Foam Dynamics in Limestone Carbonate Cores

Morten G. Aarra,* Abdul Majid Murad, Jonas S. Solbakken, and Arne Skauge

ABSTRACT: There is an increasing interest in foam applications in heterogeneous carbonate reservoirs to improve gas sweep and mitigate a high gas–oil ratio (GOR) in production wells. However, foam has been studied in sandstones more than in carbonates, and there are few experimental investigations considering matrix transport properties of foam in carbonates. Thus, this study takes a fundamental approach to improve our understanding of foam generation and transport process in the absence and presence of remaining oil in carbonates by co-injection of Alpha Olefin Sulfonate (AOS) solution and nitrogen (N₂) in outcrop Indiana Limestone at high pressure and temperature after satisfying adsorption. In the oil-free core, development of the foam generation transient period and its transition into steady-state foam was rapid for all gas fractions, where the strongest foam was obtained at 90% gas fraction. Foam properties were successfully reproduced at different gas fractions. At remaining oil saturation, foam generation and propagation were significantly delayed and were observed at a high AOS surfactant concentration (5 wt %). Persistent foams were obtained both with and without remaining oil present, which withstood pressure gradients of N₂ up to 0.5 bar/m for extended times. Therefore, if correctly designed, foam gas shut-off can be a low-cost low-risk technique to reduce problems with high GOR, gas-handling, and gas reinjections.

1. INTRODUCTION

Foam is gas dispersed in a liquid that is stabilized by surfactants. It has been used for conformance control, gas mobility control, and to shut-off unwanted gas flow into oil production wells. Most field applications of foam have been performed in sandstone reservoirs, and a few have also been performed successfully in carbonates. In situ generation of foam depends on rock properties, fluid–rock interactions, and fluid–fluid interactions.

Foam generation in porous media has been divided into three main mechanisms: snap-off, lamella division, and leave behind; and two destabilizing mechanisms: capillary-suction coalescence and diffusion coalescence. In oil-free porous media, foam generation has been described by the limiting capillary pressure (Pc) theory. Above a certain capillary pressure value, Pc, foam texture is coarsened, and gas mobility is less affected.

In low-permeability sandstone, foam generation has been characterized by the pressure difference across the core when surfactant solution and N₂ (foam) and brine and N₂ (no-foam) are co-injected into the core at the same injection rates and fractions, respectively. The higher the MRF, the stronger the foam.

Since the first field application of foam in 1970, a plethora of foam research has been conducted. The research has significantly improved our understanding of foam transport in porous media. Nevertheless, carbonate reservoirs impose challenges to understanding foam properties with respect to reservoir heterogeneity and wettability and foam–oil interactions. Fuseni et al. have demonstrated the generation of weak to moderate strength foams in high permeability heterogeneous composite carbonate reservoir core material at reservoir conditions. Although foam is generated more easily in high permeability porous media, the generation of foams in low permeability sandstone and carbonate core material has been reported. As such, foam is a candidate to reduce gas mobility and improve sweep efficiency even in carbonate reservoirs.

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reservoirs. Recently, the experimental work on foam gas shut-off (FGSO) in carbonate reservoirs has been published.

The limiting capillary pressure theory has been evaluated with respect to foam strengths versus different gas fractions (foam qualities). However, not too many studies discuss the limiting Pc* theory to foam experiments in carbonates. Experiments performed by Liu et al. in low permeability Indiana Limestone at 40 °C and 1500 psi report that a transition from low-quality regime to high-quality regime occurs at a gas fractional flow of ~85%.

The focus of foam research in carbonates has been on studies of foams in fractures (see the study by Dong et al.). In general, when generating foam, the presence of remaining oil saturation (ROS) reduces the efficiency of foams. In carbonate core material, aging of the core with crude oil may result in a more oil-wet state. Foam generation combined with wettability alteration in oil-wet low-permeability carbonates has been discussed by Ghosh and Mohanty. There are few experimental studies reported considering matrix transport properties of foam in carbonates, especially in oil-wet carbonate rocks.

The Alpha Olefin Sulfonate (AOS) surfactant has been applied in several foam field applications, and previous studies have also demonstrated foam generation with the AOS surfactant in carbonate reservoir core material. The AOS surfactant is a low-cost surfactant. Theoretically, anionic surfactants may adsorb strongly on the carbonate core material but reported adsorption data for AOS on the limestone core material show reasonable levels of adsorption and do not exclude the use of AOS surfactants for FGSO because of limited volumes needed in such treatments.

This paper discusses the results of systematic core flooding experiments performed with the AOS surfactant in limestone outcrop core material at 100 °C and 102 barg. The experiments investigated foam generation and foam transport processes in carbonate and its ability to block gas in areas where foam is generated. In addition, the influence of ROS on foam generation and foam propagation after water flooding was studied at increasing surfactant concentrations.

2. EXPERIMENTAL DESIGN

2.1. Core Material. Foam experiments were performed on two outcrop Indiana Limestone core samples. The physical properties of the core material are listed in Table 1.

| Table 1. Physical Properties of the Core Material |
|--------------------------------------------------|
| parameter                                      | limestone 1 | limestone 2 |
| length [cm]                                    | 23.6        | 23.9        |
| diameter [cm]                                  | 3.79        | 3.79        |
| pore volume [mL]                               | 45.5        | 44.8        |
| porosity [%]                                   | 17.1        | 16.6        |
| absolute permeability, k_{a,abs} [mD]          | 425         | 521         |

2.2. Fluids. In this study, N2 synthetic seawater (SSW), surfactant, mineral oils, and stock tank oil (STO) were used.

Nitrogen gas was of industrial grade with N2.5 purity (99.5%).

SSW was prepared using deionized water and pro analysis (p.a.) grade salts, which was filtered through a 0.45 μm filter before use. Table 2 summarizes the composition of the SSW.

An anionic AOS surfactant, AOS C14−C16 was used in this study (Petrostep C-1 from Stepan). The AOS surfactant was delivered as a solution of 39.45% active material. The surfactant solutions in this study were prepared by dissolving the AOS surfactant in SSW. The surface tension of 0.5 wt % AOS surfactant solution was 28.9 mN/m at ambient conditions (spinning drop measurement), and thus, the Pc between the gas phase and the surfactant solution is significantly reduced compared to Pc between gas and the brine phase.

Mineral oils, Primol 542, Marcol 152, and Marcol 52, were used for the drainage process with viscosities of 250, 50, and 10 cP at ambient conditions, respectively. Middle Eastern STO with a viscosity of 1.4 cP at experimental conditions was used for aging. The interfacial tension between the STO and 0.5 wt % AOS surfactant solution was 1.65 mN/m at ambient conditions (spinning drop measurement).

2.3. Setup. The experimental setup, Figure 1, consisted of a high-temperature high-pressure Quizix pump located inside the heating cabinet with the core holder and a gas reservoir to avoid temperature effects on the gas injection rate. The core holder had two inlets and one outlet which enables the gas and surfactant solution to meet at the sandface of the core material rather than in the pipeline. There are three additional pumps outside the heating cabinet that control the overburden pressure, the gas reservoir, and the seawater/surfactant solution injection. The seawater injection line was coiled to ensure that seawater was heated before reaching the core. A view glass, Figure 2, was mounted along the outlet line before the back-pressure regulator. A Canon SD Mark II DSLR camera with macro photo lens (MP-E 65 mm f/2.8 1−5X) mounted on a tripod and a light source were used to periodically capture images of the view glass. The purpose of the view glass was to confirm foam formation and possibly investigate foam textures.

2.4. Core Preparation. The limestone cores were dried in an oven at 80 °C for 1 day. The cores were then wrapped with a plastic foil and an aluminium foil inside a Viton rubber sleeve before being mounted in the core holder. The limestone cores were vacuumed and saturated with SSW, and then, the absolute brine permeability and dispersion profiles were measured.

| Table 2. SSW Composition |
|---------------------------|
| salt                      | concentration [wt %] |
| NaCl                      | 2.489                |
| CaCl2                     | 0.131                |
| MgCl2                     | 0.521                |
| Na2SO4                    | 0.406                |
| NaHCO3                    | 0.019                |
| KCl                       | 0.068                |
| total                     | 3.634                |

Figure 1. Experimental setup (P1: inlet pressure, P2: outlet pressure, ΔP: differential pressure, and BPR: back-pressure regulator).
Dispersion profiles were measured by injecting 10% diluted seawater (as the tracer) into the core saturated with seawater, while the conductivity of the effluent was measured by a flow-through conductivity cell. Figure 3 shows the dispersion profiles for limestone 1 and 2 along with a theoretical curve of a relatively homogeneous sample that would exhibit piston-like displacement. Breakthrough for the two core samples was very early at approximately 0.34 pore volume (PV). On the other hand, half of the injected concentration breakthrough (dashed lines shown in Figure 3) was at 0.88 and 0.90 PV for limestone 1 and 2, respectively, which is indicative of the flowing fraction of the pores. The profiles of the two cores were asymmetrical with long tail periods, indicating mass exchange with dead-end pores. Overall, the two core samples displayed similar characteristics typical of Indiana Limestone.

Limestone 2 was oriented vertically and then drained gravity-stable by injecting high viscosity mineral oil (250 cP) from the top of the core sample to minimize irreducible water saturation ($S_{wi}$). The high viscosity mineral oil was then exchanged with lower viscosity mineral oils (50 and 10 cP), followed by n-Octane. After which, oil permeability at $S_{wi}$ was measured before aging. Then, n-Octane was exchanged with STO by injecting 3 PV in each direction. Differential pressure data were recorded and showed no sign of precipitation. The core was aged for 4 weeks at 100 °C and backpressure of 10 barg while injecting STO at 1 PV/week. After aging, the permeability to STO was measured, and the core was flooded gravity-stable from the bottom at 0.1 mL/min SSW, followed by 1 and 15.6 mL/min to reach waterflood ROS. Table 3 shows saturation history and permeabilities in limestone 2.

2.5. Procedures. All foam measurements were performed at 100 ± 2 °C and backpressure of 102 ± 2 barg. Initially, baseline differential pressures were measured at different gas fractional flow ($f_g$) but at a total injection rate of 40 mL/h.

$$f_g = \frac{Q_{N_2}}{Q_{N_2} + Q_{SSW}}$$

where $Q_{N_2}$ and $Q_{SSW}$ are the nitrogen injection rate and SSW injection rate (m$^3$/s), respectively.

Table 4 summarizes the results of the baseline measurements, where the reported values represent the average steady-state differential pressure during the last 0.5 PV of gas and brine injected at each gas fraction. For limestone 2 core, which was at ROS of 0.39, saturations after baseline measurements were: ROS = 0.37 and ($S_w + S_g$) = 0.63.

Prior to foam generation experiments, surfactant adsorption was satisfied by injecting an excessive amount AOS solution to eliminate the effect of dynamic adsorption on foam properties. Foam generation experiments conducted on limestone 1 were as follows:

1.1) Injection of 6 PV of 0.5 wt % surfactant solution to satisfy adsorption.

1.2) Foam generation by co-injection of $N_2$ and 0.5 wt % AOS solution.

Table 3. Saturation History and Permeabilities in Limestone 2 Prior to Foam Experiments

| step | fluid | $S_w$ | $S_g$ | $k_w$ (S) [mD] | $k_w$ (ROS) [mD] |
|------|-------|-------|-------|---------------|----------------|
| after drainage (before aging) | n-octane | 0.32 | 0.68 | 383 | |
| after aging | STO | 0.32 | 0.68 | 276 | |
| after water flooding | SSW | 0.61 | 0.39 | 270 | |

Table 4. Baseline Differential Pressures

| core ID | gas fraction [frac] | differential pressure [mbar] |
|---------|---------------------|----------------------------|
| limestone 1 | 0.70 | 165 |
| | 0.80 | 114 |
| | 0.90 | 82 |
| | 0.95 | 66 |
| | 0.98 | 58* |
| limestone 2 | 0.80 | 196 |

*aEstimated.*

Figure 2. View glass with an inner diameter (red line) of 1.5 mm.

Figure 3. Dispersion profiles of limestone 1 and 2.
Foam generation experiments conducted on limestone 2 (at ROS and $f_f = 0.8$) were as follows:

1. Injection of 6 PV of 0.5 wt % surfactant solution to satisfy adsorption.
2. Foam generation by co-injection of $N_2$ and 0.5 wt % AOS solution.
3. Injection of 10.1 PV of 5.0 wt % surfactant solution.
4. Foam generation by co-injection of $N_2$ and 1.0 wt % AOS solution.
5. Injection of 2.0 PV of 2.5 wt % surfactant solution.
6. Foam generation by co-injection of $N_2$ and 2.5 wt % AOS solution.
7. Injection of 2.1 PV of 5.0 wt % surfactant solution.
8. Foam generation by co-injection of $N_2$ and 5.0 wt % AOS solution.

The stability of generated foams was evaluated by their capacity to block $N_2$ at different applied pressure gradients (VP). After foam generation of a certain quality, the injection was stopped, and the core was kept overnight to equalize the differential pressure. Then, a constant pressure gradient of 0.25 barg/m was applied to the foam-filled core by injection of $N_2$. Foam stability was then evaluated based on the cumulative volume of $N_2$ injected as a function of time. The lower the injected volume of gas, the better foam stability and persistence to resist gas flow. The applied pressure gradient was doubled stepwise until foam could not block $N_2$.

3. Results

3.1. Foam Properties in Limestone 1 (Oil-Free Core).

This section presents the experimental results of foam properties in limestone 1 at 100 °C and 102 barg. Foam generation, foam propagation, and foam stability are the key properties evaluated. In addition, observations of foam from the view glass at the core outlet are outlined.

The first set of experiments explore foam generation at different foam qualities between 70 and 98%. In all experiments, foam was generated by the co-injection method, where the surfactant solution (0.5 wt % AOS) and $N_2$ met at the core inlet at a total injection rate of 40 mL/h.

Figure 4 shows the steady-state foam strengths obtained at different foam qualities. In all foam experiments in the limestone 1, a foam generation transient period developed as soon as $N_2$ and surfactant solution came in contact at the sandface, as exemplified in the highlighted region in Figure 5. Moderate to strong foams were generated at all foam qualities in which the highest foam strength was achieved at 90% foam quality with an MRF of 60.

Reproducibility of the results was examined at several foam qualities (i.e., 90, 95, and 98%), following the steps 1.3–1.5 stated in the Procedures section. Figure 5 shows the reproducibility of the results at 90% foam quality, where the MRF of two experiments was 60 and 62. Similarly, reproducibility was also demonstrated for two experiments at 95% foam quality with MRFs of 44 and 46 and for four experiments at 98% with MRFs of 13, 16, 17, and 18. Images of foam textures at steady-state foam strength were taken for different foam qualities, as presented in Figure 6. At 98% foam quality, foam texture in the view glass was a mix of continuous foam and gas flow, and it was the coarsest compared to the foam texture at lower foam qualities, in line with the foam strength obtained [i.e., denser foam texture with more bubbles per area provides higher foam strengths (MRF) in limestone 1].

For 95 and 98% foam qualities, the MRF increased sharply at the start of the experiments, as shown in Figure 7a,b, respectively, before stabilizing at a lower MRF at steady-state conditions.

The average differential pressure ($\Delta P$) across the core measured at the plateau for foam qualities of 70, 80, and 90% was quite similar, but $\Delta P$ was progressively lower for 95 and 98% foam qualities. This was confirmed through calculations of foam apparent viscosities in Table 5 using Darcy’s law (eq 3) and assuming foam as one fluid phase.

\[
\mu_{app} = \frac{k \Delta P A}{Q_T L}
\]

where $k$ is absolute permeability [m$^2$], $A$ is cross-sectional area [m$^2$], $\Delta P$ measured differential pressure [Pa], $Q_T$ is total injection rate [m$^3$/s], and $L$ is the length of the core material [m].
The gas-blocking experiments were performed with foam established in the porous medium. The apparent viscosity of the foam, as derived from differential pressure over the core, was high compared to the gas phase viscosity. The applied gas pressure would nearly instantaneously create a gas finger if the core was saturated with water, but the established foam blocked the gas fingers effectively at low applied pressure gradients. We needed to apply higher gas pressure gradient for gas fingers to be formed and to create continuous gas ganglia through the core, and thereby establish a gas leakage through the foam. This was our experimental procedure to best mimic the inflow into production wells after foam placement.

Figure 6. Foam texture at different foam qualities as it appears in the view glass at the core outlet—limestone 1. (a) 90% foam quality, ~2.6 PV injected (MRF, 60–62). (b) 95% foam quality, ~2.9 PV injected (MRF, 44–46). (c) 98% Foam quality, ~2.9 PV injected (MRF, 13–18), and an example of foam and gas flow.

Table 5. Comparison of Foam Strength Based on Apparent Viscosities and MRF for Limestone 1

| foam quality [%] | μ_app [cP] | MRF [-] |
|------------------|------------|---------|
| 70               | 100        | 33      |
| 80               | 106        | 51      |
| 90               | 91         | 61      |
| 95               | 54         | 45      |
| 98               | 17         | 16      |

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Figure 8 shows the gas-blocking capacity of the foam generated at 90% foam quality in limestone 1. At pressure gradients of 0.25 and 0.5 barg/m, the injection rate of N<sub>2</sub> was very low while at the highest applied pressure gradient, 1 barg/m, the injection rate of N<sub>2</sub> increased significantly after about 6 h, indicating high gas mobility through the core.

Three gas-blocking experiments were also performed on foams generated at 98% foam quality (MRF between 13 and 18). Figure 9 shows a typical gas-blocking behavior observed in two
of the three experiments, for which the curves were almost indistinguishable and thus only one is presented. During the test period, the gas was well blocked at both 0.25 and 0.50 barg/m, respectively. However, at a pressure gradient of 1.0 barg/m, the foam became unstable, and a high gas injection rate was observed. On the other hand, a higher gas injection rate was recorded from the start of the third gas-blocking experiment, as shown in Figure 10. The reason for this was unclear but may reflect differences in foam texture that might have occurred under these high foam qualities. As mentioned earlier, during foam generation at 98% foam quality, foam texture in the view glass was a mix of continuous foam and gas flow (see Figure 6c).

3.2. Foam Properties in Limestone 2 (at ROS). Foam properties in carbonate at ROS were studied in limestone 2. The core was aged for 4 weeks at 100 °C prior to the start of foam generation experiments in which the wettability state of the core material may have become more oil-wet based on measurements of \( k_{ro}(S_{wi}) \) before and after aging (i.e., 20% reduction in oil permeability with aging). ROS was 0.37 prior to foam generation experiments (details are given in the Experimental Design). Foam generation was performed by co-injection of N\(_2\) gas and AOS surfactant solution in limestone 2 at 80% foam quality, with surfactant concentrations ranging from 0.5 to 5.0 wt %.

The lack of initiation of a foam generation transient period was common to all experiments conducted at different surfactant solution concentrations from 0.5 to 2.5 wt %. The differential pressure across the core was constant at a low value during these experiments. On the other hand, increasing the surfactant concentration from 2.5 to 5.0 wt % showed an immediate response in the differential pressure which increased steadily during the first day, as shown in Figure 11, but no foam was observed in the view glass. Therefore, the foam experiment was shut-in overnight and continued the next day during which the MRF re-established quickly to higher strength, and foam was observed in the view glass demonstrating slow foam propagation.

No free oil phase was produced during all foam experiments conducted with the presence of oil in the core material. However, the effluent liquid-phase from the core was colored, slightly brownish, which indicated solubilization of oil into the surfactant solution. The intensity of the color of the liquid-phase increased with increasing surfactant concentrations.

The stability of the generated foam, after day 2, was investigated by its ability to block N\(_2\) at different applied pressure gradients, as shown in Figure 12. Persistent foam stability was observed both at pressure gradients of 0.25 and 0.50 barg/m, similar to that in limestone 1.

4. DISCUSSION

The three main foam generation mechanisms identified from the studies in artificial porous media are snap-off, lamella division, and leave behind. It is difficult to determine whether the dominant foam generation mechanisms are the same for sandstone and limestone cores. However, our previous study showed similarities between foam properties in sandstone and limestone cores.

From this study, it is evident that the development of the foam generation transient period is important for both foam...
generation and foam propagation. Initiation of strong foam generation by the co-injection method in oil-free carbonate saturated with surfactant solution was immediate and consistent with the previous data. However, it was reported for CO2 foams in Indiana Limestone that the first 0.3 PV was a surfactant and gas mixing interval before foam is generated in situ. Moreover, even though a previously reported study indicated a transition from low- to high-quality foam regime at 85% foam quality for pregenerated foam in an Indiana Limestone core at 40 °C and back-pressure of 1500 psi (103.4 barg), our results indicate that the transition of the two regimes can occur at even higher gas fractional flow because 95% and 98% foam quality experiments generated foams of relatively moderate strengths.

Dispersion curves with single-phase brine displacement showed a breakthrough after 0.34 PV was injected. Observation of foam in the view glass at the core outlet occurred at almost the same PV injected for most foam qualities (70−95%) in the oil-free core material. It is reasonable to believe that foam generates and propagates, according to the established tracer profile in dispersion measurement, which represents areas of lower flow resistance, as this coincided with the start of the foam plateau level in most experiments. Compared to experiments in homogeneous sandstone cores, it is often observed that the foam propagation follows the injection rate. Thus, it seems like foam propagation in oil-free carbonates is faster than in sandstones, which could be reflecting the heterogeneous nature or the complexity of the pore structure of carbonates.

Comparing Figures 5 and 7, the behavior of pressure build-up is markedly different. At 95 and 98% foam qualities, the MRF stabilized at lower values than peak pressure, while at 70−90% foam qualities, the MRF stabilized around peak pressure even though the core was prepared in a similar manner prior to each foam generation. Initially, as N₂ is injected into an AOS-filled core, foam starts to generate because of the contact of N₂ with the surfactant solution already present in the core and the MRF increases. As co-injection continues, the amount of surfactant solution available in the core is reduced. The procedure of foam generation in this study did not involve surfactant alternating gas (SAG) method but rather co-injection of surfactant solution and N₂ into a surfactant-filled core. However, at high gas fractions of 95 and 98%, with so little surfactant injection, it closely resembles the SAG procedure, and the results suggest that it could be an effective method to either initiate foam generation or as a refreshment of foam in gas shut-off operations in carbonate reservoirs. The SAG foam generation method has recently been applied in the high-quality regime in very low permeability (~1 mD) carbonate rocks.

In surfactant experimental studies, the increase in differential pressure across the core may be due to various causes such as emulsions, surfactant phase behavior, precipitation, or foam formation. In order to conclude that the observed increase in differential pressure is a direct response to foam generation, additional information is needed. Because differential pressure is measured across the core and before the view glass in our setup, the observation of foam in the view glass complements the differential pressure measurements. However, the foam texture observed in the view glass does not necessarily reflect the foam texture inside the core because the texture could be slightly altered in the outlet line leading to the view glass due to the morphology differences (porous structure vs continuous flow area). Therefore, the view-glass adds qualitative value to the experimental data.

In carbonate cores at ROS, the initiation of the foam generation transient period was much more challenging and seemed to require higher surfactant concentration and larger throughput of surfactant solution. At a high surfactant concentration of 5.0 wt %, the foam generation transient period started to develop quickly but the appearance of foam in the view glass was delayed, indicating slow foam propagation. Similar results were observed in the reservoir core material at ROS using the same reservoir oil, as in a previous study, and improved foam properties at an increased surfactant concentration have also been reported in sandstones.

We believe that the delayed start of the foam generation transient period is coupled to the wetting state of the carbonate rock after aging with crude oil. The AOS surfactant is very hydrophilic but still solubilizes oil into an oil-in-water microemulsion (Winsor I type). Removing some of the oil layers on the rock will likely create water layers, or available water wet sites on the rock, leading to nucleation of foam lamellae. After the first foam generation with a higher surfactant concentration, the following foam generation could be performed at a lower surfactant concentration as has been demonstrated. However, aging in surfactant solution should not be a significant factor in these experiments because limestone 2 was exposed to the AOS surfactant solution for 4–5 days during all foam generation attempts. In our opinion, the fact that strong foam is then generated at a lower surfactant concentration can be an argument against the lack of oil tolerance often reported.

In FGSO field applications, foam is believed to be placed up to 10 m into the reservoir, and the pressure gradient will be case-specific. In the near-wellbore region, it will depend on the distance away from the wellbore, and a very low-pressure gradient is expected for the gas influx toward the well. In this study, we investigated foam stability with pressure gradients up to 1 barg/m. All generated foams showed good stability at N₂ pressure gradient of 0.5 barg/m both for oil-free and ROS case. The AOS foam is effective for FGSO in carbonate reservoirs. The operational design must start with the injection of a high concentration AOS solution which can then possibly be continued at lower concentrations. Adsorption of the surfactant to the rock surface is required to obtain robust foam properties in more oil-wet carbonates, however, the total amount of surfactant required in FGSO applications is considered rather low.
5. SUMMARY AND CONCLUSIONS

We have studied foam properties in carbonates using an AOS surfactant. Foam generation, foam transport, and ability to block gas were evaluated in outcrop Indiana Limestone carbonates using co-injection of the AOS surfactant and N₂ at 100 °C and 102 barg for FGSO processes in carbonate reservoirs. Surfactant adsorption was satisfied prior to performing foam generation experiments.

First, foam properties were investigated in an oil-free carbonate core, and the main findings are:

- Foam generation was rapid, and the steady-state foam had moderate to high foam strength over a large range of gas fraction.
- Repeated foam experiments reproduced similar foam properties.
- Gas-blocking by foam was effective with gas pressure gradient up to 0.5 barg/m.
- Foam could be generated with a low concentration of AOS.

Second, foam properties were investigated in a crude oil aged carbonate core at ROS, and the main findings are:

- Foam generation and foam propagation were delayed.
- A high concentration of AOS (5 wt %) was needed to generate the first foam, but pressure data showed a foam generation transient period to start immediately.
- Foam stability and gas-blocking capacity were good at tested pressure gradients.

AUTHOR INFORMATION

Corresponding Author
Morten G. Aarra – Norwegian Research Centre (NORCE), 5007 Bergen, Norway; orcid.org/0000-0002-7283-0084; Email: moaa@norceresearch.no

Authors
Abdul Majid Murad – Norwegian Research Centre (NORCE), 5007 Bergen, Norway; Department of Chemistry, University of Bergen, 5007 Bergen, Norway
Jonas S. Solbakken – Norwegian Research Centre (NORCE), 5007 Bergen, Norway
Arne Skauge – Norwegian Research Centre (NORCE), 5007 Bergen, Norway; Department of Chemistry, University of Bergen, 5007 Bergen, Norway

Complete contact information is available at: https://pubs.acs.org/10.1021/acsomega.0c02058

Notes
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NOMENCLATURE

MRF mobility reduction factor
SSW synthetic seawater
ΔP differential pressure [barg = 10^5 Pa]
VP pressure gradient
fₙ gas fraction
Qₑ total injection rate [mL/min]
QₑSSW injection rate synthetic seawater
Qₑgas injection rate gas
mD millidarcy
k permeability [millidarcy]
kₑ(Sₜ) oil permeability at irreducible water saturation
STO Stock Tank Oil
AOS Alpha Olefin Sulfonate
ROS remaining oil saturation
Pₘ capillary pressure

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