Foam Flow in Heterogeneous Porous Media: Effect of Crossflow


Abstract
Previous studies of foam generation and transport were conducted, mainly, in one-dimensional and homogeneous porous media. However, the field situation is primarily heterogeneous and multidimensional. To begin to bridge this gap, we have studied foam formation and propagation in an annularly heterogeneous porous medium. The experimental system was constructed by centering a 5.0 cm diameter cylindrical Fontainebleau sandstone core inside an 8.9 cm acrylic tube and packing clean Ottawa sand in the annular region. The sandstone permeability is roughly 0.1 d while the unconsolidated sand permeability is about 7 d. Experiments with and without crossflow between the two porous media were conducted. To prevent crossflow, the cylindrical face of the sandstone was encased in a heat-shrink Teflon sleeve and the annular region packed with sand as before. Nitrogen is the gas phase and an alpha olefin sulfonate (AOS 1416) in brine is the foamer. The aqueous phase saturation distribution is garnered using X-ray computed tomography.

Results from this study are striking. When the heterogeneous layers are in capillary communication and cross flow is allowed, foam fronts move at identical rates in each porous medium as quantified by the CT-scan images. Desaturation by foam is efficient and typically complete in about 1 PV of gas injection. When cross flow is prohibited, foam partially plugs the high permeability sand and diverts flow into the low permeability sandstone. The foam front moves through the low permeability region faster than in the high permeability region.

Introduction
Foam is applied broadly as a mobility-control and profile modification agent for flow in porous media. Foams are usually formed by nonwetting gases such as steam, carbon dioxide (CO₂), or nitrogen (N₂) dispersed within a continuous surfactant-laden liquid phase. Typical applications include aqueous foams for improving steam-drive and CO₂-flood performance, gelled-foams for plugging high permeability channels, foams for prevention or delay of gas or water coning, and surfactant-alternating-gas processes for clean up of ground-water aquifers. All of these methods have been tested in both the laboratory and the field.

An unfoamed gas displays low viscosity relative to water or crude oil and is thereby very mobile in porous media. However, dispersing the gas phase within a surfactant solution where the surfactant stabilizes the gas/liquid interface can substantially reduce gas mobility in porous media. Mobility is reduced because pore-spanning liquid films (foam lamellae) and lenses block some of the flow channels. Additionally, flowing lamellae encounter significant drag because of the presence of pore walls and constrictions. One aspect of foams that makes them attractive is that a relatively small amount of surfactant chemical can affect the flow properties of a very large volume of gas. The volume fraction of gas in a foam frequently exceeds 80 percent and stable foams up to 99 percent volume fraction are not uncommon. Recent reviews of foam flow phenomena and mechanisms are given in refs. 9-11.

Laboratory studies on foam generation and transport have aided greatly in formulating and improving both our microscopic and macroscopic understanding of foam flow in porous media. They have focused, for the most part, on one-dimensional and homogeneous porous media. These studies, however, leave gaps in our knowledge of foam behavior because the field situation is primarily heterogeneous and multidimensional.

While much work has been conducted in homogeneous systems, the literature on flow in stratified systems is sparse. Notable experiments in stratified systems include Casteel and Djabbarah who performed steam and CO₂ displacements with foaming agents in two parallel porous media. Robin studied foam generation and transport in layered beadpacks that simulated reservoir strata. In these experiments he surmised that foam blocked the high permeability layer. Llave et al observed that foam can divert gas flow from high permeability layers to low permeability layers when the layers are isolated. More recently, Hirasaki et al performed foam displacements in layered porous media to study the removal of organic liquids from groundwater aquifers. Gas was injected at a fixed pressure gradient rather than a specified rate. They dyes the various fluids, they observed displacement patterns directly. They found that injection of gas slugs into a porous...
medium containing surfactant resulted in foam generation and selective mobility reduction in the high permeability layers. In turn, recovery of the organic liquid was greatly enhanced.

For the most part, the effect of flow among parallel layers in capillary communication has not been investigated. We denote this as cross flow. To bridge this gap, we perform foam flow experiments in an axially symmetric, cylindrical, heterogeneous porous medium. The central portion of the porous medium is a Fontainebleau sandstone core and a uniform sand is packed in the annular region between the core and the pressure vessel wall to complete the porous medium. By the use or absence of a heat-shrink Teflon jacket around the sandstone, fluid communication, or cross-flow, is prohibited or allowed. The sandstone is about two orders of magnitude less permeable than the sand to provide a strong permeability and capillary pressure contrast. We interpret the experiments in terms of the evolution of in-situ water saturation as a function of time.

In the following sections we first discuss the construction and characterization of the porous medium, characterization of our foamer solution, and then experimental determination of water saturation via X-ray CT scanning. CT provides accurate resolution of the progress of displacement fronts as well as the in-situ displacement efficiency. Next, we outline the experimental program and give results. A discussion and conclusions complete the paper.

**Experimental Apparatus and Procedures**

The centerpiece of the experimental program is a heterogeneous porous medium. It is constructed by centering a 0.050 m diameter and 0.368 m long Fontainebleau sandstone core inside a long, cylindrical, acrylic core holder. The inner diameter of the acrylic tube is 0.089 m and total length is 0.65 m. The annular space between the sandstone and the coreholder wall is packed with Ottawa sand. Similarly, the remaining 0.282 m of coreholder is packed with sand. Hence, the tube contains a heterogeneous portion consisting of sandstone and sand, and a homogeneous portion filled with sand. For experiments where we seek to prevent exchange of fluid between the sandstone and the sand, a heat-shrink Teflon tube is fit around the sandstone. In this case, only the circular faces at the beginning and end of the Fontainebleau core are left open to flow. When cross-flow is not prevented, we make no special preparation of the sandstone core.

Figure 1 is a reconstructed image of the porosity field measured using the CT scanner. Further details on the scanner and imaging methods will be given later, but the sandstone and sand portions of the porous medium are labeled and apparent in Fig. 1. Average porosity values obtained with CT along both the sand and sandstone portions of the core are displayed in Fig. 2. Each component of the heterogeneous porous medium is relatively homogeneous with an average sandstone porosity of 0.14 and an average sand porosity of 0.32. The Ottawa sand permeability was measured at 6.7 μm² and the Fontainebleau sandstone permeability is 0.1 μm². Both values are permeability to brine. The contrast in permeability between the sand and sandstone is 67 to 1.

The coreholder is designed so that fluids can be injected from either end. Machined endcaps distribute injected fluids across the cross-sectional area of the coreholder. When gas is injected into the sand-filled region, foam can generate before reaching the heterogeneous zone. On the other hand, when gas is injected directly into the heterogeneous end, foam generation in an initially liquid-filled heterogeneous porous medium can be observed. Unfortunately, coreholder design precluded the installation of pressure taps to measure the in-situ pressure profile.

Nitrogen (N₂) is injected into the porous medium saturated with foamer solution at a rate of 3 SCCM (standard cubic centimeters per minute) using a Matheson (Montgomeryville, PA) Model 8141 0-10 SCCM mass flow controller. Nominally, the superficial gas velocity is 0.67 m/day (8.04E-6 m/s) relative to the outlet pressure of 101325 PA. Foamer solution was not injected simultaneously with the gas because such experiments in one-dimensional, homogeneous sandstones can lead to pressure drops on the order of 2000 kPa/m (100 psi/ft) (c.f. 10), and we did not wish to over-pressureize the experimental system. Previous one-dimensional experiments using gas only injection and a similar surfactant and sand resulted in moderate pressure drops17.

Through the combination of communicating and noncommunicating heterogeneities and injection into homogeneous or heterogeneous portions of the core, 4 different experiments are possible:

1. Injection across the heterogeneous side, noncommunicating sand and sandstone
2. Injection across the heterogeneous side, communicating sand and sandstone
3. Injection across the homogenous sand, noncommunicating sand and sandstone
4. Injection across the homogenous sand, communicating sand and sandstone

Figure 3 shows schematically each of these cases and indicates where gas is injected. A dark, solid line indicates the heat-shrink jacket if present.

The surfactant is an alpha olefin sulfonate (AOS C14-C16) supplied by Shell Chemical (Houston, TX). A concentration of 0.1% by weight active surfactant in a 0.5 wt% NaCl brine was chosen as the optimal foamer solution. The screening procedure was two pronged. First, the pressure drop across a small (0.01 m diameter and 0.25 m long) chromatography column packed with the Ottawa sand was measured for increasing surfactant concentrations for a variety of brines. Nitrogen was injected at a rate of 10 SCCM while the surfactant solution injection rate was 0.34 cm³/min. A backpressure of 696 kPa (100 psi) was maintained at the sandpack outlet. Next, the interfacial tension between air and surfactant solution was measured for increasing concentration of surfactant using the pendant drop method. A broad range of surfactant concentrations was used in order to identify the critical micelle concentration (CMC). Figure 4 presents both the pressure drop and surface tension data collected. For the 0.5 wt% brine, strong foaming action, as witnessed by pressure drop, is found once the CMC is exceeded. Further, no benefit is found when surfactant concentration is increased above 0.1 wt% in either the pressure-drop or surface-tension data. Hence, this 0.1 wt% surfactant concentration was chosen.
An experiment begins by flushing the porous medium with gas (CO₂ or N₂) until it is free of liquid. A dry scan is made. If needed, the core is refilled with CO₂ and saturated with brine to 100% water saturation, because the CO₂ is soluble in the brine. At the minimum, 10 pore volumes of surfactant solution are injected to saturate the solid and aqueous phases with surfactant. A wet scan of the porous medium is then obtained. Once the porosity field has been determined, CT is used to confirm that 100% liquid saturation is obtained. If it has not, more foamer solution is injected to dissolve the CO₂. Once an S_w of 100% is obtained, N₂ is injected at a constant rate. The progress of foam generation is seen directly in the CT data collected. Gas is injected until foam breakthrough at the outlet occurs and is continued for an additional 0.5 to 1 PV.

Porosity and aqueous-phase saturation fields are measured on 18 volume sections equally distributed along the core using a fourth generation (1200 fixed detectors) Picker® 1200 SX X-ray scanner. Typically, the voxel dimension is (0.25mm by 0.25mm by 4mm). The acquisition time of one image is 7 seconds while the processing time is around 40 seconds. The total time of measurement is short enough to capture accurately the position of the front and construct saturation profiles along the core. Porosity and saturation measurements require so-called "dry" and "wet" scans to obtain CT numbers for the medium free of liquid and then fully saturated with liquid. Porosity is computed by a ratio between the dry and wet counting (CT numbers) from the known air attenuation. Saturation is determined in the same way after garnering CT numbers during the displacement. The measurement accuracy depends on the different parameters chosen for the X-ray emitter such as voltage and intensity, filters, and reproducibility of the positioning system moving the coreholder apparatus into and out of the gantry. A theoretical computation of the measurement accuracy, assuming no error in the positioning system, provides an error of 6% 18.

Results
To provide a baseline, gas was injected at 3 SCCM into surfactant-free cores. Figure 5 illustrates gas flow in the absence of foam when heterogeneities communicate. Saturation values are obtained by averaging the saturation for each voxel in a cross section for the sandstone and sand regions, respectively. Time is reported nondimensionally in pore volumes of injected gas and distance is measured from the inlet. Figure 5a shows the saturation profiles for the sandstone, while Fig. 5b the profiles for the sand. Straight lines connect the individual data points. Gas displacement of water is poor. Strong displacement fronts are not witnessed and even after 4 PV of gas injection, water saturation remains high. In this case, gas breakthrough occurs at 0.05 PV and the total production at 4.5 PV is about 0.1 PV. In the case of noncommunicating heterogeneities, gas breakthrough occurs at 0.11 PV and total water production at 3 PV is only 0.17 PV.

Next, foam displacements in all four of the configurations detailed in Fig. 3 were completed. First injection through the heterogeneous face of the core is discussed and then injection through the homogeneous face. The extent of foam generation and reduction in gas mobility is quantified through the saturation profiles determined by CT and the length of time to gas breakthrough. A breakthrough time approaching 1 PV indicates efficient desaturation of the core and by implication strong foam generation.

Noncommunicating layers, heterogeneous face injection. In this experiment, the heat-shrink wrapped Fontainebleau sandstone core cannot exchange fluid with the sand except through the inflow and outflow ends. N₂ is injected from the heterogeneous region and across both sand and sandstone. Figure 6 displays typical saturation fields across the core holder at various locations. The elapsed time is 0.23 PV of gas injection. In the figure, a shading of black represents a water saturation, S_w, of 1 while white indicates S_w equal to 0. In the last section, taken at 16 cm (x/L = 0.25) from the inlet, it is evident that gas is present in the low permeability sandstone, but has not yet reached this location in the sand. The dark shading of Fig. 6 indicates that an effective displacement is occurring.

Figure 7 presents the averaged aqueous-phase saturation profiles measured at various times. Figure 7a shows the saturation profiles for the sandstone, while Fig. 7b the profiles for the sand. The 18 data points for the sand region correspond to the number of volume sections analyzed.

The first point to note is that desaturation of both sand and sandstone by foamed gas is efficient. Saturation fronts are relatively steep and sharp in both porous media. The entire porous medium is saturated with foamer solution initially and S_w=0. Downstream of the front is everywhere 1. In the case of the sandstone, S_w=0 immediately following the passage of the foam front is about 0.3 whereas in the sand it is roughly 0.15. That is, following desaturation by foam, each layer is within a few saturation units of its irreducible saturation. Foam has effectively diverted a portion of the injected gas into the sandstone.

Secondly, the position of the saturation fronts as a function of time tells an interesting story. When t equals 0.12 PV the leading edge of the foam front in both the high and low permeability media is at a dimensionless position of 0.14. At the succeeding time of 0.23 PV the front in the sandstone is at x/L equal to 0.3, while in the sand it is slightly behind at x/L equal to 0.26. At a t of 0.35 PV, it appears that the foam front has just exited the sandstone. The leading edge of the foam front in the sand at this same time significantly lags behind at a position of 0.35. Examination of the saturation profiles at 0.46 PV confirms this trend. The saturation at x/L equal to 0.45 in the sandstone clearly shows that foam has pushed its way through the sandstone core and exited into the sand. On the other hand, the foam front pushing through the annular sand region is only positioned at x/L equal to 0.4. It is apparent that the foam front in the low permeability layer moves more quickly than in the high permeability layer. This fact is also evidenced in the raw saturation data in Fig. 6. In the discussion, we will rationalize this behavior in terms of the effect of capillary pressure on foam texture.

At times of 0.46, 0.54, and 0.70 PV the effect of the foam fronts moving at different speeds in each media can still be seen in the saturation profiles. The foamed gas exiting the sandstone results in fronts positioned in the neighborhood of x/L from roughly 0.75 to 0.85. A second trailing front is also
apparent. For instance, at 0.70 PV this trailing front is positioned at roughly 0.45. This second front results from the foamed gas and water exiting the annular region packed with sand as well as water that was not displaced in the completely sand-filled region by the first foam front. By 1.3 PV, the average aqueous-phase saturation in the sand is about 0.10 and desaturation is complete.

**Communicating layers, heterogeneous face injection.** The configuration is similar to the first case, except that the heat-shrink Teflon is absent from the sandstone. The sandstone and the sand are thereby in capillary communication and free to exchange fluid along the length of the sandstone.

Figure 8 presents the results of the displacement in a fashion similar to that in Fig. 7. Sandstone saturation profiles are given in Fig. 8a and sand profiles in Fig. 8b. Again, strong and steep displacement fronts in both the sandstone and sand are witnessed. Foam effectively desaturates each layer. In contrast to Fig. 7, the displacement fronts in each porous medium move at the same rate. At times of 0.25, 0.33, and 0.41 PV front position is 0.3, 0.4, and 0.45, respectively. At the shortest time of 0.08 PV, displacement fronts do not coincide exactly. This is likely an inlet artifact.

Displacement fronts that move with identical velocity in communicating heterogeneous zones is also the expected result for the propagation of unfoamed gas if the effect of gravity is minimal. The striking result is the degree of displacement in the low permeability sandstone.

**Noncommunicating layers, homogeneous face injection.** In this, the third case, gas is injected into the saturated porous medium from the side completely filled with sand. Flow across the cylindrical face of the sandstone is again prohibited by the Teflon jacket barrier.

Figure 9 shows the saturation profiles. In the initial homogeneous section, gas enters the sand, a foam is generated, and displacement of foamer solution from the sand is quite efficient. Foam generation is rapid as a strong displacement front is seen even at 0.15 PV. At roughly 0.54 PV, the foamed gas first enters the sandstone. Again, the foamed gas moves more quickly through the low permeability sandstone than it does through the more permeable sand. The leading edge of the displacement front is at x/L equal to 0.7 in the sandstone and at 0.6 in the sand after 0.7 PV of total gas injection. At 0.85 PV of injection, front positions are roughly 0.85 and 0.75 in the sandstone and sand, respectively. Consistent with this observation, gas breakthrough occurs from the sandstone first.

Initially, foam displacement in the sandstone is not as efficient as in the earlier two cases. Examining the saturation profiles at 0.7, 0.85, and 1.1 PV, we find that the height of the displacement front grows from 0.3 to over 0.6 saturation units.

**Communicating layers, homogeneous face injection.** Figure 10 reports the saturation profiles obtained during gas injection into the homogeneous sand-filled side with capillary communication between the sandstone and sand. Displacement from both the sand and the sandstone is excellent at all time levels. As in the second case where crossflow occurs, saturation fronts move at the same speed in each layer. It is seen by comparing Figs. 10a and 10b that front positions at times of 0.63, 0.74, and 0.88 PV are equal and correspond to x/L equal to 0.65, 0.75, 0.85, respectively.

**Discussion**

The foam flow behavior discovered in each of these cases can be rationalized by considering foam texture (i.e., bubble size) and the effect that porous medium capillary pressure plays in setting foam texture. It is well established that finely textured foams, that is foams with small average bubble size, present a larger resistance to flow than do coarsely textured foams. In turn, bubble size is dictated by pore-level foam generation and coalescence events. Foam generation is largely a mechanical process and independent of surfactant formulation and concentration. On the other hand, foam collapse depends strongly on the foamer solution. Foam lamellae are stable provided that surfactant can stabilize the gas-liquid interface against suction capillary pressure that seeks to thin foam films. Hence, it is expected that the rate of foam coalescence increases with porous medium capillary pressure. In turn, the foam becomes more coarse. The characteristic value of capillary pressure that a porous medium approaches during strong foam flow is referred to as the limiting capillary pressure, and it is set principally by surfactant type and concentration.

In the first case reported in Fig. 7, each porous medium accepts whatever portion of the injected gas it desires. Because the sand and sandstone are isolated in the sense that crossflow is not allowed, foam is generated and assumes a texture that is independent of events occurring in the adjacent layers. We surmise that in the low permeability sandstone the foam is not as finely textured as in the sand. Sandstone capillary pressure is larger for a given saturation due to lower medium permeability. Hence, a greater suction pressure is exerted on foam lamellae inducing foam coalescence. This in turn leads to a more coarsely textured foam that is more mobile than its finely textured counterpart in the sand. Hence, foamed gas progresses more rapidly through the low permeability porous media. Nevertheless, gas mobility has been lowered substantially and water displacement is efficient.

In the situation summarized in Fig. 8, the porous media communicate with each other across the long cylindrical interface of the sandstone. Since the porous media communicate, gas at the foam front minimizes its flow resistance via foam bubble texture. When the flow resistance in the sandstone increases, foamed gas diverts into the sand, and vice versa. Thus, foam propagates at an equal rate in each layer because the saturation fronts are bound together by the necessity to maintain the minimum flow resistance. Bubble textures in sand and sandstone are not expected to be identical, but to yield identical gas mobility. In this case, the mobility is low and promotes effective desaturation. In the cases where the heterogeneous section is at the end of the core, similar explanations follow.

When crossflow is prohibited between the sand and the sandstone, each porous medium sets foam texture and, hence, gas mobility independently. Capillary pressure in the low permeability sandstone is higher than in the sand, coalescence
ensues, and foam in the sandstone is more mobile than in the sections filled with sand. If crossflow occurs, gas mobility is balanced because low flow resistance forces gas to divert into the adjacent layer. Foam propagates at equal rates in each layer.

Interestingly, the transient experimental results shown here bear striking qualitative similarity to previous simulation of foam behavior in heterogeneous porous media reported elsewhere\textsuperscript{19}. We note that the preceding qualitative arguments bear strong resemblance to the quantitative results reported in that study.

Conclusions

An experimental study of foam generation and propagation in heterogeneous porous media using Fontainebleau sandstone and Ottawa sand was performed. The contrast in permeability between high and low permeability homogenous zones was 67 to 1. Despite this drastic permeability contrast and despite the fact that high permeability zones typically lead to gas channeling, foamed gas is diverted to low permeability channels in these experiments. In this regard, the foam generated in these experiments can be regarded as strong. Foam effectively desaturates both the high permeability and low permeability portions of the experimental setup and desaturation is complete following roughly 1 PV of gas injection. This result is found for both systems that permit and prohibit cross flow.

Foam in heterogeneous systems appears to be self regulating in that gas mobilities in each porous medium equalize when layers communicate and nearly equalize in noncommunicating systems. Similar efficient diversion and desaturation is likely in heterogeneous, layered field situations where the permeability contrast is not as large provided that foam is tolerant of the presence of oil. Also, the capillary pressure of each layer must be less than the critical capillary pressure for foam coalescence.

In general, and in agreement with a previous theoretical study, it is observed that when permeability heterogeneities communicate and there is fluid crossflow that foam displacement fronts move at equal velocity in each zone. When crossflow is prohibited by an impermeable barrier, rapid foam propagation and desaturation of the low permeability zone is witnessed.

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References

Figure 3: Configuration of heterogeneous porous medium during experiments. Gas is injected at the left face.

Figure 4: Pressure drop and surface tension for foamer solution as a function of surfactant concentration. Brine concentration is 0.5 wt%.
Figure 5: Transient aqueous phase saturation profiles for gas-only displacement with crossflow: (a) sandstone and (b) sand regions.
Figure 6: Water saturation profiles in the heterogeneous core section, $t = 0.23$ PV. Cross flow is not permitted.
Figure 7: Transient aqueous phase saturation profiles for displacement without crossflow: (a) sandstone and (b) sand regions.
Figure 8: Transient aqueous phase saturation profiles for displacement with crossflow: (a) sandstone and (b) sand regions.
Figure 9: Transient aqueous phase saturation profiles for displacement without crossflow: (a) sandstone and (b) sand regions.
Figure 10: Transient aqueous phase saturation profiles for displacement with crossflow:
(a) sandstone and (b) sand regions.