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Enhancing Surfactant-polymer Flooding With Sacrificial Surfactants: Reducing Adsorption And Boosting Oil Recovery In High-salinity Reservoirs

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Abstract

Surfactant polymer flooding is frequently constrained by the adsorption of high-cost primary surfactants onto reservoir rock, which lowers chemical efficiency and increases operational costs. This work presents a systematic laboratory assessment of sacrificial surfactants used as adsorption inhibitors to enhance surfactant polymer flooding performance in a Russian clastic reservoir with highly saline formation water. A comprehensive experimental workflow was implemented, integrating compatibility screening, static and dynamic adsorption measurements supported by high-precision HPLC analysis, and final verification through coreflood displacement experiments.

An initial screening of twelve commercially available sacrificial surfactants was conducted in combination with a base surfactant polymer formulation. Seven candidates were selected based on solution stability and favorable interfacial tension characteristics. Static adsorption experiments performed on disaggregated reservoir rock with elevated specific surface area provided insight into adsorption behavior. Sacrificial surfactants №719, SPEMA-4, and SPESC-4 exhibited pronounced competitive adsorption effects, reducing adsorption of the primary anionic surfactant №102 by up to 33.6% after 72 hours. In contrast, several candidates led to increased adsorption, indicating unfavorable rock–fluid interactions.

Dynamic adsorption tests under flow conditions confirmed the trends observed in static experiments. Sacrificial surfactants №719 and SPEMA-4 reduced anionic surfactant adsorption by 33.8% and 29.8%, respectively. Coreflood displacement experiments further demonstrated the effectiveness of adsorption mitigation. The formulation containing sacrificial surfactant №719 achieved an incremental oil recovery of 29.28%, exceeding the baseline surfactant polymer flood by 7.41%. The SPEMA-4 formulation also delivered a notable improvement, yielding 26.9% incremental recovery.

These results confirm that appropriately selected sacrificial surfactants can substantially reduce primary surfactant losses through competitive adsorption and improve displacement efficiency. Among the evaluated agents, sacrificial surfactant №719 exhibited the most consistent performance across all experimental stages and is identified as the most promising candidate for further application.

Key words

CEOR (Chemical Enhanced Oil Recovery), Additional Oil Recovery, Core Flooding, Sacrificial Surfactant, Dynamic Adsorption, IFT (Interfacial Tension)

Introduction

The Enhanced Oil Recovery methods play a central role in sustaining hydrocarbon production in mature and complex reservoirs [1]. Among the available approaches, chemical EOR techniques are regarded as particularly effective due to their ability to improve microscopic displacement efficiency through the injection of polymers, alkalis, and surfactants into the reservoir [1,4]. Despite their proven potential, surfactant-based processes are frequently limited by the loss of active chemicals resulting from adsorption onto reservoir rock surfaces, which directly reduces process efficiency and increases chemical consumption [2,3,5]. Surfactant retention within the pore space occurs through several mechanisms, including phase trapping, precipitation, and adsorption [3,4]. While retention associated with phase trapping and precipitation can be mitigated through appropriate surfactant selection and formulation stability under reservoir temperature and salinity conditions, adsorption onto the rock surface remains unavoidable [4,6]. As a result, surfactant adsorption can be reduced but not completely eliminated [2,5]. To address this limitation, a range of chemical additives has been proposed, including alkalis, polymers, nanoparticles, and sacrificial surfactants, each targeting different aspects of the adsorption process [6,7,19,20]. From a physicochemical perspective, surfactant molecules interact with solid surfaces through hydrophobic or polar interactions, depending on the nature of both the surfactant and the mineral surface [8,9]. Adsorption typically involves individual surfactant molecules or ions, governed by mechanisms such as ion exchange, ion pairing, hydrophobic bonding, adsorption via π-electron polarization, and dispersion forces [9]. The combined contribution of these mechanisms determines the overall adsorption behavior and provides a basis for adsorption control strategies [2,9].

Surfactant adsorption is influenced by multiple parameters, including surfactant structure, concentration, molecular weight, ionic strength, pH, salinity, temperature, and the physicochemical properties of the rock surface [2,6]. In the case of anionic surfactants, adsorption is strongly affected by the presence of salts and divalent cations, with calcium ions exerting a particularly pronounced influence [10,11]. An increase in salinity raises the ionic strength of the solution, which reduces electrostatic repulsion between surfactant head groups and promotes accumulation of surfactant molecules at the solid–liquid interface, thereby increasing adsorption density [12,13]. The mineralogical composition of the reservoir rock and the pH of the aqueous phase are closely interconnected factors [14,15]. Modification of solution pH alters surface charge characteristics, which can significantly affect ion exchange and ion-pairing interactions and, consequently, surfactant adsorption behavior [14,15]. Temperature effects on surfactant adsorption are complex and depend on surfactant type, packing density, and brine composition [6,16]. Because surfactant adsorption is generally exothermic, changes in temperature may either increase or decrease adsorption density depending on system conditions [17]. In addition, temperature influences the critical micelle concentration, which affects the concentration of surfactant monomers available for adsorption [8,18]. For nonionic surfactants, adsorption commonly increases with temperature due to changes in hydration and solvation behavior [18].

Sacrificial agents enhance surfactant flooding efficiency by preferentially adsorbing onto the rock surface or by complexing polyvalent ions in solution, thereby limiting the number of available adsorption sites for the primary surfactant [19,21]. Various inhibitor classes, including alkalis, polymers, and nanoparticles, have been investigated for this purpose [7,20]. Alkalis modify rock surface charge through pH adjustment, reducing anionic surfactant adsorption on silica surfaces and altering carbonate surface properties. Polymers reduce adsorption by occupying active surface sites and forming hydrophobic surface layers, while nanoparticles mitigate adsorption through site blocking and surface modification effects [7,14,15,20]. Surfactants themselves may also act as effective inhibitors through competitive adsorption mechanisms [21]. In mixed surfactant systems, including anionic–cationic and anionic–nonionic combinations, adsorption behavior is governed by competitive interactions at the surface [22]. Although electrostatic interactions may favor equimolar surface compositions, hydrophobicity often dominates, resulting in preferential adsorption of the more hydrophobic component [22]. This effect is particularly evident in anionic–nonionic systems, where the nonionic surfactant can dominate the adsorbed layer even at lower bulk concentrations [18,22]. Additional additives, such as urea or hydrotropes including sodium xylenesulfonate, have been shown to further suppress adsorption, with effectiveness dependent on mineral surface characteristics [23]. Despite extensive research on surfactant adsorption mechanisms, the targeted use of surfactants as sacrificial agents remains comparatively underexplored, highlighting the relevance and practical significance of the present study.

This work is dedicated to a systematic investigation of sacrificial surfactants employed as adsorption inhibitors to improve the efficiency of surfactant polymer flooding for a selected Russian oilfield. The study targets a clastic reservoir with a relatively low reservoir temperature of 25 °C and formation water characterized by high salinity, with a total dissolved solids content of 131.62 g/L. Such conditions represent a challenging environment for maintaining chemical stability and ensuring effective surfactant performance.

Accordingly, the primary objective of this study is to establish and apply a structured, multi-stage laboratory methodology for the identification and validation of optimal sacrificial surfactant candidates. The proposed experimental framework follows a sequential progression from preliminary screening to displacement verification and includes four key stages. These stages comprise initial compatibility screening and evaluation of interfacial activity with the base surfactant polymer formulation, detailed static adsorption measurements to identify effective adsorption inhibitors, confirmation of adsorption reduction under dynamic flow conditions representative of reservoir transport, and final assessment of oil displacement performance through coreflood experiments.

Reservoir Characteristics

The target productive formation is a clastic (terrigenous) reservoir characterized by a reservoir temperature of 25 °C and a pressure of up to 150 bar. The in-situ oil exhibits a viscosity of 37.54 cP under reservoir conditions, while the formation water is highly saline, with a total dissolved solids (TDS) content of 131.62 g/L. The detailed ionic composition of the injection water is presented in Table 1, and the key physicochemical properties of the injection water are summarized in Table 2.

Table 1—Composition of injection water

Units	HCO_3^-	SO_4^{2-}	Cl^-	Total Anions	Ca^{2+}	Mg^{2+}	$Na^+ + K^+$	Total Cations	TDS, g/L
mg/L	256.3	0	81541	81798	9619	1945.6	38259	49824	131.62
meq/L	4.2	0	2300	2304	480	160	1664	2304	
%-	0.18	0	99.82	100	20.83	6.94	72,22	100	

Table 2—Properties of injection water

TDS, g/L	Hardness, mmol/L	pH	Density, g/cm³
131.62	640	6.82	1.087

Research agents

The study focuses on modifying a baseline surfactant-polymer (SP) formulation, which consists of a commercial anionic surfactant (№102) and a commercial polyacrylamide (R1). The primary research objectives are to enhance the properties of this baseline composition by reducing the adsorption loss of Surfactant №102 on the reservoir rock and, consequently, improving its oil displacement efficiency.

To achieve this, a screening study was conducted on twelve candidate sacrificial surfactant agents. From this set, two promising agents were selected for comprehensive coreflood experiments based on their performance in preliminary adsorption and compatibility tests.

Core Samples Material

Cylindrical core plugs, 30 mm in diameter and at least 50 mm in length, were drilled from the productive part of the core material. These plugs were subjected to solvent extraction using Soxhlet apparatus. The drilling and preparation of the core samples (50 x 30 mm) were performed in accordance with the GOST 26450.0-85. Standard core analysis was conducted, which included determining the effective gas porosity and the absolute gas permeability (with Klinkenberg correction). The preparation of core samples for the dynamic adsorption experiment involved the following steps: measuring the dry mass of the sample and saturating it with formation water. For the experiments, single core plugs were used.

Preparing core samples for core flooding experiments to assess oil displacement efficiency included the following steps: water saturation, determination of residual water saturation, and saturation with kerosene. As a result, composite core assemblies were prepared in accordance with the industrial standard OST 39-185-86.

The average permeability of the four core samples used for the dynamic adsorption study was 3882.8 mD (with a minimum of 3656.0 mD and a maximum of 4224.3 mD), classifying them as high-permeability reservoir material. The average porosity for this group was 25.9% (ranging from 25.0% to 26.5%). These parameters characterize the core material as a high-porosity, high-permeability sandstone, which is representative of the target reservoir formation.

For the series of oil displacement efficiency experiments, three composite core assemblies were prepared. Each assembly consisted of a sequence of three core plugs, designed to average out the reservoir's flow and storage properties: the average permeability of all nine core plugs was 2299.4 mD. The average porosity of all nine core plugs was 26.4%. The average residual water saturation after saturation was 3.2%. Each composite assembly was constructed to simulate reservoir heterogeneity by arranging the plugs in a sequence of decreasing permeability along the flow direction. To ensure experimental representativeness, the assemblies included samples with a wide range of permeabilities

Methods

Thermostability.

Surfactant solutions were researched of the base surfactants (at 0.1 wt%), base surfactant polymer composition (at 0.1 wt% + 0.25 wt%) both individually and in the presence of sacrificial surfactants (at 0.01 wt%) in formation water and poured into tube tests. After that, the solutions were kept in an oven at a temperature of 25 °C and the state of the solutions was checked every 24 hours for 30 days.

Determination of IFT.

The spinning drop method is a commonly used approach to measure interfacial tension. Measurements are carried out within a rotating horizontal tube that contains two different liquids: water and oil. A drop of the less dense liquid is placed inside the fluid, as the rotation of the horizontal tube creates a centrifugal force towards the tube walls. This force will cause the liquid drop to deform into an elongated shape; the elongation will stop when the interfacial tension and centrifugal forces are balanced. The surface tension between the two liquids can then be derived from the shape of the drop at this equilibrium point. In this study, IFT measurements were conducted using the KRUSS SDT. The Vonnegut formula was used to calculate interfacial tension. The measurement was carried out until the IFT value stabilized:

$$\gamma = \frac{\times \Delta\rho \times d^{3} \times \omega^{3}}{4} \qquad 1$$

Where, γ - interfacial tension (mN/m); $\Delta\rho$ - density difference between the fluids (g/cm³); ω - angular velocity (rad/s); d - equatorial diameter of the drop (cm).

HPLC

High-performance liquid chromatography (HPLC) is a reliable method for measuring surfactant concentrations, providing accurate and sensitive analysis, even in complex surfactant compositions. HPLC, commonly used to separate, identify, and quantify components in a mixture, is particularly effective for surfactant analysis. Reverse-phase (RP) HPLC utilizes a polar mobile phase and a nonpolar stationary phase, where the retention time of a substance increases with its hydrophobicity (nonpolarity). The study's surfactant concentration was determined using the HPLC method, which has a responsivity of 10–5 mol/l and is significantly more accurate than the spectrophotometric and titration methods. In addition, compared to visible radiation spectrophotometry, HPLC has the advantage of an automatic sample feed mechanism, which reduces the human factor.

Reverse-phase chromatography (RPC) and an HPLC Shimadzu Prominence system with an Evaporative Light Scattering Detector (ELSD-LT II) were used in the experiment. The "Acclaim Surfactant Plus LC" column, manufactured by Thermo Scientific, was utilized. It had dimensions of 4.6 mm in diameter, 150 mm in length, 3 µm in particle size, and 120 Å in pore size. The HPLC parameters were as follows: a sample volume of 20 µL, a flow rate of 0.6 ml/min, a column temperature maintained at 35 °C, and a detector temperature maintained at 50 °C. Mobile phases A (0.1 M NH4OAc) and B (acetonitrile) were used in the gradient program. Phase B increased from 25 to 85% for the first 25 min and remained at 85% for the following 10 min.

The next step is to construct a calibration curve. The method of absolute calibration, which is based on plotting the relationship between the area of chromatographic peaks and the amount of substance in solutions of known concentration, is used in this study to evaluate the adsorption of surfactants. Calibration curves were constructed from the results of chromatography under the same conditions with known amounts of the analyte. A series of measurements were carried out for different concentrations of solutions of the compositions studied. The calibration curve was approximated on the basis of an estimation of six concentrations and was a quadratic equation (Fig. 1). For surfactant №102, the equation was y = -43094986x2 + 21265461 x, the coefficient of determination (R2) was 0.996.

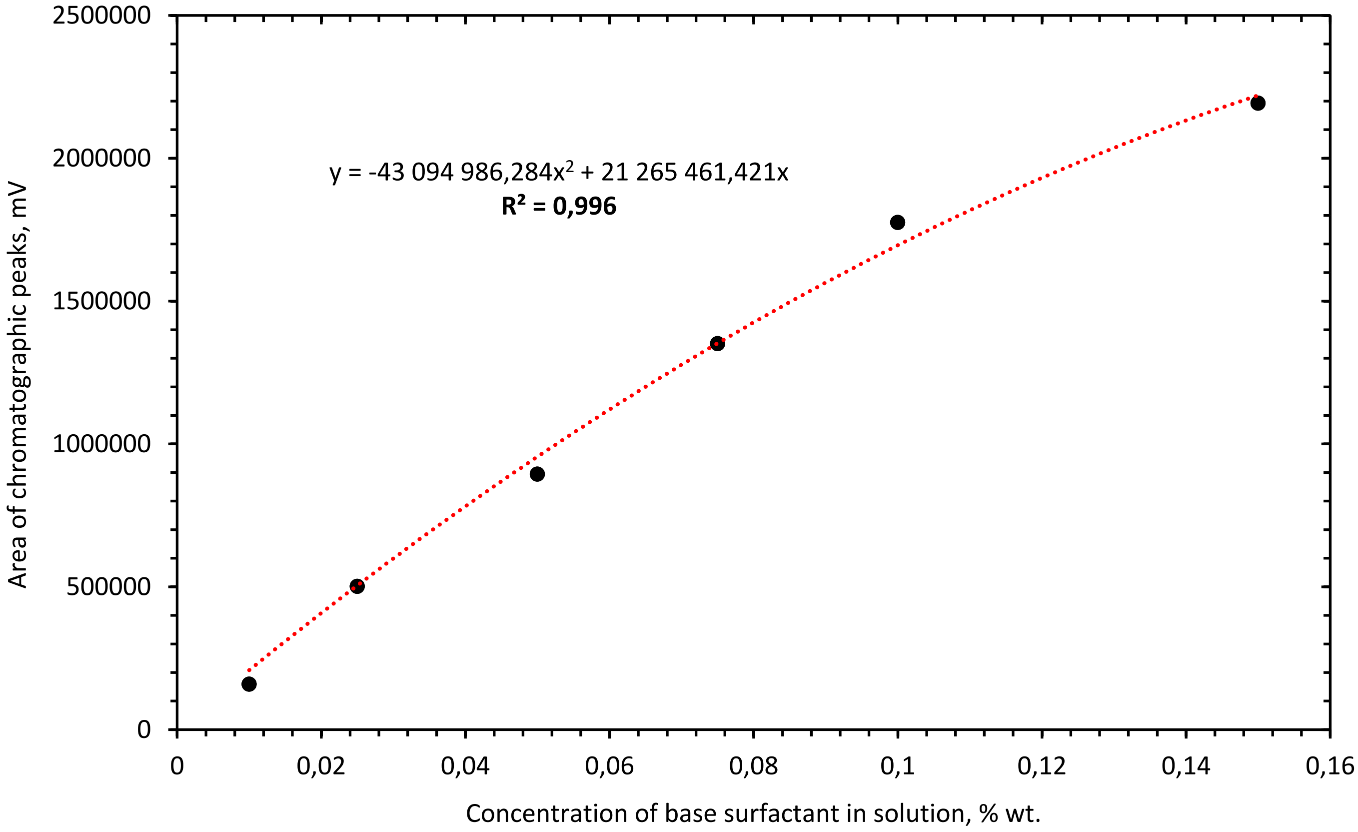

Fig. 1—Calibration curves for the determination of surfactant concentrations

Static Adsorption.

Static adsorption experiments were conducted to analyze the behavior of the base surfactants (at 0.1 wt%) both individually and in the presence of sacrificial surfactants (at 0.01 wt%) in formation water. Rock powder 0.08-0.25 mm was added to the surfactant solutions at a mass ratio of 1:5 . Samples were placed in 50 ml vials with airtight lids and stored at reservoir temperature (25°C). A separate sample was prepared for each analysis point. The evaluation was performed for seven sacrificial surfactants (at 0.01 wt% active matter in composition with the base anionic surfactant at 0.1 wt% active matter) and one reference anionic surfactant at a concentration of 0.1 wt% active matter. Concentration changes were analyzed after 12 and 72 hours. Adsorption was calculated as the mass loss of surfactant (mg) per mass of rock (g). To quantify adsorption, we employed a Shimadzu Prominence High-Performance Liquid Chromatography (HPLC) system coupled with an Evaporative Light Scattering Detector (ELSD-LT II).

Core flooding methodology

Core flooding tests provide a highly detailed assessment of surfactant-polymer effectiveness. Experiments were conducted at reservoir conditions: 25 °C and 150 bar, formation water 131,6 g/L. The experiments were carried out according to the standard scheme of core flooding unit in a thermal control chamber (Fig. 2).

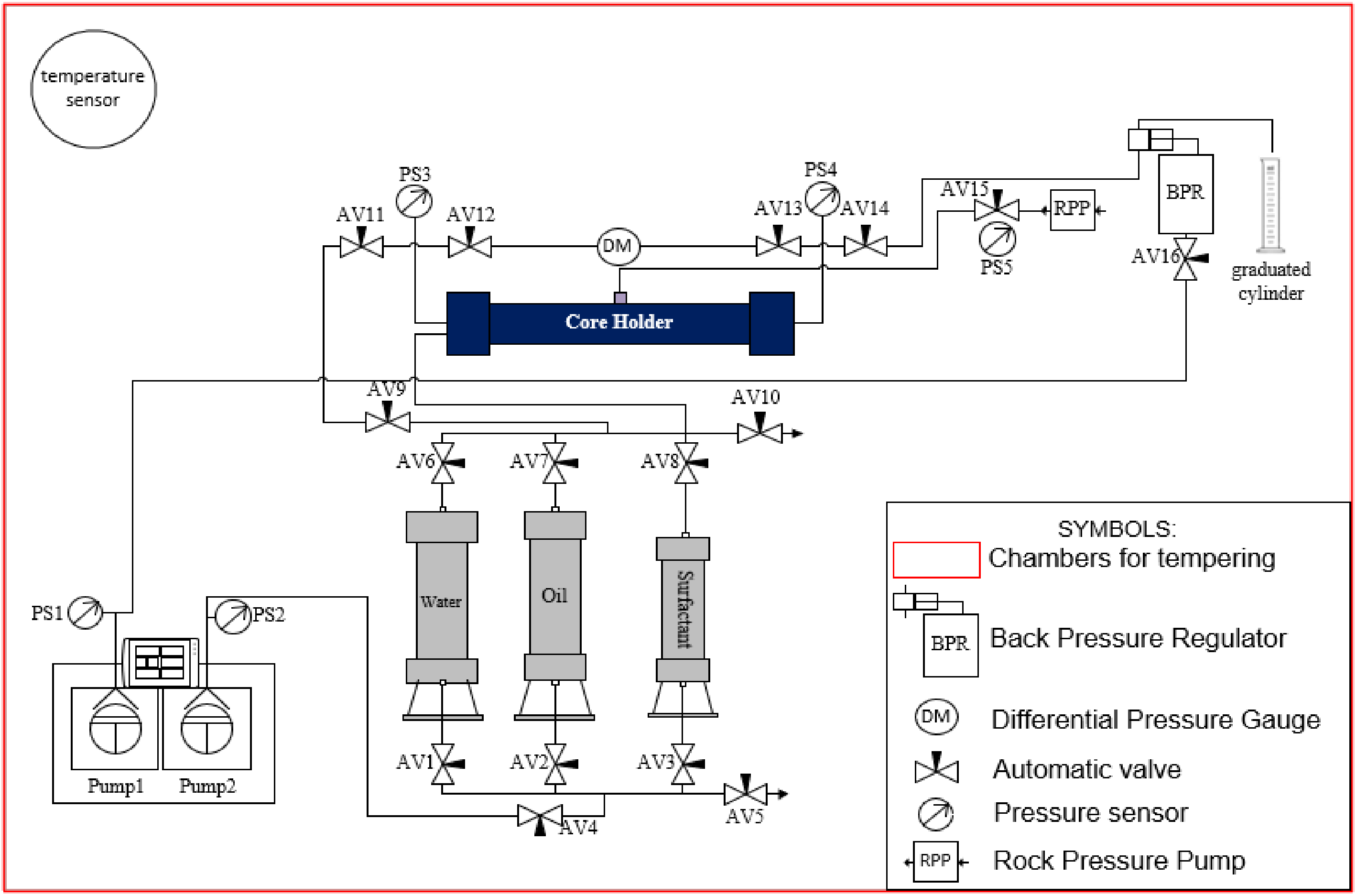

Fig. 2—Core flooding scheme

The prepared core samples, cleaned from hydrocarbons and inorganic salts in Soxhlet extractors with alcohol-benzene mixture and carbon tetrachloride and washed with distilled water, were saturated with formation water under vacuum for 24 hours, after which residual water saturation was created by centrifugation. The cores were then saturated with oil under thermobaric conditions until the pressure drop stabilized. All cores were soaked in oil for 30 days to fully restore wettability.

Then the oil was produced with formation water until the total water cut was at least 5 PV. Based on the recovery results, the oil recovery factors (*ORF*) was determined.

$$ORF = \frac{V_d}{OOIP}$$

where, Vd – volume of oil displaced by water; OOIP – original oil in place within the core.

The next step involved injecting 1 pore volume (PV) of the research composition at a flow rate of 0.25 ml/min. Subsequently, formation water was injected as chase water until the effluent reached full water cut, with a minimum injection volume of 5 PV The additional oil recovery factor (*AORF*) was then calculated using the following formula:

$$AORF = \frac{V_{ro}}{OOIP} \qquad 3$$

where, Vro – volume of oil displaced after surfactant injection.

Relative oil recovery factor (*RORF*) is used to compare different core flooding experiments taking into account differences in pore structure in order to compare the effectiveness of surfactants:

$$RORF = \frac{AORF}{(ORF + AORF)} \qquad 4$$

Dynamic Adsorption Experiments

Flooding a reservoir core with surfactants is one of the best methods to study their effect on reservoir rocks. It also allows researchers to simulate surfactant injection through laboratory measurements. The core flooding experiments replicate reservoir pressure, temperature, and other parameters. Fluids containing surfactants are injected into the reservoir core to analyze dynamic adsorption processes. During the experiment, all injected fluids exit through a tube simulating a production well, allowing for the measurement of surfactant concentration changes and adsorption dynamics. The setup and flow scheme of the core flooding station used for this experiment are shown in Fig. 3

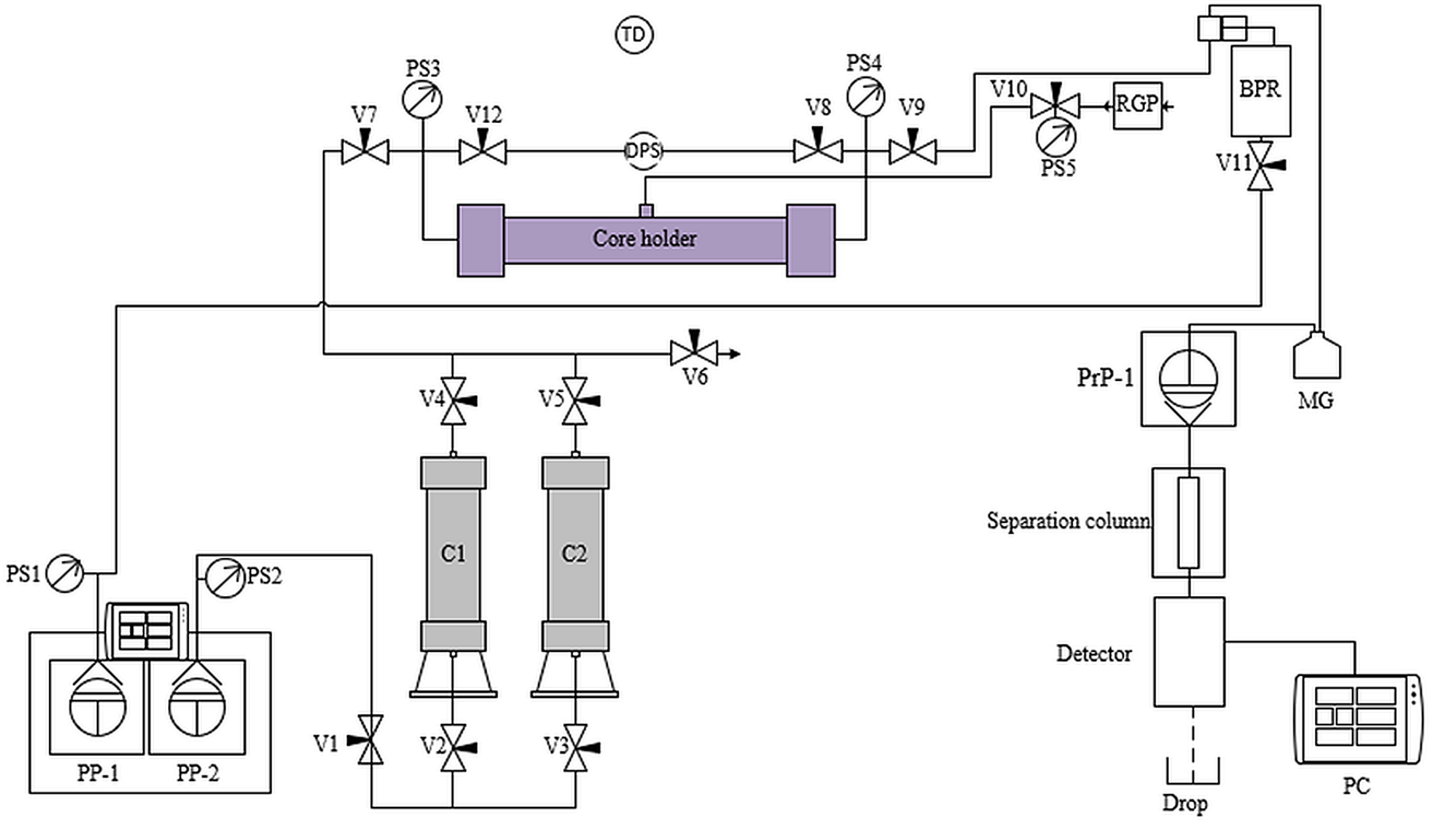

Fig. 3—Core flooding (Dynamic adsorption) scheme

Based on the physical characteristics (permeability, initial oil saturation) of the selected core samples of Bashkirian and Vereian horizons, the linear injection rate was chosen to be 1 m/day. The volumetric flow rate was calculated based on the actual parameters of the reservoir (average values for each productive layer were determined) to achieve the most accurate simulation of the dynamic adsorption experiment using Formula

$$Q = \frac{V \times F \times m \times (1 - S) \times (1 - \beta) \times 60}{864}$$

where, Q – volumetric flow rate (mL/min); V – linear injection rate (m/day); F – cross-sectional area of the composite core column (cm^2); m – average porosity of the composite core column (fraction); and β – conditionally assumed displacement coefficient (fraction).

Since the experiment does not imply an assessment of oil displacement, a rate of 0.25 ml/min was adopted based on the data obtained from laboratory core flooding experiment. The core is positioned within a core holder and saturated with formation water, ensuring that it was saturated by two pore volumes (PV), at a flow rate of 0.25 ml/min (linear velocity does not exceed 5 m/day) corresponding to the flooding regime in the reservoir, at reservoir temperature with monitoring pressure changes in order to stabilize it, and after that water permeability was determined. After saturation with water, the prepared surfactant solution is injected at a flow rate of 0.25 ml/min. The required volume of pumping surfactant solution is determined by the achievement of a constant concentration of surfactant in the selected samples at the outlet of the core holder by the method of selective analysis on HPLC. The calculation of the adsorption value in the selected volume of the sample was carried out according to Formula below. The concentration in the selected sample volume was estimated by HPLC. The value of surfactant adsorption is the mass of a substance determined by the change in concentration in the solution, reduced to the mass of dry core material.

The calculation is based on constructing a graph of the dependence of the surfactant concentration at the effluent on the volume of surfactant solution (adsorption) or the model of formation water (desorption) pumped through the pore space of core sample.

Fig. 4 shows the dependence of surfactant concentration on the pumped pore volume. Based on this plot, it is possible to construct three distinct areas: *Adac* – the area under the dynamic adsorption curve, *Addc* – the area under the dynamic desorption curve, and *Arda* – the area representing the amount of surfactant adsorbed during the injection phase. The integration and calculation of the areas under the curve were performed using the specialized software Origin Pro.

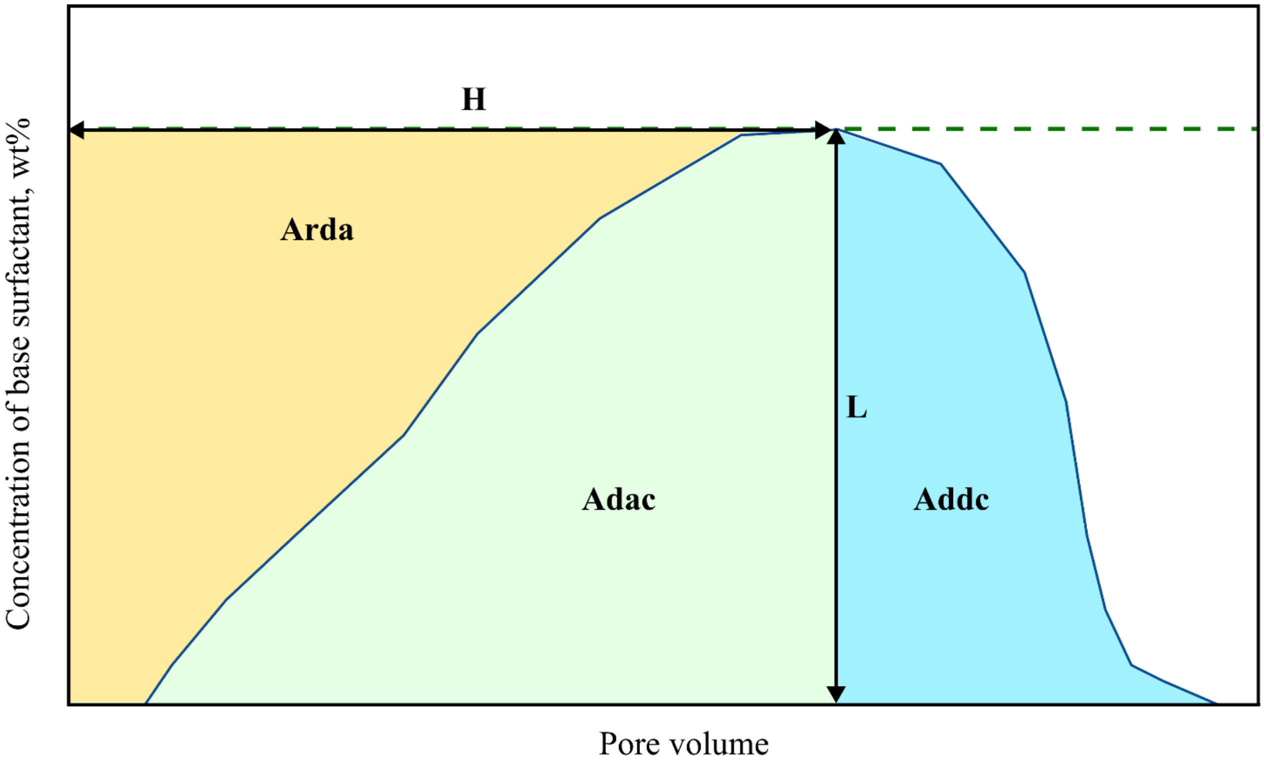

Fig. 4—Schematic graph for dependence of surfactant concentration in the effluent on the pumped pore volume

Equation (6) is used to calculate the value of dynamic adsorption of the surfactant solution on the pores surface over the entire process.

$$Q = \frac{Ci \times Arda}{At} \times \frac{1 - Addc}{Arda} \times \frac{V}{W \times 1000} \tag{6}$$

where, Γ – dynamic adsorption value (mg/g of rock); C_i – initial surfactant concentration (g/mL); V – volume of injected surfactant solution at equilibrium dynamic adsorption (mL); W – mass of the dry core sample (g); A_t – total area of the dynamic adsorption–desorption process; A_ddc – area under the dynamic desorption curve; and A_rda – dynamic adsorption area.

Results

Solubility and Thermal Stability

A total of 12 samples of sacrificial surfactants in composition with the base surfactant-polymer formulation were studied. All compositions remained visually clear (transparent) throughout the 30-day observation period.

Evaluation of IFT and Viscosity

For the compositions of sacrificial surfactant with the base surfactant-polymer formulation, viscosity and interfacial tension (IFT) were measured immediately after preparation. The addition of the sacrificial surfactant affected the IFT and viscosity values of the base composition, with results showing both positive and negative impacts (Table 3).

Table 3—Summary of bulk test data

Sacrificial Surfactants	Concentration, % wt.	Base surfactant	Concentration, % wt.	Base polymer	Concentration, % wt.	IFT, mN/m	Viscosity, sP
-	-	№102	0.1	R1	0.25	0.16	40
№719	0.01	№102	0.1	R1	0.25	0.11	36.6
SPEMA-4	0.01	№102	0.1	R1	0.25	0.12	43.8
SPESC-4	0.01	№102	0.1	R1	0.25	0.13	41.9
SPEMA-1	0.01	№102	0.1	R1	0.25	0.11	41.1
SPESC-2	0.01	№102	0.1	R1	0.25	0.12	41.1
SPEP-4	0.01	№102	0.1	R1	0.25	0.13	43.8
SPESC-1	0.01	№102	0.1	R1	0.25	0.12	42.4
SPEMA-3	0.01	№102	0.1	R1	0.25	0.12	42.9
SPESC-3	0.01	№102	0.1	R1	0.25	0.15	43.2
SPEP-2	0.01	№102	0.1	R1	0.25	0.13	42.3
SPEP-3	0.01	№102	0.1	R1	0.25	0.13	40.7
SPEMA-2	0.01	№102	0.1	R1	0.25	0.13	39.3

Static Adsorption of Base Surfactant with and without Sacrificial Surfactant

The static adsorption capacity was evaluated for the 6 most promising sacrificial surfactant + anionic surfactant (SAS + AS) compositions and 1 reference anionic surfactant.

For the base surfactant №102 (0.1 wt%), the adsorption value after 72 hours was 3.52 mg/g (see Table 4). The adsorption of the base surfactant in the presence of sacrificial surfactants varied. For compositions with agents SPESC-2 and SPEP-4, it increased. The adsorption of surfactant №102 in the presence of agents SPESC-4, SPEMA-4, and №719 decreased, indicating their effectiveness. Based on these results, sacrificial surfactants SPEMA-4 and № 719 were selected for further investigation (Fig. 5).

Table 4—Results of static adsorption for Base surfactant №102 and with the addition of Sacrificial Surfactants on top №102.

Time, h	Static adsorption, mg/g					
	№102	SPESC-2	SPEMA-1	SPEP-4	SPESC-4	SPEMA-4	№719
12	3.46	3.27	3.40	3.21	2.98	2.83	1.75
72	3.52	3.65	3.50	3.75	3.23	3.17	2.24

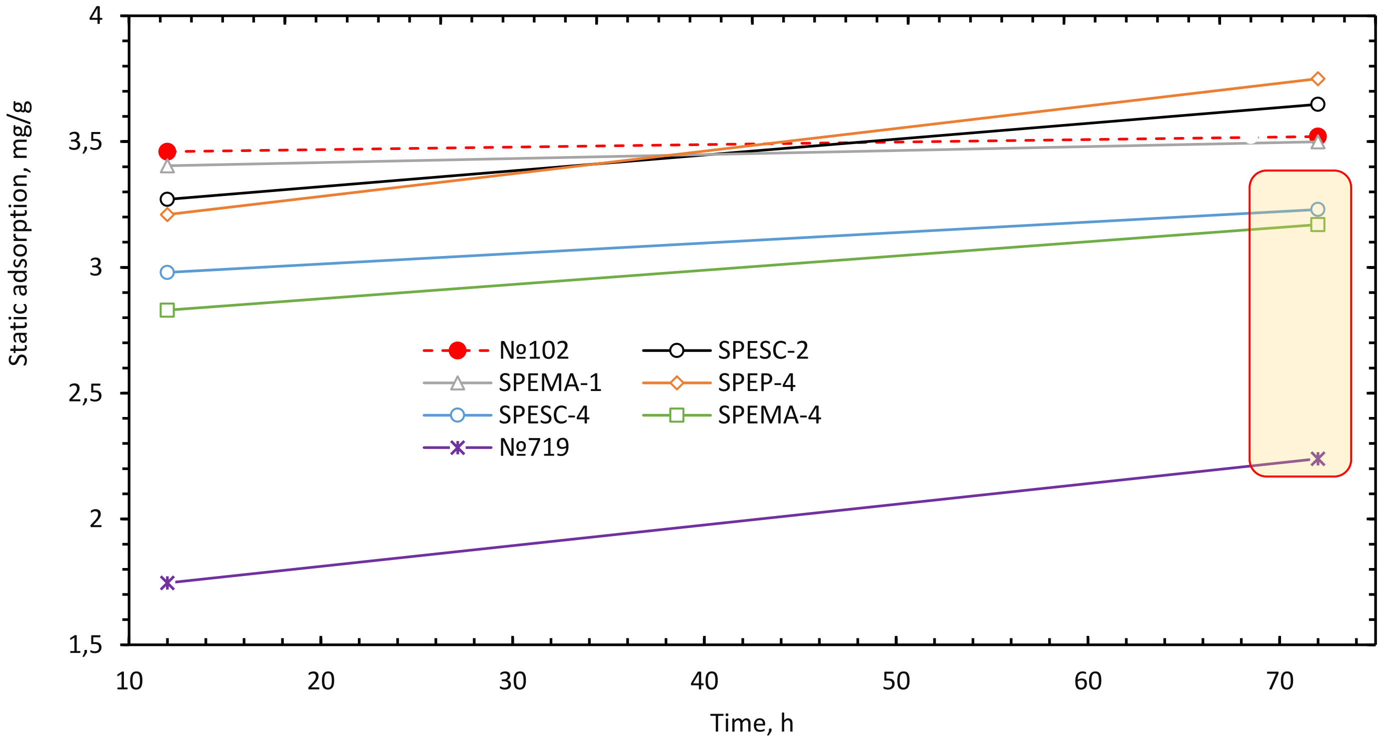

Fig. 5—Effect of sacrificial surfactants on the adsorption of base surfactant №102 (0.1 wt%).

Evaluation of Dynamic Adsorption of Base Surfactant With and Without Sacrificial Surfactant

A total of three dynamic adsorption experiments were conducted for the base surfactant to evaluate its adsorption both individually and in the presence of sacrificial agents. The dynamic adsorption value for surfactant №102 was 0.420 mg/g, which, according to literature data, is considered a low value.

The results obtained from experiments with the anionic surfactant + sacrificial surfactant (AS+SAS) compositions show that the use of sacrificial agents reduces the adsorption of the base surfactant (Fig. 6). The best results were demonstrated by sacrificial surfactants №719 and SPEMA-4, which reduced the dynamic adsorption of the anionic surfactant by 33.8% (to 0.278 mg/g) and 29.8% (to 0.295 mg/g), respectively (Table 5).

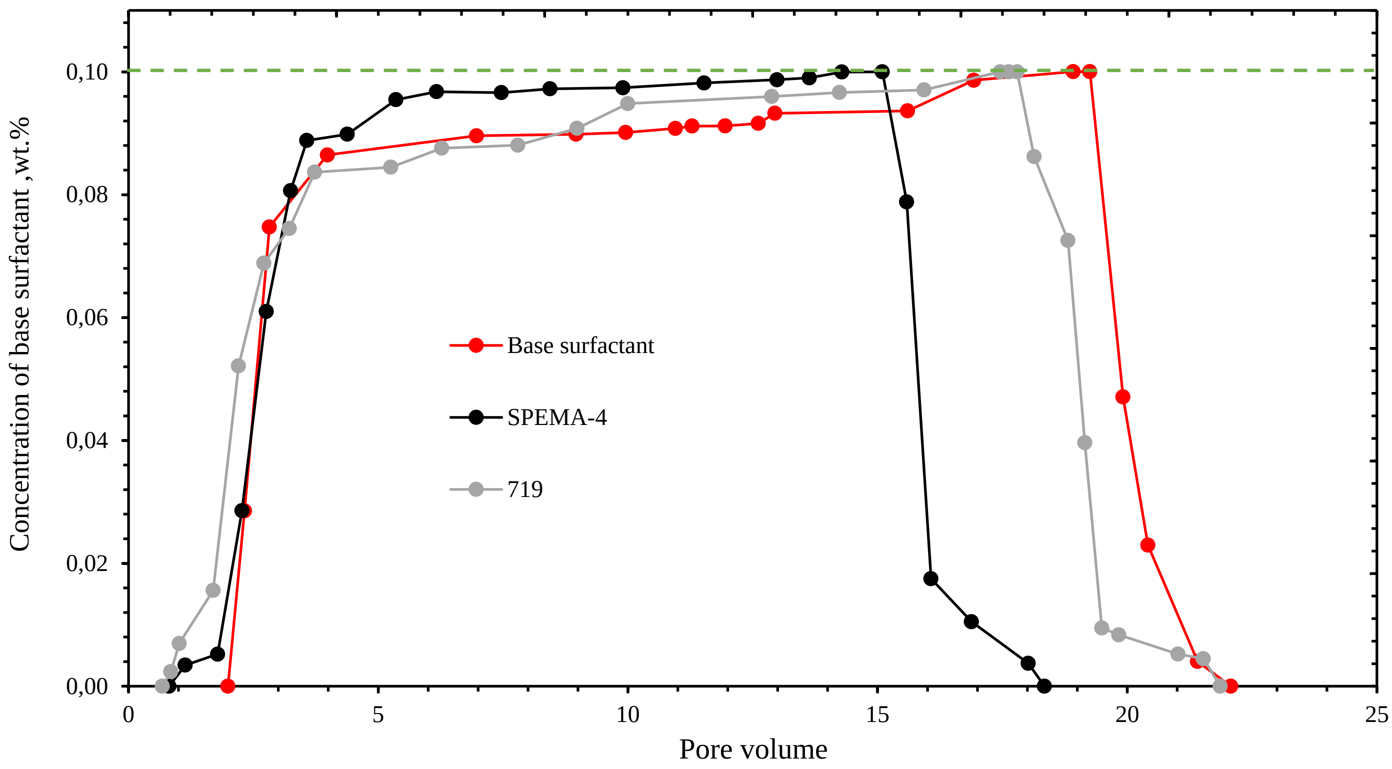

Fig. 6—Curves of surfactant concentrations in the effluent during adsorption and desorption steps

Table 5—Results of dynamic adsorption experiments for base surfactant (№102 - 0.1% wt.) with and without Sacrificial Surfactants

№	Sacrificial Surfactants	Concentration, % wt.	The volume of injected surfactant (adsorption), P.V.	Volume of injected water (desorption), P.V.	Dynamic adsorption of base surfactant, mg/g of rock	Reducing the adsorption of the base surfactant, %
1	-	-	18.9	3.2	0.42	-
2	№719	0.01	18.6	4.2	0.278	33.8
3	SPEMA - 4	0.01	14.3	4.1	0.295	29.8

1.5 Core flooding. Oil recovery

According to previous studies, three most composition were selected for flooding experiments. Oil displacement efficiency of surfactants were compared by additional oil recovery factor (AORF) and relative oil recovery factor (RORF) which represented AORF relative to overall recovery factor.

According to previous studies, base surfactant and two most thermostable surfactants SPEMA-4 and №719 were selected for flooding experiments on 30x50 mm terrigenous core models at 25°C (Fig 7-11). Oil displacement efficiency of surfactants were compared by additional oil recovery factor (AORF) and relative oil recovery factor (RORF) which represented AORF relative to overall recovery factor (Table 6). The injection process was conducted in several stages: I – displacement of oil by water (waterflooding), II – forced injection regime, III –agents slug injection, IV – water displacement.

Table 6—Properties of core models and results of filtration experiments

Surfactant	Porosity, %	Average permeability, mD	Initial volume of oil in the core model, ml	ORF, %	AORF, %	RORF, %
Base	27.32	2154.4	27.55	49.47	13.85	28.00
SPEMA-4	25.80	2060.74	26.70	51.91	19.09	36.78
№719	28.01	2058.78	27.98	46.46	18.17	39.11

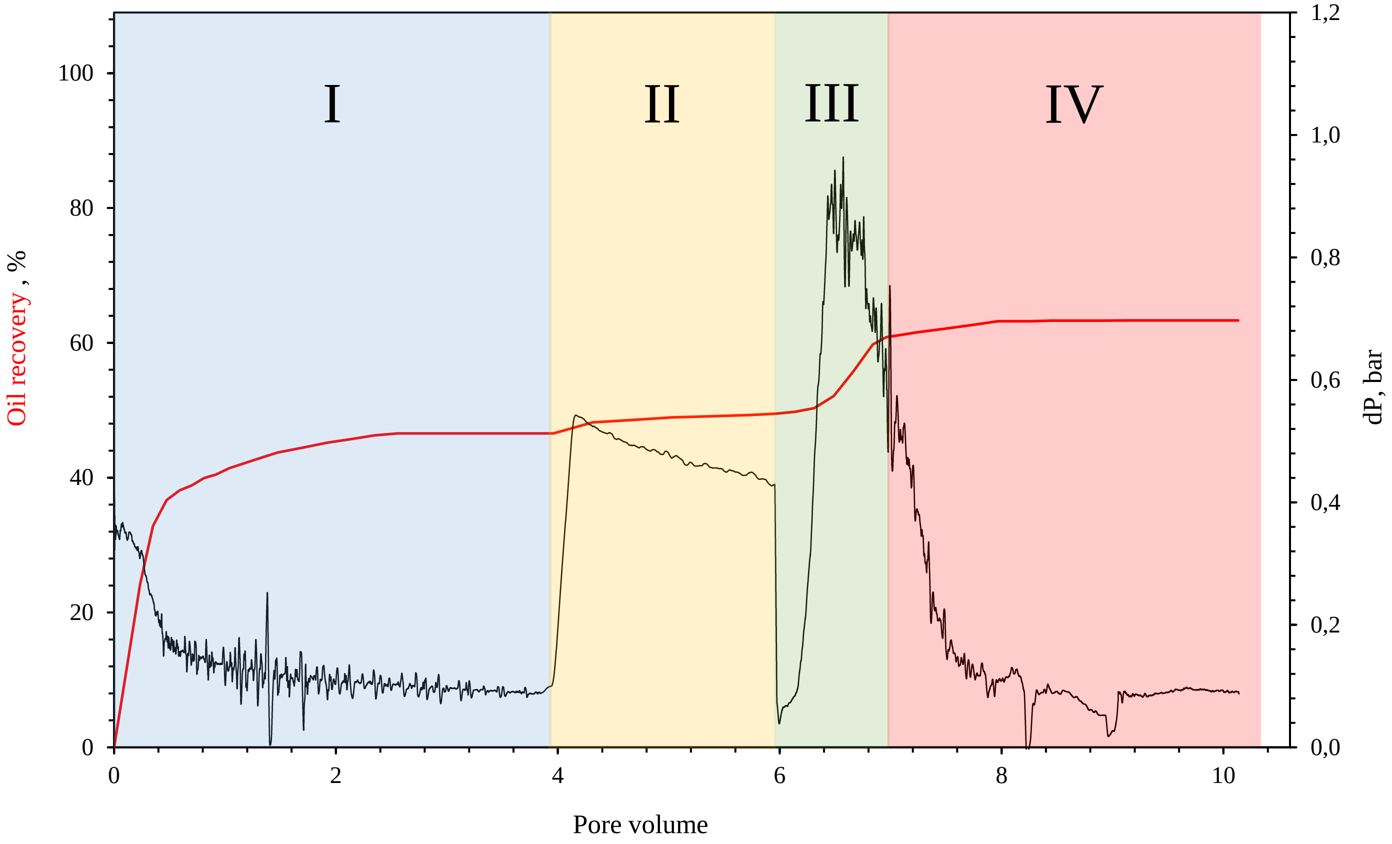

Fig. 7—Base surfactant polymer core flooding

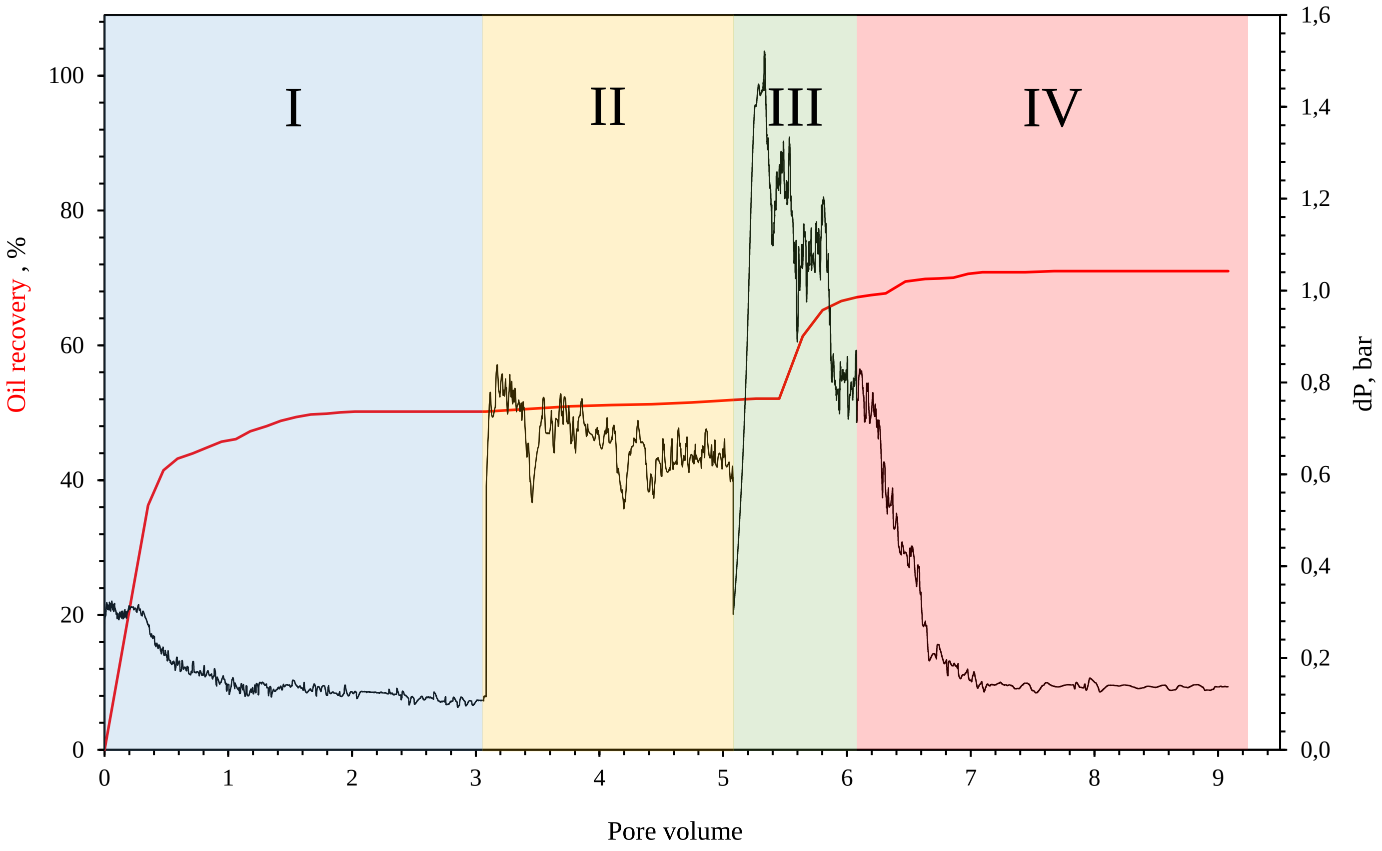

Fig. 8—Base surfactant + SPEMA-4 polymer core flooding

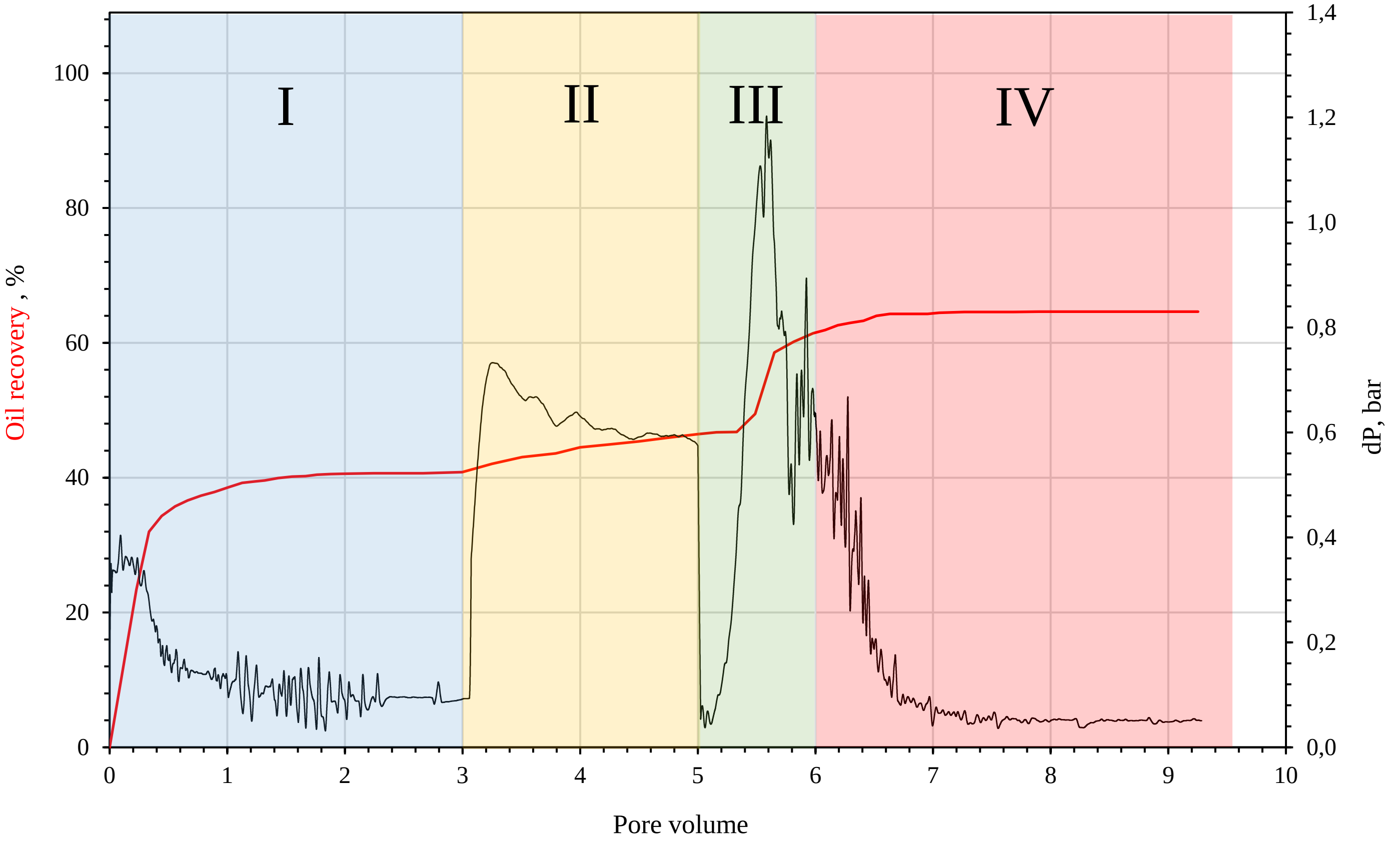

Fig. 9—Base surfactant + №719 polymer core flooding

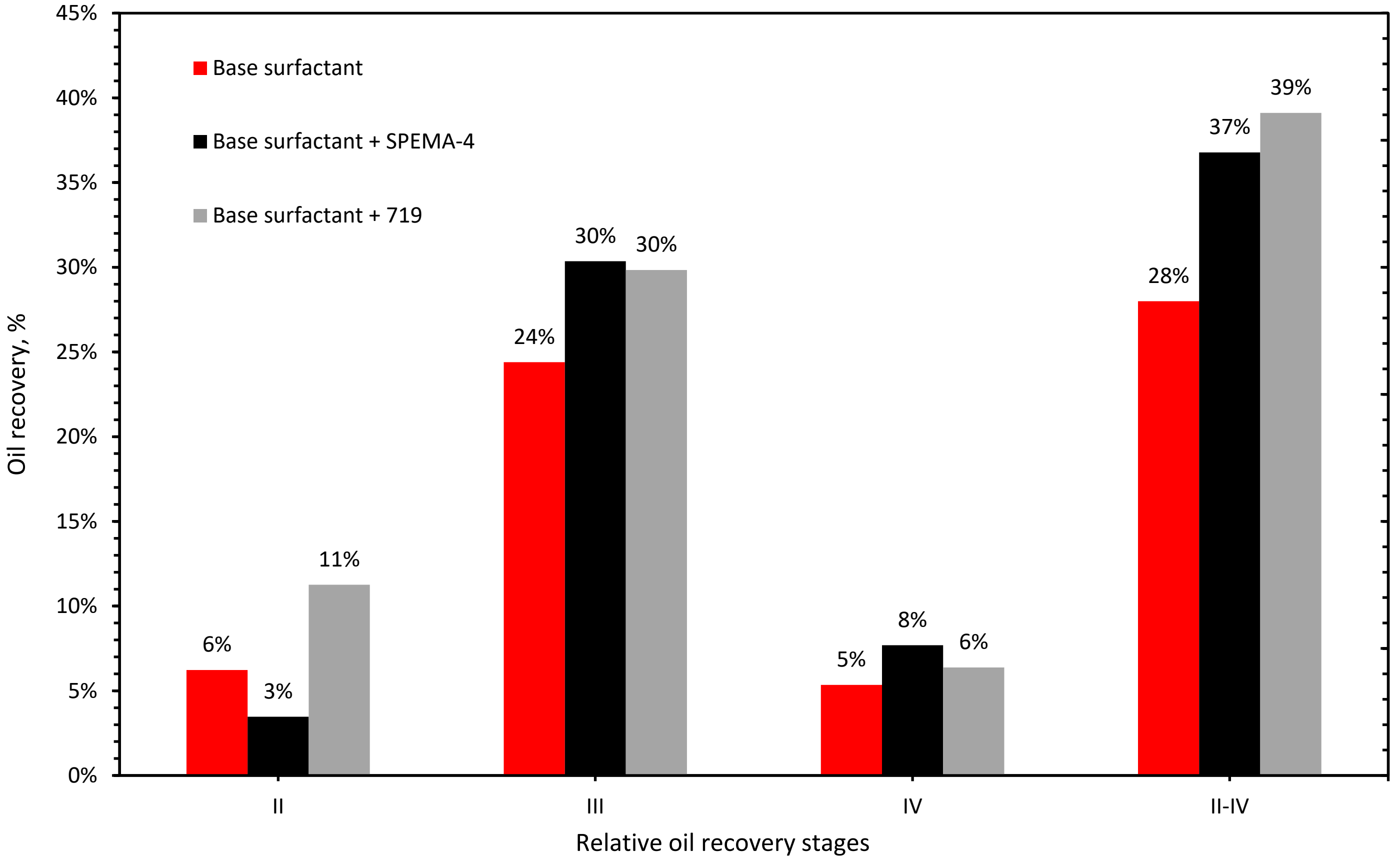

Fig. 10—Oil recovery at stages

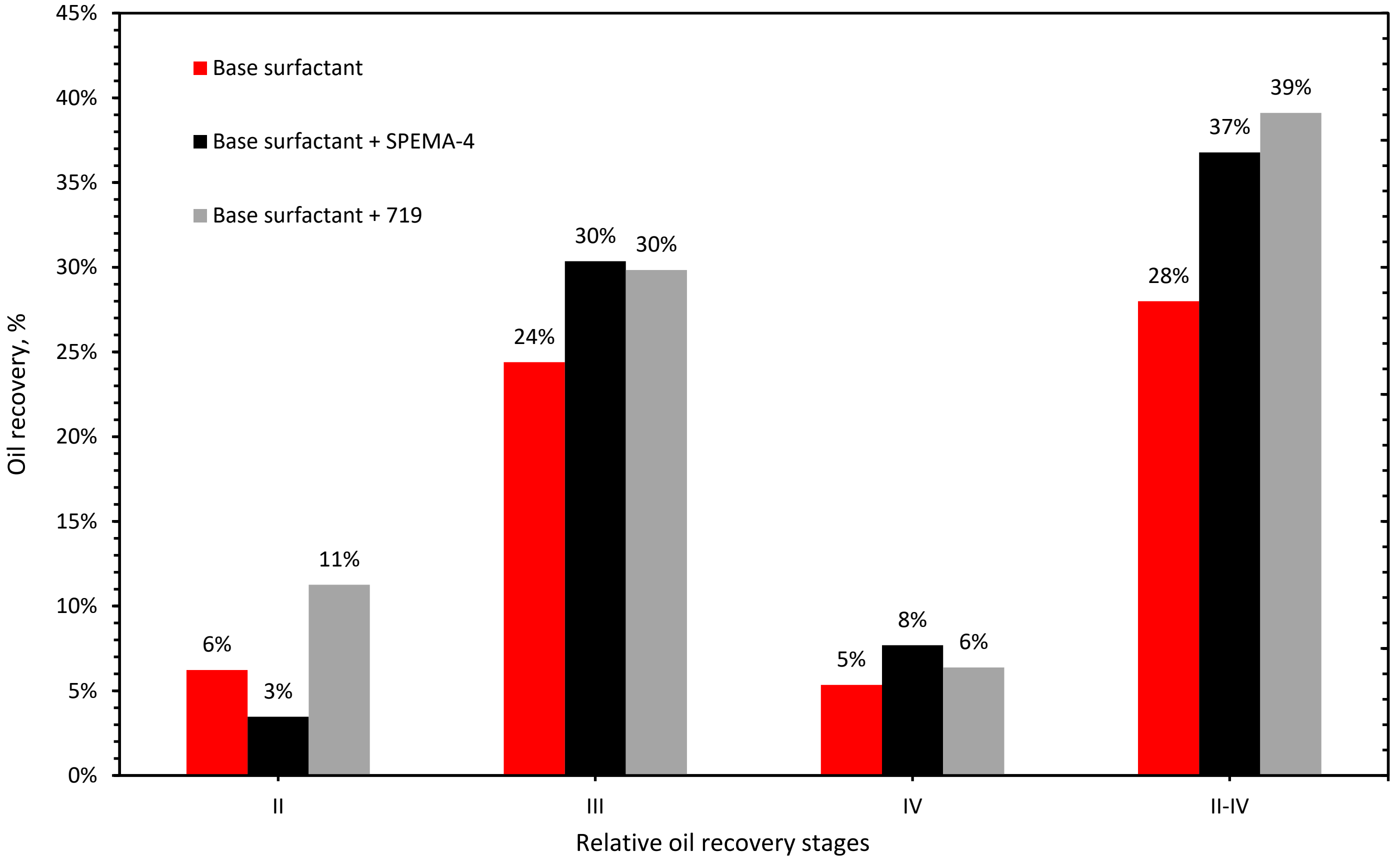

Fig. 11—Relative oil recovery factor at stages

The experiments achieved oil recovery factors (ORF) ranging from 46.46% to 51.91%, which are within the expected range for laboratory surfactant flooding. Among the tested surfactants, the thermostable SPEMA-4 yielded the highest ORF and the highest absolute additional oil recovery factor (AORF) of 19.09%, outperforming both the base surfactant (13.85%) and surfactant №719 (18.17%). However, surfactant №719 demonstrated the highest relative oil recovery factor (RORF) of 28.11%, indicating it was the most effective at mobilizing incremental oil relative to the total recoverable volume from the specific core model. The difference in performance metrics between SPEMA-4 and №719 can be attributed to the inherent properties of the core samples used, particularly the higher porosity and initial oil volume in the test with surfactant №719. The results confirm that the selected thermostable surfactants, SPEMA-4 and №719, provide a significant enhancement in displacement efficiency over the base surfactant, with SPEMA-4 offering the greatest absolute increase in recovery and surfactant №719 showing the highest relative efficiency.

Discussion

The initial evaluation of twelve commercial sacrificial surfactant candidates, combined with compatibility testing against the base surfactant polymer formulation, resulted in the selection of seven agents exhibiting favorable interfacial tension behavior. This staged screening approach, incorporating solubility, long-term thermal stability, and effects on key solution properties, is essential for the rational design of chemical EOR formulations. Early elimination of incompatible additives reduces the risk of instability during injection and ensures that only viable candidates progress to more resource-intensive testing.

Static adsorption experiments provided mechanistic insight into adsorption inhibition behavior. The relatively high adsorption value measured for the reference anionic surfactant №102 on disaggregated core material, reaching 3.52 mg/g, is primarily attributed to the artificially increased specific surface area associated with crushed rock particles in the 0.08–0.25 mm size range. Although such conditions do not directly represent intact reservoir rock, they intentionally amplify adsorption effects and enable clearer differentiation between sacrificial surfactant performances. Under these conditions, a distinct competitive adsorption effect was observed. Sacrificial surfactants №719, SPEMA-4, and SPESC-4 reduced adsorption of the base surfactant after 72 hours by 33.6%, 9.9%, and 8.2%, respectively. This behavior is consistent with preferential adsorption of highly ethoxylated molecules, which occupy active surface sites and limit subsequent adsorption of the pFrimary surfactant.

In contrast, increased adsorption of surfactant №102 in the presence of SPESC-2 and SPEP-4 indicates more complex surface interactions. One plausible mechanism is the formation of a sacrificial surfactant layer that introduces additional adsorption sites for the base surfactant, thereby enhancing overall retention rather than suppressing it. In the case of certain agents such as SPEMA-1, short-term adsorption inhibition observed at early exposure times transitioned into equilibrium conditions where the base surfactant progressively displaced the sacrificial layer. This behavior underscores the importance of long-term adsorption stability rather than transient inhibition effects.

Dynamic adsorption experiments conducted under flow conditions yielded lower absolute adsorption values but preserved the relative performance ranking observed in static tests. The base anionic surfactant exhibited a dynamic adsorption of 0.420 mg/g. Sacrificial surfactants №719 and SPEMA-4 again demonstrated the highest effectiveness, reducing adsorption by 33.8% and 29.8%, respectively. The strong agreement between static and dynamic results for №719 confirms the robustness of the screening methodology. The enhanced relative performance of SPEMA-4 under dynamic conditions suggests favorable adsorption and desorption kinetics during flow.

Coreflood displacement experiments provided final validation of the adsorption inhibition strategy. The optimized formulation containing sacrificial surfactant №719 achieved an incremental oil recovery of 39.11%, exceeding the reference surfactant polymer flood by 11.11%. The SPEMA-4 formulation also delivered a meaningful improvement, with 36.78% incremental recovery. These findings confirm that reducing adsorption losses of the primary surfactant directly translates into improved displacement efficiency and enhanced economic performance. Among the evaluated candidates, sacrificial surfactant №719 consistently exhibited superior performance across all experimental stages, supporting its selection for further field-scale evaluation.

Conclusion

The application of sacrificial surfactants in surfactant polymer flooding represents a technically effective and economically sound approach for improving oil recovery performance. The results of this study demonstrate that selected sacrificial surfactants, particularly №719 and SPEMA-4, act as efficient adsorption inhibitors for the primary anionic surfactant. Their effectiveness is attributed to a competitive adsorption mechanism in which sacrificial surfactant molecules preferentially occupy active adsorption sites on the reservoir rock surface, thereby limiting irreversible losses of the chemically active and higher-cost base surfactant.

From an economic perspective, the incorporation of a sacrificial surfactant contributes only a minor fraction to the overall chemical cost of the surfactant polymer formulation, typically accounting for approximately 2–3% of the total reagent expenditure. This additional cost is more than compensated by two primary benefits. First, adsorption inhibition reduces the consumption of the primary surfactant, which represents the most expensive component of the chemical system. Second, the use of sacrificial surfactants results in a substantial increase in oil recovery, with incremental recoveries of 29.28% and 26.9% achieved for formulations containing sacrificial surfactants №719 and SPEMA-4, respectively, relative to the base surfactant polymer flood. The economic attractiveness of the approach is further enhanced by its operational simplicity, as implementation does not require capital-intensive modifications to surface facilities. The sacrificial surfactant is incorporated directly into the integrated chemical slug without altering the injection scheme.

Overall, the integration of optimized sacrificial surfactants, particularly №719, into surfactant polymer flooding designs provides a practical strategy to enhance both technical performance and economic efficiency. This approach offers a scalable and field-applicable solution for improving the viability of chemical enhanced oil recovery projects under challenging reservoir conditions.

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