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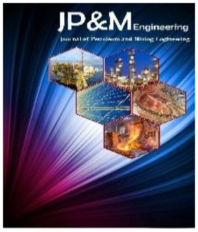

A Comprehensive Literature Survey of Advanced Foam Applications in Petroleum Engineering for Enhanced Oil Recovery

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Abstract

As global oil demand continues to rise and operators scale back on exploration investments, the adoption of enhanced oil recovery (EOR) technology is becoming increasingly essential. This approach strategically aims to optimize reserves in existing fields, maximizing production through efficient processes. In recent years, there has been a notable surge in the adoption of foam applications in EOR. These foam applications are particularly effective in managing gas mobility in injector wells and preventing gas blockages in production wells. Foam has effectively addressed reservoir heterogeneity concerns, including viscosity fingering, gravity segregation, and channeling. These solutions maintain operational stability while improving the efficiency of oil recovery. However, persistent challenges remain ongoing, such as foam solution quality, foamability, stability under high pressures and temperatures, and interactions with the oil phase. Thus, continuing research and development are crucial to overcome these challenges and optimize the use of foam in enhanced oil recovery. This paper aims to comprehensively review and synthesize the most pertinent studies on foam-based enhanced oil recovery (EOR). The study thoroughly investigates the factors that affect foam stability and efficiency, offering a comprehensive understanding of foam generation in porous media. The paper review identifies knowledge gaps and proposes methods to incorporate physical understandings of experiments into assessments of foam project performance. The paper explores the applications of foam in laboratory and field settings, highlighting recent advancements in improving foam stability.

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Introduction

One of the primary energy sources for human development is hydrocarbons, and it is anticipated that this will continue to be the case in the coming years [1], [2]. As the world's population grows, the needs of human beings for energy are constantly increasing. As stated by the US Energy Administration, the consumption of hydrocarbons is projected to be nearly 250 quadrillion BTU in the year 2050 [3], which necessitates increasing hydrocarbon production to satisfy energy needs. The extraction of hydrocarbons from a well typically occurs through three primary phases: initial, secondary, and tertiary recovery [4], [5], [6] (Figure 1). The first phase includes retrieving oil from the well-bore through the natural pressure of the reservoir and the force of gravity. The recovery of oil typically falls within the range of 10 to 20% of the total available oil in the field [7], while the second phase begins as the well pressure decreases. To increase the pressure at this stage, the wells are filled with seawater or gas injection, forcing the oil upwards [8], thereby increasing the recovery rate by about 20% to 30% of the well material extracted after primary and secondary recovery, which means that the well is exhausted, leaving more than 70% of the oil untapped [9]. This marks the beginning of the third stage, called enhanced oil recovery (EOR) or tertiary recovery. EOR is the process of injecting one or more fluids into the reservoir that is not already there to increase the production of residual oil or remaining oil after primary and secondary recovery [10], [11]. The injected fluids physically or chemically interact with the rock-oil system to promote oil recovery. EOR methods aim to improve the displacement of oil and enhance the overall recovery factor. Enhanced oil

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recovery is a group of techniques that use various injected materials to extract oil from reservoirs. EOR techniques can be broadly classified into four primary methods: gas injection, thermal injection, chemical injection, and alternative approaches such as microbial and foam EOR [12]. The effectiveness of various EOR methods relies on the characteristics of the fluid, reservoir conditions, and the composition of the rock.

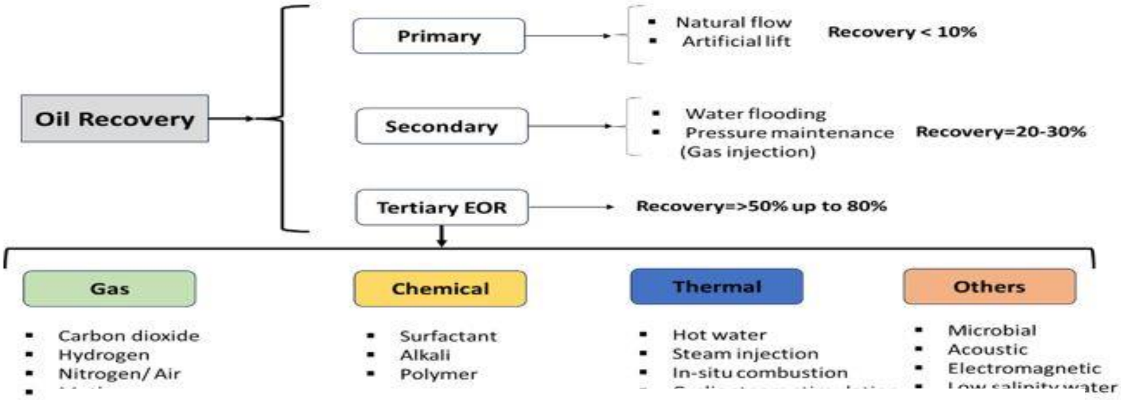

Figure 1 The various methods of oil recovery and the associated oil recovery factor. (Adapted from [2])

Gas injection involves injecting various miscible gases, such as carbon dioxide, nitrogen, flue gas, and natural gas [13], [14], [15]. This gas injection technique aims to enhance oil displacement and maintain reservoir pressure by achieving a single-phase state between the injected gas and oil. During the thermal EOR method, the oil displacement is improved by heat transfer through the reservoir, using hot water and/or steam injection processes to reduce its viscosity, making it easier to extract [16]. On the other hand, the chemical injection approach entails injecting various chemicals such as polymers, salts, alkalis, and surfactants, to facilitate oil transportation by a variety of processes, such as the modification of wettability, lowering of surface tension, and water shut-off [17], [18], [19].

Gases utilized in gas-flooding operations, including CO_2, hydrocarbons, air, and N_2, typically exhibit significantly lower viscosity and density than water and crude oil. This characteristic leads to gas preferentially channeling through high-permeability zones and experiencing gravity override [20], [21], [22], [23]. Consequently, gas flooding tends to have suboptimal volumetric sweep efficiency, especially in cases of immiscible displacement where the displacing phase has lower viscosity.

While gas injection offers the advantage of superior microscopic sweep, resulting in lower residual oil saturation in pores compared to waterflood, a significant challenge arises due to its poor volumetric sweep efficiency [24]. This inefficiency means that a substantial portion of the oil is not contacted, resulting in overall low recovery rates. The main factors contributing to this inefficiency are gravity segregation and override, resulting from the lower density of gas compared to oil and water, as well as fingering effects caused by the high mobility ratio between the injected gas and the oil or water, and channeling through high-permeability layers in heterogeneous and layered reservoirs [25], [26]. An alternative approach to continuous gas injection is water-alternating-gas (WAG) injection, where gas and water slugs are alternated. While this method partially addresses the limitations of continuous gas injection, gravity segregation during WAG flooding can still cause premature gas breakthroughs [27], [28].

To address this issue and enhance control over fluid mobility in gas flooding, foam is introduced for sweep improvement and profile modification (Figure 2). The strategic use of foam aims to boost the efficiency of the displacing fluid in sweeping through the reservoir, ensuring better contact with and recovery of oil [29], [30], [31].

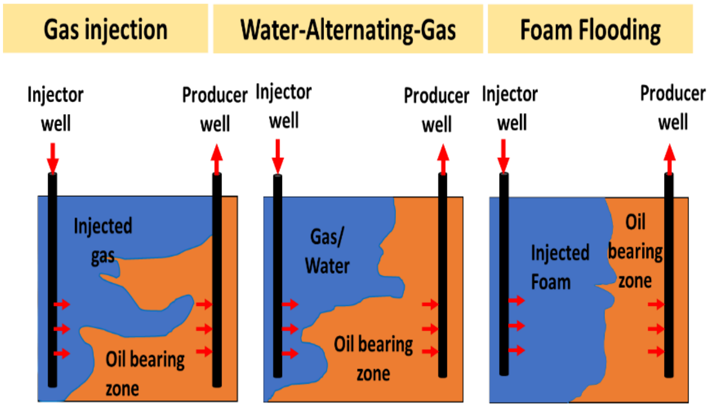

Figure 2 Comparison of the effectiveness of gas, water-alternating gas (WAG),

Table 1 A comparative analysis of foam performance against other EOR techniques [6]

Criteria	**Foam-Assisted EOR (FAWAG & Steam Foam)**	**Gas EOR Methods (WAG, SWAG, MGI)**	**Thermal EOR (Steam Injection)**
Mechanism	Foam controls gas mobility by blocking high-permeability zones, improving sweep efficiency. Foam stabilizes steam in steam foam processes.	Gas injection improves sweep efficiency and reduces residual oil saturation through miscibility and gravity drainage.	Steam reduces oil viscosity, improving mobility and recovery through heat transfer.
Performance in Heterogeneous Reservoirs	Highly effective in heterogeneous reservoirs, prevents early gas breakthrough and improves gas sweep efficiency.	WAG and SWAG have moderate efficiency, but early gas breakthrough and gravity override are common issues.	Not ideal for heterogeneous reservoirs; steam losses and uneven heat distribution can reduce efficiency.
Best Suited Geological Setting	Light oil reservoirs with high heterogeneity (e.g., North Sea); heavy oil reservoirs for steam foam (California, Canada).	Light oil reservoirs with moderate heterogeneity; applicable in North Sea (e.g., Magnus, Snorre).	Heavy oil reservoirs; suitable for viscous oil recovery (SAGD and steam flood projects in Canada and California).
Incremental Recovery Potential	High incremental recovery (5–10%) due to improved mobility control in FAWAG and better steam efficiency in steam foam.	Moderate incremental recovery (3–6%) but depends on miscibility and reservoir conditions.	High recovery potential (>50% OOIP) for heavy oil reservoirs with good steam sweep control.
Advantages	- Controls gas mobility, reduces gravity override. - Effective in high-permeability reservoirs. - Reduces steam losses in steam foam.	- Simple to implement. - Improves oil sweep in miscible conditions. - Commonly used in offshore light oil fields.	- Highly effective for reducing oil viscosity. - Steam foam improves steam efficiency and controls heat losses.
Limitations	- Requires stable surfactants for foam generation. - Oil can destabilize foam, reducing efficiency.	- Early gas breakthrough and gravity override limit effectiveness. - High reservoir pressure needed for miscibility in MGI.	- High operational costs. - Not suitable for light oil reservoirs due to heat loss in deep, cold formations.

The economic evaluation of foam-based Enhanced Oil Recovery (EOR) conducted by Farid Tayari et al. [32] illustrated its cost-effectiveness relative to alternative methods. Specifically, cost-benefit analyses reveal that Surfactant Alternating Gas (SAG) flooding results in greater oil recovery at a competitive cost, with an average expenditure of $7.50 per incremental barrel of oil produced. Furthermore, comparative assessments indicate that despite higher capital costs associated with surfactant utilization and CO2 recycling, SAG demonstrates superior profitability compared to Water Alternating Gas (WAG) and Waterflood (WF) techniques, particularly in low-heterogeneity reservoirs.

The Role of Foams in Enhanced Oil Recovery Techniques

The foam-enhanced oil recovery (EOR) technique has garnered attention from the upstream oil industry for its capacity to address challenges associated with gas-based EOR methods, such as gravity segregation, channeling, and viscous fingering [33]. Among the techniques that have emerged as promising and innovative processes in Enhanced Oil Recovery is the foam injection process. Although these techniques have shown real success for extra oil recovery efficiency in oilfields nowadays, many challenges lie ahead, mainly related to the quality of the foam solution, its foamability, and stability at high pressure and temperature [34].

Foam is a dispersed two-phase system wherein concentrated gas bubbles are dispersed in a continuous liquid phase. The liquid phase is continuous and external, whereas the gas phase is discontinuous and internal. The gas separates from the liquid by forming bubbles, thin walls, or borders that divide the gas phase from the liquid phase and are known as lamellae. Surfactants, polymers, and nanoparticles usually stabilize these films [35], [36], [37]. These latter help to reduce the surface tension of the liquid film, allowing the bubbles to maintain their shape and stability [38]. This unique structure gives foam its characteristic light and airy texture, making it useful in various applications such as wastewater treatment, food manufacturing, pharmaceuticals, cosmetics, firefighting, and Enhanced Oil Recovery (EOR) [39].

Foam has been employed in many drilling operations in the petroleum industry during various drilling stages. Due to its lighter composition compared to conventional drilling fluids, foam helps reduce the hydrostatic pressure exerted on the formation [40]. Additionally, foam exhibits excellent cuttings-carrying capacity, facilitating the efficient removal of drilled cuttings from the wellbore [41], [42]. In acidizing operations, the use of foam is intended to enhance treatment efficiency, improve well productivity, and optimize reservoir stimulation [43]. In hydraulic fracturing, foam can contribute to improved fracture extension, connectivity, fluid efficiency, and proppant distribution, thereby enhancing the effectiveness of the hydraulic fracturing process [44].

There are various foam production techniques, each employing distinct concepts that result in bubbles of varying sizes. The type of foam generated is influenced by several factors within the process, including parameters such as speed, temperature, flow regime, the viscosity of the liquid, the type of surfactant (cationic, anionic, amphoteric, nonionic), and the type of gas [39]. Processes for generating foam can be classified into two categories. The first set of methods involves capturing air bubbles from the atmosphere, encompassing actions such as shaking, pouring, and stirring. The second set of methods revolves around the artificial creation of gas bubbles, achieved through processes like electrolysis, nucleation, sparging, and chemical reactions [45].

Mechanism of foam stability

The foam's stability refers to its ability to retain or maintain its initial characteristics, such as its quality. Several physical phenomena cause the destabilization of the bulk foam [46].

After its formation, foam is not permanently static and stable. It undergoes an aging process (collapse), influenced by various phenomena occurring at different spatial and temporal scales, which may interact with each other. Despite the intricacy of this aging process, three phenomena can be distinguished as contributing to the destabilization of the foam: gravitational drainage, Ostwald ripening, and coalescence [47], [48]. Two types of foam can be distinguished based on their structure (Figure 3):

1- Wet foams, are dispersions of gases in a liquid with a high-volume fraction of liquid ranging from 5 to 20-30%. The gas bubbles form perfect spheres [49].

2- Dry foams are characterized by a liquid volume fraction that is below 5%. In these foams, the bubbles undergo deformation, taking on polyhedral shapes, and they are separated by thin films [50], [51].

Foam quality (Γ) is the volumetric ratio of gas-phase (V_G) to gas/liquid-phase (V_L) i.e.

$\Gamma = V_G/V_G+V_L$

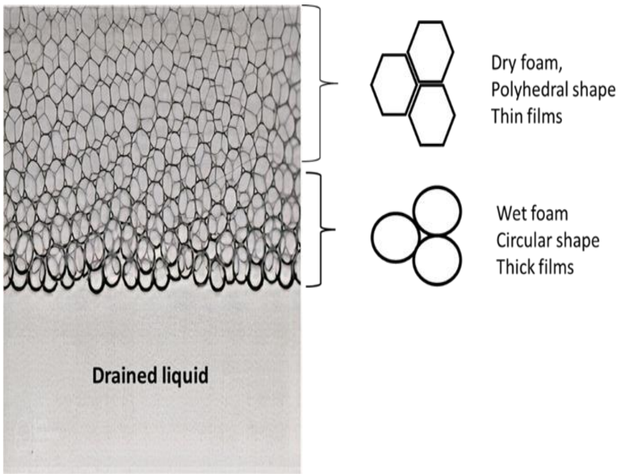

Figure 3 Structure of liquid foam (dry and wet foam) [49]

Gravitational drainage of foam is the phenomenon wherein a liquid drains out of a foam structure due to the influence of gravity. This process involves the dynamic interplay of gravity, surface tension, and viscous forces, leading to the depletion of liquid within the foam. As a result, the upper part of the foam tends to dry out. The concavity of the surface, particularly at the edges of the tray [51].

Ostwald ripening is a phenomenon observed in systems containing multiple gas bubbles. It involves the diffusion of gas from smaller bubbles to larger ones through the thin liquid films (lamellae) that separate the bubbles [52], [53]. This process is driven by the pressure difference between smaller and larger bubbles. As explained by Laplace's law, the pressure inside a bubble is inversely proportional to its radius. Consequently, smaller bubbles experience higher internal pressure than larger ones. As a consequence, gas from the smaller bubbles diffuses through the liquid films and merges into the larger bubbles (Figure 4). This leads to the shrinking of the smaller bubbles and the continued growth of the larger ones, resulting in a gradual increase in the size of the larger bubbles at the expense of the smaller ones. Ostwald ripening occurs due to the pressure discrepancy between bubbles and the diffusion of gas through the liquid films, causing a redistribution of gas and a change in bubble sizes within the system.

Coalescence refers to the phenomenon where two bubbles approach each other within a critical distance, causing the thin liquid film between them to rupture and resulting in their merging [54], [55]. This process leads to an increase in the size of the bubbles and a simultaneous decrease in their number [56]. It testifies to the fragility of films. The coalescence phenomenon can be constrained by mechanisms that stabilize the lamellae. For instance, the disjoining pressure might, in certain cases, contribute to the stability of thin films, augmenting the viscoelasticity of the interfaces is another method to impede the thinning and rupture of the films [57], [58], [59]. Nevertheless, it is important to note that a film cannot be stabilized indefinitely, primarily due to factors such as drainage, spontaneous fluctuations in thickness and density, or external disturbances [60].

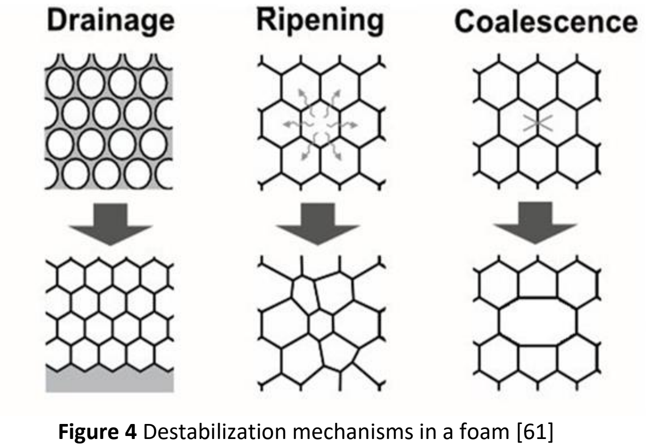

Figure 4 Destabilization mechanisms in a foam [61]

Mechanisms of foam formation in the porous media

There are four fundamental mechanisms of foam generation in porous media, including snap-off, lamella division, leave-behind, and pinch-off [62], [63]. The snap-off mechanism is a crucial step in the formation of foam in porous media. This mechanism describes how bubbles form when gas pushes the gas-liquid interface into the groove of a pore and subsequently ruptures the interface. This leads to the creation of gas bubbles that are roughly equivalent in size to the pores present in the porous medium (Figure 5 a). Snap-off takes place when the capillary pressure at the constriction surpasses the capillary pressure at the leading edge of the interface [64], [65]. This process is influenced by various factors, including pore geometry, interfacial tension between the gas and liquid phases, and the flow rate of the liquid [66], [67].

The second mechanism is lamella division, a process for generating foam in which the presence of a pre-existing foam with bubble sizes larger than those in the porous body is essential [68]. When a bubble approaches a branch line, it undergoes division, leading to the creation of two distinct bubbles [69], [70] (Figure 5 b). This mechanism contributes to the augmentation of the number of lamellae.

Leave-behind mechanism: When two liquid/gas interfaces come into contact, they create a liquid film parallel to the gas flow direction (Figure 5 c) [71]. This mechanism produces foams that are less stable and weaker compared to the two previous mechanisms.

Pinch-off: This mechanism occurs when two or more bubbles simultaneously reach a constricted point (Figure 5 d). There are two types of pinching: one occurs between a bubble and a narrowing wall (neighbor-wall pinch-off), and the other involves a bubble being pinched between two other bubbles (neighbor-neighbor pinch-off) [70]. Several factors influence this mechanism [72], including the flow rate. Higher flow rates can lead to more frequent pinch-off events. Additionally, foam properties play a role in the occurrence of the pinch-off mechanism, as foam with higher viscosity and lower surface tension is more likely to exhibit pinch-off behavior.

The characteristics of porous media, such as pore size distribution and permeability, also influence the occurrence of pinch-off. Narrower pore sizes and lower permeability can increase the likelihood of pinch-off events.

The role of surfactants in foam stability

Surfactants are organic chemical compounds that reduce the surface tension between two substances, such as a solid and a liquid or two liquids (e.g., oil and water) [73]. Surfactants have a hydrophobic tail that repels water and a hydrophilic head that attracts water, enabling them to interact with both water and non-water substances [74]. These substances are frequently employed in a variety of applications, including dispersants, foaming agents, emulsifiers, and detergents. Based on the charge in their hydrophilic head, they may be divided into four groups: zwitterionic (both negative and positive charges), non-ionic (no charge), cationic (positive charge), and anionic (negative charge) [75], [76], [77], [78]. Surfactants influence foam stability through various mechanisms. Primarily, they reduce the surface tension of liquids, facilitating bubble formation and stabilizing smaller bubbles [79], [80], [81]. Surfactant molecules tend to adsorb at the air-water interface, creating a protective film that prevents the coalescence of adjacent bubbles and helps maintain the foam structure [82], [83]. Additionally, surfactants can enhance stability by facilitating the creation of a viscoelastic layer at the interface between the liquid and gas, providing mechanical strength to resist deformation and cracking [84]. They also play a key role in improving drainage resistance in liquid films, slowing down the rate of liquid flow, and thereby contributing to increased foam stability [85], [86]. Furthermore, surfactants can prevent the coalescence of bubbles by creating a repulsive force between them [34], [87]. The chemical composition of the surfactant, along with its concentration, influences the stability of the foam.

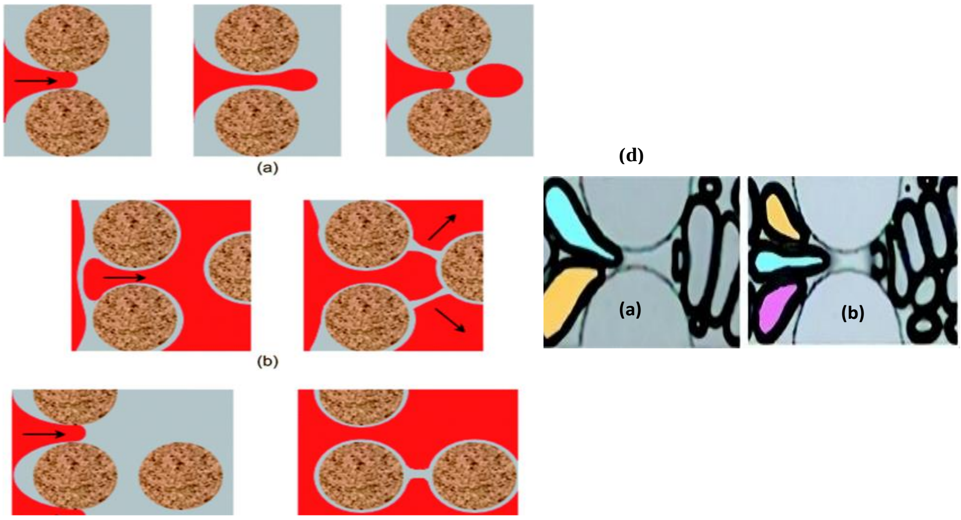

Figure 4 processes involved in foam formation within porous media, including (a) the snap-off mechanism, (b) the lamella division mechanism, and (c) the leave-behind mechanism. Additionally, (d) the pinch-off mechanism is detailed, covering (a) neighbor-wall pinch-off and (b) neighbor-neighbor pinch-off. [69]

The selection of surfactant is customized to the particular application and the desired foam characteristics. Surfactant performance in foam generation is significantly impacted by temperature, particularly for nonionic surfactants. Above the cloud point temperature, the surfactant solution separates into two phases: a surfactant-rich phase and a surfactant-poor phase. The surfactant-rich phase acts as an antifoam, inhibiting foam formation by merging into the foam films. This phase bridges the air-water interfaces, leading to destabilization of the foam. Therefore, above the cloud point, nonionic surfactants are less effective in foam-based Enhanced Oil Recovery (EOR) applications due to reduced foam stability [88].

Table 2 Surfactant type and properties

Surfactant type & Surface Charge	Common examples	Properties	Mechanism/Applications
Anionic (Negative)	AOS, SDS	- Solubility highly dependent on temperature; prone to hydrolysis at high temperature and pH - Low adsorption on negatively charged minerals (e.g., sandstone)	- Most globally used surfactant for EOR - Effective wettability alteration and IFT reduction - Low cost
Cationic (Positive)	CTAB, DTAC	- High solubility and stability at high temperature and salinity (HTHS) - Readily adsorbs onto rock surfaces	- Effective for wettability alteration in carbonate rocks - Less suitable for sandstone due to strong adsorption
Nonionic (No ionic charge)	Ethoxylates	- High adsorption on mineral surfaces - Can precipitate at HTHS - Less sensitive to water hardness and salinity	- Effective in improving phase behavior - Fairly effective IFT reduction
Zwitterionic (Positive & Negative)	Betaine salts	- Forms wormlike micelles with higher thermal stability - More expensive than other surfactants	- Highly effective for IFT reduction - Tolerant to temperature, electrolytes, and salinity changes

[89]

The application of natural surfactant in EOR:

A natural surfactant is a surface-active agent derived from renewable, biodegradable sources such as plants, animals, or microorganisms. It typically contains compounds like saponins and fatty acids, which reduce surface tension due to their hydrophilic head and hydrophobic tail. Known for their non-toxic and environmentally benign properties, these surfactants enhance wetting, spreading, and emulsification in liquids. Natural surfactants are cost-effective and efficient alternatives to synthetic surfactants, particularly in applications like Enhanced Oil Recovery (EOR) [90].

Recent research has highlighted the promising application of natural surfactants in Enhanced Oil Recovery (EOR). The examination of plant-based surfactants, including olive, Spistan, and Zizyphus spina-christi, which significantly reduced oil-water interfacial tension (IFT), leading to enhanced oil recovery [90]. Wang et al. introduced a biodegradable surfactant derived from cashew phenol, showing effective IFT reduction and stability under extreme conditions [91]. In another study [92], Vernonia Amygdalina-based surfactants displayed excellent foam stability, IFT reduction, and wettability alteration, further supporting the potential of natural surfactants as eco-friendly alternatives to synthetic options in EOR processes. The experimental investigation revealed that the saponin-based natural surfactant (SBNS) stabilized foam for extended periods, with a half-life of 1100 minutes. Nurudeen Yekeen et al. [93] compared the effectiveness of a natural saponin-based surfactant with commercial saponin and SDS (sodium dodecyl sulfate) in terms of foaming properties, wettability alteration, and interfacial tension reduction at both room and reservoir temperatures. The results were promising, demonstrating the ability of natural surfactants to match or surpass synthetic alternatives.

This underscores the potential for natural surfactants to be effective, sustainable solutions for improving oil recovery while reducing environmental impact.

In a parallel investigation, Luis Torres et al. [94] evaluated the performance of three biosurfactants one bacterial and two plant-derived against synthetic surfactants for enhanced oil recovery (EOR) applications under harsh conditions typical of the Chicontepec oil field in Veracruz, Mexico. Their study demonstrated that biosurfactants, such as rhamnolipids from Pseudomonas and guar gum, performed comparably or even better than synthetic alternatives. They resisted high temperatures and salinities, highlighting their potential as sustainable and efficient alternatives to conventional surfactants for EOR processes. Rhamnolipids, in particular, displayed excellent surface tension reduction even in brine.

Although natural surfactants have shown promising results, they still face limitations such as high production costs, scalability challenges, and performance variability depending on the source and reservoir conditions. Additionally, long-term stability data is lacking, and compatibility issues with other chemicals in recovery processes can arise. Despite their environmental benefits, some natural surfactants still pose ecological concerns, and regulatory challenges further complicate their adoption in certain regions. Overcoming these barriers is crucial to enhancing the feasibility of natural surfactants in industrial applications [95].

Stability of foam during interaction with oil:

The stability of foam has been a topic of interest in many industries, as foam is commonly used in products such as food, cosmetics, cleaning agents, and enhanced oil recovery. However, the presence of oil can significantly influence the stability of foam, affecting its quality and performance. Understanding the link between oil and foam stability is crucial for several industries to uphold the effectiveness and consistency of their products. The stability of foam in the presence of oil is a critical issue for its application in oil recovery. To achieve proper mobility control, the foam must remain stable while it comes in contact with oil [96]. According to certain research, the oil phase destabilizes the generated foam, this interaction depletes the liquid content in the thin films (lamellae) that separate gas bubbles in the foam [97]. Additionally, the presence of oil changes the wettability of the rock and disturbs the gas-water interface by spreading, resulting in foam destabilization [98]. The formation of an emulsion further compromises the structure of the foam. Several research [99], [100], [101] proposed coefficients, such as the entering coefficient (E), spreading coefficient (S), and bridging coefficient (B), as essential tools to explain the destabilizing effects of oil on foam (see figure flowchart) [102]. Positive E values suggest that oil easily infiltrates the foam, whereas positive S and B values indicate that the oil spreads and forms a bridge between gas bubbles, respectively (Table 3). These mechanisms lead to the coalescence and subsequent reduction in the stability of the foam structure [103].

$$S = \sigma_{gw} - \sigma_{ow} - \sigma_{go}$$

$$E = \sigma_{gw} + \sigma_{ow} - \sigma_{go}$$

$$B = \sigma^2_{gw} + \sigma^2_{ow} - \sigma^2_{go}$$

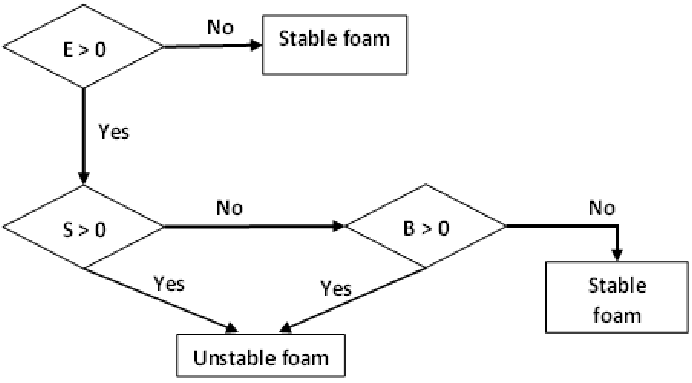

Figure 6 Flowchart for forecasting foam stability from E, S, and B coefficients [102].

where σ_{gw} represents the surface tension between gas and water, σow indicates the interfacial tension between oil and water, and σgo denotes the surface tension between gas and oil.

Schramm and Novosad presented a different interpretation for foam stability, proposing that it arises from the emulsification of oil and its integration into the foam structure. The key step in this process entails generating tiny oil droplets through emulsification, enabling them to navigate within the foam structure. They also introduced a dimensionless factor called the lamella number (L) to measure foam stability, which is calculated as the ratio of capillary pressure at Plateau borders to the pressure variance across the oil-water interface [104].

$$L = \frac{\Delta P_c}{\Delta P_R} = \frac{R_0}{R_P} \frac{\sigma_{w/g}}{\sigma w/o} = 0,15 \frac{\sigma_{w/g}}{\sigma_{w/o}}$$

R_0 is the radius of oil droplet, and R_p is the radius of the plateau border (Ro/Rp = 0.15±0.01), There are three types of foam identifiable based on the values of L, E, and S: [104]

Table 3 Predicting foam stability foam using L, E and S.[37]

Value of L	E	S	Foam stability to oil
Less than 1	-	-	Stable foam
Ranges between 1 and 7	+	-	Moderately stable foam
Bigger than 7	+	+	Unstable foam

The stability of foam in the presence of oil is not only dependent on spreading, entering, and bridging coefficients but is also highly influenced by the Winsor phase behavior of the surfactant-brine-oil system. The Winsor Phase Behavior, also known as the Winsor Classification, is a widely recognized approach for characterizing the phase behavior of microemulsion systems, which are composed of water, oil, and surfactants. This phase behavior is of particular importance in understanding the stability and properties of foams, as the partitioning of surfactants between the different phases can significantly impact foam formation and stability. According to [105], [106] distinct three types of microemulsion phase behavior, denoted as Winsor Type I, II, III (Figure 7). Winsor Type III is the most effective for enhanced oil recovery (EOR) because of its low interfacial tension and better foam stability under optimal conditions. Types I and II exhibit higher IFT and generally poor foam stability, making them less efficient for EOR (Table 4).

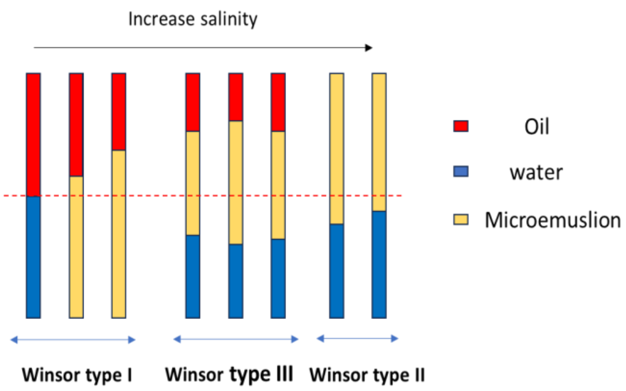

Figure 7 Winsor classification of microemulsion (surfactant system) [105]

Table 4 Comparison of Winsor Types [105], [106]

Parameter	Winsor Type I (Water-in-Oil Microemulsion)	Winsor Type III (Bicontinuous Microemulsion)	Winsor Type II (Oil-in-Water Microemulsion)
Phase Configuration	Oil phase (top), water phase (bottom), very minimal or no microemulsion	Oil phase (top), water phase (bottom), microemulsion phase (middle)	Oil phase (top), water phase (bottom), microemulsion phase in oil
Microemulsion Location	Water phase (lower phase)	Middle phase	Oil phase (upper phase)
Interfacial Tension (IFT)	Higher IFT	Lowest IFT	Higher IFT
Oil Recovery Factor (RF)	Lower RF	Higher RF (most desirable for EOR)	Lower RF
Salinity	Low salinity	Intermediate salinity	High salinity
Foam Stability	Poor foam stability	Variable foam stability, generally better under certain conditions	Poor foam stability
EOR Efficiency	Less efficient for EOR	Most efficient for EOR	Less efficient for EOR

The Gibbs-Marangoni effect is a combination of two complementary phenomena. The Gibbs effect refers to the change in surface tension that occurs when a surfactant is adsorbed at equilibrium. When two gas bubbles come close to each other, the liquid film between them stretches, causing a decrease in the amount of surfactant and resulting in an increase in surface tension at equilibrium [107], [108]. The dynamic tension in the film varies in the same direction due to the non-instantaneous equilibrium, creating a tension gradient between the stretched zone and the adjacent zone. Consequently, surfactant molecules are displaced from the adsorbed layer towards the stretched zone of the film, causing the underlying liquid to be entrained by the Marangoni effect [109], [110]. This process ultimately prevents the thinning of the film.

Experimental investigations on Enhanced Oil Recovery using foam in a laboratory setting:

Foam stability is typically evaluated through bulk foam and core flooding experiments. Bulk experiments, which are used to investigate foam stability, employ various techniques to observe foam behavior on a larger scale rather than in a porous medium. This approach offers valuable insights into foam's stability, longevity, and flow properties under different conditions, improving our understanding of its effectiveness in Enhanced Oil Recovery and other applications [89]. Conversely, core flooding experiments offer valuable insights into foam behavior in porous media. These experiments help researchers and engineers understand the stability and performance of foam under conditions that closely resemble those encountered in real reservoirs, particularly under harsh conditions [111]. Here are some of the most pertinent research studies related to the assessment of foam stability.

The paper by Liyuan Lang et al. [112] explored air-foam's effectiveness in recovering heavy oil across various reservoir conditions, analyzing its flow behavior in porous media and examined the impact of key factors like gas-liquid ratio, injection rate, and crude oil saturation.

The researchers employed the foaming agent XHY-4 at 0.1 wt%, revealing air-foam's capability to enhance oil recovery by displacing fluid from high to low permeability zones, thus decreasing water cut.

Viren Thakore et al. [113] conducted a series of experimental studies to assess the influence of pressure and temperature on foam stability. Initially, they conducted a screening investigation of temperature influences on different foam-based surfactants, including AOS, SDS, NP-40, and CTAC, with temperatures varying from 100°C to 200°C. Foam stability, specifically for CO2-based and N2-based foams, was measured using the half-time method. The results are shown in Figure 7. After the screening test, AOS was chosen as the surfactant because it exhibited the highest stability. Subsequently, the half-life of AOS foams was examined as a function of pressure at two distinct temperatures: (a) 100°C and (b) 200°C, with pressure ranging from 100 to 1000 psi. The results are presented in Figure 8.

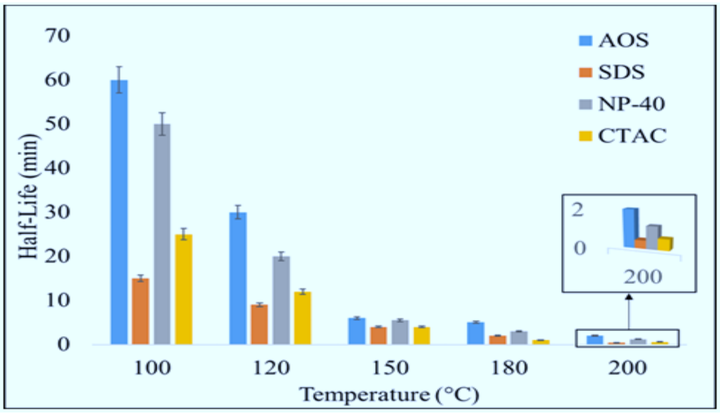

Figure 8 Thermal stability of foams with different surfactants as a function of temperature at a pressure of 400 psi. [113]

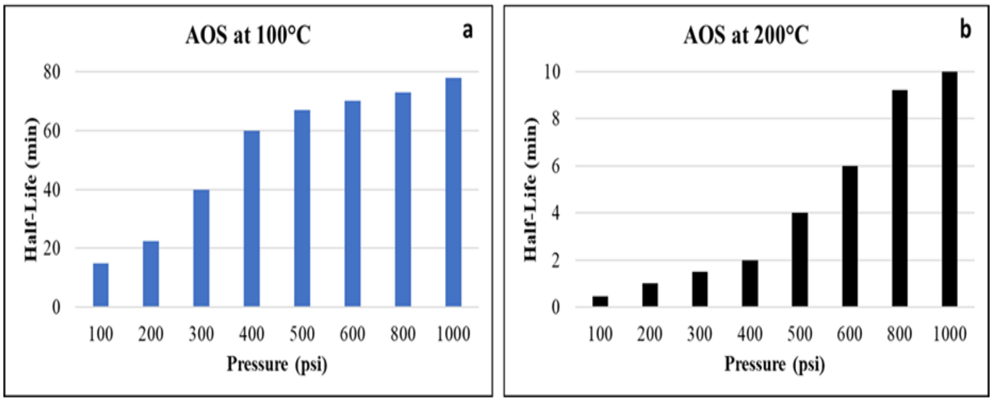

Figure 9 Half-life of AOS foams as a function of pressure at (a) 100°C and (b) 200°C. [113]

Wang et al. [114] have also examined the effect of temperature and pressure on CO2 foam stability. They reported that higher pressure tends to improve foam stability by increasing resistance to foam collapse and coalescence (Figure 10). However, it is important to note that excessively high pressure can also lead to a decrease in foam stability. The specific effects of pressure on CO2 foams depend on various factors, including temperature, foam quality, and surfactant concentration. Furthermore, they observed that higher temperatures can cause a decrease in foam stability. They found that as the temperature increased, the foam quality factor decreased, indicating a decline in foam stability.

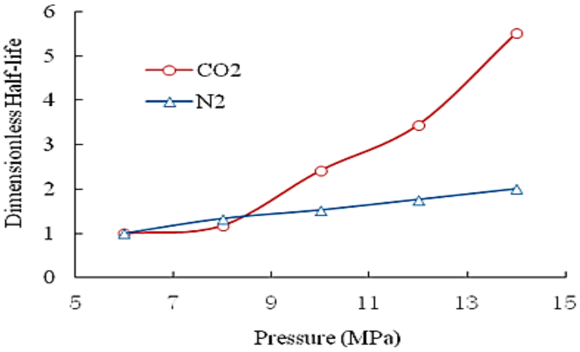

Figure 10 Influence of pressure on stability (Half-life) of N_2 and CO_2 foams with SDS foaming agent. [114]

Fernø, M. A. et al. [115] conducted a study focusing on miscible CO_2 and CO_2-foam injection tests to investigate CO_2- EOR in fractured carbonate core plugs. The objective was to evaluate the feasibility of using foam for mobility control in fractured systems under conditions of 9 MPa and 20 °C. The core plugs had a permeability range of 11–60 mD and porosity between 18–25%. AOS14-16 surfactant was employed at a concentration of 1 wt%. The researchers observed a significant increase in oil recovery during CO_2 injections under miscible conditions, ranging between 75% and 92% of the original oil in place (OOIP) in cores with irreducible initial water saturation. Additionally, they found that injecting pre-generated CO_2 foam expedited oil recovery compared to injecting pure CO_2 in fractured core plugs. This improvement was attributed to the introduction of a viscous displacement mechanism in addition to diffusion.

Mohammed et al. [116] assessed the efficacy of foam in Enhanced Oil Recovery (EOR). They studied the stability and texture of CO_2/N_2 foam in sandstone via oil-free steady-state foam flooding experiments under supercritical CO_2 conditions. By using fluoro-surfactant (FS-51) and alpha-olefin-sulfonate (AOS), they investigated varying N_2 levels with CO_2 (supercritical-CO_2-foam) using both surfactants. Co-injection of surfactant, CO_2, and N_2 was conducted, with pressure drop (P) data collected across the core. Analysis via ImageJ software on foam images revealed enhanced foam strength with N_2 addition. N_2 incorporation increased foam bubble circularity, indicating improved strength. Furthermore, N_2 addition to sc-CO_2 led to smaller, finer foam bubbles, enhancing texture. The increased pressure weakened CO_2 foam, reducing sweep efficiency for EOR.

In their study, Pacelli L. J. Zitha et al. [117] investigated into the effectiveness of the alkali-surfactant foam (ASF) process for oil extraction. The primary objectives of the research were to evaluate the effectiveness of oil recovery using ASF and to compare its performance with conventional extraction methods. Additionally, the study aimed to clarify the underlying mechanisms involved in ASF and its stability in the presence of oil. The relevant characteristics and properties of the oil surfactant and the core were as follows: the crude oil exhibited an API gravity of 37.82 and a viscosity of 2.78 ± 0.01 cP at 60°C, using an internal olefin sulfonate (IOS 2024) at 0.5 wt%, and nitrogen gas. The core-flooding experiment involved using Bentheimer sandstone, which has a porosity of 21% and a permeability of 1.2 Darcy. The investigation's key findings revealed that the ASF process achieved notable oil extraction from the porous medium, with oil recoveries reaching nearly 100%. The resulting foam exhibited heightened viscosity, thereby enhancing sweep efficiency and oil displacement. Moreover, the application of ASF has demonstrated potential for minimizing environmental impact, attributed to the reduced usage of chemically activated fluids. Notably, ASF demonstrated effectiveness in low-permeability reservoirs, where the retention of polymers might lead to plugging issues. The study emphasized the benefits of ASF in enhancing oil recovery compared to conventional methods.

Nagar Nadia Nasr et al. [118] conducted a comparative study on foam stability, investigating the impact of salinity and surfactant concentrations through bulk foam tests and sandpack flooding. They used the mixed anionic and amphoteric surfactant MFOMAX with pure nitrogen. Salinity variations of 0.5%, 2.0%, and 3.5%, as well as surfactant concentrations ranging from 0.1% to 1.0%, were examined. Experiments were conducted in a 600mm sand pack with 29% porosity and 1791 mD permeability.

While conventional bulk foam stability tests were typically used for surfactant selection, the researchers observed homogeneity in the generated foam. To address this issue, they modified the test by adding quartz river sand at the base of the column, which created a more heterogeneous foam texture.

The study concluded that all three screening methods consistently assessed the impact of surfactant concentration on foaming. Despite yielding different salinity results in standard bulk tests, they effectively identified very low-performing samples. Bulk tests with modified sand yielded results similar to those of sandpack tests, suggesting that the improved performance may be attributed to the sand inducing a more heterogeneous foam texture.

Simjoo, M et al. [119] found that oil significantly affects foam stability. They noted that AOS foam, especially with shorter carbon chain alkanes, showed reduced stability and decayed earlier. The length of the alkane chain notably affected AOS foam stability, with shorter chains causing greater destabilization (see Figure 11). This was explained by spreading and bridging coefficients. Moreover, increasing surfactant concentration from 0.1 to 1.0 wt% greatly improved foam stability in the presence of oil, increasing both liquid volume and stability.

In the research paper authored by Anjan Phukan [120] et al., they conducted an assessment of foam stability in the ASAG (alkaline-surfactant-alternated-gas) process at different temperatures. The results revealed that as the temperature increased, the stability of CO_2 foam, characterized by foam volume, decreased for both anionic surfactants (SDS and AOS). An increase in temperature typically leads to a decrease in foam stability, manifested by a reduction in the foam's half-life (foam volume) (Figure 12). This phenomenon is attributed to the increased tendency of the liquid phase to evaporate at higher temperatures, resulting in rapid bubble collapse and the release of trapped gas. Furthermore, higher temperatures enhance the solubility of the gas phase, reducing the interfacial tension between the gas and liquid. This leads to increased liquid drainage, making the foam more prone to instability. At elevated temperatures, the viscosity and elasticity of the foam lamella diminish, which adversely impacts foam performance. The extent of foam instability may vary depending on the chemical structure or the length of the hydrocarbon chains of the foaming agent employed.

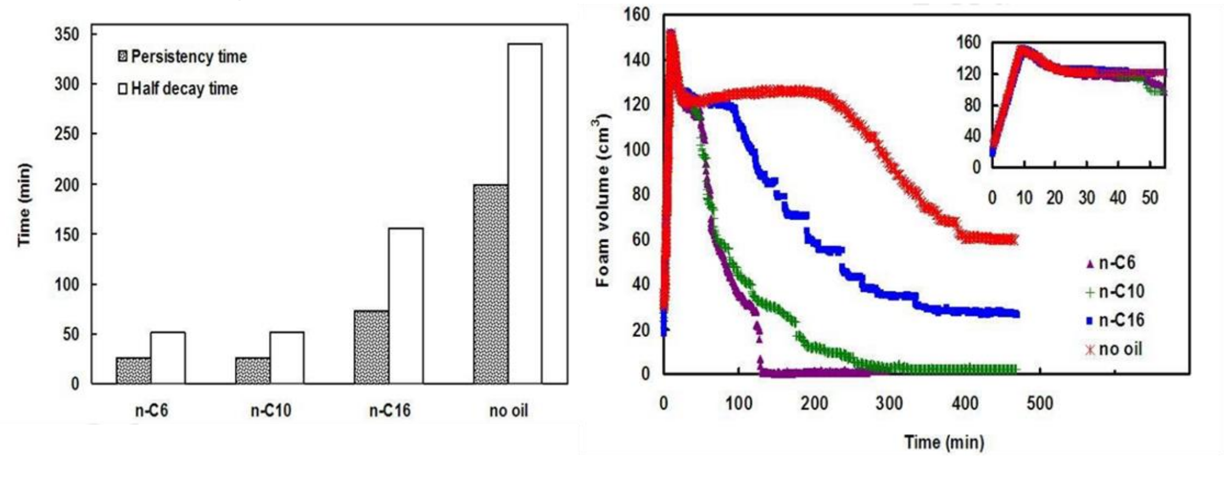

Figure 11 a) Effect of oil type on the foam longevity and half-decay time, b) Effect of oil type on the foam volume, with a constant surfactant concentration of 0.5 wt% [119]

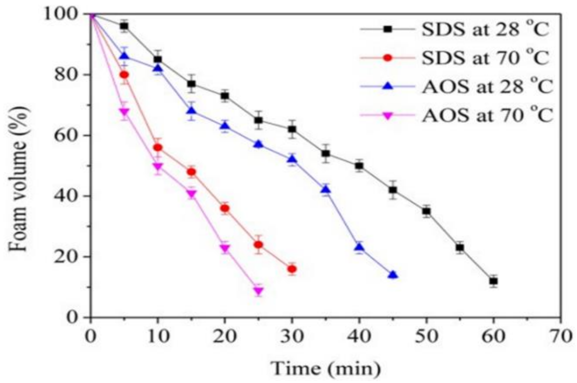

Figure 12 Stability curves for CO_2-foam with SDS and AOS were examined at both room temperature (28 °C) and reservoir temperature (70 °C) in the presence of crude oil. The surfactant concentration was kept constant at 0.5 wt%, and the crude oil content was 10 vol%. [120]

Applications of foam for enhanced oil recovery at the field scale

In the field, the injection process is intricately linked with the method of foam production, to the extent that the terms "foam generation" and "foam injection mode" can be used interchangeably. There are three main types of foam generation: pre-formed foam, foam Co-injection, and SAG [121] (see Figure 13).

1. Pre-formed Foam: This type of foam is generated outside the porous medium before entering the pay zone.

2. Foam Co-injection involves the in-situ formation of foam near the injector, achieved by simultaneously injecting a surfactant solution and gas. During the co-injection process, the surfactant can be continuously injected alone or concurrently with water in a semi-continuous manner.

3. SAG Foam: Sequential injection of a surfactant solution and gas leads to the production of SAG foam. In this case, the foam is generated within the reservoir as part of the SAG injection process.

The selection of the most suitable foam generation method depends on several factors, including reservoir characteristics, desired displacement efficiency, and economic considerations.

The reservoir pressure plays a crucial role in the EOR-foam process. Higher pressures require lower surfactant concentrations to achieve a specified mobility reduction factor (MRF) [123]. Consideration of reservoir pressure and rock permeability is crucial when selecting the injection mode (such as SAG, co-injection, or preformed foam). To ensure the success of a foam application, it is imperative to determine the specific problem to be addressed. This involves identifying the well causing the problem and pinpointing the offending well. It is also important to determine whether foam application is best suited for a production well or an injection well. Additionally, the use of foam as a mobility control agent is crucial, especially for injection wells where sustained injectivity and long-distance propagation are critical factors. This requires a low to moderate Mobility Reduction Factor.

The design for the entire foam field test should be based on laboratory experiments conducted under conditions that accurately represent the prototype, incorporating the same placement method. A.T. Turta and A.K. Singhal [123] proposed a multi-level decision tree designed to facilitate the selection of the most appropriate format and placement method (Figure 14).

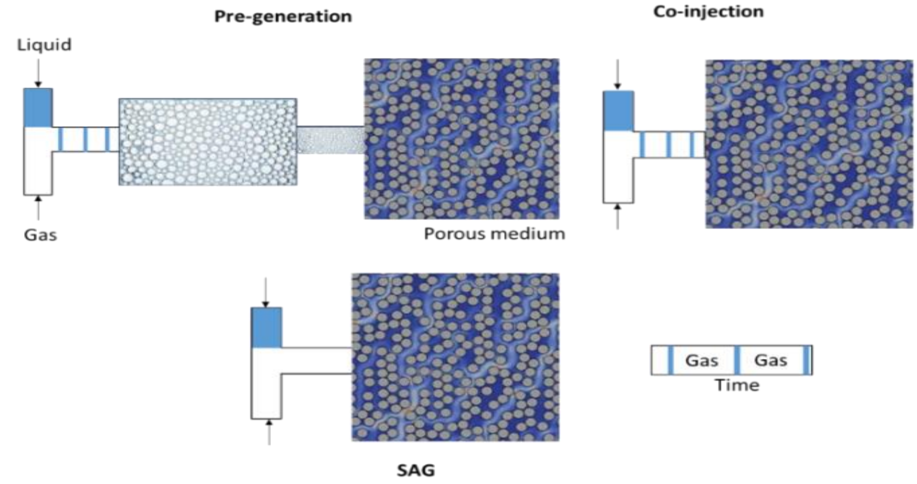

Figure 13 Illustration of the three mechanisms of injection of foam in porous medium [122]

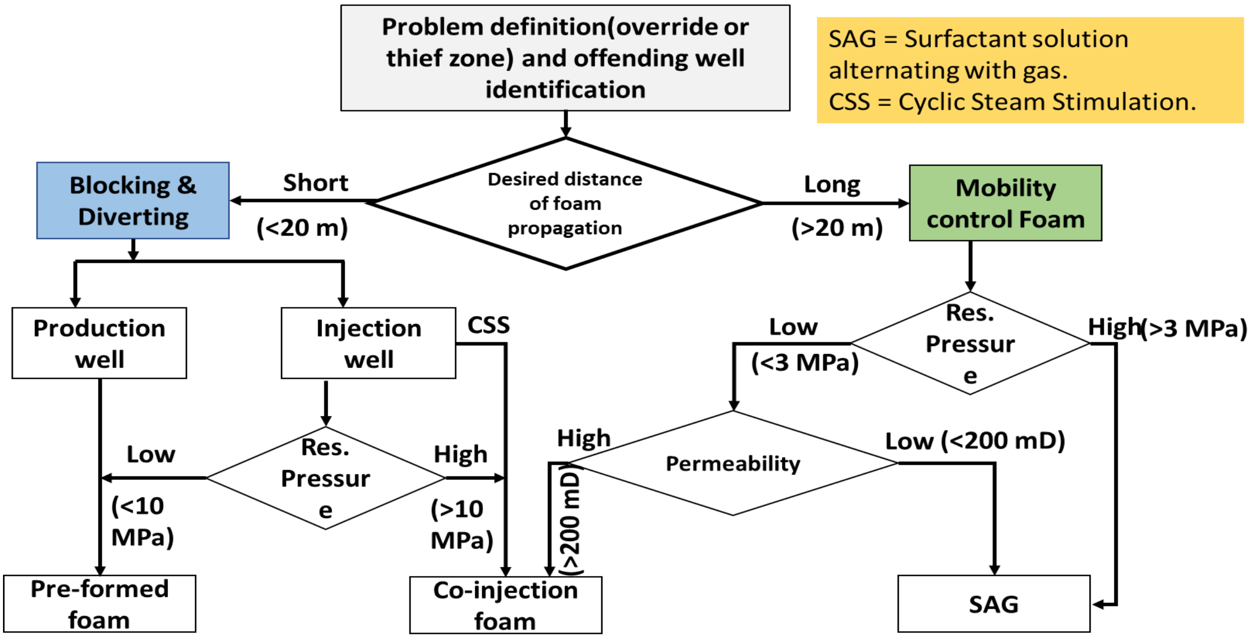

Figure 14 Selection and placement of foam in projects related to Enhanced Oil Recovery. [123]

Table 5 Applications of foam flooding in enhanced Oil Recovery Projects.

Field, Country	Reservoir characteristics and oil properties	Problem encountered in the reservoir	Surfactant used	Gas used	Main results of foam application	References
Snorre field Norway	Temperature = 90°C, Pressure = 383 bar, Depth= 2475m, Porosity=0.24, Permeability= 100 to 3000 mD, Oil viscosity= 0.687 cp, Formation type: Sandstone	Early gas breakthrough, High GOR	AOS	Hydrocarbons	Reduction of gas breakthrough, GOR reduction, improvement of sweep efficiency, higher water cut	[124]
Rock creek. WVA. USA	Depth= 610m, Porosity=0.217, Permeability= 21.5 mD, Oil gravity API= 43, Oil viscosity= 3.2 cp, Formation type: Sandstone, Temperature =73°F	Override problem High gas mobility Low oil production	Alipal CD-128	CO_2	Foam flooding could not decrease mobility under reservoir conditions.	[123], [125]
Joffre Viking Alberta Canada	Temperature = 56°C, Depth= 1500m, Porosity=0.13, Permeability= 500 mD, Oil viscosity= 1 cp, Formation type: Sandstone	Override problem	ARC	CO_2	There was no observed reduction in the Gas Oil Ratio, and the slight increase in oil production was considered negligible. It is proposed that the oil displaced from the unswept zone was redirected into the extensively swept area, preventing its recovery.	[123], [126]

Field, Country	Reservoir characteristics and oil properties	Problem encountered in the reservoir	Surfactant used	Gas used	Main results of foam application	References
North Ward-Estes Texas USA	Temperature = 28.33°C, Pressure = 1100 psi, Depth= 800m, Porosity=0.18, Permeability= 15 mD, Oil gravity API= 37, Oil viscosity= 1.4 cp, Formation type: Sandstone to siltstone	Early CO2 breakthrough, Poor sweep efficiency and low production	CD 1040 0.2% and 0.5%	CO_2	Foam within a quality range of 50-80% has demonstrated successful application, resulting in a nine-fold reduction in Gas-Oil Ratio (GOR) in the problematic well. Concurrently, oil production exhibited a remarkable 15-fold increase, accompanied by a reduction in water cut. improve the injectivity: CO_2 injectivity by 40 to 85%	[127]
Oseberg/North Sea Norway	Temperature = 100°C, Depth= 2600m, Porosity= 0.164, Permeability= 2000-3000 mD, Oil viscosity= 0.5 cp, Formation type: Sandstone	High GOR, early gas breakthrough	LSS38/AS	HC-r enriched hydrocarbon gas	Reduction in GOR by 50%, better gas mobility control	[128]
Siggins, Illinois USA	Temperature =65 F, Permeability= 75mD, P= 100 Psi, Oil viscosity= 8cP, Porosity= 0.15, Depth= 500ft,	Thief zone problem	O.K. Liquid (a modified ammonium lauryl sulfate), 0,1 to 1,5% Concentration	Air	Reducing air mobility and halting channeling in the production well	[123], [129]
East Vacuum Grayburg/San Andres Unit (EVGSAU) USA	Temperature=101°F, Depth= 4400ft, Pressure =1613 psia, Porosity= 0.117, Permeability= 11mD, Oil viscosity= 1cP, Formation type= dolomite	Poor CO2 injectivity, low sweep efficiency, high mobility of CO2, and CO2 early breakthrough	Chaser CD-1045	CO_2	Foam flooding increased oil production, Reduction in CO_2 production, Diverted gas from high to low permeable zone, thus improved volumetric sweep efficiency	[123], [130]
The Kaybob south Triassic Canada	Temperature = 88°C, Depth=2123m, Pressure =17580kPa, Porosity= 0.115, Permeability= 25-200 md, Oil viscosity=0.414 cP, Formation type= dolomite	High gas mobility, Channeling	DOWFAX surfactant	N_2/ Miscible gas	Successful reduction of gas injectivity was observed, resolve GOR problem	[131]
Bohai Bay China	Temperature = 65°C, Depth= 1300-1500m, Porosity= 28 to 35%, Permeability= 2000 mD, Oil viscosity= 305 to 924 cp, Formation type: sandstone	High oil viscosity and severe heterogeneity, early breakthrough of the injected water, water cut was 90%	Foaming agent	N_2	Plugging high permeability zone theft channels (resolve high wat cut problem), reduction of IFT and enhance recovery efficiency, resolve water coning problem and improve oil recovery,	[132]

Field, Country	Reservoir characteristics and oil properties	Problem encountered in the reservoir	Surfactant used	Gas used	Main results of foam application	References
Liaohe oilfield China	Temperature =49.7°C, Pressure =10.7MPa, Depth= 1080m, Average permeability=1079mD, Porosity=0.297, Oil viscosity= 110 to 129 m.Pa.s	Poor sweep efficiency, Severe decrease of reservoir pressure after 9 years of steam Huff-and-Puff process.	Foaming agent	N_2	Improved injection profile, sweep efficiency,	[133]
kern river field USA	Oil viscosity= 1780 cp, Depth= 120 to 425m, Porosity=0.3, Permeability = 1 to 5 D, Oil gravity API = 9 to 16, Formation type= Sandstone	Poor sweep efficiency, Severe decrease of reservoir pressure after 9 years of steam Huff-and-Puff process.	AOS	N_2	Improvement of sweep	[123] [134] [135] [136]
Midway Sunset field USA	Porosity=0.35, Permeability= 1D, Depth=420m,	Reservoir depletion, Thief zone leading to steam losses and inefficient recovery	Chaser SD1000	N_2	Significant increase in oil production, oil rate increased four-fold, injection profile improved	[123] [135] [136] [137]
North kern front, California USA	Depth = 480m, Permeability= 2200 mD, Porosity= 0.33, Oil gravity API=13,	Early steam breakthrough	COR 180 surfactant (mixture of sodium and amino oxyethylen sulfates)	N_2	Improvement of injection profiles (steam distribution) Improvement in Steam oil ratio.	[123] [135], [136]
San Ardo, California, USA	Depth = 2300 ft, Porosity= 0.349, Permeability= 1000 to 3000 mD, Pressure = 100 to 300 psig, Temperature = 100°F, Oil viscosity= 2500 cP	Steam override	AOS	N_2	Injection profile improvement	[123], [136]
South Belridge Field California USA	Depth= 570ft, Porosity= 0.35, Permeability= 1.5 to 3.5D, Oil viscosity= 1600 cP at 95 °F, Pressure = 2MPa, Temperature = 204.4°C	High gas mobility, Channeling	A balanced mixture of anionic surfactant combined with a small quantity of non-ionic surfactant.	Air	Foam successfully diverted steam to unswept zone, thus improved sweep efficiency. Gas mobility controlled and increased oil recovery.	[123], [136]
Wilmington field, Tar zone USA	Porosity= 0.24 to 0.26, Permeability= 100 to 1000 mD, Depth= 2300 ft, Temperature = 120°F, Oil gravity API= 13 to 14, Oil viscosity= 180 to 410cp, Pressure =900 to 1.100 psi	Low CO_2 injection distribution and poor sweep efficiency	Alipal CD-128 Foaming Agent	Immiscible CO_2/N_2	Improvement of gas distribution, increase oil recovery	[123], [129]

Field, Country	Reservoir characteristics and oil properties	Problem encountered in the reservoir	Surfactant used	Gas used	Main results of foam application	References
Hockley county, Texas Slaughter field USA	Formation type= carbonate, Permeability= 0.01 to 28 mD,	High CO_2 channeling	CD-128 and chaser CD-1045	CO_2	Profile and mobility control, conformance-control agent, Foam decreased gas injectivity and production, however concurrently enhanced overall oil production, particularly with a decrease in the offending well. Injecting above the formation parting pressure adversely affected foam effectiveness in this well. As a result, oil production saw significant increases of 22% and 31%, equivalent to 16 and 22 barrels of oil per day (BOPD).	[138]
Madisonville West, Woodbine, Texas USA	Average porosity= 0.13, Permeability= 100µD to 15mD, Temperature = 120°C, Pressure =3800Psi, Oil gravity API= 39,	High gas mobility	Surfactant	N_2	Improvement of the volumetric sweep efficiency and increased oil production, improvement of injectivity of gas, reduction of gas-to-oil ratio, and mobility reduction	[139]
Rangely Weber Sand Unit, Colorado USA	Temperature = 71°C Pressure = 18.9 MPa Average porosity = 12% Average permeability = 8 mD Oil viscosity = 1.7 cp	High gas production, CO_2 breakthrough and Poor sweep efficiency	Chevron chaser CD1040	CO_2	Oil production was slightly higher Sweep profile improvement CO_2 production was much lower	[140]
Cupiagua, Recetor field Colombia	Porosity= 6%, Permeability= range of 0.01 to 10 mD,	High conductivity, and poor sweep efficiency	PetroStep C1, an AOS with carbon chain length C14/C16.	N_2	A strong gas blockage, reduction in GOR, production increased	[141]
Tia Juana Field, Venezuela	Depth= 1600 to 2900 ft, Temperature = 100 to 130°F, Porosity= 0.38, Permeability= 1000 to 3000mD, Oil gravity API=10 to 15°, Oil viscosity= 100 to 10000 cP, Formation type= Sandstone	High steam mobility	Surfactant AOS	N_2	The objective of the steam-foam process was to enhance steam distribution within a reservoir by decreasing steam mobility and improving the vertical steam-injection profile.	[135], [136], [142]
Guadalupe California USA	Depth= 850m, Porosity=0.35, Permeability= 1550mD, Oil gravity API=9, Oil Viscosity= 560cp	Early steam breakthrough,	Alkyle Toluene Sulfonate,	N_2	Improved the conformance, increased the injection pressure. Foam had successfully diverted steam to unswept zones, Oil production increased (oil recovery was estimated at 29400 bbl.), improvement in injection profile.	[123], [135], [136]
South Casper Creek, USA	Depth= 790m, Oil gravity API= 13.7, Oil viscosity=600cp, Porosity=0.283, Permeability= 3600mD,	Poor steam conformance due to the presence of high permeability thief zone,	Alkylaryl sulfonate surfactant	N_2	Pressure injection improved, steam diversion to unswept zone,	[136]

Field, Country	Reservoir characteristics and oil properties	Problem encountered in the reservoir	Surfactant used	Gas used	Main results of foam application	References
Cymric, California, USA	Depth= 305m, API= 12.6, Oil viscosity=2000cP, Porosity=0.39, Permeability= 500 to 2000mD	High permeability channel, downdip migration	Surfactant Chaser SD 120	N_2	An additional production of 75 BPOD was attributed to steam foam injection.	[136]
Shengli field China	Depth= 1125m, Permeability= 10^-3µm2=2304, Porosity= 0.37, Pressure= 11.27MPa, Temperature =60°C, Oil viscosity= 74mPa.s, Oil density=0.92,	Ultra-high water cut (up to 97.2%) and the remaining oil potential is becoming lower and lower	Foaming agent	N_2	The total water cut decreased by 2.3%, the oil production rate increased by 13 t/d, foam injection raised injection pressure, improved the injection profile of the reservoir.	[136]
Sacroc field USA	Depth=6200 ft - 7000 ft, Formation type= carbonate, Permeability=19.4 mD, Porosity=0.076, Pressure= 3500 Psi, Temperature=136 °F, Oil gravity API =42, Viscosity=0.33cP	The inadequate control of mobility and overall performance issues stemming from reservoir heterogeneity caused the premature breakthrough of CO_2 in the course of the miscible CO_2 injection process.	Alipal CD-128	CO_2	Foam flooding improved conformance and mobility control.	[123], [142]
Salt Creek Light Oil Unit, USA	Formation type= Sandstone, Porosity =0.14, Permeability= 42mD, Temperature = 125°F, Pressure= 1750Psi,	Channeling of fluids through high permeability. Low volume zones (fractures, thief zone). Gravity over-ride.	Surfactant	CO_2	Foam effectively reduced CO_2 injectivity by at least 40%. Improvement in the overall CO_2 sweep.	[143]
Levantine–Moreni, Romania	Formation type= Sandstone, Depth=250m, Porosity=0.29, Permeability= 1000mD, Oil viscosity= 800 cP, Temperature = 62.6°F, P= 2MPa,	Low rate of oil production because of the viscous and heavy oil	CAPTOR 4020X	N_2	Reduction of water-cut, improve oil production,	[123], [136], [144]
Pembina Ostracod 'G' Pool, Signalta Resources Limited, Canada	Formation type= Sandstone, Depth= 1730m, Temperature= 57°C, Porosity=0.12, Permeability=70mD	Gas mobility Control Foam; Over-Ride Problem.	Dow Pusher+ XSS84321.11	Hydrocarbon Miscible gas	Gas mobility Control Foam	[145]
Painter reservoir, Wyoming, USA	Temperature = 78.8°C Oil gravity = 44 API Reservoir pressure = 31 MPa permeability = 7 mD	High mobility of the injected gas Gas breakthrough	Surfactant	N_2	Significant reduction the injectivity	[123], [146]

Recent advancements in foam-based Enhanced Oil Recovery

The primary challenge in using foam for enhanced oil recovery lies in maintaining the stability and longevity of the foam under challenging reservoir conditions, such as high temperature and pressure. These conditions include maintaining foam quality at high temperatures, high salinity, and the presence of oil components that could potentially destabilize the foam. Successful resolutions to these challenges have been achieved through the application of nanoparticles or nanofluids [147]. The introduction of nanoparticles (NPs) ranging in size from 1 to 100 nm, serves to enhance foam stability by reducing bubble coalescence, thereby contributing to the creation of a more durable foam structure [96]. This, in turn, results in improved foam stability and prolonged foam longevity [148]. Nanoparticles can irreversibly adsorb into the fluid, which is due to their elevated adsorption energy and enduring thermal-chemical stability [34]. Consequently, they contribute to improving the stability of the foam. Silica dioxide nanoparticles, SiO_2, have emerged as a highly effective nanomaterial in the context of Enhanced Oil Recovery (EOR) applications [149], [150], [151]. The incorporation of SiO_2 nanoparticles into foam formulations contributes to a reduction in foam mobility and a simultaneous enhancement of foam strength. Notably, SiO_2 nanoparticles have the capability to form strong bonds with the amphiphilic head of a surfactant, resulting in improved thermal properties and heightened efficiency in oil recovery processes [152].

Nurudeen Yekeen et al, [153] studied the impact of SiO_2 and Al_2O_3 nanoparticles on mixed solutions with SDS at bulk and bubble levels. They observed maximum surfactant adsorption at a concentration of 3 wt%. Increasing nanoparticle concentration enhanced foam stability but diminished foamability. Nanoparticles resulted in smaller bubbles and higher bubble concentration, indicating reduced coalescence. Moreover, nanoparticles extended foam half-life, stabilized bubbles, and elevated apparent viscosity through adsorption and accumulation at foam borders.

Solid particles enhance bubble stability by reducing the contact area between fluids. Adding nanoparticles to foam reduces liquid drainage by absorbing them at the liquid-gas interface, reinforcing the film, and increasing lamella elasticity. This limits gas diffusion between bubbles, thereby extending foam longevity.

Youjie Sheng et al., studied how silica nanoparticles affect the properties of mixed solutions containing fluorocarbon and nonionic hydrocarbon surfactants. They found that while nanoparticles improved foam stability, they compromised foaming properties. The presence of nanoparticles at plateau borders enhanced foam drainage, coarsening, and mechanical strength [154]. In another study [155], the thermal stability of foams stabilized with mixed dispersions of SiO_2 nanoparticles, nonionic surfactants, and fluorocarbon surfactants was investigated. The results showed that nanoparticles can prevent foam decay, drainage, and coarsening under heat, enhancing foam thermal stability.

In their research paper, Ali Esfandyari Bayat et al conducted a comparative analysis to investigate the impact of different nanoparticles (SiO_2, Al_2O_3, TiO_2, and CuO) on CO_2 foam half-life, incremental oil recovery, and residual oil saturation [155]. The findings revealed that improved stability and incremental oil recovery were primarily associated with SiO2 foam (Figure 15 a). According to the results, the sequence of CO_2 foam stability among the nanoparticles can be arranged in ascending order as follows: CuO, TiO_2, Al_2O_3, SiO_2 (Figure 15 b). This observed trend can be attributed to the increased interaction energy of silica nanoparticles, which leads to heightened inter-particle repulsive forces. This, in turn, enhances dispersion stability and extends foam half-life.

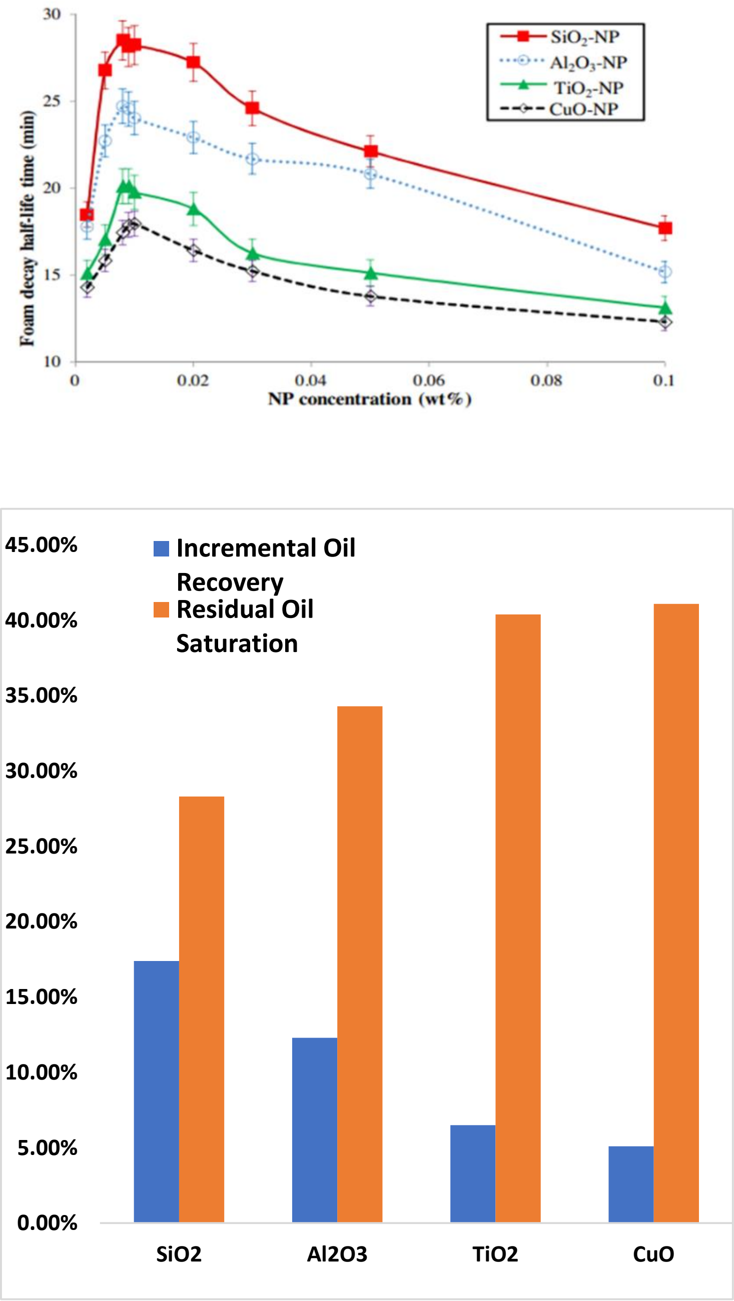

Figure 15 illustrates: (a) the half-life of CO2 foams stabilized by nanoparticles (NPs) and (b) the incremental oil recovery and residual oil saturation concerning the type of nanoparticles used. [155]

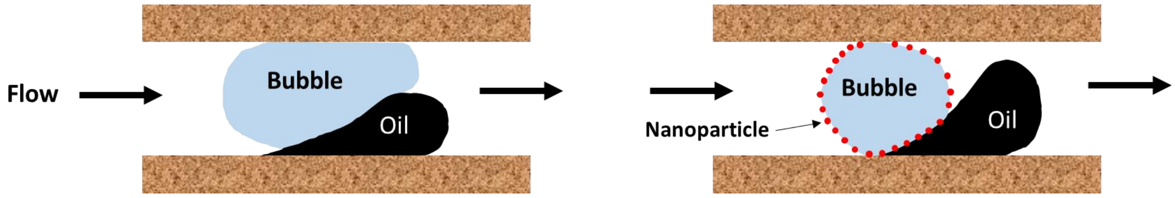

Figure 16 Comparison of mechanisms for mobilizing oil droplets using Surfactant-foam and NP-Surfactant-foam, Adapted from. [148]

Conclusions

Foam provides a cost-effective solution for improving Enhanced Oil Recovery (EOR) processes. Optimizing foam usage in EOR requires consideration of several key factors, including:

- Understanding the specific properties of the reservoir, such as permeability, porosity, and heterogeneity, is crucial for selecting the most appropriate method for generating foam. In sandstone reservoirs with a permeability range of 100 to 3000 millidarcies (mD), foam EOR has effectively reduced gas breakthrough and improved sweep efficiency, with notable reductions in water cut and improvements in oil recovery rates.
- In carbonate reservoirs, the application of foam led to significant reductions in gas mobility and improved volumetric sweep efficiency. Foam flooding in the Sacroc field improved mobility control and enhanced oil recovery.
- Successful EOR applications necessitate stable and long-lasting foam that can withstand challenging reservoir conditions, including high temperatures, pressures, and salinity levels. For example, in the Bohai Bay field, foam injection reduced water cut by 2.3% and increased the oil production rate by 13 t/d.
- The use of optimized surfactant types and concentrations is essential to reduce gas mobility and enhance conformance control. In high-permeability reservoirs such as Midway Sunset, foam application led to a four-fold increase in oil production
- Foams are thermodynamically unstable, which makes it challenging to maintain bubble stability over time. The strength of lamellae can be improved by using polymers, nanoparticles, nanofluids, and mixtures of surfactants, offering more stable foam.

By carefully considering these factors, operators can effectively optimize the use of foam in enhanced oil recovery (EOR), resulting in improved oil recovery efficiency and operational stability.

Future Research Directions in Foam Technology for Enhanced Oil Recovery

Future research on foam-based Enhanced Oil Recovery (EOR) should concentrate on several important areas to enhance efficiency and environmental sustainability. One promising direction is the creation of nano-enhanced foams that incorporate nanoparticles such as SiO_2 and Al_2O_3. These nanoparticles can greatly improve foam stability and oil recovery rates by boosting the interaction energy among foam components, resulting in better dispersion and a longer lifespan. Moreover, it is vital to investigate biodegradable surfactants that can perform effectively in challenging reservoir conditions to promote environmentally friendly EOR practices, tackling issues of foam quality and stability will be crucial for future progress. Additionally, examining the synergistic effects of various nanoparticles and surfactants may lead to innovative formulations that optimize oil recovery while reducing environmental impact. By focusing on these research avenues, we can make significant strides in foam technology for EOR, ensuring both economic feasibility and environmental stewardship.

Table 6 Laboratory investigation of nanoparticle, and nanoparticle-surfactant-stabilized foams.

Nanoparticle type	Np size (nm)	Np Concentration	Surfactant used	Temperature (°C)	Pressure	Salinity	Foam generator	Oil recovery (%)	References
Aluminum oxyhydroxide	10-100	1 wt%	SC (0-100 mM)	60	6 mPa	$CaCl_2$ (10-200M), NaCl (10- 600 mM),	Sandpack	20% OOIP	[156]
SiO_2	100-200	0.05-3.0% w/v	PEG, Tergitol 15-S-20, DCDMS	35, 50	1200-3000 psia	-	Glassbead pack	-	[157]
APTES-SiO_2	20-30	0.01 wt%	SDS(0.4wt%)	25	14.7 psi	-	Glassbead pack	18% OOIP	[158]
SiO_2, Al_2O_3	15-20	1.0 wt%	SDS (0.01-1.0 wt%)	25	-	NaCl (0.25-6.0wt%), $CaCl_2$ (0.125-5.0 wt%), $AlCl_3$(0.025-0.1wt%)	Hele-Shaw cell	-	[159]
Al_2O_3-coated SiO_2	20	1-5 wt%	Triton CG-110 AOS, PG (0.1–0.5wt%)	Ambient	100 psi	-	Berea sandstone	14.8-20.6% OOIP	[160]
SiO_2, Al_2O_3, CuO, TiO_2	10-40	0.1-1.0 wt%	AOS (0.5wt%)	Ambient	-	NaCl (2wt%)	Sandpack	5-14% OOIP	[153]
PEG-coated SiO_2	5(10)	0.3 wt%	AOS (0.5 wt%)	55.75	110 psi	NaCl(1-8wt%)	Heterogenous sandpack	34.4% OOIP 9% OOIP	[161]
PEG-coated SiO_2	10(20)	0.5 wt%	AOS(0-0.5wt%)	25	100 psi	NaCl (1-10 wt%) API Brine	Berea sandstone	10% OOIP	[162]
PECNP	-	1.0wt%	Surfonic N120	40	1300 psi, 1800 psi	KCl (2.0wt%)	Indiana limestone	10.71% OOIP	[163]
PEG-SiO_2, GLYMO-SiO_2	12.20	0.5 wt%	AOS	25, 60, 80	110 psi	NaCl (8wt%), $CaCl_2$(2wt%)	Sandpack	29.0 -43.3 OOIP	[163]
TTFA	80	0.5 wt%	Anionic and non-ionic, Cationic surfactant (0.2wt%)	25	1300 psi	NaCl (1.0wt%)	Berea sandstone	-	[164]
SiO_2	100-150	0-5 wt%	-	25, 60	1200 – 2000 psia	NaCl (0.5, 2.0, 5.0%)	Sapphire observation tube	-	[165]
MWCNT	10	0.01wt%	Tergitol 15-s-40, AOS	25	-	NaCl (2.4wt%), $CaCl_2$(0.6wt%)	-	-	[166]
Modified hydrophobic SiO_2	20 nm	1.0 wt %	Mixtures: 0.15% SDS + 0.05 wt % AOT, 0.15% SDS + 0.05 wt % C12E23, 0.15% SDS + 0.05 wt % betaine	Room temperature 25 °C	Back-pressure 1.2 MPa	-	Micro glass model	N_2 Foam:88.75% CH_4 Foam:47.25%	[167]
Silica nanoparticles	-	0.00, 0.01 and 0.10 wt. %	$C_20H_{44}BrN$ 0.019, 0.038 and 0.057 wt. %	Ambient	High pressure	-	100~150 µm glass beads	-	[168]

Nanoparticle type	Np size (nm)	Np Concentration	Surfactant used	Temperature (°C)	Pressure	Salinity	Foam generator	Oil recovery (%)	References
SiO_2	17	0.01-0.5 wt%	-	25	1200 psig, 1500 psig	NaCl (2.0%)	Berea sandstone core	-	[169]
PEG-coated SiO_2	5	0.01-0.1 wt%	-	21.1- 90	1350-1400 psia	NaCl (2-4 wt%)	Glass beads pack	-	[170]
SiO_2	20	0.25-1.0 wt%	-	25	1500 psig	NaCl	Glassbead pack and Capillary tube	-	[171]
SiO_2	5, 10	0.01 – 1.0 wt%	PEG	50-90	2000 psia, 2800 psia	NaCl (0-4 wt%)	Glassbead pack, Sandstone (Berea, Biose, Indiana)	-	[172]
SiO_2, Al_2O_3	12-20	0.05-5.0 wt%	SDS (0.03 wt%)	25	-	NaCl (0.5 wt%)	Hele-Shaw cell	-	[173]
Nanoash	100-200	-	AOS (0.031wt%)	80	80 bars	NaCl, $CaCl_2$	Bentheimer sandstone	23% remaining oil saturation	[174]
SiO_2	30 nm±1	0.50 wt%	Anionic surfactant	50 °C	1550 psi	1 wt% NaCl	corefood apparatus (non-fractured and fractured)	In non-fractured rock: 44.3%, however in fractured rock, it only yields 12.62%.	[175]
SiO_2	140 nm	0.1 wt%	Anionic AOS (0.5 wt%) and viscoelastic surfactant cocobetaine (0.4 wt%)	150˚F	1500 psi	5 wt% NaCl	Berea sandstone cores	8% in the presence of NPs, and 15% by adding NPs and viscoelastic surfactant.	[102]
Methyl coated silica	-	1% w/v solution	SDS	Ambient	-	1% wt/v NaCl	Microfluidic pore network chip	17% IOIP	[176]
CuO, SiO_2, TiO_2, and Al_2O_3	CuO and Al_2O_3: 40 nm, SiO_2: 20 – 30 nm, TiO_2: 10–30 nm	(0.5, 0.1, 1 and 0.3) wt%	AOS 0.5 wt%	Room Temperature	Room Pressure	0.5 wt% and 2 wt% of NaCl	Porous stone	Al_2O_3:14%, SiO_2: 11%, TiO_2 and CuO: 5%.	[177]
SiO_2	14 nm	0.6 wt%	SDS 0.5 wt%	60 - 80°C	Back-pressure 2.0 MPa	NaCl 0.5wt%	Sandpacks and the glass-etched micromodel	Varied between 38% and 44% for both individual and paired sandpack cores.	[178]

Nanoparticle type	Np size (nm)	Np Concentration	Surfactant used	Temperature (°C)	Pressure	Salinity	Foam generator	Oil recovery (%)	References
SiO_2	17 – 20 nm	-	Surfactant	25, 45, 60 °C	2000 psi	2 wt% NaCl	3 samples cores used: Dolomite Limestone Berea sandstone	26.5% dolomite, 33.2% limestone, 39.6% sandstone	[179]
Methyl-coated silica	12	1% w/v	SDS	~22 °C	-	1% w/v NaCl	Borosilicate glass micromodel	Compared to CO_2 flooding, the incremental output with OOIP is 10% greater.	[180]
Silica	-	-	AOS (Alpha Olefin Sulfonate)	-	-	Brine solution	Core samples: Limestone and Sandstone	17%	[181]
SiO_2	17 – 20 nm	5,000 ppm in 2% brine	Foaming agent	20°C	1200 psig	NaCl	Berea sandstone	Ranged from 36% to 49%	[182]

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Conflicts of Interest

There are no conflicts to declare.

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