Experimental Study on the Effects of Pore Pressure and Slippage on the Permeability of a Fracture Network during Depressurization of Shale Gas Reservoir Production

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ABSTRACT: Hydraulic fracturing technology is an important technical means to increase shale gas production. The seepage channels formed in the hydraulic fractures during hydraulic fracturing can help increase reservoir permeability. Therefore, it is of significance to study the seepage law of the fracture network after reservoir hydraulic fracturing. In this study, hydraulic fracturing is used to fracture full-diameter shale cores, and three typical forms of hydraulic fracture networks are obtained. The characteristics of the fracture networks are analyzed by X-ray CT scanning. The effects of pore pressure and slippage on the permeability of the fracture networks are simulated by conducting experiments. The experimental results show that in the direction of gas seepage, hydraulic fractures completely penetrate the sample, and the greater the diameter and volume of the fracture, the better the hydraulic fracture conductivity. When the confining pressure remains unchanged at 50 MPa, the apparent permeability values of the hydraulic fractures with the worst and best fracture morphologies increase by 44.4 times and 2.8 times, respectively, with the decrease in the pore pressure from 30 to 2 MPa. The apparent permeability of the shale samples has a power function relationship with the pore pressure. The test results also show that the absolute permeability is positively correlated with the number of effective seepage channels in the hydraulic fractures and the number of hydraulic fractures, whereas the Klinkenberg coefficient is negatively correlated. Our research results can provide a basis for shale gas production model research and for on-site production capacity improvement. The qualitative understanding and scientific explanation of the effects of pore pressure and slippage on fracture network permeability in the process of depressurization of reservoir production have been realized.

1. INTRODUCTION

In recent years, significant progress has been made in the commercial development of shale gas, and the permeability of shale reservoirs is an important indicator for evaluating the recoverability of shale reservoirs. The permeability of shale reservoirs is extremely low, which significantly affects the production of shale gas. The permeability of a shale matrix is between $10^{-12}$ and $10^{-18}$ m$^2$, and the permeability of shale fractures is between $10^{-6}$ and $10^{-4}$ m$^2$. Clearly, the permeability of shale fractures is higher than that of the shale matrix. Therefore, it is necessary to reform the shale reservoir to increase the number of fractures therein and expand the seepage channels of shale gas. The commonly used reservoir reconstruction technology is hydraulic fracturing. Hence, it is important to evaluate the seepage channels formed during hydraulic fracturing and study the variation in the permeability of shale during the mining process.

The Brazilian splitting method is used to create microfractures in shale, and shale samples containing natural fractures are used to study the change law of the gas permeability in the fractures. The permeability of shale fractures is affected by the effective stress along different paths. The internal pressure remains unchanged, and the increase in the external pressure can help effectively reduce the permeability of shale fractures. The relationship between the effective stress and shale fracture permeability can be characterized using the exponential model and power model. In addition to the effective stress, the permeability of shale fractures is affected by the external temperature and gas adsorption characteristics. The fracture characteristics of the shale itself cannot be ignored. The fracture conductivity is positively correlated with the penetration and opening of fractures. The permeability of shale fractures is affected by the roughness and tortuosity of the fractures and also by the gas slippage phenomenon. As a result, the measured permeability is

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Received: December 21, 2021
Accepted: March 17, 2022
Published: April 12, 2022
greater than the actual value. The lower the pore pressure, the more evident the slippage effect and the greater the error in the measured permeability.

Generally, in previous studies on the permeability variation of shale fractures, most of the fractures were artificially induced using the Brazilian splitting method, and shale samples containing natural fractures were used. The effects of effective stress, fracture roughness, and other factors on the permeability of shale fractures were studied. However, there has been no further study on the use of hydraulic fracturing to obtain shale samples with hydraulic fractures and the law of permeability variation in hydraulic fracture networks. Therefore, we prepared shale core samples with water-bearing fractures through hydraulic fracturing experiments. The X-ray CT scanning was used to observe the shape of the hydraulic fractures and analyze their characteristics and conductivity. The steady-state method was used to simulate the reservoir mining process to study the permeability changes in the hydraulic fracture network with the decrease in the reservoir pressure and to analyze the influences of the pore pressure and slippage on the permeability of the hydraulic fracture network. Our work will be of theoretical significance for guiding hydraulic fracturing and the efficient development of shale gas reservoirs.

2. MATERIALS AND METHODS

2.1. Sample Preparation. The shale samples used in the experiment were taken from the outcrop shale of the Longmaxi Formation that naturally extends the shale gas reservoir in Yibin, Sichuan. This area is currently one of the main areas for commercial development in China. X-ray diffraction (XRD) analysis showed that the shale samples are mainly composed of quartz, feldspar, carbonate, clay minerals, and other minerals. Among them, quartz accounted for 44.1%, feldspar and carbonate accounted for 34.1%, clay minerals accounted for 16.4%, and other minerals accounted for 5.3%.

Figure 1 shows the preparation process of the water-bearing fractured shale sample. A cylindrical core with a diameter of 100 mm was obtained from the shale test block using a rock core machine. The shale core length was processed to 150 mm using a rock cutter. In the process of coring and cutting, water was used as a lubricant to reduce the damage during sample processing. The sample size was determined using the shale hydraulic fracturing experimental device. A fracturing injection hole with a diameter of 10 mm and a length of 75 mm was taken from the middle of the shale core using a drilling machine. The fracturing fluid injection pipe and the fracturing fluid injection hole drilled into the core were injected through an epoxy resin glue. To
obtain the full-diameter core sample of the water-bearing fracture, the full-diameter core hydraulic fracturing test device independently developed by Liaoning Technical University was used to hydraulically fracture the full-diameter core.

Representative hydraulic fracture patterns in the shale samples after hydraulic fracturing were selected. Figure 2 shows the selected representative samples of the shale after hydraulic fracturing. Table 1 presents the hydraulic fracturing parameters of the selected shale samples. In the direction of gas flow, the hydraulic cracks of the LMX-1 sample are only in the upper half of the sample. Moreover, the hydraulic fracture has a small opening, and the lower half of the sample is still a shale matrix. The hydraulic cracks of the LMX-2 sample and the LMX-3 sample penetrated the upper and lower end faces of the sample. The hydraulic crack opening of the LMX-3 sample is greater than that of the LMX-2 sample.

Table 1. Hydraulic Fracturing Parameters of Shale Samples

| Shale sample | Bedding inclination α (°) | In situ stress $\sigma_1/\sigma_3$ (MPa) | Injection rate $q$ (L/min) | Stress contrast coefficient $K_c = (\sigma_1 - \sigma_3)/\sigma_3$ | Breakdown pressure $P_{flow}$ (MPa) |
|--------------|--------------------------|----------------------------------------|---------------------------|-------------------------------------------------|---------------------------------|
| LMX-1        | 0                        | 59/54                                  | 2.4                       | 0.99                                            | 89.1                            |
| LMX-2        | 90                       | 59/59                                  | 2.4                       | 0                                               | 81.2                            |
| LMX-3        | 60                       | 59/59                                  | 2.4                       | 0                                               | 70.5                            |

2.2. Experimental Apparatus. The high-pressure full-diameter core seepage experimental system of the State Key Laboratory of Enhanced Oil Recovery Research Institute of Petroleum Exploration & Development was used to conduct the seepage experiment on the water-bearing fractured shale core. Figure 3 shows the laboratory status and apparatus of the seepage experiment on the water-bearing fractured shale core. Petroleum Exploration & Development was used to conduct the Laboratory of Enhanced Oil Recovery Research Institute of the seepage process in the reservoir mining process. The experimental device mainly simulates the gas seepage process in the reservoir mining process. The experimental device comprises a full-diameter core holder, a pore pressure loading system, a confining pressure loading system, a flow acquisition system, and a data acquisition system. The full-diameter core holder can hold a core sample with a diameter of 100 mm and a length of 200 mm. The pore pressure loading system allows a maximum gas pressure of 58.5 MPa, and the loading accuracy of 0.05 MPa. The flow acquisition system can achieve a confining pressure of 60 MPa and a loading accuracy of 0.1 MPa. The flow acquisition system uses the drainage method to measure the gas flow, with a minimum measurement accuracy of 0.2 mL. The data acquisition system collects the pore pressure and confining pressure data during the permeability test.

2.3. Experimental Methods and Procedures. The steady-state method is used to calculate the apparent permeability of the sample. The principle of this method is Darcy’s law. The gas at the pressure $P_{in}$ is introduced from the inlet end of the sample, the gas flows through the percolation channel inside the sample to the outlet end of the sample, the gas pressure becomes $P_{out}$ and the gas flow rate $Q_{out}$ is measured. After the gas flow rate is stable, the apparent permeability of the sample can be calculated, as follows:

$$k = \frac{2P_{out}Q_{out}\mu L}{(P_{in}^2 - P_{out}^2)A}$$

where $k$ is the apparent permeability ($10^{-3}$ μm$^2$), $Q_{out}$ is the flow rate (cm$^3$/s), $A$ is the cross-sectional area of the specimen (m$^2$), $P_{in}$ is the atmospheric pressure (MPa), $P_{out} = 0.101325$ MPa, $P_{in}$ and $P_{out}$ are the gas pressures upstream and downstream of the specimen (MPa), respectively, $L$ is the specimen length (m), and $\mu$ is the hydrodynamic viscosity (Pa·s).

Before the experiment, it is necessary to plug the fracturing holes in the sample with epoxy resin and then dry the sample to eliminate the influence of residual moisture in the shale. The sample drying temperature was 105 °C, and the drying time was 24 h. The following test steps were then implemented:

1. Connect the experimental device and check the airtightness of the system.
2. Place the test sample in such a way as to ensure good airtightness of the experimental device.
3. Increase the confining pressure to the test value of 50 MPa and introduce methane gas into the sample. Stabilize the inlet gas pressure at 30 MPa so that the test sample is stably adsorbed for 72 h.
4. Open the outlet valve. Use the drainage method to measure the gas flow at the outlet. When the gas flow rate
remains constant for 3 h, read and record the gas flow value.

(5) Reduce the inlet gas pressure to 25, 20, 15, 10, 8, 6, 4, and 2 MPa and measure the gas flow at the outlet.

(6) Replace the sample and repeat steps (2)−(5). Preprocess the recorded data after the experiment.

3. RESULTS AND DISCUSSION

3.1. Analysis of the Morphological Characteristics of Hydraulic Fractures. An observation of the fracture morphology of the shale samples after hydraulic fracturing showed that hydraulic fracturing can form a complex network of fractures in the shale. This is beneficial to increase the permeability of shale samples. The shale sample was scanned by an X-ray CT scanner, and the hydraulic fracture morphology of the shale was reconstructed, with a scanning accuracy of 58.5 μm. The parameters of the hydraulic fractures were extracted using VGSTUDIO MAX 3.5 software, and the fracture volume and diameter distribution status of the hydraulic fractures in the shale were obtained.

Figure 4 shows the spatial shape of the hydraulic fractures in the shale and the distribution of the volume of the hydraulic
Figure 4a shows that the hydraulic fracture morphology of the LMX-1 sample takes the shape of "λ". The hydraulic fractures penetrate the side of the shale sample obliquely, and the hydraulic fractures are distributed in the upper half of the shale sample. Based on the scale of the fracture volume in the figure, there are tiny hydraulic fractures near the wellbore, and the hydraulic fracture openings are distributed uniformly as a whole. The total volume of the hydraulic fractures is 3785.98 mm³, which accounts for 0.321% of the volume of the entire shale sample.

Figure 4b shows that the hydraulic fracture morphology of the LMX-2 and LMX-3 samples is "Γ". The hydraulic fracture penetrates the shale sample both horizontally and vertically. The horizontal hydraulic cracks are distributed in the upper half of the shale sample, and the vertical hydraulic cracks are distributed in the edge area of the shale sample. The total volume of the hydraulic fractures of the LMX-2 sample is 5602.34 mm³, which accounts for 0.476% of the volume of the entire shale sample. The total volume of the hydraulic fractures of the LMX-3 sample is 15 081.07 mm³, which accounts for 1.280% of the volume of the entire shale sample.

Figure 5 shows the fracture diameter distribution of the hydraulic fractures and their contribution to the volume of hydraulic fractures.

Figure 5a–c shows the distribution of the hydraulic fracture diameter of the LMX-1 sample from 58.5 to 109 429.23 μm, with the main range being 200–400 μm. The diameter distribution of the hydraulic cracks in the LMX-2 sample ranges from 58.5 to 166 900.15 μm, with the main range being 100–400 μm. The diameter distribution of the hydraulic cracks in the LMX-3 sample ranges from 200 to 169 102.20 μm, with the main range being 400–800 μm. The number of hydraulic cracks in the three samples increases as the diameter of the hydraulic crack increases, and the number of hydraulic cracks first increases and then decreases. The number of hydraulic cracks in the three samples is less than 10 000 μm, accounting for 99% of the total number of hydraulic cracks. Although the number of hydraulic fractures below 10 000 μm accounted for the vast majority, 99% of the hydraulic fractures accounted for only 1% of the overall hydraulic fracture volume. The volume of hydraulic fractures is mainly provided by hydraulic fractures greater than 10 000 μm, accounting for 99% of the overall hydraulic fracture volume. The average crack diameter of the
three samples was calculated using the weighted average method. The average crack diameters of the LMX-1, LMX-2, and LMX-3 samples were 515.75, 434.82, and 1614.23 µm, respectively.

According to the Poiseuille equation,\(^9,34\) the relationship between the fluid flow on the fracture surface and the opening of the fracture can be expressed as

\[
Q = \frac{\mu^3 \Delta P}{12 \mu L \sin \theta}
\]  

(2)

where \(Q\) is the fluid flow rate at the fracture surface, \(\mu\) is the fracture opening, \(L\) is the fracture length, \(\Delta P\) is the fluid pressure difference between the inlet and outlet, \(L\) is the specimen length, and \(L/\sin \theta\) is the flow path length of the fluid in the fracture surface.

The following can be observed from the spatial morphology of the hydraulic fractures and the average fracture diameter of the sample. In the gas seepage direction, the order of the hydraulic fracture conductivity is LMX-3 sample > LMX-2 sample > LMX-1 sample. This is consistent with another study, which found that the greater the fracture opening under the effective conduction fracture, the better the fracture conductivity.\(^9\)

### 3.2. Effect of the Pore Pressure Drop on Apparent Permeability

The shale gas reservoir is a dual-porosity medium of matrix pore microfracture type. This is affected by the pressure of the overlying rock in the reservoir, and the pressure is related to the thickness and density of the overlying rock and does not change with time. However, in the actual shale gas production process, the pore pressure of the reservoir gradually decreases. The effective overburden pressure that it can bear gradually increases, causing the pores and fractures of the shale reservoir to be compressed. When the confining pressure of the shale sample is constant at 50 MPa, the pore pressure decreases from 30 to 2 MPa. Figure 6 shows a graph of the apparent permeability of a shale sample as a function of the average pore pressure.

Figure 6 shows that as the average pore pressure decreases, the apparent permeability of the shale sample gradually increases. The increasing trend is more evident at low pressures. When the average pore pressure of the LMX-1 sample is 15.1 MPa, the apparent permeability of the sample is \(4.12 \times 10^{-6}\) mD. When the average pore pressure drops to 1.1 MPa, the apparent permeability of the shale sample is \(1.87 \times 10^{-4}\) mD. During the depressurization process, the apparent permeability of the LMX-1 sample increased by 4438.83%. Under the same experimental conditions, the apparent permeability of the LMX-2 sample increased from \(1.28 \times 10^{-4}\) mD to \(8.95 \times 10^{-4}\) mD, and the permeability increased by 597.18%. The permeability of the LMX-3 sample increased from \(4.72 \times 10^{-4}\) mD to \(1.78 \times 10^{-2}\) mD, and the permeability increased by 277.33%. The reason is that most of the hydraulic cracks in the sample are at the nanometer level, and the gas slippage effect cannot be ignored. When the confining pressure is constant and the pore pressure continues to decrease, the degree of compression and deformation of the hydraulic fractures decreases. At this time, due to the dual factors of the low pore pressure and low hydraulic fracture opening, the slippage effect is enhanced. As the gas flow increases, the apparent permeability of the sample increases. Another study also gave the same reason. Under a low pore radius and low pore pressure, the slippage effect of shale is significantly enhanced.\(^8\)

The relationship between the apparent permeability of the shale sample and the pore pressure can be fitted with a power function, and a satisfactory fitting effect can be obtained. The fitting equations are expressed below

LMX - 1 sample: \(k = 2.1923 \times 10^{-4} P_m^{-1.6886} \); \(R^2 = 0.999\)  
LMX - 2 sample: \(k = 9.7099 \times 10^{-4} P_m^{-0.7756} \); \(R^2 = 0.997\)  
LMX - 3 sample: \(k = 1.8560 \times 10^{-2} P_m^{-0.5169} \); \(R^2 = 0.999\)

Based on the fitting equation, the general equation of the relationship between the apparent permeability of the shale samples and the pore pressure is as follows

\[
k = k_0 P_m^{-a}
\]  

(6)

where \(P_m\) is the average pore pressure (MPa), \(P_m = \frac{P_i + P_{out}}{2}\), \(k_0\) and \(a\) are the fitting coefficients, \(k_0\) is the apparent permeability of the sample under the initial stress state, and \(a\) is the curvature of the fitting curve, which can be used as the apparent permeability of the sample versus the average pore pressure sensitivity factor.

From the fitting eqs 3 - 5, it is found that the LMX-3 sample has the highest \(k_0\) and the lowest value. This shows that the LMX-3 sample has the highest initial apparent permeability and the highest average pore pressure sensitivity. As the hydraulic fracture conductivity of the shale decreases, the initial apparent permeability and average pore pressure sensitivity of the LMX-2 and LMX-1 samples decrease.

### 3.3. Effect of Slippage on Apparent Permeability

Theoretically, the absolute permeability of a tight rock does not influence the type and nature of the fluid medium. However, several experiments have found that there is a significant
difference between the gas and liquid test results. The lower the apparent permeability of the shale, the more evident this phenomenon is, mainly due to the slippage effect of the gas flowing in the tight rock. Shale is a typical tight rock; therefore, the effect of gas slippage on the apparent permeability of shale cannot be ignored.

Because of the gas slippage effect, the apparent permeability value of the shale hydraulic fracture measured experimentally is greater than the true permeability of the sample. Klinkenberg established a mathematical expression between the apparent permeability and absolute permeability of the porous media for the first time

\[ k = k_\infty \left(1 + \frac{4c\lambda}{r}\right) \]  

where \(k_\infty\) is the apparent permeability of the porous medium, \(k\) is the absolute permeability of the porous medium, \(c\) is the scale factor, \(\lambda\) is the mean free path of the gas, and \(r\) is the mean radius of the pores.

From experiments, Klinkenberg found that the free path of the gas molecules is inversely proportional to the average pressure \(P_m\), and the formula is

\[ k = k_\infty \left(1 + \frac{b}{P_m}\right) \]  

where \(b\) is the slippage factor. When \(b = 0\), it is Darcy’s flow. \(b\) is also called the Klinkenberg coefficient, which is determined by the temperature, gas type, and pore structure of the porous medium. It is defined as

\[ b = \frac{4c\lambda}{r} P_m \]

From eq 1, it is found that if the gas flow in the shale hydraulic fractures conforms to Darcy’s law, the pressure square difference at the inlet and outlet of the sample is proportional to the gas flow at the outlet. Based on the test results, Figure 7 shows the gas flow curve of the shale sample at a confining pressure of 50 MPa and at different pressure differences.

Figure 7 shows that the relationship between the inlet and outlet pressure squared difference and the gas flow rate is nonlinear. Under the same confining pressure, the greater the squared difference between the inlet and outlet pressures of the sample, the greater the gas penetration pressure. However, the rate of increase in the gas flow rate is reduced; therefore, the resulting shale hydraulic fracture permeability decreases. It conforms to the theory of the gas slippage effect, that is, the greater the gas penetration pressure, the lower the test permeability. This shows that there is a slippage effect of the gas in the hydraulic fractures of the shale. The main reason for the slippage effect is that the mean free path of the gas molecules is close to the pore size when gas percolates in the medium. The gas flow is dominated by collisions between gas molecules and solid walls, leading to slippage effects.

As shown in Figure 8, eq 7 can be used to fit the average pore pressure and the apparent permeability of the shale well. The apparent permeability of the shale sample can be corrected by the slippage effect, and the Klinkenberg coefficient \(b\) and absolute permeability \(k_\infty\) of the gas flow of the shale sample during the decrease in the pore pressure can be obtained. The absolute permeability obtained can better represent the true permeability of the shale in its initial state. The fitting equations are as follows

\[ \text{LMX} - 1 \text{ sample: } k = 4.9437 \times 10^{-3} \times \left(1 + \frac{3422.7893}{P_m}\right) ; R^2 = 0.885 \]  

\[ \text{LMX} - 2 \text{ sample: } k = 8.0252 \times 10^{-3} \times \left(1 + \frac{11.5806}{P_m}\right) ; R^2 = 0.990 \]  

\[ \text{LMX} - 3 \text{ sample: } k = 4.4800 \times 10^{-3} \times \left(1 + \frac{3.4481}{P_m}\right) ; R^2 = 0.97 \]
From fitting eqs 10−12, it can be known that $k_\infty$ of the LMX-3 sample is 90 620.39 times that of the LMX-1 sample, and $k_\infty$ of the LMX-2 sample is 55.82 times this value. $b$ of the LMX-1 sample is 295.66 times that of the LMX-2 sample and 992.66 times that of the LMX-3 sample. The results show that the hydraulic fracture diameter distributions of the LMX-1 and LMX-2 samples are concentrated between 100 and 400 μm. The overall hydraulic fracture volume of the LMX-2 sample is 1.48 times that of the LMX-1 sample; however, the absolute permeability of the shale sample is 1623.32 times higher. This is because the LMX-1 sample also formed hydraulic fractures through hydraulic fracturing. However, in the direction of gas seepage, the hydraulic fractures are ineffective seepage channels. The gas circulates through the pores of the shale matrix. Compared with the LMX-2 sample, the hydraulic fractures are effective seepage channels in the gas seepage direction. The gas mainly circulates in the effective seepage channels of the sample. The greater the number of effective seepage channels for hydraulic fractures in a shale sample, the greater its absolute permeability. Compared with the LMX-2 sample, the hydraulic fracture diameter distribution of the LMX-3 sample is mainly concentrated between 400 and 800 μm. This shows that the diameter of most of the hydraulic cracks of the LMX-3 sample is greater than that of the LMX-2 sample. The hydraulic fracture volume of the LMX-3 sample is 2.68 times that of the LMX-2 sample. The absolute permeability of the LMX-3 sample is 55.82 times that of the LMX-2 sample. This is because the hydraulic fractures in the LMX-2 sample and the LMX-3 sample are both effective seepage channels in the gas seepage direction. The greater the diameter of the hydraulic fractures, the better the gas seepage. Therefore, the absolute permeability of the shale samples is mainly affected by the number of effective seepage channels in the hydraulic fractures and fracture diameter, $b$ of the shale sample is negatively correlated with the effective seepage channel and the diameter of the hydraulic fracture of the shale. This is because, the smaller the effective seepage cracks and pore diameters of the shale samples, the more evident the gas slippage effect. We conclude that $k_\infty$ is positively correlated with the number of effective seepage channels in the hydraulic fractures and the diameter distribution characteristics of the hydraulic fractures of the shale samples in the direction of gas seepage. The better the conductivity of the hydraulic fracture network, the greater the $k_\infty$ value. $b$ is negatively correlated with the number of effective seepage channels in the hydraulic fractures in the shale samples and the diameter distribution characteristics of the hydraulic fractures. The lower the seepage capacity of the hydraulic fracture network, the greater the $b$ value. This conclusion is consistent with the results of another study.31

The gas slippage effect varies with the change in the gas penetration pressure. The contribution rate $M$ of the gas slippage effect to the apparent permeability of shale can be calculated using the following equation

$$M = \frac{|k - k_\infty|}{k} \times 100\%$$

(13)

Figure 9 shows that when the pore pressure decreases from 30 to 2 MPa, the contribution rate of the slippage effect to the apparent permeability of the LMX-1 sample increases from 37.48 to 91.03%. The contribution rate of the slippage effect to the apparent permeability of the LMX-3 sample increased from 5.09 to 74.85%. The contribution of the slippage effect to the apparent permeability of the shale samples showed a nonlinear increase during the entire reservoir pressure reduction mining process. The test results show that the role of the slippage effect in the permeability test of the shale is ignored. This will cause a significant deviation between the actual value of the shale permeability and the test value, which will affect the actual application of the project. This conclusion is consistent with the results of another study.5

4. CONCLUSIONS

In this study, we selected three full-diameter shale cores with representative hydraulic fracture morphologies. A 3D reconstruction of the hydraulic fractures and extraction of the hydraulic fracture parameters were performed using X-ray CT scanning. A self-built high-pressure full-diameter core seepage test device was used to study the reservoir pressure drop during the simulated reservoir mining process. The effects of the pore pressure and slippage effect on the apparent permeability of water-bearing fractured shale samples were studied. The following conclusions can be drawn:

(1) In the direction of gas seepage, the morphological characteristics of the hydraulic fractures of the shale samples significantly influence the apparent permeability of the samples. The conductivity of the shale containing hydraulic fractures that completely penetrate the sample is better than that of the shale with fractures incompletely penetrating the sample. With the same hydraulic fractures completely penetrating the sample, the greater the diameter and volume of the hydraulic fracture, the better the conductivity.

(2) Under a high overburden pressure of the reservoir, the apparent permeability of the shale continues to increase with decreasing reservoir pressure. The overall trend can be fitted with a power function. The better the conductivity of the hydraulic fracture, the more sensitive it is to the reservoir pressure.
(3) Due to the slippage effect of the gas flow, the gas permeability of the shale is higher than the actual permeability. The results showed that the absolute permeability increases with the number of effective seepage channels and the diameter of hydraulic fractures. The Klinkenberg constant decreases with the increase in the number of effective seepage channels and the fracture diameter.

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**Notes**
The authors declare no competing financial interest.

**ACKNOWLEDGMENTS**
This work was supported by the National Science and Technology Major Project of the Ministry of Science and Technology of China (Grant No. 2017ZX05037-001-004), the general project of the National Natural Science Foundation of China (Grant No. 51874166), and the Discipline Innovation Team Funding Project of Liaoning Technical University (Grant No. LNTU20TD-11).

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