EA Estimation Model of Permeability for Tight Sandstone Reservoirs Based on Nuclear Magetic Resonance T2 Centralized Distribution Method*

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Abstract

Some applications showed that the Coates model and SDR model acquired unsatisfied permeability results for tight rocks with low or ultra-low permeable properties. This study introduced a novel model with centralized distribution of pore space based on nuclear magnetic resonance T2 data. By describing the homogeneity of volume distribution of movable fluid in T2 distribution, it can been effectively used to analyze the permeability of ultra-low permeability sandstone reservoirs. Core data calculation showed that the coefficient C of pore space concentration distribution model has a good negative correlation with core permeability. The smaller the C value, the lower the concentration degree of pore size distribution, the better the permeability. Core data analysis and comparison showed that the model was more accurate than the classical permeability evaluation model of nuclear magnetic resonance logging, and has good applicability for quantitatively describing the permeability of reservoirs with complex pore structure.

Permeability Calculation Model

As the demand for oil continues to increase, there is an urgent need to increase understanding of low-porosity and low-permeability complex reservoirs. Since the birth of nuclear magnetic resonance logging technology, its unique advantages has provided a new way for geologists to solve the evaluation problem of such complex reservoirs. The maximum relative error of formation permeability determined by conventional logging is up to 50%, while the relative error of permeability calculated by NMR logging will be less than one order of magnitude. This also greatly improves the accuracy of using logging data to interpret permeability. Many empirical formulas have been established for calculating permeability using NMR relaxation and diffusion measurements. However, for low permeability sandstone reservoirs, especially in very low permeability cases, the correlation between the calculated permeability based on classical model and the measured values is very poor. There are two classical models commonly used in conventional reservoirs: Coates model and SDR model.

SDR model:

$$K_{SDR} = C_{S1}\left(\frac{\varphi_{NMR}}{100}\right)^4 T_{2g}^2$$

where C_{S1} is the model parameters, φ_{NMR} is the NMR porosity of saturated core samples, T2g is the geometric average value of T2 spectrum.

Coates-cutoff model:

$$K_{\text{Coates-cutoff}} = \left(\frac{\varphi_{NMR}}{C_{n1}}\right)^4 \left(\frac{FFI}{BVI}\right)^2$$

where C_{n1} is the model parameters, BVI and FFI are defined as bound fluid volume and free fluid volume determined by T2 spectrum.

Coates-sbvi model:

$$K_{\text{Coates-sbvi}} = \left(\frac{\varphi_{NMR}}{C_{n2}}\right)^4 \left(\frac{\varphi_{NMRm}}{\varphi_{NMRb}}\right)^2$$

where C_{n2} is the model parameters, φ_{NMRm} and φ_{NMRb} are expressed as movable water volume and bound water volume obtained by T2 weighting method respectively.

Model of T2 Distribution Concentration Degree

In the study of permeability of ultra-low porosity and permeability sandstone reservoirs, the influence of spatial distribution connectivity of pore must be fully considered. The size and distribution characteristics of pores have an important influence on reservoir permeability. Therefore, the key to evaluating reservoir permeability by NMR is to fully consider the distribution pattern of T2, focusing on the matching relationship of different pore sizes. To this end, a new quantitative evaluation physical function, a model of T2 centralized distribution was introduced.

$$C = 1 - \frac{1}{N}\sum_{i=1}^{N} (\overline{x})^{2K} / [\overline{x}^2 + (x_i - \overline{x})^2]^K$$

where xi represents the ith component of the physics distribution, is the mean value, K is the order.

C is a normalized dimensionless value ($0 \leq C < 1$); the smaller the C value, the smaller the concentration of the reflected physical field, the more uniform the distribution. Only when C = 0 is the lowest concentration degree, the distribution of the physical field is the most uniform; when C = 1, the concentration degree is the highest, and the distribution of the physical field around its mean value is the most concentrated, such as not zero only at one spatial point, other points are all zero, which is a special case of this situation.

Rock Physics Experiments

Taking the Yingcheng Formation and the Shahezi Formation reservoirs in the Shiwu Oilfield as an example, the reservoir has experienced strong diagenesis and strong compaction and cementation. The dissolution is relatively weak, and the primary pore loss is large. Primary and secondary pores have less development and poor reservoir performance. According to the identification results of the casting thin sections, there are three types of reservoir space in the oil-bearing sandstone layer of the core of the Shiwu Oilfield, namely primary pores, secondary pores and structural fractures. In the scanning electron micrograph, the phenomenon that the cement is not filled and the residual appearance of primary pores is observed; the other primary pores are capillary pores and mineral cleavage in the rock particles. With the enhancement of diagenesis the intergranular pores, dissolved pores and mold pores are affected by the compaction effects, and the pores are deformed locally, and the local connectivity is deteriorated, showing the non-uniformity of the pores. The Coates model and the SDR model were used to calculate permeability errors for an order of magnitude in reservoir permeability calculations, and the results indicate that they are not suitable for ultra-low permeability reservoirs.

In order to verify the applicability of the model, 39 core samples were selected for NMR experiments. The porosity distribution ranges from 5.33% to 14.98%, and the permeability distribution ranges from 0.01 to 9.97 ($10^{-3}\mu m^2$). In the semi-logarithmic coordinate system, with the increase of C value, the permeability decreases in an order of magnitude, which further shows that the spatial distribution of pore size is the key factor to determine permeability in ultra-low permeability reservoirs with similar porosity.

Conclusions

It is found that the pore throats of medium- and fine-grained sandstones are relatively small, and their seepage ability mainly depends on the interconnected small pores. The distribution and connection of medium or relatively small pore size are the key factors for the existence of certain seepage abilities in such reservoirs. Under different porosity and permeability conditions, the parameters C calculated by the above model are well correlated with core permeability and porosity, which indicates that the model of T2 centralized distribution degree has good applicability for quantitative characterization of ultra-low permeability sandstone reservoirs, and are more accurate than classical NMR permeability models. Of course, there are some errors in the permeability and core permeability calculated by the model of T2 centralized distribution. These errors may be caused by shale content and distribution.