Review Article

Frontier Enhanced Oil Recovery (EOR) Research on the Application of Imbibition Techniques in High-Pressure Forced Soaking of Hydraulically Fractured Shale Oil Reservoirs

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Shale reservoirs are characterized by low porosity and low permeability, and volume fracturing of horizontal wells is a key technology for the benefits development of shale oil resources. The results from laboratory and field tests show that the backflow rate of fracturing fluid is less than 50%, and the storage amount of fracturing fluid after large-scale hydraulic fracturing is positively correlated with the output of single well. The recovery of crude oil is greatly improved by means of shut-in and imbibition, therefore attracting increasing attention from researchers. In this review, we summarize the recent advances in the migration mechanisms and stimulation mechanisms of horizontal well high pressure forced soaking technology in the reservoirs. However, due to the diversity of shale mineral composition and the complexity of crude oil composition, the stimulation mechanism and effect of this technology are not clear in shale reservoir. Therefore, the mechanism of enhanced oil recovery by imbibition and the movable lower limit of imbibition cannot be characterized quantitatively. It is necessary to solve fragmentation research in the full-period fluid transport mechanisms in the follow-up research.

1. Introduction

Continental sediments are dominant in China's shale oil, showing remarkable heterogeneity, great lateral variation, relatively low porosity, low-pressure coefficient, and heavy oil quality to a certain extent [1]. Large-scale volume fracturing is needed in shale reservoirs to improve the percolation capacity of the near-well reservoir, thus increasing the productivity of single well. However, the depletion development mode is faced problems of low primary recovery ratio and rapid decline in production [2–5]. The development theory and technology based on normal pressure and low-pressure shale oil is still in the stage of exploration and progress. In recent years, many scholars put forward the fracturing technology of injecting energy increasing fluid (water, CO₂) to supplement the formation energy and adding oil displacement agent into the fracturing fluid to achieve enhanced oil

recovery [6, 7]. This technology has made some achievements in the development of tight oil, but the mechanisms of EOR by imbibition and displacement with multiscale porous are unclear and even controversial.

According to the traditional theory, the retention of a large amount of liquid in the formation will cause the clay to expand and destroy. But the field test shows that there is a positive correlation between the surface fluid volume after fracturing and the single well production [8], and spontaneous imbibition (SI) and forced imbibition (FI) may occur in the reservoir. Spontaneous imbibition is defined as “the process by which a wetting fluid is drawn into a porous medium by capillary action” [4]. Some experts believe that the fracturing fluid is imbibition into the complex fracture network area, and the mechanisms of oil recovery after hydraulic fracturing are imbibition [9]. The evaluation of fracturing fluid effect and the theoretical model of imbibition have gradually

become a research focus [10–19]. Meng et al. [5] explained that the rock fracture pressure is high during hydraulic fracturing, the fracture stress after fracturing is obviously higher than the matrix pressure. As shown in Figure 1, the conductivity of fractures and microfractures is usually produced by forced infiltration with fracturing liquid [19]. The fracture fluid can obtain a higher pressure, restore its conductivity, communicate with the far end of the reconstruction area, and increase a large drainage radius.

There are great differences between shale reservoir development methods, flowing space, and imbibition conditions from conventional reservoirs and fractured reservoirs. Displacement is not spontaneous imbibition, which leads to the complicated mechanism of fracturing fluid during forced imbibition after fracturing. Many scholars have studied the microscopic mechanism of fluid movement and the macroscopic theoretical system of EOR from three aspects, including theoretical analysis, physical experiment, and numerical simulation. However, there is still a lack of systematic theoretical explanation for the influence of the microscale effect and the essence of wettability improvement in the wetting process. In the multiscale space after fracturing, the strong interaction of complex fluid and rock interface has a great influence on the flow of shale oil.

2. Micromechanisms of Shale Reservoir

2.1. Experimental Progress in Laboratory Methods for Shale Reservoir Characteristics. Shale oil exists in the form of adsorbed and a free state, and oil is light in quality and low in viscosity. They are mainly stored in nanoscale pore throats and fracture systems and distributed along with parallel layered layers or microfractures [20]. Shale oil reservoirs have different storage modes and pore structures from conventional oil and gas reservoirs [21–23]. Theoretically, it is easier to flow and exploit shale nanoscale pore throats under high temperatures and high pressure underground [24].

- (1) According to scanning electron microscopy (SEM) and oil layer physics experiments, shale is mainly composed of three different types of porous media: nanosized organic pores distributed in kerogen and inorganic micro-sized particles in inorganic minerals, interpores, and abundant natural microcracks
- (2) Shale oil is generally stored in shale in the form of an adsorption and free state, a free state is stored in pores and fractures, and adsorbed state is stored in organic matter pores. The interaction between oil and solid molecules cannot be ignored in micrometer scale pores
- (3) The shale bedrock is very dense with a small pore size. The pores in the bedrock are mainly nanoscale, and the permeability is extremely low

Javadpour [25, 26] used the pressure decay method to measure 90% of the shale with a permeability of less than $150 \times 10^{-6} \mu\text{m}^2$ (Figure 2). The pore structure of shale was observed by atomic force microscope, and later research

FIGURE 1: Schematic diagram of high-pressure imbibition [19].

found that the pore diameter of shale oil is 30–400 nm. Loucks et al. [27, 28] used scanning electron microscopy to find that the pores of shale gas reservoirs are mainly micropores and nanopores. The nanopores are mainly distributed in organic pores, with a small amount dispersed in an inorganic matrix composed of pyrite. As shown in Figure 3, the number of intragranular pores is the largest, while the number of intergranular pores is relatively small. The diameters of nanoscale pores are between 5 nm and 800 nm, and most of them are around 100 nm.

2.2. Single Phase Migration Mechanism in Shale

2.2.1. Microscopic Pore Wall Slip Mechanisms. The mechanism of fluid migration in nanoscale pores has attracted widespread attention. At present studied, nanopores include carbon nanotubes (CNTs), boron nitride nanotubes (BNNTs), hydrophilic organic matter nanopores, and hydrophobic inorganic nanopores in shale reservoirs [29]. In the experimental study, molecular dynamics simulation (MDS) and theoretical analysis show that the actual volume flow in nanopores can be increased by 1–5 times of magnitude compared with the volume flow predicted by the nonslip Hagen-Poiseuille equation [30]. The enhanced flowability of fluid is caused by boundary slip, and it is affected by a variety of physical means, including solid-liquid molecular interaction force [31], wall roughness [32], shear rate [33], nanobubbles [34], fluid polarity [35], fluid viscosity [36], pore size [37], and pressure gradient [38].

In general, there are two methods to calculate the boundary slip length: (1) to calculate the slip length through the velocity profile obtained by MDS and (2) to measure the volume flow through microscopic experiments and, then, calculate the slip length. However, it is impossible to quantify every physical mechanism and its influence [39]. Therefore, it is necessary to analyze the effects of these physical mechanisms on fluid migration behavior in nanopores.

Most of the current researches express the fluid's ability to flow in nanopores through enhancement factors. The flow enhancement factor is defined as the ratio of the liquid's actual volume flow in the nanopore to the calculated flow of the nonslip HP [40]. Mason et al. [41] used MDS research to show that in CNTs with diameters of 1.66–4.99 nm, the slip length of water is between 105^{-30} nm and the enhancement coefficient is 433^{-47} . Whitby et al. [42] studied the slip length of water flowing in pores with diameters of 1 nm and 7 nm to

FIGURE 2: AFM images and 2D schematic of pore and throat structure of gas-bearing shale [25].

FIGURE 3: Nanopore in organic matter under a scanning electron microscope [27].

be 500 nm and 120 nm, respectively. In general, MDS results were smaller than the experimental measurement results of Majumder, and the pore wall is smooth. However, some

other factors cannot be considered in MDS, such as roughness and confined gas in the wall roughness unit. During the experiment, there are some characteristics objectively,

such as wall roughness and enclosed gas. These properties will enhance the ability of fluid to flow in nanopores. Therefore, the slip length measured by the experiment is about 14.6 times of the slip calculated by MDS. When the nanopores resize 22 nm, the slip length is about 113–177 nm in experimental studies. Blake et al. [43] extended Thomas's theoretical research idea, and the relationship between slip length and contact angle was established. Subsequently, Huang et al. [31] proposed a slip length theoretical formula $L_s = C / (1 + \cos\theta)^2$ to express the relationship between slip length and contact angle. When the constant C is equal to 6 and 0.41, it is experimental. This result is obtained by fitting the MDS result. Mattia et al. [44] proposed a theoretical model of water flow enhancement in CNTs based on surface diffusion and adhesion work. The slip length and flow enhancement factor calculated by the model are in good agreement with the experimental results and MDS. These studies based on experimental studies, MDS, and theoretical methods show that under other conditions, there are different slip lengths and flow enhancement factors in nanopores. Therefore, it is very important to use a more accurate slip length in numerical simulation or theoretical analysis for understanding the migration behavior of water in nanopores.

The slip length and flow enhancement factor can be measured or calculated by experiments, MDS, and theoretical methods. However, these methods cannot be quantitatively analyzed by the influence of different physical mechanisms, such as surface wettability, wall roughness, shear rate, nanobubble or gas film, liquid polarity, liquid viscosity, temperature, pore size, and pressure gradient. When the interaction between the hydrophilic wall is strong, the contact angle is less than 90, resulting in a small slip length [45]. That is to say, the slip length increases exponentially with the increase of the contact angle. It can be seen from the Wenzel equation and Cassie-Baxter equation [46, 47] that the roughness of the wall has a great influence on the antenna.

Considering the influence of gas film or confined gas on the rough pore wall, Vinogradova proposed that water flows on the gas film pore wall. When considering the gas film, the slip length will be more impressive [48]. The rough wall will confine a part of the gas in the rough unit; at this time, the appropriate contact angle will increase, resulting in the increase of slip length [49]. It can be seen from the experiment and MDS that the slip length is also related to the shear rate and the temperature [50]. Wu et al. [51] applied the change of sliding length with a contact angle to the flow enhancement factor model, without considering other means of the theoretical method. However, the microscopic mechanisms cannot be quantitatively analyzed by experiments.

2.2.2. The Influence of Microscopic Pore Geometry. The mechanisms of shale reservoirs are composed of inorganic and organic matrices. The pore size is 1 ~ 200 nm, and the organic nanopores are mainly smaller than 10 nm [52]. Through a large number of studies, the migration mechanisms of shale gas/oil in nanopores have been deeply studied [53]. However, the study of shale oil migration is mainly based on MDS and experimentals. The transmission mechanisms are still uncertain [54]. SEM images show that as shown in Figure 4, the

cross-sectional shapes of nanopores are various, including round, oval, rectangular, triangular, and trapezoidal [55]. Therefore, it is necessary to study the migration of shale oil in organic and inorganic nanopores with different cross-sectional shapes.

In the research process of shale oil/gas, scholars have extensively studied the fluid migration in circular cross-section nanopores based on theory, experiment, and MDS methods [56]. In addition to studying nanopores with cross-sections, Wu et al. proposed a gas migration model in shale reservoirs composed of nanopores with rectangular cross-sections and described continuous flow and slip flow through cross-sectional shape factors. Li et al. [57] show that the shape of the pores affects the distribution of water film and the mechanism of gas slip. Liang et al. [58] found that there is no regular circular cross-section in the shale matrix, and most nanopores have elliptical cross-sections. Therefore, it is necessary to study the migration mechanism of shale oil and gas in oval cross-section nanopores, as shown in Figure 5.

In addition, due to the existence of a large number of pore throat structures and different pore wall properties, the mechanisms of restricting fluid migration are more complex. At present, the mechanism of migration of confined fluid in nanopores with equal radius has been extensively studied. However, nanopores usually have different pore sizes in nature, such as water channels or carbon nanotubes with tapered inlets [59] and the pore throat structure of shale reservoirs [60]. When the fluid flows through nanopores with different radius, additional fluid resistance will be produced, which is called the outlet effect. Hydrodynamic resistance is due to the liquid streamlines bending outwards from the center of the pores, which results in viscous friction in different liquid streamlines of pore-wall and near-wall [59]. A century ago, Sampson [61] calculated the hydrodynamic resistance of a fluid passing through infinite thin circular pores for the first time. When liquid flows into the pores from infinite space, it will produce resistance, and the calculation will extend to pores of finite length. Then, Gravelle et al. [62] improved the nanopore model with a conical inlet, and the geometric optimization of the entrance effect was studied from the perspective of hydrodynamic dissipation. The results show that the cone-shaped orifice has the best opening angle, significantly improving the channel's overall permeability. There are many pore throat structures in the shale matrix, which will cause the shale oil to bend outwards into streamlining shape at the pore throats, thus generating additional hydrodynamic resistance. Therefore, in addition to the main flow characteristics, it is particularly important to consider the additional hydrodynamic resistance due to the inlet effect.

3. Multiscale Imbibition Mechanisms in Shale Reservoirs

3.1. Microscale Imbibition Mechanisms. With the application of good horizontal drilling and multistage fracturing technology, shale oil is profitable. During hydraulic fracturing, the fracturing fluid permeates into the matrix around the fracture through spontaneous imbibition (SI) or forced

FIGURE 4: SEM image of shale matrix nanopores [55].

FIGURE 5: SEM photos of nanopores in typical organic matter of well Wuxi 2 [58].

imbibition (FI). In shale reservoirs, water can only imbibe into hydrophilic inorganic pores because of the extremely high capillary pressure, which prevents water from imbibing into the hydrophobic organic pores, and adsorbed water on the surface of the mineral [63] (Figure 6). It is a universal natural phenomenon that liquid penetrates into porous media driven by surface energy, which is of great significance in the application of geoscience and microfluidic devices. Nanopores can be divided into hydrophilic inorganic nanopores and lipophilic organic nanopores [64]. Therefore, the imbibition process will become more complicated. Understanding the dynamic self-absorption characteristics of fracturing fluid in the porous matrix is of great significance for the quantitatively characterizing the loss of fracturing fluid and enhanced oil recovery. It can reduce the risk of groundwater pollution by limiting the imbibition rate and providing guidance information for cleaner production.

The main cause of abnormal coefficient is the change of liquid viscosity. It slips the boundary caused by liquid-solid molecular interaction [65]. Feng et al. [66] used the molecular dynamics method to explain the influence of viscosity, density, and slip boundary of confined fluid on capillary spontaneous imbibition. This explains the abnormal coefficient in the process of spontaneous imbibition in the nanopores. Zhan et al. [67, 68] investigated the oil-water two-phase flow behavior in the nanopores of unconventional res-

ervoirs and found that the velocity slip at the oil-water interface could enhance the oil flow in the hydrophilic nanopores. They also established [69] one novel mathematical model by considering the multiphysics, to describe such liquid-liquid two-phase flow behavior in the nanoscale porous media. However, hydrophilic inorganic nanopores and lipophilic organic nanopores may initially be saturated with oil. In a water-oil system, SI and FI also cause fracturing fluid to enter nanopores. Therefore, the influence of confined water/oil viscosity and slip boundaries on the mechanisms of SI and FI will be more complicated.

In addition to changing the viscosity and slip boundary of the near-wall liquid, there are other factors that affect the imbibition process, including the entrance effect [70], capillary length [71], and dynamic contact angle [72]. Wu et al. [73] viewed that the dynamic contact angle is the dominant factor that weakens the self-priming process. The accuracy of different dynamic contact angle models is studied based on the capillary spontaneous wicking rise experiment. Stromberg et al. [11] systematically investigated the vibrant self-priming pores of water with varying sizes of a nanometer. The results showed that the influence of the dynamic contact angle depends on the pore size and can be explained as the influence of the nonlocal flow field. However, in their research, the influence of different wall liquid viscosity and the slip boundary were ignored. According to molecular

FIGURE 6: Schematic of different fluids imbibition process and storage space in shale [63].

dynamics theory (MKT), the dynamic contact angle also depends on the thickness of liquid and density near the wall.

3.2. The Mechanism of Imbibition in Porous Media

3.2.1. Experimental Progress in Laboratory Methods for Observation of Imbibition. At present, the commonly used imbibition experimental methods include the volumetric method and weighing method, and the experiments are important methods to study imbibition. The capillary filling is the most common liquid transport experiment performed at the nanoscale. Nuclear magnetic resonance (NMR) technology is also used to analyze the relationship between imbibition and pore structure types. In 1996, Quan et al. [74] studied the distribution of fluid saturation, relaxation time spectrum, and micromechanisms of imbibition in low-permeability hydrophilic cores by using nuclear magnetic resonance imaging and multiple relaxation separation techniques. In 2002, Weiya et al. [75] conducted experiments

of matrix-fracture imbibition with low permeability artificial cores by using nuclear magnetic resonance. The absorption mechanism mainly affects the flow of crude oil in small pores. In 2014, Xiaoqian [76] analyzed the imbibition characteristics of Xinjiang glutenite through mercury intrusion experiment, nuclear magnetic resonance method, and imbibition experiment spontaneous imbibition, imbibition contribution rate, and dynamic imbibition were analyzed. In 2015, Meng et al. [77] analyzed the visual imbibition process of various lithological cores based on NMR technology. The experimental results show that the water imbibition of sandstone and volcanic rocks is consistent in micropores, mesopores, and micropores. For shale with fractures and microfractures, microfractures should be absorbed first and, then, the macropores. In 2016, Kelly et al. [78] performed experiments and found the Washburn equation is insufficient to describe imbibition kinetics due to the reduced effective capillary pressure at the liquid-gas interface, the increased effective viscosity, and the nondiffusive trend.

Imbibition is closely related to the wettability of rocks and the capillary force of oil and water. Some scholars have made experimental research on the mechanisms of chemical reagents affecting imbibition. In 2006, Jishan [79] studied the influence of surfactant on imbibition oil recovery through experiments. He thought that the main purpose of surfactants is to change wettability in low permeability fractured reservoirs. Surfactants change the wettability of oil-wet reservoirs, instead of pursuing ultralow interfacial tension, which makes imbibition oil recovery possible. Lei [80] analyzed the influence of molecular film flooding on imbibition oil recovery by spontaneous imbibition experiment in 2011. In 2019, Wu et al. [81] found that molecular film can reduce the interfacial tension and make the wettability of rock become neutral or water wetting. By changing the contact angle of the liquid phase on the solid surface, the liquid transport rate in the nanochannel can be regulated to be 10^{-1} to 10^7 times of the no-slip Hagen–Poiseuille equation prediction. Fundamentally speaking, the pore surface chemistry directly affects the contact angle of liquid, which is closely related to the slip of flow boundary and leads to different flow rates.

Early imbibition experiments mainly studied the imbibition between matrix and fracture in fractured reservoir cores [82]. Later, with the development of low/ultralow permeability reservoirs, some scholars gradually studied the phenomenon of imbibition oil recovery and periodic water injection [83, 84]. In recent years, the imbibition experiments of carbonate rocks and volcanic rocks have been carried out gradually, especially for unconventional resources and large horizontal wells [85]. With the application of hydraulic fracturing technology, the imbibition of shale and tight sandstone reservoirs has been extensively studied [86, 87]. In 2018, Wang et al. [88] used large-scale physical simulations to study the mechanism of reverse imbibition oil recovery during hydraulic fracturing and water injection huff and puff in tight reservoirs. The mechanism of imbibition oil recovery in tight reservoirs is that water enters the matrix under capillary force, replacing the crude oil in the matrix, and obtaining oil recovery. That same year, Liu et al. [89] studied water/oil two-phase flow in nanoparticles with a depth of 300–500 nm. In addition to regular piston-like mutual displacement behavior, they found that the wetting phase could form a thin film along the surface of nanopore. In Figure 7, the liquid film often breaks through faster than the meniscus, resulting in the displacement phenomenon of “fading out.” The “fading out” displacement seems to be faster than the regular piston-like displacement, which indicates that alternate hydrophobicity of the shale nanopore surface may improve shale oil recovery. In 2021, Jiang [90] constructed a new experimental method for forced imbibition based on low-field nuclear magnetic resonance (LF-NMR) measurement, and a correlation between SI and FI was discussed. The ultimate oil recovery for FI was significantly improved relative to that of SI, which was associated with the synergetic effect of enhanced SI and compaction. Zhang [91] proposed a model for the imbibition behavior in nanopores is proposed, which incorporate the increased viscosity of water near a solid wall and dynamic contact angle (Figure 8). In the same year, Xiao et al. [92] construct four porous media (Figure 9)

with different disorders and conduct a series over a broad range of wettability conditions and capillary numbers by using the combination of experiment and numerical simulation. It is observed that the coupling effects between the disorder and wettability of the porous media under different capillary numbers are complex, which has different influences on the displacement mode.

3.2.2. Modeling Techniques for Imbibition. In addition to the experimental study of imbibition, some scholars have devoted themselves to applying the experimental results to the prediction of imbibition recovery factors and imbibition productivity. In recent years, based on experiment and seepage theory, the semiempirical model, suction simulation model, and seepage simulation model were established.

In the earliest years, Aronofsky et al. [93] established an exponential model to predict oil recovery in order to analyze the law of productivity under fluctuation imbibition. In 1962, Mattax [94] established a dimensionless imbibition time expression based on the scale rate. It is considered to be matrix block size, fluid viscosity, permeability, and others. They can use the related results of core experiments to predict the changes of reservoir imbibition indexes, such as oil recovery. In 1999, Ma et al. [95] modified the Mattax model, the original water phase viscosity is replaced by the square root of the oil-water viscosity ratio, and a suitable calculation method of the characteristic length is given, so that the scale ratio can be used in a wider range of application. Some scholars have revised the viscous term. Jianchao et al. [96] extended the experimental results to reservoir-scale by scaling rate, which has specific guiding significance for the imbibition oil recovery. At the same time, considering the complexity of the actual reservoir conditions, the prediction accuracy of this method needs to be improved.

Another method for calculating imbibition is calculating the change law of imbibition distance and imbibition volume based on the capillary bundle model theory. In 1918, Lucas et al. [97] proposed the correlation equation between absorption length and time when only capillary force and viscous force are applied in a horizontal capillary. Then, Washburn [98], Bosanquet [99], and Quéré [100] et al. used fluid flow in multiple veins, and they proposed the relationship equation to conduct theoretical analysis considering imbibition length, viscous force, capillary force, and momentum change. In 2014, Liu [101] simulated the correlation between the imbibition distance and time of the above model, and he verified the model with experiments. Cai et al. [102] gave the flow law of wetting phase fluid in a single curved capillary based on fractal theory. This imbibition calculation model can better describe the flow mechanisms and law of fluid in the vein. Through some assumptions, it can be extended to the porous media model, and the simulation is more complicated for the calculation of imbibition in the large-scale reservoir.

In recent years, the imbibition calculation theories of fracturing fluid imbibition replacement crude oil are mainly based on the dual-porosity medium model in unconventional reservoirs. They explore seepage laws and imbibition productivity characteristics comprehensively considering the characteristics and explore seepage laws of unconventional reservoirs. In 2017, Zhang et al. [103] analyzed the

FIGURE 7: Oil recovery under different injecting pressure from a through e: 130, 140, 155, 183, 195 psig, respectively [89].

FIGURE 8: A spontaneous imbibition process with precursor films for water in a nanopore [90].

influence of different reservoir properties on flow back rate and productivity after shale gas wells are compressed based on numerical simulation methods. In this model, the difference of capillary force curves is used to characterize imbibition. According to the difference between displacement and suction, different values are assigned to the capillary force

curves of fracturing and flowback. In 2018, Wang [104] analyzed the fracturing flowback of tight gas reservoirs through numerical simulation, applied permeability curves of different phases to other areas, and considered that imbibition was one of the fundamental reasons for fracturing fluid retention. Moran's team [105] used LBM simulation to study

(a) $\lambda = 0$

(b) $\lambda = 0.1$

(c) $\lambda = 0.2$

FIGURE 9: Continued.

FIGURE 9: Displacement patterns for four different porous media with the different disorder [92].

FIGURE 10: LBM simulation of wet phase liquid distribution in the regular square tube with different time steps [108].

spontaneous self-priming in irregular channels, in which the wetting fluid is mainly driven by capillary pressure and hindered by viscous resistance, both of which are affected by channel geometry height, quantitatively revealing the influence of tortuosity and throat shape on self-priming behavior and competitive interface propulsion. Harris [106] clarified the interaction between surface chemical properties and pore geometry and gave the concept of apparent wetting, which is of great significance to the character of wettability in confined space. Ju [107] analyzed the influence of pore characteristics on the oil-water preferential imbibition and displacement path. The results show that the changes of pore size distribution and pore geometry will affect the water imbibition, and the fluid density ratio has a significant effect on water displacement behavior. In Figures 10 and 11, Zhao [108] used a single-phase LBM simulation and interactive

capillary bundle model to reveal the dynamic characteristics of spontaneous imbibition capillary in the square tube inner corner. The team of academician Jia Chengzao [109] introduced the molecular interaction between water and solid inner wall into the lattice Boltzmann method and simulated the seepage characteristics in nanopores with different cross-sectional shapes and wettability. In Figure 12, the results show that under the same injection pressure, the circular nanopore shows the greatest flow capacity, but the assumption of the overall pore shape is still too idealistic. In 2019, Wang [110] put forward the model of apparent viscosity and enhancement factor, which is related to the contact angle, pore size and shapes, and the boundary slip velocity. In 2021, he [111] also established a new generalized imbibition model in inorganic nanopores and porous media by LBM. He thinks that the proposed model can accurately

FIGURE 11: Dimensionless pressure distribution simulated by LBM direct simulation (top) and LBM-PNM (bottom) for different rocks [108].

FIGURE 12: Dimensionless velocity profile of different contact angles with different cross-sectional shapes [109].

describe the mechanism of the oil-water interface and is applicable to different nanoscale effects. Based on the above discussions, this study can provide the microscopic basis for water imbibing into nanopores and provide guidance information and the theoretical model for the oil recovery from tight/shale reservoirs by hydraulic fracturing, the groundwater remediation by restricting imbibition rate, and other related applications.

In 2020, Yang [112] established a mathematical model of postfracturing, in which fracturing fluid permeates into the reservoir and salt ions diffuse into fracturing fluid during soaking. The results show that the imbibition of fracturing fluid into the shale and the diffusion of salt ions into the fracturing fluid are synchronous, and the imbibition ability and the ion diffusion ability have a good linear relationship with the square root of time.

Generally speaking, in different historical periods of oil field development, the imbibition theories studied are closely related. Especially in recent years, with the development of unconventional oil and gas, the imbibition calculation theory is developing towards explaining the mechanism of fracturing fluid retention in the minefield. Although some scholars have put forward some ideas and methods, the research is still incomplete and urgently needed to be carried out.

4. Macroscale Imbibition Mechanisms after Hydraulic Fracturing

In shale reservoir development, large-scale horizontal wells with large liquid volume are usually fractured by stages. According to field experience, appropriate well soaking is

FIGURE 13: Stress distribution around the fracture in the soaking period and temperature distribution after shut-in (24 h) [127].

FIGURE 14: Imbibition mechanism of hydraulic fracturing.

helpful to improve the fracturing effect of the unconventional reservoir. Fracture is an important channel of oil and gas permeation, the key imbibition area, and the condition of water injection channeling (Figure 13). In the process of soaking well, when the equilibrium condition is reached, the injected fluid in the fracture enters the matrix pores under the capillary force, and the oil in the matrix pores realizes oil-water displacement and redistribution, thus realizing the displacement of the remaining oil (Figure 14).

In order to solve the problem of unclear imbibition mechanism and action law in hydraulic fracturing operation and production, many scholars have studied macroimbibition mechanism and formation damage evaluation. When the fracturing fluid enters the reservoir, the stress field and temperature field of the reservoir will change during the process of well soaking. Even though a few studies have been devoted to accounting for the effect of temperature changes [98–100], the full thermo-hydro-elasto-plastic coupling effect on imbi-

tion mechanism in hydraulic fracturing has rarely so far been investigated.

Scale effect is directly introduced into shale pore network simulation to characterize the flow mechanism of micro nanopore throat. Although the calculation efficiency is high, it simplifies the influence of pore size and shape to a certain extent. Therefore, some scholars [113] put forward the LBM-PNM coupling simulation method.

In 2019, Arash [114] proposed for the first time to combine the advantages of PNM and LBMs, calculate the permeability of the throat by LBM, replace the cylindrical throat permeability formula of the Hagen Poiseuille equation by pore network model, and solve the problem of inaccurate throat simulation by machine learning method for the first time. This method can well characterize the heterogeneity of microscale throat, but it is not enough to describe it only with a single permeability parameter. In 2020, Zhao [115, 116], Si [117], Eduard [118], and others developed a variety

of pore network models to describe the geometric shapes of several real pore throats, analyzed the simplified LBM simulation process of complex pore throat, and proposed a characterization method with high precision and low cost.

For porous media with three-dimensional complex geometry, Yingda [119] proposed a deep learning technique based on convolutional neural networks (CNNs), which can accurately estimate the steady-state velocity field (multiple directions) of porous media, and extended the model to the calculation of macroscale permeability. The results show that the pore throat shape accuracy of machine learning is higher than that by simple learning, but the seepage parameter error considering solute migration in complex porous media is still large. Javadpour [120] uses a watershed algorithm to extract the required data from high-precision imaging images; constructed a new triple pore network model of mesoporous, microporous, and fracture; and studies the gas-water two-phase flow law. In 2017, Lei [121] proposed a hydraulic model of shale gas reservoir, which considered multiple flow states, gas diffusion and desorption, stress-sensitive effect, and capillary pressure. The simulation results show that high capillary pressure is the main reason for the imbibition phenomenon and water blockage around hydraulic fractures. Li [122], Wang [123], and Yang [124] studied the spontaneous permeability of shale pore structure by the pore network simulation method. According to the pore network model, the representative permeability and capillary force curve are obtained. However, the above model is relatively simple, without considering the complex relationship between organic and inorganic matter. In 2019, Wu et al. [125] realized the effective combination of pore displacement and fracture system and the transition from waterflooding by displacement pressure difference to capillary force imbibition oil production. The development of a low permeability reservoir is often carried out at the same time as fracturing so that the capillary force can play a better role in the dual media. In 2020, Jiang et al. [126] used the forced imbibition experiments to show that the cores have a higher recovery ratio with a larger contact area, lower initial water saturation, and vertical bedding plane. Li [127] simulated the propagation of hydraulic fracture with the ABAQUS finite element software. As shown in Figure 14, COMSOL is used to simulate the temperature distribution around fractures, and the changes of stress field and temperature field caused by fracturing fluid entering the reservoir are studied. At the same time, the experimental imbibition model of brittle low permeability core is established, and it is verified that the appropriate soaking time is beneficial to the imbibition interaction between fracturing fluid and reservoir fluid.

5. Conclusion and Existent Problems

This work reviews the recent advances in micropore structure, spontaneous imbibition, forced imbibition, and multiscale flow in shale, including experiments, recent theoretical models, and mechanisms; and below conclusions have been drawn:

- (1) The study on the mechanisms of fluid migration in micropores is limited to single nanopores and water.

The type and geometry of pores increase the slip length and flow capacity. There are few studies on the quantitative influence of factors

- (2) Pore diameter, wettability, wall roughness, interfacial tension, pore throat effect, and external pressure difference have obvious influence on imbibition. A large amount of fracturing fluid enters the reservoir, which changes the stress and temperature, and the pressure of artificial fracture fluid diffuses to the far end properly, thus affecting the imbibition
- (3) The two-phase multicomponent flow simulation is carried out an experiment, and LBM needs further study. At the same time, few experimental studies on imbibition/displacement consider the micromechanisms after hydraulic fracturing, so it is necessary to further strengthen the research in this field
- (4) Imbibition mechanisms mainly control the early production performance in hydraulic fracturing wells. Potential large capillary force stored in shale will cause two-phase flow controlled by the imbibition mechanism in the area around the hydraulic fractures

In summary, this review paper is provided to improve the fundamental understanding of imbibition techniques to enhanced oil recovery after the hydraulically fractured applications discussed. However, considering the imbibition of shale oil reservoirs, there are still some problems in multi-scale flow.

- (1) In shale oil reservoirs, the optimized parameters of laboratory experiments are not suitable for different shale reservoirs application, and the environmental conditions have not been greatly reduced
- (2) The influence of fracture development on imbibition is not clear. At present, the relationship between fracture development degree of shale reservoir and oil recovery effect has been qualitatively evaluated. However, the quantitative evaluation of the oil recovery effect of the dual-medium systems has not been realized yet
- (3) The main influencing factors of imbibition for EOR are still unclear. It is necessary to further quantitatively analyze the law and degree of the influence of various factors on oil recovery and determine the best imbibition parameters for efficient development
- (4) The simulation of thermal-hydro-mechanical-chemistry (T-H-M-C) multifield coupling during the shut-in period has rarely so far been investigated. On the basis of existing research, the fully coupled multidomain and multiphysics model needs further supplement and study

Data Availability

All the data is presented in the manuscript.

Conflicts of Interest

The author declares that there are no potential conflicts of interest in publishing this paper.

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