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Gas and foam injection with CO_2 and enriched NGL's for enhanced oil recovery in unconventional liquid reservoirs

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ABSTRACT

In order to extend the economic life of existing horizontal wells and improve oil production for newly drilled wells in unconventional liquid reservoirs (ULR), testing of enhanced oil recovery (EOR) techniques is essential. The interaction of the fluids in the fractures system with the oil stored in the matrix is the key to understanding and implementing all EOR techniques in ULR. This study focuses on investigating the performance of different EOR agents (CO_2, rich gas, and foam) through laboratory tests.

A correlated set of Huff-n-Puff experiments were performed at reservoir temperature using different gases and foam on side-wall core samples from the Wolfcamp formation. The experimental setup was mounted into a Computed Tomography Unit (CTU) to capture time-lapse CT images which were used to monitor the fluid movement inside the core plugs, track the foam quality in glass beads pack around the cores.

Various gases (CH_4, a mixture of 85% CH_4 - 15% C_2H_6, enriched gas (50% CH_4 - 50% C_2H_6), and CO_2) were used for Huff-n-Puff experiments at reservoir conditions to explore the effects of gas composition on the recovery factor in ULR. Enriched gas (50% CH_4 - 50% C_2H_6) showed the most promising potential of improving oil recovery in the Wolfcamp formation. An increase in pressure does not always correspond to higher oil recovery in gas Huff-n-Puff experiment. During the CO_2 injection experiment conducted at 5000 psi, we recovered a smaller amount of oil than previous experiments performed at lower pressure. The primary mechanism of gas injection is multi-contact miscibility, and diffusion has a minor effect on enhancing oil recovery in ULR. Surfactants enhance oil recovery by wettability alteration and interfacial tension (IFT) reduction. Implementing surfactants into completion fluids or re-frac fluids results in additional oil recovered from ULR. From the results obtained, a combination of EOR techniques (foam or sequencing surfactant and gas injection) opens the possibility to achieve optimum oil recovery in ULR.

1. Introduction

Unconventional liquid reservoirs (ULR) have contributed to a significant portion of oil production in the United States. Wells drilled horizontally into tight oil formations continue to constitute an increasing share of crude oil production (Todd and Evans 2016). Horizontal wells accounted for about 15% of crude oil production in ULR in 2004, but the percentage of oil production from horizontal wells increased to 96% of total production in ULR in 2018 (EIA 2019). Although the number of horizontal wells did not surpass the number of vertical wells until 2017, horizontal wells have dominated U.S. oil production since 2010. By the end of 2019, oil production from ULR is over 9 million barrels/day. Specifically, the Permian Basin produces more than 50% of oil from ULR with 4.5 million barrels/day followed by the Bakken and Eagle Ford formations (EIA 2020).

Since primary oil recovery factors range from 1 to 8% (Alfarge et al., 2017; Thakur 2019) leaving behind the vast majority of the oil in the reservoir, it is imperative to develop the enormous potential of ULR and improve recovery factors by implementing EOR techniques (Thakur 2019). EOR techniques, including chemical injection, gas injection, foam injection, and thermal methods, are well understood and applied extensively in conventional reservoirs. However, the EOR methods in unconventional reservoirs are new concepts and are still at the early stages of experimental investigation, numerical simulation, and pilot project stage (Alfarge et al., 2017). EOR applications and mechanisms in unconventional reservoirs are not entirely the same as conventional

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reservoirs due to ULR characteristics of low porosity, ultra-low permeability, and complex matrix-fracture interactions (Adel et al., 2018; Tovar et al., 2014; Zhang et al., 2018c).

Gas injection is one of the most promising EOR techniques in ULR. Several research organizations and companies have investigated the potential of miscible gas injection to improve oil recovery in unconventional reservoirs using experiments, numerical simulation, and field testing. Although different gases, such as CO_2, N_2, CH_4, produced gas, and enriched natural gas, were tested since the last decade, the majority of studies focused on CO_2 because of its widespread application for EOR in conventional reservoirs (Adel et al., 2018; Alharthy et al., 2018; Gamadi et al., 2014; Li et al., 2018; Tovar et al. 2014, 2018a, 2018b; Zhang et al., 2019b). In the meantime, readily available produced gas and enriched natural gas has provided an alternative to CO_2, due to ample supply, easy accessibility, and low price. Currently, there is scant research on the potential and mechanisms of produced gas and enriched natural gas in ULR.

Most of the gas injection field pilots were performed in the Eagle Ford and Bakken formations using produced gas and CO_2. Significantly improved oil recovery was observed from produced gas injection pilots in the Eagle Ford formation. Todd et al. (2016) reported four gas injection field pilots in the Bakken formation, in which three of them injected CO_2, and the fourth injected enriched gas. Although all the CO_2 injection pilots failed to display sufficient production uplift in the Bakken formation, CO_2 injection might effectively improve oil recovery in other unconventional reservoirs. In addition, enriched natural gas has great potential as an EOR agent in ULR. EOG Resources was the first company to disclose that it had recovered from 30% to 70% more oil from Eagle Ford shale wells using the natural gas injection method. EOG reported 150 EOR wells had been converted since the start of the program, and strong results were observed from these EOR wells (Streit et al., 2019).

The recovery mechanisms of Huff-n-Puff gas injection in unconventional reservoirs include multi-contact miscibility, diffusion, vaporization, oil swelling, and viscosity reduction. Hoffman et al. (2019) found vaporization is the dominant mechanism for high GOR reservoirs (>6000 scf/STB), and oil swelling is the primary mechanism for low GOR reservoirs (500–2000 scf/STB) during Huff-n-Puff gas injection process in unconventional reservoirs. Zhang et al. (2019a) reported the primary recovery mechanism of gas injection EOR is multi-contact miscibility, and diffusion plays a minor role based on experimental results, ternary diagram analysis, and simulation results. Some other researchers reported diffusion is a dominant parameter for improving oil recovery in the unconventional reservoir (Alharthy et al., 2015; Sun et al., 2016).

Chemical and gas injection EOR techniques have the potential for improving oil recovery in unconventional liquid reservoirs. There is very limited literature on combined EOR techniques (such as sequencing surfactant/gas injection and foam injection) in ULR. The production mechanisms of sequencing surfactant/gas injection have combined the mechanisms of chemical and gas injection EOR, including multi-contact miscibility, diffusion, oil swelling, wettability alteration, and IFT reduction. Zhang et al. (2018a) performed spontaneous imbibition experiments using the shale core plugs just finished gas injection experiments. They reported that the primary production mechanisms of the hybrid EOR technique are wettability alteration and multi-contact miscibility. Ghosh and Mohanty (2019) performed surfactant alternating gas (SAG) injection experiments using low permeability rock, the author reported the primary production mechanisms of the SAG process are wettability alteration and IFT reduction.

Currently, there is a significant lack of literature on foam injection EOR techniques in unconventional liquid-rich reservoirs. The most relevant previous publications regarding the evaluation of hybrid EOR in ULR are illustrated below. Pankaj et al. (2018) investigated the impact of the natural gas-based foam on hydraulic fracture geometry and productivity in the unconventional reservoirs using numerical simulation. The authors concluded that improving relative permeability through surfactants and delivering proppants to further distances could result in higher oil recovery in unconventional reservoirs. Katiyar et al. (2019) investigated the performance of a hydrocarbon foam EOR pilot in a hydraulically fractured reservoir in the Woodbine field. They indicated that oil production of the well increased for at least six weeks after completing surfactant injection, and more than 2000 bbl. of incremental oil was recovered from foam EOR operation.

2. Laboratory experiments

This study investigated the recovery performances of gas injection and hybrid EOR (foam injection) techniques in unconventional liquid-rich reservoirs through laboratory experiments. A novel foam injection experimental workflow was developed in order to identify the challenges, risks, potentials, and mechanisms of this innovative EOR technique, and to investigate the feasibility of this method in ULR. Gas and foam Huff-n-Puff experiments were performed using sidewall core plugs from the Wolfcamp A formation, at reservoir temperature of 155 °F and 5000 psi. CT scan technology was coupled with all experiments to monitor the fluid movement inside the core samples and to examine the foam quality in the glass beads pack. The color of the produced oil was analyzed and a possible recovery mechanism was identified for each experiment. Finally, the core-scale model was developed for all the Huff-n-Puff experiments to achieve scaling parameters from history match experimental data. The workflow of the tests is presented below.

2.1. Gas injection experiment

A physical representation of a hydraulic fracture was obtained by surrounding an organic-rich shale core plug with 1 mm glass beads pack inside an aluminum core-holder, as shown in Fig. 1. This configuration closely reproduces field conditions by containing a high permeability fracture in direct connection with the matrix, which has permeability in the nano darcy range. All the experiments were performed in core-flooding equipment coupled to a CT-scanner, which enabled time-lapse to be taken during the tests. The apparatus was able to reach reservoir temperature and pressure.

Once the core holder was packed and connected to the core flooding rig, a vacuum was applied to remove the trapped air in the core-flooding system. Then, gases were injected from a floating piston accumulator until reaching the designed experimental pressure. At this point, soak time started at constant pressure for 72 h. During the soak period, CT-scans were performed regularly to track the changes in density as a function of time and space. When the soak time was completed, fresh gas was injected to displace the gas and the oil out of the core holder with a

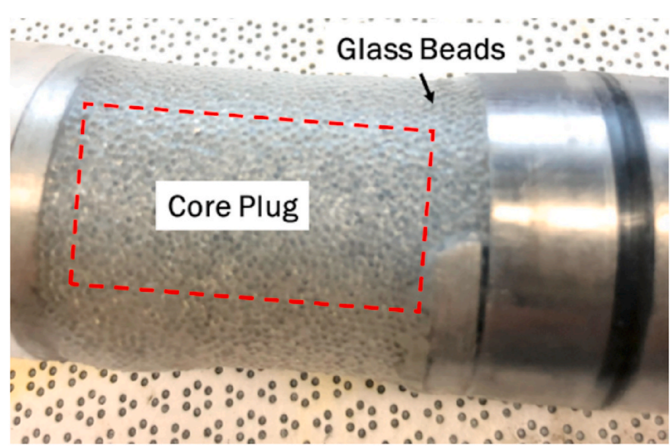


Fig. 1. Schematic of the core holder – physically simulate a fracture-matrix system in the unconventional liquid reservoir.

constant flow rate. The effluents were collected at the outlet of the system. The described procedure constitutes one Huff-and-Puff cycle. The ultimate oil recovery was achieved by repeating several cycles until no more oil was produced.

2.2. Foam injection experiment

Foam Huff-n-Puff experiments were performed at 5000 psig and reservoir temperature of 155 °F. Hydrocarbon gases and one type of surfactant solution were co-injected into the core holder with a 70% gas/liquid ratio. The configuration of the core holder was the same as for the gas injection experiments (Fig. 1). The schematic of the apparatus is available in (Zhang 2020). Hot water was circulated through the overburden of the core-holder to maintain the reservoir temperature, while heating tapes were used for the lines and the connections. CT-scans images were taken regularly to track the movement of the fluids inside the core plugs and to monitor the foam quality during the experiments.

2.3. Surfactant tests

The surfactant screening tests are comprised of contact angle and interfacial tension (IFT) measurements. The wettability of rock surfaces was quantified by measuring the contact angle under aqueous-oleic-solid phase conditions using the captive bubble method. It is important to note that the rock samples used in this measurement were processed before-hand. Several chips were cut from the sidewall core plug and cleaned by toluene, methanol, and then vacuum-dried. Finally, the rock chips were aged in their corresponding oil at reservoir temperature for at least two weeks to restore the reservoir wettability. The system is considered oil-wet when the contact angle is above 90° and water-wet when the angle is below 90°. In addition, interfacial tension of oil and water was measured utilizing the pendant drop method.

2.4. Minimum miscibility pressure (MMP) determination

Minimum miscibility pressure is one of the most crucial parameters in any gas injection project. The MMP is the lowest pressure at which the injected gas and the reservoir oil become miscible through a multi-contact process at the reservoir temperature (Elsharkawy et al., 1992). The slim tube method is considered the most accurate way to determine the MMP because it is one dimensional and avoids unfavorable conditions such as gravity override, unfavorable viscosity ratios, and fingering (Adel et al., 2018).

An 80 ft slim tube, packed with 100–150 mesh sand, was used to determine the MMP of gases and oil from unconventional liquid reservoirs. The stainless steel coil with an inside diameter of 0.25 in and a thickness of 0.063 in. The recovery factors were measured at 1.2 pore volume (PV) of injected gas. The effluents were collected and their volume measured along the duration of the experiment to calculate the recovery factor at each pressure. The recovery factors were plotted as a function of the pressure, and two regions were identified as the immiscible region and the miscible region. The MMP of each sample was determined at the intersection point of the trend lines of the two regions. The schematic of the MMP apparatus is presented in (Zhang 2020).

MMP is a critical parameter for gas injection projects, and a significant increment in oil production is observed when the injection pressure is above the MMP. Therefore, it is essential to determine the MMP of the oil and the injected gas before performing the gas injection experiments.

3. Rock and oil samples

3.1. Rock and oil

Core plugs and oil samples used in this study are retrieved from the Wolfcamp A formation in Martin County, TX. 14 ULR cores were cut from the same1-ft interval (as shown in Figs. 2) and 6 of these core samples were used in Huff-n-Puff experiments. Since all core samples were cut from the same 1-ft interval, core plugs can characterize same reservoir properties. The porosity and density of core samples is 8% and 2.7 g/cc, respectively. The permeability of core plugs retrieved from Wolfcamp formation is in the range of 200–400 nD. The diameter and length of the cut ULR cores are 0.965 in and 2 in, respectively. In addition, some rock chips were trimmed from this 1-ft Wolfcamp rock and were used for the contact angle measurements.

The oil sample used in this study was also obtained from the same Wolfcamp A formation. The density of the oil was 0.797 g/cc, and it was measured at 155 °F. The composition of the oil was determined by gas chromatography (GC), and it is shown in Fig. 3. This is a dead oil that no C_1 to C_3 components were observed in the GC results. The composition of the Wolfcamp oil is in the lighter and intermediate range, with peaks around C_5 to C_8.

3.2. Saturation process

In order to determine the original oil in place for each core plug and accurately calculate the recovery factor of each Huff-n-Puff experiment, the core samples were cleaned using the Dean-Stark method and dried under a vacuum oven. The clean cores were then saturated and aged using reservoir oil from the corresponding well at 10,000 psig and room temperature. This saturation process lasts for more than three months to restore the core samples to original reservoir conditions. CT scan technology is coupled with the entire saturation process to verify oil saturating into the cores. However, it is challenging to identify the supercritical gas phase and the oil phase in the CT image of Huff-n-Puff experiments.

Core samples were weighed and CT scanned every 1–2 weeks during the saturation/aging process. Then, all the core plugs were put back to the pressure vessel under the same conditions to continue the saturation process. The saturation process was monitored by recording the change in weight for each core sample, and this process was stopped when the weight of the core sample was constant for two consecutive weeks. The core plugs saturation data, including the mass of the core plugs before and after the saturation process, mass difference, and the oil in place for each core are shown in Appendix A.

3.3. CT images of saturation process

CT-scanning technology was used to track oil saturation changes of core samples in the aging process. Fig. 4 displays the saturation changes using the CT images for all cores. The first scan at time zero was performed after the cleaning process and before saturation. The last scan shows the final stage of saturation, after three months of the aging process. The CT-number increased at each time step as the oil penetrated into the cores. The CT-number is directly proportional to the density since the pores are being saturated with oil; therefore, the CT-number increased as more oil saturated the pores.

4. Results of experiments

The MMPs of Wolfcamp A oil and different gases are determined using the slim tube method. Gas and foam Huff-n-Puff experiments are performed using sidewall core plugs from the same Wolfcamp A formation at reservoir temperature of 155 °F and 5000 psi. The experimental results are utilized to evaluate and compare the efficiency of each method in improving oil recovery at the same operating and reservoir conditions. In addition, CT images and the color of the produced oil are analyzed and discussed to reveal the recovery mechanism of each method.

Fig. 2. Core Plugs cut from the Wolfcamp A formation in Martin County.

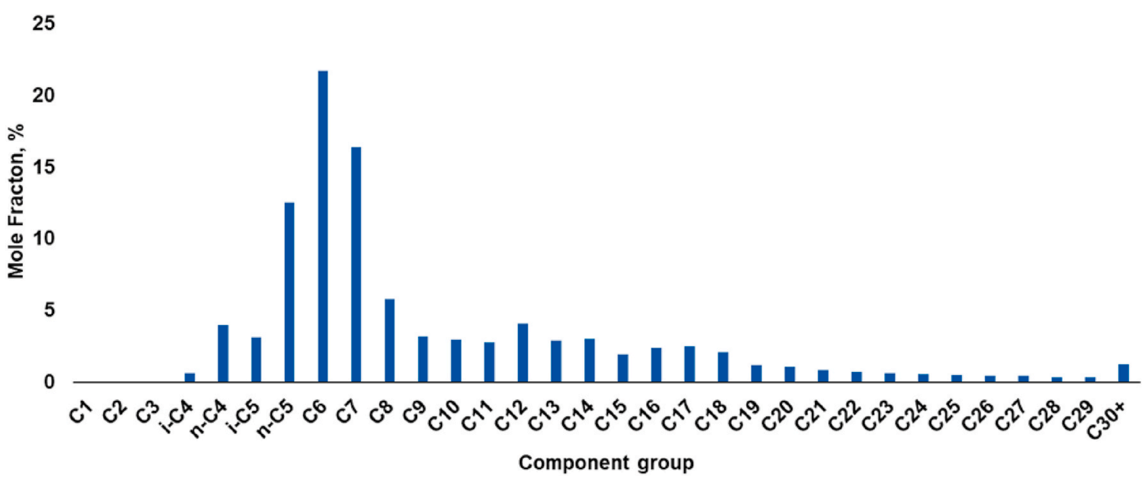


Fig. 3. Oil composition of the Wolfcamp oil determined by GC.

4.1. Minimum miscibility pressure determination for different gases

The MMP of the Wolfcamp A oil and four gases (CO_2, CH_4, a mixture of 85% CH_4 and 15% C_2H_6, and enriched gas (50% CH_4 – 50% C_2H_6)) were measured at reservoir temperature of 155 °F using the slim tube apparatus described before. The MMP of the Wolfcamp oil and all four gases are presented in Table 1. The recovery factors as a function of pressure are shown in Fig. 5 for each case.

The MMP of the Wolfcamp oil – CO_2 system was determined to be 2061 psi, which was the lowest MMP value of all four gases. The MMP of the Wolfcamp oil – CH_4 was estimated to be 5715 psi, which was the highest measured MMP among all the tested gases. From previous investigations (Adel et al., 2018; Zhang et al., 2018a), it was shown that increasing injection pressure led to higher oil recoveries, and the best results were obtained when the pressure was above the MMP. Considering the case of Wolfcamp oil – CH_4, in order to effectively enhance oil production in this reservoir, the injection pressure needs to be around 6000 psi. CH_4 may not be economically feasible for gas injection EOR in this reservoir, due to the high costs associated with the process which are directly related to the operating pressure.

A mixture of 85% CH_4 and 15% C_2H_6 was also tested in this study to represent produced gas from the Wolfcamp wells. Using a 15% ethane enrichment results in the MMP dropped to 4452 psi. Due to the oil production boost in the Wolfcamp formations, produced gas is easily accessible at moderate costs, which could make it a good candidate for gas injection processes in ULR. Compared to CH_4, a mixture of 85% CH_4 and 15% C_2H_6 is more effective to improve oil recovery in the Wolfcamp formation. Finally, enriched gas (50% CH_4 – 50% C_2H_6) was investigated to evaluate the effects on the MMP. When 50% ethane was added to pure methane, the MMP dropped from 5715 psig to 2862 psig, which was closed to the value obtained for the CO_2 case. Enriched gas (50% CH_4 – 50% C_2H_6) has a great potential of improving oil recovery in the Wolfcamp formation due to its low MMP when mixed with this particular oil and because it's cheap and readily available. The oil recovery potential of this mixture was examined by conducting the Huff-n-Puff experiment.

4.2. Gas Huff-n-Puff experiments

The gas Huff-n-Puff experiments followed the robust experimental workflow as described in the Laboratory Experiment section. Once the rock matrix-hydraulic fracture system was packed into the core-holder and connected to the core-flooding equipment, a vacuum was applied to remove the air. Gas was then injected into the system from a floating piston accumulator until reaching the desired experimental pressure. At this point, the soaking period lasted for 72 h. During soaking, CT-scans images were taken regularly to track the changes in oil saturation as a function of time and space. After completing the soak period, the surfactant solution was displaced by fresh gas at a low flow rate, and the effluents were collected from the outlet to calculate the recovery factor of each experiment.

Four gases were tested in this study to determine the optimal gas composition for gas injection EOR in ULR: CH_4, a mixture of 85% CH_4 and 15% C_2H_6 (gas (85–15)), enriched gas (50-50) (50% CH_4–50% C_2H_6), and CO_2. Gas Huff-n-Puff experiments were performed at the reservoir temperature of 155 °F and 5000 psig.

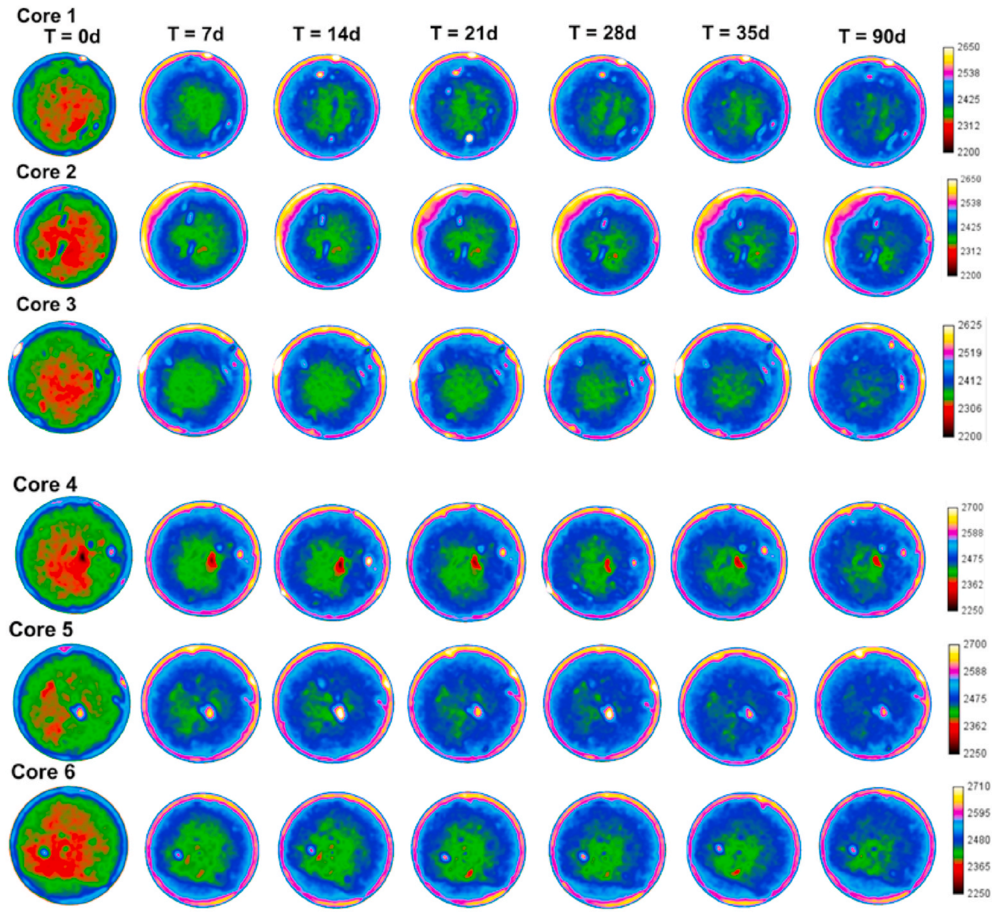


Fig. 4. CT-scan images tracking the changes in saturation time for Wolfcamp A sidewall cores.

Table 1
MMP results for the Wolfcamp oil and different gases.

Gas Composition	Temperature (^{o}F)	Crude Oil	MMP (psi)
CO_2	155	Wolfcamp A	2061
CH_4	155	Wolfcamp A	5715
85% CH_4 15% C_2H_6	155	Wolfcamp A	4452
50% CH_4 50% C_2H_6	155	Wolfcamp A	2853

4.2.1. CH_4 Huff-n-Puff experiment

The result of the CH_4 Huff-n-Puff experiment is shown in Fig. 6. The average CT number of the entire core plug for each time step was calculated from the time-lapse CT images, and the average CT number of the whole core as a function of time is shown in Fig. 6.

The CT number of CH_4 at experimental conditions is -600 Hu, and the CT numbers of other injectants are in the range of $-300 \sim -200$ Hu. In the meantime, the CT number of the crude oil at experimental conditions is 600 Hu. The CT numbers of injected fluids are much smaller than the crude oil used in this paper. Average CT number of the core plugs decreases as oil recovered from the core plug.

After 1 cycle (72 h soak time and 3 h production time), the recovery factor was 9.7% of OOIP. Compared to the chemical Huff-n-Puff experiments, the CH_4 injection process is less effective in improving the oil recovery in the Wolfcamp reservoirs. This could be caused by the experimental pressure, which is lower than the MMP obtained for pure methane. A higher oil recovery could be obtained if the injection pressure was above 6000 psi.

The average CT number change of the entire core plug throughout the experiment was 14 Hounsfield unit (HU). This indicated that the injected gas invaded the core plug and extracted some oil. Time-lapse CT-scan images of three different cross-sections (close to the inlet, in the middle of the core, and close to outlet) are presented in Fig. 7.

Apparent color shifts occur from blue/green color to green/red color for the entire core. After 4 h of soak, a color change was observed at the center of the core, indicating the CH_4 had invaded the center of the core plug. Time-lapse CT images also confirmed that oil was extracted from the plug during the CH_4 Huff-n-Puff experiment.

4.2.2. A mixture of 85% CH_4 and 15% C_2H_6 Huff-n-Puff experiment

Huff-n-Puff experiment was performed using a mixture of 85% CH_4 and 15% C_2H_6 at 5000 psig and reservoir temperature 155 °F. The recovery factor was 13% of OOIP after one Huff-n-Puff cycle, which was higher than the recovery factor using CH_4. Adding 15% ethane into pure methane not only decreased MMP but also improved the oil recovery. Since a promising result was observed after 1 cycle, more cycles were tested consequently until no more oil was produced from the plug. The ultimate oil recovery is presented in Fig. 8 and was obtained after 5 cycles. The ultimate recovery factor was 23.2%. These results indicated that using produced gas is a promising EOR method for improving the oil recovery in the Wolfcamp reservoirs.

The average CT number of the entire core plug for each time step was calculated and the average CT number change was 18 HU after the first cycle. A color shift was observed on CT images of this test, which is similar to the CH_4 Huff-n-Puff experiment. During the soak period, gas invaded into the core resulting in a density decrease. Therefore, the time-lapse CT images confirmed that oil was produced from the plug during the experiment. The color of the produced oil was lighter than the original Wolfcamp A oil, and it was similar to the color of the produced oil from the CH_4 test. This observation confirms that lighter components of the oil were recovered by the gas injection process.

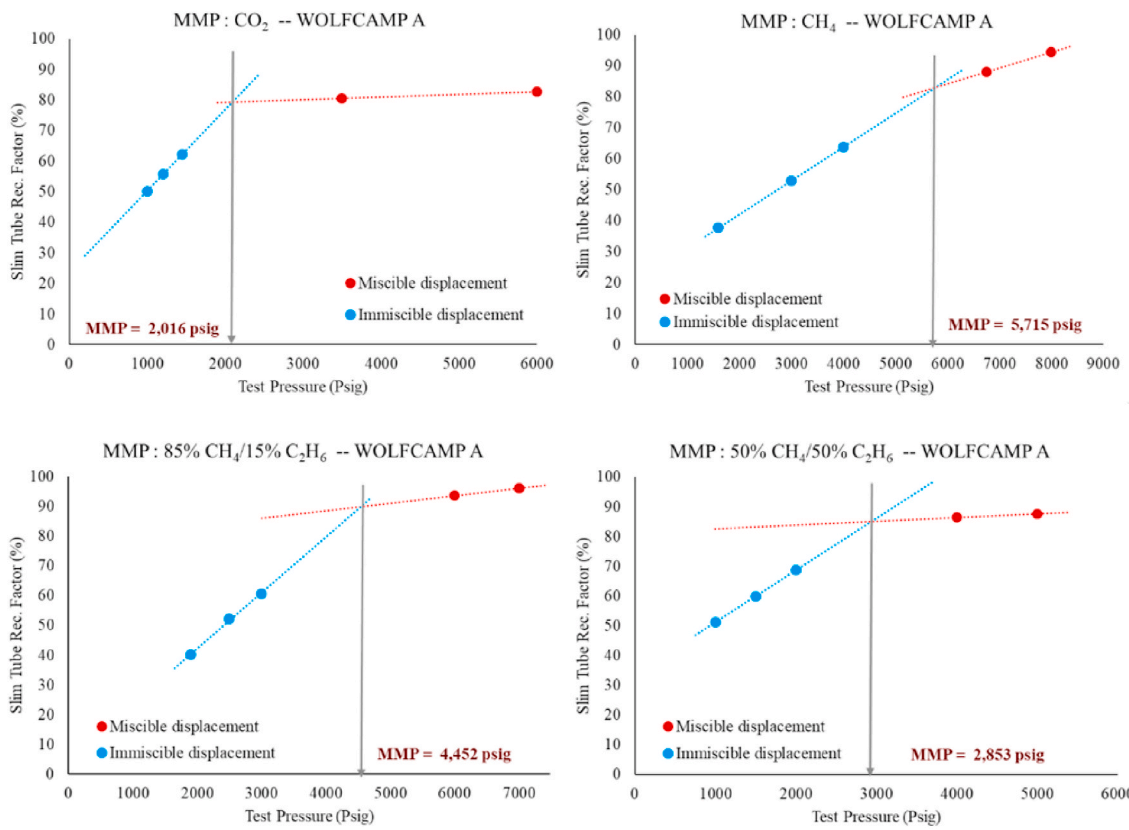


Fig. 5. Slim tube recovery factor as a function of pressure for the CO_2 –Wolfcamp A system(top–left); CH_4 –Wolfcamp A system (top–right); 85% CH_4 15% C_2H_6 –Wolfcamp A system (bottom–left); 50% CH_4 50% C_2H_6 –Wolfcamp A system (bottom–right).

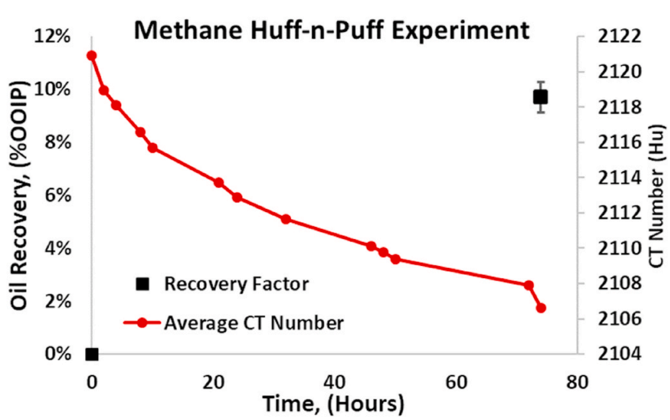


Fig. 6. Recovery factor as a function of time for the CH_4 test (left), and the average CT number of the entire core throughout the experiment (right).

4.2.3. Enriched gas (50% CH_4 – 50% C_2H_6) Huff-n-Puff experiment

Enriched gas (50% CH_4 – 50% C_2H_6) Huff-n-Puff experiment was performed to evaluate the effect of ethane enrichment on the oil recovery in the Wolfcamp reservoirs. After one cycle, the recovery factor was 23% of OOIP, which was much higher than the recovery factor obtained using the other two gases. This result proves that 50% ethane enrichment to dry gas can tremendously improve the oil recovery in the Wolfcamp reservoirs. Enriched gas (50% CH_4 – 50% C_2H_6) shows the enormous potential of the optimum gas composition for gas injection EOR in ULR. In addition, the ultimate oil recovery of the enriched gas Huff-n-Puff experiment is also investigated, and the results are presented in Fig. 9.

The ultimate oil recovery was reached after 5 Huff-n-Puff cycles, which was 36% of OOIP. More than 60% of the ultimate recovery is produced from the first Huff-n-Puff cycle, indicating that gas injection EOR is a fast process to recover more oil from unconventional reservoirs. The average CT number change of the whole core throughout the first cycle of enriched gas injection experiment is 22 HU. It confirms the average CT number change has a positive correlation with the recovery factor for gas injection experiments.

4.2.4. CO_2 Huff-n-Puff experiment

CO_2 has a promising potential for improving oil recovery in ULR based on previous tests through experiments and numerical simulation. The Huff-n-Puff experiment using CO_2 was performed at 5000 psi and reservoir temperature 155 °F.

After one cycle (72 h soak time and 3 h production time) the recovery factor of the CO_2 test was 9% of OOIP, which was the lowest recovery factor of all gas injection experiments. Because the CO_2 has the lowest MMP compared to the other gases, the oil recovery of the experiment was expected to be higher than that conducted with enriched gas. However, a surprising result was observed from the CO_2 test; the performance of CO_2 injection at 5000 psi was even lower than that of using CH_4. Then, the ultimate oil recovery of the CO_2 Huff-n-Puff experiment was compared to the ultimate recovery factor of the enriched gas experiment. The recovery factors as a function of the Huff-n-Puff cycle for the CO_2 injection experiment are plotted in Fig. 10.

The ultimate oil recovery of the enriched gas injection experiment was reached after 5 injection/production cycles, and the recovery factor was 21% of OOIP, which was slightly less than the ultimate recovery factor of the gas (85–15) test. From our previous publications (Adel et al., 2018; Zhang et al., 2018a), the ultimate recovery of the CO_2 Huff-n-Puff experiment at 3500 psi was about 50% of OOIP. Then, the recovery factors as a function of pressure for all CO_2 Huff-n-Puff experiments are plotted in Fig. 11.

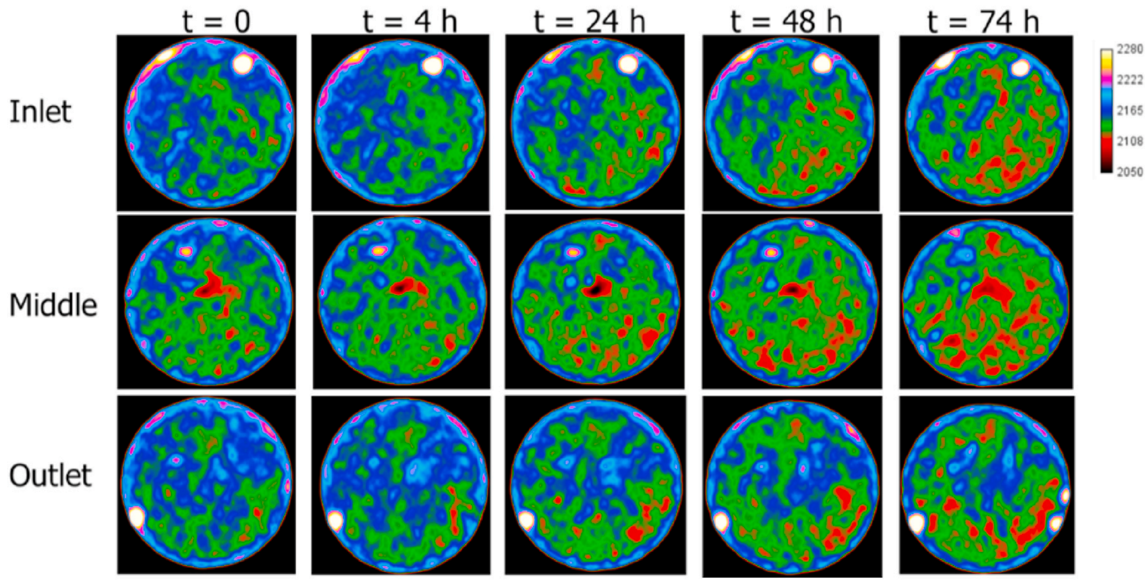


Fig. 7. Time-lapse CT images of three cross-sections from the core sample (close to the inlet, in the middle of the core, and close to outlet) for gas Huff-n-Puff experiment using CH_4.

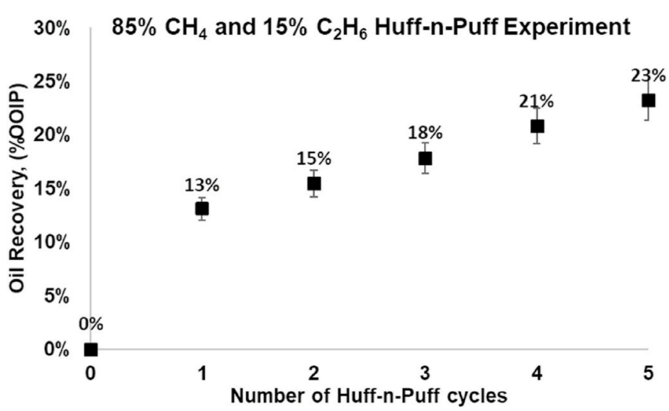


Fig. 8. Recovery factors as a function of time for the Huff-n-Puff experiment using a mixture of 85% CH_4 and 15% C_2H_6.

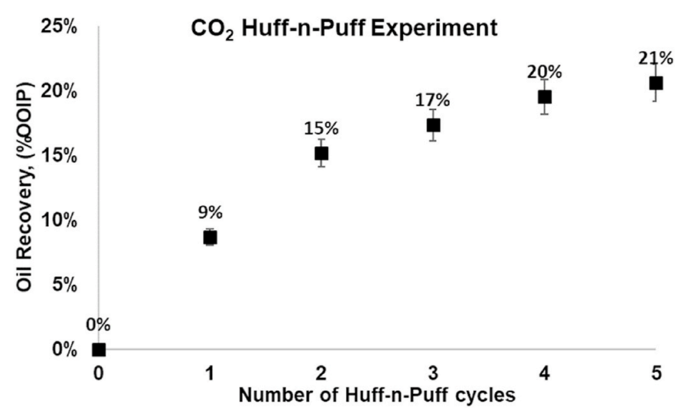


Fig. 10. Recovery factors as a function of time for the CO_2 Huff-n-Puff experiment.

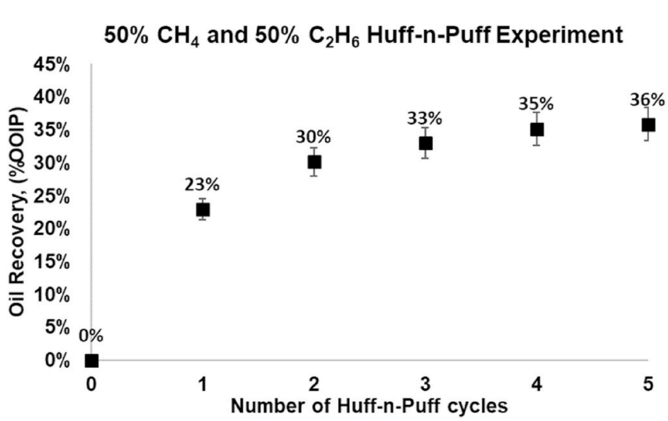
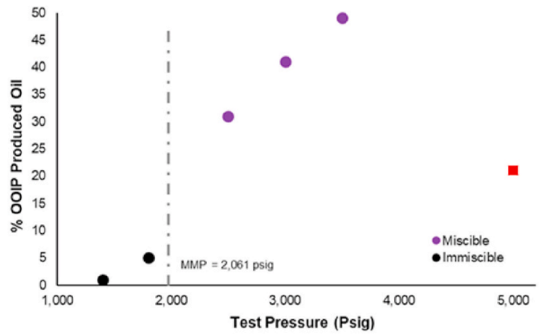


Fig. 9. Recovery factors as a function of time for the Huff-n-Puff experiment using enriched gas.

A positive correlation of experimental pressure and recovery factors was observed from the previous CO_2 tests. However, the result of the CO_2 experiment at 5000 psi fails to follow this trend, indicating higher injection pressure does not always result in higher oil production enhancement. The optimum pressure of CO_2 injection EOR in ULR is between 3500 and 5000 psi based on the laboratory observations. In deep shale reservoirs (depth > 10,000 ft), the pressure of these reservoirs may still be high after four years of oil production. If the injection pressure is 3500 psi, not enough volume of gas could be injected into those reservoirs to improve oil production from the gas injection process effectively. The corrosion issue of high pressure CO_2, which makes necessary low pressure injection (thus lesser oil yield), and the high cost of CO_2 in a large part of shale plays makes CO_2 an unsuitable choice as an EOR agent in ULR.

The average CT number change of the whole core throughout the first cycle of the CO_2 injection experiment was 17 HU, which was higher than the average CT difference of the CH_4 test. Heavier components of the oil were recovered from the CO_2 injection experiment, and the CT number has a positive correlation with density. Although the recovery factor of CH_4 experiments was higher than that from the CO_2 test, the average CT number difference of the CO_2 injection experiment was higher than using CH_4 due to the higher density of produced oil from the CO_2 injection experiment.

The color was much darker than the oil recovered from the other gas injection tests, and it was similar to the color of the original oil. Raymond and Leffler (2006) reported darker color of oil is heavier than light



Miscibility Status	Test Pressure (psig)	Oil Recovery (% of OOIP)
Miscible	5,000	21
	3,500	49
	3,000	41
	2,500	31
Immiscible	1,800	5
	1,400	1

Fig. 11. Ultimate recovery factors as a function of experimental pressure for all CO_2 Huff-n-Puff experiments.

color of oil. This observation indicates that heavier components of the oil were extracted from the core by the CO_2. The injection pressure was much higher than the MMP of the CO_2 – Wolfcamp oil system, which means that the majority of the oil components could reach the miscible state when the gas was injected. As oil was recovered from the outer layer of the core plug, gas may occupy the pore spaces, reducing the effects of the multi-contact process. On the contrary, during the other gas experiments, only the lighter components of the oil vaporized into the gas phase (much lighter color of the produced oil), and this resulted in a smaller gas blockage effect and higher oil recovery. This could explain why the recovery factor of the CO_2 Huff-n-Puff experiment at 5000 psi was lower than the recovery factors of the other gas experiments.

4.3. Foam Huff-n-Puff experiment

Injecting foam to improve oil recovery in depleted shale reservoirs is a new EOR technique. The main objectives of the foam Huff-n-Puff experiments are a) investigating the feasibility of foam injection for improving diversion in ultralow permeability shale reservoirs and b) evaluating the recovery performance of combined the gas and foam injection in ULR. A novel experimental workflow of foam injection experiments using the Huff-n-Puff protocol on saturated sidewall ULR core plugs was developed to reveal the capability of foam injection EOR in unconventional reservoirs. Two gases (gas (85–15) and enriched gas (50-50) with one type of selected surfactant are used in foam tests. The surfactant can effectively alter the wettability of rock from intermediate-wet to water-wet and adding surfactant can improve oil recovery compared to using brine alone (Zhang et al., 2018b). Results of the contact angle and IFT measurements using the selected surfactant are presented in Fig. 12. The surfactant can effectively alter the wettability of rock from intermediate-wet to water-wet and reduce IFT from 18.1 to 1.1 mN/m. It should be emphasized that we are not investigating improvement in diversion, but rather the understanding of displacement efficiency with the combined synergy of both foam and miscible gas.

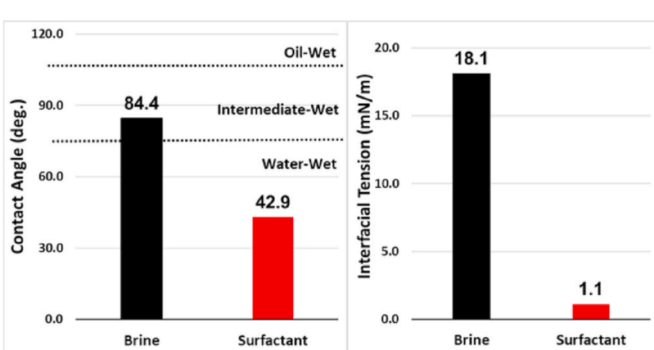


Fig. 12. Contact angle alteration and IFT reduction results using surfactants at 3 gpt with brine.

4.3.1. Foam-1 (surfactant + a mixture of 85% CH_4 and 15% C_2H_6) experiment

Foam-1 Huff-n-Puff experiment was performed at 5000 psig and reservoir temperature of 155 °F. The gas (85–15) and the selected surfactant were co-injected into the core holder at 13.9 ml/min and 5.9 ml/min, respectively, which corresponded to a 70% gas/liquid ratio. The result of the foam-1 Huff-n-Puff experiment is presented in Table 2. The time-lapse CT-scan images of three different cross-sections of the core plug and the glass beads pack in the foam-1 injection experiment are shown in Figs. 13 - 15. In addition, the color of the produced oil from the foam-1 test is shown in Fig. 16.

The recovery factor of the foam-1 injection experiment was 12.8% of OOIP, which was similar to the recovery factor obtained from the pure gas (85–15) injection experiment, which was 13% of OOIP. This is a pessimistic recovery factor due to residual oil retained in the glass beads pack. Fig. 20 shows a picture of the glass beads pack after the core holder was disassembled. Considering this residual oil, the actual recovery factor of the foam-1 experiment should be higher than the recovery factor from the corresponding gas injection test. These observations confirm the potential of foam injection as an EOR method for unconventional reservoirs. Furthermore, the foam could be used as a mobility control agent and could reduce the out of zone injection problems, making it more attractive than the pure gas injection.

Fig. 13 shows the CT images of the glass beads pack in the initial stages of the foam test (within 12 h). The first column (t = 0 gas) shows CT images of the glass beads pack invaded by pure gas (85–15) before the foam was injected in the core holder at 5000 psi. The second column (t = 0 foam) presents CT images of three different positions in the glass beads pack when the foam was initially injected in the core holder. Columns 3 to 5 show the CT change during the first 12 h of soaking. It is possible to see that the foam was successfully injected and filled the core-holder by comparing the CT images in the first two columns. Liquid water is clearly phase separating as evidenced from the CT scans. There is an obvious change in CT number across the gas-water interface (the change in CT number from −200 Hu to 1000 Hu), so it is proof that a gas-water interface exists. When the CT number is more homogeneous in the bead pack early in the test at a CT number representative of foam it is evidence that a homogeneous foam exists in the glass beads. When the foam collapsed, gravity segregation was observed, resulting in the CT number decreasing on the top part of the glass beads pack (filled with gas) and increased in the bottom part (filled with liquid).

The preliminary foam quality test indicates the foam lasts 30 min to

Table 2
Results of foam-1 Huff-n-Puff experiment using the gas mixture of 85% CH_4 and 15% C_2H_6 and pre-selected surfactant.

Injection Fluid	Pressure, psi	Temperature, °F	Recovery Factor
Surf and 85% CH_4-15% C_2H_6	5000	155	12.8%

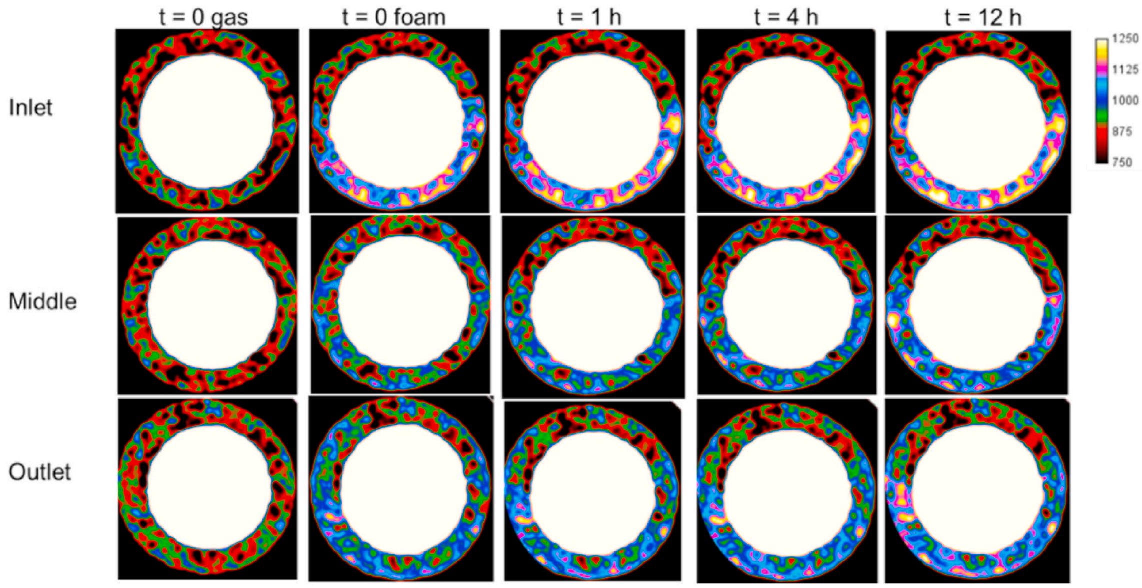


Fig. 13. Time-lapse CT images of three cross-sections (close to the inlet, in the middle of the core, and close to outlet) of the glass beads pack during the first 12 h of foam-1 Huff-n-Puff experiment.

1 h at 2000 psi and room temperature. Surprisingly, most of the foam still existed in the glass beads pack within the first 12 h of foam test. The foam tends to be more stable in the glass beads pack under pressure indicating a longer duration of foam in propped fractures. The glass beads pack is used to physical simulate hydraulic fracture and glass beads size is similar as proppant size. Porosity in the glass beads pack is also similar to porosity in the hydraulic fractures. The Huff-n-Puff experiment was designed to investigate the fluid exchange between hydraulic fractures and matrix. Foam stability observed from the foam Huff-n-Puff experiments could be used to represent the foam conditions in the field.

Fig. 14 shows the CT images of the glass beads pack throughout the entire experiment. An apparent color change from blue to almost white was observed in the bottom half of the glass beads pack; this indicated a density increase in the fluid occupying the bottom half of the glass beads pack, especially after 24 h. We could deduct that the half-life of the foam used in this experiment at 5000 psi was approximately 24 h. In addition, time-lapse CT images confirmed that the CT scanner was capable of tracking phase separation during the foam collapse process.

Fig. 15 shows the CT images of the core plug throughout the test. The average CT number change of the entire core plug was 4 HU, which was significantly smaller than the one obtained for the corresponding gas injection experiment. This was due to the competing water imbibing, which increases the CT number as opposed to gas penetration which lowers the CT number. The small average CT number change was manifested by the small color shift in the CT images.

The color of the produced oil was lighter than the original color of the Wolfcamp A, and it was similar to the produced oil from the corresponding gas test. However, darker oil was observed in the glass beads pack after the test, as shown in Fig. 16. These observations indicate that heavier components of the oil were recovered from the rock submerged in the surfactant solution, and the oil was trapped in the aqueous phase.

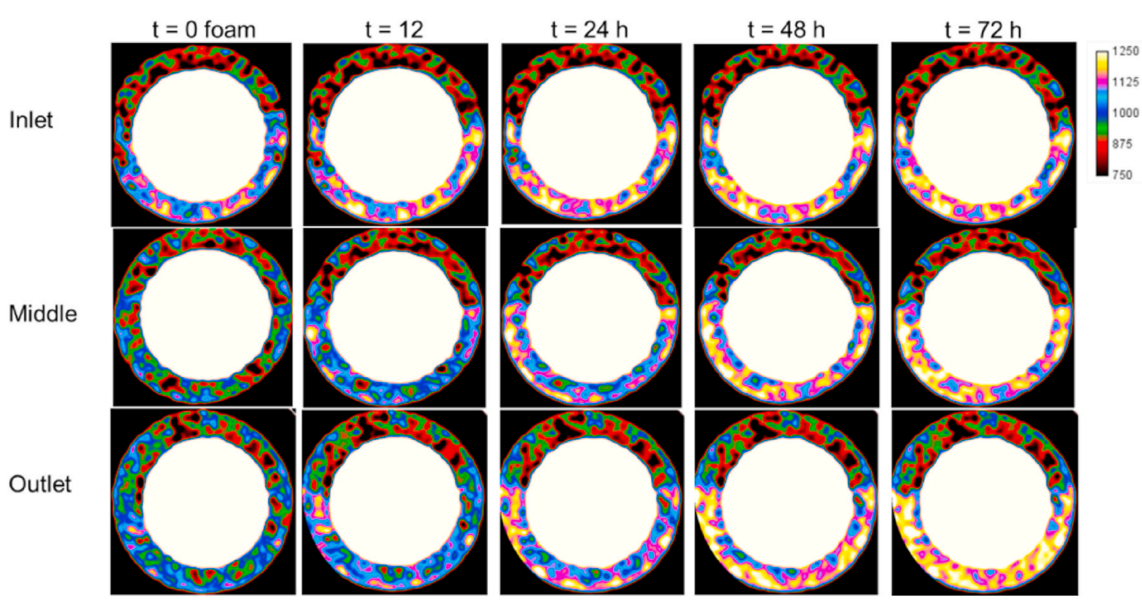


Fig. 14. Time-lapse CT images of three cross-sections (close to the inlet, in the middle of the core, and close to outlet) of the glass beads pack during the entire foam-1 Huff-n-Puff experiment.

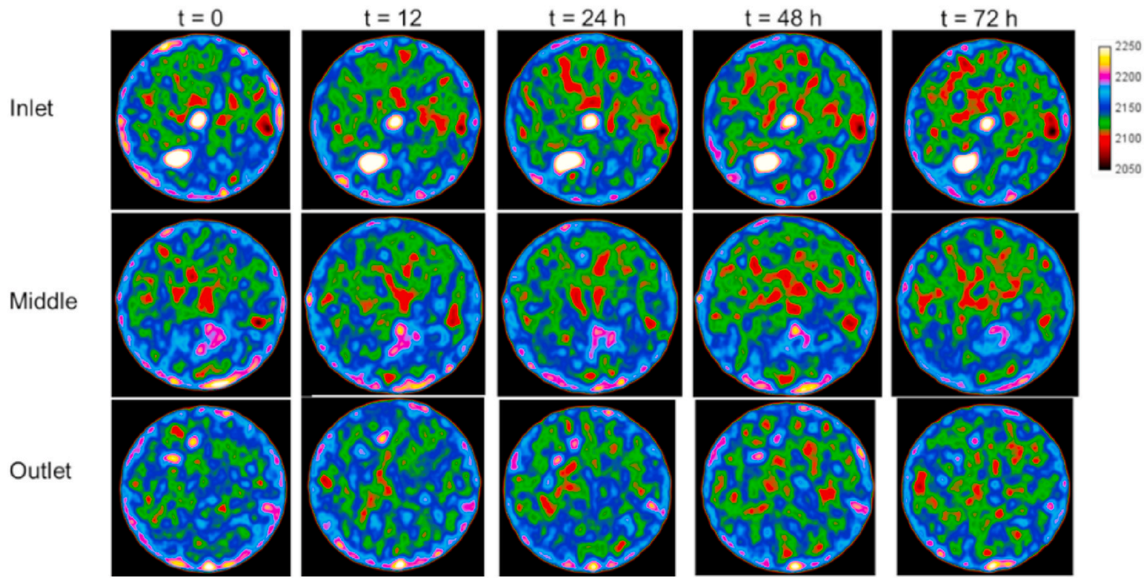


Fig. 15. Time-lapse CT images of three cross-sections from the core sample (close to the inlet, in the middle of the core, and close to outlet) during the foam-1 Huff-n-Puff experiment.

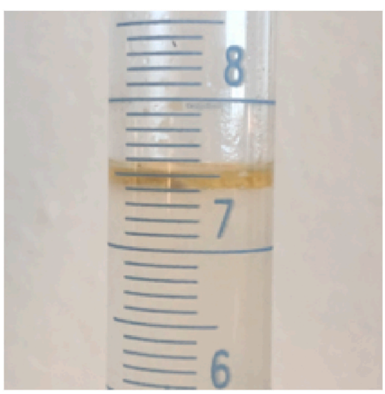


Fig. 16. Color of produced oil from the foam-1 Huff-n-Puff experiment. The color is similar to the oil produced in the corresponding gas test. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

Lighter components of the oil vaporized from the top half of the core and were produced with the gas. This indicated foam injection is a combination of chemical and gas injection EOR with the mechanisms of wettability alteration and multi-contact miscibility.

4.3.2. *Foam-2 (Surfactant + enriched gas (50% CH_4 and 50% C_2H_6)) experiment*

In the Foam-2 Huff-n-Puff experiment, enriched gas (50% CH_4 and 50% C_2H_6) and the selected surfactant were co-injected into the core holder at 13.9 ml/min and 5.9 ml/min, respectively, which corresponded to a 70% gas/liquid ratio. The result of the foam-2 injection experiment is listed in Table 3. The time-lapse CT-scan images of three different cross-sections of the glass beads pack and the core plug are shown in Figs. 17 and 18, respectively. In addition, the color of the produced oil from the foam-2 injection experiment is shown in Fig. 19.

Table 3
Results of foam-2 Huff-n-Puff experiment using the enriched gas (50% CH_4 and 50% C_2H_6) and pre-selected surfactant.

Injection Fluid	Pressure, psi	Temperature, °F	Recovery Factor
Surf and 50% CH_4-50% C_2H_6	5000	155	19.2%

The recovery factor, obtained after one cycle was 19.2% of OOIP. The enriched gas (50% CH_4 and 50% C_2H_6) seemed to perform better on ULR cores, resulting in a 6.2% increase in the ultimate recovery factor compared to the foam-1 test, however, the foam-1 test did not include the residual oil remaining in the glass beads pack. Furthermore, the recovery factor of the foam-2 test was smaller than the recovery factor of 23% obtained during the no-foam, enriched gas (50-50) experiment. Compared to the pure gas tests, however, the foam-2 experiment recovered darker oil which indicated that a larger number of oil components were recovered during the process. Surfactant can effectively alter the wettability of rock from intermediate-wet to water-wet and reduce IFT, resulting in long term oil rate improvement. Considering the effect of foam on mobility control and out of zone injection elimination, the foam injection could outperform the pure gas injection process in ULR.

Fig. 17 shows the CT images of the glass beads pack during the foam-2 experiment. The foam was successfully injected and filled the core-holder. An apparent color change from blue to bright white is observed at the bottom part of the glass beads pack, indicating that the foam collapsed after some time, leaving behind the aqueous phase. The half-life of the foam-2 at 5000 psi was also over 24 h, indicating the enriched gas (50-50) and the selected surfactant generated high quality foam. In addition, clear phase separation was observed in the glass beads pack during the soak period, with liquid occupying the bottom quarter of the glass beads pack.

Fig. 18 shows the CT images of the core plug throughout the foam-2 experiment. The average CT number change of the core plug throughout the foam-2 injection experiment was 3 HU, which was smaller than that of the previous test. Brine spontaneous imbibition process and multi-contact miscibility process co-occurred during the foam injection experiments. As brine imbibed into the core plug, the average CT number of core increased. On the contrary, the average CT number decreased as the gas dissolved into the oil phase. Thus, smaller average CT number change indicated that more brine imbibed into the core plug during the foam-2 experiment compared to the foam-1 test. A strong color shift of the core was not observed from the time-lapse CT images during the foam-2 injection experiment.

The color of the produced oil, as shown in Fig. 19, is darker than the

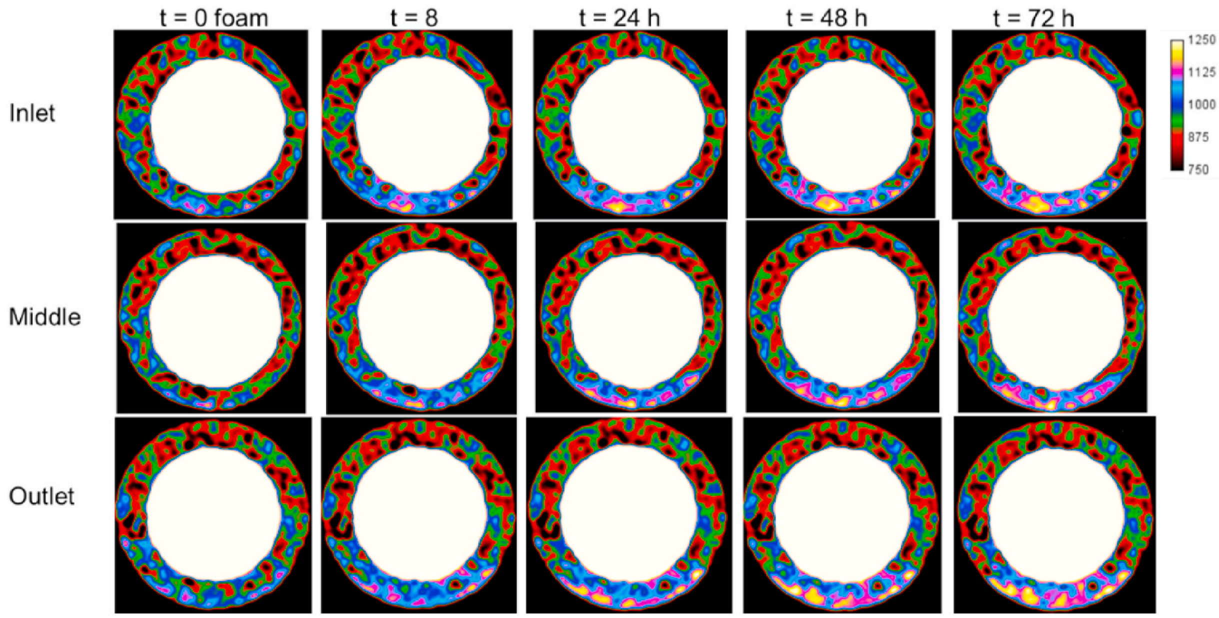


Fig. 17. Time-lapse CT images of three cross-sections (close to the inlet, in the middle of the core, and close to outlet) in the glass beads pack during the foam-2 Huff-n-Puff experiment.

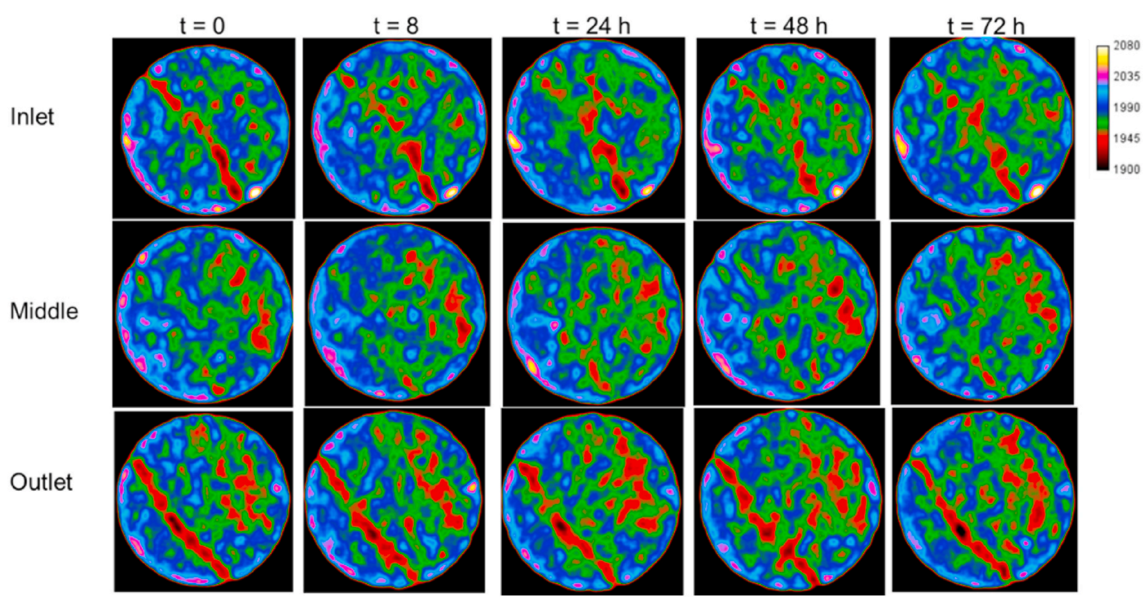


Fig. 18. Time-lapse CT images of three cross-sections from the core plug (close to the inlet, in the middle of the core, and close to outlet) during the foam-2 Huff-n-Puff experiment.

color of the produced oil from the corresponding enriched gas test. The color of produced oil from imbition tests is much darker than the oil produced from gas injection experiments (Zhang et al., 2018a). As demonstrated previously, the spontaneous imbibition process and multi-contact miscibility process co-occur during the foam Huff-n-Puff experiment. Heavier components of the oil were recovered through the imbibition process, and lighter components of the oil were extracted through the multi-contact miscibility process.

Fig. 20 compares the glass beads pack for the foam-1 and foam-2 Huff-n-Puff experiments after disassembling the core holder. The residual oil was found in the glass beads pack only after the foam-1 injection experiment, while the second test did not show any trapped oil. The main difference between the foam-1 and foam-2 tests was the gas composition that the fraction of ethane in enriched gas (50-50) is higher than gas (85–15). The supercritical enriched gas (50-50) may have a better potential to access the oil trapped in the glass beads pack and to displace oil to the outlet.

The residual oil in the glass beads pack was not included in the recovery factor calculation. The actual recovery factor of the foam-1 test is higher than that from the gas mixture (85% CH_4 - 15% C_2H_6) experiment. The additional oil produced from the foam-1 test follows the recovery mechanism of surfactant EOR. Therefore, foam injection is a combination of chemical and gas injection EOR with the mechanisms of wettability alteration and multi-contact miscibility.

In order to compare the production behavior of the gas and the foam injection processes, the normalized average CT number change as a function of time during gas and foam tests were plotted and analyzed. The slope of the normalized CT number curve represented the

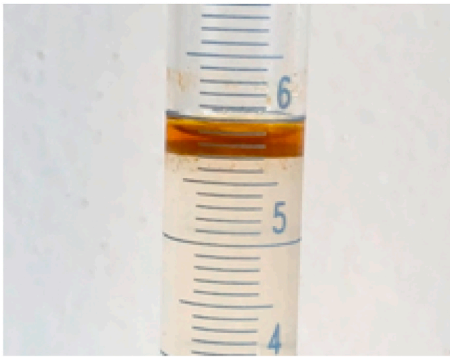


Fig. 19. Color of the produced oil (darker color than the corresponding gas test) from the foam-2 Huff-n-Puff experiment. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

production rate, and a larger slope corresponded to a higher oil production rate. Normalized average CT number curves of pure gas experiments (using CH_4, enriched gas (50-50), and CO_2) have a similar pattern (as shown in Fig. 21) that the recovery rate gradually decreases during gas injection experiments. This observation indicates that the gas injection process (regardless of gas composition) has a general normalized recovery rate curve.

The normalized CT is calculated by Eq. (1), where Average CT Number Change = $(\text{Average CT Number})_{\text{largest}} - (\text{Average CT Number})_{\text{smallest}}$ are listed in Table 4.

$$\text{Normalized CT} = \frac{(\text{Average CT Number})_{\text{current}} - (\text{Average CT Number})_{\text{end}}}{\text{Average CT Number Change}} \tag{1}$$

To systematically analyze the efficiency of foam-1 and foam-2 injection processes, the normalized average CT number curves were plotted for the CH_4, enriched gas (50-50), CO_2, foam-1, and foam-2 experiments in Figs. 22 and 23, respectively. The time lapse CT images of the glass beads pack during the two foam tests were also plotted in the corresponding figure.

In Fig. 23, the slope of normalized average CT number curve for foam-2 test is larger than other curves. It is possible to observe that the recovery rate of the foam-2 injection experiment was larger than the rate of all pure gas injection tests during the first 20 h. This observation indicates that the foam injection process could recover most of the oil in a shorter time compared to the gas injection process. On the other hand, the recovery rate of the foam-1 test is similar to gas injection experiments.

Figs. 22 and 23 shows that most of the foam collapsed within 48 h during the foam-1 experiment based on the CT images of the glass beads pack. In addition, the foam lifetime of the foam-2 experiment was 24 h. The normalized average CT number of the two foam experiments reached almost zero when all the foam collapsed (foam-1 test at 48 h and foam-2 test at 24 h), indicating that the average CT number of the foam test ceased to decrease when most of the foam collapsed. This observation demonstrates that the foam lifetime could affect the effectiveness of the foam injection processes on improving oil recovery.

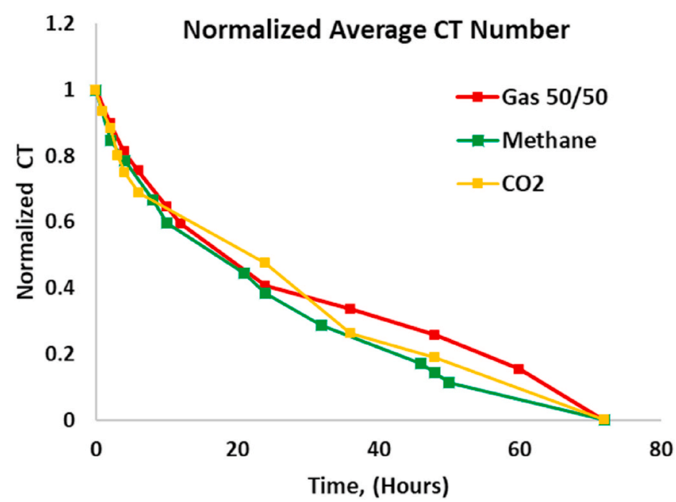


Fig. 21. The normalized average CT number as a function of time for pure gas experiments (using CH_4, enriched gas (50-50), and CO_2).

Table 4
Results of all Huff-n-Puff experiment (one Huff-n-Puff cycle) performed at 5000 psi and reservoir temperature of 155 °F.

Injection Fluid	Recovery Factor	Ave. CT No. Change (HU)
CH_4	9.7%	14
85% CH_4-15% C_2H_6	13%	18
50% CH_4-50% C_2H_6	23%	22
CO_2	9%	17
Surf. and 85% CH_4-15% C_2H_6	12.8%	4
Surf. and 50% CH_4-50% C_2H_6	19.2%	3

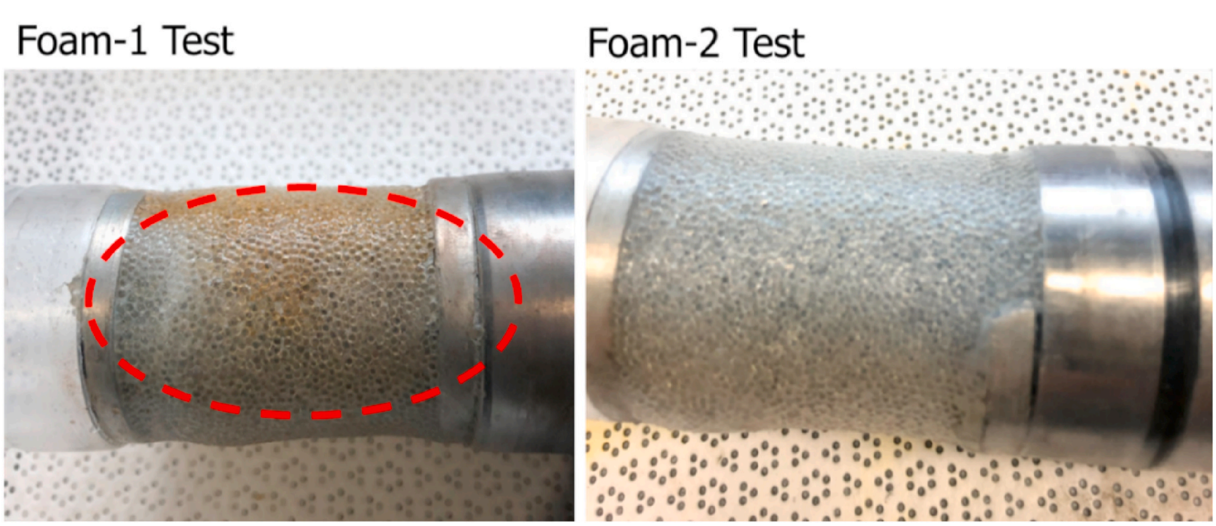


Fig. 20. Comparison of the glass beads pack for the foam-1 and foam-2 Huff-n-Puff experiments after disassembling the core holder.

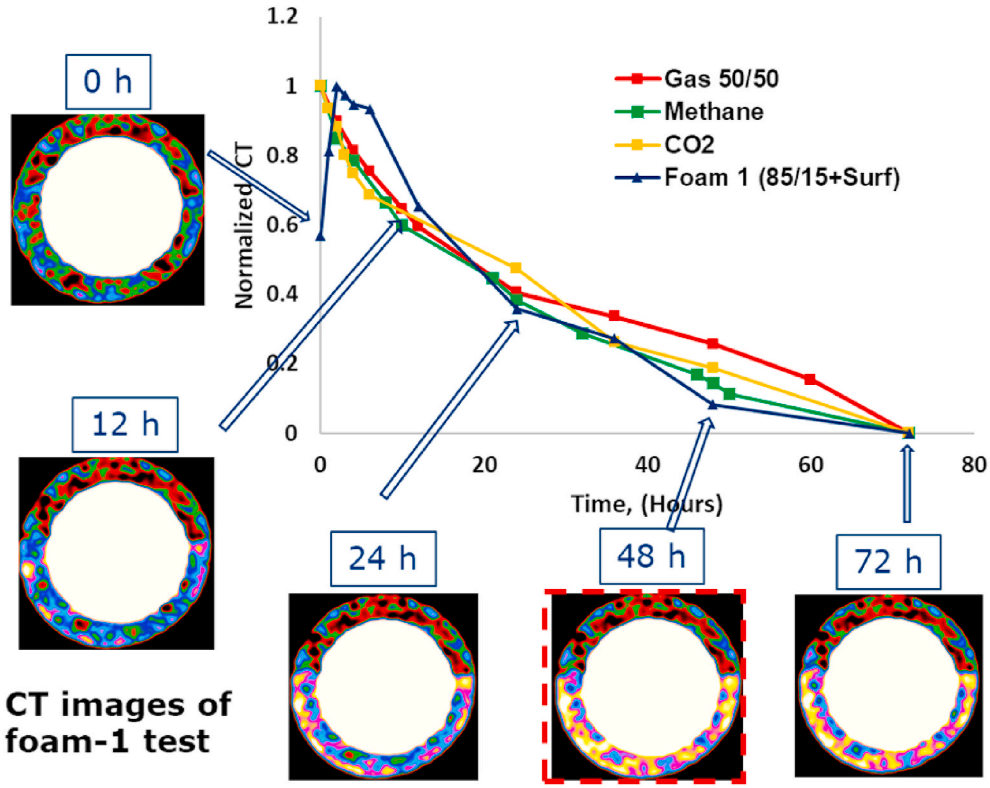


Fig. 22. The normalized average CT number curves from the Wolfcamp core plug during the CH_4, enriched gas, CO_2, and foam-1 Huff-n-Puff experiments and the time lapse CT images of the glass beads pack for the foam-1 test.

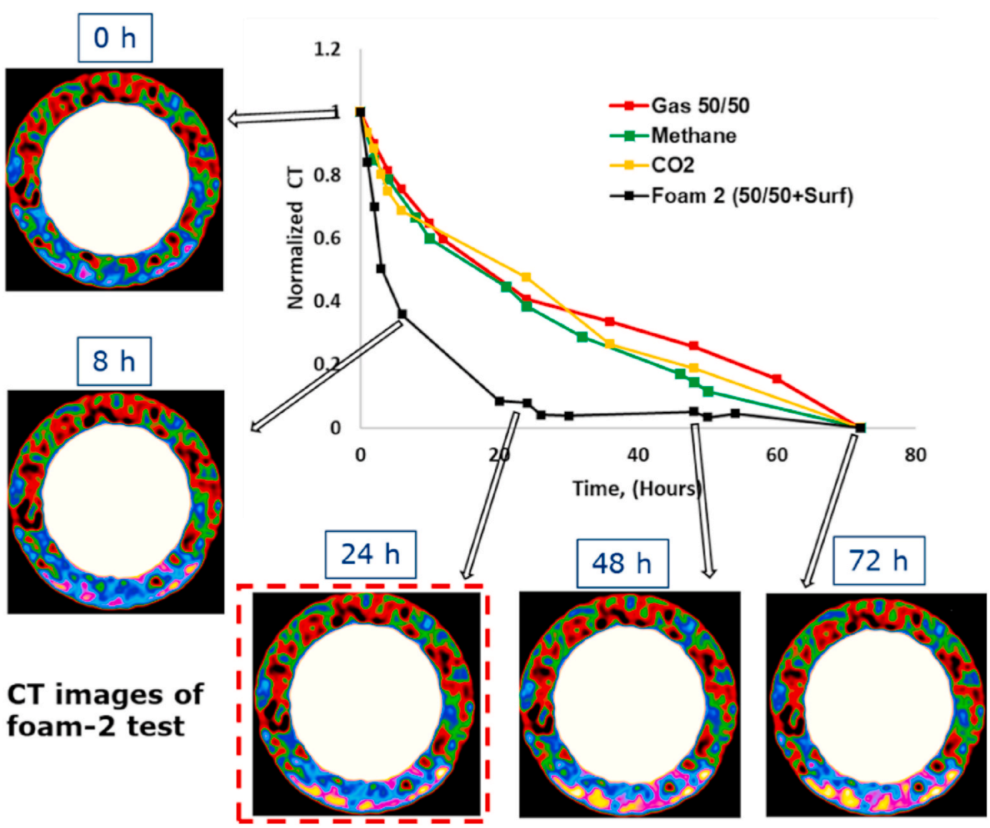


Fig. 23. The normalized average CT number curves from the Wolfcamp core sample during the CH_4, enriched gas, CO_2, and foam-2 Huff-n-Puff experiments and the time lapse CT images of the glass beads pack for the foam-2 test.

In addition, the normalized average CT number curve of the foam-1 experiment was similar to all pure gas injection tests, demonstrating that the dominant recovery mechanism of foam-1 experiment is multi-contact miscibility, which is the same to gas tests. However, the foam-2 possess showed a different curve shape compared to the other tests. Foam injection using enriched gas (50-50) was a fast process and recovered most of the oil within 24 h. Considering the color of the produced oil from the foam-2 test, heavier components were recovered during the foam-2 Huff-n-Puff experiment. These observations indicate that the recovery mechanisms of the foam-2 test are the combination of the recovery mechanisms of the gas injection and surfactant EOR. A proper foam generation formula is essential to improve oil recovery significantly and speed up this enhanced oil recovery process efficiently.

4.4. Color of the produced oil

Fig. 24 presents the color of the produced oil from all four gas Huff-n-Puff experiments after the first cycle (72 h soak and 3 h production). The oil recovered from the CO_2 injection experiment was much darker than the oil produced from all the other gas experiments, indicating that heavier components of the oil were extracted from the core by the high pressure CO_2. The oils produced from the gas Huff-n-Puff experiments using CH_4 and the mixture of 85% CH_4 and 15% C_2H_6 had a similar color (light yellow), and the colors of these oils were much lighter than the original oil. This observation demonstrates that only the lighter components were recovered by the gas injection process because the injection pressure was around the MMP. In addition, the color of the produced oil from the enriched gas experiment was slightly darker than the oil recovered from the CH_4 and the mixture tests. Some heavier components of the oil reached the miscible condition through the multi-contact miscibility process and consequently were collected in the graduated cylinder during the production period. In this case, the injection pressure (5000 psig) was much higher than the MMP (2853 psig) measured between the enriched gas and the Wolfcamp oil.

The color of the oil produced from the foam Huff-n-Puff experiments and the corresponding gas tests is presented in Fig. 25. The oil produced from the foam-1 experiment had a similar color to the oil produced from the gas mixture (85% CH_4 - 15% C_2H_6) Huff-n-Puff experiment. On the contrary, the oil produced from the foam-2 Huff-n-Puff experiment was much darker than the oil produced from the enriched gas (50% CH_4 - 50% C_2H_6) Huff-n-Puff experiment. The foam-2 generated from enriched gas (50% CH_4 - 50% C_2H_6) and the selected surfactant recovered heavier hydrocarbon components through the Huff-n-Puff experiments.

4.5. Summary of laboratory experiments

The results of all Huff-n-Puff experiments are presented in Table 4. The highest recovery factor was achieved from the enriched gas (50% CH_4 - 50% C_2H_6) Huff-n-Puff experiment and was equal to 23% of the original oil in place. Surprisingly, even if the MMP of CO_2 – Wolfcamp oil was the lowest, the recovery factor of the CO_2 Huff-n-Puff experiment was the lowest of all the gas-related Huff-n-Puff tests.

Based on the observations of gas Huff-n-Puff experiments, the injection pressure should be higher than the MMP to improve oil production in ULR significantly. However, injecting at very high pressure may have detrimental effects on the oil recovery, as shown in the CO_2 experiment. The MMP for the crude oil and the CO_2 is 2061 psi, and the Huff-n-Puff experiment is performed at a much higher pressure (5000 psi). Surprisingly, even if the high pressure CO_2 could recover heavier components of the oil, the ultimate oil recovery was less than all the other gas Huff-n-Puff experiments. Generally, the gas injection EOR technique has a better performance in improving oil production than chemical EOR methods in ULR. The optimum gas composition for gas injection EOR in the Wolfcamp reservoir is the enriched gas (50% CH_4-50% C_2H_6).

The results of the foam tests proved the feasibility of the foam injection EOR method in ULR and demonstrated that additional oil could be produced by this new technique. As the foam interacts with the reservoir rock, the imbibition process and gas vaporization process co-occur to expel oil from the matrix. Foam can be used as a mobility control agent, to improve the relative permeability, and to eliminate the out of zone injection. Injecting foam can further improve the oil recovery in ULR compared to the corresponding pure gas injection and opens the possibility of achieving optimum oil recovery for depleted well in ULR.

5. Conclusion

The results and the observations from this study confirmed the potential of various EOR methods on improving oil recovery in ULR and provide an insight into optimal EOR design for Wolfcamp reservoirs. The main conclusions and recommendations are the following:

1. Miscibility pressure measured with Wolfcamp-A oil via slim tube shows CO_2 with the lowest miscibility at 2061 psi and methane with the highest miscibility pressure of 5715 psi. Enriching methane with 15% and then 50% ethane reduces the miscibility pressure to 4452 psi and 2853 psi, respectively.

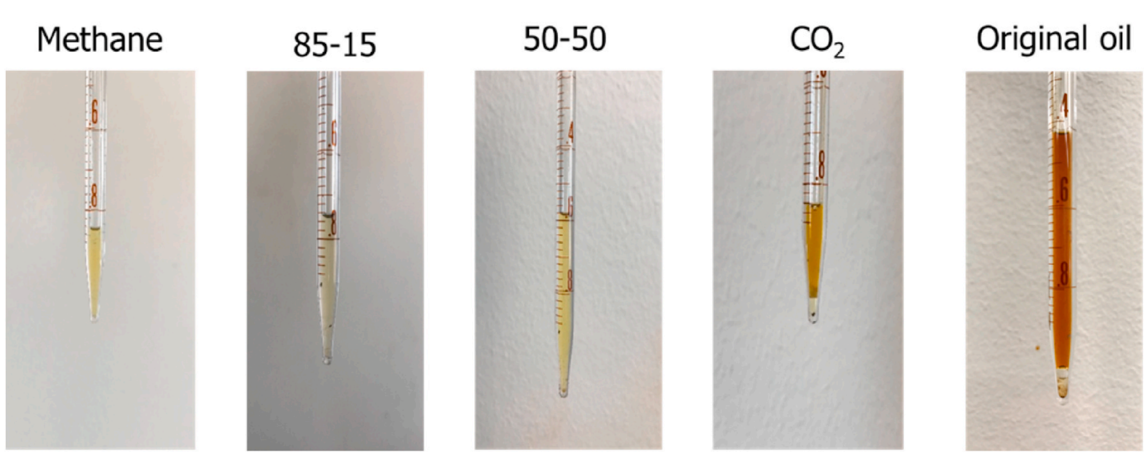


Fig. 24. The color of produced oil from all four gas Huff-n-Puff experiments. Gas 85/15 refers to the gas mixture of 85% CH_4 and 15% C_2H_6, Gas 50/50 refers to enriched gas (50% CH_4 and 50% C_2H_6), and original Wolfcamp oil. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

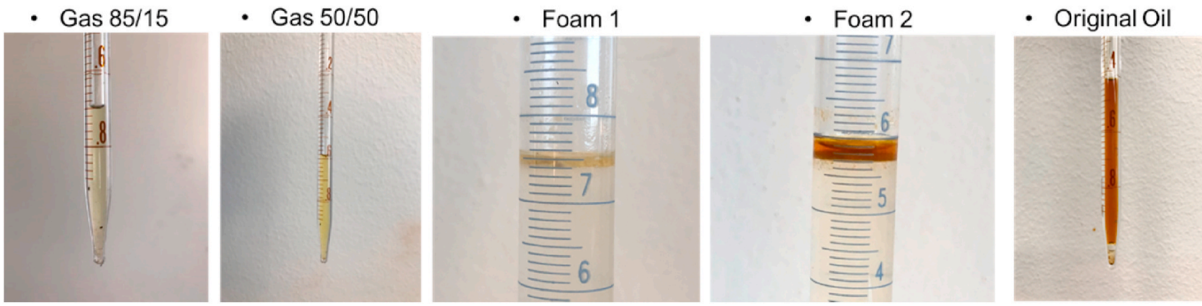


Fig. 25. The color of produced oil from foam Huff-n-Puff experiments and the corresponding gas experiments. Gas 85/15 refers to the gas mixture of 85% CH_4 and 15% C_2H_6, and Gas 50/50 refers to enriched gas (50% CH_4 and 50% C_2H_6). (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

2. When the injection pressure is lower than the MMP, less than 5% recovery factor is measured in cores aged in crude oil using CO_2. As the pressure increases above the miscibility pressure recovery factor increases substantially up to 50%. However, recovery factor diminishes to 21% at pressure well above the MMP (5000 psi) indicating an optimum pressure exists above the MMP.
3. Two experiments were performed with enriched gas (50-50) and gas (85–15) and showed a recovery factor of 23% and 13% respectively. Further enrichment of ethane results in higher recovery factors from core samples.
4. Normalized average CT number curves of pure gas experiments (using CH_4, enriched gas (50-50), and CO_2) have a similar pattern, indicating that the gas injection process (regardless of gas composition) has a general normalized recovery rate curve.
5. The surfactant used for foam trials also has the ability to alter wettability from intermediate wet (84°) to water wet (43°) and also reduces the IFT between water and crude oil from 18.1 mN/m to 1.1 mN/m.
6. Two foam experiments were performed with enriched gas, (50-50) and (85–15) and showed a recovery factor 19% and 13% respectively. Essentially, the presence of foam in the glass bead pack did not influence the recovery factor.
7. The foam tends to be more stable in the glass beads pack at high pressure indicating longer duration of foam in propped fractures. Recovery rate shows a positive trend with foam quality in that a more stable foam results in a higher recovery rate as observed in normalized CT number. The recovery rate dramatically decreases when most foam collapse.
8. The color of produced oil from foam tests is darker than the color of produced oil from no foam, pure gas injection experiments. The average CT number change during foam tests is smaller than the pure gas injection experiments. These observations indicate that the foam injection is a combination of aqueous phase penetration (increasing the CT number) from the wettability alteration effect and gas injection (decreasing the CT number) from the multi-contact miscibility mechanism.

Credit statement

Fan Zhang: Conceptualization, Methodology, Formal analysis, Investigation, Writing – original draft, Writing – review & editing, Validation. David S. Schechter: Supervision, Conceptualization, Methodology, Writing – original draft, Writing – review & editing, Validation.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.petrol.2021.108472.

Nomenclature

BPR	Back Pressure Regulators
CT	Computed tomography
CH	Core holder
DW	Distilled water
EIA	United States Energy Information Administration
EOR	Enhanced oil recovery
EUR	Estimated ultimate recovery
GC	Gas chromatography
GOR	Gas oil ratio
HU	Hounsfield Unit
IFT	Interfacial tension
MMP	Minimum miscibility pressure
PV	Pove volume
OB	Overburden

OOIP Original oil in place
SURF Surfactant
ULR Unconventional liquid reservoirs

Appendix A
Information of all core plugs used in this study

Core #	Diameter (in)	Length (in)	Clean Weight (g)	Saturated Weight (g)	Weight Diff. (g)	Pore Volume (cc)	Produced Oil (cc)
1	0.965	2	65.380	66.618	1.238	1.553	0.15
2	0.965	2	65.218	66.557	1.339	1.680	0.22
3	0.965	2	65.641	66.752	1.111	1.394	0.32
4	0.965	2	64.457	65.926	1.469	1.843	0.16
5	0.965	2	65.463	66.710	1.247	1.565	0.2
6	0.965	2	62.668	63.823	1.155	1.449	0.3

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