) compares the foam stability of CTAB in deionized water and seawater across different concentrations (100–1000 ppm), assessing stability using two metrics: half-life, which is the time it takes for half of the foam to dissipate, and total foam stability, which measures the time until complete foam collapse.

Fig. S5 (See supplementary data) compares the foam stability of SDS in deionized water and seawater across increasing concentrations (1000–3000 ppm), in terms of both half-life and total foam stability. In deionized water, foam half-life (solid purple line) and total foam stability (dashed purple line) both exhibit a steady increase with rising SDS concentration. SDS exhibits strong foam-stabilizing performance in deionized water, with both half-life and total stability increasing beyond its CMC (~2000 ppm), due to effective interfacial packing and film reinforcement. In seawater, foam stability peaks at lower concentrations (~1500–2000 ppm) but declines afterward, likely due to electrostatic screening and ion-induced suppression of SDS activity.

A comparative analysis of SDS and CTAB reveals significant differences in their foam-stabilizing capabilities under varying salinity conditions. In deionized water, SDS significantly outperforms CTAB, as evidenced by its much higher foam half-life (up to 14,500 s for SDS vs. 1150 s for CTAB) and total foam stability (≈24,000 s vs. 2600 s). This superior performance is attributed to the anionic nature of SDS, which offers stronger electrostatic repulsion between surfactant molecules and micelles, leading to more stable foam films and resistance to coalescence. In contrast, CTAB, being a cationic surfactant, exhibits weaker intermolecular repulsion and is more sensitive to ionic interactions, resulting in faster foam collapse and lower foam stability. Its performance plateaus at lower concentrations (~500 ppm), indicating earlier saturation and limited stabilization efficiency compared to SDS.

In seawater, both surfactants show reduced effectiveness due to salt interference. However, SDS maintains relatively better performance under saline conditions. This is because SDS's negatively charged head groups are less susceptible to neutralization by salt ions than CTAB's positively charged groups, which interact more readily with counter-ions like Cl^-. These interactions in CTAB systems accelerate micelle destabilization and foam breakdown. Furthermore, SDS possesses a shorter alkyl chain (C12), allowing tighter packing at the air–water interface and greater reduction in surface tension, while CTAB's longer chain (C16) can hinder interfacial packing and increase aggregation at higher concentrations. In summary, SDS provides more stable and longer-lasting foams in both deionized and saline environments, making it a more suitable candidate than CTAB for foam-based EOR applications, particularly when environmental or reservoir salinity is a concern.

3.3. Effect of seawater and salt addition on foam stability

Fig. S6 (See supplementary data) illustrates the effect of seawater dilution on foam half-life and total foam stability using optimal CTAB concentration (500 ppm). Seawater was diluted with deionized water to prepare solutions containing 0%, 9%, 16%, 25%, 33%, and 50% seawater by weight. The trends indicate that both half-life (blue bars) and total foam stability (orange bars) exhibit non-monotonic behavior, with a notable maximum at 9% seawater. At 0% seawater (pure deionized water), the foam half-life is approximately 0.066 hours (≈4 minutes) and total foam stability reaches 0.4 hours (24 minutes). In this condition, CTAB molecules effectively adsorb at the air–water interface, reducing surface tension and forming a cohesive interfacial film. The absence of interfering ions allows the cationic head groups (quaternary ammonium) of CTAB to maximize repulsive interactions and resist bubble coalescence. As seawater concentration increases to 50%, both half-life and total stability decrease moderately. The presence of salts, especially chloride (Cl^-) and sodium (Na^+), screens the positive charges on the CTAB head groups. This charge neutralization diminishes the electrostatic repulsion between adjacent surfactant molecules at the interface, promoting bubble coalescence and foam decay. Accordingly, electrostatic destabilization leads to lower foam performance at high ionic strength.

Fig. S7 (See supplementary data) illustrates the effect of seawater dilution on foam half-life and total foam stability using the optimal SDS concentration (3000 ppm). Seawater was diluted with deionized water to prepare six brine solutions with different salinities (0%, 9%, 16%, 25%, 33%, and 50% seawater by weight). Foam stability of SDS decreases steadily with increasing seawater concentration, as both half-life and total stability decline due to electrostatic screening by salt ions. Cations such as Na^+, Ca^{2+}, and Mg^{2+} disrupt SDS micelle integrity and hinder its interfacial adsorption, leading to reduced foam longevity in saline conditions.

Fig. S8 (See supplementary data) illustrates the effects of different weight concentrations (1% to 10%) of three salts—Na_2SO_4, $CaCl_2$, and $MgCl_2$—on foam half-life and total foam stability in the presence of CTAB (500 ppm). The chart allows for a detailed comparison of how monovalent and divalent ions influence foam behavior. Na_2SO_4 enhances foam stability up to 3% concentration by moderately screening electrostatic repulsion, but higher levels reduce performance due to excessive ionic strength. In contrast, $CaCl_2$ and $MgCl_2$ significantly destabilize foam beyond 2–3% due to strong interactions with CTAB head groups, with Ca^{2+} showing a sharper decline and Mg^{2+} inducing a more gradual effect.

In comparison, Na_2SO_4 provides the best foam stabilization among the three salts, especially at 3%, due to its milder interaction with surfactant molecules as a monovalent salt. $CaCl_2$ significantly disrupts foam stability beyond 2% due to the higher ionic charge of Ca^{2+}, which enhances ion-surfactant interactions and leads to faster foam collapse. $MgCl_2$ also reduces foam performance, but its effect is slightly less abrupt than $CaCl_2$, likely due to the balance between its stronger interactions and smaller ionic size. These findings highlight that the foam stability in saline systems depends not only on salt concentration but also on the type of cation present—monovalent versus divalent—and their specific electrostatic and hydration properties.

3.4. Influence of oil on foam stability

Fig. S9 (See supplementary data) illustrates the effect of varying concentrations of three hydrocarbon compounds—n-heptane, toluene, and heptol (1:1 volumetric mixture of n-heptane and toluene)—on foam half-life and total foam stability. Na_2SO_4 enhances foam stability up to 3% concentration by moderately screening electrostatic repulsion, but higher levels reduce performance due to excessive ionic strength. In contrast, $CaCl_2$ and $MgCl_2$ significantly destabilize foam beyond 2–3% due to strong interactions with CTAB head groups, with Ca^{2+} showing a sharper decline and Mg^{2+} inducing a more gradual effect.

Figure S10 (See supplementary data) illustrates the impact of increasing concentrations of asphaltene in heptol on foam half-life and total foam stability. Foam stability decreases sharply with increasing asphaltene concentration, dropping to zero beyond 1000 ppm. Asphaltene aggregates disrupt the surfactant film by weakening interfacial cohesion and increasing local surface tension, leading to rapid foam collapse. The most stable foam is observed in the absence of asphaltene.

3.5. The effect of surfactant concentration on foam stability in the presence of carbon dioxide

CO_2 injection is a prominent method for enhancing oil recovery, primarily due to its ability to reduce surface tension in water and promote foam stability. The density of CO_2 at standard conditions (25°C and atmospheric pressure) is approximately 1.773 kg/m³, while that of air is about 1.225 kg/m³. Although it is well known that increasing pressure can significantly raise the density of CO_2, thereby improving its capacity to form more stable foams near the oil phase, this study was conducted under ambient pressure conditions. Therefore, the effect of pressure on CO_2 density and foam stability was not directly evaluated. It is important to note that foams generated with CO_2 tend to be less stable than those produced with air at ambient conditions, partly due to CO_2's lower molecular weight and limited reactivity under these circumstances.

Fig. S11 (See supplementary data) presents the effect of CO_2 injection on foam stability for two surfactants, CTAB and SDS, in both distilled water and seawater. The figure compares foam half-life and total foam stability over a range of surfactant concentrations. Under CO_2 injection, SDS demonstrates superior foam-stabilizing ability compared to CTAB, especially in distilled water, due to its strong electrostatic repulsion and thicker foam films. In seawater, both surfactants show reduced performance, but SDS maintains better stability than CTAB, highlighting the negative impact of divalent ions on interfacial organization.

The graph in Fig. S12 (See supplementary data) represents foam stability in the presence of different surfactants (CTAB and SDS), two types of water (distilled water and seawater), crude oil, and under CO_2 injection conditions. Foam stability for both CTAB and SDS declines with increasing concentration, especially in seawater and in the presence of oil and CO_2. CTAB is more affected due to weaker interfacial resilience under acidic and oily conditions, while SDS maintains relatively better performance, though still diminished by ionic screening and CO_2-induced destabilization.

Fig. S13 (See supplementary data) illustrates how varying the proportion of distilled water (from 1% to 20%) in a seawater-based system affects foam half-life and total foam stability. Foam stability improves significantly with increasing distilled water percentage, especially beyond 10%, due to reduced ionic strength. At low percentages, salts from seawater destabilize the foam, but as dilution progresses, surfactant molecules form stronger interfacial films, enhancing both half-life and total stability.

3.6. The effect of lignin polymer on foam stability

3.6.1. Foam stability in the presence of air

Fig. S14 (See supplementary data) presents a comparative evaluation of foam stability, both half-life and total stability, for lignin-based systems under air injection across a concentration range of 100, 500, 1000, and 2000 ppm. Foam stability increases with lignin concentration in distilled water and is further enhanced by adding 500 ppm CTAB, showing strong lignin–surfactant synergy. While seawater reduces foam performance due to salt interference, CTAB still offers partial improvement. The presence of heptol significantly disrupts foam stability, emphasizing the sensitivity of foam systems to hydrocarbon contamination.

Furthermore, the experiments were repeated with the anionic surfactant SDS, as shown in Fig. S15 (See supplementary data). Foam stability is highest in distilled water and declines in seawater due to interference from dissolved salts, with the presence of heptol further reducing stability by disrupting bubble films. Although increasing lignin + SDS concentration improves foam performance, the surrounding medium remains a key factor, with distilled water offering optimal conditions for foam persistence.

In conclusion, CTAB demonstrates superior foam stability in both distilled water and seawater compared to SDS. However, in the presence of oils like heptol, both surfactants show a marked reduction in stability, with CTAB still having a slight edge over SDS. Both surfactants perform significantly better in distilled water than seawater, which can be attributed to the presence of salts in seawater interfering with the foam-stabilizing properties of the surfactants. Heptol, an oil phase, substantially decreases foam stability for both CTAB and SDS, highlighting the challenge of foam stability in oil-rich environments. However, CTAB maintains slightly better foam integrity than SDS under these challenging conditions.

3.6.2 Foam Stability in the Presence of CO_2

In the next set of experiments, CO_2 was injected into the system, and the foam stability was measured under different conditions, as seen in Fig. S16 (See supplementary data). Foam stability increases with lignin concentration, especially in distilled water, and is significantly enhanced by the addition of CTAB due to their synergistic effect. Seawater reduces foam performance because of ionic interference, and the presence of heptol further destabilizes the foam by disrupting film structure. The highest foam stability is achieved with lignin + CTAB in distilled water under CO_2 injection.

Fig. S17 (See supplementary data) shows the foam stability using SDS surfactant instead of CTAB. Foam stability for lignin + SDS mixtures improves with increasing concentration, especially in distilled water, where minimal interference allows strong surfactant performance. In seawater, dissolved salts reduce foam half-life and total stability due to ionic interactions that hinder SDS efficiency. The presence of heptol further decreases foam performance by disrupting surfactant films, leading to faster collapse. Overall, the best results are observed in distilled water, while seawater with oil shows the weakest foam stability.

In comparison between the two previous figures, SDS-based systems (Fig. S17) consistently show lower foam stability (both half-life and total stability) than CTAB-based systems (Fig. S16) across all concentrations. CTAB, being a cationic surfactant, tends to provide better foam stability compared to the anionic SDS surfactant. This is due to the strong electrostatic interactions between CTAB and the negatively charged lignin and other materials in the system. This stabilizes the foam more effectively than SDS, where the interactions may be weaker. Moreover, the presence of seawater reduces foam stability for both surfactants, but SDS is more affected by the salts in seawater.

Table S1 (See supplementary data) summarizes the comparative foam performance of lignin-based systems under both air and CO_2 injection at different lignin concentrations (100–2000 ppm). Air injection yields greater foam stability than CO_2, especially in distilled water, while CTAB enhances performance and heptol significantly reduces it across all systems.

Table S2 (See supplementary data) provides a comprehensive comparison of foam half-life and total foam stability for lignin-based systems using SDS as a surfactant under both air and CO_2 injection. Foam stability improves with increasing lignin concentration, peaking in SDS + distilled water under air injection, while the lowest stability occurs in CO_2 + SDS + seawater + heptol systems due to combined destabilizing effects.

To conclude, it can be stated that the stabilization mechanism of lignin in foam is influenced by its molecular structure. Lignin contains aromatic rings and hydroxyl (OH) groups, making it partially hydrophobic and partially hydrophilic. This dual character allows it to occupy the foam interface, preventing bubbles from coalescing. However, in acidic environments or in the presence of CO_2, the solubility of lignin decreases, leading to reduced foam stability. In systems with surfactants, lignin can interact with surfactants to enhance foam stability. CTAB, being a cationic surfactant, interacts with the negatively charged lignin molecules, forming a more stable film at the foam interface. In contrast, SDS, an anionic surfactant, experiences electrostatic repulsion from lignin, reducing its effectiveness in stabilizing the foam. The presence of salts in seawater (such as NaCl, $CaCl_2$, and $MgCl_2$) disrupts foam stability by competing with lignin and surfactants at the interface. This weakens the surfactant-polymer interactions and accelerates foam breakdown. The addition of oils, such as heptol, further reduces foam stability by interacting with the surfactant, reducing its availability for foam stabilization.

4. Conclusion

This study presents a novel and systematic evaluation of foam stability in lignin-based systems under both air and CO_2 injection, considering various combinations of surfactants (CTAB and SDS), salinity, oil presence, and polymer concentration. The main findings of this study can be summarized as follows:

- Foam stability strongly depends on surfactant type, with CTAB showing superior performance over SDS across all tested conditions, especially when combined with lignin in distilled water.

- Distilled water significantly enhanced foam performance compared to seawater, due to the absence of dissolved salts which otherwise compress the electric double layer and destabilize foam films.

- Oil presence (heptol) had a destabilizing effect on foam, but the reduction was less severe in CTAB-based systems than in SDS-based ones, highlighting better oil tolerance of CTAB-lignin foams.

- Lignin polymer acted as a natural foam stabilizer, improving both half-life and total foam stability, especially in combination with CTAB, in both air and CO_2 injection environments.

- CO_2 injection resulted in lower foam stability compared to air, attributed to CO_2's higher solubility and diffusivity in aqueous phases, which accelerates foam collapse, especially in saline and oily environments.

- The best foam performance was observed in the CTAB + lignin + distilled water system under air injection, with notable improvement at higher lignin concentrations (≥1000 ppm).

5. Recommendations

- **Lignin performance at elevated temperatures**: Future studies should investigate the effect of adding lignin to foam-forming solutions under high-temperature conditions, simulating reservoir conditions.
- **High-pressure experiments**: The effect of lignin under high-pressure conditions should be explored to better understand its behavior in deep reservoirs.
- **Lignin and surfactant injection into cores**: The combination of lignin and surfactants should be tested by injecting the foam solution into core samples to assess foam performance under reservoir-like conditions.

- **Foam stability with different gases**: Investigations should be conducted into foam stability generated by lignin and surfactants using different gases, such as methane and nitrogen, to evaluate the versatility of the system.
- **Effect of various surfactants on lignin**: The interaction between different surfactants and lignin should be studied to determine which combinations yield the most stable foams.
- **Microscopic and structural studies**: Microscopic and structural analyses of the interactions between lignin and the fluid interface should be performed to provide insights into the mechanisms of foam stabilization.
- **Modeling of lignin and surfactant interaction**: A detailed model describing the interaction between lignin and surfactants during foam generation and injection should be developed for application in reservoir simulations.
- **Comparison with other natural polymers**: Other natural polymers should be evaluated as potential alternatives to lignin, and their foam stabilization properties should be compared.
- **Use of alternative oils**: Different oils, besides heptane and toluene, should be tested to assess the foam stability and the performance of lignin in various oil conditions.

The supplementary data is available at:

file:///C:/Users/pc/Downloads/Supplementary%20File(1)-2.pdf

References

1. Bera, A., Vij, R. K., and Shah, S., "Impact of newly implemented enhanced oil and gas recovery screening policy on current oil production and future energy supply in India", *Journal of Petroleum Science and Engineering*, **207**, p. 109196 (2021). https://doi.org/10.1016/j.petrol.2021.109196
2. Temizel, C., Canbaz, C. H., Tran, M., Abdelfatah, E., Jia, B., Putra, D., Irani, M., and Alkouh, A., "A comprehensive review heavy oil reservoirs, latest techniques, discoveries, technologies and applications in the oil and gas industry", *SPE International Heavy Oil Conference and Exhibition*, SPE, p. D012S024R001 (2018). https://doi.org/10.2118/193646-MS
3. Tanhaei, H., Hossein, A., and Dehaghani, S., "Improvement of the quality of heavy crude oil and reducing the concentration of asphaltene hydrocarbons using microwave radiation during acidizing", *Scientific Reports*, **15**(1), p. 7434 (2025). https://doi.org/10.1038/s41598-025-91932-x

4. Ozowe, W., Daramola, G. O., and Ekemezie, I. O., “Petroleum engineering innovations: Evaluating the impact of advanced gas injection techniques on reservoir management”, *Magna Scientia Advanced Research and Reviews*, **11**(1), pp. 299–310 (2024). https://doi.org/10.30574/msarr.2024.11.1.0094
5. Du, F. and Nojabaei, B., “A review of gas injection in shale reservoirs: enhanced oil/gas recovery approaches and greenhouse gas control”, *Energies*, **12**(12), p. 2355 (2019). https://doi.org/10.3390/en12122355

6. Behnammotlagh, M. A., Hashemi, R., Taheri Rizi, Z., Mohammadtaheri, M., and Mohammadi, M., “Experimental study of the effect of the combined monoethylene glycol with NaCl/$CaCl_2$ salts on sour gas hydrate inhibition with low-concentration hydrogen sulfide”, *J. Chem. Eng. Data*, **67**(5), pp. 1250–1258 (2022). https://doi.org/10.1021/acs.jced.1c00888
7. Haddad, D. E., Long, H., Agrawal, R., and Kumar, H. T., “Reservoir mechanisms of unconventional gas injection EOR; Insights from field trials in the eagle ford”, *SPE/AAPG/SEG Unconventional Resources Technology Conference*, URTEC, p. D021S045R001 (2023). https://doi.org/10.15530/urtec-2023-3862004
8. Shiyi, Y., Haishui, H. A. N., Hongzhuang, W., Jianhui, L. U. O., Qiang, W., Zhengdong, L. E. I., Changfeng, X. I., and Junshi, L. I., “Research progress and potential of new enhanced oil recovery methods in oilfield development”, *Petroleum Exploration and Development*, **51**(4), pp. 963–980 (2024). https://doi.org/10.1016/S1876-3804(24)60518-5
9. Perticaroli, S., Herzberger, J., Sun, Y., Nickels, J. D., Murphy, R. P., Weigandt, K., and Ray, P. J., “Multiscale microstructure, composition, and stability of surfactant/polymer foams”, *Langmuir*, **36**(48), pp. 14763–14771 (2020). https://doi.org/10.1021/acs.langmuir.0c02704
10. Khan, J. A., Kim, J., Irawan, S., Permatasar, K. A., Verdin, P. G., Cai, B., and Yekeen, N., “Application of foam assisted water-alternating-gas flooding and quantification of resistivity and water saturation by experiment and simulation to determine foam propagation in sandstone”, *Heliyon*, **10**(3) (2024). https://doi.org/10.1016/j.heliyon.2024.e25435
11. Chen, H., Li, Z., Wang, F., Li, A., Wanambwa, S., and Lu, T., “Experimental study on the enhanced oil recovery by in situ foam formulation”, *Energy Science & Engineering*, **8**(4), pp. 1092–1103 (2020). https://doi.org/10.1002/ese3.570
12. Farzaneh, S. A. and Sohrabi, M., “A review of the status of foam applications in enhanced oil recovery”, *SPE Europec Featured at EAGE Conference and Exhibition?*, SPE, p. SPE-164917 (2013). https://doi.org/10.2118/164917-MS
13. Adila, A. S., Al-Shalabi, E. W., and AlAmeri, W., “Recent developments in surfactant flooding for carbonate reservoirs under harsh conditions”, *Offshore Technology Conference Asia*, OTC, p. D012S001R066 (2020). https://doi.org/10.4043/30318-MS
14. Koelsch, P. and Motschmann, H., “Relating foam lamella stability and surface dilational rheology”, *Langmuir*, **21**(14), pp. 6265–6269 (2005). https://doi.org/10.1021/la050459c
15. Mahajan, S., Yadav, H., Rellegadla, S., and Agrawal, A., “Polymers for enhanced oil recovery: fundamentals and selection criteria revisited”, *Appl Microbiol Biotechnol*, **105**(21–22), pp. 8073–8090 (2021). https://doi.org/10.1007/s00253-021-11618-y
16. Bass, G. F. and Epps, T. H., “Recent developments towards performance-enhancing lignin-based polymers”, *Polymer Chemistry*, **12**(29), pp. 4130–4158 (2021). https://doi.org/10.1039/D1PY00694K

17. Braun, L., Kühnhammer, M., and von Klitzing, R., “Stability of aqueous foam films and foams containing polymers: Discrepancies between different length scales”, *Current Opinion in Colloid & Interface Science*, **50**, p. 101379 (2020). https://doi.org/10.1016/j.cocis.2020.08.004
18. Nguyen, Q. P., Alexandrov, A. V., Zitha, P. L., and Currie, P. K., “Experimental and modeling studies on foam in porous media: a review”, *SPE International Conference and Exhibition on Formation Damage Control*, SPE, p. SPE-58799 (2000). https://doi.org/10.2118/58799-MS
19. Xu, X., Saeedi, A., and Liu, K., “Laboratory studies on CO_2 foam flooding enhanced by a novel amphiphilic ter-polymer”, *Journal of Petroleum Science and Engineering*, **138**, pp. 153–159 (2016). https://doi.org/10.1016/j.petrol.2015.10.025
20. Srivastava, A., Qiao, W., Wu, Y., Li, X., Bao, L., and Liu, C., “Effects of silica nanoparticles and polymers on foam stability with sodium dodecylbenzene sulfonate in water–liquid paraffin oil emulsions at high temperatures”, *Journal of Molecular Liquids*, **241**, pp. 1069–1078 (2017). https://doi.org/10.1016/j.molliq.2017.06.096
21. Osei-Bonsu, K., Grassia, P., and Shokri, N., “Relationship between bulk foam stability, surfactant formulation and oil displacement efficiency in porous media”, *Fuel*, **203**, pp. 403–410 (2017). https://doi.org/10.1016/j.fuel.2017.04.114
22. Telmadarreie, A. and Trivedi, J. J., “Static and dynamic performance of wet foam and polymer-enhanced foam in the presence of heavy oil”, *Colloids and Interfaces*, **2**(3), p. 38 (2018). https://doi.org/10.3390/colloids2030038
23. Ahmed, S., Elraies, K. A., Hanamertani, A. S., Hashmet, M. R., Shafian, S. R., and Hsia, I. C., “Investigation of carbon dioxide foam performance utilizing different additives for fracturing unconventional shales”, *Abu Dhabi International Petroleum Exhibition and Conference*, SPE, p. D012S138R002 (2019). https://doi.org/10.2118/197964-MS
24. Zhang, C., Xue, Y., Huang, D., and Wei, B., “Design and fabrication of anionic/cationic surfactant foams stabilized by lignin–cellulose nanofibrils for enhanced oil recovery”, *Energy Fuels*, **34**(12), pp. 16493–16501 (2020). https://doi.org/10.1021/acs.energyfuels.0c03234
25. Hanamertani, A. S. and Ahmed, S., “Probing the role of associative polymer on scCO_2–Foam strength and rheology enhancement in bulk and porous media for improving oil displacement efficiency”, *Energy*, **228**, p. 120531 (2021). https://doi.org/10.1016/j.energy.2021.120531
26. Emami, H., Ayatizadeh Tanha, A., Khaksar Manshad, A., and Mohammadi, A. H., “Experimental investigation of foam flooding using anionic and nonionic surfactants: A screening scenario to assess the effects of salinity and pH on foam stability and foam height”, *ACS Omega*, **7**(17), pp. 14832–14847 (2022). https://doi.org/10.1021/acsomega.2c00314
27. Ju, S., Huang, Q., Wang, G., Li, J., Wang, E., Qin, C., and Qiao, J., “Rheological and morphological characteristics of foam fluid using hydroxypropyl guar and surfactant”, *Journal of Petroleum Science and Engineering*, **211**, p. 110124 (2022). https://doi.org/10.1016/j.petrol.2022.110124
28. Sheng, Y., Ma, W., Yu, X., Ma, L., and Li, Y., “Effect of liquid fuel on foamability and foam stability of mixtures of fluorocarbon and hydrocarbon surfactants”, *Journal of Molecular Liquids*, **388**, p. 122762 (2023). https://doi.org/10.1016/j.molliq.2023.122762
29. Wen, Y., Zhong, Y., Zeng, P., and Li, Q., “Interfacial chemical mechanisms of brine salinity affecting the CO_2 foam stability and its effect on the sequestration capacity of CO_2 in deep saline aquifer”, *Journal of Molecular Liquids*, **399**, p. 124349 (2024). https://doi.org/10.1016/j.molliq.2024.124349

30. Wu, M., Li, B., Ruan, L., Tang, Y., and Li, Z., “Study on the control of steam front mobility in high-temperature and high-salinity conditions using polymer-enhanced foam”, *Polymers*, **16**(17), p. 2478 (2024). https://doi.org/10.3390/polym16172478
31. Ahmed, S., Hanamertani, A. S., Elraies, K. A., and Shafian, S. R. B. M., “Enhanced CO_2 trapping by hydrophobically modified polymer stabilized foam: Significance for CO_2 geo-storage”, *Energy*, **314**, p. 133839 (2025). https://doi.org/10.1016/j.energy.2024.133839
32. Ahmadi, A. and Saeedi Dehaghani, A. H., “Study and modeling the effect of brine salinity and composition and oil type on the foam stability”, *Journal of Petroleum Science and Technology*, **12**(4), pp. 2–12 (2022). https://doi.org/10.22078/jpst.2023.4972.1843
33. Paramashivaiah, B. M. and Rajashekhar, C. R., “Studies on effect of various surfactants on stable dispersion of graphene nano particles in simarouba biodiesel”, *IOP Conference Series: Materials Science and Engineering*, IOP Publishing, p. 012083 (2016). https://doi.org/10.1088/1757-899X/149/1/012083
34. Ribeiro, A. M., Santos, A. I., Veiga, F., and Figueiras, A., “Lignin nanoparticle–based nanocomposite hydrogels for biomedical applications”, In *Functional Nanocomposite Hydrogels*, Elsevier, pp. 69–90 (2023). https://doi.org/10.1016/B978-0-323-99638-9.00003-4
35. Xu, Y., Yamamoto, N., and Janda, K. D., “Catalytic antibodies: hapten design strategies and screening methods”, *Bioorganic & medicinal chemistry*, **12**(20), pp. 5247–5268 (2004). https://doi.org/10.1016/j.bmc.2004.03.077
36. Linford, M. R., “A Discussion of aspects of a paper by caporali, bardi, and lavacchi on leis and xps”, *Vacuum Technology and Coating*, pp. 2–8 (2014).
37. Vu, K. A. and Mulligan, C. N., “An overview on the treatment of oil pollutants in soil using synthetic and biological surfactant foam and nanoparticles”, *International Journal of Molecular Sciences*, **24**(3), p. 1916 (2023). https://doi.org/10.3390/ijms24031916
38. Su, G., Yang, L., Liu, S., Song, J., Jiang, W., and Jin, X., “Review on factors affecting nanofluids surface tension and mechanism analysis”, *Journal of Molecular Liquids*, p. 125159 (2024). https://doi.org/10.1016/j.molliq.2024.125159
39. Nishioka, G. M., Ross, S., and Kornbrekke, R. E., “Fundamental methods for measuring foam stability”, *Foams*, pp. 275–286 (2017). 10.1201/9780203755709-6

List of figure

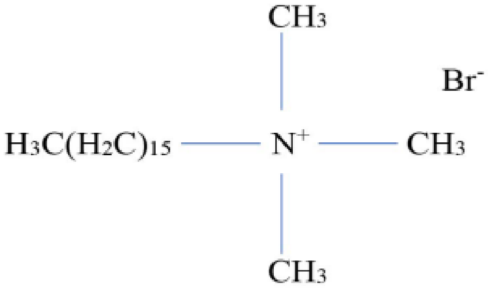
$H_3C(H_2C)_{15}-N^+(CH_3)_3\ Br^-$

Fig. 1. Schematic of the CTAB surfactant molecule[32]

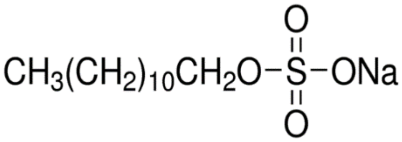
$CH_3(CH_2)_{10}CH_2O-S(=O)_2-ONa$

Fig. 2. Schematic of the SDS surfactant molecule[33]

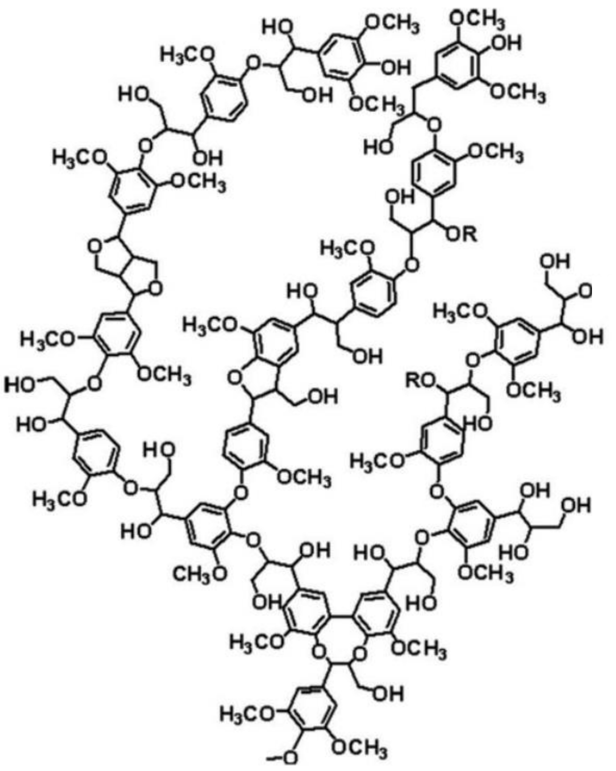

Fig. 3. Molecular structure of natural polymer lignin[34]

Fig. 8. Schematic representation of the apparatus used for asphaltene extraction from crude oil

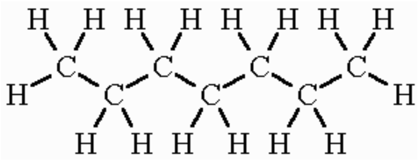

Fig. 5. molecular structure of heptane[35]

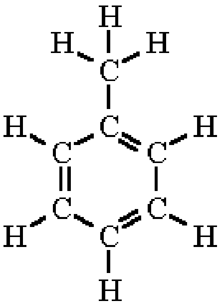

Fig. 6. molecular structure of toluene[36]

Fig. 7. The foam formed in the medium-pressure foam chamber

List of table

Table 1. The ions present in the sea-based water

Ion	Concentration (ppm)
K^+	399
Sr^+	3
HCO_3^-	166
Na^+	12000
Ca^{2+}	440
Mg^{2+}	1632
Cl^-	21410
SO_4^{2-}	3110
TDS	39160

Biographies

Dr. Amir Hossein Saeedi Dehaghani received his Ph.D. in Petroleum Engineering from Tarbiat Modares University in 2013 and has been serving as a faculty member in the Department of Petroleum Engineering, Faculty of Chemical Engineering, since then. His research interests include enhanced oil recovery through CO_2, N_2, and natural gas injection; experimental and modeling studies of wax and asphaltene deposition (solid hydrocarbons); investigation of organic and inorganic scale inhibitors in oil reservoirs; smart water injection using nanofluids and surfactants for production enhancement; kinetics of asphaltene precipitation; acidizing processes and acid sludge formation; upgrading of extra-heavy oils through physical and chemical methods; phase behavior of reservoir fluids; and membrane fabrication and separation processes for gas sweetening.

Mohammad Amin Behnam Motlagh received his M.Sc. in Petroleum Engineering from Isfahan University of Technology in 2021 and is currently pursuing his Ph.D. in Petroleum Engineering at Tarbiat Modares University. He has collaborated with several scientific and industrial institutions, including the Research Institute of Petroleum Industry (RIPI), the Ministry of Science, Research and Technology, and has also served as a university lecturer. He is currently working as a senior reservoir engineer at Petropars Oil and Gas Company. His main research interests include enhanced oil recovery (EOR), foam-assisted gas injection, gas hydrate formation and inhibition, natural gas hydrate exploitation, petroleum reservoir characterization, and the application of natural polymers in flow assurance. He is also actively engaged in studies related to petroleum geology, gas behavior in porous media, and the design of innovative chemical solutions for improving reservoir performance.