Experimental Study on the Seepage Characteristics of Multilayer Commingled Production and Influencing Factors of the Development Effect in Low-Permeability Tight Sandstone Gas Reservoirs

Renyi Lin,* Yu Jia, and Lei Sun

ABSTRACT: For low-permeability tight sandstone gas reservoirs, multilayer commingled production technology is usually adopted by a large number of production wells. This production method can significantly increase the productivity of a single well, thereby improving the efficiency of gas field development. To have a better understanding of the seepage characteristics of multilayer commingled production of the SXM (ShaXiMiao) Formation tight sandstone gas reservoirs, an indoor physical simulation experiment of commingled injection and separate production using double-pipe parallel long cores was designed under influencing factors such as formation pressures, permeability contrast, and water saturations. Finally, the contribution of high- and low-permeability reservoirs to the total production capacity under different conditions is clarified, which provides a reference for formulating reasonable development strategies for gas reservoirs. Through the experimental study, we found that the recovery degree of the high-permeability formation is higher than that of the low-permeability formation during the depletion production process. The combination of depletion development and water flooding can greatly increase the recovery degree of gas reservoirs. Under the same production pressure difference condition, the higher the formation pressure and the permeability, the higher the production capacity. If the water saturation increases, the production contribution rate of the high-permeability layer gradually increases, and the production contribution rate of the low-permeability layer gradually decreases.

1. INTRODUCTION

Multilayer commingled production is a commonly used oil and gas development method for tight sandstone gas reservoirs.1 Generally, double-pipe parallel long cores are used to simulate the process of multilayer commingled development in actual reservoirs. According to the geological characteristics of the gas reservoir, a group of cores can be used to design and establish a physical model of parallel double gas layers with different pressures. In addition, the depletion production method can be used to simulate the actual gas reservoir, and the contribution rate and influencing factors to the productivity of each layer can be obtained.

There are many factors that affect the ultimate recovery factor of multilayer commingled production. Zhang2 et al. found that these factors include permeability, pressure system, productivity, and commingled production timing. In the actual development process, the high-permeability layers are developed first, and then the low-permeability layers can be developed via the commingled production method. Li3 et al. believe that the main factors affecting the productivity of commingled wells are the production pressure difference, reservoir thickness, gas saturation, effective permeability, and gas production rate. Among them, the pressure difference has the greatest impact on productivity, and the influence of saturation is relatively limited. Hu4 et al. found that when two adjacent gas layers with different pressures use a commingled producing means at the constant volume and depletion conditions, the larger the initial pressure difference, the more unfavorable the gas production in low-pressure reservoirs. Zhang5 et al. also found that the permeability contrast in the multilayer commingled producing process will lead to significant interlayer interference, and the degree of interference increases with the increase of the permeability contrast. Wang6 et al. found that if the high- and low-permeability gas layers with small permeability differences are commingled,

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there is also obvious interlayer interference, and the gas reservoir with higher pressure will flow back to the lower pressure reservoir along the wellbore. Zhu et al. found that the phenomenon of “backflow” is more likely to occur when the gas pressures of two adjacent layers are different. Meanwhile, the differences in the contribution of each layer to productivity will increase with the increase of the physical property differences. Liao further studied the phenomenon of “backflow” and found that the length of the backflow time is inversely proportional to the back pressure, and the amount of backflow gas and the length of time are in direct proportion to the permeability contrast of cores. In addition to experimental methods, Civan simulated the multilayer commingled production and determined the changing rules of the production capacity and pressures of different reservoirs. Tan et al. used the simulation method and found that the high-pressure and high-permeability layers in gas reservoirs have a relatively high contribution to gas recovery. In addition, Gu et al. established a mathematical seepage model considering interlayer channeling and not considering interlayer channeling and concluded that the gas production of different reservoirs of a gas reservoir is affected by the value of the formation coefficient and the storage capacity coefficient.

According to the above research, the permeability contrast, pressure system, and water saturation affect the ultimate recovery factor of multilayer commingled production. The differences in the contribution of each layer to productivity increase with the increase in physical property differences. The SXM tight sandstone gas reservoir has poor physical properties, and it adopts multilayer commingled production technology. However, the influence of various factors on the production capacity is not clear. For the SXM tight sandstone gas reservoir, the double-pipe parallel long cores are used to simulate the multilayer commingled production development process. The effects of the multilayer commingled production method on the actual gas production capacity under different permeability contrasts, pressures, and water saturations are studied.

2. MATERIALS AND METHODS

2.1. Reservoir Characteristics of the SXM Tight Sandstone Gas Reservoirs. The SXM tight sandstone gas reservoir has high water saturation, and multiple sets of sand bodies are stacked vertically. The rock types include fine-grained lithic quartz sandstone, fine-grained feldspar to lithic quartz sandstone, fine-grained feldspar quartz sandstone, and coarse silt sandstone, with less clay content. The reservoir permeability is low, and the pore structures have strong heterogeneity. The SXM gas reservoir is buried at a depth of about 3000 meters and is mainly located in the central area of western Sichuan. The gas reservoir is characterized by a wide and gentle axis and asymmetric wings. There are reverse faults in the east, and the sand groups are superimposed vertically. The formation pressure coefficient is 1.92, and the water saturation is high.

So far, the recovery degree of the SXM gas reservoir is still low, but the cumulative production capacity curve of a single well has gradually become flat and has entered an obvious decline stage. It is urgent to understand and study the current physical properties and seepage characteristics of the SXM gas reservoirs.

2.2. Experimental Conditions and Procedures. Under the simulation conditions of high temperature and high pressure in the formation, the experiments of coinjection and separate production using double-pipe parallel long cores are used to simulate the natural depletion production means of gas reservoirs and the seepage process of gas driving. It can help people to study the influence of water invasion on the depletion production degrees of gas reservoirs, the multilayer seepage characteristics of reservoirs with different permeability and water saturations, and their contribution to productivity under different pressure conditions. The experimental conditions are shown in Table 1.

### Table 1. Experiment Conditions of Double-Pipe Long Cores

| Formation temperature (°C) | Original formation pressure (MPa) | Abandonment pressure (MPa) | Gas viscosity (mPa·s) | Water viscosity (mPa·s) |
|---------------------------|----------------------------------|---------------------------|----------------------|-----------------------|
| 65                        | 46                               | 6                         | 0.0178               | 0.6                   |

The long core flooding experimental equipment was divided into three parts: the core holding part, the injection part, and the production part. The samples and solvents mainly include fracturing reservoir cores, nitrogen gas, and formation water.

2.3. Core Preparation and Sorting. 2.3.1. Determination of Core Physical Parameters. To facilitate the experiments, 17 cores were selected and fractured according to the classified permeability range (30–200 mD), the fracture type belongs to a mesh type, and the porosity and permeability of the fractured cores are tested, as shown in Table 2.

According to the classification standard of physical properties, the cores can be divided into four groups: low porosity and medium permeability (1 block), low porosity and high permeability (1 block), medium porosity and medium permeability (7 blocks), and medium porosity and high permeability (8 blocks; Table 3).

The permeability of the fractured core ranged from 226.37 mD (maximum) to 33.62 mD (minimum). Overall, the average porosity is 12.02%, and the average permeability is 121.33 mD. As for the fractured cores, the permeability variation coefficient is 0.546, the permeability contrast is 6.733, and the inrush coefficient is 1.866, indicating that the permeability range is relatively small and the fractured cores are relatively homogeneous. According to whether the core permeability is greater than 100 mD, the cores are divided into two groups, and the correlation between the permeability and porosity is analyzed separately (Figure 2 and Table 4). The correlation between the porosity and permeability of the fractured cores is poor.

2.3.2. Sorting of Cores. Due to the limitation of coring conditions, the long cores in the experiment need to be spliced with conventional short cores in a certain arrangement. According to whether the permeability of the fractured cores is greater than 100 mD, they are divided into two groups: the high-permeability group and the low-permeability group. Then, the harmonic average permeability is calculated. The core that has the closest permeability was taken out and set in the outlet first; then the harmonic average permeability of the remaining n−1 cores was calculated. The permeability of the remaining n−1 cores was compared, and the one that has the closest permeability was taken out and placed in the second...
place at the outlet end; in this way, the two groups of cores were arranged in order.

\[
R = \frac{1}{d} \sum_{i=1}^{n} L_i \left( \frac{1}{K_i d_i^2} + \frac{1}{K_1 d_1^2} + \cdots + \frac{1}{K_n d_n^2} \right)
\]

(1)

where \( R \) is the harmonic average permeability of the core, mD; \( L_i \) is the length of the \( i \)th core, cm; \( K_i \) is the permeability of the \( i \)th core, mD; and \( d_i \) is the diameter of the \( i \)th core, cm.

Using the sorting method of core, the cores are sorted sequentially from the outlet end to the inlet end, and the results are shown in Tables 5 and 6. Each core was wrapped with a polytetrafluoroethylene film to protect it from breaking, and the cores were put together according to the core sorting results in the table, and they were put into the holder to establish a double-pipe long core model.

### 2.4. Experimental Process

#### 2.4.1. Natural Depletion Experiment

At a temperature of 65 \(^\circ\)C, the water saturation (50\%) was quantitatively established for the double-pipe long core high-permeability tube and low-permeability tube, and then the gas was injected into the long core, and the inlet valve was closed after the pressure was increased to 46 MPa. Then, the depletion production was conducted until the pressure reached an abandoned formation pressure of 6 MPa, and finally, the experiment reached an end.

#### 2.4.2. Water Flooding Experiments at Different Depletion Stages

The experimental process was also carried out at 65 \(^\circ\)C and 46 MPa. After the gas—water saturation was re-established.
in the double-pipe long core, the depletion production was carried out at 32 MPa, and the formation water flooding experiment was carried out at a constant pressure of 32 MPa until no gas was produced anymore. Then, the depletion production was continued at 20 MPa. Afterward, the water flooding was conducted at a constant pressure of 20 MPa again until no gas was produced; then the depletion production was still continued at 6 MPa, and the water flooding was performed at a constant pressure of 6 MPa until no gas was produced. Finally, the experiments reached an end.

### Table 5. Sorting Characteristics of the Long Cores with Permeability Less than 100 mD

| Core number | Length (cm) | Diameter (cm) | Porosity (%) | Permeability (mD) | Pore volume (cm³) | Sorting |
|-------------|-------------|---------------|--------------|------------------|------------------|---------|
| CX36        | 6.41        | 2.5           | 11.12        | 62.22            | 3.50             |         |
| CX25        | 6.2         | 2.5           | 13.07        | 44.45            | 3.98             |         |
| CX17        | 6.35        | 2.5           | 11.74        | 67.48            | 3.66             |         |
| CX31        | 6.02        | 2.5           | 10.18        | 37.88            | 3.01             |         |
| CX2         | 5.42        | 2.5           | 19.21        | 72.51            | 5.11             |         |
| CX40        | 6.17        | 2.5           | 7.62         | 33.62            | 2.31             |         |
| CX27        | 5.87        | 2.5           | 11.09        | 75.19            | 3.19             |         |
| CX7         | 5.74        | 2.5           | 11.50        | 80.74            | 3.24             |         |
| Total core length (cm) | 48.18 | Average porosity (%) | 11.94 |
| Total pore volume (cm³) | 27.98 | Harmonized permeability (mD) | 53.81 |

### Table 6. Sorting Characteristics of the Long Cores with Permeability Greater than 100 mD

| Core number | Length (cm) | Diameter (cm) | Porosity (%) | Permeability (mD) | Pore volume (cm³) | Sorting |
|-------------|-------------|---------------|--------------|------------------|------------------|---------|
| CX16        | 6.18        | 2.5           | 11.38        | 159.20           | 3.45             |         |
| CX28        | 6.00        | 2.5           | 12.81        | 190.10           | 3.77             |         |
| CX4         | 5.57        | 2.5           | 13.06        | 192.53           | 3.57             |         |
| CX26        | 5.95        | 2.5           | 10.95        | 196.22           | 3.19             |         |
| CX23        | 5.82        | 2.5           | 12.01        | 116.18           | 3.43             |         |
| CX37        | 6.67        | 2.5           | 9.75         | 199.58           | 3.19             |         |
| CX8         | 5.01        | 2.5           | 12.96        | 206.05           | 3.18             |         |
| CX9         | 5.80        | 2.5           | 13.22        | 102.23           | 3.76             |         |
| CX32        | 6.22        | 2.5           | 10.74        | 226.37           | 3.28             |         |
| Total core length (cm) | 53.2 | Average porosity (%) | 12.09 |
| Total pore volume (cm³) | 31.39 | Harmonized permeability (mD) | 155.16 |

2.4.3. Experiments of Reservoir Contribution to Production under Different Pressures. In this experiment, the temperature was maintained at 65 °C, the water saturation (50%) was re-established in the double-pipe long core, and the pressure of the long core was increased to a formation pressure of 46 MPa via injecting gas, and then the gas flooding process was carried out at a constant pressure of 46 MPa, and the production pressure difference was set to 4 MPa. When the flooding process lasted for 15 min, the inlet was closed, and the depletion production was continued at 20 MPa. After that, the gas flooding experiment was conducted again at a pressure of...
20 MPa, and the production pressure difference was set to 4 MPa, and the flooding process lasted for 15 min. Then, the production pressure difference was adjusted to 8 MPa, and the experiments above were repeated.

2.4.4. Experiments for the Contribution of Reservoir Production under Different Initial Water Saturations. The experimental temperature was maintained at 65 °C, and the flooding pressure was maintained at 20 MPa. The formation water was injected into the double-pipe long cores to make the water saturation increase to 70%, and then the gas flooding experiments were conducted under a pressure difference of 4 MPa for 25 min. Then, the temperature was maintained at 65 °C, the pressure was maintained at 20 MPa, the water saturation was increased to 80%, and the test process above was repeated.

3. EXPERIMENTAL RESULTS AND DISCUSSION

3.1. Natural Depletion Production of Double-Pipe Long Cores. The purpose of the experiment is to simulate the contribution of the gas reservoir to the productivity during the depletion development of different reservoirs under the actual formation temperature and pressure conditions. When the gas reservoir is elastically recovered from 46 to 6 MPa, the pressure and cumulative recovery degree curves are shown in Figure 3.

It can be seen from Figure 3 that in the process of depletion production, due to the difference in the permeability of the two pipes, the recovery degrees of the two pipes are also different. The maximum recovery degree of the low-permeability pipe reached 13.01%, and the maximum recovery degree of the high-permeability pipe reached 18.35%. When the final production reached an abandonment pressure of 6 MPa, the recovery degrees of the high-permeability pipe and the low-permeability pipe reached 81.21 and 68.79%, respectively. On the whole, the cumulative recovery degree curves of the two pipes show an upward changing trend. The initial slope is large, and the later period becomes slower. The final cumulative recovery degrees of the high- and low-permeability pipes are 81.21 and 68.79%, respectively. Finally, the low-permeability pipe has a low recovery degree, and the high-permeability pipe contributes more to the total production.

3.2. Effect of Water Flooding on the Recovery Degree in Different Depletion Production Stages. The relationship between the injected water volume of water flooding and the residual gas saturation is shown in Figure 4, and the relationship between different pressures and the residual gas saturations is shown in Figure 5. When the double-pipe long core is naturally depleted to 32 MPa, the high-permeability reservoir produces more gas, which corresponds to a relatively low residual gas saturation at the beginning of water flooding. With the continuous water flooding of the core, the residual gas volume of the double pipes continued to decrease. The high-permeability pipe produced more gas at the initial stage, and the residual gas saturation decreased rapidly. When the injected water reached 0.3 PV (total pore volume of the long core), the residual gas reduction rate slowed down, and the low-permeability pipe continued to produce gas; when the injected water reached 1.3 PV, the residual gas saturation remained unchanged till the end; under this pressure condition, the residual gas volume of the high-permeability pipe was larger. The main reason for this phenomenon is that there are more fractures in the high-permeability cores, and the water phase is more likely to preferentially displace the gas in the large pores and fractures and thus form seepage channels in rocks, while the gas in the small pore throats is difficult to be driven out and even easier to be compressed to form water-sealed gas, resulting in a large amount of residual gas in high-permeability reservoirs.

Similarly, when the depletion production pressure reaches 20 and 6 MPa, part of the gas phase is produced by the...
accumulated elastic energy. As water flooding continues, more gas in the pores is also driven out, and the remaining gas volume in different reservoirs decreases. However, due to factors such as the high permeability value of high-permeability reservoirs and relatively good fracture conductivity, the final residual gas volume is smaller.

The relationship between different pressures and recovery degrees is shown in Figure 6. It can be seen that the gas phase accumulates more elastic energy during the initial depletion production, so the slope of the curve is large, and the recovery degree increases rapidly. As the gas volume in the core decreases, the corresponding depletion recovery curve slope in the later stage also decreases gradually, and the curve tends to be flat. The water flooding process in different stages improves the recovery degree of the fractured reservoir. Similar to the curve of reservoir recovery in the depletion period, the water flooding process also greatly improved the gas recovery in the fractured zone in the early stage. For example, the recovery of the low-permeability layer increased from 19.46 to 61.15% after water flooding at 32 MPa, and more gas that cannot be produced by its own energy would be displaced out. But the contribution of the water flooding process to the recovery of the reservoir is relatively less. For example, when using water flooding at 20 MPa, the recovery of the low-permeability layer only increased by 6.3%. In general, high-permeability reservoirs contribute more to production, and the combination of water flooding and depletion at different stages greatly increases the degree of recovery of gas reservoirs, and the fractured zone of the reservoir is the main source of the production capacity.

### 3.3. Contribution of Reservoir Properties to Production under Different Pressures

From the experiment results, it is found that the high-permeability reservoirs produce gas first, while the low-permeability reservoirs produce gas after a period of time and the gas production rate is relatively low. According to the experiment results, the relationship between the cumulative gas volume and the instantaneous flow rate at different pressures and production pressure differences (4 and 8 MPa) is shown in Figures 7–10.

The comparison shows that under the same production pressure difference, the higher the formation pressure, the greater the reservoir production. For example, when the production pressure difference is 8 MPa, the cumulative gas volume of the high-permeability reservoir at 46 MPa is much larger than that at 20 MPa, and the instantaneous gas production is also relatively large.

![Figure 6. Relationship between pressure and the recovery degree for high- and low-permeability reservoirs.](image1)

![Figure 7. Cumulative gas production curve under a pressure difference of 4 MPa.](image2)

![Figure 8. Cumulative gas production curve under a pressure difference of 8 MPa.](image3)

![Figure 9. Instantaneous gas production curve under a pressure difference of 4 MPa.](image4)

Even though the instantaneous gas production of the high-permeability reservoir is generally greater than that of the low-permeability reservoir and its contribution to the production is relatively greater, under the same flooding pressure, when the production pressure difference is relatively small (4 MPa), it cannot fully exploit the superior seepage capacity of the reservoir. Moreover, the low-permeability reservoir also has low instantaneous and cumulative gas production capacities, and the productivity of the gas well cannot be effectively
exerted. When the production pressure difference is relatively large (8 MPa), the gas in the high-permeability reservoir is rapidly produced, the slope of the gas production curve increases, and the overall instantaneous gas production increases. However, it is difficult to maintain the situation for a long time, and the overall gas supply capacity of the low-permeability reservoirs with weak seepage capacity increases slightly, and this increase is not large, while the continuous gas supply can be maintained. This shows that when the production pressure difference is appropriately increased within a reasonable range, various types of reservoirs can not only improve their contribution to production but also better achieve stable gas supply and improve the gas supply capacity in a single layer.

3.4. Reservoir Production Contribution under Different Initial Water Saturations. According to the experimental data, the relationship between the cumulative gas production change and the instantaneous gas production curve of the reservoir under different water saturations is shown in Figures 11 and 12.

The productivity contribution experiments of simulating high- and low-permeability reservoirs under different water saturations show that the instantaneous gas production and cumulative gas production of different reservoirs both decrease significantly with the increase of the initial water saturation of the core. Moreover, the effect on the high-permeability reservoirs with better physical properties is greater, and the gas production decreases faster. When the water saturation increases above the irreducible water saturation, the gas in the reservoir needs to overcome a certain resistance to start to flow, and the high-permeability reservoir with better physical properties starts to produce formation water preferentially.

With the increase of water saturation, the production contribution rate of high-permeability reservoirs gradually increases, while that of low-permeability reservoirs gradually decreases. When the reservoir water saturation reaches 80%, about 86.67% of the gas production comes from high-permeability reservoirs, while low-permeability reservoirs only contribute about 13.33% of the total gas volume (Figure 13).

The reason is that the formation core is hydrophilic, and after the water saturation increases, the water phase is more likely to form a water film on the pore surface of the reservoir cores or fill the fine throat pores. Because the low-permeability reservoir itself has a small pore throat radius and the formation fluids seepage in the throats, the increase of the formation water saturation greatly reduces its seepage capacity and the gas supply capacity. Specifically, in the experiment, difficult and discontinuous gas outflow from low-permeability reservoirs has also been observed. Generally, the seepage of the high-permeability reservoir at this time shows more advantages, and the formation water flows rapidly to the bottom of the well along the fractures and the large pores of the high-permeability layer, thereby providing a seepage channel for its subsequent gas production. Finally, the high-permeability reservoirs become the main source of productivity for gas wells during periods of high water cut.

4. CONCLUSIONS

In this study, the double-pipe parallel long core model was used to simulate the multilayer commingled production process of the target gas reservoir, and the influence of the gas reservoir seepage characteristics on the development effect under the action of different formation pressures, permeability contrast, and water saturations was studied, and the following conclusions are drawn:

(1) Under the condition of formation temperature, and when the formation pressure is depleted from 46 MPa to an abandonment pressure of 6 MPa, the recovery degree
of the high-permeability pipe at each pressure point is higher than that of the low-permeability pipe, and the changing trends of the recovery degrees of the two pipes are similar. Both recovery degrees of the two pipes show the characteristics of a rapid increase in the initial stage and a slowing decreasing trend in the later stage. When the gas reservoir is multilayer commingled produced, the high-permeability reservoir contributes more to productivity.

(2) In the process of gas reservoir depletion production and water flooding, the water flooding at different stages can greatly make the gas recovery increase. The improvement mainly comes from the fractured zone, which contributes more in the initial process of water flooding. Meanwhile, the fractured zone makes more gas phase in the pores being displaced out that cannot rely on its own elastic energy.

(3) Under the same production pressure difference, when the driving pressure is high, the gas production of the reservoir is greater than that when the driving pressure is low; under the same formation pressure, a moderate increase in the production pressure difference is conducive to the reservoir to give full play to the seepage advantage and improve the gas supply capacity of a single layer of the reservoir. The high-permeability layer with relatively good physical properties under different conditions contributes more to gas well production.

(4) With the increase of the initial water saturation of the core, the instantaneous and cumulative gas production capacities of different reservoirs decreased significantly, and the gas production of the high-permeability layer with better physical properties decreased faster, giving priority to the water production. When the initial water saturation increases, the gas production contribution rate of the high-permeability layer gradually increases, and the seepage capacity of the low-permeability reservoir decreases sharply due to the increase in water content. Furthermore, the phenomenon of gas production difficulty or discontinuous gas production occurs, and the gas production contribution rate gradually decreases. When the water saturation of the reservoir reaches 80%, about 86.67% of the gas production comes from the high-permeability reservoir, making it the main source of productivity for gas wells in the period of high water cut.

Author Information

Corresponding Author
Renyi Lin – Geological Resources and Geological Engineering Post-doctoral Research Station, Chengdu University of Technology, Chengdu, Sichuan 610059, China; College of Energy, Chengdu University of Technology, Chengdu, Sichuan 610059, China; orcid.org/0000-0003-4058-1383; Email: 543663589@qq.com

Authors
Yu Jia – Changqing Downhole Technical Operation Company, Changqing Drilling Engineering Co., Ltd., Xi’an, Shanxi 710018, China
Lei Sun – State Key Laboratory of Oil and Gas Reservoir Geology and Exploitation, Southwest Petroleum University, Chengdu, Sichuan 610500, China

Complete contact information is available at: https://pubs.acs.org/10.1021/acsomega.2c03273

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