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Full Length Article

Large-scale visualized physical simulation of the occurrence and flow of condensate oil in fracture-vuggy condensate gas reservoir

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ABSTRACT

The Tazhong No. 1 condensate gas reservoir in Tarim Basin shows complex storage spaces and strong heterogeneity. To intuitively assess the production performance characteristics of the condensate gas reservoir and understand the occurrence mechanism of condensate oil, an experimental device and method for visualized simulation of depletion exploitation in fracture-vuggy condensate gas reservoirs were established. The condensate oil precipitation characteristics and dynamic parameters of different reservoir types during depletion were tested. The research indicates that the condensate oil occurrence characteristics in the single-fracture-vuggy model are similar to those in the multi-fracture-vuggy model. Condensate oil that precipitates on the pore walls slides down as droplets under the influence of gravity, eventually gathering at the corners of the lower areas of the pores. Unlike porous reservoirs, fracture-vuggy condensate gas reservoirs exhibit significant retrograde vaporization during the late stages of depletion production. As the depletion rate increases, the recovery degree of condensate oil also rises. For the single-fracture-vuggy model, recovery increases by 7.68%, and for the multi-fracture-vuggy model, by 9.85%, when the depletion rate is 6 MPa/h compared to 3 MPa/h. The results of this research provide crucial insights for developing technical measures to enhance condensate oil recovery in the middle and late stages of fracture-vuggy condensate gas reservoir development.

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1. Introduction

During the early stage of depletion development of condensate gas reservoirs, the reservoir pressure is above the dew point pressure, so retrograde condensation does not occur and condensate oil can be effectively recovered with the produced gas. In contrast, when the pressure drops below the dew point pressure in the middle and late stages, retrograde condensation occurs, and a large amount of condensate oil remains in the formation, sharply reducing the recovery (Choubineh et al., 2017; Ghorbani et al., 2017; Tang et al., 2005). Fractured reservoirs, which generally exhibit low porosity and high permeability (Song and Ping, 2014), differ from conventional porous reservoirs. The condensate oil in the fractures exhibits high mobility, whereas it hardly flows within the matrix pores (Ayala et al., 2007). Additionally, in conventional porous reservoirs, the vertical permeability is low or even zero, which allows the influence of gravity to be ignored. However, in fractured reservoirs, condensate oil will migrate to the lower areas along the fractures due to gravity (Salmani et al., 2020). Besides developed fractures, fracture-vuggy reservoirs feature numerous porous vugs or fractured vugs, which are quite different from both porous and fractured reservoirs. Consequently, the occurrence characteristics of condensate oil must differ from those in fractured and porous media, further increasing the difficulty of efficiently developing fracture-vuggy condensate gas reservoirs (Guo et al., 2013; Qian et al., 2020; Sun et al., 2023; Tang et al., 2021; Wang et al., 2013). A deep understanding of the main factors restricting the development of these types of reservoirs, as well as the formulation of technical measures to enhance the recovery of condensate oil in their middle and late stages, is crucial for identifying the production performance characteristics and precipitation laws of condensate oil during the depletion of fracture-vuggy condensate gas reservoirs.

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Physical simulation is an effective means to reveal the occurrence and migration mechanisms of condensate oil under complex reservoir conditions. The key to the physical simulation of fracture-vuggy condensate gas reservoirs lies in obtaining cores with properly developed fractures and vugs under actual reservoir conditions. Nevertheless, it is challenging to acquire real reservoir cores given current technical conditions. Thus, two primary simulation methods are employed: etching transparent glass slabs to simulate the reservoir, and establishing models with cores from the actual reservoir with underdeveloped fractures through artificial fractures and vugs (Wang et al., 2017b). Wang et al. (2017a; 2018) used the Sinian fracture-vuggy carbonate reservoir in the Sichuan Basin as a template, employing lasers to intricately carve plexiglass, constructing a visual fracture-vuggy structural model composed of vugs, fractures, and other different storage spaces. The flow laws of oil and gas, along with the reservoir's development performance, can be intuitively observed through the transparent glass slab model (Cheng, 2018; Cruz-Hernández et al., 2001; Su et al., 2017; Wang et al., 2011). However, the glass slab's limited pressure-bearing capacity prevents it from simulating real reservoir conditions. Utilizing the seismic data from the TH Oilfield, Lyu et al. (2017) used artificial or natural carbonate rock cores according to six fracture - cave combination patterns. They carved and dissolved different reservoir spaces based on the fracture and cave distribution map, and carried out nitrogen injection experiments after water flooding. Li et al. (2008) used outcrop cores to create artificial fractures and vugs. They designed both network and serial fracture-vuggy models to conduct water flooding experiments. Various development methods for oil and gas reservoirs can be simulated under real reservoir conditions via artificial fractures and vugs (Fahandezhsaadi et al., 2019; Xiao et al., 2012; Zhao et al., 2010), but real cores can impede visualization. Currently, visual physical simulation experiments for fracture-vuggy oil and gas reservoirs mainly use nuclear magnetic resonance, CT scanning, plexiglass devices, and fluid dyeing. Borgia et al. (1998) employed nuclear magnetic resonance technology to measure porosity and fracture distribution in carbonate cores. Ren et al. (2025) used nuclear magnetic resonance technology to monitor the oil distribution in tight cores during water flooding and supercritical CO_2 flooding and to investigate the fluid flow conditions. The T2 distribution spectrum obtained via nuclear magnetic resonance logging effectively distinguishes the fluid properties in fracture-vuggy reservoirs, although it cannot simulate the production performance characteristics of oil and gas reservoirs. Rangel-German and Kovscek (2002) performed CT scanning on oil and gas displacement experiments by water, capturing the leading-edge position of wet phases in fractures and the distribution of water saturation in the matrix. Wang et al. (2017a). Conducted CT scanning on fracture-vuggy gas reservoirs in central Sichuan to study pressure changes and production performance characteristics of various reservoir types. CT scanning reveals the dynamic distribution of oil and water and determines core pore structures, but only single-precision digital cores can be constructed for scanning use, leading to inherent contradictions between sample size and scanning resolution (Li et al., 2024; Liang et al., 2011; Liu et al., 2015). Based on the principle of similarity, Xu et al. (2020)used plexiglass to build a visual physical model according to the connection method between fractures and vugs of the studied reservoir. They dyed the oil and water, and the plexiglass device facilitated intuitive observation of oil and gas flow laws and production performance characteristics (Chen et al., 2020; Qu et al., 2018; Wang et al., 2024; Zheng et al., 2010). However, this simulation method has significant limitations as the model cannot withstand high temperatures and pressures, rendering it inappropriate for simulating condensate gas reservoirs. Additionally, the influence of reservoir porous media on fluid and rock-fluid interactions are ignored. From the literature, it is evident that due to the high pressure of fracture-vuggy condensate gas reservoirs and the challenges in creating large-size cores and observing condensate oil, large-scale visualized physical simulations of depletion production in these reservoirs remain exploratory both domestically and internationally. Conventional methods and experimental devices can only simulate the production flow process, predict and analyze development situations without directly observing and verifying production. This paper proposes new methods for making large-size cores and observing condensate oil. By analyzing visualized simulation results of depletion production in fracture-vuggy condensate gas reservoirs, the precipitation and migration law of condensate oil and the recovery degree of gas reservoirs at different depletion rates can be studied, providing scientific guidance for the exploitation of such reservoirs.

2. Experimental program and process

2.1. Preparation of large-scale visualized fracture-vuggy core model

In this study, tight carbonate matrix cores were selected as the base material for physical simulation. Due to the extremely low porosity of such matrix cores, the influence of matrix pores was neglected, and only pores and fractures were considered to represent the main storage spaces of fracture–vuggy reservoirs. The fabrication procedure of the physical model was as follows: the core samples were first cut, polished, and processed into rock plates with dimensions of 36 cm $\times$ 21 cm $\times$ 0.3 cm. One side of each rock plate was then bonded to a pressure-resistant glass plate of the same size using epoxy resin, followed by surface polishing to ensure uniform thickness. The structural design parameters of the models were derived from actual fracture and vug images obtained from well data, and proportionally scaled to 36 cm $\times$ 21 cm based on geometric similarity principles. The structural parameters of the fractures and vugs (including the size and shape of the vugs, fracture orientation, and the connectivity between fractures and vugs) were finely characterized, and an etching model diagram was drawn accordingly. The single-fracture-vuggy model is shown in Fig. 1a, while the multi-fracture-vuggy model is shown in Fig. 1b. The naming of “single-fracture-vuggy” and “multi-fracture-vuggy” models is based on the number of main vug systems in the vertical direction, rather than the overall visual complexity of the fracture-vuggy network. Finally, the prepared etching diagrams were transferred onto the rock plates using a laser etching machine, with fracture widths set to 0.12 mm, and both the production well and transfer well widths set to 2 mm.

Contact between Sudan Red particles and oil results in a chromogenic reaction (Fig. 2). The prepared Sudan Red solution was evenly applied to the surface of the fractures and vugs in the slab core. Epoxy resin glue was then evenly applied to the unengraved surface of the rock slab, which was subsequently covered with another pressure-resistant glass of the same size.

2.2. Preparation of simulated formation fluid samples

The original formation temperature of the research block is 411 K, and the formation pressure is 61.2 MPa. The dew point pressure is 45.13 MPa, with a gas-oil ratio of 2500 m^3/m^3 in production and a pressure of 20 MPa corresponding to the maximum retrograde condensate saturation. Since the experimental equipment's safety pressure is 35 MPa, the simulated condensate gas was prepared at 30 °C using a dry gas sample and decane (C10),

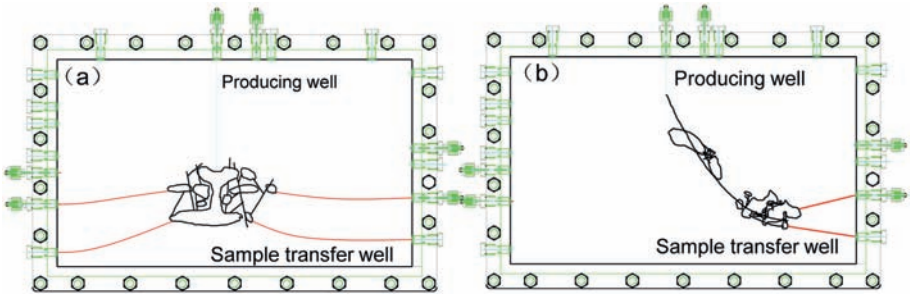


Fig. 1. (a) Single-fracture-vuggy model (b) Multi-fracture-vuggy model.

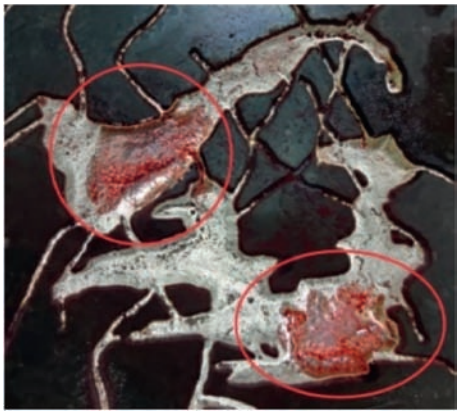


Fig. 2. Chromogenic reaction of Sudan red with degassed oil.

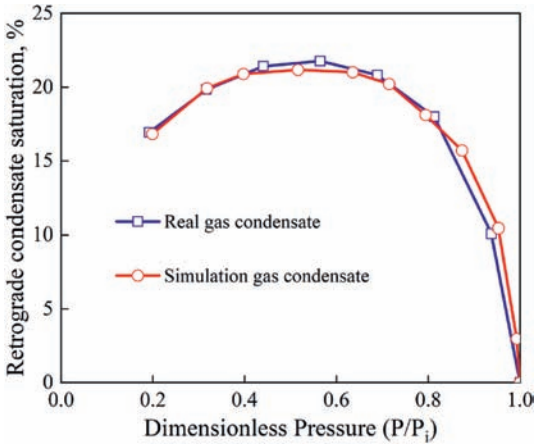


Fig. 3. Comparison of retrograde condensation characteristics in constant volume depletion experiments.

with the composition outlined in Table 1. The original pressure of the simulated condensate gas is 34.15 MPa, with a dew point pressure of 25.18 MPa, a gas-oil ratio of 2500 m^3/m^3 in production, and a pressure of 15 MPa corresponding to the maximum retrograde condensate saturation. Constant volume depletion experiments were conducted on both actual and simulated condensate gas. The experimental results, shown in Fig. 3, demonstrate that the precipitation law of the simulated condensate oil and the maximum retrograde condensate volume are generally consistent with those of actual samples, indicating that the prepared condensate gas is highly representative.

2.3. Experimental procedures

The large-scale visualized physical simulation process of depletion production is illustrated in Fig. 4. In this study, depletion rates of 3 MPa/h and 6 MPa/h were chosen, as they represent typical practical production ranges in field-scale condensate gas reservoir operations, and they are also within the stable operating range of the physical simulation system (Liu et al., 2023; Yang et al., 2020). The experimental steps are as follows:①Connect the experimental instrument and maintain the temperature at 30 °C.②Gradually increase the pore pressure to 34.15 MPa by injecting dry gas, ensuring the confining pressure remains 2 MPa higher than the pore pressure during injection.③Inject the simulated condensate gas into the slab through the injection holes on the left and right sides, replacing the dry gas in the pores.④Deplete the pressure of the slab core to 34.15 MPa, 30 MPa, 28 MPa, 25.18 MPa, 20 MPa, 15 MPa, 10 MPa, and 5 MPa at rates of 3 MPa/h and 6 MPa/h, respectively.⑤Videotape the entire process and record the experimental data for each stage.

Table 1
The composition of the prepared condensate gas sample.

Component	mol%	Component	mol%
CO_2	0.58	nC_4	0.78
N_2	0.25	iC_5	0.34
C_1	77.59	nC_5	0.18
C_2	11.06	C_6	0.07
C_3	3.71	C_{10}	4.70
iC_4	0.74		

2.4. Reserve calculation of original formation

The total pore volume V* (cm^3) of the slab core was measured by AutoCAD. According to the compression coefficient Zi of the simulated condensate gas, and the experimental temperature T_0 (K), the mole number of natural gas and condensate oil n_t (mol) under the reservoir conditions was calculated:

$$n_t = \frac{P^* \times V^*}{Z_i \times 8.314 \times T_0} \quad (1)$$

The total volume of natural gas and condensate oil on the ground G (cm^3), under the original reservoir conditions is:

$$G = n_t \times 22.4 \times \frac{293}{273} \times 10^3 \quad (2)$$

Refer to the reserve calculation formula in the professional book (Cronquist, 2001), the natural gas reserves G_c (cm^3) is:

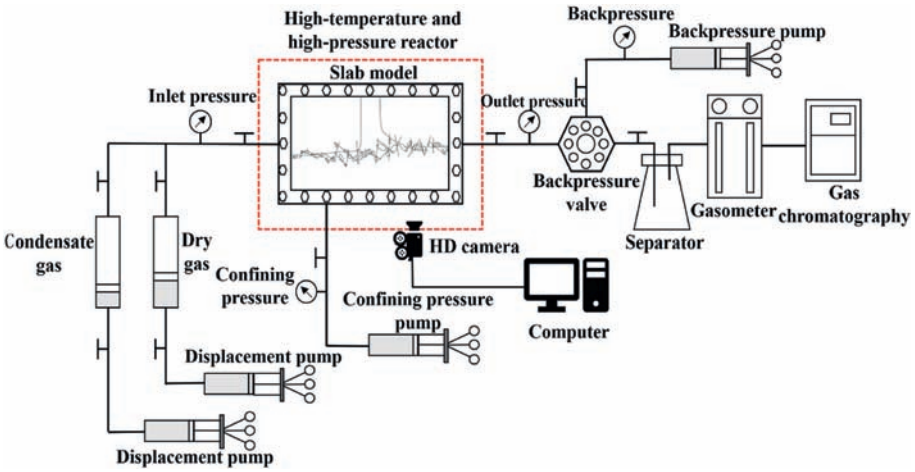


Fig. 4. Flow chart of visualized physical simulation device for fracture-vuggy slab under high temperature and pressure.

$$G_c = G \times \frac{n_g}{n_g + n_o} \tag{3}$$

Condensate oil reserve V (cm^3) is:

$$V = \frac{G_C}{GOR_0} \tag{4}$$

Where n_g is the mole number of produced natural gas, mol; n_o is the mole number of produced condensate oil, mol; GOR_0 is the gas-oil ratio in production, m^3/m^3

3. Experimental results and analysis

3.1. Depletion experiment of single-fracture-vuggy model

The single-fracture-vuggy model is mainly composed of a large pore connected to several small pores via fractures. As shown in Fig. 5, there was no obvious condensate oil precipitation during the depletion of pore pressure from the original 34.15 MPa to the dew point pressure of 25.18 MPa, at a depletion rate of 3 MPa/h. Condensate oil began to precipitate right at the dew point pressure. It was first precipitated in the small pores (labeled A) directly connected to the main pore. Then, under the effect of gravity, the condensate oil flowed along the rock wall to the large pore, accumulating at the bottom of the pore as a film-like occurrence in corner B. When the pressure was depleted to the maximum retrograde condensation pressure of 15 MPa, the condensate oil level in the large pore at the bottom reached 3.35 cm. Throughout the continuous depletion process to 5 MPa, it dropped to 3.17 cm with noticeable retrograde vaporization of condensate oil. During the entire depletion, the recovery degree of condensate oil was low in the relatively isolated small pore C, which is not directly connected to the main channel. The precipitated condensate oil migrated downward along the fractures, accumulating at corner D.

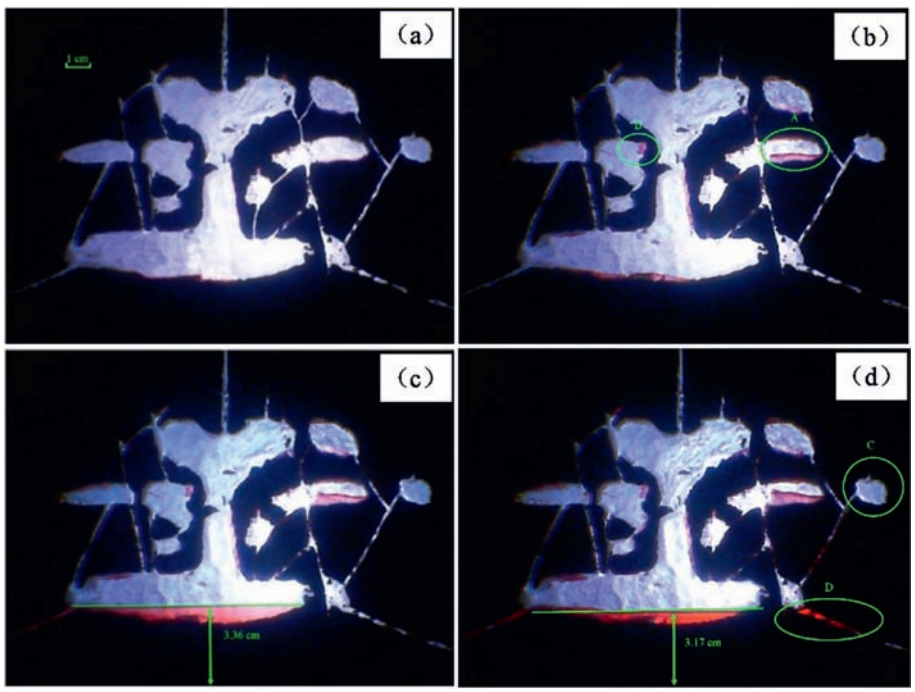


Fig. 5. Depletion of the Single-fracture-vuggy slab model: (a) 34.15 MPa (b) 25.18 MPa (c) 15 MPa (d) 5 MPa.

When the simulated gas reservoir was abandoned, a significant amount of condensate oil accumulated in the large pores at the bottom of the slab core and the low areas of the corners.

The dynamic data of depletion in the single-fracture-vuggy slab model is shown in Fig. 6. As the depletion rate increases, the recovery rate of natural gas decreases, while the recovery rate of condensate oil increases. At depletion rates of 3 MPa/h and 6 MPa/h, the recovery rates of natural gas are 86.50% and 80.86%, respectively, while the recovery rates of condensate oil are 39.93% and 47.61%, respectively. Compared to the depletion rate of 3 MPa/h, the recovery rate of natural gas decreases by 6.52 percentage points, whereas the recovery rate of condensate oil increases by 19.2 percentage points at the depletion rate of 6 MPa/h. It can be observed that as the depletion rate increases, the increase in the recovery rate of condensate oil is significantly greater than the decrease in the recovery rate of natural gas.

The component analysis of produced gas in the single-fracture-vuggy slab model under different depletion rates is shown in Fig. 7. When the pore pressure is lower than the dew point pressure, the content of light components in the produced gas gradually increases while the content of heavy components decreases as the pressure drops. With a larger depletion rate, the content of light components decreases, and the content of heavy components increases in the produced gas. This phenomenon occurs because, when the pore pressure falls to the dew point pressure, condensate oil begins to precipitate and remains in the pores. Consequently, medium and heavy hydrocarbons in the gas phase condense into the liquid phase, leading to an increase in the content of light components and a decrease in the content of heavy components. Under the influence of molecular diffusion and mass transfer, as the depletion rate rises, the content of heavy components in the condensate gas increases while the content of light components in the condensate oil also increases.

3.2. Depletion experiment of multi-fracture-vuggy model

The vertical superimposed type of multi-fracture-vuggy model primarily consists of two large pores on the upper and lower sides. As shown in Fig. 8, there was no significant condensate oil precipitation during the depletion of pore pressure from the original 34.15 MPa to the dew point pressure of 25.18 MPa, at a depletion rate of 3 MPa/h. Condensate oil first precipitated at corner A of the large pores in the higher area, precisely at the dew point pressure. It then flowed downward along the rock wall due to gravity, accumulating in the lower area B. When the pressure was depleted to the maximum retrograde condensation pressure of 15 MPa, the condensate oil level in the large pores at the bottom reached 2.89 cm. During the further pressure depletion to 5 MPa, the level decreased to 2.84 cm as a result of retrograde vaporization of the condensate oil. When the simulated gas reservoir was abandoned, condensate oil had accumulated in the large pores in the low area of the slab core.

The dynamic data of depletion in the multi-fracture-vuggy model is shown in Fig. 9. As the depletion rate rises, the recovery degree of natural gas decreases, while the recovery degree of condensate oil increases. At different depletion rates of 3 MPa/h and 6 MPa/h, the recovery degree for natural gas is 85.98% and 78.60%, respectively, and for the condensate oil it is 26.39% and 36.24%. The recovery degree decreases by 8.58 percent point for natural gas while increasing by 37.32 percent point for condensate oil at the depletion rate of 6 MPa/h, compared with that at the rate of 3 MPa/h. With the rise in the depletion rate, there is certain decrease in the recovery degree of natural gas, but the recovery degree of condensate oil can be significantly enhanced.

3.3. Comparison of depletion experiments between single-fracture-vuggy and multi-fracture-vuggy models

The occurrence characteristics of condensate oil in the single-fracture-vuggy model are similar to those in the multi-fracture-vuggy model. Initially, condensate oil precipitates and covers the pore walls, then slides down in droplets due to gravity, finally accumulating at the corners of the low areas within the pores. Noticeable retrograde vaporization occurs during the later stages of depletion production in fracture-vuggy condensate gas reservoirs. Furthermore, as the depletion rate increases, the recovery rate for condensate oil rises while the recovery rate for natural gas declines. The comparison of recovery rates between the single-fracture-vuggy and multi-fracture-vuggy models at a depletion rate of 3 MPa/h is shown in Fig. 10. The recovery rate of natural gas is 86.50% in the former and 85.98% in the latter, while the recovery rate of condensate oil is 39.93% and 26.39%, respectively. In the single-fracture-vuggy model, the recovery rate of condensate oil is 13.54 percentage points higher than in the multi-fracture-vuggy model. Compared with the multi-fracture-vuggy model, the single-fracture-vuggy model exhibited 13.54 percentage points higher condensate oil recovery. This difference is not only due to "better connectivity and a stronger carrying effect of the gas phase," but also closely related to the specific fracture–vug topology shown in Fig. 1. In the single-fracture-vuggy model, one dominant fracture directly connects to the central vug, forming a continuous and unobstructed flow channel. This topology allows the gas phase to sweep through the vuggy space more efficiently, thereby enhancing its ability to mobilize condensate oil that accumulates at the bottom and along fracture–pore interfaces. By

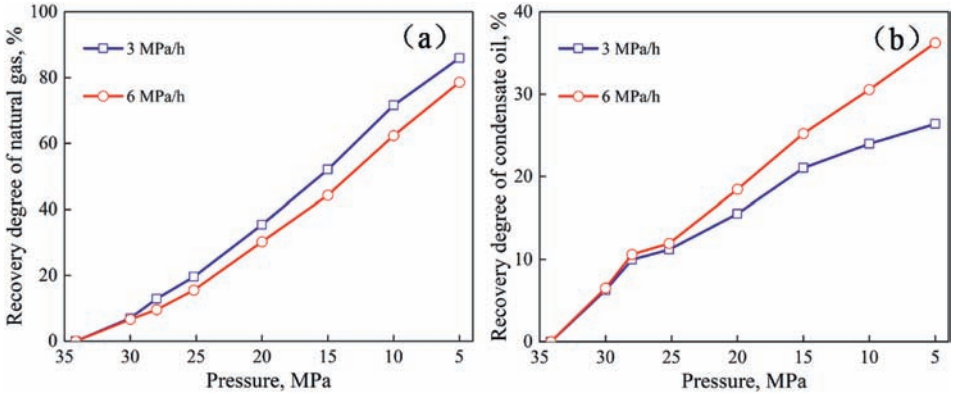


Fig. 6. The recovery degree of natural gas (a) and condensate oil (b) under different depletion rates in the single-fracture-vuggy slab mode.

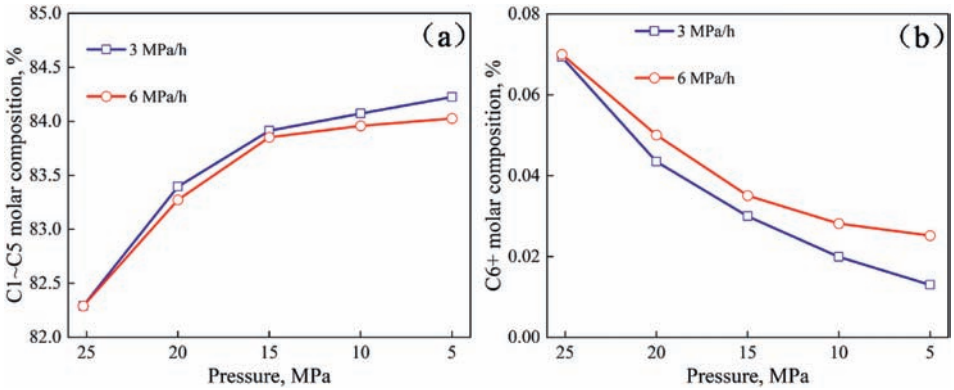


Fig. 7. Molar composition of produced gas components under different depletion rates in the single-fracture-vuggy slab model: (a) C1~C5 molar composition (b) C6+ molar composition.

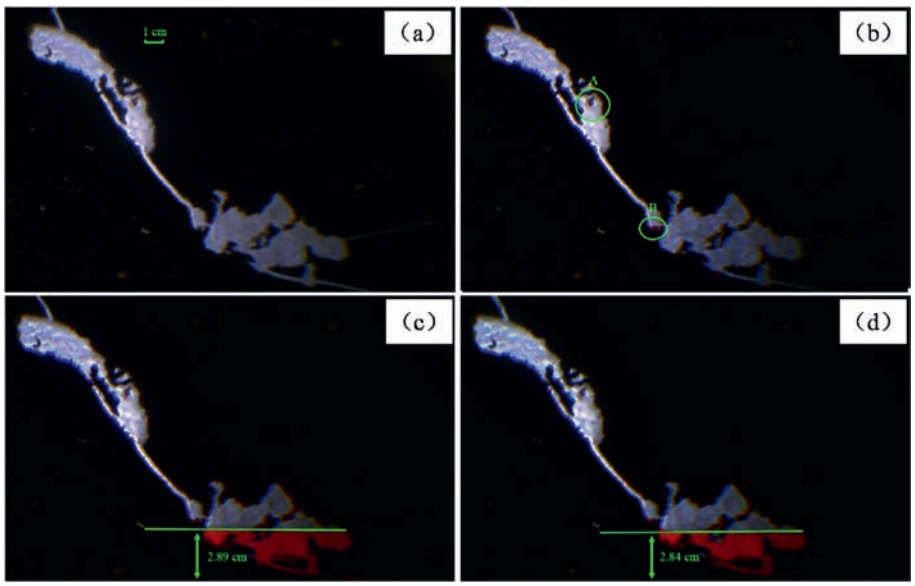


Fig. 8. Depletion of multi-fracture-vuggy model: (a) 34.15 MPa (b) 25.18 MPa (c) 15 MPa (d) 5 MPa.

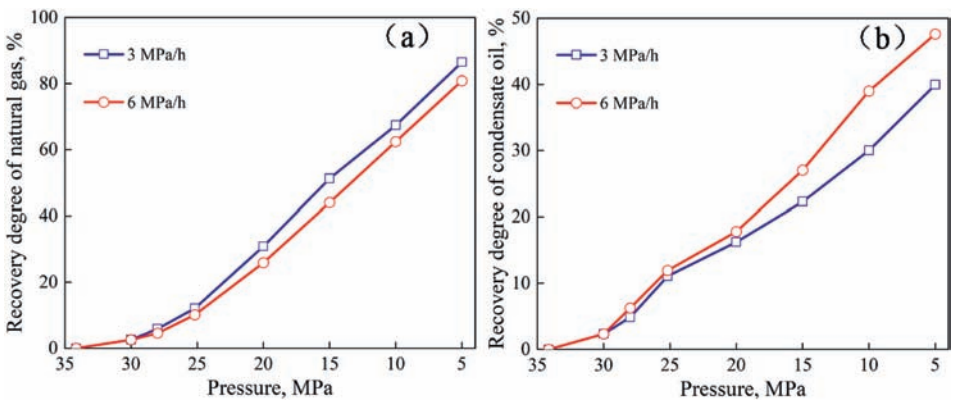


Fig. 9. The recovery degree of natural gas (a) and condensate oil (b) under different depletion rates in the multi-fracture-vuggy model.

contrast, in the multi-fracture-vuggy model, several fractures intersect the vug at different angles, which leads to flow diversion and the formation of local stagnation zones. These zones weaken the overall connectivity and create dead-end spaces, reducing the efficiency of gas in carrying out condensate oil. Therefore, the higher condensate recovery in the single-fracture-vuggy model results from both superior connectivity and a more direct, effective gas-sweeping pathway with fewer stagnant regions.

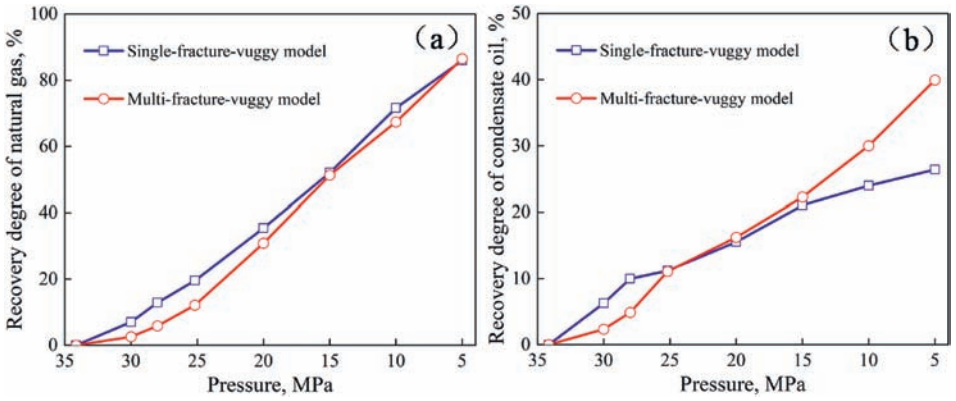


Fig. 10. Recovery degree comparison of natural gas (a) and condensate oil (b) between different models.

The greater the pressure depletion rate, the higher the recovery degree of condensate oil. The main reason for this phenomenon is that when the system pressure drops below the dew point, part of the heavy hydrocarbons in the reservoir have not yet condensed into liquid within the pores but are carried out directly by the rapidly flowing gas, resulting in a pronounced non-equilibrium effect. As the pressure decline rate increases, the oil and gas phases cannot reach equilibrium in time, and gas–liquid separation becomes increasingly incomplete. Consequently, more condensate oil fails to precipitate within the reservoir and is directly produced with the gas. Therefore, the greater the pressure decline rate, the stronger the non-equilibrium effect, and the more evident the phenomenon of "condensation lag." This interpretation is further confirmed by the produced gas composition under different depletion rates (Fig. 7b). Under rapid depletion conditions, the C6+ content in the produced gas increases significantly, indicating that heavy hydrocarbons are not fully condensed within the reservoir but are carried out with the gas, providing direct experimental evidence for the occurrence of "condensation lag" in fracture–vuggy condensate gas reservoirs.

4. Conclusion

From this study, four major conclusions can be drawn.

(1) The established experimental method for visualizing the depletion exploitation of fracture-vuggy condensate gas reservoirs—and models with varying fracture-vug matches—successfully simulates the precipitation and migration patterns of condensate oil during depletion. This provides valuable technical support for the development of fracture-vuggy condensate gas fields and for improving condensate oil recovery.

(2) The occurrence characteristics of condensate oil in single-fracture-vuggy models are similar to those in multi-fracture-vuggy models. Condensate oil precipitates onto pore walls, then slides down in droplets due to gravity, eventually accumulating at the corners of the lower areas within the pores. Additionally, significant retrograde vaporization is observed during the later stages of depletion exploitation in fracture-vuggy condensate gas reservoirs.

(3) Better connectivity between fractures and vugs leads to higher condensate oil recovery. At a depletion rate of 3 MPa/h, the single-fracture–vuggy model achieved a recovery that was 13.54% higher than that of the multiple-fracture–vuggy model. Moreover, a higher depletion rate further improves recovery; in the single-fracture–vuggy model, recovery at 6 MPa/h was 19.2% higher than at 3 MPa/h.

(4) Condensation lag is also observed in depletion experiments involving cores with fractured and porous media. The underlying mechanism may be related to the non-equilibrium phase change of fluid, suggesting a need for further in-depth research into this area.

CRediT authorship contribution statement

Zhouhua Wang: Writing – review & editing, Validation, Resources, Project administration, Funding acquisition, Formal analysis, Data curation. **Xin Zhou:** Writing – review & editing, Writing – original draft, Investigation, Formal analysis, Data curation. **Haoqi Liao:** Writing – review & editing, Writing – original draft, Visualization, Software, Resources, Investigation, Formal analysis, Data curation. **Jinchuan Wu:** Resources, Formal analysis, Data curation. **Xingliang Deng:** Resources, Investigation, Formal analysis. **Zhiliang Liu:** Resources, Investigation, Formal analysis. **Hanmin Tu:** Resources, Investigation, Formal analysis. **Ping Guo:** Writing – review & editing, Resources, Investigation, Formal analysis. **Huang Liu:** Resources, Formal analysis.

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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