SPE-191752-MS

The Impact of MMP on Recovery Factor During CO2 – EOR in Unconventional Liquid Reservoirs

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This paper was prepared for presentation at the 2018 SPE Annual Technical Conference and Exhibition held in Dallas, Texas, 24-26 September 2018.

Abstract

In our previous publications (Tovar 2017; Tovar et al. 2018a, 2018b; Tovar et al. 2014), we presented a philosophy for the operation of gas injection processes in unconventional liquid reservoirs (ULR) that consisted in using a huff-and-puff scheme at the maximum possible pressure, regardless of the MMP. We also postulated a kinetically slow peripheral vaporizing gas drive as the main recovery mechanism underlying the rationale for such operational philosophy. We based all of our findings in a collection of 21 experiments performed using crude oil and core plugs from the Wolfcamp. The main focus of this paper is that the fundamentally different production mechanisms taking place in ULR cause the recovery factor to continue increasing when pressure is increased beyond the MMP. We do this using core plugs and crude oil from a different field, the Eagle Ford. Confirmation of this finding is necessary, since it directly contradicts the behavior in conventional reservoirs. We also demonstrate the addition of a dopant, into the crude oil, has little effect in the phase behavior, which widens the validity of all our work so far; and provides additional insights into the gas transport in the porous media. The production of oil from unconventional liquid reservoirs (ULR) has seen a significant increase in the last decade due to the implementation of horizontal drilling and hydraulic fracturing technologies. However, these reservoirs have mainly been exploited through primary production, which exhibits fast production decline and low ultimate recovery. Therefore, the need to understand different transport mechanisms and to develop enhanced oil recovery (EOR) techniques to improve ultimate oil recovery and extend the life of the asset is critical. This work investigates the effects of miscibility on enhancing recovery and the implementation benefits we can obtain from it.

We performed five additional core-flooding experiments. The cores were cleaned using an extended Dean-Stark extraction and re-saturated to known initial oil in place in the laboratory. Gas injection through a hydraulic fracture was simulated using high permeability glass beads surrounding the cores that were then packed in a core holder. The high permeability media was then saturated with CO_2 at constant pressure and reservoir temperature. The production was monitored using a CT scanning technology throughout the length of the experiments to track changes in composition and saturation as a function of time and space. Soak time was maintained constant and the experimental pressures were selected above and below the slim-tube MMP to show the effect of MMP on recovery.

Our results are consistent with a kinetically slow, peripheral vaporizing gas drive production mechanism. Recovery factor was 50% at the highest pressure of 3,500 psig. This is higher than the maximum of 40% we previously observed in the Wolfcamp, possibly due to the higher concentration of intermediate hydrocarbon components in the Eagle Ford, and the higher experimental pressure. Recovery factor increases with pressure, even above the MMP. The addition of 5% Iodobenzene in the Wolfcamp oil, increased the MMP by only 136 psig, or 7 %, indicating our conclusions are valid.

This work confirms our previous findings, which challenge the paradigm that establishing miscibility is enough to achieve the highest recovery factors during CO_2 flooding, as is the case in conventional reservoirs. This finding has a significant impact on field operations and should be considered during the design of gas injection EOR processes in ULR.

Introduction

The production of oil from unconventional liquid reservoirs (ULR) has seen a significant increase in the last decade due to the implementation of horizontal drilling and hydraulic fracturing technologies. However, these reservoirs have mainly been exploited through primary production, which exhibits fast production decline and low ultimate recovery. Therefore, the need to understand different transport mechanisms and to develop enhanced oil recovery (EOR) techniques to improve ultimate oil recovery and extend the life of the asset is critical (Zhang et al. 2018b; Zhang et al. 2018c). This work investigates the effects of miscibility on enhancing recovery and the implementation benefits we can obtain from it.

In earlier publications (Tovar 2017; Tovar et al. 2018a, 2018b; Tovar et al. 2014; Zou and Schechter 2017), we presented an overall evaluation of CO_2 injection for EOR in organic-rich shale. Experiments using preserved cores gave clarity to the potential of CO_2 to extract natural oil in organic-rich shale, while re-saturated core samples allowed us to compute accurate recovery factors, and evaluate the effect of soak time, operating pressure, and the relevance of slim-tube MMP on recovery.

The resulting experiments, in preserved sidewall cores, revealed the necessity of knowing the initial oil in place volume. Lacking numerical data for initial oil saturation in preserved sidewall core caused two significant problems. The first was the increasing uncertainty in the recovery factor acquired from every successful test. The second problem was that our core samples potentially had no oil saturation, resulting in unsuccessful tests. This prompted the development of equipment and procedures to clean, measure porosity and re-saturate core samples.

The re-saturated cores were used in two sets of experiments with CO_2. Knowing the oil saturation enabled us to accurately determine the recovery factor. In the first set of experiments, using core samples and oil from a Wolfcamp well # 1, the maximum recovery factor was 40% for a six-day experiment. Whereas the second set of experiments, using core samples and oil from well 2, the maximum recovery factor was 26% obtained over the course of 4.2 days. This was remarkably rapid considering the low permeability of the samples, each requiring, on average, four to five months at 10000 psig to achieve re-saturation. This demonstrated that CO_2 injection is a viable option that can achieve significant oil recovery in a realistic time frame.

During our experiments, we observed that both pressure and soak time caused increases in recovery factor. Increasing the pressure by 1,000 psig, resulted in an improved recovery factor from 44 to 338%, depending on soak time and crude oil composition. Likewise, transitioning from continuous flooding to huff-and-puff, with a soak time of 21 and 22 hours, produced an increase in recovery factor from 78.1 to 464.2%, depending on operating pressure and crude composition.

We showed that when CO_2 is injected to displace oil from the saturated core plug, the CT-number decreases at low pressures; whereas it increases at higher pressures. This is due to the much higher dependence of the density of CO_2 on pressure compared to of crude oil (Adel et al. 2018). The density of CO_2 can be higher, similar, or lower than the density of oil depending on operational pressure. If the density is similar, the scanner is not able to detect changes in saturation and composition as there are no changes in the overall density. In order to eliminate this restriction, we introduce a dopant that is placed in the oil prior to the saturation process. We selected Idobenzene in a concentration of 5% wt. The dopant changes the CT-number of the oil without changing its density, leading to a sufficient contrast between densities of oil and CO_2 no matter the pressure.

We also analyzed the subsequent effect MMP had on recovery and discovered something that proved to be a major departure from conventional knowledge. Increasing pressure beyond the MMP continues to increase recovery factor in organic-rich shale reservoirs. This is heavily related to the recovery mechanisms taking place and results in a major departure from the conventional paradigm that establishing miscibility is enough to achieve the highest recovery factors during CO_2 flooding.

This investigation demonstrates that CO_2 EOR is a technically feasible method of extraction for significant amounts of crude oil within organic-rich shale reservoirs, and it provides an operational understanding of the management pressure to maximize recovery. The recovery factors obtained in this investigation, in the context of the vast reservoirs of crude oil contained in organic-rich shale, can sustain a second shale revolution and further capitalize oilfield infrastructure.

In this paper, we investigate the effect of adding 5% wt. the concentration of Iodobenzene on the vaporizing-condensing gas drive that leads to the development of miscibility after multiple contacts in the slim tube. If the dopant increases the MMP drastically, we could be wrongly assuming a miscible behavior at a pressure below the MMP. We also present additional experimental data and analysis on the impact of MMP on recovery factor during CO_2 EOR in a different unconventional liquid reservoir.

This investigation demonstrates that CO_2 EOR is a technically feasible method of extraction for significant amounts of crude oil within organic-rich shale reservoirs, and it provides an operational understanding of the management pressure to maximize recovery. The recovery factors obtained in this investigation, in the context of the vast reservoirs of crude oil contained in organic-rich shale, can sustain a second shale revolution and further capitalize oilfield infrastructure.

Methodology

CO_2 Injection through a Hydraulic Fracture in Organic-Rich Shale

We developed a physical representation of a hydraulic fracture in the laboratory by surrounding an organic-rich shale core plug with 1 mm glass beads inside an aluminum core-holder, as shown in Figure 1. This set up is mounted into an aluminum core-holder that enables the penetration of X-rays. With this configuration, we closely reproduce field conditions by having a high permeability fracture in direct connection a matrix of permeability in the nano-darcy range. The equipment and experimental protocol are explained with further detail in our previous publications (Tovar 2017; Tovar et al. 2018a, 2018b; Tovar et al. 2014).

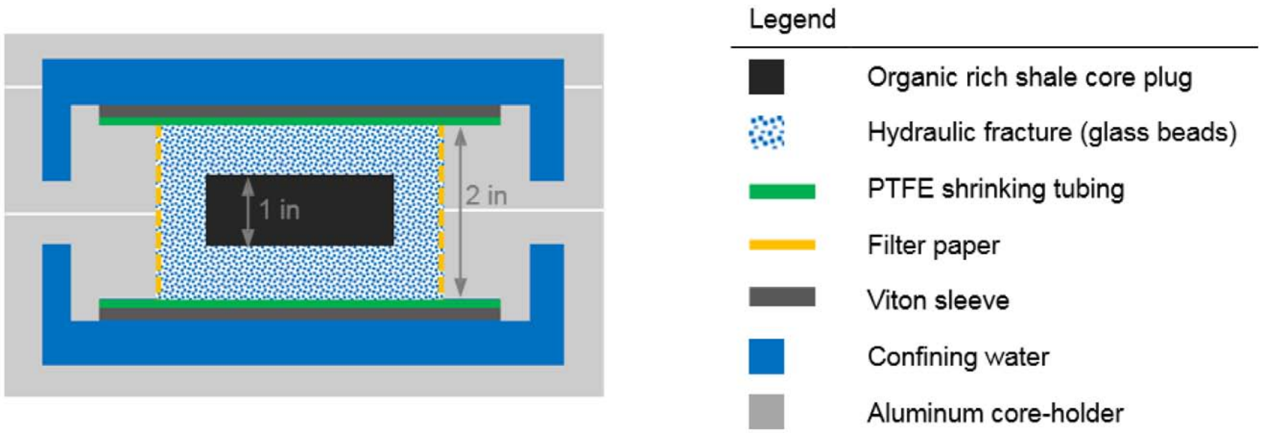


Figure 1—Schematic of the experimental representation of a hydraulic fracture well in an organic-rich shale reservoir (Tovar 190323)

All of the experiments were performed in a core- flooding equipment coupled to a CT-scanner which enabled time lapse, imaging capabilities, and gas injection under reservoir conditions of pressure and temperature, and confining pressure (Fig.2). The CT-scanner has an isotropic resolution of 350 microns. The equipment and experimental protocol are explained with further detail in our previous publications (Tovar et al. 2018a, 2018b; Zhang et al. 2018a).

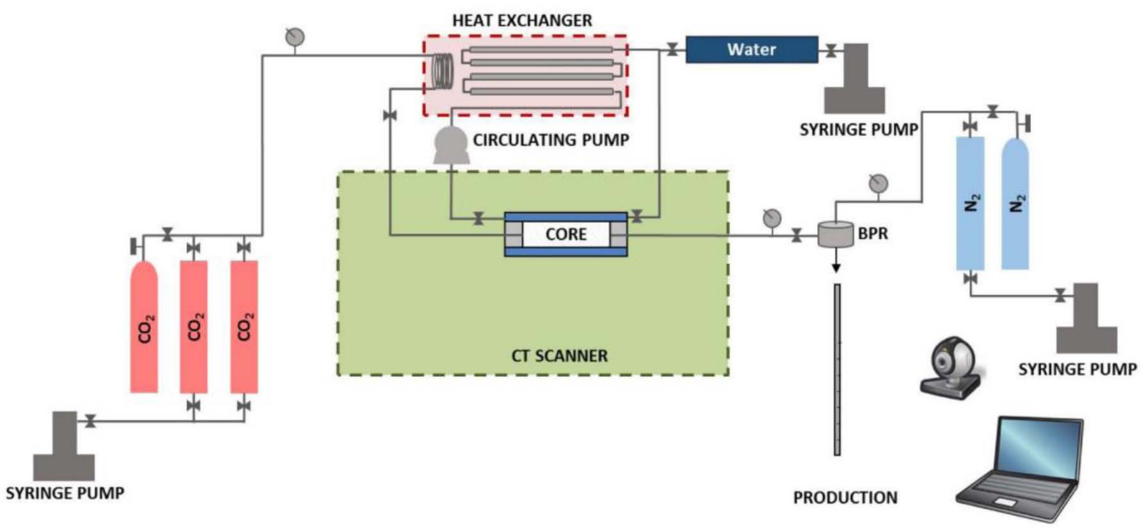


Figure 2—Schematic of the core-flooding experimental set up capable of capturing images of the interior of the core-holder by the use of Ct-scanning

Figure 3 depicts the stages of the experiment. Once the rock matrix-hydraulic fracture system is packed into the core-holder and connected to the core-flooding equipment, a vacuum is applied to remove the air. Then we inject CO_2 from a floating piston accumulator until we reach the desired experimental pressure. At this point, we start the soak time at constant pressure for 10 hours. During soaking, CT-scans are performed regularly to track the changes in density as a function of time and space.

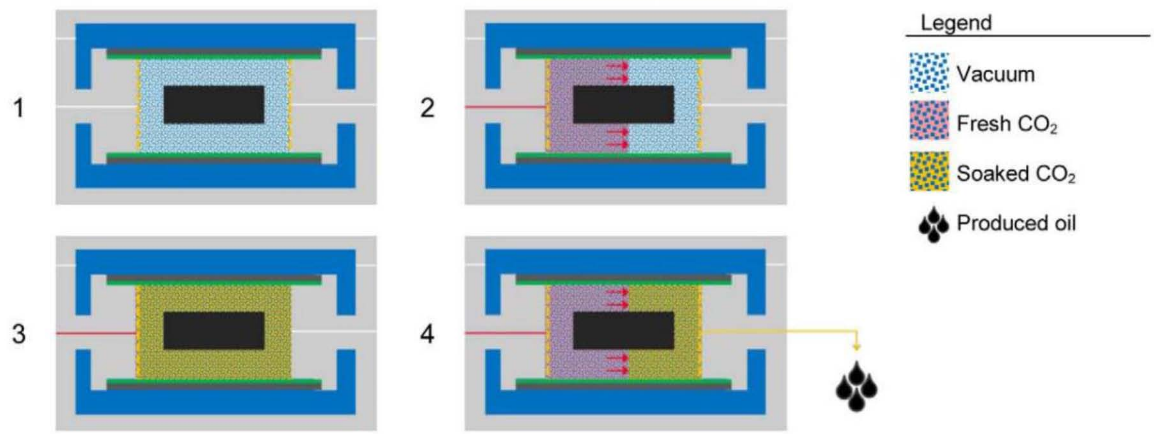


Figure 3—Stages of the injection process. (1) Air is extracted, and the core-holder is under vacuum. (2) CO_2 is injected from the accumulators at a constant pressure. (3) Soak is allowed. (4) The CO_2 that soaked the core is replaced by fresh CO_2 (Tovar et al. 2018a)

When soak time is completed, the CO_2 is displaced by fresh CO_2 at a low flow rate, and the effluents are collected. The described procedure constitutes one huff-and-puff injection cycle; the process is repeated for the subsequent huff-and-puff cycles until no more oil is produced and ultimate recovery is achieved.

Core plug preparation and re-saturation

We used five organic-rich shale core samples recovered from one well drilled in the Eagle Ford shale formation. They were cleaned using an extended version of the solvent extraction process first proposed by Dean and Stark (1920) and dried under vacuum. We re-saturated the clean core plugs in the laboratory using reservoir oil from the corresponding well. Idobenzene in a concentration of 5% wt was added to the crude oil as a dopant to improve visualization with the CT-Scanner. Re-saturation was performed under 10,000 psig at room temperature for two to four months (Fig.4) following a procedure we successfully introduced in our earlier work with the Wolfcamp (Tovar 2017; Tovar et al. 2018a).

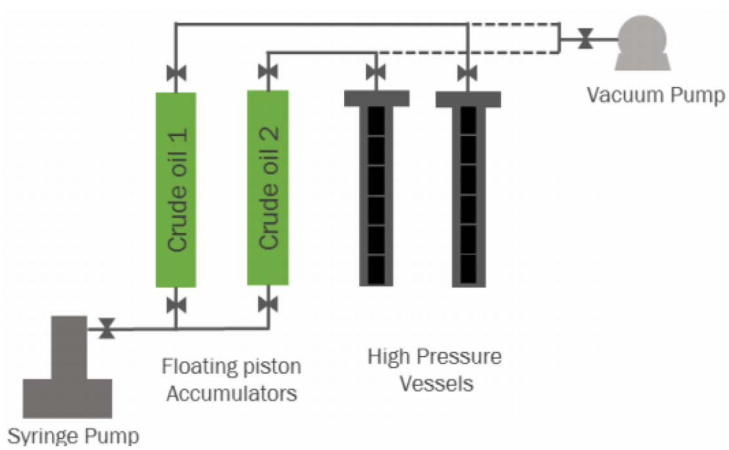


Figure 4—Schematic of the equipment used for organic-rich shale cores saturation with dead crude oil

The saturation process is monitored by recording the change in weight as a function of time for each of the samples. The process is stopped when the weight was constant for two consecutive weeks. All five core plugs have a 1in diameter, but their length varies from 1.5 to 2.3 in. The dimensions, the injected oil volume, and the experimental operating pressure for each core are presented in Table 1

Table 1—Core plugs injected oil volume, and experimental pressure

Core #	Core length (in)	Injected Oil Volume (ml)	Experimental Pressure (psig)
EF 1	2.3	2.900	2,500
EF 2	2.0	1.785	3,000
EF 3	2.0	1.744	3,500
EF 4	1.5	1.129	1,400
EF 5	1.8	2.361	1,800

CT-scanning technology is used to track the saturation changes over time. The cores are scanned and weighed weekly. Figure 5 displays the changes in CT number for two slices in core EF3. The first scan at time zero is done after the core is cleaned using the Dean-Stark method, before inserting it in the saturation equipment. The last scan shows the final saturation after three months in the saturation apparatus. The images show CT number increases at each time step, as the oil penetrates the core. The Hounsfield unit or CT-number is directly proportional to the density since the pores are being saturated with oil, the overall density is increasing and therefore, the CT-number.

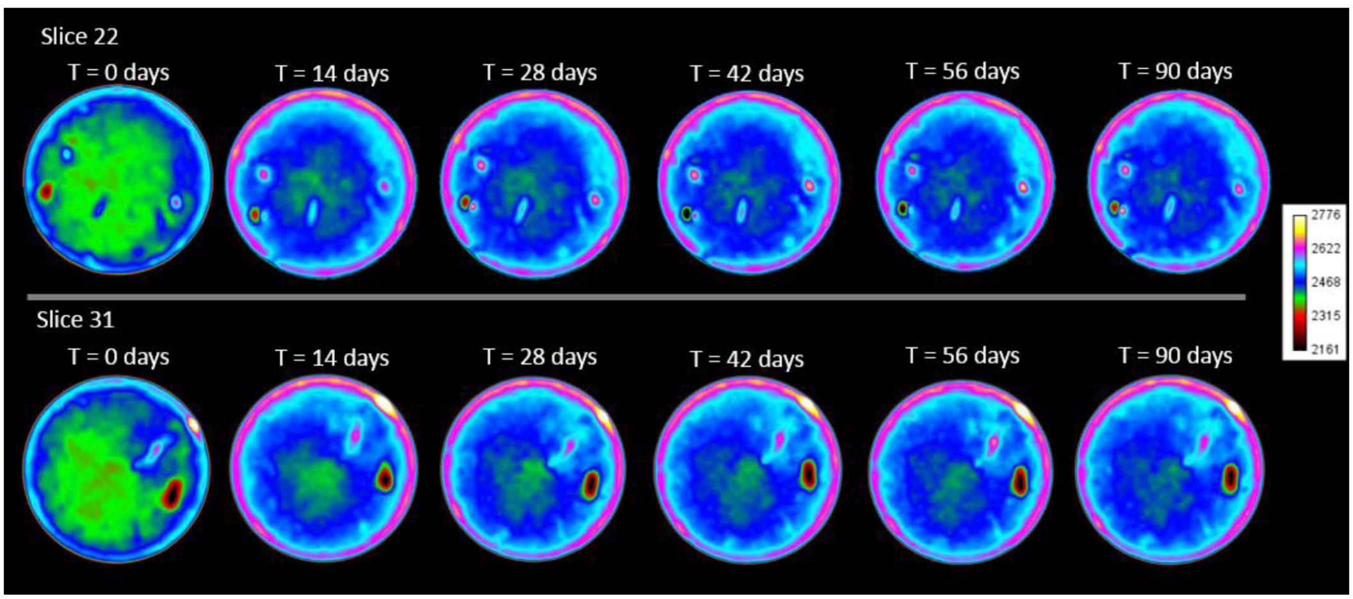


Figure 5—CT-scan images tracking the changes in saturation over time for core EF3

Minimum Miscibility Pressure Determination

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 (Adel et al. 2016). It simulates the 1-D displacement of the reservoir crude oil by the injected CO_2 through a porous medium and fully accounting for the thermodynamic phenomenon, the effect of displacement efficiency and phase behavior taking place in the CO_2 – oil system inside a sand packed stainless steel coil. This method, being one dimensional, avoids the unfavorable conditions such as gravity override, unfavorable viscosity ratios and fingering, making this method the most accurate way to determine the MMP.

Figure 6 represents the schematic of the experimental apparatus. An 80 ft slim tube coil was used for the MMP determination. The coil is made of stainless steel with an inside diameter of 0.25 in, a thickness of 0.063 in, and is packed with 100 – 150 mesh Ottawa sand.

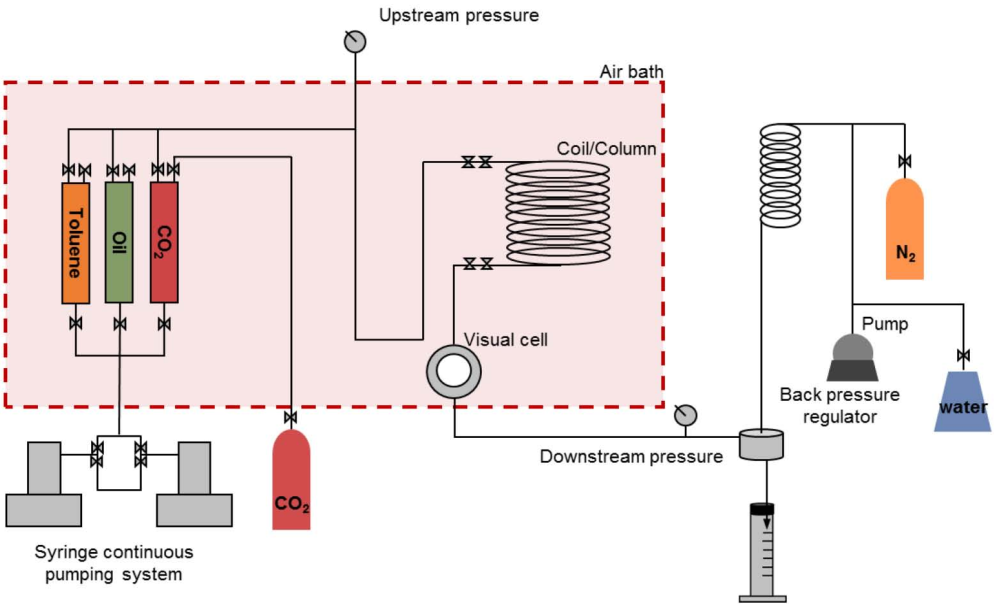


Figure 6—Schematic of the set up for the MMP determination apparatus using the slim tube technique (Tovar et al., 2015)

The effluents are measured along the duration of the experiment to calculate the recovery factor at each pressure. The resulting recovery factors are plotted as a function of the pressure, and two regions are identified. The immiscible region, where the recovery factor is a strong function of pressure, and the miscible region, where the recovery factor is a weak function of pressure. The MMP of each sample was determined by fitting a straight line through each group of data points representing either the miscible or the immiscible region and solving for the interception point of the two trend lines.

Results and Discussions

Minimum Miscibility Pressure Determination

In conventional reservoirs, MMP is a crucial parameter for the design of gas EOR projects. Miscible gas injection in high permeability sandstones and carbonates is operated slightly above the MMP. This is because further increasing the pressure does not result in additional recovery since the displacement efficiency is already close to 100 %, so there is no point in incurring at the expense of additional compression. We have argued this is not the case for unconventional reservoirs, where further increments in pressure above the MMP do result in additional oil recovery, and therefore these reservoirs should be operated at the highest possible pressure (references).

Li and Misra (2017); (Teklu et al. 2014; Zhang et al. 2016), argues that the MMP is lower in mesopores (2-50 nm) and micropores (<<2nm) as a result of confinement. However, research on phase behavior under confinement is ongoing and there is no experimental technique to determine MMP in such cases. Also, we do not know if MMP determination will be relevant in these cases. Thus, we use the slim tubing technique in our work, in order to establish the relevance of the MMP we can currently measure.

Our results show the addition of iodobenzene in a concentration of 5% wt. does not significantly affect the vaporizing-condensing gas drive that leads to the development of multi-contact miscibility. We used the crude oil from the Wolfcamp, also used in our previous work publications (Tovar 2017; Tovar et al. 2018a, 2018b; Tovar et al. 2014), and found that the addition of 5% Idobenzene increased the MMP by only 136 psig, or 7% (Table 2 and figure 7) further supporting the validity of our previous conclusions. We had shown already that the addition of Iodobenzene does not cause a significant increase in the oil density either.

Table 2—Slim tube recovery factors as a function of pressure for the MMP determination for the $CO_{2.}$ – Wolfcamp oil system.

	Original Wolfcamp Crude Oil - Well 2		Doped Wolfcamp Crude Oil - Well 2	
Miscibility Status	Test Pressure (psig)	Oil Recovery (% of OOIP)	Test Pressure (psig)	Oil recovery (% of OOIP)
Miscible	6000	83.5	6000	82.7
	3500	81.3	3500	80.5
Immiscible	1450	64.4	1450	62.6
	1000	49.7	1000	50.2
Res Temp (°F)	155		155	
MMP (psig)	1,925		2,061	

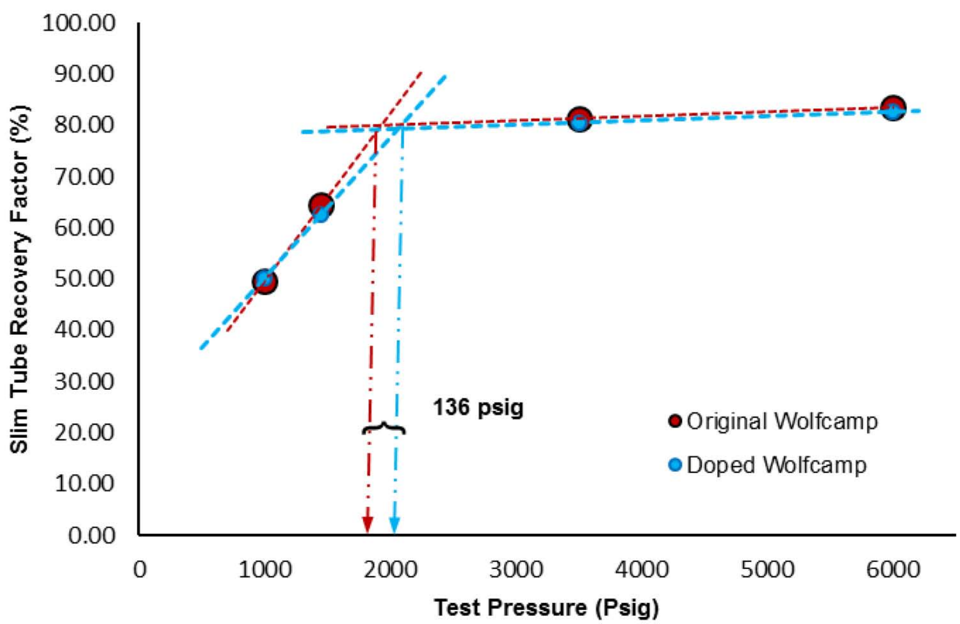
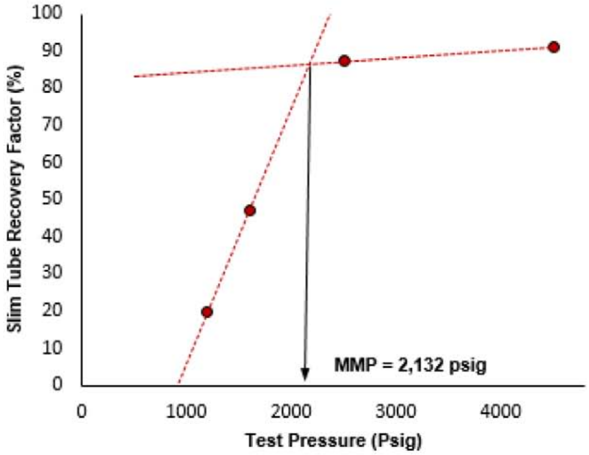


Figure 7—Slim tube recovery factors as a function of pressure for the MMP determination for the $CO_{2.}$ –Wolfcamp oil system. With dopant, MMP = 2,061 psig. Without dopant, MMP = 1,925 psig.

The Eagle Ford was chosen as a second ULR play to validate our previous results, as it has a higher temperature and a lower API gravity compared to the Wolfcamp. The recovery factor as a function of pressure for the doped Eagle Ford crude oil that is used to re-saturate the core plugs is presented in Figure 8.



Miscibility Status	Doped Eagle Ford Crude Oil	
	Test Pressure (psig)	Oil Recovery (% of OOIP)
Miscible	4500	91.3
	2500	87.24
Immiscible	1600	47.23
	1200	19.62
Res Temp (°F)	170	
MMP (psig)	2,132	

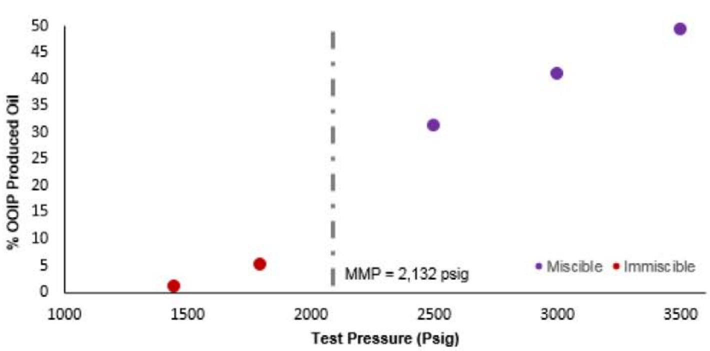
Figure 8—(a – left) MMP plot showing the recovery as a function of pressure for the doped Eagle Ford oil. (b – right) Slim tube recovery factors as a function of pressure for the MMP determination for the CO_2. – Wolfcamp oil system

CO_2 Injection through a Hydraulic Fracture in Organic-Rich Shale

We examined the relationship between the operating pressure and the slim tube MMP. The purpose is to investigate how externally controlled parameters such as the operating pressure can be optimized to maximize recovery from unconventional liquid reservoirs.

Five experiments using re-saturated Eagle Ford core plugs were conducted. The high permeability media was then saturated with CO_2 at constant pressure and reservoir temperature. The production was monitored using CT scanning technology throughout the length of the experiments to track changes in composition and saturation as a function of time and space. Soak time was maintained constant and the experimental pressures were selected above and below the slim-tube MMP to show the effect of MMP on recovery.

Effect of pressure on recovery factor.. Our results using Eagle Ford core plugs and oil for huff and puff injection clearly show that the operating pressure strongly affects the recovery factor. Increasing pressure always leads to an increase in the recovery factor. These results confirm and validate our previous conclusions from similar experiments using Wolfcamp core plugs and oil (Tovar et al. 2018a). Figure 9 presents the recovery factor as a function of operating pressure during the huff and puff experiments. Recovery factor was 49.31% at the highest pressure of 3,500 psig. This is higher than the maximum of 40% we previously observed in the Wolfcamp, and the reason is possibly due to the higher concentration of intermediate hydrocarbon components in the Eagle Ford, and the higher experimental pressure.



Miscibility Status	Test Pressure (psig)	Oil Recovery (% of OOIP)
Miscible	3500	49.31
	3000	40.9
	2500	31.03
Immiscible	1800	5.00
	1450	1.00
Res Temp (°F)	170	
MMP (psig)	2,132	

Figure 9—Ultimate recovery factor as a function of the operating pressure during the huff and puff experiment.

The crude oil produced from the CO_2 Huff and Puff experiments is much lighter than the original oil used to saturate the cores as we can see an obvious change in the color between the oil samples (Fig.10)

Figure 10—Contrast in color between the oil in place and the produced oil from core EF3 at 3,500 psig

Increasing the pressure from 2,500 psig to 3,500 psig increased the recovery factor by 60% during the CO_2 huff-and-puff experiments. Under the same conditions in conventional reservoirs, recovery is maximized once the MMP is attained.

Therefore, these results represent a sharp departure from conventional behavior. This is because further increasing pressure beyond the slim tube MMP of 2,132 psig results in much higher recovery factors. This was also observed in the set of experiments performed in the Wolfcamp.

Time-frame for recovery.. Figure 11 shows the recovery factor per cycle number for the CO_2 huff-and-puff experiment performed on core EF3 at a pressure of 3,500 psig. Most of the oil is recovered during the first cycle, which implies it occurs in the first 13 hours. Similar results were observed in all the huff-and-puff experiments.

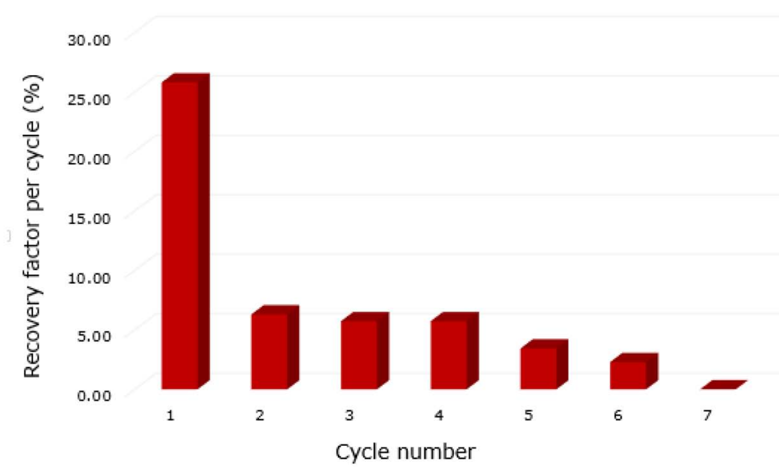


Figure 11—Recovery factor per cycle during CO_2 huff-and-puff experiment on core plug EF3 at 3,500 psig and soak time of 10 hours

Figures 12 and 13 show the recovery rates from the core plugs over time for pressures above the MMP. The first CO_2 huff-n-puff cycles, composed of a soaking interval (SI1) and a production interval (P1), depleted the cores the fastest and produced about 50% of the ultimate recovery. The oil recovery rate starts decreasing after the first cycle until it levels off as the maximum recovery is approached.

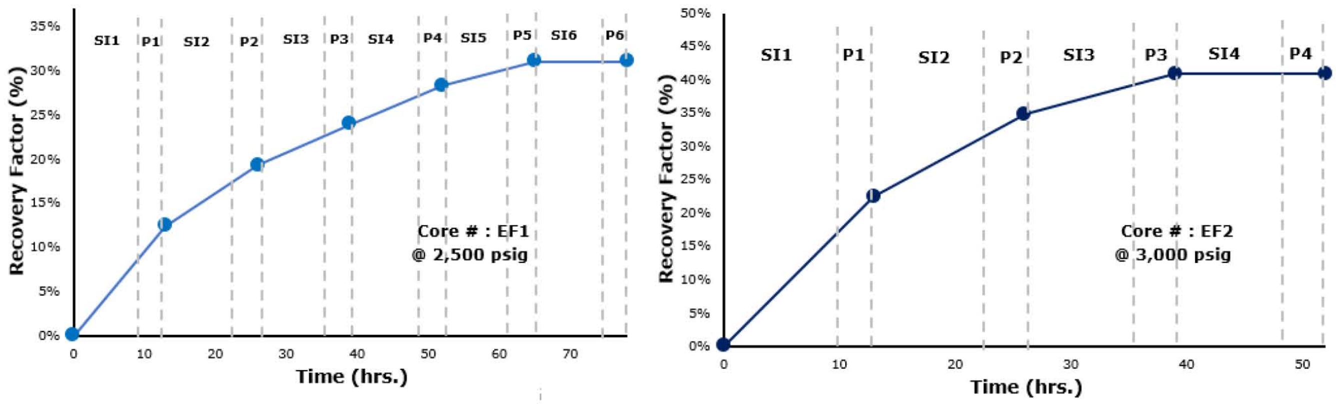


Figure 12—Recovery factors as a function of time for cores EF1 and EF2 at pressures of 2,500 and 3,000 psig.

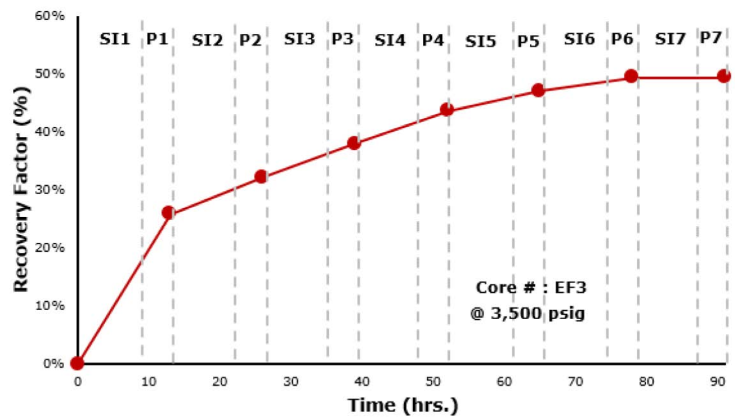


Figure 13—Recovery factors as a function of time for cores EF3 at 3,500 psig.

Figure 14 presents the oil recovery with time for CO_2 huff-n-puff experiments that were performed at pressures below MMP. In these experiments, oil was produced only in the first huff-n-puff cycle. The oil recovery factors for these experiments were 1% and 5%.

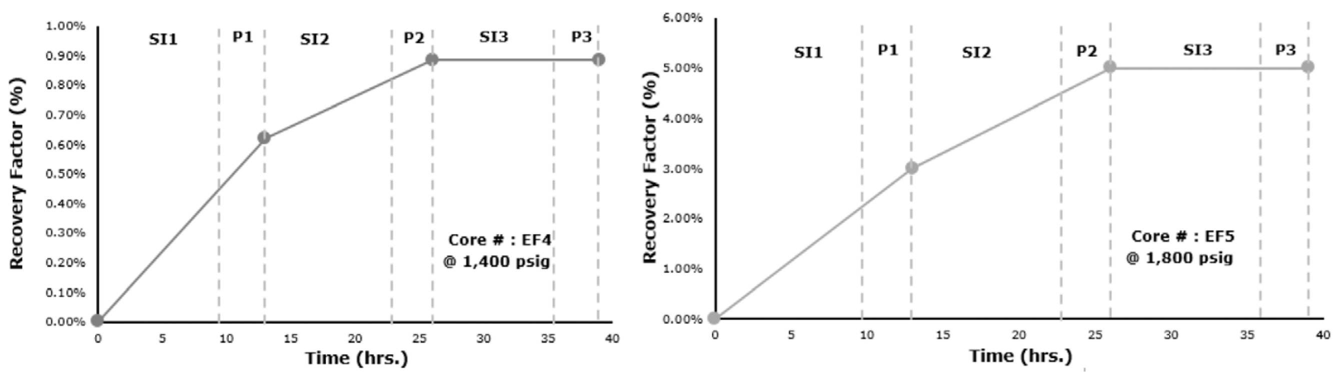


Figure 14—Recovery factors as a function of time for cores EF4 and EF5 at pressures of 1,400 and 1,800 psig.

The time frame in which oil is a recovery in any EOR project is critical for economic success. The feasibility of gas EOR processes in ULR has been questioned due to the slow fluid transport. Our experimental results illustrate that recovering oil from organic-rich shales during CO_2 huff-n-puff is not a lengthy process. Recovery from core plugs that takes several months to saturate is rapid compared to the expectations from nano-Darcy rock samples.

This work confirms our previous findings, which challenge the paradigm that establishing miscibility is enough to achieve the highest recovery factors during CO_2 flooding, as is the case in conventional reservoirs. The best way to operate gas injection processes in organic-rich shales is by designing a huff-and-puff project at the highest pressure possible, regardless of the crude oil – gas MMP. Our results show that further increasing pressure beyond the MMP results in higher recovery factors. Operating significantly above the MMP is counter-intuitive with respect to the mechanistic understanding of miscibility and decades of field industry experience with conventional reservoirs.

This finding has a significant impact on field operations and should be considered during the design of gas injection EOR processes in ULR.

CT-Scan Images

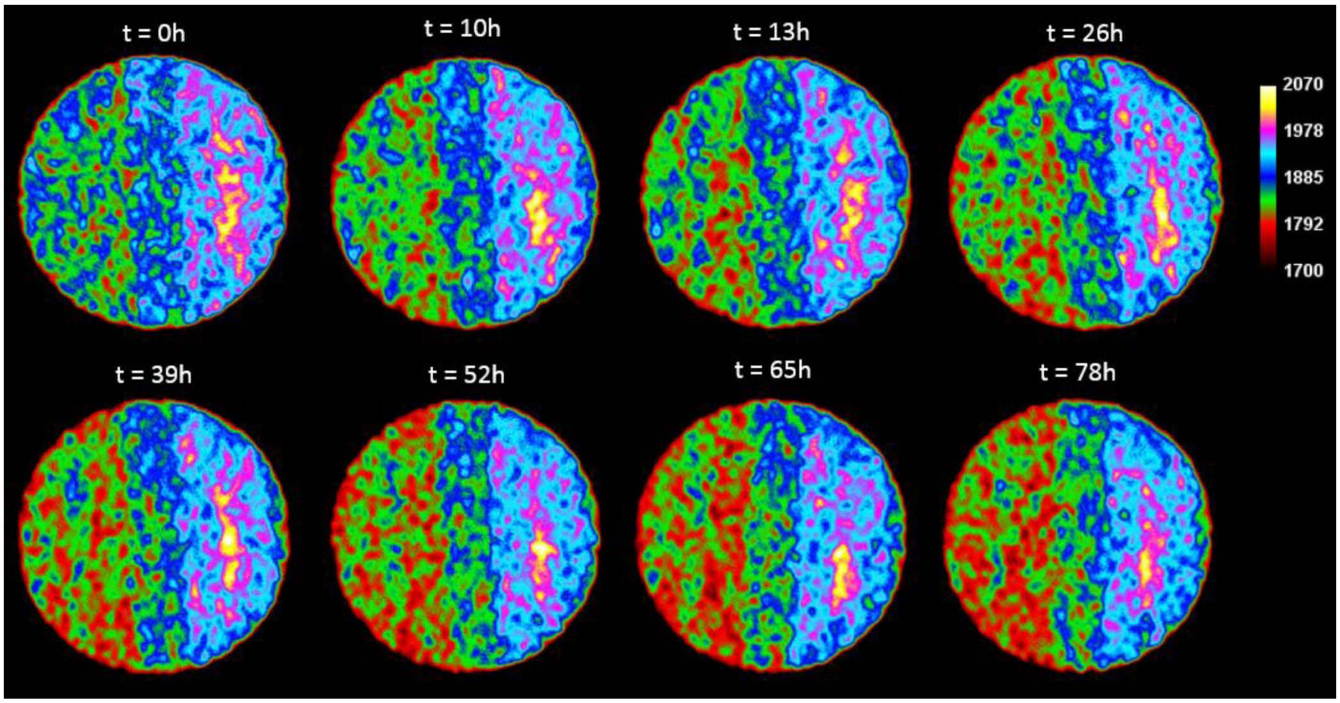


Figure 15—CT-scan images from the gas injection experiment of core EF3 at 3,500 psi

Figure 15 presents a color shift from higher CT number to lower CT number. Throughout the gas injection experiment, the color of the left side of CT images changed from initially blue and green color to red, which means the density of that area decreased to a lower value. It is evidence that CO_2 penetrate into the core plug and oil extracted out from the matrix. In addition, left part of CT images has a more considerable CT number differences than the right side. From the literature, CT number has a negative trend with porosity; higher CT numbers leads to lower porosity (Tovar 2017; Tovar et al. 2018a).

The average CT number of whole core and each slice of the core plug was calculated. We estimate these average CT numbers from the CT scans of CO_2 huff-n-puff experiment at 3,500 psi in Figures 15 and 16. In addition, a plot of CT number difference of the whole core and recovery factors is presented to demonstrate the correlation between the two factors.

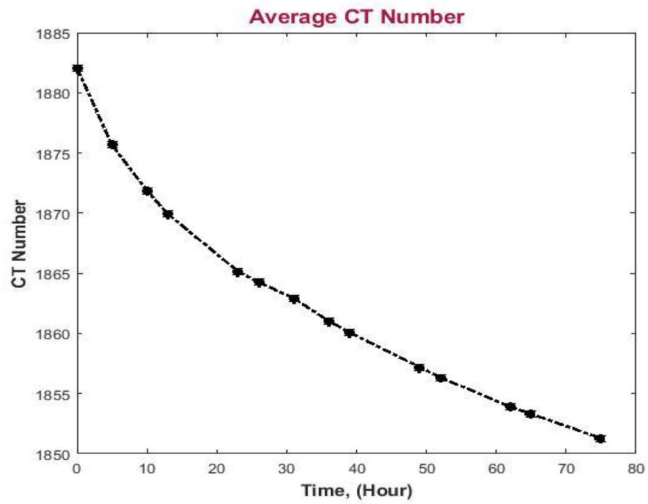


Figure 16—Average CT number for entire core plug during gas injection experiment at 3,500 psi

Figure 16 presents the average CT number of the whole core decreases as the experiment develops. Since the CT number of the doped oil is higher than the CT number of the CO_2 phase at all pressures, this CT number decreasing indicates that the oil was replaced by the CO_2 inside of the core. Figure 16 shows that the average CT number of the whole core decreases as the experiment develops. This decrease in CT number indicates that the oil was replaced by CO_2 inside of the core, since the CT number of oil is higher than the one of the CO_2 phase, this decrease in CT number indicates that the oil was replaced by CO_2 inside of the core.

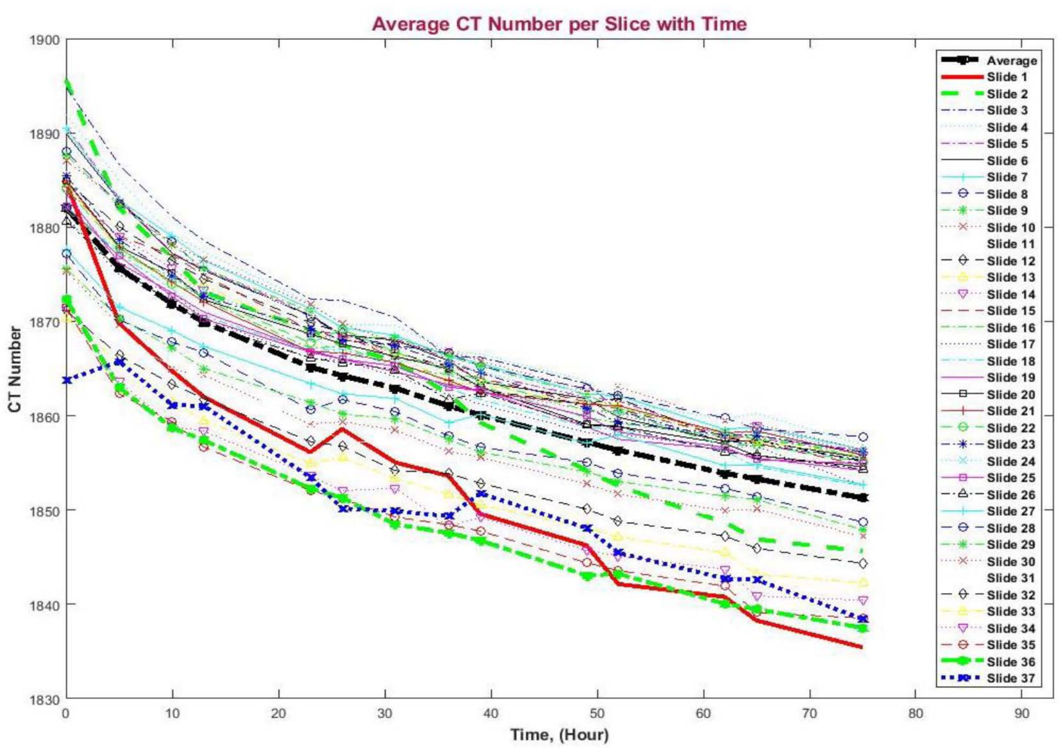


Figure 17—Average CT number for each slice during gas injection experiment at 3,500 psi

As shown in Figure 17, the slices at both end of the core plug, such as slice 1 and slice 37, have a more substantial CT number decrease during the experiment. At the end of gas injection experiment, the CT number of slice 1 and slice 37 is lower than slices at the middle of the core. This observation was expected

(Tovar et al. 2018a) as oil at the ends of the core is more accessible by CO_2, and more oil can be extracted from this part of the shale core plug.

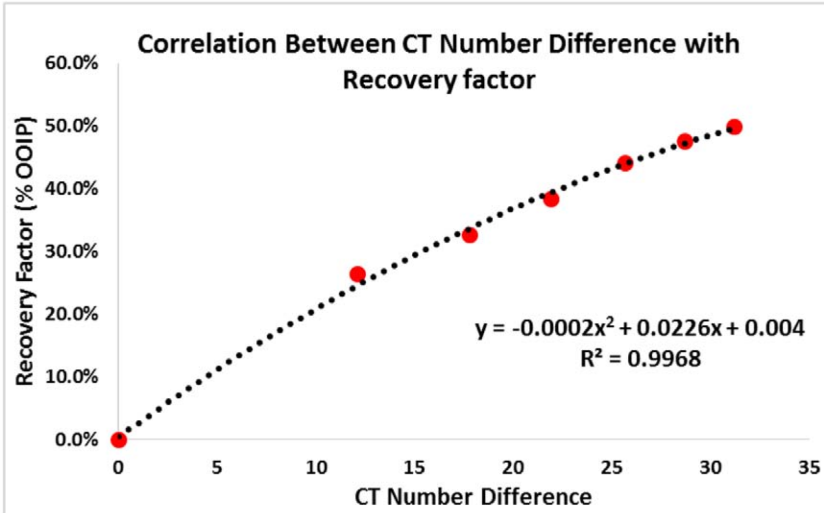


Figure 18—Correlation between delta CT numbers of the entire core during an experiment with recovery factors

Figure 18 illustrates a correlation between recovery factor and CT number difference during the experiment. Recovery factor increases as the delta CT number increases. This good correlation can be explained by the fact that all the cores used are very similar and have very close CT number values.

Additionally, we investigated the flow path of oil during production from the core plug from the CT scans taken during the experiments. We calculated delta CT numbers for each time step by using the CT number of that time step minus the CT number at time 0. Then pixels for delta CT number above 50 HU were marked as 1. We counted the number of times high CT number was shown for each pixel during the gas injection experiment. By considering the information of delta CT number for each scan, the high flow path region can be generated in Figure 19. Oil was recovered from the high flow path regions. In addition, the blue area is considered as a low flow path region where oil is trapped, and recovery factors are minimal.

Fig. 19 presents a high flow path distribution for the core plug used in gas injection experiment at 3,500 psi. A significant portion of the oil was extracted from the left side of the core, due to the heterogeneity of shale core plugs. We investigate the area where oil was produced and the relationship between porosity and recovery factor. The fraction of high flow path region for the entire core can be calculated from these high flow path images. For the core plug utilized in gas injection test at 3,500 psi, the high flow path fraction is 12.2%. This data will be applied to determine parameters of our core-scale model in the future.

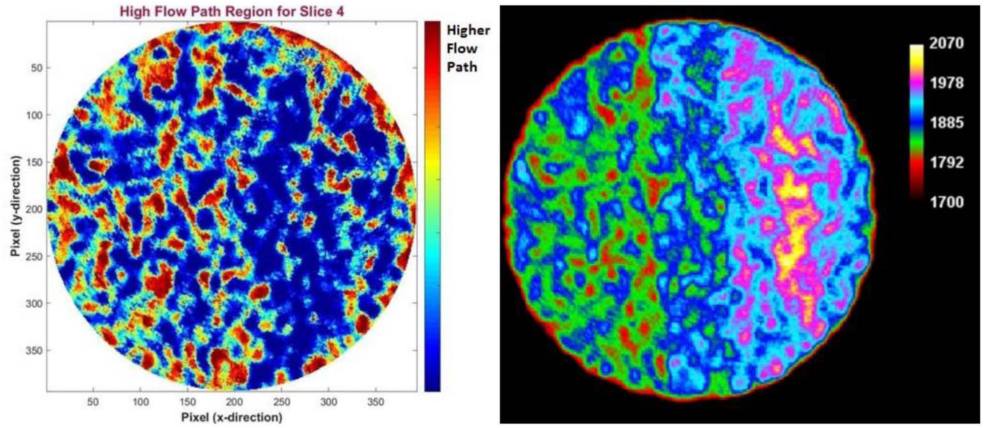


Figure 19—High flow path region from the experiment at 3,500 psi for slices 4 and corresponding CT image before the experiment

Figure 19 shows a comparison between the high flow path region and CT number distribution for the same slice. CT number has a negative correlation with porosity that higher CT number results in smaller pore size. As shown in figure 20, the higher flow path region is placed at the left part of the core that the pore sizes are bigger than the right side. Since larger pores contain lighter components than the smaller pores (Luo et al. 2018), gas injection EOR recovered a significant volume of lighter components oil from the bigger pores in ULR. These observations not only validate the high flow path work but also consistent with the mechanism of gas injection EOR technique.

Conclusions

1. CO_2 – EOR in unconventional liquid reservoir through a hydraulic fracture can lead to high recovery of the oil naturally stored in the rock matrix. This is observed in the huff-n puff experiments in both re-saturated Eagle Ford and Wolfcamp core plugs.
2. The addition of 5% Iodobenzene in the Wolfcamp oil, increased the MMP by only 136 psig, or 7 %, indicating our conclusions are valid.
3. A maximum recovery factor of 49.31% was achieved at the highest pressure of 3,500 psig in the Eagle ford cores. This is higher than the maximum of 40% we previously observed in the Wolfcamp cores.
4. Our results show that the operating pressure strongly affects the recovery factor, and that further increasing pressure beyond the MMP results in higher recovery factors.
5. Most of the produced oil is recovered during the first cycle, which indicates that recovering oil from organic-rich shales during CO_2 huff-n-puff is not a lengthy process. Recovery from core plugs that takes several months to saturate, is rapid compared to the expectations from nano-Darcy rock samples.
6. The changes in CT number with time reveal the fluid movement during gas injection experiments that CO_2 penetrates into the rock matrix to replace oil out from the core plugs.
7. The high flow path region in the core plug can be generated from CT scans during the gas injection experiments. The fraction of the high flow path region will give different parameters when building a core-scale simulation model.
8. This work confirms our previous findings, which challenge the paradigm that establishing miscibility is enough to achieve the highest recovery factors during CO_2 flooding, as is the case in conventional reservoirs. This finding has a significant impact on field operations and should be considered during the design of gas injection EOR processes in ULR.

Acknowledgments

The authors also would like to show their appreciation to the staff and student workers at the Harold Vance Department of Petroleum Engineering at Texas A&M University for their collaboration on the experimental work. The authors are thankful to Chevron and Chaparral Energy for establishing the Chevron Petrophysical Imaging Laboratory and the Chaparral-Fisher CO_2 EOR Laboratory at the Harold Vance Department of Petroleum Engineering at Texas A&M University.

Nomenclature

CT = Computed tomography
EOR = Enhanced oil recovery
MMP = Minimum miscibility pressure
OOIP = Original oil in place
P = Producing interval
SI = Soaking interval
ULR = Unconventional Liquid Reservoir

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