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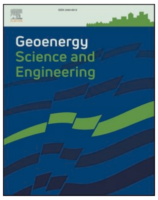

Acidizing of deep carbonate reservoirs to reduce breakdown pressure: A review

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ABSTRACT

Acid treatments aimed at reducing formation breakdown pressure are becoming increasingly popular in stimulating deep and ultra-deep geothermal and natural gas reservoirs, where high pumping pressures are typically required for fracturing. This technique effectively reduces surface pumping pressures, ensuring safe operations. Through multiscale experiments and mechanistic analysis, this study reveals the fundamental mechanisms underlying breakdown pressure reduction via acid preconditioning. Key findings include: (1) High breakdown pressures arise from high in-situ stress, low porosity and permeability, and engineering contamination. (2) Acid-induced mineral dissolution triggers dual effects-pore structure evolution enhances reservoir permeability (facilitating subsequent fracturing fluid imbibition and pressure transmission), while mechanical property degradation substantially weakens rock resistance to fracturing. (3) Comparative analysis of HCl, organic acids, and chelating agents demonstrates that high-temperature reservoirs benefit from low-corrosivity chelating agents (e.g., GLDA) or organic acid systems combined with low-concentration HCl, achieving optimal dissolution efficiency while ensuring wellbore integrity. (4) A multiscale laboratory evaluation framework was established to integrate experimental data for optimizing acid formulations and post-acid fracturing strategies. This paper provides mechanistic insights, acid system selection criteria, and experimental methodologies for breakdown pressure reduction in deep carbonate reservoirs, offering significant engineering value for achieving safe and efficient reservoir stimulation.

1. Introduction

In the face of the severe consequences of global warming, the restriction of carbon emissions and the achievement of the "Carbon Peaking and Carbon Neutrality" goals have emerged as an urgent priority (Chen et al., 2021, 2022; Huang et al., 2022; Yang et al., 2023; Zhao et al., 2022). Within this context, geothermal energy and natural gas emerge as pivotal elements in the energy transition (Liu et al., 2024e; Wu and Li, 2020). Carbonate reservoir, an important contributor for geo-resources, is one of the major targeted reservoirs for geothermal energy and natural gas (Kaminskaite-Baranauskiene et al., 2023; Kolawole et al., 2022; Malki et al., 2023; Zhou et al., 2021). Although high porosity and permeability generally can be found in conventional carbonate reservoirs, with complex fractures or vugs, the matrix porosity and permeability is often extremely low in deep and ultra-deep carbonate reservoirs (Chen et al., 2023). Therefore, stimulation technologies are often needed to improve the reservoir flow condition or even to create the reservoir like the case of Enhanced Geothermal System (EGS) (Kaminskaite-Baranauskiene et al., 2023; Lu, 2018; Wu and Li, 2020). Fracturing is the most popular technology to create complex fracture networks and has been demonstrated to be effective (Chen et al., 2025; Liu et al., 2024b). However, the extremely high breakdown pressure, defined as the peak pressure reached during hydraulic stimulation that indicates fractures are initiated to allow fluids to be injected, are often

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encountered in deep and ultra-deep reservoirs (Detournay and Carbonell, 1997; Sampath et al., 2018).

Deep reservoirs typically require higher pumping pressure to initiate and propagate fractures (Alameedy et al., 2022; Li et al., 2024). This imposes greater demands on the power and load-bearing capacity of pumping equipment, often exceeding the maximum pumping pressure the equipment can provide, thereby posing substantial risks of operation failures (Guo et al., 2020a). One of the examples is the well Pengshen 6, the deepest vertical well in Asia with a depth of 9026 m (Xiujian et al., 2024). The fracturing test demonstrated that failure to implement a pre-treatment to the reservoir led to high pumping pressures, which surpassed the equipment's pressure limitations, during hydraulic stimulation. AlTammar et al. (2020) also reported a field case where three fracturing attempts failed due to high peak bottom-hole pressure up to approximately 124 MPa, which exceeded the limit of the pumping equipment. This often led to an unsuccessful project, incurring extra costs for the operator due to non-productive time and financial expenditures. Additionally, fracturing operations with such high pumping pressures can potentially induce seismic activity, which is a major concern when developing EGS worldwide (Schultz et al., 2020). Therefore, a pre-treatment to effectively reduce the reservoir's breakdown pressure, thuslowering the pumping pressure, is crucial for ensuring efficient and safe operations.

Many technologies have been proposed to reduce reservoir breakdown pressure, such as acidizing (Chen et al., 2023; Guo et al., 2020b; Li et al., 2021c, 2024; Zhang et al., 2024b), optimizing perforation parameters (Ma et al., 2024; Zhang et al., 2024a), cyclic fracturing (Diaz et al., 2020; Patel et al., 2017; Tariq et al., 2020b), and injecting endothermic fluids (Almarri et al., 2022; Enayatpour et al., 2019; Khan et al., 2024b; Wu et al., 2021). Optimization of perforating parameters has become a necessary procedure prior to fracturing operations. However, the optimization of these parameters may necessitate the support of accurate geological data along with extensive complex simulation calculations (Ma et al., 2024; Zhang et al., 2024a). Cyclic fracturing has been utilized for the reduction of formation breakdown pressure. However, fatigue limit up to 75 %–70 % of the monotonic breakdown pressure, below which cyclic fracturing has no effects, has been observed in experiments and field tests (Cerfontaine and Collin, 2018; Wang et al., 2024). Injecting endothermic fluid technology has demonstrated potential in effectively reducing breakdown pressure in laboratory experiments tests. However, the feasibility of this approach needs further assessment (Khan et al., 2024a; Li et al., 2022). Acidizing technology, due to its easy operations, low cost, and the limited pumping requirements of the equipment, is extensively used to reduce the breakdown pressures in deep reservoirs (Al-Shargabi et al., 2023; Li et al., 2021b). Acid is injected into the formation at a low pump pressure to dissolve the minerals and cements, leading to the creation of larger pores and the enlargement of existing fractures (Jia et al., 2023; Zhang et al., 2020d). This technology, one of the oldest in the industry, has been used to boost well productivity for over a century, with the first oil well acid treatment performed in 1895 (Portier et al., 2009).

However, the performance of acidizing technology varies significantly across carbonate reservoirs at different depths. Conventional carbonate reservoirs are typically buried at depths shallower than 3500 m (Xu et al., 2020). For these reservoirs, acid fluids generally exhibit stable properties and relatively controllable risks of tubing corrosion. In contrast, deep carbonate reservoirs (>5000 m) face unique challenges in acidizing pretreatment due to the high temperature (>150 °C), high pressure (>60 MPa), and the complex geological condition (e.g. strong heterogeneity, low porosity, and low permeability) (Chen et al., 2025; Qin et al., 2024). The intricate geological settings, heterogeneous fracture-cave systems, and diverse mineral compositions in deep reservoirs significantly complicate the acid-induced reduction of reservoir breakdown pressure (Correia da Silva et al., 2024; Jia et al., 2024). Furthermore, high-temperature conditions impose stricter requirements on acid stability, exacerbate acid volatility and corrosivity, and increase the risks of equipment damage and the costs of operations (Du et al., 2024; Sui et al., 2022).

To address these challenges, researchers have made significant progress in developing high-temperature-resistant acid systems and investigating factors influencing acidizing effectiveness through experimental evaluations (Alameedy et al., 2023; Du et al., 2024; Liu et al., 2025; Sui et al., 2022; Zhang et al., 2020a). However, the mechanisms underlying acidizing-induced breakdown pressure reduction remain poorly systematized in existing literature. Compared to previous studies, a comprehensive review will help clarify the operational mechanisms of acidizing technology, identify gaps between laboratory evaluations and field applications, and provide insights for optimizing acid systems to enhance reservoir stimulation efficiency. This effort will contribute substantially to both theoretical advancements and technological innovations.

Therefore, this paper provides a comprehensive summary of the mechanisms by which acidizing reduces the breakdown pressures. The causes of high formation breakdown pressures are introduced, followed by a review on the mechanisms of acid stimulation using various acids, and a comparison of the effectiveness of different acid fluid systems in reducing breakdown pressures. Additionally, the paper focuses on laboratory evaluation methods to evaluate acidizing performance, enabling the optimization of acid fluid systems and quantification of changes in rock pore structure and mechanical properties after acidizing. Building on this, we propose innovative directions for acidizing-driven breakdown pressure reduction by integrating the geological and engineering characteristics of deep reservoirs. Additionally, this paper provides critical insights for optimizing fracturing designs in ultra-deep carbonate reservoirs.

2. Causes of high breakdown pressure in deep carbonate reservoirs

In this section, the key factors influencing reservoir breakdown pressure are identified, thus providing basic information to design optimal acidizing strategies.

2.1. In-situ stress

The in-situ stress system typically encompasses gravity stress and tectonic stress (Yin et al., 2023). In-situ stress is often represented as three principal stresses (Hossain et al., 2000). These include the vertical stress σ_v, originating from the weight of the overlying rock, and the horizontal stress, mainly resulting from geological deformation (Chen et al., 2018; Piao et al., 2023). Notably, the horizontal stress exhibits a maximum value σ_H and a minimum value σ_h along two mutually orthogonal horizontal directions (Zhang et al., 2023b). Fig. 1 illustrates the in-situ stress through stereoscopic projection, revealing the σ_v, σ_H, and σ_h. The stress state of the reservoir is a result of the combination of vertical and horizontal stresses, rock mechanical properties, porosity, pore pressure, and other factors (Yin et al., 2023).

According to the breakdown pressure model based on tensile strength proposed by Hubbert and Willis (1957), described in Eq. (1), the minimum principal stress, maximum horizontal stress, pore pressure, and rock strength are the key factors affecting the breakdown pressure. And the strong tectonic stress is one of the major reasons to cause high horizontal stresses. In deep reservoir, the vertical stress is commonly high (Brown and Hoek, 1978; Taherynia et al., 2016). Such high vertical stress results in structural changes of the pore space of rock, e.g. compaction, consolidation, cementation and stylolitisation (Rashid et al., 2017). These structure changes can then reduce the porosity and permeability of the porous rock while enhancing the mechanical strength. In addition, the strong tectonic stress is one of the major reasons to cause high horizontal deviatoric stresses. Thus, high horizontal deviatoric stress and tight reservoirs (high rock strength) can lead to abnormally high formation breakdown pressure and fracture

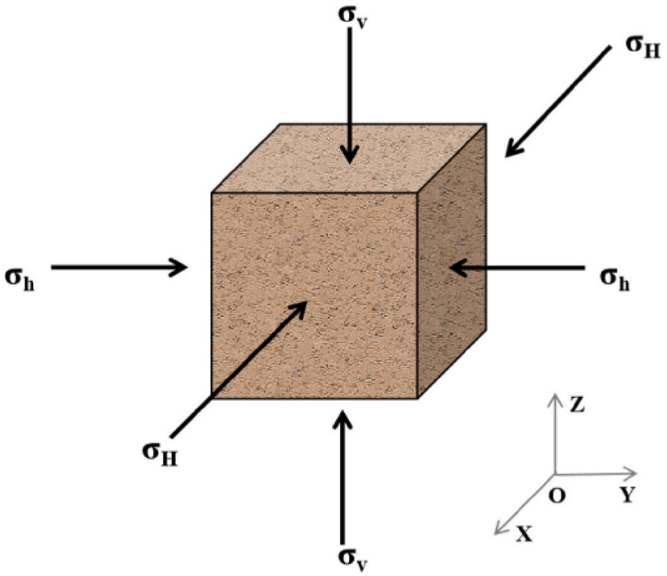

Fig. 1. In-situ stress acting on a unit of rock medium.

propagation pressure (Zhang et al., 2020c).

$$P_b = 3\sigma_h - \sigma_H + \sigma_T - P_0 \tag{1}$$

where P_b is the breakdown/initiation pressure, P_0 is the pore pressure, σ_h is minimum horizontal principal stress, σ_H is maximum horizontal principal stress and σ_T is the tensile strength of the rock.

2.2. Rocks properties

The intrinsic rock properties also contribute to the high breakdown pressure. The heterogeneity of reservoir rocks is a key factor affecting the breakdown pressure (Ehrenberg and Nadeau, 2005; Hu et al., 2020).

The heterogeneity of reservoir rocks is primarily manifested in the size, shape, distribution of mineral particles, and the pore structure. These characteristics vary due to the vertical and lateral changes in sedimentary microfacies (Ghadami et al., 2015; Malki et al., 2023; Yang et al., 2015) and the effects of subsequent diagenetic processes (Hu et al., 2020; Ng and Santamarina, 2023; Pei et al., 2022; Tian et al., 2019; Zhao et al., 2013), leading to significant differences in the rock properties in the spatial distribution. The heterogeneity of the pore structure results in varying pore sizes and pore dispersion, thereby reducing the rock's physical properties and affecting the flow of fluids within the rock and the transmission of pressure. Sun et al. (2019) conducted micro-characterization observations on two thin sections (C1, C2) from different positions of the same core sample (Fig. 2). The study found that the pore distribution in the two thin sections was uneven. This complex pore size distribution and heterogeneity of the reservoir rock, thereby affecting the transmission of pressure. In more compact local areas, there are finer particles and some calcite cement components. High-cemented rocks possess higher strength and stiffness, enabling them to withstand greater external forces without fracturing. For tight cores, the closely packed particles reduce the rock's porosity. Numerous studies have indicated that there exists a broad inverse relationship between rock strength and porosity (McBeck et al., 2019; Palchik, 1999), thus making it more difficult to fracture under external forces. For deep carbonate reservoirs, the mineral particles within the reservoir rock are typically tightly packed and exhibit high cementation due to the influence of vertical stress. Therefore, during the fracturing process, rocks with closely packed mineral particles and a higher degree of cementation require a higher pumping pressure to form effective fractures. Therefore, high pumping pressures are may required during fracturing process of deep carbonate reservoirs to create effective fractures.

2.3. Engineering operation pollution

The contamination of the reservoir caused by drilling, perforation and other operations before fracturing can also increase the breakdown pressure of reservoir to a certain extent.

The abnormal increase in breakdown pressure caused by drilling is primarily attributed to the contamination of the reservoir due to the loss of drilling fluid. Solid particles from the drilling fluid infiltrate the micro-fractures developed in the reservoir rocks, resulting in formation damage (Cai et al., 2010; Jiang et al., 2022b; Xu et al., 2018). This contamination reduces the permeability of rocks near the wellbore, hindering the infiltration of fracturing fluid into the formation during hydraulic fracturing. Particularly, the hydrostatic pressure difference between the drilling fluid and the reservoir fluid can result in the formation of a filter cake on the wellbore wall. This thin, impermeable layer, characterized by its low permeability, increases the breakdown pressure of deep formations and inhibits the propagation of fractures (Feng et al., 2016; Nunes et al., 2010; Tariq et al., 2021b).

Perforation is an essential pathway for fluid to flow into the wellbore. And it also plays a role in regulating the breakdown pressure value (Abass et al., 1996; Behrmann and Nolte, 1998; Shi et al., 2021; Veeken et al., 1989; Wang et al., 2022; Wei et al., 2020; Zhang et al., 2018). The primary perforation parameters influencing breakdown pressure include perforation density, perforation azimuth, and perforation depth (Behrmann and Nolte, 1998). Breakdown pressure exhibits a phased variation with increasing perforation density, and the overall trend indicates a reduction as density increases (Veeken et al., 1989; Wei et al., 2020). However, the breakdown pressure does not decrease linearly with the increase in perforation density (Liu et al., 2015). Therefore, the appropriate perforation density should be selected based on the characteristics of the reservoir (Zhang et al., 2018). Perforation azimuth refers to the orientation of the perforation tunnels. As the perforation azimuth angle increases within the range of 0°–90°, the number of perforation holes on the same plane decreases. This decrease impedes the connectivity of fractures between perforations, resulting in an increase in breakdown pressure (Abass et al., 1996; Chen et al., 2010). As for perforation depth, an increase in perforation depth facilitates the reorientation of fractures from the initial perforation plane and reduces breakdown pressure (Zhang et al., 2018). In summary, the impact of perforation on breakdown pressure is complex, influenced by multiple factors, including perforation density, azimuth, and depth. To minimize formation breakdown pressure, perforation parameters should be appropriately adjusted based on the wellbore's specific conditions and the operational constraints of the perforation equipment.

2.4. Discussion

The high breakdown pressure in deep and ultra-deep carbonate reservoirs is the result of combined geological and engineering factors. Geologically, the high horizontal deviatoric stress and high vertical stress caused by reservoir depth are key contributors to the high breakdown pressures. Additionally, the heterogeneity of carbonate rocks results in uneven distribution of pore structures, significantly affecting breakdown pressure. From an engineering perspective, drilling fluid contamination and filter cake formation increase formation breakdown pressure and hinder fracture propagation. Moreover, improper perforation parameters further exacerbate the increase in breakdown pressure. Table 1 summarizes the potential causes of high fracture pressure in deep carbonate reservoirs.

3. Acidizing technology

Based on the research presented in the previous section, high reservoir breakdown pressure is mainly caused by high deviatoric stress, low

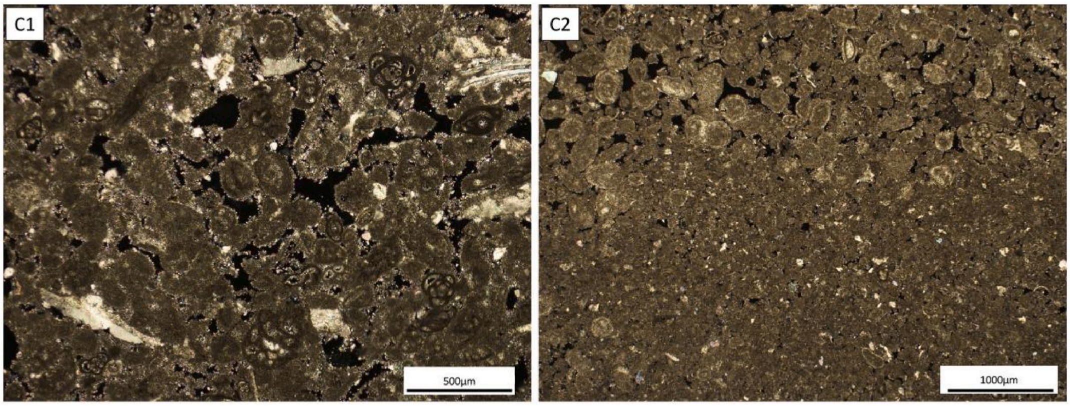

Fig. 2. Thin sections showing some poikilotopic calcite spar enveloping peloids and other intraclasts in C1, and local finer grains and more compacted area in C2 (Sun et al., 2019)[1].

porosity and permeability, high rock strength, and damage to the reservoir caused by engineering operations. This section introduces the mechanism of acidizing technology used to reduce reservoir breakdown pressure, typically for deep carbonate reservoirs.

3.1. *Mechanism of acidizing to reduce breakdown pressure*

Acidizing technology is an effective method for reducing breakdown pressure. The mechanism mainly involve the chemical reaction between rock and acid (Liu and Mostaghimi, 2017). Acid treatment dissolves carbonate minerals (such as calcite and dolomite) in carbonate reservoir rocks, leading to a reduced rock strength and altered pore structure, thus affecting the breakdown pressure.

Table 1
Causes of high breakdown pressure.

Causes	Specific Causes	Impact Mechanism
In-situ stress	Increase in overburden pressure and compaction	Vertical stress increases, leading to higher pressure on rocks. Deep carbonate rocks undergo intense compaction, reducing porosity and increasing density, thus raising rock mechanical strength
	Tectonic compression	Intense horizontal tectonic stress increases the horizontal principal stress, raising breakdown pressure
Rocks properties	Tight packing of mineral particles	Tightly packed mineral particles in deep carbonate rocks reduce porosity and increase rock strength, leading to higher breakdown pressure
	Lithological heterogeneity	Uneven pore structure reduces rock physical properties, affecting fluid flow and pressure transmission within the rock, which influences breakdown pressure.
	Cementation	Cementation fills pores, increasing rock strength and reducing permeability, thereby raising breakdown pressure
Engineering operation pollution	Drilling fluid contamination	Drilling fluid invasion increases pore pressure or alters rock mechanical properties, leading to higher breakdown pressure
	Improper perforation parameters	Poor perforation design causes inefficient fluid flow or localized stress concentration, increasing breakdown pressure

3.1.1. *Acid-rock reaction*

Carbonate rocks mainly consist of calcite ($CaCO_3$) and dolomite ($CaMg(CO_3)_2$), and may additionally contain minerals like quartz, clay minerals, and gypsum. These minerals exhibit significant differences in the capability of reacting with acids. Among those minerals, calcite and dolomite can easily react with HCl (Mou et al., 2024; Shokri et al., 2024). In deep reservoirs, where high temperatures (> 150 °C) is commonly encountered, the dolomite and limestone exhibit similar reaction rate (Aljawad et al., 2021; Mou et al., 2024). As shown in Fig. 3, the reaction between acid and carbonate rock typically comprises three processes: a) hydrogen ions (H^+) transfers to the rock surface. b) the adsorbed H^+ reacts with minerals on the rock surface (surface reaction process). c) the reaction products leave the rock surface through mass transfer (mass transfer process). The reaction between the acid solution and carbonate rock on the rock surface is a surface reaction. H^+ in the acid solution chemically react with carbonate ions (CO_3^{2-}) in carbonate rocks, producing soluble salts and carbon dioxide (CO_2) (Sayed et al., 2021). During the acidizing treatment, the acid solution dissolves carbonate minerals in the rock, releasing soluble calcium and magnesium ions, leading to the expansion of pore space within the rock. In deep high-temperature environments, both calcite and dolomite are controlled by mass transfer process (Dong et al., 2018; Lund et al., 1973). The primary chemical reactions between calcite or dolomite and the acids (HCl and organic acid) (Garrouch and Jennings, 2017) are represented by Equations (2) and (3).

$$CaCO_3 + 2H^+ \rightarrow Ca^{2+} + H_2O + CO_2\uparrow \tag{2}$$

$$CaMg(CO_3)_2 + 4H^+ \rightarrow Ca^{2+} + Mg^{2+} + 2H_2O + 2CO_2\uparrow \tag{3}$$

Unlike HCl and organic acids, chelating agents react with carbonate to form stable complexes with metal ions. This process involves the coordination of one or more carboxyl group within the chelating agent to encapsulate metal ions, resulting in the formation of water-soluble and stable metal-ligand complexes (Rabie et al., 2011). The reaction between chelating agents and carbonate minerals are described by Eq. (4), Eq. (5), Eq. (6) (Fredd and Fogler, 1998; Li et al., 2023; Tariq et al., 2021a). H_nY represents the typical structure of chelating agents, where n represents the number of carboxylic acid groups. Y^{n-} represents the fully ionized form of chelating agents. The interaction between chelating agents and carbonate rocks is influenced by a variety of factors. Specifically, increasing temperature significantly increases the total dissolution rate (Rabie et al., 2011). Moreover, in contrast to the high corrosivity of inorganic acids at high temperatures, the low corrosivity exhibited by chelating agents renders them more preferable for application in high-temperature deep reservoirs (Li et al., 2023). In addition,

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[1] Cited from Sun et al. (2019) with permission from Elsevier. License No.: 5895130684300.

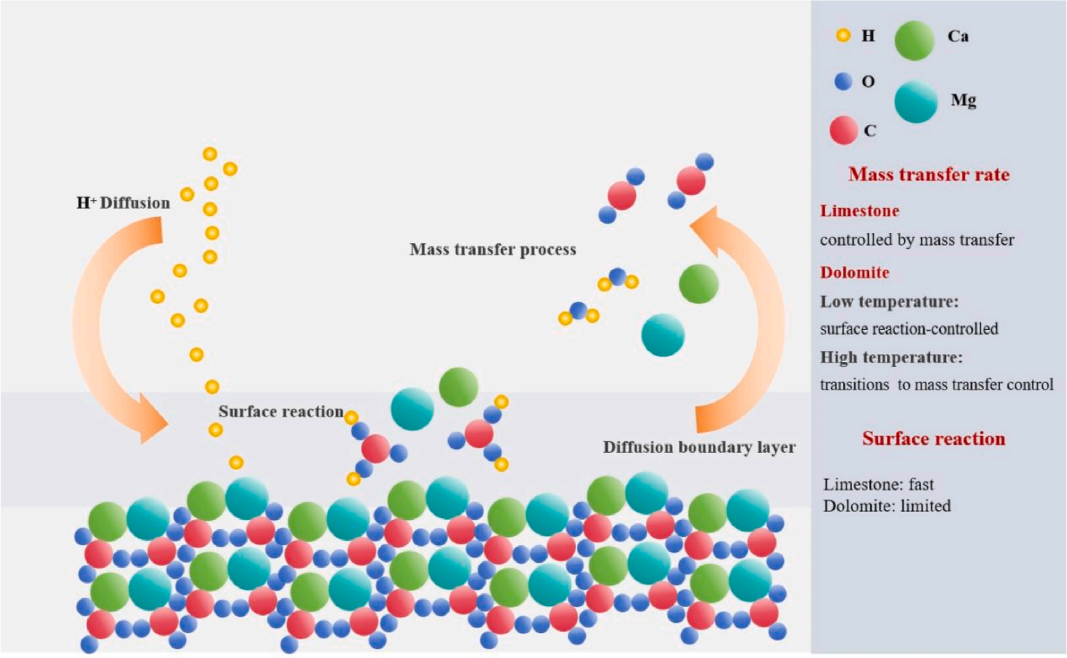

Fig. 3. Mechanism of acid-rock reaction.

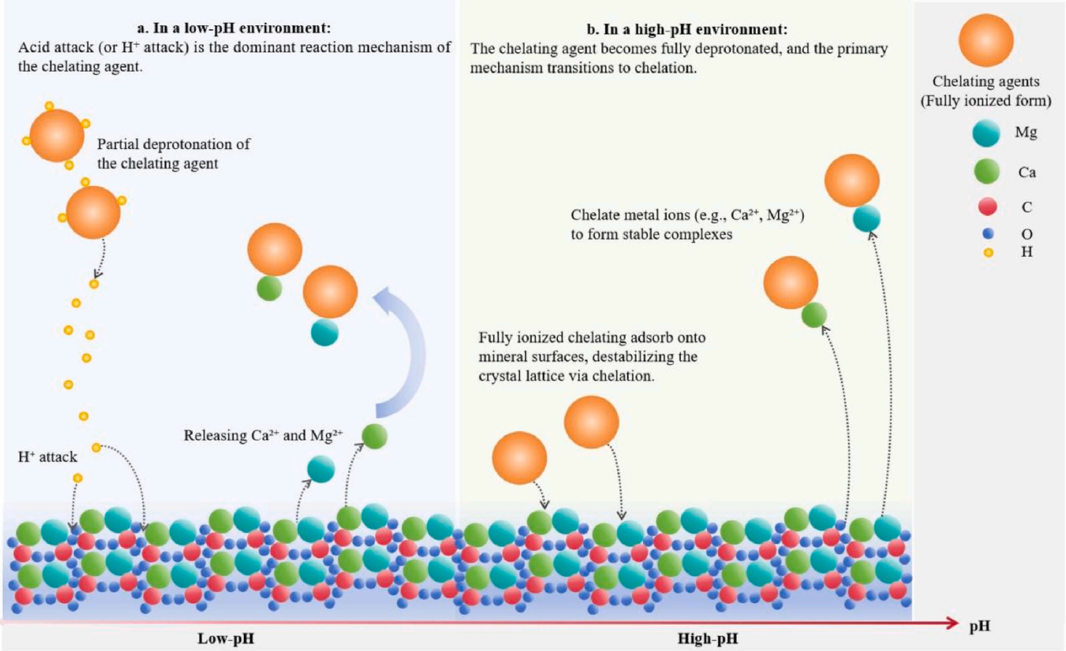

Fig. 4. Mechanism of chelating agent assisted dissolution.

the reaction between chelating agents and carbonate rocks is largely affected by the pH value of the solution (Fig. 4). In a low-pH environment, acid attack (or H^+ attack) is the dominant reaction mechanism of the chelating agent. At this pH level, the chelating agent functions as a polyprotic acid, with its hydrogen ions (H^+) attacking the carbonate components on the surface, thereby causing calcium to dissolve in the solution as free ions. Conversely, in a high-pH environment, the chelating agent becomes fully deprotonated, and the primary mechanism is changed to chelation. Under these conditions, the chelating agent targets the calcium sites, grabs the ions, and forms a stable complex (Almubarak et al., 2021; Li et al., 2023; Rabie et al., 2011; Tariq et al., 2021a). Tariq et al. (2021a) discovered that most chelating agents are in a fully ionized state at pH values above 8.5 (Y^{4-}). In this environment the combined effects of the chelating agent's ionized form (chelation of calcium ions in carbonate rocks (Eq. (5)) and the H^+ attack generated by chelating agent ionization (Eq. (6))can result in a high reaction rate in the solution. However, chelating agents are typically used to act on carbonate minerals in low pH environments. And research has shown that H^+ in the environment can help chelating agents extract metal ions from mineral surfaces, increasing dissolution rates (Fredd and Fogler, 1998; Hassan and Al-Hashim, 2020).

$$H_nY \leftrightarrow H_{n-1}Y^- + H^+ \leftrightarrow H_{n-2}Y^{2-} + 2H^+ \leftrightarrow \cdots \leftrightarrow Y^{n-} + nH^+ \tag{4}$$

$$Y^{n-} + CaCO_3 \rightarrow CaY^{2-n} + CO_3^{2-} \tag{5}$$

$$H^+ + CaCO_3 \rightarrow Ca^{2+} + HCO_3^- \tag{6}$$

3.1.2. Pore structure evolution and mechanical property alteration

The chemical dissolution of rocks by acid plays a critical role in changing the physical properties. This process not only modifies the chemical composition of the rocks but also significantly increases the porosity and reduces the mechanical strength.

Acid fluids infiltrate the rock matrix through fractures and pores, initiating chemical reactions along boundaries between mineral grains and crystal interfaces. The localized dissolution of minerals weakens the contact strength between grains, resulting in reduction in the mechanical strength and increase in the porosity, which can help alleviate stress concentrations (Zeng et al., 2024). Also, the dissolution of reservoir minerals can enhance the permeability, which is primarily influenced by pore size and interconnectivity. In addition, as pore size increases, reduced capillary forces can also facilitate fluid flow. However, due to limited connectivity between isolated pores, permeability may not improve significantly during the initial stages of acid treatment. With continued pore enlargement and the eventual connection of isolated pores, permeability exhibits a nonlinear improvement (Jiang et al., 2022a; Lovetskii and Selyakov, 1984). Overall, mineral dissolution increases the pore space and connects isolated pores, thus significantly improving the permeability of carbonate rocks (Liu et al., 2019). In addition, acid not only dissolves minerals within the matrix but also removes obstructions, such as drilling mud and acid-soluble scale or debris, from pore spaces, natural fractures, and perforation holes in the near-wellbore region. This further contributes to the overall improvement in reservoir permeability. An increase in reservoir permeability will facilitate the seepage of fracturing fluid into the rock pores(Wang et al., 2022; Zhou et al., 2020). And according to Eq. (1), this will be conducive to the reduction of reservoir breakdown pressure.

The chemical dissolution of rock by acid can also largely changes rock mechanical properties, e.g. the elastic modulus, Poisson's ratio, and rock strengths (Parandeh et al., 2023). The acidizing process leads to the dissolution of rock minerals, weakening of the binding forces between minerals, and an increase in rock porosity. Consequently, this results in a reduction of the mechanical properties, making it more prone to fracturing when exposed to external pressure (Lai et al., 2022; Liu and Mostaghimi, 2017; Mustafa et al., 2022; Nguyen et al., 2011; Zhang et al., 2020a). Alameedy et al. (2022) presented that the mechanical properties of limestone samples changed after acid treatment. The Young's modulus decreased by 26 %–37 %. Gou et al., 2019 also showed that as the contact time with HCl increased, plastic failure gradually became more pronounced, and the elastic modulus and Poisson's ratio significantly decreased. Li et al. (2024) proposed that the changes in elastic modulus, Poisson's ratio and tensile strength are the main controlling factors of breakdown pressure. The mechanical properties of dolomite (elastic modulus, Poisson's ratio, and tensile strength) decrease with increasing acid treatment time and temperature. It is worth noting that regarding the trend of Poisson's ratio changes after acidizing, and the research conclusions of Alameedy et al. (2022) are different from Li et al. (2024) and Gou et al., 2019. The rock samples studied by Li et al. (2024) and Gou et al., 2019 are all dolomite, while the rock samples studied by Alameedy et al. (2022) are limestone.

3.1.3. Mechanisms affecting breakdown pressure

Acidizing impacts reservoir breakdown pressure through two primary mechanisms. First, the reaction between acid and carbonate minerals enlarges pores and enhances permeability, enabling fracturing fluid to penetrate the reservoir more rapidly and uniformly. ((1) Second, acidizing significantly alters rock mechanical properties, particularly reducing elastic modulus and strength, making the rock more prone to fracturing under external stress. These changes not only improve fluid flow capacity but also lower breakdown pressure during fracturing operations, facilitating fracture initiation at lower pumping pressures. While these combined effects are critical for efficient fracturing, they necessitate precise control and risk management in design and execution to ensure safe and effective outcomes.

3.2. Acid system

Choosing an appropriate acid system is crucial to ensure effective acidizing in deep high-temperature carbonate reservoirs, considering the extreme in-situ conditions. Generally, the acid should possess strong dissolution capability with controlled reaction rate, exhibit good compatibility with the reservoir, while not producing any precipitates after reacting with the rock. Additionally, it is crucial to carefully consider factors such as the corrosiveness of the acid fluid on the wellbore strings.

3.2.1. HCl system

HCl is the most commonly used acid in production wells due to its low cost, strong dissolution ability (Chang et al., 2008), and usually does not leave insoluble reaction products. Under high-temperature conditions, high-concentration HCl reacts intensely with carbonate rocks, causing the acid-rock reaction to be primarily confined to the rock's inlet surface (Chang et al., 2022; Huang et al., 2003; Raj and Pal, 2014). Therefore, researchers typically additives such as polymers, emulsifiers, and viscoelastic surfactants (VES) to avoid surface reaction and reduce acid filtration (Sokhanvarian et al., 2021; Sui et al., 2022; Zhang et al., 2023a). However, Lai et al. (2022) conducted acid core flooding experiments on tight limestone using gelled acid and crosslinked acid with a higher viscosity than gelled acid. The results showed that under identical treatment conditions, gelled acid led to a more significant reduction in rock strength and Young's modulus compared to crosslinked acid. This suggests that excessively high acid viscosity may hinder the acid-rock reaction, making it unsuitable for acidizing pretreatment to reduce the breakdown pressure.

For deep carbonate rocks, the injection rate of acid solution is restricted due to relatively low pumping pressure compared to in-situ pore fluid pressure. For the same amount of acid injection, a low injection rate may lead to a longer pipeline contact time, posing a challenge to the safety of downhole tubing. The high temperature conditions exacerbate the safety issues caused by HCl corrosion of down-hole tubing, which also limits the use of high concentration HCl (Liu et al., 2024a). Therefore, for deep high-temperature carbonate reservoirs, safety issues have prompted researchers to develop corrosion inhibitors suitable for ultra-high temperatures or search for HCl alternative acid systems with lower corrosiveness and higher efficiency under high temperature conditions. However, expensive corrosion inhibitors can only protect tubular structures for a short term at high temperatures (Chang et al., 2008). The significant increase in costs caused by the extensive use of corrosion inhibitors is also an issue that cannot be ignored. Therefore, using alternative acid systems may be a better choice. Recently, Mustafa et al., 2021 investigated a new environmentally-friend acid system, developed by Enviroklean Product Development, Inc. and referred as EPDI, short for the company name. This acid system is synthesized by adding HCl to catalytic reagents. The acid produced by synthesis is stronger than HCl, but 50 times less corrosive than HCl at a temperature of 125 °C. At the same time, it is very effective in descaling, environmentally friendly, and biodegradable. However, the use of this environmentally friendly acid under ultra-high temperature (>180 °C) conditions was not mentioned.

3.2.2. Organic acid system

Currently, formic acid, acetic acid, citric acid, and lactic acid are commonly used organic acids in the field of oil and gas stimulation (Al-Khaldi et al., 2005; Alhamad et al., 2020; Mohamed et al., 2015). Unlike HCl, organic acids do not fully dissociate in water (Alkhaldi et al., 2010; Buijse et al., 2004; Chang et al., 2008), and their reactivity can be described by the dissociation constants, shown in Table 2. The organic acid with lower dissociation constant (i.e. reactivity) allows the acid to penetrate into the rock matrix more uniformly. However, this uniform reaction typically requires a longer duration, which may limit its efficiency.

Organic acids, due to their versatile functionalities, are frequently utilized in fields. Organic acids' corrosiveness significantly lower than that of HCl, thereby slowing down the corrosion of downhole tubings under high temperature. Especially, formic acid also has certain corrosion inhibition properties. When mixed with HCl, formic acid aids in inhibiting corrosion by generating carbon monoxide (CO) on the metal surface (Alhamad et al., 2020). Citric acid and lactic acid are frequently employed as components of iron control agents in treatment solutions (Alkhaldi et al., 2010; Rabie et al., 2014) to prevent precipitation of iron hydroxide or sulfide. Additionally, lactic acid is often used in conjunction to remove drilling fluid filter cake (Rabie et al., 2014).

When high-concentration organic acids are used for reservoir stimulation, they may form calcium salt precipitates with calcium and magnesium ions, thus potentially causing formation damage due to their low solubility (e.g., calcium acetate: 300 g/L, calcium formate: 166 g/L, calcium lactate: 79 g/L, calcium citrate: 0.85 g/L) (Mohamed et al., 2015; Nasr-El-Din et al., 2007; Rabie et al., 2015). Therefore, it is important to control the concentration of organic acids during field operations. Researchers generally recommend limiting the mass concentration of formic acid to 9 wt% (weight percent), acetic acid to 13 wt %, and citric acid to 1 wt% (Mohamed et al., 2015). To expand the effective concentration range of organic weak acids, efforts have been made to improve the solubility of precipitated salts. Rabie et al. (2015) and Alhamad and Miskimins (2022) introduced gluconic acid into a lactic acid system to enhance calcium ion dissolution through the synergistic effect, increasing the calcium solubility from 79 g/L to 400 g/L. Mohamed et al. (2015) further improved the solubility of organic calcium salts by adding gluconic acid to formic and citric acid systems, which increased formic acid concentration and acidizing efficiency, thereby enhancing acidization performance.

3.2.3. *Chelating agent system*

Chelating agents exhibit excellent metal chelating ability (Tariq et al., 2021a) and low corrosion characteristics to down-hole equipment (Abdelgawad et al., 2018; Li et al., 2023; Shi et al., 2020) and good adaptability to high temperature up to 180 °C (Martell et al., 1975; Sokhanvarian et al., 2016). However, even in high-temperature environments, the reaction rate between chelating agents and carbonate rock matrix remains significantly lower than that between hydrochloric acid and carbonate rock matrix. Consequently, it is not possible to efficiently weaken the rocks, which directly restricts their ability to quickly reduce reservoir breakdown pressure (Li et al., 2023). Therefore, in order to achieve the expected reservoir stimulation effect, chelating agents usually need to be used in combination with stronger acid to accelerate the weakening of rock structures through a synergistic mechanism, thereby more efficiently promoting the reduction of breakdown pressure.

The primary chelating agents used in oilfields include ethylenediaminetetraacetic acid (EDTA), hydroxyethyl ethylenediamine triacetic acid (HEDTA), nitrilotriacetic acid (NTA), glutamic acid diacetic acid (GLDA), and diethylenetriamine pentaacetic acid (DTPA) (Bucheli-Witschel and Egli, 2001). Each of these agents has its advantages and limitations. For example, NTA is the first chemically synthesized chelating agent that is biodegradable (Bucheli-Witschel and Egli, 2001). However, its potential health risks to humans and mammals have made its use controversial (Pinto et al., 2014). EDTA and DTPA are known for their strong metal-chelating abilities, particularly with metals like calcium (Ca) and iron (Fe), forming stable complexes. Barri and Mahmoud (2015) investigated the effect of EDTA on the integrity of carbonate rocks at 120 °C. The results indicated that EDTA treatment weakened the mechanical properties of the carbonate rocks. After treatment, the Young's modulus of Austin chalk core samples decreased by approximately 76 %, while that of Indiana limestone decreased by 5 %. However, similar to DTPA, the limited biodegradability of EDTA restricts its large-scale application (Sillanpaa and Pirkanniemi, 2001). GLDA, with its high water solubility, excellent metal-chelating ability, low corrosivity, high temperature resistance, and superior biodegradability, has been investigated as an efficient alternative for deep, high-temperature carbonate reservoir matrix treatments (Almubarak et al., 2021; LePage et al., 2011; Li et al., 2023; Shi et al., 2020). LePage et al. (2011); Mahmoud et al. (2011) discovered that GLDA is highly effective for enhancing production in high-temperature (180 °C) carbonate reservoirs and can function over a wide pH range (pH 1–13). Shi et al., 2020 proposed using acetic acid to adjust the pH of GLDA for the acidizing of Baota limestone. When GLDA is 3 % (pH = 4, CH_3COOH), the permeability and porosity of Baota limestone increased by about 48 times and 5 times respectively after acidizing (Fig. 5). At the same time, it was found that pores and wormholes were formed on the surface of the limestone, indicating an effective acidizing outcome.

Table 2
The dissociation constant of organic acids in water (25 °C) (Alhamad et al., 2020).

Acid type	Chemical formula	Dissociation constant(pKa)
Formic acid	HCOOH	3.75
Acetic acid	CH_3COOH	4.756
Citric acid	$C_6H_8O_7$	3.128
Lactic acid	$C_3H_6O_3$	3.86

3.3. *Factors influencing acidizing performance*

In this section, the main factors influencing acidizing performance will be explored, focusing on reservoir rock lithology, temperature-pressure conditions and operational parameters.

3.3.1. *Rock lithology*

Lithology is the primary factor influencing the acidizing performance in carbonate rocks. Rocks with distinct lithologies exhibit varying mineral compositions and chemical properties. Carbonate reservoirs are primarily composed of soluble minerals such as calcite ($CaCO_3$) and dolomite ($CaMg(CO)_3$), often accompanied by non-reactive minerals like quartz, clay minerals, and gypsum. In acidizing performance analysis, the acid-rock reaction rate is predominantly evaluated through kinetic studies. The kinetic characteristics of acid-rock reactions vary significantly depending on mineral composition. Zhang et al. (2020a) experimentally demonstrated that, even under identical acidizing conditions (90 °C and 12 % wt HCl), carbonate rocks with different mineral contents exhibit distinct reaction rates. For example, limestone (100 % calcite) showed a reaction rate constant of 1.684×10^{-6} mol/(cm^2·s), while calcitic dolomite had a lower rate of 0.945×10^{-6} mol/(cm^2·s). Minerals such as gypsum and quartz showed negligible reactivity (Li et al., 2025).

This variation in reactivity among minerals leads to selective dissolution during acidizing, resulting in varying impacts on the mechanical properties of carbonate rocks with different mineral contents. Mustafa et al. (2022) studied the Silurian dolomite (SD), Indiana limestone (IL), and Austin chalk (AC). Their research revealed that different mineral contents exhibited varying reactivity towards acids. Among them, the chalk sample exhibited the greatest sensitivity to acid treatment, whereas the dolomite sample demonstrated the least. Due to the influence of mineral content, notable differences were observed in the reduction of surface hardness (by 47 %–77 %) and Young's modulus (by 18 %–33 %) among the three rock types after acidizing under identical conditions. Additionally, there is typically a negative linear relationship between porosity (both before and after treatment) and rock hardness as

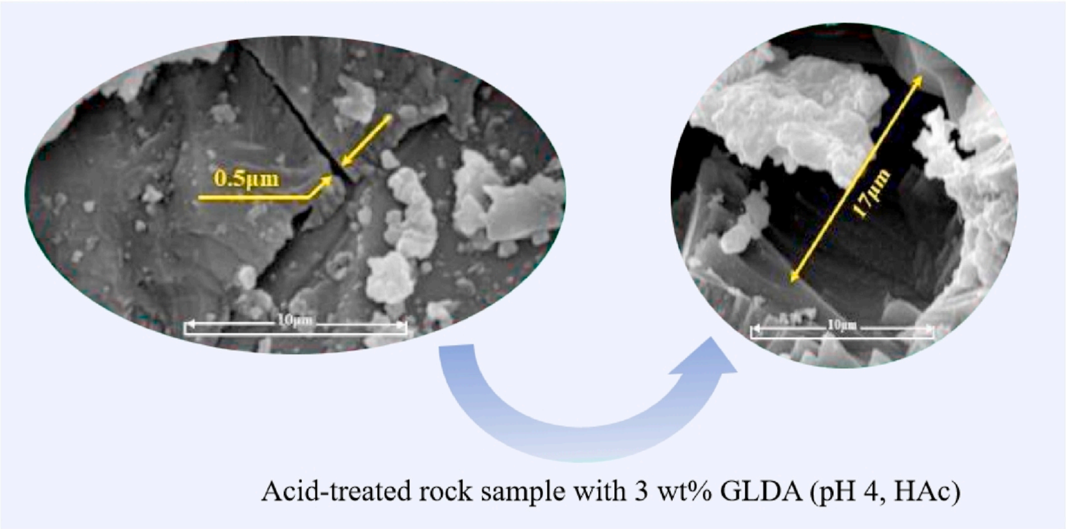

Fig. 5. CT and SEM images of rock samples before and after acidizing of Baota limestone using 3 % GLDA (pH = 4, CH_3COOH) (Shi et al., 2020)[2].

well as Young's modulus (Fig. 6). These findings confirm that acidizing effects on carbonate rocks vary with mineral composition, generally weakening mechanical properties. Additionally, acid treatment works better on carbonate rocks that contain high levels of calcite. It reduces the mechanical strength, making them easier to deform and fracture under external pressure.

3.3.2. *Reservoir temperature*

Reservoir temperature, alongside lithology, is a critical factor influencing the acidizing effectiveness of carbonate rocks. Temperature primarily governs acid-rock reaction kinetics, thereby affecting acid flow and dissolution processes (Gou et al., 2025). As carbonate reservoir depth increases, rising temperatures significantly accelerate acid-rock reaction rates. However, the response to temperature elevation varies across carbonate lithologies.

Mou et al. (2024) observed that temperature exerts a stronger influence on surface reaction rates than on mass transfer rates. At lower temperatures, reaction rates between limestone and dolomite diverge markedly, but this difference diminishes at elevated temperatures. Similarly, Li et al. (2025) demonstrated (Fig. 7) that under conditions (30 °C, 5 MPa to 180 °C, 60 MPa), the dissolution rate of dolomite in acetic acid solutions increases with rising temperature and pressure. In contrast, limestone dissolution rates decline sharply beyond 155 °C and 50 MPa. Marl exhibits significant dissolution reduction and structural failure when conditions exceed 130 °C and 40 MPa. Dolomitic limestone initially shows enhanced dissolution with increasing temperature and pressure but experiences a sharp decline in acid dissolution capacity beyond 130 °C and 40 MPa. These findings underscore the dominant role of lithology in acid-rock reaction kinetics.

3.4. *Discussion*

Acidizing technology expands pores and interconnects pore structures by dissolving carbonate minerals in rocks, thereby increasing reservoir permeability. It also degrades the mechanical strength of rocks, making them more susceptible to fracturing under lower pressures, thus effectively reducing the reservoir's breakdown pressure. For deep high-temperature carbonate reservoirs acidizing, selecting an efficient, low-corrosive, and non-secondary-damaging acid system is crucial to effectively reduce the breakdown pressure.

The HCl system, with its low cost, strong dissolution capability, and absence of secondary precipitation, can be applied to numerous reservoirs. However, the high temperature environment can cause severe corrosion of the tubing string by HCl, posing a serious threat to the safety of the down-hole tubing string. To mitigate corrosion, it is recommended to use acid systems with lower corrosivity, or to appropriately reduce the concentration of HCl and combine it with weak functional acids.

Organic acid systems are commonly used in high-temperature reservoirs and exhibit much lower corrosiveness than HCl. However, due to the fact that organic acids do not completely dissociate in water, the reaction rate of acid rock is relatively slow, and it is usually used in conjunction with HCl. It is worth noting that the solubility of the reaction products between organic acids and carbonate rock matrix is low. It is recommended to control the concentration of organic acids when using them. Alternatively, additives such as gluconate can be added to increase the useable concentration of organic acids.

Chelating agent system is another candidate to be used in deep reservoirs, with corrosiveness much lower than that of HCl and organic acids. However, due to the slow reaction between chelating agents and carbonate matrix rocks, they cannot quickly weaken the mechanical strength of rocks, so they need to be used in conjunction with acid solutions with stronger dissolution ability. Alternatively, following Sayed et al. (2023)'s approach to accelerating the reaction rate of acid with dolomite, the chelation reaction between chelating agents and carbonate rocks can be accelerated by selecting appropriate additives.

The acidizing fluid system plays a decisive role in determining acidizing performance. During acidizing operations, acid concentration selection should be prioritized to maximize dissolution efficiency while ensuring tubular integrity. This strategy may minimizes pre-treatment duration and acid volume consumption, thereby optimizing resource utilization and reducing operational costs (Zeng et al., 2025). Additionally, reservoir lithology and temperature exert significant influences on the dissolution behavior of carbonate rocks. Elevated temperatures generally enhance the acid dissolution rate of carbonates; however, different lithologies exhibit distinct optimal dissolution capacities under varying temperature environments. For instance, limestone may achieve peak dissolution at moderate temperatures (e.g. 155–160 °C), whereas dolomite-dominated formations often require a higher temperature (e.g, >160 °C) to maximize dissolution efficiency. The performance and applicable conditions of different acid systems are compared in Table 3.

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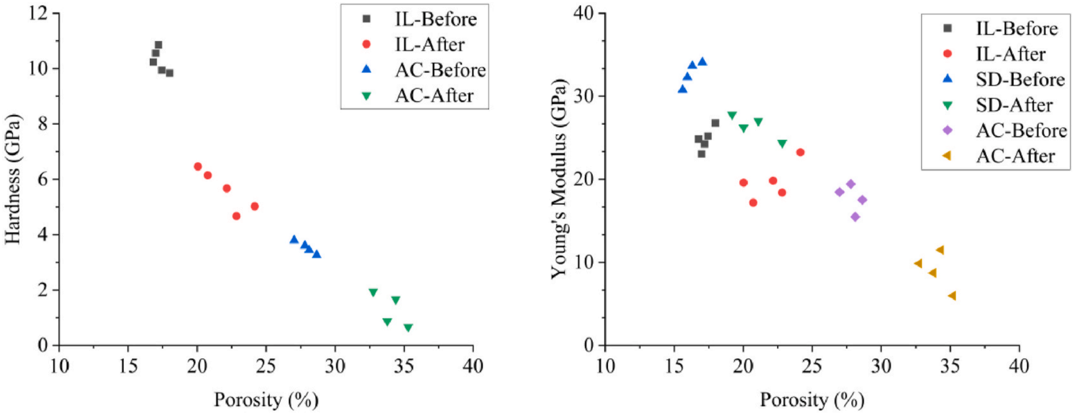
[2] Adapted from Shi et al., 2020 with permission from Elsevier. License No.: 5895221469031.



（a）**Hardness** **(b) Young's modulus**

Fig. 6. The trend of changes in rock surface hardness, and Young's modulus with porosity before and after acid treatment (Mustafa et al., 2022)[3].

4. Laboratory methods to evaluate the acidizing performance

Accurate evaluation of rock pore structure and mechanical properties is critical for assessing acidizing performance. This process is essential to optimize acid formulations, determine post-acidizing reservoir breakdown pressure reduction, and design effective fracturing operations. Conventional methods, such as measuring rock size, weight, and porosity-permeability, provide preliminary characterization but lack precision and comprehensiveness. To address these limitations, this section systematically reviews evaluation techniques across microscopic and macroscopic scales.

4.1. *Microscopic scale*

4.1.1. *Scanning electron microscope (SEM)*

Scanning electron microscope (SEM) uses an electron beam emitted by an electron gun to scan the sample surface point by point, and images the surface of the rock sample by collecting signals such as secondary electrons excited by the sample surface (Lou et al., 2020), in order to observe the micro-structure and morphological changes of the rock sample surface (Li et al., 2021a) (Fig. 8). It has the advantages of nano-scale resolution, non-contact observation, and no damage to the specimen (Ali et al., 2023; Bonilla-Jaimes et al., 2016).

Comparing the SEM scanning images of rock samples before and

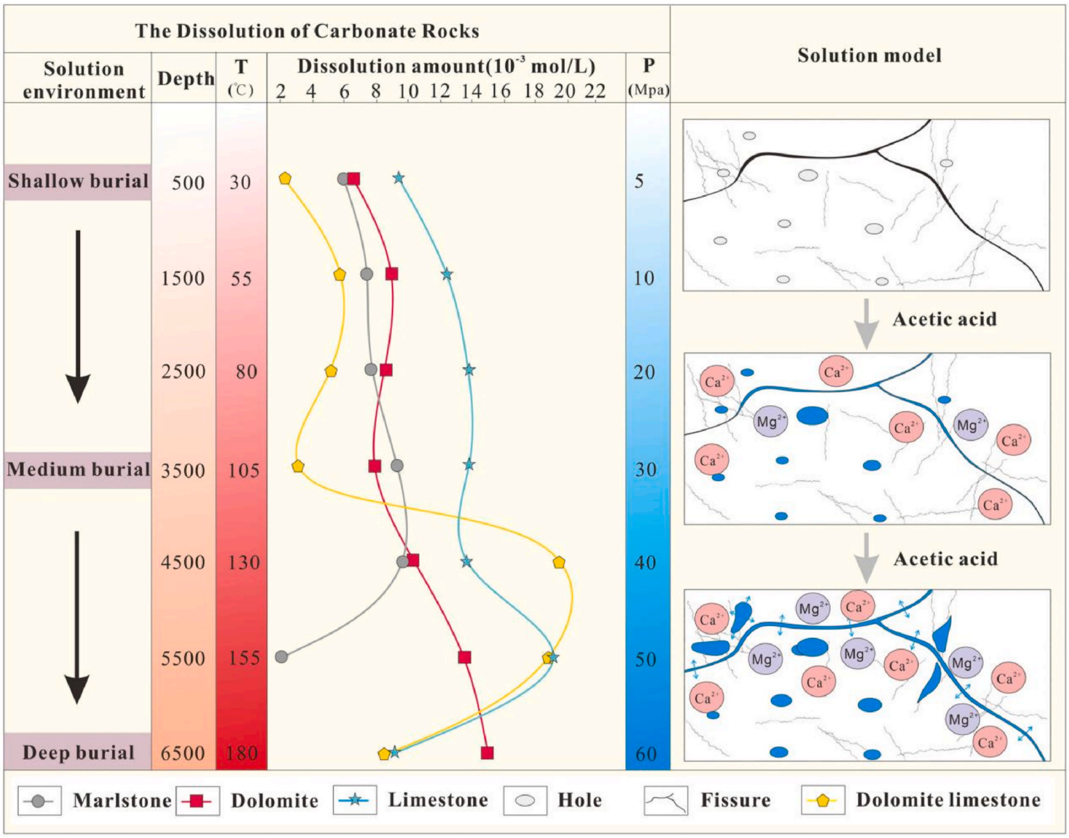


Fig. 7. The dissolution amount of carbonate rocks varies with temperature and pressure (Li et al., 2025).

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[3] Adapted from Mustafa et al. (2022).

Table 3
Comparison of different acid systems.

Performance	HCl	Organic acid	Chelating agent
Advantage	● Acid rock has a fast reaction rate (Chang et al., 2008) ● Low cost (Chang et al., 2008)	● Corrosive much lower than HCl (Liu et al., 2024a) ● Formic acid can be used as a corrosion inhibitor and enhancer (Alhamad et al., 2020) ● Lactic acid and citric acid can be used as iron control agents ● Lactic acid can be used in combination to remove filter cake	● Suitable for high temperature environments ● The corrosiveness of equipment is much lower than that of HCl and organic acids ● Environmentally friendly, with minimal damage to the reservoir
Limitation	● High corrosion, poor equipment durability (Liu et al., 2024a)	● Higher cost than HCl (Chang et al., 2008) ● The reaction rate of acidic rocks is relatively slow ● Low solubility of reaction products	● Slow acid-rock reaction ● High cost (Huang et al., 2000) ● Poor acid solubility (de Wolf et al., 2014)
Improvement measures	● Develop acid alternatives to HCl (Mustafa et al., 2021) ● Reduce the concentration of HCl appropriately and use it in combination with functional weak acids(Chang et al., 2008)	● Used in conjunction with HCl (Mohamed et al., 2015) ● Improve the solubility of reaction products	● Used in conjunction with acids that react faster with rocks (Shi et al., 2020)
Effect of acidizing on reducing breakdown pressure	● Simulations indicate that acid pre-treatment leads to a significant 46 % reduction in breakdown pressure compared to untreated conditions (Zeng et al., 2025). ● Acidizing (100 °C, 50 min) reduces breakdown pressure by approximately 15 MPa. (Li et al., 2024)	● Selecting citric acid to initiate a thermochemical reaction in laboratory fracturing simulations results in a 0.6335 MPa reduction in breakdown pressure (0.65 min) compared to tests without citric acid (Tariq et al., 2020a).	/

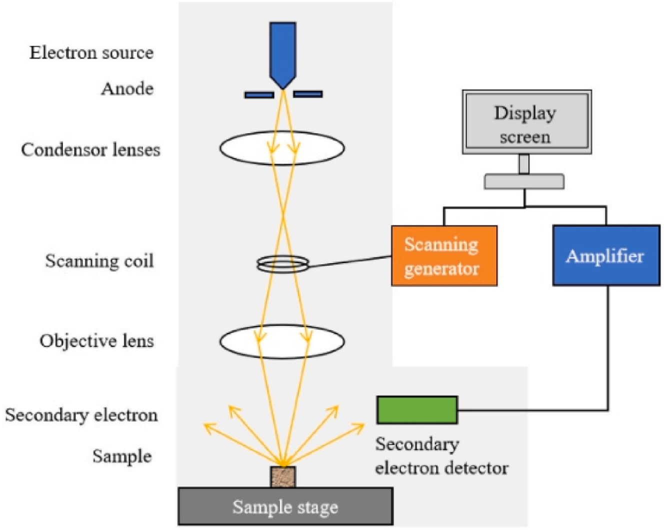

Fig. 8. Schematic diagram of scanning electron microscope (SEM) structure.

after acidizing gives us the information on the dissolution of minerals such as calcite and dolomite, and the sensitivity of minerals to the acid system (Liu et al., 2024c; Tian et al., 2020). Meanwhile, SEM can visually display the changes in pore structure, such as the expansion of pores and the improving connectivity. After acidizing, the skeleton of rock samples is destroyed, and many complex damaged structures (i.e. micro-fractures and pores) are formed inside the rock samples (Figs. 9–11). Consequently, the mechanical properties of the rock core show an exponential decreasing trend, indicating that the structural changes of rocks after acidizing are the main reason for the deterioration of mechanical properties (Xu et al., 2022; Yang et al., 2024).

4.1.2. *Computer tomography (CT scanning)*

CT scanning technology, also known as computed tomography, is a non-destructive testing method based on X-ray imaging (Raynaud et al., 2012). Micro-CT is commonly used in the field of petroleum engineering for testing rock samples. Micro-CT, a type of industrial CT, boasts micrometer-level resolution capability. X-rays pass through a rotating sample to obtain attenuation and absorption spectra at different angles. Through inversion, three-dimensional images characterizing the internal structure of the sample can be obtained (Yoo et al., 2021) (Fig. 12). CT scanning technology has advantages such as non-destructive testing and 3D imaging (Mohammadi, 2024; Yoo et al., 2021), enabling the acquisition of detailed information on the internal structure of rocks without damaging the rock samples (Machado et al., 2014).

By comparing CT images before and after acidizing, we can observe the dissolution of rock minerals, internal pore structure, and microfracture wormhole propagation (Feng et al., 2004; Mustafa et al., 2022). This provides an important basis for evaluating the degree of damage caused by acidizing to rocks. Alameedy et al. (2022) employed CT scanning technology to visualize the outcomes after acid treatment (Fig. 13). Research indicates that the size and characteristics of acid-etched wormholes, which emerge after acid treatment, may contribute to alterations in rock mechanical and physical properties. The formation of these wormholes corresponds to an increase in rock sample porosity, manifesting as a reduction in rock strength.

The availability of CT scanning technology enables further work to be conducted, aiming to refine the formulation and usage techniques of the acid system. Martyushev et al. (2022) utilized CT scanning technology to optimize the acid system, addressing the issue of pore space blockage caused by reaction products from inappropriate acid systems in carbonate rocks after acidizing, which led to reduced permeability.

4.1.3. *Nuclear magnetic resonance (NMR)*

Nuclear magnetic resonance (NMR) is a physical phenomenon (Benavides et al., 2020) characterized by its non-destructive and rapid nature (Tariq et al., 2023). In rock analysis, NMR technology typically utilizes the behavior of hydrogen nuclei (protons) in rock pores within a magnetic field to reflect the pore structure and fluid distribution of rocks (Schoenfelder et al., 2008) (Fig. 14). The intensity of NMR signals is directly proportional to the hydrogen content in the pores. When a rock is saturated with a single fluid (such as water), the detected NMR signal is directly proportional to the pore volume of the rock (Elsayed et al., 2022). The relaxation time of NMR signals (such as T_2) is related to the size and shape of pores (Mondal and Singh, 2024). Specifically, the NMR relaxation time is directly proportional to the pore size, meaning that small pores exhibit smaller T_2 values, while large pores exhibit larger T_2 values (Elsayed et al., 2022).

NMR is highly beneficial for conducting detailed studies on microscopic changes within samples, and it finds widespread application in rock analysis (Schoenfelder et al., 2008; Yao and Liu, 2012; Zhou et al.,

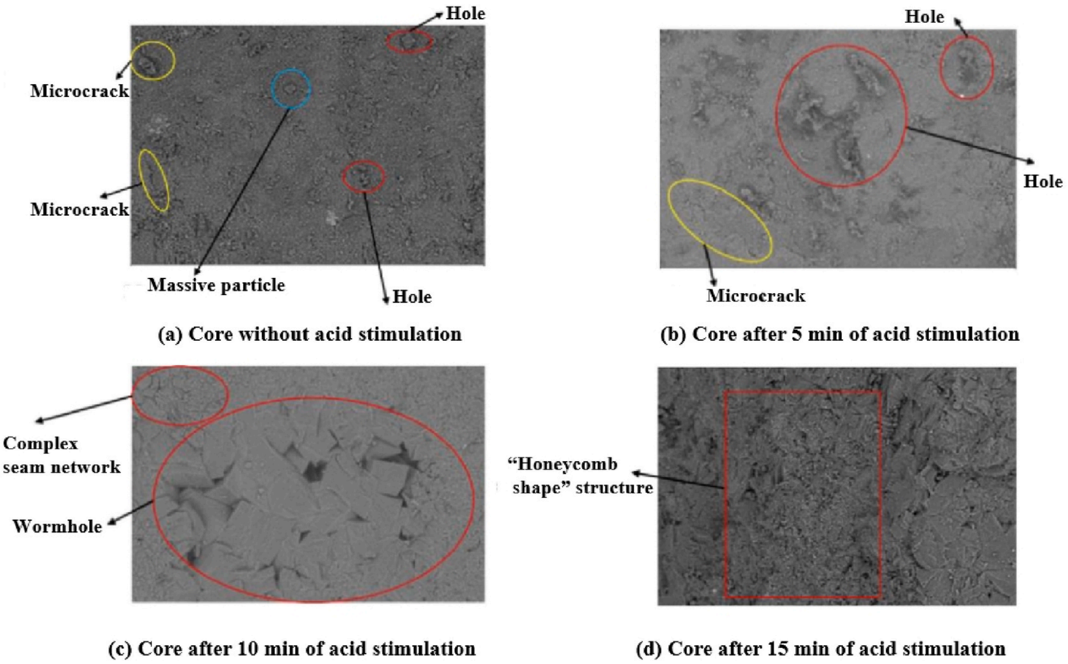

Fig. 9. Micro-structure of rock cores under different acidizing times at 120 °C (Yang et al., 2024)[4].

2015). Acidizing treatment can modify the internal pore structure of rocks and alter the distribution of fluids within them. NMR technology, by precisely analyzing fluid signals and their relaxation characteristics within rock pores, can indirectly indicate the changes in rock pore structure, fluid distribution, and physical properties resulting from acidizing treatment (Adebayo et al., 2017; Arnold et al., 2006; Li et al., 2016). Carpenter et al. (1993) and Tariq et al. (2021a) employed nuclear magnetic resonance technology to measure the distribution of saturated water content in limestone, thereby revealing alterations in the internal pore structure and permeability of rocks. Li et al. (2018) utilized nuclear magnetic resonance technology to investigate changes in porosity of limestone after erosion by chemical solutions with varying pH values (3, 5, and 7), as well as the microscopic damage evolution of limestone under triaxial mechanical loading (Figs. 15 and 16). Research has revealed that changes in porosity may be the primary cause of the decline in mechanical properties.

4.2. *Macroscopic scale*

4.2.1. *Uniaxial and triaxial compression tests*

Uniaxial compression technique is a commonly used testing method, which applies unidirectional pressure on a rock specimen. The specimen

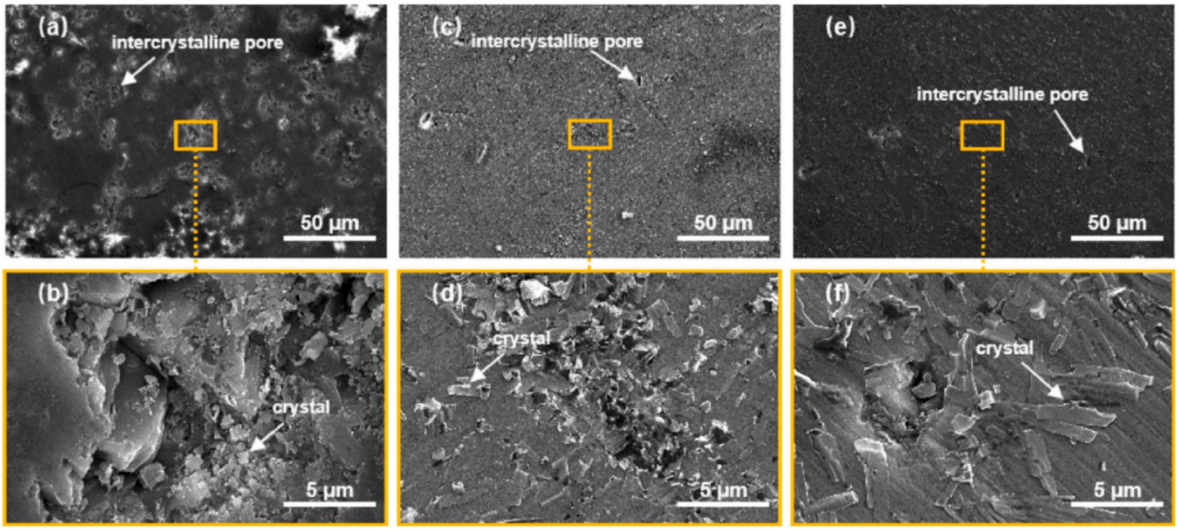

Fig. 10. Image of dolomite sample (5 × 5 × 1.5 mm) before acidizing under scanning electron microscope (Xu et al., 2022)[5].

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[4] Adapted from Yang et al., 2024 with permission from Elsevier. License No.: 55895230104760.

[5] Cited from Xu et al., 2022 with permission from Elsevier. License No.: 5895230256776.

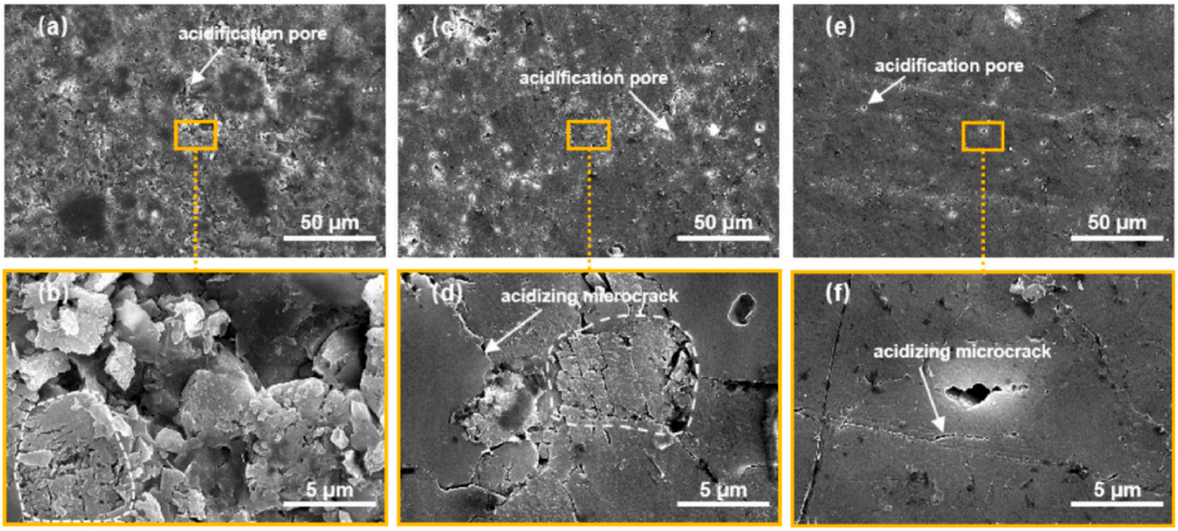

Fig. 11. Image of dolomite sample (5 × 5 × 1.5 mm) with acid (1 wt% HCl, 10 min) under scanning electron microscopy (Xu et al., 2022)[6].

undergoes axial compression and lateral expansion under axial pressure until it ultimately fails. The maximum compressive stress that a rock can withstand before failure under uniaxial compression load is called the uniaxial compressive strength of the rock, also known as the unconfined compressive strength. Because the specimen is only subjected to axial pressure and there is no lateral pressure, the deformation of the specimen is not restricted. By measuring the stress-strain relationship of the specimen during loading, mechanical parameters such as compressive strength and elastic modulus of the rock can be calculated. However, rocks in actual geological formations are controlled by three-dimensional stress fields. In uniaxial compression tests, the lack of control over confining pressure and the uneven stress load caused by frictional forces at the interface between the rock core and the pressure plate may result in inaccurate estimation of test results (Tuzingila et al., 2024).

The triaxial compression experiment, based on the uniaxial compression experiment, simultaneously applies confining pressure around the rock sample. By adjusting the magnitude of the confining pressure, the mechanical properties of the rock before and after acid treatment under different confining pressure conditions can be studied (Gou et al., 2019) (Fig. 17). Similar to uniaxial compression, the compressive strength of acidified rocks will also decrease. Under triaxial compression conditions, due to the presence of confining pressure, stress and displacement distributions are more uniform compared to uniaxial compression (Yuan et al., 2024). Zhang et al. (2020) measured the mechanical properties of carbonate rocks using uniaxial compression tests and triaxial compression tests. The test results showed that the compressive strength and elastic modulus of carbonate rocks decreased after acid treatment (Figs. 18 and 19). The degree of weakening is as follows: rocks with relatively low bonding strength > limestone with high bonding strength > limestone with high bonding strength. However, under high temperature conditions, acid severely etches both ends of the rock sample, making it unable to meet the requirements of triaxial compression experiments. This is one of the main reasons for the insufficient research on the mechanical properties of carbonate rocks after high-temperature acidizing. Yang et al., 2024 proposed using high-temperature and corrosion-resistant coatings to brush the upper and lower surfaces of rock cores to prevent acid from entering the upper

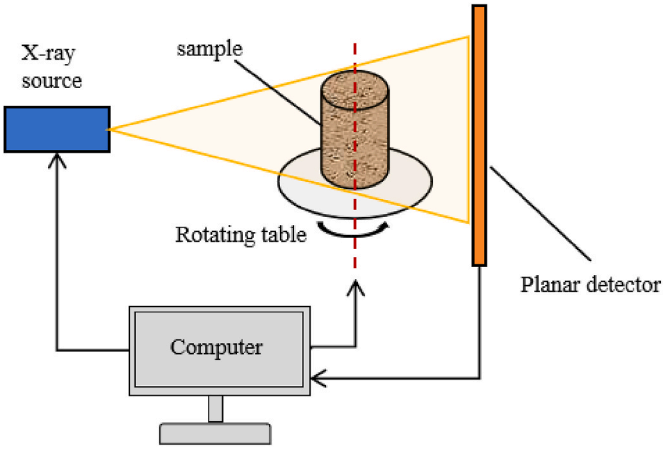

Fig. 12. Schematic diagram of micro CT scan.

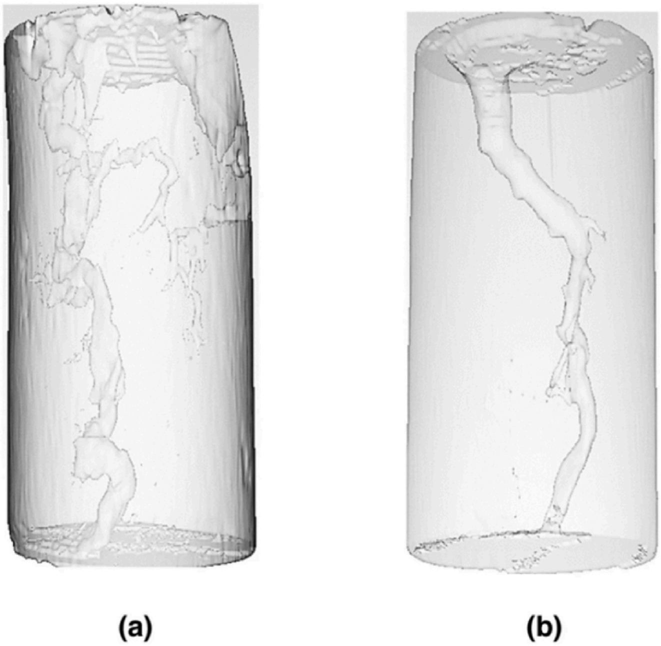

Fig. 13. Two Micro CT images of acidified rock samples were reconstructed using 3D Slicer software (Alameedy et al., 2022).

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[6] Cited from Xu et al., 2022 with permission from Elsevier. License No.: 5895230256776.

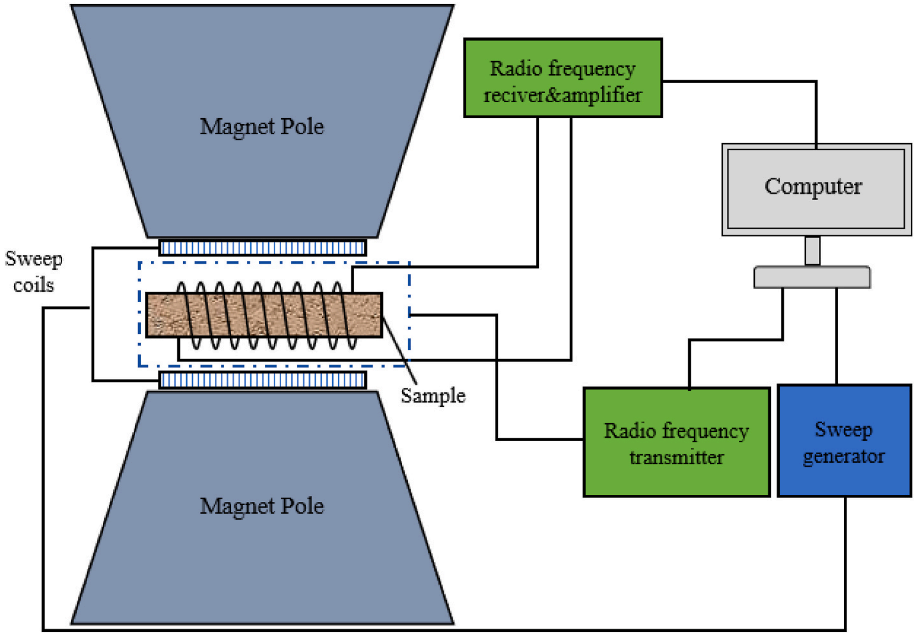
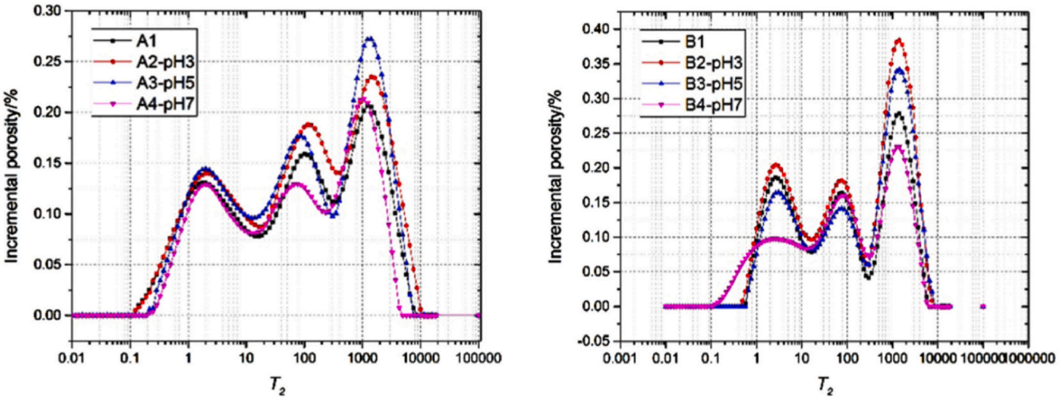
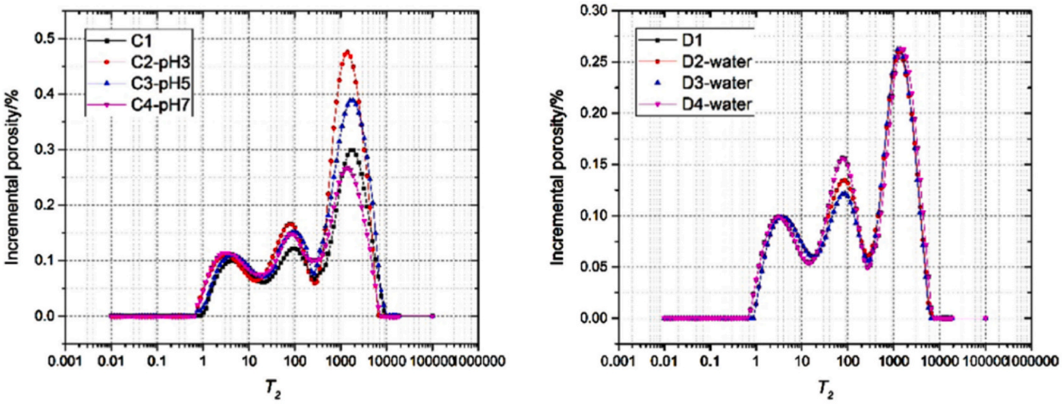


Fig. 14. NMR test schematic diagram.



(a) T_2 spectrums of samples immersed in Na_2SO_4 for 20 days (b) T_2 spectrums of samples immersed in Na_2SO_4 for 40 days



(c) T_2 spectrums of samples immersed in Na_2SO_4 for 60 days (d) T_2 spectrums of samples immersed in distilled water

Fig. 15. T_2 Spectral distribution of limestone in different chemical solutions after different soaking days (Li et al., 2018)[7].

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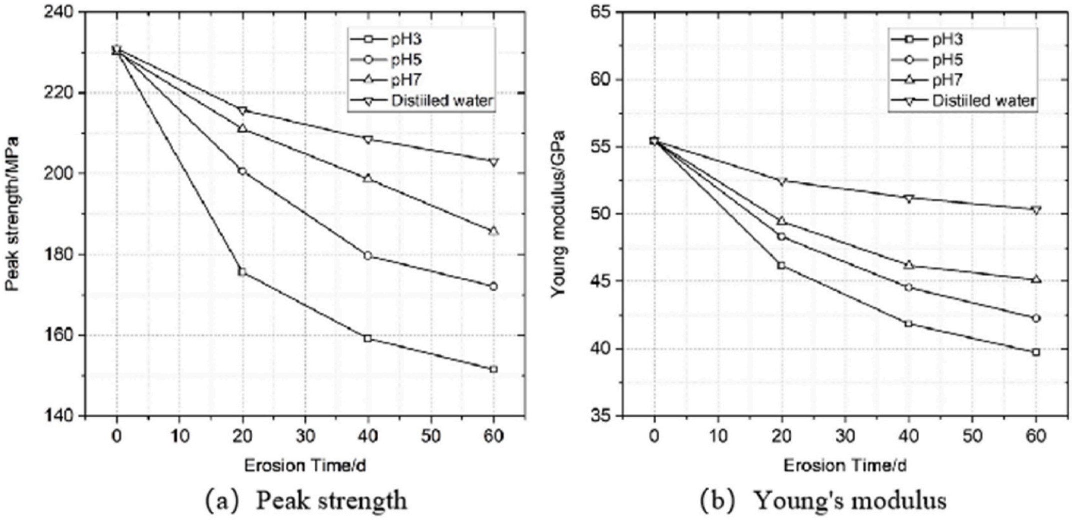
[7] Cited from Li et al. (2022) with permission from Elsevier. License No.: 5895230720938.



(a) Peak strength (b) Young's modulus

Fig. 16. The variations in mechanical characteristics of limestone when exposed to different chemical solutions (Li et al., 2018)[8].

and lower surfaces, ensuring that the acidified rock cores are suitable for triaxial compression experiments. Nevertheless, triaxial compression experiments remain an essential method for measuring the mechanical parameters of rock cores.

4.2.2. Brazilian splitting test

The Brazilian splitting technique involves applying radial pressure (also known as splitting force) at both ends of a rock specimen to cause splitting failure in a plane perpendicular to the loading direction (Li et al., 2019) (Fig. 20). This method is mainly used to determine the tensile strength of rocks (Perras and Diederichs, 2014). The Brazilian splitting technique is simple and easy to operate, but this method ignores the frictional stress at the interface between the pressure plate and the rock sample, which may affect the accuracy of determining the tensile strength (Tuzingila et al., 2024).

Tensile strength is an important parameter for analyzing rock breakdown pressure (Ibemesi and Benson, 2023; Li et al., 2024; Sampath et al., 2018). The possible changes in the micro-structure or chemical properties of rocks during acid treatment can directly affect this key mechanical property. Therefore, in order to ensure the scientific and accurate prediction of rock breakdown pressure, the degree of degradation of rock tensile strength after acid treatment should be fully considered. Li et al. (2024) conducted splitting experiments on dolomite. The experimental results show that the tensile strength of rocks decreases with the increase of acid treatment time and acid reaction temperature. Combining finite element simulation shows that the degradation of tensile strength of rocks after acid treatment is beneficial for reducing fracture propagation pressure.

4.2.3. Hardness testing

Hardness is one of the main mechanical properties of rocks. Generally speaking, hardness indicates the resistance of rocks to infiltration, scratching, or permanent deformation (Ghorbani et al., 2022b). The commonly used rock hardness testing methods currently include scratch testing, indentation testing, and rebound based hardness testing (Ghorbani et al., 2022a).

The Mohs hardness test, a type of scratch testing method, is straightforward and easy to conduct, often used for quick rock hardness

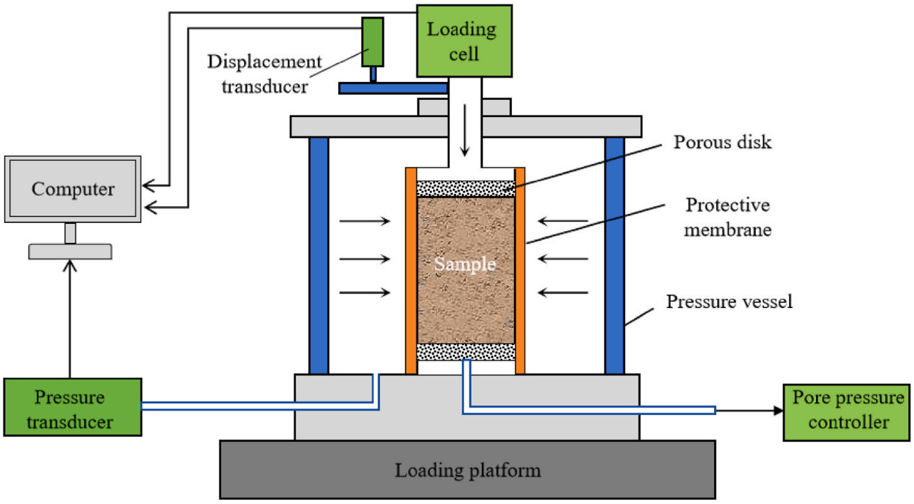


Fig. 17. Schematic diagram of triaxial compression test equipment.

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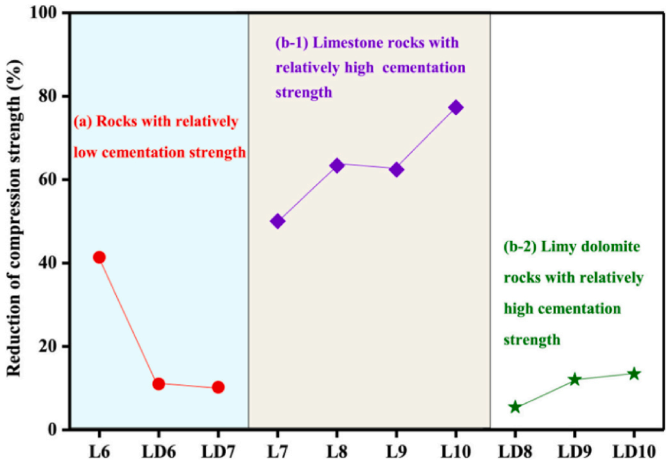

Fig. 18. The variation of rock compressive strength obtained from triaxial compression test (Zhang et al., 2020b)[9].

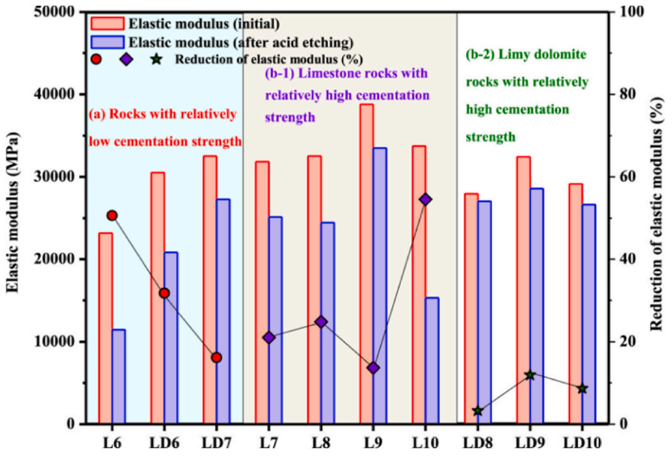

Fig. 19. The variation of rock elastic modulus obtained from triaxial compression test (Zhang et al., 2020b)[10].

assessments in the field. This method involves scratching the surface of rocks using standard minerals with known hardness, such as talc, gypsum, and calcite. The hardness level of the rocks is determined by comparing the ease of making scratches (Ghorbani et al., 2022b). Although this method can provide relative measurement of rock hardness, it may lack accuracy. At present, a relatively accurate scratch testing technology has been developed, which obtains continuous uniaxial compressive strength (UCS) by scratching the rock surface with diamond cutting tools. Unlike triaxial and uniaxial compression tests, scratch tests can measure the UCS of acid etched surfaces with rock roughness. Compared with conventional hardness testing, scratch testing can obtain more strength values from the same sample, thereby avoiding inaccurate results obtained from hardness testing due to fewer hardness data points and sampling deviations. Zhou et al., 2021 used the scratch testing technology to test the surface strength of limestone before and after acidizing. The research results showed that this technology can better reflect the heterogeneity of the fracture surface before and after acid etching (Fig. 21). Based on XRD (X-ray diffraction) analysis technology, it can be concluded that dolomite in the limestone sample is the reason for the increase in strength, while calcite is the reason for the decrease in strength.

The indentation test method is to use a pressure head (such as a metal cone or steel sphere) with a specified size and shape to press into the surface of a rock under a certain load, measure the size and depth of the indentation, and calculate the hardness value of the rock according to relevant formulas (Broitman, 2016; Ghorbani et al., 2022a). It can directly reflect the ability of rocks to resist local deformation, and the results are relatively accurate. Common indentation hardness tests include Vickers hardness test (Smith and Sandly, 1922), Brinell hardness test (Boutrid et al., 2015), Rockwell hardness test (Broitman, 2016), Knoop hardness test (Knoop et al., 1939), nanoindentation test (Ma et al., 2020), etc. However, four indentation methods, including Vickers indentation, Knoop indentation, Brinell indentation, and Rockwell indentation, were developed for the application of metallic materials (Broitman, 2016). Due to the lack of rock hardness measurement standards, their use in rock engineering may be limited (Ghorbani et al., 2022a). In recent years, nanoindentation technology has gradually become well-known to researchers due to advances in mechanical testing at the micro and nano scales (Liu et al., 2023). Nanoindentation technology can obtain mechanical parameters such as rock hardness and elastic modulus by applying a small load on the rock surface and measuring its indentation depth (Shi et al., 2019). One of the advantages of this method is that it causes less damage to the material surface. Simultaneously, multiple measurements are allowed for small-sized samples, and the measurement results are averaged or statistically analyzed to reduce random errors (Liu et al., 2024d; Luo et al., 2020). Tian et al., 2020 used nanoindentation technology to test the mechanical characteristics of shale before and after acidizing. Tests have found that the Young's modulus and hardness of shale samples significantly decrease after acid treatment, and their ductility is stronger. Xu et al., 2022 used the nanoindentation continuous stiffness measurement (CSM) mode to obtain the local mechanical properties of dolomite samples before and after acid dissolution (Fig. 22). The test found that the Young's modulus and hardness of the sample significantly decreased after acid treatment, and the ductility was stronger.

The rebound based hardness testing method calculates the hardness of rocks by measuring the height or velocity of the rebound of an impact object with a certain mass and velocity when it hits the surface of the rock (Liu et al., 2020; Ritz et al., 2014). This method usually reflects the ability of rocks to resist impact damage, and impact hardness more reflects the overall structure and strength characteristics of rocks. Acidizing can cause micro-fractures or increased porosity within rocks, which may reduce the hardness. Mustafa et al. (2022) conducted hardness tests on rocks before and after acidizing using an impulse hammer. The test results show that the hardness of the rock after acid treatment has decreased to a certain extent, with the hardness of IL, AC, and SD rock samples decreasing by 47 %, 69 %, and 77 %, respectively. Then the reduction of SD may not be accurate, as the impulse hammer may fall on uneven areas.

4.2.4. *Ultrasonic wave testing*

Ultrasonic wave testing technology, especially by measuring the longitudinal (V_p, i.e. longitudinal wave velocity) and transverse (V_s, i.e. transverse wave velocity) propagation velocities of sound waves in rocks, is an important means of evaluating the physical and mechanical properties of rocks (Al-Awsi and Khorshid, 2021; Alameedy et al., 2023)

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[10] Cited from Zhang et al. (2020a) with permission from Elsevier. License No.: 5895230866754.

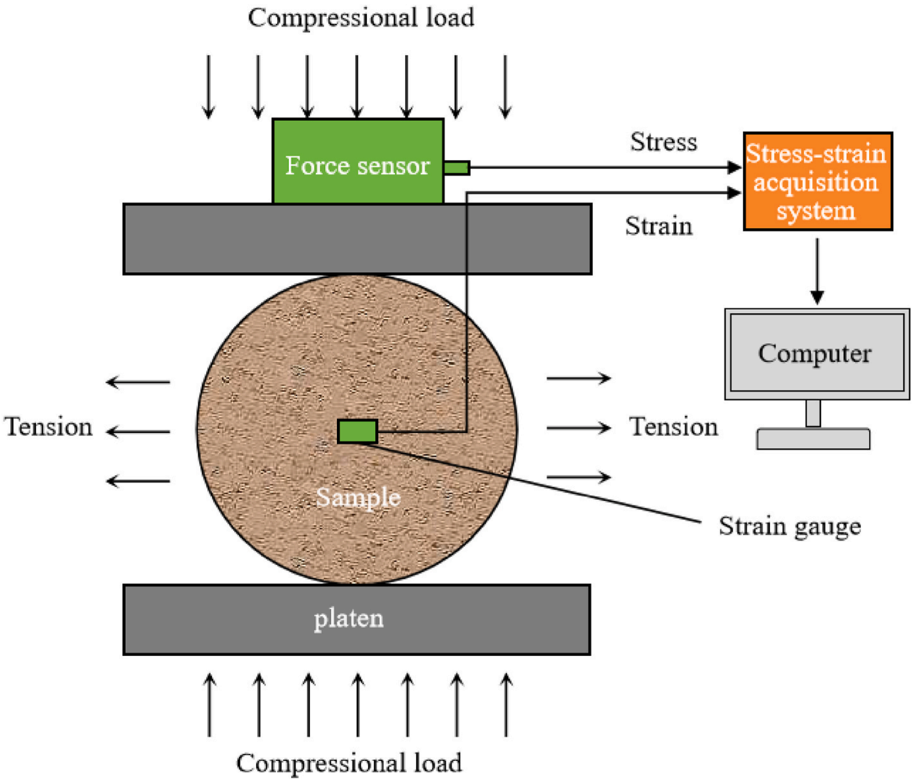

Fig. 20. Schematic diagram of Brazilian splitting experiment.

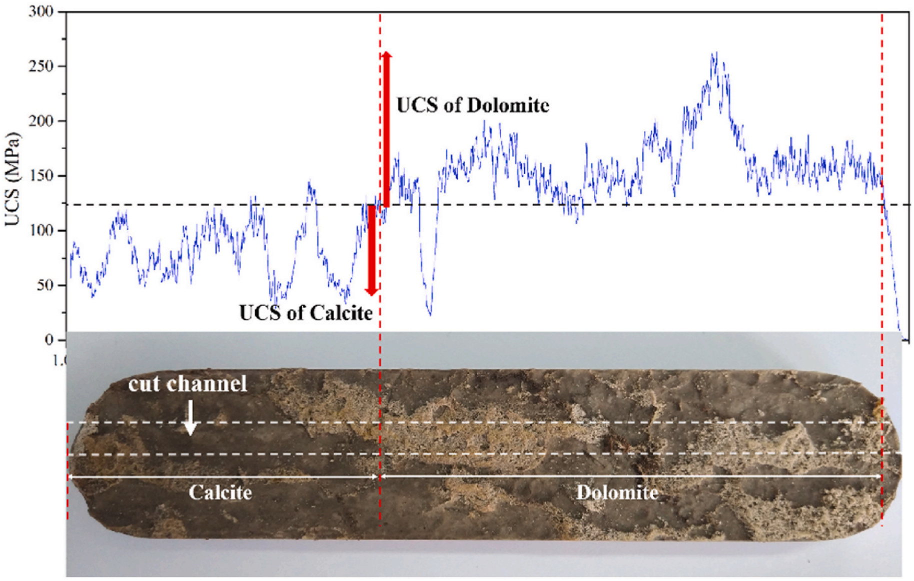

Fig. 21. Comparison of UCS between Calcite and Dolomite. Higher and whiter bumps are mainly composed of dolomite (Zhou et al., 2021)[11].

(Fig. 23). The propagation speed of sound waves in rocks is influenced by various factors such as rock density, elastic modulus, porosity, and degree of fracture propagation (Alameedy et al., 2022).

During the process of rock acidizing, changes in acoustic parameters can indirectly reflect changes in rock mechanical properties, such as rock strength, Poisson's ratio, and brittleness index. Alameedy et al. (2022) used acoustic testing techniques to test the sound velocity of rocks before and after acidizing. By using acoustic parameters (V_p and V_s), the elastic modulus (E) and Poisson's ratio (PR) of rocks were estimated using Eq. (7), Eq. (8),Eq. (9),Eq. (10), indicating the material index (IM) and static lateral soil pressure coefficient (K_o) of rock hardness. The study found that the decrease in longitudinal and transverse

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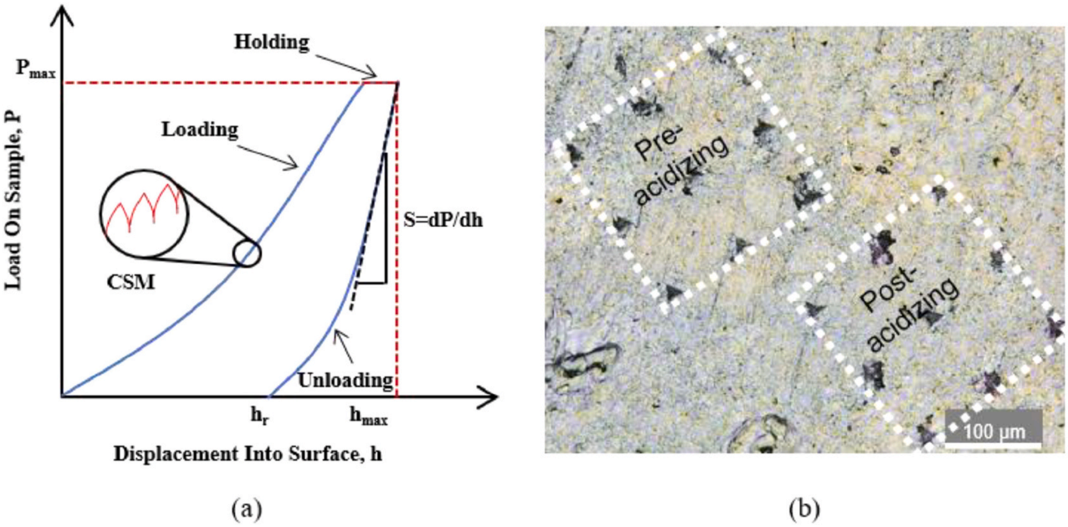

Fig. 22. (a) Nanoindentation load on sample-displacement into surface curve and continuous stiffness measurement (CSM) diagram; (b) Three-by-three matrix of Sample #2 (5 × 5 × 1.5 mm) before and after acid dissolution (1 wt% HCl, 10 min) by laser scanning (Xu et al., 2022)[12].

wave velocities of rocks after acid treatment may indicate a weakening of their mechanical properties, and the E of the studied rock samples decreased by 26%–37 %. PR, K_O, and IM increased by 13%–20 %, 23%–32 %, and 28%–125 %, respectively.

$$E = \frac{\rho V_S^2 \left(3V_P^2 - 4V_S^2\right)}{V_P^2 - V_S^2} \tag{7}$$

$$PR = \frac{0.5(V_P/V_S)^2 - 1}{(V_P/V_S)^2 - 1} \tag{8}$$

$$IM = \frac{3 - (V_P/V_S)^2}{(V_P/V_S)^2 - 1} \tag{9}$$

$$K_O = \frac{(V_P/V_S) - 2}{(V_P/V_S)^2} \tag{10}$$

4.3. Discussion

In the aforementioned studies, various evaluation methods exhibit distinct advantages and limitations. Scanning Electron Microscopy (SEM) is used to examine the microstructure and surface morphology of rock samples before and after acidizing. However, it lacks sufficient precision in quantifying changes in pore structure. Nuclear Magnetic Resonance (NMR) technology provides valuable information on pore structure and dynamic changes in rock samples, but it struggles to analyze complex structural features. While micro-CT imaging enables

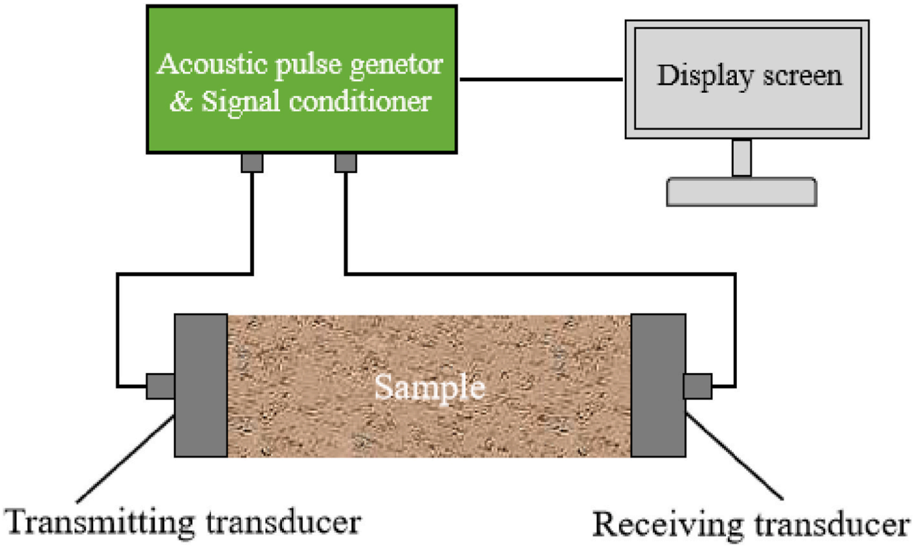

Fig. 23. Schematic diagram of ultrasonic testing system.

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Table 4
Advantages and limitations of commonly used evaluation methods for acidizing performance in laboratory.

Scale	Method		Advantage	limitation
Micro	SEM		● Nano-scale resolution ● Do not waste inspection materials	● Limited to surface analysis ● No 3D quantification
	CT scanning		● 3D internal structure visualization ● Nondestructive analysis	● High cost ● Complex image processing ● Micro-CT limiting the capture volume
	NMR		● Non destructive, fast, and accurate	● Difficult to analyze complex structures
Macro	Uniaxial compression		● Direct measurement of rock strength ● Easy to operate	● Friction at the core-pressure plate interface may cause inaccurate test results. ● Only provide stress data in a single direction ● Require the contact surface of the rock sample be smooth
	Triaxial compression		● Simulates in-situ stress conditions ● Provide more comprehensive stress-strain data	● Requires longer testing time ● Require the contact surface of the rock sample be smooth
	Brazilian splitting		● Simple and easy to operate	● Ignoring frictional stress at the pressure plate-rock interface may lead to inaccuracies
	Hardness test	Scratching test	● Simple and easy to operate ● Can provide relative comparison values of hardness	● The results are greatly affected by the surface roughness of the sample ● Destructive testing
		Nano-indentation	● No need for large volume or size samples for testing ● Less damage to the surface of the material	● Surface polishing of the sample is required, potentially distorting actual conditions
		Based on rebound	● The testing process is fast and simple	● The test results are greatly affected by the surface condition of the sample
	Ultrasonic wave testing		● Non-destructive testing	● Acoustic signal transmission may suffer losses at the probe-rock interface

3D visualization of the internal structure of rock samples before and after acidizing, its application is limited by relatively high testing costs.

Uniaxial compression testing is straightforward to perform but only provides unidirectional stress data. Triaxial compression testing, which incorporates confining pressure, offers a more comprehensive assessment of stress-strain relationships but requires longer testing durations. Similar to uniaxial tests, triaxial tests impose stringent requirements on rock samples. Rock samples with uneven contact surfaces may not meet the criteria for such tests after acidizing. The Brazilian splitting test is effective for evaluating the tensile strength of rocks. However, frictional stress between the pressure plates and the rock samples can lead to inaccuracies in the results. Rock hardness testing methods, including scratch tests, nano-indentation, and rebound-based hardness measurements, each have unique advantages and limitations. Nevertheless, like rock mechanics experiments, these methods are destructive. Ultrasonic testing is a non-destructive method for evaluating mechanical parameters of rocks, such as Young's modulus (E) and Poisson's ratio (PR). However, signal loss during transmission can introduce errors into the measurements.

Micro-scale evaluation methods excel in pore-scale characterization. Macro-scale testing quantifies bulk mechanical property changes. Integrating multiscale data improves acidizing performance evaluation, optimizes acid formulation design, and refines subsequent acid fracturing strategies. Table 4 summarizes the advantages and limitations of commonly used laboratory methods for evaluating the pore structure and mechanical properties of rock samples.

5. Further developments and future perspectives

5.1. Further developments

5.1.1. Development of high-temperature-resistant, efficient, low-corrosion acid systems

The key challenge in developing high-temperature, efficient, and low-corrosion acid systems is the conflicting requirements of acid stability, dissolution efficiency, and corrosion inhibition at ultra-high temperatures (>180 °C). At such temperatures, acids like acetic acid decompose more rapidly, reducing dissolution efficiency, while high-concentration HCl intensifies corrosion on P110 steel. Moreover, the low solubility of reaction products between organic acids and carbonate minerals can lead to secondary precipitation, further damaging the reservoir. Future development should focus on: (1) Identifying alternatives to hydrochloric acid by developing organic acid systems with high product solubility or chelating agent systems with rapid chelation rates that are stable at high temperatures, potentially enhanced by nanoparticles to improve acid fluid penetration (Zhang et al., 2025). (2) Optimizing corrosion inhibitor molecular structures to enhance film stability at high temperatures, achieving a synergistic balance between efficient dissolution and low corrosion.

5.1.2. Acidizing experiments under ultra-high temperature conditions

Under ultra-high temperature conditions, understanding the acid-rock reaction mechanisms and evaluating acidizing performance are critical for designing acidizing strategies to reduce reservoir breakdown pressure. Experimental simulations remain the most direct method to study acid-rock interactions and assess acidizing performance. However, at ultra-high temperatures, experimental equipment is highly susceptible to acid corrosion, leading to significant material loss. Thus, there is an urgent need to develop high-temperature-resistant materials, such as Hastelloy, to optimize experimental setups and accurately simulate acid-rock interactions (He et al., 2024). Additionally, some evaluation tests, such as triaxial compression experiments, require perfectly flat rock sample surfaces. Traditional acid-rock reaction methods like acid soaking cause severe surface damage, resulting in data inaccuracies. Researchers should consider designing new acidizing methods that preserve the integrity of rock sample surfaces under ultra-high

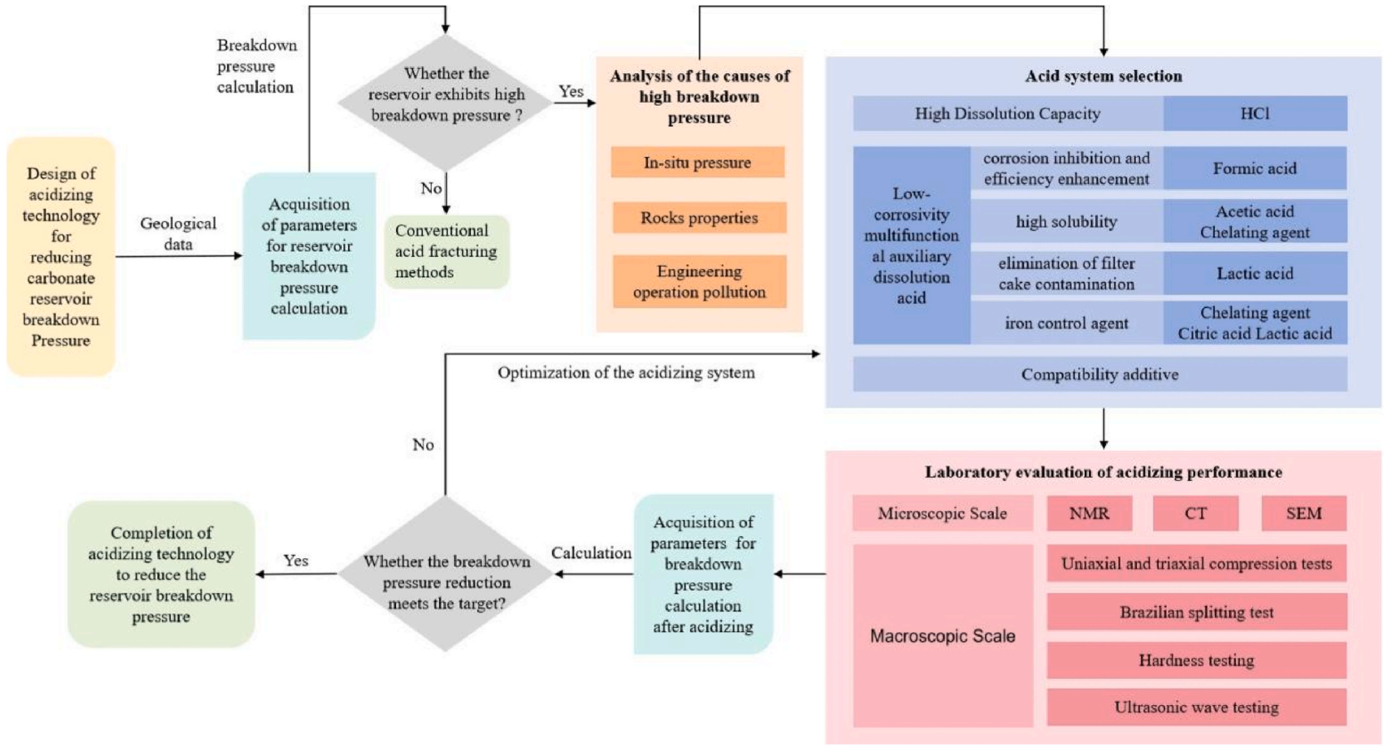

Fig. 24. Design strategy for acidizing to reduce reservoir breakdown pressure.

temperature conditions.

5.1.3. Design workflow for acidizing to reduce reservoir breakdown pressure

The current design workflow for reducing reservoir breakdown pressure through acid treatment is based on an analysis of reservoir geological features and rock mechanical response mechanisms. Acid systems are selected and optimized accordingly. Laboratory experiments simulate changes in rock mechanical properties after acidizing to guide field applications. This workflow aims to significantly improve reservoir stimulation feasibility by lowering breakdown pressure and reducing fracturing risks in deep and ultra-deep carbonate reservoirs. For example, in well P101 at 7000 m, the breakdown pressure decreased from 197.5 MPa to 179.1 MPa, a reduction of 18.4 MPa (9.3 %), which verifies the effectiveness of the design process. Fig. 24 illustrates the design approach for using acid treatment to lower breakdown pressure in carbonate reservoirs, providing a universal strategy for acidizing deep carbonate reservoirs. Future work should improve design accuracy and adaptability. It is also necessary to promote interdisciplinary research and develop multi-scale numerical models for breakdown pressure in ultra-deep carbonate reservoirs to further optimize acid treatment technology. Moreover, emerging technologies such as big data and artificial intelligence can be used to build standardized experimental databases and machine learning models. These tools can quickly match reservoir characteristics with acid systems, shorten design cycles, and enhance economic efficiency.

5.2. Future perspectives

In the future, acidizing technologies for reducing reservoir breakdown pressure may advance through interdisciplinary integration, smart optimization, and low-carbon approaches. Researchers could combine geoscience, data science, and materials science to develop multi-field coupled numerical models (thermal, fluid, and solid) and apply machine learning for dynamic optimization of acid fluid parameters. A digital platform integrating geological modeling, real-time monitoring, and intelligent control can be established, using fiber-optic sensors and IoT technologies to track acid-rock reactions in real time and enhance the adaptability of acidizing schemes. Moreover, the development of CO_2-based acid systems combined with nanotechnology may lower breakdown pressure while achieving carbon sequestration and synergistic activation of reservoir energy, thereby driving the evolution of green acidizing technologies.

6. Summary and conclusion

To investigate the causes of high breakdown pressures in deep carbonate reservoirs, this paper's second section examines contributing factors from the perspectives of in-situ stress, rock properties, and contamination from engineering operations. Geological structures that increase minimum horizontal stress, elevated vertical stress, and the heterogeneity of rock mineral particles and pore structures are identified as direct causes of elevated breakdown pressures. Indirect causes include contamination from drilling, completion, and perforation operations, which lead to reservoir blockages and reduce the reservoir's permeability. Therefore, breakdown pressure can be reduced by enhancing the connectivity of the reservoir's pore structure, improving its permeability, and weakening the mechanical strength of the rock.

The discussion then focuses on the mechanism by which acidizing technology reduces breakdown pressures (Fig. 25). Acidizing improves reservoir permeability and reduces the mechanical properties of reservoir rocks by chemically dissolving rock minerals and blockages caused by engineering operations, making the rock more prone to fracture under external pressure.

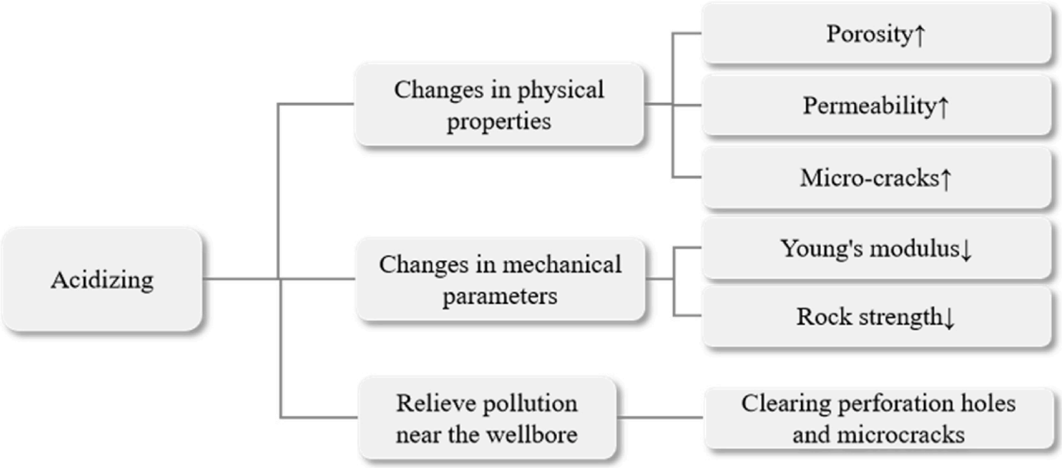

Fig. 25. Mechanism of acidizing reducing breakdown pressure.

In Section 3.2, we further examine the role of acid fluid systems in acidizing technology aimed at reducing reservoir breakdown pressure. In the absence of corrosion concerns, HCl systems are typically the most effective acid fluids for acidizing. However, in high-temperature deep wells, the safety of downhole equipment is the primary consideration. As a result, organic acid and chelating agent systems are often preferred. Organic acids exhibit significantly lower corrosiveness to downhole strings compared to HCl at the same concentration. However, due to their slower reaction rate and potential for secondary precipitation, their concentration must be carefully controlled. Chelating agents, particularly GLDA, are even less corrosive than organic acids, offering good water solubility, low corrosiveness, high-temperature resistance, and excellent biodegradability. However, due to their relatively slow chemical reaction rate with carbonate rocks, they cannot effectively weaken rock mechanical strength in the short term. This limitation restricts their ability to rapidly reduce formation fracturing pressures, which is why they are typically used in combination with stronger acids like HCl. Under high-temperature conditions, the acid fluid system is the key factor in ensuring safe and efficient acid treatment to reduce reservoir breakdown pressure. In the final of section 3, a comparative analysis of various acid fluids is presented, as summarized in Table 3.

Accurately evaluating the acidizing performance is crucial for subsequent success in fracturing operations. Changes in rock properties and mechanical performance are the foundation for studying changes in breakdown pressures. The fourth section of the paper introduces various evaluation methods from a micro to macro perspective and compares them, as shown in Table 4. SEM is commonly used for rock sample property evaluation, which can directly display the mineral composition, pore structure, and other characteristics of rock samples. CT scanning technology can quickly and non-destructively obtain detailed information on the internal structure of rocks, but the testing cost is relatively high. NMR technology cannot directly display the internal situation of rocks, but it can indirectly reflect the changes in rock pore structure, fluid distribution, and physical properties brought about by acidizing. Rock mechanical property evaluation commonly uses rock mechanical experiments (uniaxial, triaxial compression tests, Brazilian split tests) to directly measure the mechanical performance parameters of rocks, but it is destructive to rock samples. Ultrasonic testing is non-destructive and can indirectly reflect changes in rock mechanical properties, but it does not cover a comprehensive range of rock mechanical parameters. Rock hardness testing experiments can reflect the resistance of rock samples to permeation and permanent deformation, but the testing process has some destructiveness to the material surface, is cumbersome, and requires multiple point tests to avoid errors.

Based on the above discussion, the acidizing performance evaluation methods introduced can be further used to optimize, assess, and develop acid fluid systems suitable for deep high-temperature carbonate reservoirs. Attention should be given to issues such as the corrosiveness of acidic fluids to downhole tubulars. And section 5 emphasizes that finding alternatives to HCl, or developing chelating agents with improved metal ion chelation rates, the challenges associated with chelating agents can be addressed, ensuring efficient operations and the safety of downhole tubing.

Nomenclature

EGS	Enhanced Geothermal Systems
σ_v	vertical stress
σ_H	maximum horizontal principal stress
σ_h	minimum horizontal principal stress
P_b	breakdown/initiation pressure
P_0	pore fluid pressure,
σ_T	tensile strength of the rock
SD	Silurian dolomite
IL	Indiana limestone
AC	Austin chalk
PR	Poisson’s ratio
HCl	hydrochloric acid
HCOOH	Formic acid
CH_3COOH	Acetic acid
$C_6H_8O_7$	Citric acid
$C_3H_6O_3$	Lactic acid
H_nY	typical structure of chelating agents
n	number of carboxylic acid groups
Y^{n-}	fully ionized form of chelating agents
EDTA	ethylenediaminetetraacetic acid
HEDTA	hydroxyethyl ethylenediamine triacetate
NTA	nitrilotriacetic acid
GLDA	glutamic acid diacetic acid
DTPA	diethylenetriaminepentaacetic acid
SEM	glutamic acid diacetic acid
XRD	X-ray diffraction
CT	computer tomography
NMR	nuclear magnetic resonance
UCS	uniaxial compressive strength
CSM	continuous stiffness measurement
V_p	longitudinal wave velocity

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V_s	transverse wave velocity
E	elastic modulus
IM	material index
K_o	static lateral soil pressure coefficient
VES	viscoelastic surfactants

CRediT authorship contribution statement

Pingli Liu: Writing – review & editing, Supervision, Funding acquisition, Conceptualization. **Yu Wu:** Writing – original draft, Methodology, Investigation. **Xiang Chen:** Supervision. **Wen Luo:** Writing – review & editing. **Jinming Liu:** Project administration. **Pengfei Chen:** Investigation. **Gang Xiong:** Visualization. **Juan Du:** Visualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Data availability

Data will be made available on request.

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