Effects of Oil Viscosity and the Solution Gas–Oil Ratio on Foamy Oil Flow in Solution Gas Drive

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ABSTRACT: The anomalously high recovery of solution gas drive in some heavy oil reservoirs has been associated with foamy oil. The effects of external factors such as temperature, permeability, and the pressure depletion rate on foamy oil flow have been studied sufficiently, but few studies are available on the effect of heavy oil itself. In order to investigate the effect of oil viscosity and the solution gas–oil ratio on foamy oil, 11 tests of solution gas drive through a sandpack were carried out in this work. The results show that a typical foamy oil solution gas drive exists in three stages, which are the oil phase expansion stage, the foamy oil flow stage, and the oil–gas two-phase flow stage. As the oil viscosity decreases, the foamy oil flow stage shortens, resulting in reduced recovery of this stage significantly. In the experiment with an oil viscosity of 200 mPa·s, foamy oil flow was not observed. A lower limit of oil viscosity should exist for steady flow of foamy oil, which is considered to be approximately 600 mPa·s according to the experimental results. As the solution gas–oil ratio increases, the oil recovery first increases and then decreases. Foamy oil flow could be observed clearly when the solution gas–oil ratio was between 10 and 26 Sm³/m³, which indicates that there is an optimal range of solution gas–oil ratios for foamy oil solution gas drive. The test with a solution gas–oil ratio of 35 Sm³/m³ showed that oil–gas two-phase flow followed the oil phase expansion stage as a result of the production of a quantity of gas, which illustrates that excess solution gas is unbene

1. INTRODUCTION

In some heavy oil reservoirs in Venezuela, Canada, and China, the oil production rate is anomalously high in the process of pressure depletion, and primary recovery is much higher than the theoretical value expected. The anomalous behaviors of the low gas–oil ratio, high production rate, and high oil recovery during solution gas drive of heavy oil reservoirs have attracted the attention of many researchers.1−5 Smith first studied heavy oil solution gas drive systematically.6 A gas–oil mixture was used to describe the special state where gas was dispersed in heavy oil in the form of microbubbles. Maini et al. considered that it was a dispersion system where oil was a continuous phase and gas was a dispersed phase.7 Foamy oil was used to describe the flow state. Foamy oil flow observed in solution gas drive has been widely accepted as the reason for the abnormal phenomena. Owing to the high viscosity of heavy oil, it is hard for bubbles to coalesce and turn into a continuous phase. In this way, gas-phase mobility decreases, and gas channeling could be inhibited. As a result, the recovery efficiency of solution gas drive increases significantly.8,9

In order to take full advantage of foamy oil flow to improve heavy oil recovery, the influencing factors of foam oil have been studied extensively. It is believed that the pressure depletion rate plays an important role in the formation of foamy oil in solution gas drive. Lots of core experiments of solution gas drive show that the oil recovery can be improved remarkably only under high pressure depletion, which infers that foamy oil is more prone to form under a large pressure depletion rate.10−13 This rule can also be obtained in foamy oil stability experiments.14,15 The effect of the pressure depletion rate on foamy oil flow can be attributed to the supersaturation of solution gas in heavy oil. Large supersaturation means that more gas can exist in heavy oil with the status of microbubbles, which reduces the apparent viscosity of heavy oil greatly and improves the oil flow capacity.15 It is also found that gas-phase mobility should be affected by the pressure depletion rate. Gas-phase mobility gradually decreased with the increase in the pressure depletion rate. The reservoir temperature is believed to have a certain influence on foamy oil formation as well.
to be another key factor of foamy oil flow in solution gas drive. Lots of pressure depletion tests were conducted using a sandpack to examine the effects of temperature on foamy oil flow. The results show that the highest recovery does not occur at the highest temperature. Instead, there is a much lower optimum temperature that provides the highest recovery.16−19

In conventional solution gas drive, the oil recovery declines with the increase in oil viscosity. However, in solution gas drive with foamy oil, the effect of oil viscosity on recovery is different from conventional solution gas drive. Under the same condition, the higher the viscosity of dead oil, the more stable the foamy oil and the longer the duration of foamy oil flow.20−22 Sheng et al. carried out foamy oil stability evaluation experiments. They thought that the higher the viscosity of oil, the larger the amount of solution gas, the greater the pressure depletion rate, and the more stable the foamy oil.17 The amount of solution gas dissolved in heavy oil has an important influence on heavy oil recovery. A large solution gas−oil ratio means a great saturation pressure and displacement pressure difference, which is favorable to solution gas drive.23−25 Oil recovery increased with the solution gas ratio. The higher the amount of solution gas dissolving in oil is, the better the stability of foamy oil is.

Lots of studies have been conducted to investigate the effect of external factors on foamy oil flow such as temperature and the pressure depletion rate.26 However, little research is available on the effect of heavy oil itself. The objective of this research is to investigate the effect of oil viscosity and the solution gas−oil ratio on foamy oil flow based on sandpack experiments. In this paper, a total of 11 solution gas drive experiments were carried out including five tests with different viscosities of oil and six tests with different solution gas−oil ratios. In these experiments, the pressure, the oil production rate, and the gas production rate were recorded to evaluate if foamy oil flow was obtained.

2. EXPERIMENTS

2.1. Apparatus. The schematic of the experimental apparatus used in the work is shown in Figure 1. It mainly consisted of an injection system, a multifunction displacement system, a data acquisition system, and a production system.

![Schematic diagram of solution gas drive.](image)

The injection system was composed of an ISCO pump and a pressure−volume−temperature (PVT) barrel. Live oil was prepared in the PVT barrel and injected into the sandpack by a pump at a constant flow rate. A heating muff was located outside of the PVT barrel to keep the temperature of live oil at reservoir temperature.

The multifunction displacement system mainly included a sandpack model, a temperature control cabinet, and a back-pressure regulator (BPR). The sandpack model had a length of 60.00 cm and an inner diameter of 2.54 cm, on which two pressure detecting points were distributed evenly. A BPR connected to a nitrogen cylinder was used to control the pressure at the outlet of the sandpack model with an open error of less than 0.01 MPa. The sandpack model and the BPR were placed in the temperature control cabinet, which could be set to a given temperature with an accuracy of 0.1 °C.

The data acquisition system recorded the pressure at four different points and the temperature of the sandpack model in real time by pressure transducers and thermocouples that were connected to a computer.

The production system was mainly made up of an oil−gas separator, a gas mass−flow meter, and a balance. The produced fluid was separated into the liquid phase and the gas phase in the oil−gas separator, and then, the oil and gas were measured by a balance (Model PL 2002, Mettler Toledo, measurement accuracy of 0.01 g) and a gas mass−flow meter (Model SLAS850S, Brooks, measurement accuracy of 0.1 sccm).

2.2. Materials. The oil used in the experiments was live oil prepared with dead oil and solution gas in a PVT barrel. A certain amount of naphtha was added into dead oil to compound different viscosities of heavy oil in the experiments of viscosity effects. Although the diluting method would change the content of four components in oil and then affect the foamy oil formation and performance to a certain extent, this effect is small compared with the influence of oil viscosity. On the one hand, we know from our previous study that oil viscosity is the dominant factor affecting foamy oil, the effect of which is much larger than that of asphaltenes,27 and on the other hand, we can see from Table 2 that the content change of four components in oil caused by the naphtha addition was relatively little. Therefore, the difference in foamy oil performance can be attributed mainly to the change of oil viscosity. Different amounts of solution gas were dissolved in the same amount of dead oil to form the live oil with different solution gas−oil ratios in the experiments of solution gas−oil ratio effects. The initial solution gas ratio was 16 Sm³/m³, and the bubble pressure was about 5.2 MPa. The initial dead oil was collected from the MPE3 block in Venezuela. At reservoir conditions (53.7 °C and 8.5 MPa), the viscosities of the dead oil and live oil were 28,040 and 6151 mPa·s, respectively. The content of four components in oil was measured, as shown in Table 1.

| Table 1. Properties of the In-Place Heavy Oil |
|-----------------------------------------------|
| item                                          | unit | value  |
| reservoir temperature                         | °C   | 53.7   |
| reservoir pressure                            | MPa  | 8.5    |
| initial solution gas−oil ratio                | Sm³/m³ | 16    |
| bubble point pressure                         | MPa  | 5.2    |
| viscosity of dead oil at reservoir conditions | mPa·s | 28,040 |
| density of dead oil at reservoir conditions   | kg/m³ | 976.5  |
| viscosity of live oil at reservoir conditions | mPa·s | 6151   |
| density of live oil at reservoir conditions   | kg/m³ | 929.6  |
| saturate content                             | %    | 22.25  |
| aromatic content                             | %    | 42.51  |
| resin content                                | %    | 21.73  |
| asphaltene content                           | %    | 13.51  |
The solution gas was prepared in a laboratory according to the produced gas compositions of CH₄ and CO₂ with mole fractions of 87 and 13%, respectively.

The water used in the experiments was replicated according to the composition of formation water. The formation water is a NaHCO₃ type with a total salinity value of 19,120 mg/L, a HCO₃⁻ concentration of 2450 mg/L, and a Cl⁻ concentration of 10,350 mg/L. The viscosity and density of the brine at reservoir conditions were 0.62 mPa·s and 1007 kg/m³, respectively.

The sandpack models used in the experiments were packed by refined silica sand with a porosity of about 38% and a permeability of about 10,000 mD. The parameters of the sandpack models were consistent with reservoir parameters.

2.3. Procedures.

(1) Live oil was prepared in the PVT barrel according to experimental conditions. In the preparation process, dead oil, namely, degassed oil, was heated and poured into the PVT barrel first. The volume of the poured dead oil was known. Then, the mixed gas of known volume with mole fractions of 87% CH₄ and 13% CO₂ was injected into the PVT barrel. The PVT barrel was pressurized after the injection step, and it was ensured that all the injected gas dissolved completely into the oil. Finally, the live oil of known solution gas–oil ratio was obtained.

(2) Sandpack models were prepared with proper permeability and porosities. Then, the sandpack models were saturated with the prepared brine after evacuation for 4 h. The pore volume and permeability were measured and calculated.

(3) The back pressure was set at 8.5 MPa. The sandpack models were saturated with live oil at a rate of 0.1 mL/min for more than 2PV. After live oil was saturated, the irreducible water saturation and initial oil saturation were calculated.

(4) The saturated sandpacks were placed at reservoir conditions for 24 h for phase equilibrium. The back pressure was reduced gradually at a constant pressure depletion rate of 100 kPa/min with oil and gas production recorded.

(5) When the average pressure of the sandpack model declined to zero and no gas or oil was produced, the experiment was stopped.

### Table 2. Experimental Parameters and Results for Different Oil Viscosities

| no. | porosity (%) | permeability (mD) | initial oil saturation (%) | dead oil viscosity (mPa·s at 53.7 °C) | saturate content (%) | aromatic content (%) | resin content (%) | asphaltene content (%) | oil recovery (%) |
|-----|--------------|-------------------|---------------------------|--------------------------------------|---------------------|---------------------|-------------------|----------------------|-----------------|
| 1   | 38.64        | 10,040            | 88.67                     | 28,040                               | 22.25               | 42.51               | 21.73             | 13.51                | 20.62           |
| 2   | 38.13        | 9860              | 89.54                     | 8620                                 | 33.28               | 35.32               | 19.62             | 11.78                | 24.70           |
| 3   | 37.38        | 9588              | 88.60                     | 2440                                 | 35.56               | 36.70               | 18.08             | 9.66                 | 26.35           |
| 4   | 37.87        | 9730              | 87.75                     | 620                                  | 40.36               | 35.26               | 16.03             | 8.35                 | 26.28           |
| 5   | 37.11        | 9950              | 89.11                     | 200                                  | 43.12               | 35.04               | 14.13             | 7.71                 | 27.87           |

3. RESULTS AND DISCUSSION

3.1. Effect of Oil Viscosity on Foamy Oil Flow. In order to study the effect of oil viscosity on foamy oil flow in heavy oil solution gas drive, five one-dimensional pressure depletion tests were conducted with different viscosities of oil. The experimental parameters and results are listed in Table 2. The solution gas–oil ratios in the five tests were the same and equal to 16 Sm³/m³. Figures 2–6 show the oil production rate, the gas production rate, and the produced gas–oil ratio with average pressure at different oil viscosities.

Figure 2. Production behavior at an oil viscosity of 28,040 mPa·s.

Figure 3. Production behavior at an oil viscosity of 8620 mPa·s.

Figure 4. Production behavior at an oil viscosity of 2440 mPa·s.
Taking the production behavior of test 1 (shown in Figure 2) as an example, the characteristics of foamy oil during depletion production were analyzed in detail. We can see from Figure 2 clearly that the process of solution gas drive can be divided into three stages, namely, the elastic expansion stage, the foamy oil flow stage, and the oil–gas two-phase flow stage. The elastic expansion stage is the first stage, which is from the initial pressure (8.5 MPa) to the bubble point pressure. The bubble point pressure refers to the pressure at which the solution gas begins to release and usually corresponds to the pressure at which the gas production rate begins to increase rapidly. However, in heavy oil, due to high flow resistance, the released solution gas would not flow immediately but would disperse in oil in the form of microbubbles, which makes it impossible to determine the bubble point pressure by the gas production rate. Considering the effect of elastic expansion of the released solution gas on oil production, the pressure at which the oil production rate increases quickly also corresponds to the bubble point pressure. So, we inferred that the bubble point pressure was about 4.6–4.1 MPa in test 1 according to the oil production rate curve shown in Figure 2. In this stage, the oil production rate and the gas production rate are very small, and the produced gas–oil ratio is close to the solution gas–oil ratio. Oil is produced by the elastic expansion of the rock and the fluid. The foamy oil flow stage is the second stage, which is from the bubble point pressure to the pseudo-bubble point pressure. The pseudo-bubble point pressure is defined as the pressure at which the solution gas starts to efflux in quantity. In the depletion process, as the system pressure declines steadily from the bubble point pressure to the pseudo-bubble point pressure, the dispersed microbubbles in oil increase, expand, coalesce, and finally form a continuous phase. The formation of a continuous gas phase would lead to solution gas flow, and the gas production rate would begin to increase rapidly in return. So, we can determine the pseudo-bubble point pressure through the gas production rate or the produced gas–oil ratio in real experiments. As shown in Figure 2, the gas production rate and the produced gas–oil ratio increase sharply at about 2 MPa with the oil production rate declining obviously. The pseudo-bubble point pressure is defined as the pressure at which the solution gas starts to efflux in quantity. In this stage, the oil production rate increases rapidly, but the gas production rate is still small, and the produced gas–oil ratio remains low. The produced gas is dispersed in oil in the form of microbubbles, which is different from conventional solution gas drive. The special mixture of oil and gas is called foamy oil, as shown in Figure 7. The third stage is the oil–gas two-phase flow stage, in which the solution gas is produced largely in a continuous phase, but the oil production rate declines gradually, and the produced gas–oil ratio increases rapidly.

Figures 3 and 4 show the production behavior at oil viscosities of 8620 and 2440 mPa·s, respectively. From these two figures, it is found out that the whole pressure depletion process can also be divided into three stages. The phenomenon of foamy oil flow is observed clearly at these two viscosities. In the experiment with an oil viscosity of 620 mPa·s (Figure 5), as the pressure declines below the bubble point pressure, at first, the oil production rate starts increasing, and the gas production rate and the produced gas–oil ratio keep low with unconspicuous foamy oil flow. However, foamy oil flow soon turns into oil–gas two-phase flow with the gas production rate

Figure 5. Production behavior at an oil viscosity of 620 mPa·s.

Figure 6. Production behavior at an oil viscosity of 200 mPa·s.

Figure 7. Comparison of dead oil and foamy oil. The left picture shows the dead oil used in the study, and the right picture shows that oil was produced in a foamy oil state in test 1.
increasing significantly. The foamy oil flow stage at this oil viscosity is transient and unsteady. For the experiment with an oil viscosity of 200 mPa·s (Figure 6), after the pressure drops to the bubble point pressure, the oil production rate and the gas production rate both increase rapidly, and the produced gas–oil ratio is much greater than the solution gas ratio. There is no foamy oil flow in the whole pressure depletion process at this oil viscosity.

It is inferred from the five comparative experiments that oil viscosity is an important factor for the generation of foamy oil in the process of heavy oil solution gas drive. A low oil viscosity is unfavorable for the stability of the foamy oil.

Figures 8 and 9 show the oil recovery efficiency and accumulated gas production with average pressure. The effects of oil viscosity on the bubble point pressure, the pseudo-bubble point pressure, and the pressure range and the recovery proportion of the foamy oil flow stage are compared in Figures 10 and 11 and Table 3. Figure 12 shows oil recoveries at each stage in solution gas drive at different viscosities.

Oil viscosity has little effect on the bubble point pressure while playing an important role in the pseudo-bubble point pressure. With oil viscosity decreasing, the pseudo-bubble point pressure increases gradually and the pressure range and duration of the foamy oil stage are narrowed resulting in the decline of oil recovery efficiency. If the oil viscosity is too low, for example, the viscosity is 200 mPa·s, then it is easy for the solution gas to liberate, coalesce, and form a continuous gas phase, which prevents microbubbles from dispersing in oil.
steadily. At this viscosity, foamy oil flow cannot be formed, and the bubble point pressure is equal to the pseudo-bubble point pressure. From the experiment with an oil viscosity of 620 mPa·s in which transient and unsteady foamy oil flow happens, it is inferred that the viscosity limit for the formation of foamy oil flow is 600 mPa·s approximately.

3.2. Effect of the Solution Gas–Oil Ratio on Foamy Oil. Solution gas drive experiments were carried out at six different solution gas–oil ratios in a one-dimensional sandpack. The experimental parameters and results are illustrated in Table 4. Figures 13–18 plot the oil production rate, the gas production rate, and the produced gas–oil ratio with pressure at each solution gas–oil ratio.

Figure 13 shows that the oil production rate and the gas production rate are both low in the whole process of solution gas drive. There is no oil or gas produced significantly until the average pressure drops below 1 MPa. It is difficult to observe the special phenomena of foamy oil flow because of the low oil production rate and the brief oil-producing period. Figure 14 shows that in the pressure range from 2 to 1 MPa, the oil production rate increases remarkably, but the produced gas–oil ratio is still low, which suggests that foamy oil flow happens. The foamy oil flow occurring at a low solution gas–oil ratio is called poor foamy oil flow for it is unsteady and short-lived.

From Figures 15–17, it can be clearly observed that the solution gas drive process can be divided into three stages. In the second stage, i.e., the foamy oil flow stage, the typical characteristics of foamy oil flow are unambiguous with a high oil production rate, a low gas production rate, and a low produced gas–oil ratio. However, Figure 18 shows a high amount of solution gas is produced with oil simultaneously as the average pressure declines. It goes into the oil–gas two-phase flow stage directly after the elastic expansion stage without foamy oil flow in this case.

Table 4. Experimental Parameters and Results for Different Solution Gas–Oil Ratios

| no. | porosity (%) | permeability (mD) | initial oil saturation (%) | solution gas–oil ratio (Sm³/m³) | dead oil viscosity (mPa·s at 53.7 °C) | oil recovery (%) |
|-----|--------------|-------------------|----------------------------|---------------------------------|--------------------------------------|-----------------|
| 1   | 37.66        | 9320              | 86.58                      | 2.5                              | 28,040                               | 7.17            |
| 2   | 37.93        | 9570              | 88.72                      | 5.0                              | 28,040                               | 10.95           |
| 3   | 38.49        | 9955              | 88.33                      | 10.0                             | 28,040                               | 15.33           |
| 4   | 39.04        | 10,085            | 89.07                      | 16.0                             | 28,040                               | 20.62           |
| 5   | 38.22        | 9760              | 87.43                      | 26.0                             | 28,040                               | 24.83           |
| 6   | 38.71        | 9788              | 88.21                      | 35.0                             | 28,040                               | 22.36           |
It indicates that a solution gas–oil ratio that is too large or too little is unfavorable to the formation of foamy oil. If the solution gas ratio is too little, then the driving force generated by the release of solution gas cannot compensate for the viscous force of heavy oil leading to low oil production. If an excess amount of solution gas dissolves into oil, then the liberated solution gas coalesces and forms a continuous gas phase easily rather than being dispersed in oil in the form of microbubbles. So, it can be inferred that there is an optimal range of solution gas ratios for foamy oil flow, for example, solution gas ratios from 10 to 26 Sm³/m³ under this condition.

The oil recovery efficiency and accumulated gas production with average pressure are displayed in Figures 19 and 20. The effects of the solution gas–oil ratio on the bubble point pressure and the pseudo-bubble point pressure are compared in Figure 21. Figure 22 shows oil recoveries at each stage of solution gas drive at each solution gas–oil ratio.

It can be observed from Figures 19 and 22 that the oil recovery efficiency first increases and then decreases with the increase in the solution gas–oil ratio. The recovery efficiency of the foamy oil flow stage was constant basically, which accounts for about 80% of the total. However, in the case of a solution gas–oil ratio of 35 Sm³/m³, the oil recovery efficiency declines without foamy oil flow. It can be inferred that foamy oil flow could improve recovery of heavy oil solution gas drive significantly. That is why foamy oil production performance is anomalous compared with conventional solution gas drive.

Figure 21 and Table 5 show that as the solution gas–oil ratio increases, bubble point pressures and pseudo-bubble point pressures both increase, but the pressure range of the foamy oil flow stage first increases and then decreases. At a solution gas–oil ratio within the range of 10–26 Sm³/m³, there exists steady and relatively long-lasting foamy oil flow in solution gas drive, which is the optimal range of solution gas–oil ratios for foamy oil flow on this condition. Whether the
solution gas–oil ratio is too large or too little, it would depress the formation of foamy oil flow.

4. CONCLUSIONS

The effects of oil viscosity and the solution gas–oil ratio on foamy oil flow in solution gas drive were investigated through pressure depletion tests, and the thresholds for the formation of foamy oil flow were achieved.

1. A typical solution gas drive with foamy oil flow exists in three stages, which are the oil phase expansion stage, the foamy oil flow stage, and the oil–gas two-phase flow stage. At the foamy oil flow stage, the oil production rate is great, but the gas production rate is low, and the displacement pressure starts increasing.

2. As the oil viscosity decreases, the foamy oil flow stage shortens, and the contribution of foamy oil to recovery decreases significantly. It is difficult to form steady foamy oil flow in solution gas drive when the oil viscosity is below 600 mPa·s.

3. As the solution gas–oil ratio increases, the oil recovery first increases and then decreases. There exists an optimal range of solution gas–oil ratios for foamy oil flow. Whether the solution gas–oil ratio is too big or too small, it would be unfavorable for foamy oil flow. In the experiments, steady foamy oil flow was observed when the solution gas–oil ratio was within the range of 10−26 Sm³/m³.

Table 5. Effect of the Solution Gas–Oil Ratio on Parameters of Foamy Oil

| solution gas–oil ratio (Sm³/m³) | bubble point pressure (MPa) | pseudo-bubble point pressure (MPa) | pressure range of the foamy oil flow stage (MPa) | recovery proportion of the foamy oil flow stage (%) |
|---------------------------------|-----------------------------|-----------------------------------|-----------------------------------------------|-------------------------------------------------|
| 2.5                             | 0.8                         | 0.6                               | 0.2                                          | 83.72                                           |
| 5                               | 2.15                        | 0.95                              | 1.2                                          | 79.91                                           |
| 10                              | 3.0                         | 1.3                               | 1.7                                          | 85.56                                           |
| 16                              | 4.2                         | 2.07                              | 2.13                                         | 81.33                                           |
| 26                              | 6.3                         | 3.4                               | 2.9                                          | 78.58                                           |
| 35                              | 7.2                         | 7.2                               | 0                                            | 0                                               |

Figure 21. Effect of the solution gas–oil ratio on bubble point pressure and pseudo-bubble point pressure.

Figure 22. Effect of the solution gas–oil ratio on oil recovery efficiency at each stage.

| Oil recovery efficiency (%) | Solution gas-oil ratio2.5 | Solution gas-oil ratio 5 | Solution gas-oil ratio10 | Solution gas-oil ratio16 | Solution gas-oil ratio26 | Solution gas-oil ratio35 |
|-----------------------------|---------------------------|--------------------------|--------------------------|--------------------------|--------------------------|--------------------------|
| 0                           | 0                         | 0                        | 0                        | 0                        | 0                        | 0                        |
| 5                           | 5                         | 15                       | 25                       | 35                       | 45                       | 55                       |

Notes

The authors declare no competing financial interest.

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