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Perspective

Enhanced oil recovery and flow mechanisms in shale reservoirs: Toward cross-scale, low-carbon, and field-oriented development

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Abstract:
Shale oil and gas development is shifting from single stimulation methods toward integrated recovery strategies that combine flow-mechanism understanding, enhanced oil recovery, and carbon utilization and storage. Based on the discussions in Session "Shale Oil and Gas Flow Mechanisms and Enhanced Oil Recovery" of the second "International Geo-Energy Frontier Forum", this work summarizes recent advances in thermally assisted CO_2 huff-n-puff, supercritical CO_2 flow and multiscale CO_2 foam simulation, *in-situ* upgrading and thermal conversion, micro/nanobubble injection, dual geological-engineering sweet-spot identification, and shut-in optimization. The major bottleneck is no longer the lack of individual stimulation methods, but the insufficient integration among pore-scale mechanisms, fracture-matrix interactions, field-scale simulation, and carbon storage accounting. Future research should focus on mechanism-informed pilot design, lithology-specific upscaling models, CO_2-thermal-chemical coupled processes, and standardized evaluation workflows linking recovery efficiency with carbon sequestration performance.

1. Introduction

Unlike conventional reservoirs, shale reservoirs cannot be effectively developed by relying on natural depletion alone. Although horizontal drilling and hydraulic fracturing have greatly improved initial productivity, rapid production decline, limited fracture-controlled drainage volume, and low matrix permeability remain persistent challenges. These problems are particularly pronounced in continental lithologic shale reservoirs, where laminated structures, mixed lithofacies, high clay content, and variable organic matter maturity further complicate fluid occurrence states and transport mechanisms. At the pore scale, nuclear magnetic resonance, micro/nano-computed tomography, digital core reconstruction, and microfluidic visualization have revealed the occurrence, mobilization, and trapping behavior of hydrocarbons and injected fluids in nanopores, microfractures, and complex pore networks (Wang et al., 2025). CO_2 huff-n-puff, supercritical CO_2 flooding, thermally assisted recovery, and foam flooding have been shown to improve oil recovery through multiple mechanisms, including oil swelling, viscosity reduction, interfacial tension reduction, extraction of light components, wettability alteration, and suppression of gas channeling (Wang et al., 2023). At the reservoir scale, however, the translation of these mechanisms into reliable field-scale development protocols remains

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insufficient.

Against this background, Session "Shale Oil and Gas Flow Mechanisms and Enhanced Oil Recovery" of the second "International Geo-Energy Frontier Forum" focused on frontier advances in shale oil and gas seepage mechanisms and recovery enhancement. The session covered thermally assisted CO_2 huff-n-puff, supercritical CO_2 flow and multiscale simulation, *in-situ* upgrading and thermal conversion, micro/nanobubbles injection technology, dual sweet spot identification and shut-in optimization. These topics collectively indicate that shale enhanced oil recovery is entering a new stage characterized by cross-scale characterization, multi-field coupling, and the integration of oil recovery with carbon utilization and storage. A comprehensive description of the organization, scale, core themes, and emerging trends of the second International Geo-Energy Frontier Forum has been provided by Cai (2026).

2. Enhanced oil recovery (EOR) and flow mechanisms in shale

2.1 CO_2 huff-n-puff and thermally assisted recovery

CO_2 huff-n-puff has become one of the most attractive enhanced oil recovery strategies for shale reservoirs after hydraulic fracturing. However, the field performance of CO_2 huff-n-puff in continental shale reservoirs remains highly variable. The major limitation is that CO_2 transport in the shale matrix is strongly restricted by nanoscale pore throats, complex pore connectivity and fracture-matrix heterogeneity. Thus, the effective swept volume is much smaller than the designed stimulated reservoir volume. In addition, CO_2 extraction of light hydrocarbons may be accompanied by asphaltene precipitation (Li et al., 2023), pore-throat blockage and wettability alteration, which can partly offset the positive effects of CO_2 dissolution and viscosity reduction.

For CO_2 huff-n-puff in shale reservoirs, the central issue is how to increase the contact between CO_2 and retained oil while avoiding additional damage to the pore-fracture system. Thermally assisted CO_2 huff-n-puff provides a promising way to overcome this limitation. A dedicated experimental system was developed comprising three integrated apparatuses: a thermal-CO_2 cyclic permeability device that accounts for overburden stress, a fractured-core energy enhancement and permeability evaluation device, and a CO_2 mass-transfer diffusion pressure-decay apparatus (Chen et al., 2025). Experiments quantified the evolution of reservoir physical properties, energy enhancement efficiency, displacement efficiency, and CO_2 mass-transfer diffusion coefficients. Nuclear magnetic resonance observations further show that repeated CO_2 huff-n-puff under elevated temperature can shift the pore-size distribution, with fewer small pores and more medium-to-large pores.

Overall, thermally assisted CO_2 huff-n-puff should be treated as a coupled thermal-flow-chemical stimulation process rather than a simple heating-enhanced gas injection method. Its performance depends on the balance among heat transfer, CO_2 diffusion, viscosity reduction, mineral-fluid interaction, and fracture-matrix pressure communication. The next step is to define a practical operating window, including heating temperature, injection pressure, CO_2 slug size, shut-in duration, cycle number, and production timing. Pilot tests should also evaluate CO_2 retention, energy efficiency, and reservoir integrity, rather than focusing only on incremental oil recovery.

2.2 Supercritical CO_2 flow and multiscale CO_2 foam simulation

Supercritical CO_2 combines gas-like mobility with liquid-like density and strong solvency, can easily penetrate microfractures and small pore throats. However, it is controlled by the coupling of convective flow in fractures, diffusion into the matrix, phase behavior, capillary trapping and fluid-rock interactions (Yi et al., 2025). Therefore, its effectiveness depends on whether sufficient contact can be established between CO_2 and retained oil in the fracture-matrix system. Nuclear magnetic resonance, micro/nano-computed tomography reconstruction and visualization experiments have revealed that remaining oil after supercritical CO_2 flooding exhibits multiple morphological types (Li et al., 2025). Reticular remaining oil is mainly associated with viscous fingering and preferential flow paths; columnar and slug-shaped remaining oil are controlled by the Jamin effect in narrow pore throats; droplet-shaped remaining oil is related to interfacial tension and local Marangoni effects; oil films are retained along pore walls due to surface interactions and Taylor dispersion; and dead-end remaining oil is governed by pore connectivity, tortuosity and local capillary barriers (Zhang et al., 2026). However, the high mobility of supercritical CO_2 may cause preferential flow and early gas channeling in fractured shale reservoirs. CO_2 foam is therefore introduced to improve mobility control and enlarge the swept volume.

A major challenge is how to translate pore-scale CO_2 displacement into reservoir-scale simulation. Multiscale simulation frameworks are needed to bridge pore-network modeling, phase-field descriptions and reservoir-scale numerical simulation. A pore-scale CO_2 foam simulator has been developed using the dynamic invasion percolation with memory algorithm. To extend the pore-scale results to reservoir-scale prediction, the simulator was linked with numerical simulation software through an upscaling platform, allowing time-dependent relative permeability to be updated in the reservoir model (Zhao et al., 2020; Zhao et al., 2021). In parallel, microfluidic experiments and foam-material optimization provide parameters such as foam texture, effective viscosity and minimum pressure gradient for upscaling. This integration is essential for designing CO_2-based shale EOR schemes that are not only effective in improving oil recovery, but also compatible with long-term carbon utilization and storage.

2.3 In-situ upgrading and thermal conversion

In-situ upgrading and thermal conversion provide a potential route for developing low- to medium-maturity lithologic shale oil, which usually contains abundant resins and asphaltenes and exhibits poor mobility under reservoir conditions. The basic technical idea is to heat the reservoir and convert heavy components into lighter hydrocarbons in place (Zhou et al., 2025). At present, this is mainly achieved by downhole electric heating, with reservoir temperature commonly raised to 300-500 °C. Supercritical CO_2 or light solvents can also be injected during heating to improve heat transfer, extract light components, reduce oil viscosity and expand the effective stimulated zone. Thermal conversion is a coupled process involving heat transfer, component conversion, solvent extraction and fluid transport.

To characterize the thermal conversion behavior systematically, full-temperature-range (20-900 °C) *in-situ* upgrading experiments were performed on high-viscosity shale oil. These experiments identified a four-stage pyrolysis pattern - physical evaporation, evaporation of medium-weight components, cracking of resins and asphaltenes into light oil and gas, and residual coke formation at high temperature - and determined the reaction kinetic parameters for each stage (Xie et al., 2025). A high-temperature and high-pressure autoclave was constructed to carry out upgrading experiments under supercritical CO_2 conditions. The results validated the feasibility of catalytic low-temperature cracking and significantly improved light component yield, while also enabling the construction of a time-varying reaction kinetic model in which kinetic parameters vary continuously with temperature.

The main challenges are the limited controllability of the thermal conversion zone and the high uncertainty of field implementation. If heating is insufficient, viscosity reduction and component conversion are limited; if heating is excessive, coke formation, mineral alteration, fracture instability and high energy consumption may reduce the overall benefit. In addition, how to match the heating zone, reaction zone and fluid-flow pathway remains unclear. Future development should focus on establishing controllable operating method, including heating temperature, heating duration, CO_2 or solvent injection strategy, catalyst selection, and energy efficiency. With further coupling of reaction kinetics, heat transfer, fluid flow and geomechanics, *in-situ* upgrading may become an important technology for improving the recovery of low- to medium-maturity shale oil.

2.4 Micro/Nanobubbles injection technology

Micro/nanobubbles (MNBs) have unique physicochemical properties including negligible buoyancy, large gas-liquid interfacial area, continuous shrinkage-driven gas dissolution, negative surface charge and relatively long-term stability in aqueous systems (Jia et al., 2023; Cai et al., 2024). For shale oil and gas development, MNBs may act as efficient gas carriers and interfacial regulators. When combined with CO_2, CO_2-MNBs systems can improve CO_2 dispersion and residence time in injection fluids, increase the probability of CO_2 contacting retained oil in the shale matrix, and potentially cooperate with imbibition, surfactants or foam systems to enlarge the effective swept volume (Sun et al., 2025).

However, MNBs injection is still at an early stage for shale reservoirs. Most studies focus on bubble generation, stability and bulk-fluid properties, while the migration, collapse and mass-transfer behavior of MNBs in real shale pore networks remain unclear. Their stability under high temperature, high pressure, high salinity and confined nanopore conditions also needs further verification. Future work should verify MNBs transport, stability, interfacial regulation and compatibility with CO_2, surfactants and foam systems under reservoir conditions.

2.5 Dual sweet spot identification and shut-in optimization

Sweet-spot identification has evolved from static reservoir-quality evaluation toward an integrated geological-engineering workflow. Current approaches combine geological indicators such as porosity, permeability, oil saturation, lithofacies and mobility with engineering indicators. Advanced methods, including clustering analysis, 3D geological modeling, analytic hierarchy process and machine learning, have been used to classify favorable intervals and predict development performance (Yi et al., 2025). However, geological sweet spots do not always coincide with engineering sweet spots or high-production intervals, because favorable oil-bearing layers may have poor fracability, while highly fracable layers may have limited hydrocarbon supply. In addition, parameter weighting is still partly subjective, static sweet-spot maps cannot fully reflect reservoir changes after fracturing or CO_2 injection, and field-scale validation remains insufficient. Future evaluation should therefore integrate geological quality, fracability, fluid mobility, production response and economic performance into a dynamic and data-updated workflow.

For shut-in optimization, current decision-making methods mainly include field statistical analysis, imbibition experiments, analytical or semi-analytical modeling, numerical simulation, and flowback diagnosis. Field data are commonly used to compare production responses under different shut-in durations, whereas nuclear magnetic resonance, magnetic resonance imaging and computed tomography experiments help quantify fluid redistribution, imbibition depth and pore-scale oil-water exchange. Analytical models can rapidly estimate shut-in time by linking imbibition distance, pressure diffusion and fracture-matrix exchange (Guo et al., 2024), while numerical simulation further couples fracturing, shut-in, flowback and production processes. The difficulty is that shut-in is not a single imbibition process, but a transient period during which capillary-driven fluid exchange, pressure redistribution, fracture closure, water retention and relative-permeability damage may occur simultaneously, making the optimal shut-in time strongly dependent on reservoir quality, fracture complexity, fluid sensitivity and subsequent flowback strategy. Laboratory imbibition time therefore cannot be directly converted into field shut-in time, especially in heterogeneous shale reservoirs with complex fracture networks and stress-dependent permeability. Future work should integrate pore-scale imbibition characterization, fracture-matrix flow modeling, pressure-transient diagnosis and dynamic flowback control to establish reservoir-specific shut-in and production strategies.

3. Future perspectives

Future shale EOR research should move from isolated mechanism studies toward field-oriented technology design. The key is to connect pore-scale recovery mechanisms, core-scale flow behavior and reservoir-scale development performance. Instead of simply describing CO_2 diffusion, imbibition, thermal conversion or foam control, future studies should clarify how these mechanisms can be converted into practical parameters for reservoir simulation, pilot design and production optimization.

(1) Microscopic information from nuclear magnetic resonance, computed tomography, digital cores and visualization experiments should be converted into reservoir-scale parameters, such as relative permeability, diffusion coefficients, capillary pressure and CO_2 trapping capacity.

(2) Permeability, wettability and relative permeability should be treated as evolving properties influenced by fracturing, imbibition, CO_2 exposure, thermal treatment, solvent extraction and stress change.

(3) For thermally assisted CO_2 huff-n-puff and *in-situ* upgrading, heating temperature, heating duration, CO_2/solvent injection and energy efficiency should be jointly optimized.

(4) Micro/nanobubbles injection should be tested under realistic reservoir conditions to quantify gas-channeling control, water-blockage mitigation, oil mobilization and CO_2 retention.

(5) Sweet-spot identification, shut-in optimization and production control should be combined to link geological quality, fracability, imbibition behavior and production response.

(6) Future pilot tests should evaluate both incremental oil recovery and carbon-storage performance, including retained CO_2, storage stability, energy input and economic feasibility.

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Conflicts of interest

The authors declare no competing interest.

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