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Review Paper

Advances in enhanced oil recovery technologies for low permeability reservoirs

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A B S T R A C T

Low permeability oil and gas resources are rich and have great potential all over the world, which has gradually become the main goal of oil and gas development. However, after traditional primary and secondary exploitation, there is still a large amount of remaining oil that has not been recovered. Therefore, in recent years, enhanced oil recovery (EOR) technologies for low permeability reservoirs have been greatly developed to further improve crude oil production. This study presents a comprehensive review of EOR technologies in low permeability reservoirs with an emphasis on gas flooding, surfactant flooding, nanofluid flooding and imbibition EOR technologies. In addition, two kinds of gel systems are introduced for conformance control in low permeability reservoirs with channeling problems. Finally, the technical challenges, directions and outlooks of EOR in low permeability reservoirs are addressed.

1. Introduction

Low permeability reservoir refers to the one with the characteristics of low permeability, low abundance, and low oil production rate (Liu et al., 2016; Park et al., 2018). So far, there is no unified standard for the classification of low permeability reservoirs in the world. The Russia regards reservoir permeability less than 100 millidarcy (mD) as low permeability oilfields, and the United States regards reservoir permeability less than 10 mD as medium poor reservoir (Li et al., 2022d). In 2009, according to the current situation of China's oil resources, economic and technical conditions and the exploration and development practice of low permeability reservoirs, a new version of low permeability classification standards was formulated, namely, general low permeability (1–10 mD), ultra-low permeability (0.5–l mD) and super-ultra-low permeability (<0.5 mD). The classification standards of low permeability reservoirs are summarized in Table 1.

Low permeability oil and gas resources are abundant all over the world. According to the assessment of the US Department of Energy in 2013, the recoverable resources of ultra-low permeability (shale/tight oil) technology is 483 × 10^8 tons in 41 countries and 95 basins around the world (da Rocha et al., 2021). Since 2011, the proportion of crude oil production of low permeability reservoirs in the United States has gradually increased, and has reached 51% in 2021 (Shi et al., 2021). Low permeability oil and gas resources are also widely distributed in China, for example, Bohai Bay, Songliao, Erlian, Hailar, Northern Jiangsu, Jianghan basins in the east (Zhang and Fang, 2020); Ordos and Sichuan basins in the middle; low permeability sandstones in Junggar, Qaidam, Tarim and Santanghu basins in the west (Li et al., 2016c; Wang et al., 2014). At present, the proved reserves of low permeability are 158 × 10^8 tons, about 54% of the geological reserves of crude oil in low permeability reservoirs in China. The average recovery rate of low permeability reservoirs in the world is only about 20%, and most of the crude oil remains in the reservoir and cannot be recovered (Ma et al., 2022). Therefore,

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Table 1
Summary of classification standards of low permeability reservoirs.

Permeability classification, 10^{-3} μm^2	US Department of Energy (DOE)	DZ/T0217-2005—Code for calculation of oil and gas reserves	SY/T6285-2011—Evaluation method of oil and gas reservoir	Development classification and description of oil and gas reservoirs	Development of low permeability sandstone oilfield
Ultra-high permeation	/	≥1000	≥2000	/	/
High permeation	>10	500–1000	500–2000	>1000	/
Medium permeation	1–10	50–500	50–500	100–1000	/
Low permeation	0.1–1	5–50	10–50	10–100	10–50
Extra-low permeability	/	< 5	1–10	< 10	1–10
Ultra-low permeability	0.02–0.1	/	< 1	/	0.1–1
Tight	/	/	/	/	0.01–0.1
Very tight	0.001–0.02	/	/	/	0.001–0.01
Extremely tight	< 0.001	/	/	/	0.0001–0.001

EOR in low permeability reservoirs have great potential and has gradually become the major orientation of development in oil and gas industry.

The development of low permeability reservoirs has the following difficulties (Cong et al., 2013): i) Low permeability reservoirs have small pores and throats, poor connectivity, huge specific surface area, large thickness of boundary layer between crude oil and rock, strong Jamin effect and surface molecular force, which show the law of non-Darcy seepage (Yao and Ge, 2011; Zeng et al., 2010). ii) There is a start-up pressure gradient during crude oil production. The smaller the permeability is, the greater the start-up pressure gradient is (Lai et al., 2020). The pressure-sensitive effect of low permeability reservoirs is severe, that is, when the confining pressure increases, the permeability of the reservoir will deteriorate sharply, generally decreasing by 1/2–1/10. iii) The capillary force of low permeability reservoirs is greater than that of ordinary reservoir, and contains more clay minerals and impurities (Li et al., 2016a, 2020b). Clay minerals have strong water sensitivity and high swelling. When the injected fluid is incompatible with the formation fluid, it is easy to scale, precipitate and make the clay expanding, which greatly reduces the reservoir permeability (You et al., 2009). iv) Low permeability reservoirs are often separated by faults, with large coefficient of variation and permeability resistance, and inactive edge and bottom water, resulting in insufficient natural energy of oil wells, many low production wells, low oil production rate and slow pressure propagation. At the initial stage, the oil wells show the characteristics of "insufficient liquid supply and rapid production decline". The natural productivity of oil wells is low, and the primary recovery rate is generally 6%–10% (Liu et al., 2021a). v) In the development process of water injection, the saturation of water phase increases in the pore system near the well, and it easily forms bound water, which seriously affects the exploitation of crude oil (Zhang et al., 2009). Moreover, the formation energy depletion is fast, the liquid production and oil production index of oil wells drop sharply after water breaks through. When the water cut reaches 40%–50%, the oil production index is only 0.1–0.2, and the final oil recovery of a reservoir with good physical properties can reach 20%–25% of original oil in place (OOIP).

In order to solve the above problems such as small pore throat, high injection pressure and severe water sensitivity, gas flooding, surfactant flooding and imbibition enhanced oil recovery technologies are used to depressurize, increase injection and increase production in low permeability reservoirs (Mou et al., 2011; Zhao et al., 2022b). In addition, there are artificial and natural fractures in most low permeability reservoirs, resulting in severe heterogeneity. There is a significant difference between fracture and matrix permeability, which makes the injected water have obvious directionality. The water channeling along the fracture direction are severe, water cut of the oil well rises rapidly and the degree of crude oil recovery is low (Zhang et al., 2018a). Therefore, the conformance control technology is needed to improve reservoir heterogeneity.

Up to now, EOR technologies for low permeability reservoirs have been greatly developed. Based on the investigation of low permeability reservoirs, this review summarizes the progress of EOR technologies in low permeability reservoirs. Gas flooding, surfactant flooding, nanofluid flooding, imbibition enhanced oil recovery technology and gel plugging technology are mainly introduced. Finally, their challenges, future directions and prospects are analyzed and discussed.

2. Gas flooding

For the development of low permeability reservoirs, the gas flooding has advantages over water flooding in maintaining reservoir pressure and displacing oil in miscible and immiscible forms (Das et al., 2020; Xu et al., 2020). According to different types of gas, gas flooding can be divided into the following methods: CO_2 miscible and immiscible flooding, N_2 flooding, hydrocarbon gas flooding and air flooding, flue gas flooding, etc. At present, the most commonly evaluated methods are CO_2 flooding, air flooding and foam flooding.

2.1. CO_2 flooding

CO_2 has good solubility and strong extraction ability in crude oil. After contacting with crude oil, a miscible phase is formed to reduce the oil-water interfacial tension (IFT), so as to greatly improve oil recovery. Field tests show that CO_2 gas absorption index can be increased by 5 times and injection pressure can be reduced by 50% compared with water flooding (Zhao et al., 2014). The injection capacity is greatly improved, which effectively solves the problems of "difficult injection and production, low oil production rate and low oil recovery" in the water flooding development of low permeability reservoirs. At the same time, the injected CO_2 can be stored underground on a large scale to achieve efficient CO_2 emission reduction. Therefore, CO_2 flooding is one of the effective technologies for EOR in low permeability reservoirs, CO_2 emission reduction and resource utilization.

The main mechanisms of CO_2 flooding are as follows (Kamari et al., 2015; Sun et al., 2017; Wang et al., 2015). i) Reduce the IFT: In the process of CO_2 flooding, CO_2 can be mixed with the light components (C_2–C_6) in crude oil under specific temperature and pressure conditions, which can effectively reduce the IFT (Chen et al., 2022b). ii) Improve the oil-water mobility ratio: After CO_2 is dissolved in crude oil, the viscosity of crude oil will be significantly reduced. And CO_2 dissolution in water can increase the viscosity of water, so as to improve the oil-water mobility ratio (Middleton et al., 2012; Zhang et al., 2018c). iii) Dissolved gas flooding: With the displacement process, the drop of pressure will make CO_2 escape from the crude oil again and occupy the pore space, so as to form dissolved gas flooding, which is conducive to oil displacement (Cheng et al., 2017). iv) Acidizing blockage removal to improve the injection capacity: The acidic water after dissolving CO_2 can inhibit the expansion of clay and make the shale more stable. Moreover, the acidic solution will also react with soluble minerals and plugs in low permeability sandstone and carbonate reservoirs to improve formation properties (Pu et al., 2022). v) Miscibility effect: After the formation pressure reaches the minimum miscibility pressure, CO_2 is mixed with light hydrocarbons in crude oil to form an oil bank at the displacement front, which greatly improves the oil recovery (Bikkina et al., 2015; Xu, 2017; Yang et al., 2021b).

The United States, Canada, China and other countries have conducted a large number of CO_2 flooding tests both in laboratory and field (Zhang et al., 2018c). Among them, the United States has the most CO_2 miscible and immiscible flooding projects (Bikkina et al., 2015). It still maintains continuous growth and is in the leading position in the world. Due to the abundant natural CO_2 resources in the United States, nearly 80% of its projects are distributed in low and ultra-low permeability reservoirs.

There are many CO_2 displacement projects in Seminole Unit-Mainpayzone Oilfield in Texas. Its reservoir permeability is 1.3–12.3 mD, the crude oil density and viscosity are 0.85×10^3 kg/m^3 and 1 mPa s, respectively. The increased output of crude oil by CO_2 flooding was about 1.295×10^6 tons/year (Melzer et al., 2006). Littlecreek Oilfield is located in the southwest of Mississippi, with an average permeability of 33 mD. At the reservoir temperature, the density of crude oil is 0.83×10^3 kg/m^3 and the viscosity is 0.4 mPa s. The average residual oil saturation of water injection is 21%. The field test of miscible oil displacement by continuous injection of CO_2 showed that CO_2 flooding had achieved good results, increasing the total recovery of the oilfield by 35.1% of OOIP (Cheng et al., 2017).

Weyburn Oilfield is located in the southeast of Saskatchewan, Canada (Lakeman et al., 2008). The reservoir contains upper and lower layers with great differences in properties. The upper is Marly layer, mainly dolomite, with a wide permeability range of 1–100 mD and an average permeability of 10 mD. The lower is Vuggy layer, with many fractures and permeability of 15 mD. In 2000, the oilfield began to implement the CO_2 injection EOR project, which extended the service life of the oilfield by 25 years. It was estimated that more than 1.82×10^4 tons of crude oil could be recovered from depleted reservoirs (Herawati and Davis, 2003).

In the 1960s, the exploration of CO_2 flooding EOR method was carried out in Daqing Oilfield (Ran et al., 2012). In the 1990s, pilot tests of CO_2 flooding were successively carried out in Shengli, Changqing and other oilfields (Liao et al., 2012). However, due to the lack of natural CO_2 gas resources and the problems of serious gas channeling and pipeline corrosion, it had not been formed large-scale application. In 2006, PetroChina built the first CO_2-EOR national demonstration project in Jilin Oilfield (Guo et al., 2006). The average permeability of Daqingzijing block reservoir in the Jilin Oilfield is 4.5 mD, which belongs to a reservoir with medium and low porosity and low permeability. The crude oil has good properties, and the surface viscosity is 8.3 mPa s. The numerical simulation results of CO_2 miscible flooding showed that the oil recovery could be improved by about 10% of OOIP. Water injection development was in the state of slow recovery rate and low production. After CO_2 injection, the effect had been significantly improved, and the water cut had been greatly reduced from 45% to about 25%. The daily oil production has increased from about 2 tons to about 5 tons at that time.

CO_2 flooding is not only an effective method to greatly improve the recovery of low-permeability reservoirs, but also an important means to reduce CO_2 emission. It is also a strategic choice for the sustainable development and green and low-carbon development of low-permeability reservoirs (Gui et al., 2008). In recent years, with the development of the international community's response to climate change and CO_2 emission reduction technology, China has carried out research on CO_2 capture, oil displacement and storage technology (Hu et al., 2019). Through research and test, important progress has been made in CO_2 flooding theory, development technology and injection production transportation technology, and CO_2 flooding technology has entered a new stage of rapid development.

2.2. Air flooding

In gas injection development, the cost of air injection is low and is not limited by gas source. Since 1985, American Amoco Oil Company has implemented air flooding on a large scale in low permeability light reservoirs such as MPHU, Horse Creek, and BRRU in Williston Basin, and achieved obvious economic benefits (Manrique et al., 2007, 2010). Subsequently, a special air flooding laboratory was established, which attracted the attention of major oil companies to air flooding.

In recent years, whether in carbonate reservoirs or sandstone reservoirs, air flooding has shown a rapid increase trend. The air flooding project of Buffalo Oilfield in South Dakota was implemented, and the reservoir was limestone (Gutiérrez et al., 2008). A total of 6.8×10^6 m^3 of air was injected and 2.4×10^6 tons of crude oil was produced, accounting for 9.4% of the original geological reserves. In 1995, the University of Bath (UK) conducted air flooding field tests in the North Sea Oilfield after water flooding, and the final EOR was increased from 37% to 48% of OOIP (Fraim et al., 1997; Greaves et al., 1998). Many studies and experiments of air flooding have also been done in China, such as Zhongyuan Oilfield, Changqing Oilfield, Baise Oilfield, Shengli Oilfield, Yanchang Oilfield, Jilin Oilfield, and Xinjiang Oilfield (Hou et al., 2010). In the Zhongyuan Oilfield, Hu 12 sandstone reservoir has successfully implemented air foam flooding (Yu et al., 2008). The field application showed that O_2 and N_2 did not break through early, and the recovery rate increased by 3%–4% after three years. Field test cases statistics of air injection in the world are shown in Table 2.

Air flooding is an ideal development method, but its mechanism is complex. EOR mechanism of air flooding in low permeability reservoirs includes the following aspects (Chen et al., 2012; Ren et al., 2002): i) High pressure air injection increases or maintains reservoir pressure. ii) Low temperature oxidation (LTO) of crude oil consumes O_2 and forms N_2 flooding (Gushchin et al., 2018). iii) The heat generated by oxidation reaction can reduce the viscosity of crude oil, expand the volume of crude oil, increase formation energy, dissolve the generated CO_2 produced in crude oil and reduce the viscosity of crude oil (Luan et al., 2020). iv) When the reservoir pressure is suitable, the flue gas produced by LTO of air and crude oil can form miscible or near miscible displacement with crude oil (Li et al., 2021). v) For thick or inclined reservoirs, air injection at the top of the reservoir can produce gravity displacement (Ezekiel et al., 2017).

Moore et al. believed that LTO reaction had three basic reactions, including addition reaction, carbon bond stripping reaction, and pyrolysis reaction (Moore et al., 2002). In this process, a large amount of heat will be generated to accelerate the evaporation of light hydrocarbons, heating crude oil and reduce the viscosity of

Table 2
Field test statistics of air injection in the world.

Name of oil field	Permeability, mD	Buried depth, m	Formation temperature, °C	Crude oil viscosity, mPa s	Crude oil density, g/cm^3	Cumulative oil increase, t	Water cut before gas injection, %
Horse Creek	10–20	2781.3	104	1.4	0.865	1030.0×10^3	35
Buffalo	10	2575.6	102	0.5	0.876	783.5×10^3	45
MPHU	5	2895.6	110	0.5	0.83	769.5×10^3	43
West Heidelberg	35	3444.2	105	6.0	0.92	402.5×10^3	15
Baise Oilfield Lun-16	23–42	870	49.5	5.91	0.863	0.51×10^3	94
Changqing Malingmu 12-9	30	1560	48	7.0	/	0.70×10^3	91
Changqing Wuliwan Chang-6	3.67	1530	54.4	4.97	/	4.19×10^3	44.6
Zhongyuan Oilfield Hu-12	35.5	2150	84–89	43.17	0.872	4.96×10^3	97.5

crude oil, and produce a large amount of CO_2, H_2O and hydrocarbon derivatives at the same time. In addition, some minerals containing $CuCl_2$ and montmorillonite in the formation can be used as catalysts for LTO reaction to accelerate the reaction between crude oil and oxygen, which can greatly improve the utilization rate of oxygen in the injected air. Using crude oil (0.98×10^3 kg/m^3 and 74.5 mPa s) from Dagang Oilfield in China, Wei et al. conducted the laboratory experiment of air injection with low temperature (65 °C, 17 MPa) in low permeability (4.5 mD) reservoir (Wei et al., 2015). The results showed that CO, CO_2 and gasified low molecular weight hydrocarbons produced by LTO flood the oil out from the low permeability core with the recovery of 45%, and the viscosity of the produced oil decreased slightly by 2.6%. Some experts and scholars are also exploring air flooding, but their research focuses on LTO. In the process of oil displacement, the effect of oxygen consumption is similar to that of flue gas displacement, with high miscible pressure and poor oil displacement effect. LTO gravity flooding is used in some reservoirs, and its effect is relatively better (Chen et al., 2021).

Air flooding also has some disadvantages. In heterogeneous formations, the gravity difference between air and liquid leads to ineffective displacement, especially in inverse rhythm formations (Brodie et al., 2012). Under high injection pressure, due to the non piston oil displacement front, air can also easily enter the production well, forming a large area of unswept area and leaving a large amount of remaining oil in the reservoir. However, the advantages of air flooding are obvious. Compared with other gas injection technologies (such as natural gas, N_2 or CO_2), air injection is more and more favored by many large oil companies because of its easy availability and obvious economic advantages (Teramoto et al., 2006).

2.3. Foam flooding

Gas or water flooding is prone to channeling, resulting in low sweep efficiency in the reservoirs. Foam flooding, as an oil displacement method after gas flooding and water flooding, fully combines the advantages of foam and gas, and greatly improves the displacement efficiency of low permeability reservoirs (Abdelaal et al., 2020; Li et al., 2020a; Solbakken et al., 2014; Wei et al., 2018).

The important mechanism of foam flooding to EOR of low permeability reservoirs can be expressed as follows. Firstly, under the action of gravity differentiation, gas of broken foam will rise from the bottom to the top and form a gas cap. The energy of the low permeability reservoir will be effectively improved (Liu et al., 2021b). Moreover, selective plugging is the most obvious feature of foam, namely, plugging water without plugging oil. It is difficult to generate bubbles in areas with low permeability layers or high oil saturation (Liang et al., 2021; Sun et al., 2015). Not only will it form blockage in the channel, but also it will slowly dissolve in the crude oil, which is conducive to the migration of crude oil (Issakhov et al., 2021). Therefore, some remaining oil that cannot be swept by water injected can also be displaced. In addition, the foaming agent, as a surfactant, can reduce the IFT. It can also change the rock surface from lipophilic to hydrophilic, reduce the adhesion of crude oil on the rock surface and improve the recovery (Sie and Nguyen, 2021; Xu et al., 2022). Therefore, the foam flooding technology has attractive potential of application in the development of low permeability reservoirs.

Foam flooding is mainly divided into CO_2 foam flooding (Jian et al., 2019), N_2 foam flooding (Wang et al., 2021b), and air foam flooding (Lang et al., 2020), among which the air foam flooding with the wide source of gas and high efficiency is the most widely used (Zhang et al., 2019a). Air foam flooding is combined by air flooding and foam flooding, and has dual action mechanism. Air is used as an oil displacement agent and foam is used as a conformance control agent. It can not only increase the formation pressure, but also effectively avoid water channeling and gas channeling, so as to improve the oil production and oil displacement efficiency.

It is generally believed that O_2 reacts more with crude oil in LTO reactions above 80 °C. Because a large amount of O_2 will be consumed spontaneously at this temperature, this technology is mainly used for reservoirs with temperatures higher than 80 °C. Wu et al. conducted air foam flooding displacement experiments at 30 and 80 °C to evaluate O_2 consumption at different temperatures (Wu et al., 2018). The results showed that under the same experimental conditions, the oxygen consumption at 30 °C was 38.14% lower than that at 80 °C. The LTO reaction of formation crude oil hardly occurred in the reservoir, but there was still a large amount of oxygen consumption. The reasons for oxygen consumption mainly included the chemical reaction between oxygen and reducing minerals, the dissolution of formation water and oil, the adsorption of van der Waals force in the reservoir and the physical and electronic adsorption of hydrogen sulfur bond and carbon sulfur bond. Therefore, the air foam flooding can break the applied limit temperature and be applied to low temperature reservoirs.

Liu et al. injected pure foam liquid, air and air foam system into the tight matrix core and the fractured core through one-dimensional core displacement experiment (Liu et al., 2017a). The results showed that the air foam system could not be directly injected into the tight matrix core, which mainly flowed into fractured cores and plugged the fractures. Some defoaming liquid and separated air could flow into the matrix core to replace the residual oil. The air foam system could improve the conformance control effect after water flooding. The remaining oil saturation decreased by 21.12% and the oil displacement efficiency increased by 32.89% of OOIP. Moreover, it was recommended to convert water injection into air foam system as soon as the water cut reached about 90%.

In view of low-permeability fractured reservoirs with low temperature and high salinity, Zhang et al. developed the fluorocarbon foamer, betaine surfactant and polymer composite foam formulation with low IFT (Zhang et al., 2018b). For the reservoirs with large permeability contrast, it was necessary to take conformance control in advance of foam injection. In the oil displacement experiment, 0.1 pore volume (PV) conformance control system and the 0.4 PV foam system were injected into the parallel core column (high permeability 1000 mD and low permeability 10 mD cores), and the recovery of the low permeability core increased by 18.87% of OOIP.

Some low permeability oil field tests also proved the good effect of foam flooding for EOR. The permeability of Jidong Oilfield is generally 0.1–10 mD with strong heterogeneity (Zhang et al., 2019b). The comprehensive water cut is 96.6%, which is in the stage of ultra-high water cut. Zhang et al. injected double slug of foaming agent solution and N_2 with volume ratio of 1:1. The injection pressure increased 1.1 MPa, indicating that the N_2 foam system played a role in plugging the high permeability channel under the reservoir condition and increased the seepage resistance of the formation. The water cut of the test well group decreased by 2.7%, and the daily oil production increased by 1.8 times. Li et al. introduced the field test of SDBS/nano-SiO_2/WTP foam flooding in fractured low-permeability reservoirs of the Yao-280 block (0.3–1 mD) in Ordos Basin, China (Li et al., 2022b). Through the combination of water flooding and foam flooding, the average water cut decreased from 72.05% to 55%, and the average oil production increased from 0.17 to 0.22 t/d. This indicates that the injected foams can effectively plug the large cracks and divert the injected fluids into the unswept low permeability area in the reservoir.

As a system with relatively poor stability, foaming and foam stability are the main indicators for evaluating the performance of foam system. The better foaming capacity, the more bubbles will be generated, and the oil displacement effect will be enhanced. As the most important index of foam system, stability is the main factor determining the displacement and rupture of foam in the process of formation migration. Researchers in related fields should constantly improve the formulation of foaming agents, improve the bubble volume and stability of foam, reduce the tension of oil-water interface, reduce the amount of oil adsorbed on rock surface, and enhance the recovery efficiency of low permeability reservoirs.

2.4. Gas huff-puff

Gas flooding is the most promising method to improve the recovery of low permeability reservoirs. Among them, gas huff-puff has the advantages of less investment and quick effect (Lee et al., 2019; Shen and Sheng, 2017). Gas huff-puff includes CO_2 huff-puff, N_2 huff-puff, natural gas huff-puff, and hybrid gas huff-puff, of which CO_2 huff-puff is widely used and studied (Mohamedy et al., 2022). The mechanism of CO_2 huff-puff to improve the recovery of low permeability reservoir is basically similar to that of CO_2 flooding (Junira et al., 2022; Wang et al., 2020).

Different injection parameters, soaking time and production parameters will have an impact on the effect of CO_2 huff-puff (Chen et al., 2022a; Moh et al., 2022). Through 0.3 mD core test, Pu et al. showed that the crude oil recovery rate is closely related to CO_2 pressure (Pu et al., 2016a). Under 16 MPa pressure, the crude oil recovery rate can reach 30.9%. Compared with single-cyclic operation, four-cycle operation can further improve oil recovery by 10%. But the oil recovery significantly dropped after two cycles. Tang et al. pointed out that CO_2 injection volume and development speed are the main factors affecting oil recovery (Tang et al., 2021). The larger the volume of CO_2 injected, the lower the development speed and the higher the recovery. The soaking time has an optimal value, which is longer than the optimal value making little contribution to oil recovery. According to the oilfield demand and economic evaluation, the reasonable CO_2 injection volume and development speed should be determined. Ding et al. studied the effect of permeability on huff-puff efficiency (Ding et al., 2021). The results show that when the matrix permeability is less than 30.0 mD, the effectiveness of CO_2 huff-puff will be significantly weakened with the decrease in permeability, indicating that the development of tight reservoir is difficult. When the permeability exceeds this value, this effect will be weakened. At the same time, it is proved that the efficiency of natural gas huff-puff EOR is lower than that of CO_2.

Is there a better gas huff-puff mode than carbon dioxide huff-puff for EOR of low permeability reservoir? Researchers combine different gases or gases with chemicals to carry out huff-puff experimental research. Li et al. synthesized a novel hybrid CO_2–N_2 gas and conducted a series of huff-puff tests (Li et al., 2022a). The best ratio of CO_2–N_2 in the hybrid gas solvent is 1:2, and the best recovery of huff-puff is 39.0%. However, the recovery efficiency of CO_2 huff-puff is 22.4% and that of N_2 huff-puff is 34.0%. Hybrid gas huff-puff takes advantage of the decrease in viscosity induced by CO_2 and the increase in elastic energy induced by N_2. Therefore, it has more excellent EOR performance in low permeability reservoirs. Zeng et al. evaluated the mixing process of chemical blend (an anionic surfactant and a persulfate salt) and CO_2 huff-puff to improve the oil recovery of shale core (Zeng et al., 2020). Chemical blend with CO_2 huff-puff is more effective than pure CO_2 huff-puff, and its oil recovery is 24% higher than pure CO_2. This is due to the synergistic effect of surfactants and CO_2, which reduces the interfacial tension, improves wettability, expands the oil and improves the oil recovery.

Some scholars have explored the effect of other gas huff-puff on improving the recovery of low-permeability cores. For example, Shilov et al. used shale core samples for rich gas huff-puff tests (Shilov et al., 2022). The results show that under the non-miscible state, the oil recovery is from 29% to 79.55% at 15 MPa. Under the near-miscible state, the oil recovery is from 41% to 88.40% at 30 MPa, the average recovery is 63.03%, and the maximum recovery is 88.40%. Furthermore, extending the injection period and production time can improve oil recovery. In contrast, the duration of soaking has no significant effect on oil recovery.

3. Surfactant flooding and nanofluid flooding

3.1. Active water flooding

Active water flooding is an oil displacement method of injecting 0.2%–0.5% low concentration surfactant solution into the formation (Chen et al., 2018). Generally, the volume of injected into oil layer accounts for 15%–60% of pore volume. The active water solution can greatly reduce the IFT, emulsify crude oil, improve the rock wettability, reduce the capillary resistance of lipophilic oil layer, and reduce the starting pressure of water injection (Jin et al., 2016; Pu et al., 2016b). The active water can enter the smaller pore throat, so as to improve the displacement efficiency and expand the sweep volume (Pu et al., 2016c).

Which mechanism of active water flooding is the dominant factor in EOR? Li et al. studied this through a series of comparative experiments (Li et al., 2022c). The results showed that compared with reducing IFT, the *in-situ* emulsification of surfactant played an important role in oil recovery. As shown in Fig. 1, the EOR effect increased with the decrease in core permeability (5–50 mD). Surfactant had strong emulsifying ability, which was conducive to dispersing residual oil and reducing oil saturation. On the other

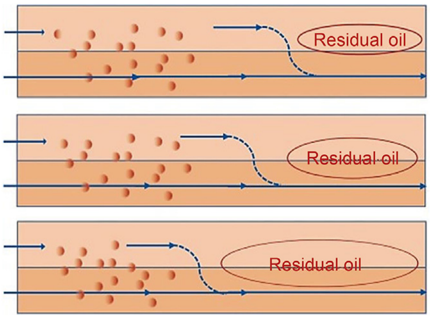

Fig. 1. Schematic diagram of the effect of permeability ratio on surfactant flooding (reproduced with permission from Li et al. (2022b).

hand, the formation of emulsion droplets could contribute to blocking pores, which was helpful in establishing pressure changes and delaying the increase in water cut. At the same time, the strong emulsifying ability of surfactants was beneficial to expand the sweep volume of micro heterogeneous distributions and avoid the formation of micro channels. Zhao et al. explored the application of microemulsion formed using olefin sulfonate and amyl alcohol in the ultra-low permeability formation (7.5 mD) (Zhao and Xia, 2020). On the basis of water flooding, the enhanced recovery of microemulsion flooding increased from 32.97% to 42.13% of OOIP, and the water cut decreased by 8.2%. They also found that after injection of microemulsion, the injection pressure decreased significantly. Compared with the initial water injection, the subsequent water injection pressure was reduced by 24%. It has ultra-low IFT, good solubilization ability, emulsification and viscosity increasing ability to control mobility, which brings new ideas for the development of low permeability reservoirs.

Tang et al. prepared a new type of low salinity active water using composite surfactant (Tang et al., 2020). It could still show good interfacial activity in the environment of low salinity water (2500 mg/L). The lower the salinity and the stronger the hydrophilicity of the active water, the greater the permeability damage rate of the natural core, and the higher the pH value and the total salinity of the produced fluid. There are three main EOR mechanisms. Firstly, the low salinity water has ion exchange interaction with the rock surface, which changes the rock surface charge, and the surfactant can change the reservoir wettability through hydrophobic interaction. Secondly, the low salinity water is easy to cause the hydration expansion, abscission and migration of clay particles in the formation, so as to block the high permeability channel and achieve the effect of conformance control and oil displacement. Finally, some hydrogen ions in the low salinity water will exchange with divalent cations on the rock surface, which will increase the pH of the aqueous solution and produce alkali flooding effect.

For the low permeability reservoirs with high temperature and salinity of 85 °C and 65010 mg/L, Zhang et al. mixed alcohol ether nonionic surfactant, methylamine, and sodium cetylsulfonate in appropriate proportion to obtain surfactant system with a total concentration of 0.4% (Zhang et al., 2021a). The system could effectively reduce the water injection pressure by 24.77%, release the residual oil trapped in small pores (0.05–0.5 μm), and improve the oil recovery by 28.86% of OOIP. In addition, higher salinity was conducive to reduce IFT and adsorption loss. The system mainly reduced the injection pressure and improved oil recovery by reducing IFT, emulsifying and changing wettability.

3.2. Micellar flooding

Micellar flooding is an oil displacement method of injecting high concentration (3%–8%) surfactant solution with 3%–20% PV into the reservoir (Thomas et al., 2000). Compared with traditional surfactant flooding, it has many advantages. Firstly, under the condition of formation shear, the micellar solution can react with hydrocarbons to form a microemulsion which can improve the oil displacement efficiency. Secondly, micellar solution can change the mobility of displacement fluid and play a certain degree of mobility control in low permeability fractured reservoir (Goswami et al., 2018).

The EOR mechanism is as follows (Bhui et al., 2018): i) Reduce the oil-water IFT. After the micellar solution is injected, on the one hand, the adhesion work of the remaining oil in the pore throat decreases and it is easy to be displaced from the low permeability area. On the other hand, the capillary resistance of residual oil passing through a narrow pore throat is reduced. Thus, the sweep volume in the low permeability area is expanded (He et al., 2015). ii) Wettability alteration (Fan and Guo, 2020). Surfactant is adsorbed on the rock surface to change the lipophilicity of the rock into hydrophilicity. So that the capillary resistance of the small pore throat can be changed into oil displacement power. iii) Emulsion carrying (Du et al., 2021). Emulsification will occur in the process of micellar flooding. The shape of the remaining oil will change from oil flow to oil wire or microemulsion of a smaller diameter than the throat, and the displacement efficiency is improved (Jia et al., 2021; Maurya and Mandal, 2018). iv) Increasing charge density on rock surface. When ionic surfactants are adsorbed on the surface of crude oil and rock, the surface charge density increases and the electrostatic repulsion between rock and crude oil is enhanced.

Cationic surfactants mainly include amine salt, alkyl pyridine salt, quaternary ammonium salt, imidazoline salt, and morpholine salt (Lv et al., 2019; Wang et al., 2017b). Due to the poor interface performance, large adsorption quantity in the sandstone formation, and easy precipitation after compounding with anions, it is generally believed that cationic surfactants are not suitable for oil displacement. However, Li et al. obtained viscoelasticity surfactant (VES-JS) by mixing a cationic surfactant and a long-chain unsaturated amide betaine in a certain proportion (Li et al., 2016b). VES-JS showed good viscoelasticity, good oil displacement effect and ultra-low IFT, which could improve the oil recovery from 10.64% to 24.72% of OOIP in low permeability core (40 mD).

Anionic surfactants mainly include carboxylate, sulfonate, sulfate and phosphate. Anionic surfactant is used as oil displacement agent because of its high interfacial activity, less adsorption on sandstone surface and good temperature resistance (Ceschia et al., 2014; Li et al., 2009). Zhan et al. studied the solubilization of paraffin oil by micelles formed by naphthenic arylsulfonates (NAS) (Zhan et al., 2021). The results showed that paraffin oil had good solubility in NAS micelles and was mainly distributed in the hydrophobic core of the micelles. The solubility of NAS micelles increased with the increase in its concentration. With the increase in paraffin oil, the micelles remained spherical until the maximum solubility was reached. At the same time, it was proved that micellar solubilization was helpful to enhance oil recovery even without ultra-low IFT.

Li et al. synthesized the modified anionic surfactant alkyl polyglucoside sodium hydroxypropyl sulfonate (APGSHS) and used it to combine with cationic surfactant cetyltrimethylammonium bromide (CTAB) to form an ultra-low IFT and low critical association concentration (CAC) system (Li et al., 2020c). APGSHS/CTAB surfactant with total concentration of 3000 mg/L and molar ratio of 6:4 could effectively improve the recovery of low permeability reservoirs with high salinity and reduce the injection pressure.

Zwitterionic surfactants for oil displacement are mostly betaine surfactants, which can be divided into carboxylic betaine (Kamal et al., 2015), sulfobetaine and sulfate betaine according to different anions. Chen synthesized double long-chain alkyl methyl betaine by reacting chloroacetic acid with double C_{12} alkyl methyl tertiary amine and double C_{10} alkyl methyl tertiary amine respectively (Chen, 2009). Without adding alkali, the IFT could be reduced by 10^{-3} mN/m, and the oil recovery could be improved by 18% of OOIP. Wu et al. studied the IFT and oil displacement effect of the new carboxybetaine (BS13) and its compound system (Wu et al., 2009). The results showed that its oil displacement effect was better than that of the strong alkali ternary system commonly used in the field. Bai et al. studied various properties of C_{22}-tailed amidosulfobetaine surfactant (EHSB) (Bai et al., 2021a). The wormlike micelles formed by EHSB had the dual functions of controlling fluidity and reducing IFT. It also had a good oil displacement effect, and the oil recovery was more than 10% higher than that of partially hydrolyzed polyacrylamide (HPAM) with the same viscosity. Compared with short tail surfactant, super long tail surfactant was more effective in increasing viscosity and reducing IFT, so the effect of EOR was better.

Based on the above literature reviews and discussion, we summarize the surfactants commonly used in EOR technologies based on laboratory research and current pilot applications (as shown in Table 3).

3.3. Nanofluid flooding

Nowadays, the application of nanotechnology in oil and gas industry has become a major research focus. Nanoparticles can form structural disjoining pressure and peel off the remaining oil (Pajouhandeh et al., 2019). It also has the ability to change reservoir wettability, reduce oil-water IFT, reduce crude oil viscosity and improve fluidity (Chen et al., 2019; Qu et al., 2022a). Nanofluid is the basic fluid that disperses nanoparticles into traditional heat transfer media such as water, alcohol and oil. Nanoparticles are small and light enough to remain suspended (Kondiparty et al., 2012). As a new oil displacement agent, nanofluids have been reported in recent years to enhance oil recovery in low permeability reservoirs (Peng et al., 2017).

Hendraningrat et al. prepared nanofluids using hydrophilic nano-silica particles and studied its EOR effect in low and medium permeability sandstone (5–20 mD) (Hendraningrat et al., 2013). According to the experimental results, the optimum concentration of nanofluid was 0.05 wt%, and the oil displacement efficiency was improved by 25% of OOIP. In addition, Liu et al. used super-hydrophobic silica nanoparticles with an average size of 7 nm and a high surface activity to prepare a nanofluid (Liu et al., 2019b). The hydrophilic rock core surface was altered to the hydrophobic, resulting from forming a dense silica nanoparticle layer on it. Finally, the injection pressure could be significantly reduced and the injection validity of water injection wells in low permeability reservoirs could be drastically prolonged.

However, nanoparticles are greatly affected by salinity, so it is necessary to modify their surface to improve their stability in solution. Modified nanoparticles have nano size effect and excellent surface and interface properties, and have higher application value in the field of EOR.

Chen synthesized hydrophobic α-zirconium phosphate (α-ZrP) nanosheets by using octadecyltrichlorosilane (OTS) (Chen et al., 2019). The results showed that hydrophobic α-ZrP nanofluid could not change the wettability of the core and form Pickering emulsions during the injection process, and then the final oil recovery can be improved 19% of OOIP. Moreover, a novel nanofluid based on sulfonated graphene (G-DS-Su) for enhanced oil recovery was developed by Radnia et al. (2018). G-DS-Su nanofluids with concentrations of 0.5 and 2 mg/mL could increase oil recovery by 16% and 19%, respectively. In the presence of G-DS-Su, the wettability of sandstone surface changed from oil-wet state to intermediate state. The mechanism of wettability alteration was shown in Fig. 2. It might be due to the formation of wedge-shaped film in the oil/nanofluid/solid three-phase contact area and the adsorption of G-DS-Su on sandstone due to the π-π and n-π interaction between the functional groups of sand and G-DS-Su. Therefore, Radnia et al. believed that the alteration of wettability played a leading role in the oil displacement mechanism.

Feng et al. prepared oleic acid modified TiO_2 nanoparticles (Feng et al., 2019). The oil displacement experiment showed that TiO_2 nanofluid could not only improve the recovery of low-permeability reservoir, but also reduced the injection pressure. Wang et al. also believed that hydrophobic nanoparticles could reduce the injection pressure (Wang et al., 2018). As shown in Fig. 3, a stable hydrophobic film was formed on the rock surface, thus improving the roughness of the pore surface of the rock, replacing the hydration layer formed by the injection water, and reducing the flow resistance.

Although nanofluids show great potential in the process of EOR, nanofluid prepared from pure nanoparticles cannot be effectively produced on a large scale. With the extensive research on the application of nanofluids in reservoir engineering and EOR

Table 3
Summary of surfactants commonly used in EOR.

Surfactants	Advantage	Shortcoming	Example
Anionic	High interfacial activity, good temperature resistance, less adsorption on the surface of negative electric rock, many kinds and low price	Most of them are not resistant to divalent cations such as Ca^{2+}, Mg^{2+}, and the chromatographic separation is serious.	Lignosulfonate, petroleum sulfonate, alkylbenzene sulfonate, petroleum carboxylate
Cationic	The cation headgroup can form ion pairs with the acidic components of crude oil to change the wettability	The adsorption capacity is large in sandstone reservoir and the price is high	Quaternary ammonium salt type and amine salt type
Zwitterionic	Temperature and salt resistance, often compounded with other surfactants, and low degree of chromatographic separation	High cost and strong adsorption	Betaine type, amino acid type
Nonionic	Temperature and salt resistance, strong emulsifying performance, strong anti adsorption performance and many kinds	Not resistant to high temperature, high price and poor interface performance	Polyoxyethylene, alkanolamide, oxidized amine
Nonionic anionic	Temperature and salt resistance, easily biodegradable. It has the advantages of both non-ionic and anionic surfactants	Few kinds and high price	Non-ionic phosphate ester salts, non-ionic carboxylic acid ester salts, non-ionic sulfate ester salts, etc.

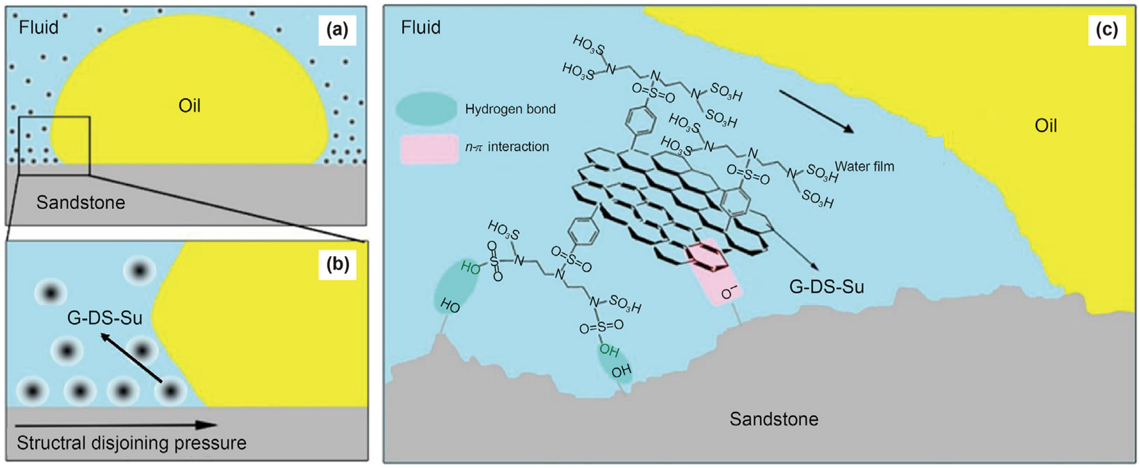

Fig. 2. The sandstone wettability alteration due to structural disjoining pressure mechanism (**a, b**) and adsorption of G-DS-Su onto the sandstone (**c**) (reproduced with permission from Radnia et al. (2018).

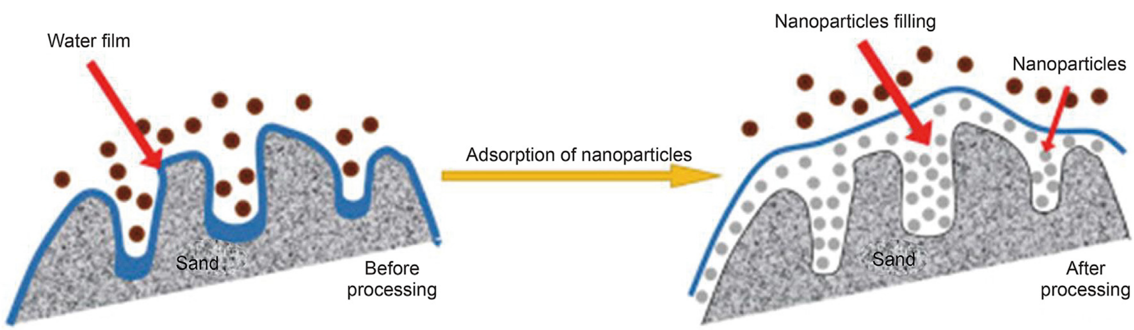

Fig. 3. Nanoparticles improve rock surface roughness (reproduced with permission from Wang et al. (2018).

technologies, surfactant/nanoparticle system as a new oil displacement agent has attracted wide attention (Ma et al., 2008). An experimental study of nanoparticle fluid by Suleimanov et al. showed that at 25 °C, compared with the surfactant alone, the addition of nanoparticles in oil displacement agent could improve the recovery of porous media by 35% and that of homogeneous porous media by 17% (Suleimanov et al., 2011). Zargartalebi et al. used hydrophilic and hydrophobic SiO_2 nanoparticles to change the properties of anionic surfactants (sodium dodecyl sulfate, SDS) and improve oil displacement performance (Zargartalebi et al., 2015). Similar results were obtained by Xu et al. (2019). 0.01% SiO_2 nanoparticle could slightly reduce IFT of anionic surfactant (KD) system, increase the surfactant concentration range of ultra-low IFT, and improve temperature resistance and long-term stability of IFT. In addition, the proper concentration of SiO_2 nanoparticles could also improve the stability of the emulsion. Therefore, the ultra-low IFT nanofluid of 0.05% KD + 0.03% SiO_2 could not only improve the oil recovery, but also reduce the injection pressure. Finally, the oil recovery was improved by 21.12% of OOIP and the injection pressure was reduced by nearly 50%. Wang et al. proposed a novel nanofluid composed of biosurfactants (rhamnolipid, sophorolipid, and surfactin) and SiO_2 nanoparticles (Wang et al., 2021a). The composite system could reduce the IFT better than a single biosurfactant, indicating that nanoparticles and biosurfactants had a good synergistic effect in EOR.

3.4. Combination flooding

Low permeability reservoirs have poor water flooding effect and low recovery, and the effect of enhanced recovery by single displacement method is limited. Therefore, researchers try to combine a variety of oil displacement methods in order to expand the sweep volume and improve the displacement efficiency.

It is generally considered that surfactant-polymer flooding is not suitable for low permeability reservoirs, which is mainly due to the injection problem of polymer molecules or the plugging of small pores after injection. However, some researchers have studied surfactant-polymer combination flooding by integrating the multiple advantages of polymer flooding that can reduce the reservoir heterogeneity, expand the sweep volume and surfactant flooding that can improve the imbibition capacity and the displacement efficiency (Guetni et al., 2021; Liao et al., 2022).

Marliere et al. demonstrated the feasibility of using surfactant-polymer EOR technology in the sandstone core with permeability of about 1 mD (Marliere et al., 2015). Core oil displacement experiments were carried out on sandstone cores with a formula composed of low molecular weight HPAM polymer (1500 mg/L) and typical oil production surfactant alkyl glyceryl ether sulfonate (AGES). The formula not only improved the fluidity control, but also reduced the IFT. Wang et al. used the surfactant system of Xinjiang petroleum sulfonate and cocamidopropyl hydroxyl sudan base + polymer composite system to carry out oil displacement experiment on heterogeneously low permeability cores (10–30 mD) (Wang et al., 2013). The results showed that the composite system had better oil displacement effect than simple surfactant. In addition, surfactant slug injection after polymer flooding was the best injection strategy, resulting in a 17.74% improvement in recovery. Liao et al. also proved that surfactant-polymer flooding had good injectivity and enhanced oil recovery effect in low permeability reservoirs (Liao et al., 2022). After the field implementation, the intra-layer and inter-layer contradictions in the reservoir has been effectively alleviated, which increased oil production by 7.77×10^4 tons and oil recovery by 3.5% of OOIP.

Not only in sandstone reservoirs, Shedid et al. have proved that alkaline-surfactant-polymer (ASP) flooding can also be successfully applied in carbonate reservoirs with permeability less than 5 mD (Shedid, 2015). It was also pointed out that compared with the later stage of water flooded low-permeability carbonate reservoir, ASP flooding could obtain higher recovery under the condition of high flowing oil saturation.

The emulsifying ability of oil displacement agent also plays a very important role in improving oil recovery (Alvarado et al., 2011; Ponce et al., 2014). In the process of chemical oil displacement in low permeability reservoirs, we should not only pay attention to the interfacial activity of oil displacement agent, but also take into account its emulsifying performance (Blaszczyk et al., 2017). Therefore, the use of composite surfactants is also a common technical means. Yang et al. developed a composite oil displacement system of 0.15% Gemini surfactant (GMS-101) + 0.15% emulsifier, which had good interfacial activity and emulsifying ability (Yang et al., 2021a). After water flooding of low permeability natural core, 0.5 PV oil displacement system was continuously injected, which could increase the recovery by 21.7% of OOIP. Jiang et al. synthesized a low-cost, green and environmentally friendly polymer surfactant (PVA-1570) (Jiang et al., 2018). When the mass ratio of PVA-1570 to CTAB was 7:3 and the concentration was 3000 mg/L, the spontaneous emulsification effect was the best, which promoted the oil phase to enter the water phase quickly and the spontaneous emulsification occurred instantaneously. Moreover, the strength of the oil/water interfacial membrane of the composite system was higher, and the stability of the emulsion was enhanced. The oil recovery of the low permeability reservoirs could be increased by 7.4%–12.4% of OOIP (Jiang et al., 2018).

EOR of low permeability reservoirs is not only the compound innovation of oil displacement agent, but also the innovation of combination mode in oil displacement methods. Ding et al. studied the surfactant-alternating-gas (SAG) foam of the sodium dodecyl sulfonate (SDS) and cocamidopropyl hydroxy sulfobetaine (CHSB) with a mixing ratio of 9:1 (Ding et al., 2022). The results showed that SAG bubbles had high stability in microchannel and porous media, and SAG foam had good injection and deep migration ability. With the decrease in permeability, the oil recovery of SAG foam was increased. However, the application of SAG had a limitation on reservoir heterogeneity, which would fail when the permeability difference was over 12. Moreover, Wang et al. studied the miscible CO_2-SAG flooding as an enhanced combination form of CO_2 flooding, which mitigated the inadequate CO_2-crude oil interaction by adding a CO_2 soaking period just after CO_2 breakthrough (Wang et al., 2021c). The results showed that the overall oil recovery factor was 72.8% after CO_2-SAG flooding, 11% higher than simple miscible CO_2 flooding (61.8%). All the above prove that the innovative oil displacement combination has good effect and foreground application.

4. Imbibition enhanced oil recovery

Imbibition is a spontaneous process and an important way to enhance oil recovery in low permeability reservoirs. Imbibition phenomenon is also known as capillary rise (Qi et al., 2022). It refers to the process in which the wetted phase liquid displaces the non wetting phase without external pressure difference in the displacement process of two-phase fluid in porous media, only depending on the pressure difference of the two-phase contact surface (Sohi et al., 2009; Tian et al., 2021). The imbibition forces are mainly gravity and capillary force, which occupy different dominant roles in different imbibition conditions and seepage stages (Zhou et al., 2021c).

According to the flow condition of matrix external imbibition fluid, imbibition oil recovery can be divided into static spontaneous imbibition and dynamic imbibition (Tian et al., 2020). The characterization of imbibition is a complex process, which is related to factors such as rock surface wettability, seepage channel, reservoir temperature and pressure, IFT and crude oil viscosity (Darvishi et al., 2010; Ghandi et al., 2019; Var et al., 2013).

Imbibition mainly enhances oil recovery efficiency of low permeability reservoir through the following mechanisms: i) Wettability alteration. Cationic surfactant will form ion pairs with organic carboxylic acids in crude oil components, so as to restore the original hydrophilicity of the rock surface (as shown in Fig. 4) (Salehi et al., 2008). In addition, it has been proved that the tight core quickly changed from weakly oil-wet to weakly water-wet after the nonionic surfactant treatment (Sun et al., 2021). ii) Increasing charge density on rock surface (as shown in Fig. 5). When the ionic surfactant is adsorbed on the surface of crude oil and rock, its surface charge density increases. Furthermore, this also makes the water film more stable and the thickness increases, and the hydrophilicity of rock is enhanced (Liu et al., 2019a). iii) Emulsified crude oil. Surfactant has a strong ability to emulsify crude oil, which can emulsify oil film into oil droplets and improve the oil washing efficiency (Huang et al., 2020). iv) Reducing IFT (Meng et al., 2018). The low IFT is conducive to the formation of low adhesion work, enhance the deformation ability of crude oil and recover more residual oil.

In addition to the above mechanism, nanofluids also have the function of “structural disjoining pressure” (Nikolov et al., 2010). The nanoparticles gather at the three-phase interface, resulting in producing structural disjoining pressure at the end of the fluid (Khosravi et al., 2021). The disjoining pressure is far greater than the electrostatic force and van der Waals forces between the particles (Kondiparty et al., 2012). Nanofluids tend to move forward under this action, replace the original interfacial film, and make the oil peel off the rock surface and enhance the oil recovery (Qu et al., 2022b; Sakthivel and Kanj, 2021).

4.1. Static spontaneous imbibition

When the imbibition solution out of the matrix is in a non

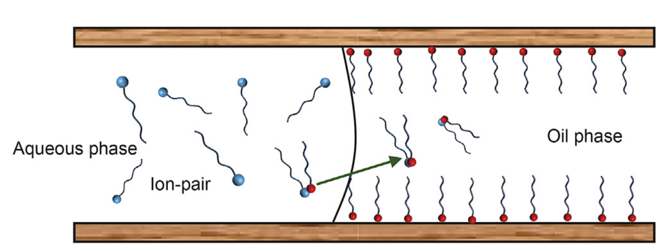

Fig. 4. Ion pair mechanism (reproduced with permission from Salehi et al. (2008).

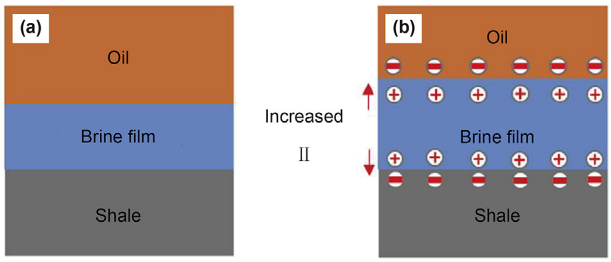

Fig. 5. Mechanism of increasing surface charge density (reproduced with permission from Liu et al. (2019a).

flowing state, the imbibition is called static spontaneous imbibition (Tian et al., 2021; Zhang et al., 2021c). Yao et al. conducted spontaneous imbibition experiments on artificial cores with different wettability (Yao et al., 2009). The results showed that the influence of IFT on the imbibition effect was related to the imbibition mode. For the reverse imbibition process, the lower the IFT, the stronger the imbibition effect. For the forward imbibition process, the lower IFT would reduce the imbibition effect. The research results of Sun et al. showed that surfactants affected the high-temperature imbibition recovery of low-permeability cores by reducing the IFT and improving the wettability (Sun et al., 2012). And it was more crucial to reduce the IFT when the cores were hydrophilic, it was more important to improve the wettability when the cores were lipophilic.

Different hydrophobic carbon chain length surfactants also had an effect on the spontaneous imbibition effect (Zhu et al., 2021). The results showed that with the increase in hydrophobic carbon number from 12 to 18, the imbibition recovery degrees of the four types of alkyl betaine were 37.8%, 39.4%, 41.0% and 42.1%, respectively. The contact angle decreased with the increase in carbon number, which was beneficial to oil stripping from the core. The IFT decreased with the increase in carbon number, which contributed to the deformation and flow of oil droplets and jointly promoted the imbibition process.

Zhang et al. constructed a surfactant compound system using anionic surfactants alpha olefin sulfonate (AOS) and zwitterionic surfactant cocoamidopropyl-hydroxysulfobetaine (CHSB-35) (Zhang et al., 2021b). Under the condition of ultra-low permeability sandstone reservoir with high salinity (11.2 wt%), when the total concentration of surfactant system was in the range of 0.20–0.35 wt%, oil-water IFT could be reduced to ultra-low value. When the total concentration was about 0.10–0.15 wt%, the imbibition rate of surfactant was higher, and the contact angle was about 35°. The oil recovery rate of this system was 4 times faster than that of simulated water and 2 times faster than that of each single surfactant. The synergistic effect between surfactants improved the heat and salt resistance, while greatly improving the IFT reduction ability (reaching ultra-low value) and wettability change ability (strong water wettability).

Kang et al. discussed the influence rule of surfactant complex system on imbibition recovery of ultra-low permeability reservoirs by analyzing the performance of surfactant complex system (Kang et al., 2019). The study indicated that emulsified crude oil was helpful to enhance oil recovery, but the emulsion was too stable to be conducive to imbibition recovery. The 0.6% anionic surfactant (HABS) + 1.4% nonionic surfactant (APG1214) complex system had a strong demulsification effect, which was more unstable than other single surfactants. So the emulsion droplet could be rapidly aggregated. And the oil droplets were quickly emulsified into small oil droplets by shearing action to pass through the pore-throat. In the stable migration, it could quickly gather and form continuous phase, reduce resistance and have better EOR effect.

In recent years, nanoparticles have been widely used in petroleum development and show great potential in imbibition recovery (Bai et al., 2021b; Keykhosravi and Simjoo, 2020). Tajmiri et al. proved that ZnO nanoparticles have the ability to reduce viscosity and alter wettability (Tajmiri et al., 2015). And the potential of these nanoparticles to improve oil imbibition recovery was verified. Zhou et al. prepared an ultra-small silicon dots (SiDots) through chemical modification (Zhou et al., 2022). The active SiDots nanofluids exhibited higher interfacial activity, reduced the IFT, increased the dilating modulus of the oil-water interfacial film, and had good temperature resistance (110 °C) and salt tolerance (12×10^4 mg/L). The maximum recovery of the active SiDots nanofluid was 38%, 15% higher than that of brine and 5% higher than that of surfactant.

Zhao et al. prepared SiO_2 nanofluid with SiO_2 nanoparticles and nonionic surfactants (TX-100), which was used to EOR through spontaneous imbibition (Zhao et al., 2018). The SiO_2 nanofluid showed excellent temperature and salt resistance. The imbibition experiments showed that comparing with about 8% oil recovery of TX-100 solution, the SiO_2 nanofluid could enhance oil recovery to about 16% of OOIP, which proved the synergistic effect mechanism. Furtherly, they mixed SiO_2 nanoparticles with anionic surfactants to prepare a new type of nanofluid with good stability (Zhao et al., 2022a). Compared with simulated water with high salinity (30000 mg/L), the IFT was decreased by 99.98% after adding nanofluid. Compared with single surfactant, the contact angle increased by 20° with the addition of nanofluid, and the rock surface changed from oil-wet to water-wet. The imbibition recovery of nanofluids could reach 28.5%, which was much higher than that of surfactants and SiO_2 nanoparticles. The EOR mechanism was shown in Fig. 6. In addition to reducing IFT and wetting alteration, there was also the unique structural disjoining pressure of nanofluids. According to the "structural disjoining pressure" theory of nanoparticles proposed by Darsh Wasan (Nikolov et al., 2010; Wasan et al., 2011), it formed a wedge-shaped structure through self-assembly in the three-phase contact area. The positive thrust generated by the wedge-shaped structure was the structural disjoining pressure, which could peel oil droplets off the rock surface and greatly improve the oil absorption and drainage effect of nanofluid.

Nazari Moghaddam et al. studied the imbibition efficiency of nanofluids formed by different kinds of nanoparticles in carbonate rocks (Nazari Moghaddam et al., 2015). The results showed that nanofluids could significantly enhance the hydrophilicity of rocks and increase the imbibition efficiency by about 20% compared with saline water. The main reason why nanofluids enhanced rock hydrophilicity was the "structural disjoining pressure" effect of nanofluids. Zhang et al. verified the "structural disjoining pressure" effect of nanofluids through single capillary imbibition and core imbibition experiments, and observed obvious wedge-shaped film in the three-phase contact angle experiment (Zhang et al., 2014). After the formation of wedge-shaped film, the crude oil was stripped from the glass plate under the action of "structural disjoining pressure" and the wettability of solid medium was changed. And then the crude oil was further recovered by the imbibition of nanofluid, and the imbibition efficiency of nanofluid was 48% higher than that of brine.

4.2. Dynamic imbibition

When the imbibition solution out of the matrix is in the flow state, the imbibition is called dynamic imbibition (Zaeri et al., 2018). Wang et al. reported that due to the combined action of capillary force and viscous force, there was an optimal displacement rate within a certain displacement rate range, which was

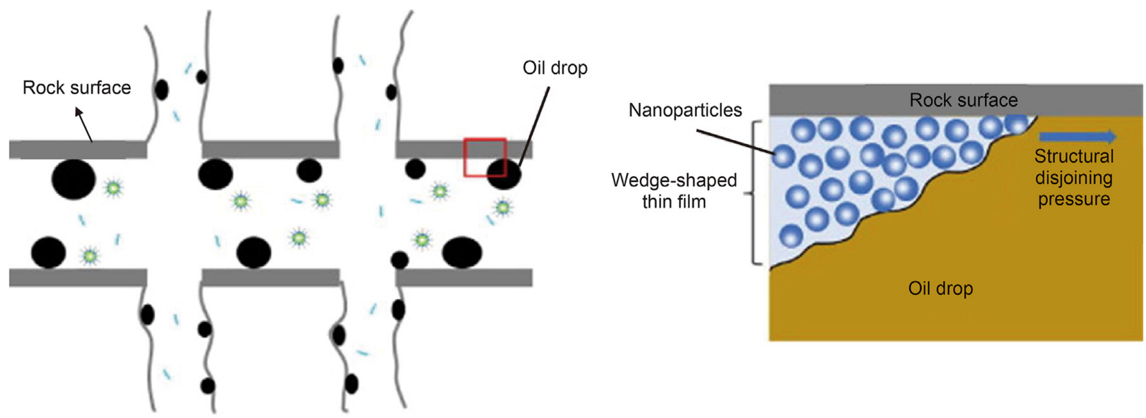

Fig. 6. Schematic diagram of structural disjoining pressure mechanism (reproduced with permission from Zhao et al. (2022a).

3.0 mL/h, and the maximum imbibition efficiency was 35.5% (Wang et al., 2009). The stronger the hydrophilicity of the matrix core (0.5–10 mD), the greater the capillary force on the fluid and the stronger the imbibition effect. Under the condition of dynamic imbibition, viscosity had a great influence on imbibition. With the decrease in oil-water viscosity ratio, the imbibition effect was improved. Zhou et al. studied the dynamic imbibition recovery effect of tight oil reservoir (2 mD), and the imbibition recovery rate increased with the increase in injection pressure (Zhou et al., 2017). With the increase in injection rate, the imbibition recovery showed a “first increase and then decrease".

Xie et al. also pointed out that when using surfactant solution for imbibition recovery, appropriate injection rate should be selected to make full use of the “water absorption and oil drainage” of capillary force, the “displacement effect” of viscous force and the “improving wettability and reducing IFT ″ effect of surfactant, so as to achieve higher imbibition recovery (Xie et al., 2017, 2018). At the same time, too low IFT weakened the capillary force of rock pores, which was not good to imbibition recovery. Moreover, with the increase in water saturation of matrix core (2 mD), the capillary force gradually decreased, the oil-water infiltration ability between matrix rock and fracture decreased, and the imbibition recovery decreased. Therefore, for low-permeability fractured reservoirs using surfactant imbibition recovery, imbibition oil recovery in advance was beneficial to play the role of capillary force in water absorption and oil drainage, and then improve the effect of imbibition recovery and enhance oil recovery.

Qu et al. compared the experimental results of dynamic imbibition and static imbibition (core permeability: 0.1–0.2 mD), and found that the small pore throat was the main storage space during static imbibition. The imbibition replacement mainly occurred in the small pore throat (Qu et al., 2018). Dynamic imbibition mainly enhanced the displacement degree of crude oil in the large pore throat. Huang et al. found that the dynamic imbibition process of class I and class II reservoirs could be divided into three stages: the rapid rising stage of oil recovery of macropores under displacement and forward imbibition, the slow rising stage of oil recovery of micro pores under reverse imbibition and the stage dynamic imbibition equilibrium. However, class III reservoir only had the first two stages in the experiment (Huang et al., 2021).

Schechter et al. reported that the gravity differentiation would dominate the capillary force when the IFT was very low (Schechter et al., 2013). Thus, the forward imbibition might occur and the imbibition recovery could be further increased. Through microscopic visual imbibition experiments, Alshehri et al. found that the capillary would become the resistance and higher than viscous and gravity forces when the core was lipophilicity, thereby retaining the crude oil in the matrix (Alshehri et al., 2009). Adding surfactant in the imbibition solution could reduce the IFT and the capillary force that became the resistance. When the resistance was low enough, gravity would become the dominant factor. At this time, buoyancy could overcome the resistance to imbibe and drain oil.

Lu et al. studied the mechanism of SiO_2 nanofluid improving the recovery of low permeability core through core displacement experiment (0.6–1 mD) and single capillary visual imbibition experiment (Lu et al., 2017). Nanofluids could enhance oil recovery by 4.48%–10.33% of OOIP compared with brine. Capillary imbibition experiment showed that nanofluid could peel off the oil film on the capillary wall (as shown in Fig. 7), thus improving the oil washing efficiency of imbibition, and the hydrophilicity of core was significantly increased after displacement. In addition, when the concentration of nanoparticles was too high, obvious core plugging would occur. Therefore, the suitable concentration of nanoparticles should be selected for practical application.

5. Conformance control technology using polymer gels

Due to micro-fractures and strong heterogeneity, low permeability reservoirs are prone to suffering channeling problems during development (Song et al., 2018). Therefore, the application of conformance control technology can improve the economic profitability (Gakhar and Lane, 2012). Currently, there are many kinds of conformance control methods in oilfields, including *in-situ* polymer gels (Zhou et al., 2021a), preformed particle gels (PPGs) (Bai et al., 2015), emulsion (Liu et al., 2017b), foam (Yang et al., 2018), and foam gel (Lai et al., 2021). Among them, *in-situ* polymer gels and PPGs are the most widely used in conformance control of low permeability reservoirs (Wang et al., 2017a).

5.1. In-situ polymer gels

For *in-situ* polymer gels, the most commonly used low-temperature reservoir gel system is HPAM with crosslinking agent (such as chromium acetate) (Bai et al., 2022; Khamees and Flori, 2018; Wang et al., 2003). The polymer and crosslinker are injected alternately, and then they crosslink in the reservoir, forming gel and plugging the fracture. The gelation time of the system is long and the gelation time will be shortened by increasing temperature (Kang et al., 2021). The fluid can be easily injected into the in-depth reservoir and effectively plug the fractures due to its low viscosity, low injection pressure and can selectively penetrate into fractures. Thus, the *in-situ* gel system commonly will not cause

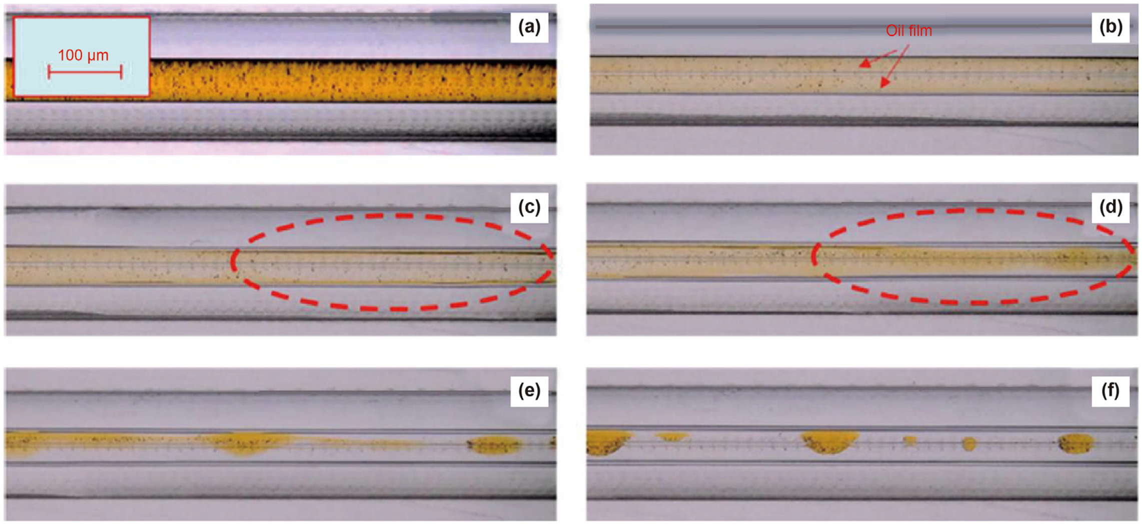

Fig. 7. Results of nanofluid capillary imbibition (reproduced with permission from Lu et al. (2017).

significant damage to the formation. It has the characteristics of low resistance factor and high residual resistance factor, and can realize deep conformance control (Hajilary et al., 2015; Yang et al., 2019b).

Polymers are mainly polyacrylamide and its derivatives, but also 2-acrylamide-2-methylpropanesulfonic acid (AMPS) copolymer, xanthan gum and so on. Crosslinkers can be divided into three categories (Zhang et al., 2020a). The first is inorganic multivalent metal ions, such as chromium lactate, chromium acetate Cr(III), aluminum citrate Al(III), etc. (Pu et al., 2019). The second is organic aldehyde crosslinkers, such as dialdehyde, urea formaldehyde resin, phenolic resin, melamine resin, furfural resin, etc. (Lashari et al., 2018). The third is composite crosslinkers, which have the characteristics of both organic system and inorganic system (Yang et al., 2019a).

Zhao et al. used organic chromium crosslinker (1–1.2 wt%) and partially hydrolyzed polyacrylamide (HPAM 2000–3000 mg/L) to prepare a gel system (Zhao et al., 2017). The initial viscosity of the gel was small, and it could effectively plug the high permeability layer. The plugging rate of the high permeability core was more than 85%, and that of the low permeability core was less than 5%, which could achieve better conformance control effect. Hutchins et al. prepared gels using HPAM and compound organic crosslinkers composed of hydroquinone (HQ) and hexamethylene tetramine (HMTA) (Hutchins et al., 1996). The gel system had good anti-aging stability, which could be stable for 12 months at 149 °C and 5 months at 176.7 °C.

In order to plug high permeable channel in low permeability reservoirs with high salinity, salt-tolerant amphiphilic polymer can be used as main agent in polymer gel system. Yang et al. developed a gel using amphiphilic polymers and crosslinker Cr(III) (Yang et al., 2019a). The results showed that the amphiphilic polymer gel not only had good strength and viscoelasticity, but also could change the gel properties by adjusting their components. Compared with HPAM gel in the high salinity reservoir, the gel had better overall stability. Zhang et al. obtained similar results using a gel formed with chromium lactate crosslinker and salt-thickening amphiphilic polymer (PADC) (Zhang et al., 2020b). In order to further improve the shear resistance of amphiphilicy polymer gel, Zhou et al. constructed the inclusion polymer gel with PADC amphiphilic polymer and cyclodextrin polymer by supramolecular inclusion force (Zhou et al., 2021a). The cyclodextrin structure in inclusion polymer gel could recombine with the damaged amphiphilic polymer through host-guest inclusion effect, which made the influence of shear effect on inclusion gel smaller.

However, both organic chromium and phenolic crosslinkers can produce toxic substances and pollute the environment. More and more oil fields are reducing the use of such crosslinkers. Therefore, Gakhar and Lane took poly(ethylene imine) (PEI) as crosslinker, and introduced an environmentally friendly low viscosity gel named PEI/HPAM (Gakhar and Lane, 2012). They pointed out that the gel had the following characteristics at lower HPAM concentration, such as lower viscosity, longer gel time and higher gel strength. The results were further compared with those of acetate Cr(III)/HPAM gel in order to control water channeling in fractured reservoirs. PEI crosslinker was more attractive than acetate Cr(III) in fractured low permeability reservoirs with narrow pore size fractures.

Although *in-situ* polymer gels have wide application and benefits in oil recovery, they have some limitations. For example, core pores can filter and retain the polymer according to the molecular weight, which blocks the flow channel and affects the deep plugging of the polymer gel. Also, the polymer may be trapped in the rock matrix near the fracture, which will increase the difficulty of subsequent water injection. If excessive polymer solution is injected, the final sweep volume will also be negatively affected (Kang et al., 2021).

5.2. Preformed particle gels

Preformed particle gels (PPGs) are formed at surface by mixing monomers, crosslinking agents, and initiators with a certain ratio, polymerization reaction, drying and crushing (Bai et al., 2007; Zhang and Bai, 2011). Compared with *in-situ* gel system, PPG system has many notable advantages (Zhang and Bai, 2011). For example, the particle size can be adjusted as needed. Crosslinking on the ground, the adverse effects of formation water dilution and temperature on the crosslinking reaction are avoided. There is a special liquid dispensing device, which has the advantages of simple liquid dispensing and convenient construction. When the gel particles are dispersed in water, they can expand several to hundreds of times, thus provide plugging to water or gas channel (Zhou et al., 2021b).

Commercial PPGs currently include millimeter-sized preformed particle gels (Zhou et al., 2021b), microgels and nanogels (Goudarzi et al., 2017). They are mainly different in particle size. Swollen PPGs are viscoelastic and can deform in the fracture or channel during injection (Elsharafi and Bai, 2016). Therefore, they can easily penetrate into the in-depth of channels. PPGs can divert subsequent fluid drive and improve the sweep efficiency. Consequently, PPGs can increase oil recovery and reduce water cut (Yang et al., 2017).

In 1999, PPG technology was successfully applied for the first time in Zhongyuan Oilfield, China. As of now, millimeter-grade PPG has been deployed in more than 10,000 wells in China to conformance control and reduce the permeability of fractures and high permeability channels. Pu et al. synthesized a novel CO_2-responsive preformed gel particle (IPN-ASAP) with an average particle size of 18.24 μm and an interpenetrating network to alleviate CO_2 breakthrough in low permeability reservoirs (Pu et al., 2021). When IPN-ASAP was contacted with CO_2, the gel particle strength increased due to the protonation reaction of IPN-ASAP. In addition, after IPN-ASAP was injected into the fractured core, the injection pressure increased from 5.0 kPa to 0.342 MPa. Finally, the plugging efficiency was 99%, and the oil recovery was increased by 23.1% of OOIP.

To deal with smaller channels and micro-fractures that commonly exist in low permeability reservoirs, researchers have made great efforts to develop PPGs with smaller sizes. Tobita et al. studied the formation of microgel in emulsion polymerization, which provided a new idea for the formation of microgel (Tobita et al., 2000). Cozic et al. studied microgel for conformance control and confirmed their superior permeability reduction ability (Cozic et al., 2008). Goudarzi et al. also investigated the application of microgels in conformance control and fluidity control (Goudarzi et al., 2017). Zhang et al. developed a small polymer microgel (SPM) for microgel treatment in low permeability reservoirs (Zhang et al., 2020c). The results showed that SPM had good compatibility with the pore throat size of reservoir. It was recommended to be applied to low permeability reservoirs, but not to medium permeability reservoirs. In the pilot test, the enhanced oil recovery of SPM injection stage and post-water injection stage were 2.1% and 5.2%, respectively. Peng determined the quantitative relationship between the particle size of polymer microspheres and the fracture opening through the plugging experiment (Peng, 2018). Nano-sized microspheres were suitable for less than 15 μm, micron-sized microspheres were suitable for 17.0–22.75 μm, and large-sized microspheres were suitable for 22.75–50.09 μm fracture opening. The oil displacement experiment showed that the oil recovery of secondary gas flooding could be improved by 22.5%–27.0% of OOIP after conformance control by microsphere.

As described above, considerable progress has been made in conformance control technology of polymer gel systems over the past decades. As shown in Table 4, the characteristic, advantage, and shortcoming for different polymer gel systems are summarized to conveniently compare and analyze the performance. However, for low-permeability fractured reservoirs, due to stress concentration, multi-scale natural fractures are randomly distributed and closed near the wellbore, the problem of “injection difficulty, plugging failure” has always been the bottleneck obstacle for the efficient application of deep conformance control and flooding technology in low-permeability fractured reservoirs. Therefore, in order to improve the application effect of in-depth conformance control and flooding technology and promote the high-efficiency water injection development of oilfields, it is particularly important to study the reasons and countermeasures for “injection difficulty, plugging failure” of conformance control and flooding agent in low-permeability fractured reservoirs.

6. Technical challenges and prospects

In recent years, the progress of science and technology has laid a good foundation for the development of low permeability reservoirs, and its development efficiency has been significantly improved, but there are still a large number of undeveloped low permeability reservoirs. As a non renewable resource, the oil consumption in the world is very huge, and the oil price is rising, so the development of low permeability reservoirs has a promising prospect.

The theoretical research of gas flooding started early, but the field scale application is still facing the following problems: i) The reserve grade is low and gas channeling is severe in the process of gas injection. Low permeability and ultra-low permeability reservoirs have strong heterogeneity and are developed by hydraulic fracturing. ii) Injection production and surface engineering, dynamic monitoring, produced gas recycling and other supporting technologies need to be further improved and cost reduced. iii) CO_2 capture and transportation costs are high, the supply is unstable, and the corrosion problem of injection production pipeline is serious. Large-scale applications require low-cost and stable gas supply. In view of different types of gas flooding technology, it is necessary to strengthen the study of the adaptability of gas injection and oil displacement mechanism of various reservoirs, clarify the suitable gas injection mode and gas source matching suitable for reservoirs, prevent gas channeling, and further evaluate the potential of enhanced oil recovery. For mature technologies such as CO_2 flooding, hydrocarbon gas flooding and air flooding in some oil fields, the scale of industrial promotion and application should be enlarged. We should reduce the cost of CO_2 capture, improve pipeline transportation technology, and develop low-cost technology to reduce miscible pressure. And the technology of CO_2 flooding development should be improved, such as developing foam compound flooding technology, CO_2 thickening technology and intelligent injection-production adjustment technology, and ultimately improve CO_2 flooding sweep volume and oil recovery.

Table 4
Comparison of conformance control technology of polymer gel systems.

Product category		Characteristic	Advantage	Shortcoming
Preformed particle gels	PPG (Bai et al., 2007)	Ground synthesis, water dispersion and low cost	Controllable strength and size, strong adaptability to formation	Only suitable for plugging fractures and large pores with high permeability
	Nanogel (Pritchett et al., 2003)	Emulsion synthesis and high cost	Gel particles are small and dispersed in water	Not suitable for high permeability formations or fractured reservoirs
	Microgel (Goudarzi et al., 2014)	Shear bulk gel formation and high cost	Controllable strength and size, good flexibility, suitable for relatively low permeability reservoirs	Not suitable for high permeability formations or fractured reservoirs
	Preformed bulk gel (McCool et al., 2009)	Form bulk gel before injection	Strong/weak gel, suitable for fractures or high permeability layers	Difficult to be injected
In-situ polymer gels	Colloidal dispersion gel (Mack and Smith, 1994)	Dispersal gel	Dispersion in water, low cost, micron sized particles, easy to inject	Not applicable to high temperature, high salt environment and strong water channeling
	Bulk gel (Muruaga et al., 2008)	Network structure gel	Reduce the permeability of fractures and high seepage channels	Sensitive to pH, temperature and Salinity

Experts and scholars agree that foam can selectively plug and greatly improve the remaining oil recovery after gas or water flooding. Although foam flooding has the advantages of plugging water without plugging oil, it is also characterized by poor stability of foam, defoaming in case of oil, short validity period, high cost of N_2 injection, complex gas injection equipment and seriously emulsified oil of produced liquid, which leads to the decrease in oil well productivity and pump efficiency and the increase in treatment cost of produced liquid. In addition, during foam flooding, surfactants are adsorbed on the surface of the rock in large quantities, reducing the concentration of surfactants in the liquid phase, and seriously affecting the formation of foam. Therefore, researchers should develop a low IFT foam system to increase the oil washing capacity. The combination of foam system and other EOR technologies are also an important direction of research. The study of flue gas foam flooding system can not only reduce costs, but it also has very significant for energy conservation and environmental protection.

In the process of surfactant flooding in low permeability reservoirs, there are many oil displacement mechanisms, which play roles simultaneously. In previous research, the most important oil displacement mechanisms are the reduction of IFT, emulsification and wettability alteration. However, the contribution of various mechanisms to oil recovery were not quantitatively analyzed, resulting in unclear mechanism. Therefore, the contribution degree of various mechanisms should be quantitatively studied to clarify the EOR mechanism. Low permeability reservoirs have low permeability, large specific surface area and more serious adsorption loss, resulting in higher use cost of surfactants. Therefore, it is necessary to develop new surfactants to reduce the cost, or develop biosurfactants to reduce environmental pollution.

Although conventional nanoparticles have the ability to enhance oil recovery, they are greatly affected by salinity. Some nanoparticles have poor stability and are easy to agglomerate in formation brine. Therefore, surface modification of nanoparticles needs to improve the ability of nanoparticles to reduce the IFT and enhance the wettability of rock surface, delay the agglomeration of nanoparticles, and improve its stability in solution and its application range in low permeability reservoirs. At present, the research on the modification of organic nanomaterials mainly focuses on the modification of graphene and polymers. Although the effect of enhanced oil recovery is good, the modification method is complicated and costly, so it is difficult to be applied on a large scale. How to modify organic nanomaterials simply, efficiently and at low cost is the focus of future research. In addition, nanoemulsions with transparent or translucent appearance and small droplet size (50–500 nm) have good stability under harsh temperature and salinity conditions, and have ultra-low IFT and good solubilization capacity for oil, which also bring new ideas for the development of low permeability reservoirs.

Polymer gels play an important role in conformance control, improvement of reservoir heterogeneity, prevention and sealing of channeling in low permeability reservoirs. But a lot of work still needs to be done in harsh reservoir conditions. For example, the injectability is poor, and the plugging ability is insufficient in low-permeability reservoirs with high temperature and high salinity. Some high temperature and salt resistant polymer gels have been developed, but only a few polymer gels have been used in oil fields due to the high cost. Therefore, special polymer gels suitable for these reservoirs need to be developed to reduce their cost and improve their injection capacity, stability and plugging efficiency. Among them, the most important is to improve the thermal and salt stability of the polymer gel system. Conventional crosslinkers (such as formaldehyde, phenolic resin or chromate) in *in-situ* crosslinking polymer gels are toxic, which will affect human health and pollute the formation environment. Therefore, supramolecular polymer gel systems with self-growth and self-healing properties without crosslinker can be developed based on supramolecular intermolecular forces. Finally, due to the severe development of artificial and natural fractures in low permeability reservoirs, the limitation of partial connectivity between fractures and matrix makes a higher demand for in-depth conformance control of gels. It is required that the new plugging agent has good injectivity, good temperature and salt resistance, less filtration, good plugging efficiency and long-term thermostability.

7. Summary

Nowadays, the world's demand for oil is increasing year by year, which makes the exploitation of oil become a major concern of society. The reserves of low permeability reservoirs are huge, so the EOR technologies in low permeability reservoirs have a broad application and development prospect.

This review comprehensively summarizes the technical progress of EOR in low permeability reservoirs. Gas flooding, surfactant flooding, nanofluid flooding, combination flooding technology and imbibition enhanced oil recovery technology are described in detail. Besides, the polymer gel treatment that is very important for conformance control in low permeability reservoirs is summarized. The current problems faced by these EOR technologies are discussed. The solutions and development trends to overcome their shortcomings are proposed.

EOR technologies in low permeability reservoirs are a very difficult and complex large-scale system engineering, which needs the integration of multiple disciplines. In the past few decades, EOR technologies for low permeability reservoirs has been extensively and deeply explored. However, various technologies still need to be further improved and optimized. On the basis of deepening the understanding of oil displacement mechanism, innovating and developing EOR theory, we need to develop cost-effective and environmentally friendly green oil displacement agents. Different EOR technologies can be comprehensively utilized and synergistic effects among different technologies can be exerted to form a series of low-cost, efficient and environmentally friendly EOR technologies suitable for different reservoirs of low permeability reservoirs, so as to promote the development of the world petroleum industry and disciplines.

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