A comprehensive review of emulsion and its field application for enhanced oil recovery

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Abstract
Emulsification plays an important role in enhancing oil recovery. Experiments and field applications of alkali/surfactant/polymer (ASP) flooding indicated that the amount of oil recovery in liquids with emulsions is 5% higher than that in liquids with no emulsions. Therefore, it is of great significance to study emulsion and its field application for enhanced oil recovery. This paper discusses the current status of emulsion for enhanced oil recovery, including the formation mechanism of emulsions in chemical flooding, rheological properties, stability, seepage characteristics, emulsion improving sweep volume, and displacement efficiency, along with future development plans of emulsion for enhanced oil recovery, especially surfactants for chemical flooding. In addition, the Pickering emulsion for application in enhanced oil recovery is also discussed. The development effects of emulsion flooding have been discussed for the Midway-Sunset Oilfield, the emulsification characteristics of ASP flooding have been analyzed in Xing-V and Xing-II of the Daqing Oilfield, and the experiences regarding emulsion for enhanced oil recovery have been summarized. The key research directions of emulsion for enhanced oil recovery are indicated.

Keywords
chemical flooding, emulsion, enhanced oil recovery, oilfield application, seepage characteristics

1 | INTRODUCTION

In petroleum reservoirs, the maximum natural-drive oil recovery is only 20%-60%, that is, nearly 9.8 x 1011 t of crude oil is the main objective of various enhanced oil recovery methods.1-3 Chemical flooding is a method used to increase oil production by adding chemical agents, which can change the physical-chemical properties of the displacing fluid, the interfacial property of the crude oil, and the interaction mechanism between the displacement fluid and crude oil.4 Many oilfield tests have been carried out by applying chemical flooding, such as polymer flooding and ASP (alkali/surfactant/polymer) flooding, but problems exist with these oilfield tests. The polymer will plug the medium and lead to low-permeability formation due to polymer molecules not matching the oil layers in polymer flooding.5,6 Scale will be formed and pollute the oil layer due to the addition of alkali in ASP flooding.7,8 Most of these pollutants and damages to oil reservoirs are irreversible, which seriously affects the later development of oil fields.

Currently, polymer is widely used in chemical flooding to control the fluidity of the displacing fluid. Due to the high viscosity loss of polymer under high-temperature and high-salinity conditions,9 the application of chemical flooding is restricted in high-temperature and high-salinity reservoirs. In recent years, surfactants with high-temperature
and high-salt resistances, such as sulfonate surfactants\textsuperscript{10,11} and ethoxylated amine surfactants,\textsuperscript{12,13} have been developed, making it possible to provide a solution for high-temperature and high-salinity reservoirs. However, the greatest disadvantage of surfactant flooding is that it has unfavorable mobility control, and the surfactant solution easily flows rapidly along the high-permeability oil layer. To solve this problem, it is important to increase the resistance of the displacing fluid. Laboratory and field tests for ASP flooding have shown that oil recovery is low for the case with no emulsion appearing in the produced fluid, while the oil recovery is quite high for the case with emulsion appearing in the produced fluid. The oil recovery in the latter case is approximately 5% higher than that in the former case.\textsuperscript{14} Therefore, the research emphasis of surfactants is to improve the emulsification performance in chemical flooding. This will provide an environmentally friendly and promising method to improve recovery in high-temperature and high-salinity reservoirs.\textsuperscript{15,16} In addition, particle-stabilized emulsions, also known as Pickering emulsions, have been developed rapidly in recent years. It has been suggested that the nanoparticles can improve the thermal stability and viscosity of O/W emulsions, and they are suitable for enhanced oil recovery (EOR) applications.\textsuperscript{17,18}

Although there have been developments in this field, some fundamental aspects of emulsion seepage and the mechanism of emulsion enhancing oil recovery remain unclear. In this paper, the emulsion formation mechanism, rheological properties, stability, seepage characteristics, and enhanced oil recovery are investigated in detail, and the Pickering emulsion for application in enhanced oil recovery is also discussed. The application of emulsion for enhanced oil recovery is analyzed, and the experiences from laboratory tests and field tests are summarized.

## 2 | THE FORMATION MECHANISM OF EMULSIONS

The formation of emulsions is a complicated physical and chemical process in a reservoir and is influenced by many factors, such as pore-throat structure, rock wettability, crude oil properties, the quantity of residual oil, and the residual oil distribution type. Compared with emulsions formed by mechanical stirring, the formation mechanism is more complex. There are few studies on the formation mechanism of emulsions in porous media, and they have been mostly carried out through visualization tests or microfluidic devices.

Microfluidic devices can be used to simulate the formation process of emulsions,\textsuperscript{19} but it is difficult to simulate high-pressure and high-temperature environments, pore and throat features, and residual oil distributions. Kokal and Al-Dokhi\textsuperscript{20} reported a novel method to observe and study the characteristics of emulsions in a high-pressure and high-temperature environment. The study was conducted in a special visual pressure/volume/temperature (PVT) cell. The results showed that the emulsions can form under reservoir conditions, with mixing, especially if the crude oil has a tendency to precipitate asphaltenes. The formation of emulsions mainly depends on the composition of crude oil, especially the content of gelatine and asphaltenes.\textsuperscript{21} Yang\textsuperscript{22} carried out a displacement experiment by injecting an ASP solution into the microscopic visual core, and the spontaneous emulsification was analyzed. The experiment showed that the residual oil was gradually drawn into the oil filament along with migration of the solution, and the oil filament was lengthened and passed through the throat. The oil filament broke into countless oil-in-water emulsions while migrating. Peña et al\textsuperscript{23} used quartz capillary tubes to analyze the flow behavior of long oil droplets and suggested that snap-off is a possible mechanism to explain emulsion formation in two-phase flow in porous media. The retention or migration of residual oil after water flooding depends on the viscous forces and capillary forces acting on the residual oil. When the viscous force increases to a certain extent, the saturation of the nonwetting phase is reduced. The nonwetting phase becomes discontinuous, it will disperse in a continuous wetting phase, and it will flow in the form of an oil droplet or emulsion. The snap-off of residual oil depends on the capillary number, velocity, viscosity ratio, and pore-throat ratio.\textsuperscript{24} Hoyer et al\textsuperscript{25} reported the snap-off process in a constricted capillary with an elastic interface, suggesting that interface rheology greatly influences the snap-off of drops and that a reasonable viscoelastic behavior at the interface may lead to optimal interfacial stability against snap-off. Zhou et al\textsuperscript{26} investigated the formation process of an emulsion through a displacement experiment with a microscopic visual. The results showed that formation mechanisms are mainly the snapping action of residual oil and the shearing action of the emulsifier solution, as shown in Figure 1. Kim et al\textsuperscript{27} simulated the droplet formation in a cross-junction micro-channel using the lattice Boltzmann method, and the surface tension affecting the droplet length and the interval between droplets were investigated. The results indicated that the droplet length and the interval between droplets were increased with increased surface tension. Fu et al\textsuperscript{28} also simulated the emulsion formation by a ternary Lattice Boltzmann method, and the simulation results showed favorable agreement of emulsion formation with the experimental data, as shown in Figure 2. The results showed that the flow rate of outer fluid supplied viscous shear force against interface tension, which made the droplet pinch-off occurred near the exit orifice. As the fluid viscosities increased, the droplet pinch-off was delayed.
3 | RHEOLOGICAL PROPERTY AND STABILITY OF EMULSIONS

3.1 | Rheological property of emulsions

The rheological properties of emulsions affect seepage characteristics in porous media, such as deformation, migration, coalescence, and blocking of the throat. They are also important factors affecting the swept volume and displacement efficiency. The emulsion behaviors include different characteristics such as Newtonian fluid, expansion fluid, pseudoplastic fluid, and viscoelastic fluid. The interfacial rheological method is the most common method for measuring the rheological properties of emulsions. It includes a shear test and an expansion test, and they are used to measure the shear rheological property and expansion rheological property, respectively. The shear test method utilizes a stress rheometer with a double-wall ring geometry and an interfacial rheology cell with bi-cone geometry. The expansion test method includes the pendant drop method, the oscillating drop method, and the spinning drop method.

For an oil-in-water emulsion, the viscosity increases with decreasing droplet size, and its behavior can vary from a Newtonian fluid to a shear-thinning fluid. The power law model can describe the behavior of an emulsion when the shearing rate is beyond the limit. A water-in-oil emulsion generally behaves as a Newtonian fluid when the water cut is less than 30%. When the water cut increases, the friction and collision frequency of droplets increase, and the emulsion behaves as a non-Newtonian fluid and has thixotropic properties.

Huang and Wang formulated three types of water-in-oil emulsions using surfactant and crude oil with a wax content of 6.59%, 8.73%, and 21.63% and determined the yield characteristics of emulsions using a stress rheometer. The results indicated that the yield stress of the emulsion increased with increased water cut, and non-Newtonian
characteristics are more obvious for a higher water cut. Kumar and Manda\textsuperscript{38} prepared nanoemulsions by the high-energy method using Tween 80 and n-heptane. The ultra-low IFT value ranged from $10^{-3}$ to $10^{-5}$ mN/m in the oil-middle phase emulsion with 0.5 wt% Tween 80. The nanoemulsions show pseudoplastic behavior when the viscosity is in the range of 9-12.5 mPa·S. Currently, there are many calculation models describing emulsion viscosity\textsuperscript{39,40} but none of them are universal. The reason is that there are many factors influencing emulsion viscosity, and it is difficult to describe emulsion viscosity by adding only a few parameters, such as the dispersed phase volume fraction. An emulsion also has yielding characteristics as well as yield stress for emulsions with high water cuts.\textsuperscript{41} The yield stress of an emulsion increases with increasing water cut. When the water cut is less than 30%, the yield stress of the emulsion slightly increases with increasing water cut. When the water content is high, the yield stress greatly increases with increasing water cut.\textsuperscript{42} Sharma et al\textsuperscript{43} reported the effect of high-pressure and high-temperature conditions on the viscosity of Pickering emulsions for varying concentrations of nanoparticles (SiO$_2$ and clay) in the presence of 1000 mg/L polymer (PAM) at 0.22 wt%. The results showed that the viscosity and yield stress are predominantly constant for varying pressure and temperature conditions for this Pickering emulsion. The Herschel-Bulkley model can be used to predict the viscosity of this Pickering emulsion.

Viscoelasticity is also a topic of interest in the field of emulsion research. In general, the viscoelasticity of emulsions increases with increasing dispersed phase volume fraction. Oil-water interfacial tension is the reason for the increase in the viscoelasticity of emulsions.\textsuperscript{44} An emulsion droplet will deform when there is shear stress. However, there is a tendency to restore sphericity due to the interfacial tension, and this behavior increases the elasticity.\textsuperscript{45} In addition, the internal structures of emulsions (such as droplet flocculation) are also responsible for increases in viscoelasticity. Sharma et al\textsuperscript{46} investigated the viscoelastic behavior of the Pickering emulsion stabilized by a nanoparticle-surfactant-polymer system as a function of pressure (0.1-30 MPa) and temperature (19.85-97.83°C). The results showed that Pickering emulsions behave like viscoelastic fluid at all pressure conditions, and the storage modulus increases rapidly with increasing pressure. Additionally, Pickering emulsions exhibit better viscoelastic properties for varying conditions of temperature compared with surfactant-polymer-stabilized emulsions. Mandal and Bera\textsuperscript{47} formulated stable oil-in-water nanoemulsions using nonionic surfactant ( Tween 40) and light mineral oil. The droplet sizes were 18-31 nm based on dynamic light scattering analysis, and surface charge values were $-35$ mV based on $\zeta$ potential measurement. The nanoemulsions have favorable thermal stability; the viscosity remains stable over a wide temperature (30-70°C) range. The storage modulus (G’) and loss modulus (G”') of these nanoemulsions increase with increasing surfactant concentration and angular frequency.

3.2 Stability of emulsions

The stability of an emulsion is relative and mainly depends on the aggregation rate and coalescence rate of a droplet. The smaller the aggregation rate and coalescence rate, the more stable an emulsion is. Currently, the stability of emulsions has been mainly investigated for three different scales: macroscopic phase separation, mesoscopic droplet size, and microscopic interfacial film,\textsuperscript{48} as shown in Figure 3. Macroscopic phase separation is a conventional method for evaluating the stability of emulsions. Mesoscopic droplet size can more accurately reflect the flocculation, coalescence, and settlement of a dispersed phase.\textsuperscript{49} Microscopic interfacial films are used to test the stability mechanism of emulsions by investigating interfacial films and have been a topic of interest in recent years.\textsuperscript{50} The main methods include light scattering,\textsuperscript{51} low-field nuclear magnetic resonance,\textsuperscript{52} Langmuir trough,\textsuperscript{53} microporous pipette,\textsuperscript{54} and scanning electron microscopy.\textsuperscript{55} The interfacial film strength of an emulsion is the key factor affecting its stability. In the process of emulsion seepage in porous media, the dispersed emulsions frequently crowd and collide. If the interfacial film strength is small, the emulsions can easily coalesce and break up,\textsuperscript{56} and the displacement effect is poor. The interfacial film strength of emulsions is closely related to the emulsifier molecular structure, properties, concentration, crude oil composition, emulsion droplet size, and water cut. In general, the larger the emulsion droplet size, the smaller the interfacial film strength, and the more likely an emulsion is to break up.\textsuperscript{57} The gelatine, asphaltene, and wax components of crude oil have certain interfacial activities. They can form directional adsorption at the oil-water interface, promote the emulsification of crude oil and form strong interfacial films.\textsuperscript{58} The molecular structure and properties of emulsifiers are the most important factors affecting the strength of interfacial films.

![FIGURE 3 Schematic diagram of the multiscale study method for emulsions](with permission from Chemical Industry and Engineering Progress)
When the emulsifier concentration is low, the interfacial film strength is poor, and the emulsion formed is unstable due to the lower number of emulsifier molecules absorbed on the interface. When the emulsifier concentration increases to a certain value, the interfacial film strength is high, and the stability of the emulsion is improved.59 Zhang et al60 reported a straightforward and cost-efficient strategy to develop Janus nanoplate surfactants, which exhibit an excellent emulsifiability, stability. Such colloidal surfactants can stabilize Pickering emulsions of different oil/water systems. Sharma et al61 formulated a novel O/W emulsion stabilized using a nanoparticle-surfactant-polymer system using lubricating oil, and polymer polyacrylamide (PAM), surfactant, sodium dodecyl sulfate (SDS), and nanoparticles such as SiO2, clay, and CuO were used. The thermal stability was investigated, and the results showed that this Pickering emulsion exhibits better thermal stability than that of emulsions stabilized by a surfactant-polymer system, and partially, hydrophobic clay nanoparticles and salt (NaCl) can improve the thermal stability of Pickering emulsions. The stability of Pickering emulsions and the emulsions stabilized by a surfactant-polymer system are shown in Figure 4.

The interfacial viscosity and elasticity of emulsions affect the aggregation and drainage rates and greatly affect the stability of emulsions. The higher the interfacial viscosity and interfacial elasticity of an emulsion are, the lower the aggregation and drainage rates and the more stable the emulsion.62 The rotating speed plays a decisive role in the stability of emulsions. The droplet size is smaller, and an emulsion is more stable when the rotating rate is higher. The stability of the emulsion decreases with increasing water cut when the water cut is less than 50%. The stability of the emulsion is poorer with increasing temperature.63 Kang et al64 prepared emulsions using 50% crude oil and 50% wastewater of Henan Oilfield containing polymer and surfactant at 55°C and studied the stability mechanism of polymers and surfactants on emulsions. Their work indicated that low interfacial tension is not the key factor in stabilizing emulsions. Compared with surfactants, polymers can increase the interfacial elasticity of emulsions and improve the stability of emulsions. Maurya and Mandal65 formulated oil-in-water emulsions using n-decane and paraffin oil, silica nanoparticles, anionic sodium dodecyl sulfate (SDS), and cationic cetyl trimethyl ammonium bromide (CTAB). The nanoparticles can enhance the stability of oil-in-water emulsions and can improve the emulsion viscosity.

4 | EMULSION FOR ENHANCED OIL RECOVERY

4.1 | The seepage characteristics of emulsions in porous media

Currently, research on the seepage characteristics of emulsions has mainly focused on two aspects: one is through the experimental method and the other uses the mathematical model of emulsion seepage.

If the emulsion droplet size is very small compared with the pore and throat diameters of a porous media, the emulsion can be regarded as a continuous phase, and the
continuous phase model can be used to describe the seepage characteristics of emulsions. Kang et al. studied the seepage characteristics of amphiphilic polymer emulsions. The results showed that the amphiphilic polymer emulsion had a strong viscoelastic effect and high seepage resistance in the seepage process. The seepage resistance greatly increases with increasing emulsion droplet size. Yang et al. reported that the relative sizes between an emulsion particle and pore diameter significantly influenced the migration resistance of emulsions. The migration resistance of an emulsion is high when the emulsion droplet size is not much different from the pore diameter, and the mobility of the emulsion is low.

Emulsions with different droplet sizes have different migration characteristics in a pore throat. Zhou et al. divided emulsion droplet sizes into three categories according to the relative sizes between the emulsion particle and pore-throat diameters, as shown in Figure 5. The categories are as follows: (a) The emulsion droplet size is far smaller than the throat diameter. The migration characteristics of such emulsions are similar to those of the continuous phase in porous media. (b) The emulsion droplet size is slightly larger than the throat diameter but smaller than the pore diameter. This was defined as the pore-throat scale emulsion. Such emulsions will block the throat due to the Jamin effect. (c) The emulsion droplet size is much larger than the pore diameter. Such emulsions are unstable, and they will be dissociated oil and water or multiple dispersed emulsions in the seepage process. The resistance factors for three types of droplet size emulsions are shown in Figure 5. The resistance factor $f$ is defined as the ratio of the pressure difference at the inlet and outlet of the throat $\Delta P_e$ with that of water flow $\Delta P_w$ and is calculated as $f = \frac{\Delta P_e}{\Delta P_w}$. For the pore-throat scale emulsion, the resistance factor is largest due to the Jamin effect, and its migration process mainly includes three stages: retention, migration, and passing through the throat. When the pore-throat scale emulsion enters into the throat, the emulsion is trapped at the inlet of the throat. The emulsion moves slowly into the throat as the driving force increases; meanwhile, the resistance factor decreases sharply. When the emulsion passes through the throat, the pressure difference at the inlet and outlet of the throat is approximately the same as the water flow, and $f$ is approximately equal to 1. For the emulsion with a droplet size far smaller than the throat diameter, $f$ is almost equal to 1, and the emulsion easily passes through the throat. For the emulsion with a droplet size that is much larger than the pore diameter, the emulsion easily breaks up due to its poor interfacial film strength, and $f$ decreases sharply after breaking up.

Regarding mathematical models, there are currently three classic mathematical models that describe emulsion seepage, and they are the bulk viscosity model, droplet retardation model, and filtration model. The emulsion was regarded as a single-phase non-Newtonian fluid in the bulk viscosity model, and it was similar to the flow of polymer solution in the porous media. An emulsion viscosity model was presented for different shear rates. However, the model did not consider the interaction between emulsion droplets and porous media; it can only be used for very small droplets or very high flow velocity. The emulsion was regarded as a two-phase fluid in the droplet retardation model, and the condition of the pore and throat preventing emulsion droplet migration was described by the addition of resistance to the dispersed phase. The model successfully calculated the permeability reduction of porous media, but some results were different from the experimental results, such as the case of injecting water after emulsion flowing. The filtration model is currently the most widely used and is based on the theory of deep bed filtration. It is suitable for describing the seepage of thin and stable emulsions. It successfully describes pore blockage and emulsion droplet retention. The subsequent mathematical models of emulsion seepage were mostly modifications and improvements of the above models, such as those by Rege and Bera and Mandal et al. However, the filtration model did not consider the change in pressure gradient, and it cannot simulate restarting of the emulsion droplets under a large pressure difference.

**FIGURE 5** The resistance factor for different droplet size emulsions. (A) The emulsion droplet size is far smaller than the throat diameter; (B) the emulsion droplet size is slightly larger than the throat diameter but smaller than the pore diameter; and (C) the emulsion droplet size is much larger than the pore diameter.
4.2 Emulsion for enhanced oil recovery

Currently, research on emulsion improvements in oil recovery is still in the laboratory investigation stage, and the research methods consist mainly experimental methods and numerical simulation methods.

In displacement experiments, Mandal et al.\textsuperscript{79} reported that emulsion flooding can increase the recovery by more than 15% compared with conventional water flooding. The displacement mechanism of oil-in-water emulsions mainly reduces the displacing liquid mobility and decreases the interfacial tension. Karambeigi et al.\textsuperscript{80} used core displacement experiments and micro visual displacement experiments to study the enhanced oil recovery effect of emulsions. The results showed that emulsion flooding can increase oil recovery by approximately 28% compared with water flooding. The non-Newtonian fluid characteristics and interface potential of the emulsion are important factors for increasing the number of capillaries and oil recovery. Wang et al.\textsuperscript{81} concluded that the displacement mechanism of emulsions proceeded as follows. First, the emulsion could block the large throat, and the continuous phase displaced the unswept residual oil. Second, the residual oil at the edge and corner could be effectively displaced by the pushing and pulling action of the emulsion.

Xu et al.\textsuperscript{82} used a microfluidic device to study the mechanism for sweep improvement of emulsions. The results showed that stable emulsion droplets can effectively block the high-permeability pathways and improve flux through low-permeability pathways when the droplet size is larger than the throat diameter of the high-permeability pathways. Kang et al.\textsuperscript{83} indicated that the displacement effect of spontaneous emulsification was better for different permeability cores. The residual oil was spontaneously emulsified into the emulsion, the droplet size of which was much smaller than the pore and throat diameters, and the capillary force of the residual oil decreased. The displacement efficiency is improved by interfacial disturbance, elastic deformation, and reduction of interfacial tension. Zhou et al.\textsuperscript{84} investigated the displacement mechanism of a pore-throat scale emulsion, showing that an elastic stress is created due to viscoelastic deformation of the pore-throat scale emulsion when the emulsion contacts the residual oil. This elastic stress is a driving force for the residual oil, and it can pull the residual oil to migrate, as shown in Figures 6 and 7. Pei et al.\textsuperscript{85} indicated that emulsion flooding can not only improve the sweep efficiency by blocking the highly permeable zone but also improve the displacement efficiency by mobilizing the trapped oil. Farias et al.\textsuperscript{86} used X-ray tomography monitoring to study oil displacement flow during emulsion injection in a 3D sandstone block and showed that injecting an emulsion slug after water flooding reduced the oil saturation in two different regions—near the injection well and near the displacement front. The emulsion injection can change the migration path of the injecting fluid, and it can significantly reduce the oil saturation.\textsuperscript{87} Taherpour et al.\textsuperscript{88} reported the effect of nonionic surfactant on wettability alteration and viscosity variation of emulsions for oil recovery. Sharma et al.\textsuperscript{89} formulated novel Pickering emulsions stabilized by a nanoparticle-surfactant-polymer system, which is thermally stable at elevated temperatures suitable for EOR application. Core flooding experiments of surfactant-polymer (SP) and O/W Pickering emulsions were carried out to study the additional oil recovery at a reservoir pressure of 13.6 MPa and temperature range from 39.85 to 89.85°C. The results showed that the Pickering emulsion achieved greater than 60% more cumulative oil recovery at all test temperatures than SP flooding. Kumar et al.\textsuperscript{90} formulated surfactant-polymer-nanoparticle (SPN) Pickering emulsions using light mineral oil, carboxy methyl cellulose (CMC), and silica nanoparticles (SiO\textsubscript{2}) in the presence of anionic surfactant. The viscosity remains stable over a wide temperature range (30-100°C), and the Pickering emulsion shows a stable value of loss modulus, indicating better flow ability of the emulsion.

![Figure 6](https://example.com/figure6.jpg)

**Figure 6** Emulsion displacing oil droplet. (A) Residual oil droplet in the throat; (B) emulsion migrated to the throat; (C) emulsion entered into the throat; (D) emulsion pushed the oil droplet; (E) oil droplet was elongated and coalesced; and (F) oil droplet migrated out of the throat\textsuperscript{84} (with permission from Elsevier)
emulsion. The flooding experiment with a sand pack system showed that the Pickering emulsion can achieve additional recovery of more than 24% after conventional water flooding.

In emulsion flooding, different droplet sizes play a different role in the displacement process. A small droplet can increase the effective driving force for both oil-wet reservoirs and water-wet reservoirs, and a large droplet can temporarily plug the throat. Emulsion can enhance oil recovery due to the synergistic effect of small and large droplet size emulsions. Baldygin et al.92 presented a new water-alternate-emulsion technique for enhanced oil recovery, and it proved to be a promising enhanced oil recovery technique. Abdul and Ali93 investigated the injection mode for polymers and emulsions in reservoirs with bottom water and showed that the oil-in-water emulsion acted as a water-plugging agent, while alternate injection of emulsions and polymer had a better displacement effect. This alternate injection can increase the recovery by more than 10% compared with water flooding. Kumar and Ali94 studied the effect of spontaneous emulsification enhancing heavy oil recovery and showed that the recovery achieved using emulsions could be increased by 10%–35% compared with that achieved using water flooding.

In numerical simulations, Ma et al.95 established a mathematical model of ASP flooding with oil-in-water emulsions and showed that emulsification can effectively reduce the water cut and increase oil output, and this effectiveness increases with increasing emulsification ability. Lei and Yuan et al.96 reported that when the permeability variation coefficient was 0.75, emulsification could improve the displacement efficiency by 3.17%, increase the sweep volume by 4.7%, and increase the oil recovery by 4.5%. Zhou et al.97 established a model of emulsions displacing residual oil film in a single pore, and it showed that elastic stress can be generated due to viscoelastic deformation, and the oil film can deform and migrate under the effect of elastic stress. Ranena et al.98 investigated the effect of emulsions expanding sweep volume and improving displacement efficiency through a numerical simulation and showed that emulsion injection benefits are obtained even in favorable mobility ratios. If the emulsion is injected earlier, the displacement effect is better, and the oil production is higher. Demikhova et al.99 used a filtration model to describe emulsion flow through porous media, and the simulation showed that the oil recovery was due to a wettability change.

Therefore, the effect of an emulsion increasing the swept volume is the combined action of a continuous phase (or the emulsion droplet size is far less than the throat diameter) and the pore-throat scale emulsion. Emulsions with different droplet sizes play different roles. Pore-throat scale emulsions can plug the throat, which has been swept by water and has little residual oil, and emulsions with a small droplet size can flow into the low-permeability reservoir.

5 | FIELD APPLICATIONS

Currently, emulsion flooding is still in the experimental laboratory stage. The design of field applications requires full understanding of the above aspects. There are very few field test cases of emulsion flooding, and the most successful case is the field test at Section 5K of the Midway-Sunset Oil Field.100,101 However, an obvious emulsification phenomenon appeared in the ASP flooding field test,102-105 which resulted in the development of reference values for laboratory studies and field tests of emulsion flooding.

5.1 | Emulsion flooding field test at Section 5K of the Midway-Sunset Oil Field

Section 5K of the Midway-Sunset Oil Field is near Taft, California. The sands under the flood are the Top Oil sands and the Kinsey Oil sands. The sand thickness of Top Oil sands ranges between 3.05 and 6.10 m, and the thickness of
Kinsey Oil sands ranges between 1.83 and 3.66 m. The porosity ranges from 33% to 35%. The average permeability of the Top Oil and Kinsey Oil sands is $450 \times 10^{-3}$ μm². The oil saturation is approximately 40%, the residual oil saturation ranges from 30% to 33% after core water flooding, and the movable oil is very low. The oil gravity is approximately 20° API for the Top Oil sands, and it is approximately 25° API for the Kinsey Oil sands. The salinity is approximately 14,000-15,000 mg/L. Water flooding was started in September 1962. The water cut increased from approximately 25% to approximately 92% from the end of 1965 to mid-1970.

The emulsion was prepared using 70% Midway-Sunset Section 26C crude oil (14° API) and 30% fresh water phase containing 1% sodium hydroxide. The average droplet diameter of the emulsion was 3 μm, and the viscosity was approximately 200 mPa·S. The emulsion was injected into three wells in April 1967. The field test indicated that the emulsion did not migrate with the water from the injection wells to the oil wells. Oil well 6-1 is 60.96 m away, which is the closest well to injection well 35. No emulsion was observed in the produced fluid from oil well 6-1, and no decrease in API gravity was found in the produced oil. The API gravity of the produced oil was 24°, while the API gravity of emulsion was 14°.

After the emulsion was injected for 4 months, the oil production of oil wells surrounding emulsion-treated injectors increased significantly and the water cut decreased compared with that resulting from water flooding. In all, 33,040 t of 14%-emulsion (4620 t of crude oil) was injected, and the volume of the emulsion was approximately 0.04 pore volume at Section 5K. The total produced fluid remained approximately constant, and the oil production increased. The oil production was approximately 7700 t by May 1970, which was greater than the extrapolated value. The produced water salinity increased after emulsion injection, indicating that more formation water was produced, and the sweep efficiency was also improved.

5.2 Emulsification characteristics in Xing-V

Xing-V is an ASP flooding field test area in the Daqing Oilfield. The average net pay thickness is 6.8 m, the permeability is $589 \times 10^{-3}$ μm², and the viscosity of the crude oil is 6.1 mPa·S in the reservoir. There are five wells, including one injection well and four oil wells. The five-point well pattern was thus adopted, and there are five wells with one injection well and four oil wells in the test. The formulation of the ASP flooding system consists of NaOH with a concentration of 1.2%, ORS-41 with a concentration of 0.3%, and polymer with a concentration of 1200 mg/L. When the injecting liquid was approximately 0.08 PV (pore volume), the oil production was successively increased in the four oil wells. When the injecting liquid was approximately 0.7 PV, the water cut decreased from 96.9% to 80.7% (16.2% decrease). The cumulative oil production increased by 13,102 t. Different degrees of emulsification were observed in the fluids produced by the four oil wells, and more emulsion was observed in oil wells Y5-S3-2 and Y5-S1-1 with a viscosity of 40 mPa·S. To study the emulsification characteristics and their influence on the recovery in ASP flooding, the oil color, water color, and emulsification of the produced liquid were observed in well Y5-S3-2. The emulsification characteristics of well Y5-S3-2 were shown in the following stages:

1. Nonemulsifying stage: This stage appeared when the injection liquid was less than 0.209 PV. The oil is black, and the water is colorless and transparent in this stage. Cumulative oil production in this stage accounts for 14.1% of the total oil production.
2. W/O type emulsion stage: This stage appeared when the injection liquid was greater than 0.209 PV but less than 0.516 PV. The oil was turned into claybank, the water was still colorless, and a W/O type emulsion was observed in this stage. There was little surfactant and no alkali in the produced oil. The water color was cloudy. The emulsion is mostly O/W type, and the oil production in this stage accounts for 57% of the total oil production.
3. W/O type and O/W type emulsion stage: This stage appeared when the injection liquid was greater than 0.516 PV but less than 0.76 PV. The water gradually turned cloudy. There was an O/W type emulsion, a W/O type emulsion, and a small amount of multiple emulsion in the produced liquid. The oil cut increased, and the water cut decreased rapidly. The emulsion of oil production accounts for 22.5% of the total oil production.
4. O/W type emulsion stage: This stage appeared when the water cut of the produced liquid was greater than 90%. The oil and water were brown, the concentrations of alkali and polymer were low in the produced liquid, but the concentration of surfactant was high in the produced liquid. The emulsion is mostly O/W type, and the oil production in this stage accounts for 4% of the total oil production.

5.3 Emulsification characteristic in Xing-II

The area of Xing-II is also in the Daqing Oilfield. The average net pay thickness is 5.8 m, the permeability is $675 \times 10^{-3}$ μm², and the inverted five spot well pattern was adopted in this area, including four injection wells and nine oil wells. Different degrees of emulsification were observed in the nine oil wells after injecting chemical fluid. The emulsion is greatest in the produced liquid of center well Y2-2-S1. In addition, the incremental oil production is highest in well Y2-2-S1. The water cut remained 100% for nine months before injecting chemical fluid. The minimum water cut was 50.7% and decreased by 49.3%. The average incremental oil...
production was 29 t/d, and the water cut stabilized between 50% and 80% for 16 months. The oil recovery was enhanced by more than 20%.

In addition, the ASP flooding field test was carried out in other areas, and the emulsification appeared. The emulsification was found in the field test, namely the more uniform the oil layer and the larger the injection-production well spacing, the more emulsion that appeared in the produced liquid. It is easier to emulsify residual oil by adding strong alkali than by adding weak alkali. After the residual oil emulsified, the viscosity of the displacing fluid increased, and its flow resistance increased. Thus, the amount of produced liquid greatly decreases, but the water cut also decreases, and the oil production rate greatly increases. The water cut decreases significantly when more emulsion appears in the produced liquid, which indicates that the emulsion can effectively adjust the displacement liquid mobility ratio and enhance the recovery. It was also found in surfactant flooding field tests that, although the oil-water interfacial tension is low, the oil recovery is not high if little or no emulsion is produced. Therefore, the research emphasis on the surfactant is important to increase the emulsifying performance.\textsuperscript{106, 107}

It is important to improve the emulsion performance of surfactant in chemical flooding. The mobility of displacing fluid can be controlled by forming emulsion through interactions between surfactant and crude oil, which can expand the sweep volume. Moreover, the emulsion can significantly decrease damage to oil layers. A green surfactant was developed.\textsuperscript{108-110} The following research should focus on improving the emulsifying property of surfactant based on the existing green surfactant. Therefore, the development of a green surfactant with high efficiency, low-cost, and good emulsifying properties should be accelerated, and the environmental friendliness of chemical flooding in field applications should be ensured.

6 \hspace{1cm} CONCLUSIONS

1. The unstable phenomena of emulsions, such as flocculation, coalescence, and fracture, have a significant influence on recovery, and there are few studies on these phenomena. This research focused on quantifying the impact of these factors on recovery. The choice of emulsifier is important, as is the optimization of the injection parameters.

2. The dispersibility and droplet size of emulsions were not distinguished in the research of emulsion for enhanced oil recovery. The seepage characteristics of emulsions with different droplet sizes are different in the reservoir, and emulsions with different droplet sizes play different roles in enhancing oil recovery. This aspect is more complex and less studied, so it should be given priority.

3. The development of chemical flooding technology is increasingly influenced by environmental pollution. In the future, the development direction of chemical flooding research should give priority to environmental protection, with low oil pollution and damage. Therefore, it is necessary to accelerate the development and production of surfactants with high efficiency that are low-cost, green and provide good emulsifying properties.

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