



Experimental Study on the Combination of Nanoparticles and Surfactant Solutions to Investigate Various Mechanisms in Enhanced Oil Recovery

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ABSTRACT

Conducting enhanced oil recovery (EOR) operations remains a critical challenge in the petroleum industry, necessitating innovative techniques to increase the efficiency of production from mature and low-permeability oil reservoirs. In this paper, a hybrid approach combining silica (SiO_2) and gamma-alumina ($\gamma\text{-Al}_2\text{O}_3$) nanoparticles with an anionic surfactant was experimentally investigated to assess their combined effects on key solution properties. Experiments were conducted under constant salinity and temperature to evaluate changes in wettability, interfacial tension (IFT), viscosity, density, and pH. A Central Composite Design (CCD) method was employed to optimize the concentration of nanoparticles and analyze their interactions with SDS. Results indicated that the formulated hybrid nanofluid substantially altered the wettability of the oil-wet glass surface, as indicated by the increase in the contact angle. The lowest IFT (1.485 mN/m) was achieved with one formulation, while the formulation selected for micromodel flooding (0.09 wt% SiO_2 + 0.05 wt% $\gamma\text{-Al}_2\text{O}_3$ + 0.1 wt% SDS) was chosen based on its overall performance across the measured properties, particularly wettability alteration and viscosity enhancement. The solutions also exhibited increases in viscosity and density by increasing the concentration of nanoparticles, which may influence fluid mobility and transport behavior. Oil recovery experiments in a quasi two-dimensional glass micromodel confirmed the effectiveness of the selected formulation, achieving an oil recovery of 60.6% of the original oil in place (OOIP) under the investigated conditions, compared with 13% for brine. These findings suggest that the hybrid nanoparticle-surfactant system may improve oil displacement under the investigated laboratory conditions.

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1. Introduction

A staggering 50-70% of the original oil in place (OOIP) remains trapped in mature reservoirs after primary and secondary recovery stages, representing both a significant economic loss and a technical challenge for the global energy industry [3, 10]. This trapped oil is primarily held by high capillary forces within complex pore networks and unfavorable rock-fluid interactions, which conventional water flooding fails to overcome. As easily accessible resources dwindle, the development of advanced enhanced oil recovery (EOR) techniques for unlocking this stranded resource has become paramount, particularly in heterogeneous and low-permeability formations [15]. Traditional EOR methods, including chemical, gas, and thermal injection, have been extensively studied and deployed with varying degrees of success [15, 30]. However, their effectiveness is often hampered by high costs, operational complexities, and environmental concerns [2]. Among emerging technologies, nanotechnology has attracted considerable attention because of its ability to engineer fluid properties and manipulate interfacial phenomena at the pore scale [14, 17]. The high surface-area-to-volume ratio, tunable surface chemistry, and superior mobility of nanoparticles (NPs) within porous media enable mechanisms such as significant IFT reduction, profound wettability alteration, and viscosity enhancement, which are challenging to achieve with conventional chemical agents [18, 29]. SmartWater-based technologies have been shown to improve oil recovery through wettability alteration and interfacial tension reduction in carbonate reservoirs [4].

Among the diverse range of nanomaterials, silica nanoparticles (SiO_2) have been the most widely investigated for EOR applications due to their chemical inertness, high stability, and favorable interactions with reservoir rocks.

Chen et al. [5] demonstrated that SiO_2 NPs could effectively shift the wettability of carbonate rocks towards a more water-wet state. These findings were corroborated by Kalantari et al. [13], who reported an approximate 30% increase in oil recovery attributed to IFT reduction and favorable wettability alteration. Rezaei et al. [21] further confirmed the effectiveness of silica nanoparticles in altering wettability and improving oil recovery. Polymer-enhanced low-salinity brine flooding has also been reported to improve displacement efficiency by controlling in-situ mixing and salt dispersion during waterflooding [6]. Despite these promising results, a consensus has emerged that many foundational studies on silica NPs overlook critical aspects such as long-term colloidal stability under reservoir conditions, the susceptibility to aggregation in high-salinity environments, and the ability to predict performance under heterogeneous mineralogical conditions [9, 16]. Following silica, gamma-alumina nanoparticles ($\gamma\text{-Al}_2\text{O}_3$) have garnered attention for their distinct surface properties and potential to enhance fluid rheology. Feng et al. [8] reported that $\gamma\text{-Al}_2\text{O}_3$ nanoparticles could improve fluid properties and contribute to wettability alteration, highlighting their potential for enhanced oil recovery applications. The physicochemical properties of $\gamma\text{-Al}_2\text{O}_3$, including its surface charge characteristics, may complement those of silica nanoparticles. However, compared with single-nanoparticle systems, hybrid silica–alumina formulations have received relatively limited attention. Beyond silica and alumina, other metal oxide nanoparticles such as TiO_2 have also demonstrated promising EOR performance. Jafarbeigi et al. [11] reported significant wettability alteration and interfacial tension reduction using TiO_2 -based nanoparticles,

while Zhao et al. [30] summarized the performance of a wide range of metal oxide nanomaterials in enhanced oil recovery. Ahmad et al. [1] showed that hybrid nanofluids containing SiO₂ nanoparticles with anionic surfactants significantly reduced interfacial tension and altered wettability in carbonate reservoirs. Jafarbeigi et al. [11] reported that TiO₂ nanoparticles combined with surfactants effectively modified surface properties and improved oil recovery. Qu et al. [20] developed monodisperse silica nanoparticles with superior stability for low-permeability reservoirs, highlighting the potential of tailored nanomaterials for EOR applications. Low salinity polymer flooding has been shown to significantly improve polymer rheology, injectivity, and oil recovery efficiency compared with the conventional polymer flooding [12]. The integration of nanoparticles with surfactants represents a combined approach in chemical EOR, designed to overcome the limitations of either agent used alone. Surfactants can stabilize nanoparticle dispersions and enhance their adsorption at interfaces, while nanoparticles can improve the thermal stability and reduce the adsorption loss of surfactants [22, 29].

The surface properties of silica and alumina nanoparticle additives suggest that their combined use may provide synergistic effects in hybrid systems. While single-nanoparticle systems have been extensively studied, the interaction between two distinct types of nanoparticles and the effect of their combination with surfactants on interfacial phenomena remains largely unexplored. Zhao et al. [30] emphasized, in their comprehensive review, the critical need for systematic multi-parameter optimization studies on binary nanoparticle systems to advance the design of nanofluids for EOR. Previous studies have shown that combining nanoparticles with surfactants can enhance interfacial activity

compared with the use of either component alone [1]. Similarly, Wang et al. [28] reported improved oil recovery by integrating surfactant-based chemical flooding with complementary EOR strategies, highlighting the potential benefit of combining different recovery mechanisms. Narendra and Ajay Kumar [19] also reported improved oil recovery through wettability alteration using surfactant-stabilized nanoemulsions. Recent studies have further improved the understanding of nanofluid behavior under conditions relevant to enhanced oil recovery. Several recent studies have addressed nanoparticle distribution and pH influence in porous environments [23, 31]. Additional findings on nanofluid stability under reservoir conditions were reported by Mehra et al. [17] and Tohidi et al. [26], who highlighted future opportunities in Janus nanoparticles, a type of nanoparticle with two distinct surface chemistries, and other functionalized nanomaterials for targeted EOR applications. Addressing these limitations is important for developing more reliable hybrid nanofluids with improved displacement efficiency under practical reservoir conditions. By understanding the interactions between nanoparticles and surfactants, it becomes possible to design formulations that simultaneously target multiple mechanisms, such as recovery, wettability alteration, IFT reduction, and mobility control, leading to improved displacement efficiency under challenging reservoir conditions.

Despite these advancements, critical research gaps persist. First, there is a lack of studies on systematic, multi-parameter optimization that simultaneously evaluate the interactive effects of binary nanoparticle systems on key EOR performance indicators. Second, the majority of research on hybrid nanofluids has focused on nanoparticle-surfactant pairs, with investigation into the combined effects

resulting from the integration of two distinct types of nanoparticles have been limited. Finally, a robust integration of statistical optimization methodologies with direct pore-scale visualization techniques is often missing, limiting the generalization of laboratory findings to predictable performance at field scale. Based on these observations, this study investigates a hybrid nanofluid composed of SiO_2 and $\gamma\text{-Al}_2\text{O}_3$ nanoparticles stabilized with SDS. We employ a Central Composite Design (CCD) to systematically optimize the concentrations of both nanoparticles and to analyze their combined effects on IFT, wettability, viscosity, density, and pH. The formulation selected based on the CCD results was subsequently evaluated through micromodel flooding experiments to assess its performance in oil displacement under controlled laboratory conditions.

The novelty of this study lies in integrating statistical optimization, using the Central

Composite Design (CCD) approach, with validation at the pore scale through glass micromodel flooding experiments. This integrated methodology provides a comprehensive evaluation of the combined effects of silica nanoparticles, γ -alumina nanoparticles, and SDS surfactant on the key mechanisms governing enhanced oil recovery.

2. Materials and methods

2.1. Materials

Silica (SiO_2) and gamma-alumina ($\gamma\text{-Al}_2\text{O}_3$) nanoparticles were purchased from Pishgaman Nanomaterials Co. (Iran). The main physicochemical properties of the nanoparticles, as provided by the manufacturer, are summarized in Table 1. Sodium Dodecyl Sulfate (SDS), an anionic surfactant with a purity exceeding 99%, was obtained from Merck KGaA (Germany).

Table 1.

Properties of the nanoparticles used for preparing the solution designed by the design expert software

Nanoparticle Name	Chemical Formula	Particle Size (nm)	Specific Surface Area (m^2/g)	Density (g/cm^3)
Alumina	Al_2O_3	20	65-90	3.89
Silica	SiO_2	20	100-180	~ 2.2

Table 2 summarizes the critical properties of SDS. To simulate reservoir conditions,

synthetic brine with a total salinity of approximately 12,000 ppm was prepared.

Table 2.

properties of the surfactant used for stabilizing nanoparticles in prepared solutions

Name	Chemical Formula	Molecular Weight (g/mol)	Density (g/cm^3)	Flash Point	Critical Micelle Concentration (CMC)
Sodium Dodecyl Sulfate	$\text{NaC}_{12}\text{H}_{25}\text{SO}_4$	288.38	1.1	206°C	8.2 mM at 25°C

As detailed in Table 3, the brine's ionic composition was primarily composed of chloride, sodium, and sulfate ions. All interfacial characterization and flooding experiments were carried out using a medium

crude oil obtained from an Iranian reservoir. Table 3 also includes the fundamental properties of this crude oil, such as its API gravity, viscosity, and SARA analysis. The experiments were intentionally performed at

ambient temperature to provide consistent laboratory conditions and to enable a reliable comparison of the effects of the concentration of nanoparticles on the measured properties. The evaluation of the optimized nanofluid under reservoir temperature conditions is recommended for future studies. The objective of the present study was to investigate the

fundamental mechanisms governing the interaction between silica, $\gamma\text{-Al}_2\text{O}_3$ nanoparticles, and SDS under well-controlled laboratory conditions. Therefore, experiments were intentionally conducted at ambient temperature (25 °C), while evaluation at temperatures representative of the reservoir is considered a subject for future investigation.

Table 3.

Properties of the crude oil and saline water used for the contact angle, IFT, and injection tests

Oil Properties	value	Water ion compositions	Concentration (ppm)
Specific Gravity	0.834	Chloride	5517
API Gravity	36.36	Sodium	4470
Pour Point (°C)	21	Sulfate	1500
Saturates (%)	65.8	Magnesium	500
Aromatics (%)	14.4	Potassium	100
Resins (%)	3.6	Calcium	160
Asphaltenes (%)	1.2	--	--
Viscosity (cP)	12.2	--	--
Density (g/cm ³)	0.837	--	--

Fig. 1(a) presents a schematic illustration of the quasi-two-dimensional glass micromodel setup used in the flooding experiments. The system consisted of a syringe pump for controlled fluid injection, a glass micromodel holder, and an optical imaging system for the real-time monitoring of the displacement process. Figure 1(b) illustrates the

experimental workflow used for fluid characterization, including the measurements of interfacial tension, contact angle, viscosity, density, and pH before the flooding experiments. This workflow allowed the relationship between the measured fluid properties and the flooding performance to be evaluated in a systematic manner.

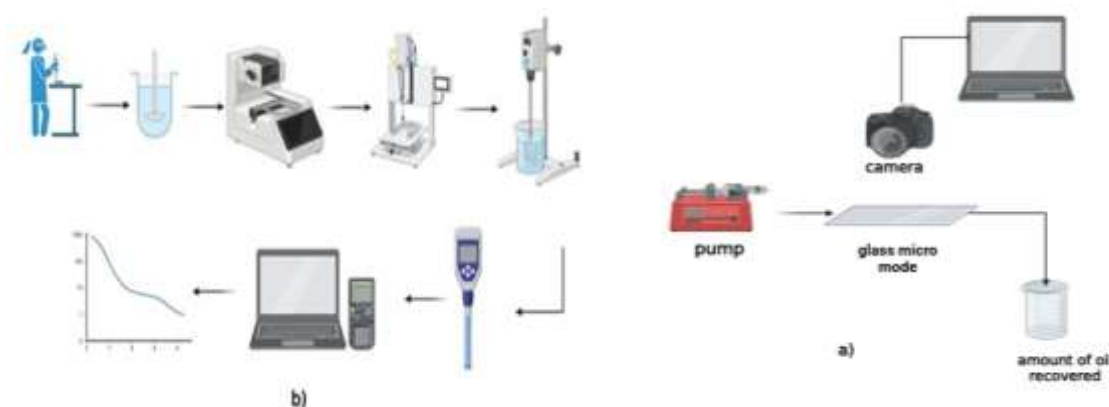


Figure 1. Experimental setup for oil recovery and solution property tests. (a) Diagram of the injection procedure used to assess the oil recovery in the glass micromodel. (b) Flowchart of the steps followed for testing surface and rheological properties, including the contact angle, interfacial tension, viscosity, and pH measurements. This setup ensures a controlled evaluation of nanofluid performance, allowing simultaneous investigation of displacement efficiency at the pore scale and changes in fluid properties.

2.2. Experimental procedure

To prepare stable nanofluids, a two-step dispersion method was employed. First, a concentrated master suspension was prepared. This was done by dispersing a total of 0.75 grams of an equal-weight mixture of silica and alumina nanoparticles in 149.25 grams of synthetic brine. This master batch was then subjected to 1 hour of homogenization in an ultrasonic bath (Elma, Germany). Throughout this step, the bath was kept at 0-4°C using an ice-water mixture, a precaution taken to prevent thermal degradation and reduce the tendency of the nanoparticles, particularly alumina, to aggregate. The specific nanofluid compositions required for the CCD matrix, detailed in Table 4, were then prepared by accurately diluting this master batch with

additional synthetic brine. Subsequently, SDS was added to each formulation to obtain a final concentration of 0.1 wt% of the surfactant. To ensure complete dissolution and integration of the SDS, each solution was first stirred magnetically (Heidolph, Germany) for 10 minutes. A final 20-minute cycle in the ultrasonic bath concluded the preparation, a final 20-minute ultrasonication step was applied to obtain a homogeneous nanofluid before characterization and flooding experiments. The experimental design was based on a Central Composite Design with 12 runs, including three replicates at the center point (0.05 wt% SiO₂ + 0.05 wt% Al₂O₃). The center point replicates were performed to evaluate experimental repeatability and to estimate the pure error of the measurements.

Table 4.

Experimental design and determination of the quantities of materials in each solution. The experimental design consisted of 12 runs in total, including three replicates at the center point (0.05 wt% SiO₂ + 0.05 wt% Al₂O₃). The center point replicates were used to estimate experimental error and are not listed individually in this table.

Silica(wt%)	Alumina(wt%)	SDS(wt%)
0.03	0.03	0.1
0.01	0.05	0.1
0.05	0.01	0.1
0.03	0.07	0.1
0.05	0.05	0.1
0.05	0.09	0.1
0.07	0.03	0.1
0.07	0.07	0.1
0.09	0.05	0.1

A quasi-two-dimensional glass micromodel, illustrated in Figure 2, was designed and fabricated to replicate the porous structure of reservoir rocks. The micromodel was used to visualize fluid displacement and evaluate oil recovery performance at the pore scale. Its

physical properties, including dimensions and porosity, are listed in Table 5. To simulate oil-wet reservoir conditions, the glass plates were immersed in a solution containing 2 wt% silane and 98 wt% toluene for 5 min, followed by drying.



Figure 2. Two-dimensional glass micromodel used for oil recovery tests. The micromodel was treated with a mixture of 2 wt% silane and 98 wt% toluene to create oil-wet conditions, simulating a reservoir environment for evaluation. This treatment provides a realistic representation of reservoir wettability, which is critical for assessing the effectiveness of nanofluids under conditions that mimic actual subsurface formations.

Table 5.

Properties of the glass micromodel used for oil recovery tests

Pore Volume	Porosity	Height (μm)	Width (cm)	Length (cm)
1286.145	40.83%	1	3.5	9

All experiments, from fluid property measurements to the flooding tests, were carried out at a constant temperature of 25°C. This temperature was chosen as a practical and controlled baseline for our laboratory investigations, ensuring consistent and repeatable results. For the flooding tests, the nanofluid was injected at a constant rate of 0.7 mL/hour, which often falls within the range of 120 to 150 barrels per day. This approach strengthens the practical relevance of our laboratory findings. Furthermore, the injection volume was standardized at 1 pore volume (PV). This is a conventional practice in core and micromodel flooding studies, as it provides a clear and consistent benchmark for comparing the displacement efficiency of different fluids under identical conditions.

The prepared nanofluids were characterized by measuring the contact angle, interfacial tension, viscosity, density, and pH. To ensure reliability, all tests were performed under consistent temperature and pressure, with

equipment regularly calibrated. All fluid properties measurements were performed in triplicate. The micromodel flooding experiment was conducted as a single screening test for the selected formulation and brine reference under identical operating conditions.

2.3. Contact angle and IFT tests

In the contact angle experiment, glass slides were initially treated to achieve oil-wet conditions by immersing them in a 2 wt% silane solution dissolved in 98 wt% toluene for 5 minutes. The contact angle measurements were performed using the sessile drop method in air after immersion of the glass slides in the nanofluid. This ex-situ procedure was adopted to evaluate the persistent wettability alteration resulting from the nanoparticle adsorption on the surface, following the methodology reported in previous nanoparticle-assisted EOR studies [7, 5]. The contact angle values reported here therefore represent the surface

condition after treatment and removal from the nanofluid, rather than the wettability under dynamic immersion conditions. This treatment was used to produce a reproducible oil-affine surface for the wettability experiments. After this pre-treatment, the initial contact angle of oil on the glass surface was measured using a goniometer (Krüss DSA25, Germany) with an accuracy of $\pm 0.1^\circ$. This method is widely used in studies on wettability alteration to quantify the degree of surface hydrophobicity or hydrophilicity. Subsequently, the pre-treated glass slides were immersed in the nanofluid solutions, as detailed in Table 4, for 20 minutes to allow the nanoparticles and surfactant to interact with the surface and alter its wettability. After immersion, the slides were carefully removed from the nanofluid, and any excess liquid was gently drained. The contact angle was then measured immediately by placing a crude oil droplet on the treated surface in air environment. This approach directly assesses the persistent wettability alteration induced by nanoparticle and surfactant adsorption onto the solid surface. After the immersion period, a droplet of the crude oil (or standard oil phase) was carefully placed on the treated glass slide. The contact angle between the droplet and the surface was recorded at the equilibrium stage using the goniometer. This test was crucial in evaluating the effectiveness of the nanoparticle and surfactant combination in altering the wettability of the surface from oil-wet to water-wet, which is a critical mechanism in EOR processes. The measured contact angle values are summarized in Table 6, with an experimental standard deviation of 0.942, indicating the consistency of the results across multiple measurements. The objective of the contact angle measurements was to evaluate the persistent wettability alteration resulting from nanoparticle and surfactant adsorption onto the solid surface. Therefore, the

measurements were intentionally performed after immersion and removal from the nanofluid. Although this procedure does not fully reproduce the three-phase reservoir equilibrium, it provides a reproducible laboratory method for comparing the surface-modification capability of different nanofluid formulations under identical experimental conditions. This ex-situ approach is specifically designed to evaluate the persistent wettability alteration induced by nanoparticle adsorption and has been widely employed in previous studies on the nanoparticle-assisted EOR [7, 5]. In this measurement configuration, because the contact angle was measured using a crude-oil droplet on the treated surface in air, an increase in the measured oil contact angle was interpreted as a decrease in the surface affinity toward oil and, consequently, a shift toward more water-wet behavior. This approach has been widely adopted in studies on wettability [7, 5, 11].

The IFT between the crude oil and the nanofluid solutions was measured using the pendant drop method under ambient conditions (25°C). A calibrated drop shape analyzer (Krüss DSA100, Germany) was employed for this purpose. In this setup, a droplet of the nanofluid was carefully dispensed and suspended within a chamber filled with the bulk crude oil phase. The instrument captures the droplet's profile and calculates the IFT value by analyzing its shape based on the Young–Laplace equation. This method is widely accepted and particularly suitable for nanofluid-oil systems as it allows direct observation of the interfacial behavior [24, 25]. To ensure statistical reliability, each measurement was conducted in triplicate, yielding an average standard deviation of 0.141 mN/m across all samples. The observed IFT reduction is a key EOR mechanism, as it directly reduces the capillary forces that trap oil droplets in the pore throats of the reservoir

[29]. The results of these experiments are critical for understanding the mechanism by which nanoparticles, in conjunction with surfactants, alter the surface properties of reservoir rocks and improve the efficiency of the oil displacement. The changes in the contact angle and IFT provide a direct correlation with the potential for enhanced oil recovery in reservoir simulations.

2.4. Viscosity, pH, and density measurements

The viscosity of the nanofluids was measured using a Brookfield DV2T viscometer at a constant shear rate of 100 s^{-1} and 25°C . The density was determined with a calibrated pycnometer, and the pH was recorded using a digital pH meter (± 0.01 accuracy). All measurements were performed under ambient conditions, and each sample was tested in triplicate to ensure statistical reliability. The stability of the prepared nanofluids was qualitatively confirmed by visual observation; no visible sedimentation or phase separation was observed for any formulation within the duration of the experiments. Furthermore, the repeated measurements showed good experimental repeatability; however, these measurements do not provide a quantitative assessment of colloidal stability. The standard deviations for viscosity, density, and pH measurements were 0.818 cP, 0.141 g/cm^3 , and 0.818, respectively, confirming high repeatability. The observed increase in viscosity and density proportional to the concentration of nanoparticles may influence fluid mobility and transport behavior. However, these measurements alone do not provide a quantitative assessment of colloidal stability. The slight shift towards acidity in pH, predominantly influenced by silica nanoparticles, reflects changes in surface chemistry that can affect both nanofluid stability and rock-fluid interactions [29, 15].

The pH of the solutions was recorded using a digital pH meter (± 0.01 accuracy) under ambient conditions to determine the chemical stability and interactions between nanoparticles, surfactant, and brine. The pH measurement serves as an important parameter for understanding the surface chemistry of the solution, which can influence the wettability of reservoir rocks and the overall interaction between oil, water, and surfactant during EOR processes. It was observed that the pH of the solution shifted slightly by increasing the concentration of both SiO_2 and $\gamma\text{-Al}_2\text{O}_3$ nanoparticles. This shift reflects chemical changes that may occur due to the surface charge and reactivity of the nanoparticles in the presence of the surfactant and brine. The pH changes are important because they can affect the IFT and wettability alteration, which play significant roles in improving oil recovery. The slight decrease in pH suggests that the nanoparticles may help to alter the interaction between water and oil phases, enhancing the ability of the fluid to displace oil in a reservoir. The results for pH measurements, with a standard deviation of 0.818, are reported in Table 6, confirming the consistency of the results under identical experimental conditions.

The density of the solutions was determined using a pycnometer, which provided highly accurate measurements of the fluid's specific gravity. Density measurements are essential for understanding the distribution of nanoparticles in the solution and their influence on the fluid's overall behavior in porous media. The density of the solution is an important parameter for characterizing the solution's displacement properties and evaluating its ability to interact with the oil phase during injection. The results showed that the density increased at higher concentrations of SiO_2 and $\gamma\text{-Al}_2\text{O}_3$ nanoparticles. The increase in density is mainly associated with

the higher density of the dispersed nanoparticles compared with the base fluid. The observed density changes were relatively small. However, these measurements alone do not provide sufficient evidence to evaluate the

colloidal stability of the nanofluids. The density data, with a standard deviation of 0.141, is summarized in Table 6, indicating minimal experimental variation across the samples.

Table 6.

Results of IFT, contact angle, viscosity, density and pH measurements for various test samples

Test Number	Solution Compositions	Interfacial Tension (mN/m)	Density (kg/m ³)	Viscosity (cP)	pH	Contact Angle (°)
1	0.03SiO ₂ +0.03Al ₂ O ₃ +0.1SDS	1.54	1024.79	1.81	8.1	65
2	0.01SiO ₂ +0.05Al ₂ O ₃ +0.1SDS	1.62	1024.72	1.65	8.6	72
3	0.05SiO ₂ +0.01Al ₂ O ₃ +0.1SDS	1.485	1025.25	1.84	8	116
4	0.03SiO ₂ +0.07Al ₂ O ₃ +0.1SDS	1.65	1025.33	1.86	8	123
5	0.05SiO ₂ +0.05Al ₂ O ₃ +0.1SDS	1.677	1025.31	1.87	7.9	127
6	0.05SiO ₂ +0.09Al ₂ O ₃ +0.1SDS	1.699	1025.87	1.91	8	128
7	0.07SiO ₂ +0.03Al ₂ O ₃ +0.1SDS	1.68	1025.40	1.88	7.7	130
8	0.07SiO ₂ +0.07Al ₂ O ₃ +0.1SDS	1.69	1025.94	1.98	7.7	132
9	0.09SiO ₂ +0.05Al ₂ O ₃ +0.1SDS	1.707	1026.23	2.28	7.6	135

2.5. Flooding test in the micro-model

The selected formulation, containing 0.09 wt% SiO₂, 0.05 wt% γ -Al₂O₃, and 0.1 wt% SDS, was injected into a glass micromodel pre-saturated with the crude oil. The objective of this experiment was to evaluate its oil displacement performance under the selected experimental conditions. The micromodel, fabricated from glass, was designed to replicate the porous structure of a reservoir rock, providing a controlled environment for investigating oil displacement at the pore scale. The dimensions of the micromodel are as follows: porosity = 40.83%, pore volume = 1286 μ L, and the physical dimensions are 9 cm $\times$ 3.5 cm $\times$ 1 mm. Prior to testing, the micromodel was oil-wet by treating it with a solution containing 2 wt% silane and 98 wt% toluene for 5 minutes, followed by drying. The micromodel was initially saturated with the crude oil under atmospheric pressure, and the original oil in place (OOIP) was determined by

the pore volume and porosity measurements. The volume of the produced oil was measured by visual observation and the image analysis using the calibrated optical imaging system. The recovery factor was calculated as the percentage of the produced oil volume relative to the OOIP. No pressure measurements were recorded during the flooding tests, as the experiments were conducted at ambient pressure. This treatment ensured a consistent and reproducible oil-wet condition, simulating typical reservoir rock properties in oil fields. For the flooding procedure, the selected formulation, containing 0.09 wt% SiO₂, 0.05 wt% γ -Al₂O₃, and 0.1 wt% SDS, was used for the micromodel flooding experiment. The solution was injected at a constant rate of 0.7 mL/hour. The micromodel was initially saturated with the crude oil before the injection process. Following the injection of 1 pore volume (PV) of the nanofluid (0.7 mL/hour for $\sim$ 1.8 hours), the volume of recovered oil was

measured by collecting the produced oil after injection. The objective of the flooding experiment was to compare the displacement performance of the selected formulations under identical operating conditions. The flooding experiment was conducted as a preliminary screening test to compare the selected nanofluid with the reference brine under identical operating conditions. Independent replicate flooding experiments were not performed; therefore, the reported recovery values are presented as preliminary screening results rather than statistically averaged recovery data. Replicate flooding experiments are recommended in future work to assess experimental variability. The recovery efficiency was then calculated by comparing the volume of the oil recovered to the total volume of the oil initially present in the micromodel. This allowed for an accurate evaluation of the displacement efficiency of the nanofluid solution. The detailed flooding results are presented and discussed in the Results and Discussion section. As discussed earlier, the flooding test with the optimal formulation confirmed the performance observed in surface property measurements, as brought in Table 6. The formulation selected for the flooding experiments was not based on a single response parameter, such as the minimum interfacial tension or the maximum contact angle. Instead, it was selected according to the overall comparison of the responses obtained from the Central Composite Design, which simultaneously

considered the contact angle, interfacial tension, viscosity, density, and pH. The formulation was selected by considering the measured contact angle, IFT, viscosity, density, and pH values together rather than relying on a single response.

The ANOVA results, presented in Table 7, indicate that all developed quadratic models, with p-values less than 0.01 for all responses, are statistically significant. The high R^2 values, ranging from 0.9371 to 0.9981, confirm that the models adequately describe the experimental data. The p-values for lack-of-fit for all responses are greater than 0.05, indicating that the models are valid and no significant lack of fit exists. Among the responses, the viscosity model showed the highest F-value (380.58), followed by density (228.38) and IFT (120.30), suggesting that these models have the strongest predictive capability. The final quadratic regression equations obtained from the response surface analysis are presented below. The equations were used to describe the relationship between the concentrations of SiO_2 and $\gamma\text{-Al}_2\text{O}_3$ and the measured responses within the experimental range. The final quadratic regression equations, obtained from the response surface analysis, are presented below. These equations describe the relationship between the independent variables (concentration of SiO_2 , A; concentration of $\gamma\text{-Al}_2\text{O}_3$, B) and each measured response within the investigated experimental range.

$$\text{IFT} = 1.67 + 0.0501A + 0.0195B - 0.0230AB - 0.0036A^2 - 0.0214B^2 - 0.0071A^3 + 0.0085B^3 \quad (1)$$

$$\text{Contact angle} = 106.11 + 17.25A + 6.42B - 12.25AB - 6.45A^2 \quad (2)$$

$$\text{Viscosity} = 1.87 + 0.0108A + 0.0175B + 0.0125AB + 0.0235A^2 + 0.0010B^2 + 0.0200A^2B + 0.0367A^3 \quad (3)$$

$$\text{Density} = 1025.30 + 0.2808A + 0.3038B + 0.0404A^2 + 0.0617B^2 + 0.0242A^3 - 0.0383B^3 \quad (4)$$

$$\text{pH} = 7.87 - 0.1500A - 0.0333B + 0.233B^2 + 0.0483A^2 + 0.0083B^3 - 0.0250A^3 \quad (5)$$

Table 7.

Statistical parameters of the quadratic response surface models for the investigated responses.

Response	R ²	Adjusted R ²	Predicted R ²	Lack-of-fit p-value	F-value	p-value (Model)
IFT	0.9941	0.95	0.91	0.12	120.30	<0.0001
Contact angle	0.9371	0.94	0.89	0.08	29.66	<0.0001
Viscosity	0.9981	0.92	0.87	0.15	380.58	<0.0001
Density	0.9969	0.90	0.85	0.2	228.38	<0.0001
pH	0.9577	0.89	0.83	0.18	22.62	0.0007

The regression models were used to predict the response values within the experimental domain and to identify the formulation with the most favorable overall performance across the measured properties.

These results provide valuable insights into the mechanisms by which nanoparticle-based solutions improve oil recovery. Specifically, the interaction between nanoparticles and the porous medium alters the wettability, reduces the interfacial tension, and improves the displacement efficiency, ultimately enhancing the overall oil recovery from the reservoir model. Although Formulation 3 showed the lowest IFT value of 1.485 mN/m, Formulation 9 was selected for the micromodel flooding experiment because it showed the highest contact angle (135°) among the investigated formulations, together with a low IFT of 1.707 mN/m. The selection was therefore based on considering both wettability alteration and interfacial properties rather than selecting the formulation according to IFT alone. Formulation 9 was consequently used as the selected formulation for the flooding experiment under the same experimental conditions.

3. Results and discussion

3.1. Contact angle evaluation

The results of the contact angle experiments, summarized in Table 6, clearly demonstrate that increasing the concentration of nanoparticles—while keeping the

concentration of the surfactant constant at 0.1 wt%—significantly alters the wettability of the glass substrate from oil-wet to water-wet. The maximum contact angle recorded was 135° in the solution containing 0.09 wt% SiO₂ and 0.05 wt% γ -Al₂O₃, indicating a substantial wettability shift. Based on the experimental design and the measured contact angle values presented in Table 6, the formulation containing 0.09 wt% SiO₂ and 0.05 wt% γ -Al₂O₃ produced the highest contact angle value. Therefore, this formulation was considered the optimum nanoparticle dosage for wettability alteration under the investigated experimental conditions. This outcome reflects the ability of the combined nanofluid system to effectively alter the solid–liquid interfacial energy, which is crucial for EOR applications. The observed increase in the contact angle may be related to the combined presence of the nanoparticles and SDS, which can modify the surface characteristics of the treated glass. However, control experiments involving single components and binary mixtures were not performed in the present study. Therefore, the available results are not sufficient to establish a synergistic interaction among SiO₂, γ -Al₂O₃, and SDS. The observed improvement is consequently described here as a combined effect rather than a demonstrated synergistic effect. These findings are consistent with those of previous research conducted by Ebrahimi et al. [7] and Chen [5], who demonstrated

comparable wettability alteration trends using nanoparticle-assisted EOR techniques under similar experimental conditions.

Figure 3 provides visual confirmation of the contact angle changes. The initial image displays the oil-wet condition of the silanized glass surface (pre-treated with 2 wt% silane in toluene), where the oil droplet spreads widely. In contrast, the post-treatment images demonstrate an increasing contact angle as the concentration of nanoparticles rises, visually confirming the transition from oil-wet to intermediate and finally to water-wet conditions. The measurements were conducted using the sessile drop method with a goniometer at ambient temperature ($\sim 25^{\circ}\text{C}$). Following immersion in the nanofluid, the glass slides were removed and the contact angle was measured immediately by placing a

crude oil droplet on the treated surface in air. This procedure was designed to evaluate the persistent wettability alteration induced by nanoparticle adsorption and to provide a consistent basis for comparing the effectiveness of different formulations. Taken together, these results indicate the hypothesis that nanoparticle-surfactant systems are effective in modifying surface wettability toward more water-wet conditions, thereby improving capillary-driven displacement and, ultimately, oil recovery efficiency. Although this ex-situ method does not fully reproduce the three-phase reservoir equilibrium, it provides a reproducible laboratory method for comparing the surface-modification capability of different nanofluid formulations under identical experimental conditions.

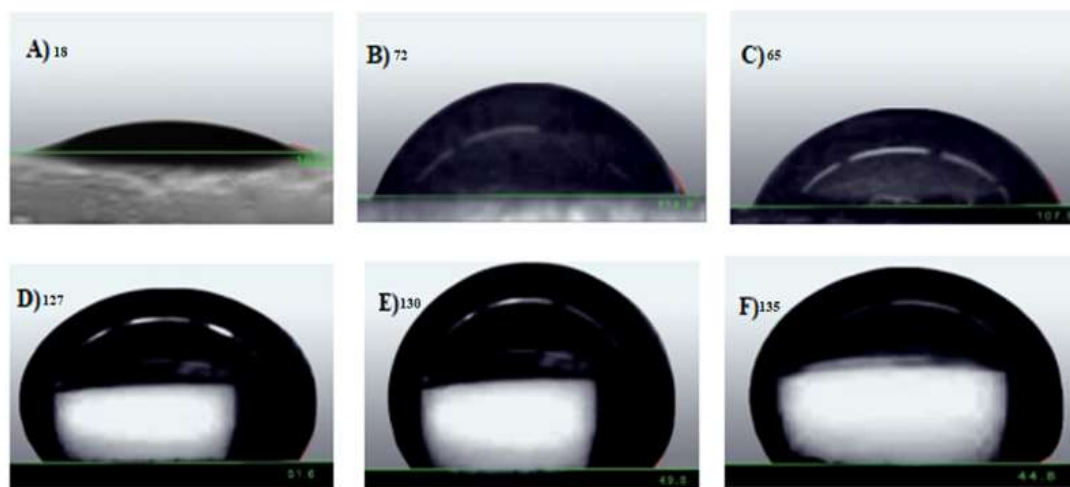


Figure 3. Variation in the contact angle. (a) Initial contact angle on an oil-wet glass surface. (b) Improved wettability after treatment with Solution 1 (0.03 silica + 0.03 alumina). (c–f) Progressive transition toward a water-wet state after treatments with Solutions 2–9 containing varying concentrations of silica and alumina nanoparticles (0.01–0.09 silica, 0.03–0.07 alumina). These images highlight the gradual shift from oil-wet to water-wet conditions, demonstrating the strong impact of the concentration of nanoparticles on wettability alteration, which plays a critical role in enhancing oil recovery performance.

Figures 4 and 5 illustrate the experimental trends and the model's predictive performance using the Design Expert software. As shown in Figure 4, there is a clear positive correlation between the concentration of nanoparticles and

the contact angle. This increase may be related to the adsorption of nanoparticles onto the glass surface, which could modify the surface characteristics and reduce oil affinity. SiO_2 nanoparticles, with their abundant silanol

groups, may create hydrogen bonds with the surface, while γ - Al_2O_3 nanoparticles may enhance surface charge density and promote further adsorption. Similar trends have been reported by Ebrahimi et al. [7], who observed that the contact angle increased from 58° to 112° using alumina nanoparticles on carbonate surfaces, and by Chen et al. [5], who reported wettability alteration from 135° to 65° using SiO_2 nanoparticles. This trend may indicate that increasing the concentration of nanoparticles modifies the surface characteristics and reduces oil affinity. Notably, the presence of silica may contribute to surface hydrophilicity, while γ -alumina may enhance surface charge density and dispersion stability. Fig 5 presents the contact angle variation with respect to the concentration of nanoparticles in ppm (mg/L). The vertical axis represents the contact angle in degrees, while the horizontal axis shows the combined concentration of silica and alumina nanoparticles. These visual data, supported by the experimental model, confirm the robustness and repeatability of the test results.

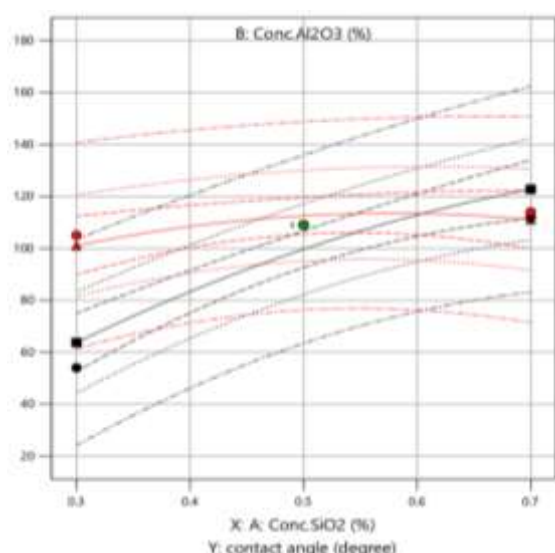


Figure 4. Effect of the concentrations of SiO_2 and γ - Al_2O_3 on the measured contact angle at a constant concentration of 0.1 wt% of SDS. The experimental results show the variation in the contact angle obtained for the nine formulations investigated in the CCD matrix.

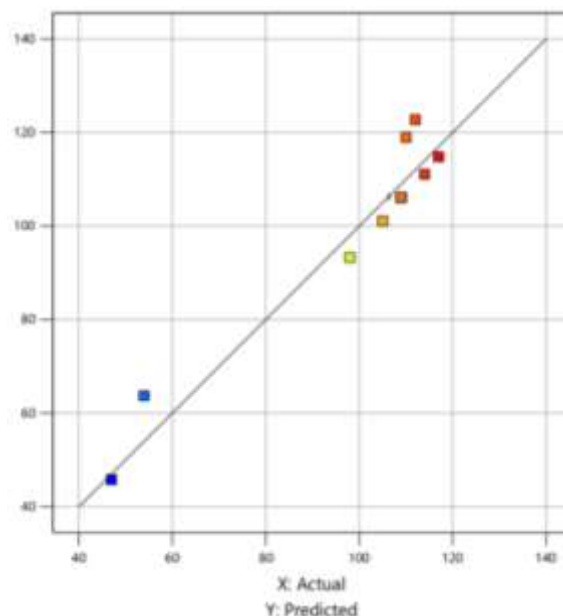


Figure 5. Comparison between the experimental and model-predicted contact angle values obtained from the CCD analysis. The experimental values are plotted against the corresponding predicted values to evaluate the agreement between the model and measurements.

3.2. Changes in IFT with the addition of nanoparticles

The IFT measurements, presented in Table 6, reveal a clear trend influenced by the concentration of nanoparticles at a fixed concentration of the surfactant (0.1 wt% SDS). As the concentration of nanoparticles increases up to an optimal point, the IFT decreases significantly, indicating enhanced interfacial activity and favorable conditions for oil displacement. Notably, the nanofluid containing 0.05 wt% silica (SiO_2) and 0.01 wt% gamma-alumina (γ - Al_2O_3) exhibited the lowest IFT value of 1.485 mN/m. At higher concentrations of nanoparticles, the IFT increased, with a value of 1.707 mN/m obtained for 0.09 wt% SiO_2 and 0.05 wt% γ - Al_2O_3 . The increase in IFT at higher concentrations may be related to changes in nanoparticle–surfactant interactions at the interface. However, aggregation and

interfacial packing were not directly characterized in the present study.

This non-linear trend is well-captured by the statistical model developed using the Design Expert software, as shown in Figs. 6 and 7. Fig 6 illustrates the response surface for IFT variation, demonstrating the parabolic nature of the response by increasing the concentration of nanoparticles. This parabolic trend highlights the importance of optimizing concentration levels, as excessive nanoparticles can lead to aggregation and diminished efficiency in lowering IFT.

Fig. 7 confirms the accuracy of the predictive model with a high correlation coefficient ($R^2 > 0.95$), validating the experimental results. The close match between experimental and predicted values demonstrates the robustness of the model and its capacity to capture nanoparticle–fluid interactions under varying conditions. The observed behavior can be explained by the balance between enhanced surface activity at moderate concentrations of nanoparticles and the adverse effects of excessive particle aggregation and competitive adsorption at higher concentrations. Similar trends have been reported in prior studies on EOR [7, 5], where nanoparticles initially aid in lowering IFT but lose efficiency when overdosed. Therefore, the optimized combination of silica and alumina nanoparticles not only achieves the lowest IFT but also supports enhanced oil recovery by improving interfacial interactions under the investigated laboratory conditions.

The improved performance of the combined SiO_2 and $\gamma\text{-Al}_2\text{O}_3$ nanoparticles can be attributed to their complementary roles at the fluid–fluid and rock–fluid interfaces. Silica nanoparticles, owing to the presence of surface silanol groups, contribute mainly to wettability alteration by modifying the solid surface. In contrast, $\gamma\text{-Al}_2\text{O}_3$ nanoparticles enhance the adsorption and distribution of SDS molecules

at the oil–water interface, leading to more effective interfacial tension reduction. The combination of these mechanisms explains the improved performance of the hybrid nanofluid compared with the investigated formulations.

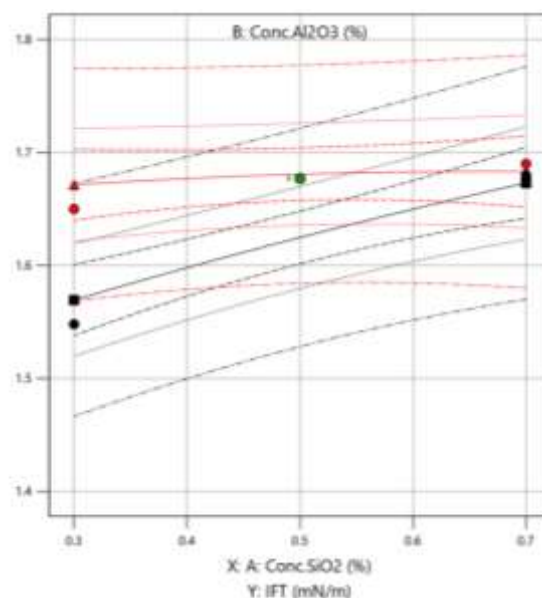


Figure 6. Interfacial tension (IFT) behavior at varying concentrations of nanoparticles. The graph shows that IFT decreases by increasing the concentration of nanoparticles, reaches an optimum point, and then increases at higher loadings.

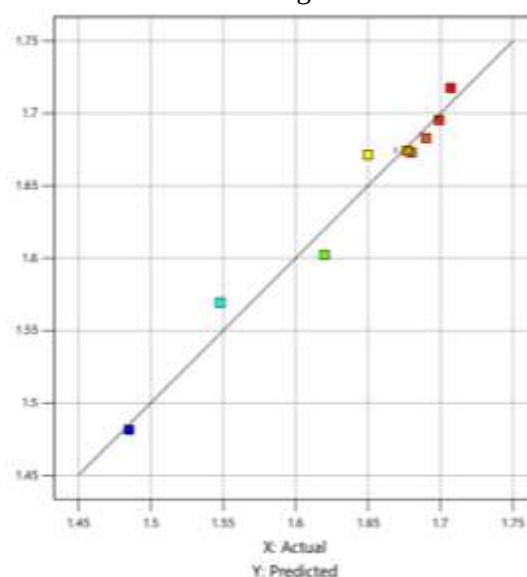


Figure 7. Correlation between the experimental and predicted IFT. The color gradient from blue to red represents the IFT values (in mN/m).

3.3. Effect of nanoparticles on the viscosity of solutions

The influence of the concentration of nanoparticles on the viscosity of nanofluid solutions was evaluated at a constant concentration of the surfactant. The experimental results, presented in Table 6, demonstrate that increasing the concentration of nanoparticles leads to a noticeable increase in the viscosity of the solution. This viscosity enhancement results from the formation of a dynamic nanoparticle network within the solution. As the concentration of nanoparticles increases, interparticle interactions become more frequent, creating structured domains that resist flow. The highest viscosity (2.28 cP) observed at 0.09 wt% SiO₂ + 0.05 wt% Al₂O₃ corresponds to the formation of such networks. However, excessive nanoparticle loading may lead to aggregation and potential injectivity issues in porous media, highlighting the importance of optimization. The increase in viscosity can be attributed to enhanced interactions among the dispersed nanoparticles, resulting from particle-particle interactions and hydrodynamic forces, as their concentration increases [8]. Johnson [15] reported similar viscosity enhancements for γ -Al₂O₃ nanoparticles in brine solutions, and attributed the effect to particle-particle interactions and hydrodynamic forces. This trend is clearly illustrated in Figs 8 and 9, which show both the experimental data and the fitted model generated using the Design Expert software. The agreement between the experimental and predicted values indicates that the model adequately represents the viscosity response within the investigated experimental range. The observed increase in viscosity may be associated with increased interparticle interactions as the concentration of nanoparticles increases. The observed increase in viscosity may be associated with increased interparticle interactions as the

concentration of nanoparticles increases. As the concentration of nanoparticles rises, the likelihood of interparticle interactions and cluster formation increases, leading to enhanced resistance to flow. This phenomenon is particularly significant in systems containing colloidal particles such as silica (SiO₂) and alumina (γ -Al₂O₃), which are known to form structured dispersions under appropriate conditions. The viscosity measurements were performed using a Brookfield viscometer (model X, spindle Y) at a constant shear rate and the temperature of 25 ± 0.5 °C to ensure consistent comparison across all samples. The horizontal axis of Fig. 8 represents the concentrations of SiO₂ and γ -Al₂O₃ nanoparticles (wt%), while the vertical axis represents viscosity (cP). The response surface illustrates the increase in viscosity by increasing the concentration of nanoparticles. These graphical representations highlight the nonlinear relationship between the concentration and viscosity of nanoparticles. Among the tested samples, the solution containing 0.01 wt% silica and 0.05 wt% alumina nanoparticles exhibited the lowest viscosity of 1.65 cP, suggesting minimal particle-particle interactions at this concentration. In contrast, the formulation with 0.09 wt% silica and 0.05 wt% alumina nanoparticles resulted in the highest recorded viscosity of 2.28 cP, consistent with increased network formation and potential agglomeration at higher concentrations. These results suggest that while moderate nanoparticle loadings can be beneficial for modifying the rheology of the fluid, excessive concentrations may hinder injectivity in porous media due to elevated viscosity. Therefore, selecting an appropriate concentration of nanoparticles is important to improve mobility control while avoiding excessive viscosity that could adversely affect injectivity during flooding operations.

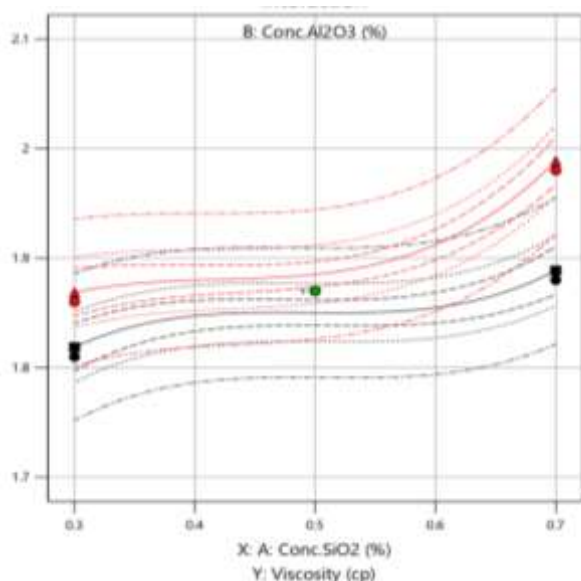


Figure 8. Viscosity measurements for nanoparticle-enhanced solutions.

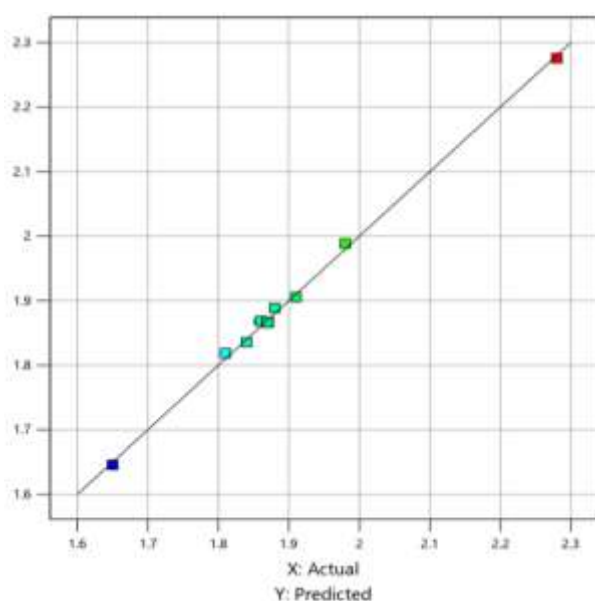


Figure 9. Correlation between the experimental and predicted values of viscosity. The color gradient from blue to red represents the viscosity values (in cP).

3.4. Effect of nanoparticles on the density of solutions

The addition of nanoparticles to surfactant-based solutions leads to measurable changes in the density of the fluid, which can influence nanoparticle transport, distribution, and adsorption behavior within porous media. As shown in Table 6, increasing the concentration

of nanoparticles at a fixed concentration of the surfactant consistently resulted in a slight but noticeable increase in the density of the solution. The lowest density (1024.72 kg/m^3) was obtained for the formulation containing $0.01 \text{ wt\% SiO}_2$ and $0.05 \text{ wt\% } \gamma\text{-Al}_2\text{O}_3$, whereas the highest density (1026.23 kg/m^3) was observed at $0.09 \text{ wt\% SiO}_2$ and $0.05 \text{ wt\% } \gamma\text{-Al}_2\text{O}_3$. This trend is expected because the density of the dispersed nanoparticles is higher than that of the base fluid, resulting in a gradual increase in the overall density of the nanofluid as the concentration of nanoparticles increases.

Figures 10 and 11 present the experimental results together with the response surface model developed using the Design Expert software. Figure 10 illustrates the effect of the concentration of SiO_2 and $\gamma\text{-Al}_2\text{O}_3$ on the density of the solution. The results show a gradual increase in density by increasing the concentration of nanoparticles, reflecting the contribution of the dispersed solid phase to the overall density of the fluid. Fig. 11 compares the experimental and model-predicted density values, demonstrating good agreement between the measured and predicted data. The increase in density is primarily associated with the higher specific gravity of the dispersed nanoparticles relative to that of the base fluid. Although the observed density changes were relatively small, they may influence fluid transport and distribution within porous media during injection. At the same time, the limited magnitude of the density increase indicates that the addition of nanoparticles did not substantially alter the handling characteristics of the injection fluid while still providing favorable interfacial and wettability modification. Overall, these results demonstrate that the concentration of nanoparticles has a measurable influence on the density of the fluid and should be considered together with viscosity, interfacial

tension, and wettability when selecting an appropriate nanofluid formulation for enhanced oil recovery applications.

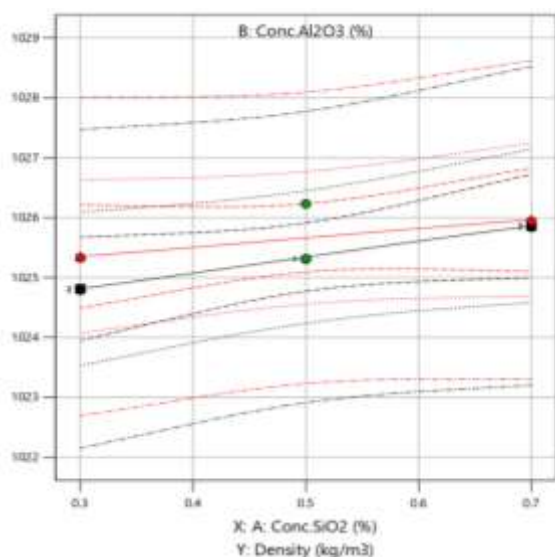


Figure 10. Response surface showing the variation in the density of the nanofluid as a function of the concentration of SiO_2 and $\gamma\text{-Al}_2\text{O}_3$.

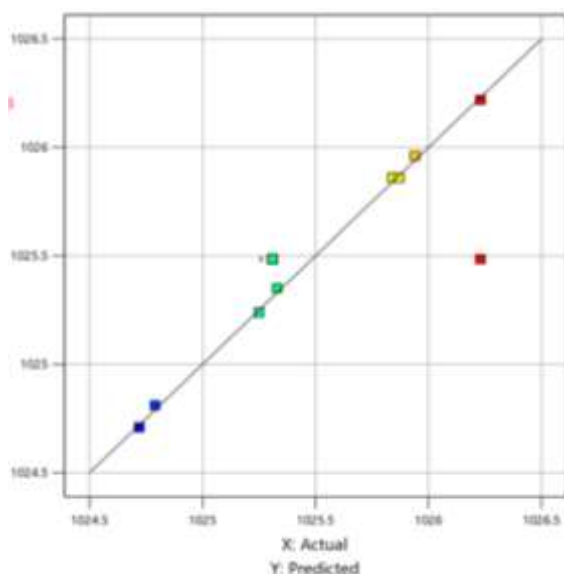


Figure 11. Comparison between experimental and model-predicted density values.

3.6. Effect of nanoparticles on pH

The incorporation of nanoparticles into surfactant-based nanofluids significantly influences the pH of the solution due to physicochemical interactions between the

nanoparticles and the aqueous phase. As presented in Table 6, a gradual decrease in pH was observed by increasing the concentration of nanoparticles. This behavior is mainly attributed to the surface chemistry of the nanoparticles. Silica (SiO_2) nanoparticles contain abundant silanol (Si-OH) groups that can partially dissociate in water, contributing to a slight increase in the concentration of hydrogen ions. In contrast, $\gamma\text{-Al}_2\text{O}_3$ nanoparticles exhibit amphoteric surface characteristics and therefore have a less pronounced effect on the pH of the solution.

The lowest pH value was obtained for the formulation containing 0.09 wt% SiO_2 and 0.05 wt% $\gamma\text{-Al}_2\text{O}_3$, whereas the highest pH (8.6) was measured for the solution containing 0.01 wt% SiO_2 and 0.05 wt% $\gamma\text{-Al}_2\text{O}_3$. These results indicate that increasing the concentration of silica has a greater influence on the pH than increasing the concentration of alumina. Figures 12 and 13 illustrate the experimental results together with the response surface model developed using the Design Expert software. In Fig. 12, the concentrations of SiO_2 and $\gamma\text{-Al}_2\text{O}_3$ nanoparticles (wt%) are represented on the horizontal axes, while the solution pH is shown on the vertical axis. It indicates that pH decreases with the addition of nanoparticles, with silica-dominant systems showing stronger reductions compared to alumina-based solutions. This behavior suggests surface charge interactions, which play a critical role in nanoparticle stability and transport in porous media. Figure 13 compares the experimental and predicted pH values, demonstrating good agreement between the model and the experimental data. The observed trend is consistent with previous studies on oxide nanoparticles in aqueous systems, where increasing the concentration of nanoparticles enhances surface reactions and modifies the acid-base characteristics of the

suspension. These changes in pH are important because they can influence nanoparticle stability, surface charge, and interactions with rock surfaces during enhanced oil recovery. All pH measurements were performed at 25 ± 0.5 °C using a calibrated digital pH meter to ensure measurement accuracy and repeatability.

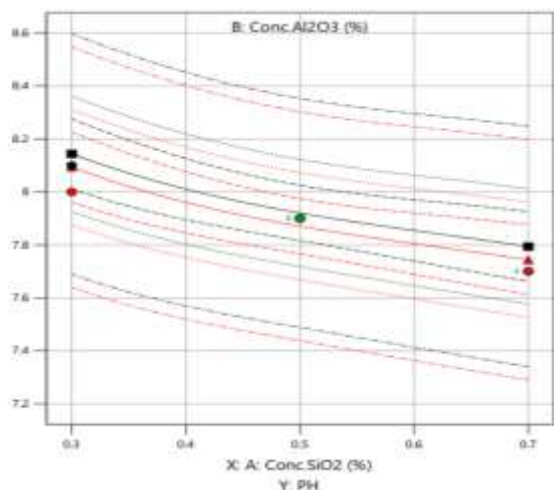


Figure 12. pH variation by increasing the concentration of nanoparticles. The graph indicates that pH decreases with the addition of nanoparticles, with silica-dominant systems showing stronger reductions compared to alumina-based solutions.

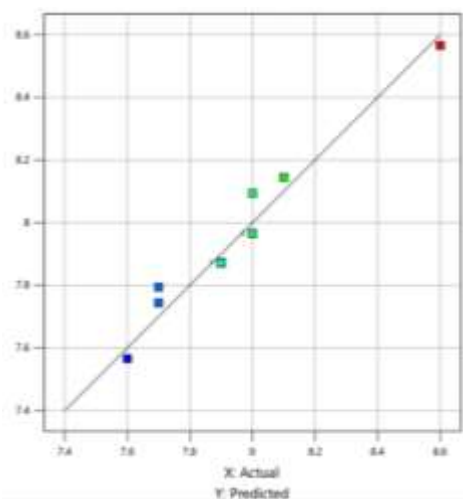


Figure 13. Correlation between the experimental and predicted pH. The color gradient from blue to red represents the pH values. The agreement between the experimental and predicted values indicates that the model adequately represents the pH response within the investigated experimental range.

3.7. Oil recovery analysis in the 2D glass micromodel

The final stage of the experimental study involved evaluating the oil displacement performance of the optimal nanofluid formulation in a 2D glass micromodel. The solution, optimized through the response surface methodology, consisted of 0.09 wt% silica nanoparticles, 0.05 wt% alumina nanoparticles, and 0.1 wt% SDS as a surfactant. The primary objective of this test was to evaluate the efficiency of the selected formulation in enhancing oil recovery under controlled laboratory conditions using a glass micromodel as a pore-scale visualization tool. As shown in Table 8 and illustrated in Figs 14 and 15, the injection of the optimized nanofluid resulted in a substantial increase in oil recovery, reaching up to 60.6% of the original oil in place (OOIP), compared to only 13% recovery using brine under identical injection conditions. The observed difference indicates the improved displacement performance of the selected formulation under the investigated micromodel conditions. The flooding comparison was conducted using the same injection volumes for the reference brine and the selected formulation. The recovery values reported in the range of 0.2–1.0 PV represent the cumulative oil recovery measured during the corresponding flooding runs. Figure 15 provides a visual comparison of oil displacement in the glass micromodel using saline water and the selected nanoparticle–surfactant formulation. The selected formulation produced a higher displacement response than saline water under the same experimental conditions. This comparison supports the observed difference in cumulative oil recovery; however, because only one flooding experiment was conducted for each condition, the results are considered

preliminary screening results rather than statistically averaged recovery values.

These results suggest that the combined use of silica and alumina nanoparticles with SDS leads to significant improvement in wettability alteration, IFT reduction, and displacement efficiency.

Although Formulation 3 exhibited the lowest IFT value (1.485 mN/m), it did not provide the highest contact angle or viscosity among the tested formulations. Formulation 9, containing 0.09 wt% SiO₂, 0.05 wt% γ -Al₂O₃, and 0.1 wt% SDS, showed the highest contact angle (135°) together with the highest viscosity (2.28 cP). Therefore, the formulation used for the micromodel flooding test was selected based on the combined performance of the measured responses rather than on the minimum value of a single parameter. In particular, wettability alteration and mobility control were considered alongside IFT reduction because these properties can simultaneously influence oil displacement. Formulation 9 was consequently selected as the formulation with desirable overall-performance for the flooding experiment, whereas Formulation 3 represents the optimal choice specifically with respect to IFT. The lowest IFT (1.485 mN/m) was obtained with Formulation 3, while Formulation 9 (selected for flooding) exhibited an IFT of 1.707 mN/m, which is still significantly lower than the oil-brine's IFT (~25 mN/m). This confirms that even the selected formulation provides substantial interfacial activity while offering superior wettability alteration and viscosity enhancement. The flooding test was therefore conducted as a screening test to assess whether the improvements observed in the laboratory characterization tests could be translated into

enhanced oil displacement performance. It is important to clarify that the micromodel flooding experiment was conducted as a preliminary proof-of-concept and screening test, rather than a comprehensive study to determine ultimate oil recovery. The primary objective was to compare the displacement performance of the optimized nanofluid with that of brine under identical and controlled conditions. For this purpose, an injection volume of 1 PV was selected as a standardized screening criterion, which is a common practice in micromodel studies for evaluating the early-stage displacement efficiency and the effectiveness of wettability alteration and IFT reduction mechanisms. Therefore, the recovery factor of 60.6% OOIP is presented as an indicative result, demonstrating the potential of the formulation. To obtain a statistically validated recovery curve and determine the ultimate oil recovery, replicate experiments and multi-pore-volume injections are recommended in future work.

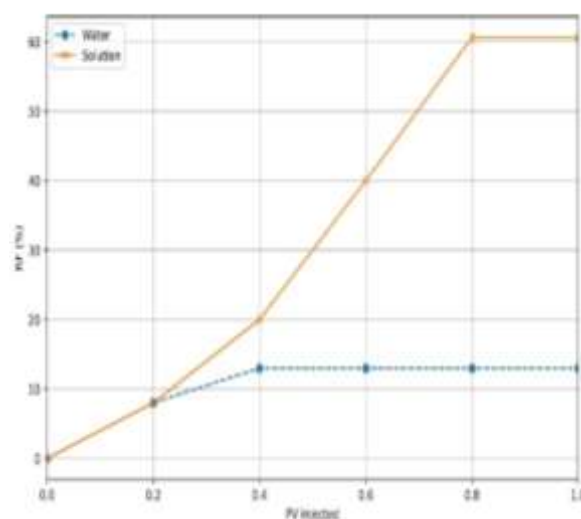


Figure 14. Comparison of oil recovery using optimized solutions and saline water.

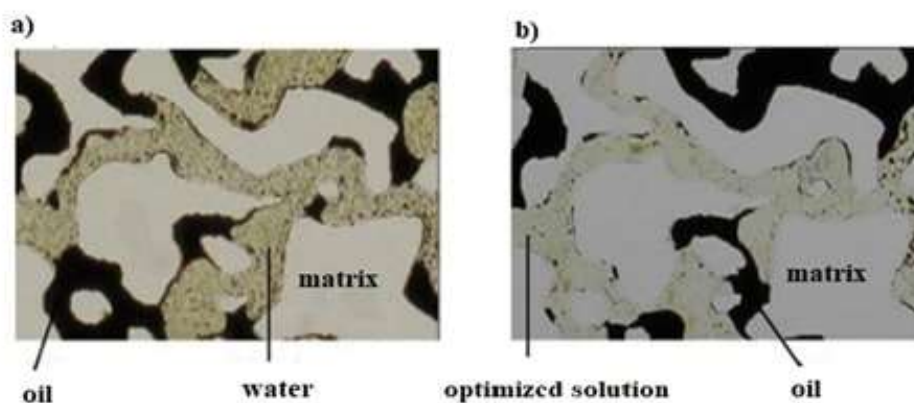


Figure 15. Oil recovery from the glass micromodel using saline water and the optimized nanoparticle-surfactant formulation. (a) Recovery with saline water and (b) recovery with the optimized formulation.

Table 8.

Results of injection volumes and oil recovery percentages in the micro model.

Parameter	Pore Volume Ratio (PV)					
Pore Volume Ratio	0	0.2	0.4	0.6	0.8	1
Oil Recovery with Saline Water (%)	0	8	13	13	13	13
Oil Recovery with Optimized Solution (%)	0	8	20	40	60.6	60.6

The experimental results indicate that the hybrid nanofluid system containing SiO_2 and $\gamma\text{-Al}_2\text{O}_3$ nanoparticles, stabilized with SDS, significantly reduced IFT, improved wettability, and modified rheological properties under controlled salinity and temperature conditions. These outcomes suggest that the combined use of dual nanoparticles and surfactants can contribute to enhanced oil recovery efficiency. Nonetheless, it is important to note that the experiments were conducted under laboratory-scale conditions, which may not fully replicate real reservoir environments. Therefore, the observed improvements in physicochemical parameters should be considered as a strong indication of the potential performance of the hybrid nanofluid, justifying further evaluations under conditions similar to actual field settings.

The higher oil recovery observed with the selected formulation may be related to the changes in wettability, interfacial tension, and

viscosity observed in the characterization experiments. The observed increase in the contact angle indicates a substantial change in the affinity of the treated surface toward the oil phase. The measured reduction in IFT may facilitate oil displacement by reducing interfacial resistance; however, this effect was not independently quantified during the flooding experiment. The increase in viscosity observed to be proportional to the concentration of nanoparticles may contribute to mobility control during displacement. However, the mobility ratio and the effect of viscosity on viscous fingering were not independently quantified in this study. Overall, the observed recovery improvement is consistent with the simultaneous changes in the measured physicochemical properties. Nevertheless, the individual contribution of each mechanism cannot be separated using the present experimental data.

4. Conclusion

This study demonstrated that combining of silica (SiO_2) and gamma-alumina ($\gamma\text{-Al}_2\text{O}_3$) nanoparticles with SDS surfactant can improve the physicochemical properties of the injection fluid and enhance oil recovery performance. The effects of the concentration of nanoparticles were evaluated in terms of interfacial tension (IFT), contact angle, viscosity, pH, and density using a Central Composite Design (CCD). The main findings of this study are summarized as follows:

- The lowest IFT value of 1.485 mN/m was obtained with Formulation 3, containing 0.05 wt% SiO_2 and 0.01 wt% $\gamma\text{-Al}_2\text{O}_3$. However, this formulation was not selected for the micromodel flooding test because the selection of the flooding formulation was based on the overall performance of the investigated properties rather than IFT alone. Formulation 9, containing 0.09 wt% SiO_2 , 0.05 wt% $\gamma\text{-Al}_2\text{O}_3$, and 0.1 wt% SDS, was selected for the micromodel flooding test because it provided the most favorable overall combination of wettability alteration and fluid properties among the investigated formulations.
- The contact angle increased from that of the initial state of oil-wet condition to values as high as 135° after treatment with the nanofluids. This change indicates a significant modification of the surface wettability. The observed wettability alteration can be associated with the adsorption of nanoparticles and surfactant at the glass surface. The presence of hydrophilic SiO_2 and $\gamma\text{-Al}_2\text{O}_3$ nanoparticles can modify the surface characteristics and reduce the affinity of the surface for the oil phase.
- The viscosity and density of the nanofluids generally increased by increasing the concentration of nanoparticles. The highest viscosity of 2.28 cP and density of 1026.23 kg/m^3 were obtained at 0.09 wt% SiO_2 and

0.05 wt% $\gamma\text{-Al}_2\text{O}_3$. The increase in viscosity may contribute to improved mobility control during displacement, although the effect on mobility ratio was not independently quantified in this study.

- Increasing the concentration of nanoparticles resulted in a decrease in pH, with the observed change being more pronounced in silica-containing formulations. This behavior can be related to the surface chemistry of SiO_2 and the presence of silanol groups, which may affect the surface charge and interactions between nanoparticles, brine, and the solid surface.

- Among the investigated formulations, the nanofluid containing 0.09 wt% SiO_2 , 0.05 wt% $\gamma\text{-Al}_2\text{O}_3$, and 0.1 wt% SDS provided the most favorable overall combination of the investigated properties. Therefore, this formulation was selected for the micromodel flooding experiment.

- The optimized formulation resulted in an oil recovery of 60.6% of the original oil in place (OOIP), compared with 13% obtained using conventional brine under the same experimental conditions. This improvement suggests that the combined formulation contributed to enhanced oil displacement through wettability alteration, interfacial tension reduction, and the modification of fluid properties under the investigated experimental conditions.

- The present experiments were conducted at 25°C and at a fixed brine salinity using a glass micromodel. Therefore, further investigations are required to evaluate the stability and performance of the optimized nanofluid under reservoir conditions, including higher temperatures, different salinity levels, and varying ionic compositions. Core-flooding experiments using representative carbonate and sandstone rocks are also recommended to evaluate the applicability of the formulation in more realistic porous media. Future studies should investigate zeta potential to better

understand nanoparticle surface charge and colloidal stability, as well as evaluating the economic feasibility of the proposed formulation.

- The present experiments were conducted at 25°C and at a fixed brine salinity using a glass micromodel. Further studies should therefore evaluate the stability and performance of the optimized nanofluid under reservoir temperatures, salinity levels, and ionic compositions. Zeta potential and particle-size measurements such as DLS could also be used to provide additional information on nanoparticle surface charge and colloidal stability. Core-flooding experiments using representative carbonate and sandstone rocks are recommended to further evaluate the applicability of the formulation in realistic porous media.

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AI declares

During the final stages of preparing this manuscript, AI-based tools (e.g., ChatGPT) were used exclusively to correct grammar, improve sentence clarity, and rephrase expressions. The content, structure, and scientific analysis were entirely developed and

written by the authors. No parts of the research methodology, interpretation of results, or discussion were generated by artificial intelligence systems.

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