

Review Paper

A review of matrix acidizing for carbonate reservoirs

Xiang Chen^{a,b,c}, Zhao-Xu Deng^{a,c}, Ping-Li Liu^{a,c,*}, Juan Du^{a,c}, Tian-Yu Zhang^{a,c},
Ying Xiong^d, Hong-Ming Tang^a, Wei Li^d, Zi-Lan Xiong^c

^a State Key Laboratory of Oil and Gas Reservoir Geology and Exploitation, Southwest Petroleum University, Chengdu, 610500, Sichuan, China

^b Engineering Research Center of Geothermal Resources Development Technology and Equipment, Ministry of Education, Jilin University, Changchun, 130026, Jilin, China

^c Petroleum Engineering School, Southwest Petroleum University, Chengdu, 610500, Sichuan, China

^d Natural Gas Technology Research Institute, PetroChina Southwest Oil & Gas Field Company, Chengdu, 610051, Sichuan, China

ARTICLE INFO

Article history:

Received 9 September 2025

Received in revised form

12 February 2026

Accepted 9 June 2026

Available online 17 June 2026

Edited by Xi Zhang

Keywords:

Carbonate rock
Geothermal reservoir
Petroleum reservoir
Matrix acidizing
Research progress

ABSTRACT

Carbonate reservoirs are rich in geothermal and petroleum resources, and matrix acidizing is one of the main methods for such reservoir's stimulation. This study systematically reviewed the research progress of matrix acidizing technology for carbonate reservoirs. It introduced the development history of acidizing technology, judgment method of whether to use matrix acidizing, acid-rock reaction mechanism and steps, acid system and its optimization methods, the influencing factors and simulation methods of wormhole, acid distribution processes, optimization methods of construction parameters, real-time diagnosis and effectiveness evaluation methods of acid treatment. Then, the future development trend of matrix acidizing for carbonate reservoirs was prospected. Some interesting insights were as follows. Firstly, due to the influence of factors such as closure stress and rock mechanical properties, there were significant differences in the critical permeability values suitable for matrix acidizing in different reservoirs. Secondly, compared to strong acids, the reaction between weak acids and rocks involved an additional step. Starting from the idea of controlling the steps of acid-rock reaction, a new approach was provided for the development of slow reactive acid fluids for high temperature reservoirs. Thirdly, the dual scale wormhole model had good prospects at the engineering scale, and in the future, it should focus on breaking through the three-dimensional radial flow wormhole extension simulation considering pores, cracks, and caves. Fourthly, uniform acid distribution methods included two categories, i.e., mechanical and chemical methods, with four and six sub-categories respectively. Its action areas were in the wellbore and the formation respectively, and the mechanical methods were generally more expensive. Fifthly, the acidizing efficiency was highest when forming the dominant wormhole, and the displacement should be appropriately increased with the increase of injection time during acid treatment. Lastly, it was necessary to focus on establishing evaluation criteria for diversion methods and evaluation method for acidizing effects considering complex reservoir and diversion acidizing.

© 2026 The Authors. Publishing services by Elsevier B.V. on behalf of KeAi Communications Co. Ltd. This is an open access article under the CC BY license (<http://creativecommons.org/licenses/by/4.0/>).

1. Introduction

Geothermal energy represents a clean and renewable resource, and carbonate rock reservoirs are abundant in geothermal energy resources (Chen et al., 2026a; Liu et al., 2024). In the context of carbon peaking and carbon neutrality goals, it has garnered significant attention from governments and enterprises (Deng et al.,

2025a, 2025b). There are numerous commercially developed geothermal projects in carbonate reservoirs worldwide, such as Altheim in Austria, St. Gallen in Switzerland, Mauerstetten in Germany, as well as Xian County and Xiong'an in China (Al-Ghamdi et al., 2025; Arndt et al., 2021; Chen et al., 2025e; Kaminskaite-Baranauskiene et al., 2023; Vadiie et al., 2025). Furthermore, carbonate reservoirs account for approximately 70% of the total petroleum reserves and contribute to roughly 60% of petroleum production (Guo et al., 2020; Li et al., 2018; Mou, 2023). Evidently, carbonate reservoirs constitute the mainstay of petroleum reserves and production, presenting vast prospects for exploitation. There are numerous renowned carbonate reservoir

* Corresponding author.

E-mail address: liupingli@swpu.edu.cn (P.-L. Liu).

Peer review under the responsibility of China University of Petroleum (Beijing).

oil and gas fields that have undergone commercial development worldwide, such as Ghawar oilfield in Saudi Arabia, Burgan oilfield in Kuwait, Ahvaz oilfield in Iran, Sarira oilfield in Libya, Baghdad oilfield in Iraq, Zohr gas field in Egypt, Libra oilfields in Brazil, Lloydminster oilfield in Canada, and the Tarim oilfield in China (Liu et al., 2025a, 2026a; Abdel-Fattah et al., 2022; Wang et al., 2025a; Xue et al., 2019; Zhao et al., 2020c).

During operations such as drilling, completion, cementing, well workover, and production, the reservoir is susceptible to damage. Hence, reservoir stimulation is highly necessary to improve petroleum production and geothermal energy extraction efficiency (Chen et al., 2024b, 2025d; Liu et al., 2023b; Xue et al., 2025; Zuo et al., 2025, 2026). Acid treatment is a commonly utilized method for carbonate reservoirs stimulation and has been successfully implemented in various oilfields worldwide (Chen et al., 2025b; Liu et al., 2025c; Yuan et al., 2025). The origins of acidizing technology can be traced back to the U.S. patents granted to Frasch and Van Dyke of Standard Oil in 1896 for their acidizing methods. Since then, acidizing technology has garnered attention from both academic and industrial circles. In 1979, Williams et al. authored the seminal book titled “Acidizing Fundamentals”, which was the first specialized monograph on reservoir acidizing. Subsequently, numerous scholars conducted systematic and in-depth research on acidizing technology, which has been widely applied in carbonate reservoir formations (Ali et al., 2016; Chen et al., 2024c; Luo et al., 2021; Zhao et al., 2020a, 2024).

Based on differences in processing objects, injection pressures, and stimulation principles, acid treatments can be categorized into three techniques: acid washing, matrix acidizing, and acid fracturing. Acid washing primarily targets the wellbore and perforation holes, with the main objective of dissolving blockages within it. In contrast, both matrix acidizing and acid fracturing focus on the reservoir. During matrix acidizing, the injection pressure is maintained below the formation fracture pressure, whereas in acid fracturing, the injection pressure is greater than the formation fracture pressure.

This study focuses on the theme of matrix acidizing, and its working principle is shown in Fig. 1. Due to the complexity of formations, varying well types, and the real-time variations arising from acid-rock reactions during acid treatment processes, the technical selection, design, and post-evaluation of acid treatment are intricate systemic challenges. Some scholars had reviewed the development of matrix acidizing from different perspectives, as shown in Table 1. However, there is currently a lack of a systematic review of the entire process of matrix acidizing, including what characteristics of reservoirs are suitable for matrix acidizing, how to select the best acid system from numerous acid systems, how to design construction parameters (e.g., acid volume and displacement), how to release acid to the desired location, how to diagnose the effect in real time during acidizing process, and how to evaluate the acidizing effect after acidizing treatment.

This study will systematically review the research progress of matrix acidizing technology for carbonate reservoirs, covering aspects such as the suitability of various carbonate reservoirs for matrix acidizing, the mechanisms and processes of acid-rock reactions, acid systems and its selection, factors influencing and simulation of matrix acidizing, acid distribution techniques, optimization of construction parameters, and post-acidizing evaluation methods. This study can provide reference for relevant practitioners.

2. Selection of acid treatment technique

Currently, the industry generally recognizes that matrix acidizing should be conducted in high-permeability carbonate reservoirs, while acid fracturing is more suitable for low-permeability carbonate reservoirs. However, regarding the threshold value for permeability, there exists considerable variation among the critical values adopted by different oilfield companies. Daneshy et al. (1998) suggested 20 mD as a general reference point, albeit without providing a scientific rationale for selecting this value in their literature. Palharini Schwalbert et al. (2020) proposed that a combination of parameters such as reservoir permeability, closure stress, and rock mechanical properties could serve as criteria to determine whether matrix acidizing or acid fracturing was the optimal choice. For a specific reservoir, both rock mechanics and closure stress have a critical threshold; if these values were below their thresholds, acid fracturing yielded higher productivity compared to matrix acidizing. Conversely, when permeability exceeded this threshold, matrix acidizing becomes a more favorable option. Notably, the critical thresholds varied significantly among reservoirs with different conditions. Schwalbert (2019) employed numerical simulation to calculate the dimensionless production index (J_D) of the reservoir after both matrix acidizing and acid fracturing with the same volume of acid fluid. The stimulation method corresponding to the maximum J_D value was selected. The expression for J_D was:

$$J_D = \frac{q/\Delta p}{2\pi k_H h/B\mu} = \frac{B\mu}{2\pi k_H h} J \quad (1)$$

where J_D was the dimensionless production index; q was the production; Δp was the production pressure difference; k_H was the reservoir permeability; h was the reservoir thickness; B was the fluid volume coefficient; μ was the fluid viscosity; J was the production index.

For a detailed introduction to the fully coupled acid fracturing model utilized in numerical simulation calculations, please refer to the references (Aljawad et al., 2020a, 2020b; Deng et al., 2012; Murtada, 2018). This model primarily involved fracture propagation (Murtada, 2018), acid flow in different media (Aljawad et al., 2020a), acid-rock reaction and acid etching (Aljawad et al., 2020b), temperature field variation (Murtada, 2018), and acid-fracture conductivity (Deng et al., 2012). The coupled calculation process was illustrated in Fig. 2(a). It was noteworthy that this acid fracturing model did not account for the influence of natural fractures and was applicable to porous reservoirs. For a comprehensive explanation of the matrix acidizing model employed in numerical simulation calculations, please consult references (Liu et al., 2016; Palharini Schwalbert et al., 2020; Schwalbert et al., 2019; Xue et al., 2018a). This model primarily involved the wormhole propagation due to acid dissolution (Liu et al., 2016), temperature field (Xue et al., 2018a), and skin factors variation (Schwalbert et al., 2019). The simulation calculation workflow was depicted in Fig. 2(b).

Using the aforementioned model, with the basic parameters outlined in Table A1 of the Appendix, and considering burial depths of 3048.0 m and 914.4 m for Case 1 and Case 2, respectively, the calculated J_D for acid fracturing and matrix acidizing stimulation were shown in Fig. 3. When the reservoir permeability was less than 0.1 mD, it became difficult to achieve the optimal injection rate for matrix acidizing, with minimal variation observed in

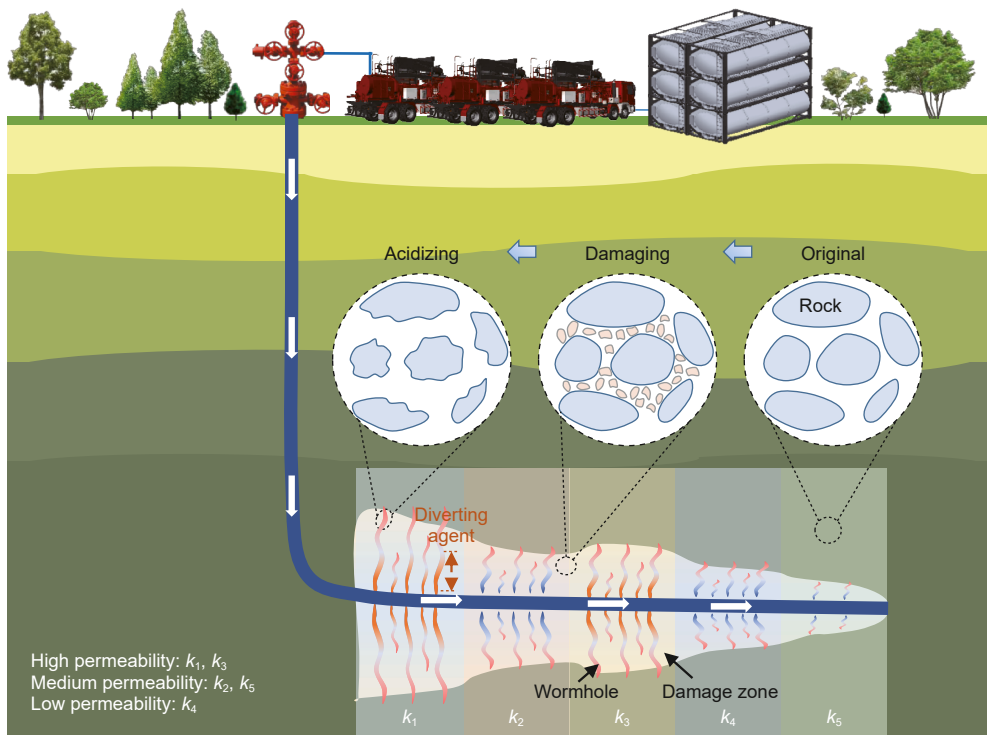


Fig. 1. Schematic diagram of diversion acidizing during matrix acidizing treatment.

Table 1
Summary of matrix acidizing review papers.

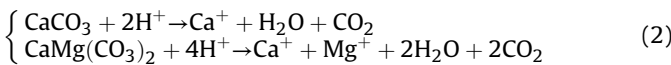
Author	Year	Main work
Chen et al. (2026b)	2026	It reviewed the recent progress in acid fracturing under ultra-high temperature and high pressure (UHTHP) environments, as well as the limitations of current acid-rock reaction kinetics models for UHTHP environments.
Khojastehmehr et al. (2025)	2025	The influence of reaction product CO ₂ on the kinetics of acid-rock reactions was presented.
Urgel-Pinto and Alcázar-Vara (2024)	2024	The qualitative and quantitative characterization of carbonate mineral dissolution profiles (e.g., wormhole) generated during matrix acidizing processes using X-ray computed microtomography was reviewed.
Baioumy et al. (2024)	2024	A review of case studies on matrix acidizing for optimizing acid placement in smart completion application was presented.
Alameedy et al. (2023)	2023	The influence of matrix acidizing on the mechanical properties of carbonate rock was presented.
Mohammadi and Shabbazi (2023)	2023	The mechanism and solution of acid-induced sludge formation during matrix acidizing process was reviewed.
Garrouch and Jennings (2017)	2017	The selection guidelines for acid fluids and additives during matrix acidizing treatment of vertical well in carbonate reservoirs were presented.
This work		The entire process of matrix acidizing is reviewed, including formation selection, acid system, acid-rock reaction kinetics, acidizing numerical simulation, construction parameter design, acid distribution technology, real-time diagnosis, and post acidizing evaluation.

the J_D (Fig. 3(a)). Once the permeability exceeded 6.0 mD, matrix acidizing could effectively eliminate reservoir damage, with the J_D up to 0.3. When the permeability surpassed 22 mD, matrix acidizing yielded a greater J_D compared to acid fracturing. For such reservoirs, the critical permeability threshold was 22 mD. For Case 2, as shown in Fig. 3(b), the critical permeability threshold was 120 mD. The difference between Case 2 and Case 1 was attributed to varying burial depths. It was evident that the critical permeability threshold varied significantly under different reservoir conditions. The detailed mechanism of this phenomenon is described in the literature (Palharini Schwalbert et al., 2020). Therefore, it was essential to calculate and determine which type of carbonate reservoir was suitable for matrix acidizing based on reservoir conditions.

3. Acid-rock reaction mechanisms

Matrix acidizing involved injecting acid fluids at pressures below the reservoir fracture pressure, where chemical reactions occurred between the acid, rocks, and blockage. By analyzing the mechanism of acid-rock reactions, methods could be identified to address issues such as rapid acid-rock reaction rates and tubing corrosion under high temperatures.

The main minerals in carbonate reservoirs were calcite and dolomite. The chemical reaction equations for strong acids (e.g., hydrochloric acid and sulfuric acid) with calcite (CaCO₃) and dolomite (CaMg(CO₃)₂) were as follows:



The reaction product CO₂ could form carbonic acid (H₂CO₃), but it did not dissociate in strong acids. When the solution became supersaturated with CO₂, the CO₂ would exist in the gaseous phase, and bubbling at the rock surface will accelerate mixing and

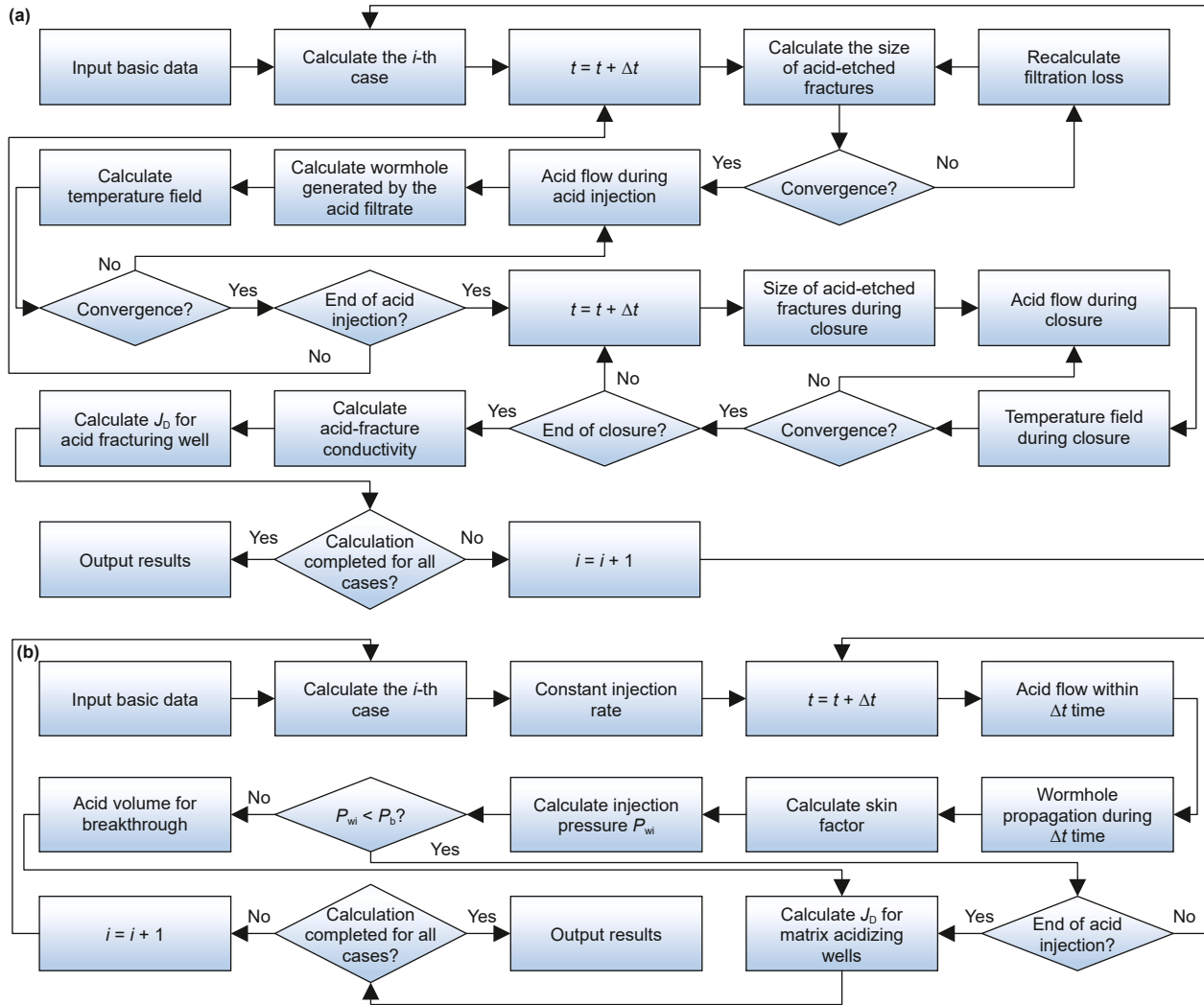


Fig. 2. Flowchart of numerical simulation. (a) Acid fracturing, and (b) matrix acidizing.

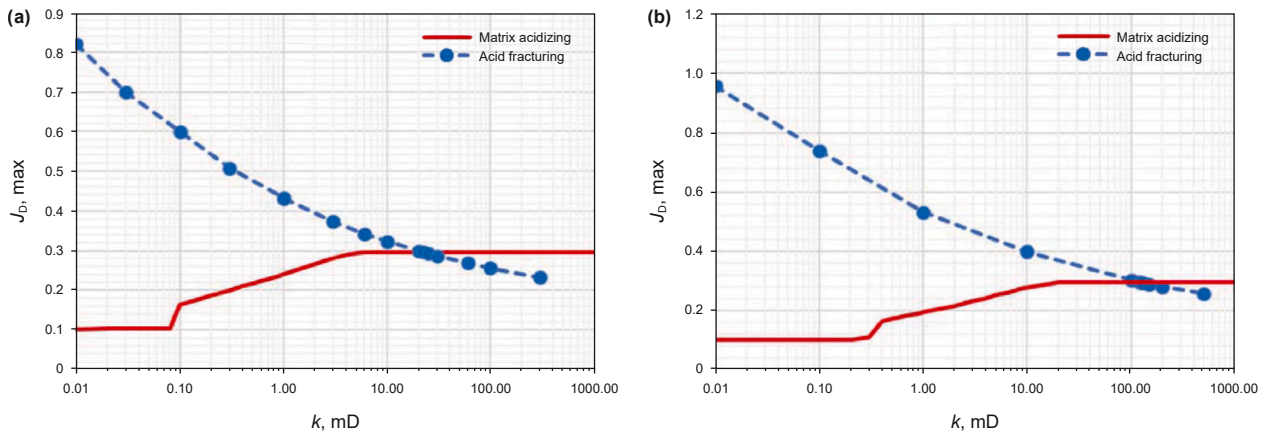


Fig. 3. Simulation results under different acid treatment technique. (a) Case 1: reservoir depth 3048.0 m, and (b) Case 2: reservoir depth 914.4 m (Palharini Schwalbert et al., 2020).

mass transfer (Alhammad et al., 2024; Wang et al., 2025b; Xue et al., 2018a). As the reaction products accumulate, the common ion effect increasingly inhibited the acid-rock reaction, particularly in low-viscosity acid solutions (Belshaw et al., 2024; Ren and

Xiong, 1989). As shown in Fig. 4, when acid reacted with rock, a diffusion boundary layer formed by reaction products existed near the rock surface, resulting in a concentration gradient. H^+ reach the rock surface through both convection and diffusion, and the

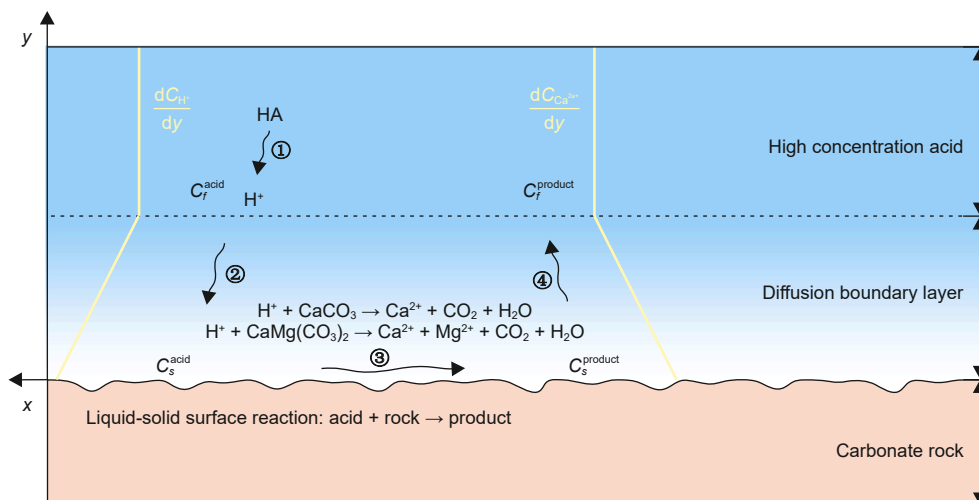


Fig. 4. Schematic diagram of acid-rock multiphase reaction mechanism and processes.

speed at which this occurs was referred to as the mass transfer rate. The rate at which acid solution reached the rock surface or the rate at which reaction products departed from the rock surface, denoted as J , could be expressed as:

$$J = K_{mt}(\bar{A}_f - \bar{A}_s) \quad (3)$$

where K_{mt} was the mass transfer coefficient; $\bar{A}_f$ was the activity of the acid solution or product far away from the rock surface; $\bar{A}_s$ was the activity at the rock surface. The activity was the product of the activity coefficient (α) and the concentration (C) of the acid solution or product.

The reaction rate R of the acid-rock surface interaction could be expressed as:

$$R = K_r C_s^n \quad (4)$$

where K_r was the reaction rate constant; C_s was the concentration of the acid solution at the rock surface; n was the order of the reaction.

Unlike strong acids, weak acids (e.g., formic acid, citric acid, etc.) undergone slow dissociation, with the dissociation process being:



where A^- was the ligand, e.g., $HCOO^-$ and CH_3COO^- . The products Ca^{2+} and Mg^{2+} would form weak acid salts with the ligand A^- . The product CO_2 reacted with water to form carbonic acid, influencing the dissociation of weak acids.

The reaction between weak acids and rocks differed from that of strong acids, proceeding through four stages (Fig. 4) (Du et al., 2026; Li et al., 2024b; Mouallem et al., 2025): (1) dissociation to release active H^+ ; (2) transport of H^+ towards the rock surface; (3) chemical reaction between the adsorbed H^+ on the rock surface and the carbonate mineral present there; and (4) transport of the reaction products from the rock surface. Since strong acids undergone complete dissociation, stage (1) could be accomplished within an extremely short period of time and could be neglected (Li, 2023). If one of the four stages was significantly slower than the other three, then the slowest stage would dominate the overall reaction, and it could be approximated as the rate-determining step for the overall reaction rate. For strong acids, the acid-

calcite reaction was controlled by mass transfer at temperatures above 25 °C (i.e., stage 2 above), while the acid-dolomite reaction was controlled by surface reactions at temperatures below 100 °C (i.e., stage 3 above) (Ali et al., 2016). Therefore, by controlling any of the aforementioned four processes, particularly the slowest one, acid-rock reaction rate could be delayed to a certain extent, addressing the challenges posed by high temperatures. By controlling process (1) and reducing the concentration of H^+ within the wellbore, the corrosion challenge faced by tubular strings at high temperatures could be mitigated.

4. Acid system and selection

Acid fluid served as a crucial material in matrix acidizing. Based on differences in acid types and primary mechanisms of action, acid fluids could be classified into conventional acids (e.g., hydrochloric acid), retarded acids (e.g., gelled acid, cross-linked acid, self-generating acid, and isolation membrane acid), and diverting acids (e.g., self-diverting acid, emulsified acid, and foam acid), as shown in Table 2. It was important to note that some diverting acids also possessed retarded effects.

By adding a gelling agent or cross-linking agent to a hydrochloric acid system, gelled acid or cross-linked acid could be formulated (Chen et al., 2025a). These systems exhibited higher viscosity compared to conventional acids, and their retardation mechanism involved reducing the acid-rock reaction rate by increasing the mass transfer resistance of stages (2) and (4) discussed in the previous section (Fig. 5(a)). Gomaa and Nasr-El-Din (2015), Xu et al. (2017), Wang et al. (2018), and Gong et al. (2020) reviewed the development history and primary materials of this type of acid fluid. Compared to conventional acids, the retardation mechanism of self-generating acid involved an additional stage (1), namely the slow release of H^+ . Depending on the type of self-generating acid fluid, self-generating acids could be further subdivided into self-generating hydrochloric acid, self-generating organic acid, and composite self-generating acids. Du et al. (2024), Liu et al. (2025b), and Zhang et al. (2023) systematically reviewed the advancements, acid-generating mechanisms, and performance characteristics of various self-generating acids. By forming an adsorptive film on the rock surface, the isolation membrane acid isolated the acid solution from direct contact with the rock face (Fig. 5(a)), which increased the mass transfer

Table 2
Summary of characteristics of different acid systems.

Name	Application temperature	Retarded mechanism	Diversion mechanism	Advantage	Disadvantage
Gelled acid (Al-Shargabi et al., 2023; Wang et al., 2018)	<176 °C	Increasing the H ⁺ mass transfer resistance	\	Retarded reaction rate	High corrosion; increased friction resistance
Cross-linked acid (Gong et al., 2020; Xu et al., 2017)	<180 °C	Increasing the H ⁺ mass transfer resistance	\	Retarded reaction rate	Excessive gel-breaking residues; high corrosion; increased friction resistance
Self-generating acid (Du et al., 2024; Liu et al., 2025b; Zhang et al., 2023)	70–371 °C	Delay the release rate of H ⁺	\	Retarded reaction rate; relatively low corrosion	Low acidity from ester hydrolysis; high toxicity of raw materials yielding acid via nucleophilic substitution (e.g., formaldehyde)
Isolation membrane acid (Gou et al., 2024; Shen et al., 2023; Zakaria et al., 2022)	≤149 °C	Reducing the contact area between acid and rock, increasing the H ⁺ mass transfer resistance	\	Retarded reaction rate; low friction resistance	Changed the wettability of rock; not resistant to ultra-high temperatures; high corrosion
Self-diverting acid (Du et al., 2025; Al-Shargabi et al., 2023)	≤160 °C	Increased H ⁺ transport resistance caused by viscosity rise	Changed in flow resistance caused by viscosity variations	Automatic viscosity change; retarded reaction rate; minor reservoir damage	Not resistant to ultra-high temperatures; low to medium reservoir permeability difference; high corrosion
Emulsified acid (Carvalho et al., 2019; Al-Shargabi et al., 2023; Yousufi et al., 2024)	≤150 °C	Acid is wrapped in oil, which hinders the diffusion and migration of H ⁺	Different wettability of rock surfaces in oil and water channels	Low corrosion, low filtration loss, retarded reaction rate	High concentration emulsifier; low stability under high temperature, pH, and salinity
Foam acid (Jiang et al., 2025; Al-Shargabi et al., 2023)	≤90 °C	Reducing the contact area between acid and rock, increasing the apparent viscosity	Jamin effect	Retarded reaction rate, promoting fluid backflow, minor reservoir damage	Not resistant to high temperatures

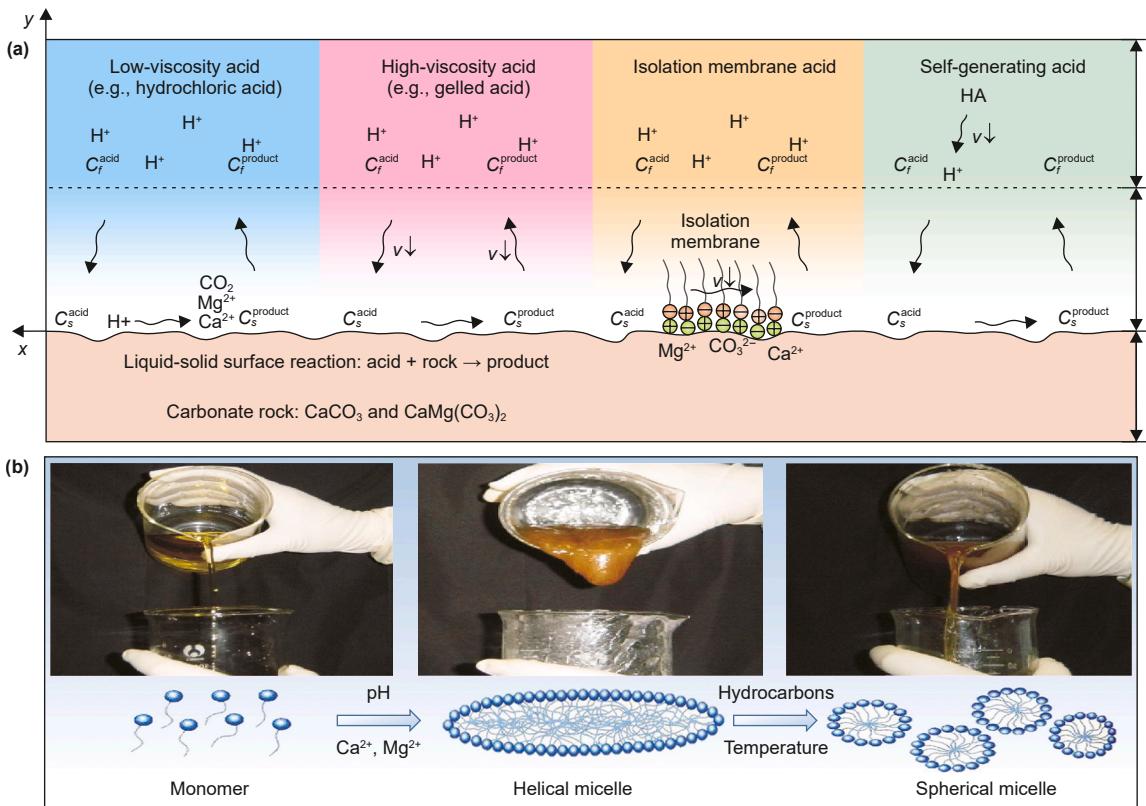


Fig. 5. Schematic diagram of the mechanism of acid action. (a) The retarded mechanism of retarded acids, and (b) the viscosity change mechanism of VES acid (Zhao et al., 2020b).

resistance in stage (2) and reduced the acid-rock reaction area in stage (3) (Gou et al., 2024).

By incorporating viscoelastic surfactants (VES) into a hydrochloric acid system, a self-diverting acid (VES acid) was formulated, which exhibited low initial viscosity. However, as the acid-rock reaction progresses, it generated Ca^{2+} and Mg^{2+} and resulted in an increase in pH, triggering the VES acid system to automatically increase in viscosity. It was noteworthy that while the viscosity change of self-diverting acid conferred a certain degree of retardation, this was not its primary objective; diversion remained its main function. Upon the conclusion of the acidizing process, the high viscosity VES acid automatically degraded into a low viscosity solution for backflow at reservoir temperature or upon contact with hydrocarbons (Chen et al., 2024a; Liu et al., 2023a; Wilson, 2016; Zhao et al., 2020b), as shown in Fig. 5(b). The mechanism of diversion acidizing of VES acid as follows: initially, based on the principle of minimum flow resistance, most of the acid fluid entered the high-permeability zones. The acid-rock reactions in these zones caused the viscosity of the acid fluid system to increase, which in turn raised the resistance for subsequent acid fluid to flow back into these areas. This forced the subsequent acid fluid to divert into low-permeability zones or unacidized areas, thereby achieving uniform acidizing throughout the entire wellbore and formation. Emulsified acid, formulated from acid, oil, and emulsifier, took advantage of the wettability differences between oil and water flow channels, enabling more acid fluid to enter the oil channels for diversion acidizing. Du et al. (2025), Yousufi et al. (2024), Jiang et al. (2025), Al-Shargabi et al. (2023), and Zhao et al. (2020b) systematically reviewed the research progress of VES acid, emulsified acid, and foam acid.

There were numerous acid fluid systems available, and selecting the appropriate one was crucial for the success of matrix acidizing. When selecting an optimal acid fluid, the following aspects could be considered (Fig. 6) (Ali et al., 2016; Economides et al., 2015; Economides and Nolte, 2002; Garrouch and Jennings, 2017; Leonard, 2008; Li, 2023; Liu et al., 2025d; Mou,

2023; Nan et al., 2025): (1) based on the reservoir characteristics, identify the key issues that need attention when selecting an acid fluid for matrix acidizing, such as diversion in long well intervals, acid corrosion and acid-rock reaction rate at high temperature; (2) the ability of the acid fluid to remove reservoir plugging and reservoir minerals; (3) the capacity of the acid fluid to create wormholes in carbonate reservoirs; (4) the damage to the reservoir caused by residual acid.

5. Influencing factors and simulation methods of matrix acidizing

The primary means of removing the skin factor in carbonate reservoir matrix acidizing involved dissolving the plugging materials and reservoir minerals or creating acid-etched wormholes to bypass the damaged zones. During matrix acidizing, it was generally desirable to create elongated wormholes in reservoir, i.e., the dominant wormhole in Fig. 7(b), which could reduce the reservoir skin factor from a positive number to zero, or even to a negative value (Yang et al., 2020).

Numerous factors influenced the formation of wormholes, encompassing geological factors (e.g., pore-fracture-vug structures, reservoir heterogeneity, pressure, mineral composition, and temperature), and engineering factors (e.g., injection rate, injection temperature, acid concentration, and acid type) (Li et al., 2024c; Liu et al., 2017b; Mo et al., 2025; Xie et al., 2023). The breakthrough volume (PV_{Bt}) referred to the number of times the pore volume of the acid solution required to break through the core. The influence of acid concentration and injection rate on PV_{Bt} was shown in Fig. 7. As the acid concentration increased, PV_{Bt} initially decreased rapidly and then more gradually, with a higher injection rate required to achieve the corresponding minimum PV_{Bt} . As the injection rate increased, PV_{Bt} first decreased and then increased, during which five typical dissolution patterns emerged (Fig. 7(b)). Among them, the dominant wormhole pattern was the highest acidification efficiency. Injecting acid into a high-

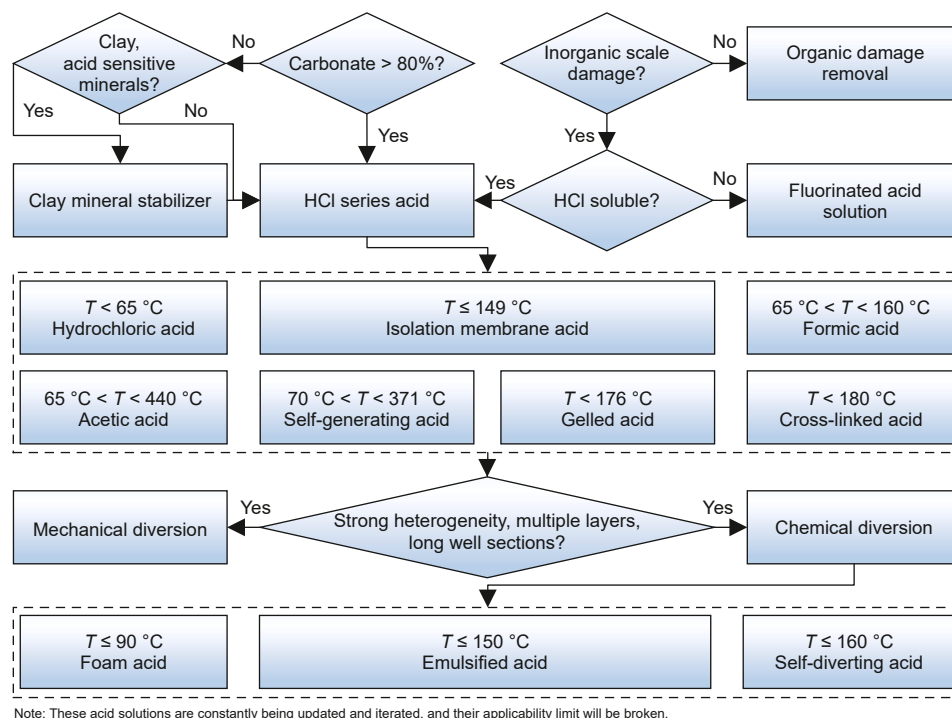


Fig. 6. The decision flowchart for acid system selection.

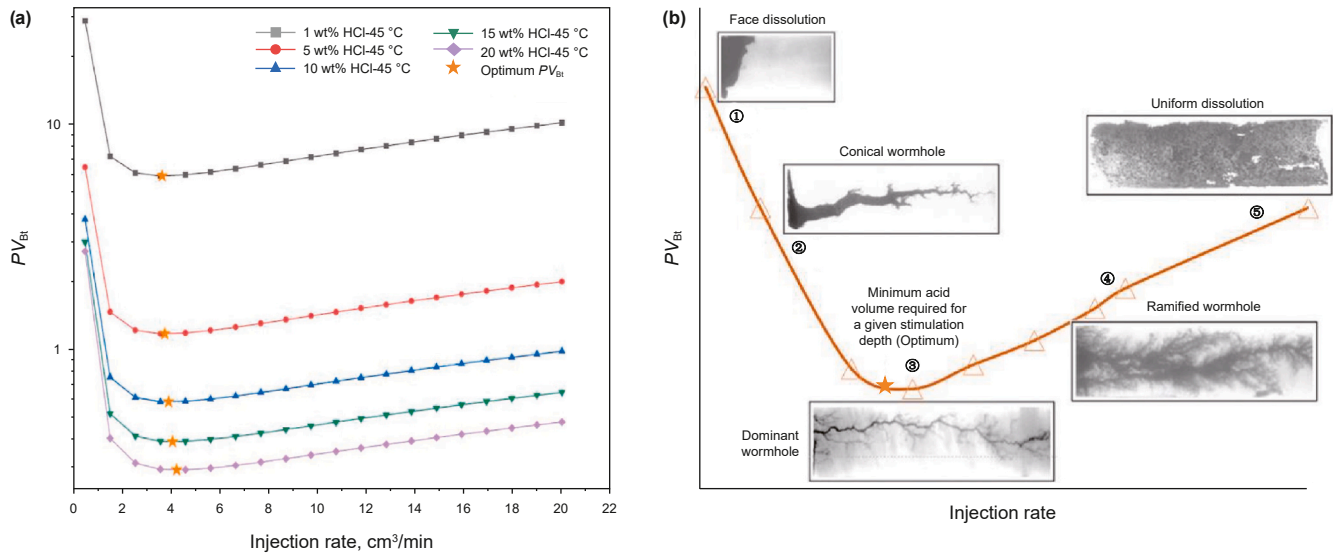


Fig. 7. The influence of injection rate and acid concentration. (a) PV_{Bt} (dos Santos Lucas et al., 2023), and (b) dissolution patterns.

temperature reservoir at a lower injection temperature could result in longer wormholes, facilitating deeper penetration (dos Santos Lucas et al., 2023). The impact of temperature on PV_{Bt} varied significantly for different types of acid fluids, and it could either increase (e.g., hydrochloric acid) or decrease (e.g., EDTA chelating acids) (Ali et al., 2016). Pressure influenced the phase state and solubility of CO_2 produced during the acid-rock reaction, thereby affecting the reaction rate. Compared to low pressure, the extension rate of acid-etched wormholes was faster at high pressure (Xue et al., 2018a). The pore-fracture-vug structures and reservoir heterogeneity not only influenced the morphology of wormholes but also affected the magnitude of PV_{Bt} , as shown in Fig. 8. The flow of acid followed the principle of minimal flow resistance, and the presence of pores, fractures, and cavities

altered the acid flow field and the reactive surface area, fundamentally changing the local Damköhler number, which in turn determined the resulting dissolution patterns. Therefore, when simulating wormhole propagation, it was necessary to not only study the influence of engineering factors but also take into account geological factors.

Fracture-cavity carbonate reservoirs were characterized by strong structural heterogeneity, where natural fractures and dissolution vugs or cavities constituted the primary flow pathways, while the rock matrix commonly exhibited relatively low permeability. Extensive experimental and numerical studies have demonstrated that the presence of fractures, vugs, and cavities fundamentally altered fluid flow geometry, acid transport behavior, and acid-rock interaction mechanisms during matrix

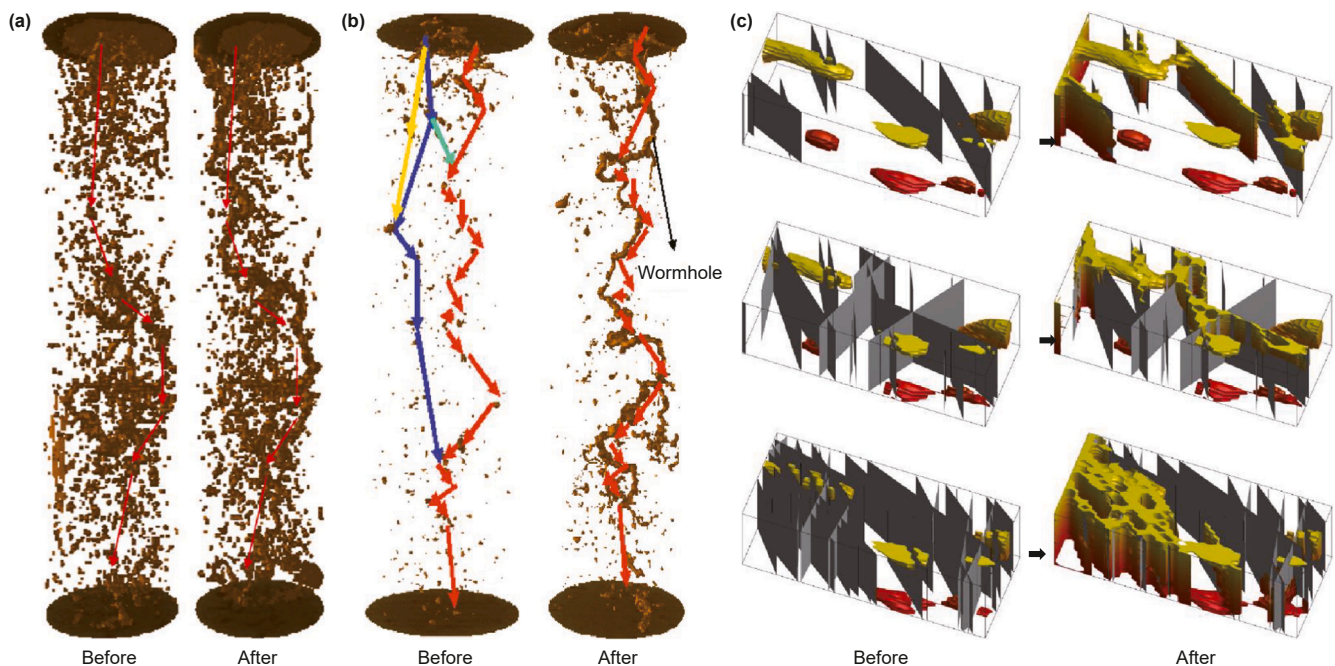


Fig. 8. The influence of pore-fracture-vug structure and reservoir heterogeneity. (a) CT scan before and after acid injection (Izgec et al., 2010), and (c) wormhole propagation under different geological conditions (Liu et al., 2023c).

acidizing (Ali et al., 2020; Chen et al., 2026c; Lei et al., 2019; Liu et al., 2022; Liu et al., 2025e; dos Santos et al., 2025; Wang et al., 2014; Zhou et al., 2022b). As a result, acid injection in such reservoirs was prone to preferential channeling along high-conductivity features, leading to early acid breakthrough and limited stimulation of the surrounding matrix. Unlike porous carbonate reservoirs, where stimulation effectiveness was often associated with the initiation and propagation of dominant wormholes, matrix acidizing in fracture-cavity systems was mainly governed by dissolution along fracture surfaces and cavity boundaries. Acid-rock reactions were concentrated on fracture walls, and the enlargement or interconnection of existing fractures and cavities became the primary mechanism for permeability enhancement. Consequently, classical wormhole growth models developed for porous reservoirs cannot adequately capture the acidizing behavior in fracture-cavity carbonate reservoirs. Furthermore, recent studies incorporating thermal-hydrologic-chemical or fully coupled thermo-hydro-mechanical-chemical processes from Chen et al. (2025c, 2026c), Lei et al. (2019), Zhou et al. (2022b), and Liu et al. (2023c) have revealed that reaction heat generation, temperature redistribution, and fracture deformation can significantly influence acid transport and reaction kinetics in fracture-cavity systems. These coupled effects further increased the complexity of matrix acidizing behavior.

Tight carbonate reservoirs were typically characterized by low porosity and ultra-low permeability, with pore structures dominated by micro-pores. In such reservoirs, matrix acidizing was strongly constrained by limited pore connectivity, high threshold pressure gradients, and short effective acid penetration distances (Andriamihaja et al., 2019; Liu et al., 2026b; Palharini Schwalbert et al., 2020). The initiation and stable propagation of wormholes in tight carbonate rocks were significantly more difficult to achieve (Ali and Ziauddin, 2020; Ali and Nasr-El-Din, 2020). Acid tended to be rapidly consumed near the wellbore, resulting in localized dissolution without the formation of wormhole channels (Cohen et al., 2008). For matrix-acidizing treatments, the minimum permeability was required to be able to inject at the optimal injection rate to propagate efficient wormholes (Fig. 7(b)). Taking Fig. 3(a) as an example, if the permeability was too low, matrix acidizing was not efficient because the injection velocity was too small. For permeabilities less than 0.1 mD, matrix acidizing cannot even remove all the formation damage.

The wormholes propagation models were summarized in Table 3. Among them, the numerical simulation models for wormholes propagation primarily encompassed the capillary model (Xue, 2017), fractal model (Hewen et al., 2017; Zhang, 2015), network model (Budek and Szymczak, 2012; Qi et al., 2020; Tansey and Balhoff, 2016), continuum medium model (Liu et al., 2017a; Nami et al., 2023; Panga et al., 2005), and porous media model (Kang et al., 2002; Ma et al., 2017). Firstly, the capillary model assumed wormholes to be cylindrical in shape (Fig. 9(a)), which did not consider the mass transfer and reaction mechanisms within the pores. Secondly, the fractal dimension was employed to characterize the complex dissolution morphology of wormholes, and the relationship between acid volume and equivalent wormhole radius (Fig. 9(d)), combined with the Damkohler criterion, was utilized to optimize acid volume and injection rate. Thirdly, the network model assumed that pores were cylindrical conduits within which acid fluid flowed and reacted (Fig. 9(c)). The acid-rock reaction resulted in an enlargement of conduit diameters. Generally, the calculated results of this model tended to be on the higher side, and the computational load was also relatively heavy. Fourthly, the continuum medium model operated at a scale larger than that of the network model, reaching the Darcy scale. It relied on empirical relationships to represent the microstructural

Table 3

Summary of characteristics of different matrix acidizing models.

Model	Ref.	Characteristic
Semi-analytical model	Buijse and Glasbergen (2005)	Propose a semi-empirical model for radial flow to predict the relationship between the wormhole growth rate and injection rate.
	Talbot and Gdansk (2008)	Propose to use a global function to fit experimental data on temperature, acid concentration, core aspect ratio, porosity, and permeability together to form a main curve and predict the optimal injection rate.
	Baghel and Praves (2016)	Consider the impact of chelating-agent-based acidizing fluid and compared it with HCl system.
Capillary model	Wei (2020)	Assume wormhole to be cylindrical in shape, and develop a mathematical model considering reaction kinetics, acid transfer rate, and fluid loss. This assumption deviates significantly from the observed wormhole structure in experiments.
Fractal model	Huang et al. (1999), and Huang et al. (2000)	Develop a wormhole process theory to predict the wormhole pattern based on acid flux and other processing variables.
	Frick et al. (1994)	The complex structure of wormholes had self-similarity characteristics, so fractal geometry was used to describe it, and the relationship between acid injection rate and equivalent radius of wormholes was derived.
	Liu et al. (2012)	Calculation of fractal dimension of two-dimensional acid dissolution morphology using box dimension method.
Network model	Fredd and Fogler (1998), and Fredd and Fogler (1999)	It was a pore-scale model composed of nodes connected by cylindrical pipes called bonds. These nodes act pore spaces, and bonds represent pore throats.
Continuum medium model	Panga et al. (2005), Xue et al. (2016, 2018b), and Xue et al. (2022)	It was the first to introduce reaction and mass-transfer control variables into the continuous medium model, which not only had the advantages of continuous medium model but also could accurately reflect physical and chemical processes such as flow, reaction, and local mass transfer like network model and porous medium model. The simulation results were consistent with experimental results, and the simulation

Table 3 (continued)

Model	Ref.	Characteristic
Porous media model		calculation amount was smaller.
	Ma et al. (2022), and Aboluhom and Aljawad (2023)	A wormhole propagation model for three-dimensional linear flow in porous or fracture-vug reservoirs.
	Aboluhom et al. (2024), and Saleh Aljawad (2023)	A wormhole propagation model for three-dimensional radial flow in porous or fractured reservoirs.
	Aljawad et al. (2021), and Wang et al. (2023)	The influences of the distribution patterns and spatial correlations of dolomite and calcite minerals, porosity and permeability, natural fracture or vug on two-dimensional wormhole propagation were discussed.
Lattice Boltzmann (LBM)	Békri et al. (1995), and Jyoti and Haese (2021)	It could truly describe the flow, mass transfer, reaction, and chemical kinetics in porous media, and was the most accurate model, but its computational workload was very large.
	Kang et al. (2002)	Using the LBM to simulate the convection, diffusion, and reaction of fluids in porous media, i.e. the dissolution of carbonate rock in 0.5M HCl and 0.5M HAc.
PHREEQC	Kashani et al. (2024), and Ma et al. (2017)	LBM was a mesoscopic scale method, and non-equilibrium extrapolation was used to handle reaction boundaries. The acid dissolution patterns of two-dimensional single pore and double pore media were studied.
	Parkhurst and Appelo (2025)	PHREEQC was an open-source package developed by the United States Geological Survey for the study of aqueous solution geochemistry.

changes in pore throats due to acid-rock reactions, which limited the model's computational accuracy. Panga et al. (2005) introduced reaction and mass transfer control variables into the continuum model, developing the Panga two-scale model (Fig. 9(b)). Numerous studies indicated that the simulation results from two-scale model were generally consistent with experimental results, with simulation accuracy generally exceeding 85% (Aboluhom and Aljawad, 2023; Cheng et al., 2020; Ghommem et al., 2015), and have reported its application to naturally fractured, vuggy, and heterogeneous carbonate reservoirs. The equivalent permeability tensor method and Stokes–Brinkman equation had been utilized to describe flow in discontinuous, multi-scale porous media (Liu et al., 2026b; Ma et al., 2018; Mou et al., 2024). Although these approaches exhibited certain discrepancies compared to actual subsurface flow behavior, they can still provide valuable guidance for engineering applications and acid treatment design, which has

also been demonstrated in numerous field applications (Tan et al., 2016; Yue et al., 2018). Finally, pore media models represented interfaces such as the fluid-mineral boundaries and avoided the volume-averaged properties such as porosity, permeability, and reaction rates as required in continuum-scale methods. Its advantage lay in accurately calculating local reaction rates and fluid compositions, with reported accuracy rates exceeding 93% (Alameedy et al., 2023; Jyoti and Haese, 2021). The research scale of pore media models was small, capable of accurately describing processes such as acid fluid flow, mass transfer, and reactions within pores.

Furthermore, in addition to using the acidizing mechanism model mentioned above for numerical simulation prediction, some researchers in recent years have begun training artificial intelligence or machine learning models with historical acidizing data to predict acidizing performance and optimize acid injection parameters (Alkathim et al., 2023; Temizel et al., 2021; Wu et al., 2025; Zhou et al., 2024). Temizel et al. (2021), Wu et al. (2025), and Ebadi et al. (2025) reviewed the application of machine learning techniques in hydraulic fracturing and acidizing, chemical and gas flooding, as well as water injection scenarios, and discussed the advantages and disadvantages of these machine learning methods. Sidaoui et al. (2018) used core type, dimensions, porosity, permeability, HCl concentration, temperature, and pressure as input parameters to train a machine learning model capable of predicting PV_{Bt} with 90% accuracy and optimizing injection rate. Ebadi et al. (2025) introduced an integrated computational framework for optimizing matrix acidizing processes. The framework first predicted post-treatment outcomes and then determined optimal injection volume and rate. In the prediction phase, four machine learning algorithms were trained to estimate post-acidizing skin factor. Among these models, the ExTree algorithm achieved the highest predictive accuracy, reaching 93% for skin factor. During the optimization phase, the validated ExTree model was coupled with two metaheuristic algorithm to identify the optimal injection volume and rate. Hatamizadeh and Sedaei (2023) used fluid saturation, injection rate, temperature, and acid concentration as input parameters. By employing a stacking method and combining different machine learning with the multi-level perceptron algorithm of meta-learning, the prediction accuracy of PV_{Bt} improved and reached 83%. By combining various artificial neural networks and deep learning models with a neural network algorithm as the meta-learning model, the PV_{Bt} accuracy of 90% could be achieved. Hence, it was used in conjunction with a genetic algorithm to optimize injection rate and acid concentration. Dargi et al. (2023) utilized permeability, porosity, skin factor, calcite content, and injection rate as input parameters. By employing three machine learning models, such as artificial neural networks, random forests, and XGBoost, along with genetic programming, they estimated the permeability change after hydrochloric acidizing in carbonate reservoir and optimized the volume of acid injection, achieving a prediction accuracy of 82%.

6. Acid distribution techniques

Due to the influence of inter-layer and intra-layer heterogeneity, the acid distribution techniques significantly determined the effectiveness of matrix acidizing for vertical wells with combined production from multiple layers and horizontal wells with long intervals (Fig. 1). Based on difference in acid placement methods, acid distribution techniques could be classified into sweeping acidizing and diversion acidizing. Furthermore, diversion methods could be subdivided into chemical diversion and mechanical diversion, as shown in Fig. 10. Mechanical diversion methods encompassed packers, bridge plug, ball sealers, coiled tubing, and

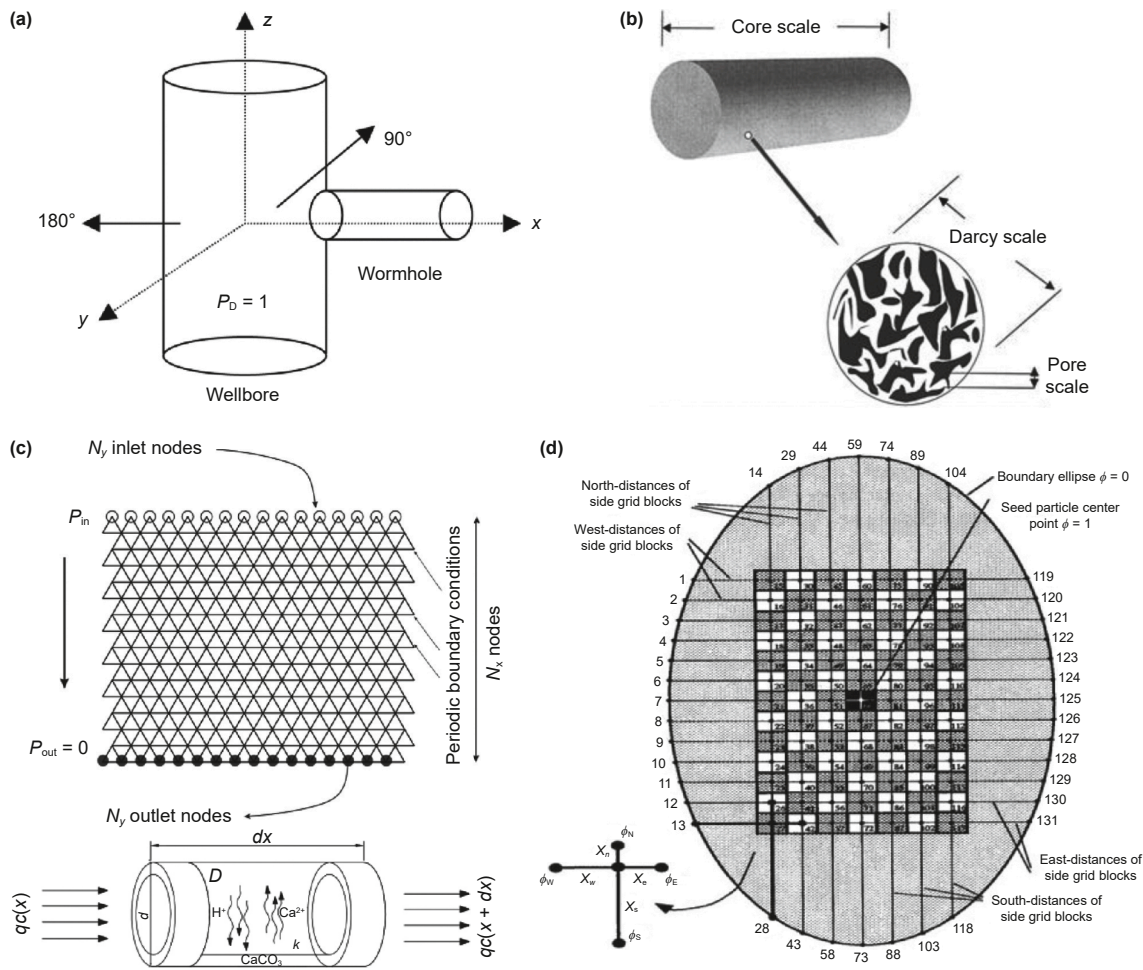


Fig. 9. Schematic diagrams of several typical wormhole propagation models. (a) Wellbore and wormhole system (capillary model) (Huang et al., 1999). (b) Two-scale model (continuum medium model) (Panga et al., 2005). (c) Network with line inputs and outputs, a pore and reactions at its surface (network model) (Budek and Szymczak, 2012), and (d) grid construction of the permeability driven fingering model (fractal model) (Pichler et al., 1992).

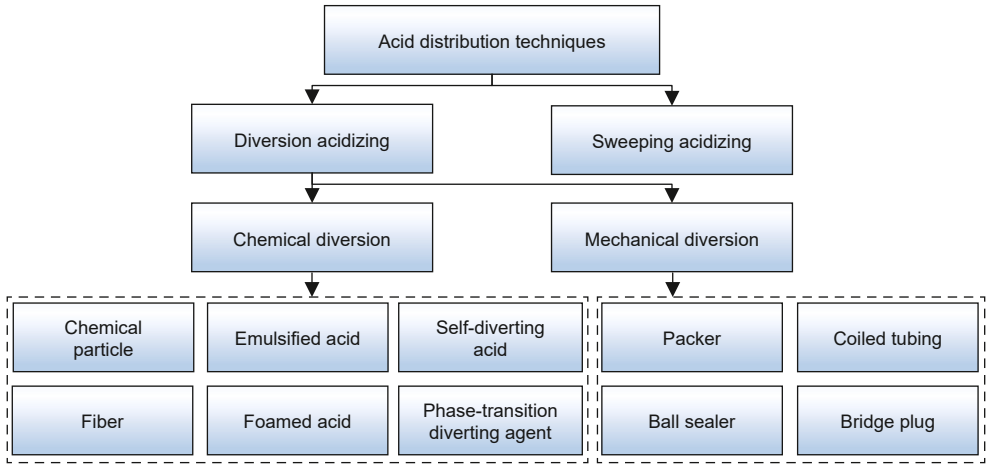


Fig. 10. Classification of acid distribution techniques.

hydraulic jetting, etc., while chemical diversion methods included chemical particulates, fibers, foamed acids, emulsified acids, self-diverting acids, and phase-change liquid diverting agent (Chen et al., 2021a, 2021b, 2023, 2024a; Du et al., 2023; Liu et al.,

2025c; Ndonhong et al., 2018; Sun et al., 2024; Zhao et al., 2020b). Mechanical diversion primarily functioned within the wellbore, whereas chemical diversion primarily operated within the reservoir.

The diversion mechanism of packer was physically isolating different layers or sections, and this technology was mature. However, the process of inserting, sealing, unsealing, and recycling the packer was time-consuming and costly. The diverting mechanism of ball sealer was sealing off the perforation holes. It placed relatively high demands on the string size, injection rate, and well deviation, and it was suitable for perforated completions. The coiled tubing diversion mechanism was injecting acid into specific locations by controlling the coiled tubing dragging speed and dwell time. However, it was limited by the small size of the coiled tubing, low displacement capacity, and restricted depth of insertion. Mao et al. (2018) and Bist et al. (2024) had elaborated on the characteristics and applicable scope of mechanical diversion technology. The diversion mechanism of chemical particulates, fibers, self-diverting acids, phase-change liquid diverting agent, foamed acids, and emulsified acids were the formation of filter cakes, filter screens, viscosity changes, temporary plugging by volume, wettability difference, phase permeability adjustments, and the Jamin effect, respectively (Table 2). Zhou et al. (2022a, 2025), Chen et al. (2024a), and Zhao et al. (2020b) had systematically reviewed and elaborated on the materials, characteristics, and applicable conditions of chemical diversion technology, as shown in Table 4.

In extremely heterogeneous reservoirs, mechanical diversion techniques such as packer and bridge plug could only isolate relatively long intervals macroscopically and were ineffective in cases where permeability varies drastically within a single interval. These tools were also prone to sticking or encountering obstruction in open-hole or deformed wellbores, and face high risks of seal failure under ultra-high temperatures (Bist et al., 2024; Mao et al., 2018). The diversion effectiveness of chemical particulate and fiber was highly dependent on the match between their size and the pore or fracture size in the formation. In reservoirs with extremely wide pore-throat size distributions, it was difficult to select a single size or a mixture of particulates or fibers to achieve comprehensive and effective temporary plugging (Chen et al., 2024a; Zhao et al., 2020b; Zhou et al., 2025). In high-temperature ($>90\text{ }^{\circ}\text{C}$), high-salinity ($>41 \times 10^4\text{ mg/L}$) environments or in the presence of crude oil, foam structures were easily destabilized, leading to a sharp decline in foam stability (Gao et al., 2026; Kong et al., 2023; Li et al., 2024a; Li and Zheng, 2023). Under high pressure, gases in the foam could dissolve extensively into the crude oil or acid, causing foam collapse. Emulsified acid was prone to premature demulsification under high-temperature ($>150\text{ }^{\circ}\text{C}$) or high-shear conditions (Al-Dogail et al., 2023; Zakaria and Nasr-El-Din, 2016). In formations with low carbonate content, strong buffering capacity, or in vugs and fractures, self-diverting acid might be diluted, and the concentration of reaction products (e.g., Ca^{2+} , Mg^{2+}) might remain too low or the pH might rise too slowly to reach the threshold required to trigger viscosity changes, resulting in delayed or failed diversion (Du et al., 2025; Al-Shargabi et al., 2023). In extremely heterogeneous reservoirs with characterized by large permeability difference multiple (>9.1) and extremely wide pore-throat or fracture size distributions (e.g., from microns to centimeters), chemical diversion techniques such as self-diverting acid, emulsified acid, and foamed acid were difficult to establish effective temporary plugging (Liu et al., 2015; Zhang et al., 2019; Zheng et al., 2024; Zhou et al., 2011).

7. Optimization of construction parameters

By optimizing the injection rate, a larger stimulation range could be achieved with a certain amount of acid, or the minimum amount of acid could be used to achieve the same stimulation effect, thereby improving acidizing efficiency and reducing

acidizing costs. As shown in Fig. 7(b), the acidizing efficiency was highest when the dominant wormhole was formed.

There were two primary methods for optimizing construction parameters: experimental and numerical simulation. Indoor physical simulation experiments were mostly characterized by linear flow, which differed to some extent from the actual radial flow in underground reservoirs. Alternatively, numerical simulation models for wormhole propagation could be utilized for prediction. By plotting a graph of injection rate versus PV_{Bt} , as shown in Fig. 7(a), the optimal injection rate corresponded to the inflection point on the curve. The criteria for determining the optimal injection rate included those proposed by Fredd & Fogler, Talbot & Gdansk, Panga, and Gong & El-Rabaa (Panga et al., 2005; Talbot and Gdansk, 2008). Akanni and Nasr-El-Din (2015) reviewed the principles, expressions, and applicable conditions of these criteria and considered the Talbot & Gdansk and Panga criteria to be highly accurate and universally applicable. In particular, the Talbot & Gdansk criterion was suitable for reactions between limestone and HCl. Based on the acidizing objectives for carbonate reservoir matrices, a skin factor reduction to -3 was often targeted in field operations. By combining the wormhole model with the skin factor model, the acid volume required at the optimal injection rate could be calculated. Additionally, empirical formulas could also be used for rough estimations:

$$V_{\text{acid}} = \phi h \pi (r_{\text{wh}}^2 - r_w^2) PV_{\text{Bt}} \quad (6)$$

where V_{acid} was the acid volume; ϕ was formation porosity; h was the layer thickness; r_{wh} was the acidized radius; r_w was the wellbore radius. When using the aforementioned equation for calculation, the effective action time of the acid should be determined based on the acid-rock reaction rate to guide the selection of acid volume.

Some studies indicated that PV_{Bt} during matrix acidizing of pore-vug carbonate reservoirs was 1 to 2 orders of magnitude lower than that of porous reservoirs (Ali et al., 2016; Buijse, 2000; Fan et al., 2021; Izgec et al., 2008). The magnitude of PV_{Bt} was inversely proportional to the proportion of vugs in the total pore volume. Experimental results confirmed the existence of an optimal injection rate for the reaction between HCl and carbonate rocks. However, further research was needed to determine whether similar characteristics exist for self-generating acids. There was an order-of-magnitude difference between the optimal injection rates obtained from linear flow results and those from radial flow results (Liu et al., 2015; Xue, 2017). Moreover, in radial flow, there was no constant optimal injection rate, which increased with the depth of wormhole (Xue et al., 2016, 2017). Therefore, during field acidizing operations, the injection rate should be appropriately increased as the acidizing time progresses.

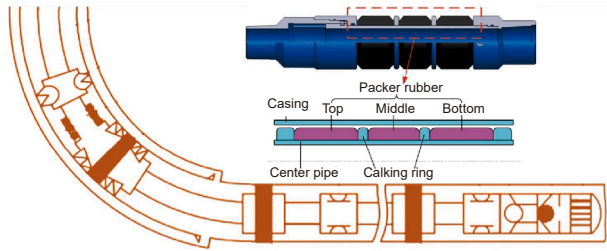
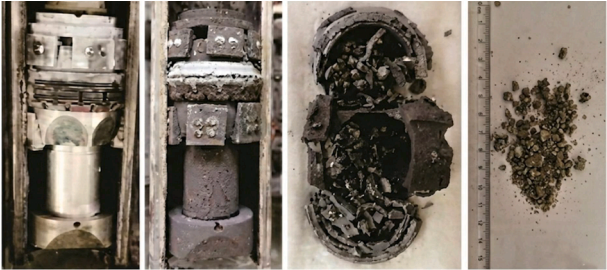
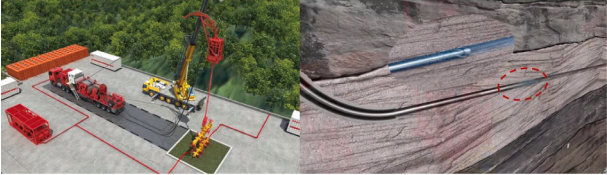
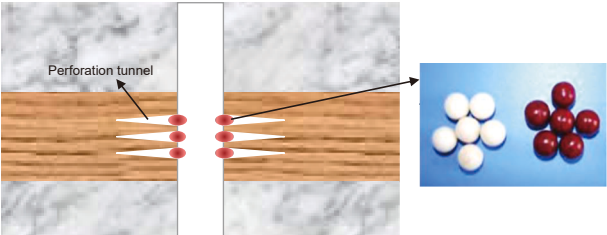
8. Real-time diagnosis and effectiveness evaluation

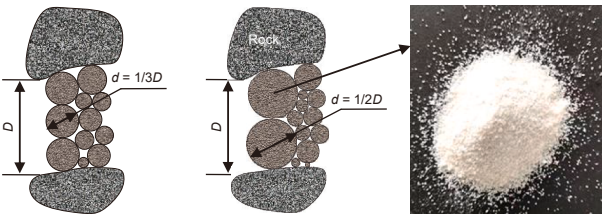
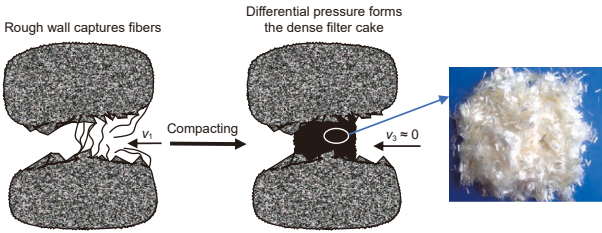
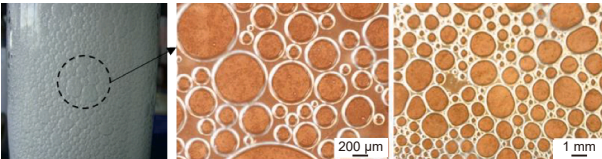
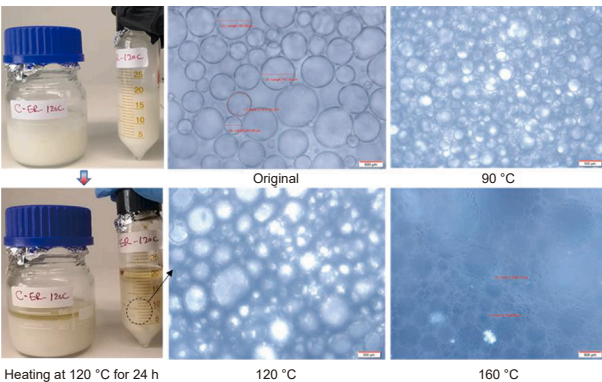
Due to its low cost and high economic return, matrix acidizing was highly favored by enterprises. Consequently, additional monitoring methods, which would increase costs, were often not employed to evaluate the effectiveness of matrix acidizing treatment. Instead, by integrating geological and reservoir characteristic parameters, acidizing pump injection data could be utilized for real-time diagnostics or post-acidizing effectiveness assessments, thereby guiding the design of acidizing treatments (Cruz-Maya et al., 2011).

Based on the principle of steady-state radial flow, Paccaloni and Tambini (1993) presented a method for real-time calculation of the

Table 4

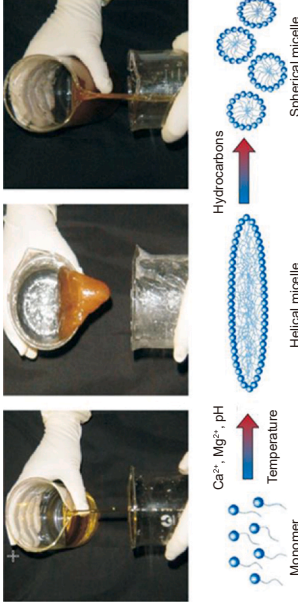
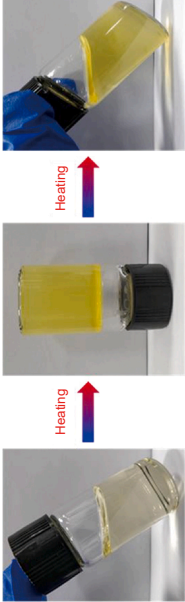
Summary of characteristics of diversion methods.

Diversion methods		Application position	Application temperature, °C	Diversion mechanism	Typical composition	Schematic diagram	Ref.
Mechanical diversion	Packer diversion	Inside the wellbore	≤ 200 °C	Segmented acidizing	Polymer of tetrafluoroethylene and propylene		Lan et al. (2019)
	Bridge plug		≤ 177 °C		Cast iron; magnesium; aluminum alloy	Soluble bridge plug in a solution with a Cl^- concentration of 5000 mg/L at 80 °C  Original 24 h 72 h 168 h	Zhang et al. (2024)
	Coiled tubing and hydraulic jetting		\	Fixed-point jetting	Low-carbon alloy steel; special alloy steel	Coiled tubing drag acidizing 	Wehunt et al. (2019)
	Ball sealer	Perforation tunnel	≤ 180 °C	Plugging	Soluble alloys; resins		Guo et al. (2023)

Chemical diversion	Chemical particulate	Within formation and fracture near the wellbore	$\leq 149\text{ }^{\circ}\text{C}$	Filter cake	Calcium carbonate; paraffin; rosin; resin		Zhao et al. (2020b)
	Fiber		$\leq 160\text{ }^{\circ}\text{C}$	Filter screen	Polyester fiber; polylactic acid fiber; polypropylene fiber		Chen et al. (2024a)
	Foamed acid	Within reservoirs and fractures	$\leq 90\text{ }^{\circ}\text{C}$	Jamin effect	Acid and surfactant		Kong et al. (2023) , and Jiang et al. (2025)
	Emulsified acid		$\leq 150\text{ }^{\circ}\text{C}$	Wettability difference	Oil, surfactants, and acids		AL-Dogail et al. (2023)

(continued on next page)

Table 4 (continued)

Ref.	Schematic diagram	Typical composition	Diversion mechanism	Application temperature, °C	Application position	Diversion methods
Zhao et al. (2020b), and Chen et al. (2024a)		Cationic surfactants; amphoteric surfactants; erucic acid amido propyl betaine; cationic amido propyl quaternary ammonium salt	Viscosity change	≤160 °C	Self-diverting acid	
Chen et al. (2025e)		β-cyclodextrin, methyl cellulose, N, N-dimethylformamide, salt, etc.	Temporary plugging by volume	≥30 °C	Phase-change diverting agent	

skin factor using injection pressure and rate. This method was convenient to use, but it neglected transient flow effects and tended to overestimate the skin factor. Considering single-phase liquid flow, Ali et al. (2016) described the relationship between injection pressure, injection rate, and time for an injection well using transient flow equations:

$$\begin{cases} \frac{P_{wi} - P_i}{q} = m \log(t) + b \\ m = \frac{162.6B\mu}{kh} \\ b = m \left[\log\left(\frac{k}{\phi\mu C_t r_w^2}\right) - 3.23 + 0.87S \right] \end{cases} \tag{7}$$

where P_{wi} was the bottom-hole pressure; P_i was the formation pressure; q was the injection rate; t was the injection time; B was the formation volume factor; μ was the fluid viscosity; k was the formation permeability; C_t was the total compressibility; S was the skin factor. When the injection rate remained constant, a $P_{wi} - \log(t)$ curve could be plotted to obtain the slope m and intercept b . By rearranging the above equation, the skin factor S could be calculated:

$$S = \frac{1}{0.87} \left[\frac{b}{m} - \log\left(\frac{k}{\phi\mu C_t r_w^2}\right) + 3.23 \right] \tag{8}$$

During acidizing operations, the injection rate would vary. Based on the superposition principle, the pressure responses under different injection rates could be superimposed, transforming Eq. (7) into:

$$\begin{cases} \frac{P_{wi} - P_i}{q} = m\Delta t_{sup} + b \\ \Delta t_{sup} = \sum_{j=1}^N \frac{q_j - q_{j-1}}{q_N} \log(t_N - t_{j-1}) \\ S = \frac{1}{0.87} \left[\frac{b}{m} - \Delta t_{sup} + 3.23 \right] \end{cases} \tag{9}$$

When the reservoir was a gas reservoir, the aforementioned equations were no longer applicable. However, the underlying principle remained the same, and the transient flow equation for gas reservoirs should be used instead (Li, 2023; Mou, 2023). When there was a difference in viscosity between the injected acid solution and the reservoir fluid, the viscosity ratio could affect the pressure response, leading to an overestimation or underestimation of the skin factor, especially in gas wells.

However, the aforementioned methods have limitations when applied to multi-zone or long horizontal well during diversion acidizing treatments. Some researchers have integrated a worm-hole propagation model into a real-time computation framework. Starting from initial reservoir parameters and the treatment design, the framework continuously receives real-time injection rate and pressure data during the operation. It then employed an inversion algorithm to dynamically adjust key parameters, such as wormhole length and conductivity, and zonal skin factors, so that the model's predicted pressure response matches the measured pressure response (Li et al., 2008; Reznikov et al., 2024; Yuan et al., 2015; Zhou et al., 2012). Furui et al. (2012) integrated the wellbore flow, the reservoir transient flow, and the wormhole propagation model. The wellbore flow model was based on steady-state, 1D, pressure-based nodal method. The wormhole propagation in the formation was calculated based on the modified Buijse-Glasbergen

correlation and upscaling model developed. The resultant wormholing skin factor was calculated by simulating and updating the changing well injectivity along the entire injection interval at every timestep. Reznikov et al. (2024) devised a computationally effective technique for interpretation of fluid injection in a well-bore interval with multiple geological layers based on the bottom-hole pressure measurements. The permeability, porosity and compressibility in each layer were initially setup, while the skin factor and partitioning of injected fluids among the zones during the injection are found as a solution of the problem. The problem took into account Darcy flow and chemical interactions between the injected acids, diverter fluids and reservoir rock typical in modern matrix acidizing treatments. Using the synchronously recorded injection rate and bottom-hole pressure, the skin factor changes in each layer and actual fluid placement into the reservoir during different pumping jobs was evaluated. Nozaki and Hill (2010) developed an acid-placement model for acid injection into vertically extensive gas wells in heterogeneous carbonate reservoirs that included gravity segregation in the wellbore, viscosity contrast, relative permeability effects, and a wormhole model. The effects of all these factors on the local injectivity during acid injection are incorporated into a dynamic-skin-factor model. For multi-zone or long horizontal completions, the zonal skin factors obtained through numerical simulation could effectively characterize the stimulation effectiveness of isolated intervals in such complex scenarios (Lu et al., 2025; Xue et al., 2018b, 2022), as shown in Fig. 11.

9. Discussion and summary

Based on the findings from literature research and our work experience, there were several aspects of matrix acidizing in carbonate reservoirs that warrant further in-depth study.

For determining which carbonate reservoirs were suitable for matrix acidizing, a comprehensive evaluation method included the following. Firstly, under the same volume of acid fluid usage, the reservoir productivity after matrix acidizing and acid

fracturing should be calculated separately, with the stimulation method corresponding to the highest productivity being preferred. Then, if acid fracturing was selected, it was necessary to assess whether the acid-etched fractures would propagate into unnecessary areas, such as causing pressure breakthrough or communicating with water zones. Finally, acid fracturing placed higher demands on tubular strings and pumping equipment, and required a larger construction site. Therefore, the optimal choice should be made based on economic considerations and the actual conditions of the oilfield.

The research on acid-rock reaction mechanisms was relatively thorough, but the research on how to accurately determine the kinetics of acid rock reaction and theoretical calculation of kinetic parameters was relatively weak. Currently, the commonly used method was the rotating disk experiment, but its calculation formula assumed theoretical conditions such as an activity coefficient $\alpha = 1$, constant fluid viscosity, and mass transfer controlled reaction ($C_s = 0$) (Ivanishin et al., 2021; Kotb et al., 2021; Song and Lee, 2023; Yoo et al., 2019).

Acid fluids thickened through methods such as the use of vegetable gums, polymers, and surfactants commonly suffer from chain scission or carbonization failure at high temperatures. For instance, self-diverting acids generally had a temperature tolerance within 150 °C and were not suitable for reservoirs with excessively high permeability contrasts (Du et al., 2025; Al-Shargabi et al., 2023; Zhao et al., 2020b). Zwitter-ionic surfactants (primarily betaines) could increase the viscosity of acid fluids to a greater extent than cationic surfactants (primarily quaternary ammonium salts), but its cost was higher. Due to factors such as stringent environmental protection requirements, volatile international oil prices, and complex reservoir conditions, the development of acid fluids with characteristics such as low cost, environmental friendliness, high temperature resistance, good retardation, low corrosion, and effective etching pores (such as wormhole acids) was an inevitable trend for future development.

To address the impact of fluid flow patterns and core dimensions on wormhole propagation during laboratory physical simulations, radial flow should be adopted whenever possible. The core length should be no less than 152 mm, with an aspect ratio greater than 0.4. Additionally, the pressure inside the core should be as close as possible to the reservoir pressure, and at a minimum, not lower than 7 MPa. Most numerical simulation models for wormhole propagation focused on two-dimensional linear flow, radial flow, or three-dimensional linear flow. The next step was to develop a wormhole propagation model that considered three-dimensional radial flow and pore-fracture-vug structures, which involved acid fluid flow at different scales and multi-field coupling of thermodynamics, hydraulics, and chemistry (i.e., THC coupling) processes. Furthermore, the impact of acid additives on acidizing needed to be incorporated into the model, as their influence could not be ignored (Rabie and Nasr-El-Din, 2015; Taylor et al., 2004; Zuo et al., 2024). While artificial intelligence or machine learning models offer significantly faster predictions for acidizing outcomes, their training were highly dependent on large volumes of high-quality historical data. These models perform well within the distribution of their training data, but when faced with novel scenarios not adequately represented in the training set, their predictive performance could sharply decline or even fail, reflecting limitations in model generalization (Al-Fakih et al., 2024; AlGaier et al., 2024; Temizel et al., 2021; Wu et al., 2025; Zhou et al., 2024).

The exploitation of deep and high-temperature carbonate reservoir resources was an inevitable trend in the future. Efforts should be made to further enhance the depth capabilities of coiled tubing and strengthen collaborative research between coiled

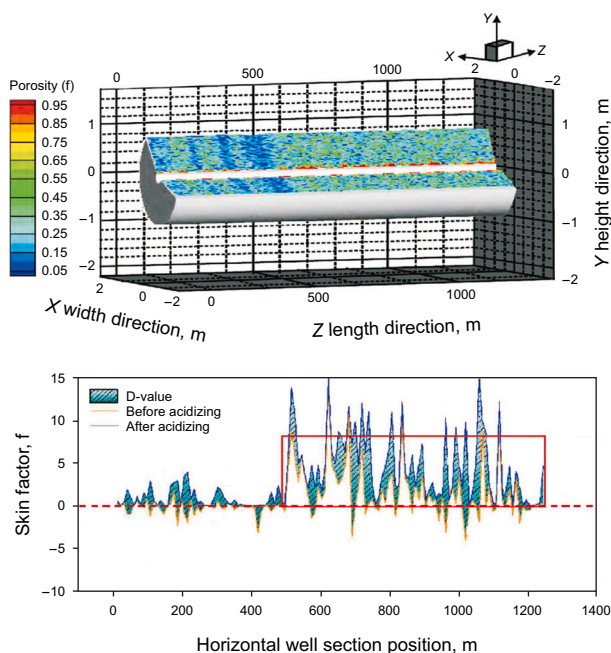


Fig. 11. Skin factor of horizontal well section before and after acidizing (Xue et al., 2018b).

tubing and technologies such as chemical diversion and hydraulic jetting. Additionally, there was a need to develop new types of chemical diversion agents (also known as temporary plugging agents or diverting agents) that were easy to inject, high-temperature resistant, low-cost, possess high temporary plugging strength, cause minimal reservoir damage, and are environmentally friendly. Furthermore, the market demand for diversion agents has been increasing annually. However, the industry currently lacked evaluation standards and usage guidelines for diversion agents. There was also a lack of unified understanding regarding the assessment of diversion effectiveness, temporary plugging effect, or temporary plugging strength. Therefore, further research in this area was needed.

The size of experimental rock samples and flow patterns had significant impacts on the optimal injection rate. However, it was difficult to obtain large-sized rock samples underground. The accuracy of experimental results obtained by using large-sized outcrop rock samples as substitutes for underground rock samples still needed further verification. Therefore, radial flow experiments should be conducted whenever possible. A comprehensive approach for optimizing construction parameters included the following. Firstly, after comprehensively considering factors such as string dimensions, acidizing depth, wellhead pressure limitations, ground equipment capabilities, and fluid intake capacity of formation, the upper limit of injection rate was determined under the condition of not fracturing the formation. Secondly, the injection rate corresponding to the minimum PV_{Bt} was determined based on radial flow acidizing experiments using large-scale rock samples or wormhole propagation models. Afterwards, based on the degree and distribution of reservoir damage, the required acid volume to achieve the reservoir stimulation objectives was calculated using empirical formulas or coupled models integrating wormhole propagation and skin factor changes. Finally, utilizing the wormhole propagation model, the injection rate at different time points was determined to ensure that the acid fluid velocity at the wormhole tip consistently maintains the optimal velocity obtained in the second step.

For vertical wells with multi-layer commingled production and horizontal wells with long intervals, it was challenging to calculate the changes in skin factor for each layer or interval and assessed the acidizing effectiveness solely based on the pumping data during diversion acidizing operations. Comprehensive evaluation could be conducted by combining pre-acidizing and post-acidizing well logging, production (e.g., oil and gas) or injection (e.g., acid) profiling tests, and downhole temperature and pressure monitoring.

10. Conclusions

Matrix acidizing was a crucial means for carbonate reservoir stimulation, and developing a scientific method for selecting the appropriate reservoirs was a prerequisite for the success of matrix acidizing. By revealing the mechanism of acid-rock reactions, it could gain insights into how to slow down the acid-rock reaction rate from the perspectives of both process technology and acid

fluid systems, in order to address the challenges posed by high temperatures. The creation of wormholes was pivotal in bypassing damage zones and establishing flow pathways for oil, gas, or geothermal fluid. By aligning process optimization with reservoir characteristics and acid fluid properties to form dominant wormholes, it was the key to achieving successful and efficient matrix acidizing. A thorough analysis of pump injection data during the acidizing operation, combined with other auxiliary methods, served as an important means to evaluate the effectiveness of matrix acidizing and guide subsequent acidizing designs.

CRedit authorship contribution statement

Xiang Chen: Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Resources, Project administration, Methodology, Investigation, Funding acquisition, Conceptualization. **Zhao-Xu Deng:** Writing – review & editing, Writing – original draft, Validation, Software, Resources, Methodology, Investigation. **Ping-Li Liu:** Writing – review & editing, Software, Resources, Project administration, Funding acquisition. **Juan Du:** Project administration, Methodology, Investigation, Formal analysis, Data curation. **Tian-Yu Zhang:** Visualization, Validation, Software, Resources, Data curation, Conceptualization. **Ying Xiong:** Software, Resources, Conceptualization. **Hong-Ming Tang:** Supervision, Project administration, Conceptualization. **Wei Li:** Resources, Project administration, Investigation. **Zi-Lan Xiong:** Visualization, Validation, Software, Data curation.

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.

Acknowledgements

This paper was supported by the National Natural Science Foundation of China (52504041); Engineering Research Center of Geothermal Resources Development Technology and Equipment, Ministry of Education, Jilin University (25017); China Postdoctoral Science Foundation (2025M772950); Open Fund (PLN202433) of State Key Laboratory of Oil and Gas Reservoir Geology and Exploitation (Southwest Petroleum University); College Students' Innovative Entrepreneurial Training Plan Program (S202510615205); Open Experimental Fund of Southwest Petroleum University (2024KSZ01011).

Appendix

The basic parameters for numerical simulation are shown in [Table A1](#).

Table A1
Basic parameters

Object	Name	Value	Unit	Object	Name	Value	Unit
Reservoir	Permeability	0.10	mD	Reservoir	Effective thickness	30.48	m
	Porosity	15.00	%		Reservoir length	1000.00	m
	Pore pressure gradient	0.98	MPa/100m		Reservoir width	1000.00	m
	Stress gradient	1.36	MPa/100m		Fluid density	948.97	kg/m ³
	Fracture pressure gradient	1.58	MPa/100m		Fluid viscosity	1.00	mPa·s
	Biot coefficient	1.00	\		Fluid Compress-ibility Factor	1.30	RB/STB
	Poisson's ratio	0.25	\		Total compressibility	0.06	Pa ⁻¹
	Young's modulus	27.58	GPa		Temperature	100.00	°C
	Fracture toughness	1.64	MPa/m		Rock density	2598.82	kg/m ³
	Embedding strength	344.75	MPa		Specific heat capacity	878.81	J/(kg·°C)
	Mineral	Pure calcite	\		Thermal conductivity	1.56	J/(m·°C·s)
Acid	Density	1073.23	kg/m ³	Acid	Specific heat capacity	4036.09	J/(kg·°C)
	Concentration	15.00	%		Thermal conductivity	0.60	J/(m·°C·s)
	Volume	79.50	m ³		Temperature	27.00	°C
Vertical well	Outer casing radius	0.11	m	Caprock/Basement	Poisson's ratio	0.25	\
	Inner casing radius	0.10	m		Young's modulus	27.58	GPa
	Thermal conductivity	0.04	J/(m·°C·s)		Fracture toughness	2.42	MPa/m
	Surface temperature	25.00	°C		Higher Stress than Reservoir	2.76	MPa

References

- Abdel-Fattah, M.I., Mahdi, A.Q., Theyab, M.A., et al., 2022. Lithofacies classification and sequence stratigraphic description as a guide for the prediction and distribution of carbonate reservoir quality: A case study of the Upper Cretaceous Khasib Formation (East Baghdad oilfield, central Iraq). *J. Petrol. Sci. Eng.* 209, 109835. <https://doi.org/10.1016/j.petrol.2021.109835>.
- Aboluhom, H., Aljawad, M.S., 2023. Computationally efficient 3D fully coupled reactive transport model for wormhole propagation in carbonate formation. *Transp. Porous Medium.* 150 (2), 229–256. <https://doi.org/10.1007/s11242-023-02007-2>.
- Aboluhom, H., Aljawad, M.S., Alafnan, S., et al., 2024. A coupled three-dimensional wormhole modeling in heterogeneous carbonate lithology in limited-entry and openhole completions. *Geoenery Sci. Eng.* 241, 213150. <https://doi.org/10.1016/j.geoen.2024.213150>.
- Akanni, O.O., Nasr-El-Din, H.A., 2015. The accuracy of carbonate matrix-acidizing models in predicting optimum injection and wormhole propagation rates. In: *SPE Middle East Oil & Gas Show and Conference*. Society of Petroleum Engineers. <https://doi.org/10.2118/172575-ms>.
- Al-Dogail, A., Gajbhiye, R., Sultan, A., et al., 2023. Development of emulsified acid system (EAS) using organoclays (OC): Rheology and implication to the acidizing. *Geoenery Sci. Eng.* 228, 212022. <https://doi.org/10.1016/j.geoen.2023.212022>.
- Al-Fakih, A., Abdulraheem, A., Kaka, S., 2024. Application of machine learning and deep learning in geothermal resource development: Trends and perspectives. *Deep Undergr. Sci. Eng.* 3 (3), 286–301. <https://doi.org/10.1002/dug2.12098>.
- Al-Ghamdi, A., Hassan, A., Mahmoud, M., et al., 2025. Novel thermochemical fracturing: A breakthrough in sustainable and efficient enhanced geothermal systems (EGS). *Petroleum* 11 (5), 613–623. <https://doi.org/10.1016/j.petlm.2025.07.004>.
- Al-Shargabi, M., Davoodi, S., Wood, D.A., et al., 2023. A critical review of self-diverting acid treatments applied to carbonate oil and gas reservoirs. *Pet. Sci.* 20 (2), 922–950. <https://doi.org/10.1016/j.petsci.2022.10.005>.
- Alameedy, U., Fatah, A., Abbas, A.K., et al., 2023. Matrix acidizing in carbonate rocks and the impact on geomechanical properties: A review. *Fuel* 349, 128586. <https://doi.org/10.1016/j.fuel.2023.128586>.
- AlGaier, M., Hossain, M., Petrovski, A., et al., 2024. Applications of artificial intelligence in geothermal resource exploration: A review. *Deep Undergr. Sci. Eng.* 3 (3), 269–285. <https://doi.org/10.1002/dug2.12122>.
- Alhammad, F., Ali, M., Yekeen, N., et al., 2024. The influence of methyl orange on the CO₂-brine wettability of organic-acid-aged calcite samples: Implications for CO₂ geo-storage. *Adv. Geo-Energy Res.* 12 (2), 102–112. <https://doi.org/10.46690/ager.2024.05.03>.
- Ali, M.T., Nasr-El-Din, H.A., 2020. New insights into carbonate matrix acidizing treatments: A mathematical and experimental study. *SPE J.* 25 (3), 1272–1284. <https://doi.org/10.2118/200472-pa>.
- Ali, M., Ziauddin, M., 2020. Carbonate acidizing: A mechanistic model for wormhole growth in linear and radial flow. *J. Petrol. Sci. Eng.* 186, 106776. <https://doi.org/10.1016/j.petrol.2019.106776>.
- Ali, S.A., Kalfayan, L., Montgomery, C.T., 2016. Acid Stimulation. Society of petroleum engineers (SPE). <https://doi.org/10.2118/9781613994269>.
- Ali, M.T., Ezzat, A.A., Nasr-El-Din, H.A., 2020. A model to simulate matrix-acid stimulation for wells in dolomite reservoirs with vugs and natural fractures. *SPE J.* 25 (2), 609–631. <https://doi.org/10.2118/199341-pa>.
- Aljawad, M.S., Schwalbert, M.P., Zhu, D., et al., 2020a. Improving acid fracture design in dolomite formations utilizing a fully integrated acid fracture model. *J. Petrol. Sci. Eng.* 184, 106481. <https://doi.org/10.1016/j.petrol.2019.106481>.
- Aljawad, M.S., Palharini Schwalbert, M., Zhu, D., et al., 2020b. Optimizing acid fracture design in calcite formations: guidelines using a fully integrated model. *SPE Prod. Oper.* 35 (1), 161–177. <https://doi.org/10.2118/198912-pa>.
- Aljawad, M.S., Aboluhom, H., Schwalbert, M.P., et al., 2021. Temperature impact on linear and radial wormhole propagation in limestone, dolomite, and mixed mineralogy. *J. Nat. Gas Sci. Eng.* 93, 104031. <https://doi.org/10.1016/j.jngse.2021.104031>.
- Alkathim, M., Aljawad, M.S., Hassan, A., et al., 2023. A data-driven model to estimate the pore volume to breakthrough for carbonate acidizing. *J. Pet. Explor. Prod. Technol.* 13 (8), 1789–1806. <https://doi.org/10.1007/s13202-023-01642-1>.
- Andriamihaja, S., Padmanabhan, E., Ben-Awuah, J., et al., 2019. Static dissolution-induced 3D pore network modification and its impact on critical pore attributes of carbonate rocks. *Petrol. Explor. Dev.* 46 (2), 374–383. [https://doi.org/10.1016/S1876-3804\(19\)60017-0](https://doi.org/10.1016/S1876-3804(19)60017-0).
- Arndt, M., Fritschle, T., Thiel, A., et al., 2021. The DGE-ROLLOUT project: Deep geothermal Energy potential of Carboniferous carbonate rocks in North-West Europe—History, characterisation, modelling and exploration. *Z. Dtsch. Ges. Geowiss.* 172 (3), 205–210. <https://doi.org/10.1127/zdgg/2021/0309>.
- Baghel, V.S., Praveesh, J., 2016. A semi-empirical carbonate acidizing model for chelating-agent-based fluids. In: *IADC/SPE Asia Pacific Drilling Technology Conference*, Richardson. Society of Petroleum Engineers. <https://doi.org/10.2118/180590-ms>.
- Baioumy, B., Prossaird, S., Rivas, J., et al., 2024. Customized matrix acidizing simulation for optimum acid placement in smart completion applications resulting in homogeneous acid placement, a case study review. In: *International Petroleum Technology Conference*. IPTC. <https://doi.org/10.2523/iptc-23172-ea>. IPTC-23172-EA.
- Békri, S., Thovet, J.F., Adler, P.M., 1995. Dissolution of porous media. *Chem. Eng. Sci.* 50 (17), 2765–2791. [https://doi.org/10.1016/0009-2509\(95\)00121-K](https://doi.org/10.1016/0009-2509(95)00121-K).
- Belshaw, G.E., Steer, E., Ji, Y., et al., 2024. Fluid-rock interaction experiments with andesite at 100°C for potential carbon storage in geothermal reservoirs. *Deep Undergr. Sci. Eng.* 3 (3), 369–382. <https://doi.org/10.1002/dug2.12097>.
- Bist, N., Nair, A., Yadav, K., et al., 2024. Diverting agents in the oil and gas industry: a comprehensive analysis of their origins, types, and applications. *Petrol. Res.* 9 (1), 72–84. <https://doi.org/10.1016/j.ptlrs.2023.09.004>.
- Budek, X., Szymczak, P., 2012. Network models of dissolution of porous media. *Phys. Rev. E* 86 (5), 056318. <https://doi.org/10.1103/physreve.86.056318>.
- Buijse, M.A., 2000. Understanding wormholing mechanisms can improve acid treatments in carbonate formations. *SPE Prod. Facil.* 15 (3), 168–175. <https://doi.org/10.2118/65068-pa>.
- Buijse, M., Glasbergen, G., 2005. A semiempirical model to calculate wormhole growth in carbonate acidizing. In: *SPE Annual Technical Conference and Exhibition*, Richardson. Society of Petroleum Engineers. <https://doi.org/10.2118/96892-ms>.
- Carvalho, R.T.R., Oliveira, P.F., Palermo, L.C.M., et al., 2019. Prospective acid microemulsions development for matrix acidizing petroleum reservoirs. *Fuel* 238, 75–85. <https://doi.org/10.1016/j.fuel.2018.10.003>.
- Chen, X., Zhao, L., Liu, P., et al., 2021a. Laboratory study and field verification of a thermo-responsive water shutoff agent. *J. Petrol. Sci. Eng.* 201, 108499. <https://doi.org/10.1016/j.petrol.2021.108499>.
- Chen, X., Zhao, L., Liu, P., et al., 2021b. Experimental study and field verification of fracturing technique using a thermo-responsive diverting agent. *J. Nat. Gas Sci. Eng.* 92, 103993. <https://doi.org/10.1016/j.jngse.2021.103993>.
- Chen, X., Liu, P., Zhao, L., et al., 2023. Diverting fracturing stimulation technique using a novel temporary plugging agent with multiphase transition properties at different temperatures. In: *SPE Canadian Energy Technology Conference and*

- Exhibition, Richardson. Society of Petroleum Engineers. <https://doi.org/10.2118/212735-ms>.
- Chen, X., Lu, X., Liu, P., et al., 2024a. A critical review of key points in temporary plugging fracturing: materials, injection, temporary plugging, and design. *Geoenergy Sci. Eng.* 240, 212981. <https://doi.org/10.1016/j.geoen.2024.212981>.
- Chen, X., Wang, G., Liu, P., et al., 2024b. Research on improving permeability of granite reservoir: polyhydrogen chelating acid acidizing. *Energy sources part A recovery Util. Environ. Eff.* 46 (1), 22–37. <https://doi.org/10.1080/15567036.2024.2419569>.
- Chen, X., Wang, G., Liu, P.L., et al., 2024c. Experimental and simulation study on fracture conductivity of acid-fracturing in dengying Formation of Sichuan basin. *Petrol. Reserv. Eval. Dev.* 14 (4), 569–576. <https://doi.org/10.13809/j.cnki.cn32-1825/te.2024.04.006> (in Chinese).
- Chen, W., Liu, P., University, S.P., et al., 2025a. Retarded gelled acid for high-temperature carbonate reservoir acidizing: retardancy and mechanism study. *ACS Omega* 10 (12), 12441–12452. <https://doi.org/10.1021/acsomega.4c11617>.
- Chen, X., Hu, H., Liu, P., et al., 2025b. Enhancing fracture conductivity in carbonate formations through mineral alteration. *Int. J. Rock Mech. Min. Sci.* 186, 106027. <https://doi.org/10.1016/j.ijrmms.2025.106027>.
- Chen, X., Huang, Q., Liu, P., et al., 2025c. Numerical simulation of CO₂ sequestration stability in carbonate-bearing saline aquifers: effects of mineral dissolution. *Energy* 335, 138273. <https://doi.org/10.1016/j.energy.2025.138273>.
- Chen, X., Liu, K., Liu, P., et al., 2025d. Binary composite depolymerization system targeting polymer injection wells: a fusion of experiment and mechanism. *Geoenergy Sci. Eng.* 246, 213552. <https://doi.org/10.1016/j.geoen.2024.213552>.
- Chen, X., Wang, G., Liu, P., et al., 2025e. Diverting fracturing stimulation using a novel diverting agent: laboratory study and field application. *Geoenergy Sci. Eng.* 247, 213715. <https://doi.org/10.1016/j.geoen.2025.213715>.
- Chen, X., Deng, Z., Liu, P., et al., 2026a. Rapidly improving the acid-fracture conductivity in deep and ultra-deep carbonate reservoirs through mineral alteration: a new method. *Int. J. Rock Mech. Min. Sci.* 199, 106415. <https://doi.org/10.1016/j.ijrmms.2026.106415>.
- Chen, X., Huang, Q., Liu, P., et al., 2026b. Review of key technologies for ultra-deep carbonate reservoir development: acid fracturing and challenges. *Geoenergy Sci. Eng.* 257, 214247. <https://doi.org/10.1016/j.geoen.2025.214247>.
- Chen, X., Huang, Q., Liu, P., et al., 2026c. Thermo-hydro-chemical coupling model of acid treatment in complex carbonate geothermal reservoirs. *Geoenergy Sci. Eng.* 257, 214242. <https://doi.org/10.1016/j.geoen.2025.214242>.
- Cheng, H., Palharini Schwalbert, M., Hill, A.D., et al., 2020. A fundamental model for wormhole formation including multiphase flow. *SPE Prod. Oper.* 35 (4), 929–941. <https://doi.org/10.2118/201213-pa>.
- Cohen, C.E., Ding, D., Quintard, M., et al., 2008. From pore scale to wellbore scale: impact of geometry on wormhole growth in carbonate acidization. *Chem. Eng. Sci.* 63 (12), 3088–3099. <https://doi.org/10.1016/j.ces.2008.03.021>.
- Cruz-Maya, J.A., Rosas-Flores, J.A., Godoy-Alcantar, M., et al., 2011. A real-time virtual monitoring system of the skin factor for matrix acidizing treatments. *Flow Meas. Instrum.* 22 (5), 413–420. <https://doi.org/10.1016/j.flowmeasinst.2011.06.005>.
- Daneshy, A., Valko, P., Norman, L., 1998. *Well Stimulation*. Wiley.
- Dargi, M., Khamsehchi, E., Mahdavi Kalatehno, J., 2023. Optimizing acidizing design and effectiveness assessment with machine learning for predicting post-acidizing permeability. *Sci. Rep.* 13, 11851. <https://doi.org/10.1038/s41598-023-39156-9>.
- Deng, J., Mou, J., Hill, A.D.D., et al., 2012. A new correlation of acid-fracture conductivity subject to closure stress. *SPE Prod. Oper.* 27 (2), 158–169. <https://doi.org/10.2118/140402-pa>.
- Deng, P., Chen, Z., Peng, X., et al., 2025a. Converting underground natural gas storage for hydrogen: a review of advantages, challenges and economics. *Renew. Sustain. Energy Rev.* 213, 115438. <https://doi.org/10.1016/j.rser.2025.115438>.
- Deng, P., Ma, H., Song, J., et al., 2025b. Carbon dioxide as cushion gas for large-scale underground hydrogen storage: mechanisms and implications. *Appl. Energy* 388, 125622. <https://doi.org/10.1016/j.apenergy.2025.125622>.
- dos Santos, Y.R.P., Gomes, I.F., Lima, A., et al., 2025. Acid-rock interaction investigation and the influence of fractures during matrix acidizing in carbonate rocks. *Petroleum* 11 (4), 475–495. <https://doi.org/10.1016/j.petlm.2025.06.001>.
- dos Santos Lucas, C.R., Neyra, J.R., Araújo, E.A., et al., 2023. Carbonate acidizing—A review on influencing parameters of wormholes formation. *J. Petrol. Sci. Eng.* 220, 111168. <https://doi.org/10.1016/j.petrol.2022.111168>.
- Du, J., Wang, Q., Liu, P., et al., 2023. Nanocomposite gels for water shut-off and temporary plugging in the petroleum industry: A review. *Petrol. Sci. Technol.* 41 (23), 2204–2239. <https://doi.org/10.1080/10916466.2022.2108839>.
- Du, J., Yuan, Y., Liu, P., et al., 2024. A review of self-generating acid system of high temperature reservoir. *Energy Sources part A recovery Util. Environ. Eff.* 46 (1), 2059–2079. <https://doi.org/10.1080/15567036.2024.2302367>.
- Du, J., Shi, Y., Liu, P., et al., 2025. Influencing factors of viscoelastic surfactant diverting acid: a review. *Petrol. Sci. Technol.* 43 (22), 3270–3302. <https://doi.org/10.1080/10916466.2024.2415521>.
- Du, J., Shu, H., Shi, Y., et al., 2026. Experimental investigation of acid-rock reaction kinetics and fracture conductivity under ultra-high temperature carbonate reservoir conditions. *Results Eng.* 29, 108522. <https://doi.org/10.1016/j.rineng.2025.108522>.
- Ebadi, S.M., Khamsehchi, E., Mahdavi Kalatehno, J., 2025. A comprehensive comparative analysis of particle swarm optimization and genetic algorithms in well acidizing optimization. *J. Pet. Explor. Prod. Technol.* 16 (1), 4. <https://doi.org/10.1007/s13202-025-02109-1>.
- Economides, M.J., Nolte, K.G., 2002. *In: Reservoir Stimulation*, third ed. Wiley.
- Economides, M.J., Hill, A.D., Ehlig-Economides, C., et al., 2015. *Petroleum Production Systems*. Petroleum Industry Press, Beijing.
- Fan, Y., Chen, L., Tang, S., 2021. Efficient acidification technology for carbonate gas reservoirs. In: Longwangmiao Formation, Moxi, Sichuan Basin. Petroleum Industry Press (in Chinese).
- Fredd, C.N., Fogler, H.S., 1998. Influence of transport and reaction on wormhole formation in porous media. *AIChE. J.* 44 (9), 1933–1949. <https://doi.org/10.1002/aic.690440902>.
- Fredd, C.N., Fogler, H.S., 1999. Optimum conditions for wormhole formation in carbonate porous media: influence of transport and reaction. *SPE J.* 4 (3), 196–205. <https://doi.org/10.2118/56995-pa>.
- Frick, T.P., Kürmayr, T.P., Economides, M.J., 1994. Modeling of fractal patterns in matrix acidizing and their impact on well performance. *SPE Prod. Facil.* 9 (1), 61–68. <https://doi.org/10.2118/23789-pa>.
- Furui, K., Burton, R.C.C., Burkhead, D.W.W., et al., 2012. A comprehensive model of high-rate matrix-acid stimulation for long horizontal wells in carbonate reservoirs: part II: wellbore/reservoir coupled-flow modeling and field application. *SPE J.* 17 (1), 280–291. <https://doi.org/10.2118/155497-pa>.
- Gao, F., Dong, S., Wang, D., et al., 2026. A novel foaming formulation with excellent salt-resistant for foam assisted deliquification of gas wells. *J. Dispersion Sci. Technol.* 47 (1), 105–115. <https://doi.org/10.1080/01932691.2024.2399136>.
- Garrouch, A.A., Jennings Jr., A.R., 2017. A contemporary approach to carbonate matrix acidizing. *J. Petrol. Sci. Eng.* 158, 129–143. <https://doi.org/10.1016/j.petrol.2017.08.045>.
- Ghommem, M., Zhao, W., Dyer, S., et al., 2015. Carbonate acidizing: modeling, analysis, and characterization of wormhole formation and propagation. *J. Petrol. Sci. Eng.* 131, 18–33. <https://doi.org/10.1016/j.petrol.2015.04.021>.
- Gomaa, A.M., Nasr-El-Din, H.A., 2015. Effect of elastic properties on the propagation of gelled and *in-situ* gelled acids in carbonate cores. *J. Petrol. Sci. Eng.* 127, 101–108. <https://doi.org/10.1016/j.petrol.2015.01.031>.
- Gong, J.C., Wang, Y.L., Luo, M.L., et al., 2020. Research and prospect of crosslinked acid fracturing fluid. *Appl. Chem. Ind.* 49 (8), 2058–2062. <https://doi.org/10.3969/j.issn.1671-3206.2020.08.042> (in Chinese).
- Gou, B., Xu, K., Zhang, J., et al., 2024. Acid-etched fracture morphology and conductivity of acid fracturing in carbonate rock using novel isolation membrane acid. *Geoenergy Sci. Eng.* 240, 213003. <https://doi.org/10.1016/j.geoen.2024.213003>.
- Guo, J., Gou, B., Qin, N., et al., 2020. An innovative concept on deep carbonate reservoir stimulation: three-dimensional acid fracturing technology. *Nat. Gas Ind. B* 7 (5), 484–497. <https://doi.org/10.1016/j.ngib.2020.09.006>.
- Guo, J.C., Zhao, F., Zhan, L., et al., 2023. Recent advances and development suggestions of temporary plugging and diverting fracturing technology for shale gas reservoirs in the Sichuan basin. *Petrol. Drill. Tech.* 51 (4), 170–183. <https://doi.org/10.1191/syztj.2023039> (in Chinese).
- Hatamizadeh, A., Sedaee, B., 2023. Simulation of carbonate reservoirs acidizing using machine and meta-learning methods and its optimization by the genetic algorithm. *Geoenergy Sci. Eng.* 223, 211509. <https://doi.org/10.1016/j.geoen.2023.211509>.
- Hewen, Z., Honglan, Z., Xuemei, Y., Mingyue, C., Weidong, J., 2017. Fractal model of carbonate acidized wormhole and acidizing parameter optimization. *Journal of Southwest Petroleum University (Science & Technology Edition)* 39 (2), 105–110. <https://doi.org/10.11885/j.issn.1674-5086.2015.08.06.02> (in Chinese).
- Huang, T., Zhu, D., Hill, A.D., 1999. Prediction of wormhole population density in carbonate matrix acidizing. In: *Proceedings of SPE European Formation Damage Conference*, Society of Petroleum Engineers. <https://doi.org/10.2523/54723-ms>.
- Huang, T., Hill, A.D., Schechter, R.S., 2000. Reaction rate and fluid loss: the keys to wormhole initiation and propagation in carbonate acidizing. *SPE J.* 5 (3), 287–292. <https://doi.org/10.2118/65400-pa>.
- Ivanishin, I., Kotb, A., Nasr-El-Din, H.A., 2021. Turbulence leads to overestimation of the acid-diffusion coefficient at typical experimental conditions using the rotating disk apparatus. *J. Petrol. Sci. Eng.* 205, 108805. <https://doi.org/10.1016/j.petrol.2021.108805>.
- Izgec, O., Keys, R., Zhu, D., et al., 2008. An integrated theoretical and experimental study on the effects of multiscale heterogeneities in matrix acidizing of carbonates. In: *SPE Annual Technical Conference and Exhibition*, Richardson. Society of Petroleum Engineers. <https://doi.org/10.2118/115143-ms>.
- Izgec, O., Zhu, D., Hill, A.D., 2010. Numerical and experimental investigation of acid wormholing during acidization of vuggy carbonate rocks. *J. Petrol. Sci. Eng.* 74 (1–2), 51–66. <https://doi.org/10.1016/j.petrol.2010.08.006>.
- Jiang, O., Zhang, P., Jia, H., et al., 2025. A retarded foam acid fluid system for low-temperature dolomite geothermal reservoir stimulation and its action mechanisms. *Colloids Surf. A Physicochem. Eng. Aspects* 705, 135717. <https://doi.org/10.1016/j.colsurfa.2024.135717>.
- Jyoti, A., Haese, R.R., 2021. Validation of a multicomponent reactive-transport model at pore scale based on the coupling of COMSOL and PhreeQC. *Comput. Geosci.* 156, 104870. <https://doi.org/10.1016/j.cageo.2021.104870>.
- Kaminskaite-Baranauskiene, I., Wang, H., Liu, Z., et al., 2023. Geothermal carbonate reservoirs and their sustainability: What can natural hydrothermal systems tell us. *Geothermics* 114, 102798. <https://doi.org/10.1016/j.geothermics.2023.102798>.

- Kang, Q., Zhang, D., Chen, S., et al., 2002. Lattice Boltzmann simulation of chemical dissolution in porous media. *Phys. Rev. E* 65 (3), 036318. <https://doi.org/10.1103/physreve.65.036318>.
- Kashani, E., Mohebbi, A., Feili Monfared, A.E., et al., 2024. Lattice Boltzmann simulation of dissolution patterns in porous media: single porosity versus dual porosity media. *Adv. Water Resour.* 188, 104712. <https://doi.org/10.1016/j.advwatres.2024.104712>.
- Khojastehmehr, M., Bazargan, M., Masihi, M., 2025. Reviewing CO₂ dynamics in acidizing carbonate reservoirs: mechanisms, impacts, and models. *Geoenergy Sci. Eng.* 249, 213767. <https://doi.org/10.1016/j.geoen.2025.213767>.
- Kong, X., Liu, B., Xu, H., et al., 2023. Optimization and performance evaluation of foam acid systems for plugging removal in low pressure oil and gas reservoirs. *Processes* 11 (3), 649. <https://doi.org/10.3390/pr11030649>.
- Kotb, A., Ezzat, A.A., Ali, M., et al., 2021. A calibrated computational fluid dynamics model for simulating the rotating disk apparatus. *SPE J.* 26 (6), 4022–4036. <https://doi.org/10.2118/193739-pa>.
- Lan, W.J., Wang, H.X., Zhang, X., et al., 2019. Sealing properties and structure optimization of packer rubber under high pressure and high temperature. *Pet. Sci.* 16 (3), 632–644. <https://doi.org/10.1007/s12182-018-0296-0>.
- Lei, G., Liao, Q., Zhang, D., 2019. A new analytical model for flow in acidized fractured-vuggy porous media. *Sci. Rep.* 9, 8293. <https://doi.org/10.1038/s41598-019-44802-2>.
- Leonard, K., 2008. *Production Enhancement with Acid Stimulation*. PennWell Corporation.
- Li, N., 2023. *Theory and Technology of Acid Stimulation*. Petroleum Industry Press (in Chinese).
- Li, J., Zheng, C., 2023. Preparation and performance of a chelating anionic foaming agent. *J. Dispersion Sci. Technol.* 44 (7), 1296–1304. <https://doi.org/10.1080/01932691.2021.2013868>.
- Li, S., Li, Z., Lin, R., 2008. Mathematical models for foam-diverted acidizing and their applications. *Pet. Sci.* 5 (2), 145–152. <https://doi.org/10.1007/s12182-008-0022-4>.
- Li, Y., Kang, Z., Xue, Z., et al., 2018. Theories and practices of carbonate reservoirs development in China. *Petrol. Explor. Dev.* 45 (4), 712–722. [https://doi.org/10.1016/S1876-3804\(18\)30074-0](https://doi.org/10.1016/S1876-3804(18)30074-0).
- Li, J., Wen, M., Lei, L., et al., 2024a. Development and analysis of pH-sensitive surfactants for enhancing foam drainage gas retrieval. *J. Mol. Liq.* 396, 124106. <https://doi.org/10.1016/j.molliq.2024.124106>.
- Li, X.S., Qi, N., Zhang, Z.H., et al., 2024b. Acid-rock reaction kinetics in a two-scale model based on reaction order correction. *Pet. Sci.* 21 (3), 2089–2101. <https://doi.org/10.1016/j.petsci.2023.11.023>.
- Li, Y., Mo, W., Jiang, Y., et al., 2024c. Influence of fractures and heat transmission on wormhole propagation in fractured carbonate rocks. *Geoenergy Sci. Eng.* 239, 212916. <https://doi.org/10.1016/j.geoen.2024.212916>.
- Liu, M., Zhang, S., Mou, J., 2012. Fractal nature of acid-etched wormholes and the influence of acid type on wormholes. *Petrol. Explor. Dev.* 39 (5), 630–635. [https://doi.org/10.1016/S1876-3804\(12\)60086-X](https://doi.org/10.1016/S1876-3804(12)60086-X).
- Liu, P., Xue, H., Zhao, L.Q., et al., 2015. Analysis and simulation of rheological behavior and diverting mechanism of in Situ Self-diverting acid. *J. Petrol. Sci. Eng.* 132, 39–52. <https://doi.org/10.1016/j.petrol.2015.04.042>.
- Liu, P., Xue, H., Zhao, L., et al., 2016. Simulation of 3D multi-scale wormhole propagation in carbonates considering correlation spatial distribution of petrophysical properties. *J. Nat. Gas Sci. Eng.* 32, 81–94. <https://doi.org/10.1016/j.jngse.2016.04.014>.
- Liu, P., Yao, J., Couples, G.D., et al., 2017a. 3-D modelling and experimental comparison of reactive flow in carbonates under radial flow conditions. *Sci. Rep.* 7, 17711. <https://doi.org/10.1038/s41598-017-18095-2>.
- Liu, P., Yao, J., Couples, G.D., et al., 2017b. Modeling and simulation of wormhole formation during acidization of fractured carbonate rocks. *J. Petrol. Sci. Eng.* 154, 284–301. <https://doi.org/10.1016/j.petrol.2017.04.040>.
- Liu, P., Huang, C., Jia, L., et al., 2022. Numerical simulation of the wormhole propagation in fractured carbonate rocks during acidization using a thermal-hydrologic-mechanics-chemical coupled model. *Water* 14 (24), 4117. <https://doi.org/10.3390/w14244117>.
- Liu, J., Liu, P., Du, J., et al., 2023a. Review on high-temperature-resistant viscoelastic surfactant fracturing fluids: State-of-the-art and perspectives. *Energy Fuel* 37 (14), 9790–9821. <https://doi.org/10.1021/acs.energyfuels.3c00488>.
- Liu, P., Lou, F., Du, J., et al., 2023b. Impact of key parameters on far-field temporary plugging and diverting fracturing in fractured reservoirs: a 2D finite element study. *Adv. Geo-Energy Res.* 10 (2), 104–116. <https://doi.org/10.46690/ager.2023.11.05>.
- Liu, P., Kong, X., Feng, G., et al., 2023c. Three-dimensional simulation of wormhole propagation in fractured-vuggy carbonate rocks during acidization. *Adv. Geo-Energy Res.* 7 (3), 199–210. <https://doi.org/10.46690/ager.2023.03.06>.
- Liu, P., Hu, H., Chen, X., et al., 2024. The influencing parameters and improve methods of acid-etched fracture conductivity: A review. *Geoenergy Sci. Eng.* 238, 212844. <https://doi.org/10.1016/j.geoen.2024.212844>.
- Liu, P., Li, J., Du, J., et al., 2025a. Evaluation of acid retardation based on acid-etched fracture morphology. *Geoenergy Sci. Eng.* 244, 213492. <https://doi.org/10.1016/j.geoen.2024.213492>.
- Liu, P., Wang, G., Zhang, H., et al., 2025b. Reaction between *in-situ* generated acid and carbonate rock at ultra-high temperatures: a fusion of kinetic mechanisms and experiments. *Geothermics* 131, 103357. <https://doi.org/10.1016/j.geothermics.2025.103357>.
- Liu, P., Wang, M., Fu, Y., et al., 2025c. Preparation and performance of an environmental-friendly degradable semi-interpenetrating network temporary plugging agent for acidification. *Petrol. Sci. Technol.* 43 (5), 508–534. <https://doi.org/10.1080/10916466.2024.2305337>.
- Liu, P., Wu, Y., Chen, X., et al., 2025d. Acidizing of deep carbonate reservoirs to reduce breakdown pressure: a review. *Geoenergy Sci. Eng.* 251, 213856. <https://doi.org/10.1016/j.geoen.2025.213856>.
- Liu, X., Li, Q., Chen, W., et al., 2025e. Numerical simulation of power-law acid flow in rough fractures of carbonate rocks. *Adv. Geo-Energy Res.* 17 (3), 226–240. <https://doi.org/10.46690/ager.2025.09.05>.
- Liu, P., University, S.P., School, P.E., et al., 2026a. A review of wax deposition in waxy crude oil pipelines: recent advances and future perspectives. *Energy Fuel* 40 (9), 4406–4444. <https://doi.org/10.1021/acs.energyfuels.5c06407>.
- Liu, P., Wang, Z., Chen, X., et al., 2026b. Study on the influence of mineral heterogeneity and temperature on acid-rock reaction behavior in mixed sedimentary reservoirs. *Int. J. Heat Mass Tran.* 260, 128485. <https://doi.org/10.1016/j.jijheatmasstransfer.2026.128485>.
- Lu, P.P., Mou, J.Y., Cheng, Y., et al., 2025. Multiscale modeling and optimization of coiled tubing acidizing in carbonate horizontal wells. *Pet. Sci. Bull.* 10 (4), 747–761. <https://doi.org/10.3969/j.issn.2096-1693.2025.03.016> (in Chinese).
- Luo, Z., Li, J., Zhao, L., et al., 2021. Preparation and characterization of a self-suspending ultra-low density proppant. *RSC Adv.* 11 (52), 33083–33092. <https://doi.org/10.1039/d1ra05611e>.
- Ma, X., Mou, J., Lin, H., et al., 2017. Lattice Boltzmann simulation of wormhole propagation in carbonate acidizing. *J. Energy Resour. Technol.* 139 (4), 042002. <https://doi.org/10.1115/1.4035909>.
- Ma, G., Chen, Y., Jin, Y., et al., 2018. Modelling temperature-influenced acidizing process in fractured carbonate rocks. *Int. J. Rock Mech. Min. Sci.* 105, 73–84. <https://doi.org/10.1016/j.ijrmms.2018.03.019>.
- Ma, G., Chen, Y., Wang, H., et al., 2022. Numerical analysis of two-phase acidizing in fractured carbonate rocks. *J. Nat. Gas Sci. Eng.* 103, 104616. <https://doi.org/10.1016/j.jngse.2022.104616>.
- Mao, J.C., Lu, W., Zhang, Z.Y., et al., 2018. Research and development of demopary plugging diverting technology for reservoir re-stimulation. *Appl. Chem. Ind.* 47 (10), 2202–2206. <https://doi.org/10.16581/j.cnki.issn1671-3206.20180829.014> (in Chinese).
- Mo, W., Jiang, Y., Li, Y., et al., 2025. Non-isothermal simulation of wormhole propagation in fractured carbonate rocks based on 3D-EDFM. *Geoenergy Sci. Eng.* 244, 213453. <https://doi.org/10.1016/j.geoen.2024.213453>.
- Mohammadi, S., Shahbazi, K., 2023. A comprehensive review on acid-induced sludge formation during matrix acidizing: Nature, mechanism, and effective parameters. *Geoenergy Sci. Eng.* 229, 212150. <https://doi.org/10.1016/j.geoen.2023.212150>.
- Mou, J., 2023. *Principle of acid stimulation*. Petroleum Industry Press (in Chinese).
- Mou, J., Gao, B., He, J., et al., 2024. Wormhole behavior in matrix acidizing in vuggy, naturally fractured carbonate reservoirs. *Geoenergy Sci. Eng.* 235, 212732. <https://doi.org/10.1016/j.geoen.2024.212732>.
- Mouallem, J., Al-Abdrabalnabi, R., Raza, A., et al., 2025. Experimental investigation of CO₂ residual trapping in naturally water-wet and artificially tailored oil-wet limestones: implications for geological CO₂ storage. *Adv. Geo-Energy Res.* 17 (1), 43–55. <https://doi.org/10.46690/ager.2025.07.04>.
- Murtada, S.A.J., 2018. *Development of a fully integrated acid fracture model*. Texas A&M University. Dissertation/Thesis Thesis.
- Nami, M.H., Ahmadi, M., Sharifi, M., 2023. Heat transfer included simulation of carbonate rock acidizing using two-scale continuum model with varying rock physics curves. *SPE J.* 28 (6), 2917–2945. <https://doi.org/10.2118/215845-pa>.
- Nan, Y., Ma, S.Z., Zhang, Y.Y., et al., 2025. Damage mechanism and improvement measures of strong acid acidification in calcium-rich cement low-permeability reservoirs. *Chem. Eng. Oil Gas* 54 (2), 113–118. <https://doi.org/10.3969/j.issn.1007-3426.2025.02.016> (in Chinese).
- Ndonhong, V., Belostrino, E., Zhu, D., et al., 2018. Acid jetting in carbonate rocks: An experimental study. *SPE Prod. Oper.* 33 (2), 382–392. <https://doi.org/10.2118/180113-pa>.
- Nozaki, M., Hill, A.D.D., 2010. A placement model for matrix acidizing of vertically extensive, heterogeneous gas reservoirs. *SPE Prod. Oper.* 25 (3), 388–397. <https://doi.org/10.2118/124881-pa>.
- Pacaloni, G., Tambini, M., 1993. Advances in matrix stimulation technology. *J. Petrol. Technol.* 45 (3), 256–263. <https://doi.org/10.2118/20623-pa>.
- Palharini Schwalbert, M., Aljawad, M.S., Hill, A.D., et al., 2020. Decision criterion for acid-stimulation method in carbonate reservoirs: Matrix acidizing or acid fracturing. *SPE J.* 25 (5), 2296–2318. <https://doi.org/10.2118/199236-pa>.
- Panga, M.K.R., Ziauddin, M., Balakotiah, V., 2005. Two-scale continuum model for simulation of wormholes in carbonate acidization. *AIChE. J.* 51 (12), 3231–3248. <https://doi.org/10.1002/aic.10574>.
- Parkhurst, D.L., Appelo, C.A.J., 2025. Description of input and examples for PHREEQC version 3: a computer program for speciation, batch-reaction, one-dimensional transport, and inverse geochemical calculations. Chapter 43 of Section A: Groundwater in Book 6 Modeling Techniques. <https://doi.org/10.3133/tm6A43>.
- Pichler, T., Frick, T.P., Economides, M.J., et al., 1992. Stochastic modeling of wormhole growth in carbonate acidizing with biased randomness. In: All Days, Richardson. Society of Petroleum Engineers SPE 25004 MS. <https://doi.org/10.2118/25004-ms>.
- Qi, N., Chen, G.B., Li, Z.L., et al., 2020. Numerical simulation of large-scale acidification in fractured carbonate reservoirs based on a step-by-step algorithm.

- Acta Pet. Sin. 41 (3), 348–362. <https://doi.org/10.7623/syxb202003009> (in Chinese).
- Rabie, A.I., Nasr-El-Din, H.A., 2015. Effect of acid additives on the reaction of stimulating fluids during acidizing treatments. In: SPE North Africa Technical Conference and Exhibition, Richardson. Society of Petroleum Engineers. <https://doi.org/10.2118/175827-ms>.
- Ren, S.Q., Xiong, H.J., 1989. Temperature and common ion effects on effective acid penetration in a fracture. SPE Prod. Eng. 4 (3), 221–225. <https://doi.org/10.2118/14852-pa>.
- Reznikov, I., Abdrzakov, D., Chuprakov, D., 2024. Model-based interpretation of bottomhole pressure records during matrix treatments in layered formations. Pet. Sci. 21 (5), 3587–3611. <https://doi.org/10.1016/j.petsci.2024.05.027>.
- Saleh Aljawad, M., 2023. Permeability anisotropy impact on wormhole propagation in openhole and limited-entry completions: A 3D numerical study. Gas Sci. Eng. 116, 205050. <https://doi.org/10.1016/j.gsc.2023.205050>.
- Schwalbert, P., 2019. Comprehensive Analysis of Acid Stimulation in Carbonates. Texas A&M University. Dissertation/Thesis Thesis.
- Schwalbert, M.P., Zhu, D., Hill, A.D., 2019. Skin-factor equations for anisotropic wormhole networks and limited-entry completions. SPE Prod. Oper. 34 (3), 586–602. <https://doi.org/10.2118/189486-pa>.
- Shen, X., Guo, J.C., Wang, S.B., 2023. Acidification retardation caused by shielding of cationic surfactants. Petrol. Reserv. Eval. Dev. 13 (1), 117–126. <https://doi.org/10.13809/j.cnki.cn32-1825/te.2023.01.013> (in Chinese).
- Sidaoui, Z., Abdurhaheem, A., Abbad, M., 2018. Prediction of optimum injection rate for carbonate acidizing using machine learning. In: SPE Kingdom of Saudi Arabia Annual Technical Symposium and Exhibition, Richardson. Society of Petroleum Engineers. <https://doi.org/10.2118/192344-ms>.
- Song, C., Lee, J., 2023. Reaction kinetics of an emulsified acid using a mixed emulsifier and carbonate rocks. Colloids Surf. A Physicochem. Eng. Aspects 679, 132544. <https://doi.org/10.1016/j.colsurfa.2023.132544>.
- Sun, J., Li, Y., Liao, B., et al., 2024. Development and performance evaluation of bioenzyme-responsive temporary plugging materials. Adv. Geo-Energy Res. 11 (1), 20–28. <https://doi.org/10.46690/ager.2024.01.03>.
- Talbot, M.S., Gdansk, R.D., 2008. Beyond the damkohler number: a new interpretation of carbonate wormholing. In: Europec/EAGE Conference and Exhibition, Richardson. Society of Petroleum Engineers. <https://doi.org/10.2118/113042-ms>.
- Tan, X., Weng, X., Cohen, C.E., 2016. An improved wormhole propagation model with a field example. In: SPE International Conference and Exhibition on Formation Damage Control, Richardson. Society of Petroleum Engineers. <https://doi.org/10.2118/179017-ms>.
- Tansey, J., Balhoff, M.T., 2016. Pore network modeling of reactive transport and dissolution in porous media. Transp. Porous Medium. 113 (2), 303–327. <https://doi.org/10.1007/s11242-016-0695-x>.
- Taylor, K.C., Al-Ghamdi, A.H., Nasr-El-Din, H.A., 2004. Effect of additives on the acid dissolution rates of calcium and magnesium carbonates. SPE Prod. Facil. 19 (3), 122–127. <https://doi.org/10.2118/80256-pa>.
- Temizel, C., Canbaz, C.H., Palabiyik, Y., et al., 2021. A thorough review of machine learning applications in oil and gas industry. In: SPE/IATMI Asia Pacific Oil & Gas Conference and Exhibition, Richardson. <https://doi.org/10.2118/205720-ms>.
- Urgel-Pinto, R., Alcázar-Vara, L.A., 2024. Microstructural analysis applied to carbonate matrix acidizing: An overview and a case study. Micron 187, 103724. <https://doi.org/10.1016/j.micron.2024.103724>.
- Vadiei, S., Li, B., Raymond, J., et al., 2025. Numerical modeling of the long-term poromechanical performance of a deep enhanced geothermal system in northern Québec. Rock Mech. Bull. 4 (1), 100170. <https://doi.org/10.1016/j.rockmb.2024.100170>.
- Wang, L., Wang, X., Luo, E., et al., 2014. Analytical modeling of flow behavior for wormholes in naturally fractured-vuggy porous media. Transp. Porous Medium. 105 (3), 539–558. <https://doi.org/10.1007/s11242-014-0383-7>.
- Wang, L., Xue, R., Zhao, Q.Y., et al., 2018. A critical review of acidizing fluids in reservoirs for recent years. Appl. Chem. Ind. 47 (3), 548–553. <https://doi.org/10.3969/j.issn.1671-3206.2018.03.032> (in Chinese).
- Wang, Y., Zhou, F., Zhang, Y., et al., 2023. Numerical studies and analysis on reaction characteristics of limestone and dolomite in carbonate matrix acidizing. Geoenergy Sci. Eng. 222, 211452. <https://doi.org/10.1016/j.geoen.2023.211452>.
- Wang, C., Liu, P., Zhao, J., et al., 2025a. Topological isomerism governs asphaltene aggregation: a mechanistic study combining molecular dynamics and experiments. Fuel 385, 134165. <https://doi.org/10.1016/j.fuel.2024.134165>.
- Wang, Y.F., Wang, J., Liu, H.Q., et al., 2025b. Effects of gas components on acid-rock reaction during CO₂-contained industrial waste gas (CO₂-contained IWG) injection into deep shale reservoir on geologic time scale. Pet. Sci. 22 (6), 2604–2618. <https://doi.org/10.1016/j.petsci.2025.02.023>.
- Wehant, C.D., Lattimer, S.K., McDuff, D.R., 2019. Dendritic-acidizing update: The light at the end of the tunnel. SPE Prod. Oper. 34 (1), 130–144. <https://doi.org/10.2118/189945-pa>.
- Wei, W., 2020. Numerical modeling of matrix acidizing in carbonate and sandstone reservoirs. University of Texas at Austin.
- Wilson, A., 2016. No-damage stimulation by use of residual-free diverting fluids. J. Petrol. Technol. 68 (6), 63–64. <https://doi.org/10.2118/0616-0063-jpt>.
- Wu, B., Sheng, J., Wu, D., et al., 2025. A critical review of limited-entry liner (LEL) technology for unconventional oil and gas: A case study of tight carbonate reservoirs. Energies 18 (19), 5159. <https://doi.org/10.3390/en18195159>.
- Xie, Y., Luo, Z., Cheng, L., et al., 2023. Numerical modeling and analysis of the matrix acidizing process in fractured sandstone rocks with the Extended-FEM. J. Petrol. Sci. Eng. 220, 111215. <https://doi.org/10.1016/j.petrol.2022.111215>.
- Xu, Z.L., Dai, C.L., Zhao, M.W., et al., 2017. Research and application progress of crosslinked gelled acid. Appl. Chem. Ind. 46 (12), 2424–2427. <https://doi.org/10.3969/j.issn.1671-3206.2017.12.034> (in Chinese).
- Xue, H., 2017. Numerical simulation study on efficient acidification of horizontal wells in complex carbonate reservoirs. Southwest Petroleum University (in Chinese).
- Xue, H., Zhao, L.Q., Liu, P.L., et al., 2016. Dynamic simulation of 3-D multiple-scale wormhole propagation in carbonate rocks. Oil Gas Geol. 37 (5), 792–798. <https://doi.org/10.11743/ogg20160520> (in Chinese).
- Xue, H., Zhang, L., Liu, P., et al., 2017. Simulation and analysis of wormhole propagation in carbonates through the use of models with different dimensions. Chem. Technol. Fuels Oils 53 (5), 727–738. <https://doi.org/10.1007/s10553-017-0855-x>.
- Xue, H., Huang, Z., Zhao, L., et al., 2018a. Influence of acid-rock reaction heat and heat transmission on wormholing in carbonate rock. J. Nat. Gas Sci. Eng. 50, 189–204. <https://doi.org/10.1016/j.jngse.2017.12.008>.
- Xue, H., Huang, Z.X., Zhao, L.Q., et al., 2018b. Optimization study on horizontal well acidizing modes and injection parameters in carbonate reservoir. Reserv. Eval. Dev. 8 (3), 66–72. <https://doi.org/10.13809/j.cnki.cn32-1825/te.2018.03.014> (in Chinese).
- Xue, H., Huang, Z., Liu, F., et al., 2019. 3D acid fracturing simulation and application in the Upper Sinian Dengying Fm. gas reservoirs in China. In: International Petroleum Technology Conference. <https://doi.org/10.2523/19137-ms>.
- Xue, H., He, B., Jiang, L.P., et al., 2022. Research and application of targeted acidizing tech in horizontal well of carbonate reservoir. J. Southwest Petrol. Univ. Sci. Technol. Ed. 44 (4), 121–128. <https://doi.org/10.11885/j.issn.1674-5086.2020.05.28.01> (in Chinese).
- Xue, X., Chen, X., Huang, C., et al., 2025. Numerical simulation study on reservoir damage caused by adsorption and capture retention in polymer injection. Petroleum 11 (5), 624–637. <https://doi.org/10.1016/j.petlm.2025.08.003>.
- Yang, Z.Z., Deng, Z., Yu, M.N., et al., 2020. Experimental research on growth mechanism of acid wormhole in carbonate matrix. Reserv. Eval. Dev. 10 (2), 24–29. <https://doi.org/10.13809/j.cnki.cn32-1825/te.2020.02.004> (in Chinese).
- Yoo, H., Park, J., Lee, Y., et al., 2019. An experimental investigation into the effect of pore size distribution on the acid-rock reaction in carbonate acidizing. J. Petrol. Sci. Eng. 180, 504–517. <https://doi.org/10.1016/j.petrol.2019.05.061>.
- Yousufi, M.M., Mohyaldin Elhaj, M.E., Bin Dzulkarnain, I., 2024. A review on use of emulsified acids for matrix acidizing in carbonate reservoirs. ACS Omega 9 (10), 11027–11049. <https://doi.org/10.1021/acsomega.3c07132>.
- Yuan, L., Li, X.P., Tan, X.H., et al., 2015. Study on skin factor and productivity of horizontal well after acidizing with nonuniform damage. J. Chem. 2015, 706312. <https://doi.org/10.1155/2015/706312>.
- Yuan, Y., Du, J., Liu, P., et al., 2025. Research on acidizing blockage removal and perfusion enhancement technology for sandstone geothermal reservoir recharge wells. Geothermics 125, 103200. <https://doi.org/10.1016/j.geothermics.2024.103200>.
- Yue, H., Liu, F., Xue, H., et al., 2018. Numerical simulation and field application of diverting acid acidizing in the Lower Cambrian Longwangmiao Fm. gas reservoirs in the Sichuan Basin. Nat. Gas Ind. B 5 (3), 204–211. <https://doi.org/10.1016/j.ngib.2018.04.007>.
- Zakaria, A.S., Nasr-El-Din, H.A., 2016. A novel polymer-assisted emulsified-acid system improves the efficiency of carbonate matrix acidizing. SPE J. 21 (3), 1061–1074. <https://doi.org/10.2118/173711-pa>.
- Zakaria, A., Singh, A., Bhaduri, S., 2022. Novel low viscosity, single phase, polymer-free delayed HCl acid system for stimulation of high temperature carbonate reservoirs. In: SPE International Conference and Exhibition on Formation Damage Control, Richardson. Society of Petroleum Engineers. <https://doi.org/10.2118/208847-ms>.
- Zhang, H., 2015. Experimental Simulation and Fractal Model Study of Acid Etched Wormholes in Carbonate Rocks. University of Chinese Academy of Sciences (in Chinese).
- Zhang, W., Mao, J., Yang, X., et al., 2019. Development of a stimuli-responsive gemini zwitterionic viscoelastic surfactant for self-diverting acid. J. Surfactants Deterg. 22 (3), 535–547. <https://doi.org/10.1002/jsde.12267>.
- Zhang, Q., Liu, P., Xiong, Y., et al., 2023. Self-generated organic acid system for acid fracturing in an ultrahigh-temperature carbonate reservoir. ACS Omega 8 (13), 12019–12027. <https://doi.org/10.1021/acsomega.2c07738>.
- Zhang, Y., Zhang, G.T., Liu, Y., et al., 2024. Development and application of high-performance series soluble bridge plugs. China Petrol. Mach 52 (1), 124–129. <https://doi.org/10.16082/j.cnki.issn.1001-4578.2024.01.016> (in Chinese).
- Zhao, L., Chen, X., Shun, J., et al., 2020a. Research and application of chelating acid blocking removal system for injection wells. J. Southwest Petrol. Univ. Sci. Technol. Ed. 42 (3), 123–131. <https://doi.org/10.11885/j.issn.1674-5086.2019.08.18.01> (in Chinese).
- Zhao, L., Chen, X., Zou, H., et al., 2020b. A review of diverting agents for reservoir stimulation. J. Petrol. Sci. Eng. 187, 106734. <https://doi.org/10.1016/j.petrol.2019.106734>.
- Zhao, L.Q., Zhang, N.L., Zhang, Y.M., et al., 2020c. Laboratory study and field application of self-propping phase-transition fracturing technology. Nat. Gas. Ind. 40 (11), 60–67. <https://doi.org/10.3787/j.issn.1000-0976.2020.11.007> (in Chinese).

- Zhao, F., Jiao, X., Xia, X., et al., 2024. Evolution of rock pore structure and physical properties due to acidification: Recent advances and future perspectives. *Adv. Geo-Energy Res.* 14 (3), 238–240. <https://doi.org/10.46690/ager.2024.12.08>.
- Zheng, N., Zhu, J., Yang, Z., et al., 2024. Molecular dynamics simulation and key performance study of VES self-diverting acid system for deep carbonate reservoirs. *J. Mol. Liq.* 401, 124645. <https://doi.org/10.1016/j.molliq.2024.124645>.
- Zhou, F.J., Xiong, C.M., Shi, Y., et al., 2011. Study on a self-diverting acid system for well stimulation based on novel visco-elastic surfactant. *Adv. Mater. Res.* 287–290, 3120–3126. <https://doi.org/10.4028/www.scientific.net/amr.287-290.3120>.
- Zhou, S.T., Li, Z.M., Wang, F., 2012. Numerical simulation on the foam acidizing diversion in horizontal wells. *Acta Pet. Sin.* 33 (3), 448–452 (in Chinese).
- Zhou, H., Wu, X., Song, Z., et al., 2022a. A review on mechanism and adaptive materials of temporary plugging agent for chemical diverting fracturing. *J. Petrol. Sci. Eng.* 212, 110256. <https://doi.org/10.1016/j.petrol.2022.110256>.
- Zhou, L., Guo, A., Wang, X., et al., 2022b. The effect of temperature, natural fractures and vugs on the acidizing process in fractured-vuggy reservoirs with hydro-thermal-chemical coupled modeling. *J. Petrol. Sci. Eng.* 213, 110416. <https://doi.org/10.1016/j.petrol.2022.110416>.
- Zhou, W., Liu, C., Liu, Y., et al., 2024. Machine learning in reservoir engineering: A review. *Processes* 12 (6), 1219. <https://doi.org/10.3390/pr12061219>.
- Zhou, Q., Luo, Z., Fu, H., et al., 2025. Research and application progress of temporary plugging agent for acidification fracturing: A review. *Geoenergy Sci. Eng.* 247, 213600. <https://doi.org/10.1016/j.geoen.2024.213600>.
- Zuo, C., Liu, P., Gao, S., et al., 2024. Study on the scale inhibition performance and mechanism of a high-performance graft copolymer cellulose green scale inhibitor on oilfield Ca^{2+} . *ACS Appl. Polym. Mater.* 6 (20), 12708–12718. <https://doi.org/10.1021/acsapm.4c02316>.
- Zuo, C., Liu, P., Du, J., et al., 2025. A review: supramolecular polymers used in high-temperature fracturing fluids research status and prospects on the coupling relationship between molecular conformation and temperature resistance mechanism. *Geoenergy Sci. Eng.* 247, 213699. <https://doi.org/10.1016/j.geoen.2025.213699>.
- Zuo, C., Liu, P., Du, J., et al., 2026. Polymer nano-network topological fluid via tri-functional nano-grafting and multifunctional free radical capture groups strategy for ultra-high temperature and deep reservoir stimulation. *Chem. Eng. J.* 528, 172297. <https://doi.org/10.1016/j.cej.2025.172297>.