



Experimental study on the performance of emulsions produced during ASP flooding

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Abstract

ASP (Alkaline/Surfactant/Polymer) flooding is one of the most promising techniques that has proven to have successful application in several laboratory and pilot tests. However, the formation of persistent and stable emulsions is one of the associated problems with ASP flooding. The present work investigated the effect of sodium carbonate alkaline, Alpha Olefin Sulfonate (AOS) surfactant, and GLP100 polymer on produced crude oil emulsion. The study was conducted by measuring the emulsion stability in terms of water separation and rag layer volume using a TurbiScan analyzer, the dispersed droplet size using cross-polarization microscopy, the interfacial tension using spinning drop tensiometer, and rheological properties using rheometer. The experimental results have shown that AOS presence increased the emulsion stability only when its concentration is above 100 ppm. Meanwhile, below 100 ppm, the presence of AOS promoted water separation and reduced the rag layer volume. In a less significant manner, a high concentration of sodium carbonate alkali increased the stability of the emulsion. The use of GLP100 Polymer has shown substantial ability in promoting water separation and reducing the rag layer volume to a minimal level. It is believed that the outcomes of this work will aid in developing a suitable destabilization process to enhance the oil–water separation and produced water treatment from ASP flooding in the oil production fields. Further investigations on AS, AP, SP as well as the ASP's combined effect on emulsion stability, droplet size, interfacial tension and rheological properties are highly recommended to support the decision-makers on the EOR implementations with chemical additives.

Keywords Alkaline/surfactant/polymer (ASP) · Crude oil · Emulsion stability · EOR · IFT · Rag layer

Introduction

The increasing demand for crude oil and the declining number of new oil fields discoveries have imposed a need to apply new recovery technologies to extract additional oil (Belhaj et al. 2019a; Saxena et al. 2019). Over the years, enhanced oil recovery (EOR) processes have been developed to recover additional trapped oil from the remaining oil in the developed reservoirs (Yekeen et al. 2019). Compared to other EOR techniques, chemical flooding appears to be more effective and economic (Belhaj et al. 2019b; Li et al. 2019). For a mature water flooding, the capillary number is usually in the range of 10^{-7} to 10^{-6} , which is considered insufficient to recover a sufficient oil volume; thus, a great deal of residual oil remains behind (Ahmed and Khaled 2018). Therefore, a higher capillary means more residual oil recovery after the water flooding process (Kang et al. 2020). The utilization of chemical enhanced oil Recovery (CEOR) contributes to

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increasing the capillary number, which will result in reducing the residual oil saturation (Pal et al. 2019). CEOR is a type of EOR used to increase oil recovery by injecting alkali (A), surfactant (S), polymer (P) or a combination of the chemicals such as, SP or ASP (Belhaj et al. 2021a; Sheng 2011). In recent years, several ASP projects were reported from oilfields in different countries. It has been surveyed that the ASP flooding is adopted for EOR in 87 fields worldwide. Seventy-four projects are reported in the US, three projects in China and Indonesia, two projects in France and Romania, and one project Germany, UK, and Russia (Riswati et al. 2019; Sheng 2015; Al-Shuaili et al. 2016; Fortenberry et al. 2016; Onyekonwu and Akaranta 2016; Rohilla et al. 2016). In ASP flooding, surfactants reduce the interfacial tension (IFT) between the injected water and trapped oil, therefore, mobilizing the residual oil from its pores (Sayed et al. 2019). Meanwhile, alkalis reduce the surfactant adsorption on the rock and assist in further reducing IFT to ultralow level by producing in-situ surfactant (soap) through a chemical reaction between the alkali and the organic acids existing in the reservoir. Polymers increase the injection water viscosity, making it a key in mobility control, leading to improved sweep efficiency (Sheng 2014). ASP flooding has proven to increase oil recovery up to 20% OOIP after waterflooding (Kang and Wang 2001; Olsen et al. 1990).

One of the associated problems with ASP flooding is the formation of stable emulsions (Weatherill 2009). Emulsion formation induces many operational problems such as pressure drop in flow lines, difficulty in producing water treatment and water–oil separation (Sheng 2014). The problem of separating water from crude oil is known since the beginning of the oil industry. An emulsion is a system in which the droplets of one liquid are dispersed immiscibly in another continuous liquid phase. The crude oil emulsion is typically a dispersion of water and oil caused by excessive turbulence throughout the production system (Belhaj et al. 2020a; Khatri et al. 2011). Most of the produced emulsions in oilfields are water-in-oil (W/O) emulsions, a dispersion of water droplets in oil. However, other emulsion types are also experienced in oilfields, such as oil-in-water (O/W) emulsion and multiple emulsions of water-in-oil-in-water (W/O/W) and oil-in-water-in-oil (O/W/O) emulsion (Sheng 2014). Generally, the emulsion is thermodynamically unstable, i.e., the phases comprising it tend to revert to the original and stable state of being immiscible and separate phases (Kang et al. 2012). The stability of the emulsion is increased when a surface-active agent (i.e., emulsifier) is present in the emulsion system. Emulsifiers such as asphaltene, wax, and resins are present naturally in crude oil. They tend to stabilize the emulsion by forming an interfacial film on the dispersed droplets hindering their coalescence (Sjoblom 2005). In ASP flooding, the injected chemical components tend to be produced with oil and water, increasing

the emulsion stability (Jeirani et al. 2014). The emulsion behavior changes as the type and concentration of emulsifiers change and the properties of water and crude oil (Sheng 2010). Various alkali was used for CEOR techniques. In the laboratory tests concerning the chemical selection for EOR injection at the field, NaOH and Na₂CO₃ were tested and yielded better results; and therefore selected for the CEOR pilot test (Ibrahim et al. 2006; Belhaj et al. 2020d; Othman et al. 2007). However, there seemed to be a shift of interest from sodium-based to ammonia-based alkali in recent years. Sharma et al. (2016) recommended NH₄OH as an alternative alkali for ASP processes transportation and storage advantages. Kusumah and Vazquez (2017) found that NH₄OH would only require 9% of the storage required for Na₂CO₃ to achieve the same pH value. These findings agree with Southwick et al. (2016), although there was a concern about health safety and environmental issues that need further study.

The contribution of alkaline/Surfactant/Polymer to the stability of produced crude oil emulsions is neither fully understood nor thoroughly investigated. However, there have been reports from previous projects that implicate risk-produced water treatment. A study by Khan et al. (2015) focused on water in oil (W/O) emulsions imposed by ASP flooding for an EOR field in Malaysia to understand the stability of the emulsion layer under typical process conditions. Another group of researchers (Kalra et al. 2012) have attempted to present the rheology of the problematic water in oil emulsion produced at the facility site. They stated that oil production is generally a complicated multiphase flow inside pipelines. Possible water-in-oil (W/O) emulsions present with other usual phases such as free water and free oil. The W/O emulsions formed can present significant hurdles in production facilities for pumping fluids and during pipeline transport. It is well known that high shear rates provided by pumps, chokes, or valves result in stable emulsion behavior for a field in primary production. Kalra et al. (2012) also reported that understanding W/O-emulsion rheology in ASP-injection oil recovery was essential for the design of pumps and pipelines and handling flow-assurance issues. The formation of a W/O emulsion with chemical injection is a renowned problem on the facility side, as it stabilizes the emulsion (Dalmazzone et al. 2012).

The present study is performed as a recommendation from previous research work associated with the crude emulsion treatment problem and extra water handling of an offshore Malaysian field. Sabzabadi et al. (2013) reported that the facility site of that field is experiencing fluid transport problems due to water production in oil emulsion. This offshore Malaysian field is slated to be the first in the world for Alkaline/Surfactant/Polymer (ASP) chemical flooding via a floating structure in an offshore environment. In continuation of the facility problem due to water in oil emulsion in

this offshore Malaysian field, the present study is carried out with the actual breakthrough of alkali/surfactant and polymer in the primary separator. The objective of this study is to determine the stabilization of produced crude oil emulsion at various low concentrations of ASP as EOR chemicals. This work was carried out to investigate the impact of varying percentages of ASP components on the separation process. Experimental measurements have been made to study the effectiveness of EOR chemicals on the separation of 40% of water cut emulsion, with ten different combinations of ASP emulsion. First, the indigenous components of the crude oil in terms of emulsion stability were characterized. Each emulsion with the chemical compound added, i.e., ASP, was characterized by its effect on emulsion stability and droplet size. The experimental investigations focused on the water in oil emulsions imposed by different ASP flooding compositions. In addition, the ability of the polymer concentration on the viscosity of emulsion has been explored. Droplet size distribution has been used to analyze and predict the effectiveness of each individual and combined additives on the stabilization of the emulsion.

Experimental procedure

Materials

The crude oil used in this study was obtained from an identified oilfield in Malaysia. Table 1 shows the physical and chemical properties of the crude oil sample. These parameters were characterized at ambient pressure and 60 °C temperature. The brine water was prepared in UTP laboratory based on the field-produced water properties provided by PETRONAS Research Sdn. Bhd. (PRSB). The composition of the produced water is given in Table 2. All the chemicals

Table 2 Brine properties

Chemical compound	Concentration (g/L)
CaCl ₂ (H ₂ O) ₂	0.8153
MgCl ₂ (H ₂ O) ₆	0.7517
NaCl	9.2734
SrCl ₂ (H ₂ O) ₆	0.0296
KCl	0.4238
NaHCO ₃	7.1593
Na ₂ SO ₄	0.5172

were A.R. grade obtained from Sigma-Aldrich and used without further processing.

For this study, the crude oil used was supplied from the oil field. Alkali solution used is Sodium Carbonate (Na₂CO₃) solution with a stock concentration of 50,000 ppm. Anionic Alpha Olefin Sulfonate (AOS) surfactant at a stock concentration of 10,000 ppm, with a structural formula RCH(OH)(CH₂)_nSO₃Na was used. The polymer used is in-house GLP100 produced at a stock concentration of 0.1% (1000 ppm). The polymer is anionic hydrolyzed polyacrylamide with 16 (million Dalton) molecular weight. The client provided the crude oil sample and stock chemicals. The pH value (1.0% aq. solution) is in the range of 9.5–11.5. The experiments were carried out at 60 °C.

Preparation of emulsion

A total of 10 emulsion samples were prepared to investigate the effect of the chemicals: alkaline (A), surfactant (S), and polymer (P) separately on water separation and rag layer volumes. The emulsion samples were prepared by mixing equal volumes of oil and synthetic produced water with different concentrations of the chemicals, as shown in Table 3.

Table 1 Physical and chemical properties of crude oil

Physical properties		
Property	Units	Value
Density	g/cc	0.79
Viscosity	cp	0.4
API gravity	°API	42
Wax content	wt%	18.82
Total acid number	mg KOH g ⁻¹	0.19
Chemical contents		
Asphaltenes	wt%	0.69
Saturates	wt%	22.52
Aromatics	wt%	10.38
Resins	wt%	1.67

Table 3 Chemical concentration for base case samples

Case	Composition (ppm)		
	Alkaline	Surfactant	Polymer
1	0	0	0
2	250	0	0
3	500	0	0
4	750	0	0
5	0	100	0
6	0	200	0
7	0	300	0
8	0	0	400
9	0	0	500
10	0	0	600

Previously, (Al-Kayiem and Khan 2017; Khan et al. 2019) have carried out experimental studies on the impact of ASP on crude emulsion stabilization, but the concentration of chemicals is higher compared to the low concentrations adopted in the current research. The present study was performed at a minimum possible concentration of the chemical that breaks through in the primary separator. The mixture was prepared using a digital disperser at 12,000 rpm for 2 min. The samples were then poured into the test tube attached with the TurbiScan stability analyzer. Using the TurbiScan, the emulsion stability was measured as a function of the amount of water separated from the emulsion over a time range of 0, 0.5, 1, 2, 6, 12, and 24 h. Between the readings, the emulsion samples were allowed to settle in a thermal water bath at a temperature of 60 °C. All emulsion preparations and measurements were carried out at 60 °C to emulate the temperature of the field separator.

Testing and characterization

Experimental studies were conducted to identify the mechanism by which the emulsion is affected by the chemicals. The interfacial tension properties between crude oil and the solutions of alkali and surfactant were measured using a spinning drop tensiometer. The viscosity of polymer solutions was measured using Anton Paar's rotational rheometer. Micrographic images of the emulsion samples were captured using cross-polarization Microscopy to validate the findings from the stability study.

Measurement of emulsion stability

Investigating the effect of natural emulsifiers and added chemicals on the crude oil emulsion could be achieved by conducting a stability test. The stability of the emulsion is indicated by the separation of the phases, compromising it

over time. In other words, it is indicated by the amount of water separated; the larger the water separated volume, the lower the emulsion stability (Sun et al. 2017). The samples' emulsion stability was evaluated using the TurbiScan test (TurbiScan Lab. Formulation) as described by Kowalska and Żbikowska (2016). Emulsions of the various samples in the glass cells were scanned by a pulsed near the infrared light source and two synchronous detectors. The transmission detectors received the incident beam passing through the samples, indicating the separated water zone, while the light scattered was received by backscattering detectors indicating the unresolved emulsion layer. In the end, the results were presented as the dependency of transmitted and backscattered light intensity as a function of sample height.

Measurement of interfacial tension

The interfacial tension (IFT) properties between crude oil and the solutions of alkaline and surfactant were measured using a spinning drop tensiometer. The interfacial tension measurements were performed using SVT 20 N spinning drop tensiometer from Data Physics Company, Germany. All the experimental interfacial tension results were collected using a fast image processing system with the appropriate software. The measurement was done automatically, and the interfacial tensions were recorded. The tensiometer was calibrated before each measurement cycle to ensure accurate results.

Viscosity measurement of polymer solutions

The effect of polymer concentration on the viscosity of brine was measured using MCR 302 Anton Paar's rotational rheometer at a shear rate ranging between 0 and 1000 1/s and a temperature of 60 °C. The device used a parallel plate measuring system and Peltier temperature control for heating. The viscosity of polymer solutions of concentration ranging between 0 to 800 ppm was measured multiple times, and the average value was taken.

Droplet size analysis for the dispersed water droplet

The size of dispersed droplets was found to influence other properties in the emulsion, such as its stability and rheology (Kokal 2005). This analysis was done to monitor the changes in water droplet size as a function of chemical concentration. Monitoring the changes of water droplet sizes as the chemical composition differs gives information on the stability of the emulsion system. The measurements were done using BX53 Olympus Cross-Polarization Microscopy (CPM), which employs a 24 pins CMOS colored camera with a frame rate range of 10 to 49 images per second. The CPM is supported by a hot-stage (HS82) control unit (HS1)

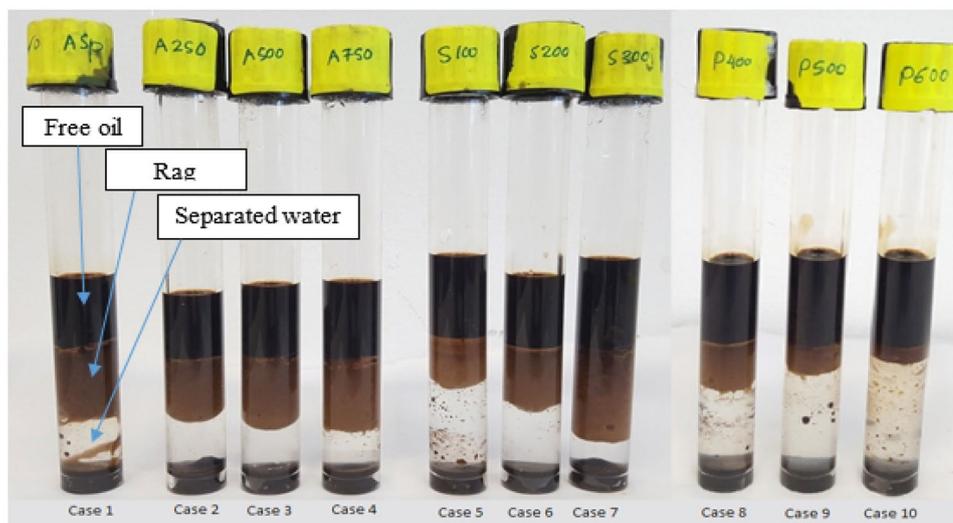
from Mettler Toledo. The measurements were conducted under a 10× magnification lens at 60 °C.

Results and discussion

Effect of indigenous stabilizing components

Figure 1 shows the emulsion samples after 24 h of settling separation test. Case 1 represents the effect of natural emulsifiers alone as alkaline, surfactant, and polymer are absent in this case. The results revealed that only 40% of the original water volume was separated while the remaining water was trapped within the unresolved emulsion layer, also known as the rag layer (Khatri et al. 2011). The rag layer makes up to 50% of the emulsion sample volume of Case 1. The existence of the rag layer after the separation process ceased indicates that the separation process was aborted due to termination in the droplet coalescence (merging) process. The behavior was attributed to the effect of indigenous stabilizing components such as asphaltenes, wax, resins, saturates, aromatics and organic and inorganic solids. The interfacially active components are believed to come mostly from asphaltenes and resins of the crude oil (Li et al. 2002; Sjoblom 2005). Asphaltene and resins have a hydrophilic and hydrophobic nature that accumulates at the oil–water interface, forming an interfacial film around the water droplets. The emulsion was then stabilized as the water droplets become unable to coalesce and settle, so they favor remaining in the rag layer. Wax further increases the stability of the emulsion by precipitating at the oil–water interface, strengthening the interfacial film's rheological properties (Sjoblom 2005). The synergistic effect of the indigenous stabilizers was clear to cause the stability of emulsion in the absence of chemicals.

Fig. 1 Base case emulsion samples after 24 h of settling test



Effect of alkali concentration

Interfacial tension

The interfacial tension (IFT) between the crude oil and alkali solutions is shown in Fig. 2. Noticeably, the interfacial tension between the crude oil and the aqueous phase has increased from 9.66 to 12.2 m N/m in the presence of 250 ppm alkali. However, when the alkali concentration increased above 250 ppm, the interfacial tension decreased until it eventually became the lowest at 8.4 m N/m for an alkali concentration of 1000 ppm. The observations indicated that the interfacially active components (in-situ surfactant), formed by the reaction between the alkali and the crude oil acids, have partially replaced the natural emulsifiers at the oil–water interface. When the alkali concentration was below 250 ppm, the in-situ surfactant that replaced the indigenous emulsifiers, was less interfacially active than that of the indigenous emulsifiers. Thus, interfacial tension was increased.

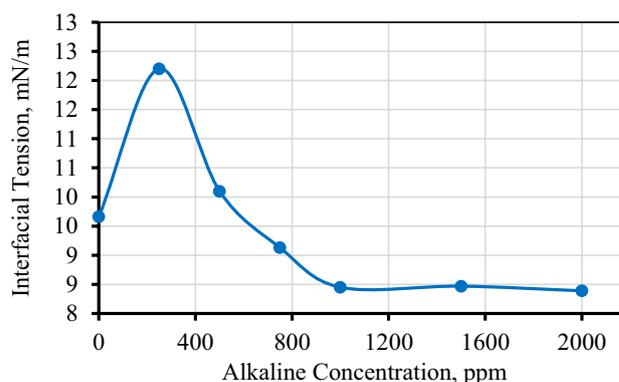


Fig. 2 Effect of alkali concentrations on interfacial tension

Conversely, when the alkali concentration exceeds 250 ppm, the in-situ surfactant becomes more interfacially active as more active components are produced. Therefore, the interfacial tension between oil and water decreases. Similar findings were reported in Sjoblom, (2005). The interfacial tension behavior directly influences the stability of emulsion as the stability increases when the interfacial tension between oil and water decreases (Belhaj et al. 2021b; Deng et al. 2005).

Stability of emulsion

The effect of alkali on emulsion stability was investigated. The stability was measured in terms of water separation and rag layer volume. The results indicated that emulsion stability increases as alkali concentration increases, as shown in Fig. 3. In the absence of alkali, the natural emulsifiers have a significant influence and only 40% of the original water was separated, and 51% of the rag layer remained unresolved. Initially, when alkali concentration increased from 0 to 250 ppm, the water separation increased the rag layer volume decreased. However, the subsequent increase in alkali concentration has decreased water separation and increased the unresolved rag layer. Overall, it was observed that alkali does not significantly influence the emulsion behavior within the envelope of the experimental conditions.

Droplet size analysis

Micrograph images of the dispersed water droplets were captured using CPM. The images were then processed using the equipment's software to measure the size of a minimum of 100 droplets for each emulsion sample. The measured droplet diameters were then normally distributed using Excel software to produce droplet size distribution curves. The graphs illustrate a clear picture of the effect of chemicals on water droplet sizes and distribution. The peak point of the

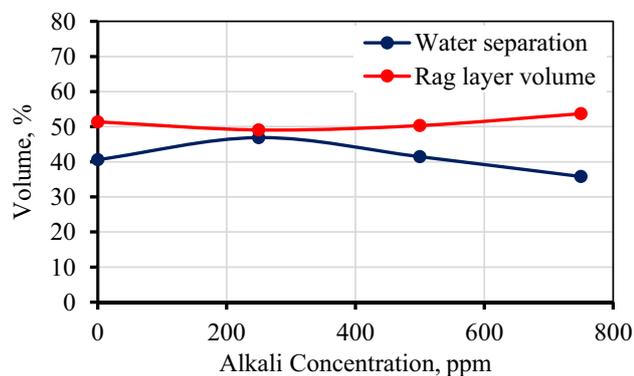


Fig. 3 Effect of alkali on water separation and rag layer volume after separation for 24 h

curve represented the mean water droplet diameter. Larger water droplets were distributed on the right side of the curve, while the smaller droplets were distributed along the left side of the curve. The effect of alkali concentration on water droplet size is shown in Fig. 4. Water droplet size decreases as alkali concentration increases. Initially, the droplet size distribution range becomes wider as alkali concentration increases from 0 to 250 ppm. However, it becomes narrower eventually at an alkali concentration of 750 ppm.

Figure 5 shows the water changes in mean droplet diameter as a function of alkali concentration. The results explain and support the findings from the stability study. As alkali concentration increased above 250 ppm, the interfacial tension between oil and water decreased, deterring smaller water droplets from merging. Thus, the water separation reduced, and rag layer volume increased. Consequently, the quantity of smaller size droplets was growing as alkali concentration increased. The emulsion stability is directly related to the droplet size as smaller droplets find it hard to coalesce and separate from the emulsion layer (Kang and Wang 2001).

Effect of surfactant concentration

Interfacial tension

Figure 6 shows the interfacial tension between crude oil and AOS surfactant solution at different concentrations. The addition of the surfactant reduced the IFT significantly. However, at or below 100 ppm of surfactant concentration, the interfacial tension between the crude oil and aqueous phase increased as compared to the case when the surfactant was not introduced. The increase in IFT by adding 100 ppm of the surfactant was due to the presence of bound molecules (surfactant) at the oil/water interface which hampers the coalescence of the droplets. Thus, the coalescence profile depends on the size distribution of the droplets and the amount of surfactant adsorption on the

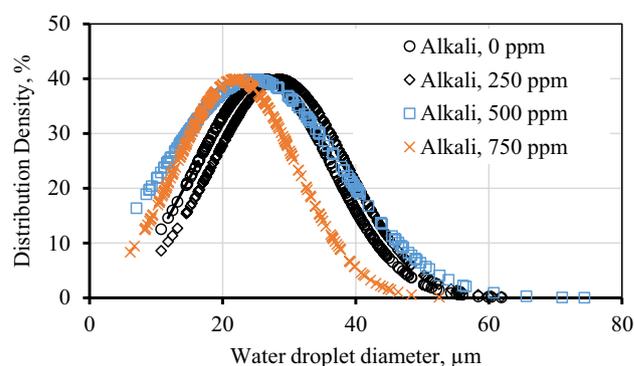


Fig. 4 Effect of alkali on water droplet size distribution

Fig. 5 Micrographs of alkali effect on the water mean droplet diameter

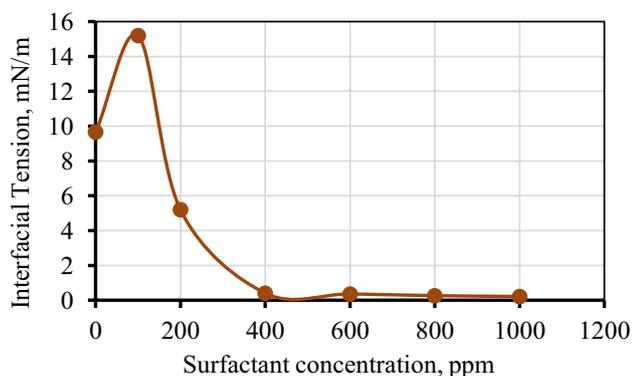
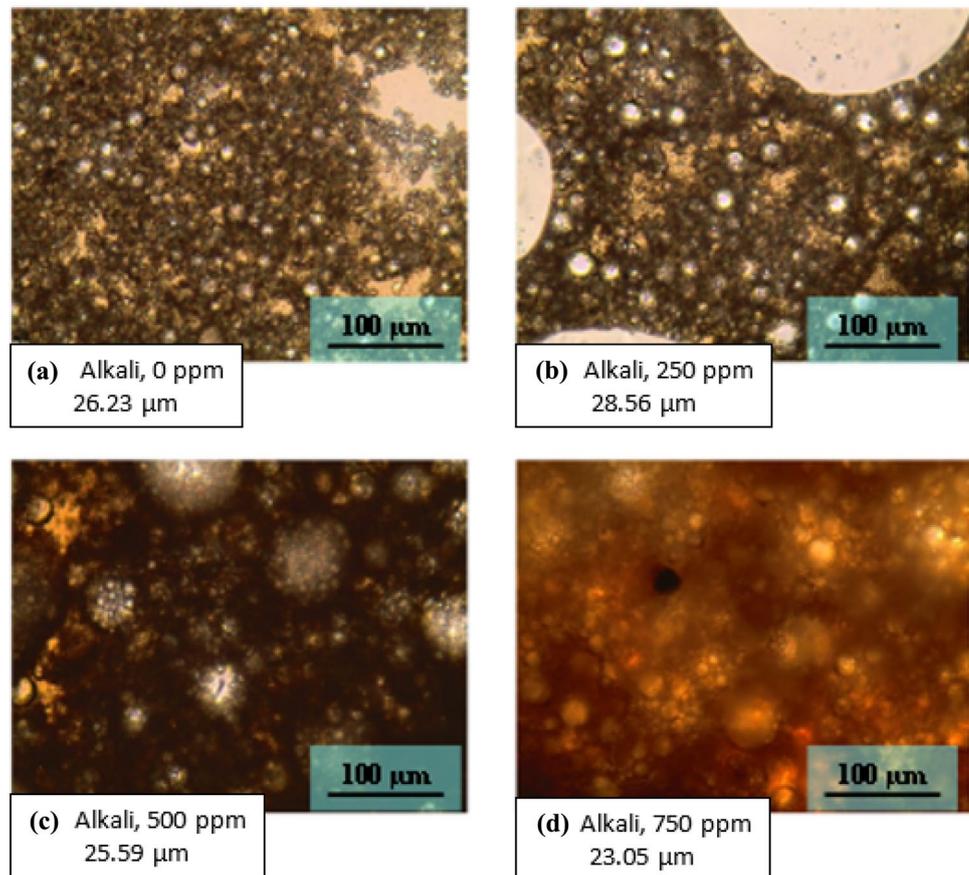


Fig. 6 Effect of different surfactant concentrations on interfacial tension

oil/water interface (Belhaj et al. 2020b). The presence of bound molecules can affect all the mechanisms of the sedimentation process and, therefore, provide major insight into the destabilization of the emulsion (Abeynaike et al. 2012). Pal (2014) reported an increase in the dispersed phase of the O/W emulsion with surfactant which was explained by the increase in the energy destruction rate significantly due to an increase in the emulsion viscosity.

The reason behind the stabilization of the emulsion with surfactant addition is that at a higher surfactant concentration, the solubilization of oil and water makes it possible to increase the oil recovery (Hirasaki et al. 2010). This indicated that 100 ppm of surfactant was not as interfacially active as the indigenous emulsifiers that it replaced. Thus, the interfacial tension increased. Above 100 ppm of AOS solution, the interfacial tension between crude oil and the aqueous solution has decreased significantly, indicating an accumulation of more surfactant molecules at the area between oil–water phases.

AOS as an anionic surfactant consists of a negatively charged head group that is polar (hydrophilic) and a positively charged tail group that is non-polar (hydrophobic). The hydrophilic head of the surfactant extends into the water phase, and the hydrophobic tail extends into the oil phase, therefore changing the interfacial properties between the oil and water phase (Wang et al. 2011; Belhaj et al. 2020c; Hussien et al. 2019). As surfactant concentration increased above 100 ppm, the interfacial tension decreased sharply until 400 ppm. Beyond 400 ppm, the interfacial tension was very low. At less than 0.5 m•N/m, the surfactant concentration has little effect on the interfacial tension.

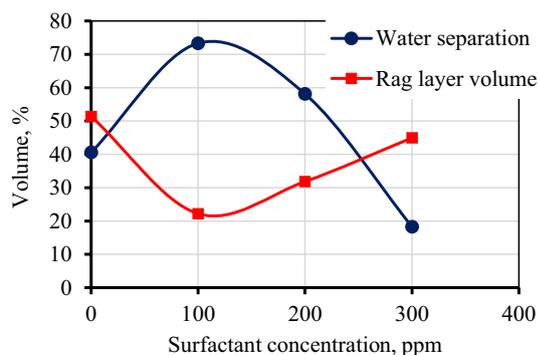


Fig. 7 Effect of surfactant on water separation and rag layer volume after separation for 24 h

Stability of emulsion

Figure 7 represents the effect of different surfactant concentrations on water separation and rag layer volume. Compared to alkali, surfactant had a more significant influence on the emulsion behavior observed on both rag layer and water separation. The addition of surfactant has increased emulsion stability in which water separation volume decreased as surfactant concentration increased. When 100 ppm of surfactant was loaded to the emulsion system, a substantial change was observed in the emulsion behavior. The water separation volume has increased from 40 to 73.3% resulting in a reduction in rag layer volume from 51 to 22%.

A similar trend was observed in terms of interfacial tension behavior (Fig. 7). Increasing surfactant concentration from 0 to 100 ppm leads to increased interfacial tension from 9.66 to 15.2 m•N/m, respectively. The behaviors are interrelated, as when interfacial tension between oil and water was elevated, the water droplet coalescence was promoted. Therefore, water separation volume was increased. That implies a reduction in the volume of the rag layer as a smaller amount of water droplets were trapped within the rag layer. As surfactant concentration increased above 100 ppm, water separation was observed to reduce while the rag layer volume increased. The more surfactant is supplied into the emulsion system, the more emulsifying agents (surfactant molecules) accumulate at the oil–water interface.

For this reason, the interfacial tension between oil and water has declined, as the accumulation of surfactant molecules has further reduced the intermolecular interaction between water droplets. Therefore, the water droplets have a weaker ability to approach and coalesce, reducing the volume of water separation from the emulsion and increasing the rag layer volume. At 300 ppm surfactants, the water separation reduced to 18%, leaving 44% of the unresolved rag layer. The stability of the emulsion was not expected to undergo significant changes above 300 ppm of surfactant

concentration as there were minor changes in interfacial tension above the mentioned value.

Droplet size analysis

Figure 8 shows the surfactant effect on water droplet size and distribution. Initially, the droplet size distribution expands as the surfactant concentration increases from 0 to 100 ppm. Then, the droplet size distribution becomes narrower when surfactant concentration was increased from 100 to 300 ppm.

Likewise, the mean droplet diameter also reduces as surfactant concentration increases from 100 to 300 ppm, as shown in Fig. 9. The behavior matches the observations from the interfacial tension and stability test results. When surfactant concentration was increased up to 100 ppm, the water droplet size increases due to higher interfacial tension between oil and water, which permits the smaller water droplets to merge and form bigger droplets. Consequently, water separation was enhanced, and rag layer volume was degraded, indicating the reduced stability of the emulsion sample. Conversely, above 100 ppm of surfactant, the water droplet size reduces due to lower the interfacial tension between oil and water, which subdues the ability of smaller droplets to merge and separate from the emulsion. Hence, the emulsion was more stable as less water separated from the emulsion and more rag layer volume remained unresolved. Similar observations have been discussed in Kang and Wang (2001).

Effect of polymer concentration

Viscosity

The effect of polymer concentration on the viscosity of synthetic produced water is shown in Fig. 10. The viscosity was measured at a shear rate ranging between 0 and 1000 1/s at 60 °C. The results indicate that the increase in shear rate

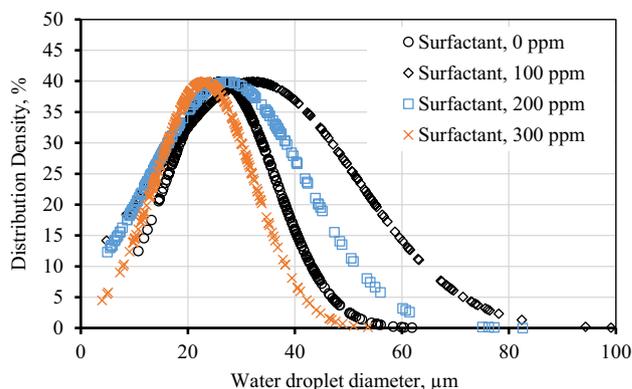


Fig. 8 Effect of surfactant on water droplet size distribution

Fig. 9 Micrographs of surfactant effect on water droplet mean diameter

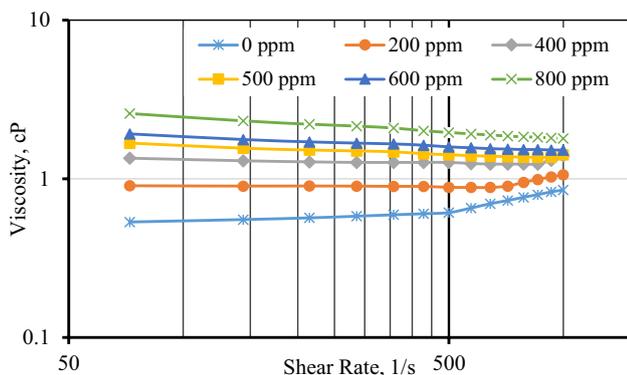
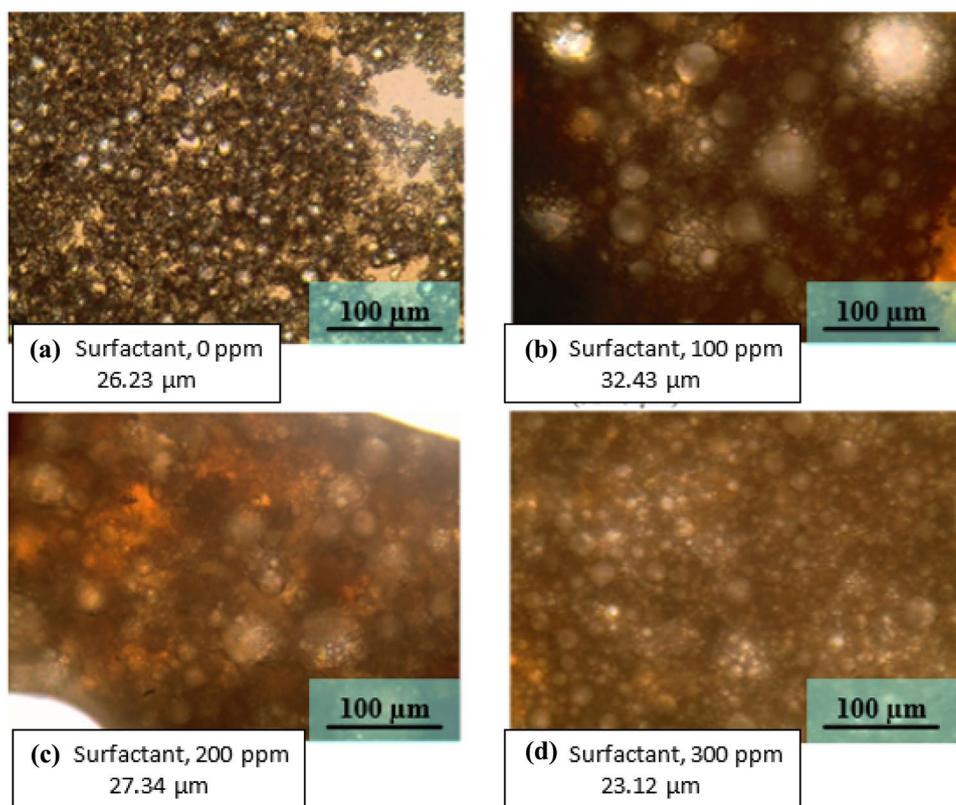


Fig. 10 Effect of different polymer concentrations on the viscosity of aqueous phase

increases the viscosity up to 400 ppm of polymer concentration. However, the viscosity undergoes insignificant changes with the increase in shear rate. On the contrary, the viscosity reduces as the shear rate increases when polymer concentration increases above 400 ppm. This observation suggests that GLP100 is a low-molecular-weight (LMW) polymer as high-molecular-weight (HMW) polymers are known to be highly shear sensitive (Wang et al. 2011; Weatherill 2009).

Increasing the polymer concentration has a clear effect on increasing the aqueous phase viscosity. Hence, the stability of the emulsion was expected to be affected by the presence

of polymer as a function of the viscosity effect. Stock’s law states that the sedimentation velocity is inversely proportional to the viscosity of the aqueous phase of an emulsion, which implies that the emulsion stability could be increased by increasing the aqueous phase viscosity. However, the intensity of viscosity effect on stabilizing the emulsion depends on the molecular weight of the polymer (Wang et al. 2011). HMW polymers significantly increase the viscosity of the aqueous phase at a lower concentration than LMW polymers. The viscosity effect for HMW and LMW polymers appears when the polymer concentration reaches a critical concentration point. Below the critical concentration point, the polymer acts as a de-emulsifier and promotes droplet flocculation, reducing the emulsion’s stability (Wang et al. 2011). In this case, the stability of the emulsion was expected to decline as the polymer concentration increases up to the critical concentration level, then upsurges when the polymer concentration was above that critical level. Emulsion stability tests were conducted to examine the behavior. Khatibi et al. 2016 have currently presented experimental measurements on the effect of salt on the rheological properties of Non-Newtonian fluids. Their results have the same trend on the change in viscosity as of the results obtained in the current study, as shown in the Fig. 11. The pure water, water with 5%wt salt, and water with 20%wt KCOOH all show a slight increase in the viscosity with an increase of shear rate. However, a higher concentration of salt, the

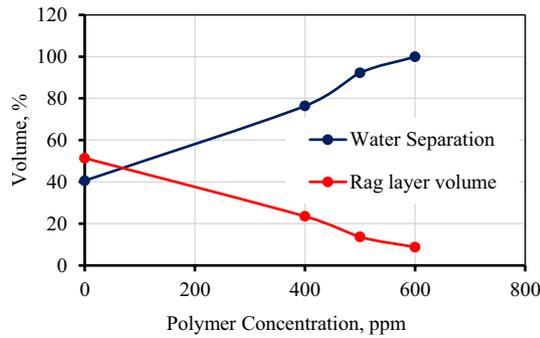


Fig. 11 Effect of polymer concentrations on water separation and rag layer volume after separation for 24 h

experiment temperature, and the type of additive to water all affect the produced brines' behavior. It seems interesting to further investigate the viscosity of brines from different oil wells at various testing temperatures and then with different added polymers and/or salt. Researchers who worked and published in the field also recommend that there is still a debate to finalize the conclusion of polymer on the stabilization of emulsion (Koh 2015; Seright 2017).

Stability of emulsion

The effect of different polymer concentrations on rag layer volume and water separation is shown in Fig. 11. The results revealed that as polymer concentration increased, the amount of water separated from the emulsion increased. Correspondingly, the rag layer reduced from 50 to 23, 13 and 8% for polymer concentrations of 0, 400, 500, and 600 ppm, respectively. The behavior shown in Fig. 10 demonstrates that as polymer increases aqueous phase viscosity, the strength of the interfacial film surrounding the water droplets was weakened, which allowed the water droplets to merge and separate from the emulsion to the free water zone. Therefore, the amount of water separation was enhanced. At 600 ppm polymer, 99% of the water separated from the emulsion. Similar behavior was discussed by Deng et al. (2005).

The results suggest that the investigated range of polymer concentrations falls below the critical concentration point above which polymer begins to elevate the emulsion stability as a function of increasing viscosity (Wang et al. 2011). The findings also support the assumption that GLP100 polymer is a low-molecular-weight (LMW) polymer. Similar behavior was recorded as LMW of partially hydrolyzed polyacrylamide (HPAM) polymer destabilized the emulsion when its concentration was below 800 ppm. At the same time, high-molecular-weight (HMW) HPAM destabilizes the emulsion when its concentration was not more than 300 ppm. From the observations, it could be concluded that the presence

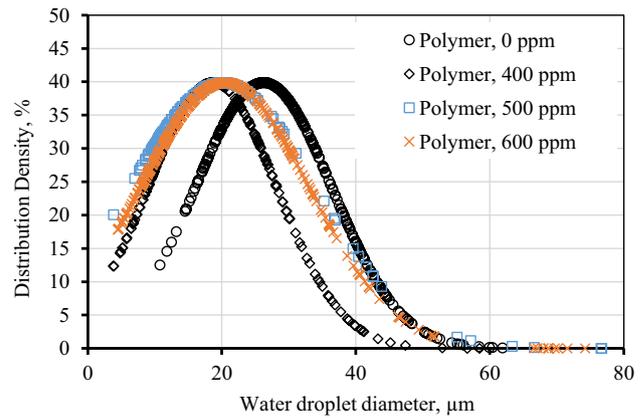


Fig. 12 Effect of polymer on water droplet size and distribution

of polymer in the emulsion system would function as a demulsifier that promotes the separation of water and reduces the emulsion stability under the investigated conditions.

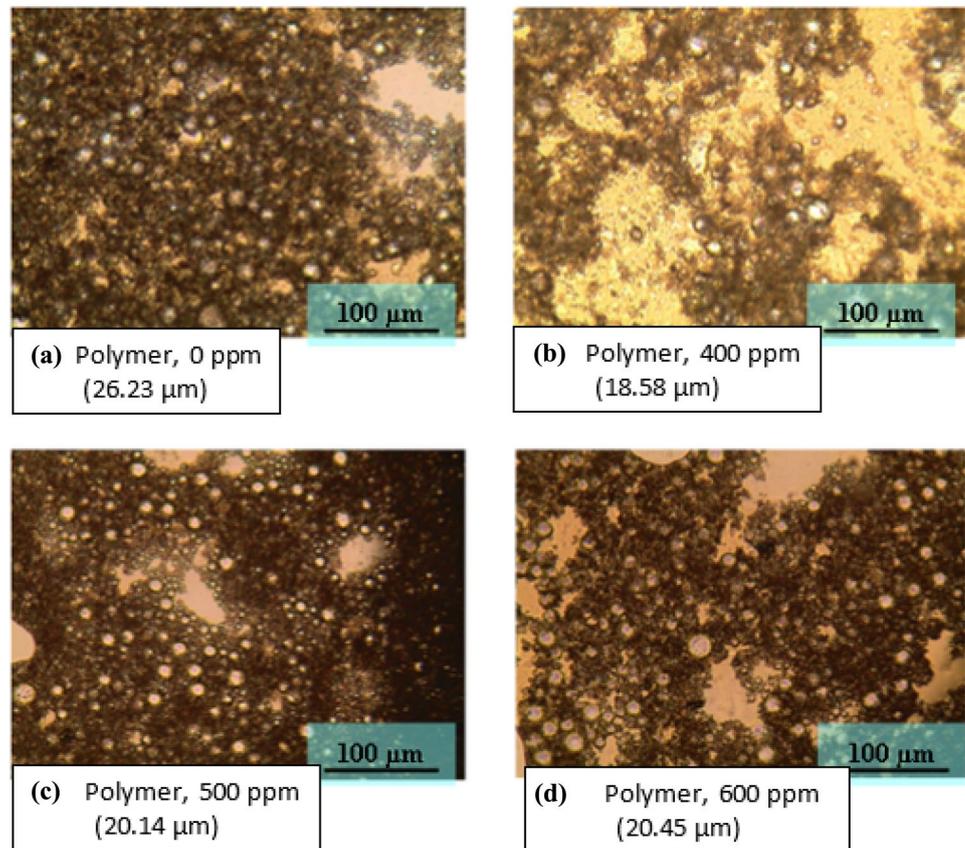
Droplet size analysis

The effect of polymer on water droplet size is illustrated in Fig. 12. The observations demonstrate interesting findings regarding the polymer exhibiting complicated behavior when added to the emulsion system.

At zero ppm of polymer, the water droplet sizes range from 10 to 63 μm . When polymer concentration increases from 0 to 400 ppm, the droplet distribution range becomes narrower, expanding to the left side of the curve to cover between 3 and 58 μm . However, the density of larger droplets was noticed to decrease significantly. For instance, at 0 ppm polymer, 15% of the water droplets have a diameter size of 40 μm , while at 400 ppm only 2.5% of the water droplets have a size of 40 μm . However, above 400 ppm of polymer, the droplet size distribution range was expanded to larger droplets ranging between 3 and 76 μm . The behavior was almost identical when polymer concentration changes from 500 to 600 ppm. Additionally, it could be noticed that the mean water droplet diameter was lesser when the polymer was added to the emulsion, as shown in Fig. 13.

The droplet size analysis suggests that the polymer favors the stabilizing emulsion since the water droplets were smaller as the polymer was introduced to the emulsion system. However, this behavior contradicts the findings from the stability study as the polymer exhibited substantial ability in reducing emulsion stability and enhancing water separation. The contradiction could be explained by the results obtained from the stability study. The stability study shows that a high percentage of water was separated as a function of polymer concentration. Correspondingly, the number of water droplets that remained in the rag layer was much lesser in quantity than the previous alkali and surfactant

Fig. 13 Micrographs of polymer effect on the water mean droplet diameter



cases. Hence, it is expected for the bigger water droplets to have completely separated from the emulsion and moved from the rag layer to the free water zone. As the polymer is known to promote droplet coalescence (Wang et al. 2011), it is believed that droplets had coalesced and separated from the emulsion leaving behind smaller droplets. Therefore, the density of smaller droplets increases, and the overall water means droplet diameter has reduced.

Conclusion

Emulsion stability, interfacial tension, and droplet size of various oil/water emulsions with alkali, surfactant, and polymer concentrations were investigated. Low concentrations of alkali and surfactant were expected to assist the separation process. The interfacial tension was increased between oil and water, which facilitated the coalescence of the water droplets. At higher concentrations, alkali and surfactant were not efficient for the separation process. The interfacial tension was reduced between oil and water, making the emulsion much more stable hence, the separation becomes difficult. These findings were reflected in the water droplet size as bigger water droplets were measured at low alkali and surfactant concentrations. In contrary, smaller water

droplets were present when a high concentration of alkali and surfactant were added.

The polymer GLP100 acted as an effective de-emulsifier. The analysis of the emulsion with polymer presence has achieved a close to complete separation process. This separation was mainly attributed to the ability of the polymer to promote bigger water droplets to coalesce and eventually separate them from the emulsion. GLP100 is advisable for the enhanced oil recovery process as it increases the oil recovery by improving the sweep efficiency. At the same time, it can assist in countering the effect of surfactant and alkali in the event of a breakthrough. The viscosity behavior of the brine with added polymers has room for further investigation considering the brine composition, the type of polymer and the testing temperature. Further investigations on AS, AP and SP as well as the ASP's combined effect on emulsion stability, droplet size, interfacial tension and rheological properties are highly recommended to support the decision-makers on the EOR implementations with chemical additives.

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Declarations

Conflict of interest Here, We confirm that there is no conflict of interest.

Ethical approval Hereby, We assure that this paper has not been previously published and the manuscript reflects our own research and analysis in a truthful and complete manner.

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