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Study on the Imbibition Damage Mechanisms of Fracturing Fluid for the Whole Fracturing Process in a Tight Sandstone Gas Reservoir

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Abstract: Tight sandstone gas is a significant unconventional natural gas resource, and has been exploited economically mostly through the application of hydraulic fracturing technology in recent decades. However, formation damage occurs when fracturing fluid percolates into the pores inside sandstones through imbibition driven by capillary pressure during fracturing operations. In this work, the formation damage resulting from the whole operation process composed of fracturing, well shut-in and flowback, and the degree of damage at different moments were investigated through core flow experiments and the low-field Nuclear Magnetic Resonance (NMR) technique. The results show that imbibition damage occurs starting from the contact surface between the formation and the fracturing fluid, which penetrates into an increasingly deep position with time down to a certain depth. The T2 spectra of NMR at different moments indicates that fracturing fluid initially enters the small pores, followed by the large pores due to the larger capillary pressure in the former. Thus, the sandstone cores with low permeability incur a higher degree of damage due to their stronger capability of retaining fracturing fluid compared to high-permeability cores. The front position of the fracturing fluid imbibition at different moments, along with the degree of damage, were characterized through the one-dimensional encoding processing of the NMR signal. These results underlie the effective strategy to relieve formation damage resulting from imbibition during hydraulic fracturing operations.

Keywords: tight sandstone gas; low-field Nuclear Magnetic Resonance; linxing gas field; imbibition damage; imbibition experiment

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1. Introduction

Tight sandstone gas reserves constitute the majority of unconventional natural gas resources in China [1,2]. Compared to conventional natural gas, tight sandstone gas is characterized by poor physical properties due to the small size of pores, and it fails to achieve economical production using a conventional exploitation approach. Horizontal drilling and multi-stage hydraulic fracturing have been widely adopted in order to effectively recover unconventional oil and gas resources in recent decades. Tight gas reservoirs are characterized by strong heterogeneity, a small pore radius, and great capillary force, which lead to the considerable retention of fracturing fluid in the formation, and thus to formation damage [3], which not only affect negatively the production of individual wells but also the overall development of oil and gas reservoirs. Thus, a mechanism study on formation damage resulting from fracturing fluid imbibition is of great significance to the improvement of the recovery of tight sandstone gas reservoirs [4,5].

Numerous researchers have explored the damage mechanism of fracturing fluid imbibition and associated factors. Holditch [6] suggested that the pores with high water saturation could not contribute to production if the formation pressure is insufficient to overcome the capillary pressure. This is especially true for tight gas reservoirs due to high capillary pressure. Yan and Cui [7] analyzed the factors affecting the formation damage in low-permeability gas reservoirs from three aspects: stress sensitivity, the water blocking effect, and reverse imbibition. Lai et al. [8] found that the degree of damage increases with pressure and the duration of contact between the fracturing fluid and formation.

Dutta et al. [9] reported the quantitative characterization of the heterogeneity of rocks, tracking fracturing fluid migration with time and space, and an investigation on the effects of capillary pressure on fluid migration and retention in low-permeability sandstone cores utilizing CT scanning technology. Shi et al. [10] explored the damage mechanism of guar gum fracturing fluids in the Sulige gas field through nuclear magnetic resonance (NMR) and core flooding experiments. Huang et al. [11] studied the microstructure of cores from the western Sichuan tight sandstone gas reservoir using scanning electron microscopy (SEM) and constant-velocity mercury injection. The formation sensitivity and water-blocking damage were also analyzed. He later suggested certain technique measures to reduce formation damage, such as the reduction of the amount of fracturing fluids used, the introduction of liquid nitrogen co-injection during the whole fracturing process, and increasing flowback pressure. Bazin et al. [12,13] derived the absolute permeability damage and multiphase flow upon the return of gas permeability after core invasion by a fracturing fluid by methods used in Special Core Analysis Laboratory (SCAL). The experimental data of absolute permeability damage due to the fracturing fluid filtration and water sensitivity of this illitic sandstone, and the water saturation profiles measured by X-Ray in two-phase flow experiments are interpreted. Bekri B et al. [14] presented a new experimental setup combining laboratory high-resolution computed micro-tomography (MCT) with a flow microcell specially designed to reproduce in-situ multiphase flow experiments and monitor the fluid distribution at the pore scale.

Currently, studies in the literature in terms of the mechanisms of imbibition damage are mainly aimed at that caused by external fluids (e.g., fracturing fluid) entering the formation, and the corresponding relief measures. There is a lack of quantitative analysis of formation damage from fracturing fluid imbibition during the whole process of fracturing, well shut-in and flowback. This work physically simulates the imbibition damage during the whole process of tight gas fracturing through experiments. We also analyzed the position of the imbibition front of the fracturing fluid in the sandstone cores at different moments, and quantitatively evaluated of the damage degree of the cores using the low-field NMR technique. These data and analyses could serve as a quantitative reference to support the measures to relieve formation damage for the flowback after fracturing.

2. Experiments

2.1. Apparatus

The experimental apparatus included a SPEC-023 nuclear magnetic resonance (NMR) core analyzer (as shown in Figure 1), a portable low-field (3M) NMR analyzer, a high-precision electronic balance, a high-sensitivity pressure transducer, a syringe pump for the exertion of confining pressure, a syringe pump of model UPUMP-100D which was capable of operating at a constant pressure and speed, a soap-film flowmeter, an intermediate container used to load the experimental fracturing fluid, and a high-pressure nitrogen gas cylinder.

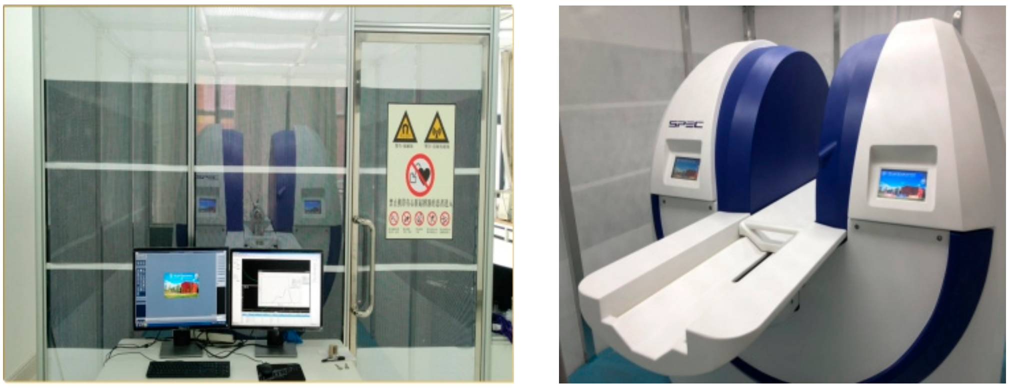

Figure 1. Key experimental equipment.

2.2. Materials

Linxing tight gas reservoir has serious heterogeneity and poor physical properties. The average porosity of the main gas reservoirs is small, ranging from 5.11% to 12.6%. The average permeability ranges from 0.18 mD to 2.57 mD, and the water saturation ranges from 30.0% to 60.9%. Two sandstone cores with large permeability differences (i.e., core 96 and core 57) from Linxing tight gas reservoir were selected in order to study imbibition damage patterns under different physical parameters; the appearance and parameters are shown in Figure 2 and Table 1, respectively. The fracturing fluid is the same as that adopted in field fracturing operations in Linxing tight gas reservoir [15], the components of which are as follows: 0.005% bactericides + 0.1% clay stabilizer + 0.02% gel breaker + 0.1% cleanup additive + 0.18% pH regulator + 0.04% low temperature gel breaker catalyst + 0.3% guar gum + 0.1% enzyme breaker + 0.001% crosslinking agent A + 0.1% crosslinking agent B.

Figure 2. Experimental cores and the fracturing fluid.

Table 1. Parameters of the sandstone cores in Linxing tight gas reservoir.

Sandstone Cores	Formation Layer	Formation Depth/m	Permeability/mD	Mass/g	Length/cm	Diameter/cm
Core 96	Tai 2	1821.11	1.081	54.855	4.652	2.523
Core 57	He 8	1770.1	0.062	52.059	4.105	2.526

2.3. Experimental Design

The hydraulic fracturing technology mainly adopted in the development of tight sandstone gas includes vertical wells with fracturing on individual formation layers and horizontal wells with multi-stage hydraulic fracturing (Figure 3). The whole process of a fracturing operation in a tight sandstone gas reservoir includes fracturing, well shut-in, and the flowback of the fracturing fluid. However, formation damage occurs, resulting from spontaneous imbibition upon contact between fracturing fluids and sandstones during the fracturing operation. In other words, the fracturing fluid will enter the pores inside the tight sandstone, driven spontaneously by capillary pressure, which could otherwise be the channels for the gas flow. In this work, two sandstone cores were selected from the targeted fracturing formation in order to investigate quantitatively the depth of fracturing fluid penetrating into the cores and the degree of imbibition damage with time during the whole process. The migration pattern of the fracturing fluid inside the cores is characterized from a microscopic perspective with the T2 spectrum and real-time imaging utilizing a low-field NMR apparatus and the associated imaging technique.

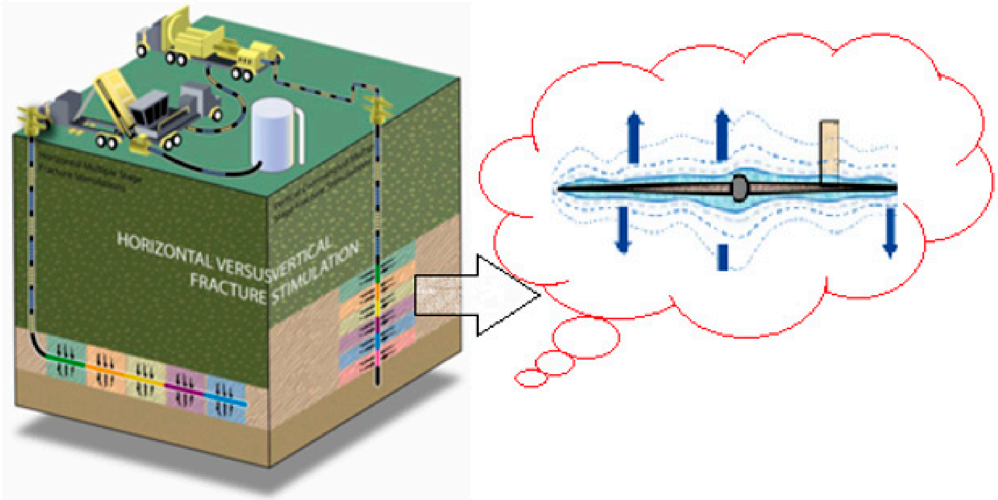

Figure 3. Schematic diagram of hydraulic fracturing in vertical and horizontal wells in a tight sandstone gas reservoir.

In order to evaluate the effects of varying imbibition parameters on formation damage, the whole dynamic imbibition process under simulated formation was monitored using NMR, which quantitatively characterizes the imbibition velocity, the imbibition front position between the fracturing fluid and the formation at different stages, and the distribution of the fracturing fluid [16]. The experimental parameters were adopted based on those from the physical properties of the Linxing tight gas reservoir and field fracturing operation, which include a reservoir temperature of 40 °C, the fracture extension pressure adopted as the imbibition pressure, and the imbibition time calculated from the fracturing operation parameters of the formation layers of Tai 2 and He 8, which are 235 min and 208 min, respectively (Table 2).

Table 2. Statistics of the imbibition pressure and time in different formation layers of the Linxing tight gas reservoir.

Fracturing Operation Parameters	Average Pump-Stop Pressure/MPa	Average Formation Pressure/MPa	Pump-Stop Pressure Difference/MPa	Total Time = Fracturing Operation Time + Diffusion Time after Well Shut-In/min
Tai 2	26.82	17.1	9.72	235
He 8	25.67	15.02	10.65	208

2.4. Experimental Procedure

(1) The NMR analyzer was tuned to determine the frequency of the radio-frequency pulse and the phase of the corresponding receiver. A validation test was performed.
(2) The initial mass, m0, of the sandstone cores was measured using the mass balance. Each core was then placed in the core holder in order to measure its initial permeability, K0, through the core flow experiment.
(3) The intermediate container was filled with fracturing fluid. The sandstone core was put into the core holder and brought up the confining pressure.
(4) The fracturing fluid inside the intermediate container was injected into the individual core with the syringe pump at a constant pressure and a constant speed, the output pressure of which was set to be the pump-stop pressure difference of the

corresponding formation layer. During the whole injection process, the NMR analyzer continuously acquires the one-dimensional frequency code and the NMR images.

(5) The permeability K1 and mass m1 of the sandstone cores were measured using the same procedure as step (2). The damage rate of the cores after imbibition and soaking with fracturing fluid was calculated.

3. Results and Discussion

3.1. Analysis of the Real-Time T2 Spectrum and Core Imaging

The duration of the relaxation time of H+ in the pores will increase with the pore size in the NMR analysis. In other words, the water in the smaller pores will be subject to a greater confinement effect, and will show a shorter relaxation time. Therefore, the position of the peak in the T2 spectrum is correlated to the pore size, whereas the area is associated with the proportion of the corresponding pore size. A typical continuous T2 spectrum (Figure 4) of core 96 acquired during the fracturing fluid dynamic imbibition process shows that the fracturing fluid enters into small pores in the early stage and then large pores in the later stage.

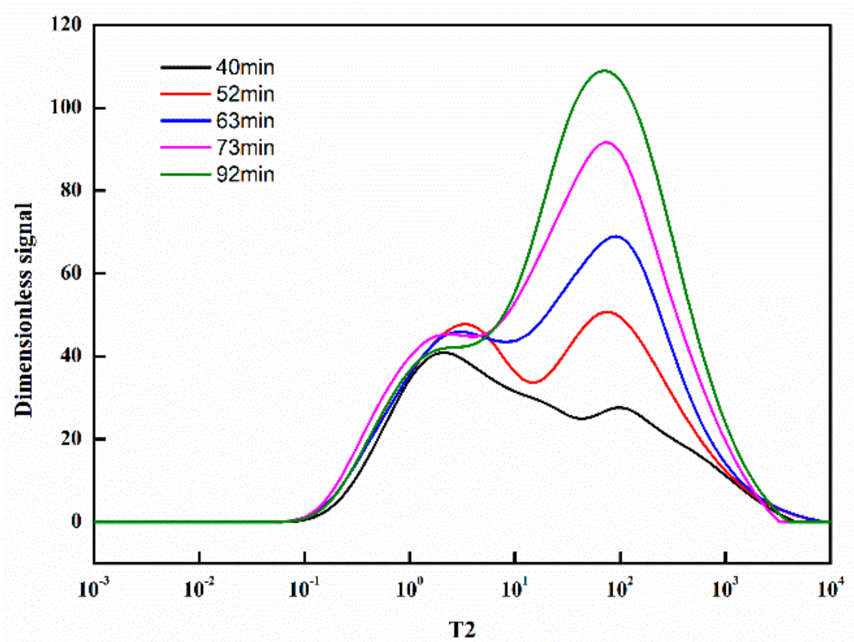

Figure 4. T2 spectrum of core 96 during the dynamic imbibition process.

The signal acquired from the NMR technique stems solely from the H+ in the fracturing fluid, rather than the natural gas. Thus, the imaging of the flow process of the fracturing fluid inside the core is obtained based on the H+ density image of the core after NMR signal processing [17,18]. The higher color saturation in the image at a specific position corresponds to a stronger signal, and in turn a greater amount of fracturing fluid compared to those with weaker color saturation. The NMR imaging technique could show the process of fracturing fluid entering the cores, the front position, and the distribution of the fracturing fluid.

The imaging results of core 96 (Figure 5) show that the highest color saturation occurs at the end face of the core, as this is where the fracturing fluid imbibition starts and full contact between fluid and core occurs, which represents the highest amount of fracturing fluid. With the increase of the imbibition time, the part with low color saturation is gradually replaced by high color saturation, which indicates that the fracturing fluid has entered the pores in a deeper position until the end of imbibition.

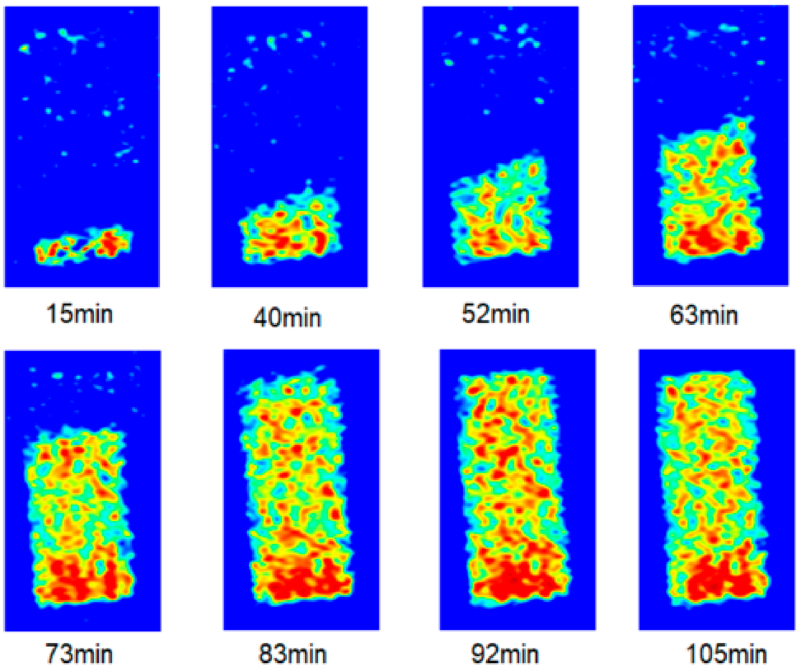

Figure 5. NMR imaging results of the fracturing fluid imbibition process in core 96 at various moments.

3.2. Real-Time Characterization of the Front Position of the Imbibition Damage

In order to reveal the imbibition pattern of the fracturing fluid, we analyzed the NMR signal magnitude at different positions inside the cores using the NMR one-dimensional frequency code acquired during the fracturing fluid imbibition process. It should be noted that only the part of the cores has been analyzed where the signal processed is strong enough to characterize the flow pattern. As shown in Figures 6 and 7, the imbibition direction of the fracturing fluid corresponds to the direction of the NMR one-dimensional frequency code (from left to right).

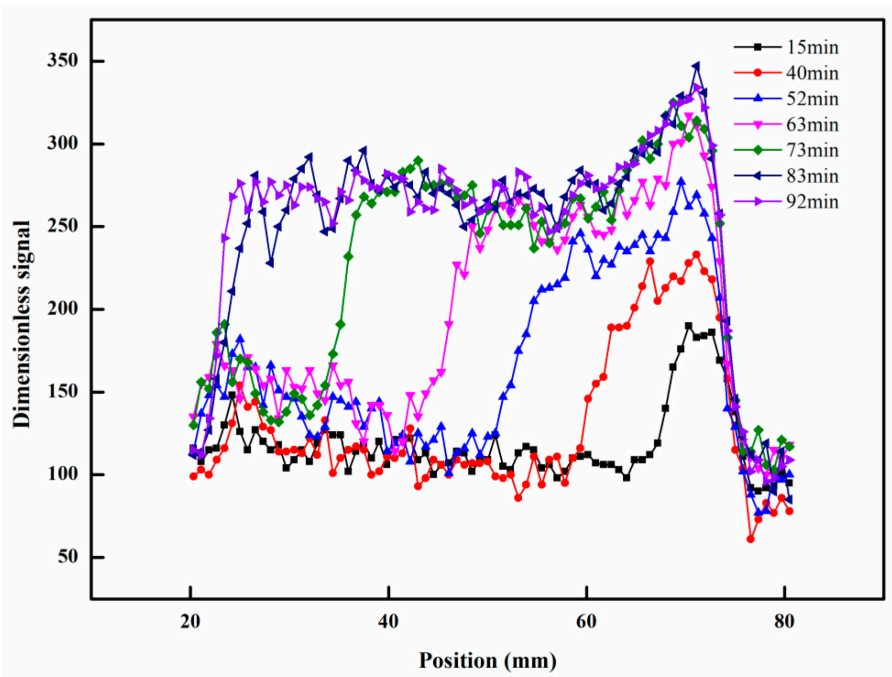

Figure 6. One-dimensional frequency coding of the fracturing fluid imbibition process of core 96.

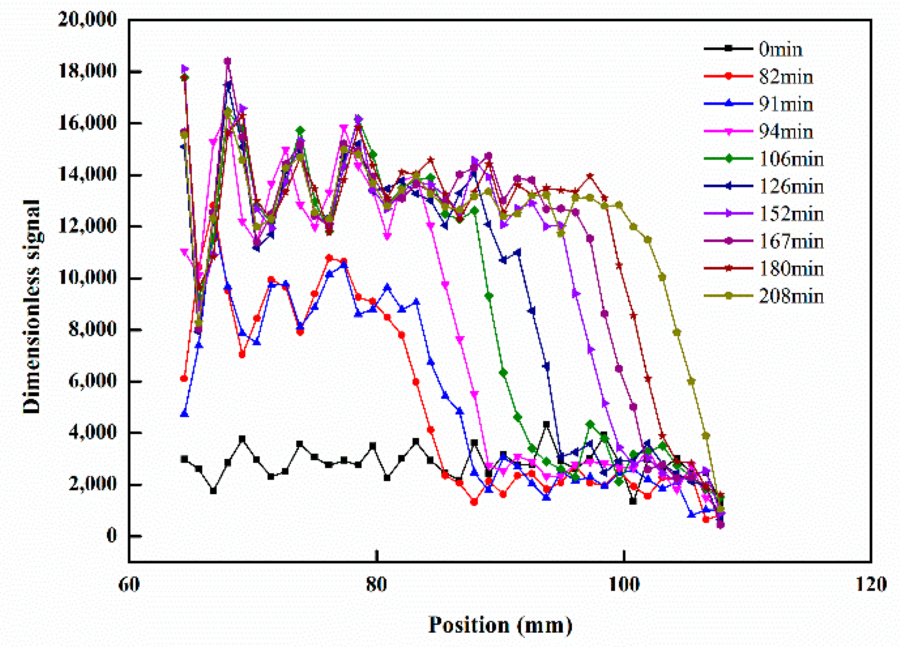

Figure 7. One-dimensional frequency coding of the fracturing fluid imbibition process of core 57.

Figures 6 and 7 indicate the signal magnitude at different positions of core 96 and core 57, respectively. The greater signal magnitude denotes the higher saturation of fracturing fluid at a specific position. The leftmost position corresponds to the initial point of the imbibition process, i.e., the contact surface between the fracturing fluid and rock cores. By contrast, the rightmost position represents the ultimate depth of the imbibition, which corresponds to the complete penetration of the core through imbibition. The durations of the complete penetration of the two cores are 182 min for core 96 and 208 min for core 57, respectively. For a specific position, the signal magnitude increases with time until reaching a plateau, which means that the amount of fracturing fluid imbibed at this position increases until the saturation of the pores. The imbibition depths at various instants for the two cores are demonstrated in Figures 8 and 9. It can be observed that the fracturing fluid advances into a deeper position with time.

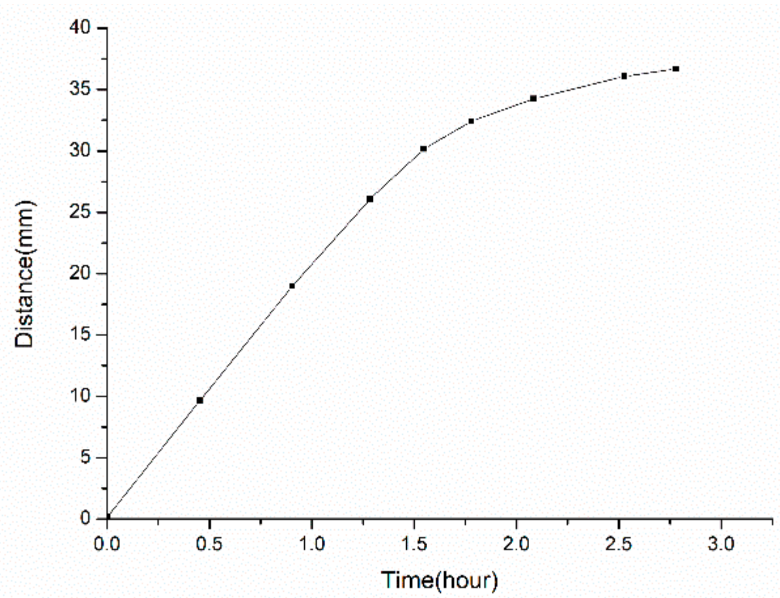

Figure 8. The penetration depth of the fracturing fluid versus time for core 96.

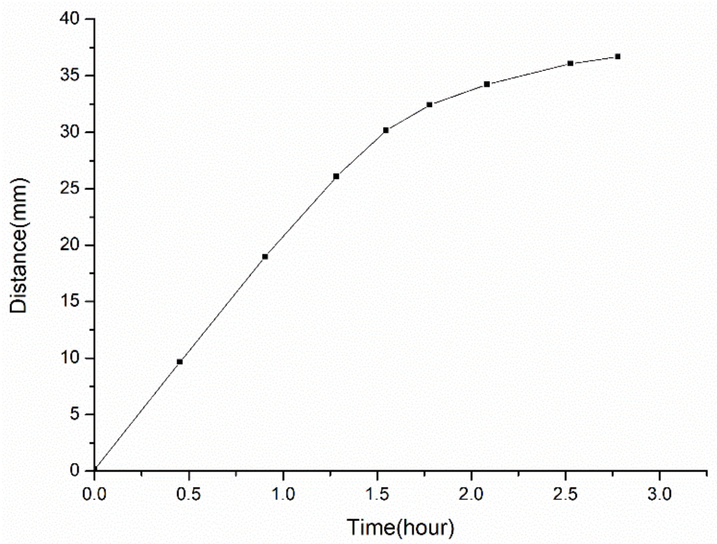

Figure 9. The penetration depth of the fracturing fluid versus time for core 57.

3.3. Real-Time Characterization of the Imbibition Damage Velocity

We can derived the imbibition velocity of the fracturing fluid versus time based on the relationship of the depth at various instants in Figures 8 and 9 using the following equation:

$$v = \frac{x_n - x_{n-1}}{\Delta t} \tag{1}$$

where v is imbibition velocity of the fracturing fluid, mm/h; x_n is the position of the fracturing fluid front at a certain instant, mm; x_{n-1} is the fracturing fluid front position at a previous instant, mm; and Δt is the duration of the adjacent time instant, h.

Figures 10 and 11 show that the imbibition velocity of the fracturing fluid for the two cores decreases nonlinearly with time. The velocity decreases significantly at an early stage and gradually reaches the lowest velocity fixed at a constant. This is because the fracturing enters the empty pores with the highest velocity driven by high capillary pressure at the beginning of imbibition. Thereafter, the velocity decreases significantly due to the increasing viscous resistance force resulting from the fluid gradually filling the pores, along with the decreasing capillary pressure at the early stage. At the middle and late stage of imbibition, the velocity gradually decreases and is maintained at a minimum, as the viscous resistance force is approximately maintained at a high value due to the saturation of the fracturing fluid inside the pores.

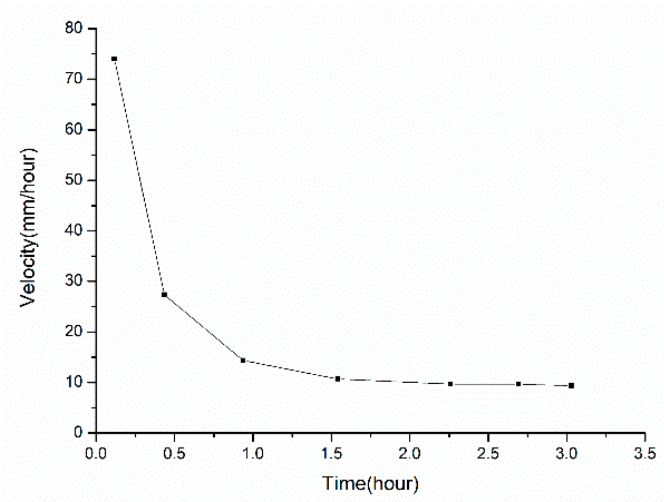

Figure 10. Imbibition velocity of the fracturing fluid versus time for core 96.

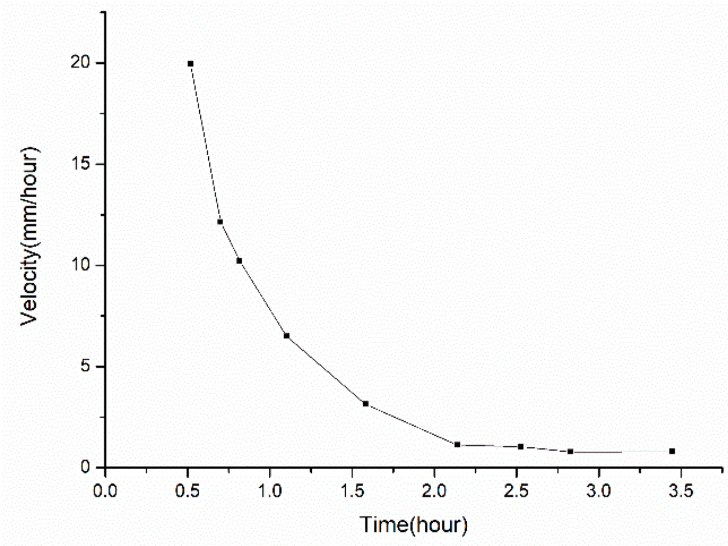

Figure 11. Imbibition velocity of the fracturing fluid versus time for core 57.

4. Conclusions

In this work, we investigated the formation damage resulting from the imbibition of fracturing fluids in tight sandstone cores using the NMR technique, and reached the following conclusions:

(1) The imbibition damage of the fracturing fluid occurs upon contact between the fracturing fluid and the core. The imbibition process starts with a high imbibition velocity, and decreases significantly at the early stage due to the increasing viscous force of the fracturing fluid and decreasing capillary pressure. At later stages, the velocity gradually reaches a minimum and remains constant due to the saturation of the pores with fracturing fluid. The fracturing fluid reaches an increasingly deep position with the imbibition time until a certain depth.
(2) The T2 spectrum from the NMR shows that the fracturing fluid will be imbibed into small pores followed by large pores, driven by capillary pressure. Thus, the cores with lower permeability will be subject to a greater degree of damage due to their greater capability of retaining fracturing fluid compared to those with higher permeability.
(3) The front position of the fracturing fluid during the imbibition process at different instants, i.e., the depth of the cores subject to damage, is determined quantitatively using the one-dimensional encoding processing of the NMR signal.
(4) This paper only studied the imbibition mechanism between the fracturing fluid and the reservoir. The next step is to ascertain how to solve this damage, such as by improving the flowback production pressure difference, nitrogen-assisted flowback, and so on.

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Informed Consent Statement: Informed consent was obtained from all subjects involved in the study.

Conflicts of Interest: The authors declare no conflict of interest.

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