Introduction

Oil saturation calculation is an important part of formation evaluation via log data. Scholars have carried out in-depth studies and have formed a series of achievements. For the moment, the methods in conventional reservoirs are relatively perfect, such as Archie model (Archie, 1942), W-S model (Waxman and Smits, 1968), dual-water model (Clavier et al., 1984), et al. However, due to complex lithology, low matrix porosity and strong heterogeneity of tight conglomerate reservoirs, resistivity log response is affected seriously by rock matrix and pore structure, while the effect of fluid property is weak (Amitabha et al., 2016). In the past two decades, NMR logs are more and more commonly applied to fluid analysis and evaluation. The differential spectrum method and shift spectrum method are frequently used in the identification of reservoir fluid property (Deng, 2010). Hence, in this study, a NMR based model is proposed for predicting oil saturation of tight conglomerate reservoirs. Firstly, an empirical method is proposed to reconstruct the NMR $T_2$ spectrum under completely watered condition using the mercury injection capillary pressure (MICP) curve based on the “three-piece” power function. Second, the $T_2$ geometric means of the $T_2$ spectra under oil-bearing and completely watered conditions are extracted and the quantitative relation between oil saturation and their ratio is established. Finally, the established method are verified and applied with good application effect.

Junggar Basin is situated in Northwest China (Figure. 1a). The basin is rich in petroleum, and the studied area refers to the Mahu Foreland Sag in the northwestern margin of Junggar Basin (Figure. 1b). As shown in Figure. 1c, the Wuxia fault belt lies in the north of the studied area, Kebai fault belt in the northwest, Zhongguai swell in the southwest, Dabasong swell in the south, Xiayan swell in the east and Luliang swell in the northeast. The target studied area is the Triassic Baikouquan and Permian Urho Formation. The reservoir lithology mainly refers to a conglomerate of varying sizes: generally between 0.5 cm - 2 cm and up to about 10 cm at most. Porosity and permeability change greatly.

Material and methods

In order to set a better petrophysical model, systematic petrophysical experiments are carried out. First, 10 typical cores were selected. Second, the NMR $T_2$ spectra under completely watered condition were measured via a tester manufactured by Oxford Instruments (Figure. 2a). The echo interval and waiting time of the NMR $T_2$ spectrum measurements are 0.1 ms and 6 s respectively. The MICP curves were then measured, as given in Figure. 2b. It can be learnt from the comparison that the reservoir physical properties reflected by $T_2$ spectrum and MICP curve are basically consistent.
According to the principle of NMR logging, only NMR $T_2$ spectrum under completely watered condition can completely reflect reservoir pore structure (Feng et al., 2017). Therefore, the MICP curve can be used to reconstruct the NMR $T_2$ spectrum under completely watered condition. It is discovered that the $T_2$ value and the reciprocal of mercury injection pressure present the “three-piece” feature on the log-log coordinate (Figure 3). In combination with the lithologic characteristics of conglomerate, long relaxation time part exhibits the properties between large gravel, sand and cement. Medium relaxation time part exhibits the properties between medium-small gravel and fine silt; short relaxation time part exhibits the properties between fine silt and cement (Figure 4).

Based on the model proposed and the above piecewise characteristics (He et al., 2005), a method of reconstructing NMR $T_2$ spectrum under completely watered condition using the MICP curve based on “three-piece” power function is proposed. It can be expressed as:

$$T_2 = m_i \left( \frac{1}{P_c} \right)^{n_i}$$

where $T_2$ refers to the transverse relaxation time, ms; $P_c$ refers to the capillary pressure, dyn/cm²; $m_i$ and $n_i$ ($i=1, 2, 3$) refer to the model coefficients with different pore types.

The conglomerate reservoir shows water-wet property via geological background and core sample observation. According to NMR logging principle and experimental data, the oil bulk relaxation is larger than 200 ms, which is far bigger than the surface relaxation of water, indicating that the measured NMR $T_2$ spectrum shows an obvious difference when the reservoir is full of water and saturated with oil. To build a model for predicting oil saturation in a quantitative way, the difference between the two NMR $T_2$ spectra can be reflected in a quantitative way by extracting the ratio of geometric means of the NMR $T_2$ spectra under oil-bearing and completely watered condition. Therefore, the reconstructing $T_2$ spectra and the corresponding part of the NMR $T_2$ spectra under completely watered condition are used to calculate the $T_{2lm_o}$ and $T_{2lm_w}$ as follows:

$$\lambda = \frac{T_{2lm_o}}{T_{2lm_w}}$$

where $T_{2lm_o}$ and $T_{2lm_w}$ refers to the $T_2$ geometric mean of NMR $T_2$ spectrum under oil-bearing and completely watered condition respectively, ms; $\lambda$ refers to the ratio of $T_2$ geometric means.

From the above, with oil saturation is larger, the $T_2$ geometric mean of NMR $T_2$ spectrum under oil-bearing and completely watered condition increase, which means that the ratio of $T_2$ geometric means grows. Hence, the ratio of $T_2$ geometric means should have a positive correlation relation to the oil saturation of the reservoir.

Then the relation is established based on the measured oil saturation and $T_2$ geometric mean of sealed cores, as shown in equation (3):

$$S_o = t(\lambda)$$

where, $S_o$ refers to the oil saturation, %; $t(\lambda)$ refers to the function with $\lambda$ as an independent variable, either linear or non-linear function.

After the parameter in the function $t(\lambda)$ in equation (7) is obtained by regression, the new empirical model is built for predicting oil saturation based on the ratio of NMR $T_2$ geometric means.
In the studied area, the experimental data on T2 spectra and MICP curves of the 10 cores are used for modeling. Based on the multivariate statistics regression model; the $m$ and $n$ parameters of large, medium and small pore models can be acquired with high correlation coefficients. The classification standards of the large, medium and small pores are higher than 0.184 μm, 0.011 μm - 0.184 μm, and lower than 0.011 μm, respectively. And the correlation between $T_2$ relaxation time and mercury injection pressure is also established (Table 1).

<table>
<thead>
<tr>
<th>Type</th>
<th>Model</th>
<th>Correlation coefficient</th>
</tr>
</thead>
<tbody>
<tr>
<td>large pore</td>
<td>$T_2 = 31.31 \times \left( \frac{1}{P} \right)^{0.08}$</td>
<td>0.90</td>
</tr>
<tr>
<td>medium pore</td>
<td>$T_2 = 20.31 \times \left( \frac{1}{P} \right)^{-0.64}$</td>
<td>0.94</td>
</tr>
<tr>
<td>small pore</td>
<td>$T_2 = 89.45 \times \left( \frac{1}{P} \right)^{1.02}$</td>
<td>0.81</td>
</tr>
</tbody>
</table>

The MICP data serving as the input in the model are from the experiment rather than continuous log data. Hence, the experimental data on the MICP curve of 180 cores are collected to ensure better application of the model in actual formation evaluation. Therein, the variation ranges of porosity, permeability, composite physical property index (the radication of the ratio between permeability and porosity) and medium radius are 3.3% - 17.4%, 0.029×10^{-3} μm² - 127×10^{-3} μm² and 0.083 - 4.613, respectively. By using them as the selection criteria, the corresponding MICP curve is substituted into equation (1) and Table 1 to acquire the reconstructed NMR $T_2$ spectrum under completely watered condition.

In order to ensure a good application in formation evaluation, sealed coring experimental data are selected as the basis to build and calibrate the model and parameters in equation (3). The oil saturation measured through sealed coring and the ratio of the $T_2$ geometric means is used to draw the scatter plot, as shown in Figure. 5. The model is given in equation (4) through statistical regression. The correlation coefficient of linear fitting is 0.82, indicating high reliability.

$$S_o = 27.02 \times \ln(\lambda) + 16.19$$ (4)

The sealed coring interval of the well that is not used in modeling is selected to test the model. The comparison between the predicted oil saturation and the oil saturation measured by the sealed coring experiment is presented in Figure. 6. The data points are distributed near the diagonal with the mean relative error and root mean square error (RMSE) around 10% and 3% respectively, indicating high reliability of the oil saturation prediction model.

Figure. 7 presents the resulting plot of Well A. The first three lines refer to the conventional log curves, and the fifth to the tenth lines refer to the porosity, permeability, MICP curve, NMR $T_2$ spectrum, $\lambda$ and oil saturation respectively. The red and green NMR $T_2$ spectra in the line eight are measured and predicted $T_2$ spectra respectively. The black curves and red dots in the tenth line are the predicted and the measured oil saturation respectively. It can be directly seen from the plot that the oil saturation calculated by the ratio of $T_2$ geometric means well coincides with the result of sealed coring experiments with slight error.

To sum up, it is clear that the NMR $T_2$ spectrum prediction method and oil saturation prediction method are highly reliable and they can be well applied in tight conglomerate reservoirs.

**Conclusions**

Through the comparative analysis of the experimental data of $T_2$ distribution and MICP curve of tight conglomerate cores, it is proposed a method of reconstructing the NMR $T_2$ spectrum under completely watered condition using the MICP curve based on the “three-piece” power function. The jointly measured experimental data are used for parameter calibration. The 180 measured MICP curves are used as the input database for formation evaluation. On such a basis, the $T_2$ geometric means of NMR $T_2$ spectra under oil-bearing and completely watered conditions are extracted. The quantitative relation
is established between the ratio of the two and the oil saturation measured by sealed coring experiment, for the quantitative prediction of oil saturation of tight conglomerate reservoirs. The model is verified by the core experimental data to prove high reliability and favorable application effect. As the proposed method is only influenced by the wettability of reservoir and viscosity of oil, it is not only appropriate for the studied area, but also other water-wet reservoirs containing light oil. It is important to identify oil layers, to calculate oil saturation and to improve log interpretation accuracy in tight conglomerate reservoirs.

\[ y = 27.02 \times \ln(x) + 16.19 \]

\[ R = 0.82 \]

**Figure 5** The relation between oil saturation and \( \lambda \).

**Figure 6** The comparison between the predicted oil saturation and the oil saturation measured by sealed coring experiment.

**Figure 7** A field study of tight conglomerate reservoirs of Well A in the studied area.

**Acknowledgements**

This paper was supported by the Natural Science Foundation of Xinjiang Uygur Autonomous Region (No. 2017D01B57), the Natural Science Project of Xinjiang Uygur Autonomous Region Education Department (No. XJEDU2017S063).

**References**


Deng, K. J. [2010]. Nuclear magnetic resonance petrophysical and logging applications. *China University of Petroleum Press*.

