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Experimental Study on the Control Mechanism of Non-Equilibrium Retrograde Condensation in Buried Hill Fractured Condensate Gas Reservoirs

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Abstract: During the depletion development of condensate gas reservoirs, when the formation pressure drops below the dew point pressure, the condensate oil and natural gas systems are in the non-equilibrium state of foggy retrograde condensation. The rational use of the non-equilibrium phase characteristics of the foggy retrograde condensation phenomenon during the development process will be beneficial to the recovery of condensate oil and natural gas. In order to clarify the retrograde condensation control mechanism during the non-equilibrium depletion development of condensate gas reservoirs, the phase characteristics of a condensate oil and gas system were studied by constant composition expansion and constant volume depletion experiments. Then, on the basis of a long core depletion experiment and chromatographic analysis experiment, the influence of different pressure drop speeds, fluid properties, and reservoir physical properties on the control effect of non-equilibrium retrograde condensation after the coupling of the fluid retrograde condensation and reservoir core is analyzed. The results show that during the pressure decline process, the condensate oil and gas system will produce a strong foggy retrograde condensation phenomenon, with the saturation of the retrograde condensate increasing and then decreasing. The cumulative recovery of the condensate oil and natural gas, as well as the mass fraction of the heavy components in the condensate oil, increase with the increase in the depletion rate. Different fluid properties and reservoir physical properties have a great influence on the cumulative recovery degree of the condensate oil, and have little influence on the recovery degree of the natural gas. This work has a certain guiding role for the stable production and enhanced recovery of fractured condensate gas reservoirs in subsurface structures of metamorphic rocks.

Keywords: condensate gas reservoir; foggy retrograde condensation; long core depletion experiment

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1. Introduction

Condensate gas reservoirs are usually developed by depletion or gas injection pressurization. Due to its low investment cost and short investment payback period, depleted development has become the main development method for condensate gas reservoirs in China [1–6]. Unlike general condensate gas reservoirs, the Bozhong 19-6 condensate gas field is the first large-scale condensate gas reservoir in Eastern China. Its main gas-bearing formation structure is the exposed Archean metamorphic rock with a low buried hill. The internal reservoir is dominated by the development of a large-scale three-dimensional fracture network, with the local dissolution of pore spaces develops along the fractures. The reservoir has strong heterogeneity and overall poor physical properties, with an average permeability of 3 mD and a porosity of 4.05%. The condensate oil is high and the difference between the formation pressure and dew point pressure is small. Ground condensate oil has the characteristics of a low density, low viscosity, high wax content, and high setting point [7–11]. During depletion development, strong retrograde condensation occurs when the formation pressure is reduced to the dew point or near dew point pressure. At this time, some condensate oil in the condensate gas system is dispersed in an unstable mist-like flow in the natural gas and is carried out with the airflow. Some of the precipitated condensate oil is adsorbed in the rock pores and cannot be displaced. As the development progresses, the formation near the wellbore will soon experience retrograde condensation blockage and gas–oil two-phase flow [12–16]. This has a very adverse impact on the stable production of early gas wells and the use of depleted development methods to improve oil recovery by utilizing the elastic expansion energy of gas reservoirs [17]. Therefore, how to ensure the efficient transmission of condensate gas in a mist-like flow and reduce its adsorption loss in the formation is a critical issue currently for the efficient development of condensate gas reservoirs [18–23].

Researchers have been investigating the methods to enhance condensate oil recovery. Yuan et al. conducted non-equilibrium pressure drop PVT phase behavior experiments on sandstone condensate gas reservoirs with moderate condensate oil content in Yakula, Xinjiang, and found that after the formation pressure drops to the dew point pressure, a reasonable increase in gas well production and overall gas reservoir production rate can improve condensate oil recovery [24]. Guo et al. proved that a large mining speed is conducive to the efficient development of condensate gas reservoirs through long core experiments [25]. Li et al. carried out long core depletion experiments with artificial fractures and caves in carbonate rock cores. It was found that the pressure drop rate was positively correlated with the recovery rate of condensate oil and gas, and the location of fractures and caves would affect the residual amount of condensate oil in the core [26]. Wang et al. conducted non equilibrium constant volume depletion phase state experiments and long core retrograde condensation damage experiments on tight sandstone condensate gas reservoirs. They found that the greater the pressure drop rate, the more conducive it is to improving the condensate oil recovery rate [27]. Zhang et al. conducted a full-diameter core depletion experiment on low permeability gas reservoirs and condensate gas fluids with medium to low condensate oil content. The study found that factors such as the depletion rate and bound water saturation will have different degrees of impact on condensate oil recovery [28].

The influence of condensate content and strong retrograde condensate phenomena on the development of near critical condensate gas reservoirs with fractures is not clear. In this study, chromatographic analysis was first used to analyze the condensate gas foggy retrograde condensation. Then, long core depletion experiments were carried out to study the influence of multiple factors, such as pressure drop rates, fluid properties, and reservoir physical properties, on the oil and condensate oil recovery, thus providing efficient guidance for the formulation of depleted development technology policies for such condensate gas reservoirs.

2. Experimental Materials and Methods

2.1. Experimental Fluids

The experimental fluid samples were taken from the formation fluid separators of wells 19-6-A6 and 19-6-A5H in the Bozhong condensate gas reservoir of CNOOC. The laboratory compounding was carried out with formation pressure of 51.3 MPa, formation temperature of 178 °C, and gas–oil ratio of 1035 m^3/m^3 for well 19-6-A6, while the compounding conditions for well 19-6-A5H included formation pressure of 51.8 MPa, formation temperature of 180 °C, and sample gas–oil ratio of 834 m^3/m^3, respectively [29]. Results of flash separation test are shown in Table 1. Under surface conditions, the tested gas–oil ratio of well A6 was 1031 m^3/m^3, the density of condensate oil was 0.793 g/cm^3, and the content of condensate oil was 734.26 g/m^3, the A5H well formation fluid test gas–oil ratio was 821 m^3/m^3, condensate density was 0.795 g/cm^3, and condensate content was 953.24 g/m^3.

Table 1. Composition of condensate gas fluid.

A6		A5H	
Composition	**Value (mol%)**	**Composition**	**Value (mol%)**
CO_2	9.32	CO_2	7.68
N_2	0	N_2	0
C_1	71.97	C_1	70.36
C_2	7.12	C_2	4.59
C_3	0.44	C_3	2.74
IC_4	0.06	IC_4	0.57
NC_4	0.68	NC_4	0.99
IC_5	0.28	IC_5	0.60
NC_5	0.31	NC_5	0.64
C_6	0.54	C_6	0.06
C_{7+}	9.27	C_{7+}	11.75

Under reservoir conditions, the mist-like retrograde condensate phase characteristics under the non-equilibrium conditions of the formation fluid were tested in a PVT tube. The constant composition expansion experiments and constant volume depletion experiments were performed to analyze the PVT properties. Figures 1 and 2 show the P–T phase diagrams of the formation fluids in wells A6 and A5H, respectively. Figure 3 shows the variation in the retrograde condensate saturation with pressure during the constant volume depletion process. At the formation temperature of around 180 °C, the dew point pressures of the condensate gas in wells A6 and A5H are 44.28 MPa and 40.89 MPa, respectively (Figures 1 and 2). The maximum retrograde condensation pressure of the formation fluid in well A6 is 40 MPa, and the maximum retrograde condensation saturation is 29.46%. The maximum retrograde condensation pressure of the A5H well is 35 MPa, and the maximum retrograde condensation saturation is 36.27% (Figure 3). The difference between the formation pressure and dew point pressure for the formation fluids is relatively small, and during the period of depressurization and depletion, the pressure drop range only needs about 5 MPa from the occurrence of retrograde condensation to the maximum retrograde condensate saturation. This indicates that such condensate gas reservoirs are subjected to retrograde condensation.

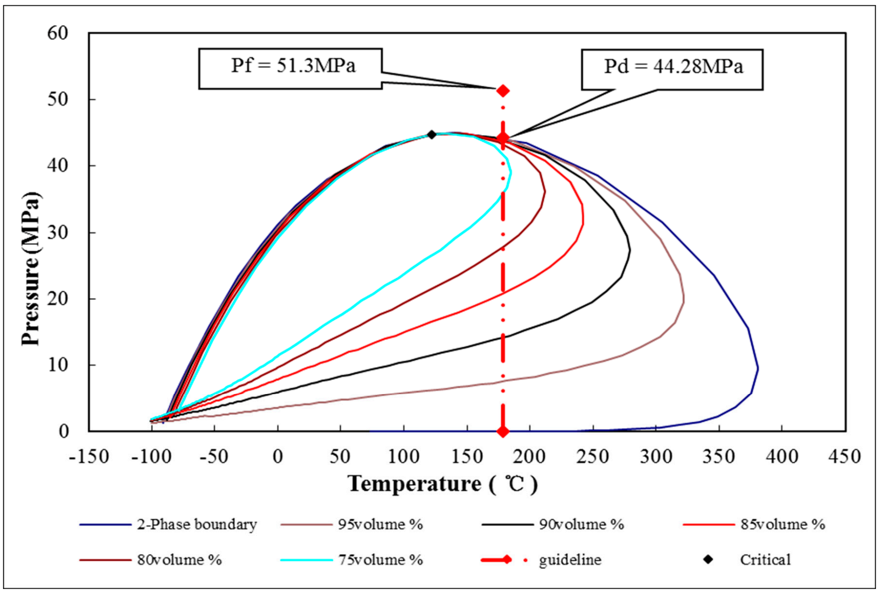


Figure 1. P–T phase diagram of A6 well fluid.

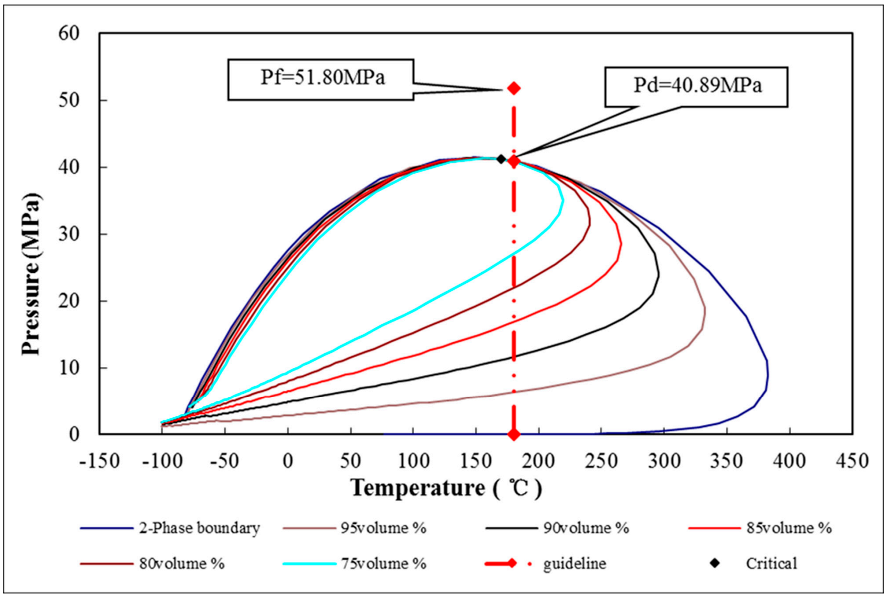


Figure 2. P–T phase diagram of A5H well fluid.

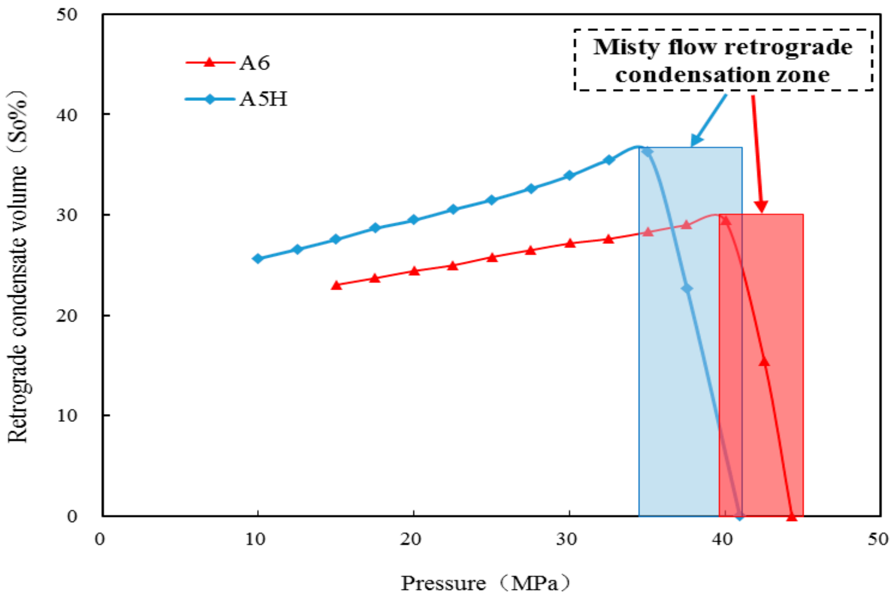


Figure 3. The characteristics of saturation of retrograde condensate as a function of pressure.

2.2. Observation of Foggy Retrograde Condensation Settlement

Figure 4 shows the precipitation and phase change process of retrograde condensate in the formation fluid of the A5H well during constant composition expansion at different pressure drop stages. Under the original formation pressure of 51.80 MPa, the condensate gas is orange-red under the effect of light transmission. As the pressure drops to about the dew point pressure, the condensate gas color deepens and becomes dark orange. At this point, a small amount of condensate oil has been separated and evenly dispersed in the gas. When the pressure drops to 39.30 MPa, which is below the dew point pressure, the condensate gas phase behavior changes significantly, the fluid color changes from orange-red to opaque fog, and then changes to dark orange after 1.58 min of fog. When the pressure is further reduced to 37.34 MPa, the fluid color changes back to an opaque mist. The mist lasts for 1.16 min, after which, the fluid changes back to a deep orange color. The results show that when the system pressure is slightly reduced to a pressure lower than the dew point pressure, a rapid and strong retrograde condensation sedimentation phenomenon occurs. Subsequent pressure reduction will still result in foggy retrograde condensation, but the amount of foggy retrograde condensation oil will gradually decrease and the duration of foggy condensation will be shortened. The final pressure drops to 31.47 MPa, which is close to the maximum retrograde condensate pressure. At this point, the amount of retrograde condensate liquid reaches its maximum and there is no more mist-like retrograde condensate oil precipitation. The condensate gas on the upper part of the deposited retrograde condensate oil is in a light yellow transparent state. The phenomenon caused by this phase behavior change will cause serious retrograde condensation damage in the near-wellbore formation. Therefore, it is necessary to formulate reasonable production measures to extend the duration of the mist-like flow state of the condensate oil, so that more condensate oil could be carried out by the airflow after being precipitated in the mist-like flow state in the early stage, thereby reducing the blockage of the seepage channel caused by retrograde condensation in the near-wellbore formation.

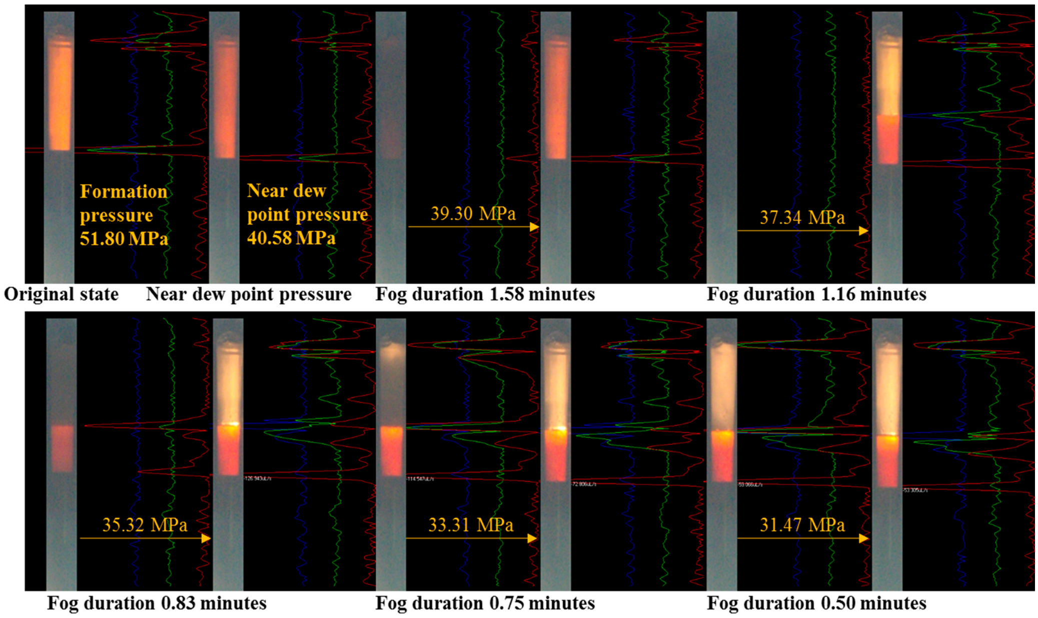


Figure 4. Changes in the precipitation of formation fluid retrograde condensate during the constant composition expansion process.

When the pressure of the condensate gas fluid with high-concentration condensate oil in A5H well drops to the dew point pressure range, the condensate gas system undergoes phase behavior change, that is, the initial orange-red gas will instantly change into a black opaque fog. At this time, the separated condensate oil is evenly distributed in the natural gas and in a non-equilibrium state. As continuous droplets have not formed yet, it is easier for the condensate oil to be carried out by the gas flow. As the pressure continues dropping, rapid retrograde condensation will occur, and the pressure range from the occurrence of foggy flow to the absence of foggy flow is very short, which results in a retrograde condensation saturation of about 30%.

Under the condition of a stable system temperature and constant equilibrium, the state of the oil and gas system is supposed to only be related to pressure [30]. Under non-equilibrium conditions, the rate of change in external conditions is equal to the rate of exchange between phases. Therefore, the parameter that determines the relationship between phases in such conditions is the rate of the change in pressure. According to the non-instantaneous equilibrium theory, the relationship between the condensate content in the system and the rate of pressure change is as follows:

$$q = A\left[p_{\mathrm{b}} - p + \int_{0}^{t} K(T-t)\frac{dp(t)}{dt}dt\right] \quad (1)$$

where $A = q_{MAX}/(p_{\mathrm{b}} - p_{MAX})$, $K(t) = K_0 e^{-t/T}$. p_{b} and p_{MAX} are the initial and maximum condensation pressures, respectively. q and q_{MAX} are the relative amounts of condensate precipitated at the current pressure and maximum condensate pressure, respectively. K_0 is the weight coefficient, T is the relaxation time. $K(t)$ is the relaxation coefficient of the system, and the conditions to be followed are $K(t) > 0$, $dK(t)/dt < 0$, $K(\infty) = 0$. When the pressure drop speed is infinitely small, i.e., $dp/dt \to 0$, Formula (1) will become $q = A(p_{\mathrm{b}} - p)$, that is, the relationship between the amount of retrograde condensate under equilibrium conditions and the formation pressure at this time. When the pressure drops under non-equilibrium conditions, $dp/dt < 0$. From this, it can be seen that the amount of condensate liquid precipitated from the condensate gas system at this time is lower than the amount of liquid precipitated under equilibrium conditions. Based on the results in Figure 4, it was found that the pressure drop rate is negatively correlated with the saturation of the retrograde condensate liquid, indicating that increasing the pressure drop rate within a reasonable range can effectively reduce the retrograde condensate pollution of the condensate oil in the formation. Therefore, long core experiments considering different pressure drop rates (1~7 MPa/h) for long core depletion extraction experiments were designed to study the relationship between different depletion rates and the degree of condensate and gas recovery.

2.3. Other Experimental Materials

The experimental cores are real reservoir cores from the Bozhong 19-6 condensate gas reservoir. Fourteen core samples with lengths of 2~5 cm were prepared and the matrix cores were artificially fractured. After grinding, cleaning, and drying, their basic physical parameters were measured. After harmonic and average sorting of each core, they were loaded into a long core holder and connected to the pipeline. The total length of the composite core is 50.46 cm, with an average diameter of 2.52 cm, an average permeability of 3.46 mD, and a total pore volume of 13.79 cm^3. The oil and gas fluid used in this experiment test is the formation fluid of well A5H. The water type of the formation water sample is sodium bicarbonate, with a total mineralization degree of 9000 ppm.

2.4. Experimental Methods

The procedure of the long core depletion experiment are as follows (the experimental process is shown in Figure 5):

(1) Each parameter of the core sample was measured, and then the composite long core was cleaned and vacuumed. The parameters for the core samples are listed in Table 2.
(2) Quantitative water was displaced into the long core, and established a bound water saturation of 38% within the core.
(3) Under reservoir temperature, dry gas was injected into the core while alternately increasing the back pressure and confining the pressure to establish a system pressure of 51.3 MPa, and then 2 PV of condensate gas was injected into the core to replace dry gas. When the fluid components and gas–oil ratio produced at the outlet were consistent with the displacement condensate gas, the gas phase permeability of the condensate gas under this condition was measured.
(4) By controlling the back pressure at the outlet of the long core to achieve depletion production at a pressure drop rate of 1~7 MPa/h, starting from the formation pressure, the oil and gas were collected at a temporary stable pressure for each 5 MPa decrease. The experiment was stopped at around 15 MPa.

Table 2. Physical properties of cores.

Core Number	Length (cm)	Diameter (cm)	Permeability ($\times 10^{-3}$ μm^2)	Porosity (%)
12-5	4.32	2.52	2.27	3.04
10-10A	5.16	2.51	2.00	9.52
10-11A	5.10	2.52	4.06	11.12
10-29A	4.96	2.52	4.80	2.56
10-32A	4.89	2.53	1.99	4.27
10-34A	4.62	2.53	7.90	3.79
10-001B	2.88	2.52	2.57	5.78
10-002B	2.89	2.53	2.50	5.94
10-016B	2.89	2.53	3.16	9.98
10-034B	2.92	2.52	4.80	4.03
14-3B	2.49	2.52	3.14	2.71
14-5B	2.42	2.54	4.47	4.80
14-6B	2.44	2.54	1.12	2.44
14-9B	2.48	2.54	3.73	3.03

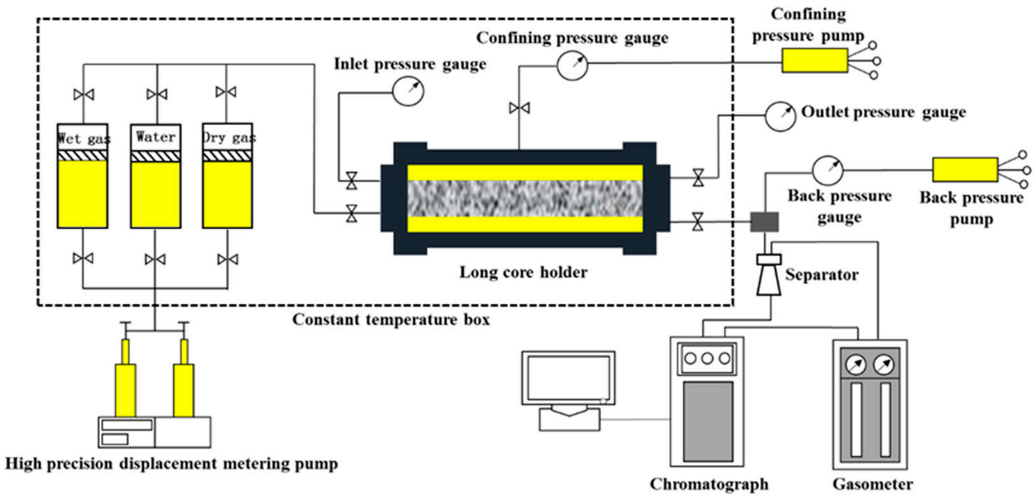


Figure 5. Flow chart of long core experiment.

3. Results and Discussion

Figure 6 shows the relationship between the pressure drop rate in the long core depletion experiment and the cumulative recovery degree of the condensate oil. As the pressure drop rate increases from 1 MPa/h to 5 MPa/h, there is a significant increasing trend in the cumulative recovery of the condensate oil. However, when the pressure drop rate increases from 5 MPa/h to 6 Mpa/h, the corresponding increase in the cumulative recovery of condensate oil is not significant, and the cumulative recovery of the condensate oil slightly decreases when the pressure drop rate increases to 7 MPa/h. This indicates that increasing the pressure drop rate can effectively improve the recovery rate of condensate oil, but increasing the pressure drop rate is not always better. An excessive pressure drop rate can easily cause premature retrograde condensation at the far end of the formation, and a large amount of condensate liquid is trapped in the pores, resulting in a decrease in the final cumulative recovery rate of condensate oil.

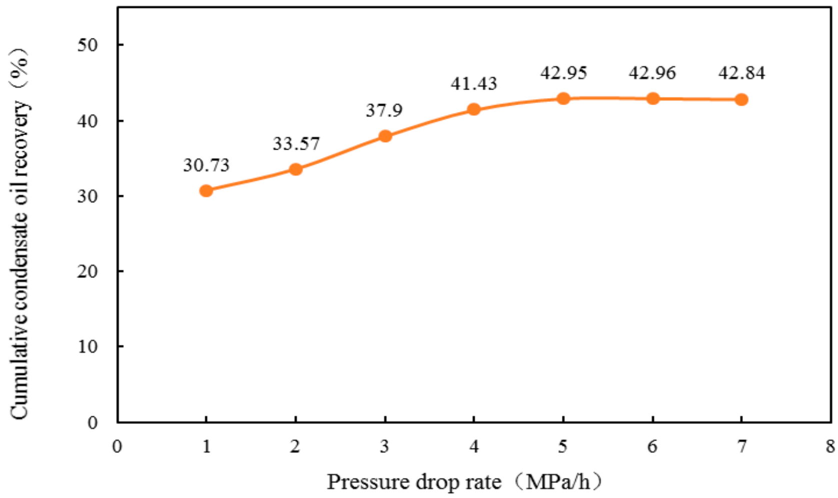


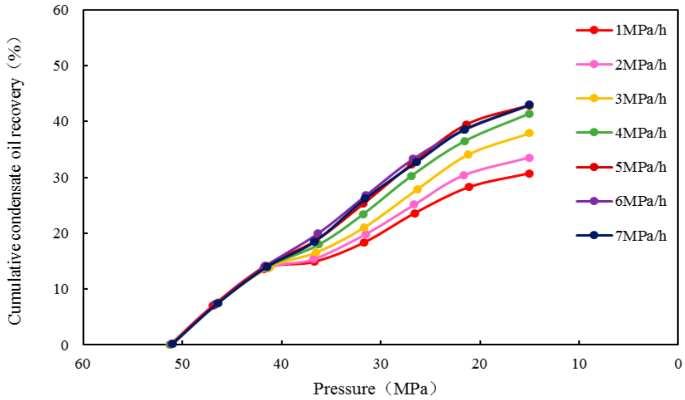
Figure 6. The relationship between pressure drop rate and the degree of condensate recovery.

Table 3 shows the recovery of condensate oil and gas in the long core depletion experiment under different pressure drop rates. Figure 7 shows the comparison of the recovery curve for oil and gas at different pressure drop rates. Figure 8 shows the comparison of the gas–oil ratio in the long core depletion experiment. The experimental results show that the formation pressure is depleted from 51.8 MPa to 41 MPa. Since the pressure is still higher than the dew point pressure of 40.89 MPa, there is no retrograde pollution in the core, so the cumulative recovery of condensate oil and gas does not change. When the pressure decreases from 41 MPa to 36 MPa, some condensate oil is retained in the core under gravity sedimentation and core adsorption, resulting in a decrease in the flow capacity of the seepage channel. The corresponding cumulative recovery of the condensate oil slows down, and the amount of gas produced is also slightly reduced. When the pressure decreases from 36 MPa to 21 MPa, the saturation of the condensate oil inside the core has reached the critical flow saturation, and the condensate oil that occupies a portion of the flow channel is blown out as the gas flow. Therefore, the amount of condensate oil extracted gradually increases, and the growth rate of the produced gas–oil ratio slows down. When the pressure decreases from 21 MPa to 15 MPa, the produced condensate oil mainly relies on the retrograde evaporation inside the core, so the growth of the condensate oil recovery rate slows down, and the corresponding gas–oil ratio increases faster.

As the pressure drop rate is increased to 5 MPa/h, the cumulative recovery degree of the condensate oil increases significantly. When the pressure drop rate is increased to 6 MPa/h, the increase in the condensate oil recovery is relatively small. When the pressure drop rate is increased to 7 MPa/h, the cumulative recovery degree of the condensate oil slightly decreases (Figure 7a), and the overall change in the natural gas recovery is not significant (Figure 7b). However, the production gas–oil ratio decreases as the pressure drop rate increases (Figure 8). This indicates that with a proper increase in the depletion rate, the gas displacement capacity and carrying capacity of the condensate in the formation will increase. Most of the mist flow condensate separated in the near well area is carried out by high-speed gas flow, thus improving the recovery of the condensate oil, while the corresponding gas–oil ratio will gradually decrease. However, when the pressure drop rate increases to a certain range, the imbalanced pressure drop in the formation can lead to the premature retrograde condensation of condensate gas in the far wellbore area, with a large amount of retrograde condensate liquid trapped and adsorbed in the pores, reducing the permeability of the seepage channel and even causing blockage. The condensate gas flowing to the bottom of the well becomes lighter, carrying less condensate oil, and ultimately leading to the decrease in the cumulative recovery of the condensate oil.

Table 3. Condensate oil and gas final cumulative recovery degree data.

Pressure Drop Rate (MPa/h)	Cumulative Recovery Degree of Condensate Oil (%)	Natural Gas Recovery Degree (%)
1	30.73	62.95
2	33.57	62.74
3	37.90	62.42
4	41.43	62.11
5	42.95	61.99
6	42.96	62.02
7	42.84	61.98



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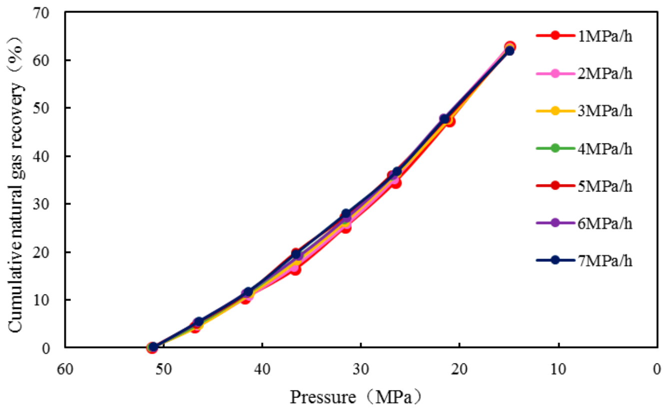

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Figure 7. Comparison of recovery degree at different pressure drop rates. (**a**) Cumulative recovery curve of condensate oil. (**b**) Cumulative recovery curve of natural gas.

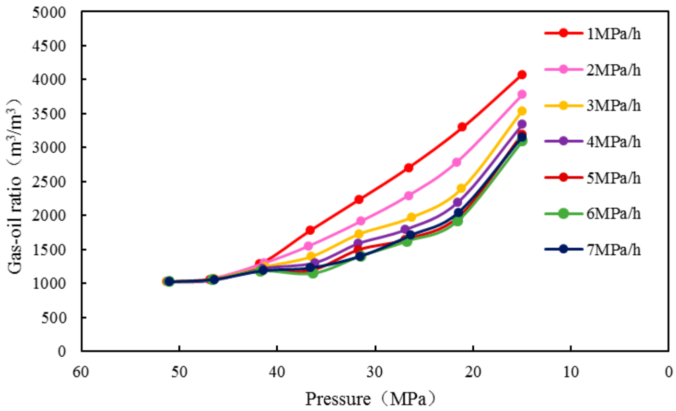


Figure 8. Gas–oil ratio curve at different pressure drop rates.

When the pressure dropped to 35 MPa, chromatographic analysis was carried out to analyze the components of the condensate oil, as shown in Figure 9. According to the results of the chromatographic analysis, it can be found that the mole fraction of the C6 and C7 components in the condensate oil produced at the maximum retrograde condensation pressure point changes little with the increase in the pressure drop rate from 1 MPa/h to 7 MPa/h. The mole fraction of the C8~C10 components evidently decreases with the increase in the pressure drop rate from 1 MPa/h to 5 MPa/h, decreases slightly when it increases to 6 MPa/h, but increases slightly when it increases to 7 MPa/h. The mole fraction of the heavy components such as C11+ increased significantly with the pressure drop rate from 1 MPa/h to 5 MPa/h, increased slightly to 6 MPa/h, but decreased slightly with the pressure drop rate to 7 MPa/h. This result is corroborated with the previous rule of change in the condensate recovery, indicating that the pressure drop rate has a greater impact on condensate recovery, and the reasonable increase in the pressure drop rate is more significant for the extraction and precipitation of the condensate; however, when the pressure drop rate increases to a certain extent, it will have an adverse effect on the condensate extraction.

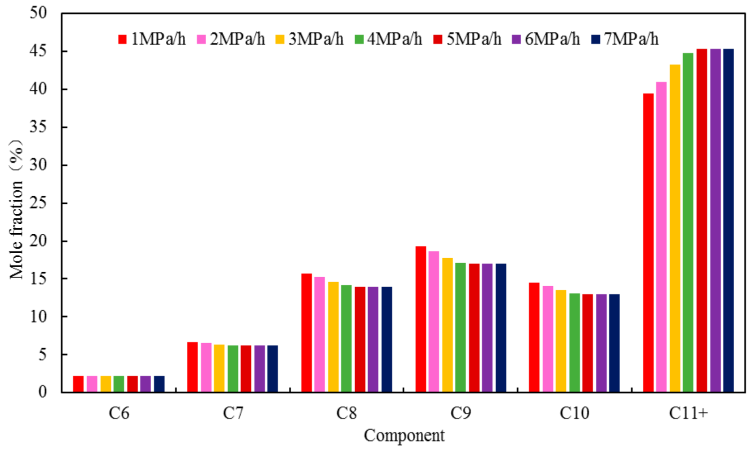
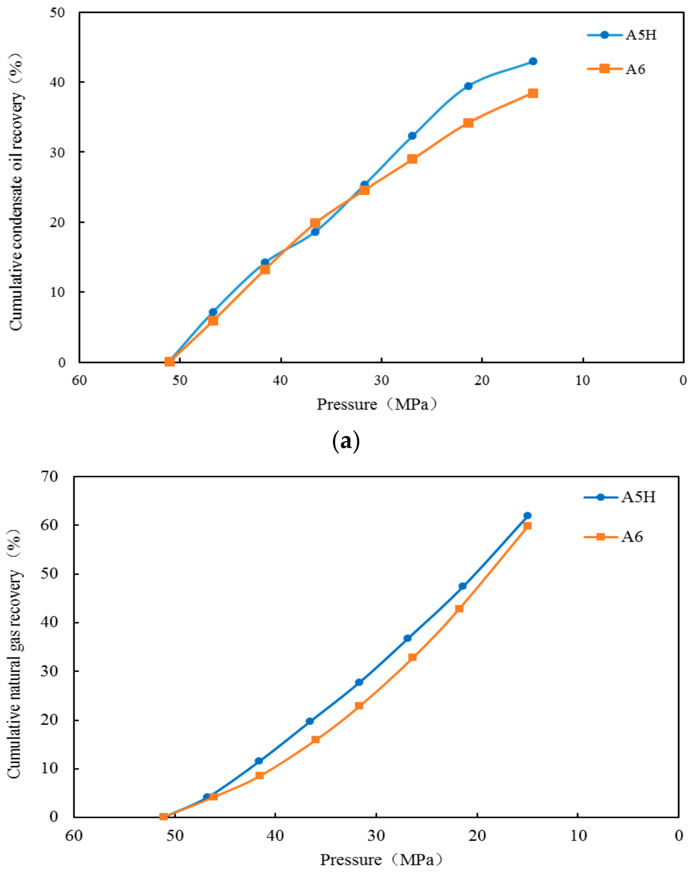


Figure 9. Mole fraction of condensate components at 35 MPa.

Based on the long core experiment, there is an influence of the fluid properties, rock properties, and length of the core on gas and oil recovery. The cores were subjected to petroleum ether and ethyl alcohol displacement to wash the cores for recycling. In the first set of experiments, the long core experiments were carried out using the formation fluids of the A6 well and A5H well with a pressure drop rate of 5 MPa/h.

Figure 10a,b are the recovery curves of the condensate oil and natural gas with different formation fluids. The final recovery rate of the condensate oil from wells A5H and A6 are 42.95% and 38.43%, respectively, and the final recovery rates of natural gas are 61.99% and 59.91%, respectively. It can be seen that the formation fluids of the A5H well with a high condensate oil content will generate more condensate oil in the process of long core depletion. The dew point pressure of the formation fluid in the A5H well is 40.89 MPa, which is lower than 44.28 MPa in the A6 well. Combined with the analysis of the precipitation change in the formation fluid retrograde condensate during the constant composition expansion process in Figure 4, it can be seen that after the depletion pressure decreases to 40 MPa, the formation fluid in the A5H well will produce a strong mist-like retrograde condensate phenomenon, and the occurrence of the retrograde condensate phenomenon will slightly reduce the condensate production amount. Therefore, the degree of condensate production in the A5 well is slightly lower than that in the A6 well when the depletion production pressure decreases from 41 MPa to 36 MPa. The experimental results illustrate that the different types of formation fluids have a significant impact on the degree of condensate oil recovery, but the fluid type has a smaller impact on the degree of natural gas recovery.

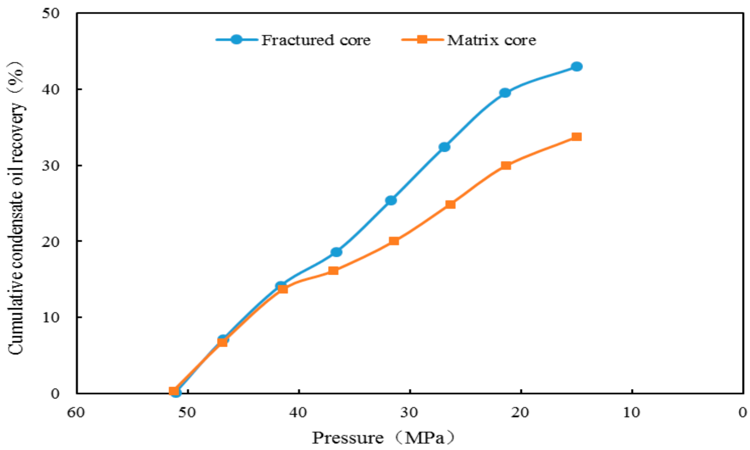


(**a**)

(**b**)

Figure 10. Comparison of the influence of fluid properties on recovery degree. (**a**) Cumulative recovery degree of condensate oil. (**b**) Cumulative recovery degree of natural gas.

In the second set of experiments, long core experiments were carried out using the unfractured core with an average permeability of 0.109 mD and an artificially fractured core with an average permeability of 0.109 mD. The pressure drop rate was set at 5 MPa/h. Figure 11a,b show the recovery of the condensate oil and natural gas with different reservoir properties. The final recovery of the condensate oil in the fractured core and matrix core are 42.95% and 33.69%, respectively, and the final recovery rates of natural gas are 61.99% and 62.02%, respectively. When the pressure decreases from 51.8 MPa to 41 MPa, the pressure is higher than the dew point pressure, there has been no retrograde condensation pollution in the core, so the cumulative recovery degree of condensate oil and gas has not changed. When the pressure is lower than 41 MPa, the formation flow begins to produce mist-like retrograde condensation pollution, and some condensate oil is adsorbed in the rock core, resulting in a decrease in the amount of condensate oil produced and a slowdown in the cumulative recovery rate of condensate oil, but due to the high permeability of fractured rock cores, formation fluids are easily extracted along high permeability channels, so the cumulative recovery rate of the condensate oil in fractured rock cores is higher than that in the matrix rock cores. As the pressure further decreases from 36 MPa to 15 MPa, some of the condensate produced by retrograde condensation is adsorbed on the pores of the matrix core due to gravity sedimentation and wetting. Most of the seepage channels were occupied by condensate, increasing the seepage resistance, resulting in an increase in the amount of condensate trapped in the matrix core and a decrease in the amount of condensate produced. Therefore, the cumulative recovery of the condensate in the matrix core showed a significantly lower than that in the fractured core. This indicates that reservoirs with different physical properties have a significant impact on the recovery of condensate oil, but have a smaller impact on the recovery of natural gas.



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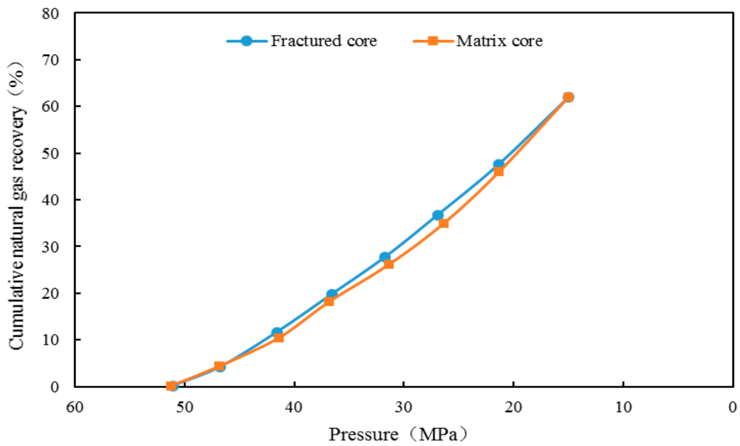

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Figure 11. Comparison of the influence of reservoir physical properties on recovery degree. (**a**) Cumulative recovery degree of condensate oil. (**b**) Natural gas recovery degree.

4. Conclusions

(1) The retrograde condensation phenomenon occurs when the reservoir pressure drops to dew point pressure. From the dew point pressure to the maximum retrograde condensation pressure, the retrograde condensation gradually becomes lighter with the decrease in the pressure. When the maximum retrograde condensation pressure is reached, the mist flow disappears and the retrograde condensate saturation reaches its maximum.

(2) A pressure value between the dew point pressure and the maximum retrograde condensation pressure is beneficial for the duration of the mist-like flow state of condensate oil, allowing for more condensate oil to be immediately taken out by the airflow after being precipitated in the mist-like flow state at an early stage, thereby reducing the blockage of the seepage channel in the near-wellbore formation caused by the retrograde condensation.

(3) A reasonable increase in the pressure drop rate is beneficial for recovering the heavy components in condensate, and the degree of condensate recovery also increases.

(4) For the formation fluid with a high condensate oil content, more condensate oil will be produced during the foggy retrograde condensation due to the non-equilibrium depletion. When the reservoir physical properties are different, the natural gas recovery rate does not change much. However, the foggy retrograde condensate fluid is easier to flow for formation with a high permeability, which corresponds to the evident improvement of the condensate oil recovery.

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