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Review

Recent Advance and Prospect of Enhanced Oil Recovery Mechanisms in Reservoir Sandstone

Surajudeen Sikiru [1,2,*], Hassan Soleimani [2,3], Jemilat Yetunde Yusuf [4], Yarima Mudassir Hassan [3], Mohammed Falalu Hamza [1,4] and Ramesh Singh

[1] Institute of power engineering, Universiti Tenaga Nasional Malaysia, 43300, Kajang Selangor Malaysia
[2] Center for subsurface imaging, Universiti Teknologi PETRONAS, 32610 Tronoh, Perak, Malaysia
[3] Geoscience department Universiti Teknologi PETRONAS, Bandar Seri Iskandar, 32610 Tronoh, Perak, Malaysia
[4] Fundamental and Applied Science Department, Universiti Teknologi PETRONAS 32610 Tronoh, Perak, Malaysia
[5] Department of Pure & Industrial Chemistry, Bayero University, PMB 3011, Gwarzo Kano, Nigeria
* Correspondence: surajudeen86@gmail.com

Abstract: Enhanced oil recovery (EOR) refers to the various techniques used to increase the amount of crude oil that can be extracted from an oil field. These techniques are used after the primary and secondary recovery methods have been depleted. There are three main types of EOR: thermal, gas injection, and chemical. EOR techniques can be expensive and complex, but they can help to recover additional oil that would otherwise be left in the reservoir. EOR can also extend the life of an oil field and increase the overall production from a given field. The parameters affecting oil recovery are a major concern in EOR systems, and these parameters need more consideration with the factors affecting them. In this study, the influence of permeability variations on fluid flow in a sandstone reservoir was explored, as well as an up-to-date description of three states of EOR with thorough explanations of the methods utilized and the mechanisms driving their oil recovery application. The difficulties encountered in the use of the different standard EOR Mechanisms were noted, and solutions to these difficulties were proposed. Furthermore, the contemporary trend of adding nanotechnology and its synergistic effects on the stability and efficiency of traditional chemicals for EOR were examined and analysed. Finally, laboratory findings and field initiatives were discussed. The review went into detail about the transport of nanoparticles across reservoirs, as well as the evaluation of EOR, mobility ratio, and fluid displacement efficiency. This review provides thorough information on the uses of improved oil recovery mechanisms for sustainable energy production.

Keywords: enhanced oil recovery; rock permeability; reservoir fluid; porosity; fluid flow

1. Introduction

Oil and gas make up a large percentage of energy consumption around the globe. They are naturally formed from remains of ancient plants and animals that died millions of years ago [1]. Layers of sand and rocks covered the remains over millions of years, and pressure and heat transformed them into oil and gas [2–4]. Oil and gas can be found within the tiny spaces in sedimentary rocks. To produce the oil and gas, production wells will be drilled, and oil will flow through the pores in the reservoir rock into the well with the help of natural pressure from the reservoir [5]. However, the natural pressure from the reservoir will decrease with time and it might not be able to produce oil efficiently. To further regain the oil, enhanced oil recovery (EOR) methods are introduced [3,6,7]. Due to the high demand for oil and gas and the decline in the discovery of oil reservoirs, EOR methods play a vital role in the new oil recovery methods to recover more oil from the trapped zone [8–12]. To increase the oil recovery factor, oil reservoir parameters such as permeability, porosity, temperature, and viscosity need to be considered. One of the most critical parameters is permeability, as the oil recovery factor will be low if the reservoir rock is not porous [13,14].

Conventionally, oil recovery is divided into three phases: primary, secondary, and tertiary recoveries. The initial recovery stage, where oil is produced through the natural displacement energy of the reservoir, is referred to as the primary recovery [15,16]. The natural driving force may be derived from rock and fluid expansion, gas cap expansion, dissolved gas expansion, gravity drainage, or from a combination of them [5,17]. Whereas Secondary recovery is generally implemented after the decline of primary production. The standard secondary recovery methods are fluid or water alternative gas injection (WAG) [15]. After primary and secondary recovery, around 67% of the original oil in place (OOIP) is still confined in the reservoir due to capillary and viscous forces [18]. Therefore, the tertiary recovery method or so-called EOR is introduced to recover the oil further. Figure 1 illustrates EOR mechanisms [19–21]. Due to the speedy increase of oil prices globally, the consumption of oil, and the decline of discoveries of reserves, IOR has become more and more common nowadays. There are a few key EOR methods, which are chemical flooding, gas injection, thermal techniques, microbial flooding process, and electromagnetic-assisted EOR [22]. The choice of the IOR method depends on the rock properties and reservoir fluids. A thorough understanding of reservoir fluids is vital since it allows for setting the product strategy and dimensioning the surface facilities [22–24]. It was reported recently by Suleimanov et al. that the suspension of non-ferrous metal nanoparticles (70-150 nm) in an aqueous solution through experimental procedure interaction disseminated in a solution of an anionic surfactant (sulfanole-alkyl aryl sodium sulfonate) resulted in a 35% rise in oil displacement efficacy in a homogeneous porous medium. In their testing, they employed a pure hydrocarbon [25], these researchers revealed that the increase in improved oil recovery (IOR) was caused by a drop in interfacial tension and a variation in the flow characteristics of nanofluids transitioning from a Newtonian to a non-Newtonian state, based on their finding, nanofluids affect oil wettability [26]. A study revealed that capillary imbibition is the process of oil recovery with the use of different surfactants and polymer solutions, lowering the interfacial tension between the aqueous phase and oil-triggered speed and increasing oil recovery [27]. According to Karimi et al., the use of nanofluid with zirconium oxide nanoparticles (24 nm) led to increased oil recovery, and a nonanoic surfactant (ethoxylated nonylphenol) was primarily due to the carbonate rocks' wettability changing from highly oil-wet to strongly water-wet [28]. However, the change in wettability takes at least two days, but the most effective oil recovery rate arises quickly after contact between the nanofluids and core plugs. In brief, two traditional EOR processes involving nanofluids have been proposed: This results in the reduction of interfacial tension between the aqueous and oil phases and the modification of rock wettability. Both systems are thought to be active in some cases. EOR procedures are used to recover oil by injecting fluids and energy not existing in the reservoir [29,30]. Because one of the injection program's aims is to maintain pressure from dropping, the injection of a fluid into the reservoir under immiscible conditions is frequently referred to as pressure maintenance. In certain contemporary reservoirs, pressure maintenance is now undertaken from the start of production. Pressure maintenance is the initial or "primary production" stage in this situation. The composition of sandstone rock typically includes a significant proportion of quartz (SiO_2), alongside smaller quantities of carbonate, clay, and silicate minerals. Within Berea sandstone, apart from quartz, clay minerals (primarily kaolinite and illite) contribute approximately 5-9% of its mass. Sandstone reservoirs have been widely used for Chemical Enhanced Oil Recovery (CEOR) applications due to their homogeneity. Anionic surfactants are commonly employed in sandstone reservoirs as they experience electrostatic repulsion from the sandstone surface, which limits adsorption. Silicon dioxide (silica) shows little to no adsorption of anionic surfactants at higher pH levels [31]. The response of a reservoir to water flooding can be influenced by its wettability, which varies depending on the nature of the rock. If the rock is more inclined towards oil, the rate of recovery will be reduced. Enhanced oil recovery (EOR) techniques are utilized to improve oil recovery by modifying the wettability to a more water-oriented state. Chemical and thermal EOR methods have proven effective in transforming the reservoir wettability. However, their efficacy depends on the effect they have on the properties of crude oil, brine, and rock. The way crude oil interacts with rock and brine can differ from one reservoir to another, depending on variables such as crude oil and brine composition, rock mineralogy, and other reservoir properties. To change the wettability of a reservoir, a deep understanding of the mechanisms behind the rock's oil-wet surfaces is essential [32].This review discusses the parameters that influence the oil mobility in the reservoir, EOR stages, the mechanisms that affect EOR, and their fluids properties such as viscosity, temperature, pressure, porosity, permeability, wettability alteration, and mobility factors.

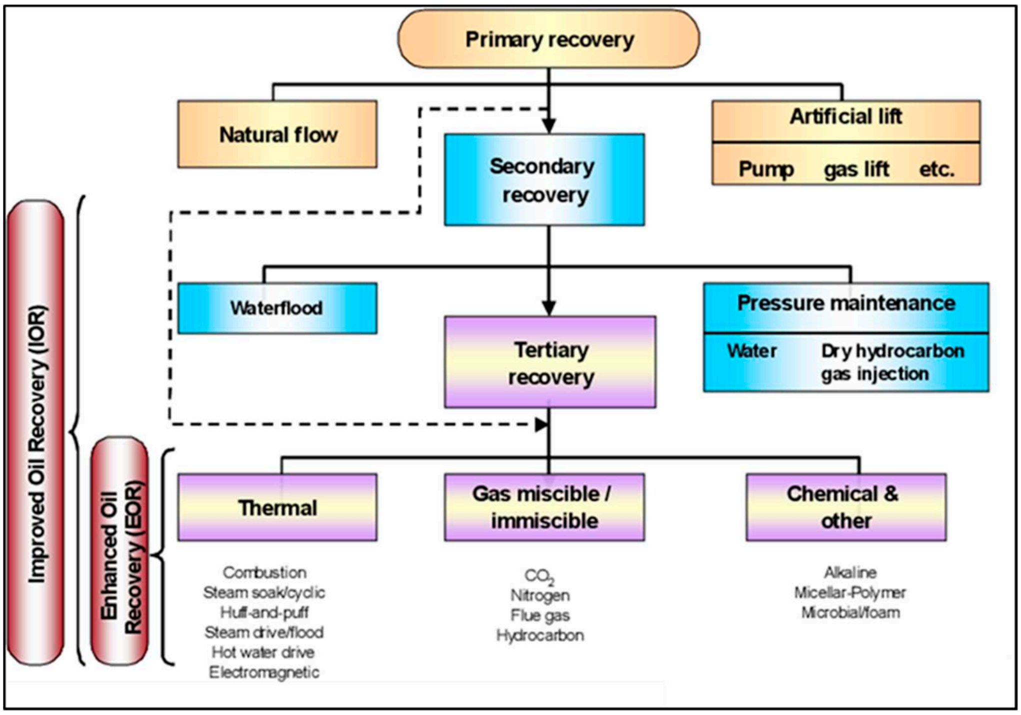

Figure 1. Summary of EOR mechanism from primary to tertiary recovery.

1.1. Enhanced Oil Recovery

Since most oil production in the world comes from mature fields, boosting oil recovery from mature reservoirs is a crucial priority for oil corporations and governments. Furthermore, seeking alternatives for the reserves provided by discoveries has dwindled steadily over the previous decades [4,33]. As a result, improving oil recovery factors based on mature fields under primary and secondary products would be crucial in meeting the increasing energy demand in the future years. Malaysia is attempting to maximize the impact of its indigenous oil reserves on the overall supply [34,35]. The primary focus is to improve the performance of the existing oil field in the country by using the EOR techniques in technical ways, to access previously inaccessible reserves due to geological problems or high expenses. EOR is mainly concerned with the mobility of the oil through the process of drilling. This is done through the injection of fluids into the reservoir, resulting in 30-50 percent of the original Oil in Place (OOIP), compared to 20-40 percent extracted during primary or secondary recovery techniques [36–39]. EOR production is divided into three segments: Primary, secondary, and tertiary recovery. Primary recovery involves using natural force or artificial tools to lift the oil to the surface. In contrast, secondary recovery comprises water and gas injection at high temperature and high pressure (HTHP) to raise the oil and move it to the surface. Various researchers and the US Department of Energy have reported that production can recover up to 65% of the trapped oil in the reservoir using primary and secondary techniques. Further, increase the oil production by using a tertiary recovery method which can be displaced up to 75% of the trapped oil from the well but is more expensive to utilize in the heavy oil field where there are poor permeability and irregular fault lines [40–42]. EOR is involved in changing the actual properties of the hydrocarbons for proper fluid mobility, which further differentiates it from the secondary recovery methods. Figure 2. shows a schematic diagram of the EOR mechanism. In this case, EOR techniques restore the damaged formation and enhance oil displacement in the reservoir. Moreover, water flooding, steam injection, and (CO_2) gas injection are used during the secondary recovery methods.

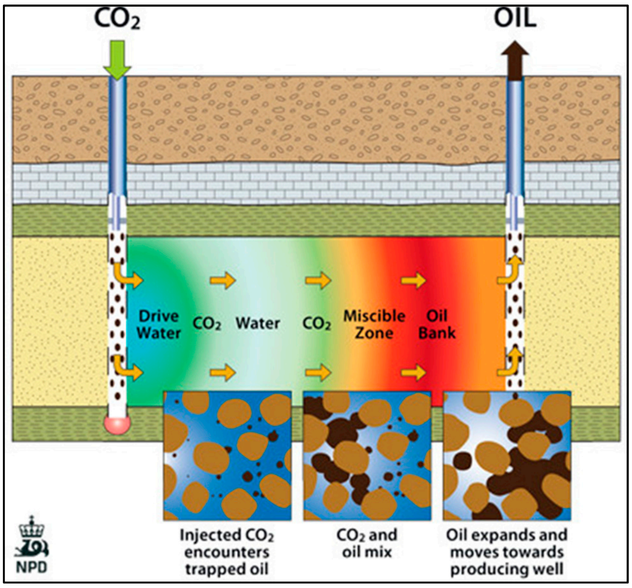

Figure 2. EOR illustration for carbon dioxide and water used in flushing residual oil from the reservoir [43].

The gas injection process is used in tertiary recovery methods that involve the injection of natural gas, carbon dioxide, or nitrogen into the reservoir. In this process, the gases will dissolve within the oil and decrease the viscosity which leads to an increase in the flow of the fluid. While the chemical injection process helps in removing the trapped oil within the reservoir, this technique introduces long-chained molecules called polymers into the reservoir to increase the effectiveness of water flooding or to improve the efficiency of surfactants which helps in lowering the interfacial tension that increases the flow of oil in the reservoir. Lastly, thermal recovery is the way of introducing heat into the reservoir to lower the viscosity of the oil and increase the fluid viscosity for oil displacements and this includes by applied steam into the reservoir environment to enhance its ability to flow. Table 1 shows the literature review on enhanced oil recovery mechanisms from previous studies. Though it has been reported that EOR techniques have been widely implemented in sandstone formations [36], sandstone reservoirs show the highest prospective to implement EOR studies because of the technologies involved which have been tested on pilot and commercial scales. Additionally, there are some fields where different EOR technologies have been evaluated successfully at a pilot scale demonstrating the technical applicability of different EOR methods in the same field such as Buracica and Carmópolis (Brazil), and Karazhanbas (Kazakhstan) are good field examples that have been subject to several EOR technologies at pilot scale in sandstone formations.

Table 1. The details of the enhanced oil recovery mechanism from the previous research.

Authors	Method	EOR Factor influenced	Result/finding	Parameters Value
Ibrahim Khan et al. (2017) [44]	Nano flooding	Physiochemical properties.	Temperature, pressure, time, and pH value can play important role in controlling the shape and morphology of nanoparticles materials	10^{-4} to 10^{-2} mN/m
Baoliang Peng et al.,2017-[75]	Nano flooding	Wettability alteration, Reduction of interfacial tension,	Salinity, temperature, and pH value, Surface modification of nanomaterial, intrinsic properties; electrical, magnetic, rheological, and thermal Potential	10^{-3} to 10^{-2} mN/m

		Controllable viscosity, and Disjoint pressure for oil displacement.	mechanism of nanofluid flooding are explained.	
Goshtasp Cheraghian et al.,-2016–[45]	Nano Chemical flooding	Reduction IFT, emulsion formation, wettability alteration, Capillary forces	Nanotechnology has the potential to have a positive effect on the chemical EOR process.	10^{-3} to 10^{-2} mN/m
Hon Chung Lau et al,2017 [46]	Chemical EOR	Rock wettability alteration, oil-water IFT reduction, Oil viscosity, and injection fluid viscosity	Six applications of nanoparticles are considered, and it is discovered that reservoir imaging, Drilling, tight reservoir applications and EOR ranked higher and have the highest potential impact.	10^{-5} to 10^{-3} mN/m

1.2. Miscible Gas Injection Method

EOR using the miscible gas injection method has been widely used for the recovery of light oil and it has been considered one of the most effective EOR methods. There are several types of injected gases, which are hydrocarbon gases, nitrogen gas (N_2), carbon dioxide gas (CO_2), and flue gas. In a miscible condition, two phases could be mixed at any ratio [19,47]. To achieve the miscible condition between injected gas and reservoir oil, the gas is injected above the Minimum Miscible Pressure (MMP). Take CO_2 gas as an example, when pressure increases, CO_2 gas density increases, which reduces the difference in density between CO_2 gas and the reservoir oil [48]. This results in a reduction of IFT between CO_2 gas and crude oil, and they become miscible in each other. The MMP between CO_2 gas and crude oil is affected by the temperature of the reservoir, the composition of the oil, and the purity of the injected gas. For example, a reservoir with a low temperature, containing light oils will have lower MMP between CO_2 gas and reservoir oil. The impact of the impurity, on the other hand, depends on the type of impurity components, the addition of H_2S will reduce the MMP, but adding N_2 will increase the MMP between CO_2 gas and reservoir oil [49–51].

To ensure that the oil can achieve miscibility with nitrogen without damaging the producing formation, the reservoir must have a depth of at least 5,000 feet and be capable of sustaining injection pressures over 5,000 psi. Nitrogen gas (N_2) is an ideal choice for flooding this type of reservoir as it can be produced on-site at a lower cost and is non-corrosive because of its inert properties. N_2 is separated from the air through cryogenic processes, providing an unlimited source. When injected into the reservoir, N_2 forms a miscible front by vaporizing some of the lighter oil components [52]. As the gas continues to move away from the injection wells, it contacts new oil and vaporizes more components, further enriching it. This process continues, with the leading edge of the gas front becoming so enriched that it goes into solution with the reservoir oil, resulting in a single fluid mixture. Continual injection of nitrogen pushes the miscible front through the reservoir, displacing oil towards production wells. To increase sweep efficiency and oil recovery, water slugs are alternately injected with N_2. The produced reservoir fluids, including natural gas liquids and injected nitrogen, can be separated at the surface [53].

Carbon dioxide (CO_2) is often used for enhanced oil recovery (EOR) in sandstone reservoirs. The CO_2 is injected into the reservoir to displace the oil and push it toward the production well. This technique is known as CO_2 flooding or CO_2-EOR. The process involves injecting CO_2 into the reservoir at a pressure and temperature that is suitable for the rock and fluid properties of the reservoir. The CO_2 mixes with the oil, reducing its viscosity and allowing it to flow more easily. This helps to increase the amount of oil that can be recovered from the reservoir [54].

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CO_2-EOR is considered a more environmentally friendly method of oil production because it uses CO_2 that would otherwise be released into the atmosphere, such as from power plants or industrial processes. The captured CO_2 is stored underground in the reservoir, reducing greenhouse gas emissions. However, there are some challenges associated with CO_2-EOR in sandstone reservoirs. One of the main challenges is ensuring that the injected CO_2 stays within the reservoir and does not leak into the surrounding rock formations. This requires careful monitoring and management of the injection process. Another challenge is the cost of capturing and compressing CO_2 for injection. This can be expensive, especially for smaller oil fields. However, as the technology for CO_2 capture and storage improves and the demand for EOR increases, the cost is expected to decrease. CO_2-EOR in sandstone reservoirs is a promising method for increasing oil recovery while reducing greenhouse gas emissions [55]. CO_2 gas injection had also reported an increment in oil recovery factor of 7%-23% of OOIP. In addition, choosing CO_2 as the injection gas could also help in CO_2 sequestration which results in the reduction of greenhouse gas in the atmosphere [19,54,56]. Normally, CO_2 gas has the largest one-phase region compared to N_2 gas and dry gas, the larger the one-phase region, the higher the miscibility. CO_2 gas also has lower miscibility pressure (around 1200-1500 psi) compared to N_2 gas and dry gas which have high miscibility pressure (around 3000 psi or more). Lower miscibility pressure allows the gas to be miscible with the reservoir oil at a lower pressure which would cost lesser. However, the use of CO_2 gas as an injection gas needs to be taken care of as it is slightly acidic and could cause corrosion to the surface facilities.

In the process of miscible CO_2 gas injection, CO_2 gas is injected into the reservoir, it will interact chemically and physically with the existing hydrocarbon fluid and the reservoir rock. These interactions are the mechanisms that help to recover the oil. The mechanisms include swelling of oil volume, reduction of oil and water density, reduction of oil viscosity, reduction of IFT between the crude oil and reservoir rock which hinders the flow of oil through the pores in the reservoir, and vaporization and extraction of trapped crude oil [57–59]. CO_2 gas has a high solubility in oil which helps to swell the oil and leads to a reduction of density and viscosity of the crude oil. In addition, CO_2 gas injection could also help to reduce the density of the water that is left in the reservoir from previous water flooding as CO_2 gas is soluble in water. As a result, the oil and water density becomes almost similar, which leads to gravity segregation effect reduction, lesser override flow, and a fingering phenomenon that would be less likely to occur [60]. Although miscible gas injection has many advantages, it has its limitation and problems too. Miscible gas injection is affected by the high mobility of gas as it is a single-phase process. Due to that, the miscible gas injection method requires a very large depth to ensure miscibility. Moreover, the formation thickness might also affect the effectiveness of miscible gas injection. Gravity override effects might occur in very thick formations and lead to poor sweeping efficiency [61]. Besides that, there are also some problems in the operation of miscible gas injection which includes transportation problem, equipment, and tubing corrosion due to the gas, and separation and recycling problem of the miscible gas [62–64].

1.3. Thermal method

From the research papers, thermal EOR techniques are very crucial and are widely available worldwide. Over the past few decades, different types of aqueous approaches dealing with water and its derivatives have been commonly used. The most popular thermal EOR methods are processes such as hot fluid injection. This hot fluid injection can be divided into three techniques which are cyclic steam stimulation (CSS), in-situ combustion (ISC), hot water steam flooding, and steam-assisted gravity drainage (SAGD). The other thermal EOR techniques are the use of non-aqueous approaches that, without injecting water or its derivatives, provide thermal energy to the reservoir [65,66].

Hot fluid injection as an EOR method, as its name suggests, requires the use of hot fluid in an oil reservoir to ease the flow of oil for extraction. Using the combined action of convection and conduction processes, thermal energy is transmitted (in the form of heat) to the reservoir [9]. This thermal energy contributes to the reduction of high viscosity and thermal expansion of the reservoir's crude oil. In this thermal EOR technology, injecting steam is the most popular technique, and it is the most commercially efficient. Three techniques, which are CSS (also called the huff-and-puff technique), steam flooding, and SAGD, are used in steam injection processes, Figure 3 shows the structure of the steam-assisted process. In steam flooding, in addition to the sweeping effect produced by steam flooding, steam is pumped into injection wells, reducing oil viscosity. However, despite being more effective, this solution takes more steam than the CSS.

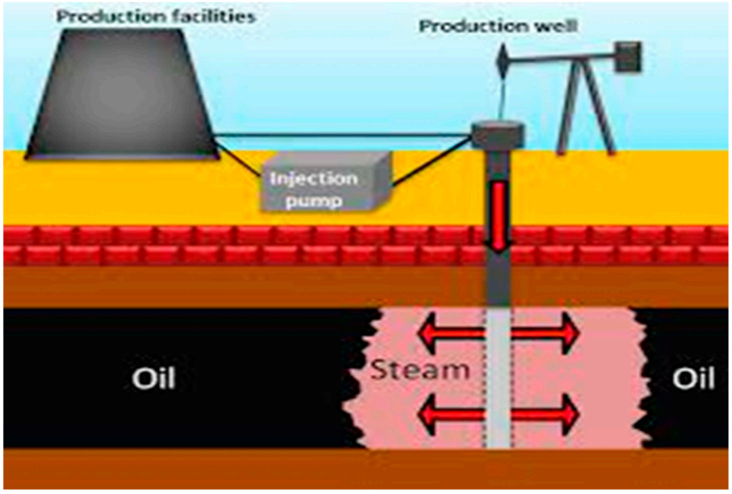

Figure 3. shows the steam assisted EOR method during the thermal EOR.

Next, in Cyclic Steam Simulation (CSS), steam is pumped for a period into the processing well. The well is then shut in and allowed to be soaked for some time by steam before it returns to output. Due to high initial oil saturation, high elevated reservoir pressure, and decreased oil viscosity, the initial oil rate is high. The reservoir pressure becomes lower as the oil saturation becomes lower and the oil viscosity becomes higher due to heat losses to the underlying rock and fluids, decreasing the oil rate. Another cycle of steam injection is started at some point [67]. This loop can be repeated many or more times. To define CSS, the expressions steam soak and steam huff-and-puff are also used.

On the other hand, Steam flooding is also called steam injection or steam drive continuous. This steam flooding is a thermal recovery method in which surface-generated steam is pumped into especially distributed injection wells into the reservoir. It heats the crude oil as steam reaches the tank and reduces its viscosity. The heat also distills light crude oil components that condense in the oil bank ahead of the steam front, further reducing the viscosity of the oil. The hot water condensing from the steam creates an artificial force that sweeps oil into the output of wells [67]. Near-wellbore clean-up is another contributing factor that increases oil production during steam injection. In this case, steam removes the interfacial tension that connects paraffin and asphaltenes to the rock surfaces while a small solvent bank that can immiscibly extract trapped oil is created by steam distillation of crude oil light ends.

Besides that, a method that is commonly used to remove bitumen from underground oil sand deposits is called steam-assisted gravity drainage or SAGD [68]. This strategy requires pushing steam to heat the bitumen trapped in the sand into subsurface oil sand deposits, causing it to flow long enough to be removed. This method is a heavy oil thermal processing method that pairs a high-angle injection well with a drilled well of neighbouring production in a parallel trajectory. With a vertical separation of around 5 m, the pair of high-angle wells are perforated. Steam from the upper well is injected into the tank. It heats the heavy oil as the steam increases and spreads, thus, reducing its viscosity. Gravity causes the oil to flow to where it is formed in the lower well [68]. Lastly, In-Situ Combustion (ISC) is known as fire flooding. this is a technique for thermal recovery where the fire is produced inside the reservoir by infusing a gas containing oxygen, for example, air. In this technique, air or oxygen is pumped into a reservoir to produce heat by consuming parts of unrefined petroleum for about 10%. A particular heater in the well lights the oil in the reservoir and produced fire. The heat created by consuming the hefty hydrocarbons set up produces hydrocarbon breaking,

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vaporization of light hydrocarbons, and reservoir water notwithstanding the deposition of heavier hydrocarbons known as coke. As the fire moves, the consuming front pushes ahead a combination of hot ignition gases, steam, and boiling water, which thusly decreases oil consistency and uproots oil toward creation wells. Also, the light hydrocarbons and the steam push forward of the consuming front, consolidating into fluids, which adds the benefits of miscible relocation and hot water flooding.

1.4. Chemical method

EOR tends to have two means of achieving its purpose of oil recovery. First is boosting the energy within the reservoir, and second is the create an optimal condition within the reservoir to facilitate the displacement of hydrocarbon. These methods involve increasing the capillary number, reducing the capillary forces, reducing IFT, reducing oil viscosity, or rising water viscosity [69]. Chemical methods of EOR exploit the method of creating favourable environments by increasing water viscosity, improving permeability to oil, and decreasing permeability to water [67]. It achieves this by adding chemicals into the injected water; in essence, chemical methods are an alteration of secondary oil recovery where water is injected [5]. However, instead of pure water, chemicals are added to improve the oil recovery rates. In chemical methods, three main chemicals are used: alkalis, better known as polymers and surfactants, foam, and nanofluids. These conventional chemical methods were widely used in the 1980s on sandstone reservoirs, especially polymer flooding. Since the 1990s, the method has fallen off around the globe except for China due to the volatility of the market and the lower cost of other chemical additives [68]. Of the three chemicals, alkali is the one of most used chemical EOR especially in polymer flooding. (e.g., Xanthan gum, Carboxymethylcellulose, Hydroxyethyl cellulose) They help improve oil recovery using three mechanisms, mobility control, the viscoelastic nature of polymer molecules, and disproportionate permeability reduction. Mobility control uses a factor called the mobility ratio, which describes the ratio of the mobility of the water over the mobility of oil. When the mobility ratio is more than one, it shows that the water injected is more mobile than the oil, these will affect the injected water and prevent it to break through the oil zone to displace the oil. To ensure that the mobility ratio is less than one, polymers are mixed in with the water to raise the viscosity of the injectant and allow for higher sweep efficiency. Some reservoirs tend to be heterogeneous and have uneven permeability throughout. This causes water to flow to higher permeability spaces, and primary or secondary methods will have a rough time retrieving the oil from lower permeability spaces. Polymer flooding will block water flow in sections of the reservoir, decreasing relative water permeability, although oil relative permeability remains unchanged. This method can divert the water to displace the oil in lower permeability regions as high permeability regions are “blocked off” by polymer flooding using the relative permeability modification mechanism. The nature of polymer molecules increases sweep efficiency as they undergo expansion and contraction when flowing in porous media, which generates elastic viscosity. Due to studies by Urbissinova and Veerabhadrappa, it is concluded that high elastic polymers can result in higher resistance to flow through porous media or higher viscosity [70,71]. This method has some challenges: the electrostatic and the weakest intermolecular force between the polymer and rock surface can cause retention. Retention leads to a lower viscosity than intended and, by association, lower oil recovery.

Foam flooding is another chemical method of EOR. This method was introduced due to limitations of gas injections, such as gravity override and viscous fingering. Thus, foam gas trapped within a thin liquid film called lamellae allowed a continuous liquid phase separated by a gas. Foam flooding controls two mechanisms to increase oil recovery efficiency. The first is by increasing the viscosity of the injectant to improve the mobility ratio, like polymer flooding. Second, gas bubbles can expand in porous media and increase the permeability of untouched regions within the reservoir. Foam flooding can be classified as a gas-injected method; however, chemicals such as protein and surfactant have replaced the traditional CO_2 and nitrogen foams as they provide more stable foams with a longer half-life. Foam flooding has various drawbacks, including its reliance on foam lamellae renewal for effective propagation, lamellae stability while utilizing surfactants once they come into contact with crude oil, and lamellae loss by coalescence. More recent advancements in EOR have seen the use of nanotechnology in the form of nanofluid flooding. Nanofluids are a class of fluids that consist of a base fluid, such as water or oil, with tiny particles of solid material suspended in it. The solid particles are typically less than 100 nanometres in size, hence the name "nanofluids." These small particles are often made from metals, metal oxides, or carbon-based materials, and they can improve the thermal and mechanical properties of the base fluid. The addition of nanoparticles to the base fluid can enhance its thermal conductivity, which means that it can transfer heat more efficiently. This property makes nanofluids particularly useful in applications such as electronics cooling, heat exchangers, and solar thermal collectors. Nanofluids have been investigated for their potential use in Enhanced Oil Recovery (EOR) due to their unique thermal and rheological properties. In EOR, nanofluids can be used to improve the efficiency of the process by increasing sweep efficiency, reducing interfacial tension, and enhancing oil recovery.

One of the main advantages of nanofluids is their ability to alter the viscosity of the fluid. By adding nanoparticles to the fluid, the viscosity of the nanofluid can be increased or decreased, depending on the type and concentration of nanoparticles used. This property is particularly useful in EOR, where a higher viscosity fluid can help to displace oil from porous media. Nanofluids can also improve the thermal properties of the fluid. By adding nanoparticles with high thermal conductivity to the fluid, the overall thermal conductivity of the fluid can be increased, which can help to reduce the energy required to heat the fluid during EOR operations. Furthermore, nanoparticles can help to reduce the interfacial tension between the fluid and the reservoir rock, which can facilitate the movement of the fluid through the reservoir and enhance oil recovery. This effect is due to the fact that nanoparticles have a high surface area, which can absorb onto the rock surface and modify its wettability.

Wettability is defined as a fluid's tendency to disperse over a rock surface due to instability in interfacial tensions between the aqueous, solid surface, and oleic layers [72]. Brownian movement of the NPs allows them to form a wedge between the oil and reservoir surface and form a pressure gradient at the vertex. High pressures will cause the nanofluid to spread and dislodge the oil. Nanofluid also reduces the friction force between water and oil or IFT, which improves oil recovery rates due to the hydrophilic nature of NPs. This phenomenon was proven by a few experiments conducted by [22,73] the addition of NPs can change the phase behaviour of a system. In contrast to surfactants, NPs form more stable emulsions that do absorb into the interface. This means that they can adsorb to the interface between two immiscible liquids (such as oil and water) more effectively, creating a stable barrier that prevents the liquids from separating. Additionally, NPs often have surface properties that can be tailored to promote their adsorption to the interface and prevent aggregation. This can include surface functionalization with hydrophilic or hydrophobic groups, or the use of surfactants or other stabilizing agents to create a protective layer around the particles. Because of their high stability and ability to remain at the interface, NPs in emulsions are less likely to coalesce or migrate, which can lead to instability and phase separation. This makes NPs a promising option for creating stable emulsions for a range of applications, such as in hydrocarbon prediction, food and beverage production, pharmaceuticals, and personal care products. Emulsions are protected from coalescence and flocculants and can divert flow by plugging pathways, thus increasing vertical and areal sweep efficiency.

Although this class of EOR types can be used to improve macroscopic and microscopic displacement efficiency, its recovery technique is majorly through surface tension reduction. It is usually applied on the reservoir with a considerable oil having high acid content [74]. Despite that, some of the standard methods of chemical EOR have been found efficient, e.g., surfactant, their application at harsh reservoir conditions of high temperature and pressure is ineffective as they suffer from thermal degradation. As a result of this highlighted problem, nanoparticles have emerged as a new class of chemical-enhanced oil recovery agents [75] due to their thermodynamic stability. Detailed information on nanoparticle application is provided soon after a brief introduction of electric field application for oil mobilization in the oil industry.

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1.5. Polymeric Surfactants in EOR

Polymeric surfactant injection is a unique chemical technique for Enhanced Oil Recovery (EOR) because it provides good microscopic and macroscopic displacement efficiencies at the same time. Polymeric surfactants have been presented to minimize the number of chemical additives/slugs used in implementing chemical floods in oil reservoirs, simplifying operations, and lowering costs [75]. Several researchers have proposed them as an alternative to conventional surfactant-polymer and alkaline-surfactant-polymer flooding since they may potentially reduce IFT while increasing the viscosity of the injected fluid [76]. It was added that the synergistic action of polymer and surfactant might raise the displacement liquid viscosity and lower the oil-water interfacial tension when the polymer and surfactant system, which is one form of displacement media in tertiary oil recovery technology, enters the porous medium [77]. Besides, many technical hurdles formerly experienced in chemical flooding procedures, such as chromatographic separation owing to selective adsorption, mechanical entrapment, and unwanted fluid-fluid interactions, may be avoided using polymeric surfactants [77].

In a study by Larry et al, functionalized polymeric surfactant was used for EOR in the Illinois basin. Compared to the conventional HPAM, more than 5% OOIP was achieved with the FPS. Surfactant-like monomers attached to the NPS backbone increase the microscopic displacement efficiency of water-soluble polymers by attracting them to the oil-water interface and forming an oil-water emulsion. A laboratory investigation was carried out on polymeric surfactant for EOR in high salinity and temperature [78]. This study observed that polymetric surfactants have good amity with the injection fluids. In addition, the surface activity of polymeric surfactants reduces the interfacial tension of the reservoir compared to the normal polymer fluids. In another study by Chen et al. [79], Polymeric surfactants' migration rules and emulsification process in porous media were investigated. The findings revealed that, unlike polymers, it was challenging to maintain a constant pressure when the polymeric surfactant was conveyed through a porous media. The plugging of a single big particle, stacking and plugging of tiny particles, building an "emulsion bridge" to block super large pores and vortex spinning of different-sized particles are the significant transport properties of the studied polymeric surfactant in porous media. Thus, Small quantities of a correctly chosen polymeric surfactant together with appropriate injection brine can reduce interfacial tension in the water-crude oil system, resulting in a beneficial change in wettability. Polymeric surfactants are also mechanically and thermochemically stable molecules, preserving their capacity to improve brine rheological behavior while concurrently lowering interfacial tension in the water/crude system.

1.6. Low-salinity water flooding (LS-WF)

Water flooding is widely used to boost oil recovery across the globe. On the other hand, low-salinity water injection has been proven to improve oil recovery compared to high-salinity water injection. In LS-WF, the salinity of injected water in the oilfield is much lower than that of the reservoir's original water formation [80]. Besides, many studies have showed that low salinity water flooding may minimize residual oil saturation, enhance water flooding recovery, and increase oil output. According to current research, the mechanism of LS-WF impacting the recovery factor is mainly influenced by clay expansion and particle migration, which may alter pore structure and increase the reservoir's heat and mass transfer efficiency. Aside from the intensified clay expansion due to low salinity water, the mineral-induced changes in the rock wettability can also impact the oil displacement efficiency [81]. The influence of LS-WF on numerous parameters, such as the concentration of injected water, ionic concentration, flow rates, injection volume, reservoir temperature, formation pressure, and solid materials, was explored to find out the mechanism of LSWF in EOR in Wyoming. A series of laboratory experiments confirmed that LSWF might boost oil recovery [82,83].

Furthermore, data from the carbonate reservoir's field logging and pilot injection production tests demonstrate that LSWF may minimize the reservoir's residual oil saturation. Similarly, Wang et al. performed a series of tests to confirm that LSWF may increase carbonate reservoir recovery by developing a new relative permeability model and moisture content calculation model that considers

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interface micro-forces and capillary pressure [84]. The findings demonstrated that the model matches the actual data well, allowing us to define the micro-displacement mechanism of the LSWF. The recovery rate might be boosted by 9% than formation water flooding (FWF). Based on the research conducted by Webb et al, it was presented that the first field proof of low-salinity water injection reducing residual oil [85]. The residual oil inside the wellbore was decreased by up to 60% when LSW was applied, according to the log injection experiments. McGuire et al. researched Alaska and they discovered that LSW injection resulted in a significant decrease in residual oil saturation in 6–12 percent of the original oil in place (OOIP) [86]. Because of LSW, the Omar field in Syria demonstrated a gradual recovery of 10–15 percent of STOIIP [87].

1.7. Cellulose nanocrystal EOR agents

Cellulose is a water-insoluble, fibrous, readily accessible natural glucose biopolymer with a long chain of harmless carbohydrates derived from plant cell walls. The crystalline area of cellulose with the elimination of amorphous sections, cellulose nanocrystal, belongs to the family of natural nanoparticles. It has non-toxicity, biodegradability, renewability, biocompatibility, high stiffness, and mechanical modulus. Cellulose nanocrystal has recently received attention as an applicable rheological modifier for controlling the rheological characteristics of diverse fluids, owing to their unique shear-thinning behaviours, thixotropic performance, quick recovery of steady-state viscosity, and viscoelastic qualities. Using cellulose nanocrystals as a flooding agent improves the injectivity of hybrid fluids in enhancing oil recovery due to the rheological impact of increasing viscosity with heat and time [88]. Therefore, cellulose nanocrystal shows distinct thermal stability when used for oil field applications. According to Reiner and Rudie, Cellulose nanocrystal particles do not significantly modify the viscosity of injection brine, but flow diversion improves microscopic and macroscopic sweep efficiency. Cellulose nanocrystal is commonly made with 64 wt.% sulphuric acids at a temperature of 45^{0}C, like the particles used in the current experiments, with reaction times varying depending on the reaction temperature chosen. The structure, chemistry, and phase separation characteristics of dispersed Cellulose nanocrystals are heavily influenced by the acid type, acid concentration, hydrolysis temperature and duration, and sonication intensity [89].

Log-jamming is a proposed EOR process for Cellulose nanocrystals in porous media, in which particles block pore throats (more significant than the particle size) and create microscopic flow diversion inside the pore matrix. Log-jamming is influenced by various parameters, including pore size distribution, particle concentration, adequate hydrodynamic size, and injection flow rate [88]. Although the utilization of Cellulose nanocrystals in EOR application has not been thoroughly studied, cellulose derivatives such as modified hydroxyethyl cellulose (HM-HEC) have been investigated. This is also supported by a study by Molnes et al. Results revealed that Cellulose nanocrystal particles may participate in log jamming and agglomeration in pore throats, as the core flooding showed increased pressure drop fluctuations during Cellulose nanocrystals in low salinity brine injection [88]. Thus, Cellulose nanocrystals are beneficial as additives in EOR.

1.7.1. Structure-function relationships for EOR surfactants and EOR polymers

Surfactants adsorb at several interfaces, including solid, liquid, liquid, and liquid gas. Surfactants' capacity to form a compact dense layer at the air-water or liquid-liquid interface causes the interfacial tension to be reduced [89]. Structure-function relationships give information on the functional groups, charge density, hydrophobic/hydrophilic balance, and macromolecular architecture. The studied show that structure-function connections for combinations of sulfonate and different non-ionic surfactants using oil/water IFT measurements [90]. The combination of non-ionic surfactants with aromatic rings in the hydrophobic chains produced the most noticeable synergistic effect for the surfactant employed. Although the surfactant species impacts wettability, several studies have demonstrated that the surfactant structure, such as the length of the alkyl chain and the spacer, also affects wettability. This might be ascribed to modifier attributes changing with their structures. It was reported from a study that piperazine-based polyether Gemini surfactants with various lengths of the spacer and alkyl chain exhibit opposing wetting behaviours [91]. The hydrophobicity of the organo-montmorillonite increases with the lengthening of the Gemini surfactant's alkyl chain, but the spacer's length has only a modest influence on wettability [91]. Non-ionic surfactants with shorter hydrophilic units have also been shown to improve wettability alteration, which is highly dependent on the modifier structure [92]. The structure-function relationships of both surfactants and polymers need to be studied for EOR application to utilize them in EOR application entirely [90].

1.7.2. Carbonate reservoir overview

The most common kind of hydrocarbon reservoir is carbonate deposits. The global occurrence of this kind of reservoir is unknown, nevertheless, Akbar et al estimated that carbonate reservoirs hold around 60% of the world's oil reserves. According to Schlumberger, 70% of conventional oil reserves in the Middle East are in carbonate reservoirs. Fractures of various sizes and lengths, ranging from extremely tiny to kilometre-wide fissures, make up carbonate reservoirs[92]. Interaction between cracks and rock layers via capillary and gravity forces is the critical component that governs production in carbonate reservoirs. During the EOR process, most of the injected fluids infiltrate through the fractures and elude the oil in the porous media. Because of the high permeability of the fractures and the resulting reduced pore capacity, the injected fluids are typically produced early [93]. The injected fluids are more likely to infiltrate through the cracks and elude the oil in the porous medium when EOR procedures are used. Because of the high permeability of the fractures and the resulting reduced pore capacity, the injected fluids are typically produced early. Moreover, oil recovery is difficult due to the nature of the neutral to oil-wet wettability of carbonate rocks. The injected fluids are more likely to infiltrate through the cracks and elude the oil in the porous medium when EOR procedures are used. Because of the high permeability of the fractures and the resulting reduced pore capacity, the injected fluids are typically produced early. Furthermore, due to the nature of the neutral to oil-wet wettability, oil recovery from carbonate rocks is difficult. As a result of the oil adhering to the walls of the carbonate rock, flow out of the reservoir will be problematic, resulting in poorer hydrocarbon recovery rates.

2. Parameters that affect EOR mechanisms

2.1. Porosity

One of the most essential factors that affect the EOR mechanism is porosity. Porosity may be used to calculate the actual volume of oil and gas in a reservoir. It is defined as the proportion of the total rock volume V that is not occupied by solid materials, and can be stated as follows:

$$Porosity = \Phi = \frac{V_p}{V_b} = \frac{Pore\ Volume}{Total\ Bulk\ Volume} \text{Error! Bookmark not defined.} \qquad 1$$

Reservoir rock must contain pores for storing oil and gas which are adequately large to be produced. However, porosity does not provide information about the size of the pore, distribution of pore size, and connectivity of the pore, it is not enough to justify the oil recovery factor, the rocks must be permeable, where the pores should be well connected to allow the flow of oil and gas through the reservoir rocks. If the rock has low permeability, the oil that accumulated in the rock might not be able to be produced as the build-up of the oil could not flow into the drilling wells fast enough. Therefore, rocks with the same porosity might vary widely in physical properties. The pores inside the mortar texture can be divided mainly into three (Figure 4): (1) Effective porosity: this type of pores represents the open porosity within the mortar body. The pores are connected, and the water can flow through the texture. This type of porosity considers the major contributor to mortar permeability. (2), The second type is the dead-end pores, this pore will contribute to the total porosity of the mortar. However, it does contribute to permeability. The content of these pores is affected by the saturation conditions. (3), The last type is closed porosity. This type of porosity does not contribute to the total porosity of the mortar and its content will remain isolated.

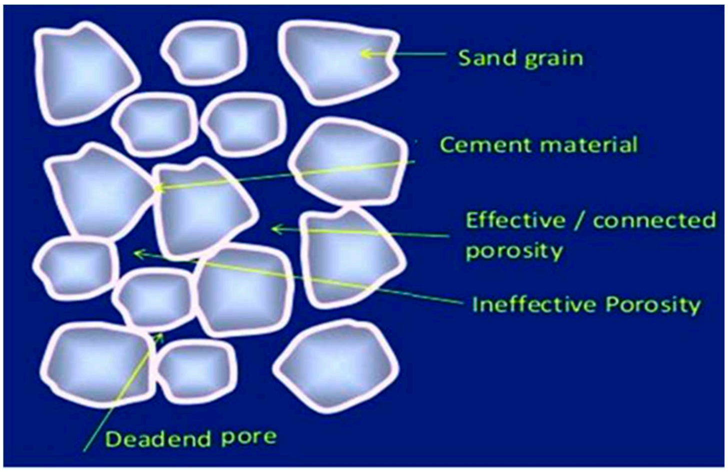

Figure 4. types of porosity present in the reservoir condition.

2.2. Permeability

The ease with which a fluid flows through rock is referred to as permeability. In the science of petroleum production, permeability is one of the most important parameters to be studied. The velocity of water flowing through a soil mass between any two points depends directly on the hydraulic gradient or the head loss per unit length between the two points [13]. The property of the soil that permits the flow of water through its voids with ease is known as permeability. In short, quantitatively, permeability is defined as the velocity of flowing water under a hydraulic gradient. The unit of permeability is the same as velocity, which is cm/s or m/day. The knowledge of the permeability of soil is essential to the design of well and hydraulic structures [95,96]. Permeability is influenced by many variables, including grain size. Permeability is proportional to the square of the effective diameter of particle size (D_{10}).

$$K = C(D_{10})^2 \qquad 2$$

where K is the permeability, C is a constant Value and D is the diameter of the particle or grain size.

Permeability in reservoir sandstone can be affected by various factors such as the Grain size and sorting: The permeability of sandstone is largely determined by the size and sorting of its grains. Coarse-grained and well-sorted sandstones tend to have higher permeability than fine-grained and poorly sorted sandstones. Porosity: The interconnected pore space within the sandstone can affect the permeability. The higher the porosity, the more interconnected the pore space, and the higher the permeability. Cementation: The presence of mineral cement between the grains can reduce the size of the pore space, thereby reducing permeability. Saturation: The presence of fluids, such as water or hydrocarbons, can either increase or decrease permeability depending on the type and amount of fluid present. Compaction: Over time, the weight of overlying sediment can compact the sandstone, reducing its porosity and permeability. Diagenesis: Changes in the sandstone due to chemical or physical processes during burial and lithification can alter the porosity and permeability. Fractures: The presence of fractures can greatly enhance the permeability of a sandstone reservoir by providing additional pathways for fluid flow.

Another factor that affects permeability is the characteristics of pore fluid, i.e., the fluids that occupy the areas of pores in rock or soil. Permeability is inversely proportional to the pore fluid viscosity and directly proportional to the unit weight of pore fluid [96]. Next is the temperature: Since pore fluid viscosity decreases with temperature, the permeability will increase with temperature. Besides that, permeability is also affected by adsorbed water that surrounds the individual soil grains, Figure 5 gives an illustration of the oil confined in the reservoir because of impermeable. The water adsorbed on the soil grain could not move freely, therefore reducing the effective pore space and leading to a decrease in permeability. Moreover, entrapped air and organic impurities would also hinder the flow and reduce permeability. The degree of saturation of soil could also affect the permeability, where fully saturated soil would be more saturated than partially saturated soil. Lastly,

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the shape of particles also affects permeability. Soil with a higher specific surface area will be less permeable.

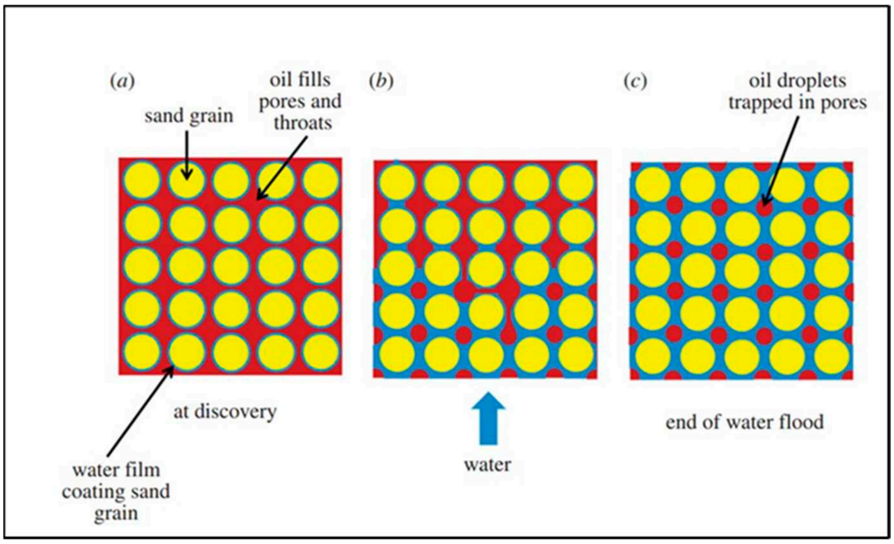

Figure 5. Illustration of trapped oil in wet rock, (a) Sand grain covered with a thin water coating and pores filled with oil (b) progresses in water flooding thickens the water films (c) water films and oil loss [96].

Table 2. Criteria of permeability for EOR methods.

EOR Method	Permeability, md
Steam	≥ 200
In situ	≥ 200
Alkaline	≥ 20
Surfactant	≥ 20
Polymer	≥ 20
CO_2	Any range
HP gas	Not a critical factor

Permeability can be determined with Darcy's law. This law is introduced by Henry Darcy which is a French hydrology engineer in 1856 to study the behavior of water flowing through sand filters [97]. determined the volumetric flow rate of water through a sand filter with the experiment and derived the following equation [97,98]:

$$q = -\frac{k}{\mu}\frac{\Delta P}{L} \qquad 3$$

where μ is the dynamic viscosity of the fluid, k is the permeability of the porous medium, and L length in the flow direction.

Darcy discovered that the volumetric flow rate of water through a sand filter is a function of the porous medium's size and the disparity in the hydraulic head. [99].

2.3. Reservoir Pressure

Another parameter that affects the EOR mechanism is the reservoir pressure. It is the pressure of the fluid present in the reservoir. Reservoir pressure is useful in the volumetric calculation. To measure reservoir pressure, bottom-hole pressure measuring instruments are used to measure the pressure of fluids in the reservoir pores. Since the reservoir pressure is constantly changing when oil and gas are produced, the reservoir pressure should be described as measured at a specific time [100]. There are three types of pressure distribution in the reservoir during fluid flow, which are steady-state flow, pseudo-steady-state flow, and transient flow.

2.4. Temperature

The temperature of the reservoir could also affect the EOR mechanism. Besides affecting oil mobility, temperature also alters the wettability of reservoir rock. Higher temperatures will make the rock surface from oil-wet (OW) to more water-wet (WW), which promotes oil recovery. Furthermore, the influence of pressure on permeability decreases with increasing temperature, especially at lower pressures. This is because when the temperature rises, the rock matrix and fluids in rock pores expand, which exactly counteracts the rock's compaction.

2.5. Viscosity

Viscosity could also affect the EOR mechanism; viscosity is the internal resistance of a fluid to flow. This parameter is needed for any calculation related to the movement of fluids. Several factors affect viscosity, which includes the composition of oil, temperature, dissolved gas, and pressure. Moreover, oil composition can be described with the API gravity, as crude oil API gravity decreases, the viscosity increases. Viscosity also increases almost linearly with pressure and temperature [101]. The fluid viscosity changes with temperature, pressure, and composition, it is generally known that the viscosity in the gaseous state is much lower than in the liquid state [102]. Momentum is transmitted primarily via intermolecular processes between densely packed molecules in the liquid phase, whereas momentum is transferred by collisions of freely moving molecules in the gaseous phase [103]. Eynas Muhamad Majeed and Tariq Mohammed Naife 2020 experimented with the viscosity reduction in heavy crude oil by different additives. It is known that the high viscosity of heavy oil is a major factor that affects the upstream and downstream of oil recovery. Furthermore, due to the application of different additives, the viscosity of the heavy was reduced to a maximum of 3.78 cSt at 75^0C and 26 API at 25^0C [104]. In another study by Sherif Fakher and Abdulmohsin Imqam 2018, the reduction of heavy oil hydrocarbon utilizing a chemical solvent was studied. Four novel formulations were created with excellent stability in adverse reservoir conditions and good solubility in crude oil to significantly lower heavy oil viscosity and thus enhance production from these reservoirs and enable transportation of these heavy oils [105].

2.6. Wettability Alteration

Wettability is the predisposition or proclivity of a solid surface towards a certain type of fluid in the presence of other non-miscible fluids [2,32,106]. The rock surface's wettability tenets control the position of the reservoir rock fluid flow distribution in a particular reservoir [107–109]. The reservoir's petrophysical properties are one of the major parameters due to their significant influence on the recovery of the oil such as the relative permeability, and capillary pressure. Reservoir oil wettability is mostly classified into WW, OW, and mixed wet state [32,110]. The reservoir rock properties system can be determined by measuring the contact angle, spontaneous imbibition, zeta potential, and surface imaging test. Most research papers on reservoir wettability use a contact angle to depict the point at which the interface of the oil and water interacts at the rock surface [111]. The change of wettability of a rock's surface from oil wet to water-wet lessens the viscous force of thermodynamics force. Therefore, it enhances the oil permeability of the reservoir, as indicated in Figure 6. However, most research output reports that oil recovery is more effortless in water-wet reservoirs than in OW reservoirs [112]. Wettability is a term in the oil industry that is used to describe the preference of a solid surface for a particular fluid in the presence of another immiscible fluid [113]. Wettability is an essential parameter because it controls fluid location and distribution inside the reservoir [85]. By this definition, and the awareness that oil reservoir is mainly composed of oil and saline water, the reservoirs can be categorized as oil wet, water wet, and intermediate wet (Figure 6). Reservoir water (also known as connate brine) is considered as wetting fluid (or the reservoir rock is viewed as water wet) when the angle of contact of water on the rock is between 0 and 90^0C. Conversely, oil is the wetting fluid (or the reservoir rock is considered oil wet) when the angle of contact is between 90 and 180^0C. The rock becomes evenly wet, i.e., intermediate, if the angle of contact is 90^0C. In terms of capillary pressure, defined as the pressure difference between oil and water at the interface of the two fluids, when the surface is oil wet, the surface forces will displace water in favor of oil and vice-versa (Figure 6). For oil wet reservoir, the recovery will be challenging in comparison to water wet reservoir, the preferred state of wettability for efficient recovery [114]. Therefore, the aim has always been to change the natural wettability of the formation to more water-wet conditions. As an example, carbonate reservoirs are mostly characterized as oil-wet or intermediate wet while the opposite is the case for sandstone reservoirs [113]. From the published articles, the major modes of investigation of rock wettability in the presence and absence of alteration agents have been contacting angle measurements, spontaneous imbibition, zeta potential measurements, as well as surface imaging tests. Furthermore, the use of some characterization tools such as atomic force microscopy, scanning electron microscopy, and nuclear magnetic resonance spectroscopy can delineate the change of properties occurring to the rock during the process of wettability alteration.

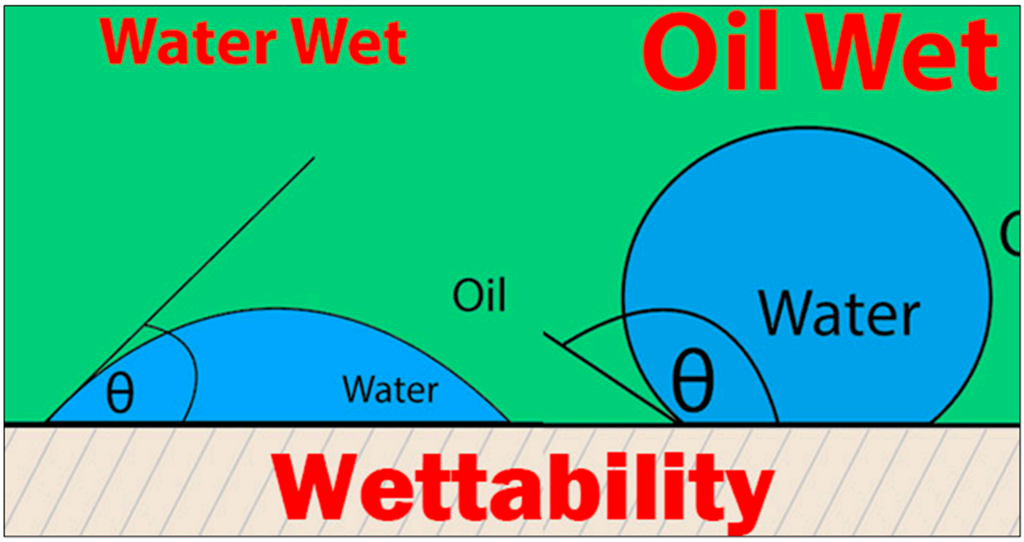

Figure 6. Wettability alteration of the rock from OW to WW with an increase in permeability. Adapted from [112].

Wetting and spreading are essential for oil production, especially during primary, secondary, or EOR. Capillary, or interfacial, forces hold microscopically trapped oil in place. Viscous or gravity forces must overcome the capillary forces holding the trapped oil in place to mobilize it. The capillary number N_{Ca}, is the ratio between viscous and capillary forces. This is a dimensionless number calculated by

$$N_{c8} = \frac{V_b \mu_b}{\gamma} \qquad 4$$

where V_b represents the velocity of the brine phase in the pore, μ_b represents the viscosity of the brine phase, γ and is the interfacial tension. Between the brine and oil phases, there is tension. The proportion of the Bond number is the sum of gravity and capillary forces. N_{Bo}. This is a dimensionless number calculated by

$$N_{B0} = \frac{\Delta_{pak}}{\gamma} \qquad 5$$

where Δ_ρ is the absolute density difference between the brine and oil phases, **a** represents gravity or acceleration, and **k** is the porous medium's permeability to brine. While the literature has offered a variety of distinct, but more or less equal, definitions of capillary and Bond number [111,115], we employ the definitions above in this work.

Figure 7 depicts the effects of wettability on residual oil saturation and oil remaining after primary and secondary oil recovery.

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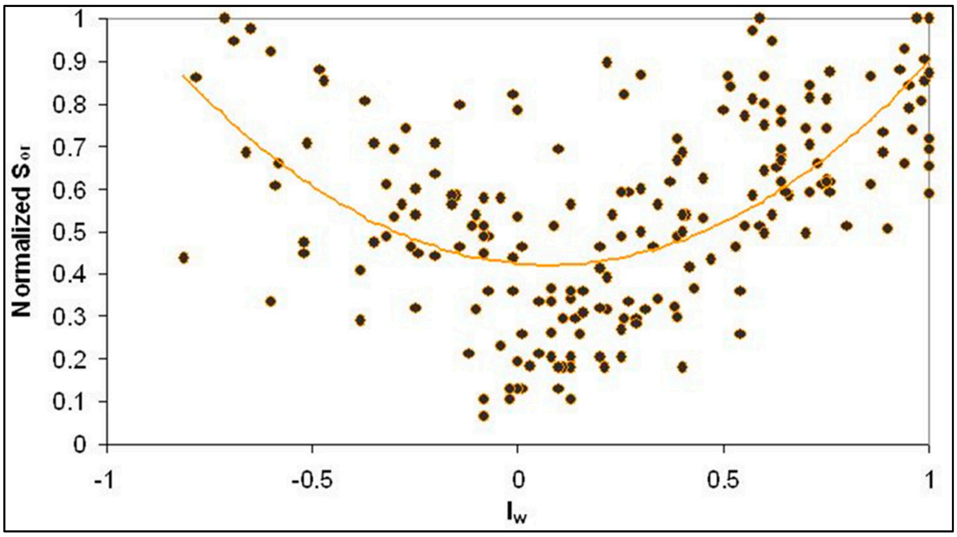

Figure 7. General Effects of wettability on residual oil saturation, oil left from primary and secondary oil recovery [116–118].

The spreading and adhesion interfacial phenomena of the fluid-rock surface, which is well known as wettability alteration because they influenced multi-phase flow has a very serious implication therefore it has recovery effectiveness in petroleum reservoirs. One of the main factors controlling the fluid flow of the reservoir into the porous medium is wettability (Table 3), which also has a great influence on both the relative permeability values of the liquid and gas stages and recovery [119–121]. The inadequate liquid for drilling and production would affect the wettability of the reservoir negatively which can lead to damage to the reservoir and reduced production in terms of recovery factors [122,123]. in this case, most countries have been finding alternative ways to increase their oil production by introducing nanotechnology EOR mechanisms [111].

Table 3. The effect of nanoparticles on wettability alteration.

Properties	Condition	Nanofluid & Variables	Substrate	Result	Ref.
Hydrophilic, 14 nm, Spherical		Based Fluid: DW. NPs conc. (0.1-5 wt.%)	Glass	The surface was completely altered to water wet (0°) at 5wt% NF conc.	[124]
Hydrophobic, 10nm, Spherical		NPs conc. = 0.5-4wt%, NaCl = 0-20 wt%,	Calcite	SiO_2 altered θ from 120° to 45° at 2wt% optimum conc. This was altered further to 40° at 30000 ppm salinity.	[125]
Hydrophobic, 5nm, Spherical		Based Fluid = DW, Size = 5 & 25nm, Temp. = 23&50°C	Calcite	Size has no effect. θ decreased with higher temp.	[126]
Spherical, 35nm	T= 70°C, P = 600psi	Based Fluid = DW, NPs conc. = 5wt% Salinity = 3-12wt%	Calcite	SiO_2 NPs reduced the θ below 90° up until 8wt% salinity.	[127]
Hydrophilic, 15nm	T<30°C	Based Fluid = DI NPs conc= 0.1wt% Surfactant conc. = 0.14wt%.	Sandstone	SiO_2 NPs with and without surfactant altered wettability to strong water wet by	[128]

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				9.87% and 6.15% respectively.	
15nm	N.A	NF=H_2O+NPs+ SF(AOT, 11.25mM)+SA(NaCl+Na_2SO_4+$CaCl_2$+ $MgSO_4{\cdot}7H_2O$).	Berea Sandstone	Increase in NPs conc. does not magnify W.A. Highest W.A. was achieved with 0.1wt% conc. of NPs at 0.3wt% salinity.	[129]
Spherical,15nm	Room	NF = H_2O+NPs+SA(NaCl)	Calcite	W.A. reduces with an increase in NP conc. (73.72% changes). The reduction was further enhanced in the presence of NaCl	[130]
Hydrophilic (40nm) and surface modified (6nm) SiO_2, Spherical.	Room	NF= H_2O +NPs+ SA (NaCl+$CaCl_2$+KCL+$MgSO_4$+$MgCl_2$, 73050 ppm).	Sandstone	Adhesion forces reduce up until 0.5wt% NPs conc. Treated NPs outperformed unmodified ones due to increased interfacial activity,	[131]
Silane treated SiO_2 (15nm)	Room	NF = Propanol+NPs.		θ reduces with increase in conc.	[132]

2.7. Capillary pressure effect

Capillary force is regarded as a critical element in fluid flow through porous media. The wetting phase is prone to flow to the pore wall, reducing the pore cross-section as a result. As a result, the adsorption of the wetting phase on the surface of the porous medium reduces the ability of fluid to flow through it. Capillary pressure, according to the definition (P_c):

$$P_c = \frac{2\sigma COS\theta}{r_c} \qquad 7$$

where $\sigma$is surface tension, σ is contact angle, and r_c is capillary radius as more wetting phase is adsorbed on the rock surface, the value of r_c decreases, resulting in higher capillary pressure. Seismic waves might generate mechanical Vibro-energy on the pore surface, reducing the adsorption of liquid films to the pore wall and, as a result, increasing the capillary radius (r_c) (decreasing the capillary pressure). Furthermore, other critical characteristics might influence the P_c, such as surface tension (σ). Other studies suggested, based on the experimental data, that Vibro-energy can lower the oil/water surface tension owing to agitation and fluid temperature increase, resulting in a decrease in P_c [133]. When vibration is used, Kouznetsov et al. [134] claim that the interfacial tension of oil/water may be lowered by two orders of magnitude. Kouznetsov et al. [135] developed the equation for acoustic capillary pressure by assuming the vibration acceleration is constant (14% of the maximum amplitude):

$$P_{ac} = \int_0^z \omega^2 A_{\rho\omega} \frac{1-\Delta}{1+2\Delta} dz \qquad 8$$

where ω is the wave frequency, A is the maximum offset amplitude, $\rho\omega$ is the wetting phase density, $\Delta = {}^{\rho_{nw}}/_{\rho w}$ is the nonwetting phase to wetting phase ratio, and z is the linear coordinate. The equation for the link between wetting phase pressure and non-wetting phase pressure is:

$$P_{nw.0} - P_{w.0} + \int_0^z \omega^2 A_{\rho\omega} \frac{1-\Delta}{1+2\Delta} dz = \sigma j(S_\omega) \cos\theta \sqrt{\frac{\theta}{K}} \qquad 9$$

where $P_{nw.0}$ is the capillary pressure for the nonwetting phase without vibration; $P_{w.0}$ is the capillary pressure for the wetting phase without vibration; θ is the contact angle; $j(S_\omega)$ is the leverets J function, θ is the porosity.

2.8. The relative permeability effect.

During the oil recovery process, the water phase and oil phase are combined; particularly at the late stage of oilfield development, the oil phase is distributed into the water phase, resulting in a discontinuous flow condition for the oil phase. The oil phase is broken down into minute, discrete droplets at low oil saturation. The relative permeability curve is critical to reservoir oil production because it reveals the oil saturation threshold Sor below which the oil is immobile. Nikolaevsky [136] determined that seismic waves can raise the relative permeability of the oil phase, hence increasing the oil phase's movement ability lower than Sor. By altering the flow direction of the oil or water phase regularly, Vibro-energy can produce quasi- or periodic motions. As a result of surface vibration and periodic motions, fluid adhesion to the solid phase might be decreased. The fluid coating deposited on the pore surface is destructed, allowing more fluid to flow through the narrow pore throats. Oil molecules, on the other hand, are substantially bigger than water molecules. As a result, whereas water molecules may pass through some of the smallest pores, oil molecules find it difficult to get through due to their huge molecular size. When the pore size rises, the oil molecules may flow through these open pores, resulting in a greater influence on the oil phase relative permeability compared to the water phase's relative permeability. Both high and low power frequency waves can cause fluid film degradation, reducing the sealing portion of the pore throat.

The viscosity of crude oil reduced by the ultrasonic wave may reach more than 20%. Some studies, however, argued that the effect of ultrasonic waves on oil viscosity may be classified into three phases [137]. Stage I, the oil viscosity increases with time due to the dissolution of suspended particles, which can increase internal friction within the oil components; in Stage II, the oil viscosity decreases due to the thermal effect and disintegration of the large components of crude oil; and Stage III, the oil viscosity increases due to the integration of the broken chains asphaltenes particles into long chain flocs. The presence of an ultrasonic wave can lower oil viscosity by 20-25 %; however, the viscosity can be restored to pre-treatment levels by continuing the sonicating [138,139]. For low-frequency waves, it is claimed that wave dispersion inside the formation may create high-frequency harmonics, introducing a thermal influence on oil viscosity [140]. Experiments confirmed a similar viscosity reduction effect, and low-frequency waves (30 Hz - 60 Hz) enhanced the flow of polyacrylamide solution by a factor of one to two [138]. The cause might be attributed to a decrease in oil viscosity; however, this hypothesis could not be quantified. It also raises the question of whether the viscosity decrease is due to the employment of low-frequency waves, or a secondary impact linked to the dissipation of Vibro-energy followed by heating the crude oil.

2.9. Interfacial tension

Interfacial tension (IFT) is the Gibbs free surface energy acting between two different immiscible liquids [141], say oil and connate brine in EOR. IFT is so crucial that it becomes a standard characterization parameter in chemical EOR, as it determines the movement and distribution of fluids through the formation. The IFT is inversely correlated to a dimensionless number called Capillary number (N_{ca}) mathematically expressed and usually used in connection to the recovery factor. The lower the IFT, the higher the N_{ca} and recoverability.

$$N_{ca} = \frac{Viscous\ forces}{Capillary\ forces} = \frac{v\mu}{\sigma cos\theta} \quad (10)$$

where v represents velocity, μ represents dynamic viscosity, σ stands for interfacial tension and θ is for contact angle. It is essential to have a very high capillary number to obtain a great reduction of residual oil situation. To achieve this goal, the IFT must be reduced to as low as possibly 10^{-3} mN/m [142–145]. Mostly than not, the IFT measurement between oil and nanofluid is done with the pendant drop technique [118]. During the conduct of the IFT experiment at constant pressure and temperature, the oil droplet is released at the outer end of a capillary needle inside the nanofluid. Thereafter, the value for IFT is determined by estimating the shape of the oil droplet completely with the help of a high-grade precision video system and analytical software.

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3. Fluid Displacement Efficiency

Fluid displacement efficiency refers to the effectiveness with which one fluid displaces another in a reservoir during oil production. In other words, it is a measure of how much oil can be recovered from a reservoir by injecting a displacing fluid (such as water or gas) into it. The fluid displacement efficiency is influenced by several factors, including the properties of the reservoir rock and fluids, the injection rate and pressure, and the mobility ratio between the displacing and displaced fluids. A high fluid displacement efficiency means that a significant amount of the oil in the reservoir can be recovered by the injection of a displacing fluid. Conversely, low efficiency means that a significant amount of the oil is left behind in the reservoir. Optimizing fluid displacement efficiency is an important consideration in the design and operation of oil production processes, as it can have a significant impact on the amount of recoverable oil and the economics of the project. Displacement efficiency is a key factor that affects the recovery of oil from the reservoir zone [146–150]. In the reservoir system rock pore properties, fluids properties, and interaction of the fluids with the pore walls i.e., wettability are all essential. A reservoir rock comprises larger spaces (pores), that are associated with smaller spaces or constraints (throats). Though, larger pores may be linked by larger throats and smaller pores to smaller throats. That is, pore sizes and throat sizes may be arranged in a correlated rather than random or disordered manner. To determine the performance of the fluid in a tight clastic rock reservoir, this has reverted to some crucial issues during the experimental studies. This includes the pore throat morphology and the physical interaction of the reservoir's fluid-pore wall (Figure 8) [151–158].

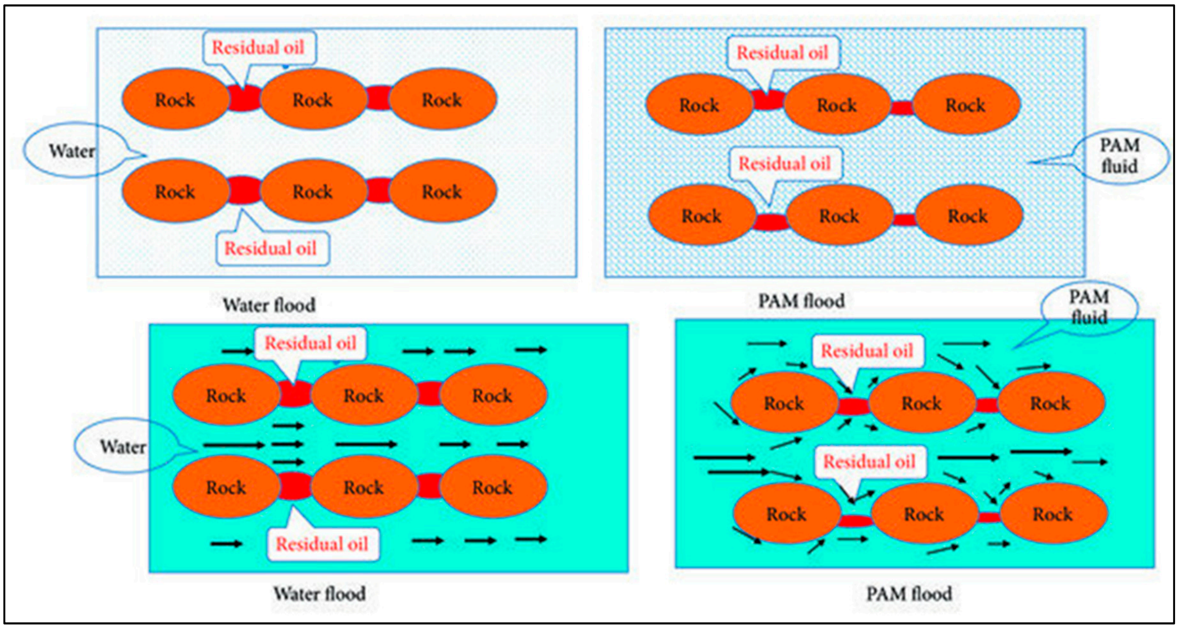

Figure 8. The fluid displacement efficiency in the porous medium.

Nevertheless, the pore-throat architecture differs dramatically in tight clastic rock reservoirs, and the fluid movement inside must be carefully monitored [156,159–163]. Therefore, throats are characterized in terms of diameter and pores in terms of diameter and volume. These two parameters are the major factor controlling the reservoir fluids, Pores represent the capacity of the rock to contain fluids but, in rocks where throats are much smaller than pores, it is the throats that have the major effect on fluid flow. In multiphase fluid flow, the properties affecting the flow of fluid are the size, and frequency distribution of the pore and throat. Properties affecting multiphase fluid flow include the size-frequency distribution of pores and throats, the size connection directly linked throats and pores, and the spatial structure of pores and throats [164–167]. Figure 9 gives an illustration of the four mechanisms of oil-trapped at a pore scale for three wettability alterations in reservoir environments.

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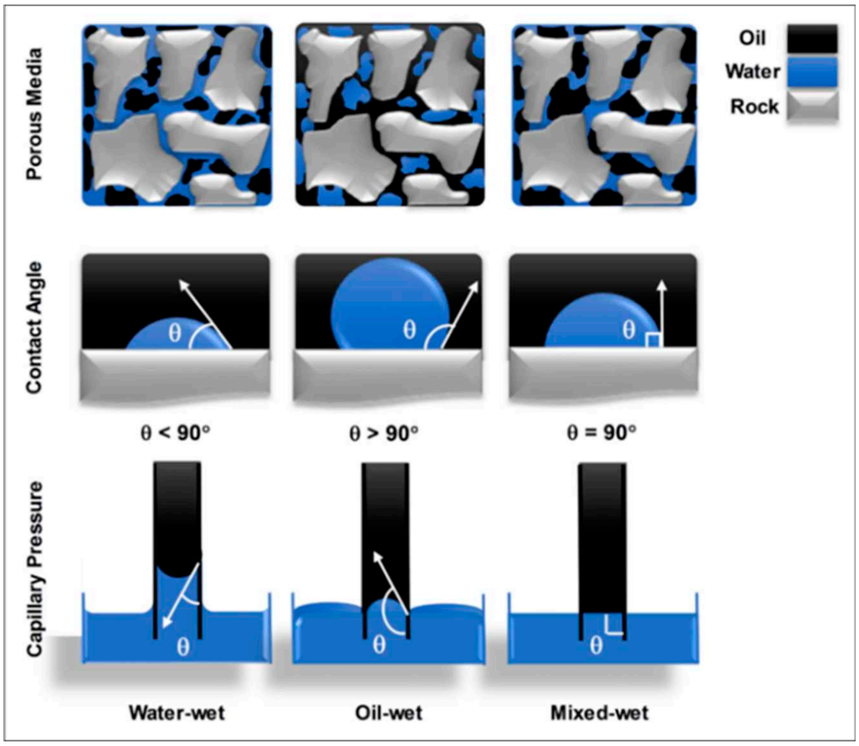

Figure 9. Mechanisms of oil trapped on the microscope scale for threes wettability conditions [168].

3.1. Mobility Ratio

Oil mobility is the primary concern in most oil reservoirs. Even though the Petro-physical properties are the main components affecting the oil mobility ratio, the type of porous medium will also play its role. In the displacement of fluid process, if the mobility ratio of the fluids is greater than 1 it is considered disparaging, while when the mobility ratio of the fluid is less than 1, it will be considered promising. The displacing fluid's mobility at the average water saturation behind the advancing front of displaced oil (S_{wa}) is divided by the oil's mobility at the average saturation in the advancing oil band (Figure 10)[169]. Increased or high mobility ratios in the reservoir environment can cause poor displacement and sweep efficiency, resulting in the early development of injected water. Water mobility can be reduced, and water breakthrough can also be prolonged by enhancing areal, displacement, and vertical sweep efficiency; hence, more oil can be regained at any given water cut.

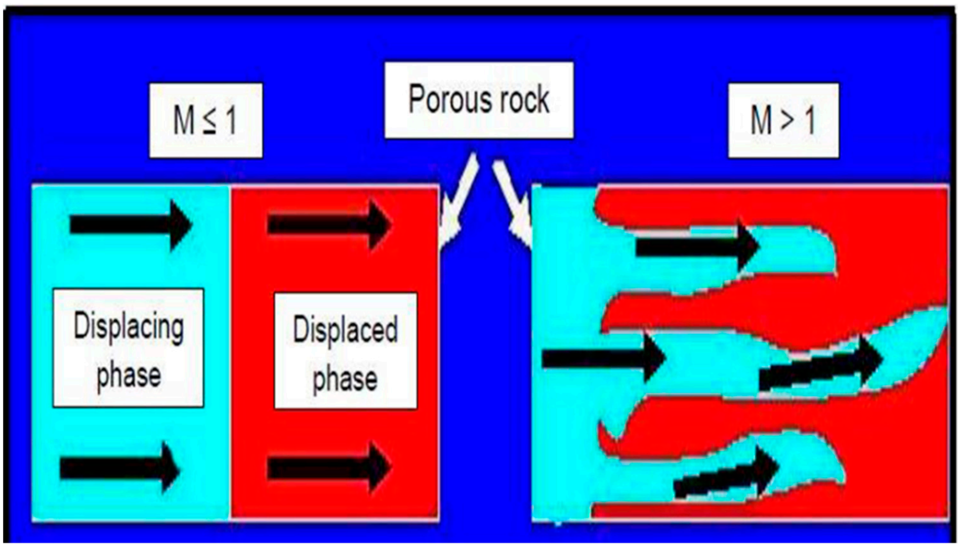

Figure 10. Displacement of oil by water in a water-wet system [170].

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Front instabilities are found in homogenous porous media when the injected fluid (water) is less viscous than oil [171]. In fluid dynamics, this is known as fingering, and it is a kind of Rayleigh-Taylor turbulence. Water fingers spread over the porous surface, leaving behind an assemblage of oil when the displacing fluid is less adhesive (more mobile) than the supplanted phase [172]. This happens when the velocity of the injected fluid and the viscosity ratio of the injection fluid are both very low. The mobility aspect must be addressed in this scenario. If, on the other hand, the porous medium is inhomogeneous and has a high permeability layer, the injected fluid reaches this area first. Fluids prefer to flow through the lower resistive region because the higher permeability zone has lower flow resistance [173]. This layer makes a route to the outlet, causing the injected fluid to burst through early [171]. Following the breakthrough, the bulk of the injected fluids run directly through this channel, whereas some other medium components are left in the sweep. Sweep efficiency can thus be enhanced by including magnetic NPs in the injected water. As a result, NPs tend to enter the reservoir's interior pores [174]. Because they may be triggered by EM radiation, the viscosity of the NP solution rises, resulting in a high resistivity zone appearing in front of the water that has been flooded after flooding with polymer. As a result, the water can be steered to the zone with poor permeability.

3.2. Causative factors for poor mobility of oil to the production site

A large portion of oil is retained inside the reservoir after water-based flooding (Secondary recovery) due to the viscosity of the oil and capillary forces in form of discontinuous hydrocarbon ganglia. The formation of an oil bank from the left-over oil inside the reservoir is essential for high production to be achieved by any technique after secondary recovery. The understanding of the conventional recovery technique regarding the retention of oil is on three forces namely the capillary force, viscous force, and gravitational force. However, for unconventional nanotechnology, forces predominant in the nanoscale have to be the center of focus. That is the coulomb force of interaction and disjoining forces. Table 4 presents the details of the mechanism of six forces that is relevant to the EOR process. In addition to macro and micro scale operation, EOR operation depends on nanoscale processes. Oil recovery at the nano-scale, is dominated by mineralogy, pore shape, roughness, water distribution, and surface film behavior [175].

At the micro-scale, oil displacement is primarily governed by boundary conditions (wettability and pore geometry) and the imbalance of interfaces associated with them, although the suppression of capillary forces is as well important. In a system wetted by water, when there is high interfacial force, the capillary force at the pore throat is large and cannot be subdued by localized buoyancy or viscous forces, and hence eventually leads to oil entrapment.

Table 4. Relevant forces operating during the production process.

Force	Indication	Ref
Viscous force	This is the force occurring as a result of the difference in the viscosity of two fluids, leading to the displacement of one by another	[176]
Gravitational/ buoyancy force	This is the force accounting for the separation of less dense fluid (e.g., oil) from the dense fluid (e.g., water) at the microscale	[176]
Capillary force	This is the force responsible for the difference in pressure between two fluid phases when the interfaces of a fluid are curve	[176]
Coulombic force	These are intermolecular forces and include van der Waal forces such as induced dipole (London), hydrogen bond, and dipole. In the case ions and polar molecules are present, forces such as ionic bonding and ion-dipole bond occur	[177]
Mahogany force	This force arises as a result of variation or gradient of properties such as interfacial tension or concentration	[178]

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Disjoining force	These are surface forces such as an electric double layer, steric force, and van der Waal forces. They are associated with the thin film due to their separation from bulk properties.	[179]

3.3. Assessment of EOR

The categorization of various EOR systems has shown us that one method should not be used for all reservoirs. As a result, the most appropriate approach for reservoir conditions that may be reached through EOR evaluation must be understood. The primary goals of evaluating EOR are to select an optimum approach from among possibilities or to highlight reservoir features based on oil quality criteria. These are classified as fluids and rock parameters, with rock characteristics including permeability, porosity, fluid saturation, initial oil saturation, depth, and density, and fluid parameters including temperature, viscosity, gravity, pressure, and specific volume [180–182].

4. Transport of nanoparticles through a reservoir

The first factor to be considered in the application of nanoparticles as EOR agent is their transport behaviour through the reservoir media. An investigation on the transportation of Si-Zn-DTPMP nanoparticles on both calcite and sandstone cores showed that nanoparticles can navigate through the porous rock [183]. Better mobility of nanoparticles can still be observed if used after flushing with a surfactant solution. The prospect of efficient dispersion stability of iron oxide nanoparticles for a long time was conducted [184] with the modification of its surface property (Table 5). The report showed that these nanoparticles can travel through without recording much retention [139]. The application of nanoparticles can generate stabilized emulsions, which enhances their transport through the formation of rock. Similarly, the harsh conditions of the reservoir environment can also contribute to the stability of the in-situ emulsion due to the preferential adsorption of nanoparticles [185].

Table 5. Summary of studies conducted with nanoparticles for enhanced oil recovery.

Parameters	Outcomes	Ref
➢ Si-Zn-DTPMP applied on both sandstone and calcite core samples	➢ Nanoparticles migration was reasonably good	[183]
➢ Lipophobic and hydrophilic (LHP) nanoparticles. ➢ Wettability alteration of reservoir rock and retention outlook	➢ About 1.6 to 2.1 increase in original values of water phase permeabilities. Absolute permeability reduction due to retention	[186]
➢ Lipophobic and hydrophilic (LHP) nanoparticles	➢ The optimum concentration is 0.02 up to 0.03. ➢ Interfacial tension modification for enhanced oil recovery	[187]
➢ Hydrophilic Silicon dioxide (SiO_2)	➢ The optimum concentration of nanoparticles was 0.05% for recovery due to interfacial tension (IFT) reduction	[188]
➢ Hydrophilic zinc oxide	➢ The performance of nanoparticles on interfacial tension (IFT) and viscosity depends on the size	[189]

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➢ Hydrophilic zinc oxide	➢ 0.3wt% of ZnO nanofluid had the highest surface tension and oil recovery factor. ➢ Both interfacial tensions (IFT) reduction and wettability change were achieved.	[190]
➢ The nanocomposite of Nickel oxide and Silicon dioxide	➢ High interfacial tension (IFT) reduction ➢ future work is recommended at reservoir condition.	[191]
➢ Magnetite (Fe_2O_3), Copper oxide (CuO), and Nickel oxide (NiO). ➢ Less than 50nm in size ➢ A constant electric voltage of 2V/cm	➢ Dielectric and hydrophilic CuO performed better than the rest in a simultaneous application. ➢ Magnetic and hydrophilic Fe_3O_4 performed better than the remaining in the sequential method. ➢ Dominating factors are density and electrical conductivity	[192]

Lipophobic and hydrophobic polysilicon nanoparticles (LHP) were synthesized and characterized to investigate their wettability alteration potential and retention capacity [186]. With the aid of a mathematical transport model developed, it was concluded that there was an increase in water relative permeability from 1.6 to 2.1 times its initial values. However, a reduction in absolute permeability was also observed [186]. In another related research conducted by [187] through simulations on the absolute permeability sweeping and displacement efficiencies of LHP nanoparticles, a concentration less than 0.03 was deemed suitable for application-enhanced oil recovery. Recently, a study was conducted with the combination of an external electric field and nanoparticles on a carbonate reservoir to improve the transport of nanoparticles through the cores. Copper (II) oxide (CuO), Nickel (II) oxide (NiO), and Iron (III) oxide (Fe_2O_3) were deployed simultaneously with constant 2 V/cm application, with anode as injector and cathode as producer [192]. From the results, NiO had the highest recovery of 80.31% followed by CuO, with 69.70%, and lastly Fe_2O_3, with a 52.80% increase in the absence of an electric field. When 2 V/cm was applied, the recovery was 80.49%, 81.83%, and 62.77% for NiO, CuO & Fe_2O_3 respectively. This indicates that electric field application alongside nanofluid flooding is practical and efficient in improving oil recovery and the properties of the nanoparticle such as density, conductivity, and dielectric constant, play a determinant role as well. The dielectric constant is a measure of the capacitance of a material relative to a vacuum. The exposure of this material to an electric field makes them undergo polarization which leads to capacitance enhancement. CuO, being a dielectric material, was influenced most and recorded increase of 12.13% due to applied voltage, followed by Fe_2O_3 (9.94% increase) and NiO (0.18% increase).

4.1. Discussion

The power of oil displacement in the development process of water injection is primarily given by the driving pressure differential, capillary force, and gravity. Capillary forces in the matrix are primarily responsible for spontaneous infiltration and oil drainage during the formation of steady water injection. This phenomenon, however, is only visible when the reservoir is moist, and it has the characteristics of quick speed and low efficiency. Sandstone reservoir wettability can be increased by modifying the characteristics of injected water (such as low-salinity treatment and carbonation). The poor efficiency of spontaneous imbibition and oil drainage is mostly due to the high pore-throat ratio and oil-water viscosity ratio. Water drive and gravity are the major elements in a fracture system, and the technique of water injection used has a significant impact on oil recovery. Based on literatures unstable water injection is an excellent method for improving the recovery of cracked carbonate reserves. The residual oil may be retrieved successfully by changing the direction of the flow field and raising the spreading coefficient.

The viscosity of crude oil and the production of channelling are two limiting variables that impact the development of sandstone reserves. When crude oil has a high viscosity, steam injection and thermal recovery are frequently employed to lower the viscosity of crude oil. The use of a surfactant reduces the oil-water interfacial tension and improves washing efficiency. Polymer injection has the potential to raise the sweep coefficient and so block the channel. Foam-type plugging agents and particle-based plugging agents improve plugging capacities. Deep plugging can be accomplished by transporting particle plugging agents in foam. The difficult formation circumstances of sandstone reservoirs, on the other hand, frequently have a significant influence on the performance of chemical agents, and the development of temperature- and salt-resistant surfactants and polymers is an important challenge. Similarly, the usage of nanoparticles can have a beneficial synergistic impact on chemical agents, and the chemical process of adding nanoparticles will be studied further.

Overall, EOR in sandstone reservoirs is a methodical endeavour. Reasonable acidizing and fracturing techniques should be used to safeguard reservoirs, Acidizing is the process of pumping acid into a well to dissolve the rocks and increase the permeability of the formation, allowing oil and gas to flow more freely. It is important to use the appropriate type and concentration of acid, as well as to ensure that the acid is pumped at a safe rate to prevent damage to the wellbore and reservoir. In addition, it is important to consider the environmental impact of these techniques. Acidizing and fracturing can both potentially contaminate groundwater if not done properly and can lead to the release of harmful chemicals into the environment. Therefore, it is crucial to use reasonable techniques that prioritize safety and environmental protection. The use of reasonable acidizing and fracturing techniques can help to safeguard reservoirs, while also ensuring that production can be maximized in a safe and responsible manner. Furthermore, new injection media, intelligent optimization, and other backup technologies should be created as soon as possible. Production control should be carried out during the development of natural energy drives to prevent premature channelling. In the early stages of water and gas injection development, injection, and production well patterns should be established based on the reservoir unit's type, connectivity, and spatial location to improve the control effect of water and gas injection and the degree of oil production while reducing remaining oil reserves. In the middle and late stages of water and gas injection development, it is necessary to strengthen oil well control based on the main control factors and the distribution characteristics of the remaining oil, as well as to use measures such as gravity drainage and spontaneous infiltration and drainage to disturb (reform) the flow field. Chemical Enhanced oil recovery (C-EOR) technology research cannot be overlooked; these technologies can, to some degree, replace water injection and gas injection and maximize the oil output of carbonate reservoirs. Finally, a flexible and faultless development plan and the technical system should be built in conjunction with current approaches such as artificial intelligence to accomplish the cost-effective development of carbonate reservoirs and boost the growth of the world's petroleum sector.

5. Conclusion and Future Prospect

In oil and gas industries, the recovery of the oil production of the microscopic displacement effectiveness in the reservoir rock system is contacted by the displacing fluid and the volumetric sweep efficiency. This review work did a rigorous review of the parameters affecting the oil recovery, primary, secondary, and tertiary recovery procedures. This study highlights the effect of porosity, permeability, temperature, reservoir pressure, fluid viscosity, wettability alteration, fluid displacement efficiency, mobility factors, fluid-rock interactions, and fluid volume in the oil recovery factor. This review discussed the influence of the mobility factor in oil recovery, which stated that the basic mechanics of oil displacement by water could be understood by considering the mobilities of the separate fluids. In oil reservoir conditions, capillary force is assumed to regulate fluid movement in the reservoir. In the future, we propose the following prospective research directions. Surfactant structure, additives, and environmental conditions (salt, temperature, pH) could have a substantial

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influence on microemulsion properties, which are thermodynamically stable, optically transparent, and isotropic dispersions of two immiscible liquids (usually oil and water) stabilized by an interfacial film of surfactant molecules and sometimes co-surfactants. They typically have droplet sizes ranging from 10 to 100 nm, making them highly attractive for a range of applications, including drug delivery, chemical synthesis, and enhanced oil recovery.

- Surfactant structure, additives, and environmental conditions (salt, temperature, pH) all substantially influence microemulsion properties, which impacts its application on IOR.
- The adsorption of surfactants is a significant barrier to using microemulsions in forms. An anionic surfactant or its compound system is frequently utilized, and pre-fluid is usually injected to decrease adsorption.
- Different chemical floodings agents such as nanoparticles, foam, polymer, and alkali affect the EOR mechanisms and their displacement efficacies.
- Issues exacerbated by severe reservoir conditions typically complicate surfactant flooding. These issues mainly concern surfactant adsorption and instability at high (or standard) temperatures and salinities. Consequently, researchers established criteria for surfactant screening based on reservoir conditions and rock type. Based on this recommendation, surface adsorption should not exceed 1 mg/g rock. Furthermore, the surfactant under consideration should be capable of reducing the oil-water IFT to 0.01-0.001 dynes/cm. Moreover, the surfactant should be effective at low concentrations ranging from 0.1 to 0.3 percent. If the concentration limit is exceeded, the economic feasibility of surfactant flooding may be jeopardized.
- In the form of nanofluids, nano-emulsions, and Nano-catalysts, NPs offer enormous promise for EOR. The application procedures determine their EOR techniques. Nanofluids can be utilized as a tertiary recovery technology to boost oil recovery from floods caused by water or gas. Nano catalysts are constantly employed with thermal EOR procedures to execute in-situ upgrading inside reservoirs via aqua thermolysis. Nano-emulsions offer a broader range of applications, including water, gas, and chemical flooding.

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