

Article

Oil–Water–Quartz Interfacial Regulation by a Temperature- and Salinity-Responsive Gemini Carboxybetaine in Low-Permeability Sandstone: A Digital-Core-Informed Case Study

Yukun Du ^{1,2,*}, Gang Zhou ³, Xingyin Huang ⁴, Yirui Yu ⁵, Fangfei Li ⁶ and Runlin Du ⁷

¹ State Key Laboratory of Deep Oil and Gas, China University of Petroleum, Qingdao 266580, China

² School of Petroleum Engineering, China University of Petroleum, Qingdao 266580, China

³ No. 3 Oil Production Plant, PetroChina Daqing Oilfield Co., Ltd., Daqing 163000, China; gucezb586@163.com

⁴ Zhenhua Oil Co., Ltd., Beijing 100031, China; rtaefghkz675@163.com

⁵ No. 3 Oil Production Plant, PetroChina Qinghai Oilfield Company, Haixi 816400, China; xxnfp3667897@163.com

⁶ No. 1 Operation Zone, No. 8 Oil Production Plant, PetroChina Daqing Oilfield Co., Ltd., Daqing 163000, China; zdzxdn4366@163.com

⁷ Qingdao Institute of Marine Geology, Qingdao 266237, China; durunlin123@163.com

* Correspondence: duyukun@upc.edu.cn

Highlights

What are the main findings?

- Gemini carboxybetaine TS-CB reduced oil–water IFT to 0.019 mN/m at 45 °C and 0.5 wt%.
- Apparent viscosity reached 78.5 mPa·s at 50 °C with G' exceeding G'' in bulk solution.
- TS-CB reversed oil-aged quartz wettability to strongly water-wet with a 12.5° contact angle.
- Dual-core flooding yielded a 16.0 pp recovery gain, outperforming conventional controls.

What are the implications of the main findings?

- Digital core analysis offers reliable physical constraints for surfactant design.
- Dual responsive behavior connects fluid mobility control with interfacial regulation.
- Provides a practical chemical formulation strategy for saline tight reservoirs.

Abstract

The pore geometry and mineral surfaces of low-permeability sandstone constrain both surfactant transport and oil mobilization. We used micro-computed tomography (micro-CT) and scanning electron microscopy (SEM) of Yanchang Formation sandstone from the Hua 182 block to define formulation-screening targets, then evaluated a temperature- and salinity-responsive gemini carboxybetaine (TS-CB) at oil–water and oil-aged quartz interfaces. The core had an average porosity of 12.7%, a network tortuosity of 1.8, an average fracture aperture of 18.5 μm , and a clay content of 7.5%. TS-CB had a critical micelle concentration (CMC) of 2.8×10^{-4} mol/L and reduced oil–water interfacial tension (IFT) to 1.9×10^{-2} mN/m at 0.5 wt% and 45 °C. Its apparent viscosity reached 78.5 mPa·s at 50 °C, and the contact angle on oil-aged quartz was 12.5° at 0.5 wt%. In parallel-core flooding, the total recovery increment was 16.0 percentage points, compared with 12.0 and 10.2 percentage points for OPAB and HPAB. The results link the measured interfacial and bulk-flow responses with improved recovery in the tested core system. The position and cause of flow redistribution inside the rock remain to be established by direct diagnostics.



Academic Editor: María Dolores Fernández Ramos

Received: 12 August 2026

Revised: 19 September 2026

Accepted: 23 September 2026

Published: 26 September 2026

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Keywords: oil–water interface; quartz wettability; interfacial regulation; gemini carboxybetaine; low-permeability sandstone; digital core

1. Introduction

Low-permeability sandstone contains narrow throats, tortuous connected pores, and fractures that create large contrasts in capillary entry pressure and flow conductance. During waterflooding, injected water therefore follows the most accessible pathways while oil remains trapped in poorly swept pores. Studies of imbibition, microemulsion flooding, and tight-reservoir fluid exchange show that interfacial forces and pore connectivity jointly control recovery in such rocks [1–4]. A chemical treatment for this setting must mobilize capillary-trapped oil without losing its ability to move through a heterogeneous pore network.

Surfactants address the capillary component by adsorbing at oil–water and water–mineral interfaces. Lower oil–water interfacial tension (IFT) reduces the force required to deform and release trapped oil, whereas a shift toward water-wet mineral surfaces can assist spontaneous imbibition and limit oil adhesion. In situ or spontaneous emulsification provides a further route for dispersing mobilized oil [5–7]. Related low-permeability studies have combined interfacial activity with amphiphilic particles or rapidly emulsifying surfactant systems [8–10]. These effects concern reversible molecular organization at fluid and mineral surfaces; their presence must be established with interfacial and wettability measurements rather than inferred from recovery alone. Interfacial activity by itself does not ensure effective displacement. Polymer–surfactant systems add mobility control, but their performance depends on viscosity retention, injectivity, and the order in which the formulation encounters reservoir brine [11]. Field chemical-flooding practice further shows that slug design, conformance, scale control, and produced-fluid handling affect the outcome [12]. A negative salinity gradient can also change surfactant–polymer performance during displacement [13]. The relevant formulation target is therefore a coupled response involving interface activity, bulk-flow resistance, and compatibility with the actual injection water.

These requirements become more restrictive in low-permeability rock. High salinity can alter surfactant solubility, aggregate packing, and the IFT reached against crude oil; mixed anionic–zwitterionic systems have consequently been developed for saline low-permeability reservoirs [14,15]. Associative polymers and surfactant emulsification have been used to combine oil mobilization with profile control [16]. Small throats also make injectivity and water blocking important: both the flow physics of surfactant treatment and micellar water-block removal depend on the pore system through which the formulation is transported [17,18]. Thus, a bulk property measured in a vial cannot by itself establish behavior inside an individual throat or fracture.

Zwitterionic and gemini surfactants offer structural variables for balancing these demands. Reviews of viscoelastic surfactants describe how hydrophobic association and molecular architecture govern network formation [19]. Responsive surfactant systems have been investigated for thickening and foam stability under elevated temperature or salinity [20–23]. Thermo-switchable zwitterionic gemini surfactants further demonstrate that headgroup, spacer, and hydrophobe design can change association in saline water [24]. Pseudo-gemini and amphoteric-gemini formulations have also been evaluated for combined flow control and oil recovery [25,26]. These studies establish useful molecular options, but they do not define a unique structure for every reservoir. Digital-core characterization provides the rock-side information needed to define the screening problem.

Micro-computed tomography (micro-CT) resolves connected pores and fractures above its voxel scale, while scanning electron microscopy (SEM) provides higher-resolution two-dimensional information on minerals and pore-surface contacts. Digital-rock studies have used these images to quantify pore geometry, describe the distribution of discontinuous oil, and simulate flow through reconstructed pore networks [27–30]. The resolution and dimensionality of each method remain important: a feature smaller than the micro-CT voxel cannot be treated as directly resolved, and a two-dimensional mineral map does not establish the full three-dimensional distribution.

A gap remains between digital-rock description and surfactant development. Imaging studies commonly end with pore-network descriptors or flow simulation, whereas formulation studies commonly begin with a candidate molecule and optimize interfacial or rheological performance. A defensible connection between the two should identify, for each rock descriptor, the formulation constraint that it creates, the molecular variable considered, the experiment used to test the response, and the part of the proposed mechanism that remains unmeasured. Without that traceability, the phrase ‘digital-core-guided design’ overstates what imaging alone can establish. The surface-science contribution of the present work lies in the response of a dissolved surfactant at oil–water and oil-aged quartz interfaces. Surfactants act at oil–water and water–mineral interfaces throughout porous rock. Lower IFT, changes in mineral wettability, and stabilization of oil droplets can reduce capillary trapping. In this study, surface regulation means molecular interactions at fluid and quartz surfaces; no deposited coating or permanent film was fabricated. We therefore use CMC, oil–water IFT, emulsion separation, and contact angle on oil-aged quartz as interfacial evidence and treat core flooding as a separate macroscopic test.

This study evaluates a temperature- and salinity-responsive gemini carboxybetaine (TS-CB) against the constraints identified for Yanchang Formation sandstone from the Hua 182 block. Micro-CT and SEM are used to describe pore-fracture geometry and mineral contact; We then connect those descriptors with the TS-CB structural variables and the corresponding interfacial, rheological, and flooding measurements. HPAB and OPAB provide single-chain performance comparisons, but they are not a matched test of molecules selected with and without digital-core input. The study therefore asks whether the evaluated TS-CB changes oil–water and quartz interfacial behavior and improves recovery in the tested heterogeneous core system, while keeping the proposed pore-scale redistribution separate from direct observation.

2. Experimental

2.1. Materials

Hexadecanol, octadecanol, epichlorohydrin, tetrabutylammonium bromide, petroleum ether, absolute ethanol, isopropanol, ethyl acetate, anhydrous sodium sulfate, and sodium hydroxide were purchased from Chengdu Kelong Chemical Reagent Co., Ltd. (Chengdu, China). *N,N'*-dimethylethylenediamine, sodium chloroacetate, sodium 3-chloro-2-hydroxypropanesulfonate, and monomethoxy polyethylene glycol (average degree of polymerization $n = 3$) were obtained from Shanghai Aladdin Biochemical Technology Co., Ltd. (Shanghai, China). Deuterated chloroform (99.8 atom% D) was supplied by the same vendor. Simulated crude oil was prepared from dehydrated crude produced from the Hua 182 block of the Yanchang Oilfield. Natural core-plug samples were collected from the corresponding low-permeability sandstone interval. Quartz plates (20 mm × 20 mm) were custom-fabricated.

2.2. Core Samples and Digital Characterization

Natural core plugs were processed into cylinders through standardized drilling, cutting, and polishing. Multiscale characterization used micro-computed tomography (micro-CT) and field-emission scanning electron microscopy (FE-SEM). Micro-CT scans were acquired with a micro-CT system (Xtalon International GmbH, Hamburg, Germany) at 100 kV and 100 μ A over a 360° rotation, producing isotropic three-dimensional voxels with a 1.5 μ m edge length for reconstruction of resolvable pores and fractures. Polished thin sections were examined using a field-emission scanning electron microscope (Quanta 650, FEI Company, Hillsboro, OR, USA) under low vacuum for mineral identification and assessment of clay distribution along pore surfaces. As schematically illustrated in Figure 1, an integrated digital-core image-analysis workflow was developed. For micro-CT, a three-dimensional DeepLabV3+ workflow classified solid, pores, and fractures. The SEM branch used a U-Net with an EfficientNet-B4 encoder to distinguish quartz, K-feldspar, plagioclase, calcite, dolomite, illite, and kaolinite [31–33]. DeepLabV3+ was chosen for multiscale context around connected voids; U-Net provided pixel localization for mineral boundaries. The archived analysis identifies the model branches and output classes but does not include the image inventory, annotation logs, data partitions, or training configuration. We consequently use the maps for reservoir description and omit model-ranking scores that cannot be independently checked. To ensure computational reproducibility, the detailed network architectures (3D DeepLabV3+ and U-Net), loss functions, hyperparameters, and computer hardware environment for rock segmentation are systematically documented in Table S1 in the Supporting Information.

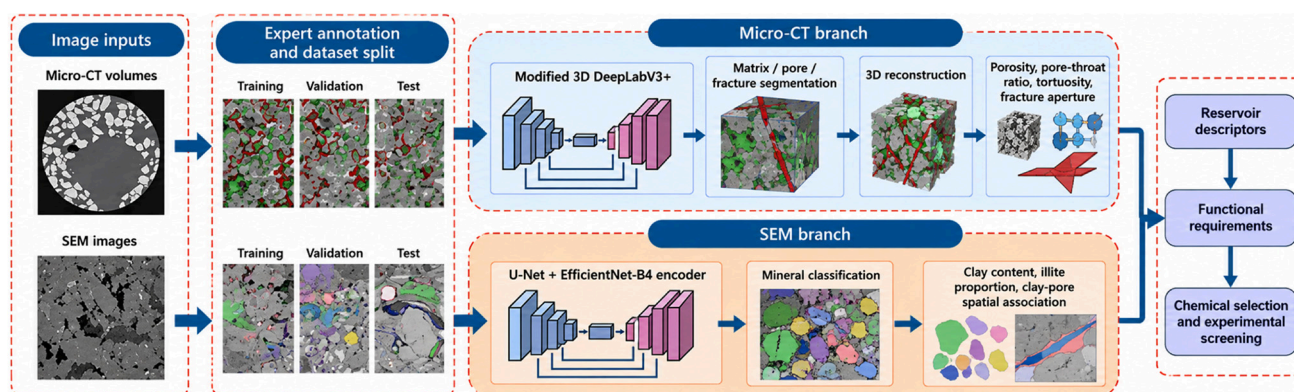


Figure 1. Digital-core image-analysis workflow showing the separate micro-CT pore-fracture segmentation and SEM mineral-classification branches and the use of extracted descriptors in chemical reasoning and experimental screening.

2.3. Synthesis and Characterization of TS-CB

2.3.1. Molecular Synthesis

The small equivalent throat estimate made injection pressure relevant during the 2.5 wt% core-flood slug. Tortuosity and fractures motivated bulk-viscoelastic and parallel-core tests, while clay-pore association made mineral retention a screening risk. The measured brine salinity set the salt-response test condition. TS-CB contains two C16 hydrophobes, a gemini linkage, carboxylate and sulfonate groups, and a short poly(ethylene oxide) segment with an average repeat number of approximately three (Figure 2). These variables define the molecule evaluated here; the core images did not determine their unique optimal values.

TS-CB was synthesized via a three-step route. First, hexadecyl glycidyl ether was prepared under phase-transfer catalysis in a nitrogen atmosphere by reacting hexadecanol with epichlorohydrin in the presence of sodium hydroxide and tetrabutylammonium bro-

mide at 50 °C. The reaction mixture was stirred for four hours, filtered, extracted, dried, and vacuum-distilled to yield a colorless liquid (89% yield). Second, the tertiary amine intermediate was obtained by reacting the glycidyl ether with *N,N'*-dimethylethylenediamine in ethanol at 40–60 °C under pH-controlled conditions, followed by the removal of solids and solvent to afford a pale yellow viscous intermediate. Third, quaternization and functionalization were performed by reacting the tertiary amine intermediate with sodium chloroacetate and sodium 3-chloro-2-hydroxypropanesulfonate in an isopropanol–water mixture at 80 °C under pH control, followed by the addition of monomethoxy polyethylene glycol and a catalytic amount of *p*-toluenesulfonic acid. The product was purified via solvent removal, ethyl acetate washing, and ethanol recrystallization to yield a pale yellow waxy solid, TS-CB, with an overall yield of 71%. For comparison, conventional single-chain carboxybetaine surfactants HPAB and OPAB, bearing C16 and C18 hydrophobic chains, respectively, were synthesized according to the literature procedures.

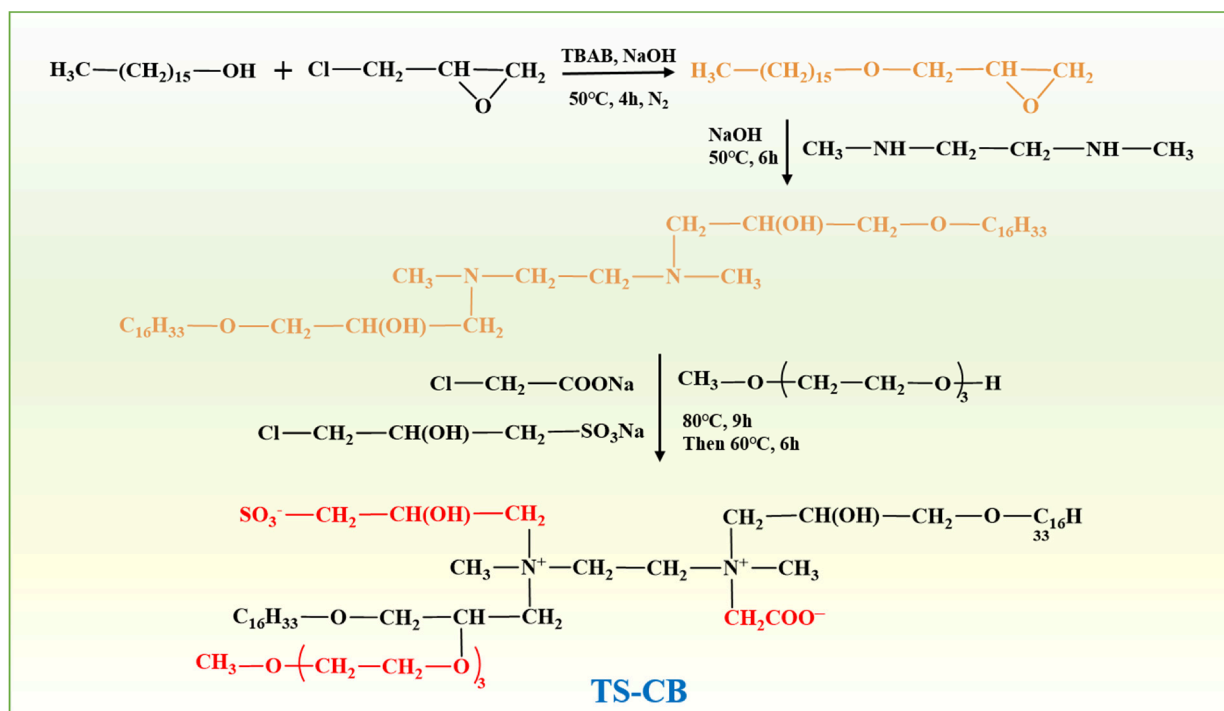


Figure 2. Synthetic route of TS-CB, the sample code used for the temperature- and salinity-responsive gemini carboxybetaine prepared in this study.

2.3.2. Structural Characterization

The structure of TS-CB was confirmed using multiple complementary techniques. Fourier transform infrared (FT-IR) spectra were recorded using a Thermo Fisher Nicolet iS50 spectrometer (Nicolet iS50, Thermo Fisher Scientific, Waltham, MA, USA) in KBr pellet form over a wavenumber range of 4000–400 cm^{-1} , accumulating 32 scans per sample. Proton nuclear magnetic resonance (^1H NMR) spectra were acquired on a Bruker AVANCE III 400 MHz spectrometer (Bruker Corporation, Billerica, MA, USA) using deuterated chloroform. Elemental analysis was performed with an Elementar Vario EL cube analyzer (Vario EL cube, Elementar Analysensysteme GmbH, Langenselbold, Germany) in CHN mode.

2.3.3. Electron Microscopy

The ex situ morphology of TS-CB aggregates was examined using a field-emission scanning electron microscope (Quanta 650, FEI Company, Hillsboro, OR, USA). A 0.5 wt% TS-CB solution was prepared in simulated formation water, whose ionic composition is

given in Table 1, and left undisturbed at 45 °C for 12 h. An aliquot was deposited on a clean silicon wafer, freeze-dried, and sputter-coated with gold before imaging at an accelerating voltage of 10 kV and a working distance of 10 mm. Because the sample was freeze-dried, the image is interpreted as ex situ aggregate morphology and not as a direct observation of the solution-state or pore-scale structure.

Table 1. Ionic composition of simulated formation water for Hua 182 block.

Ion Type	K ⁺ + Na ⁺	Cl [−]	Ca ²⁺	Mg ²⁺	HCO ₃ [−]	Total Salinity
Content (mg/L)	12,779	37,914	10,455	410	135	6.2×10^4

Simulated formation water used in the laboratory tests; concentrations are reported in mg/L.

2.4. Performance Evaluation

Simulated formation water matching the Hua 182 block (Table 1) was used for surfactant preparation. Measurements conducted at the reservoir-representative temperature of 45 °C used thermostatted baths or ovens controlled to ± 0.1 °C.

Surface tension was measured with a KRÜSS DSA100 pendant-drop instrument (DSA100, KRÜSS GmbH, Hamburg, Germany) at 25.0 ± 0.1 °C over the investigated concentration series (1.0×10^{-6} to 5.0×10^{-3} mol/L), with three independent measurements at each condition ($n = 3$). The CMC was determined from the sharp intersection of straight lines fitted to the pre- and post-micellar regimes of γ versus $\log_{10} C$. The complete surface-tension isotherms, dual-linear fitting protocols, and Gibbs surface-excess equations are documented in Section S1 and Figure S1 in the Supporting Information.

Dynamic oil–water IFT was measured with a TX500C spinning-drop tensiometer (Bowen Scientific Instrument Co., Ltd., Shanghai, China) at 45.0 ± 0.2 °C and 5000 rpm using 0.5 wt% surfactant solutions prepared in simulated formation water (TDS = 6.2×10^4 mg/L). IFT values were calculated using the Vonnegut equation with a calibrated density difference $\Delta\rho = 0.182$ g/cm³, and dynamic decay profiles over 120 min are provided in Figure S2 in the Supporting Information.

A DHR-2 rheometer (Discovery HR-2, TA Instruments, New Castle, DE, USA) with a 60 mm, 1° cone-plate geometry was used for frequency sweeps from 0.1 to 10 Hz at 45 °C, yielding storage and loss moduli (G' and G''). Apparent viscosity of 2.5 wt% solutions was measured over 30–65 °C and total salinities of 2 – 10×10^4 mg/L at 7.34 s^{−1}. For emulsion tests, equal volumes of surfactant solution and simulated oil were shaken 200 times, and the time for 2 mL of water to separate was recorded at 45 °C.

Oil-aged quartz wettability was measured at 45 °C with a JC2000D1 goniometer (JC2000D1, Shanghai Zhongchen Digital Technic Apparatus Co., Ltd., Shanghai, China). A 5 μ L aqueous droplet was placed on the quartz plate, and the contact angle was recorded after 120 s.

2.5. Core Flooding Experiments

Permeability heterogeneity was represented by parallel high-permeability (25–35 mD) and low-permeability (5–10 mD) cores. After drying and vacuum saturation with simulated formation water, porosity and permeability were determined. Oil was injected in reverse at 0.02 mL/min to establish irreducible water saturation; this rate applies only to core preparation. Forward waterflooding continued until water cut exceeded 98%, followed by 0.5 pore volume (PV) of 2.5 wt% surfactant, 0.3 PV of 0.5 wt% surfactant, and subsequent waterflooding to the same cutoff. PV denotes injected volume divided by the pore volume of the parallel-core combination. Common inlet pressure, oil and water production, and water cut were recorded. Each formulation was tested twice.

3. Results and Discussion

3.1. Quantitative Digital-Core Characterization of Reservoir Micro-Heterogeneity

The micro-CT analysis gave 12.7% average porosity, 1.8 network tortuosity, and 18.5 μm average fracture aperture (Table 2). The reported 0.68 μm median equivalent throat radius is a cross-scale estimate: its 1.36 μm diameter is below the 1.5 μm micro-CT voxel edge and is not a directly resolved micro-CT throat. SEM mineral maps gave 7.5% clay content, with illite accounting for more than 60% of the clay fraction; more than 60% of the clay signal lay next to pore space in the examined sections. Together these observations set the transport, flow-resistance, brine, and mineral-contact tests listed in Table 3.

Table 2. Key microstructural descriptors of the target low-permeability sandstone cores.

Parameter	Value	Data Basis
Average porosity	12.70%	3D micro-CT
Median equivalent throat radius (cross-scale estimate)	0.68 μm	Cross-scale estimate; below the 1.5 μm voxel size
Average pore-to-throat radius ratio	3.1	3D micro-CT-derived descriptor
Pore-network tortuosity	1.8	3D micro-CT-derived descriptor
Average fracture aperture	18.5 μm	3D micro-CT-derived descriptor
Clay mineral content	7.50%	2D SEM mineral map
Illite proportion in clay minerals	>60%	2D SEM mineral map
Correlation degree between clay minerals and pore space	>60%	2D SEM spatial association

Note: Porosity, tortuosity, and fracture descriptors are based on three-dimensional micro-CT analysis, whereas clay content and clay-pore spatial association are derived from two-dimensional SEM mineral maps. The reported 0.68 μm equivalent throat radius is a cross-scale estimate and is not interpreted as a feature directly resolved by the 1.5 μm micro-CT voxel size.

Table 3. Rock descriptors, TS-CB variables, test conditions, and observed responses.

Rock Descriptor	Test Requirement	TS-CB Variable	Observed Response
Throat radius: 0.68 μm (cross-scale)	Monitor pressure during 2.5 wt% injection	Two C16 chains; PEO $n \approx 3$	Viscosity: 78.5 mPa·s at 50 °C; throat flow unmeasured
Tortuosity: 1.8; fracture: 18.5 μm	Test core-scale flow resistance	Gemini linkage; PEO $n \approx 3$	$G' > G''$ in bulk; common inlet pressure rose
Clay: 7.5%; illite > 60%	Assess mineral retention	Carboxylate; sulfonate; ammonium	Clay retention unmeasured
Brine: 6.2×10^4 mg/L	Test salinity compatibility	Charged headgroups; PEO $n \approx 3$	Viscosity: 76.8 mPa·s near 6×10^4 mg/L
Oil-aged quartz	Lower IFT; alter quartz wetting	Two C16 chains; amphiphilic headgroups	IFT: 0.019 mN/m; angle: 12.5°

Note: The table records the tested structure and response in this reservoir case. HPAB and OPAB are single-chain performance controls, not a matched comparison of molecules selected with and without digital-core input.

3.2. Structural Characterization of TS-CB

FT-IR analysis (Figure 3a) confirmed the presence of TS-CB's designed functional groups. The broad peak at 3408 cm^{-1} arises from O–H stretching, while those at 2924 and 2853 cm^{-1} represent asymmetric and symmetric methylene stretching, respectively. Absorption at 1732 cm^{-1} signifies ester carbonyl groups, and the bands at 1635 and 1401 cm^{-1}

correspond to asymmetric and symmetric carboxylate stretching—a characteristic betaine signature. A strong band at 1186 cm^{-1} originates from sulfonate group vibrations, and the broad absorption around 1110 cm^{-1} confirms the presence of polyoxyethylene segments. Collectively, these signals demonstrate the successful incorporation of the key functional moieties in TS-CB.

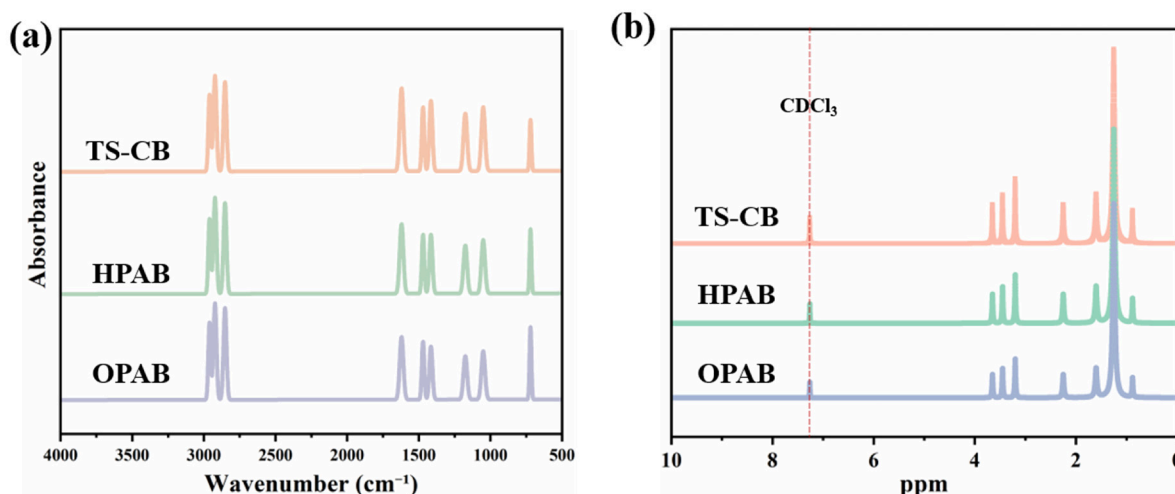


Figure 3. (a) FT-IR spectrum of TS-CB and (b) ^1H NMR spectrum of TS-CB.

^1H NMR spectra (Figure 3b) further corroborated the molecular structure. The chemical shifts and splitting patterns were assigned as follows: δ 0.86 for terminal methyl protons, δ 1.26 for long-chain methylene protons, δ 1.62 for methylene protons adjacent to oxygen, δ 2.38 for methylene groups linking the geminal quaternary-ammonium centers, δ 3.15 for N-methyl protons, δ 3.45–3.75 for complex multiplets corresponding to methylene protons adjacent to quaternary-ammonium nitrogen, sulfonate and hydroxyl groups, and polyoxyethylene chain methylenes, δ 4.05 for methylene protons directly attached to quaternary-ammonium nitrogen, and δ 4.42 for ester methylene protons.

Elemental analysis yielded C 58.32%, H 9.85%, and N 3.41%, closely matching the theoretical values of C 58.41%, H 9.88%, and N 3.39% with deviations under 0.3% (Table 4), indicating high product purity. Together, FT-IR, ^1H NMR, and elemental analysis confirmed that the synthesized product corresponds to the designed temperature- and salinity-responsive gemini carboxybetaine TS-CB.

Table 4. Elemental analysis data of the target product TS-CB.

Sample	Element	Theoretical (%)	Found (%)	Difference, Found – Theoretical (Percentage Points)
TS-CB	C	58.41	58.32	−0.09
	H	9.88	9.85	−0.03
	N	3.39	3.41	0.02

The freeze-dried TS-CB sample displayed interconnected aggregate features in the ex situ SEM image (Figure 4). This morphology is consistent with the viscoelastic response measured in bulk solution, but freeze-drying can alter aggregate structure. Figure 4 therefore does not directly demonstrate worm-like micelles in solution, transport through pore throats, or selective plugging of fractures.

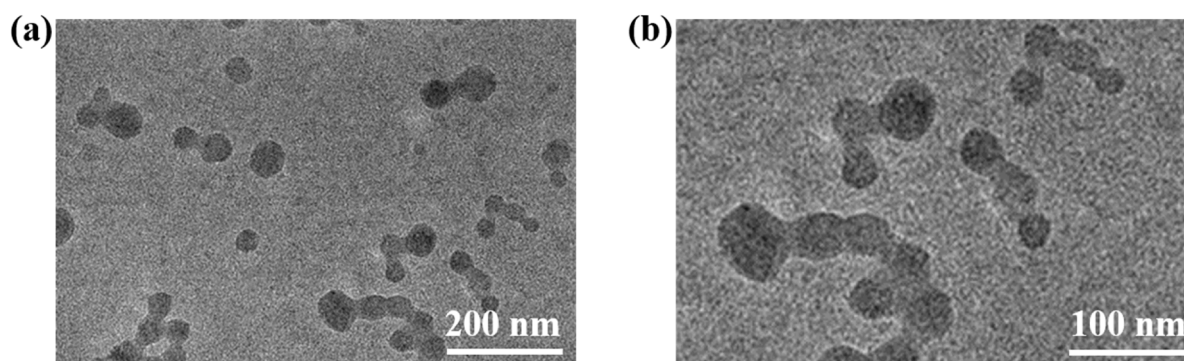


Figure 4. Ex situ SEM image of freeze-dried TS-CB aggregates prepared from simulated formation water. (a) Low-magnification image and (b) enlarged image. The observed morphology represents the freeze-dried state and is not an in situ observation of aggregate structure in bulk solution or porous media.

3.3. Performance Analysis

3.3.1. Oil–Water Interfacial Activity

At the stated concentrations and temperatures, TS-CB had the lowest CMC and oil–water IFT among the three tested surfactants (Table 5). As shown in the equilibrium surface-tension isotherms (Figure S1 in the Supporting Information), TS-CB achieved a substantially lower CMC of 2.8×10^{-4} mol/L and a lower γ_{CMC} of 28.5 mN/m. According to the Gibbs adsorption equations, TS-CB yielded a higher maximum surface excess $\Gamma_{\text{max}} = 6.20 \times 10^{-10}$ mol/cm² and a more compact minimum molecular area ($A_{\text{min}} = 0.269$ nm²), confirming tight molecular packing at the interface.

Furthermore, time-resolved dynamic IFT measurements (Figure S2 in the Supporting Information) demonstrate that TS-CB rapidly reaches an ultra-low interfacial tension plateau of 1.9×10^{-2} mN/m within 45 min at 45 °C in high-salinity brine, outperforming HPAB (2.3×10^{-2} mN/m) and OPAB (2.2×10^{-2} mN/m).

Table 5. Comparison of surface, interfacial, rheological, and emulsion parameters of the three surfactants under the stated test conditions.

Parameter	TS-CB	HPAB	OPAB
Critical micelle concentration, CMC ($\times 10^{-4}$ mol/L; $n = 3$)	2.8	7.5	3.4
Surface tension at CMC, γ_{CMC} (mN/m; $n = 3$)	28.5	31.5	29.2
Oil–water IFT at 0.5 wt% and 45 °C ($\times 10^{-2}$ mN/m)	1.9	2.3	2.2
Apparent viscosity of 2.5 wt% solution at 50 °C and 7.34 s^{-1} (mPa·s)	78.5	64.0	69.0
Apparent viscosity at 6×10^4 mg/L and 7.34 s^{-1} (mPa·s)	76.8	50.0	56.0
Contact angle on oil-aged quartz at 0.5 wt% and 45 °C (°)	12.5	16.8	18.6
Water-separation time at 0.5 wt% and 45 °C (s)	920	410	460
Maximum surface excess, Γ_{max} ($\times 10^{-10}$ mol/cm ²)	6.20	4.15	5.44
Minimum molecular area, A_{min} (nm ²)	0.269	0.401	0.306
pC20	3.83	3.14	3.46

3.3.2. Temperature- and Salinity-Responsive Viscoelastic Behavior

At 50 °C, the 2.5 wt% TS-CB solution reached 78.5 mPa·s, compared with 64.0 mPa·s for HPAB and 69.0 mPa·s for OPAB at 7.34 s^{-1} (Figure 5a). The rise and subsequent decline with temperature are consistent with changes in PEO hydration and aggregate association. The elastic response in Figure 6 supports a bulk network under the test conditions; its behavior inside individual core pathways has not been measured.

Along the total-salinity scan, TS-CB apparent viscosity peaked at 76.8 mPa·s near 6×10^4 mg/L, against 50.0 mPa·s for HPAB and 56.0 mPa·s for OPAB (Figure 5b). The

simulated formation water has a comparable salinity of 6.2×10^4 mg/L. This scan tests total salt content; the proportions of individual ions and pH were not varied separately.

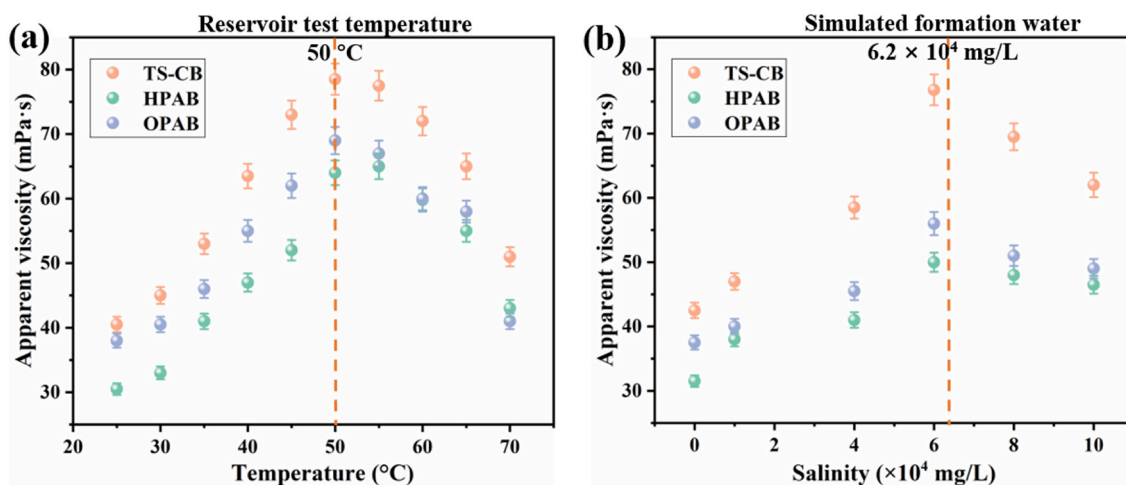


Figure 5. Apparent viscosity versus (a) temperature and (b) total salinity for TS-CB, HPAB, and OPAB. Error bars are shown on the plotted measurements.

For TS-CB, G' remained above G'' throughout the tested frequency range and both moduli exceeded those of HPAB and OPAB (Figure 6). This provides a bulk-flow explanation for the increase in inlet pressure seen during chemical injection, although the experiment did not resolve which parallel-core branch developed the additional resistance.

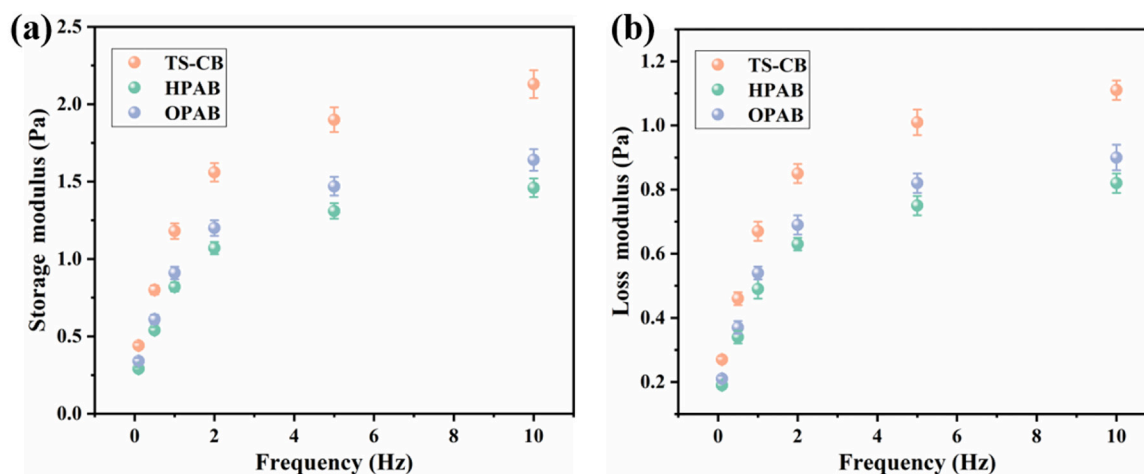


Figure 6. Frequency-sweep response: (a) storage modulus, G' , and (b) loss modulus, G'' . Error bars are shown on the plotted measurements.

3.3.3. Emulsion Stability and Wettability Response on Quartz

At 0.5 wt%, water separation required 920 s with TS-CB, compared with 460 s for OPAB and 410 s for HPAB (Figure 7). The longer separation time indicates more persistent emulsification in the vial test, consistent with the low measured IFT.

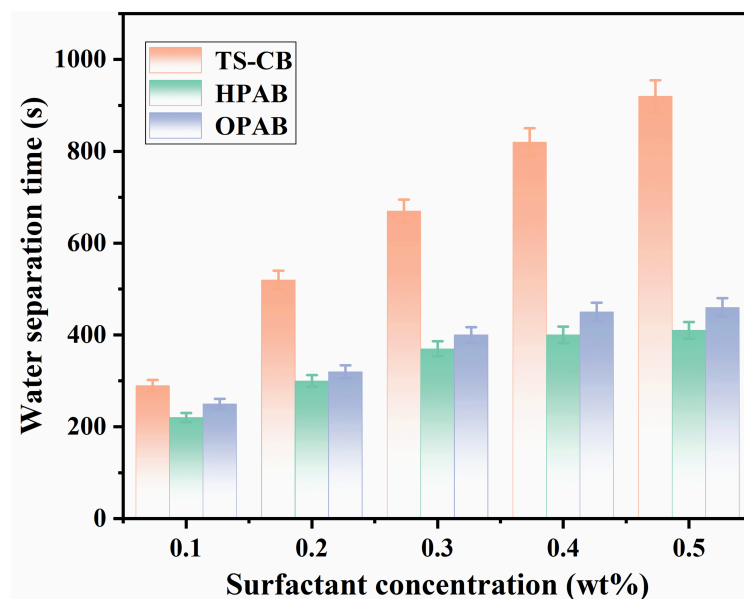


Figure 7. Water-separation time of the emulsions versus surfactant concentration. Error bars are shown.

On oil-aged quartz at 0.5 wt%, the contact angle was 12.5° with TS-CB, compared with 16.8° with HPAB and 18.6° with OPAB (Figure 8, Table 5). The quartz result directly shows a shift toward water wetting on that model surface. Adsorption on the clay minerals present in the core was not tested.

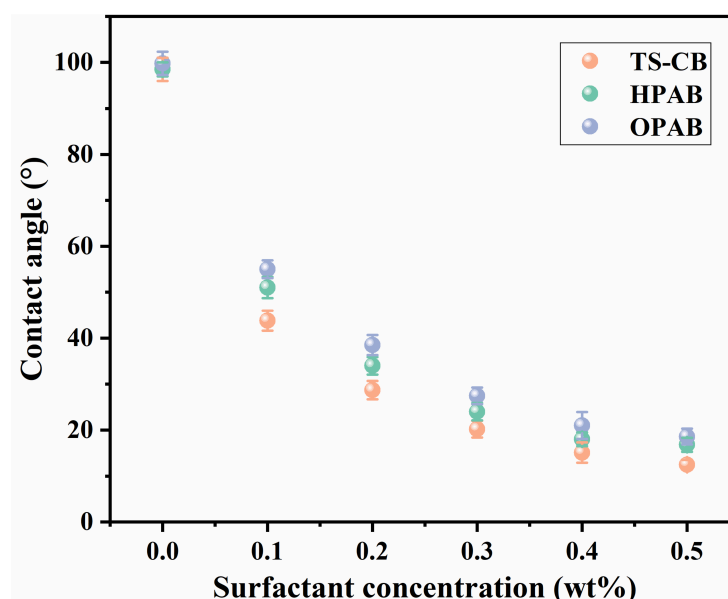


Figure 8. Contact angle on oil-aged quartz versus surfactant concentration. Error bars are shown.

3.4. Parallel-Core Flooding Performance and Macroscopic Oil Recovery

Initial waterflooding favored the high-permeability branch (Table 6, Figure 9). The total recovery increments were 16.0, 12.0, and 10.2 percentage points with TS-CB, OPAB, and HPAB, respectively; TS-CB therefore gave observed differences of 4.0 and 5.8 percentage points against the controls. In the low-permeability branch the respective increments were 20.0, 13.9, and 15.3 percentage points, giving TS-CB differences of 6.1 and 4.7 percentage points. Total recovery was weighted by initial oil in place in the two branches, rather than averaged from their separate recovery factors.

Table 6. Summary of parallel-core flooding experiments.

Surfactant	Contrast (K_H/K_L)	High-k Waterflood Recovery (%)	Low-k Waterflood Recovery (%)	Low-k Recovery Gain (pp)	Total Recovery Gain (pp)
TS-CB	5.0	60.1	16.5	20.0	16.0
OPAB	4.8	59.4	15.4	13.9	12.0
HPAB	5.4	58.4	16.1	15.3	10.2

Note: Recovery is referenced to initial oil in place (OOIP) across the dual-core assembly. Incremental recovery is final recovery minus baseline waterflood recovery, expressed in percentage points (pp). Detailed individual core dimensions, permeabilities, porosities, and fluid material balances are documented in Table S2 in the Supporting Information.

During TS-CB injection, water cut fell and total oil recovery rose (Figure 9). The flood summary also reports an increase in common inlet pressure. That observation supports a change in overall flow resistance but cannot locate that change within the high- or low-permeability branch. The core apparatus had no branch-specific pressure taps, and post-flood permeability was not measured.

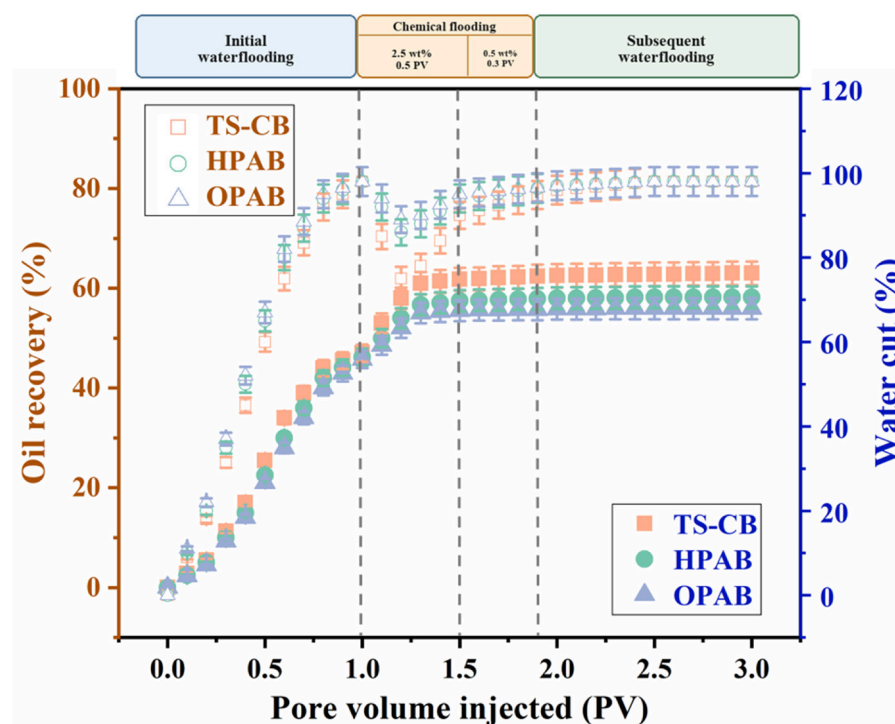


Figure 9. Oil-recovery and water-cut curves during initial waterflooding, 0.5 PV of 2.5 wt% surfactant, 0.3 PV of 0.5 wt% surfactant, and subsequent waterflooding. Error bars are shown. PV is normalized to the pore volume of each parallel-core combination.

Although the three core pairs possessed slight variations in permeability contrast ($K_H/K_L = 5.0, 4.6$ and 5.4 for TS-CB, OPAB, and HPAB, respectively; Table S2), the pronounced incremental recovery in the low-permeability branch (20.0 pp for TS-CB vs. 13.9 pp for OPAB and 15.3 pp for HPAB) indicates effective dynamic fluid diversion. The complete petrophysical ledger and material-balance splits provided in Table S2 confirm that mobilizing bypassed oil from tight matrix domains is the primary driver for total EOR enhancement.

3.5. Interfacial Effects and Proposed Flow Redistribution

The sequence in Figure 10 connects the measured bulk viscoelasticity and interfacial effects to the parallel-core recovery response. Preferential flow during initial waterflooding can leave oil in less-swept pores. TS-CB may increase resistance along favored pathways while lower IFT and more water-wet quartz promote oil mobilization. The common pressure rise and cumulative recovery are compatible with this sequence, but they cannot establish a fracture plug or map flow into the matrix.

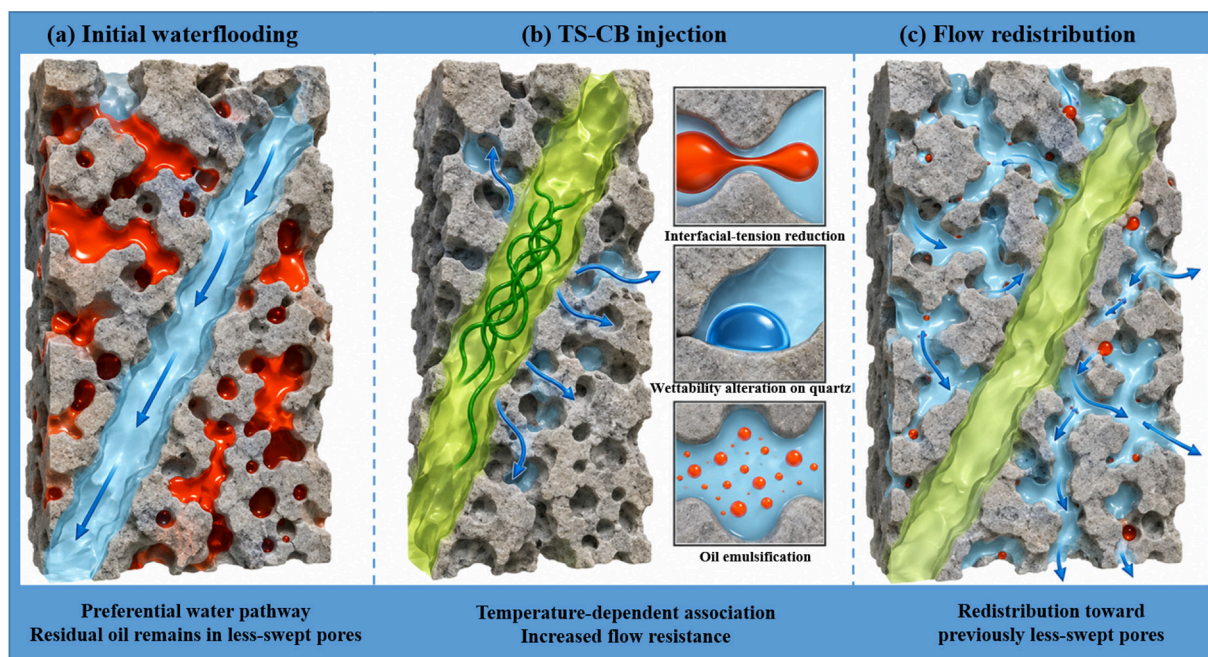


Figure 10. Conceptual sequence linking measured TS-CB responses with proposed flow redistribution: (a) preferential waterflooding; (b) bulk viscoelasticity, lower oil–water IFT, altered oil-aged quartz wettability, and emulsification; and (c) proposed entry into less-swept pores. The rock pathways are schematic; no in situ flow map was obtained.

A direct test of the pathway proposed in Figure 10 would combine separate pressure and flow measurements for the parallel branches with produced-fluid surfactant concentrations and a tracer. Post-flood micro-CT or a transparent fracture–matrix model could then show whether flow entered previously bypassed regions. These diagnostics would distinguish diversion from a simple rise in inlet resistance.

3.6. Potential Effects of Water Chemistry on Performance

The salinity series in Figure 5b varies total salinity but does not isolate pH or individual-ion effects. The quaternary-ammonium centers of TS-CB carry permanent positive charge, whereas the protonation state of carboxyl groups can vary with pH and affect interfacial adsorption and aggregate packing. Salt effects depend on ionic strength, ion activity, and specific interactions; greater hardness or salinity can alter aggregate morphology, solubility, and phase stability [24].

Dissolved CO₂ can lower aqueous-phase pH and influence oil-phase behavior and mineral reactions. CO₂-responsive mechanisms involving protonatable amines cannot be transferred directly to the permanently charged quaternary-ammonium centers in TS-CB [34]. Because pH, CO₂ pressure, and individual Na⁺, K⁺, Ca²⁺, and Mg²⁺ concentrations were not varied independently, no ion-specific or CO₂-responsive recovery claim is made.

3.7. Dynamic Injection Conditions and Field Applicability

The parallel-core tests are dynamic displacement experiments, whereas the interfacial and rheological measurements were performed under controlled laboratory conditions. Field injection additionally involves temperature gradients, pore-scale shear and extensional flow, mixing with formation water, dilution, retention, and pressure variation. The local aggregation state and flow resistance can therefore differ from the bulk measurements.

The two-slug sequence was designed to combine increased flow resistance at 2.5 wt% with interfacial oil mobilization at 0.5 wt%. The branch allocation and effective transport distance were not measured directly. Consequently, the results are limited to the tested cores, fluids, and injection sequence and are not extrapolated quantitatively to field injectivity or treatment radius.

3.8. Chemical Dosage and Economic Constraints

TS-CB requires multistep synthesis, purification, and solvent handling, and the 71% laboratory yield is not a measure of industrial production cost. For 1 m³ of treated pore volume, the nominal chemical requirement of the reported two-slug design is $m = (0.5 \text{ m}^3)\rho_1(0.025) + (0.3 \text{ m}^3)\rho_2(0.005)$, where ρ_1 and ρ_2 are the solution densities. Assuming both densities are 1000 kg/m³ gives $m \approx 14 \text{ kg}$.

A screening expression for cost per unit mass of incremental oil is $C_{\text{inc}} = (mP + C_{\text{other}})/\Delta m$, where P is the chemical unit price, Δm is incremental-oil mass on the same treatment basis, and C_{other} includes preparation, injection, and produced-fluid treatment. Because scaled-up manufacturing cost, active content, chemical loss, and field incremental-oil data were not established, no economic advantage is claimed for TS-CB.

3.9. Limitations and Future Research

3.9.1. Transferability and Limits of the Design Approach

The present results apply to low-permeability Yanchang Formation sandstone from the Hua 182 block and represent a single-reservoir case. Applying the workflow elsewhere requires new pore-throat, fracture, mineral, oil, and water-chemistry data and an assessment of image-segmentation uncertainty for the new lithology. Screening constraints should then be defined using adsorption risk and allowable injection pressure as well as interfacial and rheological targets.

Smaller throats or stricter pressure limits may favor lower concentrations or formulations with less pronounced aggregation. Greater fracture control may require adjustment of concentration and slug volume, whereas stronger clay-pore association increases the importance of adsorption and retention. Candidate structures can be varied through hydrophobic-chain length, spacer structure, headgroup composition, and PEO segments, followed by joint experimental evaluation. No validated one-to-one mapping between reservoir descriptors and an optimal molecule is claimed.

3.9.2. Methodological Constraints of the Present Record

Three parts of the present record limit a stronger causal interpretation. While the current study provides the essential algorithmic configurations (Table S1), complete surface-tension isotherms and dynamic IFT curves (Figures S1 and S2), and granular parallel-core petrophysical ledgers (Table S2), certain physical constraints remain. Specifically, in situ visualization of microscale emulsification and pore-level fluid redistribution inside opaque core matrix was not directly imaged during flooding. Future investigations combining real-time branch pressure monitoring with post-flood micro-CT imaging will provide direct spatial proof of dynamic diversion.

3.9.3. Future Research

The next validation should archive the image and annotation inventory and split the training, validation, and test sets by independent core. For interfacial testing, a complete surface-tension curve with fitting points, dynamic IFT traces, fluid densities, and the replicate values underlying each error bar should accompany the summary measurements. Matched parallel-core pairs with at least three independent runs per formulation should report core dimensions, pore volume, porosity, permeability, initial oil saturation, material-balance closure, and produced-fluid concentration. Branch pressure and tracer or post-flood images would directly test the Figure 10 flow sequence.

4. Conclusions

Digital-core analysis of the Hua 182 sandstone identified small-throat transport, preferential-flow resistance, reservoir-brine compatibility, and mineral contact as constraints for surfactant screening. The evaluated TS-CB molecule combined two C16 hydrophobes, a gemini linkage, carboxylate and sulfonate groups, and a short PEO segment. At the stated laboratory conditions it reached a CMC of 2.8×10^{-4} mol/L, an oil–water IFT of 1.9×10^{-2} mN/m, 78.5 mPa·s apparent viscosity at 50 °C, a 12.5° contact angle on oil-aged quartz, and a 16.0-percentage-point total recovery increment in the tested parallel-core combination. The control combinations yielded increments of 12.0 and 10.2 percentage points. These data support interfacial oil mobilization alongside a change in bulk-flow resistance. Matching the cores and resolving branch-specific flow are the remaining steps needed to test whether TS-CB causes selective diversion inside the rock.

Supplementary Materials: The following supporting information can be downloaded at <https://www.mdpi.com/article/10.3390/coatings16101147/s1>, Section S1: Physicochemical Surface and Interfacial Tension Characterization (including Figure S1: Equilibrium surface tension (γ) isotherms and dual-linear CMC regression fits for TS-CB, OPAB, and HPAB; Figure S2: Time-dependent dynamic oil–water interfacial tension (IFT) decay curves for TS-CB, OPAB, and HPAB systems); Section S2: Deep-Learning Digital Rock Segmentation Configuration (including Table S1: Neural network architectural hyperparameters and training configurations for digital rock segmentation); Section S3: Petrophysical Ledger of Parallel-Core Flooding Experiments (including Table S2: Comprehensive petrophysical ledger and displacement performance splits for parallel-core flooding experiments).

Author Contributions: Y.D., Conceptualization, Investigation, Methodology, Writing—original draft; G.Z., Data Curation; X.H., Formal analysis; Y.Y., Investigation; F.L., Methodology; R.D., Writing—review and editing. All authors have read and agreed to the published version of the manuscript.

Funding: This research was funded by the Natural Science Foundation of Shandong Province (ZR2023ME119, ZR2022ME077) and the Deep Earth National Science and Technology Major Project (2024ZD1000904).

Data Availability Statement: The original contributions presented in this study are included in the article/Supplementary Materials. Further inquiries can be directed to the corresponding author.

Conflicts of Interest: Gang Zhou was employed by the company PetroChina Daqing Oilfield Co., Ltd., Xingyin Huang was employed by the company Zhenhua Oil Co., Ltd., Yirui Yu was employed by the company PetroChina Qinghai Oilfield Company, Fangfei Li was employed by the company PetroChina Daqing Oilfield Co., Ltd., Runlin Du was employed by the company Qingdao Institute of Marine Geology. The remaining author declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

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