

# Application of Electrokinetics-Assisted Flooding for Enhanced Oil Recovery in Niger Delta

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## Abstract

As global oil demand continues to increase, conventional reservoir extraction methods have proven inadequate to meet current production requirements. To address this challenge, this study explores economically viable enhanced oil recovery (EOR) techniques, focusing on the application of direct current (DC) electrokinetics in a Niger Delta reservoir. Experimental investigations demonstrated that electrokinetic enhanced oil recovery (EK-EOR) combined with alkylpolyglycoside (APG) surfactant at varying concentrations (1-3%) and different voltage levels achieved significant improvements. Specifically, EK-EOR with APG resulted in an incremental oil recovery improvement of 14-22%, enhanced sweep efficiency, reduced interfacial tension, and improved reservoir wettability compared to conventional surfactant EOR methods. Furthermore, EK-EOR with MgO nanofluid achieved even higher recovery rates, yielding incremental recoveries of 19-26%, surpassing the performance of EK-EOR with APG. MgO nanofluid flooding also exhibited superior mobility control and recovery efficiency compared to APG, as evidenced by the experimental results. To support these findings, a predictive model was developed to estimate recovery rates based on surfactant or nanofluid concentration and applied voltage. The EK-EOR technology leverages multiple electrokinetic mechanisms, including Joule heating, electrophoresis, electroosmosis, electromigration, and electrochemically enhanced reactions. However, further research is necessary to optimize the application of APG and other surfactants or nanofluids in EK-EOR-assisted flooding. A deeper understanding of the underlying mechanisms and the potential of hybrid techniques could significantly enhance the efficiency and economic feasibility of this innovative approach in petroleum engineering.

## Introduction

Electrokinetic-enhanced oil recovery (EK-EOR) is an emerging technology that utilizes the application of a low direct current (DC) between a subsurface anode and cathode in the producing well to improve oil recovery. This technology offers several advantages, including fluid viscosity reduction, permeability enhancement, and decreased water cut, as highlighted by Wittle et al. (2008). The electrical current facilitates hydrodynamic fluid movement from the injection well to the production well, improving recovery efficiency. However, a comprehensive systematic review of the literature is essential to critically evaluate laboratory results, establish the effectiveness of the EK-EOR mechanism, and identify potential future research directions, as noted by Ikpeka et al. (2022).

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Simulation insights indicate that EK-EOR alone has limited effectiveness, with a reported success rate of approximately 45%. Published laboratory experiments have further shown that interstitial clay significantly affects the electro-osmotic permeability of reservoir rocks, a key determinant of EK-EOR performance. Limitations such as salt deposition on the cathode and gas generation (oxygen and chlorine) at the anode also pose challenges to the widespread adoption of this technology (Farhadi et al. 2022; Abou et al. 2012). These findings underscore the need to explore hybrid approaches, such as EK-assisted surfactant flooding, which leverage the benefits of electrokinetics alongside other EOR methods.

Given that hydrocarbons will continue to play a critical role in meeting global energy demand (Kulmar 2010; Tian and Wang 2017), the development of environmentally sustainable extraction methods is of paramount importance. Amidst growing concerns about the environmental impact of oil and gas production, researchers are increasingly focused on innovative and sustainable solutions to maximize recovery while minimizing ecological footprints (Ghosh et al. 2012). This research aims to address these challenges by advancing the understanding and application of EK-assisted surfactant flooding as a sustainable and efficient EOR technology.

The enhancement of oil recovery from reservoirs has garnered significant global interest and remains a dynamic area of research. This focus is driven by the growing demand for energy, the decline in new oil discoveries, and the critical role that Enhanced Oil Recovery (EOR) and Improved Oil Recovery (IOR) technologies play in ensuring the future energy supply. These methods have become indispensable for addressing the challenges of declining production from mature reservoirs and meeting global energy demands (Alvarado and Manrique 2010; Iglauer et al. 2004; Zhang 2020).

Electrokinetic (EK) oil recovery is influenced by five primary mechanisms: Joule heating, electromigration, electrophoresis (EP), electroosmosis, and electrochemically enhanced reactions. These mechanisms play a pivotal role in enhancing oil displacement and recovery within reservoirs. Joule heating increases the reservoir temperature, reducing oil viscosity and improving mobility. Electromigration facilitates the movement of ions and charged particles, while electrophoresis promotes the transport of charged oil droplets toward the production well. Electroosmosis enhances fluid flow through capillary pathways by generating pressure gradients, and electrochemically enhanced reactions alter the chemical composition of the reservoir fluids, improving displacement efficiency. While the specific details of these mechanisms are extensively discussed in prior studies (Wittle et al. 2008; Haroun 2009; Chilingar et al. 2014; Rehman and Meribout 2012), they were not elaborated upon in this study to maintain focus on experimental observations and results.

## Experimental Setup and Flooding Fluids for Core Flooding Studies

The flooding fluids used in the core flow studies consisted of alkyl polyglycoside (APG) solutions at concentrations of 1%, 2%, and 3%, as well as MgO nanofluid solutions at 1% and 2%, prepared in deionized water. Niger Delta sandstone cores, saturated with brine, were brought to oil saturation at irreducible water saturation ( $S_{wirr}$ ) conditions using filtered crude oil of medium API gravity (Alotaibi and Nasr-El-Din 2011). The sandstone core plugs used in the experiments had approximate permeabilities of 24.5% and 18%, and the flow studies were conducted using light oil density. Following these experiments, the same core plugs were cleaned and reused for subsequent experiments with medium-density crude oil. **Tables 1** and **2** provide detailed oil and core petrophysical properties recorded at each stage of the flooding experiments.

**Table 1—Petrophysical properties of core plug.**

CORES	Length (cm)	Diameter (cm)	Dry Weight (g)	Wet Weight (g)	Bulk Volume (ml)	Pore Volume (ml)	Porosity (%)	OIIP (ml)
CORE A	7.20	3.60	139.8	157.8	73.29	18.0	24.5	17.95
CORE B	7.10	3.40	180.3	192.4	64.46	12.1	18.0	11.60

**Table 2—Fluid properties of crude oil**

Density (g/cm <sup>3</sup> )	Specific gravity	API	Type	Viscosity (cp)	Pressure (psi)
0.868	0.867	31.50	Light	<10	15

The experiments were conducted in multiple sets and phases. In the first set of experiments on core A was injection of brine through the core at a constant pump pressure of 15 psi of rate of about 10 ml/min of water flooding (WF) alone until there is a water cut. In the second phase surfactant flooding (SF) alone was injected until ultimate recovery was achieved. In the third phase, potential for additional recovery was examined by applying the DC field onto the existing hydrodynamic field, this is done at different concentration of APG (1, 2, 3%) surfactant and at different voltage (2,4,6 and 8V), respectively. In the fourth phase the SF was conducted simultaneously with DC application from the beginning of each test after WF ultimate recovery was achieved. In the second set of experiments on Core B, the same procedure as in the first set. But on different petrophysical core properties and same crude oil properties. The four distinct features of the experiments were the following,

1. Core Saturation: Before the commencement of WF, core plugs A and B were brought to natural reservoirs condition by flooding with brine then followed by crude oil to get to connate water saturation (Swc) condition.
2. WF: The Core plugs were loaded into the stainless-steel core holder having rubber sleeves specially designed and connected electrically to the DC box with the cathode at the producing end and the anode at the injection end. All core flood experiments were conducted under pump pressure of 15psi.
3. Brine solution was injected at the rate of 10 mL/min. The produced fluid was collected in an oil water separation and measuring device. At each step, water flow continued until no further oil recovery was possible. All the experiments were conducted at room temperature.
4. SF: SF alone was injected until ultimate recovery was achieved. The surfactant solution was injected at the rate of 10 mL/min. The produced fluid was collected in an oil water separation and measuring device. At each step, surfactant flow continued until no further oil recovery was possible before the collection.
5. Application of DC: The electrode configuration used during DC application was the distributor at injection side as anode and the distributor at production end as cathode.

In both sets of experiments involving DC (SEQ and SMF), different voltages (2,4,6 and 8V) at different concentration of surfactant was applied. The schematic of experimental set up is shown in **Figures 1 and 2.**

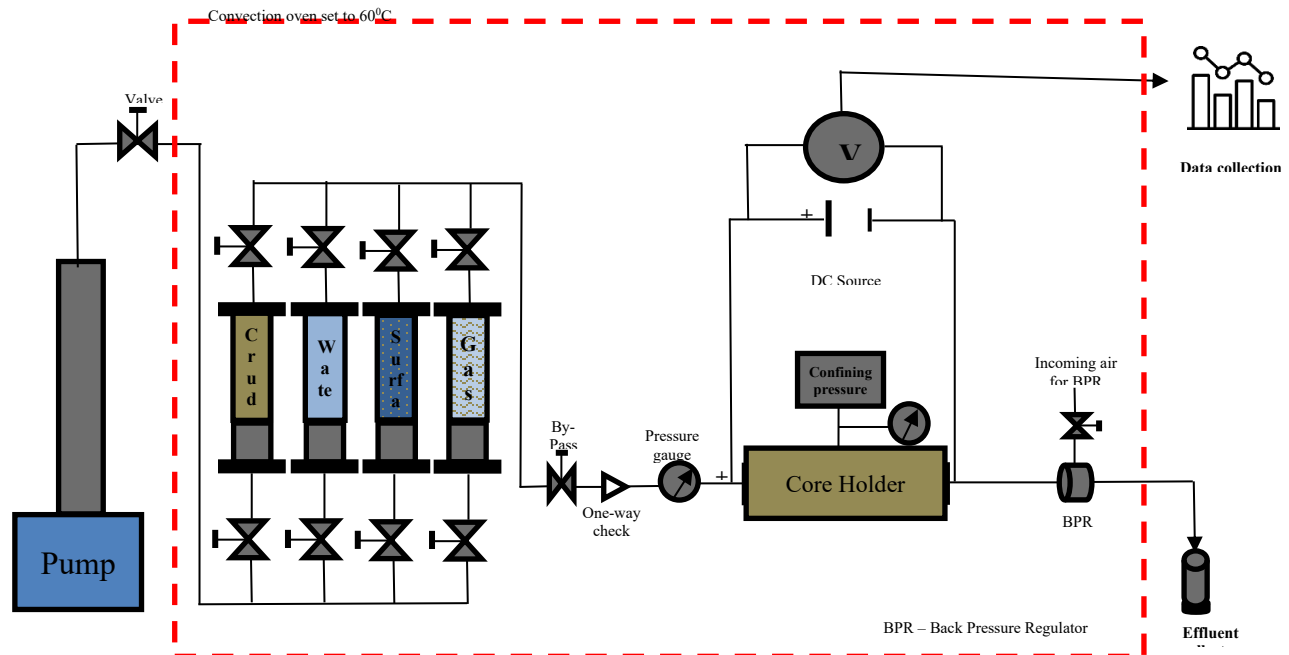


Figure 1—A schematics setup of an electrokinetic core flooding equipment (FUPRE LAB).



Figure 2—A schematics setup of an electrokinetic core flooding equipment (FUPRE LAB).

## Experimental Data Analysis

**EK-EOR Recovery Analysis for Core A at 15.0 psia.** Tables 3 and 4 present the recovery performance of EK-EOR under sequential and simultaneous flooding methods, respectively, across varying APG concentrations (1%, 2%, 3%) and applied voltages (2V, 4V, 6V, 8V) on Core A. In Table 3, sequential flooding (SEQ) shows a progressive increase in recovery as both APG concentration and voltage increase, with maximum recovery observed at 3% APG and 8V (5.0 ml). Water flooding (WF) and surfactant flooding (SF) alone yield comparatively lower recovery, indicating the added benefit of applying voltage in sequential processes. Table 4 highlights the superior performance of simultaneous flooding (SMF), where recovery significantly outperforms sequential methods, reaching 13.0 ml at 3% APG and 8V. Recovery increases steadily with both APG concentration and voltage, demonstrating the synergistic effect of combining flooding techniques with electrical

energy. These results underscore the effectiveness of simultaneous flooding in maximizing oil recovery, particularly under high voltage and APG concentration conditions.

**Table 3—EK-EOR sequential recovery for Core A at different APG concentration and voltage @ 15psi.**

Core A	APG concentration (%)	Avg. rec. water flooding (ml)(WF)	Avg. rec surf. flooding (ml)(SF)	Rec. seq. flooding @2V(ml) (SEQ)	Rec. seq. flooding @4V(ml) (SEQ)	Rec. seq. Flooding @6V(ml) (SEQ)	Rec. seq. Flooding @8V(ml) (SEQ)
	1	3.05	4.30	2.8	3.0	3.0	3.8
2	3.15	5.03	3.1	3.3	3.2	4.0	
3	3.25	5.90	3.6	4.0	4.4	5.0	

**Table 4—EK-EOR simultaneous recovery at different APG concentration and voltage @ 15psi.**

Core A	APG concentration (%)	Avg. rec. water flooding (ml)(WF)	Rec. sim. flooding @2V(ml) (SMF)	Rec. sim. flooding @4V(ml) (SMF)	Rec. sim. flooding @6V(ml) (SMF)	Rec. sim. flooding @8V(ml) (SMF)
	1	3.05	8.0	9.0	10.0	10.3
2	3.15	9.0	10.2	11.3	11.9	
3	3.25	11.5	11.7	12.5	13.0	

**EK-EOR Recovery Analysis for Core A at 30.0 psia.** Table 5 illustrates the EK-EOR recovery performance for Core A at 30.0 psia pump pressure under sequential (SEQ) and simultaneous flooding (SMF) methods with varying APG concentrations (1%, 2%, 3%) and applied voltages. The data demonstrates that recovery efficiency improves consistently with increased APG concentration and voltage for both methods. Sequential flooding yields a maximum recovery of 3.5 ml at 3% APG and 4V, showing moderate efficiency enhancements compared to water flooding (WF) and surfactant flooding (SF) alone. In contrast, simultaneous flooding exhibits significantly higher recovery potential, achieving 9.0 ml at 3% APG and 4V. The results indicate that simultaneous flooding consistently outperforms sequential methods, particularly at higher APG concentrations, highlighting its superiority in enhancing oil recovery under increased pressure conditions.

The EK-EOR recovery performance for Core A under 15.0 psia and 30.0 psia pump pressures show notable differences in efficiency across sequential (SEQ) and simultaneous flooding (SMF) methods. At 15.0 psia, the sequential flooding method achieves a maximum recovery of 3.2 ml at 3% APG concentration and 8V, while simultaneous flooding significantly outperforms with a maximum recovery of 7.3 ml under the same conditions. In contrast, at 30.0 psia, sequential flooding exhibits a slightly higher maximum recovery of 3.5 ml at 3% APG and 4V, but simultaneous flooding demonstrates a substantial improvement, achieving a maximum recovery of 9.0 ml under similar conditions.

Comparing the two pressure conditions, the overall recovery efficiency increases with higher pressure (30.0 psia) for both methods. The relative enhancement is more pronounced for simultaneous flooding, which benefits significantly from the combined effects of elevated pressure, voltage, and APG concentration. These results indicate that increasing pump pressure amplifies the effectiveness of EK-EOR processes, particularly for simultaneous flooding, making it a more efficient strategy for oil recovery in higher-pressure scenarios.

**Table 5—EK-EOR sequential and simultaneous recovery at different APG concentration and voltage@ 30psi.**

Core A	APG concentration (%)	Avg. rec. water flooding(ml) (WF)	Avg. rec surf. flooding(ml) (SF)	Rec. seq. flooding @2V(ml) (SEQ)	Rec. seq. flooding @4V(ml) (SEQ)	Rec. sim. flooding @2V(ml) (SMF)	Rec. sim. flooding @4V(ml) (SMF)
	1	2.40	4.25	2.20	2.70	6.00	7.0
	2	2.48	4.70	3.00	3.00	6.50	8.2
	3	2.80	4.70	3.20	3.50	7.0	9.0

**EK-EOR Recovery Analysis for Core B at 15.0 psia.** Tables 6 and 7 summarize the EK-EOR recovery performance for Core B under sequential and simultaneous flooding methods at a pump pressure of 15.0 psia. Table 5 demonstrates that sequential flooding (SEQ) yields increasing recovery efficiencies with both higher APG concentrations and voltages. The maximum recovery (3.20 ml) is achieved at 3% APG and 8V. However, the recovery for water flooding (WF) and surfactant flooding (SF) alone remains comparatively low, indicating limited effectiveness without the application of voltage. Table 6, on the other hand, reveals the enhanced recovery potential of simultaneous flooding (SMF), with recovery volumes notably exceeding those of sequential methods. The highest recovery (7.30 ml) is observed at 3% APG and 8V. Simultaneous flooding shows a consistent trend of improved recovery with increased APG concentrations and applied voltages, further highlighting its effectiveness as a more efficient EOR method. These results underscore the potential of simultaneous flooding in maximizing oil recovery under controlled pressure and optimized conditions.

**Table 6—EK-EOR sequential recovery for Core B at different APG concentrations and voltages @ 15psi.**

Core B	APG % Conc.	Avg. Rec waterflooding (ml)(WF)	Avg. rec surf. flooding (ml)(SF)	Rec. seq. flooding @2V(ml) (SEQ)	Rec. Seq. flooding @4V(ml) (SEQ)	Rec. seq. flooding @6V(ml) (SEQ)	Rec. seq. flooding @8V(ml) (SEQ)
	1	2.10	2.53	1.80	2.10	2.20	2.40
	2	2.18	3.00	2.00	2.60	2.00	2.60
	3	2.05	3.50	2.80	2.90	2.50	3.20

**Table 7—EK-EOR simultaneous recovery for Core B at different APG concentrations and voltages @ 15psi.**

CORE B	APG % Conc.	Avg. rec water flooding (ml)(WF)	Rec. sim. flooding @2V(ml) (SMF)	Rec. sim. flooding @4V(ml) (SMF)	Rec. sim. flooding @6V(ml) (SMF)	Rec. sim. flooding @8V(ml) (SMF)
	1	2.10	4.50	4.80	4.70	4.80
	2	2.18	6.80	6.20	6.40	5.80
	3	2.05	7.20	6.80	6.80	7.30

**EK-EOR Recovery with MgO Nanofluid on Core A at 15.0 psia.** Tables 8 and 9 summarize the EK-EOR recovery performance for Core A at 15.0 psia pump pressure using MgO nanofluid under sequential (SEQ) and simultaneous flooding (SMF) methods with different nanofluid concentrations (1% and 2%) and applied voltages. Table 8 demonstrates that sequential flooding achieves increasing recovery efficiencies as nanofluid concentration and voltage increase. The maximum recovery (7.0 ml) occurs at 2% nanofluid and 8V, indicating a moderate enhancement compared to water flooding (WF) and nanofluid flooding (NF) alone. Table 9 highlights

the superior recovery performance of simultaneous flooding, achieving significantly higher recoveries, with a maximum of 15.3 ml at 2% nanofluid and 8V. This indicates that simultaneous flooding benefits substantially from the synergistic effects of nanofluid, voltage, and pressure, demonstrating a significant improvement over sequential method. The results confirm that the integration of nanofluid with EK-EOR enhances oil recovery, particularly under simultaneous flooding conditions, making it a more effective approach for improving oil recovery efficiency.

**Table 8—EK-EOR sequential recovery for Core A at different nanofluid concentration and voltage @ 15psi.**

Core A	Nanofluid (MgO) concentration (%)	Avg. rec water flooding (ml) (WF)	Avg. rec nano. flooding (ml)(NF)	Rec. seq. flooding @2V(ml) (SEQ)	Rec. seq. flooding @4V(ml) (SEQ)	Rec. seq. flooding @6V(ml) (SEQ)	Rec. seq. flooding @8V(ml) (SEQ)
	1	3.0	6.0	3.3	3.8	4.5	6.5
	2	3.15	7.0	4.2	4.8	6.2	7

**Table 9—EK-EOR simultaneous recovery for Core A at different nanofluid concentration and voltage @ 15psi.**

Core A	Nanofluid (MgO) concentration (%)	Avg. rec water flooding (ml) (WF)	Rec. sim. flooding @2V(ml) (SMNF)	Rec. sim. flooding @4V(ml) (SMNF)	Rec. sim. flooding @6V(ml) (SMNF)	Rec. sim. flooding @8V(ml) (SMNF)
	1%	3.0	9	10.3	12.3	13.8
	2%	3.2	9.5	11.5	13.5	15.3

**EK-EOR Recovery with MgO Nanofluid on Core B at 15.0 psia.** Tables 10 and 11 summarize the EK-EOR recovery results for Core B using MgO nanofluid under sequential (SEQ) and simultaneous flooding (SMF) methods at 15.0 psia pump pressure with varying nanofluid concentrations (1% and 2%) and applied voltages. Table 10 shows that sequential flooding yields increasing recovery efficiencies as both nanofluid concentration and voltage rise, with the maximum recovery of 4.6 ml observed at 2% nanofluid and 8V. Despite the improvement over water flooding (WF) and nanofluid flooding (NF) alone, the recovery remains moderate compared to simultaneous methods. Table 11, in contrast, demonstrates the significantly higher recovery achieved through simultaneous flooding, with a maximum of 7.8 ml at 2% nanofluid and 8V. This highlights the enhanced synergistic effect of nanofluid and electric field in the simultaneous flooding process, further amplified under increased voltage and nanofluid concentration. These results confirm the superior efficiency of simultaneous flooding as a more effective EK-EOR strategy for improving oil recovery, particularly in the presence of nanofluids.

**Table 10—EK-EOR sequential recovery for Core B at different nanofluid concentration and voltage @ 15psi.**

Core B	Nanofluid (MgO) concentration (%)	Avg. Rec water flooding(ml) (WF)	Avg. rec nano. flooding (ml) (NF)	Rec. seq. flooding @2V(ml) (SEQ)	Rec. seq. flooding @4V(ml) (SEQ)	Rec. seq. flooding @6V(ml) (SEQ)	Rec. seq. flooding @8V(ml) (SEQ)
	1	2.10	2.93	2.40	2.90	3.50	3.80
	2	2.18	3.5	3.00	3.30	4.20	4.60

**Table 11—EK-EOR simultaneous recovery for Core B at different nanofluid concentration and voltage @ 15psi.**

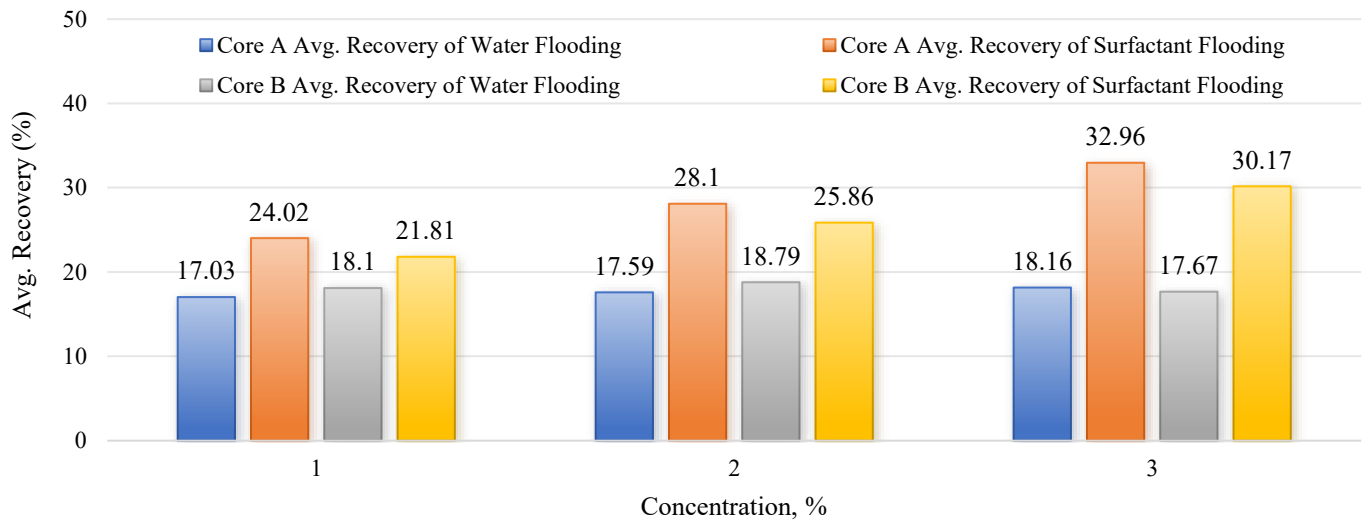
Core B	Nanofluid (MgO) concentration (%)	Avg. rec Water flooding (ml)(WF)	Rec. sim. flooding @2V(ml) (SMNF)	Rec. sim. flooding @4V(ml) (SMNF)	Rec. sim. flooding @6V(ml) (SMNF)	Rec. sim. flooding @8V(ml) (SMNF)
	1	2.10	5.00	5.50	5.70	6.20
	2	2.18	5.30	5.80	6.90	7.80

## Comparative Analysis

**Comparison of Oil Recovery via Waterflooding and Surfactant Flooding with APG.** Table 12 and Figure 3 summarize the average oil recoveries achieved through waterflooding and surfactant flooding for Core A and Core B at varying APG concentrations (1-3%). For waterflooding, Core A shows a slight increase in recovery from 17.03% at 1% APG to 18.16% at 3% APG, while Core B exhibits a non-linear trend, with recovery peaking at 18.79% at 2% APG before decreasing to 17.67% at 3%. Conversely, for surfactant flooding, both cores show a significant increase in recovery as APG concentration rises. Core A demonstrates the highest recovery of 32.96% at 3% APG, while Core B achieves a recovery of 30.17% under the same conditions. The bar chart visually reinforces the substantial enhancement in recovery using surfactant flooding compared to waterflooding, particularly at higher APG concentrations. These results highlight the superior efficiency of surfactant flooding in improving oil recovery, especially at optimal APG concentrations, for both Core A and Core B.

**Table 12—Oil Recovery of waterflooding and surfactant flooding.**

APG concentration, %	Core A		Core B	
	Avg. rec. water flooding, %	Avg. rec. surf. flooding, %	Avg. rec. water flooding, %	Avg. rec. surf. flooding, %
1	17.03	24.02	18.1	21.81
2	17.59	28.1	18.79	25.86
3	18.16	32.96	17.67	30.17

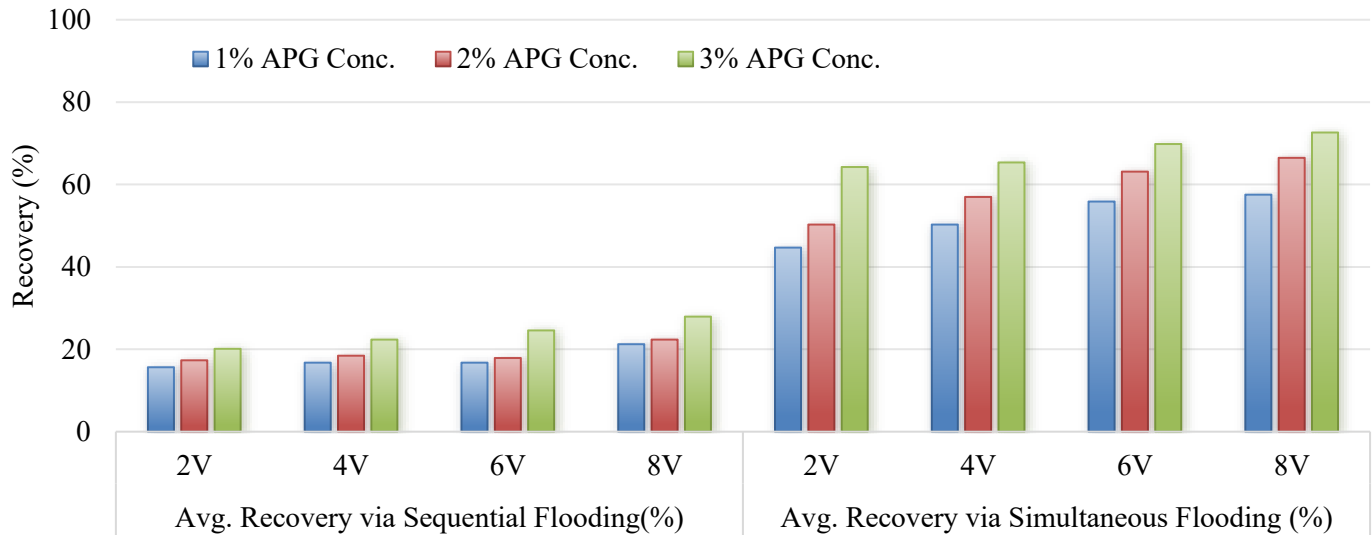


**Figure 3—Average oil recovery of water and surfactant flooding.**

**Comparison of EK-EOR Oil Recovery for Core A.** Table 13 and Figure 4 presents the oil recovery performance via sequential and simultaneous EK-EOR surfactant flooding for Core A at 15 psia under varying APG concentrations (1–3%) and voltages (2V, 4V, 6V, 8V). For sequential flooding, oil recovery increases with both higher APG concentration and applied voltage. The maximum recovery is achieved at 3% APG and 8V, with an average recovery of 27.93%. Conversely, simultaneous flooding exhibits significantly higher recoveries across all conditions, with the maximum recovery of 72.63% recorded at 3% APG and 8V. Simultaneous flooding consistently outperforms sequential flooding, demonstrating a marked enhancement in recovery efficiency due to the synergistic effects of surfactant flooding, electric field application, and higher APG concentrations. These results highlight the superior efficiency of simultaneous EK-EOR flooding in optimizing oil recovery, particularly under higher voltage and APG concentration conditions.

**Table 13—Oil Recovery via sequential and simultaneous EK-EOR surfactant flooding for core A at 15 psia.**

APG concentration, %	Avg. rec. EK-EOR surf. seq. flooding (%)				Avg. rec. EK-EOR surf. sim. flooding (%)			
	2V	4V	6V	8V	2V	4V	6V	8V
1	15.64	16.75	16.75	21.23	44.69	50.28	55.87	57.54
2	17.32	18.44	17.88	22.35	50.28	56.98	63.13	66.48
3	20.11	22.35	24.58	27.93	64.25	65.36	69.83	72.63

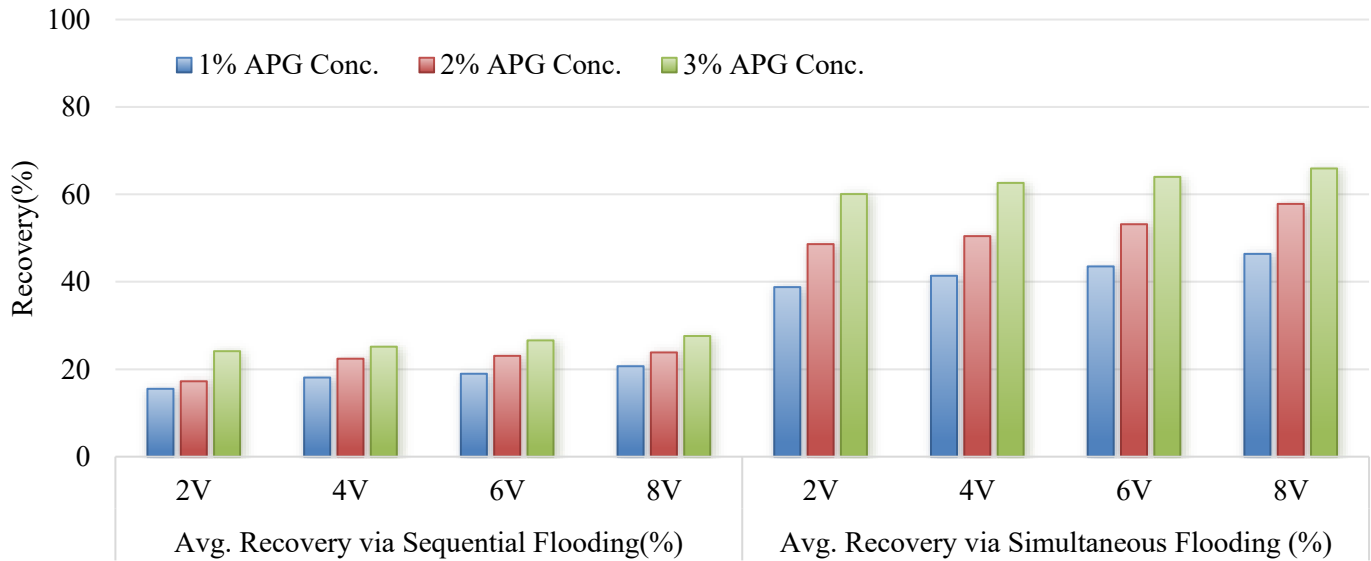


**Figure 4—Average oil recovery of sequential and simultaneous EK-EOR surfactant flooding for Core A**

**Comparison of EK-EOR Oil Recovery for Core B.** Table 14 and Figure 5 illustrate the oil recovery performance of Core B via sequential and simultaneous EK-EOR surfactant flooding at 15 psia with varying APG concentrations (1%, 2%, 3%) and applied voltages (2V, 4V, 6V, 8V). Sequential flooding shows a gradual increase in recovery with both APG concentration and voltage. The highest recovery of 27.60% is observed at 3% APG and 8V, indicating moderate improvement compared to lower concentrations and voltages. However, simultaneous flooding exhibits substantially higher recoveries, reaching a maximum of 65.93% under the same conditions. The bar chart in Figure 5 visually emphasizes the superior performance of simultaneous flooding compared to sequential flooding across all conditions. The recovery trends highlight the synergistic effects of APG concentration, electric field, and simultaneous flooding, which collectively enhance oil recovery efficiency. These results demonstrate that simultaneous flooding is a more effective approach for EK-EOR applications in Core B.

**Table 14—Oil recovery via sequential and simultaneous EK-EOR surfactant flooding for Core B at 15 psia.**

APG concentration, %	Avg. recovery via sequential Flooding (%)				Avg. recovery via simultaneous flooding (%)			
	2V	4V	6V	8V	2V	4V	6V	8V
1	15.52	18.10	18.97	20.69	38.79	41.38	43.52	46.38
2	17.24	22.41	23.06	23.84	48.62	50.45	53.17	57.82
3	24.13	25.15	26.60	27.60	60.07	62.62	64.00	65.93



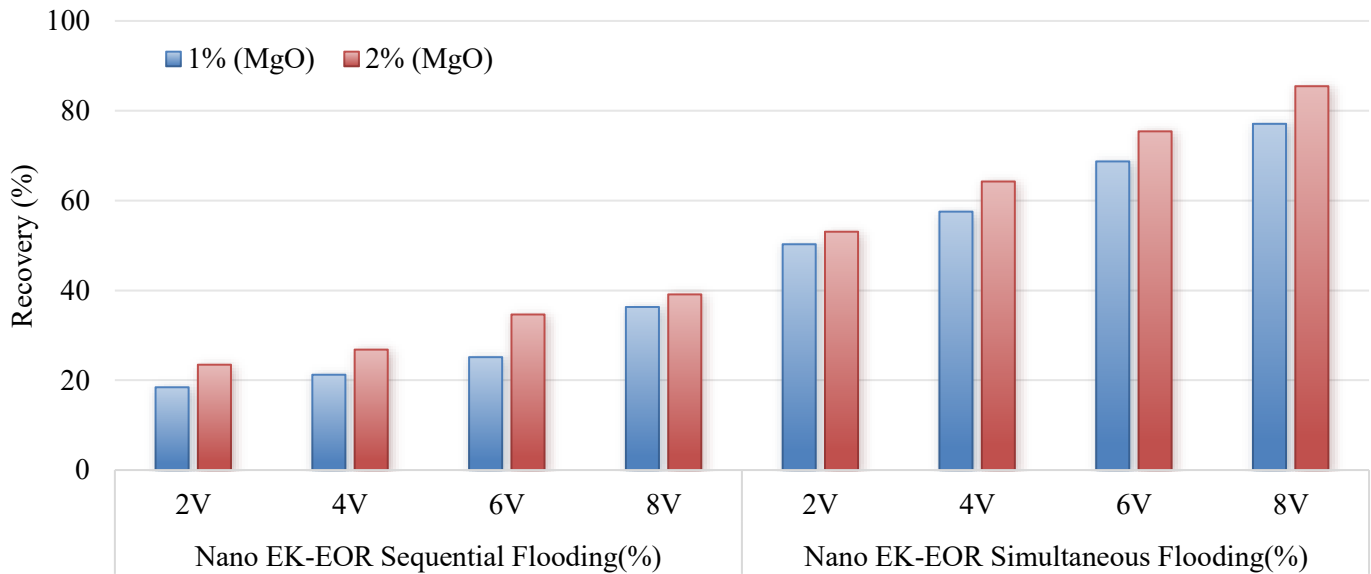
**Figure 5—Average oil recovery of sequential and simultaneous EK-EOR surfactant flooding for Core B**

**Comparison of Oil Recovery Using Nano-EK-EOR with MgO Nanofluid for Core A.** Table 15 summarizes the oil recovery results from Nano-EK-EOR using MgO nanofluid under sequential and simultaneous flooding methods for Core A at 15 psia, with nanofluid concentrations of 1% and 2% and voltages ranging from 2V to 8V. Sequential flooding shows a consistent increase in recovery efficiency with higher voltage and nanofluid concentration. The maximum recovery of 39.11% is observed at 2% nanofluid and 8V, demonstrating moderate improvement compared to lower concentrations and voltages. Simultaneous flooding, however, achieves significantly higher recoveries, with a peak value of 85.47% under the same conditions. Figure 6 visually highlights the superior performance of simultaneous flooding across all conditions, particularly at higher voltages and nanofluid concentrations. The results underscore the enhanced synergistic effects of nanofluid and electric field in simultaneous flooding, making it a more effective strategy for improving oil recovery compared to sequential flooding.

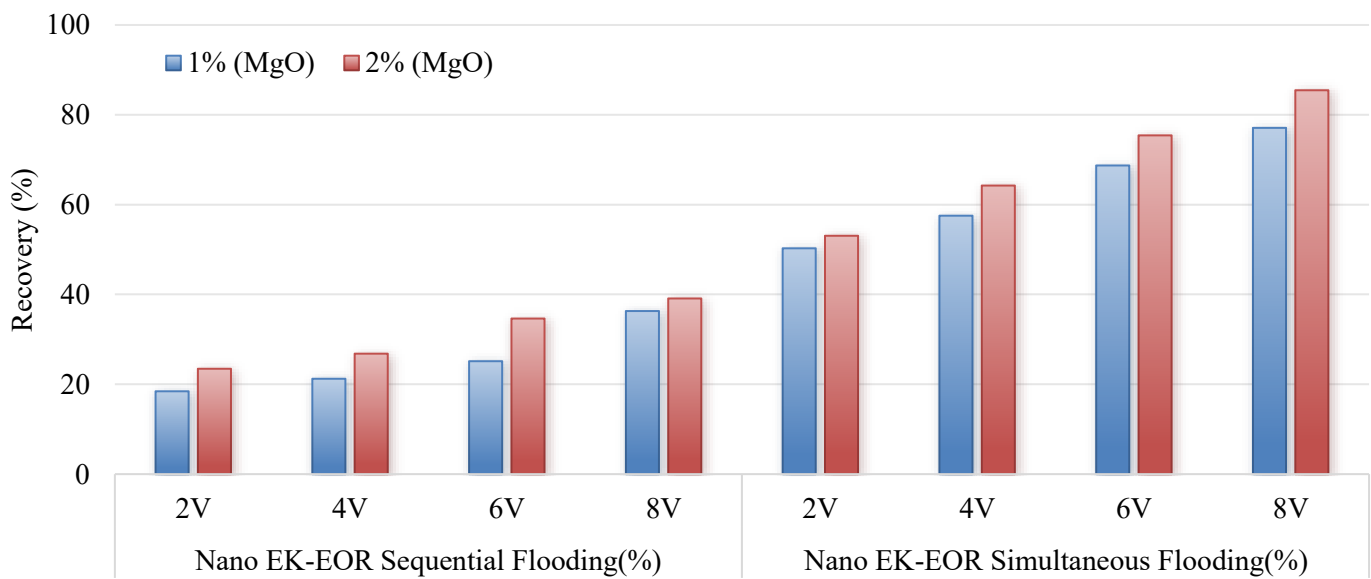
**Table 15—Oil recovery via sequential and simultaneous EK-EOR-Nano flooding for Core A at 15 psia.**

Nano (MgO) flooding (%)	Avg. recovery via sequential flooding (%)				Avg. recovery via simultaneous flooding (%)			
	2V	4V	6V	8V	2V	4V	6V	8V
1%	18.44	21.23	25.14	36.31	50.28	57.54	68.72	77.09
2%	23.46	26.82	34.64	39.11	53.07	64.25	75.42	85.47

Figure 7 shows the oil recovery performance of MgO for sequential and simultaneous flooding in cores B. As observed, the introduction of sequential electro-kinetics at varying voltage, improved oil recovery. This is attributed to mobility alteration effect of electro-kinetics on crude oil through crude oil viscosity reduction which enables better sweep efficiency by the nanoparticles. As observed too, the introduction of EK in simultaneous mode yielded better crude oil recovery, and this attributed to the enhanced impact of heated MgO concentration and reduced crude oil viscosity to enable more suitable sweeping of entrapped crude oil to the wellbore.

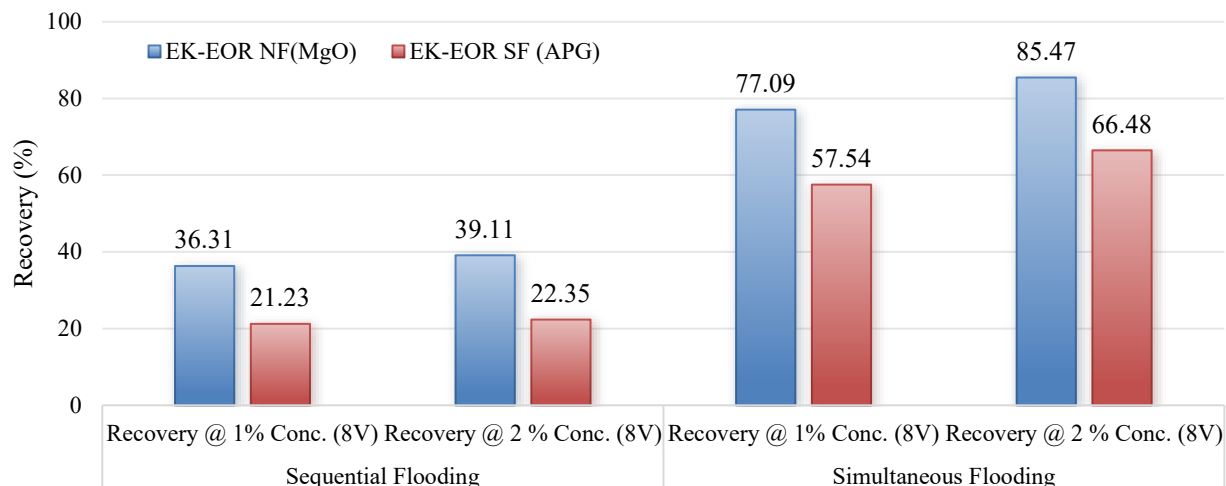


**Figure 6—Recovery via Nano-EK-EOR Sequential and Simultaneous flooding from Core A**



**Figure 7—Recovery via Nano-EK-EOR Sequential and Simultaneous flooding from Core B.**

**Figure 8** shows the comparison of oil recovery between EK-EOR nanoflooding and EK-EOR surfactant flooding. As observed, EK-EOR-NF recorded better recovery than EK-EOR-SF in both sequential and simultaneous flooding. As observed too, the simultaneous flooding of EK recorded better oil recovery with both SF and NF than sequential flooding.



**Figure 8—Comparison of oil recovery between EK-EOR nano flooding and EK-EOR surfactant flooding.**

**Oil Recovery Differences Between Surfactant and Water Flooding Across APG Concentrations.** Table 16 presents the differences in oil recovery between surfactant flooding (SF) and water flooding (WF) for Core samples A and B across varying APG concentrations (1%, 2%, 3%). For Core A, the recovery difference increases significantly with higher APG concentrations, starting from 6.99% at 1% APG, rising to 10.51% at 2%, and reaching a maximum of 14.8% at 3%. Similarly, for Core B, the recovery differences also increase with APG concentration, albeit at a slightly lower magnitude compared to Core A, ranging from 3.7% at 1% APG to 7.07% at 2% and 12.5% at 3%. These results demonstrate that surfactant flooding substantially outperforms water flooding, with the enhancement more pronounced at higher APG concentrations. The differences between Core A and Core B suggest that the efficiency of surfactant flooding may depend on core-specific properties, such as porosity or permeability, alongside APG concentration.

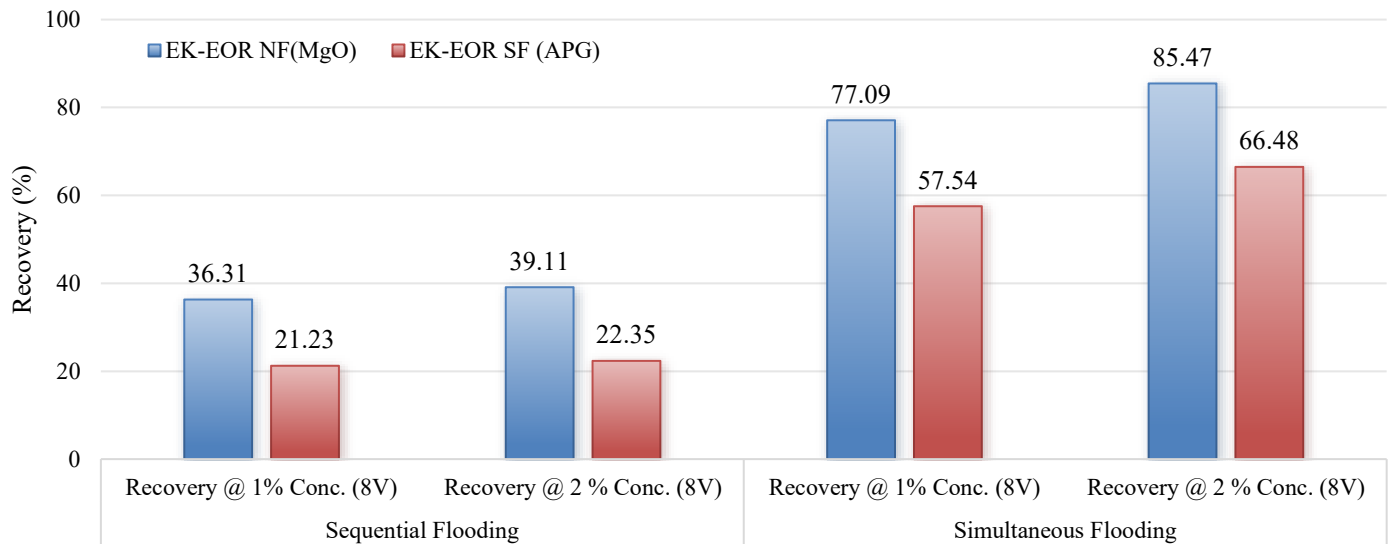
**Table 16—Enhanced oil recovery across the concentrations**

Core samples	Rec. Difference bet. SF and WF @1% APG Conc. (%)	Rec. Difference bet. SF and WF @2% APG Conc. (%)	Recovery Difference bet. SF and WF @3% APG Conc. (%)
A	6.99	10.51	14.8
B	3.7	7.07	12.5

**Comparison of EK-EOR Nano and Surfactant Flooding Recoveries at 8V.** Table 17 and Figure 9 compare the oil recovery achieved through EK-EOR nano flooding (NF) using MgO and EK-EOR surfactant flooding (SF) with APG under sequential and simultaneous flooding methods at 8V potential and concentrations of 1% and 2%. Sequential flooding demonstrates higher recoveries for nano flooding, with 36.31% and 39.11% at 1% and 2% concentrations, respectively, compared to 21.23% and 22.35% for surfactant flooding. Similarly, simultaneous flooding achieves significantly better recoveries for nano flooding, reaching 77.09% and 85.47% for 1% and 2% concentrations, respectively, compared to 57.54% and 66.48% for surfactant flooding. The bar chart in Figure 9 visually reinforces the superior performance of nano flooding over surfactant flooding across all conditions, particularly under simultaneous flooding. These results highlight the enhanced efficiency of MgO nano flooding in improving oil recovery, attributed to the synergistic effects of nanoparticles and the applied electric field, which outperform the conventional surfactant-based method.

**Table 17—Recovery of EK-EOR nano flooding (NF) and EK-EOR surfactant flooding (SF) at 8V potential.**

Means of Recovery	Sequential Flooding		Simultaneous Flooding	
	1% of Conc. (8V)	2% of Conc. (8V)	1% of Conc. (8V)	2 % of Conc. (8V)
EK-EOR NF(MgO)	36.31%	39.11%	77.09%	85.47%
EK-EOR SF (APG)	21.23%	22.35%	57.54%	66.48%

**Figure 9—Comparison of oil recovery between EK-EOR nano flooding and EK-EOR surfactant flooding.**

## Modeling of Experimental data

All experimental data and results from core flood experiments pertaining to simultaneous and sequential flooding are presented **Tables 18 and 19**.

**Table 18—Experimental data for nano flooding.**

X1	X2	X3	X4	Y
Nano Fluid Concentration (wt %)	Current density(volt)	Core porosity (%)	Simultaneous flooding	Oil recovery (ml)
0.01	2	0.245	1	9
0.02	2	0.245	1	9.5
0.01	4	0.245	1	10.3
0.02	4	0.245	1	11.5
0.01	6	0.245	1	12.3
0.02	6	0.245	1	13.5
0.01	8	0.245	1	13.8
0.02	8	0.245	1	15.3
0.01	2	0.18	1	5
0.02	2	0.18	1	5.3
0.01	4	0.18	1	5.5
0.02	4	0.18	1	5.8
0.01	6	0.18	1	5.7
0.02	6	0.18	1	6.9
0.01	8	0.18	1	6.2
0.02	8	0.18	1	7.8
0.01	2	0.245	2	3.3
0.02	2	0.245	2	4.2
0.01	4	0.245	2	3.8
0.02	4	0.245	2	4.8
0.01	6	0.245	2	4.5
0.02	6	0.245	2	6.2
0.01	8	0.245	2	6.5
0.02	8	0.245	2	7
0.01	2	0.18	2	2.4
0.02	2	0.18	2	3
0.01	4	0.18	2	2.9
0.02	4	0.18	2	3.3
0.01	6	0.18	2	3.5
0.02	6	0.18	2	4.2
0.01	8	0.18	2	3.8
0.02	8	0.18	2	4.6

**Table 19—Surfactant core flooding experimental data.**

X1	X2	X3	X4	Y1
Surfactant Concentration (wt%)	Current Density (volt)	Core Porosity (%)	Simultaneous flooding	Oil recovery (%)
0.01	2	0.245	1	8.0
0.02	2	0.245	1	9.0
0.03	2	0.245	1	11.5
0.01	4	0.245	1	9.0
0.02	4	0.245	1	10.2
0.03	4	0.245	1	11.7
0.01	6	0.245	1	10.0
0.02	6	0.245	1	11.3
0.03	6	0.245	1	12.5
0.01	8	0.245	1	10.3
0.02	8	0.245	1	11.9
0.03	8	0.245	1	13.0
0.01	2	0.18	1	4.50
0.02	2	0.18	1	6.80
0.03	2	0.18	1	7.20
0.01	4	0.18	1	4.80
0.02	4	0.18	1	6.20
0.03	4	0.18	1	6.80
0.01	6	0.18	1	4.70
0.02	6	0.18	1	6.40
0.03	6	0.18	1	6.80
0.01	8	0.18	1	4.80
0.02	8	0.18	1	5.80
0.03	8	0.18	1	7.30
0.01	2	0.245	2	2.8
0.02	2	0.245	2	3.1
0.03	2	0.245	2	3.6
0.01	4	0.245	2	3.0
0.02	4	0.245	2	3.3
0.03	4	0.245	2	4.0
0.01	6	0.245	2	3.0
0.02	6	0.245	2	3.2
0.03	6	0.245	2	4.4
0.01	8	0.245	2	3.8
0.02	8	0.245	2	4.0
0.03	8	0.245	2	5.0
0.01	2	0.18	2	1.80
0.02	2	0.18	2	2.00
0.03	2	0.18	2	2.80
0.01	4	0.18	2	2.10
0.02	4	0.18	2	2.60
0.03	4	0.18	2	2.90
0.01	6	0.18	2	2.20
0.02	6	0.18	2	2.00
0.03	6	0.18	2	2.50
0.01	8	0.18	2	2.40
0.02	8	0.18	2	2.60
0.03	8	0.18	2	3.20

The data in Tables 20 and 21 were analyzed using Design Expert Software. Analysis of Variance (ANOVA) was conducted to determine parameters that are influential to the model. ANOVA results for surfactant and nano fluid flooding scenarios are shown, respectively.

**Table 20—Analysis of variance results for the surfactant coreflood experimental data.**

Source	Sum of Squares	df	Mean Square	F-value	p-value	
Model	518.10	7	74.01	312.80	< 0.0001	significant
A-A	24.50	1	24.50	103.54	< 0.0001	
B-B	5.15	1	5.15	21.77	< 0.0001	
C-C	16.52	1	16.52	69.81	< 0.0001	
D-D	12.65	1	12.65	53.48	< 0.0001	
AD	5.61	1	5.61	23.71	< 0.0001	
CD	30.23	1	30.23	127.76	< 0.0001	
C <sup>2</sup>	7.25	1	7.25	30.66	< 0.0001	
Residual	9.46	40	0.2366			
Cor Total	527.57	47				

**Table 21—Analysis of variance results for the nano fluid flooding experimental data.**

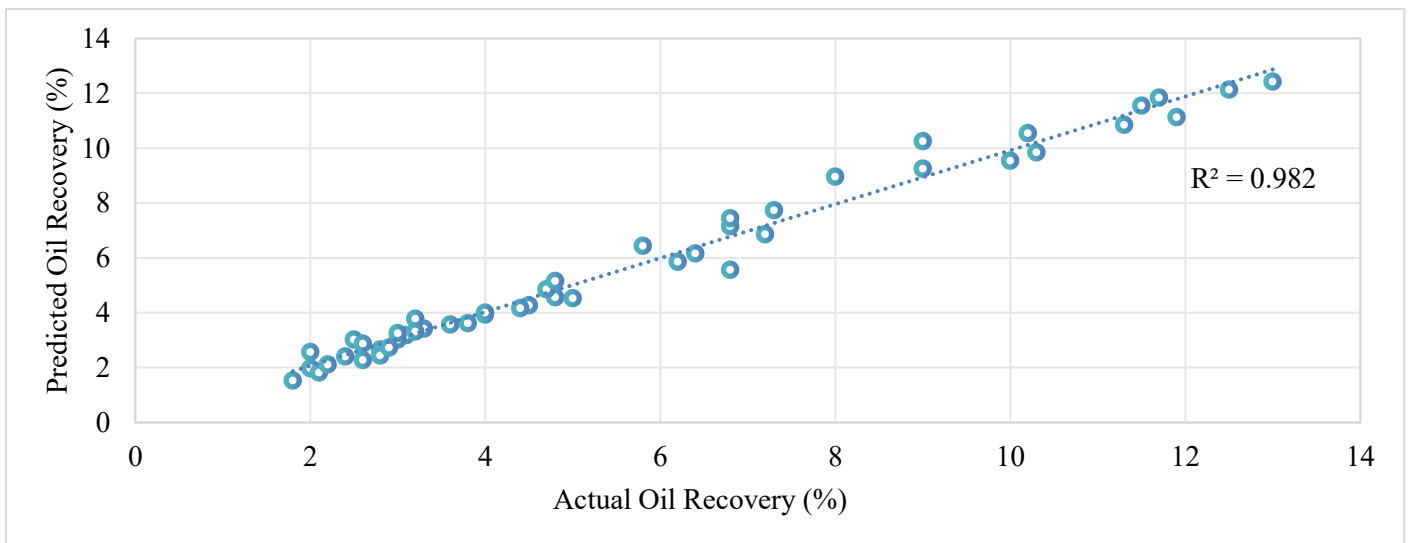
Source	Sum of Squares	df	Mean Square	F-value	p-value	
Model	380.10	8	47.51	381.96	< 0.0001	significant
A-A	6.89	1	6.89	55.42	< 0.0001	
B-B	0.8957	1	0.8957	7.20	0.0133	
C-C	117.75	1	117.75	946.61	< 0.0001	
D-D	57.34	1	57.34	460.98	< 0.0001	
AB	0.4203	1	0.4203	3.38	0.0790	
BC	6.81	1	6.81	54.72	< 0.0001	
BD	1.94	1	1.94	15.56	0.0006	
CD	36.98	1	36.98	297.29	< 0.0001	
Residual	2.86	23	0.1244			
Cor Total	382.96	31				

According to the ANOVA results shown in Table 20 and 21, the model derived from the data in Tables 18 and 19 and all the parameters to the model are significant. This is because the model or its parameters have p-values less than 0.05 depicted as < 0.0001. Based on this assertion, the model for predicting oil recovery due to surfactant and nano fluid flooding can be outputted and presented as shown in Eqs. (1) and (2), respectively.

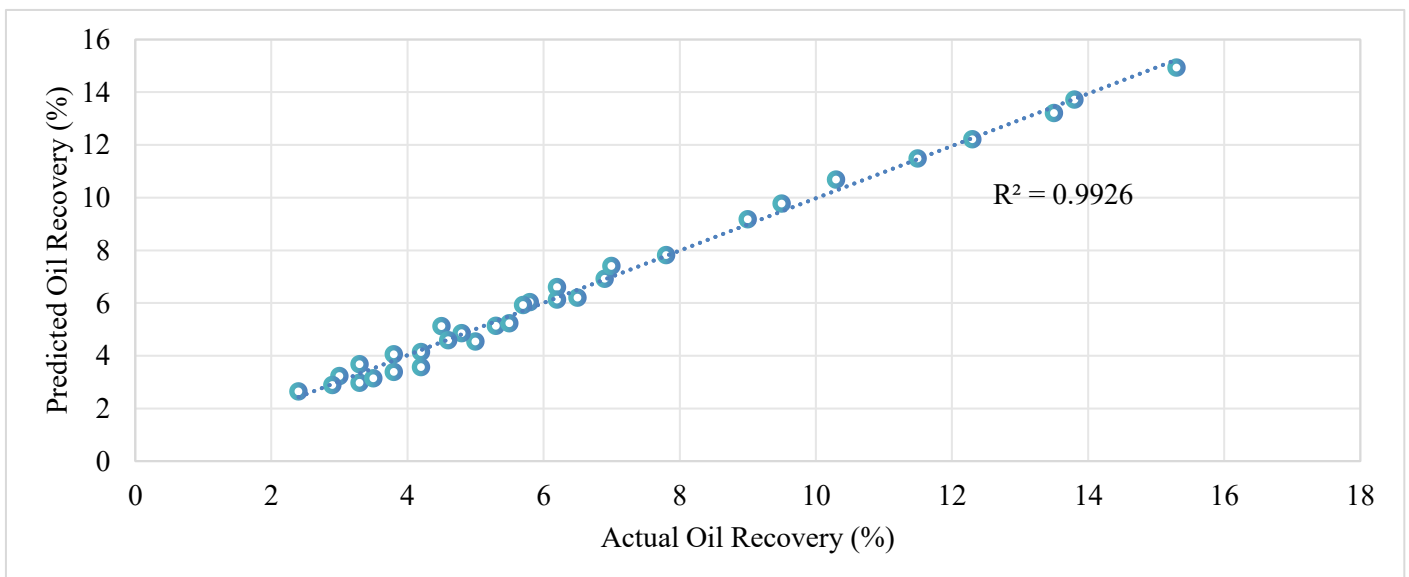
$$Y_{surfactant} = -13.8633 + 213.125 * X1 + 0.146927 * X2 + 84.7148 * X3 + 7.92527 * X4 + 83.75 * X1 * X4 + 54.6311 * X3 * X4 + 99.049 * X3^2, \dots \dots \dots (1)$$

$$Y_{nano\ fluid} = -17.5404 + 38.75 * X1 + -0.679808 * X2 + 124.808 * X3 + 10.4452 * X4 + 10.25 * X1 * X2 + 6.34615 * X2 * X3 + 0.22 * X2 * X4 + 66.1538 * X3 * X4 \dots \dots \dots (2)$$

**Validation of Model.** A model can be validated using existing equations or using data used for its development or by conducting the experiment and inserting experimental data into the model to ascertain if results from experiment are in close agreement with results from the model. **Figures 10 and 11** illustrate cross-plots of actual versus predicted oil recovery for surfactant flooding and nano flooding, respectively. Both graphs demonstrate strong correlations between observed and predicted values, as indicated by high coefficients of determination ( $R^2 = 0.982$  for surfactant flooding and  $R^2 = 0.9926$  for nano flooding). The data points align closely with the 1:1 trend line in both cases, suggesting that the predictive models are highly accurate in capturing the recovery mechanisms for each flooding method. The slightly higher  $R^2$  for nano flooding implies that the model is even more precise in predicting oil recovery for nano flooding compared to surfactant flooding. These results validate the reliability of the models for predicting performance and highlight their potential application in optimizing enhanced oil recovery processes.



**Figure 10—Cross plot of actual vs predicted oil recovery due to surfactant flooding.**



**Figure 11—Cross plot of actual vs predicted oil recovery due to nano flooding.**

## Conclusions

This study demonstrates the efficacy of EK-EOR coupled with APG surfactant flooding and MgO nanofluid flooding in Niger Delta sandstone core plugs. Key findings reveal that concurrent NF-DC flow significantly outperforms sequential flow in recovery enhancement. Both methods address critical challenges of water scarcity and surfactant cost in conventional waterflooding, offering environmentally constrained oilfields a viable alternative to reduce operational costs and fluid disposal burdens.

APG Surfactant Flooding Achieves:

1. Incremental oil recovery of 14-22% OOIP through interfacial tension reduction and wettability alteration toward water-wet conditions.
2. Enhanced sweep efficiency due to improved mobility control.
3. Operational advantages include lower chemical concentration requirements and reduced implementation costs.

MgO Nanofluid Flooding Demonstrates:

1. Superior incremental recovery of 19-26% OOIP, attributed to nanofluid retention mechanisms increasing contact time within pore matrices.
2. Favorable mobility ratio adjustment and residual oil saturation reduction.
3. Extended reservoir effects through nanoparticle adsorption/retention, though accompanied by higher material cost and environmental concerns regarding nanoparticle disposal.

While MgO nanofluids exhibit higher recovery efficiency than APG surfactants, their economic viability is constrained by elevated nanoparticle costs and unquantified long-term reservoir impacts. APG systems offer cost-effective implementation but require optimization of concentration thresholds to maximize recovery. Both technologies show potential for field applications pending further research into MgO environmental mitigation strategies and APG formulation improvements for low-permeability formations.

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## Conflicting Interests

The author(s) declare that they have no Conflicting interests.

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