

Review

A Comprehensive Review of the Role of CO₂ Foam EOR in the Reduction of Carbon Footprint in the Petroleum Industry

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Abstract: By trapping CO₂ and storing it in matured and depleted geological formations, atmospheric CO₂ release can be reduced. Carbon capture and storage on a large scale can help to stabilize atmospheric greenhouse gas emissions. This can be achieved by using anthropogenic CO₂ for enhanced oil recovery (EOR), which encourages advances in secure CO₂ storage while enhancing the oil production process. This interaction is expected to hasten the development of CO₂ storage technology and lower emissions from oil producing operations. Reducing CO₂ mobility in the reservoir is crucial to achieving this goal as effectively as possible, and in situ foam generation offers a viable solution. It has been shown that implementing a blend of CO₂ and foaming solution considerably reduces CO₂ mobility and front propagation. Although there have been a few reviews of carbon capture, utilization, and storage (CCUS), none of these have concentrated on the role of foam EOR in achieving carbon neutrality. Therefore, in this brief review, methods for achieving carbon neutrality with foam EOR are comprehensively reviewed. In order to store CO₂, the utilisation of atmospheric CO₂ to generate foam is the main topic of this review. This approach can boost financial incentives for the energy sector, help to lower carbon emissions, and make it possible to produce oil from depleted reservoirs in a more sustainable way. Thus, identifying and examining the governing mechanisms that affect CO₂ storage during foam flooding as well as reviewing the various techniques for estimating CO₂ storage under actual reservoir circumstances are among the goals of this work.

Keywords: foam; surfactants; oil; CO₂ storage; carbon footprint; CCUS



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1. Introduction

The term “carbon footprint” refers to greenhouse gas emissions. Their decrease is crucial, as it lessens the impact of climate change, thereby benefiting human health and the diversity of plants and animals [1,2]. Additionally, it promotes the global economy by producing creative and environmentally responsible solutions. In general, the top three sources of CO₂ emissions are coal, oil, and natural gas [3]. The percentage compositions of carbon in these sources are 60–80%, 82–85%, and about 87%, respectively [3–6]. Thus, because carbon is a key component, cutting back on consumption- or production-related emissions has a significant positive impact on the environment, economy, and public health. The gases that contribute to the greenhouse effect are listed as follows with their corresponding percentage compositions: carbon dioxide (79%); methane (11%); nitrous oxide (7%); and fluorinated gases (3%) [7–9]. Thus, as the primary component of greenhouse gas emissions, CO₂ emissions in particular are viewed as a challenging problem that must be resolved [10].

In 2021, CO₂ emissions from industrial activities and the combustion of energy increased to their greatest annual level [11]. Emissions increased by 6% from 2020 to 36.3 gigatons (Figure 1). However, it should be considered that energy consumption in 2020 was significantly impacted by the COVID-19 pandemic, which resulted in a 5.2% decrease in

global CO₂ emissions. Subsequently, the global economy has recovered incredibly quickly thanks to massive fiscal and monetary support as well as a quick mobilization of vaccines [11,12]. The development of global emissions from the middle of the 18th century to date is seen in the figure above. It can be observed that emissions were very minimal before the industrial revolution, and emissions growth remained comparatively slow until the middle of the 20th century [13,14]. The globe released about 6 billion tonnes of CO₂ in 1950. This amount increased nearly four-fold by 1990, rising to over 22 billion tonnes (Figure 1). Recently, CO₂ emissions stand at more than 34 billion tonnes annually as a result of the rapid increase of these emissions [11,15].

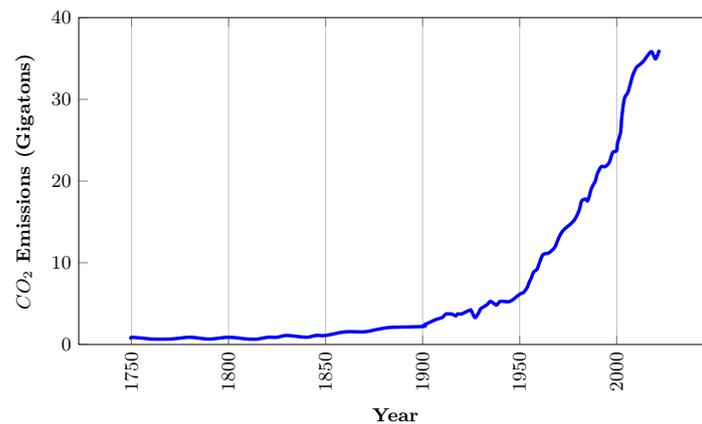


Figure 1. Annual CO₂ emissions from all industrial activities (Adapted from IEA Global Energy Review [11]).

Figure 2 shows the increase in worldwide emissions due to fossil fuels from the middle of the 18th Century to the present. As can be seen, emissions from fossil fuels have significantly increased. Overall, this indicates that overall emissions have essentially stabilised during the past ten years.

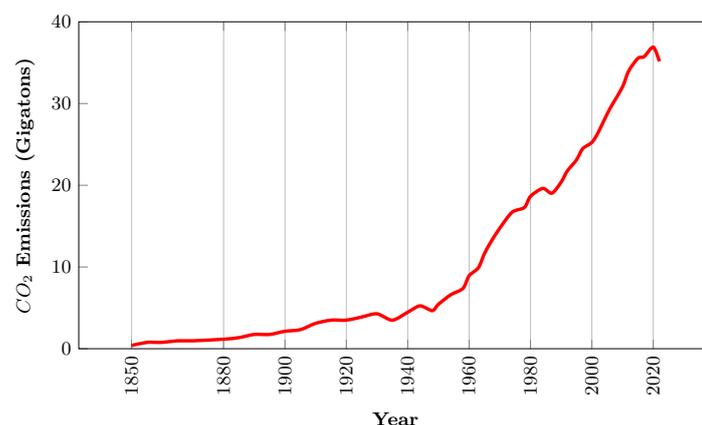


Figure 2. Global CO₂ emissions from fossil fuels (Adapted from IEA Global Energy Review [11]).

In the petroleum industry, CO₂ capture and storage (CCS) in appropriate reservoir formations can reduce atmospheric CO₂ accumulation. Globally, subsurface storage for CO₂ could be at least 2000 gigatonnes [16,17]. This is eighty times more than annual CO₂ emissions. The stabilization of atmospheric greenhouse gas concentrations can be aided by extensive CCS implementations [18]. CCS is frequently mentioned as a solution to permanently store carbon dioxide emissions from large polluters underground, thereby keeping them out of the atmosphere [19]. However, CCS can be utilized in a more economical way to produce crude oil, which when burned releases emissions and contributes to climate change. Using CO₂ emitted from coal plants to produce more oil may actually reduce the

overall amount of CO₂ released into the atmosphere as a result of burning coal and crude oil, according to industry experts [20,21].

This practice is known as CO₂ EOR. CO₂ is captured and re-injected into old or depleted oil fields where production has reached its peak [22,23]. Residual oil can react with CO₂ and swell underground by being injected into oil wells that have been producing less oil. This reduces the oil's viscosity and allows it to flow more freely to the production well, thereby reviving production. This offers a good way to protect the environment, as burning coal and crude oil results in fewer overall emissions [24–26]. Here, CO₂ injection is expected to produce effects that are greater than or comparable to those of oil consumption [27,28]. Many oil and gas operations today employ CO₂ from underground natural sources produced specifically for oil fields; however, this has no positive impact on the climate. Numerous environmentalists have stated that CO₂ EOR does nothing to reduce emissions, and only serves as a way to extend the use of fossil fuels because it produces oil that emits carbon [29,30].

However, a recent study by Nunez-Lopez et al. [31] has revealed that, depending on strategic operational decisions, the incremental oil produced from CO₂ EOR can achieve a net carbon negative status for the majority of the operation. This is because a significant portion of the injected CO₂ is unavoidably and permanently trapped in the reservoir. In the petroleum industry, CO₂ storage combined with EOR can be both a profitable activity and a way to reduce greenhouse gas emissions, in contrast to most industries, where CO₂ storage is typically considered as a waste disposal operation [23,28]. By turning CO₂ emissions from industrial and power plants into a valuable raw material for the petroleum industry, injecting CO₂ for the production of residual oil can assist in reducing emissions by accelerating the storage of CO₂ emissions that are responsible for climate change.

Although CO₂ can be injected to recover oil, this is ineffective, as reservoir oil has a significantly higher density and viscosity. Hydrocarbon gas dissolves far less readily in water than CO₂ [32]. Under high pressures, carbon dioxide becomes more soluble in water, which is advantageous for most reservoirs. Additionally, when carbon dioxide is dissolved in oil, the volume of the oil increases, greatly enhancing oil recovery [33].

During CO₂-EOR, miscibility and interfacial mass transfer between reservoir oil and CO₂ occurs [34,35]. If total miscibility is achieved, the viscosity and density of the mixture reduce and oil is easily displaced [36]. However, if total miscibility is not achieved, only a portion of the CO₂ is in a free form, which means that the gas can only draw out lighter hydrocarbons from the oil [36,37]. As a result, the effectiveness of gas displacement decreases as the residual portion of the gas breaks through and causes viscous fingering [38,39]. In order to overcome these challenges, foam EOR has been proposed. This technique involves injecting CO₂ gas into the reservoir together with a surfactant solution. This ensures an improvement in sweep efficiency as well as an increase in recovery efficiency due to the uniform displacement front [40,41].

Therefore, the purpose of this paper is to evaluate foam EOR as a means of advancing CO₂ EOR for carbon storage. To the best of our knowledge, no review paper exists on the use of CO₂ foam for CO₂ storage. Hence, we have reviewed the recent developments in foam flooding for the purpose of carbon storage. In this work, we carefully discuss the existing carbon footprint in oil production and the potential of foam EOR as a dual-purpose technique for oil recovery and carbon storage. Additionally, we examine different methods of calculating the effectiveness of foam for CO₂ storage used by various authors, identify their limitations, and propose a novel function that captures the majority of the factors involved. The latter sections of this work examine past and recent CO₂ foam experiments for CCUS research and offer recommendations on how they might be enhanced in future work.

2. Carbon Footprint in Oil Production

In addition to helping to solve environmental and climate challenges, decarbonization is now used to ensure product differentiation and worldwide competitiveness. As a measure of the quality of any product or process, the carbon footprint is progressively assuming the highest priority [42]. Decarbonization criteria are becoming more stringent as large institutional investors and investment funds with a significant impact on the petroleum industry make public pronouncements about their climate aims [42,43].

In reality, the ability to show visible decarbonization progress has become one of the most important goals of major petroleum production companies. Major stakeholders frequently fault the petroleum industry for contributing to climate change [44]. However, understanding the types of GHG emissions that the industry generates is important in order to provide a thorough response to this issue. Emissions are typically categorised into three major classes in accordance with international practice (Figure 3) [45].

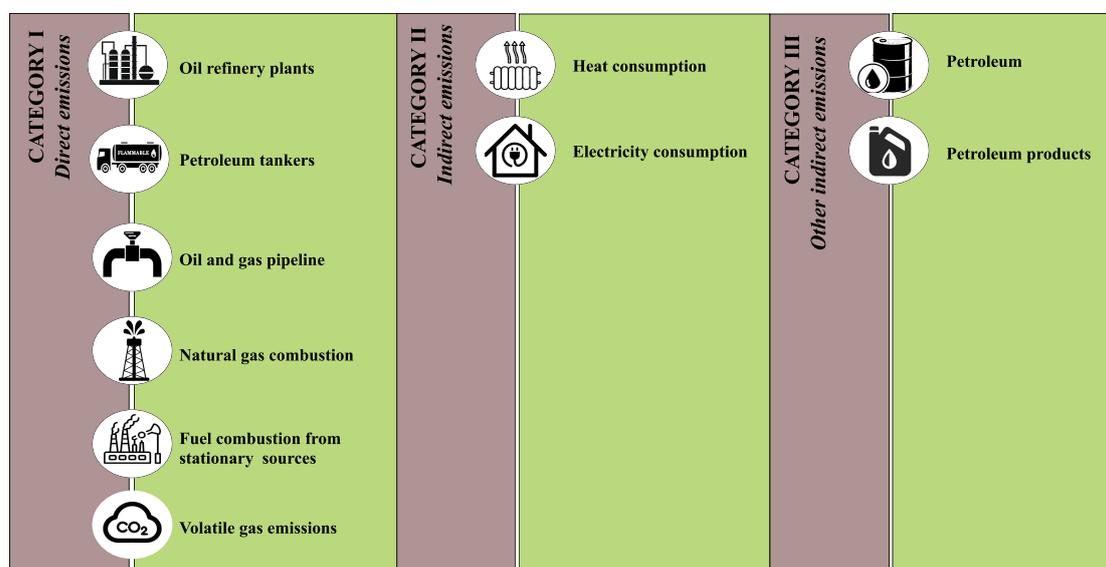


Figure 3. Categories of emissions from oil production.

The first category consists of emissions produced directly by production activities. For the petroleum industry, this category comprises GHG emissions from the extraction, processing, and burning of oil and natural gas as well as from the operation of the company's energy sources and the provision of heat for its production facilities and operations. The second category consists of indirect GHG emissions from the use of heat and energy sources that the industry purchases for its purposes. The third category, which consists of emissions resulting from the burning of fuels such as oil and gas, are related to the consumption of petroleum goods.

Within the oil and gas sector, the positions of companies vary greatly in terms of their GHG emissions. European companies operate in an environment where GHG emissions management has existed for a long time; for example, in Norway a carbon tax was introduced in 1992 [46,47]. As a result, their activities are relatively low in carbon intensity, and they are more focused on developing the industry and investing in renewable energy and other clean technologies.

The introduction of CCUS technologies as well as the generation and use of hydrogen as fuel are just a few of the deep decarbonization strategies that many oil and gas companies have in place. Hundreds of pertinent initiatives are in various phases of research and development across Europe, the United States, and the Middle East, although up to this point they have solely relied on large state subsidies [48].

The combined capacity of CCUS projects today is only 10 Mt of CO₂ [49,50]; however, under scenarios that are consistent with the goals of the Paris Agreement, by 2050 this

amount should be 6 Gt of CO₂, which exceeds the size of the entire current global oil and gas industry. This creates enormous opportunities for the new industry practices that make use of core oil production competencies [50,51].

3. CO₂ Storage Mechanisms in CO₂ and CO₂ Foam EOR

Injecting CO₂ into a reservoir is a very practical and feasible method of storing carbon, as described in the preceding section. Generally, two or three recovery stages are implemented during the development of an oil field. Oil is produced during primary recovery by natural driving mechanisms backed by the reservoir's natural energy (dissolved gas expansion, gas cap expansion, saline water influx, etc.) [21]. Oil production rates decrease as reservoir pressure decreases due to the removal of reservoir fluids. Thus, techniques for fluid lifting and pressure maintenance are needed to extend the primary production time. In secondary recovery, a fluid (most frequently water) is injected to push oil to producing wells by maintaining reservoir pressure [52,53].

After secondary recovery, only 30 to 50% of the oil is typically recovered, leaving 50 to 70% of the oil in the reservoir [54]. Because extracting the residual oil requires more sophisticated and expensive technology, reservoirs have traditionally been abandoned at this point. Any method used following secondary recovery is referred to as tertiary recovery [55]. EOR is often considered a tertiary phase of recovery, even though it can be applied at any stage of the development of a petroleum field. For instance, CO₂ injection is considered one of the most promising EOR methods [54]. Due to its low viscosity and density in comparison to the reservoir fluids, CO₂ typically has a significant mobility contrast. This results in unstable displacement in the form of viscous fingering, which adversely impacts oil recovery [40].

Therefore, CO₂ is typically injected along with water that contains surfactant and other additives that can lower the unfavorable mobility of CO₂ in the reservoir. This is known as foam EOR. When gas is mixed with a liquid solution, foam is generated. This strengthens the displacement front and increases the viscosity of the injected fluid, enhancing sweep efficiency and mobility control [56].

Additionally, the relative phase permeability of gas is automatically decreased by the addition of water and gas to generate foam due to an increase in the saturation of mobile water. Due to gravitational segregation, the gas effectively displaces the oil while moving through the top portions of the reservoir [57,58]. As a result, water fills the lower portion of the reservoir in place of the oil, which causes water and gas to move together close to the injection well. Additionally, the capillary effects of foam films considerably restrict gas mobility by confining the gas bubbles and raising their flow resistance. This decrease in gas mobility increases sweep efficiency and leaves more swept zones for CO₂ storage. Thus, rather than propagating in the direction of the production well, additional CO₂ is trapped in the pore spaces [59].

It is important to note that not all of the CO₂ injected is recovered at production wells. Due to capillary forces that immobilize CO₂ mobility within pores, as well as by dissolving in residual oil and water, a significant amount of the CO₂ in the reservoir remains trapped [60]. This volume is referred as CO₂ retention. In CCUS, associated storage refers to the CO₂ that is lost in the formation during the conventional EOR process. The amount of CO₂ that can be stored in this way relies on the characteristics of both the reservoir and the crude oil, as well as operational aspects of oil production such as well spacing, the distance between injection and production wells, and the injection scheme [61].

As seen in Figure 4, there are four primary mechanisms for trapping CO₂ in porous material during CO₂ sequestration. These include stratigraphical or structural trapping, residual trapping, solubility trapping, and mineral trapping [62–64].

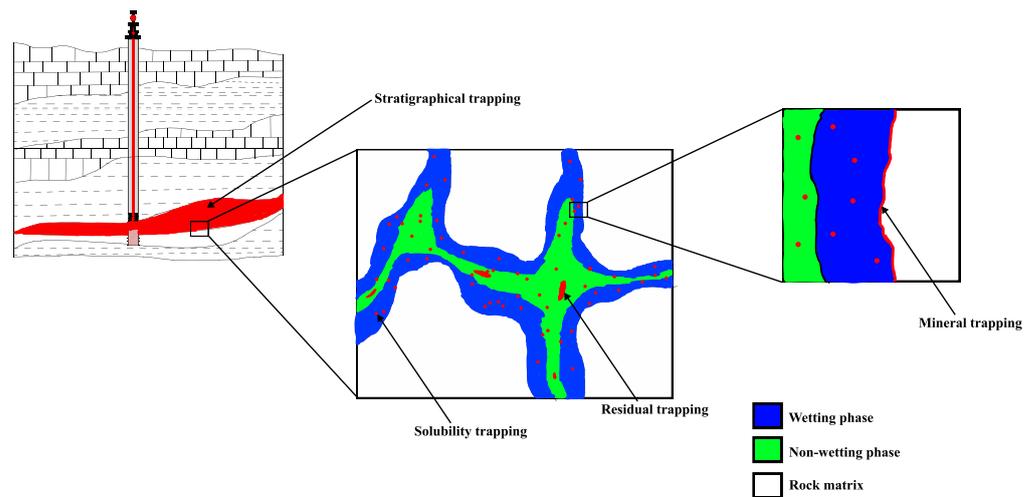


Figure 4. CO₂ storage mechanisms in a porous medium.

- **Structural trapping** refers to the confinement of CO₂ as a mobile phase by the field-scale reservoir stratigraphy and structure. CO₂ typically accumulates beneath the impermeable regions of the reservoir, such as caprocks. These tight caprocks serve as a barrier characterized by low permeability. This prevents both buoyancy-induced CO₂ migration upward and percolation across the rock system.
- **Residual trapping**, is related to structural trapping, as both describe the capillary forces that confine supercritical CO₂ in pores as an immobile phase. Capillary pressures cause CO₂ to be stored as an immobile phase within porous media; this mechanism is significant because it can function without a caprock or stratigraphic seal.
- **Solubility trapping** refers to the dissolution of CO₂ into reservoir fluids, such as formation water and reservoir oil. This can happen in either the formation water phase or the oil phase, and is dependent on the formation's pressure, temperature, and salinity.
- The last mechanism is **mineral trapping**, which is related to solubility trapping, as it depends on CO₂ dissolution into reservoir brine. CO₂ solubility in brine is necessary for mineral trapping. Numerous minerals found in the formation rock become more soluble when CO₂ is dissolved in brine, which lowers the pH of the brine. Therefore, CO₂ interacts both directly and indirectly with the minerals in the formation rock, precipitating secondary carbonate minerals.

The relative importance of the various trapping mechanisms is influenced by the number of factors, including the characteristics and type of the geologic formation and the characteristics of the reservoir fluids [62,65]. Additionally, based on the CO₂ injection approach and settings, the significance of various trapping processes may vary. However, structural and residual trapping account for about 95% of CO₂ storage, making them the most vital mechanisms [66–69], probably because they heavily rely on the already present capillary forces and tend to balance out the buoyant forces that are directed upward [70].

The time scale of the various trapping mechanisms is shown in Figure 5:

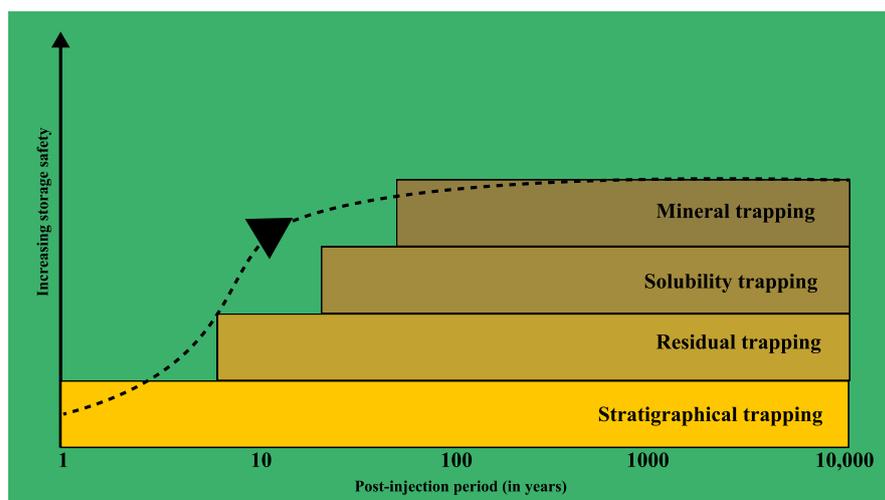


Figure 5. The time scale of CO₂ storage mechanisms.

The time scale for various trapping techniques in subterranean geological formations is shown in Figure 5. Over time, more secure trapping processes develop following the injection phase, thereby strengthening the long-term safe storage of CO₂ [71,72].

Not all of the residual brine is mobilized, as it may remain trapped during the displacement process. This is mainly because of the significant density and viscosity differences between CO₂ and reservoir brine during the recovery process [73]. CO₂ storage is hampered by these factors, which dominate flow behavior in extremely porous reservoirs. This may limit the amount of CO₂ that can flow through the aquifer's pore spaces [74]. As a result, while lowering CO₂ mobility is an important task that helps to minimize the aforementioned viscosity and density contrasts, ultimately increasing storage capacity by lowering the amount of residual brine, it is very difficult. In this respect, foams show great potential [63,75].

3.1. Mechanisms of CO₂ Sequestration Peculiar to Foams

3.1.1. Gas Trapping by Foam

Gas trapping is one of the most significant microscopic mechanisms involved in foam flow in porous media. A.N. Fried [76] noted that foam movement increases trapped gas saturation. This has subsequently been confirmed by other researchers [77–80], and it has been revealed that trapped gas saturation in porous media can range from 10–70% when utilizing foam injection. The liquid phase in the foam traps the gas phase during a miscible displacement process using one of the following trapping methods:

- **Snap-off** is a phenomenon in which the interface between the wetting phase and the non-wetting phase (gas or oil) continues to swell during an imbibition process. This causes the globule to shear thin until it forms a discontinuous phase and becomes trapped in the pores [81].
- Another mechanism is **bypassing**, in which a non-wetting phase replaces the wetting phase in the small pores or pore throats of an immiscible displacement process [82].
- Finally, the **Jamin effect** is another phenomenon that occurs when liquid flow in capillaries encounters resistance from gas bubbles or liquid globules caught in pore throats because of the differential capillary pressure across the bubble or globule [83].

These trapping mechanisms can occur during foam flow in porous media due to the fact that foams possess properties that make them conducive for gas trapping [84]. First, foams are made up of variously sized gas bubbles that are sparged throughout a continuous liquid phase. Second, the wetting phase fills the small pores, leaving no room for gas bubbles in the non-wetting phase, meaning that they occupy the middle of the large pores. Third, bubbles can have sizes as large as the pores where they are generated, and can migrate from a large pore before becoming trapped in a smaller pore [85].

Foam traps and holds CO₂ bubbles within the swept area [62,79]. Additionally, a portion of the gas dissolves into the residual formation water, and over time may interact with the formation salts and minerals to remain in the form of minerals. Compared to a gas–liquid flow without foam, residual CO₂ saturation in foam is significantly higher [86].

In the works of Gong et al. [87,88], it was found that even in the region of “collapsed foam” created during gas injection very near the well, much gas is retained upon subsequent imbibition of surfactant solution or water, including a gas saturation greater than 50% in corefloods. In the portion of the core corresponding to the formation beyond the immediate vicinity of the wellbore, where the foam has not yet collapsed, residual saturation can be greater than 70%. Thus, foam increases both the sweep efficiency and the saturation of gas trapped by capillary forces within the region.

3.1.2. Reduction of Gravitational Segregation

Al-Ayesh et al. [89] and Kapetas et al. [90] highlighted the CO₂ storage mechanism of foam by enhancing the injection profile in terms of gravitational segregation. Foam can redirect the flow towards the less permeable layers in the bottom zone of the reservoir, as shown in Figure 6 for a geological formation with highly permeable layers in the upper zone. CO₂ is able to spread further after being injected into these zones before reaching the higher zone. This indicates that more reservoir volume is swept, trapping more CO₂. Thus, foam provides yet another benefit by reducing the effects of gravity override in heterogeneous formations [91].

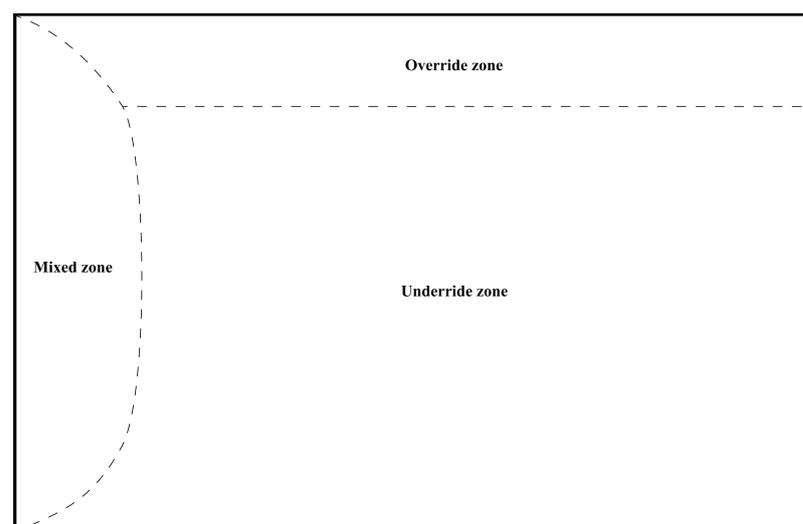


Figure 6. Flow zones in a porous medium during gas injection.

In a laboratory core flood experiment, Tanzil et al. [92] revealed that a capillary effect prevented gas from flowing across the boundary from a low-permeability zone to a high-permeability one. Due to the presence of a surfactant in the liquid phase, the foam was generated as the gas passed through the barrier. As a result, gas can remain at the interface and regenerate or collapse; alternatively, it may propagate as foam. In either case, there is a decrease in both vertical permeability and upward movement of the gas [91,93].

3.1.3. Blockage of CO₂ Leakage

According to several studies [94,95], foam may help to mitigate CO₂ storage reservoir leaks. Keeping CO₂ safely underground is the major objective of storage in geological formations. In essence, CO₂ is stored in caprock-covered geological formations such as saline aquifers, depleted reservoirs, and other geological formations [96]. While the caprock is relatively impermeable, these reservoirs often have significantly high porosities and permeabilities. While this condition is fairly ideal for the long-term storage of CO₂, there is

a chance that in specific circumstances CO₂ could undesirably migrate out of porous media through two distinct pathways [94,97]. These two pathways are outlined below in Figure 7.

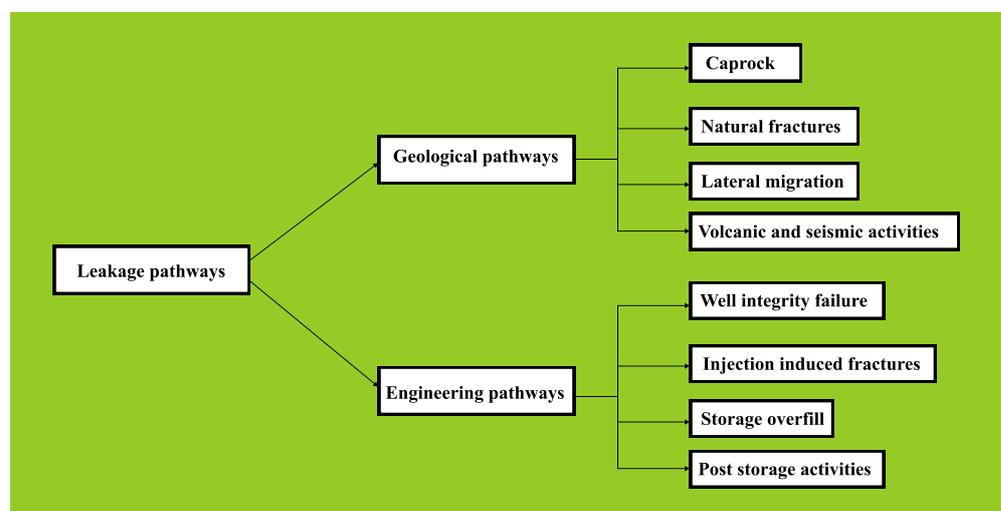


Figure 7. CO₂ leakage pathways.

Geological leakage involves naturally occurring fractures, whereas engineering leakage pathways are those caused by wellbore cementing failure or through fractures induced by engineering operations [98].

Because foams are used for CO₂ mobility control, they are well equipped to reduce or eliminate the leakage of stored CO₂. The following explanations describe how foams reduce CO₂ leakage in porous media.

First, the apparent viscosity of CO₂ increases as a result of the coalescing fluidity of the foam, allowing the extra driving pressure difference to easily displace the bubbles [40]. Additionally, the spread of the surfactant can cause a gradient in the surface tension, lessening bubble movement. Finally, by redistributing the interactions between gravity and viscous forces the foam is able to lessen the impact of gravitational segregation.

In these ways, foam can decrease CO₂ leakage, improving the ability of porous media to effectively store CO₂. These claims are supported by previous studies [99–101] in which it has been observed that in situ generation of foam reduces CO₂ leakage and decreases the mobility of free CO₂ due to increased viscosity and enhanced resistance to gas flow.

4. Determination of CO₂ Storage Efficiency and Co-Optimization with EOR

The term “CO₂ storage efficiency” is crucial to this review, as it indicates how much CO₂ can be stored in a reservoir. It can be used to evaluate how the process or the used chemicals are effective. Generally, it is the volume fraction of the pore space for CO₂ storage. It has several components that reflect the different physical barriers that mitigate CO₂ contact with the reservoir pore volume [102]. However, the determination of this parameter is not as simple as it appears. It stems from several variables, including the formation’s heterogeneity, the injection scheme and mode, other formation properties, transport processes, and other factors that can affect how efficiently CO₂ is stored. Additionally, different CO₂ storage mechanisms may take place at different stages depending on the thermodynamic conditions under which CO₂ is injected [103,104]. As a result, different studies have used a range of approaches, which makes it challenging to compare and assess them. In this section, we cover three recently developed and frequently applied functions for estimating CO₂ storage efficiency and propose an improvement to these functions.

According to Kovscek et al. [104], CO₂ storage efficiency is the ratio of the volume of stored CO₂ to the reservoir’s total pore volume (Equation (1)). However, this method does not account for the geological limitations of the reservoir or consider that the total pore volume in the reservoir may not be available for CO₂ storage. Furthermore, this function

assumes that CO₂ has the same volume even when thermobaric conditions change, which is not possible. In fact, as the temperature and pressure in the reservoir change, the volume and phase of CO₂ change as well [105].

$$\text{CO}_2 \text{ storage efficiency} = \frac{\text{CO}_2 \text{ stored}}{\text{Total PV}} \quad (1)$$

Thus, Jahangiri et al. [106] modified this function and proposed that CO₂ storage efficiency be defined as the ratio of CO₂ stored in the reservoir to the total CO₂ storage capacity of the reservoir (Equation (2)). Although this might be true for theoretical definitions, the total amount of CO₂ storage capacity in the reservoir is an unclear factor in analytical terms [103]. This is because CO₂ storage capacity in geological formations exists on four different levels, and the calculations for each of these storage capacity levels are different [107–109].

$$\text{CO}_2 \text{ storage efficiency} = \frac{\text{CO}_2 \text{ stored}}{\text{Total CO}_2 \text{ injected}} \quad (2)$$

Due to this, Kamali et al. [110] continued to work on this function, and claimed that the ratio of stored CO₂ to CO₂ injected in the reservoir can be used to determine the CO₂ storage efficiency (Equation (3)). However, this function only represents the injected CO₂ utilization factor, not the reservoir's storage capacity [105]. Additionally, operating companies usually account for CO₂ loss from production or injecting wells, which is not taken into consideration in this function [111,112].

$$\text{CO}_2 \text{ storage efficiency} = \frac{\text{CO}_2 \text{ stored}}{\text{CO}_2 \text{ injected}} \quad (3)$$

Due to the shortcomings of earlier research, in this work we suggest a modified function for CO₂ storage efficiency. The CO₂ storage factor can be calculated as the ratio of the reservoir's theoretical CO₂ storage capacity to the cumulative amount of CO₂ that is injected, produced, and lost (Equation (4)).

$$\text{CO}_2 \text{ storage efficiency} = \frac{\text{CO}_2 \text{ injected} - (\text{CO}_2 \text{ produced} + \text{CO}_2 \text{ loss})}{\text{CO}_2 \text{ theoretical storage capacity}} \quad (4)$$

Because CO₂ loss mostly consists of surface and subsurface losses, there are neither exact statistics nor a known method by which it can be computed. When a power outage occurs, or when pipes need to be repaired, a portion of CO₂ is lost to surface loss, while subsurface loss might happen when CO₂ migrates laterally outside of the production well [112]. According to industry experience, the recommended figure for CO₂ loss is 5% of the cumulative injected CO₂.

The purpose of injecting CO₂ into the reservoir in various ways, as indicated in earlier sections, is not only for CO₂ storage; it can aid in oil recovery as well. Therefore, it is essential to co-optimize CO₂ storage and oil production. In order to co-optimize both functions, the aforementioned proposed function can be paired with a recovery factor parameter and the addition of weighting variables.

$$f = X_1 \frac{\text{Oil produced}}{\text{OOIP}} + X_2 \frac{\text{CO}_2 \text{ injected} - (\text{CO}_2 \text{ produced} + \text{CO}_2 \text{ loss})}{\text{CO}_2 \text{ theoretical storage capacity}} \quad (5)$$

Here, X_1 and X_2 are weighting factors and maximally equal 0.5, which demonstrates that CO₂ and oil recovery have the same priority. Although each weighting element can be altered depending on the operation's objective, their combined value must be 1.

Levels of CO₂ Storage Capacity

The most pertinent and important concept is theoretical storage capacity, which relates to the actual constraint on the quantity of CO₂ that can be stored by the porous medium [107]. It is built on the assumption that the full geometric space of the produced oil can be utilized for CO₂ storage, and is based on the material balance equation. This means that CO₂ can fill the swept zones left behind by the produced oil, and can dissolve into crude oil and/or water during injection [109].

$$M_t = \rho_{gas} [RF \times \{Ah\phi(1 - S_{wi}) - V_{iw} + V_{pw}\} + C_{ws} \times \{Ah\phi S_{wi} + V_{iw} - V_{pw}\} + C_{os} \times \{Ah\phi(1 - RF)(1 - S_{wi})\}] \quad (6)$$

where M_t = theoretical CO₂ storage capacity in the porous medium, kg; ρ_{gas} = the density of CO₂ in reservoir conditions, kg/m³; RF = the recovery factor; A = the cross-sectional area of the porous medium, m²; h = reservoir thickness, m; ϕ = porosity; V_{iw} = the volume of injected water, m³; V_{pw} = the volume of produced water, m³; S_{wi} = irreducible water saturation; C_{ws} = the solubility coefficient of CO₂ in formation water; and C_{os} = the solubility coefficient of CO₂ in oil.

Effective storage capacity, on the other hand, takes into account the numerous properties of the geological formation, including pressure and pore volume. It is a part of the theoretical storage capacity. It is usually influenced by the mobility of the injectant, gravitational separation, and reservoir heterogeneity. Thus, it cannot be more than the theoretical storage capacity [63,108].

Therefore, multiple calculation methods can be utilized for estimating CO₂ storage capacity based on the objectives of the evaluation and storage mechanisms [107]. The key is to ascertain the theoretical and effective storage capacity, as the matched and practical storage capacities are rarely used in practice.

5. Experimental and Numerical Studies of CO₂ Foam for CO₂ Storage

The viscosity of CO₂ can be 10 to 50 times lower than that of reservoir oil under typical reservoir conditions, placing the gas at significant risk of channeling through the oil and preferentially flowing through the more permeable zones [56,58]. Surfactants can be added to a liquid solution and injected simultaneously or successively with CO₂ to reduce this effect [113]. The mixture produces foam, which is more viscous than either the liquid or gas. As a result, the flow is diverted from the highly permeable areas, and can flow towards the unswept low-permeability zones [114].

Furthermore, the propagation front becomes more uniform, as opposed to the fingering scenario with just CO₂, which enhances oil recovery and makes more reservoir space available for CO₂ storage [40,115]. CO₂ foams themselves are ideally classified as a non-toxic carbon sequestration technique that can greatly lower industrial greenhouse gas emissions. This satisfies the requirements set forth by the US Environmental Protection Agency for a procedure to be termed as green chemistry [116].

The effect of foam on CO₂ storage capacity during foam flooding was investigated in Foyen et al. [117]. In order to study foam generation, propagation, and coalescence, the authors of this study injected dense CO₂ into surfactant-saturated sandstone cores. In their work, CO₂ storage capacity was assessed as the fraction of the pore volume that was accessible for storing CO₂. Their results showed that the CO₂ storage capacity of the sandstone core increased by 27% when foam was generated, as compared to the baseline CO₂ injection without foam. The authors attributed this to reduced water–CO₂ interfacial tension, which in turn reduced residual water saturation and improved microscopic and volumetric sweeps. As such, the results of this study imply increased storage capacity for the sequestered CO₂.

This argument was further supported in the work of Yu et al. [118], in which the storage potential of CO₂ in Berea sandstones was evaluated. CO₂ foams were generated with Amphosol CS-50 and Ammonyx LO SPECIAL surfactants, then compared with the injection of CO₂ alone. The results are shown in Figure 8.

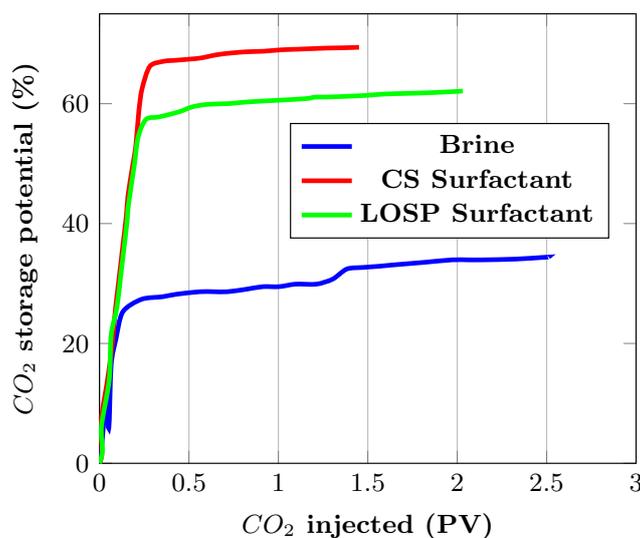


Figure 8. CO₂ storage capacity evaluated during injection with brine, CS, and LOSP surfactant solutions (Adapted from Yu et al. [118]).

It can be seen that there is an early breakthrough of CO₂ during CO₂ injection after about 0.11 injected pore volumes. However, the breakthrough was not noticeable when using Amphosol and Ammonyx before 0.28 and 0.24 PV, respectively. Furthermore, the CO₂ storage potentials were 69.4% and 62.1%, which are significantly higher than 34.3% for CO₂ flooding without a surfactant. The authors noted that the presence of the surfactants greatly aided in controlling the propagation front, resulting in a 200% increase in the amount of original water that was displaced. The authors attributed this to a significant reduction in CO₂ mobility.

Implementing CO₂ foam in field conditions is challenging due to the complicated physics involved; foam strength under reservoir conditions plays a vital role in determining its sequestration performance. To address these problems, in Iskandar et al. [119] the authors developed machine learning models that could precisely predict apparent viscosity for both bulk phase and sandstone formations. The authors used these models to compute foam quality under various conditions and determine the apparent viscosity, with the aim of effectively reducing gas mobility while simultaneously improving EOR and sequestration processes. The results in Viktoonkijvanich et al. [120] further support these arguments; there, the authors investigated CO₂ storage in aquifers while co-injecting CO₂ with surfactants to generate foam. According to the authors, alternating injections of CO₂ and surfactant solutions at 0.85 fractional flow resulted in the best performance when there was no seal, while simultaneous injection at 0.5 fractional flow produced the best results when a reliable trapping mechanism was present.

Furthermore, in Lyu et al. [121], the complex phase behavior of an aquifer fluid system was precisely described using the Peng–Robinson equation of state (PR EOS) and an activity model. When the capillary transition zone was absent, the simulation results showed good agreement with analytical answers. According to the authors, injected foam successfully restricted gas mobility by trapping bubbles and preventing upward migration caused by gravity, which increased sweep efficiency and freed up more space for CO₂ storage. Furthermore, their results indicated that dissolution trapping mechanisms may not be important in the long term, as residual foam trapping becomes more efficient with time, potentially suggesting new methods of efficient carbon sequestration.

Other studies on the application of foam for CO₂ storage are summarized in Table 1.

Table 1. Studies on the use of foam for CO₂ storage.

Ref.	Foam Injection Mode	Liquid Phase	Foam Quality	Oil Specifications	Thermobaric Conditions	Salinity	CO ₂ Storage Remarks
[122]	SAG	0.25 wt.% and 0.5 wt.% Huntsman surfactant solution	60%	n-Decane	40 °C; 18 MPa	3.5 wt.% NaCl	CO ₂ storage capacity increased from 12% during pure CO ₂ injection to 70% during SAG injections.
[117]	In-situ	0.5 wt.% AOS surfactant solution	75%	N/A	40 °C; 20 MPa	3.8 wt.%	CO ₂ storage capacity increased by 27 %
[123]	Pre-generated	Huntsman surfactant solution	70%	East Seminole oil with viscosity 1.2 cP	40 °C; 17.2 MPa	70,000 ppm	Improvement in CO ₂ utilization by 35% and a 20% reduction in producing GOR
[120]	Pre-generated	Surfactant solution	85%	N/A	N/A	N/A	The use of surfactants to generate foam significantly improves the storage efficiency from 20% to 60%
[121]	In-situ	Surfactant solution	80%	N/A	50 °C and 9 MPa	N/A	Foam injection increased the amount of residual trapped CO ₂ by 32%
[124]	In-situ	Mixture of surfactant and silica nanoparticles solution	N/A	N/A	24 °C and 9.3 MPa	2 wt.% NaBr	When compared to the base case, the use of nanoparticles made about 90% of the injected CO ₂ immobile and increased sweep efficiency by 20%.
[125]	Pre-generated	SDS surfactant and FLOPAAM polymer solutions	75%	Crude oil with viscosity 670 cP	22 °C and 1 MPa	1000 ppm NaCl	CO ₂ polymer enhanced foam performed the best and resulted in over 40% CO ₂ storage efficiency
[118]	In-situ	0.5 wt.% Zwitterionic surfactant solution	90%	N/A	90 °C and 13.79 MPa	17.4% NaCl; 3.12% CaCl ₂ ; 0.44% MgCl ₂	CO ₂ storage potential increased by more than 2 times.
[126]	In-situ	Mixture of surfactant and silica nanoparticles solution	70%	Crude oil with density 0.849 g/cm ³	80 °C and 9 MPa	2% NaCl	A fourfold increase in pressure gradient during tertiary EOR was caused by nanoparticle stabilisation of CO ₂ foam. Due to this, CO ₂ storage efficiency rose from 27% to 42% and EOR increased from 6% to 10%.
[127]	Pre-generated	Binary mixture of AOS + Betaine surfactant solutions and fumed silica nanoparticles	60–90%	N/A	20 °C and 2 MPa	NaCl + CaCl ₂	Compared to CO ₂ injection, CO ₂ foam increased CO ₂ storage in the microfluidic device by 20% to 40%.
[128]	In-situ	1 wt.% Huntsman surfactant solution	70–80%	Crude oil with density 0.736 g/cm ³	40 °C and 17.5 MPa	27.1 g/L NaCl; 2.76 g/L MgCl ₂ ; 5.82 g/L CaCl ₂ ; 0.46 g/L KCl	During tertiary EOR CO ₂ foam, the ideal gas fraction (70%) produced a stronger foam and enhanced CO ₂ storage by 50%.
[129]	In-situ	Mixture of surfactant and silica aerogel nanosolution	83%	N/A	22 °C and 1 MPa	N/A	CO ₂ sequestration rate of 60.8% was achieved with the injection of CO ₂ -aerogel stabilized foam.

6. Enhancing Foam for CO₂ Storage

In order to implement foam injection as a reliable and favorable green technology, more research and efforts are needed to address the advancement and improvement of CO₂ capture and storage technology. On the laboratory scale, the CO₂ storage efficiency of foams can be improved using CO₂-soluble surfactants and introducing nanoparticles to the liquid phase.

- The use of CO₂-philic soluble surfactants in the generation of CO₂ foam can guarantee the accessibility of surfactant for foam generation wherever CO₂ flows in the reservoir [117,130]. Due to the significant volumes of brine already present in oil-bearing formations, the ability to inject a CO₂-based surfactant solution might lessen the need for alternating injections of brine. An SAG process in which surfactant is present in

the aqueous phase may be possible by the identification of CO₂-soluble surfactants, increasing the likelihood of in situ foam generation [131,132]. CO₂-soluble surfactants provide better film stabilization ability than conventional aqueous surfactants. This ensures faster propagation in porous media, increasing the pressure drop and boosting sweep efficiency. Several commercially available non-ionic hydrocarbon-based surfactants that are soluble in water have shown sufficient solubility in CO₂ [133,134]. Examples include fatty acid-based surfactants, alkylphenol, and styryl phenol surfactants.

- Nanoparticles can be used to increase foam stability, subsequently increasing its ability to store CO₂. The intense adsorption at the liquid surface caused by the high adhesion energy of solid nanoparticles allows for the generation of a strong and stable foam [135,136]. Nanoparticles are excellent for CO₂ foam generation, as an emulsion can be created without first solubilizing them with CO₂. A water phase without solid particles can pass through without destabilizing the foam, as the particles that are adsorbed at the foam interface do not easily desorb [137]. Surfactant molecules frequently enter and exit the liquid interface, providing only short term stabilization. However, because nanoparticles have hydrophilic properties they can exist primarily in the liquid phase. In addition, the small size of nanoparticles allows them to travel far from the injector without experiencing considerable particle retention or loss [138].

7. Conclusions and Future Research

This work has reviewed the possible advantages of using CO₂ foams in the context of carbon storage. Their use can ensure that the carbon footprint of the oil production process is reduced while continuing to supply the world with secure energy. However, optimizing foam systems necessitates a thorough comprehension of every component involved in foam flow in porous media. Therefore, in subsequent experimental works, more focus should be placed on the stability and performance of CO₂ foams. Furthermore, the synergistic interactions that result from combining nanoparticles with surfactants as foaming agents could potentially be an economical method of generating high-performing and field-specific foam systems. The following conclusions can be drawn from this review:

- A co-optimization function was developed that takes into account CO₂ loss during actual operation and combines oil recovery with CO₂ storage.
- The amount of CO₂ stored by the solubility trapping mechanism, which is regarded as one of the primary CO₂ storage processes in oil reservoirs, is directly influenced by the solubility of CO₂ in residual oil and formation water.
- Because CO₂ dissolution causes oil to swell, viscosity to decrease, and interfacial tension to decrease, it is one of the key mechanisms that contributes to the significant potential for improving CO₂ storage. As a result, the effectiveness of any CO₂-CCUS project largely depends on how soluble CO₂ is in oil under reservoir conditions.
- Because the injection of CO₂ increases pressure, it has the ability to propagate upwards; if fractures exist, CO₂ leakage can occur. Thus, the risk of CO₂ leakage from storage sites represents a significant challenge. Additional study is required in order to better comprehend the geological mobility of CO₂ gas released by foam after it has coalesced, as well as the interactions of foam with geomaterials, minerals, and ground chemicals.
- It is crucial that the CO₂ trapped in a reservoir by capillary forces stays there forever, or at least for a very long time. The surfactant or related reagents may degrade chemically or thermally while stored, and may even be displaced outside the swept zone. Thus, investigating their long-term stability under reservoir conditions is very important to CO₂ storage.
- The use of CO₂ foam for sequestration necessitates the extensive injection of surfactants into the ground. This raises questions around their environmental safety. Therefore, it is crucial to conduct in-depth research on the environmental effects of potential leakage of foaming agents and their additives.
- It is imperative to design less harmful surfactant systems and foaming additives, taking into account the possibility of their degradation in reservoir conditions. Thus,

our ongoing research is focused on the use of binary surfactants to improve the stability of foams under harsh reservoir conditions where the use of surfactants in their single forms has led to foam instability in these conditions.

- The efficiency of oil recovery and CO₂ storage in tight oil reservoirs should be a future focus in light of the global development of unconventional reservoirs. Future research in this area might be concentrated on investigating the effects of various foam injection techniques on simultaneous EOR and sequestration in core samples with extremely low permeability. Additionally, it is important to analyze the effects of natural and artificial fractures in the matrix on the effectiveness of co-optimizing EOR and CO₂ storage in unconventional formations.
- In addition to enhancing foam stability, recent studies have proposed adding nanoparticles to aqueous foaming solutions in order to improve the CO₂ sequestration process and increase the ability of CO₂ to be absorbed in the liquid phase. Thus, it is imperative to look into how nanoparticles can be formulated in foams to increase both residual oil displacement and sequestration, as well as their role in lowering CO₂ emissions.
- Mineralization trapping is a significant mechanism of CO₂ storage. It aims to safely sequester CO₂ over the long term. However, it is challenging to implement in a lab setting due to the time constraints. Therefore, future work should be directed towards developing numerical models that can simulate the concurrent processes of CO₂ storage. For the purpose of understanding the impact and contribution of the mineralization trapping mechanism and how it influences EOR, these models should have interfaces that can adequately simulate all of the aqueous reactions occurring in the formation.

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