Recovery of Oil Using Surfactant-Based Foams

Kristian Mogensen

Abstract This chapter describes the application of surfactant-based foams for recovery of oil with a focus on subsurface aspects. While the concept of foaming may be qualitatively well understood, the physical behaviour of a foam system comprising gas, brine, and surfactant depends on the type of each of these three constituents and their interaction, in addition to the properties of the porous medium in which the foam is designed to be generated and perhaps propagate. Key physical properties, which must be investigated during a laboratory experimental program, are discussed. A critical review is provided of a number of key applications where foam is utilised for recovery of oil, starting with drilling, completion, and stimulation before moving on to chemical conformance and enhanced oil recovery.

Keywords Film drainage · Bubble coalescence · Foam stability · Foam quality · FGSO · FAWAG · Adsorption · Mobility control

1 Introduction

A stringent definition of foam would be that it is a dispersed medium where gas bubbles are separated by interconnected liquid films called lamellae. Lamellae are thin, on the order of 100 nm. Spanning a 3D network, they connect to one another at so-called Plateau borders. Figure 1, which presents a schematic 2D view of a foam network. Unlike gas hydrates, which trap single gas molecules inside a cage of water molecules, the gas bubbles in a foam contain many molecules.

Soap bubbles are an illustrative everyday example of a foam. Detergents added to the water phase help trap air bubbles and the water jetted from the tap of a hose provides mixing energy for the foam to form. If left untouched, the foam typically lasts only for a few minutes before it breaks due to coalescence of adjacent gas bubbles.

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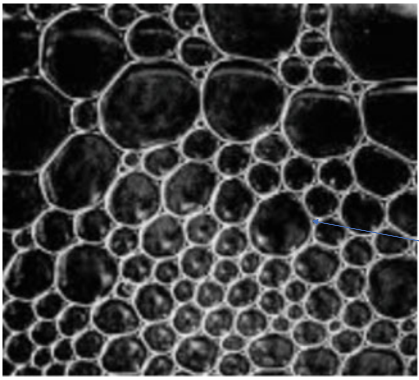

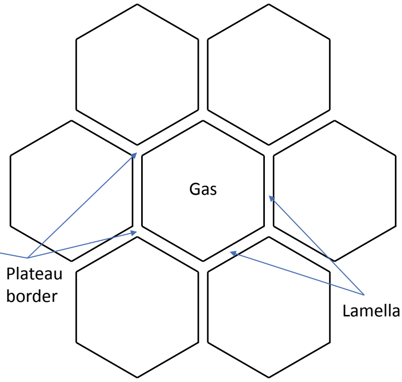

Fig. 1 Left: Actual image of a foam. Right: Schematic of a foam network

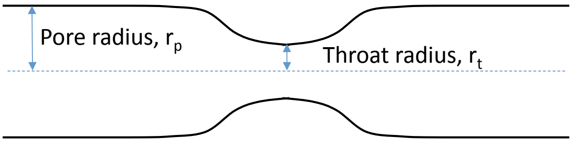

Fig. 2 Schematic of a porous medium consisting of two pores connected by a throat

It is tempting to draw analogies between foams formed in bulk (ex-situ, without a porous medium) and foams which are created inside a pore system (in-situ). However, the two situations turn out to be very different, as will become clear in the next paragraphs.

The topology of the void space of a porous medium is often described as a 3D network of pores connected to each other by restrictions called throats, see Fig. 2. If the fluids filling the void space are water and gas, water preferentially covers the surface of the rock. This molecular adsorption phenomenon is known as wettability and the rock is said to be water-wet. Wettability has profound implications for immiscible displacement of one fluid by another. When two phases are brought into contact with each other, a curved interface will form and the interface curvature is related to the local radius at the position of the interface. The difference in pressure between the two phases is known as the capillary pressure, P_c, which for a circular cross-section is given as a function of interfacial tension and radius of curvature:

$$P_c = \frac{2 \times IFT}{r}.$$

The smaller the radius, the larger the pressure difference. The presence of capillarity during an immiscible displacement leads to a certain amount of trapping of the non-wetting phase, in this case gas. Fundamental flow studies conducted in the

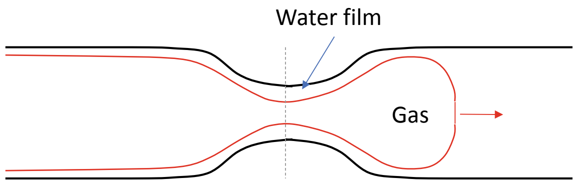

Fig. 3 Advancement of a gas finger in a pore

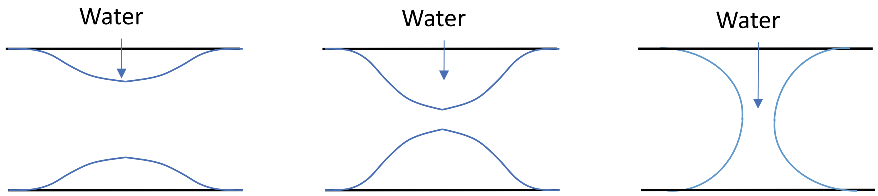

Fig. 4 Liquid film instability leading to snap-off

1980s made use of transparent micro-models where a reproducible 2D pore structure is created by an etching technique. The studies revealed that fluid front advance involves pore-level events which occur within a few milli-seconds. Roof [36] demonstrated that if the aspect ratio, defined as the pore radius divided by the throat radius, exceeds 2 the liquid film wetting the surface is pulled towards the centre of the throat by capillarity. This phenomenon is known as snap-off and is depicted schematically in Figs. 3, 4. Snap-off is the main physical mechanism responsible for trapping of oil and gas by water at the microscopic level, the other mechanism is bypassing due to velocity differences caused by the pore-size distribution.

The advancing gas finger illustrated in Fig. 3 will be snapped off by the water film at the throat resulting in the formation of a trapped gas bubble. The gas trapping process will then repeat itself until the pore on the right-hand side is filled with bubbles. Note that liquid films are thinnest in the pores and thickest at the throats, which is why snap-off occurs at or close to the throats.

Although gas trapping and foam creation are the result of the same underlying capillary-driven mechanism, the two phenomena are clearly different. Trapping of gas bubbles is controlled entirely by the pore topology and does not require surfactants to occur.

The liquid films separating the gas bubbles are very thin and will quickly rupture as a result of film drainage. The role of the surfactant is therefore to stabilize the films by diffusion towards the gas-liquid interface, see Fig. 5. In the presence of surfactants, lamellae division can occur and Plateau borders will emerge.

From a thermodynamic point of view, foam is unstable, because foam destruction leads to a reduced interfacial area. However, according to Chambers and Radke [10], foam can reach a meta-stable configuration which depends on a force balance between the local capillary pressure working towards interfacial area reduction and hence foam destruction on one hand, and then a repulsive contribution to the disjoining pressure, which is affected by the presence of adsorbed surfactant. The net force

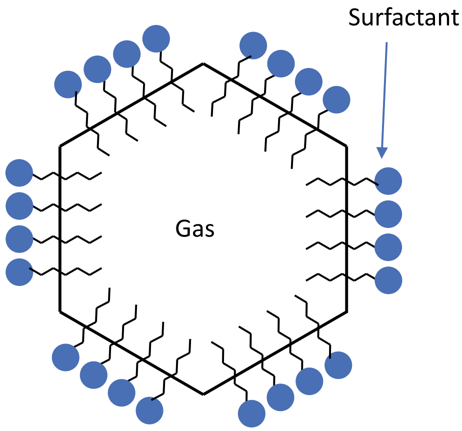

Fig. 5 Film stabilization with a surfactant

depends on the size of the wetting film, h, and a meta-stable situation can arise if the two forces balance each other, see Fig. 6. Note that in the absence of a porous medium, gravity is the main force leading to film drainage and foam break-up, but in a porous medium, gravity does not play an active role. This difference is important to remember when designing foam stability tests. The micro-structure of foam is shaped by the porous medium in which it resides.

Two adjacent gas bubbles with a different curvature will result in a different gas phase pressure inside the bubbles. This pressure gradient will lead to gas diffusion and bubble coalescence and explains why adjacent gas bubbles often have similar curvatures. Gas diffusion rates depend on the curvature difference, the type of gas, and on the solubility of gas in the aqueous phase.

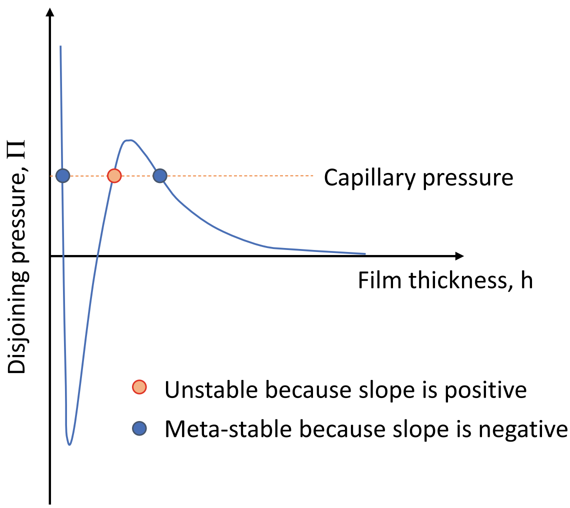

Fig. 6 Force balance, showing disjoining pressure isotherm Adapted from [10]

Figure 6 shows that there exists a maximum capillary pressure, which the disjoining pressure can sustain without breaking the foam. Since gas-water capillary pressure increases with increasing gas saturation, this translates to a maximum gas saturation above which the foam collapses. In such a case, the foam is said to be drying out. A key experimental design parameter is the foam quality defined as the fractional flow of gas. Experience shows that there exists an optimum foam quality, which generates the strongest foam.

A higher capillary pressure would also occur in low-permeability rock because of the smaller pores. Hence, foams will preferentially break down in tight formations. Lake et al. [28] mention that larger aspect ratios lead to quicker bubble coalescence and that larger film thickness variation occurs at higher gas rates.

The presence of oil in the porous medium may destabilize foams. One explanation is that it is predominantly the lighter alkanes which diffuse towards the gas-liquid interface and alter the force balance. This means that light oils are more problematic than heavy oils. Another argument often mentioned is that the surfactant may partially dissolve in the oil phase, depending on the alkane chain length of the surfactant. The dissolution into the oil phase could then lead to oil-water emulsion formation. Wettability also comes into play. Carbonate rocks have a higher affinity towards the polar components in the oil phase and are predominantly mixed-wet or in some cases strongly oil-wet. This means that there will often be a mobile oil phase remaining as an oil layer in each pore after displacement by water or gas. Oil wetness also implies that snap-off of gas by water is hindered. In mixed-wet rocks, foam is therefore expected to form only in pores which are not strongly oil-wet or where the oil saturation has been significantly reduced. As a consequence, foam stands a better chance of surviving in gas caps where there is no oil or in miscible gas injection projects where the gas reduces the residual oil saturation to very low levels. The advantage of foam destruction by oil is of course that foam will never block oil flow; this behavior is exploited in foam gas shut-off treatments of wells coning gas from an overlaying gas cap.

While the concept of foaming may be qualitatively understood, the physical behavior of a foam system comprising gas, brine, and surfactant depends on the type of each of these three constituents and their interaction, in addition to the properties of the porous medium in which the foam is designed to be generated and perhaps propagate. In Sect. 2, we begin with a description of the key properties, which must be investigated during a laboratory experimental program to screen suitable surfactants for foaming potential, not just in bulk but also in-situ. In Sect. 3, we review a number of key applications where foam is applied for recovery of oil, starting with drilling, completion, and stimulation before moving on to chemical conformance and enhanced oil recovery. Finally, in Sect. 4, we present some concluding remarks and share our view on what the future of foam may look like.

2 Laboratory Studies

Reservoirs around the globe vary in terms of oil properties, brine composition, temperature, and rock properties. Chemical systems which seem to work in one environment cannot always be transferred or adapted to different rock and fluid conditions. Therefore, comprehensive laboratory experiments are a mandatory step towards derisking a field trial.

Laboratory experiments themselves are divided into two main parts. The first part involves only bulk fluid tests whereas the second part studies the interplay between fluid and porous medium.

2.1 Fluid-Only Testing

The key goal of the fluid-only testing phase is to identify a surfactant formulation, which

- Is soluble with the carrier fluid, which is most often brine.
- Foams when brought in contact with the selected gas.
- Is stable at reservoir pressure and temperature conditions.
- Maintains foam properties for a prolonged time.
- Is somewhat tolerant towards presence of oil.
- Is commercially available.
- Is environmentally approved for field application.

It is common practice to contact several chemical vendors and test a number of their recommended surfactants. Solubility in brine is very much dictated by alkane chain length although temperature and brine salinity also play a role. Solubility testing is quick and may eliminate some candidates. Surfactants often work within a certain temperature range; for high-temperature applications, only a very limited number of surfactant families are applicable, such as alpha-olefin sulfonates (AOS).

Contrary to surfactants for interfacial tension reduction, no high-throughput screening methods exist for testing a large number of surfactants automatically in terms of foaming capacity. In practice, this makes screening somewhat more tedious without the ability to probe a large number of possible chemical combinations. Therefore, researchers are often restricted to conducting experiments with chemicals pre-screened by the chemical vendors.

In light of the tremendous advances made in computational chemistry over the past few decades, it is this author's belief that foam systems comprising gas mixtures, brines, and surfactants can be modelled with tools such as molecular dynamics or density functional theory because all components have a well-defined chemical structure and because the relevant force fields have been described. Computational screening of surfactants in terms of foaming tendency could then be automated once the agreement between predictions and measurements is demonstrated. Estimation of foam stability, on the other hand, occurs on a length scale which is orders of magnitudes beyond what can be handled in molecular dynamics simulations. Since foam is thermodynamically unstable, the rate of film thinning induced by gravity must be modelled, which requires an estimate of the liquid conductivity as a function of the geometry of the lamellae. In a porous medium, film drainage is a wetting/de-wetting phenomenon, which is treated in some dynamic pore network models, see [3] for details.

The ability to create stable foams is examined next. Ex-situ foam generation requires external energy in the form of mixing to develop. The mixing results in movement of molecules inside the fluid and gives rise to shear forces. A fluid is referred to as sheared when different layers of molecules move past one another within the fluid itself. The relative difference in velocity between molecular layers gives rise to a velocity gradient perpendicular to the main flow direction, which is known as the shear rate. The mixing energy applied in the laboratory should be comparable to the shear rates which can be expected to occur in the field. Shear rates encountered in rocks depend on the fluid rheology as well as on the rock properties. The following expression by Cannella et al. [9] developed for polymer flooding can also be applied to foam:

$$\gamma_{eff} = C \times \left[\frac{3n+1}{4n}\right]^{n/(n-1)} \times \frac{4}{\sqrt{8}} \times \frac{u}{\sqrt{k_{rw} \times k \times S_w \times \varphi}}$$

C and n are fluid rheology properties, u is velocity, k_{rw} denotes the relative permeability to water at water saturation S_w, k is permeability and ϕ is porosity. Berg and van Wunnik [5] provide a detailed review of shear rate determination for pore level calculations and arrive at a simpler expression:

$$\gamma_{eff} = C \times \frac{u}{\sqrt{k \times \varphi}}$$

A typical field-scale velocity is 0.5–1.0 ft/d, but could be an order of magnitude higher close to the wellbore.

A common approach to quantifying foaming capability is to measure the foam height in a capillary tube, either visually or with a light source and a sensor. Neither approach has a good reproducibility. The foam height is tracked versus time and the longer the foam can maintain its structure, the better. Lunkenheimer and Malysa [29] advocated for the use of a foam height ratio defined as the foam height after 5 min relative to the initial foam height. It is debatable whether foam height can be used as a proxy for in-situ foam stability since the pore space provides a 3D geometrical confinement of the foam bubbles which cannot easily be mimicked with other means. Film drainage rates in-situ will be different from the ones obtained by bulk phase experiments because foam destruction ex-situ is caused by gravity whereas capillary pressure is responsible for foam collapse in-situ. Nevertheless, it is argued that a surfactant which fails to foam in a capillary will also not foam inside a porous medium. In other words, foam height is seen as a necessary but insufficient screening criterion.

It is often observed that foam creation, in additional to a threshold shear force, also requires a minimum surfactant concentration. Similar to the critical micelle concentration (CMC), this value increases with the brine salinity, which may pose a logistical and economical challenge in high-salinity formations. In such frontier applications, foam may potentially be piloted in combination with a pre-flush of low-salinity brine to bring down the chemical consumption. A lower salinity also seems to reduce the chemical adsorption.

The choice of gas impacts the foam stability. Since brine can dissolve ten times more CO_2 than methane, CO_2 foam is weakened by diffusion of CO_2 bubbles towards the aqueous phase. CO_2 solubility decreases with increasing brine salinity and temperature, which should then, in theory, lead to better stability. However, few surfactants exhibit the required tolerance towards high-salinity brines and high temperatures. Foams targeting natural gas or nitrogen show better stability than CO_2 foams.

Foam rheology can be assessed by measuring the relationship between shear stress and shear rate, similar to drilling muds or polymers. In general, foam is considered to be visco-elastic, but the power-law stress-strain relation does not have a constant exponent, see [14]. Conventional bulk testing of foams targeting oil recovery applications does not focus on foam rheology, although foam texture can be visually inspected.

2.2 Synergies with Polymers

Foam collapses due to gradual thinning of the liquid films separating the gas bubbles. The observation that the rate of thinning is influenced by the viscosity of the liquid film has led researchers to investigate whether addition of polymer can improve foam stability since polymers are known to increase the viscosity. Friedmann et al. [19] described laboratory studies and preliminary field pilot observations for the Rangely field CO_2 project and referred to the concept as a foam-gel.

Hernando et al. [22] performed both bulk tests and core floods to investigate various combinations of surfactants and polymers and found that associative polymers rather than classical non-ionic polymers were effective for water profile control in both core floods and sandpack experiments. Non-ionic polymers, on the other hand, decreased the foaming tendency as the higher solution viscosity was thought to reduce the surfactant diffusivity towards the gas-water interface. This effect could perhaps have been avoided if the polymer was added after foam was created instead of mixing surfactant and polymer together first.

An important learning point from this study is therefore, that the impact of polymers on foam stability depends on the particular combination of surfactant and polymer. Brine composition, characterized by salinity as well as the amount of divalent ions, will also impact the synergy between surfactant and polymers. Low-salinity brine with salinities less than 1000–2000 ppm are known to increase polymer viscosity which could lead to a stronger foam. Note that if the polymer does improve stability, it should not decrease the foam mobility to a point where the foam cannot be propagated.

2.3 Synergies with Nano-Particles (NP)

The past decade has seen a steady increase in the use of nano-technology in various areas such as materials design, biomedicine and electronics, see review by Bennetzen and Mogensen [4]. Cross-disciplinary research has also demonstrated that nano-technology may be applicable in enhanced oil recovery (EOR). Nano-particles are small spherical particles with a diameter in the range of 1–1000 nm with a large area-to-volume ratio. The surface of the particles can be modified by attaching various chemical molecules, a process referred to as conjugation or grafting. The molecular coating of the naked particles can be tailored for a specific application. One such example is described by Espinoza et al. [18], who showed that silica nano-particles coated with poly-ethylene glycol (PEG) could help stabilize CO_2 foams by aggregating at the CO_2-water interface. It is speculated that the synergetic effect would manifest itself in at least three ways; by speeding up the diffusing of surfactant towards the gas-water interface, by reducing the amount of surfactant required to cover the gas-water interface, and via stronger molecular forces preventing the films from draining completely. Espinoza et al. [18] showed that foam remained stable without a surfactant at reservoir conditions. Once pressure was reduced to surface conditions, the foam disintegrated.

The NP-stabilized foam was able to withstand high temperature and remained stable at surfactant concentrations as low as 0.05 wt%, almost two orders of magnitude lower than for conventional applications, although the required surfactant concentration increased with brine salinity. The foam generation itself was brought about by co-injection and required a threshold shear rate to take place. From a field application perspective, co-injection into the wellbore poses some operational challenges. In one scenario, it may cause gas and liquid to segregate preventing the foam from forming; in another scenario, the foam mobility may lead to a significant reduction in injectivity.

2.4 Fluid-Rock Testing

Once a subset of surfactants or even just a single surfactant formulation has passed the preliminary screening, the interplay between fluids and rock must be investigated. The following parameters must be assessed:

- Foam generation in the porous medium at realistic shear rates.
- Foam strength as a function of foam quality (gas saturation).
- Optimum foam quality.
- Foam mobility reduction.
- Dynamic adsorption to the rock.
- Pressure gradient needed to mobilize a stagnant foam.
- Tolerance towards oil.

The choice of porous medium varies among investigators and each one has its pros and cons. 2D micro-models, which provided a breakthrough in the understanding of two-flow displacement mechanisms more than thirty years ago have also been used to investigate foam flow. Micro-models have a well-defined pore structure and are ideally suited for imaging which is a major attraction. Unfortunately, the foam creation in real reservoir rocks is impacted by the pore geometry, which is poorly captured by today's 2D micromodels. Other drawbacks to using micro-models is that they do not enable steady-state two-phase flow, they cannot account for wettability variation, effluent analysis is not feasible and flow is dominated by capillary end effects (defined later). It is speculated that the use of 3D printing techniques may pave the way for construction of more realistic micro-models in the future, which may alleviate some of the before-mentioned limitations.

Sandpacks have been used primarily in Academia by researchers who wish to study fundamental properties at larger scale without having access to reservoir core material. Sandpacks are easy to work with, they can be imaged, and may show some similarities to high-permeability sandstone reservoirs but certainly not to carbonate rocks, which have complex pore geometries.

Slimtubes, which can in some way be regarded as sandpacks have also been used for foam testing. With a clear protocol for packing of the sand grains, the slimtube is the only industry-accepted method for evaluating dispersion-free minimum miscibility pressures for gas injection studies. However, confinement of the porous medium inside a steel cylinder does not allow for imaging to take place. The advantage of slimtube testing is that pure 1D flow can be investigated at length scales up to 60 ft.

The best option is to conduct flow experiments with real rocks at realistic flow rates. Experience shows that foam forms within a mixing zone, which can exceed the length of a typical core plug. The solution could therefore be to put several cores in series, a technique known as composite cores. Extreme care must be taken to ensure capillary continuity between consecutive core plugs to avoid introduction of capillary artefacts. Saturation monitoring using CT imaging has proven useful to test for capillary continuity and to study diversion of gas towards unswept parts of the rock. The alternative to composite cores is to select analogue outcrops, such as Indiana limestone. The most popular outcrops can be ordered to possess a certain permeability and with a length suitable for foam flooding (typically 50 cm or more). A key question remains whether the dynamic adsorption in outcrop is similar to that found in the reservoir rock. Note that static adsorption, as measured on a flat polished surface, is much higher than the dynamic adsorption inferred from core floods. The surfactant does not come into contact with the entire pore space, either due to pore geometry restrictions or because of wettability effects.

It is sometimes observed that foam leads to a reduction in residual oil saturation. One reason may be that the surfactant, in addition to creating foam is also capable of lowering the oil-water interfacial tension to a point where residual oil can be mobilized. Another explanation is that the incremental oil is in fact an experimental artefact known as the capillary end effect. Since gas is the non-wetting phase, there will still be connected oil left at the time of gas breakthrough because the gas-oil capillary pressure is positive. Foam creation leads to a higher pressure drop due to the reduced gas mobility. This pressure drop is often sufficient to overcome the gas-oil capillary pressure and push out the mobile oil. To eliminate or reduce the capillary end effect, it is common practice to conduct a bump flood whereby the injection rate is increased tenfold to make sure that all mobile oil is displaced.

The optimum foam quality (gas fractional flow) often lies close to 70% but this can be investigated with a couple of core floods. What defines optimum is the mobility reduction relative to the mobility of gas. Since the gas viscosity is low, as a rule-of-thumb a mobility reduction in the order of 50 or above is often required. However, weaker foams may be preferred in a continuous injection scheme to ensure injectivity remains high whereas strong foam may be required in gas shut-off applications.

Many chemicals tend to adsorb more in carbonates compared to sandstones because adsorption is linked to surface area. For a continuous foam application, a high adsorption will significantly impact the economics, whereas for a near well-bore treatment, the adsorption level is of secondary importance. The adsorption can be inferred based on the breakthrough time of a surfactant-only flood. It is unclear how the adsorption is affected by the foam creation, but it is believed that surfactant is first spent satisfying the adsorption before assisting in foam generation.

Finally, in gas shut-off operations, where the generated foam will remain stagnant after being formed, the pressure drop needed to (re-)mobilize the foam is of interest. In fact, it is worth remembering that most of the foam generated in-situ will remain stagnant and that foam flow occurs in a small portion of the pore network.

3 Foam Applications for Recovery of Oil

The following paragraphs describe various applications of foam in the upstream value chain from drilling and completions to fluid flow diversion in the reservoir. Each of these examples will eventually lead to recovery of more oil, whether directly, such as in enhanced oil recovery, or indirectly, by lowering operational costs.

3.1 Foam for Air Drilling and Corrosion Inhibition

Most drilling operations make use of expensive mud systems to stabilize the wellbore, prevent clay swelling, reduce unwanted fluid influx from the reservoir using appropriate weighing materials, cool the drilling bit and circulate the drill cuttings to surface where they are removed at the shakers. Such mud systems which require several chemical additives are expensive.

In air drilling, compressed air is used to cool the bit and transport drill cuttings to surface. Air is clearly a cheaper option, but suffers from poor heat capacity, hence less cooling effect, and is not suitable for handling influx of reservoir fluids. Generation of air foam increases the cuttings' carrying capacity substantially and enables removal of liquids entering the wellbore. Saline formation water is known to be corrosive towards drilling tools but Meng et al. [31] found that foam, in addition to providing better lifting of fluids and solids, also helped reduce the corrosion rates. The authors conducted laboratory experiments at ambient conditions using a mixture of dodecyl alcohol sulfonate, HPAM and biopolymer as foam stabilizers, in addition to several other additives. With such a large array of chemicals, it is not clear whether it was the foam which provided better corrosion resistance. It is speculated that the two polymers which were added to enhance the foam strength may have diffused towards the metal surface providing a thin coating and thereby shielding the pipe from the corrosive formation water. HPAM is also known for its drag reduction effect whereby a laminar sub-layer is created close to the tubing wall, see [43]. The authors did not address foam destabilization in the presence of hydrocarbons, which could become an issue in situations where a high reservoir pressure causes an unwanted influx of hydrocarbons from the reservoir into the wellbore, a situation known as a kick.

3.2 Additive in Cement Slurry

Cementing operations are critical for providing well integrity and zonal isolation both during and after drilling a well. As for drilling muds, a multitude of chemical additives are required to design a slurry with the appropriate temperature resistance, density, setting time, fluid loss, compressive strength and other important design variables. According to McElfresh and Boncan [30], foam offers the possibility to achieve a low-density, yet high-strength material. The authors mention the use of foam cement in formations which are weak, highly fractured, vuggy, or containing thief zones. From an operational point of view, the drilling mud must be circulated out and replaced with the foamed cement, just like in traditional cementing applications. However, in the case of foamed cement, it is presumably lighter and less viscous than the mud it needs to displace, so care must be taken to avoid viscous instabilities leading to unwanted contamination of the cement with the mud. As a side note, the drilling operations during the Deepwater Horizon incident made use of a foamed cement recipe, which was not sufficiently tested for the particular conditions encountered. Foamed cement is still regarded as a niche application.

3.3 Wellbore Insulation

Well integrity is a major headache for the oil industry. According to Penberthy and Bayless [34] the high heat loss from the wellbore during steam injection operations necessitates a high wellhead temperature to maintain a given steam quality downhole but can lead to thermally-induced stresses causing casing failures. Research was therefore conducted to reduce the heat loss through annulus insulation with a low thermal conductivity fluid. A silicate foam, formed by boiling a sodium silicate solution, turned out to possess excellent insulating properties. Implementing the technique required several steps. The silicate solution was first injected into the annulus and began boiling once steam injection took place in the well. The boiling resulted in foam generation. The excess silicate solution was then displaced by water and lifted out using gas-lift leaving only the foam in the annulus.

3.4 Foam Fracturing Treatments

Hydraulic fracturing is a cornerstone for delivering economic production rates from low-permeability reservoirs. Efficient fracture propagation requires a high-viscosity fracturing fluid with good fluid loss control and with the ability to transport a proppant which serves to keep the fracture open and conductive once created. Aqueous phase fracturing fluids rely on gelling agents to increase the viscosity and control fluid loss. A drawback in low-pressure reservoirs is that back-production of such high-viscosity, high-density fluids requires some sort of artificial lift. According to Gaydos and Harris [20], foam has already been used as a fracturing fluid for several decades due to its excellent fluid loss properties. Foams help minimize water damage to sensitive formations containing clays. Furthermore, when the wellhead pressure is reduced during back-production after the stimulation, the lower hydrostatic pressure in the wellbore helps to lift both gas and liquids. Use of foam therefore speeds up the recovery of fracturing fluids after the stimulation.

3.5 Foam as Additive in Matrix Acidization

The goal of matrix acidization of carbonate formations is to remove drilling-induced reservoir damage and to increase well productivity. The acid, which is typically hydrochloric acid with a concentration in the range of 10–32 wt% reacts with the rock and can, under the right flow conditions, create dissolution patterns referred to as wormholes, which penetrate up to 20 ft into the formation. Wormholing makes more efficient use of the acid which is expensive.

Wormhole growth depends on acid velocity at the tip of the wormhole. In radial flow, the velocity decreases with distance from the well, and furthermore, an increasing amount of acid is spent broadening the stem as well as an increasing number of branches on the wormhole "tree". While some branching is beneficial to the skin reduction, it does limit further wormhole growth away from the wellbore.

Bernardiner et al. [6] investigated the use of foam additives in the acid stimulation treatment with the purpose to promote deeper wormhole penetration by reducing acid leak-off into the side-branches. The authors performed linear core floods and imaged the dissolution patterns during in-situ foam creation. The foam was created by a mixture of nitrogen and dodecyl-benzene sulfonic acid (DBSA) and was able to maintain structure at low pH. One of the stated advantages of the foam was that wormhole propagation was enhanced even at injection rates below the optimum conditions for wormholing. Similar to leak-off control in fracturing applications, foam served to temporarily block unwanted fluid movement while favouring displacement in the main direction of convection (linear in the core flood but radial in a field application). While the experimental evidence speaks for itself, the standard laboratory practice suffered from some limitations. First, linear core floods are now known to artificially enhanced wormhole propagation because the fluid can only exit at the end of the plug. Second, presence of reservoir oil would negatively affect foam stability, especially at reservoir pressure and temperature. Third, the chemical reaction between acid and rock produces carbon dioxide, which is in super-critical state at reservoir conditions and is able to block pore restrictions. Despite these drawbacks, this early attempt to control acid diversion by means of additives has become common industry practice although different additives have been developed since.

3.6 Foam as Additive in Gravel Packs

Weak rocks consisting of loosely held sand grains require screens to prevent solids from entering into the wellbore and reducing flow. Gravel packs are an example of a completion type designed for soft formations. Elson and Anderson [16] proposed to use foam as the carrier fluid instead of polymers in low-pressure reservoirs. The tested foam gravel pack came at half the price of a conventional gravel pack. The authors quoted a number of other advantages but did not comment on the durability of the foam.

3.7 Foam Gas Shut-off

Gas viscosity typically ranges from 0.02 to 0.06 cP whereas liquid viscosity can span several orders of magnitude. This means that gas mobility is often much higher than liquid mobility, which results in an unstable viscous gas-oil displacement.

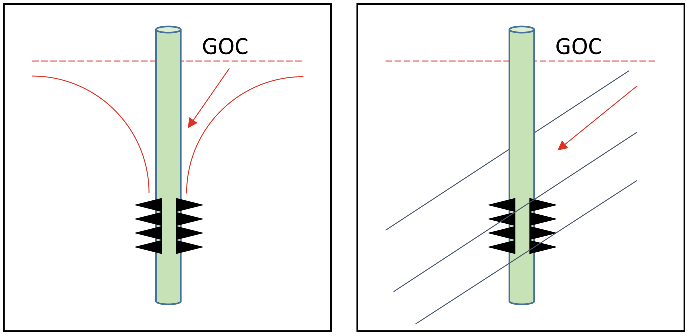

Fig. 7 Situations where FGSO may block unwanted gas Adapted from [38]

In saturated oil reservoirs containing a sizeable gas cap, oil production is often hampered by increasing gas influx from the overlaying gas cap, a phenomenon referred to as gas coning. As the gas saturation around the well increases, so does the gas relative permeability, which leads to higher gas rates thereby choking oil production. The key operational metric is the gas-oil producing ratio (GOR), which must be controlled to maintain stable oil production rates and avoid reaching the maximum gas handling capacity of the surface facilities. Presence of fractures or high-permeability streaks may further accelerate unwanted gas production (Fig. 7).

Need for GOR control was addressed more than eighty years ago by Sullivan [40]. GOR management strategies have been covered by numerous authors, including Kyi et al. [27] and Sarsekov et al. [37]. The key elements is frequent testing, choking back of the worst GOR offenders, well segmentation with zonal control, pressure support by water injection and placement of wells at a safe distance from the gas cap.

However, in mature fields where economics do not allow such major investments, chemical gas shut-off treatments present a low-cost option to temporarily reduce gas production. Such near wellbore treatments require the use of foam, generated by a surfactant tailored to the gas composition, the brine, and the rock, hence the term foam gas shut-off (FGSO). The foam must be strong and should withstand a large pressure drop when stagnant, once placed in the formation. Foam gas shut-off is said to be auto-selective because it is destabilized in the presence of oil; hence, if it is injected close to the gas-oil contact, it will preferentially form in the invaded gas zone. Furthermore, high gas shear rates caused by pressure drawdown around the wellbore will help maintain and regenerate the foam and continue to block or reduce the flow of free gas. In practice, treatments do not have a lasting effect and must be repeated every 6 months or so.

Heuer and Jacobs [23] patented the technology for gas shut off using foam. The first field application, reported by Holm [25], confirmed the laboratory-derived observations of foam as an effective method for decreasing high gas mobility caused by severe gas channeling. Interestingly, the foam also decreased the water production, reflected in a notable decrease in the producing water-oil ratio (WOR).

Since the first reported field trial some fifty years ago, a number of published applications have shown a mix of successes and failures. Aarra and Skauge [1] and Aarra et al. [2] describe the details of an FGSO pilot performed in the Oseberg field, located offshore Norway some 140 km from the coastal city of Bergen. The main objectives were first and foremost to obtain field experience with foam placement and foam generation in a production well, and as a secondary goal to evaluate if foam could be used to reduce gas production caused by gas coning. The pilot well was producing from a 2–3 Darcy homogeneous sandstone through five perforated intervals. After gas breakthrough occurred, only the top perforation interval was opened for foam treatment and back-production. The well was monitored with production logging tools (PLT) during injection and start of back-production after foam placement. Alternating injection of gas and alpha-olefin sulphonate (AOS) surfactant solution was chosen and the surfactant was injected together with seawater in two slugs at 1–2 wt% concentration and then displaced by gas. Production tests prior to the foam treatment were carried out to obtain a baseline GOR level and to calibrate the reservoir simulation model. The foam pilot was deemed operationally successful and showed that foam can be generated by slug injection of gas and surfactant solution.

Following the positive results from Norway, the mid-to-late 1990s saw a number of foam gas shut-off trials around the world. Pilot design for a well in the Rabi field in Gabon was covered by Bouts et al. [8]. The well in question was a vertical producer suffering from severe gas coning originating from an overlaying gas cap. As in the Oseberg field, the reservoir permeability was in the Darcy range, which accelerated gas breakthrough. The authors stressed the importance of proper foam placement as a key success factor. Since the foam is generated in-situ, the injected gas must be able contact the surfactant solution, which in this case was designed to be oil-soluble rather than water-soluble. In the absence of water, one suggestion was to add a solvent to reduce the surfactant mixture density below the oil density and thereby enhance gravity segregation. The recommended surfactant concentration was 1–2 wt%, in line with previous indications that foam generation requires a certain threshold concentration to take place.

The Prudhoe Bay field is one of the largest fields discovered in the United States. Located on the North Slope of Alaska, technologies such as enriched hydrocarbon gas flooding, horizontal drilling, and hydraulic fracturing have been deployed at an early stage to improve recovery. While fractures improve early production of oil, they also accelerate subsequent unwanted production of water and gas. In the case of Prudhoe Bay, the presence of a large gas cap soon resulted in excessive gas production, according to Thach et al. [41]. Prior to the foam pilots, other methods to control GOR included shut-in of high-GOR wells, side-tracking, or cyclic production-injection schemes to modify the sweep patterns. Laboratory studies confirmed that aqueous-phase foams provided larger foam strength than non-aqueous foams and that addition of polymers could further strengthen the foam. A complicating factor was to identify a surfactant which would work at a reservoir temperature of 200 °F. While most commercial products available at the time were found to be unsuitable, several AOS-based system were chosen for further studies. Surfactant chain length was found to play a key role with regards to stability. The shortest chain length generated unstable foam, the largest chain length was more oil-soluble and gave rise to oil-in-water emulsions. In the end, a mix of several surfactants was chosen because it improved the foam stability.

An important aspect when piloting new concepts is to select not one but several wells to evaluate the outcome in a statistically meaningful manner. Some trials may fail whereas others will hopefully be successful. Therefore, large fields with many wells offer better opportunities for testing new technology, including near-wellbore treatments; the scope for field-wide implementation is simply larger. Chukwueke et al. [12] described a field trial with a 50% success rate in Nigeria involving eight wells, two foam systems and two different foam generation techniques. Similar to the previous field trials, the reservoir permeability was above 1 D but instead of relying on sand packs for flow studies, the experimental protocol involved reservoir cores. Increased tolerance towards oil was regarded as desirable, which prompted the use of a combination of water-soluble fluoro-surfactants and the traditional AOS formulations, fortified by addition of a low molecular weight polymer. Fluorinated surfactants have since become subject to import bans in some countries due to environmental concerns.

Mixed results from a number of trials, environmental restrictions, and lack of long-term foam stability have remained an Achilles heel for large-scale foam applications. After a quiet period, interest in foam is picking up again. Noteworthy studies over the past decade include Skoreyko et al. [01], Enick and Olsen [17], and Ocambo et al. [33].

A recent FGSO trial took place in a mixed-wet carbonate reservoir offshore Abu Dhabi with a target reservoir permeability much lower compared to prior applications. A comprehensive laboratory work program was detailed by Skauge et al. [38] involving extended stability tests and bulk rheology experiments followed by core flooding to establish mobility reduction, adsorption, and pressure gradient resistance. Strong foam was eventually obtained with a 5 wt% AOS formulation. Addition of fluorinated surfactants and a new high-temperature resistant polymer did not improve foam stability. Design of the FGSO pilot using the selected surfactant formulations was described by Elhassan et al. [15]. The carbonate reservoir is characterized by a large gas cap overlaying an oil rim, a permeability variation from 5 to 1000 mD, a temperature of 220 °F and a formation brine salinity in excess of 200,000 ppm with more than 20,000 ppm divalent ions. Given the high required surfactant concentration of 5 wt% and the offshore location, the logistics of the operation proved challenging because the footprint had to be limited to a confined space on the barge used for well interventions. Prior to the shut-off, the pilot wells were subjected to production testing and PLT followed by a shut-in period to estimate permeability and skin. The same monitoring campaign was then repeated after the foam treatment to be able to compare changes not only to GOR but also with regards to inflow profile, injectivity/productivity and effective skin. In terms of injection techniques, both surfactant-alternating-gas and co-injection were piloted; the co-injection data showed clear signs of foam generation in-situ.

3.8 Mobility Control in Gas Floods

Whereas gels are seen as mobility control agents for aqueous phases, foams represent a mobility control solution for gas-based EOR. Foam stability over prolonged periods still remains a challenge, but foam is in principle well-suited for reduction of fluid mobility in fractures and high-permeability channels. Gland et al. [21] discuss a new development of cationic surfactants for creation of CO_2 foam in carbonates whereas Chevallier et al. [11] discuss foam in naturally-fractured reservoirs in general. The dilemma with foam is that on one hand, foam stability is important. On the other hand, a low gas-oil interfacial tension is highly desirable to force gas into an oil-wet matrix. Creation of a viscous pressure drop due to a strong and stable foam is more important than lowering the gas-oil IFT.

A successful near-wellbore treatment with foam is critically dependent on the correct placement of foam, which should remain strong also at stagnant conditions. In other words, the foam mobility should be low. On the other hand, weaker and more mobile foams are preferable for gas injection aiming at mobility control deeper into the porous formation without impairing injectivity. Therefore, a successful foam system for a near-wellbore treatment cannot be directly transferred to a gas flood requiring mobility control.

In water-alternating-gas (WAG) floods, a water-soluble surfactant slug would be added during the water cycle. The foam would then be (re-)generated during the subsequent gas cycle and the scheme would therefore be referred to as foam-assisted WAG or FAWAG. Turta and Singhal [42] have compiled an extensive list of foam pilots from North America to guide screening and design of foam applications.

3.8.1 Hydrocarbon Gas Foam

The FAWAG concept was piloted in the Snorre field, located 150 km offshore Norway, from 1997 to 2000. Blaker et al. [7] describe how an FGSO treatment in the field was carried out a year earlier to test if foam would block gas movement in-situ. A favorable outcome of the FGSO treatment was regarded as an important step in derisking the larger-scale FAWAG pilot. FAWAG differs from FGSO in a number of ways. FGSO is a near wellbore treatment performed in producing wells involving a limited volume of surfactant. A high surfactant adsorption is of little importance to the economics of FGSO, as long as the stagnant foam is strong enough to significantly reduce gas influx for several months. FAWAG, on the other hand, targets injection wells, and requires a substantial volume of surfactant to propagate foam far into the formation. Both surfactant adsorption and concentration must be as low as possible and the foam strength is a compromise between achieving a much wanted gas mobility reduction and yet maintain ability to inject gas and water to maintain reservoir pressure and sustain production. In terms of injection scheme surfactant-alternating-gas (SAG) appeared to be superior to co-injection of surfactant and gas, which the numerical simulations had been unable to quantify. One important reason is the operational challenges associated with co-injection. Surfactant and gas have to mix at surface in the right proportions at the right pressure and must mix and foam prior to reaching the reservoir to avoid segregation once inside the reservoir. Three WAG cycles were performed and surfactant was added to each of the water cycles. Analysis of injection bottom-hole pressure data showed that the gas injectivity increased during the end of the first gas cycle and this was interpreted as a sign of foam drying out and disintegrating. Data from the second and third cycles indicated that gas and surfactant gradually began following different paths, possibly with the help from natural fractures. Despite operational challenges and difficulty in propagating foam deep into the reservoir, the overall results showed that gas breakthrough was delayed and the gas oil ratio was considerably lowered.

The Cusiana field in Colombia contains a volatile oil in equilibrium with a gas cap. A combination of development strategies had been implemented since the start of production in 1994, such as natural depletion, water injection, and gas recycling into the gas cap for condensate recovery, see [33]. Gas injection also targeted recovery of oil from the oil rim through conversion of old water injection wells. As the gas injection project matured, there was an increasing need for mobility control to improve sweep. Conformance had to tackle not only the unfavorable viscosity ratio between gas and oil but also existence of high-permeability streaks as well as reactivation of fracture corridors. The main treatment involved a surfactant concentration of only 0.2 wt% followed by a non-foaming low-IFT solution to push the foam further into the reservoir. After 2–3 months, the oil rate decline was arrested and the GOR was reduced in a number of wells. One of the drawbacks of the SAG scheme is that the treatment zone for foam is relatively limited. At some distance away from the injection well, gas and surfactant may segregate away from each other just like in a normal WAG situation, and further foam generation is no longer possible.

3.8.2 Carbon Dioxide Foam

Carbon dioxide flooding was initiated in the SACROC unit in the Permian Basin almost fifty years ago, see [13]. Compared to nitrogen and hydrocarbon gas, carbon dioxide benefits from a higher density at reservoir conditions which can match or even exceed that of the reservoir fluid in some cases. Hence, gravity override caused by density differences is not as prominent in carbon dioxide floods. Viscous instabilities caused by unfavorable mobility ratio, in addition to presence of high-permeability channels, on the other hand, are more than enough to cause premature gas breakthrough, even in miscible floods. In mixed-wet reservoirs where injectivity is not impaired by a low water relative permeability end-point, conversion to a tapered water-alternating-gas (WAG) scheme is beneficial for mobility control. In water-wet rocks, conversion to WAG is not an option because it would substantially reduce the injectivity and incremental recovery has to come from continuous gas injection. In both situations (i.e. continuous gas injection and WAG), foam is able to address the need for improved mobility control.

If the target is a continuous CO_2 flood, the absence of an aqueous phase may require thinking outside the box in terms of surfactant selection. One proposal which spurred interest around 2010 involved creation of a nano-particle stabilized foam without the need for a surfactant, see [18]. Laboratory studies showed that the foam would disintegrate at surface following a large pressure reduction. Other studies pointed towards dissolving surfactant in the super-critical CO_2 phase itself [44].

CCUS is an area which may also benefit in the future from stable CO_2 foams.

3.8.3 Nitrogen Foam

Nitrogen foam is relatively well-studied because nitrogen is an inert gas and hence easier to work with in a laboratory. Also, the solubility of nitrogen in brine is much lower than for carbon dioxide, which may help generate and propagate a more stable foam. Nitrogen is often used as a proxy for hydrocarbon gas during laboratory programs.

The most well-described field implementation of nitrogen injection comes from a highly fractured carbonate reservoir in Mexico. Akal, the main field in the large offshore Cantarell complex, has undergone immiscible nitrogen injection since 1997. Rodríguez et al. [35] have summarized the field history and captured some key learnings. The reservoir thickness is close to 4000 ft, which favors a gas-oil gravity drainage (GOGD) scheme. As with other naturally fractured reservoirs, the initial production came from primary depletion where high fracture conductivity contributed to high initial production rates and therefore quicker payback of the investment costs. The recovery factor after primary production was low, which soon prompted the need for a pressure maintenance scheme. Gas injection was identified as the most feasible EOR method, but the choice of gas required detailed studies.

Based on availability, cost, safety and numerous other considerations, nitrogen was selected as the preferred injectant. This is a remarkable project given the fact that although nitrogen makes up almost 80% of the air, it had to be separated from oxygen in an energy-intensive operation onshore and then piped offshore to the field. Also, the breakthrough gas would consist of an increasing amount of nitrogen which would have to be dealt with in the surface facilities since nitrogen has no heating value. Other concerns were mostly reservoir related.

Nitrogen channeling leading to premature breakthrough was seen as the biggest potential drawback to the project but the risk was toned down due to field evidence suggesting very effective gravity segregation was taking place as long as injection was carried out from the top of the reservoir. Not all injection wells were positioned at the top of the structure and nitrogen did break through earlier than expected in some wells. The Cantarell nitrogen project is still unprecedented in terms of scale and must be characterized as a success, regardless of operational issues resulting from early gas breakthrough. Skoreyko et al. [39] refers to three foam pilots being conducted in Cantarell and described the efforts to model the foam process based on laboratory experiments as well as the data recorded during the pilots.

3.9 Mobility Control in Steam Floods

Steam flooding is a thermal EOR technique applicable to shallow reservoirs containing heavy oil. The principle relies on heat transfer from condensation as the super-saturated steam contacts the reservoir fluid. At depths beyond some 2500 ft, steam condenses in the wellbore and becomes hot water, which has a much lower capacity to transfer heat than steam. The steam is most often generated at surface using gas turbines, and in rare instances using solar panels. Steam injection is an energy-intensive operation and it is therefore paramount to make the most efficient use of the steam. As with any injection scheme, mobility control helps the injectant contact the target reservoir fluid. According to the review paper by Hirasaki [24], the use of temperature-resistant foams for steam applications was patented by Needham [32]. The goal was to plug high-permeability channels with foam and hence divert the steam towards unswept zones with lower permeability.

Steam drives are known to reduce the residual oil saturation below the values reported for waterflooding as a result of high-temperature distillation taking place in the reservoir. Since presence of oil can have a detrimental effect on foam stability, much research went into developing a surfactant solution which would not only create a stable foam but also reduce the residual oil saturation. AOS surfactants with longer alkane chain lengths in combination with alkali were found to meet both targets. It must be emphasized that the gas used for foam generation is not water vapour. In most field applications summarized by Hirasaki [24], the gas consisted of nitrogen or air. Foam was either injected continuously or as slugs.

A key metric used to evaluate steam flood performance is the steam-oil ratio, defined as the amount of steam required to yield an incremental barrel of oil relative to a baseline, which is sometimes taken as zero. Observations from various pilots was that even if foam was unable to increase the ultimate recovery factor, it would often accelerate production and hence improve the project economics.

4 Concluding Remarks

The field applications of foam are numerous but the properties of foam are best exploited in situations where long-term stability may not be needed, such as in hydraulic fracturing or in near wellbore treatments where chemical placement can be controlled. Foam for enhanced oil recovery is a topic of active research but has so far failed to gain widespread acceptance as a reliable method for in-depth conformance and mobility control. Such frontier applications require a surfactant which at low concentrations generates a very stable foam that can be propagated from the wellbore and far into the formation, and has low adsorption.

Most EOR processes struggle with high unit technical cost (UTC) and the current oil price environment does nothing to entice operators to initiate multi-year foam pilots. The appetite for risk varies among operators, but the economic upside in terms of improved sweep has to be present to justify continuous injection; i.e. a base case scenario without foam which yields a poor recovery is preferable. Although the concept as such can no longer be regarded as novel, a near wellbore treatment such as FGSO is still regarded as an important stepping stone towards derisking FAWAG. A good start would be to pilot foam in benign conditions such as low salinity and low temperature reservoirs where the foaming agents (i.e., surfactants) are readily available.

The behavior of foam systems comprising gas mixtures, brines, and surfactants can in principle be modelled with tools such as molecular dynamics or density functional theory because all components have a well-defined chemical structure. This author believes that a systematic brute-force computational approach towards screening of surfactants in terms of foaming tendency is needed to develop new chemicals which can maintain longer stability.

Frontier applications of foam involve high-temperature, high-salinity, and low-permeability reservoirs. An earlier paragraph described how small pores lead to a high capillary pressure, which destroy foam. A further complicating factor in low-permeability reservoirs is that some mobility reduction is required without sacrificing injectivity. Katiyar et al. [26] released details about the first hydrocarbon foam pilot in an unconventional reservoir; however, the purpose of the foam was to penetrate the hydraulic fracture network, not the tight matrix. In any case, the operational envelope of chemical EOR to which foam belongs will continue to expand in the coming decade as production of easy oil declines.

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