

Editorial

Fluid flow mechanisms and efficient development technologies in hydrocarbon reservoirs: Progress and perspectives

Sen Wang^{1,2*}, Xianxiang Chu^{1,2}, Yang Wang³, Fengjiao Wang⁴, Jia Deng⁵

¹School of Petroleum Engineering, China University of Petroleum (East China), Qingdao 266580, P. R. China

²State Key Laboratory of Deep Oil and Gas, China University of Petroleum (East China), Qingdao 266580, P. R. China

³State Key Laboratory of Petroleum Resources and Engineering, China University of Petroleum, Beijing 102249, P. R. China

⁴Laboratory of Enhanced Oil Recovery of Education Ministry, College of Petroleum Engineering, Northeast Petroleum University, Daqing 163318, P. R. China

⁵School of Mechanics and Safety Engineering, Zhengzhou University, Zhengzhou 450001, P. R. China

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Abstract:

Elucidating fluid flow mechanisms is critical for the efficient development of oil and gas reservoirs. This work summarizes recent advances in fluid flow mechanisms and development technologies for hydrocarbon reservoirs across three aspects: transport principles, numerical simulation, and intelligent optimization. Across scales from the pore to the reservoir, fluid transport capacity is governed by hydrocarbon adsorption, diffusion, flow mechanisms within the matrix, as well as fracture conductivity. Discrete fracture models and embedded discrete fracture models characterize pore-fracture connectivity and fracture conductivity as quantifiable variables, and physics-constrained surrogate models help alleviate the computational demands of traditional high-fidelity simulations. Future work should integrate mechanistic insights, numerical simulation techniques, and intelligent optimization algorithms into an agent for efficient reservoir development.

1. Introduction

Understanding fluid flow mechanisms is essential for the efficient development of hydrocarbon reservoirs. However, because of reservoir heterogeneity, scale differences between pores and fractures, and the complex geofluid properties, fluid flow in oil and gas reservoirs is characterized by coupled multiphase and multiscale behavior involving multiple mechanisms. The limitations of classical theory and technology have become particularly prominent with the rapid development of unconventional resources in recent years. The widespread development of micro- and nanopores can induce a confinement effect that weakens the applicability of Darcy's law. In addition, at the high water-cut stage of a conventional reservoir, discontinuous flow caused by highly dispersed remaining oil

further renders classical continuous-flow theory increasingly inadequate.

Reservoir numerical simulation predicts the production performance of oil and gas fields by solving multiphase flow equations, providing a scientific foundation for development decisions. However, current simulation methods face significant challenges in accurately characterizing matrix-fracture mass transfer, time-dependent fracture conductivity, and evolving formation parameters, which limits the reliability of reservoir dynamics predictions (Cavalcante et al., 2024). Additionally, these simulations necessitate solving large-scale partial differential equations, resulting in high computational costs that constrain production optimization efficiency (Aziz-zadenesheli et al., 2024; Badawi et al., 2025). As a result, ad-

vancing the characterization of flow mechanisms, developing improved reservoir simulation techniques, and implementing intelligent optimization algorithms are essential for enhancing prediction accuracy and decision-making efficiency—both of which are crucial for the effective development of complex hydrocarbon reservoirs.

2. Flow mechanisms

Fluid flow mechanisms in hydrocarbon reservoirs involve interactions between rock properties and fluid behavior. Hydraulic fractures, natural fractures, and matrix pores create interconnected pathways across multiple scales, with their transport effectiveness determined by both matrix supply and fracture conductivity. Additionally, the development of preferential flow paths and changes in multiphase fluid distribution modify flow resistance and affect oil recovery.

(1) Fluid transport in matrix pores

Tight and shale reservoirs are characterized by abundant nanopores, where strong fluid-solid interactions lead to nano-confinement effects that alter flow behavior compared to conventional reservoirs (Schlaich et al., 2025). Within these nanopores, hydrocarbon can exist in free, adsorbed, or confined states. The dominant flow regime is governed by a complex interplay of adsorption, diffusion, slip flow, sticky boundary layers, and interphase competition (Li et al., 2024). Consequently, flow in matrix pores should be understood as a coupled adsorption-diffusion-confined-flow process, rather than simple Darcy flow. Additionally, fluid mobilization in nanopores is influenced by pore size, fluid composition, solid material properties, pressure, and temperature.

(2) Fracture conductivity evolution

Fracture conductivity determines whether matrix fluids can be produced effectively. It evolves with effective stress, proppant placement, embedment, and crushing. Additionally, complex branching fractures redistribute flow from the matrix into fractures and then to the wellbore—with their contributions influenced by factors like length ratio, aperture ratio, branching angle, and branching order (Deng et al., 2024). Therefore, efficient development depends on dynamically matching fracture conductivity to the matrix's supply capacity, rather than simply maximizing a single fracture parameter.

(3) Fluid complexity

Fluid transport mechanisms in hydrocarbon reservoirs are strongly influenced by fluid complexity. For instance, prolonged waterflooding causes a steady decline in oil saturation, resulting in a highly dispersed distribution of remaining oil and potentially undermining traditional continuous-flow theory (Feng et al., 2017). Fracturing-assisted oil displacement modifies seepage distances from fractures into the matrix and shifts the phase front due to high-pressure injection and changes in viscosity fields. CO₂ injection further improves mobilization by promoting oil swelling, reducing viscosity, enhancing competitive adsorption, and altering wettability (Wang et al., 2025).

3. Numerical simulation methods

Numerical simulation translates multiscale flow mechanisms into quantitative predictions for reservoir dynamic performance. Serving as the foundation for decision-making and production optimization in hydrocarbon reservoirs, numerical models must accurately capture matrix–fracture mass transfer and fracture network connectivity. They should also account for complex flow mechanisms, variations in formation parameters, and transitions between different development strategies.

(1) Coupled pore-fracture simulation

Discrete fracture model directly resolves fracture geometry, but it demands complex meshing and incurs high computational costs. In contrast, the embedded discrete fracture model inserts fractures within matrix grids and uses non-neighboring transmissibility terms to calculate matrix-fracture and fracture-fracture exchanges, achieving a balance between fracture characterization and computational efficiency (Cavalcante et al., 2024). Additionally, proppant transport, settling, bridging, and placement govern the formation of effective conductive channels in hydraulically fractured reservoirs. These factors should be incorporated into reservoir numerical simulations (Yang et al., 2025).

(2) Production performance analysis

Production performance analysis relies on field data—including production rate, bottomhole pressure, and water cut—to infer reservoir properties and provide dynamic constraints for numerical models. For multi-fractured horizontal wells, productivity evaluation must take into account not only the geometry of the fracture network and flow mechanisms, but also the spatial distribution and temporal variation of fracture conductivity. Fractures should not be solely characterized by an equivalent fracture length or a single conductivity parameter (Deng et al., 2024). For fracturing-assisted oil displacement within low-permeability or tight reservoirs, factors such as adsorption loss of the displacement agent, pressure differential, matrix permeability, and the viscosity–concentration relationship collectively determine the displacement front and the swept area. Nonlinear flow models establish links between injection parameters and the mobilization of remaining oil (Wang et al., 2024). Note that the purpose of production performance evaluation is not to replace high-fidelity simulation, but to transform field responses into corrective constraints for fracture parameters, boundary conditions, and fluid mobilization states, thereby enhancing the accuracy of production performance prediction.

4. Intelligent optimization

Intelligent optimization involves decision systems that integrate fast surrogate models, optimization algorithms, and reservoir constraints to enhance operational control efficiency within physical limits. In scenarios with complex multi-variable combinations—such as well patterns, fracture networks, injection-production strategies, and pressure-control schedules—high-fidelity numerical simulations are too time-consuming for rapid optimization. By leveraging surrogate models and intelligent algorithms, these approaches can quickly evaluate development schemes while maintaining

physical consistency, enabling the dynamic adjustment of development strategies.

(1) Surrogate models

Several approaches have been developed to construct surrogate models for reservoir numerical simulations to improve prediction efficiency. Neural operators learn the mappings between input and solution fields, offering a versatile framework for accelerating scientific simulations (Azizzadenesheli et al., 2024). Reservoir-specific neural-operator surrogates further accommodate variations in well settings, locations, and permeability fields (Badawi et al., 2025). Nonetheless, these surrogate models remain sensitive to training data coverage, the formulation of physical constraints, and the characterization of uncertainty; as such, their suitability should be carefully evaluated for each case.

(2) Optimization with intelligent algorithms

Intelligent optimization leverages the computer's automatic optimization capabilities to identify development plans that achieve optimal objectives within specified constraints. This approach reduces the burden of manual calculations and comparisons, providing more effective guidance for oilfield development decisions. In unconventional reservoirs, joint optimization of well and fracturing parameters can be achieved by integrating embedded discrete fracture models with evolutionary algorithms (Xu et al., 2018). Nevertheless, because reservoir simulations must account for complex multiscale flow mechanisms, fracture network characteristics, and reservoir heterogeneity, simulation-based optimization remains highly time-consuming, which limits its practical use. Surrogate-model-based optimization offers a promising solution to this challenge, though research in this area is still at an early stage.

5. Perspectives

Future research should elucidate the fundamental flow principles governing reservoirs, focusing on the coupling of multiphase, multiscale, multi-mechanism, and multi-physics processes. Mechanistically, factors such as adsorption, diffusion, confined flow, stress sensitivity, and interfacial effects should be characterized within a unified, transferable framework suitable for various reservoir types and development stages. Numerically, the primary challenge is balancing high-fidelity modeling with computational efficiency, particularly for systems involving coupled pore-fracture networks, time-dependent conductivity, and variable formation parameters. Looking ahead, the scope of development should expand from isolated optimization tasks to comprehensive reservoir agents that integrate physics-constrained learning, neural operators, domain-specific foundation models, and large language models. These agents should seamlessly combine production dynamic analysis, model updating, uncertainty assessment, and scheme optimization, ultimately enabling rapid closed-loop decision-making for efficient reservoir management.

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Conflicts of interest

The authors declare no competing interest.

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