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Experimental NMR Analysis of Oil and Water Imbibition during Fracturing in Longmaxi Shale, SE Sichuan Basin

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The decrease in fracturing fluid flowback rate in the process of hydraulic fracturing and the improvement of initial gas production rate after well shut-in for a period of time were investigated using weight and nuclear magnetic resonance (NMR) T_2 spectra of dried shale cores and shale cores in the “as received” state after spontaneous oil and water imbibition. Experimental results indicated that the rate and weight during spontaneous water imbibition were much higher than those of spontaneous oil imbibition, contrary to capillary-driven imbibition models. Therefore, spontaneous water imbibition was related to both capillary pressure and additional hydration stress generated by clay swelling. NMR T_2 spectra of different imbibition fluids (oil and water) demonstrated that signals between 0.01 ms and 1 ms were total responses of pore fluids and irreducible water, and excess imbibed water was mainly present as irreducible water in shale. Excess imbibed water flowed into the matrix and reacted with minerals to generate many micro-fractures which may connect isolated organic pores to mitigate water blocking.

Keywords

Longmaxi shale, Spontaneous imbibition, NMR, Excessive imbibed water, Isolated organic pore

1. Introduction

Hydraulic fracturing is a process in which a relatively large volume of fracturing fluid is pumped under high pressure into a deep rock formation to increase the density of cracks allowing free flow of natural gas, petroleum, and water within a shale gas reservoir. Massive hydraulic fracturing is presently essential to improve shale gas production^{1)~3)}. However, a large amount of water contained in the fracturing fluids may be absorbed into the shale matrix to reduce the permeability. Consequently, the flowback rate of fracturing fluids may fall by more than 50 % and reservoir damage may occur^{4)~9)}. The latest studies of spontaneous imbibition in shale gas reservoirs suggest that the migration pathways and initial gas production rate may improve after well shut-in for a period of time^{10),11)}. The correct use of shale spontaneous imbibition characteristics may improve shale gas recovery^{12),13)}. Therefore, optimization of the fracturing fluid formula and evaluation of the fluid-shale model require understanding of spontaneous imbibition in gas shale, including the process of imbibition, position of fluids imbibed in shale, and

the mechanism of occurrence. However, the dependence of spontaneous imbibition in shale on wettability and the location of excess imbibed fluids in shale are little understood.

In conventional sandstone and carbonate reservoirs, capillary pressure is related to surface tension, wettability and pore radius, and may dominate the volume of spontaneous imbibition^{14)~19)}. However, the progress of spontaneous imbibition in shale may be challenging to measure and simulate because of the intense mixed wettability in organic-rich shale^{20)~22)}. Micron- and nano-scale pores, and bedding planes in organic-rich shale exert strong capillary forces²³⁾. Oil and water will be spontaneously imbibed into core pores under strong capillary pressure which can reflect the migration of fluid in the reservoir. Water contact with clay minerals will generate hydration stress to further complicate the process of spontaneous water imbibition. The volume of spontaneous water imbibition is dominated by the type of clay minerals and water salinity^{24)~26)}. In addition, clay swelling and hydration stress caused by water adsorption may detach the clay seam²⁷⁾. The occurrence of induced fractures may lead to reduction in shale density²⁸⁾ and increase in absolute permeability²⁹⁾ if no confining pressure is present. Therefore, spontaneous imbibition is directly related to the effects of shale gas reservoir fracturing, especially pore connec-

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tivity^{30)~32)}. Clarification of the differences between spontaneous imbibition of oil and water is likely to be beneficial for production and development.

Previous studies of shale spontaneous imbibition have considered many details^{29),33)~35)}, but the following problems still require clarification: (1) driving force of spontaneous imbibition in shale, (2) location and form of oil and water after spontaneous imbibition fluid in shale, and (3) pore connectivity and mitigating water blocking during fracturing. The present study focused on the NMR response tests in the process of spontaneous imbibition, imbibition weight profile, and correlations, to investigate pore connectivity and mitigating water blocking during hydraulic fracturing.

2. Samples and Methods

2.1. Geological Overview and Characteristics

For this study, shale samples were obtained from the Lower Silurian Longmaxi black shale formation in the Sichuan Basin, in the south of China, as shown in **Fig. 1**. This formation is about 40-250 m thick, the porosity range is 3.4-8.2 %³⁶⁾ and the total organic content (TOC) is commonly higher than 0.5 %³⁷⁾, which indicate that the Longmaxi black shale has high potential for exploration and development. Three pairs of shale core plugs were selected from the A1, B201, and H5 wells (A1-1 and A1-2; B201-1 and B201-2; H5-1 and H5-2), with each pair obtained from the same full diameter rock core to enhance the contrast of the results. Mineral content was measured with an X-ray diffractometer and quantitative phase analysis was performed by the rietveld refinement, following established clay mineral structure models³⁸⁾. Clay content of A1, B201 and H5 was 30.88, 41.19 and 31.17 %, respectively. H5 had the highest quartz content of 45.85 % and lowest carbonate content of 9.32 %. The specific characteristics are shown in **Table 1**.

2.2. Fluids

Deionized water and *n*-decane (oil) were used in the imbibition tests. The density, viscosity and surface tension of water and oil are listed in **Table 2**.

2.3. Contact Angle Measurements

Contact angle measurements were conducted using the Interface parameters Integrated measurement system (KRUS DSA30S) which is equipped with an optical system (zoom lens with 6 times magnification and camera speed of 52 images per second) and an LED light source. This system has a high-precision injection unit with 0.0067 μL resolution, which ensures that every drop of liquid in the experiment has the same volume to exclude the effect of droplet size on contact angle measurement. The contact angle of each sample was measured three times to calculate the mean value using different locations on the same sample. **Figure 2** shows fluid drops (oil and water) on the sur-

Fig. 1 Geographical Map of the Study Area

Table 1 Physical Properties of Each Core Sample

No.	Depth [m]	Initial weight [g]	Surface area [cm ²]	Height [cm]	Diameter [cm]	Post-drying weight [g]
A1-1	2089.35	64.38	79.76	5.02	2.53	63.96
A1-2	2089.35	64.32	79.76	5.02	2.53	63.89
B201-1	2054.23	66.21	78.33	4.93	2.53	65.58
B201-2	2054.23	65.76	78.32	4.91	2.53	64.22
H5-1	2155.78	55.93	64.67	4.07	2.53	undried
H5-2	2155.78	59.00	69.11	4.35	2.53	undried

Core weight was measured using an electronic balance with accuracy of 1/1000 g; the length was gauged using a Vernier caliper with 50 scale marks.

Table 2 Properties of Different Fluid Used for Imbibition Experiments at 25 °C

Fluids	Density [g/cm ³]	Viscosity	Surface tension [N/m]
Water	1	0.9	72
<i>n</i> -Decane	0.74	0.5	28.5

Oil drops completely spread on all samples.

Fig. 2 Oil (left) and Water (right) Drops on the Surfaces of A1 ((a) and (b)), B201 ((c) and (d)) and H5 ((e) and (f))

face of every sample. **Table 3** shows the results of all contact angle measurements, which indicate that these shale cores exhibit intense mixed wettability. All samples were lipophilic and could even imbibe oil spontaneously.

2. 4. Experimental Procedure

To investigate the effect of the original water saturation on oil and water imbibition, samples of A1 and B201 were dried at 100 °C until the weight remained unchanged. H5 sample (“as received”) was directly used for imbibition without any treatment.

To analyze the difference between water imbibition and oil imbibition of shale samples, sample pairs were used in the experiment. The first group experiment was water imbibition of A1-1, B201-1 and H5-2, then oil imbibition (water imbibition → oil imbibition). The second group experiment was oil imbibition of A1-2, B201-2 and H5-1, then water imbibition (oil imbibition → water imbibition). To facilitate analysis of the results, the experiment was divided into two imbibition processes as shown in **Fig. 3**. The weight and T_2 spectrums were measured at different times during the spontaneous imbibition of water and oil. The test procedure for the imbibition experiments comprised the

Table 3 Results of Contact Angle and Water-oil Capillary Pressure Ratio

Parameter	A1	B201	H5
Water contact angle, θ_w [°]	33.33	43.71	33.10
Oil contact angle, θ_o [°]	0	0	0
$\sigma_w \cos(\theta_w) / \sigma_o \cos(\theta_o)$	2.11	1.83	2.12

σ_w is the surface tension of water and σ_o is the surface tension of *n*-decane.

To facilitate the analysis of test results, the experiment was divided into two imbibition processes.

Fig. 3 Pairs of Shale Samples Imbibition Flow-process Diagram

following steps:

- (1) Measure core weight, volume and NMR T_2 spectrum in the “as received” state.
- (2) Dry the sample of A1 and B201 at 100 °C until the weight remained unchanged. Then measure core weight and NMR T_2 spectrum.
- (3) Put the sample into a 250 mL beaker with 150 mL imbibition water to soak the whole of the sample in the imbibition fluid.
- (4) After a period of time, remove the sample gently with forceps, use absorbent paper to take up the surface water and use a sponge to take up oil, and measure the water/oil imbibition profile and NMR T_2 spectrums at different times.
- (5) Exchange the order of imbibition fluid after 90 h and repeat step (3) to the record oil/water imbibition profile and NMR T_2 spectrums at different times.

Experimental measurements could be convincing as many researchers have asserted^{(33), (39), (40)}. Core weights and NMR T_2 spectrums were measured for these three groups of samples under lab conditions. The core was weighed using an electronic balance with an accuracy

The clay-rich sample of A1-1 completely disintegrated after exposure to deionized water, and so the corresponding imbibition profile is incomplete. P_c ratio is $(\sigma_w \cos(\theta_w)/\sigma_o \cos(\theta_o))$ as given in Table 3.

Fig. 4 Water and Oil Normalized Imbibed Mass vs. Time

of 1/1000 g. The NMR T_2 spectrum was measured using a MacroMR with low magnetic field strength (0.5 T) and resonance frequency of 23.51 MHz. The relevant parameters were 1024 echoes, scanning for 128 times, echo interval T_E of 0.01 ms, and waiting time T_w of 4000 ms to acquire a more complete NMR T_2 spectrum.

3. Results

3.1. Water and Oil Imbibition Weight Profiles

Figure 4 compares the imbibition weight profiles of oil and water for different samples. The imbibition rate and volume of water were significantly higher than those of oil imbibition in the first imbibition process. The primary driving force for spontaneous imbibition is capillary pressure. If spontaneous imbibition is only dependent on capillary pressure, the volume of water imbibition is only related to pore structure, liquid surface tension and rock surface wettability. Contact angle measurements showed that all shale samples had mixed wettability and so oil was more likely to enter the pores in shale rock. In accordance with the capillary pressure model, the capillary pressure at the pore scale is approximated by $((\sigma \cdot \cos(\theta))/(r))$, where σ , $\cos(\theta)$, and r are the surface tension, cosine value of contact angle, and average pore diameter of the porous medium, respectively. Surface tension and contact angle between water and oil are different, so the oil imbibition profiles are multiplied by capillary pressure ratio P_c ($\sigma_w \cos(\theta_w)/\sigma_o \cos(\theta_o)$) to obtain the dashed curve (imbibition oil weight profiles under capillary pressure with similar conditions) in Fig. 3. The values of P_c are listed in Table 3. If capillary pressure is the only factor controlling the water imbibition volume, the maximum water intake should be around the dashed curve. However, the water imbibition weight profiles were much higher than the dashed curve of all samples. Therefore, other driving forces were also involved in

spontaneous water imbibition in the shale.

Compared with A1 and B201, H5 had lower volume of water imbibition, possibly due to the presence of irreducible fluids in the “as received” state shale core causing blockage of some pores and throats. However, all samples had similar volumes of oil imbibition, which indicates that the original water saturation does not affect oil imbibition and so oil imbibition in the shale core was controlled only by capillary pressure.

Core weights decreased in the process of water imbibition $\rightarrow$ oil imbibition (Fig. 4). If oil only flows into the organic pores and water into the inorganic pores, core weights will increase during the second imbibition process. Therefore, oil displaces water in the process of second imbibition and the loss of weight is related to the oil-water density contrast. Micro-fractures generated after water imbibition resulting in improved shale core porosity and permeability caused core weights after the second oil imbibition to decrease slightly compared to the first water imbibition. Consequently, pores allowing both water and oil flow can exhibit both oil wettability and water wettability. Such pores are the interconnected pores formed during fracturing.

3.2. NMR T_2 Spectra after Water and Oil Imbibition at Different Times

3.2.1. NMR T_2 Spectra after First Water and Oil Imbibition

The NMR T_2 spectra of all samples showed bimodal patterns after oil imbibition as shown in Fig. 5 (5(a), 5(b) and 5(c)), and the peaks increased with imbibition time. The amplitude and position of these peaks reflected the distribution of pore size. The three sample groups had similar primary peak and amplitude, indicating that oil imbibition was independent of initial water saturation and oil imbibition volume was only controlled by capillary pressure. The primary peaks firstly increased between 0.1 ms and 1 ms and then the second peaks increased after 1 ms after oil imbibition in A1-1 and B201-1 in Fig. 5 (5(a), 5(b) and 5(c)). These

Fig. 5 Time Dependent T_2 Spectra of A1, B201 and H5 after the First Spontaneous Imbibition of Water and Oil

findings suggest that oil may firstly flow into the micropores and then into the mesopores and micro fractures. Finally the oil saturated the sample, similar to the previous observation (insert reference here). The NMR T_2 spectra of all samples exhibited unimodal pattern during water imbibition before 36 h. With longer imbibition time, water and clay minerals will react together resulting in clay swelling and induction of micro fractures parallel to the bedding planes^{41)~44)}. The NMR T_2 times of all NMR T_2 spectras after water imbibition were distributed between 1 ms and 100 ms and contained two or three peaks as shown in Fig. 5 (5(d), 5(e) and 5(f)). Such findings indicate improvement in the migration pathway and initial gas production rate after well shut-in for a period of time after spontaneous imbibition^{39),43)}.

The amplitude and peak position in the NMR T_2 spectra of oil imbibition were far less than those of water imbibition, similar to the profiles of water and oil imbibition. Therefore, the rate and volume of water imbibition are higher than those of oil imbibition. Low oil imbibition rate and volume was attributed to water wettability of pores with good connectivity in the intact core, whereas organic pores with oil wettability have poor connectivity⁴⁵⁾. The porosity and permeability may be improved by the induction of micro fractures generated by clay swelling⁴⁵⁾. However, contact angle measurements in Fig. 2 indicates the shale core surface may have more oil wettability pores and good connectivity. In addition, oil imbibition was independent of initial water saturation which indicates that oil imbibition in the shale core was controlled only by cap-

illary pressure. In contrast, water imbibition must involve additional driving forces provided through water adsorption by the clay minerals, which may enhance water imbibition.

3. 2. 2. NMR T_2 Spectra after Second Water and Oil Imbibition

Organic pores have short NMR T_2 time distribution (small pore diameter) and the shale exhibits mixed wettability and greater oil wettability^{46)~49)}. During the second imbibition, NMR T_2 spectra showed bimodal pattern during oil imbibition in all samples. The primary peak amplitude first decreased and then increased with leftward shift (Figs. 6(a) and 6(b)) as the imbibition time increased. These phenomena may be caused by the following reasons: organic pores with oil wettability have smaller diameter in shale, and mesopores and more micro-fractures were induced after water imbibition to connect some isolated organic pores, enlarging the pore space which is beneficial to oil flowing in the rock.

The NMR T_2 spectra after the second water imbibition also exhibited bimodal patterns in all core samples. The amplitudes of primary and the second peaks significantly increased with imbibition time, and also expanded and increased with longer NMR T_2 time distribution (Figs. 6(d), 6(e) and 6(f)). However, the peak was far smaller than that in the first water imbibition. Therefore, some micropore throats were blocked after oil imbibition. Consequently, the contact area between the rock and water was reduced to cause less water flow into the micropores and shale matrix, and less water was adsorbed by clay minerals which reduced the

(a) and (b) show NMR T_2 spectra of B201-1 and H5-2 after water imbibition followed by oil imbibition. (c), (d) and (e) show NMR T_2 spectra of A1-2, B201-2 and H5-1 after oil imbibition followed by water imbibition, respectively.

Fig. 6 NMR T_2 Spectra after Exchanging the Order of Water and Oil in the Second Imbibition

Fig. 7 SEM Photos of Thin Sections after Argon Ion Polishing

swelling of clay minerals and generated lower hydration stress resulting in fewer micro-fractures.

In summary, micro-fractures generated by clay mineral swelling maybe connected some isolated organic pores during water imbibition, so the NMR T_2 spectrum shifted leftward after the second water imbibition. Some micropore throats may be blocked by oil to reduce the contact area between water and clay minerals and decrease the water imbibition capacity in the second water imbibition.

3.3. SEM Photos

Scanning electron microscope (SEM) photos of thin sections after argon ion polishing demonstrated many

organic pores and inorganic pores in the shale samples as shown in **Fig. 7**. Organic pores with cellular shape exhibited better connectivity than inorganic pores, but pore diameter was commonly smaller. Many isolated organic pores were surrounded by water wettable minerals, such as clay minerals, carbonate minerals and quartz, which prevent oil flow into these unconnected organic pores. Oil imbibition in the second imbibition may be driven by capillary pressure to displace water in the crude mesopores and micro-fractures to contact with more organic matter. On the other hand, oil may move into the micro-fractures induced by hydration stress and then flow into the isolated organic pores con-

nected by clay swelling. Such mechanisms may cause the primary NMR T_2 spectrum peak shift leftward. The H5 sample had more organic pores surrounded by water wettability minerals and the primary NMR T_2 spectrum peak shifted leftward significantly after the second oil imbibition. Compared with NMR T_2 spectra after the first oil imbibition, the NMR T_2 spectra of the second oil imbibition exhibited longer T_2 time for the small pores (organic pores), indicating oil flowed into more organic pores. Therefore, hydration stress may connect some isolated organic pores.

4. Discussions

4.1. Determination of Water Imbibition and Capillary Pressure

The water imbibition profile represents the relationship between imbibition volume and connectivity of shale. However, water imbibition is also controlled by capillary pressure and the extra stress generated by clay mineral swelling. During the initial imbibition stage, the sample is in contact with water, so the shale core physical properties are not changed. Water can adhere to the uneven core surface and ion diffusion and advection may occur, but this process is transient, so can be neglected^{(50),(51)}. An imbibition model was developed (Handy, 1960) to calculate imbibition rate or volume⁽⁵²⁾.

$$V_{\text{imb}} = \sqrt{(2A_c^2 \phi K_w S_{\text{wf}} P_c) / \mu_w} \cdot \sqrt{t} \quad (1)$$

Where, P_c is capillary pressure; μ_w is water viscosity; K_w is relative permeability of water; ϕ is rock porosity; A_c is surface area; and S_{wf} is initial water saturation.

Equation (1) can be written as:

$$V_{\text{imb}}/A_c = \sqrt{(2\phi K_w S_{\text{wf}} P_c) / \mu_w} \cdot \sqrt{t} = A \cdot \sqrt{t} \quad (2)$$

Where, A is the slope of imbibition curve.

Equation (2) shows a linear relationship between imbibition volume/surface area and the square root of time (Fig. 8(a)). This relationship, called the capillary part, can describe the process of water imbibition driven by capillary pressure, and the nonlinear segment represents water diffusion into the shale matrix, called the diffusion part. Imbibition volume/surface area and time have a double logarithmic linear relationship^{(53),(54)}, if Eq. (2) is written in log scale (Fig. 8(b)). The capillary part and diffusion part can be recognized from the double logarithm coordinate. If capillary pressure is inhibited or reaches a transient balance due to increased imbibition volume, the capillary part will terminate. Subsequently, water flows into the matrix through imbibition diffusion.

As the relationship between imbibition volume/surface area and time square root demonstrates (Fig. 9), capillary pressure was the dominant driving force in the first 20 h for samples of A1 and B201, but only in the first 10 h for sample H5. Imbibition volume/surface

Fig. 8 Schematic of Imbibition/Diffusion Curve Behaviors

area is defined as imbibition height and the slope reflects pore connectivity⁽³⁰⁾. The slopes of A1, B201, and H5 were 0.82, 0.43, and 0.64, respectively. Imbibition slope of B201 was smaller than for the other two samples, which indicates B201 sample had poor pore connectivity. Therefore, the diffusion part is more obvious than for the other two samples. Water flow progress in shale pores is more complex. H5 had shorter time for the capillary part, which may be related to initial water saturation. Mineral composition and pore structure are other contributing factors, but the specific mechanisms are still unknown and require further study.

4.2. NMR Response Characteristics of Oil and Water Imbibition

The relationships between NMR signals with T_2 time smaller than 3 ms and water including clay-bound water, interlayer water and pore water remain controversial. The cutoff of $T_2 = 3$ ms has been used to identify clay-bound water^{(54)~(56)}, but separate NMR signals of clay-bound water may be hard to identify because of coupling with the water within the clay size openings^{(57),(58)}. As a result, interlayer water, clay-bound water and pore water will all exchange spins on the time scale of the measurement. Therefore, fluid in nanometer-sized pores will have undergone fast relaxation on a similar time scale to that of clay-bound water and differentiation between the two is not possible.

Fig. 9 Imbibed Water Volume/Surface Area vs. Square Root of Time and in log Scale: (a) A1 sample, (b) B201 sample, (c) H5 sample

Fig. 10 NMR T_2 Spectra of Different Imbibition States

Therefore, a single peak would be observed between 0.01 ms and 1 ms on the NMR T_2 spectrum. Consequently, identification of irreducible fluids using a single T_2 time cutoff is unconvincing.

NMR signals of dry shale samples are caused by clay minerals, especially smectite containing some interstratified water in mixed illite-smectite layers⁵⁹. In our study, the dry shale samples demonstrated weak NMR signals indicating that interlayer water had little impact on our experimental results (**Fig. 10**). Compared with the first oil imbibition, the amplitude of water imbibition NMR T_2 spectra were much higher. The amplitude of water and oil imbibition in the second imbibition progress was lower than in the first water imbibition, and the T_2 time component of the primary peak was shorter as shown in **Fig. 11**. If oil is present

in the shale core and occupies a certain pore volume, the amplitude and the primary peak of NMR T_2 spectra were lower than in the first water imbibition, especially in B201 because of poor pore connectivity. In addition, the NMR T_2 spectra of water imbibition without clay swelling (capillary part) were also lower than in the second imbibition but higher than in oil imbibition. These findings indicate that organic pores have small T_2 time distribution (smaller pore diameter) and water is bound by swollen clay minerals after water imbibition. Therefore, NMR signals between 0.01 ms and 1 ms are the mixed responses of pore fluids and irreducible water, and excess water is mainly present as irreducible water in shale.

Fig. 11 Water Flow into the Matrix Induces Micro-fractures to Mitigate Water Blocking and Connect Some Isolated Organic Pores

4.3. Fractures Generated by Excessive Water Imbibition Increase Gas Recovery

After the stage of capillary pressure, the curves still demonstrate a slow upward trend. The NMR response characteristics of water imbibition indicate that long NMR T_2 time increases during imbibition diffusion. Therefore, water flows into the matrix through imbibition diffusion and then generates micro fractures which may connect some isolated organic pores and improve permeability. After imbibition diffusion, excess fracturing fluid will be imbibed and bind to the shale matrix. Gas may flow out into the wellhole through micro-fractures induced by clay mineral swelling. Thus, shale has the potential to automatically mitigate water blocking (Fig. 11). The pressure in the well-hole will be higher after well shut-in for a period of time, because more organic pores will be connected with micro-fractures generated by excessive water imbibition during imbibition diffusion. This interpretation also indicates that the end of capillary pressure stage may be taken as a boundary in the study of water imbibition and pore connectivity in shale.

The present shale imbibition and NMR experiments were conducted to investigate why the flowback rate of fracturing fluids drops in hydraulic fracturing and how the migration pathway and initial gas production are improved after well shut-in for a period of time. NMR T_2 spectra may also be used to characterize irreducible water volume and connected pore volume. NMR technology can potentially estimate reservoir effective porosity and improve recovery.

5. Conclusions

(1) The contact angle measurements showed that shale core exhibits mixed-wettability and is more lipophilic. However, the results of oil and water imbibition profiles indicated that the shale cores are more hydrophilic. These findings contradict the capillary-driven imbibition models. Therefore, both capillary pressure and hydration stress generated by clay mineral swelling occur in the spontaneous water imbibition in shale.

(2) NMR signals between 0.01 ms and 1 ms are the total responses of pore fluids and irreducible water, and excess imbibition water in shale mainly occurs as irreducible water.

(3) NMR T_2 time component increases to longer than 10 ms with longer imbibition time, which implies water imbibition in shale may generate many micro-fractures.

(4) NMR T_2 spectrum peaks in the second oil imbibition decreased and shifted leftward, by more than that of the first oil imbibition, and SEM observation revealed some isolated organic pores in shale. These findings indicate water imbibition in shale may generate many micro-fractures which may connect some isolated organic pores to increase gas production. Excess fracturing fluid will be imbibed and bind to the shale matrix. Gas can flow out into the wellhole through micro-fractures induced by clay mineral swelling. Consequently water blocking would be mitigated.

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