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**Experimental investigation on the effect of SiO₂ in
enhanced oil recovery**

Bachelor thesis

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Experimental investigation on the effect of SiO₂ in enhanced oil recovery

Anotace:

Pro zvýšení výtěžnosti ropy se používá řada chemických roztoků jako účinných látek intenzifikujících terciální metody těžby (EOR). Tradiční chemická řešení EOR se na druhé straně setkávají se značnými problémy a překážkami při mobilizaci a surové ropy v porézních horninách. Nanofluida (kombinace nanočástic a tekutin) mají v aplikacích EOR v současnosti rostoucí využití. V této práci byly pro přípravu nanofluid použity nanočástice (NP) oxidu křemičitého. Tato nanofluida s 250, 500, 1000 a 2000 ppm NP byly podrobeny různým teplotně závislým testům, včetně měření pH, viskozity, hustoty, vodivosti, mezifázového napětí (IFT), kontaktního úhlu (CA) a testování výtěžnosti na vrtném jádru. Výsledky ukazují, že použitá nanofluida mají vysokou stabilitu a že IFT a kontaktní úhel se snižují se zvyšující se koncentrací NP. Kombinace ropy a nanotekutin při koncentraci 2000 ppm NP v destilované vodě má nejnižší IFT. Stejná nanokapalina má zároveň nejlepší výkon při minimalizaci kontaktního úhlu, který je 65,5°. Nanofluida vyrobená z 2000 ppm NP a vody byla aplikována na vrtná jádra. Nanofluidum na bázi DW zlepšuje výtěžnost ropy ze 44 na 65.42% OOIP při použití v terciálních metodách těžby.

Klíčová slova: mezifázové napětí; stykový úhel; oxid křemičitý; regenerace ropy; vylepšená regenerace oleje

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To improve oil recovery, several chemical solutions have been used as effective agents for enhanced oil recovery (EOR). Traditional chemical EOR solutions, on the other hand, encounter considerable problems and hurdles in mobilizing and displacing crude oil in porous media. Nanofluids (a combination of nanoparticles and fluid) are now used in EOR applications. In this work, silica nanoparticles (NPs) were used to prepare EOR nanofluids. The nanofluids with 250, 500, 1000 and 2000 ppm of the used NPs were subjected to a variety of temperature-dependent tests, including pH, viscosity, density, conductivity, interfacial tension (IFT), contact angle (CA), and core flooding. The results reveal that the produced nanofluids have high stability, and that the IFT and contact angle decreased as the NPs concentration increases, the oil/nanofluid combination generated by combining 2000 ppm NPs in distilled water has the lowest IFT; nevertheless, the same nanofluid has the highest performance in minimizing the contact angle, which is 65.5°. Tertiary recovery phase, nanofluids made from 2000 ppm NPs and water are introduced into the core plugs. DW-based nanofluid improves oil recovery from 44 to 65.42% OOIP when employed in tertiary recovery.

Keywords: interfacial tension; contact angle; silicon dioxide; oil recovery; enhanced oil recovery

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I declare that this dissertation is the result of my own work, except where explicit reference made to the contribution of others.

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.....

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Nomenclature and abbreviation

EOR	Enhanced Oil Recovery
SiO₂	Silicon Dioxide (Silica)
ZnO	Zinc Oxide (Oxozinc)
NPs	Nano Particles
IFT	Interfacial Tension
SCF	Standard Cubic Feet
M	It Represents One Thousand
MM	It Represents One Million
MMM	It Represents One Billion
STB	Stock-Tank Barrel
Bo	Oil Volume Factors
Bg	Gas Volume Factors
Boi	Initial Oil Volume Factors
Bwi	Initial Water Volume Factors
Kro	Relative Permeability to Oil
Krg	Relative Permeability to Gas
Krw	Relative Permeability to Water
ϕ_t	Total Porosity
V_p	Pore Volume
V_b	Bulk Rock Volume
V_{ma}	Matrix Minerals Volume (Solid Volume or Grain Volume).
pH	Hydrogen Ion Concentrations

1. Introduction

It is obvious that the primary amount of oil collected from reservoirs natural driving energy would fall drastically following the discovery of new oil and gas sources. To meet the demand for hydrocarbons, several oil companies have enhanced oil recovery from depleted oil reserves. To increase the oil recovery factor, EOR technologies such as polymer nanocomposite flooding are applied (Gbadamosi et al., 2019). According to Zahiri and Choi. (2022) water flooding is the initial candidate option, and the secondary recovery procedure may remove up to 40% of the oil. However, more than 60% of the initial oil cannot be recovered due to challenges such as bypassing and inappropriate sweeping of the oil during water flooding. Materials like as nanoparticles (NPs) can be employed to improve the effectiveness of water flooding IFT by increasing reservoir rock wettability and decreasing oil/water interfacial tension. Nano-fluids consisting of nanoparticles and bulk liquid have attracted substantial attention in EOR due to the progress of nanomaterials. Some NPs in distilled water or low salinity water have proven to be effective in boosting oil recovery. Nanotechnology is becoming increasingly important in a variety of sectors, notably the petroleum industry. It has the ability to address critical difficulties in the oil industry. The generation of heavy oil is one of the most important challenges. The use of nanomaterials and nanoparticles in the oil and gas sector, as well as nanoscale process management, is crucial for enhancing oil and gas recovery (Raffa and Druetta, 2019). EOR is defined as the process of rejuvenating reservoir characteristics and enhancing oil output (Rahimi et al., 2022). Fluid properties such as viscosity, density, specific heat, and thermal conductivity change drastically when nanoparticles and nanomaterials are added. To gain an advantage in EOR, nanoparticles have the ability to affect some formation and oil properties. Using nanosensors, nanofiltration, and nanocatalysts, in situ fluid properties such as IFT reduction, fine fixation, and wettability modification may be achieved. Nanoparticles, in general, have properties that make them appropriate for the EOR process. Fine fixation, and wettability change may be accomplished by utilizing nano sensors, nanofiltration, and nano catalysts. In general, nanoparticles have certain features that make them suitable for the EOR process (Rahimi et al., 2022). It is simple changeable to enhance properties and increase oil recovery. They are both environmentally and economically favorable. They may move freely through porous material without blocking the pore throats. They can alter the interfacial tension between oil and water. Metallic nanoparticles are easily separated by magnetic separation. They create a wedge film or structural disjoining pressure to sweep the oil droplets from the rock surface. It is inexpensive to install. It has a high surface-

to-volume ratio, which enhances thermal properties (Panchal et al., 2021). According to (Raffa and Druetta, 2019), silicon nanoparticles are used since they are the most often used material in the experimental investigation of silica-based NP. Silica NPs are one of the most preferred for EOR applications because they are inexpensive to produce, have well-known physical-chemical characteristics, and can be customized to have qualities ranging from hydrophobic to hydrophilic. Furthermore, silica nanoparticles are one of the most abundant non-toxic inorganic materials, with a lower manufacturing cost than other nanoparticles. Several types of customized silica NPs have been developed. Polysilicon nanomaterials are classified into three types based on their wettability characteristics: lipophobic and hydrophilic polysilicon, hydrophobic and lipophilic polysilicon, and neutral-wet polysilicon. They also discovered that when polysilicon NPs were adsorbed on the surface of a porous surface, they might affect its wettability (Gbadamosi et al., 2019).

1.1 Research objectives

The purpose of this study is to look at the impact of different concentrations of nanoparticle additives in the process of oil recovery. Hence, four specific amounts of nano-silica (SiO_2) in smart water and the smart nanofluid system are used as chemical substances in the processes of EOR. After that, examine the effects of the quantified SiO_2 in the process of EOR.

Moreover, the objectives of this research are as follows:

- Effect of nano-silica (SiO_2) on IFT
- Effect of nano-silica (SiO_2) on wettability alteration
- Effect of nano-silica (SiO_2) on recovery factor

1.2 Report outlines

This report is divided into five sections. The first section has an introduction, objectives, and a report outline. Background and a liturgical review are included in section two which include (reservoir rock properties, porosity, permeability, saturation, capillary pressure, oil recovery mechanism, chemical EOR, EOR mechanisms, Nanotechnology). The material and procedures utilized in this study are covered in section three. Results and discussion are included in section four. The last section includes a conclusion and further recommendations.

2. Background

This section seeks to clarify the terminology used throughout the book to the reader by providing context for the words and describing how the concepts interact. Look at Figure 1, which displays a cross-section of a producing petroleum reservoir, before digging into these ideas. A reservoir is not a big underground cavern full of oil and gas. It is instead a section of porous rock beneath an impervious layer of rock that has collected significant volumes of oil and gas in the minute void spaces that weave through the rock. The oil, gas, and water are trapped behind the impermeable rock (Bliefnick and Kaldi, 1996).

Aminzadeh et al. (2013) define porosity as the proportion of vacuum space in a rock that is filled by reservoir fluid. The density of reservoir fluids is used to classify them. Oil specific gravity (ρ_o) is the ratio of the density of oil to the density of water, whereas gas specific gravity (ρ_g) is the ratio of the density of natural gas to the density of air (S_g). Gas is near the top of the reservoir because it has a lower density than oil, and both have a lower density than water. The horizontal interface between two reservoir fluid phases is referred to as a contact. If there is no oil phase, the contact between gas and oil is called a gas-oil contact, the contact between oil and water is called an oil-water contact, and the contact between gas and water is called a gas-water contact. Connate (or interstitial) water is a minute quantity of water that lingers in the reservoir's oil and gas zones. The volume of fluid in a reservoir at the start is crucial. In practice, the sign N (from the Greek word naphtha) represents the reservoir's initial volume of oil as a standard surface volume, such as a stock-tank barrel. The starting reservoir gas and water are denoted by G and W , respectively. The subscript p is appended when these fluids are created to show the total amount of oil (N_p), gas (G_p), or water (W_p) produced (Bliefnick and Kaldi, 1996). The entire reservoir volume is fixed and determined by the area's geological formations. Both the rock and the fluid left in the reservoir expand when reservoir fluid is generated and reservoir pressure falls. If only 10% of the fluid is created, the remaining 90% in the reservoir must expand in order to fill the full reservoir void space. When a hydrocarbon reservoir comes into touch with an aquifer, both the hydrocarbon fluids and the aquifer water expand as hydrocarbons are created, and water entering the hydrocarbon space can replace the volume of produced hydrocarbons (Sun et al., 2017).

A volume factor (B) is employed to account for all reservoir fluid when pressure changes. The volume factor is a ratio of the fluid's volume in the reservoir to its volume at atmospheric circumstances (typically 60°F and 14.7 psi). At these atmospheric circumstances, oil volume is measured in STBs (one barrel is equal to 42 gallons) (Aminzadeh et al., 2013). The volume

of gases produced is measured in standard cubic feet (SCF). The units SCF are usually preceded by a M (1000), MM (1 million), or MMM (1 billion). If only liquid phases are present in the reservoir, the oil and water volume factors (B_o and B_w) will begin at the initial oil volume factors (B_{oi} and B_{wi}) and gradually grow (by 1%–5%). When the saturation pressure is attained, and gas begins to emerge from the solution, the oil volume factor decreases. As reservoir pressure falls, gas volume factors (B_g) will grow significantly (10-fold or more). The volume factor changes for a measured change in reservoir pressure enables for straightforward estimate of the starting gas or oil volume (Sun et al., 2017). As stated by (Deich, 2015) Furthermore, when the well fluid reaches the surface, it is separated into gas and oil.

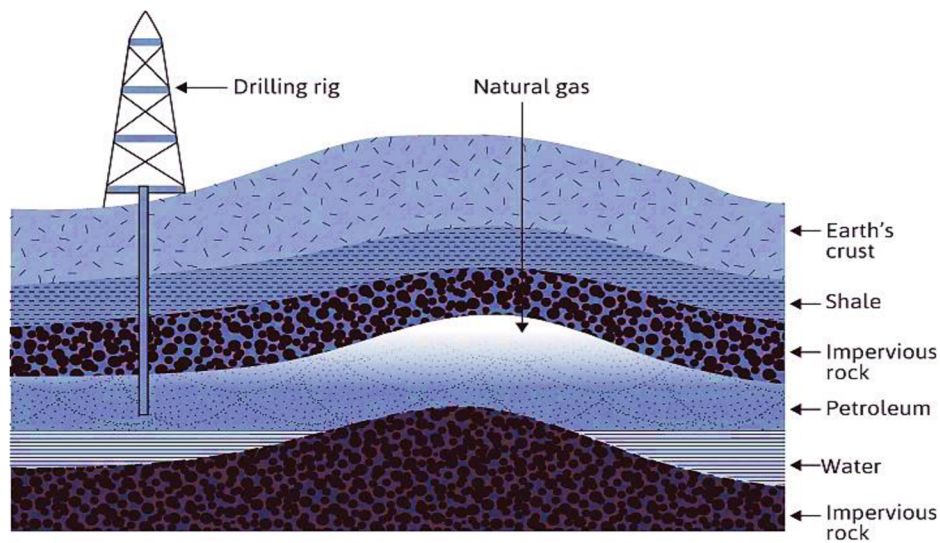


Figure 1 Illustration of the occurrence of petroleum under the earth's surface (Terry et al., 2014).

2.1 Reservoir rock properties

- **Porosity**

Porosity is defined as the ratio of pore volume (or void space) in a reservoir's rock to its total volume (bulk volume), given as a percentage (Dandekar, 2013). In general, the porosity of a particular rock sample should be divided into five kinds, as it illustrated in Figure 2. Hence, the types of porosity are stated below: total porosity (t) refers to all voids inside the rock, whether linked or isolated. Connected porosity (c) refers to the portion of the total porosity that is interconnected through the pore throats. Effective porosity (e) is that part of connected porosity that is accessible to free fluids, excluding non-connecting porosity and the volume occupied by swelled clays, and thus is smaller than connected and total porosity. Dead-end pore spaces (Dead) are that part of connected porosity that is not accessible for fluids, and isolated pore spaces (iso) are that part of total porosity that is isolated away from the fluid path.

It can also be found as an intracrystalline, intragranular, or intraparticle inside grains, crystals, or fossil remnants.

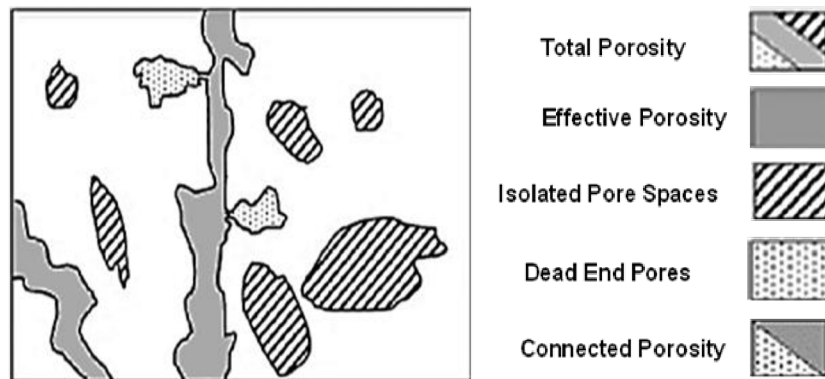


Figure 2 Schematic illustration of the main types of porosity (Dandekar, 2013).

- **Permeability**

Permeability is primarily a flow attribute (dynamic) and can only be determined by conducting flow experiments in a reservoir rock. Permeability of a rock filled with a single fluid differs from the permeability of the same rock when filled with two or more fluids (Dandekar, 2013). Figure 3 depicts the extremely low permeability with few pore spaces, the low permeability with disconnected pore spaces, and the high permeability with linked pore spaces. The ratio of effective permeability to relative permeability is defined as relative permeability of oil, gas, or water to absolute permeability. Relative permeability can be stated as a number between 0 and 1.0 or as a percentage (Ahmed, 2010). The oil and water relative permeability curves' crossover point is frequently suggestive of the porous material's water or oil moist nature. When crossover happens with $S_w > 0.5$, this is termed a water-wet system (Wheaton, 2016), and when $S_w < 0.5$ it is classed as oil wet.

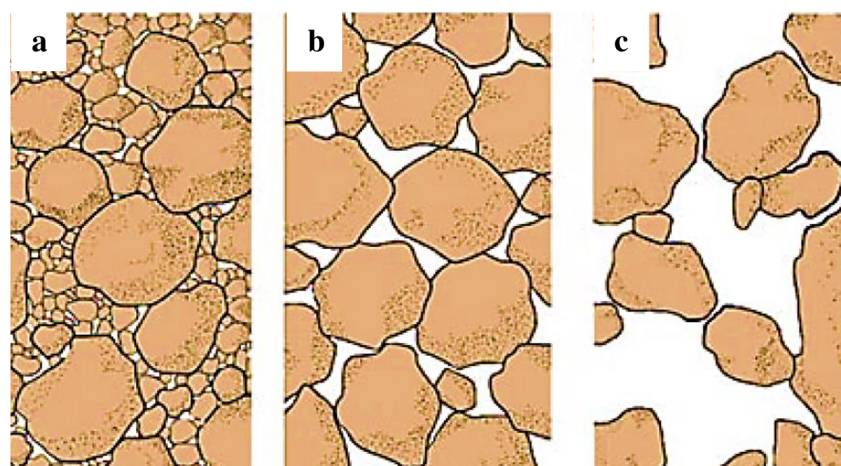


Figure 3 Permeability; a) very low permeability, b) intermediate permeability, and c) high permeability (Wheaton, 2016).

- ***Saturation***

Most oil formations are thought to have been entirely saturated with water prior to oil migration and entrapment. Less dense hydrocarbons move to places of hydrostatic and dynamic equilibrium by displacing the original water. The oil will not displace all the water that was previously in pores (Zhang, 2019). Saturation is defined as the fraction, or percentage, of pore volume occupied by a certain fluid (oil, gas, or water). This attribute is mathematically represented as follows:

$$\text{Fluid saturation} = \frac{\text{total volume of the fluid}}{\text{pore volume}} \quad (\text{Eq.1})$$

The saturation of each individual phase goes from 0% to 100%. The oil must surpass a threshold for the oil to flow. All saturations are calculated using pore volume rather than reservoir gross volume. This means that the oil stays in the pores and does not flow. According to Zhang (2019), Saturation of mobile oil is another saturation of importance (S_{om}) which is defined as the proportion of pore volume filled by mobile oil as stated by the equation below:

$$S_{om} = 1 - S_{wc} - S_{oc} \quad (\text{Eq.2})$$

where,

S_{om} , mobile oil saturation.

S_{wc} , connate (interstitial) water Saturation

S_{oc} , oil Saturation.

Saturation of connate (interstitial) water is significant because it decreases the amount of space available across oil and gas reservoirs. Another phase saturation of relevance is the critical saturation, which is unique to each reservoir fluid. The critical saturation for each phase is defined and explained in detail below (Zhang, 2019). The gas phase stays immobile until its saturation surpasses a particular saturation, known as critical gas saturation. At this point, the gas begins to move beneath the reservoir's surface (Zhang, 2019). The terms critical water saturation, connate water saturation and irreducible water saturation are used to refer to different levels of water solubility (Ahmadi et al., 2022).

- ***Capillary pressure***

Capillary pressure (P_c) is lower in high-permeability rocks with proportionally broad pore radius. Capillary pressure cannot be monitored directly in a reservoir. However, capillary pressure is frequently assessed by doing centrifuge tests on water reservoirs. Capillary pressure measurements are utilized in reservoir engineering to determine two main essential phenomena in the reservoir, which are stated below. Capillary pressure is particularly significant in

explaining fluid flow from fractured reservoirs because it governs the flow of fluids between the crack and the rock matrix.

Hence, capillary pressure is proportional to IFT, contact angle, and pore radius as follows:

$$P_C = \frac{2\sigma \cos \theta}{r} \quad (\text{Eq.3})$$

where,

p_C , Capillary pressure [dynes/cm²]

r , Pore radius [cm]

σ , Interfacial (or surface) tension [mN/m or dynes/cm]

θ , Contact angle [degrees]

The formula above illustrates that capillary pressure in reservoirs is affected by, the IFT between two immiscible fluids The contact angle between rock and fluid, in which it is the function of wettability. And, pore radius (r), a microscopic rock feature. A drop in P_c is caused by an increase in pore radius.

2.2 Oil recovery mechanisms

The absence of sufficient natural drive in most reservoirs has led to the practice of augmenting natural reservoir energy with some type of artificial drive. The most basic of which is the injection of gas or liquid into the reservoir, such as water and/or hydrocarbons (Gbadamosi et al., 2019). In addition, Gbadamosi et al. (2019) Oil recovery refers to the increased recovery that occurs because of the traditional procedures of water injection and immiscible gas injection. The specified secondary recovery procedure is usually carried out after the primary recovery, although it can alternatively be carried out concurrently with the first restoration. Water flooding is the most popular secondary recovery strategy. Though, Ahmed. (2010) Major cause of oil entrapment in porous media is a restriction on oil mobility. Critical force for oil displacement decreases when reservoirs are depleted. Oil adsorption on rock surfaces traps oil inside rock pores, resulting in 50–80% of oil remaining in the reservoir. The amount of residual oil is limited, and because of industrial innovations, global energy consumption has skyrocketed. EOR technologies are critical to expanding oil output from hydrocarbon sources (Mehrjoo et al., 2022). Moreover, Figure 4 shows the diagram of the oil recovery processes, from primary recovery then secondary recovery, hereafter the tertiary recovery stage. Besides, typical methods of each stage are stated.

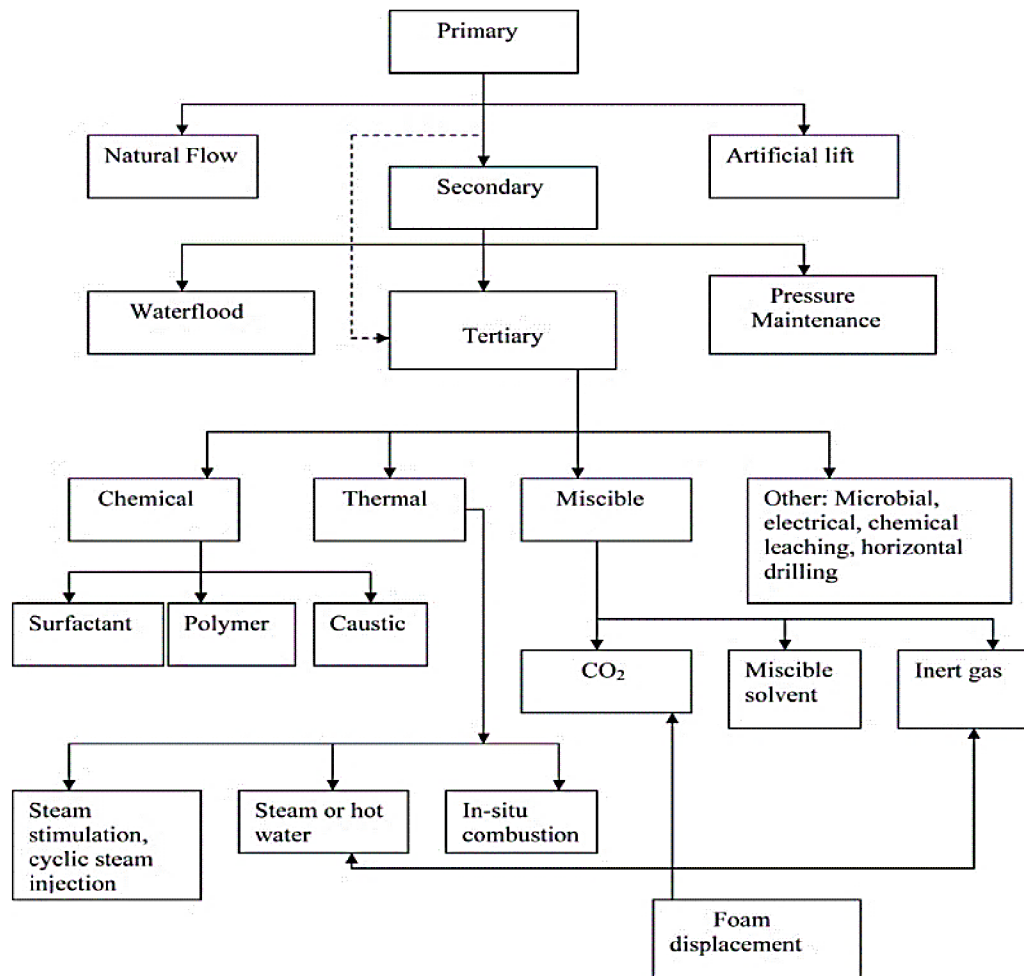


Figure 4 Oil recovery methods and techniques from the primary to the tertiary phase (Adeniyi, Nwalor and Ako, 2008).

2.3 Chemical EOR

The enhanced oil recovery by definition is the oil recovery by injection of chemicals or gases and/or thermal energy into the reservoir (Sheng, 2011). Tertiary oil recovery, also recognized as enhanced oil recovery (EOR), is the third stage of oil extraction from a reservoir. It is a costlier and typical method illustrated in Figure 5. Tertiary recovery involves primarily gas or chemical injections, and thermal recovery (Maroufi et al., 2013). Besides, the residual oil after water flooding is (60-70) percentage, depending on the physical-chemical methods used to displace it, and this is referred to as tertiary oil recovery (Li et al., 2017). According to Sheng. (2011) almost all chemical enhanced oil recovery has been conducted in sandstone reservoir. Except for a few stimulation experiments and a fewer that not been published have been performed in carbonate reservoir. This is due to the reason that the anionic surfactants have high adsorption in carbonates reservoir. Other reason is that the anhydrite presents in

carbonate reservoir, which cause precipitation and high alkaline consumption. Besides, clays cause high polymer and surfactant adsorption and high alkaline consumption. As a result, contents of clay must be low for a chemical enhanced oil recovery application to be effective. Further, Sheng. (2011) has stated that the formation water divalent and salinity are critical to chemical enhanced oil recovery processes, for both polymers and surfactants. Chemical EOR has been regarded as the most promising of the many EOR technologies. Despite recent breakthroughs in low surfactant concentrations and inexpensive chemical additive prices, chemical flooding remains vulnerable to the volatility of oil markets. microbial flooding and, more recently, Nano fluid flooding are also important CEOR approaches (Raffa and Druetta, 2019). Chemical Engineered Recovery of Oil (Chemical EOR) has significant limits, despite its great stated efficiency and recognized promise. Most of the newly produced compounds have been abandoned since they were shown to raise the total cost of the EOR process by a large amount (Gbadamosi et al., 2019). Nano-fluids have the potential to be the future of heat transfer fluids in a variety of heat transfer applications. Dispersed nanoparticles with high thermal conductivity are projected to provide higher thermal performance than traditional fluids. Numerous studies have recently shown the increase in thermal conductivity and greater heat transfer rate of Nano fluids. Several studies have found significant increases in heat transfer rates with the use of different Nano fluids in diverse applications as compared to traditional fluids. Understanding the characteristics of Nano fluids, such as thermal conductivity, viscosity, and specific heat is critical for their use in a variety of applications (Bhanvase et al., 2018).

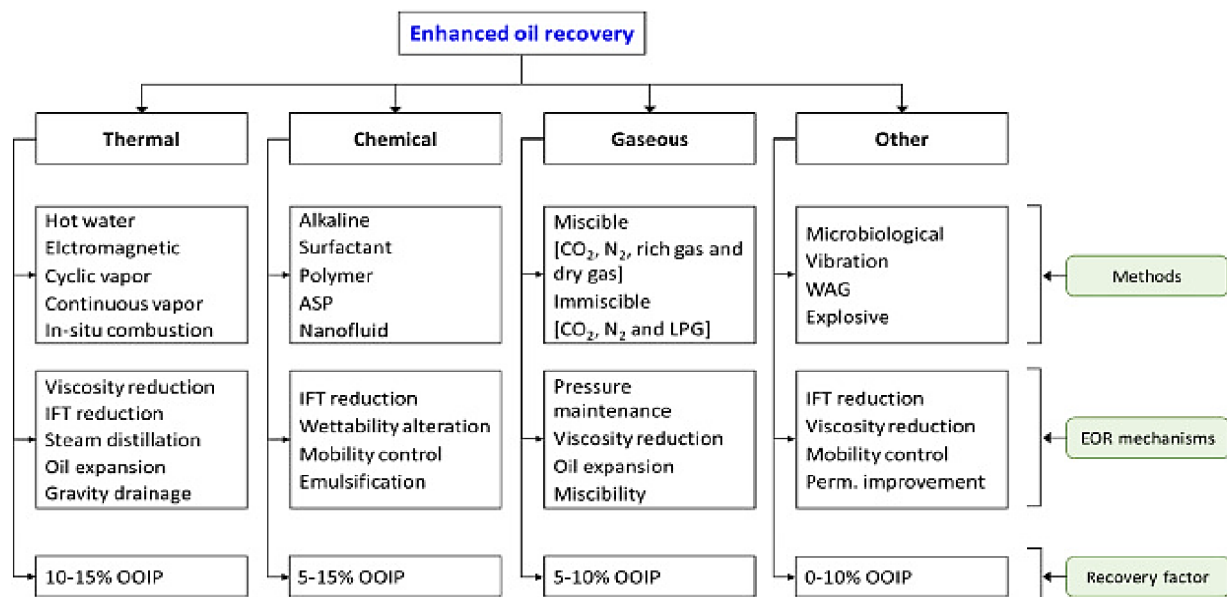


Figure 5 Tertiary recovery involves primarily gas or chemical injections, and thermal recovery (Colombo et al., 2019).

2.4. EOR mechanisms

2.4.1. IFT reduction

Water cannot displace all the oil in the pore scale during secondary recovery by water flooding due to capillary pressures retaining the oil. This capillary force is quantified by a dimensionless capillary number (N_c) which is defined in Eq. (4) as follows:

$$N_c = \frac{\mu \cdot v}{\sigma \cdot \cos(\theta)} \quad (\text{Eq.4})$$

where,

μ , is the viscosity of the displacing fluid.

v , is the Darcy velocity of the displacing fluid.

θ , is the contact angle and is the IFT between the displacing fluid (water) and the displaced (oil).

Increasing N at from this value to a range decreases residual oil saturation to a bare minimum and increases the oil recovery factor. According to Eq. (4), it may be accomplished in three ways: Raising the viscosity of the displacement fluid (v), increasing the injection fluid velocity (v) and decreasing the IFT. Surfactants are used to increase concentration by 1000 times in practice. Increasing the displacing fluid viscosity with polymer solutions raises capillary number by fewer than 100 times. Figure 6 illustrates decrease and increase of interfacial tension (IFT) Kumar and Mandal (2017).

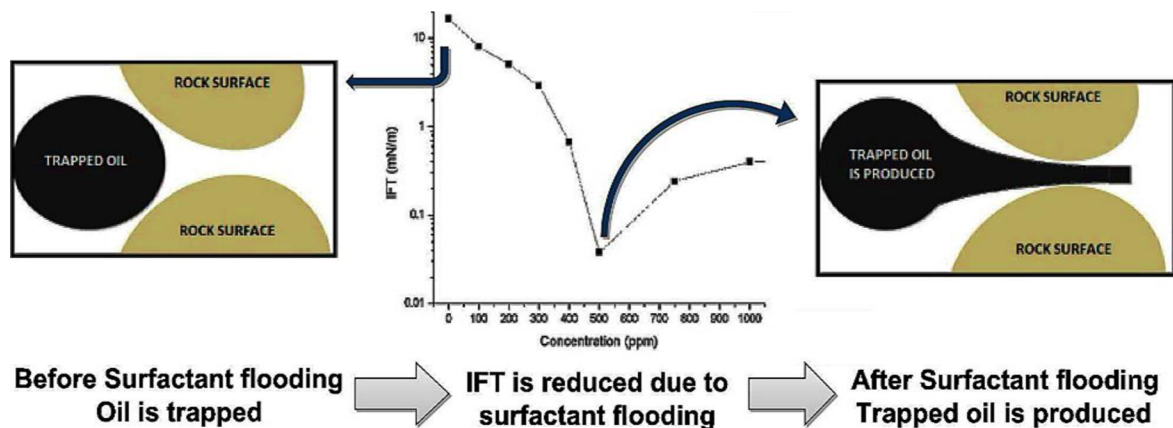


Figure 6 IFT values of zwitterion surfactant reported by Kumar and Mandal (2017).

2.4.2. Wettability alteration

According to Mohammed and Babadagli (2015) wettability refers to a solid surface's proclivity or inclination for a specific fluid type in the presence of other immiscible fluids. It dictates and controls the location, distribution, and flow of fluids within a reservoir rock system. Besides, wettability is a significant petrophysical property because it affects oil recovery parameters such as capillary pressure and relative permeability. In addition, Christensen and Tanino (2017) Contact angle measurements are used to assess whether a rock surface is water- or oil-wet. Contact angle is defined as the point where the interface of the oil and water surfaces meet. Surface imaging tests, zeta potential measurements, spontaneous imbibition and contact angle measurements can all be used to measure this property (Alhammedi et al., 2017). Figure 7 illustrates effect of nanofluid injection on wettability and oil-recovery of originally oil-wet reservoirs. As a result, oil recovery is more easily achieved in water-wet reservoirs than in oil-wet reservoirs (Kułynycz, Pikłowska and Kulynych, 2018).

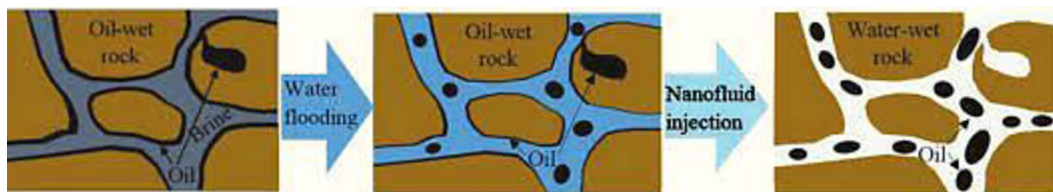


Figure 7 Effect of nanofluid injection on wettability and oil-recovery of originally oil-wet reservoirs (Kułynycz, Pikłowska and Kulynych, 2018).

2.5 Nanotechnology

Nanotechnology is the study of materials and devices whose most minor functional organization, in at least one dimension, is on the nanoscale scale, or one billionth of a meter. At these scales, consideration of individual molecules and interacting groups of molecules with the bulk macroscopic properties of the material or device becomes essential (Saini et al., 2010). Nanotechnology refers to any technology on the nanoscale (one billion times smaller than a meter) that has various real-world applications. It is the manufacturing and use of chemical, physical, and biological systems at sizes ranging from individual molecules or atoms to submicron dimensions (Nasrolla et al., 2019). Nanotechnology has opened up a range of new fields of technology, including nanomedicine, biosensors, and bioelectronics. It can solve problems in catalysis, medicine, solar energy conversion, and water purification (Kanwar et al., 2019).

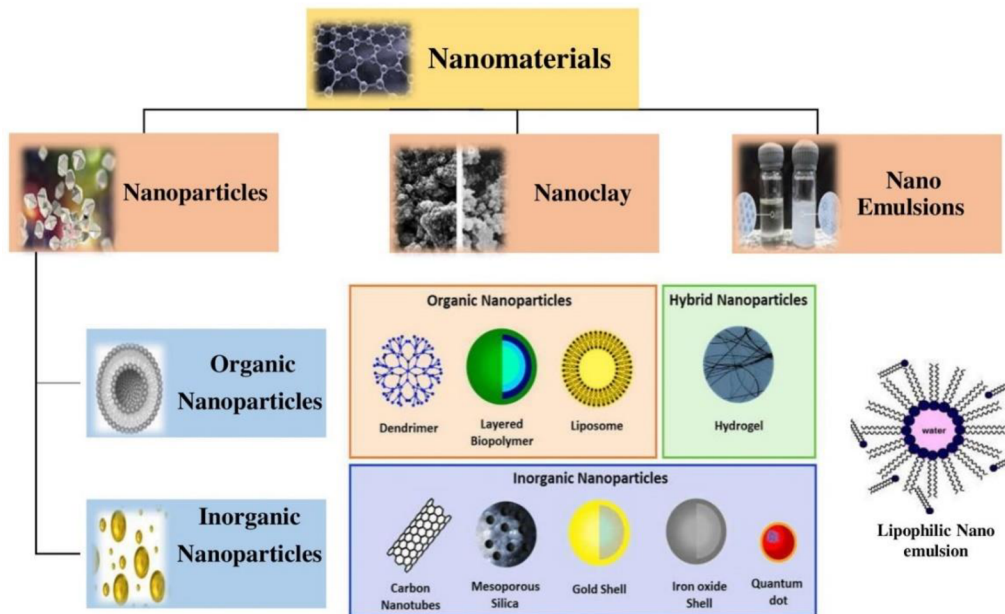


Figure 8 Types of nanomaterials used in oil and gas industry (Sircar et al., 2021).

2.5.1. Effect of nanomaterial on IFT reduction

NPs form a thin layer atop the surfactant, which spreads oil and injected fluids. Capillary numbers grow while capillary forces decrease dramatically throughout this process (Rosen et al., 2005). Several research studies stated that NPs increase surfactant fluids and the rheological characteristics of injection solutions for oil recovery. Data are illustrated in Figure (9) (Kumar et al., 2018). Barati and Kharrat (2014) Nanosuspension surfactants (NSS) form a thin layer atop the surfactant, which spreads oil and injected into a reservoir. The critical micelle concentration (CMC) plays a vital role in determining the optimal quantity of NP-surfactant. Adsorption on the reservoir rock surface is significantly reduced in the presence of hydrophobic NPs compared to silica NPs. Another study conducted by Barati and Kharrat (2015) revealed that at the stability of hydrophilic TiO_2 NPs in polyvinylpyrrolidone for the EOR process. The TiO_2 -based nanofluid showed good wettability alteration and significantly lowered the IFT between the aqueous and oleic phases. In a similar study conducted by Hendraningrat and Zhang (2015) Table 1 shows some experimental studies that indicate the effect of NPs on IFT. Figure (2-10) @ ambient temperature, displays the decrease in IFT between the surfactant solution and crude oil and the wettability change. It shows how the presence of NPs between interfacial layers reduces IFT. Low NP concentrations facilitate absorption and lowering surface tension. At high concentrations, nanoparticles almost cause surfactant depletion in the bulk aqueous solution (Xu et al., 2019).

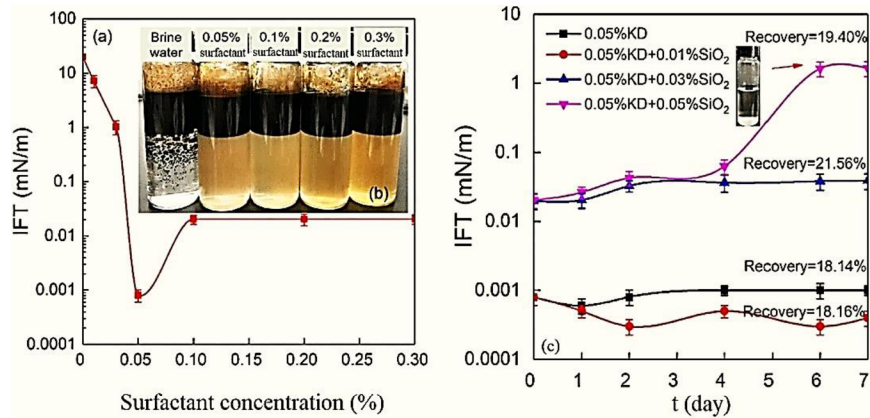


Figure 9 (a) IFT Between Surfactant Solutions and Oil at 80 °C. (b) Emulsion Stabilization Image after 24 h at 80 °C. (c) IFT Stability of surfactant-based nano-SiO₂ Solutions at 80 °C (Xu et al., 2019).

Table 1 stating the summarized data of conducted experiment by the following researchers: Joonaki and Ghanaatian (2014a); Joonaki and Ghanaatian (2014b); Joonaki and Ghanaatian (2014c); Li et al. (2017); Azarshin et al. (2017); Betancur et al. (2020); El Shafey (2017), Moslan et al. (2017); Hethnawi and Nassar (2020); Ali et al. (2019); Manshad et al. (2020); Davoodi et al. (2022).

Besides, table (1) affirms the types of NPs and their quantity used in the experiment by each researcher. In addition, the attained values of IFT alone and IFT with NPs, of each experiment are stated. The data are stated in table (1) experimentally obtained by different researchers from 2014 to 2022.

Table 1 Effect of NPs on IFT.

NPs	NPs concentration	IFT (mN/m)		Reference
		without NPs	with NPs	
SiO ₂	1 – 4 g/L	26.5	1.95	Joonaki & Ghanaatian (2014a)
Al ₂ O ₃	0.5–3 g/L	38.5	3.5	Joonaki & Ghanaatian (2014b)
Fe ₂ O ₃	3 g/L	38.5	2.7	Joonaki & Ghanaatian (2014c)
Cnp	0.1 wt. %	26.2	13.4	Li et al. (2017)
SiO ₂	1 wt. %	37.5	22.1	Azarshin et al. (2017)
Iron core–carbon shell	100 mg /L	10.72	2.7	Betancur et al., (2020)
Hlp	0.05 wt. %	18.4	5.4	El shafey (2017)
ZrO ₂	0.05 wt. %	9.88	2.78	Moslan et al. (2017a)
Hydroxylated nano Pyroxene	50 ppm	20.6	10	Hethnawi & Nassar (2020)
ZrO ₂	10–500 mg/L	9.13	2.64	Moslan et al. (2017b)
Zno/SiO ₂	2000 ppm	28.3	2.016	Ali et al. (2019)
Cuo/Fe ₃ O ₄	2000 ppm	24	4.5	Manshad et al. (2020)
SiO ₂	2000 Ppm	30	2.28	Davoodi et al. (2022)

2.5.2 Effect of nanomaterials on Wettability alteration

Wettability modification and its applications are one of the most challenging issues in subsurface engineering. The wettability of reservoir rocks influences fluid distribution in oil reservoirs and oil recovery throughout the EOR process (Rostami et al., 2020). According to Kuang and Piri (2019) The influence of silica NPs on wettability modification has a significant impact on enhanced oil recovery. A moist surface boosts the imbibition process into medium and small-sized pores, whereas a lower IFT promotes the drainage process and lowers entrance pressures. Skauge et al. (2010) studied silica nanoparticles and stated that silica nanoparticles are one of the most frequently utilised materials for modifying wettability. Besides, their study showed nano-sized silica particles' behavior in oil mobilisation. They also investigated the microscopic process of flow diversion using colloidal gel dispersion. Another study conducted by Skauge et al. (2010) in which discovered that polysilicon NPs (PSNP) had the potential to affect the wettability of rocks. Their findings reveal that organically treated hydrophobic and lipophilic PSNP (HLPN) chemicals boost oil recovery in water-wet rocks by more than 50%. Additionally, Ju and Fan (2009) investigated the capacity of nano powders to modify wettability for EOR in a similar study. The results show that using lipophobic and hydrophilic polysilicon NPs may shift the wettability of reservoir rocks from oil-wet to water-wet. Besides, absolute permeability decreases while effective permeability increases. Hendraningrat and Torsæter (2014) Hydrophilic NPs (in an optimum range) with altered wettability play a significant role in oil displacement on porous surfaces. SiO₂ nanofluid generates more oil from medium and small-sized pores due to reduced IFT. There are various experimental efforts in the oil recovery sector utilising hydrophilic silica NPs. Moreover, Figure (10) illustrates the digital microscope images of solution injection in the micromodel in which the pore-scale configuration and distribution of wetting and non-wetting phases within an initially preferential oil-wet medium for (a,b) surfactant solution and (c,d) surfactant and NP solution (Cheraghian et al., 2017). NP droplets are smaller than colloid droplets and may readily travel through reservoir rock holes and crevices. Because of their small average diameters, spherical fumed silica particles are commonly utilized. NPs can modify the wettability of the surface through silanol groups (Safari, 2014). The study conducted by Cheraghian and Afrand (2020) demonstrated that zirconium dioxide has the greatest potential among NPs for changing surface wettability during surfactant flooding and creating a water-wet surface. In the study conducted by Maghzi et al. (2010) revealed that the silica nanoparticles (NPs) minimize trapped oil in throats and pores while also increasing heavy oil recovery from reservoirs.

According to the study conducted by Rostami et al. (2019) silica NPs are an excellent alternative for altering wettability in polymer flooding, as well as increasing sweep efficiency and heavy oil recovery. However, in the case of light oil, the experimental findings showed that other NPs had stronger wettability alteration ability and IFT. Another study carried out by Ershadi et al. (2015) A study has shown that certain hybrids of carbon nanotubes and silica have potential to modify the wettability and rheological characteristics of injected fluids in reservoirs. In another study conducted by Ershadi et al. (2015) Additional nanoparticles (NP) have a more significant impact on modifying the nonwetting phase relative to permeability curves than the wetting phase in both drainage and imbibition processes. Table (2) shows some experimental studies (the influence of NPs on contact angle).

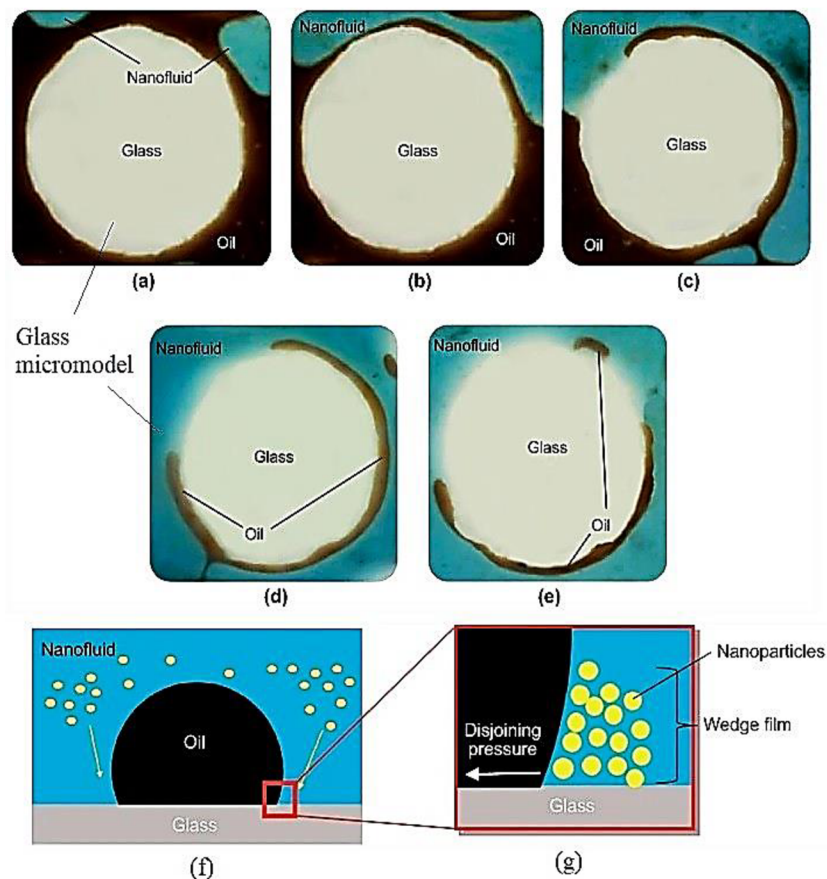


Figure 10 Surface wettability changes under the influence of the nanoparticles during the nanofluid flooding (Ju and Fan, 2009).

Table (2) affirms concise data of experiments conducted by the following researchers: Hendraningrat and Torsæter (2014); Joonaki and Ghanaatian (2014); Giraldo et al. (2013); Nazari et al. 2015; Cheraghian et al. (2017); Betancur et al. (2020); Qi et al. (2017); Sagala and Nassar (2020); Ali et al. (2019); Manshad et al. (2020); Najafi-Marghmaleki et al. (2018);

Davoodi et al. (2022). In addition, table (2) states the types of different concentrations of NPs employed in their experiment by each researcher. Besides, the values of initial CA and final CA, as well as the percentage of CA reduction, are stated for each experiment. The obtained data are stated in the table (2), which were obtained by different researchers experimentally.

Table 2 Effect of NPs on wettability

Type of NPs	NPs concentration	Initial CA [°]	Final CA [°]	CA reduction [%]	Reference
SiO ₂	0.05 wt.%	129	28	78	Hendraningrat and Torsæter (2014a)
Al ₂ O ₃	0.5-3 g/L	134	39	70	Joonaki and Ghanaatian (2014a)
Fe ₂ O ₃	3 g/L	134	31	76	Joonaki and Ghanaatian (2014b)
Al ₂ O ₃	1000 ppm	141	32	77	Giraldo et al. (2013)
Fumed silica	2.2 wt.%	102	92	9	Cheraghian et al. (2017)
Mgo	0.005 g/ml	39	42	7	Nazari et al. 2015
Cnp	0.1 wt.%	35	85	4	Qi et al. (2017)
Al ₂ O ₃	0.05 wt.%	110	70	36	Betancur et al. (2020a)
Iron core carbon shell	100 mg/L	108	76	29	Betancur et al., (2020b)
Zro ₂	0.05 wt.%	70	10	85	Qi et al., (2017)
Hydroxylated nano pyroxene	50 ppm	76	52	31	Sagala and Nassar,(2020)
Zno/ SiO ₂	2000 ppm	132	98	25	Ali et al. (2019)
Cuo/Fe ₃ O ₄	2000 ppm	135	61	54	Manshad et al. (2020)
γ-Al ₂ O ₃	0.5 wt.%	80	11	86	Najafi-Marghmaleki et al., (2018)
SiO ₂	0.05 wt.%	139	28	79	Hendraningrat and Torsæter (2014b)
Graphene/SiO ₂	70wt.%	143.47	58.5	59	Davoodi et al. (2022)

2.5.3 Effect of nanomaterials on recovery factor

NPs have stable conditions at elevated temperatures and avoid particle aggregation in porous media (Hendraningrat and Torsæter, 2014). Nanoparticle nanoparticles (NPs) could be used to improve oil recovery and surfactant flooding, according to a study by Zargartalebi and Barati (2015). Hydrophobic NPs outperformed hydrophilic NP-modified surfactants in terms of their ability to dampen water. A study conducted by Ye et al. (2013) deployed nano-SiO₂ and free radical polymerization to create a novel polymer nanocomposite for use in a polymer flooding system. Under various conditions, oil displacement efficiency, mobility control ability, salt tolerance, temperature tolerance, viscoelasticity, and rheological properties were evaluated. In addition, Hendraningrat and Zhang (2015) NPs can reduce water permeability and mobility ratio, causing polymer solutions to migrate to bypassed oil zones. Additionally, the study conducted by Saha and Tiwari (2019) high concentrations of non-polarizing

polycyclic hydrocarbons (NP) increase oil recovery more than standard polymer flooding with high concentrations of NPs, according to a study published in the journal *Frontiers in Energy and Process Engineering* by researchers at Aberystwyth University. Likewise, according to several studies, hydrophilic silica nanoparticles were distributed through reservoir porous media. According to some studies, the concentration of silica NPs should not exceed 0.1 weight percent. This is because the subject can have varying effects on EOR (Ali et al., 2021). Furthermore, a high concentration of NPs inevitably results in high oil recovery. Even at high concentrations, however, residual oil saturation can be reduced by 2-13 percentages. The performance of nano hydrophilic metal oxide as a polymeric nanofluid for oil recovery has been investigated. TiO₂ performs better in polymer flooding and wettability alteration among non-polarised polymers (NP) than silica-based NPs (Hendraningrat and Torsæter, 2014). Silica nanoparticles diffuse into wet porous media but do not move with oil in sandstone channels. In this system, silica NPs with 600 ppm HPAM can reduce residual oil saturation by around 20% (Cheraghian et al., 2013). Furthermore, propanol and SiO₂ NPs are effective combinations for improving oil recovery by changing wettability and lowering IFT. As a result, if NPs are injected into porous media, they can significantly reduce trapped oil (Joonaki and Ghanaatian, 2014). Nanosuspensions can be used to replace polymeric solutions in enhanced oil recovery. NPs at a concentration of 0.1 weight percent improve the rheological properties of the polymer at low shear rates (pseudo-plasticity behavior), researchers have shown (Maghzi et al., 2013). According to the study conducted by Rahimi and Adibifard (2014) injecting nano particles with a surfactant into a reservoir increases ultimate oil recovery by 11%. The main mechanisms underlying this oil recovery were altered wettability (from water to oil-wet) by nano particles and reduced IFT by surfactant and nano particles. Figure (11a) depicts the schematic wettability alteration in porous media while deploying polymer-coated additive to recover heavy oil. Figure (11b) stating the emulsification of oil-in-water with changes in solution pH, and (11c) indicate the wetting of oil–water micro emulsion phases with polymeric NPs. (11d) schematic of oil–water micro emulsion phases with polymer-coated NP additives (Qi et al., 2017).

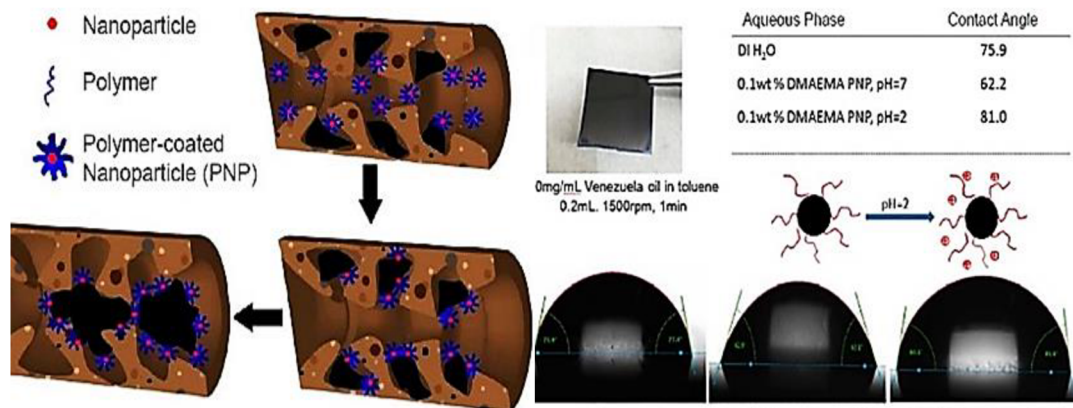


Figure 11 Effect of the polymer coated nanoparticles on the flow of the crude oil through the porous media and crude-oil/nanofluid emulsion (Qi et al., 2018).

Furthermore, Figure 12 shows the plotted graph of experimental data acquired from different experiments for different nanoparticles stating their impact on the oil recovery improvement for each of the different nanoparticles.

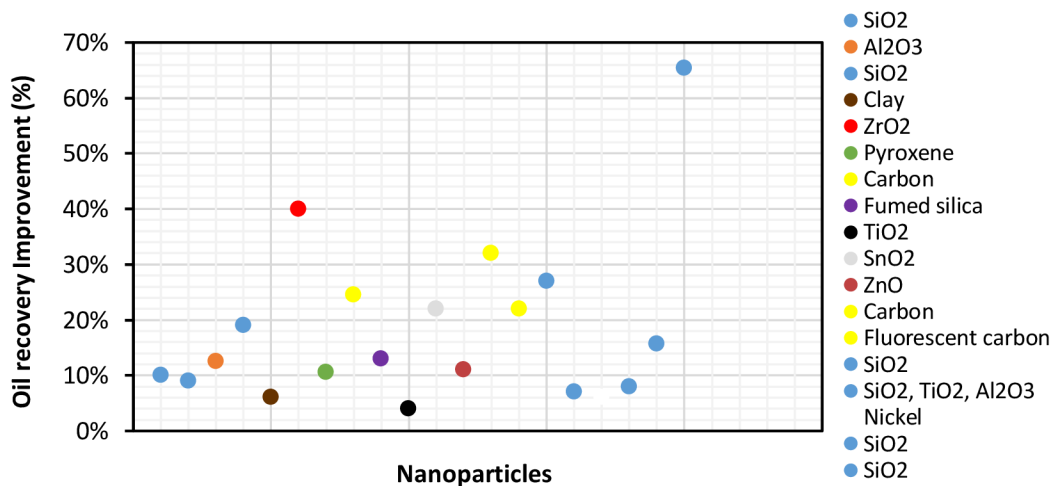


Figure 12 Plotted Graph of data obtained for oil recovery improvement deploying different nanoparticles.

3. Materials and Methods

3.1 Materials

3.1.1 Chemical reagents

The chemical reagents (methanol, ethanol and toluene) were purchased from Merck Company with high purity.

3.1.2 Crude oil

Tawkee oilfield crude oil was obtained with a density of 0.878 gm/cm³ (32.6°API) and viscosity of 13.23 cP. The crude oil's density and viscosity were determined using the PAAR density meter and the Brookfield viscometer. Furthermore, the crude oil was first filtered using a 5 mm filter paper to remove solid particles, dissolved gases, and water. Oil filtration system shown in Figure (13).



Figure 13 Oil Filtration System.

3.1.3 Water

For the preparation of nanofluid, distilled water was utilized.

3.1.4 Rock sample

For this research, three core samples from carbonate rock were used. The plates for contact angle measurements were made from the rock samples. Table 3 states the specification of the core samples purchased. Besides, three core plugs were also constructed for core flooding. Additionally, the first core sample, measuring 7.74 cm in length and 3.69 cm in diameter. It has a porosity of 14.32 % and a permeability of 7.36 mD. The second core sample is 8.44 cm long and 3.69 cm in diameter. It has a porosity of 16.3 percent and a permeability of 7.55 mD.

Finally, the third core sample is 7.05 cm long and 3.69 cm in diameter. It has a porosity of 15.2 percent and a permeability of 6.93 mD.

Table 3 Core samples that used and their properties.

Core name	L (cm)	D (cm)	Porosity (%)	K (md)	PV (cc)	Bulk volume (cc)	OOIP (cc)	Swi (%)
C#1	7.74	3.69	14.32	7.36	11.32	78.9	10.08	10.95
C#2	8.44	3.69	16.3	7.55	13.07	80.14	11.32	13.38
C#3	7.05	3.69	15.2	6.93	11.61	76.37	9.43	18.77

3.2 Methodology

3.2.1 Preparation of nanofluids

The obtained distilled water was utilized to make nanofluids with varied quantities of the produced NPs. The synthesized NPs are combined with distilled water at varying concentrations of 250, 500, 1000, and 2000 ppm. These nanofluids were generated by stirring (LABINCO L81 Stirrer) at 600 rpm for 6 hours while keeping the operating temperature below 30 °C to avoid homogenizer overheating. Following that, nanofluids were mixed for 2 hours using ultrasonic waves generated by a UIP200 ultrasonic mixer to achieve great stability. Consequently, the stability of the produced nanofluids was monitored and analyzed visually over time using transparent containers. Additionally, under ambient temperature and pressure, the density, viscosity, conductivity, and pH of nanofluids were determined as shown in figure (14) using a PAAR density meter, a Brookfield DV2T viscometer, a Mettler Toledo S230, and a WTW TM inoLab™ Cond 7310, respectively.

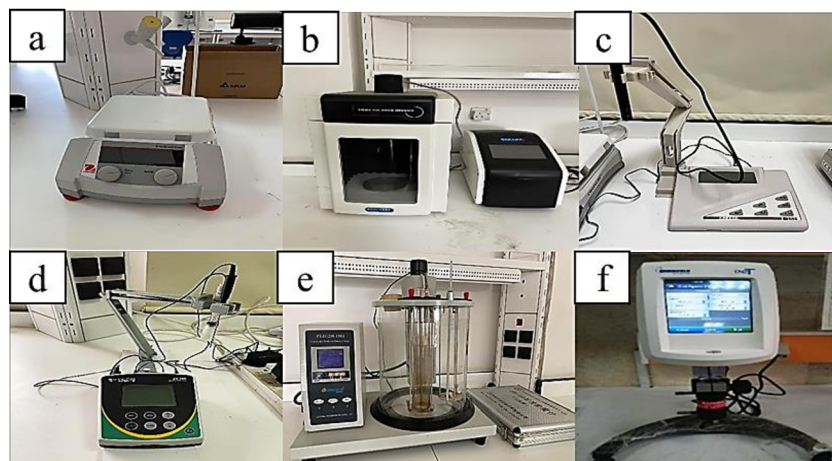


Figure 14 The apparatus that used for the fluid characteristic measurements; a) Hotplate Magnetic Stirrer (Labinco Model L-81) b) UIP200 Ultrasonic Mixer. c) Conductivity Meter Device. d) pH Meter. e) Anton PAAR DMA45 Measuring Density of Solutions. f) Brookfield DV2T Viscometer.

3.2.2 Core preparation

Core samples used in this experiment were cut to the necessary lengths with a 3.69 cm in diameter. The plug was cleaned using a Soxhlet extraction, as stated in Figure (15), with ethanol and toluene at a temperature of (60-80) °C for 24 hours to remove any remaining water, oil, or residues. After that, the core sample was dried in a (70 °C) oven for 6 hours. The prepared core samples' dry weight was determined. Hereafter, the porosity, and permeability of core samples were examined using a helium porosity meter and a gas permeameter, respectively. Moreover, to determine the saturation profiles within the prepared cores, each core sample was placed at core holder, and the brine accumulator was connected to the core holder, before applying a confining pressure 1000 psi greater than the injection pressure. After connecting the core flooding system, the Brine was injected with a fluid injection pump at a rate of 0.25 cm³/min. The dead volume of the core holder and tubes was measured before inserting the cores into the core holder. When the core produced brine and injection was ceased, the cores were saturated. The weight and pore volume of the saturated cores were determined using the following equation to obtain the pore volume:

$$V_p = \frac{W_{Sat} - W_{Dry}}{\rho_{Brine}} \quad (\text{Eq.5})$$

where,

V_p , Pore Volume.

W_{Sat} , Weight of Saturated Core.

W_{Dry} , Weight of dry Core.

ρ_{Brine} , Brine Density.

Following that, the oil accumulator was linked to the core holder rather than the brine accumulator, and confining pressure was supplied to the core. Then, the crude oil was injected at various rates ranging from 0.1 to 0.5 cm³/min into the core samples, and the produced water was measured in a graduated flask. Following the breakthrough, an additional 2 pore volumes (PVs) of crude oil were injected to finish the saturation process. The initial water saturation (S_{wi}) was calculated using the water collected in the graduated flask. The saturated cores were then stored for one week in order to establish a full and stable oil-wet condition.

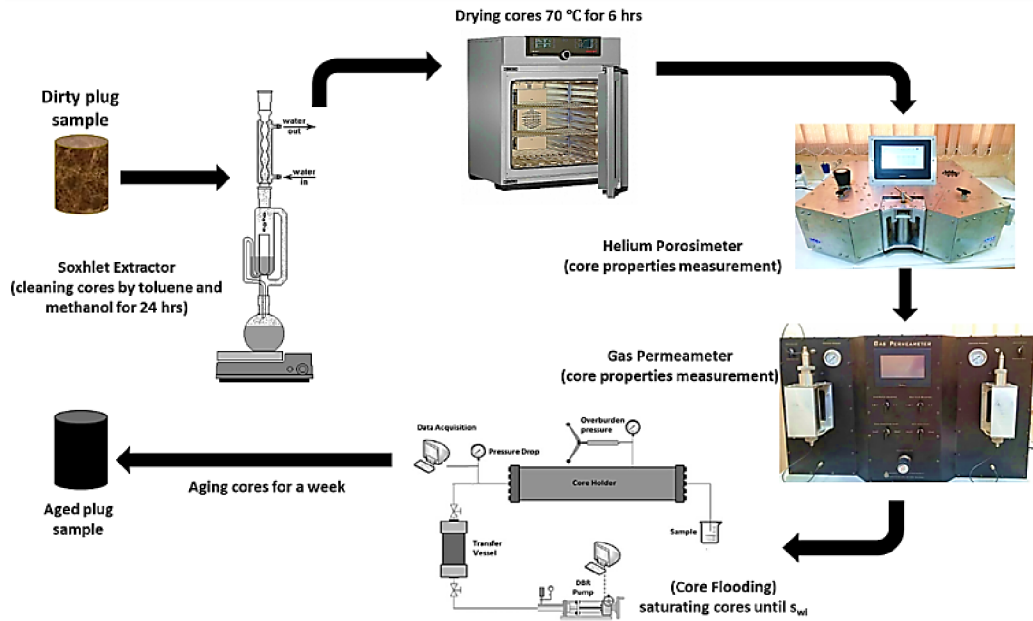


Figure 15 Procedural steps of the aging and preparation of core samples for core flooding (Ali et al., 2021).

3.2.3 Interfacial tension and contact angle measurement

The interfacial tension (VIT-6000) deployed to evaluate crude oil and various aqueous phases in which using a pendant drop technique from determining the size of the suspended droplet of liquid. After receiving the droplet picture from a camera, the program calculated the value of IFT using the formula:

$$\gamma = \frac{\Delta\rho \cdot g \cdot D}{H} \quad (6)$$

where,

$\Delta\rho$, the density difference between drop and bulk fluids (gm/cm^3),

g , the density of the drop.

D , the huge diameter of the droplet (cm).

H , the droplet form factor.

The IFT for the crude oil with various aqueous phases was determined in this work utilizing a pendant drop and the ADSA (Axisymmetric Drop Shape Analysis) shape analysis technique. At ambient conditions, IFT was measured for the crude-oil/distilled-water system with and without the presence of SiO_2 NPs at concentrations of 250,500, 1000, and 2000 ppm. When two immiscible liquids are present, one of the most common methods for estimating the

wettability condition of the rock is sessile drop. Fig (16) This method was used to determine the contact angle (CA) of crude oil on the surface of carbonate rocks with distinct aqueous phases present. The sessile drop method involves placing a drop of water or oil onto a flat mineral surface and measuring the contact angle. Furthermore, the angle measured from the solid surface to the denser liquid The contact angle between an oil/brine/rock system and water is a critical factor in determining its wetness. The size of the contact angle influences the surface's wetness (wettability state).

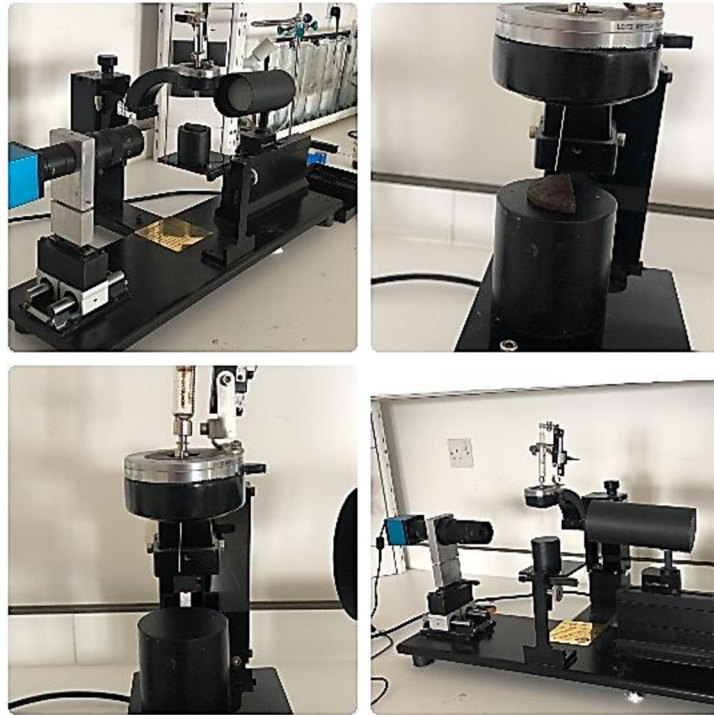


Figure 16 IFT and contact angle set up used in this study.

The experiment began with the preparation of 2 mm rock plates from carbonate outcrop samples. Toluene and distilled water were used to clean the smooth plates once they were obtained. The smooth and cleansed parts were then immersed in crude oil for 12 days at 70 °C to obtain the oil-wet, as shown in Figure (17). Following that, the aged rock slices were placed into enclosed containers filled with different aqueous phases employed in this work (distilled water and nanofluids) under static conditions for 3 days. Thereafter, evaluated the wettability modification. Finally, the contact angle (CA) of crude oil droplets on the surface of all aged slices was determined. The following are the steps for measuring contact angle for all systems covered in this study: At ambient conditions, the CA of crude oil droplets on the surface of carbonate rocks in the presence of a distilled-water system with and without SiO₂ NPs at concentrations of 250, 500, 1000, and 2000 ppm was observed. At ambient conditions, the CA

of crude oil in the presence determined with distilled water at varying concentrations. Eventually, the CA values recorded are the result of a sufficient period of time to determine the wettability of each system.

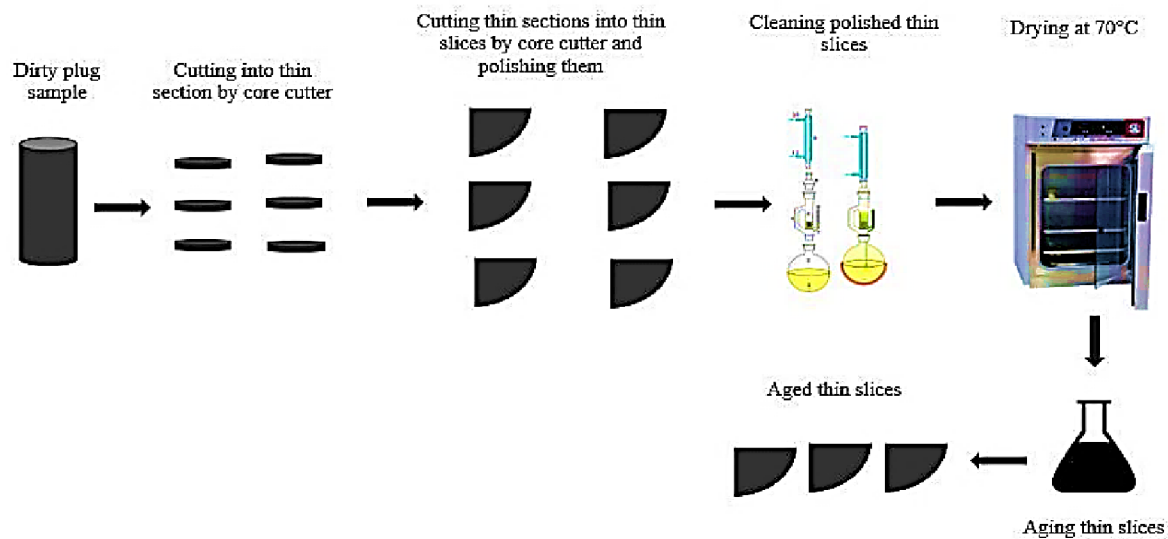


Figure 17 Procedural steps of the preparation and aging of rock plates used in measuring contact angle (Nazarahari et al., 2020).

3.2.4 Oil displacement

The oil displacement measurements were carried out using the core flooding experimental setup. The setup comprises of the following: fluid-containing tanks, pumps, a core holder, and a fraction collector. The HPLC pump automatically injects hydraulic fluid to the back of the pistons in three cylinders based on the fluid selection, which must be pushed into the core holding chamber and injected into the core at the user-specified rate or input pressure. Besides, core holding chamber and pumped into the core at the user-specified pace or input pressure to apply the temperature to the system, cylinders holding crude oil, water, and nanofluid solution are placed inside an oven, along with a core holder. Then, the core holding chamber's output line is disconnected from the oven, and the outlet fluid is collected in a specific fluid collecting tank. The core holding chamber itself is made up of two portions of the fluid flow (inlet and outlet), as well as a specific rubber to stop the fluid flow around a plug that is manually controlled by a hydraulic fluid pump. Moreover, core displacement experiments were performed on 3 core samples by DW and nanofluids at 75 °C and 1400 pressure at a rate of 0.5 cm³/min. The existing core flooding procedure consisted of pumping formation water into each core plug independently as a supplementary recovery strategy. The tertiary recovery was then carried out in three stages, beginning with the injection of DW nanofluid into the first core

plug. Finally, the volume of oil displaced was collected in a jar from the core holder's exit. Throughout the testing, the pressure, temperature, and pore volume pumped into cores were monitored. Figure (18) depicts the oil displacement test equipment that deployed for this experiment.

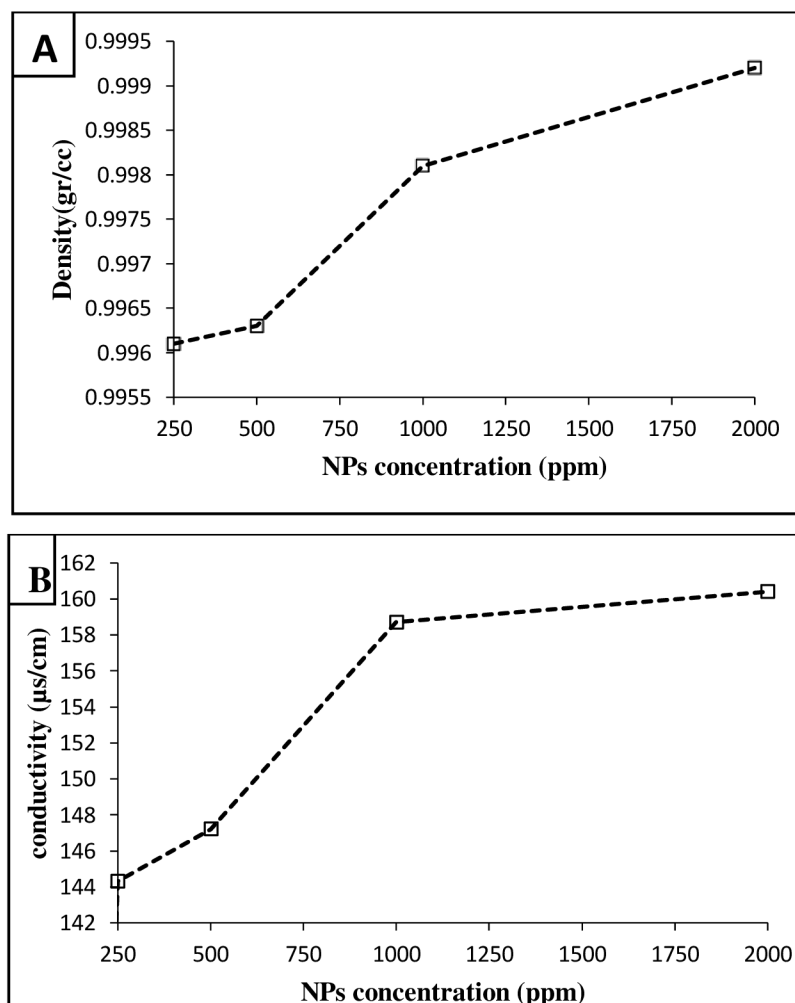


Figure 18 Core flooding apparatus.

4. Results and Discussion

4.1 Characterization of nanofluids

The dispersion stability of the produced NPs inside the dispersion media is critical for precisely identifying the role of NPs. The dispersion stability of colloidal solid particles inside the generated nanofluids is measured and observed in this section by measuring and monitoring pH, density, conductivity, and appearance aspects of nanofluids. As expected, pH has a direct impact on the aggregation and suspension stability of nanoparticles in colloidal solution. The pH of all generated nanofluids at various NPs concentrations is shown in Fig. 19c. As can be observed, the pH range where a stable aqueous phase may be formed is 6.91 to 7.53. The pH changes as the concentration of NPs increases; the pH rises as the concentration of NPs rises. Meanwhile, more consistent trends in nanofluid conductivity and density were established (see Figure 19a). These two qualities were more impacted by SiO₂ NP concentration. In general, the density of the nanofluid was enhanced slightly from 0.9961 to 0.9992 gm/cm³. The conductivity is highly changed from 144.3 to 160.4 μ s/cm with increasing NPs concentration as shown in figure 19b.



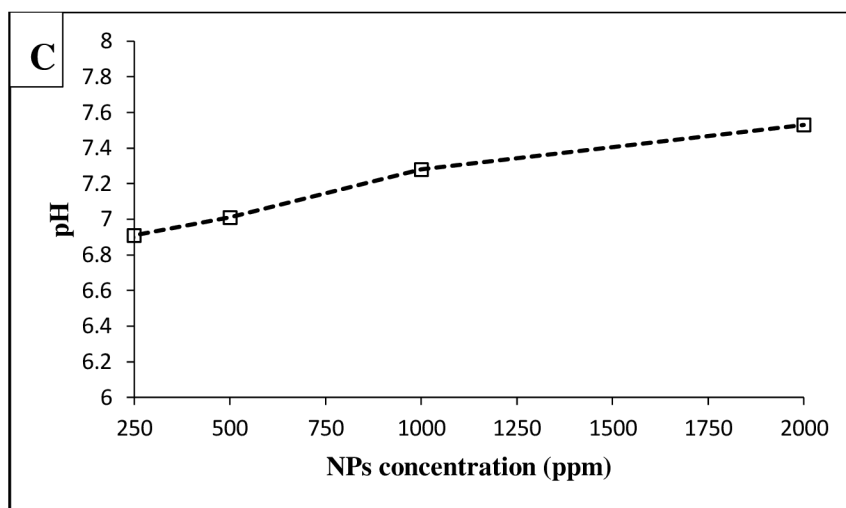


Figure 19 Nanofluid characteristics: density, pH, and conductivity with increasing concentration.

4.2. Interfacial tension

At various temperatures and pressures, the interfacial tension of crude oil and manufactured nanofluids was determined. Figures 20 and 21 The acquired photos of the crude oil droplet in the presence of the produced nanofluids at varied NP concentrations and 80 °C are presented in Fig. 20, with varying droplet sizes visible. As expected, the maximum IFTs were obtained when nanofluids with an NP concentration of 250 ppm in 20 c were utilized. As a result, when 250, 500, 1000, and 2000 ppm NPs in 80 c were tested, the minimum IFTs were 6.67, 5.28, 3.8, and 2.59 mN/m, respectively. Figure 21 depicts the measured values of IFTs as a function of NP concentration (250, 500, 1000, and 2000 ppm) and experimental conditions (20, 50, and 80 °C). As can be shown, the highest IFT was 9.6 mN/m when DW nanofluid-250 was used at 20 °C, while the minimum IFT was 2.59 mN/m when DW nanofluid-2000 was used at 80 °C. In general, raising the concentration of SiO₂ NPs and increasing the temperature lowered the IFT. At the ambient conditions depicted in Fig. 21. IFT decreased as NP concentration increased from 9.6 mN/m to 4.05 mN/m in 20c. Also, increasing the temperature of the experiment to 50 and 80 °C improved the effectiveness of SiO₂ NPs in lowering IFT. In 50 degrees Celsius, IFT decreased from 6.02 mN/m to 4.88 mN/m, and in 80 degrees Celsius, it decreased from 6.67 mN/m to 2.59 mN/m. Nevertheless, the lowest IFT was attained in 80c with an NPs concentration of 2000ppm, as illustrated in Figure (21).

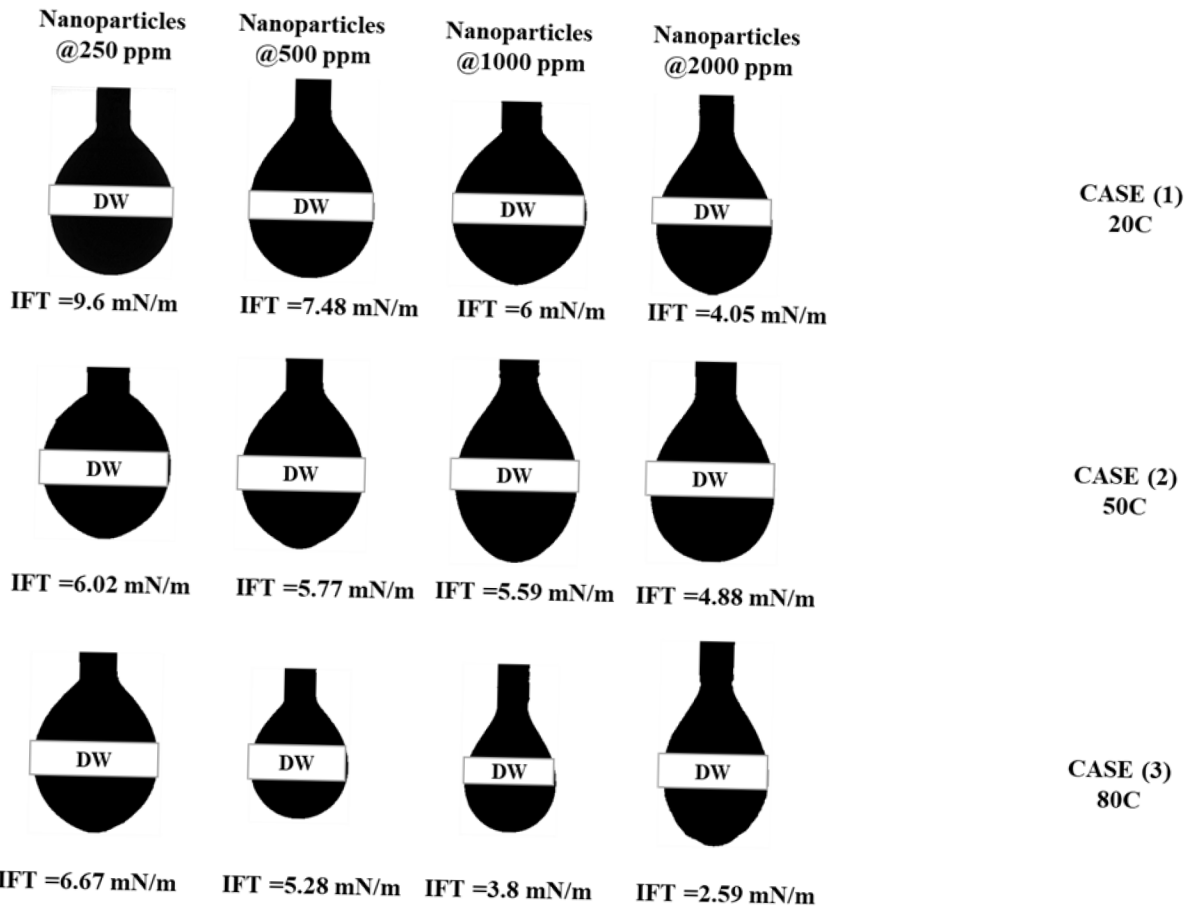


Figure 20 Crude oil droplets under the influence of SiO₂ and different temperature conditions.

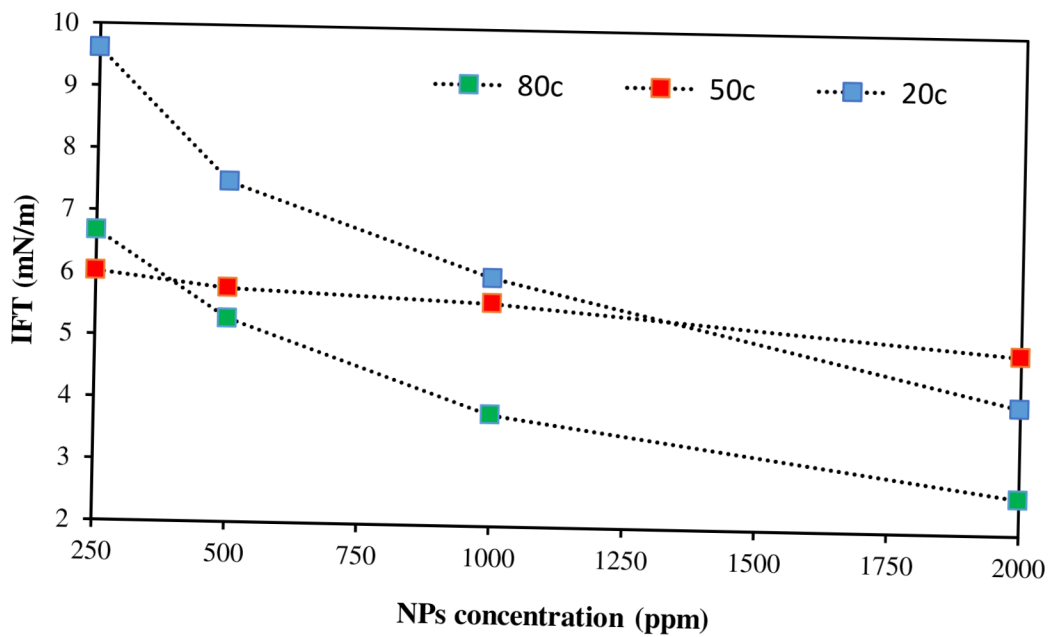


Figure 21 IFT values of crude-oil/nanofluid systems measured at different temperature conditions.

4.3 Wettability alteration

The contact angle of crude oil on the surface of carbonate slices before and after treatment with SiO₂ nanoparticles was measured to determine the wettability behavior of various aqueous systems (see Figure 22). The performance of the synthesized NPs was studied in relation to the experimental temperature. Essentially, the presence of DW-250 nanofluid generated by mixing 250 ppm NPs in distilled water at 20 °C resulted in the strongest oil-wet condition of 124.3 ° CA (see Figures 22 and 23). Nevertheless, using DW-2000 nanofluid at 80 °C resulted in satisfactory wettability behavior on the carbonate rock, as shown by a 65.5° contact angle (see Figures 22 and 23). Figures 22 and 23 illustrate the contact angles recorded using various nanofluid solutions with varying NP concentrations, but at an ambient temperature of 20 °C. As can be seen, the synthesized NPs had no effect on lowering the contact angle, which caused wettability to remain in the oil-wet phase in all of the experimental test trials. The lowest CA achieved in the presence of DW-2000 nanofluid is 105.5°, which is still higher than 90° and depicts an oil-wet system depending on When the temperature of the experiment was raised to 50 °C, different CA values for the identical nanofluids were measured. The CAs of the four prepared kinds of nanofluids at varying NP concentrations are shown in Fig. 23. Also, when the temperature of the tests was increased to 80 °C, the performance of the generated nanofluids with varying NPs concentrations improved. Therefore, nanofluids permitted CA reductions of up to 38% and 42%, respectively, compared to what was achieved in both testing settings of 20 °C and 50 °C. In this experiment, DW-2000 nanofluid made by combining 2000 ppm NPs with distilled water reduced the CA of oil droplets on the surface of the utilized carbonate rock by 53%, from 124.3° to 65.5°. As a result, the wettability of the carbonate rock has been changed to a mild water-wet system, which is advantageous for additional oil production as EOR recovery.

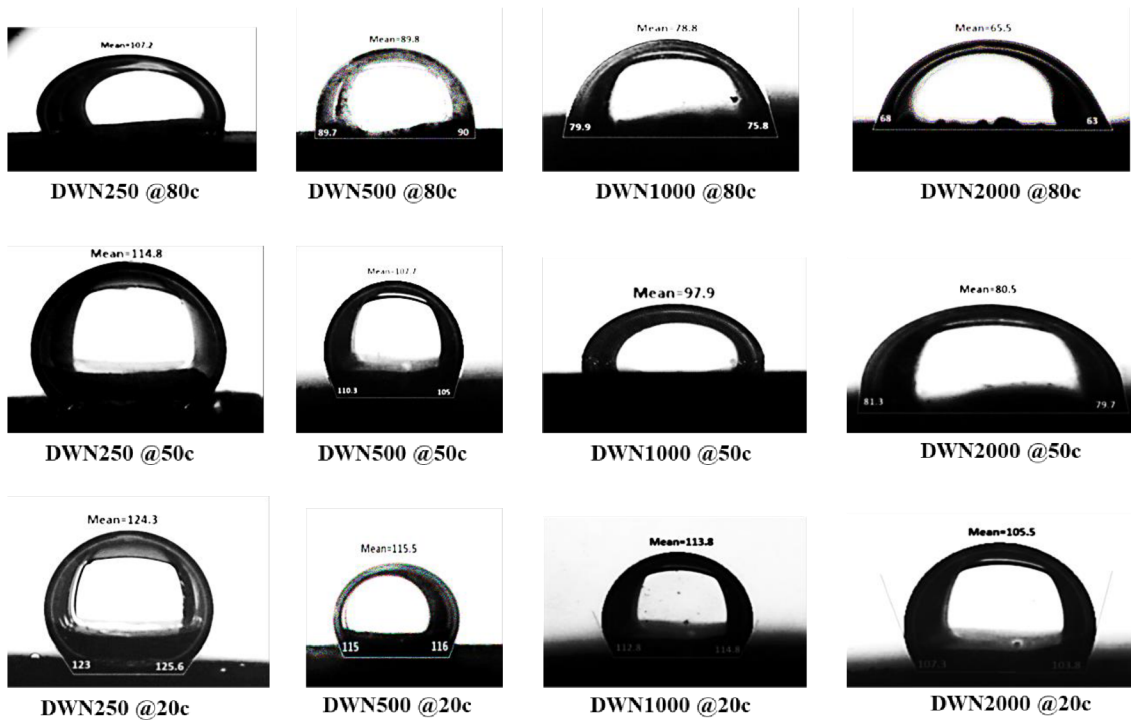


Figure 22 Oil droplets on the surface of the prepared thin sections of the carbonate rock under the influence of the silica nanoparticles and temperature.

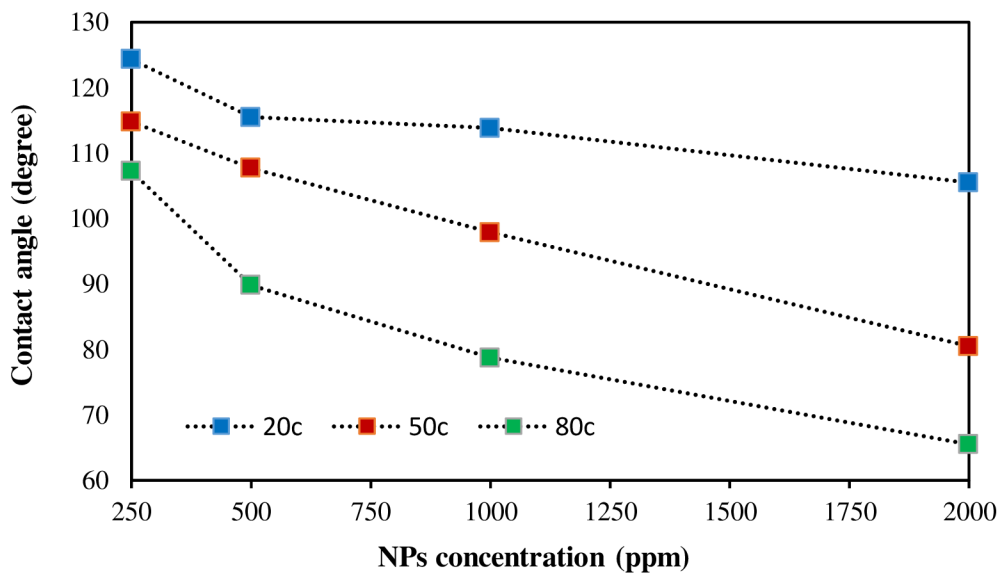


Figure 23 Contact angles measured for the crude oil droplets on the surface of the carbonate rock with the presence of the nanofluids at different temperature conditions.

4.4 Oil recovery

These crude oil displacements were treated as secondary and tertiary recoveries. Moreover, oil from core plugs was displaced in two steps: (1) by water as a secondary recovery technique, and (2) by DW-2000 nanofluids as a tertiary recovery method. All core plugs were tested for oil displacement under the identical experimental conditions of temperature, pressure, and injection rate. Nevertheless, the petrophysical parameters of the employed core plugs differ somewhat but are from the same outcrop. The porosity of the employed plugs ranges from 14.32 to 16.3%, with permeability ranging from 6.93 to 7.36 mD. Waterflooding produced only 44.2% OOIP, whereas injecting the nanofluids created more hydrocarbon. The recovery efficiency of the core plug was obviously increased by water and the addition of the synthesized NPs. Fig. 18 also depicts the production curve of oil displacement from core plugs. Waterflooding allowed for the extraction of 44.2 % OOIP. Yet, in both phases of recovery, the higher recovery efficiency. waterflooding displaced 44.2 % OOIP as secondary recovery, and 21.41% OOIP additional oil was extracted when DW-2000 nanofluid was put into core plugs after waterflooding. In general, the maximum oil recovery factor (65.42% OOIP) was obtained when DW-2000 nanofluid was injected as a tertiary recovery technique.

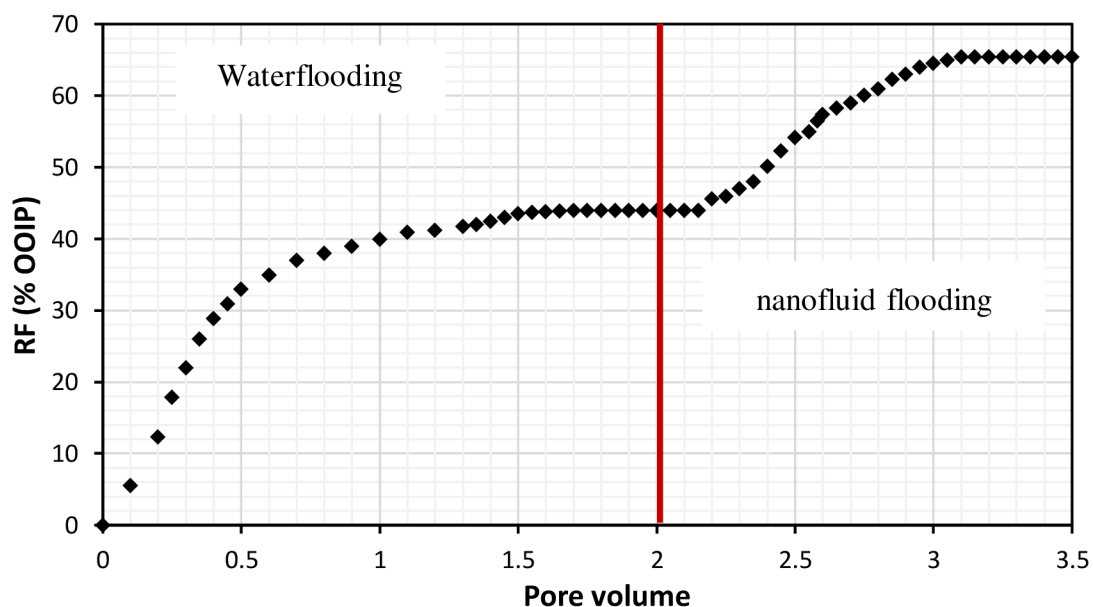


Figure 24 Oil recovery factor profile versus pore volume injected; secondary recovery by waterflooding and tertiary recovery by nanofluid injection.

5. Conclusion and recommendation

5.1 Conclusion

This study investigated the effect of newly produced nanoparticles known as SiO₂ on oil recovery, IFT decrease, and wettability change during secondary and tertiary recovery procedures under various experimental settings. In this study, the presence of DW-2000 nanofluid generated by combining 2000 ppm SiO₂ NPs inside distilled water at 80 °C resulted in the lowest IFT of crude oil droplet, which is 2.59 mN/m. Furthermore, the same nanofluid was able to change the wettability from a strong oil-wet to a mild water-wet. Both the NP content and the experiment temperature had a significant influence on the lowering of IFT and CA. The greatest recovery efficiency was found when the DW-2000 nanofluid was injected into a core plug as the chemical EOR flooding at 75 °C and 1400 pressure at a rate of 0.5 cm³/min, resulting in a 65.42% OOIP.

5.2 Recommendation

Through the outcomes of this study, it can be recommended that the application of SiO₂ on the oil recovery can be studied under the effect of the pressure and salinity. In addition, using the surface modified silica nanoparticles can be studied as well.

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