International Journal of Environmental Sciences
ISSN: 2229-7359
Vol. 11 No. 7s, 2025
https://www.theaspd.com/ijes.php

A Review on Hybrid EOR Techniques: The Role of Nanofluids in Low Salinity Water Flooding

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Abstract

As global energy demands persist, crude oil remains a dominant energy source despite the maturity of many reservoirs. Enhanced Oil Recovery (EOR) techniques such as chemical, thermal, microbial, low salinity water flooding (LSWF), and nanotechnology offer promising solutions to extract remaining oil economically. LSWF, particularly effective for less viscous crude oils, alters rock wettability and reduces interfacial tension (IFT), especially when sodium chloride concentrations are below 10,000 ppm. The effectiveness of LSWF is influenced by ionic strength, with divalent ions like Ca^{2+} and Mg^{2+} playing distinct roles in secondary and tertiary recovery stages. Combining surfactants with LSW can further reduce IFT and enhance wettability, although challenges such as surfactant loss and degradation at reservoir conditions persist. Recent advancements explore integrating nanoparticles (NPs) with LSW to improve EOR efficiency. Nanoparticles like SiO_2, TiO_2, and Al_2O_3 enhance fluid stability, wettability, and IFT reduction. The high surface-area-to-volume ratio of NPs promotes favourable nanoscale interactions essential for oil mobilization. However, NP stability, influenced by size, surface charge, ionic strength, and hydrophobicity, must be evaluated using tools like zeta potential analysis and DLVO theory. Studies indicate that while SiO_2 NPs offer high stability, their adsorption during transport can limit recovery efficiency. Moreover, the synergy between surfactants and NPs in nanofluids under varying salinity levels demonstrates enhanced oil recovery through improved dispersion and wettability alteration. This study investigates the combined effect of LSW and nanoparticle-assisted EOR, emphasizing NP stability, transport mechanisms, and physicochemical interactions to maximize recovery efficiency under harsh reservoir conditions.

Keywords: Nanoparticles, Low salinity water, Interfacial tension, Wettability, Zeta Potential, Ionic Strength

1. INTRODUCTION

Most of the world's energy is derived from conventional sources, primarily fossil fuels [1]. In the 21st century, crude oil will remain vital for meeting energy requirements [2]. Although most crude oil reservoirs are maturing, a significant portion of the remaining oil can be affordably [3] extracted after secondary recovery [4] using inevitable EOR techniques like chemical, thermal, microbial, low salinity water injection, and Nanotechnology shown in figure1. A viscous crude oil reservoir is ideal for thermal EOR or polymer flooding techniques to improve crude oil production. For less viscous crude oils, surfactant, alkali, or LSW injection methods are more effective. [4-6]. LSWF reduces interfacial tension (IFT) between oil and water systems and operates the wettability alternation (WA) of rock surfaces, thus EOR [7, 8]. The LSWF recovered more oil using sodium chloride (NaCl) brine with concentrations less than 10,000 ppm (0.1711 mol/l) than with the use of distilled water (DW) during experiments on a sand pack core [9, 10]. Oil recovery was not efficient when the NaCl concentration was more than 10,000 ppm, while it increased when the concentration was from 0-10,000 ppm. The wettability and thickness of the electric double layer (EDL) between rock and oil surfaces are inversely proportional to the Ionic Strength (IS). It was reported in past research work that LSW flooding can enhance a 20% increase in oil production due to its effect of increasing the EDL thickness and wettability. LSWF has actively gained increasing research attention for its effectiveness and affordability [11, 12]. Recent Researchers studied the role of Ca^{2+} and Mg^{2+} ions in LSW enhanced oil recovery through core flooding experiments with synthetic formation waters enriched in these ions as injection fluids. During secondary oil recovery, Mg^{2+} ions contribute more significantly than Ca^{2+} in LSWF, while the opposite occurs in tertiary oil recovery [13]. The researchers group column experiments showed the significant role of calcite in oil recovery during LSW injection. At test temperature [14] pure quartz columns yield greater oil recovery with LSW injection than other sand and calcite compositions. The sand pack experiment effectively demonstrated the function of clay in EOR during LSW Injection. Clay does not contribute significantly to oil recovery in sandstone reservoirs [15]. Adding surfactants increases the LSW performance by significantly reducing the oil-water interfacial tension (IFT). Researchers have studied the synergetic influence of low salinity water and surfactant on IFT and wettability in the oil-water and rock-fluid system by experimenting with their mixture. Ultralow IFT in oil-water systems was achieved only when LSW with surfactant was used with pure hydrocarbon or light crude oil, not with heavy crude oil [16, 17]. The adsorption, precipitation, and retention during LSW have been reported to lead to a lesser loss of surfactant than under high salinity conditions [18, 19].

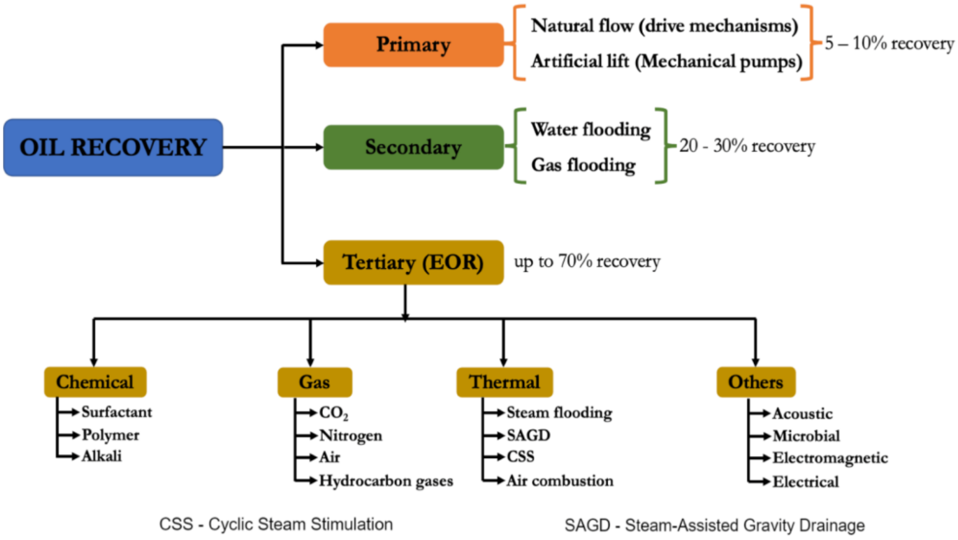

Figure 1. Oil Recovery Techniques

The addition of chemicals/surfactants in the reservoir raises production expenses, so it is important to control surfactant loss during the EOR process. A study on oil recovery using LSW injection with carbon dioxide (CO_2) did not yield satisfactory results [20, 21], because at decreasing salinity, CO_2 dissolves more readily in seawater than in crude oil. This is because, as the salinity concentration decreases in the seawater, CO_2 tends to dissolve in the seawater instead of in crude oil [22]. A hybrid method combining LSW, CO_2, alkaline, and surfactant as an injection fluid for oil recovery has yielded positive results [23]. Due to the harsh condition of the reservoir, the surfactant ability to modify the interfacial properties of the liquid–liquid-solid system with time decreases due to its degradation [24]. During this condition, NPs form a stabilizing emulsion with surfactants, improving thermal stability, lowering IFT and enhancing wettability conditions. NPs exhibit a significantly increased surface area as the particle diameter decreases due to their high surface area per unit volume, active surfaces, and unique optical & chemical properties. The surface energy rises with a larger material surface due to a greater number of particles on the surface per unit volume shown in Figure2.

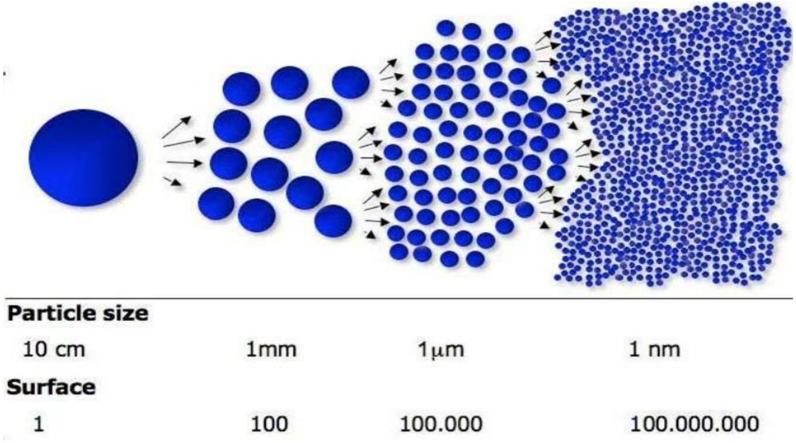

Figure 2. High Surface area per unit volume

Hence, under high temperatures and pressures, this large surface-to-volume ratio drives micrometre-scale processes related to EOR, necessitating an understanding of oil distribution, drop mobilization, and bank formation at the nanometre scale. EOR functions at the nanoscale and affects processes at the macroscale and microscale [25]. This paper employed a combination of LSW–EOR and nano-EOR methods to maximise each approach's benefits. NP stability should be assessed before LSW-NP injection [27, 28]. In one research group despite the individual application of zeta potential (ZP) analysis, particle size analysis, sedimentation tests, and spectral analysis to assess NP stability, the potential for a comprehensive synergetic physicochemical evaluation has been largely overlooked and it's shown in Table 1. Therefore, the combination of LSW-EOR and Nano-EOR has received extensive research attention. According to the Derjaguin, Landau, Verwey and Overbeek (DLVO) theory [29], the stability of NPs is predicated on their size, surface charge, IS, and hydrophobicity. DLVO theory can be broadened for hydrophobic interactions alongside van der Waals and electrostatic double-layer (EDL) forces. The DLVO energy barrier size determines whether NPs will aggregate or remain stable. If NPs in an injection fluid fail to disperse, their injectivity decreases and blocks reservoir pores, diminishing EOR efficiency [30, 31]. The transport mechanisms and stability of three NP metal oxides, Al_2O_3, TiO_2, and SiO_2, through porous media, were experimentally investigated by a research group. The oil recovery rate was lower with SiO_2 nanofluid at 41.4% than with Al_2O_3 nanofluid of 92.7%, despite the higher stability of SiO_2, due to the adsorption of SiO_2 during transport within the porous media. They tested nanofluids in DI water without considering LSW [32]. The recovery mechanisms of SiO_2 nanofluid under various LSW 5,000, 20,000, and 40,000 ppm conditions. Sodium dodecyl sulfate (SDS) surfactant was used to prepare stable nanofluids by increasing NP zeta potential. Their results indicated that SiO_2–LSW could reduce IFT and promoting water wet rock surfaces. To interpret NP stability, they measured NP zeta potential, but not NP hydrodynamic diameter [33]. The researcher examined SiO_2 LSW WA and oil recovery during the displacement process and it was ultimately found that the NP could enhance the efficiency of LSW by changing wettability and improving sweep efficiency. However, their inquiry into NP stability was limited to an investigation of changes in turbidity [34]. The effects of salt cations and EOR chemicals on SiO2 NP stability were also recently investigated [35]. Nanofluid was synthesized through various dispersion techniques, including pH variation, different salt types, surfactant addition, as well as acid-base and polyelectrolyte incorporation. While the stability of the nanoparticles was discussed in the context of DLVO theory, the calculations related to acid-base interactions, which consider the surface hydrophilicity or hydrophobicity, as well as steric interactions due to surfactants or polyelectrolytes, were not included. Furthermore, despite the implementation of multiple dispersion methods, only one type of anionic surfactant was utilized for enhanced oil recovery (EOR), with no exploration of other surfactants.

Table 1. Summary of LSW-Nano previously used for EOR

SL	EOR Method	NP	Ionic (mol/l)	DLVO Implementation	Reference
1	LSW - Nano	SiO2	0.513	No	[29]
2	LSW- Nano	SiO2	0.513	No	[31]
3	LSW-Nano	ZrO2 and NiO	0.513- 3.420	No	[36]
4	LSW-Nano	SiO2	0.513	No	[30]
5	Nano	Al2O3, TiO2, and SiO2		yes	[32]
6	LSW-Nano	SiO2	0.085 and 0.342	No	[31]
7	LSW-Nano	SiO2	0.011–0.583	No	[34]
8	LSW-Nano	SiO2	0.1-1	No	[35]

2. MECHANISM OF THE NANO-LSW EOR

By utilizing NPs capacity to modify reservoir wettability and improve fluid contact with rock surfaces, nano-LSW flooding is made possible. The ionic composition of reservoir fluids is further altered by low salinity water, which improves the environment for the better displacement. In Comparison to traditional techniques, the combined approach seeks to decrease residual oil saturation and boost sweep efficiency. Nano-LSW EOR is a promising EOR method, and it outlines underlying mechanisms.

2.1 Mechanisms in LSW flooding

In LSW, water that is less salinized than formation water is injected. By using this method, the reservoir fluids ionic composition is altered, which results in:

2.1.1 Fine migration

In LSWF, the insufficient concentration of total cations especially divalent cations like Ca^{2+} and Mg^{2+} reduces the IS of the injection fluid, triggering clay hydration, swelling, and fine migration through chemical mechanisms. This destabilization of clay and silt particles leads to their detachment and transport through fractures, potentially EOR by creating new flow paths and increasing sweep efficiency. The critical flocculation concentration (CFC), which governs particle stability, is highly influenced by the proportion of divalent cations, and its reduction under low salinity promotes clay dispersion [36]. Electrostatic interactions also play a key role, as negatively charged clay surfaces and crude oil interact with positively charged rock surfaces and brine ions; clays act as cation exchangers, weakening electrostatic forces and promoting fine migration. Experimental studies show that while fine migration enhances oil recovery through blockage and redirection of flow, excessive fines can reduce permeability and cause formation damage, especially in montmorillonite rich formations due to their swelling nature. Conversely, kaolinite-rich rocks, with limited swelling capacity, offer more stability during LSWF [37]. The overall effect of fines migration depends heavily on mineralogy, lithology, reservoir conditions, and differential pressure, with some studies even reporting sand production or negligible effects, highlighting the complex and context-dependent nature of this mechanism in enhancing oil recovery.

2.1.2 Wettability Modification

WA is widely recognized as the primary mechanism influencing EOR during LSWF, as it governs the shifting capacities of water and oil within porous media and directly impacts macroscopic relative permeability. This alternation is commonly quantified by measuring the CA, with oil wet surfaces ranging from 115° – 180°, water wet from 0° -75°, and mixed wet from 75°-115°. Studies show that LSWF can shift wettability from oil wet to mixed wet conditions, as observed in tight carbonate reservoirs where Contact angles reduced from 158° to 113°, or from 140°-108°, upon injection. The extent of WA is influenced by factors such as the salinity of the injection fluid, mineralogical composition of the rock and clays, and the chemical nature of oil and brine [39]. In sandstone, injecting low salinity water induces a surfactant like effect and elevates pH to around 9, decreasing IFT and promoting oil detachment from the rock surface, leading to improved imbibition and EOR. While initial studies linked wettability changes to clay presence and mechanisms like salt in/ salt out effects and fine migration, more recent findings highlight additional contributions from EDL expansion and mineral dissolution (e.g., Calcite in Carbonates). The shift in wettability is also pH-dependent, with low salinity conditions typically yielding a PH below 9, favouring a transition from oil we to intermediate wet or mixed wet states rather than complete water wetness. Moreover, due to the electrostatic attraction between negatively charged crude oil and positively charged carbonate rock, oil adheres strongly to rock surfaces [40]. The introduction of LSW through chemisorption mechanisms increase the negative surface charge, enhancing disjoining pressure and enabling wettability shift toward more water wet conditions. This can result in the formation of thin water films on mineral surfaces, supported by EDL which promotes spontaneous imbibition and improves flow pathways within the reservoir [41].

2.1.3 Double Layer Extension/ Disjoining Pressure

The EDL theory, names after Derjaguin, Landau, Verwey, and Overbeel, is widely used to explain the electrostatic interactions that play a critical role in LSWF. This classical theory models disjoining pressure as comprising two main forces: Electrostatic repulsion (arising from EDL) and Van der Waals attraction (which includes orientation, induction and dispersion forces also known as Keesom, Debye, and London dispersion forces) [42]. These van der Waals forces represent the totality of intermolecular attractions. The EDL forms due to preferential adsorption of potential determining ions on rock surfaces, creating an inner layer of adsorbed ions and an outer layer of counter-ions, leading to coulombic repulsion between surfaces. When LSW is injected, it causes expansion of this EDL, increasing repulsive forces between clay particles, reducing clay-clay contact, and enhancing the stability of thin water films between oil/brine and brine/rock interfaces. This results in better oil detachment from rock surfaces and the formation of more water wet conditions, improving oil mobility [43]. The stability of these thin films can be measured using zeta potential (ζ-potential), where a value greater than ±10 mV indicates film stability; values below this threshold suggest instability. EDL also leads to spatially heterogeneous wetting, contributing to mixed wet particles detaching from the rock matrix and increasing oil recovery. However, the classical DLVO theory cannot fully explain complex behaviours in real reservoir conditions, such as colloid and polymer stability, which has led researchers to incorporate non-DLVO forces into the model. These include structural forces, which arise from molecular level interactions in thin films, especially when macromolecules like polymers are present [44]. Additionally, Hydration forces which result from the formation or disruption of hydrogen bonds or ion exchange involving hydrated cations many become significant. These forces can act as either primary or secondary contributions to disjoining pressure depending on the interaction dynamics. In tertiary recovery, LSWF is often combined with surfactant or polymer injection to further enhance oil recovery. Surfactants can alter surface charges and interfacial properties, while polymers can adsorb onto recovery. Surfactants can alter surface charges and interfacial properties, while polymers can adsorb onto suspended particles, producing steric hindrance or bridging forces through chain entanglement and thermal fluctuations [45]. Sometimes, interactions between oil and rock surfaces transition from hydrophilic to hydrophobic, leading to hydrophobic forces that can further influence fluid behaviour. Overall electrostatic interactions remain fundamental to LSWF, but a complete understanding requires consideration of multiple force types, including can der Waals, electrical, structural, hydration, steric, and hydrophobic forces [46], all of which contribute to mechanisms such as fine migration, multicomponent ion exchange, and WA and shown in figure3.

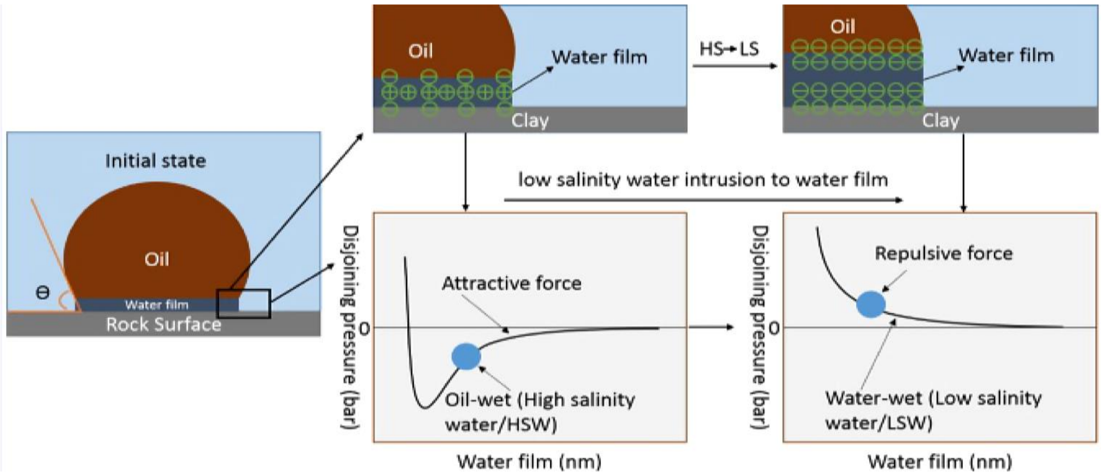

Figure 3. The diagram shows that low-salinity water injection triggers ion exchange, altering rock wettability and enhancing oil recovery.

2.1.4 Ion Exchange

The Multiple ion exchange (MIE) mechanism describes the interaction between surface active components in injected LSW and clays minerals, highlighting the role of ion exchange in EOR. In Oil wet reservoirs, divalent cations like Ca^{2+} and Mg^{2+} are strongly adsorbed onto negatively charged clay surfaces, where they serve as bridges between the clay and organic carboxylate groups in crude oil, thereby increasing water wetness [47]. During LSWF, the reduction in IS promotes the desorption of these organic polar molecules and organo- metallic complexes, as divalent cations displace them and blind directly to the clay surface. This reduces the oil adhesion to rock surfaces, enhances electrostatic repulsion between oil and clay, and leads to the detachment of oil molecules improving oil mobility and recovery. Initially, oil wet conditions are dominant due to the presence of polar compounds and their interaction with multivalent cations forming stable complexes [48]. However, low salinity brines dilute or replaces these complexes, particularly when precipitation of salts like $Mg(OH)_2$ is minimal, allowing uncomplexed divalent cations to stabilize the clay surface. Additional MIE related processes, including cation exchange, ligand bridging, and water bridging, and further support this transition by facilitating the replacement of organics with water wetting bridging, further support this transition by facilitating the replacement of organics with water wetting ions [49]. Overall, MIE emphasizers the chemical restructuring at the oil -brine- rock interface, where divalent ion substitution and complex breakdown collectively shift the system toward a more water wet state, aiding in EOR.

2.1.5 Effect of pH

The role of pH in LSWF is crucial, as it directly influences surface chemistry and mechanisms such as electrostatic interaction, EDL and clay migration. Studies show that low pH reduces clay dispersion, while high pH affects fine release and can reduce permeability [50]. Surface complexation modelling quantities how pH affects wettability using the bond product sum, representing electrostatic bridges at oil/brine and brine/rock interfaces higher values indicate more oil wet conditions. Changes in pH impact the concentration of surface-active species and can shift wettability, especially in systems containing salts like $CaCl_2$ or Na_2SO_4. Generally, lower pH leads to water wet conditions due to H^+ adsorption, while higher pH can cause oil wetness with variability depending on oil type, rock type, ion composition, and salinity [51]. In carbonate reservoirs, low pH often sustains oil wetness, explaining why LSWF may fail there. Higher pH, associated with increased disjoining pressure, promotes wettability alternation. ζ- potential an indicator of surface charge, increases with pH in most brine systems, signifying a shift to positive surface charge. However, this trend may reverse depending on the brine type; in single salt solutions with Na^+ or K^+, the surface many become more negatively charged with rising ph. Cation exchange also improves with pH. Low pH results in weaker repulsion and stronger oil adhesion to rock, which inhibits oil recovery. In contrast, higher pH can promote oil detachment and enhance recovery by releasing previously adsorbed organic material. However, an optimal pH window (5-6) is recommended in practice. Some researchers argue that pH values often fall below thresholds for key LSWF mechanisms like emulsification or fine migration, suggesting pH alone may not validate LSWF effectiveness it often varies based on external factors.

2.1.6 Effect of Temperature & Pressure

The effectiveness of LSWF in EOR is influenced by temperature and pressure, which impact surface interactions and ion adsorption. LSWF is generally applied below 100°C, but studies [52] show its efficiency improves at higher temperatures (above 100°C), particularly when brine salinity is low (e.g., 23,000 ppm). At higher salinities (200,000 ppm), this benefit is not observed. With increasing temperature, the adsorption of organic polar compounds declines, which affects wettability. This has important implications for high-temperature reservoirs in regions like the South China Sea, Middle East, and Xinjiang, where chemical EOR methods (e.g., polymer/surfactant flooding) can degrade. Research from the Tarim Field (China) shows that while temperature influences wettability, water chemistry plays a more dominant role [53]. For reservoirs with acid numbers (AN) > 2 mg KOH/g, LSWF remains effective even at 140°C. Experiments using $CaCl_2$ and Na_2SO_4 brines revealed that contact angle increases with temperature, especially under high salinity and pH, until it stabilizes at a certain point. Pressure also affects LSWF outcomes. Lowering the reservoir pressure tends to reduce contact angles, promoting a shift from oil-wet to water-wet conditions. However, heavy oil recovery, which often requires high pressure, demands careful salinity optimization to maintain EOR effectiveness.

2.1.7 Effect of sample age

Recent studies suggest that sample age significantly affects low salinity waterflooding mechanisms. Under identical pH increases (from 2.55 to 5.68), aged samples show a much larger rise in contact angle (from 35° to 175°) compared to unaged samples (30° to 81°), indicating a stronger wettability shift. Additionally, combining low salinity waterflooding with surfactant flooding has been shown to enhance oil recovery more effectively in aged samples, due to a stronger re-trapping effect on mobilized oil. Thus, aging enhances the responsiveness of reservoir rocks to EOR treatments.

2.2 Mechanism of Nano-EOR

2.2.1 Wettability Alternation

Nanoparticles have the potential to alter reservoir rock wettability, shifting it from oil-wet to water-wet or intermediate-wet, thereby improving residual oil recovery. While the exact mechanism of nanoparticle-assisted EOR remains unclear, research suggests that NPs can adsorb onto rock surfaces, altering their surface energy and hence the contact angle, which is a direct indicator of wettability [54]. Wettability plays a critical role in fluid distribution, saturation, and relative permeability in reservoirs. The wettability is the tendency of one fluid to spread on a surface in the presence of another and wettability depends heavily on the mineralogy of the rock and the properties of reservoir fluids [55]. Rocks are generally classified as: Water-wet (strong preference for water;

contact angle < 90°), Oil-wet (strong preference for oil; contact angle > 90°), Intermediate-wet (no strong preference; contact angle ≈ 90°) and Mixed-wet (heterogeneous surface wettability). Most reservoir rocks are initially water-wet due to their formation in aquatic sedimentary environments (Warner, 2007). The contact angle (θ) helps determine the wettability class: $\theta < 90°$ → water-wet; $\theta > 90°$ → oil-wet and $\theta \approx 90°$ → intermediate-wet. Nanoparticles influence this balance, making them promise for modifying wettability and enhancing oil recovery.

2.2.2 Nano-scale movement in micro size porous media/Selective Plugging

Injection of nanoparticles into porous reservoir media can sometimes lead to pore throat blockage, which reduces permeability and increases injection costs. However, this risk is generally minimal because: Most reservoir pores are larger than 10 µm, Nanoparticles typically range between 100–500 nm, and so they can easily pass through the pore network without causing significant clogging. A notable method called "dust injection" involves introducing nanoparticles into oil-saturated formations, targeting both fluid-fluid and fluid-solid interfaces. These nanoparticles are designed to modify interfacial tension, wettability, and other fluid properties, thus improving oil mobilization and recovery efficiency.

2.2.3 Enhancing Sweep Efficiency through Selective Nanoparticle Plugging

In the oil and gas industry, NPs are emerging as effective tools to EOR by improving fluid diversion and sweep efficiency. They can selectively plug high-permeability zones, forcing injected fluids into less-swept, oil-rich areas [56]. Their large surface area and high surface activity make them ideal for modifying fluid and rock interactions. For example, reactive sodium NPs have been used to recover heavy oil at room temperature by generating heat, hydrogen gas, and NaOH through chemical reactions [57]. Additionally, combining nanoparticles with polymers improves recovery beyond traditional methods like surfactant-polymer or alkaline-surfactant-polymer flooding. Nanoparticles enhance wettability, rheology, and interfacial tension, while polymers increase viscosity. Their lower cost compared to surfactants also makes nanoparticle-polymer blends more attractive for large-scale application [58].

2.2.4 Improved Mobility Control

Nanoparticles improve oil recovery by targeting high-permeability zones to redirect fluid flow toward less-swept areas, enhancing sweep efficiency. They stabilize injected fluids, preventing early precipitation, and ensure better contact with reservoir surfaces. Nanoparticles also reduce oil-water interfacial tension, aiding oil mobilization; alter rock wettability from oil-wet to water-wet to improve water flooding; and increase fluid viscosity for more uniform displacement especially useful in heterogeneous reservoirs.

2.2.5 Enhancement in Displacement efficiency

In EOR, NPs enhance oil mobility by reducing capillary forces and lowering IFT between oil and water phases. This facilitates the release of trapped oil from rock pores and improves its movement toward production wells.

2.2.6 Reduction of Capillary Forces

Capillary forces, driven by interfacial tension at the oil-water interface, trap oil in the small pores of reservoir rocks, especially in tight formations. Introducing nanoparticles helps reduce these forces by adsorbing onto rock surfaces and altering rock wettability from oil-wet to water-wet. This change lowers the resistance to oil flow, allowing trapped oil to be more easily displaced by injected EOR fluids.

2.2.7 Lowering IFT

NPs reduce the IFT between oil and water phases, which lowers the capillary forces that trap oil in reservoir pores. This reduction in IFT promotes the coalescence of oil droplets and makes it easier for them to detach from rock surfaces, improving oil mobility and enhancing displacement by injected fluids toward production wells.

2.2.8 Facilitation of Oil Movement

NPs enhance oil recovery by reducing capillary forces and lowering IFT, thereby improving oil mobility within the reservoir. This promotes a more efficient flow of oil towards production wells and increases sweep efficiency, leading to higher recovery rates. Key mechanisms include:

Adsorption at Interfaces – NPs adsorb at the oil-water interface, lowering IFT and capillary forces.

Wettability Alteration – They shift rock surfaces from oil-wet to water-wet, aiding in oil mobilization.

Emulsion Stabilization – NPs help stabilize oil-water emulsions, further aiding residual oil recovery.

Displacement Efficiency – Nanofluids can increase viscosity, improving sweep efficiency and uniform oil displacement.

Overall, NPs represent a promising EOR strategy to enhance oil displacement and maximize recovery.

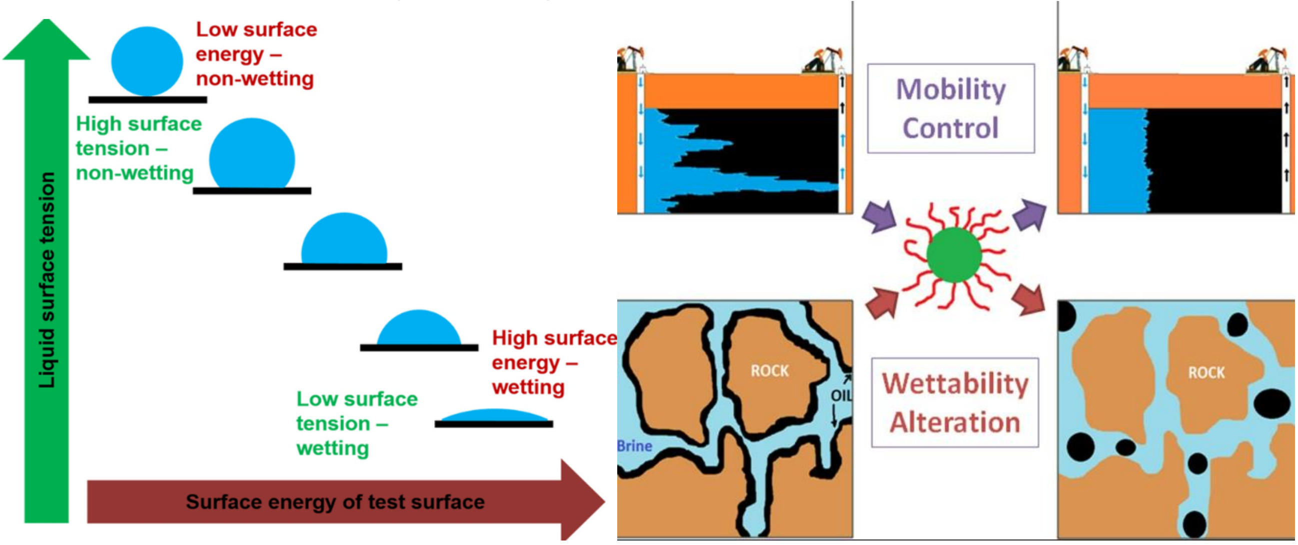

Figure 4. The diagram illustrates how nanoparticles alter wettability and provide mobility control in the reservoir, enhancing fluid displacement.

2.3 Integration of NPs with LSW flooding

The combination of NPs with LSW represents a cutting-edge approach in the field of EOR. By leveraging the unique properties of nanoparticles to modify reservoir wettability and improve fluid displacement efficiency, alongside the strategic use of low salinity water to further enhance sweep efficiency, operators can achieve higher oil recovery rates while potentially reducing costs and environmental impact compared to traditional methods. However, ongoing research and field trials are essential to refine these techniques and optimize their application across diverse reservoir conditions. The combination of NPs with LSWF offers a promising approach to EOR by optimizing fluid interactions and reservoir wettability. Through synergistic effects, these techniques improve sweep efficiency and reduce residual oil saturation, ultimately increasing the overall recovery factor of oil reservoirs. Continued research and field applications are essential to further refine these methods and adapt them to various reservoir conditions and operational challenges.

Synergistic Effects lead to enhancing the overall sweep efficiency by below the main two efficiencies

Enhanced Displacement Efficiency: Nanoparticles stabilize the low salinity water and prevent its destabilization or premature precipitation. This stabilization ensures consistent alteration of wettability and enhances the interaction between injected fluids and reservoir surfaces.

Selective Plugging and Improved Sweep Efficiency: Nanoparticles can selectively plug high-permeability zones, ensuring a more uniform sweep of the injected fluid across the reservoir. This improves overall recovery efficiency.

3. CHALLENGES OF NANO-LSW (NPS COMBINED WITH LSW) FLOODING ARGUMENT EOR

Though Nano-LSW flooding has several promising benefits for EOR, it is associated with several challenges to be addressed towards successful implementation. Here are the key challenges associated with Nano-LSW flooding:

3.1 Nanoparticle Stability and Mobility

Challenge: Ensuring nanoparticles remain stable under reservoir conditions (e.g., temperature, pressure, salinity) and maintaining their mobility to reach target zones within the reservoir.
Impact: If nanoparticles aggregate or settle prematurely, their effectiveness in altering wettability and enhancing sweep efficiency can be reduced.

3.2 Reservoir Heterogeneity

Challenge: Reservoirs often exhibit heterogeneity in terms of permeability, porosity, and mineralogy. This heterogeneity can affect the distribution and effectiveness of injected nano-LSW fluids.
Impact: Uneven distribution may lead to bypassed oil zones or ineffective coverage of high-permeability channels, limiting overall oil recovery efficiency.

3.3 Complex Fluid-Rock Interactions

Challenge: Nano-LSW flooding involves complex interactions between nanoparticles, low salinity water, and reservoir rock surfaces.
Impact: Variations in mineralogy and surface chemistry can affect the efficacy of wettability alteration and nanoparticle retention, impacting the overall success of the flooding operation.

3.4 Scale-Up from Lab to Field

Challenge: Transitioning from laboratory-scale experiments to field-scale applications poses challenges in maintaining consistency and effectiveness.
Impact: Factors such as fluid dynamics, injection rates, and reservoir heterogeneity can differ significantly in field conditions, requiring careful optimization and monitoring.

3.5 Cost Considerations

Challenge: The production, procurement, and deployment of nanoparticles can be costly, impacting the economic feasibility of nano-LSW flooding.
Impact: High costs may limit widespread adoption or require innovative cost-saving strategies to justify the investment in enhanced oil recovery.

3.6 Environmental and Regulatory Compliance

Challenge: Addressing environmental impacts associated with nanoparticle use and low salinity water injection.
Impact: Regulatory requirements for handling and disposal of nanoparticles and injected fluids must be met, adding complexity to operational planning and execution.

3.7 Monitoring and Control

Challenge: Continuous monitoring of reservoir response and fluid behavior is essential for optimizing nano-LSW flooding.
Impact: Lack of real-time data or inadequate monitoring techniques can hinder the ability to adjust injection parameters and maximize recovery efficiency.

4. CONCLUSION

The integration of LSWF with nanoparticle-assisted EOR presents a promising strategy to EOR from mature reservoirs. LSWF proves effective in modifying rock wettability and lowering IFT, particularly at salinity levels below 10,000 ppm, with divalent ions like Ca^{2+} and Mg^{2+} playing a critical role in recovery performance. The incorporation of nanoparticles such as SiO_2, TiO_2, and Al_2O_3 further enhances EOR by improving fluid stability, augmenting wettability alteration, and promoting nanoscale interactions essential for oil displacement. However, the stability and transport behavior of nanoparticles are crucial to their effectiveness, as factors like particle size, surface charge, and ionic strength significantly influence their performance. Analytical tools like zeta potential measurement and DLVO theory are essential in evaluating NP stability under reservoir conditions. While SiO_2 NPs show high stability, their potential for adsorption may hinder recovery. Nevertheless, the synergistic effect of surfactants and nanoparticles in nanofluid formulations under varied salinity conditions offers enhanced dispersion and wettability modification, leading to improved oil mobilization. This study underlines the importance of optimizing nanoparticle characteristics and salinity levels to maximize the efficiency of LSW-NP hybrid EOR techniques, paving the way for more sustainable and cost-effective oil recovery from challenging reservoirs.

Conflict of interest

The authors declare that they have no competing interests, financial or non-financial, that are directly or indirectly related to the work submitted for publication.

Funding

No funding was received

Acknowledgement

The Authors would like to express their sincere gratitude to the Dibrugarh University for providing the excess of institutional facilities and resources to carry out the work without which this work would not have been possible.

Credit authorship contribution statement: Joyshree Barman: Manuscript writing, investigation, methodology, review and editing; Bhaskar Jyoti Saikia: Review and editing; Gauri Sankar Bora: Review and editing. Tanaya Bordoloi: Review and editing. Prasenjit Talukdar: Review and editing, supervision.

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