CO_2 EOR SIMULATION IN UNCONVENTIONAL LIQUID RESERVOIRS: AN EAGLE FORD CASE STUDY

A Thesis

by

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MASTER OF SCIENCE

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ABSTRACT

The purpose of this work is to perform an improved method to optimize different CO_2 Enhanced Oil Recovery (EOR) processes in unconventional liquid reservoirs, particularly in the volatile oil region of the Eagle Ford shale. The dual-porosity, structured grid model in this research will be history matched with actual data collected from the field to ensure the results of CO_2 EOR study to be meaningful. Previous simulation studies of CO_2 EOR in the unconventional liquid reservoirs were not done in full field-scale and were not history matched before applying CO_2 EOR to the model. Without history matching step, the simulation might generate misleading results in CO_2 EOR studies. In addition, we are implementing the simulation in the dual-porosity mode to account for the presence of natural fractures which have been observed on Eagle Ford outcrop.

This research provides comprehensive sensitivity analyses of important parameters in both matrix and natural fracture systems of the dual-porosity model. The history matched model suggests that matrix porosity in the volatile oil region of Eagle Ford shale might be overestimated in many previous investigations. Also, sensitivity analysis shows that the natural fracture permeability perpendicular to the direction of the horizontal well has a significant impact on oil rates in numerical simulation.

Different injection schemes were considered as performed in CO_2 EOR in conventional floods. WAG (water alternating gas) and continuous injection were both tested to provide the basic output performance in order to calibrate economic models. Among different CO_2 EOR methods tested in this research, huff-n-puff yields the most

promising outcome as compared to continuous injection in both oil production and economic performance in the volatile oil region of the Eagle Ford shale.

DEDICATION

This work is dedicated to my wonderful family:

My wife, Myo Myo Khin, who makes me a better person every day

My grandparents, Thai Hoai Son and Vu Thi Hong, who always support me no matter where I am

My parents, Phi Van Dau and Thai Thi Hong Thanh, who love me, unconditionally

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I also want to thank Dr. Berna Hascakir and Dr. Frederick Chester for their valuable feedback and guidance to this thesis. I would like to thank Dr. Hadi Nasrabadi for his great comments and recommendations to my defense presentation.

Finally, I would like to thank Computer Modelling Group, Ltd. (CMG) for providing their simulator and amazing training courses.

NOMENCLATURE

atm	Atmosphere
bbl	Barrels
BSCF	1,000,000,000 SCF
DFN	Discrete fracture network
EOR	Enhanced oil recovery
EOS	Equation of State
EUR	Estimated ultimate recovery
F	Degree Fahrenheit
FCM	First contact miscible
ft	Foot
HCPV	Hydrocarbon pore volume
K	Kelvin
LGR	Local grid refinement
MCM	Multiple contact miscible
md	Milli-darcy
MMP	Minimum miscibility pressure
MMSCF	1,000,000 SCF
MMSTB	Million of stock tank barrels
MSCF	1,000 SCF
MSCFPD	1,000 SCF per day

nd	Nano-darcy
Pc	Critical pressure
PV	Pore volume
RF	Recovery factor
SCF	Standard cubic foot
SRV	Simulated reservoir volume
STB	Stock tank barrel
Tc	Critical temperature
ULR	Unconventional liquid reservoirs
WAG	Water-alternating-gas

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1. INTRODUCTION

The use of numerical simulation to optimize reservoir performance in unconventional liquid reservoirs (ULR) continues to be an important topic in the industry. There are sparse lab experiments and theoretical studies showing estimated ultimate recovery (EUR) improvement after CO_2 injection in core collected from ULR (Hawthorne et al. 2013, Tovar et al. 2014). However, these studies have not been widely applied to the field because of cost effectiveness, limited facilities, and unexpected issues when upscaling lab experiments to field conditions with reservoir simulation. Inconsistency among lab experiments, numerical simulation, and actual field performance occurs regularly in ULR. One of the most important steps that previous EOR simulation studies commonly neglected was history matching primary depletion. Moreover, the relationship of hydraulic fractures and natural fractures in these ULR should be carefully investigated to avoid misleading results for EOR performance. In this work, we will focus on two parts: (1) building a robust model representing volatile oil region in Eagle Ford shale using a dual-porosity model, and (2) applying different CO_2 EOR scenarios such as CO_2 continuous injection, CO_2 huff-n-puff, and CO_2 water-alternating-gas (WAG) in naturally fractured system to optimize the production and economic performance using numerical simulation.

Although unstructured algorithm may be able to simulate detailed discrete fracture networks (DFN), this method requires a significant amount of computational time not only in discretizing and history matching but also in optimizing different EOR methods (**Figure**

1). Decline curve analysis, on the other hand, is too simple to represent the physics of unconventional reservoirs. Usually, decline curve analysis is used to forecast the production when the well is operated under the same conditions as the primary depletion. If any stimulation or enhanced oil recovery method is applied, the decline curve analysis will be invalid to forecast production. Dual-porosity unstructured grid model is more complicated and detailed than the decline curve analysis but less sophisticated than unstructured discrete fracture network model.

The first part of this thesis focused on history matching a volatile oil reservoir with actual data collected from different reports in Eagle Ford shale using a dual-porosity model. Before history matching, several important parameters in both matrix and natural fracture will be investigated thoroughly. After that, this matched model used in the primary depletion will be redesigned accordingly to simulate different CO_2 EOR processes. Finally, a comprehensive uncertainty analysis will be performed to select the best EOR scenario to improve oil recovery in the volatile oil region of Eagle Ford shale.

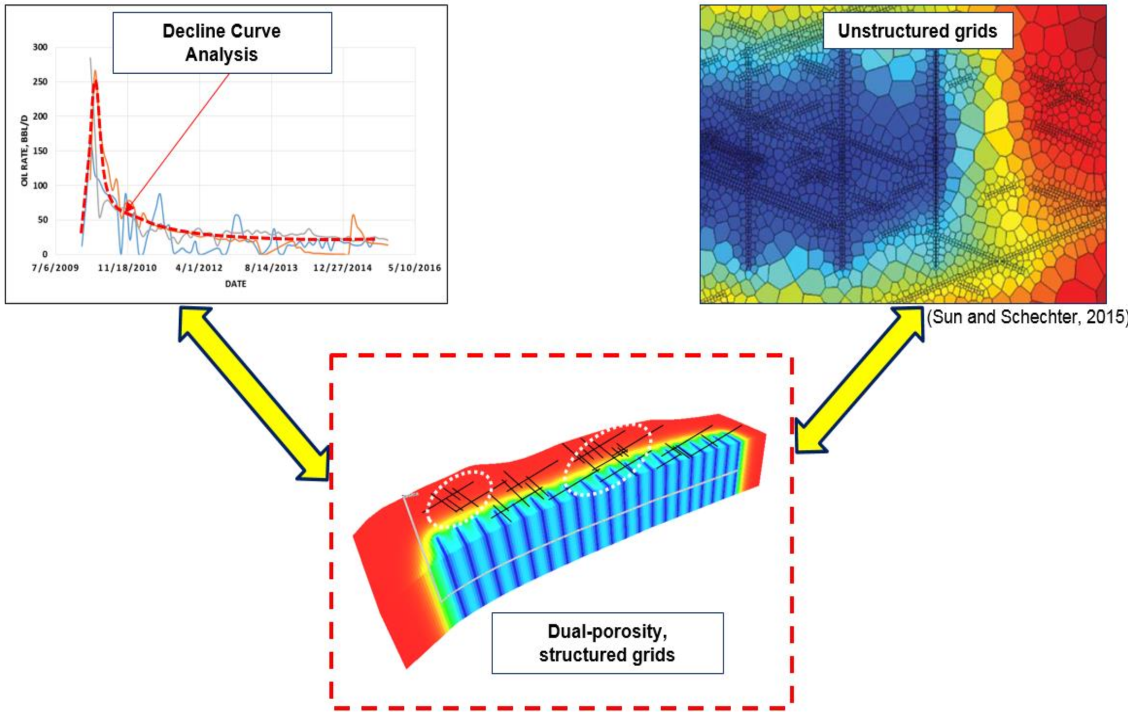


Figure 1. Dual-porosity model compared to decline curve analysis and unstructured meshing model

1.1 Previous Works

Several lab experiments have been conducted to study the impact of CO_2 enhanced oil recovery (EOR) on unconventional liquid reservoirs (Tovar et al. 2014, Hawthorne et al. 2013). The oil recovery factors after applying CO_2 EOR from these experiments are very promising. Hawthorne et al. (2013) compared the hydrocarbon recovery when CO_2 is flooded into Bakken rocks versus conventional rocks. Since the mechanisms of CO_2 EOR applied in unconventional rocks, and conventional rocks are different, Hawthorne et al. (2013) concludes that conventional method of CO_2 injection cannot be applied directly to unconventional liquid reservoirs such as Bakken or Eagle Ford. However, the promising recovery factor from the experimental works was a great motivation for many following simulation studies of CO_2 EOR in unconventional liquid reservoirs.

Decline curve analysis and reservoir simulation are common practices to estimate total oil reserve and forecast the ultimate recovery factor in ULR. Amongst various simulation studies of primary recovery in ULR, important parameters such as matrix porosity, matrix permeability, natural fracture porosity, and natural fracture permeability are usually assigned or estimated differently in each study. For example, Offenberger et al. (2013) estimated the matrix permeability in Eagle Ford was 5E-6 md, while Wang and Liu (2011) used 5E-4 md of matrix permeability in their model.

CO_2 EOR simulation in ULR has remained as an interesting topic in the industry. Some related subjects regarding CO_2 EOR in ULR have been well studied using numerical simulation. For instance, Chen et al. (2014) found a significant impact of reservoir heterogeneity on both primary and CO_2 huff-n-puff recoveries in Bakken, and optimized

CO_2 huff-n-puff in Bakken using numerical simulation (2014). Both Chen et al. and Rivera's models were not history matched with actual field data before applying CO_2 EOR. In fact, many other CO_2 EOR simulation studies did not include history matching, too (Zou 2015, Zhu 2015, Wan and Sheng 2015). Without history matching, these models might generate misleading results of incremental oil recovery at the end of the simulation.

Lately, a graduate student in our group introduced an advanced method of coupled discrete fracture network and unstructured meshing algorithms to simulate complex fractured reservoirs (**Figure 2**). He applied an unstructured grid model to conduct many comprehensive studies regarding the relationship between hydraulic fracture and natural fracture (Sun and Schechter 2015, Sun et al. 2016). This advanced model is totally capable of capturing complex behaviors of natural fracture and hydraulic fracture in unconventional resources.

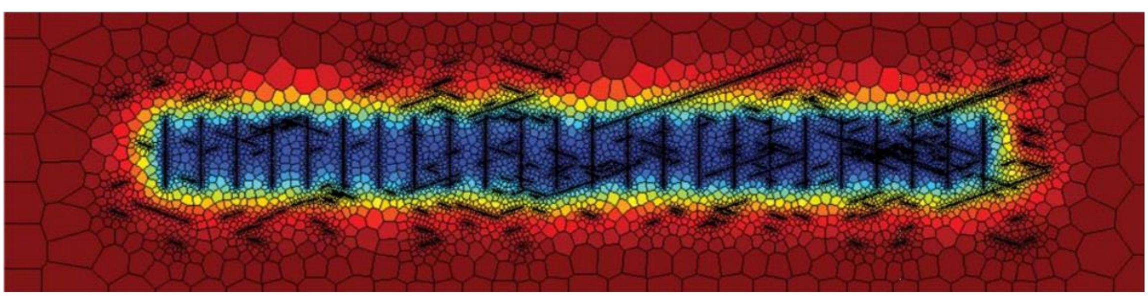


Figure 2. Unstructured grid model of naturally fractured reservoir (Sun and Schechter 2015)

However, by using this unstructured grid model to simulate a whole horizontal well, significant computational time is required. Furthermore, history matching this unstructured model is another challenging task that needs a powerful computer. A dual-porosity structured grid model developed in this research will be used to history match actual field data in ULR and then benchmark against Sun and Schechter's unstructured model in the future.

1.2 Approach

First, all data will be gathered from public sources. These data include production reports, outcrop map, natural fracture, hydraulic fracture, geology, rock, and fluid. Multiple grid sizes and number of refinements for hydraulic fractures will be tested to ensure the accuracy of the simulation is preserved yet speed up computational time. Several sensitivity analyses will be conducted to investigate which parameters from the matrix system and the natural fracture system would have a significant impact on the incremental oil recovery. These parameters will be adjusted scientifically in the process of history matching to capture the primary depletion. Then, this history-matched model will be used to apply multiple CO_2 EOR studies (**Figure 3**).

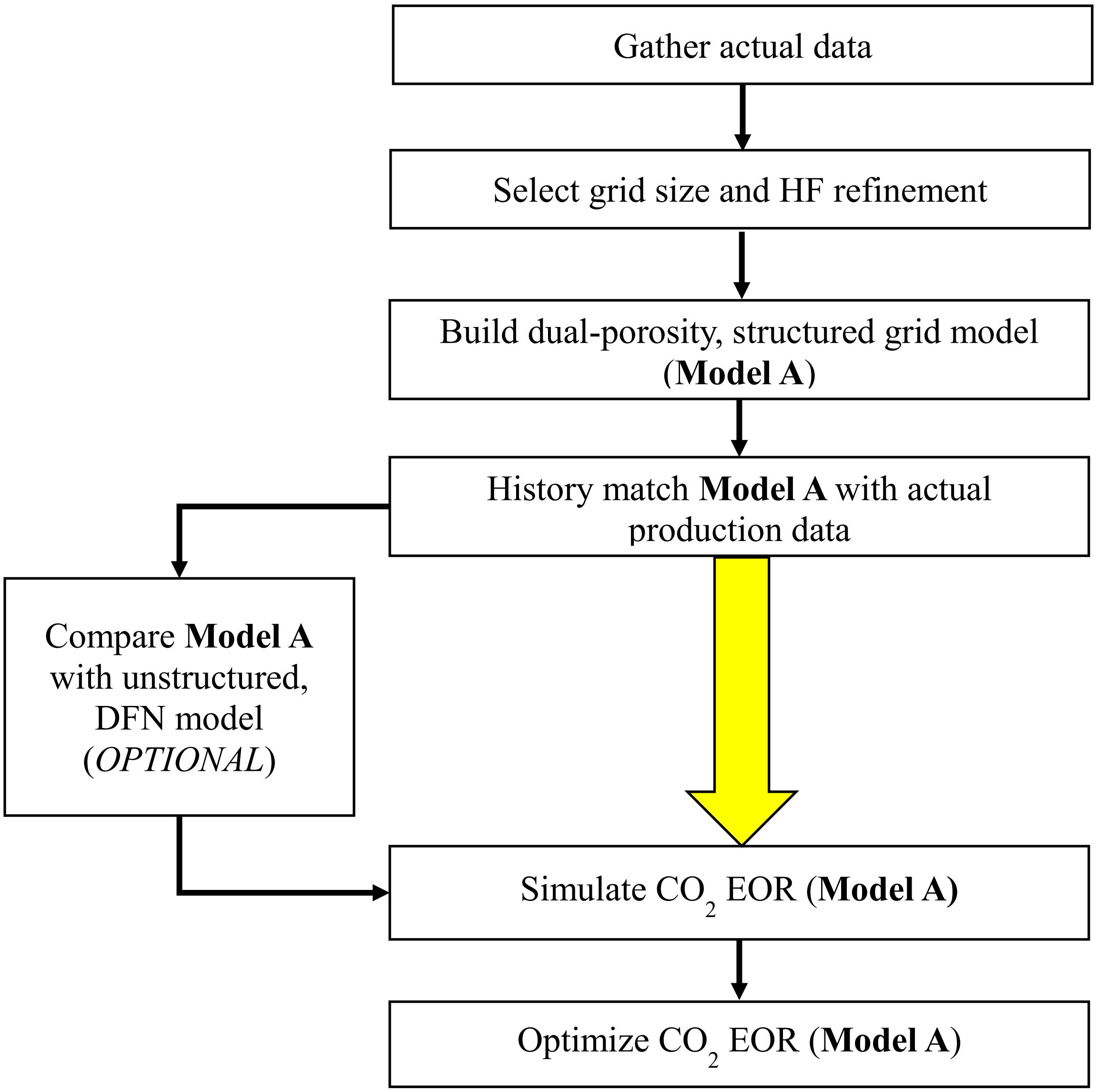


Figure 3. Workflow of this study

1.3 Novelty of This Work and Its Limitations

At the end of this research, we will realize the advantages and disadvantages of different CO_2 EOR methods in the volatile oil region of Eagle Ford shale. Full field-scale of horizontal wells will be simulated using a dual-porosity structured grid model. Unlike previous works, we will perform a complete process of history matching the model with actual field data before applying different CO_2 EOR methods. This tuned model will avoid misleading results from the study of optimizing CO_2 EOR in the unconventional liquid reservoirs. This work also provides comprehensive sensitivity analyses of several important parameters in matrix and natural fracture systems during history matching process.

Due to the limited time and resources, there are some limitations in this study which might be great topics for future research. First, the dual-porosity model in this study will not include the effect of wettability change by hydraulic fracture fluid and flow back data. Second, the outcrop map of natural fracture network will be simplified and averaged carefully to fit the dual-porosity model. Third, this model does not combine any geomechanics of rocks and hydraulic fractures in flow simulation. Instead, a planar model of hydraulic fracture will be used to save computation time in the history matching process yet preserve the accuracy of the final results.

1.4 Organization of the Thesis

Section 1 of this thesis is a summary of previous works associated with CO_2 EOR simulation in unconventional liquid reservoirs. We will address the missing points in these studies and propose our solution.

In section 2, we will introduce a brief background of Eagle Ford shale and describe the volatile oil region chosen in this study.

Section 3 shows how the dual-porosity structured grid model is constructed to history match production data in the volatile oil region of the Eagle Ford shale. In this section, several sensitivity analyses of important parameters of the matrix and natural fracture systems will be presented.

Section 4 will construct and analyze different CO_2 EOR methods such as CO_2 continuous injection, CO_2 huff-n-puff, and CO_2 WAG (water-alternating-gas) in the Eagle Ford shale.

Section 5 will conclude this study and recommend some topics for future work.

2. THE VOLATILE OIL REGION OF THE EAGLE FORD SHALE

2.1 Background

Eagle Ford is located in South Central Texas. It is one of the most active unconventional resources in the United States till today. From 2010 to 2015, oil production in Eagle Ford increased significantly from 15,149 barrels per day (bbl/d) to 1,164,563 bbl/d (**Figure 4**).

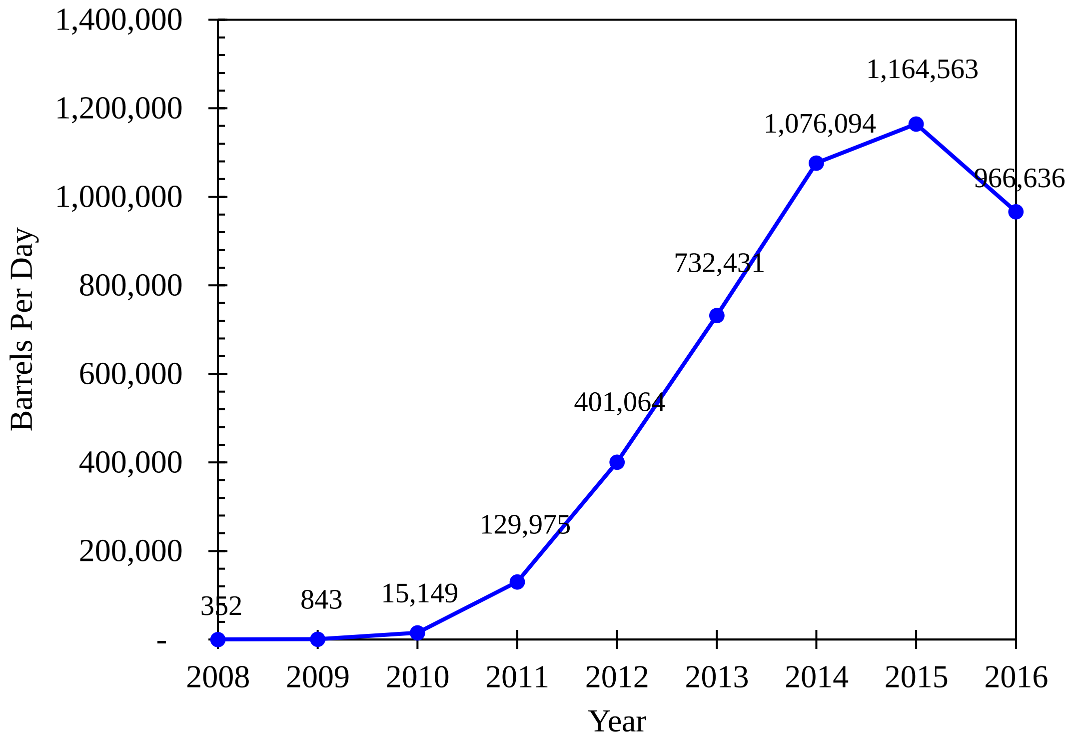


Figure 4. Oil production in Texas Eagle Ford shale from 2008 to March 2016 (adapted from Railroad Commission of Texas, 2016)

Tian et al. (2012) used eight production regions to characterize different fluid types in Eagle Ford shale (**Figure 5**). PR6 (Volatile oil region) is chosen in this study (**Table 1**). According to Gong et al. (2013), technical recoverable oil over 20 years in the volatile oil region is approximately 454,000 STB per well. Until today, cumulative oil production of active wells in this region is approximately 160,000 - 180,000 STB. That means 274,000 – 294,000 barrels of residual oil can be recovered per well. Typically, after the first year of production, oil rates in this region dropped more than 90%. For the last few years, to maintain the production rate, operators in this region decided to drill new horizontal wells. With the oil price over $100/barrels in 2011-2014, drilling new horizontal wells and performing hydraulic fractures generated great cash flow quickly for the operators at that time. As a result, after a few years, these wells are producing at very low to uneconomical rate despite the fact that there are still great amounts of recoverable oil left in this region.

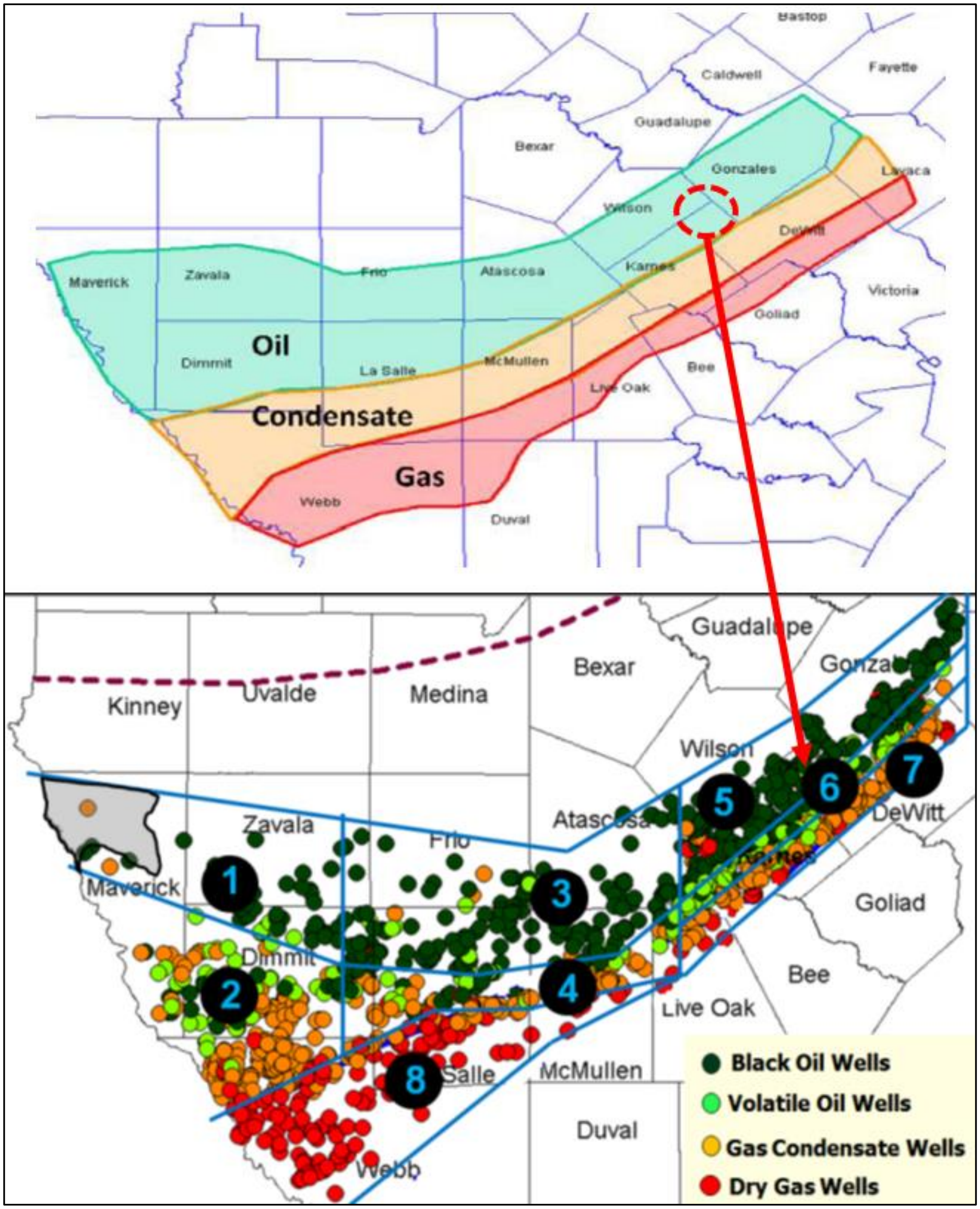


Figure 5. Location of the volatile oil region of the Eagle Ford shale (modified from Tian et al. 2012)

Table 1. Characteristics of fluid in Eagle Ford Shale (adapted from Gong et al. 2013)

Production Region	**Fluid Type**
PR1	Black Oil
PR2	Condensate/Volatile Oil
PR3	Black Oil
PR4	Condensate
PR5	Black Oil
PR6	**Volatile Oil**
PR7	Condensate
PR8	Dry Gas

2.2 Fluid Model

The fluid model we chose in this study falls into volatile oil window in Eagle Ford shale (**Figure 5**). The original composition of this oil is listed in **Table 2**. These components will be lumped and tuned by regression process by WINPROP, a fluid modelling tool by CMG. Basic properties of pseudocomponents after regression is listed in **Table 3**.

The tuned fluid model will be converted to equation of state (EOS) using Peng-Robinson model and input to the dual-porosity model of this study.

Table 2. Compositions of the Eagle Ford volatile oil region

Component	Composition
H2S	0
N2	0.14
CO2	1.12
C1	62.54
C2	11.76
C3	5.59
IC4	1.36
NC4	2.32
IC5	1.17
NC5	1.1
C6	1.55
C7+	11.36
C7+ Molecular Weight	164.63
C7+ Specific Gravity (Water = 1)	0.8

Table 3. Basic properties of pseudocomponents after regression

	Composition	Pc (atm)	Tc (K)	Acentric factor	Mol. Weight
CO2	0.0112	72.80	304.20	0.2250	44.010
N2 toCH4	0.6267	45.20	189.41	0.0086	16.254
C2toC3	0.1735	46.14	327.74	0.1154	34.589
C4toC5	0.0595	35.55	436.98	0.2065	63.475
C6	0.0155	32.46	507.50	0.2750	86.000
C7+	0.1136	20.40	674.81	0.4901	164.630

3. DUAL-POROSITY, STRUCTURED GRID MODEL

3.1 Reservoir Description

A full field-scale reservoir is built to simulate, and history match one horizontal well in the volatile oil region of the Eagle Ford shale. The domain of this simulation study is 5,000 ft in I-direction and 1,800 ft in J-direction (**Figure 6**). The length of the lateral well is 4,000 ft in I-direction. Since the vertical flow is not the main focus of this study, this model has only one layer with the thickness of 100 ft. The depth of this model is around 11,734 ft from sea level. The temperature at this depth is 307 F.

GEM, a compositional simulator from CMG, is chosen to simulate the dual-porosity structured grid model in this research. There are two main reasons to use a compositional simulator instead of black oil simulator in this work. First, the fluid in this region falls into volatile oil window. The compositions and phases of the volatile oil are very sensitive as the well starts producing. The second reason is the study of CO_2 EOR requires the simulator's ability to represent the process of multiple contact miscibility between CO_2 and oil appropriately.

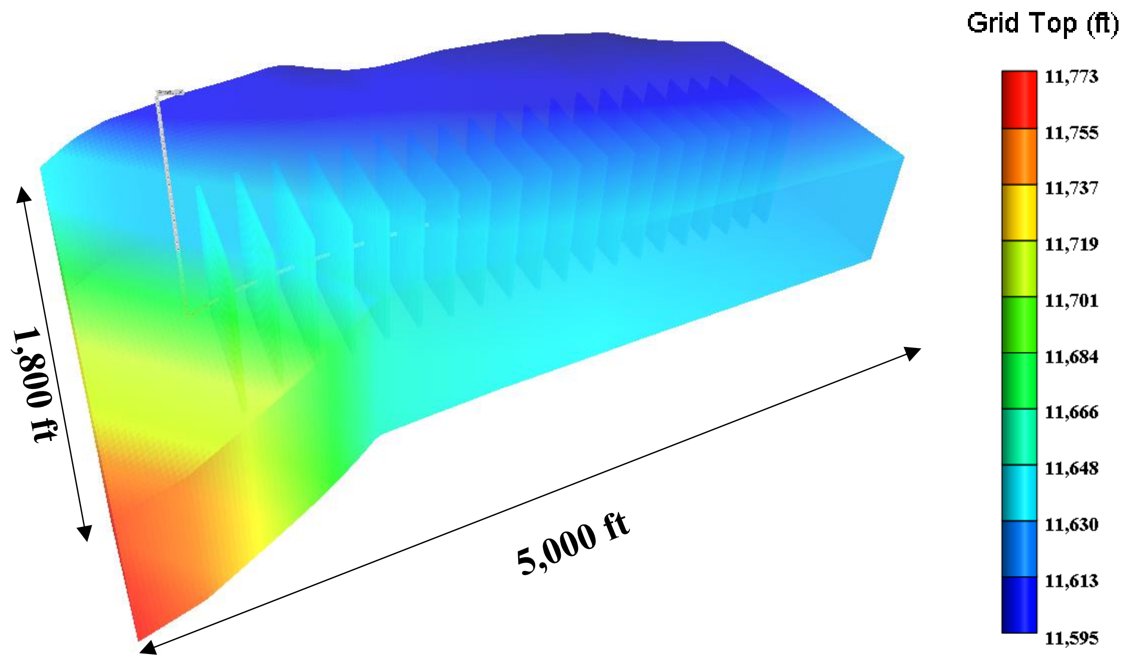


Figure 6. Computational domain

3.2 Grid Size and Refinement

Before going through a complicated and time consuming history matching process, an appropriate grid size should be carefully selected to save computational time yet preserve the accuracy of the study. Three grid block sizes of 25 ft x 25 ft (fine), 50 ft x 50 ft and 100 ft x 100 ft (coarse) in I- and J-directions are used to test whether they generate the same results after ten years of production. **Figure 7** shows that although all of the grid sizes has similar oil rate in the late time (from 2014 to 2020), they have distinctive results during the first three years. The coarse model, 100 ft x 100 ft, is not able to produce much oil in the first year. The oil rate dropped immediately from 400 bbl/day to 250 bbl/day on the same day. As a result, it will be very difficult to match the early time using the coarse model.

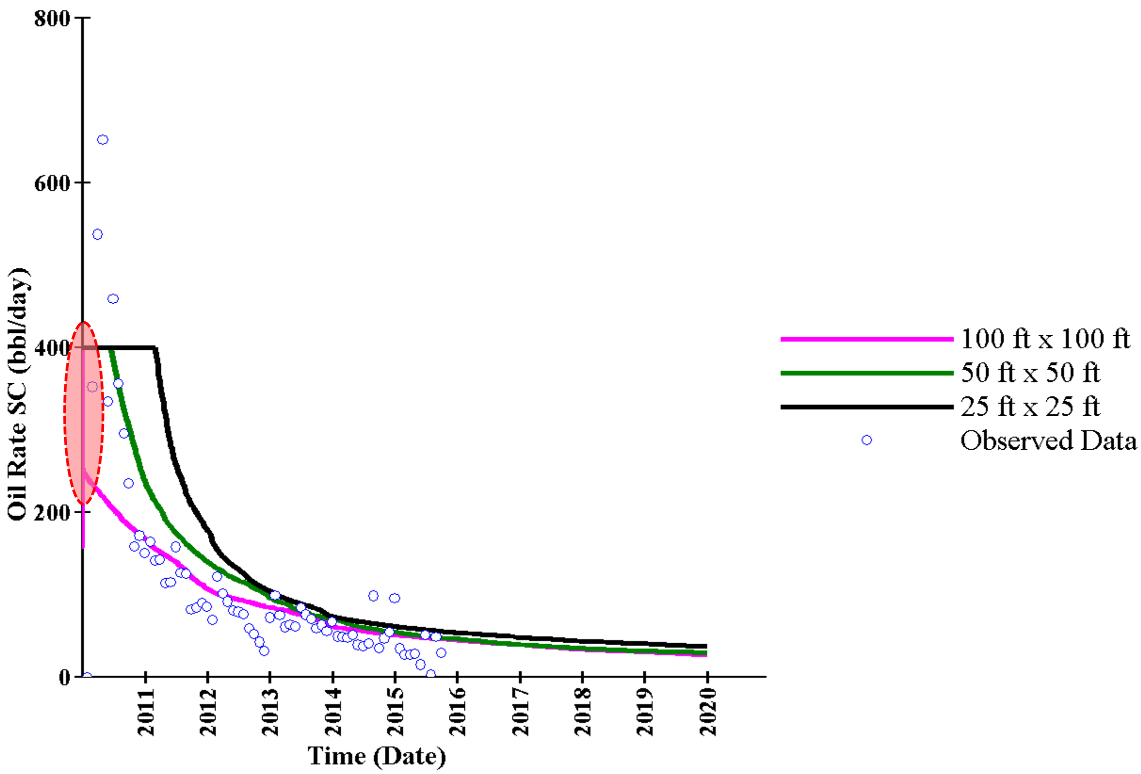


Figure 7. Different grid sizes comparison

Despite the fact that the fine model might generate a better result, its computational time is approximately ten times longer than the 50 ft x 50 ft grid model (**Figure 8**). Moreover, after local grid refinement was applied to hydraulic fractures of the 50 ft x 50 ft grid model, the gap between this model and the fine model reduced.

It is essential to model the flows around hydraulic fractures correctly. In general, when simulating gas reservoirs, non-Darcy flows are used to represent the movement of fluid around the hydraulic fractures. In this study, non-Darcy flow option is also verified if it has any significant impact on the final results. **Figure 9** clearly shows that non-Darcy option is unnecessary in this study because it takes a longer time to generate the same oil rate as the models without the non-Darcy option.

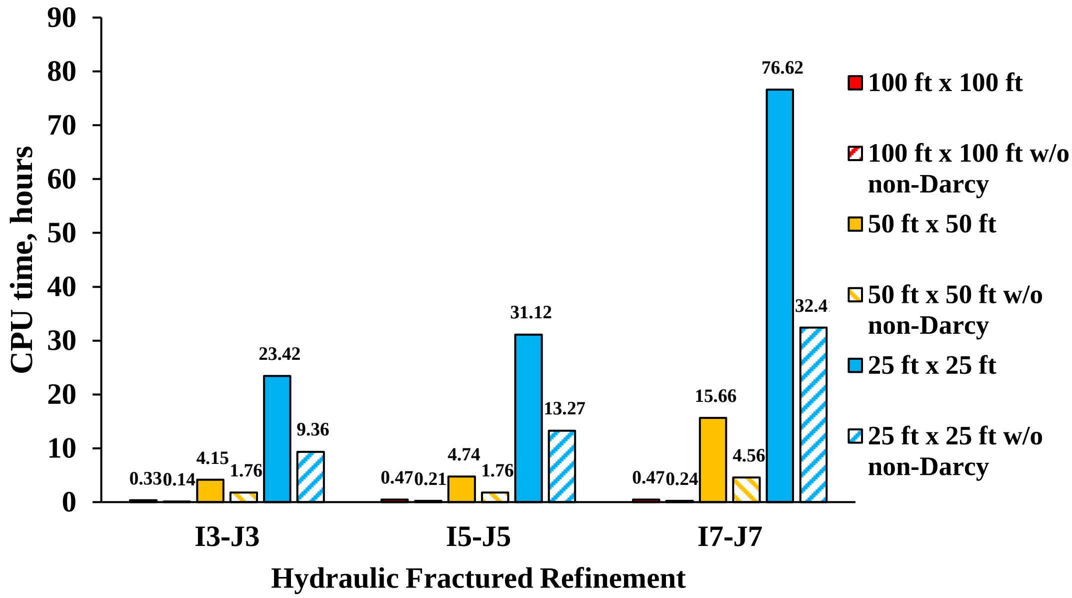


Figure 8. Computational time comparison among different grid sizes and refinements

The chosen size of 1 cell in this model is 50 ft x 50 ft in I- and J-directions. To capture the transient process around the hydraulic fractures correctly, it is vital to apply local grid refinement (LGR) to the hydraulic fracture cells in I- and J-directions. Refinement in K-direction is unnecessary since there is only one layer in this direction. The refinement process will create more grid blocks resulting longer computational time. Therefore, a sensitivity analysis of this LGR is conducted to select the best number of refinements to simulate the flow accurately in this study. According to CMG manual, I3-J3 refinement in hydraulic fracture design means the grids representing hydraulic fractures will be refined into three grids in I-direction and three grids in J-direction (2015). The same concept is applied to I5-J5 and I7-J7 refinements. Comparing different refinement cases, I3-J3 is the best scenario because it can generate the same outcomes as the I7-J7 model, yet shortens the computational time significantly.

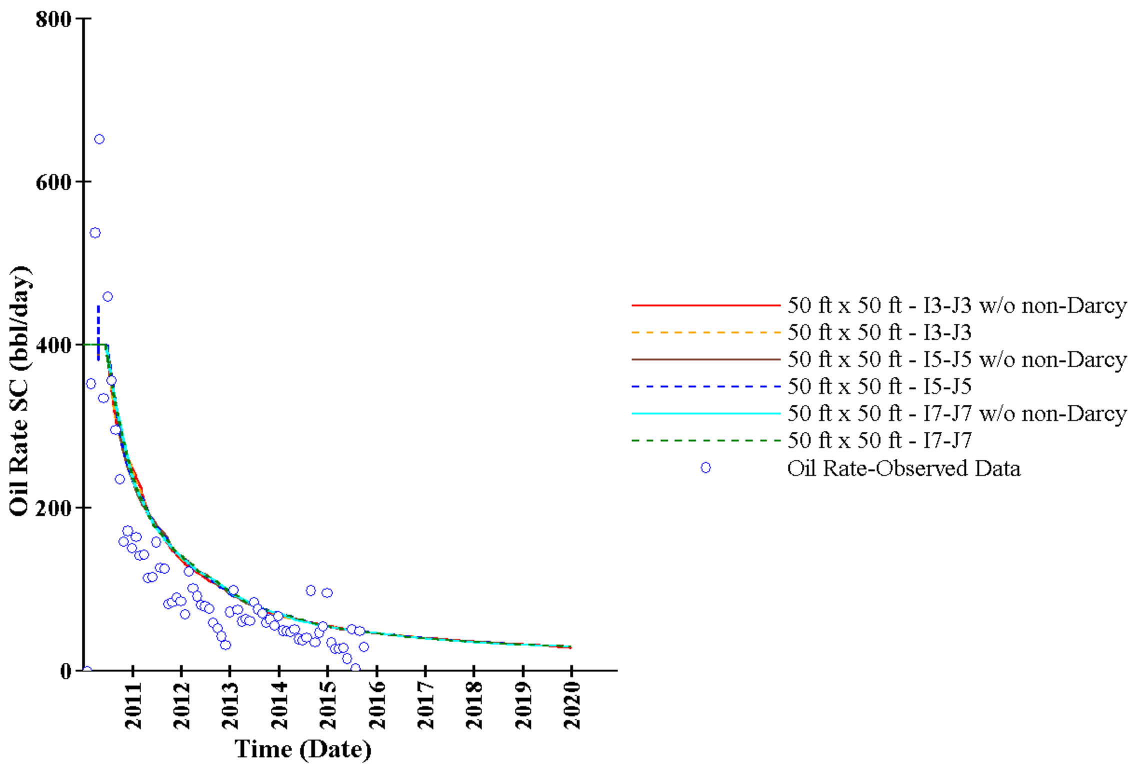


Figure 9. Sensitivity analysis of non-Darcy flow and hydraulic fractured refinement

For all of the observations above, the best model for the history matching has 50 ft x 50 ft of grid size without non-Darcy flow option, and three refinements in I- and J-directions for the hydraulic fractures.

3.3 Hydraulic Fractures Design

In Eagle Ford, typical length of a lateral well is 3,000 - 5,000 ft with the completion of 4-8 clusters per stages, and 10-20 stages total, as shown in **Figure 10** (Fan 2011). Based on the information collected from different operators in Wilson and Karnes counties, a detailed hydraulic fractured model is built as a reference. After that, a simplified hydraulic fracture model is constructed to mimic the behavior of the detailed model to reduce the computational time. Moreover, since this study does not focus on shapes, shadows, or geomechanics of hydraulic fractures, a simplified hydraulic fracture model is preferred. The detailed model has ten stages total; each stage has four clusters. The simplified model has twenty stages; each stage has only one clusters. Each cluster in the simplified model is a planar hydraulic fracture of 10 md-ft conductivity at the heel and gradually decrease to 5 md-ft at the tip. All hydraulic fractures have 300 ft half-length (**Figure 11**). A summary of important properties of the simplified hydraulic fracture model is listed in **Table 4**.

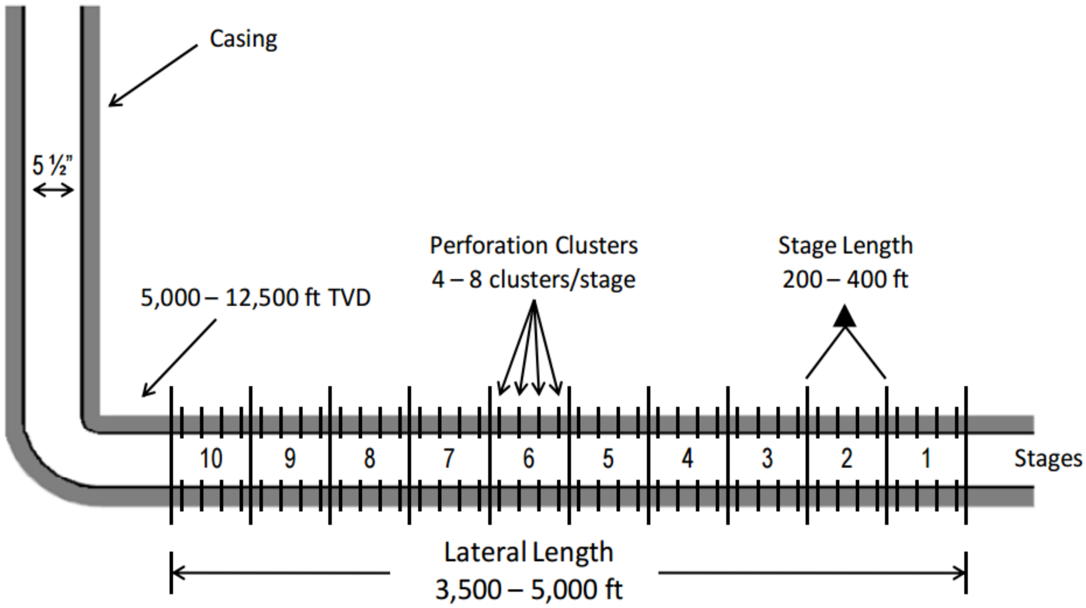


Figure 10. Typical completions in Eagle Ford shale (Fan 2011)

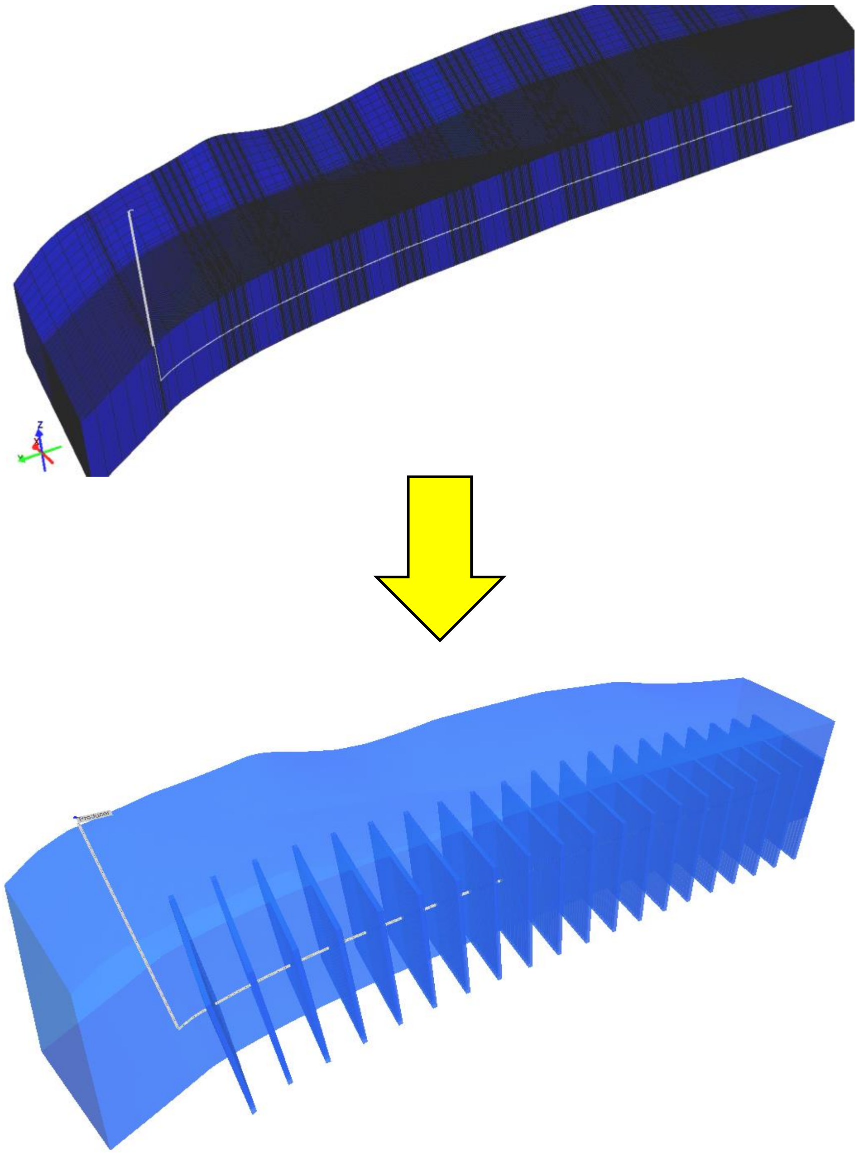


Figure 11. Detailed hydraulic fracture model (top) and simplified hydraulic fracture model (bottom)

Table 4. Simplified hydraulic fracture properties

Type	Planar
Fracture width	0.001 ft.
Intrinsic perm	10,000 md
Modeled width	2 ft.
Modeled perm	5 md
Total stage	20
Stage spacing	200 ft.
Fracture half length	300 ft.

3.4 Sensitivity Analysis

Before history matching is processed, several comprehensive sensitivity analyses for all important parameters in both matrix and natural fracture systems are conducted. As expected, some parameters, but not all, from both matrix and natural fracture systems influence the production significantly. The tornado plot from **Figure 12** shows that natural fracture width, representing porosity and permeability in natural fracture system, and matrix porosity have 48% and 30% impact on oil production, respectively. To understand better which parameters are more important than the others, two separate sensitivity analyses are proceeded: one for matrix system and one for natural fracture system.

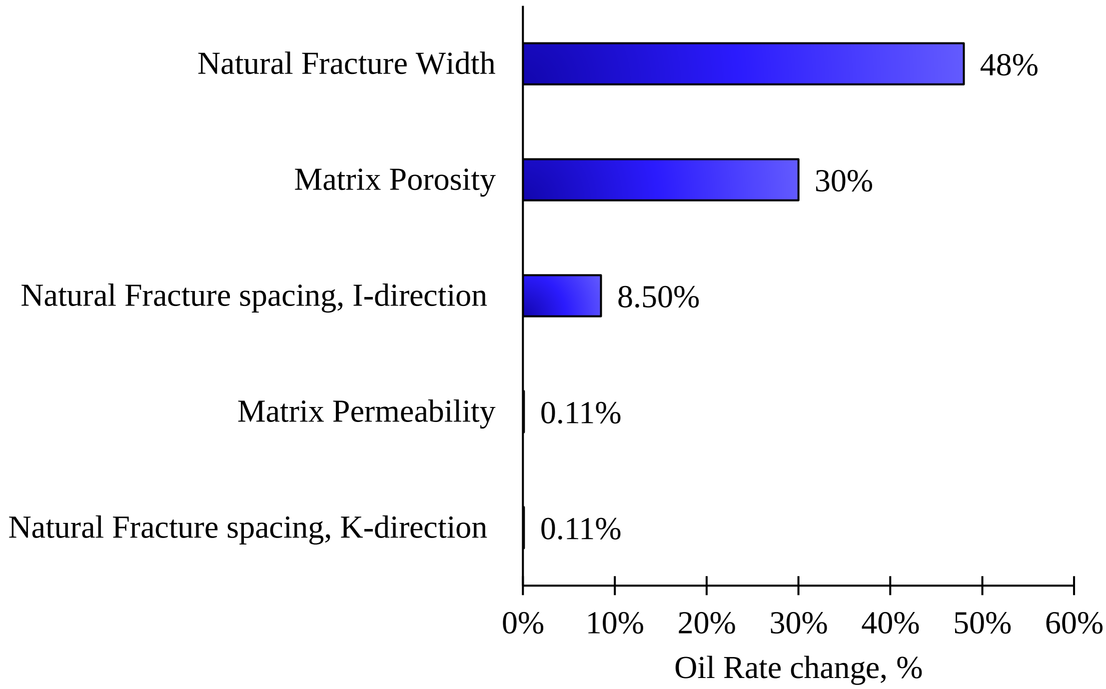


Figure 12. Initial sensitivity analysis of matrix and natural fracture parameters

3.4.1 Sensitivity Analysis for Matrix System

In matrix system, porosity and permeability are two parameters needed to be focused the most. Unfortunately, there is no document proving exactly how porosity and permeability distribution in Eagle Ford is. In fact, each operator in this region uses their own values based on their in-house method of estimating these parameters. In the case of extremely tight rock in Eagle Ford shale, the estimation of permeability and porosity from logs and laboratory is typically uncertain to be applied directly to simulation.

In the dual-porosity model, the porosity in matrix system represents reservoir storage (Kazemi et al. 1976, Warren and Root 1963). Therefore, an incorrect estimation of porosity in matrix system will affect the total original fluid in place. On the other hand, permeability in matrix system should not impact the overall simulation. **Figure 13** clearly shows that matrix porosity should be focused more than matrix permeability because matrix porosity has up to 30% impact on oil production while matrix permeability only has 0.11% influence on the simulation. The result of this sensitivity analysis is consistent with the concept behind dual-porosity model and previous work performed by Wang and Liu (2011)

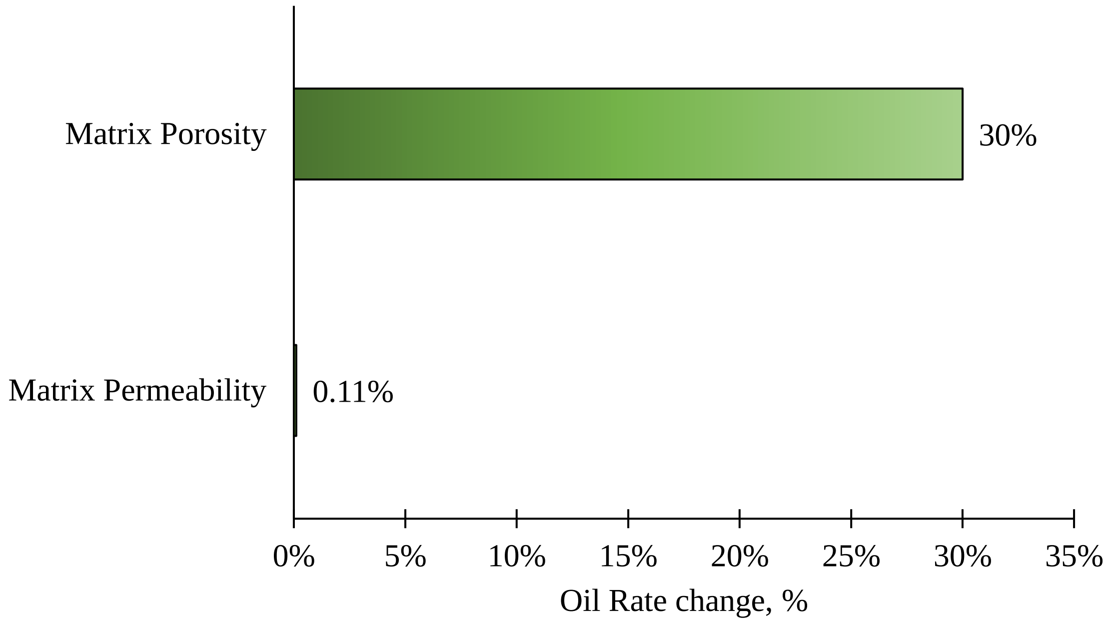


Figure 13. Sensitivity analysis of matrix parameters

In early time, the factors that have a strong impact on oil production in unconventional liquid reservoirs are flow back and wettability change due to fracture fluids such as surfactant and chemical. These factors are not the main focus of this research and only affect the early time of production. The simulator was forced to produce the first three data points to capture the effects of these factors correctly. After that, the production constraints were removed so the fluids can flow freely.

Two porosity values of 2% and 6% were run to compare their oil rates in **Figure 14**. Changing porosity in matrix system not only impacts the late time production but also affects peak oil production in the early time. The higher matrix porosity is, the better oil production is in during the first year of production. **Figure 14** also shows that the higher matrix porosity model allows the well to produce at peak production of 652.5 bbl/day for a longer period compared to the lower matrix porosity model.

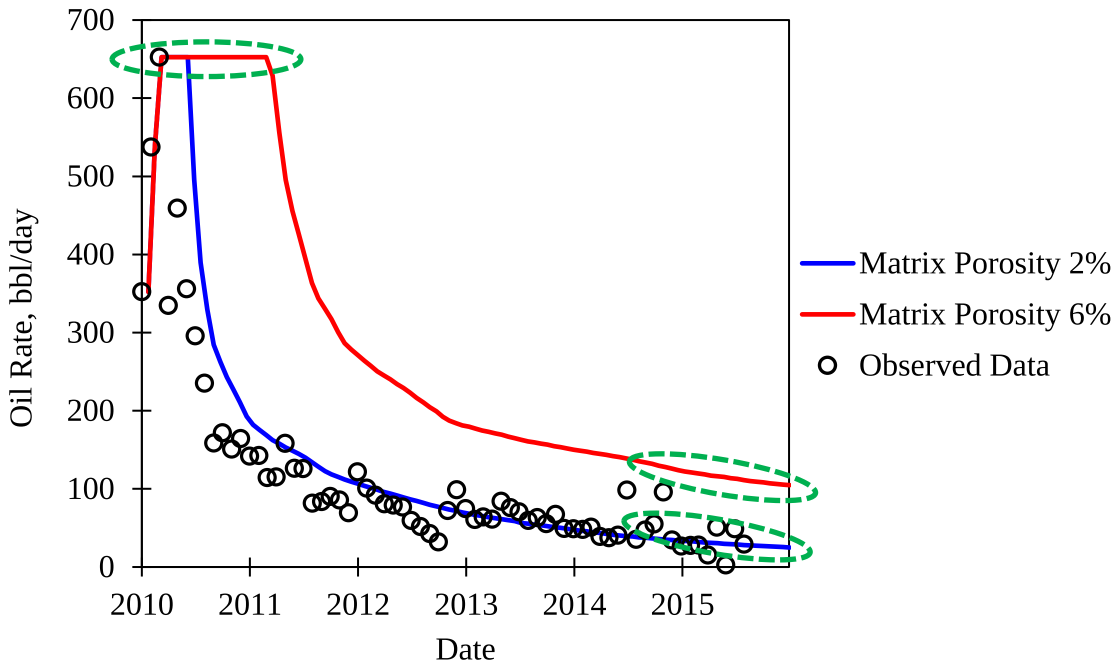


Figure 14. Impact of matrix porosity on oil production

Next, to visualize the effect of permeability in matrix system, two simulations were run with different values of matrix permeability: 1E-5 md and 1E-6 md. The oil rates are almost overlapped each other in **Figure 15** indicating the insignificance of permeability of the matrix system on the simulation in ULR. This observation is consistent with the theory behind the dual-porosity model that cells does not communicate within matrix system. Instead, the matrix cells communicate with their corresponding cells in the fracture system, and the cells within fracture system will communicate to each other. **Figure 15** also strengthens the results generated from the tornado plot of matrix parameters sensitivity analysis earlier (**Figure 13**).

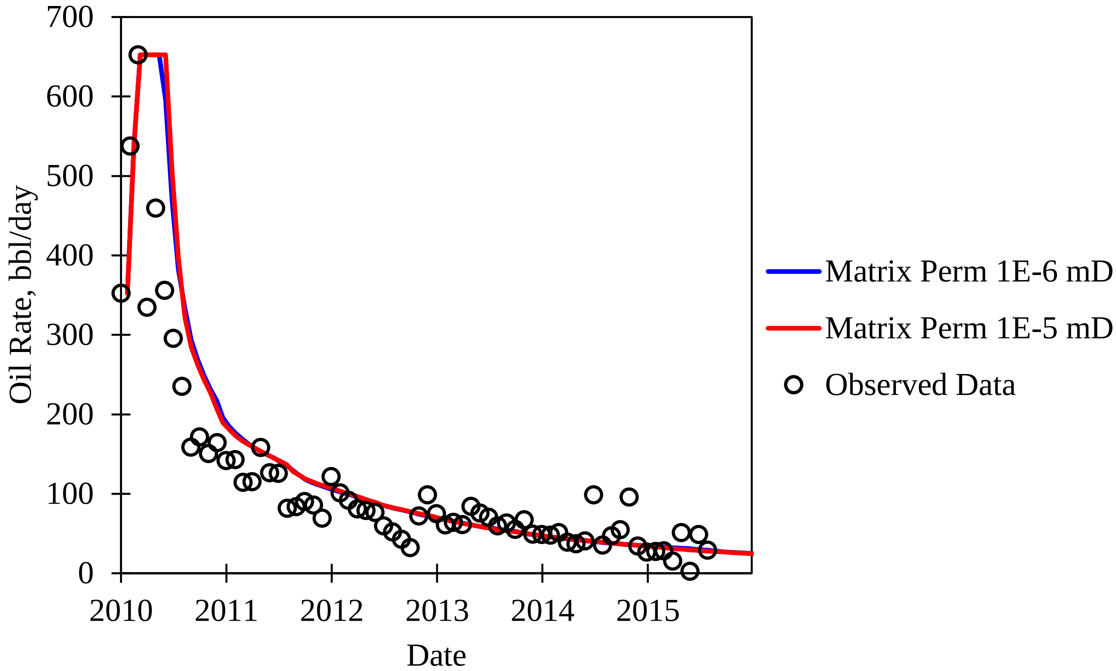


Figure 15. Impact of matrix permeability on oil production

3.4.2 Sensitivity Analysis for Fracture System

Unlike in matrix system, changing permeability in fracture system can impact the simulation greatly. **Figure 16** shows that permeability in fracture system is much more sensitive than porosity. Since natural fracture network is unique in each formation, directions of permeability and fracture spacing should be carefully investigated. From **Figure 16**, permeabilities in I- and J-directions are more sensitive than porosity. This result is, again, consistent with Wang and Liu's work (2011) even though they used a coarse dual-porosity model with only 468 cells. Our work shows a different observation to Zou's work (2015). Zou found that fracture permeability does not impact oil production.

Because this study does not focus on complexity in the vertical direction, investigating permeability and natural fracture spacing in K-direction is irrelevant.

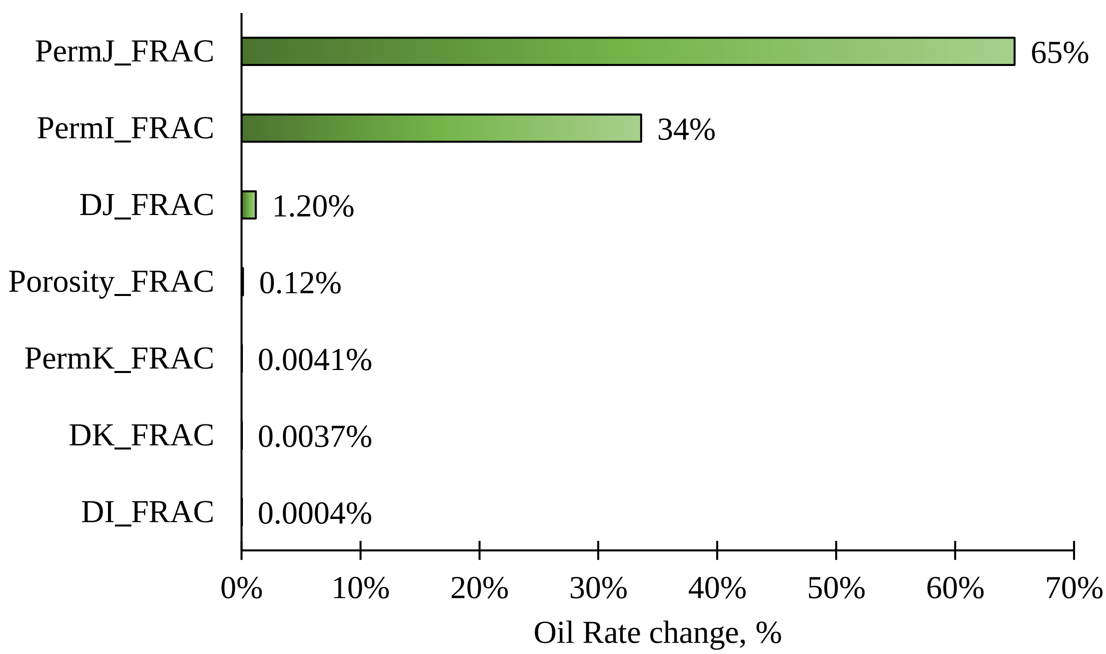


Figure 16. Sensitivity analysis of natural fracture parameters

Figure 17 shows that oil rate can reach to higher peak if fracture permeability in I- direction is higher. From 2011 to 2016, the oil production rates is almost identical. Thus, natural fracture permeability in I-direction will have more impact on the oil production in the early time and less impact after one year of primary depletion.

Natural fracture permeability in J-direction, on the other hand, has a more serious impact than the permeability in I-direction. The two models in **Figure 17** shows how it affects the oil rates from the beginning until the end of the simulation. In this study, dual-porosity structured grid model does not display natural fracture's intrinsic directions, lengths, and apertures. These parameters are combined to generate effective permeabilities and spacing in I-, J-, and K-directions. Since the horizontal well is in I-direction and the hydraulic fractures are in J-direction, fracture permeability in I-direction allows fluid to flow from natural fractures to hydraulic fractures while permeability in J-direction allows fluid to flow directly from natural fractures to the horizontal well (**Figure 18**). As a result, the simulated oil production is very sensitive to fracture permeability in J-direction in the dual-porosity model.

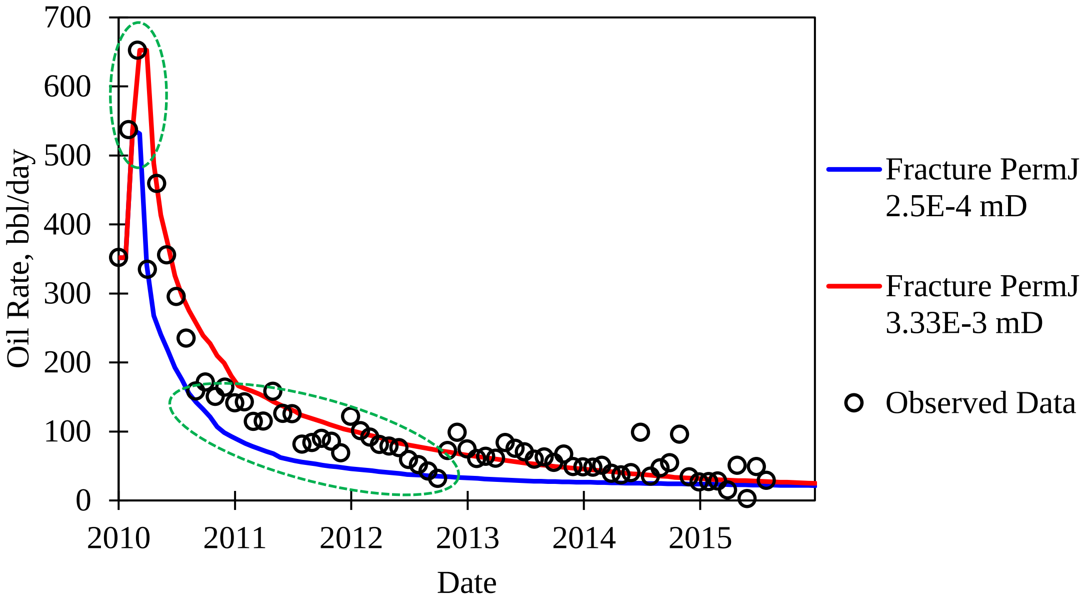
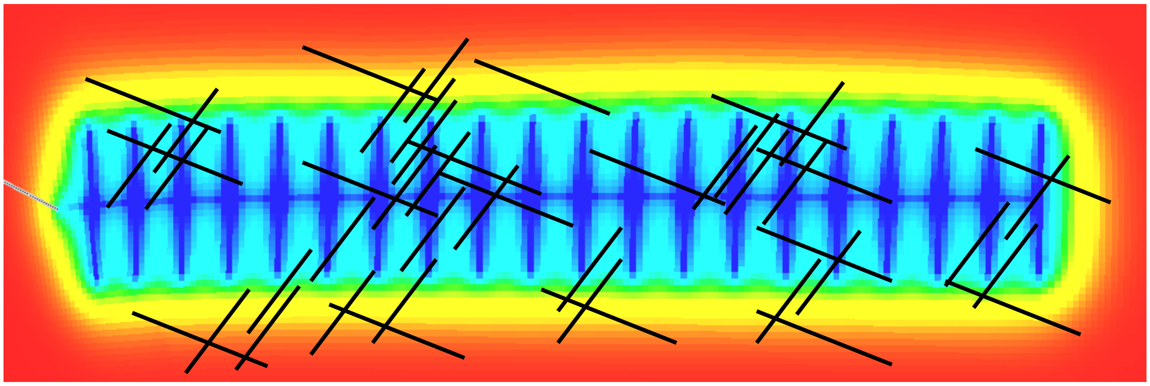


Figure 17. Impact of fracture permeability in J-direction on oil production

(a)



(b)

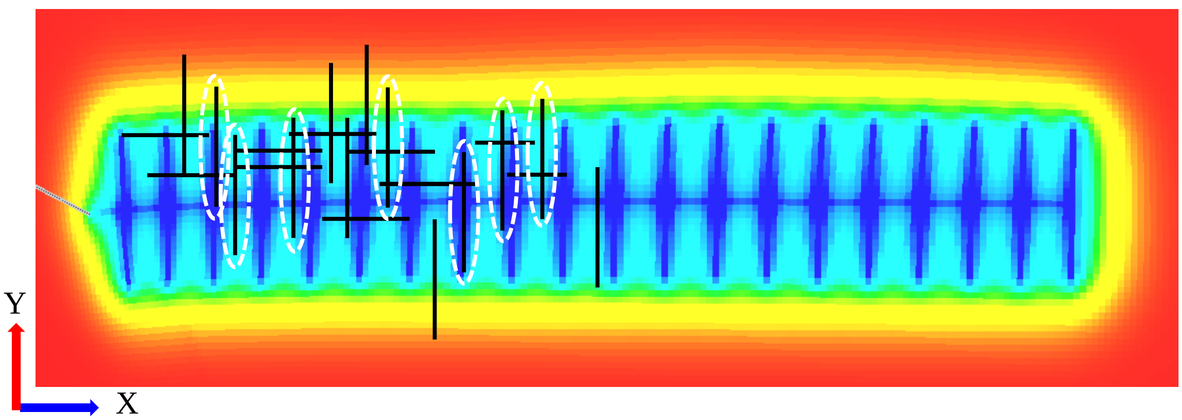


Figure 18. Visualization of how natural fractures interact with hydraulic fractures and horizontal well in (a) discrete fracture network model and (b) dual-porosity model

There is only one layer in K-direction, so the vertical permeability in the natural fracture system do not impact the simulation result. **Figure 19** shows that the two models with different natural fracture permeabilities in K-direction generate almost the same oil production.

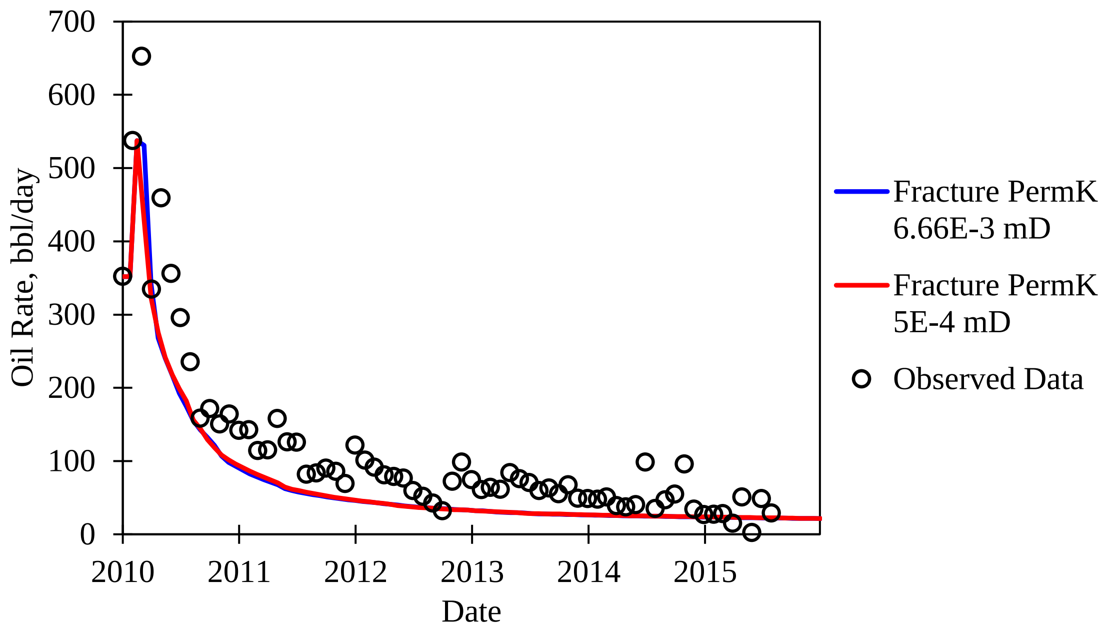


Figure 19. Impact of fracture permeability in K-direction on oil production

As expected, porosity in natural fracture system of the dual-porosity model is not the main parameter to be considered in the history matching process. **Figure 20** shows the same results for the two models of fracture porosity of 0.02% and 0.002%.

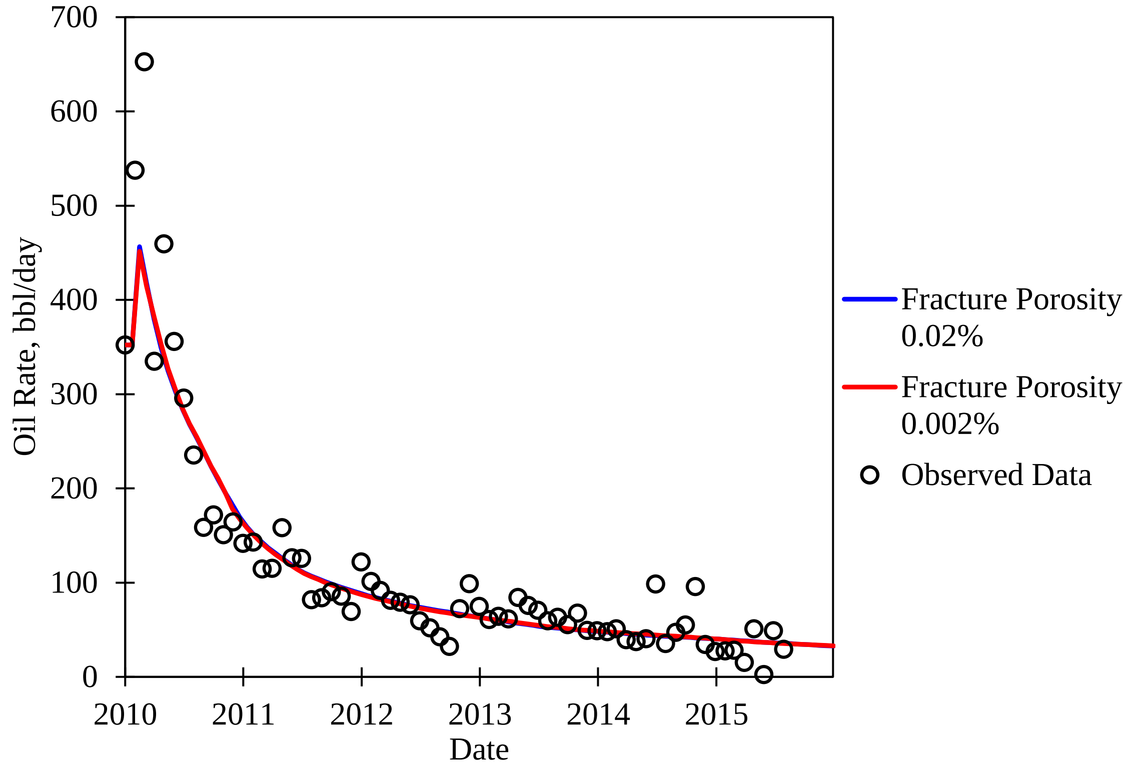


Figure 20. Impact of fracture porosity on oil production

The impact of fracture spacing in this study is very small because this parameter is used to calculate effective permeabilities in natural fracture system. The small spacing means more numbers of natural fractures and higher effective permeability. **Figure 21** and **Figure 22** show that changing the fracture spacing in I- and J-direction does not impact the oil recovery.

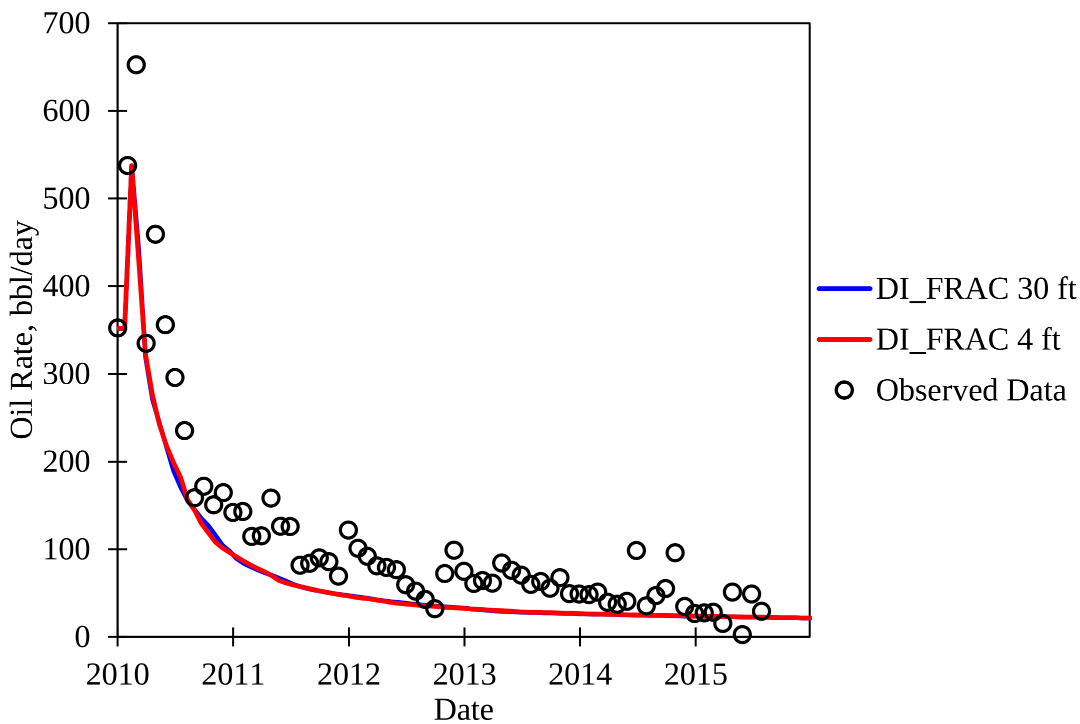


Figure 21. Impact of fracture spacing in I-direction on oil production

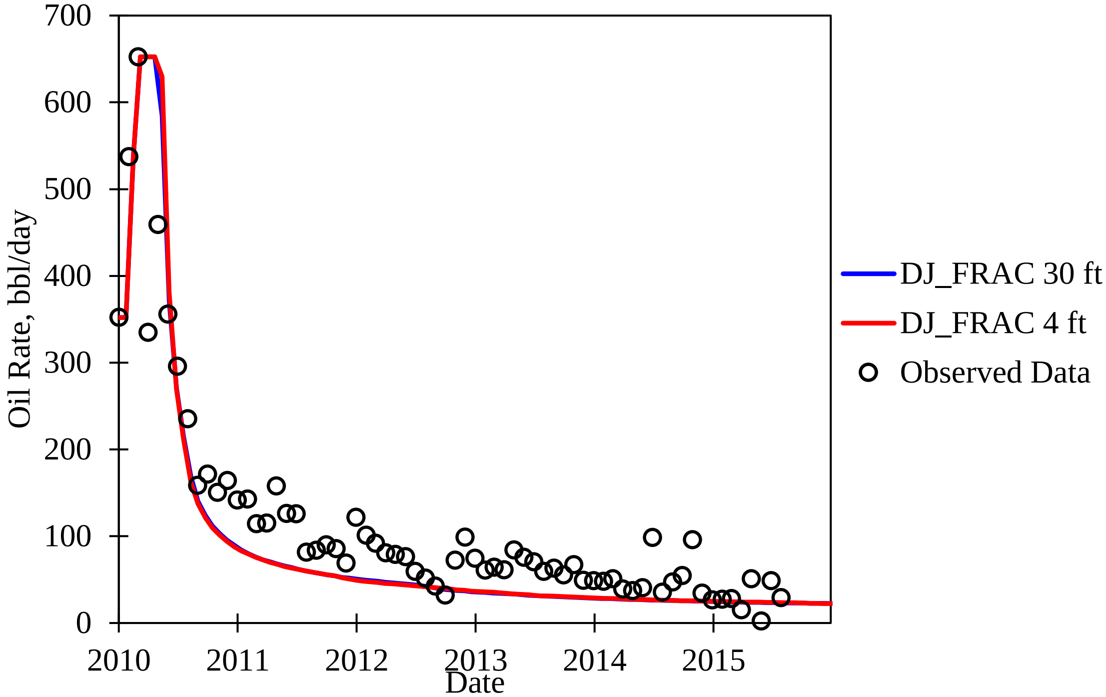


Figure 22. Impact of fracture spacing in J-direction on oil production

Table 5 is a summary of how the parameters in the matrix and natural fracture systems affect the simulated oil rate in this study.

Table 5. Summary impact of matrix and natural fracture parameters on oil rate

System	Parameter	Impact	*Notes*
Matrix	Porosity	Yes	Significant. Peak oil rate. Early time. Late time
	Permeability_I	No	
	Permeability_J	No	
Natural Fracture	Porosity	No	
	Permeability_I	Yes	Peak oil rate. Early time.
	Permeability_J	Yes	Significant. Peak oil rate. Early time. Mid time.
	Spacing_I	No	
	Spacing_J	Yes	Very small

*Horizontal well is in I-direction

**Hydraulic fractures are in J-direction

3.5 History Matching

The average oil rate of the volatile oil region from Wilson and Karnes counties will be used as the observed data of the history matching in this study. All oil production in Eagle Ford commonly reaches to the peak production rate during the first few months. After that, it dropped significantly at the end of the first year of production. **Figure 23** shows that multiple wells in this region dropped from several hundreds of bbl/day to 200 bbl/day in a few months. In some areas, oil rates even drop to zero bbl/d in two years. Obviously, some workover and restimulation had been done to bring some wells back to economic production rates. The reports of these events cannot be found easily in public sources. Because the scope of this work is not about mechanisms or geomechanics of hydraulic fracture and natural fracture, these events were excluded from the history matching process.

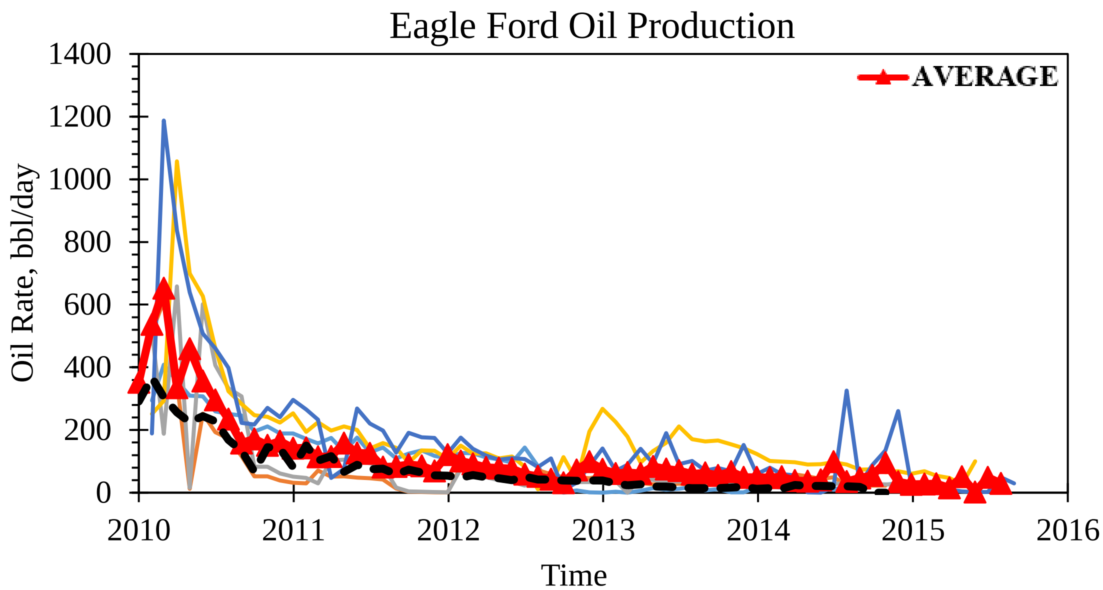


Figure 23. Average oil rate of multiple wells from Wilson and Karnes counties in the Eagle Ford shale

After sensitivity analyses of all important parameters in the matrix and natural fracture system are completed, we know which parameters affect which part of the oil production, and which parameters should be excluded in the history matching process. At early time, the flow back effect and the change of wettability caused by adding surfactant and chemical to fracture fluids will affect the oil rate (**Figure 24**). Then, natural fracture permeabilities in I- and J-directions play an essential role to the peak production rate in ULR, particularly the volatile oil region in the Eagle Ford shale. Besides natural fracture permeabilities in I- and J-directions, matrix porosity is also an important parameter needed to be investigated carefully in ULR simulation study. Matrix porosity influences the peak oil rate in the early time and in the late time. Matrix porosity is a major indicator of how much fluid in place a reservoir has. Natural fracture permeability in J-direction in this study has a great impact on the simulation results because it might allow fluid to flow directly to the horizontal well.

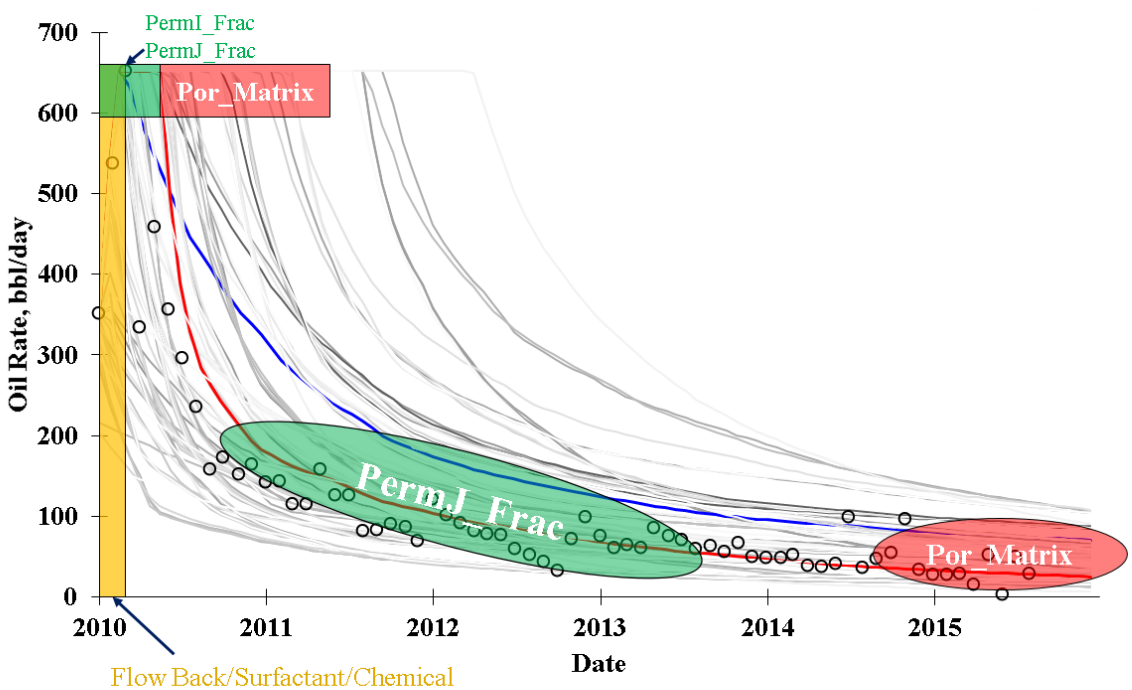


Figure 24. Parameters affect oil rate

After understanding the roles of the parameters in matrix and fracture systems, a thorough plan is constructed to history match the oil rate in the volatile oil region of the Eagle Ford shale. Since we do not have the pressure data, production is the only candidate in this history match. An assisted history matching tool called CMOST from CMG was used in this study. After hundreds of runs, CMOST recommended an optimal solution shown in **Figure 25** based on the lowest error between the simulated oil rate and the observed data. However, because we lack additional data such as workover, stimulation, or any special treatments performed by operators in this region, another model chosen manually by the user will represent the primary depletion of the volatile oil region in this study (**Figure 25**). The two yellow dashed lines in **Figure 25** represents the closing mechanism of hydraulic fractures blocking the fluid's ability to flow to the lateral well.

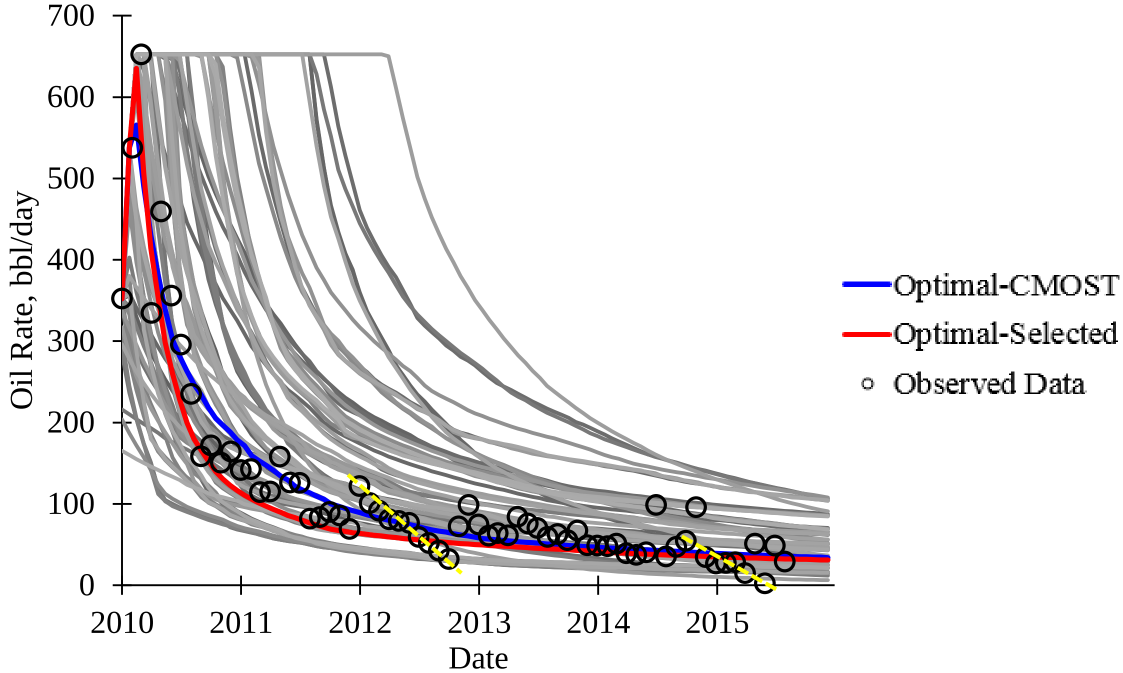


Figure 25. Optimal solution recommended by CMOST vs. optimal solution selected by the user

The optimal model selected by the user also has a very good match to the average oil rate. Its slope in the first year is more accurate compared to the optimal solution recommended by CMOST. Although the optimal solution selected by the user has slightly lower cumulative oil production after six years of primary production because no special treatments are included in the simulation, the model selected by the user guarantees better accuracy when different CO_2 EOR methods are applied in the next part of this study (**Figure 26**).

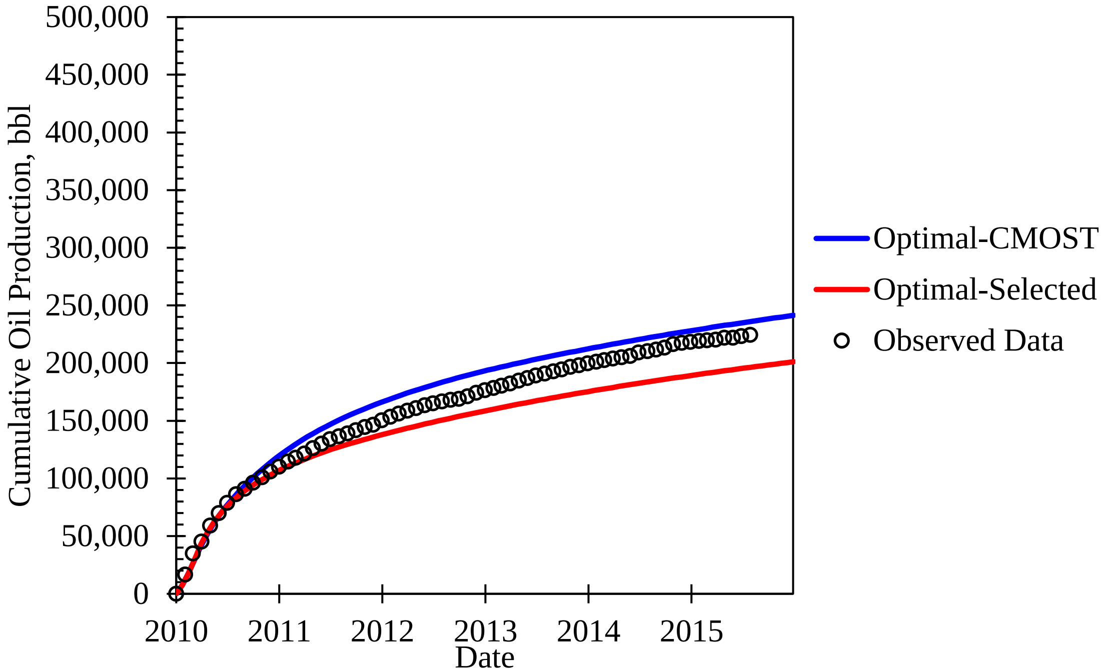


Figure 26. Cumulative oil production of optimal solution recommended by CMOST vs. optimal solution selected by user

After history matching, matrix porosity is reduced greatly from 6% to 2%. It indicates that matrix porosity might be overestimated in several previous studies. The decrease of porosity in matrix system also lowers the original oil in place of the reservoir approximately three times from 2.4219 MMSTB to 0.79745 MMSTB (**Table 6**).

Table 6. Summary of some parameters before and after history matching

	Before History Matching	***After History Matching***
Porosity_Matrix	6%	2%
PermI_Matrix	1E-4 md	5E-6 md
PermJ_Matrix	1E-4 md	5E-6 md
PermK_Matrix	1E-4 md	5E-6 md
Porosity_FRAC	0.06%	0.0067%
PermI_FRAC	2E-4 md	6.7E-4 md
PermJ_FRAC	1E-4 md	6.7E-4 md
PermK_FRAC	3e-4 md	13E-4 md
OOIP	2.42190 MMSTB	0.797446 MMSTB

4. CO_2 EOR SIMULATION

In unconventional liquid reservoirs, oil production drops significantly after one year of primary depletion. Technically, the conductivity of hydraulic fractures gradually decreases after a while. In Eagle Ford shale, after five or six years of primary depletion, many wells could be considered uneconomic because of their low production rates. Hence, there is an obvious need of secondary or enhanced oil recovery (EOR) methods for these uneconomic wells. In ULR such as Bakken and Eagle Ford, water flooding seemed to be unfit because of the low injectivity in the extremely low permeability formations.

Instead of injecting water into the ULR, some operators used rich gas or CO_2 to improve oil production rate. Previous studies reached the same conclusion that CO_2 injection is better than water injection in unconventional resources (Gamadi et al. 2013, Song and Yang 2013). Therefore, this research will focus on CO_2 as a main injecting gas for different EOR techniques in the volatile oil region of the Eagle Ford shale.

There are three main methods of CO_2 injection used in this study: (1) continuous injection, (2) huff-n-puff, and (3) WAG (water-alternating-gas). Each method requires a different setup to capture the EOR process correctly. Particularly, for continuous injection and WAG, the model will have two separate wells: one injector and one producer (**Figure 27**) while for huff-n-puff, there is only one well acting as a producer and an injector (**Figure 28**).

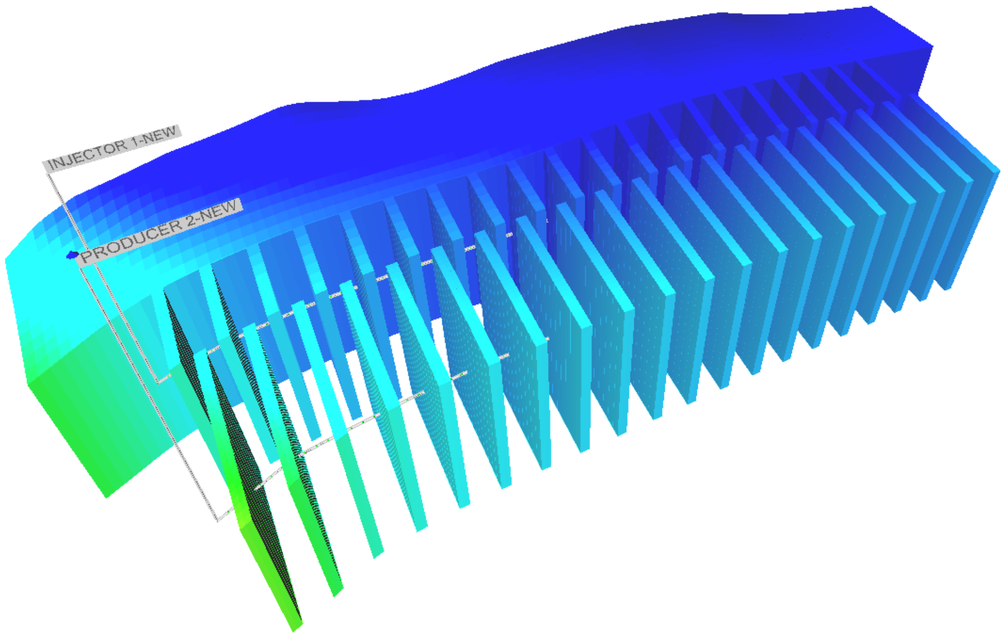


Figure 27. Two lateral wells used for continuous CO_2 injection and WAG

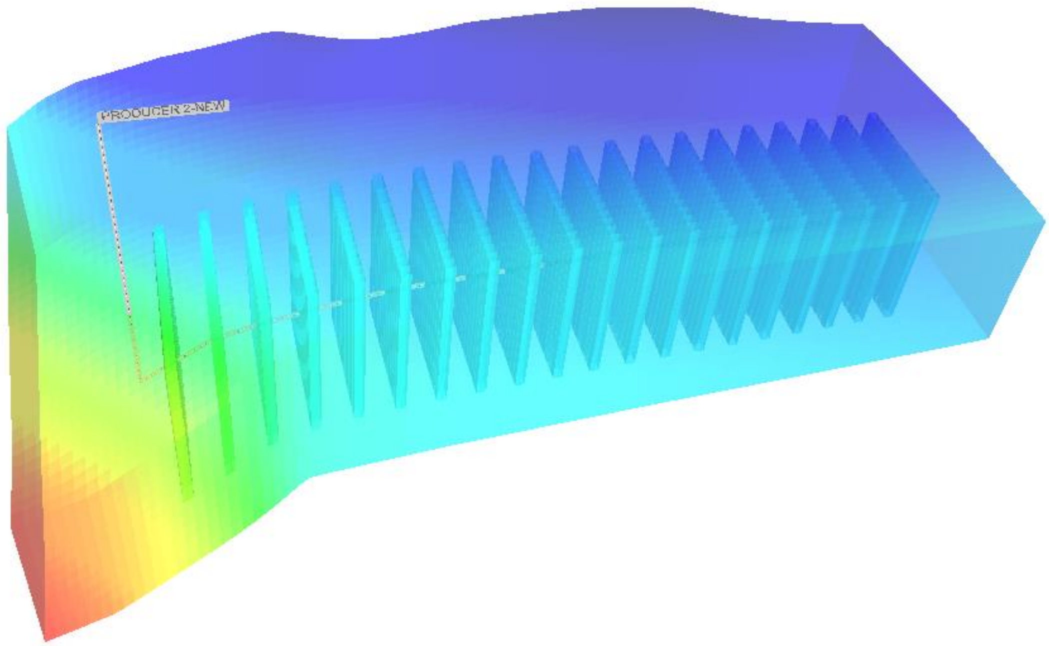


Figure 28. One lateral well setup for CO_2 huff-n-puff

4.1 Miscibility Review

When gas is injected into oil reservoirs, there are two types of events will happen: immiscible and miscible. In the unconventional liquid reservoirs, miscible injection is more effective to recover residual oil than immiscible injection (Pasala 2010). An experiment study conducted by Gamadi et al. concluded that when the reservoir conditions are maintained at a certain minimum pressure to form miscibility, a great amount of residual oil is recovered (2013). This pressure is defined as minimum miscibility pressure and measured by slim tube test (Pedersen et al. 2007). **Figure 29** shows how minimum miscibility pressure (MMP) is obtained using the slim tube test.

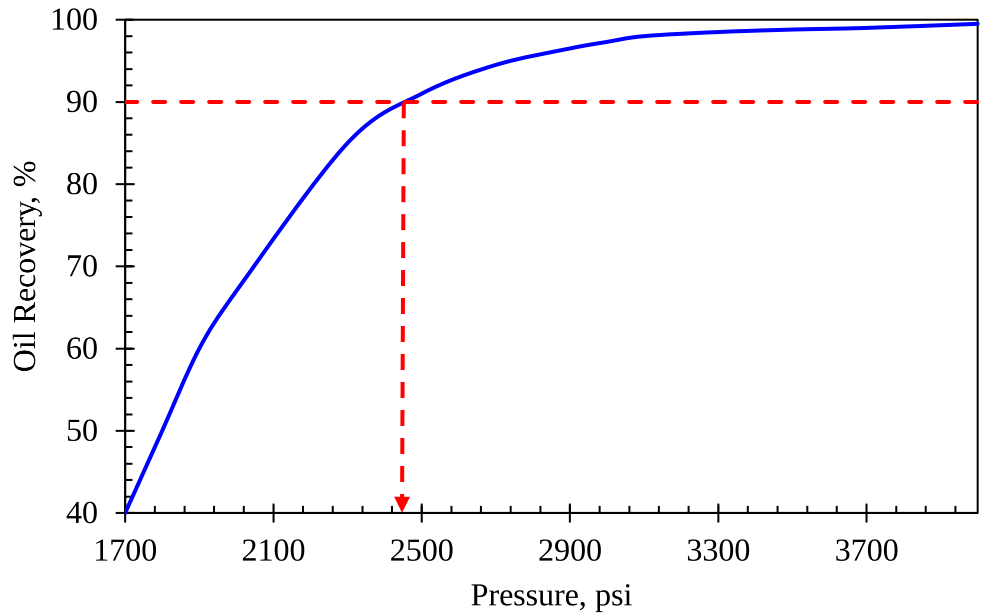


Figure 29. Example of measuring minimum miscibility pressure in slim tube test

When MMP is reached, gas and oil in the reservoir will be miscible under first contact or multiple contact process. First contact miscibility allowed oil and injected gas to be mixed immediately (Donaldson et al. 1989) (**Figure 30**). Multiple contact miscibility requires a certain amount of time so that oil and injected gas can be mixed completely (**Figure 31**).

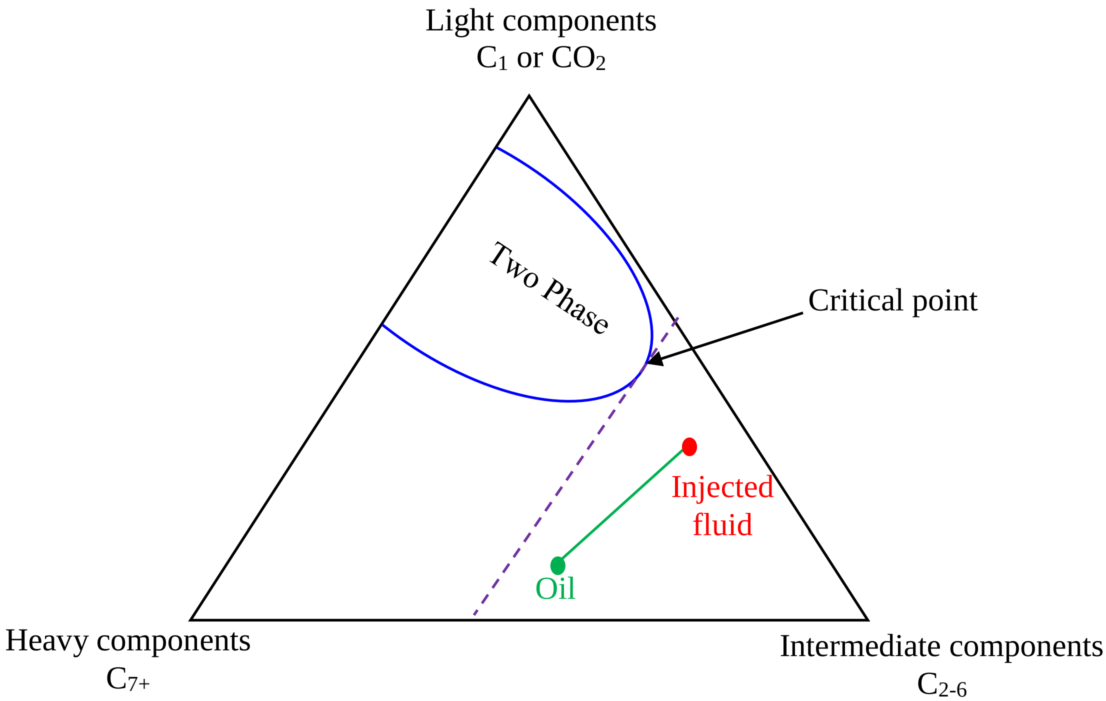


Figure 30. Pseudo-ternary diagram of first contact miscibility

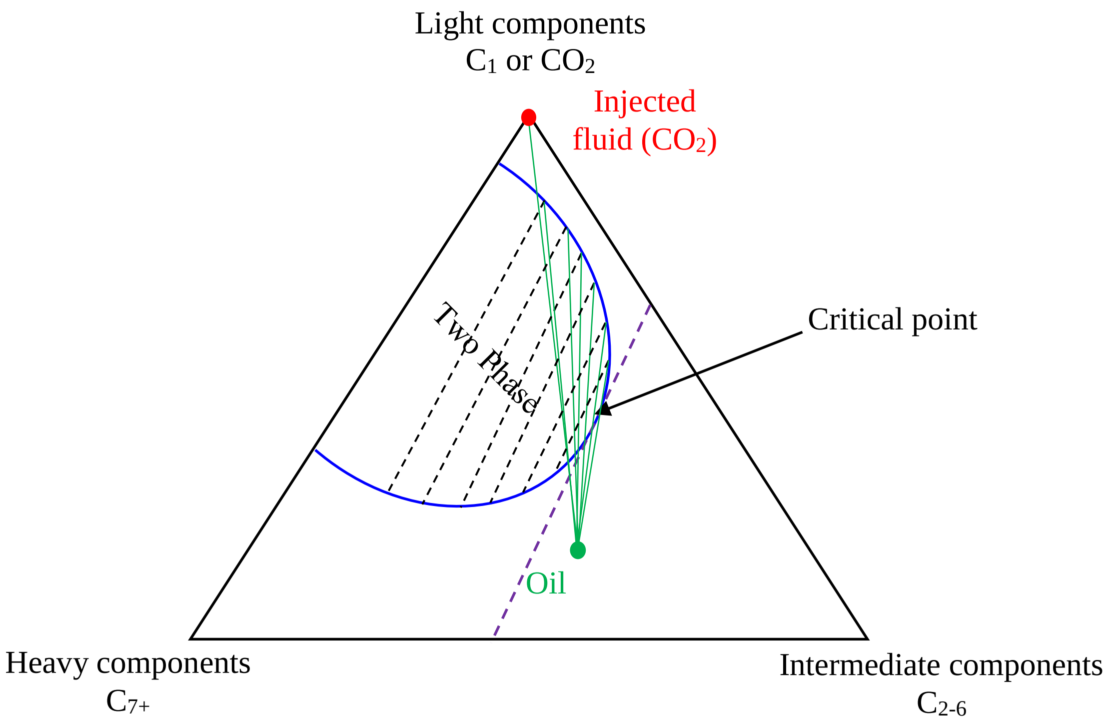


Figure 31. Pseudo-ternary diagram of multiple contact miscibility

According to Alston et al. (1985), to obtain the miscible stage, the injection pressure should be higher than the minimum miscibility pressure. Therefore, some constraints will be applied in CO_2 huff-n-puff and CO_2 WAG scenarios to ensure injected CO_2 and residual oil will be miscible.

4.2 CO_2 Continuous Injection

Two subcategories are introduced in CO_2 continuous injection method. First, the producer will be open the whole time. Second, the producer will be shut in for a certain amount of time when CO_2 is being injected. The results hint that the second scenario of continuous injection when the producer is shut in for a certain amount of time is more efficient compared to the first one. More details will be discussed below.

4.2.1 Producer Is Open the Whole Time

In this case, there are two separate wells in the domain: one injector and one producer. The same hydraulic fractures design from the history matched model is applied to both wells. **Figure 32** shows cumulative oil production after five years applying this method. The base case means no EOR method are applied to the model. Hydraulic fracture's geomechanics will not be included in all of the scenarios including the base case.

Figure 32 is a comparison between small injected CO_2 volume and large injected CO_2 volume used in the case the producer is open the whole time. Surprisingly, when a large amount of CO_2 is injected, the oil production after five years of EOR is worse than the base case. When the producer is open the whole time as CO_2 is being injected with a large volume, the velocity of CO_2 traveling in the pores is dashing. The density of CO_2 is much smaller than the density of the residual oil. So, when CO_2 travels with the high speed, it will create viscous fingering effect resulting insufficient vertical sweep and early CO_2 breakthrough. Consequently, the producer will only receive mostly CO_2 instead of oil. The main reason to inject CO_2 in this type or reservoir is to allow CO_2 to mix with oil by multiple contact miscibility. Then, oil will be able to move easier in the tight pore because its viscosity is reduced. When CO_2 travels with high speed, oil and CO_2 cannot maintain the miscible stage. To test how much CO_2 should be injected to increase the incremental oil recovery, multiple CO_2 injection rates from 1 to 1,000 MSCF/day are examined. **Figure 32** shows that the optimum case in using this method only can recover 14,687 bbl of incremental oil. Many cases in this scenario have lower oil production compared to the base case. The cost to get that amount of incremental oil is 1.83 MMSCF of CO_2 has to be injected over five years of EOR (**Figure 33**).

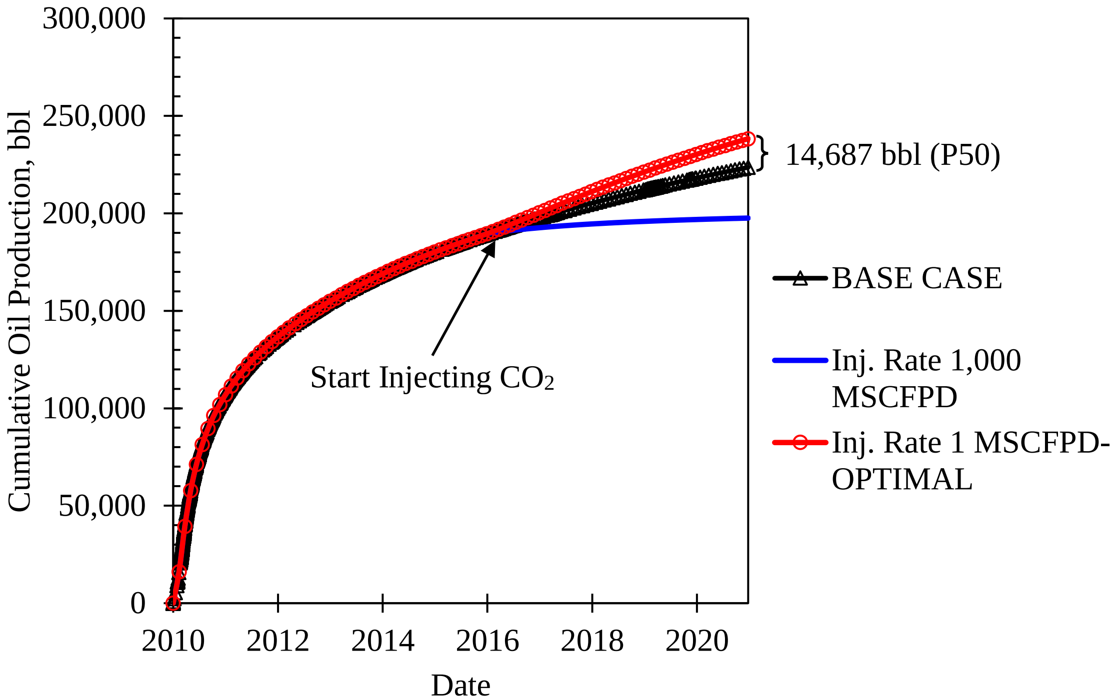


Figure 32. Cumulative oil production of 1,000 vs. 1 MSCF/day CO_2 injection (producer is open the whole time)

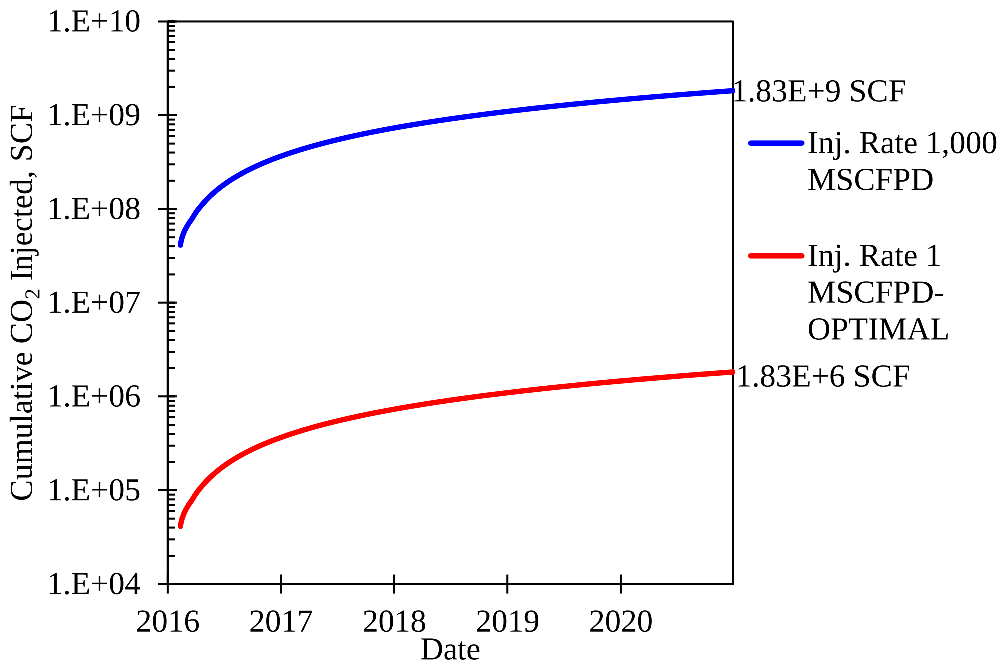


Figure 33. Semi-log cumulative CO_2 injection of 1,000 vs 1 MSCFPD (producer is open the whole time)

There is a high probability to have a negative impact on oil recovery in this scenario. The mobility control is recommended to this scenario to avoid viscous fingering and ensure the miscible process between CO_2 and oil to be obtained during the whole process of EOR. **Figure 34** shows the pressure of the injector during five years of EOR in this scenario. **Figure 35** shows that 29.8% of oil recovery factor was recovered after five years of EOR. This oil recovery factor is calculated based on the amount of oil only in the stimulated reservoir volume (SRV).

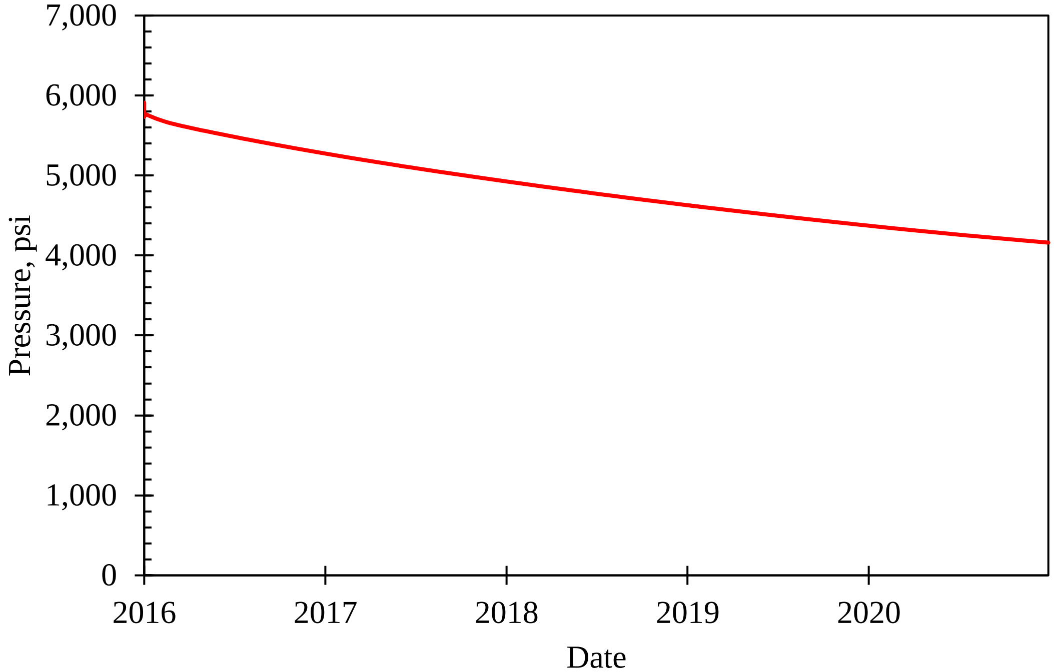


Figure 34. Pressure of injector in continuous CO_2 injection scenario (producer is open the whole time)

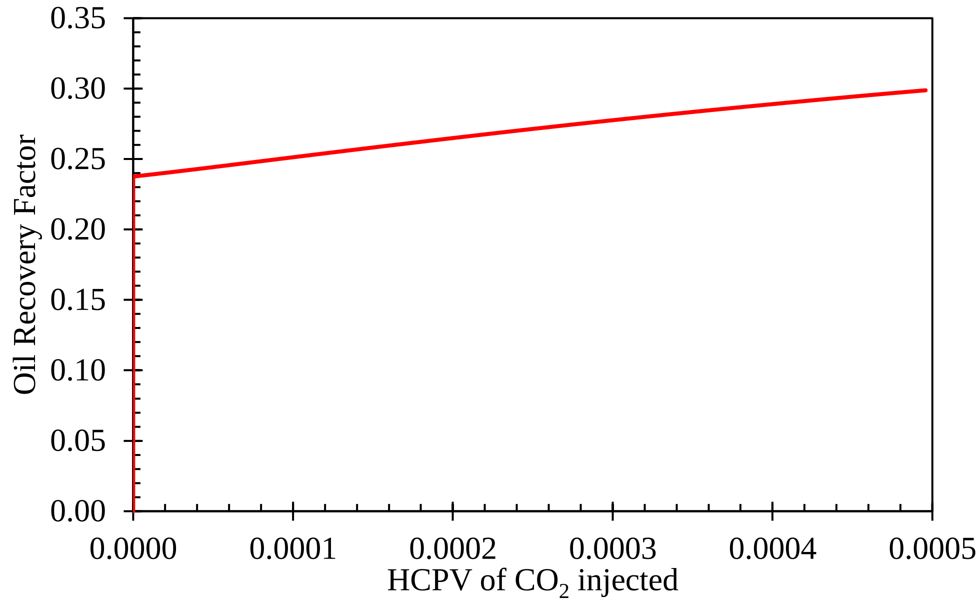


Figure 35. P50 of oil recovery factor vs. HCPV of CO_2 injected (producer is open the whole time)

4.2.2 Producer Is Shut In For a Certain Amount of Time

The first CO_2 continuous injection EOR scenario indicates that it is necessary to shut in the producer for a certain amount of time so that the injected CO_2 and the oil in the reservoir can be miscible and viscous fingering effect can be avoided. Moreover, shutting the producer as CO_2 is being injected will allow the reservoir's pressure to be built up greatly.

In this section, two main parameters are adjusted to optimize the production performance. They are *CO_2 injection rat*e from the injector and *shut in period* from the producer. More than a hundred simulations were completed to analyze this EOR scenario. **Figure 36** shows four selected runs to demonstrate the impact of CO_2 injection rate and shut in period on the cumulative oil production.

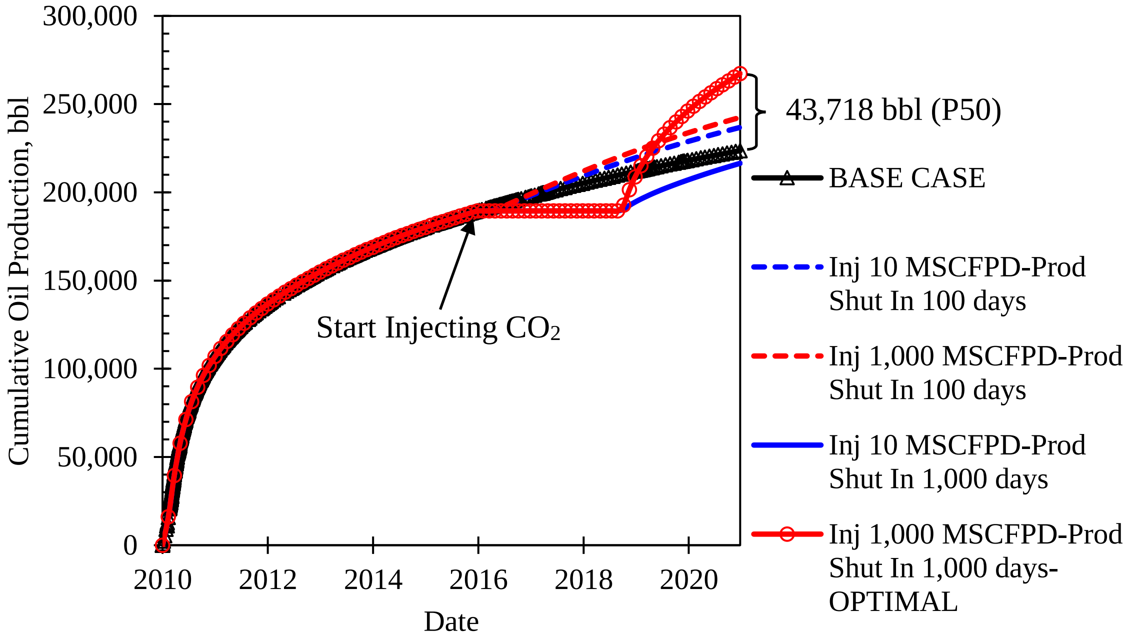


Figure 36. Cumulative oil production of different injection rates (producer is shut in for 100 days and 1,000 days)

In the case of the producer is shut in for 100 days as CO_2 is being injected, the cumulative oil production plots after five years of EOR are not very different (**Figure 36**).

On the other hand, the case of the producer is shut in for 1,000 days shows noticeable cumulative oil production at the end of the EOR period. Even though it is not preferable to shut in the producer for 1,000 days, the purpose of this study is to show how sensitive the shut in period is to the cumulative oil production. As a result, the P50 in this scenario can recover 43,718 barrels of incremental oil after five years of EOR. For the optimal P50 in this case, a total of 1 BSCF CO_2 was injected (**Figure 37**).

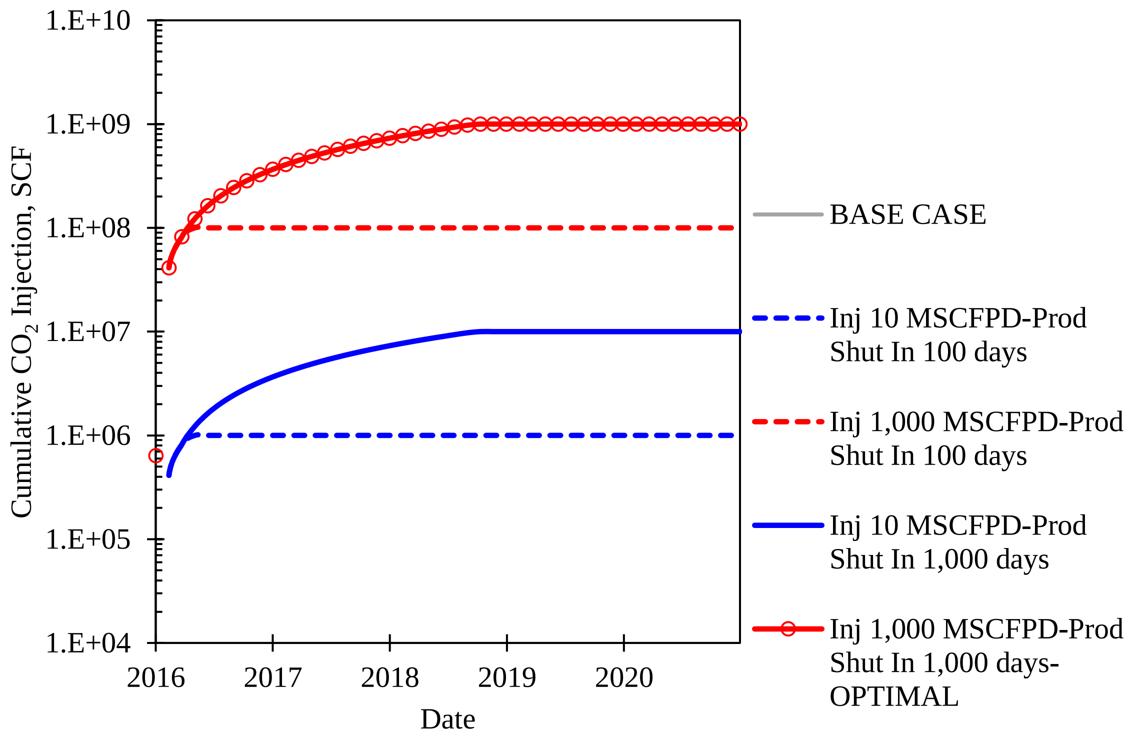


Figure 37. Cumulative CO_2 injection of different injection rates (producer is shut in for 100 days and 1,000 days)

The results of this scenario confirm that CO_2 needs a certain amount of time to be mixed with oil at a certain pressure. The disadvantage of this scenario is the negative cash flow for 1,000 days as a producer is shut in. It is a long period that should be considered and calculated carefully to generate profit for the operators in the a long run. **Figure 38** shows that approximately 0.32 hydrocarbon pore volume of CO_2 is injected to recover 33.5% of oil recovery factor in this region.

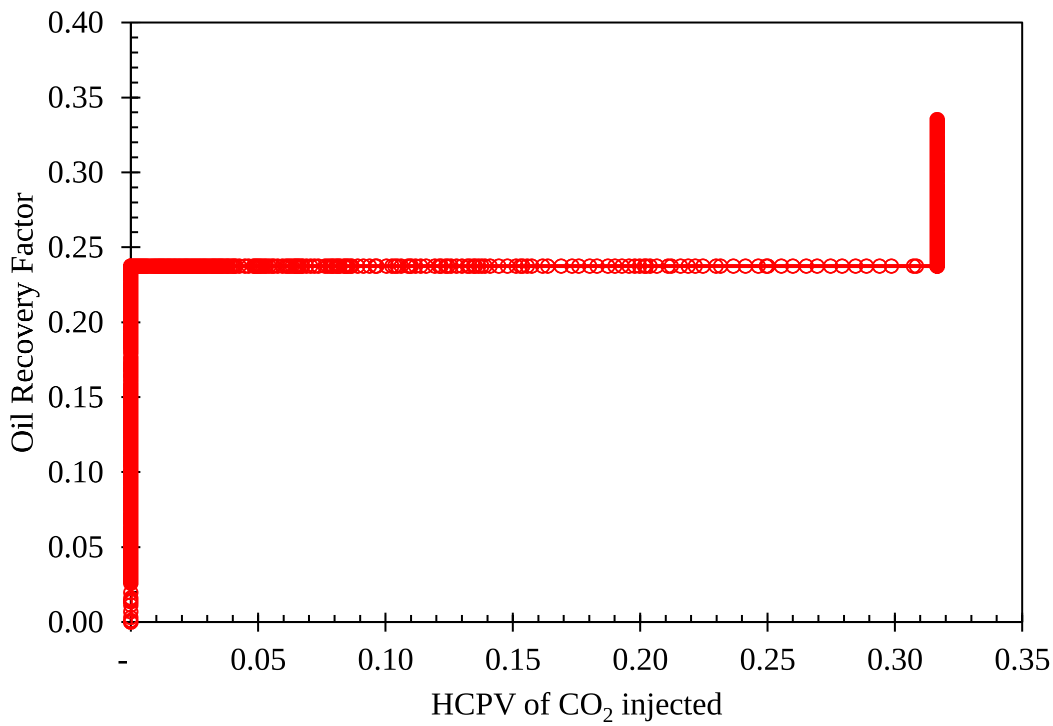


Figure 38. P50 of oil recovery factor vs. HCPV of CO_2 in CO_2 continuous method (producer is shut in for a certain amount of time)

4.3 CO_2 Huff-n-Puff

Huff-n-puff in ULR has been an interesting topic lately. Some operators have already started pilot tests and received positive results using this method. There are several types of gases to be considered in huff-n-puff in ULR such as rich gases and CO_2.

Unlike conventional reservoirs, the oil rate of in ULR dropped significantly after a few years of production. Therefore, operators have to decide to do something with those wells or drill new wells. When oil price was above $100/bbl, the cost of drilling a new lateral well is reasonable, so operators were easily making profits at that time. In the last few years, drilling new wells seemed to be the economical solution to improving production instead of applying any secondary or tertiary method to existing wells. Moreover, not many studies about using cyclic gas injection to improve oil production in ULR are upscaled and applied to field test successfully. So, the operators do not want to take a risky move until more successes of this EOR method are reported in the industry.

Many lab experiments came to the same conclusion that CO_2 huff-n-puff performed better than CO_2 continuous injection in unconventional resources. Especially, in naturally fractured reservoirs, continuous injection allows the injected CO_2 to flow easily through natural fracture network (Tovar et al. 2014). This event will lead to early CO_2 breakthrough at the producer. Consequently, oil recovery efficiency is reduced significantly (Hawthorne at al. 2013).

In huff-n-puff, CO_2 is injected for a period. Then, the injection is paused for a while to allow the CO_2 to soak into oil in the reservoir effectively. Under some required conditions, CO_2 and oil will be miscible by the multi-contact mechanism (Green and

Willhite 1998). Subsequently, oil viscosity will be reduced, and oil can travel through the tight pores easier than before. Finally, the well is open, so the reduced-viscosity oil can be produced until it hits the uneconomic rate. The combination of the injecting, soaking, and producing represents one cycle of CO_2 huff-n-puff. There are multiple cycles applied to the field over time. To optimize the oil production using the huff-n-puff method, four main parameters are introduced in this section to observe their impacts on the oil production: (1) injection rate, (2) injection period, (3) soaking period, and (4) producing period.

First, CO_2 *injection rate* is investigated. It is obvious that the amount of CO_2 being injected will be an important factor affecting the oil production. **Figure 39** shows how different the incremental oil recovery is when the rates of 1,000 and 10,000 MSCF of CO_2 injected per day were used in the simulation. It is safe to conclude that the more CO_2 being injected in huff-n-puff, the more oil can be recovered in a cycle, as shown in **Figure 40**. However, there is a limit of total CO_2 can be injected based on the injectivity, cost, facility, and other factors of the reservoir. The more CO_2 injected, the more costly to operate (**Figure 41**).

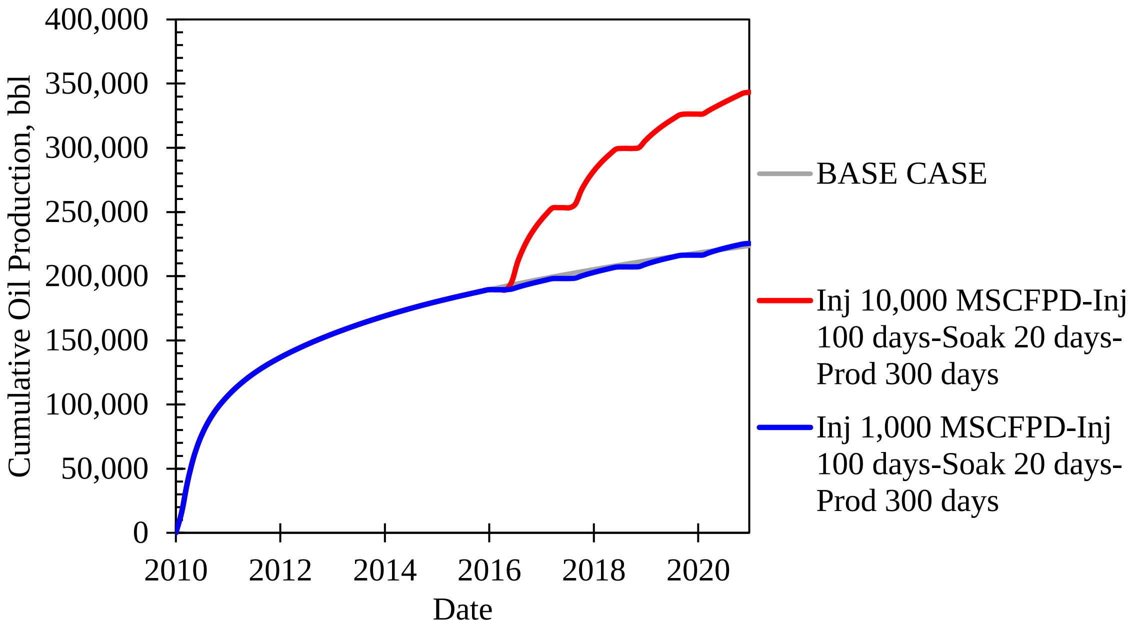


Figure 39. Cumulative oil production of 10,000 MSCFPD vs. 1,000 MSCFPD CO_2 injection huff-n-puff

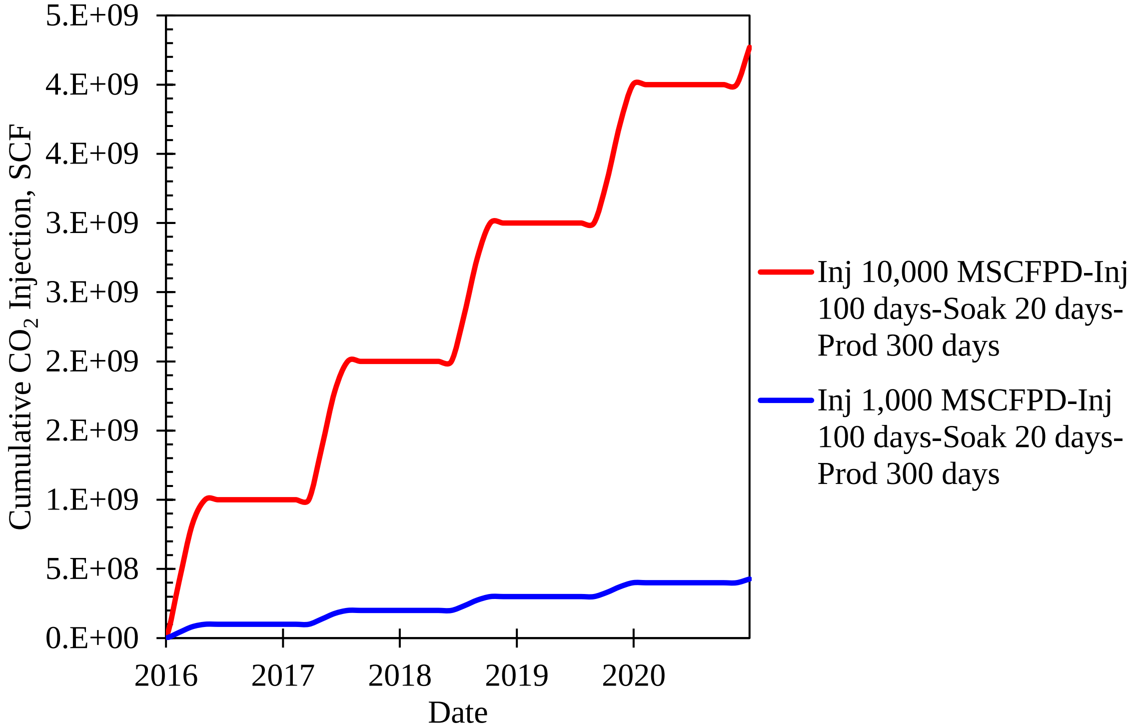


Figure 40. Cumulative CO_2 injection of 10,000 MSCFPD vs. 1,000 MSCFPD CO_2 injection huff-n-puff

Another parameter which is also very important in huff-n-puff is *injecting period*. **Figure 41** indicate that 10 days might not be enough so that CO_2 can travel to the SRV of the producer. In addition, shorter injection period cannot increase the reservoir pressure much. As a result, the oil recovery might not be improved at all.

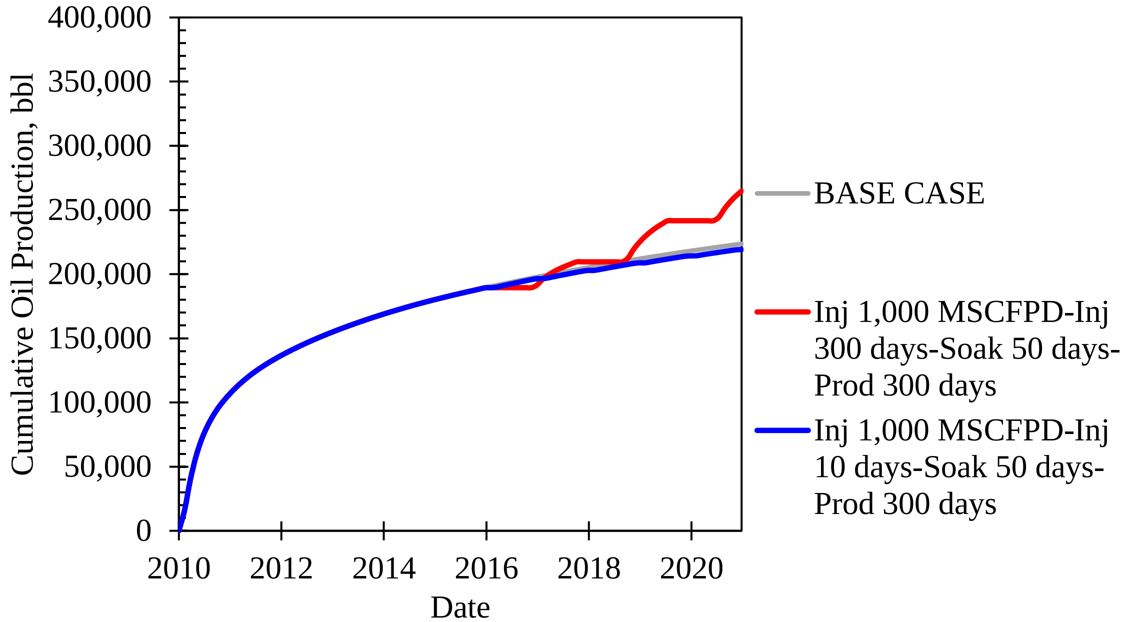


Figure 41. Cumulative oil production of 300 vs. 10 injection days in huff-n-puff

In contrast, long *soaking time* does not guarantee higher production in the end. The results of this study suggested that short soaking period is more preferable to increase both production and economic performances. **Figure 42** shows that 10 days and 50 days of the soaking period are not considerably different after five years of EOR. We can see that shorter soaking period case has slightly higher cumulative oil production than the longer one in the end. In short, the soaking period is not sensitive to the simulation, but it is necessary to have a reasonable soaking time so that oil viscosity can be reduced sufficiently.

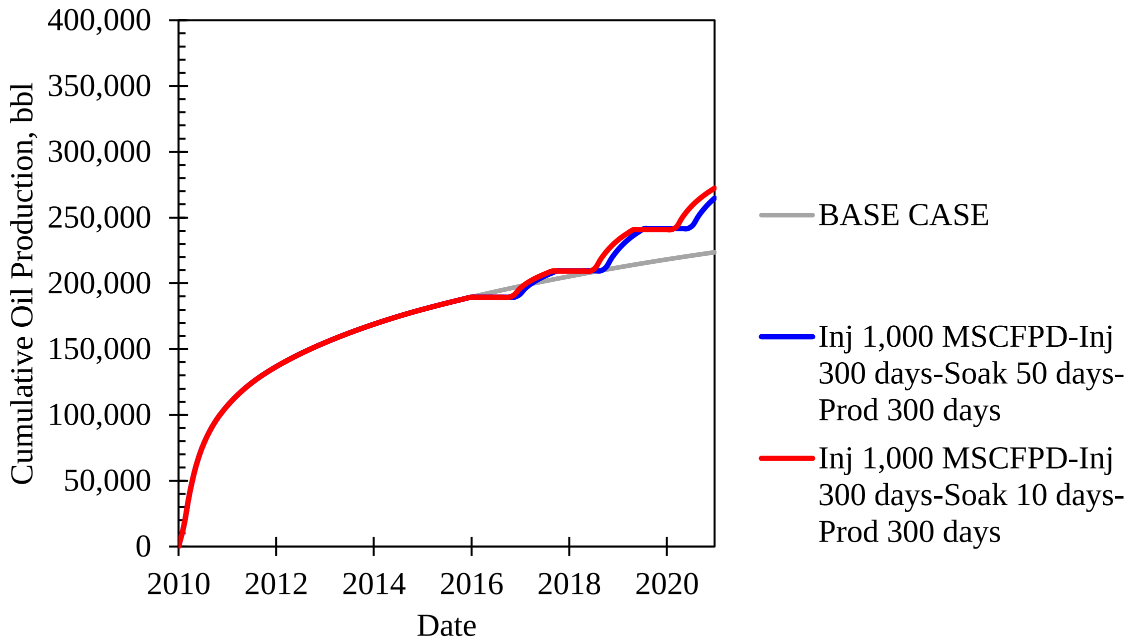


Figure 42. Cumulative oil production of 50 vs. 10 soaking days in huff-n-puff

The last parameter to be investigated in CO_2 huff-n-puff simulation is the *production time*. It does not have a notable impact on the mechanisms of reducing oil viscosity, but it is necessary to optimize this parameter, so we do not miss any production for a long run. **Figure 43** indicates that 50 days of production is too short because the oil rate is still above the economic limit.

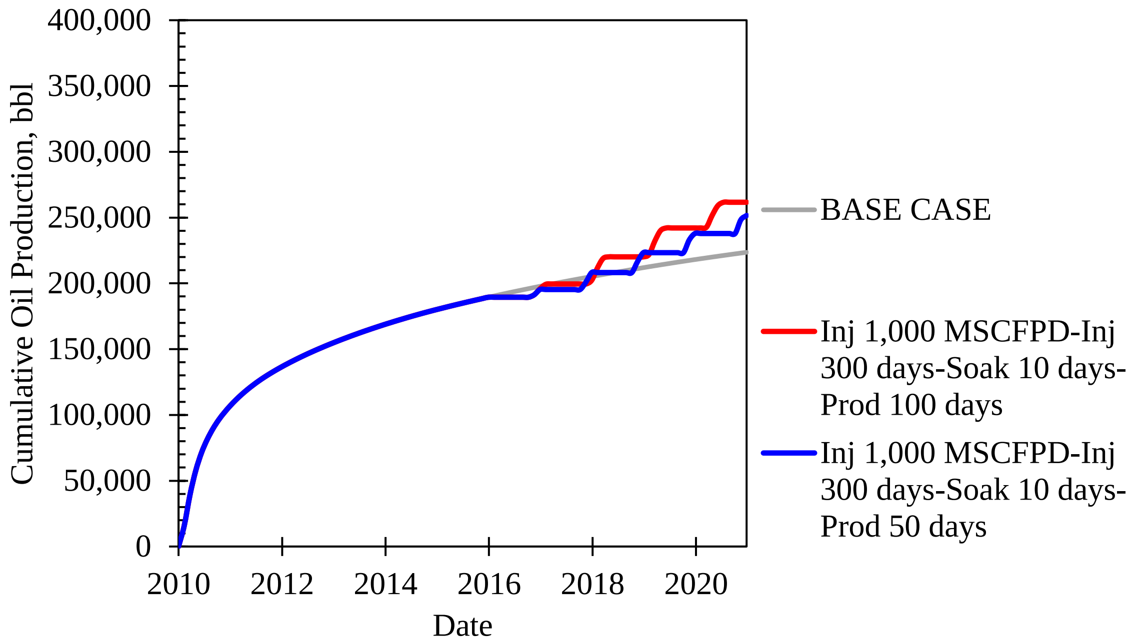


Figure 43. Cumulative oil production of 100 vs. 10 production days in huff-n-puff

Figure 44 is a summary of the sensitivity analysis of four parameters in CO_2 huff-n-puff method. We can see that *injection rate* and *injection period* are more sensitive to the oil production compared to *soaking period* and *production period*. However, all of the above parameters should be optimized carefully in order to produce the most oil with less amount of CO_2 being injected.

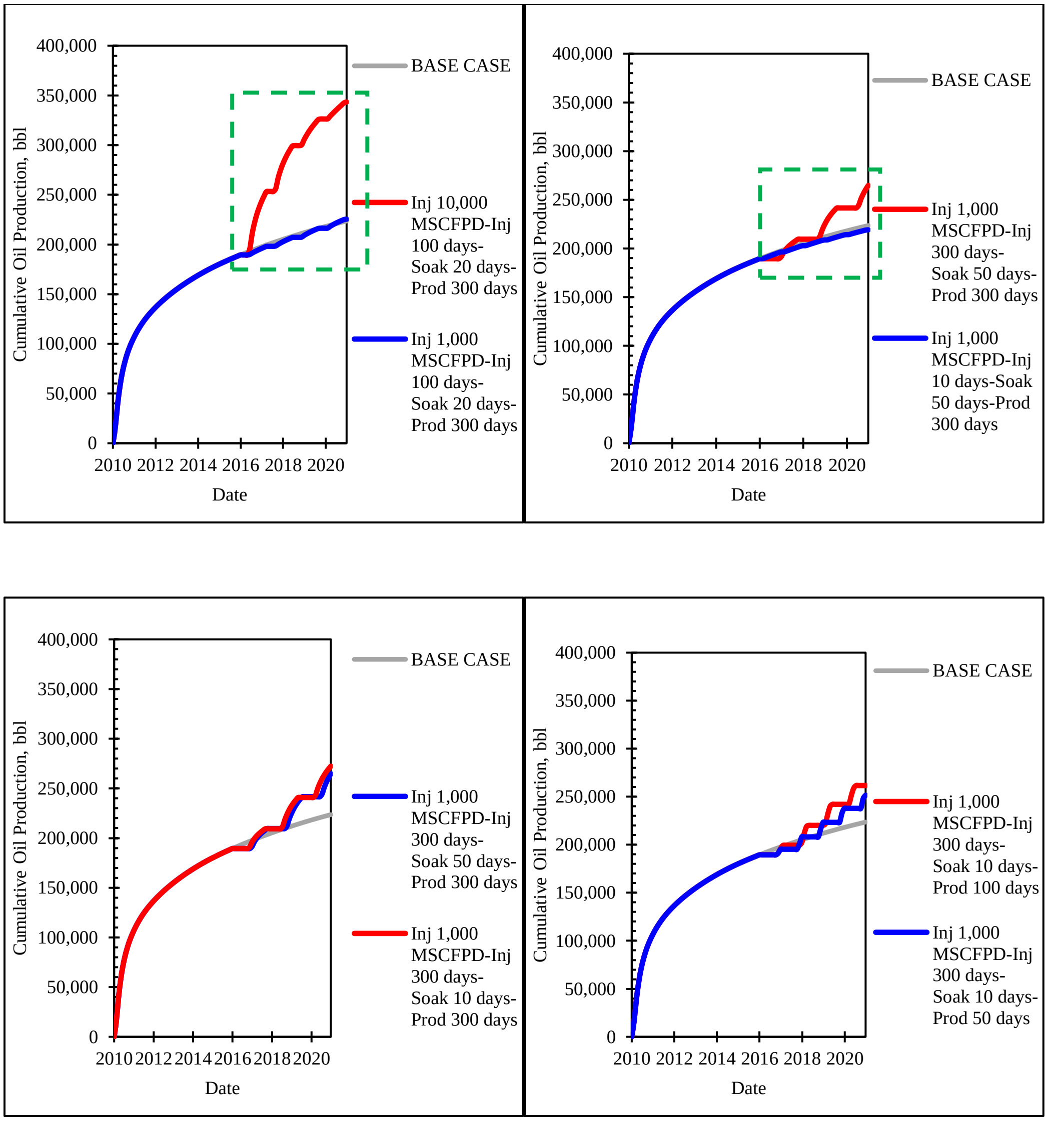


Figure 44. Summary of sensitivity analysis of main parameters to optimize CO_2 huff-n-puff in the volative oil region of the Eagle Ford shale

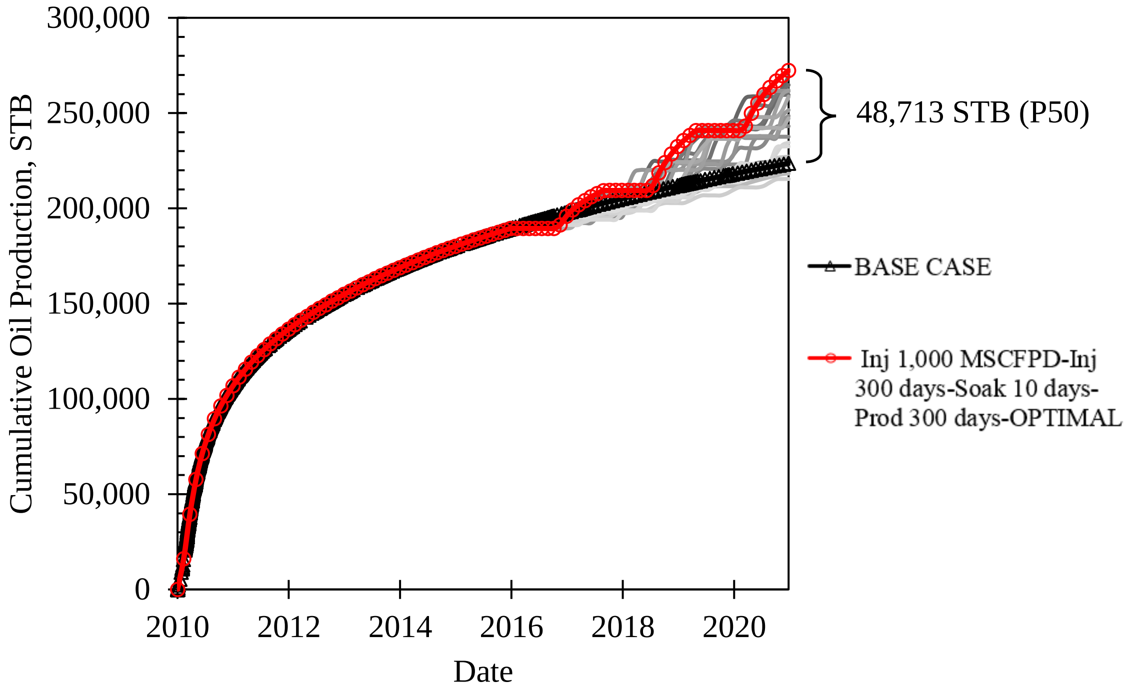


Figure 45. Cumulative oil production of optimal CO_2 huff-n-puff in the volatile oil region of the Eagle Ford shale

After optimization process is complete in CMOST, the P50 optimal of CO_2 huff-n-puff scenario show that 48,713 barrels of oil can be recovered more than the base case after five years (**Figure 45**). In 10 or 20 years, it will surely outperform the base case even more. **Figure 46** shows how pressure changes throughout the huff-n-puff period. **Figure 47** shows that approximately 34% of oil is recovered at the end of the huff-n-puff process.

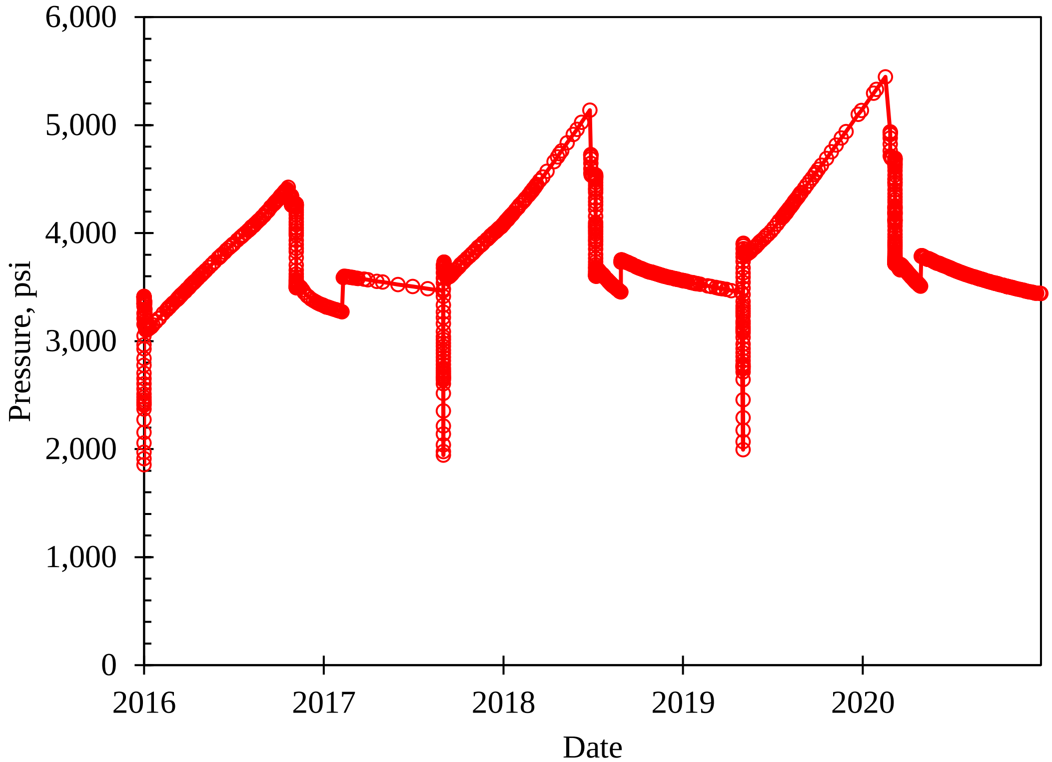


Figure 46. Pressure of injector in CO_2 huff-n-puff

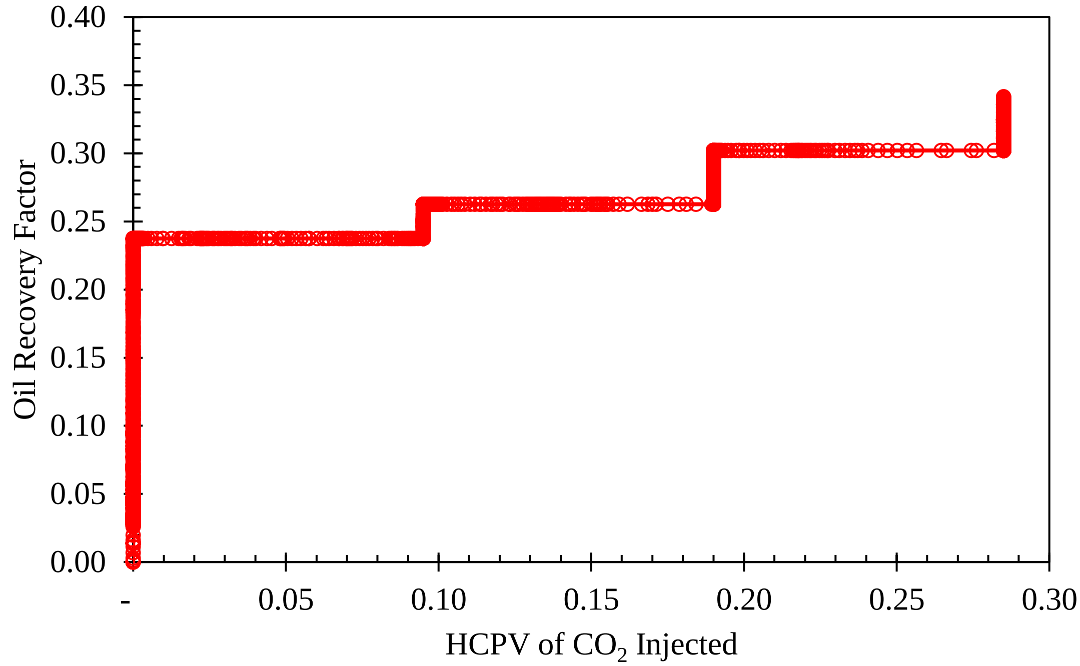


Figure 47. P50 of oil recovery factor vs. HCPV of CO_2 injected in CO_2 huff-n-puff

4.4 CO_2 WAG (Water-Alternating-Gas)

The miscible water-alternating-gas method is designed for mobility control. A water slug will be flooded first then a CO_2 slug will follow. Theoretically, in this scenario, CO_2 cannot travel too fast adding more time so that CO_2 can mix with oil completely. This method has been successful in the past (Christensen et al. 2001). However, there is no evidence to claim its success in the unconventional liquid reservoirs. In fact, injecting water into tight rock of nano-darcy permeability like Eagle Ford shale is quite challenging.

Figure 48 and **Figure 49** show the P50 of the optimal case using WAG in Eagle Ford volatile oil region. It is not worth to be considered to move forward with this scenario unless some modifications are made.

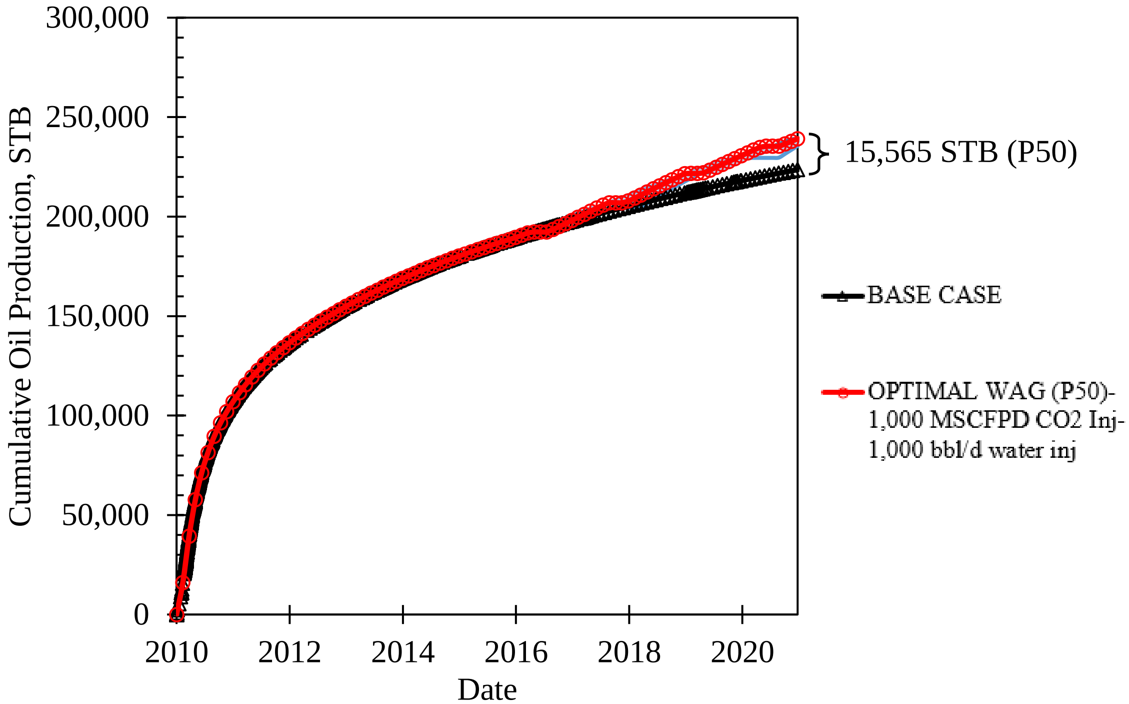


Figure 48. Cumulative oil production of the optimal scenario WAG in Eagle Ford

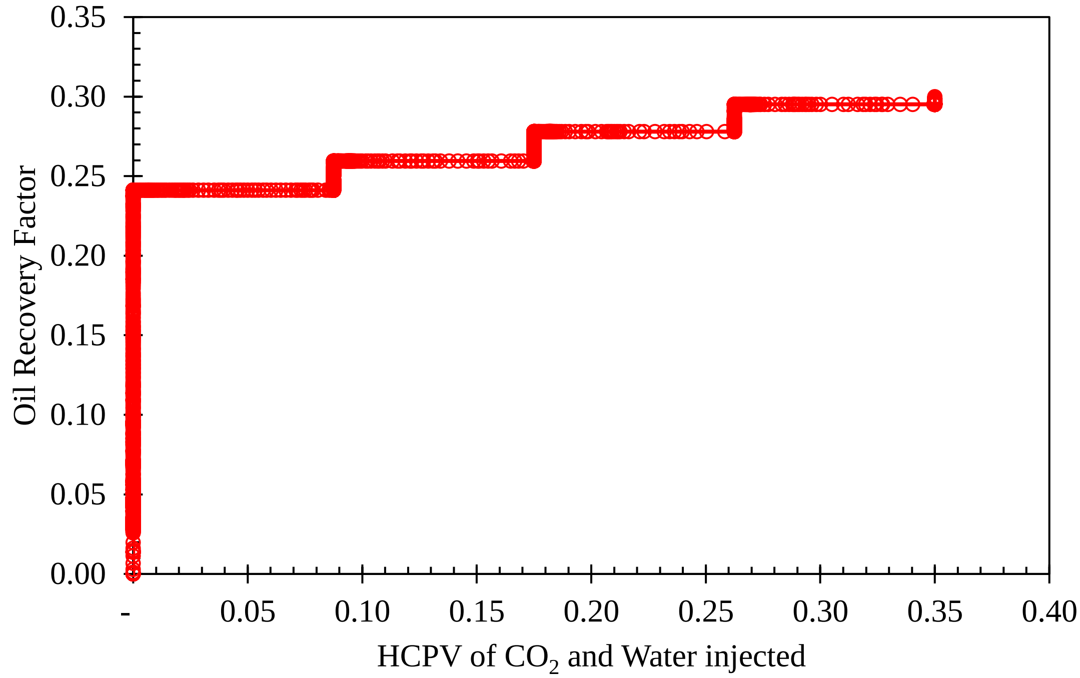


Figure 49. P50 of oil recovery factor vs. HCPV of CO_2 and water injected in CO_2 WAG

4.5 Discussion

Huff-n-puff shows very promising results compared to the two continuous CO_2 injection scenarios and WAG (**Figure 50**). Huff-n-puff not only recovers more oil after five years of EOR but also requires less CO_2 to be injected than the shut-in producer case from continuous CO_2 injection EOR scenario (**Figure 51**). Moreover, based on the fact that only one well is used in CO_2 huff-n-puff method, operators can double their profit with the same amount of wells they already had in the field. Thus, CO_2 huff-n-puff remains as a great EOR method in the volatile oil region of the Eagle Ford shale.

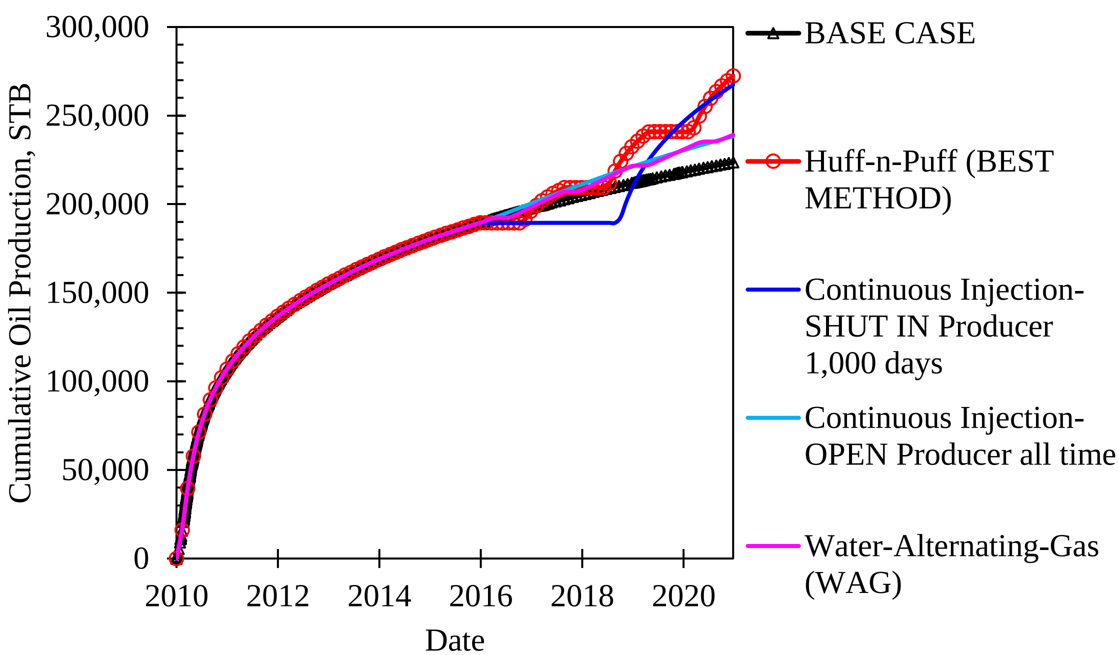


Figure 50. P50 of cumulative oil production of different CO_2 EOR methods in the volatile oil of the Eagle Ford shale

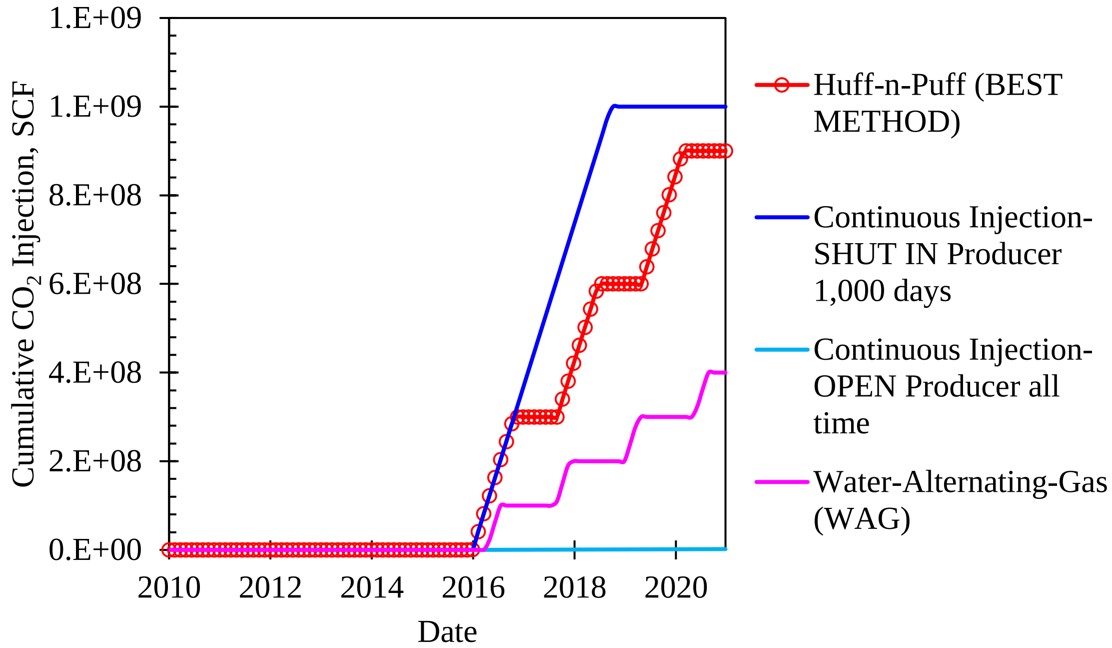


Figure 51. Cumulative CO_2 injection of different CO_2 EOR methods in the volatile oil of the Eagle Ford shale

A comprehensive uncertainty analysis was completed so that we can have a clearer picture of all possible outcomes of different methods of CO_2 EOR in this study. The P90s of the two continuous CO_2 injection scenarios and CO_2 WAG are, indeed, negative **Figure 52**). Evidently, it is not a good signal to select any of these methods as a primary CO_2 EOR for the volatile oil region of the Eagle Ford shale.

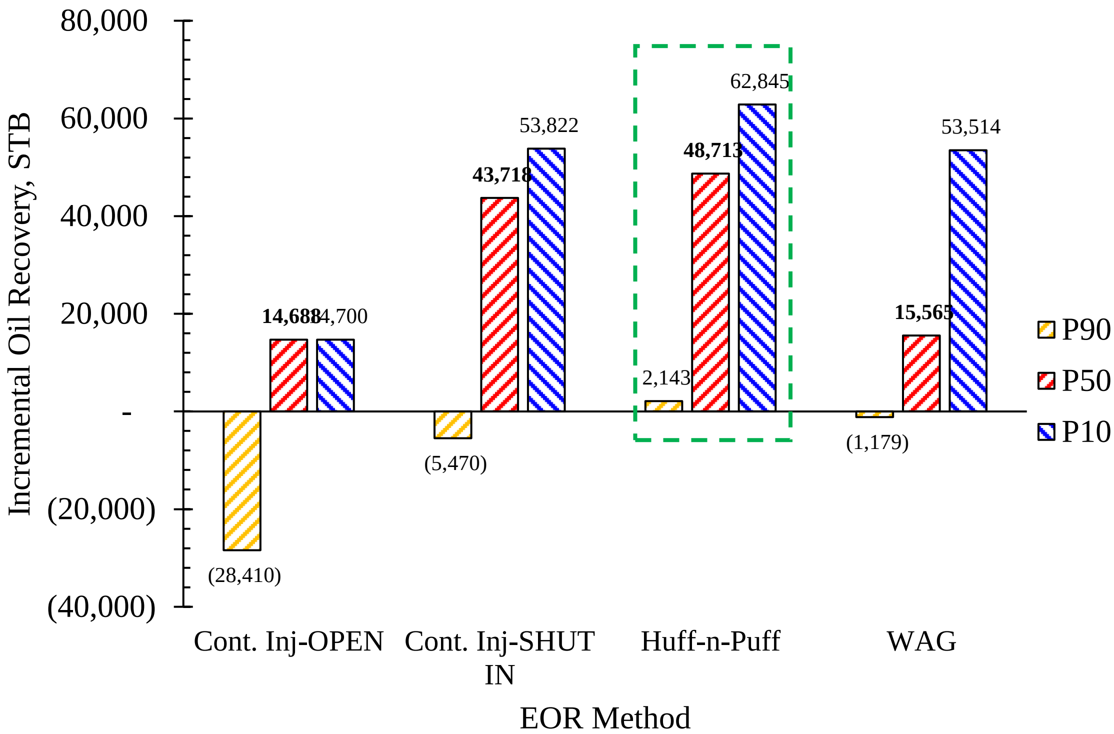


Figure 52. Summary of production performance of different CO_2 EOR in Eagle Ford

Table 7. Utilization efficiencies of different CO_2 EOR methods

	Cumulative Oil Production, STB	Incremental Oil Recovery, STB	CO_2 Injected, Mscf	Water Injected, STB	Utilization Efficiency (Mscf/STB)
BASE CASE	223,610.1	-	-	-	-
CO_2 cont. inj. - OPEN	238,297.7	14,688	1,827	-	0.12
CO_2 cont. inj. - SHUTIN	267,328.1	43,718	1,000,000	-	22.87
CO_2 Huff-n-Puff	272,323.4	48,713	900,000	-	18.48
Water-alternating-gas (WAG)	239,175.0	15,565	400,000	200,000	25.70

Table 7 shows the utilization efficiencies comparison among CO_2 EOR methods in this study. The scenario of continuous CO_2 injection with the producer is open the whole time has the lowest utilization efficiency because it uses little amount of CO_2 to recover a small amount of incremental oil after five years compared to other cases. The more CO_2 injected in this scenario, the lower incremental oil recovery it gets. As mentioned earlier, there is a high chance to have negative incremental oil recovery when this scenario is applied in this study. In CO_2 huff-n-puff scenario, each barrel of oil requires approximately 18.48 Mscf of injected CO_2. All CO_2 EOR methods used in this study was not applied any recycled gas from the producer. In the future, when the cost of injecting and operating CO_2 is lower and the oil price is higher, CO_2 huff-n-puff will be worth to be considered as

the main EOR method in ULR. In addition, the efficiency will be much better if CO_2 is recycled.

5. CONCLUSIONS AND FUTURE WORK

This study provides a complete workflow to optimize different CO_2 EOR in unconventional liquid reservoirs, specifically in the volatile oil region of the Eagle Ford shale, using dual-porosity structured grid model. Unlike previous studies of CO_2 EOR in ULR, this study performed a comprehensive history-matching process before applying any CO_2 EOR. Main conclusions of this study are listed below:

- It is essential to include history matching process to avoid misleading results in EOR simulation studies.
- The results of the sensitivity analysis shows that matrix porosity is a dominant parameter because it not only represents the storage of the reservoir but also has a significant impact on the oil production rate in the early time and the late time.
- The result of history matching in this study shows that matrix porosity in the volatile oil region of the Eagle Ford shale might have been overestimated in many previous studies. The range of matrix porosity found after history matching in this study is 2-6% compared to 6-12% as several previous studies assumed.
- The fracture permeabilities in I- and J-directions are important parameters that could affect the simulated oil rate during the first few years of primary depletion. The fracture permeability that is perpendicular to the direction of the lateral well will also affect the slope of the oil rate in reservoir simulation.
- Among different CO_2 EOR methods used to optimize the oil production in the volatile oil region of the Eagle Ford shale, CO_2 huff-n-puff is the most promising

scenario because it not only recovers the most incremental oil but also requires a reasonable amount of CO_2 to be injected.

- The scenario of continuous CO_2 injection with the producer is open the whole time might have a negative impact on not only production but also economic performance in ULR.

Some future works are recommended to improve different aspects of this study:

- Benchmarking the dual-porosity in this study against unstructured, DFN model will highlight the advantages and disadvantages of the two methods.
- Study of flow back and wettability change by fracture fluid will improve the accuracy of the history matching.
- Geomechanics of hydraulic fracture and natural fracture can be included to optimize the well completion design in ULR.
- Heterogeneity of porosity and permeability distribution in both matrix and fracture systems in Eagle Ford is another great aspect that can be further investigated using the model in this research.

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