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Effect of Salinity on some Selected Nanoparticles for Enhanced Oil Recovery using Niger-Delta Formation

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Abstract:

The role of nanoparticles in enhancing oil recovery from oil reservoirs is an increasingly important topic of research. Nanoparticles have the properties that are potentially useful for enhanced oil recovery (EOR) processes. One of the important roles of nanoparticles in petroleum industry is to reduce permeability and porosity damage, change the wettability and to also reduce the interfacial tension of reservoir rocks. The main objective of this study is to investigate the efficiency of copper oxide, zinc oxide and silicon oxide nanoparticles in enhancing oil recovery in the presence ofdifferent salinity concentrations.The flooding experiment was done using three different formulated nanofluids of 50000ppm, 70000ppm and 10000ppm at 0.1 weight percent nanoparticles (Copper oxide, Zinc oxide and silicon oxide) on the Niger Delta sand samples plugs at 29^{o}C temperature.The effect of viscosity and PH were also investigated using the three salinity concentrations. The result shows that the three different salinity nanoparticles increased oil recovery with different pattern, but 50000ppm gave the highest cumulative oil recovery followed by 70000ppm, and 10000ppm respectively. Silicon oxide nanofluid at 50000ppm gave the highest oil recovery of87.50% for all the salinity range studied. The permeability, porosity and PH decrease with increase in salinity.

***Keywords* —**Enhanced Oil Recovery, Nanoparticle, Petrophysical Properties, Salinity Concentration, Viscosity

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1. INTRODUCTION

The demand for energy resources is always up and increasing since the wheel of economy is creating new opportunities to cover up the increasing population of the earth. Depletion of oil reservoir is one of the major problems faced by the petroleum industry and great part of this industry technology is focused on retrieving oil portions left in formation's strata after the reservoir has exhausted its natural energy. Every reservoir, whether mature, recently discovered or even yet to be discovered, are all potential candidates for EOR [1]. For the past five years, an array of improved enhanced oil recovery methods has been developed and applied to mature and mostly depleted oil reservoirs. These methods help improve the efficiency of oil recovery by extracting a good part of oil left behind in the reservoir after primary and secondary recovery processes. Primary recovery process involves displacing oil from porous rocks in the reservoir towards the production well using its own reservoir energy such as natural water drive, gas-cap drive, or gravity drainage. Primary methods extract only about 30% to 40% of the original oil in place [2]. In secondary recovery, a fluid (most commonly water) is injected into the reservoir to maintain reservoir pressure and continue oil displacement into the wellbore.

Recently, some authors like [3], [4], [5] and [6], has shown the ability of nanoparticles to alter the certain factors in the formation and in oil properties as to improve oil recovery. The process involves introducing nanoparticles to the reservoir and studying its effects on oil properties. It has been reported that nanoparticles can change oil formations to water wet formations, change the rock wettability, reduce interfacial tension, and reduce permeability and porosity damage. They can improve fluid-rock interaction characteristics and heat transfer coefficient enhancement. They also help in reduction of interfacial tension and improving displacement efficiency ([3], [7]). There are many parameters that can affect nanoparticles applications in porous media. These parameters include nanoparticles characteristics, porous media features, fluid properties, and operational conditions. As already stated, the effects of parameters on application of these nanoparticles have been evaluated in porous media. Parameters such as different concentrations of nanoparticles, presence of different salinities, number of clays, type of crude oil and temperature.

The salinity in the reservoir is significantly high; therefore, an understanding of the interactions between nanoparticle -oil-rock and the influence of different concentrations of salinity is needed to verify whether NPs can withstand the high salinity condition. From the open literature, [8] and [9] demonstrated from their research work that increasing salinity will reduce the stability of nanoparticles and that affect the efficiency of NP application. [10] and [11] proved that electrostatic repulsion force between the Nanoparticles-oil-rock is the major mechanism affecting the stability of dispersed NPs in aqueous solution. In a high salinity environment, the ionic strength will be high, and will cause the compression of the electric double layer (EDL) and lead to lower zeta potential. Consequently, the electrostatic repulsion between the NPs will be drastically reduced, and surface neutralization with NPs might occur because of the large number of ions in solution. Meanwhile, van der Waals attractive forces become significant in high salinity conditions, where attraction forces occur between the regions of molecules with high and low electrons [12].

Few research has investigated the injection of nanoparticles into high salinity reservoirs ([13], [14], [15], [16], [17]). They found out that retention of nanoparticles can adversely affect the wettability alteration, flow capacity, reservoir permeability, and porosity. An experiment conducted by [18] revealed that the viscosity of rice husk silica NPs decreased as the salinity level increased because of the reduction in electrostatic repulsion force. In addition, [19] found that the interfacial tension increased as the salinity increased. Experimental work by [20] indicated that oil recovery was reduced by approximately 10% when the salinity level increased from 0 to 3 wt.% NaCl. However, experimental work from [21] showed that the introduction of high salinity water with Janus-silica NPs did not lead to any significant effect; in particular, the effect on IFT reduction was not changed.

[22] investigated the effects of salinity on nano-silica applications in altering limestone rock wettability for enhanced oil recovery. The wettability alteration and oil–water interfacial tension modification induced by introducing different concentrations of 0.01, 0.05, 0.1wt % nano-silica and different concentrations of NaCl formation brine (0.3, 1, 2, 3, 4 wt.%) was studied by experimental approach. The results revealed that interfacial tension and contact angle tests were found to have the same optimal salinity of 0.3wt % and optimal nano-silica concentration of 0.1wt %. The authors obtained the highest displacement efficiency at 0.05wt % nano-silica and salinity of 0.3 wt. % NaCl. Nanoparticles stability in saline water depends on its concentration, size, and solution pH. Salt ions lead to NPs coagulation by preventing particle repulsion; moreover, proton exchange is dominant in the low-salinity solution, eventually increasing the surface potential. Higher NPs concentration reduces the pH of the system, whereas higher solution acidity and smaller NPs sizes improve the stability of NPs. The addition of salt ions to the solution reduces the zeta potential towards zero leading to NPs coagulation. For an effective surfactant EOR mechanism, injectant salinity is an important factor to consider. Majority of reservoir has high salinity, therefore, a proper understanding of the interactions between nanoparticle, oil, rock, and the influence of different concentrations of salinity is needed for proper EOR processes. The study focuses on using three different salinity ranges of 50000ppm, 70000ppm and 10000ppm in copper Oxide, Zinc Oxide, and Silicon Oxide for enhanced oil recovery using Niger Delta formations.

2. NANOPARTICLES

Nanomaterials are nanosized particles that are smaller than one micrometre. They are classified according to their structure and shape as nanoparticles, nano-clays, and nano-emulsions, as shown in Fig. 1 ([23], [24]). Nanoparticles are divided into inorganic nanoparticles, including ceramic and metal nanoparticles, and organic nanoparticles, including polymer, carbon, and lipid-based nanoparticles. Nano-clays consist of layers of silicate minerals such as saponite and kaolinite, while nano-emulsions are suspended systems consisting of water in oil, oil in water, and bi-continuous nano emulsions. [25]showed more literature on nanoparticle. Ceramic, metal, metal oxide, and semiconducting nanoparticles are inorganic, while biomolecules and polymeric nanoparticles are organic. Ceramic NPs consist of ceramic materials such as silica, alumina, titanium dioxide, zirconium, and calcium phosphates. Ceramic NPs are porous, making them resistant to degranulation, degradation, and extreme environments (Temperature and pH). They are synthesized under heat or heat and pressure, and they consist of a solid core. Ceramic NPs can be a combination of a metal and a nonmetal. Metal and metal oxide nanoparticles include gold, silver, platinum, palladium, zinc and zinc oxide, copper and copper oxide, nickel and nickel oxide, titanium dioxide, and iron oxide. Metal and metal oxide NPs are characterized by improved mechanical, electrical, electromagnetic, thermal, and chemical properties, making them feasible for many fields application [26].

2.1 Properties of some selected Nanoparticles

The properties of the selected nanoparticles for this research are essential as it gives us an insight to its probability of success and failure. The diverse and unique properties of these nanoparticles offer the potential to revolutionize permeability modification strategies in Enhanced Oil Recovery, presenting novel pathways for improving fluid-rock interactions and enhancing oil recovery.

2.1.1 Iron Oxide nanoparticle

Magnetic Properties: Iron Oxide nanoparticles, consisting of magnetite (Fe_3O_4) and hematite (Fe_2O_3) phases, exhibit superparamagnetic behaviour due to their nanoscale dimensions. This unique property enables them to respond to external magnetic fields, facilitating their manipulation and control within reservoirs. By applying magnetic fields, these nanoparticles can be precisely positioned and concentrated in specific regions, offering the potential for targeted permeability alteration and enhanced oil recovery [27].

High Surface Area: Iron Oxide nanoparticles possess an elevated surface area-to-volume ratio owing to their nanoscale size. This high surface area enhances their interaction with reservoir fluids and rock surfaces, potentially increasing the efficiency of adsorption, dissolution, and surface reactions that contribute to permeability modification [27].

Enhanced Dispersibility: The surface of Iron Oxide nanoparticles can be modified and functionalized to improve their dispersibility in various reservoir fluids. This modification ensures uniform distribution of nanoparticles within the reservoir, promoting consistent and targeted permeability alteration effects [28].

Compatibility: Iron Oxide nanoparticles are known for their compatibility with reservoir conditions, retaining their stability and performance across a range of temperature, pressure, and salinity conditions. This robustness makes them suitable for long-term applications in reservoirs without compromising their permeability alteration capabilities [27].

Responsive Behavior: Iron Oxide nanoparticles' superparamagnetic behavior offers a unique responsiveness to external magnetic fields. This property can be exploited to alter pore throat geometry, manipulate fluid flow paths, and enhance sweep efficiency, ultimately improving fluid conformance within the reservoir [27].

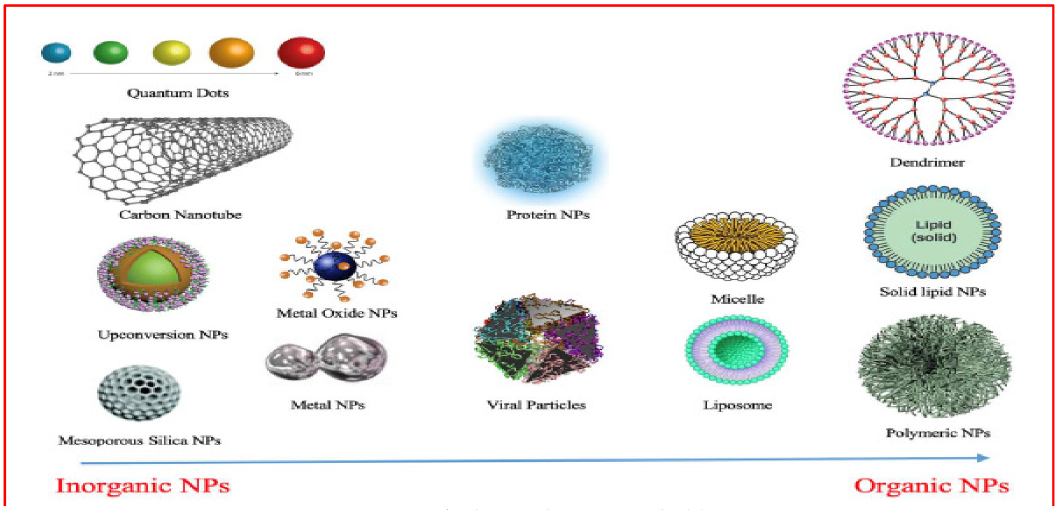

Fig. 1*Types of Nanomaterials [25]*

2.1.2 Silicon Oxide nanoparticles

Thermal Stability: Silicon Oxide nanoparticles, composed primarily of silica (S_iO_2), possess exceptional thermal stability. This property allows them to withstand the high-temperature conditions encountered within reservoirs, ensuring their integrity and performance during EOR operations [29].

Chemical Inertness: Silicon Oxide nanoparticles are chemically inert, making them resistant to reactivity with reservoir fluids and rock components. This inert nature preserves the stability of the nanoparticles and ensures their suitability for EOR applications without introducing unintended chemical interactions [30].

Surface Modification: The surface of Silicon Oxide nanoparticles can be modified through functionalization to tailor their interactions with reservoir rock surfaces. This modification can influence adsorption, wettability, and interfacial tension, enabling precise and targeted permeability alteration effects [31].

Reduced Interfacial Tension: Silicon Oxide nanoparticles have been shown to reduce interfacial tension between oil and water. This reduction promotes the mobilization of trapped oil by minimizing capillary forces and enhancing fluid flow, ultimately contributing to improved oil recovery and sweep efficiency [33].

Long-Term Stability: Silicon Oxide nanoparticles exhibit long-term stability under reservoir conditions. This stability ensures that the effects of nanoparticle-induced permeability alteration are sustained over extended periods, providing a consistent and durable strategy for EOR [30].

2.1.3 Zinc Oxide Nanoparticles

Semiconducting Behaviour: Zinc Oxide nanoparticles exhibit semiconducting properties, particularly when exposed to ultraviolet (UV) irradiation. These properties give rise to photocatalytic activity, allowing the nanoparticles to generate reactive oxygen species that contribute to the degradation of heavy crude oil components.

Photocatalytic Activity: Under UV irradiation, Zinc Oxide nanoparticles initiate a photocatalytic process that results in the generation of reactive oxygen species. These species facilitate the breakdown of complex hydrocarbons, reducing oil viscosity and improving fluid mobility within the reservoir. This photocatalytic activity can lead to enhanced oil recovery through improved oil displacement [31].

Surface Chemistry: The surface of Zinc Oxide nanoparticles can be engineered and tailored to achieve specific interactions with reservoir fluids and rock surfaces. This ability to modify surface chemistry provides a means to optimize adsorption, wettability alteration, and interfacial tension reduction, all of which contribute to permeability modification [27].

Wettability Alteration: Zinc Oxide nanoparticles have the potential to influence the wettability characteristics of reservoir rock surfaces. By altering contact angles and fluid-solid interactions, these nanoparticles can impact capillary forces and fluid distribution within porous media, leading to improved sweep efficiency and oil recovery [12].

Chemical Stability: Zinc Oxide nanoparticles exhibit chemical stability under reservoir conditions. This stability ensures the long-term effectiveness of nanoparticle-induced permeability alteration and oil recovery, making them a viable option for EOR applications [6].

2.2 Factors Affecting Nano-Fluid Flooding Recovery

The choice of nanoparticles used: The choice of nanoparticles used for nano-fluid flooding determines the oil recovery factor and for typical reservoir conditions, the choice of appropriate nanoparticles is of great importance. Different nanoparticles have different characteristics on altering reservoir or fluid properties.

Concentration of the Nanoparticles: The nanoparticles concentration used when conducting a nano flooding assisted EOR process, is the most essential factor to consider irrespective of its bilateral influence on nano-fluid flooding. On the other hand, an increase in the nanoparticles concentration results in a reduction in porosity and permeability of the reservoir rock due to the increased rate of nanoparticle deposition on the rock surfaces. Increase in nanoparticle concentration also increases oil displacement efficiency and this can occur due to the distribution of nanofluids on the surface and increases the viscosity of fluid ([32], [33]).

Size of nanoparticles: Size of nanoparticles and the corresponding charge density also affect the disjoining pressure. The smaller the size of nanoparticles, the higher the repulsive force and thus the higher the disjoining pressure that exist between them. The size of nanoparticles should be in the range, it cannot be big to be trapped or too small to cause log-jamming [8].

Salinity: Ideally, the stability of nanoparticles reduces as the salinity of the system increases. In fact, increasing the salinity of the system, causes a reduction in zeta potential and hence, results in agglomeration of colloidal particles. This is due to the lack of modification of nanoparticles that maintains the disjoining pressure functionality and stability in this environment. However, increasing the salinity of the system by adding different ions doesn't prevent nanoparticles from its movement, rather, it significantly increases the deposition of nanoparticles on the rock surfaces [8].

Dispersing Agent: The type of base fluid also has effect on the functionality of nanoparticles. Some of the dispersing fluids are distilled water, diesel, brine, and ethanol. Some of this dispersing fluid has characteristics of increasing viscosity, alteration of rock wettability and aids in giving better homogeneity with nanoparticle.

3. METHODOLOGY

3.1 Materials

The experiment involved the use of nanofluidson encapsulated cores of unconsolidated NigerDelta sandstone formation. Materials include encapsulated plug sample, Crude oil, Brine, Distilled water, Nanoparticles (Copper (ii) oxide,Silicon oxide and Zinc oxide).

3.1.1 Laboratory Equipment

The equipment used are:Encapsulated plug sample (unconsolidated Sand-packs), Venire calliper, Density bottle, P^H meter, Hydrometer, Thermometer, Canon U-tube Viscometer, Electronic Weighing balance, Stopwatch, Retort Stand, Pump, Flooding Pump Setup, Core-holder, Sieve and Stirrer.

Crude Oil Properties: The crude oil sample was obtained from a field from Niger Delta of Nigeria and has the following properties: specific gravity of 0.860, density of 0.8958g/cm^3, viscosity of 43.022cP and ^{o}API gravity of 33.99 at the 29^{o}C.

Preparation of Laboratory Brine: The brine was prepared using 30g, 50g, 70g and 100g industrial sodium chloride (NaCl) in 1000liters of distilled water. The 30000ppm salinity was used for secondary flooding while the 50000ppm, 70000ppm and 100000ppm were used for tertiary flooding. The density of the formulated 30000ppm brine is1.0218g/cm^3.

Nanofluids Preparation: The copper oxide, silicon oxide and zinc oxide nanoparticles used in this research were gotten from JoeChem Chemical Shop Port Harcourt, River's state, Nigeria. 0.1g of each of the selected nanoparticles of silicon oxide, copper oxide, zinc oxide was dissolved in equal volume of 1000ml of brine respectively as to acquire homogeneous mixture of different enhanced oil recovery agents at 50000ppm, 70000ppm and 100000ppm.

3.2 Experimental Procedure

i. The nine unconsolidated Niger - Delta core sampleslabelled B1 to B9 were cleaned and fully dried in an oven. B1 to B3, B4 to B6 and B7-B9 are different core samples that were flooded with different salinity of 50000ppm, 70000ppm and 100000ppm nanofluids formulated with 0.1g zinc oxide, silicon oxide and copper oxide respectively.
ii. The various core's weight, length and diameter were measured, and the results are presented in Table 2.
iii. The cores were fully submerged or saturated in a laboratory brine water as to measure the saturated weight of the individual core samples.
iv. The pore volume of each core sample was calculated using Equation 1, by subtracting the saturated weight from dry weight and the result was divided by thedensity of the brine solution and result is shown in Table 4.
v. The porosity was determined by using the result obtained from bulk volume (Table 2) and pore volume (Table 4) using Equation 2.
vi. The flooding experiment started by injecting crude oil into the core to displace the brine solution. It should be noted that not all the brine solution was displaced, and the remaining water is known as connate water.
vii. The same quantity of oil that entered the unconsolidated core is equivalent to brine solution displaced from the core sample at constant flow rate.
viii. The brine (30000ppm) was injected (secondary recovery) into the core to displace crude oil and the amount of oil recovered was measured and recorded. The laboratory brine water injection was a control experiment.

ix. Other laboratory experiments were carried out following the above procedures. The water breakthrough time was recorded.

x. The different concentrations of nanofluid EOR agents at the different salinity range of 50000ppm, 70000ppm and 10000ppmas presented in Table 5 were injected into the individual core until no oil could be recovered at the residual oil saturation.

xi. Finally, the unconsolidated core was removed from the core-holder and re-weighted, the recovered oil was measured, and permeability was determined using Equation 3 and was presented in Table 5.

Pore Volume Equation:

$$PV = \frac{W_{sat.plug} - Weight_{dry\,plug}}{P_{NaCl}} \quad (1)$$

Where; $W_{sat.plug}$ = weight of saturated plug, $Weight_{dry\,plug}$ = weight of dry sample, P_{NaCl} = density ofBrine

Porosity: $$Porosity, \emptyset = \frac{P.V}{B.V} \times 100\% \quad (2)$$

Where, P.V = pore volume, B.V = bulk volume

Permeability: $$K = \frac{Q\mu_{NaCl/KCl} L_{plug} 14700}{A_{plug} \Delta P} \quad (3)$$

Where, Q = flow rate, μ_{NaCl} = viscosity of NaCl/KCl (Brine), L_{plug} = length of plug, A_{plug} = cross section area of plug, ΔP = differential pressure and K = permeability.

4. RESULTS AND DISCUSSION

The results of the experimental evaluation using different nanoparticles of copper oxide, zinc oxide and silicon oxide for enhanced oil recovery using different salinity range of 50,000ppm, 70,000ppm and 10,000ppm brine are discussed. It examines the physical characteristics of plug samples, rheological properties, fluid properties, and their effects on oil recovery and permeability with respect to salinity different.

4.1 Petrophysical Results

The physical properties of the plug samples are very importantin interpreting flow behaviour and fluid-rock interactions during enhanced oil recovery (EOR) method. This section presents a detailed results of the characterization for encapsulated plug samples, encompassing their bulk volume, pore volume, porosity, and permeability.

The measured bulk volumes of the encapsulated plug samples varied from 45.12 cm³ and 67.12 cm³ for the samples with identity of B1 to B9, as shown in Table1. B3 sample has the highest bulk volume of 67.12cm^{3}and B8 has the lowest bulk volume of 45.12 cm^3. The range indicates the natural heterogeneity of reservoir rocks, even within a single formation. The variations can be attributed to differences in mineral composition, grain size distribution, and geological history. Understanding this heterogeneity is crucial for designing effective EOR strategies that account for varying flow patterns and fluid-rock interactions.

Table 1. Experimental Result of Bulk volume of an Encapsulated plug Sample

Sample ID	Thickness of stainless screen (cm)	Total length of plug (cm)	Actual plug length (cm)	Plug diameter (cm)	Plug radius (cm)	Bulk volume (cm)
B1	0.036	7.27	7.24	3.35	1.68	64.12
B2	0.036	7.31	7.27	3.36	1.68	64.46
B3	0.036	7.52	7.48	3.37	1.69	67.12
B4	0.036	7.15	7.11	3.36	1.68	63.04
B5	0.036	7.53	7.49	3.34	1.67	65.62
B6	0.036	6.55	6.51	3.36	1.68	57.72
B7	0.036	6.41	6.37	3.21	1.61	51.87
B8	0.036	5.19	5.15	3.34	1.67	45.12
B9	0.036	6.23	6.11	3.34	1.67	53.53

The pore volume reflects the storage capacity of the reservoir, with higher pore volumes indicating a greater potential for oil accumulation. The variability in pore volumes likely stems from differences in pore size distribution, connectivity, and the presence of natural fractures. These factors significantly influence fluid flow and oil recovery during EOR processes. The pore volumes of the plug samples as shown in Table 2, ranges from 19.20cm³ to 25.94cm³ for the plug samples of B8 and B3. This indicates that B3 plug can contain more reservoir fluid and vice versa for B8.

The porosity values were calculated using Equation 2, as shown in Table 2, which varies from 34.99% to 42.55%. It measures the accessible pore space within the rock matrix, directly impacting fluid flow and oil recovery potential. The observed variations in porosity suggest a degree of heterogeneity in pore structure and connectivity within the reservoir. This heterogeneity needs to be considered when modelling and predicting fluid displacement mechanisms during EOR.

Generally, the analysis of plug characterization results underscores the importance of capturing reservoir heterogeneity and its implications for EOR processes. The observed variations in bulk volume, pore volume, and porosity highlight the complexities of the reservoir system and the need for tailored EOR strategies that can address these variations effectively. Understanding these characteristics is essential for designing efficient and successful EOR operations that maximize oil recovery while minimizing potential risks and uncertainties.

Table 2. Experimental Result of pore volume of an Encapsulated plug Sample

Sample ID	Weight of stainless Screen +foil (g)	Weight of stainless screen + foil + dry plug (g)	Weight of dry plug sample (g)	Weight of stainless screen + foil + sat plug (g)	Weight of saturated plug in brine (g)	Density of brine (g/cm^3)	Pore volume (cm^3)	Porosity
B1	25.66	125.45	99.79	149.88	24.38	1.0207	23.89	37.26
B2	30.46	134.09	103.63	128.74	25.11	1.0207	24.60	38.16
B3	31.84	136.74	104.90	131.38	26.48	1.0207	25.94	38.64
B4	35.28	143.05	107.77	132.59	24.82	1.0207	24.32	38.58
B5	32.00	148.72	116.72	140.16	23.44	1.0207	22.96	34.99
B6	32.46	138.10	105.64	129.64	24.00	1.0207	23.51	40.73
B7	22.44	99.71	77.27	98.46	21.19	1.0207	20.76	40.02
B8	22.45	111.59	88.14	108.55	20.41	1.0207	19.20	42.55
B9	31.62	134.34	103.91	130.22	24.46	1.0207	23.96	43.85

4.2 Fluid Properties

The density of the concentrations (different nanofluids) as measured are presented in Table 3. Fluid density govern fluid flow, displacement mechanisms, and interactions with the rock matrix, ultimately shaping the effectiveness of EOR strategies. A meticulous examination of these Tables 3 will illuminate trends and variations in fluidproperties, sparking insights into their potential impact on oil recovery.

Table 3 reveals variations in density and pH for all the different nanofluid concentrations. The density values for the nanofluids ranges from 1.0002 to 1.0048 g/cm³, brine has 1.0207g/cm³ and crude oil has 0.9996 g/cm³. (Table 3).It was observed that as the salinity concentration increases the PH decreases to 5.5.

Table 3. Experimental Result of Fluid Density

Fluid sample	Weight of density bottle (g)	Weight of density bottle + fluid sample (g)	Weight of fluid sample (g)	volume of density bottle (cm^3)	Density of fluid sample	PH
Brine	24.25	75.15	50.90	49.87	1.0207	
5000 ppm						
ZnO 0.1%/brine	24.25	74.23	49.98	49.87	1.0022	7.90
CuO 0.1%/brine	24.25	74.22	49.97	49.87	1.0020	7.30
SiO_2 0.1%/brine	24.25	74.13	49.88	49.87	1.0002	8.10
7000 ppm						
ZnO 0.1%/brine	24.25	74.28	50.03	49.87	1.0032	6.40
CuO 0.1%/brine	24.25	74.24	49.99	49.87	1.0024	6.20
SiO_2 0.1%/brine	24.25	74.16	49.91	49.87	1.0008	6.70
10000ppm						
ZnO 0.1%/brine	24.25	74.36	50.11	49.87	1.0048	5.70
CuO 0.1%/brine	24.25	74.28	50.03	49.87	1.0032	5.50
SiO_2 0.1%/brine	24.25	74.24	49.99	49.87	1.0024	6.10

Table 4 showcases the kinematic viscosity values for each fluid at 29°C. Notably, crude oil exhibits the highest viscosity (12.22 cp), significantly hindering its flow compared to brine and nanofluids. Among nanofluids, a slight increase in viscosity is observed with increasing nanoparticle concentration, indicating potential changes in flow behaviour and interaction with the rock matrix. However, these increases are relatively small compared to the viscosity of crude oil, suggesting potential benefits for enhanced oil mobility with nanofluids.

Dividing kinematic viscosity with fluid density, we can calculate the dynamic viscosity for each sample. Crude oil again shines a spotlight with its high dynamic viscosity (12.22 cp), further emphasizing its flow resistance. The nanofluids, despite a minor

rise in kinematic viscosity, show a limited increase in dynamic viscosity compared to brine. This observation reinforces the potential of nanofluids to improve flow conditions and facilitate oil displacement within the reservoir.

The analysis of fluid properties highlights crucial factors for EOR effectiveness. The low density and viscosity of nanofluids compared to crude oil suggest their potential to overcome oil's inertia and enhance flow. Additionally, the minimal variations in pH between fluids minimize concerns about rock alteration or incompatibility. Further investigating the interplay between these properties and oil recovery data in subsequent sections will reveal the true impact of nanofluids on EOR performance.

The fluid properties of brine, crude oil, and nanofluids play a crucial role in EOR. Crude oil's high viscosity and density compared to brine hinder its flow, while nanofluids offer a promising alternative with their lower viscosities. Table 4 reveals a slight increase in viscosity with increasing nanofluid concentration, suggesting potential trade-offs between enhanced flow and nanoparticle aggregation. Density variations within the tested fluids are minimal, suggesting negligible impact on buoyancy-driven flow mechanisms

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Table 4. Kinematic and Dynamic Viscosity of Fluids

Fluid sample ID	Fluids concentration	Salinity Concentration (ppm)	Density of Fluid (g/cm3)	Kinematic Viscosity (cp)	Dynamic Viscosity (cp)
Z 1	ZnO 0.1%/brine	50,000	1.0207	2.6219	2.6761
C1	CuO 0.1%/brine		1.0022	1.9464	1.9507
S1	SiO_2 0.1%/brine		1.002	1.5542	1.5573
Z2	ZnO 0.1%/brine	70,000	1.0002	2.6583	2.6588
C2	CuO 0.1%/brine		1.0032	2.1856	2.1926
S2	SiO_2 0.1%/brine		1.0024	1.8411	1.8455
Z3	ZnO 0.1%/brine	10,000	1.0008	3.8236	3.8267
C3	CuO 0.1%/brine		1.0048	3.3138	3.3297
S3	SiO_2 0.1%/brine		1.0032	1.9398	1.946

4.3 Oil Recovery using Secondary and Tertiary Methods

The flooding experiment unveils the oil recovery results achieved with different nanofluids formulated with zinc oxide, silicon oxide and copper oxide using different nanofluids formulated with different salinity ranges of 5000ppm, 7000ppm, and 10000ppm.

Table 5 showcases the original oil in place (OOIP), secondary recovery, tertiary recovery, residual oil, cumulative recovery, and percentage recovery using different formulated nanofluids under various salinity range. The initial oil originally (OOIP) in the plug samples ranged from 14 to 22 ml, indicating a moderate oil content. Secondary recovery with 30,000ppm brine achieved a maximum of 16 ml recovery and the minimum value of 10ml indicating the limitation of conventional flooding techniques hence introduction of EOR methods. Tertiary recovery using nanofluids of the same concentrations of 0.1wt.% for Zinc oxide, Copper oxide and silicon oxide using different salinity concentration yielded additional oil, ranging from 1ml to 3.5 ml. The nanofluids dispersed in 50,000ppm achieved a tertiary recovery of 2.0ml to 3.5ml while that for 70,000ppm gave recovery of 2.5ml to 3.5ml and 10,000ppm gave1ml to 3ml with respect to the volume of original oil in place.The residual oil is the oil that remain after the secondary and tertiary recovery regarding the original oil in place, and it ranges from 2ml to 7ml suggesting incomplete displacement.

Percentage cumulative oil recovery was gotten by combining secondary and tertiary recovery which gave the maximum recovery of 87.50% and minimum recovery of 55% for all the fluid investigated, indicating a positive impact of nanofluids on oil recovery for the various salinity range examined (Table 5 and Fig. 1). Generally, it was observed that nanofluid formulated with 50,000ppm gave the highest oil recovery with the cumulative oil recovery of 87.50% with SiO_2 0.1%/ in brine among all the nanofluids evaluated. It was also observed that increasing concentration from 50000ppm to 10000ppm decreases oil recovery at the constant concentration of 0.1wt% brine (Table 5). This is because in a high salinity formation, the ionic strength is high, and causes the compression of the electric double layer (EDL) and leads to lower zeta potential. ZP quantifies the surface charge to examine the stability of the produced nanoparticle in terms of dispersion.

Table 5. Oil Recovery Performance with Nanofluids and Brine Flooding

Sample ID	Salinity Concentration (ppm)	OOIP (ml)	Secondary recovery (ml)	Fluids concentration	Tertiary recovery (ml)	Residual oil (ml)	Cumulative Recovery (ml)	Percentage Recovery (%)
B1	5,000	20.00	14.00	ZnO 0.1%/brine	3.00	3.00	17.00	85
B2		21.00	16.00	CuO 0.1%/brine	2.00	2.00	17.00	85
B3		21.00	14.00	SiO_2 0.1%/brine	3.50	2.50	17.50	87.5
B4	7,000	22.00	13.00	ZnO 0.1%/brine	3.50	5.50	16.50	77.5
B5		20.00	13.00	CuO 0.1%/brine	2.50	4.50	15.50	80
B6		21.00	13.00	SiO_2 0.1%/brine	3.00	5.00	16.00	82.5
B7	10,000	14.00	10.00	ZnO 0.1%/brine	1.00	3.00	11.00	55
B8		20.00	11.00	CuO 0.1%/brine	2.00	7.00	13.00	65
B9		20.00	12.00	SiO_2 0.1%/brine	3.00	5.00	15.00	75

Zinc oxide nanofluid increases oil recovery from 85% to 77.5% to 55% for 50000ppm, 70000ppm and 10000ppm salinityrange respectively for 0.1wt% concentrations(Figs. 2 and 3).There is a sharp drop in oil recovery for the 10000ppm salinity. The recovery acquired by silicon oxide nanofluids using the three investigated salinity ranges decreases gradually from 87.50% to 82.5% to 75% all at 0.1wt%. Copper oxide increases recovery gradually from 85% to 80% for the salinity concentrations of 50000ppm and 70000ppm but recovery dropped sharply at 10000ppm at 0.1wt.% to 65%. The results show that athigher concentration of 10000ppm brine there is a much decrease in oil recovery.

Water cut, representing the proportion of produced water, increased as expected with oil recovery. Breakthrough time and pressure drop during drainage varied slightly between experiments, requiring further analysis to identify correlations with fluid properties or reservoir conditions.Table 5 and Fig. 3 shines a spotlight on the transformative power of nanofluids. Tertiary recovery with nanofluids consistently surpassed brine flooding, demonstrating their ability to mobilize previously trapped oil. S_iO_2 nanofluids generally achieved slightly higher oil recovery compared to CuO and ZnO, indicating potential differences in their interaction with the rock-oil interface and mobilization mechanisms. However, residual oil remains after nanofluid injection, suggesting further optimization of nanofluid formulation and injection strategies is needed to maximize oil extraction

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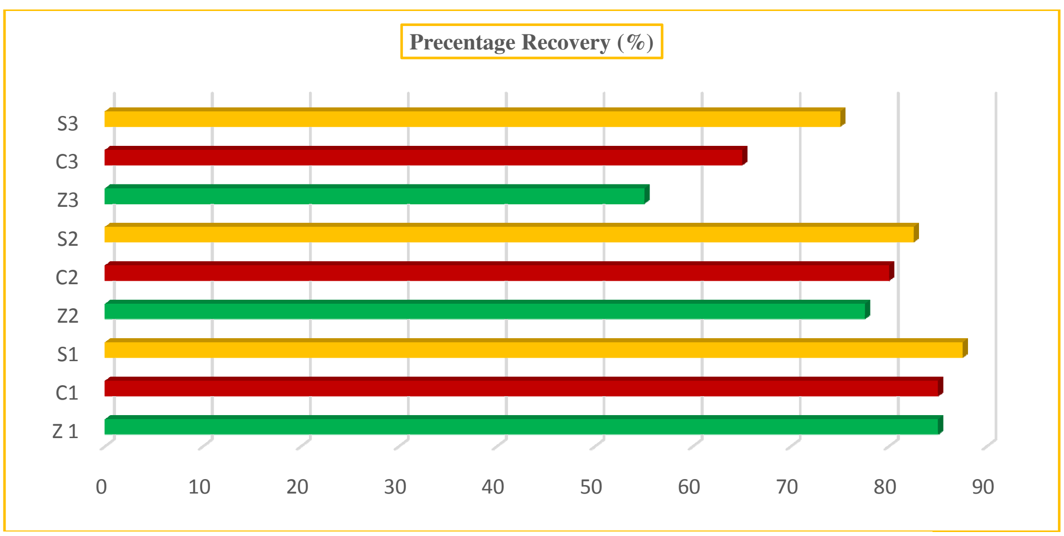

Fig. 2.*Cumulative Oil Recovery vs Fluid Concentration*

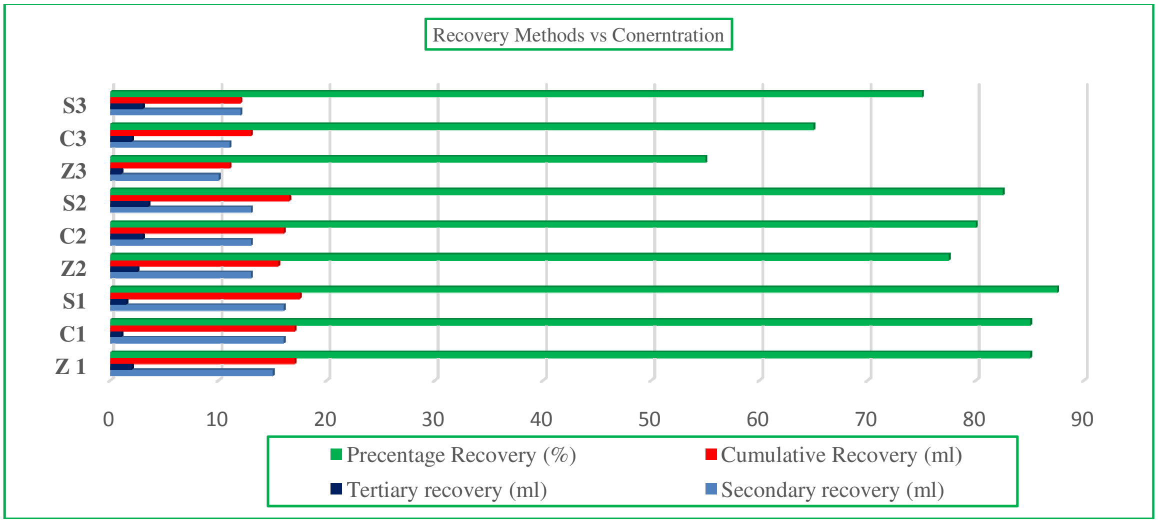

Fig. 3.*Recovery methods vs fluid concentration*

4.2 Permeability Change Result

After the secondary and tertiary flooding, the core's permeability was measured as to evaluate the extent of formation damage caused by EOR agents under various salinity range of 50000ppm, 70000ppm and 10000ppm. There is a significant decrease in permeability of the reservoir formation after the tertiary flooding most especially with fluid solution of 10000ppm salinity concentration.Fig. 5 show the change in permeability at 0.1wt.% zinc oxide, copper oxide and silicon oxide nanoparticles using the different concentration of various salinity. Permeability alteration for 50000ppm salinity concentrations gave the lowest permeability change which ranges from312.65 md to 576.34md. The lowest value of 312.65 md permeability change was gotten from fluid concentration of 0.1g silicon oxide in 50000ppm brine as to compare to 530.95md of 0.1g silicon oxide in70000ppm and 645.65 md for 10000ppm respectively. It was observed that the increase in salinity affect the formation negatively and this bring about increase in permeability and porosity damage and lowers oil recovery.

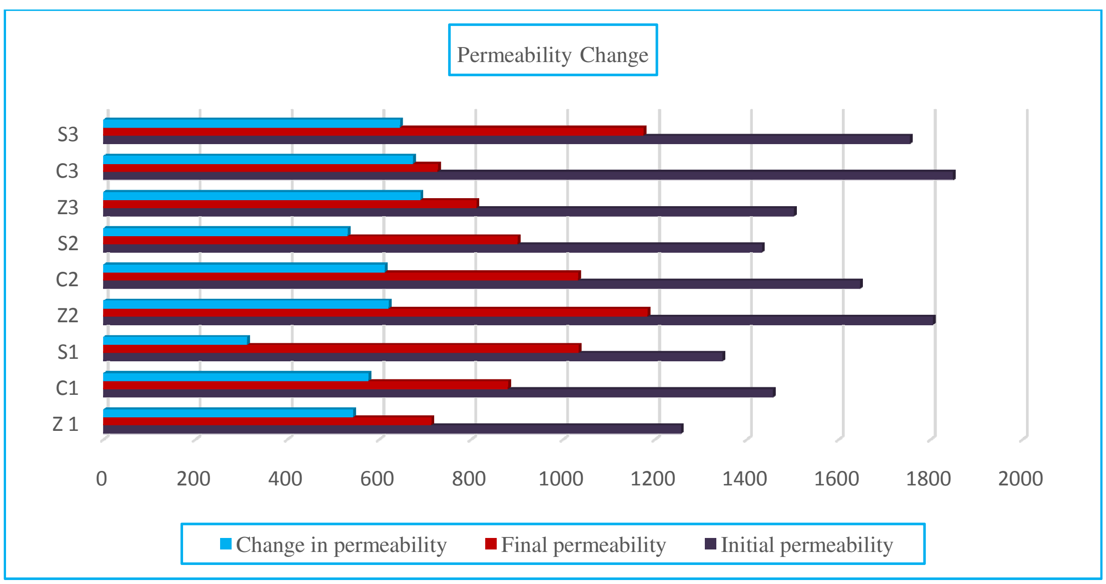

Fig. 5*. Permeability Alteration for different concentration of EOR agents*

5. CONCLUSION

Nanoparticlesof copper oxide, zinc oxide and silica Oxide were used to investigate enhanced oil recovery using different salinity concentrations of 50000ppm, 70000ppm, and 10000ppm.The concentrations of the three nanoparticles were kept at 0.1wt% constant. The experimental results revealed that increase in sodium chloride decreases oil recovery due to decrease in Zeta potential as related to the decreased P^H values obtained from different formulated nanofluids. 50000ppm formulated nanofluids generally gave the highest oil recovery of 87.5% using silicon oxide nanoparticles followed by copper and zinc oxide that gave 85% cumulative recovery respectively. At the salinity of 10000ppm, the silicon oxide recovered 75% cumulative oil while copper and zinc oxide achieved 65% and 55% respectively. Silicon oxide performed better than other investigated nanoparticles for all the salinity ranges studied. The increase in salinity also increases permeability damage.

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