Evaluation of Methyl Ester Sulfonate (MES) and Ammonium Lauryl Sulfate (ALS) Surfactant Characteristics under Temperature and Salinity Variations for Enhanced Oil Recovery Applications

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Abstract.
This study evaluates the characteristics and effectiveness of two anionic surfactants, palm oil-based Methyl Ester Sulfonate (MES) and synthetic detergent-based Ammonium Lauryl Sulfate (ALS), for chemical Enhanced Oil Recovery (EOR). Tests were performed at five concentrations (0.5–1.7%) under two salinities (4,000 and 15,000 ppm) and two temperatures (60°C and 90°C), evaluating density, aqueous stability, phase behavior, interfacial tension (IFT), and oil recovery via coreflooding on Berea sandstone cores. Density decreased with rising temperature but increased with concentration for both surfactants. MES at 1.1% and 4,000 ppm salinity formed the most stable Winsor Type III middle-phase emulsion at 60°C, persisting 14 days, with the lowest IFT (0.05112 mN/m, low IFT). At 15,000 ppm, the optimum MES concentration shifted to 1.4–1.7%, also yielding stable middle-phase emulsions. ALS formed a middle-phase emulsion only under limited conditions (0.5%; 4,000 ppm; 60°C), with poor stability and a much higher IFT (1.6348 mN/m). Coreflooding showed MES 1.1% achieved the highest cumulative recovery factor (RF) of 82.76%, a 27.59-point gain over waterflooding, outperforming ALS 0.5%, which reached only 54.38% RF with a 20.00-point gain. Overall, MES is recommended as the superior EOR surfactant for sandstone reservoirs with low-to-moderate salinity and temperatures up to 60°C.
Keywords: *MES Surfactant, ALS Surfactant and Enhanced Oil Recovery.*

I. INTRODUCTION

The oil and gas industry faces serious challenges in the form of declining reservoir pressure and diminishing oil reserves in fields that have been operating over the long term. The 2024 International Energy Agency (IEA) report recorded global oil consumption growth of 960 thousand barrels per day, while production capacity in many regions has stagnated. In Indonesia, average crude oil and condensate production is recorded at 660 MBOPD, a condition that has driven an urgent need to apply Enhanced Oil Recovery (EOR) methods to sustain and increase national production levels [1],[2]

EOR via chemical injection, particularly surfactant injection, is one of the most extensively studied approaches owing to its ability to reduce the interfacial tension (IFT) between oil and water within reservoir rock pores. The principal mechanism of surfactant action is the placement of amphiphilic molecules possessing hydrophilic (water-loving) and hydrophobic (oil-loving) groups—at the interface between the two fluid phases, thereby reducing the capillary forces that trap oil within the rock pores and making the oil more readily mobilized toward the production well [3], [4], [5]. Under high-salinity and high-temperature conditions, the effectiveness of conventional surfactants often decreases owing to ionic shielding effects and thermal degradation, making it necessary to select the appropriate surfactant type for the characteristics of the target reservoir [6], [7].

Two commonly used anionic surfactants, and the focus of this study, are Methyl Ester Sulfonate (MES) and Ammonium Lauryl Sulfate (ALS). MES is a palm oil–based anionic surfactant known for being environmentally friendly, possessing strong emulsifying properties, high compatibility with hard water, and the ability to form stable middle-phase emulsions. ALS, by contrast, is a synthetic detergent–based anionic surfactant that is widely available commercially, relatively inexpensive, and capable of forming emulsions, albeit with more limited phase stability ([8], [9]). The difference in molecular structure MES possessing a sulfonate group (SO_3^-) that is more stable against divalent ions, whereas ALS possesses a sulfate group

(OSO_3^-) that is more susceptible to hydrolysis and precipitation—forms the basis of the hypothesis that MES will exhibit superior performance under extreme salinity and temperature conditions..

Although MES and ALS have each been studied extensively in isolation, integrated comparative studies that simultaneously examine physical characteristics, phase behavior, interfacial tension, and coreflooding performance across well-defined salinity and temperature variations remain limited, particularly for light oil (45°API) and Berea sandstone representative of Indonesian reservoir conditions. This study aims to address this gap by comprehensively evaluating the physical characteristics and effectiveness of both surfactants across concentration variations of 0.5, 0.8, 1.1, 1.4, and 1.7% at two salinity levels (4,000 and 15,000 ppm) and two representative reservoir temperatures (60 and 90°C). The evaluation encompasses density measurement, aqueous stability testing, phase behavior assessment, interfacial tension (IFT) measurement, and oil-recovery testing through coreflooding on Berea sandstone. The findings of this study are expected to provide a scientific basis for selecting the optimal surfactant for chemical EOR injection applications in Indonesian oil fields.

Literature Review

Oil production from a reservoir is generally divided into three stages: primary recovery, secondary recovery, and tertiary recovery (EOR). In the primary recovery stage, oil is produced using the reservoir's natural pressure, whereas in secondary recovery, fluids such as water or gas are injected to maintain pressure and drive the oil. However, these two stages together typically recover only about 20–40% of the original oil in place (OOIP), leaving the remaining oil trapped within the rock pores by capillary forces [10]. In the EOR stage, external fluids or energy are injected into the reservoir to increase the recovery of residual oil that cannot be produced through conventional methods. One classification of EOR methods proposed by [11] includes water injection, chemical injection, gas injection, thermal injection, and other methods. Surfactant injection falls under the chemical injection category, together with polymer injection, alkali injection, and the combined Alkali-Surfactant-Polymer (ASP) method [11], [12]. Surfactants function by reducing the IFT between oil and water, altering rock wettability from oil-wet to water-wet, and forming stable emulsions or microemulsions that mobilize residual oil within the rock pores [13]. A significant reduction in IFT increases the capillary number, causing the viscous forces that drive the oil to become more dominant relative to the capillary forces that retain it. The IFT value required for chemical flooding techniques ranges from 10^{-1} to 10^{-3} dyne/cm (ultralow IFT) in order for oil droplets trapped within the rock to be efficiently mobilized [6].

Methyl Ester Sulfonate (MES) is an anionic surfactant synthesized from vegetable oil through the sulfonation of methyl esters. Its molecular structure consists of a hydrophobic ester chain and a hydrophilic sulfonate group, which confer good emulsifying capability and stability across a range of salinity conditions, including high salinity (>15,000 ppm). MES exhibits relatively low adsorption on sandstone, making it suitable for EOR applications in sandstone [10], [14]

Ammonium Lauryl Sulfate (ALS) is a commercial detergent–based anionic surfactant with a sulfate group as its hydrophilic head and a C12 laurate chain as its hydrophobic tail. The physical properties of ALS, including density, can be measured using conventional methods. ALS is capable of reducing the IFT between oil and water and of forming emulsions, although its phase stability tends to be lower than that of MES, particularly at elevated temperatures ([8]). ALS acts through an adsorption mechanism at the oil–water interface, in which the sulfate group ($–OSO_3^-$) interacts with water molecules while the C12 laurate chain interacts with oil. However, the sulfate group in ALS is more susceptible to hydrolysis and precipitation under high-salinity conditions than the sulfonate group in MES, causing its phase stability to decline sharply at sufficiently high salinity [7].

Phase behavior testing is a crucial initial screening stage for determining the compatibility of a surfactant with formation oil and water. This test is conducted to examine the behavior of surfactant, salinity, and hydrocarbon mixtures at a given temperature. The resulting emulsions are classified as lower-phase emulsions (Winsor Type I), middle-phase emulsions or microemulsions (Winsor Type III), and upper-phase emulsions (Winsor Type II). The transition between these phase types is strongly influenced by salinity, with increasing salinity generally shifting the system from Winsor I (lower) to Winsor III (middle) and eventually

to Winsor II (upper) [15]. The formation of a middle-phase microemulsion is an indicator of optimal surfactant performance in EOR, as it reflects miscible-displacement conditions that yield ultralow IFT values in the range of 10^{-2}–10^{-4} mN/m and simultaneously enhance the solubilization of both oil and water [16].

Coreflooding testing is a standard laboratory method used to simulate the injection of fluids into small-scale reservoir rock samples. This test typically begins with waterflooding until residual oil saturation (Sor) is reached, followed by injection of a surfactant slug, and concludes with a postflush using formation water to displace the mobilized residual oil. The recovery factor (RF) is calculated from the volume of oil produced relative to the original oil in place (OOIP) within the core. Another important parameter obtained from this test is the residual oil saturation (Sor), which indicates the amount of oil that remains trapped after the displacement process is complete. A typical coreflooding test scenario consists of waterflooding (secondary recovery), surfactant flooding, and postflush stages [17].

II. METHODS

Materials and Solution Preparation

This study was conducted at the Enhanced Oil Recovery (EOR) Laboratory and the Reservoir Fluid Analysis Laboratory (AFR), Universitas Trisakti. The materials used included MES surfactant (solid form) and ALS surfactant (liquid form), light crude oil from the STN field (45°API), pure NaCl salt, and distilled water. Synthetic brine solutions were prepared by dissolving NaCl salt in distilled water to obtain salinities of 4,000 ppm and 15,000 ppm. MES and ALS surfactant solutions were each prepared at five concentration levels: 0.5, 0.8, 1.1, 1.4, and 1.7% (w/w)in both the 4,000 ppm and 15,000 ppm brine solutions.

Testing Procedure

Density was measured using a DMA-4100 Densitometer at 60℃ and 90℃. Aqueous stability testing was then performed by storing the solutions in an oven at 60℃ and 90℃ for seven days and periodically observing changes in solution condition. Phase behavior testing was carried out by mixing 2 mL of surfactant sample with 2 mL of light crude oil in a pipette tube, shaking for 2 minutes, and then storing the mixture in an oven at 60℃ and 90℃. Emulsion volume was observed at time intervals of 0, 0.5, 1, 2, 24, 48, 168, and 336 hours. IFT measurements were performed using a Spinning Drop Tensiometer, Series TX 500D, at a rotational speed of 6,000 rpm for 30 minutes at 60℃, and were conducted only for surfactant formulations that met the middle-phase emulsion formation criterion in the phase behavior test. Coreflooding tests were performed using a core holder with four Berea sandstone rock samples. Each core was first saturated with brine and then injected with oil to determine the OOIP value. The test scenario consisted of (1) waterflooding up to 3 pore volumes (PV), (2) surfactant flooding up to 1 PV, and (3) postflush. The recovery factor was calculated based on the cumulative volume of oil produced

III. RESULT AND DISCUSSION

Physical Characteristics of Surfactant Solutions

Density measurements were performed to determine the effect of surfactant concentration, salinity, and temperature on solution density. In general, the density of both surfactants increased with increasing concentration under both salinity conditions, but decreased when the temperature was raised from 60℃ to 90℃. This pattern is consistent with the principles of fluid thermodynamics, in which the increase in molecular kinetic energy at higher temperatures causes volumetric expansion and a corresponding decrease in density. At a salinity of 4,000 ppm, the MES surfactant exhibited densities ranging from 0.9843–0.9855 g/cc at 60℃ and 0.9766–0.9781 g/cc at 90℃. Under the same salinity, the ALS surfactant exhibited slightly higher densities of 1.0015–1.0030 g/cc at 60℃ and 0.9787–0.9981 g/cc at 90℃.

The higher density of ALS compared with MES at the same concentration is attributable to the larger molecular weight of the ammonium lauryl sulfate group and the more polar nature of the solution. At a salinity of 15,000 ppm, the density of both surfactants—particularly MES—decreased more markedly at 90℃, with values ranging from 0.7952–0.8164 g/cc. This indicates that under conditions of high salinity and high temperature, the interaction between salt ions and surfactant molecules more significantly affects the

solution structure, resulting in greater volumetric expansion. The complete density data are presented in Table 1.

Table 1. Density of MES and ALS surfactants at various concentrations, salinities, and temperatures

Jenis Surfaktan	Konsentrasi (%)	Salinitas 4000 ppm		Salinitas 15000 ppm	
		Densitas 60°C (g/cc)	Densitas 90°C (g/cc)	Densitas 60°C (g/cc)	Densitas 90°C (g/cc)
MES	0.5	0.9843	0.9766	0.9088	0.7952
MES	0.8	0.9846	0.9769	0.9100	0.7960
MES	1.1	0.9849	0.9773	0.9108	0.7984
MES	1.4	0.9852	0.9777	0.9136	0.7988
MES	1.7	0.9855	0.9781	0.9144	0.8164
ALS	0.5	1.0015	0.9973	0.9076	0.7908
ALS	0.8	1.0019	0.9978	0.9081	0.7913
ALS	1.1	1.0023	0.9981	0.9088	0.7915
ALS	1.4	1.0025	0.9787	0.9092	0.7916
ALS	1.7	1.0030	0.9802	0.9096	0.7924

Aqueous Stability Test

The aqueous stability test was conducted to confirm the compatibility and stability of the surfactant solutions under reservoir temperature and salinity conditions over a seven-day observation period. Based on periodic observations from the first hour through day seven, all MES and ALS surfactant solutions at both salinity levels (4,000 ppm and 15,000 ppm) and both temperatures (60 and 90℃) remained homogeneous, with no precipitation, bubble formation, or phase separation observed. These results confirm that both surfactants, across all tested concentrations, exhibit good compatibility with the synthetic formation water at both salinity levels and were therefore deemed suitable for further evaluation through phase behavior and subsequent testing. A summary of the stability test results is presented in Table 2.

Table 2. Aqueous stability test results for MES and ALS surfactants

Surfactant	Concentration (%)	4,000 ppm, 60°C	4,000 ppm, 90°C	15,000 ppm, 60°C	15,000 ppm, 90°C
MES	0.5	Homogeneous	Homogeneous	Homogeneous	Homogeneous
MES	0.8	Homogeneous	Homogeneous	Homogeneous	Homogeneous
MES	1.1	Homogeneous	Homogeneous	Homogeneous	Homogeneous
MES	1.4	Homogeneous	Homogeneous	Homogeneous	Homogeneous
MES	1.7	Homogeneous	Homogeneous	Homogeneous	Homogeneous
ALS	0.5	Homogeneous	Homogeneous	Homogeneous	Homogeneous
ALS	0.8	Homogeneous	Homogeneous	Homogeneous	Homogeneous
ALS	1.1	Homogeneous	Homogeneous	Homogeneous	Homogeneous
ALS	1.4	Homogeneous	Homogeneous	Homogeneous	Homogeneous
ALS	1.7	Homogeneous	Homogeneous	Homogeneous	Homogeneous

Phase Behavior Test

Phase behavior testing is a critical stage in surfactant screening for EOR applications. At 60℃, the MES surfactant at a concentration of 1.1% produced the most stable Winsor Type III middle-phase emulsion, with an emulsion percentage of 21.50% at the end of the 336-hour observation period. The formation of a middle phase indicates an optimal condition in which the surfactant is balanced at the oil–water interface, yielding a very low IFT. At concentrations of 1.4 and 1.7%, the resulting emulsions shifted toward the upper phase (Winsor Type II), indicating oil-phase dominance.

For the MES surfactant at 4,000 ppm salinity and 60°C, the 1.1% concentration produced the most stable Winsor Type III middle-phase emulsion, with an emulsion percentage of 21.50% at the end of the 336-hour observation period. Concentrations of 0.5% and 0.8% produced unstable Winsor Type I (lower-phase) emulsions that broke down by day 7. Concentrations of 1.4% and 1.7% produced Winsor Type II (upper-phase) emulsions that were likewise unstable. At 90°C, all MES concentrations failed to maintain a stable emulsion, with most exhibiting no phase separation after 24 hours. This indicates that, at low salinity, MES requires lower-temperature conditions to achieve an optimal HLB balance.

A different phenomenon was observed for the MES surfactant at a salinity of 15,000 ppm. At 60°C, MES concentrations of 1.4 and 1.7% produced stable middle-phase emulsions persisting for 14 days, whereas lower concentrations (0.5, 0.8, and 1.1%) produced only unstable lower-phase emulsions. The requirement for a higher concentration at 15,000 ppm salinity is attributable to the ionic shielding effect of Na^+ and Cl^- ions, which hinders the adsorption of surfactant molecules at the interface, thereby necessitating a higher MES concentration to offset this effect. At 90°C, all MES concentrations at 15,000 ppm salinity produced only Winsor Type I (lower-phase) emulsions and failed to reach the middle-phase condition.

Table 3. Summary of MES surfactant phase behavior test results across concentration, salinity, and temperature variations

Salinity	Concentration (%)	Phase Type (60°C)	Remarks (60°C)	Phase Type (90°C)	Remarks (90°C)
4,000 ppm	0.50	Winsor I (Lower)	Unstable, broke on day 7	Winsor II (Upper)	Thin emulsion, broke on day 2
4,000 ppm	0.8	Winsor I (Lower)	Unstable, broke on day 7	No phase	No emulsion formed
4,000 ppm	1.10	Winsor III (Middle)	Stable for 14 days (best candidate)	No phase	No emulsion formed
4,000 ppm	1.40	Winsor I (Lower)	Unstable	No phase	No emulsion formed
4,000 ppm	1.70	Winsor I (Lower)	Unstable	No phase	No emulsion formed
15,000 ppm	0.50	Winsor I (Lower)	Very thin emulsion, unstable	Winsor I (Lower)	Did not reach middle phase
15,000 ppm	0.80	Winsor I (Lower)	Unstable	Winsor I (Lower)	Did not reach middle phase
15,000 ppm	1.10	Winsor I (Lower)	Unstable	Winsor I (Lower)	Did not reach middle phase
15,000 ppm	1.40	Winsor III (Middle)	Stable for 14 days (best candidate)	Winsor I (Lower)	Did not reach middle phase
15,000 ppm	1.70%	Winsor III (Middle)	Stable for 14 days (best candidate)	Winsor I (Lower)	Did not reach middle phase

For the ALS surfactant at 4,000 ppm salinity and 60°C, only the 0.5% concentration produced a Winsor Type III middle-phase emulsion, albeit with limited stability (the emulsion began to break down after day 7 and had fully dissipated by day 14). Higher concentrations (0.8%, 1.1%, 1.4%, and 1.7%) did not produce any meaningful emulsion. At 90°C, all ALS concentrations failed to form a stable emulsion. At a salinity of 15,000 ppm, ALS failed to form any meaningful emulsion under either temperature condition. This confirms a fundamental limitation of ALS in adapting to high-salinity environments, attributable to the sensitivity of the sulfate group to multivalent salt ions, which can cause precipitation or a drastic reduction in surface activity.

Table 4. Summary of ALS surfactant phase behavior test results across concentration, salinity, and temperature variations

Salinity	Concentration	Phase Type (60°C)	Remarks (60°C)	Phase Type (90°C)	Remarks (90°C)
4,000 ppm	0.5	Winsor III (Middle)	Poor stability (broke day 7, gone day 14)	No phase	No emulsion formed
4,000 ppm	0.8	No phase	No emulsion formed	No phase	No emulsion formed
4,000 ppm	1.1	No phase	No emulsion formed	No phase	No emulsion formed
4,000 ppm	1.4	No phase	No emulsion formed	No phase	No emulsion formed
4,000 ppm	1.7	No phase	No emulsion formed	No phase	No emulsion formed
15,000 ppm	0.5	No phase	No emulsion formed (incompatible with high salinity)	No phase	No emulsion formed
15,000 ppm	0.8	No phase	No emulsion formed (incompatible with high salinity)	No phase	No emulsion formed
15,000 ppm	1.1	No phase	No emulsion formed (incompatible with high salinity)	No phase	No emulsion formed
15,000 ppm	1.4	No phase	No emulsion formed (incompatible with high salinity)	No phase	No emulsion formed
15,000 ppm	1.7	No phase	No emulsion formed (incompatible with high salinity)	No phase	No emulsion formed

Interfacial Tension (IFT) Test

Interfacial tension (IFT) measurements were conducted to evaluate each surfactant's ability to reduce capillary forces between oil and water. Testing was performed using a Spinning Drop Tensiometer TX 500D at 60°C and 6,000 rpm for 30 minutes. Only samples that formed a Winsor Type III middle-phase emulsion in the phase behavior test were evaluated—namely, MES 1.1%, MES 1.4%, MES 1.7%, and ALS 0.5%. The results show that the lowest IFT value was obtained for MES 1.1% at 4,000 ppm salinity, with a value of 0.05112 dyne/cm. Meanwhile, MES 1.4% and 1.7% at 15,000 ppm salinity yielded IFT values of 0.863 dyne/cm and 0.941 dyne/cm, respectively. ALS 0.5% yielded an IFT value of 1.6348 dyne/cm.

Table 5. IFT measurement results for selected surfactants at 60°C

Surfactant	Concentration	Salinity (ppm)	IFT (dyne/cm)	Category
MES	1.10%	4,000	5.112×10^{-2}	Low IFT
MES	1.40%	15,000	8.63×10^{-1}	Low IFT
MES	1.70%	15,000	9.41×10^{-1}	Low IFT
ALS	0.50%	4,000	1.6348	Moderate IFT

The lowest IFT value, obtained for MES 1.1% at 4,000 ppm salinity, indicates that this concentration is close to the Critical Micelle Concentration (CMC) under this salinity condition. At higher salinity (15,000 ppm), MES performance declined, as reflected in the higher IFT values for MES 1.4% and 1.7%, owing to the ionic shielding effect that hinders the adsorption of surfactant molecules at the oil–water interface. As a result, surfactant molecules tend to form micelles within the bulk liquid phase rather than adsorbing at the interface, requiring a higher concentration (1.4–1.7%) to achieve an optimal reduction in IFT. Meanwhile,

ALS 0.5% yielded the highest IFT value, indicating that ALS possesses lower interfacial activity than MES under equivalent conditions. Overall, MES proved superior to ALS in reducing interfacial tension. Nevertheless, all IFT values obtained remain above the ultralow range (10^{-3} dyne/cm), indicating that further formulation optimization is required.

Rock Sample Characterization

Four Berea sandstone core samples were used in the coreflooding tests, each designated for testing a selected surfactant formulation based on the results of the preceding evaluation. Cores A and B were used to test the MES surfactant at 15,000 ppm salinity (concentrations of 1.4% and 1.7%, respectively), while Cores C and D were used to test MES 1.1% and ALS 0.5%, respectively, at 4,000 ppm salinity. All four cores possessed an identical permeability value (170 mD) but differed in dimensions, porosity, pore volume, OOIP, and initial saturation conditions. The complete specifications of the four rock samples are presented in Table 6.

Table 6. Physical characteristics of the Berea sandstone core samples used in the coreflooding tests

Parameter	Core A	Core B	Core C	Core D
Surfactant Variant	MES 1.4%	MES 1.7%	MES 1.1%	ALS 0.5%
Salinity Condition (ppm)	15,000 ppm	15,000 ppm	4,000 ppm	4,000 ppm
Rock Type	Berea Sandstone	Berea Sandstone	Berea Sandstone	Berea Sandstone
Diameter (cm)	2.5	2.5	2.51	2.51
Length (cm)	2.8	2.6	3.52	3.32
Bulk Volume (cm^3)	13.74	12.76	17.43	16.45
Porosity (%)	14	14	27.23	28.92
Permeability (mD)	170	170	170	170
Pore Volume (mL/cc)	12.19	12.22	5.001	4.997
OOIP (cc)	1.1	1.2	1.45	1.6
Initial Oil Saturation (%)	55.88	60.07	29	32.02
Initial Water Saturation (%)	44.12	39.93	71	67.98

Coreflooding Test and Oil Recovery

Coreflooding tests were performed to evaluate the effectiveness of the selected surfactants in improving oil recovery at laboratory scale. The tests consisted of three stages: waterflooding (water injection), surfactant flooding (surfactant injection), and postflush (subsequent water injection). A summary of the coreflooding results for all four core samples is presented in Table 7.

Table 7. Coreflooding test results for the four core samples

Parameter	Core A	Core B	Core C	Core D
Surfactant Variant	MES 1.4%	MES 1.7%	MES 1.1%	ALS 0.5%
Salinity (ppm)	15,000	15,000	4,000	4,000
Total PV Injected	~5.00 PV	~5.01 PV	4.86 PV	4.86 PV
Waterflooding RF	34.55%	62.50%	55.17%	34.38%
Surfactant Flooding RF	7.22%	5.05%	27.59%	20.00%
Total Final RF	41.76%	67.55%	82.76%	54.38%
RF Increase from Surfactant	7.21%	5.05%	27.59%	20.00%
Final Residual Oil Saturation (Sor)	58.24%	32.45%	17.24%	45.62%

To visualize the comparative dynamics of oil recovery during the injection process, Figure 1 presents recovery factor (RF) curves plotted against injected pore volume (PV) for the four core samples (Cores A–D). These plots clarify the differences in displacement profile between the MES and ALS surfactants under different salinity conditions and illustrate the stages at which oil recovery occurs progressively. In Figure 1c (Core C, MES 1.1%, 4,000 ppm salinity), the curve profile shows the best performance among the four samples. During the waterflooding stage, RF rose sharply and reached a plateau of 55.17% after 1.69 PV had been injected. Following the start of surfactant injection (indicated by the change in curve color), RF increased significantly to reach 82.76% by the end of injection, an additional 27.59 percentage points. The steep curve during the surfactant flooding stage indicates that MES 1.1% at low salinity is highly effective in reducing interfacial tension and releasing trapped residual oil.

In Figure 1b (Core B, MES 1.7%, 15,000 ppm salinity), the waterflooding stage achieved the highest RF among all cores (62.50%), indicating rock characteristics highly favorable to water displacement. However, surfactant injection contributed only an additional 5.05% RF, bringing the total to 67.55%. The relatively flat curve during the surfactant flooding stage indicates that, because most of the oil had already been displaced during waterflooding, the amount of residual oil remaining for surfactant mobilization was limited. Nevertheless, the final residual oil saturation (Sor) of Core B decreased sharply to 32.45%, indicating the effectiveness of MES 1.7% in displacing the remaining trapped oil. In Figure 1a (Core A, MES 1.4%, 15,000 ppm salinity), the curve profile shows that waterflooding achieved only 34.55%, indicating low water sweep efficiency owing to unfavorable rock characteristics or pore-size distribution. Following MES 1.4% injection, RF increased gradually, with an addition of only 7.21%, reaching a total of 41.76%, with a final Sor that remained very high (58.24%). This indicates that, at high salinity, MES 1.4% requires a higher concentration or different operating conditions to optimize the reduction in IFT. In Figure 1d (Core D, ALS 0.5%, 4,000 ppm salinity), the curve profile shows that the waterflooding stage plateaued at 34.38%, and following surfactant injection, RF increased only to 54.38%, an addition of 20.00 percentage points. The gentle slope of the curve during the surfactant flooding stage indicates that ALS is less effective than MES in reducing interfacial tension, such that a substantial portion of residual oil remained trapped within the rock pores. This is consistent with the markedly higher IFT value of ALS (1.6348 mN/m) compared with MES 1.1% (0.05112 mN/m).

Variation in oil recovery during the waterflooding stage shows that, although all four cores possessed the same permeability value (170 mD), differences in porosity and initial oil saturation (Soi) affected water sweep efficiency. Core B, with lower porosity (14%) and higher Soi (60.07%), nevertheless exhibited the best waterflooding performance, indicating rock characteristics more favorable to water displacement. During the surfactant flooding stage, all cores showed an increase in RF. The largest increase was obtained for Core C (MES 1.1%, 4,000 ppm salinity), at 27.59 percentage points—the best result among all samples and consistent with the lowest IFT value achieved by MES 1.1%. For Cores A and B at 15,000 ppm salinity, the RF increase attributable to MES was only 7.21% and 5.05%, respectively, indicating that MES performance at high salinity is less optimal than at low salinity, consistent with the phase behavior and IFT test results. Meanwhile, Core D (ALS 0.5%, 4,000 ppm salinity) showed an RF increase of 20.00 percentage points, with a cumulative RF of 54.38% and a final Sor of 45.62%. Although ALS is capable of reducing IFT, its effectiveness in displacing residual oil remains far below that of MES, primarily owing to poor emulsion stability and its inability to adapt to high salinity. During the postflush stage, which is not shown in the figure, none of the cores exhibited additional oil production (RF = 0%), indicating that the surfactant had already exerted its maximum effect during the preceding stage and that continued water injection was no longer capable of further reducing the capillary forces retaining the residual oil. Overall, MES 1.1% at low salinity proved to be the most effective in improving oil recovery, supported by favorable middle-phase stability and superior IFT-reduction capability.

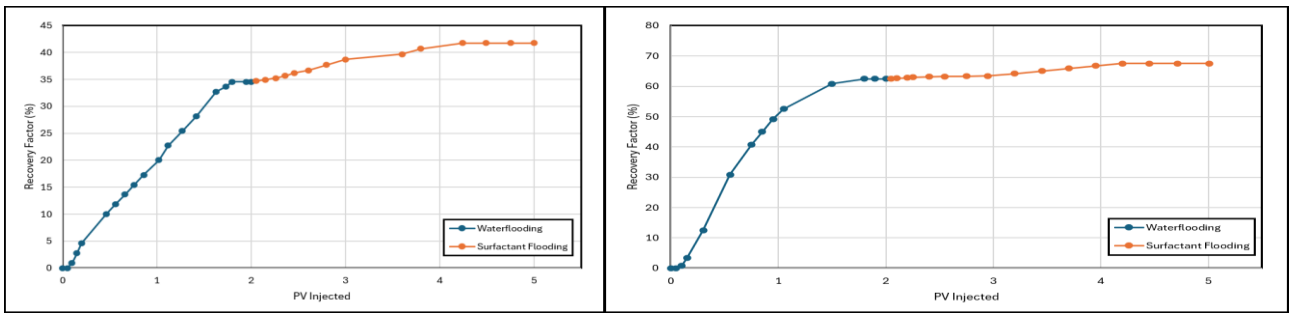

Figure 1a. Recovery factor curve for Core A — surfactant flooding, MES 1.4% (15,000 ppm) Figure 1b. Recovery factor curve for Core B — surfactant flooding, MES 1.7% (15,000 ppm)

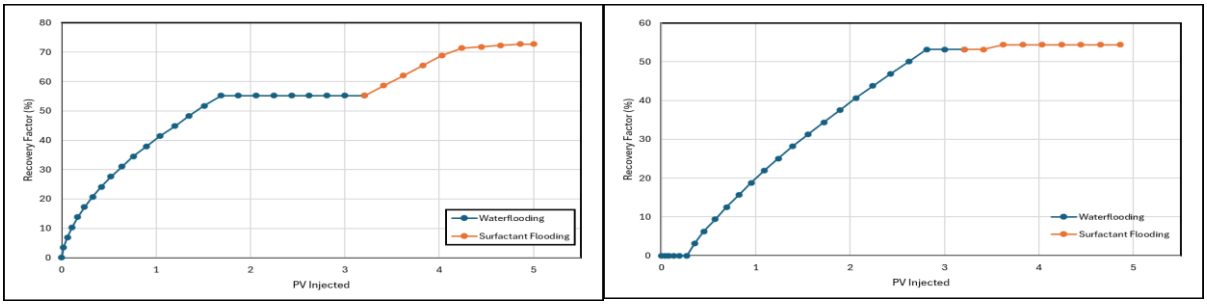

Fig.1c. Recovery factor curve for Core C — surfactant flooding, MES 1.1% (4,000 ppm) Figure 1d. Recovery factor curve for Core D — surfactant flooding, ALS 0.5% (4,000 ppm)

Figure 1. Oil recovery profile (recovery factor) versus injected pore volume in the coreflooding tests: (a) Core A — MES 1.4% (15,000 ppm); (b) Core B — MES 1.7% (15,000 ppm); (c) Core C — MES 1.1% (4,000 ppm); (d) Core D — ALS 0.5% (4,000 ppm). All tests were conducted at 60°C. The curves show two injection stages: waterflooding (WF) and surfactant flooding (SF).

IV. CONCLUSION

Based on a series of laboratory tests encompassing physical property measurement, aqueous stability, phase behavior, interfacial tension, and coreflooding, it can be concluded that the density of both surfactants increases with increasing concentration but decreases at higher temperature, consistent with the principles of fluid thermodynamics. The MES surfactant at a concentration of 1.1%, salinity of 4,000 ppm, and temperature of 60°C exhibited the best performance, marked by the formation of a stable Winsor Type III middle-phase emulsion persisting for 14 days with an emulsion percentage of 21.50%, and the lowest IFT value of 0.05112 mN/m (classified as low IFT). In contrast, the ALS surfactant formed a middle-phase emulsion only under highly limited conditions (0.5%; 4,000 ppm; 60°C), with poor stability (the emulsion broke down by day 7) and a markedly higher IFT value (1.6348 mN/m), and failed entirely at 15,000 ppm salinity. In the coreflooding tests, MES 1.1% produced the highest cumulative recovery factor, at 82.76%, an increase of 27.59 percentage points over waterflooding, far outperforming ALS 0.5%, which achieved only a 54.38% cumulative RF with an increase of 20.00 percentage points. Overall, the MES surfactant is recommended for chemical EOR injection applications in sandstone reservoirs with low-to-moderate salinity ($\leq$ 4,000 ppm) and operating temperatures up to 60°C, supported by favorable phase stability, superior IFT-reduction capability, and high oil-recovery efficiency, whereas ALS is not recommended, particularly under high-salinity conditions.

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