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Liquid phase blockage in micro-nano capillary pores of tight condensate reservoirs

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Abstract:
The development of tight condensate gas reservoirs faces complex formation damage mechanisms, seepage characteristics and hydrocarbon phase changes, which are common challenges for both tight gas reservoirs and condensate gas reservoirs. In the near-well area, the liquid phase blockage problem due to water phase retention formed by capillary spontaneous imbibition of invasive water and oil phase accumulation due to retrograde condensation precipitation has become a key obstacle to the efficient development of tight condensate gas reservoirs. Experiments were conducted to evaluate the damage of liquid phase blockage under different conditions near the wellbore area. The results show that when the liquid phase saturation in the near-wellbore area increased to 80.12%, the relative permeability of the gas phase decreased to 0. It is concluded that the mixed wettability of formation rocks, ultra-low water saturation, abundant hydrophilic clay minerals and high capillary resistance of micro-nano pores are the main causes for the easy adsorption and retention of liquid phase. Reduced pressure transmission capacity and irreversible formation damage induced by liquid-phase blockage are the two major controlling factors for the low liquid phase flowback rate. It is suggested that developing a flowback system based on the formation physical properties differentiation to control water phase invasion, and changing wettability or injecting thermochemical fluid to control condensate blocking are feasible methods to relieve liquid phase blockage damage in tight condensate reservoirs.

1. Introduction

The aim of low-carbon transition requires great demands on clean and efficient energy (Li et al., 2021a). Natural gas is considered to be one of the cleanest fossil fuels, with 188.1 trillion cubic meters of recoverable reserves in the world (Liang et al., 2012). Gas condensate reservoirs are the unique type of hydrocarbon reservoirs with abundant reserves and extremely high exploration and development potential (Li et al., 2021b). However, compared with dry gas reservoirs, the development and production of condensate gas reservoirs are more difficult, because a phenomenon called retrograde condensation occurs with changes in formation temperature and pressure (Bennion et al., 2001). Once retrograde condensation occurs, natural gas will condense into liquid phase and accumulate around the wellbore, resulting in significant reduction in both effective gas and total natural gas production (Muskat, 1949).

Most condensate reservoirs in China are characterized by low permeability, low porosity, high capillary pressure, and develpoed micro and nano pores. Condensate blocking will seriously hinder gas transportation from deep reservoirs to wellbore (Guo et al., 2020) through the accumulated immobile condensate oil acting as a block (Cluff and Byrnes, 2010; Liu et al., 2015; Sayed and Al-Muntasheri, 2016; Hassan et al., 2019). Existing research shows that the condensate always precipitates in the finest capillary pores first (Barsotti et al., 2016; Lowry and Piri, 2018). Due to the effect of adsorption, the condensate gradually accumulates in the micro-nano pore throat, which hinders the gas phase seepage. The

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smaller the radius of pores, the more serious the effect of capillary condensation (Elizabeth et al., 2020; Zeng et al., 2020). In addition, micro-nano pores have a significant effect on capillary condensation, as they can change the critical condensation temperature and pressure, causing a shift in the critical point (Zarragoicoechea and Kuz, 2004; Akand et al., 2015; Jiang, 2021). The tighter the reservoir, the higher the percentage of micro and nano pores, the higher the degree of influence on the critical point shift. In general, as for tight condensate gas reservoirs, condensate blockage in micro-nano capillary pores can lead to severe permeability reduction, wellhead pressure decreases, and lower gas production index. Notably, mitigating liquid phase blockage damage has become one of the engineering technology problems to be solved urgently in the oil and gas industry (Mokhtari et al., 2013; Saeed et al., 2020).

Current research on liquid phase blockage damage in tight condensate reservoirs mainly focuses on liquid phase damage range prediction, damage evaluation, and damage removal methods (Liu et al., 2015; Jin et al., 2016; Guo et al., 2020; Saeed et al., 2020; Li et al., 2021b). The phase behavior determines the profile of condensate saturation distribution near the wellbore. Numerical models and experimental measurements are widely used to analyze the behavior of hydrocarbons (Najafi et al., 2018). Condensate reservoirs can be divided into three different regions considering the phase behavior, fluid saturation profile and fluid flow capacity (Hassan et al., 2019; Panja et al., 2020). The first region refers to the two-phase flow zone near the wellbore, where the condensate saturation is greater than the critical flow saturation and both gas and liquid phases can flow directly. The second region corresponds to the case where the condensate saturation is less than the critical flow saturation, with the presence of flowable condensate gas and non-flowable condensate oil. The third region refers to the single-phase gas flow away from the wellbore, where the pressure is higher than the dew point. It is worthwhile to note that condensation in both region 1 and region 2 has a significant impact on the gas phase flow capacity, regardless of whether the condensate can flow or not (Hassan et al., 2020).

A clear understanding of the damage characteristics is needed after determining the range of condensate blocking to alleviate condensate blocking and facilitate the development of condensate reservoirs. Current methods for evaluating condensate blocking damage mainly include core damage experiments, empirical formulas, well test analysis and numerical simulations (Hassan et al., 2019; Guo et al., 2020; Panja et al., 2020). However, these methods concern more with single-factor studies of condensate blockage damage, and less on the coupling of multiple factors and various operational processes. Several treatment measures have been implemented to enhance the productivity of condensate gas reservoirs, based on the principles of removing condensate blocking, improving condensate flow capacity, and improving seepage conditions in the near-well zone (Liu et al., 2015; Hassan et al., 2019, 2020; Guo et al., 2020). The most popular methods include gas recycling, wettability alteration, and hydraulic fracturing (Liu et al., 2015; Sheng et al., 2016; Hassan et al., 2019). Nevertheless, the applicability of these treatments depends on the formation characteristics and the causes of condensate blocking, making some condensate reservoirs ineffective or even worsening the formation damage after treatment (Asgari et al., 2014). For instance, hydraulic fracturing can increase formation permeability and improve flow space, but the use of large volumes of fracturing fluid and extremely low flowback rates of this fracturing fluid can cause fracturing fluid to remain in the formation and occupy gas-phase seepage channels, resulting in water phase trapping damage (Bennion et al., 1994; You et al., 2013). Water phase trapping is one of the most serious types of formation damage in tight reservoirs, with damage rates generally as high as 70% and above (Bennion, 2002; Zhang et al., 2019a). Reducing or eliminating water phase trapping damage caused by capillary pressure has long attracted attention worldwide, and many scholars have produced excellent results (Bennion, 2002; Zhang et al., 2019a). Nevertheless, when the water phase trapping damage encounters the condensate blockage damage unique to condensate gas reservoirs, oil, gas and water phases will exist simultaneously in the near-wellbore and the gas-phase flow capacity will be significantly reduced. It is worth noting that many gas wells in the Tarim Basin, Sichuan Basin, and Bohai Bay Basin were found to have serious oil and water blockage damage in the near-wellbore zone, and the gas wells showed low or even no production (Zhang et al., 2019a; Wang et al., 2021).

The integrated liquid phase blockage induced by the retention of condensate oil and fracturing fluid becomes particularly serious in tight reservoirs with an extremely high proportion of micro-nano pores. To our best knowledge, there are few studies considering the combined effects of multiple damage factors and the superposition of time-scale formation damage. To fill this gap, current work takes gas reservoir #D in the Tarim Basin as an example, which is a typical deep tight sandstone condensate gas reservoir. This gas reservoir suffers from severe liquid phase damage in the near-wellbore area due to aqueous phase spontaneous imbibition and retrograde condensation. Herein, this paper carried out the gas drive oil-water flowback experiments, pressure transmission capacity tests, and the gas-liquid relative permeability experiments. The effect of liquid phase blockage of micro-nano pores on gas seepage capacity was investigated, and the reasons for the easy retention of the liquid phase and the low flowback rate of gas displacement were addressed. Also, feasible measures to control liquid phase blockage in tight condensate gas reservoirs were proposed. The research results of this paper can provide theoretical support for preventing and controlling liquid phase blockage damage in tight gas condensate reservoirs and improving the liquid phase flowback capability.

2. Materials and methods

2.1 Material

Samples were collected from the #D gas reservoir in the Tarim Basin, which has diverse mineral components, complex pore structures and strong heterogeneity in permeability and porosity. The Jurassic deep tight sandstone gas reservoir is in the central part of the Yiqikelike Thrust Belt (Ju and Wang,

Table 1. Basic parameters of the selected core samples and experimental plan.

Sample ID	Length (L/mm)	Diameter (R/mm)	Porosity (Φ/%)	Permeability (K/mD)	Experiment scheme
F-13-4	53.10	25.40	9.21	0.5052	Liquid phase blockage experiment with different degrees of retrograde condensation
F-13-1	52.10	25.40	9.23	0.6608	
F-13-2	43.40	25.40	9.01	0.6300	
M-3-1	45.40	25.40	9.87	0.8784	Pressure transmission capacity test
M-3-2	44.30	25.40	9.81	0.6878	
M-3-3	48.80	25.40	9.76	0.7872	
M-2-11	54.40	25.40	8.65	0.0410	Incremental pressure gradients gas displacement

Table 2. The elements analysis of the formation water.

Inorganic salt types	$NaHCO_3$	Na_2SO_4	NaCl	KCl	$CaCl_2$	Total salinity	Water type	pH value
Content (mg/L)	1785.0	8.5	6475.0	6731.0	124.3	39800.5	$NaHCO_3$	6.85

2018). The Jurassic Ahe formation in Kuqa depression, a group of lithic sandstone, is the main pay zone of this gas reservoir. It is characterized by (1) significant underground depth (> 4500 m), (2) high temperature (130∼150 °C), (3) high formation pressure (pressure coefficient of 1.73∼1.84 MPa/100 m), (4) low porosity (1%∼14%, median porosity is 7.2%), (5) low permeability (in-between permeability of the matrix is 0.075 mD under in situ effective stress), narrow pores and throats (0.01∼116.00 μm), and high percent clay minerals (7.3% by average). The clay minerals are mainly hairy and flaky illite, with an average relative content of 64.1%, followed by chlorite and illite/smectite mixed-layer minerals, potentially leading to water-sensitive, water phase trapping and fines migration damage (Wang et al., 2021). In addition, #D gas reservoir combines the development difficulties of tight and condensate gas reservoirs, with more complex formation damage mechanisms, seepage characteristics, and hydrocarbon phase change. On the one hand, the most important characteristics of the tight gas reservoir are low porosity, low permeability, and high capillary pressure. Capillary pressure is not only the driving force of fluid spontaneous imbibition, but also the resistance of flow back. This will result in the liquid phase drainage needed to overcome extremely high interfacial tension and capillary pressure, which is manifested as strong water phase trapping damage. On the other hand, under certain temperature and pressure conditions in condensate reservoirs, the near-well formation is highly susceptible to retrograde condensate damage, making the gas-phase seepage channel severely blocked and the resistance to seepage significantly increased, resulting in a dramatic decrease in production capacity. In order to evaluate the degree of liquid phase blockage and reveal the formation damage mechanisms, cylindrical cores and granular samples were selected from the same sandstone block to avoid inconsistencies. The basic physical properties of the experimental rock samples are shown in Table 1. According to the analytical data of the formation water in the stratum where the experimental rock samples are located, the formulated formation water salinity is about 39800 mg/L, and the specific contents are shown in Table 2.

2.2 Experimental procedures

2.2.1 Laboratory experiment of liquid phase blockage near-wellbore

As mentioned above, condensate reservoirs can be divided into three different regions classified by phase behavior, fluid saturation profile and fluid flow capacity. For region 1, if the condensate saturation can reach the critical flow saturation, the condensate output will make the gas-phase seepage capacity to be relieved to some extent (Hassan et al., 2020). In addition, the near-wellbore situation of gas reservoir #D belongs to the situation where condensate is immobile, with a condensate content of 74.96 g/m^3 and a maximum retrograde amount below 9%. Therefore, our study focuses on the liquid phase blockage problem in region 2. In order to simulate the liquid phase blockage in the near-wellbore zone of the reservoir after the occurrence of retrograde condensate behavior, and to explore the effect of different condensate oil saturation on the flowback process, the gas displacement experiments with varying condensate saturation under irreducible water conditions were conducted. To eliminate the gas slippage effect and ensure the accuracy of the gas measurement permeability, 1 MPa back pressure was applied to the outlet end of the rock sample (You et al., 2013; Wang et al., 2021). High-purity nitrogen was used as the experimental gas measurement medium to weaken the gas adsorption effect, and the experimental rock samples were aged under the *in-situ* effective stress (30 MPa) for 24 h before the experiment to eliminate the time-dependent creep effect. The experimental apparatu is shown in Fig. 1, and the specific steps are as follows: (1) representative sandstone samples were selected, whose weight, permeability, and porosity were measured; (2) the initial water saturation S_{wi} (20%) was established based on oil-based drilling fluid sealing coring data and nuclear magnetic resonance (NMR) logging

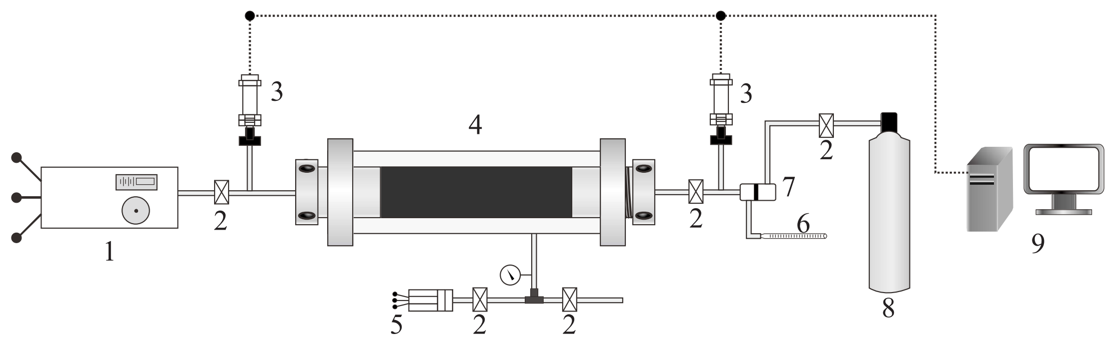

Fig. 1. Diagram of gas displacement flowback experimental device. 1-pump, 2-valve, 3-pressure sensor, 4-core holder, 5-confining pressure system, 6-glass tube flow meter, 7-back pressure valve, 8-gas cylinder, 9- data capture system.

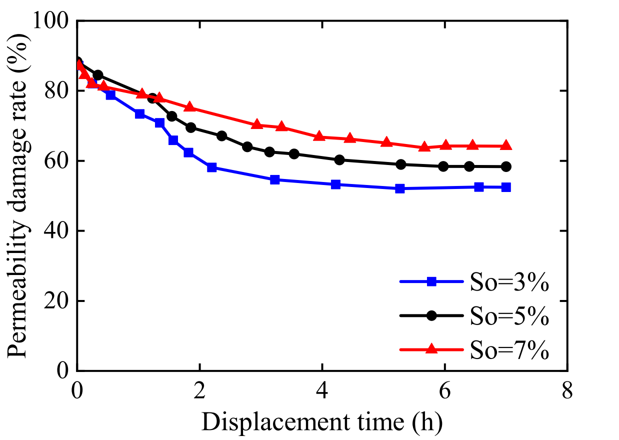

Fig. 2. Damage rate of liquid phase blockage with different degrees of retrograde condensation.

data; (3) the initial gas permeability K_o was measured, back pressure was set at the outlet (You et al., 2013); (4) the spontaneous imbibition experiments of formation water were conducted, and the experimental time was set 12 h; (5) the gas displacement experiments were conducted at an confining pressure of 7 MPa and a pressure gradient of 0.3 MPa/cm, and the cores were displaced to the irreducible water saturation; (6) the capillary self-absorption method was used to establish the oil saturation of 3%, 5% and 7% in order to simulate the precipitation of condensate after the occurrence of retrograde condensate behavior; (5) the experimental sample was displaced by gas at a confining pressure of 7 MPa and a pressure gradient of 0.3 MPa/cm, and the weight of core samples every 20 min was measured; (6) the permeability K_i was measured after the displacement, and the degree of liquid blockage damage was also evaluated (Mahadevan et al., 2007).

2.2.2 Gas-liquid relative permeability

The gas-liquid permeability curves were tested by the gas displacement method (You et al., 2013; Amin et al., 2021), and the specific experimental steps were as follows: (1) the capillary self-absorption method was used to establish the different water saturation, and the gas flow of the rock sample was measured under the condition of constant pressure difference; (2) the desiccant device was connected to the outlet end of the rock sample, and the quality difference produced before and after the displacement experiment was calculated by the water absorption property of the desiccant, and the relative permeability of the liquid was calculated; (3) the core saturation was established as the irreducible water saturation by the gas displacement method, and the gas phase permeability was measured as the initial permeability, and the oil saturation was increased in turn to determine the relative permeability of the gas phase under the condition of irreducible water.

3. Results and discussion

3.1 Effect of liquid-phase blocking near the wellbore on gas-phase seepage capacity

Fig. 2 shows the temporal variations of permeability damage rate under gas displacement for three tight sandstone samples with different retrograde condensate saturation. Under natural flowback of gas displacement, the rapid drainage of tight sandstone mainly occurs in the first 4 h. At this time, as the degree of retrograde content becomes higher, the pressure is harder to transimit to the micro-pores and the gas phase permeability decreases more. After the end of the drainage, the permeability damage rate of three rock samples were 54.46%, 62.31% and 66.23%, respectively. It can be seen that the relative permeability of the gas phase gradually decreases with the increase of condensate content when part of the pore space is occupied by irreducible water.

Fig. 3 shows the gas-oil relative permeability, gas-irreducible water and oil phase relative permeability curves. Compared with the relative permeability of gas-oil two phase, the relative permeability of both gas phase and liquid phase decrease significantly in the process of increasing oil saturation based on irreducible water saturation. In addition, the co-permeable zone of the gas phase and liquid phase is narrow, and the isotonic point is extremely low, with a value of 0.0237 of the relative permeability. The relative permeability of the gas phase drops to zero when the saturation of the liquid phase increases to 80.12%, and only liquid phase seepage exists at this time (Cluff and Byrnes, 2010). Fig. 4(a) shows the initial state of the gas reservoir, in which gas phase occupies the macro/meso-pore channels and initial water occupies part of the meso/micro pore channels. After large-scale hydraulic fracturing, a large amount of fracturing fluid enters the reservoir and occupies the main seepage channels, which could be adsorbed by the hydrophilic clay minerals, and be spontaneously imbibed into the deep area of the formation

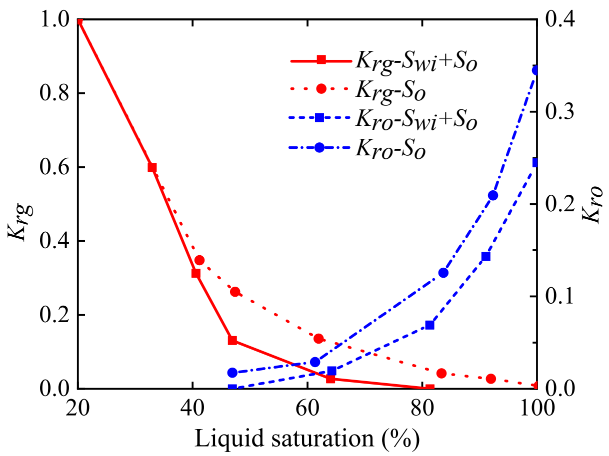

Fig. 3. Comparison of gas-oil and gas-irreducible water and oil phase relative permeability curves.

under the action of capillary pressure (Cai et al., 2021; Qi et al., 2021) (Fig. 4(b)). A large amount of water phase is trapped in the formation in the state of irreducible water to occupy micro-pore spaces and blind areas of pore spaces, untimately resulting in an extremely low flowback rate (Fig. 4(c)). At this time, the gas phase occupies the macro-pore channels and part of the micro-pore pore channels, forming the stable seepage channels. Under such a situation, the permeability could be recovered to some extent. As the formation temperature and pressure are changed, the retrograde behavior makes the condensate gas that occupies the macro/meso pore channels transform into condensate oil (Shi et al., 2015). With the increase of condensate saturation, the liquid phase cut the gas phase into a discontinuous phase, which in turn leads to the trapping of condensate gas (Fig. 4(d)). At this moment, the gas is mainly coalesced and transported through the pore-throats in the form of microbubbles. Bubbles collide with each other and become larger in the process of flow and transportation. Large bubbles are difficult to pass through the micro-nano pore throats and will be sheared into microbubbles suspended in the liquid, ultimately leading to the failure of the gas phase to form

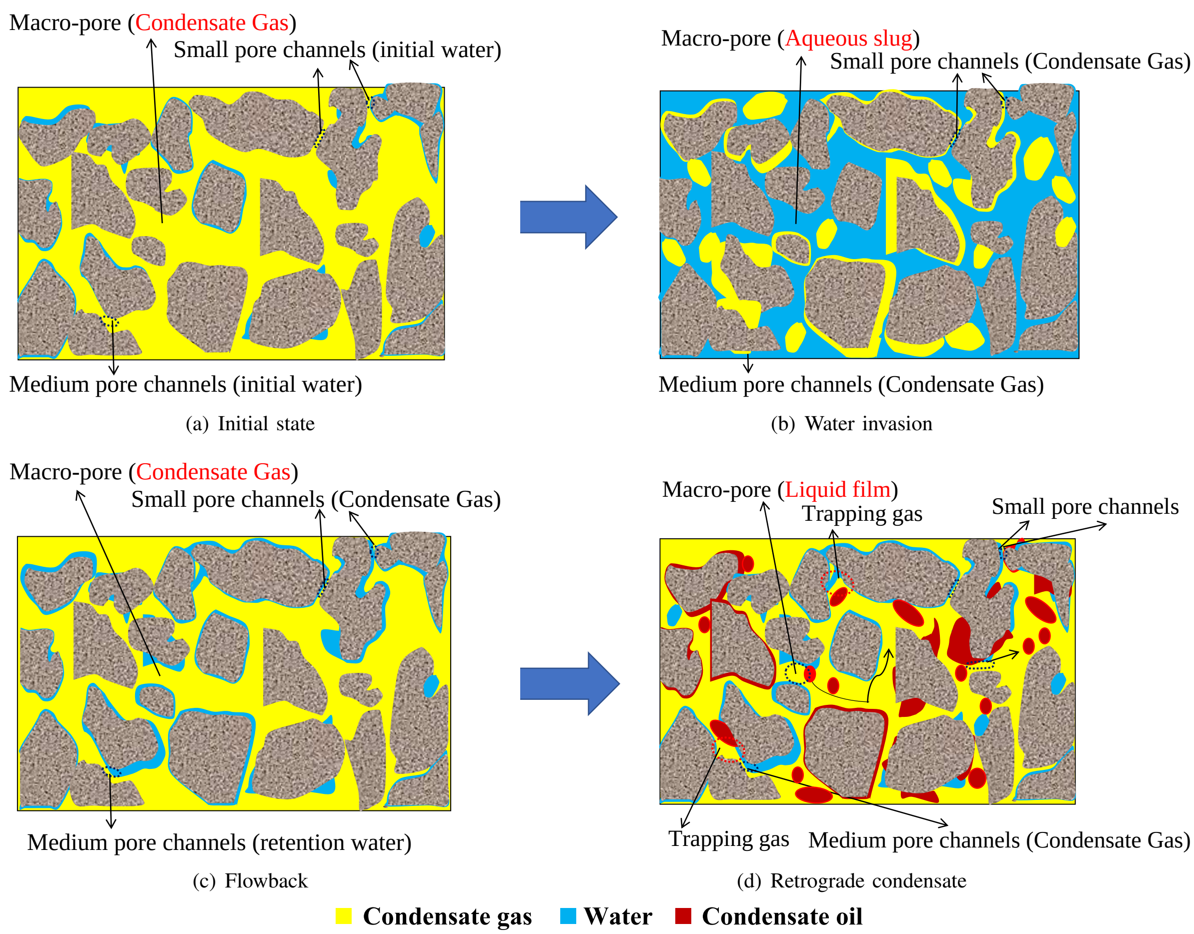

Fig. 4. Schematic diagram of gas-liquid distribution state at different time scales in micro-nano capillary pores of tight condensate reservoirs. (a) The initial state of the reservoir, condensate gas and initial water; (b) fracturing fluid spontaneous imbibed into the deep parts of the formation under the action of capillary pressure; (c) a large amount of fracturing fluid retention after flowback; (d) retrograde condensate and retained water phases disrupt the continuous state of the gas phase, causing the condensate gas to be trapped.

the stable seepage channels (Cluff and Byrnes, 2010; Tian et al., 2021). The macroscopic manifestation of this phenomenon is a decrease in the relative permeability of the gas phase and a decline in the gas production capacity of the reservoir.

3.2 High retention rate of liquid phase

3.2.1 Ultra-low water saturation and significant liquid phase retention

Ultra-low water saturation refers to the special phenomenon that the initial water saturation of oil and gas reservoir is much lower than the irreducible water saturation, which is closely related to the hydrocarbon-generating environment, formation temperature and fracture development characteristics (You et al., 2013; Zhang et al., 2019a). The initial water saturation of the #D gas reservoir as interpreted by the logging data is 18%∼36%, and the irreducible water saturation from laboratory experiments is 40.9%∼62.8% with a mean value of 54.7%, and the NMR irreducible water saturation is 37.8%∼63.5% with a mean value of 50.2% (Wang et al., 2021). Therefore, it can be concluded that there is a local ultra-low water saturation phenomenon in the #D gas reservoir. This is mainly caused by the large thickness of the hydrocarbon source rock layer in gas reservoir #D and the high intensity of hydrocarbon generation and drainage, coupled with the development of natural fractures. The generation, transport and accumulation of hydrocarbons lead to the continuous discharge of formation water from the reservoir by natural gas, and this process is further exacerbated by the well-developed fractures.

The existence of the ultra-low water saturation phenomenon is one of the important reasons that unconventional gas reservoirs can provide economic recovery value (Tian et al., 2020). This both increase the realistic reserves of the reservoir and create significant engineering operational hazards, which also arouses serious liquid phase trapping damage concerns. Additionally, this phenomenon also causes the excess capillary pressure of the formation rock to be unbalanced by bound water, resulting in significant capillary spontaneous imbibition. As can be seen from Fig. 5, the initial water saturation is much lower than the irreducible water saturation in gas reservoir D. After the water phase spontaneous imbibition and flowback, part of the water phase in the macropore can successfully flowback, but a large amount of pore water cannot flowback, and the water phase trapping damage caused by the increase of water saturation from initial one to irreducible one is permanently-irreversible damaged (as shown in the yellow area in Fig. 5).

The TX500C contact angle measurement system was used to evaluate the contact angle of the wetting fluid to the tight sandstone of the #D gas reservoir, and the wetting fluid included simulated formation water and condensate oil. The wettability test results show that the wetting fluid spreads to the rock surface immediately after contacting the rock, which indicates that the formation rocks have strong mixed wettability, that is, the rocks are both hydrophilic and lipophilic (Fig. 6). The water phase of the capillary spontaneous imbibition into the reservoir and the oil phase of the retrograde condensation precipitation both have extremely strong adsorption and retention effects (Diao et al., 2021; Wang et al., 2022).

3.2.2 The failure of formation pressure difference to overcome the high capillary pressure

High capillary pressure is one of the key factors for liquid phase retention, and the degree of liquid phase drainage flow-

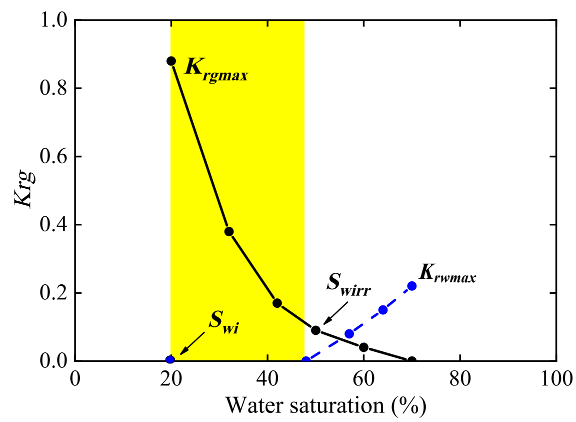

Fig. 5. The role of ultra-low water saturation in liquid phase trapping damage (Modified by Bennion, 2002).

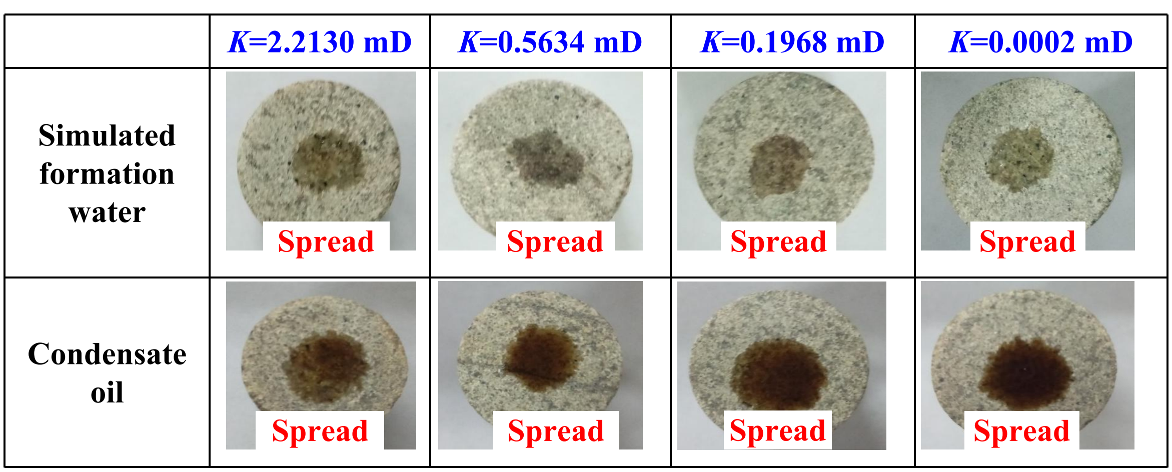

Fig. 6. Rock wettability test results.

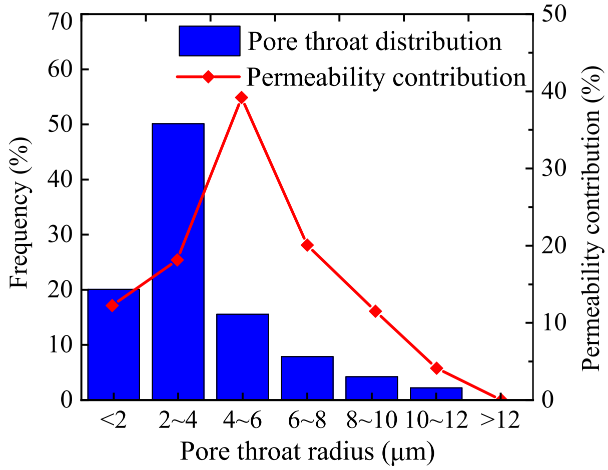

Fig. 7. Core pore throat distribution and permeability contribution.

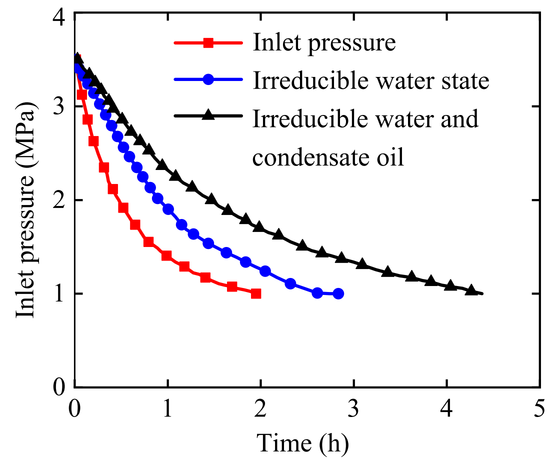

Fig. 8. Pressure transmission capacity test curve under different conditions.

back is related to the pressure drop provided by the reservoir (Tian et al., 2021). $(K/\varphi)^{0.5}$ is defined as the composite physical index of the formation rock, which can approximately represent the average pore throat radius of the rock. The calculation shows that the average pore throat radius of gas reservoir #D is less than 0.1 μm. Condensate will first precipitate in these nano-pores and cover the walls of the pores as a liquid film of variable thickness (Barsotti et al., 2016; Lowry and Piri, 2018). High specific surface area of rock skeleton particles and a large number of minerals make the rock have a strong adsorption effect, which causes the condensate to gradually accumulate and retain in the micro-nano pore throats, hindering gas-phase seepage (Elizabeth et al., 2020). The smaller the radius of pores, the more serious the effect of capillary condensation is (Barsotti et al., 2016). In addition, micro-nano pores have a significant effect on capillary condensation, as they can change the critical condensation temperature and pressure, causing a shift in the critical point (Zarragoicoechea and Kuz, 2004; Akand et al., 2015). The capillary condensation effect affects the dew point pressure of condensate reservoirs, leading to an increase in the upper dew point and a decrease in the lower dew point, resulting in actual retrograde condensate behavior occurring earlier, a larger retrograde condensate interval, and more condensate precipitated. The tighter the pore structure of formation (higher percentage of micro and nano pores), the greater the effect is (Gao et al., 2018). In general, condensate blockage in micro-nano capillary pores can lead to tight condensate gas reservoirs suffering from severe permeability reduction.

Fig. 7 exhibits the mercury intrusion results. It can be seen that the pore throat radius of the formation rock is ranging from 0.01 to 12.00 μm, the median pore throat radius is 2~3 μm, and the pore throat interval which contributes to the permeability is mainly between 4~6 μm. According to the empirical model of capillary pressure $P_c = 0.735/r$, the smaller the pore throat radius tends to exhibit a larger capillary pressure. Most of the pore throat radius of tight reservoir rocks is less than 0.1 μm, and the capillary pressure can be as high as tens or even hundreds of megapascals. When multiple throats are connected in series, the accumulated capillary pressure will be insurmountable for formation pressure difference. In addition, capillary pressure is the driving force when the fluid is spontaneously imbibed and the resistance in the opposite process (Tian et al., 2020). The abnormally high capillary pressure will make the liquid phase invade deeper and make it more difficult to displace the liquid phase from the micro-nanopore throats.

3.3 Low liquid phase flowback rate for gas drive

3.3.1 Effect of three-phase complex seepage on pressure transmission capacity

The gas-liquid relative permeability curve shows that a slight increase in the saturation of the liquid phase will result in a significant decrease in the effective permeability of the gas phase (Amin et al., 2021). Due to the aqueous spontaneous imbibition and retrograde condensation, a multiphase complex seepage of oil, gas and water simultaneously exists in the tight gas condensate reservoir near the wellbore. The invaded water phase and the precipitated oil phase are contained in the macro-pore throats and fine pores, which significantly reduces the gas flow capacity of tight sandstones, causes a significant reduction in the pressure transmission capacity of tight cores and ultimately affects the flowback capacity. The results of the pressure transmission capacity experiments are shown in Fig. 8. Compared with the initial state, the decline time of the pressure at the entrance end of the tight core in the irreducible water state is extended from 38 to 68 min when the pressure decays from the initial pressure to half of its value. After the subsequent spontaneous imbibition of condensate, the decline time was extended from 38 to 113 min, with a increase of 1.97 times. Considering that the permeability measured in laboratory experiments is generally larger than the permeability under *in-situ* effective stress, the permeability is only about 1/3~1/8 of the permeability under laboratory test conditions if it is corrected to *in-situ* conditions. Therefore, under the formation stress conditions, the trend of decreasing permeability of tight rocks caused by liquid phase retention is more obvious, the pressure transmission rate will become slower, and the resistance to liquid phase flowback is greater.

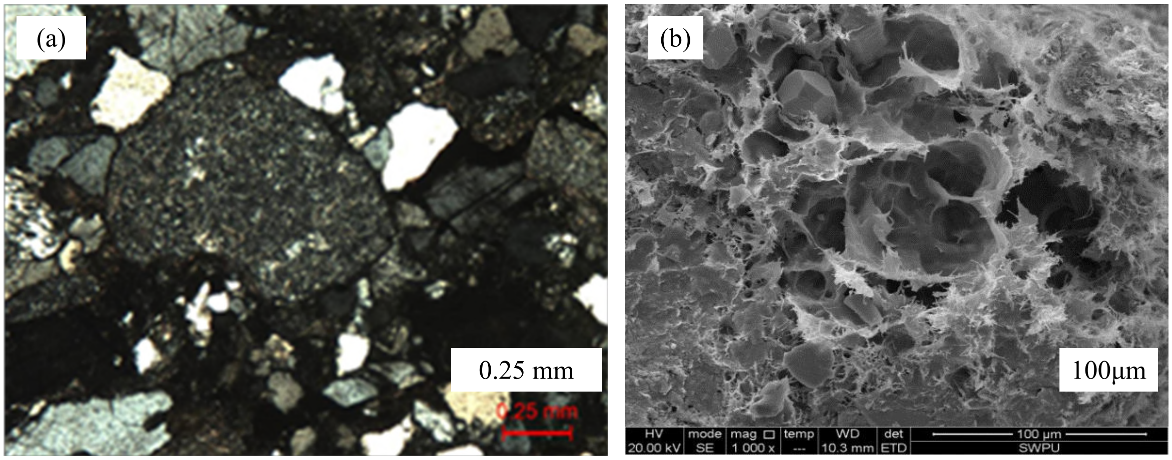

Fig. 9. Rock mineral characteristics and microstructure. (a) Thin section analysis results show that the rock framework grains are mainly quartz and feldspar, and has a huge specific surface; (b) SEM results show that scanning electron microscopy results show that hairy illite is abundantly deposited between the pores, cutting the pores into smaller ones.

3.3.2 Liquid-phase adsorption and retention by sensitive minerals

The results of the thin section analysis show that the rock framework grains of the formation are mainly quartz and feldspar, and the rock framework has a huge specific surface (Fig. 9(a)). The huge specific surface makes the rock have strong liquid-phase adsorption capacity, and the liquid-phase flowback needs to overcome the capillary pressure and the adsorption resistance of the mineral surface at the same time, which makes the flowback difficult (Hassan et al., 2019; Zhang et al., 2019b). The analysis of mineral composition reveals that experimental rocks are dominated by quartz (79.5%) and feldspar (11.7%) with a small amount of clay minerals (8.8%). The clay minerals are dominated by illite (66.5%), followed by illite/smectite interstratified clay minerals (18.1%), chlorite (10.9%) and kaolinite (4.5%). A large number of clay minerals is deposited between the rock framework grains of the reservoir, and the clay minerals cut the main seepage channels in the formation into smaller pores (Fig. 9(b)). The invaded water phase and the precipitated oil phase are contained in the macro-pore throats and fine pores. The wetting fluid in the large pore throat can be drained because it can form a dominant flow channel. Nevertheless, it is difficult for the liquid phase inside the fine pore throats to be affected by the pore pressure, resulting in the liquid phase being trapped and difficult to flowback. Eventually, the permeability of the main seepage channel of the rock sample is significantly reduced. In addition, quartz, feldspar and clay minerals such as kaolinite, illite and illite/smectite mixed layer are hydrophilic minerals (Fig. 9(b)). Once the tight sandstone is contacted with water, spontaneous imbibition of the water phase occurs. Water-sensitive damage is also likely to occur when the invaded water phase is in contact with water-sensitive minerals such as illite and illite/smectite mixed layer, resulting in pore throat blockage and low permeability recovery during flowback.

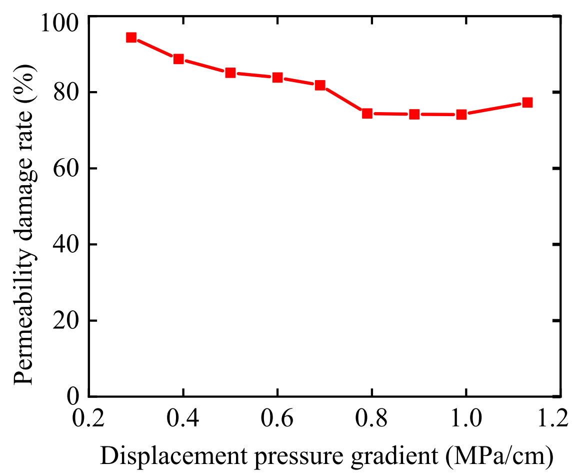

Fig. 10. The curve of permeability damage rate under different flowback pressure gradients.

3.3.3 Liquid phase blockage caused by irreversible formation damage

Retention of the liquid phase in the near-wellbore area induces fluid-sensitive and liquid-phase trapping damage, enhances stress-sensitive damage and reduces gas-phase permeability (Liu et al., 2015; Zhang et al., 2019a; Wang et al., 2021). In addition, condensate precipitation may also induce wax precipitation, scaling and emulsification problems, further reducing formation permeability (Hassan et al., 2019; Guo et al., 2020). As well-known, most of these damages are irreversible and it is difficult to restore the initial seepage capacity of the formation even with other remedial measures. The results of the gas displacement experiments with incremental pressure gradients are shown in Fig. 10. The experimental results show that the incremental pressure gradient flowback also shows the characteristics of fast flowback at the early stage and slow flowback at the later stage, with a low final flowback rate and a large amount of liquid phase retention. Even if the pressure gradient is increased, the liquid phase in the fine pore throat is still difficult to displace. On the contrary, the flow rate is too high due to the high differential pressure of the displacement, which can induce velocity-sensitive damage. The field case study shows that high permeability and high production condensate gas wells have high fluid-carrying capacity due to the capillary number effect, which can mitigate retrograde condensate damage and formation damage caused by retained fluid to a certain extent. However, tight and low-production condensate gas wells have the poor liquid-carrying capacity, and it is difficult to mitigate formation damage with higher pressure gradients. Instead, they may induce fines migration damage, aggravate formation damage, and restrict gas well productivity.

3.4 Liquid phase blockage prevention and control method

The water phase of the capillary spontaneous imbibition into the reservoir and the oil phase of the retrograde condensation precipitation both have extremely strong adsorption and retention effects, and the degree of gas displacement flowback is low, resulting in serious blockage of the liquid phase in the near-wellbore zone and low gas-phase flow capacity (Hassan et al., 2019; Guo et al., 2020). Based on the experimental results and related analysis, more measures should be taken, focusing on preventing the invasion of the water phase or promoting its rapid discharge from micro-nano pores. The following technical measures can be implemented to reduce the degree of liquid phase blockage damage in tight sandstone condensate gas reservoirs: (1) optimize the properties of fracturing fluids, develop a flowback system based on the differentiation of formation physical properties to control water phase invasion, reasonably control the scale of stimulation (Tian et al., 2020, 2021), achieve less invasion and faster flowback to reduce water phase trapping damage; (2) use surfactants or nanoparticles to control the spontaneous imbibition and wetting behavior of fracturing fluid and reduce the degree of spontaneous imbibition (Dong et al., 2019; Wang et al., 2021; Mansour and Gamadi, 2022); (3) adopt interface modification technology to change formation mixed wetting to gas wetting (Liu et al., 2015); (4) inject thermochemical fluid (Hassan et al., 2018, 2020), heat up and exothermic to convert condensate oil to condensate gas. At the same time, exothermic also can make the water phase vaporization, relieving the liquid phase blockage damage.

4. Conclusions

1) The near-wellbore zone of deep tight condensate reservoirs suffers from severe liquid-phase blockage damage due to the aqueous phase spontaneous imbibition and retrograde condensation.
2) The mixed wettability, ultra-low water saturation, abundant hydrophilic clay minerals and high capillary resistance of micro-nano pores intensified the invasion and retention of invasive water phase, and the adsorption and retention of condensate oil phase.
3) Complex three-phase seepage in the near-wellbore zone reduces the pressure transmission capability and irreversible formation damage induced by liquid-phase blockage are the major contributing factors to the low degree of oil and water drainage from gas displacement.
4) Reducing the scale of water phase invasion, developing a flowback system based on the differentiation of formation physical property to control water phase invasion, and changing wettability or injecting thermochemical fluid to control condensate blocking are feasible methods to prevent and control liquid phase blocking damage in tight condensate reservoirs.

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Conflict of interest

The authors declare no competing interest.

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