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A New Imbibition Scale Model for Tight Reservoirs Considering Diffusion and Water Sensitivity

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ABSTRACT

Imbibition is an important mechanism for resource development in tight reservoirs. Scaling models describe the mathematical relationship between imbibition cumulative production and time, which is important when associating experiments with reservoir behavior. For tight reservoirs, diffusion and water sensitivity have a great influence on imbibition, and the scaling effect of the classical model is poor and needs to be modified. In this study, nuclear magnetic resonance (NMR) method was used to test the imbibition process of eight samples, and a new model considering diffusion and water sensitivity was proposed, and the scaling effect of the new model was verified by the experimental results. The results show that diffusion and water sensitivity have an important influence on the imbibition of tight reservoirs. A new parameter of imbibition diffusion radius is proposed. It has two characteristics. One is that it increases with the increase of imbibition recovery rate, which can reflect the diffusion capacity, and the other is that it decreases with the increase of small holes, which can reflect the influence of water sensitivity. Compared with the average radius used by the classic model, it can better describe the process of tight reservoir imbibition. The scaling effect of the new model modified with new parameters is better than that of the classic model, and the dispersion of imbibition curve is well eliminated, which can make laboratory imbibition data more conveniently used to guide reservoir production. The research results provide a new model and experimental reference for the development of unconventional oil and gas resources.

Keywords: tight oil, imbibition, scaling models, diffusion effect, water sensitivity

NONMENCLATURE

Abbreviations	
NMR	Nuclear magnetic resonance
Symbols	
t	Actual imbibition time
k	Permeability
ϕ	Porosity
μ_W	Viscosity of the wetting phase
μ_{NW}	Viscosity of the non-wetting phase
μ_w	Viscosity of water phase
σ	Interfacial tension
L_C	Characteristic length of the core
L	Core length
S_w	Water saturation
P_C	Capillary force
r_S	Imbibition diffusion radius
r_{ref}	Reference radius of J function
Θ	Wetting angle

1. INTRODUCTION

With the increase in global energy demand and the depletion of conventional oil and gas energy, industry and investors have turned their attention to unconventional oil and gas resources, such as tight oil reservoirs [1-2]. Oil recovery by imbibition after fracturing is an important mechanism in the development [3]. The mathematical relationship between the cumulative imbibition production and time is called the scaling model. When connecting the experiment to the reservoir behavior, the scaling model is very important [4].

Through the dimensionless time in the scaling model, the relationship between the time and the recovery factor in the imbibition experiment can be applied to actual production, guiding the on-site determination of parameters such as the soaking time. After scaling, the more convergent the imbibition curves of different samples, the better the performance of the scaling model. The classic MK model is mainly derived from the capillary bundle model [5], and many scholars have modified the model [4,6-7], such as the commonly used Mason model [4]. However, in the study of tight oil reservoirs, the classical model has limitations. Due to the tightness of porous media, in the multiple stages of imbibition, the diffusion stage has a greater impact on imbibition, and water sensitivity can cause significant changes in the pore structure, and it is necessary to carry out research on a scale model that considers diffusion and media changes for tight oil reservoirs. [8].

In this study, nuclear magnetic resonance (NMR) method was used to test the imbibition process of 8 typical samples. New parameters were proposed to revise the classic model, and a new model that could consider diffusion and water sensitivity was given. Finally, the scaling effect of the new model was verified, which confirmed the application value of the new model.

2. SAMPLES AND EXPERIMENTAL PROCESS

The tight rock samples were taken from the Mahu sag in the Junggar Basin. The samples used for the NMR-imbibition experiment were cylindrical, 6 cm long and 3.8 cm in diameter. Perform basic physical property testing according to standard SY/T 6385-2016.

To simulate the properties of the formation crude oil, the simulated oil with a viscosity of 3.3 mPa·s was configured as the saturated oil, and the experimental core was evacuated for 12 hours and then saturated. Configure a liquid containing 70g/L of $MnCl_2$ as the imbibition liquid.

Test the T2 spectrum at the selected time point in the core imbibition process, and put it back into the imbibition cup immediately after the measurement.. Repeat the above steps until the end, and calculate the oil production based on the ratio of the envelope area of the T2 spectrum before and after imbibition. The T2 relaxation time was converted to the pore radius using the high-pressure mercury injection data from parallel samples [9].

3. RESULT AND DISCUSSION

3.1 Results of imbibition experiment

The 8 cores have been tested by NMR, and the T2 spectrum characteristics of two typical samples are shown in Figure 1. Figure 1-A is a weak water-sensitive sample. The double peaks of the T2 spectrum decrease uniformly with imbibition. Figure 21-B is a strong water-sensitive sample. The left peak of the small hole has an abnormal increase, which is mainly caused by the pore filling segmentation caused by the expansion of the clay.

The relationship between cumulative oil production and time of a typical sample is shown in Figure 1-C. The imbibition increases with time, and finally approaches stability. The imbibition of each sample is divided into three stages [8]: The first stage is the early stage of rapid suction stage, the second stage is the slow diffusion stage, and the third stage is the near stable stage. The production contribution of each stage is shown in Table 1. The oil production of conventional reservoirs is mainly

Tab. 1. Experimental data of each core

Sample ID	Imbibition recovery (%)	Mean radius (μm)	Imbibition diffusion radius (μm)	Diffusion stage recovery ratio (%)	Water sensitivity degree
1	14.5	0.227	0.007	37.4	strong
2	17.2	0.179	0.0056	26.0	strong
3	15.9	0.046	0.0063	32.7	strong
4	20.8	0.041	0.0073	24.8	weak
5	31.5	0.325	0.086	38.1	weak
6	33.1	0.457	0.13	41.2	weak
7	46.3	0.674	0.125	42.6	weak
8	43.5	1.078	0.148	37.3	weak

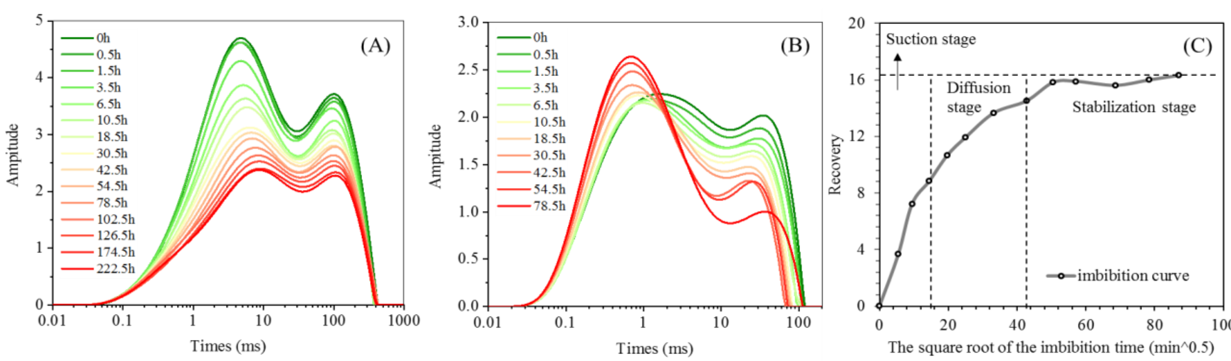

Fig. 1. The results of the imbibition experiment. Figures A and B are the T2 spectra of the imbibition process of normal and strongly water-sensitive cores, respectively, Figure C is the relationship between the cumulative oil production and time.

contributed by the first stage [8], the oil recovery in the diffusion stage is often less than 20%, while the oil recovery in the diffusion stage of the tight reservoir in this study can account for 24.8%-42.6%. the influence of diffusion cannot be ignored.

3.2 The scale of the classic model

Introduce the time t_D to scale the imbibition data on the time scale, in order to aggregate the imbibition curves of samples with different properties, so as to guide production. Assuming that the core shape is the same as the oil-water viscosity, the commonly used Mason model is first used for scaling [4], the formula is:

$$t_D = \frac{1}{L_C^{\ 2}} \sqrt{\frac{k}{\phi}} \frac{\sigma}{\mu_W (1+\sqrt{\mu_{NW} / \mu_W})} t \qquad (1)$$

Among them: t is the imbibition time, k is the permeability, ϕ is the porosity, μ_W is the viscosity of the wetting phase, μ_{NW} is the viscosity of the non-wetting phase, σ is the interfacial tension, and L_C is the characteristic length of the core.

The results are shown in Figure 5-A and B. It can be seen that the dispersion of data has been eliminated to a certain extent, and the imbibition curves of cores with similar physical properties coincide, using Mason model to scale has a certain rationality. The dispersion of the scale curve may be caused by the following reasons: (1) The large difference in pore size distribution, different capillary pressure curves, and different effects of diffusion effect; (2) Some samples have strong water sensitivity and the pore throat structure is changed.

3.3 New parameter "Imbibition Diffusion Radius"

In order to modify the scale model, a new parameter is proposed, that is, the imbibition diffusion radius. The idea of determining this parameter comes from T2cutoff. In the NMR-centrifugal experiment powered by centrifugal force, it is believed that the fluid in the large

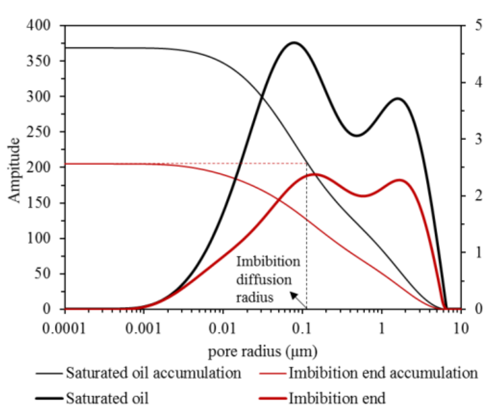

Fig. 2. Calculation method of imbibition diffusion radius

pores is thrown out first, and the fluid in the pores set to be larger than the T2cutoff is passively used. In the spontaneous imbibition process, the oil in the small pores is first used. Therefore, the fluid in the pores smaller than the imbibition diffusion radius is used passively. The calculation process of the imbibition diffusion radius is as follows: (1) The cumulative pore size distribution curve from large hole to small hole after core saturated oil and imbibition is drawn respectively; (2) From the peak of the accumulated curve after imbibition, a parallel line is made and compared with the saturation accumulated curve at a point; (3) The vertical line intersects the abscissa with the focal point, and the reading at this point is the imbibition diffusion radius. This value has the following two characteristics:

1. This value increases with the increase of imbibition recovery, which can reflect the diffusion capacity. It can be seen from the calculation process that the larger the imbibition recovery factor, the greater the value. Figure 3-B shows that the positive correlation between this value and the recovery is more significant, and the imbibition recovery of tight cores is significantly affected by diffusion. In addition, it can be seen from Figure 3-A that the mean radius has a significant negative correlation with the slope of the suction stage, and the imbibition diffusion radius has a good positive correlation with the slope of the diffusion stage, that is,

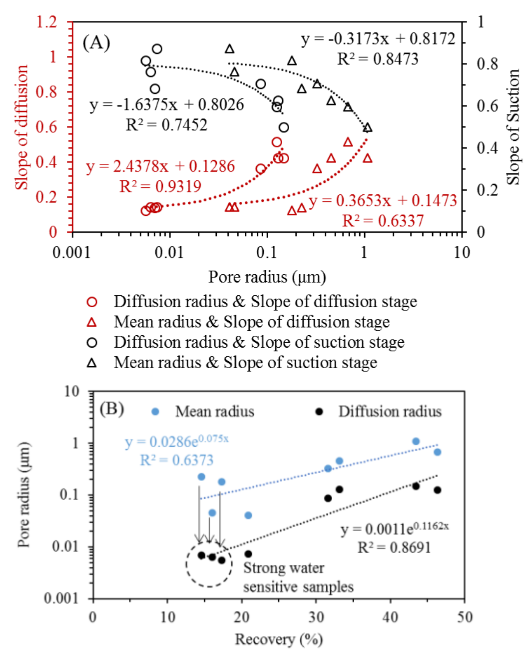

Fig.3. Figure. A shows the relationship between the imbibition diffusion radius, mean radius and the slope of the diffusion stage and the suction stage; Figure. B shows the relationship between imbibition diffusion radius, mean radius and recovery factor.

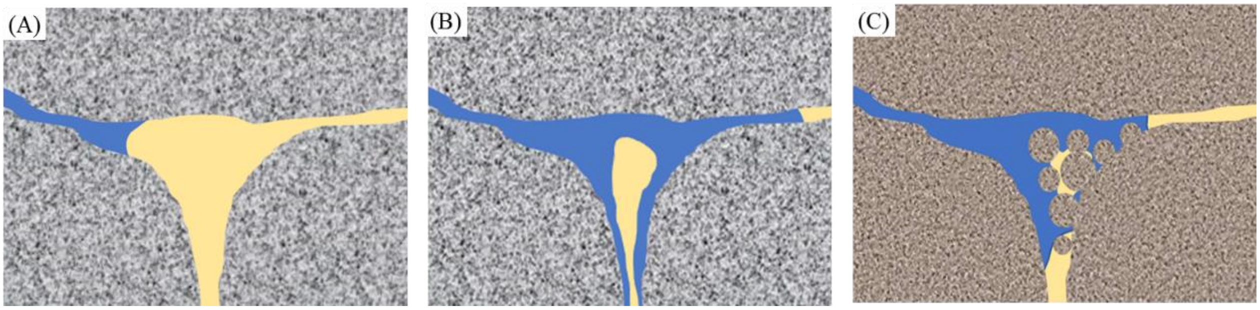

Fig. 4. Schematic diagram of imbibition stage and water sensitivity at pore scale. Fugure. A shows the suction stage. The capillary force provides the power. The smaller the pores are, the stronger the power is. Figure. B shows the diffusion stage, when the foreign liquid diffuses into small pores, and the capillary force provides partial resistance. The smaller the pore network, the weaker the diffusion ability. Figure C shows that clay minerals expand and block pore throats, resulting in reduced diffusion.

the mean radius can better reflect the imbibition force of the suction stage, the smaller the radius, the stronger the force, and the imbibition diffusion radius represents the difficulty of the diffusion stage. The larger the radius, the smoother the pore network and the easier the diffusion (Figure 4-A, B).

2. This value can reflect the influence of water sensitivity. It can be seen from Section 3.1 that water sensitivity will cause the small pores of the T2 spectrum to expand, thereby reducing the calculated recovery factor, which in turn leads to a decrease in the calculated imbibition diffusion radius. The diffusion radius of the strong water-sensitive sample in Figure 3-B is significantly lower than the mean radius. This change also has its actual physical meaning, that is, the increase of small pores makes the connectivity of the pore network worse, and the diffusion capacity decreases, which is manifested as a decrease in the imbibition diffusion radius (Figure 4-C).

3.4 Revision of the scale model

In previous studies, the correction of the scale model was mostly for the viscosity term. In this study, the new parameter imbibition diffusion radius is used to modify the capillary force. The process is as follows:

First of all, the time ratio condition of the similar imbibition form under the reservoir and laboratory conditions should satisfy [5, 10]:

$$\left(\frac{tk}{\phi\mu_w L^2}\frac{dP_C}{dS_w}\right)_{model} = \left(\frac{tk}{\phi\mu_w L^2}\frac{dP_C}{dS_w}\right)_{\substack{matrix\\block}} \quad (2)$$

In the formula: μ_w is the water phase viscosity, L is the core length, P_C is the capillary force, and S_w is the water saturation. The capillary pressure functions of the same rock type can be correlated with each other through the Leverett J function. The J function is modified here. The previous analysis shows that the imbibition diffusion radius can better describe the imbibition behavior of tight cores than the mean radius. Here, the reference radius of the J function is replaced by the mean radius [11] with the imbibition diffusion radius, that is, the reference radius r_{ref} is taken as:

$$r_{ref} = 2r_s \quad (3)$$

r_s is the imbibition diffusion radius. The reference capillary pressure corresponding to the r_{ref} is:

$$P_c = \frac{2\sigma\cos\theta}{r_{ref}} = \frac{\sigma f(\theta)}{r_s} \quad (4)$$

θ is the wetting angle. Define the ratio of the measured core capillary pressure to the reference capillary pressure as the modified J function, and the expression is:

$$J(S_{wn}) = \frac{P_c r_s}{\sigma f(\theta)} \quad (5)$$

Where: J (S_{wn}) is the normalized saturation of the core. From the following equation:

$$\left(\frac{dJs_w}{dS_w}\right)_{lab} = \left(\frac{dJs_w}{dS_w}\right)_{field} \quad (6)$$

$$\left(f(\theta)\right)_{lab} = \left(f(\theta)\right)_{field} \quad (7)$$

Substituting equation (5)-(7) into (2), we can get:

$$\left(t\frac{k}{\phi r_s}\frac{\sigma}{\mu_w L^2}\right)_{lab} = \left(t\frac{k}{\phi r_s}\frac{\sigma}{\mu_w L^2}\right)_{field} \quad (7)$$

Replace the viscosity term μ_w and the length term L with the form modified by Mason et al., respectively, then the modified time-scale model of no hence is:

$$t_D = \frac{1}{{L_C}^2}\frac{k}{\phi r_s}\frac{\sigma}{\mu_W(1+\sqrt{\mu_{NW}/\mu_W})}t \quad (8)$$

Using the modified model to scale the imbibition relative recovery degree curve in this study, it can be seen that the dispersion of each curve is well eliminated, which also reflects the rationality of the imbibition diffusion radius characterizing the imbibition capacity of tight cores. Of course, the correction method proposed in this study is a kind of correction idea. How to combine the classical mean radius and the imbibition diffusion radius according to the different stages of imbibition for correction can be further studied.

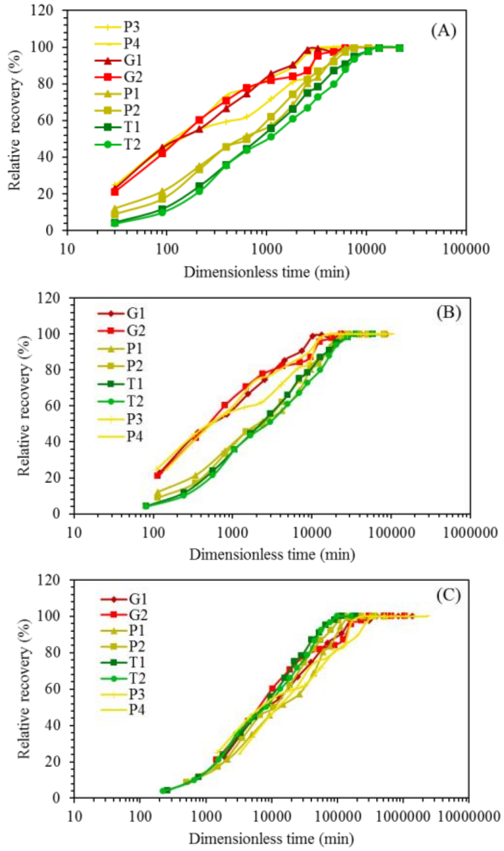

Fig.5. The scale effect of the classic model and the modified model. Figure A is the normalized oil recovery curve before scaling, which is rather scattered. Figure B is the curve scaled with the Mason model, and the dispersion is eliminated to some extent. Figure C is the curve scaled with the new model, and the dispersion is better eliminated.

4. CONCLUSIONS

In this study, a nuclear magnetic resonance imbibition experiment of tight reservoir cores was carried out, and new imbibition characterization parameters were proposed. Based on this, the capillary force term of the classic scale model was revised, and the influence of diffusion and water sensitivity in the process of imbibition was further considered, Obtained a more effective mathematical relationship between recovery factor and imbibition time applicable to tight reservoirs, and achieved a better scaling effect, which can better apply laboratory imbibition data to reservoir production, and provide new models and experimental reference for tight reservoir development.

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