IFT Role on Oil Recovery During Surfactant Based EOR Methods

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Abstract In general, it is believed that the ultra-low IFT provided by surfactant is a requirement for the higher microscopic recovery efficiency during enhanced oil recovery (EOR). In tight oil shale and shale reservoirs, capillary imbibition become a dominant recovery mechanism where ultra-low IFT becomes less significant or even a retarding force in certain scenarios. Recent researches have emphasized that the microscopic efficiency of CO_2 flooding could be improved by adding low IFT surfactants. Surfactants are also used for conformance/mobility control applications in the form of foam. During foam flooding application in naturally fractured reservoirs, the ultra low-IFT conditions is advantageous for oil recovery in dolomite but not in limestone rocks. Although low-IFT conditions positively influences the microscopic recovery during alkali steam-foam flooding, ultra-low IFT is not required. This chapter compiles these cases and sheds insight using fundamental reservoir engineering concepts to understand why the ultra-low IFT conditions, conventionally considered to be a prerequisite for the higher residual oil recovery, are not always beneficial or required or enough during many of the EOR applications.

1 Fundamental Concepts of Enhanced Oil Recovery

1.1 Microscopic Displacement

Total recovery factor during enhanced oil recovery (EOR) is a product of microscopic displacement and macroscopic sweep efficiency (Eq. 1).

$$E = E_d * E_V \tag{1}$$

where

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E = total recovery factor; E_d = microscopic displacement efficiency; E_V = macroscopic sweep efficiency.

Generally, microscopic displacement efficiency gives a measure of how much trapped oil that is swept by the injection fluids can be mobilized to the total swept oil. It is a pore-scale phenomenon quantifying the amount of well-swept residual oil can that be recovered during flooding (Eq. 2).

$$E_d = \frac{S_{oi} - S_{or}}{S_{oi}} \tag{2}$$

where

S_{oi} = initial oil saturation; S_{or} = residual oil saturation.

For the residual oil to get recovered, it is a must that the injection fluid should contact it. In other words, sweeping effect is a precursor to micro-displacement effect. Not all the swept oil will be mobilized during water flooding because of the higher capillary pressure. A sample calculation shown in the next section illustrates the fact that capillary pressure that traps the oil within the pores would be on order to 1000 psi/ft. Capillary pressure could also be a driving force during spontaneous imbibition. Capillary pressure is directly proportional to interfacial tension (IFT), wettability and radius of the pore (Eq. 3).

$$P_c = \frac{2 * \sigma * \cos\theta}{r} \tag{3}$$

where

P_c = capillary pressure, psi; σ = Interfacial tension between the displacing and displaced fluids, mN/m; r = pore radius, microns

As per the snap-off concepts, the likelihood of the trapping capillary pressure will be higher when the difference between pore body radius and pore throat radius (aspect ratio) is higher (Eq. 4). The readers are suggested to refer Fig. 2.14 of Green and Willhite's [1] for more information about the different capillary pressure gradient caused due to variations in contact angle, IFT etc.

$$\frac{P_c}{L} = \frac{2 * \sigma * \cos\theta}{L}\left(\frac{1}{r1} - \frac{1}{r2}\right) * \left(\frac{14.696 * 30.48}{1.0133 \times 10^6}\right) \tag{4}$$

where

$\frac{P_c}{L}$ = capillary pressure gradient, psi/ft.; $r1$ = radius of pore throat or smaller pores, centimeter; $r2$ = radius of pore body or larger pores, centimeter; L = length of an oil blob, centimeter

For the oil to get mobilized from the pore, driving viscous force should exceed the capillary force (Eq. 4). The driving viscous force can be calculated through the Darcy law (Eq. 5).

$$\frac{dP}{L} = \frac{v * \mu}{K * 0.001127 * 5.615} \tag{5}$$

where

$\frac{dP}{L}$ = pressure gradient, psi/ft; v = flux rate, ft/day; μ = apparent viscosity, cP; k = permeability, mD

The balance between the driving viscous and trapping force can also be explained in terms of the capillary number (N_c). Many versions of capillary number exist in the literature [2]; Al-Quaimi and Rosen [3–5] and the most common number expressed as a ratio of viscous force to the capillary force is represented through Eqs. (6) and (7) respectively.

$$N_c = \frac{v * \mu}{\sigma * \cos\theta} \tag{6}$$

$$N_c = \frac{k * \left(\frac{dp}{L}\right)}{\sigma * \cos\theta} \tag{7}$$

where

N_c = capillary number, dimensionless; v = flux rate of the displacing fluid, ms^{-1}; μ = apparent viscosity of the displacing slug, cP; σ = interfacial tension between the displacing and displaced slugs, mN/m; θ = contact angle; k = permeability, cm^2; $\frac{dp}{L}$ = pressure gradient, psi/cm.

Higher fluxes, higher displacing slug's viscosity, higher pressure gradient and ultra-low IFT leads to higher value of capillary number (Eqs. 6 and 7). Capillary number must be 10^{-3} or 10^{-2} in order to have a significant reduction in S_{or}. Viscous force generated during water flooding at the normal flux rate of 1ft/day would be on the order of 1 psi/ft and corresponding capillary number would be around 10^{-7} [6]. Practical means of enhancing the capillary number is by reducing the IFT between the displacing solutions and displaced oil (Eqs. 6 and 7). By reducing the IFT, trapping capillary pressure will be reduced (Eq. 3), and oil will be mobilized. Low IFT is provided by adding surfactant to the displacing solutions. Surfactant flooding is the common chemical EOR method which aims to improve the microscopic displacement efficiency. The interplay between the gravity forces and capillary forces also influences the microscopic recovery if there is good vertical support. Bond number has been used to characterize the relative importance of gravity forces over capillary forces (Eq. 8).

$$N_b = \frac{\Delta\rho * g * k}{\sigma * \cos\theta} \tag{8}$$

where

N_b = Bond number, dimensionless; $\Delta\rho$ = density difference between the displacing and displaced slugs, Kg/m^3; k = permeability, m^2; σ = interfacial tension between the displacing and displaced slugs, mN/m; θ = contact angle

The numerator and denominator term of (Eq. 8) denotes the gravity and capillary forces respectively. Ultra-low IFT and higher permeable conditions will induce higher gravity forces. As per the conventional belief, lower the IFT, the higher the capillary number and bond number and therefore, higher the oil recovery. However, it is not the case always. Sometimes ultra-low IFT conditions may be detrimental or insignificant or will need to be supplemented by other factors to have an enhanced oil recovery. This will be discussed in this chapter.

In miscible CO_2 flooding, there is a complete removal of interface which means theoretically capillary number should be at infinity and S_{or} should be zero (Eqs. 6 and 7). However, to have the miscibility, certain pressure is required which is known as minimum miscibility pressure (MMP). Unless, the reservoir oil, injection gas composition meets the miscibility requirements, the flooding will be operated in immiscible mode. Recently, surfactants are used to reduce the IFT and MMP of crude oil-CO_2 system. The IFT role on MMP reduction and oil recovery is also discussed.

1.2 Macroscopic Sweep

Macroscopic sweep efficiency gives a measure of how much oil could be contacted volumetrically by the injected fluids to the total oil available before the flooding. Macroscopic sweep efficiency can be further decomposed into vertical and areal sweep efficiency (Eq. 9).

$$E_V = E_A * E_I \tag{9}$$

where

E_A = areal sweep efficiency, the swept area divided by the total reservoir area; E_I = vertical sweep efficiency, the pore space swept by the injection fluid to the total pore spaces in all the layers behind the areal location of the front.

Sweep is not only a field-scale phenomenon and it could be important at the core-scale. At the core scale, the mobilized oil needs to be pushed forward for which a favorable mobility ratio needs to be maintained between the mobility buffer, injection chemical slugs and oil/water bank. Mobility buffer efficiency along with the volumetric sweep efficiency and microscopic displacement efficiency determines the overall recovery factor [7]. Sweep is a function of time on both the field-scale [1] and core-scale [4, 5]. Viscous fingering due to the viscosity contrast between the displacing and displaced fluids, excessive channeling of the injection fluids through the high permeable streaks are the main reasons for the poor sweep efficiency during water flooding. Gravity override due to the density differences between the displacing and displaced slugs also leads to poor sweep efficiency in low dense EOR methods such as CO_2 EOR and steam flooding. Mobility ratio (M) is a ratio of the mobility of the displacing slugs to the mobility of the displaced slugs (Eq. 10). Mobility is the ratio of relative permeability of the fluid to its viscosity.

$$M = \left(\frac{K_{rw}}{\mu_w}\right)_{Sor} * \left(\frac{\mu_o}{K_{ro}}\right)_{Siw} \tag{10}$$

where

M = end point mobility ratio, no unit; $\left(\frac{K_{rw}}{\mu_w}\right)_{Sor}$ = mobility of the displacing slug at residual oil saturation; $\left(\frac{K_{ro}}{\mu_o}\right)_{Siw}$ = mobility of the displaced slug at immobile water saturation.

The above definition of mobility ratio holds for water flood in which only the oil flows ahead of the waterfront and only water flows behind the front. However, there will be a saturation variation with respect to space and time in most of the immiscible floods. Mobility ratio at average saturation can be calculated using the average saturation (Eq. 11).

$$M_s = \left(\frac{K_{rD}}{\mu_D}\right)_{S_D} * \left(\frac{\mu_d}{K_{rd}}\right)_{S_d} \tag{11}$$

where

M_s = mobility ratio at average saturation; $\left(\frac{K_{rD}}{\mu_D}\right)_{S_D}$ = mobility of the displacing-phase at the breakthrough saturation; $\left(\frac{K_{rd}}{\mu_d}\right)_{S_d}$ = mobility of the displaced phase at average saturation ahead of the flood front.

For more details about the mobility ratio, the readers can refer to Craig [8] and Green and Willhite [1]. Mobility ratio influences the core-scale linear displacement, areal sweep efficiency and vertical sweep efficiency. To have a better sweep efficiency, mobility ratio needs to be reduced which is accomplished through the injection of the viscous fluids such as polymer and foam solutions. These fluids can impart higher resistance to the flow of the displacing slugs by generating higher apparent viscosity. Surfactants are used in foam flooding and the prime expectation from these surfactants is to have a good foam stability (and not the low IFT), so that the apparent viscosity needed for the enhanced sweep could be achieved. The basic understanding is that foam flooding used for conformance control or used to reduce the adverse mobility of low dense EOR fluids such as steam cannot reduce Sor. However, to have an overall good recovery factor, Sor reduction through enhanced microscopic displacement is needed (Eq. 1). The surfactant blends and surfactant system combined with alkali can lead to higher interfacial activity during foam-based flooding. The role of IFT on Sor reduction during foam-based flooding is discussed in this chapter.

2 Conventional Surfactant Flooding

During surfactant flooding (also called as low-tension or micellar flooding), the surfactants are added to the injection water to reduce the IFT. Reduction in IFT leads to the reduction of capillary pressure and an increase in capillary number (Eqs. 6 and 7). Increase in the capillary number leads to Sor reduction. The example calculations taken from Peter [6] illustrates the importance of having ultra-low IFT for residual oil mobilization during the dynamic surfactant injection at 1ft/day. Please note the words "dynamic surfactant injection", "forced surfactant flooding" and "conventional surfactant flooding" bears the same meaning i.e., the flooding is aided by the imposed flux. These words should not be confused with the surfactant aided spontaneous imbibition where there will be no imposed fluxes. The entire discussion in Sect. 2 pertain only to forced displacement. The discussion about spontaneous imbibition is deferred to Sect. 3.

Problem 1 An oil droplet that got trapped due to snap off at the pore-scale needs to be mobilized. Rock and fluid properties are reported in Table 1.

Determine (a) the pressure gradient that is needed to be release the trapped oil (b) the pressure gradient that could be generated during water flood (c) the new trapping pressure gradient during surfactant flooding who IFT is assumed to be (1) 0.01 mN/m (2) 0.1 mN/m (3) 1 mN/m (Fig. 1).

(a) Calculated trapping pressure gradient using (Eq. 4) is 169.75 psi/ft. During flooding, the gradient higher than 169.75 psi/ft needs to be exerted so that oil will get mobilized.
(b) Calculated pressure gradient that could be generated during forced water flood at 1 ft/day using (Eq. 5) is 0.079 psi/ft. The trapped oil cannot be mobilized because the pressure gradient generated during water flood is less than that required for oil mobilization
(c) Using (Eq. 4), the trapping gradient during surfactants injections with the IFT of 0.01 mN/m, 0.1 mN/m and 1 mN/m are 0.057 psi/ft, 0.57 psi/ft and 5.7 psi/ft respectively.

Table 1 Rock and Fluid properties for sample problem 1

Rock type	Water-wet
$\theta°$	0
IFT between water and oil, mN/m	30
Pore-throat radius, microns	50
Pore-body radius, microns	250
Length of oil blob, microns	250
Darcy velocity, ft/day	1
Water viscosity, cP	1
Permeability, mD	2000

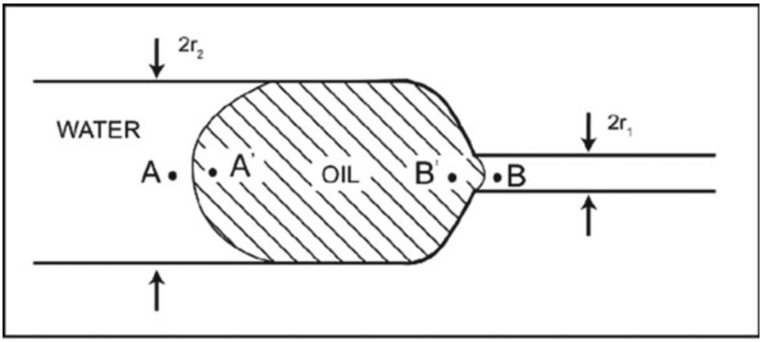


Fig. 1 Trapped oil blob (from [6])

If the surfactant addition to the displacing water reduces the IFT from 30 to 0.01 mN/m, trapping capillary pressure gradient would be reduced from 169.75 to 0.057 psi/ft. The value of 0.057 psi/ft is lower than 0.079 psi/ft, the calculated viscous driving force that could be generated during the water flood. Therefore, trapped oil could be mobilized during the surfactant injection at 1ft/day during the ultra-low IFT conditions of 0.01 mN/m. At the moderate to high IFT conditions of 0.1 to 1 mN/m, the surfactant injection could reduce the capillary pressure gradient from 169.75 psi/ft. to 0.57–5.7 psi/ft. Since these values are more than the viscous pressure gradient generated during the water flood, residual oil cannot be mobilized at 1 ft/day. Operating the flood with the moderate IFT of 0.1 mN/m but at the higher flux of 10 ft/day could have the driving viscous gradient (0.79 psi/ft) exceeding the capillary trapping gradient (0.57 psi/ft). Since the driving viscous force is higher than the trapping capillary force, residual oil could be mobilized. One can expect to have relatively low IFT reduction by surfactant when the flux rate is higher. However, high fluxes are seen only around the wellbore and therefore residual oil in farthest portion of the reservoir would remain immobilized. This signifies the importance of having ultra-low IFT condition during surfactant injection.

Please note the performed calculation is a simplified one because IFT value with vary with respect to time and location due to surfactant's adsorption. Also, formation of micro-emulsion will lead to higher apparent viscosity which may influence the calculation and interpretation. Nevertheless, the performed calculation illustrates the importance of having ultra-low IFT conditions for having a higher microscopic displacement efficiency at 1ft/day. An important point to note here is that there should be an imposed force for the surfactant flooding to be effective in reducing the capillary pressure gradient to be comparable with viscous flood gradient. Reservoirs shouldn't be highly heterogeneous with the extensive presence of high conductivity fractures, and permeability shouldn't ultra-low so that the forced viscous based displacement can be imposed. In the matrix-fracture system characterized by the very low permeable matrix and in very tight rocks, spontaneous imbibition will be a dominant mechanism.

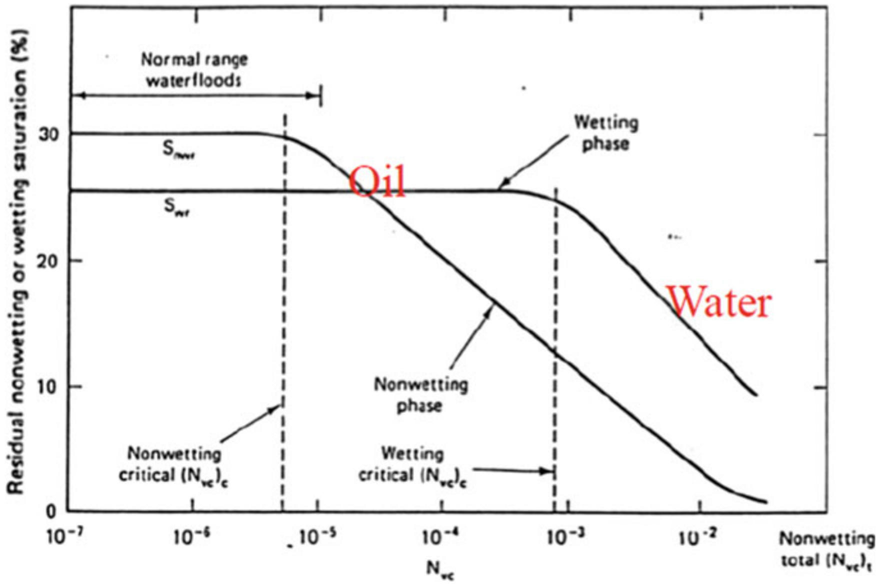


Fig. 2 Residual non-wetting or wetting phase as a function of capillary number (From [9, 10])

The relation between the capillary number and Sor are represented through capillary desaturation curve (CDC). In CDC curve, there will be critical capillary number above which the oil mobilization will be significant (shown as dashed vertical lines in Fig. 2).

At capillary number less than critical capillary number (such as in water flood), capillary force dominates so the injection fluids imbibe into the finer pores and oil gets snapped off in the larger pores. After the critical capillary number, viscous forces relatively dominate the capillary forces and therefore could results in the rapid oil mobilization especially from larger pores [11]. Relative domination of viscous force over capillary force is achieved by the reduction in IFT during the surfactant injection. IFT lowering requirement is dependent on several parameters during forced displacement. In this section, we shall see the effect of rock wettability, oil connectivity, oil viscosity on IFT reduction requirement during oil recovery.

2.1 Effect of Wettability on IFT Requirement

Wettability of the rock is an important parameter which influences the requirement of IFT reduction during flooding. In oil-wet rocks, residual oil can occur (1) in the small pore as continuous oil (2) as trapped large globules in many pores (3) as trapped discontinuous oil droplets at the pore throat (4) as pendulum rings along the pore walls. Several studies conducted in the past revealed that when compared to water-wet media, significant reduction in IFT is needed to displace the residual oil occurring in the form of discontinuous droplets or pendulum rings in the oil-wet media [12–16]. Critical capillary number (denoted as Nvc in Fig. 2) that quantifies that onset of rapid oil mobilization is higher when the non-wetting phase displaces the wetting phase. To displace most of the trapping wetting phase by non-wetting phase, a very high capillary number of 2 is needed (Dombrowski and Brownell's curve in Fig. 3) whereas for the efficient displacement of non-wetting phase by the wetting phase, a relatively lower capillary number suffices (Fig. 3). Therefore, it can be said more energy needs to be expended for displacing the wetting phase by the non-wetting phase which can be achieved at the ultra-low IFT conditions.

One important point is that in some oil-wet media, a critical capillary number may appear to occur early, or a visible transition may not be seen.

However, a careful look into Du prey's curve in Fig. 3 and CDC curve for Indiana limestone in Fig. 4 reveals that reduction in Sor with respect to increase in capillary number (or therefore decrease in IFT) is much lesser because of the complex nature of the oil wet rock. This indicates in oil-wet media, recovering the residual oil is relatively a difficult process. For example, in most of the sandstone rocks, increasing the capillary number from 10^{-5} to 10^{-2} could result in the Sor ~5% (Fig. 4). However, for Indiana limestone, Sor could not be reduced to more than 18% with the similar increase in capillary number (Fig. 4). IFT reduction alone may not suffice always in oil-wet rocks because of strong adhesion forces and wider pore size distribution. A strong wettability alteration may need to be coupled with IFT reduction in case of oil-wet rocks.

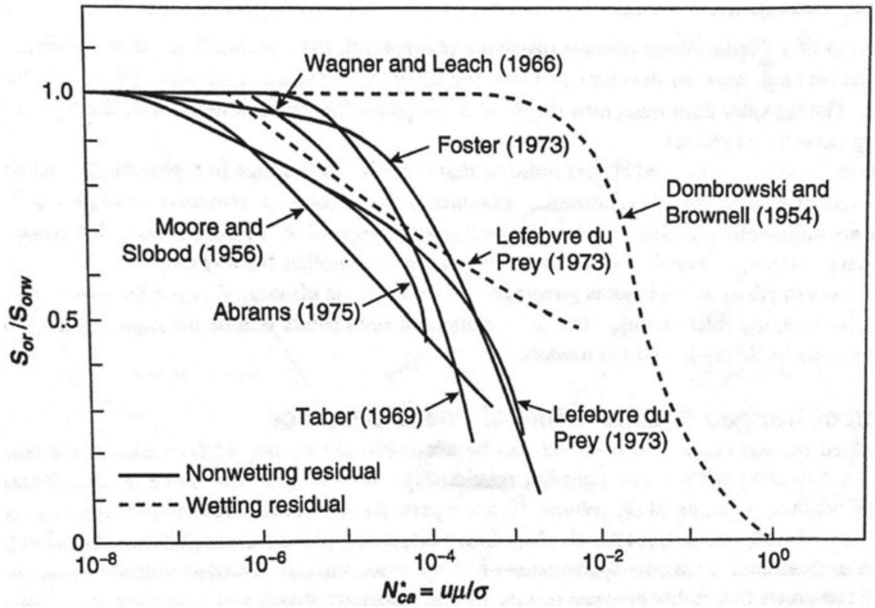


Fig. 3 CDC curve generated by different EOR researchers (From [1])

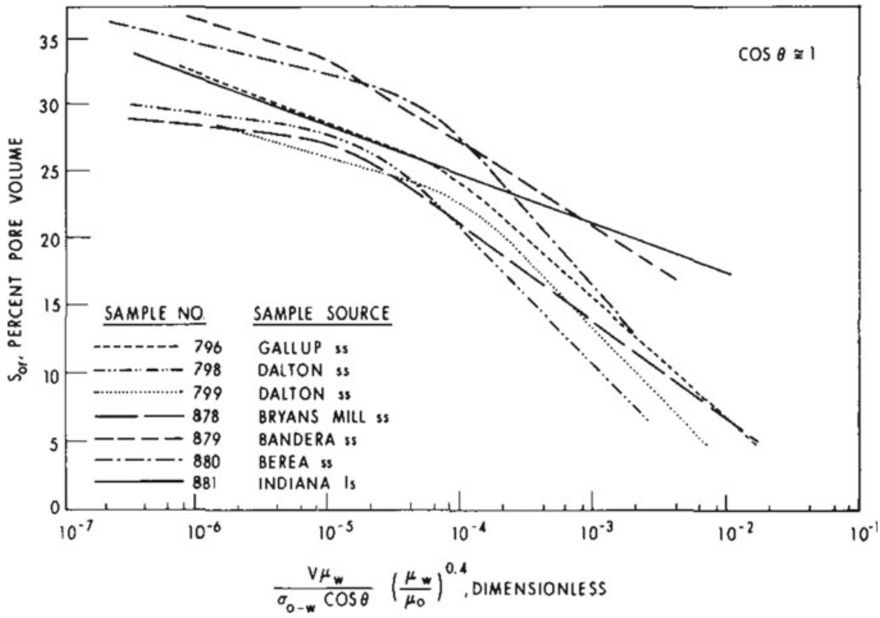


Fig. 4 CDC curve for various sandstone and limestone rocks (From [11])

2.2 *Effect of Oil Continuity on IFT Requirement*

IFT lowering is also dependent on whether the oil exists in a disconnected form or in a continuous form. Aspect ratio between the pore body and pore throat gives a measure of radial capillary variation that the flowing fluid will experience in porous media (Eq. 4). When the oil gets snapped off due to high aspect ratio of above 3, they exist as single smaller droplet in a single pore [17]. Therefore, the trapping capillary pressure is expected to be higher as per (Eq. 4). On a contrary at lower aspect ratio of 3, residual oil exists as large continuous clusters [17]. At the aspect ratio of 2 or less, no significant trapping occurs [17] because capillary pressure tends to be lower as per (Eq. 4). More energy needs to be expended in mobilizing the disconnected oil when compared to recovering the oil that is not trapped. This can be understood by comparing the CDC curve for both the connected and disconnected oil (Fig. 5).

Critical capillary number needed for mobilizing the disconnected oil is relatively higher. Therefore, IFT lowering requirement should be higher for recovering the disconnected oil.

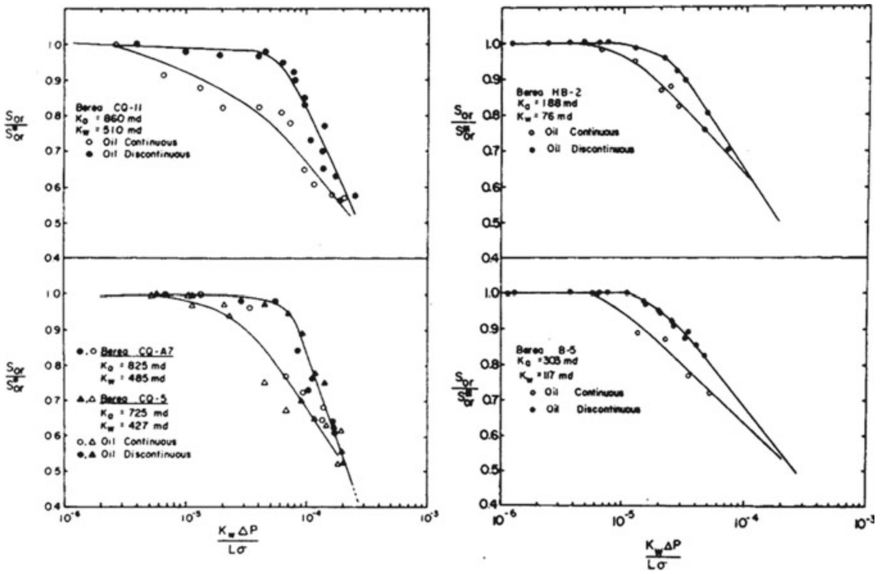


Fig. 5 CDC curve for Berea stones saturated with disconnected and connected oil (From [18])

2.3 *Effect of Oil Viscosity on IFT Requirement*

Displaced oil viscosity is usually not considered in convention capillary number definitions (Eqs. 6 and 7). Therefore, CDC curve generated for the oil of various viscosity looks scattered (Fig. 6).

A closer look into the Fig. 6 reveals at the similar values of capillary number, triangle and diamond symbols representing the higher viscous oil are located at the region of higher Sor. This signifies at the similar IFT level, the higher the oil viscosity, the lesser the recovery. The question arises whether the lowering of IFT will have a beneficial effect on heavy oil recovery during non-thermal EOR methods? To answer this, Zhang et al. [19]'s work is considered.

Zhang et al. [19] performed a systematic study to analyze the relative importance of mobility control and IFT reduction during 1500 cP heavy oil recovery in 3–3.8 Darcy sand pack. Floodings were performed using Alkali surfactant polymer (ASP), alkali surfactant (AS), alkali (A), alkali polymer (AP). Injection rate was 12 mL/hr, an indication that it is a forced displacement. The IFT values and recovery performance of AS and ASP systems are shown in Figs. 7 and 8 respectively. The recovery performance of AP system is shown in Fig. 9.

IFT of AS system is ultra-low on the order of 10^{-3} mN/m (Fig. 7). Adding polymer to alkali-surfactant system increase the IFT by almost an order at all alkali concentration (Fig. 7). Analyzing the poorer recovery performance of ultra-low IFT AS system with the relatively high IFT ASP system at lower NaOH concentration (Fig. 8), detrimental effect of ultra-low IFT is clear. At 0.1% NaOH, AP and ASP

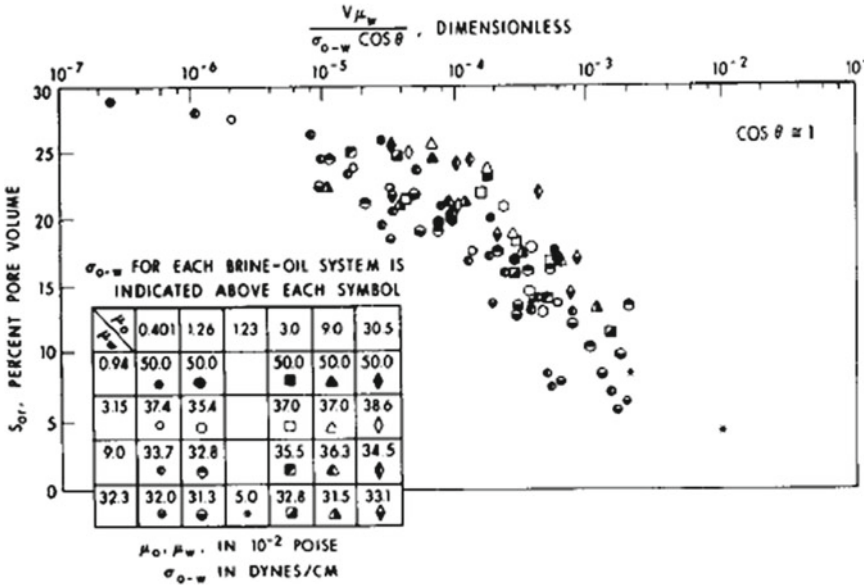


Fig. 6 Effect of oil viscosity on CDC generated using conventional capillary number (From [11])

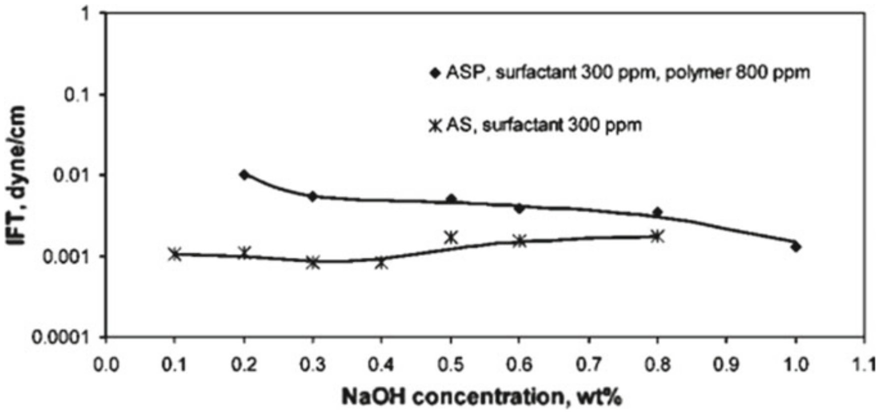


Fig. 7 IFT values as a function of NaOH concentration for ASP and AS systems (From [19])

system corresponded to the recovery factors are 15% and 28% (See Figs. 8 and 9). Maximum pressure drops experienced during these flooding is 9.8 kPa are 6.4 kPa respectively [19]. Higher pressure drop is exhibited by AP flooding. Higher pressure drops means a higher apparent viscosity (Eq. 5) and therefore a lower mobility ratio (Eqs. 10 and 11) and a better recovery. Therefore, it can be said mobility control is more important to arrest the fingering issues in the unstable immiscible floods and the ultra-low IFT conditions should be avoided during heavy oil recovery.

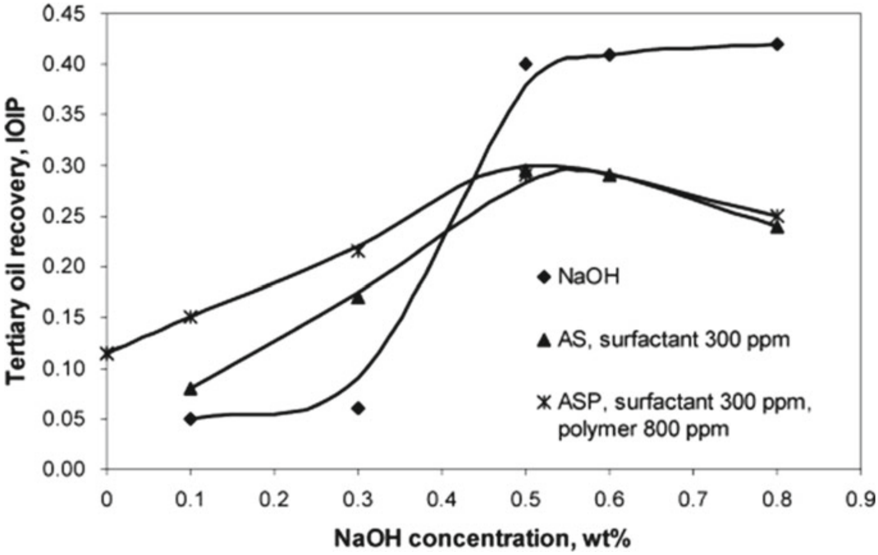


Fig. 8 Recovery performance of ASP and AS systems (From [19])

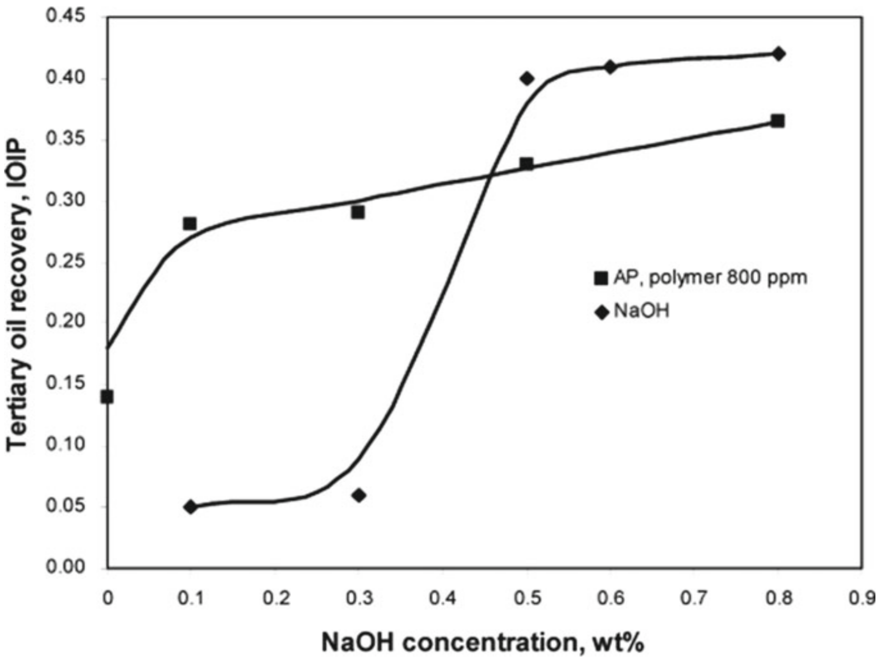


Fig. 9 Recovery performance of AP and A systems (From [19])

3 Spontaneous Imbibition

The spontaneous imbibition is the process in which the wetting phase is imbibed into the pores by the driving capillary force. In the case of tight shale reservoirs, imbibition cannot be a forced one due to permeability constraints, and therefore, spontaneous imbibition must be the main driving mechanisms. Capillary forces and gravity forces are the important forces that governs the imbibition process. The relative importance of these two forces can be quantified through the bond number (Eq. 8). There are two modes of spontaneous imbibition. (1) Counter-current imbibition (2) Co-current imbibition. Capillary force that usually acts as a trapping force in forced displacement is the driving force during spontaneous imbibition. Capillary force drives the aqueous injection fluid to imbibe into the matrix pore (with out an imposed force) and the oil would be expelled out in the opposite direction in a process called counter-current imbibition (Fig. 10a). If the matrix has enough height, gravity forces can cause the fluids to separate so that the low-density oil can be driven out upwardly at the low IFT conditions through the process called co-current imbibition (Fig. 10b).

In this section, I shall discuss the role of IFT on these processes during oil recovery from very tight shale rocks, low permeable limestone and a relatively permeable Berea core.

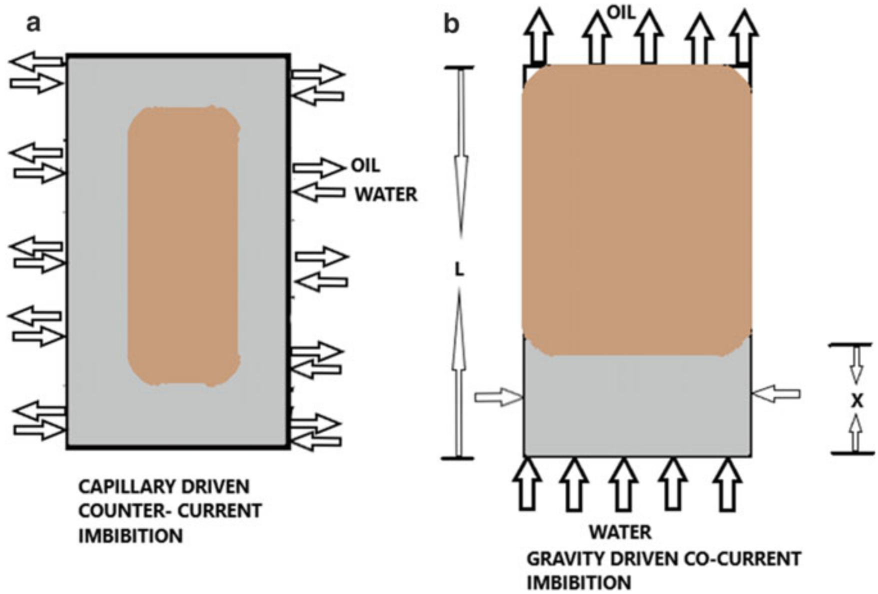


Fig. 10 Schematic showing the **a** Counter-current imbibition **b** Co-current imbibition

3.1 IFT Role in Tight Shale Rocks

Tight shale rocks are usually characterized by a very low permeability (For ex.10^{-6} Darcy) and oil-wet nature. For oil-wet rocks, the contact angle is usually higher than 90° and therefore, the capillary pressure for the oil-wet rocks would be negative as per the (Eq. 3). and it is imperative to have a water-wet surface for the capillary imbibition. Therefore, wettability alteration plays a crucial role. Along with the wettability alteration to water wet, high IFT is important to ensure the good capillary driven counter-current imbibition and therefore a higher recovery rate. Figure 11 compares the simulation effect of ultra-low IFT versus IFT conditions on the recovery factor from the shale core whose wettability got altered from the oil-wet to water-wet.

While 20 mN/m surfactant system could achieve the recovery factor of 40% in 100 days, 1 million days would be needed for 0.008 mN/m system to achieve the similar recovery factor. The higher the IFT, the higher the capillary pressure (Eq. 3) which is beneficial to induce capillary driven counter-current flow during spontaneous imbibition. As can be seen from the schematic depicting the typical capillary dominated flow (Fig. 10a), more oil will be expelled because almost all the faces are open to flow during the counter-current imbibition process. This is the reason for the higher imbibition recovery rate with high IFT system.

While the counter-current capillary imbibition needs high IFT, low IFT should favor gravity driven co-current imbibition (Eq. 8). However, gravity forces, the numerator term in Eq. (8) is also dependent on permeability. Lower the permeability, the lower the gravity forces, and therefore lower the co-current imbibition recovery. Even in the presence ultra-low IFT conditions, gravity forces would be of diminished relevance to separate the two fluids of different density if the media are not permeable. For example, Bond number calculated for ultra-low IFT systems

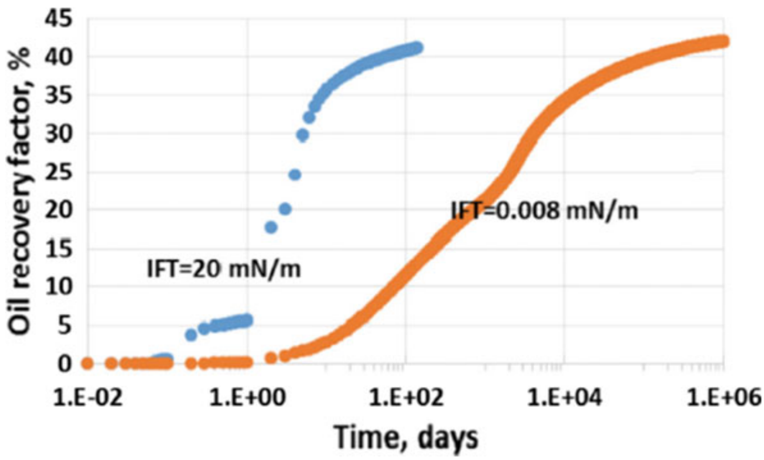


Fig. 11 Effect on IFT on oil recovery rate during spontaneous imbibition from 3.3×10^{-4} mD tight shale (From [20])

(0.008 mN/m) in the shale rock with the permeability of $3.3*10^{-4}$ mD is extremely low ~$7.35*10^{-11}$. Simulation studies performed by Sheng [20] revealed that recovery factor of such ultra-low IFT system will be 0.01 after 138 days. To have a reasonable recovery factor of 22% with ultra-low IFT system through gravity drive, 1.33 million days will be needed [20]. Therefore, the existence of ultra-low IFT conditions on the order of 10^{-3} mN/m will be totally unfavorable for recovering the oil through either co-current or counter-current imbibition from the tight shale rocks. It can be said that maintaining high IFT on the order of more than 10 mN/m and relying mainly on the capillary drive counter-current imbibition is the feasible recovery mechanism in extremely tight shale rocks.

3.2 IFT Role in Low Permeable Limestone and a Relatively Permeable Berea

In the previous para, the detrimental effect of having ultra-low IFT condition during oil recovery from extremely low permeable shale oil reservoir was discussed. The IFT role on oil recovery on the relatively permeable medias are discussed by choosing a limestone core with the low permeability of 15 mD and a Berea core with the medium permeability of 100 mD. 15 mD is also relatively low permeable. Therefore, capillary driven counter-current imbibition should dominate. The low IFT systems will ruin the much-needed capillary forces and therefore, the recovery rate is expected to be lower when compared with the high IFT system (Fig. 12).

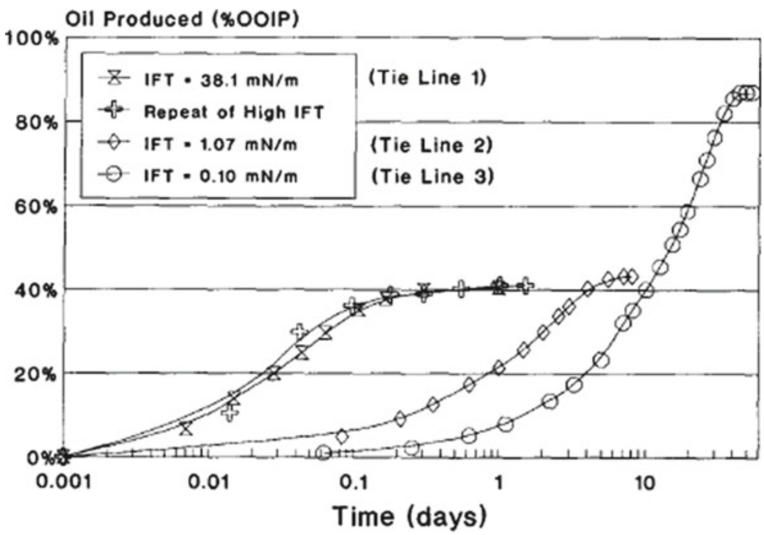


Fig. 12 Effect on IFT on oil recovery rate during spontaneous imbibition from 15 mD limestone (From [21])

As the permeability increases the gravity forces should increase relative to the capillary force as per the bond number (Eq. 8) and therefore co-current imbibition can occur. The lower the IFT, the higher the gravity forces as per the bond number (Eq. 8). Therefore, one would expect the lowest IFT conditions to be of benefit during the co-current process. However, comparing to counter-current imbibition in which all the faces are open to flow (Fig. 10a), a pure vertical co-current imbibition has relatively lesser spaces for fluid intake (Fig. 10b). The higher the fluid intake, the higher the recovery rate. So, the early time recovery should be less with the lowest IFT system which relies mostly on gravity aided co-current imbibition. This is reflected in the relatively lower recovery rate of lowest IFT system (0.1 mN/m) when compared to the one order higher IFT system (1.07 mN/m) during the first two days (Fig. 13).

Therefore, an optimal IFT system which shouldn't be too low nor too high is needed in a relatively high permeable media so that both co-current and counter-current imbibition takes place for a better recovery rate. In other words, both gravity and capillary driven mechanism will be of use, when using an optimal IFT system. In terms of total oil recovery, the system with lowest IFT will be beneficial in both the low permeable limestone and the relatively high permeable Berea (Figs. 12 and 13). It could be attributed to the reduced Sor at the lowest IFT conditions. However, to achieve those recovery, several weeks will be needed especially for the low permeable system. For the medium permeable rocks such as Berea, a low IFT on the order of 10^{-1} mN/m could be fine for having a good recovery rate and ultimate recovery. But an ultra-low IFT on the order of 10^{-3} may hamper the capillary driven counter-current flow which is also needed along with co-current imbibition.

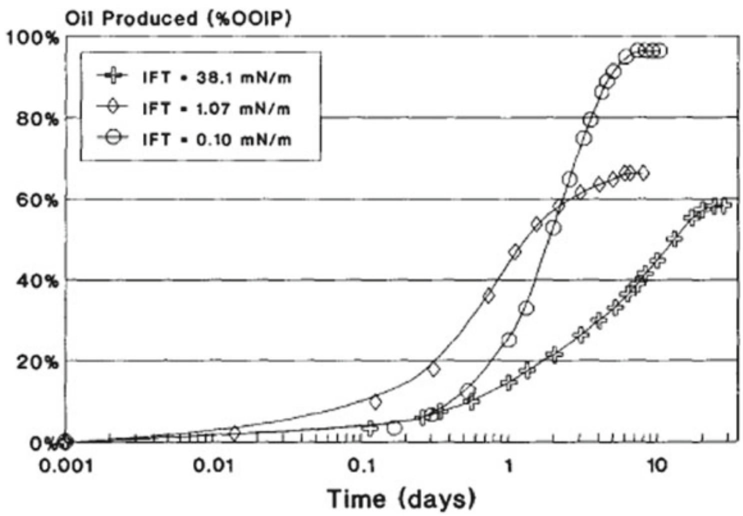


Fig. 13 Effect on IFT on oil recovery rate during spontaneous imbibition from 100 mD Berea (From [21])

4 CO_2 Flooding

Carbon dioxide flooding is one of the most implemented EOR process. Viscosity reduction, oil-swelling and miscibility are some of the recovery mechanisms associated with CO_2 flooding. Miscibility is the most influencing parameter. Basically, miscibility means the two phases are distinguishable and they can flow as a single phase without any interfacial or relative permeability effects. Miscibility between crude oil and CO_2 occur through multiple contacts in the form of vaporizing drive i.e., the intermediate components of crude oil get vaporized into the CO_2 phase. Minimum miscibility pressure (MMP) is the important parameter that governs the efficiency of miscible EOR process. It is defined as the minimum pressure in which the both the injection fluid and crude oil become miscible and any further increase in the pressure will not lead to significant addition in oil recovery.

Miscibility between CO_2 and oil is dependent on reservoir pressure, reservoir temperature, and crude composition etc. For an isothermal reservoir, the only concern is the reservoir pressure [22]. As pressure increases, more CO_2 can be solubilized. The larger the depth, the larger the pressure. Therefore, deeper reservoirs are typical candidate for miscible flooding in general. As per the EOR screening criteria [23], the depth should be greater than 2500 ft for CO_2 to be miscible with crude oil possessing the gravity greater than 40 API °. For 22 API ° oil, the depth should be greater than 4000 ft. CO_2 flooding conducted in miscible mode contributes to higher recovery than the immiscible CO_2 flood. This is because, when the displacing and displaced slugs are miscible, the IFT should be zero theoretically and capillary number should be infinite (Eq. 6). Although, 100% microscopic displacement efficiency though expected theoretically could not be achieved, a very high recovery percent could be expected in the miscible mode. Several low depth reservoirs are the ideal candidates for achieving the MMP associated with CO_2 flooding due to pressure constraints. Efforts were made to reduce the IFT between CO_2 and oil by adding the surfactants to CO_2. In this section, the role of surfactant in reducing the MMP requirement during CO_2 flooding is discussed.

4.1 Role of IFT in MMP Reduction and Oil Recovery

One of way enabling the miscibility is by imposing a pressure so the components between the immiscible fluids get exchanged. Another way is to lower the IFT between two immiscible fluids so that molecules between them come closer. A complete removal of interface means two fluids could become miscible. Surfactants are active interfacial agents and their addition to CO_2 can reduce the IFT between CO_2 and oil after a threshold pressure (Fig. 14).

In general, an increase in pressure leads to the decrease in IFT between the systems. However, there should be a threshold pressure beyond which the interfacial activity of surfactant begins to get active because of enhanced solubility. Generally, the higher

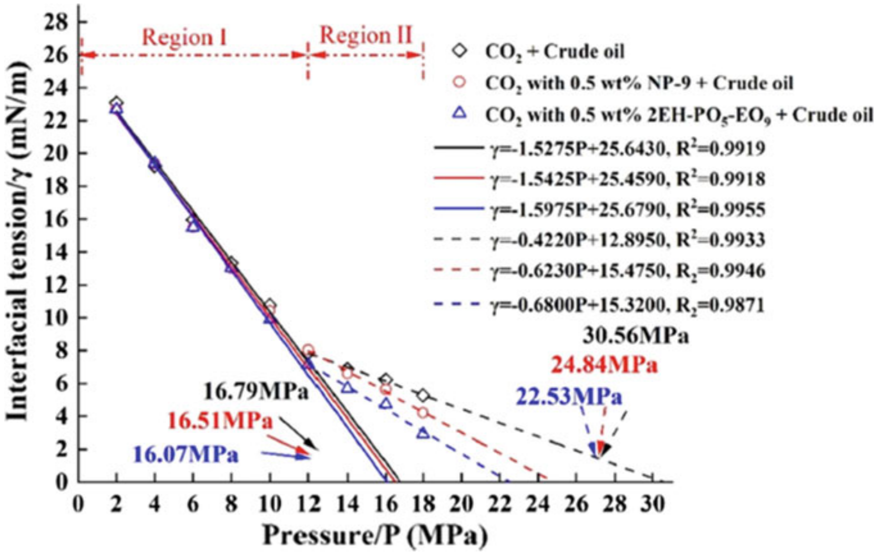


Fig. 14 Effect of pressure on the IFT between crude oil and CO_2 in the absence and presence of CO_2 soluble surfactants (From [24]). NP-9 and 2 EH-PO5-EO9 in Fig. 14 refers to non-ionic and anionic surfactants

the pressure, the higher the solubility. At lower pressures, the surfactants addition doesn't change the MMP of CO_2. MMP of CO_2-crude oil, CO_2 with non-ionic surfactant- crude oil, CO_2 with anionic surfactant-crude oil are 16.79 MPa, 16.51 MPa and 16.07 MPa respectively. Therefore, at lower pressure one cannot expect to have an added benefit of surfactant' interfacial activity during CO_2 flooding because of their limited solubility. At higher pressure greater than 12 MPa, the surfactant begins to show an enhanced interfacial activity. Miscibility between crude oil and CO_2 occurs at the highest pressure of 30 MPA. Miscibility between crude oil and CO_2 can be reduced in the presence of surfactant because of the additional interfacial activity. In the presence of non-ionic surfactant, miscibility between crude oil and CO_2 can occur at 24.84 MPa. In the presence of anionic surfactant, miscibility between crude oil and CO_2 got reduced to 22.53 MPa. Please note that the experiments were carried out by Zhang et al. [24] by dissolving the powdered surfactant in CO_2 without brine. When interacted with formation brine, the foam may be formed which would be of benefit to have a conformance control and thereby an enhanced sweep and overall recovery efficiency. However, the role of IFT on foam-based conformance control during CO_2 flooding is not discussed in this chapter.

The oil soluble surfactant that could reduce the MMP of CO_2 (from 27.3 to 21.2 MPa) could increase the oil recovery factor marginally (Fig. 15). These experiments were performed by Guo et al. [25] using slim tube.

Although, the recovery factor improvement due to surfactant addition is not very significant, the reduction in MMP due to surfactant addition may draw attention

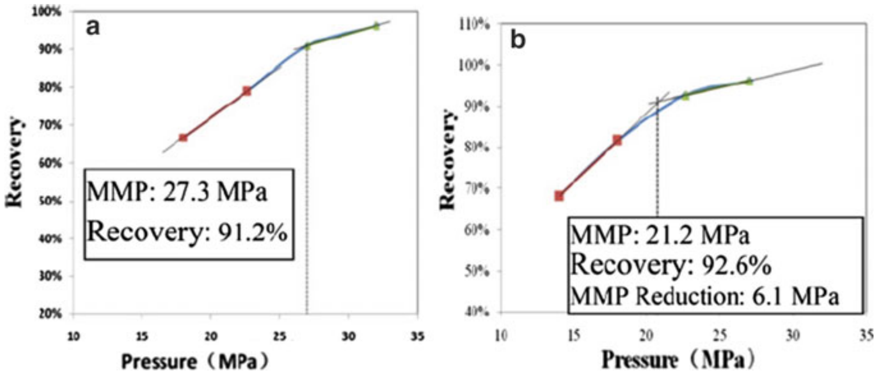


Fig. 15 **a** MMP and the associated recovery of pure CO_2 displacement **b** MMP of oil soluble surfactant pre-slug CO_2 displacement (From [25])

among the EOR community. Slim-tube experiments is a good representative of microscopic efficiencies without macroscopic effects such as gravity override. In miscible conditions, theoretically, IFT is zero, capillary number should be infinite (Eqs 6 and 7) and up to 97% recovery could be expected during MCM process [26].

Oil soluble surfactants may hinder the contact between CO_2 and oil; therefore, miscibility of the process may not be efficient or intact (Fig. 16a).

CO_2 soluble surfactants could be a better option [24] because they can facilitate direct miscible contact between the oil and CO_2 without any hinderance (Fig. 16b). Also, in heterogenous formation, the usage of CO_2 soluble surfactants means the underride problem associated with oil soluble surfactants could be eliminated and IFT

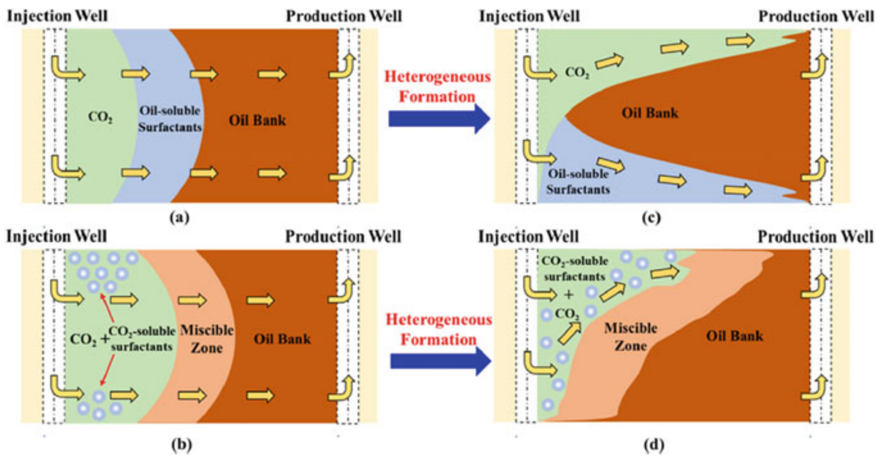


Fig. 16 Schematic depicting the possible advantage of CO_2- soluble surfactant (b and d) over oil-soluble surfactants (a and c) during CO_2 EOR (From [24])

free regimes can be facilitated in CO_2 contacted area (Fig. 16c and d). More works need to be done in this area before the possible consideration of MMP reduction through low IFT surfactants.

5 Foam Flooding Applications

A relatively large volume of gas dispersed in the small volume of liquid is called foam [1]. Generally, such dispersions are quite unstable and tends to break. Stability of foam could be improved by adding surfactants to the liquid [7]. The resistance generated during foam flow is much higher than the resistance generated during the flow of surfactant or gas. The general requirement from mobility control fluids is that they should possess more resistance to flow so that areal, vertical and linear sweep could be improved. While polymer solutions are the widely used mobility control agent, foam are used as mobility control agent in low dense, low viscous gas based EOR methods such as steam flooding [27, 28] and CO_2 flooding [29]. Because the foam has higher apparent viscosity in high permeable media, when compared to low permeable media [30], diversion of the injection fluid from high permeable streaks/fractures to low permeable matrix would be aided by foaming solution. Naturally fractured reservoirs characterized by fracture and matrix are one of the candidate reservoirs for foam-based mobility control applications [31–33]. It is the foam stability that is vital for having a higher apparent viscosity and therefore a favorable mobility ratio (Eqs. and 11). In Sect. 5.1, I shall discuss how the ultra-low IFT and foam stability are related? In Sect. 5.2, the role of IFT on oil recovery during foam-based application in NFR cores such as dolomite and limestone are discussed. The role of IFT on oil recove10ry during alkali steam foam flooding is discussed in Sect. 6.1.

5.1 *Ultra-Low IFT and Foam Stability—A Dilemma*

Ultra-low IFT is important for microscopic displacement efficiency and foam stability is important for mobility and conformance control. For a conventional surfactant system, both cannot be attained simultaneously because of the dependence of surfactant system on salinity. To understand this, Yanatatsaneejit et al. [34]'s work is considered. The authors studied the IFT (Fig. 17) and foam stability (Fig. 18) of an anionic surfactant (Alfoterra 145-4PO) with respect to NaCl concentration.

To have ultra-low IFT for a surfactant solution, optimal salinity of 5% NaCl is needed (Fig. 17). It is because solubilization ratio of oil-surfactant and water-surfactant become equal at the optimal salinity which results in the formation of middle-phase microemulsion with excess water and oil as a separate phase. Since both oil and water can be solubilized equally by the surface-active agents at optimal salinity, an ultra-low IFT can be expected at optimal salinity. For more information

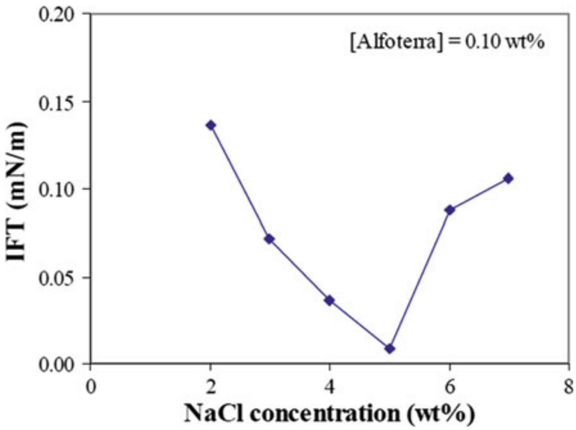


Fig. 17 Effect of NaCl concentration on IFT (From [34])

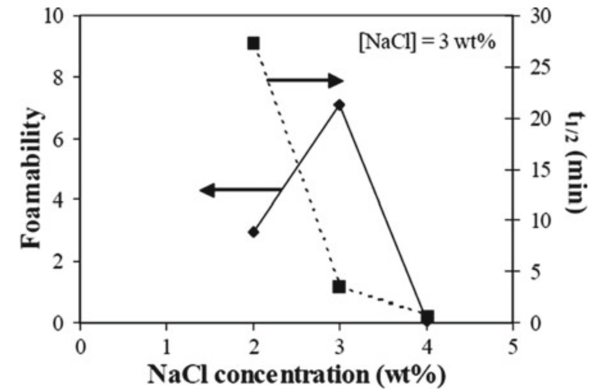


Fig. 18 Effect of NaCl concentration on foamability and foam stability [34]

about the effect of various parameters on IFT and phase behavior, the readers are referred to Green and Willhite [1].

However, for having the better foam stability, the low salinity of 2% NaCl is preferred (Fig. 18). At 2% NaCl, the coalescence time (represented by $t_{1/2}$ in Fig. 18) is higher, which means more time would be needed form an unstable larger foam bubble. Contrarily at high salinity, coalescence time decreases because the negative charge in anionic surfactant gets neutralized by the more amount of positive Na+ ions. Therefore, the repulsive forces between the surfactant head group reduces drastically which cause causes the bubbles to get coalesced to a larger bubble of dry foam in a relatively quicker time. Larger bubble size foam generally tends to be unstable [7]. Therefore, if one wants to have an ultra-low IFT, an optimal salinity that causes the foam instability would be needed.

5.2 IFT Role During Foam Flooding in Naturally Fractured Carbonates

Surfactant formulations for foam-based mobility/conformance control applications were chosen based on foam stability. Attention were not given for optimizing the IFT reduction during foam EOR process and therefore high IFT foam has been used in the past for EOR applications [35, 36]. Because of high IFT, flooding lacks Sor reduction potential which leaves lot of residual oil especially in the matrix. Recent researches have emphasized the formulation of surfactant blends that could achieve both ultra-low IFT and good foam stability [31–33]. The recovery performance of high and low IFT foam in fractured dolomite and limestone are compared from the works of Dong et al. [31] and [33].

5.2.1 High IFT Versus Low IFT Foam Performance in Fractured Dolomite Core

A special low IFT foam is prepared using a zwitterionic surfactant (lauryl betaine-LB), an anionic surfactant called internal olefin sulfonate (IOS), and another anionic surfactant called ethoxylated carboxylate (L38). The salinity of the surfactant solution is 32,690 ppm. LB and IOS produced Winsor-3 regime with n-octane and Winsor-1 regime with simulated live oil made by combining the crude and n-octane. Even though, Winsor-1 regime was achieved with live oil, oil solubilization ratio of 6 leads to the much lower IFT of 0.017 mN/m. The positive charge in the zwitterionic surfactant and negative charge in the anionic surfactant induces a strong synergetic interaction which leads to low IFT even at Winsor-1 regime. However, LB/IOS combination precipitated. L38 increased the aqueous stability without affecting the low IFT potential of LB/IOS system at reservoir temperature. The mixture posses good foamability and foam stability. Alpha olefin sulfonate (AOS) with the chain length of 14 to 16 carbons was used as high IFT foaming surfactant. 1.1 wt% of LB/LOS/L38) and 1% AOS are chosen for comparing the recovery performance of low and high IFT foam. Oil viscosity was 0.9 cP. For more details, please refer to Dong et al. [31].

The incremental recovery performance of 1.1 wt% LB/LOS/L38 (low IFT foam) and 1% AOS (high IFT foam) is compared by injecting the pre-generated foam and nitrogen at 4 ft/day into the water flooded oil-wet fractured dolomite core (Fig. 19). Permeability in the matrix and fracture are 140–149 mD and 120,300 to 158,400 mD respectively. 1.1 wt% LB/LOS/L38 and 1.1% AOS corresponds to the IFT value of 0.017 mN/m and 0.491 mN/m respectively (please note that 0.017 mN/m can also be called as ultra-low IFT. However, for the sake of consistency with Dong et al. [31], it is being called low IFT) Half-time of these bulk foams are 42 min and 16 min indicating low IFT foam possess good foam stability as-well.

Since diverting the fluid from fracture to matrix is important initially, both the foam performed similarly during early stage ~2.5 PV injection at the high flux rate

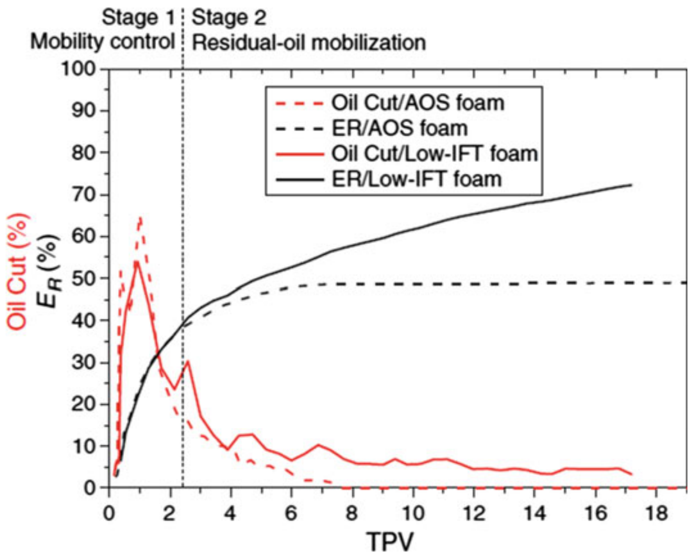


Fig. 19 Recovery performance of low IFT and high IFT foam in oil-wet fractured dolomite [31]

of 4 ft/day. Initially, oil saturation in the matrix should be higher than water flooded Sor and therefore, most of the mobile oil in the matrix gets recovered by the foaming solutions regardless of their IFT reduction potential. In the later stage after 2.5 PV injection, high IFT foam fails to recover the additional residual oil trapped by the capillarity. Despite injecting many PV, a plateau in the recovery profile is seen signifying that the well-swept oil cannot be mobilized at high IFT conditions. Low IFT foam which can contribute to IFT reduction of more than one-order effectively mobilizes well-swept, capillary-trapped residual oil from the matrix. Another advantage with low IFT foam is that lower forced entry pressure is needed for low IFT solutions when compared to gas or high IFT solutions. This could let the low IFT solutions to effectively mobilize more oil from the matrix. More than 20% higher Sor reduction was achieved during low IFT foam injection when compared to high IFT foam. Therefore, it can be said, the microscopic displacement efficiency which is the main constituent of overall recovery factor (Eq. 1) increased in the case of low-IFT foam injecting in fractured reservoirs. Another important point to note is that higher Sor reduction with low IFT foam ensures that oil destabilizing effect on foam is lesser. This was reflected in the reported apparent viscosity of 84 cP and 15 cP during low and high IFT foam injection respectively. Therefore, it can be said that foam stability got improved due to low IFT in dolomite rocks and therefore a potential of good sweep with low IFT foam is also a possibility.

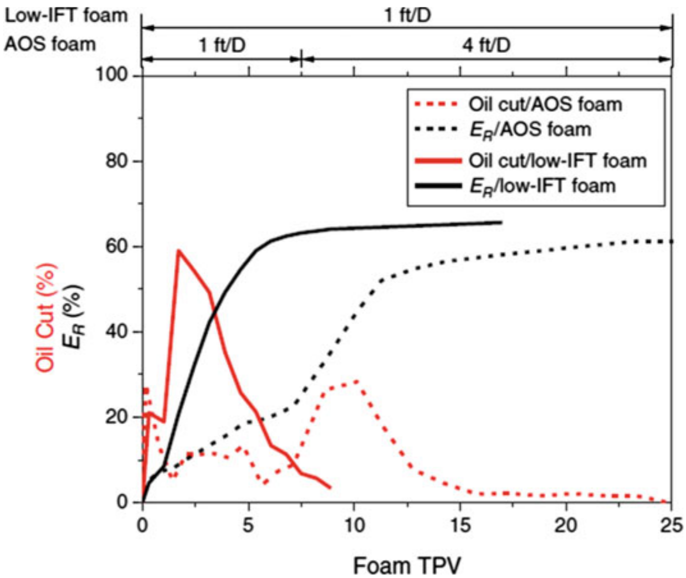


Fig. 20 Recovery performance of low IFT and high IFT foam in oil-wet fractured limestone [33]

5.2.2 Low IFT Foam Performance in Limestone Rocks

In this sub-section, the recovery potential of low IFT foam and AOS foam in the fractured limestone core is compared. Matrix and fracture permeabilities of cores used in the experiments are 5.6–6.4 mD and 85,000–75,322 mD respectively. The concentration, salinity and the IFT values of formulation used in these experiments were same as the one used in the dolomite rocks. The used oil is also the same in both the set of experiments. The recovery performance of low-IFT and high-IFT foam is shown in Fig. 20.

Overall recovery factor is similar during both low (63.8%) and high IFT flooding (61.1%). However, to achieve an incremental oil recovery of 50%, low IFT foam requires 5 PV whereas high IFT foam requires 11 PV of injection. Further, high IFT foam if injected at 1 ft/day can contribute to incremental recovery factor of just 20% after 5 PV. However higher injection rate of 4 ft/day provided the additional viscous force therefore, recovered further oil (Eq. 6). In the early stage mobility control is more important, and therefore it can be said that low IFT foam can effectively contribute to mobility control at low flux of 1ft/day whereas the high IFT foam requires higher flux rate. In the presence of oil, low IFT foam possess more stability than high IFT foam [31]. The main reason is because low IFT ensures additional oil mobilization which means the effect of oil on destabilizing the foam is less.

Comparing the performance of low IFT foam in dolomite and limestone (Figs. 19 and 20), we can see in dolomite, low IFT foam give more than 70% recovery whereas in limestone only around 60% recovery is achieved. Moreover, a plateau in the recovery is seen in limestone formation but not for dolomite formation. This suggests that relative permeability of the oil is getting very low in limestone—a indication of trapping (Fig. 21).

A darker spot in the end of core for low IFT foam indicates that (1) Sor in the matrix is getting mobilized during low IFT foam when compared to high IFT foam (2) Mobilized oil due to low IFT foam injection is getting trapped at the end. Therefore, incremental curve become flattened in the case of low IFT foam. But what causes the trapping in limestone? Why low IFT conditions is detrimental in limestone? Limestone is unstable geochemically and can leads to dissolutions and ion exchange (Fig. 22).

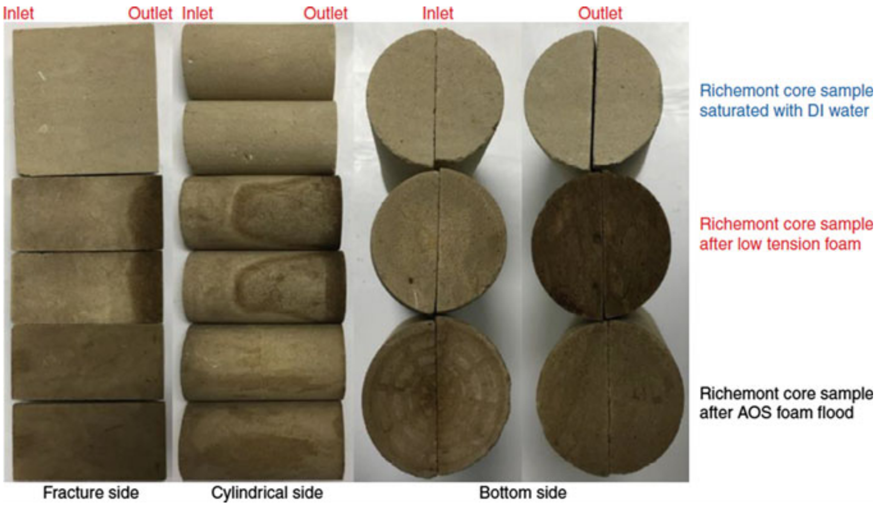
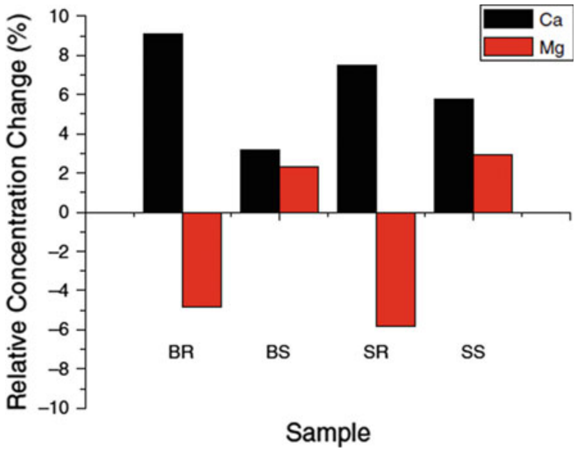


Fig. 21 Cores used during low and high IFT foam flooding [33]

Fig. 22 Changes in concentration of brine and surfactant solutions after contacting with limestone and dolomite rock samples. BR—Brine with Limestone; BS—Brine with Dolomite; SR—Surfactant with Limestone; SS—Surfactant with Dolomite [33]



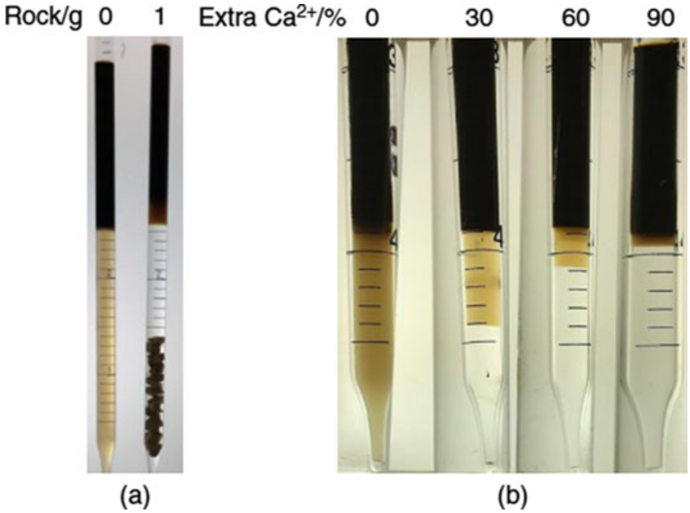


Fig. 23 Phase behavior studies showing the detrimental effect of limestone on low IFT formulations [33]

The concentrations of both the calcium and magnesium ions changes significantly in both the brine and surfactant solutions upon contacting with the limestone rocks when compared to the dolomite rocks (Fig. 22). In limestone rocks, more ions are transferred to surfactant solutions making the system to be over-optimum which in turn leads to a very high viscous micro-emulsion (Winsor 2) that get trapped. A phase behavior study clearly indicates adding limestone (Fig. 23a) and calcium (Fig. 23b) ions will convert lower phase microemulsion into upper phase microemulsion.

Please note in lower-phase micro-emulsion some oil is solubilized and were yellow in color and it is because of this oil solubilization, low IFT was achievable. But the transferring of divalent ions from limestone makes the created low IFT conditions to become highly viscous and therefore, futile. This is the reason why incremental recovery curve during low IFT foam injection is flattening in the case of limestone whereas for dolomite, a steady increase in seen.

This analysis indicates that low IFT foam formulated using surfactants carrying different charge could be expensive but a good option for NFR reservoirs. However, caution need to be exercised when using low IFT foam for EOR applications in different carbonate reservoirs because of their mineralogy etc. Geochemically unstable limestone rocks can make the low IFT injection system to become over optimal which can affect the linear sweep. Both oil mobilization and linear displacement are important, and this issue may be aggravated at the field scale and therefore a case by case investigation about the potential of low IFT foam for various carbonate reservoir is warranted.

6 Steam Flooding

Steam flooding is one of most successful EOR method. During steam flooding, the high temperature steam is injected into heavy oil reservoir. The heat reduces the viscosity of heavy oil thereby enabling its mobility. Steam channelling is one of the main issues that affects the sweep efficiency during the steam flood. Steam channeling occurs around the high permeable streaks. Only oil in high permeable zone would be swept by the steam leaving lots of bypassed oil in the lower permeable region. Generally, steam flooding is not susceptible to fingering as one would think because of its healing nature. For more information about the steam stability, the reader can refer to Green and Willhite [1]. However, the low viscous nature of steam will make the channels or high permeable streaks a short circuit.

Gravity override also affects the sweep efficiency during steam flood. Steam is low dense fluid and gravitational forces causes the steam to override on the top of the reservoir. Oil gets swept by the steam selectively only in the top portion of the reservoir reducing the overall sweep efficiency. The oil remaining in the lower part of the reservoir remain unswept (Fig. 24).

Gravity override will be more severe when the reservoir has non-zero vertical permeability, or not having enough horizontal permeability/ high dip angle [37]. It is important that mobility of steam needs to be reduced to order to increase the sweep efficiency.

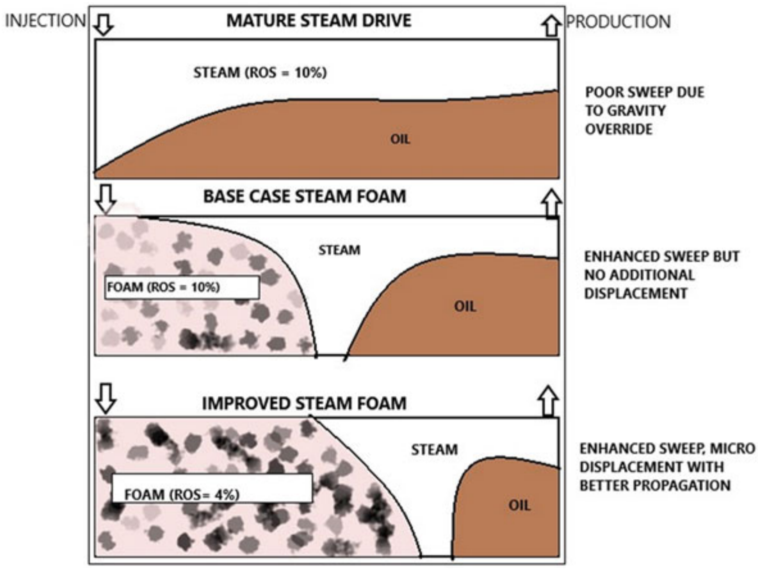


Fig. 24 Schematic showing advantage of using improved steam foam for an enhanced oil recovery (From [28])

6.1 Steam Foam Flooding

Foam generated by the injection of surfactant and steam has gained attention for improving the sweep efficiency. Steam foam used for plugging the high permeable strata and addressing the gravity override was patented by Needham [38] and Dilgren et al. [39]. Since then several researches were done in that area. The prime expectation from foam-steam is to have an enhanced sweep efficiency. Shell company conducted two steam-foam pilots in Kern river field [40]. Foam was generated by continuous injection of 50% quality steam containing 0.5% of Alpha olefin sulfonate (AOS) 1618 and 4 wt% NaCl in the aqueous phase and 0.06 mol% of N_2 in vapor phase. Injected foam generated the apparent viscosity by a factor of 20 to 60 near the injectors and allowed the steam to contact oil in the lower portion of the reservoir thereby improving the vertical sweep efficiency of the project. However, Sor to steam foam is around 10% (Fig. 25) which is similar to Sor values reported during steam flood in Kern river [28, 41] (Fig. 24).

This implies that microscopic displacement efficiency could not be improved with AOS foam during steam flood. To have a high recovery factor, both microscopic displacement and macroscopic sweep are important (Eq. 1). Overall, recovery efficiency during steam flood could be improved if Sor could be reduced in the steam-foam contacted area (Fig. 25).

6.2 IFT Role on Sor Reduction During Alkaline Steam Foam Flooding

Lau and Borchardt [28] undertook an interesting work for Shell company after realizing the performance (microscopic recovery performance in particular) of steam-foam formulation based on alpha olefin sulfonate (AOS) could be improved. Superior formulation consisting of alkaline enhanced steam foam reduce the Sor to very low or even zero whereas for steam foam without alkali, Sor was around 10% [28, 41,

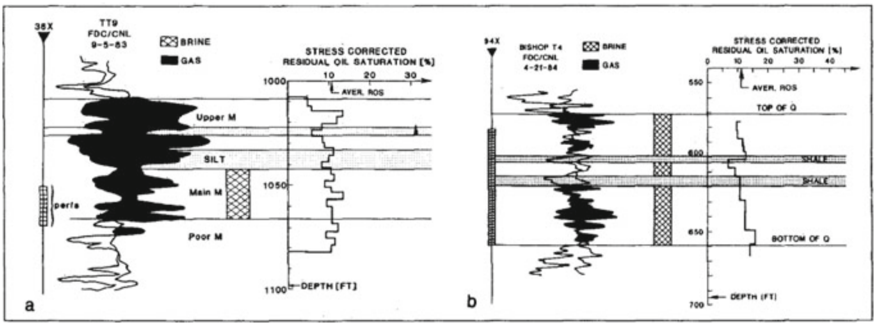


Fig. 25 Average Sor during steam foam flood in Kern river (From [40])

a) b)

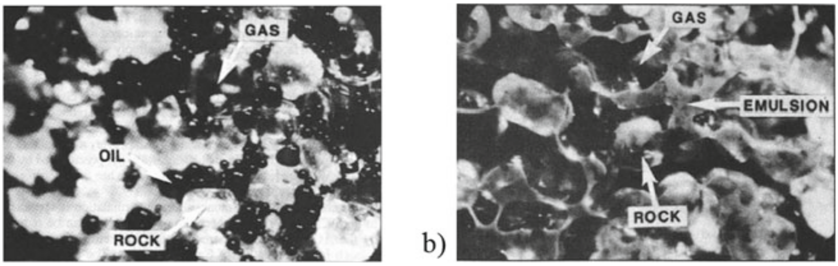


Fig. 26 **a** Larger oil droplets getting trapped in nitrogen-foam. **b** Smaller oil droplets getting mobilized in alkali nitrogen foam [28]. Please note Lau and Borchardt [28] observed the similar behavior when steam was the vapor phase

42]. Alkali generated the in-situ surfactants that lead to low IFT conditions. However, the IFT value is 0.1 mN/m which is not ultra-low. As per (Eq. 6), to have the higher capillary number (and therefore to have low Sor), IFT should be very low. Therefore, to have a higher microscopic displacement, ultra-low IFT conditions are not needed in the case of alkali steam foam flooding. Flowing vapor phase enhances emulsification of the oil beyond that could be achievable by surfactant and alkali alone. It was observed that in the absence of alkali, crude oil remained as the large oil droplets which is too big to propagate through the pore throat (Fig. 26a). Therefore, Sor was higher in the conventional steam-based foam flooding. In the presence of alkali, oil become emulsified into oil-in-water emulsion which shrink its size low enough (Fig. 26b) so that it could propagate through the pore-throat with out getting trapped. As more oil is getting emulsified in to in-situ generated surfactant solutions, there will be a reduction in IFT to some level. Therefore, low IFT conditions might have been needed. However, unless the oil is getting trapped, ultra-low IFT needed to reduce the capillary pressure (Eq. 3) in order to increase the capillary number (Eq. 6) and Sor reduction (Fig. 2) is not needed.

The emphasis that ultra-low IFT is not a requirement for higher microscopic efficiency during alkaline steam foam process can also be understood by looking into the activity maps drawn between Sor and surfactant and alkali concentration (Fig. 27). The region of ultra-low IFT band for kern river is also shown in Fig. 27. Lots of alkaline steam foam experiments corresponds to low Sor of 3 to 4% at the wide range of alkaline and surfactant concentrations which doesn't correspond to ultra-low IFT regimes.

7 Conclusions

Surfactant system has been used for many upstream applications in oil industry such as drilling, stimulation and EOR. For optimal EOR applications, the conventional belief is that a potential surfactant should have capability to reduce IFT between

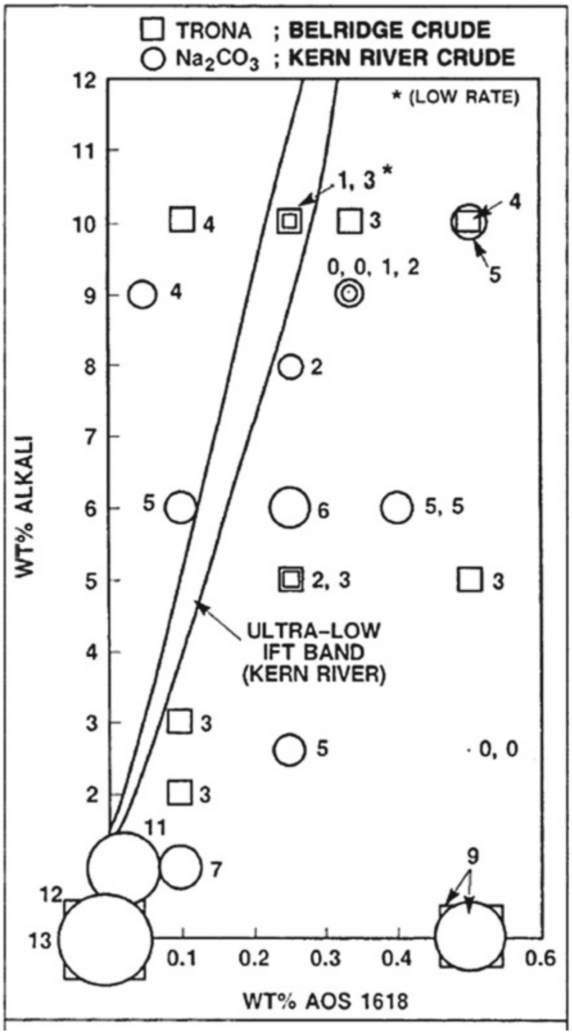


Fig. 27 Sor to alkali steam foam. Area of circle and square proportionate to the Sor [28]

the displacing solutions and displaced oil to an ultra-low level (in the order of 10^{-3} mN/m). Although this is generally true for the forced surfactant injection, the effect of rock-wettability and oil-viscosity needs to be considered to see if there could be a need or precedence for additional recovery mechanism such as mobility control, wettability alteration etc. The effect of rock permeability should also be considered to see if one cannot impose a forced displacement but must rely on capillary driven spontaneous mechanisms such as counter-current, or co-current. An optimal level of IFT which should not be ultra-low should be framed accordingly. CO_2 soluble surfactant appears to reduce the IFT and MMP requirement for a miscible CO_2 flooding. However, more researches are warranted in this area to see if a possible modification to EOR technical screening criteria can be made. Ultra-low IFT foam generated using surfactant blend could be beneficial for both sweep and Sor reductions in naturally fractured carbonates if the ion-exchange, the rock dissolution and other geo-chemical instabilities of the rocks will not induce over-optimal conditions to the displacing systems. In this regard, dolomite rocks are the more preferred candidate than geo-chemically unstable limestone rocks for the ultra-low IFT foam flooding. During steam-based foam flooding at alkaline conditions, having an ultra-low IFT is not a requirement if the in-situ surfactant generation and the subsequent emulsification will ensure that there will be no significant trapping of oil at the pores.

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