Experimental Investigation of the Pressure Decay Characteristics of Oil Reservoirs after Fracturing Operations

Liu Yang, Fukun Shi, Xiaoming Sun,* Shuo Wang, Qingping Jiang, and Huanyu Lu

ABSTRACT: Field experience shows that extending shut-in periods are conducive to increasing tight oil production after fracturing operations. Understanding the regularity of pressure decay is helpful to establish an appropriate shut-in time. However, the characteristics and influencing factors of pressure decay are unclear. This paper studies the porosity, permeability, mineral composition, and pore structure of samples in six different blocks. The pressure decay regularity is tested according to an independently designed indoor shut-in experimental device, and the oil distribution of experimental samples is monitored using nuclear magnetic resonance technology. The results show that the fracturing fluid enters the matrix pores under the action of percolation to slowly drive out the oil, causing the well pressure to decay over time. There are three types of pressure decay characteristics: concave type, fluctuation type, and quadratic type. Compared with conventional sandstone, the pressure decay rate of tight reservoirs is slower, and the pressure decay characteristics are more complicated. Clay mineral-rich reservoirs will swell when exposed to water. As a result, the strength of the framework will be weakened and collapsed. What’s more, it will cause blockage of the throat, blocking the flow of oil and the decay of pressure. In addition, the rate of pressure decay is also related to the volume of fracturing fluid, initial borehole pressure, and formation closure stress. At a certain proppant thickness (fracture width), the larger the fracturing fluid volume, the larger the fracture surface area and the faster the pressure decay rate; Moreover, the greater the initial shut-in pressure, the greater the pressure difference and the faster the decay rate; the formation closure stress causes the core porosity and the permeability to decrease, resulting in a decrease in the decay rate. The experimental results are of great significance for establishing a proper shut-in time and enhancing the oil recovery of tight reservoirs.

1. INTRODUCTION

With the gradual depletion of energy, the development of oil and gas fields is gradually inclined to unconventional exploitation. In general, unconventional energy sources often have the characteristics of low porosity, low permeability, and low formation pressure, and thus, a series of problems have arisen for oil and gas field production, such as rapid production depletion and low oil recovery. In response to such problems, domestic and foreign experts have proposed hydraulic fracturing technology, which forms a complex fracture network by injecting a large amount of fracturing fluid into the well and increasing the pressure coefficient of the reservoir. After hydraulic fracturing operations, the oil well is usually closed for a period of time to promote the imbibition of fracturing fluid in the reservoir as soon as possible, so that the fracture network continues to expand. This method has been used in on-site mining and has been proved to be an effective method to increase production.

Prolonging the shut-in time will lead to special production performance, including pressure decay, low flowback efficiency, and high-salinity flowback water. These production dynamics are mainly caused by the interaction between fracturing fluids and reservoirs. After the fracturing operations, a large amount of fracturing fluid flowback in the fracture network interacts strongly with micro–nano-pores. As a result, the fracturing fluid enters the matrix pores under the action of percolation, which makes the fracturing fluid difficult to flowback, and the flowback rate is low. At the same time, the flow of the fracturing fluid will cause the decay of the well pressure. In addition, salt ions in the matrix pores diffuse into the fracturing fluid, causing the salinity in the fracturing fluid to rise rapidly. When the imbibition front comes into contact with the pore wall, salt ions will dissolve and diffuse into the fracturing fluid. However, the dissolution and imbibition of salt ions will...
also change the surface wettability and water–rock chemical potential difference, which will affect the permeability advancing speed of the suction front. Understanding the production performance of tight reservoirs is helpful for understanding reservoir characteristics and artificial fracture patterns and is of great significance for optimizing shut-in time and enhancing oil recovery.12–15

To optimize the initiation threshold pressure and shut-in time, Zhang et al.10 considered the effect of fracturing fluid intrusion into shale reservoirs and on-site production data and obtained the effects of shut-in time and flowback measures at different times on shale gas productivity. Based on the criterion of fracture closure judgment criteria, Han et al.11 studied the triaxial in-situ stress test results of the Changning block in the Sichuan Basin and obtained the fracture initiation threshold pressure of shale gas wells. In addition, the reasonable shut-in time of the block was calculated. However, the calculation process of shut-in time did not take into account the chemical changes during the interaction between the fracturing fluid and the reservoir, which made the calculation results have a certain deviation.16

Existing results indicate that a series of physicochemical reactions will occur when clay minerals encounter water, causing expansion of clay minerals, leading to a decrease in reservoir strength and cracks.12–15 Dehghanpour et al.16 conducted in-depth research on the water absorption capacity of shale and found that the water absorption capacity of shale is related to the ability of clay minerals to absorb water and capillary forces. In addition, microfractures would be generated after shale absorbs water, making the rocks smooth surface and small sandy particles. In addition, the permeability is 0.064 mD and the porosity is 5.6%, which belongs to a low-porosity and low-permeability reservoir. The A1 sample is a tight sandstone, and glutenite. The A2 sample is tight sandstone in the Ordos area, the A2 sample is tight sandstone in the Ordos area, which is grayish white, with a smooth surface and uniformly smooth sandstone, and glutenite.

The A1 sample is tight sandstone from Ordos, China. It is grayish white, with a smooth surface and uniformly distributed sand particles. In addition, the permeability is 0.0023 mD and the porosity is 1.8%, which belongs to a low-porosity and low-permeability reservoir. The A2 sample is tight sandstone in the Ordos area, the A2 sample is tight sandstone in the Ordos area, which is grayish white, with a smooth surface and small sandy particles. In addition, the permeability is 0.18 mD and the porosity is 7.4%, and hence, it has low porosity and low permeability characteristics. The A3 sample is a sandy conglomerate, from the Xinjiang Province, China. The gravel is cemented with grayish black color, smooth surface, and tight structure. In addition, the permeability is 0.06 mD and the porosity is 7.4%, and it belongs to a low-porosity and low-permeability reservoir.

The A4 sample is shale from Jilin Province, China, with a gray-black color, smooth surface, and tight structure. In addition, the permeability is 0.0023 mD and the porosity is 2.5%, which belongs to low-porosity and low-permeability reservoirs. The A5 sample is shale from Sichuan province, China, which is black. Moreover, its permeability is 0.054 mD and porosity is 1.8%, and it belongs to a low-porosity and low-permeability reservoir. The A6 sample is conventional sandstone 1.1 mD and the porosity is 9.2%, which belongs to a low-porosity and low-permeability reservoir.

Table 1. Physical Characteristics of Experimental Samples

| numbering | lithology          | permeability (mD) | porosity (%) | length (cm) | diameter (cm) |
|-----------|--------------------|-------------------|--------------|-------------|---------------|
| A1        | tight sandstone    | 0.0064            | 5.6          | 5.1         | 2.5           |
| A2        | tight sandstone    | 0.18              | 3.6          | 4.0         | 2.5           |
| A3        | glutenite          | 0.06              | 7.4          | 5.3         | 2.5           |
| A4        | shale              | 0.0023            | 2.5          | 5.2         | 2.5           |
| A5        | shale              | 0.054             | 1.8          | 5.0         | 2.5           |
| A6        | conventional sandstone | 1.1            | 9.2          | 4.2         | 2.5           |

Table 2. Results of Mineral Composition Analysis

| label | total mineral composition (wt %) | relative clay abundance (wt %) |
|-------|---------------------------------|------------------------------|
|       | quartz  | feldspar | calcite | clay | montmorillonite | illite | I/S | chlorite | kaolinite |
| A1    | 42.8    | 28.7     | 12.6    | 15.9 | 5.6            | 23.4  | 42.2 | 8.9      | 19.9      |
| A2    | 35.6    | 33.7     | 9.9     | 20.8 | 20.1           | 41.2  | 28.7 | 0        | 6.7       |
| A3    | 27.4    | 21.4     | 21.6    | 29.6 | 45.7           | 13.7  | 44.4 | 0        | 8.2       |
| A4    | 30.3    | 13.2     | 22.4    | 34.1 | 55.0           | 16.0  | 43.7 | 7.3      | 0         |
| A5    | 13      | 22.1     | 33.7    | 31.2 | 65.0           | 12.7  | 0    | 5.8      | 3.5       |
| A6    | 33      | 32.3     | 25.8    | 8.9  | 0              | 53.2  | 13.2 | 33.6     | 0         |

I/S represents the Illite–smectite mixed layer.

2. EXPERIMENTAL SECTION

2.1. Sample and Fluid Information. Experimental sample numbers are A1—A6. The samples selected for this experiment are cylinders with a diameter of 2.5 cm and lengths ranging from 2.5 to 5 cm. They come from Xinjiang Basin, Jilin Basin, and Sichuan Basin, respectively. Lithology includes four types of shale, tight sandstone, conventional sandstone, and glutenite.
sandstone, which is light yellow. In addition, the permeability is 1.1 mD and the porosity is 9.2%. It belongs to a low-porosity and low-permeability reservoir. The physical characteristics information of experimental samples is shown in Table 1, and the mineral composition information is shown in Table 2.

Deuterium water is used as the experimental fluid in this experiment. Deuterium water can shield the nuclear magnetic resonance signals and help in studying the distribution and migration of oil in the pores.

2.2. Experimental Instruments and Procedures. The experimental equipment is designed and developed independently, including grippers, intermediate containers, pressurization systems, nuclear magnetic resonance (NMR) detection systems, and pressure detection systems. Among them, the holder uses a Hasler type core holder to wrap the core. The nuclear magnetic resonance detection device uses a MesoMR-060H-HTHP-I low-field nuclear magnetic resonance analyzer, which is produced by Newman Analytical Instrument Co., Ltd and has a resonance frequency of 21.326 MHz. The intermediate container provides the fluid space required for the manhole well of a high-pressure piston container. The booster system uses a Quizix SP-5000 high-pressure metering pump with a maximum injection pressure of 68.97 MPa (10 000 psi) and a maximum flow rate of 15 mL/min. The experimental temperature is 24 °C, and the confinement pressure and initial displacement pressure are provided. The experimental design is shown in Figure 1, and the inner diameter of the intermediate container is 8.3 cm. Before starting, deuterium water with a height of 3.62 cm is injected into an intermediate container to ensure the volume of the pump. The core was put into the holder with a diameter of 2.5 cm and an ISCO pump was used to increase the confining pressure to 18 MPa. The ISCO pump was used to pressurize the pressure in the intermediate container to 15 MPa. The valve between the intermediate container and the holder was opened. When the pressure sensor reached 15 MPa, the valve between the ISCO pump and the intermediate container was closed.

(4) The number of counts connected to the pressure sensor was observed and the experimental data were recorded. The T2 spectrum was tested again, and the experiment is complete.

3. RESULTS AND DISCUSSION

3.1. Decay Characteristics. 3.1.1. Pressure Decay Characteristics. Figure 2 shows the pressure decay characteristics of six samples. To make the experimental data more effective, use origin software to curve fit the obtained experimental data points. The fitting result found that A1 fitting factor R^2 is 0.9929, A2 fitting factor R^2 is 0.9870 and A6 fitting factor R^2 is 0.9992. The pressure decay characteristic curves of the A1 and A6 samples are both concave type. A1 and A6 samples conform to the exponential function decay characteristic. The exponential function formula is as follows

\[ P = P_0 + a e^{-t/t_0} \]

where \( P \) is the total pressure-dependent variable, \( P_0 \) is the initial value of pressure decay, \( t \) is a time variable, and \( a \) and \( t_0 \) are constants. When time \( t = 0 \), the pressure \( P \) is close to the initial value of the experiment. When time \( t \) is infinite, the pressure \( P \) is close to the lower limit of pressure decay of the reservoir.

The exponential function formula is derived once to obtain the pressure decay rate formula as follows

\[ P' = -\frac{a}{t_0} e^{-t/t_0} \]
From this formula, it can be concluded that the pressure decay rate of A1 and A6 samples gradually decreases with the increase of shut-in time. It can be seen from the figure that although the decay characteristics of the two are similar, the shut-in time required when dropping the same pressure is different. Considering that A1 is tight sandstone and A6 is conventional sandstone, the physical characteristics of the two are quite different, and thus, further analysis is needed based on physical characteristics.

The A2 sample meets the characteristics of the quadratic function, which is derived once to obtain the pressure decay rate

\[
P' = 0.0536t - 0.8712
\]
When $P' = 0$, $t_0 = 16.25$ days is obtained. Considering that the pressure decay rate is zero, the fluid velocity in the core is reduced to zero. In addition, the A2 sample is tight sandstone. The clay content is low, and the decrease in the pressure decay rate is mainly due to the decrease in the fluid pressure difference. Therefore, when the shut-in time is $t_0 = 16.25$ days, the pressure environment of the A2 sample is in equilibrium.

The pressure decay curves of A3, A4, and A5 samples are more complicated. Therefore, the curve is segmented. To ensure the validity of the data, the fluctuation range of the fitting factor $R^2$ is around $0-1$. What is more, compared with A1, A2, and A6, the fitting effect of A4 and A5 samples still has a significant gap. The introduction of the same variable cannot fit the pressure decay law better. During the pressure decay process of A3, A4, and A5, the phenomenon of shut-in pressure “not falling but rising” occurs in varying degrees. Specifically, the overall trend of section I in the A3 sample accord with the decline stage, which is due to the phenomenon of the fluid entering the core. The pressure in section II gradually increases. Due to the high clay content of the A3 sample, the poor bonding ability between the filler and the matrix leads to blockage of the fluid channel. There is a significant drop in the pressure in section III. This is due to the dissolution of part of the mineral composition and the partial opening of the fluid channel, resulting in a drop in pressure. For the A4 sample, the phenomenon of shut-in pressure “not falling but rising” is more obvious. In the first stage, the pressure decay value rises above the initial pressure value by 15 MPa and reaches 16 MPa. The analysis showed that the reason for the increase in pressure is due to the decrease in the pore volume within the rock. The pressure of section II decreases first and then increases because the A4 sample is shale and a pore network is developed. The fluid causes a pressure drop during the expansion of the pore network. In addition, water reacts with the clay to cause the clay to expand and increase the pressure. The pressure in section III drops slowly, which is caused by the dissolution of some rock minerals.

In the A5 sample, the pressure in section I first decreases and then increases. As the pressure of the fluid entering the pore channel decreases, the pressure rises after the water encounters the clay and expands due to water absorption. The pressure trend of section II is similar to that of section III. When the clay minerals are dissolved, the fluid channel partially penetrates and the fluid passes through. When new clay minerals are encountered, they absorb water and expand again. Generally speaking, A3, A4, and A5 show undulating characteristics of pressure decay.

3.1.2. T2 Spectrum Decay Characteristics. Figure 3 shows the NMR T2 spectra of the experimental sample before and after the pressure decay experiment. The ordinate represents the signal amplitude. The larger the amount of pore fluid, the higher the signal peak. The abscissa represents the relaxation time $T2$, which has a positive correlation with the pore size. The deuterium water used in the experiment has no signal so a change in the signal amplitude before and after the experiment reflects the kerosene content in the sample. It can be seen from the figure that after the experiment, the signal intensity peaks of the experimental samples have been reduced to varying degrees. This is because the deuterium water in the intermediate container drives away the kerosene in the core. Therefore, the peak value of the T2 spectrum after the experiment is smaller than that before the experiment. Among them, the signal amplitudes of tight sandstone A1 and conventional sandstone A6 decreased relatively significantly to 81.2 and 66.5%, respectively. The amplitudes of tight sandstone A2 and shale A5 changed to relatively smaller values of 27.4 and 17.3%, respectively. The amplitudes of glutenite A3 and shale A4 decreased to 37.7 and 66.9%, respectively.

It can be seen from Figure 4 that the T2 spectrum of A3, A4, and A5 has relatively special changes. The amplitude of the signal after the experiment is in a certain relaxation...
period, a phenomenon larger than that before the experiment occurred. After the experiment, the relaxation time of sample A3 is $0.1 \sim 10$ ms and the relaxation time is $10 \sim 100$ ms. After the experiment, the penetration phenomenon appeared. The clay mineral content of sample A3 is relatively high. The clay minerals softened due to water absorption and expansion. Under the action of pressure, new fractures appeared. After the sample A4 is shut-in for a period of time, the signal amplitude increased significantly during the relaxation time of $10 \sim 1000$ ms, and its large pores and large fractures have an obvious expansion effect. In addition, there are a few new cracks in the relaxation time of $0.1 \sim 10$ ms. The signal amplitude of sample A5 has a certain increase within the relaxation time of $10 \sim 100$ ms, indicating that after a period of simmering in the well. What is more, the pore structure has a tendency to penetrate through and form large fractures. In addition, the lithology of samples A4 and A5 revealed that they are both shale, with high clay contents and tight and small pore distributions. The pore structure of hydrophilic minerals in both samples changed significantly after encountering water. Under the interaction of the movable

![Figure 4. T2 spectrum of pressure decay nuclear magnetic resonance: (a) tight sandstone, (b) tight sandstone, (c) glutenite, (d) shale, (e) shale, and (f) conventional sandstone.](https://dx.doi.org/10.1021/acsomega.0c02909)
fluid and pressure, the matrix between the pores will dissolve and disintegrate to produce new cracks.

The area of the T2 spectrum reflects the amount of fluid in the pore structure of the sample. Therefore, the amount of oil present in the core is quantitatively expressed by calculating the T2 spectrum area. When the indoor temperature is 24 °C, the overpressure is 18 MPa and the displacement pressure is 15 MPa. The oil content of the six samples is calculated. A1 is replaced with 22.1% remaining, A2 is replaced with 70.7% remaining, A3 is replaced with 70.6% remaining, A4 is replaced with 64.9% remaining, A5 is replaced with the highest remaining oil amount, reaching 84.7%, and A6 is replaced with the least remaining oil.

| Table 3. Information Sheet of the Recovery Factor |
|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|-----------------|
| numbering       | A1              | A2              | A3              | A4              | A5              | A6              |
| T2 spectral area before the experiment | 15 | 1697.1 | 7929.89 | 5674.84 | 2191.41 | 1966.18 |
| after the experiment | 3357.76 | 5610.19 | 4008.07 | 1422.42 | 1666.13 | 1422.43 |
| recovery factor (%) | 77.9 | 29.3 | 29.4 | 35.1 | 15.3 | 96.2 |

Figure 5. Pressure decay rate under pore infiltration.

Figure 6. Pressure decay rate under the action of clay minerals.
amount, leaving only 3.8%. The detailed recovery ratio is shown in Table 3.

3.2. Influencing Factors. In the pressure decay experiment, the characteristics of the pressure decay of the six reservoir samples are quite different, especially for the A3, A4, and A5 samples. The fitting effect of the pressure decay law shows that there are many factors that affect the pressure drop. Based on this, the physical properties of the six samples and the experimental conditions analyze the reasons for the effect of pressure decay, exploring the main factors affecting pressure decay, and provide theoretical guidance for on-site development.

3.2.1. Physical Properties of Rocks. Figure 5 shows the effect of the physical properties of rocks on the pressure decay rate. It can be seen from the figure that both porosity and permeability are positively correlated with the pressure decay rate, and the fitting factors $R^2$ are 0.4167 and 0.9802, respectively. This means that the permeability has a high correlation with the pressure decay rate. Specifically, as can be seen from Figure 4, if tight sandstone A1 is not taken into account, it can be seen that the permeability has a strong correlation with the pressure decay rate; however, the effect of porosity on the pressure decay rate is relatively small. This is due to the throat that can't let the fluid through smoothly.

The reason why the tight physical properties of the tight sandstone A1 have a weak correlation with the pressure decay rate is that the porosity and permeability are not very large but the permeability has increased significantly. Analysis of the reason found that this is related to the less absorbable clay mineral content in the tight sandstone. Due to the high clay content of the A3–A5 samples, the clay particles will block thethroating phenomenon when they absorb water and expand. The shale A5 sample has high porosity and high clay content. The throat is easily blocked after water absorption so the pressure decay rate is not high.

It can be seen from the figure that the permeability of the other samples is less than 0.2 mD except for the permeability of conventional sandstone A6. If the conventional sandstone A6 is not considered, the correlation between permeability and recovery can be seen as small. In addition, it is considered that porosity and mineral composition have a decisive influence on permeability. The coupling between the mineral composition and water will cause the porosity to change so the mineral composition needs to be analyzed.

3.2.2. Mineral Composition. Figure 6 shows the effect of clay minerals on the rate of pressure decay. Considering that the water encounters different types of rocks and minerals, the degree of interaction is different, and the formation of montmorillonite, illite, and illite-smectite encounters physical and chemical reactions more strongly when they encounter water. Based on this, the relationship between the pressure decay rate and the formation of montmorillonite, illite, and illite-smectite is obtained. According to the fitting factor $R^2$, it can be seen that the correlation between the formation of montmorillonite, illite-smectite, and illite and the pressure decay rate gradually decreases.

Samples A1 and A2 are both tight sandstone. Because its clay content is relatively small, when the water passes through the rock surface, it only causes the expansion deformation of the throat. The fluid channel becomes smaller, but the fluid can still pass through. The porosity of the A3 conglomerate is large, its clay content is high, and the bonding ability between the matrix and the filler is poor. Therefore, it is easy to swell and fall off when it encounters water, causing the

Figure 7. Fracturing fluid injection into the reservoir: (a) Injection of 0.9 V of the fracturing fluid, (b) injection of 1.8 V of the fracturing fluid, and (c) injection of 3.6 V of the fracturing fluid, where V represents the volume of the fracturing fluid initially injected into the reservoir.
fluid channel to be blocked, and the fluid cannot pass through. The pore structures of A4 and A5 shales are extremely developed, with small pores and high montmorillonite contents. Therefore, the specific surface area of shale is large, and the fluid can be in contact with minerals on the shale surface to a high degree. Montmorillonite blocks the fluid channel after expansion, keeping the pressure at a high value during shut-in. For the A1 sample, due to the low clay content, there is no obvious physical and chemical change in the pore structure when the rock is in contact with water. In addition, the fluid channel is not blocked, and the pressure decay rate is fast.

3.2.3. Initial Volume. After the fracturing fluid is injected into the oil well, the reservoir pressure increases rapidly. When it is higher than the in-situ stress, a complex fracture network is formed around the oil well. After the well is closed for a period of time, the injected fracturing fluid continues to diffuse around the fracture channel along with the fracture channel network expansion, as shown in Figure 7, considering that the volume of the injected fracturing fluid is close to the volume of fractures formed after fracturing. Based on this, the pressure decay experiment under different initial volumes (0.9, 1.8, and 3.6 V) is carried out for the same sample, and the pressure decay characteristic graph is obtained. As shown in Figure 8, where V represents the volume of the intermediate container with a fluid height of 1 cm and a cross-sectional area of 54.08 cm$^2$. In addition, V represents the volume of the fracturing fluid initially injected into the reservoir. It can be seen from the figure that when the decay time reaches 6.9 days, the pressure drop has a large difference. Specifically, when the volume is 0.9 V, the pressure drops by 29.3%. When the volume is 1.8 V, the pressure decays by 54.0%. When the volume is 3.6 V, the pressure is reduced by 79.7%. Comparing the above experimental results, it can be found that when the initial pressure of the same core is constant, the larger the volume of liquid in the intermediate container, the faster the pressure decay rate.

The larger the volume, the greater the volume of fractures formed after fracturing. At a certain thickness of the proppant (fracture width), the increase in the fracture surface area promotes the flow of fracturing fluid into the reservoir and causes pressure decay. Therefore, pressure decay can reflect the scale of the volume of fractures.

3.2.4. Initial Borehole Pressure. The pressure decay experiment under different initial borehole pressures (5, 15,
and 25 MPa) is carried out for the same sample, and the pressure decay characteristic diagram is obtained, as shown in Figure 9. It can be seen from the figure that the fastest pressure decay rate is when the initial displacement pressure is 25 MPa, followed by 15 MPa and finally 5 MPa. Specifically, when the decay time reaches 6.9 days. For an initial pressure of 25 MPa, the initial pressure decay is 82.2%; for an initial pressure of 15 MPa, the initial pressure decay is 82%; and for an initial pressure of 5 MPa, the initial pressure decay is 77.6%.

When the initial pressures are different, according to Darcy’s law, the seepage velocity increases due to the increase in pressure difference. Therefore, it can be concluded that for the same core decay time, the greater the initial pressure, the faster the pressure decay rate.

3.2.5. Formation Closure Stress. Figure 10 shows the pressure decay characteristics under different restraint pressures (18, 28, and 38 MPa). It can be seen from the figure that when the restraint pressures are different, the decay laws are significantly different. Therefore, when the shut-in time is 6.9 days and the restraint pressure is 18 MPa, the pressure decay rate is the fastest and the pressure decay amplitude is 82.0%. In addition, no obvious pressure fluctuations are seen during the decay process. When the restraint pressure is 28 MPa, the pressure decay rate is significantly slowed down and the pressure decay amplitude is 37.8%. Moreover, the binding pressure has a significant effect on the flow of fluid in the rock; when the restraint pressure is 38 MPa, the pressure decay amplitude is only 2.1%. With the increase of time, the pressure does not significantly decay and fluctuates around the initial pressure value.

Generally speaking, the physical properties of rocks include porosity and permeability. The effect of porosity on the pressure decay characteristics of rocks is mainly achieved by affecting the compressibility of rocks under pressure. Rocks are composed of rock particles and fillers. The forces between the rock particles include pore pressure and effective stress. When the rock is overburdened, the pore pressure is reduced due to the mutual deformation of the rock particles. Therefore, the effective force between rock particles enhanced. In addition, the pore structure of the rock will also change, and as a result, the pores become smaller and the permeability of the movable fluid through the rock decreases. In this paper, the compressibility of the rock pore structure is mainly derived from the effect of confining pressure, as shown in Figure 11.

3.3. Discussion. Production analysis of five wells in the Mahu block and three wells in the Changning block is done. Among them, the Mahu block is produced by oil reservoirs, and the physical properties of the reservoirs are similar. However, the difference in the depth of the oil layer is obvious, and the amount of fracturing fluid used in each section is different. Therefore, the initial well pressure is quite different. It can be seen from Figure 12a that the initial simmering well pressure of the reservoir where the well in the block is distributed is between $10^{-35}$ MPa, and the pressure decay characteristic curve is similar to the pressure decay characteristic curve of samples A3–A5 in the indoor shut-in experiment similar. In addition, the phenomenon that the
initial pressure rises when the well is closed, the pressure does not drop, and the magnitude of the drop is not large belongs to wave-type decay or linear-type decay. Figure 12b is the B5 well in the Mahu block. It can be seen that the characteristics of the wells in the block are similar to the A2 curve in the indoor experiment, and all belong to quadratic linear fluctuations. In Figure 12c, C1–C3 is the on-site data graph of shale gas production in the Changning block. The wells in the three wells in this block are 15, 10, and 9 days, respectively. The experimental data A1 and A6 of the experimental data obtained by the indoor experimental research have similar pressure decay characteristics, which are in line with the concave characteristics. The pressure decay trend conforms to the mathematical formula

\[ P = P_0 + ae^{-t/t_0} \]

By referring to the field data of the eight wells in the two blocks, it is shown that the indoor experiments carried out in this paper have important reference significance for the development of oil and gas fields.

4. CONCLUSIONS

(1) In the indoor shut-in experiment, there are three types of pressure decay characteristics: concave type, fluctuation type, and quadratic type.

(2) There are many factors that affect the shut-in effect. The fitting factor \( R^2 \) can be obtained: Porosity and permeability have a positive relationship with the pressure decay rate, and the porosity has a greater correlation. The correlation between the formation of montmorillonite, illite–smectite, and illite with the pressure decay rate of the shut-in gradually decreases. During the experiment, the initial simmering well pressure and initial volume are all positively correlated with the pressure decay rate. In addition, the restraint pressure has a negative correlation with the pressure decay rate.

(3) Compared with conventional sandstone, the pressure decay rate of a tight sandstone reservoir is slower, and the decay characteristics are more complicated. Reservoirs rich in clay minerals will swell when they encounter water, which will cause the strength of the skeleton to collapse and cause blockage of the bellows. In addition, the blockage of the bellows hinders oil flow and pressure decay.

(4) The pressure decay rate is also related to the volume of the fracturing fluid, initial shut-in pressure, and formation closure stress. At a certain proppant thickness (fracture width), the larger the volume of the fracturing fluid, the greater the fracture surface area and the faster the pressure decay rate. Moreover, the greater the initial shut-in pressure, the greater the pressure difference and the faster the decay rate. The formation closure stress causes the core porosity to
decrease and the permeability to decrease, which cause the pressure decay rate to decrease.

# AUTHOR INFORMATION

## Corresponding Author

Xiaoming Sun — State Key Laboratory for Geomechanics and Deep Underground Engineering, China University of Mining and Technology (Beijing), Beijing 100083, China; School of Mechanics and Civil Engineering, China University of Mining & Technology (Beijing), Beijing 100083, China; Email: sxmcyumb@163.com

## Authors

Liu Yang — State Key Laboratory for Geomechanics and Deep Underground Engineering, China University of Mining and Technology (Beijing), Beijing 100083, China; School of Mechanics and Civil Engineering, China University of Mining & Technology (Beijing), Beijing 100083, China; orcid.org/0000-0002-7568-8685

Fukun Shi — State Key Laboratory for Geomechanics and Deep Underground Engineering, China University of Mining and Technology (Beijing), Beijing 100083, China; School of Mechanics and Civil Engineering, China University of Mining & Technology (Beijing), Beijing 100083, China; orcid.org/0000-0002-7568-8685

Shuo Wang — State Key Laboratory for Geomechanics and Deep Underground Engineering, China University of Mining and Technology (Beijing), Beijing 100083, China; School of Mechanics and Civil Engineering, China University of Mining & Technology (Beijing), Beijing 100083, China; orcid.org/0000-0002-7568-8685

Qingping Jiang — China Research Institute of Exploration and Development, Xinjiang Oilfield Company, PetroChina, Xinjiang 834000, China

Huanyu Lu — State Key Laboratory for Geomechanics and Deep Underground Engineering, China University of Mining and Technology (Beijing), Beijing 100083, China

Complete contact information is available at: https://pubs.acs.org/10.1021/acsomega.0c02909

## Author Contributions

The manuscript was written through contributions of all the authors. All authors have read and agreed to the published version of the manuscript.

## Notes

The authors declare no competing financial interest.

# ACKNOWLEDGMENTS

The research was funded by the National Natural Science Foundation of China (41941018), the National Key Research and Development Program (Grant nos. 2018YFC0603705 and 2016YFC0600901), and the Fundamental Research Funds for the Central Universities.

# REFERENCES

(1) Huang, B.; Cheng, Q.; Chen, S. Phenomenon of methane driven caused by hydraulic fracturing in methane-bearing coal seams. *Int. J. Min. Sci. Technol.* 2016, 26, 919−927.

(2) Holditch, S. A.; Tschihart, N. Optimal Stimulation Treatments in Tight Gas Sands. *SPE Annual Technical Conference and Exhibition*; Dallas, TX, Oct 9−12, 2005; SPE 96104; Society of Petroleum Engineers: Richardson, TX, 2005.

(3) Barzegar Alamdari, B.; Kiani, M.; Kazemi, H. Experimental and Numerical Simulation Of Surfactant-Assisted Oil Recovery In Tight Fractured Carbonate Reservoir Cores. *SPE Improved Oil Recovery Symposium; Tulsa, OK April 14−18, 2012; SPE 153902; Society of Petroleum Engineers: Richardson, TX, 2012.

(4) Kathel, P.; Mohanty, K. K. Wettability Alteration in a Tight Oil Reservoir. *Energy Fuels* 2013, 27, 6460−8.

(5) Habibi, A.; Xu, M.; Dehghanpour, H.; Bryan, D.; Usik, G. Understanding Rock-Fluid Interactions in the Montney Tight Oil Play*SPE/CSUR Unconventional Resources Conference; Calgary, Alberta, Canada, Oct 20−22, 2015; SPE 175924; Society of Petroleum Engineers: Richardson, TX, 2015.

(6) Carpenter, C. Impact of Hydraulic Fracture on Well Productivity. *J. Pet. Technol.* 2013, 65, 162−165.

(7) Jiang, Y.; Shi, Y.; Xu, G.; Jia, C.; Meng, Z.; Yang, X.; Zhu, H.; Ding, B. Experimental Study on Spontaneous Imbibition under Confining Pressure in Tight Sandstone Cores Based on Low-Field Nuclear Magnetic Resonance Measurements. *Energy Fuels* 2018, 3152−3162.

(8) Jiang, R.; Wang, P.; Wei, X.; Wang, G.; Li, H. Study on the influencing factors of the start-up status of low fluid reservoirs. *Special Oil Gas Reserv.* 2012, 19, 153−154.

(9) Wang, F.; Bian, H.; Zhang, Y.; Duan, C.; Gang, C. Hilbert-Huang transform combined smooth pseudo-Wigner-Ville time-frequency distribution to identify reservoir fluid properties. *Geophys. Prospect.* Pet. 2016, 55, 851−860.

(10) Zhang, T.; Li, X.; Yang, L.; Li, J.; Wang, Y.; Feng, D.; Yang, J.; Li, P. Impact of shut-in timing on shale gas well return rate and productivity. *Nat. Gas Ind.* 2017, 37, 48−60.

(11) Han, H.; Yang, B.; Peng, J. Study on the initiation and expansion of shale water absorption during manholes during fracturing—Taking a platform well in the Longmaxi Formation in the Changning block of Sichuan Basin as an example. *Nat. Gas Ind.* 2019, 39, 74−80.

(12) He, M.; Zhou, L.; Li, D.; Wang, C.; Nie, W. Experimental study on water absorption characteristics of deep well mudstones. *Chin. J. Rock Mech. Eng.* 2008, 06, 1113−1120.

(13) Fan, M.; Jin, Y.; Fu, W.; Chen, M.; Han, H.; Zhou, X. Experimental study on acoustic emission characteristics of hydraulic fracture propagation behavior. *Chin. J. Rock Mech. Eng.* 2018, 37, 3834−3841.

(14) Lu, Y.; Wang, H.; Guan, B.; Liu, P.; Guo, L.; Wu, J.; Yi, X. Causes of low return rate of marine shale fracturing fluids. *Nat. Gas Ind.* 2017, 37, 46−51.

(15) Cai, J.; Perfect, E.; Cheng, C. L.; Hu, X. Y. Generalized modeling of spontaneous imbibition based on Hagen–Poiseuille flow in tortuous capillaries with variably shaped apertures. *Langmuir* 2014, 30, 5142−5151.

(16) Dehghanpour, H.; Lan, Q.; Saeed, Y.; Fei, H.; Qi, Z. Spontaneous imbibition of brine and oil in gas shales: Effect of water adsorption and resulting microfractures. *Energy Fuels* 2013, 27, 3039−3049.

(17) S, D.; A, T.; M, R.; H, R. R.; K, M.; S, J.; M, S. Pressure and rate transient modeling of multi fractured horizontal wells in shale gas condensate reservoirs. *J. Pet. Sci. Eng.* 2020, 185.

(18) Wang, G. Water absorption characteristics of shale reservoirs and their influence on fracture conductivity. *Fault Block Oil and Gas Fields* 2020, 27, 95−98.

(19) Zhu, B.; Li, X.; Wu, X.; Wang, Y. Experimental study on microscopic characteristics of black shale swelling with water. *Chin. J. Rock Mech. Eng.* 2015, 34, 3896−3905.

(20) Sun, W.; Zuo, Y.; Xi, Z.; Xu, Y. Characteristics of pore fissures and permeability in shale pores of Niutitang Formation in northern Guizhou. *Coal Technol.* 2017, 36, 95−98.

(21) Li, Y.; Liu, C.; Liu, L.; Sun, J.; Liu, H.; Meng, Q. Experimental study on evolution behaviors of triaxial-shearing parameters for hydrate-bearing intermediate fine sediment. *Adv. Geo-Energy Res.* 2018, 2, 43−52.

(22) Meng, Q.; Cai, J. Recent advances in spontaneous imbibition with different boundary conditions. *Capillarity* 2018, 1, 19−26.
(23) Han, G.; Liu, Y.; Kumar, N.; Zhou, Y. Discussion on seepage governing equations for low permeability reservoirs with a threshold pressure gradient. *Adv. Geo-Energy Res.* 2018, 2, 245–259.

(24) Wijaya, N.; Sheng, J. J. Mitigating near-fracture blockage and enhancing oil recovery in tight reservoirs by adding surfactants in hydraulic fracturing fluid. *J. Pet. Sci. Eng.* 2020, No. 106611.

(25) You, L.; Xie, B.; Yang, J.; Kang, Y.; Han, H.; Wang, L.; Yang, B. Damage mechanism of shale gas well fracturing fluid return to reservoir fractures. *Nat. Gas Ind.* 2018, 38, 61–69.

(26) Wang, D. M.; Butler, R.; Liu, H.; Ahmed, S. Flow-rate behavior and imbibition in shale. *SPE Reserv. Eval. Eng.* 2011, 14, 485–492.