

Accepted Manuscript

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PII: S0927-7757(18)30537-5
DOI: <https://doi.org/10.1016/j.colsurfa.2018.06.043>
Reference: COLSUA 22612

To appear in: *Colloids and Surfaces A: Physicochem. Eng. Aspects*

Received date: 23-3-2018
Revised date: 15-6-2018
Accepted date: 16-6-2018

Please cite this article as: Rafati R, Oludara OK, Haddad AS, Hamidi H, Experimental Investigation of Emulsified Oil Dispersion on Bulk Foam Stability, *Colloids and Surfaces A: Physicochemical and Engineering Aspects* (2018), <https://doi.org/10.1016/j.colsurfa.2018.06.043>

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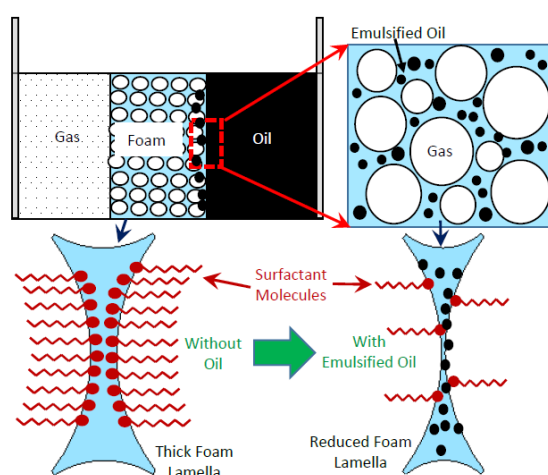
Experimental Investigation of Emulsified Oil Dispersion on Bulk Foam Stability

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Graphical abstract



Abstract

Recently aqueous foams have shown promising results to overcome viscous fingering and gravity segregation problems during gas injection process. However, one of the main challenges is the stability of the foams in the presence of oil bank at the front of injected foam. Oil can penetrate into the foam structure in the form of continuous phase or emulsions which might deteriorate lamellae and plateau borders that can result in bubble coalescence and foam rupture. The combination of the surfactant solution, responsible for stabilizing foams, with oil increases the potential for the formation of oil emulsions. In this condition emulsions stability and phase behaviour have the main influence on the bulk foam stability. The objective of this research is to conduct a comprehensive study on the effect of emulsified oil, at different concentrations and salinities on the stability of bulk foams used during oil displacement processes. This was achieved using a foam column test, in which foam is generated and its decay monitored with time. The half-life for each sample was noted and a comparison was made for different cases. Furthermore, changes in the foam bubble sizes and distribution were observed and analysed using an image processing software. A gradual reduction in the half-life

of foam was observed with increasing concentration of emulsified oil. The degree to which a foam structure is destabilized by the emulsified oil droplets is dependent on the type and concentration of surfactant employed in generating the foam. At 2 wt% concentration of emulsion, the half-life recorded for foam generated by AOS surfactant, was 107 minutes, while for the foam generated by SDBS was only 39 minutes. Further analysis of the results showed a reduction in the number of dispersed oil droplets with increasing the salinity. In addition, the effect of increased salinity of the emulsion on foam stability was again found to be a function of the type of the surfactant is present in the foam system.

Keywords

Foam stability, Emulsified oil, Surfactant, Foam texture, Bubble size distribution.

1. Introduction

Natural energy responsible for displacing hydrocarbons diminishes gradually with time. To increase the recovery factor, certain enhanced oil recovery techniques are being employed in the oil industry. One of such methods involves the injection of immiscible gases to reduce oil viscosity and interfacial tension between displacing and displaced fluids, thus improving the mobility of hydrocarbons [1-3]. Due to extreme differences in the density and viscosity of gas and oil, there is a continuous penetration of gas into the oil phase. This results in viscous fingering effects which ultimately reduce the sweep efficiency in the reservoir [1, 4]. A successful technique commonly employed to curb the problem of gravity override is the injection of foamed gas into the reservoir. The foamed gas is generated by introducing gas into a solution of surfactant. When the foam is generated, the gas phase is discontinuous and separated by thin liquid films of Lamella [4, 5]. Therefore, the movement of gas within the system is highly restricted and dependent on the breaking and reforming of the lamellas [6]. This process reduces gas mobility and improves the sweep efficiency in reservoirs significantly. Foam gas also applied in the gas lifting and liquid loading process and shown successful results in improving oil unloading and reducing gas mobility in the vertical wells [7-9]

Boud and Holbrook in 1958 pioneered the use of foams for gas mobility reduction [10]. In their pursuit of enhancing the effectiveness of secondary gas injection, they injected a specific volume of foaming solution before gas injection. They observed an increase in oil recovery and a reduction in gas mobility with the generation of the foamed gas. A number of research studies have been conducted on the application of foams in reducing the gas mobility [6, 11-17].

Bernard and Holm conducted experiments to study the effect of foam on the permeability of a system to gas [9,11]. Their observations showed that the effectiveness of foams in gas permeability reduction increased with the permeability of the system. They later concluded that foams could be used for selective blocking of higher permeable regions. Therefore, the integrity of foams, used in recovery processes is of utmost importance, which depends on several factors such as the properties of foaming agent, presence of additional liquid or solid phase in the foam structure, rock petrophysical properties and the reservoir condition. [18-20]. A foam that maintains its integrity for the most part of a flood project, is the one in which the rate of coalescence of bubbles is low due to the presence of sufficient stabilising agents. Bulk foam is a term used in describing foams collectively at large scale. It is imperative that a prolonged separation between the gas and liquid is maintained for foams used in enhanced oil recovery processes. Thus, many studies have been conducted to test the behaviour and stability of foams under various conditions [18, 20-24].

The type and concentration of surfactants used in foam generation have a large influence on foam stability [23, 25-28]. The foamability, obtained by measuring the time taken to generate a certain volume of foam [12, 28], is a function of the chemical structure of the surfactant. Jones and Laskaris, conducted bulk and core flood experiments to study the effect of different concentrations of surfactant on the foam behaviour [25]. Results from bulk test showed the foam stability is enhanced as the concentration is increased beyond the critical micelle concentration. In the core-flood tests, a decrease in concentration of surfactant caused a reduction in the foam quality as well as the apparent viscosity of gas which are signs of an early gas breakthrough. Simjoo et al. investigated the foaming capacity and foam maximum density of alpha-olefin-sulfonate (AOS) surfactant at different concentrations [28]. Analysis of the results showed an increase in the foaming capacity and maximum density at higher concentrations of surfactants in foam films. Wang and Li also conducted experiments to study the effect of increasing the concentration of surfactant on the foam stability [29]. Triton X-100 and propane (C_3H_8) was used as surfactant and gas respectively. The results from their experiments showed that the stability of foam is insensitive to changes in concentration beyond the critical micelle concentration. This observation was not consistent with that of Jones and Laskaris, who conducted experiments on ionic surfactants [25]. Their experiments showed that foam stability increases with concentration even beyond the critical micelle concentration. Wang and Li conducted the experiment using non-ionic Triton X-100 surfactant as opposed to Jones and Laskaris who conducted experiments using two formulations of anionic Alpha Olefin

Sulfonate (AOS). Based on the experiments outlined above, it is evident that surfactants behave differently depending on their ionic properties. Thus, sufficient screening tests should be conducted to determine the behaviour and characteristics of each surfactant under different conditions.

The stability of foams is also influenced by the presence of continuous hydrocarbons due to interactions between the oil phase and lamella. In oil recovery processes where oil is present within a foam system, a secondary film is developed between the gas and oil phases which is called a pseudo-emulsion film [4]. Lower chain hydrocarbons are known to have an adverse effect on the stability of foams [18, 30, and 31]. This is purely a function of the entering and bridging coefficients of the liquid film separating the gas phase from the liquid phase. For a short chain hydrocarbon molecules with lower viscosity, the magnitude of these coefficients is high, ensuring easier penetration. Once, penetration occurs, a non-symmetrical unstable pseudo-emulsion film separating the oil from the gas phase is created. Longer chain hydrocarbon molecules are less detrimental due to their increased viscosity. The oil droplet may not penetrate but accumulates at the plateau borders slowing down the thinning rate of the films. [18, 28, 32-39].

Schramm and Novosad, observed the interactions between foam and oil using an etched glass micromodel [30- 31]. They pointed out that three types of foams could be formed in the presence of oil. Type A foam shows little or no interaction with oil, and the stability of this foam is credited to the formation of a very large droplet of oil, making it difficult to pass through plateau junctions to destabilize the lamellas. Type A foams are formed in the presence of long chain hydrocarbon molecules within the foam structure. Type B foams, on the other hand, are less stable. This is because smaller oil droplets are formed upon contact with the foam that can be transported up the plateau borders into the lamella. Type C foams proved to be more detrimental to the stability of foams as even smaller oil droplets are formed. These droplets can enter even the thinnest lamella causing a rapid coalescence of the lamella. Type C foams are formed as a result of the presence of shorter chain hydrocarbon molecules in the foam structure. These results are consistent with Robinson and Woods' theory which explains that an oil droplet will cause destabilization if it penetrates the gas-liquid interface on contact and in turn spread strongly along the interface [40]. Schramm and Novosad also described different criteria that must be met for the destabilization of foams by oils; the entering (E), spreading (S) and bridging (B) coefficients [31]. For an oil phase to enter, spread or bridge a foam lamella,

the individual coefficients must be positive. These coefficients are calculated with the following equations:

$$E = \sigma_{w/g} + \sigma_{w/o} - \sigma_{o/g}, \quad (1)$$

$$S = \sigma_{w/g} - \sigma_{w/o} - \sigma_{o/g}, \quad (2)$$

$$B = \sigma_{w/g}^2 + \sigma_{w/o}^2 - \sigma_{o/g}^2, \quad (3)$$

where, $\sigma_{w/g}$ is the surface tension between water and gas, $\sigma_{w/o}$ the interfacial tension between water and oil, and $\sigma_{o/g}$ is the surface tension between oil and gas. In addition, they discussed another parameter that affects the stability of foams which is lamella number. The lamella number, described as the number that must be exceeded for an oil phase to be emulsified into the foam lamella, and is given by Equation (4):

$$L = \frac{R_o \sigma_{w/g}}{R_p \sigma_{w/o}}, \quad (4)$$

where R_o is the radius of the oil droplet and R_p is the radius of the plateau boarder. Aveyard et al [14] calculated the initial entering and spreading coefficients of hydrocarbons ranging from hexane to hexadecane. Their results were consistent with the work of Schramm and Novosad, as lighter hydrocarbons showed greater tendencies to enter the gas-water interface and destabilise the foam films [31].

Mannhardt and Svorstol, conducted several foam flood experiments at different oil saturations, on core samples from the Snorre reservoir located in the Northern part of the North Sea [41]. Analysis of the results showed a decrease in the rate of foam propagation with increasing oil saturation. Oil saturation was also found to affect the apparent viscosity of the foam.

Based on previous studies it can be concluded that the stability of foams used in enhanced oil recovery processes, is adversely influenced by the presence of continuous oil in the porous media [34, 35, 42]. A foam's ability to withstand rupture or coalescence under mild or extreme conditions is a direct representation of its potential in preventing early gas breakthrough during a gas injection process. In most of these studies, oil was brought into contact with foam such that an interface between the foam and bulk oil phase was developed. These studies are representative of the cases when a foam phase is generated and then brought into contact with an oil phase in porous media. However, the most common method of generating foams in porous media is the surfactant alternating gas injection. This approach which requires prior injection of surfactant into the reservoir provides a risk of the formation of emulsified oil as the surfactant is combined with crude oil. Emulsions are formed when crude oil is combined

with an aqueous solution in the presence of a surfactant [43-46]. The presence of emulsified oil in the foam structure could have a positive or negative influence on the stability of foams as gas is injected through the surfactant solution. Therefore, an understanding of the influence of emulsified oil on foams is of utmost importance before conducting foam flood processes. This research aims to analyse the impact of the presence of emulsified oil droplets on foam performance/stability at different salinities.

2. Experimental setup

To investigate the effect of emulsified oil droplets on foam stability, two anionic surfactants were used; alpha olefin sulfonate (AOS) (supplied by Enaspol, Czech Republic) and sodium dodecyl benzene sulfonate (SDBS) (supplied by Sigma-Aldrich). AOS surfactant was supplied in liquid form while SDBS was in powder form with yellowish colour. Crude oil used in the preparation of the emulsion is a light crude obtained from a field in the North Sea. Sodium chloride (NaCl) (supplied by Fisher Scientific), was used in controlling the salinity of the emulsions. It was in white odourless solid form with a purity greater than 99%. Deionized water was used for dilution in all experiments and air was used as a gas phase for foam generation in our experiments. Properties of all chemicals are shown in Table 1

Table 1: Properties of the materials used in the experiment

Material	Surface tension (mN/m)	Density (g/cm ³)	PH	Viscosity (cp)
Alpha olefin Sulfonate	36.1	1.05 @ 20 °C	7.0-8.0	1 @ 22 °C
Sodium dodecyl benzene sulfonate	36.1	1 @ 20 °C	7-10.5	1 @ 22 °C
Triton X-100	33.7	1.07 20 °C	9.7	1 @ 22 °C
Crude Oil	44	0.908 22 °C	-	53.87 @ 22 °C
Sodium Chloride		2.165 @ room Temp.	5.0-8.0	-
Deionized water	72	1 @ room Temp.	7	1 @ 22 °C
Air	-	0.001 @ room Temp.	-	-

The equipment used for foam stability analysis is an assembly of various parts as shown in Figure 1. There is a vertical and transparent foam column with the height of 57 cm, outer and inner diameter of 7.95 cm and 5.94 cm respectively. The top end of the column is opened to the atmosphere, and as such, there is no pressure build up in the system. The bottom of the column is fitted with a gas diffuser with pore diameter ranging from 40-100 μ m, through which

gas is introduced into the system. A high-resolution microscope camera with a magnification of 500X was used to capture images of the foam bubbles at different time intervals. These images were in turn fed into an image processing software to characterize the texture of foam. The flowrate of the gas is controlled with a flow meter and valves connected to the system.

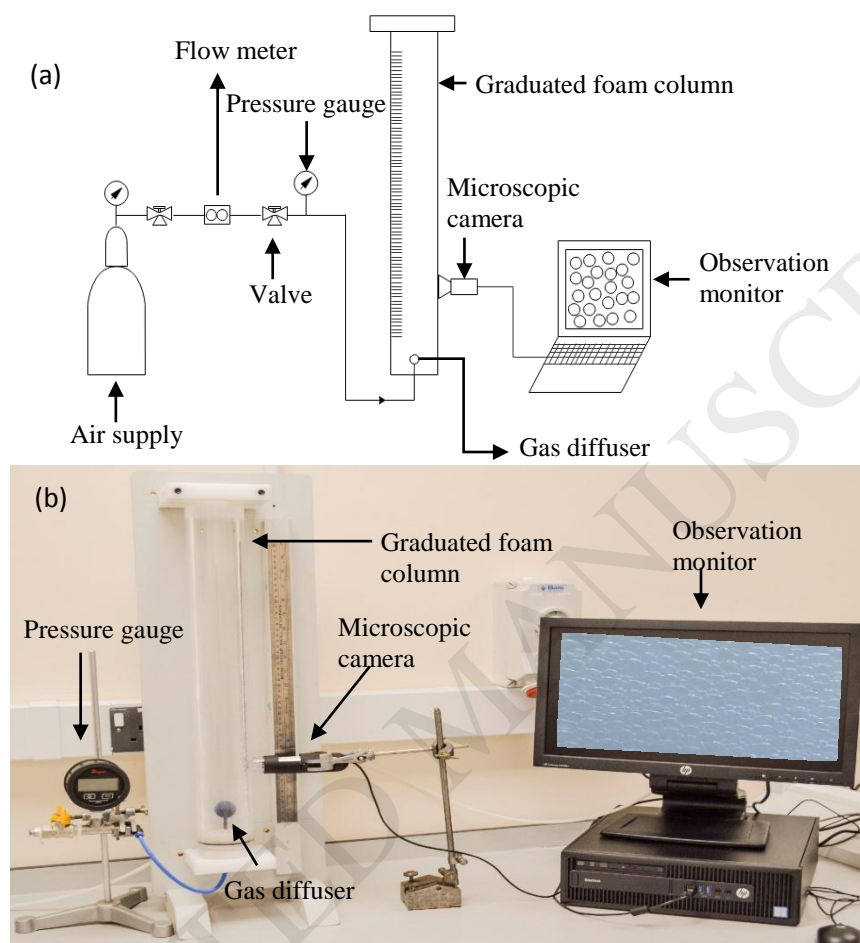


Figure 1: Experimental setup: (a) Schematic diagram and (b) pictorial representation

2.1. Methodology

2.1.1. Formulation and preparation of emulsions

Laboratory preparation of emulsions requires sufficient agitation of oil droplets into the aqueous solution containing surfactants, at a concentration greater than the critical micelle concentration. Five emulsion samples of different salinities were prepared, and their respective formulations are shown in Table 2. For each sample, an aqueous solution containing surfactant, brine and deionized water was stirred and placed in glass sample jars. The critical micelle concentration (CMC) of AOS (Alpha Olefin Sulfonate) type surfactant was measured to be 0.1

wt% in deionised water. A surfactant concentration five times greater than the CMC (0.5 wt%), was deemed appropriate for the experiment [47]. Crude oil was carefully poured over the aqueous samples in the glass jars. Sufficient agitation of the mixture was provided, first by using magnetic stirrer at a speed of 500 revolutions per minute for one hour. Then after samples were immediately transferred to an ultrasonic bath for further agitation. The bath was set at a constant temperature of 40 °C and filled with water to a level that covers the samples completely. Dispersion by ultrasonic bath was run for three hours after which samples were taken out and left to stabilize for 24 hours. Figure 2 shows the final oil emulsion samples in equilibrium with the excess oil phase.

Table 2: Formulation of emulsion samples with different salinities

S/N	Volume of oil phase (ml)	Volume of aqueous phase (ml)	Salinity of aqueous phase (wt%)
1	20	70	0.0
2	20	70	0.5
3	20	70	1
4	20	70	1.5
5	20	70	2

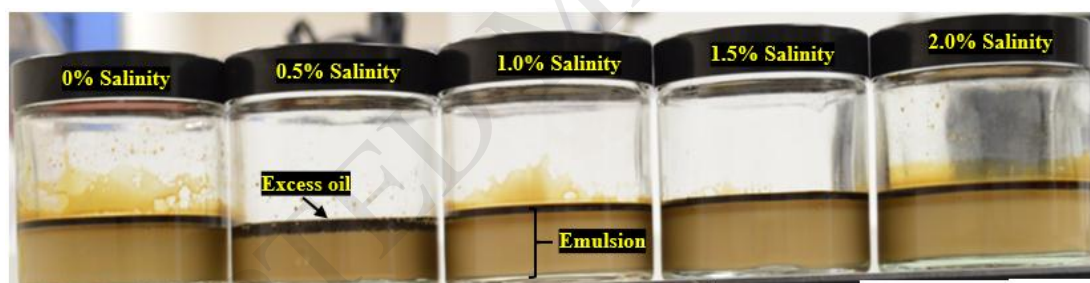


Figure 2: Prepared emulsion samples with different salinities

2.1.2. Bulk foam stability test

A total of eighteen test samples with the surfactant concentration of 0.5 wt%, were prepared using two different types of surfactants (nine samples for each type of surfactant; alpha olefin sulfonate and sodium dodecyl benzene sulfonate (SDBS)). Considering the target volume, each solution was prepared by mixing appropriate volumes of surfactant with deionized water. The volume of surfactant that must be added to obtain the desired concentration is calculated using Equation (5):

$$V_s = C \times V_t \quad (5)$$

where V_s is the volume of the surfactant in the solution, C is the concentration in ppm and V_t is the target volume. A target volume of 175 ml was chosen to ensure the gas diffuser is completely submerged in the test solution, and at the same time, it does not limit the space available to house the foam in the column. For each type of surfactant, prepared samples of emulsions were added to four test solutions in different percentages, relative to the volume of existing surfactant solution (2 vol%, 4 vol%, 8 vol% and 16 vol%). All experiments were conducted at room temperature and atmospheric pressure. Gas was sparged into the column containing the test solution until the desired height of 41 cm was achieved. The gas flow rate was maintained at 0.8 litre per minute and the corresponding injection pressure was 2.1 Kpa. Foam height as a function of time was monitored. Results obtained for each type of surfactant were compared against each other, to observe the effect of emulsion on foam stability with different types of surfactant. Two sets of experiments were carried out. The first set of experiments were conducted to observe the effect of emulsion concentration without salinity, on foam stability. Results obtained from this set of the experiment were compared with a base case where the test solution contained no emulsion. The second set of experiments were conducted to observe the effect of different emulsion salinities on foam stability. A constant emulsion concentration of 8 vol% was used and the only varying parameter was salinity. Table 3 summarizes the type and number of experiments conducted using two types of surfactants.

Table 3: Summary of foam stability tests

S/N	DESCRIPTION	CODE NAME FOR SURFACTANTS USED	
		AOS	SDBS
	-		
1	Test solution without emulsion	E0%(A)	E0%(S)
2	Test solution with 2% emulsion concentration	E2%(A)	E2%(S)
3	Test solution with 4% emulsion concentration	E4%(A)	E4%(S)
4	Test solution with 8% emulsion concentration	E8%(A)	E8%(S)
5	Test solution with 16% emulsion concentration	E16%(A)	E8%(S)
6	Test solution with 8% emulsion concentration and 0.5 wt% salinity	E8%+S0.5(A)	E8%+S0.5(S)
7	Test solution with 8% emulsion concentration and 1.0 wt% salinity	E8%+S1.0(A)	E8%+S1.0(S)
8	Test solution with 8% emulsion concentration and 1.5 wt% salinity	E8%+S1.5(A)	E8%+S1.5(S)

9	Test solution with 8% emulsion concentration and 2.0 wt% salinity	E8%+S2.0(A)	E8%+S2.0(S)
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2.1.3. Image analysis

Microscopic pictures of foam were taken at selected time intervals and analysed using the ImageJ digital image processor. This software requires all images to be converted to an 8-bit grey scale image. A suitable threshold is then applied to produce binary images and to properly delineate the boundaries of the foam bubbles. Figure 3 shows a contrast between the original image of the foam bubbles and the same image after applying the grey scale function.

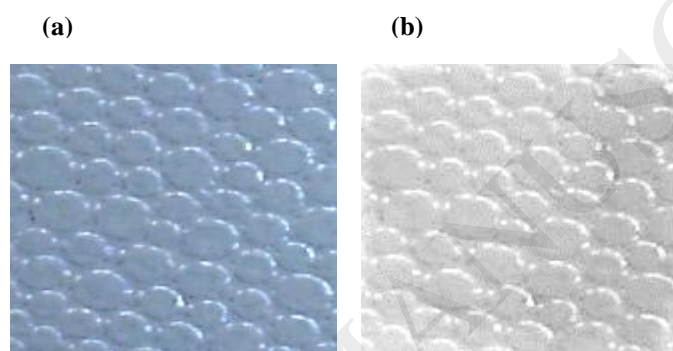


Figure 3: Combined image showing (a) original image of foam bubble and (b) 8-bit grey scale image after a threshold

3. Results and discussion

3.1. Analysis of emulsion samples

Emulsion samples were tested under a microscope to visualise and make sure the oil droplets were completely dispersed in the aqueous phase. Figure 4 shows the dispersion of oil droplets into the aqueous solution with different salinities. The oil droplets have low interfacial tension with the aqueous phase, as they were surrounded by surfactant molecules. This reduction in interfacial tension ensures the oil droplets remain stable in the aqueous phase.

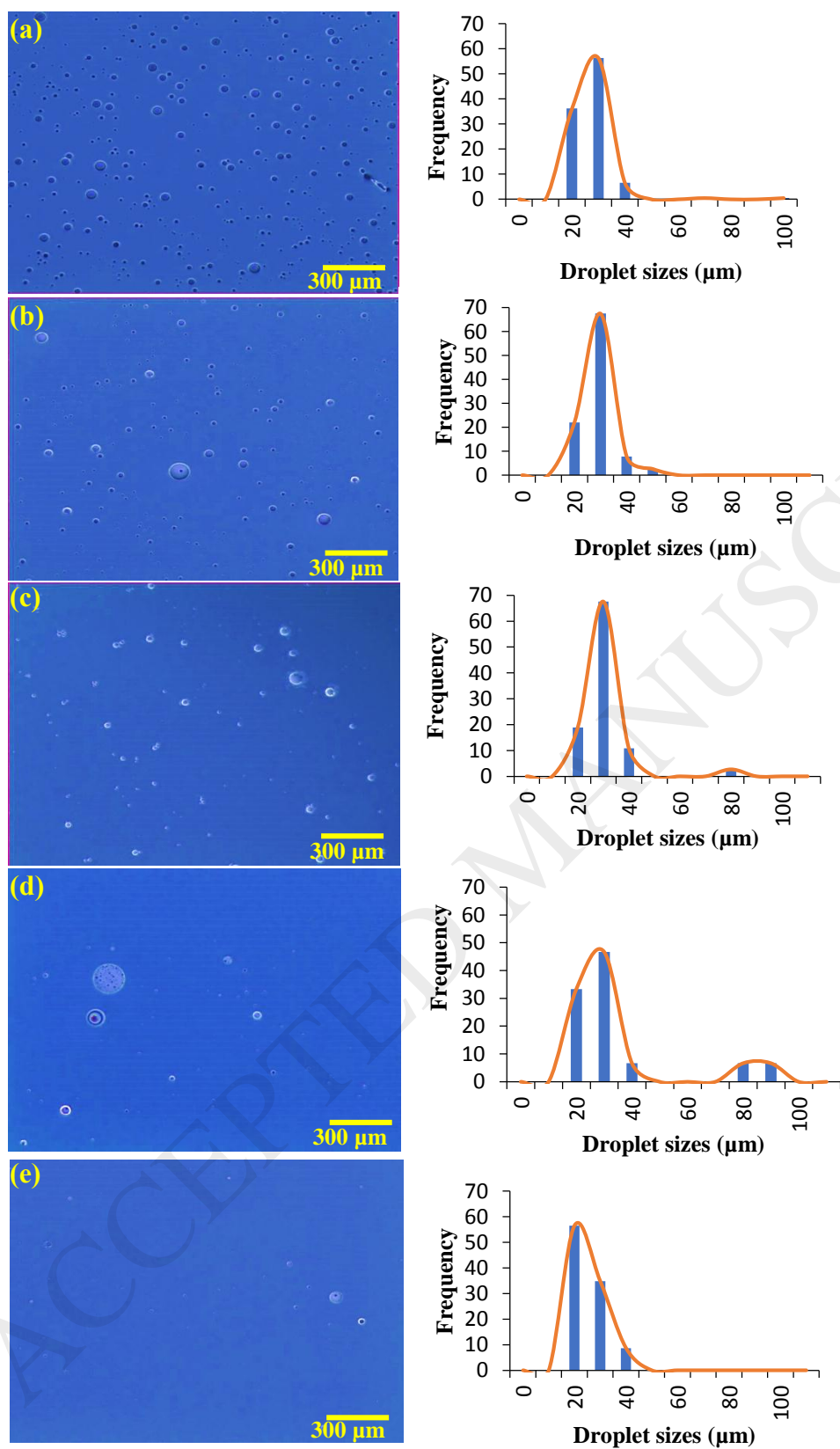


Figure 4: Microscopic image showing dispersed oil droplets in aqueous solutions at (a) 0 wt% salinity, (b) 0.5wt% salinity (c)1.0wt% salinity (d)1.5wt% salinity (e) 2.0wt% salinity

It can be seen that the amount of dispersed oil was reduced with increasing salinity of the aqueous phase. Emulsion samples with lower concentrations of salt have a larger amount of dispersed oil compared to the samples containing higher concentrations of salt. This behaviour is due to the fact that the efficiency of surfactants in reducing the interfacial tension between oil and water decreases by increasing the concentration of salt in the system. The number of dissolved surfactant molecules available to form a stable film around the oil droplets is significantly reduced, hence a reduction in the number of oil droplets occurred. However, the frequency distributions for the droplet size of the dispersed oil show similarities at all concentrations of salinity.

Figure 5 compares the number of dispersed oil droplets in one square centimetre of the emulsions, as a function of salinity. There is a sharp reduction in the number of oil droplets during the initial addition of salt into the emulsion. Afterwards, the rate of decline in the number of oil droplets is reduced at higher concentrations of salt. This figure demonstrates that the effect of salinity on the emulsification of oil is more pronounced in the number of dispersed droplets than the change in their size. The result presented in Figure 5, shows that at some levels of salinity, there would be no oil drops dispersed into the aqueous phase and hence no emulsion can be generated. To justify this result, a fresh emulsion sample was prepared using the salt concentration of 3 wt%. As shown in Figure 6 oil emulsion at the solution with 3 wt% salinity was transparent, while emulsions in solutions with lower salt concentrations were opaque. This shows that relatively few numbers of oil drops were dispersed.

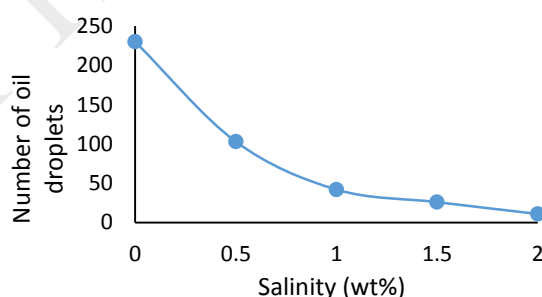


Figure 5: Number of dispersed oil droplets as a function of salinity

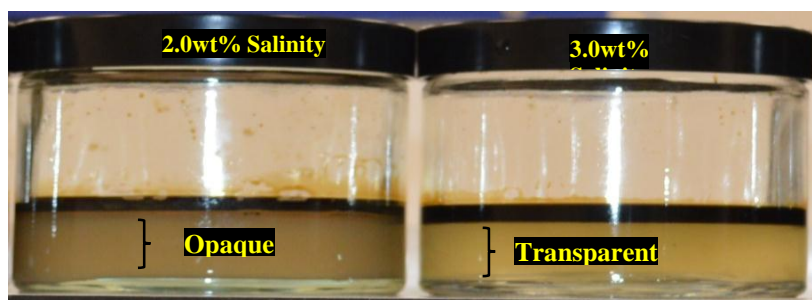


Figure 6: Comparison of emulsion samples for 2.0wt% and 3.0wt% salinity

3.2. Effect of emulsified oil on foam stability

3.2.1. Foam decay

An experimental investigation of the effect of emulsified oil on foam stability was carried out using AOS and SDBS surfactants. The results presented in Figure 7 (a) and (b), show a reduction in foam life with addition of a small concentration of emulsified oil. The sensitivity of each surfactant to the presence of emulsified oil is different. AOS surfactant demonstrated a more tolerant behaviour compared to SDBS. The stability profiles of AOS samples showed gradual and gentle changes by increasing the concentration of emulsified oil. In the case of SDBS, the detrimental effect of the emulsified oil was increased. There is a very sharp shift in the decay profile, between emulsion concentrations of 0% and 2%. For the AOS surfactant, the effect of emulsified oil on foam destabilisation showed an onset time of 20 minutes after running the experiment. This can be seen in Figure 7(a) where the foam decay profiles at different concentrations start to deviate at different decline rates. The onset time for the effect of emulsified oil on SDBS foam was 5 minutes after running the experiment as shown in Figure 7(b).

Figure 8 illustrates a comparison of the half-life of each surfactant at various concentrations of emulsified oil. It gives a better illustration of the destabilization degree of each surfactant in the presence of oil emulsions. For AOS type surfactant, a gradual decline in half-life was observed with increasing concentration of emulsions in the foam structure. The declining trend in SDBS is steeper and insensitive to increasing concentration. Addition of a small concentration of emulsified oil results in a reduction in half-life to a value less than 50% of the half-life of the foam with no emulsions. Further addition of emulsions to the SDBS foam shows insignificant changes in the half-life.

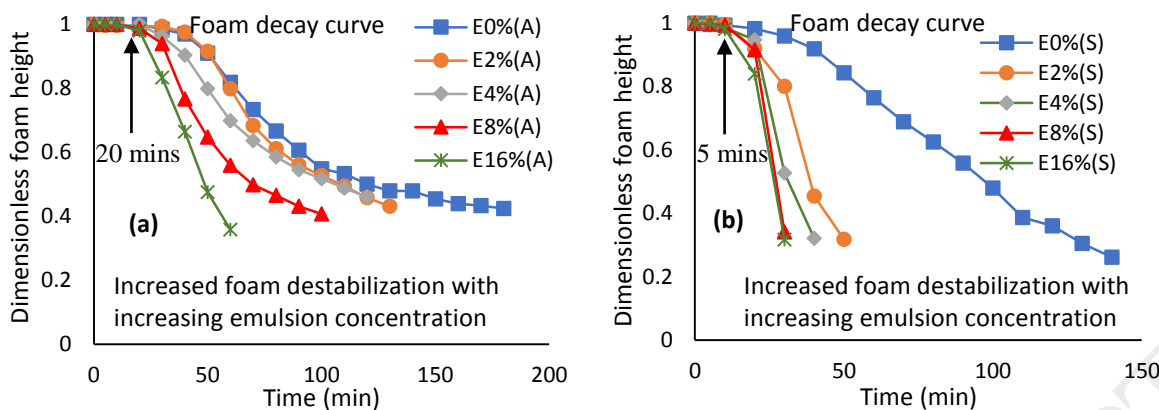


Figure 7: Foam decay curves for, (a) AOS and (b) SDBS at different concentrations of oil emulsion

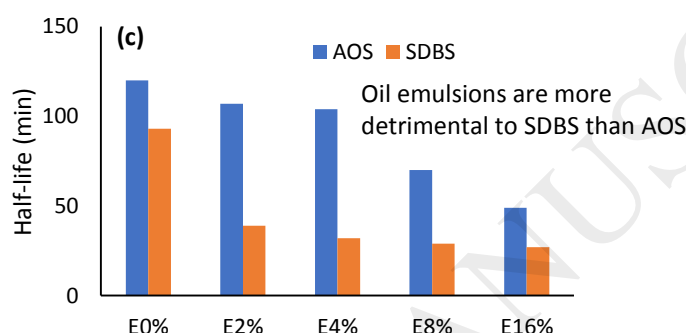


Figure 8: Half-life comparison for AOS and SDBS in the presence of oil emulsions at different concentrations

To buttress these observations in our experimental study, foam height images were taken after 30 minutes and compared in Figure 9 (a) and (b). The foam height of AOS is significantly higher than the foam height of SDBS. The main difference between the stability of the foams generated by AOS and SDBS can be explained through the strength of charges contributed by the anionic surfactants. As shown in Figure 10, negatively charged ions in these surfactants arranged at the liquid-gas interface that separate the gas phase from the liquid phase in the foam structure. This creates a repulsive force between the interfaces on both sides of a lamella. AOS ions are believed to have a charge density that is considerably larger than the ions associated with SDBS. Therefore the repulsive force created by AOS ions is greater, which will increase the thickness of the lamella and plateau border. The thickened layers are generally associated with more stable foam structure and provide more room to house the oil droplets. Therefore, these droplets can flow easier inside lamellae without draining the whole surfactant as they move downwards. Also, the increased thickness of lamellae, in addition to the stronger negative charges on the interface of AOS foam keep oil droplets (which have negatively charged components) away from the gas-liquid interface. This helps to avoid the disturbance of the

arrangement of the surfactant ions at the interface of bubbles, and as a result foam life can be higher compared to the surfactants that have ions with a weaker electrical charge such as SDBS.

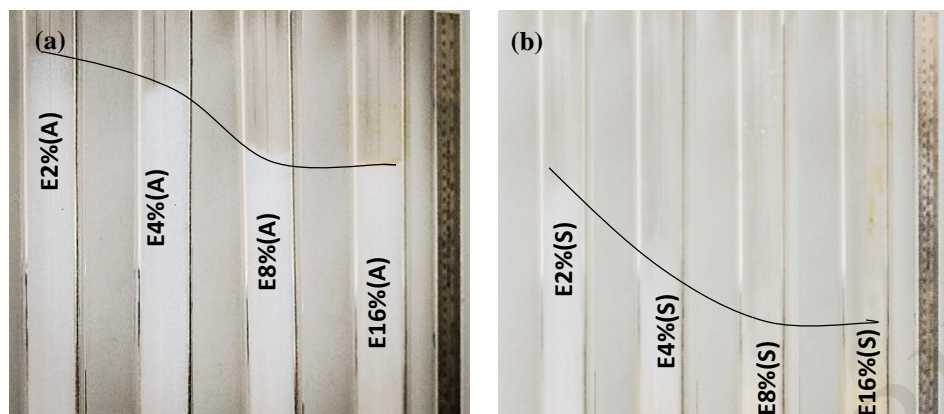


Figure 9: Bulk foam images of (a) AOS and (b) SDBS at different concentration of the emulsions

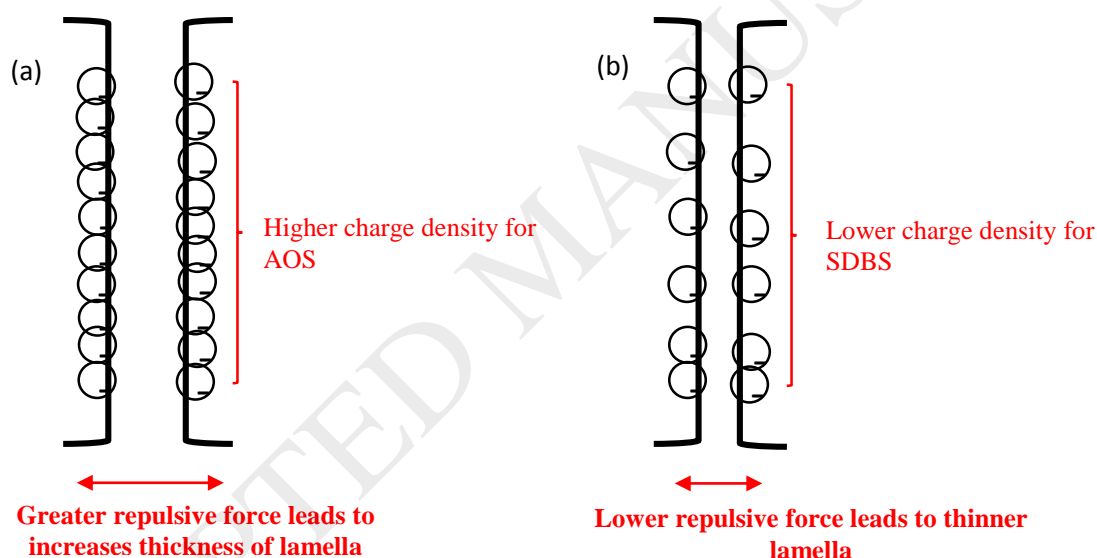


Figure 10: Diagrammatic representation of the arrangements of ions along the gas-liquid interface for (a) AOS surfactants and (b) SDBS surfactants

3.2.2. Foam texture

The results obtained from the digital image analysis are presented and discussed in this section. Figures 11 and 12 show microscopic images of foam bubbles at different concentrations of emulsions, were taken after 10 minutes of foam generation. Emulsion concentrations of 2% and 8% were compared with the case with no emulsion (E0%). Figure 11 represents the foam texture and bubble size distribution of AOS and Figure 12 represents them for SDBS foam. Both figures show an increase in the average bubbles sizes with increasing the concentration of emulsions i.e., larger sized bubbles were formed in the presence of emulsions.

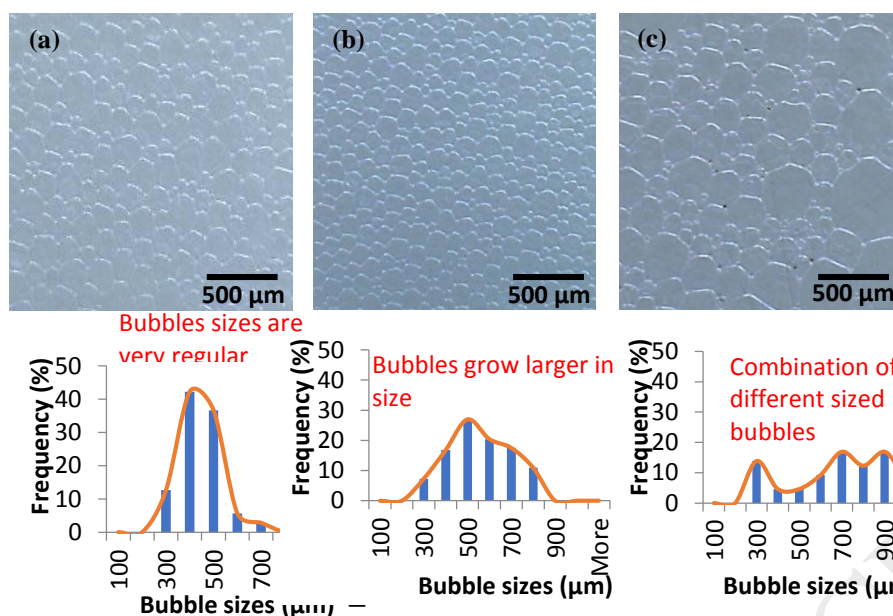


Figure 11: Microscopic images and bubble size distribution of foam after 10 minutes for (a) E0%(A), (b) E2%(A) and (c) E8%(A)

It was noted that the transition from spherically shaped bubbles to polyhedral shaped bubbles after foam generation was rapid. The destabilising nature of the oil emulsions enhances liquid drainage due to gravity by squeezing it out of the lamella. The aqueous liquids are replaced with oil droplets in the foam structure. Comparing the frequency distribution for both surfactants, it is evident that the SDBS surfactant shows a broader and less uniform distribution of bubble sizes due to its reduced tolerance in the presence of oil emulsions.

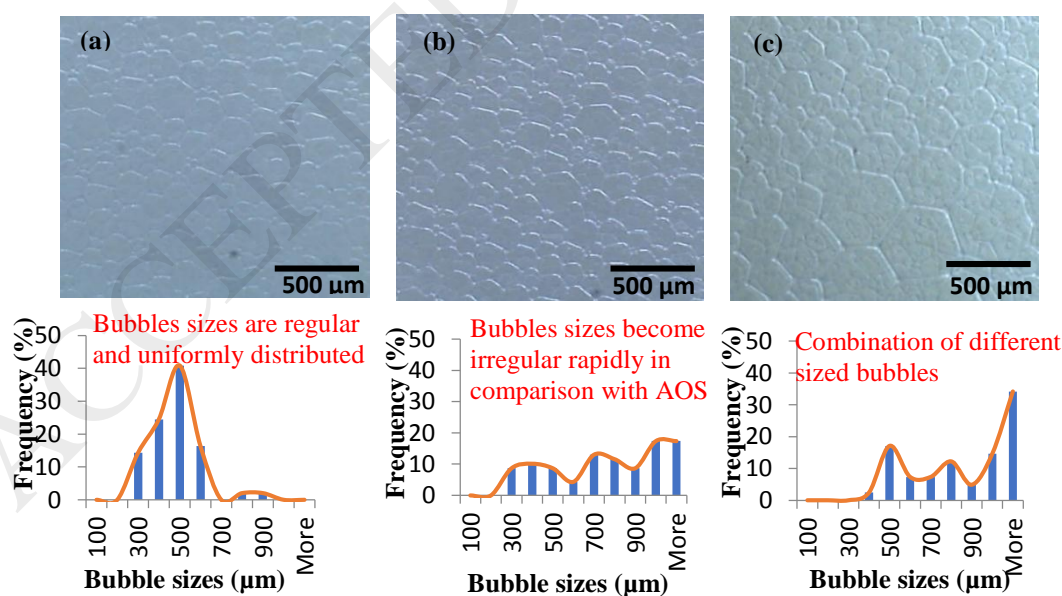


Figure 12: Microscopic images and bubble size distribution of foam after 10 minutes for (a) E0%(S), (b) E2%(S) and (c) E8%(S)

3.2.3. Mechanism of foam destabilization

An oil emulsion is a combination of oil and aqueous phases in the presence of a surface acting agent, which is the AOS surfactant in this research. Since surfactants enhance the stability of foams, the observed destabilization of the foams in the presence of emulsions, is a function of the emulsified oil in the aqueous solution. Destabilisation of foam is highly dependent on the ability of the oil droplets to enter and spread in the lamella, and destroying it in this process. Equations (1) and (2) proposed by Schramm and Novosad [31] were employed to validate the destabilising effect of the crude oil used in this research. Based on the measurements in this study, an entering and spreading coefficient of 52.65 and 13.75 were calculated respectively. However, in an actual reservoir, high magnitudes of pressure and temperature are almost always expected. This suggests that the entry and spreading ability of the same crude from the North Sea, utilised in this experiment would be significantly higher due to a further reduction in the viscosity of the oil. Hence, it is expected that the destabilising effect of oil emulsions would be greater at reservoir conditions. Schramm and Novosad stated that a positive coefficient value is an indication of the antifoam capacity of any oil type, which the destabilising effect in this study confirmed their statement. The mechanism of oil destabilisation at the gas-liquid interface of a foam structure is illustrated in Figure 13.

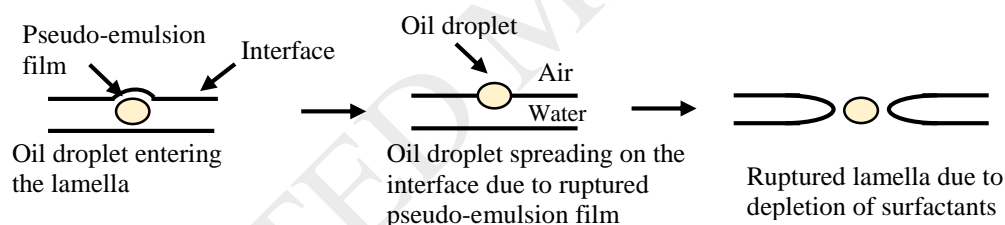


Figure 13: mechanism of foam destabilisation at the lamella

The entry of an oil droplet into the lamella forms a pseudo-emulsion film which separates the gas phase from the oil phase. If this film ruptures, the oil droplets are free to invade and spread on the interface. This forms an oil lens that drains out the liquid from the film interface. The rupture of the pseudo-emulsion film could be attributed to the lack of adequate amount of surfactant in the film to stabilise it. Lobo et al. showed that when oil is dissolved in a saturated surfactant solution, the concentration of surfactant is depleted due to the solubilisation of oil in the existing micelles [42]. This would, in turn, lead to an increase in Vander Waals forces between micelles, decreasing its concentration.

In relation to the mechanism described above, Figure 14 is a microscopic picture of the foam selectively taken to show the process of entering of oil droplets into the foam lamella. It shows

oil droplets embedded in the lamella of the foam structure, which results in the formation of a pseudo emulsion film that separates the gas phase from the liquid phase.

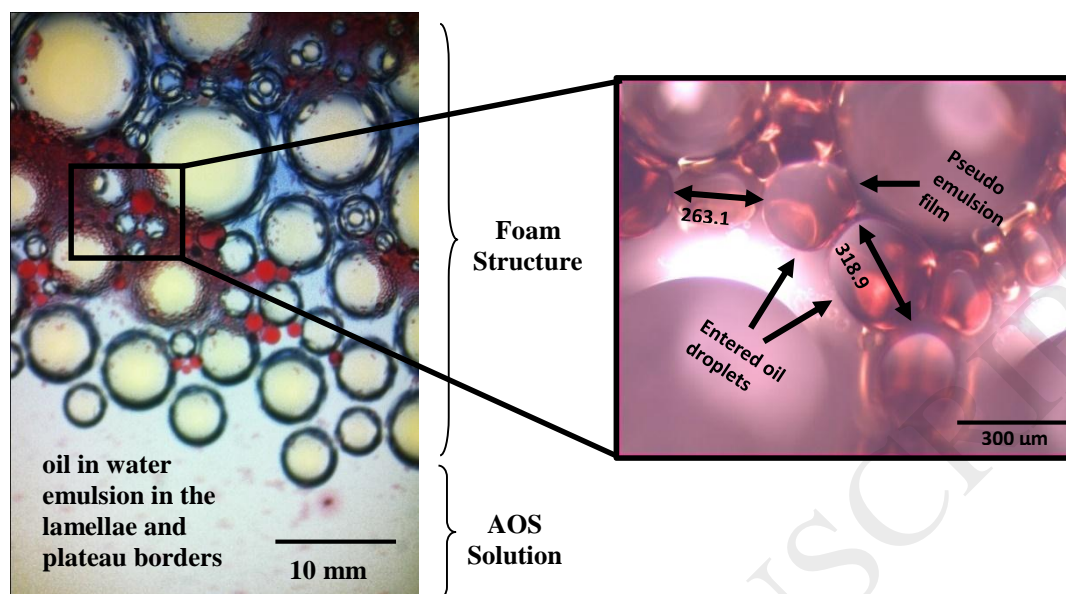


Figure 14: Microscopic image of oil droplets entering the lamella

3.3. Effect of salinity on foam stability in the presence of emulsified oil

3.3.1. Foam decay

The stability of foams in the presence of saline emulsions was analysed using both surfactants. As the salinity of the emulsified oil increases, less oil will be solubilised in the surfactant. It is therefore expected that the stability of foam in the presence of saline emulsion is higher compared to the foam stability in the presence of emulsified oil with zero salinity. Figure 16 (a) and (b) shows the foam decay at different emulsion salinities for AOS and SDBS surfactants respectively. Figure 15 compares the half-life for both surfactants in the presence of saline emulsions. Individual surfactant showed completely different results for each test. Results obtained for AOS surfactant showed the expected trend as explained earlier, where foam stability increases with increasing salinity of the emulsion. A close examination of Figure 15(a) and Figure 16 shows the greatest level of stability occurred at the salinity of 1.5 wt% and 2.0 wt%. The trend in foam decay and the foam half-life, remain the same at these salinities. Only small improvements in the stability were seen at higher salinities. Therefore, at higher salinities, the stabilising effect of salt on AOS remains constant. Again, the stabilizing effect of salt on AOS kicks in after 20 minutes. This time is consistent with the previous tests on the effect of pure oil emulsions, in which the destabilising effect kicked in also after 20 minutes of running the experiment.

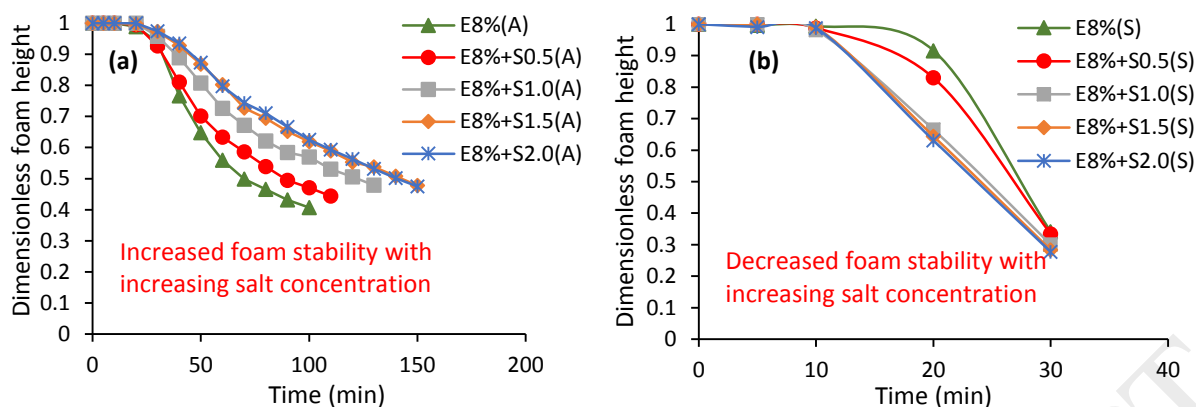


Figure 15: Foam decay curve for (a) AOS, and (b) SDBS at different salinities of emulsion

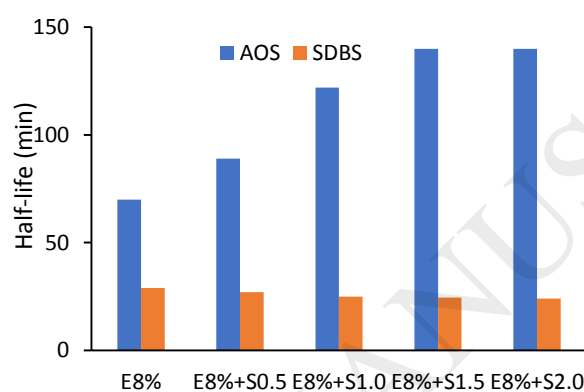


Figure 16 : Half-life comparison for AOS and SDBS in the presence of oil emulsions at different salinities

In as much as a stabilising effect was achieved for AOS, an interesting result was observed in the case of SDBS. Although a smaller volume of oil is solubilised in the aqueous solution containing salt, there is a further decrease in foam stability with increasing salinity. Figure 15(b) shows a steady decline in foam stability between an emulsion salinity of 0 wt% and 0.5wt%. The foam decay profiles for both salinities followed the same trend. However, at salinities above 0.5wt%, the foam decay is steep and remained constant at higher salinities. The half-life as shown in Figure 16 remained almost the same at salinities of 1wt% and above. The destabilising effect of salt on SDBS surfactant occurred only after 10 minutes of running the experiment. The difference in time between both surfactant can be translated as the AOS has a higher capacity of withstanding changes in conditions to which it is exposed.

The effect of emulsified oil on foam stability from this study have been compared with the effect of continuous oil phase on foam stability tests conducted by Farzaneh et al [39]. As can be seen in Figure 17, it was found that emulsified oil has much less deteriorative effect on bulk foam stability in comparison with the continuous oil phase. This is probably because of

minimal changes in interfacial properties of lamellae and plateau borders when emulsified oil enters into their structures compare to bulk oil. However, Farzaneh et al [39] used heavy crude oil with density of 16 API° and viscosity of 674 mPa.s, but our study has been conducted using a crude oil with density of 24 API° and viscosity of 53.87 mPa.s at 20 °C. There might also be an effect of oil viscosity and density which need to be investigated in further studies.

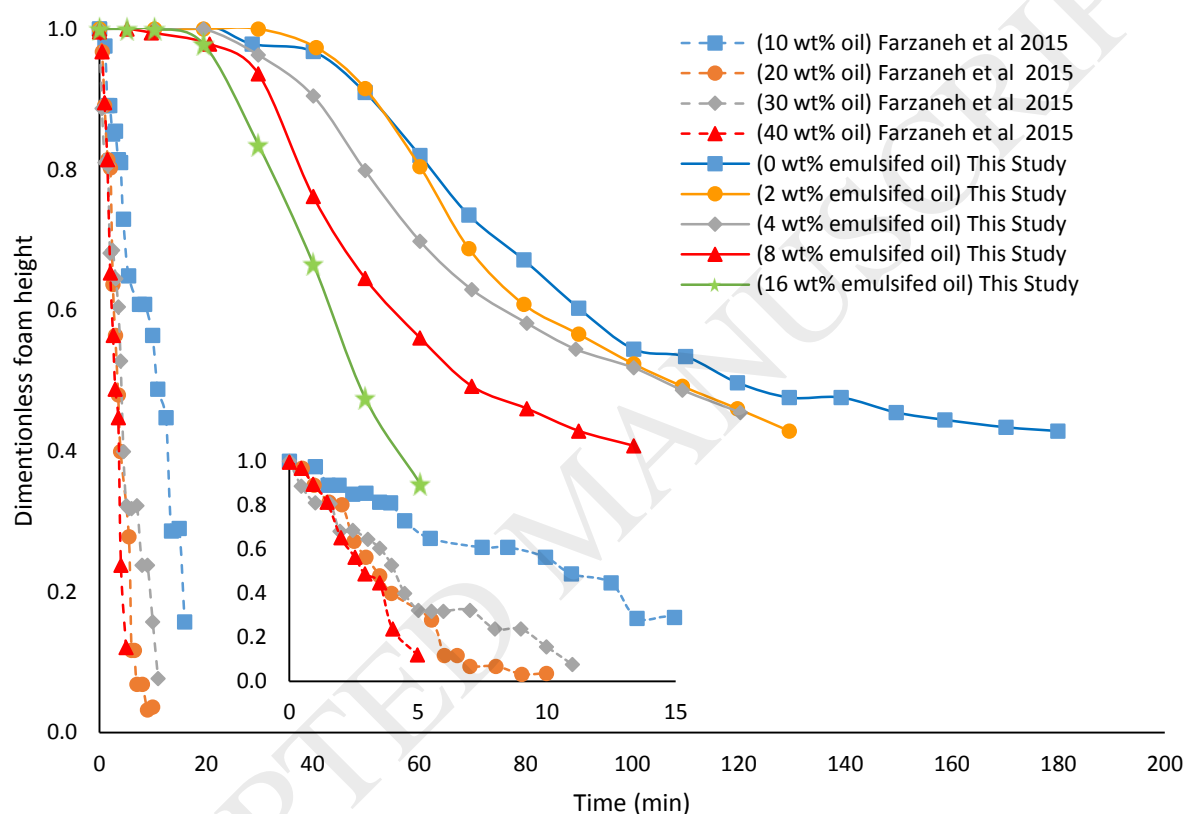


Figure 17: Comparison of foam decay curves between emulsified and continuous oil phase. Inset plot is expanded time-axis for the results shown by Farzaneh et al 2015.

3.3.2. Foam texture

Analysis of bubble images for both surfactants is presented in Figure 18 and 19 to compare the effect of saline emulsions on the foam texture. AOS surfactant showed an improvement on the foam texture with increasing salinity. Smaller foam bubbles which are an indication of foam

stability were generated with increasing salinity. This result is consistent with the results obtained from the foam decay profiles.

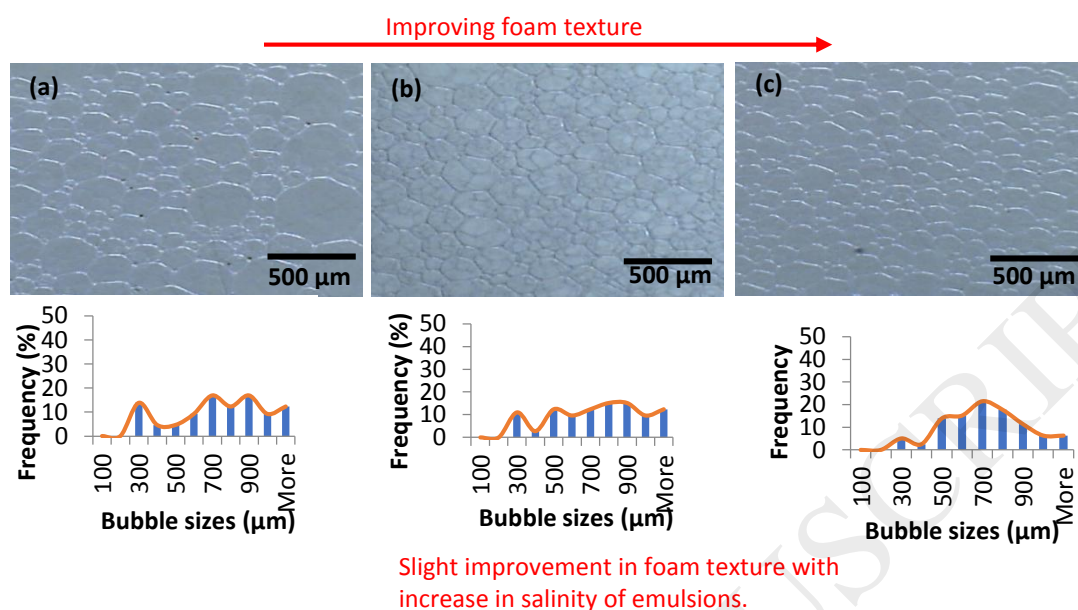


Figure 18: Microscopic images and bubble size distribution of foam after 10 minutes for (a) E8%(A), (b) E8%+S1.0(A) and (c) E8%+S2.0(A)

The SDBS surfactant showed no significant difference in the distribution of bubble sizes with changing salinity. Bubbles remained large and coarse, with a very broad distribution frequency. This result is consistent with the foam decay profiles presented in Figure 15(b).

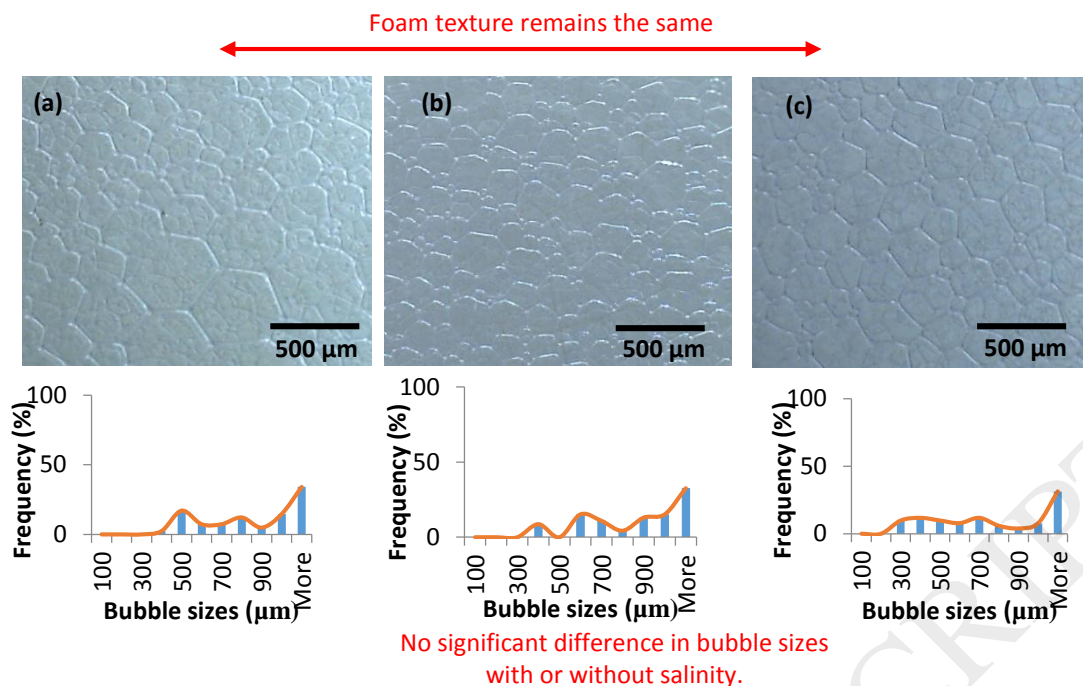


Figure 19: Microscopic images and bubble size distribution of foam after 10 minutes for (a) E8%(S), (b) E8%+S1.0(S) and (c) E8%+S2.0(A)

3.3.3. Nature of salt in the foam structure

The stability of AOS has been shown to increase in the presence of highly saline emulsions. Since the number of dispersed oil droplets decreases with salinity, the stabilising effect can be thought as a function of salinity of the aqueous solution. In a typical foam structure, depending on the ionic property of the surfactants, the gas-liquid interface is saturated with the respective charge of the monomers of the surfactant molecules. This causes a movement of ions initially present in the aqueous solution towards the interface. This action motivates the creation of an electric double layer in which counter ions are attracted to the charges on the gas-liquid interface. Due to this electric double layer, the interface is not capable of absorbing a large number of the surfactant molecules from the aqueous solution.

The introduction of salt into the foam structure suppresses the formation of this electric double layer, thus enhancing surfactant adsorption at the interface. Several studies have shown that the presence of monovalent salt molecules in foam structure increases adsorption of surfactant thus strengthening the foam film [48-50]. The foam film becomes rigid thus delaying liquid drainage and enhancing stability.

On the other hand, the stability of SDBS was reduced with increasing salinity. This could be due to an intrinsic property of the surfactant that reduces its tolerance to salt.

4. Conclusions

A thorough investigation on the effect of emulsified oil on foams was conducted through the foam column test at room temperature and atmospheric pressure. The results obtained from the column tests indicated that a strong interaction between the oil emulsions and foams depends on the entering and spreading ability of the oil into the structure of lamella. Experiments were performed to calculate the entering and spreading coefficient of the North Sea crude oil, and their positive values signified a destabilising effect which correlated well with the bulk foam stability tests.

An observation on the number of dispersed oil droplets in the aqueous solution showed a reduction with the salinity of the aqueous phase. Therefore, the stability of the foam generated with AOS surfactant was significantly enhanced whereas the foam generated with SDBS surfactant showed a poor performance in the presence of saline emulsions. The disparity in foam stability with the two surfactants is believed to be a result of ionic charges and an intrinsic property associated with the respective surfactant molecules. Since the majority of petroleum reservoirs are highly saline, it is imperative that a thorough study and research is conducted on various surfactants to select the most suitable one for the project to be undertaken.

This research has shown that the oil emulsions are detrimental to the stability of foams generated regardless of the type of surfactant. Since oil is present in any reservoir, there is always a threat of foam destabilization through emulsified oil droplets in the lamella. Methods which could be employed to improve foam stability in the presence of oil require detailed research and analysis of the type of surfactants to be used in foam generation. Depending on the properties and salinity of the reservoir, the most tolerant surfactant should be identified and considered for the foam generation. The second alternative would be the generation of foam outside of the reservoir. Though this method is often applied to highly permeable and low pressured reservoirs, the formation of oil emulsion due to injection of surfactant is avoided and the risk of foam destabilization can be reduced.

Acknowledgements

The authors would like to thank the School of Engineering at the University of Aberdeen for providing materials and facilities to conduct this research.

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