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An investigation of viscous oil displacement in a fractured porous medium using polymer-enhanced surfactant alternating foam flooding

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ABSTRACT

Naturally fractured reservoirs are one of the hydrocarbon resources where the application of foam flooding is particularly recommended, as foam can divert the flow of displacing fluid from high-permeability regions (fracture networks) to low-permeability regions (rock matrix blocks). However, its application in heavy oil reservoirs is challenging and results in inadequate sweep efficiencies. The current practice of foam flooding (including polymer enhanced foam flooding, PEF) is inefficient in displacing high viscosity oils. This is due to large viscous forces associated with the oil phase flow and the high rate of bubbles coalescence (foam collapse), which make it difficult for foam to displace the heavy oil from the matrix. Thus, we investigated feasibility of polymer-enhanced surfactant alternating foam (PESAF) flooding (as a new hybrid enhanced oil recovery process) to displace the oil phase in porous media. We hypothesized that PESAF flooding can emulsify the oil phase and generate oil globules by reducing the interfacial tension forces between the oil and water phase, and also it increases the foam stability, leading to higher displacement efficiencies in the presence of viscous oils. For this purpose, three different oils (low, medium, and high viscosity oils) were used in a micromodel to simulate the immiscible displacement process in fractured rocks. The experimental results showed that PEF flooding is efficient in displacing the low viscosity oil, however it cannot yield a high efficiency displacement in viscous oil cases. It was found that the hybrid enhanced oil recovery (EOR) process of PESAF flooding can increase the oil recovery factors for the medium and high viscosity oil cases significantly. These experimental results supported the hypothesis of applying PESAF flooding to improve the displacement efficiency of high viscosity oils in fractured porous media.

1. Introduction

Naturally fractured reservoirs contain a significant amount of hydrocarbons; however, these types of reservoirs include fracture networks that have a considerable impact on oil recovery processes (Wu, 2016). Therefore, many investigators have studied the flow and transport phenomena in fractured formations (Sharifi Haddad et al., 2013, 2014, 2015; Trivedi and Babadagli, 2009; Vilhena et al., 2020). There are many challenges associated with oil recovery from fractured reservoirs such as reservoir heterogeneities and complex fracture geometries compared to conventional reservoirs, leading to poor sweep efficiencies in EOR processes (Babadagli, 2001; Schechter et al., 1996; Firoozabadi and Ishimoto, 1994; Firoozabadi, 2000). The permeability contrast between matrix and fracture provides preferential flow paths for the flow of fluids (through fractures), which reduces the efficiency of immiscible oil displacement processes (Babadagli, 2001; Schechter et al., 1996).

There have been processes such as foam flooding to reduce the mobility of the injected gas (displacing fluid) leading to a higher sweep efficiency from the matrix zones (Farajzadeh et al., 2010; Fathollahi et al., 2019; Hanssen et al., 1994; Hirasaki, 1989). Also, foams can reduce the IFT (interfacial tension) between the oil and aqueous phases which helps the aqueous phase to enter to the matrix when the original wettability condition is unfavourable (Chevallier et al., 2018; Bouquet et al., 2020). Although there have been successful processes for oil displacement in the fractured reservoirs, oil recovery from heavy oil fractured reservoirs is still a challenge and current processes have drawbacks when it comes to displacing viscous oils from the matrix blocks.

Steam-based thermal oil recovery processes have been widely used to recover heavy oil from sandstone reservoirs and they yield high oil recovery factors. However, these processes require huge volume of water to generate steam, and they could suffer from steam override, steam

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channelling and significant heat loss in fractured heavy oil reservoirs (Al-Gosayir et al., 2015; Zhao et al., 2014). In situ combustion (ISC) is another thermal process that can be used for heavy oil recovery, however early breakthrough of air might limit its application in fractured reservoirs, in addition, the air injection rate and controlling the reaction mode are critical for the success of ISC and managing them in heterogeneous reservoirs are extremely difficult (Ursenbach et al., 2010; Fadaei et al., 2010). There are solvent-based oil recovery processes that could be used in fractured heavy oil reservoirs, although they are low emissions processes, the cost of solvents might hinder their application in some reservoirs (Sherratt et al., 2018; Sharifi Haddad et al., 2017). Foam injection has been a promising oil recovery process in fractured reservoirs when the oil viscosity is low, however its application for heavy oil cases has not been widely explored. Therefore, in the rest of this section we focused on the foam injection process and summarised current understanding of this immiscible displacement process in fractured reservoirs. We then proposed a new derivative of foam injection process to be used in heavy oil fractured reservoirs.

Several laboratory studies have investigated the foam diversion ability in fracture reservoirs, and foam efficiency in reducing the gas mobility by a greater fraction in high-permeability zones than in low-permeability zones (Lee et al., 1991; John et al., 2010; Yan et al., 2006; Fernø et al., 2016; Kovscek et al., 1995). This is due to the fact that foam effectively blocks the flow channels in high-permeability zones and increases the resistance to flow; thus, the flow is diverted from the fractures to matrix blocks (Hirasaki, 1989; Zhou and Rossen, 1995; Haugen et al., 2014; Conn et al., 2014). Conn et al. (2014) conducted a study in a 2D fractured porous media model to investigate oil displacement and sweep efficiency by foam flooding. Their results showed that foam effectively displaced trapped oil in the low-permeability region by bubbles resistance to flow in the fracture (high-permeability zone). This is because the bubbles were trapped in the fracture, and this caused a higher pressure gradient across the fracture which consequently pushed the foam into the matrix. Haugen et al. (2012) studied foam flow in fractured oil-wet carbonate rocks to investigate the effect of foam generation methods on the oil recovery in an oil-wet system. The outcomes of their study revealed that the presence of foam reduced the gas mobility and increased the differential pressure which resulted in a flow diversion into the oil-saturated matrix. In addition, the oil recovery by pre-generated foam was much higher (up to 78% IOIP) than the oil recovery using water, surfactant, or gas injection (only 10%); however, a large volume of pre-generated foam was injected to achieve this recovery. Yan et al. (2006) conducted an experimental study on foam flow mechanisms and efficiency in uniform and heterogeneous fracture systems through transparent glass plates. An improved sweep efficiency was observed in the heterogeneous fracture system by using foam injection which directed the surfactant flow into the low-permeability zones and reduced the amount of surfactant required in their immiscible displacement process. Foam viscosity was increased with increasing the fractional gas flow, and the viscosity was higher in the fractures with large apertures, which directed the foam flow from large fractures to tighter fractures.

Generally, the effectiveness of surfactants to generate stable foams reduces at harsh reservoir conditions and in the presence of oil. Therefore, many studies have been conducted to improve the efficiency of foam flooding by using different chemical additives to increase foam stability and its performance in immiscible displacement processes. Bashir et al. (2019) found that with the addition of silica nanoparticles and xanthan gum polymer, foam stability can be enhanced through the combination of two mechanisms: large adhesion energy of nanoparticles on the thin liquid films, and viscosity improvement of the liquid inside the lamellae by using the polymer. Zhou et al. (2020) examined the polymer-enhanced foam (PEF) flooding to enhance the heavy oil recovery in thin reservoirs using micromodel and core-flood experiments. Their results showed that PEF is an effective method for oil displacement in thin heavy oil reservoirs compared to other EOR processes. They reported that after an initial waterflooding stage, the recovery factor of PEF flooding was higher than that of surfactant/polymer (SP) flooding; and by increasing the PEF slug size, the PEF recovery factor was gradually improved. In another study, Xu et al. (2017) investigated the effect of combining foam flooding and SP flooding and compared with other two injections models (e.g., direct foam flooding and CO_2/SP flooding) to maximise the EOR efficiency from Berea sandstone core plug. The results revealed that the combination of foam and SP flooding exhibited remarkable blocking ability, low water cut and higher oil recovery than foam flooding and CO_2/SP flooding. Moreover, Xu et al. concluded that the combined foam/SP flooding was more appropriate for the reservoirs with formation pressures above the minimum miscibility pressure. Telmadarreie and Trivedi (2016a) investigated the pore-scale displacement phenomena for PEF flooding following solvent flooding to access the unrecovered heavy oil in fractured carbonate reservoirs and compared it with the other conventional processes. They found that generating a strong foam can be considered to produce oil from the matrix, as foam bubbles jammed and blocked the fracture path and allowed the injected fluid to flow into the matrix; thus, more oil was swept from the matrix zone. It was found that PEF flooding increased the oil recovery by 70% after solvent flooding compared to 5% and 49% oil recoveries for the CO_2 gas injection and foam flooding after solvent flooding, respectively. They concluded that improving the liquid viscosity and the presence of foam bubbles are the main reasons for high sweep efficiency in their fractured porous media.

Although there have been many studies on the use of foam for oil recovery in fractured reservoir with light oils, its application in fractured reservoirs with heavy oils has not been well understood. To the best of our knowledge, few studies have attempted to examine the performance of foam flooding in fractured reservoirs in the presence of medium and high viscosity oils and its efficiency compared to the other flooding processes (Telmadarreie and Trivedi, 2016b; Kang et al., 2010; Wang et al., 2011; Pei et al., 2011). Foam flooding in the presence of viscous oils in fractured reservoirs is challenging due to the high oil viscosities that cause a significant antifoam effect, increase foam instability and the collapse of bubbles, in addition to the high viscous forces associated with the oil displacement. Therefore, it seems the foam flooding by itself cannot improve the recovery from fractured reservoirs when a viscous oil is present in porous media. In this study, we hypothesized that alternating surfactant injection with the foam flooding can assist foam stability and emulsification of the viscous oils and then the emulsified oil droplets will be displaced by the foam effectively. As a result, this study is focused on experimental investigations PESAF flooding, as a new hybrid EOR process, for oil displacement in fractured rocks with medium to high oil viscosities. This alternative technology can be attractive for the oil and gas industry specially in shallow fractured heavy oil reservoirs where other methods of oil recovery may not be feasible.

A micromodel was used to visualize the displacement fronts and pore-scale phenomena of the PEF flooding and PESAF flooding processes. Moreover, we present the effect of injection rate, different oil viscosities, foam slug volume on the efficiency of these processes. Additionally, local equilibrium foam models of the experiments were built with a CMG STARS and history-matched with the experimental results to be able to support the theory and flow mechanisms in such processes.

2. Experimental set-up and procedure

2.1. Materials

Gas: Carbon dioxide (CO_2) with a purity greater than 99% was used as our gas phase, and distilled water was mixed with surfactants in all the experiments.

Surfactant: An anionic surfactant (alpha-olefin sulfonate, AOS) with a viscosity of 1.0 mPa s at 22 °C, and pH of 7.0–8.0, was used in this study. AOS is widely used in EOR processes to provide a solution with

Table 1
Physical properties of mineral oils (25 °C, atmospheric pressure).

Oil type (based on Viscosity)	Density, g/cm^3	Viscosity, mPa.s
Low	0.8605	134
Medium	0.9675	338
High	0.9684	976

low interfacial tension and low adsorption rate on rock surfaces.

Polymer: Xanthan gum polymer with a molecular weight of 3.2 × 10^6 g/mol (molecular weight was measured using a Zetasizer Nano ZS) was used to enhance the stability of the foam by increasing the solution viscosity.

Oil: Mineral oils were used in this study with three different viscosities (low, medium, and high viscosity oils), and their properties are listed in Table 1.

In this study, we focused on understanding the feasibility of the proposed enhanced oil recovery process from fractured heavy oil reservoirs and exploring the involved mechanisms, therefore the selected chemicals (i.e., the type of the surfactant and polymer), and gas (CO_2) are based on typical components used in the literature. However, a sensitivity analysis for the type of components could be considered to optimise the design of the enhanced oil recovery process in a reservoir.

Sample preparations: Distilled water was used for the water flooding experiments, and foam was prepared using CO_2 and a surfactant solution. The surfactant solution consisted of distilled water, AOS surfactant (0.5 wt%) and xanthan gum polymer (0.3 wt%), and it was mixed for 2 h using a magnetic stirrer. The foam quality was fixed to 95% with a volumetric flowrate of 1.0 mL/min for all experiments, where the CO_2 gas and surfactant solution flow rates were adjusted to 0.95 and 0.05 mL/min, respectively. The foam and surfactant solutions were then used in the PESAF, and the PES flooding experiments.

To distinguish the interfaces of the foam, oil, and PES solution, and have a good visual contrast, we used 0.5 wt% Oil Red O to dye the oil to red colour. The oil was filtered using 0.5 μm filter paper to remove any undissolved dye particles. Similarly, the PES solution colour was changed to blue by adding a 0.3 wt% water-soluble dye (methylene blue solution).

2.2. Porous media (micromodel)

The micromodel that is used as the porous media in this study is shown in Fig. 1; it consists of two parallel glass sheets placed on a stainless steel metal frame. The glass sheet has a length of 14 cm, and a width of 10 cm, with a thickness of 2 cm. The gap between the top and bottom glass sheets is 0.4 cm and it was filled with glass beads that aim to simulate the porous media. The inlet and outlet ports were fitted on the two ends of the fracture in the micromodel. The fracture was created from a stainless steel mesh tube (mesh size: 350 μm) in a rectangular conduit shape, and was placed in the centre of the model which created two volumes on each side to represent the matrix regions. The fracture (rectangular conduit mesh) has a dimension of 12 × 0.5 × 0.4 cm (L × W × T), and it was packed with spherical glass beads with a diameter of 2.0 mm.

The two matrix regions were packed with smaller spherical glass beads (diameter: 0.50 mm). The difference in the sizes of the glass beads between the fracture and matrix was designed to create a high-permeability contrast between the matrix and fracture to simulate an element of naturally fractured reservoir formation. The total pore volume of the micromodel was approximately 12.5 mL, and the matrix and fracture porosities were measured as 29.4% and 46%, respectively. The matrix and fracture permeabilities (calculated by using Darcy's law) were 21.0 and 330 Darcys, respectively. The micromodel was 100% saturated with the mineral oil (Table 1) using a Harvard syringe infusion pump at a low flow rate (0.2 mL/min) and left to stabilise for 24 h before running any experiment.

2.3. Experimental set-up

A schematic diagram of the set-up for the foam flooding experiments

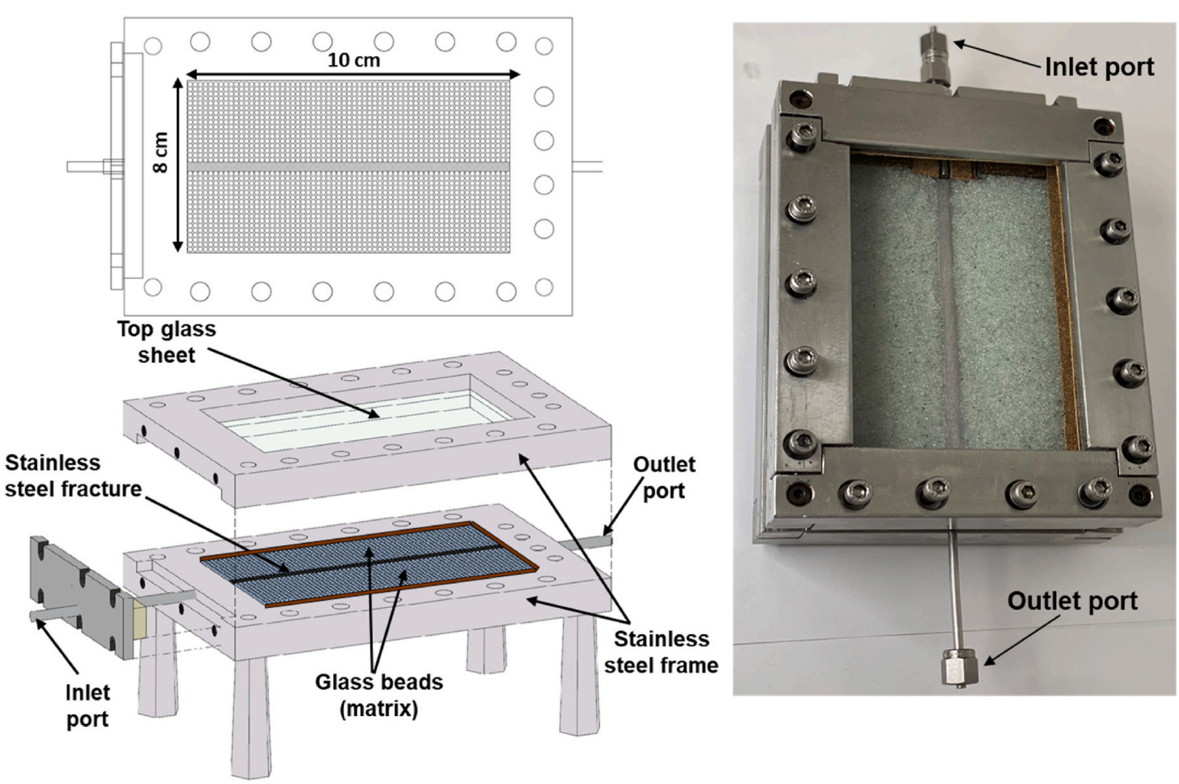

Fig. 1. Fractured micromodel.

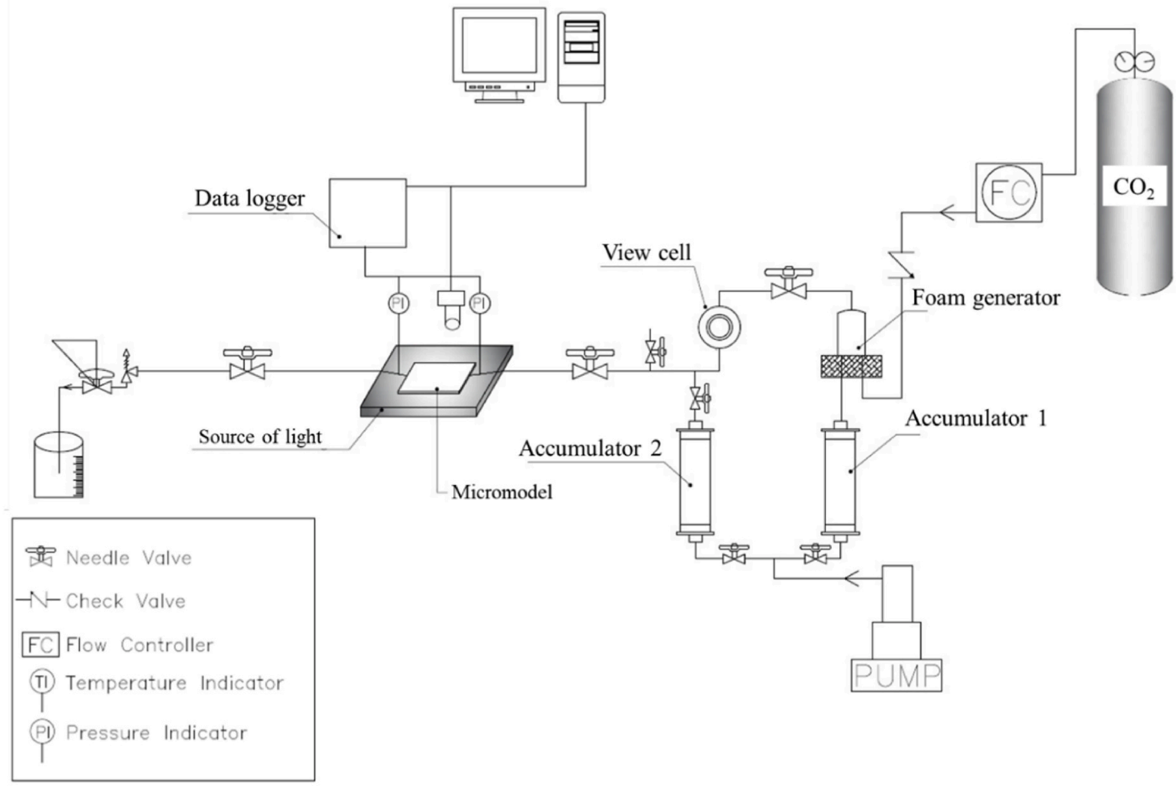

Fig. 2. Schematic of the experimental set-up.

is shown in Fig. 2. The surfactant solution was injected into the system using a syringe pump through a piston accumulator, while the CO_2 was injected from a CO_2 cylinder and controlled by a gas flow controller. Another piston accumulator was fitted for injecting the PES solution directly into the micromodel. The foam was generated in a customised stainless steel cylindrical foam generator (ID = 2.10 cm, L = 6.10 cm), filled with spherical glass beads (diameter: 0.50 mm), and two stainless steel mesh screens (0.41 mm) were placed on each side of the foam generator. The foam was pre-generated inside the foam generator, and after reaching a steady state foam flow in the pipes, it was directed into the micromodel. The differential pressure along the micromodel was measured using two pressure transducers connected to the inlet and outlet of the micromodel. All experiments were performed at 25 °C, and the micromodel was always held in a horizontal position. The outlet of the experiments was connected to a back pressure regulator to maintain the pressure at 50 kPa.

To monitor the displacement front and pore-scale flow, time-lapse images were taken by an Olympus microscope SZX100 (positioned over the micromodel). The oil recoveries from different oil displacement experiments were evaluated by collecting the produced oil and foam from the outlet. The produced fluids were centrifuged to separate the oil from the foam; thus, the produced oil versus pore volume injected was recorded.

To investigate the displacement efficiency of PEF flooding and PESAF flooding in the micromodel, the following displacing fluids were considered:

PEF flooding: Pre-generated PEF with 95% quality consisting of 0.95 mL/min CO_2 and 0.05 mL/min surfactant solution (0.5 wt% AOS, and 0.3 wt% xanthan gum).

PESAF flooding: PES solution was injected alternating with pre-generated PEF using different cycle lengths. PEF slug was injected with the same foam quality and flow rate as the PEF flooding tests, and the PES solution slug (0.5 wt% AOS and 0.3 wt% xanthan gum) was injected at a rate of 0.2 mL/min.

3. Results and discussion

3.1. PEF flooding

Waterflooding in water-wet fractured reservoirs that comprise light oils could be considered as an efficient EOR process. This relies on capillary imbibition process as matrix blocks with low permeability can imbibe the water, therefore the oil can be pushed out of the matrix blocks. In our study, porous media is water-wet however matrix permeability is high (negligible capillary pressure), and the oil viscosity is not low to allow an effective capillary imbibition process to take place. To confirm that the imbibition process has low efficiency in improving the oil recovery from the micromodel, initially we conducted waterflooding in the micromodel saturated with the low viscosity oil (134 mPa.s) at an injection rate of 1.0 mL/min. The displacement efficiency by waterflooding after 4.8 PVI was less than 7.0% of the initial oil in place (IOIP), although most of the oil stored in the fracture was displaced, waterflooding was unable to overcome the viscous forces associated with the oil phase stored in the matrix region. Therefore, waterflooding only swept the oil from the fracture region without any effect on the oil in the matrix region and we discard this process as an option for viscous oil displacement processes.

Gas injection is not recommended for water-wet rocks in fractured reservoir. High-permeability fracture zones cause early breakthrough of the gas phase; hence foam injection could be a more promising option. Therefore, PEF flooding was introduced to overcome viscous forces in porous media and to improve the oil sweep efficiency by pushing the oil out of the matrix toward the fracture. Additionally, since waterflooding only swept the oil from the fracture region with no water channelling into the matrix region, we investigated the effect of PEF flooding as a primary flooding process for viscous oil displacement without

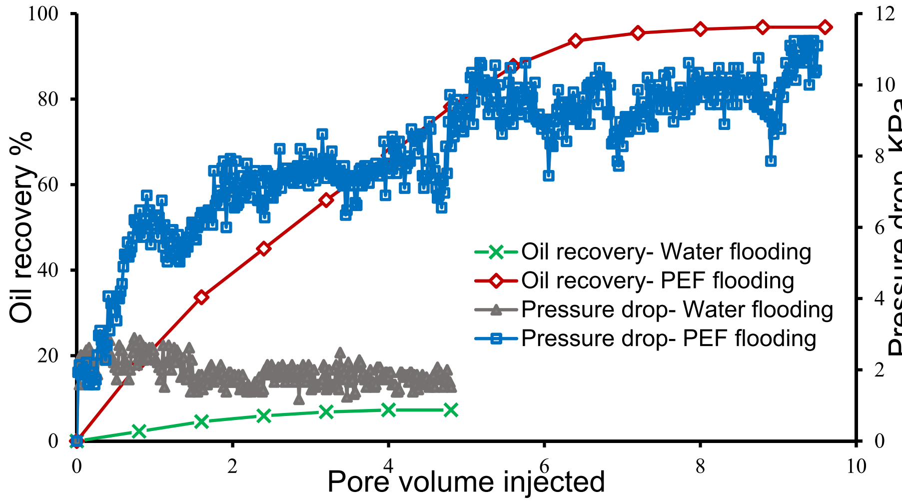

Fig. 3. Oil recovery and pressure drop vs pore volume injected, measured during water flooding and PEF foam flooding.

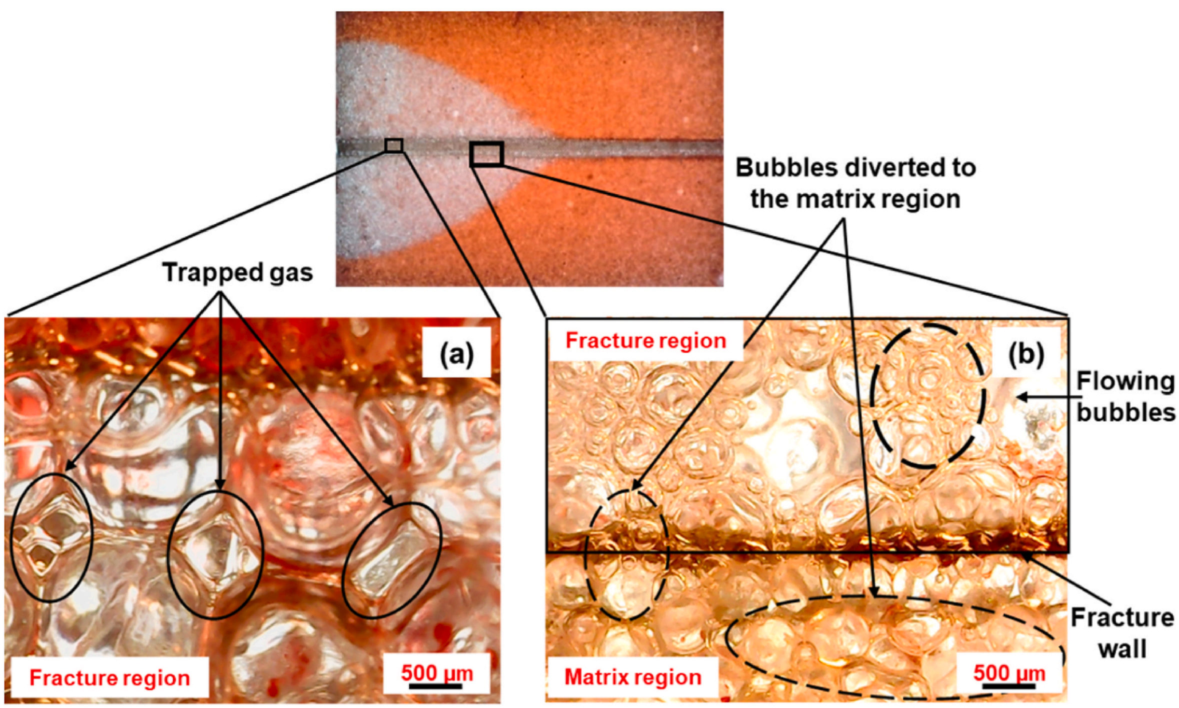

Fig. 4. Pore-scale images of the fracture and matrix during PEF flooding experiment, showing foam bubbles blocking the fracture region and diverting the flow of foam bubbles to the matrix. A supplementary video in.avi format is also provided.

considering waterflooding in advance of it.

The presence of the polymer in the surfactant solution generates more stable foam bubbles compared to the conventional foam bubbles, and this was considered in this study (Bashir et al., 2019). Oil recovery and pressure drop during the water flood and PEF flood processes are presented in Fig. 3. The results showed that PEF flooding displaced a substantial volume of oil from the matrix region and the recovery factor was 97% IOIP after 10 PVI. The increase in the pressure drop for the PEF flooding experiment was due to the reduction in the gas relative permeability. The gas bubbles inside the fracture region along with the flow resistance of lamellae decreased the mobility of foam, and this caused a high pressure drop across the fracture which helped foam to overcome the viscous forces required to enter to the matrix. Therefore, these phenomena diverted the foam into the low permeability region, resulting in an effective oil displacement from the matrix. This was supported by visualisation observations of the PEF flooding experiment that showed that foam bubbles created flow resistance inside the fracture and slowed down the gas flow in it. This caused pushing the foam bubbles to the matrix developing a viscous crossflow, i.e., foam flow was diverted from the high-permeability region (fracture) to the low-permeability areas (matrix), as shown in Fig. 4. In addition, this can be visualised in the supplementary document (a video file) that elucidates the trapped gas inside bubbles (reduced gas relative permeability) blocking the fracture flow path, creating flow resistance by a train of foam bubbles inside the fracture region, which increase the foam apparent viscosity. It should be noted that the presence of xanthan gum polymer increases the viscosity of the liquid in the lamellae, and this helps to prevent bubbles coalescence. Additionally, it was noticed that the oil was also produced through the foam lamellae. This refers to the emulsification mechanism, in which the oil is emulsified by the

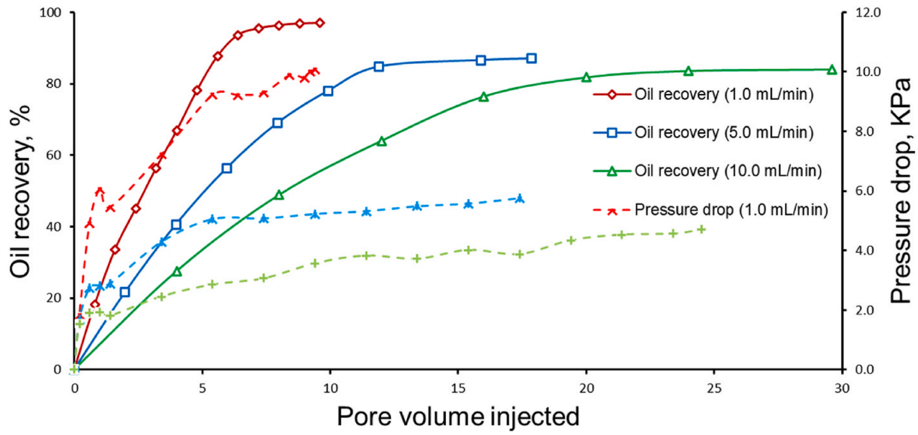

Fig. 5. Oil recovery and pressure drop vs pore volume injected at different injection rates of PEF flooding.

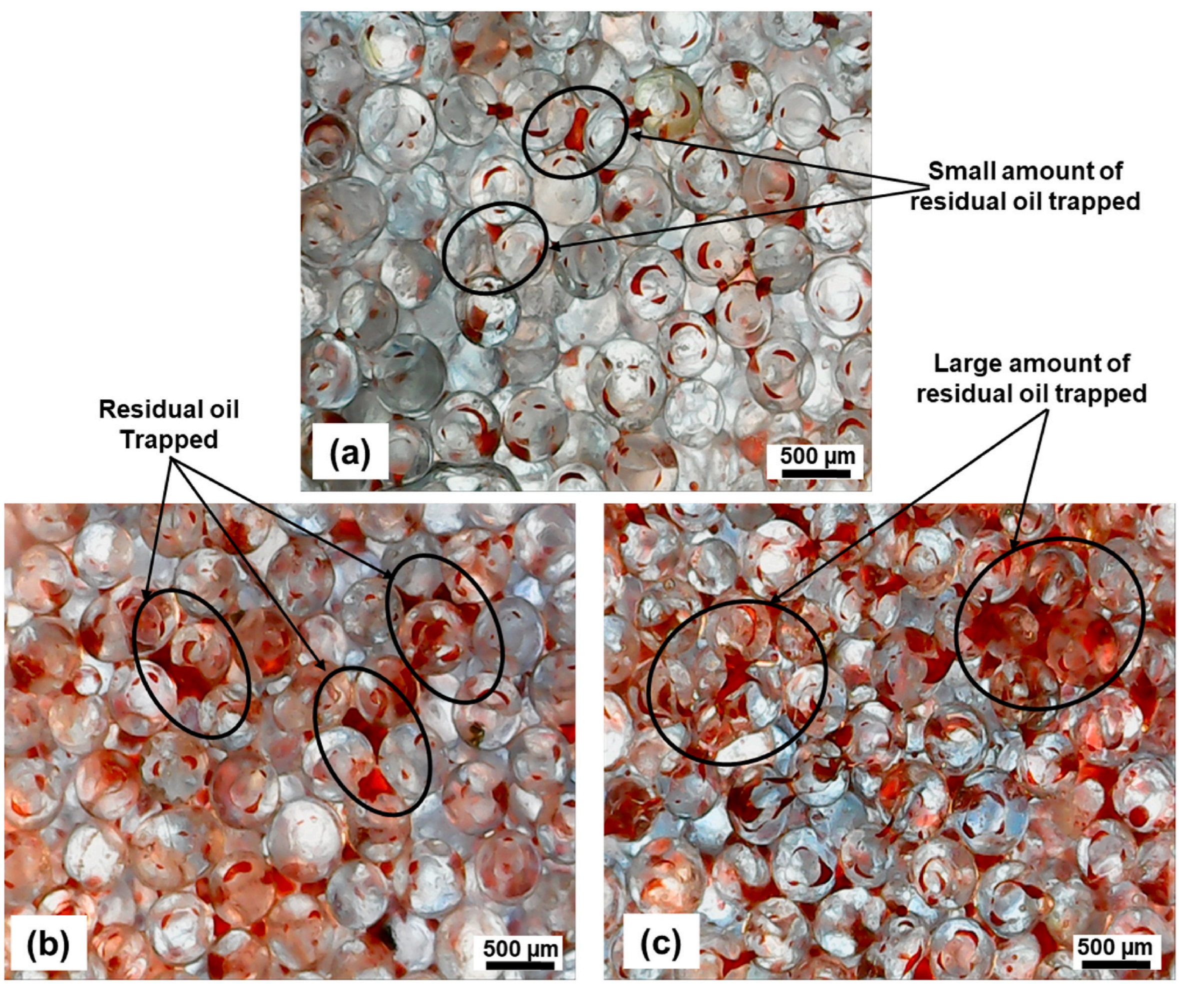

Fig. 6. Pore-scale images of oil trapped in the matrix porous media at the end of the PEF flooding (red coloured low viscosity oil) using (a) 1.0 mL/min, (b) 5.0 mL/min and (c) 10 mL/min. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

surfactant solution in the lamellae. Therefore, oil in water emulsions can flow with the aqueous solution in the lamellae as stable emulsions without entering or penetrating the gas-liquid interface (Bashir et al., 2019; Rafati et al., 2018; Zhang et al., 1991; Alsabagh et al., 2021).

3.1.1. Effect of injection rate

The injection flow rate is a controlling parameter that can affect the displacement efficiency of PEF flooding in the fractured reservoirs. As foam is a shear thinning fluid, at higher injection rates its apparent viscosity is lower, and it can flow easily in high-permeability zones (fracture), therefore flow diversion to low-permeability zones (matrix) will be less effective.

In order to analyse the effect of the injection rate, the PEF flooding experiments were conducted with three different injection rates of 1.0, 5.0 and 10 mL/min. The oil recovery and pressure drop versus pore volume injected for the three different flow rates are presented in Fig. 5.

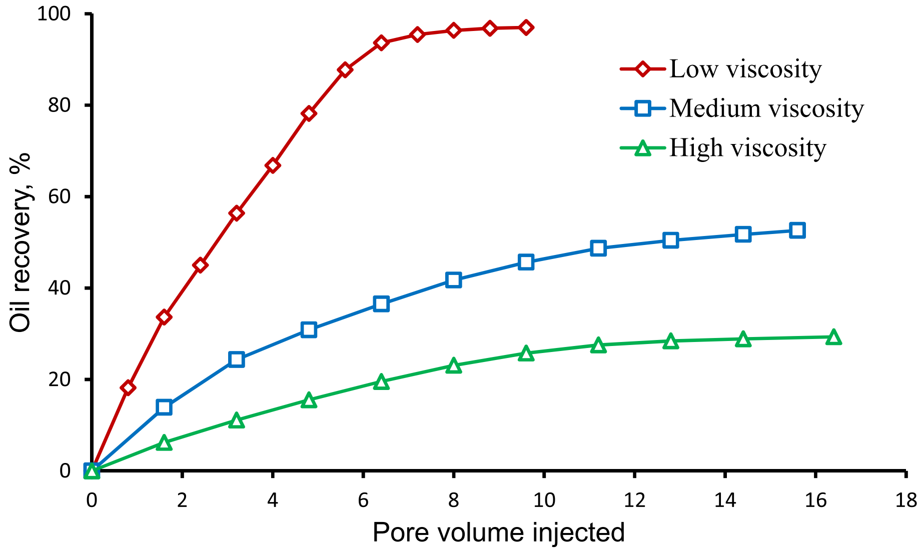

Fig. 7. Oil recovery vs pore volume injected of PEF flooding at different oil viscosities and the injection rate of 1.0 mL/min.

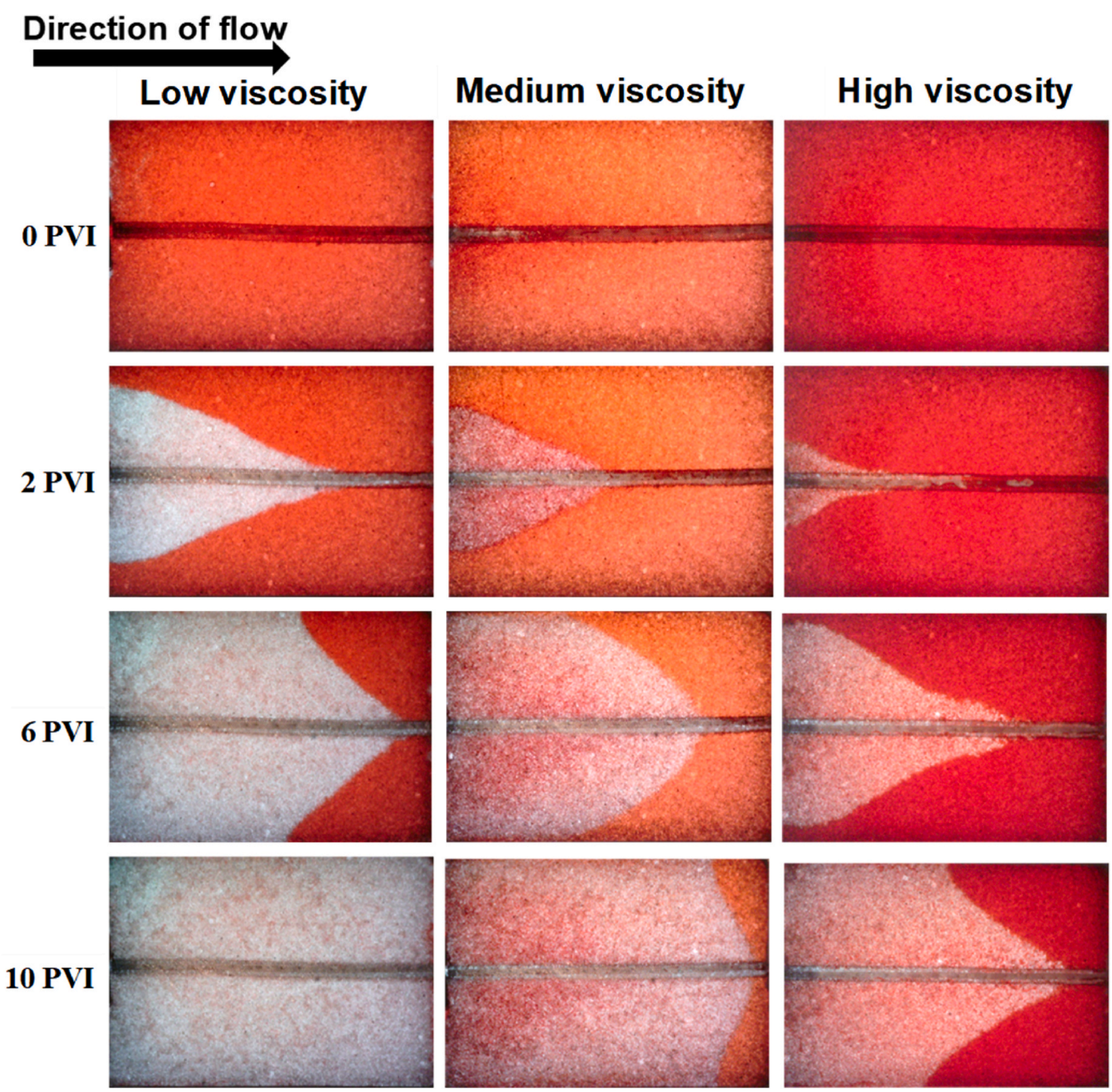

Fig. 8. Displacement fronts of different oil viscosities at different PVI of PEF flooding.

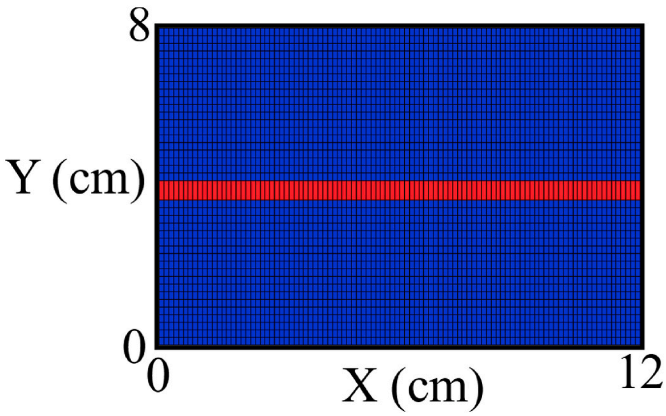

Fig. 9. Schematic of the numerical model showing the matrix (blue) and fracture (red). (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

Table 2
Properties of the porous media in the micromodel.

Parameter	Matrix	Fracture
Permeability, *k* (*Darcy*)	21	330
Porosity, φ	0.294	0.460

A higher oil recovery was achieved at a lower PVI when the injection rate was low. With the injection rate of 1.0 mL/min, only 6 PVI were required to achieve 95% oil recovery, which provided sufficient viscosity for foam bubbles to block and resist the flow in the fracture region. This allowed foam bubbles to overcome the viscous forces in the small pore spaces of the matrix and divert the flow from the fracture to the matrix leading to an increased sweep efficiency. For the experiments with the injection rates of 5.0 and 10 mL/min, although the required pressure gradients to displace oil were lower, only 85% and 82% of IOIP were produced after 12 PVI and 20 PVI of PEF flooding (the time at which recovery factor reached to a plateau), respectively. Based on a study conducted by Bashir and his co-workers (Bashir et al., 2021) on foam rheological properties, the reason for such behaviour is that by increasing the shear rate, foam apparent viscosity decreases (shear thinning behaviour). This means at a high flow rate, a less viscous foam flows through the preferential flow path of the fracture, and most of the injected fluid will bypass the low-permeability region (matrix), and it translates to a longer time for foam to slowly penetrate the matrix. Therefore, a large volume of PEF is required when a high injection rate is used. This highlights the need for the optimisation of the injection rate in designing a foam injection process in fractured reservoirs.

Moreover, at high injection rates the interaction between the injected foam and the oil inside the matrix will be less; therefore, foam becomes less effective in pushing the oil out of the pore spaces, less oil will be emulsified, and hence lower microscopic sweep efficiency will be achieved. As shown in Fig. 6, the pore-scale images of the swept regions of the matrix indicate that at a low injection rate, less oil was trapped inside the porous media at the end of the flooding process (a low residual oil saturation). While at the higher injection rates larger fractions of the oil are trapped in the matrix; thus, the flow of PEF in the matrix becomes less efficient as the rate is increased.

3.1.2. *Effect of oil viscosity*

In order to evaluate the effect of oil viscosity on the displacement efficiency of PEF flooding in fractured reservoirs, three experiments were conducted using the micromodel that was saturated with three different mineral oils. As shown in Fig. 7, when the oil viscosity increases from low to high, the efficiency of PEF flooding (injection rate of 1.0 mL/min) decreases dramatically. It can be seen that in the presence of the low viscosity oil, a recovery of 95% IOIP was achieved after 6 PVI of foam injection. In contrast, PEF flooding in cases where the model was saturated with medium or high viscosity oils, resulted in recoveries of 50% and 29% IOIP after 13 PVI and 16.4 PVI of foam injection, respectively, leading to poor sweep efficiencies in the matrix compared to the low viscosity oil. In theory, the presence of PEF reduces viscous fingering and gravity override, however, in the displacement process of viscous oils viscous forces associated with the oil flow are larger, and the rate of foam coalescence is higher. This means the foam cannot overcome these viscous forces related to the oil phase and also its stability is lower, and as a result, immiscible displacement of such oils with PEF flooding is difficult. Fig. 8 shows a comparison of the swept areas of the micromodel when different oils were used. It can be seen that for the medium and high viscosity oils significant amount of the oil remained in the matrix after 10 PVI of foam injection (PEF). In addition, the colour contrast in the swept areas shows that the lower the oil viscosity, the higher the microscopic sweep efficiency. This is mainly due to sufficient energy of the foam (PEF) to overcome the viscous forces related to the lighter oils, emulsification of the oil in the lamellae, and displacing the oil globules, that reduces the residual oil saturation.

Table 3
LE foam model parameters for low, medium, and high viscosity oil.

Parameter	Low Viscosity		Medium Viscosity		High Viscosity	
	Matrix	Fracture	Matrix	Fracture	Matrix	Fracture
FMMOB	4000	4000	4000	4000	4000	4000
fmsurf	0.005	0.005	0.005	0.005	0.005	0.005
fmoil	1.0	0.8	1.0	0.8	1.0	0.8
floil	0	0	0	0	0	0
epsurf	1	1	1	1	1	1
epoil	0.6	0.6	1.2	1.2	1.3	1.3
SFDRY	0.05	0.02	0.05	0.02	0.05	0.02
SFBET	1000	1000	1000	1000	1000	1000

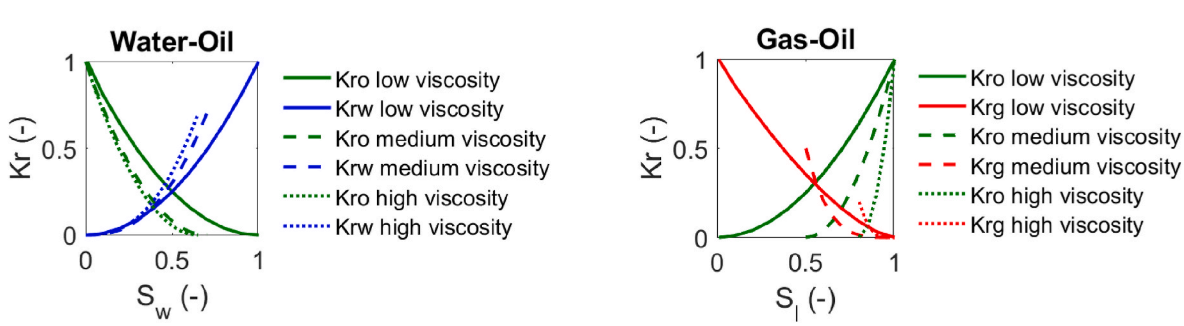

Fig. 10. Matrix relative permeability curves from history matching PEF with the low, medium, and high viscosity oils.

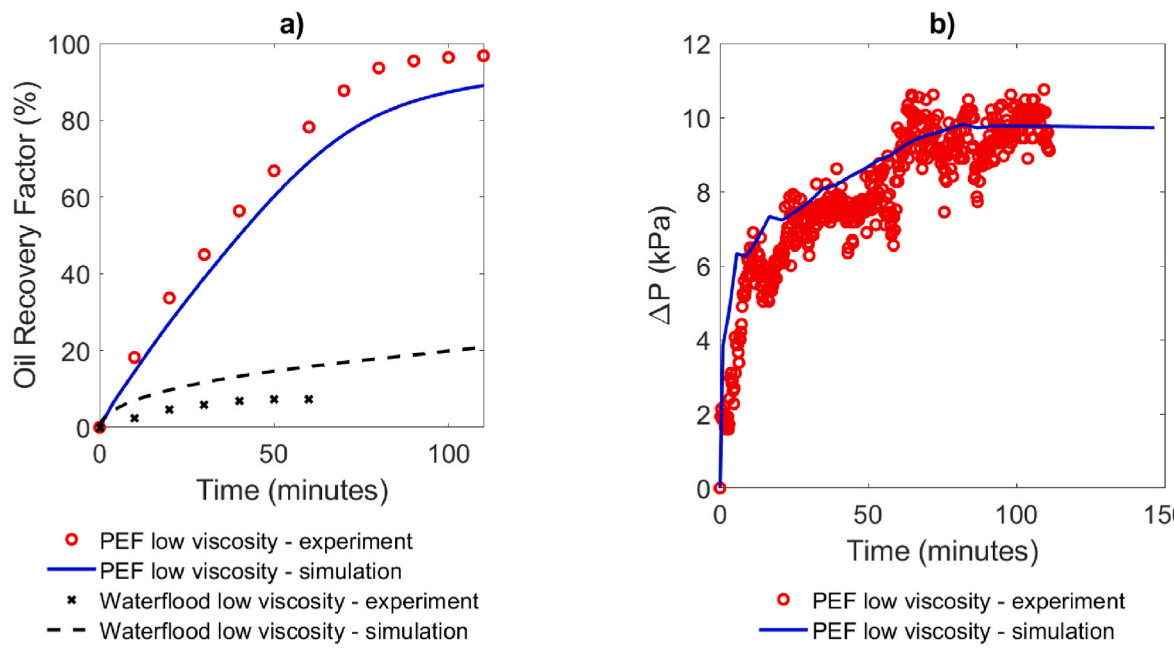

Fig. 11. Simulation and experimental results of PEF flooding in the model saturated with the low viscosity oil for (a) oil recovery factor, and (b) pressure drop, at different times.

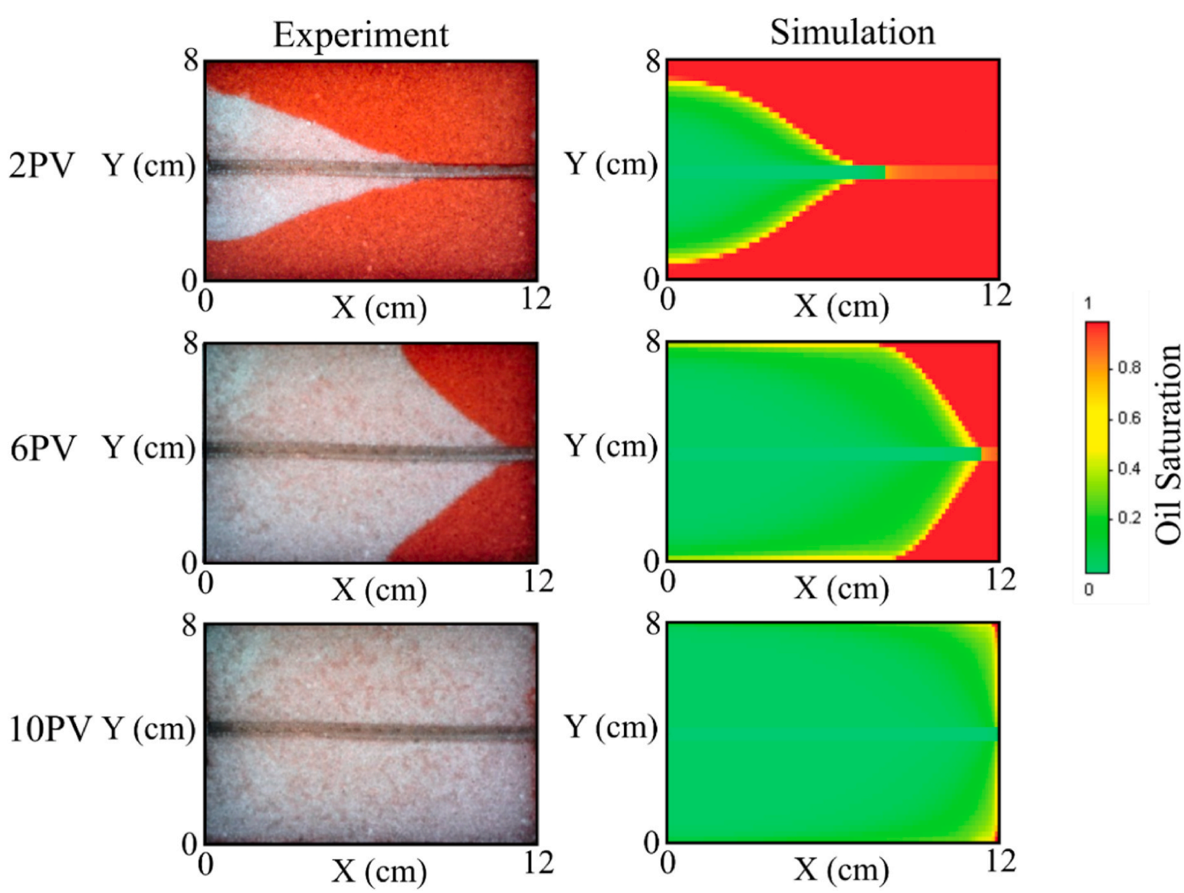

Fig. 12. Comparison of oil saturation from the experiments and simulations at different times during PEF flooding of the model saturated with the low viscosity oil.

3.1.3. Numerical simulation of the PEF flooding

In the previous section, we observed that PEF flooding was less effective in displacing viscous oils, and we believe that the reasons for such performance were the high viscous forces against the oil flow and the higher rate of foam coalescence in the presence of viscous oils, which reduces PEF flooding efficiency to displace oil. Furthermore, there can be less emulsification of the oils by the surfactant solution in the lamellae in PEF flooding, however this might not be a dominant

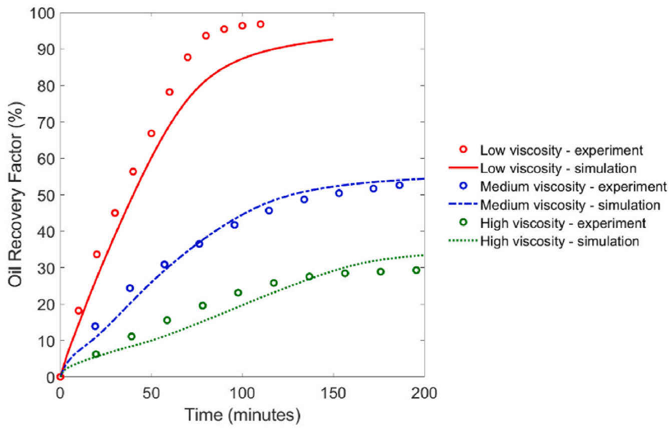

Fig. 13. Oil recovery based on simulation and experimental results of PEF flooding in the model saturated with light, medium and heavy oils.

mechanism as the fraction of surfactant solution is very low in the foam structure. Therefore, based on this hypothesis foam instability and the large viscous forces related to the oils cause reductions in both macroscopic and microscopic sweep efficiencies.

To test this hypothesis, a 2D model is built using CMG STARS to simulate the lab experiments (Zhang et al., 1991). The model has dimensions of 12 × 8 × 0.4 cm and can be split into two distinct regions of the fracture and the matrix, and it is comprised of 100 × 40 × 1 grid blocks as shown in Fig. 9. The fracture (red) is represented by a single row of grid blocks through the centre of the model each with a size of 0.12 × 0.5 × 0.4 cm and the matrix grids blocks (blue) are 0.12 × 0.192 × 0.4 cm. STARS uses a local equilibrium (LE) foam model to capture the foam flow in porous media, the details of the model and its parameters are defined in the Appendix section. The displacing fluid is injected into the left-hand side of the fracture and produced from the right-hand side. The matrix and fracture are both homogeneous but are considered as different regions with different properties as shown in Table 2.

The model is run using five components: water, surfactant, polymer, oil, and gas. The surfactant and polymer are both in the aqueous phase and do not partition into the oil or gas phases. The gas is also considered as non-condensable and therefore does not partition into the oil phase. Capillary pressure is also assumed to be negligible.

To capture the foam flow in our tests and predict the oil recovery performance, we history matched the water-oil and gas-oil relative permeability curves in addition to the LE foam model parameters. This information is presented in Fig. 10 and Table 3. The relative permeability curves in the fracture are linear and there are no residual phase saturations.

The oil recovery and pressure drop associated with the experiment and simulation are shown in Fig. 11. The oil saturation at different times during PEF flooding is also compared Fig. 12. These figures show reasonable quantitative and qualitative matches between the simulation and the experimental results. It should be noted that some differences are expected as the physics of foam propagation is complex and aspects such as emulsification of oil by collapsed foam is not captured in the LE foam model. This demonstrates that a reasonable prediction of oil displacement process can be made, comparing the experimental results with the numerical simulation outcomes from the foam and multiphase flow models used.

The simulations were also repeated for the medium and high viscosity oils and the recovery versus time is shown in Fig. 13. To achieve a good match with the experimental data the relative permeability curves also had to be history matched for each experiment which are shown in

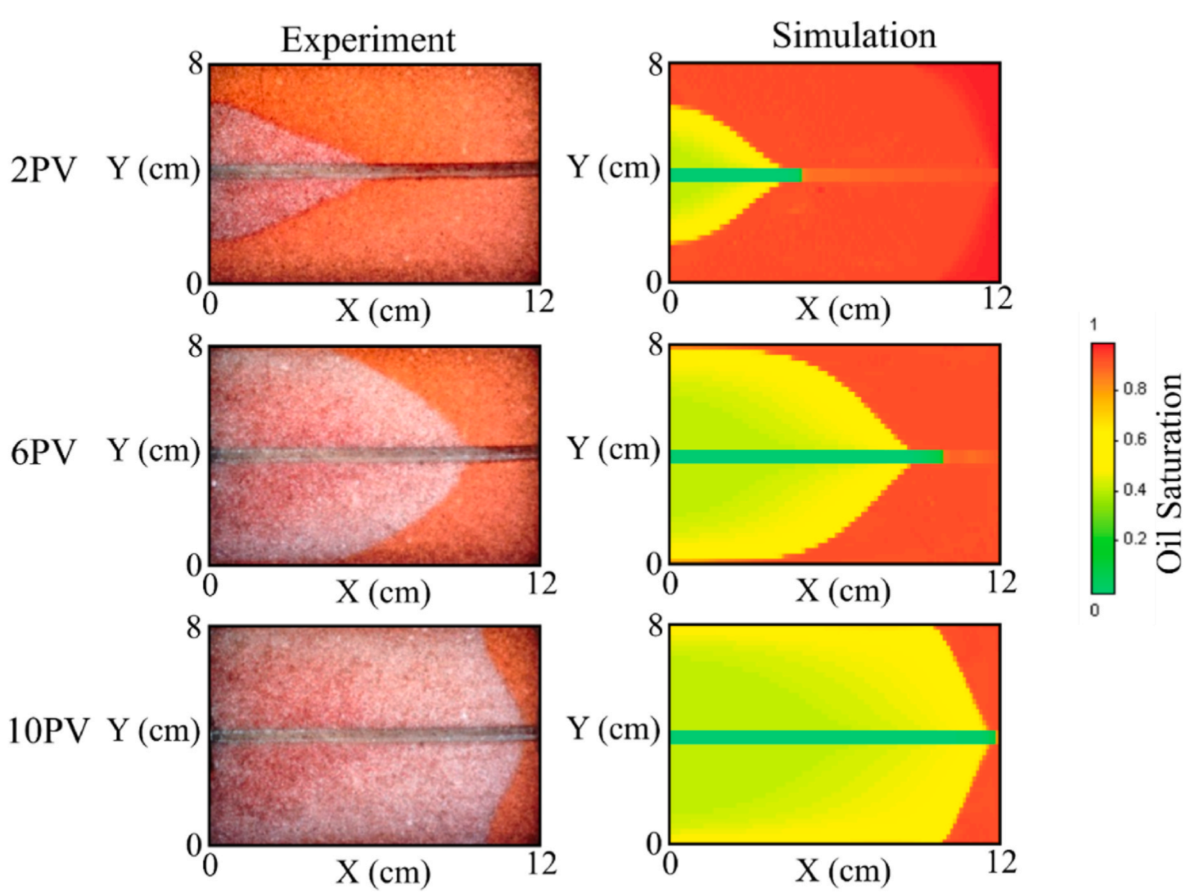

Fig. 14. Comparison of oil saturation from the experiments and simulations at different times during PEF flooding of medium viscosity oil.

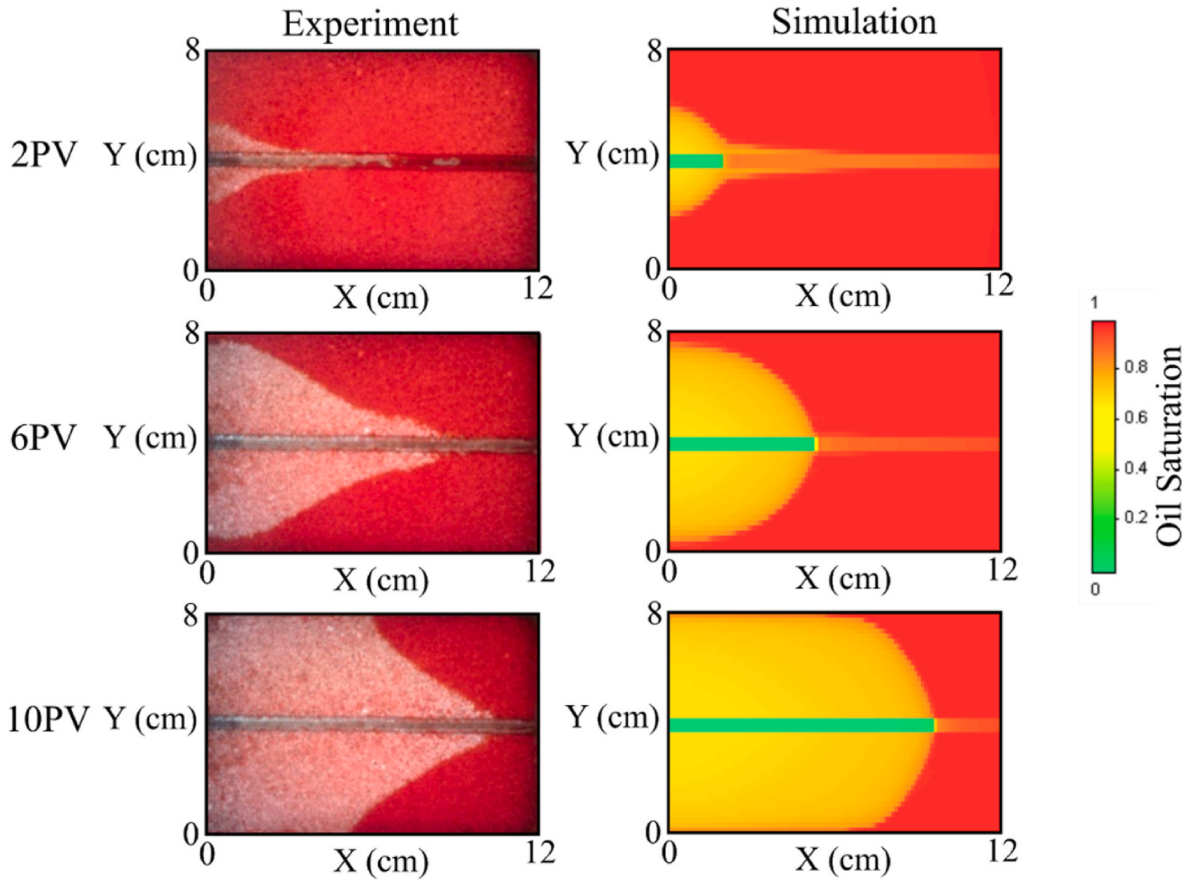

Fig. 15. Comparison of oil saturation from the experiments and simulations at different times during PEF flooding of high viscosity oil.

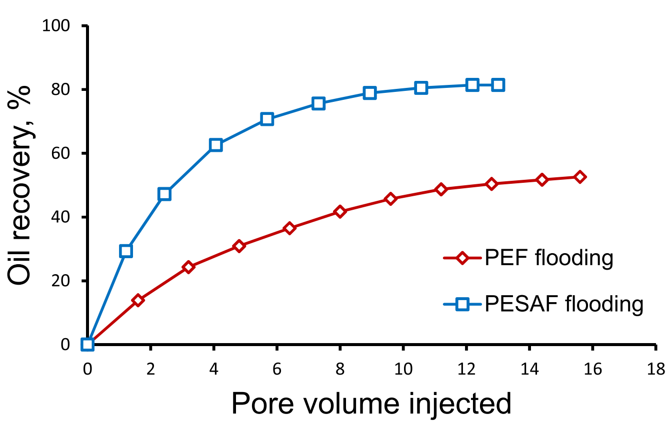

Fig. 16. Oil recovery vs pore volume injected for PEF flooding and PESAF flooding in the presence of medium oil viscosity. A video in. avi format shows the displacement front during PEF flooding and PESAF flooding in the presence of medium oil viscosity.

Fig. 10. The values of the LE foam model used to achieve these matches are detailed in Table 3.

The oil saturation at different times during PEF flooding for medium and high viscosity oils are shown in Figs. 14 and 15, respectively. These show a reasonable match between the simulation and experimental results. Most noticeably the residual oil saturation increases with the medium and high viscosity oils compared to the light oil based on the relative permeability information (Fig. 10). The foam-oil front also takes longer to travel across the model as the oil viscosity increases. The simulation outcomes suggest a general trend for the relative permeability curves, in which as the oil viscosity increases, the residual oil saturation becomes higher, and the oil relative permeability value gets lower. Furthermore, these result in both lower residual oil behind the foam front and also higher foam strength due to the decreased residual oil causing less foam collapse. Therefore, our simulations ratified that the key parameters that have changed are the effect of oil on foam coalescence and relative permeability curves (related to the oil phase viscous forces). We can conclude that displacing viscous oils by PEF flooding may not yield a high efficiency.

Consequently, designing a new hybrid process to improve the foam sweep efficiency in porous media with viscous oils at an economical rate is needed. An optimized solution for using foam should mobilize the viscous oil and minimize the rate of foam coalescence, therefore, in the next section, we proposed and tested a modification to the PEF flooding process to increase the efficiency of it for displacing viscous oils.

3.2. *PESAF flooding*

Conventional foam flooding and even PEF flooding processes in fractured reservoirs containing medium and high viscosity oils, are challenging as discussed in the previous section. Therefore, here we propose the hybrid injection process of PESAF flooding for oil displacement in fractured porous media containing medium and high viscosity oils. This hybrid process of PESAF is proposed based on the hypothesis that higher saturation of surfactant solutions at the interface of the foam and oil can enhance the displacement of the viscous oil via two main mechanisms; firstly, the IFT between the viscous oil and aqueous phase can be reduced effectively (low-tension aqueous solution is available around the viscous oil), and this helps to emulsify the oil and generate oil globules, and as reported by Zhang et al. (1991), viscosity of oil-in-water emulsion is significantly lower than the oil viscosity for oil

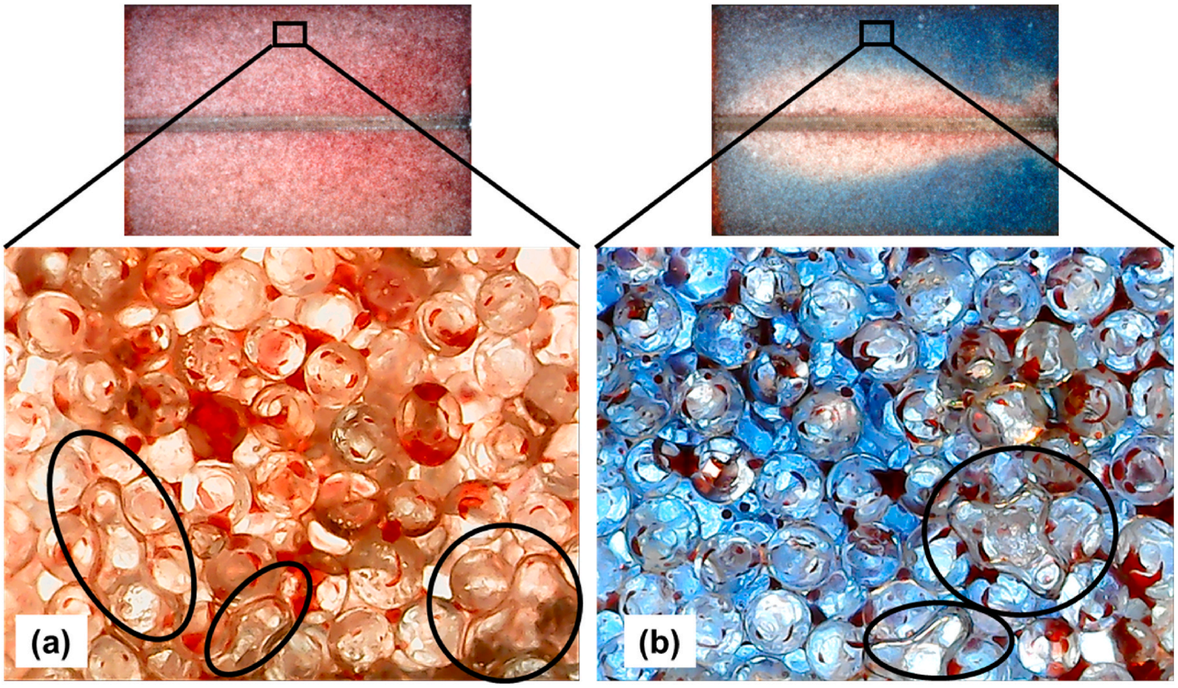

Fig. 17. Pore-scale images showing the swept zones (oil: red colour) at the end of (a) PEF flooding and (b) PESAF flooding (blue colour represents the FES slug invading the matrix region) in the presence of medium oil viscosity. Black ellipses indicate the examples of the trapped foam bubbles inside the matrix region. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

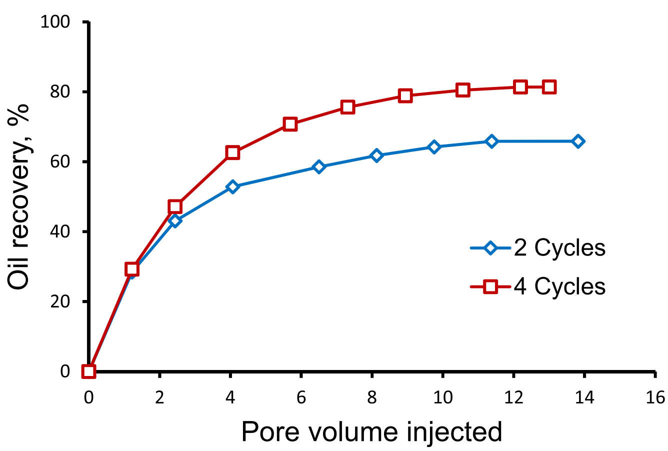

Fig. 18. il recovery vs pore volume injected in the presence of medium oil viscosity.

volume fraction less than 80%. Secondly, higher liquid saturation means thicker foam lamellae can be generated, which in turn increases the foam stability and effectiveness in the presence of long-chain hydrocarbon molecules and reduces the rate of foam coalescence and dry-out. Therefore, the oil droplets which have higher mobility and lower viscosity than the oil will be transported within the aqueous phase and also displaced by the foam phase. As the viscosity of oil increases the viscosity of O/W emulsion increases too (Chen et al., 2018), and hence the efficiency of PESAF flooding in displacing the viscous oil emulsion decreases.

To get the benefit of these mechanisms and implementing them in the oil displacement process, slugs of the surfactant solution should be injected alternatively with the foam. The foam which has a lower rate of coalescence due to the slug of surfactant and polymer solution, will then push the emulsified oil immiscibly and also displace it through the lamellae.

To understand and validate the above hypothesis during the PESAF process, the PES and PEF slugs were injected alternately for four cycles and then PEF flooding was continued to the end of the test. In each cycle, 0.1 PV of PES slug was injected with an injection rate of 0.2 mL/min, and it was followed with 1 PV of PEF flooding (the PEF injection rate was 1 mL/min). At the end of the fourth cycle the PEF flooding was continued until no significant change in recovery factor was observed. Fig. 16 shows the oil recovery versus the number of pore volume injected for PEF flooding and PESAF flooding when the micromodel was saturated with the medium viscosity oil. It demonstrates that PESAF flooding significantly improved the recovery compared to PEF flooding. Also, this can be visualised in the supplementary video file that shows the displacement of the front up to 13 PV injection in PEF flooding and PESAF flooding. The ultimate oil recoveries were 53% and 81% after 16 and 13 PV injections in PEF flooding and PESAF flooding, respectively. In addition to the previously discussed mechanisms, it should be noted that the generation of a strong foam leads to a higher pressure gradient in the fracture, that helps to push the foam and surfactant solution toward the matrix regions improving the matrix sweep efficiency.

Fig. 17 shows the pore-scale images for PEF flooding and PESAF flooding in the presence of the medium viscosity oil. Although, PEF flooding swept the oil from the matrix (high macroscopic sweep efficiency), the microscopic sweep efficiency was low, and a high fraction of the oil left behind (Fig. 17a). On the other hand, PESAF flooding effectively displaced most of the oil from the matrix and shows a higher microscopic sweep efficiency i.e., a low residual oil saturation (Fig. 17b). Therefore, the combination of PES and PEF flooding is capable of improving the efficiency of the oil displacement process. It should be highlighted that for foam generation we used CO_2, considering the potential benefit of CO_2 geological storage during oil recovery from fractured heavy oil reservoirs, however the use of nitrogen gas could also be considered in designing the PESAF process.

3.2.1. *Number of cycles*

To further understand the role of surfactant slug on the performance of PESAF flooding, we tested a case of reduced number of cycles (two

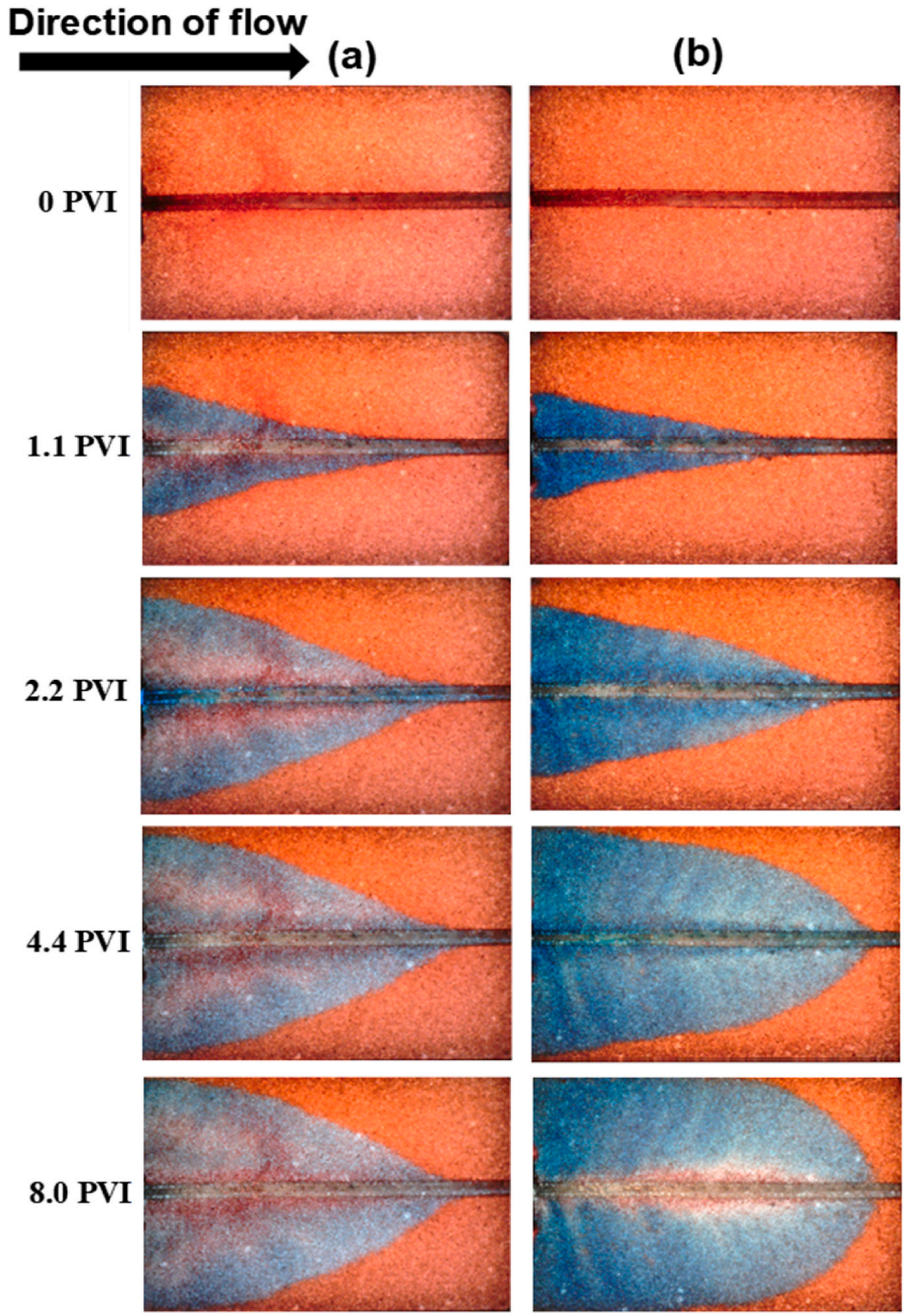

Fig. 19. Displacement fronts of (a) 2 cycles and (b) 4 cycles of PESAF followed by PEF flooding at different pore volumes injected (cumulative) in the presence of medium oil viscosity.

cycles) and compared it with our initial four cycle PESAF flooding experiments. Similarly, in the two cycle PESAF flooding experiment, each cycle consisted of 0.1 PV injection of PES and 1.0 PV injection of PEF. A lower recovery factor was observed for the two cycle PESAF, as shown in Fig. 18. In the case with two cycles, the total volume of the PES (0.2 PV) that invaded the matrix was not adequate to alter the IFT and emulsify most of the oil inside the matrix region and reduce the rate of foam coalescence. This is shown in Fig. 19a, in which PEF flooding pushed the PES slug to invade parts of the matrix region, creating interaction between the PES and the oil, and allowing more oil to be produced. However, the displacement front moved slowly after the second cycle (2.2 PVI), and this resulted in a reduction in the oil production rate (a lower slope of the oil recovery curve), leading to a total oil recovery of 66% IOIP. When four cycles of PESAF were considered, the PESAF flooding significantly improved the oil sweep efficiency in the matrix, leading to recover 81% IOIP. We can conclude that by increasing the number of cycles a larger volume of PES penetrates into the matrix, and in turn a lower rate of foam coalescence at the interface of the foam and viscous oil is expected, this also helps better emulsification of the oil and therefore a more efficient displacement process occurs as shown in Fig. 19b. There could be higher oil recovery factor with increasing the number of cycles beyond four cycles, however, we decided to limit our PES injection volume to 0.4 PV (the PVI of commonly used surfactant and/or polymer varied from 0.2 to 0.4 PVI) as an economical criterion for the volume of surfactant and polymer solutions in chemical enhanced oil recovery processes (Cao et al., 2020; Dawson and Lantz, 1972; Pancharoen et al., 2010; Rai et al., 2015; Samanta et al., 2011). For the same reason, the PES slug sizes larger than 0.1 PV was not investigated in this study, in addition the larger PES slug size than 0.1 PV could result in a breakthrough via the fracture in the physical model.

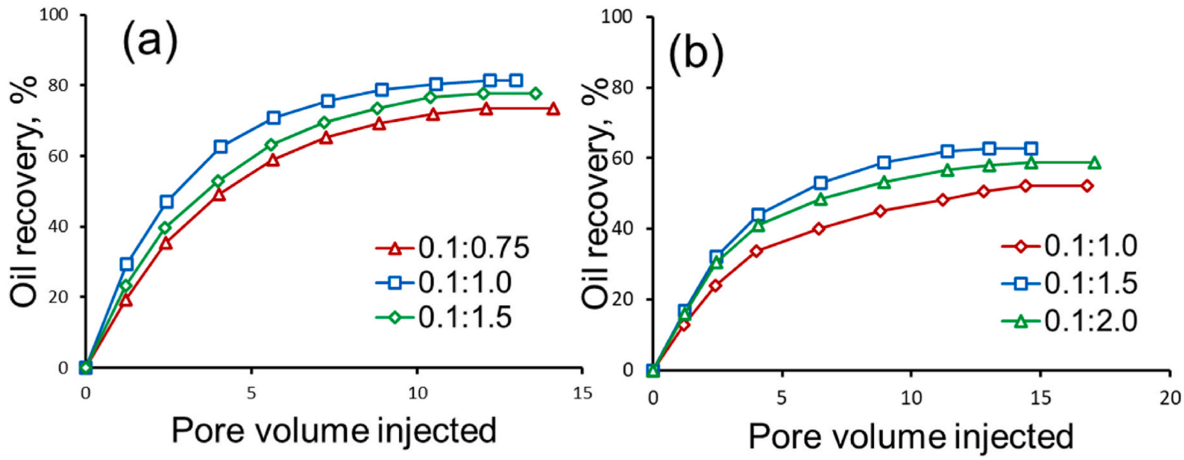

Fig. 20. Oil recovery vs pore volume injected for different PEF slug sizes using (a) medium viscosity oil and (b) high viscosity oil.

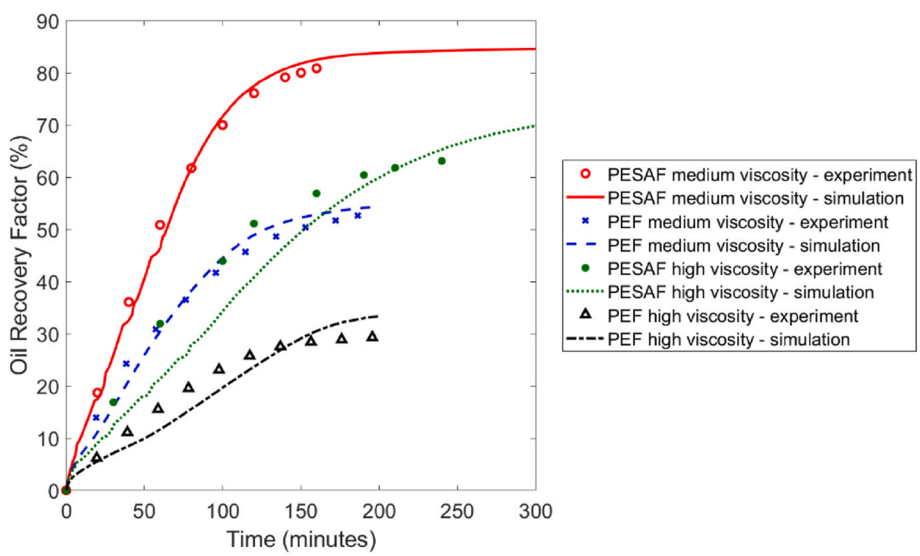

Fig. 21. Oil recovery for simulation and lab experiments of PEF and PESAF flooding with medium and high viscosity oils.

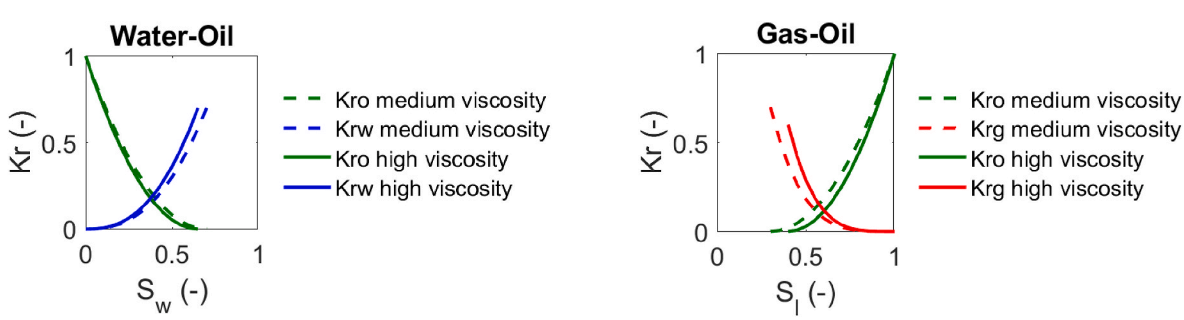

Fig. 22. Relative Permeability curves for PESAF flooding.

Nevertheless, the size of the PES slug size can be investigated to optimise the size of the PES slugs in designing PESAF flooding for field cases.

3.2.2. Foam slug size and oil viscosity

In addition to the number of cycles (i.e., the total volume of PES injected), the size of the foam slug and also oil viscosity are important parameters that should be considered for optimizing PESAF flooding. In this section, we demonstrated the effect of these parameters on the efficiency of PESAF flooding and proposed that an optimized foam slug size is needed for different oil viscosities. Two different oils were compared i.e., the medium and high viscosity oils as described in Table 1. Three different foam slug sizes were used to optimise the process efficiency and maximise the oil displacement efficiency. For the medium viscosity oil, each cycle consisted of 0.1 PV of PES; and the PEF slug sizes of 0.75, 1.0 and 1.5 PV were examined. For the high viscosity oil, it was expected that the displacement process to be slower and hence a longer period of foam injection was considered to ensure immiscible displacement of emulsified oil is effective. Therefore, each cycle

Table 4
Relative permeability endpoints for PEF and PESAF flooding for medium and high viscosity oil.

Parameter	Medium Viscosity		High Viscosity	
	PEF	PESAF	PEF	PESAF
S_{wc}	0	0	0	0
S_{orw}	0.3	0.3	0.35	0.35
k_{rw}^{max}	0.7	0.7	0.7	0.7
S_{gc}	0	0	0	0
S_{org}	0.5	0.3	0.8	0.4
k_{rg}^{max}	0.5	0.7	0.2	0.6

consisted of 0.1 PVI of PES; and the PEF slug sizes of 1, 1.5 and 2 PV were considered. In all the tests, a total of four cycles of PESAF were conducted, followed by continuous PEF flooding until the recovery factor has reached a plateau. The results revealed that a higher oil recovery could be achieved when the PEF slug size increased from 0.75 PV to 1 PV for the medium viscosity oil case and then the recovery factor decreased when the PEF slug size further increased to 1.5 PV (Fig. 20a). Similarly, for the high viscosity oil tests, a higher recovery factor was achieved when the PEF slug size increased from 1 PV to 1.5 PV, and then it decreased when the PES slug size further increased to 2 PV (Fig. 20b). Therefore, the PEF slug sizes of 1 PV and 1.5 PV were optimal in PESAF flooding of the models that were saturated with the medium and high viscosity oils, respectively. This means that as the oil viscosity increases, a larger PEF slug size is needed to maximise the recovery factor. Based on these experiments, it is believed that for viscous oils (typically a bigger molecular weight), emulsified oil droplets have higher viscosity, hence the PEF slug size should be large enough to overcome the viscous forces and displace the emulsified oil. On the other hand, the PEF slug size should not be too large as there will be no remarkable benefit after the mobilized oil is displaced with optimum size of the slug. This means once a specific volume of the viscous oil is emulsified, it can be displaced with an optimum size of the PEF slug, and further injection of foam would not provide any further benefit to the displacement process. The latter will in fact decrease the saturation of surfactant inside the matrix by flowing through the foam lamellae back to the fracture, which can negatively affect the displacement mechanisms.

Therefore, the optimum PEF slug sizes push the surfactant into a larger area in the matrix and displace the emulsified oil efficiently; hence, an optimum PESAF flooding can improve both the macroscopic and microscopic efficiencies. We can conclude that the optimum size of slug needs to be determined for each oil viscosity, to maximise the sweep efficiency of PESAF flooding.

3.2.3. Numerical simulation of the PESAF flooding

Experiments have shown that PESAF flooding can increase the displacement efficiency compared to PEF flooding. We can also compare the numerical tools to simulate the PESAF flooding. This will enable us to support the proposed hypothesis for the mechanisms of oil flow in PESAF flooding. However, it should be noted that to capture the impact of emulsification of the oil and generation of oil globules in PESAF flooding, the bulk- and emulsified-oil phases should be modelled separately in terms of their mobilities (their viscosity and relative permeability are different), but current commercial flow simulators may not be able to capture these phenomena. To simulate this process, we assumed the bulk- and emulsified-oil flows can be shown with a single set of relative permeability curves as equivalent relative permeability curves for the total oil flow, and the viscosity of the emulsified oil remains the same as the bulk oil.

The numerical model was developed with the properties of porous media and foam parameters detailed in Tables 2 and 3 The numerical model is used to simulate the optimal slug sizes found in the experiments. The oil recovery versus time for medium and heavy viscosity oils for both PEF and PESAF flooding with a 0.1:1 and 0.1:1.5 slug size respectively for medium and high viscosity oils is shown in Fig. 21. The relative permeability curves that are used to achieve a match between the experimental and simulation results of PESAF flooding are shown in Fig. 22. This shows that a good match can be achieved with both PEF and PESAF using the LE foam model.

The relative permeability curves in Fig. 22 are considerably different compared to the PEF flooding simulations for the same oils as shown in Fig. 10. The major difference between the curves is the PESAF flooding relative permeability curves have much lower residual oil saturations (Table 4). These relative permeability curves show that the oil becomes mobilized with higher relative permeability values as the gas saturation increases (this effect could be associated with the emulsified oil flow assumption). In addition, since surfactant saturation would be higher in the porous media, this will help to have stronger foam which means foam viscosity would be higher and then larger viscous forces associated with the oil phase can be overcome. STARS also interpolates between the two relative permeability curves based on the foam strength allowing the effect of gas trapping at high foam strengths which was crucial to achieving a match with the PESAF flooding. The maximum trapped gas saturation, S_{gr} at maximum foam strength is 0.5 and 0.4 for medium and high viscosity oils, respectively. This demonstrates that the mechanisms of oil recovery during PESAF and PEF flooding are

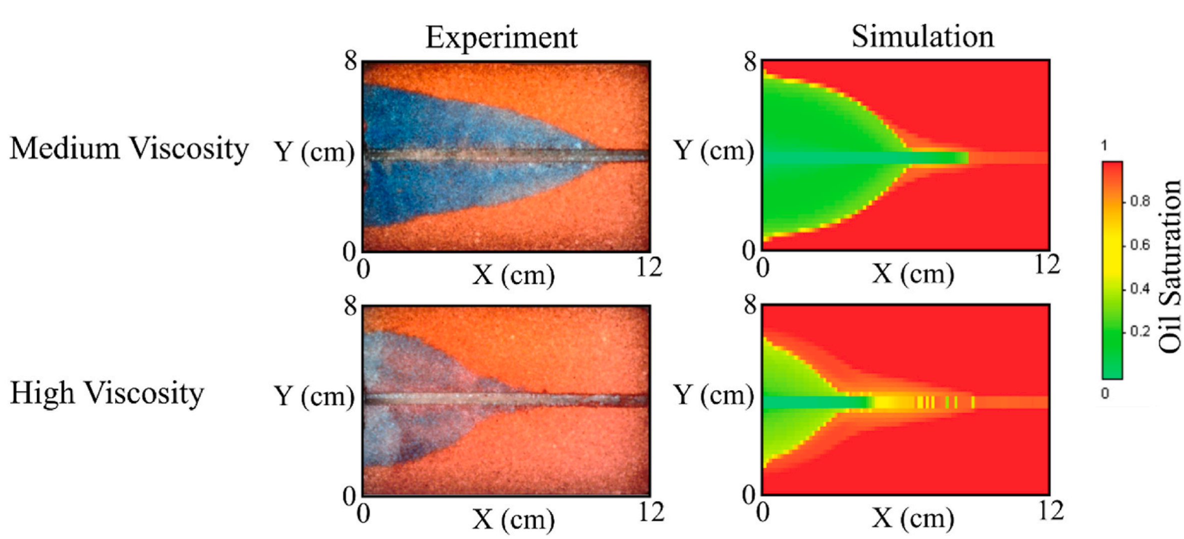

Fig. 23. Comparison of oil saturation from the experiments and simulations after 2 PVI of PESAF flooding of medium and high viscosity oils.

considerably different which can only be captured by changing the relative permeability curves. This includes the effect of oil emulsification which can mobilize the high viscosity oils that were immobile during PEF flooding. The oil saturation profile after 2 PVI for both the lab experiment and the simulation is shown in Fig. 23 which also shows that a reasonable match between the lab and simulation results.

These simulation results show that PESAF flooding can be modelled using a LE foam model. But this also required significant alterations of the relative permeability curves compared to the PEF flooding which support the hypothesis that other flow mechanisms are involved in the oil displacement process during PESAF flooding, i.e., the emulsification of the oil phase and the foam stability enhancement.

4. Conclusions

In this study, the displacement efficiency of PEF and PESAF flooding were investigated in a fractured micromodel using three different oil viscosities (low, medium, and high). The change in oil displacement efficiency, pore-scale phenomena, and flow mechanisms were analysed quantitatively and qualitatively. Based on the observations and analyses presented, the following conclusions can be drawn:

- PEF flooding improved the total oil displacement in the presence of the low viscosity oil. However, increasing the oil viscosity appeared to have a strong influence on the efficiency of PEF flooding (the displacement efficiency decreased). Therefore, a new hybrid process was introduced to improve the displacement efficiency from the fractured porous media in the presence of medium and high viscosity oils.
- PESAF flooding was proposed based on the hypothesis that viscous oils could be emulsified (oil globules and O/W emulsions) with the injection of surfactant solution. The emulsified oil has higher mobility, furthermore, the foam that pushes the oil phase would be more stable at higher saturations of the foaming agent. These phenomena helped to improve the microscopic and macroscopic sweep efficiencies; thus, higher displacement efficiencies were achieved for viscous oils.
- During PESAF flooding, the flow of foam in the fracture created flow resistance due to the higher viscosity of the trapped foam bubbles inside the fracture. Therefore, the trapped bubbles generated additional force to divert the PES solution and also the foam bubbles to the matrix.
- Based on the results of this study, for an efficient displacement of viscous oils from fractured porous media through PEF flooding and PESAF flooding, parameters such as injection rate, oil viscosity, foam and surfactant solutions slug sizes, and the type of foaming agent and gas should be considered in the design of such processes.

Credit author statement

Ahmed Bashir: Investigation, Methodology, Validation, Visualisation, Writing – original draft. Amin Sharifi Haddad: Conceptualization, Methodology, Funding acquisition, Supervision, Formal analysis, Project administration, Writing – review & editing. Joseph Sherratt: Formal analysis, Validation, Visualisation, Writing – original draft. Roozbeh Rafati: Supervision, Methodology, Writing – review & editing

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Nomenclature

K	Permeability [Darcy]
φ	Porosity [-]
k_{rw}	Water relative permeability [-]
S_{wc}	Critical water saturation
S_{orw}	Irreducible oil saturation in oil-water two phase flow
k_{rg}	Gas relative permeability [-]
k_{ro}	Oil relative permeability [-]
EOR	Enhanced Oil Recovery
NFRs	Natural fractured reservoirs
SP	Surfactant polymer
CO_2	Carbon Dioxide
LE	Local equilibrium
PEF	Polymer-enhanced foam
PES	Polymer-enhanced surfactant
PESAF	Polymer-enhanced surfactant alternating foam
PVI	Pore volume injected
IFT	Interfacial tension
cEOR	Chemical Enhanced Oil Recovery
IOIP	Initial oil in place
NPs	Nanoparticles
SiO_2	Silica
RHA	Rice husk ask
XG	Xanthan gum

AOS	Alpha olefin sulfonate
FMMOB	Maximum foam mobility reduction factor
FDRY	Foam dry out
FM	Interpolation factor
F_1	Function of surfactant concentration
F_2	Function of oil saturation
F_3	Function of capillary number
F_4	Function of foam generation (capillary number)
F_5	Function of oil composition
F_6	Function of oil salinity
C_{surf}	Surfactant mol concentration
fmsurf	Surfactant mol fraction
fmoil	Upper limit of oil saturation
epsurf	Exponent of F_1
epoil	Exponent of F_2
floil	Lower limit of oil saturation
SFBET	Parameter controlling the abruptness of foam coalescence near SFDRY
SFDRY	Limiting water saturation in foam dry-out function

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.petrol.2022.110280.

Appendix

To represent the effect of foam on multiphase flow equations in porous media, STARS uses a local equilibrium (LE) model, in which the foam is represented by a gas phase with decreased mobility. When STARS determines that foam is present in a grid block the gas permeability is modified by multiplying the gas permeability in absence of foam, k_{rg}, by an interpolation factor, FM, resulting in,k_{rg}^{*}.

$$k_{rg}^{*} = FM \bullet \mathrm{k_{rg}} \tag{1}$$

The interpolation factor FM is calculated by,

$$FM = \frac{1}{1 + FMMOB \times F_1 \times F_2 \times F_3 \times F_4 \times F_5 \times F_6 \times F_{DRY}} \tag{2}$$

where FMMOB is the maximum foam mobility reduction factor and the terms F_1 to F_6 represent the effect of different parameters on the foam mobility and F_{DRY} represents the effect of foam dry out. This results in FM in the range of 1 (no foam) to 1/[FMMOB+1] (strong foam). By including more of the F terms the foam model becomes more complex and the strength of the foam is influenced by more variables. It is common to ignore some of these terms that have negligible effects in some cases, and in this study, only the effects of FMMOB, surfactant concentration (F_1), oil saturation (F_2) and foam dry out (F_{DRY}) are considered, so Equation (2) can be reduced to,

$$FM = \frac{1}{1 + FMMOB \times F_1 \times F_2 \times F_{DRY}} \tag{3}$$

where,

$$F_1 = \left(\frac{C_{surf}}{fmsurf}\right)^{epsurf} \tag{4}$$

$$F_2 = \left(\frac{fmoil - S_o}{fmoil - floil}\right)^{epoil} \tag{5}$$

$$F_{dry} = 0.5 + \frac{\arctan(sfbet \times (S_w - SFDRY))}{\pi} \tag{6}$$

where C_{surf} is the surfactant mol fraction and *fmsurf* is the surfactant mol fraction above which the foam strength is constant and not impacted by surfactant concentration. The exponent *epsurf* determines how the foam strength varies between $C_{surf} = 0$ and $C_{surf} = fmsurf$. *floil* is the lower limit of oil saturation below which foam strength is considered strong and not impacted by oil saturation and *fmoil* is the upper limit of oil saturation above which foam is considered completely collapsed. The exponent *epoil* determines how the oil saturation changes between the two $S_o = floil$ and $S_o = fmoil$. The dry-out term F_{dry} accounts for the effect of water saturation, S_w on foam strength and results in the foam strength being very weak beneath the critical water saturation, *SFDRY*.

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