



Original Article

Dynamic simulation of preformed aqueous foam stability for enhanced oil recovery application

Tayeb Sakhi^{a,b*}, Rachida Chemini^a, Yacine Salhi^a, Abdellah Arhaliass^b

^aLaboratory of Theoretical and Applied Fluid Mechanics University of Sciences and Technology Houari Boumediene, BP 32, El Allia – Bab Ezzouar 16111, Algiers, Algeria

^bLaboratory of Process Engineering – Environment – Agrifood (GEPEA-UMR CNRS 6144) C.R.T.T.-37, bd- BP 406 44602 SAINT-NAZAIRE, University of Nantes, France.

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ABSTRACT

Aqueous foam is a two-phase system consisting of a continuous liquid phase and a dispersed gas phase. Foams are widely used in a variety of industrial operations, such as the enhanced recovery of hydrocarbons. Because of their unique properties, they can solve a variety of reservoir heterogeneity problems, including early gas breakthrough, channeling, and even viscous fingering. A variety of phenomena affect the stability of foams during flow, for example, the drainage process, gas diffusion, and bubble coalescence. In this research, we used the level-set method to simulate foam stability in various aspects, such as factors affecting foam drainage and coalescence phenomena. According to the simulation results, the foam's lifetime is greatly impacted by the phenomena of drainage and coalescence. Moreover, its stability is strongly influenced by salt as well as the type of gas used to generate it.

1. Introduction

Enhanced oil recovery (EOR), also known as tertiary recovery, refers to the application of developed technologies to further increase hydrocarbon recovery production after primary and secondary recovery [1]. Such a recovery method involves the injection of a specific fluid to displace oil from the injector toward the producer well [2]. Examples of EOR injections are surfactant flooding, polymers, microbial flooding, and steam flooding [3]. Among these techniques, foam flooding has been identified as a great potential solution for many challenges encountered during various phases of hydrocarbon recovery [4, 5]. It includes channeling, defined as the gas flow in the highly permeable zones inside the reservoir; gravity override, which is a consequence of the high-density difference between gas and oil, and viscous fingering due to the large difference in viscosity between

oil and gas [6, 7] (Figures 1 and 2). Foam application modes can be CO₂ foam, steam foam, and gas-miscible flood foam injection [8]. The injection of foam, which is mainly composed of gas, makes it possible to mitigate these challenges, which could significantly enhance sweep efficiency. In addition, foam reduces gas mobility by increasing its viscosity and/or reducing its relative permeability [9]. It can also divert gas to unswept regions by blocking highly permeable zones. Furthermore, it fixes the early gas breakthrough problem. There are three foam generation methods for foam-assisted EOR; preformed foam is generated on the surface using a foam generator, and co-injection foam is formed near the injector where the solution of surfactant is co-injected with gas. Alternate injection of surfactant and gas (surfactant alternate gas, or SAG); the liquid containing the surfactant and the gas are

* Corresponding author.

Tel.: +213 (0) 23 93 48 19

E-mail address: sakhitayebgr@gmail.com

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injected alternately in the form of "slugs." Hence, the foam is generated in situ in the porous medium [10].

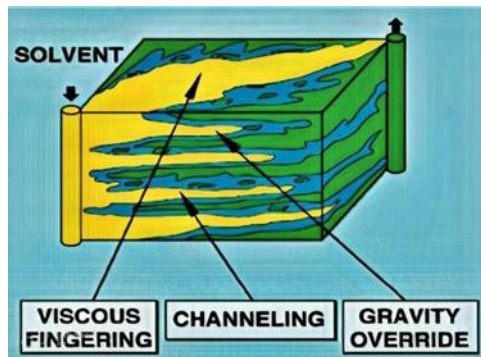


Figure 1: Illustrative schematic of different challenges leading to poor sweep efficiency [4]

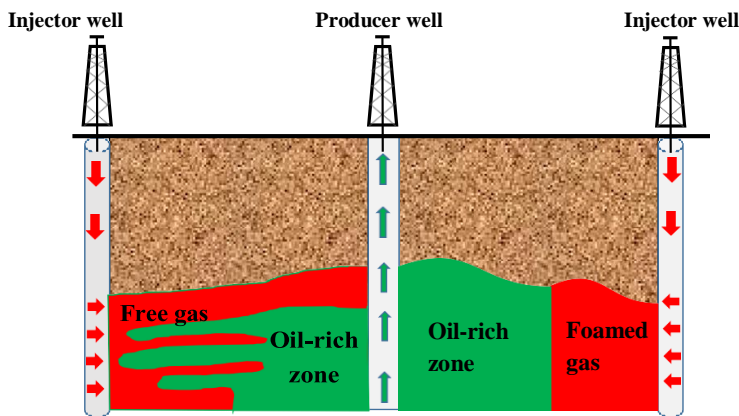


Fig 2. Comparative illustration between gas injection and foam flooding [5]

It has been proven in many pilot studies [11, 12] and field studies [13, 14, 15] that the application of foam in EOR can improve the recovery of hydrocarbons. The fundamental difficulty of foam-assisted EOR is the stability of the foam during flow in porous media. To obtain a higher recovery factor, it must be stable enough during its flow. Foam stability is defined as the ability of this foam to keep or maintain its initial properties, such as its quality. Foam drainage, coalescence, and bubble coarsening are the main physical phenomena that destabilize the foam [16, 17].

The rupture of foam can have a significant impact on the performance of foam flooding inside the reservoir. Numerous studies have investigated the effect of salt on foam stability, which is one of the factors limiting foam injection in EOR applications [18,19]. Salts, in general, increase the collapse rate, hence destabilizing the foam and reducing its performance [20]. Masoud Hatami Laoghaire and al [21] conducted a series of experiments to highlight

the influence of various gases and their mixtures on the performance of foams in EOR, including bulk stability tests, apparent foam viscosity measurements, and core flooding testing. Their findings verified the significance of gas types on foam stability. In the literature, a multitude of models has been proposed to predict the behavior of foam in porous media. These models can be classified into two categories: population balance models to simulate the generation, destruction, and transport of lamellae in porous media and local equilibrium models to predict only the reduction in mobility of gas in a steady state when it flows in the form of foam [22].

These latter models are based on empirical formulations calibrated from foam displacements on core samples in the laboratory [23, 24]. The work of Wang et al. [25] focused on the simulation of foam interface evolution in terms of foam drainage, foam migration, and the Jamin effect, which are crucial results in studying and evaluating foam stability. On the other hand, their study lacked the influence of salt on foam stability as well as the influence of the type of gas used to generate this aqueous foam.

The purpose of the current research was to study and evaluate the stability of aqueous foam by simulation using the level set method and gas-liquid two-phase flow. A successful application of fluid foam-assisted EOR requires a thorough understanding of its fundamental performance and flow mechanism.

2. Materials and Methods

There are different ways to represent the interface behavior between fluids and understand the change in foam morphology. The volume of fluid (VOF) method was implemented for multiphase flow modeling and was suitable to resolve sharp interfaces. This method traces the volume of each fluid instead of the motion of particles [26]. Another method to simulate the evolution of the foam interface is the level set method. The level set approach uses a signed distance function of space and time to define the interface between two fluids (Equation 1). This sign indicates whether point x is inside the material (Figure 3) [27]. It is useful when it comes to modifying the foam structure. In addition, it can handle geometric complexity and topological changes.

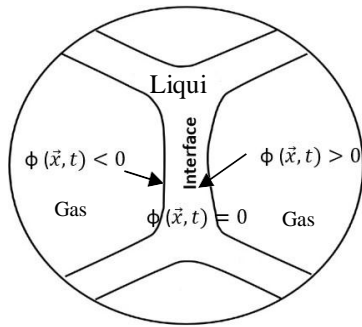


Fig 3. Schematic of level set function in foam interface where i represents interface of the foam and ϕ represents level Set function.

Equation (1)

$$|\phi(\vec{x}, t)| = d(\vec{x}) = \min_{x_i \in i} (|\vec{x} - \vec{x}_i|) \quad [28] \quad (1)$$

On the interface, the density and viscosity vary as follows (Equation 2, 3):

$$\rho = \rho_1 + (\rho_2 - \rho_1)\phi \quad (2)$$

$$\mu = \mu_1 + (\mu_2 - \mu_1)\phi \quad (3)$$

ρ_1, ρ_2 are the densities of the two fluids respectively, and μ_1, μ_2 are their viscosities.

These are the Navier-Stokes equations [28]:

Equation (4)

$$\rho \bar{u}_t + \rho(\bar{u} \cdot \nabla) \bar{u} = \nabla \cdot \left\{ -\bar{p} I + n \left[\nabla \bar{u} + (\nabla \bar{u})^T \right] \right\} + \bar{F}_{SV} \quad (4)$$

The unit matrix is I , the pressure is p , and the continuity equation is $\bar{u} = 0$ FSV provides by converting surface tension to volume force. Using (CSF) model [24]

Equation (5)

$$\bar{F}_{sv}(x) = \sigma \delta(-\nabla \cdot \bar{n}) \bar{n} \quad (5)$$

σ is the surface tension and δ is the Dirac function.

3. Results and Discussion

3.1. Foam Drainage

Foam drainage, defined as the process of liquid draining through networks of plateau borders, is the result of both gravitational and capillary forces. This phenomenon has a substantial impact on the stability of foams [29].

The geometric shape of the model is described as follows (Figure 4) [25]: The geometric model is a square with sides measuring 6 mm, in which hexagonal-shaped bubbles of 1 mm in radius contain the gas phase, namely nitrogen. These bubbles are interconnected by liquid films with a 0.12 mm thickness that contains a surfactant solution. The upper part of the model is open, while the others are walls. Furthermore, the surface tension of this foam was 10 mN/m, and the contact angle equaled $\pi/3$.

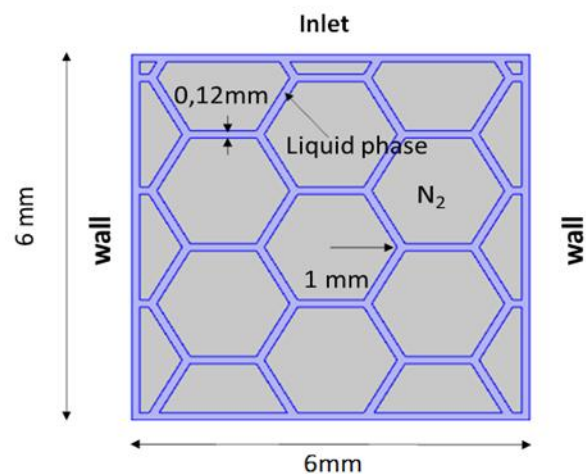


Fig 4. Geometric model of foam drainage

The simulation results indicate that during drainage, there was a continuous downward migration of liquid due to gravitational, viscous, and capillary forces (Figure 5). The upper part of this foam became increasingly dry, which caused the liquid films to thin. Therefore, they became weak and unstable, which caused their rupture.

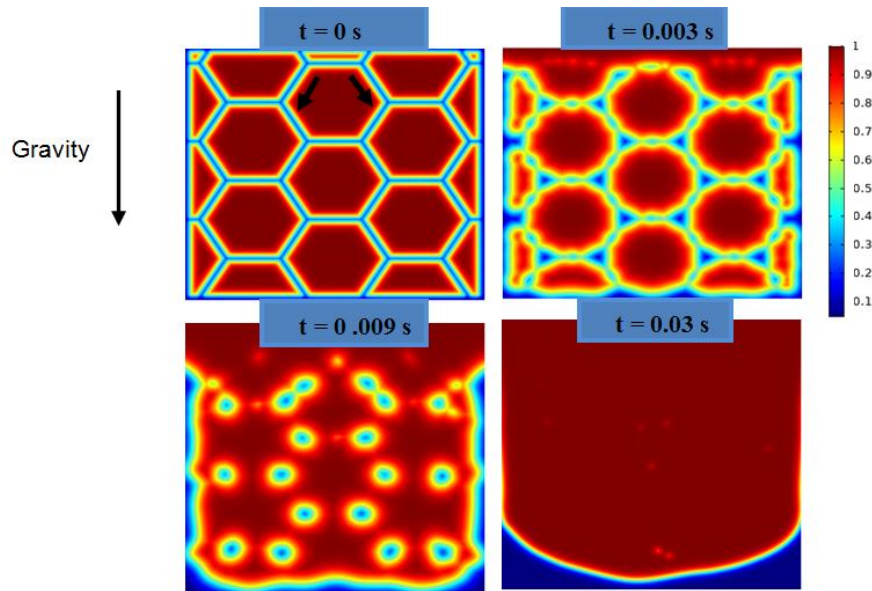


Fig 5. Foam drainage simulation results at different times

3.1.1. Influence of surface tension on foam stability

Surface tension is one of the most crucial factors for foam stability [30]. To highlight the influence of surface tension on foam stability, the structure of the foam was compared for different values of surface tension at the same time of foam drainage ($t = 0.005$ s). Thus, the results showed that when the surface tension of this foam was equal to 10 mN/m, the drainage of liquid increased swiftly (Figure 6),

and some bubbles ruptures were observed. Nevertheless, with a surface tension of 0.01 mN/m, the drainage of liquid was not important and most of the bubbles kept their initial structure. When comparing liquid film thickness between the two cases, the lower surface tension corresponded to more stable bubbles due to the fact that lower surface tension may minimize the energy of the foam system, promoting foam stability [30].

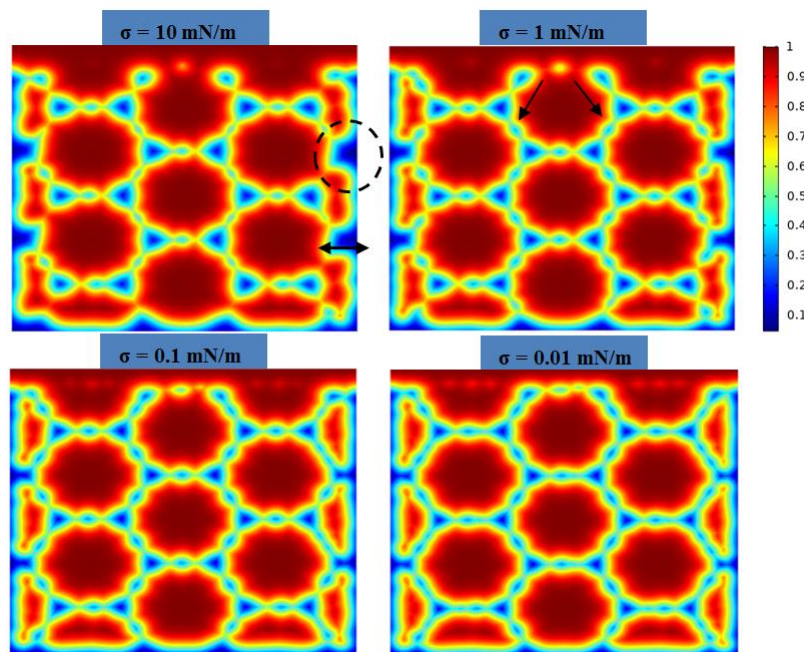


Fig 6. Simulation results of surface tension influence on foam stability

3.1.2. Influence of salt on foam drainage

Several studies have addressed the influence of salt (brine) on foam stability [31,32]. In this regard, the effect of salt on foam drainage was tested under the same conditions mentioned before. The addition of salt to foam

significantly increased the liquid drainage, and the bubbles also faced an important and swift rupture (Figure 7). It has been found that salt causes a reduction in the electrostatic repulsion in liquid film [33]. Accordingly, the two sides of the liquid film gradually approached each other. This made the liquid film thinner and more fragile, and consequently, the bubbles of this foam ended up breaking.

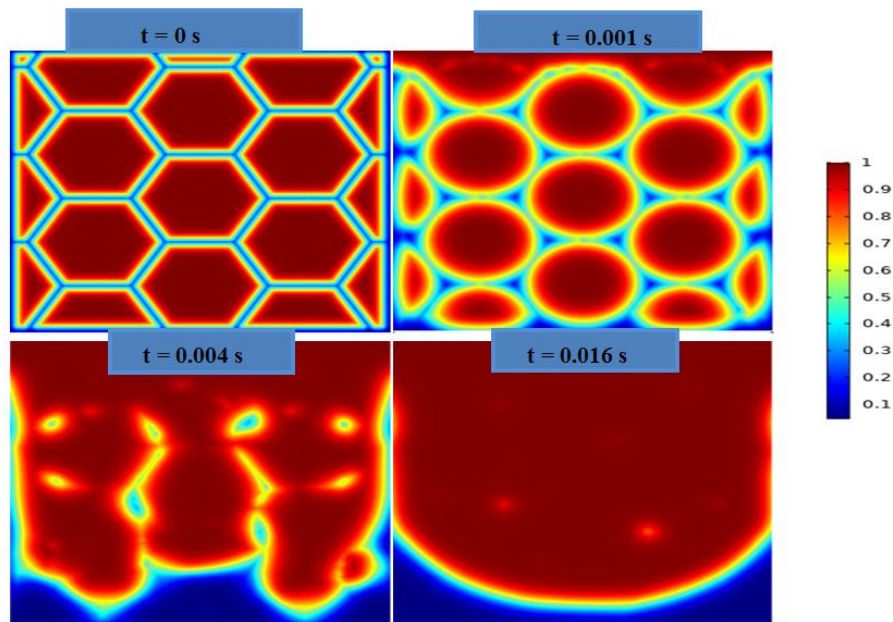


Fig 7. simulation results of salt effect on foam lifetime

3.1.3. Influence of gases type on foam drainage

The type of used gas to form the foam was critical for evaluating and studying its stability. Most experimental studies of foams in porous media used either N_2 nitrogen-based foams or CO_2 carbon dioxide-based foams [34]. Comparative studies have shown that nitrogen-based foams generate greater pressure gradients than CO_2 -based foams [35, 36]. Indeed, CO_2 foams remained weaker than N_2 foams, attributed to the solubility of CO_2 in water

which was 55 times greater than N_2 [36]. This high solubility of the gas in the liquid favored the diffusion, the coalescence of the bubbles, and the rupture of this foam. In this context, the stability of nitrogen, carbon dioxide, and methane foams were simulated under the same conditions of foam drainage at ($t= 0.003s$). The results revealed that N_2 foam had superior foam stability compared to CO_2 and Methane (Figure 8), which was consistent with other research results [31, 37, 38].

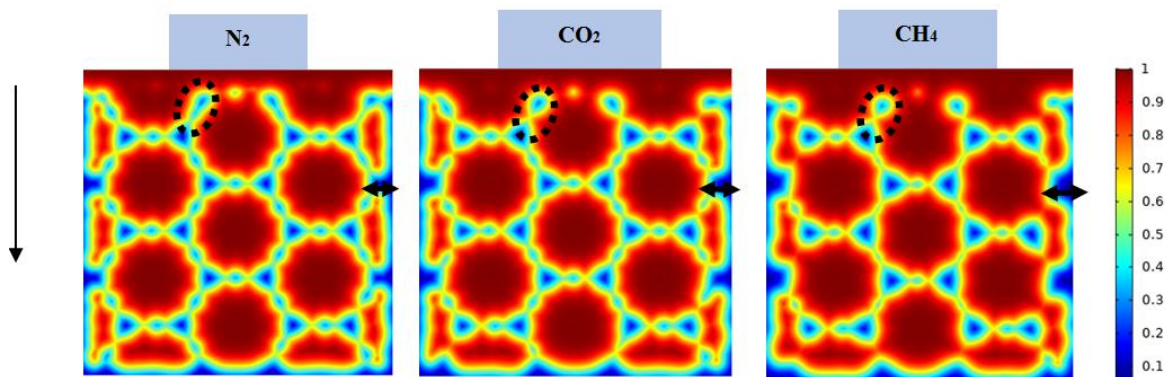


Fig 8. Simulation results of the impact of gases types on foam drainage

3.2. Foam Coalescence phenomenon

When two bubbles come within a short critical distance of each other, the thin film between the two bubbles breaks, merging these two bubbles into one large bubble. This is the phenomenon of coalescence. It takes place in three stages: bubbles collision, liquid film drainage during the collision and film rupture leading to a bigger bubble [39]. For the current study, the geometric model was a channel of 15 mm with a pore diameter 5 mm in which there were two bubbles of nitrogen with initial diameter of 4 mm, and the liquid phase was surfactant solution (Figure 9).

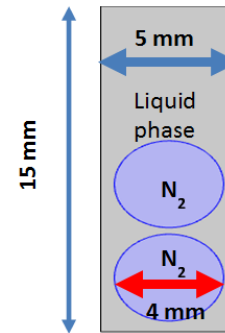


Fig 9. Geometric model of foam coalescence

The results are as follow (Figure 10):

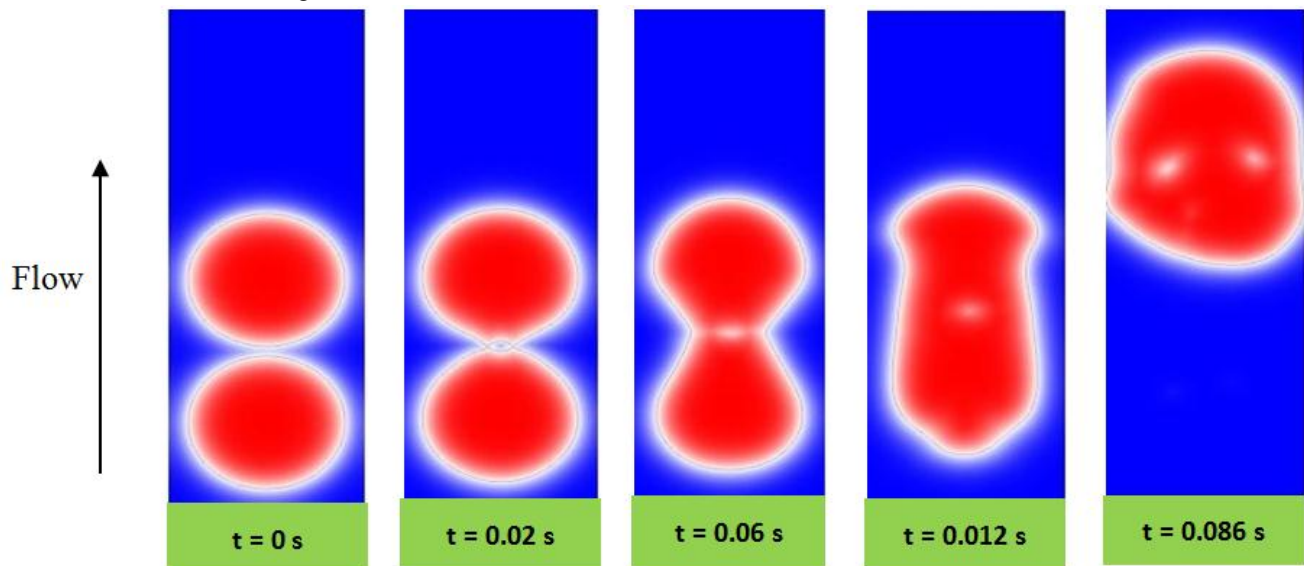


Fig 10. Simulation results of foam coalescence at different time

In the beginning, the two nitrogen bubbles approach each other and then collide. After a time, the liquid film between them gradually disappears, resulting in their union and the appearance of a single larger bubble. The result of this phenomenon is a growth in the size of the bubbles and a decrease in their number until the bubbles completely disappear [40].

4. Conclusion

In this work, the stability of aqueous foam has been addressed in terms of foam drainage, and coalescence phenomenon using a level-set method. The following conclusion may be drawn.

1. The lower surface tension (σ) corresponds to a more stable foam
2. N_2 -based foam are more stable foam than CO_2 -based foam and CH_4 -based foam
3. Foam stability is strongly influenced by salt

4. The coalescence phenomenon leads to a growth in the bubbles size and a diminution in their number.

List of symbols

\emptyset : Level Set function

ρ_1 : Gas density

ρ_2 : Liquid density

μ_1 : Gas viscosity (Pa. s)

μ_2 : Liquid viscosity (Pa. s)

σ : Surface tension (N/m)

δ : Dirac function

\vec{u} : Velocity field (m/s)

t: Time (s)

P: Pressure field (Pa)

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