Comparative Evaluation of Anionic Surfactants (AOS, ALS, ABS, and MES) for Enhanced Oil Recovery at Varied Concentrations and Temperatures in Sandstone Reservoir

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ABSTRACT: This research aims to evaluate and compare the effectiveness of four anionic surfactants—Alpha Olefin Sulfonate (AOS), Ammonium Lauryl Sulfate (ALS), Alkyl Benzene Sulfonate (ABS), and Methyl Ester Sulfonate (MES)—for Enhanced Oil Recovery (EOR) applications in sandstone reservoirs. Experiments were conducted using five surfactant concentrations (0.5%, 0.7%, 0.9%, 1.1%, and 1.3%), a fixed brine salinity of 9000 ppm, and two temperature conditions (60°C and 80°C).

Physical fluid properties including density, specific gravity, and viscosity were characterized for each surfactant solution. Results demonstrate that increasing surfactant concentration raises both density and viscosity, while increasing temperature tends to decrease these values. Phase behavior tests showed that AOS and ALS were capable of forming stable microemulsions (Winsor III) at 1.3% concentration across both temperatures, whereas ABS and MES formed microemulsions only at 60°C and higher concentrations, with a notable decline in performance at 80°C.

Interfacial tension (IFT) measurements identified ALS as the most effective, reducing IFT to the optimal range for EOR (<0.01 dyne/cm), outperforming AOS, ABS, and MES. Core flooding tests further validated ALS, which delivered the highest increase in oil recovery factor (RF), achieving a 30.83% increment at 1.3% concentration and 60°C. MES followed as a promising alternative, contributing approximately a 5% RF increase under the same conditions, while AOS and ABS yielded lower enhancements.

The study concludes that selection of surfactant type, concentration, and operational temperature critically influences oil recovery efficiency. ALS is identified as the most effective surfactant under the tested conditions, with MES offering additional environmental benefits and solid EOR performance at moderate temperatures. Future research is recommended to explore surfactant-polymer combinations, varied salinity scenarios, and field-scale validations to optimize EOR strategies for mature oil reservoirs.

KEYWORDS: ABS Surfactant, AOS Surfactant, ALS Surfactant, MES Surfactant, Recovery Factor (RF)

INTRODUCTION

The growing demand for energy has intensified the need for efficient hydrocarbon extraction from maturing oil fields. Oil production from mature reservoirs typically faces challenges due to decreasing reservoir pressure and diminishing efficiency of primary and secondary recovery methods. After primary and secondary recovery, a substantial proportion of oil remains trapped due to capillary forces and unfavorable water-oil mobility ratios. Enhanced Oil Recovery (EOR) using chemical injections such as surfactant flooding, have proven effective in mobilizing residual oil by lowering the interfacial tension between hydrocarbons and water, improving oil displacement efficiency.

Anionic surfactants—especially AOS, ALS, ABS, and MES—stand out in both literature and field trials, offering substantial IFT reduction and microemulsion formation under particular concentration and temperature regimes. However, surfactant efficiency is highly contingent on reservoir characteristics and operational parameters, such as salinity, temperature, and surfactant formulation. This study aims to compare the effectiveness of these four surfactants across a range of concentrations and reservoir-relevant temperatures using laboratory-based physical characterization, phase behavior analysis, interfacial tension measurement, and core flooding recovery tests.

LITERATURE REVIEW

Enhanced Oil Recovery (EOR) is an advanced stage of oil recovery techniques used after primary and secondary methods are no longer effective in extracting oil from reservoirs. EOR processes do supplement primary and secondary methods via deployment of chemical, gas, and thermal agents for increases in the volume of extractable hydrocarbons (Darmapala, 2019; Kesuma and Kasmungin, 2015). EOR techniques include the injection of chemicals, gases, or heat with the aim of reducing interfacial tension, changing fluid properties, or other mechanisms that can loosen oil in rocks and increase its mobility. Surfactants are active substances that work chemically to reduce the interfacial tension between oil and water, making oil easier to move and produce. Chemical EOR, in particular surfactant flooding, acts to decrease the interfacial tension that exists between oil plus injected water, which eases the detachment of any residual oil films, specifically from rock surfaces, plus improves fluid mobility inside porous media (Rivai et al., 1997; Damanik et al., 2018).

For the hydrophilic group, the charge determines surfactants' classification (Ristawati et al, 2018). They are anionic, cationic, non-ionic, together with zwitterionic. Due to their negatively charged hydrophilic head groups obstructing adsorption on negatively charged sandstone surfaces, anionic surfactants are utilized preferentially in sandstone reservoirs; this maintains higher effective concentrations in the liquid reservoir phase. Anionic surfactants such as Alpha Olefin Sulfonate (AOS), Ammonium Lauryl Sulfate (ALS), Alkyl Benzene Sulfonate (ABS), and Methyl Ester Sulfonate (MES) are known to be effective for EOR because laboratory studies show a significant reduction in interfacial tension. AOS and ALS have been extensively studied as surfactants with good solution stability under various temperature and salinity conditions, capable of forming microemulsions (middle phase) that optimize oil displacement and significantly increase the recovery factor. Meanwhile, ABS and MES are often applied due to their relatively low adsorption values on sandstone rocks and readily available raw materials. MES also has the advantage of being environmentally friendly because it is made from vegetable oil.

Studies related to the effect of surfactant concentration on the physical stability of solutions and phase behavior show that increasing surfactant concentration increases the density and viscosity of solutions, but increasing temperature generally decreases these values. The formation of stable microemulsions within a certain concentration window is a key factor in the effectiveness of surfactants in EOR. An interfacial tension value that can be reduced to a logarithmic range of 10^{-3} dyne/cm is an optimal indication for maximum oil recovery. Core flooding is a standard method for testing surfactant injection performance in laboratories that replicate reservoir conditions from the rock side.

Various literature and field studies indicate that surfactants capable of forming stable microemulsions under reservoir temperature and salinity conditions and having supportive physical characteristics, such as viscosity that is not too high for injection and adequate density, will provide a significant increase in recovery factor compared to without surfactants or injection with water alone. Therefore, this study is important to compare the characteristics of each surfactant in the context of specific operating conditions in sandstone with a salinity of 9000 ppm and temperatures of 60 and 80°C.

A. Fundamentals of Enhanced Oil Recovery and Role of Chemical Methods

Enhanced Oil Recovery (EOR) refers to a suite of techniques implemented after primary and secondary recoveries to extract additional oil from reservoirs that would otherwise remain unrecoverable. EOR methods are generally categorized into thermal, gas injection, and chemical techniques. Chemical EOR specifically involves the injection of chemical agents such as polymers, surfactants, or alkalis to modify fluid and rock surface interactions and improve oil displacement efficiency. Among these, surfactant flooding is integral, leveraging the ability of surfactants to reduce interfacial tension (IFT) between oil and water phases, thereby mobilizing trapped oil by overcoming capillary forces. The efficiency of EOR, particularly chemical methods, is strongly influenced by reservoir characteristics including porosity, permeability, temperature, and salinity, which affect the behavior and stability of injected chemicals. Thus, a nuanced understanding of these parameters is critical to optimizing EOR performance.

B. Surfactant Flooding in Sandstone Reservoirs

Sandstone reservoirs, characterized by their mineral composition and pore structure, present unique challenges and opportunities for surfactant flooding. Key concerns include surfactant adsorption on the rock surface, which diminishes effective surfactant concentration and increases chemical costs, and retention that impacts flow dynamics. Effective surfactants must demonstrate low adsorption affinity and retain stability under reservoir conditions to maximize recovery. Earlier research and field experiments have shown that anionic surfactants, due to their charge and molecular structure, often display favorable interactions in sandstone

formations that reduce adsorption relative to cationic or nonionic surfactants. Laboratory studies frequently simulate reservoir conditions to evaluate surfactant efficacy under controlled conditions, providing insights into their phase behavior, stability, and oil displacement capabilities in sandstone.

C. Importance of Surfactant Concentration and Operating Temperature

Surfactant concentration directly affects the physical properties of injection fluids and the effectiveness of microemulsion formation, a primary mechanism for IFT reduction. Increasing concentration typically elevates density and viscosity, enhancing sweep efficiency but posing injection challenges if viscosity becomes excessive. Temperature acts as a critical parameter influencing surfactant solubility, phase equilibrium, and chemical degradation rates. Higher temperatures tend to reduce solution viscosity and density but may compromise surfactant stability and microemulsion integrity. Additionally, the combined effect of temperature and salinity modulates micelle formation and aggregate structures, thereby influencing the overall displacement efficiency and recovery in EOR.

D. Alpha Olefin Sulfonate (AOS)

Alpha Olefin Sulfonate (AOS) is an anionic surfactant featuring a hydrophobic alkenyl carbon chain linked to a sulfonate head group. AOS displays strong surface active properties that enable significant IFT reduction and emulsification abilities which are essential for mobilizing residual oils. Specifically, AOS has been noted for forming stable microemulsions conducive to efficient oil displacement when combined with appropriate salinity and temperature conditions. However, its performance diminishes at elevated temperatures due to reduced thermal stability, which limits its applicability in high-temperature reservoirs.

E. Ammonium Lauryl Sulfate (ALS)

Ammonium Lauryl Sulfate (ALS) contains a lauryl (C12) hydrophobic tail and an anionic sulfate head group with an ammonium counterion, contributing to its solubility and interfacial activity in brine environments. The physical properties of ALS surfactants, such as viscosity and density, are measured using the Ostwald viscosity method and a pycnometer. The physical properties of activated carbon for calculating the minimum fluidization rate, such as measuring the porosity of activated carbon, are determined by measuring the remaining empty space (void volume) in packaged activated carbon.

F. Alkyl Benzene Sulfonate (ABS)

Alkyl Benzene Sulfonate (ABS) is a widely used anionic surfactant, structurally characterized by a benzene ring linked to an alkyl chain terminating in a sulfonate head group. Though efficacious in multiple industrial applications, ABS presents challenges in sandstone reservoirs due to its tendency for higher adsorption onto mineral surfaces, thereby reducing its effective concentration. ABS demonstrates microemulsion formation and emulsification under laboratory conditions, but its phase stability critically decreases at higher temperatures, limiting its efficacy as an EOR agent under such conditions. These temperature-dependent limitations reduce ABS's suitability for reservoirs exceeding moderate thermal conditions.

ABS is a conventional surfactant typified through a benzene ring that is linked to an alkyl group for conferring hydrophobicity, plus a sulfonate group for imparting of negative charge. Widely documented is its high stability in brine solutions and efficacy in forming microemulsions, critical factors in reducing oil-water interfacial tension. ABS, in effect, increases oil recovery through the lowering of capillary forces that trap oil inside porous sandstone structures, as laboratory tests have shown us. It is resilient inside reservoirs with moderate to high salinity as well as temperatures up to 60°C (Ahmad and Idris, 2015; Hani and Martanto, 2020; Zhang and Liu, 2014; Tsai dan Chen, 2016).

G. Methyl Ester Sulfonate (MES)

Methyl Ester Sulfonate (MES) is notable for its bio-based origin and biodegradability, distinguishing it as an environmentally favorable alternative among anionic surfactants. MES demonstrates the ability to reduce IFT effectively, albeit usually not attaining the ultralow values exhibited by ALS. Despite moderate recovery factors, MES's sustainability and acceptable EOR efficiency position it as a promising candidate for environmentally conscious reservoir projects.

MES represents a class of newer anionic surfactants that are synthesized from animal fats or methyl esters of vegetable oils. MES has effective surface activity, so it is also biodegradable. Its biodegradability aligns with global trends toward environmentally friendly EOR chemicals. Also, MES maintains stable physicochemical properties at higher salinities and temperatures, even

outperforming ABS in certain reservoir conditions, and thus it offers improved recovery potential, particularly in the warm, saline, harsh reservoirs (Yadav and Suri, 2016; Kim and Lee, 2017; Tsai dan Chen, 2016).

MATERIALS AND METHODS

A. Surfactant and Brine Preparation

Alpha Olefin Sulfonate (AOS) was prepared from powder, ALS from a commercial liquid base, and both ABS and MES from respective analytical solutions. Surfactants were dissolved in brine at targeted concentrations (0.5, 0.7, 0.9, 1.1, and 1.3% by weight) using 9000 ppm NaCl solution as the base

B. Physical – Chemical Analysis

- **Density and Viscosity**
  Samples were analyzed for density using a DMA-4100 densitometer and for viscosity using an Ostwald viscometer at both 60°C and 80°C after thermostating for equilibrium. Each measurement was repeated to ensure accuracy.

- **Phase Behavior**
  Phase behavior tests were performed by mixing oil, brine, and surfactant solutions in test tubes, which were then incubated at their target temperatures. Visual readings were taken at periodic intervals over 14–21 days to observe formation and stability of middle-phase microemulsions (Winsor III).

- **Interfacial Tension (IFT)**
  IFT was measured with a spinning drop tensiometer at optimal concentrations as identified from phase behavior tests. The ability to achieve ultra-low IFT (<0.01 dyne/cm) was the benchmark for high-performance EOR.

C. Core Flooding Experiments

Porous sandstone cores (19% porosity, 170 mD permeability) were saturated with oil and waterflooded as baseline. Surfactant flooding was then conducted using the best concentration and temperature conditions per surfactant. Oil recovery was monitored, with the recovery factor (RF) calculated as a percentage of original oil in place (OOIP).

RESULTS AND DISCUSSION

A. Physical Properties: Density and Viscosity

Plots of density and viscosity versus surfactant concentration at both temperatures (Table 1) reveal that all surfactants showed increases in both parameters as concentration increased from 0.5% to 1.3%. ALS and AOS showed strong correlation, with density rising from 0.9817 to 0.9896 g/cm³ (AOS, 60°C) and viscosity from 1.2170 to 1.5345 cp over the tested range.

At 80°C, all surfactants exhibited decreased density and viscosity, with MES maintaining the highest viscosity (>2 cp at 1.3%), indicating challenges for injectivity but benefits for sweep efficiency. ABS followed the same pattern, with measurable decrease in both properties upon temperature increase

Table 1. Density and viscosity vs concentration and temperature

Concentration (%)	AOS_60 Density	ALS_60 Density	ABS_60 Density	MES_60 Density	AOS_80 Density	ALS_80 Density	ABS_80 Density	MES_80 Density	AOS_60 Viscosity	ALS_60 Viscosity	ABS_60 Viscosity	MES_60 Viscosity	AOS_80 Viscosity	ALS_80 Viscosity	ABS_80 Viscosity	MES_80 Viscosity
0.5	0.9817	0.9835	0.9831	0.9939	0.9749	0.9736	0.9845	0.9882	1.2170	1.2322	1.1700	1.8600	1.1604	1.0932	1.1100	2.0100
0.7	0.9840	0.9858	0.9852	0.9954	0.9772	0.9757	0.9867	0.9900	1.3036	1.3440	1.2500	1.9300	1.2460	1.1291	1.1700	2.0500
0.9	0.9862	0.9880	0.9870	0.9965	0.9791	0.9776	0.9877	0.9915	1.3737	1.3722	1.3200	1.9700	1.2730	1.2451	1.2100	2.0700
1.1	0.9881	0.9901	0.9887	0.9983	0.9811	0.9789	0.9879	0.9930	1.5132	1.4142	1.4100	1.9900	1.3623	1.3611	1.2600	2.0800
1.3	0.9896	0.9929	0.9902	0.9997	0.9837	0.9786	0.9882	0.9940	1.5345	1.4424	1.5100	2.0200	1.4516	1.4235	1.2900	2.0900

B. Phase Behavior: Microemulsion Stability

Phase behavior experiments (Table 2 and Table 3) showed that AOS and ALS formed stable middle-phase (Winsor III) microemulsions at 1.3% for both temperatures, remaining unchanged through at least 14 days. MES and ABS only produced stable

microemulsions at 60°C and ≥1.1% concentration; at 80°C, phase separation dominated and no significant microemulsion was sustained after 14 days.

Table 2. Summary of core physical and chemical test results

Surfactant	Concentration (%)	Temperature (°C)	Density (g/cm³)	Viscosity (cp)	Microemulsion (Y/N)	IFT (dyne/cm)	Incremental RF (%)
AOS	1.3	60	0.9896	15.345	Yes	0.82	1.82
ALS	1.3	60	0.9929	14.424	Yes	<0.01	30.83
ABS	1.3	60	0.9902	–	Yes	–	n.s.
MES	1.3	60	0.9997	2.02	Yes	0.65	5
MES	1.3	80	0.9882	2.09	No	–	n.s.

Table 3. Emulsion stability kaplan-meier plot vs time for aos, als, abs, and mes at both temps (*values represent emulsion stability fraction which 1.0 is fully stable and 0.0 is broken*)

Time (days)	AOS_60	ALS_60	ABS_60	MES_60	AOS_80	ALS_80	ABS_80	MES_80
0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
7	1.0	1.0	1.0	1.0	1.0	0.95	0.90	0.85
14	1.0	1.0	0.6	0.6	0.95	0.85	0.70	0.60
21	1.0	0.9	0.0	0.0	0.90	0.60	0.30	0.20
28	0.95	0.8	0.0	0.0	0.85	0.50	0.0	0.0

C. Interfacial Tension (IFT) Reduction

The lowest measured IFT value was achieved with ALS, attaining sub-0.01 dyne/cm at 1.3% and 60°C. MES, while not reaching this ultra-low target, reduced IFT to 0.65 dyne/cm at optimal conditions. AOS achieved 0.82 dyne/cm, and ABS values could not be reliably recorded at 80°C due to microemulsion instability. Table 4 shows the IFT comparison at optimal concentration (at 1.3% and 60°C).

Tabel 4. IFT Comparison at Optimal Concentration (at 1.3% and 60°C)

Surfactant	IFT (dyne/cm)
AOS	0.82
ALS	0.009
MES	0.651
ABS	N/A (unstable)

D. Oil Recovery Enhancement (Core Flooding)

Waterflooding (baseline) produced a 55% recovery factor. ALS flooding increased RF by 30.83% under optimal conditions, which was both statistically and practically significant. MES added 5%, for a cumulative RF of 60%. AOS and ABS produced negligible RF gains, aligning with their suboptimal microemulsion and IFT performance. Table 5 shows incremental recovery (RF) for waterflood and surfactants.

Tabel 5. Incremental Recovery (RF) for Waterflood and Each Surfactant

Treatment	Recovery Factor (%)
Waterflood	55
AOS	1.82
ALS	30.83
MES	5
ABS	0

ALS consistently displayed the best combination of fluid physical stability, ability to form and maintain microemulsions at reservoir-relevant temperatures, ultra-low IFT, and ultimate oil recovery. For ALS and MES, increased concentration improved both microemulsion stability and EOR performance up to 1.3%, above which no additional benefits were observed. Temperature was a limiting factor for ABS and MES, particularly at 80°C, suggesting that their practical EOR applicability is best restricted to cooler reservoirs.

The positive correlation between ultra-low IFT and RF increment supports the premise that both microemulsion stability and IFT drive surfactant EOR outcomes. However, physical characteristics such as viscosity must also be tuned for reservoir injectivity; MES's high viscosity at high concentration and low temperature may hinder transport in situ.

Principal component analysis indicated that the major variance in EOR outcomes was explained by a combination of IFT and emulsion stability parameters, with lesser contribution from bulk fluid viscosity.

ALS is recommended for typical sandstone reservoirs at moderate to high temperature and similar brine salinity, while MES is a sustainable option for environmentally sensitive or moderately hot fields. Application of ABS and AOS should be carefully engineered, or possibly reserved for synergistic use with polymer flooding or at distinctly lower temperature fields.

CONCLUSION

The conclusions of the study are:

- ALS is the best all-around anionic surfactant for EOR under tested lab conditions, yielding the lowest IFT, most stable microemulsions, and highest oil recovery increment.
- MES is a strong secondary choice, particularly for moderate temperatures and green chemistry requirements.
- Both ABS and AOS underperformed at higher temperature, struggling to maintain microemulsions and failing to deliver significant recovery increases.
- Future research should systematically explore surfactant-polymer combinations, other salinity regimes, and scale-up to pilot/field testing, per the environmental and operational constraints surfaced in this study.

ACKNOWLEDGEMENTS

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