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REVIEW PAPER

A critical review on nanoparticle-assisted enhanced oil recovery: Introducing scaling approach

Arifur Rahman[1, 2], *Ezeddin Shirif*[1, *], *Farshid Torabi*[1], *Aria Rahimbakhsh*[1]

[1] *Petroleum Systems Engineering, Faculty of Engineering and Applied Science, University of Regina, Regina, SKS4S 0A2, Canada*

[2] *Petroleum and Mining Engineering, School of Applied Science and Engineering, Shahjalal University of Science and Technology, Sylhet-3114, Bangladesh*

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Abstract

Nanotechnology has the capability to modernize both the upstream and downstream oil and gas industry. It has been effectively used in exploration, drilling, production, refinery as well as in enhanced oil recovery (EOR) fields. Understanding the basics of scaling criteria development along with nanoparticle stabilized EOR mechanism will assist petroleum engineers in designing, analyzing, and evaluating nanoparticle-assisted EOR techniques. This paper aims to deliver a critical review on nanoparticle-assisted EOR methods along with introducing scaling approaches and their applications in EOR. Scaling criteria can be employed to assess the performance of a specific EOR technique so that it can be accurately applied to the field scale. In this study, scaling criteria or dimensionless approaches are briefly summarized along with their applications in EOR. In addition, it reviews how scaling criteria can be derived using a mathematical model along with their benefits and shortcomings. This work concentrates on assessing the application of nanoparticles in EOR processes and addresses the process controlling parameters. This study briefly evaluates a few appropriate analytical and semi-analytical studies directly related to nanoparticle-assisted EOR techniques. Several nanoparticles assisted experimental works have been reviewed for both core flooding and micromodel systems.

Keywords: *Dimensional Analysis; Enhanced Oil Recovery; Iinspectional Analysis; Micromodel; Nanoparticle; Scaling Criteria.*

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INTRODUCTION

As global energy demand increases day by day, great attention has been paid to exploring the heavy oil and bitumen reservoirs, which are comparatively difficult to recover their oil with existing technological efforts and manners. Various oil recovery techniques are proposed to successfully extract heavy oil and bitumen to fulfill the increasing energy demand. However, these recovery methods experiencing low recovery rates (<10%) and economic and environmental drawbacks.

* Corresponding Author Email: *ezeddin.shirif@uregina.ca*

Over the past few decades, researchers from all over the world became interested in studying nanomaterials and their applications in various fields of science and engineering because of their novel physical and chemical properties (size, shape, surface properties, etc.) [1-2]. Nanotechnology has emerged as one of the most promising technologies for both upstream and downstream petroleum industry, including exploration, drilling, production, refinery processes, and EOR [3]. Nanotechnology has been used in the last decade to unlock the remaining oil resources after primary and secondary oil production and is considered one of the new EOR techniques [4]. One of the most appealing properties of nanoparticles in the petroleum sector is their ability to pass through reservoir pores due to their ultra-small size [5]. Different characteristics of nanoparticles can be easily modified, which will assist in altering favorable wettability, IFT, mobility ratio, rheological properties of injection fluid (nanofluid) that will be useful to EOR applications [6]. The transport or flow of nanoparticles to the desired zone of the reservoir is a key factor in achieving enhanced oil recovery [7]. Previous researchers summarized the application of nanotechnology in EOR in their studies [8-11].

Various EOR techniques have a tendency to recover more oil through numerous mechanisms, including wettability control, mobility control, IFT reduction, gravity drainage, and changes in physical and chemical characteristics. Each technique, however, has inherent disadvantages or obstacles that must be addressed to get better oil recovery. Thermal techniques, for example, have encountered issues such as excessive heat leakage, low rock fluid thermal conductivity, minimal effective thermal deterioration, high energy costs, and so on [12]. Gas flooding has the difficulty of gravity override, fingering, or early gas breakthrough with high MMP (minimum miscibility pressure) for miscible flooding, asphaltene deposition, and CO_2 corrosion [13-14]. Chemical flooding, on the other hand, has significant drawbacks, including low efficiency in terms of interfacial tension (IFT) and viscosity reduction, an unfavorable mobility ratio, sluggish diffusion in the pore structure, formation damage, and high cost owing to the large number of chemicals required [15-16]. Therefore, finding out less expensive, more effective, and environmentally friendly EOR techniques is crucial. Nanoparticles can present a unique pathway to tackle those problems and overcome them to a large extent. Nanoparticles, which range in size from 1 nanometer (nm) to 100 nm, are characterized as particles with some effective properties for working as an EOR agent when compared to the typically injected fluids (gas, water, and chemicals) used in EOR methods [17]. It has a very high surface-to-volume ratio caused by its ultra-small size, which ultimately enhances the number of atoms on the surface of nanoparticles [18]. Nanofluids are mixtures of nanoparticles and water in various quantities [19]. The effects of the type, size, and the number of nanoparticles such as polystyrene, SiO_2, Al_2O_3, and their micelles on nanofluid characteristics were also investigated by some researchers [19-21]. Nanoparticles provide a solution to the challenges of existing traditional EOR methods due to their characteristics, as mentioned above. Therefore, this study briefly describes different analytical and semi-analytical works of nanoparticle-assisted EOR techniques.

Various experiments and research have been conducted over the years to find the most effective and efficient EOR approach for lowering oil viscosity and boosting sweep efficiency, improving oil recovery. Different EOR mechanisms can also be studied through numerical simulation and scaled model studies analyses. Numerical simulations were designed to extrapolate lab-scale results to estimate oil field production performance. On the other hand, scaled model experiments were designed to permit the lab-scale results correlated with a field-scale process to accurately duplicate the behavior of a field-scale process. Among all EOR processes, CO_2 flooding is probably the most effective, reliable, and economical technique when a vast source of CO_2 is available near the petroleum reservoir. However, one of the key limitations of CO_2 flooding is its poor volumetric sweep efficiency due to its early breakthrough. CO_2 foam flooding with surfactant has been widely investigated as a viable solution to this problem. Nanoparticles can stabilize CO_2 foam better than surfactants because of their better tolerance to high temperature, pressure, and salinity conditions, which have gotten much attention recently. In addition, nanoparticle-stabilized oil-in-water emulsions draw an increasing interest as a technique to enhance heavy oil recovery. Moreover, nanoparticles can be used as a smart coating of solids to make them extremely hydrophilic or hydrophobic to investigate their efficacy in altering rocks' wettability for EOR.

A critical assessment of the nanoparticle aided EOR method will be provided in this work, along with the introduction of scaling methodologies. The benefits and limits of dimensional and inspectional assessments will be presented, and the need to generate dimensionless numbers. In addition, core flooding and micromodel experimental studies using nanoparticles will be reviewed, along with some analytical and semi-analytical studies. A novel technique to developing scaling criteria will be proposed, which may capture the influence of different process controlling parameters in groups rather than individuals. This investigation will assist in designing, testing, and implementing nanoparticle-assisted EOR techniques with an effective combination of scaling approaches. When both scaling development and nanoparticle aided EOR are examined combined, we can gain a more precise picture of field scale behavior, since scaling criteria will help lab-scale results be linked with real-world or field-scale EOR processes. Therefore, this paper will guide the researchers on correlating lab-scale results to field-scale operations and implementing nanoparticle-assisted EOR for field-scale processes.

SCALING CRITERIA

The scaling study has been extensively used in the field of engineering for many years. It can assist in reproducing the behavior of the actual system on a small laboratory scale [22]. Scaling is a useful and efficient approach to simulate the behavior of the reservoir and evaluate the performance and advantages of various EOR techniques [23]. Upscaling is a formidable challenge in the petroleum engineering field in situations where rock-fluid and fluid-fluid interactions are unavoidable, such as in complex reservoir systems. The main element of the scaling requirements is that dimensionless properties must be the same function of dimensionless variables in both the model and prototype. However, in reality, the lab-scale results do not represent the field-scale process properly. Furthermore, satisfying all scaling requirements is quite challenging, allowing the potential for mistakes when choosing more important scaling groups.

Scaling *Techniques*

Scaled model studies have been extensively used in science and engineering problems for many years, particularly in heat transfer and fluid flow through porous media or in structural design studies [24-28]. However, the application of scaling in a petroleum engineering field is relatively new, and its application is increasing day by day [28-37]. Using the fluid memory concept, an adequately scaled model can provide dimensionless numbers to characterize a complex fluid displacement process in porous media [38-39]. Dimensional analysis [27,40-42] and inspectional analysis [43-46] are two well-recognized methods for obtaining dimensionless numbers.

Dimensional Analysis

Dimensional analysis is a mathematical procedure for upscaling and downscaling a specific process that does not involve any governing equation and its numerical solutions. It provides a functional relationship between different parameters to describe a complex mechanism or process. It is necessary to understand the physics of the mechanism or the chemistry of the process to perform dimensional analysis. Otherwise, it could mislead investigators while identifying the variables involved in a specific process. For any particular process, the conservative laws could be written as follows:

$$\text{Accumulation} = \text{input-output} + \text{generation} \tag{1}$$

Each term in equation (1) comprises several physical values like parameters, constants, and variables. While constants do not change from one process to the next, parameters and variables do. The dimensional analysis provides a relationship between the dependent and a minimum number of independent variables. Dimensional analysis may also be used to create an experimental program. For example, performing the dimensional analysis can create dimensionless groups using dimensional variables that can reduce the independent variables. Minimizing independent variables leads to the reduction of experimental requirements for a mechanism or process. This is a firm and logical procedure that contains easy steps to develop a theory of models. In fact, with this technique, any complex mechanism or process can be upscaled or downscaled. Fig. 1 shows the dimensional analysis procedure.

It is important to note that dimensional analysis only looks at physical quantities, which only considers intrinsic properties rather than their physical magnitudes. On the other hand, this approach does not give an analytical solution to a process's governing equations (conservative laws and constitutive relations). Therefore, it is quite impossible to know whether critical physical properties or parameters are missing from a functional solution proposed by this technique. In addition, it does not indicate whether the correct physical quantities or variables are used or not. Moreover, this technique does not provide any unique solution.

Inspectional Analysis

The inspectional analysis is considered the

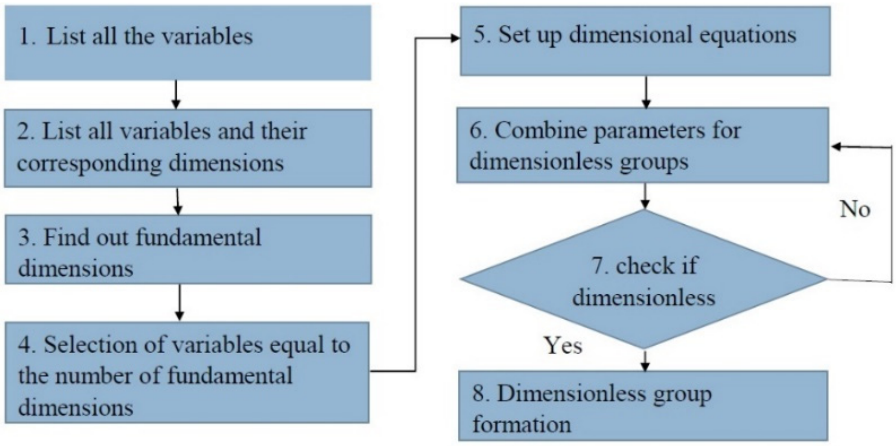

Fig. 1. Dimensional analysis procedure [47].

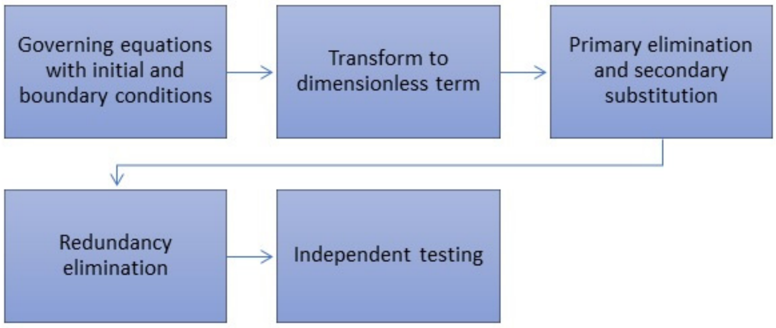

Fig. 2. Inspectional analysis procedure [44].

broadening of dimensional analysis, where dimensionless numbers are derived using governing equations and their initial and boundary conditions. The inspectional analysis is ideal for the petroleum engineering sector since it is based on existing differential equations working with boundary conditions [45, 47]. Although dimensionless numbers do not have any physical significance in the dimensional analysis, every group has a physical meaning in the inspectional study. This analysis uses parameters instead of dimensions, and dimensionless numbers are generated directly from governing equations; as a result, it may provide meaningful dimensionless numbers that can characterize a specific process. One of the principal applications of inspectional analysis is its capability in describing the natural phenomena that could occur in a particular EOR technique. This method requires a mathematically derived formula, so its physical significance is evident. However, implementing this technique is time-consuming and tedious because of its dependency on the parameters involved in the equations. Inspectional analysis steps are given below in Fig. 2:

SCALING AND NANOPARTICLE APPLICATION IN EOR

Most of the EOR techniques are first examined in the laboratory so that the mechanisms involved are identified and well understood. Nanoparticle assisted EOR method is relatively new and is in its early stage; hence, the mechanism involved in its performance and applicability is not fully understood. Researchers have been trying to provide a framework for applying this new technique in the field, based on their findings in the laboratory. A novel fluid memory approach [44] can be used to develop scaling criteria or dimensionless numbers for nanoparticle-assisted enhanced oil recovery. The benefit of utilizing a fluid memory method is that it can capture the many phenomena throughout an EOR operation. The relationship between a lab-scale and a field-scale process is thought to be defined by establishing scaling criteria. Table 1 lists the nanoparticles with their essential EOR applications.

Nanoparticle Properties

Nanoparticles are solid particles with a diameter of less than 100 nm that come in various forms, including spheres, cubes, tubes, sheets with varying shapes, and other complex geometries. A suspension of metallic, nonmetallic, or polymeric nanosized particles distributed in a base liquid is referred to as a nanofluid. Nanofluids have many applications and are often used to enhance oil recovery utilizing their novel physical and chemical properties [48]. The increased surface area of the same mass after it is split into tiny bits is one of the key characteristics of nanofluids. This extremely large surface area per mass is a key feature that nanoparticles are used in the petroleum industry. The nanoscale size of nanoparticles is another significant element to consider when using them in the petroleum sector. It can lead nanoparticles to flow through porous media with minimum retention and core plugging. Nanoparticles can also be used as a stabilizer for foams and emulsions, which have certain unique characteristics compared to surfactants [49]. Nanoparticles have the immense potential to perform a specific task in the reservoir, which can be compared with the task of bees to assist in maintaining ecological balance as the bees spread out to gather honey and come back to the habitat to transfer their harvest and repeat this process throughout their lifetime. Similarly, properly controlled and designed dispersed nanoparticles can perform various oilfield operations in the deep formation or at the wellbore, returning to the surface after downloading some factual information from the porous media they collected and repeating the process to characterize the

Table 1. Different nanoparticles and their applications in EOR.

Nanoparticles	EOR Applications
Aluminum Oxide (Al_2O_3) Nickel Oxide (Ni_2O_3) Copper (II) Oxide, CuO C_2H_5OH and MgO Nano Particles (Polymer Coated) Iron Oxide, (Fe_2O_3/Fe_3O_4)	Mobility ratio
Tin Oxide (SnO_2) Silicon Dioxide (SiO_2) Hydrophobic Silicon oxide (SiO_2) Hydrophilic Polysilicon Polymer Coated Nano Particles Spherical Fumed Silica Nanoparticles Alumina Coated Silica Nanoparticles Neutrally Wet Polysilicon	Wettability alteration
Silicon Dioxide (SiO_2) Polyacrylamide Micro-gel Lipophilic Polysilicon Ferrofluid Nano Particles (Polymer Coated)	IFT reduction
Nano Particles (Polymer) Colloidal Dispersion Gels (Nano-Sized) Nano Particles (Polymer Coated)	Sweep and displacement efficiency
Aluminum Oxide (Al_2O_3) Silicon Dioxide (SiO_2) Nanoclay Polysilicon Titanium Dioxide (TiO_2) MWCNT-SiO_2	Rheological flow behavior
ZnO Carbon Nanoparticles ZrO_2 Carbon Nanotubes Fluids (Ferrotype)	Further investigation should be done

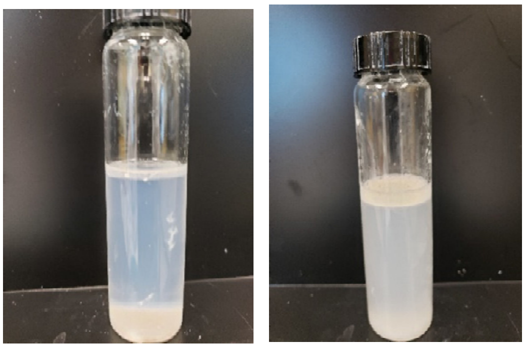

Fig. 3. (a) SiO_2 and (b) Al_2O_3 Nanoparticles dispersed in deionized water.

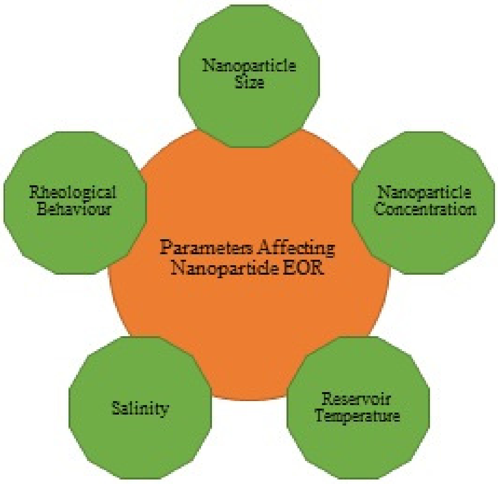

Fig. 4. Parameters affecting nanoparticle-assisted EOR.

reservoir [50]. Moreover, nanoparticles can offer an environmentally friendly oilfield operation, which is crucial for achieving sustainable development. The most commonly used nanoparticles are SiO_2 coated with alumina in oil field applications. The SiO_2 and Al_2O_3 nanoparticles dispersed in deionized water are shown in Figs. 3a and 3b.

Nanoparticle Transport in Porous Media

Nanoparticle deposition in the porous medium can be reversible or irreversible, depending on the characteristics of the porous media and the physicochemical conditions of the nanoparticles. In general, two-particle transport models exist the clean-bed colloid filtration theory (CFT) [52] and the modified version of the CFT model (MFT), which takes into account the porous medium walls restricted capacity for particle attachment [53]. The general mass balance equation considering dispersion, advection, and retention processes for nanoparticle transport in porous media can be written as follows [54].

$$\frac{\partial}{\partial t}(\rho C_n + \phi S) + \rho v \frac{\partial}{\partial x} C_n - \rho D \frac{\partial^2}{\partial x^2} C_n = 0 \quad (2)$$

Both models considered attachment of nanoparticles is kinetic controlled, and the detachment is first ordered. On the other hand, the CFT model can consider the capacity of porous media unlimited and controlled by a constitutive equation.

Parameters Affecting Nanoparticle Assisted EOR

Several parameters that can affect the nanoparticle-assisted EOR are shown in Fig. 4 and some of them are discussed below.

Nanoparticle Concentration

Nanoparticle concentration is one of the main factors affecting the enhancement of oil recovery factor. Chengara *et al.* [55] determined that the disjoining pressure of two thin surfaces depends on the concentration of nanoparticles, and increasing concentration can raise the disjoining pressure and repulsion forces. Higher concentration nanoparticles can generate more viscous foams at a given shear rate than lower concentration nanoparticles. The higher concentrated nanoparticles increase the density at the interface and create a more rigid barrier at the bubble surface. Espinoza *et al.* [56] analyzed the impact of nanoparticle concentration on CO_2 foam generation. They found that 0.05 wt.% concentrated polyethylene glycol (PEG)-coated silica nanoparticles dispersed in deionized water require a 5 : 1 CO_2/water ratio to generate 83.3% foam quality at 21.10C and 1350 psia. The quality of foam increases to 91.7% when the 11 : 1 ratio was used under the same test conditions. On the other hand, lower concentrated (0.025 wt.% and 0.01 wt.%) nanoparticles cannot generate stabilized CO_2-in-water foam. Ehtesabi *et al.* [57] investigated and found that low concentrated TiO_2 could easily boost the heavy oil recovery. Hu *et al.* [58] conducted oil displacement tests with TiO_2 nanoparticles and found that lower concentration (20 ppm) nanoparticles can increase the oil recovery from 30.3% (waterflooding without nanoparticles) to 39.8%. They also mentioned that the peak value could reach 41.8% when a 10-ppm concentration of the same nanoparticle is used. Tarek [59] conducted several oil displacement tests taking different concentrated nanoparticle mixtures in a high permeability core and found that the optimum concentration of nanoparticles depends on both rock and fluid properties. Hamedi-Shokrlu and Babadagli [60-62] and Hamedi-Shokrlu *et al.* [63] conducted various laboratory tests to determine the impact of using micro and nano-sized metal particles on heavy oil upgrading and discovered that viscosity reduction is a direct function of nanoparticle concentration. There is an optimal nanoparticle concentration to achieve maximum viscosity reduction. The IFT between different reservoir fluids is reduced by increasing nanoparticle concentration [64], and a greater concentration leads to improved wettability alteration and therefore increased oil recovery. However, the optimum concentration of nanoparticles strongly depends on oil composition, asphaltene content, type and size of the nanoparticles, porous medium, and operating conditions. The size of nanoparticle is one of the key properties in the application of oil and gas reservoirs. Its ultra-small size allows them to flow through the pores of reservoir rocks without being trapped. Brownian diffusion controls the long-range force between individual particles in a dispersion of nanoparticles, which can cause repulsion or flocculation. As a result, the influence of Brownian energy on particle energy becomes increasingly important as particle size decreases [65]. High Brownian energy allows the collision between particles and the porous media surfaces; therefore, fewer particles are deposited during nanoparticle transport [66]. The size and density of nanoparticles are vital variables that can influence the strength of disjoining pressure between thin liquid layers. Smaller nanoparticles exert a higher density than larger ones, reducing the contact angle between the fluid and the formation for the same mass of nanoparticles. The disjoining pressure can be improved significantly due to the utilization of higher density nanoparticles [67]. Also, smaller nanoparticles can spread faster in less hydrophilic rock surfaces compared with the bigger ones. McElfresh *et al.* [68] reported that smaller particles exert higher density, resulting in a stronger electrostatic repulsive force if the particle is considered stable. On the other hand, Hendraningrat and Torsæter [69] examined and concluded that the smaller the particle size, the greater its displacement efficiency and consequently the oil recovery. Some of the researchers conducted experiments and concluded that the ultimate recovery of oil is increased due to the smaller size of the nanoparticles [10]. According to Kondiparty *et al.* [67], decreasing the size of nanoparticles from 30 nm to 18.5 nm, was disjoining structural pressures to rise by 4.5 times their initial value. El-Diasty and Aly [10] investigated and found that the dimension of the nanoparticles was sufficiently tiny so that they could not be trapped mechanically and large enough to avert additional log-jamming. It should be noted that the smaller size nanoparticles are preferable for higher oil recovery [70]. As a result, it can be concluded that nanoparticle size and density are critical parameters influencing nanoparticle deposition on reservoir rock pores.

Reservoir Temperature

Since surface and reservoir temperatures may differ substantially, it is essential to determine whether nanofluids can be used for EOR under high-temperature conditions [10]. Cedalas *et al.* [71] found that temperature has no influence on nanoparticle adsorption and desorption and hence has no effect on nanoparticle retention on porous media surfaces.

In contrast, Hendraningrat and Torsæter [72] examined and concluded that temperature could significantly affect the parameters responsible for assisting EOR. Higher temperature condition is always desirable for better oil recovery since it will lessen the oil's viscosity [69] and modify the contact angle to alter the wettability to water wet. Undoubtfully, the mechanism of temperature and its impact on EOR are complex and challenging to understand due to the involvement of numerous parameters. The higher temperature can increase the oil recovery by reducing oil viscosity and changing the rock wettability. The zeta potential should be decreasing as the temperature rises. When the zeta potential of nanofluids is reduced, agglomeration of nanoparticles might occur, which will block the pore spaces and therefore limit oil production [3, 68]. Also, the temperature can equally affect the nanofluid and reservoir system. As a result, it is essential to conduct an advanced analysis of the temperature effect on a nanofluid-reservoir system to understand better the mechanisms involved in the nanoparticle EOR process. To summarize, nanoparticles should be carefully selected based on the reservoir type and depth, which are both strongly connected to temperature.

Salinity

The salinity of nanofluids (nanoparticles dispersed in deionized water) and reservoir fluids are primarily reliant on and significantly influences dispersion stability. The increased salinity can reduce the zeta potential of particles that will help the flocculation or agglomeration of particles [68]. The presence of more saline in the fluid indicates a higher ionic strength, which reduces repulsive electrical interactions between particles, allowing strong Van der Waals forces to dominate. The high salinity will charge most of the rock surfaces; thus, it can be projected that the attraction and collision forces will occur between particle-particle but not in a rock-particle system [73]. Consequently, it is practical to alter nanoparticles in an extreme saline environment to preserve stability and increase oil recovery. This can be attained by altering the surface and dominating ionic charges by introducing a surfactant or combining the two [10]. Worthen *et al.* [74] used low molecular weight ligands to the nanoparticle surfaces to examine their stabilization and found that it can improve their stabilization. Kanj *et al.* [75] investigated the effect of salinity on nanoparticle aided EOR. They found that increasing salinity did not obstruct nanoparticle transport but enhanced nanoparticle adsorption on the rock. Alternatively, Hendraningrat [70] studied and revealed that high salinity nanofluid could modify the wettability of rock surfaces to be further water-wet, which will ultimately assist in improving the oil recovery. The high salinity environment and their physicochemical interaction can lead to the adsorption of nanoparticles on the surface of the reservoir formations [76]. The existence of salt in nanofluid can increase the adsorption in the rock surfaces and make it more water-wet, which will help to augment the oil recovery factor. Nevertheless, at the same time, the presence of salt can significantly reduce the stability of the nanoparticles. As a result, choosing the salinity level carefully and surface modification technique is essential to prevent the flocculation of nanoparticles from optimizing the oil recovery.

Rheological Behavior

The connections between shear stress and shear rate may be used to explain the rheological behavior of any fluid. Shear rate is defined as the change in shear strain per unit time, while shear stress is defined as the lateral force applied to an object per unit area [77]. Alternatively, any fluid viscosity is defined as the ratio of shear stress to shear rate, which may be used to determine the resistance provided by one layer to another during fluid flow [77]. Newtonian and non-Newtonian fluids are two types of fluids that may be classified based on their rheological behavior (Bingham, Bingham plastic, dilatant, pseudoplastic, etc.). The viscosity of a Newtonian fluid remains constant, implying that shear stress and shear rate have a linear relationship. Non-Newtonian fluids, on the other hand, may have varying viscosity, indicating that the shear stress and shear rate connection is no longer constant, and therefore exhibit Bingham plastic behavior. The rheological behavior of nanofluid has a significant effect on ultimate oil recovery. It can influence the nanofluid's pressure gradient and give insight into nanoparticle structure as well as the thermal conductivity of the fluid. The rheological behavior of nanofluids can be determined by a rheometer [78-84], and nanofluid's viscosity can be measured using a viscometer [84-87]. Richmond *et al.* [85] depicted that mixing TiO_2 nanoparticles on SiO_2 dispersed in water can alter the flow behavior of nanofluid from Newtonian to non-Newtonian. TiO_2 nanoparticles dispersed in water exhibit shear-thinning behavior [78, 81, 83, 86] except the observation of Penkavova *et al.* [84]. TiO_2 with ethylene glycol (EG) as the base fluid, on the other hand, exhibits Newtonian behavior even at high shear rates. The type of base fluid can play an important role for multi-walled carbon nanotube (MWCNT) nanofluids in deciding whether they will exhibit Newtonian or non-Newtonian behavior. MWCNT also displays shear-thinning behavior when combined with EG (ethylene glycol), water, glue, or oil. This behavior was observed by many researchers [88-97] except for one study for MWCNT with EG [98]. Numerous studies show that nanofluids containing SiO_2 nanoparticles exhibit Newtonian behavior [99-104], while Al_2O_3 nanoparticles dispersed in water show non-Newtonian behavior [105-106]. On the other hand, Al_2O_3 nanoparticles with base fluid EG and propylene glycol (PG) show Newtonian behavior. Most of the nanofluids show Newtonian behavior at low concentrations and non-Newtonian at high concentrations. Regardless of the base fluid or shear rate, SiO_2 nanofluids always behave Newtonian. When the concentration of nanoparticles in Al_2O_3 nanofluids surpasses a specific critical value, the switch from shear-thinning to shear thickening occurs. This critical value is dependent on the concentration of nanoparticles. The rheological behavior of nanofluids is influenced by several variables such as nanoparticle concentration, size, shape, shear rate, etc. A list of those parameters and their effect on the rheological behavior of nanofluid is given below in Table 2.

EOR Mechanism Using Nanoparticles

Several EOR techniques for increasing oil recovery have been proposed, including wettability modification, mobility control, IFT reduction, structural disjoining pressure, and so on. The adsorption, desorption, and transport of nanoparticles occur in the reservoir rock's pore throat; thus, those mechanisms have been considered for nanoparticle-assisted EOR [134]. Nanoparticles' ultra-small size (1-100 nm) compared to the pore throat of reservoir rock results in five types of energy responsible for their interaction with the pore throat [135]. The adsorption of nanoparticles on the surface of the porous media occurs when attractive forces are stronger than repulsive forces, and desorption occurs when repulsive forces are stronger than attractive ones. On the other hand, the transportation of nanoparticles within the pore throat is driven by convection and diffusion. The pore throat can be plugged or clogged due to the flocculation of nanoparticles. Fig. 5 depicts the nanoparticle mechanisms which are related to EOR. Some of the main mechanisms of nanoparticle-aided EOR are summarized below.

Wettability Alteration

Wettability can be described as the affinity of a specific fluid to expand on a solid surface in the existence of other immiscible fluids in the identical system [136]. In other terms, it may be characterized as a solid surface's temptation to fill a pore with a specific liquid, notwithstanding the presence of another immiscible liquid [10]. It can also be specified as the connection between the solid-fluid and fluid-fluid interactions with the solid surface [137]. Wettability can control the distribution and location of a specific fluid in the subsurface formation [138]. Figs. 6a, 6b, and 6c depict the alteration in wettability from a water-wet to an intermediate-wet to an oil-wet system. Many studies have demonstrated that wettability is essential for determining two-phase or multiphase flow during hydrocarbon accumulation in the reservoir to get production and the maximum oil recovery factor [139-141].

Wettability can significantly improve the capillary pressure and relative permeability, which are the main parameters for fluid flow through the porous media [142]. The wettability and dynamic properties can be altered by the confinement size of the pores of the reservoir rock [143]. A reservoir can be classified as oil-wet, water-wet, or intermediate-wet, depending on the degree of wettability. Generally, the recovery from water-oil reservoirs is higher compared with oil-wet reservoirs. Wettability modification is the process of altering wettability from oil-wet to water-wet to improve oil recovery [144]. Techniques such as spontaneous imbibition, contact angle measurements, surface imaging experiments, zeta potential measurements, amott tests, and others can be used to detect or quantify wettability alteration. The wettability change is influenced by a number of parameters, including

Table 2. Parameters affected the rheological behavior of nanofluids.

References	Nanoparticle	Base fluid	Shape	Size (nm)	Rheological behavior
[104]	SiO_2	mineral oil (paraffinic)	spherical	20	Newtonian
[107]	GNP	water (distilled)	platelets	2	shear-thinning
[108]	rutile TiO_2	ethylene glycol		47±18	non-Newtonian
[109]	graphene	glycerol	platelets	15-50	Newtonian at a low shear rate, non-Newtonian at a high shear rate
[108]	anatase TiO_2	ethylene glycol	tetragonal	35±17	non-Newtonian
[97]	MWCTN	water (deionized)	tube	20-30	shear-thinning at high conc., Newtonian at low conc.
[110]	graphite	water (deionized)	complex	3-4	shear-thinning
[96]	MWCTN	ethylene glycol	tube	10-30	shear-thinning
[111]	CuO	oil	spherical	50	Newtonian
[112]	carbon powder black	ethylene glycol	spherical	20	shear-thinning
[113]	Al_2O_3	water	spherical	30	non-Newtonian at a low shear rate, Newtonian at a high shear rate
[103]	SiO_2	water (distilled)	spherical	12	Newtonian at low conc., shear-thinning at high conc.
[114]	α-Fe_2O_3	glycerol	spherical	26	shear-thinning
[115]	Fe_2O_3	ethylene glycol	spherical	29±18	shear-thinning
[116]	Gold	water	spherical	10,20,50	Newtonian
[117]	Al_2O_3	ethylene glycol	spherical	40-50	Newtonian
[84]	TiO_2	water	spherical	20,25,40,100	Newtonian
[118]	$CaCO_3$	water (distilled)	spherical	20-50	Newtonian
[119]	Silver	DEG	spherical	40	pseudoplastic
[120]	CuO	water and propylene glycol (40:60)	spherical	<50	Newtonian
[121]	MgO	ethylene glycol	spherical	20	Newtonian
[122]	ZnO	ethylene glycol	spherical	10-20	Newtonian at low conc. shear-thinning., at high conc.
[87]	TiO_2	water (deionized)	spherical	21	Newtonian at low conc., shear-thinning at high conc.
[123]	TNT	ethylene glycol	Rod-like	10	shear-thinning
[124]	Al_2O_3	water	spherical	50	Newtonian
[82]	TiO_2	water	spherical	5-6/80-90	Newtonian at low conc., shear-thinning at high conc.
[101]	SiO_2	ethanol	spherical	10-100	Newtonian
[125]	TNT	ethylene glycol	tube	10	shear-thinning
[81]	Titanate	water (distilled)	tube	10	shear-thinning
[126]	CuO	ethylene glycol and water	spherical	29	Newtonian
[127]	Fe_2O_3	water (deionized)	-	10	shear-thinning at low conc., Newtonian at high conc.
[99]	SiO_2	ethanol	spherical	35, 94, 190	Newtonian
[91]	MWCTN	Vinyl ester-polyester	tube	15	shear-thinning
[78]	TiO_2	water (distilled)	spherical	20	shear-thinning
[92]	MWCTN	water (distilled)	tube		shear-thinning
[128]	Nickel	α-terpineol	spherical	90	shear-thinning
[129]	Alumina	propylene glycol	spherical	27, 40, 50	Newtonian
[130]	ITO	water (deionized)	spherical	10	Bingham plastic at a high shear rate, Newtonian
[131]	CuO	water (deionized)	spherical	30, 75, 150	pseudoplastic
[132]	CuO	ethylene glycol	Rod-like	10-30	shear-thinning
[105]	Al_2O_3	water (pure)	spherical	37	shear-thinning
[133]	MWCTN	polycarbonate	nanotube	10-15	Newtonian at low conc., non-Newtonian at high conc.
[85]	TiO_2, SiO_2	water (deionized)	Irregular prismatic	0.16-1.73 µm	Bingham plastic

nanoparticle concentration, nanoparticle size, water salinity, dispersion media, reservoir nature, hydrophobicity, and so on. Nanoparticles can assist the alteration of wettability due to their adsorption on rock surfaces, forming a layer of water-wet on rock grains. Adsorption of nanoparticles on rock surfaces is considered an active and energetic process that can considerably modify the surface strength and wettability of the structure [145]. Many studies used nanoparticles alone or in combination with surfactants to explore wettability alterations. Ju *et al.* [134] studied silica

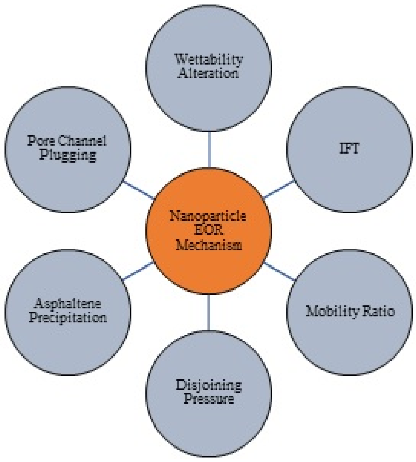

Fig. 5. Nanoparticle-assisted EOR mechanism.

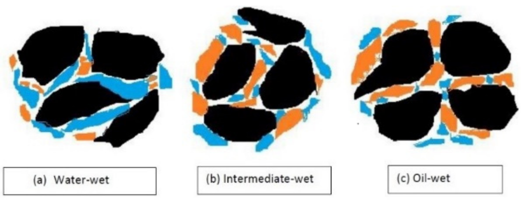

Fig. 6. Wettability alteration (a) Water-wet (b) Intermediate-wet (c) Oil-wet.

polysilicon nanoparticles' effect on rock wettability alteration. They revealed that hydrophilic polysilicon nanoparticles might easily adsorb on sandstone rock surfaces and alter wettability. Maghzi *et al.* [146] examined the impact of SiO_2 nanoparticles in modifying the wettability by conducting a five-spot glass micromodel test. The authors determined that a robust hydrogen bond exists between silicon dioxide nanoparticles and water that increases surface free energy, which results in a modification of wettability from oil-wet to water-wet. Karimi *et al.* [147] examined the impact of the ZrO_2 nanoparticles on the wettability change of carbonate rock reservoirs. The wettability of ZrO_2 nanoparticles was found to be considerably altered, as evidenced by XRD and SEM tests. Roustaei *et al.* [148] investigated the effect of modified silica nanoparticles on wettability in light and heavy oils. The results show that silica nanoparticles are more effective in changing the wettability of light oil than heavy oil. Joonaki and Ghanaatian [149] examined the validity of different nanoparticles (SiO_2, Al_2O_3, Fe_2O_3) on the wettability modification of sandstone rocks using propanol as a dispersed medium. According to the findings, SiO_2 nanoparticles were more effective in changing the wettability of the rocks. Hendraningrat and Torsæter [150] revealed the effect of Al_2O_3 nanoparticles on wettability alteration using sandstone cores. The authors observed that the Al_2O_3 nanoparticles dispersed in brine could alter the wettability from strongly oil-wet to greatly water-wet conditions. Seid *et al.* [151] demonstrated the effectiveness of gamma-alumina nanoparticles on improving the oil recovery by an extreme alter in contact angle, which results in an 11.25% rise in oil recovery. Roustaei and Bagherzadeh [152] found an optimal concentration of silica nanoparticles for altering the wettability of carbonate reservoir rock. Investigators concluded that silica nanoparticles might efficiently and successfully transform the wettability of carbonate rocks from oil-wet to water-wet. Li *et al.* [153] investigated and calculated the wettability index utilizing amott tests. The wettability might change from strongly oil-wet to neutral-wet when SiO_2 nanoparticles were used in a sandstone core. Sulaiman *et al.* [154] investigated the effectiveness of silica nanoparticles in altering the wettability of carbonate rock with high salinity, reporting a 65.5% recovery of oil initially in place. Moradi *et al.* [155] investigated the effect of nanoparticles on wettability change and discovered that nanoparticles might adsorb on the surface of carbonate rocks, assisting in the modification of wettability and therefore improving recovery. Nazari *et al.* [156] utilized ZrO_2, TiO_2, MgO, Al_2O_3, CeO_2, and carbon nanotube for altering the wettability of the carbonated rocks by measuring the contact angles. On the other hand, they used SiO_2 and $CaCO_3$ for core flooding experiments. The outcome revealed an additional 8-9% oil recovery. Moustafa *et al.* [157] demonstrated the contact angle change using magnesium and aluminum layered hydroxide nanoparticles with a 4g/L concentration dispersed in brine. Their result showed the change of contact angle from 66^0 to 60^0 in the oil phase. Ershadi *et al.* [158] explored the wettability modification of different rocks using MWCNT silicon dioxide nanofluid. The influence of ZrO_2 and NiO nanoparticles on the wettability behavior of rocks was also studied by Nwidee *et al.* [159]. They found that oil-wet or intermediate-wet formation can drastically improve the oil recovery by altering the wettability to water-wet, as evidenced by contact angle measurements. The contact angle decrease is caused by various parameters such as exposure time, salinity, nanoparticle concentration, and so on. Huibers *et al.* [160] recommended using 0.001 wt.% silica nanoparticles to change the wettability of sandstone rock by measuring the contact angle for light crude oil. Finally, it can be said that to improve oil recovery, nanoparticles can be carefully chosen based on their wettability alteration capacity.

IFT Reduction

The surface free energy between two non-mixable liquids can be defined as the interfacial tension (IFT). The reduction of IFT between two fluids can assist in obtaining a higher capillary number [161]. The capillary force is responsible for the fluid distribution and movement control in the reservoir system. The degree of capillary force largely depends on the IFT between rock samples and reservoir fluids. Oil recovery from a porous medium system can be limited by capillary force [162]. IFT drop is one of the primary mechanisms which can affect the EOR technique. Therefore, evaluating the efficacy of a given EOR approach requires measuring the IFT between injected fluid and oil. IFT plays a critical role in rock-fluid interactions, and a few studies have been undertaken to investigate the IFT where nanoparticles and surfactants were involved [163]. Various nanoparticles are considered the primary agents to lessen IFT between injected fluid and oil [164]. The pendant drop [12] and the spinning drop [165] are two approaches for determining the IFT between injected nanofluid and crude oil. The IFT between nanofluid and oil can be determined by employing the pendant drop technique. Numerous investigations have been performed to demonstrate the ability of nanoparticles to reduce IFT between injected fluids and oil [3]. Compared to high salt concentrated brine, Rostami *et al.* [166] investigated the use of low concentrated salt in brine to reduce IFT, resulting in higher oil recovery. Roustaie *et al.* [167] explored the impact of lipophilic polysilicon (HLP) and naturally wet polysilicon (NWP) silica nanoparticles on enhanced oil recovery. The result indicates the reduction of oil-water IFT from 26.3 mN/m to 1.75 mN/m and 2.55 mN/m, respectively. Lan *et al.* [168] demonstrated the effect of cationic surfactant and silicon dioxide nanoparticles on interfacial tension. The cationic surfactant may readily alter the surface of nanoparticles from extremely hydrophilic to partially hydrophobic, aiding in nanoparticle flocculation and lowering IFT. The cationic surfactant can easily change the surface of nanoparticles from extremely hydrophilic to partially hydrophobic, which assists the flocculation of nanoparticles resulting in the reduction of IFT. Hendraningrat *et al.* [64] investigated the effects of several variables on IFT reduction as a method for enhanced oil recovery. The findings show that nanoparticle concentration, type, and the dispersed fluid system all significantly impact the IFT. Silica-based nanoparticles can reduce the IFT from 19.3 mN/m to 15.7 mN/m, while nanoparticles dispersed in oil can reduce the IFT to 12.8 mN/m. Afzali *et al.* [169] examined the impact of CNTs as a potential agent of EOR to reduce the IFT. Ragab and Hannora [170] conducted studies at ambient pressure and temperature to demonstrate the influence of nanoparticles dispersed in brine on IFT reduction. The result indicates SiO_2 nanoparticles dispersed in a base fluid had lowered IFT compared with Al_2O_3 nanofluid. Esmaeilzadeh *et al.* [171] examined the influence of ZrO_2 nanoparticles on

IFT reduction using an anionic surfactant. The enhanced surface activity of the anionic surfactant by ZrO_2 nanoparticles resulted in a substantial decrease in IFT between nanofluid and oil. Alomair *et al.* [172] investigated and compared the effect of various nanoparticles (SiO_2, Al_2O_3, NiO) on IFT reduction. Olayiwola and Dejam [173] investigated and proposed a mathematical model that can quantify the changes of IFT using different-sized nanoparticles dispersed in deionized water. They found the structural impact of nanoparticle and dipole-dipole interaction to derive the mathematical model, which the IFT of nanoparticles in brine can represent. The use of nanoparticles in dispersed brine not only improves the stability but also assists in reducing the IFT due to the effective charges of surfactants and nanoparticles [174]. Munshi *et al.* [175] demonstrated that the presence of nanoparticles in a surfactant mixture could improve the solution's rheology and reduce IFT. Suleimanov *et al.* [176] analyzed the impact of adsorption of nanoparticles on the surface of fluid that can successfully lessen the IFT between nanofluid and the oil. Esmaeilzadeh *et al.* [171] explored the influence of ZrO_2 nanoparticles mixed with surfactant on IFT reduction. The finding shows a substantial decrease in IFT for both heptane-fluid and air-fluid systems. It can be concluded that IFT is a critical factor to consider when choosing nanoparticles for enhanced oil recovery.

Mobility Ratio

Mobility is described as the ratio of relative permeability and viscosity of the fluid. Mobility ratio during an EOR process is specified as the ratio of displacing fluid (injected fluid) and displaced fluid (oil) mobility. It is one of the crucial elements that control the enhanced oil recovery method. It can be expressed through the following equation [177].

$$M = \frac{\lambda_i}{\lambda_o} = \frac{k_{ri}/\mu_i}{k_{ro}/\mu_o} = \frac{k_{ri}\mu_o}{k_{ro}\mu_i} \qquad (3)$$

Where subscript *i* and *o* represent injected fluid and oil. λ, k_r, μ represent mobility, relative permeability, and viscosity of injected fluid and oil. The stability of the displacement largely depends on this mobility ratio [178]. During an EOR process, it is very important to manage the mobility ratio of injected fluid to obtain a higher sweep efficiency, which ultimately enhances the oil recovery. A higher mobility ratio for displacing fluid can result in viscous fingering and poor sweep efficiency, which precedes the early breakthrough and lower the oil recovery [179]. The mobility ratio is very important for macroscopic displacement efficiency. When the mobility ratio is less than or equal to 1 ($M \leq 1$), it is considered a favorable mobility ratio, enhancing displacement efficiency. On the other hand, unfavorable mobility ratios arise when the mobility ratios seem to be larger than one ($M>1$), resulting in inadequate residual oil displacement. Polymer flooding has been investigated and used successfully as a mobility controlling agent to improve sweep efficiency for several decades [180-181]. However, with an adverse reservoir condition of high temperature, pressure, and salinity, the polymer solution became ruined resulted in viscosity reduction of injected polymer, which advances to poor sweep efficiency [182-183]. It can be concluded that the mobility ratio is an essential element for enhanced oil recovery since it determines how much reservoir fluid (oil) is displaced.

Preventing Asphaltene Precipitation

Asphaltene precipitation is a common phenomenon during the implementation of different EOR techniques. Due to unfavorable reservoir circumstances, large quantities of asphaltene precipitation can occur, promoting the loss of formation permeability, wettability modification, transportation pipeline blockage, and other effects during CO_2 flooding [184-186]. As a result, preventing asphaltene precipitation is critical for various EOR methods to maximize oil recovery. Some investigators determined that nanoparticles could solve asphaltene precipitation to a large extent without causing environmental hazards. Nanoparticle concentrations over a certain threshold can delay asphaltene precipitation by allowing nanoparticles to adsorb onto the molecular surfaces of asphaltenes. This action can reduce the flocculation of asphaltene molecules and hence prevents asphaltene precipitations. Tarboush and Husein [186] looked into the influence of nanoparticles on asphaltene precipitation and discovered that nanoparticles might help stabilize asphaltene precipitation.

Alomair *et al.* [172] examined the consequence of using mixed nanofluids (Al_2O_3-SiO_2) and their effect on asphaltene precipitation. They found that increasing the concentration of nanofluid can slow down additional precipitation of asphaltenes. Kazemzadeh *et al.* [187] used a micromodel to test the effects of SiO_2, Fe_2O_3, and NiO nanoparticles on asphaltene precipitation. The authors found that the presence of nanoparticles leads to the adsorption of nanoparticles on the surface of the asphaltene molecules, which drastically reduces the flocculation of asphaltenes in the porous media. Temperature, water content, asphaltene, and contact time have all been investigated in other research to see how they affect the adsorption of asphaltenes onto nanoparticle surfaces [188-189]. Those studies showed that as the contact time increases, asphaltene adsorbed onto the nanoparticle surfaces increased. A large number of asphaltenes were adsorbed on top of the nanoparticles' surface in a short amount of time. On the other hand, the amount of asphaltene adsorbed was increased with increasing asphaltene content along with the reduction of temperature and the volume of water available. It can be summarized that nanoparticles can assist in reducing asphaltene precipitation, resulting in increased oil production.

Pore Channels Plugging

There are three key mechanisms available that alter the propagation of nanoparticles through the porous medium. These are (1) Chemical stability of the solution, (2) Physical filtration, and (3) Adsorption on the surface of the rock. The solubility and dispersibility of nanoparticles are termed the chemical stability of the solution. The poor solubility of the chemicals can occur due to the elevated salinity, which promotes the precipitation of nanoparticles. When nanoparticle size is bigger compared with the size of the pore, then physical filtration can occur. This mechanism can occur even with well-dispersed nanoparticles, particularly when nanoparticles are injected in the low permeability reservoirs (e.g., tight sandstones or shale reservoirs). The third mechanism is the adsorption on the rock's surface, which reduces the transportation of nanoparticles through the porous media. The oil recovery may improve if the adsorption of the nanoparticles on the rock surface becomes low. Different experiments in the lab have shown that polymer coatings assist in stabilizing the nanoparticle solution, but adsorption and retardation will increase in the porous media [190]. The concentration of nanoparticles will reduce as it enters the porous medium because of different process control mechanisms. One of the main mechanisms is pore channel plugging, which can be subdivided into mechanical entrapment and log jamming [191]. When injected nanoparticles' size is bigger than the size of the pore throat through which it will pass, mechanical entrapment can occur. Generally, the size of the pore throat is in microscale, and the nanoparticles are in nanoscale, which means pore throats are a thousand times larger than the nanoparticles. However, it was reported that some of the metal-type nanoparticles plug the pore channels because of their larger sizes [192-193]. This mechanism is considered straining. Smaller size nanoparticles compared with pore throat size should be used to avoid straining [10]. The density difference between nanoparticles and water can decrease the movement of nanoparticles, hence promoting them to flocculate together; as a result, the size of the pore throat reduces, leading to the blockage of pore throats. This blockage can boost the pressure exerted on the adjoining pores, which can pressurize the oils to flow out of the pores [194]. As the oil is released from the adjacent pores, the pressure drops, causing the nanoparticles blocking the pores to dissolve and flow with the water. This process is known as temporary log-jamming and largely depends on the quantity and size of nanoparticles, pore throats, flow rate, etc. [10]. Pore channel plugging is a key mechanism that can reduce oil production. Therefore, nanoparticles can be selected carefully so that pore channel plugging should be minimized.

Disjoining Pressure

The structural disjoining pressure can be described as the attractive and repulsive forces acting between two thin layers of a fluid [195]. Structural disjoining pressure is defined by Engeset [196] as the pressure exerted by two thin surface layers as a result of their mutual overlap. Disjoining pressure has been researched extensively and is thought to be one of the most important processes for nanoparticle aided EOR [197-198]. Chengara *et al.* [55] identified disjoining pressure as the extra pressure exerted in the thin liquid film relative to a bulk solution. The disjoining pressure normally works to the liquid-solid interface. It tends to generate due to nanoparticle structuring in the wedge-type film between a solid surface and oil droplet [199]. Nanoparticles are considered one of the key elements directly affecting the disjoining pressure exerted between two immiscible fluids. The nature of nanoparticles' expanding and adhesion properties are quite complex when they are in contact with solid surfaces. Their behavior is quite different from that of simple liquid due to a three-phase contact region [200]. When nanoparticles dispersed in the base fluid come into contact with the oil phase, they form a wedge-shaped film [194]. This wedge-shaped film tries to detach the oil droplets from the solid surface, which ultimately assists in recovering additional oil compared with the conventional fluid injection [201]. In other words, nanofluids introduced into the formation put pressure on nanoparticles, forcing them to seek a confined space and causing them to arrange themselves into a wedge-shaped film. These configurations may eventually aid in generating disjoining pressure at the interface between nanofluids and the oil phase, therefore improving oil recovery [12]. The pressure exerted by a specific nanoparticle is insignificant, but the resulting aggregate pressure by a significant number of nanoparticles can attain up to $5*10^4$ Pa. The driving force created by these phenomena or mechanisms is due to the combining effect of Browning force and electrostatic repulsion [202]. In summary, disjoining pressure causes the oil to separate from the solid surface, allowing the nanoparticles to spread. The disjoining pressure is affected by several variables, including nanoparticle concentration, size, charge density, salinity, temperature, and solid surface characteristics [68]. Nanoparticles with a smaller size and higher concentration can impose a stronger disjoining pressure, according to Kondiparty *et al.* [67]. Furthermore, electrostatic repulsion nanoparticles of smaller size and higher charge density can be utilized to augment the force exerted on the wedge film [203]. However, it is important to consider the polydispersity of nanoparticles as it has a significant impact on disjoining pressure magnitude [204]. In summary, it can be said that disjoining pressure is an important mechanism that can affect a particular EOR process. The summary of nanoparticle aided EOR is given below in Table 3.

EXPERIMENTAL STUDIES

The experimental study of nanoparticle-assisted EOR is given below for both core flooding and micromodel scales.

Core Flooding Studies Using Nanoparticles

Core flooding is a laboratory test used widely in the oil and gas industry to evaluate oil recovery under various pressure and temperature conditions [161]. Core flooding experiments can reveal and provide accurate information about altering formation evaluation properties used in laboratory experiments [241]. Despite all great capabilities, core flooding experiments are time-consuming, and to conduct several tests, one must change the core properties every time. Therefore, it is very important to perform screening tests to explore IFT, wettability alteration, injected fluid type, concentration, and before conducting core flooding tests. Numerous core flooding studies have been done in the laboratory to evaluate the influence of nanoparticles on oil recovery, much like many other EOR approaches. Some of them are summarized below:

Rodriguez *et al.* [240] used modified silica nanoparticles in a series of core flooding tests to look into nanoparticle transport pathways and core plug retention time. The result demonstrates that the transport of silica nanoparticles in porous media is much easier than any other colloidal dispersion. Moreover, the retention of nanoparticles in the core plug is much lesser because of the ultra-small size of the nanoparticles, and the surface modification makes them uniformly distributed and dispersed in the core flooding experiments. The homogeneity and aggregation of nanoparticles in the injected fluid can be influenced by the fluid's flow rate, pH value, and salinity.

Onyekonwu and Ogolo [239] illustrated the effect of polynanoparticles by conducting core flooding experiments on oil recovery by demonstrating wettability alteration and interfacial tension reduction mechanism. The results suggest that nanoparticles may recover 50 to 80 percent of the oil. The main mechanism of oil recovery was wettability alteration and IFT reduction. They recommended using less than 3g concentration of nanoparticles in 1 liter of base fluid for better oil recovery.

Espinosa [242] conducted a series of core

Table 3. Summary of nanoparticles-assisted EOR methods.

References	Nanoparticle Type	Base Fluids	Oil Type Oil Properties			Core Type	Influential Parameters	Concentration	Additional RF
			Oil Type	Density (kg/m^3)	Viscosity (cP)				
[162]	Complex nanofluid	water, brine, surfactant				tensleep core		1	16-21
[205]	SnO_2	brine				carbonate core		0.1 wt.%	22
[206]	SiO_2	water and surfactant				carbonate core		5 wt.%	
[207]	SiO_2	brine	N-decane			calcite	salinity, time, nanoparticle concentration, and reversibility of nanoparticle adsorption		
[208]	MWCNT	MWCNT fluid				glass bed		0.01–0.10 wt.%	31.8
[209]	Nanoclay	water				Sandstone core		0.9	5.8
[210]	TiO_2	polymer and water				sandstone core		1.9–2.5	4
[153]	SiO_2	brine	light oil	847	15.3	sandstone	nanoparticle concentration and size		5-15
[156]	CeO_2, TiO_2, SiO_2CaCO_3, ZrO_2, Al_2O_3, MgO, CNT	brine (3–12 wt. %)				sandstone core		5	8–9
[170]	SiO_2	brine	light oil	851	75	sandstone core	nanoparticle concentration and size		5-10
[211]	SiO_2	water		933	870	glass		4 wt%	
[212]	SiO_2	brine	mineral oil	891	-	sandstone	nanoparticle concentration and size	0.01; 0.5 and 3 wt.%	9-19
[213]	Al_2O_3, SiO_2	brine	medium crude oil	851	75	sandstone	nanoparticle size and concentration		4.65-13.88
[214]	ZrO_2		heavy oil		130.4	glass		100 ppm	
[59]	Fe_2O_3 + Al_2O_3 + SiO_2	brine	mineral oil	919	5.12	sandstone	mixture concentration		8.99-20.42
[215]	SiO_2	surfactant and polymer				Berea sandstone		1	21
[216]	SiO_2	5000 ppm NaCl brine		884.5	10.07	Berea sandstone		700 ppm	
[187]	Fe_3O_4, NiO, SiO_2	asphaltene+ toluene solution		-	-	micromodel	nanoparticle size and concentration		4.6-22.6
[10]	SiO_2	water				sandstone core		0.01–3	29
[217]	SiO_2- biomaterial	water	heavy oil	925	200	micromodel (shale)	nanoparticle concentration, shale orientation, length, distance, injection pressure		28-40
[217]	SiO_2 and TiO_2	synthetic brine	heavy oil		200	glass			
[152]	SiO_2	5 wt.% NaCl	light oil	857	11	carbonate	aging time	1 – 6 g/L	9.12-17

Continued Table 3. Summary of nanoparticles-assisted EOR methods.

References	Nanoparticle Type	Base Fluids	Oil Type Oil Properties: Oil Type	Density (kg/m^3)	Viscosity (cP)	Core Type	Influential Parameters	Concentration	Additional RF
[218]	$Fe_2O_3 + Al_2O_3 + SiO_2$	brine	mineral oil	919	5.12	sandstone	injection mode and salinity		0.9-9.49
[219]	TiO_2	brine (NaCl 0.5 wt. %)		920	41.21	sandstone core		0.01 and 1	51
[220]	Partially Hydrophobic SiO_2	0.5 wt.% NaCl brine		913.9	413	sandpack		0.5 wt.%	
[220]	Partially hydrophobic SiO_2	0.5 wt.% NaCl brine		913.9	413	glass etched micromodel		0.0 to 2.0 wt.%	
[221]	Hydrophilic SiO_2	10.3 g/L brine	light oil			Berea sandstone		1 wt.%	
[222]	Al_2O_3, TiO_2, SiO_2	DI water		863	21.7	limestone		0.005 wt.%	
[57]	TiO_2	brine	medium crude oil	920	41.21	sandstone core	nanoparticle concentration		10-14
[223]	Nickel nanoparticles	DI water				glass		0.05 wt.%	
[224]	Coated silica	ethanol – DI water	light, medium, and heavy oil			Berea sandstone		1 % (w/v)	
[225]	Al_2O_3, TiO_2, SiO_2	brine (NaCl 3 wt. %)				sandstone core		0.05	7–11
[226]	SiO_2 and Al_2O_3	36000 ppm brine		850	25	glass		0 to 1000 ppm	
[149]	Fe_2O_3, Al_2O_3, silane	propanol				sandpack		0.05–0.3	22.5
[149]	Al_2O_3, Fe_2O_3, and SiO_2	25000 ppm brine	medium oil		40.38	sandstone		0 – 4 g/L	
[51]	Alumina coated silica	ultra-pure water			30	Berea sandstone		1 wt.%	
[227]	SiO_2	2% NaCl				dolomite, Berea, limestone			
[172]	TiO_2, SiO_2, NiO, Al_2O_3	brine	heavy oil	950	208.88	sandstone core	nanoparticle type		16.94-23.72
[225]	SiO_2, Al_2O_3, TiO_2	brine	Light oil	826	5.1	sandstone core	nanoparticle type		7-11
[228]	SiO_2	Polyacrylamide				glass bed		0.1	10
[228]	Hydrophilic SiO_2	1400 to 84000 ppm brine	medium oil		1000	glass (laser etching)		0.1 to 5 wt%	
[229]	LHP SiO_2	brine (NaCl 3 wt. %)				Berea sandstone		0.01–0.1	10
[230]	SiO_2	DI water		840	85	glass		1000 ppm	
[231]	Hydrophilic SiO_2	3 wt.% NaCl brine	light oil	826	5.1	glass	Two-phase flow behavior, nanoparticle concentration, emulsions, and adsorptions	0.01, 0.05, and 0.10 wt.%	
[64]	SiO_2	brine	light oil	826	5.1	sandstone	permeability, nanoparticle concentration, and PV		5.93-14.29

Continued Table 3. Summary of nanoparticles-assisted EOR methods.

References	Nanoparticle Type	Base Fluids	Oil Type Oil Properties			Core Type	Influential Parameters	Concentration	Additional RF
			Oil Type	Density (kg/m^3)	Viscosity (cP)				
[145]	Al_2O_3	anionic surfactant solution	heavy oil	895	64	sandstone	nanoparticle concentration		
[231]	SiO_2	brine	light oil	826	5.1	sandstone	nanoparticle concentration		4.26-5.32
[69]	Hydrophilic SiO_2	3 wt.% NaCl brine	light oil	826	5.1	Berea sandstone	permeability and nanoparticle concentration	0.05 wt.%	0-9.9
[232]	HLP and LHP SiO_2	ethanol				Sandstone core		0.1–0.4	19.31
[164]	SiO_2	0.05 NaCl brine				Berea sandstone, limestone		1-35%	
[146]	Hydrophilic SiO_2	200000 ppm brine	heavy oil	933	870	micromodel	nanoparticle concentration	0.1 to 5 wt.%	8.7-26
[233]	Surface treated silica	2 wt.% NaBr brine				Boise sandstone		5 wt.%	
[147]	ZrO_2 + Surfactants	water (distilled)	heavy oil	861	425	carbonate	type of nonionic surfactants and aging time		
[234]	Hydrophilic SiO_2	3 wt.% NaCl brine		802	2	glass		0.1 to 1.0 wt.%	
[235]	SiO_2	ethanol	medium crude oil	911	53.28	sandpack	base fluid and type of nanoparticle		13.3-24.1
[236]	SiO_2	brine	paraffinic oil	803	1.958	sandstone	Injection timing		tertiary (<2) secondary (8)
[237]	Fe_2O_3, NiO, CuO,	brine	medium crude oil	887	47.9	carbonate	type of nanoparticle	5	7.59-14.07
[238]	SiO_2	DI water		1400	85	glass		1000 ppm	
[56]	Surface treated silica	DI water and 4% NaCl brine						0.05-0.50 g/L	
[239]	SiO_2, Fe_2O_3, Al_2O_3, ZnO, SnO_2, ZrO_2, NiO, MgO,	ethanol brine and water				sandstone core		0.3	12
[239]	Polysilicon	brine 30000 ppm	medium oil		41			2-3 g/L	
[240]	Surface treated SiO_2	NaCl brine				limestone and Berea and Boise sandstone		0.20	
[134]	SiO_2	water				sandstone core		0.02–0.03	-

flooding tests to investigate the stabilization of CO_2 in water foam using silica nanoparticles. The findings indicated that using nanoparticles and CO_2 gas injection to control mobility is a viable option that avoids gravity overriding.

Singh and Mohanty [51] described 20 percent additional oil recovery by conducting core flood experiments using hydrophilic nanoparticles. They recommend using hydrophilic nanoparticles to stabilize foam, which ultimately assists in enhancing the oil recovery.

Metin *et al.* [243] studied the dynamic viscosity of nanofluids by conducting core flood experiments using silica nanoparticles. They showed that the viscosity decrease is primarily determined by nanoparticle concentration, and the nanofluid type also influences Newtonian behavior. A significant amount of nanoparticle retention in the sandstone core plug is caused by the clay swelling effect.

Hendraningrat and Torsæter [69] examined the effect of different process control factors such as flow rate, particle size, wettability, temperature, and rock permeability on oil recovery by conducting core flood experiments using water enriched with nanoparticles. The result indicates an additional recovery of 5 to 10 percent while using nanoparticles. The recovery was comparatively better when intermediate or oil-wet cores were used because nanoparticles can easily change the wettability from intermediate or oil-wet to water-wet.

Li *et al.* [231] conducted core flooding tests in Berea sandstone using hydrophilic nanoparticles. Approximately 4 to 5 percent additional oil recovery was reported using silica nanoparticles in brine compared to waterflooding.

Zaid *et al.* [244] examined the formation and stability of emulsions using aluminum oxide (Al_2O_3) and Zinc oxide (ZnO) nanoparticles by conducting core flooding experiments. The emulsion formed in the oil and water interface has a higher viscosity, providing more force to push out the residual oil. IFT reduction and increased recovery of 117 percent were observed using nanoparticles compared with surfactant flooding. They suggested that additional oil recovery can be a result of stable emulsion formation. In addition, Aluminum oxide nanoparticles are more effective than zinc oxide nanoparticles in terms of oil recovery. An additional 23% rise in oil recovery was detected using nanoparticles compared with waterflooding.

Sharma *et al.* [221] performed core flooding experiments to explore the impact of nanoparticles on the formation of emulsion at high pressure (13.6 MPa) at four different temperatures. The result indicates that the stable emulsion formation using nanoparticles can enhance the oil recovery by two well-known mechanisms of thermal stability and stabilized flow behavior.

Esfandyari Bayat *et al.* [222] analyzed the impact of different nanoparticles on oil recovery using intermediate wet limestone core for their core flooding experiments. Aluminum oxide (Al_2O_3), titanium dioxide (TiO_2), and silicon dioxide (SiO_2) nanoparticles were employed with different temperatures to perform the tests. Wettability modification from intermediate wet to water wet and a considerable amount of viscosity reduction was observed due to thermal conductivity enhancement. The measured contact angles reported for Al_2O_3, TiO_2, and SiO_2 were 71^0, 57^0, and 26^0, respectively.

Sun *et al.* [220] depicted the influence of hydrophilic silica nanoparticles on oil recovery and nitrogen foam stability by conducting core flooding experiments. The results showed high-temperature stability for nitrogen foam compared with surfactant. The authors recommended the optimal concentration for silica nanoparticles should be 1.5 wt.% in brine.

Nguyen *et al.* [224] examined the influence of nanoparticles on CO_2 stability and ultimate oil recovery by conducting core flooding tests. The foams are stabilized for ten days by nanoparticles but only for one day by surfactants. An additional 15% oil recovery was reported when nanoparticles stabilized foam flooding was used.

Mo *et al.* [227] conducted core flooding experiments using silica nanoparticles with stabilized foam for enhanced oil recovery. An additional 30% recovery of oil was reported using nanofluids compared with waterflooding.

Joonaki and Ghanaatian [149] examined the effects of nanoparticles (SiO_2 and Al_2O_3) on oil recovery by conducting core flooding tests. The result indicates an IFT reduction from 6 to 2 dyne/cm and the alteration of wettability from oil-wet to intermediate wet, characterized by the contact angle change from 1300 to 900. Their study reported an additional 20% oil recovery.

Roustaei and Bagherzadeh [152] conducted core flooding experiments using oil-wet carbonate rock as porous media to study the effects of nanoparticles. The findings indicate increased oil recovery by 10 to 20%, caused by the wettability alteration from oil-wet to water-wet. It was suggested to use 4 gm of nanoparticles on 1 liter of brine for maximum oil recovery.

Nazari Moghadam *et al.* [156] examined different types of nanoparticles on oil recovery. They investigated the effects of SiO_2, MgO, Al_2O_3, TiO_2, ZrO_2, $CaCO_3$, CeO_2, and carbon nanotube effects on enhanced oil recovery and reported an additional recovery of 9% using core flooding experiments.

Jafari *et al.* [245] performed core flooding tests using nanoparticles to explore the consequence of using nanoparticles on heavy oil recovery. Approximately 5% of additional oil recovery was reported by their experiments using nanoparticles.

Ragab and Hannora [170] investigated the impacts of SiO_2 and Al_2O_3 nanoparticles on IFT reduction using ambient pressure and temperature conditions. SiO_2 nanoparticles can significantly reduce IFT compared with Al_2O_3 nanoparticles, resulting in more oil recovery using SiO_2.

EI-Diasty [212] studied the effect of different sizes (5 to 60 nm) of SiO_2 nanoparticles on EOR using Egyptian sandstone for their core flooding experiments.

Ahmadi *et al.* [206] investigated the nanoparticle-assisted surfactant flooding on oil recovery and reported an additional 25% recovery using silica nanoparticles dispersed in surfactant.

Jafamezhad *et al.* [246] analyzed the impact of silica nanoparticles on carbonate rocks in terms of heavy oil recovery. The authors performed core flooding tests using 0.5 wt.% silica nanoparticles dispersed in brine, which resulted in 39 to 61% additional oil recovery.

Coreflooding experiments are critical for determining various operational parameters and nanoparticle selection. It is might aid researchers in determining how various nanoparticles influence different EOR techniques.

Micromodel Studies Using Nanoparticles

Properly designed and carefully executed core flooding experiments can represent most reservoir conditions, heterogeneities, and complexities at the centimeter length scale. Therefore, core flooding experiments are frequently employed in the petroleum industry to study the critical component of the reservoir fluid recovery process. It is quite impossible to visualize the displacement process during the core flooding tests due to the unclear nature of the core. Moreover, it is also impractical to reuse the core after one experiment because some conditions may change due to the nature of the core. These drawbacks may be overcome by using a transparent micromodel. Micromodels are two-dimensional (2D) porous media with varying pore depth, size, and geometries built on a piece of glass. Micromodels represent the geometric structure of a rock pore network designed for direct visual observation of the flow phenomena. Micromodels have been used for many years to investigate the interaction between rock-fluid, displacement efficiency, and the impact of various variables on the performance of different enhanced oil recovery techniques. It also offers the unique ability to visualize a specific EOR process, which will aid in investigating the mechanism. Reservoir cores and core plugs are commonly utilized in lab-scale core flooding experiments. Micromodels help to get real-time visualization of fluid flow behavior. Most core flooding studies only monitor nanoparticle parameters (injection rate, pressure, temperature, etc.) and oil recovery without direct visualization. However, in micromodel experiments, the oil recovery process can be seen using a high-resolution video camera with a millimeter-level resolution. Micromodels assist direct observation of flow paths and displacement mechanisms that can help determine and understand the two-phase flow. It can help and make it possible to study how pore-scale results are directly correlated with the large-scale process. The bubble nucleation, growth, breakdown, and coalescence processes may all be quantified using the CO_2 exsolution process from heavy oil. In addition, the major mechanisms of additional heavy oil recoveries will be studied, including viscosity decrease, IFT reduction, contact angle change, and wettability change. The micromodel visualization process can assist in detecting the flow pattern, front location concerning time, and the formation of fingering will be studied for a different combination of pore structure and fluids. The micromodel and its microscopic view are shown in Fig. 7.

Following the observation of fluid dynamics within the micromodel, flow patterns in the actual reservoir may be predicted. It can also let you run experiments in less time than you would with traditional methods. Some of the micromodel

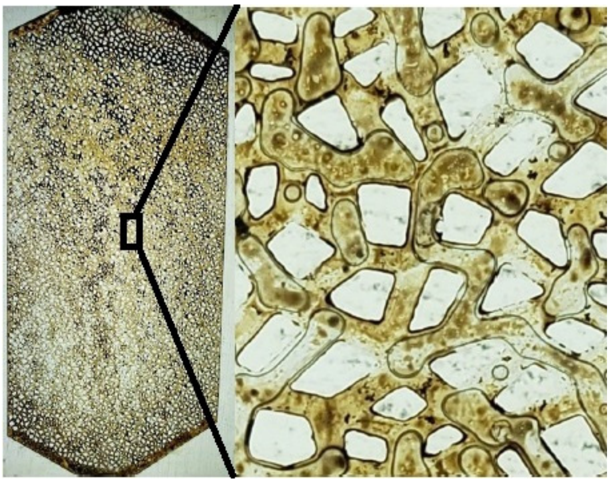

Fig. 7. Micromodel and its microscopic view.

tests using nanoparticles are summarized below:

Magzhi *et al.* [238] investigated the effect of nanoparticles on oil recovery in a micromodel system by infusing nanoparticles dispersed in the polymer solution. The findings revealed a shift in wettability from oil-wet or intermediately wet to substantially water-wet, as well as an additional 10% oil recovery.

Magzhi *et al.* [145] analyzed the impact of nanoparticle concentration dispersed in deionized (DI) water on EOR by conducting micromodel tests. The oil recovery improved from 8.7 to 26% for a nanoparticle concentration of 0.1 to 3 wt.%. They reported optimum concentration of nanoparticles in DI water was three wt.% for enhanced oil recovery, and the wettability changed to strong water wet.

Hendraningrat *et al.* [234] reviewed the impact of hydrophilic nanoparticles dispersed in brine on oil recovery. They used micromodel experiments to evaluate wettability changes, IFT reduction, nanoparticle retention in porous media, and permeability impairment. The permeability was reduced because of the pore plugging or blockage by the aggregation of nanoparticles. This limitation can be easily avoided by using uniformly distributed nanoparticles.

Li *et al.* [231] depicted the impacts of the concentration of nanoparticles on oil in water emulsion generation by conducting several micromodel experiments. They used hydrophilic nanoparticles (7 nm) in their experiments.

Sun *et al.* [220] explored the effect of partially hydrophilic modified SiO_2 nanoparticles on EOR. They also depicted the generation of nitrogen and stability of foam using nanoparticles in a micromodel study.

Nguyen *et al.* [224] revealed the effect of nanoparticle-assisted CO_2 foam on enhanced oil recovery using a micromodel study. The result indicated that the oil in water emulsion significantly reduced when nanoparticle was used to form foam. In addition, it was also reported that viscous fingering was dampened by using nanoparticle stabilized foam as a mobility control factor. They also depicted that the area in contact with CO_2 foam is larger than waterflooding, and 15% additional oil recovery was also reported.

Khezrnezad *et al.* [226] investigated two different kinds of nanoparticles (SiO_2, Al_2O_3) effect on enhanced oil recovery by considering WAG ratio and nanoparticle concentration as the main factors. A significant IFT reduction was reported when brine was used as a base fluid for nanoparticles. Silica nanoparticles are more effective than alumina nanoparticles in oil recovery, and oil recovery was improved from 15 to 20% using nanoparticles.

Hamedi-Shokrlu and Babadagli [223] researched the impact of nickel nanoparticles on enhanced oil recovery by performing micromodel tests. The stabilization and transportation of nickel nanoparticles were investigated during the injection process in micromodel. Nickel was used as a nanoparticle due to its high thermal conductivity, which was ultimately assisting in recovering more oil because of its catalytic performance.

Gharibshahi *et al.* [211] revealed the impact of silica nanofluid on enhanced oil recovery by conducting micromodel tests. They also compared their experimental results with simulation and reported that viscous fingering could be avoided by using nanoparticles. Moreover, many processes controlling parameters such as pore trapping, heterogeneity, tortuosity, breakthrough time, pore shape, and connectivity were also studied.

Mohebbifar v [217] investigated wettability alteration from oil-wet to water-wet, IFT reduction, thinning oil film, emulsion formation, and stability by conducting micromodel tests using nanoparticles. The result indicates the oil recovery was increased by 78% when nanoparticles were used, and it was reported that nanoparticles were highly effective for improving microscopic sweep efficiency.

Mohazeri *et al.* [214] analyzed the effect of ZrO_2 nanoparticles on enhanced oil recovery using micromodel tests. The result indicates 40% additional oil recovery using nanoparticles.

This summary can assist researchers in designing micromodel operating parameters and selecting appropriate nanoparticles. Furthermore, it will aid in the selection of a mixture of nanoparticles rather than a single nanoparticle for micromodel testing.

CURRENT RESEARCH TRENDS AND FUTURE DIRECTIONS

Although nanoparticles have the potential to be used as an EOR agent, most of their applications are restricted to laboratory experiments and not appropriate for field use. There are quite a few challenges that need to be addressed before the nano-assisted EOR techniques can be applied in field applications. The preparation of homogeneous nanofluid is one of the technical challenges [219]. The strong Vander Waals force acting between nanoparticles always tries to aggregate them together under high-temperature, high-pressure reservoir conditions, resulting in a heterogeneous solution. The majority of nanoparticle research is focused on nanofluid flooding, although the mechanisms involved and the interactions between nanofluid and rock and nanofluid and oil are still not clearly understood. Some laboratory experiments can investigate the effects of metal nanoparticles on oil recovery. However, the combination of different nanoparticles' effects is still in its early stages. More experimental studies with a mixture of nanoparticles are needed to uncover their broad range of applications in EOR. The fundamental understanding of nanoparticle-assisted EOR requires comprehensive mathematical modeling, accurately representing or duplicating the field conditions. However, developing a mathematical model to represent such EOR processes since nanoparticle transport through porous media is complex and the mechanism is unclear. Therefore, it is important to derive scaling numbers by developing a mathematical model to characterize nanoparticle-assisted EOR techniques accurately. Some unique scaling numbers may be presented by effectively combining multiple dimensionless numbers, which can aid in assessing the efficacy of nanoparticle-aided EOR processes.

CONCLUSION AND RECOMMENDATIONS

This research provides an overview and comprehensive analysis of the nanoparticle-aided EOR method in conjunction with scaling methodologies. Different scaling criteria development procedures are outlined along with their advantages and limitations. Various nanoparticles and their applications on EOR are reviewed. Several nanoparticles aided EOR experimental works are summarized for both core flooding and micromodel studies. Nanoparticles have been considered one of the potential agents for EOR due to some unique properties and environmental friendliness compared with chemicals. The EOR mechanism involved in nanoparticles still is not well understood. Mathematical models and theoretical understanding are urgently needed to realize the mechanism involved in nanoparticle transport in porous media and reduce its risk to apply in field conditions. It is recommended to use a favorable mixture of nanofluids as a single nanofluid does not occupy all properties needed for EOR. Although nanoparticles are considered potential EOR agents, their use is limited to only laboratory research. Thus, it is required to develop a relationship between lab-scale results in field-scale processes through scaling. Finally, it is recommended to develop comprehensive modeling to scale the nanoparticles aided EOR and their field performance accurately.

AUTHOR CONTRIBUTIONS

Conceptualization, A.R., E.S., and F.T.; methodology, A. R., and A.RB.; validation, A.R., E.S., and F.T.; formal analysis, A.R.; investigation, A.R.; resources, A.R., E.S., F.T. and A.RB.; writing—

original draft preparation, A.R.; writing—review and editing, A.R. and F.T.; supervision, E.S., and F.T.; project administration, E.S., and F.T.; funding acquisition, E.S., and F.T. All authors have read and agreed to the published version of the manuscript.

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CONFLICTS OF INTEREST

All authors have read and declare no conflict of interest.

NOMENCLATURES

C_n	Nanoparticle concentration, mole/m^3
S	Retained concentration, mole/kg
ϕ	Porosity, fraction
$\tilde{n}$	Bulk density, kg/m^3
D	Hydrodynamic dispersion, m/s^2
v	Interstitial velocity, m/s

ABBREVIATIONS

EOR	Enhanced oil recovery
IF	Interfacial tension
MMP	Minimum miscibility pressure
CNT	Carbon nanotube
MWCNT	Multi-walled carbon nanotube
EG	Ethylene glycol
PG	Propylene glycol
GNP	Graphene nanoplatelets
PEG	Polyethylene glycol
XRD	X-ray diffraction
SEM	Scanning electron microscope

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