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Experimental and Numerical Studies of EOR for the Wolfcamp Formation by Surfactant Enriched Completion Fluids and Multi-Cycle Surfactant Injection

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Abstract

Field observations and laboratory experiments have proven the possibility of production enhancement of shale oil wells through surfactant addition into completion fluid and perhaps, surfactant injection for EOR. This study numerically upscaled laboratory data for multi-stage hydraulic fracturing treatment and injection process proposed for the Wolfcamp formation. A combination of rock mechanic and reservoir numerical modeling was used to approximate the field-scale performance of both techniques. Novel completion fluid formulations and optimum surfactant injection schemes were designed, based on actual completion and production data.

Surfactant-Assisted Spontaneous Imbibition (SASI) experiments data for two surfactants investigated on the core-scale were upscaled to model production response of a hydraulically fractured well in Upton County, Texas, with realistic fracture geometry and conductivity. Core plugs were saturated and aged with their corresponding oil to restore the original oil saturation. Contact angle, interfacial tension (IFT), and zeta-potential were measured to investigate the role of capillary pressure for surfactant tests. We use a dual-porosity compositional model to determine the surfactant transport and adsorption.

With the proposed methodology, we show that lateral heterogeneity may limit both hydraulic fracture propagation and uniform distribution of EOR fluids, which cannot be ignored for the sake of simplicity. The primary production mechanism of aqueous phase surfactant EOR is wettability alteration and the reduction of IFT. Laboratory-scale SASI experimental results revealed that 2 gpt of surfactant solutions recovered up to 30% of the original oil in place (OOIP), whereas water alone recovered 10%. Capillary pressure and relative permeability curves were generated by scaling group analysis and history-matching the results of imbibition experiments on CT-generated core-scale model. On the next step, these curves were applied to surfactant completion and injection simulation models.

The field-scale model was achieved from history-matching actual well production data. We tested different soak times, injection pressure, and number of cycles in surfactant injection simulations to provide an optimum design for this scheme. Simulation results indicated that surfactant injection has further potential for higher recovery factor in addition to the incremental Estimated Ultimate Recovery (EUR) observed with application of surfactant as a completion fluid alone. Also, we investigated water-injection after primary depletion (water without surfactant) to provide another possible method for unconventional liquid reservoirs

(ULR). Instead of referring to Huff-n-Puff which implies gas injection, in this manuscript we use the terminology Multi-Cycle Surfactant-Assisted Spontaneous Imbibition (MC-SASI) to describe surfactant Huff-n-Puff for EOR.

This paper provides a complete workflow on SASI-EOR that has been evaluated in laboratory experiments, during the completion phase, and after primary depletion. In addition, we assessed the potential of water-injection after primary depletion in enhancing EUR. The numerical models were developed by accounting for geomechanics based on actual data combined with surfactant EOR laboratory experiments, field data, and industry-accepted simulators. A new modeling workflow for SASI-EOR is proposed to unveil the actual potential of surfactant additives.

Introduction

Unconventional shale reservoirs have contributed to a significant portion of oil production in the United States for the last decade. Multistage hydraulic fracturing along with horizontal well leads to the intense exploration and production in ULR. During completion treatments, hydraulic fractures interact with existing natural fractures to generate complex high-conductivity fracture networks in tight sandstone, carbonate and shale reservoirs. The multistage hydraulic fracturing revolution substantially enhanced oil production from ULR. However, the average ultimate recovery factor is still less than 10% OOIP. With the significant amount of oil left behind after primary depletion in ULR, it is necessary and valuable to apply EOR techniques to improve the ultimate oil recovery.

Gas injection EOR and the addition of surfactants into the completion fluid (SASI-EOR) techniques both have shown great potential to enhance oil recovery in ULR. Several researchers studied these EOR techniques through laboratory scale experiments and field-scale simulation. Alvarez and Schechter (2017) studied the effectiveness and mechanism of SASI-EOR through laboratory-scale experiments. The experimental results evidenced SASI-EOR can significantly enhance oil recovery from ULR core plugs. Several studies were published about the effectiveness of surfactant in stimulation fluids (Afra et al. 2019a, b; Nguyen et al. 2017; Wang et al. 2016). Saputra and Schechter (2018) investigated the SASI-EOR in the completion process using field scale numerical simulation. Simulation results agreed with experimental data that the SASI-EOR could improve the ultimate oil recovery in ULR. Gas injection EOR technique was also studied in the laboratory experiments using core plugs from ULR (Adel et al. 2018a; Adel et al. 2018b; Tovar, F. et al. 2018; Tovar, F.D. et al. 2018). Through huff-and-puff gas injection experiments, Adel et al. present the potential of gas injection EOR technique in ULR and demonstrate that recovery factors increase as pressure increases. (Zou and Schechter 2017) investigated the effectiveness of gas injection EOR in shale reservoirs using numerical simulation. In addition, Zhang et al. (2018a) studied the hybrid EOR technique (combining gas injection EOR with SASI-EOR) on core plugs from unconventional shale reservoirs. The hybrid EOR technique investigation opens a possibility to achieve optimum oil recovery in ULR.

Wettability is commonly defined as water-wet, intermediate-wet, and oil-wet in petroleum system, which is determined by the affinity of oil or water to spread on the rock surface. The fluid has a higher affinity toward the rock surface is defined as the wetting phase (Anderson 1987). In order to replace the wetting phase fluid from porous media, the driving force at least needs to be larger than the capillary pressure. Typically, the wettability of the Eagle Ford and the Wolfcamp shale reservoirs is oil-wet or intermediate-wet, which makes the production of oil from matrix more difficult when compared to water-wet reservoirs.

$$P_c = \frac{2\sigma\, cos\theta}{r} \tag{1}$$

Amphiphilic is a chemical compound which possesses both hydrophilic and hydrophobic properties. A surfactant molecule is an amphiphilic molecule, which has a hydrophilic head and hydrophobic tail. During hydraulic fracturing treatment, surfactant molecules interact with the rock surface in order to alter the wettability of the rock from oil wet to water wet and reduce the interfacial tension. Spontaneous imbibition is driven by capillary forces, which is defined by the Young-Laplace equation shown in Eq. 1, where σ is the IFT, θ is the contact angle, and r is the pore radius. Capillary pressure has a negative value in oil-wet reservoirs, meaning that water cannot spontaneously imbibe from the fractures into the matrix. Wettability alteration changes the sign of capillary pressure from negative to positive, attaining the capabality water replacing oil from the reservoir matrix. In addition, reduction in interfacial tension causes relative permeability curve shift. Lower IFT leads to relative permeability profile closer to straight lines (Schechter and Haynes 1992; Schechter et al. 1994). The effects of wettabililty alteration and IFT reduction can improve oil production in ULR.

Hydraulic fracture geometry significantly determines the accuracy of reservoir numerical simulation. A proper hydraulic fracturing simulator could provide more realistic fracture apertures and conductivity map by accounting for rock mechanics, fluid flow and proppant transport (Kou et al. 2018a, b). The primary challenge is to couple all available information related to rock properties and reconstruct reservoir depletion model. Physics-driven flow models attempt to solve this problem and make significant progress in the completion designs.

Wolfcamp A and B are common primary targets for drilling in the Midland Basin today, but previously there were attempts to test the deeper Wolfcamp-C formation previously described in (Parsegov et al. 2018a; Parsegov et al. 2018b). The primary source of underperformance was a high watercut with effective fracturing design and created conductivity.

In this manuscript, we focus on SASI-EOR in both laboratory-scale tests and field-scale numerical simulation as well as water-injection after primary depletion. Complete and systematic laboratory workflows were developed to test SASI related properties on performance in enhancing oil recovery on shale core plugs. We performed contact angle and interfacial tension measurements as well as SASI experiments to evaluate the effectiveness of surfactants in SASI-EOR. Then, core-scale simulation models were generated using CT-scan technology to run history-match on the laboratory data. The capillary pressure curves for the imbibition process were constructed from scaling group analysis, while the relative permeability profiles were built from the history-matching process. These two sets of curves were applied to our field models. Next, hydraulic fracture geometry and conductivity maps were created using commercial simulators which considers rock mechanics, fluid flow and proppant transport. Then, field-scale models were developed based on the hydraulic fracturing model results. Next, we validated and determined the properties of our field models by history-matching actual production data. Finally, we investigated the efficiency and economics of four EOR strategies on the field-scale model, which includes (1) the addition of surfactant into completion fluid, (2) surfactant-injection, (3) water injection after primary depletion, and (4) surfactant MC-SASI after initial depletion.

Methodology

The primary objective of this study is to assess the impact of EOR techniques (SASI-EOR in the completion process, surfactant injection and water injection after primary depletion) on improving the ultimate oil recovery in ULR. To generate reliable field-scale simulation models, we considered pumping schedules, proppant load, and geomechanical data to construct gridding of hydraulic fracture system. Other parameters were determined by history-matching real production data of the well. We estimated the oil production enhancement of SASI-EOR by upscaling laboratory data to the field. The capillary pressure and the relative permeability profiles were generated by scaling group analysis and history-matching of our experimental results.

The comprehensive workflow of this study comprises of four parts. First, laboratory experiments were performed to achieve all the information related to SASI-EOR. Second, core-scale models were constructed from CT-images to history-match the experimental data. Third, hydraulic fracturing model was created based on rock mechanics, fluid flow and proppant transport to obtain the fracture geometry and the conductivity distribution. Lastly, the field-scale model was generated by considering all the information from the previous three steps and history-matching field production data. In addition, we investigated different EOR scenarios through numerical simulation.

Experiment Procedures

Laboratory-scale SASI study includes different experimental tests, including contact angle, interfacial tension, zeta-potential, surfactant adsorption, CT-scan, and spontaneous imbibition experiments. This set of experiments provides enough information to evaluate surfactant performance in ULR. The experimental results serve as the basis for field-scale simulation.

To ensure the representability and the accuracy of SASI laboratory experiments, the sidewall core plugs and oil samples were retrieved from the same Wolfcamp well. We followed a robust workflow of core plug preparation procedure to restore the cores to their original reservoir conditions. Rock samples were cleaned using the Dean-Stark method and were then vacuum dried. After cleaning and drying process, we saturated the core plugs with the reservoir oil under 10,000 psi for over three months until ultimate oil saturation was reached. Core samples were weighted and CT-scanned periodically throughout the duration of the aging process. Original Oil In Place (OOIP) of each core plug was determined by through the weight difference before and after the saturation process.

In this study, wettability was quantified by measuring the contact angle under aqueous-oleic-solid phases conditions. Captive bubble method was utilized to measure the contact angle for the determination of wettability. We used aged rock chips from sidewall core plugs as rock medium for wettability tests. Contact angle measurements were performed under reservoir temperature, which is 155 °F for the Wolfcamp samples. The picture of the oil bubble placed on the rock surface was captured using a high-speed camera; then the contact angle can be calculated from the image. Interfacial tension was measured using the same device as contact angle with different setups. For the interfacial tension determination, oil-water IFT was measured using the inversed pendant drop method. An oil bubble is slowly dispensed upward into a cuvette filled with the aqueous-phase at reservoir temperature. Then, the interfacial tension is calculated from the image of the oil bubble as it is precisely about to detach from the needle.

Zeta-potential measurements were performed to estimate the surface charge and the charge of surfactant solution. Special sample preparation needs to be conducted for each zeta-potential measurement. Rock samples from sidewall core plugs are pulverized and filtered by ASTM #325 sieve, which filters out the rock powder larger than 45 μm.

Surfactant adsorption is a significant parameter in this study, which determines the wettability alteration of the rock surface. Adsorption also plays a significant role in reservoir simulation. Surfactant adsorption measurements were performed using UV spectroscopy, which measures the concentration of surfactant solution with a calibration curve constructed beforehand. Surfactant adsorption is quantified by the difference in surfactant concentration in the solution before and after the contact of rock samples.

SASI experiment is a direct method to evaluate surfactant performance in enhancing oil recovery in core scale. Modified Amott cells were utilized for SASI experiments, and SASI tests were conducted at reservoir temperature. Typically, core plugs were submerged into an aqueous phase solution until reached the ultimate oil recovery. Spontaneous imbibition experiments were periodically CT-scanned throughout the duration of the tests. CT images can be used to demonstrate fluid movement inside of the rock. In this study, we tested three fluid system, including two different types of surfactant solution and distilled water (base case). The concentration of surfactant solution is 2 gpt.

Further details about the procedure of SASI related experiments in this study are available in (Alvarez et al. 2017a, b; Alvarez and Schechter 2016).

Capillary Pressure and Relative Permeability Curves

Capillary pressure and relative permeability curves are critical inputs for numerical simulation, especially for SASI-EOR simulation. The interaction of surfactant with the oil-water-rock system alters the wettability of the rock surface from oil-wet to water-wet and causes IFT reduction. These two effects lead to the transformation of the capillary pressure and the relative permeability curves, leading to improvement of oil production and water imbibition into the matrix. A reliable set of these two curves not only can simulate fluid flow in the reservoir close to real state but it also increases the accuracy of predicting SASI-EOR performance in the field. In this study, we estimated the capillary pressure profiles from scaling group analysis of experimental data and generated relative permeability curves from history-matching the oil recovery of laboratory-scale SASI experiments.

Capillary pressure curves were generated based on our previously proposed scaling group analysis. The scaling group is defined in Eq. 2, which considers the Young Laplace equation and oil recovery measured from SASI experiment. This capillary pressure generated method was designed based on our laboratory measurements and validated by history-matching experimental results using core-scale model. Further details about this scaling group and capillary pressure generation are available in (Zhang et al. 2018c)

$$P_c\mathrm{T} = \mathrm{t}\frac{2\sigma\ cos\theta}{\sqrt{\frac{k}{\emptyset}}} \tag{2}$$

Relative permeability curves were determined from history-matching results through core-scale simulation model. The relative permeability curve generated from history-matching SASI experiment with water alone was defined as the initial relative permeability in the matrix.

To improve the accuracy of the relative permeability curve, we created the core-scale model by considering the heterogeneity of the shale core plugs. CT-scan technique was utilized in setting the porosity for each grid block of the core-scale model. Other parameters of our core-scale model were obtained from experimental measurements or logging information. Further details about the core-scale model are available in (Saputra and Schechter 2018).

Hydraulic Fracturing Model

To model the application of EOR methods on the field scale, the reservoir model was constructed through the utilization of a physics driven hydraulic fracturing model (Parsegov et al. 2018b; Parsegov and Schechter 2017).

Fracture modeling workflow includes the following steps:

1. Importing well survey, casing, and perforation designs;
2. Building a grid-based model of rock properties from logs and geological correlations;
3. Importing actual or planned pumping schedules, type of fluid, and proppant add-ups;
4. Running fracturing simulations and history-matching of treatment pressure data.

Effective conductivity in [mD·ft], calculated with conductivity losses mechanism, was exported for each transverse fracture plane. Conductivity losses from laboratory measurement API proppant pack permeability under closure stress at anticipated drawdown were taken into account. After that, the baseline conductivity attribute for each fracture was imported into a commercial reservoir composite simulator.

It can be inferred from Fig. 8 that the effective fracture half-length defined by conductivity cutoff is significantly smaller than fracture half-length derived from that of proppant placement. Fractures exhibit limited height (~100 ft), despite the large volumes of fluid pumped.

Smaller, than expected from proppant concentration map, fracture half-length creates local pressure drawdown during production and changes the efficiency of the proposed EOR techniques. As we will explain later, we proposed repressurizing EOR with or without surfactant is the most effective in the case of understimulated legacy well drilled into formation with high initial watercut.

Previous observations of pressure depletion, assuming a hundred nanodarcy range of matrix permeability leads us to the idea of enhanced permeability region. In this paper, we extended this approach and used a dual-porosity model to capture early and late time production data. It is essential to take into account the proppant embedment and cruising, imperfect gel breakdown, and other damaging mechanisms. Multiphase flow, however, was modeled inside the reservoir simulator with realistic relative permeability curves.

Field-scale Modeling

The field-scale reservoir model was constructed by combining the results of laboratory experiments, scaling group analysis, and core-scale history-matching simulation, surfactant adsorption isothermal, capillary pressure curves, and relative permeability curves. The gridding structure of the field-scale model was based on results of hydraulic fracturing model. SASI modeling algorithm used on the core-scale model was also applied to the reservoir model to represent the mechanism of SASI in the field-model. The orientation, position, and perforation location of the well were determined based on real well data. All the other parameters regarding the model were obtained from the history-match process of the corresponding well production data.

Physics-driven hydraulic fracturing simulation results provided the conductivity distribution for each grid block of the hydraulic fractures. We assigned permeability for each hydraulic fracture grid depending on the conductivity distribution in order to achieve a more accurate and realistic hydraulic fracture system (Rubin 2010). The permeability distribution of hydraulic fractures is presented in Fig. 1.

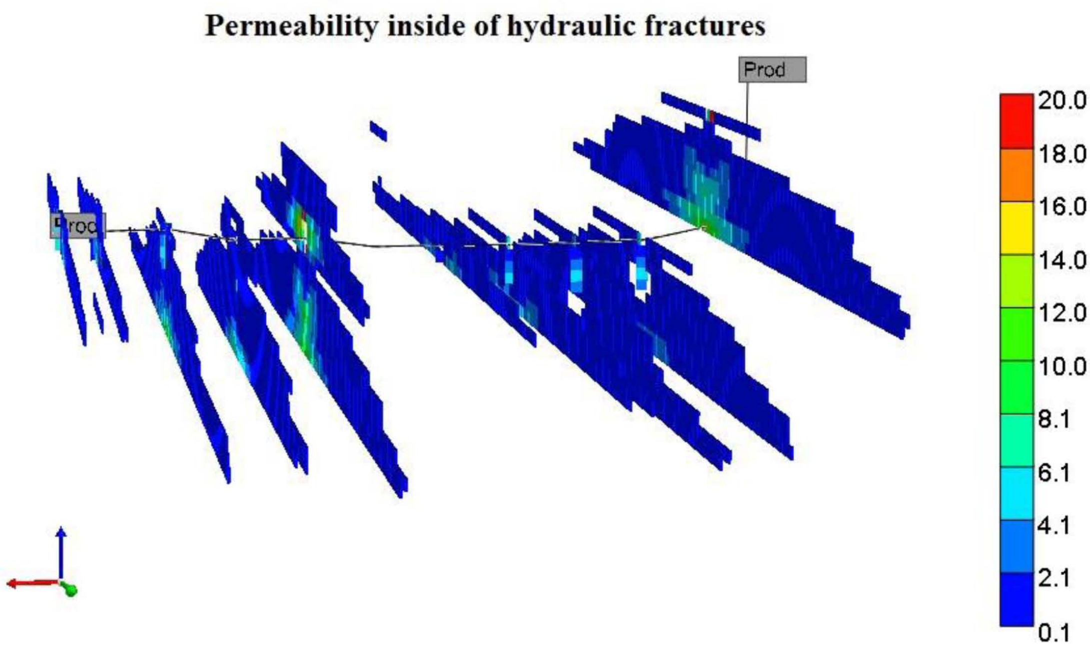

Figure 1—Equivalent permeability (md) inside of hydraulic fractures based on effective fracture conductivity shown in Fig. 8.

To decrease the total grid number and ensure the accuracy of the simulation results, we refined the grids around hydraulic fractures and utilized a mixed gridding structure. The grids around and inside of hydraulic fractures are equally distributed in all three directions (X, Y, Z). I direction is along the wellbore, and J direction is along hydraulic fractures. Other grids are constructed using a logarithmic distribution, the ratio of two grids next to each other is less than 1.5. The gridding structures of all three dimensions are depicted in Fig. 2.

Allocation of production from each fracture stage was approximated by analyzing previously-published tracing data (Parsegov et al. 2018a). Traced segment ‘5-2’ (Stages 2-5) indicated a 13.1% contribution from normalized oil-soluble tracer flowback. The average contribution for each stage was 3.28%, compared to Stage 16 which had 3.4% contribution to flowback. We conclude that, surprisingly, oil and water production from each tracer segment is almost the same.

Two neighboring stages out of the total 30 stages were modeled to reduce the simulation run time. Production was normalized and assigned correspondingly for history-match purposes. This cropped reservoir model has the dimension (X, Y, Z) of 600 ft, 2,000 ft, and 200 ft with the fracture half-length of 500 ft along the Y direction.

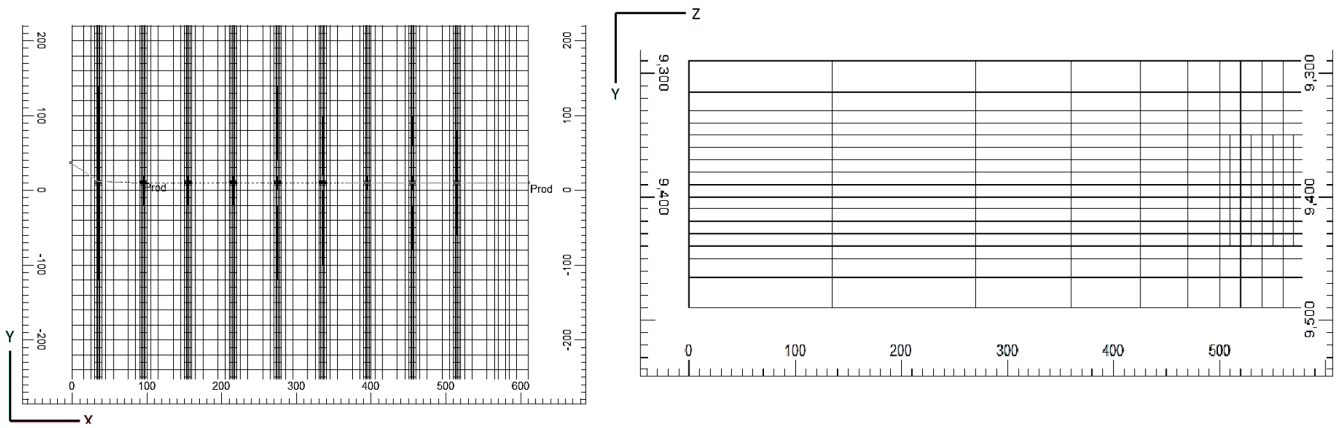

Figure 2—Gridding structure for all three directions.

On this reservoir model, the history-matching process was executed to obtain all the undetermined parameters in the field-scale model. Then, four different shale EOR scenarios: SASI in the completion, SASI-injection, water-injection after primary recovery, and MC-SASI after initial depletion, were tested. Multiple control variables in direct connection to this EOR mechanism were also investigated to observe the effect of each on the efficacy of the method.

Results and Discussion

Three different fluid systems, water, Surf1, and Surf2, were tested during the experimental workflow. Laboratory experiments consisting of contact angle, IFT, zeta potential, surfactant adsorption, and SASI experiments were performed, and the results are presented in the first section. Then, we discuss the construction of the capillary pressure curve from dimensionless scaling group analysis and determination of relative permeability curves from CT-assisted core-scale modeling. Next, the two curves and the field-scale model were validated by history-matching either laboratory results or real production data. Finally, the potential of the four EOR techniques including SASI-EOR in the completion, water-injection, and SASI-injection, and MC-SASI are investigated through reservoir simulation.

Laboratory Experimental Results

The first part of this work is the laboratory experiment assessment of the three fluid systems. Five different measurements were done on the tested fluids, comprise of contact angle, interfacial tension, zeta-potential, surfactant adsorption isotherm measurement, and SASI experiment. The rock and oil samples used in these measurements were retrieved from the same Wolfcamp formation. Contact angle, IFT, and zeta potential results are presented in Fig. 3.

Contact angle measurements were performed on the rock sample before and after surfactant contact. The results of contact angle measurements present a significant wettability alteration occurred on the two rock samples tested in surfactant solutions. Initial wettability of the rock sample was observed to be in the oil-wet region as all of the contact angles are above 105°. After contact with surfactant Surf1, contact angle decreased to 30°, while contact with Surf2 reduced the contact angle value to 55°. The addition of surfactant altered the wettability of the rock from initially oil-wet to water-wet with Surf1 performed a more pronounce alteration compared to Surf2.

Interfacial tension measurement was performed, and the results are presented in the middle figure of Fig. 3. As expected, the amphiphilic nature of the surfactant molecule reduces the interfacial tension between oil and water as it bridges the polar and non-polar molecule of oil and water. Interfacial tension was reduced to 0.1 mN/m with Surf1 and to 10 mN/m when Surf2 was present in the solution.

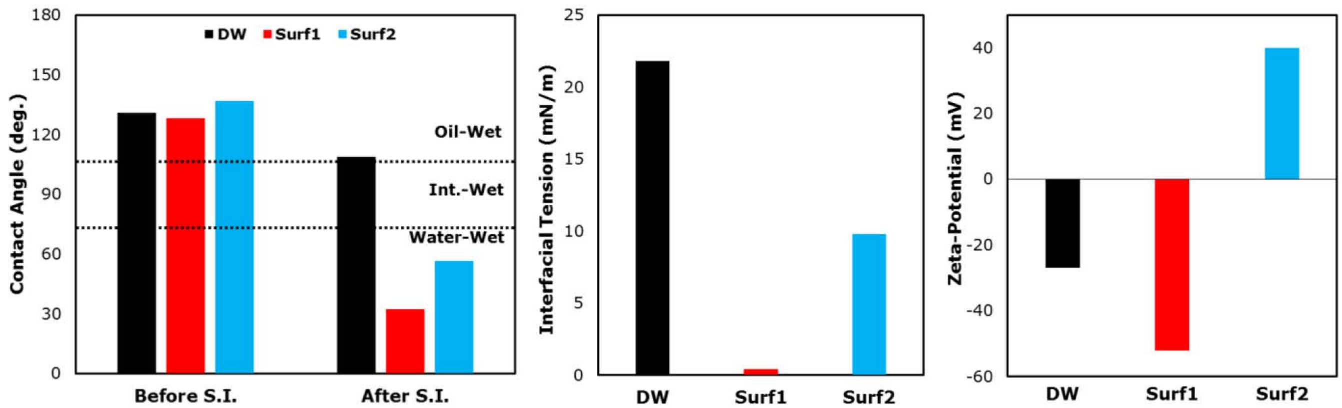

Figure 3—Results of contact angle (left), IFT (middle), and zeta-potential (right) measurements.

Zeta potential results are shown in the right figure of Fig. 3 reveal that the surfactants improve the stability of the double layer on the rock surface as the absolute value of zeta-potential has a positive trend with the stability of the double layer.

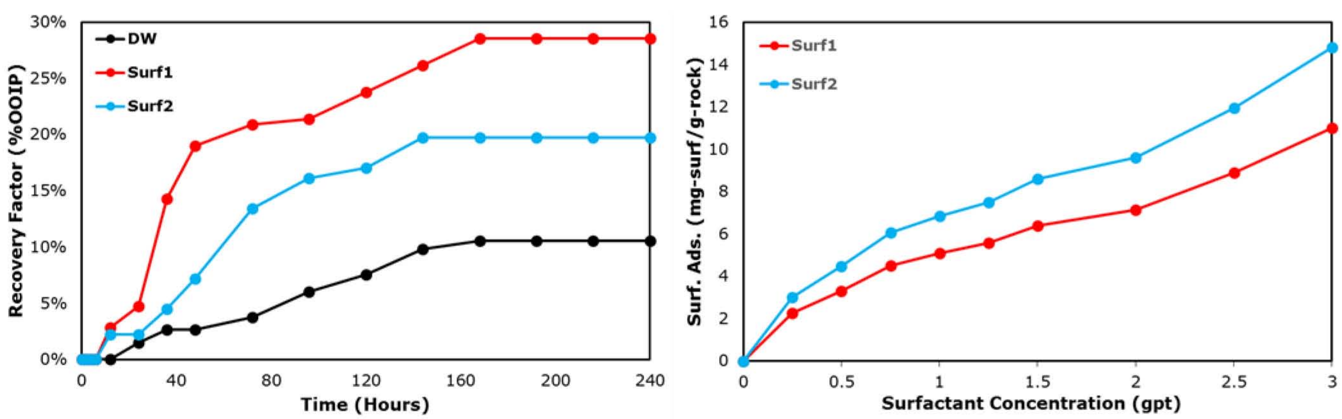

Figure 4—Results of surfactant adsorption isotherm measurement (left) and oil recovery from SASI experiment (right).

Spontaneous imbibition experiment was executed on all three tested fluid systems. We evaluate the effectiveness of surfactants by comparing the ultimate recovery factor. The SASI experiments were run for ten days, and the time-lapsed oil recovery was recorded throughout the duration of the experiments. The results of SASI tests are presented in Fig. 4. The recovery factors of both surfactant cases are higher than the base case. The SASI experiment results present that the addition of surfactants results in a significant improvement of oil recovery. A proper selection of surfactant is also highly essential as disparity was observed when comparing the recovery factor of the two surfactant cases. Surf1 had a stronger wettability alteration capability and produced more oil from the SASI experiment than Surf2. This finding indicates that wettability alteration capacity may act as a more dominant control of surfactant performance compared to IFT. More details about the surfactant selection in ULR are presented in (Zhang et al. 2018b)

Surfactant adsorption isotherm was also measured with the result shown in the right figure of Fig. 4. Adsorption of each surfactant is required for both the core-scale and the field-scale model. It controls the amount of capillary pressure and relative permeability modification. The results of adsorption present that more Surf2 was absorbed on the rock.

Capillary Pressure Determination

The capillary pressure curve is a critical input for any numerical simulation model. To ensure the accuracy of the capillary pressure curves, we estimated the capillary pressure profiles for all three fluid systems by using a scaling group analysis of experimental data. The estimated capillary pressure curves of each fluid systems are presented in Fig. 5. The generated capillary pressure curves were applied to the core and field-scale models and validated from history-matching oil recovery of SASI experiments using core-scale model. The details of this capillary pressure generation method are available in (Zhang et al. 2018c).

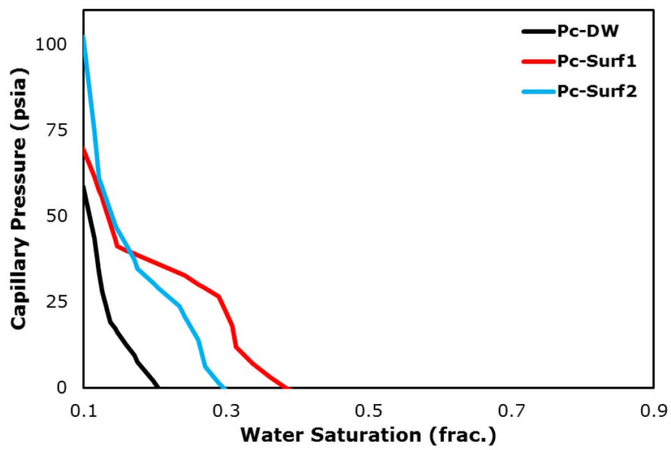

Figure 5—Capillary pressure curves of all three fluid systems from scaling analysis.

Fig. 5 depicts the ultimate recovery factor from imbibtion experiment controls the intersection of the curve to the water saturation axis with the intersection of Surf1 is the furthest to the right, followed by Surf2 and DW. On the other hand, the maximum capillary pressure of the surfactant cases was observed to be in relation to the measured IFT, with higher maximum pressure observed from Surf2.

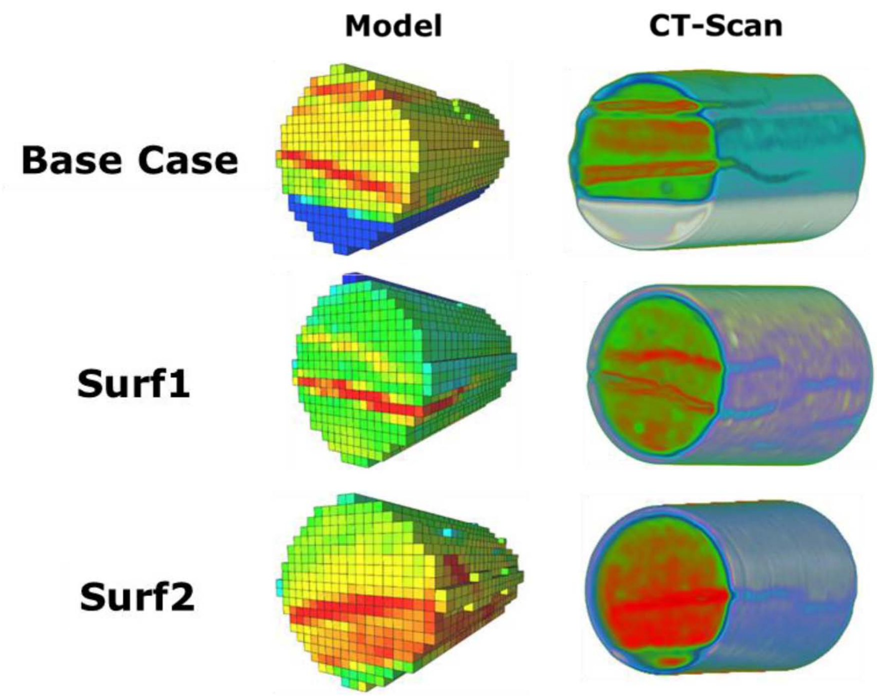

Figure 6—Comparison of the 3D CT-scan image and core-scale model.

Core-Scale Model and Relative Permeability Curves from History-Matching

Previously, the capillary pressure was constructed through scaling group analysis with the result presented in Fig. 5. The next part of this work is to construct the relative permeability curves of each fluid system as both capillary pressure and relative permeability are needed to execute the field-scale model of SASI implementation. The construction of relative permeability was done by modeling the imbibition experiment and history-match the oil recovery as observed by trial-and-error of relative permeability curves. With the highly-heterogeneous nature of shale core samples, the integration of this heterogeneity into the model is highly essential to ensure the accuracy of the relative permeability curve that will be obtained from this step. Incorporation of heterogeneity was done by converting CT images of the three core plugs used on the imbibition experiments in clean condition. CT image is fundamentally a map of the density of the core plug, the idea of the method is to convert the density to porosity which then also results in permeability. More details on the conversion process are presented in (Alvarez et al. 2017b; Saputra and Schechter 2018). Comparison of conversion product to the real rock is presented in Fig. 6. From this figure, it can be clearly seen the high degree of heterogeneity by comparing the three different plugs used for the three imbibition experiments and even from looking at a single plug, indicating the significance of incorporating heterogeneity into the core-scale numerical model. Multiple features of the high flow path, as well as a change in bedding plane observed in the CT images of all core plugs, are accurately modeled in the numerical grid model.

Initialization of the core-scale model was established to mimic the laboratory condition accurately. Core plug grid model shown above was positioned in the middle of three different water bath with three different fluid, corresponding to the fluid of where each core plug was submerged on the imbibition experiment. Similar to the laboratory condition, surfactant was only present outside of the core plug. All core plugs initially had the base case relative permeability and capillary pressure when the simulation initialized. As more aqueous-phase imbibed into the rock, alteration of the two curves occurred. The degree of alteration of the two curves was controlled by the amount of surfactant adsorbed on each grid block. This surfactant modeling algorithm was incorporated as it was believed to be the most accurate method to depict the effect of surfactant addition into the oil-water-rock system.

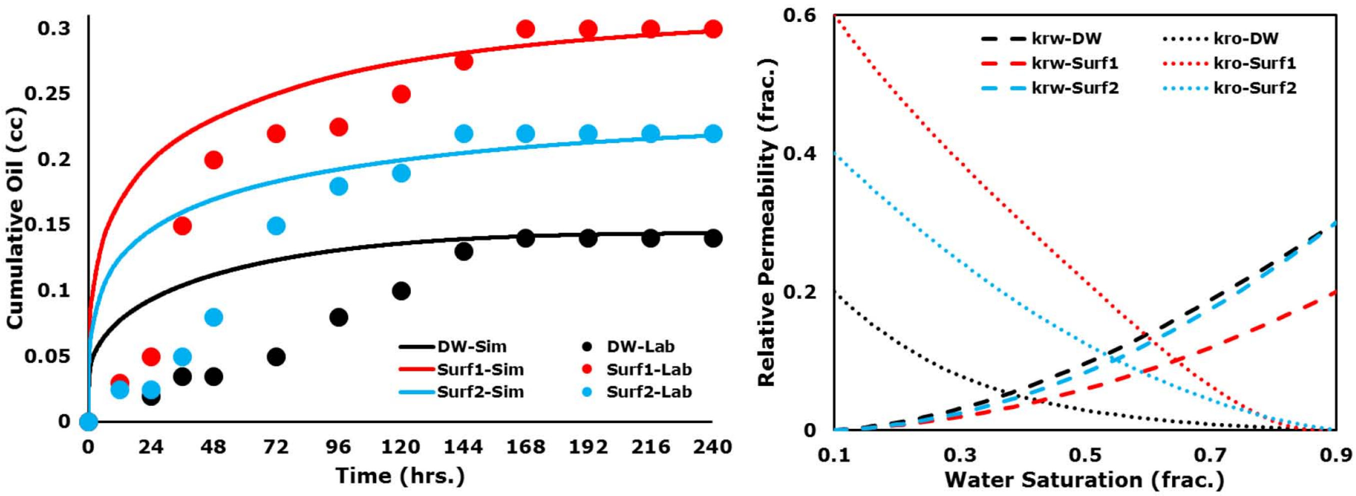

Figure 7—The history-matching results of all three SASI experiments (left) and corresponding relative permeability curves (right).

History-match was performed on each of the imbibition experiments with the relative permeability curve as the control variable. Numerous curves were fed into the model and oil production from each case was compared to the recovery curve obtained from the laboratory experiment. IFT and contact angle value were considered in the design of the relative permeability curves to ensure the physical possibility of such curve and also to cut the duration of history-matching as an educated guess would reduce the number of curves investigated. The results of this history-matching are presented in Fig. 7 with the best-match oil recovery curve presented in the left figure and the corresponding relative permeability curves shown in the right figure. Three oil relative permeability as well as three water relative permeability were obtained from this step and will be fed into the field-scale model in combination with the capillary pressure curve constructed previously. An apparent relation between relative permeability and measured IFT was observed where a fluid system with lower IFT also had higher maximum relative permeability. It is important to note that although that good match between the laboratory data and the simulation data was observed on the later time on all three fluid systems, the same cannot be said for the early time. Over-estimation of oil recovery on the early time could be caused by the adherence of oil bubble to the core plug after being expulsed out from the pore space which is often observed but was not able to be modeled by the simulator.

Hydraulic Fracturing Results

The field-scale reservoir model was constructed using conductivity distribution from the result of a physics-driven hydraulic fracturing model. We developed a hydraulic fracturing model for this study following our fracturing modeling workflow, which was stated in the methodology. The effective conductivity attribute for hydraulic fractures was achieved from hydraulic fracturing simulation. Fig. 8 presents the conductivity attribute for each stage, and the zoomed-in was used to develop the field-scale model. This conductive information was extracted from hydraulic fracturing simulation and converted to the dual-porosity field-scale model to describe the heterogeneity of hydraulic fracture properties.

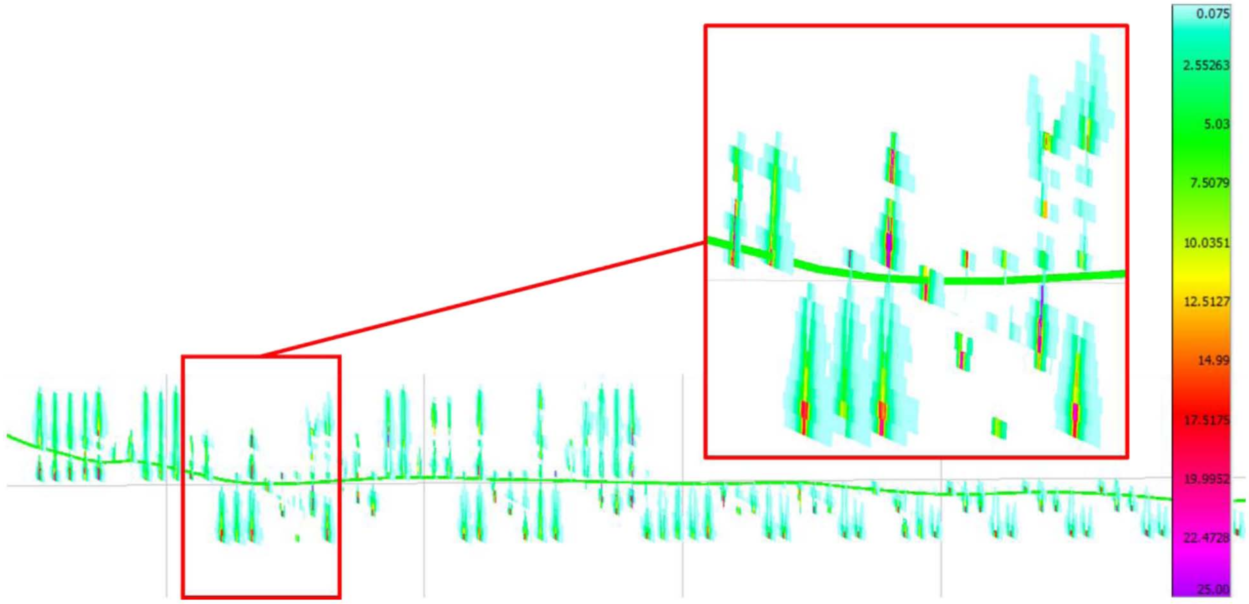

Figure 8—Effective conductivity [mD·ft] for the well with zoom in Stages 4 and 5.

Field-Scale Model

Comprehensive work has shown previously in combining laboratory-work, dimensionless scaling group, core-scale numerical simulation, and physics-driven hydraulic fracturing simulation ultimately resulted in the field-scale model shown in Fig. 9. We randomly picked two adjacent hydraulic fracture stages to construct our field-scale model. Because the well has 30 hydraulic fracturing stages, the field-scale simulation results need to be multiplied by 15 to represent the production data for the entire well. The dimensions of the field-scale model are 600 ft by 2,000 ft by 200 ft with a combination of homogenous and logarithmic gridding to save computational time while still maintaining accuracy. Fig. 9 shows that each stage has five clusters and two or three hydraulic fractures were suppressed by stress shadow effect, which is consistent with reality. In order to consider the impact of natural fractures that are commonly found in the Wolfcamp formation, we developed the field-scale reservoir model using the dual-porosity model.

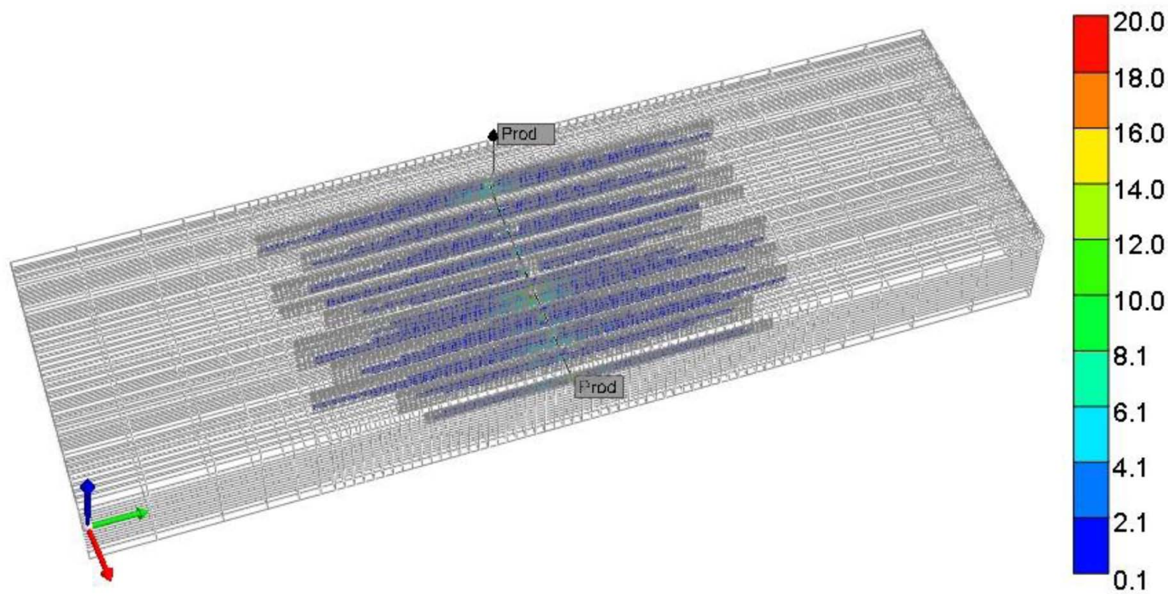

Figure 9—Gridding structure and permeability distribution of the field-scale.

In spite of the lengthy process of incorporating multiple analysis to provide the required data for the field-scale model, several important variables were still not yet established. For instance, the permeability and porosity of the natural fracture system are two of the unknown variables. Another history-matching process was incorporated, field production data of the corresponding well was retrieved and applied as the objective of the history-matching process. Cumulative oil and water production were matched by modifying several variables on the field-scale model with the best-matched scenario presented in Fig. 10 and the reservoir properties from the shown case presented in Table 1.

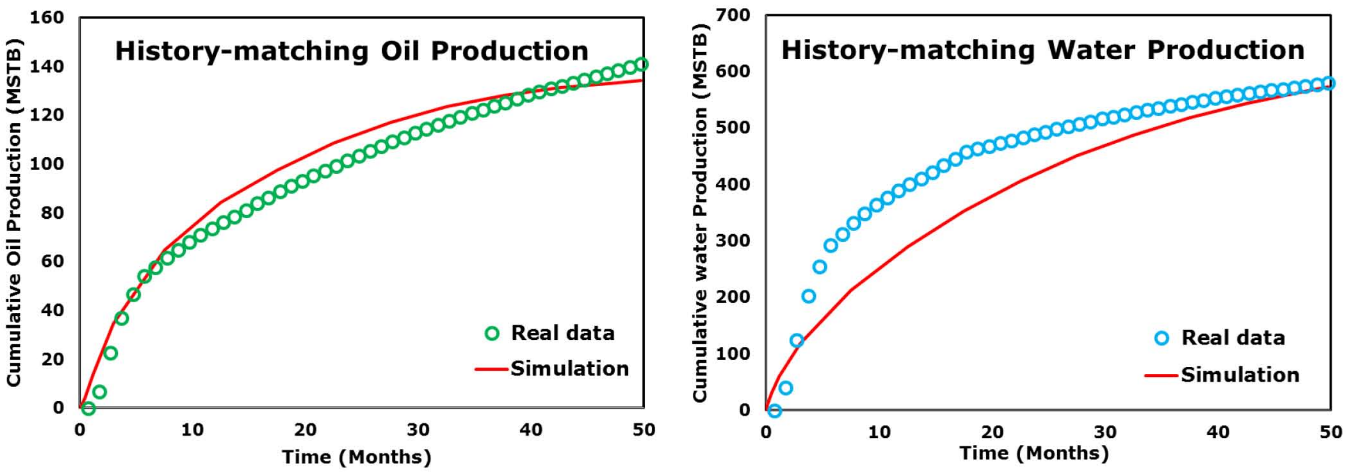

Figure 10—The history-matching results of the field-scale model to the real oil (left) and water (right) production data

The global error of history-matching oil production is less than 4%, and the 4-years cumulative oil production error is less than 1%. When history-matching the cumulative water production, the global error between the simulation results and the actual production data is less than 10%, and the 4-years cumulative oil production error is less than 1%. Based on the history-matching results, the field-scale model is capable of representing real reservoir conditions. The field-scale model provides convincing simulation results for investigating different EOR scenarios.

Table 1—Reservoir properties of the field-scale model

Reservoir Property	Value	Reservoir Property	Value
Thickness (ft)	200	Hydraulic fracture half-length (ft)	500
Matrix porosity	5%	Fracture spacing (ft)	0.5
Fracture porosity	0.05%	Water saturation	0.45
Matrix permeability (nd)	150	Initial pressure (psi)	5,500
Fracture permeability (md)	0.04	Temperature (°F)	155

SASI-EOR in the Completion Process

Three methods of SASI applications were investigated in this work, SASI in the completion, SASI-injection, and MC-SASI. In addition, one case of water without surfactant was also a part of the study. All four methods were tested on the field-scale model explained in the previous section.

The first SASI application to be explored is the application of SASI as a part of completion design. Integration of SASI in the completion design is completed by adding a properly-selected surfactant into the fracturing fluid. Interaction of surfactant and oil-water-rock system observed in the laboratory experiment should be able to improve production of the well when compared to the base case of no surfactant added into the completion fluid. In this study, this method is explored by the trial of four surfactant concentration with two different surfactants and comparing the results to the base case or the best-matched case from the field-scale history-matching. In addition to concentration, soak time was also varied to observe its effect on the well performance. Oil production rate and cumulative oil production were chosen as the two factors to indicate the performance of this method and the effect of all tested variables.

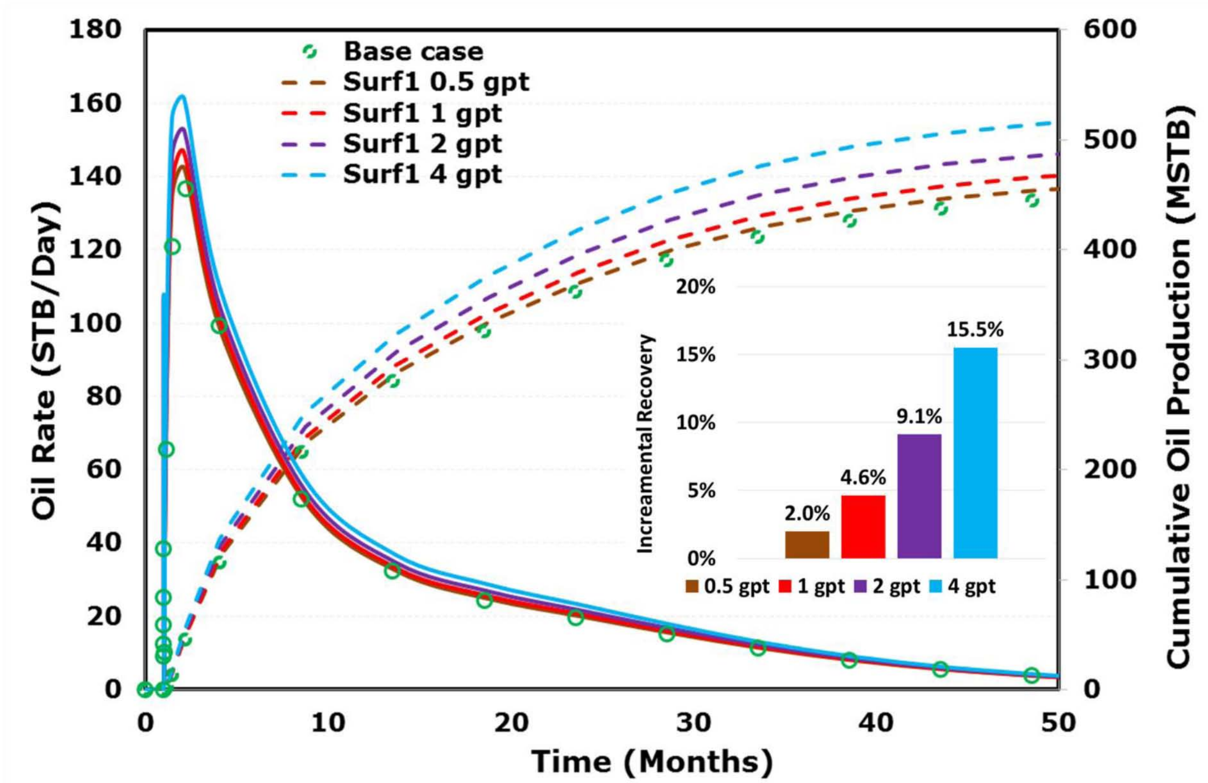

Figure 11—Simulation results of cumulative oil production, recovery incremental and oil rate for different concentration of Surf1 in the completion fluid

The addition of Surf1 and Surf2 to the completion fluid resulted in improvement of oil recovery in both peak oil rate and cumulative production with higher concentration implicates on even better improvement as shown in Fig. 11 and Fig. 12. Four surfactant concentrations, 0.5, 1, 2, and 4 gpt were tested on both surfactants. The better performance of Surf1 as observed in the laboratory experiment translates to the field-scale result as higher oil production on all surfactant concentration tested were observed on Surf1 compared to Surf2. For 0.5 gpt concentration, Surf1 improved cumulative recovery 20 times better than Surf2, indicating the importance of proper surfactant selection when a minimal amount of surfactant is allocated to be added into the completion fluid. The performance improvement associated with surfactant concentration was analyzed, and roll-off characteristics were observed. Although the continuous increase in surfactant concentration in the completion fluid results in higher recovery, the increase does not follow a linear trend. As some commercial surfactants come at a pretty significant price, it is highly essential to combine economic analysis with field-scale numerical simulation to find the optimum surfactant concentration for the completion fluid.

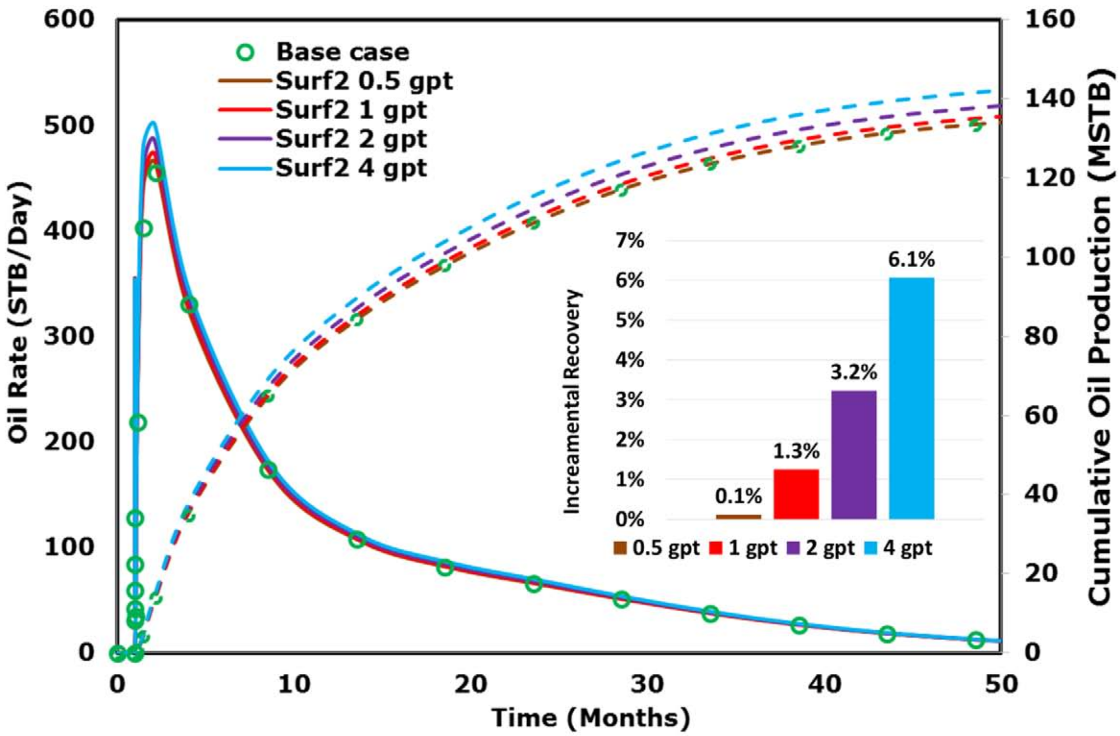

Figure 12—Simulation results of cumulative oil production, recovery incremental and oil rate for different concentration of Surf2 in the completion fluid

The impact of soak time for SASI EOR in the completion process is then investigated, and the results are presented in Fig. 13. Soak time is defined as the time between the end of completion and the start of production where the well is in shut-in condition. Soak time allows capillary pressure to play a role in the production as water imbibed into the matrix and the replace the oil. The different soak times tested are 5 days, 15 days, 1 month, and 2 months. The concentration for the surfactant was kept constant at 2 gpt for all cases. From the results of Fig. 13, the longer soak time lead to the higher oil cumulative recovery.

Based on the simulation results, the addition of surfactant into completion fluid shows great potential for enhancing oil recovery in ULR. The surfactant also improves the flow performance of fluid in the fracture system which also leads to better well performance. Surfactant concentration and soak time control the efficacy of this method with higher concentration and longer time correlates to better well performance. In this study, the surfactant concentration needs to be higher than 2 gpt to achieve an economic oil production improvement in high initial water saturation reservoirs. A large amount of water contained in the reservoir may dilute the surfactant concentration that decreases the impact of the SASI EOR in ULR. In addition, a minimum soak period of one month is recommended during SASI EOR for optimum performance.

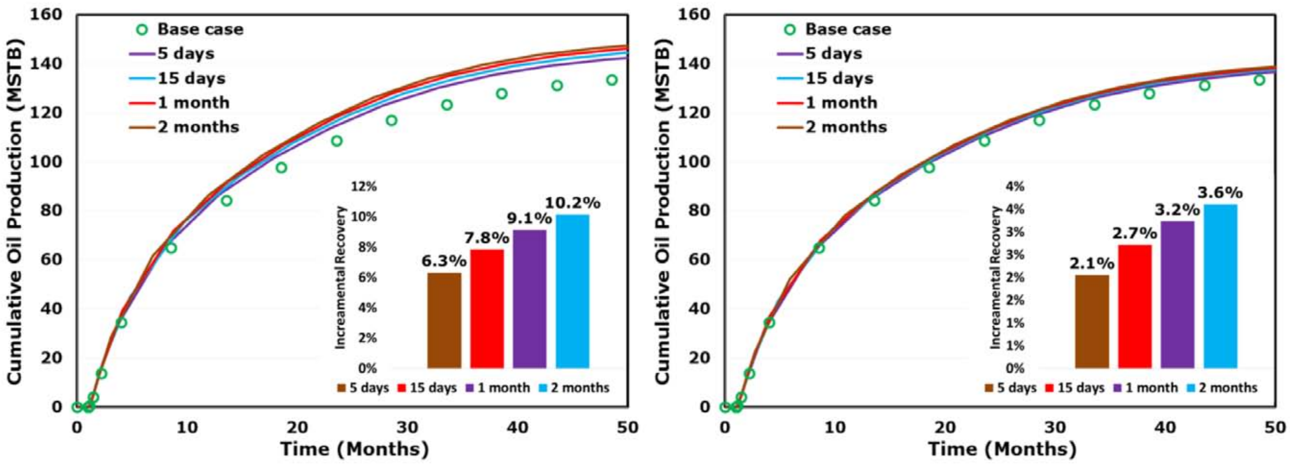

Figure 13—Simulation results of cumulative oil production and incremental recovery for different soak time using Surf1 (left) and Surf2 (right)

Water-Injection after Primary Depletion (Water without Surfactant)

The first after primary depletion recovery enhancement method tested was through the injection of water without any surfactant added into the injected fluid. The primary mechanism of this method is the pressure build-up through water injection. As mentioned before, the driving mechanism of shale oil reservoir is the expansion of oil due to pressure drawdown. In a conventional reservoir, this driving mechanism is well-known as the least efficient mechanism. Shale reservoirs are characterized by ultra-low permeability and relatively weak communication. During primary depletion, the pressure of the matrix around the hydraulic fracture system decreases to the wellbore's pressure. However, the matrix far from the hydraulic fractures maintains a high pressure (close to initial reservoir pressure). Injection of water was investigated as a test of whether re-energizing the depleted shale oil reservoir could provide any incremental in recovery. Water-injection following primary depletion could have a significant impact in improving oil production by repressurizing the reservoir.

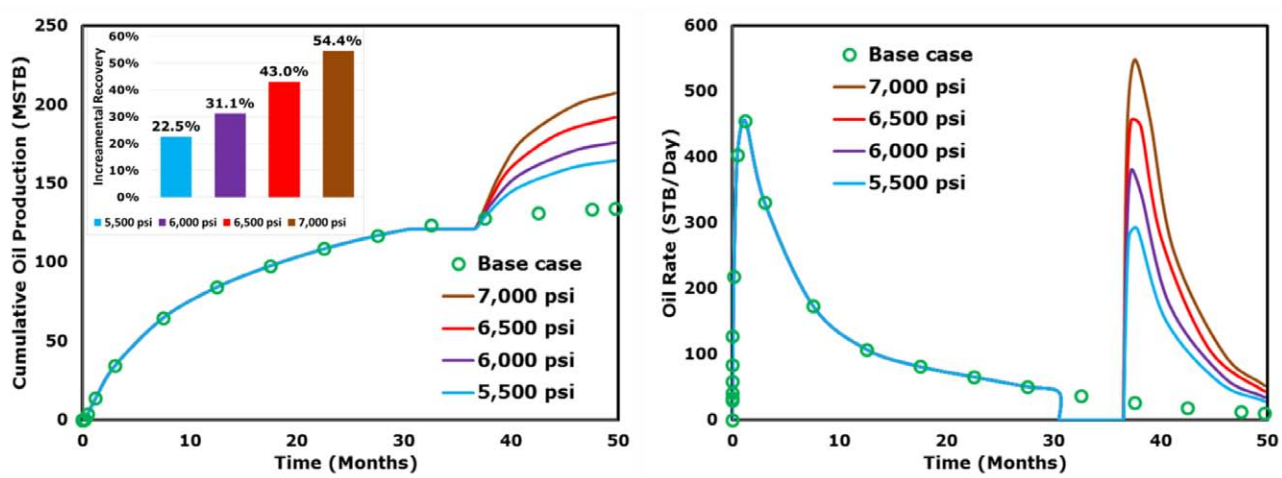

Figure 14—Simulation results of cumulative oil production, recovery incremental, and oil rate (right) for different water-injection pressure

The preliminary result of this water without surfactant method showed the promising result. Therefore, a set of sensitivity analysis was run to gather more information on this method. We investigate the potential of water without surfactant by studying the impact of water injection pressure and period on oil production improvement using the field-scale model. Four injection pressures and five soak times were tested. Results were investigated by normalizing the enhanced EUR to the EUR of a base case on the same production time. The water-injection starts after 30 months oil production. Four different pressures ranging from 5,500 to 7,000 psi in 500 psi increment were tested to analyze the impact of injection pressure. In time sensitivity study, a constant injection pressure of 5,500 psi was applied to five different injection periods of 1 month to up to 12 months. and the injection pressures ranged between 5,500 psi to 7,000 psi.

The impact of pressure variation on the incremental recovery is presented in Fig. 14. Four different injection pressure were investigated at a constant injection period of 6 months for all cases. It is important to note that the highest injection pressure tested was still lower than the fracture gradient of the formation. As expected, higher injection pressure resulted in both higher incremental of recover and secondary initial production rate. Incremental recovery of 22.5% was observed on the case of 5,500 psi injection pressure while injecting at 7,000 psi resulted in the incremental recovery of 54.4%. Higher injection pressure allows for higher reservoir pressure after six months of injection which in the end resulting in more oil to be produced after the injection period.

The results of this injection time sensitivity study are presented in Fig. 15. Injection of water without surfactant for one month resulted in 7.8% of incremental recovery. Longer injection duration leads to higher incremental of recovery with the maximum of 22.6% incremental on 12 months case. The longer injection time leads to higher cumulative oil production and oil rate. However, the injection periods of 6 and 12 months lead to similar oil production over the span of 4-years. A water-injection period of 6 to 12 months provides an optimum enhancement in oil production.

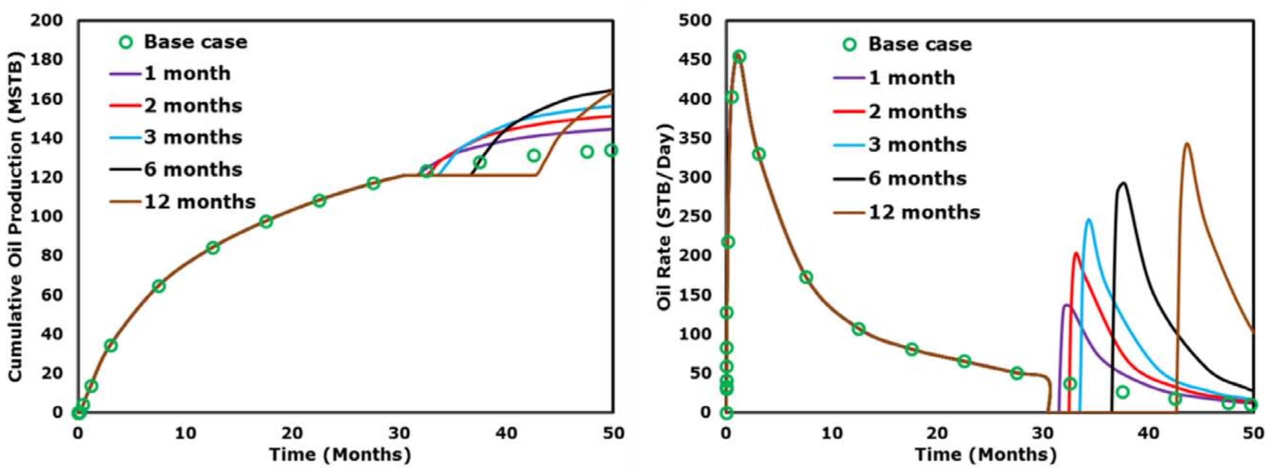

Figure 15—Simulation results of cumulative oil production, recovery incremental, and oil rate (right) for different water-injection periods

It is logical to analyze the volume of water injected when investigating an enhanced recovery method that involves the injection of water. Water injection process could come with a high economic requirement when the water source is limited. However, applying this method on the Wolfcamp formation can be highly beneficial as an abundant volume of water is also produced from every producing well in the formation. Fig. 16 contains the information of injected water volume on the cases tested in Fig. 14. The cumulative water injection increases with the increase of the injection pressure, resulting in a higher reservoir pressure build-up and a higher oil production. The results also prove that the primary production mechanism behind the water without surfactant method is the reservoir presses build-up. Although that the average cumulative water production after 30 months of production of wells in the area is twice the maximum amount of water injected, this method could still provide a significant solution for the produced water problem.

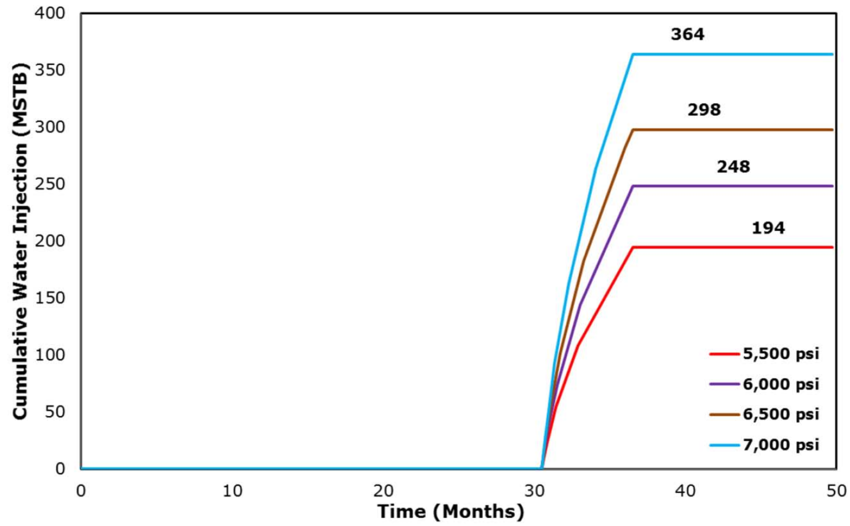

Figure 16—Cumulative water for different injection pressure.

The field-scale simulation results of water-injection after primary depletion indicate that this method could have a significant potential in improving oil production in ULR. Water without surfactant could be a feasible and economical method in enhancing oil recovery in ULR, especially for shale formations that have a high water-cut.

Surfactant-Injection after Primary Depletion (SASI-Injection EOR)

The simulation results indicate that water injection without surfactant method has a significance potential for enhancing oil recovery. Adding surfactants should lead to an even better performance in ULR due to the wettability alteration and the IFT reduction induced by the surfactant. In this section, we investigate the potential of SASI-injection EOR by varying the surfactant types and concentration. The injection pressure of all the SASI-injection EOR is 5,500 psi with a 6 months injection period. Surf1 and Surf2 were tested at 4 different concentrations of 0.5, 1, 2, and 4 gpt. The simulation results for the cumulative oil production and the oil rate for different cases are depicted in Fig. 17 and 18.

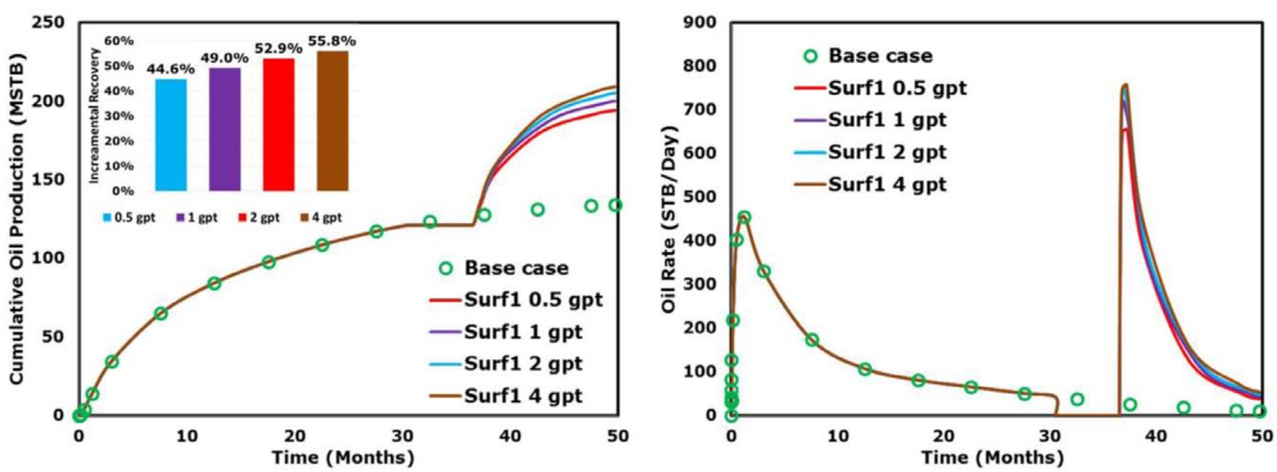

Figure 17—Simulation results of cumulative oil production, recovery incremental, and oil rate (right) for different surfactant concentration of SASI-injection EOR using Surf1

The addition of surfactants Surf1 and Surf2 on this EOR method was the precisely same surfactants that were studied in the laboratory experiments. As shown previously, Surf1 had a better performance compared to Surf2. Similar results were observed on this surfactant EOR method where injection of Surf1 resulted in higher incremental of recovery compared to injection of Surf2 where production increment as a result of 0.5 gpt Surf1 was larger than 4 gpt of Surf2.

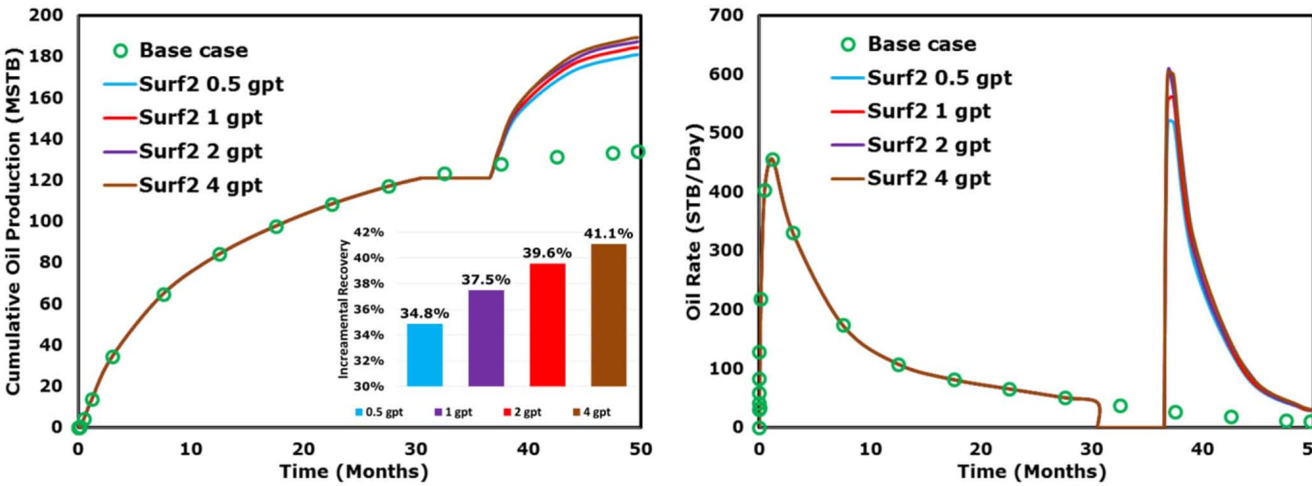

Figure 18—Simulation results of cumulative oil production, recovery incremental, and oil rate (right) for different surfactant concentration of SASI-injection EOR using Surf2

The incremental oil production shows a positive trend with surfactant concentration for both surfactant types tested. However, increasing the surfactant concentration does not result in significant oil production enhancement, especially when the surfactant concentration is above 2 gpt. Considering the surfactant cost, the economic surfactant concentration for SASI-injection EOR is no more than 2 gpt. Surf1 performs better than Surf2 as it alters the wettability of rock to more water-wet and shifts oil relative permeability higher.

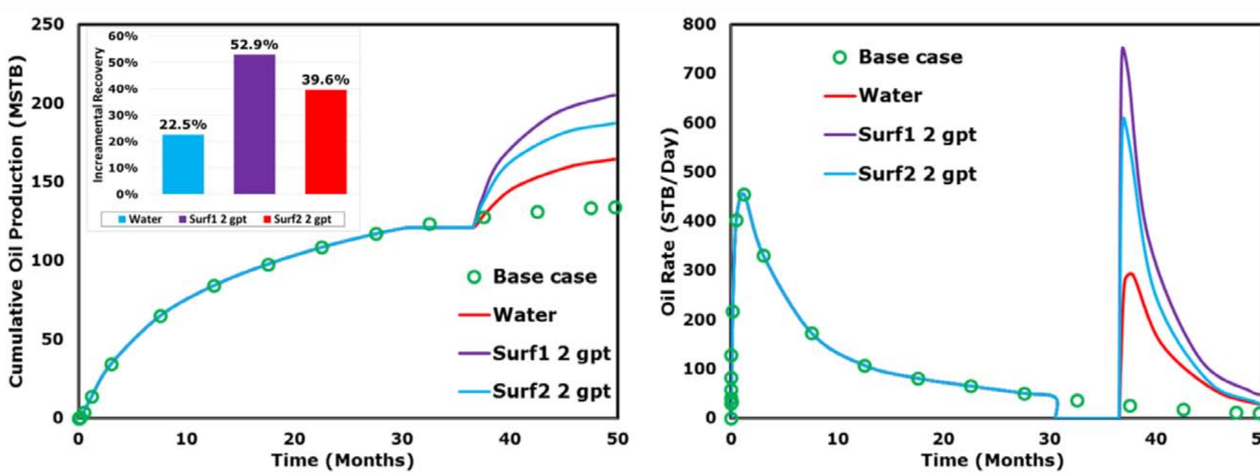

Figure 19—Comparision of SASI-injection EOR using the two surfactants and water-injection case

It is unavoidable that the injection of surfactant also includes the pressure build-up effect as caused by the injection pressure. Therefore, it is essential to investigate the dominant mechanism of SASI injection EOR, to determine production increment caused by the addition of surfactants or pressure build-up. The comparison results of investigating this issue are shown in Fig. 19 and 20.

The comparison of production increment for no-surfactant, Surf1, and Surf2 at 5,500 psi injection cases is presented in Fig. 19. The results indicate that involving surfactant in the injection fluids improved the effectivity of the EOR method tremendously with incremental recovery improved from 22.5% for the without surfactant case to up to 53% for the case of 2 gpt of Surf1 injected. It was determined then that surfactant could have a significant impact on incremental of production when injected after the primary recovery period.

Both surfactants can tremendously improve oil recovery from the matrix when compared to the water-injection base case. SASI-injection EOR not only improves oil recovery but also increases the oil rate. During SASI-injection EOR, 195 MSTB of surfactant solution was injected into the reservoir. In this case, the total cost of the surfactant is estimated around 100,000 USD. An additional 27 MSTB of oil (1.2 million USD, based on 45 USD/bbl) is being produced by during the SASI-injection EOR when compared to the water without surfactant base case. Therefore, the addition of surfactant into both the completion and the injection fluid leads to higher recovery and better economics.

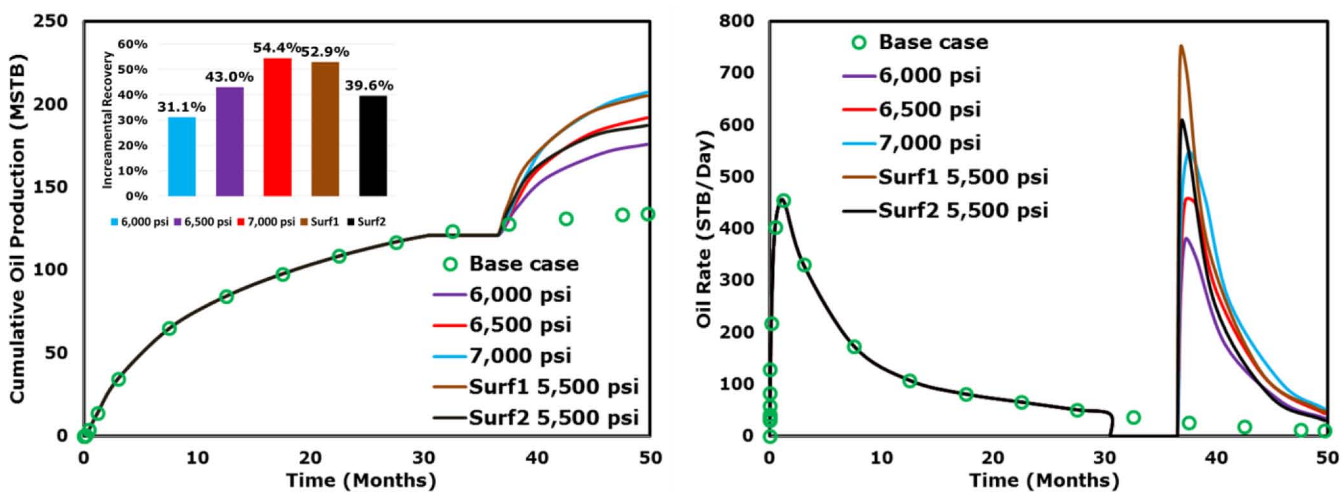

Figure 20—Comparision of SASI-injection EOR and water-injection with different pressure

To emphasize more the effect of surfactant, Fig. 20 presents three different injection pressure of water without surfactant were compared to two cases of injection of 2 gpt Surf1 and Surf2 with 5,500 psi injection pressure. Surprisingly, the cumulative oil production of SASI injection using Surf1 at 5,500 psi is similar to the oil production of water-injection at 7,000 psi, but has a higher initial oil rate than the water-injection case. SASI-injection EOR can be implemented at lower pressures than the water without surfactant technique and still lead to similar improvements in recovery. This should be taken into consideration if the surfactant price is too high or if the fracture pressure of the formation is low.

SASI-injection EOR technique results in the best oil enhancement when compared to corresponding SASI EOR in the completion process and water without surfactant. The economic surfactant concentration of SASI-injection EOR in this study is 2 gpt. SASI-injection EOR opens a substantial possibility to recover significant volumes of hydrocarbons from depleted wells and achieve an optimum oil recovery in ULR.

Surfactant and Multi-Cycles Water Injection after Primary Depletion (MC-SASI EOR)

In the last three sections, we tested the impact of different unconventional EOR techniques for implementation of Improved Oil Recovery (IOR). We have presented that injection of water results in reservoir pressure build-up, allowing for higher EUR compared to the base case of primary depletion only. In addition, we presented that the addition of surfactants into the injected water further improves the incremental recovery by allowing a better flow of oil through the fracture system as well as the larger volume of oil transferred from the matrix to the fracture system. Based on the two findings, a more complex EOR method was developed which includes a multiple injection and production period in consecutive order.

In this section, we extend the production period to 7 years in order to investigate the effectiveness of surfactant-injection and water-injection over a more extended production period. MC-SASI and multi-cycles water-injection techniques are implemented in the field scale model. For each injection cycle, the injection time is 6 months at 5,500 psi and the production period is 12 months following 30 months primary depletion. In the MC-SASI EOR plan, the surfactant is only added in the first injection cycle with 2 gpt concentration, while in the following two cycles only water is injected without any surfactant. Three cases are studied utilizing two surfactants and water for three injection cycles after initial depletion. The simulation results are presented in Fig. 21, including cumulative oil production, oil rate, and recovery incremental.

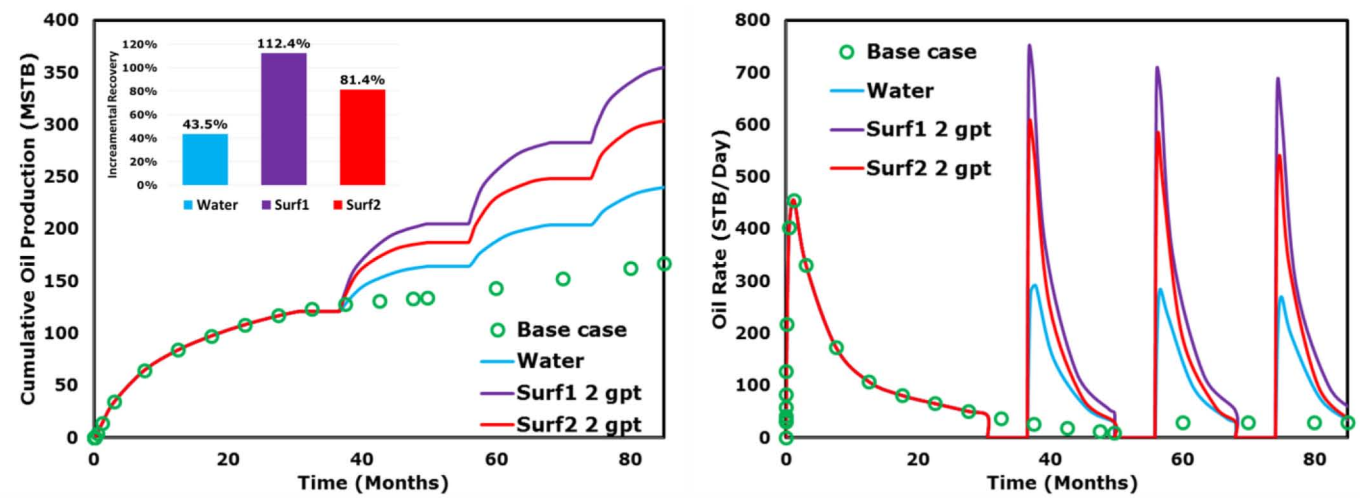

Figure 21—Comparision of MC-SASI EOR using the two surfactants and corresponding multi-cycle water-injection method

Injection of water without surfactant on this multi-cycles injection study improved the recovery by 43%. The addition of surfactants into injection fluid increases oil production tremendously using MC-SASI EOR technique in ULR. Compared to the multi-cycle water injection case, surfactant additive causes up to 70% of additional recovery incremental for 7-years oil production. Since surfactants were only added into injection fluid in the first cycle, the cost of surfactant is estimated as 100,000 USD per well. The cumulative production and oil rates are similar for all three cycles with minor decrease trend. Therefore, MC-SASI EOR technique could extend the well production life and significantly enhance oil production in ULR under certain conditions.

Summary

In this study, we presented a thorough and comprehensive evaluation of SASI-EOR. Since numerical modeling is the main approach to assessing the effectiveness of SASI-EOR on a field-scale application, an extensive approach was taken into measure during the construction of the field model. Data compiled from laboratory experiments, laboratory-scale modeling, physics-driven hydraulic fracture numerical model, and field-scale modeling were applied to the field-scale model to ensure the validity of the field-scale model. Two different surfactants as well as a base case fluid system were tested through the whole workflow. In the end, three SASI-EOR applications and one water without surfactant on shale oil well were investigated to evaluate the efficiency of each method.

The addition of surfactant into the completion fluid possesses the capability of improving both oil production rate and cumulative oil production with the degree of improvement that was observed to have a positive correlation to the surfactant concentration as well as the soak time. It is a common practice in the field to apply a minimal concentration of surfactant in the completion fluid which is driven mostly by the economic aspect. We have demonstrated that at a low concentration, proper surfactant selection is highly significant with the difference in cumulative production improvement between the two surfactants tested were significantly disparate. In addition, a complete study including an economic point of view must be finished as well due to the roll-off characteristic observed on the improvement of recovery when a higher surfactant concentration was tested.

The results of water without surfactant shows that re-energizing the reservoir could lead to the enhancement of shale oil well production. Primary depletion of shale oil reservoir is mainly driven by the expansion of oil as lower pressure traverses through the reservoir from the pressure drawdown applied at the well. It is a commonly-known reservoir engineering knowledge that this production mechanism is the least efficient. Therefore, re-pressurizing the well by water injection should be able to improve the oil recovery. We demonstrated that improvement was significant and indicated a positive correlation to injection pressure as well as soak time. Roll-off of improvement was also observed at the higher-end value of injection pressure and soak time tests.

Another form of SASI-EOR application where instead of water, injection of surfactant solution was applied after the primary recovery period was also investigated. Significant improvement was observed where the effect of re-energizing the well by injection of water was also amplified by the presence of surfactant in the injected water. As expected, higher surfactant concentration in the injected fluid resulted in higher recovery improvement from both cumulative and rate of production. Surf1 has better performance than Surf2 on laboratory experiment and SASI in the completion studies, and it also performed better on this application. To better understand the effect of surfactant addition into the injected fluid, we presented a comparison study of surfactant injection and corresponding water injection. The addition of 2 gpt of Surf1 increased the incremental recovery to 53% from the base case of water with 22% of incremental recovery.

On the last part of the work, an MC-SASI scheme was tested. The sequence of injection and production was applied after the primary depletion period with three different fluids. It has been demonstrated that this mechanism has a significant potential to improve recovery from a depleted shale oil well. Three cycles of water-injection improved the recovery by 43.9% at the end of the third cycle for the base case where no surfactant was added into the injected fluid. Addition of surfactant increased the incremental recovery to 112% and 81% for Surf1 and Surf2 respectively.

Conclusion

Based on our laboratory experiments and reservoir simulation for a particular Wolfcamp well we conclude:

1. The addition of surfactant into both completion and injection fluids has the potential to improve the recovery of oil due to wettability alteration and interfacial tension reduction caused by the interaction of surfactant molecules with the commonly oil-wet ULR rock.
2. Calibrated and validated field-scale model of an actual producing well in the Wolfcamp formation was generated by compiling data from multiple laboratory experiments, laboratory-scale model, physics-driven hydraulic fracturing model, and field-scale history-matching.
3. Addition of surfactant into the completion fluids allows for more oil to be produced during primary production by enhancing the volume of oil transported from the matrix to the fracture system as well as improving the flow capacity of oil in the fracture system. Surfactant type, surfactant concentration, and soak time must be taken into consideration in order to properly incorporate surfactants into the completion design.
4. Re-energizing the well by water injection was observed to have a significant capability for improvement of oil production. Injection pressure, as well as soak time, were observed to have substantial effect on the degree of production enhancement from the water without surfactant technique.
5. The addition of surfactants to the injected water to re-energize the reservoir pressure could further improve production enhancement.

6. MC-SASI scheme was tested with three consecutive sequences of injection and production periods with water and surfactant serving as the injection fluid. Production enhancement from this method was observed to be the greatest when compared to the other three methods. The highest value of 112% incremental recovery was observed after three cycles with 2 gpt of Surf1.
7. MC-SASI EOR opens an exciting range of extending well production life and improving optimum oil production in ULR.

Acknowledgments

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Nomenclature

k = Permeability
P_c = Capillary pressure
r = Radius of curvature
θ = Contact angle
σ = Interfacial tension (IFT)
ϕ = Porosity
CA = Contact angle
CT = Computed tomography
EOR = Enhanced oil recovery
OOIP = Original oil in place
SASI = Surfactant-assisted spontaneous imbibition
ULR = Unconventional Liquid Reservoir

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