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Applicability of CO2-EOR in Shale-Oil Reservoirs Using Diagnostic Plots

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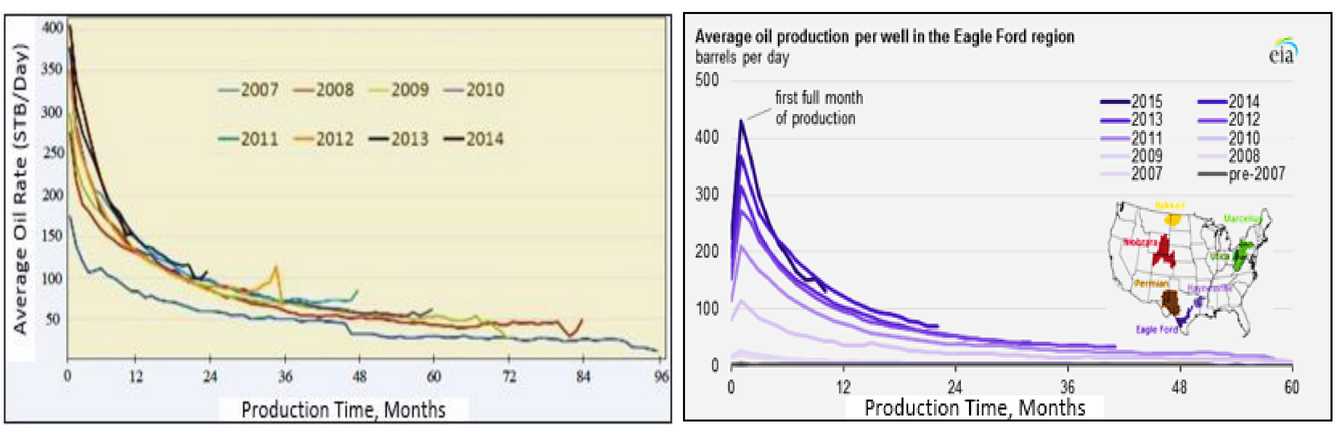
Abstract

Unconventional resources have played a significant role in changing oil industry plans recently. Shale formations in North America such as Bakken, Niobrara, and Eagle Ford have huge oil in place, 100-900 Billion barrels of recoverable oil in Bakken only. However, the predicted primary recovery is still below 10%. Therefore, seeking for techniques to enhance oil recovery in these complex plays is inevitable. In this paper, two engineering-reversed approaches have been integrated to investigate the feasibility of CO_2 huff-n-puff process in shale oil reservoirs. Firstly, a numerical simulation study was conducted to upscale the reported experimental-studies outcomes to the field conditions. As a result, different forward diagnostic plots have been generated from different combinations of CO_2 physical mechanisms with different shale-reservoirs conditions. Secondly, different backward diagnostic plots have been produced from the history match with CO_2 performances in fields' pilots which were performed in Bakken formation of North Dakota and Montana. Finally, fitting the backward with the forward diagnostic plots was used to report and diagnose some findings regarding the injected-CO_2 performance in field scale.

This study found that the porosity and permeability of natural fractures in shale reservoirs are significantly changed with production time, which in turn, led to a clear gap between CO_2 performances in lab-conditions versus to what happened in field pilots. As a result, although experimental studies reported that CO_2 molecular-diffusion mechanism has a significant impact on CO_2 performance to extract oils from shale cores, pilot tests performances indicated a poor role for this mechanism in field conditions. Therefore, the bare upscaling process for the oil recovery improvement and the CO_2-molecualr diffusion rate, which are obtained from CO_2 injection in lab-cores, to the field scale via numerical simulations needs to be reconsidered. In addition, this study found that kinetics of oil recovery process in productive areas and CO_2-diffusivity level are the keys to perform a successful CO_2-EOR project. Furthermore, general guidelines have been produced from this work to perform successful CO_2 projects in these complex plays. Finally, this paper provides a thorough idea about how CO_2 performance is different in field scale of shale oil reservoirs as in lab-scale conditions.

Introduction

In current days, conventional oil and gas reservoirs are showing a clear trend of depletion and diminish in number. Therefore, seeking for unconventional reservoirs has been the target over the 20 years. Fortunately, the investment in these unconventional plays has been yet successful. Oil production from tight formations including shale plays has shared for more than 50% of total oil production in the US (Alfarge et al., 2017). Hoffman et al., (2016) reported that 4 million barrels per day as an increment in US-oil daily production comes from these unconventional oil reservoirs. From 2011 to 2014, Unconventional Liquid Rich (ULR) reservoirs contributed to all natural gas growth and nearly 92% of oil production growth in the US (Alfarge et al., 2017). Specifically, Bakken and Eagle Ford contributed more than 80% of total US oil production from these tight formations (Yu et al., 2016a). More recently, Bakken formation alone delivers close to 10% of the total US production with more than 1.1 million barrels per day (Alvarez et al, 2016). This revolution in oil and gas production happened mainly because shale oil reservoirs have been just increasingly developed due to the advancements in horizontal wells and hydraulic fracturing in last decade. Several studies have been conducted to estimate the recoverable oil in place in these complex formations indicating a large amount of oil in place. The available information refers to 100-900 Billion barrels in Bakken only. However, the predicted recovery from primary depletion could lead to 7% only of original oil in place (Clark, 2009). Furthermore, some investigators argued that the primary recovery factor is still in a range of 1-2 % in some of the plays in North America (Wang et al., 2016). For example, the North Dakota Council reported that "With today's best technology, it is predicted that 1-2% of the reserves can be recovered" (Sheng, 2015). The main problem during the development of unconventional reservoirs is how to sustain the hydrocarbon production rate, which also leads to low oil recovery factor. **Fig. 1** explains the typical trend for oil production in these complex plays. The producing wells usually start with high production rate initially; however, they show steep decline rate in first 3-5 years until they get leveled off at very low rate. According to Yu et al. (2014), the main reason beyond the quick decline in production rate is due to the fast depletion of natural fractures networks with slow recharging from matrix system, which is the major source of hydrocarbon. Therefore, oil recovery factor from primary depletion has been predicted typically to be less than 10% (LeFever et al, 2008; Clark, 2009; Alharthy et al., 2015; Kathel and Mohanty 2013, Wan et al., 2015; Alvarez et al, 2016).



A-Bakken Play **B-Eagle Ford Play**

Fig. 1: Average oil production per well in unconventional reservoirs (EIA, 2016)

Since these reservoirs have huge original oil in place, any improvement in oil recovery factor would result in enormous produced oil volumes. Therefore, IOR methods have huge potential to be the major stirrer in these huge reserves.

Although IOR methods are well understood in conventional reservoirs, they are a new concept in unconventional ones. All basic logic-steps such as experimental works, simulation studies, and pilot tests for investigating the applicability of different IOR methods have just started over the last decade. Miscible gas injection has shown excellent results in conventional reservoirs with low permeability and light oils. Extending this approach to unconventional reservoirs including shale oil reservoirs in North America has been extensively investigated over the last decade. The gases which have been investigated are CO_2, N_2, and an enrich natural gases. However, the majority of studies focused on CO_2 due to different reasons. CO_2 can dissolve in shale oil easily, swells the oil and lowers its viscosity. CO_2 has a lower miscibility pressure with shale oil rather than other gases such as N_2 and CH_4 (Zhang et al., 2016). Moreover, the CO_2 performance in lab conditions was excellent in increasing oil recovery from shale cores as shown in **Fig. 2**. However, the minimum miscible pressure of CO_2 in these types of oil has a controversial range in between 2500 psi to 3300 psi. Furthermore, it has been reported that oil of these reservoirs has a low acid number which might give the hope to apply CO_2 injection successfully without asphaltenes precipitation problems (Kurtoglu et al., 2014). Unfortunately, the results of pilot-tests for CO_2-EOR, huff-n-puff protocol, which have been conducted in unconventional reservoirs of North America were disappointing (Hoffman et al., 2016). This gap in CO_2 performance between lab-conditions versus to what happened in field-scale suggests that there is something missing between microscopic-level and macroscopic-level in these plays. Most of the experimental studies reported that the molecular-diffusion mechanism for CO_2 is beyond the increment in oil recovery obtained in lab scale (Alfarge et al., 2017). Furthermore, most of the previous simulation studies relied on the lab-diffusivity level for these miscible gases to predict the expected oil increment on field scale (Alfarge et al., 2017). One of the main reasons for the poor-performance for CO_2 in the pilot tests might be due to the wrong prediction for CO_2 diffusion-mechanism in these types of reservoirs. The purpose of this study is to diagnose the reasons behind the gap in the CO_2 performance in lab-conditions versus to what happened in field-scale.

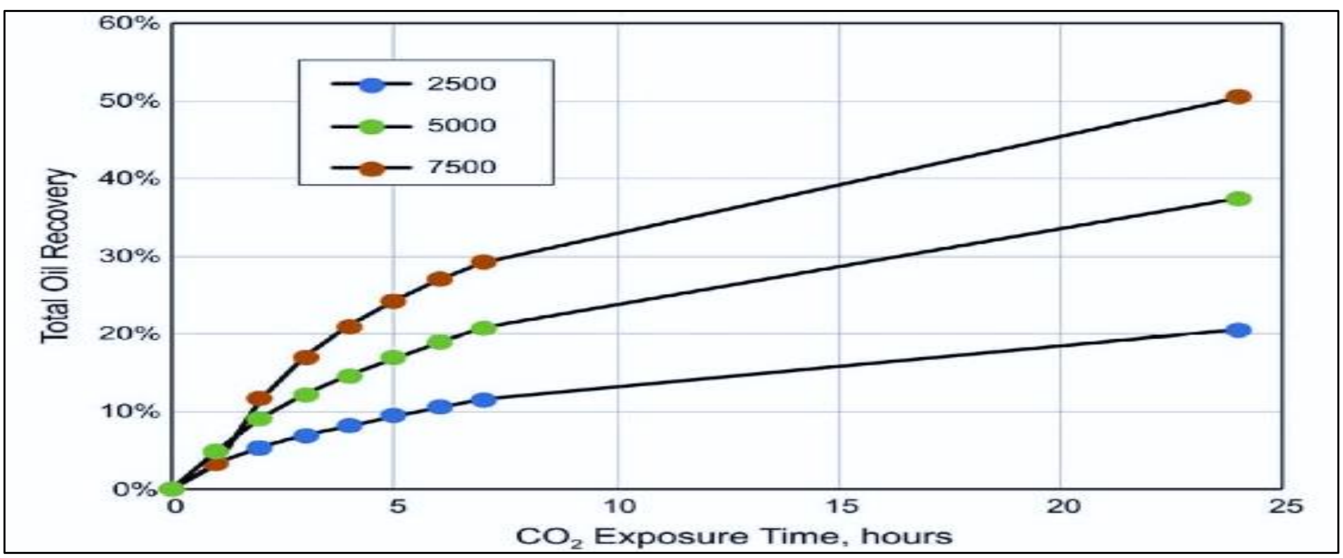


Fig. 2: Sample for how much oil extracted from natural cores by CO_2 in lab conditions (Hawthorne et al., 2017)

Background

Starting with lab-work tools, the study of Song et al. (2013) conducted an experimental investigation to compare results from injecting CO_2 and water in cores from Bakken. They found that water flooding would enhance oil recovery better than immiscible CO_2 in Huff-n-Puff protocol. However, miscible and near miscible CO_2 Huff-n-Puff would achieve better performance than water flooding in enhancing oil recovery. Hawthorne et al., (2013) investigated the mechanism beyond increasing oil recovery by CO_2 injection in Bakken cores. They proved that diffusion mechanism is the main mechanism for CO_2 to increase oil recovery in these complex plays. However, to extract oil from shale matrix by CO_2, long times of exposure combined with large contact areas are required. Gamadi et al. (2014) conducted experimental work on shale cores from Mancos and Eagle Ford to investigate the potential of CO_2 injection in these reservoirs. Their laboratory results indicated that cyclic CO_2 injection could improve oil recovery from shale oil cores from 33% to 85% depending on the shale core type and other operating parameters. Alharthy et al., (2015) compared the performance of injecting different types of gases such CO_2, C_1-C_2 mixtures, and N_2 on enhancing oil recovery from Bakken cores experimentally. They concluded that the injecting gas, composed of C_1, C_2, C_3, and C_4, could produce nearly as much oil as CO_2 injection could which was 90% from several Middle Bakken cores and nearly 40% from Lower Bakken cores. Also, they found the counter-current mechanism is the main mechanism for these gases to recover oil from shale cores. Finally, Yu et al., (2016) investigated N_2 flooding process experimentally on Eagle Ford core plugs saturated with dead oil. They examined different flooding time range and different injection pressure on N_2 flooding performance. They found that more oil was produced with a longer flooding time and higher injection pressure. To sum up, CO_2 showed a good potential to extract oil from shale cores in experimental works (Jin et al., 2016).

The numerical simulation studies of Shuaib et al., (2009) and Wang et al., (2010) might be the early-published studies in this area. Those models showed that 10-20% of increment oil could be recovered by continuous gas flooding while 5-10% could be recovered by huff-n-puff gas protocol (Hoffman et al., 2016). Dong et al., (2013) reported a numerical study evaluating CO_2 injection performance for the Bakken interval in a sector of the Sanish Field. They came up with a scenario to increase CO_2 injectivity in that field by drilling more horizontal injection wells. This scenario predicted the possibility to inject 5000 Mscf/day at a maximum injection pressure of 8000 psi. From their simulation study, they found that using CO_2 injection method might increase oil recovery from 5% to 24% in that field. Xu et al., (2013) evaluated the reservoir performance of Elm Coulee field in Eastern Montana under CO_2 flooding with different hydraulic fracture orientations. They found that transverse fractures have higher oil recovery factor, but it has lower utilization value than longitudinal fractures due to breakthrough problems. Zhu et al., (2015) constructed a model in which gas could be injected into a hydraulic fracture along a horizontal well and the production process could occur from an adjacent fracture which has an intersection with the same well. They found a substantial improvement in oil recovery by injecting CO_2 in reservoirs with fluid flow from fracture to fracture. Pu et al., (2016) introduced a new model which considers capillarity and adsorption effect of the small pores for shale reservoirs. They found that using this model would simulate CO_2-EOR in unconventional reservoirs properly. Furthermore, capillarity consideration in modeling process would predict higher oil recovery by CO_2 injection than the cases which did not include capillarity property.

It is clear from the previous studies that CO_2 would have a great potential to enhance oil recovery in these poor-quality reservoirs. However, whether using CO_2 in Huff-n-Puff protocol or injecting CO_2 in flooding scenario is still a controversial argument. Due to the low permeability, conformance problems in these reservoirs, and the significant observed molecular-diffusion rate for CO_2 in lab conditions, most of the previous researchers prefer the CO_2 Huff-n-Puff on CO_2 flooding. Unfortunately, the results of pilot tests of CO_2 in the cyclic process were disappointing (Hoffman et al., 2016). Therefore, this study has been conducted for determining the reasons causing the gap for CO_2 performance in lab-conditions versus to what happened in field-scale.

Molecular Diffusion

Gravity drainage, physical diffusion, viscous flow, and capillary forces are the common forces which control the fluids flow in porous media. However, one force might eliminate the contributions of others depending on the reservoir properties and operating conditions. Molecular diffusion is defined as the movement of molecules caused by Brownian motion or composition gradient in a mixture of fluids (Mohebbinia et al., 2017). This type of flow would be the most dominated flow in fractured reservoirs with a low-permeability matrix when gravitational drainage is inefficient (Moorgate and Firoozabadi, 2013; Mohebbinia et al., 2017). It has been noticed and approved that gas injection is the most common EOR-process affected by calculations of molecular-diffusion considerations. Ignoring or specifying incorrect diffusion-rate during simulation process can lead to overestimate or underestimate the oil recovery caused by the injected gas. This happens not only due to the variance in miscibility-process between the injected-gas and formation-oil but also due to the path change of the injected gas species from fractures to the formation-matrix.

The Péclet number (Pe) is a class of dimensionless numbers which have been used to measure the relative importance of molecular diffusion flow to the convection flow. This number can be calculated as shown in **Eq. 1**. If Pe number is less than 1, diffusion is the dominant flow. However, if Pe is greater than 50, convection is the dominant flow. The dispersion flow is dominant when Pe in range 1 to 50 (Hoteit and Firoozabadi, 2009). **Fig. 3** explains the flow regimes according to Péclet number cutoffs.

$$\text{Pe} = \frac{diffusion\ time}{convection\ time} = (L2/D)/(L/v) = Lv/D \tag{1}$$

Where v is the bulk velocity, L is a characteristic length, and D is the diffusion coefficient.

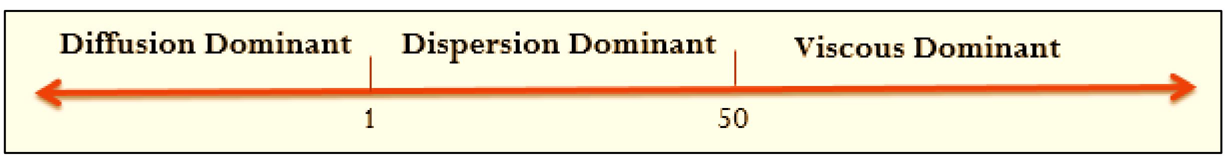


Fig. 3: Flow Regimes According to Péclet Number Cutoffs

CO_2 Molecular-Diffusion Mechanism

Different mechanisms have been proposed for the injected CO_2 to improve oil recovery in unconventional reservoirs as shown in **Table 1**. However, since the matrix permeability in these unconventional reservoirs is in range (0.1 –0.00001 md), CO_2 would not be transported by convection flux from fracture to matrix (Yu et al., 2014). The main transportation method for CO_2 is happening due to the difference in the concentration gradient between CO_2 concentration in the injected gases and the target-oil. This process of transportation is subjected to Fick's law. Hawthorne et al., (2013) extensively investigated the CO_2 diffusion-mechanism in Bakken cores and proposed five conceptual-steps to explain it. These conceptual steps include: (1) CO_2 flows into and through the fractures, (2) unfractured rock matrix is exposed to CO_2 at fracture surfaces, (3) CO_2 permeates the rock driven by pressure, carrying some hydrocarbon inward; however, the oil is also swelling and extruding some oil out of the pores, (4) oil migrates to the bulk CO_2 in the fractures via swelling and reduced viscosity, and (5) as the CO_2 pressure gradient gets smaller, oil production is slowly driven by concentration-gradient diffusion from pores into the bulk CO_2 in the fractures.

Table 1: The proposed CO_2 EOR mechanisms for improving oil recovery in unconventional reservoirs

CO_2 mechanism	Approach tool
1-Diffusion	Lab
2-Reduction in Capillary forces	Lab and simulation
3-Repressurization	Lab
4-Extraction	Lab
5-Oil swelling and pressure maintenance	Lab and simulation
6-Oil Viscosity reduction	Lab and simulation
7-Combination of more than one mechanism from above	-

Most of the previous experimental studies reported that CO_2 diffusion mechanism is beyond the increment in oil recovery obtained in lab conditions. Then, the observed increment in oil-recovery and/or the CO_2 diffusion-rate obtained in lab conditions were upscaled directly to field scale by using numerical simulation methods. This direct upscaling methodology might be so optimistic due to that the lab-cores have higher contact area and longer exposure time to CO_2 than what might happen in the real-conditions of unconventional reservoirs. As a result, both of previous simulation studies and experimental works might be too optimistic to predict a quick improvement in oil recovery from injecting CO_2 in these tight formations.

Methodology

To determine the reasons causing the gap for CO_2 performance in lab conditions versus to what happened in the pilot tests, field scale conditions, we need to start with screening the parmeters which we are sure of them and the parameters which have some ambiguity. The parameters which are known in these pilot-tests are the following:

- PVT data, and oil composition properties
- Major Wells and stimulation criteria
- Rock properties
- CO_2 injection operating parameters (rate, pressure, time)
- Produced oil rate versus time
- CO_2 performance in lab conditions (most of the mechanisms and observations)

On the other hand, the parameters which have ambiguity in these pilot-tests are the following:

- CO_2 diffusivity level in field scale
- Natural fracture intensity, porosity, and permeability in field scale

According to the previous diagnose, the systematic methodology for this work is falling into two reversed scenarios. Firstly, a numerical simulation study was conducted to upscale the reported experimental-studies outcomes to the field conditions. As a result, different forward diagnostic plots have been generated from different combinations of CO_2 physical mechanisms with different shale-reservoirs conditions. Secondly, different backward diagnostic plots have been produced from the history match with CO_2 performances in fields' pilots which were performed in Bakken formation of North Dakota and Montana. Finally, fitting the backward with the forward diagnostic plots was used to report and diagnose some findings regarding the injected-CO_2 performance in field scale. **Fig. 4** shows the detailed methodology for this study. This study is the first numerical simulation study to integrate the two reversed approaches in this area of research. All of the previous numerical simulation studies either chose the direct upscale for lab observation or built merely a conceptual model.

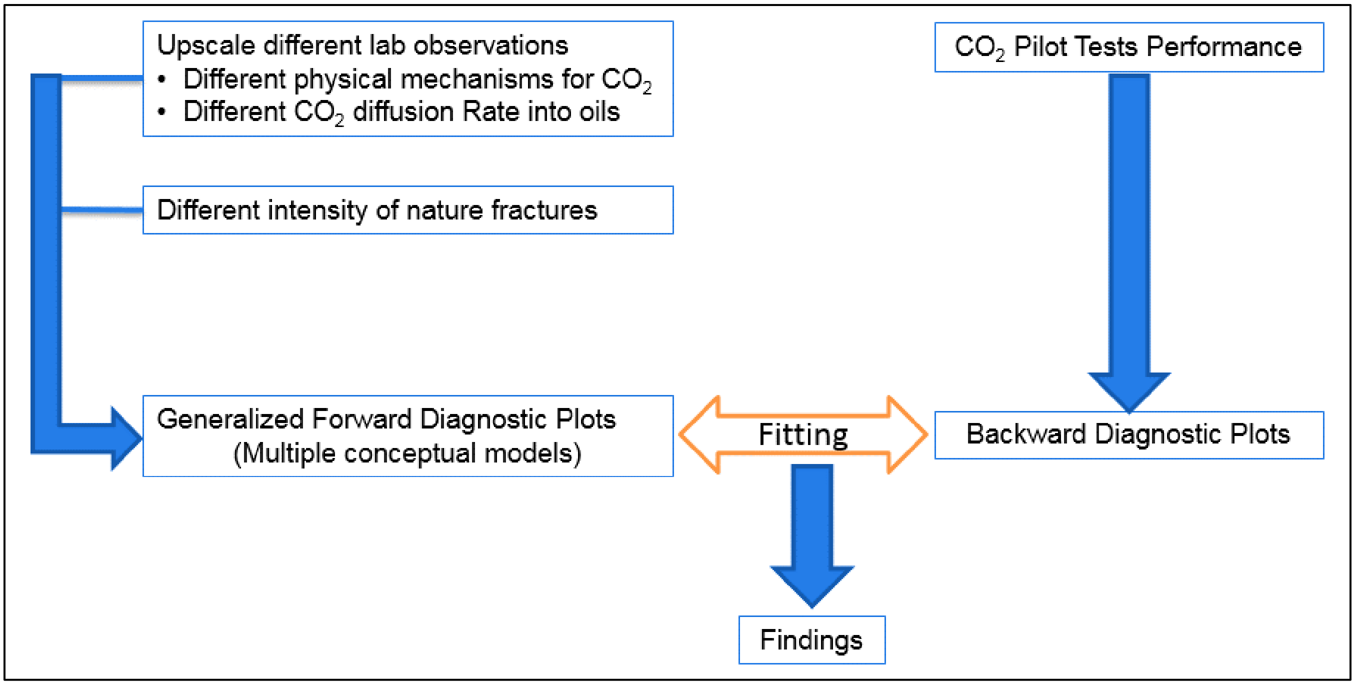


Fig. 4: Systematic methodology for this study

Numerical Simulation

In this simulation study, the LS-LR-DK (logarithmically spaced, locally refined, and dual permeability) model is used. The LS-LR-DK method can accurately simulate the fluid flow in fractured shale-oil reservoirs. Also, an advanced general equation-of-state compositional simulator has been used to build an equation-of-state model. Then, both of models have been combined to simulate compositional effects of reservoir fluid during primary and enhanced oil recovery processes. Furthermore, implementation of a diffusion model in the LS-LR-DK (logarithmically spaced, locally refined, and dual permeability) model has been conducted. In this study, we tried to build a numerical model which has the typical fluid and rock properties of Bakken formation, one of the most productive unconventional formations in the US. In this model, we injected EOR-CO_2 in different scenarios as Huff-n-Puff protocol through hydraulically fractured well in Bakken formation. All the mechanisms which were proposed in **Table 1** have been considered in this model.

In this field case study, the production well was stimulated with 5 hydraulic fractures as shown in **Fig. 5**. The spacing between the hydraulic fractures is 200 ft. The simulation model includes two regions which are stimulated reservoir volume (SRV) and un-stimulated reservoir volume (USRV). The dimensions of the reservoir model are 2000 ft x 2000ft x42 ft, which corresponds to length, width, and thickness respectively. The dimensions of the fractured region are 5 fractures with half-length of 350 ft in J direction, width 0.001 ft in I direction, and fracture height of 42 ft in K direction. Fracture conductivity is 15 md.ft. The other model input parameters are shown in **Table 2**.

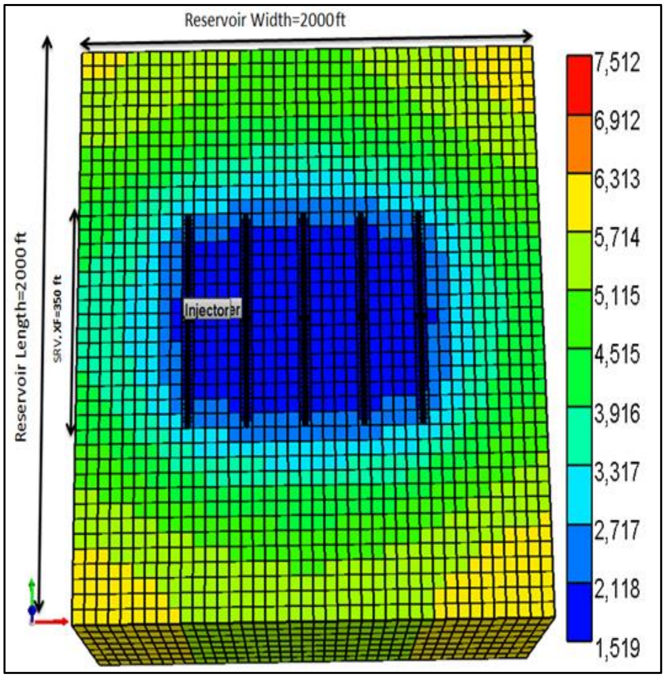


Figure 5a- Average Pressure in a depleted well in Bakken

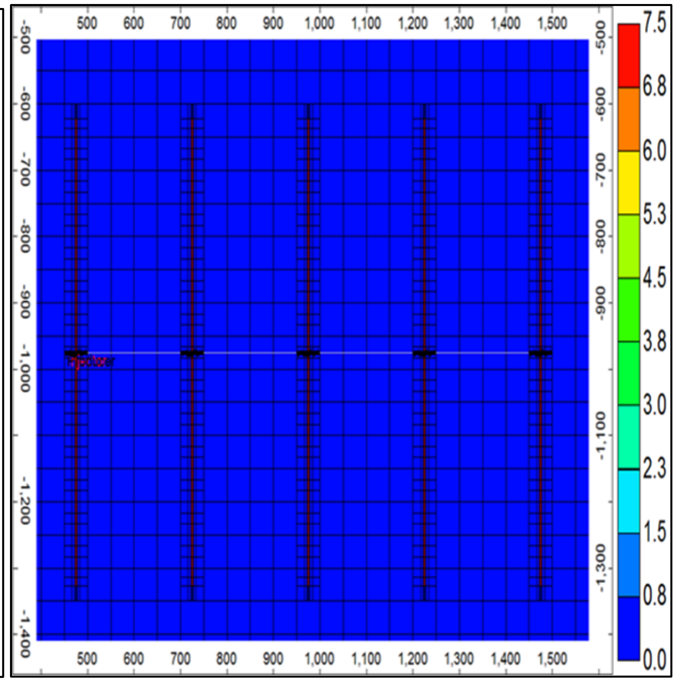


Figure 5b- A closed view for SRV of Production well

Table 2: Model input parameters for the base case

Parameter	value	Unit
The model dimensions	2000x2000x42	ft
Production Time	20	year
Top of Reservoir	8000	ft
Reservoir Temperature	240	°F
Reservoir pressure	7500	psi
Initial Water saturation	0.3	value
Total compressibility	1×10^{-6}	psi^{-1}
Matrix permeability	0.005	mD
Matrix porosity	0.085	value
Horizontal Well length	1000	ft
Total number of fractures	5	value
Fracture conductivity	15	mD-ft
Fracture half-length	250	ft
Fracture Height	42	ft

Compositional Model for the Formation Fluids

The typical Bakken oil has been simulated in this study. The oil which was used in this model has 42 API°, 725

SCF/STB, and 1850 psi as oil gravity, gas oil ratio, and bubble point pressure respectively. It is known that compositional models are the most time-consumed models due to the number of components in a typical reservoir oil. In our model, we have 34 components so that would take a long time for the simulator to complete run one scenario. The common practice in numerical simulation for such situation is the careful lump of reservoir oil components into a short representative list of pseudo components. These pseudo components could be acceptable if they have matched with the laboratory–measured phase behavior data. The supplied data for reservoir oil needs to have a description of associated single carbon numbers and their fractions, saturation pressure test results, separator results, constant composition expansion test results, differential liberation test results, and swelling test results (CMG, 2016). All of these data can be used for tuning the EOS to match the fluid behavior. In our simulation, we lumped the original 34 components into 7 pseudo components as shown in **Table 3** by using WinProp-CMG. WinProp is an Equation-of-State (EOS)-based fluid behavior and PVT modeling package. In WinProp laboratory data for fluids can be imported and an EOS can be tuned to match its physical behavior. Fluid interactions can be then predicted and a fluid model can be also created for use in CMG software (CMG, 2016). **Table 4** presents the Peng-Robinson EOS fluid description and binary interaction coefficients of the Bakken crude oil with different gases. **Fig. 6** represents the two-phase envelope for Bakken oil which was generated by WinProp-CMG.

Table 3: Compositional data for the Peng-Robinson EOS in the model oil

Component	Mole fraction	Critical pressure (atm)	Critical Temp. (K)	Acentric Factor	Molar Weight (g/gmole)
CO2	0	7.28E+01	3.04E+02	0.225	4.40E+01
N2-CH4	0.2704	4.52E+01	1.90E+02	0.0084	1.62E+01
C2H-NC4	0.2563	4.35E+01	4.12E+02	0.1481	4.48E+01
IC5-CO7	0.127	3.77E+01	5.57E+02	0.2486	8.35E+01
CO8-C12	0.2215	3.10E+01	6.68E+02	0.3279	1.21E+02
C13-C19	0.074	1.93E+01	6.74E+02	0.5672	2.20E+02
C20-C30	0.0508	1.54E+01	7.92E+02	0.9422	3.22E+02

Table 4: Binary interaction coeficients for Bakken oil

Component	CO2	N2-CH4	C2H-NC4	IC5-CO7	CO8-C12	C13-C19	C20-C30
CO2							
N2-CH4	1.01E-01						
C2H-NC4	1.32E-01	1.30E-02					
IC5-CO7	1.42E-01	3.58E-02	5.90E-03				
CO8-C12	1.50E-01	5.61E-02	1.60E-02	2.50E-03			
C13-C19	1.50E-01	9.76E-02	4.24E-02	1.72E-02	6.70E-03		
C20-C30	1.50E-01	1.45E-01	7.79E-02	4.27E-02	2.51E-02	6.00E-03	

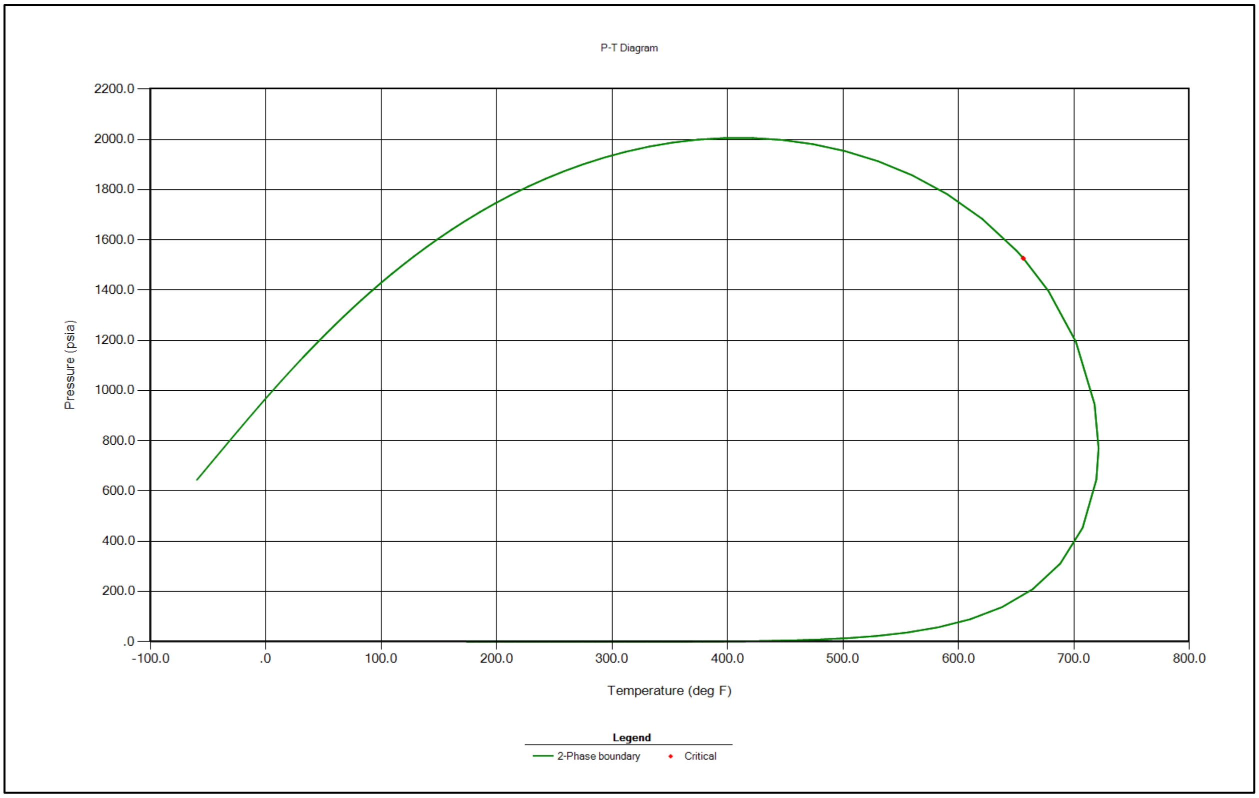


Fig. 6: The two-phase envelope for Bakken oil which was generated by WinProp-CMG

Results and Discussion

Hoffman et al., (2016) reported seven pilot-tests in Bakken formation which was conducted in North Dakota and Montana. We are presenting just one pilot of them in this section. This pilot was indicated in his paper as pilot test#2. This pilot-test injected CO_2 as Huff-n-Puff process in Bakken formation, in Montana portion. They injected 1500-2000 Mscf/day of CO2 for 45 days at 2000-3000 psi. The soaking period was proposed to be 2 weeks. Then, the well was put back in the production process. The operating parameters for this pilot tests were suggested as shown in **Table 5**.

Table 5: The operating parameters for Pilot test#2 conducted in Bakken formation

Scenario	Time
Primary depletion at BHP=1500psi	9 Years
CO_2 Injection period (at rate of 1500 Mscf/day)	2 months
Soaking	14 days
Back for production	10 years and 7.5 months

Different proposed mechanisms for CO_2 to enhance oil recovery in shale oil reservoirs, which are shown in **Table 1,** have been combined with both of different intensity, porosity, and permeability for natural fractures and the operating parameters for pilot test#2 which are shown in **Table 5**. As a result, different diagnostic plots of these combinations have been generated. In this paper, we call these diagnostic plots as the forward diagnostic plots as shown in **Fig. 7**. In the meantime, we create a history match process for pilot test#2 as shown in **Fig. 7b.** We call these plots, history-match plots, as backward diagnostic plots. If we compare the forward diagnostic plots, **Fig. 7**, with the pilot test#2 performance which is shown in **Fig. 8a,** it is clear there are some diagnostic curves are close to what happened in that pilot test, however, other diagnostic curves are far away from what happened in the field. We concluded that the diagnostic plots which have a good match with the pilot test have two main criteria. These two main properties are as following:

(1) The pilot test is matching the solutions of low-effective diffusivity for the injected CO_2.

(2) The pilot test is matching the solutions which have natural fractures of changeable porosity and permeability as shown in **Fig. 8b.** In the beginning of the well life, the well performance is matching the solutions which have high porosity and permeability for the simulated natural fractures. However, the well performance would match the solutions which have lower porosity and permeability at a later time. The reasons beyond this behavior are similar to the reasons causing the permeability and porosity reduction with production time progress in both of shale gas and coal-bed methane reservoirs as shown in **Fig. 10**.

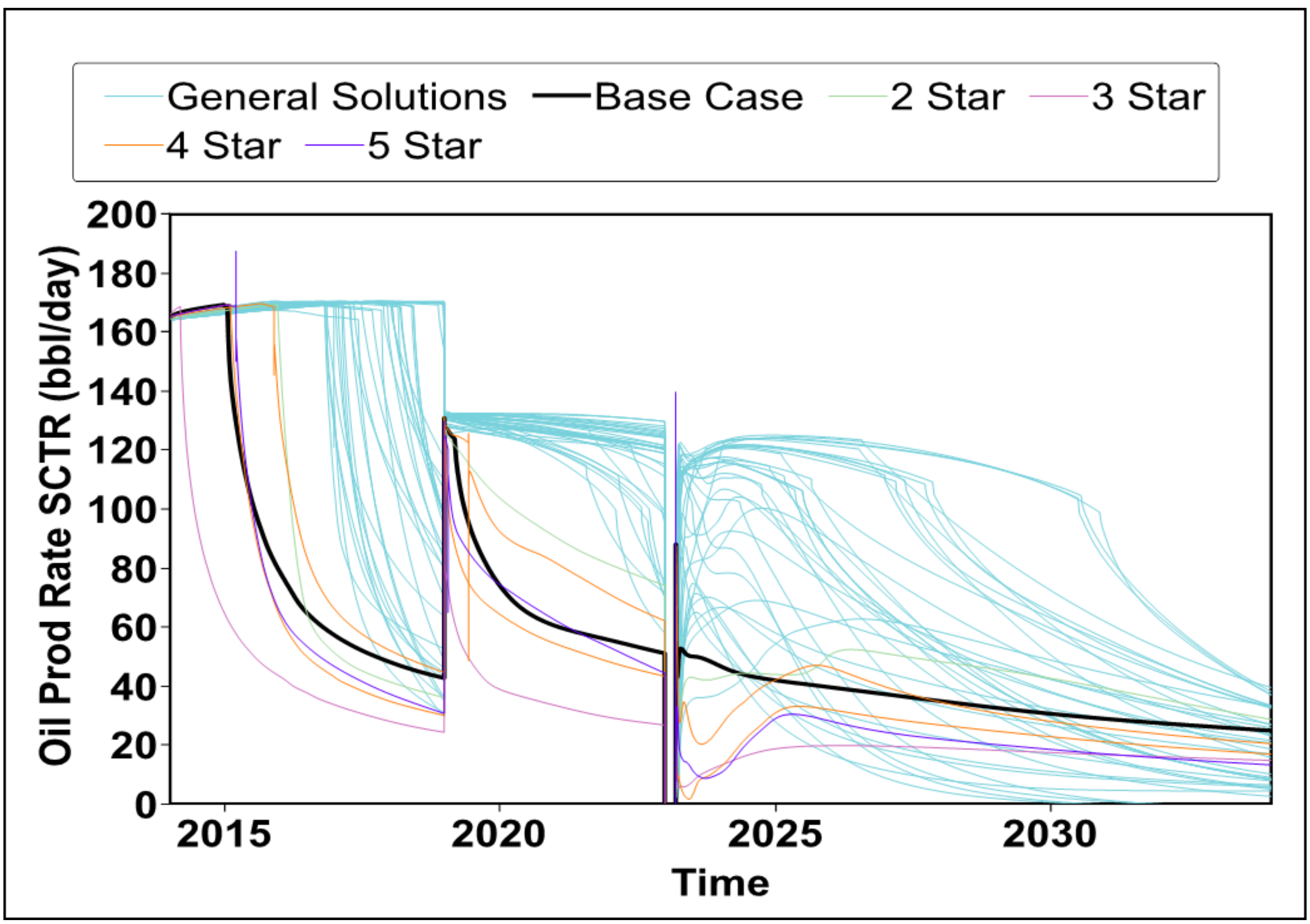
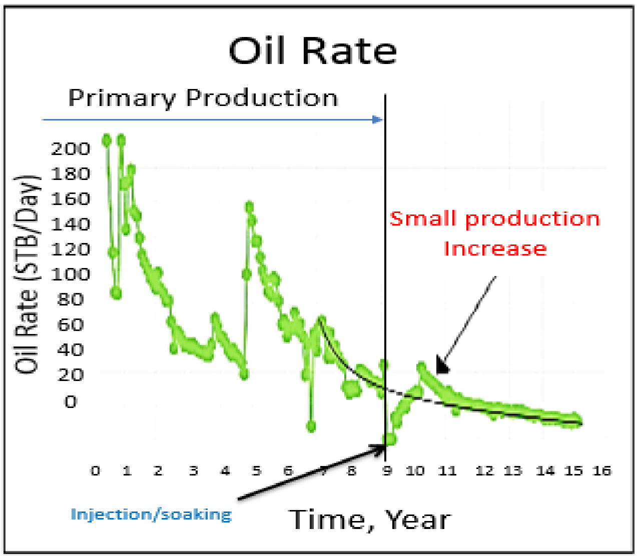


Fig. 7: The simulated forward diagnostic plots



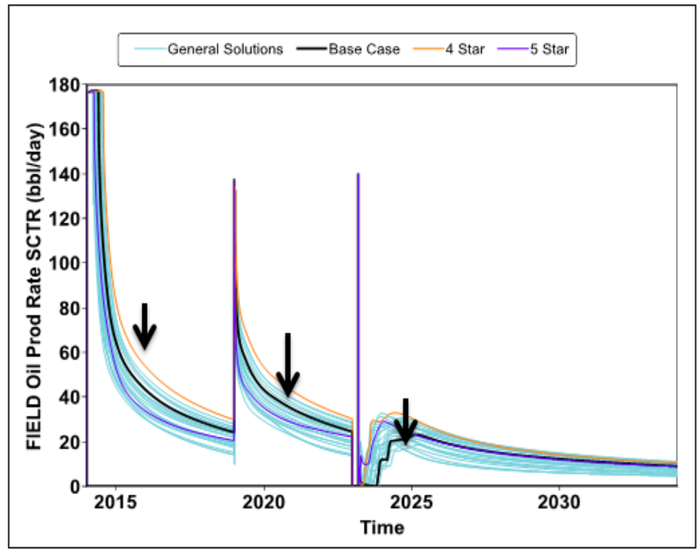
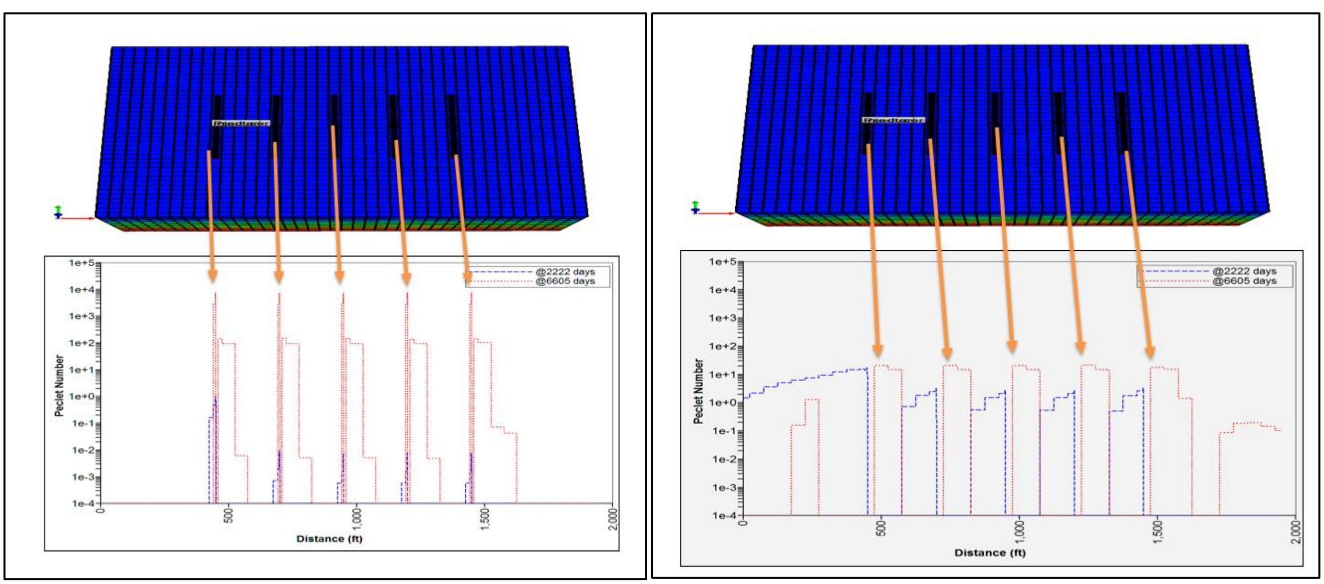


Fig. 8a: CO_2 Pilot test#2 (Hoffman et al. 2016) **Fig. 8b: History match from the simulated model**

We think that the previous two main characteristics for shale reservoirs are the critical points for CO_2-EOR success in shale reservoirs. In addition, these two main criteria are not fully considered in lab conditions which in turn led to this gap in CO_2 performance in lab conditions versus to what happened in field scale. In most of the reported experimental studies, small chips of natural cores were exposed to CO_2 for a long time under high pressure and temperature. Therefore, in lab scale, the contact area and exposure time between CO_2 and formation cores are much larger than what happens in the field scale. In the reported pilot test, there is no such long exposure time and large contact area. Therefore, CO_2 needs a good molar-diffusivity so it can invade the matrix-oil and extract the formation-oil by counter-current mechanism because the diffusion flow is the dominated flow in these types of reservoirs as shown in **Fig. 9.** Furthermore, it needs larger contact area between the injected CO_2 and the formation-oil. This can be done by performing CO_2 in early time of the production well life before natural fractures get closed.



A-Gas Phase B-Oil Phase

Figure 9: Péclet number distribution a long cross section in the matrix-model

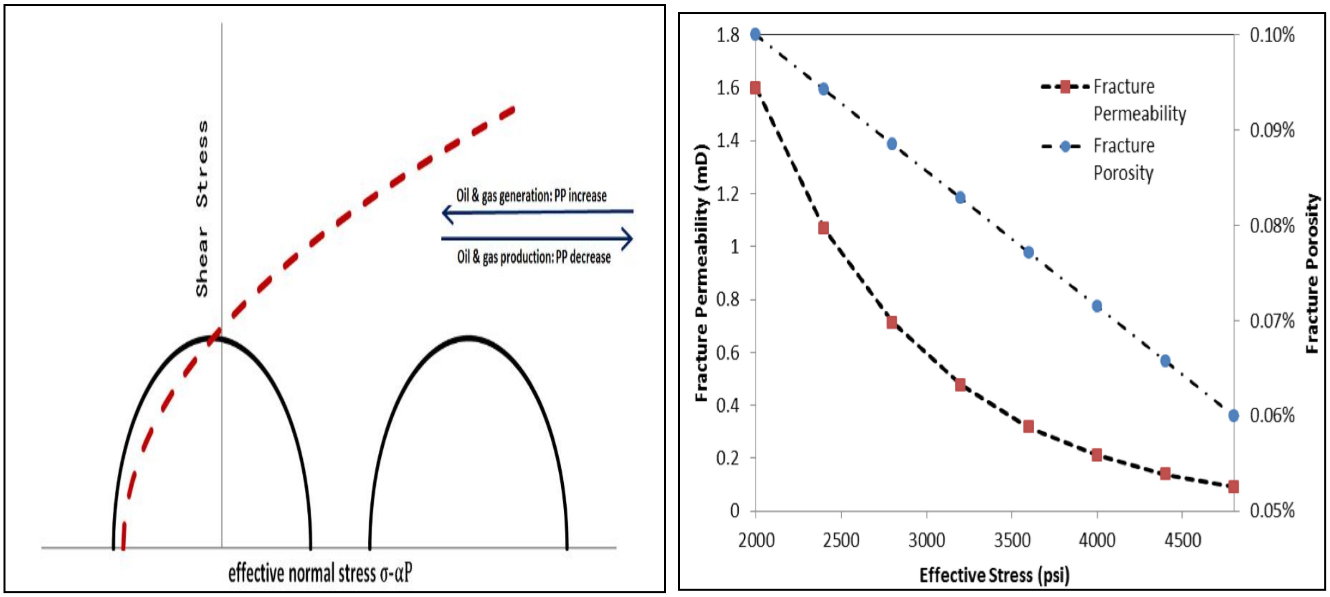


Fig. 10: How and why permeability and porosity of natural fractures are changeable with time (Wang et al., 2015)

To approve these speculations, we injected CO_2 CO2 into the same well of Bakken in two separated cases. In the first case, we injected CO_2 in the production well assuming there is no molecular-diffusion for CO_2 into formation-oil. However, in the second scenario, we injected CO_2 with a molecular-diffusion mechanism enabled. Two cycles of CO_2 Huff-n-Puff have been used for each case. The agenda and the time breakdown for both cases are shown in **Table 6**.

Table 6: The agenda and time breakdown for both of two cases in CO2 Huff-n-Puff scenario

Scenario	Time
Primary depletion at BHP=1500 psi	10 Years
CO2 Injection at rate of 500 Mscf/day (1st cycle)	6 months
Soaking time	3 months
Back for production	4 years and 3 months
CO2 Injection at rate of 500 Mscf/day (2nd Cycle)	6 months
Soaking	3 months
Back for production	4 years and 3 months
Total time for modeling	20 years

The results indicated that the CO_2 performance for without-molecular diffusion case did not provide a significant improvement in oil recovery or oil production rate from what was obtained at natural depletion production as shown in **Fig. 9**. If we look closely, we found that the enhancement in oil recovery due to CO_2 injection would not offset the loss in oil production which was happening due to the soaking and injection period. However, CO_2 with the molecular-diffusion case has improved the oil recovery and oil production in a significant way as shown in **Fig. 11**.

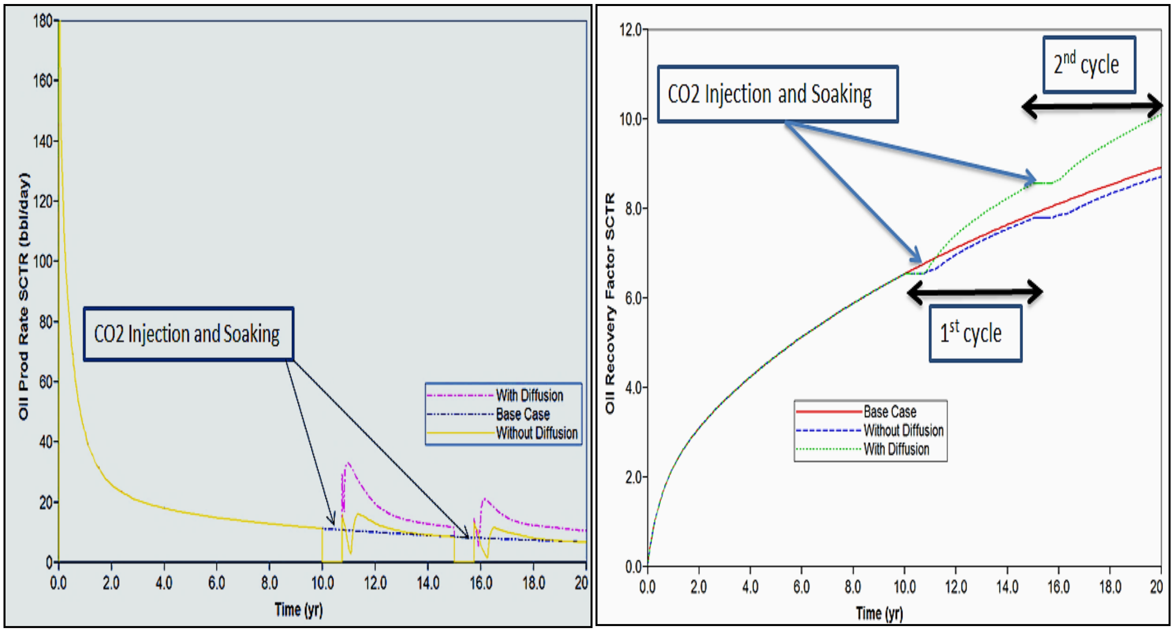


Fig. 11: Effect of Molecular diffusion on CO2-EOR in Shale Oil reservoirs

If we investigate the reasons beyond the role of molecular-diffusion mechanism on CO_2 performance to enhance oil recovery in these tight formations, we found this mechanism makes CO_2 penetrate deeper into the tight matrix, far away from hydraulic fractures as shown in **Fig. 12**. However, the case of CO_2 injection which does not have diffusion capacity makes the CO_2 penetrate just in the limited areas around the hydraulic fractures. Therefore, for the cases in which CO_2 penetrate deeper in the tight matrix, CO_2 would swell more volumes of oil, reduce oil viscosity, and finally produce larger quantities of oil by counter-current mechanism. On the other hand, the cases in which CO_2 has low molecular-diffusion rate would produce the injected-CO_2 back very soon. Therefore, producing the injected CO_2 back would put another hold on oil production due to slippage-effect making the enhancement in oil production for these types of reservoirs even worse. Since the diffusion mechanism for CO_2 has a significant effect to enhance oil recovery in shale oil reservoirs, any change in CO_2 diffusion rate would result in a clear change in oil recovery factor.

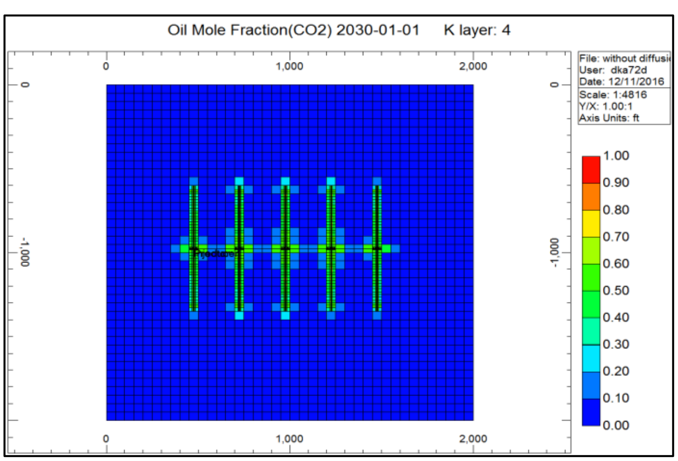


Fig. 12a- CO2 Injection without-molecular diffusion

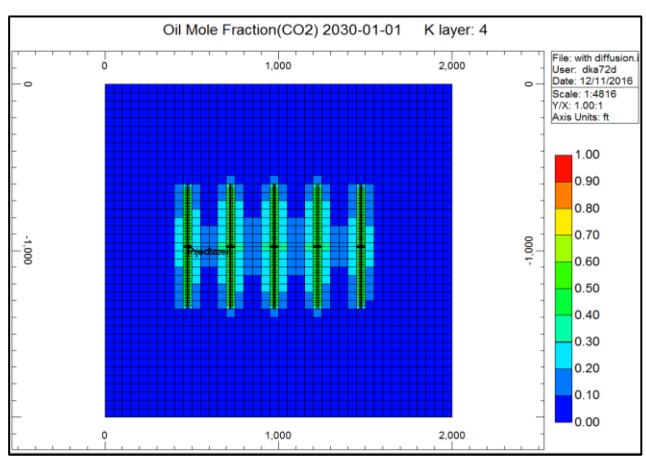


Fig. 12b- CO2 Injection with Molecular Diffusion

To investigate the effect of the CO2-EOR performing time on CO2 performance, we injected CO2 at a different time from the production-well life. In the first scenario, we injected CO2 after 5 years of production life. However, in the second scenario, we injected CO2 after 10 years from the production life as in the pilot-test case. The results confirmed the prediction which is that CO2 would perform better in the cases which have earlier CO2-EOR rather than the cases which have late CO2-EOR as shown in Fig. 13. This could be explained by the effective-stress principle which might be significantly important to control the permeability and porosity of natural fractures in shale oil reservoirs. As far as the CO2-EOR performed earlier, its performance would be better because the injected CO2 would find a good intensity of natural fracture which helps in enhancing its diffusivity into formation-oil. Another verification has been conducted to verify the effect of exposure time on CO2-molecular diffusion. This verification has been done by injecting CO2 in low-conductivity hydraulic fractures versus injecting CO2 in high-conductivity hydraulic fractures. The results indicated that CO2 would enhance oil recovery in low-conductivity fractures more than in high-conductivity fractures. The reason causing the difference in CO2-EOR performance according to the fracture conductivity is that the CO2 would be produced back in a faster way in high-conductivity fractures cases as shown in Fig. 14. The fast production for CO2 would downgrade the CO2 diffusivity into formation-oil, which in turn would reduce its performance to enhance production more oil. To sum up, as far as the kinetic of oil recovery process in productive areas does not overcome the CO2-diffusion rate, the CO2 would experience more exposure time with formation oil before its being produced back which is making CO2 successful to enhance oil recovery in these poor-quality reservoirs.

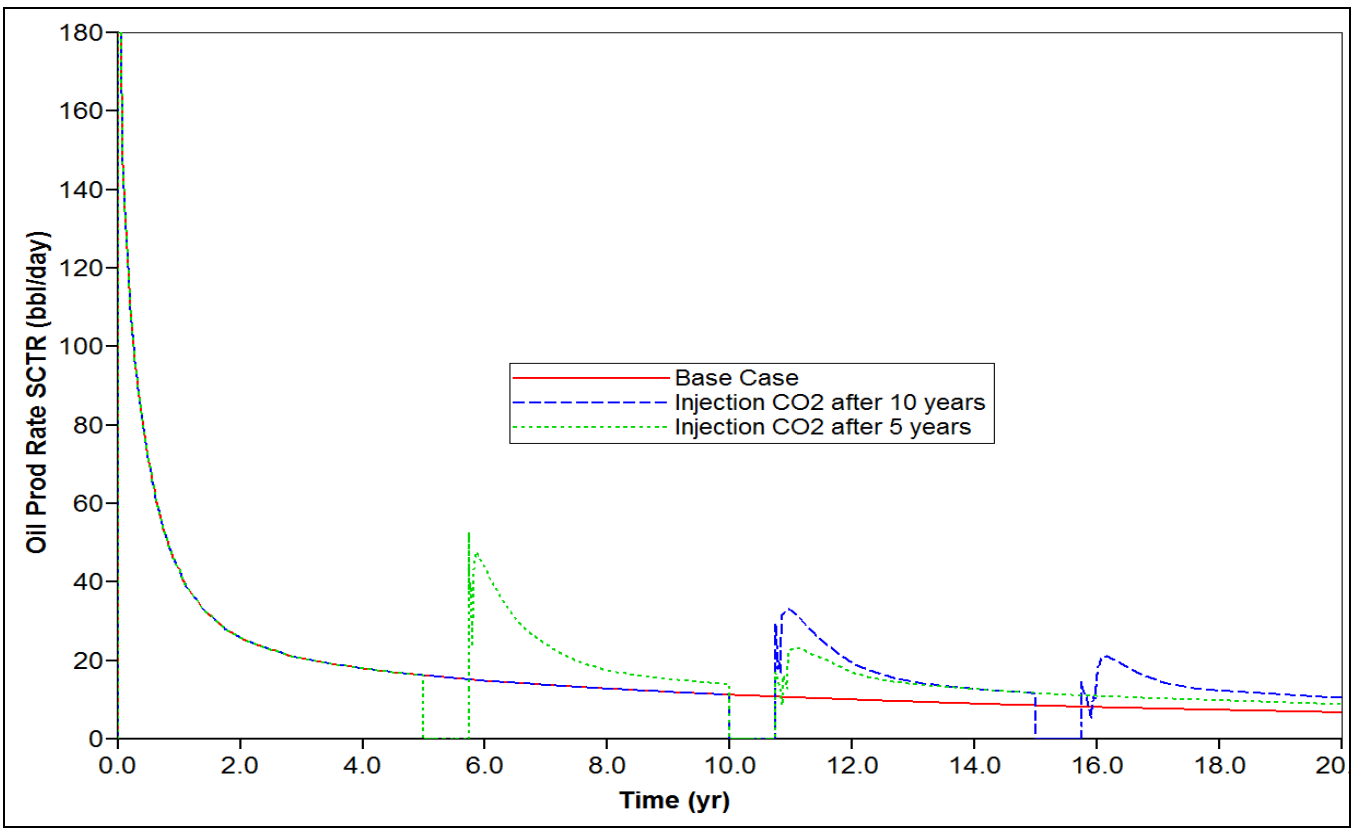
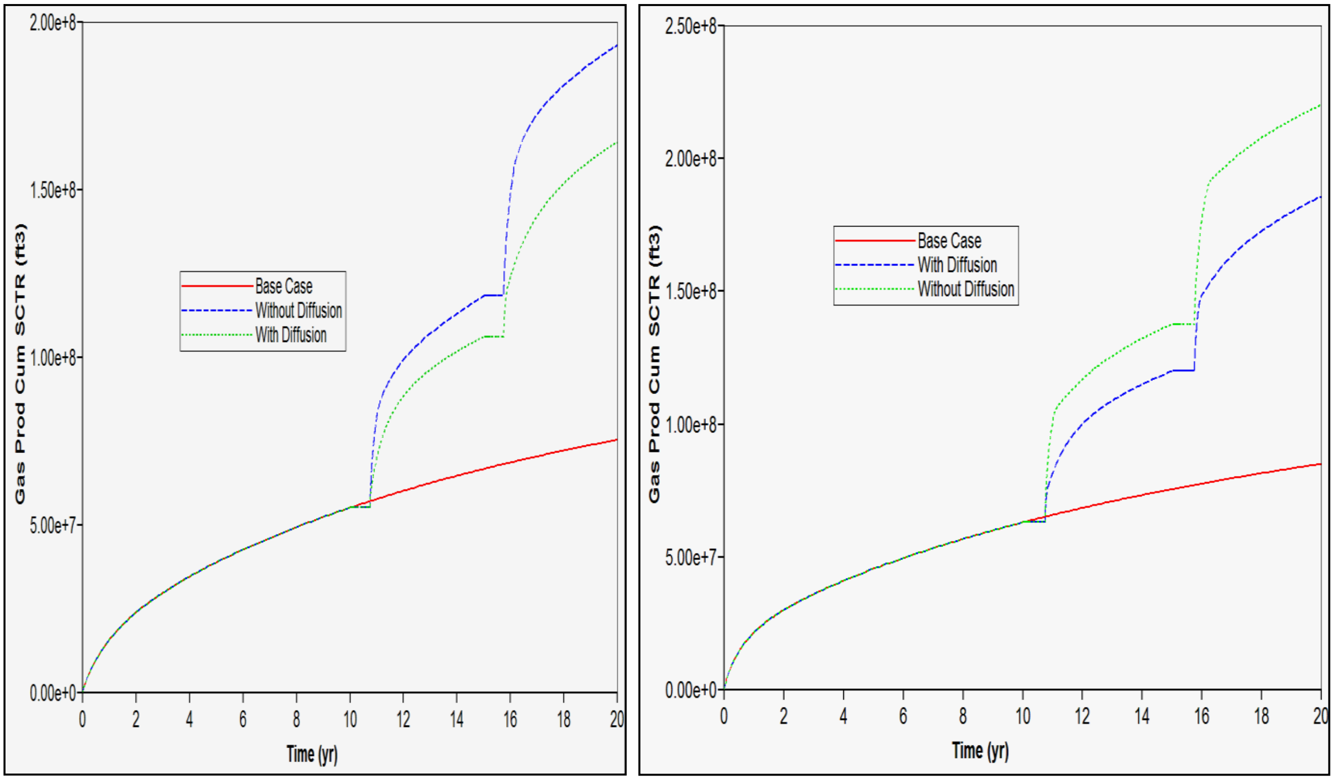


Fig. 13: Effect of the performing time on CO2-EOR in shale oil reservoirs



5 md.ft **15 md.ft**

Fig. 14: Effect of fracture conductivity on CO_2-EOR performance

Conclusions

- Most of the previous experimental studies relied on CO_2 Molecular-diffusion mechanism to predict the potential success for CO_2-EOR in shale reservoirs.
- Upscaling this mechanism to the field scale via conventional simulation methods by using the same lab-obtained CO_2-diffusion rate is misleading.
- To be significant in the field scale, this mechanism requires having either of the kinetics for oil recovery process in the productive areas of these reservoirs to be too slow or the CO_2 diffusion rate in field conditions to be too fast.
- The results from the reported pilot-tests are matching with the low-diffusivity diagnostic plots.
- The intensity of natural fractures has the potential role for the successful CO2-EOR project. However, CO2-EOR projects need to be performed earlier to find opened natural-fractures which help in enhancing CO_2 performance in these complex reservoirs.

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