Tight-Gas-Sand Permeability Estimation From Nuclear-Magnetic-Resonance (NMR) Logs Based on the Hydraulic-Flow-Unit (HFU) Approach

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Summary
The crossplot of porosity vs. Klinkenberg permeability (PERM) for 378 core samples, drilled from tight gas sands in the Xujiahe formation of the Anlu region-central Sichuan basin, southwest China, showed that tight-gas-sand permeability cannot be estimated effectively from porosity directly because only a poor relationship can be found between core-derived porosity and permeability because of the strong heterogeneity, especially for reservoirs with dominant microfractures (with porosities lower than 6.5%). However, the problem can be solved by introducing the HFU approach. In this paper, the 378 core samples were divided into five types on the basis of the difference of the flow-zone indicator (FZI), and then relationships of rock porosity and permeability were established for each type of core sample. By virtue of the analysis of the expression of FZI and the classical Schlumberger Doll Research (SDR) Center model, a novel technique used to obtain FZI from NMR logs was proposed and a corresponding model was established. The model parameters were calibrated by use of the laboratory NMR measurements of 54 plug samples taken from the Xujiahe formation. Carried out on the experimental data sets, this procedure can be extended to reservoir conditions to estimate consecutive formation permeability along the intervals through which NMR logs were acquired. The processing results of field examples illustrate that the calculated FZI values from field NMR logs match very well with the core analyzed results; the absolute errors among them are within the scope of ±0.15. Moreover, permeability, estimated by use of the proposed technique and the core analyzed results are consistent. However, the calibrated SDR model is exclusive to the cases where formation permeability ranges from 0.2 to 0.4 md. To improve permeability prediction with the SDR model, many more core samples drilled from formations with dominant microfractures needed to be tested for laboratory NMR experiments to calibrate the SDR model for each HFU.

Introduction
Permeability plays a significant role in predicting hydrocarbon deliverability and formulating a development program for petroleum engineering, especially for tight gas sands. A reliable value of permeability contributes to improving reservoir-effectiveness evaluation and exploring potential layers (Xiao et al. 2012a; Mao et al. 2013). Generally, permeability is estimated from porosity through an established relationship based on routine core analysis in conventional reservoirs (Nelson 1994; Al-Ajmi and Holditch 2000; Jennings and Lucia 2003; Bust et al. 2011). However, permeability estimation in tight gas sands being a great challenge, a good relationship between core analyzed porosity and permeability cannot be established in the target intervals because of the strong heterogeneity. Fig. 1 shows a crossplot of core-derived porosity and the PERM acquired from 378 core samples, which were drilled from tight gas sands in the Xujiahe formation of the Anlu region, central Sichuan basin, southwest China. In this study, to acquire permeability for routine core analysis in tight gas sandstones, an instantaneous-pulse permeability-test method was applied instead of the conventional steady-state method. By using the instantaneous-pulse permeability-test method, the extremely low permeability of 0.000001 md can also be measured under the experimental conditions of confinement pressure (10.0–60.0 MPa) and pore pressure (0.0–15.0 MPa) (Gao et al. 1991; Yang 2001; Yang et al. 2001). Meanwhile, 20 core samples were also chosen for Klinkenberg-permeability measurements in the Xujiahe formation, and the relationship between air permeability and PERM for these 20 core samples is as shown in Fig. 2. It can also be observed from Fig. 2 that there is high correlation between these two kinds of permeability, indicating that air permeability can be precisely corrected as PERM for tight-gas-reservoir evaluation. The PERM shown on the y-axis in Fig. 1 was corrected by using the relationship shown in Fig. 2. Fig. 1 shows that the formations are strongly heterogeneous, and that the relationship between core-derived porosity and PERM cannot be expressed by a single function in the whole Xujiahe formation. In different boreholes, the tendencies of core-derived porosity and permeability differ, and even in a single borehole, the trends are not quite similar. For formations with dominant microfractures (with porosities lower than 6.5%), as porosity increases, permeability increases much more quickly. Therefore, it is difficult to estimate permeability from porosity directly by use of an established single relationship.

In this study, the HFU approach is introduced to predict permeability for tight-gas-sand evaluation, the parameter of the FZI is used to classify rocks, and the relationships between core-derived porosity and permeability are established for each type of rock. In order that the established relationships can be used to predict permeability at all of the target intervals, a new technique used to extract FZI from NMR logs is proposed, and the corresponding FZI-calculation model is established.

Method of Predicting Permeability From Porosity by Use of the HFU Approach. Theory of the HFU Approach. An HFU is defined as the volume of rock within which geological properties that control porous-media flow are internally consistent but are different from those of other rocks (Abbaszadeh et al. 1996; D’Windt 2007). A flow unit is a reservoir zone that is continuous laterally and vertically with similar permeability, porosity, and bedding characteristics (Hearn et al. 1984). The flow properties of
porous media are mainly controlled by mineralogy (such as type, abundance, and location) and texture (such as grain size, grain shape, sorting, and packing). Rocks with some of these geological properties often have similar pore-throat attributes and therefore belong to the same HFU. Thus, the HFU consists of the basic materials that are used to classify a formation and thus is of great help to the process of reservoir classification in the presence of strong heterogeneity.

On the basis of a modified Kozeny-Carman equation and the concept of mean hydraulic radius, Tiab et al. (1993) and Amaefule et al. (1993) developed a technique for identifying and characterizing formations with similar HFUs by application of microscopic measurements of rock core samples (Kozeny 1927; Carman 1937; Nooruddin and Hossain et al. 2011). On the basis of this technique, a generalized expression of the relationship between porosity and permeability is established, which can be obtained by dividing both sides of Eq. 1 by porosity and taking the square root of both:

$$\sqrt{\frac{K}{\phi}} = \frac{\phi}{1 - \phi} \times \frac{1}{\sqrt{K_T S_{gr}}}.$$  

(3)

where 0.0314 is the conversion coefficient for $K$ from $\mu m^2$ to md.

In the HFU theory, there are three important parameters: reservoir-quality index (RQI), FZI, and normalized porosity ($\phi_z$). These are defined as follows:

$$RQI = 0.0314 \times \sqrt{\frac{K}{\phi}}.$$  

(4)

$$FZI = \frac{1}{\sqrt{K_T S_{gr}}}.$$  

(5)

$$\phi_z = \frac{\phi}{1 - \phi}.$$  

(6)

Substitute Eqs. 4 through 6 into Eq. 3 and take logarithms on both sides; the following formula is obtained:

$$\log(RQI) = \log(FZI) + \log(\phi_z).$$  

(7)

By carrying out some algebraic manipulations of Eq. 3, the expression of FZI can be rewritten as follows:

$$FZI = 0.0314 \times \sqrt{\frac{K}{\phi}} \times \frac{1 - \phi}{\phi}.$$  

(8)

Eq. 7 indicates that in log-log coordinates of $\phi_z$ vs. RQI, the plot for them will be a straight line for core samples with similar FZI. The intercept of this straight line at $\phi_z=1$ is the FZI. Core samples with a different FZI will be on other parallel lines.

**Establishment of Permeability-Estimation Model Based on the HFU Approach in Tight Gas Sands of Target Formation.**

To ensure that the established models can be used to consecutively estimate permeability in the target formations, 378 core samples drilled from three adjacent wells are intermingled and processed by use of the theory of HFU. **Fig. 3** shows the cumulative frequency distribution of FZI, and **Fig. 4** shows a crossplot of $\phi_z$ and RQI in log-log coordinates. These two figures clearly indicate that in the Xujiahe formation, rocks can be classified into five types of HFU. For rocks with different types of HFU, the variation tendency of cumulative frequency for FZI is diverse. Although the cumulative frequency for core samples with FZI higher than 1.80 has another trend, they are ignored because there are only four core samples of this kind. Meanwhile, the trend lines vary among flow units, $K_T$ is constant within a given unit (Amaefule et al. 1993; Biniwale and Behrenbruch 2004; Tiab and Donaldson 2012).

If permeability is expressed in millidarcies, then the following formula can be obtained by dividing both sides of Eq. 1 by porosity and taking the square root of both:

$$0.0314 \times \sqrt{\frac{K}{\phi}} = \frac{\phi}{1 - \phi} \times \frac{1}{\sqrt{K_T S_{gr}}}.$$  

where 0.0314 is the conversion coefficient for $K$ from $\mu m^2$ to md.

On the basis of a modified Kozeny-Carman equation and the concept of mean hydraulic radius, Tiab et al. (1993) and Amaefule et al. (1993) developed a technique for identifying and characterizing formations with similar HFUs by application of microscopic measurements of rock core samples (Kozeny 1927; Carman 1937; Nooruddin and Hossain et al. 2011). On the basis of this technique, a generalized expression of the relationship between porosity and permeability is established, which can be expressed as follows:

$$K = \frac{\phi^3}{(1 - \phi)^2} \times \frac{1}{K_T S_{gr}^2}.$$  

(1)

where

$$K_T = K_m \tau.$$  

(2)

$K$ is the rock permeability in $\mu m^2$, $\phi$ is the rock porosity in front of the fraction, $S_{gr}$ is the specific surface area per unit grain volume in $m^2/cm^3$, $K_m$ is the pore-shape factor, $\tau$ is the pore tortuosity, and $K_T$ is the pore-level effective zoning factor. Though

**Fig. 1**—A crossplot of core-derived porosity and PERM for 378 core samples, which were drilled from tight gas sands in the Xujiahe formation of the Anlu region, central Sichuan basin, southwest China.

**Fig. 2**—Relationship between air permeability and PERM for 20 core samples in the Xujiahe tight gas sands.

**Fig. 3**—The cumulative frequency distribution of FZI for 378 core samples in the Xujiahe formation.
between $\phi_z$ and RQI in log-log coordinates are parallel for core samples belonging to a different HFU.

On the basis of the analyzed results shown in Figs. 3 and 4, 378 core samples were reused and classified into five types. The correlations between core-derived porosity and permeability for every type of rock are displayed in Fig. 5. It can be clearly seen that the correlations between core porosity and permeability have been greatly improved since the HFU approach was introduced, with correlation coefficients between them all higher than 0.90. For every type of rock, a single function can be established to extract permeability from porosity. The formation classification criteria of FZI and corresponding permeability-estimation models are listed in Table 1.

### A New Technique for Predicting FZI From NMR Logs

Formation-classification criteria by using the difference between FZI and corresponding permeability-estimation models for every type of rock have been presented in the preceding section. In order to extend this technique to reservoir conditions, it is necessary to first calculate consecutive FZIs. Well log data can be used to continuously record formation information; therefore, it was used to extend this technique to reservoir conditions, it is necessary to directly from NMR logs (Kenyon 1997; Kenyon et al. 1988; Coates et al. 2000; Dunn et al. 2002; Richard 2002) and can be written as

$$K = C_1 \times \phi^{m_1} \times T_{21m}^n.$$  \hspace{1cm} (9)

where $T_{21m}$ is the logarithmic mean of NMR $T_2$ distribution in milliseconds and $C_1$, $m_1$, and $n_1$ are the statistical model parameters that can be derived from the experimental data sets of core samples. Assuming that enough core samples are not available, $C_1$, $m_1$, and $n_1$ can be assigned to empirical values of 10, 4, and 2, respectively.

By carrying out some algebraic transformations, Eq. 9 can be rewritten as follows:

$$\sqrt{\frac{K}{\phi}} = \sqrt[C_1]{\phi}^{\frac{m_1 - 1}{2}} \times \frac{n_1}{\sqrt{T_{21m}}}, \hspace{1cm} \text{Eq. } 10$$

### A New Model of Estimating FZI From NMR Logs

By substituting Eq. 10 into Eq. 8, a derivative expression can be written as follows:

$$\text{FZI} = 0.0314 \times \frac{\sqrt{C_1 \times \phi^{m_1 - 1}} \times T_{21m}^n}{1 - \phi}$$

$$= 0.0314 \times \sqrt{C_1} \times \phi^{m_1 - 1} \times T_{21m}^n \times (1 - \phi)$$

$$= C \times \phi^{m_1 - 1} \times T_{21m}^n \times (1 - \phi), \hspace{1cm} \text{Eq. } 11$$

### Table 1—Permeability-Estimation Models for Rocks with Different Types of FZI in the Xujiahe Tight Gas Reservoirs of the Anlu Region, Central Sichuan Basin, Southwest China

<table>
<thead>
<tr>
<th>Types of Rock</th>
<th>Classification of FZI</th>
<th>Permeability-Estimation Models</th>
<th>Correlation Coefficient ($R^2$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Type 1</td>
<td>Less than 0.22</td>
<td>$K = 0.00003 \times \phi^{3.2247}$</td>
<td>0.914</td>
</tr>
<tr>
<td>Type 2</td>
<td>Between 0.22 and 0.37</td>
<td>$K = 0.0001 \times \phi^{2.9887}$</td>
<td>0.936</td>
</tr>
<tr>
<td>Type 3</td>
<td>Between 0.37 and 0.54</td>
<td>$K = 0.0002 \times \phi^{3.1483}$</td>
<td>0.982</td>
</tr>
<tr>
<td>Type 4</td>
<td>Between 0.54 and 1.05</td>
<td>$K = 0.0006 \times \phi^{3.0782}$</td>
<td>0.954</td>
</tr>
<tr>
<td>Type 5</td>
<td>Greater than 1.05</td>
<td>$K = 0.0019 \times \phi^{3.0462}$</td>
<td>0.955</td>
</tr>
</tbody>
</table>
where

\[
C = 0.0314 \times \sqrt{C_1} \quad \cdots \quad (12)
\]

\[
m = \frac{m_1 - \frac{3}{2}}{2} \quad \cdots \quad (13)
\]

\[
n = n_1 \cdot \frac{1}{2} \quad \cdots \quad (14)
\]

By combining Eq. 9 and Eqs. 12 through 14, it can be observed that the model parameters of \(C\), \(m\), and \(n\) in Eq. 11 are constant for a given formation. Therefore, the determination of their values lies in the experimental data sets of core samples.

Eq. 11 indicates that FZI is associated with \(C\), \(m\), and \(T_{2lm}\). Once the values of \(\phi\) and \(T_{2lm}\) are obtained, FZI can be predicted. \(\phi\) and \(T_{2lm}\) can be acquired directly from NMR logs; thus, FZI can be obtained from NMR logs by use of Eq. 11. Subsequently, once FZI is calculated from NMR logs to classify reservoirs, permeability can be estimated from NMR porosity by using the models listed in Table 1.

### Estimating Permeability From NMR Logs in Tight Gas Reservoirs

**Calibration of FZI-Estimation-Model Parameters From Laboratory NMR Measurements.** Eq. 11 indicates that FZI can be estimated from NMR logs once the statistical model parameters of \(C\), \(m\), and \(n\) are calibrated. In order to determine the values of \(C\), \(m\), and \(n\), 54 core samples, chosen from the 378 core samples, are employed for laboratory NMR measurements. The experimental data sets are listed in Table 2, and the experimental parameters of laboratory NMR measurement are listed as follows: polarization time, 6.0 seconds; interecho spacing (TE), 0.2 milliseconds; the number of echoes per echo train, 4096; and scanning number, 128.

### TABLE 2—DATA SETS OF LABORATORY NMR MEASUREMENTS FOR 54 CORE SAMPLES DRILLED FROM THE XUJIAHE TIGHT GAS RESERVOIRS

<table>
<thead>
<tr>
<th>Wells</th>
<th>Sample Number</th>
<th>Depth (m)</th>
<th>Porosity (%)</th>
<th>Permeability (md)</th>
<th>(T_{2lm}) (ms)</th>
<th>FZI</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well A</td>
<td>1 xx38.56</td>
<td>8.05</td>
<td>0.016</td>
<td>24.80</td>
<td>0.161</td>
<td></td>
</tr>
<tr>
<td>Well A</td>
<td>2 xx38.82</td>
<td>7.12</td>
<td>0.018</td>
<td>23.28</td>
<td>0.204</td>
<td></td>
</tr>
<tr>
<td>Well A</td>
<td>3 xx41.43</td>
<td>4.94</td>
<td>0.018</td>
<td>17.42</td>
<td>0.362</td>
<td></td>
</tr>
<tr>
<td>Well A</td>
<td>4 xx44.37</td>
<td>4.53</td>
<td>0.016</td>
<td>16.95</td>
<td>0.388</td>
<td></td>
</tr>
<tr>
<td>Well A</td>
<td>5 xx45.01</td>
<td>4.93</td>
<td>0.028</td>
<td>17.72</td>
<td>0.456</td>
<td></td>
</tr>
<tr>
<td>Well A</td>
<td>6 xx45.51</td>
<td>3.91</td>
<td>0.013</td>
<td>13.35</td>
<td>0.436</td>
<td></td>
</tr>
<tr>
<td>Well A</td>
<td>7 xx47.15</td>
<td>5.48</td>
<td>0.021</td>
<td>19.99</td>
<td>0.334</td>
<td></td>
</tr>
<tr>
<td>Well A</td>
<td>8 xx48.68</td>
<td>8.76</td>
<td>0.023</td>
<td>24.84</td>
<td>0.166</td>
<td></td>
</tr>
<tr>
<td>Well A</td>
<td>9 xx50.77</td>
<td>9.27</td>
<td>0.016</td>
<td>24.24</td>
<td>0.128</td>
<td></td>
</tr>
<tr>
<td>Well A</td>
<td>10 xx51.99</td>
<td>5.89</td>
<td>0.027</td>
<td>22.49</td>
<td>0.314</td>
<td></td>
</tr>
<tr>
<td>Well A</td>
<td>11 xx53.62</td>
<td>6.56</td>
<td>0.030</td>
<td>23.49</td>
<td>0.302</td>
<td></td>
</tr>
<tr>
<td>Well A</td>
<td>12 xx98.61</td>
<td>11.48</td>
<td>0.113</td>
<td>42.23</td>
<td>0.240</td>
<td></td>
</tr>
<tr>
<td>Well A</td>
<td>13 xx97.90</td>
<td>11.10</td>
<td>0.082</td>
<td>39.40</td>
<td>0.216</td>
<td></td>
</tr>
<tr>
<td>Well A</td>
<td>14 xx98.84</td>
<td>10.52</td>
<td>0.087</td>
<td>36.65</td>
<td>0.242</td>
<td></td>
</tr>
<tr>
<td>Well A</td>
<td>15 xx00.82</td>
<td>10.74</td>
<td>0.121</td>
<td>34.03</td>
<td>0.277</td>
<td></td>
</tr>
<tr>
<td>Well A</td>
<td>16 xx02.57</td>
<td>8.28</td>
<td>0.038</td>
<td>17.07</td>
<td>0.235</td>
<td></td>
</tr>
<tr>
<td>Well B</td>
<td>17 xx32.20</td>
<td>13.91</td>
<td>0.315</td>
<td>20.20</td>
<td>0.292</td>
<td></td>
</tr>
<tr>
<td>Well B</td>
<td>18 xx31.65</td>
<td>14.47</td>
<td>1.440</td>
<td>28.81</td>
<td>0.585</td>
<td></td>
</tr>
<tr>
<td>Well B</td>
<td>19 xx31.30</td>
<td>14.34</td>
<td>0.399</td>
<td>28.34</td>
<td>0.313</td>
<td></td>
</tr>
<tr>
<td>Well B</td>
<td>20 xx27.40</td>
<td>13.40</td>
<td>0.139</td>
<td>21.91</td>
<td>0.207</td>
<td></td>
</tr>
<tr>
<td>Well B</td>
<td>21 xx26.10</td>
<td>11.34</td>
<td>0.186</td>
<td>21.99</td>
<td>0.314</td>
<td></td>
</tr>
<tr>
<td>Well B</td>
<td>22 xx25.80</td>
<td>10.41</td>
<td>0.115</td>
<td>22.22</td>
<td>0.284</td>
<td></td>
</tr>
<tr>
<td>Well B</td>
<td>23 xx23.40</td>
<td>11.97</td>
<td>0.148</td>
<td>21.11</td>
<td>0.257</td>
<td></td>
</tr>
<tr>
<td>Well B</td>
<td>24 xx23.25</td>
<td>12.34</td>
<td>0.332</td>
<td>18.92</td>
<td>0.366</td>
<td></td>
</tr>
<tr>
<td>Well B</td>
<td>25 xx22.50</td>
<td>12.74</td>
<td>0.138</td>
<td>20.12</td>
<td>0.224</td>
<td></td>
</tr>
<tr>
<td>Well B</td>
<td>26 xx21.50</td>
<td>14.87</td>
<td>1.170</td>
<td>32.54</td>
<td>0.504</td>
<td></td>
</tr>
<tr>
<td>Well B</td>
<td>27 xx20.50</td>
<td>15.67</td>
<td>5.280</td>
<td>33.47</td>
<td>0.981</td>
<td></td>
</tr>
<tr>
<td>Well B</td>
<td>28 xx17.80</td>
<td>15.60</td>
<td>16.800</td>
<td>38.15</td>
<td>1.763</td>
<td></td>
</tr>
<tr>
<td>Well B</td>
<td>29 xx03.90</td>
<td>4.73</td>
<td>0.103</td>
<td>25.92</td>
<td>0.933</td>
<td></td>
</tr>
<tr>
<td>Well B</td>
<td>30 xx02.95</td>
<td>2.59</td>
<td>0.006</td>
<td>14.94</td>
<td>0.547</td>
<td></td>
</tr>
<tr>
<td>Well B</td>
<td>31 xx00.10</td>
<td>12.87</td>
<td>0.853</td>
<td>41.28</td>
<td>0.547</td>
<td></td>
</tr>
<tr>
<td>Well B</td>
<td>32 xx30.50</td>
<td>14.13</td>
<td>0.767</td>
<td>29.10</td>
<td>0.445</td>
<td></td>
</tr>
<tr>
<td>Well B</td>
<td>33 xx30.30</td>
<td>12.96</td>
<td>0.405</td>
<td>24.63</td>
<td>0.373</td>
<td></td>
</tr>
<tr>
<td>Well C</td>
<td>34 xx30.12</td>
<td>4.80</td>
<td>0.025</td>
<td>10.80</td>
<td>0.449</td>
<td></td>
</tr>
<tr>
<td>Well C</td>
<td>35 xx32.00</td>
<td>5.69</td>
<td>0.032</td>
<td>11.67</td>
<td>0.390</td>
<td></td>
</tr>
<tr>
<td>Well C</td>
<td>36 xx34.04</td>
<td>4.50</td>
<td>0.013</td>
<td>9.69</td>
<td>0.358</td>
<td></td>
</tr>
<tr>
<td>Well C</td>
<td>37 xx34.55</td>
<td>3.91</td>
<td>0.011</td>
<td>8.61</td>
<td>0.409</td>
<td></td>
</tr>
<tr>
<td>Well C</td>
<td>38 xx35.17</td>
<td>7.24</td>
<td>0.035</td>
<td>16.76</td>
<td>0.280</td>
<td></td>
</tr>
<tr>
<td>Well C</td>
<td>39 xx35.63</td>
<td>7.75</td>
<td>0.066</td>
<td>22.25</td>
<td>0.345</td>
<td></td>
</tr>
<tr>
<td>Well C</td>
<td>40 xx38.78</td>
<td>11.06</td>
<td>0.216</td>
<td>35.71</td>
<td>0.353</td>
<td></td>
</tr>
<tr>
<td>Well C</td>
<td>41 xx39.11</td>
<td>12.13</td>
<td>0.986</td>
<td>45.93</td>
<td>0.649</td>
<td></td>
</tr>
</tbody>
</table>
By performing some algebraic transformations in Eq. 11, a derivative formula can be expressed as follows:

\[
\log(\text{FZI}) - \log(1 - \phi) = \log(C) + m \times \log(\phi) + n \times \log(T_{2m}) \quad \ldots \quad (15)
\]

Eq. 15 indicates that FZI-estimation-model parameters can be calibrated from laboratory NMR measurements by use of the multivariate regression method.

Fig. 6 displays a crossplot of \(\log(\phi)\) and \([\log(\text{FZI}) - \log(1 - \phi)]\) for all 54 core samples listed in Table 2. This figure illustrates that a good relationship between FZI and NMR parameters exists. However, for core samples with different porosities, the tendency is disparate and they are divided by the porosity value of 9.0%.

To understand the factor that causes two tendencies in the crossplot of \(\log(\phi)\) and \([\log(\text{FZI}) - \log(1 - \phi)]\) shown in Fig. 6, the crossplot of core porosity and PERM for all 54 core samples is shown in Fig. 7. This figure illustrates that two tendencies exist between core porosity and PERM, the boundary of which is the porosity of 9.0%. Therefore, in the next section, with 9.0% as a porosity boundary, the data sets listed in Table 2 are reused, and the parameters mentioned in the SDR model are calibrated and can be expressed as follows:

\[
K = 0.00000389 \times \phi^{2.282} \times T_{165}^{-0.653},
\]

\[R^2 = 0.702.\quad \ldots \quad (18)
\]

For \(\phi < 9.0\%\),

\[
\text{FZI} = 0.0227 \times \phi^{-0.985} \times T_{2m}^{-0.0259} \times (1 - \phi),
\]

\[R^2 = 0.852.\quad \ldots \quad (16)
\]

For \(\phi \geq 9.0\%\),

\[
\text{FZI} = 5.524 \times \phi^{2.731} \times T_{2m}^{0.933} \times (1 - \phi),
\]

\[R^2 = 0.880.\quad \ldots \quad (17)
\]

Eqs. 16 and 17 show that in the Xujiahe formation, FZI can be calculated from NMR logs because the correlation coefficients are all higher than 0.85. Once this technique is extended to reservoir conditions, a continuous FZI will be predicted along the intervals through which NMR logs were acquired.

In the meantime, the applicability of the classical SDR model in tight gas sands is also studied in this paper. The data sets listed in Table 2 are reused, and the parameters mentioned in the SDR model are calibrated and can be expressed as follows:

\[
K = 0.00000389 \times \phi^{2.282} \times T_{165}^{-0.653},
\]

\[R^2 = 0.702.\quad \ldots \quad (18)
\]
In Eq. 18, a good relationship among permeability, porosity, and \( T_{2\text{low}} \) is observed, as well as a sharp difference between SDR-model parameters in tight gas sands and the empirical values can be observed.

**Reliability Verification for FZI Estimation.** To verify the feasibility of these FZI-estimation models, expressed in Eqs. 16 and 17, in field applications, they are applied to tight gas reservoirs in the Xujiahe formation to obtain consecutive FZIs from field NMR logs. By means of the proposed technique, a well in tight gas sands is processed and subsequently FZI obtained from the core analyzed results is compared with that calculated from field NMR logs, with results shown in Fig. 8. To reduce the impact of natural gas on the input parameters in permeability estimation to the minimum, techniques proposed by Xiao et al. (2012a, 2012b) are cited to calibrate the effect of gas on NMR porosity and \( T_{2\text{low}} \). In the first track of Fig. 8, the displayed curves are GR, spontaneous potential, and borehole diameter, all contributing significantly to the indication of the effective formation. The second track represents depth, and the unit is metres. The AC, density log, and compensated neutron log used for porosity estimation are shown in the third track. The RT displayed in the fourth track represents deep induction resistivity, and RXO is shallow induction resistivity. In the Xujiahe formation of the Anlu Region in central Sichuan basin, the formation-water salinity is 130 000 mg/L, the drill fluid is water-based mud, its density is 1.22 g/cm³, and the viscosity is 61.0 mPa·s. The invasion of water-based mud leads to a slight negative divergence between RT and RXO. The NMR \( T_2 \) distribution acquired by using Halliburton’s MRIL-C tool is displayed in the fifth track. The sixth track of Fig. 8 indicates a reasonable match between core analyzed porosity (CPOR) and corrected total NMR porosity (CMRP). It suggests that total NMR porosity is reliable and there will be little error when it is applied in permeability estimation. The CFZI displayed in the seventh track is FZI obtained from routine core analysis; that is to say, the FZI is estimated from field NMR logs by use of the proposed technique. From Fig. 8, it can be observed that the calculated FZI from field NMR logs is in accordance with the core-derived results (CPERM), which can be used to classify formations, and the corresponding permeability-estimation models can be applied to consecutive prediction of permeability. In the eighth track, the comparison of estimated permeability by using the SDR model obtained from the core analyzed results is displayed. It can be inferred from the comparison that for a formation with a permeability ranging from 0.2 to 0.4 md, the SDR model remains effective. However, in cases where the formation permeability is higher than 0.4 md or lower than 0.2 md, the SDR permeability will be underestimated or overestimated correspondingly. Comparison of core-derived permeability and predicted results by use of the proposed technique is displayed in the ninth track, illustrating that the accuracy of permeability estimation is largely improved when the HFU approach is employed in the Xujiahe formation.

In order to quantitatively analyze the uncertainty of the FZI-estimation model, the absolute errors between the FZI predicted by use of the proposed technique and that from core analyzed results are compared statistically, as displayed in Fig. 9. This figure clearly indicates that the FZI estimated by use of the proposed model is close to the core-derived FZI because the absolute errors between them are within the scope of \( \pm 0.15 \). The closeness ensures the credibility of formation classification by use of the predicted FZI.

**Case Studies.** Figs. 10 and 11 show two field examples of estimating tight gas permeability from field NMR logs based on the proposed technique in this study. The physical significance of these two curves, shown in the first seven tracks, is the same as that of the curves shown in the first seven tracks in Fig. 8. A comparison between the FZI predicted from field NMR logs (FZI) and that extracted from routine core analyses shows consistency. On
the basis of the predicted FZI, formations are classified and the corresponding permeability-estimation models are applied, followed by the consecutive prediction of PERM, which was compared with CPERM in the eighth track in Figs. 10 and 11. These two comparisons illustrate that the estimated permeability from field NMR logs by use of the proposed technique is credible because the values are all close to core analyzed permeability. In the meantime, the comparison between formation permeability estimated by use of the calibrated SDR model and core analyzed results is displayed in the ninth track. From Fig. 10, it can be observed that permeability predicted by using the SDR model coincides with core samples for formation permeability ranging from 0.2 to 0.4 md, similar to what is shown in Fig. 8.

Fig. 11 shows another field example comparing estimated permeability by use of different methods. The core-derived permeability shows that formation permeability is close to 0.1 md in this interval. Close to the routine PERM, the estimated permeability by using the proposed technique can be used directly for tight-gas-reservoir evaluation and deliverability prediction. While predicted permeability based on the SDR model still ranges from 0.2 to 0.4 md, permeability will be overestimated once the SDR calibrated model is used directly in this well.

Discussion
To intuitively illustrate the improvement of permeability estimation by using the proposed technique, the crossplots of PERM vs. estimated permeability by use of the proposed technique and of PERM vs. SDR-based permeability are displayed in Figs. 12 and 13, respectively. The red lines in these two figures represent the diagonal lines, which highlight the discrepancy between predicted permeability and that of core analyzed results. Fig. 12 demonstrates that estimated permeabilities, by using the proposed technique, and the measured results, by using the routine method, are located in the vicinity of the diagonal line, indicating the proximity between the permeabilities obtained from these two methods.
While in Fig. 13, the SDR-based permeability matches the CPERM only when PERM ranges from 0.2 to 0.4 md. In this range, the data points are located in the vicinity of the diagonal line. In cases where PERM is lower than 0.2 md or higher than 0.4 md, the estimated permeability is overestimated or underestimated, correspondingly.

To investigate the factors that cause predicted permeability by use of the classical SDR model to diverge from PERM in the Xujiahe tight gas sands, the relationship, which reflects the correlation of porosity and PERM for 54 core samples with laboratory NMR measurements, displayed in Fig. 7 is reanalyzed. If only the correlation coefficient is observed, it can be concluded that a good relationship can be found between porosity and PERM for all core samples. However, the regressed trend line illustrates that permeability will be overestimated by using the established relationship of porosity and permeability when formation permeability is lower than 0.2 md. For core samples with a permeability ranging from 0.2 to 0.4 md, the regressed trend line passes through these points. However, when the core-derived permeability is higher than 0.4 md, the trend line passes below the points. This means that the established relationship can be used to effectively predict permeability for formations with permeability ranging from 0.2 to 0.4 md. However, when formation permeability is higher than 0.4 md, the true permeability will be underestimated by use of the established model. This coincides with the results from the SDR model, because the parameters mentioned in this model are calibrated by using the same data sets. To improve permeability prediction by use of the classical SDR model in the Xujiahe formation, the core samples should be classified into five types of HFU, and the SDR model should be calibrated for each HFU. Also, many more core samples, especially core samples drilled from formations with dominant microfractures, would need to be tested for laboratory NMR experiments, because in the current 54 core samples, only one core sample was drilled from this kind of formation.

Conclusions

Though tight-gas-sand permeability cannot be directly estimated from porosity in the target reservoirs, permeability estimation in the Xujiahe formation is still greatly improved by use of the HFU process and NMR technology.

On the basis of the difference of the HFUs, rocks are classified into five types, and for every type of rock, good relationships of core porosity and PERM are established.

On the basis of the analysis of FZI-estimation formulae and the classical SDR model, a new technique for predicting FZI from NMR logs is proposed, and the corresponding model is established. With the calibration of 54 core samples drilled from the target formation for laboratory NMR measurements, the model parameters were obtained. After this technique is extended to reservoir conditions, consecutive FZIs are obtained to classify for-mation and estimate permeability along the intervals through which NMR logs were acquired.

Field examples show that predicted FZI values from field NMR logs are consistent with results extracted from core samples; the absolute errors between them are within the scope of ±0.15. Useful for tight-gas-reservoir evaluation and deliverability prediction, the reservoir permeability can be effectively predicted by use of the proposed technique.

By introducing the HFU approach, the dependability of permeability estimation is greatly improved. The SDR model is exclusive to the cases where formation permeability ranges from 0.2 to 0.4 md, whereas the proposed technique can be more widely applied and can be extended to all tight gas sands.

To improve permeability prediction with the SDR model, many more core samples drilled from formations with dominant microfractures would need to be tested for laboratory NMR experiments, and the mentioned parameters in the SDR model should be calibrated for each HFU.

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