Advances in
Geo-Energy Research

Vol. 2, No. 3, p. 292-304, 2018
www.astp-agr.com

Original article

Experimental study on spontaneous imbibition chatacteristics of tight rocks

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(Received June 14, 2018; revised July 2, 2018; accepted July 3, 2018; available online July 11, 2018)

Citation:
Gao, L., Yang, Z., Shi, Y. Experimental study on spontaneous imbibition chatacteristics of tight rocks. *Advances in Geo-Energy Research*, 2018, 2(3): 292-304, doi: 10.26804/ager.2018.03.07.

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Keywords:
Tight rocks
spontaneous imbibition
capillary pressure

Abstract:
In the exploitation of tight oil and gas reservoirs, multi-stage hydraulic fracturing technology is mainly used and a complex system of fractures and matrix is formed after fracturing. In the process of field production, it is reported that longer shut-in time results in good oil and gas production rate. The reason of this phenomenon is considered as the spontaneous imbibition of oil and gas driven by capillary force in reservoirs. Spontaneous imbibition is an important recovery mechanism in low permeability and tight reservoirs. The pore structure of tight rocks is very complex and the pore connectivity is poor. It is of great significance to study the imbibition mechanism of tight porous rocks. Through the combination of spontaneous imbibition experiments, this work studies the influencing factors and reveals the mechanism of the gas/oil recovery from tight reservoirs. The spontaneous imbibition experiments were carried on the gas/water system and the oil/water system. The swelling clay minerals in shales will enhance the imbibition. Cores with high permeability have small recovery, which may be due to the low capillary force in tight cores. Fractures can promote the imbibition volume of tight cores.

1. Introduction

Energy is an important material basis for the survival and development of humankind. The oil and gas industry has made great contributions to national construction. Since the 21st century, China's total energy consumption has grown steadily. Although the growth rate of coal energy consumption in fossil energy has declined, the oil and gas energy consumption keeps a growth trend (see Fig. 1). Therefore, the exploration and development of oil and gas resources are still in a strategic position. The imbalance of energy supply and demand has become a bottleneck restricting the realization of economic development goals in all countries of the world, the solution to energy problems cannot be delayed. With the continuous deepening of oil and gas exploration and development, the exploration focus has shifted from the traditional conventional oil and gas reservoirs to unconventional oil and gas resources (Jia et al., 2012; Zhao et al., 2012; Du et al., 2014).

The exploration and development of unconventional oil and gas resources have received extensive attention. The shale gas revolution in the United States, the successful exploration and development of tight oil and gas reservoirs, and the successful trial production of natural gas hydrates in China are enough to show that unconventional oil and gas resources will become strategic areas for oil exploration and development in the future (Zhao, 2012). Unconventional oil and gas resources include: tight oil and gas, shale oil and gas, coalbed gas, oil shale, and natural gas hydrates (Jia et al., 2012).

Among the unconventional oil and gas resources, the development potential of tight oil and gas resources is huge, the reservoir conditions are relatively good, and the resources are widely distributed, especially in North America and the Asia-Pacific region. Therefore, tight oil and gas are the most promising unconventional oil and gas resources, and they are also the focus of unconventional oil and gas (Hill et al., 2007; Zhao, 2012; Wang et al., 2014). However, the oil and gas reservoirs are tight, and most of them are hydrocarbon accumulations outside source rocks, causing high development costs and high yield deceleration rates (Liu et al., 2013).

https://doi.org/10.26804/ager.2018.03.07.
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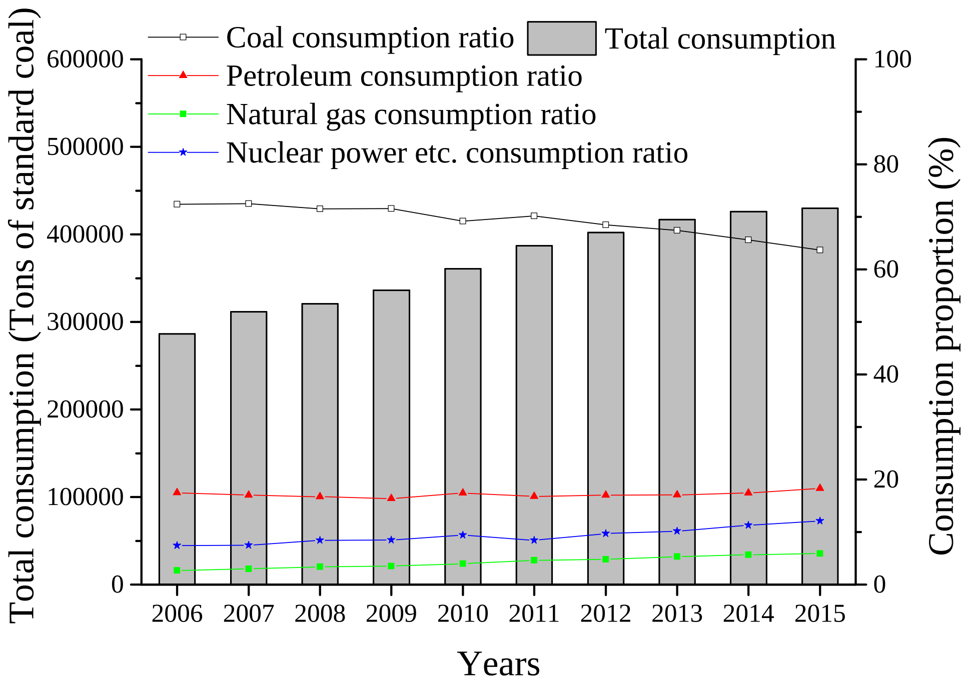


Fig. 1. Total energy consumption and composition of China's calendar year (data extracted from "*China statistical summary 2017*").

Tight reservoirs often show the characteristics of low porosity and low permeability, and the pores are mainly micro-scale connected pores, which leads to the accumulation of non-buoyancy, the lack of obvious hydrodynamic effect and the high recovery in the fracture area (Cao et al., 2014; Gao et al., 2014).

In the production of tight oil and gas, the traditional development method is no longer applicable. Many researchers have (Zhou et al., 2000; Darvishi et al., 2010; Cai and Sun, 2013; Wu et al., 2017) shown that imbibition is an incentive for the recovery of tight oil and gas, but at present, the understanding of the imbibition characteristics of tight reservoirs is not enough.

In the tight reservoirs, the primary oil recovery rate is very low and the ultimate recovery needs to be improved. In the 1950s, oilfield engineers in the United States discovered that the imbibition could be used as a mechanism for secondary oil recovery (Mannon and Chilingarian, 1972). Imbibition is the flow of fluid driven by capillary force, that is, the process by which the wetting phase spontaneously displaces the non-wetting phase of porous rock under the action of capillary pressure (Graham and Richardson, 1959; Cai et al., 2010; Cai and Yu, 2011; Cai et al., 2012; Cai and Sun, 2013). When the surface of the porous rock contacts the wetting liquid, the wetting liquid enters the porous medium along the fine pore throat due to capillary suction and the non-wetting liquid is displaced. There are two classification methods for imbibition (Vizika et al., 1994; Pooladi-Darvish and Firoozabadi, 2000; Zhou et al., 2001; Zhou et al., 2002; Silin and Patzek, 2004; Meng et al., 2017a; Wang and Sheng, 2018): one is spontaneous imbibition and forced imbibition; the other is co-current imbibition and counter-current imbibition (see Fig. 2). Co-current imbibition means that the flow direction of wetting phase and non-wetting phase is the same (Georgiou et al., 2015; Bajwa and Blunt, 2016). When the flow direction of wetting phase and non-wetting phase is opposite, it is called counter-current imbibition (Li et al., 2017; Xu et al., 2017) (see Fig. 3). When tight reservoirs are in wet conditions, co-current imbibition plays a dominant role in displacing crude oil. Oil passes the single-phase area in co-current behavior, however, oil passes the two-phase area in counter-current behavior; counter-current imbibition mainly occurs in fractured tight reservoirs, and many literatures (Bourbiaux and Kalaydjian, 1990; Cuiec et al., 1994; Pooladi-Darvish and Firoozabadi, 2000; Li and Horne, 2004) show that the oil recovery in the co-current imbibition is faster than the counter-current imbibition.

In porous rocks, capillary pressure at the front edge is the main driving force in spontaneous imbibition process (see Fig. 4). The capillary pressure p_c is determined by the Young-Laplace equation (Ahn et al., 1991). In the early 19th century, Washburn (1921) established a mathematical expression for the rate of spontaneous imbibition of a wetting liquid in a single capillary. Aronofsky et al. (1958) deduced an exponential model of core oil recovery over time, called the Aronofsky empirical model. Handy (1960) pointed out that the imbibed volume in porous rock is linear with square root of time. Mattax and Kyte (1962) first described the imbibition process and normalized the time of the imbibition, indicating that the dimensionless time was related to the nature of the core geometry and fluid. Since then, many scholars (Zhang et al., 1996; Zhou et al., 2002; Li and Horne, 2006; Fischer et al.,

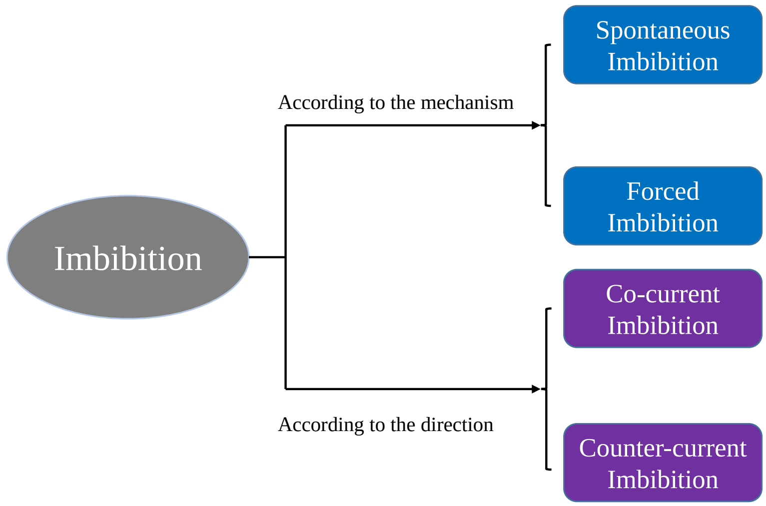


Fig. 2. Imbibition classification method (Zhou, 2015).

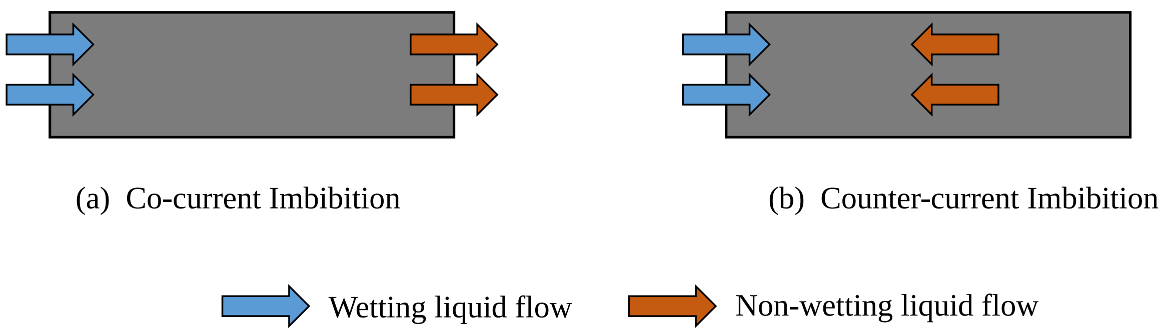


Fig. 3. Co-current imbibition and counter-current imbibition.

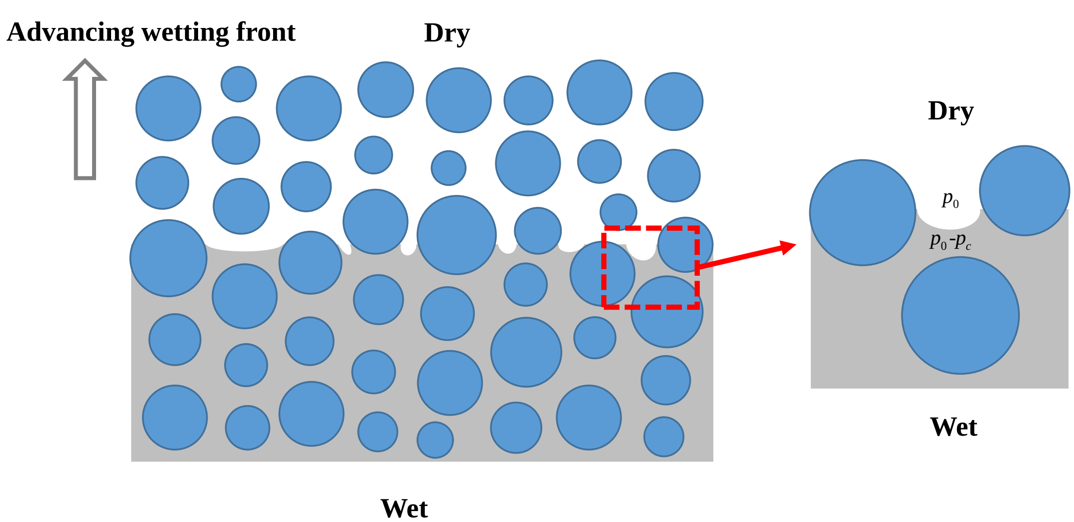


Fig. 4. A schematic drawing of the imbibition front of inhomogeneous porous rock (Xiao, 2016) (The blue circle represents the porous structure, the gray area represents the wetting liquid, p_0 is the atmospheric pressure, and p_c is the capillary pressure).

2008; Standnes, 2009; Mason et al., 2010; Mirzaei-Paiaman and Masihi, 2014) have extended and deepened the work of Mattax and Kyte, and made corrections to the non-dimensional times for different conditions. In the initial analysis of the effect of low interfacial tension on the imbibition process, the influence of gravity was often neglected. Schechter et al. (1991) considered the gravity factor and defined the ratio of the capillary pressure to the gravity as the inverse Bond number. According to the size of the inverse Bond number, the relative magnitude of capillary pressure and gravity can be determined.

In water flooding studies, imbibition is considered to be an effective method for enhanced oil recovery in tight oil and gas reservoirs, and is an important mechanism for oil production. The main factors affecting the imbibition are: wettability, clay content, temperature, pressure, fluid properties, rock properties (porosity, permeability, etc.) and initial water saturation. The wettability reflects the affinity of the fluid on the solid surface. In order to increase the oil displacement efficiency, many scholars (Abdallah et al., 2007; Wang et al., 2012; Dehghanpour et al., 2013) have controlled changes in the wettability of the core. Chahardowli et al. (2016) proposed a new technology to increase crude oil recovery using dimethyl ether/saline as active agent during spontaneous leaching of sandstone and carbonate rocks. Rock samples with high clay content can accelerate the imbibition rate, so the water saturation is higher than the calculated value in areas with high clay mineral content (Lan et al., 2014). Raising the temperature can increase the imbibition rate of diatomaceous rocks (Peng and Kovscek, 2011). In terms of pressure, Cheng et al. (2013) used Nuclear Magnetic Resonance technology to study the influence of pressure on the imbibition, and the pressure had a greater impact on the imbibition of small pore cores. The fluid properties mainly include the viscosity ratio and the mobility ratio. Meng et al. (2016) studied the influence of wet phase viscosity on the recovery degree by imbibition, and pointed out that the recovery degree decreases with the increasing of the viscosity of wet phase. In addition, the rock properties such as porosity, permeability, and initial water saturation also affect the imbibition rate. Yang et al. (2016a; 2016b) studied the water imbibition curves of shale cores with different boundary conditions in the Ordos, Songliao, and Sichuan basins of China. The reason why the Handy model does not apply to tight cores was analyzed. The imbibition of tight rocks with four different pore distributions was summarized. At the same time, the effects of porosity, clay minerals, surfactants and matrix treated with potassium chloride on the spontaneous imbibition characteristics of tight rock were systematically analyzed. Shen et al. (2016) studied the fluid imbibition characteristics of continental shale in the Sichuan Basin and the continental shale in the Ordos Basin and the permeability changes during the imbibition process. It was found that shales have greater imbibition capacity than sandstones with high permeability, and that marine shales have greater imbibition capacity than continental shales. Gao and Hu (2016) studied the effects of initial water saturation and imbibition fluid (water or n-decane) on the spontaneous imbibition of Barnett shale. Through a variety of imbibition experiments, Meng et al. (2015, 2017) discussed the various factors affecting the process of imbibition, such as boundary conditions and pore structure. Lee (2010) studied the effects of different injection rates and combinations of fluids in fractured reservoirs on spontaneous imbibition.

At present, the main technical methods to study imbibition are experimental research and numerical simulation. With the deepening of the study (Coninck and Blake, 2008; Dutta et al., 2014), CT scanning technology, nuclear magnetic resonance technology (NMR), Lattice Boltzmann Method (LBM), Finite Element Method (FEM) and molecular simulation technology have gradually formed integrated research methods of modern science and traditional methods (see Fig. 5). Traditional experimental methods include volume method and mass method (Zhou et al., 2001, 2002; Wang et al., 2016). The volume method can only measure the volume of crude oil that has been expelled out of the rock sample, but cannot measure the volume of the oil beads that attached to the core wall, which causes the inaccuracy in measuring crude oil volume, resulting in a huge error in calculating the oil displacement efficiency. High-precision electronic balances are used for mass methods nowadays often to weigh mass changes of the rock sample during imbibition, and an automatic data recording system can improve the experimental efficiency and accuracy. CT scans, NMR techniques, and other methods enabled dynamic monitoring of imbibition. Schembre and Kovscek (2001) used CT scan technology to directly and accurately calculate dynamic relative permeability. This technique does not require determination of capillary pressure under stable conditions, especially in low-permeability rocks. Wei et al. (2016) used nuclear magnetic resonance technology to study the influence of microscopic pore structure of rock on the process of the imbibition of tight sandstone, and pointed out that tight sandstone reservoirs with better permeability and higher proportion of medium porosity are more appropriate to use imbibition to enhance oil recovery.

Therefore, revealing the tight porous rock imbibition mechanism, studying the specific factors that affect imbibition, promoting the mobility of fluid in tight rock, motivating reservoirs and enhancing oil recovery are of great significance, thus effectively enhance the oil development economic benefits.

2. Experimental procedure

The physical properties of tight rock reservoirs are complex and the law of imbibition is uncertain. In this work, the imbibition experiments of tight rocks saturated with oil and gas are conducted. The porosity and permeability of experimental core samples are measured by nitrogen gas, that is, gas porosity and gas permeability. The wettability of tight rocks is determined by Yang et al. (2017). The deionized water is used as imbibition liquid. First, the core is saturated with a simulated oil by a vacuum saturation test device. Then, the core of the saturated oil is then immersed in a graduated cylinder and covered with an imbibition bottle to regularly monitor the volume of oil discharged from the core. The volume method and mass method are used in spontaneous imbibition experiments, as shown in Fig. 6 and Fig. 7. Mass

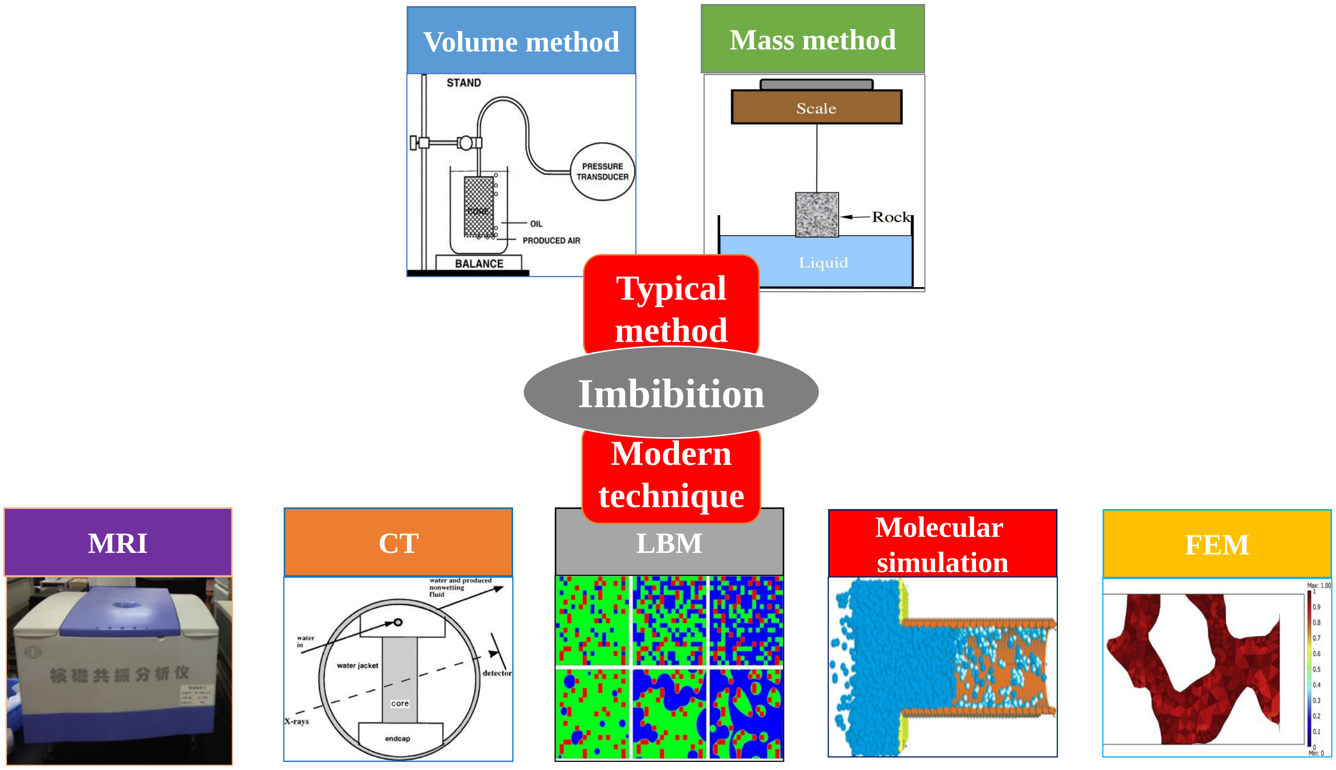


Fig. 5. The main research method of imbibition (Li and Horne, 2000; Zhou et al., 2002; Li et al., 2006; Gunde et al., 2010; Dou and Zhou, 2013; Meng et al., 2015a; Wang et al., 2016).

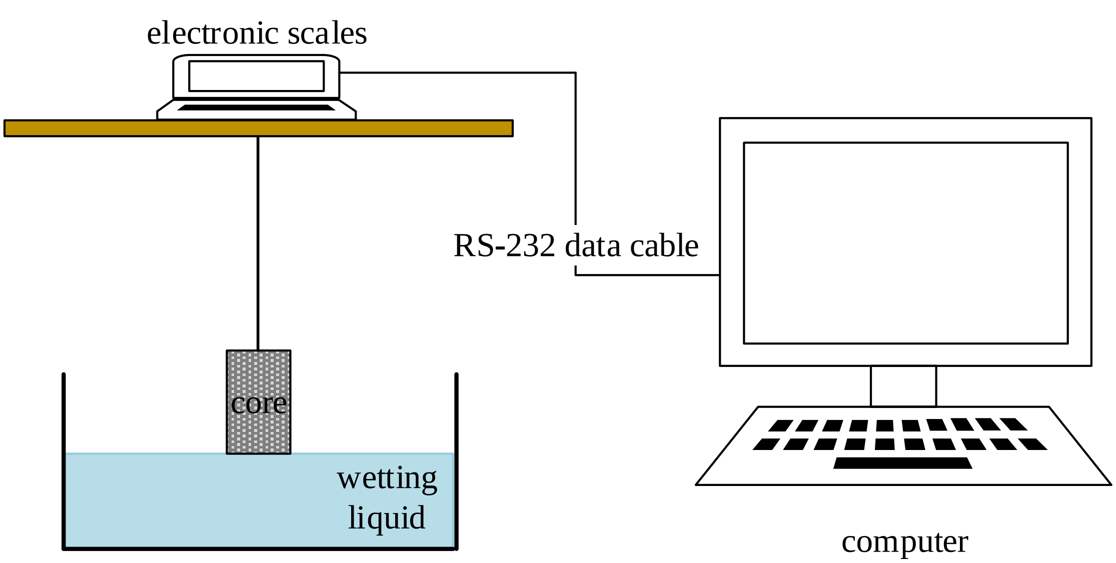


Fig. 6. Schematic diagram of spontaneous imbibition experiment (mass method).

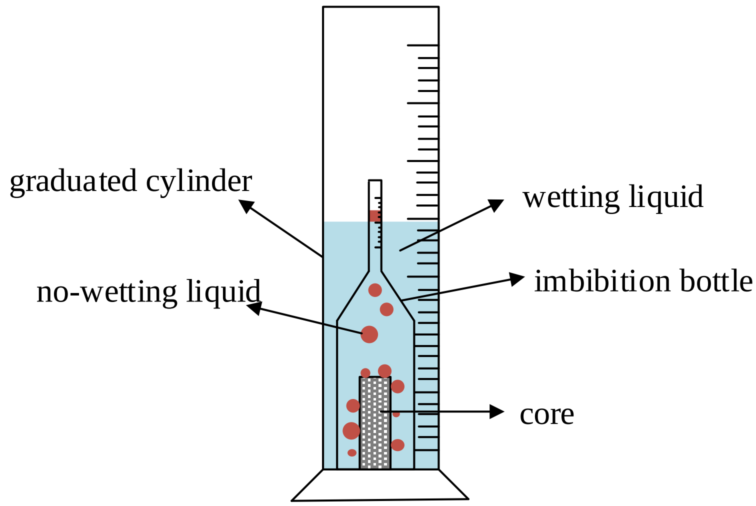


Fig. 7. Schematic diagram of spontaneous imbibition experiment (volume method).

Table 1. Basic property of cores in gas/water system spontaneous imbibition experiments.

Lithology	Numbers	Length (cm)	Diameter (cm)	Porosity (%)	Permeability (mD)
tight sandstones	P-4	4.11	2.50	18.80	0.5600
	P-5	2.39	2.50	8.20	0.1500
shales	S-6	3.50	2.51	1.49	0.0089
	S-7	3.50	2.50	2.74	0.0140
dolomites	D-8	1.05	2.50	0.13	0.0210
	D-9	1.70	2.51	3.19	0.5900
	D-10	2.20	2.50	1.07	0.0310

method is used to measure the change of the mass during the imbibition process with time. It is mainly used in the process of spontaneous imbibition of gas/water system. We use the European imported RADWAG brand full-automatic internal calibration high-precision analytical electronic balance for measurement. The analytical balance has a dual-range of 60g/220g, the accuracy readability reaches 0.01mg/0.1mg. For oil/water system, since the density difference of oil and water is relatively small, the core mass changes during the imbibition process is not obvious, the mass method is no longer applicable. The imbibition data can be obtained by measuring the volume of crude oil removed from the core over time. Therefore, the volume method is more appropriate for oil/water system.

The main operation steps of the spontaneous imbibition experiment (mass method) are as follows:

1) Measure basic physical parameters such as the length and diameter of the core.

2) Dry the cores in a drying oven at a temperature of approximately 60 °C for approximately 48 hours until the mass changes are very small. Record the initial mass of the core.

3) Place the dry core hanging under the balance and adjust the lift platform so that the bottom surface of the core contacts the liquid in the flat dish. At the same time, the computer acquisition system collects the data.

4) At the end of the imbibition process, use a wet paper towel to wipe off the moisture that has adhered to the bottom surface of the core, weigh and record the final mass of the core.

The main steps of the volume method are similar to the mass method. The difference is that the mass method records the increased mass of the wetting fluid in the core, while the volumetric method records the volume of the non-wetting liquid produced by the core during the experiment.

3. Results and discussion

3.1 Gas/water system spontaneous imbibition

In this experiment, we used three different types of tight cores (tight sandstones P-4∼P-5, shales S-6∼S-7, and dolomites D-8∼D-10) to conduct spontaneous gas/water system imbibition experiments. The physical parameters of the studied cores are shown in Table 1.

Fig. 8∼Fig. 10 shows the results of gas/water system spontaneous imbibition experiments for three cores of tight sandstones, shales and dolomites, the trend of accumulated weight gain curve in the three cores is basically the same. At the initial stage of the imbibition experiment, the moment the core touched the water, the inertial force and the capillary pressure played the dominant role, the water quickly entered the pores of the core, and the imbibition rate was fast. As the water entering the core increases, the viscous gradually become apparent, the imbibition rate slows down, and eventually reaches an equilibrium state. Shi et al. (2017) proposed the possible reason for the equilibrium is that the imbibition reaches the boundary of the core. In the Fig. 9, the imbibition weight of core P-5 is much smaller than core P-4. This is because the porosity and permeability of core P-5 are very low. In the spontaneous imbibition experiments on shales, when the time was after 320 minutes, the imbibition weight of shale S-7 increased again. This may be caused by the water absorption of the swelling clay minerals such as montmorillonite, and there are micro fractures formed in the core during the experiment. In the Fig. 10, due to the high porosity and permeability of dolomite D-9, the cumulative imbibition mass is the largest. In the middle imbibition experiment of the core D-10, the imbibition mass is decreased slightly, which may becaused by the complex mineral composition. Many scholars (Benavente et al., 2002; Alava et al., 2004; Fries and Dreyer, 2008; Gruener et al., 2009) have studied the relationship between recovery and time at the initial stage of imbibition, and pointed out that the amount of recovery is exponential with time:

$$N_{wt} \propto t^m \tag{1}$$

where N_{wt} denotes the amount of recovery, m is the imbibition time exponent. We have fitted the slope of the initial period of imbibition. Table 2 summarizes the results of the fitting time indexes of different lithological cores. The time index is concentrated between 0.16 and 0.40, which are all less than 0.5. It may be due to the very complex pore structure of the tight core, low porosity and poor pore connectivity.

In order to determine the effect of fractures on core impregnation, we chose tight sandstone core numbered P-4, cut it longitudinally into two parts, and then put it together to artificially construct a fracture (see Fig. 11) and then repeat the spontaneous imbibition experiment. Through image analysis,

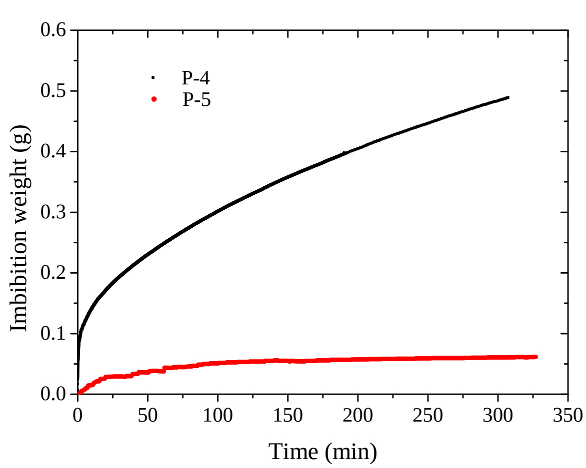


Fig. 8. Experimental results of tight sandstones.

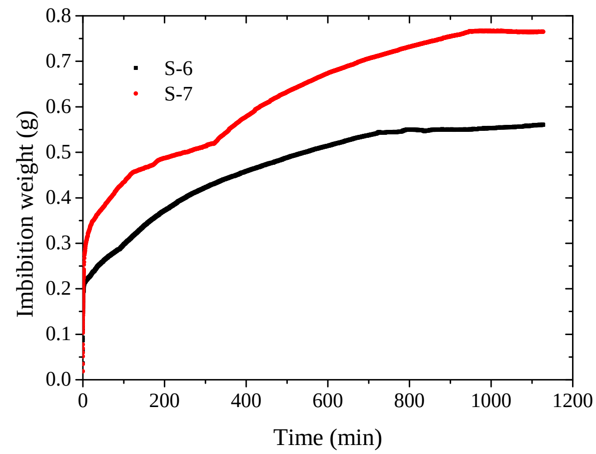


Fig. 9. Experimental results of shales.

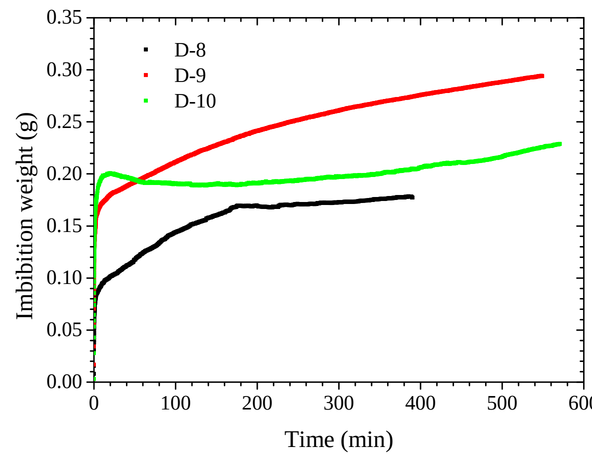


Fig. 10. Experimental results of dolomites.

Table 2. Imbibition time indexes.

Lithological classification	Numbers	Time indexes
tight sandstones	P-4	0.3357
	P-5	0.2948
shales	S-6	0.1616
	S-7	0.3091
dolomites	D-8	0.2391
	D-9	0.1927
	D-10	0.2297

the crack width of the core P-4 is 0.33 mm. Fig. 12 shows the effect of fractures on the spontaneous imbibition experiment of the tight sandstone core P-4. We can see that the mass of the accumulated weight gain in the core with artificial fracture is obviously increased. Therefore, fractures can effectively promote the imbibition of cores. After the experiment, we found that the volume of the core containing fracture is larger than the volume of no-fracture cores (see Fig. 13). In cores

Table 3. Basic parameters of tight sandstones in oil/water system spontaneous imbibition experiments.

Numbers	Length (cm)	Diameter (cm)	Porosity (%)	Permeability (mD)	Wettability	Pore volume (ml)	Saturated oil volume (ml)
YC-10	2.74	2.51	5.78	0.045	weak water wet	0.78	0.31
YC-11	3.74	2.51	5.18	0.042	weak oil wet	0.96	0.41
YC-12	2.93	2.52	6.25	0.103	weak water wet	0.91	0.61
YC-13	5.50	2.52	6.76	0.103	water wet	1.85	1.50
YC-14	3.41	2.51	6.24	0.020	weak water wet	1.05	0.52
YC-15	3.58	2.52	6.30	0.047	weak oil wet	1.12	0.31
YC-16	5.56	2.51	10.18	0.089	weak water wet	2.68	1.30
YC-17	5.47	2.51	8.37	0.083	weak water wet	2.27	1.20
YC-18	5.39	2.52	9.94	0.082	water wet	2.85	1.20

Fig. 11 . Artificial fracture diagram.

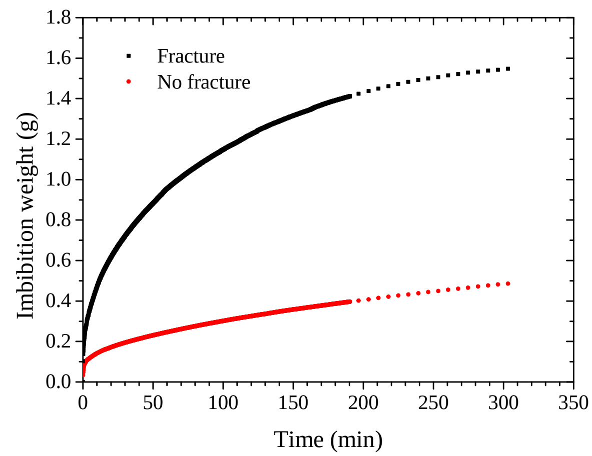


Fig. 12 . Influence of fractures on gas/water system spontaneous imbibition experiment of core P-4.

Fig. 13 . Comparative diagrams of spontaneous imbibition in cores with or no fractures.

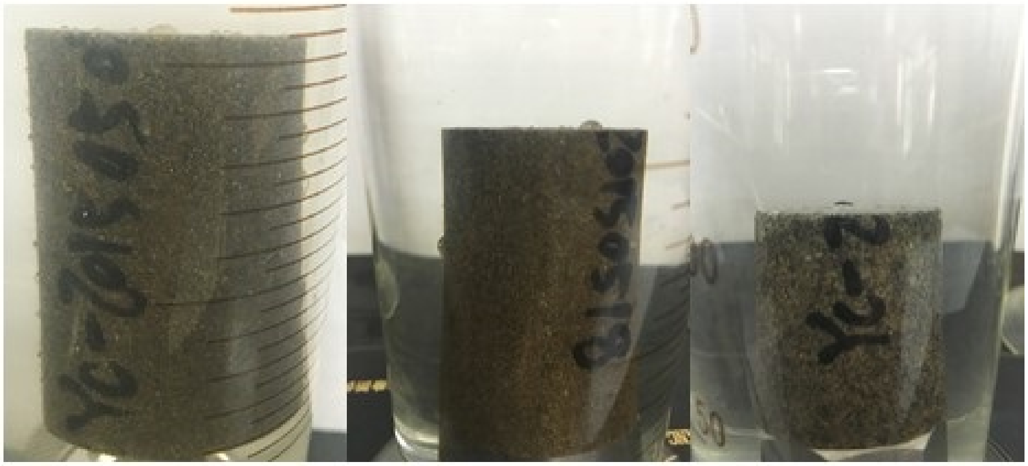


Fig. 14 . Experimental pictures of oil/water system spontaneous imbibition in tight sandstones.

with fracture, deionized water rises up through the fracture to the upper surface of the core and the imbibition of cores is enhanced.

3.2 Oil/water system spontaneous imbibition

We mainly used tight sandstone cores in oil/water system spontaneous imbibition experiments. The cores physical parameters are shown in Table 3. The fluids used in the experiment were simulated oil and deionized water respectively; at room temperature, the simulated oil viscosity was 5.21 mPa·s and the viscosity of the deionized water was 1 mPa·s.

Fig. 14 is oil/water system imbibition experimental photographs of several tight sandstones. Fig. 15 and Fig. 16 are the cumulative oil recovery volume and recovery degree of tight sandstones, respectively. From Fig. 15, it can be seen that the cumulative oil recovery of tight sandstone imbibition has increased continuously and finally reached the equilibrium. By calculating the ratio of the cumulative oil recovery volume to the core saturated oil volume at different times, we can obtain the curve of the degree of imbibition recovery with time (see Fig. 16). It can be seen that the recovery degree of tight sandstones with permeability between 0.2∼1.0 mD is between 12%∼35%.

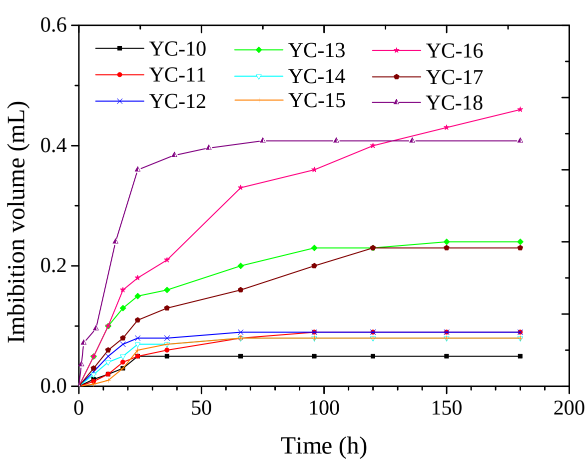


Fig. 15 . Accumulated oil production volume curve of tight sandstones.

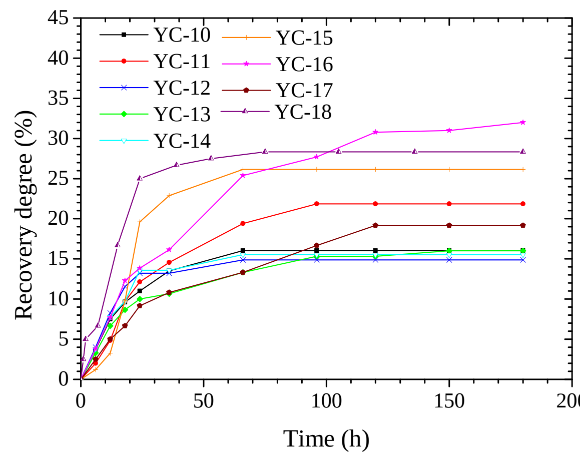
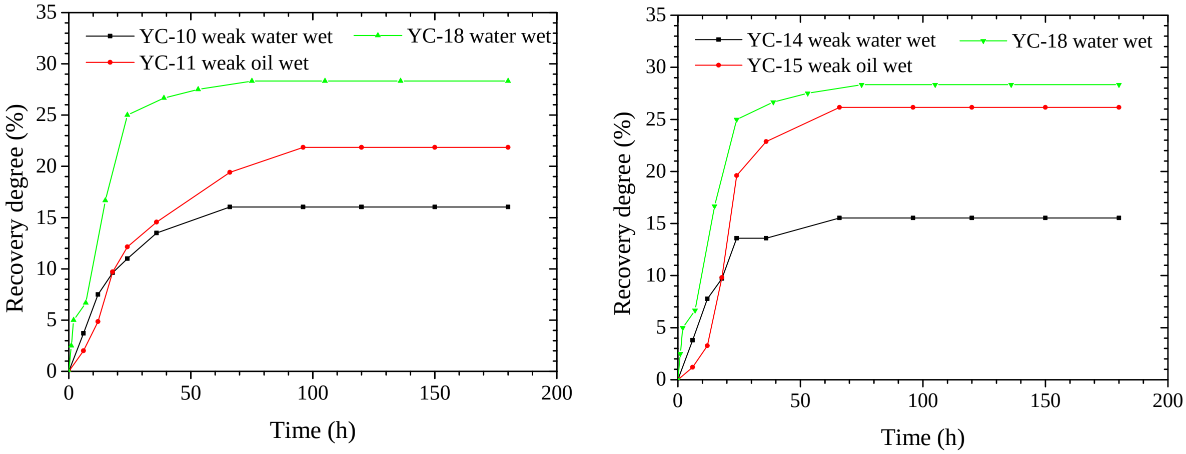


Fig. 16 . The imbibition recovery degree of tight sandstones.

We analyzed the effects of different lengths, different permeability, and different wettability on the oil/water system spontaneous imbibition process of tight sandstones. The imbibition recovery degree of tight sandstones with different lengths is shown in Fig. 17. The rate of imbibition of the short core is higher than that of the long core, but the ultimate recovery of the long core and the short core is not significantly different. The recovery of the long core is slightly higher than the short core. Fig. 18 is the result of core imbibition with different permeability. In tight sandstone, the permeability of core is increased and the degree of imbibition decreases under the condition of close length, which may be due to the poor effect of imbibition on large permeability cores. Therefore, the permeability is low, and the pore radius is small, so that the core has a large capillary effect and a high degree of recovery. Fig. 19 shows the degree of spontaneous imbibition of tight sandstones with different wettability. The highest degree of recovery corresponds to water wet, followed by weak oil wet, and finally weak water wet. It is possible that the core of weak



(a) (b)

Fig. 19 . The imbibition recovery degree of tight sandstones with different wettability.

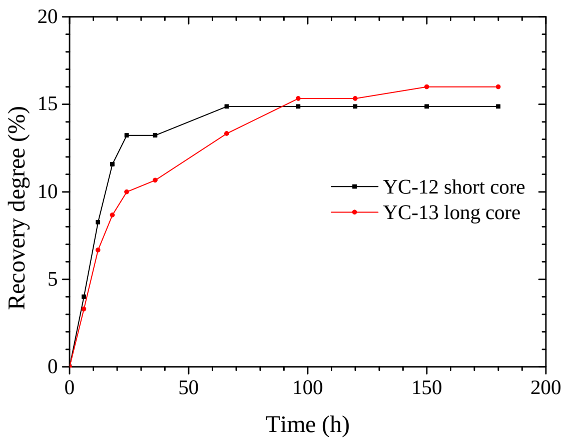


Fig. 17 . The imbibition recovery degree of tight sandstones with different length.

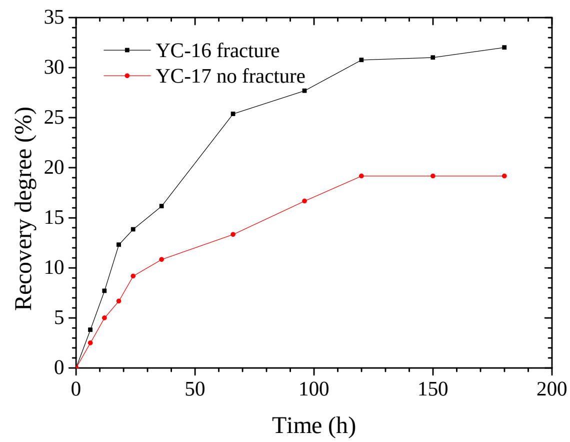


Fig. 20 . Influence of fractures on oil/water system spontaneous imbibition experiment.

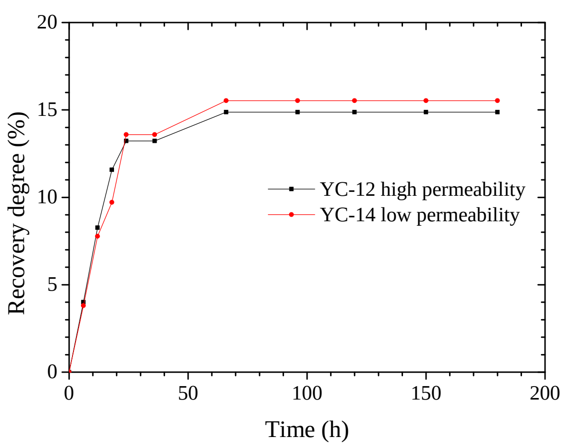


Fig. 18 . The imbibition recovery degree of tight sandstones with different permeability.

oil wet and weak water is mixed wet, some part is oil wet, and the other part is water wet (Rokhforouz and Akhlaghi Amiri, 2017). The recovery degree of YC-11 and YC-15 cores with weak oil-wet are different. It may be that the porosity of YC-15 is slightly larger than that of YC-11, and the connectivity of pores is better, so the efficiency of imbibition is high.

In order to study the effect of fractures on the oil/water system spontaneous imbibition of tight sandstones, we chose YC-16 and YC-17 cores. YC-17 core is intact and YC-16 has fractures, and the other parameters are similar. The effect of fractures on the recovery degree of tight sandstones is shown in Fig. 20. The experimental results show that the fracture can effectively improve the imbibition recovery of tight sandstones, which is consistent with the experimental result of gas/water system spontaneous imbibition in tight cores. Therefore, inducing fractures can improve the imbibition of tight sandstones.

4. Conclusions

In this paper, physical experiments have been used to study the imbibition characteristics of tight porous rock. The main findings are as follows:

The spontaneous imbibition characteristics of three different cores were summarized. When shale minerals contain the swelling mineral, it may enhance the imbibition capacity. The time indexes of gas/water system imbibition experiments for different tight cores were fitted. It was found that the time indexes range from 0.16 to 0.40.

The influence of different conditions on the imbibition of tight cores was explored, and the main imbibition mechanism of tight cores was analyzed: the imbibition rate of short cores was higher than that of long cores. In the case of similar lengths, cores with high permeability have a small degree of imbibition and recovery, which may be due to the small capillary force for oil recovery. When core permeability is low, pore radius is small and capillary pressure is large, so the degree of imbibition is large. Strong water-wet cores work well when water is used for imbibition and recovery. Fractures can promote the imbibition of tight cores.

Acknowledgments

This project was supported by the National Natural Science Foundation of China (No. 41572116), the Hubei Provincial Natural Science Foundation of China (No. 2018CFA051) and National Science and Technology Major Project of China (2017ZX5013-001).

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