1. Introduction

In the early stage of the oil production, referred to as primary recovery, oil is brought up to the surface by inner-driving forces of the reservoir, which are supplemented by the injection of a cheap material (gas, water or a mixture of both) in the stage of secondary recovery. The injected material is intended to stimulate the oil-bearing matrix to increase the recovery of oil. This secondary production can retrieve up to 60% of the total oil production. However, adsorption of injected surfactant on minerals in the oil-bearing rock matrix reduces the effectiveness of this method. The present study investigated the effects of surfactant adsorption and desorption in the rock matrix on the oil recovery ratio achieved by surfactant-EOR. Sodium dodecylbenzene sulfonate (SDBS), a common surfactant in EOR, was used with Berea sandstone samples (rock particles and cores) as adsorbent. Adsorption of SDBS in the samples increased with concentration, and the static saturated amount was 0.9 mg-SDBS/g-rock for 1.0 wt% SDBS-water solution. If brine (1.0 wt% salinity) was injected after saturated adsorption of SDBS in the core, 83% of adsorbed SDBS was desorbed into the brine (the reversibility effect). To clarify the reversibility effect in oil reservoirs, field-scale numerical simulations were conducted for a typical 5 spot model (area: 180 m x 180 m, thickness: 60 m) using core-flooding data reported previously. By introducing the reversibility model into the simulations on surfactant flooding injection of slugs of 0.1 PV and 0.3 PV into the initial reservoir, oil recovery factor showed differences of 2.3% and 2.9% compared to without the model, respectively. Injection of the surfactant solution after water-flooding caused a difference of only 0.4%.

Keywords
Adsorption reversibility, Surfactant flooding, Chemical enhanced oil recovery, Interfacial tension, Simulation
becomes relatively less severe at higher temperatures\(^9\). According to the principle point of zero charge (p.z.c.), the pH changes the rock surface charge from negative to positive or vice versa\(^10\).

On the other hand, surfactant molecules packed in solid layers are detached at or beyond a certain concentration, referred to as desorption. Under certain conditions, surfactant molecules are desorbed from the attached surface and returned to the crude oil/brine system\(^11\),\(^12\). This reversibility enables further reduction in IFT\(^8\),\(^13\),\(^14\).

Reservoir simulation can analyze the effectiveness of any studied technique on a larger scale based on fitting with obtained experimental results and validating the model performance. In addition, injection schemes and operational parameters can be thoroughly studied prior to actual field implementation. Previous studies have used reservoir simulation based on both laboratory-scale experiments and field-scale production data.

Surfactant flooding was extensively modeled in different commercial simulators. A homogenous model was developed in ECLIPSE for The Norne E-Segment to study surfactant-EOR\(^15\). The model showed an increase of 5% in production over waterflooding. UTCHEM was utilized to conduct a sensitivity analysis on chemical injection volume and concentration, salinity, reservoir heterogeneity and surfactant adsorption in a dolomite reservoir\(^16\). The results showed that surfactant increased production by 27.8%. CMG (STARS) study of Alkali-Surfactant-Polymer (ASP) flooding concluded that surfactant concentration controlled the efficiency of ASP flooding in both primary and secondary slugs\(^17\). Several uncertain parameters such as fracture to matrix permeability ratio, initial water saturation and grid numbers of the model have also been considered for surfactant injection in fractured reservoirs\(^18\).

CMG (STARS) was used to build a numerical approach for surfactant EOR study and showed that increasing the flow rate, concentration and flooding periods all improved the total oil recovery\(^19\). A numerical study was developed of surfactant flooding for field application and showed that additional recovery of approximately 3 to 4% of oil was achieved by injecting surfactant into a heterogeneous sandstone reservoir, and the calculations deviated from those obtained experimentally by 6%\(^20\). Table 1 summarizes the key investigations of simulation of chemical flooding.

Much information is available regarding changes in the performance of surfactant adsorption and reservoir properties, but how the desorption mechanism improves the oil recovery remains unclear. Furthermore, the reversibility of surfactant adsorption has not been fully considered in reservoir simulations, possibly with misleading results. Therefore, the present study primarily evaluated the influence of the operational parameters on adsorption reversibility, based on both experimental and simulation analyses. The present study included the following. Adsorption and desorption between an anionic surfactant and sandstone were studied in both static and dynamic modes. The obtained results were imported into a commercial simulator, STARS. Three sets of history matching were performed on published coreflood data. The best matched model was used to correlate with the adsorption results to study the effect on a validated field scale model. Finally the operational parameters reported to affect the efficiency of

| Previous studies | Type of EOR | Surfactant concentration | Type of adsorbent | Consideration of surfactant adsorption | Investigated parameters | Recovery factor by waterflooding [%] | Increment in oil recovery after waterflooding [%] |
|------------------|-------------|--------------------------|-------------------|----------------------------------------|------------------------|------------------------------------|-----------------------------------------------|
| Stanislaus and Mahmud, 2017\(^{20}\) | Surfactant | 0.8 wt% | Sandstone | Ignored | Flow rate, concentration, flooding period | 56.3 | 4.90 |
| Le Van and Chon, 2016\(^{20}\) | Surfactant-polymer | 0.83 vol% | Sandstone | No | Well patterns, reservoir heterogeneity | 65.0 | 9.45 |
| Keshtkar et al., 2016\(^{20}\) | Surfactant | 0.01 mol fraction | Sandstone | Not considered | Partition coefficient, surface tension, oil viscosity and injection concentration | 35.0 | 20.0 |
| Rai et al., 2015\(^{22}\) | Surfactant-polymer | 0.1 wt% | Sandstone | No | Validation by CMG (STARS) | 21.6 | 17.7 |
| Sinha et al., 2015\(^{25}\) | ASP | 0.1 wt% | Sandstone | No | Model and experimental results comparison | 51.7 | 19.5 |
| Hakiki et al., 2015\(^{25}\) | Surfactant-polymer | 1.0 wt% and 2.0 wt% | Sandstone | No | Uncertainty on relative permeability | 45.0 | 20.0 |
| Sayed Akram and Mamora, 2011\(^{30}\) | Surfactant-polymer | 0.09 wt% | Carbonate | Yes | Natural fractures, wettability alteration, IFT and mobility reduction | 50.0 | 15.0 |
| Song et al., 2011\(^{30}\) | Surfactant-polymer | 1000-2000 mg/L | Sandstone | Yes | Chemical concentrations and slug sizes | 48.9 | 12.9-17.6 |

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surfactant EOR were investigated.

2. Experimental Section

2.1. Aqueous Surfactant Solutions, Brine and Reservoir Formation

A lyophilized anionic surfactant, sodium dodecyl-benzene sulfonate (SDBS), supplied by Sigma-Aldrich, was used as the primary slug, based on the availability and common application in current oil fields. Consequently, the findings of this study will be applicable to other adsorbent-adsorbate systems, in which both the surfactant and rock surface possess negative charge. Surfactant solution 1.0 wt% was initially prepared as baseline and diluted further to a range from 0.1 to 0.9 wt%. Synthetic brine (10,000 ppm salinity) was prepared to represent the common average reservoir water in onshore oil fields in Thailand. The brine was synthesized in-house primarily from sodium chloride (NaCl), calcium chloride (CaCl₂), magnesium chloride (MgCl₂), sodium hydrogen carbonate (NaHCO₃), potassium chloride (KCl) and sodium sulfate (Na₂SO₄), all supplied by Sigma-Aldrich. Brine was prepared in 1 L lots and the chemical composition is outlined in Table 2.

Berea sandstone was used as the primary adsorbent. The rock core sample was 4.1 cm long with a diameter of 3.78 cm. The permeability was 100 mD (measured during water saturation in core-flooding). The porosity, measured using the fluid saturation method, was estimated to be 20%. The rock core was ground into fine grains and dried at 101°C to eliminate interstitial water. All chemicals were used as received and were 99.99 % pure.

2.2. Methods

2.2.1. Static Adsorption Test

Crushed rock 5 g was stirred in 50 mL of SDBS solution for 6 h at 45°C and was allowed to equilibrate overnight. The mixture was then filtered through a 40 μm filter paper to remove any suspended solid. The concentration in SDBS was analyzed in the effluent solution by a two-phase titration method using standard 0.004 M hyamine solution, methylene blue, chloroform, anhydrous sodium sulfate, and sulfuric acid. The upper phase consisted of a mixture of effluent solution, methylene blue, chloroform, anhydrous sodium sulfate and sulfuric acid, and the bottom phase contained chloroform. Before titration, the mixture of the upper phase solution and chloroform were shaken vigorously until the color of both phases became identical (blue). Then, hyamine solution 0.004 M was titrated into the two-phase mixture dropwise until the chloroform phase became colorless, which indicated the end point of the titration. The concentration of the adsorbed surfactant was then calculated as,

$$A_d = \frac{V}{m}(C_o - C_e)$$

where $A_d$ is adsorption magnitude (mg/g-rock), $V$ is mass of the solution (g), $m$ is mass of rock (g), $C_o$ is initial concentration (wt%) and $C_e$ is concentration after adsorption (wt%).

2.2.2. Dynamic Adsorption-desorption Experiments

Dynamic adsorption tests were conducted in equipment as shown in Fig. 1. Berea sandstone core sample was washed with toluene, and dried at 101°C to remove any residual trapped fluid. Three SDBS concentrations (0.2, 0.5 and 1.0 wt%) were selected for these experiments. Initially, the test temperature was increased to match the reservoir condition of 45°C, then the sample was saturated with brine in the core holder until air bubbles were no longer observed at the fractionator. The aqueous surfactant was then injected at 0.02 cm³/min for 1.9, 1.5 and 1.1 pore volumes (PVs) for 0.2, 0.5 and 1.0 wt% cases respectively. The surfactant flooding was stopped when the concentration at the effluent was constant. The injection fluid was changed to brine, injected at the same rate. The effluent water was continuously collected in a fractionator and titrated to determine the SDBS concentration. The core was flooded with brine until the concentration of the desorbed surfactant was minimal in the effluent. The values of adsorption and desorp-

| Ionic composition | Na⁺ | Ca²⁺ | K⁺ | Mg²⁺ | Cl⁻ | HCO₃⁻ | SO₄²⁻ |
|-------------------|-----|------|----|------|-----|-------|-------|
| Concentration [ppm] | 3089.3 | 105.3 | 86.9 | 330.6 | 4967.5 | 36.4 | 1384 |

Fig. 1 Schematic Representation of the Dynamic Adsorption Apparatus; (1) pump, (2) jacketed cell containing the injection fluids (brine and surfactant), (3) injector pressure indicator, (4) thermostatic bath, (5) temperature indicator, (6) core holder, (7) back pressure regulator, (8) fractionator
tion were measured by material balance, and reversibility was calculated as the ratio of desorption to maximum adsorption.

3. Results and Discussion

3.1. Static and Dynamic Adsorption Tests

Figure 2 shows the results of static and dynamic adsorption of aqueous SDBS solutions in the Berea sandstone.

Adsorption of SDBS by crushed Berea sandstone grains increased with surfactant concentration. Static adsorption results could be divided into 4 regions classified by different slopes. Region I extended from 0 to 0.4 wt%, in which adsorption showed linear increase probably due to the low amount of SDBS in solution. This adsorption behavior is believed to be the result of the electrostatic attraction between surfactant monomers and rock surface. Region II extended from 0.4 to 0.6 wt%, in which the sharp increase in adsorption suggested formation of aggregates on the rock surface. Therefore, the surfactant is believed to have reached its Critical Admicelle Concentration (CAC), at which the first layer of surfactant monomers is fully packed. Region III extended from 0.6 to 0.8 wt%, in which the adsorption shifted to higher values, which indicated the formation of surfactant bi-layer. Region IV extended from 0.8 to 1.0 wt%, in which adsorption reached its plateau value, implying that the second layer is completely occupied and repulses surfactant monomers in the bulk solution. Therefore, further adsorption will not occur even if the SBDS concentration is increased.

Dynamic adsorption of SDBS solutions was evaluated using 0.2, 0.5 and 1.0 wt% solutions, representative of the changes in surfactant behavior in a static mode. Adsorption plateaued around 1.9 PV of injected surfactant solution at a low concentration of 0.2 wt%. This equilibrium occurred earlier at 1.5 PV and 1.1 PV with concentrations of 0.5 wt% and 1.0 wt%, respectively. Equalization of the concentration of surfactant at the inlet and outlet decreased the injectivity as the injectant shifted to brine. This phenomenon was due to reduction of pore size caused by surfactant adsorption. Therefore, injection of brine was delayed during the experiment. The results corroborated previous findings which suggested that this adsorption pattern was characteristic of a strong attraction force between the rock surface and surfactant monomers. Comparative analysis (Table 3) revealed that SDBS was adsorbed more at higher concentration, but more importantly less PV was required to reach the plateau value. With brine injected after surfactant, adsorption was found to decrease without reaching the 0-value, indicating that not all surfactant molecules were washed away from the sandstone. Therefore, some SDBS molecules were still attached to the native minerals of the sandstone, suggesting SDBS reversibility is possible.

Table 3 Comparison with Previous Studies of Adsorption between Anionic Surfactant and Berea Sandstone Core

| Type of surfactant | Concentration [wt%] | Injected PV at the plateau value |
|--------------------|---------------------|---------------------------------|
| This work SDBS     | 0.20                | 1.9                             |
|                    | 0.50                | 1.5                             |
|                    | 1.00                | 1.1                             |
| Trogus et al., 1977 | C12ABS              |                                 |
|                    | 0.17                | 14                              |
|                    | 0.35                | 8.2                             |
|                    | 0.70                | 7.8                             |

a) SDBS: sodium dodecylbenzene sulfonate; C12ABS: C12-linear alkylbenzene sulfonate.
3.2. Adsorption and Reversibility of SDBS

Adsorption is greater at higher concentration, but reversibility showed the opposite pattern. For example, high reversibility (97%) was observed at low concentration of 0.2 wt%. This low concentration of 0.2 wt% falls in region I (Fig. 2(a)), in which the adsorption depends only on the electrostatic interactions between the rock surface and surfactant monomers. Therefore, the brine flow should return almost all monomers back to system. The lowest reversibility of 41% was observed with higher concentration of 0.5 wt%, which falls in region II of Fig. 2(a). The interaction between surfactant molecules in this region occurs through van der Waals forces, so increasing the adsorption density. Presumably the attractive forces are stronger at this stage. As a result, the adsorbed surfactant monomers are relatively difficult to detach by brine flow.

Reversibility then increased to 83% at the highest concentration of 1.0 wt%, at which adsorption reached its plateau in the static mode, in region IV of Fig. 2(a), in which surfactant bi-layer had been formed. Bi-layer monomers are attached to each other by the tail portion, which forms relatively weak bonds compared to the monomer head. The surface potential is significantly decreased at larger distance from the charged surface. As the second-layer monomers are relatively further from the charged sandstone surface, these molecules are entirely removable by brine flow, together with some monomers in the first layer. This reason could explain the higher reversibility at 1.0 wt% than 0.5 wt%.

4. Numerical Modeling and Sorption Mechanisms

4.1. History Matching with Sorption Results

History matching was performed on a one-dimensional model of 10 blocks, which simulated the sandstone plug used during the dynamic adsorption experiments. Fluid and reservoir properties of the model are given in Table 4 based on the core and surfactant properties. The injected fluid was assumed to flow in only one direction from injection well to production well, and surfactant was considered as the aqueous phase (as in the experiment investigation), the conservation equation of flow follows Eq. (2), and the adsorption and desorption function follows Eqs. (3) and (4).

\[
\frac{\partial}{\partial t} \left( \phi f \rho w \right) = \sum_{i} \left[ \rho w \Delta \Phi w \right] \delta_{w} + \delta_{w} \left( \rho w q_{w} \right) + \delta_{w} \left( \rho w q_{w} \right)
\]

\[
Ad = \frac{(Tad 1 + Tad 2 \times xNaCl) \times ca}{(1 + Tad 3 \times ca)}
\]

\[
ADRT = ADMAXT - DESex
\]

where DESex is experimented reversible adsorption.

Adsorption and desorption values during surfactant injection and water flooding were used as variables to match the laboratory data and the simulations. Two models were simulated, in which the effects of reversability decreased at larger distance from the charged surface. As the second-layer monomers are relatively further from the charged sandstone surface, these molecules are entirely removable by brine flow, together with some monomers in the first layer. This reason could explain the higher reversibility at 1.0 wt% than 0.5 wt%.

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Adsorption and desorption values during surfactant injection and water flooding were used as variables to match the laboratory data and the simulations. Two models were simulated, in which the effects of revers-
ibility were considered (S1) and in which desorption was neglected (S2). To simulate the experimental dynamic adsorption, the adsorption of each block was measured and calculated for maximum surfactant adsorption and desorption, as obtained from the material balance. The deviation was estimated from the difference in the adsorption and desorption values obtained from the experimental results and from the simulations. The results are shown in Fig. 4.

Model S1, which considered both adsorption and desorption, achieved better matching with the experimental results for the investigated cases (Fig. 4(a)). Deviation from the experimental results (Table 5) found a marginal error of 3.5% for S1. Therefore, SDBS flooding at higher concentration, i.e. more than 1.0 wt%, will not cause any further adsorption, probably because of maximum packing at the rock surface.

In contrast, model S2, which excluded reversibility effects, showed poor matching with the experimental data (Fig. 4(b)) and large deviation as high as 45% during the post-waterflooding stage (Table 5). Injection of brine was followed by sharp decrease in SDBS concentration to 0 at the producer indicating no surfactant molecules were desorbed from the rock surface. These observations, inconsistent with the experimental results, suggest that surfactant could only be trapped by the porous media during micellar injection in this model, and brine cannot detach adsorbed surfactant. If the effect of reversible adsorption is neglected, brine flooding after surfactant slug will then behave as waterflooding, which does not agree with the experimental results. Surfactant desorption should partially reduce the IFT of affected blocks, and trapped oil will be recovered through this proposed effect. Based on these considerations, we selected the S1 model for further analyses.

4.2. History Matching with Oil Production Data

To evaluate the effect of adsorption/desorption, we obtained experimental coreflood data from experimental studies on sodium dodecyl sulfate (SDS) flooding in sand packs to evaluate improve oil recovery, and low salinity waterflooding and SDBS in Berea sandstone. None of these studies reported adsorption and/or desorption. The coreflood data are shown in Table 6. Curve fitting for history matching used major controlling parameters such as residual oil saturation, relative permeabilities and corey exponent. Furthermore, other operational parameters such as injection rate, injection volume and injectant concentra-

![Fig. 4 History Matching of Core Flooding with One-dimensional Core Models](image-url)

### Table 6 Oil Recovery of Targeted Studies and Simulations

| Parameters               | Salih et al., 2016 (27) | Samanta et al., 2011 (28) | Enge, 2014 (29) |
|--------------------------|-------------------------|----------------------------|-----------------|
| Reservoir properties     |                         |                            |                 |
| Porosity [%]             | 33.86                   | 38.67                      | 15.47           |
| Permeability [mD]        | 848                     | 1233                       | 309             |
| Temperature [°C]         | 70                      | -                          | 60              |
| Formation fluids         |                         |                            |                 |
| Oil density [°API]       | 29.47                   | -                          | 33.5            |
| Salinity [ppm]          | 5500                    | 10000                      | 32500           |
| Micellar solution        |                         |                            |                 |
| Type         | SDS                    | SDS                        | SDBS            |
| Concentration [wt%]     | 0.29                    | 0.3                        | 0.05            |
| Oil recovery            |                         |                            |                 |
| Experiment              | 89.9                    | 73.0                       | 53.3            |
| Simulation              | 90.2                    | 73.7                       | 53.3            |

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tion were kept constant, because these parameters were provided and fixed in previous studies, so variation would contradict the actual experimental data.

History matching showed deviation of 1.04% with the previous study28), that we believe can be imputed to the limited information on oil properties and experimental conditions (Fig. 5(b)). The matching error with the other study27) is due to the absence of relative permeability data, which caused the simulated result to shift in waterflooding followed by surfactant flooding (Fig. 5(a)). However, the agreement in total oil recovery was lower at 0.32%. Given that Fig. 5(c) gave the better match, this was selected to investigate the effect of the adsorption/desorption mechanisms on production.

5. Sensitivity Analysis

To evaluate the effects of the slug injection parameters during actual oil production, we merged both the history match obtained for S1 (Fig. 4(a)) and that for coreflood (Fig. 5(c)). The sensitivity analysis was performed on a typical field scale 5-spot model, upscaled from the previous coreflood data29). The size of the model is 180 × 180 × 60 m divided into 30 × 30 × 10 grids in horizontal and vertical directions (x, y, z) respectively. The model is saturated with light crude oil with petro-physical properties similar to those of 33.5 °API, with initial pressure and temperature of 9.5 MPa and 60 °C. Three parameters were selected as follows: surfactant injection schedule, slug concentration and slug size. These parameters were selected based on the effects on the adsorption/desorption mechanism. All simulation models were operated for 30 years, which equivalent to approximately 1 PV of the entire reservoir.

5.1. Effects of Surfactant Concentration

Figure 6 shows the effect of SDBS concentration on oil production and reversibility. For consistency with the experimental results, we considered that the slug was injected before waterflooding at three concentrations (0.2, 0.5 and 1.0 wt%), after which low saline water (1.0 wt% NaCl) was injected.

The results showed that 1.0 wt%. SDBS causes high recovery of 74.6% as shown in Fig. 6, which was 16% higher than that achieved using lower concentration (0.5 wt%). These findings were consistent with
the experimental observations. Oil production at higher slug concentration is believed to result from the large amount of desorbed SDBS (83%), which increased the production by 2.9%, due to stable lower IFT during brine chasing as shown in Fig. 7.

Examination of the IFT profiles of candidate concentrations with 0.1 PV water chasing showed that IFT of 0.2 wt% was unfavorable for oil recovery, due to relatively less initial adsorption from the primary SDBS slug, then later desorption having little or no effect on IFT reduction. Increasing injection solution to 0.5 wt% resulted in relatively more adsorption, but lower desorption (41%) caused unfavorable IFT as for 0.2 wt%. Reversibility increased to 83% at 1.0 wt%, so the larger amount of desorbed surfactant greatly reduced the IFT of the reservoir, so improving oil recovery. Therefore, 1.0 wt% concentration was adopted for further investigation of the effect of various injection slug sizes.

5.2 Effects of Surfactant Slug Size

Figure 8 shows the effects of slug size, using 0.1, 0.2 and 0.3 PV without brine preflush to establish the validity of the present model with varied surfactant injection pore volumes.

Large volume of SDBS solution injection resulted in the highest recovery of 77.5% as shown in Fig. 8. This observation indicated higher desorption of SDBS. Under the same flooding conditions, reducing the slug volume from 0.3 to 0.2 PV or even 0.1 PV had a smaller effect on oil recovery. As larger volume of micellar solution during surfactant flooding promotes higher adsorption, the chase water probably returns more surfactant back to the oil phase within which a SDBS reserve is formed.

Figure 9 shows that after chasing with brine for 0.1 PV, the IFT of the SDBS reserve in smaller slugs decreases and behaves as waterflooding.

Therefore, the present range of IFT is inadequate to liberate residual oil. The SDBS reserve can maintain lower IFT after brine chasing for 0.2 PV and 0.3 PV. Consequently, increasing micellar slug size is advantageous not only during surfactant flooding but also post-waterflooding. As the IFT of the reservoir fluids can be maintained in the lower range for longer period, residual oil is relatively easier to liberate and recover along with injected brine.

5.3 Effect of Surfactant Injection Schedule

The timing of initiation of surfactant injection always affects the effectiveness of CEOR. In this study, we assumed two typical scenarios, micellar solution flooding was conducted at the beginning of operation (i.e. no preflush), and SDBS solution was injected after waterflooding. The simulations were conducted for the fixed concentration of 1.0 wt%. The results are shown in Fig. 10.

Micellar flooding without water preflush (Fig. 10(a)) and after waterflooding (Fig. 10(b)) does not much improve oil production if the reversibility is not considered. However, after accounting for the effects of reversibility, oil recovery was increased by 2.9% with no water preflush and 0.4% injection after waterflooding. Injection of surfactant solution without preflush water probably induced higher adsorption as the injected SDBS solution is free from dilution by pre-injected brine. This finding agrees with the experimental re-
sults which suggested that higher adsorption occurs with higher surfactant concentration. Desorbed surfactant after post-waterflooding then continues to maintain favorable lower IFT between the reservoir fluid phases. In contrast, injection of micellar slug at water breakthrough (WBT) causes dilution effects twice, initially by pre-brine injection and later by brine chasing.

Furthermore, micellar flooding without pre-brine injection leads to earlier initiation of oil production by 0.05 PV, with advantages to economic viability as faster oil recovery is always preferred. Slug injecting at the early stage is more sensitive to adsorption reversibility and benefits oil production, so is more suitable for surfactant flooding in which adsorption reversibility is selected for further study of other parameters of interest.

6. Ideal Injection Scenario

Sensitivity analysis revealed that by considering the effect of reversibility, injection would ideally be initiated at the beginning of operation with 1.0 wt% and 0.3 PV of micellar solution. Figure 11 compares the ideal injection with a simulated coreflooding result29).

Surfactant flooding at optimum conditions promoted oil recovery over actual injection by 24.2 %. This increase in oil production is due to the difference in micellar concentration (0.05 wt% in the actual case). As higher surfactant concentration induces lower IFT, the ideal injection with higher concentration will achieve better oil recovery. In addition, half of the injection volume (from 0.5 to 1 PV) was occupied by micellar solution in actual operation. Therefore, the
effect of reversibility was neglected. Therefore, ideal operation could minimize micellar solution injection time and improve oil recovery by accounting for the effect of reversibility.

7. Conclusion

The key findings of this study are summarized as follows:
(1) Adsorption of sodium dodecylbenzene sulfonate (SDBS) on Berea sandstone surface increased with concentration and plateaued at 1.0 wt%.
(2) Dynamic adsorption showed that reversibility of SDBS depended on the electrostatic attractions between the monomer active head and rock surfaces.
(3) Coreflooding suggested reversible surfactant adsorption occurs at 97, 41 and 83 % corresponding to 0.2, 0.5 and 1.0 wt%. This effect of reversibility promoted oil recovery factor by 2.9 % at 1.0 wt%.
(4) Decreasing micellar slug size from 0.3 to 0.2 PV and even 0.1 PV showed that the model was still valid to show the reducing effect of reversibility on oil recovery.
(5) Implementing surfactant flooding after water breakthrough, with large PV of surfactant, will achieve better oil recovery than either none or low surfactant flooding. However, reversibility is more pronounced with surfactant flooding without water preflush.

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Nomenclatures

\( A_d \) : adsorption of a component [gmol/cm\(^3\)]
\( A_{di} \) : adsorption of component \( i \) [gmol/cm\(^3\)]
\( A_{MAXT} \) : maximum adsorption capacity [gmol/cm\(^3\)]
\( A_{RT} \) : residual adsorption [gmol/cm\(^3\)]
\( c_{it} \) : mole fraction of a component in the water phase [-]
\( D_{wa} \) : water dispersibility [-]
\( D_{res} \) : desorption [gmol/cm\(^3\)]
\( q_{ws} \) : volumetric water flow rate in layer \( k \) [cm\(^3\)/min]
\( q_{wbs} \) : volumetric water flow rate through block face \( k \) to/from the adjacent aquifer [cm\(^3\)/min]
\( r_k \) : volumetric rate of reaction \( k \) [-]
\( x_{oi} \) : reactant stoichiometric coefficient of component \( i \) in reaction \( k \) [-]
\( s'_{oi} \) : product stoichiometric coefficient of component \( i \) in reaction \( k \) [-]
\( S_w \) : saturation of water phase [fraction]
\( T_w \) : transmissibility in the water phase [-]
\( Tad \) : Langmuir parameters [gmol/cm\(^3\)]
\( V \) : total volume of solid and water phases [cm\(^3\)]
\( w_{i} \) : water concentration [ppm]
\( \delta_{NaCl} \) : salinity of brine [ppm]
\( \Delta \phi_{i} \) : potential difference of water [-]
\( \Delta \phi_{i} \) : potential difference of water [-]
\( \phi_{i} \) : porosity [fraction]
\( \phi_{v} \) : void porosity [fraction]

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要害

ドデシルベンゼンスルホン酸ナトリウム（SDBS）を用いた採油増進における可逆特性の影響

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界面活性剤による石油増進回収（EOR）のキーとなる原理は、石油貯留層内の残存油と貯留水との間の界面張力の減少である。ただし、圧入された界面活性剤が貯留層の岩石マトリックス中に吸着されることが課題の一つとなっている。本研究では、岩石マトリックスへの界面活性剤の吸着および脱着（可逆特性と呼ぶ）が油回収率に及ぼす影響について実験および数値シミュレーションによって調べた。一般的に界面活性剤として用いられるドデシルベンゼンスルホン酸ナトリウム（SDBS）1％溶液をベレア砂岩コアに圧入してSDBSを飽和吸着させた後に1％の低濃度塩水を圧入する実験によって、飽和吸着量0.9 mg-SDBS/g-rockの83％が塩水中に戻ることが明らかになった。既往の界面活性剤吸着のコア試験やフィールド試験データを参照し、典型的なスリットパラメタ（種質油、貯留層面積：180 m × 180 m、厚さ：60 m）の数値シミュレーションを実施した。0.1 PVおよび0.3 PVの界面活性剤溶液スラグを初期油層に注入する数値シミュレーションに可逆特性モデルを適用した場合では、適用しない場合に比較して油回収率がそれぞれ2.3％および2.9％高くなる相違が得られた。一方、水洗法を適用した後の貯留層に界面活性剤を注入する場合の差は0.4％であると予測した。