**RESEARCH ARTICLE**

Influence of CO₂ injection on the pore size distribution and petrophysical properties of tight sandstone cores using nuclear magnetic resonance

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**Abstract**

CO₂ injection has been proposed as an efficient method for enhanced oil recovery in low-permeability sandstone reservoirs. When CO₂ is injected into such reservoirs, the petrophysical properties as well as the pore size distribution of tight formation can be altered due to the interactions between CO₂, water, and rock minerals. In this work, CO₂ is introduced into the water-saturated sandstone cores; nuclear magnetic resonance technique is then applied to obtain $T_2$ spectrum of the sandstone cores before and after CO₂ injection. The effect of CO₂ injection on the pore size distribution is analyzed by comparing the obtained $T_2$ spectrum. In addition, the change of petrophysical properties, that is, total porosity, porosity of the movable fluid, and permeability, are also discussed in this work. Test results show that after introducing CO₂, the total volume of small pores is significantly increased. On the contrary, the total volume of medium pores decreases. In addition, the immovable fluid porosity increases in the small pores, while it decreases in the medium pores after injecting CO₂. Based on the composition analysis, the concentration of the ions of Na⁺, K⁺, Ca²⁺, and Mg²⁺ increases in the produced fluid due to the interactions between CO₂ and albite, and potash feldspar. After CO₂ injection, the total porosity, movable fluid porosity, and permeability of these tight cores are significantly improved. This study is expected to be significant for understanding the mechanisms of alterations of petrophysical properties and pore size distribution of tight sandstone cores due to the CO₂ flooding.

**KEYWORDS**

CO₂ injection, nuclear magnetic resonance technique, petrophysical properties, pore size distribution, tight sandstone

1 | INTRODUCTION

CO₂ flooding has been recognized as an efficient method for enhancing oil recovery from unconventional reservoirs, which has been confirmed by laboratory tests and field applications.¹⁻⁴ Due to the unique characteristics of unconventional reservoirs, physical properties of fluids, such as phase behavior and adsorption behavior, in such reservoirs...
are quite different from those in conventional reservoirs.\textsuperscript{5,8} CO\textsubscript{2} has the superiority of easily dissolving in crude oil, which can significantly reduce the viscosity of crude oil and surface tension between two immiscible fluids.\textsuperscript{9,10} The dissolution of CO\textsubscript{2} into crude oil can make oil swell and extensively increases the elastic energy of crude oil.\textsuperscript{10,11} After injecting CO\textsubscript{2} in oil reservoirs, some chemical reactions may take place among CO\textsubscript{2}\textsubscript{2}, water, and the core minerals. It has been found that the reactions due to the CO\textsubscript{2} injection can greatly improve the petrophysical properties of oil reservoirs.\textsuperscript{12,13} However, some precipitation can also be resulted from the reactions between CO\textsubscript{2} and core minerals, such as carbonate. Such precipitation can block pores present in reservoir formation, leading to a poor condition for enhancing oil recovery with CO\textsubscript{2} injection.\textsuperscript{14,15} Tight sandstone reservoirs have complex pore throat structure with a wide pore throat sizes ranging from the nanoscale to microscale. The microstructure of pore throat affects reservoir property and oil displacement efficiency.\textsuperscript{16,17} Thereby, investigation of the variations of reservoir properties due to CO\textsubscript{2} injection is beneficial for understanding the fundamental mechanisms of CO\textsubscript{2} injection for enhanced oil recovery in tight sandstone reservoirs.

Previous studies have been conducted to investigate the variation of petrophysical properties of oil reservoirs due to the CO\textsubscript{2} injection. Mohamed et al\textsuperscript{18} investigated the changes of petrophysical properties of some core samples during CO\textsubscript{2} flooding; they observed that the porosity and permeability of these core samples were greatly improved. Moreover, some previous studies found that the porosity and permeability of core samples either from sandstone or from carbonate reservoirs are enhanced due to the interactions of feldspar-CO\textsubscript{2} or carbonate-CO\textsubscript{2}.\textsuperscript{19-21} As for sandstone reservoirs, it has been found that some carbonate minerals such as dolomite and calcite should firstly be dissolved in CO\textsubscript{2}-rich solution and then followed by the dissolution of the silicate minerals such as feldspar.\textsuperscript{22-24} In addition, the solubility of carbonate minerals is found to be higher than that of silicate minerals.\textsuperscript{25,26} On the contrary, some studies proposed that CO\textsubscript{2} can also bring some negative effects on oil reservoirs. For example, some mineral deposits due to the chemical reactions can somewhat block pores present in oil reservoirs, which significantly decreases the porosity and permeability of the reservoirs.\textsuperscript{27-29} Although extensive studies have been carried to investigate the change of petrophysical properties, such as porosity and permeability due to CO\textsubscript{2} injection, the effect of CO\textsubscript{2} on pore size distribution is scarcely published in the literature, which, however, is fundamental for understanding the mechanisms of using CO\textsubscript{2} for enhanced oil recovery.

Previous works\textsuperscript{14,30,31} have been conducted to investigate the reactions that may occur in oil reservoirs due to the CO\textsubscript{2} injection. After injected into water-containing oil reservoir, CO\textsubscript{2} is readily dissolved into the formation water, forming weak acid solution.\textsuperscript{15,30,31} It has been proposed that CO\textsubscript{2} will first form carbonic acid after dissolving into formation water. The carbonic acid will decompose into bicarbonate ion and hydrogen ion. Minerals can thus dissolve into the acid solutions.\textsuperscript{15,30,31} The formation of acid solution can be expressed as,

\begin{equation}
\text{CO}_2 + \text{H}_2\text{O} \leftrightarrow \text{H}_2\text{CO}_3
\end{equation}

\begin{equation}
\text{H}_2\text{CO}_3 \leftrightarrow \text{H}^+ + \text{HCO}_3^-
\end{equation}

Minerals in sandstone reservoirs are mainly carbonate mineral, such as dolomite and calcite, and silicate minerals of feldspar, including potassium feldspar, sodium feldspar, and calcium feldspar. These minerals are readily dissolved into the carbonic acid solution.\textsuperscript{30,31} The possible reactions are given as follows,\textsuperscript{15,27,28}

\begin{equation}
2\text{H}^+ + \text{CaMg} \left(\text{CO}_3\right)_2 \rightarrow \text{Mg}^{2+} \text{Ca}^{2+} + 2\text{HCO}_3^-
\end{equation}

\begin{equation}
\text{H}^+ + \text{CaCO}_3 \rightarrow \text{Ca}^{2+} + \text{HCO}_3^-
\end{equation}

\begin{equation}
2\text{KAlSi}_3\text{O}_8 \rightarrow 2\text{H}^+ + 3\text{H}_2\text{O} \rightarrow \text{Al}_2\text{Si}_2\text{O}_5 \left(\text{OH}\right)_4 + 2\text{K}^+ + 4\text{H}_2\text{SiO}_4
\end{equation}

\begin{equation}
2\text{NaAlSi}_3\text{O}_8 \rightarrow 2\text{H}_2\text{O} + 2\text{CO}_2 \rightarrow \text{Al}_2\text{Si}_2\text{O}_5 \left(\text{OH}\right)_4 + 4\text{SiO}_2 + 2\text{Na}^+ + 2\text{HCO}_3^-
\end{equation}

\begin{equation}
\text{CaAlSi}_2\text{O}_8 \rightarrow \text{H}_2\text{CO}_3 + \text{H}_2\text{O}
\end{equation}

\begin{equation}
\text{CaCO}_3 + \text{Al}_2\text{Si}_2\text{O}_5 \left(\text{OH}\right)_4
\end{equation}

Nuclear magnetic resonance (NMR) is a technique used for detecting the distribution of hydrogen-containing fluid in porous media. When hydrogen-containing fluids are exposed in a static magnetic field, the nuclear magnetic resonance can occur due to the oscillating magnetic field.\textsuperscript{32,33} NMR technique has been used for evaluating the movable fluid porosity in low-permeability reservoirs.\textsuperscript{34,35} As for low-permeability reservoirs, fluid cannot flow readily in micro- or nanoscale pores due to the complex pore throat structure, which may directly affect the productivity and development potential of low-permeability reservoirs. The movable fluid porosity is defined as the ratio of the pore volume occupied by movable fluid divided by the total pore volume, which can be used to characterize the features of movable fluid in reservoir. Thereby, the movable fluid porosity is quite important for evaluating the development potential of low-permeability reservoirs.\textsuperscript{36} Commonly, the centrifugal method based on the NMR technique is mostly applied in determining the movable fluid porosity.\textsuperscript{36,37} Recently, NMR technique is also used in the oil industry for determining the pore size distribution and the permeability of rock samples derived from oil reservoirs.\textsuperscript{38-40} To
obtain the pore size distribution, the measured $T_2$ spectrum should be firstly transformed into pore radius. Based on the mechanisms of NMR technique, the measured $T_2$ spectrum represents the distribution of transverse relaxation time of hydrogen nucleus of fluid in pores.\textsuperscript{41,42} Thereby, the pore size correlates with the corresponding transverse relaxation time.\textsuperscript{43,44} Conventionally, pore size distribution is determined by three commonly used methods, that is, mercury injection, nitrogen adsorption, and micro-CT.\textsuperscript{10,44,45} Compared to the conventional methods, nuclear magnetic resonance (NMR) technology has no damage to core samples and can determine the pore size distribution more accurately.\textsuperscript{44} Especially, NMR technique can achieve an accurate description of pores in the micron-nanometer scale, rendering the NMR more potentially applicable in evaluating the pore size distribution of core samples.\textsuperscript{46-48}

In order to avoid the precipitation generated by the reaction between CO\textsubscript{2} and formation water, and the asphaltene precipitation caused by CO\textsubscript{2} extraction light hydrocarbons from crude oil, which can change core physical properties and pore throat distribution, the core samples are saturated only with distilled water but not with formation water and crude oil. Therefore, in comparison with previous publications.\textsuperscript{46-48} This study is devoted to studying the effects of the chemical reactions between CO\textsubscript{2} and rock minerals on core physical properties and pore size distribution. In this work, the NMR technique is used to investigate the change of pore size distribution and petrophysical properties of sandstone core samples due to the CO\textsubscript{2} injection. Based on the measured $T_2$ spectrum before and after CO\textsubscript{2} injection, the effect of CO\textsubscript{2} on three kinds of pores, that is, small pores, medium pores, and large pore, is discussed. In addition, the change of petrophysical properties, that is, total porosity, movable fluid porosity, and permeability of the sandstone core samples due to the presence of CO\textsubscript{2}, is also investigated. To our knowledge, studying the effect of asphaltene precipitation on the change of pore size distribution and petrophysical properties during CO\textsubscript{2} flooding using NMR technique has been reported.\textsuperscript{46-48} but using NMR technique for investigating the effect of CO\textsubscript{2}-core mineral reactions on the change of pore size distribution and petrophysical properties due to CO\textsubscript{2} injection is scarcely reported. This study is expected to help in understanding the fundamental mechanisms of enhancing oil recovery using CO\textsubscript{2} in tight sandstone oil reservoirs.

### TABLE 1

| Core sample | Clastic materials (wt\%) | Interstitial materials (wt\%) |
|-------------|--------------------------|-------------------------------|
|             | Quartz | Potash feldspar | Plagioclase | Debris type | Hydromica | Chlorite | Calcite | Siliceous | Dolomite |
| #1          | 32.7   | 10.6   | 26.9     | 13.8       | 6.7       | 2.3      | 4.8     | 0.9       | 1.3      |
| #2          | 31.4   | 9.3    | 27.1     | 14.9       | 7.5       | 2.0      | 4.7     | 0.8       | 2.3      |

2 | SAMPLES AND METHODS

2.1 Materials

In this study, two sandstone core samples, labeled with #1 and #2, are obtained from Ansai oilfield in Chang 6 Reservoir of China. The length of core samples #1 and #2 is 3.83 and 3.80 cm, respectively, while the two core samples have a uniform core radius of 2.52 cm. The mineral compositions of the two core samples are analyzed using the X-ray diffraction (XRD) analysis. The mineral composition of the two cores is summarized in Table 1. CO\textsubscript{2} used in this experiment has a purity of 99.99 mol\% (Xi’an Guodu Gas Supply Station). Distilled water is used to saturate the core samples.

2.2 Experimental setups

NMR apparatus (Mini-MR, Niumag), as the key apparatus in this experiment, is mainly applied to obtain the $T_2$ spectrum of the tight sandstone cores. The confinement pressure and back pressure are maintained by a syringe pump (Hai’an Co., Ltd.) and a back pressure valve (Hai’an Co., Ltd.); the measured pressure is read with an accuracy of ±0.5 kPa. The system temperature is controlled by a thermostat with an accuracy of ±0.5 K. A centrifuge setup (Nantong Co., Ltd.) is employed to centrifuge the movable water from core samples. The mineral composition of the two core samples and the produced fluids is analyzed using the X-ray diffraction (XRD) analysis. A core-saturation equipment (Hongbo Co., Ltd.) is used to saturate distilled water into core samples.

2.3 Experimental procedures

Figure 1 presents the schematic of CO\textsubscript{2} injection for investigating the variation of pore size distribution and petrophysical properties of sandstone cores using NMR technique. In this experiment, CO\textsubscript{2} is first injected into the water-saturated core samples. NMR technique is then used to investigate the change of pore size distribution and petrophysical properties of core samples by comparing the measured $T_2$ spectrum.
before and after CO₂ injection. The detailed experimental procedures are described as follows:

Before the experiment, two core samples are first cleaned with benzene. The cleaned core samples are then dried at 373.15 K for 24 hours to remove the moisture. A permeability meter is then employed to measure the initial permeability of the core samples. The details for the gas permeability measurement can be found anywhere in the literature. Core samples are then vacuumed to saturate with distilled water using a core-saturation equipment. NMR apparatus is then used to scan the saturated core samples to obtain the $T_2$ spectrum. The measured $T_2$ spectrum is analyzed to estimate the original total porosity and pore size distribution of the core samples. To obtain the original movable fluid porosity, the water-saturated core samples are first centrifuged for 60 minutes at a constant rate of 9000 r/min to remove the movable water in core samples. $T_2$ spectrum of the centrifuged core samples is then measured to assess the porosity of the immovable fluid, which is then used to infer the movable fluid porosity.

Next, distilled water is resaturated into the centrifuged core samples. CO₂ is then injected into the core samples at a constant injection rate of 0.5 mL/min at 343.15 K for 48 hours. The back pressure is controlled at a constant pressure of 10.0 MPa. With the knowledge of the total porosity of these core samples, the total injected volume is calculated as about 1000 PV. Meanwhile, the produced fluid is collected instantaneously during the CO₂ injection. The ionic composition of the produced fluid is analyzed to estimate the reactions that may occur among CO₂, water, and core minerals. After CO₂ injection, the core samples are dried again at 373.15 K for 24 hours, of which the gas permeability after CO₂ injection is then measured. By comparing the permeability of core samples before and after CO₂ injection, the effect of CO₂ on the permeability of sandstone cores is analyzed.

The core samples are then saturated with the distilled water again. After water saturation, the core samples are scanned to obtain the $T_2$ spectrum, which is used to determine the total porosity and pore size distribution of core samples after CO₂ injection. The core samples are consequently centrifuged at a constant rate of 9000 r/min for 60 minutes to remove the movable water residing in core samples. $T_2$ spectrum is measured again to infer the movable fluid porosity after CO₂ injection. Based on the mechanisms of NMR technique, the $T_2$ spectra obtained before and after CO₂ injection are converted into pore radius. By comparing the pore size distribution before and after CO₂ injection, the influence of CO₂ injection on pore size distribution in sandstone cores is discussed.

3 | NUCLEAR MAGNETIC RESONANCE (NMR) TECHNIQUE

Based on the mechanisms of NMR technique, nuclear magnetic resonance can occur when hydrogen proton-containing molecules are placed in a static magnetic field. Tight core belongs to solid porous media. In a porous media, the measured $T_2$ spectrum in a magnetic field is generally affected by the bulk relaxation, diffusion in magnetic gradients, and surface relaxation, which can be expressed as,

$$
\frac{1}{T_2} = \frac{1}{T_{2B}} + \frac{1}{T_{2D}} + \frac{1}{T_{2S}}
$$

(8)

where $T_{2B}$ corresponds to the transverse time due to bulk relaxation, ms; $T_{2D}$ is the transverse time due to the diffusion in magnetic gradients, ms; and $T_{2S}$ represents the transverse time due to the surface relaxation, ms. It has been found that in tight cores, the diffusion relaxation is too small and can be neglected. The surface relaxation strongly correlates with the specific surface area of the tight core, here, the ratio of the pore's surface area to the total pore volume. Therefore, Equation 8 can be transformed to,

$$
\frac{1}{T_2} = \frac{1}{T_{2B}} + \frac{1}{T_{2S}} = \frac{1}{T_{2B}} + \frac{\rho S}{V}
$$

(9)
Where $\rho$ represents the relaxation rate, $\mu$m/ms; and $S/V$ represents the specific area, $1/\mu$m; The specific area ($S$), as depicted in Equation 9, correlates to the radius of the pore throat ($1/\mu$m). The relationship between $T_2$ spectrum and the radius of the pore throat can be expressed with the following equation,

$$r = CT_2$$

where $r$ is the radius of the pore throat ($\mu$m); $T_2$ spectrum is the transverse relaxation time (ms); and $C$ is a proportional constant (dimensionless). In order to convert $T_2$ spectrum to pore distribution, the constant $C$ should be determined. As for low-permeability sandstone, the constant $C$ can be determined by the following equation,

$$C = 0.038e^{-0.2872\sqrt{\phi}}$$

where $\phi$ is the porosity of core sample (%); and $k$ is the permeability of core sample (mD). After obtaining the constant $C$ from Equation 11, the $T_2$ spectrum of NMR can be eventually converted into the curve of pore size distribution.

4 | RESULTS AND DISCUSSION

4.1 | Variation of the pore size distribution due to the CO$_2$ injection

Figures 2 and 3 present the pore size distribution of the two core samples before and after CO$_2$ injection. Generally, the pore size distribution of core samples after CO$_2$ injection is quite different from that of the original cores. Specifically, by introducing CO$_2$ into core samples, which are initially saturated with distilled water, total volume of the small pores (ie, 0.0001-0.035 $\mu$m) increases, while the total volume of the medium pores (ie, 0.035-0.35 $\mu$m) decreases. On the contrary, total volume of the large pores (ie, 0.35-20 $\mu$m) either increases or decreases depending on the physical properties of core samples. When CO$_2$ is injected into core samples, CO$_2$ can react with core minerals present in the core samples, such as feldspar and carbonate minerals. Small pores may form in the core samples due to the reactions. It is probably the main reason why the total volume of small pores increases. However, the reactions between dissolved CO$_2$ and these core minerals can possibly form precipitate, such as calcium carbonate and kaolinite, which may consequently block the medium pores and further increase the total volume of small pores. As for the core sample #1, the total pore volume of large pores increases, while it decreases for that of the core sample #2. Due to the heterogeneity of the tight core samples, the mineral composition may show a difference in the large pores between the core samples #1 and #2. As for the core sample #1, corrosion reactions dominate between core minerals and the injected CO$_2$, which thus increases the total pore volume of the large pores. However, as for the core sample #2, precipitates resulted from the CO$_2$-core mineral reactions can significantly block the large pore, decreasing the total pore volume of the large pores. In addition, the dissolved CO$_2$ in medium pores may corrode the core minerals by forming large pores, which increases the pore volume of large pores. On the contrary, precipitation resulted from these reactions can also block the large pores, which, however, decreases the total pore volume of large pore. In summary, for the CO$_2$ injection in tight sandstone cores, the pore size distribution of core samples changes greatly before and after CO$_2$ injection. Compared with the large pores, the volume of small pores and medium pores varies greatly, but the total pore volume including small pores, medium pores, and large pores increases (see Table 2), which results in the increase in core physical properties (see Table 3). The variation of pore size distribution for the two core samples is summarized in Table 2.

**FIGURE 2** Pore size distribution of the core sample #1 before and after CO$_2$ injection

**FIGURE 3** Pore size distribution of the core sample #2 before and after CO$_2$ injection
4.2 Variation of the immovable fluid distribution due to the CO₂ injection

Figures 4 and 5 present distribution of the immovable fluid in pores of the two core samples before and after CO₂ injection. As for the two core samples, we observe that more immovable fluid appears in the small pores after introducing CO₂, while the immovable fluid in the medium pores slightly decreases. CO₂ is not likely affecting the distribution of immovable fluid in the large pores. As has been mentioned above, when CO₂ is injected into core samples, CO₂ can react with the core minerals, forming bunch of small pores. Reservoir fluids may enter and be locked in these created small pores, becoming immovable fluid. Similarly, due to the chemical reactions in medium pores, the medium pores are altered into large pores. As a result, the immovable fluid in medium pores then becomes movable fluid. That is the main reason why the immovable fluid in medium pores decreases.

4.3 Variation of the petrophysical properties of core samples due to the CO₂ injection

Due to the injection of CO₂, the petrophysical properties of reservoir cores, such as total porosity, porosity of the movable fluid, and permeability, are altered. Figures 6 and 7 show the measured \( T_2 \) spectrum of the core samples #1 and #2 before and after CO₂ injection. We calculate the porosity accumulation for the two core samples before and after CO₂ injection, as depicted in Figures 6 and 7. As for the two core samples, the total porosity increases after CO₂ injection due...
to the corrosion of CO\textsubscript{2} on core samples. However, by comparing Figure 6A,B and comparing Figure 7A,B, we find that the immovable fluid in core samples after CO\textsubscript{2} injection changes slightly. By subtracting the porosity of the immovable fluid from the total porosity, the porosity of the movable fluid in each core is obtained, as depicted in Figures 6 and 7. We observe that the porosity of the movable fluid in the two core samples is significantly improved after CO\textsubscript{2} injection.

We measure the permeability of the two core samples before and after CO\textsubscript{2} injection, as summarized in Table 3. It shows that the permeability after CO\textsubscript{2} injection is significantly higher than that of the original core samples. The change of permeability is mainly caused by the reactions between the injected CO\textsubscript{2} and core minerals. As shown in Table 1, based on the XRD analysis, the two core samples contain minerals including feldspar, calcite, and dolomite, which are ready to react with the injected CO\textsubscript{2}. To confirm this conclusion, we measure the ion concentration in the produced fluid. The ion concentration is summarized in Table 4. We find that the ions of Na\textsuperscript{+}, K\textsuperscript{+}, Ca\textsuperscript{2+}, and Mg\textsuperscript{2+} appear in the produced fluid after CO\textsubscript{2} injection due to the reactions between CO\textsubscript{2} and core minerals. Moreover, the ion concentration of Na\textsuperscript{+} is much higher than that of K\textsuperscript{+} and Ca\textsuperscript{2+}, which is because the solubility of albite in acid solution is higher than that of potash feldspar and anorthite.\textsuperscript{56} As depicted in Equations 5 and 6, Na\textsuperscript{+} ion and K\textsuperscript{+} ion in the produced fluid are derived from albite and potash feldspar due to the chemical reactions with CO\textsubscript{2}. In addition, Mg\textsuperscript{2+} ion appeared in the produced fluid may derive from dolomite due to the reaction with CO\textsubscript{2}, as expressed in Equation 3. The Ca\textsuperscript{2+} ion in the produced fluid is expected

\begin{figure}
\centering
\includegraphics[width=\textwidth]{figure6.png}
\caption{The measured $T_2$ spectrum of the core sample #1 (A) before and (B) after CO\textsubscript{2} injection. We also show the porosity accumulation for the core sample #1 before and after CO\textsubscript{2} injection in this figure.}
\end{figure}
to derive from the dolomite and calcite because of the reactions between CO$_2$ and dolomite and calcite, which is the main reason that the total porosity and movable fluid porosity increase.

Interestingly, we observe that for the two core samples, the increase in the permeability is uniformly greater than that of porosity. It is likely because the solubility of carbonate minerals in carbonic acid solution is much higher than that of silicate minerals. Thereby, the interstitial minerals, that is, dolomite and calcite, can extensively dissolve, increasing the connectivity of pore throats in core samples; it thus improves the permeability. Additionally, the mineral dissolution also produces some new mineral precipitates during CO$_2$ injection, which blocks the pores present in the core samples. It can be inferred that permeability of the ultra-low-permeability sandstone reservoirs may be more improved than the total porosity after CO$_2$ injection. It is important for improving the seepage characteristics, which can enhance the oil displacement efficiency in ultra-low-permeability sandstone reservoirs.

**FIGURE 7** The measured $T_2$ spectrum of the core sample #2 (A) before and (B) after CO$_2$ injection. We also show the porosity accumulation for the core sample #2 before and after CO$_2$ injection.

**TABLE 4** Ion concentrations detected in the produced fluid.

| Core No. | Ions          | Na$^+$ (mg/L) | K$^+$ (mg/L) | Ca$^{2+}$ (mg/L) | Mg$^{2+}$ (mg/L) |
|----------|---------------|---------------|--------------|-----------------|-----------------|
| 1#       |               | 52.64         | 6.13         | 28.15           | 25.06           |
| 2#       |               | 48.27         | 7.05         | 25.62           | 24.03           |
5 | CONCLUSIONS

In this work, the change of pore size distribution and petrophysical properties of two sandstone cores is quantitatively compared before and after CO₂ injection using low-field NMR technique. Specifically, by reasonably converting the measured T₂ spectrum to pore radius, the pore size distribution is divided into three kinds of pores; the effect of CO₂-water-rock interactions on different pores is thus evaluated. Moreover, the effect of CO₂ on the petrophysical properties, that is, total porosity, movable fluid porosity, and permeability, is also discussed. The detailed conclusions are summarized as follows:

- By comparing the pore size distribution before and after CO₂ injection, the total volume of small pores is significantly increased, while the volume of medium pores decreases. CO₂ exhibits the least effect on the large pores. It indicates that the reactions among CO₂, water, and core minerals create small pores; however, the precipitation due to the reaction can possibly block the medium pores;
- Due to the interactions among CO₂, water, and core minerals, the immovable fluid porosity increases in the small pores but decreases in the medium pores. It suggests that CO₂ injection increases the total volume of the small pores, while fluid in these created small pores is locked, becoming immovable fluid. Such effect makes the fluid residing in small pores more difficultly be recovered;
- Based on the composition analysis of the produced fluid, it can be inferred that the injected CO₂ reacts with the core minerals, such as albite and potash feldspar. It is the main reason resulting in the appearance of the ions of Na⁺, K⁺, Ca²⁺, and Mg²⁺ in the produced fluid;
- After CO₂ injection, the total porosity, movable fluid porosity, and permeability of the two core samples are improved. More importantly, the increase in permeability is much higher than that of the total porosity, which is critical for the improvement of sandstone tight reservoirs.

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CONFLICT OF INTEREST

The authors declare no conflict of interest.

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