Data Mining on the Influence of Capillary Force on the Productivity of CBM Wells

Liu Bin\textsuperscript{1,a}, Wang Hongli\textsuperscript{2,b}, Zhang Suian\textsuperscript{2}, Zhang Xiao\textsuperscript{2}, Liu Qiguang\textsuperscript{2}

\textsuperscript{1}PetroChina Huabei Oilfield Company Hebei, China
\textsuperscript{2}China University of Petroleum, Beijing, Beijing, China
\textsuperscript{a}cyy_zqz@petrochina.com.cn
\textsuperscript{b}15210870454@163.com

Abstract—To explore the influence of the capillary force in the coal matrix on the productivity, based on the dynamic capillary force of the gas and water phase, the high-pressure Hg injection method, the porous plate method, and the centrifuge method were used to analyze the No.3 coal seam of the Zhengzhuang block in the southern Qinshui Basin. Through the experimental analysis of 97 samples, 3 different capillary force models are proposed. Through data mining, it is found that when the displacement pressure is 1.247 MPa, the average residual water saturation of the sample is 89.21%; when the displacement pressure is 4.0 MPa, the residual saturation of 82.5% of the samples exceeds 80%. This means that the desorption process of adsorbed coalbed methane is subject to greater capillary force. If the capillary force cannot be overcome, the gas production of coalbed methane wells will be at a low level.

1. Introduction
The capillary phenomenon in the coal matrix is universal, and capillary force has a binding effect on both water and gas in the coal seam, especially in the later stage of drainage and gas desorption. In the micropores, the main function of capillary force is to restrain the coal seam water, organize the outflow of water, and have a certain suction effect on the external water of hydraulic fracturing. The presence of large amounts of moisture in coal seams tends to cause a sharp decline in coalbed methane production. Therefore, the capillary force test of the coal samples in the study area was conducted, the calculation and classification of reservoir capillary force, and the study of the influence of capillary force on fluid flowing in coal reservoirs are of great significance for guiding the actual production of coalbed methane wells.

At present, the impact of capillary force on fluid flow is mainly concentrated in the field of petroleum engineering, and there are few studies on its impact on coalbed methane (CBM) reservoirs. It is generally believed that the pressure difference between the two-phase fluids in the pores in the static state is the capillary force, and the capillary force is only related to the saturation [2]. Recent studies have shown that the pressure difference between the two-phase fluid in the pore is not only related to the capillary force in the equilibrium state, but also related to the effective contact area and the rate of change of saturation over time. This is the so-called dynamic capillary effect. In actual production, the capillary force gradually changes with the fluid flow. To describe the influence of the capillary force in the formation pores on the fluid seepage more accurately, it is necessary to consider the dynamic effect of the capillary force. The classic dynamic capillary force models mainly include Hassanizadeh-Gray model [3], Barenblatt model [4] and Stauffer model [5], all of which consider the relationship between
satisfaction and time. Joekar-Niasar V [6] believed that not only the physical properties of rocks and wet-phase fluid properties will affect the dynamic capillary pressure, but the properties of non-wet-phase fluids (such as density, viscosity, etc.) also affect the dynamic capillary pressure. Joekar-Niasar V [7] emphasized that the strength of the dynamic effect of capillary force depended on the viscosity ratio and effective contact area between the two-phase fluids. When the viscosity ratio is less than a certain value during the displacement process, or the self-absorption process, or the viscosity ratio is greater than a certain value, the displacement front will become extremely unstable; on the contrary, if the viscosity ratio is within a certain range, the displacement front will be relatively stable. Similarly, the density ratio between the two-phase fluid also affects the dynamic characteristics of the capillary force. Bhusan D D [8] believed that a higher density ratio leads to a stronger dynamic effect of capillary force, which directly leads to weaker interface stability between fluids, resulting in viscous fingering. Existing oil-water two-phase studies have a large change in the viscosity ratio of the two-phase fluid, but the density values between the two phases are not much different, so the influence of the viscosity ratio is usually considered separately and the influence of the density ratio is ignored. The experimental results of Civan F [9] showed that with the increase of rock water wetness, the value of the dynamic capillary coefficient also increased sharply. At this time, it is necessary to consider the impact of dynamic capillary force when studying the flow of fluid in the formation.

AbidoyeLK [12] designed a set of experiments to study the relationship between dynamic capillary coefficient and saturation. The capillary force curves at different viscosity ratios and different inlet pressures obtained in the experiment show that as the inlet pressure increases, the capillary force increases, and the capillary pressure, which is the resistance to the oil phase flow, increases correspondingly with the increase of the non-wet phase pressure. As the viscosity ratio increases, the capillary pressure curve gradually shifts to the upper right. It can be understood that the greater the viscosity ratio, the greater the flow resistance; the more difficult the oil flow, the greater the water saturation when it starts to flow. Tsakiroglou CD introduced dynamic capillary force into the two-phase seepage of Newtonian fluid and non-Newtonian fluid, and substituted the dynamic capillary force into the governing equation of two-phase seepage flow, supplemented by auxiliary equations such as saturation equation and relative permeability equation, and studied the influence of capillary force dynamic effect on seepage. Salimi H considered factors such as dynamic capillary force and relative permeability in the three-dimensional grid calculation of fractured reservoirs. The calculation results show that the introduction of dynamic capillary force will lead to a decrease in oil recovery. This conclusion is consistent with the conclusions of Jia A [10] and Zhang H [11].

2. Experimental method

2.1. High-pressure Hg injection method

The high-pressure Hg injection method is based on the capillary bundle model, assuming that the porous medium is composed of capillary bundles with unequal diameters. Hg does not wet the rock surface and is in the non-wetting phase. Relatively speaking, the air or Hg vapor in the rock pores is the wetting phase. Injecting Hg into rock pores is to replace the wetting phase with the non-wetting phase. When the injection pressure is higher than the corresponding capillary pressure of the pore throat, Hg enters the pore. At this time, the injection pressure is equivalent to the capillary pressure. The corresponding capillary radius is the radius of the pore throat, and the volume of Hg entering the pore is the volume of pores connected by the throat. By continuously changing the injection pressure, the pore distribution curve and capillary pressure curve can be obtained. The calculation formula is:

$$p_c = \frac{2\sigma \cos \theta}{r}$$

Where:
The capillary pressure corresponding to the pore radius \( r \) is

\[
P_r = \frac{0.735}{r}
\]

2.2. **Porous plate method**

When the pressure is less than the breakthrough pressure, only the wetting phase can pass through the porous plate. The core is placed on the baffle and vacuum or pressurization is used to establish a displacement pressure difference between the two ends of the rock sample to remove the liquid. The pressure required to displace these pores is equal to the capillary pressure of these pores.

When the capillary pressure is balanced during the displacement process, the corresponding wetting phase saturation in the rock sample can be obtained. A series of capillary pressure and wetting phase saturation values can be plotted to obtain the capillary pressure curve of the diaphragm method. The calculation formula for water saturation is:

\[
S_w = \frac{W_r - W_i}{\rho_w V_p} \times 100\%
\]

Where:
- \( S_w \): Core water saturation, \%;
- \( W_r \): The quality of the rock sample at each capillary pressure balance point, g;
- \( W_i \): Dry rock sample quality, g;
- \( \rho_w \): The density of formation water, g/mL;
- \( V_p \): The pore volume of the rock sample, mL.

2.3. **Centrifugation method**

The rock sample saturated with the wetting phase fluid is placed in a centrifuge sample box filled with the non-wetting phase fluid to rotate at a series of selected angular velocities. Due to the different density of the fluid inside and outside the rock sample, the two fluids are under the different centrifugal force. With the help of the centrifugal pressure difference of the two-phase fluid, the capillary pressure of the rock sample is overcome, so that the non-wetting phase fluid enters the rock sample and the wet phase fluid is expelled. The higher the rotation speed of the centrifuge, the greater the centrifugal pressure difference of the two-phase fluid, so as the rotation speed of the centrifuge increases, less and less wet phase fluids in the pores are expelled. By measuring the cumulative discharge volume of the phase fluid at a series of stable speeds, the centrifugal capillary pressure curve of the rock sample can be obtained.

The centrifugal pressure difference of the two-phase fluid at different speeds is equal to the capillary pressure:

\[
P_c = 1.097 \times 10^{-3} \Delta \rho L \left( R_e - \frac{L}{2} \right) n^2
\]

Where:
- \( P_c \): Displacement capillary pressure of coal sample, MPa;
L: length of coal sample, cm;  
\( R_c \): Outer radius of rotation of coal sample, cm;  
\( \Delta \rho L \): two-phase fluid density difference, g/mL;  
n: Centrifuge speed, r/min.

The corresponding average remaining water saturation in the rock sample is:

\[
\bar{S}_w = \frac{V_{st} - V_w}{V_{st}} \times 100\%
\]

Where:

\( \bar{S}_w \): The average remaining water saturation, %;  
\( V_{st} \): Rock sample saturated formation water volume, mL;  
\( V_w \): The volume of formation water accumulated and discharged by the rock sample, mL.

3. Overview of the study area

The overall geological structural characteristics of the Qinshui Basin are as follows: The basic appearance is a wide and gentle compound syncline; low and gentle parallel folds are commonly developed, mainly linear structures; there are many faults, mainly small. The Sihe fault divides the block into two structural units, Fanzhuang and Zhengzhuang. Fanzhuang is buried at a depth of 300-800m, with small faults locally developed, and the strata is higher in the southeast and lower in the northwest; Zhengzhuang is buried at 600-1000m, with the Houchengyao fault developed in the area, and the strata is higher in the southwest and lower in the northeast. Other faults in the area are generally normal faults. There is no obvious fault in the No. 15 coal seam in Zhengcun well area. According to the fault classification standards, the Fanzhuang-Zhengzhuang block is divided into fine interpretation and division of seismic data. A total of 2 first-level faults, 142 second-level faults,
and 216 third-level faults are classified (level I fault: fault distance greater than 50m; level II fault: fault distance greater than 50m; level III fault: fault distance greater than 50m).

When the production well is less than 1000m away from the level I fault, the desorption pressure is generally less than 0.5MPa, the gas content is low, and the gas well does not produce gas. When the production well is more than 1000m away from the level I fault, the desorption pressure is high and the gas content is not affected. When the level II fault is less than 150m, the desorption pressure is low, which has a significant impact on the gas content.

When the level II fault is larger than 150m, the desorption pressure will increase significantly, which has little effect on the gas content. The desorption pressure in the zone affected by the level III fault is generally higher and has little effect on the gas content.

4. Data mining of experimental results

4.1. Capillary force test results

Select Hg injection method, centrifugal method, and porous plate method to carry out the capillary force test of the coal samples of 97 samples. We choose 27 cases, including 9 samples of Hg injection method, 9 samples of the centrifugal method, and 9 samples of porous method. Analyze. The test results are shown in Table 1 to Table 3.

Table 1 Test results of the porous plate method

| No. | Sampling location | diameter, cm | length, cm | volume, cm³ | Dry weight, g | Density, g/cm³ | Saturated weight, g | Porosity, % | Maximum displacement pressure, MPa | Critical saturation, % |
|-----|------------------|--------------|------------|-------------|---------------|----------------|---------------------|-------------|-----------------------------------|----------------------|
| HB1 | Shihe            | 4.982        | 2.489      | 24.24       | 35.276        | 1.44           | 36.69               | 5.8         | 1.247                             | 90.9                 |
| HB2 | Shihe            | 4.983        | 2.47       | 23.88       | 41.232        | 1.73           | 42.32               | 4.6         | 1.247                             | 87.1                 |
| HB3 | Shihe            | 4.977        | 2.476      | 23.96       | 46.632        | 1.95           | 47.54               | 3.8         | 1.247                             | 86.1                 |
| HB12| Pingsheng        | 4.946        | 2.485      | 23.99       | 44.278        | 1.85           | 45.03               | 3.1         | 1.247                             | 89.0                 |
| HB13| Pingsheng        | 4.957        | 2.484      | 24.02       | 34.549        | 1.43           | 36.25               | 7.1         | 1.247                             | 94.4                 |
| HB14| Pingsheng        | 4.998        | 2.496      | 24.46       | 46.226        | 1.9            | 47.28               | 4.3         | 1.247                             | 77.1                 |
| HB21| Yusi             | 4.993        | 2.474      | 24.00       | 40.452        | 1.68           | 41.64               | 4.9         | 1.247                             | 94.9                 |
| HB22| Yusi             | 4.962        | 2.485      | 24.07       | 43.178        | 1.8            | 43.98               | 3.3         | 1.247                             | 95.5                 |
| HB23| Yusi             | 5.013        | 2.485      | 24.31       | 34.769        | 1.43           | 36.31               | 6.3         | 1.247                             | 96.8                 |

Table 2 test result of centrifuge method

| No. | Sampling location | diameter, cm | length, cm | volume, cm³ | Dry weight, g | Density, g/cm³ | Saturated weight, g | Porosity, % | Critical centrifugal force, MPa | Critical saturation, % |
|-----|------------------|--------------|------------|-------------|---------------|----------------|---------------------|-------------|---------------------------------|----------------------|
| HB34| Pingsheng        | 2.475        | 2.485      | 11.955      | 21.322        | 1.78           | 21.821              | 4.2         | 84                              | 6.124337             |
| HB35| Pingsheng        | 2.479        | 2.44       | 11.777      | 18.374        | 1.56           | 18.948              | 4.9         | 89.4                            | 6.132611             |
| HB36| Pingsheng        | 2.469        | 2.443      | 11.690      | 19.556        | 1.67           | 19.964              | 3.5         | 88                              | 6.111995             |
| HB42| Yusi             | 2.477        | 2.489      | 11.994      | 18.228        | 1.52           | 18.685              | 3.8         | 85.8                            | 6.128474             |
| HB43| Yusi             | 2.487        | 2.495      | 12.12       | 17.887        | 1.48           | 18.495              | 5           | 90.5                            | 6.149089             |
| HB44| Yusi             | 2.483        | 2.428      | 11.757      | 22.161        | 1.88           | 22.883              | 4.4         | 72.8                            | 6.140884             |
| HB50| Shihe            | 2.479        | 2.493      | 12.03276    | 18.521        | 1.54           | 19.046              | 4.4         | 81.9                            | 6.132611             |
| HB51| Shihe            | 2.47         | 2.505      | 12.00305    | 20.232        | 1.69           | 20.655              | 3.5         | 87                              | 6.186114             |
| HB54| Shihe            | 2.483        | 2.494      | 12.07646    | 18.38         | 1.52           | 18.917              | 4.4         | 79.7                            | 6.140884             |
Table 3  test result of the high-pressure injection method

| No.   | Sampling location | Permeability, mD | Maximum pore throat radius, μm | Median pore throat radius, μm | Sorting coefficient | Maximum Hg saturation, % | Maximum Hg removal efficiency | Discharge pressure, MPa | Porosity, % |
|-------|------------------|-----------------|-------------------------------|-----------------------------|--------------------|--------------------------|-----------------------------|-------------------------|------------|
| HB58  | Pingshang        | 0.00131         | 0.134                         | 0.099                       | 1.659              | 89.877                   | 83.777                      | 5.492                   | 3.741      |
| HB59  | Pingshang        | 0.000857        | 0.053                         | 0.099                       | 1.298              | 92.59                    | 80.665                      | 13.778                  | 3.66       |
| HB60  | Pingshang        | 0.000419        | 0.053                         | 0.007                       | 1.275              | 82.403                   | 89.568                      | 13.776                  | 3.772      |
| HB71  | Sihe             | 0.00153         | 0.067                         | 0.012                       | 1.453              | 81.25                    | 48.669                      | 11.019                  | 6.849      |
| HB72  | Sihe             | 0.000236        | 0.021                         | 0.007                       | 0.893              | 78.297                   | 74.914                      | 34.44                   | 4.616      |
| HB73  | Sihe             | 0.583           | 5.332                         | 0.008                       | 3.242              | 77.08                    | 82.892                      | 0.138                   | 4.622      |
| HB84  | Yuxi             | 0.000439        | 0.053                         | 0.01                        | 1.316              | 91.477                   | 81.617                      | 13.771                  | 2.629      |
| HB85  | Yuxi             | 0.000455        | 0.053                         | 0.008                       | 1.284              | 86.533                   | 81.375                      | 13.772                  | 3.455      |
| HB86  | Yuxi             | 0.000411        | 0.053                         | 0.006                       | 1.245              | 73.305                   | 83.427                      | 13.776                  | 4.32       |

4.2. Calculation and classification of capillary force

The porous plate method and the centrifugal method can directly obtain the gas-water capillary force curve. The Hg injection method needs to obtain the gas-water capillary pressure curve through a conversion formula. The calculation results of 97 coal samples are comprehensively analyzed, and the capillary obtained by the same test method is found that the force curve types are similar, and the curve forms for the three test methods are shown in Fig.2.

Figure 2 Capillary force curves obtained by three test methods

The capillary force curves measured by the three methods are classified. Since the semi-permeable partition method and the centrifugal method can only measure the low pressure section, the curves obtained by the above two methods are drawn together with the Hg injection method, and it can be found that: The morphological characteristics of the capillary force curve obtained by the plate method, centrifugal method, and Hg injection method are consistent with the capillary force characteristics of dual-porosity media.

5. Conclusion

1. Coal samples from Pingshang, Sihe, and Yuxi coal mines in the No. 3 coal seam of Zhengcun block in Qinshui Basin were collected, and the capillary force test of 97 samples was carried out by Hg injection method, centrifugal method, and porous plate method. The test results show that the porosity of the coal samples is 2 to 5%, and the average permeability of the coal samples is 0.00068 mD, which are all low-porosity and low-permeability coal samples.

2. The capillary force curve morphology characteristics obtained in the laboratory experiment have the morphological characteristics of the capillary force curve of the dual-porous medium, so the capillary
force type of the coal sample tested in the experiment belongs to the dual-porous medium. This is consistent with the previous research conclusions that the coal body has a dual pore structure of pores and fractures obtained by the physical property testing and analysis of coal reservoirs.

3. Indoor experiments have measured that the capillary force of the No.3 coal seam sample in the Zhengcun block of Qinshui Basin is relatively large. When the displacement pressure is 1.247 MPa, the average residual water saturation of the sample is 89.21%; when the displacement pressure is 4.0 MPa, the residual saturation of 82.5% of the samples exceeds 80%. This means that the desorption process of adsorbed coalbed methane is subject to greater capillary force. If the capillary force cannot be overcome, the gas production of coalbed methane wells will be at a low level.

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