Experimental study on performance of foamy oil flow under different solution gas-oil ratios

Songyan Li, Zhaomin Li, Zhuangzhuang Wang

College of Petroleum Engineering, China University of Petroleum (East China), 266580, China

ABSTRACT: Foamy oil flow has been widely accepted as an explanation for the high oil recovery observed in certain heavy oil reservoirs, and a number of studies have been conducted to understand the mechanisms involved. However, insufficient information is available on the effects of the initial gas-oil ratio on the foamy oil flow. The effects of the solution gas-oil ratio were investigated based on sandpack and visualization experiments for solution gas drive with the foamy oil from Carabobo reservoir. As the solution gas-oil ratio decreases, the differences in the bubble point and pseudo-bubble point pressure (markers for the foamy oil production period) decrease, resulting in an obvious reduction of the oil recovery efficiency. The effects of the solution gas-oil ratio on foamy oil flow in porous media can be explained by higher interfacial tension, lower interfacial dilational viscoelasticity, higher live oil viscosity, and lower elastic energy under lower solution gas-oil ratios. A lower limit of the solution gas-oil ratio should exist for foamy oils with different properties, which is believed to be approximately 5.0 Sm^3/m^3 for the Carabobo reservoir, according to experimental results. For reservoirs with foamy oil cold production, the solution gas can be separated from the produced oil and injected into the formation to increase the solution gas-oil ratio, extend the foamy oil production time, and improve the oil recovery efficiency. The experimental results provide theoretical support for foamy oil production.

Key words: foamy oil, solution gas-oil ratio, performance, oil recovery efficiency, porous media

1. Introduction

Solution gas drive production in heavy oil reservoirs, which is frequently referred to as foamy oil cold production, has been applied in Canada, Venezuela, China, and Oman.[1-5] Oil recovery as high as 20% by cold production is estimated for those heavy oil reservoirs, which is believed unusual for notably heavy oils. Foamy oil flow is a widely accepted explanation for the high recovery factors. High oil recovery is frequently related with a low gas-oil ratio in the produced fluid and a low rate of pressure drop in the formation. The foamy oil maintains the released solution gas that is dispersed in the heavy oil, which obviously differs from that of conventional light oil.[6-10]

A number of experimental, theoretical, and field studies related to this subject have been conducted to develop an understanding of the mechanisms involved. The effects of several important factors on foamy oil flow have been researched, i.e., pressure depletion rate, temperature, and initial solution gas-oil ratio.

Several researchers have presented the results from pressure depletion experiments for foamy oil.[11-14] These results indicate that the beneficial effects of foamy oil diminish as the rate of pressure change decreases. Ostos *et al.* conducted core depletion tests at different pressure decrease rates and concluded that a high pressure depletion rate promotes higher recovery and that the foamy oil phenomenon primarily occurs when pressure rapidly decreases.[15] Bondino *et al.* studied how the pressure depletion rate affects the foamy oil in porous media using a mathematical model and core experiment tests; their study provided a better understanding of gas bubble nucleation.[16] Li *et al.* researched the effects of the pressure depletion rate on foamy oil micro-flow characteristics based on microscopic visualization experiments.[17] Those research results show very clearly that the increase of the pressure depletion rate is beneficial for improving the foamy oil effect and the oil recovery efficiency.

Temperature is also an important factor for foamy oil, which has been intensively studied. Sheng reported that foamy oil stability decreases with the viscosity reduction of heavy oil, and the benefits of foamy oil flow diminish rapidly with increasing temperature.[18] Maini *et al.* also suggested that foamy oil is likely to be less stable at elevated temperatures.[19] Wong *et al.* conducted an experimental study at 50°C, 80°C, and 180°C using Cold Lake bitumen and cores from the Cold Lake reservoir.[20-21] Their studies have shown that the oil recovery efficiencies increase moderately as the oil viscosity decreases. Foamy oil flow in porous media becomes more difficult to generate as the oil viscosity decreases, and high depletion rates are required to obtain large recovery efficiencies in low viscosity systems.[22] Zhang *et al.* examined the effects of temperature on foamy oil flow in clean sand with Cold Lake oil and methane gas, and found that the maximum oil recovery was achieved at a significantly lower optimum temperature in the experiments.[23] The research results above illustrate that the temperature increase exerts unfavourable influence on foamy oil stability, and there should be an optimum temperature for the maximum oil recovery efficiency.

Only several researchers have studied the effects of initial solution gas-oil ratio on foamy oil flow. Chen *et al.* performed core tests to investigate the correlation between initial gas-oil ratio and primary oil recovery.[24] Four experimental tests were conducted in their study with different initial gas-oil ratios and pressure depletion rates. However, it is difficult to find the relationship between initial gas-oil ratio and foamy oil recovery according to their experiments, because the experiment was not conducted using single parameter design. Liu *et al.* conducted visualized experiments using a holder packed with transparent toughened glass beads to evaluate the performance of foam stability under different conditions, including temperature, dissolved gas-oil ratio, etc.[25] As indicated by their experimental results, stable foamy oil exists only if the initial dissolved gas-oil ratio was greater than 4.23 Sm^3/m^3. Nevertheless, they did not gave the method for deciding the lowest dissolved gas-oil ratio for a foamy oil under reservoir conditions, and they also did not explain clearly the reasons for the effect of dissolved gas-oil ratio on foamy oil flow. Certain experimental studies have been conducted to develop an understanding of the effects of the solution gas-oil ratio; however, sufficient information is not yet available.

The purpose of this study is to get more information about the effects of solution gas-oil ratio of foamy oil flow from Orinoco heavy oil belt. The Carabobo reservoir is located in the southern margin of the Eastern Venezuelan Basin at the eastern end of the Orinoco heavy oil belt. The heavy oil from the Carabobo reservoir has a high gas-oil ratio and complex characteristics of foamy oil flow with the reduction in reservoir pressure for cold production. The production of foamy oil has achieved satisfactory development, and the effects of initial gas-oil ratio is important for understanding foamy oil flow in porous media.[26-33] However, as the production progressing, the dissolve gas oil ratio is decreasing in the reservoir. It is still not clear that whether there should be a lowest dissolved gas-oil ratio for producing foamy oil flow. What should we do to continue the foamy oil production if the dissolved gas-oil ratio is lower than the lowest value?

In this study, some novel work has been conducted for foamy oil flow. Firstly, the lower limit of the solution gas-oil ratio for the foamy oil was determined by the difference of the bubble point and pseudo-bubble point pressures based on sandpack and visualization experiments under the reservoir conditions, which was different from the previous researches. Secondly, the reasons for effects of solution gas-oil ratio on foamy oil flow in porous media were analyzed from new viewpoints, i.e., interfacial tension, interfacial dilational viscoelasticity, live oil viscosity, and elastic energy. Thirdly, the experimental results can provide theoretical support for foamy oil production. It is recommended that the solution gas should be separated from the produced oil and injected into the formation to increase the solution gas-oil ratio, thus extending the foamy oil production time. This paper has some novelty and application meaning.

2. Experimental methods

Apparatus. The apparatus schematically shown in Fig. 1 was used in the experiments. The sandpack and microscopic models are shown in Fig. 1 for the different experiments. The sandpack model has a length of 60.0 cm and an inner diameter of 2.54 cm. Heating muffs are located outside of the sandpack and microscopic models to enable accurate heating of the porous media to the reservoir temperature. The live oil cylinder, sandpack and microscopic models within the dotted enclosure in Fig. 1 were contained in a thermostatic convection oven that could be set to a given temperature with an accuracy of less than 1°C. The live oil vertically placed inside the live oil cylinder was delivered via a piston pump (Model 100DX, Teledyne Technologies) at a constant volumetric flow rate into the sandpack or microscopic models. The pressure differences of the sandpack and microscopic model were measured using differential pressure transducers (Model 3210PD, Haian Group). A back-pressure regulator (BPR) was used to control the back pressures of the microscopic and sandpack model with a pressure open error of less than 0.01 MPa. A nitrogen intermediate container was used to maintain the pressure of the BPR, which was connected to a gas mass-flow controller (Model SLA5850S, Brooks) and could be released at a smooth rate. An oil-gas separator was used to separate the oil and gas in the produced foamy oil out of the sandpack, and the oil and gas were measured using a balance (Model PL2002, Mettler Toledo) and gas mass-flow controller (Model SLA5850S, Brooks). The foamy oil flow in the microscopic model was observed and recorded by a camera connected to a computer.

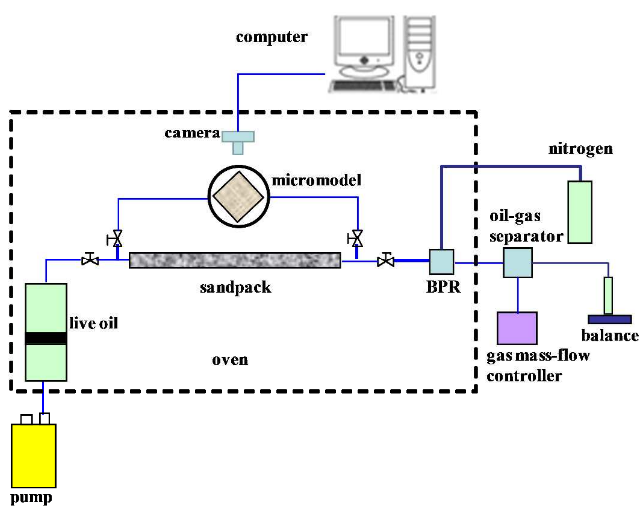


Fig. 1 Experimental apparatus.

Crude oil and solution gas. The parameters for the crude oil and solution gas used in the experiment are shown in Table 1. The crude oil was collected from the Carabobo reservoir in the Orinoco Belt of Venezuela, and the solution gas was mixed in the laboratory according to the produced gas components. The solution gas consists of CH_4 and CO_2 with mole fractions of 87.0% and 13.0%, respectively. The initial solution gas-oil ratio is 16.0 Sm^3/m^3, and the bubble point pressure of the live oil is 5.2 MPa at the reservoir temperature of 54°C. The viscosities for the dead oil and live oil at 50°C are 28040 mPa.s and 8120 mPa.s, respectively. The dead oil is degassed crude oil produced from Carabobo reservoir. The live oil is crude oil with the solution gas of 16.0 Sm^3/m^3, which was replicated in the laboratory according to the solution gas properties listed in Table 1. The heavy oil was classified as extra heavy oil in accordance with the heavy oil classification. The four components of the heavy oil were tested, as shown in Table 1. The resin and asphaltene contents are 21.73 wt% and 13.51 wt%, respectively, which are quite high compared with those of other heavy oils.[34-35]

Table 1 Parameters for heavy oil and solution gas

Item	Unit	Value
Initial reservoir pressure	MPa	8.5
Initial reservoir temperature	°C	54
Bubble point pressure	MPa	5.2
Solution gas-oil ratio	Sm^3/m^3	16.0
Viscosity of dead oil at 50°C	mPa•s	28040
Viscosity of live oil at 50°C	mPa•s	8120
Density of dead oil at 50°C	kg/m^3	976.5
Density of live oil at 50°C	kg/m^3	929.6
Mole fraction of CH_4 in solution gas	%	87.0
Mole fraction of CO_2 in solution gas	%	13.0
Saturate content in oil	%	22.25
Aromatic content in oil	%	42.51
Resin content in oil	%	21.73
Asphaltene content in oil	%	13.51

Sandpack. Sandpacks with porosities from 37.11% to 39.15% and permeabilities from 9524 mD to 10154 mD were employed in the displacement experiments, and the physical properties were similar to the reservoir conditions. The main parameters of the sandpacks are listed in Table 2.

Microscopic model. Microscopic models built of toughened glass were used in the visualization experiments, which were conducted according to the core sample drilled from the Carabobo reservoir. Foamy oil flow in the microscopic model indicates the two-dimensional flow in the real reservoir. The porous media area of the microscopic model is approximately 40 mm × 40 mm. The depth and width of the flow channel are approximately 40 μm and 50 μm, respectively. The microscopic model was placed in a holder with a pressure of less than 20 MPa and temperature less than 100°C. The video of the foamy oil flow was recorded by a digital microscopic imaging system.

Brine. The formation water was replicated according to the formation water properties of $NaHCO_3$-type water with the total mineral value of 19120 mg/L, an HCO_3^- concentration of 2450 mg/L, a Cl^- concentration of 10350 mg/L, and pH value of 7.15-7.72. Distilled water served as the liquid phase. The viscosity and density of the brine at 25°C are 1.12 mPa•s and 1021 kg/m^3, respectively.

Experimental procedure. Solution gas drive experiments for foamy oil with different solution gas-oil ratios were performed in the laboratory using the experimental apparatus shown in Fig. 1. The experimental procedures for sandpack displacement are described as follows:

(1) Live oil was prepared in a Pressure-Volume-Temperature (PVT) barrel using the crude oil and solution gas described above under reservoir temperature and pressure. Next, the live oil was delivered into the live oil cylinder in the oven with a back pressure greater than 8.5 MPa. (2) Silica sand with the same particle-diameter distribution was used to prepare sandpacks with similar permeabilities and porosities. The sandpacks were evacuated for more than 4 hours before saturation with brine, and the permeabilities and porosities were tested. (3) Live oil was displaced into the sandpack with a flow rate of 0.1 mL/min for 2.0 PV until water production ceased. The back-pressure of the sandpack was 8.5 MPa, which was much higher than the bubble point pressure. The initial oil saturation and irreducible water saturation were calculated. (4) The saturated sandpack was held for 24 h under reservoir conditions for phase equilibrium. The back pressure of the sandpack was gradually reduced at the rate of 20 kPa/min, and the oil and gas productions and pressure difference of the sandpack were recorded over time. (5) The experiment was halted when the oil and gas productions ceased and the pressure in the BPR reached atmospheric pressure, and the foamy oil production was analyzed.

The experimental procedures for the microscopic model are similar to those of the sandpack. The only difference was that the flow rate of the live oil was 0.05 mL/min for oil saturation because the flow area of the microscopic model was small. The video of the foamy oil flow through the microscopic model was recorded by a digital microscopic imaging system.

3. Experimental results

3.1. Sandpack experiment

The effects of the initial solution gas-oil ratio on foamy oil flow in porous media were studied by solution gas drive simulation in a one-dimensional sandpack. The experimental parameters and results are illustrated in Table 2. The foamy oil produced from the outlet of the sandpack was quite stable and could exist for more than 20 h under normal temperature and pressure. The experimental temperature was 54°C (reservoir temperature), and the pressure was dropped from 8.5 MPa (reservoir pressure) to 0 MPa with a pressure depletion rate of 20 kPa/min. The initial solution gas-oil ratios for foamy oil were 26.0 Sm^3/m^3, 16.0 Sm^3/m^3, 10.0 Sm^3/m^3, 5.0 Sm^3/m^3 and 2.5 Sm^3/m^3.

Table 2 Experimental parameters and results for different gas-oil ratios

NO.	Sandpack length (cm)	Sandpack diameter (cm)	Porosity (%)	Permeability (mD)	Initial oil saturation (%)	Pressure depletion rate	Gas-oil ratio (Sm^3/m^3)	Oil recovery efficiency

						(kPa/min)		(%)
1	60.0	2.54	39.15	10112	84.33	20.0	2.5	6.33
2	60.0	2.54	38.21	9788	82.12	20.0	5.0	11.52
3	60.0	2.54	38.38	9524	84.16	20.0	10.0	14.61
4	60.0	2.54	37.11	9949	82.11	20.0	16.0	20.53
5	60.0	2.54	38.28	10154	83.34	20.0	26.0	25.93

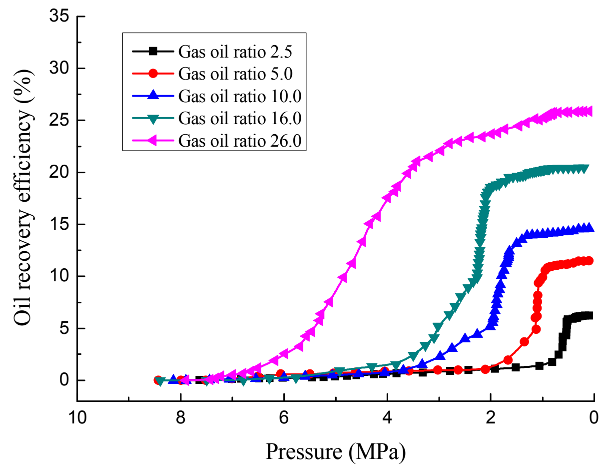


Fig. 2 Effects of solution gas-oil ratio on oil recovery efficiency.

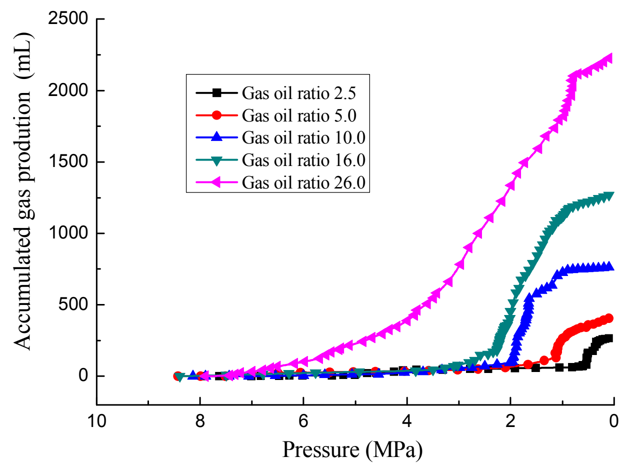


Fig. 3 Effects of solution gas-oil ratio on accumulated gas production.

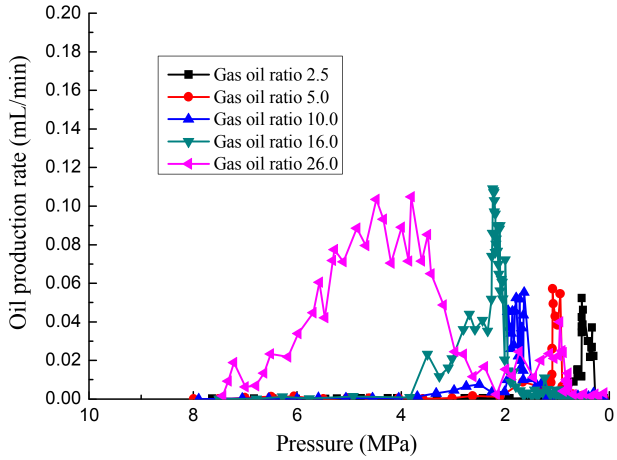


Fig. 4 Effects of solution gas-oil ratio on oil production rate.

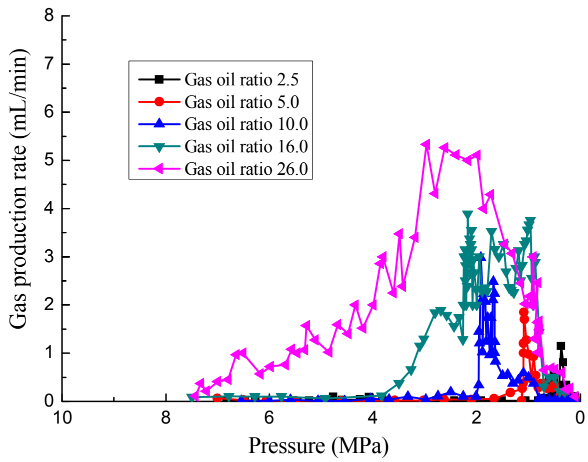


Fig. 5 Effects of solution gas-oil ratio on gas production rate.

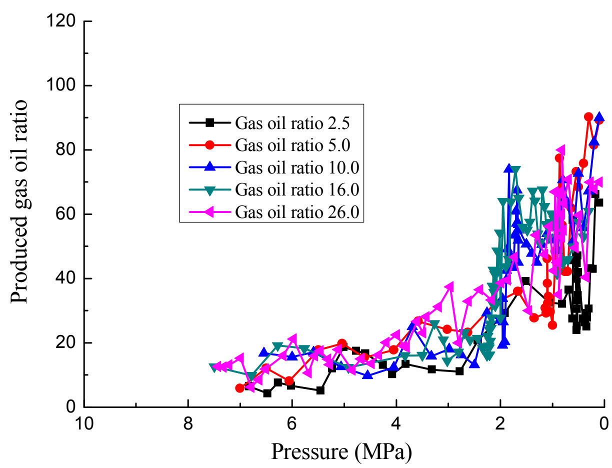


Fig. 6 Effects of solution gas-oil ratio on produced gas-oil ratio.

Oil recovery efficiency, accumulated gas production, oil production rate, gas production rate and produced gas-oil ratio with average pressure in the sandpack are shown in Figs 2-6. From the results, it can be observed that the foamy oil development process can be divided into three stages, i.e., elastic drive, foamy oil flow, and conventional solution gas drive.

The first stage is defined from the initial formation pressure (8.5 MPa) to the bubble point pressure, which are different for different initial solution gas-oil ratios. The bubble point pressure is the pressure at which the first bubble is separated from the live oil during depressurization period. The produced gas-oil ratio is equivalent to the initial solution gas-oil ratio, and all of the produced gas is dissolved in the live oil as a single-phase flow. The oil production is a result of live oil and sand volume expansion caused by the pressure decline in the sandpack. The rate of pressure depletion during the experiments was 20 kPa/min. The oil recovery efficiency for the first stage is quite low and ranges only from 1% to 2%.

The second stage is defined from the bubble point pressure to the pseudo-bubble point pressure. The pseudo-bubble point pressure is the pressure under which the gas phase in the foamy oil becomes a continuous phase in the porous media, which is a transition from the foamy oil flow to conventional solution gas drive.[36] In the second stage, the pressure in the sandpack is lower than the bubble point pressure of the live oil, and gas is gradually released from the live oil as pressure dropping. The released solution gas disperses in the heavy oil in the form of bubbles and flows with the crude oil to form foamy oil. The oil production rates increase rapidly in this period as shown in Fig. 4. The produced gas-oil ratio is still low in this stage because the released gas is in a dispersed state, and the oil films between gas bubbles prevent gas viscous fingering, which reduces the gas phase mobility. The produced oil is primarily driven by the oil and gas expansion, and oil recovery occurs primarily in this stage. The oil recovery efficiency, accumulated gas production, and maximum oil and gas production rates all decrease with the solution gas-oil ratio.

The third stage occurs after the pseudo-bubble point pressure. In this stage, the dispersed bubbles in the second period gradually form a continuous gas phase and form a conventional two-phase flow of oil and gas. Because the mobility of the continuous gas is several orders higher than that of the oil due to the viscosity difference, the oil production rate reduces substantially and the produced gas-oil ratio increases rapidly. The gas production results mainly from this stage.

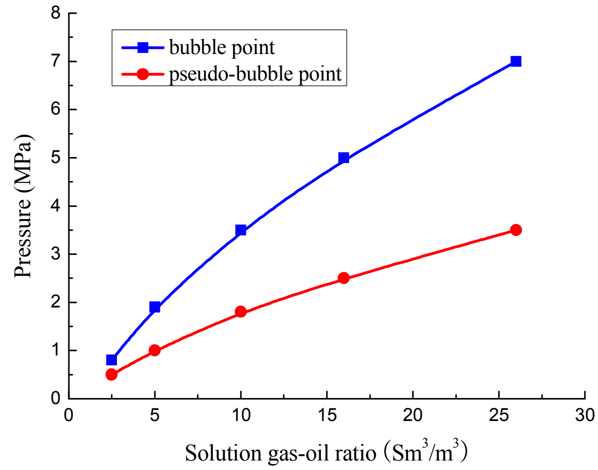


Fig. 7 Effects of solution gas-oil ratio on bubble point and pseudo-bubble point pressures.

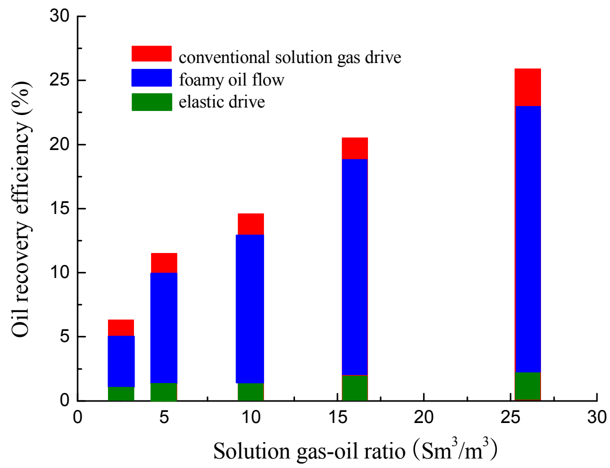


Fig. 8 Effects of solution gas-oil ratio on stage oil recovery efficiency.

The difference of bubble point pressure and pseudo-bubble point pressure represents the function range of foamy oil flow. The effects of the solution gas-oil ratio on the bubble point and pseudo-bubble point pressures for foamy oil were analyzed, which is displayed in Fig. 7. It can be observed from the figure that as the solution gas-oil ratio decreases from 26.0 Sm^3/m^3 to 2.5 Sm^3/m^3, the bubble point and pseudo-bubble point pressures both obviously decrease, and the difference in the two pressures decreases from 3.5 MPa to 0.3 MPa. The foamy oil production period indicated by the difference of the two pressures (as discussed previously) decreases from 175 min to 15 min, because the pressure depletion rates are all 20.0 kPa/min for different solution gas-oil rations. It means that the foamy oil flow is disappearing, and the solution gas-oil ratio for foamy oil must be higher than a certain value.

The foamy oil development process was divided into three stages as discussed previously, i.e., elastic drive, foamy oil flow, and conventional solution gas drive. The effects of the solution gas-oil ratio on oil recoveries for the three stages are illustrated in Fig. 8. It can be observed from the figure that the oil recovery efficiencies from the elastic drive period and conventional solution gas drive period are rather low and differ little from each other. The oil recovery results primarily from the foamy oil flow period. The oil recovery efficiency of foamy oil flow obviously decreases from 20.1% to 4.6% as the solution gas-oil ratio drops from 26.0 Sm^3/m^3 to 2.5 Sm^3/m^3. According to the experimental results in this paper, the lowest initial solution gas-oil ratio that can be used to obtain foamy oil for Carabobo reservoir in Orinoco Belt is believed to be approximately 5.0 Sm^3/m^3, which is different for other crude oils.

3.2. Microscopic visualization experiment

The effects of the initial solution gas-oil ratio on foamy oil flow in porous media were studied via a microscopic visualization experiment. The experimental parameters and results are illustrated in Table 3. The experimental temperature was 54°C (reservoir temperature), and the pressure was dropped from 8.5 MPa (reservoir pressure) to 0 MPa with a pressure depletion rate of 20 kPa/min. The initial solution gas-oil ratios for foamy oil were 26.0 Sm^3/m^3, 10.0 Sm^3/m^3, and 5.0 Sm^3/m^3, respectively. Figs 9-11 and Table 3 show the results obtained from the microscopic visualization experiments.

In the conventional solution gas drive with light oil, the small bubbles separated out from live oil due to pressure drop in the reservoir soon merge into larger bubbles, forming a continuous gas phase. Most of the oil cannot flow with the solution gas because of gas viscous fingering. The produced gas-oil ratio increases rapidly.[17, 37-38] Figs 9-11 show the state of foamy oil flow with different solution gas-oil ratios. Three processes of bubble flow occur in the oil, namely, bubble division, bubble merging, and bubble deformation.

Bubble division is an important mechanism of foamy oil flow in porous media, which makes the gas the dispersed phase in heavy oil. A large bubble moves to the adjacent pores and splits in the middle of the bubble at a high flow rate.

The second process is bubble merging. When two bubbles contact each over a long time, they can easily merge into one bubble because the gas diffuses from the small bubble into the larger bubble through the oil film between them in a process known as Ostwald ripening or coarsening, as shown in Fig. 10 in the dotted circle. This process causes the number of bubbles in foamy oil to decreases. [39]

The third process is bubble deformation. As shown in Fig. 10, a large bubble stretches as it flows through a pore throat in the porous media. After passing through the pore throat, the bubble immediately returns to its original spherical shape because of interfacial tension of the oil and solution gas. In this process, bubble deformation will produce an extra capillary force that increases the gas flow resistance and reduces the gas mobility, which can maintain foamy oil production with a low produced gas-oil ratio for a long period and thus increase the oil recovery efficiency.

In a certain period of time, the merging and dividing bubbles achieve a dynamic balance that determines the bubble size distribution in foamy oil. Therefore, foamy oil maintains a relative stable bubble flow state. An amount of the heavy oil can flow with the solution gas, and the oil recovery efficiency is much higher for foamy oil flow.

It can be observed from Figs 9-11 and Table 3 that the greater the solution gas-oil ratio, the higher the bubble point pressure. When the solution gas-oil ratio increases from 5.0 Sm^3/m^3 to 26.0 Sm^3/m^3, the bubble velocity increases from 0.11 μm/s to 4.20 μm/s, which is more than one order of magnitude. The reason for this observation is that live oil viscosity obviously decreases under a high solution gas-oil ratio, and more elastic energy is available in the foamy oil due to additional bubbles. The foamy oil under higher solution gas-oil ratio is much easier to flow, and the flow resistance in the porous media is low, which can result in higher oil recovery shown in Fig 2.

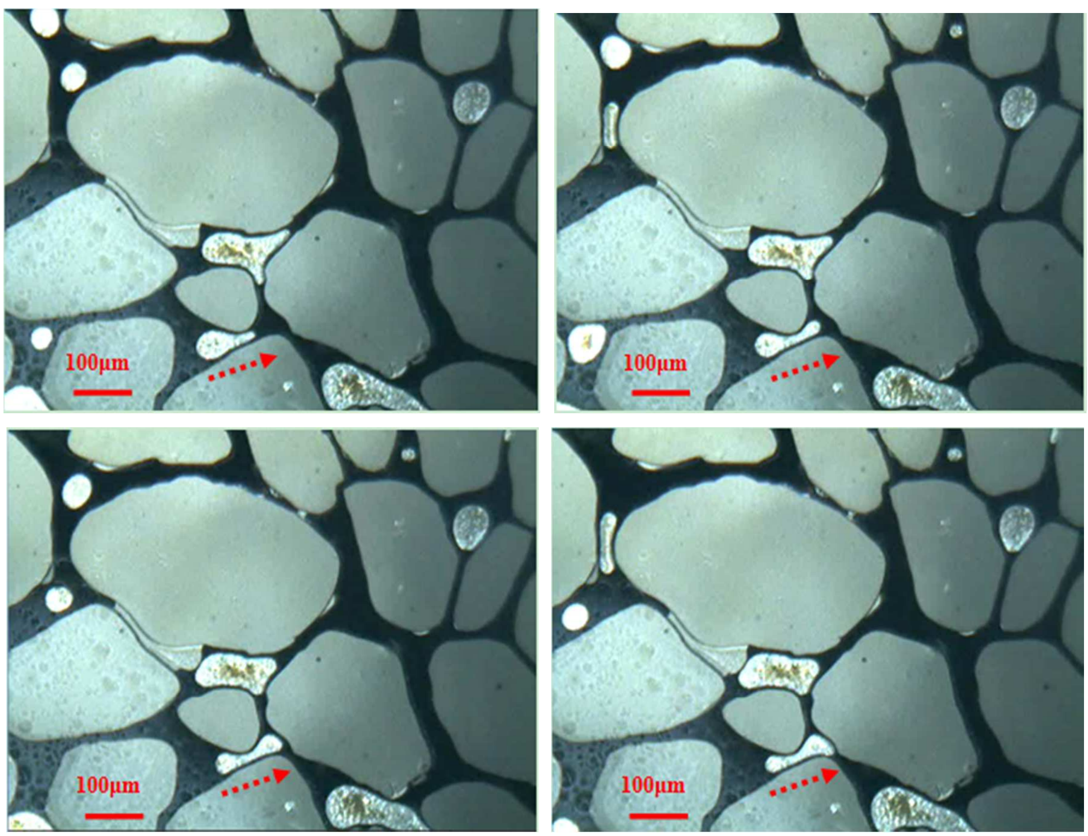


Fig. 9 The four images depict a continuous process for foamy oil flow in porous media with a time delay of 25 s. The solution gas-oil ratio is 5.0 Sm^3/m^3, and the pressure in the microscopic model is 1.1 MPa, which lies between the bubble point pressure and the pseudo-bubble pressure.

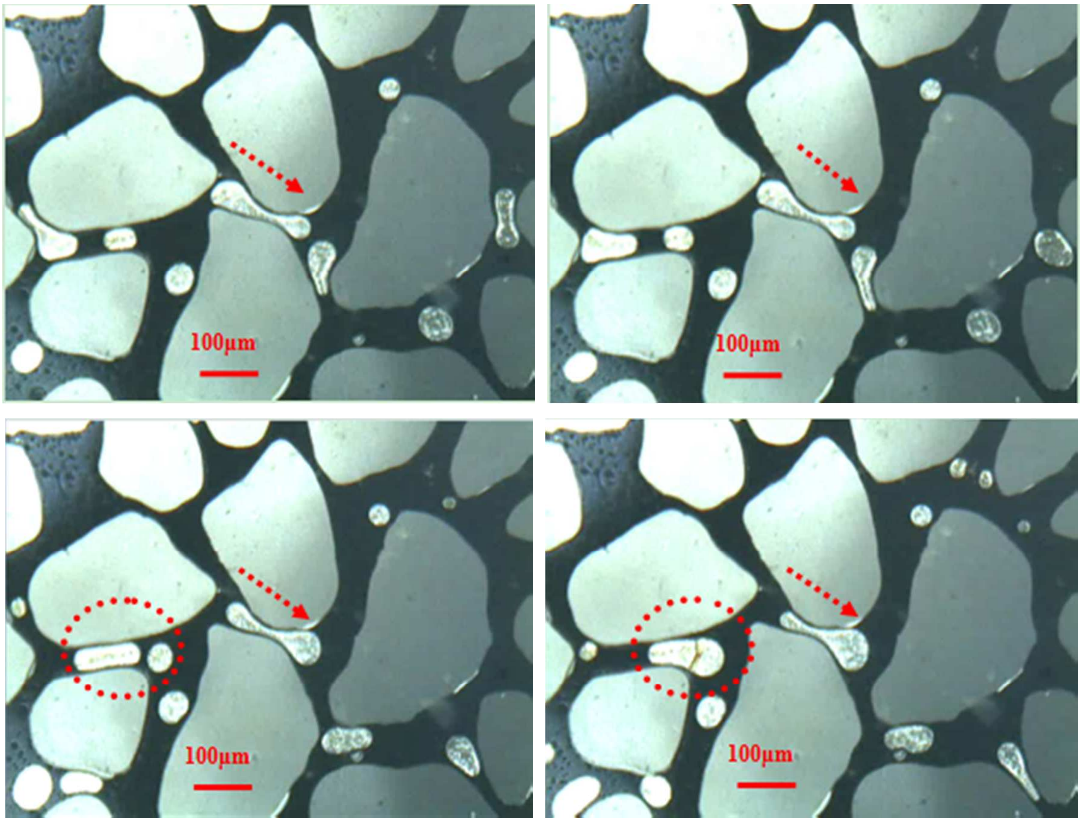
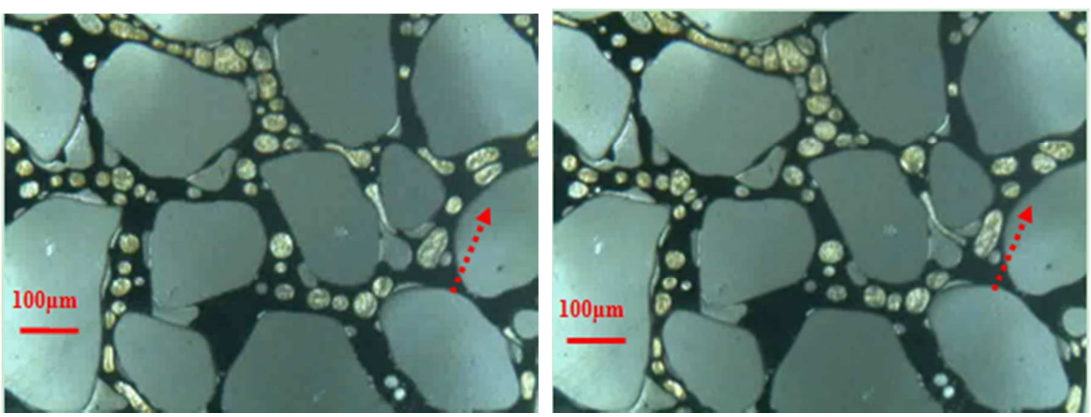


Fig. 10 The four images depict a continuous process for foamy oil flow in porous media with a time delay of 7 s. The solution gas-oil ratio is 16.0 Sm^3/m^3, and the pressure in the microscopic model is 3.1 MPa, which lies between the bubble point pressure and the pseudo-bubble pressure.



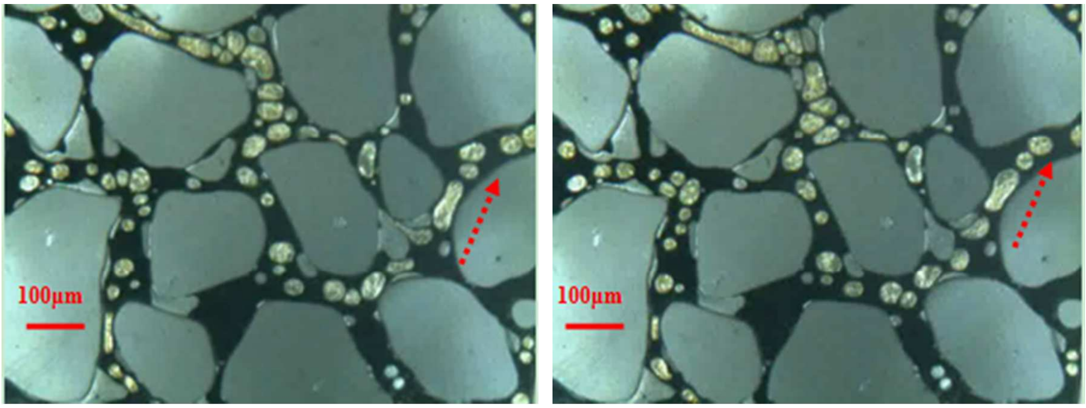


Fig. 11 The four images depict a continuous process for foamy oil flow in porous media with a time delay of 1.5 s. The solution gas-oil ratio is 26.0 Sm^3/m^3, and the pressure in the microscopic model is 4.1 MPa, which is between the bubble point pressure and the pseudo-bubble pressure.

Table 3 Effects of solution gas-oil ratio on foamy oil flow in microscopic model.

NO.	Gas-oil ratio (Sm^3/m^3)	Pressure depletion rate (kPa/min)	Bubble point pressure (MPa)	Bubble moving velocity (μm/s)
6	5.0	20.0	1.9	0.11
7	16.0	20.0	5.1	0.51
8	26.0	20.0	7.1	4.21

3.3. Discussions

The gas content in a foamy oil exerts a strong influence on the recovery factor of heavy oil. Solution gas oil ratio depends primarily on the saturation pressure. Higher saturation pressure would be beneficial in solution gas drive since it permits higher drawdown pressure. There are four reasons for the effects of the solution gas-oil ratio on foamy oil flow in porous media, i.e., interfacial tension, interfacial dilational viscoelasticity, live oil viscosity, and elastic energy of solution gas under different solution oil gas ratios. The four factors are analyzed as follows.

The interfacial tension of crude oil and solution gas at difference pressures were tested through a drop shape tensiometer (Tracker-H, TECLIS, France),[40] as shown in Fig. 12. The result illustrates that the interfacial tension obviously decreases from 44.7 mN/m to 26.7 mN/m with a pressure increase from 0.18 MPa to 6.9 MPa. The curve was described by an exponential relation shown in Fig. 12. The lower the interfacial tension is, the higher the stability of a foam is. The foamy oil with a high solution gas-oil ratio under high pressure is more stable than that with a low solution gas-oil ratio under low pressure. As the pressure depletes in the porous media during the experiments for different gas-oil ratios, the foamy oil is more unstable and the bubbles are easy to coarsen, which will result in conventional solution gas drive. Thus, the gas relative permeabilities will increase with the pressure drop, and the foamy oil production period is quite short.

Sheng *et al.* conducted an experimental study of the stability of foamy oil created by liberation of dissolved gas. Experiments were conducted in a high-pressure cell (bulk vessel).[41-42] The decay of foamy oil produced was observed visually. Their experimental results show that foamy oil stability increases with higher dissolved gas content. The foam quality of foamy oils was very low (less than 20%). Liu *et al.* conducted experiments to evaluate the performance of foam stability under different conditions, including temperature, dissolved gas-oil ratio, etc.[25] As indicated by their experimental results, stable foamy oil exists only if the initial dissolved gas-oil ratio was greater than 4.23 Sm^3/m^3. Their results from the bulk vessel experiments all show that the stability of foamy oil decreases with the drop of solution gas-oil ratio, which is the same trend as the results from the sandpack experiments in this study.

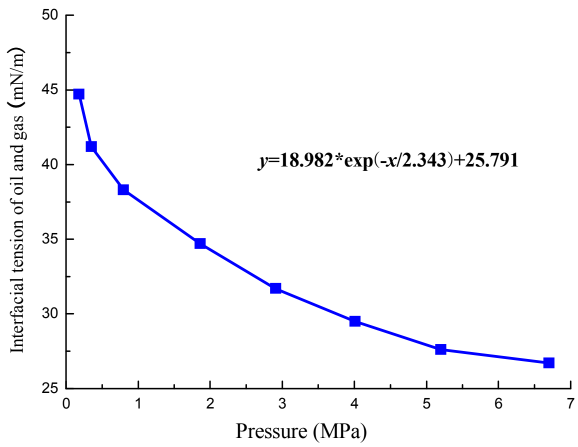


Fig. 12 Interfacial tension of oil and solution gas under different pressures.

The interfacial dilational viscoelasticity of crude oil and solution gas at difference pressures were also measured through the drop shape tensiometer. The experimental results are shown in Fig. 13. The interfacial dilational viscoelasticity increases from 43.89 mN/m to 57.29 mN/m with the pressure rise from 0.18 MPa to 6.70 MPa due to the increase of the solution gas-oil ration. The curve was described by an exponential relation shown in Fig. 13. Although we cannot find the studies in the literatures on the interfacial dilational viscoelasticity of heavy oil and solution gas, there are many researches about the interfacial dilational viscoelasticity of aqueous foam. The values of aqueous foam are much lower than that of foamy oil, which are from 3.7 mN/m to 16.8 mN/m for sodium dodecyl sulfate (SDS) stabilized aqueous foam.[43] The stability of foamy oil and aqueous foam has the same properties. The dilational viscoelasticity of bubble film determines its capability to resist external disturbances and to avoid the bubble coarsening and rupture. The higher the interfacial dilational viscoelasticity is, the higher the stability of a bubble is.[44-45] Higher pressure under higher solution gas-oil ratio improves the stability of foamy oil flowing in the porous media, which results in higher oil recovery efficiency.

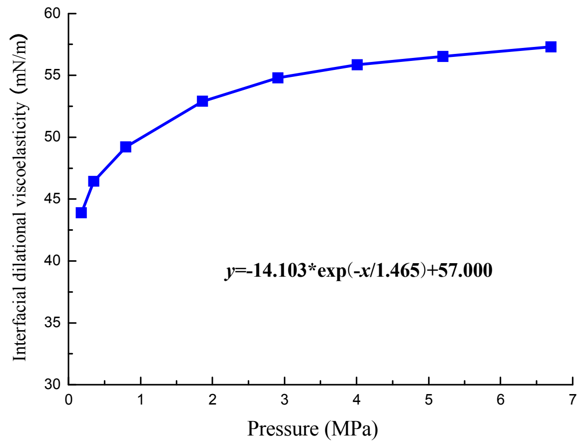


Fig. 13 Interfacial dilational viscoelasticity of oil and solution gas under different pressures.

The live oil viscosities with different solution gas-oil ratios were tested, and the results are shown in Fig. 14. The figure illustrates that as the solution gas-oil ratio increases from 2.5 Sm^3/m^3 to 26.0 Sm^3/m^3, the live oil viscosity at a reservoir temperature of 54°C decreases from 12897 mPa·s to 5701 mPa·s. The curve was described by an exponential relation shown in Fig. 14. The results show that the solution gas has a good effect of viscosity reduction for the heavy oil, which can decrease the flow resistance in porous media at the same flow rate. The viscosity reduction enhances the oil flow in reservoir conditions with dispersed gas bubbles, which can result in lower produced gas-oil ratio and higher oil recovery efficiency for foamy oil. The experimental data from Baibakov *et al.* also show that oil recovery decreases as gas content decreases, especially in the case of low permeability reservoirs, because increased gas-oil ratio would give lower live oil viscosity and increased gas flow.[46] However, the effect of increased gas-oil ratio at a constant saturation pressure due to compositional effects is not obvious. The most important factor that affects the oil recovery performance was the drawdown pressure.

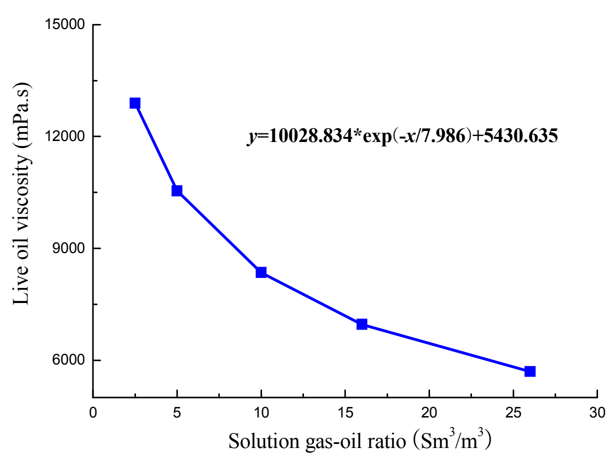


Fig. 14 Relationship between live oil viscosity with solution gas-oil ratio.

The elastic energy of the solution gas is generated by the gas volume expansion when the pressure in the sandpack drops from the initial reservoir pressure to the atmospheric pressure, which can drive the heavy oil flow in the sandpack. Since gas compressibility is much higher than oil compressibility, the total compressibility of the foamy oil is dominated by solution gas, once a significant fraction of gas has evolved and become dispersed in the oil. Smith calculated the oil compressibility in numerical simulation of solution gas drive in foamy heavy oil reservoirs. For a Lloydminster oil, the oil/gas combination is about one-fourth as compressible as an ideal gas.[47]

The relationship between the elastic energy of the solution gas in the sandpack and the solution gas-oil ratio was determined using formula (1) based on the accumulated gas production with pressure in Fig. 3, and the results are shown in Fig. 15. As the solution gas-oil ratio increases, the elastic energy of produced solution gas from the sandpack increases with an accelerating rate, which provides additional energy for foamy oil flow in porous media. As the solution gas-oil ratio increases from 2.5 Sm^3/m^3 to 26.0 Sm^3/m^3, the elastic energy of the solution gas increases by 18 times, which play an important role in the oil recovery. The curve was described by an exponential relation shown in Fig. 15.

$$W_g = \sum_{i=1}^{N} \left(\frac{p_i + p_{i+1}}{2} \right) \cdot \left[\left(Q_{i+1} - Q_i \right) - \frac{2\left(Q_{i+1} - Q_i \right)}{p_i + p_{i+1}} \right] \tag{1}$$

where W_g is the elastic energy of produced solution gas from the sandpack (J); p_i and p_{i+1} are the pressures in the sandpack at time i and i+1 (Pa), respectively; and Q_i and Q_{i+1} are the accumulated gas productions at time i and i+1 (m^3), respectively.

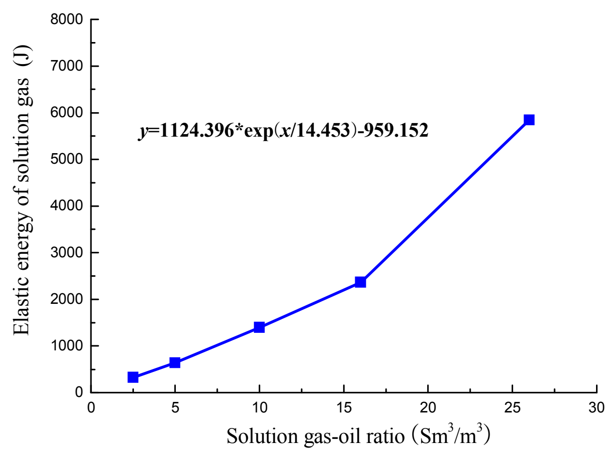


Fig. 15 Relationship between the elastic energy of the solution gas in the sandpack and the solution gas-oil ratio.

The results obtained for the experiments with Orinoco Belt heavy oil indicate that the main mechanism for the effect of the solution gas-oil ratio on foamy oil is caused by the interfacial tension, interfacial dilational viscoelasticity, live oil viscosity, and elastic energy of solution gas. These four factors are all disadvantageous for foamy oil with lower solution gas-oil ratios, and thus, a lower limit of solution gas-oil ratio should exist for the foamy oils with different properties. Usually, the reservoirs with foamy oil flow have a high initial solution gas-oil ratio; however, as the cold production progresses, the gas-oil ration in the formation will decrease. It is recommended that for reservoirs with foamy oil cold production, the produced gas can be separated from the oil and injected into the formation to increase the solution gas-oil ratio and maintain the formation pressure, which will extend the foamy oil production time and improve the oil recovery efficiency for cold production.

4. Conclusions

The effects of the solution gas-oil ratio on performance of foamy oil flow were investigated using sandpack and visualization experiments for solution gas drive. As the solution gas-oil ratio decreases from 26.0 Sm^3/m^3 to 2.5 Sm^3/m^3, the difference in the bubble point and pseudo-bubble point pressures (that indicate the foamy oil production period) decreases from 3.5 MPa to 0.3 MPa, and the oil recovery efficiency of foamy oil flow obviously decreases from 20.1% to 4.6%. When the solution gas-oil ratio increases from 5.0 Sm^3/m^3 to 26.0 Sm^3/m^3, the bubble velocity in foamy oil increases by more than an order of magnitude.

The effects of solution gas-oil ratio on foamy oil flow in porous media can be explained by higher interfacial tension, lower interfacial dilational viscoelasticity, higher live oil viscosity, and lower elastic energy under a lower solution gas-oil ratio. The four factors are all disadvantageous for foamy oil with lower solution gas-oil ratios. A lower limit of solution gas-oil ratio should exist for foamy oils with different properties, and the lowest solution gas-oil ratio for the Carabobo reservoir is believed to be approximately 5.0 Sm^3/m^3, according to the experimental results. For reservoirs with foamy oil cold production, it is recommended that the solution gas should be separated from the produced oil and injected into the formation to increase the solution gas-oil ratio, thus extending the foamy oil production time and improving the oil recovery efficiency.

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