CO_2 EOR Performance Evaluation in Unconventional Reservoir using Huff'n'Puff Scheme

Master Thesis report

by

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Abstract

The increasing global demand for energy has necessitated the exploration of untapped potential energy resources. Unconventional oil reservoirs present a significant opportunity for development through various enhanced oil recovery (EOR) methods. Among these methods, the huff'n'puff scheme using Carbon Dioxide (CO_2) EOR has emerged as a potent technique, considering both productivity and its impact on global warming. Unlike water injection, CO_2 EOR exhibits high injectivity potential in tight formations, making it a promising approach.

This thesis focuses on investigating the performance of CO_2 EOR in unconventional oil reservoirs using the huff'n'puff scheme through a comprehensive reservoir simulation study based on an open-source geological model. The study evaluates the effects of key parameters on oil production, including injection rate, injection time, soaking time, diffusion coefficient, and well completion.

The simulation results demonstrate that CO_2 EOR can effectively enhance oil recovery from unconventional oil reservoirs. Specifically, the study reveals that implementing CO_2 EOR increases cumulative oil production by 27% after 20 years compared to natural depletion cases. Furthermore, when incorporating a two-year primary recovery period, cumulative oil production is further elevated to 45%. By implementing the findings from the sensitivity study, cumulative oil production can be increased up to 67% in the optimum case.

In terms of the influence of the tested parameters on oil production, the study identifies that higher injection rates and longer injection, soaking, and production times for each cycle improve oil recovery until reaching an optimum value. Additionally, extending injection period by 10 times in each cycle with the same CO_2 injected volume improved cumulative oil production by 7% compared to fixed injection rate as a result of longer diffusion and dissolution time. Moreover, implementing bottom CO_2 injection targeting bottom layers improves vertical sweep efficiency due to buoyancy forces. The study also highlights the importance of the diffusion coefficient, as higher values facilitate faster CO_2 transport, resulting in higher oil recovery and reduced CO_2 reproduction.

This thesis provides valuable insights into the design and implementation of CO_2 EOR projects in tight oil reservoirs. It emphasizes the need for careful selection of optimal operating conditions based on specific reservoir properties and highlights the significance of the diffusion mechanism in CO_2 EOR performance. The findings contribute to the development of more effective CO_2 EOR strategies for unconventional oil reservoirs, addressing gaps in previous research. Moreover, the study's outcomes have practical implications for improving the design and implementation of CO_2 EOR projects in the field, ultimately leading to increased oil production.

Contents

Nomenclature

List of Abbreviations

ACW	Active Carbonated Water
ACWAG	Active Carbonated Water-Alternating Gas
ACWI	Active Carbonated Water Injection
API	American Petroleum Institute
CW	Carbonated Water
CWI	Carbonated Water Injection
EOR	Enhanced Oil Recovery
EOS	Equation of State
FCM	First Contact Miscibility
FWL	Free Water Level
GOR	Gas-Oil Ratio
IFT	Interfacial Tension
MCM	Multiple Contact Miscibility
MICP	Mercury Injection Capillary Pressure
MMP	Minimum Miscibility Pressure
RBA	Rising-Bubble Apparatus
RRT	Reservoir Rock Type
SACROC	Scurry Area Canyon Reef Operations Committee
U.A.E	United Arab Emirates
VIT	Vanishing Interfacial Tension
WAG	Water-Alternating Gas
WI	Water Injection

List of Symbols

^oC	Degree Celsius
a_g	Gas endpoint relative permeability
b_g	Exponential factor
CO_2	Carbon Dioxide
K	Kalvin
k	Permeability
k_h	Horizontal permeability
k_{rg}	Gas relative permeability
k_{rog}	Oil relative permeability
k_v	Vertical permeability
m	Meter
m^2/d	Square meter per day
mD	milliDarcy
mm^3	Thousand cubic meter
mm^3/d	Thousand cubic meter per day
Mpa	Mega Pascal
n_{pg}	Angular velocity
p_{cog}	Gas-oil system capillary pressure
$pc_{S_{lc}}$	Capillary pressure at critical liquid saturation
s_{gc}	Residual gas saturation
s_g	Gas saturation
s_{lc}	Critical liquid saturation
s_{org}	Angle of attack
s_{or}	Residual oil saturation
s_o	Oil saturation
s_{wc}	Connate water saturation

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1 Introduction

1.1. CO_2 EOR Background

The use of carbon dioxide (CO_2) to enhance oil recovery in oil reservoirs is not a new topic. According to [1], CO_2 flooding for EOR approach started in 1930s with experimental and laboratory studies until the first field scale application of CO_2 EOR in 1972 at Scurry Area Canyon Reef Operations Committee (SACROC) unit of Permian Basin. Over the past four decades, CO_2 EOR experienced an immense success in conventional oil reservoirs [2]. After CO_2 EOR had proven its influence on oil recovery in conventional reservoirs, a focus has been directed towards understanding CO_2 EOR potential in unconventional oil reservoirs over the past decade [3]. The development of unconventional reservoirs uses infill drilling and multistage fracturing as a current practice for short-term oil gain, which only enhances recovery by 10% over primary recovery [4][5]. The use of water injection as a mean for enhancing recovery in tight reservoirs did not result in significant oil gain. According to [6], the increase in oil recovery in tight reservoir after water injection is less than 10%, with a significant oil production reduction post water breakthrough. There are several factors that limit oil gain when water flooding is utilized in tight formations. One is the low injectivity of tight formations due to low permeability that leads to low water injection rates [7]. Another issue is the water fingering in tight reservoirs due to the difference in viscosity between injected water and reservoir oil [7]. In addition, water can lead to swelling of clay minerals that can create a damaged zone and reduction in permeability in some reservoirs [8]. On the other hand, CO_2 flooding is easier to inject and would not lead to noticeable formation damage resulting in higher oil recovery [5][9]. This makes CO_2 flooding a more attractive approach to be utilized for enhancing oil recovery in unconventional reservoirs.

1.2. Research Motivation

There is a continuous demand on energy supply worldwide, and this demand is increasing with time due to world population increase. According to [10], fossil fuel will be the dominant energy source until 2050 even with the current energy transition. Unconventional oil reservoirs holds great untapped potential that can be unveiled with the implementation of a well designed EOR method. The use of CO_2 as EOR method in tight oil reservoirs not only improves recovery, but also aids in reducing CO_2 emissions. The industrial revolution over the past decades increased CO_2 emissions and there is a great need to capture these emissions to avoid global warming [1]. Therefore, utilizing CO_2 for EOR would maintain the world energy supply while storing CO_2 in the subsurface. In fact, CO_2 is considered one of the most potent EOR methods when accounting for global warming [11]. The research aims to evaluate CO_2 EOR in unconventional oil reservoirs using huff'n'puff scheme. The selection of the huff'n'puff scheme is mainly due to the advantages it holds in terms of short-term oil gain and low economic cost. The use of a single well for CO_2 injection and oil production leads to a lower project capital cost. Even though the topic has been discussed in several studies in the literature, there is few areas of gap and other areas that show contradiction. This study will shed more light on these gaps and provide a detailed assessment on the points of contradiction in previous studies.

1.3. Problem Statement and Objective

There are many factors that affect CO_2 EOR performance in unconventional oil reservoirs using huff'n'puff scheme. Previous studies on the topic using numerical modeling covered several parameters including

injection rate, injection time, soaking time and diffusion coefficient. However, these factors were not deeply investigated with gaps to be filled in order to enhance oil production. Therefore, the objective of this thesis is to understand the influence of the controlling factors on CO_2 EOR performance in unconventional oil reservoirs using huff'n'puff scheme through reservoir simulation. This includes the evaluation of the previously studied parameters to verify findings along with the assessment of new parameters that can enhance oil production.

1.4. Structure of the Thesis

This thesis includes a total of six chapters. Chapter 1 is the current chapter and it provides a brief background on CO_2 EOR and the motivation behind choosing this research topic along with problem statement and objectives. Then, Chapter 2 shares a literature review from previous studies on CO_2 EOR in unconventional reservoirs. It includes the findings on main CO_2 EOR mechanisms, different injection schemes, major challenges and field scale applications. After that, Chapter 3 describes the chosen geological model and the implemented modifications to meet the objectives of the numerical simulation study. Then, Chapter 4 presents the simulation software and dynamic properties used as input parameter for reservoir simulation. Moreover, Chapter 5 presents a detailed evaluation of CO_2 EOR in tight reservoir using huff'n'puff scheme based on simulation results. A sensitivity study is performed on several parameters influencing CO_2 EOR performance in terms of oil recovery. Based on findings and conclusions from the sensitivity study, an optimum CO_2 EOR is presented and discussed. Finally, Chapter 6 summarises the major findings from this thesis and Chapter 7 provides recommendations for future work.

2

Literature Review

2.1. CO_2 EOR Mechanisms

There are several mechanisms that take place in the subsurface hydrocarbon reservoirs during CO_2 enhanced recovery. According to [10], there are four main mechanisms: Interfacial tension (IFT) reduction, oil swelling, oil viscosity reduction and light component extraction. During CO_2 injection, CO_2 will dissolve in reservoir crude oil leading to these different mechanisms. The dissolution of CO_2 in crude oil will firstly lead to oil swelling and viscosity reduction that will improve the mobility of the mixture resulting in higher oil recovery. The rate of dissolution is dependent on CO_2 injection pressure, and higher pressures will result in higher dissolution leading to an improvement in oil recovery and sweep efficiency [11]. Moreover, a reduction in interfacial tension between CO_2 and crude oil will occur resulting in a more homogeneous mixture reducing the residual oil and improving fluid displacement leading to higher oil recovery. The degree of IFT reduction will depend on fluid miscibility, which will be discussed in the next section. The dissolved CO_2 in oil would also lead to the extraction of lighter oil component in the reservoir. Density of injection CO2 would control the hydrocarbons extraction process, where CO_2 will extract more and heavier hydrocarbon components at higher CO_2 densities [12]. [13] included two more EOR mechanisms: alternation of wettability and relative permeability and an increase in reservoir pressure. Wettability is defined as the degree of adhesion of a fluid to rock surface when other immiscible fluids are present, and it can be measured by the contact angle between fluid to rock surface [14]. The alternation in wettability towards water-wet will lead to reduction in residual oil leading to higher oil recovery. All of the mentioned mechanisms during CO_2 EOR process are acting to improve crude oil recovery.

2.2. CO_2 Miscibility

Fluid miscibility is considered one of the key mechanisms that can take place during CO_2 EOR. Miscibility is defined as the formation of a homogeneous mixture through the mixing of different substances due to a reduction in their IFT [15]. For CO2 injection in a hydrocarbon reservoir, miscibility can be established as either first contact miscibility (FCM) or multiple contact miscibility (MCM) [16]. In FCM, injected gas can mix directly with crude oil under reservoir condition [16]. On the other hand, MCM is achieved through continuous contacts between injected CO_2 and crude oil reducing IFT gradually while continuous CO_2 dissolution in oil is taking place until reaching complete miscibility [16]. In the case of CO_2 injection in crude oil reservoir, the process would be a multiple contact miscibility (MCM) [17][16]. To achieve CO_2 miscibility with crude oil, crude oil must have sufficient amount of light components to be be extracted by CO_2 to achieve complete miscibility [16]. In addition, the operating subsurface pressure during CO_2 injection has to exceed a limit called minimum miscibility pressure (MMP). This is defined as the minimum operating pressure that would result in CO_2 dynamic or MCM with crude oil [17]. Otherwise, CO_2 flooding will be immiscible. MMP can be measured in the lab using different tools and techniques such as slim-tube test, Rising-bubble apparatus (RBA) and Vanishing interfacial tension (VIT) technique [17]. MMP is highly dependent on crude oil molecular weight and chemical composition [17].

In immiscible CO_2 flooding, the main oil recovery mechanisms are oil viscosity reduction, oil swelling, IFT reduction and immiscible displacement [17]. However, viscous fingering and gas channeling are disadvantages observed in immiscible technique and can lead to low sweep efficiency [18]. Moreover,

gravity plays a role in influencing the displacement of CO_2, where top gas injection leads to better performance compared to bottom injection [19]. Gravity effect is directly related to reservoir thickness, but it can be minimized at high CO_2 injection rates [19]. As for for miscible CO_2 flooding, it has the same oil recovery mechanisms as immiscible flooding with the addition of diminishing IFT by reducing the density difference due to pressure increase above MMP [1]. In this technique, most light components in the crude oil are extracted by CO_2, and oil-CO_2 interface almost disappears to form a single phase flow which can easily flow in porous medium [19]. Unlike immiscible technique, viscous fingering and early gas breakthrough are eliminated during miscible flooding [16]. In addition, gravity doesn't have an important role in miscible flooding [19]. For unconventional reservoirs, majority of previous studies recommended miscible gas EOR [3]. According to [19], highest oil recovery and CO_2 storage potential is achieved during miscible flooding. Moreover, coreflood experiments resulted in an average recovery of 90% following a miscible CO_2 flooding illustrating the high efficiency in oil recovery enhancement in tight formation [6]. Lastly, [17] observed that after CO_2 breakthrough, oil recovery increases slightly in immiscible flooding but significantly in miscible flooding as a result of strong light hydrocarbon extraction by CO_2 and miscible displacement.

2.3. CO_2 Molecular Diffusion

Molecular diffusion is considered a key mechanism in CO_2 EOR process in shale oil reservoirs [20][3]. Molecular diffusion is defined as the movement of molecules due to a difference in concentration gradient in a mixture of fluids [20]. For CO_2 injection in crude oil reservoir, the injected CO_2 molecules diffuse into the oil moving from high concentration of CO_2 into low concentration of CO_2 in oil. According to [4], performance of CO_2 huff-n-puff pilot tests were not meeting expectations due to the inaccurate prediction of CO_2 diffusion mechanism in these reservoirs. Based on several literature reports, the significance of molecular diffusion mechanism on CO_2 EOR performance is dependent on injection scheme and reservoir type. According to [4], molecular diffusion mechanism is significant in huff-n-puff injection scheme but not in continuous gas injection. As for reservoir type, the effect of CO_2 diffusion mechanism on EOR process in conventional reservoirs is almost non-existence based on experimental studies [3]. This is because of the higher permeability in conventional reservoirs resulting in a dominant advective flow due to pressure gradient. To incorporate CO_2 molecular diffusion in a scientific research or field development, CO_2 diffusivity rate has to evaluated. Identification of CO_2 diffusivity rate is a key factor in the success of CO_2 EOR in shale oil reservoirs [4]. This is highly important in numerical simulations as neglecting or inaccurately identifying diffusion rate might result in underestimation or overestimation of oil recovery during CO_2 EOR [20]. In a low CO_2 molecular diffusivity cases, exposure time and contact area between injected CO_2 and reservoir oil need to be substantially increased for better EOR performance [3]. There are several parameters that can influence CO_2 diffusion coefficient in an oil reservoir. [21] study concluded that reservoir pressure, temperature and oil composition would impact CO_2 diffusion coefficient. Higher reservoir pressure and temperature with lighter crude oil leads to higher CO_2 diffusion coefficient.

2.4. CO_2 Injection Schemes

CO_2 Huff'n'Puff Scheme

The CO_2 huff'n'puff scheme is one of the schemes used for CO_2 EOR. It follows a cyclic process utilizing a single well, where each cycle starts with CO_2 injection followed by a soaking period and ends with production as shown in figure2.1. First CO_2 EOR huff'n'puff project was conducted in Trinidad and Tobago for conventional reservoirs in 1984 [3]. This scheme has been implemented successfully since then in conventional reservoirs showing to be most effective for short term EOR, and it can be designed for tight reservoirs as well [13]. In tight reservoirs, EOR mechanism depends on CO_2 diffusion, viscosity reduction and dissolution drive [10]. Soaking period within each cycle provides time for CO_2 diffusion and dissolution in oil reducing its viscosity [13]. Based on lab experiments conducted on fractured plugs, this scheme had a better performance compared to continuous CO_2 flooding [2]. One disadvantage of this scheme is that most of the injected CO_2 will be reproduced [5]. There are also challenges that need to be addressed and evaluated when studying CO_2 huff'n'puff. One challenge is the drainage area that can be covered and swept from a single well. This is controlled by the reservoir permeability and CO_2 ability to spread during injection and soaking times. After several cycles, the performance of huff'n'puff significantly drops due to the reduction of oil saturation near well, and more CO_2 needs to be injected to maintain production [13][22]. Another challenge is the CO_2 utilization aspect and the control of CO_2 reproduction. These challenges can

also be linked to the soaking period as it can influence both oil recovery and CO_2 utilization. However, previous research on soaking period effect is not aligned in order overcome these challenges. According to one study conducted by [13], soaking time doesn't have much impact of oil recovery. Another experiment indicated that soaking time is needed to yield the highest oil recovery regardless of the soaking time used [13]. A third research found that soaking time is needed and there is an optimum soaking time of 1 month to achieve highest oil recovery [22]. Therefore, a more in depth analysis of the soaking time influence on not only oil recovery, but also CO_2 utilization is needed for better implementation of CO_2 huff'n'puff scheme.

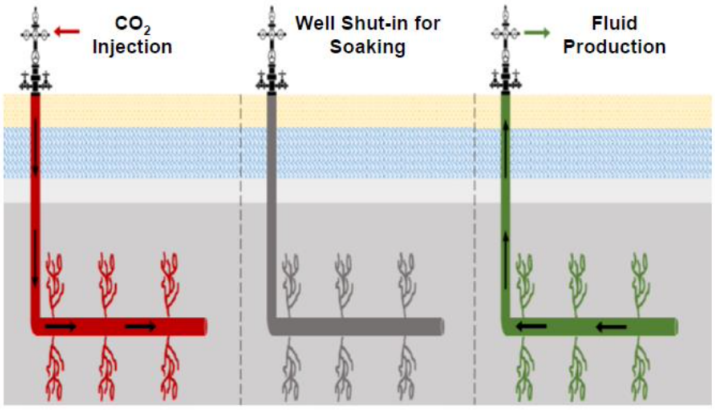

Figure 2.1: Diagram of CO2 Huff'n'Puff injection scheme [23]

2.4.1. Other Injection Schemes

There are several other CO_2 EOR injection schemes that were evaluated and tested through lab experiments, numerical simulation and field applications. The following list includes eight different CO_2 injection schemes: (1) Continuous CO_2 flooding, (2) CO_2 flooding coupled with soaking period, (3) Water-alternate CO_2 injection (WAG), (4) CO_2 injection with chased WI, (5) Carbonated water injection (CWI), (6) Carbonated water-alternating gas injection, (7) Active carbonated water injection (ACWI), (8) Active carbonated water-alternating gas (ACWAG). These schemes will not only differ in their resulting oil recovery, but also CO_2 utilization [24]. Starting with continuous CO_2 flooding, it consists of both injection and production wells that can be placed with different patterns. One advantage this scheme holds is the higher CO_2 storage [10]. However, it results in low displacement efficiency and gas channeling leading to early CO_2 breakthrough, which is considered a major disadvantage for this scheme [11]. This scheme can be modified by including a shut-in period after injection, and it would be called CO_2 flooding coupled with soaking period. Results showed that this modification leads to higher oil recovery due to the given time for CO_2 to transport and further dissolve in oil while reacting with formation to increase its permeability [7].

Other schemes have included water in the CO_2 EOR process in order to improve oil recovery. Starting with WAG scheme, the use of water results in a delayed gas breakthrough and a control in mobility avoiding CO_2 fingering and an improved sweep and displacement efficiency based on several field applications [10][6]. However, CO_2 WAG is less effective in high heterogeneity formations, as it recovers residual oil in high permeability zones [18]. Rather than having an alternating injection, CO_2 injection chased with WI scheme can be followed. Based on a numerical study comparing the two schemes, CO_2 injection chased with WI is considered the better option because of the resulting incremental oil and CO_2 utilization [24]. After that, a new approach evolved by using carbonated water (CW) instead, where CO_2 is mixed with water before injection to have higher viscosity and lower mobility for an enhanced volumetric sweep efficiency [1]. After injection of carbonated water, CO_2 transports from formation water to reservoir oil due to the solubility of CO_2 in oil [6]. The acidic behaviour would also lead to a reduction in interfacial tension and alteration in wetability to a more favourable water-wet system [1]. From coreflood experiments, CWI had a better performance compared to WAG utilizing similar CO_2 amount during injection [6]. Another approach is to utilize CW in a WAG scheme. According to a comparison study between different CO_2 flooding scheme, carbonated water alternating gas injection yielded the highest oil recovery [5]. Other than

formation water and carbonated water, a new scheme is developed by adding surfactant on CW to become active carbonated water (ACW). The advantage of including surfactant is to reduce interfacial tension significantly in addition to wettability alteration [6]. An experiment conducted by [6] showed that ACW if used as direct injection or as a WAG approach would lead to higher oil recovery compared to previous methods. Nevertheless, the use of CW or ACW might impose several challenges such as corrosion when implemented at a field scale, since conducted studies on this topic is mainly based on lab experiments and numerical simulation.

2.5. Supercritical CO_2

The utilization of CO_2 in its supercritical condition for EOR in conventional and unconventional reservoirs has been investigated in several researches. Supercritical CO_2 has different fluid properties compared to its gaseous phase, where it maintains the characteristics of a gas and the density of a liquid [1][25]. It also has a near gas viscosity and high diffusion coefficient [25]. Supercritical would also maintain a good injectivity in tight reservoirs [26]. CO_2 will reach its supercritical condition once the temperature exceeds 31.26° C and the pressure exceeds 7.4 Mpa [8].

2.6. CO_2 Storage

Research and field applications of CO_2 storage in subsurface reservoirs have been of great interest in the past decade in order to reduce CO_2 emissions to avoid global warming. As part of CO_2 EOR, CO_2 storage will also occur indirectly in the subsurface by replacing the produced oil. In general, there are four main CO_2 storage mechanisms: stratigraphic trapping, solubility trapping, capillary trapping and mineral trapping [10]. For CO_2 EOR in tight formations, the dominating storage mechanisms are solubility trapping and capillary trapping [10]. Different CO_2 injection schemes can result in different sequestration ratio and volume. In a numerical simulation study performed by [10], results showed that continuous injection scheme leads to a higher CO_2 storage volume by 15% compared to WAG scheme, mainly because continuous injection scheme uses a much larger CO_2 during injection. The study also observed that water injection rate in WAG scheme would negatively influence CO_2 storage. To evaluated storage in another scheme, [6] performed a coreflood experiment using carbonated water injection (CWI) scheme to identify 46% stored CO_2 volume, highlighting the storage potential this scheme offers. The storage potential during the use of supercritical CO_2 was also investigated in long-core experiments done by [26] showing effective CO_2 storage results. The same study also showed that another factor that can influence the sequestration volume is CO_2 breakthrough time. Results showed that gas breakthrough can negatively impact CO_2 storage. 85% of injected CO_2 was stored before breakthrough and reduced to 38-46% post breakthrough at its final stage. The study also evaluated the impact of reservoir permeability and stated that lower permeability would lead to higher CO_2 storage volume.

2.7. Petrophysical Changes During CO_2 Flooding

When CO_2 is injected in a subsurface reservoir, the formation petrophysical properties can be impacted through multiple chemical reactions. Some studies showed that CO_2 injection can negatively impact reservoir petrophysical properties, while others observed enhancement in reservoir porosity and permeability [14]. One chemical reaction that occurs is the one between injected CO_2 and formation water shown in the following chemical formula [27]:

$$H_2O + CO_2 \longleftrightarrow H_2CO_3 \tag{2.1}$$

In this reaction, the formed carbonic acid as a result of CO_2 dissolution in brine can dissolve parts of dolomite, calcite and feldspar in the rock resulting in new micro and nanopores [27]. This is represented through the following chemical reaction [24]:

$$H_2O + CO_2 + CaCO_3 \longleftrightarrow Ca(HCO_3)_2 \tag{2.2}$$

The carbonic acid reaction with calcite results in the the formation of calcium bicarbonate. A large number

of research results show that injected CO_2 into formation during CO_2 flooding will dissolve in the formation water to produce carbonate precipitation [28]. Therefore, mineral dissolution increases porosity and permeability through dissolution of minerals, but resulting secondary precipitation decreases porosity and permeability [29][24]. According to a numerical study, large amount of precipitation occurs near bottom of the well as a result of large pressure difference near production well [28]. Accounting for these chemical reactions in numerical modeling can also have an noticeable impact on oil recovery prediction. A simulation study performed by [28] showed that after 20 years of production, ultimate recovery drops from 37.64% to 33.45% after including precipitation. Therefore, CO_2 injection impact on reservoir petrophysical properties should be considered in numerical models to have more representative results.

2.8. Major Challenges

There are many challenges that can be encountered during the development of CO_2 EOR project. These challenges can greatly influence the outcome and performance of any CO_2 flooding project in terms of enhanced recovery. The main challenges that will be covered and discussed in this section are sweep efficiency, presence of fractures and asphaltene precipitation.

2.8.1. Sweep Efficiency

The low areal and vertical sweep efficiency during CO_2 flooding is a major challenge, especially in tight reservoirs [10]. Reservoir heterogeneity has a significant impact on horizontal and vertical sweep efficiency that can lead to gas channeling in high conductive pathways [30]. Gas channeling would result in early CO_2 breakthrough time which will negatively impact areal sweep efficiency and oil recovery. Viscous fingering is another behaviour that can occur in oil reservoirs during the injection of CO_2, leading to significant amount of bypassed oil [10]. This is due to the difference in viscosities between injected CO_2 and crude oil, where CO_2 viscosity is much lower resulting in unfavorable mobility ratio [13]. In addition to reservoir heterogeneity, buoyancy-driven forces have also an impact on vertical sweep efficiency. According to [10], CO_2 buoyancy-driven forces would lead to lower vertical sweep efficiency with highest sweep at top layer. Several studies investigated methods to overcome gas channeling challenge in order to improve sweep efficiency and enhance oil recovery. There are common methods in controlling gas channeling: Blocking agent injection, WAG flooding and Foam flooding [18]. The use of blocking agents aims to block-off high conductive pathways such as high permeability zones or natural fractures to have a higher swept volume in order to enhance oil recovery [18].

2.8.2. Presence of Fractures

There are two different types of fractures that can be present in unconventional reservoirs: natural fractures and induced fractures. Starting with natural fractures, it frequently exists as a network creating high conductive pathways for fluid flow. Many researches have investigated the influence of natural fractures on CO_2 EOR in unconventional reservoirs. According to [20], intensity of natural fractures is a key factor that controls the success of CO_2 EOR in shale oil reservoirs. Natural fracture network is a main characteristic of unconventional reservoirs, and it can result in gas channeling and early gas breakthrough lowering sweep efficiency and oil recovery in CO_2 EOR projects [10][2][18][13]. On the other hand, other researchers stated that highly intensive natural fractures can enhance diffusivity of CO_2 leading to higher oil recovery [31][4].

As for induced fractures, it can be created around a drilled wellbore due to either high injection pressure above formation fracture gradient or thermal fractures due to temperature difference during injection. These induced fractures will have the same influence as the natural fractures in terms of offering high conductive pathways for fluid flow, which can be undesired in some cases. A field pilot test in Abu Dhabi evaluated the importance of surface heating of CO_2 prior to injection to avoid thermofrac [32]. It concluded that CO_2 will heat significantly during injection leading to minor temperature difference across sand face which will not create thermofrac.

2.8.3. Asphaltene Precipitation

Another highlighted challenge in the literature during injection of CO_2 in tight oil reservoir is the formation of asphaltene precipitation. It is defined as an insoluble material that can lead to formation damage, reduction in reservoir permeability and wettability alteration when precipitated [17]. Asphaltene precipitation can

form as a result of injected CO_2 interaction with reservoir crude oil [27]. The main reason for asphaltene precipitation during CO_2 injection is CO_2 solubility in crude oil [33]. A study by [33] found that asphaltene precipitation has a higher likelyhood of occurring in light oil compared to heavy oil. Moreover, the study concluded that the precipitation is directly related to injection pressure and volume because it would lead to higher CO_2 dissolution. Another study conducted by [24] through a coreflood experiment to understand asphaltene precipitation during CO_2 flooding showed that asphaltene started to precipitate when CO_2 concentration reached to 29%. Thus, it has been concluded that asphaltene precipitation is directly proportional to CO_2 concentration.

The performance of CO_2 EOR project will be impacted by asphaltene precipitation due to resulting formation damage and reduction in permeability [7]. Therefore, actions have to be taken to overcome this challenge. One solution that has been implemented in a field trial test in Abu Dhabi is the injection of inhibitors to avoid any asphaltene deposition [32]. Continuous monitoring of asphaltene precipitation is highly important to ensure CO_2 injection rate is maintained to have the best CO_2 EOR performance.

2.9. Field Scale Pilot Tests

Several pilots tests were conducted at field scale to identify the potential of CO_2 EOR projects in tight reservoirs before full field implementation. In this section, a number of pilot tests will be discussed with their major findings. Starting with a pilot test conducted in Jilin oilfield in China in 2008, CO_2 EOR followed a continuous flooding scheme with a reversed 7-spot patter [16]. The injection pressure was above MMP aiming for miscible flooding technique. Results showed that due to low permeability, pressure could not propagate from injector to producer resulting in large area near the producer with immiscible flooding. Also, early CO_2 breakthrough observed was attributed to short well distance and presence of natural fractures. Another pilot test conducted in Bakken formation in North Dakota and Montana in 2008 and 2009, following a huff'n'puff scheme under miscible conditions [4]. Results did not show any clear oil increment under CO_2 EOR, although there was no reported injectivity issue. The disappointing results of huff'n'puff EOR was attributed to possible difference between proposed CO_2 diffusion mechanism in lab conditions and field conditions.

Moving to another pilot test in Abu Dhabi in 2009 utilizing continuous flooding scheme under miscible conditions [24]. During the pilot test, data were collected using logging and coring showing evidence of very low oil residual oil saturation. This proves the effectiveness of miscible displacement in enhancing oil recovery. The pilot did not experience any injectivity issues nor reservoir damage during the test. However, once CO_2 concentration increased in reservoir fluid to 29%, a tendency of asphaltene deposition is observed. Therefore, it was concluded that CO_2 concentration and asphaltene deposition are directly related. Another pilot test was conducted in Elm Coulee Area in Montana in 2009 utilizing CO_2 huff'n'puff scheme [3]. After injection and soaking, the well produced naturally for only 38 days. After which, it was put on a pump to restore production where rate increased reaching a peak followed by a continuous decline until end of test. Around half of the injected CO_2 volume in the first year was reproduced. There is an uncertainty when it comes to the increase in rate post injection in this test if it is attributed to CO_2 injection or the artificial pump. The discussed pilot tests does not capture all CO_2 EOR pilot tests in tight reservoirs, as there are many other pilots conducted in recent years available in the literature.

3

Geological Model

3.1. COSTA Model

In order to study CO_2 EOR process using huff'n'puff approach, a realistic geological model is needed. Unfortunately, there is a lack of detailed open-source geological models that would represent realistic geological features. Majority of these open-source models available are fully synthesized models that can include many uncertainties when used for numerical modeling. A recently developed open-source carbonate reservoir model called COSTA model [34] is chosen for this study. This geological model can be used to study CO_2 EOR and storage projects. COSTA model is a considered semi-synthetic but geologically realistic model since it is based on mixture of real and synthesized data. The model does not include any faults or fractures. The model consists of 1.3 million active grid cells, where each grid cell has a size of 250 m x 250 m with a thickness varying from 0.2 to 2 m. The model is roughly 50 m thick subdivided into 62 geological layers.

3.2. Geological Background

The Geological setting of COSTA carbonate model is in the Upper Kharaib Member (Early Cretaceous) in Rub Al Khali basin, which is a sub-basin of the wider Arabian Basin. Figure 3.1 presents the lithostratigraphic column of Rub AlKhali basin across multiple countries in the Middle East. Within the U.A.E. alone, this geological formation is referred to as both the Upper Kharaib Member and Thamama Zone B and is estimated to cover an area of 36,000 km^2. It is located in the north-eastern part of the Rub Al Khali basin. In terms of geological structure, Upper Kharaib Member geological structure consists of 3 main anticlines. The Upper Kharaib Member is roughly 50 m thick, and its thickness remains relatively constant. It is subdivided into two main units: B-Upper and B-Lower. The upper unit is made of grainy facies with higher rock permeability, while lower unit is made of Packstone/Wackestone facies with lower rock permeability.

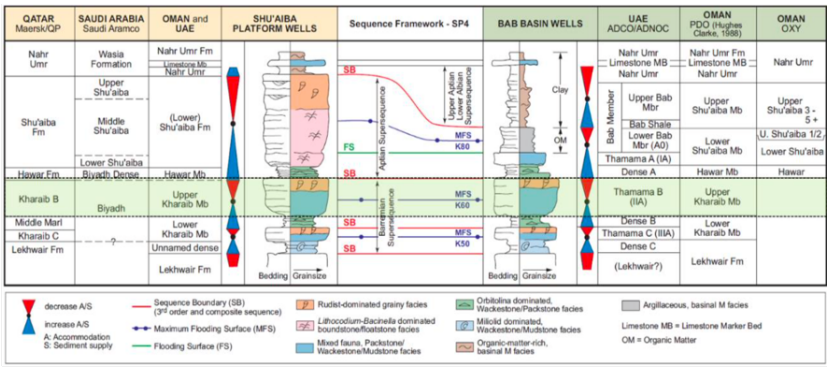

Figure 3.1: Lithostratigraphic column of Rub AlKhali basin [34]

3.3. Data Used

The dataset to build COSTA model uses 43 wells from fully anonymized published data from the north-eastern part of the Rub Al Khali basin. The dataset is a mixture of real and synthetic data from 22 fields in

U.A.E used as an analogue. Gathered well data such as real wireline logs and core data are used. To generate COSTA model, Upper Kharaib Member area in Rub Al Khali Basin had to be downsized from 36,000 km^2 down to 8,300 km^2. Thus, the downsized model would result in an area of 124 x 67 km size with 11 million grid blocks. The original well locations of all 43 wells were rescaled proportionally by a factor of four to decrease the areal coverage from 36,000 km^2 down to 8,300 km^2. After that, COSTA model is subdivided into three individual anticline structures. Each geological closure will act as a different reservoir. Thus, a sector model of the full COSTA model containing 17 wells out of 43 in one anticline with a size of 60 km x 26 km is shared as an open-source sector model. A 3D view of COSTA sector model is shown in figure 3.2.

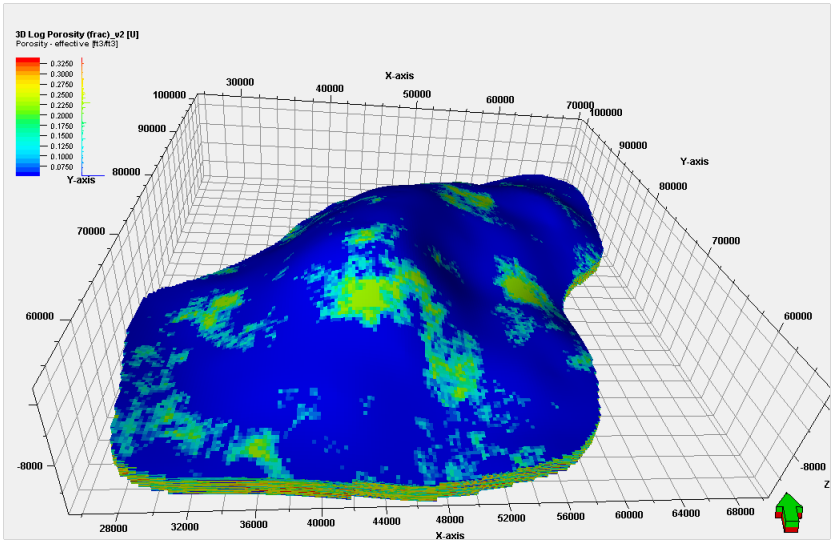

Figure 3.2: COSTA sector model

3.4. Sector Model

For this study, a small sector of COSTA model with 1000 m x 750 m area with an existing vertical well is initially chosen to perform numerical study for CO_2 EOR with huff'n'puff approach. Figure 3.3 shows the chosen sector model with well location. Moreover, figure 3.4 shows a histogram of porosity and permeability within this sector model. It is important to mention that the original COSTA model does not account for any permeability differences in vertical and horizontal directions. Therefore, k_v/k_h ratio is set to be 1 for this study based also on a study conducted on Upper Kharaib carbonate reservoir in U.A.E [35].

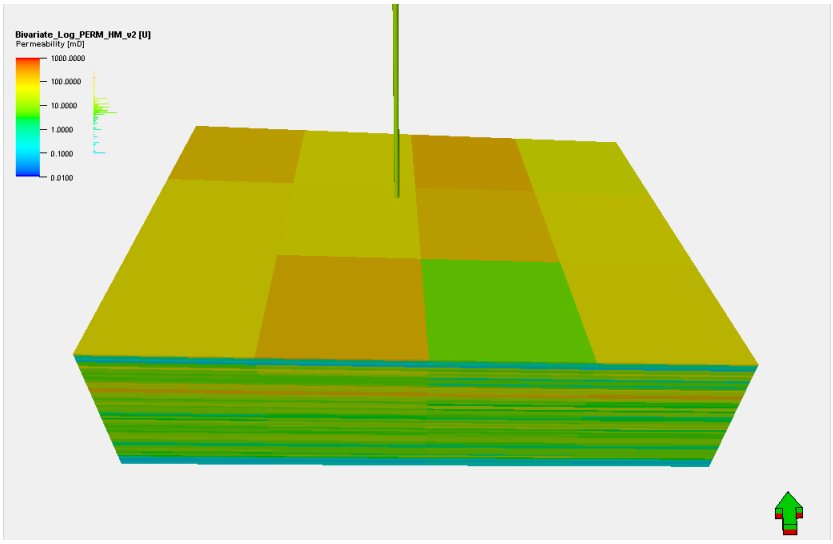

Figure 3.3: Selected sector model for dynamic simulation

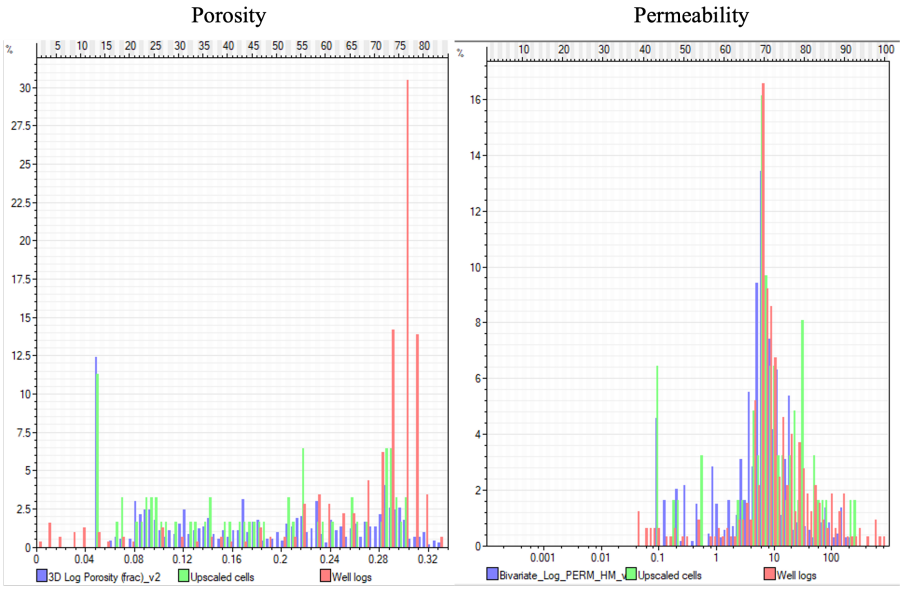

Figure 3.4: Sector model porosity and permeability histogram

3.5. Sector Model Modifications

In order for the sector model to represent an unconventional reservoir, it requires further modifications. The modification is also needed to have a higher model resolution to observe changes during dynamic simulation in the x and y directions.

3.5.1. Permeability Multiplier

A reservoir would be considered unconventional when its permeability is less than 1 mD [36]. Thus, a permeability multiplier of 0.01 K is used for this sector model to represent unconventional reservoir. A 3D permeability distribution of the modified sector model is shown in figure 3.5. In addition, the modified sector model permeability histogram is presented in figure 3.6 highlighting the range of permeability values with a mean value less than 1 mD.

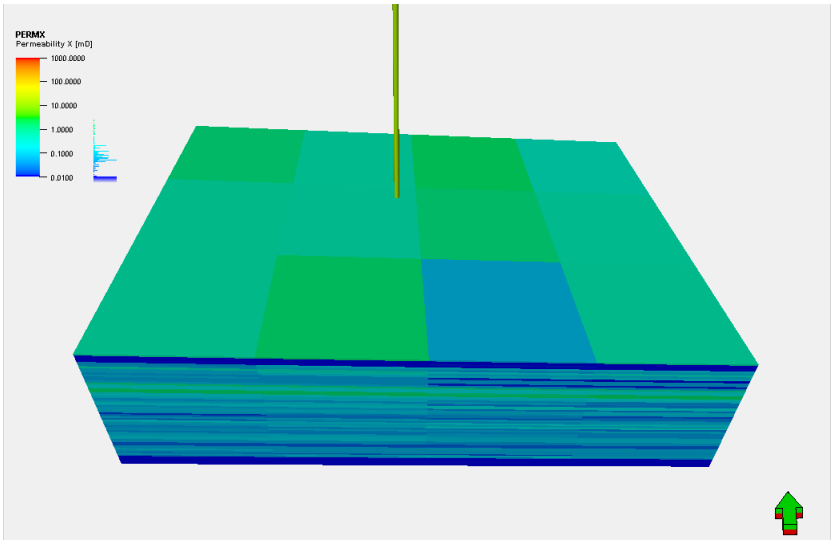

Figure 3.5: Selected sector model after permeability multiplier

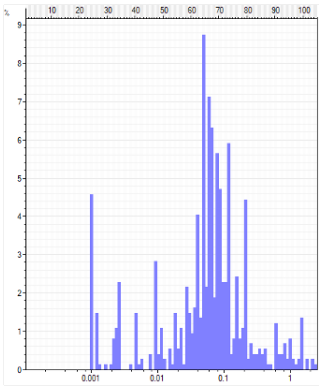

Figure 3.6: Sector model permeability histogram with 0.01 K multiplier

3.5.2. Grid Refinement

In order to improve sector model resolution, each grid cell is split into smaller cells. This would be performed on the areal resolution only since COSTA model captures a high vertical resolution with thickness varying from 0.2 to 2 m. The original areal grid cell size of COSTA model is 250 m x 250 m. Each areal grid cell is split into 100 grid cells with a new grid cell size of 25 m x 25 m in the modified sector model. The modified sector model is shown in figure 3.7 including grid refinement and further cropping of the sector model with a final size of 750 m x 750 m. As can be observed for the figure, the new split cells would still maintain the same petrophysical properties as the original cell. This modified sector model will be used as the static model for reservoir simulation study. The chosen static model size and resolution is based on computational time optimization along with its ability to capture changes in the dynamic simulation. Table 3.1 shows a comparison between three tested model resolutions in terms of grid size and computational time for a base case, where second model resolution is chosen for this study.

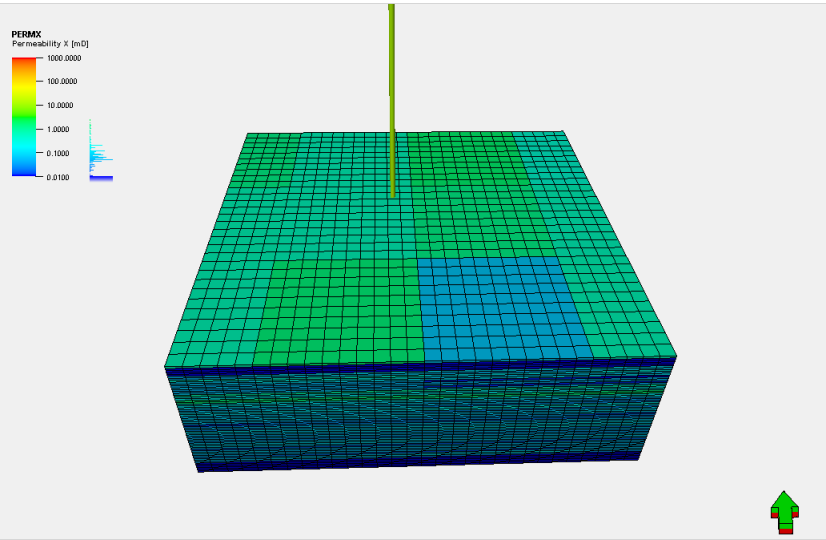

Figure 3.7: Selected sector model after grid refinement

Table 3.1: Model parameters for optimum case

Model Resolution	Grid Size	Model Dimension	Grid Cells	Base Case Run Time (hrs)
1	50 m x 50 m x (0.2 to 2 m)	15 x 16 x 62	14,880	0.23
2	25 m x 25 m x (0.2 to 2 m)	30 x 30 x 62	55,800	4.04
3	50 m x 50 m x (0.2 to 2 m)	60 x 60 x 62	223,200	12

4

Reservoir Simulation

4.1. Sector Model

Reservoir simulation in this study is performed using Schlumberger ECLIPSE reservoir simulation software E300 [37] along with Schlumberger Petrel software [38] for visualization of results. To simulate reservoir fluids behaviour, compositional run is used with Peng-Robinson Equation of state (EOS). The used sector model for dynamic simulation is 750 m x 750 m x 50 m in size. A total of 55,800 grid blocks are included in the sector model with a 30 x 30 x 62 model dimensions. Each grid cell has a size of 25 m x 25 m with varying thickness from 0.24 to 2.4 m. Simulation of CO_2 injection is computationally demanding and requires optimization on number of grid blocks used in the sector model run. A comparison with other CO_2 EOR numerical studies performed on tight reservoirs are listed in table 4.1 showing that this study uses the highest number of grid cells to simulate CO_2 flooding in a huff'n'puff scheme.

Table 4.1: Model size comparison with literature

Source	Model Size	Grid Size	Model Dimension	Grid Cells
CO2 injection for enhanced oil recovery in Bakken tight oil reservoirs [12]	104 m x 396 m x 12 m	6 m x 6 m x 12 m	17 x 65 x 1	1,105
Simulation study of factors affecting CO2 Huff-n-Puff process in tight oil reservoirs [39]	1609 m x 1207 m x 15 m	12 m x 12 m x 15 m	132 x 99 x 1	13,068
CO2 Utilization for Enhance Oil Recovery with Huff-N-Puff Process in Depleting Heterogeneous Reservoir [40]	381 m x 381 m x 9 m	15 m x 15 m x 2 m	25 x 25 x 6	3,750
Numerical Simulation and Optimization of Enhanced Oil Recovery by the In Situ Generated CO2 Huff-n-Puff Process with Compound Surfactant [41]	-	-	29 x 24 x 21	14,616
Reservoir Simulation Study and Optimizations of CO2 Huff-n-Puff Mechanisms in Three Forks Formation [23]	762 m x 2134 m x 41 m	13 m x 71 m x 4 m	60 x 30 x 11	19,800
Numerical Simulation and Performance Evaluation of CO2 Huff-n-Puff Processes in Unconventional Oil Reservoirs [42]	2000 m x 500 m x 15 m	10 m x 10 m x 5 m	200 x 50 x 3	30,000
Optimization of CO2 huff-n-puff EOR in the Bakken Formation using numerical simulation and response surface methodology [43]	572 m x 1829 m x 51 m	-	31 x 30 x 5	11,650
MSc Thesis Model	750 m x 750 m x 50 m	25 m x 25m x (0.2 to 2 m)	30 x 30 x 62	55,800

4.2. Dynamic Reservoir Properties

4.2.1. Reservoir Conditions

In this section, reservoir parameters are based on data from open-source COSTA model [34]. The carbonate reservoir has an anticline structure bearing oil with 42 API and a bottom water aquifer support. The original free water level (FWL) is at a depth of 2478 m. The chosen sector model is located at a depth of 2386 m with a thickness of around 50 m. It is located at the crestal part of the anticline structure above FWL. Thus, the sector model is saturated with reservoir hydrocarbons. Nevertheless, water is present in the formation in the form of connate water based on synthetic MICP provided in COSTA model that will be discussed in relative permeability section. At a datum depth of 2240 m, the reservoir has an initial pressure of 303 bar and an initial temperature of 395 K. The reservoir pressure is above the bubble point pressure of 149.3 bar, which means that it is at an undersaturated state with no free gas. The formation rock has a compressibility of 1.45×10^{-5} 1/bar.

4.2.2. Relative Permeability

Starting with water-oil system relative permeability, it is based on synthetic MICP provided in COSTA model. Since the chosen sector model is located in the oil zone, water-oil system relative permeability is needed to identify connate water saturation (S_{wc}) and residual oil saturation (S_{or}). Different water-oil relative permeability curves for different reservoir rock types (RRTs) were used and normalized to get a representative S_{wc} of 0.38 and S_{or} of 0.13. This would lead to a total immobile fluid ratio of 0.51 in the reservoir. After that, gas-oil system relative permeability is estimated to describe oil displacement during CO_2 injection. Unlike water-oil system relative permeability, there are no MICP data to be used to plot relative permeability curves. Therefore, Corey's method is firstly used to get endpoint relative permeabilities [44]. Residual gas saturation (S_{gc}) and S_g=1-S_{org}-S_{wc} will be used for endpoint gas relative permeability (k_{rg}) calculation. As per a study conducted by [45] to understand CO_2-oil relative permeability under miscible flooding condition, residual gas saturation would become zero after flooding with the presence of connate water saturation. Therefore, S_{gc} is set to be 0 and maximum S_g is 0.49. To calculate endpoint gas relative permeability, the following equations are used:

$$S_g^* = \frac{S_g}{1 - S_{wc}} \tag{4.1}$$

$$k_{rg} = (S_g^*)^3(2 - S_g^*) \tag{4.2}$$

This results in k_{rg} of 1 at S_{gc} and k_{rg} of 0.607 at S_g=1-S_{org}-S_{wc}. The resulting endpoint relative permeabilities are then used to plot gas relative permeability curve for all gas saturation values in between using modified Corey method [45]:

$$k_{rg} = a_g(\frac{S_g - S_{gc}}{1 - S_{or} - S_{wc} - S_{gc}})^{b_g} \tag{4.3}$$

Where a_g is the is gas endpoint relative permeability at S_g=1-S_{org}-S_{wc}, and b_g is an exponential factor with empirical value of 3.5. The resulting gas relative permeability curve (k_{rg}) is shown in figure 4.1.

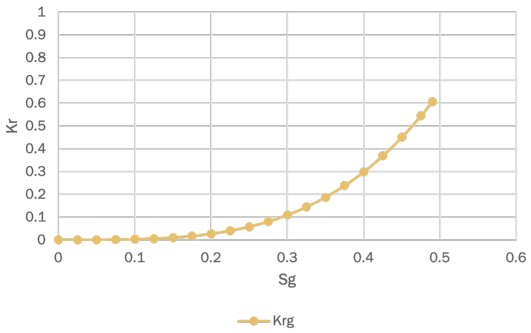

Figure 4.1: Gas relative permeability curve versus gas saturation

As for oil relative permeability curve (k_{rog}) in gas-oil system, it is calculated as a function of S_o using Honarpour method for limestone [46]:

$$k_{rog} = 0.93752\left[\frac{S_o}{1 - S_{wc}}\right]^4\left[\frac{S_o - S_{or}}{1 - S_{wc} - S_{or}}\right]^2 \tag{4.4}$$

The resulting oil relative permeability curve as a function of oil saturation is shown in figure 4.2. It starts with an oil saturation from S_o=S_{or} to S_o=1-S_{wc} reaching to a maximum k_{rog} of 0.94. The presented gas and oil relative permeability curves will be used as an input for CO_2 EOR dynamic simulation.

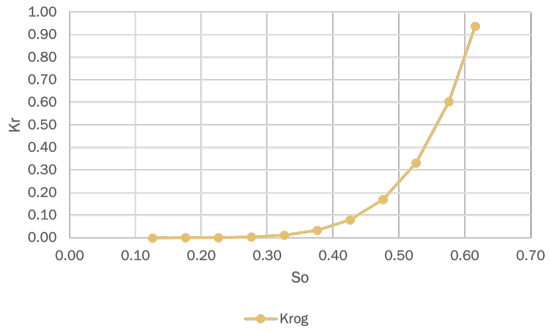

Figure 4.2: Oil relative permeability curve versus oil saturation

4.2.3. Capillary Pressure

To represent capillary forces during gas injection for oil displacement in gas-oil system, capillary pressure curve as a function of gas saturation is calculated using modified Corey method [44]:

$$p_{cgo} = (p_c)_{S_{lc}} \left[\frac{S_g - S_{gc}}{1 - S_{1c} - S_{gc}} \right]^{n_{pg}} \tag{4.5}$$

Where S_{1c}=S_{wc}+S_{or}, $(p_c)_{S_{lc}}$ is the capillary pressure at critical liquid saturation and n_{pg} is an exponential factor. $(p_c)_{S_{lc}}$ of 0.5 bars and n_{pg} of 1.5 are used based on lab experiment conducted on a tight rock with similar critical liquid saturation [47]. Figure 4.3 illustrates the resulting capillary pressure curve as a function of gas saturation. Capillary pressure curve is used as an input parameter for CO_2 EOR dynamic simulation.

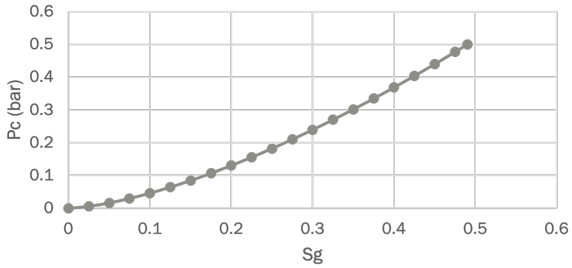

Figure 4.3: Capillary pressure versus gas saturation

4.2.4. Reservoir Fluid Properties

Reservoir and injected fluids characterization is a key aspect in any reservoir simulation study. Since majority of the used geological and dynamic reservoir data are based on COSTA model, it would be preferred to proceed with COSTA model reservoir fluid characterization. Unfortunately, COSTA model uses black oil run that does not include any reservoir fluid composition and does not account for interaction between different components during CO_2 injection. Instead, compositional run is needed to capture the dynamic changes during CO_2 EOR simulation. Therefore, an analogue with similar oil gravity of 42 API as COSTA model is used for fluid characterization. The used analogue is from Bakken oil formation that is a tight formation with similar oil gravity where different studies took place on CO_2 EOR [12]. Table 4.2 includes 7 pseudo components in reservoir oil with its composition, critical properties, molecular weight, acentric factor and parachor values. Moreover, binary interaction coefficients for oil components listed in table 4.3 is used from the same Bakken formation study [12]. Lastly, 0.00864 m^2/d CO_2 diffusion coefficient is included as part of the dynamic simulation input parameters since molecular diffusion is a key mechanism in huff'n'puff CO_2 injection in tight reservoirs.

Table 4.2: Reservoir crude oil compositional data for the Peng–Robinson EOS [12]

Component	Mole (%)	Pc (bar)	Tc (K)	Vcrit (m3/kg)	MW (g/gmol)	w	Parachor
CO_2	0.0002	73.8	304.2	0.0021	44.01	0.225	78
N_2	0.0004	33.9	126.2	0.0032	28.01	0.04	41
CH_4	0.25	46.0	190.6	0.0062	16.04	0.008	77
C_2-C_4	0.22	43.1	363.3	0.0046	42.82	0.1432	145.2
C_5-C_7	0.2	34.2	511.56	0.0040	83.74	0.2474	250
C_8-C_9	0.13	31.3	579.34	0.0038	105.91	0.2861	306
C_{10+}	0.1994	21.9	788.74	0.0046	200	0.6869	686.3

Table 4.3: Binary interaction parameters for oil components [12]

Component	CO_2	N_2	CH_4	C_2-C_4	C_5-C_7	C_8-C_9	C_{10+}
CO_2							
N_2	-0.02						
CH_4	0.103	0.031					
C_2-C_4	0.1327	0.0784	0.0078				
C_5-C_7	0.1413	0.1113	0.0242	0.0046			
C_8-C_9	0.15	0.12	0.0324	0.0087	0.0006		
C_{10+}	0.15	0.12	0.0779	0.0384	0.0169	0.0111	

5

Assessment of CO_2 EOR Performance

In this chapter, a comprehensive evaluation of CO_2 EOR performance in tight oil reservoir with a huff'n'puff scheme will be presented and discussed utilizing numerical simulation. Initially, a base case scenario will be used as a starting point, where the need of primary recovery period will be assessed in order to set an optimum starting time for CO_2 EOR. A discussion on the ongoing physical mechanisms that take place at each stage during the CO_2 EOR process will follow. Then, a detailed sensitivity study will be presented and discussed including many parameters that can have an influence on CO_2 EOR performance and resulting oil recovery. Lastly, an optimum case will be presented based on the findings from the sensitivity study. The optimum case objective is to generate the highest oil recovery within a projected lifetime of 20 years.

5.1. Base Case

In order to initiate the evaluation of CO_2 EOR performance, a scenario is chosen as a base case. The parameters used for this base case are presented in table 5.1. All rates that are presented and discussed are at surface conditions. In this base case, CO_2 EOR will commence from the original reservoir conditions with no primary recovery period. The simulation results of base case are illustrated in figure 5.1. Results of oil production rate and cumulative oil production show that oil recovery is higher at earlier periods of CO_2 EOR and relatively declines with time. This is because of the challenge to produce oil in further areas from the well location in this tight reservoir at later times. As for gas production, it accounts for both injected CO_2 reproduction and solution gas. Eventhough CO_2 injection is introduced, reservoir pressure experiences a decline with time due to the production of both oil and injected CO_2.

Table 5.1: Model input parameters for base case

Parameter	**Value**
Lifetime, years	20
Production bottomhole pressure constraint, bars	100
Injection rate, mm^3/d	0.025
Injection time per cycle, days	60
Soaking time per cycle, days	30
Production time per cycle, days	60
Number of cycles	49

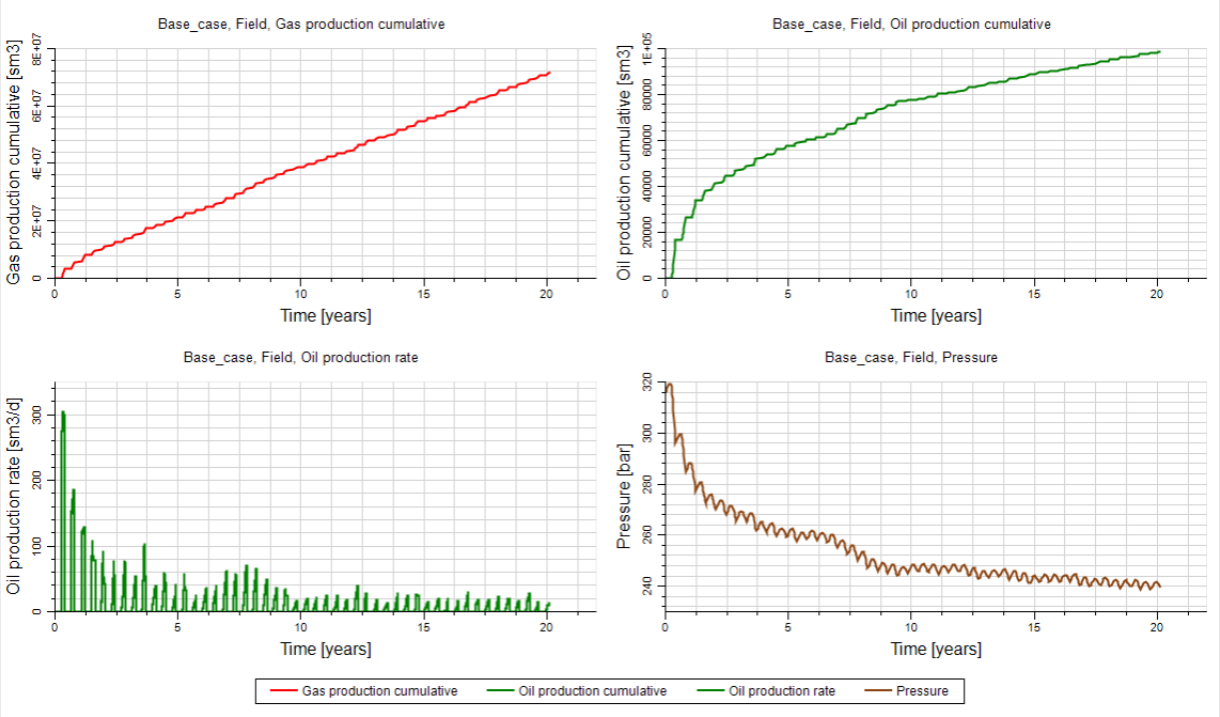

Figure 5.1: Simulation Results of base case

5.1.1. Primary Recovery

In order to assess the added value of EOR in terms of oil recovery, it has to be compared to natural depletion case. In figure 5.2, cumulative oil production of both cases are shown highlighting additional gain from CO_2 EOR at the end of lifetime. However, it can be observed that natural depletion case results in much higher oil recovery at the first two years of the simulation compared to the base case, and then starts to plateau with no oil production for the remaining years. This indicates that at the first two years, the reservoir has the ability to produce naturally at the bottomhole pressure constraint with more oil gain than the base case. This is attributed to the initial reservoir pressure that can maintain oil production for the first two years with no pressure support. Including CO_2 EOR results in injection and shut-in periods that would reduce cumulative oil production. In addition, production of injected CO_2 back would hinder oil production due to the effect of slippage [4].

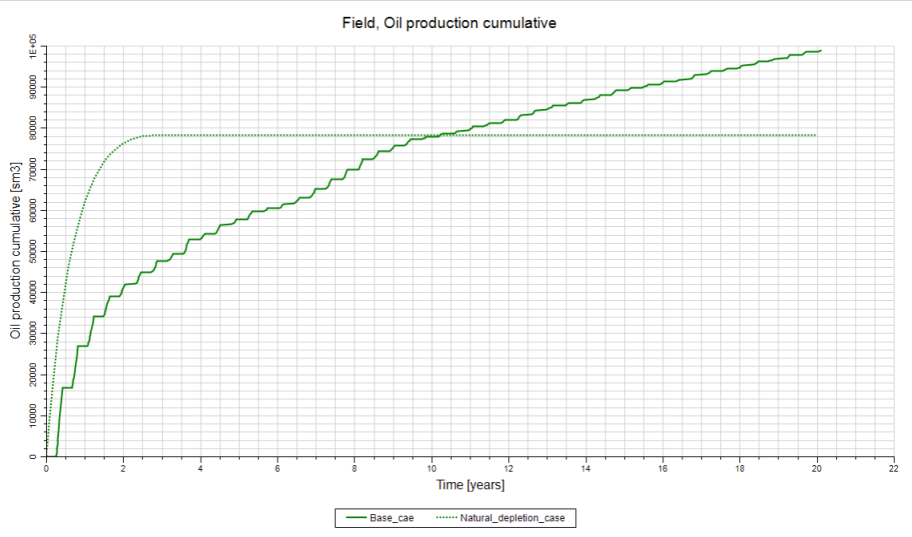

Figure 5.2: Cumulative oil production of base case and natural depletion case

A new case is tested to shift the starting time for CO_2 EOR by introducing a primary recovery period at the first 600 days. This would reduce the number of cycles in the new case from 49 to 45 cycles. The resulting cumulative oil production in figure 5.3 shows that introducing a primary recovery period prior to CO_2 EOR would yield the highest oil recovery. Therefore, this will become the new base case and it will be called the modified base case.

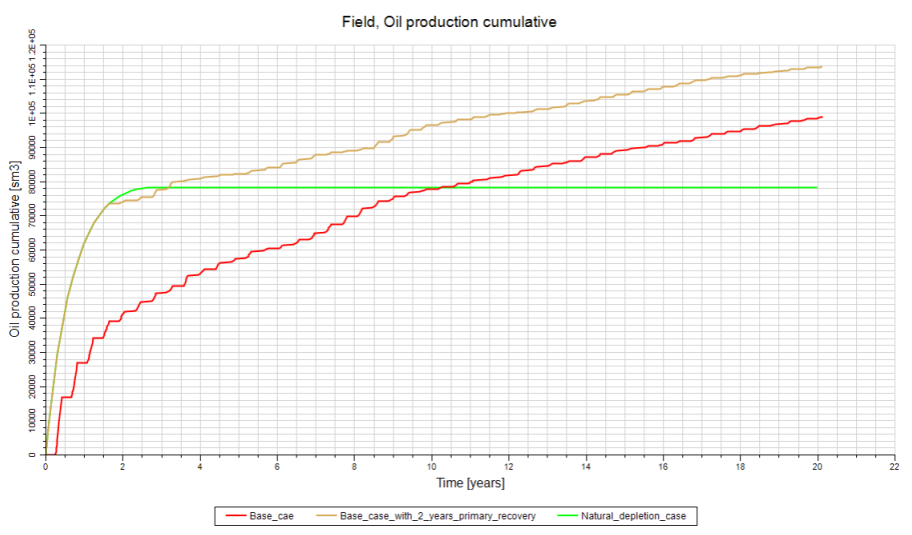

Figure 5.3: Cumulative oil production with primary recovery period

As observed, it is highly important to evaluate and assess the optimum starting time for CO_2 EOR to obtain highest oil recovery. Including a primary recovery period in the reservoir development plan would not only result in higher oil recovery, but also lower CO_2 utilization by reducing the number of cycles. The time can vary depending on reservoir conditions and bottomhole pressure constraints. It can also be influenced by the pressure drawdown generated by low permeability in targeted zones depending on reservoir heterogeneity and well contact area.

5.1.2. Injection Stage

After including primary recovery period before CO_2 EOR, the reservoir will experience a pressure decline as shown in figure 5.4 due to oil withdrawal. Once the first injection cycle of CO_2 is performed, a pressure build up occurs. It is observed that the highest pressure build up is located near the well location. This is due to the low reservoir permeability that limits the flow of CO_2 and pressure propagation into the entire sector model in order to achieve equilibrium. CO_2 transports in the oil reservoir via two different flow mechanisms: mechanical dispersion and molecular diffusion. The difference between the two mechanisms is that CO_2 will spread into the reservoir due to pressure gradient in mechanical dispersion mechanism, while in molecular diffusion it will spread due to concentration gradient. Since this is a tight reservoir, mechanical diffusion would be the dominant transport mechanism. [19] divided CO_2 huff'n'puff transport into flow sweep and diffusion sweep. Flow sweep refers to CO_2 movement under the influence of pressure difference, and diffusion sweep refers to the CO_2 movement under the influence of diffusion.

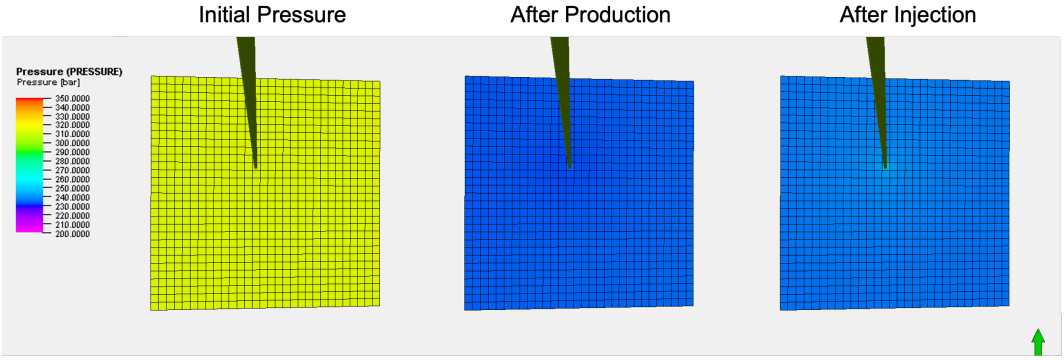

Figure 5.4: Pressure map from initial time until first injection cycle

Once CO_2 comes into contact with the reservoir oil, it will dissolve in it. With time, a reduction in interfacial tension between CO_2 and oil will occur since the injection is under miscible conditions. The influence of those two EOR mechanisms will be discussed in Production Stage section. Figure 5.5 highlights the injected gas saturation distribution in the reservoir model post first injection cycle. It can be observed that injected gas saturation is concentrated around the well, especially in the upper layers. Additional cross-section plot of reservoir permeability is shown on the same figure to correlate gas saturation distribution with reservoir permeability. The reasons behind having higher gas saturation in the upper layers are reservoir heterogeneity and buoyancy forces. Upper reservoir layers have higher permeability values resulting in easier injection pathways and higher gas saturation. Buoyancy forces are also acting on injected CO_2 at its supercritical state due to the difference in densities with reservoir oil leading to CO_2 upward movement and accumulation in the upper interval.

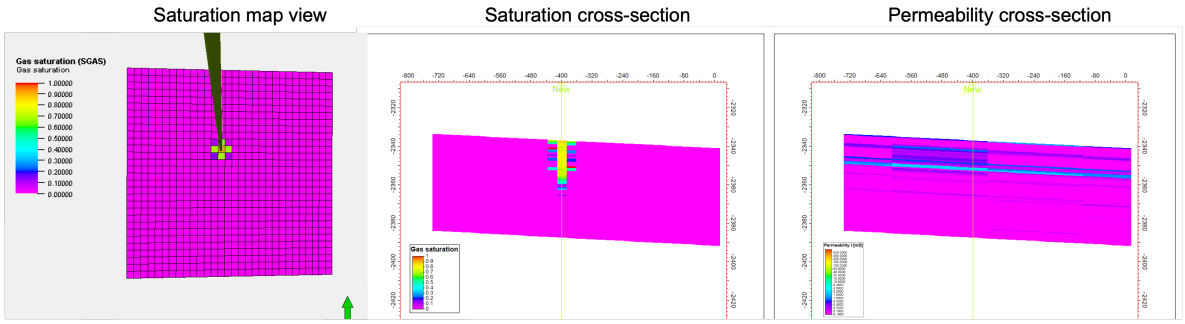

Figure 5.5: Gas saturation map after first injection period

5.1.3. Soaking Stage

In the huff'n'puff scheme, each injection cycle is followed by a soaking period. The objective of the soaking period is to allow for more time for CO_2 to transport deeper into the formation mainly through molecular diffusion. This would be dependent on CO_2 diffusivity that will be discussed in the sensitivity study section. The additional time for CO_2 transport would allow it to come into contact with larger volume of reservoir oil, leading to more CO_2 dissolution and higher oil recovery during production. This would be tested and discussed in soaking time sensitivity study section. The changes in injected gas saturation shown in figure 5.6 illustrates CO_2 transport after soaking period. The high gas saturation areas before soaking are distributed to new areas after soaking. This means that diffusion is taking place during soaking, where gas is moving due to CO_2 concentration gradient.

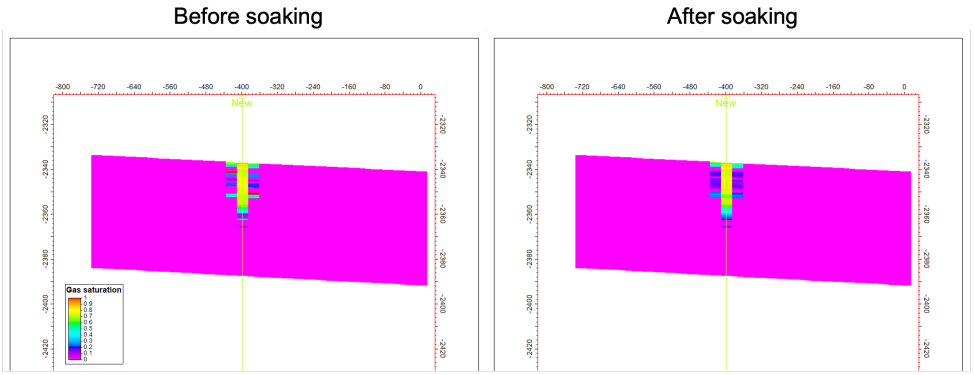

Figure 5.6: Gas saturation map after first soaking period

In terms of pressure changes, the reservoir pressure doesn't experience noticeable changes during soaking periods as shown in figure 5.7. However, the pressure is distributed during soaking period in order to achieve pressure equilibrium within the reservoir as can be seen in figure 5.8.

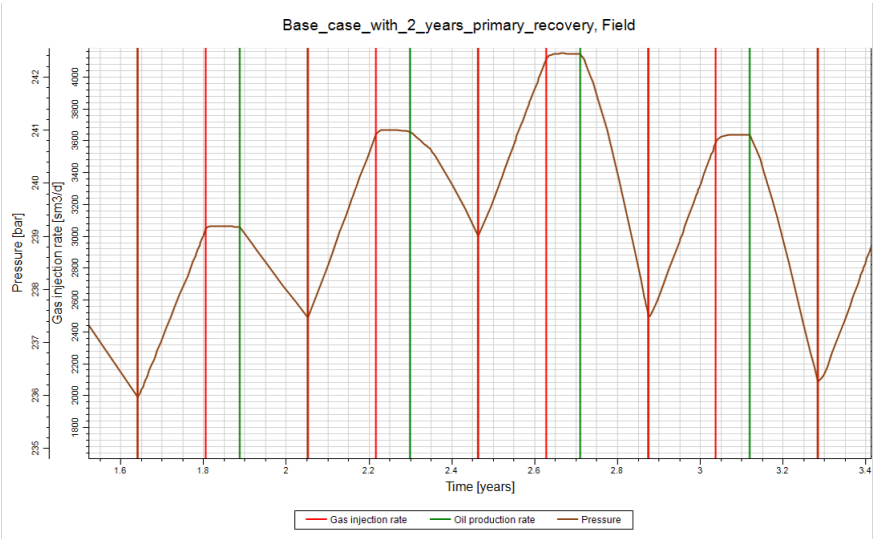

Figure 5.7: Pressure profile in huff'n'puff cycles

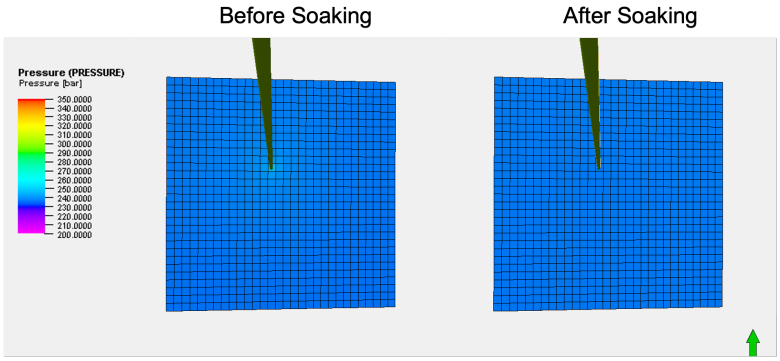

Figure 5.8: Pressure map before and after soaking

5.1.4. Production Stage

The last stage of each huff'n'puff cycle is production. During production stage, both oil and CO_2 would be produced. The production in CO_2 EOR relies on many advantages over natural production in primary recovery. One advantage is the reservoir pressure buildup generated during CO_2 injection in each cycle. Dissolved CO2 in oil during injection and soaking is able to generate effect of dissolved gas drive [16]. This drive would allow for higher oil recovery compared to natural production since it offers higher pressure gradient between reservoir and bottomhole pressure during production. Another advantage is the improved oil mobility after CO_2 dissolution. The dissolved CO_2 in oil will result in swelling of reservoir oil and reduction in its viscosity leading to an improvement in mobility during production resulting in higher oil recovery.

The amount of CO_2 dissolution is dependent on two controlled parameters: dissolution rate and time. Injection pressure has an influence on dissolution rate, as higher injection pressures would lead to higher dissolution rate of CO_2 in oil [11]. As for dissolution time, it is controlled by the injection and soaking durations. The influence of time on dissolution will be verified and discussed in the sensitivity study section. From the modified base case simulation results, the amount of CO_2 dissolution can be inferred from GOR plot in figure 5.9. The GOR spikes at the beginning of each production cycle indicate that not all injected CO_2 had dissolved. In fact, some of the injected CO_2 is reproduced in the form of free gas. Based on that, the production period can be divided into two main parts: free gas production with some oil, and oil with dissolved gas production. The free and dissolved gas production can also be observed by the changes in gas saturation after the first production cycle in figure 5.10. Having higher dissolution would reduce the amount of free gas around the well and enhance oil production. Therefore, CO_2 dissolution plays a major role in not only oil recovery, but also CO_2 utilization.

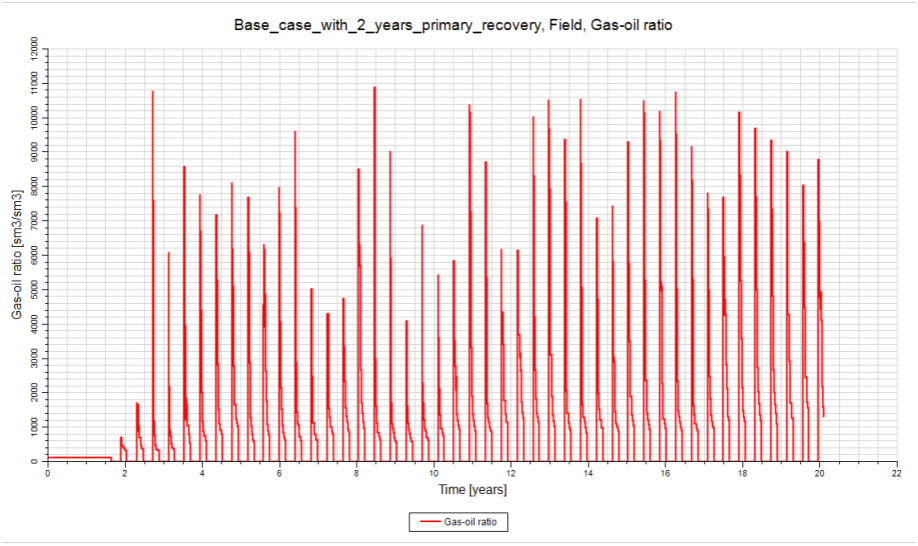

Figure 5.9: Production gas-oil ratio plot

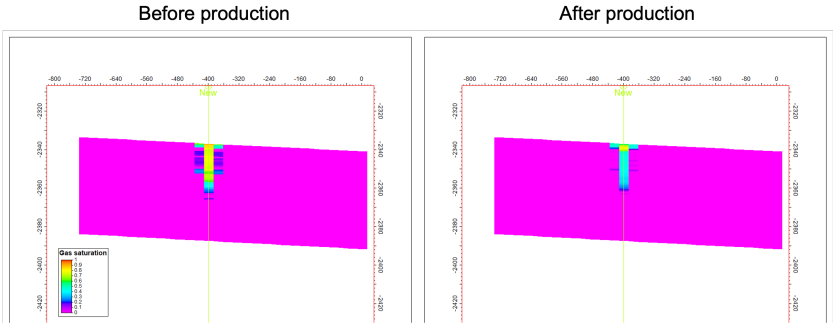

Figure 5.10: Gas saturation map after first EOR production period

In the huff'n'puff scheme, not all injected CO_2 is reproduced. In fact, a significant volume of injected CO_2 is stored in the reservoir. Figure 5.11 highlights the difference between cumulative gas injection and production, showing a higher cumulative gas injection during the 20 years lifetime. This is with the inclusion of solution gas production with CO_2 as a total gas production.

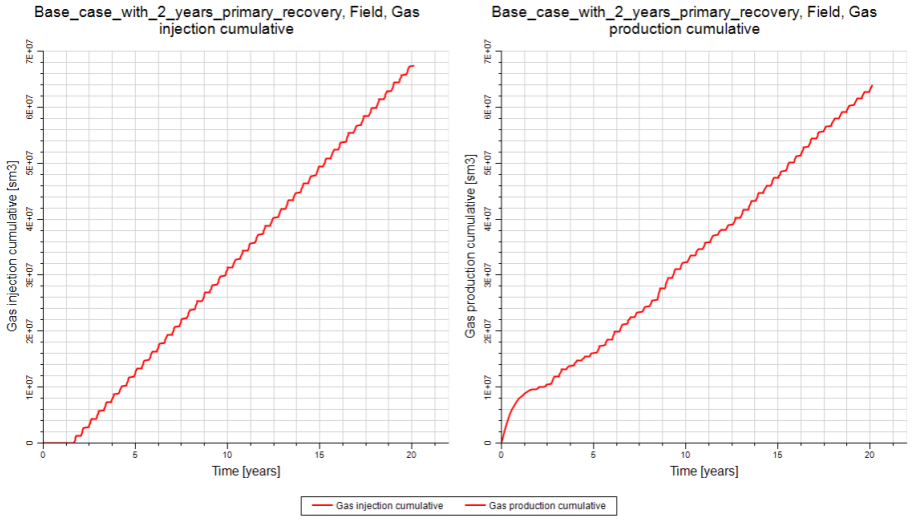

Figure 5.11: Cumulative gas injection and production

5.2. Sensitivity Study

In this section, a detailed evaluation of the impact of different parameters on the cumulative oil production is presented and discussed. It also includes a description of main mechanisms leading to the resulting impact. The strategy is to build an optimum CO_2 EOR huff'n'puff case based on the findings from each sensitivity parameter and include it in the next case. Each part would end with a comparison with any previous studies done in terms of numerical simulation. The starting case would be the modified base case that includes primary recovery period.

5.2.1. Injection Rate

To evaluate injection rate, the same input parameters presented in table 5.1 are used, with the reduction of number of cycles to 45 due to the addition of a primary recovery period at the beginning. Six different injection rates are tested: 0 mm^3/d, 0.01 mm^3/d, 0.025 mm^3/d, 0.05 mm^3/d, 0.075 mm^3/d, 0.1 mm^3/d. Cumulative oil production results in figure 5.12 show that an injection rate of 0.025 mm^3/d would yield the highest oil recovery at the end of the lifetime. With a closer look into the cumulative oil production results, figure 5.13 presents the difference in cumulative oil production between different injection rates. Based on the results, an increase in injection rate would lead to a higher cumulative oil production, until an optimum injection rate is reached. At injection rates higher than the optimum rate, the cumulative oil production would decline.

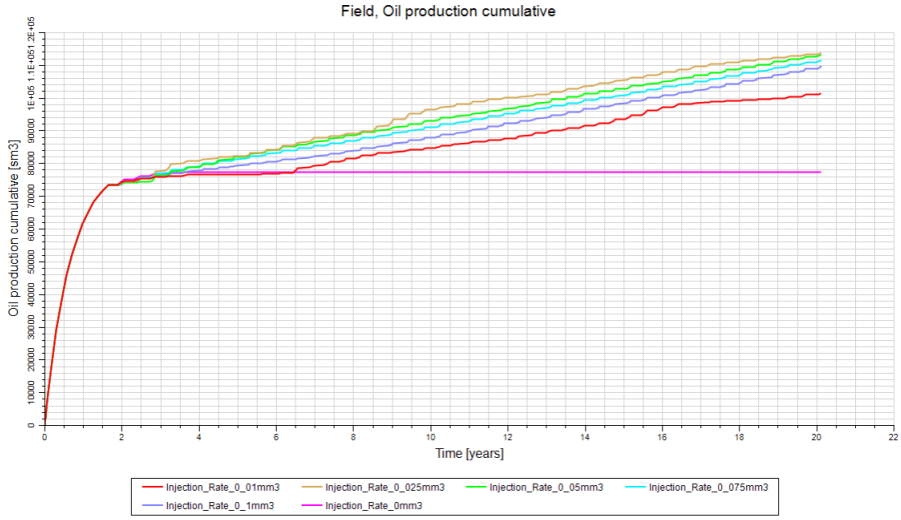

Figure 5.12: Cumulative oil production plots at different injection rates

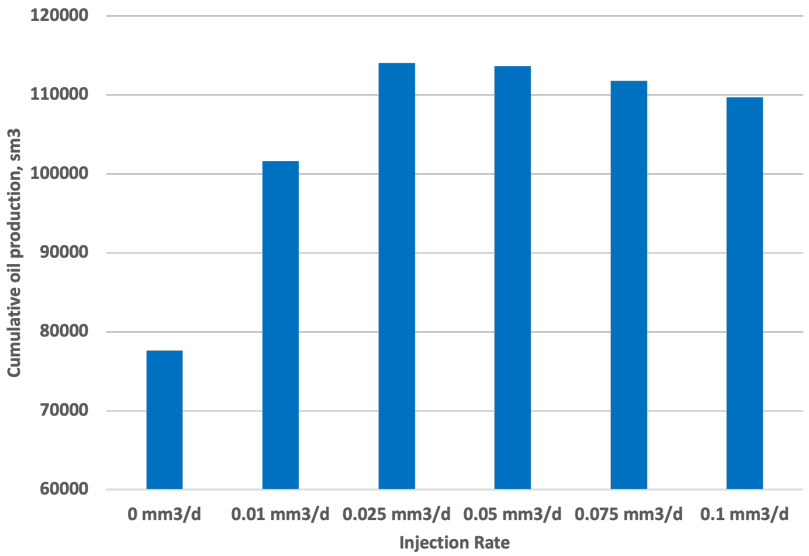

Figure 5.13: Cumulative oil production at different injection rates

To understand the reasons behind the changes in cumulative oil production at different injection rates, one must look at the physical influence of injection rate on CO_2 EOR mechanisms. First, the increase in injection rate would lead to an increase in injection pressure. As discussed earlier, there is a direct relation between injection pressures and dissolution rates. This means that the increase in injection pressure would have a positive influence on dissolution rate, which can lead to higher oil recovery. However, this would add value to a certain limit because of CO_2 transport limitation in tight reservoirs. The high dissolution rate would not be beneficial once CO_2 exposed area in the reservoir is fully saturated. This would lead to an accumulation of free gas around the well in the cases of high injection rates, leading to higher gas production as shown in figure 5.14. The high gas production can hinder oil production as discussed previously. Since the dominant CO_2 transport mechanism is molecular diffusion in tight reservoirs, higher injection pressures would have a minor impact on CO_2 exposure area within the reservoir. Diffusion coefficient and injection and soaking periods are the main factors controlling this exposure area of CO_2 in a given reservoir conditions. This will be verified and discussed in the sensitivity study. Therefore, for a given injection and soaking time, there

would be an optimum injection rate to yield the highest oil recovery.

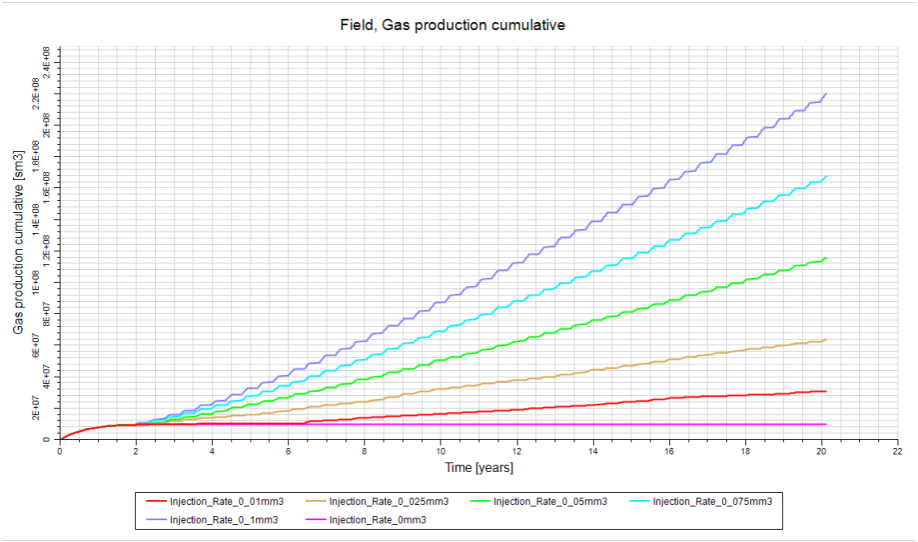

Figure 5.14: Cumulative gas production at different injection rates

Comparing the findings with previous work done in the literature, four different studies were conducted on the influence of injection rates on oil recovery using numerical simulation. Two of those studies reached to a similar conclusion that oil recovery would increase with the increase in injection rate until an optimum injection rate is achieved [48][42]. The third study concluded that once the optimum injection rate is achieved, higher injection rates would not result in any oil gain nor decline [23]. The last study concluded that the injection rate is always directly related to oil recovery [39].

5.2.2. Injection Time

Building on the findings from injection rate sensitivity, injection time is evaluated by testing 7 different injection durations per cycle: 10 days, 30 days, 60 days, 90 days, 120 days, 150 days and 180 days. In this test, production and soaking periods are maintained the same while changing total lifetime period depending on injection time in each scenario. This is to have comparable results and conclusive understanding of the influence of injection time while keeping other parameters constant. The test is performed using the same modified base case parameters while using the optimum injection rate of 0.025 mm^3/d based on previous findings. Simulation results of cumulative oil production in figures 5.15 and 5.16 show that the highest oil recovery will be achieved with an injection time of 150 days. Results show that oil recovery increases with longer injection time until an optimum injection time is reached. Cumulative oil production would decline at higher injection times as can be seen in 180 days injection scenario.

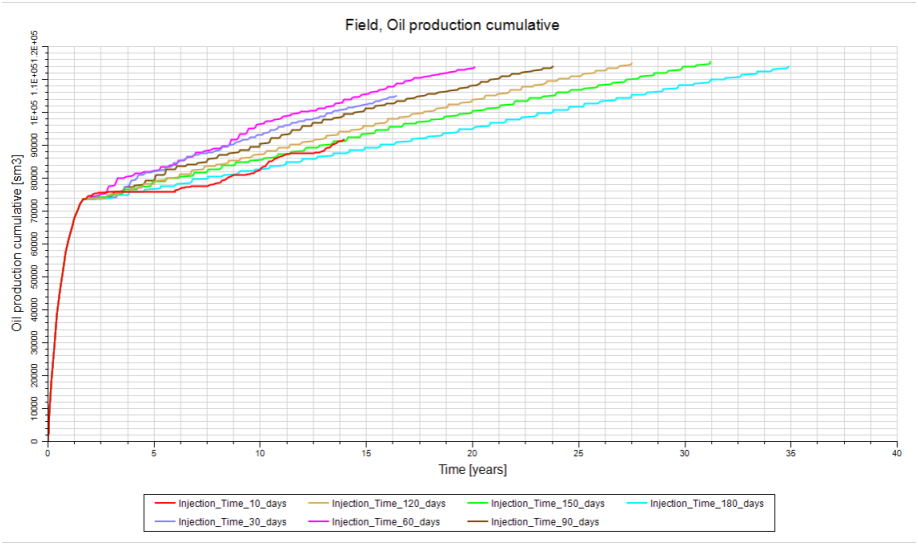

Figure 5.15: Cumulative oil production plots at different injection durations

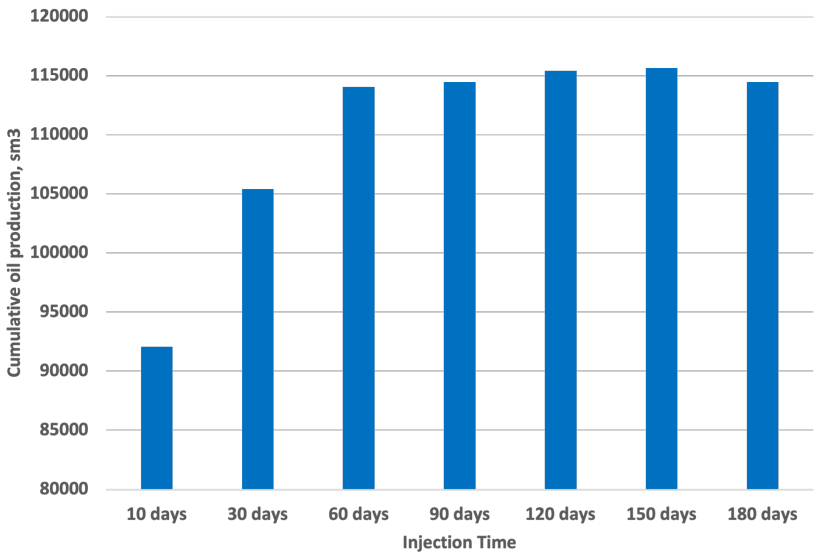

Figure 5.16: Cumulative oil production at different injection durations

The changes in cumulative oil production at different injection times can be explained by several CO_2 EOR mechanisms. One is the reservoir pressure increase due to higher injected CO_2 volume with longer injection duration at the same injection rate. As discussed previously, the increase in pressure will result in higher dissolution rate of CO_2 in oil leading to higher oil recovery during production stage. Similar to the understanding in injection rate sensitivity study, higher CO_2 injected volumes can be beneficial up to a certain optimum value in a given reservoir conditions. Beyond this optimum volume, free gas will hinder oil production leading to a decline in cumulative oil production. Another mechanism that enhances oil recovery with higher injection times is longer CO_2 transport and dissolution time. Figure 5.17 shows gas saturation distribution comparison after first injection cycle between 10 days and 150 days injection time cases. This illustrates the influence of injection time on CO_2 transport contacting larger area of the reservoir leading to higher recovery. Therefore, for a given injection rate, there would be an optimum injection time to yield the highest oil recovery. In this case, 150 days scenario resulted in the highest oil recovery, but with a longer lifetime. To determine the optimum injection time scenario with respect to CO_2

EOR lifetime, figure 5.18 is presented to highlight incremental oil gain per day for the additional project lifetime. It can be concluded that 60 days injection time would be the optimum injection time with respect to oil gain per day. At injection time scenarios higher than 60 days, additional oil gain per day is very low making it economically unfeasible.

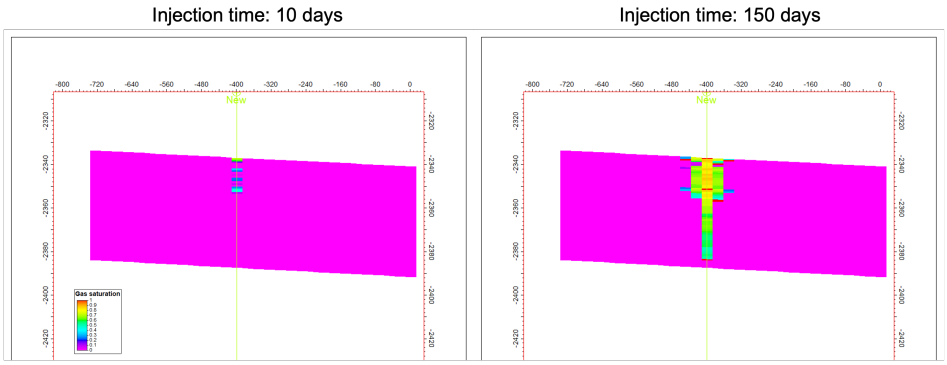

Figure 5.17: Gas saturation cross section map after first injection cycle

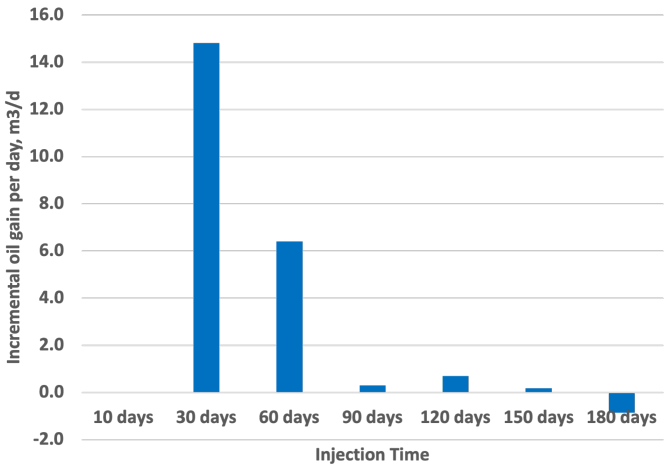

Figure 5.18: Incremental oil gain per day for the additional lifetime needed

Comparing the findings with previous work done in the literature, three different studies were conducted on the influence of injection time on oil recovery using numerical simulation. Two of those studies reached to a similar conclusion that oil recovery would increase with the increase in injection time until an optimum injection time is achieved [48][42]. The third study concluded that the injection time is always directly related to oil recovery since it leads to higher injected volumes [23].

5.2.3. Injection Time at Constant Volume

During the evaluation of injection time on oil recovery, another parameter is changing alongside time which is injection volume. Another approach is followed where injection volume is kept constant by changing injection rate to observe the influence of injection time and confirm previous findings. Four different cases are tested with a fixed injection volume of 3.75 mm^3 per cycle. The cases are shown in table 5.2 with their corresponding injection times and rates. The resulting cumulative oil production for these cases are shown in figures 5.19 and 5.20 with a direct relation between injection time and oil recovery. There is a realized cumulative oil production increase of 7% when comparing first and last case. Thus, higher injection time with fixed injection volume would lead to higher oil recovery.

Table 5.2: Different injection cases at fixed injection volume

Case	Injection Time (days)	Injection Rate (mm^3/d)
1	37.5	0.1
2	50	0.075
3	150	0.025
4	375	0.01

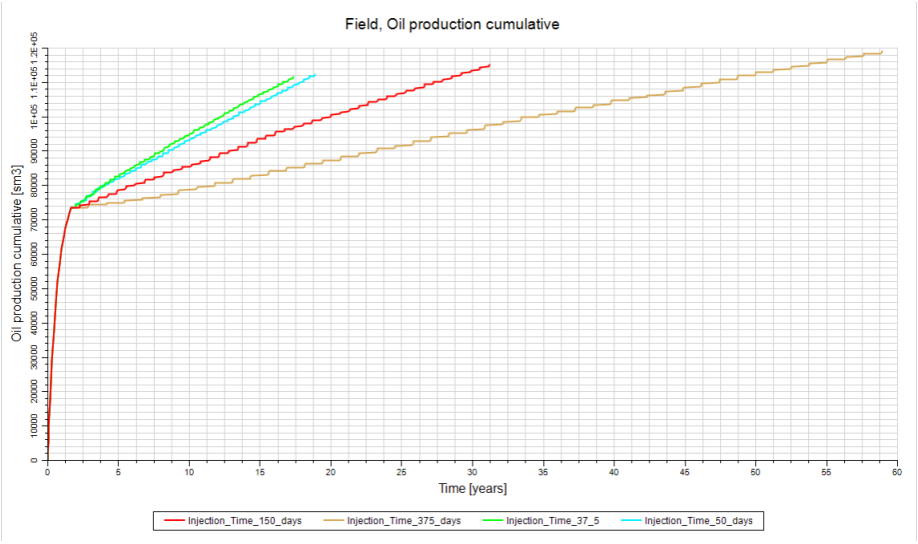

Figure 5.19: Cumulative oil production plots at different injection durations with fixed volume

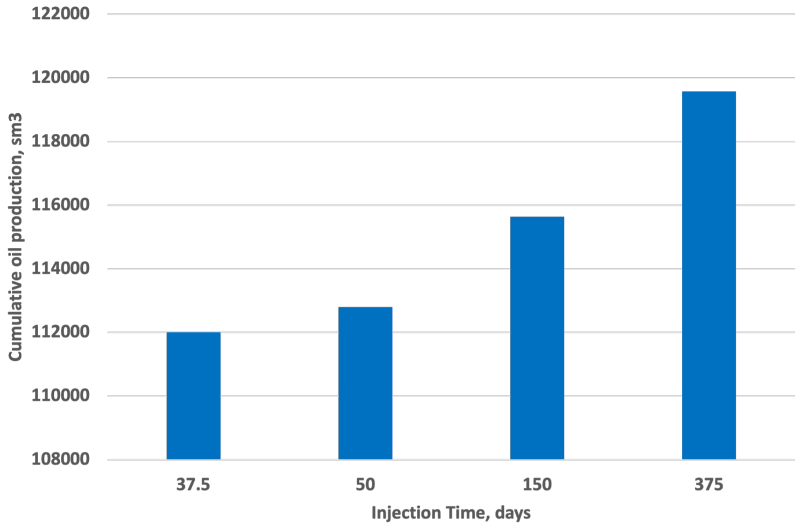

Figure 5.20: Cumulative oil production at different injection durations with fixed volume

The influence of injection time on oil recovery confirms previous findings. Longer injection time allows for more CO_2 transport and dissolution time as indicated by cumulative gas production in figure 5.21. Lower gas production with longer injection time is a result of higher CO_2 dissolution and lower free gas volume to

be reproduced. Although injection rate is reduced at higher injection times, the impact of lower pressure support on dissolution rate is insignificant. This indicates that time factor has a higher influence on oil recovery than injection rate in tight reservoirs. This approach of evaluating injection time using a fixed injected volume on CO_2 EOR has not been covered in previous CO_2 EOR numerical studies on tight oil reservoirs.

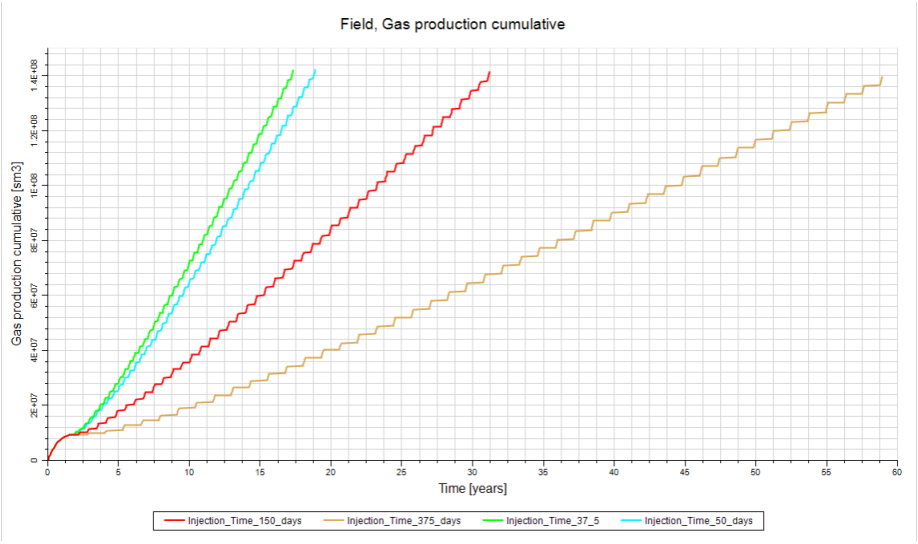

Figure 5.21: Cumulative gas production plots at different injection durations with fixed volume

5.2.4. Soaking Time

One of the key parameters in CO_2 EOR huff'n'puff is soaking time. In this study, soaking time is evaluated using the modified base case including the optimum injection rate and time scenario from previous findings. Six different soaking times are tested: 0 days (without soaking), 7 days, 10 days, 30 days, 90 days and 120 days. Production and injection periods are maintained the same while changing the total lifetime period depending on soaking time in each scenario in order to have have comparable results and conclusive understanding on the influence of soaking time while keeping other parameters the same. Cumulative oil production results in figures 5.22 and 5.23 show that the highest oil recovery is achieved with a soaking time of 90 days. Results show that oil recovery increases with longer soaking time until an optimum time is reached. Once soaking time exceeds the optimum value, cumulative oil would decline, as can be seen in 120 days soaking scenario.

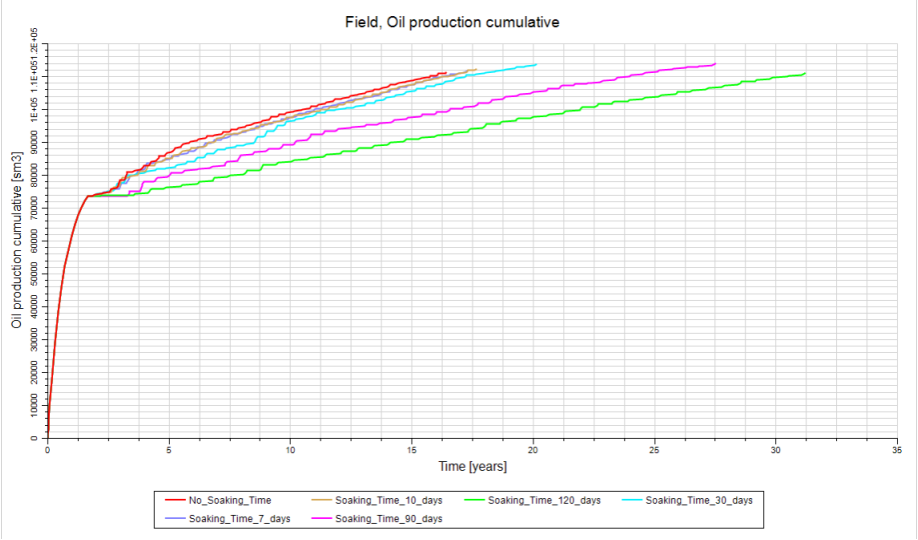

Figure 5.22: Cumulative oil production plots at different soaking periods

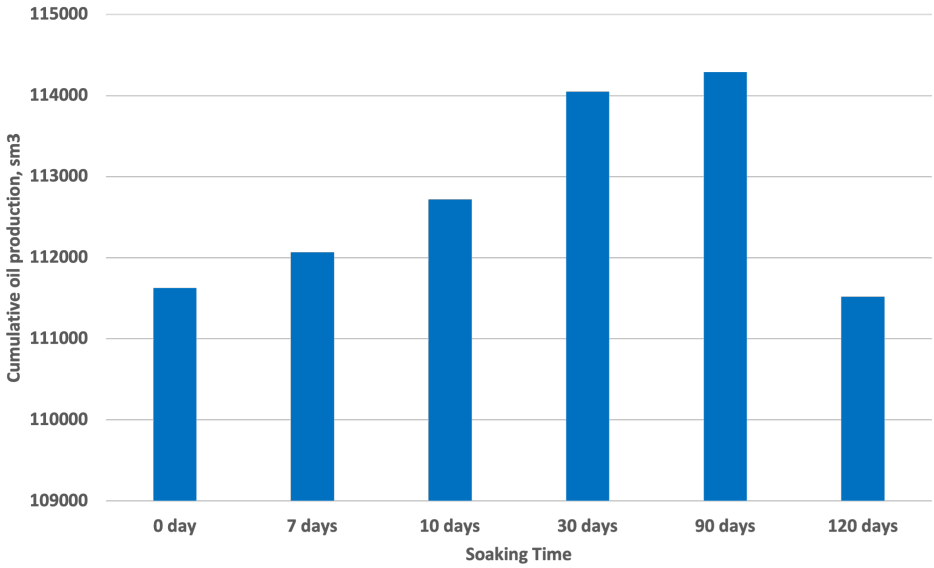

Figure 5.23: Cumulative oil production at different soaking periods

The influence of soaking during CO_2 EOR huff'n'puff has been discussed in the soaking stage section. Cumulative gas production results in figure 5.24 confirm the impact of soaking through diffusion and dissolution as longer soaking time would lead to lower cumulative gas production. Nevertheless, the relation between soaking time and oil recovery is not always proportional. Too long soaking time would lead to a reduction in injected CO_2 concentration around the well that will be insufficient for oil displacement during production stage. This is observed in gas saturation distribution before and after soaking in figure 5.25 for 120 days soaking time case. Even though the highest oil recovery is achieved with 90 days of soaking, the optimum soaking time is to be determined following the incremental oil gain per day for the additional project lifetime approach. Results in figure 5.26 show that 30 days soaking time would be the optimum time with respect to oil gain per day. At longer soaking time, additional oil gain per day is very low making it economically unfeasible. Therefore, a soaking time of 30 days is chosen as the optimum time in this study.

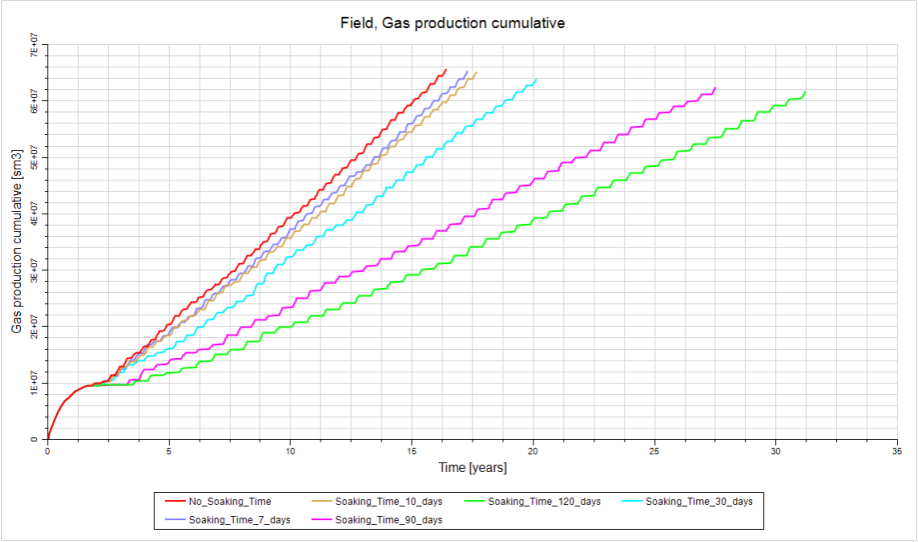

Figure 5.24: Cumulative gas production plots at different soaking periods

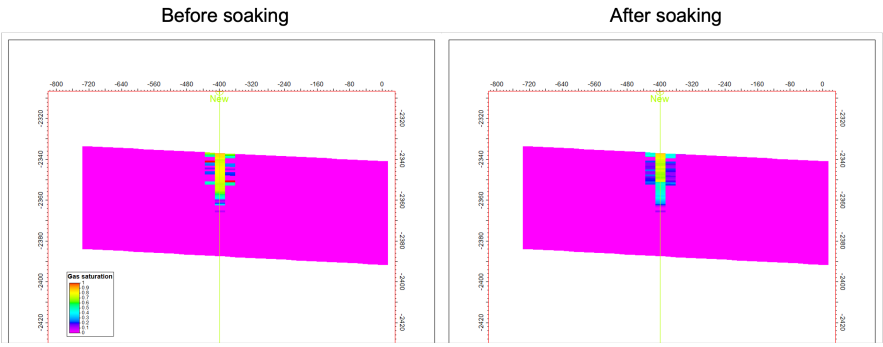

Figure 5.25: Gas saturation cross section map for 120 days soaking time case

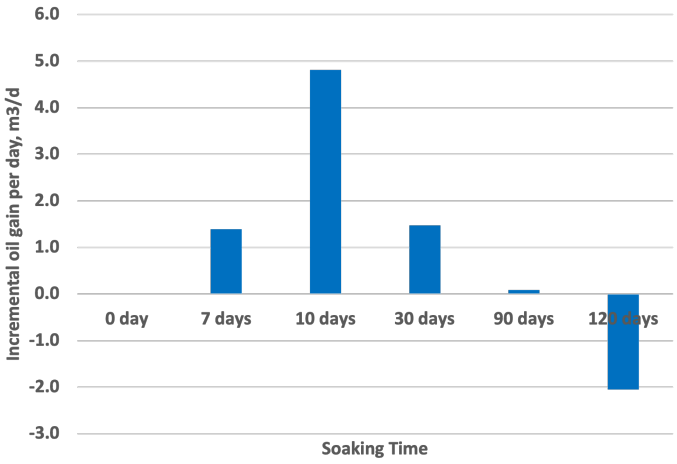

Figure 5.26: Incremental oil gain per day for the additional lifetime needed

Comparing the findings with previous work done in the literature, two different studies were conducted on

the influence of soaking time on oil recovery using numerical simulation. They both reached to a similar conclusion that oil recovery would increase with the increase in soaking time until an optimum time is achieved [48][42]. In both studies, 30 days is chosen as the optimum soaking time in agreement with this study as well.

5.2.5. Production Time and Number of Cycles

Another key parameters to be evaluated are production time and number of cycles. At a fixed project lifetime, number of cycles will be determined based on optimum injection, soaking and production periods for each cycle. In this study, production time and number of cycles are evaluated together at a fixed lifetime using optimum injection and soaking times from previous findings. Six different cases of production time and number of cycles are evaluated as listed in table 5.3 while maintaining a fixed project lifetime of around 20 years. Cumulative oil production results in figures 5.27 and 5.28 show that the highest oil recovery will be achieved with a production time of 150 days and 28 cycles. Results show that oil recovery increases with longer production time and less cycles until an optimum time is reached. At longer production period and less cycles, cumulative oil would decline as can be seen in case 6.

Table 5.3: Production time and number of cycles cases at a fixed project lifetime

Case	Production Time (Days)	Number of Cycles
1	30	56
2	60	45
3	90	37
4	120	32
5	150	28
6	365	15

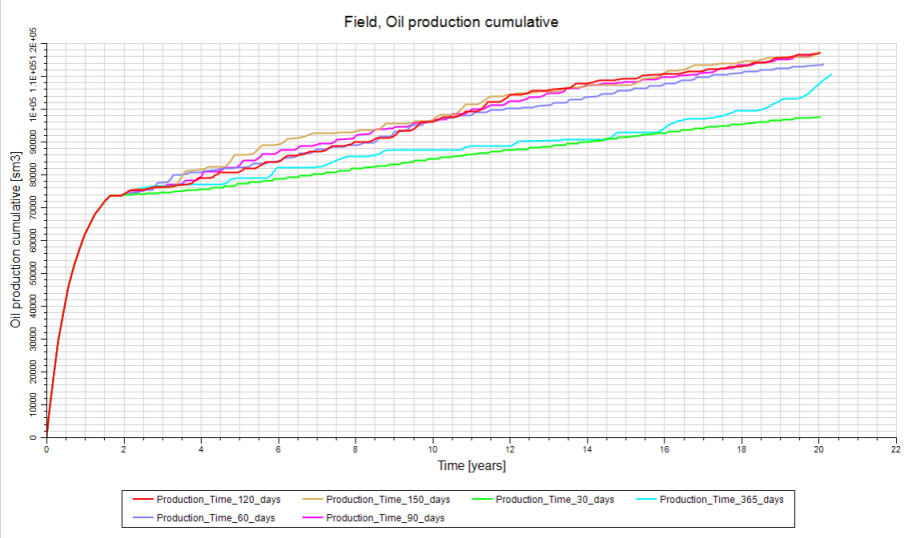

Figure 5.27: Cumulative oil production plots at different production periods

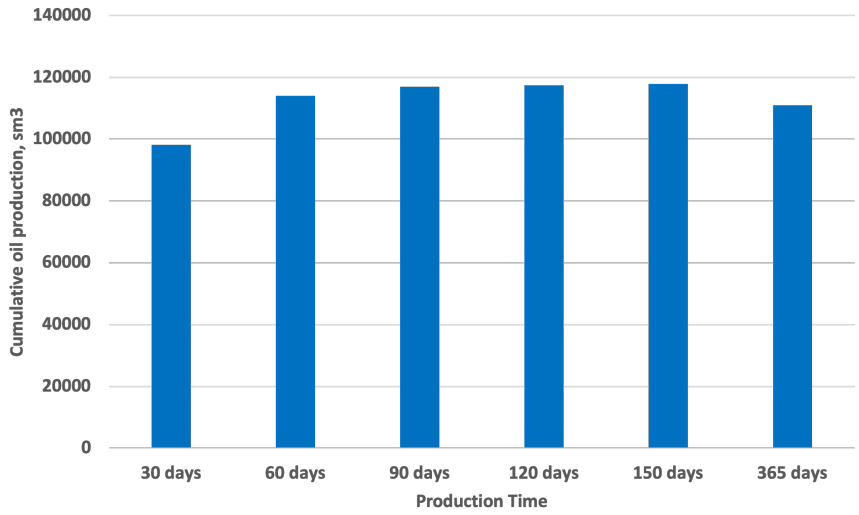

Figure 5.28: Cumulative oil production at different production periods

Results have to be analyzed from both production time and number of cycles aspects. For production time, extending the duration would give the ability to maximize oil recovery after each injection and soaking stage in each cycle. However, the increase in production time is beneficial up to a point where oil is unable to follow due to pressure drop requiring another cycle of injection. Therefore, there would be an optimum production time to achieve maximum oil recovery without non-flow time to be wasted. As for the number of cycles, it controls the amount of CO_2 injected volume and pressure support in a fixed lifetime. Having large number of cycles can lead to large injected CO_2 volume that will accumulate around the well and backflow during production stage hindering oil recovery as explained previously in injection rate and time sensitivity sections. On the other hand, having low number of cycles would lead to low CO_2 injected volume that will limit the swept area for oil recovery. Based on that, there would be an optimum number of cycles at a fixed lifetime to achieve highest oil recovery with an optimized CO_2 utilization. In this study, 150 days of production time with 28 cycles is considered optimum with respect to oil recovery and CO_2 utilization.

Comparing the findings with previous work done in the literature, two different studies were conducted on the influence of number of cycles on oil recovery using numerical simulation. First study concluded that oil recovery increases with more cycles reaching to an optimum of 3 cycles [12]. Similarly, the second study reached to the same conclusion that more cycles will result in higher oil recovery until reaching an optimum of 8 cycles [42]. Unlike this study, both previous studies did not test large number of cycles to identify its negative impact on oil recovery due to large injected CO_2 volume.

5.2.6. Incremental Increase in Injection Rates

Another test is performed to evaluate incremental injection rates at consecutive cycles in comparison to fixed injection rate. The test includes six different injection scenarios listed in table 5.4, where injection rates are divided on the total number of huff'n'puff cycles with an incremental sequence. Case 1 would represent fixed injection rate scenario. All cases start with the optimum injection rate of 0.025 mm^3/d identified during fixed injection rate assessment. Cumulative oil production results in figures 5.29 and 5.30 show that having incremental injection rate at consecutive cycles would result in higher cumulative oil production with an increase by 10% compared to fixed injection rate. Also, higher oil recovery would be achieved with more incremental injection rates cases.

Table 5.4: Different cases of incremental injection rates

Case	Injection Rate (mm^3/d)					
1	0.025					
2	0.025			0.05		
3	0.025		0.05		0.075	
4	0.025	0.05	0.075		0.1	
5	0.025	0.05	0.075	0.1	0.125	
6	0.025	0.05	0.075	0.1	0.125	0.15

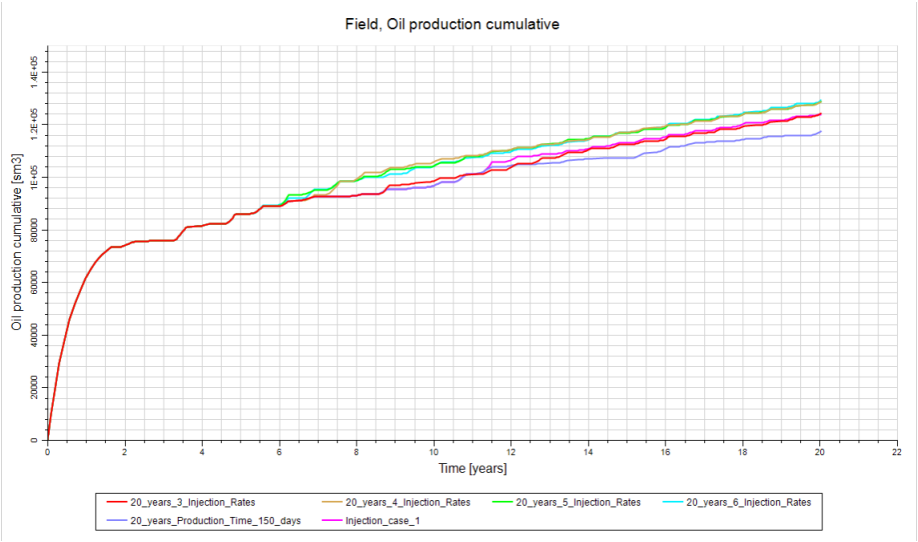

Figure 5.29: Cumulative oil production plots at different incremental injection rate cases

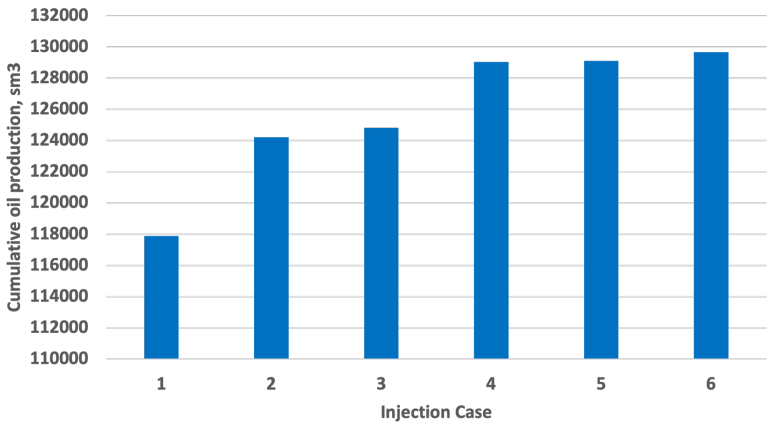

Figure 5.30: Cumulative oil production at different incremental injection rate cases

One aspect that controls oil recovery is pressure support. At a fixed injection rate, reservoir pressure is declining over time due to oil depletion and CO_2 backflow during production as can be observed in figure 5.31. On the other hand, reservoir pressure would increase over time in the case of incremental injection rates. This increase in reservoir pressure due to larger injection rate and volume would lead to higher

dissolution rate as discussed previously. Moreover, it would lead to an increase in advective flow due to pressure gradient in the reservoir leading to a deeper penetration of CO_2 at the later life of EOR. This would be highly beneficial to EOR process as it would manage to produce oil at further areas from the well at a later stage since majority of oil close to the well would be depleted at the early stage leading to higher oil recovery at the end of lifetime. This can be observed through gas saturation distribution comparison between case 1 and 6 at different stages in figure 5.32. Although it holds a great advantage on oil recovery, the use of incremental injection rates would lead to one disadvantage which is higher CO_2 utilization. More CO_2 would need to be injection and handled as well during reproduction. Thus, the optimization in field application of incremental injection rates has to be evaluated based on economic feasibility and CO_2 availability. Nevertheless, this study considers case 6 to be the optimum injection case because it yields the highest oil recovery. This approach of evaluating incremental injection rates at consecutive cycles has not been covered in previous CO_2 EOR numerical studies on tight oil reservoirs.

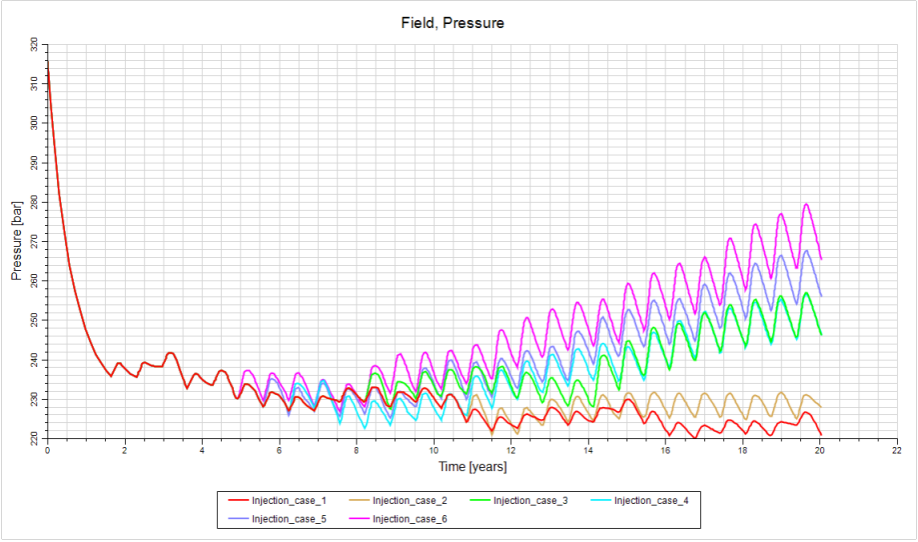

Figure 5.31: Reservoir pressure plots for different incremental injection rate cases

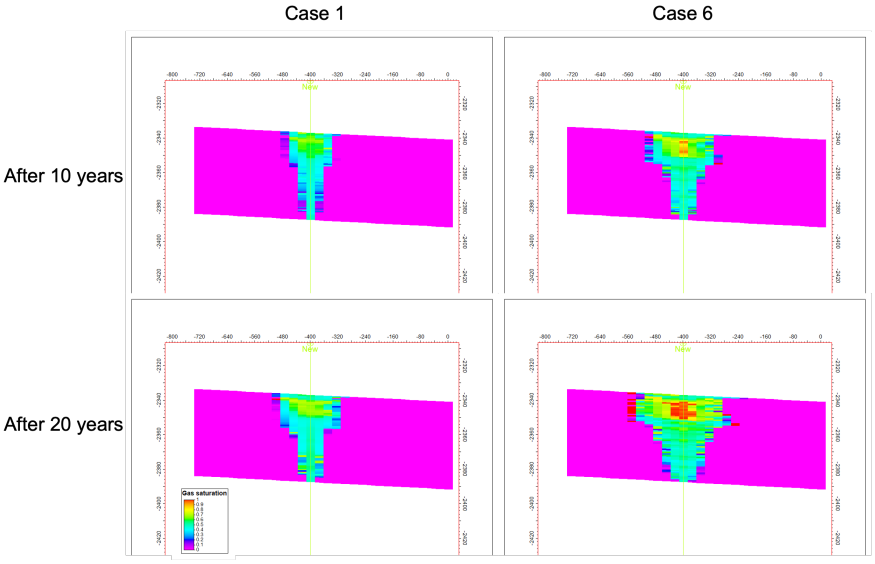

Figure 5.32: Gas saturation cross section map comparison between case 1 and 6

5.2.7. Diffusion Coefficient

A sensitivity test is performed to identify the influence of molecular diffusion mechanism on CO_2 EOR in tight oil reservoir. This is done through running 4 simulation cases with different diffusion coefficients: no diffusion, 0.00432 m^2/d, 0.00864 m^2/d and 0.0864 m^2/d. The modified base case is used with an update including findings from discussed sensitivity studies. Results of cumulative oil production presented in figure 5.33 show that higher diffusion coefficient would result in higher oil recovery. Figure 5.34 shows also the cumulative oil production at the end of project lifetime with the inclusion of cumulative gas production. It indicates that higher diffusion coefficient will not only increase oil recovery, but also reduce CO_2 backflow.

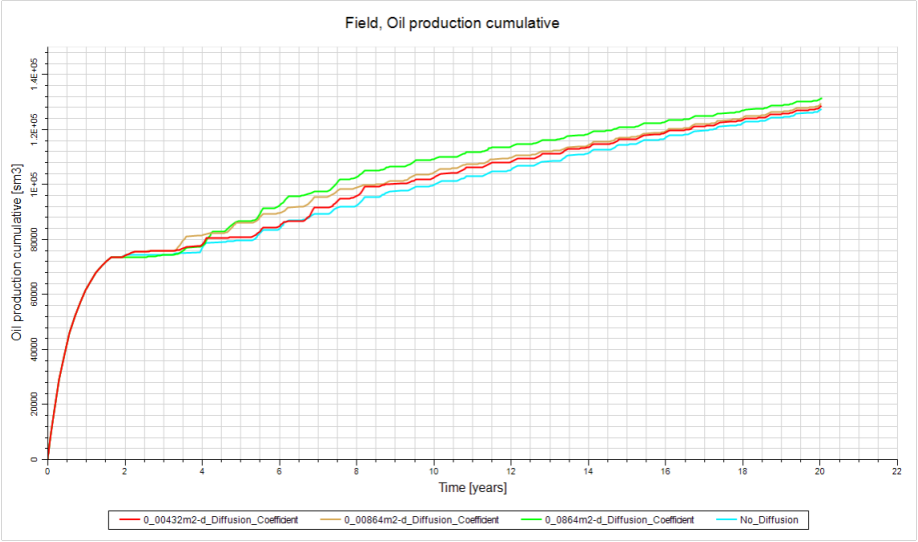

Figure 5.33: Cumulative oil production plots at different diffusion coefficients

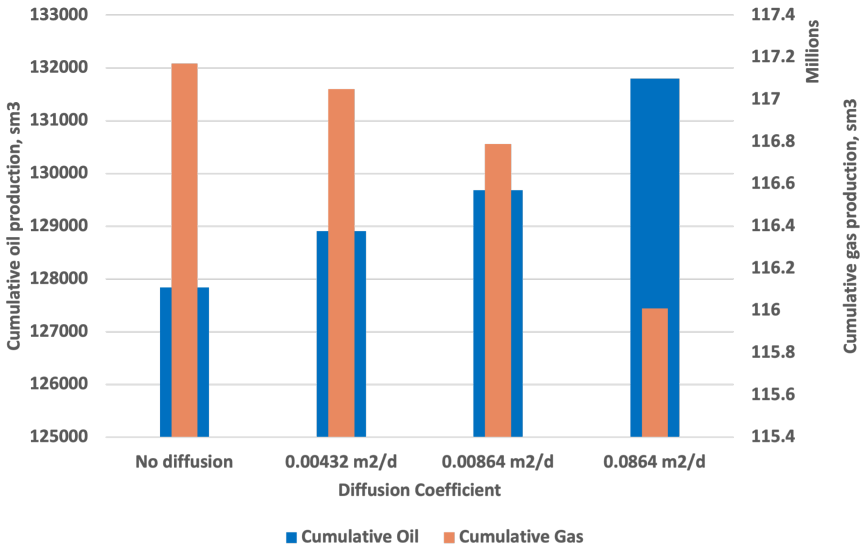

Figure 5.34: Cumulative oil and gas production at different diffusion coefficients

The reason behind the increase in oil recovery and reduction in CO_2 backflow with higher diffusion coefficient is injected CO_2 transport. Higher diffusion coefficient allows injected CO_2 to spread into the reservoir expanding the oil swept area leading to higher oil depletion during production stage. Additionally, the larger movement of injected CO_2 would reduce free gas within the reservoir as it comes into contact with larger

oil volume resulting in larger CO_2 dissolution. This can be observed though gas saturation distribution map in figure 5.35 of different diffusion coefficient cases. These results highlights the significance of molecular diffusion mechanism and the importance of including an accurate estimation of diffusion coefficient in the simulation model for more accurate results.

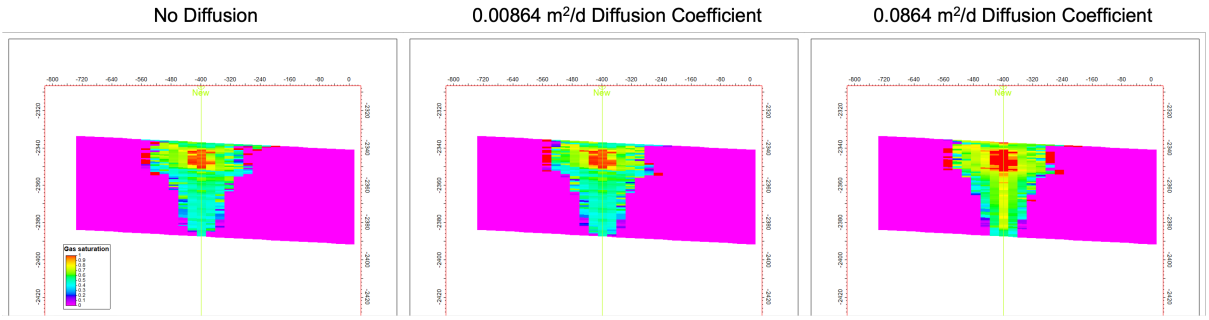

Figure 5.35: Gas saturation cross section map for different diffusion coefficient cases

Comparing the findings with previous work done in the literature, three different studies were conducted on the influence of diffusion coefficient on oil recovery using numerical simulation. Two of those studies reached to a similar conclusion that higher diffusion coefficient would result in higher oil recovery with a maximum tested diffusion coefficient of 0.0864 m^2/d similar to this study [12][23]. The third study reached to the same conclusion as well with a maximum tested diffusion coefficient of 0.00432 m^2/d [39].

5.2.8. Well Completion

Final test is performed to identify the influence of well completion on CO_2 EOR performance in tight oil reservoir using huff'n'puff scheme. Six different well completion and completion cases listed in table 5.5 are evaluated using optimum input parameters based on previous findings. Results of cumulative oil production in figures 5.36 and 5.37 show that the last case yields the highest oil recovery with 200 m horizontal well completion targeting high permeability layer. The last case shows an increase in cumulative oil production by 1% compared to first case.

Table 5.5: Different cases of well completion

Case	Well Geometry	Well Completion
1	Vertical	All layers perforated (50 m)
2	Vertical	Top layers perforated (25 m)
3	Vertical	Bottom layers perforated (25 m)
4	Horizontal	Perforated 100 m
5	Horizontal	Perforated 200 m
6	Horizontal	Perforated 200 m (High perm)

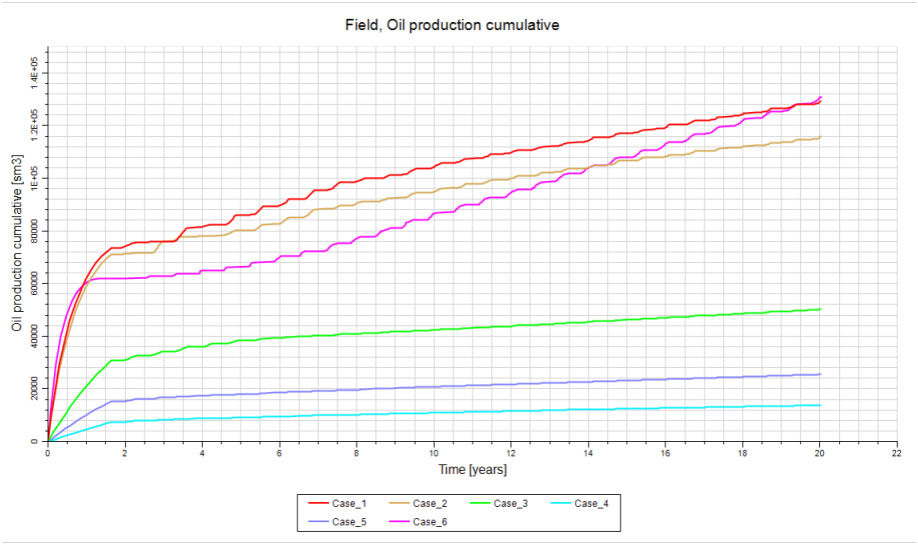

Figure 5.36: Cumulative oil production plots at different well completion cases

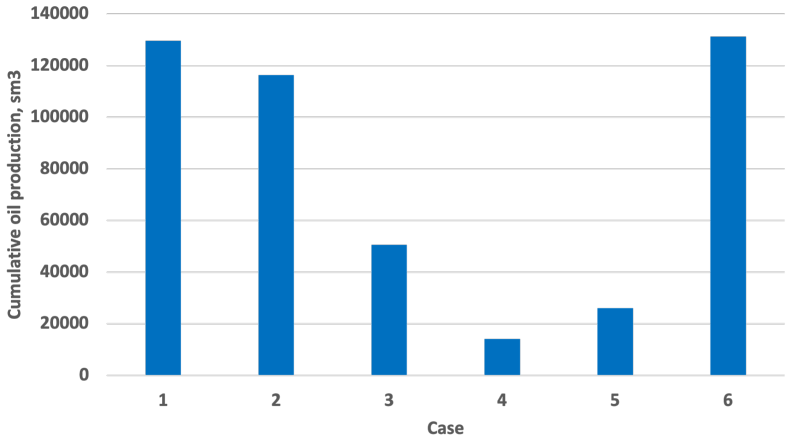

Figure 5.37: Cumulative oil production at different well completion cases

Firstly, the first 3 cases with vertical well completion are evaluated. The difference between those cases is the targeted layer and completion interval. Based on the results, having a high length of perforation across multiple layers would result in higher oil recovery compared to targeting selective layers with shorter completion interval. This is because a larger contact reservoir area would result in a higher well injectivity and larger CO_2 contact volume with the reservoir oil. Cumulative gas injection in figure 5.38 shows that case 3 with selective perforation and limited reservoir contact could not achieve the target CO_2 injection volume compared to the first two cases because of the shorter interval in low permeability section. This led to reaching injection pressure constraint and shuting-off CO_2 injection at later stages. As for case 2, it meets injectivity target similar to case 1 but it still produces less due to lower contact area with the reservoir.

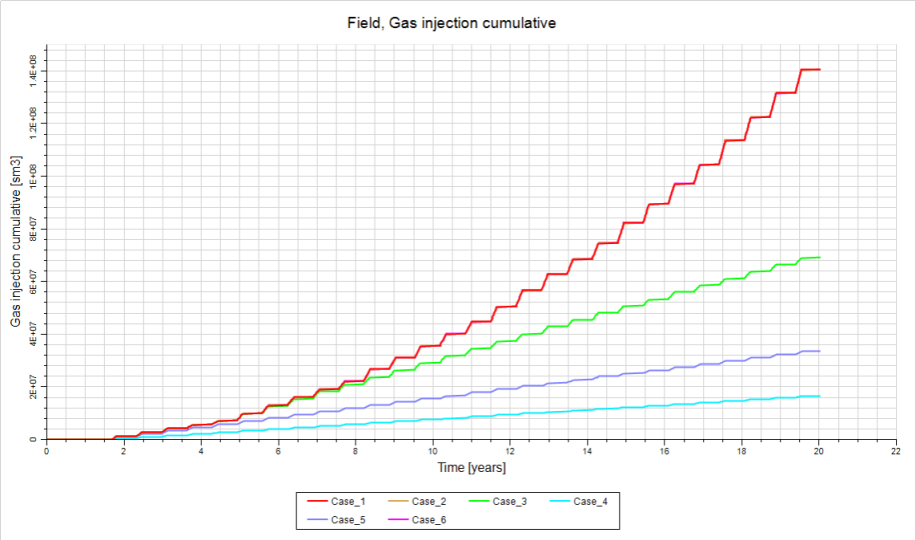

Figure 5.38: Cumulative gas injection plots at different well completion cases

After that, the last 3 cases with horizontal well completion are evaluated. When looking at cases 4 and 5, the only difference is well length since they are both targeting the same layer. Therefore, higher well length would result in higher cumulative oil production. The reason is that it offers larger reservoir contact area leading to higher well injectivity as shown in figure 5.38, where it is similar to cases 1 and 2. When the same well length is targeting a higher permeability layer as in case 6, much higher oil recovery is achieved. This is because of the major well injectivity improvement due to formation permeability. Therefore, it can be concluded that a horizontal well with higher well length targeting a higher permeability layer would yield the highest oil recovery. A horizontal well will outperform the vertical well in the case of targeting a higher permeability layer. The model does not account for permeability difference in the vertical direction, which can restrict injectivity in the case of a k_v/k_h lower than 1. Therefore, it would be recommended to further study the horizontal well performance with various k_v/k_h values and compare it with vertical well performance.

In terms of sweep efficiency, horizontal sweep is relatively good in all cases due to relatively similar reservoir petrophysical properties in the geological model. On the other hand, the model accounts for high petrophysical properties' variations vertically since the model is divided into 62 different layers within a 50 m thickness. Figure 5.39 shows a cross section of gas saturation distribution at the end of CO_2 EOR for all cases. A low vertical sweep efficiency is observed in first and second cases with higher sweep in upper layers. On the other hand, case 3 with bottom perforation shows a good vertical sweep across reservoir thickness. This can be attributed to the effect of buoyancy force that leads to the upward movement of injected CO_2. This is also observed in the horizontal completion cases. It can be concluded that targeting bottom layers in horizontal or vertical well completion will improve vertical sweep efficiency.

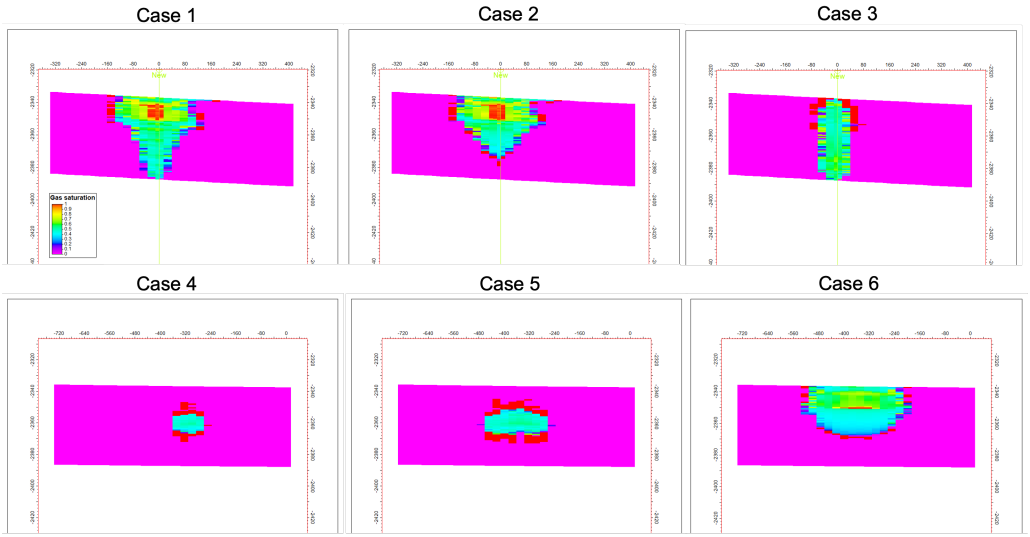

Figure 5.39: Gas saturation cross section map of different well completion cases

Lastly, it is worth noting that all these cases will have different oil production performance during the primary recovery stage. This can be observed in figure 5.40 showing oil production rate for the different cases during primary recovery stage. Thus, each case would need a separate assessment of primary recovery period and starting time for CO_2 EOR to achieve the highest oil recovery. Nevertheless, the conclusions from the well completion evaluation still stands without the need to perform individual changes on CO_2 EOR period.

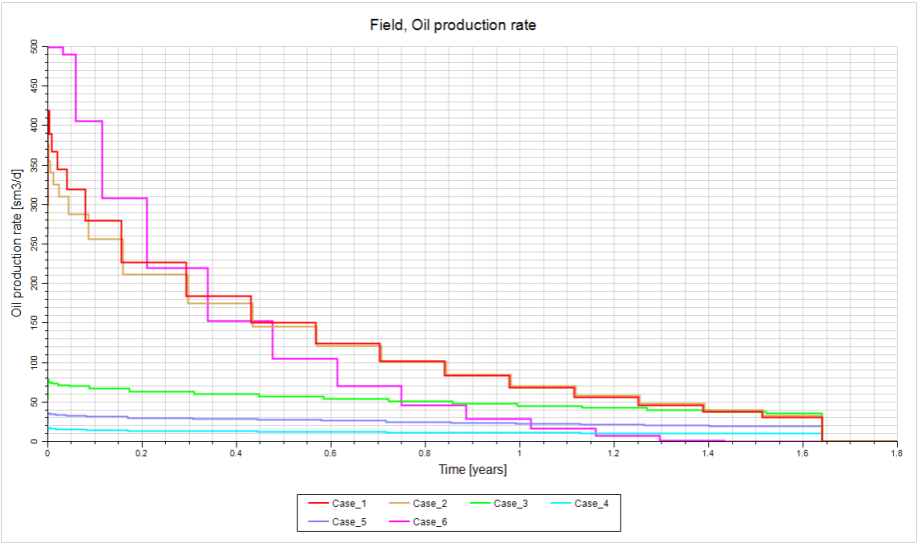

Figure 5.40: Oil production rates at different well completion cases during primary recovery

5.3. Optimum Case

Based on the findings and conclusions from the performed sensitivity study, an optimum CO_2 EOR huff'n'puff case is designed. The parameters used for this optimum case are presented in table 5.6. As for injection strategy, it is listed in table 5.7 showing a detailed sequence of injection rates following incremental injection rate approach. In this case, a horizontal well completion is chosen with 200 m length. Simulation results of the optimum case are illustrated in figure 5.41. Unlike the base case, optimum case results show a maintained reservoir pressure across project lifetime after primary depletion period. In addition,

higher oil recovery is observed at later life indicating the potential of the optimum case to continue for a longer lifetime. The modifications made during the sensitivity study managed to enhance cumulative oil production by 32% from the initially set base case. This highlights the significance of different controlled parameters on CO_2 EOR huff'n'puff oil recovery.

Table 5.6: Model parameters for optimum case

Parameter	Value
Lifetime, years	20
Production bottomhole pressure constraint, bars	100
Injection time per cycle, days	60
Soaking time per cycle, days	30
Production time per cycle, days	150
Number of cycles	29
Well length, m	200

Table 5.7: Injection rates sequence

Step	Injection rate, mm^3/d	Number of Cycle
1	0.025	6
2	0.05	5
3	0.075	5
4	0.1	5
5	0.125	4
6	0.15	4

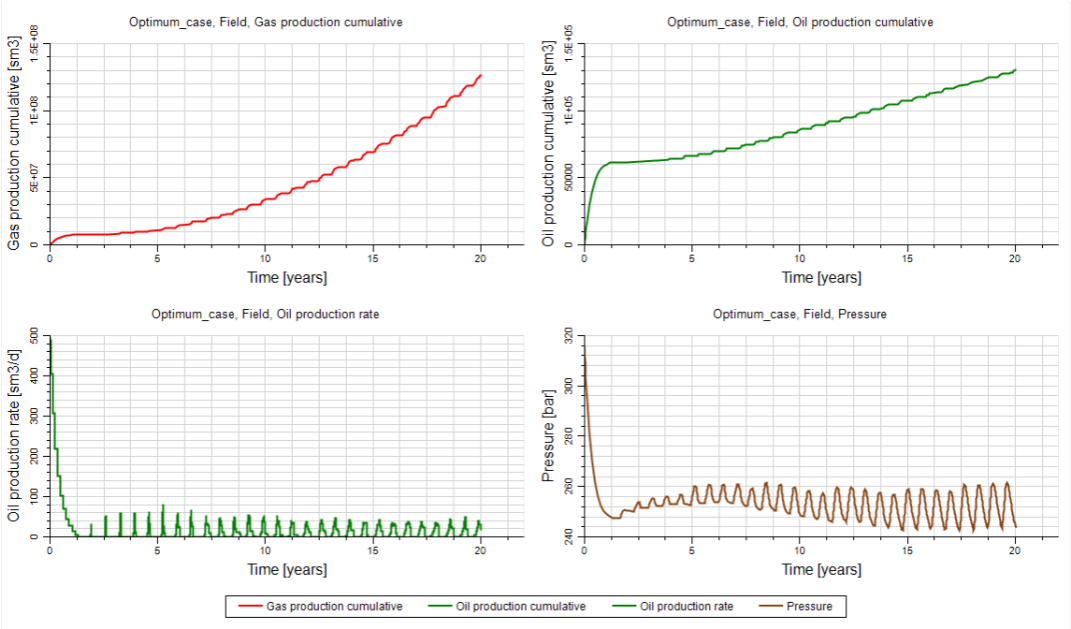

Figure 5.41: Simulation results of optimum case

6

Conclusions

In this thesis, a comprehensive assessment has been conducted on CO_2 EOR performance in unconventional oil reservoir using huff'n'puff scheme. Numerical simulation has been used to perform the assessment utilizing a sector model from an open-source geological model. A sensitivity study conducted on several parameters to determine their impact on cumulative oil production in unconventional oil reservoir. The main conclusions drawn from this thesis are as follows:

1) The best strategy to develop an unconventional oil reservoir using CO_2 huff'n'puff is by including a primary recovery period utilizing reservoir driven pressure. Results showed that after including a primary recovery period of 2 years, an increase of 15% in cumulative oil production is realized compared to the case where CO_2 huff'n'puff started from the beginning. The duration of the primary recovery period would be dependent on reservoir conditions such as reservoir pressure and fluid properties.

2) The conducted Sensitivity study on previously studied CO_2 huff'n'puff parameters in the literature verified their findings in terms of their influence on oil production. This work extends beyond sharing the results and comparison with previous studies, but also provides its own interpretation and evaluation leading to these results.

3) The implementation of incremental injection rates in subsequent cycles as a CO_2 injection scheme in huff'n'puff method instead of fixed injection rate improved cumulative oil production. Results showed that cumulative oil production becomes 10% higher when incremental injection scheme is followed due to higher pressure support after oil and CO_2 depletion after each cycle. This strategy is aiming to maintain reservoir pressure and allow for deeper penetration of injected CO_2 for larger oil sweep volume.

4) A new approach is used to evaluate injection time impact on oil production by maintaining a fixed CO_2 injection in each cycle through changing injection rate. Increasing injection period by 10 times in each cycle with a fixed injected CO_2 volume of 3.75 mm^3 per cycle improved cumulative oil production by 7%. This is a result of longer diffusion and dissolution time given eventhough injection rate and pressure is lower.

5) The evaluation of different well completions and geometries indicated that bottom CO_2 injection by targeting bottom layers improves vertical sweep efficiency. This is attributed to the effect of buoyancy forces due to the difference in densities between injected CO_2 and reservoir fluids.

7

Recommendations

This chapter provides a brief overview of the primary recommendations for the future continuation of this research project.

1) The study focuses on CO_2 EOR performance from oil production aspect. Nevertheless, it would be recommended to include the impact of each scenario on CO_2 utilization and storage for a comprehensive evaluation.

2) The used geological model has certain boundary conditions that can influence simulation results when a different geological model is used. Therefore, it is recommended to include petrophysical changes such as presence of fractures, mineral dissolution and aspheltene precipitation that can occur due to CO_2 injection in the reservoir simulation. Simulation results after implementing these petrophysical changes can be used to compared the findings of this thesis work.

3) This study uses a light oil composition for the evaluation of CO_2 EOR in unconventional reservoir with no other mobile fluids present. It would be recommended to perform this study with different oil composition in addition to the inclusion of other mobile fluids such as water aquifer or gas cap. This is to evaluate the influence of other mobile fluids present on oil recovery and to confirm findings and share differences.

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