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Invited review

A comprehensive review of shale wettability characterization: Mechanisms, measurements and influencing factors

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Abstract:
Shale reservoir wettability is a critical parameter governing the occurrence, migration and recovery efficiency of oil and gas. This paper systematically reviews the recent advances in shale wettability assessment methods and their influencing factors. These factors are evaluated by various methods, each offering distinct advantages and limitations. The contact angle method provides rapid macroscopic wettability assessment but is constrained by the properties of mineral and fluid. Spontaneous imbibition effectively characterizes macroscopic wettability but is time-consuming owing to the inherently low porosity and permeability of shale formations. Nuclear magnetic resonance enables the dynamic monitoring of fluid distribution across multi-scale pores, whereas it is constrained by high technical complexity and cost. Numerical simulations investigate wettability from the perspectives of interfacial mechanics and at the molecular scale, while their parameterization and accuracy still depend on experimental validation. The spatial distribution of hydrophilic minerals alongside oleophilic organic matter leads to mixed-wettability states. Increased total organic carbon content enhances the oil-wetting propensity, while higher maturity further promotes the development of hydrophobic organic pores. Elevated temperature generally strengthens the water-wet characteristics, whereas increased pressure induces a preference for oil-wetting. High salinity fluids, particularly those containing divalent cations, asphaltenes and aromatic compounds, enhance oil affinity. Macroscopic wetting behavior is ultimately determined by the connectivity and relative abundance of organic versus inorganic pores. Future studies should integrate multidisciplinary approaches combining advanced experimental characterization with computational modeling to enhance dynamic wettability prediction under real reservoir conditions.

1. Introduction

During shale reservoir development, wettability affects the spontaneous imbibition and flowback efficiency of fracturing fluids in porous media via capillary forces, thereby influencing hydrocarbon desorption, diffusion and flow, as well as damage mechanisms such as water blockage and the Jamin effect. To improve fluid mobility, surfactants and other chemical additives are commonly introduced into fracturing fluids to

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alter the rock's wettability (Bai et al., 2013; Makhanov et al., 2014). Wettability in shale not only affects the occurrence and spatial distribution of fluid within the pore system but also largely determines the capacity for hydrocarbon adsorption, desorption and flow (Zhang et al., 2023). Among the source rocks of reservoirs, water-wet rocks generate stronger capillary resistance, requiring greater buoyant forces for hydrocarbons to penetrate pore throats. In contrast, oil-wet rocks reduce resistance through wettability, facilitating hydrocarbon migration, which in turn influences whether hydrocarbons are expelled in a continuous or dispersed phase and ultimately determines the pathway and efficiency of secondary migration. These phenomena demonstrate that wettability differences can directly influence the scale and distribution of hydrocarbon accumulation within the reservoir (Schowalter, 1979; Aghajanzadeh et al., 2019).

Wettability denotes the propensity of a solid to adsorb one fluid phase over others. Accordingly, the conventional classification of reservoirs distinguishes water-wet, oil-wet, or neutral wet types, which are determined by the contact angle observed at the liquid-pore wall interface (Craig, 1971; Morrow, 1990). Conventional reservoir rocks typically exhibit higher permeability and have simpler mineral compositions. For instance, limestones are comprised mainly of calcite, in contrast to sandstones that largely contain quartz and feldspar. The determination of wettability in such conventional reservoirs relies on long-standing experimental procedures: The Amott-Harvey test, the United States Bureau of Mines (USBM) method, spontaneous imbibition, and the contact angle method (Graue et al., 1999; Gu et al., 2016). In contrast, shale reservoirs are complex due to their heterogeneous pore systems, comprising pores in organic matter, intercrystalline pores among clay minerals, and intragranular dissolution pores in carbonates, alongside laminations and microfractures. Pore wettability is determined by key intrinsic characteristics of shale, especially the mineral composition, organic matter content, and pore architecture. For instance, clay minerals typically exhibit hydrophilic behavior, whereas organic matter pores are generally oil-wet (Lan et al., 2015; Liang et al., 2016). External factors such as fluid properties and reservoir temperature-pressure conditions can also affect shale wettability, thereby regulating the storage and flow of hydrocarbons (Elgmati et al., 2011; Yang et al., 2018; Alhammad et al., 2024). These complexities distinguish the evaluation of shale wettability from that of conventional reservoirs, necessitating more precise and micro-scale characterization methods (Arif et al., 2016; Guiltinan et al., 2017; Huang et al., 2020).

While existing technologies have considerably advanced shale wettability studies, this field remains constrained by unresolved challenges. Established techniques including contact angle analysis and spontaneous imbibition are primarily limited to macroscopic evaluation, failing to accurately represent wettability at the micro- and nano-scales. Moreover, the inherent heterogeneity of shale reservoirs leads to spatial and scale-dependent variations in wettability, making precise characterization even more difficult.

In view of these challenges, this study systematically outlines the evaluation methods of shale wettability, summarizes the applicability, advantages and limitations of major techniques, analyzes the key influencing factors, and reviews the current research progress, existing challenges, and future trends, with the aim to provide directional guidance for further investigations in shale wettability.

2. Evaluation methods for shale wettability

The accurate determination of shale wettability is essential for the optimization of development strategies and the enhancement of recovery efficiency. However, owing to the inherent complexity of shale, particularly the diversity in mineralogy, the multi-scale heterogeneity of pore systems, and the spatial distribution of organic or inorganic components, the accuracy and applicability of wettability assessment methods have considerable limitations. Moreover, a unified evaluation standard is currently lacking. Recent advances in technology and research have facilitated the development of advanced wettability measurement techniques, which have their own advantages and limitations and are suited to different research objectives and conditions.

2.1 Laboratory experiments

(1) Contact angle method

Contact angle is defined as the angle formed at the interface between a liquid and a solid surface. It results from the interaction of three distinct interfaces and varies depending on the affinity of the solid surface for different liquids. This angle is conventionally used for measuring wettability. In laboratory settings, contact angle measurement methods are generally categorized into sessile drop method (SDM) and captive bubble method (CBM). The principle of the SDM is illustrated in Fig. 1(a). This method is applied in a three-phase system that comprises solid, liquid (typically water or oil), and gas (usually air) phases. Therein, a droplet (typically water) is dispensed onto the solid surface via a needle, and the angle between the liquid and the solid is measured to determine wettability (Huhtamäki et al., 2018). The CBM, shown schematically in Fig. 1(b), is applied to a three-phase system that contains a solid and two immiscible liquids. In this approach, the solid is placed horizontally in a transparent chamber filled with a liquid that is immiscible with the liquid to be tested. The liquid is introduced beneath the surface via a needle, forming a bubble that attaches to the solid. Subsequently, wettability is evaluated by measuring the angle formed at the interface between the captured bubble and the solid surface (Haeri et al., 2020).

According to the Young's equation, the equilibrium configuration of an oil droplet on an ideal solid surface under the influence of three interfacial tensions is defined by:

$$\gamma_{lg}\cos\theta_Y = \gamma_{sg} - \gamma_{sl} \tag{1}$$

where γ_{lg}, γ_{sg}, γ_{sl} represent the interfacial tensions at the liquid-gas, solid-gas, and solid-liquid interfaces; θ_Y is the Young's contact angle.

For the wettability of rough solid surfaces, Wenzel (1936) introduced the surface roughness factor to modify its effect on the contact angle, as shown below:

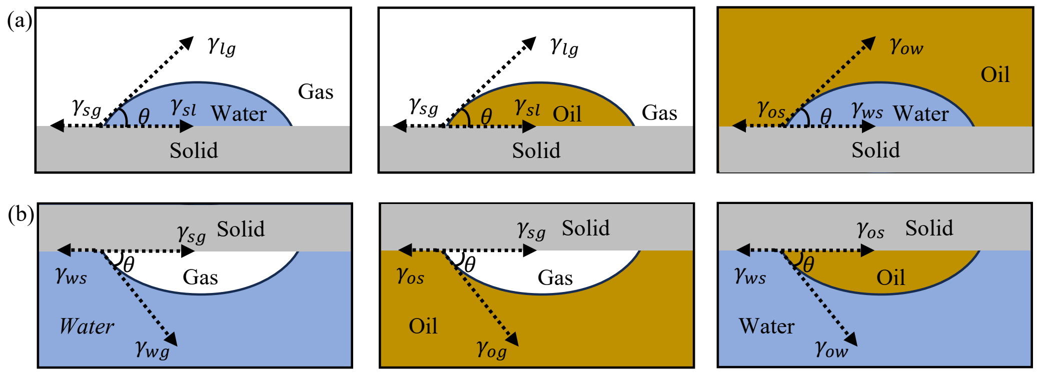

Fig. 1. Methods for measuring three-phase contact angles: (a) SDM and (b) CBM.

Table 1. Comparison between different measurement standards.

Standards	Extremely water-wet	Water-wet	Weakly water-wet	Neutral-wet	Oil-wet
ASTM D7334-08	[0°, 20°]	(20°, 45°]	(45°, 90°]	/	(90°, 180°]
SY/T 5153-2017	/	[0°, 75°)	/	[75°, 105°]	(105°, 180°]
Wang and Gupta (1995)	/	[0°, 60°)	/	(60°, 120°)	(120°, 180°]
Xue et al. (2021)	[0°, 30°)	(30°, 60°)	(60°, 90°)	/	/

$$\cos\theta_m = R\cos\theta_Y \tag{2}$$

where θ_m represents the measured contact angle; R denotes the roughness factor, defined as the ratio of the true contact area between the liquid and the rough solid surface to the apparent geometric area of the liquid-solid interface, and $R > 1$ for any physically realistic rough surface.

Subsequently, the contact angle calculation formula for the air-brine and oil-shale system was improved (Siddiqui et al., 2018).

This modification was applied to study shale wettability under *in-situ* conditions, specifically the oil-water-shale contact angle, as presented below:

$$\theta_{ow} = \cos^{-1}\frac{\gamma_{og}\cos\theta_{og} - \gamma_{wg}\cos\theta_{wg}}{r_{ow}} \tag{3}$$

where γ_{og}, γ_{wg} and γ_{ow} represent the oil-gas, water-gas, and oil-water interfacial tensions, respectively; θ_{og}, θ_{wg} and θ_{ow} represent the contact angles of the gas-oil-rock, gas-water-rock, and oil-water-rock systems, respectively.

According to the international standard ASTM D7334-08, with water as the testing fluid, the contact angle of $0° \leq \theta \leq 20°$ indicates extremely water-wet condition; $20° < \theta \leq 45°$ indicates water-wet condition; $45° < \theta \leq 90°$ indicates weak hydrophilicity; and $\theta > 90°$ indicates oil-wet condition. This standard strictly uses 90° as the boundary to classify wettability into hydrophilic and hydrophobic categories. The presence of diverse minerals, high organic content, and complex pore structures leads to mixed wettability in shale reservoirs. The standard SY/T 5153-2017 defines contact angles of $0° \leq \theta < 75°$ as water-wet, $75° \leq \theta \leq 105°$ as neutral-wet, and $105° < \theta \leq 180°$ as oil-wet condition. The mixed wettability characteristics of shale surfaces make this standard more reasonable (Liu et al., 2022; Gong et al., 2024; Lv et al., 2025).

However, since the wettability intervals in this standard are relatively broad and do not define wettability strength, different researchers have proposed more detailed classifications based on the distribution of experimental results. For example, Xue et al. (2021) employed shale samples sourced from two different formations within the northern Songliao Basin, finding that the samples were almost entirely hydrophilic, with contact angles mostly between 20° and 80°. They subsequently defined $\theta < 30°$ as strongly hydrophilic; $30° < \theta < 60°$ as moderately hydrophilic; and $60° < \theta < 90°$ as weakly hydrophilic. Wang and Gupta (1995) conducted research on representative calcite and quartz in shale reservoirs and defined $\theta < 60°$ as hydrophilic, $60° < \theta < 120°$ as neutral wettability, and $\theta > 120°$ as oil-wet. A comparison between the above measurement standards is presented in Table 1.

The contact angle method assesses surface wettability by measuring the angle formed by a liquid droplet on the solid substrate. The value of the contact angle indicates the degree of hydrophilicity or hydrophobicity of a surface. This method is simple in operation and suitable for the rapid assessment of surface wettability (Guo et al., 2020; Gao et al., 2021). The preferential affinity of rocks for the first contacted fluid may impact the experimental data of contact angle. Some researchers measured the interfacial tension and contact angle in the surfactant-oil-water-shale system (Mirchi et al., 2014). During shale immersion in distilled water for oil-bubble measurement, a thin aqueous film was observed to develop on the rock surface prior to oil droplet injection. This film inhibited oil penetration into oil-wet pores, thereby affecting the experimental results. A comparison between theoretical predictions from Eq. (3) and experimental measurements revealed that the actual contact angles in the three-phase system are consistently more hydrophilic than theoretically predicted (Xue et al., 2021). This phenomenon was ascribed to a pre-existing aqueous layer formed during initial water exposure, which hinders direct oil-rock contact, leading to an amplification of hydrophilic behavior.

Since the wetting behavior of droplets is influenced by the microscopic structure and chemical composition of shale surfaces, the contact angle method only reflects the macroscopic wettability of the sample surface, which can lead to systematic errors when assessing pore-scale wettability, thus limiting the applicability of the contact angle method in measuring complex porous media such as shale.

(2) Spontaneous imbibition method

Spontaneous imbibition describes the penetration of a wetting-phase fluid into rock pores and its subsequent displacement of non-wetting phase fluid driven exclusively by capillary forces. This process is governed by several factors, including boundary conditions, fluid viscosity, temperature, pressure, wettability, pore size distribution, and mineral composition (Shahri et al., 2012; Meng and Cai, 2018; Su et al., 2022; Yang and Yang, 2025).

A method for calculating the pore wettability index by Eq. (4) was proposed based on a study of wettability of Duvernay shale samples from Canada (Yassin et al., 2017). Therein, a linear function with the slope given by $\cos\theta/r$ was defined as the pore wettability index. This formula takes into account both the surface contact angle and the pore size influence. Thus, it can evaluate wettability according to the imbibition behavior within different-sized pores:

$$\left(\frac{Q\varphi}{AL}\right)^2 \frac{L^2\varphi\mu}{4\sigma k} = \frac{t\cos\theta}{r} \tag{4}$$

where Q represents the imbibed liquid volume; A represents the sample's cross-sectional area; L represents the liquid penetration depth; φ represents the porosity; σ represents the interfacial tension; μ represents the wetting-phase viscosity; θ represents the contact angle; k represents the permeability; r represents the pore radius; t represents the imbibition time.

The gravimetric method can also be utilized for wettability assessment. Therein, a dried core sample is sequentially immersed in two distinct fluids while its mass change is tracked until stabilization. The difference in weight gained by the core after the imbibition of each fluid can be used to indicate its wetting preference (Alinejad and Dehghanpour, 2021). The wettability of shale samples from the Montney and Horn River formations in Canada was quantitatively evaluated using spontaneous imbibition experiments and Eq. (5) (Lan et al., 2015), and the results showed a clear contrast in wettability. Montney samples typically had W_{io} values between 0.58 and 0.74, indicating oil-wet characteristics, while Horn River samples had values between 0.23 and 0.33, indicating water-wet characteristics:

$$W_{io} = 1 - \frac{V_w}{V_w + V_o} \tag{5}$$

where W_{io} is the oil-wet index, V_w and V_o represent the total volume of imbibed water and oil, respectively, divided by the sample's total pore volume.

The application of wettability indices for characterizing wettability has been extensively analyzed by numerous scholars in spontaneous imbibition experiments. The wettability of powdered shale samples from the Longmaxi Formation was evaluated by Ye et al. (2019), revealing mixed-wet behavior. The oil-wet index ranged from 0.53 to 0.6, while the water-wet index ranged from 0.44 to 0.47, indicating a weak oil-wet behavior since the oil index was higher than the water index. An analysis of the wettability of Barnett Shale samples from north-central Texas revealed water imbibition slopes ranging from 0.269 to 0.313 (Gao and Hu, 2016). The imbibition slope and sample weight changes enabled the qualitative classification of Barnett samples into oil-wet, water-wet, and mixed-wet categories. The spontaneous imbibition results showed strong consistency with contact angle measurements. An investigation of shale samples from the Yanchang Formation in the Ordos Basin identified consistently oil-wet behavior (Li et al., 2020). After reaching imbibition equilibrium, the oil imbibition slope ranged from 0.269 to 0.571. Samples exhibiting more pronounced oil-wet behavior demonstrated steeper oil imbibition slopes, aligning with reduced oil droplet contact angles. These results from spontaneous imbibition corroborated the trends identified in contact angle measurements.

Offering the advantages of speed and convenience, the spontaneous imbibition method is widely used in reservoir rock wettability studies. Moreover, it can also reflect the hydrophilicity or hydrophobicity of internal pores. However, the low porosity and permeability of shale affect the imbibition time, resulting in a long experimental period. Besides, spontaneous imbibition alone cannot distinguish the wettability of different pore scales, therefore it needs to be combined with other methods for comprehensive analysis.

(3) Ratio method

As part of the ratio method, both the Amott-Harvey and USBM techniques are grounded in the concept of capillary-driven displacement, where the wetting phase spontaneously replaces the non-wetting phase. The ratio of spontaneously to forcibly imbibed/drained fluid volumes reflects the fluid affinity of the porous medium, serving as an indicator of core-scale wettability (Al-Garadi et al., 2022). Some studies evaluated the wettability of shale oil reservoirs in the Lucaogou Formation using the Amott-Harvey method, and they revealed a wettability index ranging from -1 to 0.33, reflecting neutral to oil-wet characteristics. Furthermore, the results consistently indicated a highly heterogeneous distribution of oil-wet and neutral-wet zone (Liu et al., 2022; Lai et al., 2023).

The USBM method, proposed by Donaldson et al. (1969), employs centrifuge measurements for the quantitative evaluation of reservoir rock wettability. This method determines the wettability index by calculating the area beneath capillary pressure curves generated through forced imbibition and drainage cycles. Some researchers combined the two methods and refined the corresponding indicators, thus improving the accuracy of measurements (Sharma and Wunderlich, 1987). By using Eqs. (6)-(8) for calculation and quantitative analysis,

Table 2. Wettability evaluation index based on the ratio method.

Methods	Water-wet	Neutral-wet	Oil-wet
USBM	(0, $+\infty$)	0	($-\infty$, 0)
Amott-Harvey	(0.1, 1.0]	[-0.1, 0.1]	[-1.0, -0.1)

an integration of the Amott-Harvey, USBM, and nuclear magnetic resonance methods was developed by Liu et al. (2022), facilitating a more accurate assessment of reservoir wettability and fluid flow characteristics. The wettability evaluation indicators are shown in Table 2:

$$\log \frac{A_5 - A_4}{A_2 - A_3} \tag{6}$$

$$I = W_w - W_o = \frac{A_1 - A_2}{A_1 - A_3} - \frac{A_4 - A_3}{A_5 - A_3} \tag{7}$$

$$A_I = I_w - I_o = \frac{\Delta S_1}{\Delta S_1 + \Delta S_2} - \frac{\Delta S_3}{\Delta S_3 + \Delta S_4} \tag{8}$$

where ΔS_1 represents the percentage decrease in oil saturation due to water imbibition; ΔS_2 represents the percentage decrease due to water flooding; ΔS_3 represents the percentage increase due to oil imbibition; ΔS_4 represents the percentage increase due to oil flooding; $A_1 \sim A_5$ are the integrated areas of the nuclear magnetic resonance (NMR) T_2 spectra corresponding to the following core states: Oil-saturated state, after spontaneous water imbibition and oil displacement, after water flooding until no oil remains, after spontaneous oil imbibition and water displacement, and after oil flooding until no water remains; W_w and W_o represent the water-wet index and oil-wet index based on the USBM, respectively; I_w and I_o represent the water-wet index and oil-wet index based on the Amott-Harvey method, respectively; W represents the total wettability index calculated by the USBM; I represents the total wettability index calculated by the Amott-Harvey method; A_I represents the integrated wettability index derived from the combination of the Amott-Harvey method, USBM, and nuclear magnetic resonance method.

Wettability indices derived from ratio methods characterize the macroscopic wetting behavior of the sample. The displacement pressure difference enables fluids to fully penetrate different pores, effectively quantifying the wettability of conventional reservoir cores with relatively simple pore structures and higher permeability. Additionally, the USBM method can significantly shorten the experimental duration by applying centrifugal force. Owing to shale's complex pore networks and low permeability, establishing reliable displacement models poses significant challenges, thereby diminishing the practicality and precision of these methods.

(4) Wilhelmy method

The Wilhelmy method is a technique for measuring wettability, which detects changes in solid-liquid interfacial tension during sample immersion in and withdrawal from a liquid. On the basis of dynamic force balance, it calculates the interfacial tension using Eq. (9) and the contact angle using Eq. (10), thereby determining wettability (Zhang et al., 2002):

$$F = \gamma_{lv} p \cos\theta \tag{9}$$

$$\theta = \arccos \frac{F}{\gamma_{lv} p} \tag{10}$$

where F represents the equilibrium force exerted on the solid; γ_{lv} represents the surface tension of the liquid; p represents the wetted perimeter.

Based on Wilhelmy plate measurements performed on North Texas shale samples, surfactant inclusion was found to reduce contact angles, indicating enhanced oil affinity (Phan et al., 2018). The consistency between these outcomes and spontaneous imbibition results validated the experimental hypotheses.

The Wilhelmy method determines wettability by measuring the force changes caused by wetting hysteresis on the surface. This method can measure dynamic contact angles, thus better reflecting wettability under fluid flow conditions during reservoir development. Its advantages include a large contact area, enabling the characterization of macroscopic statistical wettability of heterogeneous and rough samples, high repeatability, and the ability to connect tensiometers to computers for direct data acquisition and output. However, due to the macroscopic and microscopic heterogeneity of rock wettability, different wettability behaviors may appear on the same rock surface. Therefore, the Wilhelmy method cannot fully capture spot wettability or mixed wettability within rocks.

(5) NMR method

NMR, as an efficient and non-destructive fluid detection technique, is widely employed in laboratory core analysis and serves as a vital method for characterizing complex reservoirs (Dunn et al., 2002; El-Husseiny and Knight, 2017; Wang et al., 2018b; Cai et al., 2025). This technique indirectly evaluates wettability by measuring the relaxation times of atomic nuclei in fluids under a magnetic field, enabling the analysis of fluid distribution, flow dynamics, and interactions within porous media or on surfaces.

In terms of reservoir wettability evaluation, it can be achieved by analyzing the relaxation behavior of fluids confined in porous media. Researchers have used both longitudinal relaxation time (T_1) and transverse relaxation time (T_2) to characterize sample wettability features (Liang et al., 2019; Al-Garadi et al., 2022). The successful application of NMR relaxation measurements for wettability characterization highlights this method's capacity to reliably discriminate water-wet from oil-wet surfaces (Hsu et al., 1992). Moreover, wettability characteristics obtained by this method correlate well with those determined by the Amott-Harvey and USBM methods.

A systematic review of the connections between NMR relaxation mechanisms and wettability assessment was provided by Liang et al. (2023). It was concluded that he relaxation processes at the fluid interfaces are governed by the wettability properties of the surface, with surface relaxation occurring exclusively in the wetting-phase fluid. In conventional reservoirs, water typically acts as the wetting phase, coating the pore walls. Oil as the non-wetting phase therefore resides in the central pore space without interacting with the pore surfaces. As a result, the NMR response of oil is principally governed by bulk relaxation, while that of water is chiefly shaped by surface relaxation. Conversely, shale reservoirs frequently display mixed-wettability characteristics, allowing oil to contact the matrix and undergo surface relaxation. This leads to a more complex NMR relaxation behavior in the pore fluids. In rocks with heterogeneous wettability that contain both oil and water, the NMR T_2 relaxation behavior of fluids can be represented by the following expression, which assumes that the influence of the magnetic field gradient is minimal:

$$\frac{1}{T_2} = \frac{1}{T_{2,w}} + \frac{1}{T_{2,o}} \tag{11}$$

$$\frac{1}{T_{2,w}} = \frac{1}{T_{2,b,w}} + \rho_{2,w}\frac{A_w}{V_w} = \frac{1}{T_{2,b,w}} + \rho_{2,w}\frac{A_w}{VS_w} \tag{12}$$

$$\frac{1}{T_{2,o}} = \frac{1}{T_{2,b,o}} + \rho_{2,o}\frac{A_o}{V_o} = \frac{1}{T_{2,b,o}} + \rho_{2,o}\frac{A_o}{VS_o} \tag{13}$$

where $1/T_{2,b,w}$ and $1/T_{2,b,o}$ represent the bulk relaxation term of the fluid; $\rho_{2,w}(A_w/V_w)$ and $\rho_{2,o}(A_o/V_o)$ represent the surface relaxation terms of water and oil in the pores, respectively; V is the pore volume; A_w and A_o represent the water-wetted area and oil-wetted area, respectively; S_w and S_o represent the water saturation and oil saturation, respectively; $\rho_{2,w}$ and $\rho_{2,o}$ represent the surface relaxation rates of water and oil, respectively.

Technological progress has enabled two-dimensional NMR to determine the diffusion coefficient (D), longitudinal relaxation time (T_1), and transverse relaxation time (T_2) concurrently. To this end, the combination of these parameters provides new indicators for wettability evaluation. In the application of NMR diffusion-relaxation (D-T_2) mapping, Su et al. (2018) conducted a study on shales from the Zhanhua Sag. Utilizing the NMR D-T_2 technique to assess shale wettability, their results demonstrated that the shale in this region exhibited a mixed-wet behavior. The D-T_2 maps enabled effective discrimination between oil-wet organic and water-wet inorganic pores, thereby revealing their distinct distribution characteristics.

In the context of two-dimensional NMR (T_1-T_2) mapping, T_2 relaxation data provide a robust representation of pore-scale fluid occupancy. This approach is frequently integrated with spontaneous imbibition experiments to investigate the spatial distribution of absorbed fluids in shale reservoirs at the microscopic pore level (Liu et al., 2016; Meng et al., 2016). The combined use of gravimetric and NMR methods was employed by Sulucarnain et al. (2012) to monitor brine and dodecane imbibition across varying depths in organic-rich Ordovician shale, leading to the development of the NMR wettability index. The measured values across ten samples ranged from -0.75 to 0.92, with gravimetric data corroborating the NMR-based wettability interpretation. In a related two-dimensional NMR analysis, Wang et al. (2024) reported a wettability index of 0.34 through spontaneous imbibition and 0.14 through NMR, with both approaches confirming water-wet characteristics and demonstrating the consistency of NMR-derived wettability evaluation. Further refining the pore-scale insight, shale samples from the Jiyang Depression in China were characterized using NMR signals to classify pores into micropores, mesopores and macropores. The integration of spontaneous imbibition and two-dimensional NMR revealed that micropores exhibited water-wet behavior, with wettability indices between 2.64 and 4.96, while both mesopores and macropores showed oil-wet characteristics, with indices ranging from 0.08 to 0.61 and 0.08 to 0.56, respectively. These results demonstrate the capability of NMR to accurately represent microscale wettability variations within shale pores (Lv et al., 2025).

NMR technology enables the dynamic monitoring of fluid distribution within multi-scale pore structures: It not only offers a continuous pore size distribution and reveals the occurrence states of fluids across varying pore sizes but also enables a more refined assessment of shale wettability through integrated data analysis. However, the current technology faces limitations due to the prohibitively high cost of equipment, which hinders application for large-scale sample analyses. Additionally, the interpretation of NMR signals is intricate, and the overall technical expenses remain substantial.

(6) Other methods

Common laboratory methods for determining rock wettability further include the capillary rise method, *in-situ* characterization, and relative permeability measurement. The capillary rise technique assesses wettability by quantifying the height of liquid ascent in a narrow tube. Although simple to operate, it is limited to powdered samples, has low reproducibility, and cannot accurately reflect the original wettability under reservoir conditions (Galet et al., 2010). *In-situ* characterization employs micro- and nanoscale imaging techniques to directly observe wettability behavior under reservoir conditions, providing realistic geological insights; however, it requires high instrument precision, meticulous sample preparation, and is therefore costly (Andrew et al., 2014; AlRatrout et al., 2017). The relative permeability measurement method indirectly characterizes wettability through two-phase flow experiments, linking it to macroscopic flow characteristics, whereas it suffers from long experimental durations and the coupling effects of multiple factors (Anderson, 1987). These methods each have unique features in terms of characterization scale, experimental conditions and data interpretation. In practical applications, a comprehensive consideration of factors affecting shale wettability and multi-method synergistic validation are necessary to achieve precise wettability characterization.

2.2 Numerical simulation

(1) Lattice Boltzmann method

The lattice Boltzmann method (LBM) is a computational fluid dynamics approach based on microscopic simulation scales. It regulates interfacial tension by defining the interaction parameters among fluids of wetting and non-wetting phases, whereas the wettability of the reservoir is primarily determined by the interaction parameters between the rock matrix and the fluids. By decoupling interfacial tension from wettability, this method offers a more faithful depiction of rock wettability under relevant reservoir conditions. Liquid-liquid slip at the oil-water interfaces in porous structures with varying wettability was investigated using the pseudopotential LBM model (Wang et al., 2022a). In oil-wet systems, the measured contact angles of oil and water on the solid substrate were about $\theta_o \approx 20^\circ$ and $\theta_w \approx 160^\circ$, respectively, whereas in water-wet systems, they were approximately $\theta_o \approx 160^\circ$ and $\theta_w \approx 20^\circ$. The comparison between molecular simulations and theoretical results validated the accuracy of this model for wettability research. Separately, wettability variation in porous media was simulated with the free energy LBM model by adjusting the contact angle, covering a transition from displacement phase-wet to neutral wettability, and finally to displaced phase-wet conditions (Ansarinasab and Jamialahmadi, 2017). The simulated contact angles showed strong agreement with theoretical function computations, validating the reliability of the simulation outcomes.

Compared with other traditional simulation methods, the LBM operates at a simulation scale between microscopic molecular dynamics models and macroscopic continuum models. Its strengths include controllable parameters, dynamic visualization, simplified representation of fluid interactions, convenient treatment of complex boundaries, suitability for parallel computation, and straightforward implementation. The LBM is now broadly acknowledged as an efficient approach for modeling fluid dynamics and solving engineering problems.

(2) Molecular dynamics simulation

Molecular dynamics simulation is an approach that employs molecular dynamics techniques to investigate fluid wetting on solid substrates and to elucidate the underlying microscopic mechanisms. With the technological progress, molecular dynamics simulation has become a commonly used tool in evaluating reservoir wettability (Xu et al., 2011; Moncayo-Riascos et al., 2016; Wang et al., 2022b; Fang et al., 2025).

Molecular dynamics simulations are often validated through laboratory experimental results. For example, quartz was selected as a representative reservoir rock mineral to comparatively investigate the wettability behavior of various heavy oil-water systems on rock surfaces using both contact angle measurements and molecular dynamics simulations (Lu et al., 2023). The results showed that the heavy oil contact angle measured by the contact angle method at 20 °C was 61.3°, which gradually decreased with increasing temperature, dropping from 60.8° to 59.2°. Molecular dynamics simulations showed that the contact angle decreased slightly as temperature increased, which was in agreement with experimental observations. Molecular dynamics simulations were integrated with experimental analysis to examine fluid wettability within nanoscale pores of the Longmaxi Formation shale by Xiong et al. (2022). To investigate the water contact angles, illite, quartz and oxygen-functionalized graphite were used as representatives of clay minerals, non-clay minerals and organic matter, respectively, based on the reservoir characteristics. While quartz and illite displayed strong hydrophilicity, evidenced by low contact angles of 25.4° and 23.4°, respectively, pure graphite demonstrated slight hydrophobicity with a contact angle of 99.1°. Molecular dynamics simulation can provide detailed information at the microscopic scale: After constructing the pore-scale model, it can simulate complex multiphase flow and interfacial phenomena, making it suitable for studying reservoir wettability. When combined with experimental data, the reliability of the simulation results can be significantly improved. However, this method requires substantial computational resources for high-precision wettability simulations, and the accuracy of the results depends on the rationality of the model and the precision of the parameters. Therefore, laboratory experimental data are still necessary to validate the simulation outcomes.

The accurate evaluation of wettability is difficult using numerical simulation, which often treats wettability as a predefined parameter. Current studies focus more on examining how different degrees of wettability affect fluid flow behavior. Although it is an emerging approach for evaluating shale reservoir wettability, numerical simulation cannot entirely replace traditional experimental measurements.

2.3 Comparative analysis

The application procedures of the aforementioned wettability evaluation methods are illustrated in Fig. 2, while their advantages and limitations are comparatively analyzed in Table 3. Accurately assessing wettability in unconventional reservoirs is still difficult due to their limited porosity and permeability, heterogeneous mineral composition, and complex pore network. Given the ongoing technological innovation, diverse wettability interpretation methods, and improved understanding of shale reservoirs, traditional methods such as ratio and Wilhelmy methods are gradually being replaced. Different methods exhibit clear complementarity due to their distinct principles. For example, contact angle and spontaneous imbibition methods can only reflect limited wettability characteristics of samples, while NMR can overcome this limitation: It distinguishes fluid distribution and wettability variations across different pore sizes. NMR also provides microscale information, making it particularly suitable for complex pore systems. Processing laboratory data enables numerical simulations to reproduce experiments multiple times. This approach reduces the experimental costs, validates result accuracy, and also strengthens theoretical reliability. Importantly, combining multiple research methods offers deeper insights into wettability mechanisms. Therefore, it is recommended to integrate multiple complementary methods to comprehensively evaluate the wettability of unconventional reservoirs.

3. Factors influencing wettability

Shale wettability regulates the mechanical behavior at the solid-liquid interface, thereby controlling the strength of oil adsorption and retention, as well as its mobility within nanopores. The accuracy of wettability evaluation directly affects the prediction results of imbibition, displacement efficiency and recovery in the reservoir. However, dynamically characterizing wettability is complicated by the interplay of mineralogical heterogeneity, multi-scale pore architectures, fluctuating temperature and pressure, and variations in fluid ionic composition (Arif et al., 2016; Guiltinan et al., 2017; Huang et al., 2020; Shi et al., 2023). Current research on the factors influencing shale oil reservoir wettability mainly focuses on the aspects discussed below.

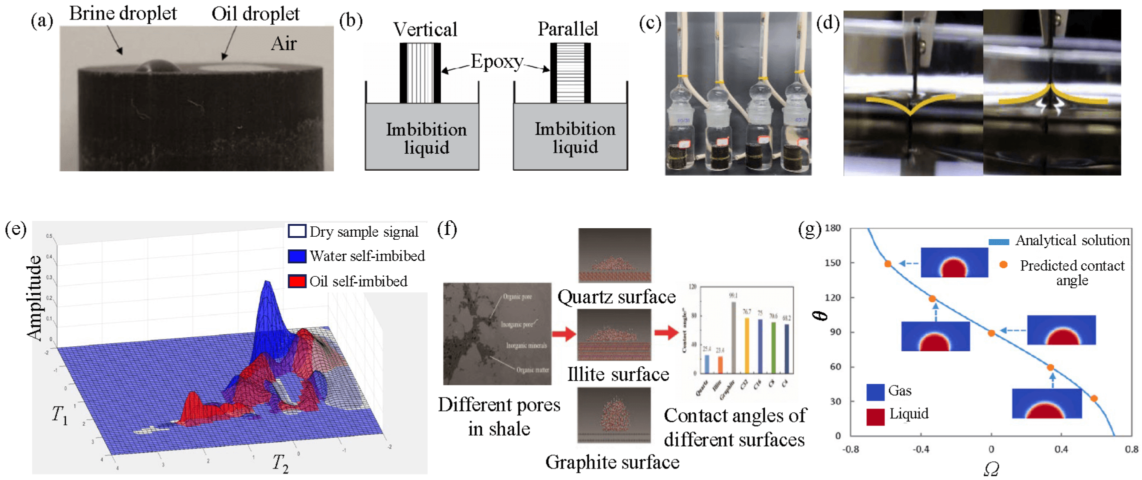

Fig. 2. Examples of wettability evaluation method applications: (a) Contact angle method (Sheng, 2018), (b) spontaneous imbibition method (Xue et al., 2022), (c) amott method (Lai et al., 2023), (d) wilhelmy method (Park et al., 2017), (e) two-dimensional NMR method, (f) molecular dynamics simulation method (Xiong et al., 2022) and (g) Lattice Boltzmann method (He et al., 2017).

3.1 Mineral composition

Shale is a compositionally diverse rock, consisting of numerous fine detrital minerals. Among these, clay minerals like illite, kaolinite, illite-smectite mixed layers, and chlorite are commonly present. Shale also includes a considerable amount of quartz and carbonates. Different minerals exhibit distinct wettability characteristics: Clay minerals are typically strongly hydrophilic, whereas inorganic minerals like quartz and carbonates tend to be weakly hydrophilic or neutrally wetting. The mineral type and content cause variations in shale surface wettability; therefore, mineralogical differences and interactions between minerals within shale may influence oil-water affinity (Borysenko et al., 2009; Sharifigaliuk et al., 2021).

A single pore may exhibit multiple wettability conditions, such as water-wet, oil-wet, neutral-wet, and mixed-wet. As illustrated in Fig. 3, at the microscopic scale, clay minerals, quartz and feldspar are hydrophilic, the surfaces of organic matter and organic pores are oil-wet, whereas carbonate minerals generally display neutral wettability. Consequently, at the macroscopic level, the overall pore system manifests a mixed-wet behavior (Gupta et al., 2018).

In shale wettability research, the role of quartz serves as a representative case. A positive correlation between quartz content and oil-wetness was reported in Longmaxi Shale by Wang et al. (2018a), whereas other studies have indicated that quartz content is positively correlated with water-wetness (Liang et al., 2015; Xue et al., 2021). These contradictory findings are attributed to the origin of quartz: The biogenic origin of quartz in the Longmaxi Shale versus the terrigenous detrital origin in Wufeng Shale results in differences in their surface properties. Meanwhile, the impact of clay minerals has garnered broader consensus. A series of studies have shown that clay minerals typically promote water-wet characteristics in shale (Gupta et al., 2018; Wang et al., 2018a; Shi et al., 2023). Gupta et al. (2018) further quantified this relationship, indicating that samples with clay contents below 10% tend to be oil-wet, those exceeding 65% are water-wet, and intermediate states exhibit mixed-wettability. Additionally, carbonate minerals have been found to positively correlate with oil-wetness (Xue et al., 2021).

In summary, the precise assessment of shale wettability is influenced by the composition and content of minerals, along with their physicochemical interactions with various fluids. For example, quartz is generally considered a hydrophilic mineral, while variations in diagenesis may cause its surface to exhibit oil-wet behavior. Furthermore, an increase in clay content typically leads to greater water adsorption and affinity, yet the specific type of clay also influences the overall shale wettability. Therefore, the diversity of mineralogy and structural complexity remains a major challenge in current shale wettability research.

3.2 Total organic carbon content

Total organic carbon content (TOC) reflects the abundance of organic matter within shale formations. The schematic diagram illustrated in Fig. 4 depicts the wettability characteristics of organic matter pores in shale, with this organic matter acting as the primary source for hydrocarbon generation. The rock's tendency to exhibit oil-wet behavior arises mainly from the nature of its organic constituents, whose non-polar carbon chains induce hydrophobicity. During thermal evolution, increasing maturity leads to higher organic matter content, which process also promotes the development of micro- to nano-scale organic pores. At higher maturity levels, the number of organic pores increases significantly. Simultaneously, their surface properties become more oil-wetting (Begum et al., 2019; Jagadisan and Heidari, 2019). These pores provide essential storage space for oil and gas. Therefore, both organic matter content and maturity significantly influence shale wettability across both micro and macro scales, with this interplay currently being a major focus of research in this field (Sharifigaliuk et al., 2021).

Table 3. Comparison of common wettability evaluation methods.

Methods	Principles	Advantages	Disadvantages
Contact angle	Measures angle between liquid droplet and surface.	Simple and intuitive, quantitatively reflects surface wettability.	Influenced by mineral and fluid, macroscopic wettability only.
Spontaneous imbibition	Compares amounts of spontaneously absorbed fluids.	Simple and intuitive, can reflect realistic flow.	Significantly affected by pore connectivity, time-consuming, cannot differentiate wettability across pore scales.
Ratio	Uses ratio of imbibed/displaced fluid volumes under force.	Fast, distinguishes extreme wettability.	Fails to replicate real conditions, not suitable for shale.
Wilhelmy	Calculates contact angle from immersion force changes.	Measures dynamic process, combines analysis of tension and wettability.	Requires flat/shaped samples, not for rough shale.
NMR	Tracks fluid distribution via signal strength during imbibition.	Pore-type differentiation, micro-scale.	Costly, not suitable for large sample volumes, complex interpretation.
Lattice Boltzmann	Adjusts interaction parameters to control interfacial tension.	Easy setup, parallelizable, simple interactions.	Needs theory background, requires validation.
Molecular dynamics simulation	Dynamics simulation method.	Simulates multiphase flow and interfaces at pore scale, considers extreme conditions.	Requires experimental verification, computationally heavy, model-dependent.

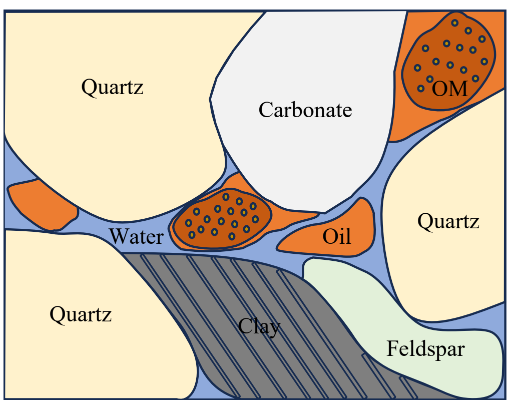

Fig. 3. Complex wettability characteristics of shale minerals and pores.

Current studies on the effect of TOC content on shale wettability report broadly consistent results, with most indicating that higher TOC levels markedly increase the oil-wet tendency of shale. Some researchers observed higher TOC content in mixed-wet shale samples compared to water-wet samples (Standal et al., 1999). Meanwhile, a reduction in TOC content corresponds to an increased tendency for samples to exhibit water-wet behavior (Mokhtari et al., 2013). Studies have directly evidenced that higher TOC levels contribute to more oil-wet shale surfaces (Arif et al., 2017; Xue et al., 2021). Furthermore, it was demonstrated that high-TOC shales exhibit enhanced oil affinity (Pan et al., 2020). In contrast, a more complex, parabolic relationship was reported between TOC content and water contact angle, which decreased initially and then increased with rising TOC (Liu et al., 2015). This behavior was attributed to the incomplete degradation of polar functional groups in organic matter within low-to-medium maturity intervals, resulting in a temporarily hydrophilic-dominated wettability. This finding corroborates the speculation proposed by Xue et al. (2021) that low TOC shales may exhibit water-wet characteristics due to insufficient oil generation.

In summary, the abundant distribution of organic matter and the considerable variability of TOC content in shale contribute to uncertainties in its wettability. Rocks with high TOC content typically have hydrophobic organic matter that tends to adsorb oil rather than water, resulting in stronger oil-wet characteristics on the rock surface, whereas those with low TOC content are generally dominated by water-wet behavior.

3.3 Reservoir temperature and pressure

Temperature and pressure are regarded as external factors influencing wettability. Variations in reservoir conditions alter the interfacial tensions between water-rock, oil-rock, and oil-water interfaces, consequently affecting wettability (Josh et al., 2012; Zhang et al., 2018). However, several studies have put forward perspectives on how wettability may vary and to what extent it is influenced by temperature and pressure.

Regarding the effect of temperature on wettability, studies have consistently demonstrated that under consistent ambient pressure conditions, measurements of contact angles reveal increased hydrophilicity in shale as temperature rises. This suggests that a generally positive correlation exists between temperature and shale wettability (Xue et al., 2021; Yekeen et al., 2021). In studies of different minerals, contrasting trends in contact angle with temperature were reported for calcite and quartz (Wang and Gupta, 1995). Calcite surfaces

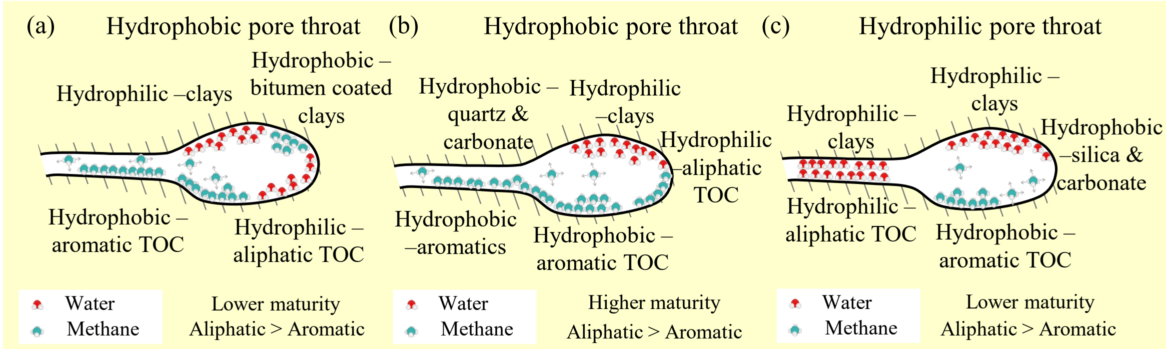

Fig. 4. Schematic diagram of wettability characteristics in shale organic matter pores (Chalmers and Bustin, 2010).

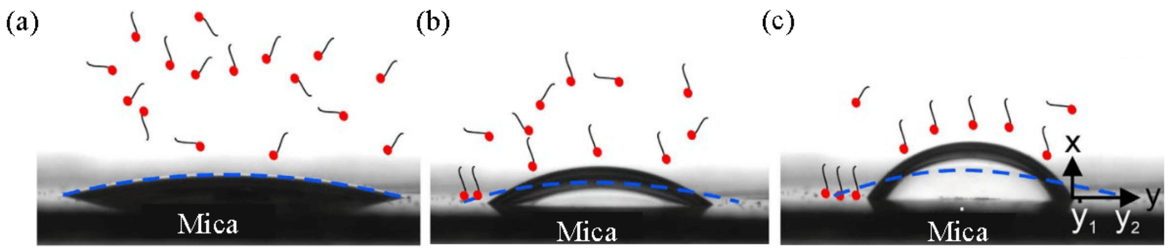

Fig. 5. States of $CaCl_2$ droplet on the surface at (a) 0 s, (b) 5 s and (c) 10 s (Mugele et al., 2015).

were mildly water-wet at room temperature, with the contact angle reaching a minimum near 79 °C. In contrast, quartz surfaces were strongly water-wet under ambient conditions, yet they exhibited a non-monotonic response: The contact angle peaked around 54 °C and declined to a minimum near 82 °C. Pan et al. (2019) constructed an ideal shale system using clay-coated quartz and observed opposing behaviors: The contact angle of pure quartz increased with temperature, while that of clay-coated quartz decreased. Furthermore, Arif et al. (2017) demonstrated that temperature enhanced water-wettability in medium- and high-TOC shales but reduced it in low-TOC shales, indicating that the thermal response of wettability is highly dependent on rock composition. These findings highlight the need for further investigations to clarify the underlying mechanisms governing temperature and composition-dependent wettability behavior.

Regarding the influence of pressure on wettability, some researchers believe that increasing pressure enhances the oil-wetness of shale, while lower pressure conditions tend to be more water-wet (Mirchi et al., 2015; Roshan et al., 2016). Similarly, Pan et al. (2019) observed that with increasing pressure, the water contact angles of pure quartz and quartz coated with kaolinite or montmorillonite increased, reflecting diminished water-wettability. The same increase in water contact angle with pressure was observed in shale-CO_2-saline systems, indicating enhanced oil-wettability (Yekeen et al., 2021). Furthermore, some researchers suggested that rising pressure disrupts the water film on the reservoir surface, leading to decreased water-wettability (Xue et al., 2021). Overall, the academic community holds a relatively consistent view that pressure increase tends to reduce water-wettability and enhance oil-wettability on shale surfaces.

In summary, existing studies generally agree that increasing temperature usually makes shale more water-wet, while increasing pressure tends to make the shale surface more oil-wet. However, there remains a controversy regarding the wettability changes of specific minerals. Thus, future studies should focus on samples with varying mineral compositions to precisely assess the impact of temperature and pressure on wettability. Besides, wettability is typically measured at ambient temperature and pressure, markedly deviating from the *in-situ* conditions of shale reservoirs and unable to replicate their high-temperature and high-pressure environments. Therefore, preserving the *in-situ* state of porous media and experimental fluids is crucial for accurately measuring shale wettability.

3.4 Fluid properties

A considerable amount of research has been devoted to examining the influence of fluid characteristics on wettability. It is generally believed that with increasing salinity, the sample's hydrophilicity gradually decreases. Monovalent and divalent cations affect shale wettability by adsorbing onto the shale surface and interacting with the surface polarity, as shown in Fig. 5 (Mugele et al., 2015; Saputra et al., 2022). Compared to monovalent cations, divalent cations strongly adsorb onto clay surfaces, further reducing hydrophilicity (Pan et al., 2018; Shi et al., 2025).

The influence of fluid ions on shale wettability has been widely studied. In oil-brine systems of varying salinities, contact angle tests on shale minerals showed that beyond a certain threshold, oil contact angles decreased, indicating stronger oil-wettability (Xie et al., 2015). Experiments demonstrated that ions such as Na^+ and Ca^{2+} modify the rock-oil-water interfacial behavior, and low-salinity injection can shift surfaces from oil-wet to neutral-wet, reducing adhesion and

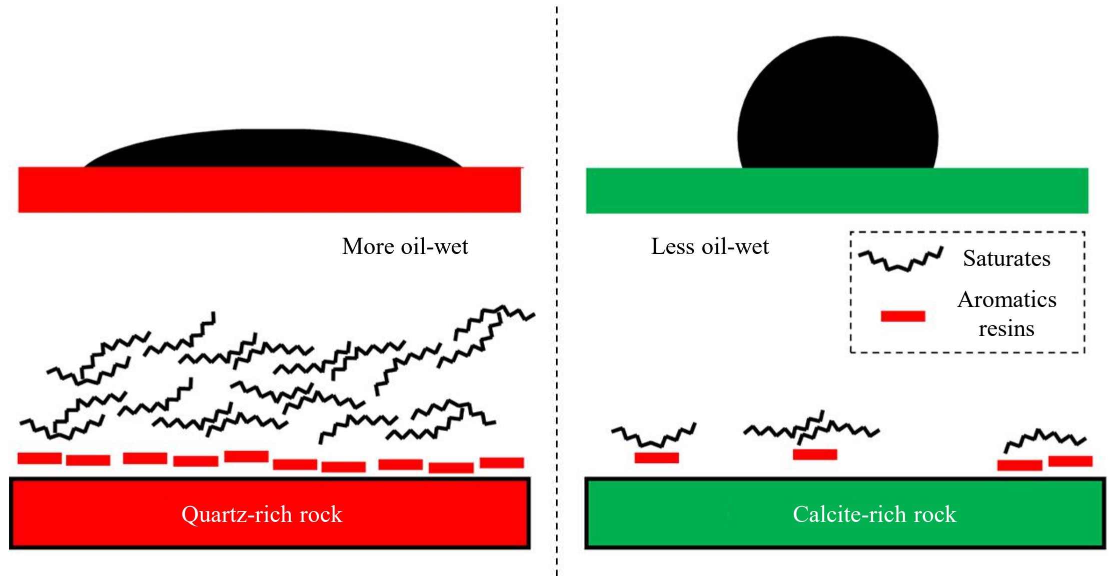

Fig. 6. Oil-wetting mechanism for shale oil/brine/rock systems (Saputra et al., 2022).

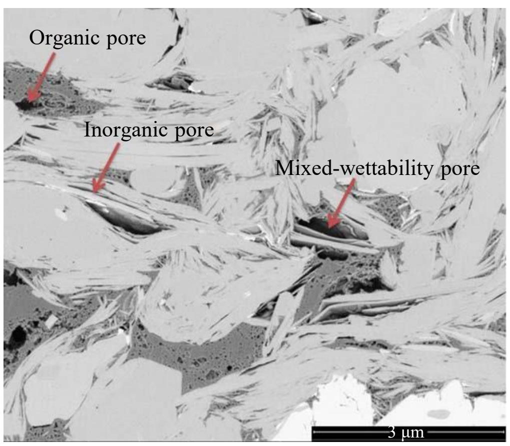

Fig. 7. Pore distribution and wettability interfaces in shale (Tinni et al., 2017).

enhancing hydrophilicity (Yang et al., 2020). Contradictory trends have also been noted: Brine contact angles first increased and then declined with rising $CaCl_2$ concentration (Xue et al., 2021). In shale-oil-brine systems, salinity reduced oil contact angles, whereas in shale-CO_2-brine systems, it increased water contact angles (Yekeen et al., 2021).

The polar components and various carbon chain structures in oil also influence rock surface wettability. When asphaltenes in oil become less soluble, they precipitate on the surface. An increase in the concentration of lighter oil components promoted asphaltene precipitation, enhancing the adhesion of lighter oil to the rock surface (Al-Maamari and Buckley, 2003).The influence of saturates, aromatics, resins, and asphaltenes on rock wettability was investigated by Saputra et al. (2022), finding that higher levels of aromatics, resins and asphaltenes increased the adsorption of oil components on the rock surface, enhancing its oil-wet character. Conversely, oil containing lower levels of aromatics, resins and asphaltenes but higher saturates exhibited reduced initial adsorption on the surface, leading to weaker oil-wettability. Higher brine salinity increases the polarity of the aqueous phase, forcing more adsorption of aromatic and resin components from the oil onto the rock surface, thereby enhancing oil-wetness, as shown in Fig. 6. Some researchers observed that higher-carbon-number alkanes have greater affinity for mineral surfaces than lower-carbon-number alkanes, with the mineral and oil affinity and the contact angle increasing alongside carbon number (Xue et al., 2021). Compared with alkanes, aromatics have greater mineral affinity, and polar components of oil display stronger interactions with mineral surfaces than nonpolar components.

In summary, increasing salinity enhances the oil-wet nature of rock surfaces, and the oil composition largely controls the degree of oil-wet behavior in the oil-water-rock system. Furthermore, the presence of more unsaturated hydrocarbons enhances the oil-wet character of the surface. As demonstrated by these findings, research on the interaction between fluid properties and rock surfaces provides valuable guidance for reservoir wettability studies.

3.5 Pore structure

Unlike the influencing factors mentioned earlier, pore structure mainly affects the overall wettability characterization of shale. Conventional reservoir rocks typically have larger pore sizes and are dominated by inorganic pores. In contrast, shale samples exhibit more developed nanoscale organic pores, along with some inorganic pores. Shale exhibits more complex wettability due to the coexistence of oil-wet and water-wet pores, as shown in Fig. 7. In addition, variations in the connectivity between oil-bearing and water-bearing pores can cause differences in the overall wettability of shale (Loucks et al., 2009; Clarkson et al., 2013).

The wettability of different shale formations varies significantly. Marine Longmaxi Formation samples showed stronger oil-wettability, whereas continental Yan'an Formation samples were more water-wet (Gao and Hu, 2018). The latter shale, with poorly developed organic pores and weaker compaction, exhibited numerous water-wet inorganic pores, while the former shale, with higher maturity and compacted inorganic pores, had oil-wet organic pores and exhibited stronger oil-wettability. Detailed analysis of the former shale further revealed that sample Z1 with TOC 2.6% contained organic pores mostly smaller than 10 nm alongside water-wet inorganic pores, whereas sample Z4 with TOC 2.7% possessed oil-wet pore networks formed by organic pores and microfractures, yielding higher overall oil-wettability (Gao et al., 2020). Pore connectivity also plays a critical role: In Woodford shale cores from Texas, contact angle and spontaneous imbibition tests indicated weak water-wet but strong oil-wet behavior, with imbibition slopes of 0.25 for water and 0.5 for oil. Tracer imbibition and high-pressure intrusion further confirmed the presence of well-connected hydrophobic organic pores, producing a strongly oil-wet system (Kibria et al., 2018).

In summary, wettability in shale is largely governed by the development of various pore types, and the complex development of inorganic and organic pores leads to diverse wettability characteristics. Organic pore connectivity is controlled by organic matter content and thermal maturity, whereas inorganic pore connectivity depends on mineral composition and diagenetic processes, such as compaction, cementation and dissolution. These factors govern reservoir wettability simultaneously.

4. Conclusions and outlook

The accurate characterization of shale-reservoir wettability is challenging because of the complex mineral compositions, high organic content, and intricate pore structures. This paper systematically reviews the characteristics, applicability, advantages, and limitations of existing methods for evaluating shale wettability. It is established that, to obtain accurate wettability assessments, it is essential to integrate results from multiple experimental approaches. Furthermore, research shows that shale wettability is controlled by multiple factors. First, the heterogeneous distribution of hydrophilic minerals and hydrophobic organic matter results in mixed wettability. Second, TOC content and thermal maturity influence the development of hydrophobic organic pores. Third, increasing temperature and decreasing pressure enhance hydrophilic tendencies. Fourth, highly mineralized fluids and asphaltic components in crude oil promote hydrophobicity. Ultimately, the connectivity of organic and inorganic pore networks determines the distribution of wettability phases. While it has been widely reported that shale exhibits mixed-wettability behavior, findings remain contentious due to variations in the sample handling protocols and experimental artifacts. As a result, investigating shale wettability remains a complex and dynamic task, requiring research designs adapted to particular goals, sample characteristics and experimental conditions. Considering these issues, the following recommendations are proposed:

1) Further improve the standards of shale reservoir wettability evaluation. To address shale heterogeneity, develop a multi-indicator, multi-scale integrated experimental evaluation system combining contact angle, spontaneous imbibition index, and NMR techniques.
2) Integrate multi-scale experiments and simulation technologies to restore reservoir *in-situ* conditions and quantify the influence of various factors on wettability. Future research can entail the integration of digital rock modeling with machine learning techniques to predict rock surface wettability. Such combined approach can hold promise to enable the cost-effective yet highly accurate assessment of shale wettability.
3) Given that enhancing oil recovery is the objective of wettability studies, future work should prioritize several key areas, including (i) addressing the challenges posed by low-permeability reservoirs, (ii) studying the selective adsorption behavior of surfactants in mixed-wet shale, and (iii) quantitatively assessing how wettability alterations affect the recovery efficiency. The latter can be achieved by integrating fracturing fluid flowback data with production performance metrics.

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Conflict of interest

The authors declare no competing interest.

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