Effect of non-Darcy seepage on productivity of tight gas reservoir

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Abstract. In the process of gas reservoir development, with the production of formation fluid, the effective overburden pressure on the rock skeleton of the reservoir increases, and the rock is deformed under compression, which changes the physical properties of the rock (porosity, permeability, etc.), especially the influence on permeability. Stress sensitivity and threshold pressure gradient are important factors for non-linear seepage in tight gas reservoirs. This paper establishes an empirical prediction model through experimental tests and uses numerical simulation to analyze the effects on productivity. The experimental results show that the relationship between stress sensitivity and permeability is exponential, and there is a strong hysteresis effect. The starting pressure gradient of gas presents a power function relationship with water saturation and permeability respectively, and an empirical relationship is established to predict the starting pressure gradient by comprehensively considering the influence of permeability and water saturation. The single well productivity simulation shows that: The effect of starting pressure gradient on gas well development is greater than stress sensitivity. When starting pressure gradient or stress sensitivity is taken into account, the formation average pressure increases relative to each other and the stable production period decreases obviously.

1. Introduction

Tight gas reservoirs are rich in resources, have great development potential and good development prospect, and are of great significance to meet energy demand[1]. These reservoirs are usually characterized by low porosity and permeability, high heterogeneity, prominent capillary, and high initial water saturation. With the continuous production of the reservoir fluid, the productivity decreases obviously. The flow mode of the fluid is mainly non-Darcy seepage, and the non-Darcy seepage law is greatly affected by the stress sensitivity and the start-up pressure gradient[2]. Li Songquan et al. established a nonlinear seepage equation on the basis of considering the start-up pressure gradient and medium deformation, which provided a theoretical basis for determining a reasonable injection-production well spacing[3]. Xu Xuan established the characterization method of start-up pressure gradient and determined the effective producing radius of gas well, forming the diagram of the relationship between the effective producing radius and reservoir permeability and water saturation[4]. Xiao Wenlian et al. established three stress sensitivity coefficient equations to analyze and classify the sensitivity of tight reservoirs. They believed that tight reservoirs with obvious fracture characteristics
showed strong stress sensitivity, and rock particle size and lithology were also important factors affecting stress sensitivity[5]. Wang Ruiyang found that the stress sensitive state of the reservoir could not be ignored in the productivity prediction of low permeability and water-bearing gas reservoirs. In the analysis, it was found that when considering the existence of stress sensitive effect, the open flow of a well in this gas reservoir was about half of that before, and its productivity decreased rapidly[6]. In order to clarify the influence of two special effects of low permeability on development, this paper established a single well numerical conceptual model based on the laboratory test results of stress sensitivity and stress sensitivity, and studied the productivity variation law under the influence of non-Darcy seepage effect in reservoir.

2. Stress sensitivity study
The stress sensitivity of tight gas reservoirs is mainly due to the fact that the reservoir rocks are intergranular pores and pore cemented, and the interstitial material is argillaceous. The increase of effective stress will reduce the volume of pores and snarl, thus showing the decrease of rock porosity and permeability[7].

2.1. The experimental scheme
The effective stress increased by increasing the confining pressure in the experiment firstly acts on the skeleton particles on the rock surface, while the upstream pressure and return force of the core remain unchanged[8]. The specific experimental steps are as follows:
1) Put the core into the core gripper after drying;
2) Set the backpressure as the formation condition pressure, stabilize the injection pressure, increase the confining pressure, and maintain the effective stress of 2 MPa, 4 MPa, 6 MPa...... 25MPa. Stable at each pressure point for 30min, using nitrogen to test rock permeability;
3) After the confining pressure is adjusted to the maximum value set, slowly reduce the confining pressure to the initial confining pressure according to the pressure point set in Step (2). Hold at each set pressure point for 1h, and then test core permeability with nitrogen after stabilization;
4) The relationship curve between permeability and net confining pressure is drawn and the formula is fitted.

![Flow chart of stress sensitivity test](image)

**Figure 1.** Flow chart of stress sensitivity test

2.2. Analysis of experimental results and empirical prediction equation
When gas flows in the core, the gas measurement permeability of the core is calculated according to Darcy's law:

\[
K_s = \frac{2Q_p \mu L}{(P_i^2 - P_e^2)A} \times 10^5
\]  (1)
At present, the research on the stress sensitivity of low permeability reservoir mainly adopts exponential relationship fitting experimental data, namely:

$$K = K_0 e^{a(p-p_0)}$$

(2)

Figure 2. Core net confining pressure and permeability curve

Figure 2. shows the stress sensitivity test results of the three cores. The initial permeability of the cores is $0.338 \times 10^{-3}\mu m^2$, $0.107 \times 10^{-3}\mu m^2$ and $0.071 \times 10^{-3}\mu m^2$ respectively. The permeability of the core decreases with the increase of the net confining pressure, and the relationship between the two is exponential. Moreover, there is a hysteresis effect of permeability in the core, that is, when the confining pressure is first increased and then decreased, the permeability cannot be restored to the initial value. This indicates that the core has been permanently damaged, which is closely related to the elastoplastic deformation of the core. The permeability changes sharply in the net confining pressure of 10MPa, and little changes in the net confining pressure of 20MPa. This is because in the process of the increase of effective stress, the pores that are easy to close are closed first, so the permeability of rock decreases faster. With the further increase of the effective stress, some difficult to close pores will be further compacted. When the effective stress reaches enough, the pores will basically close, and the rock permeability will not change significantly.

By fitting the core stress sensitivity coefficient, the relationship between the core stress sensitivity coefficient and the original permeability can be obtained:

$$\alpha = aK_0^{b}$$

(3)

Where, a and b are coefficients. In the pressure boost stage, the fitting data can be obtained as follows: $\alpha = 0.0269K_0^{0.288}$, Step down: $\alpha = 0.0184K_0^{-0.205}$. The above two formulae are bidirectional stress sensitive models of permeability rise and pressure drop for low permeability cores. The effective permeability of
cores with arbitrary permeability under pressure rise and pressure drop conditions can be calculated by using this model.

3. The gas starting pressure gradient

The starting pressure of gas flow refers to the pressure when the pressure difference between two ends of a rock sample with gas and water phases increases to a certain extent. The most essential reason is that the fluid is subjected to great solid wall action in the process of seepage, and its seepage law no longer conforms to the classical Darcy's law[9]. The fluid will flow only when the driving pressure is greater than a certain value.

3.1. Experimental test method

At present, there is no unified standard for the test method of starting pressure gradient, but the widely used methods are bubble method and seepage method, which reflect different gas flow characteristics. The bubble method represents the instantaneous value of the gas phase from the static state to the movement, which overcomes the resistance of the minimum roar in the core to the gas phase. However, the seepage method tests the pressure difference in the whole core when the gas phase is in a steady flow state just after the formation of continuous flow state[10]. In this experiment, bubble method is chosen as the experimental method. The specific experimental steps are as follows:

1) After vacuuming out the core saturated formation water, put it into the core gripper;
2) Add back pressure of 35MPa at the core outlet, drive the core at a small flow rate to a certain water saturation, and close the air source. The backpressure was set at 0MPa and stabilized for 30 min. After the gas and water were redistributed in the core, the gas start-up pressure gradient experiment was carried out under the water saturation;
3) The upstream pressure is measured with an electronic pressure gauge. The displacement starts from a very small pressure at a constant pressure, and the displacement stays stable at each pressure point for 30 min until gas is generated at the core outlet. At this time, The upstream pressure difference at this time is the starting pressure;
4) Repeat steps 1) ~3) for the next gas start-up pressure gradient experiment with water saturation.

3.2. Analysis of experimental results and empirical prediction equation

Permeability ranges from 0.15 to 6.47×10^{-3} \mu m^2 and porosity ranges from 5.0 to 14.0%. As shown in Fig 4, the core start-up pressure gradient increases in a power function relationship with the increase of water saturation. This is mainly due to the difference in wettability between gas and water relative to
rock in the experiment. The water phase has stronger wettability and will adhere to the surface of rock particles, which will wrap a layer of water film in the pore throat of rock. With the increase of the water saturation of the rock, the thickness of the water film becomes larger, and the flow channel of the gas phase becomes narrower, which is equivalent to the capillary diameter of the gas phase flow becoming smaller. As a result, the capillary force to be overcome when the gas phase begins to flow becomes larger, so that the starting pressure gradient of the core increases with increasing water saturation.

Figure 4. The relationship between starting pressure gradient and water saturation

As shown in Fig 5, at the same water saturation, the gas starting pressure gradient decreases with the increase of core permeability. In general, the higher the core permeability, the larger the core pore-throat diameter. Moreover, at the same water saturation, the water film thickness on the pore surface is certain, so the larger the core permeability is, the wider the flow channel of the gas phase will be. The less capillary force the gas phase has to overcome to begin to flow, so that the starting pressure gradient of the gas decreases.

Figure 5. The relation curve of starting pressure gradient and permeability

According to Fig 4 and Fig 5, core permeability and water saturation are the key parameters affecting the start-up pressure gradient. Therefore, K and Sw are used as independent variables and λ as dependent variables:

\[ \lambda = C_1 K^{C_2} \]  \hspace{1cm} (4)

\[ \lambda = C_3 S_w^{C_4} \]  \hspace{1cm} (5)

Where: \( \lambda \) is the starting pressure gradient, MPa/m; K is absolute permeability, \( 10^{-3} \mu m^2 \); \( S_w \) is water saturation, %; \( C_1, C_2, C_3, \) and \( C_4 \) are constant, dimensionless.

Take the logarithm of both sides of Equations (4) and (5) to get:
\[ \ln \lambda = C_1 \ln K + \ln C_i \]  
\[ \ln \lambda = C_1 \ln S_w + \ln C_i \]  
(6)  
(7)

According to Equations (6) and (7), the linear relationship between and can be obtained. Assume that the regression equation has the following basic form:

\[ \ln \lambda = a \ln K + b \ln S_w + c + \varepsilon \]  
(8)

Where: \( a \) and \( b \) are regression coefficients, dimensionless; \( c \) is the regression constant, dimensionless; \( \varepsilon \) is the random error term.

\( K, S_w \) and \( \lambda \) were sorted out as paired data, and corresponding programs were compiled. Multiple linear regression was selected to obtain regression coefficients and constants, which were substituted into (8) to obtain:

\[ \ln \lambda = -0.228 \ln K + 3.37 \ln S_w + 14.582 \]  
(9)

By deformation of Equation (9), we can get:

\[ \lambda = e^{14.582} e^{-0.228 S_w^{3.37}} \]  
(10)

Equation (10) can be used to better calculate the starting pressure gradient of the low-permeability tight core.

4. Consider the influence of non-Darcy effect on productivity

After the mathematical expressions of stress sensitivity and start-up pressure gradient were obtained, the influence of the two factors on productivity was studied by using the Eclipse simulator distribution. Firstly, a single well numerical conceptual model is established. Since the well circumference is the region where pressure changes most dramatically, a near-well logarithmic infill radial grid model is adopted [11]. After input parameters, stress sensitivity and the effect of starting pressure gradient on productivity are considered/ignored respectively [12].

4.1. Influence of stress sensitivity on productivity

The key word Rucktabh was introduced in Eclipse, the corresponding parameters were entered, and the production allocation was set to 35×104m3/d. The results of simulation calculation showed that: Stress sensitivity has an obvious effect on the average formation pressure, and the average formation pressure decreases more quickly in the production process after considering the stress sensitivity. This is because under the stress sensitive action, the permeability of the reservoir decreases, the gas supply capacity of the formation is weakened, and the formation pressure conduction is slow, which makes the formation average pressure considering the stress sensitive model significantly increase at the end of production. And the steady production time of gas well decreased obviously.

![Figure 6. Influence of stress sensitivity on formation average pressure](image)
4.2. Impact of starting pressure gradient on productivity

The keyword Threshold Pressure is introduced into Eclipse and the corresponding parameters are entered[13]. The simulation results can be seen as follows: The starting pressure gradient has some effect on the formation average pressure, but this effect does not appear until after the gas well is in production. After considering the start-up pressure gradient, the gas supply capacity of the formation is weakened. At the end of production, the average formation pressure is as high as 19.5MPa, and the stable production time of the gas well is significantly reduced.

![Figure 7. Influence of stress sensitivity on yield](image1)

**Figure 7.** Influence of stress sensitivity on yield

![Figure 8. Influence of starting pressure gradient on formation average pressure](image2)

**Figure 8.** Influence of starting pressure gradient on formation average pressure

![Figure 9. Effect of starting pressure gradient on production](image3)

**Figure 9.** Effect of starting pressure gradient on production
5. Conclusion
In tight gas reservoirs, the relationship between stress sensitivity and permeability is exponential. During the depressurization process following the pressure boost, the permeability does not return to its initial value, indicating that the core has been permanently damaged. The effective permeability of cores with arbitrary permeability can be calculated by the established prediction equation under pressure boost and pressure drop conditions.

The bubble method is used to test the start-up pressure gradient of gas, and it is concluded that the water saturation and permeability are respectively in a power function relationship with the start-up pressure gradient. The regression equation is established based on the experimental data, which can better calculate the starting pressure gradient of low permeability cores.

Single well productivity simulation shows that the effect of start-up pressure gradient on gas well development is greater than that of stress sensitivity. When starting pressure gradient or stress sensitivity is taken into account, the formation average pressure increases relative to each other and the stable production period decreases obviously.

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