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Invited review

Advances and challenges in shale oil development: A critical review

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Abstract:
Different from the conventional oil reservoirs, the primary storage space of shale is micro/nano pore networks. Moreover, the multiscale and multi-minerals characteristics of shale also attract increasing attentions from researchers. In this work, the advances and challenges in the development of shale oil are summarized from following aspects: phase behavior, flow mechanisms, reservoir numerical simulation and production optimization. The phase behavior of fluids confined in shale nanopores are discussed on the basis of theoretical calculations, experiments, and molecular simulations. The fluid transport mechanisms through shale matrix are analyzed in terms of molecular dynamics, pore scale simulations, and experimental studies. The methods employed in fracture propagation simulation and production optimization of shale oil are also introduced. Clarifying the problems of current research and the need for future studies are conducive to promoting the scientific and effective development of shale oil resources.

1. Introduction

Thanks to the rapid development of the stimulation technologies such as multi-stage hydraulic fracturing and refracturing of horizontal wells, the recovery of unconventional oil and gas resources made a major breakthrough in North American and sparked a worldwide energy revolution. Shale oil has become a new bright spot in the development of unconventional reservoirs. Abundant shale oil resources have been discovered in several basins in China, including the Junggar basin, Songliao basin, and Ordos basin. The technically recoverable hydrocarbon resources were approximately $30\sim60\times10^8$ t (Zou et al., 2013). Therefore, developing the shale oil resources effectively is of great importance in promoting the theory and technologies upgrade in the petroleum industry and enduring the national energy security.

In comparison with conventional reservoirs, the rock and fluid properties of shale oil are completely different. Firstly, the storage space of shale oil is mainly composed of the nanopore system whereas micro-scale and millimeter-scale pores only developed locally. Secondly, the chemical composition of shale is complex, which contains abundant organic matters and different proportions of inorganic minerals, such as quartz, calcite, and clay minerals. Thirdly, fluids in the shale reservoir are prone to condensate due to the high proportion of light components in the fluids. Previous studies (Teklu et al., 2014; Sobecki et al., 2019) have confirmed that the physical and chemical properties of fluids confined in shale nanopores, such as interfacial tension, contact angle, critical temperature, and pressure, etc., are tremendously different from those of bulk fluids. This will lead to the fluid transport behavior in the nanoscale pore is significantly different from those predicted using classical theory, such as enhanced flow in carbon nanotube (Majumder et al., 2005; Holt et al., 2006) and strong hydrophobicity of the materials (Lafuma and Quéré, 2003). Therefore, the classical Darcy's law might become infeasible to characterize the fluid flow in shale matrix. Moreover, the fluid transport is significantly affected by the mineralogy due to the distinct interactions between different types of minerals and fluids. For multiphase flow in nanoporous media, the variations in flow patterns (such as bubble flow and annulus flow)

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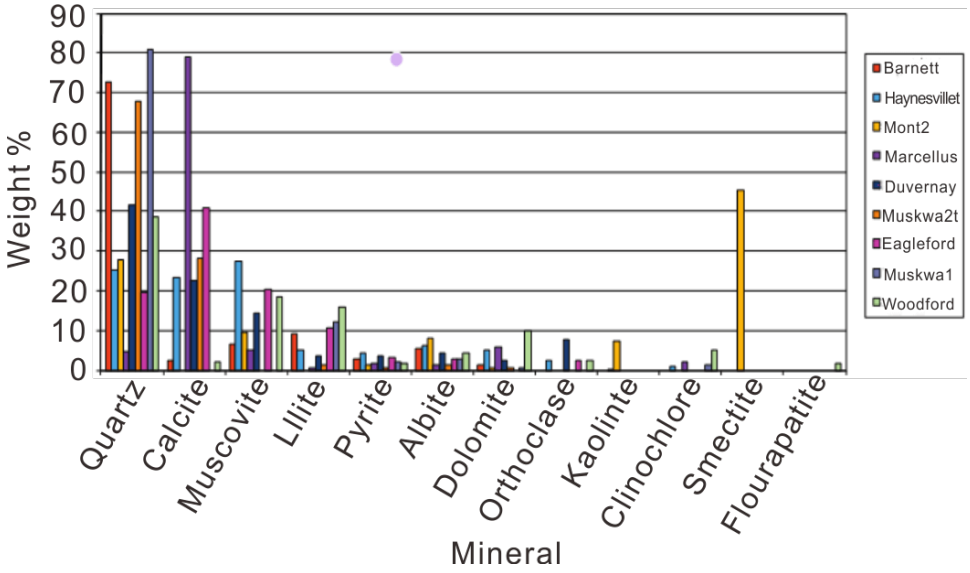


Fig. 1. Comparison of mineralogical composition of the shale samples based on XRD analysis (Clarkson et al., 2013).

and phase behavior are also observed (Ho and Striolo, 2015). The contact angle and interfacial tension also change with pore size (Wang et al., 2016a). Owing to the aforementioned particularities, the phase behavior and multiphase flow principles in shale matrix is extremely complicated. Conventional approaches for predicting phase behavior and hydrocarbon transport in porous media are insufficient in shale reservoir, which bring severe challenges to the numerical simulation and production performance prediction of shale oil.

Besides reservoir fluid properties and flow mechanisms, the rock deformation and failure are also important for the performance prediction of shale oil. Hydraulic fracturing technology will cause rock failure and generate complex fractures. These fractures, providing high-speed flow channels between matrix and wellbore, can significantly affect the pressure and saturation fields. However, the fracture morphology is usually very complex and difficult to predict. To obtain reliable fracture morphology, it is necessary to combine experiment and numerical simulations. Moreover, a reservoir numerical simulator that takes into account the comprehensive mechanisms, including phase behavior, flow mechanisms, rock deformation, fracture propagation, etc., are required to predict the dynamic performance of shale oil. Corresponding optimization methods are also required to provide a more accurate and effective guidance for the design of shale oil development schemes.

This work provides a comprehensive review on the advances and challenges in the development of shale oil from these aspects: phase behavior, flow mechanisms, numerical simulation, and production optimization. We also analyze the issues of existing studies and put forward the future research directions. It is expected that this work can inspire much more interesting studies and lead to a better exploitation performance of shale oil.

2. Phase behavior of shale oil

The pore structure and mineral composition of shale have a great influence on the hydrocarbon phase behavior and migration. Several techniques, such as scanning electron microscopy (SEM), nitrogen adsorption, and capillary pressure has been utilized to characterize the pore structure of shales. Recent studies suggested the complexity of the pore structure of samples in different layers of Bakken shales is different, and the mineralogical compositions affect the total pore volume (Liu et al., 2017). X-ray diffraction (XRD) was used to analyze the mineralogical compositions (Clarkson et al., 2013). As shown in Fig. 1, shale contains both organic (e.g., kerogen and bitumen) and inorganic components (e.g., calcite and silica).

In comparison with conventional reservoirs, the phase characteristics of shale oil are special. In the nanoconfined space, the critical parameters (critical temperature, critical pressure) of fluids are quite different from those of bulk fluids (Zarragoicoechea et al., 2004; Luo et al., 2016). In micropores, the thermophysical properties of fluids, such as surface tension and contact angle, do not rely on the pore size; however, these physical quantities vary with the pore diameter in the nanopores, which makes the calculation of the capillary force more complex (Tolman et al., 1949; Werder et al., 2003). Also note that the strong interactions between shale organic matter and alkanes will lead to the adsorption of alkanes, which further impacts the phase behavior (Dong et al., 2016). Therefore, the traditional thermodynamic theory doesn't apply to shale reservoirs. In order to clarify the phase behavior of shale oil, several researchers have carried out a lot of studies and achieved a series of valuable achievements.

From a molecular perspective, the Monte Carlo simulation has been utilized to investigate various thermophysical properties of hydrocarbons confined in shale nanopores. On the basis of the configurational-bias grand-canonical transition-matrix Monte Carlo simulations, Singh et al. (2009) studied the phase coexistence, critical properties, and surface tension of liquid and vapor phases of methane, ethane, propane, *n*-butane, and *n*-octane in bulk and slit-shaped pores of graphite

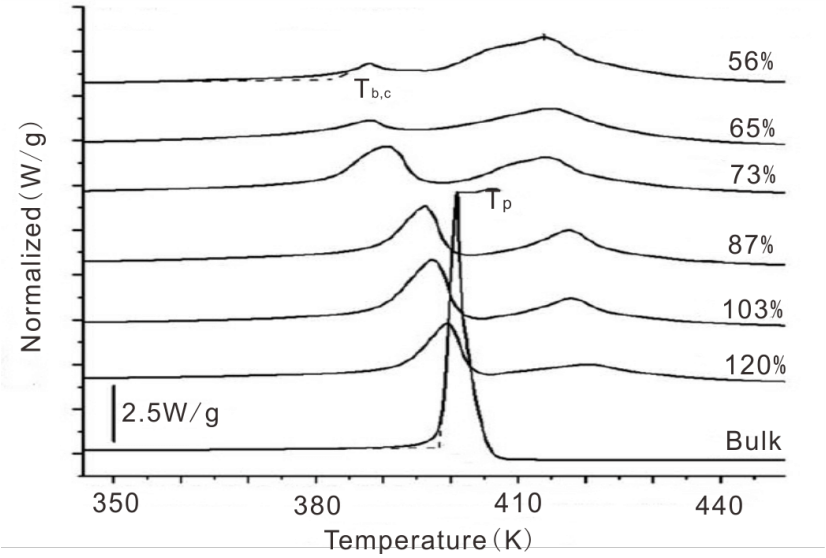


Fig. 2. DSC thermograms for octane infiltrated into 4.3 nm pore diameter CPGs for various loadings (Luo et al., 2016).

and mica pores. They suggested that the variation of the critical temperature is tremendously influenced by the nature of the solid surface. Sobecki et al. (2019) developed a robust NPT bubble point Monte Carlo method in the Gibbs ensemble to estimate the thermodynamic properties of confined mixtures. They reported that, in comparison to the bulk fluid, the critical temperature and pressure under confinement tend to be lower and the bubble point pressure decreases while the dew point pressure increases.

Differential scanning calorimetry (DSC) and thermogravimetric analysis serve as useful tools to measure the fluid properties in confined space. Using these techniques, Luo et al. (2016) measured the bubble point temperature of C_8H_{18} and $C_{10}H_{22}$ in controlled-pore glass (CPG) and reported that when the pore diameter was 38.1 nm, the spatial scale had negligible effect on the bubble point temperature. However, when the diameter is 4.3 nm, two different bubble point temperatures appear and their deviation can be as high as 30 K, indicating that there are two forms of alkanes in the nanopore: free state and adsorbed state (Fig. 2).

Although molecular simulation can accurately predict the thermophysical properties of both pure components and mixtures in the confined space, it always consumes extraordinary computations and it is difficult to capture all the complex properties of the shale matrix, such as the multiscale pore networks and complicated fluid compositions. The key limitation of the abovementioned experimental techniques is that it is primarily suitable for the nanoporous materials having uniform pore size distributions; however, the pore structure of shales are too complex, which ranges from several nanometer to hundreds of micrometer. Thus, most of the current experimental studies can only provide the qualitative analyses on the phase behavior in shale nanopores, but cannot measure the phase change properties of shale oil directly.

Therefore, to readily characterize the phase behavior of shale oil, some theoretical models have been proposed. Using a van der Waals model for a non-wetting fluid, Zarragoicoechea et al. (2004) predicted a shift in the critical temperature of fluid confined in the nanopores, with respect to the bulk value. A good agreement is found for this model (Eq. 1) given that the fluid is only characterized by the Lennard-Jones potential parameters,

$$\frac{T_c - T_{cp}}{T_c} = 0.9409\frac{\sigma}{r_p} - 0.2415\left(\frac{\sigma}{r_p}\right)^2 \quad (1)$$

where T_c is the critical temperature of bulk fluid, T_{cp} is the critical temperature in a nanopore, σ is the size parameter of the Lennard-Jones potential, and r_p is the pore radius.

Nojabaei et al. (2013) accounted for the influence of capillary forces on the basis of the conventional phase equilibrium equation and found that the bubble point pressure of fluids in the nanopores decreased, while the dew point pressure may increase or decrease (Fig. 3). Introducing the phase change of shale oil into reservoir numerical simulation makes the production prediction results better agreement with the actual performance. Teklu et al. (2014) took into account the variations of critical temperature and pressure of the fluid in the nanopores and estimated the minimum miscible pressure between CO_2 and oil using an improved gas-liquid equilibrium equation. The results suggest that as the pore becomes smaller, the bubble point pressure of the fluid, the gas-oil interfacial tension, and the minimum miscibility pressure decrease whereas the upper dew point pressure increases and the lower dew point pressure decreases.

A modified model developed by Dong et al. (2016), which coupled the cubic Peng-Robinson (PR) equation of state (EOS) with capillary pressure equation and adsorption theory, was used to study the phase equilibrium of pure alkanes and their mixtures in shale nanopores. Their results show that the presence of adsorption film increases the vapor-liquid equilibrium constant (K-value) of confined mixtures and capillary pressure of pure-component fluid, and the smaller the pore size, the greater the effect. Recently, Song et al.

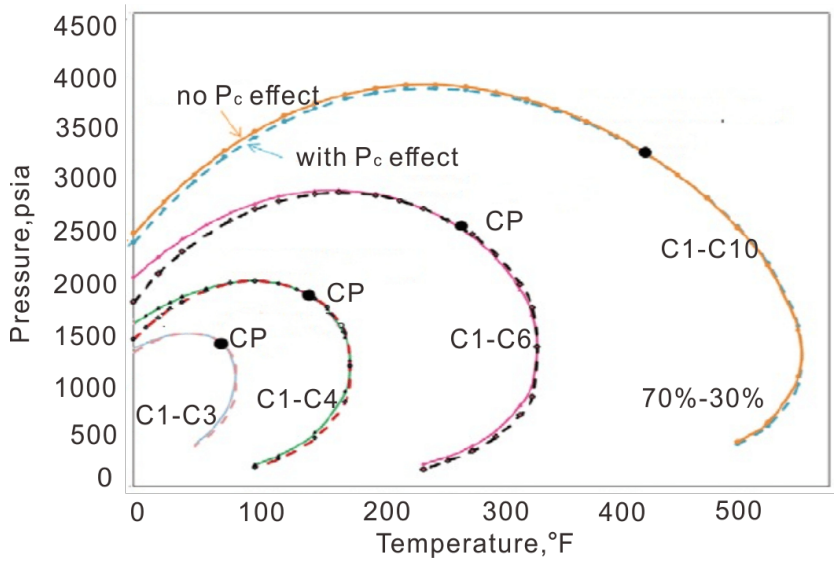


Fig. 3. Phase envelopes with and without capillary pressure for binary mixtures in a 10-nm nanopore (Nojabaei et al., 2013).

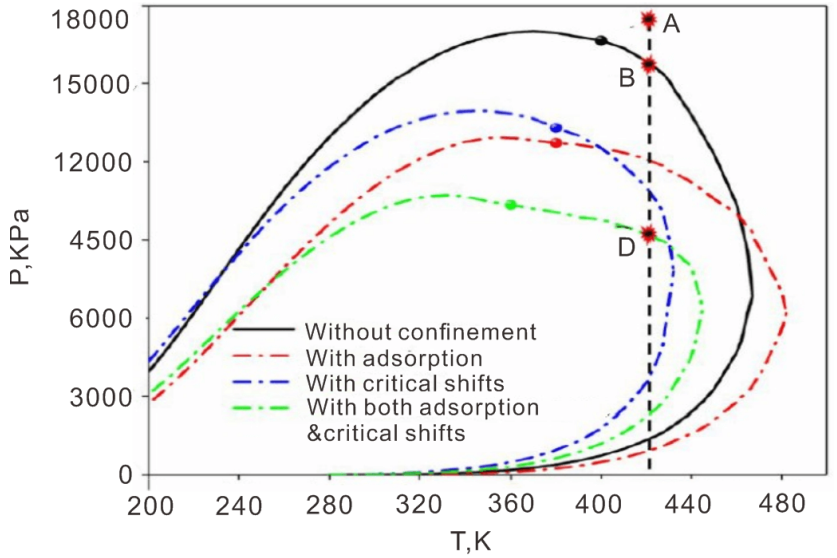


Fig. 4. Phase envelopes of the ternary mixture considering different effects in a 10-nm pore (Song et al., 2020).

(2019) presented an adsorption-dependent PR EOS to calculate the phase equilibrium of a ternary mixture (CH_4, nC_4, and nC_8) and actual Bakken shale oil (Fig. 4). The shift in the saturation pressures shows that, under the combined influence of adsorption and critical parameter changes, the bubble point pressure and the upper dew point pressure decrease, while the lower dew point pressure increases (Fig. 4). Although several theoretical models have been developed for shale oil, it is still difficult to justify these results using experiments.

3. Multiphase flow mechanisms in shale

Current researches on the fluid transport mechanisms in shale nanoporous matrix can be primarily classified into three aspects: molecular dynamics (MD), pore scale simulation, and microfluidics experiments.

Molecular dynamics simulations have been utilized to study the fluid transport behavior in a single shale nanopore. The effects of wettability, pore size and pressure gradient on fluid transport have been analyzed, from which the mathematical model can be established to characterize the flow behavior under nanoconfinement. Using MD, Thomas and McGaughey (2008) reported that the actual flow rates of pressure-driven water flow through carbon nanotube (CNT) with diameter varying from 1.66 to 4.99 nm were 47-433 times higher than that predicted by no-slip Poiseuille relation, and the fluid flow enhancement factor decreases with the increase of the CNT aperture, which effectively supported the previous experiments (Majumder et al., 2005; Holt et al., 2006). Falk et al. (2012) analyzed the flow behavior of different fluids in CNT and stated that the perfect structure of carbon nanotube leading to ultra-small friction between solids and fluids, thereby enhancing the fluid flow rate. Moreover, they suggested that the fluid transport behavior in a single

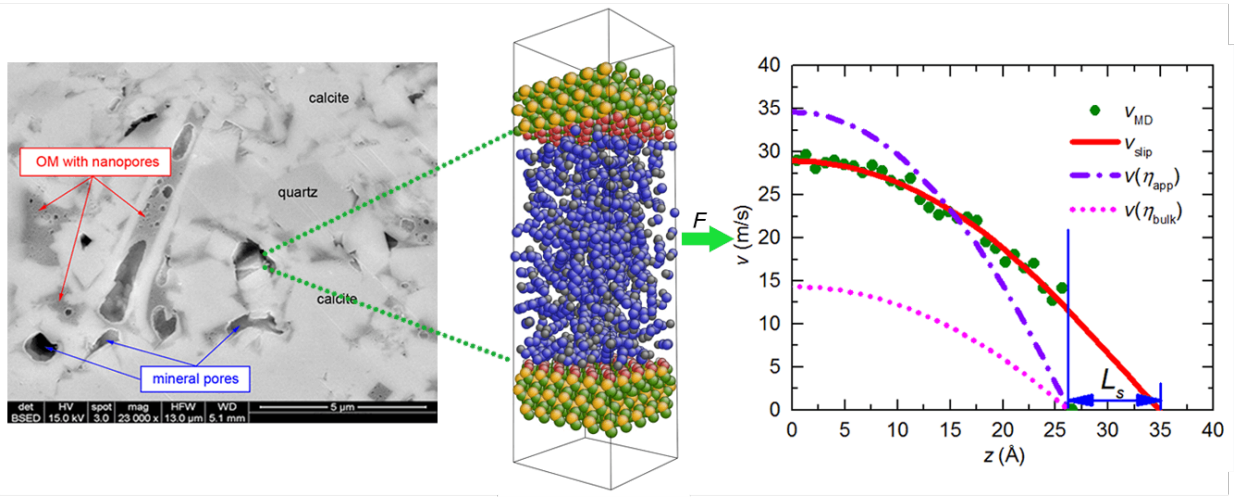
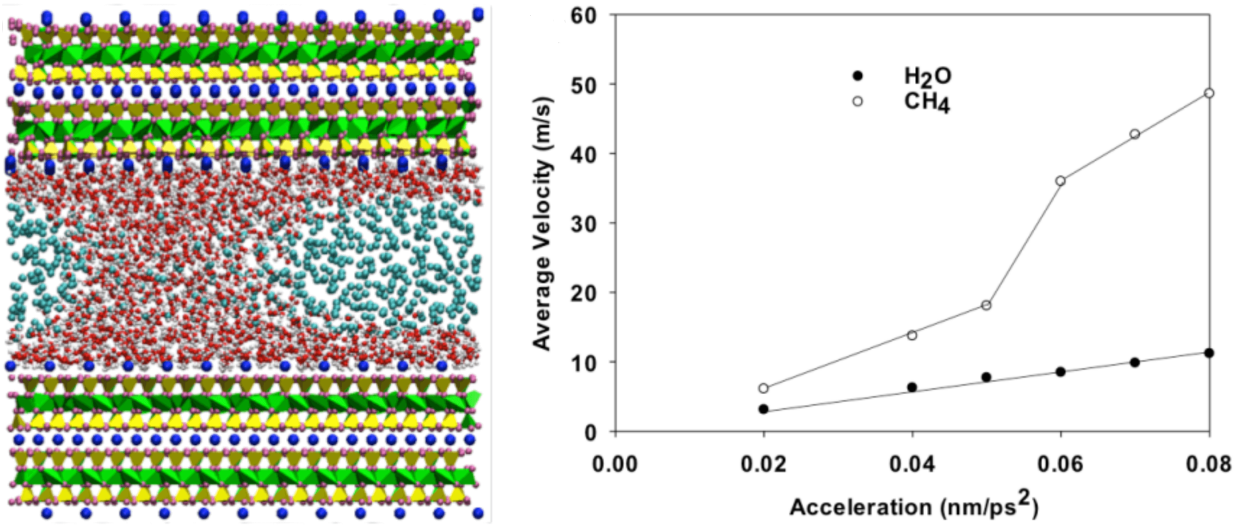


Fig. 5. Molecular model and velocity profiles of octane transports through quartz nanopores (Wang et al., 2016b).



(a) (b)

Fig. 6. (a) Snapshot of the molecular dynamic simulation configuration of gas-water in muscovite nanopore, and (b) water and methane flow rate as the function of the applied acceleration (Ho and Striolo, 2015).

nanopore can be described by the slip-corrected Poiseuille equation. They further studied the transport behavior of alkanes in kerogen pores and revealed the breakdown of Darcy's law in shale matrix due to the strong adsorption of alkane upon kerogen (Falk et al., 2015). Based on the MD simulations of alkanes flow in shale organic and inorganic nanopores, Wang et al. (2016b) reported that the mineral types have significant effects on the flow behavior of alkanes; they also derived a mathematical model to describe the transport properties of single-phase fluid in shale nanopores (Fig. 5). Water-methane two-phase flow in nanoscale clay and quartz slits suggested the variation of flow pattern when the pressure gradient exceeds the critical value and the correlation between pressure gradient and flow rate was nonlinear (Fig. 6) (Ho and Striolo, 2015). Also note that the existence of water film on the quartz surface shows different effects on the processes of displacement and imbibition (de Almeida and Miranda, 2016). Zhang et al. (2019) presented that water impeded the adsorption and diffusion of oil in different types of shale nanopores and this effect were more evident in organic nanopores. Li et al. (2019) studied oil and water two-phase flow in shale organic matters and found that the fluid flow is affected by the mixture composition. They updated the Navier-Stokes equation with slip boundary condition to describe the mixture flow in organic nanochannels.

However, molecular dynamics simulation is mainly utilized to study the mass transfer through limited number of pores with diameters smaller than 50 nm. Therefore, upscaling techniques are still required to investigate fluid flow within shale matrix. Golparvar et al. (2018) proposed a integrated review of pore scale modeling technologies for multiphase flow in porous media. Two types of pore scale simulation techniques are commonly utilized: the direct simulation method (DSM) and the pore network modeling (PNM). On the basis of digital

rocks, DSM directly computes the fluid properties using the hydrodynamics method (such as finite volume method, Volume of Fluid, and Lattice Boltzmann method). However, PNM extracts the pore space of the rock as network model and then compute the physical properties using the percolation theory (Wang et al., 2020). The direct simulation involves dividing the model into a large number of lattices or grids, which demands significant computational resources. Moreover, the theoretical basis of the direct simulation is the Navier-Stokes equation, which is difficult to be employed to simulate fluid flow through nanoporous media because the introduction of complex phenomena and boundary conditions (such as slip/sticky boundaries and alkane adsorption) is not a trivial. In comparison to direct simulation, the computational efficiency of PNM is very high because the simplified network model is always employed instead of the realistic complex pore structure model. In addition, the complicated mechanisms are readily to be taken into consideration in PNM; thus, this method has been widely employed to study pore scale flow principles through shale matrix. However, the reliability and accuracy of PNM for shale nanoporous matrix still need to be justified.

Mehamani et al. (2013) constructed shale pore network model by uniformly reducing the radius of pores and throats of a conventional sandstone network to 10%. They studied shale gas flow behavior with consideration of the transport mechanisms, such as Knudsen diffusion and slippage. They subsequently put forward a pore network construction method that incorporates both interparticle porosity and microporosity, and estimated the capillary pressure-saturation and relative permeability curves using the traditional quasi-state flow model (Mehmani and Prodanović, 2014). The adsorption and spatial variation of surface wettability were took into account by Huang et al. (2016) to propose a gas-water two-phase flow simulation method in shale pore network. Recently, Yang et al. (2019) reconstructed the pore network model of shale through SEM images using the Markov chain Monte Carlo method, and reported that shale oil permeability is strongly influenced by the slip length, which depends on the adsorption phenomena and total organic content. They also constructed a multi-scale pore network model incorporating the distribution, connectivity, and pore size of both organic and inorganic materials and illustrated that the distribution pattern and local volume of organic matters in shale is the dominant factor of mass transfer in nanoporous media (Yao et al., 2019).

Owing to the technical challenges on the preparation and measurement of fluid flow through shale nanopores, only few experimental studies have been reported in this area. Wang et al. (2009) found that the behavior of water flow through a 2-μm molten silicon tube deviated from classic Poiseuille equation and this deviation is strongly influenced by surface wettability. The microfluidic experiments were also adopted to study the pressure-driven single-phase water flow and gas-water two-phase flow in nano-scale channels (depth: 100 nm) (Wu et al., 2013). The linear relationship between flow rate and pressure gradient was obtained, which confirms the feasibility of the Poiseuille flow equation. Two different patterns, annulus flow and laminar flow, were also observed. Recently, nano/microfluidic experiments have made great progress in investigating the effects of the pore topology and the surface roughness on immiscible flow (Alfi et al., 2019; Mehmani et al., 2019) and the mechanisms of enhanced oil flow in shale reservoirs (Nguyen et al., 2018; Zhang et al., 2019). Using the Atomic Force Microscope, Javadpour et al. (2015) measured the slip length of water on the surface of shale organic matter.

Regarding the nonlinear flow mechanism, it is commonly recognized the slip effect of single-phase liquid or gas in confined nano-scaled pores, which afterwards results in a nonlinear flow behavior in shale and tight reservoirs. Based on the slip boundary condition observed in molecular simulation and experiments, several improved mathematical models were derived to describe the single-phase flow in shale and numerous investigations have carried out to discuss the influencing factors of the slip lengths and its effect on fluid transport (Xu et al., 2007, 2015; Zhang et al., 2017a, 2017b; Liu et al., 2018). Since the interaction between liquid and solid dominated the flow behavior, the mathematical model with introducing the concept of effective slip, which is the function of contact angle and apparent slip, is adopted in nanoconfined flow (Wu et al., 2017, 2019). Although many attempts have been carried out to investigate the nonlinear flow mechanisms in microscopic scale, it is still far from being understood.

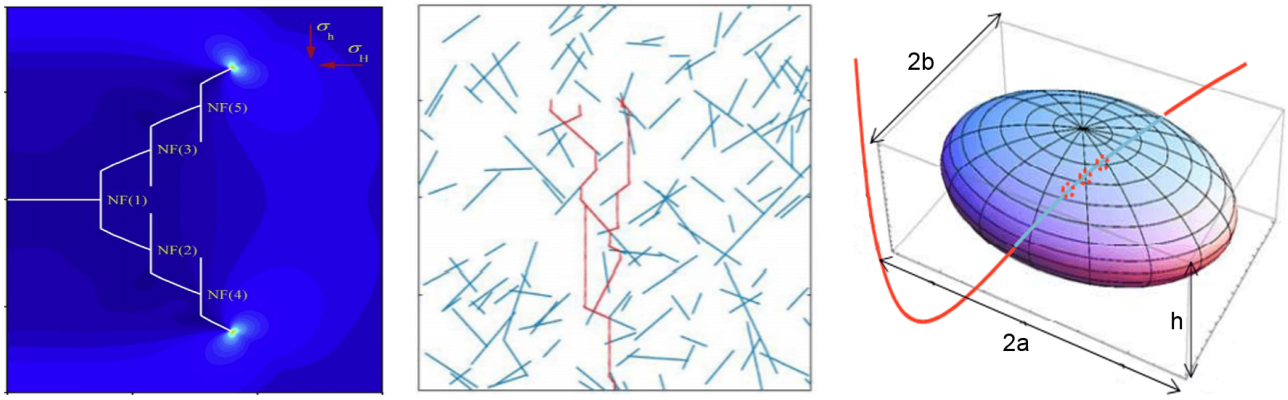
Form a macroscopic perspective, previous studies reported the fluid nonlinear flow behaviors in tight porous media with considering of the complex boundary slippage effect and pseudo-threshold pressure gradient. Most of those nonlinear prediction models were capillary bundle based except the three-parameter model derived by Deng and Liu (2001) and Huang et al. (2013), which were nonlinear flow curve based models. Recent advanced prediction model introduced the yield stress to represent the effects of the boundary layer (Xu et al., 2012; Xiong et al., 2017). However, the complex micro-scaled pore structures of tight reservoir were not considered.

4. Reservoir numerical simulation method of shale oil

Several methods have been proposed to simulate the propagation of hydraulic fractures numerically:

(1) Extended finite element method (XFEM). This approach was improved from the traditional finite element method and the hydraulic fractures can arbitrarily extend in the regular grid without re-meshing. Lecampion (2009) pioneered applying XFEM to simulate hydraulic fracture propagation; however, this study failed to take the fluid flow effect into account. Taleghani (2009) used this method to study the effect of natural fractures on the morphology of fracture propagation. Gordeliy and Peirce (2013) proposed an implicit level set method to describe the behavior of the fracture tip. Zhuang et al. (2016) developed two-dimensional and three-dimensional (3D) fracture simulation methods for solids. They also investigated the interactions between hydraulic fractures and natural fractures by developing a new level set model.

(2) Discontinuous displacement method (DDM). Olson (2008) first adopted DDM to examine the effect of natural fractures and simulate the propagation of complex fractures.



(a) (b) (c)

Fig. 7. Fracture propagation model: (a) XFEM with 5 natural fractures (Wang et al., 2018), (b) DDM with numerous natural fractures (Liu and Reynolds, 2019), and (c) wire-mesh model with SRV (Xu et al., 2010).

Wu and Olson (2015, 2016) further improved this model to deal with the effect of fracturing fluid and simulate the simultaneous propagation of multiple fractures. This work pointed out that the stress shadow effect can be weaken by optimizing the perforation diameter and fracture spacing. By coupling fluid flow and geomechanics, Mcclure (2012) simulated the propagation of complex fracture networks with considering different failure modes of natural fractures, including both tensile and shear failures.

(3) Discrete fracture network. This method has a higher computational efficiency, but it is difficult to address the influence of natural fractures and rock anisotropy on the fracture network morphology. On the basis of this idea, Xu et al. (2010) simplified the stimulated reservoir volume (SRV) into an ellipsoid and proposed a wire-mesh model, in which the main fractures are orthogonal to each other. Meyer and Bazan (2011) developed MShale software considering fluid loss and stress interference between fractures.

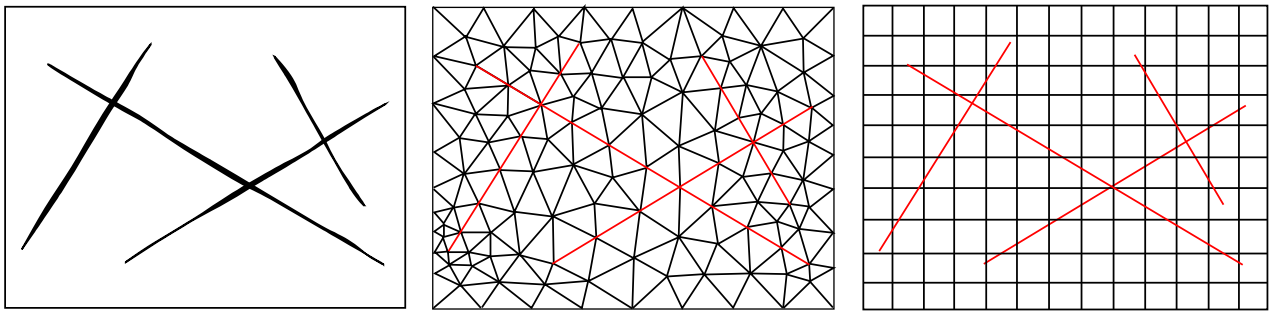
These three methods have different treatment capabilities for natural fractures. As shown in Fig. 7, the number of natural fractures treated by XFEM is relatively limited, because XFEM needs to add enrichment nodes around natural fractures. Although its calculation accuracy is relatively high, natural fractures will significantly increase computing costs. While DDM can handle many natural fractures, DDM only needs to solve unknown variables on the fracture surface. In comparison with XFEM and DDM, the wire-mesh model is very simple to deal with natural fractures. But the wire-mesh model just provide simplified SRV model instead of discrete fracture network.

Because the phase behavior of oil and gas in the shale matrix is very complex, the reservoir numerical simulation of shale oil should use a compositional model. Furthermore, during the production, with the reservoir pressure decreases, the pore space will gradually decrease under the geomechanical effect, which not only causes a decrease in permeability and porosity, but also further affect the estimation of capillary pressure (Li et al., 2019) and phase behavior. Yan et al. (2017) accounted for this process to improve the capability of compositional simulator. They found that it can show better performance on history matching of the gas-oil ratio. However, this numerical simulator is relatively elementary: it is very simplified in the treatment of pseudo-components, and can only deal with the bi-wing fractures with the same parameters. It is worth noting that the fracture network generated by hydraulic fracturing in shale has a great impact on production performance (Meng et al., 2020). Ren et al. (2016, 2018) proposed a mixed discretization approach to fully couple geomechanics and multiphase flow, which can tackle with complex fractures and predict the performance, but the flow part is not a compositional model. Therefore, it is necessary to develop a shale oil reservoir numerical simulation method integrating both the compositional model and complex fracture networks.

For the current production prediction model, complex fracture network is primarily simulated using discrete fracture model (DFM) and embedded discrete fracture model (EDFM). The grids of these methods are shown in Fig. 8. DFM can describe the fracture morphology more accurately. Because the grid shape is adjusted to fit the fracture morphology (Karimi-Fard et al., 2004). However, the fracture grid in EDFM will not be influenced by the matrix grid. Therefore, the computing cost of DFM is generally higher than EDFM (Wang et al., 2017). Several studies have been carried out to combine EDFM with numerical simulators. Moinfar et al. (2014) introduced EDFM into a fully implicit component reservoir simulator and considered the effect of stress on hydraulic fracture parameters. Shakiba (2014) coupled EDFM with the compositional simulator UTCOMP and chemical simulator UTGEL, embodying the feasibility of EDFM to simulate complex underground flow problems.

5. Production optimization methods of shale oil

To improve the production and economic benefits of shale oil, many studies have been carried out to optimize the hydraulic fracturing parameters. The methods can be primarily divided into two categories. The first is from the perspective of simulating fracture propagation. In general, these methods



(a) (b) (c)

Fig. 8. Grid comparison: (a) physical domain, (b) grid domain for DFM, and (c) grid domain for EDFM. The black, thick segments in panel (a) represent actual fractures and are shown in red solid lines in the grid domains (b, c) (Xu et al., 2018).

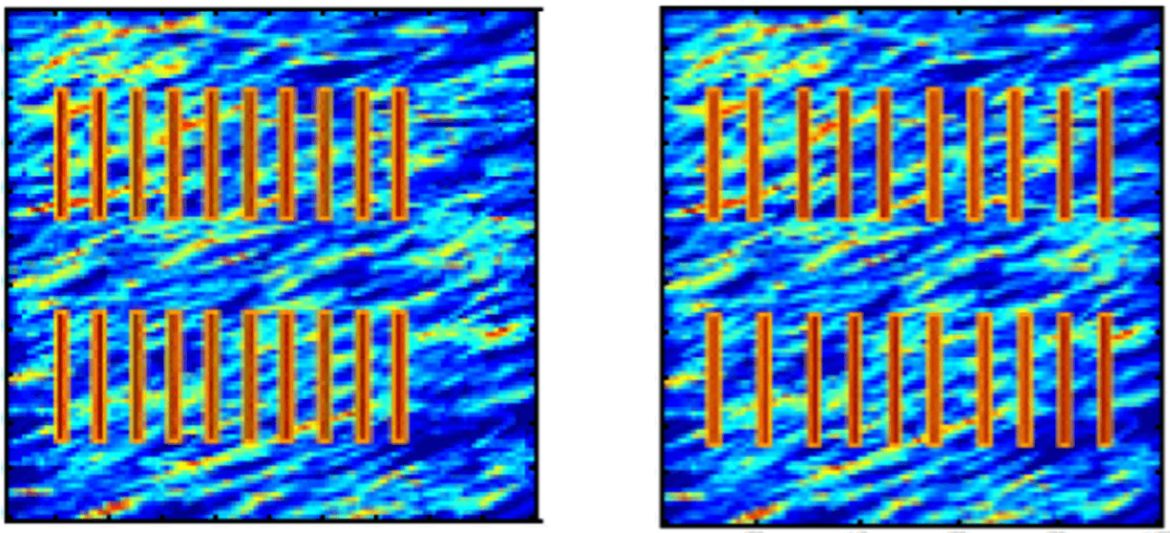
pursue maximum contact area between fractures and matrix, or uniform fracture length (Wu and Olson, 2016b; Wu et al., 2017). Liu et al. (2015) calculated the extent of stress reorientation of the multi-stage fractured horizontal well, and then obtained the fracture network area caused by the reorientation of in-situ stress. In this way, they optimized fracture spacing to maximize fracture network area. Using a simplified 3D DDM, Wu and Olson (2016a) reported that adjusting perforation friction is an effective way to minimize the negative effects of stress shadowing to get uniform fracture length. In order to maximize the total fracture area, Li and Zhang (2017) proposed a mixed finite-element and finite-volume method to study the optimal completion techniques. This kind of method can obtain relatively reliable hydraulic fracture geometry. However, the optimal results don't necessarily obtain the maximum oil production or economic benefits.

The second category is from the view of production simulation. Through comparing the production performance under different fracture parameters, Cipolla et al. (2009) pointed out that when the fracture conductivity is high enough (50∼200 mD·ft), a higher profit can be obtained by increasing the fracture spacing. Sahai et al. (2013) studied the effect of different fracture spacing on the oil production. Holt (2011) took the lead in coupling the intelligent algorithm with reservoir simulator to optimize the well position and the fracture number. To improve the efficiency, Wilson and Durlofsky (2013) constructed a proxy model during optimization. Ma et al. (2013, 2015) proposed a hierarchical optimization method that couples the optimization of well position and non-uniform fracture spacing into one process, and applied it to homogeneous and heterogeneous reservoirs. Subsequently, they further evaluated the performance of discrete simultaneous perturbation stochastic approximation algorithm and genetic algorithm on the optimization of fracture locations. Plaksina and Gildin (2015) introduced multi-objective optimization to this problem, trying to reduce development risks while maximizing economic benefits. From the perspective of reservoir fracability, Jahandideh and Jafarpour (2016) considered the reservoir heterogeneity and optimized the parameters, including fracture number, length and spacing. Most recently, Feng et al. (2019) considered tight oil characteristics to optimize well and fracture parameters. They suggested that if the nonlinear flow and stress sensitivity of shale oil were not taken into account, the optimal results still show worse development efficiency. Regarding this kind of method, the maximum oil production or economic benefits can be guaranteed. However, the hydraulic fracture geometry is generally assumed to be bi-wing planar which is not controllable in the field operation.

6. Current limitations and future directions

(1) These studies have greatly improved our understanding of the fluid phase behavior in the shale matrix; however, there are still some open issues. The main controlling factors for the change of critical parameters of alkanes in confined spaces are still ambiguous, and there is also a lack of mathematical models for shale (Wu et al., 2016). Because the variation of critical parameters is influenced by the liquid-solid interaction, the fluid critical parameters in the pores having different chemical compositions are expected to be distinct. It is unclear whether the mathematical models established for other materials are suitable for shale. Although current literature has included the influence of capillary force when calculating the phase behavior of shale oil, the accuracy of capillary force estimation and the reliability of phase state prediction have yet to be fully examined, because it is difficult to measure these thermophysical properties in shale nanopores experimentally. Furthermore, the adsorption characteristics of alkanes in shale, especially the adsorption of heavy components and alkane mixtures are not well understood yet, causing the unreliable estimation of adsorption layer thickness. Therefore, in the future, it is necessary to use experimental and simulation methods to study the influence of shale mineral composition on critical properties, interfacial tension, and wetting angle, and construct corresponding theoretical models. Meanwhile, the competitive adsorption should also be taken into account to make a reliable estimation of shale oil phase behavior.

(2) A lot of problems still exist in understanding the fluid flow mechanisms through shale multiscale pore networks: ① most of the previous research focuses on the transport mechanisms of single-phase flow, and only few studies explored the multiphase flow behavior. The mathematical model for characterizing the transport properties is still urgently required; ② Although it is commonly known that solid-liquid interactions are significant for fluid flow and the multiphase



(a) (b)

Fig. 9. Well position and fracture spacing optimization: (a) Initial case, and (b) Optimized case (Ma et al., 2015).

flow behavior in nanopores composed of various minerals are distinct, seldom studies were conducted; ③ The experimental data on nanoscale flow is relatively scarce and there are also huge contradictions among experimental data from different researchers; ④ because the flow mechanisms in a single nanopore are still obscure, pore-scale simulations cannot fully account for the special mechanisms of multiphase flow in nanopores and the variations of thermophysical properties at the interfacial region.

(3) The greatest issue of the shale oil reservoir numerical simulation technique lays in the separation of hydraulic fracturing simulation from the production process. Recent approaches for fracturing simulation can calculate geomechanics, such as rock deformation and hydraulic fractures propagation; however, the treatment of the fluid is relatively simple; only the single-phase flow within and nearby the fractures are taken into account. Therefore, the production performance of shale oil wells, which involves complex transport behavior of multiphase fluid and phase change, cannot be estimated from the fracturing simulation. When predicting the production performance of shale oil wells, the geometry of hydraulic fractures are always given artificially, which cannot accurately characterize the real morphology and parameters of fractures under the subsurface conditions, nor does it consider the dynamic fracture conductivity over time and space. In view of the complicated heterogeneous geological and in-situ stress conditions, this treatment could lead to tremendously erroneous results. Moreover, there are a lot of bedding planes in shale reservoirs. Discontinuous interfaces will inevitably have a large impact on fracture propagation. However, this factor has not been fully considered in existing studies. Although most recent research begins to focus on the coupling simulation of geomechanics and hydrocarbon production (McClure and Kang, 2017; Reagan et al., 2019), the treatment of fracture propagation is still too simple, especially for the branching simulation. Another significant challenge is the accurate and fast simulation of fracture propagation with accounting for the influences of bedding planes, natural fractures, and reservoir heterogeneity. From the view of production simulation, the third challenge is to build a compositional model accounting for the characteristics of shale oil, including phase behavior, nonlinear flow and stress sensitivity of shale matrix and fracture. Because in the confined space of micro and nano pores in shale reservoirs, the phase behavior and seepage law are significantly different from conventional reservoirs. After considering these physics, effective nonlinear equation solving algorithms will be required.

(4) Owing to the independent simulation of fracturing and production processes, current optimization studies cannot meet the requirement of shale oil exploitation. From the perspective of production, the optimized fracture geometry is always assumed to be bi-wing planar and perpendicular to the horizontal wellbore (Fig. 9). However, the optimal fracture geometry is difficult to be achieved in an actual fracturing operation because the morphology of hydraulic fracture network is much more complicated due to the influence of lithology, natural fractures, and bedding planes. From the perspective of hydraulic fracturing, the optimization of fracturing parameters is often aimed at maximizing the contact area between the fracture networks and the formation or the uniform propagation of multiple hydraulic fractures (Rongved et al., 2019; Xu et al., 2019). However, several field cases have justified that this cannot guarantee the maximum economic benefits. Therefore, to the best of our knowledge, there is little research on the optimization of controllable fracturing parameters to maximize oil production or economic benefit (Morozov et al., 2020). Furthermore, due to the special phase behavior and flow mechanisms of shale oil, the optimization result may be different from that without considering shale oil characteristics (Feng et al., 2019). For future studies, we suggest carrying out the production optimization of shale oil (including the fracturing parameters, well pattern, schedule,

etc.) by coupling intelligent algorithms and the comprehensive shale oil simulator. Moreover, accounting for the high computational budget of shale oil simulator, robust and efficient algorithms, such as gradient algorithms or machine learning techniques, are preferred to be used to make the optimization (Fonseca et al., 2017; Wang et al., 2018; Liu and Reynolds, 2020).

7. Conclusions

This study reviews the advances and challenges in the development of shale oil, and enhanced the understanding of phase behavior, flow mechanisms, numerical simulation, and production optimization techniques in shale oil.

Current studies show that the critical parameters of single-component fluid in shale nanopores are shifted when compared to bulk phase. The bubble point pressure of the multicomponent fluid in the nanopores is also lower. Theoretical studies have proposed models that considering critical parameters shift, capillary pressure, and adsorption theory, but further considerations of the fluid-solid interactions as well as the model validation using experimental data are still required. Molecular simulation and nano/microfluidic experiments are feasible to investigate the static and dynamic behaviors of fluid in nanoscale porous media. However, the upscaling method from molecular scale to pore scale, such as lattice Boltzmann and pore network modeling, still need to be improved to take into account the variations of thermophysical properties and complex multiphase transport mechanisms.

On the basis of accurately elucidating the phase transition laws and transport mechanism, we recommend the development of an integrated numerical simulator coupling rock deformation, fracture propagation, and production performance prediction. And then establish an optimization technology for the design of shale oil hydraulic fracturing and production schedule. In this way, these future works will provide a theoretical basis for the scientific and effective development of shale oil resources. These works will not only help to improve the fundamental theory for unconventional oil and gas development, but also provides strong support for the breakthrough of technical bottlenecks in shale oil production.

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Conflict of interest

The authors declare no competing interest.

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