Petroleum Science 23 (2026) 4999–5019

Contents lists available at ScienceDirect

Petroleum Science

journal homepage: www.keaipublishing.com/en/journals/petroleum-science

Review Paper

Chemical plugging systems for preventing gas channeling in CO_2 flooding: Progress and prospects

Shun-Dong Jiang [a,b,c], Li-Feng Chen [a,b,c,*], Dai-Gang Wang [d], Wei-Wei Sheng [a,b,c], Ming-Chen Shi [a,b,c], Ming-Hao Xue [a,b,c], Hui-Yong Zeng [a,b,c], Lei Hu [a,b,c], Xu-Rui Long [a,b,c]

[a] *School of Petroleum Engineering, Yangtze University, Wuhan, 430100, Hubei, China*
[b] *State Key Laboratory of Low Carbon Catalysis and Carbon Dioxide Utilization (Yangtze University), Wuhan, 430100, Hubei, China*
[c] *Hubei Key Laboratory of Oil and Gas Drilling and Production Engineering (Yangtze University), Wuhan, 430100, Hubei, China*
[d] *State Key Laboratory of Petroleum Resources and Engineering, China University of Petroleum (Beijing), Beijing, 102249, China*

A R T I C L E I N F O

Article history:
Received 12 January 2026
Received in revised form
12 April 2026
Accepted 13 April 2026
Available online 17 April 2026

Edited by Yan-Hua Sun

Keywords:
CO_2 flooding
Gas channeling control
Chemical plugging system
CO_2-responsive intelligent plugging
Enhanced oil recovery

A B S T R A C T

As an important component of carbon capture, utilization, and storage (CCUS), CO_2 flooding technology can improve oil recovery while realizing CO_2 geological storage. However, due to reservoir heterogeneity and physical property differences between CO_2 and formation fluids, gas channeling severely limits its development efficiency. This paper systematically summarizes the dominant mechanisms of gas channeling and accordingly reviews in depth the research progress and technical characteristics of three major chemical plugging systems: foam-based gas channeling control, gel-based gas channeling control, and CO_2-responsive intelligent gas channeling control. Foam systems achieve selective plugging based on the Jamin effect, gel systems form physical barriers through three-dimensional network structures, and CO_2-responsive systems trigger in-situ gelation by the acidity of CO_2 itself. Each of the three has unique advantages, but limitations remain in its plugging strength, environmental adaptability, and long-term stability. On this basis, the applicable conditions and key bottlenecks of various technologies are compared and analyzed, and their future development trends are prospected. Gas channeling control technology requires the coordinated development of material innovation and process optimization: on the one hand, developing intelligent composite materials with multi-response characteristics, temperature resistance, and salt tolerance; on the other hand, building a data-driven intelligent decision-making platform to realize precise placement of plugging agents and dynamic optimization of processes. Ultimately, a systematic solution featuring “intelligent sensing–precise regulation–long-term stability” will be formed, providing technical support for the large-scale application of CO_2 flooding.

1. Introduction

In the current global energy supply and demand pattern, the continuous depletion of conventional oil and gas reserves and the tightening of carbon emission constraints have become two core issues restricting energy security (Ampomah et al., 2017). With the continuous intensification of the exploitation of conventional oil and gas resources, high-quality resources are becoming increasingly depleted, and the pressure on energy supply is rising steadily; meanwhile, the high carbon emissions associated with conventional oil and gas development models are in significant contradiction with the global carbon neutrality goal. Against this backdrop, carbon capture, utilization, and storage (CCUS) technology provides an innovative solution for achieving the balance between energy supply and demand and advancing low-carbon transition (Wilberforce et al., 2021). This technology not only provides a reliable storage pathway for carbon emissions in the industrial sector but also establishes a virtuous cycle between ensuring energy security and advancing low-carbon development by improving the development efficiency of unconventional oil and gas resources (Prasad et al., 2023).

Against the backdrop of in-depth advancement in global energy structure transformation and the “dual carbon” (carbon peaking

* Corresponding author.
E-mail address: LYJ50552352@126.com (L.-F. Chen).
Peer review under the responsibility of China University of Petroleum (Beijing).

https://doi.org/10.1016/j.petsci.2026.04.016
1995-8226/

and carbon neutrality) strategic goals, CO_2-EOR technology has emerged as a key technical direction for improving oil and gas recovery due to its distinctive merits (Fig. 1) (Ali et al., 2022). Through the synergistic action of multiple mechanisms, including crude oil viscosity reduction, mobility ratio improvement, crude oil swelling induction, and interfacial tension reduction, this technology not only markedly enhances oil displacement efficiency but also achieves effective sequestration of greenhouse gases (Al-Obaidi et al., 2024; Chen et al., 2025b; Masalmeh et al., 2025; Zhang et al., 2024a; Zhang et al., 2024b). However, the disparities in physical properties between CO_2 and reservoir crude oil and aqueous phases, coupled with the effects of reservoir heterogeneity, readily trigger severe gas channeling issues, which in turn have emerged as a critical bottleneck restricting the large-scale field deployment of this technology. Gas channeling is primarily characterized by the premature breakthrough of injected CO_2 into production wells along preferential pathways such as high-permeability streaks and natural fractures, leaving substantial volumes of crude oil stranded in low-permeability zones without effective sweep. This phenomenon is comprehensively influenced by factors including viscous fingering and gravity segregation, and it couples with reservoir heterogeneity, which significantly reduces the displacement sweep volume and oil displacement efficiency, directly impairing the development performance and economic benefits of CO_2-EOR technology (Hou et al., 2022). Accordingly, the development of high-efficiency gas channeling control and mitigation technologies has become the research core of the CO_2-EOR field. At present, techniques such as water-alternating-gas (WAG) injection and chemical plugging agent-based channeling control are widely used to address the issue of premature CO_2 breakthrough. Nevertheless, under complex reservoir conditions (e.g., high temperature and high salinity, strong heterogeneity), these technologies still face challenges such as insufficient stability and long-term effectiveness.

In this paper, the mechanisms and key influencing factors of CO_2 gas channeling are systematically sorted out; the research progress and technical characteristics of foam system for gas channeling plugging, gel systems for gas channeling plugging, CO_2-responsive intelligent systems for gas channeling plugging are thoroughly reviewed; the applicable conditions and limitations of various technologies are analyzed and compared; and the development trends and innovative directions of gas channeling prevention and control technologies are prospected.

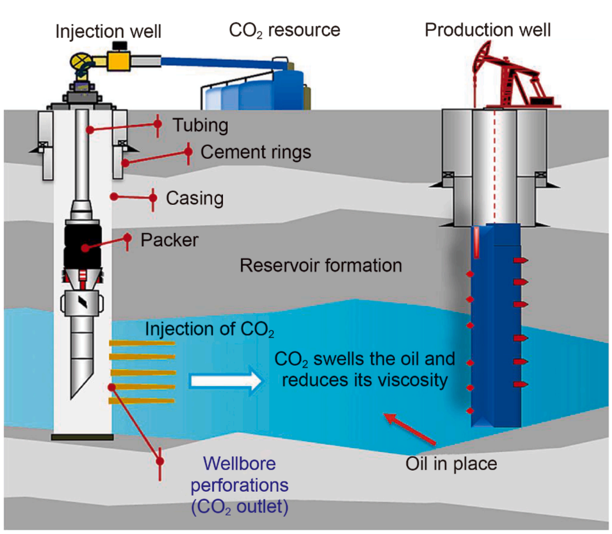

Fig. 1. Schematic diagram of CO_2-EOR. Adapted with permission from Davoodi et al. (2024).

2. Mechanism of CO_2 gas channeling in CO_2-EOR

CO_2 exhibits strong fluidity. When dissolved in crude oil, CO_2 not only significantly reduces oil viscosity and improves crude oil mobility but also induces crude oil volume expansion, thereby enhancing displacement efficiency (Kumar et al., 2022). Meanwhile, CO_2 can also effectively reduce the interfacial tension of the reservoir system, thereby enhancing oil washing efficiency. Thus, compared with water flooding, gas flooding is more efficient and can reduce the residual oil saturation in the formation to a lower level. However, CO_2 gas tends to rapidly break through along high-permeability channels, formation fractures, or channeling pathways, prematurely channeling into production wells. This leaves a large volume of crude oil stranded due to insufficient contact with CO_2, thereby reducing displacement efficiency; in severe cases, it can even trigger issues such as water flooding or gas cap breakthrough, ultimately impairing the overall development benefits of the reservoir.

2.1. Viscous fingering

Viscous fingering refers to a phenomenon in which the displacement front advances in a “finger-like” pattern when a low-viscosity fluid displaces a high-viscosity fluid during the immiscible two-phase fluid displacement process (Chen et al., 2018). In 1964, Crane verified through glass bead-packed model experiments that the difference in the viscosity–gravity ratio between the displacing phase and the displaced phase constitutes the core cause of viscous fingering formation. Since the viscosity of CO_2 is much lower than that of reservoir crude oil and formation water, the interface between the two fluid phases becomes highly unstable when low-viscosity CO_2 displaces high-viscosity oil or water phases. This renders CO_2 prone to penetrating the oil or water phases ahead and advancing rapidly along the seepage channels with the least resistance; consequently, it bypasses a large number of oil-bearing pores and causes channeling, which significantly reduces displacement sweep efficiency and ultimately impairs the reservoir recovery factor (Bin et al., 2015; Jamaloei et al., 2016; Joachim, 2016; Xu et al., 2020b).

2.2. Reservoir heterogeneity

Low-resistance zones in reservoirs, such as high-permeability streaks, macropores, natural fracture networks, and vugs, act as preferential seepage pathways for CO_2. This causes CO_2 to advance rapidly and bypass low-permeability oil-bearing zones, directly reducing sweep efficiency. In addition, the vertical heterogeneity of reservoirs exerts a particularly significant influence on the performance of CO_2 gas flooding. CO_2 is a colorless gas under standard conditions; when the pressure and temperature of its surrounding environment exceed the critical thresholds (Fig. 2), it transforms into a supercritical state. Both gaseous and supercritical CO_2 have densities far lower than those of formation water and crude oil, and this significant density difference gives rise to a strong gravitational override tendency. In vertically heterogeneous reservoirs, CO_2 tends to preferentially channel along the upper formations and accumulate at structural tops or the tops of high-permeability layers, thereby giving rise to the phenomenon of “gas cap breakthrough”. That is, it prematurely channels into production wells without achieving sufficient displacement of crude oil in the middle and lower formations (Nasir and Chong, 2009; Xu et al., 2020b; Zhang et al., 2018). Even for reservoirs

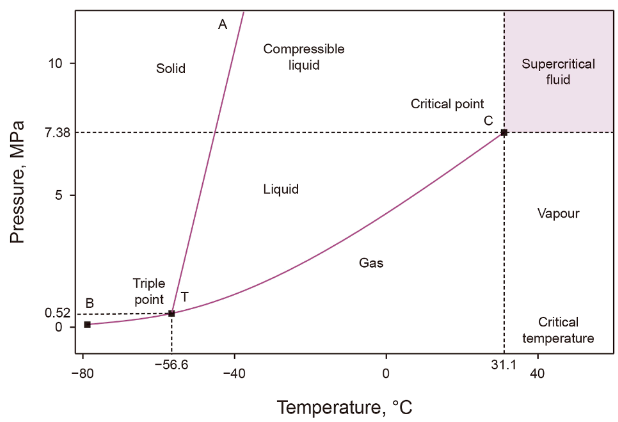

Fig. 2. Phase diagram of CO_2. Adapted with permission from Guo et al. (2016).

with high vertical permeability, where the vertical sweep range may be slightly improved, the combined effects of gravitational segregation and reduced displacement rate will still generally impair the gas flooding development performance. Meanwhile, differences in the size distribution and connectivity of reservoir pore throats can also alter the flow paths of CO_2: CO_2 tends to more easily enter large pore-throat channels, while it may become trapped or bypass small pore throats. In summary, the stronger the reservoir heterogeneity, the more severe the CO_2 gas channeling phenomenon (Wei et al., 2014).

2.3. Rock wettability and capillary force

The wettability of rock surfaces and capillary forces exert a significant influence on the distribution state and flow paths of CO_2 in the reservoir (Al-Shargabi et al., 2022). In water-wet rock reservoirs, formation water occupies small pore spaces and particle surfaces, while CO_2 accumulates in the central regions of large pores; capillary action tends to draw water into small pores, thereby segregating or trapping CO_2. In oil-wet rock reservoirs, CO_2 can more easily contact crude oil and achieve miscibility, but under the influence of reservoir heterogeneity, capillary forces may still hinder CO_2 from entering low-permeability zones, causing it to preferentially channel along high-permeability pathways (Shi et al., 2011). In addition, the vicinity of production wells is characterized by high pressure gradients and high fluid flow velocities; under such conditions, capillary forces can hardly impose effective constraints on CO_2, which can easily cause the formed CO_2 gas clusters to rapidly breakthrough to the wellbore via the viscous fingering effect.

2.4. Other factors

CO_2 molecules feature a small molecular volume and a high diffusion coefficient; even in low-permeability zones, they can migrate toward production wells via molecular diffusion, resulting in the formation of "diffusion-type gas channeling" and premature gas breakthrough in production wells (Guo et al., 2016). Although its diffusion proceeds relatively slowly, it enables CO_2 to enter low-flow-rate zones or dead pores, particularly near gas channeling pathways; it will significantly exacerbate the migration of CO_2 toward the wellbore. Meanwhile, carbonic acid generated by the dissolution of CO_2 in water reacts with reservoir minerals, dissolving some minerals to increase porosity and permeability; this in turn alters reservoir pore structures, exacerbates reservoir heterogeneity, and ultimately aggravates the gas channeling problem (Bisweswar et al., 2020; Luquot and Gouze, 2009; Peter et al., 2022). In addition, the adsorption capacity of CO_2 on rocks is much lower than that of crude oil or polymers, making it difficult to form effective retention on rock surfaces; in contrast, crude oil can form a "bound phase" through adsorption, while CO_2 remains in a free-flowing state at all times, and this difference further exacerbates the channeling phenomenon.

3. Research progress on gas channeling plugging systems

3.1. Foam system for gas channeling plugging

Aiming at the problem of CO_2 preferential breakthrough along high-permeability channels caused by viscous fingering, the foam system for gas channeling plugging increases flow resistance in high-permeability zones through the Jamin effect generated by foam bubbles at pore throats, thus mitigating gas channeling.

The diameter of bubbles in foam is generally larger than that of reservoir pore throats, especially the pore throats of high-permeability gas channeling pathways. When bubbles flow through pore throats, they undergo extrusion and deformation due to the "constriction effect" of pore throats, thereby generating additional resistance at the gas–liquid interface, namely the "Jamin resistance" (Wang et al., 2023). After foam is injected into the formation, it preferentially enters high-permeability channeling zones. Under the effect of the Jamin effect, the flow resistance of formation fluids gradually increases, thereby achieving the effect of retarding gas channeling. This effect can not only effectively improve the sweep coefficient and oil displacement efficiency of CO_2 flooding but also realize the effective supplement of formation energy, ultimately significantly enhancing oil recovery (Al Sumaiti et al., 2017).

Foam plugging technology can effectively inhibit the gas channeling phenomenon during CO_2 flooding, thereby achieving crude oil production increment (Oliveira da Rocha et al., 2021). In 1958, Boud and Holbrook (1958) first proposed a technical scheme for applying foam to improve gas flooding development performance and obtained patent authorization. After the technology was put into practical field application, the gas breakthrough time was significantly delayed, and crude oil recovery was increased by 5%–15% compared with conventional gas flooding. Hassanzadeh et al. (2022) applied the CO_2 foam system to water control and oil increment operations in oilfields. Field application results showed that after the injection of CO_2 foam, gas utilization efficiency increased by 17% and the water cut of oil wells decreased by as much as 50%. Friedmann et al. (1991) established a mathematical model for predicting the fluidity of continuous gas and discrete gas foam through theoretical research and quantitatively analyzed the regulatory effect of surfactant-stabilized foam on gas fluidity.

Through in-depth analyses of foam stability, plugging mechanisms, and flow behavior, researchers have clarified the migration and plugging laws of foam in formations. Translating such theoretical insights into foam plugging systems with engineering application value has become the key to addressing the practical challenge of gas channeling control in oilfield sites. At present, the commonly used foam plugging systems in oilfields mainly include three-phase foam, polymer-reinforced foam, and gel foam (Liu et al., 2022).

Although conventional foam systems can plug gas channeling pathways to a certain extent, they suffer from issues such as insufficient plugging strength and exhibit poor gas channeling control performance in severely heterogeneous reservoirs. To address this, polymers can be incorporated into conventional foam systems. The stability and plugging strength of foam can be enhanced by virtue of the thickening effect of polymers (Yang et al., 2026). Rezaeiakmal and Parsaei (2021) constructed a polymer-enhanced foam (PEF) system composed of 0.3 wt% cetyltrimethylammonium bromide (CTAB) and 0.1 wt% polyvinylalcohol (PVA). Experiments showed that the foam stability of this system was improved by more than 20% compared with the single CTAB system; in comparison with conventional foam, the PEF system could enhance crude oil recovery by 15%–20%.

Wang et al. (2022b) prepared a gel-enhanced foam plugging system using partially hydrolyzed polyacrylamide (HPAM) and an organic chromium crosslinker as the main agents, with the addition of 0.05–0.1 wt% SiO_2 nanoparticles. Among them, SiO_2 nanoparticles can prolong the dehydration time of the foam liquid film through the water-locking effect of surface hydroxyl groups, thereby enhancing the mechanical strength of the liquid film. Under the conditions of 55 °C and 12 MPa, the gelation time of this system reached 6–35 h. In displacement experiments with a permeability ratio of 12, the crude oil recovery reached 53.33%; after 15 d of aging treatment, the recovery of this nanoparticle-modified system in fractured cores reached 25.24%, which was 12.38% higher than that of the conventional gel foam system.

Foam tends to destabilize under high-temperature conditions, resulting in poor plugging performance and low oil displacement efficiency. To address this issue, a high-temperature and high-salinity resistant foaming agent can be selected to improve foam stability, thereby enhancing its plugging strength. Kang et al. (2021) constructed a high-temperature-resistant and high-salt-tolerant CO_2 foam system using 0.5 wt% anionic-nonionic surfactant EC-1 as the main agent and 1.0 wt% hydrophilic SiO_2 nanoparticles as foam stabilizer. Experiments showed that under the conditions of 85 °C, salinity of 6×10^4 mg/L, and pressure of 8.5 MPa, the foam half-life of this system could reach 18 min, which was 14 min longer than that of the single EC-1 system. When the SiO_2 concentration is 1.0 wt%, the resistance factor of the system reached 39.46, and it could still maintain a resistance factor of 37.93 even at a high temperature of 85 °C. Chen et al. (2024b) developed a high-temperature-resistant foam system (EFS) compounded from zwitterionic surfactant EBB, polymeric surfactant (FA), and SiO_2 nanoparticles. After aging at 150 °C for 10 d, the viscosity retention rate of this system remained as high as 77.76%. Under high-temperature conditions, SiO_2 particles can form a spatial network structure by enhancing molecular thermal motion, extending the foam half-life of the system to 106 min at 150 °C and 6 MPa, with a foaming volume exceeding 500 mL, and its stability was improved by 147% compared with the single EBB system. Compared with pure CO_2 flooding, this foam flooding technology can enhance crude oil recovery by 13.74%.

To meet the displacement and plugging requirements of complex reservoirs with high temperature, high salinity, and strong heterogeneity, some scholars have proposed constructing a dual-network foam system through a “structural synergy” strategy, thereby achieving high foam stability, strong environmental adaptability, and efficient plugging capacity (Fig. 3). The liquid film of single-surfactant foam is only supported by surface tension and a monomolecular layer, which is prone to rupture when the liquid film thins or is subjected to external force impact; thus, its half-life is usually relatively short. In contrast, the dual-network foam system can extend the half-life to several hours or even days. The dual-network structure achieves synergistic stabilization via the “multiple liquid film reinforcement” mechanism. The first network reduces the gas–liquid surface tension through interfacial adsorption, forming a stable basic liquid film. The second network either constructs a three-dimensional spatial network inside the liquid film or adsorbs onto the liquid film surface to enhance its mechanical strength, thereby effectively retarding liquid film drainage and bubble coalescence.

Zou et al. (2025) constructed a salt-induced dual network gel-strengthened foam (SDG-Foam) using sodium alginate (SA) and acrylamide (AM) as raw materials via the synergistic effect of calcium ion-induced ionic crosslinking and high-temperature-initiated covalent crosslinking. Under the conditions of high temperature (130 °C) and high salinity (21.9×10^4 mg/L), the foam half-life of this system exceeded 18 d, and its volume retention rate still reached 50% after 18 d of aging treatment. Core experiment results showed that after preferentially plugging fracture-vuggy high-permeability channeling pathways with SDG-Foam, the oil recovery was enhanced by 11.5% compared with that before plugging.

Liu et al. (2022) prepared a dual-network semi-solidified gel foam system using SA and AM monomers, high-molecular-weight PAM, and crosslinkers as raw materials, supplemented with betaine surfactants. The gel formation and stabilization mechanism of this system is divided into two stages: In the first stage, SA can rapidly react with divalent cations (Ca^{2+}) in formation water to form an ion-crosslinked network and a protective film, thereby enhancing foam stability. In the second stage, AM, PAM, and crosslinkers further react to form a covalent crosslinked network, and the dual-network semi-solidified gel foam is finally obtained after system optimization. Experiments showed that under the conditions of 130 °C and high salinity of 22.37×10^4 mg/L, the foam half-life of this system could reach 40 d, which was more than 600 times higher than that of conventional gel foam. Displacement experiments indicated that after the injection of the plugging agent, the injection pressure increased from 0.12 to 0.58 MPa, and the breakthrough pressure gradient could reach more than 9.9 MPa/m. This system can effectively address the technical difficulties of conventional foam in high-temperature, high-salinity, fracture-vuggy reservoirs, such as instability caused by the lack of pore-throat support and easy dilution by formation water, and is suitable for gas channeling plugging operations in deep carbonate reservoirs.

At present, foam plugging technology has achieved remarkable results in the treatment of reservoir gas channeling in oilfield sites, but the technology still has defects such as a short action cycle and limited effective action distance. The core problem is that foam systems optimized under laboratory conditions cannot fully adapt to complex and variable reservoir environments, and field engineering constraints also prevent their plugging performance from being exerted accurately.

In terms of long-term stability, foaming agent molecules are prone to thermal degradation or hydrolysis at high temperatures, resulting in loss of surface activity and a sharp reduction in foam half-life. In high-salinity environments, multivalent ions such as Ca^{2+} and Mg^{2+} can form precipitates with anionic surfactants, damage the integrity of foam liquid films, and accelerate foam collapse. For polymer-enhanced foam systems, amide groups on polymer chains are easily hydrolyzed in the acidic CO_2 environment, reducing thickening ability and further weakening the long-term plugging performance of foams. In addition, although nanomaterials (e.g., SiO_2) can improve foam stability, they tend to agglomerate and settle during long-term service and lose their foam-stabilizing effect. The above time-dependent degradation mechanisms are coupled with each other, which jointly restricts the long-term application of foam plugging systems under harsh reservoir conditions.

While pursuing long-term effective performance, foam plugging systems also face an inherent trade-off between deep injectivity and near-wellbore plugging risk. High-strength foam tends to cause excessive superposition of the Jamin effect near the wellbore during injection, leading to a sudden increase in injection pressure and forcing subsequent foam to divert to unswept zones.

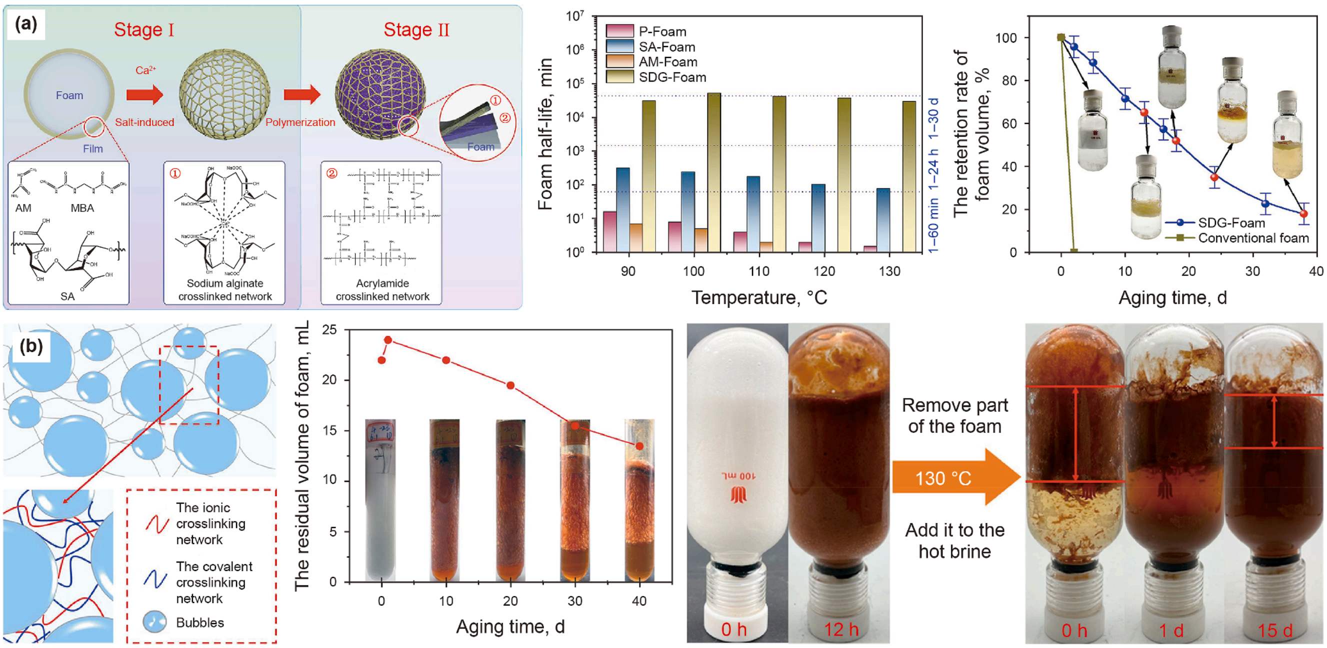

Fig. 3. Different double-network foam systems. (**a**) Schematic diagram of salt-induced dual-network gel-strengthened foam synthesis and its performance test; (**b**) schematic diagram of dual-network semi-solidified gelled-foam synthesis and its salt resistance test. Adapted with permission from Liu et al. (2022) and Zou et al. (2025).

In tight reservoirs (permeability of less than 10 mD), the matching relationship between foam bubble size and pore-throat size is more sensitive: Oversized bubbles cannot enter the deep matrix, while undersized bubbles provide insufficient Jamin effect to effectively control gas channeling. Although high-strength foam can form effective plugging in fractured reservoirs, its fluid loss on fracture walls causes foam dehydration and reduced stability, further impairing the durability of plugging.

The adverse effects of foam plugging systems on reservoirs during application are also factors that need to be considered in their subsequent development. Surfactant adsorption can change rock wettability, and the residual solution after collapse may cause a water blocking effect, reducing oil-phase permeability in low-permeability zones. Excessive accumulation in fractured reservoirs is likely to form dense filter cakes, which are difficult to flow back and cause permanent damage to near-wellbore zones. In field applications, the foam treatment radius is restricted by injection rate, foam quality, and reservoir heterogeneity. If parameters are improperly controlled, foam will preferentially enter high-permeability intervals, which will instead intensify the heterogeneity of channeling channels.

Therefore, it is urgent to introduce intelligent dynamic monitoring technology to realize real-time evaluation of foam performance and online optimization of process parameters. Meanwhile, it is necessary to accelerate the research and development of new low-cost, environment-friendly foam systems and other high-efficiency plugging technologies, seek an optimized balance between foam plugging strength and injectivity, establish quantitative relationships among foam properties for different reservoir conditions, and achieve precise regulation. In this way, the bottlenecks of existing technologies can be broken through to meet the long-term demand for gas channeling control in complex reservoirs.

3.2. Gel systems for gas channeling plugging

Affected by reservoir heterogeneity and gravitational differentiation of CO_2, CO_2 tends to channel along high-permeability streaks, fractures, or structural tops, making it difficult to produce crude oil in low-permeability zones. The gel systems for gas channeling plugging physically plugs the dominant channels by forming a three-dimensional network structure, thus improving sweep efficiency. In recent years, further studies (Liu et al., 2025b) of the fluid occurrence states and migration characteristics in heterogeneous tight reservoirs have revealed that pore-throat structure and permeability differences are the key factors controlling seepage stability and fluid mobilization efficiency, which provides a theoretical basis for understanding the migration behavior of gels in heterogeneous reservoirs and their sensitivity to fracture aperture.

The development course of gel systems for gas channeling control is shown in Fig. 4. Compared with foam plugging technology, gel plugging has remarkable advantages, such as strong plugging capacity, excellent stability, high compressive strength after gelation, and a wide application range. As early as 1999, Raje et al. (1999) applied gel systems to the field of gas channeling prevention in CO_2 flooding. Studies showed that compared with the state before gel injection, the core permeability decreased significantly, confirming that the gel system could form an effective plugging effect on CO_2 channeling pathways. Hild and Wackowski (1999) applied chromium acetate-acrylamide polymer gel to the CO_2 flooding oilfield in northwest Colorado, USA, and found that the oil displacement effect of CO_2 flooding was significantly improved. At present, the commonly used gel systems for gas channeling plugging in oilfields mainly include delayed-crosslinking polyacrylamide gel, preformed particle gel, two-stage gas channeling plugging gel systems, and foam gel.

3.2.1. Delayed-crosslinking polyacrylamide gel

To endow gel systems with excellent injectability, delayed crosslinking technology is commonly adopted in engineering practice. This technology uses low-viscosity substances as stock solutions; after being injected into the designated formation positions, crosslinking reactions are triggered to form gels, thereby achieving precise plugging of formation channeling pathways. By

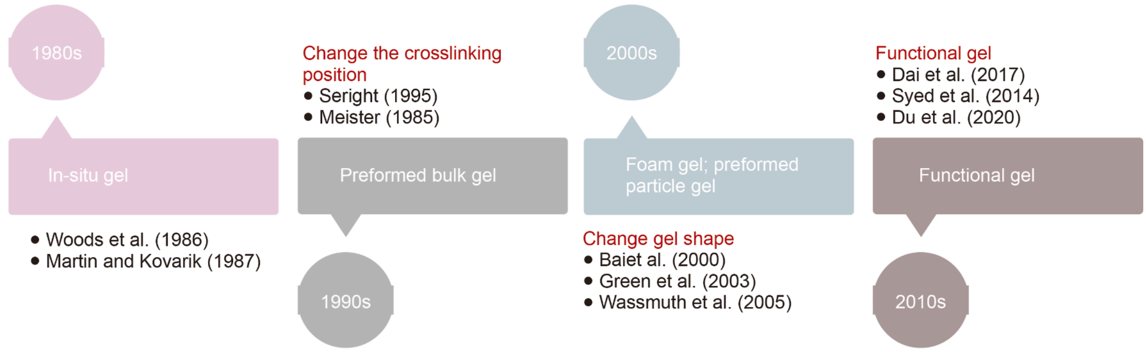

Fig. 4. Research progress of CO_2 channeling control gel systems. Reprinted with permission from Zhao et al. (2024).

regulating the crosslinking reaction rate, the gelation time can be accurately controlled, and thus the migration distance of gel plugging agents in formations can be effectively regulated.

Delayed-crosslinking polyacrylamide gel is an early-applied type of delayed-crosslinking gel system. This system realizes the plugging of gas channeling pathways through the slow cross-linking reaction between functional groups on polymer molecular chains and crosslinkers to form a three-dimensional network structure (Fig. 5). It features strong fluidity and low adsorption loss, enabling it to penetrate deep into the formation well, and has a relatively low cost; thus, it has been widely used in the field of profile control and gas channeling plugging in conventional reservoirs. Among (PAM)-based gels, HPAM/Cr(III) polymer gel is the most commonly used type for gas channeling plugging in CO_2 flooding (Sun et al., 2020). Among (PAM)-based gels, HPAM/Cr(III) polymer gel is the most commonly used type for gas channeling plugging in CO_2 flooding. Partially HPAM can flow along large pores and undergo tensile deformation, allowing it to pass through porous media and preferentially enter high-permeability zones. This reduces the permeability of high-permeability layers, improves interlayer heterogeneity of reservoirs, expands the sweep volume of displacement, and ultimately achieves an increase in crude oil recovery.

However, this system has many obvious shortcomings. First, it is difficult to accurately control gelation strength and gelation time. Under complex reservoir conditions, it may fail to achieve effective deep injection due to premature gelation or fail to form reliable plugging due to insufficient gelation strength. Second, in the acidic environment of CO_2 flooding, the amide groups on the PAM molecular chains are prone to hydrolysis under high-temperature and acidic conditions to form carboxylic acid groups, which causes the molecular chains to curl and the viscosity to decrease. Meanwhile, carbonic acid formed by the dissolution of CO_2 in water can catalyze the main chain scission. In particular, when the temperature exceeds 90 °C, the synergistic effect of hydrolysis and thermal degradation will accelerate the damage to the gel network structure. For metal-crosslinked gels, the chromium ions of crosslinkers may undergo changes in complexation

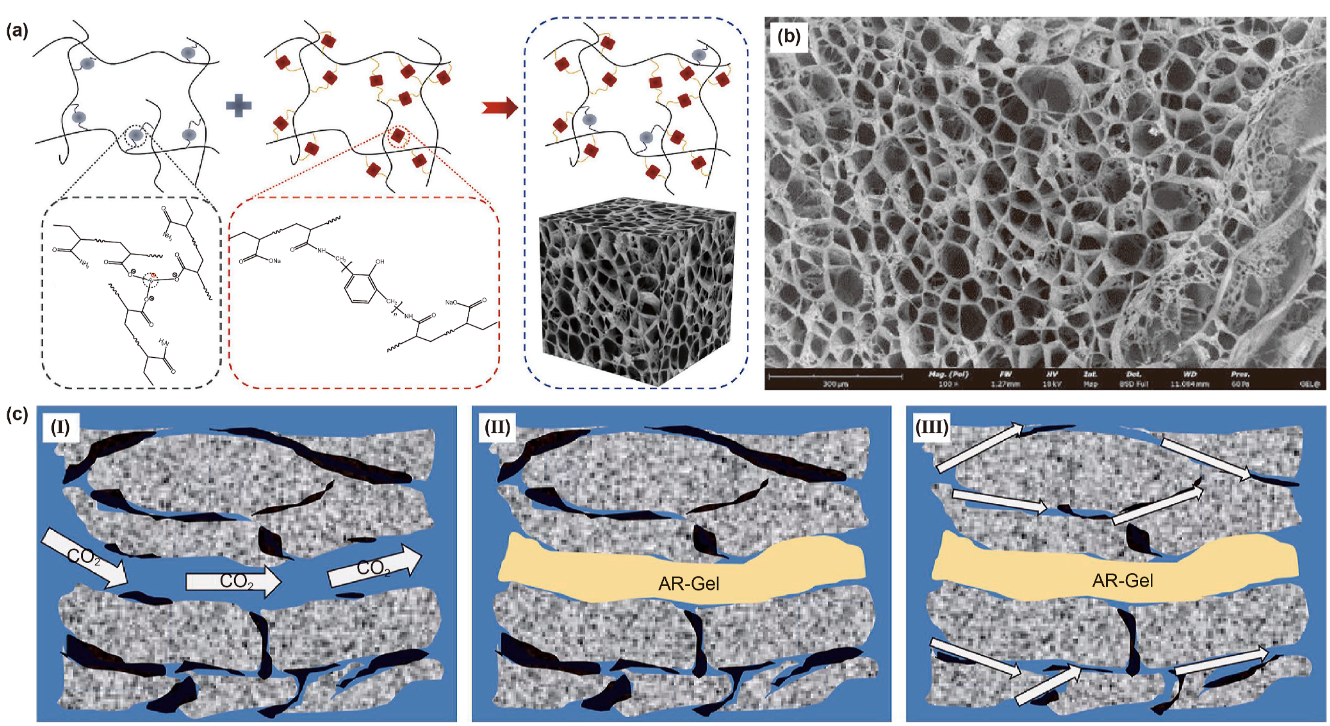

Fig. 5. Composite crosslinked polymer gel. (**a**) Gel synthesis route; (**b**) microstructure of the gel after 30 d of aging; (**c**) schematic diagram of gas channeling plugging and enhanced oil recovery mechanism. Adapted from Yang et al. (2025).

state or dissociation in acidic environments, leading to the failure of crosslinking points and irreversible syneresis of the gels. For organic-crosslinked gels, crosslinkers may undergo further poly-condensation at high temperatures, resulting in over-crosslinking and embrittlement of the gels, or ether bond scission under acidic conditions, triggering the collapse of the network structure. The combined effect of the above multiple factors leads to a significant decline in system stability, which seriously impairs the gas channeling plugging performance and its effective service life. Third, the preparation of delayed-crosslinking gel requires processes such as dissolution and mixing, and the costs of polymer and crosslinker injection equipment, instrument operation, and labor for conventional delayed-crosslinking gel are relatively high (Bai et al., 2008). The aforementioned shortcomings have hindered the industrial application of PAM gels to a certain extent, but given their low cost and good plugging performance, this system still has considerable research value and optimization potential.

The main research progress of delayed-crosslinking PAM gel is detailed in Table 1. Based on differences in crosslinker types, PAM gels can generally be classified into two categories: metal-crosslinked gels and organic-crosslinked gels. The formation mechanism of metal-crosslinked gels lies in the crosslinking reaction between high-valence metal ions and polymer molecular chains, which is specifically manifested as the process where carboxyl groups on polymer molecules replace the ligands of high-valence metal ions. To achieve the delayed-crosslinking effect of this type of gel system, the core lies in the precise regulation of the ligand exchange process; by retarding the generation of high-valence metal ions, the goal of extending the gelation time of the system is achieved. Organic-crosslinked gel systems, on the other hand, are developed to meet the requirements of profile control and displacement in special reservoir conditions such as high temperature, high salinity, and high pH. The gelation mechanism of organic crosslinkers involves triggering free radical reactions and functional group reactions to promote the crosslinking of the system and form gels. Common organic crosslinkers currently include phenolic resin (PR), formaldehyde, phthalaldehyde, phenol, resorcinol, hydroquinone, terephthalic acid, glutaric acid, hexamethylenetetramine, and organic peroxides.

Syed et al. (2014) constructed a gel plugging system suitable for CO_2 leakage control using a polymer as the matrix and chromium(III) acetate (Cr(III)) as the crosslinker. The results showed that the gelation time of this gel system exhibited an exponential decrease with the increase in system concentration; after its application in fractured core treatment, the gas permeability of high-permeability sandstone decreased by 99.7%, which confirmed that the polymer gel solution could achieve efficient remediation of fracture leakage pathways.

Bratteks et al. (2019) conducted fracture plugging experiments using chromium(III)-acetate crosslinked partially HPAM gel. The study found that HPAM gel undergoes dehydration during migration in fractures, and this dehydration effect exerts a significant influence on the migration capacity and plugging strength of the gel in fractures.

Sun et al. (2019) constructed a delayed-crosslinking gel system using partially HPAM and chromium(III) acetate as raw materials. This system can achieve a delayed gelation effect of more than 10 d based on the coordination complexation mechanism. Field application results showed that the total crude oil recovery could be increased by 33% with this gel system.

Singh and Mahto (2017) used chromium acetate as the crosslinker, first grafted gelatinized starch (St) onto AM molecular chains for copolymerization, and then compounded it with nano-montmorillonite (MMT) to prepare the composite material PAM-g-St/MMT. The study found that with the increase in crosslinker content, the gelation time of the composite increased from 0.75 to 18 h, the gel strength increased from 0.024 to 0.078 MPa, and the plugging rate for target channels could reach 93.6%. Further

Table 1
Main research progress on delayed-crosslinking polyacrylamide gel.

Types of crosslinking agents	Composition		Conclusions	References
	Polymers/monomers	Crosslinking agents		
Metal crosslinking agents	PAM	Chromium(III)	The gelation time decreases with the increase in polymer concentration. It can achieve efficient plugging of fracture leakage channels.	Syed et al. (2014)
	HPAM	Chromium(III)	HPAM undergoes dehydration, which impairs the plugging strength of the gel.	Bratteks et al. (2019)
	HPAM	Chromium(III)	The gel of this system has favorable elastic strength and can stably plug large pores and channels.	Sun et al. (2019)
	PAM-g-starch	Chromium(III)	The gelation time is prolonged from 0.75 to 18 h. This system exhibits high gel strength and stability.	Singh and Mahto (2017)
	HPAM	Chromium(III)	The physical properties of CO_2 exert a more significant influence on gel channeling control than fractures do.	Al-Ali et al. (2013)
	HPAM	Chromium(III)	The diffusion of CO_2 in low-permeability layers causes damage to polymer gels, and the gel damage rate depends on the CO_2 diffusion rate. The gel in the near-wellbore zone degrades slowly, while the gel in the deep reservoir can still perform its plugging function.	Sun et al. (2021)
Organic crosslinking agents	MPAM	HMTA, RSE	This system exhibits excellent CO_2 sensitivity. The gelation time and strength are positively proportional to the polymer concentration.	Li et al. (2016)
	AM	PHE, HMTA	The salt resistance, temperature resistance, and shear resistance of this system are superior to those of conventional HPAM.	Xu et al. (2019a)
Composite crosslinking agents	CX-305	PF, ALCit	Dual networks are formed via dual cross-linking, endowing the gel with high strength and excellent long-term stability and making it suitable for high-temperature and high-salinity reservoirs.	Yang et al. (2025)

Notes: PAM: Polyacrylamide; HPAM: Partially hydrolyzed polyacrylamide; PAM-g-starch: Polyacrylamide grafted starch; MPAM: Modified polyacrylamide; HMTA: Hexamine; RES: Resorcinol; AM: Acrylamide; PHE: Phenol; PF: Phenolic resin; ALCit: Aluminum citrate; CX-305: High molecular weight polymer.

experimental results showed that the strength of the gel system increased with the rises in polymer concentration and crosslinker concentration, and no dehydration shrinkage occurred under high crosslinker concentration conditions; even in a high-salinity environment of 3×10^4 mg/L, the system could still form gel stably, but the increase in salt concentration would lead to the shortening of gelation time and the synchronous increase in strength.

Al-Ali et al. (2013) developed a fracture-regulating gel system and systematically evaluated its plugging performance by combining CT imaging technology. The study found that the high-concentration gel system had a stable three-dimensional network structure and could achieve effective plugging of high-permeability channeling pathways; in contrast, the low-concentration gel system exhibited partial leakage, with only a small amount of gel being able to form plugging on CO_2 channeling pathways.

Sun et al. (2021) constructed a flow-control gel system suitable for CO_2 flooding using HPAM as the polymer matrix and chromium(III) acetate (Cr(III)) as the crosslinker. Experimental results showed that the gelation time of this system at 45 °C was 5 h. When the gel in the near-wellbore area came into contact with diffused CO_2, it underwent slow degradation, which in turn led to a decrease in plugging strength, but the gel in deep formations could still exert a good fluid diversion effect.

Zhou et al. (2022) prepared a type of delayed-swelling double-crosslinked nanoscale polymer gel microsphere (DCNPM-A). This microsphere used AM, sodium *p*-styrenesulfonate (SSS), and dimethyl diallyl ammonium chloride (DMDAAC) as polymer monomers (molar ratio of 66:22:12), with 1.5 wt% composite crosslinker (mass ratio of *N*,*N*′-methylenebisacrylamide (MBA) to diacrylate (UCA) being 9:1). Experimental results showed that the initial particle size of the microsphere was 217.3 nm. Under harsh conditions of 8.5×10^4 mg/L salinity, pH of 3, and 80 °C, the microspheres achieved a swelling ratio of 13.5 and exhibited obvious delayed-swelling characteristics within 0.17–0.5 d. Core plugging experiments indicated that after the microspheres were injected into the formation, the breakthrough pressure increased significantly, and the plugging rate for supercritical CO_2 flooding was as high as 95.48%. In addition, the microspheres were prepared via the inverse microemulsion method, and they simultaneously possessed deep migration capability endowed by their nanoscale size and temperature-responsive delayed-swelling properties. This provides a brand-new technical solution for the prevention and control of CO_2 gas channeling in low-permeability fractured reservoirs.

Li et al. (2016) constructed a CO_2-responsive gel system using modified PAM as the polymer matrix and hexamethylenetetramine-resorcinol as the composite crosslinker and systematically investigated the influence of factors such as temperature and PAM concentration on gel strength. Experimental results showed that the gelation time of the system shortened with the increase in temperature; the higher the PAM concentration, the longer the gelation time of the system, and the greater the gel strength. Further analysis confirmed that the gel system had good viscosity–temperature characteristics, and its viscosity decreased with the increase in temperature; meanwhile, the system exhibited excellent CO_2 responsiveness. Under high-concentration conditions, it could form a high-strength gel in the high-permeability zones of heterogeneous formations, effectively inhibiting the channeling of CO_2 in deep formations and thus improving the sweep efficiency of injected CO_2.

Xu et al. (2019a) synthesized an amphiphilic polymer P(AM-NaA-DDAM) via ternary copolymerization using AM, sodium acrylate (NaA), and *N*-dodecylacrylamide (DDAM) as monomers. Experimental comparisons showed that the comprehensive properties of this amphiphilic polymer, such as salt resistance, temperature resistance, and shear resistance, were all superior to those of conventional HPAM.

Yang et al. (2025) developed an organic/metal ion double-crosslinked polymer gel system (AR-Gel) with both high-temperature resistance and acid resistance, using PR and aluminum citrate (AC) as composite crosslinkers. Experimental results showed that under harsh reservoir conditions of 110 °C and 2×10^4 mg/L, the gel strength of this system could reach Grade H, and it could maintain stable performance for more than 60 d, with a plugging rate of 97%–98% for channeling pathways in subsequent CO_2 flooding applications. The injection of 0.8 PV of this system can enhance crude oil recovery by 34.5%.

The vast majority of reservoirs currently fall into the category of high-temperature and high-salinity reservoirs. Under such harsh conditions, metal crosslinkers (e.g., chromium-based crosslinkers) exhibit poor performance stability, which seriously affects the gelation time and gelation strength of gel systems; in contrast, most types of organic delayed crosslinkers (e.g., phenol, formaldehyde) have strong toxicity and carcinogenicity, which not only pose significant hazards to the health of on-site construction personnel but also trigger severe environmental pollution issues. With the increasingly stringent global requirements for environmental protection and health, safety, and environment (HSE), the application of such toxic crosslinkers is facing growing restrictions. To address the above problems, some scholars have proposed new delayed crosslinking technical solutions, such as the delayed crosslinking technology of novel multiple emulsion gel systems (Dai et al., 2013; Guo et al., 1997) and the delayed crosslinking technology of novel polyethylenimine (PEI) gel systems (El-Karsani et al., 2014). However, the current field application scale of such new delayed gel systems is relatively limited, and controversies remain in the industry regarding their comprehensive performance and long-term stability.

Therefore, it is imperative to develop delayed gel systems with high efficiency, environmental friendliness, low cost, and strong adaptability. This requires the optimization of coordinating ions with high electronegativity, small molecular radius, low polarizability, and easy formation of stable complexes, while actively developing green alternative systems based on bio-based materials (such as chitosan, cellulose, etc.) or low-toxicity organic crosslinkers. In recent years, gel systems based on low-toxicity crosslinkers such as poly(amino acids) and PEI have shown promising application potential, providing new ideas for balancing plugging performance and environmental friendliness. Furthermore, further improving the selective plugging performance of the system on the basis of realizing delayed gelation will also become a key research direction in this field in the future.

3.2.2. Preformed particle gel

Preformed particle gel (PPG) plays an extremely important role in the field of oilfield development. Unlike delayed crosslinking gels, PPG are preformed solid gel particles on the ground and do not need to undergo the phase transition from solution to gel in the formation. The particles are prefabricated on the surface to form finished products with specific strength and particle size. After being injected into the formation, driven by formation fluids, the preformed particle gels will preferentially enter high-permeability channeling pathways and undergo a swelling effect with formation water to achieve volume expansion (Ma et al., 2024). Endowed with elastic mechanical properties by their three-dimensional network structure, the swollen gel particles experience extrusion and stacking between particles under external forces, thereby forming a “filter cake-type plugging zone”

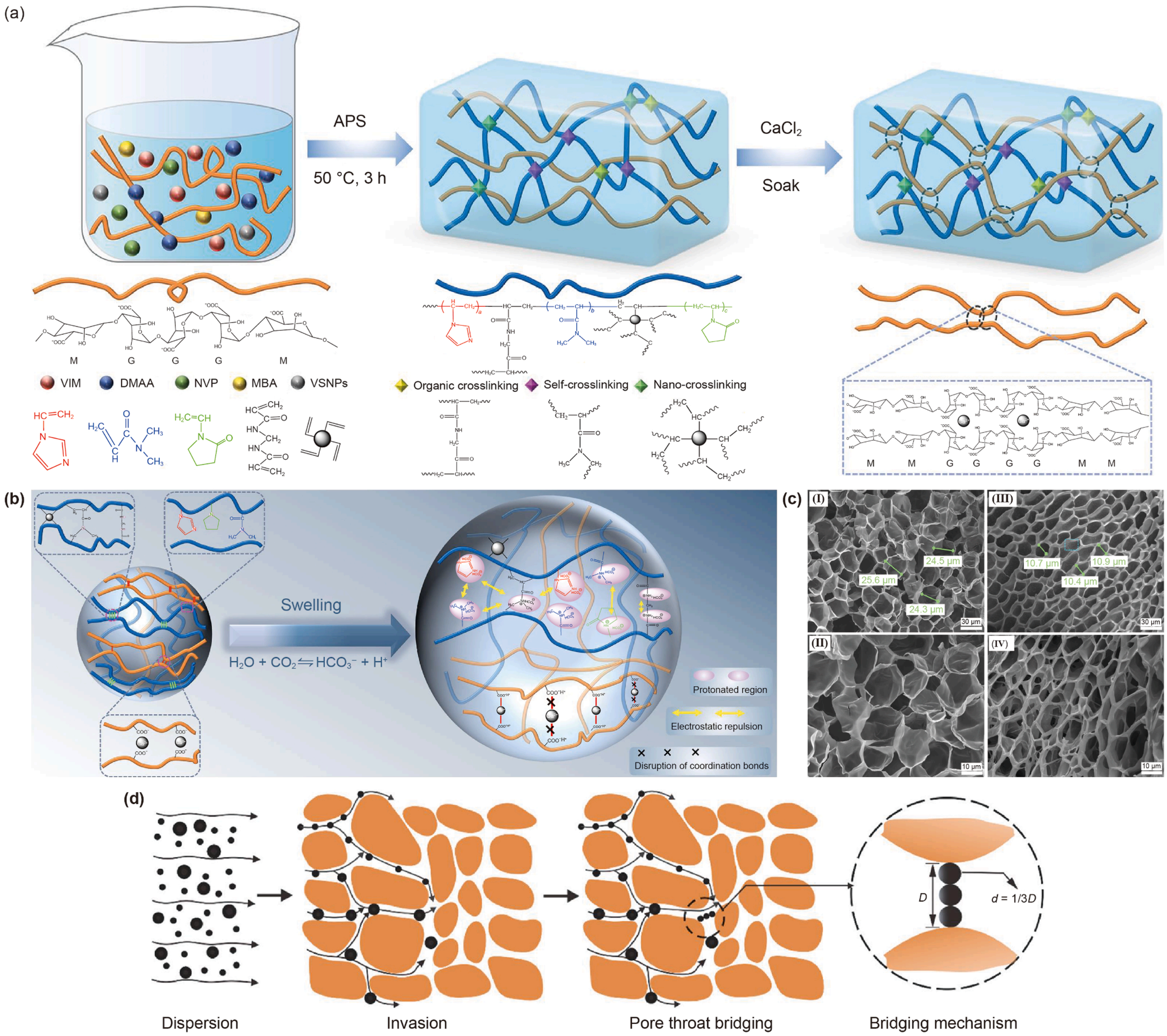

Fig. 6. CR-PPG. (**a**) Synthetic route; (**b**) CO_2 response mechanism; (**c**) particle microstructure; (**d**) particle plugging mechanism. Adapted with permission from Deng et al. (2025) and Guo et al. (2022).

with a certain compressive strength and ultimately realizing long-term and effective plugging of gas channeling pathways (see Fig. 6).

PPG is mainly synthesized using acrylamide-based monomers as the primary polymerization monomers, supplemented by functional monomers to regulate the hydrophilic-lipophilic properties of the system. Meanwhile, initiators and crosslinkers are introduced to carry out pre-crosslinking reactions on the surface, forming bulk gels; subsequent mechanical crushing and sieving processes yield semi-finished particles with different particle size ranges, which are then subjected to washing, drying, and other procedures to finally produce preformed particle gels. The gelation time, mechanical strength, and particle size of such particles can be precisely regulated during the preparation stage, enabling them to better meet the plugging requirements of reservoirs with strong heterogeneity. The current research status of preformed particle gels is detailed in Table 2.

Zhao et al. (2024) developed a novel dual-network CO_2-responsive preformed particle gel (DN-CRPPG) for controlling CO_2 channeling and leakage during CO_2 flooding and geological storage processes. Experimental results showed that the CO_2 responsiveness of DN-CRPPG induces its volume expansion; the swollen gel particles fill the interparticle voids, endowing DN-CRPPG with in-situ self-reinforcing plugging capability. Moreover, the dual-network structure consisting of a relatively rigid network and a more flexible network enhances its mechanical properties and resistance to CO_2 scouring. After the application of this gel, the CO_2 breakthrough time is delayed, and the oil recovery is enhanced by more than 30%.

Deng et al. (2025) used *N*,*N*-dimethylacrylamide (DMAA), vinylimidazole (VIM), and *N*-vinylpyrrolidone (NVP) as functional monomers, introduced vinyl silane nanoparticles (VSNPs) as nanoscale crosslinkers, and constructed high-strength CO_2-responsive preformed particle gels (CR-PPGs) via the coordination

Table 2
Main research progress on preformed particle gels.

Composition	Polymerization type	Conclusions	References
AMPS, AM, PEI, MBA, CrAc, APS	FRP	This gel exhibits remarkable CO_2 responsiveness. DN-CRPPG achieves swelling through the elongation of molecular chains driven by electrostatic repulsion, thereby occupying pore spaces and controlling gas channeling. The dual-network structure of DN-CRPPG ensures its excellent mechanical strength and fluidity.	Zhao et al. (2024)
DMAA, VIM, NVP, VSNPs, SA	FRP	The incorporation of VSNPs increases the crosslinking density of CR-PPG, thereby enhancing the stability of its network structure. CR-PPG gel exhibits significantly higher strength than conventional PPG.	Deng et al. (2025)
LMA, AM, SA, SDS	FRP	This gel exhibits superior mechanical properties, self-healing capability, and plugging performance owing to the synergistic effect of the dual-network structure.	Bai et al. (2022)
AM, MBA, DMDACC, APS, SSS	FRP	Sulfonic acid groups enhance the acid resistance and shear resistance of PPG, endowing AR-PPG with superior swelling capacity, thermal stability, and viscoelastic properties in acidic environments. This system exhibits excellent plugging performance, with the plugging rate reaching up to 70.8%.	Zhou et al. (2021)
AM, AA, AMPS-Na, PEG-DA, MBA, APS, hydrophobic monomer, hydrophilic monomer, cationic monomer, AC, bentonite	FRP	The swelling time of PPG incorporated with AMPS monomer is delayed by 10 d compared with that of traditional PPG. The plugging performance of AMPS-based PPG for both CO_2 and water is superior to that of conventional PPG. In the presence of supercritical CO_2, CR-PPG reacts with CO_2 to achieve a higher swelling ratio. CRG exhibits a high swelling ratio and superior plugging performance under acidic conditions. Six migration mechanisms of PPG in pore throats were revealed.	Bai et al. (2007a, 2007b); Bai and Sun (2020)
AM, AFAPE-20, DMAEMA, MBA, APS	FRP	IPN-PAASP exhibits good injectability and excellent plugging performance, with a plugging efficiency of up to 99%.	Pu et al. (2021)
AM, AMPS, MBA	FRP	The gel strength is positively proportional to the salinity, and this gel can selectively reduce the permeability of the aqueous phase and CO_2.	Alotibi et al. (2024)
PAM, MBA, AM, Chitosan CS	FRP	The system maintains a stable structure even after 30 d of aging under high-temperature and high-salinity conditions. The particle size after swelling can be precisely controlled by adjusting the ratio of PAM to CS.	Elaf et al. (2023a, 2023b)
PSSS, PAM, NaSS, VA-044, DMA, DVB	FRP	After aging at 150 °C for 18 months, the system maintains a stable structure without degradation. Displacement experiments confirm that HT-PPG exhibits excellent plugging efficiency.	Salunkhe et al. (2021)
AM, VP, AMPS, MBA, bentonite nanoclay, nano-silica	FRP	Compared with particle gels without nanomaterial reinforcement, those incorporated with reinforcing agents exhibit superior long-term thermal stability and shear deformation resistance.	Pandit et al. (2024)

Notes: AMPS: 2-Acrylamido-2-methylpropane sulfonic acid; PEI: Polyethyleneimine; MBA: *N,N*′-Methylenebisacrylamide; CrAc: Chromium acetate; APS: Ammonium persulfate; DMAA: *N,N*-Dimethylacrylamide; VIM: 1-Vinylimidazole; NVP: *N*-Vinylpyrrolidone; VSNPs: Vinyl-functionalized silica nanoparticles; SA: Sodium alginate; LMA: Lauryl methacrylate; SDS: Sodium dodecyl sulfate; SSS: Sodium styrene sulfonate; DMDACC: Dimethyldiallylammonium chloride; AA: Acrylic acid; AMPS-Na: Sodium 2-acrylamido-2-methylpropane sulfonate; PEG-DA: Poly(ethylene glycol) diacrylate; AC: Ammonium chloride; PSSS: Poly(sodium styrene sulfonate); NaSS: Sodium styrene sulfonate; DMA: Dimethylacrylamide; DVB: Divinylbenzene; VP: Vinylpyrrolidone; DMAEMA: 2-(Dimethylamino)ethyl methacrylate; VA-044: 2,2′-Azobis[2-(2-imidazolin-2-yl)propane] dihydrochloride; FRP: Free radical polymerization; CS: Chitosan.

interaction between Ca^{2+} and COO^- groups in SA. Experimental results showed that the swelling ratio of this gel in water could reach 750%. Under acidic conditions of high temperature (100 °C) and high salinity (1×10^4 mg/L NaCl), the decrease in swelling ratio was less than 20%, with excellent long-term stability and no degradation observed after continuous aging for 2 months. Displacement experiments indicated that the plugging efficiency of CR-PPGs was as high as 99.92%; after alternating water/CO_2 flooding, the oil recovery was enhanced to 52.74%, demonstrating good oil increment potential and making it suitable for profile control and channeling plugging operations in CO_2 flooding of heterogeneous reservoirs.

Bai et al. (2022) prepared a series of dual-network self-healing hydrogels based on the synergistic effect of hydrophobic association and ionic bonding and further fabricated PPG dual-network gels with self-healing properties on this basis. The gels simultaneously possess excellent mechanical properties and self-healing performance, and their plugging strength for porous media with a permeability of 30 mD can reach 4.21 MPa.

Zhou et al. (2021) prepared an acid-resistant preformed particle gel (AR-PPG) via free radical polymerization using AM, MBA, and DMDAAC as raw materials. The microstructure of AR-PPG was characterized by Fourier transform infrared spectroscopy (FTIR) and scanning electron microscopy (SEM), and its swelling degree, viscoelasticity, shear resistance, and plugging performance in acidic environments were investigated. Results showed that the swelling rate of AR-PPG increased linearly within 2–16 d; after 16 d, its swelling ratio reached 1.41 in acidic conditions, with a plugging rate of 70.8%. Compared with conventional PPG, AR-PPG exhibited superior swelling performance, shear resistance, and viscoelasticity, achieving a plugging efficiency of 70.8% in low-permeability microfractures. The main reasons for its performance improvement are as follows: Electrostatic repulsion exists between the cationic groups of DMDAAC and H^+; meanwhile, the ionization of sulfonic acid groups is not affected by external acidic media; in addition, the steric hindrance effect among sulfonic acid groups effectively inhibits the compression of polymer molecular chains, thus significantly enhancing the acid resistance and shear resistance of AR-PPG.

Bai and his coworkers (Bai et al., 2007a, 2007b; Bai and Sun, 2020) designed and prepared three types of millimeter-scale modified gels targeting the channeling problem in CO_2 flooding, including AMPS-based PPG, CO_2-responsive preformed particle gel (CR-PPG), and CO_2-resistance preformed particle gel (CRG). The swelling time of this gel series is controllable from several hours to three months, and they simultaneously exhibit excellent CO_2 corrosion resistance, acid resistance, and stability, maintaining a high swelling rate even in acidic environments. The team also developed polymer/clay composite preformed particle gel (PG); by regulating monomer concentration, crosslinker dosage, and bentonite ratio, the gel strength and expansion rate were controllable. Based on the systematic evaluation of gel strength and swelling performance, the influence of gel composition and external environment on PG properties was explored in depth. With the aid of etched glass micromodel experiments, the study further revealed six migration mechanisms of PPG in the pore throats of porous media, namely direct passage, adsorption retention, deformation passage, fracture passage, shrinkage passage, and trapping. These mechanisms provide an important basis for understanding the interaction between particles and pore throats. Recent studies (Liu et al., 2025c) of the migration of multi-slug CO_2 flooding have shown that under constrained seepage conditions, the migration and redistribution of fluids are jointly dominated by mass transfer, pore-scale connectivity, and migration stage characteristics. This understanding provides an important theoretical reference for understanding the deep migration and retention behavior of PPG in fractured reservoirs.

Pu et al. (2021) used AM, acryloyl fatty alcohol polyoxyethylene ether (AFAPE-20), and 2-(dimethylamino)ethyl methacrylate (DMAEMA) as the main agents, supplemented by the crosslinker MBA and the initiator ammonium persulfate (APS), and synthesized interpenetrating network CO_2-responsive preformed particle gels (IPN-PAASP) via the seed swelling-two-step polymerization method, aiming to address the gas channeling challenge in fractured complex tight reservoirs. Upon contact with CO_2, the gel particles undergo a protonation reaction, leading to a synchronous increase in particle size and strength, which in turn significantly enhances their plugging performance.

Alotibi et al. (2024) used AM and 2-acrylamido-2-methylpropanesulfonic acid (AMPS) as the main monomers, introduced L-lysine hydrochloride (Lys-HCl), zirconium acetate, and MBA for copolymerization and crosslinking, and developed a recrosslinkable CO_2-resistant branched preformed particle gel (CO_2-BRPPG). Results showed that the gel exhibited good stability in low-pH acidic environments, and its strength increased with rising salinity. Meanwhile, the gel could selectively reduce the permeability of the aqueous phase and CO_2, making it suitable for profile control and channeling plugging operations in high-permeability channeling pathways.

To promote the large-scale engineering application of PPG, some scholars have established a systematic performance evaluation method, which conducts comprehensive characterization through key indicators such as swelling ratio, swelling rate, swelling time, particle size, and gel strength, providing theoretical support for the standardized production and field promotion of such materials. However, in practical oilfield applications, reservoirs generally exhibit heterogeneous characteristics such as high-permeability zones or fractures. Conventional preformed particle gels, due to their relatively large particle size, are difficult to enter low-permeability formations; meanwhile, the particles are prone to strength attenuation and stability decline during water absorption and swelling and are highly susceptible to fragmentation in high-velocity gas channeling environments, thereby significantly reducing the plugging effect.

To address the technical bottleneck of excessively large particle size, researchers from Shengli Oilfield introduced branched chain structures into the polymer main chain, which significantly improved the viscosity of the particle suspension and successfully developed a novel branched preformed particle gel (B-PPG). The particle size of this material after water absorption and swelling is much smaller than that of traditional PPG, enabling it to smoothly enter low-permeability formations and achieve deep profile control and displacement. In addition, some scholars have proposed a technical approach using millimeter-scale PPG. Particles of this size specification can not only effectively plug reservoir fractures and high-permeability channels but also meet the plugging requirements of low-permeability reservoirs (Bai et al., 2013; Qiu et al., 2014). It should be emphasized that multiple factors need to be considered for the field application of PPG, including the compatibility between particles and formation fluids, swelling ratio, and strength after swelling. Meanwhile, combining PPG profile control technology with development methods such as water flooding, gas flooding, and polymer flooding can not only enhance the plugging effect but also improve the sweep efficiency of displacement fluids (Al Brahim et al., 2023; Alhuraishawy et al., 2018a, 2018b; Kang et al., 2019; Sun et al., 2018; Zhao et al., 2021). It is worth noting that particle size is a key parameter determining the plugging effectiveness of PPG, and the potential damage of PPG to reservoirs should also be incorporated into the performance evaluation system. Studies by Elsharafi and Bai (2012, 2013) have shown that compared with low-strength PPG, high-strength PPG causes less damage to low-permeability reservoirs.

Traditional PPG are based on an acrylamide homopolymer network and are prone to rapid dehydration and degradation in high-temperature and high-salinity reservoir environments (Xiong et al., 2018). Hydrolysis of amide groups at elevated temperatures alters the hydrophilicity of the network structure, thereby triggering volume shrinkage and strength degradation. In high-salinity environments, the charge screening effect of cations on carboxylate groups weakens electrostatic repulsion between molecular chains and promotes network collapse. Divalent ions in formation water can undergo complexation reactions with hydrolyzed carboxylate groups, inducing local structural damage and accelerating particle fracture and failure. In the acidic environment of CO_2, the hydrolysis rate is further accelerated; meanwhile, acidic media can penetrate into the particles, causing uniform deterioration of the internal network structure. To address this defect, three main methods are currently adopted to improve their heat resistance: copolymerization with functional monomers, optimization of crosslinker types, and introduction of inorganic materials for composite modification (Ahdaya et al., 2023; do Amparo et al., 2022; Kumar et al., 2023; Pereira et al., 2020; Xu et al., 2019b; Zhai et al., 2024; Zhu et al., 2017).

Elaf et al. (2023a, 2023b) used PAM and chitosan as crosslinking matrices to develop a biodegradable PPG; meanwhile, MBA was introduced as a crosslinker, and AM and MBA were grafted onto the chitosan molecular skeleton via a microwave-assisted synthesis process, ultimately preparing an environmentally friendly gel particle (Cs/PAMBAs) with both temperature and salt resistance. The particle size of this material can be regulated within the range of 10 μm to 1 mm, and its swelling performance and mechanical strength can remain stable under harsh conditions of salinity 20×10^4 mg/L and temperature ≤ 130 °C, exhibiting excellent long-term stability. This green system, based on natural polymer materials, provides a feasible approach to replace traditional toxic crosslinkers and reduce HSE risks in field operations.

Salunkhe et al. (2021) used DMAA and sodium styrene sulfonate (NaSS) as polymerization monomers, selected divinylbenzene (DVB) as the crosslinker, and successfully synthesized high-temperature-resistant preformed particle gels (HT-PPG) by optimizing the raw material ratio. Performance test results showed that the gel particles did not exhibit degradation or dehydration after aging at 150 °C for 18 months; further characterization via SEM confirmed that their original chemical composition and crosslinked network structure remained intact even after long-term aging.

Pandit et al. (2024) prepared a nanomaterial-reinforced particle gel system (NRPG) via free radical polymerization, using AM, vinyl pyrrolidone (VP), and AMPS as polymerization monomers, MBA as the crosslinker, and bentonite nanoclay and silica nanomaterials as reinforcing agents. Experimental results showed that the long-term thermal stability time of this gel system at 120 °C could exceed 390 d; its swelling ratio in distilled water reached 41 times, and in harsh environments with high salinity, extreme pH values, and coexisting multivalent ions, its swelling performance exhibited more excellent stability.

In summary, the development of acid-resistant, CO_2-resistant, salt-tolerant, and high-temperature-resistant PPG in recent years has effectively addressed the technical defect of poor stability in traditional gels. However, such preformed particle gels still suffer from issues such as excessively large particle size and poor injectability. If the technical bottleneck of the synergistic optimization of gel stability and mechanical strength after swelling can be further overcome, preformed particle gels will surely exhibit broader application prospects in the field of oil and gas development.

3.2.3. Two-stage gel systems

Two-stage gas channeling plugging gel systems are a key system for controlling gas channeling in oilfields and enhancing oil recovery. Through the synergistic effect of dual-stage differentiated plugging, compared with a single gel system, this system can more comprehensively address the complex gas channeling conditions in reservoirs and effectively increase the sweep efficiency of displacement fluids.

The function of this system is divided into two stages: In the first stage, the high-strength characteristics of rigid gels are utilized to plug and fill large-scale fractures, thereby blocking the rapid gas channeling pathways. Typical representatives of rigid gels include modified starch gels and acrylamide-based gels. The former is biodegradable, easy to prepare, adjustable in viscosity, and excellent in injectability, making it suitable for fractures of different widths; the latter exhibits high strength and outstanding temperature and salt resistance. In the second stage, materials such as fatty amine-based reagents and ethylenediamine are adopted to implement precise plugging for high-permeability zones and small-to-medium-scale fractures. Among them, the amino groups in fatty amine molecules can undergo adsorption reactions with hydroxyl groups on the surface of reservoir rocks or clay minerals to form a dense adsorption film; meanwhile, they can also react with acidic components in formation fluids to generate salt precipitates, achieving effective blocking of micropores. Such plugging agents feature a small molecular weight and low viscosity, which not only facilitates deep targeted plugging but also has the advantages of low cost and simple construction.

At the current stage, amine-based plugging agents have exhibited particularly outstanding performance in addressing the challenge of gas channeling pathway plugging during CO_2 injection development in ultra-low permeability reservoirs. In the formation water environment, they can react with CO_2 and metal ions to form low-solubility crystals, which physically plug reservoir pores and fractures, and also possess significant selective plugging characteristics. CO_2 is enriched in high-permeability gas channeling pathways, which serve as the main reaction zones, and the generated solid-phase products can efficiently plug the pathways; in contrast, the CO_2 concentration in low-permeability matrix zones is extremely low, leading to a low reaction probability and thus no damage to the reservoir, thereby achieving the effect of "plugging high-permeability zones without blocking low-permeability zones".

The plugging effectiveness of organic amine-based plugging agents depends crucially on the distribution concentration of formation CO_2 and the use of protective slugs. The addition of protective slugs can effectively extend their radius of action and improve the plugging effect. Such plugging agents feature small molecular weight and small volume, which not only facilitate injection but also do not cause additional damage to oil reservoirs; the solid particles generated from their reactions also exhibit excellent temperature resistance. However, it should be noted that such plugging agents have obvious defects in field applications. They have a low flash point, posing certain potential safety hazards; meanwhile, they possess biological toxicity, which will exert adverse impacts on the surrounding environment. These factors together restrict their large-scale application in mines. The research progress of common dual-stage gel channeling plugging systems is shown in Table 3.

Hao et al. (2016) designed and constructed a three-dimensional radial flow physical simulation model and simulated actual formation conditions to conduct a systematic evaluation of the channeling control effect of the composite plugging technology. The study screened high-strength fracture plugging gels for plugging the main fractures and microfractures in the physical model; meanwhile, ethylenediamine was optimized as the matrix-diverting plugging agent. When this reagent reacts with CO_2, the complete reaction produces white solid particles, while the incomplete reaction forms a viscous liquid, and both products can effectively plug high-permeability channeling pathways. After composite regulation via “gel plugging + ethylenediamine diversion + WAG flooding”, the reservoir heterogeneity of the physical model was significantly improved, with the oil recovery increase reaching 15.09%.

In view of the applicable conditions of the dual-stage channeling-blocking gel system, relevant scholars have carried out targeted research. Xu et al. (2020a) conducted laboratory experiments focusing on the gas channeling problem in CO_2 flooding, clarified the applicable fracture scale of the dual-stage channeling-blocking system, and optimized the gas channeling prevention and control scheme by means of numerical simulation. The research results show that the modified starch gel has a significant plugging effect on medium-to-large fractures with widths ranging from 0.42 to 0.65 mm, and the plugging rate for fractures of 0.42 mm reaches as high as 99.98%. Ethylenediamine is suitable for small-to-micro fractures with widths of less than 0.24 mm, and the viscous liquid generated by its reaction with formation fluids can enhance oil recovery by 23.1%. In addition, field application practices have indicated that after treatment with the dual-stage plugging technology, the CO_2 sweep efficiency of the reservoir has increased from 1.4% to 24.1%, with the oil recovery increment reaching 3.76%.

Zhao et al. (2020) systematically investigated the performance and applicable conditions of the multi-stage gas channeling control system for CO_2 flooding by means of a self-developed physical simulation model. Experimental results verified that the primary gas channeling control system (WAG flooding) is suitable for homogeneous or weakly heterogeneous reservoirs where the permeability ratio is less than or equal to 5; the secondary gas channeling control system (ethylenediamine plugging) is applicable to reservoirs with a permeability ratio more than 30 or fractures with a width less than 0.08 mm; whereas for high-permeability channeling pathways or fractures with a width of

Table 3
Research progress on two-stage gas channeling plugging gel systems.

Composition		Conclusions	References
Primary channel plugging	Secondary channel plugging		
Modified starch gel, acrylamide; initiator, stabilizer	EDA	Specify the applicable conditions for respective systems: Stage 1: major fractures and microfractures; Stage 2: high-permeability channeling paths.	Hao et al. (2016)
Modified starch gel	EDA	Specify the applicable fracture scales for respective systems: Stage 1: 0.42–0.65 mm; Stage 2: <0.24 mm.	Xu et al. (2020a)
Modified starch gel	EDA	The applicable conditions for respective systems have been specified: Stage 1 (WAG): permeability <5 mD; Stage 2 (EDA): permeability >30 mD or fracture width <0.08 mm; Stage 3 (modified starch gel + EDA): fracture width 0.2–0.4 mm.	Zhao et al. (2020)

Notes: EDA: Ethylenediamine; WAG: Water alternating gas.

0.24–0.40 mm, it is more appropriate to adopt the tertiary gas channeling control system (modified starch gel + ethylenediamine composite plugging).

In addition, aiming at the gas channeling problem of CO_2 flooding in ultra-low permeability reservoirs, Wang et al. (2022a) used *n*-butylamine as the CO_2 channeling–blocking agent and introduced ethanol as the protective slug to construct a new EOR system. Experimental results show that when 0.3 PV of *n*-butylamine is injected into the system under reservoir conditions, the breakthrough pressure of subsequent gas flooding is increased to 4.8 MPa, and the oil recovery increment reaches 25%–30%.

In summary, the mechanism of action of the dual-stage channeling–blocking gel system is as follows: Modified starch gel is first used as the primary plugging agent to seal fractures in the formation; then, after CO_2 immiscible flooding, ethylenediamine is employed as the secondary plugging agent to achieve precise plugging of gas channeling pathways. This system has strong adaptability and can meet the gas channeling control requirements of various complex heterogeneous reservoirs. However, the system still has obvious performance shortcomings. The modified starch gel has poor high-temperature resistance and salt tolerance, making it difficult to adapt to harsh reservoir conditions. Amine-based substances have high water solubility, and if the formation water has high fluidity, they are prone to being scoured and lost, resulting in poor long-term stability of the plugging system. In addition, amine reagents used in secondary gas channeling plugging (such as ethylenediamine) exhibit certain biological toxicity and low flash points, posing HSE risks in field applications. Therefore, additional protection measures should be implemented in the injection process, and the usage concentration must be strictly controlled. Therefore, the two-stage gas channeling plugging gel system centered on “naturally modified gels + fatty amines” is currently only suitable for conventional reservoirs with medium and low temperatures. To address the gas channeling plugging demands of high-temperature and high-salinity reservoirs, there is an urgent need to develop novel two-stage plugging systems that simultaneously possess high temperature/salt tolerance and environmental benignity. For instance, exploring the use of bio-based amines (e.g., chitosan derivatives) to replace traditional fatty amines, or introducing non-toxic or low-toxic CO_2-responsive materials as the secondary plugging agent, would provide a viable solution to achieve high plugging efficiency and long-term stability while meeting the requirements of green and environmentally friendly development.

3.2.4. *Foam gel*

Foam gel is a type of plugging system that integrates the dual characteristics of foam and gel. Among them, foam can provide initial plugging capacity and good flowability and can form liquid films in gas channeling pathways to block gas channeling; gel can enhance the structural stability and plugging durability of the system. Therefore, foam gel has great application potential in the field of gas channeling plugging during CO_2 flooding (Qi et al., 2018; Schramm et al., 1999).

The mechanism of action of this system is mainly reflected in two aspects: (1) After gel formation, it can encapsulate the foam to maintain the stability of the internal environment of the foam, and the addition of foam stabilizers can further improve the overall stability of the system (Platzer, 1962). (2) After the foam gel is injected into the formation, it generates a diverting effect via the Jamin effect. This prompts more system components to enter high-permeability zones, increases the fluid flow resistance in those zones, and diverts the subsequent displacement fluid to low-permeability zones, thus improving sweep efficiency. In addition, the foam gel system has the advantage of low formation damage. It can defoam upon contact with oil without causing formation plugging and also has the characteristics of easy injectability, good stability, and high strength, showing significant advantages in controlling gas channeling and improving the effect of gas flooding development (Jin et al., 2016; Romero-Zeron and Kantzas, 2006, 2007).

It should be pointed out that the stability of foam gel directly determines the gas channeling plugging efficiency and further affects the displacement swept volume. Although research interest in foam gel has been continuously surging in recent years, the development progress of temperature-resistant foam gel has been relatively sluggish. At high temperatures, foam collapses due to thermal degradation or hydrolysis of surfactants, while gels soften as a result of polymer hydrolysis and crosslinker dissociation. Their synergistic effect leads to rapid deterioration of the overall system performance. In the acidic environment caused by CO_2, the hydrolysis rate of amide groups in the gel matrix is accelerated. Meanwhile, acidic media can destabilize the charge on foam liquid films, promoting liquid drainage and coalescence. Nanoparticles in nano-enhanced foam gels tend to agglomerate and settle, losing their interfacial strengthening effect. Most of the currently developed foam gels have insufficient high-temperature resistance; in high-temperature reservoir environments, the foam is prone to collapse, and the gel performance will deteriorate accordingly, making it difficult to achieve long-term plugging (Jin et al., 2016). In recent years, the research and development of temperature- and salt-resistant foam gel has attracted increasing attention from scholars, and a summary of relevant research progress is presented in Table 4.

Zhao et al. (2015) prepared a temperature-resistant foam gel system suitable for high-temperature reservoirs by introducing a comb-shaped polymer gel. Experimental results showed that an

Table 4
Research progress on foam gels.

Composition			Conclusions	References
Polymers	Surfactants	Additives		
Comb-shaped polymer	HN-1	PF	An increase in gel viscosity can enhance the thickness and strength of the foam film, thereby improving its stability and plugging capacity.	Zhao et al. (2015)
Modified starch polyacrylamide	α-A, S-16	Crosslinking agent, initiator	The system exhibits excellent temperature and salt resistance. It preferentially plugs fractures and vugs in high-permeabily areas, enabling the oil recovery factor to exceed 80%.	Qu et al. (2017)
HPAM	-	SD, SS, AC, SN	After injection into the core, it can effectively plug large pore throats and improve reservoir heterogeneity. The swelling and plugging capacity of the gel is regulated by pH value, with the optimal plugging effect achieved at pH of 6.8. It can realize in-situ heat generation and is suitable for low-temperature reservoirs.	Qi et al. (2018)

Notes: PR: Phenolic resin; SD: Sodium dichromate; SS: Sodium sulfite; SN: Sodium nitrite.

increase in gel viscosity can effectively enhance the thickness and strength of the foam film, thereby improving the stability of the foam system and its plugging performance in porous media. Through sand-packed tube displacement experiments and microscopic visualization experiments, the study further revealed the mechanism of action of this foam gel system. The synergistic effects of the Jamin effect, bridging effect, and emulsification viscosity reduction effect collectively improve displacement sweep efficiency. After the application of this technology in Henan Oilfield, remarkable results have been achieved, with the cumulative oil increment reaching 5568 tons and the oil recovery improvement margin being 9.8%.

Qu et al. (2017) used modified starch gel as the foam stabilizer and selected the α-A/S-16 compound surfactant as the foaming agent to successfully develop a temperature-resistant and salt-tolerant modified starch foam gel system suitable for fractured-vuggy carbonate reservoirs and conducted systematic static and dynamic performance tests on it. Experimental results showed that under the harsh conditions of salinity of 22×10^4 mg/L, temperature of 120 °C, and pressure of 5–10 MPa, the foam volume of this system reached the maximum value, and the half-life was extended to 510 min; meanwhile, it could form a thick liquid film with high viscoelasticity and dense structure and realize preferential plugging of high-position fractures and vugs via gravity differentiation, ultimately enhancing the oil recovery to more than 80%.

Research on foam gels for high-temperature reservoirs has become increasingly extensive; meanwhile, some scholars have carried out tests and evaluations on the application potential of foam gels in low-temperature reservoirs. Qi et al. (2018) prepared a self-heating expandable foam gel system suitable for low-temperature reservoirs using partially HPAM, sodium dichromate, sodium sulfite, ammonium chloride, and sodium nitrite as raw materials and completed the optimization and screening of its formulation. Experimental results showed that at a low temperature of 30 °C, the gelation time of this system was 40 h, and its strength could reach grade G. After being injected into cores, it could effectively plug large pore throats and shrink pore throats into small ones, thereby improving reservoir heterogeneity. In addition, this system can simultaneously achieve in-situ heating and nitrogen foaming through the chemical reaction of ammonium nitrite salts, and its expansion and plugging performance can be regulated by pH value, which provides a brand-new technical scheme for profile control and plugging operations in low-temperature reservoirs. It should be noted that low-temperature environments will significantly reduce the reaction rate of polymers and crosslinking agents, which not only prolongs gelation time but also prevents the system from gelling in severe cases. In contrast, the self-heating expandable foam gel can increase its own temperature through in-situ heating to shorten gelation time, ensuring that the foam gel has an excellent gas-channeling plugging effect in low-temperature reservoir environments.

Foam gel has been relatively widely applied in field channeling-plugging operations, but this technology exhibits poor application effects in high-temperature and high-salinity reservoirs, as well as some special low-temperature oil and gas reservoirs. Meanwhile, it also faces problems such as high surface foaming costs, large equipment floor space, and easy defoaming failure caused by gas channeling after injection into the formation. To address the above technical difficulties, future research should focus on two major directions: material modification and formula optimization. On the one hand, it is necessary to develop foam gel systems with both temperature and salt resistance to adapt to complex and variable reservoir conditions; on the other hand, efforts should be made to actively explore new mechanisms, such as in-situ gas generation and develop in-situ gas-generating foaming gel systems. By virtue of the inherent environmental characteristics of the formation to generate gas in-situ and form foam gel, the dependence on surface gas supply equipment can be reduced, and the risk of defoaming caused by gas channeling can be mitigated.

Gels possess dual functions of “plugging” and “displacing” in the field of oilfield development. When used as plugging agents (Ji et al., 2023; Liu et al., 2023), their core mechanism of action is to block high-permeability pathways via high-strength gels, forcing subsequent displacement fluids to divert to unswept oil-bearing zones. When serving as oil-displacing agents (Chen et al., 2025a; Xue et al., 2025), they can leverage the controllable fluidity and viscoelasticity of gel systems to optimize the displacement mobility ratio, thereby enhancing microscopic oil washing efficiency.

In summary, existing gel systems present significant advantages in gas channeling control during CO_2 flooding but also suffer from widespread technical bottlenecks. High-strength gels usually have high viscosity and poor injectivity; low-strength gels, while easy to inject, can hardly achieve effective plugging, showing an inherent trade-off between high strength and deep placement. For delayed crosslinking gels, gelation time must be precisely controlled: If it is too short (<12 h), premature gelation occurs near the wellbore and fails to plug deep zones; if it is too long (>72 h), the resulting gel lacks sufficient strength to resist high-velocity CO_2 flooding. Particle size design is critical for PPG: The particle-to-pore-throat diameter ratio should be controlled within 1.2–2.0. Unduly small particles are prone to channel through, while oversized ones cause near-wellbore plugging (Chen et al., 2023). Although the high apparent viscosity (>100 mPa·s) of foam gels can improve breakthrough pressure gradient (>8 MPa/m), it tends to induce gas phase trapping near the wellbore, leading to a sharp increase in injection pressure and hindered deep migration.

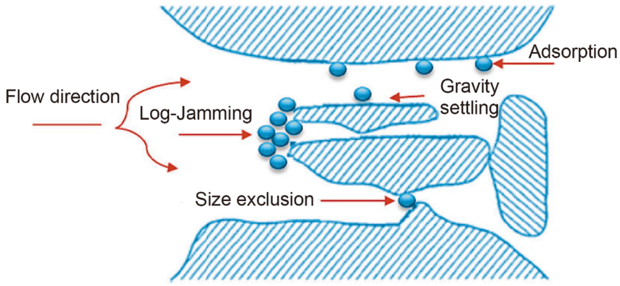

Fig. 7. Retention of residual gel in the formation after system application. Adapted with permission from Ab Rasid et al. (2022).

Studies (Chen et al., 2022) have shown that flow regime transition and resistance evolution during displacement follow specific laws, which provides favorable guidance for understanding the changes in the resistance coefficient of gel systems during injection and the definition of construction windows.

Meanwhile, such systems also face problems, including insufficient long-term stability, gelation process easily disturbed by formation conditions, single function, and poor adaptability to strongly heterogeneous reservoirs. In addition, gel systems may also cause irreversible damage to reservoirs during application and face multiple challenges at the engineering scale-up level (Fig. 7) (Chen et al., 2024a). Delayed crosslinking gels are difficult to flow back after gelation, which may form permanent plugging; preformed particle gels (PPG) are prone to bridging plugging near the wellbore, with a particle retention rate of 40%–60%, causing permeability damage to low-permeability zones. Gel debris remaining after foam gel collapse may block small pore throats, and the permeability recovery rate is usually less than 20%. In fractured reservoirs, the fluid loss behavior of the above systems may lead to gel dehydration and shrinkage, forming debris that causes secondary damage. From the perspective of engineering scale-up, reservoir heterogeneity intensifies the selective entry of gels into high-permeability intervals, worsening interlayer contradictions. The gravity override effect causes low-density gels to float upward, affecting the spatial distribution of plugging. The construction timing needs to accurately match the gelation time and migration distance, premature gelation leads to early gelation near the wellbore and limited treatment radius, while delayed gelation results in insufficient strength. In addition, the control of treatment radius is comprehensively restricted by injection rate, material performance, and reservoir conditions, making deep targeted plugging difficult.

Therefore, the future research and development of gel systems should focus on three core directions: (1) develop intelligent gels responsive to formation environments to achieve precise plugging effects of “low viscosity and easy injection during injection, rapid gelation after placement”, and enhance their self-healing performance to ensure long-term plugging stability, (2) improve gel strength, temperature resistance, and salt tolerance by introducing functional reinforcing agents to adapt to complex and harsh reservoir conditions, (3) break through the traditional empirical selection mode, establish quantitative design criteria considering reservoir damage risks and engineering scale-up bottlenecks, realize precise matching between plugging systems and reservoir conditions, and ultimately achieve deep reservoir profile control and displacement and significantly improve oil recovery.

3.3. CO_2-responsive intelligent systems for gas channeling plugging

Driven by the “dual carbon” goals, humanity's understanding of carbon has achieved transformation and upgrading. As an important application scenario for CO_2 emission and resource utilization, oilfields have typical representativeness in the global carbon governance system for their relevant technical practice experience (Bai et al., 2025). As an environmentally friendly stimulus, CO_2 exhibits broad application prospects owing to its advantages of abundant reserves, low cost, green and low toxicity, and excellent biocompatibility. Its response mode does not alter the inherent properties of the system and is adaptable to special working conditions, which has been widely recognized in the industry. Aiming at the prevalent gas channeling problem in the process of CO_2 flooding development, numerous scholars have carried out a series of research and development on channeling-blocking systems based on CO_2-responsive characteristics. In view of the strong diffusivity and long-distance migration of CO_2 along channeling paths, the CO_2-responsive intelligent channeling control system utilizes the acidity of CO_2 to trigger structural transformation of the materials, thereby achieving in-situ identification and in-situ gelation for precise plugging.

3.3.1. CO_2-responsive mechanism

The core principle of CO_2 responsiveness lies in introducing CO_2-sensitive functional groups (Fig. 8) such as amino, amido, guanidino, and carboxyl groups, through molecular structure design, and using the weak acidity of CO_2 to trigger changes in the material's structure or performance (Cunningham and Jessop, 2019). When CO_2 is present in the environment, these functional groups combine with H^+ generated from CO_2 dissolution and undergo protonation to form cationic groups; they then bind to anionic crosslinkers via electrostatic attraction or hydrogen bonding to rapidly construct a three-dimensional network gel structure (Fig. 9). Owing to the gaseous nature of CO_2, it preferentially migrates toward high-permeability and high-porosity channeling pathways in reservoirs; in turn, CO_2-responsive channeling-blocking agents can accurately reach channeling zones along the migration trajectory of CO_2 and form plugging bodies in situ to achieve high-efficiency plugging.

3.3.2. CO_2-responsive polymer system

In existing research on polymer channeling-blocking systems, numerous scholars have conducted extensive studies of the feasibility of applying CO_2-responsive polymers as channeling–blocking agents in oilfield field operations. Compared with other types of channeling–blocking systems, this type of system not only has good adaptability in plugging performance but also features response reversibility, which can effectively avoid permanent damage to reservoirs.

Shao et al. (2025) successfully prepared a CO_2-responsive nanoparticle plugging agent with a core–shell structure via emulsion polymerization. Experiments demonstrated that after aging at 100 °C for 3 months, the nanoparticles still maintained structural integrity and exhibited excellent long-term stability; their CO_2-responsive characteristics were prominent, with the particle size increasing significantly within 5 h upon exposure to an acidic environment of pH = 5; the residual resistance factor reached 2.47 after the plugging agent was injected into the cores for plugging.

Liu et al. (2025a) prepared a CO_2-responsive plugging gel system using PEI (molecular weight 70,000), sodium dodecyl sulfate (SDS), and aminated nano-silica as raw materials. This system induces protonation of PEI via CO_2, which in turn forms a pseudo-hydrophobic association structure with SDS; meanwhile, aminated silica nanoparticles can act as physical cross-linking sites to strengthen the three-dimensional network structure of the gel. The system can achieve high-efficiency plugging of high-permeability channeling pathways with a plugging efficiency

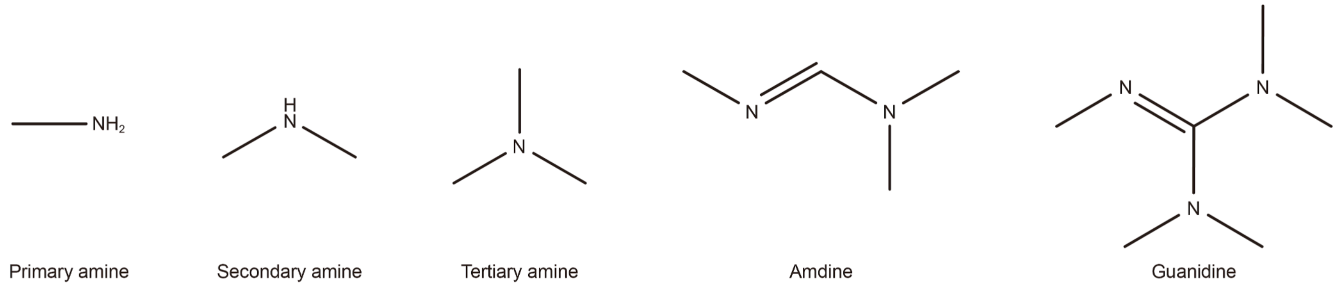

Fig. 8. Commonly used CO_2-sensitive functional groups. Reprinted with permission from Zhang et al. (2019).

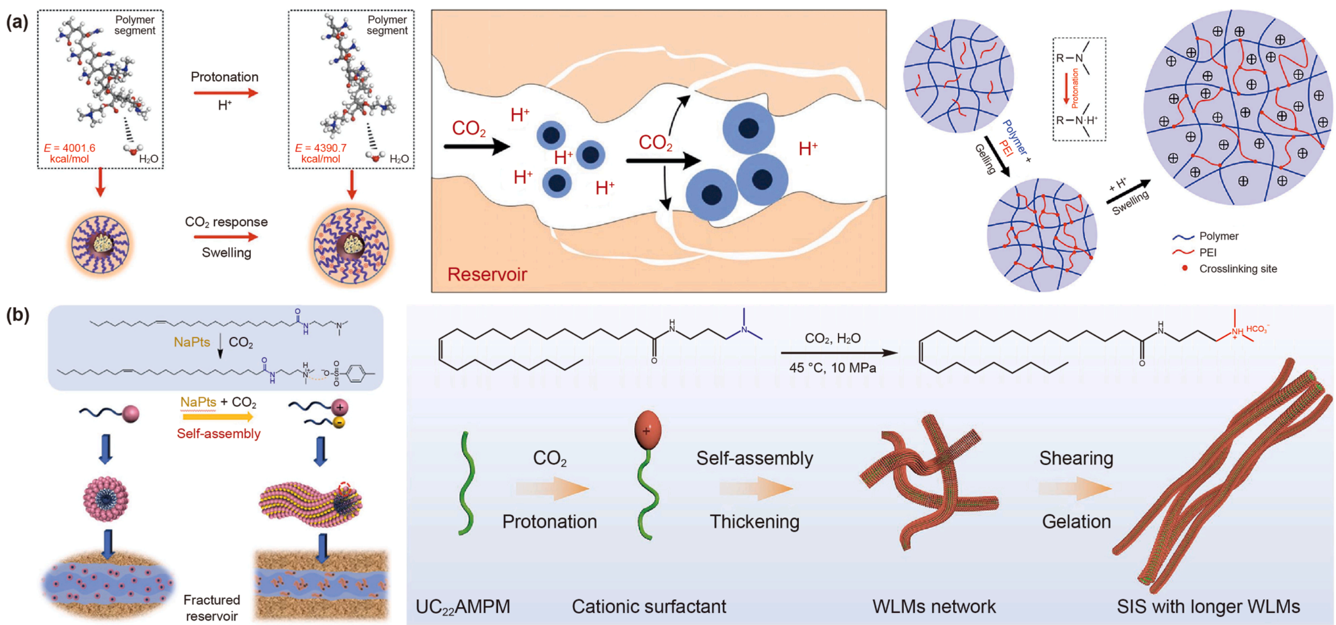

Fig. 9. Formation mechanism of CO_2-responsive intelligent system for gas channeling plugging. (**a**) Polymer system for gas channeling plugging: group protonation induces changes in molecular chain crosslinking; (**b**) wormlike micelle system for gas channeling plugging: group protonation triggers self-assembly morphology transformation. Adapted with permission from Luo et al. (2023), Shao et al. (2025), Wu et al. (2023), and Xin et al. (2025a).

exceeding 95%, providing an intelligent technical solution for gas channeling control during CO_2 flooding in heterogeneous reservoirs.

Gu et al. (2024) successfully prepared a reversible CO_2-responsive ternary composite microgel (CS-DP-AA) using chitosan (CS) as the raw material and introducing CO_2-responsive monomers *N*-(3-dimethylaminopropyl) methacrylamide (DMAPMA) and acrylic acid (AA) via free-radical polymerization. After responding to CO_2, this microgel exhibited excellent viscoelasticity and could maintain high viscosity even under harsh working conditions of high temperature, high pressure, and high shear. Through dual-core parallel displacement experiments, it was found that the microgel could achieve high-efficiency plugging of large pore throats, increasing the resistance factor by 80 times and significantly improving the sweep coefficient and swept volume of CO_2 flooding.

Huang et al. (2024) prepared a series of novel CO_2-responsive polymers (PAD-H) with unique hydrophobic structures. Studies have shown that introducing hydrophilic polyether long chains into the hydrophobic structure helps improve the CO_2-responsive viscosity-enhancing performance of the polymer, and significant CO_2-responsive viscosity enhancement can be achieved even at low concentrations. This study confirmed that CO_2 can promote the protonation of tertiary amine groups in the polymer, thereby triggering the synergistic effect of electrostatic repulsion and hydrophobic association; it also verified that the introduction of polyether long chains can effectively expand the association range of hydrophobic long chains and facilitate the formation of intermolecular cross-linked networks.

Wu et al. (2023) used AM and DMAPMA as polymerization monomers to synthesize a CO_2-responsive polymer containing protonatable groups via free-radical copolymerization and then prepared a CO_2-intelligently responsive hydrogel system using PEI as the cross-linking agent. Experimental results showed that H^+ generated from the dissolution of CO_2 in water can protonate the tertiary amine groups in the polymer, enhancing the hydrophilicity of the system and the electrostatic repulsion between molecular chains, which promotes the extension and water absorption-swelling of molecular chains. The hydrogel exhibits rapid swelling response in acidic environments with a swelling ratio of more than 10 times and can form effective plugging of gas channeling pathways.

3.3.3. CO_2-responsive wormlike micelle system

The CO_2-responsive polymer system for gas channeling plugging boasts technical advantages such as high plugging strength, excellent stability, and a wide plugging range, and it can meet the long-term plugging demands of high-permeability and large-fracture reservoirs. However, it is faced with drawbacks including high injection difficulty, incomplete plugging removal, and low regulation flexibility. In recent years, numerous scholars have also shifted their research focus to CO_2-responsive wormlike micelle system gas channeling plugging. With viscoelastic micelles as the core, this system features easy injectability, rapid responsiveness, no formation residue, and repeatable regulation, making it more suitable for channeling control in small-to-medium pore throats of medium-low permeability reservoirs. Nevertheless, the associative structure of wormlike micelles is sensitive to temperature. At elevated temperatures, intensified thermal motion of molecules tends to dissociate the micellar network, resulting in a sharp decrease in viscosity. In high-salinity environments, the charge screening effect of counter-ions on the micelle surface disrupts the electrostatic association equilibrium, causing wormlike micelles to degenerate into spherical micelles and lose their viscosity-enhancing ability. In addition, the dynamic associative characteristic of wormlike micelles keeps them in a continuous dissociation–recombination equilibrium. Under long-term CO_2 flooding, the stability of the micellar network can hardly be maintained, leading to a limited effective plugging life.

Zhang et al. (2019) determined five chemical agents containing CO_2-sensitive groups via a rheometer and screened out the optimal system formulation as a composite system of 4.4 wt% *N*,*N*-dimethyl octylamide-propyl tertiary amine (DOAPA) and 2.0 wt% sodium *p*-toluenesulfonate (NaPts). On this basis, a CO_2-responsive intelligent mobility control system was constructed. Experiments showed that after contact with CO_2, this system can induce the protonation of DOAPA to form DOAPA-H^+, which interacts with anions ionized from NaPts through electrostatic forces to trigger the transformation of spherical micelles into wormlike micelles (WLMs) and then form a three-dimensional spatial network structure. This leads to a rapid increase in system viscosity, and the final plugging efficiency for gas channeling pathways reaches as high as 99.2%.

Zhang et al. (2024c) prepared a nanoparticle-reinforced wormlike micelle intelligent gel system. Rheological tests confirmed the formation of WLMs in the system, and relevant data calculations revealed the mechanism underlying the reinforcing effect of nanoparticles on WLMs. After applying this system to laboratory plugging experiments, it achieved a plugging efficiency of 97% and enhanced the oil recovery factor of CO_2 flooding by 22.2%.

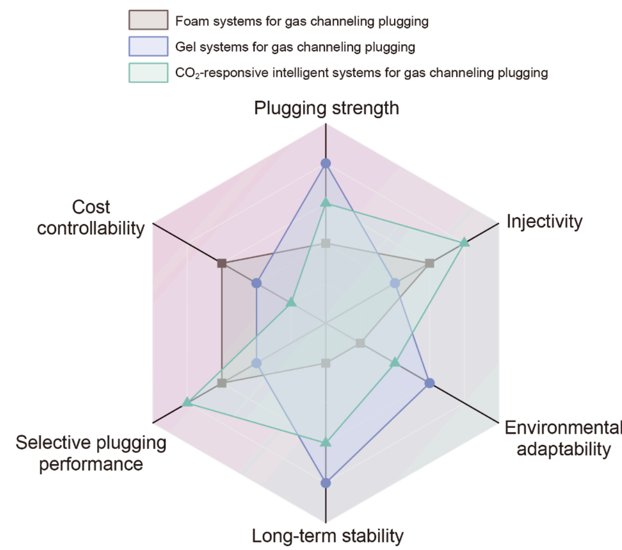

Fig. 10. Performance indicator comparison chart of different plugging systems.

Luo et al. (2023) used *N*-acrylamidopropyl-*N*,*N*-dimethylamine ($UC_{22}AMPM$) as an intelligent surfactant and introduced it into the water slug. Under the high-temperature and high-pressure CO_2 reservoir environment, this surfactant undergoes protonation to form WLMs and constructs a three-dimensional network structure via shear induction, thereby achieving in-situ thickening and gelation of the system. Core flooding experiment results confirmed that the system can form effective plugging of gas channeling pathways in high-permeability zones, and the oil recovery increment reaches 8.0% compared with conventional WAG flooding.

Shen et al. (2021) used *N*,*N*-dimethyl erucamide tertiary amine (DMETA) as the CO_2-responsive agent and constructed a novel CO_2-responsive system for gas channeling plugging via the self-assembly of WLMs. Experiments showed that upon contact with CO_2, this system can achieve rapid thickening through the self-assembly of WLMs, with the solution viscosity increasing up to 605,700 mPa·s. It was also found that the spatial network structure formed by WLMs is not in a stable state but continuously dissociates and reconstructs in the form of “living polymers”; when CO_2

Table 5
Performance comparison of different systems.

Systems for gas channeling plugging	Foam systems	Gel systems	CO_2-responsive intelligent systems
Core mechanism	Jamin effect	Physical plugging of dominant channels via three-dimensional network structure	CO_2-triggered protonation reaction, leading to in-situ gelation or self-assembly viscosity enhancement
Plugging strength	Medium (depends on foam stability)	High strength after gelation	High for polymer gels, medium for wormlike micelles
Injectivity	It can preferentially enter high-permeability layers	Delayed crosslinking systems show good injectivity; preformed particle gels require a matching particle size	Low viscosity and easy injection for wormlike micelles
Action distance	Foam stability is affected by the reservoir environment	Delayed crosslinking gels and preformed particle gels enable deep migration	Precise positioning along the CO_2 migration path
Long-term stability	Foam is prone to collapse	High-strength gels exhibit excellent stability	Polymer-based systems show high stability; wormlike micelles have reversible responses
Selective plugging performance	Preferentially enters high-permeability layers	Adjustable via particle size and gelation time	Preferential response in CO_2-enriched zones
Plug removal/reversibility	Defoams in contact with oil, easy to unplug	Permanent plugging	Viscosity of wormlike micelles decreases after CO_2 removal
Cost and environmental friendliness	Moderate cost and good environmental friendliness	Low cost for conventional gels, high cost for special gels; some crosslinkers are toxic	Relatively high cost; good environmental friendliness for some systems

is removed, the system reverts to its initial low-viscosity state, exhibiting excellent response reversibility.

Xin et al. (2025a, 2025b) used long-chain alkyl acid amidopropyl dimethyl tertiary amine as the main agent and introduced NaPts as the counterion salt additive to construct a CO_2-responsive gel system. Cryogenic transmission electron microscopy characterization confirmed that under CO_2 induction, the surfactant molecules undergo protonation and self-assemble into WLMs, which then crosslink to form a three-dimensional network structure, realizing macroscopic viscosity enhancement of the system. After applying this system to microscopic oil displacement experiments, it was found that it can improve oil washing efficiency through the synergistic mechanism of emulsification viscosity reduction and fracture plugging diversion, and ultimately, the oil recovery increment reaches 18.19%–21.70%.

CO_2-responsive intelligent systems for gas channeling plugging have demonstrated excellent and versatile application effects under laboratory conditions, but they also face challenges of reservoir damage and engineering scale-up. The three-dimensional network of polymer-based responsive systems is difficult to flow back and remove after gelation, with a permeability recovery rate of less than 40%, which is prone to forming permanent plugging. Although wormlike micelle-based systems have reversible responsiveness, the micellar network may be retained in pore throats at high concentrations, and surfactant adsorption changes wettability, affecting subsequent displacement. In fractured reservoirs, responsive materials preferentially enter large fractures, and fluid loss behavior leads to excessive retention in the matrix, causing secondary damage. The treatment radius is restricted by CO_2 distribution, injection rate, and heterogeneity, and uneven CO_2 distribution results in response failure. In addition, the long-term stability of the system is affected by temperature, salinity, and multiple CO_2 flooding cycles, so it is necessary to establish a long-term service performance evaluation method to assess its applicability under complex reservoir conditions.

Overall, existing chemical plugging systems each have their own merits and demerits in addressing gas channeling problems in complex reservoirs, with a detailed comparison provided in Table 5 and Fig. 10. As reservoir development gradually advances toward deep formations, high temperature, high salinity and strong heterogeneity, developing systems for preventing gas channeling featuring acid resistance, temperature tolerance, excellent long-term stability and adaptability to strongly heterogeneous reservoirs have become an urgent key direction for breakthroughs in this field. By optimizing system formulations, improving preparation processes, and thoroughly investigating the interaction mechanism between gels and reservoir media, it is expected to further enhance the comprehensive performance of gel channeling-blocking systems, providing more solid technical support for efficiently solving the problem of reservoir gas channeling.

4. Summary and prospects

Gas channeling during CO_2 flooding is mainly caused by key factors such as viscous fingering and reservoir heterogeneity, which seriously restrict the improvement of oil displacement efficiency. To address this challenge, three major types of plugging systems, foam, gel, and CO_2-responsive systems, have been developed. Relying on differentiated plugging mechanisms, these technologies exhibit significant potential in improving gas flooding sweep efficiency. However, various systems still have certain limitations in core performance indicators such as plugging strength, effective action distance, environmental adaptability, and long-term stability, and thus urgent further optimization and technological breakthroughs are required.

In the future, the development of gas channeling plugging technologies requires breakthroughs in two major aspects: material innovation and process optimization. It will further advance toward intelligent and data-driven systematic solutions so as to establish an intelligent plugging system integrating intelligent materials, intelligent operation, and intelligent design. (1) At the material level, the focus should be on developing intelligent composite materials with multiple responsive properties. CO_2-responsive groups and temperature/salt-resistant functional groups can be simultaneously introduced into polymer chains through molecular structure design; alternatively, the stability and plugging performance of materials under harsh reservoir conditions (such as high temperature and high salinity) can be improved by constructing organic–inorganic hybrid network structures. Meanwhile, the response characteristics of materials should shift from a single “stimulus-response” mode to a closed-loop intelligent mode of “sensing–decision–execution”, enabling autonomous identification of gas channeling signals and adaptive plugging. (2) At the construction technology level, efforts should be made to promote the integration of “precision” and “integration” technologies. Based on real-time downhole transmission data, a dynamic monitoring and feedback control mechanism shall be established to realize real-time optimization and adaptive adjustment of plugging agent injection parameters. Combined with intelligent completion technology, the targeted placement of plugging agents in the formation can be achieved, which significantly improves the success rate and effectiveness of plugging operations. (3) At the technical scheme design level, a gas channeling risk prediction and plugging scheme optimization platform based on big data and artificial intelligence should be established. Through deep learning and mining of historical operation data, reservoir characteristic parameters and plugging agent performance data, gas channeling path identification models, and plugging effect prediction models can be constructed, realizing the transformation from “empirical selection” to “data-driven design”. On this basis, a multi-barrier cooperative plugging strategy suitable for different reservoir conditions can be formed. For example, CO_2-responsive wormlike micelles can be injected first to achieve deep fluid diversion and then combined with gel-enhanced foam to strengthen the plugging of dominant flow channels. A gas channeling control technology system featuring “intelligent sensing–precise regulation–long-term stability” will thus be established.

Therefore, through the collaborative innovation of intelligent materials, intelligent construction, and intelligent design, the development of an intelligent plugging system adaptable to complex reservoir conditions will provide solid technical support for the large-scale promotion and application of CO_2-EOR technologies. This will further accelerate the leapfrog development of gas channeling control technologies, shifting then paradigm from “passive plugging” to “proactive prevention and control”.

CRediT authorship contribution statement

Shun-Dong Jiang: Writing – review & editing, Writing – original draft, Visualization. **Li-Feng Chen:** Conceptualization. **Dai-Gang Wang:** Data curation. **Wei-Wei Sheng:** Formal analysis. **Ming-Chen Shi:** Methodology. **Ming-Hao Xue:** Investigation. **Hui-Yong Zeng:** Validation. **Lei Hu:** Resources. **Xu-Rui Long:** Investigation.

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.

Acknowledgments

This work is supported by the National Natural Science Foundation of China (No. 52374028) and the National Science and Technology Major Project on Oil & Gas (No. 2025ZD1406407).

References

Ab Rasid, S.A., Mahmood, S.M., Kechut, N.I., Akbari, S., 2022. A review on parameters affecting nanoparticles stabilized foam performance based on recent analyses. J. Pet. Sci. Eng. 208, 109475. https://doi.org/10.1016/j.petrol.2021.109475.

Ahdaya, M., Al Brahim, A., Song, T., Bai, B., Eriyagama, Y., Schuman, T., Zhang, Y., 2023. Impact of different additives on low-temperature recrosslinkable preformed particle gel to mitigate fluid losses in fractured formations. Geoenergy Sci. Eng. 224, 211597. https://doi.org/10.1016/j.geoen.2023.211597.

Al-Ali, A.H., Schechter, D.S., Lane, R.H., 2013. Application of polymer gels as conformance control agents for carbon dioxide EOR WAG floods. In: Proceedings of SPE International Symposium on Oilfield Chemistry. https://doi.org/10.2118/164096-MS.

Al-Obaidi, D.A., Al-Mudhafar, W.J., Hussein, H.H., Rao, D.N., 2024. Experimental influence assessments of water drive and gas breakthrough through the CO_2-assisted gravity drainage process in reservoirs with strong aquifers. Fuel 370, 131873. https://doi.org/10.1016/j.fuel.2024.131873.

Al-Shargabi, M., Davoodi, S., Wood, D.A., Rukavishnikov, V.S., Minaev, K.M., 2022. Carbon dioxide applications for enhanced oil recovery assisted by nanoparticles: Recent developments. ACS Omega 7 (12), 9984–9994. https://doi.org/10.1021/acsomega.1c07123.

Al Brahim, A., Eriyagama, Y., Bai, B., Schuman, T., 2023. Feasibility study of recrosslinkable preformed particle gels for natural gas injection profile control. SPE J. 28 (4), 1829–1841. https://doi.org/10.2118/210127-PA.

Al Sumaiti, A., Shai, A.R., Mathew, E.S., Al Ameri, W., 2017. Tuning foam parameters for mobility control using co_2 foam: Field application to maximize oil recovery from a high temperature high salinity layered carbonate reservoir. Energy Fuels 31 (5), 4637–4654. https://doi.org/10.1021/acs.energyfuels.6b02595.

Alhuraishawy, A.K., Bai, B., Imqam, A., Wei, M., 2018a. Experimental study of combining low salinity water flooding and preformed particle gel to enhance oil recovery for fractured carbonate reservoirs. Fuel 214, 342–350. https://doi.org/10.1016/j.fuel.2017.10.060.

Alhuraishawy, A.K., Sun, X., Bai, B., Wei, M., Imqam, A., 2018b. Areal sweep efficiency improvement by integrating preformed particle gel and low salinity water flooding in fractured reservoirs. Fuel 221, 380–392. https://doi.org/10.1016/j.fuel.2018.02.122.

Ali, M., Jha, N.K., Pal, N., Keshavarz, A., Hoteit, H., Sarmadivaleh, M., 2022. Recent advances in carbon dioxide geological storage, experimental procedures, influencing parameters, and future outlook. Earth Sci. Rev. 225, 103895. https://doi.org/10.1016/j.earscirev.2021.103895.

Alotibi, A., Song, T., Brahim, A.A., Bai, B., Schuman, T., 2024. Experimental evaluation of a recrosslinkable CO_2-resistant micro-sized preformed particle gel for CO_2 sweep efficiency improvement in reservoirs with super-K channels. Gels 10 (12), 765. https://doi.org/10.3390/gels10120765.

Ampomah, W., Balch, R., Will, R., Cather, M., Gunda, D., Dai, Z., 2017. Co-optimization of CO_2-EOR and storage processes under geological uncertainty. Energy Proc. 114, 6928–6941. https://doi.org/10.1016/j.egypro.2017.03.1835.

Bai, B., Sun, X., 2020. Development of swelling-rate controllable particle gels to control the conformance of CO_2 flooding. In: Proceedings of SPE Improved Oil Recovery Conference. https://doi.org/10.2118/200339-MS.

Bai, B., Liu, Y., Coste, J.P., Li, L., 2007a. Preformed particle gel for conformance control: Transport mechanism through porous media. SPE Reservoir Eval. Eng. 10 (2), 176–184. https://doi.org/10.2118/89468-PA.

Bai, B., Li, L., Liu, Y., Liu, H., Wang, Z., You, C., 2007b. Preformed particle gel for conformance control: Factors affecting its properties and applications. SPE Reservoir Eval. Eng. 10 (4), 415–422. https://doi.org/10.2118/89389-PA.

Bai, B., Huang, F., Liu, Y., Seright, R.S., Wang, Y., 2008. Case study on preformed particle gel for in-depth fluid diversion. In: Proceedings of SPE Symposium on Improved Oil Recovery. https://doi.org/10.2118/113997-MS.

Bai, B., Wei, M., Liu, Y., 2013. Field and lab experience with a successful preformed particle gel conformance control technology. In: Proceedings of SPE Production and Operations Symposium. https://doi.org/10.2118/164511-MS.

Bai, Y.-R., Zhang, Q.-T., Sun, J.-S., Jiang, G.-C., Lv, K.-H., 2022. Double network self-healing hydrogel based on hydrophobic association and ionic bond for formation plugging. Pet. Sci. 19 (5), 2150–2164. https://doi.org/10.1016/j.petsci.2022.07.006.

Bai, Y., Chen, L., Fu, H., Zhao, J., Lian, Y., Zhang, H., 2025. Thermochemical heat storage biogel with environmental friendliness for solar-powered heavy oil recovery and carbon capture. ACS Sustain. Chem. Eng. 14 (1), 292–309. https://doi.org/10.1021/acssuschemeng.5c09640.

Bin, Y., Su, Y., Moghanloo, R.G., Rui, Z., Wang, W., Shang, Y., 2015. A new analytical multi-linear solution for gas flow toward fractured horizontal wells with different fracture intensity. J. Nat. Gas Sci. Eng. 23, 227–238. https://doi.org/10.1016/j.jngse.2015.01.045.

Bisweswar, G., Al-Hamairi, A., Jin, S., 2020. Carbonated water injection: An efficient EOR approach. A review of fundamentals and prospects. J. Pet. Explor. Prod. Technol. 10, 673–685. https://doi.org/10.1007/s13202-019-0738-2.

Boud, D.C., Holbrook, O.C., 1958. Gas drive oil recovery process. U.S. Patent No. 2,866,507.

Bratteks, B., Seright, R., Ersland, G., 2019. Water leakoff during gel placement in fractures: Extension to oil-saturated porous media. SPE Prod. Oper. 35 (2), 202–213. https://doi.org/10.2118/190256-PA.

Chen, H., Liu, X., Zhang, C., Tan, X., Yang, R., Yang, S., Yang, J., 2022. Effects of miscible degree and pore scale on seepage characteristics of unconventional reservoirs fluids due to supercritical CO_2 injection. Energy 239, 122287. https://doi.org/10.1016/j.energy.2021.122287.

Chen, L., Huang, F., Li, G., Mao, Z., Hu, Y., Liu, L., Zeng, H., Xu, S., 2023. Experimental study on fiber balls for bridging in fractured-vuggy reservoir. SPE J. 28 (4), 1880–1894. https://doi.org/10.2118/214315-PA.

Chen, L., Zhang, Z., Zeng, H., Huang, F., Lu, X., Sheng, W., 2024a. Preparation and performance of high-temperature-resistant, degradable inorganic gel for steam applications. SPE J. 29 (8), 4266–4281. https://doi.org/10.2118/219775-PA.

Chen, L., Xue, M., Bai, Y., Antonio, P., Lv, W., Hou, B., 2025a. Self-healing movable gel for enhanced heavy oil recovery in harsh fractured reservoirs. Phys. Fluids 37 (8), 083116. https://doi.org/10.1063/5.0282037.

Chen, X., Zhang, Q., Trivedi, J., Li, Y., Liu, J., Liu, Z., Liu, S., 2024b. Investigation on enhanced oil recovery and CO_2 storage efficiency of temperature-resistant CO_2 foam flooding. Fuel 364, 130870. https://doi.org/10.1016/j.fuel.2024.130870.

Chen, Y., Wu, D., Fang, S., Hu, R., 2018. Experimental study on two-phase flow in rough fracture: Phase diagram and localized flow channel. Int. J. Heat Mass Tran. 122, 1298–1307. https://doi.org/10.1016/j.ijheatmasstransfer.2018.02.031.

Chen, Z., Chen, J., Zhang, X., 2025b. A comprehensive review of minimum miscibility pressure determination and reduction strategies between CO_2 and crude oil in CCUS processes. Fuel 384, 134053. https://doi.org/10.1016/j.fuel.2024.134053.

Cunningham, M.F., Jessop, P.G., 2019. Carbon dioxide-switchable polymers: Where are the future opportunities? Macromolecules 52 (18), 6801–6816. https://doi.org/10.1021/acs.macromol.9b00914.

Dai, C.-L., Zhao, J., Jiang, H.-Q., Lv, X.-R., Wang, L.-S., Jin, Y.-X., Zhao, F.-L., 2013. Research and field application of polymer-multiple emulsion crosslinker gel for the deep profile control. Pet. Sci. Technol. 31 (9), 902–912. https://doi.org/10.1080/10916466.2010.531340.

Davoodi, S., Al-Shargabi, M., Wood, D.A., Mehrad, M., Rukavishnikov, V.S., 2024. Carbon dioxide sequestration through enhanced oil recovery: A review of storage mechanisms and technological applications. Fuel 366, 131313. https://doi.org/10.1016/j.fuel.2024.131313.

Deng, J., Zhao, H., Zheng, H., Zhuang, Y., Wei, K., Yuan, H., Deng, Z., Gao, Y., Zhou, X., Yu, T., Hu, H., Lu, G., Zhang, X., 2025. CO_2-responsive preformed particle gels with high strength for CO_2 conformance control in heterogeneous reservoirs. Fuel 379, 133040. https://doi.org/10.1016/j.fuel.2024.133040.

do Amparo, S.Z.S., de Vasconcelos, C.K.B., Almeida, A.I.A.R., Sena, L.E.B., Lima, M.C.F.S., Medeiros, F.S., Viana, M.M., 2022. Microwave-assisted synthesis of PAM preformed particle gels reinforced with carbon nanomaterials for conformance control in oil recovery. Fuel 330, 125650. https://doi.org/10.1016/j.fuel.2022.125650.

El-Karsani, K.S.M., Al-Muntasheri, G.A., Sultan, A.S., Hussein, I.A., 2014. Gelation kinetics of PAM/PEI system. J. Therm. Anal. Calorim. 116, 1409–1415. https://doi.org/10.1007/s10973-014-3754-y.

Elaf, R., Ben Ali, A., Saad, M., Hussein, I.A., Bai, B., 2023a. Development of eco-friendly chitosan-g-polyacrylamide preformed particle gel for conformance control in high-temperature and high-salinity reservoirs. Geoenergy Sci. Eng. 230, 212136. https://doi.org/10.1016/j.geoen.2023.212136.

Elaf, R., Ben Ali, A., Saad, M., Hussein, I.A., Nimir, H., Bai, B., 2023b. Biodegradable preformed particle gel (PPG) made of natural chitosan material for water shut-off application. Polymers 15 (8), 1961. https://doi.org/10.3390/polym15081961.

Elsharafi, M.O., Bai, B., 2012. Effect of weak preformed particle gel on unswept oil zones/areas during conformance control treatments. Ind. Eng. Chem. Res. 51 (35), 11547–11554. https://doi.org/10.1021/ie3007227.

Elsharafi, M.O., Bai, B., 2013. Effect of strong preformed particle gel on unswept oil zones/areas during conformance control treatments. In: Proceedings of EAGE Annual Conference & Exhibition Incorporating SPE Europec. https://doi.org/10.2118/164879-MS.

Friedmann, F., Chen, W.H., Gauglitz, P.A., 1991. Experimental and simulation study of high-temperature foam displacement in porous media. SPE Reserv. Eng. 6 (1), 37–45. https://doi.org/10.2118/17357-PA.

Gu, Y., Tu, H., Zhou, M., 2024. Preparation of CO_2-responsive biobased ternary composite microgel and its application in reservoir gas channeling plugging. Energy Fuels 38 (7), 6182–6194. https://doi.org/10.1021/acs.energyfuels.4c00088.

Guo, H., Hamielec, A.E., Zhu, S., 1997. Experimental study of emulsion polymerization with crosslinking. J. Appl. Polym. Sci. 66 (5), 935–957. https://doi.org/10.1002/(SICI)1097-4628(19971031)66:5<935::AID-APP14>3.0.CO;2-M.

Guo, P., Tian, Z., Zhou, R., Chen, F., Du, J., Wang, Z., Hu, S., 2022. Chemical water shutoff agents and their plugging mechanism for gas reservoirs: A review and prospects. J. Nat. Gas Sci. Eng. 104, 104658. https://doi.org/10.1016/j.jngse.2022.104658.

Guo, X., Yan, X., Yu, J., Zhang, Y., Chen, S., Mahgerefteh, H., Martynov, S., Collard, A., Proust, C., 2016. Pressure response and phase transition in supercritical CO_2

releases from a large-scale pipeline. Appl. Energy 178, 189–197. https://doi.org/10.1016/j.apenergy.2016.06.026.
Hao, H., Hou, J., Zhao, F., Song, Z., Hou, L., Wang, Z., 2016. Gas channeling control during CO_2 immiscible flooding in 3D radial flow model with complex fractures and heterogeneity. J. Pet. Sci. Eng. 146, 890–901. https://doi.org/10.1016/j.petrol.2016.07.034.
Hassanzadeh, A., Katiyar, A., Kalaei, H., Pecore, D., Schofield, E., Nguyen, Q., Gilchrist, C., 2022. Successful CO_2-foam field implementation for improving oil sweep efficiency in EVGSAU field at Permian Basin: Expansion phase. In: SPE Annual Technical Conference and Exhibition. https://doi.org/10.2118/210182-MS.
Hild, G.P., Wackowski, R.K., 1999. Reservoir polymer gel treatments to improve miscible CO_2 flood. SPE Reservoir Eval. Eng. 2 (2), 196–204. https://doi.org/10.2118/56008-PA.
Hou, L., Yu, Z., Luo, X., Wu, S., 2022. Self-sealing of caprocks during CO_2 geological sequestration. Energy 252, 124064. https://doi.org/10.1016/j.energy.2022.124064.
Huang, X., Zhang, M., Su, X., Feng, Y., 2024. CO_2-responsive polymer promoted by polyether to efficient viscosity increase for CO_2 plugging. Polymer 306, 127227. https://doi.org/10.1016/j.polymer.2024.127227.
Jamaloei, B.Y., Babolmorad, R., Kharrat, R., 2016. Correlations of viscous fingering in heavy oil waterflooding. Fuel 179, 97–102. https://doi.org/10.1016/j.fuel.2016.03.064.
Ji, W., Dai, C., Cao, Y., Yang, N., Wang, T., Zhao, G., 2023. A novel CO_2-resistant dispersed particle gel for gas channeling control in low-permeability reservoirs. J. Mol. Liq. 374, 121251. https://doi.org/10.1016/j.molliq.2023.121251.
Jin, J., Wang, Y., Wei, M., Ma, H., Wang, K., 2016. Coreflooding and pore-scale visualization of foamed gel flowed in porous network media. J. Dispersion Sci. Technol. 36 (19), 1274–1281. https://doi.org/10.1080/01932691.2015.1111146.
Joachim, M., 2016. Viscous and gravitational fingering in multiphase compositional and compressible flow. Adv. Water Resour. 89, 53–66. https://doi.org/10.1016/j.advwatres.2016.01.002.
Kang, W., Shao, S., Yang, H., Chen, C., Gabdullin, M., 2019. The effect of stepwise increasing of water injection rates on enhanced oil recovery after preformed particle gel treatment. J. Pet. Sci. Eng. 182, 106239. https://doi.org/10.1016/j.petrol.2019.106239.
Kang, W., Jiang, H., Yang, H., Li, Z., Zhou, B., He, Y., Sarsenbekuly, B., Gabdullin, M., 2021. Study of nano-SiO_2 reinforced CO_2 foam for anti-gas channeling with a high temperature and high salinity reservoir. J. Ind. Eng. Chem. 97, 506–514. https://doi.org/10.1016/j.jiec.2021.03.007.
Kumar, A., Mahto, V., Sharma, V.P., 2023. A systematic multi-scale experimental investigation of a newly developed halloysite nanotubes reinforced preformed particle gel for improving oil recovery from heterogeneous reservoir: Synthesis, characterization, optimization and performance assessment. Geoenergy Sci. Eng. 226, 211786. https://doi.org/10.1016/j.geoen.2023.211786.
Kumar, N., Sampaio, M.A., Ojha, K., Hoteit, H., Mandal, A., 2022. Fundamental aspects, mechanisms and emerging possibilities of CO_2 miscible flooding in enhanced oil recovery: A review. Fuel 330, 125633. https://doi.org/10.1016/j.fuel.2022.125633.
Li, D.-X., Zhang, L., Liu, Y.-M., Kang, W.-L., Ren, S.-R., 2016. CO_2-triggered gelation for mobility control and channeling blocking during CO_2 flooding processes. Pet. Sci. 13 (2), 247–258. https://doi.org/10.1007/s12182-016-0090-9.
Liu, F., Zhang, M., Huang, H., Cheng, R., Su, X., 2025a. CO_2-responsive plugging gel with sodium dodecyl sulfate, polyethyleneimine, and silica. Polymers 17 (6), 706. https://doi.org/10.3390/polym17060706.
Liu, Q., Liu, C., Li, Y., Fang, N., Yan, X., Dai, C., Huang, Y., Wu, Y., 2022. Preparation of dual network semi-solidified gelled-foam for sealing gas channeling in fractured-vuggy reservoirs. J. Pet. Sci. Eng. 216, 110687. https://doi.org/10.1016/j.petrol.2022.110687.
Liu, X., Chen, H., Cheng, W., Li, Y., Zhao, Y., Zhu, Y., Zeng, H., 2025b. Occurrence states and transport behavior of crude oil in different permeability oil reservoirs during depletion development. Geoenergy Sci. Eng. 252, 213944. https://doi.org/10.1016/j.geoen.2025.213944.
Liu, X., Chen, H., Li, Y., Zhu, Y., Liao, H., Zhao, Q., Zhou, X., Zeng, H., 2025c. Oil production characteristics and CO_2 storage mechanisms of CO_2 flooding in ultra-low permeability sandstone oil reservoirs. Petrol. Explor. Dev. 52 (1), 196–207. https://doi.org/10.1016/S1876-3804(25)60014-0.
Liu, Z., Wei, P., Qi, Y., Huang, X., Xie, Y., 2023. High stretchable and self-healing nanocellulose-poly(acrylic acid) composite hydrogels for sustainable CO_2 shutoff. Carbohydr. Polym. 311, 120759. https://doi.org/10.1016/j.carbpol.2023.120759.
Luo, X.-J., Wei, B., Gao, K., Jing, B., Huang, B., Guo, P., Yin, H.-Y., Feng, Y.-J., Zhang, X., 2023. Gas channeling control with an in-situ smart surfactant gel during water-alternating-CO_2 enhanced oil recovery. Pet. Sci. 20 (5), 2835–2851. https://doi.org/10.1016/j.petsci.2023.03.003.
Luquot, L., Gouze, P., 2009. Experimental determination of porosity and permeability changes induced by injection of CO_2 into carbonate rocks. Chem. Geol. 265 (1–2), 148–159. https://doi.org/10.1016/j.chemgeo.2009.03.028.
Ma, W., Li, Y., Liu, P., Liu, Z., Song, T., 2024. Progress of research into preformed particle gels for profile control and water shutoff techniques. Gels 10 (6), 372. https://doi.org/10.3390/gels10060372.
Masalmeh, S.K., Farzaneh, S.A., Sohrabi, M., Alhammadi, M., 2025. Experimental investigation of factors affecting oil recovery and displacement efficiency of CO_2 injection in carbonate reservoirs. SPE J. 30 (3), 1492–1509. https://doi.org/10.2118/218525-PA.
Nasir, F.M., Chong, Y.Y., 2009. The effect of different carbon dioxide injection modes on oil recovery. Int. J. Eng. Technol. 9 (10), 55.
Oliveira da Rocha, H., Santos da Costa, J.L., Gonzaléz Carrasquilla, A.A., Vallejos Carrasco, A.M., 2021. Permeability estimation and analysis of fracture networks using resistivity logs in an offshore Aptian carbonate reservoir pre-salt, in the Southeastern Santos Basin. J. Appl. Geophys. 184, 104241. https://doi.org/10.1016/j.jappgeo.2020.104241.
Pandit, Y.K., Mahto, V., Udayabhanu, G., Ravishankar, B., Dhandi, M., 2024. Preparation, characterization, and evaluation of a nanomaterial reinforced particle gel system for the control of excessive water production in the mature oil fields. Geoenergy Sci. Eng. 235, 212707. https://doi.org/10.1016/j.geoen.2024.212707.
Pereira, K.A.B., Pereira, K.A.B., Oliveira, P.F., Mansur, C.R.E., 2020. Behavior of partially hydrolyzed polyacrylamide/polyethyleneimine reinforced with coal fly ash for preformed particle hydrogels. J. Appl. Polym. Sci. 137 (46), 49423. https://doi.org/10.1002/app.49423.
Peter, A., Yang, D., Eshiet, K.I.-I.I., Sheng, Y., 2022. A review of the studies on CO_2–brine–rock interaction in geological storage process. Geosciences 12 (4), 168. https://doi.org/10.3390/geosciences12040168.
Platzer, A.J., 1962. Polymerization and Polycondensation Process. American Chemical Society, Washington.
Prasad, S.K., Sangwai, J., Byun, H.S., 2023. A review of the supercritical CO_2 fluid applications for improved oil and gas production and associated carbon storage. J. CO_2 Util. 72, 102479. https://doi.org/10.1016/j.jcou.2023.102479.
Pu, W., Du, D., Fan, H., Chen, B., Yuan, C., Varfolomeev, M.A., 2021. CO_2-responsive preformed gel particles with interpenetrating networks for controlling CO_2 breakthrough in tight reservoirs. Colloids Surf., A 613, 126065. https://doi.org/10.1016/j.colsurfa.2020.126065.
Qi, N., Li, B., Chen, G., Liang, C., Ren, X., Gao, M., 2018. Heat-generating expandable foamed gel used for water plugging in low-temperature oil reservoirs. Energy Fuels 32 (2), 1126–1131. https://doi.org/10.1021/acs.energyfuels.7b02705.
Qiu, Y., Wu, F., Wei, M., Kang, W., Li, B., 2014. Lessons learned from applying particle gels in mature oilfields. In: Proceedings of SPE Improved Oil Recovery Symposium. https://doi.org/10.2118/169161-MS.
Qu, M., Hou, J., Wang, Q., Su, W., Ma, S., Yang, T., Li, P., Bai, Y., 2017. Modified starch gel foam: Research and application in naturally fractured-vuggy carbonate reservoir. In: Proceedings of Abu Dhabi International Petroleum Exhibition & Conference. https://doi.org/10.2118/188812-MS.
Raje, M., Asghari, K., Vossoughi, S., Green, D.W., Willhite, G.P., 1999. Gel systems for controlling CO_2 mobility in carbon dioxide miscible flooding. SPE Reservoir Eval. Eng. 2 (2), 205–210. https://doi.org/10.2118/55965-PA.
Rezaeiakmal, F., Parsaei, R., 2021. Visualization study of polymer enhanced foam (PEF) flooding for recovery of waterflood residual oil: Effect of cross flow. J. Pet. Sci. Eng. 203. https://doi.org/10.1016/j.petrol.2021.108583.
Romero-Zeron, L., Kantzas, A., 2006. Evolution of foamed gel confined in pore network models. J. Can. Pet. Technol. 45 (11). https://doi.org/10.2118/06-11-07.
Romero-Zeron, L., Kantzas, A., 2007. The effect of wettability and pore geometry on foamed-gel-blockage performance. SPE Reservoir Eval. Eng. 10 (2), 150–163. https://doi.org/10.2118/89388-PA.
Salunkhe, B., Schuman, T., Al Brahim, A., Bai, B., 2021. Ultra-high temperature resistant preformed particle gels for enhanced oil recovery. Chem. Eng. J. 426, 130712. https://doi.org/10.1016/j.cej.2021.130712.
Schramm, L.L., Kutay, S.M., Mikula, R.J., Munoz, V.A., 1999. The morphology of non-equilibrium foam and gelled foam lamellae in porous media. J. Pet. Sci. Eng. 23 (2), 117–132. https://doi.org/10.1016/S0920-4105(99)00011-X.
Shao, M.L., Cheng, M.J., Gong, J., Chang, A.L., Fu, L.P., Liao, K.L., Liu, X.Q., 2025. Preparation and performance evaluation of nanoparticle plugging agent for CO_2 gas channeling control. J. Dispersion Sci. Technol. 1–12. https://doi.org/10.1080/01932691.2025.2461099.
Shen, H., Yang, Z., Li, X., Peng, Y., Lin, M., Zhang, J., Dong, Z., 2021. CO_2-responsive agent for restraining gas channeling during CO_2 flooding in low permeability reservoirs. Fuel 292, 120306. https://doi.org/10.1016/j.fuel.2021.120306.
Shi, J., Xue, Z., Durucan, S., 2011. Supercritical CO_2 core flooding and imbibition in Tako sandstone—Influence of sub-core scale heterogeneity. Int. J. Greenh. Gas Control 5 (1), 75–87. https://doi.org/10.1016/j.ijggc.2010.07.003.
Singh, R., Mahto, V., 2017. Synthesis, characterization and evaluation of polyacrylamide graft starch/clay nanocomposite hydrogel system for enhanced oil recovery. Pet. Sci. 14, 765–779. https://doi.org/10.1007/s12182-017-0185-y.
Sun, F., Lin, M., Dong, Z., Zhang, G., 2019. Delayed-crosslink hydrogel for improving oil recovery in differential heterogeneous reservoirs. ACS Omega 5 (1), 228–235. https://doi.org/10.1021/acsomega.9b02545.
Sun, X., Alhuraishawy, A.K., Bai, B., Wei, M., 2018. Combining preformed particle gel and low salinity waterflooding to improve conformance control in fractured reservoirs. Fuel 221, 501–512. https://doi.org/10.1016/j.fuel.2018.02.084.
Sun, X., Bai, B., Long, Y., Wang, Z., 2020. A comprehensive review of hydrogel performance under CO_2 conditions for conformance control. J. Pet. Sci. Eng. 185, 106662. https://doi.org/10.1016/j.petrol.2019.106662.
Sun, X., Bai, B., Alhuraishawy, A.K., Zhu, D., 2021. Understanding the plugging performance of HPAM-Cr(III) polymer gel for CO_2 conformance control. SPE J. 26 (5), 3109–3118. https://doi.org/10.2118/204229-PA.
Syed, A., Pantin, B., Durucan, S., Korre, A., Shi, J., 2014. The use of polymer-gel solutions for remediation of potential CO_2 leakage from storage reservoirs. Energy Proc. 63, 4638–4645. https://doi.org/10.1016/j.egypro.2014.11.497.
Wang, C., Ma, B., Zhang, L., 2022a. Experimental study on CO_2 capture by using *n*-butylamine to plug the gas channeling to enhanced oil recovery. J. Pet. Explor. Prod. Technol. 12 (9), 2523–2531. https://doi.org/10.1007/s13202-022-01503-3.

Wang, F., Zhang, Y., Yu, Z., Chen, J., 2023. Simulation research on Jamin effect and oil displacement mechanism of CO_2 foam under microscale. Arab. J. Chem. 16 (11), 105123. https://doi.org/10.1016/j.arabjc.2023.105123.

Wang, T., Wang, L., Qin, H., Zhao, C., Bai, Z., Meng, X., 2022b. Identification of gas channeling and construction of a gel-enhanced foam plugging system for oxygen-reduced air flooding in the changqing oilfield. Gels 8 (6), 373. https://doi.org/10.3390/gels8060373.

Wei, B., Romero-Zerón, L., Rodrigue, D., 2014. Oil displacement mechanisms of viscoelastic polymers in enhanced oil recovery (EOR): A review. J. Pet. Explor. Prod. Technol. 4 (2), 113–121. https://doi.org/10.1007/s13202-013-0087-5.

Wilberforce, T., Olabi, A.G., Sayed, E.T., Elsaid, K., Abdelkareem, M.A., 2021. Progress in carbon capture technologies. Sci. Total Environ. 761, 143203. https://doi.org/10.1016/j.scitotenv.2020.143203.

Wu, Y., Liu, Q., Liu, D., Cao, X., Yuan, B., Zhao, M., 2023. CO_2 responsive expansion hydrogels with programmable swelling for in-depth CO_2 conformance control in porous media. Fuel 332, 126047. https://doi.org/10.1016/j.fuel.2022.126047.

Xin, Y., Li, B., Li, Z., Li, Z., Wang, B., Wang, X., Zhang, M., Li, W., 2025a. Gas channeling control with CO_2-responsive gel system in fractured low-permeability reservoirs: Enhancing oil recovery during CO_2 flooding. Sep. Purif. Technol. 353, 128475. https://doi.org/10.1016/j.seppur.2024.128475.

Xin, Y., Li, Z., Cao, A., Li, B., Zhang, C., Yang, G., Li, W., Zhang, M., 2025b. CO_2-responsive gel system for gas channeling mitigation in fractured reservoirs: Mechanisms and performance evaluation. J. Environ. Chem. Eng. 13 (4), 117305. https://doi.org/10.1016/j.jece.2025.117305.

Xiong, B., Loss, R.D., Shields, D., Pawlik, T., Hochreiter, R., Zydney, A.L., Kumar, M., 2018. Polyacrylamide degradation and its implications in environmental systems. npj Clean Water 1 (1), 17. https://doi.org/10.1038/s41545-018-0016-8.

Xu, B., Zhang, H., Bian, H., 2019a. Delayed crosslinking amphiphilic polymer gel system with adjustable gelation time based on competitive inclusion method. Polymers 11 (2), 381. https://doi.org/10.3390/polym11020381.

Xu, L., Qiu, Z., Gong, H., Zhu, C., Dong, M., 2019b. Synergy of microbial polysaccharides and branched-preformed particle gel on thickening and enhanced oil recovery. Chem. Eng. Sci. 208, 115138. https://doi.org/10.1016/j.ces.2019.07.056.

Xu, T., Wei, Y., Ma, T., 2020a. Experiment and simulation of gas channeling control technique during CO_2 flooding in normal pressure tight oil reservoir of South Ordos Basin. In: Proceedings of Abu Dhabi International Petroleum Exhibition & Conference. https://doi.org/10.2118/203153-MS.

Xu, Z., Li, S., Li, B., Chen, D.i., Liu, Z., Li, Z., 2020. A review of development methods and EOR technologies for carbonate reservoirs. Pet. Sci. 17 (4), 990–1013. https://doi.org/10.1007/s12182-020-00467-5.

Xue, M., Chen, L., Chen, H., Fu, L., Bai, Y., Lv, W., Hou, B., Riazi, M., 2025. Hydrogen-bond-modulated flowable weak gel for EOR in ultra-high temperature and ultra-high salinity fracture-cavity ordinary heavy oil reservoirs. Colloids Surf., A 725, 137537. https://doi.org/10.1016/j.colsurfa.2025.137537.

Yang, H.-B., Jiang, H.-Z., Xu, Z., Zhang, X., Wang, T., Liu, H.-N., Ma, X., Zhu, J.-J., Zhang, X.-F., Kang, W.-L., 2025. Development and evaluation of organic/metal ion double crosslinking polymer gel for anti-CO_2 gas channeling in high temperature and low permeability reservoirs. Pet. Sci. 22 (2), 724–738. https://doi.org/10.1016/j.petsci.2024.11.016.

Yang, H., Li, H., Xu, H., Wang, R., Zhang, Y., Xing, L., Chen, X., Peng, L., Kang, W., Sarsenbekuly, B., 2026. Enhanced CO_2 foam stabilization with fluorescent nano polymer microspheres for improved oil recovery: Insights from microscopic and macroscopic displacement studies. Geoenergy Sci. Eng. 257, 214222. https://doi.org/10.1016/j.geoen.2025.214222.

Zhai, Y., Fang, Z., Feng, J., Sun, C., Deng, W., Wen, Y., 2024. Development and performance evaluation of re-crosslinkable preformed particle gel under high temperature and high salt conditions. Polymer 296, 126824. https://doi.org/10.1016/j.polymer.2024.126824.

Zhang, H., Gong, H., He, X., Wu, J., Sun, H., Xu, L., Dong, M., 2024a. Simultaneous adjustment on the CO_2/oil and CO_2/water interface tensions using hydrophilic, lipophilic and CO_2-philic surfactants during CO_2 flooding to enhance shale oil recovery after hydraulic fracturing. Chem. Eng. J. 486, 150244. https://doi.org/10.1016/j.cej.2024.150244.

Zhang, M., Li, B., Lei, W., Zhao, X., Ding, W., Zhang, X., Xin, Y., Li, Z., 2024b. Oil displacement and CO_2 storage during CO_2 immiscible huff-n-puff within a saturated reservoir: An experimental study. Fuel 371, 132026. https://doi.org/10.1016/j.fuel.2024.132026.

Zhang, N., Wei, M., Bai, B., 2018. Statistical and analytical review of worldwide CO_2 immiscible field applications. Fuel 220, 89–100. https://doi.org/10.1016/j.fuel.2018.01.140.

Zhang, Y., Gao, M., You, Q., Fan, H., Li, W., Liu, Y., Fang, J., Zhao, G., Jin, Z., Dai, C., 2019. Smart mobility control agent for enhanced oil recovery during CO_2 flooding in ultra-low permeability reservoirs. Fuel 241, 442–450. https://doi.org/10.1016/j.fuel.2018.12.069.

Zhang, Z., Sun, L., Huo, X., Liu, X., Pan, X., 2024c. Rheological properties and gas channeling plugging ability in CO_2 flooding of a hydrophobic nanoparticle-enhanced smart gel system constructed with wormlike micelles. Chem. Eng. Res. Des. 202, 506–516. https://doi.org/10.1016/j.cherd.2024.01.014.

Zhao, F., Wang, P., Huang, S., Hao, H., Zhang, M., Lu, G., 2020. Performance and applicable limits of multi-stage gas channeling control system for CO_2 flooding in ultra-low permeability reservoirs. J. Pet. Sci. Eng. 192, 107336. https://doi.org/10.1016/j.petrol.2020.107336.

Zhao, G., Dai, C., Zhang, Y., Chen, A., Yan, Z., Zhao, M., 2015. Enhanced foam stability by adding comb polymer gel for in-depth profile control in high temperature reservoirs. Colloids Surf., A 482, 115–124. https://doi.org/10.1016/j.colsurfa.2015.04.041.

Zhao, Y., Leng, J., Lin, B., Wei, M., Bai, B., 2021. Experimental study of microgel conformance-control treatment for a polymer-flooding reservoir containing superpermeable channels. SPE J. 26 (4), 1–13. https://doi.org/10.2118/205486-PA.

Zhao, Y., Wen, X., Rui, Z., Ding, Y., 2024. A novel dual-network CO_2-responsive particle gel for mitigating CO_2 channeling and leakage in hydrocarbon recovery and carbon storage. Chem. Eng. J. 498, 155187. https://doi.org/10.1016/j.cej.2024.155187.

Zhou, B., Kang, W., Yang, H., Zhu, T., Zhang, H., Li, X., Sarsenbekuly, B., Sarsenbek, T., 2021. Preparation and properties of an acid-resistant preformed particle gel for conformance control. J. Pet. Sci. Eng. 197, 107964. https://doi.org/10.1016/j.petrol.2020.107964.

Zhou, B., Kang, W., Jiang, H., Yang, H., Li, Z., Lv, Z., Xu, Z., Ning, C., Wang, H., Xie, S., 2022. Preparation and crosslinking mechanism of delayed swelling double-crosslinking nano polymer gel microsphere for anti-CO_2 gas channeling. J. Pet. Sci. Eng. 219, 111122. https://doi.org/10.1016/j.petrol.2022.111122.

Zhu, D., Hou, J., Wei, Q., Wu, X., Bai, B., 2017. Terpolymer gel system formed by resorcinol-hexamethylenetetramine (HMTA) for water management in extremely high temperature reservoirs. Energy Fuels 31 (2), 1519–1528. https://doi.org/10.1021/acs.energyfuels.6b03188.

Zou, C., Liu, Y., Dai, C., Yuan, X., Wang, H., Huang, Y., Xu, Z., Yang, N., 2025. Salt-induced dual network gel-strengthened foam for gas channeling control in fractured-cavity carbonate reservoirs. Geoenergy Sci. Eng. 253, 213975. https://doi.org/10.1016/j.geoen.2025.213975.