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Mechanisms of microfracture impact on reservoir quality and gas saturation in tight sandstones



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ABSTRACT

Microfractures are believed to significantly influence gas storage and flow in tight sandstones, yet there is a continued need for quantitative methods to better understand their impact on reservoir quality and gas saturation. We integrate imaging techniques and petrophysical tests to assess how different types of microfractures influence porosity and permeability in tight sandstones. Gas accumulation in tight sandstones was simulated at the core scale using a gas-charging instrument developed from NMR technology, and the changes in gas saturation during the charging process were quantitatively measured; numerical simulations were conducted based on a porous media model constructed via digital core technology and the phase-field method. Overall, microfractures contribute minimally to the porosity. A cross-linked network of structural and circumgranular microfractures with sufficient apertures significantly enhances matrix permeability. Dissolution microfractures display small apertures and limited propagation, and do not form cross-linked networks, resulting in a negligible contribution to permeability. Bedding-plane microfractures typically develop in parallel orientations and contribute little to vertical permeability. During the gas charging process, capillary pressure controls the sequence of pore filling and the spatial arrangement of gas in tight sandstones. Microfractures are considerably larger than the pore throats, allowing water displacement at lower gas entry pressures during gas invasion. However, because tight sandstones contain a significantly higher proportion of small pore throats, the presence of a few microfractures has a negligible impact on overall gas saturation. These findings enhance our understanding of how microfractures influence reservoir quality and the processes controlling fluid migration and storage in tight sandstone gas reservoirs, offering critical insights for the assessment of reservoir quality and gas saturation in tight sandstone exploration.

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1. Introduction

Tight sandstone gas have emerged as significant contributors to global hydrocarbon resources. Tight sandstone gas reservoirs are characterized by micro-Darcy permeability and low porosity (Holditch, 2006; Khlaifat, and Barakat, 2011; Zou et al., 2012; Boak

and Kleinberg, 2020). Fractures are an important attribute of tight sandstone reservoirs. Based on the classification of fractures and their roles in oilfield development, the fracture system refers to fractures with apertures greater than 1 mm, while the matrix system includes pore throats and micro-fractures with apertures smaller than 1 mm (Anders et al., 2014; Lai et al., 2018; Rokhforouz and Amiri, 2018). In general, micro-fractures are too narrow to be observed by the naked eye and typically require microscopic techniques for clear identification (Anders et al., 2014; Zhu et al., 2015; Rokhforouz and Amiri, 2018).

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Microfractures in tight sandstones originate both from mechanical processes (such as tectonic lateral compression and grain-boundary fracturing) and chemical processes (including dehydration, cementation and metasomatism) (Laubach, 2003; Fall et al., 2015; Watkins et al., 2020). The aperture and spatial extent (length) of microfractures vary significantly and depends on their genesis, and consequently different types of microfractures have different impacts on reservoir behavior (Olson et al., 2007; Tao et al., 2021). Research suggests that tectonically-induced microfractures increase overall porosity, form networks, and provide pathways that bypass the low permeability of matrix pore throats (Sakhaee-Pour and Bryant, 2014; Bjørlykke, 2015; Lai et al., 2023; Han et al., 2024; Su et al., 2025). These microfractures enhance effective permeability and significantly facilitate gas migration (Ding et al., 2012; Lyu et al., 2017; Tao et al., 2021; Cao et al., 2024). However, some studies suggest that microfractures, due to their small apertures and limited propagation, do not significantly alter the storage and movement of gas in tight sandstones (Wanniarachchi et al., 2018; Zhou et al., 2020). The contribution of different microfracture types to reservoir quality is not been well understood.

Gas saturation is also a significant parameter effecting gas production from tight gas sandstone reservoirs, where small increases in saturation can significantly enhance fractional flow and overall deliverability. The converse is also true; once water saturation surpasses a critical threshold, gas flow rates decline sharply, rendering the reservoir rock inefficient for gas extraction (Cluff and Byrnes, 2010; Shanley et al., 2004, 2015). The influence of microfractures on gas saturation in tight sandstones remains a topic of debate. Microfractures are commonly in sandstone reservoirs of the Mesaverde Group in the Piceance Basin and the Permian in the Sichuan Basin, where high gas saturation is present. These fractures are believed to promote the accumulation of gas in tight sandstones (Cumella and Scheevel, 2008; Hood and Yurewicz, 2008; Zhang et al., 2021). In contrast, in the Permian of the northern Ordos Basin, many tight sandstone reservoirs with well-developed microfractures exhibit high water saturation. Water-producing wells are primarily concentrated in these microfractured reservoirs (Wu et al., 2020). Furthermore, most studies to date have focused on qualitative assessments, and there remains a need for more quantitative approaches that can measure the direct impact of microfractures on gas accumulation and gas saturation in tight sandstones.

By integrating imaging techniques, petrophysical analyses, and simulations, along with gas saturation evaluations derived from well data, we aim to provide a comprehensive understanding of the impact of microfractures on reservoir quality and gas saturation in tight sandstones. In this study, microfracture types in the tight sandstone matrix were identified through optical thin section and scanning electron microscope (SEM) analyses. The impact of microfractures on permeability was assessed using porosity-permeability and mercury intrusion capillary pressure (MICP) tests. We developed a core-scale gas charging experimental system based on NMR technology to simulate tight sandstone gas accumulation and measure gas saturation, and further integrated two-phase flow phase-field simulations to quantitatively evaluate the impact of microfractures on gas accumulation and saturation. To ensure the applicability of our results, we further validate the experimental and simulation outcomes using in-situ gas saturation data obtained from well logs. This study aims to (1) evaluate how microfractures affect reservoir quality and gas saturation, and (2) improve understanding of the processes by which microfractures control fluid migration and storage in tight sandstone gas reservoirs.

2. Data and method

2.1. Dataset

The tight sandstone samples for this study were obtained from the Upper Carboniferous and Lower Permian formations in the Linxing–Shenfu gas field, located in the northeastern Ordos Basin (Fig. 1). In this setting, mature (R_o between 0.9% and 2.0%), gas-generating, and gas-expelling coal-bearing hydrocarbon source rocks are in close proximity to the Upper Carboniferous and Lower Permian tight sandstone reservoirs (Fig. 1). Additionally, in-situ gas saturation data for the tight sandstone reservoirs were obtained from the Linxing–Shenfu gas field. Gas saturation was derived primarily from well-log interpretation using the Archie equation.

Short cylindrical plugs, measuring 3.5 cm in length and 2.5 cm in diameter, were acquired from remnants of core collected from wells LD-1, LD-4, LD-18, LD-26, and S-12. The presence or absence of microfractures was assessed through thin section observations (Fig. 2). The re-drilled short plugs were subsequently used for optical thin section, SEM observation, XRD, contact angle, porosity permeability, MICP analysis and gas-charging experiments (Fig. 2).

2.2. XRD and contact angle analysis

The XRD analysis was conducted to ensure that the samples used for comparative experiments had similar mineral compositions, except for the presence or absence of microfractures. For whole-rock and clay XRD analysis, 1–2 g of powdered rock sample was put into a D/max-2600 X-ray powder diffractometer at 40 mA and 40 kV and scanned at a rate of 2 °/min. The collected diffractograms were imported into JADE software to search for and match minerals in the ICDD and CSD databases.

The contact angle measurements were performed to provide essential wettability parameters for the numerical simulation of gas charging. Contact angle measurements were completed with a JC2000D instrument. The samples were finely polished with 2000 mesh sandpaper on the measurement surface and the samples were dried. The contact angle of wettability in air–water–rock systems was measured. The measuring range is from 0° to 180° with a precision of 0.1°. Automatic adjustment and calibration of liquid–solid contact angles are feasible.

2.3. Imaging methods and petrophysical analysis

Thin section and SEM petrography was used to identify pore and fracture features. Natural microfractures were distinguished from preparation artefacts based on their continuity across grains and cements, mineral infillings, and consistent orientations verified in multiple thin-section orientations (Anders et al., 2014; Rokhforouz and Amiri, 2018). Thin sections petrography studies of thin sections were carried out using a polarized light optical microscope (Zeiss Axio microscope). SEM analysis was accomplished with Freshly obtained rock fragments from each sample coated with platinum and then placed on a FEI Quanta FEG 450 scanning electron microscope for SEI. SEM analysis used accelerating voltages of 2–5 kV. Tests were performed in an environment of 10% humidity and 23 °C. The width of the micro-fractures in the optical thin section and SEM images was measured by applying the classical commercial software AVIZO.

Short plugs for porosity and permeability testing were dried at 110 °C for 24 h. Porosity was measured using UltraPore 300 porosimetry equipment based on Boyle's Law. The gas permeability was measured using an FCG-059VINCI permeability instrument under confining pressure conditions. During the

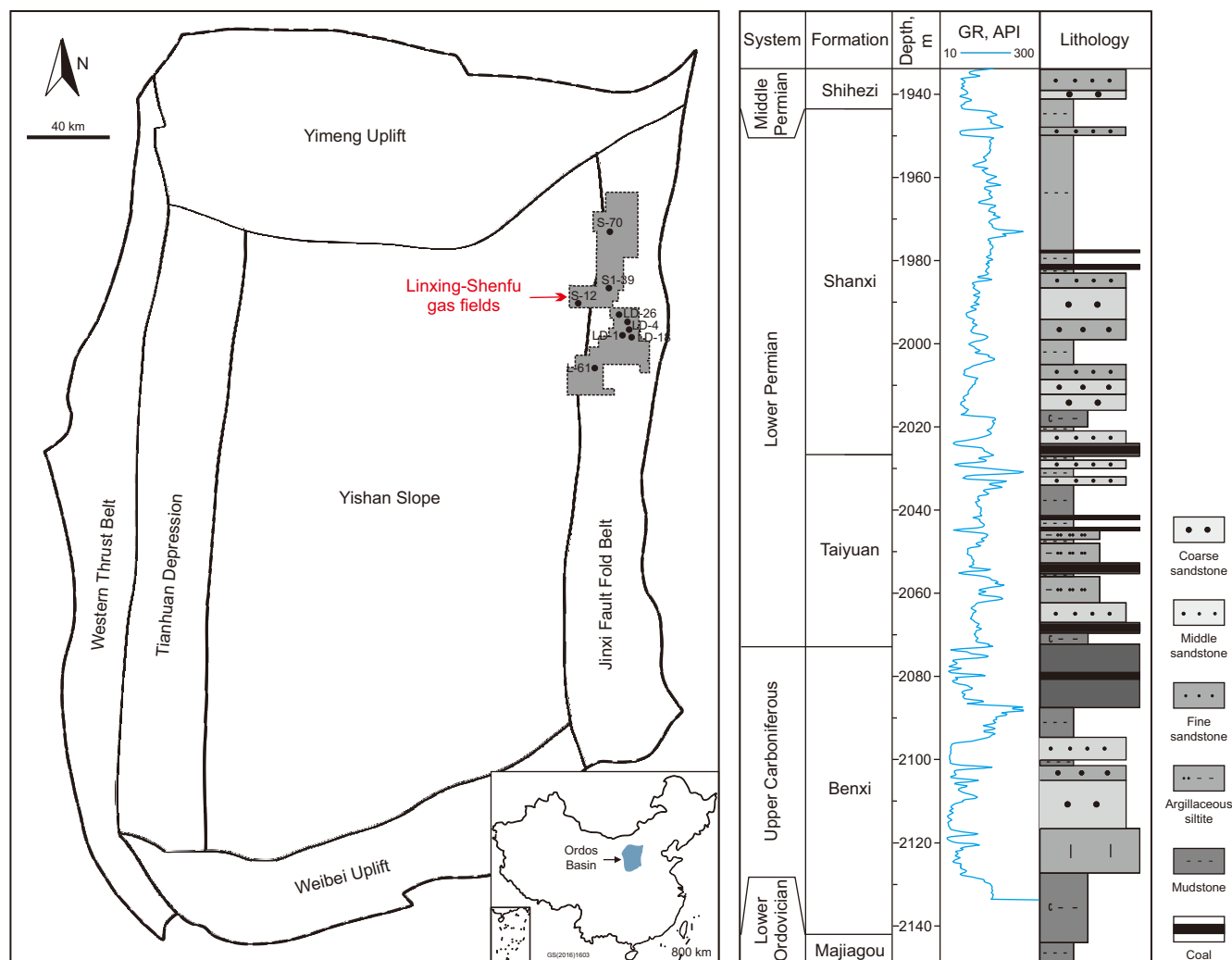


Fig. 1. The classification of tectonic units in the Ordos Basin and the stratigraphy of Upper Carboniferous and Lower Permian strata.

permeability tests, a confining pressure of 5 MPa. Pore throat size distributions of short plugs were evaluated under vacuum conditions with an Autopore IV 9500 mercury porosimeter, using the methodology established by Alyafei et al. (2016).

2.4. Gas charging experiments

2.4.1. Experimental instrument

Tight gas sandstone reservoirs often exhibit unique gas accumulation mechanisms because of their poor reservoir quality. Buoyancy-driven pressure is usually insufficient for gas to penetrate the tight pore structure. As a result, gas accumulation in tight sandstone reservoirs generally requires proximity to mature source rocks that can generate and expel large amounts of gas (Cumella and Scheevel, 2008; Pang et al., 2014; Jiang et al., 2016). When gas generation surpasses the containment capacity under normal pressures, overpressurization occurs (Shanley et al., 2004; Hood and Yurewicz, 2008; Jiang et al., 2015) (Fig. 3(a)). This overpressure is critical because it offsets the high capillary entry pressures in the tight pore structure, displacing water from the pores and resulting in a gas-saturated environment (Yin et al., 2020a, 2020b) (Fig. 3(b)).

The gas charging experiment is composed of four components: (1) a confining stress control system, (2) a gas pressure control

system, (3) a temperature control system, and (4) an NMR test, all designed to simulate the natural gas accumulation process in tight sandstone (Fig. 4). The confining stress control system ensures uniform stress by using a circulating pump to fill the core plug holder with fluorinated fluid. Fluorinated fluid was used as a temperature- and pressure-transmitting medium during gas charging, as it lacks hydrogen nuclei and does not interfere with NMR signal detection. The gas pressure control system consists of a booster pump, buffer tank, and pressure-reducing valve, with an inlet gas pressure of up to 20 MPa and an outlet gas pressure at atmospheric pressure. The temperature control system regulates the fluorinated fluid's temperature, which in turn controls the temperature of the core plug holder, using a circulation pump and electric heating wire. The NMR experimental parameters are as follows: a waiting time of 3000 ms, an echo time of 0.07 ms, 6000 echoes, and 64 superpositions.

Nuclear magnetic resonance (NMR) is used to measure the porosity of water-saturated cores by detecting the behavior of hydrogen nuclei in water molecules under an applied magnetic field (Elsayed et al., 2022). When a rock is saturated with water, the NMR signal detected is directly proportional to the rock's pore volume. Therefore, the NMR signal can be used to calculate the porosity by measuring the amount of water present in the pores. The NMR T_2 spectrum of the water-saturated core plug shows the

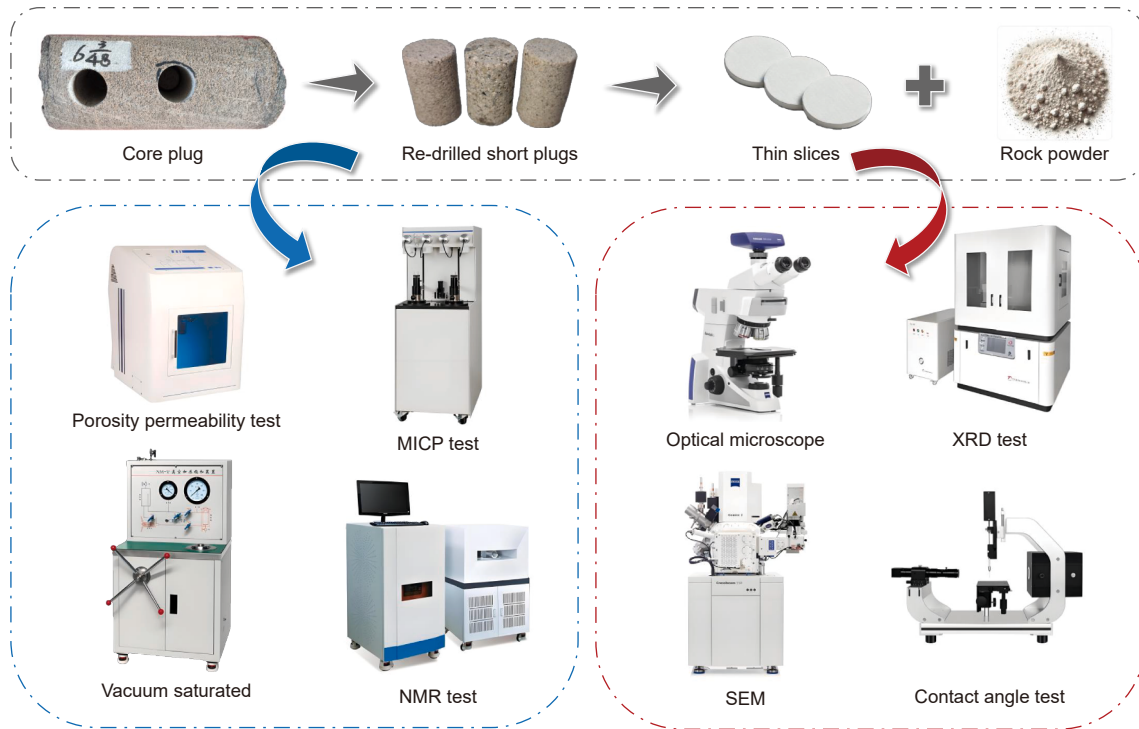


Fig. 2. Sample collection, preparation and test.

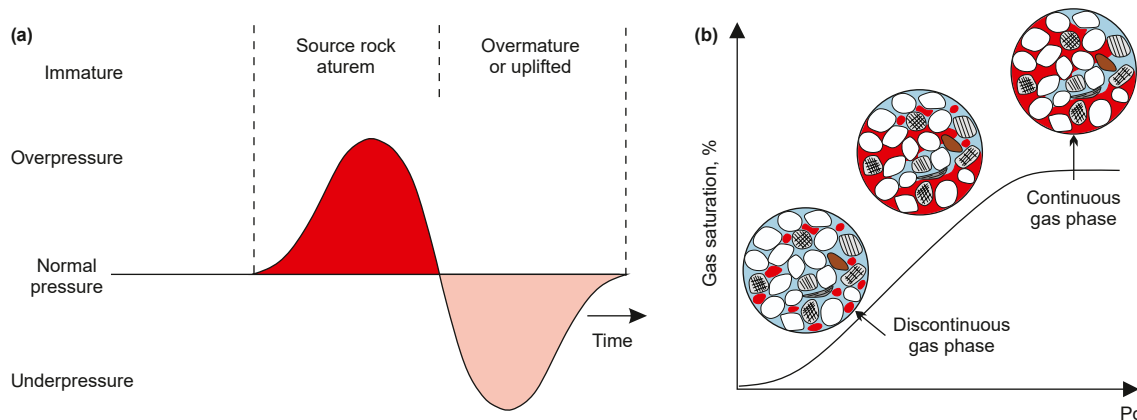


Fig. 3. (a) A conceptual model showing the evolution of a dynamic pressure system with time. The red is overpressured; the pink is underpressured (modified from Meissner, 1987). (b) End-face saturations of the core plug (blue: water; red: gas), illustrating the different phase distribution during drainage.

highest amplitude. When gas is injected, it displaces the water in the pores of the core plug (Fig. 5(a)).

If the gas lacks hydrogen nuclei (e.g., N_2), the amplitude of the NMR T_2 spectrum decreases (Fig. 5(b)). This principle is applied to generate NMR gas saturation data for tight sandstone samples during gas injection:

$$T_2 \approx \frac{S_w}{\rho_2} \left(\frac{V}{S} \right) \quad (1)$$

S_w represents the fluid saturation, S denotes the surface area, V refers to the volume of the saturating fluid in the pores, and ρ_2 is the surface relaxivity, which characterizes the relaxation rate on the surface (S).

2.4.2. Experimental procedure

Based on microscopic image observations, five core samples with developed fractures were selected, while adjacent cores without fractures were used as a control group. Test results indicate that both fractured and non-fractured core samples from the same charging experiment have similar detrital components, porosity, and clay mineral composition (Table 1). The primary experiments consist of two procedures designed to measure changes in gas saturation during gas injection.

- (i) The samples were dried in a vacuum oven at 100 °C for 24 h. Following this, a fluid pressure of 10 MPa was applied to the

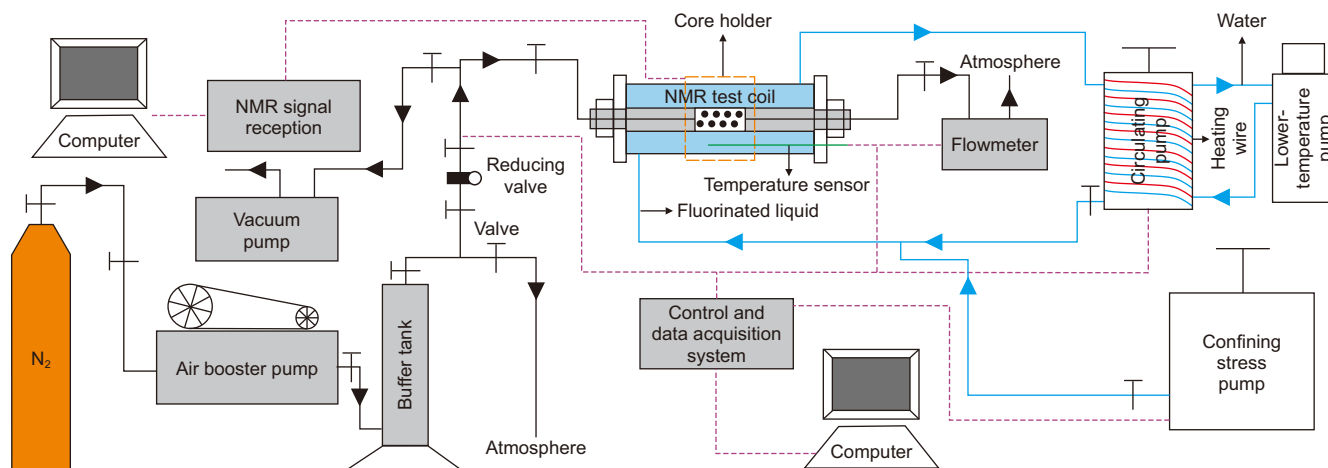


Fig. 4. Gas charging experimental setup diagram.

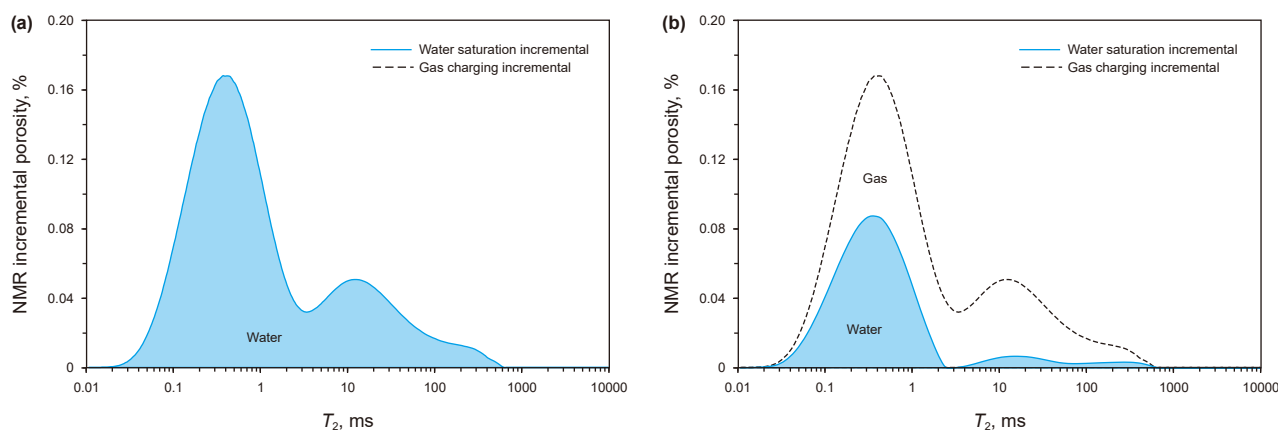
Fig. 5. (a) The NMR T_2 spectra of the core fully saturated water. (b) The NMR T_2 spectra of the core after methane charging to obtain the gas saturation.

Table 1

Gas charging test sample basic information.

Samples	Depth, m	Fracture	Porosity, %	Permeability, mD	Quartz, %	K-feldspar, %	Plagioclase, %	Siderite, %	Calcite, %	Total clay, %	XRD clay mineral fraction mass fraction			
											I/S, %	Illite, %	Kaolinite, %	Chlorite, %
LD-15-a	2252.5	Developed microfractures	16.84	59.75	79.84	0.00	9.56	0.00	2.82	7.78	0	97	1	2
LD-15-b	2252.8	Undeveloped microfractures	16.54	0.75	82.21	0.00	8.06	0.00	1.35	8.37	0	93	7	0
LD-4-a	2298.2	Developed microfractures	14.59	2.10	78.62	0.00	19.07	0.00	0.00	2.31	8	90	0	2
LD-4-b	2297.7	Undeveloped microfractures	15.53	0.71	78.99	0.00	16.78	0.00	0.77	3.47	5	91	0	3
S-12-a	2039.3	Developed microfractures	3.04	0.03	77.53	0.00	0.48	0.00	0.00	21.99	0	8	81	6
S-12-b	2039.6	Undeveloped microfractures	3.12	0.04	79.51	0.00	0.00	2.28	2.44	15.77	0	2	90	8
LD-18-a	1971.2	Developed microfractures	3.52	0.03	52.36	6.84	16.33	0.00	0.00	22.57	0	97	1	2
LD-18-b	1970.9	Undeveloped microfractures	3.35	0.06	50.50	7.01	20.02	0.00	0.00	22.50	0	94	4	2
LD-1-a	2176.8	Developed microfractures	4.39	0.02	75.69	3.19	1.32	0.00	0.00	19.80	0	95	4	1
LD-1-b	2177.3	Undeveloped microfractures	4.17	0.04	73.11	4.39	3.92	0.00	0.00	18.59	0	98	1	1

dried cores in a water-saturation device for 7 days to ensure complete pore saturation with water.

- (ii) The water-saturated core was placed in the gas charging experimental apparatus. The confining pressure was maintained at 10 MPa, the temperature remained constant at 23 °C, and the inlet gas pressures for N₂ charging ranged from 0.15 to 3.7 MPa, increasing progressively from low to high. Each gas-charging step lasted 15 min at each inlet pressure. The NMR T_2 spectra of the core were measured after N₂ charging at each inlet pressure to determine the gas saturation.

2.5. Numerical simulation of gas charging

2.5.1. Image processing

This study uses a two-dimensional porous media system for numerical simulation of gas charging. While the two-dimensional porous media model differs from the three-dimensional model in terms of pore system uniformity and connectivity, the fluid flow mechanism at the pore scale remains consistent (Tsuji et al., 2016; Maaref et al., 2017). The two-dimensional model allows clearer visualization of the immiscible two-phase flow at the pore scale, while improving computational efficiency.

An optical thin section image showing developed microfractures was selected and reconstructed using Avizo software (Fig. 6(a)). The image was then filtered, noise reduced, and binarized to isolate pores, microfractures, and detrital grains in a binary image (Fig. 6(b)). The binarized image was imported into COMSOL Multiphysics to segment pores, microfractures, and detrital grains.

The gray area represents the porous medium, comprising pores and microfractures, while the white area indicates detrital grains (Fig. 6(c)). Finally, the porous medium regions underwent grid division for the subsequent numerical simulation of gas charging (Fig. 6(d)).

2.5.2. Governing equations

COMSOL Multiphysics software was used to simulate gas–water two-phase flow in porous media during gas charging, employing the phase-field method. The phase-field method provides higher accuracy and faster computation for simulating two-phase flow in porous media compared to the level-set method (Akhlaghi and Hamouda, 2013; Wang et al., 2025). The equation governing fluid flow is as follows:

$$\rho \frac{\partial u}{\partial t} + \rho(u \times \nabla)u = \nabla \left[-pI + \mu(\nabla u + (\nabla u)^T) \right] + F_{st} \quad (2)$$

The continuity equation is presented below:

$$\nabla \times u = 0 \quad (3)$$

Here, u represents the fluid velocity, m/s; ρ denotes the fluid density, kg/m³; p is the fluid pressure, Pa; I is the unit vector; μ refers to the viscosity of the Newtonian fluid, Pa·s; and F_{st} is the interfacial tension term between the fluid and phase interface, described using phase field variables.

Phase field variables are used to differentiate between the phase fluid and the phase interface. The deformation and evolution of the phase interface are governed by the Cahn-Hilliard equation (Cahn and Hilliard, 1958), as shown below:

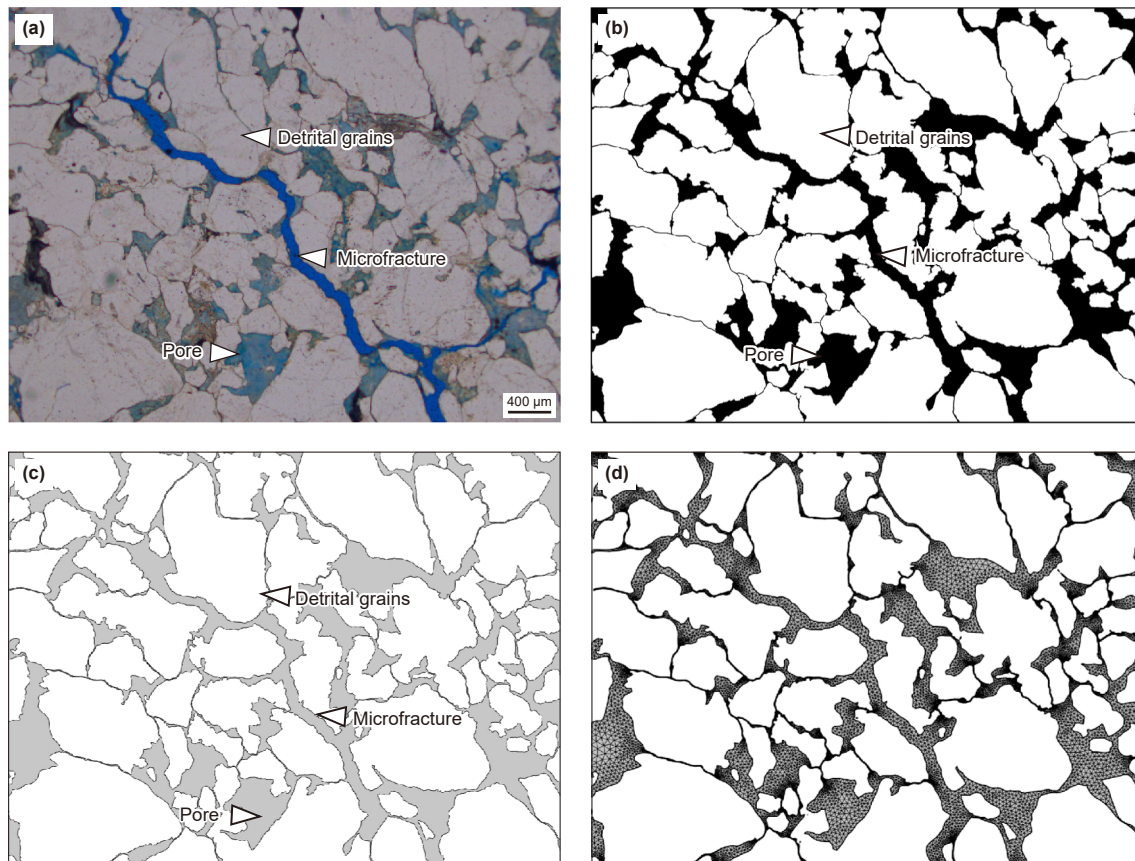


Fig. 6. The digital core construction process involves several steps: (a) capturing an optical thin section image, (b) generating a binarized image through image processing, (c) defining the computational domain in COMSOL Multiphysics software, and (d) performing grid division.

$$\frac{\partial \varphi}{\partial t} + u \nabla \varphi = \nabla \frac{\gamma \lambda}{\varepsilon^2} \nabla \psi \tag{4}$$

$$\psi = -\nabla \varepsilon^2 \nabla \varphi + (\varphi^2 - 1) \varphi \tag{5}$$

Here, φ represents the phase field parameter, indicating the two-phase concentration. The value of φ ranges from -1 to 1 , where $\varphi = 1$ represents the displacing phase, and $\varphi = -1$ represents the displaced phase. The variable u denotes the fluid velocity, m/s; γ indicates mobility, which refers to the migration rate at the interface per unit driving force, $\text{m}^3 \cdot \text{s} / \text{kg}$. λ refers to the mixing energy density, N , ψ is an auxiliary parameter, and ε represents the interface thickness, m.

2.5.3. Details of the numerical simulation

The left and right boundaries of the two-dimensional porous medium were set with symmetric boundary conditions. The wall wettability in the 2D porous medium was set to 30.4° , based on test results at 23°C . Initially, the pore space was saturated with the aqueous phase, and gas was injected from the bottom and discharged from the top. Inlet pressure set at 0.6 MPa and 2.4 MPa, while the outlet pressure was maintained at 0 MPa, consistent with the gas injection experiment.

3. Results

3.1. Characteristics of microfractures and pores

Four types of fractures are identified in the samples: structural microfractures, bedding-plane microfractures, circumgranular microfractures, and dissolution microfractures (Table 2). Structural microfractures are typically the most significant and easily recognizable. Structural microfractures form cross-linked networks that cut across the matrix, cement, and grains of varying competency (Fig. 7(a)–(c)). Bedding-plane microfractures are typically found along interfaces between the matrix and detrital grain stratification (Fig. 7(d)). Circumgranular microfractures form around detrital grains (Fig. 7(e)). Unlike structural microfractures, circumgranular microfractures do not typically cut through grains and are more sparsely distributed (Fig. 7(f) and (g)). Dissolution microfractures typically form within specific minerals, such as feldspar and mica (Fig. 7(h) and (i)). Measurements show that the width of structural microfractures ranges from 4.2 to 220.3 μm , with an average of 14.5 μm (Table 2). Bedding-plane microfractures range from 6.3 to 102.3 μm , averaging 7.6 μm (Table 2). Circumgranular microfractures have a width of 1.7–32.6 μm , with a mean value of 4.6 μm , while dissolution microfractures are the narrowest, ranging from 1.2 to 8.0 μm , with an average width of 3.2 μm (Table 2).

According to pore size, the pores in the studied samples can be classified into macropores (pore diameter $>10\ \mu\text{m}$) and micropores (pore diameter $<10\ \mu\text{m}$) (Worden and Burley, 2003; Taylor and Lander, 2022). Macropores can be further classified by origin into primary intergranular pores and secondary intragranular dissolution pores formed by the partial or complete dissolution of unstable feldspar minerals (Shang et al., 2025) (Fig. 7(h)). The predominant micropores are primarily associated with clay minerals (Fig. 7(a) and (b)).

The pore throat diameters of the tight sandstone samples, measured by MICP, range from 0.05 to 2 μm (Fig. 8(c)). The highest S_{Hg}/P_c ratio, known as the Swanson parameter, represents the peak of the hyperbolic curve on the log-log mercury injection plot (Swanson, 1981). The r_{apex} refers to the equivalent pore-throat radius corresponding to the pressure at the Swanson inflection point, which is derived MICP curves using the Washburn equation (Fig. 8(a) and (b)). The r_{apex} in this curve indicates the transition from a wide, well-connected pore throat to a narrower, poorly interconnected pore throat. When mercury is introduced into pore throats larger than the r_{apex} , the cumulative permeability contribution increases significantly (Fig. 8(c)). In contrast, when mercury intrudes pore throats with radii smaller than the r_{apex} , the cumulative permeability contribution increases only marginally (Fig. 8(c)), indicating limited flow capacity through these narrower pore throats. Although pore throats larger than the r_{apex} account for less than 30% of the total pore volume, they contribute disproportionately—between 65.7% and 85.7%—to the overall permeability due to their significantly lower capillary entry pressures and higher connectivity.

3.2. Effects of microfractures on porosity and permeability

To evaluate the impact of microfractures on porosity and permeability, each test group was established based on samples collected from the same core interval, thereby ensuring consistent sedimentary facies and diagenetic characteristics within each group. Within each group, re-drilled short-plug core samples were further categorized according to the presence or absence of microfractures, as identified through thin section and microscopic image analysis. To ensure meaningful comparisons and isolate the influence of individual microfracture types, samples exhibiting multiple types of microfractures were excluded from porosity and permeability testing. This approach was adopted to control for confounding variables and ensure that observed differences in reservoir properties could be attributed primarily to a single microfracture type.

In the first test group, samples with structural microfractures had an average porosity of 8.1% and a permeability of 2.17 mD (Fig. 9(a)). Samples without structural microfractures had an average porosity of 8.6% and a permeability of 0.38 mD (Fig. 9(a)).

Table 2
Type of microfracture developed in the samples.

Microfracture types	Description	Microfracture width range, μm	Average microfracture width, μm
Structural microfractures	Structural microfractures are generally the most prominent and easily identifiable fractures. These open microfractures traverse the matrix, cement, and grains of varying mechanical properties.	4.2–220.3	14.5
Bedding-plane microfractures	Bedding-parallel microfractures are distributed along stratification interfaces within the rock.	6.3–102.3	7.6
Circumgranular microfractures	Microfractures surrounding the detrital grains.	1.7–32.6	4.6
Dissolution microfractures	Microfractures formed by dissolution, often developed in minerals such as feldspar and mica.	1.2–8.0	3.2

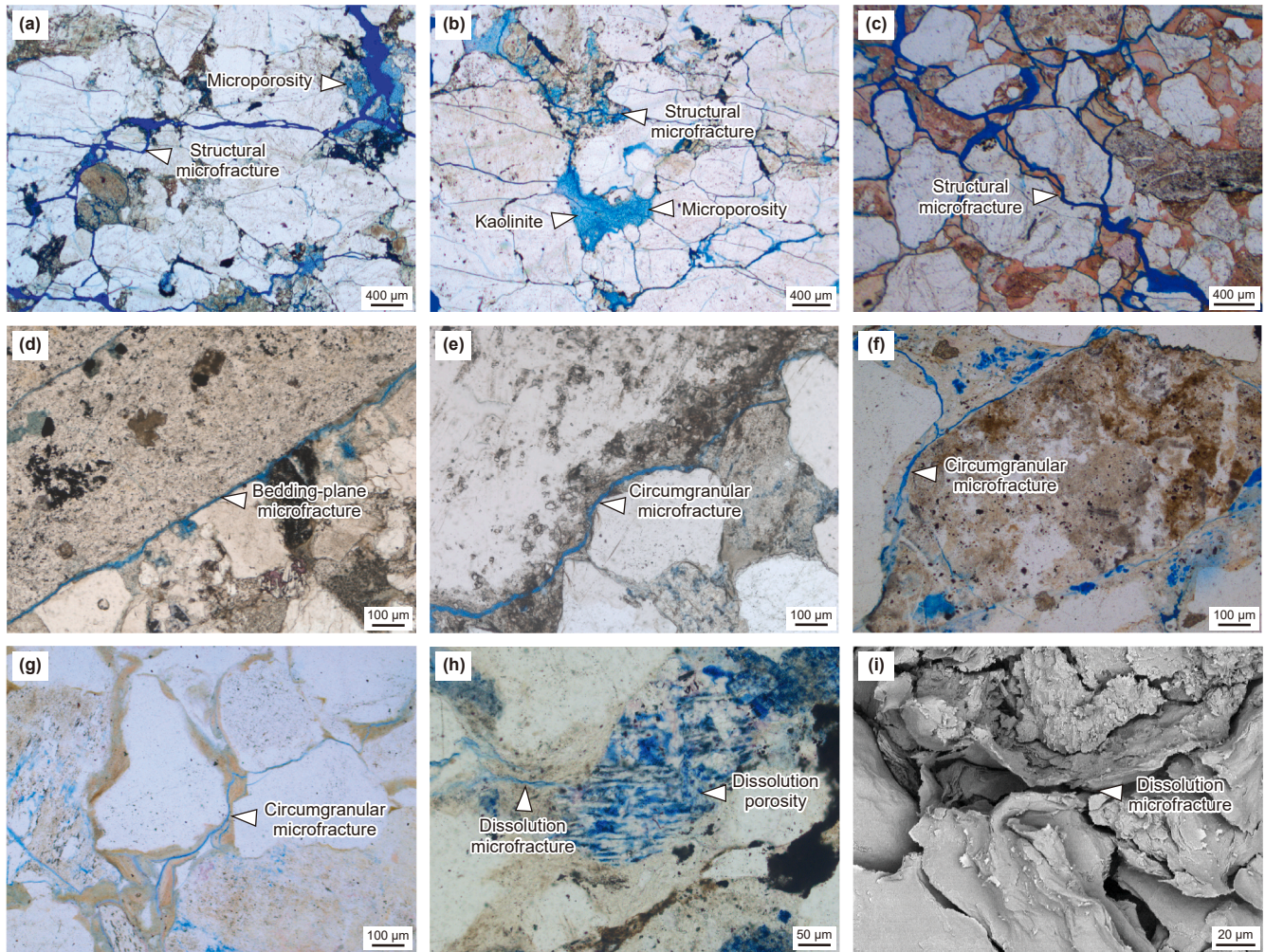


Fig. 7. Microscopic characterisation of microfractures in tight sandstone samples. (a)–(c) Structural microfractures. (d) Bedding-parallel microfractures. (e)–(f) Circumgranular microfractures. (h)–(i) Dissolution microfractures.

In the second test group, samples with structural microfractures exhibited an average porosity of 5.8% and a permeability of 1.05 mD (Fig. 9(b)). Samples without structural microfractures had an average porosity of 6.7% and a permeability of 0.1 mD (Fig. 9(b)). In the third test group, samples with structural microfractures had an average porosity of 8.7% and a permeability of 0.93 mD (Fig. 9(c)). Samples without structural microfractures had an average porosity of 8.9% and a permeability of 0.3 mD (Fig. 9(c)).

In the fourth test group, samples with circumgranular microfractures exhibited an average porosity of 8.8% and a permeability of 1.27 mD (Fig. 9(d)). Samples without circumgranular microfractures had an average porosity of 8.6% and a permeability of 0.56 mD (Fig. 9(d)). In the fifth test group, samples without bedding-plane microfractures had an average porosity of 6.1% and a permeability of 0.07 mD (Fig. 9(e)). In samples with bedding-plane microfractures, the average porosity was 6.6%. Two samples showed high permeability of 1.12 and 1.22 mD, while the other two exhibited low permeability of 0.09 and 0.04 mD (Fig. 9(e)). In the sixth test group, samples with dissolution microfractures had an average porosity of 5.7% and a permeability of 0.05 mD (Fig. 9(f)). Samples without dissolution microfractures had an average porosity of 4.7% and a permeability of 0.05 mD (Fig. 9(f)).

To assess the statistical significance of the influence of microfractures on reservoir properties, two-sample Student's *t*-test were

conducted comparing porosity and permeability between samples with and without microfractures across six test groups (Table 3). These groups were established based on core intervals, with microfracture types identified by thin section and imaging analysis. The results show that structural microfractures (Groups 1–3) and circumgranular microfractures (Group 4) exhibit a statistically significant enhancement in permeability ($p < 0.01$), while their impact on porosity remains statistically insignificant ($p > 0.05$) (Table 3). In contrast, bedding-plane microfractures (Group 5) and dissolution microfractures (Group 6) do not result in significant differences in either porosity or permeability (Table 3).

Overall, microfractures contribute minimally to the porosity of tight sandstones. Samples with well-developed structural and circumgranular microfractures, as well as some with bedding-plane microfractures, exhibit increases in permeability ranging from approximately 2-fold to an order of magnitude compared to non-fractured samples. Dissolution microfractures do not appear to contribute to increased permeability.

3.3. Gas charging experimental results

In water-saturated sandstone samples, pore width directly influences the T_2 relaxation time (*X*-axis), while the porosity mainly impacts the amplitude of the T_2 spectrum (*Y*-axis) (Anovitz and Cole, 2015). Previous observations suggest that in tight

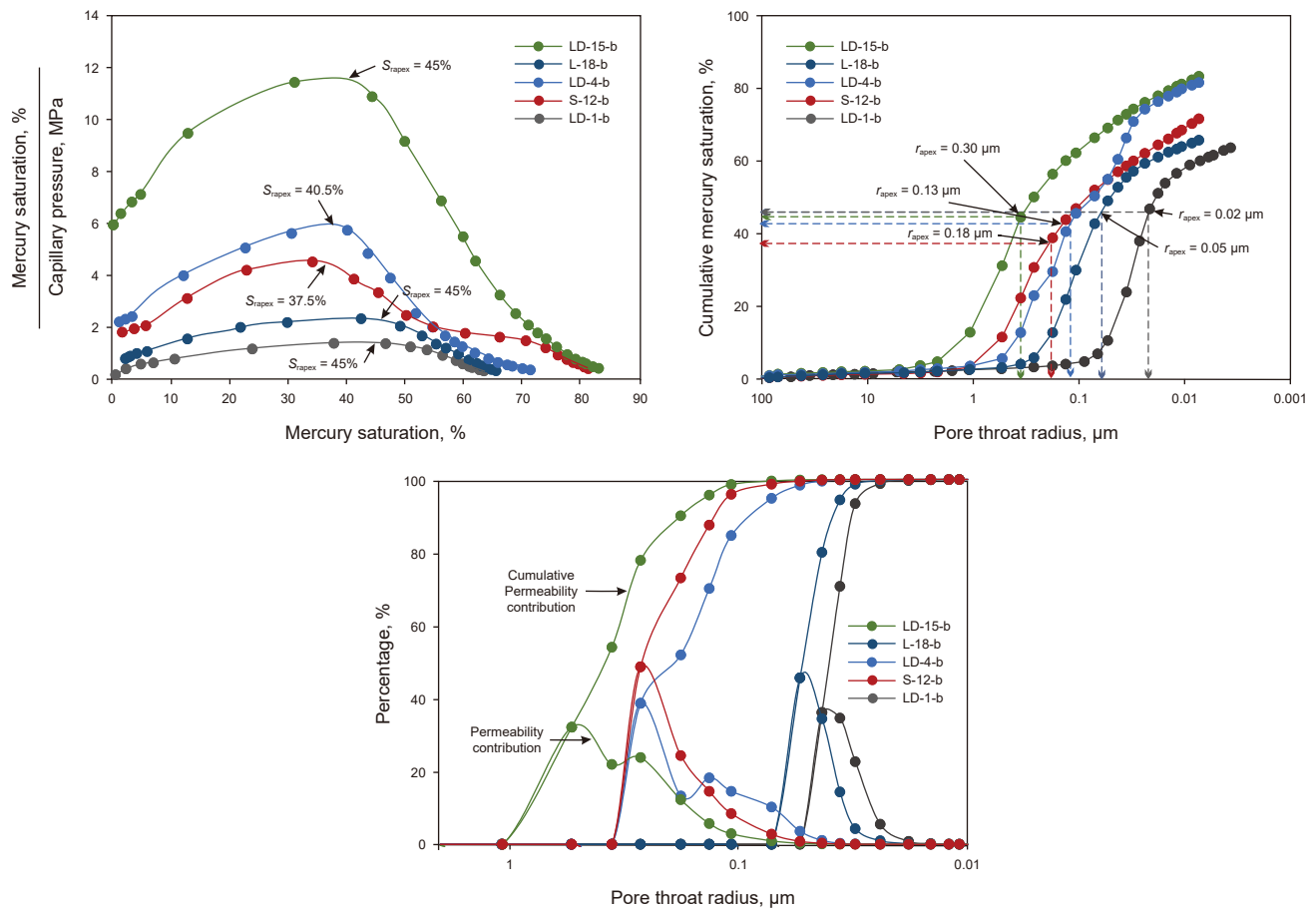


Fig. 8. (a) A plot showing mercury saturation as a function of injection pressure; (b) a plot depicting the relationship between pore throat radius and cumulative mercury saturation; (c) an analysis of how different pore throat diameters influence permeability.

sandstones, pores with T_2 relaxation times greater than 10 ms are typically associated with macropores, while micropores linked to clay minerals generally have T_2 relaxation times of less than 10 ms (Lai et al., 2018; Wang et al., 2023a, 2023b). During the gas charging experiments, the T_2 spectra corresponding to relaxation times greater than 10 ms disappeared first, even under very low gas inlet pressures, indicating that water in macropores was preferentially displaced. As the gas inlet pressure gradually increased, the T_2 spectra corresponding to relaxation times less than 10 ms progressively decreased, suggesting that water in smaller pores was gradually displaced with increasing gas pressure (Fig. 10). Based on the gas saturation statistics obtained during the gas charging experiments, the gas saturation in the samples increases rapidly at lower gas inlet pressures (<0.6 MPa) (Fig. 10). As the gas inlet pressure continues to increase, the rise in gas saturation slows and eventually stabilizes at a plateau (Fig. 10).

One sample containing structural microfractures reached higher gas saturations than samples without microfractures under identical experimental conditions. Sample LD-15-a (Fig. 10(a)), containing structural microfractures, reached a gas saturation of 53.8% at an inlet pressure of 3.7 MPa (Fig. 10(c)). In contrast, sample LD-15-b (Fig. 10(b)), lacking microfractures, attained a gas saturation of 48.5% under identical the same pressure of 3.7 MPa (Fig. 10(c)). However, the LD-4-a sample (Fig. 10(d)), with structural microfractures, reached a maximum gas saturation of 44.7%, while the LD-4-b sample, lacking microfractures, achieved 44.2% (Fig. 10(f)).

Samples containing other types of microfractures exhibit little or no difference with their unfractured counterparts. The S-12-a sample (Fig. 10(g)), containing circumgranular microfractures, reached a

gas saturation of 31.6%, while the S-12-b sample (Fig. 10(h)), lacking microfractures, achieved 29.6% (Fig. 10(i)). The LD-18-a sample (Fig. 10(j)), containing bedding-plane microfractures, reached a gas saturation of 25.5%, while the LD-18-b sample (Fig. 10(k)), without microfractures, attained 27.9% (Fig. 10(l)). The LD-1-a sample (Fig. 10(m)), with dissolution microfractures, attained a gas saturation of 26.5%, while the LD-1-b sample (Fig. 10(n)), without microfractures, reached 26.9% (Fig. 10(o)).

3.4. Simulation results

Fig. 11 shows the gas-water distribution characteristics within the 2D porous media under different simulated gas pressures. The pore network at the start of gas invasion (gas saturation = 0%), without gas. Under the gas pressures of 0.6 MPa, the gas first invades the microfractures (Fig. 11(a)), and then the gas occupies the pores connected by the large pore throats (Fig. 11(b)). As the gas pressures increase, the gas gradually invades the pores connected by smaller-sized pore throats (Fig. 11(c) and (d)). It is worth noting that a portion of the water in the pore space cannot be driven out even at relatively high replacement pressures. These residual water-endowed pores are mainly interconnected by narrow pore throats.

4. Discussions

4.1. Influence of microfractures on permeability

The majority of pore-throat sizes in the tight sandstone samples tested in this study are smaller than $1 \mu\text{m}$ (Fig. 8(b)). MICP

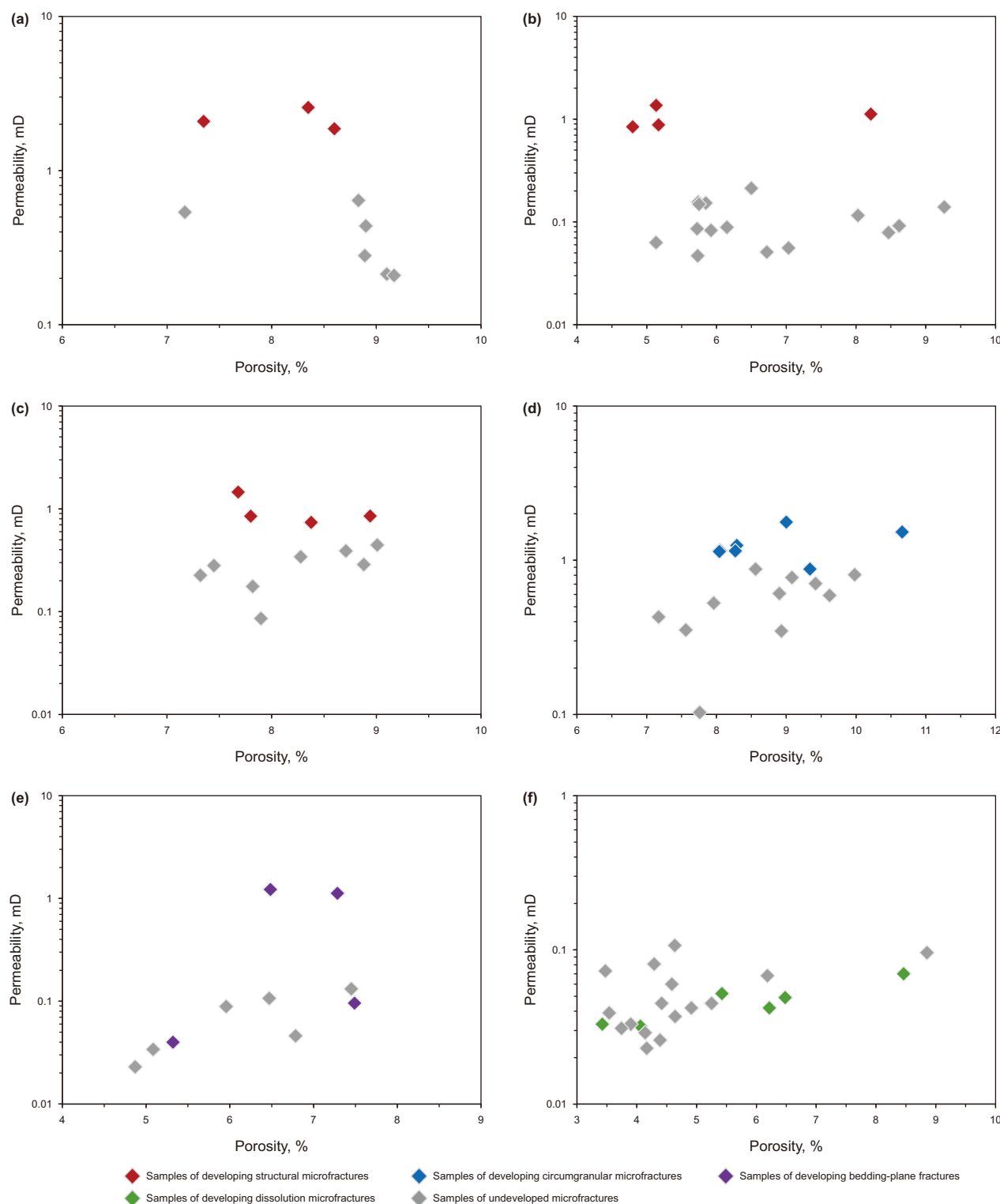


Fig. 9. Relationship between porosity and permeability in samples with different microfracture types. (a) Structural microfractures. (b) Circumgranular microfractures. (c) Bedding-plane microfractures. (d) Dissolution microfractures.

analyses indicate that pore throats larger than rapex contribute around 70% of the overall permeability in tight sandstone samples without microfractures (Fig. 8(b)). However, the pore volume associated with these larger throat's accounts for only ~25% of the total pore volume (Fig. 8(c)). This indicates that permeability is primarily governed by larger pore-throats ($>r_{\text{apex}}$) (Fig. 8(c)). The

size of microfractures in the test samples is typically one to three orders of magnitude larger than the pore-throat dimensions (Table 2).

Structural and circumgranular microfractures have adequate apertures, ranging from a few micrometers up to approximately 200 μm (Table 2). More importantly, these fractures create

Table 3
t-test results for the influence of microfractures on porosity and permeability.

Group	Microfracture type	Porosity <i>p</i> -value	Permeability <i>p</i> -value
1	Structural microfractures	0.29568	0.00713
2	Structural microfractures	0.36560	0.00405
3	Structural microfractures	0.79350	0.00796
4	Circumgranular microfractures	0.70406	0.00023
5	Bedding-plane microfractures	0.42439	0.18409
6	Dissolution microfractures	0.24585	0.74223

complex fluid flow channels through an interconnected fracture network, similar to the macroporous network in the matrix, effectively facilitating fluid flow (Fig. 8(a) and (b)). Consequently, the development of structural and circumgranular microfractures significantly improves the permeability of tight sandstone samples (Fig. 9(a)–(d)). Some samples with bedding-plane microfractures show significantly higher permeability than those with undeveloped microfractures. However, in other cases, the permeability of samples with bedding-plane microfractures is similar to samples that lack microfractures (Fig. 9(e)).

While microfractures in tight sandstones can provide additional flow channels, their impact on permeability depends aperture, fracture network connectivity, and fracture orientation (Aydin, 2000; Ishibashi et al., 2019). Larger microfracture apertures and better connectivity, especially when aligned with the flow direction, lead to greater contributions to permeability (Lu et al., 2013; Delle et al., 2015). If a microfracture is perpendicular to the flow direction, its contribution to permeability may be limited as it does not provide a direct pathway for fluid flow. The similar permeability in some samples with developed bedding-plane microfractures and undeveloped microfractures is likely due to the bedding-plane microfractures not being aligned with the gas flow direction during permeability testing.

The small apertures and limited propagation of dissolution microfractures prevent them from developing a pervasive network (Fig. 7(h) and (i)) with well-connected flow pathways. As a result, dissolution microfractures contribute very little to permeability (Fig. 9(f)).

4.2. Influence of microfractures on gas accumulation

Numerical simulations of gas migration in water-filled pore networks show that during gas charging, invasion percolation quickly occupies microfractures and large pore throats at low saturation (Fig. 11). As gas pressure increases, the gas phase moves slowly through smaller pore throats, reaching new equilibrium points at higher pressures. Our results from the gas charging experiments indicate that water in larger pores is more easily displaced by gas at lower inlet pressures (Fig. 10). By the end of gas charging, water remains trapped in small pores (Fig. 10). This shows that gas charging in tight sandstone is controlled by threshold entry pressures during displacement. In tight gas sandstone, water acts as the wetting phase, and gas as the non-wetting phase (Ramstad et al., 2019). In slow displacement, pore-scale gas filling is governed by local capillary pressure (Hunt et al., 2017; Qiao et al., 2022). Each pore region has a threshold capillary pressure at which gas can displace water. This threshold pressure is determined by energy balance with a known contact angle. Capillary pressures dictate the sequence of filling and fluid arrangement.

Gas must overcome capillary pressure to pass through the tight pore structure during gas charging (Blunt, 2017). The Washburn equation (Washburn, 1921) is commonly used to describe the relationship between capillary pressure and pore size. In our

experiments, as gas pressure is applied to the core, the imposed pressure must overcome the capillary entry pressure in order to displace the wetting phase (water). Once the capillary threshold is exceeded, water is gradually expelled from the pore spaces (Fig. 12).

$$f = p_{c2} - p_{c1} \quad (6)$$

We now focus on the rock to examine displacement at the micro-scale. Considering a pore throat with a circular cross-section of radius r and no curvature along its length, we can apply the Young–Laplace equation to calculate the capillary pressure across the pore interface:

$$f = 2\sigma \cos \theta \left(\frac{1}{r_2} - \frac{1}{r_1} \right) \quad (7)$$

In this equation, f represents the resistance force, N; p_{c2} and p_{c1} are the capillary pressures of the small and large pore throats, respectively, MPa; σ is the interfacial tension, mN/m; and θ is the contact angle, °. r_1 and r_2 represent the radii of the small and large pore throats, respectively, μm .

We plotted a two-dimensional multitype pore network model to explain gas saturation changes in the microfracture-pore system of tight sandstones during gas charging. The thick blue lines represent microfractures. The black lines represent pore throats, where the thickness of the line represents the thickness of the throat. Because of diagenetic modification, the pore types of tight sandstones are mainly intragranular dissolution pores and intergranular micropores of clay minerals, which are represented by the treelike pore structure model (Fig. 13) (Sakhaee-Pou and Bryant, 2014).

A two-dimensional conceptual pore network model was constructed to illustrate, in a simplified and visualized manner, the changes in gas saturation within the microfracture-pore system of tight sandstones during gas charging (Fig. 13). This model is intended to aid conceptual understanding of gas migration and phase displacement behavior within heterogeneous pore structures. Thick blue lines indicate microfractures. Black lines represent throats, with their thickness corresponding to throat size. Due to diagenetic alteration, the pore types in tight sandstones are predominantly intragranular dissolution pores and intergranular clay mineral micropores, represented by a treelike pore structure model (Fig. 13) (Sakhaee-Pou and Bryant, 2014). Gas flow is depicted by a red line in the pore network model (Fig. 13). At low inlet gas pressures, many small pore throats still retain water. As inlet gas pressure increases, more water is expelled, although tight pore spaces still retain water, which could be displaced only at very high capillary pressure (Fig. 13). While water in microfractures can be expelled at low inlet gas pressures, porosity test results show that their contribution to overall porosity is minimal. However, because tight sandstones contain a higher proportion of small pore throats, the invasion of a few microfractures has a negligible effect on gas accumulation and saturation (Fig. 10).

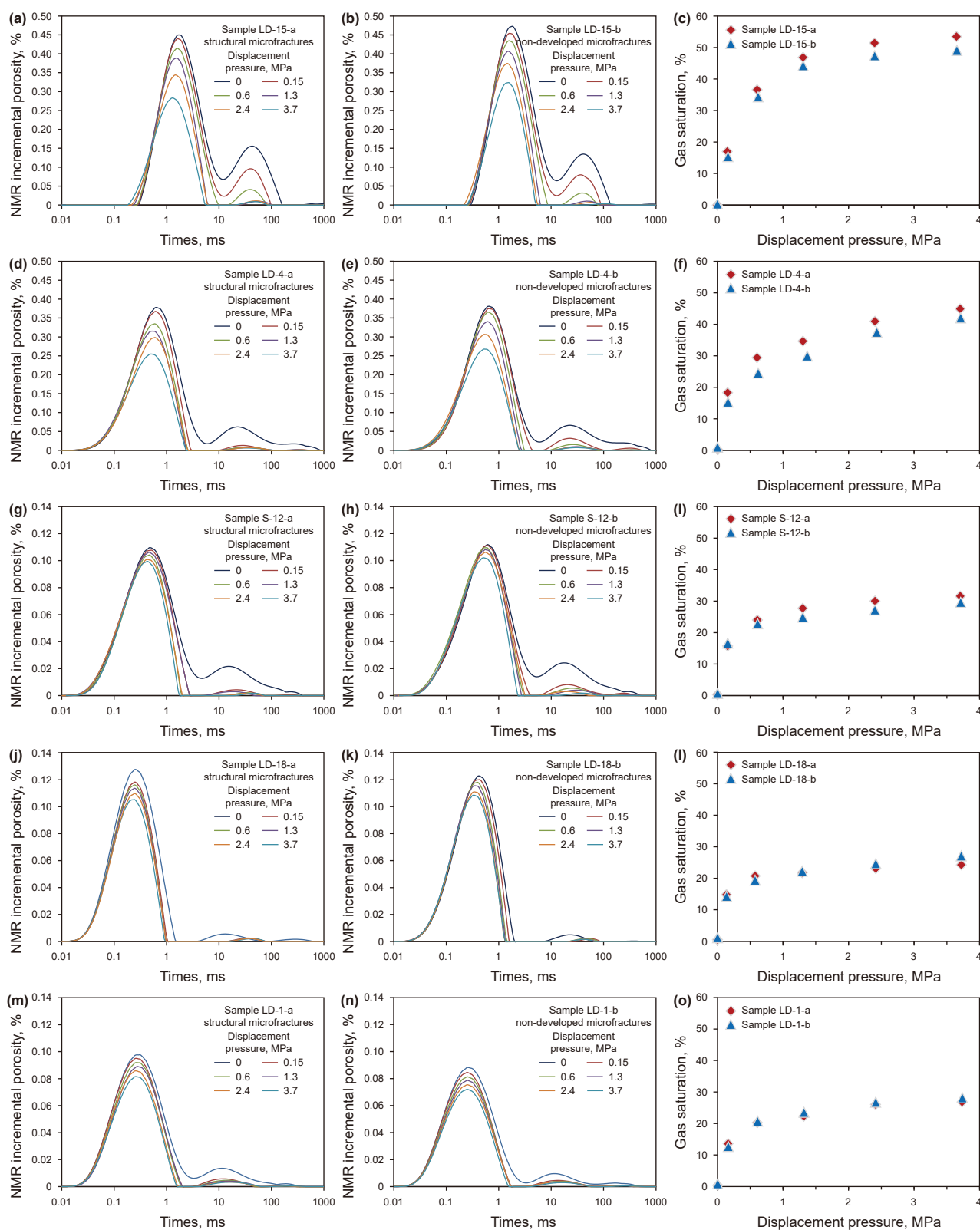


Fig. 10. (a), (d), (g), (j), (m) NMR T_2 spectral distribution of develop microfractures samples obtained under different inlet gas pressures. (b), (e), (h), (k), (n) NMR T_2 spectral distribution of undeveloped microfractures samples obtained under different inlet gas pressures. (c), (f), (i), (l), (o) Relationship of mobile water amount with inlet gas pressures difference.

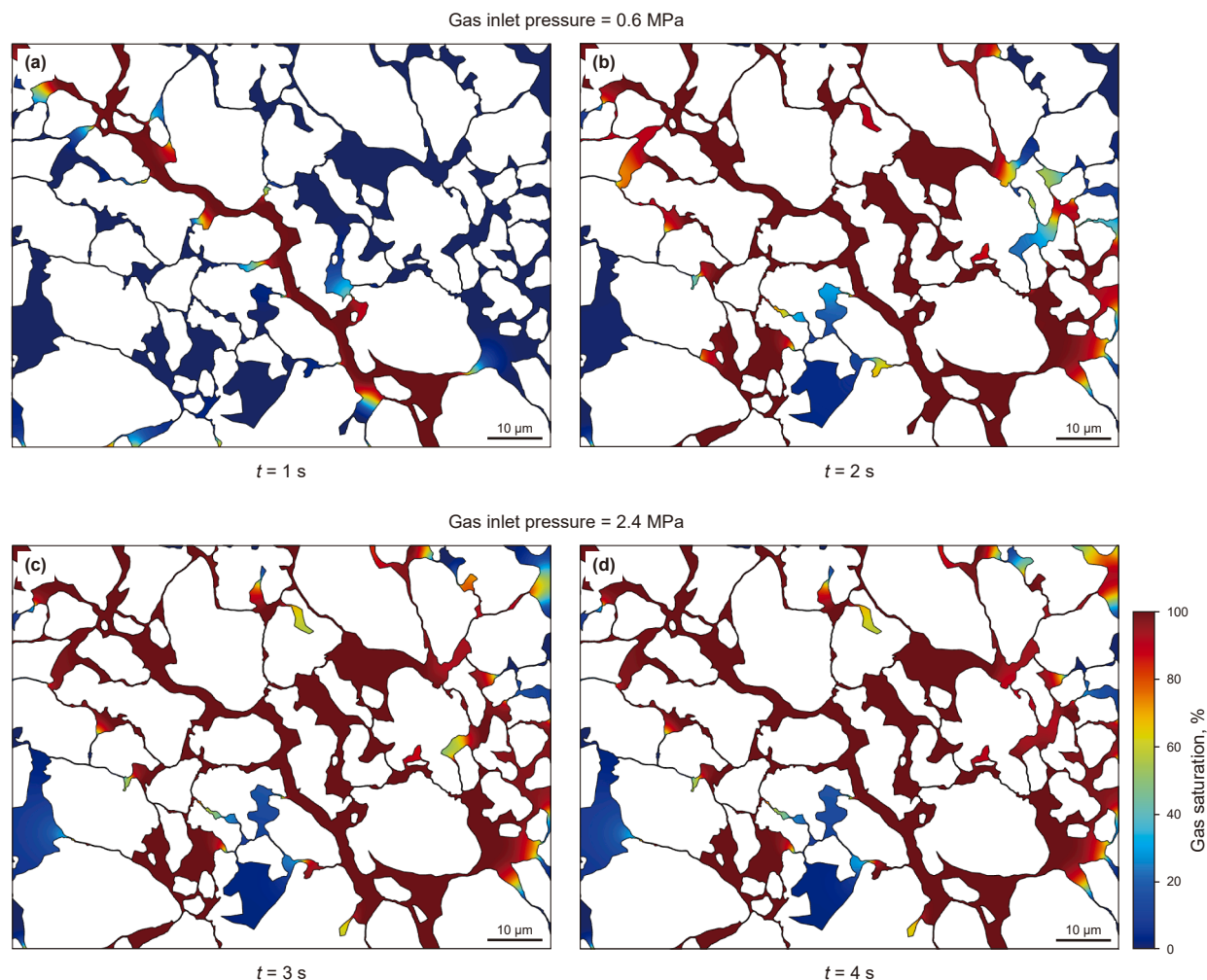


Fig. 11. Initial gas pressure is set to 0.6 MPa, showing (a) gas saturation distribution in the porous medium at 1 s of inlet time and (b) at 2 s of gas inlet time. The gas pressure is then increased to 2.4 MPa, showing (c) gas saturation distribution at 3 s and (d) at 4 s of gas inlet time.

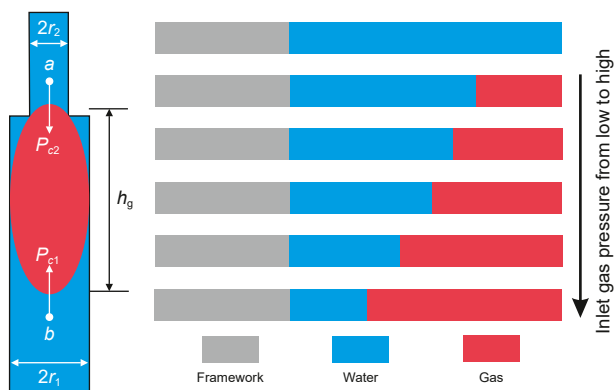


Fig. 12. The figure on the left illustrates the forces acting on the capillary tube during gas injection. The figure on the right depicts the changes in gas saturation within a rock sample under specific inlet gas pressures. The left schematic diagram of capillary force is adapted from Zhao et al. (2022) with modifications.

4.3. Well case evidence on microfractures and gas saturation

To evaluate whether microfracture development significantly affects gas saturation in subsurface tight sandstone gas reservoirs, we conducted a comparative analysis based on geological

case studies. To minimize the influence of other variables, we selected adjacent tight sandstone intervals from the same well with comparable porosity, where the primary difference lies in the presence or absence of microfractures. This approach also helps to avoid the potential effects of variations in source rock quality and source–reservoir contact relationships on gas saturation (Dai et al., 2014; Cao et al., 2024). Gas saturation was calculated using log-derived parameters based on Archie's equation.

In the selected tight sandstone gas reservoirs, mature gas-prone source rocks are interbedded with or adjacent to the tight sandstone intervals, forming a source–reservoir proximal system that facilitates short-distance hydrocarbon migration. The temporal relationship between gas accumulation and reservoir evolution exhibits a “densification-before-accumulation” pattern, wherein porosity and permeability reduction largely occurred prior to the main stage of gas generation and migration (Wang et al., 2023c). The onset of overpressure closely coincides with the expulsion of natural gas from the source rocks (Fig. 14). The overpressure generated by the continuous gas expulsion from source rocks has been widely recognized as the dominant driving force for gas accumulation in tight sandstones (Guo et al., 2023).

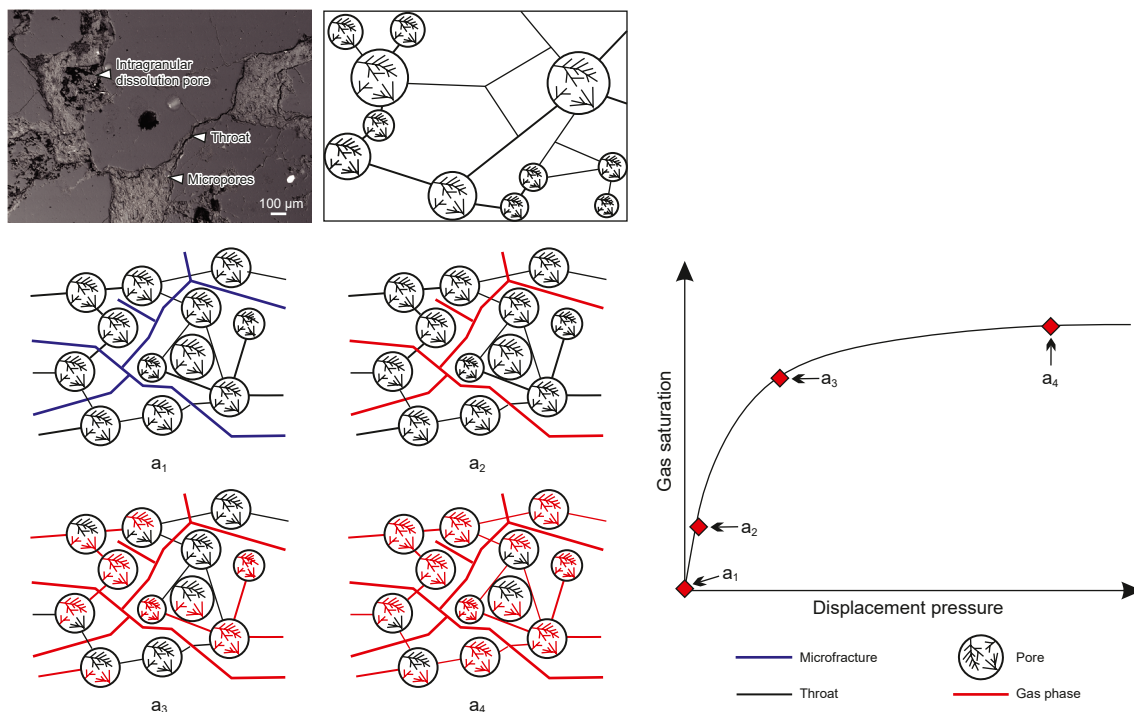


Fig. 13. A two-dimensional multitype pore network model is used to explain gas saturation changes within the microfracture-pore system. The thick blue lines represent microfractures. Thick blue lines represent microfractures in the model. Black lines indicate the throats, with their thickness corresponding to the throat size. Matrix porosity is modeled using a treelike pore structure. In the network model, gas is represented by red lines, and gas intrusion follows the paths $a_1 \rightarrow a_4$. The schematic diagram of the pore-network model is adapted from [Sakhaee-Pour and Steven \(2014\)](#)

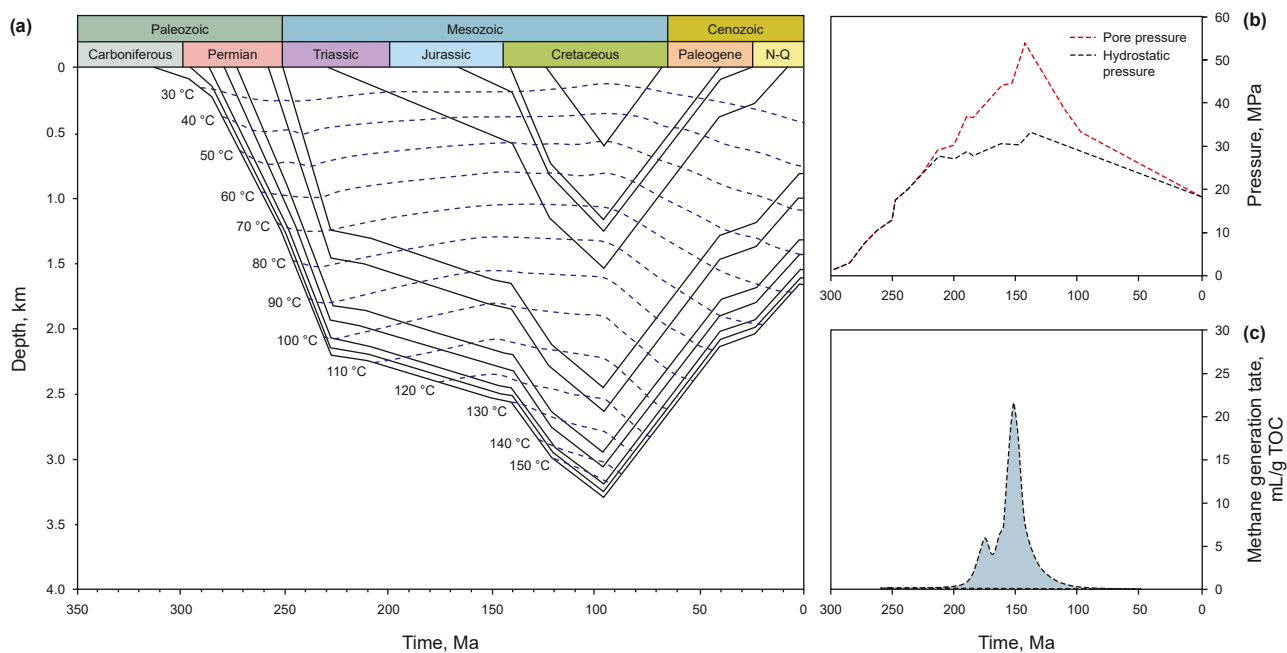


Fig. 14. Formation pressure evolution and hydrocarbon generation rate of the source rock. (a) Burial and thermal history of the study area ([Wang et al., 2023c](#)). (b) Evolution of formation pore pressure and hydrostatic pressure through geological time ([Guo et al., 2023](#)). (c) Methane generation rate curve based on thermal maturity modeling ([Wang et al., 2023c](#)).

The comparison reveals that the difference in gas saturation between microfractured and non-microfractured tight sandstone intervals is minimal, typically ranging from -2.8% to 2.5% ([Table 4](#)). In addition, statistical analysis using the Student's t -test confirms that

the presence of microfractures does not exert a statistically significant influence on gas saturation ([Table 4](#)). These results indicate that, under in-situ burial conditions, the development of microfractures does not notably enhance gas saturation in tight sandstone reservoirs.

Table 4
In-situ gas saturation characteristics of tight sandstone gas reservoirs.

Well	Depth, m	Dissolution microfractures	Porosity, %	Permeability, mD	Gas saturation, %
L-61	1841.52–1842.22	Bedding-plane microfractures	7.60	0.52	48.2
	1834.72–1839.02	Non-microfractured	7.78	0.22	46.2
LD-2	1844.5–1847.4	Circumgranular microfractures	9.16	2.04	46.7
	1847.4–1849.8	Non-microfractured	8.90	0.61	48.6
LD-3	1733.4–1735.0	Dissolution microfractures	8.35	0.85	47.9
	1739.0–1740.6	Non-microfractured	7.34	0.25	46.9
LD-4	1289.0–1290.7	Dissolution microfractures	12.24	4.72	55.5
	1295.3–1297.1	Non-microfractured	11.96	0.78	54.5
	1527.4–1529.3	Circumgranular microfractures	7.47	0.62	52.9
LD-5	1529.3–1531.5	Non-microfractured	6.27	0.13	43.8
	1554.5–1556.0	Dissolution microfractures	8.37	2.36	37.2
	1556.9–1558.8	Non-microfractured	9.44	0.44	38.0
LD-13	1739.0–1742.3	Circumgranular microfractures	12.17	10.91	54.2
	1742.3–1743.2	Non-microfractured	11.96	1.03	48.5
LD-15	1881.5–1886.2	Dissolution microfractures	8.55	0.50	47.0
	1886.2–1891.6	Non-microfractured	9.02	0.61	54.5
LD-17	1380.8–1384.9	Dissolution microfractures	11.96	6.19	51.1
	1384.9–1390.0	Non-microfractured	12.99	1.66	53.3
	1834.1–1835.4	Dissolution microfractures	8.76	0.54	45.1
S1-39	1838.4–1843.4	Non-microfractured	8.45	0.45	44.7
	2068.7–2071.1	Dissolution microfractures	8.33	4.66	43.5
	2071.1–2072.4	Non-microfractured	10.02	1.11	38.1
S-70	2174.7–2175.6	Dissolution microfractures	7.80	1.21	40.0
	2175.6–2176.6	Non-microfractured	6.20	0.11	39.9
	2092.9–2094.4	Dissolution microfractures	11.30	3.15	61.1
	2097.8–2098.8	Non-microfractured	7.50	0.20	60.1

5. Conclusions

This study integrates imaging, petrophysical analyses, and both physical and numerical simulations to evaluate how microfractures affect reservoir quality and gas saturation in tight sandstone gas reservoirs, validated by well-based in-situ gas saturation data. Our results provide new insights into the mechanisms by which microfractures control fluid migration and storage in tight sandstone gas reservoirs.

- (1) Four distinct types of microfractures are observed in the tight sandstone samples: structural microfractures, bedding-plane microfractures, circumgranular microfractures, and dissolution microfractures.
- (2) The permeability of samples with well-developed structural and circumgranular microfractures, as well as some with bedding-plane microfractures, is approximately 2-fold to an order of magnitude compared to non-fractured samples. Dissolution microfractures do not appear to significantly contribute to permeability.
- (3) Gas accumulation in tight sandstone is governed by threshold entry pressure for invasion, with capillary pressure controlling the sequence of pore filling and the spatial arrangement of gas.
- (4) The microfractures are considerably larger than the pore throats, allowing water displacement at lower gas entry pressures during gas invasion. However, because tight sandstones contain a significantly higher proportion of small pore throats, the presence of a few microfractures has a negligible impact on gas accumulation and saturation.

CRediT authorship contribution statement

Zi-Yi Wang: Writing – original draft, Methodology, Investigation, Conceptualization. **Nicholas B. Harris:** Writing – review & editing, Investigation. **Shuang-Fang Lu:** Supervision, Project

administration. **Neng-Wu Zhou:** Investigation. **Ya-Xin Shang:** Investigation.

Declaration of interest statement

We confirm that there are no known conflicts of interest associated with this publication and there has been no significant financial support for this work that could have influenced its outcome. We confirm that the manuscript has been read and approved by all named authors and that there are no other persons who satisfied the criteria for authorship but are not listed. We further confirm that the order of authors listed in the manuscript has been approved by all of us. We confirm that we have given due consideration to the protection of intellectual property associated with this work and that there are no impediments to publication, including the timing of publication, with respect to intellectual property. In so doing we confirm that we have followed the regulations of our institutions concerning intellectual property.

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