SIMULATION OF HIGH WATER-CUT IN TIGHT OIL RESERVOIRS
DURING CYCLIC GAS INJECTION

by

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ABSTRACT

Data from a pilot test imply substantial water production after gas injection, which may impede oil production, but the underlying mechanisms are poorly understood. A compositional model is developed to study possible mechanisms for high water-cut pilot results.

First, eight pseudo-components were used to match the PVT lab results of a typical oil sample from the Wolfcamp shale. A lab scale model was then established in our simulation study to match the results of gas huff-n-puff experiments in cores, in which key parameters were identified and tuned. A half-stage field model consisting of five fractures was built, where stress-dependent permeability was represented by compaction tables. In addition, a sensitivity analysis was conducted to examine the roles of different mechanisms behind the abnormal high water-cut phenomenon. Our simulation results have shown that initial water saturation, IFT-dependent relative permeability, reactivation of water-bearing layers, and re-opening of unpropped hydraulic fractures may affect the water-cut after gas injection. Among them, re-opening of unpropped hydraulic fractures was the most critical factor.

This study also optimized the period of injection and soaking phases and well bottom-hole pressure to improve the economic benefits of production operations.
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LIST OF SYMBOLS

Asymptotic values of permeability…………………………………………………………………….. \( k_c \)

Asymptotic values of porosity…………………………………………………………………………………… \( \varphi_c \)

Average pore compressibility……………………………………………………………………………… \( \bar{c}_p \)

Biot coefficient…………………………………………………………………………………………………… \( \alpha \)

Changes in effective stress………………………………………………………………………………… \( \Delta \sigma \)

Discount rate (fraction)……………………………………………………………………………….. \( i \)

Effective stress…………………………………………………………………………………………………… \( \sigma' \)

Exponent determined by experiment………………………………………………………………………… \( c \)

Exponent of correlation………………………………………………………………………………………… \( \tau \)

Grid effective permeability……………………………………………………………………………… \( k_{HFeff} \)

Grid width…………………………………………………………………………………………………… \( w_{grid} \)

Month……………………………………………………………………………………………………… \( k \)

Net cash flow for period \( k \)……………………………………………………………………………… \( (NCF)_k \)

Normal stress……………………………………………………………………………………………….. \( \sigma \)

Permeability at zero stress……………………………………………………………………………….. \( k_0 \)

Pore pressure………………………………………………………………………………………………… \( P \)

Porosity at zero stress………………………………………………………………………………………… \( \varphi_0 \)

Project life…………………………………………………………………………………………………….. \( t \)
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CHAPTER 1
INTRODUCTION

1.1 Background

CO₂ huff-n-puff pilot tests have been completed in the Wolfcamp formation, Permian basin. In the pilot tests, four cycles of huff-n-puff injection/production were carried out on three wells, and data collected suggested significant incremental oil, yet higher than expected water-cut up to 30%. This is a new phenomenon discovered in shale oil formation during gas EOR processes. An industry sponsor also completed CO₂ and CH₄ injection lab tests; high water cut after cyclic gas injection was confirmed. Lab test results showed that initial water saturation reduced oil production, and cyclic CO₂ injection gained higher production of both oil and water compared with CH₄. Therefore, to predict and manage the high water production after gas injection, this work aims at investigating water flow and transport mechanisms behind the high water-cut.

The commercial oil recovery of unconventional liquid-rich basins, such as the Permian, has been a huge success due to the combination of horizontal well and multistage hydraulic fracturing. Tight oil produced from ultra-low permeability shale, sandstone, and carbonate formations contributed approximately 61% of total U.S. crude oil production in 2018 (EIA 2019). But smaller fracture spacings, or longer lateral lengths do not necessarily guarantee a long-term success. In fact, the oil recovery factor (RF) is typically lower than 10% in most unconventional oil plays and a rapid decline in production rate is often very common (Sheng 2015). Hence IOR/EOR in tight oil reservoirs has never been more important for operators.

Over the past decade, many technologies have been tested for IOR/EOR in tight oil reservoirs, among which the most promising one seems to be gas injection (injecting hydrocarbon gas, CO₂,
N\textsubscript{2}, etc.). Compared with water, gas has a much higher injectivity and could better supply reservoirs with additional energy. Gas could also lead to the swelling and viscosity reduction of oil. In addition, a reduced IFT in miscible injection often means more mobilized oil (Yang et al. 2019). Lastly, gas injection with hydrocarbon gas or CO\textsubscript{2} could reduce the environmental impact from gas flaring or greenhouse gas emissions (Wang et al. 2017). Gas huff-n-puff is often favored compared with flooding when reservoir permeability is lower than 1 md, because of shorter response time and the ease of single-well operation (Sheng 2015). Among all of the gas sources, CO\textsubscript{2} is an ideal solvent owing to its capability of extracting intermediate hydrocarbon components (Wang et al. 2017).

1.2 Geological Background

The Wolfcamp formation deposited during late Pennsylvanian time. It consists mostly of organic-rich shale and argillaceous carbonates intervals. Stratigraphically, the Wolfcamp consists of four intervals and forms a stacked play (Figure 1.1). Those four intervals have been designated as the A, B, C, and D sections from top to bottom (Tarka Resources 2016). The Wolfcamp shale is a most prolific tight oil and shale gas-bearing formation. The U.S. Geological Survey (USGS) assessed technically recoverable mean resources of 20 billion barrels of oil and 16 trillion cubic feet of gas in the Wolfcamp shale in the Midland Basin in 2016 (Gaswirth et al. 2016). The average porosity of Wolfcamp formation is 6%. The depth of the Wolfcamp formation ranges from 5,500 to 11,000 ft. The thickness varies between 1,500 to 2,600 ft. According to core and petrophysical data (Pioneer 2014), quartz, carbonate and clay account for 20-50\%, 10-60\%, and 10-45\%, respectively. The scope of permeability in the Wolfcamp shale is from 10 nd to 3,000 nd. Ramiro-Ramirez et al. (2018) measured four samples from the lower interval of the Delaware Basin Wolfcamp formation. The results show that the effective permeability of argillaceous and siliceous
mudstones lithofacies varies from 10 nd to 30 nd. Total porosity ranges from 13.5% to 16.5%, and these lithofacies account for 70% of the thickness. The laminated mudstone and siliceous wackestone/packstone lithofacies show effective permeability ranging from 500 nd to 1,000 nd and total porosity of 5.5%. These lithofacies only occupy 7% of the thickness. By distinguishing the lithofacies that stored oil and water from transmitted fluids during production, their work turned out to be a good approach to explain the high water-cut phenomenon. Li and Robinson (2018) characterized the natural fracture system in the Permian Wolfcamp formation, Midland Basin. By integrating borehole image technology with core data, they interpreted that fracture density varies significantly in the vertical and horizontal direction among the studied wells. The fracture density is higher compared with other shale formations, and it may range from 0 to 2.5 fractures/ft in the study area.

Figure 1.1 Permian basin cross section (Tarka Resources 2016).
1.3 Objective

The primary objective of this thesis work is to investigate the physics behind fluid flow and transport in tight oil reservoirs, especially, the flow and displacement of hydrocarbon and formation brine during gas huff-n-puff (e.g., CO$_2$ and hydrocarbon gas) for IOR/EOR. In this research, the following aspects that could explain the phenomenon of excessive water production and restrain water-cut during cyclic gas injection in unconventional reservoirs are studied:

1) Build lab and field scale models considering complex physics during gas huff-n-puff processes to match production data. E.g., reactivation of micro-fractures, hydraulic fractures, and local faults due to cyclic stress change during gas huff-n-puff, which could significantly affect the fluid transport process in low permeable reservoirs.

2) Perform sensitivity analysis of the impact of CO$_2$/hydrocarbon gas injection on rock-fluid properties, including IFT, wettability, relative permeability curves, etc.

3) Propose operational schemes to optimize field oil production, reduce water-cut and improve economic benefits of CO$_2$ injection.
2.1 Related concepts

In this chapter, several crucial concepts related to our study are clarified.

2.1.1 Cyclic gas injection

Huff and Puff (Huff-n-Puff) cyclic gas injection is one of the most efficient EOR techniques in shale oil formations. A schematic diagram of Huff-n-Puff is illustrated in Figure 2.1. In the huff phase, gas is injected into a well at a high injecting pressure to achieve miscibility. Then, the well is shut in so that the gas can spread through the formation. During the soaking period, oil is swelled and its viscosity decreased. Last, the well is set back into operation with an increased oil production rate. One cycle that consists of above three processes can be repeated until the reservoir cannot be extracted in an economic recoverable way any longer (GeoMark Research 2018).

Figure 2.1 Huff and Puff cyclic gas injection (GeoMark Research 2018).
Sheng (2017) investigated the optimum huff-n-puff times, number of cycles and soaking time under practical operational and reservoir conditions. The author found the optimum huff time is the time when pressure near the wellbore reaches the set maximum injection pressure during the huff period. The optimum puff time is the time when pressure near the wellbore reaches the set minimum production pressure during the puff period. Last, the number of huff-n-puff cycles heavily depends on economic rate cut-off.

2.1.2 Interfacial Tension

The interfacial tension (IFT) may have a huge impact on excessive water production. IFT between oil and brine is supposed to be decreased, and a wettability alteration to an intermediate-wet state appears due to gas injection, which implies it is much easier for formation water to flow. Shen et al. (2010) state that changes in IFT may affect relative permeability in the two-phase flow system. They proved that two crucial IFT values appear to exist that characterize IFT effects on relative permeability behavior and residual oil saturation. Their experimental results indicate that a certain correlation between residual oil saturation and water-oil IFT exists under different surfactant concentrations within core-fluid flow systems.

Mohammed et al. (2006) proposed a screening criterion for CO₂ Huff and Puff operations. They summarized that the mechanisms of enhancing oil recovery are due to oil swelling, solution gas drive, the reduction of oil viscosity, interfacial tensions, and variation in relative permeability to water and gas during the puff phase due to hysteresis, etc.

2.1.3 Wettability

Wettability is defined as the preference of a solid to be in contact with one fluid, such as oil or water rather than another. As shown in Figure 2.2, when an oil drop (green bead) is surrounded by water on a water-wet surface (left), zero contact angle is obtained. However, on the
right oil-wet surface, an oil drop spreads on it and around 180° contact angle evolves. If the solid does not have an apparent preference for one fluid over the other, this condition is termed intermediate wetting. A bead also can be formed on an intermediate-wet surface (center), and the contact angle results from a force balance among the interfacial tension terms, which are $\gamma_{so}$ and $\gamma_{sw}$ for the surface-oil and surface-water terms, respectively, and $\gamma_{ow}$ for the oil-water term.

![Contact angle diagram](image)

Figure 2.2 Contact angle (Abdallah et al. 2007)

2.1.4 Capillary pressure

As mentioned above, wettability alteration to an intermediate-wet state appears due to gas injection, which implies that it is much easier for formation water to flow. Figure 2.3 shows the capillary pressure (red) and relative permeability (green) for water-wet (left) and mixed-wet (right) conditions. In the water-wet condition, values of capillary pressure are generally positive over most of the saturation range, while both positive and negative values might be obtained in the mixed-wet situation. Considering the relative permeability curves, water and oil will respectively be in the small pores and large pores for the water-wet case in conventional reservoirs. There will be a high oil relative permeability at low water saturation, since oil flows through the large pores (Abdallah et al. 2007). With the water gradually occupying pore that were formerly filled with oil, the oil cannot overcome the capillary entry pressure so it gets trapped in place. In the end, the final water relative permeability is lower due to the trapped oil. For the mixed-wet case, however, the
oil occupying large pores will alter the wettability of the contacted pore surfaces (Abdallah et al. 2007; Dernaika et al. 2012; Masalmeh 2001). With the water saturation increasing, water invades the largest pores and oil relative permeability will decline rapidly. Since water fills the most permeable paths, water does not trap the oil in this case. When the water break through phenomenon occurs, oil production can still maintain for a long time, even though the water cut increases. In general, high water cut can arrive quickly in mixed-wet condition compared with water-wet. Capillary pressure also exerts a large effect on flash calculation. Wang et al. (2019) developed a compositional simulator and implemented a deep learning-based flash calculation module so as to accelerate and stabilize the process.

Figure 2.3 Capillary pressure and relative permeability for water-wet and mixed-wet conditions (Abdallah et al. 2007).

2.1.5 Stress-dependent permeability

Geomechanics is one of the most important factors that should be taken into account in unconventional reservoirs. Terzaghi (1936) initially defined effective stress as the difference
between the normal stress and pore pressure. Biot and Willis (1957) proposed a coefficient in the effective stress equation as below:

\[ \sigma' = \sigma - \alpha P \]  

(2.1)

where,

\( \sigma' \) = effective stress

\( \sigma \) = normal stress

\( \alpha \) = Biot coefficient

\( P \) = Pore pressure

Verma and Pruess (1988) developed a conceptual and mathematical model for porosity change from silica redistribution and associated permeability effects. The following correlation was provided for porosity and permeability.

\[ \frac{k - k_c}{k_0 - k_c} = \left( \frac{\phi - \phi_c}{\phi_0 - \phi_c} \right)^\tau \]  

(2.2)

Where,

\( k_c \) and \( \phi_c \) represent asymptotic values of permeability and porosity, respectively, which are the lowest values to which they can be reduced by increasing the confining pressure, \( \tau \) represents the exponent of correlation which was determined from experiment.

McKee et al. (1988) have derived fundamental relationships for permeability, porosity, and density as a function of effective stress. The relationship of porosity and effective stress from poro-elasticity theory for incompressible rock grains was derived:

\[ \Phi = \frac{\Phi_0}{1 - \Phi_0 \left(1 - e^{-c_p \Delta \sigma}\right)} \]  

(2.3)

where,

\( \Delta \sigma \) = Changes in effective stress
\( \bar{c}_p \) = Average pore compressibility

The following relationship between permeability and porosity can be obtained based on Carman-Kozeny equation:

\[
 k \propto \frac{\phi^3}{(1 - \phi)^2}
\]  

(2.4)

These relationships fit laboratory and field data in their study. Coal, granite, sandstone and clay core these samples illustrated the applicability of the permeability and porosity theory.

Rutqvist et al. (2002) presented a modeling approach for analysis of coupled multiphase fluid flow, heat transfer and deformation in fractured porous rock. For porous sedimentary rock, porosity and permeability are corrected using empirical relationships. The permeability is correlated to the porosity according to the following exponential function:

\[
 k = k_0 \exp [c \times (\frac{\phi}{\phi_0} - 1)]
\]  

(2.5)

Where,

\( k_0 \) = Permeability at zero stress
\( c \) = Exponent determined by experiment
\( \phi_0 \) = Porosity at zero stress

Reyes and Osisanya (2002) developed empirical relationships that correlate porosity and permeability of shales based on the effective stress concept. Also, they proved that porosity and permeability are not constant; both are functions of confining and formation pressure.

Mokhtari et al. (2013) characterized the impact of natural and induced fractures on permeability anisotropy and presented the effect of stress on the permeability of such fractured reservoirs. In Mancos Shale, the intrinsic anisotropy due to layering was investigated. It was found
that all the shale core samples exhibit an exponential decline in permeability with applied effective stress.

Lei et al. (2015) have summarized some correlations for stress-dependent permeability. They developed a novel predictive model for normalized porosity and normalized permeability in tight-sandstone porous media under effective stress, those two parameters can be expressed as a function of the effective stress, rock elastic modulus, microstructural parameters, and initial irreducible water saturation. They also found wetting-phase relative permeability is related to the effective stress, microstructural parameters and initial irreducible water saturation.

### 2.2 Field observations

A CO\(_2\) huff-n-puff pilot implemented in the Wolfcamp formation of the Midland Basin suggested a significant oil rate improvement, but also an elevated water-cut with an increase up to 0.3. To the best of the author’s knowledge, this phenomenon has never been reported or explained in the related literature. In order to find out the reason of high water cut occurrence during cyclic gas injection, and better to manage such excessive water production in tight oil reservoirs, the related work in the literature needs to be reviewed.

Most published studies on unconventional reservoirs focused on the incremental oil recovery after gas huff-n-puff, but they paid less attention to associated water production. Hoffman and Evans (2016) reviewed several IOR/EOR pilots in the Bakken. Gas huff-n-puff pilots showed little improvement regarding oil rate and water production data was not mentioned. However, they reported a well which had neither oil or water rate increase immediately after water huff-n-puff, but almost a year later it exhibited both increased oil rate and a water-cut increase to 0.7. Hoffman (2018) summarized seven gas huff-n-puff pilots in the Eagle Ford and reported that gas injection would improve the cumulative oil production by 30%-70% in comparison to the depletion case.
But no water production data were reported. An important reason is that water-cut for depletion stage is often quite stable except for an initial spike, which is largely due to the flowback to fracturing fluids (Pankaj et al. 2018). But sometimes, water cut would surge if induced fractures invaded other zones, such as the overlaying Lodgepole formation in Bakken play (Jin et al. 2017) or Bone Spring Formation in Delaware Basin (Pettit and Muirhea 2016). Specifically, for the Wolfcamp formation in the Delaware basin, Pettit and Muirhea (2016) classified the water cut behaviors into three categories: a) High water cut, with average value as 0.8. b) Medium water cut with an average value as 0.4. c) Low to high water cut, well exhibiting water cut 0.2-0.4 at first, but then a surge to 0.9 within 6 months. Their simulation model concluded that it was the hydraulic fractures propagating from the Wolfcamp into the Bone Spring Formation, which caused the rising water-cut, and fracture height must be a critical factor contributing to excessive water production during depletion. Unfortunately, little water production data is available for huff-n-puff operations in liquid-rich shale.

Water production data is more accessible in conventional, high permeable reservoirs, but the water-cut is often observed as unchanged or reduced after gas injection, especially for immiscible projects. Hsu and Brugman (1986) reported an immiscible CO$_2$ huff-n-puff pilot by Texaco in Paradis Field, Louisiana. The pre-injection water cut was 0.9, and the average water-cuts for first and second cycle were almost unchanged. Denoyelle and Lemonnier (1987) reported a stripper well case in a shallow sandstone reservoir with permeability ranging from 5~20 md and in-situ oil viscosity as 2.68 cp. Though not explicitly mentioned, the project should be immiscible as a black oil simulator was used. Before CO$_2$ injection, one well produced at 2 bbl/day with water-cut as 0.9. After CO$_2$ injection, water-cut first decreased, and then bounced back to 0.9. Haskin and Alston (1989) evaluated 28 immiscible CO$_2$ huff-n-puff projects in Miocene reservoirs and
found that water rates would generally decrease with increased oil rate after injection, and finally water-cut would return to the pre-injection value. Monger and Coma (1988) summarized nine successful pilots in south Louisiana oil-bearing sands. Eight of the wells experienced water-cut reduction after CO$_2$ injection. Only one well, Well J, experienced a water-cut surge from 0.30 to 0.67 after injection. Unlike the other eight wells, this well was apparently injecting above the MMP (Minimum Miscibility Pressure). Hence achieving miscibility might or not be a vital factor for water-cut surge.

Monger et al. (1991) reported an immiscible CO$_2$ huff-n-puff in the Appalachian Basin in Eastern Kentucky. Sixty five wells were tested in a fractured reservoir with average permeability as 10 md. The author compared water-cut data before and after CO$_2$ injection and proposed that water was pushed away by injected CO$_2$, leading to a reduced water-cut. For the viscous oil, there was even a patented technology, called the Anti-Water Coning Technology (AWACT), which involves injecting immiscible gas into a watered-out well to suppress water conning (Luhning et al. 1990). AWACT succeeded in 40 wells in South Jenner oil Field with the in-situ viscosity as 97 cp (Lai and Wardlaw 1999). The reduced water-cut and improved oil recovery were attributed to the trapped gas which lowered the relative permeability to water and redirected the water influx.

Mohammed-Singh et al. (2006) reviewed sixteen CO$_2$ huff-n-puff projects in the Forest Reserve oilfield of Trinidad and Tobago. Projects were successful in reservoirs with in-situ oil viscosities from 0.5 to 3,000 cp and permeabilities ranging from 10 to 2500 md. They concluded that CO$_2$ injection could reduce the relative permeability to water phase due to trapped gas saturation and oil swelling. Hence redistribution of fluid saturation and the resulting relative permeability alteration due to injection might be also influential factors.
Simpson (1988) reported two immiscible CO\textsubscript{2} huff-n-puff tests in a bottom-water reservoir with water-cut between 0.98 and 0.99, caused by water coning. Though both tests witnessed incremental oil production, the water-cut responses were very different. For Well 271, the water cut was as low as 0.002 once the puff started. Then within five days, the water cut increased to 0.57; but it remained between 0.7 and 0.8 for almost two months. Finally, it went back to the pre-test value as 0.99 in 100 days. For Well 272, once the puff started, the water-cut was continuously decreasing from 1 to 0.78, and it rose again back to 0.92. Then the well was shut-in again for two months, and water cut again reduced to 0.76, but gradually returned to the pre-test value as 0.99 in 50 days. Well 271 was shut-in for 51 days in contrast to the 28 days of Well 272. Moreover, Well 271 received 18\% more CO\textsubscript{2} than Well 272 within the 5-day injection time. Operational parameters such as shut-in time and injected gas volume may contribute to the different water-cut responses.

2.3 Laboratory studies

Many lab-scale investigations of CO\textsubscript{2} injection have been performed on low-permeability cores, but most of them focused on the improved oil recovery. Very few of them contemplated initial water saturation (Tovar et al. 2014; Jin et al. 2017; Song and Yang 2017; Li et al. 2018) and let alone the production of water. For example, Tovar et al. (2014) investigated CO\textsubscript{2} huff-n-puff in preserved shale samples of nd permeability with packed glass beads simulating fractures. Their work confirmed the incremental RF but observed no water production even with initial water saturation estimated as 0.3. Li et al. (2018) investigated the effect of water on CO\textsubscript{2} huff-n-puff performance and found that RF would decrease 45\% with an initial Sw as 0.4 in contrast to cores without water. Water-cut, though not explicitly plotted, was increasing with time.

In highly permeable rocks, water related data is still very limited. Darvish et al. (2006) investigated the efficiency of immiscible CO\textsubscript{2} injection into fractured cores with permeability of 4
CO₂ was injected to displace the residual oil in a water-flooded core. The results indicated that the water production rate was around ten times higher than oil rate at first, and it decreased to zero after several days. The author concluded that the high-water cut was the result of high initial water saturation in the core. Torabi and Asghari (2010) examined the performance and efficiency of cyclic CO₂ injection in light-oil fractured porous media. Two Berea cores were tested as matrix with permeability of 100 and 1000 md, respectively. The cylindrical core was held in a steel cell with 0.5 cm annular spacing to simulate a matrix and surrounding fracture in this set-up. The results suggested that connate water existence would favor RF during immiscible CO₂ huff and puff processes, but there was no obvious difference in RF for miscible condition. Abedini and Torabi (2014) investigated CO₂ huff-and-puff in cores with permeability around 70 md and connate water saturation ranging from 0.443 to 0.459. Their experimental results indicated that no water production was found after CO₂ injection even for cases above MMP.

In summary, the initial water-cut spike during depletion of liquid-rich unconventional reservoirs is largely due to the flowback of fracturing fluids. Fracture propagation into adjacent water layers is a possible reason for water-cut growth after flowback. For conventional reservoirs, gas injection rarely results in water-cut increase, even for watered-out wells except one case when injection was under miscible condition. Fluid saturation redistribution and a further shifted relative permeability curve might also be important factors. The injection scheme, such as shut-in time, and injected volume may also affect the behavior of the water-cut. Experimental studies of gas huff-n-puff in cores have shown contradicting roles of initial water saturation on oil RF, but initial water saturation is a decisive factor worth exploring during gas huff-n-puff. We plan to investigate the above-mentioned relevant factors with a compositional model, whose key inputs, including pseudo-components, corresponding fluid properties and relative permeability curves, were all
specified based on the related laboratory studies. The developed workflow is not only of great importance for engineers to understand the reason of high water cut during cyclic gas injection, but also of great use to manage excessive water production for gas EOR in tight oil reservoirs.
CHAPTER 3
PVT MODEL AND LAB MODEL

3.1 PVT Model

In this chapter, processes of lumping components and PVT experimental data regression are demonstrated. A typical oil sample was obtained from the Wolfcamp shale formation. The composition of this reservoir fluid was analyzed up to C_{36}^+ in the laboratory by a sponsor oil company. The full extended analysis provided mole fraction, MW and SG for each SCN (Single Carbon Number) fraction, so that the SCNs can be entered as user components directly on the Component Selection/Properties form in CMG-WinProp. Then, on the basis of K-values estimated from Wilson’s correlation using the Lee-Kesler mixing rules, the SCNs representing the C_{7}^+ fraction can be lumped into fewer components (e.g., C_7-C_{15}, C_{16}-C_{25}, C_{26}-C_{30}, C_{31}^+). Also, the critical properties of the pseudo-components are estimated using the Lee-Kesler correlation (CMG 2018). To achieve an accurate prediction of the PVT behavior, a large number of pseudo-components should be used in characterizing the hydrocarbon plus fraction (Ahmed 2001). The computing time and storage, however, will largely increase as the number of components increasing in compositional models. Hence, original components are usually lumped into a smaller number of pseudo-components. Moreover, the lumping scheme was explicitly inputted by the user instead of relying on the CMG-WinProp internal algorithm.

In the CMG-Winprop, PR (1978) equation of state, psia and deg F units and mole of feed were chosen. Click Tab “Component Selection/Properties”, insert components in order from “Ins Lib”, the composition of components was provided by oil company’s Reservoir Fluid Compositional Analysis Report. Click Tab “Composition”, primary composition is the composition of reservoir fluid and secondary composition is the composition of injecting fluid.
Produced gas was injecting fluid in this study, thus the composition of produced gas was input into secondary column. The saturation pressure was tested as 2,274 psia from the laboratory experiment and reservoir temperature was 170 °F. The experimental saturation pressure was input as shown in Figure 3.1 to prepare for next regression work.

![Figure 3.1 Input interface when matching saturation pressure.](image)

Click menu “Lab-Constant Composition Expansion”, then input temperature and saturation pressure. Paste the CCE experimental data to corresponding place as shown in Figure 3.2: Pressure, Relative volume (ROV), Oil density.
Figure 3.2 Input interface when matching constant composition expansion experiment.

Click menu “Lab-Differential Liberation”, paste the DL experimental data (Figure 3.3) to corresponding place: Pressure, Oil formation volume factor (FVF), Gas oil ratio (GOR), Oil specific gravity (SG) and other parameters.

Figure 3.3 Input interface when matching differential liberation experiment.

Click menu “Lab-Swelling Test”, paste the swelling test experimental data as shown in Figure 3.4 to corresponding place: Gas mole fraction, saturation pressure estimated and
experimental data and swelling factor. Estimated saturation pressure was input exactly same as experimental data here.

![Image of input interface](image.png)

**Figure 3.4 Input interface when matching swelling test experiment.**

Click “Composition-Start Regression” and add those experiments to “Regression Parameter”. Save the file then run it, and all the processes above was the preliminary regression before lumping.

In this study, components were lumped into eight pseudo-components, i.e., C₁, CO₂, N₂-C₂, C₃, C₄-6, C₇-15, C₁₆-2₄, and C₂₅+. Their properties were tuned to match the various experiment results, including constant composition expansion, differential liberation, and swelling test. Since CH₄ will also be used as injectant in our future work, it was deliberately not lumped together with CO₂. C₃ was also listed as an individual pseudo-component to represent the improved recovery of natural gas liquids (NGL). NGL are liquid at surface and thus can be a significant indicator of liquid production, which is further utilized to evaluate the water cut. Therefore, click “Characterization-Component Lumping”, then chose lumping method “Define lumping scheme in grid below” and set number of lumped components as eight. Save the file and run it. Eight pseudo-
components were lumped. After tuning up, the composition and thermodynamic properties for each component are summarized in Table 3.1. PR EOS was used to calculate the oil properties at the reservoir temperature of 170 °F, and estimated the saturation pressure as 2,263.7 psi, oil gravity as 43 °API, formation volume factor as 1.38 rb/STB and GOR as 780 scf/STB.

Table 3.1 Properties of the pseudo-components of a typical oil sample in Wolfcamp Shale

<table>
<thead>
<tr>
<th>Pseudo-component</th>
<th>Mole fraction</th>
<th>Pc, atm</th>
<th>Tc, K</th>
<th>Vc, L/mol</th>
<th>Acentric Factor</th>
<th>MW, g/mol</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂</td>
<td>0.0048</td>
<td>72.80</td>
<td>304.2</td>
<td>0.0940</td>
<td>0.2250</td>
<td>44.0</td>
</tr>
<tr>
<td>CH₄</td>
<td>0.3517</td>
<td>45.40</td>
<td>190.6</td>
<td>0.0990</td>
<td>0.0080</td>
<td>16.0</td>
</tr>
<tr>
<td>N₂-C₂</td>
<td>0.0972</td>
<td>48.06</td>
<td>301.2</td>
<td>0.1464</td>
<td>0.0966</td>
<td>30.0</td>
</tr>
<tr>
<td>C₃</td>
<td>0.0801</td>
<td>41.90</td>
<td>369.8</td>
<td>0.2030</td>
<td>0.1520</td>
<td>44.1</td>
</tr>
<tr>
<td>C₄-6</td>
<td>0.1173</td>
<td>34.84</td>
<td>457.4</td>
<td>0.2919</td>
<td>0.2260</td>
<td>69.2</td>
</tr>
<tr>
<td>C₅-15</td>
<td>0.2400</td>
<td>25.42</td>
<td>616.6</td>
<td>0.5096</td>
<td>0.4277</td>
<td>138.6</td>
</tr>
<tr>
<td>C₁₆-2₄</td>
<td>0.0592</td>
<td>14.95</td>
<td>828.1</td>
<td>0.9833</td>
<td>0.7949</td>
<td>265.4</td>
</tr>
<tr>
<td>C₂₅+</td>
<td>0.0496</td>
<td>15.00</td>
<td>987.8</td>
<td>1.4830</td>
<td>1.1223</td>
<td>359.6</td>
</tr>
</tbody>
</table>

“Update Component Properties” must be done to update the number and properties of components either in lumping or regression process. Adjustable variables include critical pressure, critical temperature, volume shift of N₂ to C₂H and C₂₅ to C₃₆ were chosen.

To check the regression results of each property, click “Simulation Results-Simulation Output”. If the error did not satisfy the tolerance, following ways can be adopted. For certain regression parameters such as density, saturation pressure, we can increase their weight. Lower and upper bound of variables can be adjusted based on regression results or add more parameters. Finally, regression errors were controlled within 5% in general.

In terms of multiple contact calculations, Figure 3.5 presents the input interface and the result in Figure 3.6 shows the pressure of first contact miscibility was larger than 3,600 psi, the pressure of multiple contact miscibility was 3,387.8 psi in a vaporizing and condensing combined
gas drive manner. We found that binary interaction coefficients between \( \text{CH}_4 \) and heavier components, Omega A and Omega B exert a large effect during the regression of MMP.

<table>
<thead>
<tr>
<th>Conditions/Method</th>
<th>Compositions</th>
<th>Feed/K values/Output level/Stability test level</th>
</tr>
</thead>
<tbody>
<tr>
<td>Comments</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

| Temperature (deg F) | 170          |
| Solvent increment ratio | 0.01        |
| Equilibrium gas/original oil mixing ratio | 0.1        |

**Pressure Data**

| Start Pressure (psia) | 2800         |
| Pressure Step (psia)  | 50           |
| Max. No. of Pressure Steps | 16       |

**MMP / MME calculation method selection**

- Cell to Cell Simulation
- Semi-empirical (Key Tie Lines) Method
- Multiple Mixing-Cell Method

- Use cell-to-cell simulation to estimate the starting pressure value

**Experimental Data**

- Experimental MMP (psia): 3297
- Weighting Factor: 100

Figure 3.5 Input interface when matching minimum miscibility pressure.
The results from PVT data and core experiments were matched first to provide critical inputs for the next lab-scale and reservoir-scale model. The PVT model utilized the Peng-Robinson (PR) equation of state (EOS) and the calculated curves after regression in WinProp matched the original experimental data well, as shown in Figure 3.7 to Figure 3.10.
Figure 3.7 Matching results of ROV between the experimental data and calculated values.

Figure 3.8 Matching results of differential liberation experimental data and calculated values.
Figure 3.9 Matching results of swelling test experimental data and calculated values.

Figure 3.10 Matching oil density experimental data and calculated values.
3.2 Lab Model

An experiment of gas huff-n-puff tests in a composite core was designed and conducted by a sponsor oil company, consisting of a low permeability rock and a high permeability rock, as shown in Figure 3.11. All the experimental data here was provided by the oil company. The low permeability rock had a permeability of 0.11 md, equivalent to the effective permeability of Wolfcamp matrix and natural fractures. The high permeability rock with a permeability of 2,200 md represented the propped hydraulic fracture. The core holder was maintained at reservoir temperature of 170 °F through a run. The initial oil saturation was estimated at 0.5 in the low permeability rock and 0.0 in the high permeability rock. The system was initially at 4,000 psi and then depleted to 600 psi. Gas was then injected through top rock and pressurized the system to 4,000 psi. The system was closed to simulate soaking processes and was depleted to 600 psi again. The produced oil and water were collected and measured during the production period.

![Figure 3.11 Schematic of gas huff-n-puff set-up with composite cores.](image)

We then have built a simulation model to match the results of lab-scale experimental results. There were 10 grids in radial direction and six grids in axial direction in the cylindrical
model, as shown in Figure 3.12. The PVT model established earlier was used in this lab-scale model.

![Figure 3.12 Simulation model for lab-scale gas huff-n-puff.](image)

History matching of the experimental results were then completed. Since the BHP (bottom hole pressure) was set as well constrain during the whole simulation process, its values were the same as the history data. Relative permeability curves of tight rock representing matrix were tuned primarily to match the cumulative oil and water production as shown in Figure 3.13. Though the water-oil ratio is lower than the value observed in the field, the water production was not zero unlike many previous huff-n-puff experiments in tight cores.
The relative permeability curves for high permeability rock representing fractures were generated by assuming a minimal residual saturation for all phases. The final relative permeability curves that led to the best match are shown in Figure 3.14 to Figure 3.17. Matrix rock compressibility was also found decisive in the matching process and a final value of $5 \times 10^{-6}$ psi$^{-1}$ was found to provide the best match. Please note that the original experiment used CH$_4$ as the injected gas, but the water-oil relative permeability curves should be reliable after matching. It was assumed that the gas-liquid curve for CH$_4$ and CO$_2$ was the same.
Figure 3.14 Matrix water-oil relative permeability curve obtained after history match.

Figure 3.15 Matrix liquid-gas relative permeability curve obtained after history match.
Figure 3.16 Fracture water-oil relative permeability curve obtained after history match.

Figure 3.17 Fracture liquid-gas relative permeability curve obtained after history match.
CHAPTER 4
FIELD MODEL

4.1 Set-up of base case

A typical horizontal producer in this region has a perforated lateral length of 10,000 ft with 100 fracturing stages. There are five perforation clusters in each stage, which are assumed identical to each other and uniformly distributed over the lateral as shown in Figure 4.1. Propped and unpropped hydraulic fracture, enhanced permeability region, and natural fracture and matrix were entirely taken into consideration in the model, as shown in Figure 4.2. The dual permeability model was used to capture natural fracture networks. Within a hydraulic fracture, it is assumed that the fracture tip region is unpropped, therefore has a smaller conductivity (blue region). The hydraulic fracture half-length is 390 ft and propped length (red and yellow region) is 147 ft.

Figure 4.1 Conceptual reservoir model illustrating fracture conductivity variations.
The width of the model in I direction is 100 ft to cover a single fracturing stage. Since the distance between two parallel horizontal wells in J direction is set to be 880 ft, by assuming they are identical, and a closed flow boundary can then be established by symmetry. Therefore, the whole stage can be simplified with a half-stage model with size as 440 ft in J direction. In K direction, there is no symmetry hence the entire formation is modelled with all 15 layers. The simplification using symmetry was commonly used in other work (Brown et al. 2011; Tian et al. 2019). Table 4.1 summarizes the geometry of the half-stage model with five planar fractures.

Table 4.1 Geometry of the base case for reservoir simulation

<table>
<thead>
<tr>
<th>Well geometry</th>
<th>Model dimension</th>
</tr>
</thead>
<tbody>
<tr>
<td>Perforated lateral length, ft</td>
<td>X, ft 100</td>
</tr>
<tr>
<td>Stage number</td>
<td>Y, ft 440</td>
</tr>
<tr>
<td>Clusters per stage</td>
<td>Z, ft 236</td>
</tr>
<tr>
<td>Cluster spacing, ft</td>
<td>Fracture half-length, ft 390</td>
</tr>
</tbody>
</table>

For the primary mesh, there are 35 grid blocks in the I-direction, 15 grid blocks in the J direction, and 15 grid blocks in the K direction. Then the hydraulic fractures were created with a planar fracture template and refined grids were used near the fracture which made the total grid
block number as 14,625. The grid system of the conceptual model after refinement was shown in Figure 4.3.

A planar (bi-wing) fracture template in CMG-GEM simulator was used to apply the planar model in multiple locations and simplify the model in this case, where propagation mainly in the direction of fracture length. However, for unconventional shale fracture, it is easier to see a multi-fracture geometry and fracture propagation into a complex network structure (Gomaa 2014). Local 3*3*1 grid refinement was done. One grid was refined with three grids in I and J directions while Z direction kept the same. The transverse fracture zone was a single plane of blocks that extends from the center outward to the fracture tips. Seven layers were above the fracture layer and seven layers were under it.

![Figure 4.3 The grid system in the I-J plane for the base case.](image)

For the natural fracture mesh, it is assumed that porosity is constant as 0.0001 and horizontal permeability as 0.025 md. For the matrix grid block, it is assumed that rock properties including porosity, horizontal permeability, and initial water saturation only vary vertically and within each layer they are all homogeneous. The matrix properties of different layers are
summarized in Table 4.2 and were provided by oil company. For both matrix and fracture, vertical permeability is assumed to be one tenth of horizontal permeability. The natural fracture spacing is 50 ft in I, J direction and 0 ft in K direction.

<table>
<thead>
<tr>
<th>Layer</th>
<th>Thickness, ft</th>
<th>Porosity</th>
<th>Permeability, md</th>
<th>Initial water saturation</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>10</td>
<td>0.0661</td>
<td>2.046E-04</td>
<td>0.57</td>
</tr>
<tr>
<td>2</td>
<td>30</td>
<td>0.0581</td>
<td>1.271E-04</td>
<td>0.68</td>
</tr>
<tr>
<td>3</td>
<td>24</td>
<td>0.1037</td>
<td>1.101E-03</td>
<td>0.36</td>
</tr>
<tr>
<td>4</td>
<td>18</td>
<td>0.0713</td>
<td>2.720E-04</td>
<td>0.36</td>
</tr>
<tr>
<td>5</td>
<td>13</td>
<td>0.0617</td>
<td>1.591E-04</td>
<td>0.65</td>
</tr>
<tr>
<td>6</td>
<td>17</td>
<td>0.0598</td>
<td>1.409E-04</td>
<td>0.70</td>
</tr>
<tr>
<td>7</td>
<td>13</td>
<td>0.0677</td>
<td>2.240E-04</td>
<td>0.59</td>
</tr>
<tr>
<td>8</td>
<td>17</td>
<td>0.0590</td>
<td>1.346E-04</td>
<td>0.66</td>
</tr>
<tr>
<td>9</td>
<td>15</td>
<td>0.0499</td>
<td>7.171E-05</td>
<td>0.84</td>
</tr>
<tr>
<td>10</td>
<td>13</td>
<td>0.0502</td>
<td>7.371E-05</td>
<td>0.94</td>
</tr>
<tr>
<td>11</td>
<td>12</td>
<td>0.0362</td>
<td>2.171E-05</td>
<td>1.00</td>
</tr>
<tr>
<td>12</td>
<td>15</td>
<td>0.0338</td>
<td>1.686E-05</td>
<td>0.81</td>
</tr>
<tr>
<td>13</td>
<td>15</td>
<td>0.0882</td>
<td>6.020E-04</td>
<td>0.70</td>
</tr>
<tr>
<td>14</td>
<td>10</td>
<td>0.0439</td>
<td>4.457E-05</td>
<td>0.63</td>
</tr>
<tr>
<td>15</td>
<td>14</td>
<td>0.0763</td>
<td>3.509E-04</td>
<td>0.53</td>
</tr>
</tbody>
</table>

Since the hydraulic fracture (HF) is modeled explicitly by local refined grids, and the grid width \( w_{\text{grid}} \) containing HF as 0.1 ft is much larger than the actual width of HF, \( w_{\text{HF}} \) as 0.001 ft. The grid effective permeability \( k_{\text{HFeff}} \) is scaled accordingly to maintain the same fracture conductivity as specified (CMG 2018).

\[
k_{\text{HFeff}} = \frac{k_{\text{HF}} w_{\text{HF}}}{w_{\text{grid}}} \tag{4.1}
\]

For example, the grid block effective permeability for the propped HF is 50 md, which is the propped HF’s conductivity (5 md·ft) divided by the grid width (0.1 ft). The stress-dependency of fracture permeability is modeled by the usage of a compaction table. In the future, an in-house simulator (Wang et al. 2019) will be used to include geomechanics effects on CO\(_2\)-EOR processes.
The unpropped HF and natural fracture (NF) are assumed to follow the same trend, while propped HF should follow a different curve with weaker dependency on stress and higher remaining permeability as shown in Figure 4.4.

![Figure 4.4 The stress-dependent permeability correlation in the model.](image)

In order to simulate the water-cut spike caused by flowback, water was first injected with total volume as 2,320 STB to match a typical stimulation design for the half-stage model in this region. The well was first depleted for four years with a maximum oil rate as 10 STB and a minimum BHP set as 1,200 psi. Then the well was injected with a maximum CO₂ rate as 6,000 scf/day and maximum BHP as 7,000 psi for 50 days. Shut-in time was set as 10 days. In the puff stage, the well was set to produce with a maximum oil rate as 10 STB and minimum BHP as 1,200 psi for 300 days. The time period of three phases in huff-n-puff were designed based on general practical field operation. It is worth mentioning that the “stage” in our model is a half-stage, hence a factor of 200 should be used for scaling rates to a well with 100 full stages. The timeline of huff-
n-puff base case was drawn in Figure 4.5. A sensitivity study was carried out to quantify the impacts of high water cut. The goal is to provide insights into key parameters controlling the high water cut after a CO₂ huff-n-puff process in the Wolfcamp formation.

![Figure 4.5 Timeline of huff-n-puff base case.](image)

**4.2 Huff-n-puff vs. depletion**

The base model was established with six CO₂ huff-n-puff cycles simulated. A case with only depletion was also run as shown in Figure 4.6. The recovery factor for huff-n-puff case was 11.46%, which was 1.48 times the 7.74% RF of depletion. The improvement factor of 1.48 matched the field observations in the literature (Wang et al. 2017; Hoffman 2018).

![Figure 4.6 Comparison of huff-n-puff and depletion oil recovery factor](image)

Table 4.3 shows the component RF of C₃. After gas injection, less C₃ was recovered from oil phase, but more significantly amount of C₃ increase was found in the produced gas,
demonstrating increased yield of NGL and the enrichment of the produced gas due to vaporizing effect. The component RF of C$_3$ was slightly higher than that of oil due to the compositional nature of the gas huff-n-puff.

Table 4.3 Component Recovery Factor of C$_3$

<table>
<thead>
<tr>
<th></th>
<th>Produced C$_3$ in Oil, mol</th>
<th>Produced C$_3$ in Gas, mol</th>
<th>Original in place, mol</th>
<th>RF</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depletion</td>
<td>89991</td>
<td>279217</td>
<td>369208</td>
<td>7.73%</td>
</tr>
<tr>
<td>Huff-n-puff</td>
<td>87333</td>
<td>482661</td>
<td>569994</td>
<td>11.93%</td>
</tr>
</tbody>
</table>

With respect to water-cut, it reached a peak at 1.0 due to flowback, then it fell and remained almost constant as 0.38 which represented a typical water-cut behavior during depletion. For huff-n-puff, the water cut would start at a very low value i.e. 0 as only CO$_2$ was being produced when the well was first opened. It then would reach a peak as 0.43 around 10 days and then fell to a value of 0.36. Finally, it would bounce back to a plateau as 0.44 and remain constant for the rest of puff stage. With more cycles, the peak would gradually increase, and the plateau value would decrease as shown in Figure 4.7.

![Figure 4.7](image_url)

Figure 4.7 Comparison of huff-n-puff and depletion water-cut.

Interestingly, the simulated water-cut somehow resembles the water-cut response of Well
271 with CO₂ huff-n-puff in a conventional reservoir (Simpson 1988) as shown in Figure 4.8. But it is different from what was observed in the CO₂ pilot for Wolfcamp formation. The observation from the unconventional play in the CO₂ pilot for Wolfcamp formation of Midland shows that the water cut will increase 0.3 from depletion basis. It will slightly decrease at early stage for each cycle but remain at a level higher than depletion. Hence, we hereinafter explore several possible reasons behind abnormal water-cut response.

![Figure 4.8 Water-cut response after CO₂ huff-n-puff in Well 271 by Simpson (1988).](image)

**4.3 Reasons for high-water cut**

In this part, several influencing factors including underestimation of initial water saturation, IFT-dependent relative permeability, reactivation of water-bearing layers, and re-opening of unpropped hydraulic fractures on water-cut were simulated and identified.

**4.3.1 Initial water saturation**

First, we assumed there were errors in the initial water saturation, and hence raised the
initial water saturation $Sw_i$ of each layer by 10%. One was used, if the new initial water saturation of a layer exceeded one. The new water-cut showed approximately a translation of 0.1 in vertical axis based on the previous curve as shown in Figure 4.9. But the trend still could not match the field observation. Initial water saturation though could significantly shift the water-cut might not be a reason behind above-mentioned abnormal water-cut behaviors after huff-n-puff.

![Figure 4.9 Water-cut after increasing the $Sw_i$.](image)

**4.3.2 IFT-dependent relative permeability**

By default, the CMG simulator would not consider the effect of interfacial tension on relative permeability (CMG 2018) though it is a very important mechanism for miscible injection, which is the case in this study. We hence turned on the IFT-dependent relative permeability option. The new water-cut curve showed a decreased value of its peak, but an increased plateau value as shown in Figure 4.10. But overall, the oil recovery factor was almost unchanged with or without considering the IFT-dependent relative permeability. The reason might be that only oil and gas phase relative permeability are treated as function of IFT but not water relative permeability. However, according to Monger and Coma (1988), water-cut did increase from 0.30 to 0.67 after
CO₂ injection above MMP. In this study, since MMP for CO₂ is 2020 psi based on our calculation, miscible injection is also the case for this pilot. Hence more related work on IFT-dependent water relative permeability might be required to further correlate MMP with high water-cut.

![Figure 4.10 Water-cut after considering IFT-dependent relative permeability.](image)

**4.3.3 Reopening of water bearing layers**

Then we simulated the reopening of water bearing layers i.e. layer 9 and 12 by increasing the permeability of NF grid blocks from 0.025 md to 0.25 md, supposing that natural fracture in these layers were reactivated due to gas injection. As shown in Figure 4.11, the water cut did increase, but the peak value was still lower than observed from the field.
4.3.4 Reopening of unpropped hydraulic fractures

Previous studies by Chen et al. 2015; Ishida et al. 2016 have shown the average breakdown pressure of supercritical CO$_2$ is only 73% of water due to its lower viscosity. The injected CO$_2$ in our case was in supercritical state under the injection pressure and in-situ temperature, and its breakdown pressure might be even lower with pre-existing hydraulic fractures. The reopening of fractures during huff-n-puff can also be verified to some extent by the CO$_2$ breakthrough observed in the pilot. CO$_2$ breakthrough was observed in offset wells at late time of injection under higher injection pressure, and its level would return to normal once the injection stopped. Moreover, the severity of breakthrough could be reduced by increasing injection pressure in a stepwise manner, which strongly indicates such inter-well connectivity is mostly dominated by the reopening of existing fractures. Hence, we hypothetically changed the relative permeability curve of unpropped fractures from matrix types, as shown in Figure 3.14 to Figure 3.15 to fracture types, as shown in Figure 3.16 to Figure 3.17 assuming that unpropped hydraulic fractures were reopened due to the injection of CO$_2$. Finally, we were able to obtain a relatively good match with field observations. As shown in Figure 4.12, the water-cut did increase due to enhanced fractional
flow of water, and the water cut reached a maximum as 0.63. The water-cut slightly decreased with more cycles, but its value was still higher than the depletion value as 0.38 which is closer to the field observations. Figure 4.13 exhibits the different recovery factors among depletion, huff-n-puff base and huff-n-puff with high water-cut. And excessive water production would reduce the RF from 11.46% to 10.12%.

Figure 4.12 Water-cut considering reactivation of unpropped HF.

Figure 4.13 Comparison of recovery factors among cases.

According to our simulation results, the most possible reason behind high water-cut is the
reopening of unpropped hydraulic fracture. Hence, several operational constraints are proposed for the future work. For example, the maximum BHP of injector must be tightly controlled at a lower value so as to restrain the unpropped hydraulic fracture from reopening when injecting CO$_2$ into the well. In addition, reactivation of water layers is one of the indispensable factors in processing high water-cut, and it could be controlled by BHP in this way as well.
SENSITIVITY ANALYSIS

Sensitivity analysis was primarily used to identify the simulation results under variation of different reservoir parameters so that guide practical production. Generally, operating conditions in sensitivity analysis include parameters such as injection rate, injection temperature, injection time, soaking time and production time. In this chapter, soaking time, injection time and bottom hole pressure will be investigated in detail. The case that already matched field observation was utilized as the base case for sensitivity analysis, and we attempt to adjust the period of injection and soaking phases to identify whether the economic benefits will be improved. The base case started CO$_2$ injection on October 1$^{st}$, 2021 for 50 days, then shut in the well for 10 days during soaking period and reopened the well to production for 300 days. Injection rate was set as 60,000 ft$^3$/day and bottom-hole pressure of producer was maintained at 1200 psi. Six cycles were conducted to predict the cumulative oil and water production.

5.1 Effect of soaking time

First, we investigated the effect of soaking time on cumulative oil production. The cumulative oil production histories at different soaking times (soaking 1D, 5D, 10D, 50D and 100D) for six cycles have been shown in Figure 5.1. The cumulative oil production of those five cases were summarized in Table 5.1. There is a general trend that late cycles yielded more oil than the earlier cycles among five cases. Cumulative oil production ranges from about 3,428 to 3,462 bbl, and a longer soaking time did achieve a slightly higher cumulative oil production. However, the small increase might not make up for the time costs. Therefore, a shorter soaking time is suggested to the development plan of this reservoir so that the development time can be shortened.
Also, it was probably because of the instantaneous equilibrium within the CMG-GEM simulator, the soaking time thus does not make any major difference on enhancing cumulative oil production.

![Cumulative Oil Production at different soaking times.](image)

**Figure 5.1 Cumulative Oil Production at different soaking times.**

<table>
<thead>
<tr>
<th>Soaking Time in Each Cycle</th>
<th>Injection Starts Date</th>
<th>End Date After Six Cycles</th>
<th>Cumulative Oil Production (bbl)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2021-10-01</td>
<td>2027-07-08</td>
<td>3428.64</td>
</tr>
<tr>
<td>5</td>
<td>2021-10-01</td>
<td>2027-08-01</td>
<td>3436.22</td>
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<td>3443.95</td>
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<td>2021-10-01</td>
<td>2028-04-27</td>
<td>3458.19</td>
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<tr>
<td>100</td>
<td>2021-10-01</td>
<td>2029-02-21</td>
<td>3462.41</td>
</tr>
</tbody>
</table>

To further analyze the change during the soaking period, the matrix pressure variations and fracture gas saturation variations in one cycle of huff-n-puff process (before CO2 injection, soaking
11D, 42D, 73D and 100D) were examined (Figure 5.2 to Figure 5.6). We chose first I plane and JK 2D view of matrix pressure as the representative to identify the variation. The 15th plane and IK 2D view was chosen to study the gas saturation in fracture system (Figure 5.7 to Figure 5.11). The reason why we chose the 15th plane was because the well was located in this plane. Thus, apparent variations were better to identify. It was observed the matrix pressure gently decreased with the increase of soaking time and became stable after soaking 42 days. Also, gas saturation in fracture nearly had no decrease after soaking 42 days, which means the gas have diffused the whole reservoir in a short time and longer soaking time turned out to be meaningless.

Figure 5.2 Matrix pressure before CO$_2$ injection.
Figure 5.3 Matrix pressure at soaking 11D.

Figure 5.4 Matrix pressure at soaking 42D.
Figure 5.5 Matrix pressure at soaking 73D.

Figure 5.6 Matrix pressure at soaking 100D.
Figure 5.7 Gas saturation in fracture system before CO$_2$ injection.

Figure 5.8 Gas saturation in fracture at soaking 11D.
Figure 5.9 Gas saturation in fracture at soaking 42D.

Figure 5.10 Gas saturation in fracture at soaking 73D.
5.2 Effect of bottom-hole pressure

Four cases were run under conditions bottom-hole pressure (BHP) of the producer maintained at 800 psi, 1000 psi, 1200 psi and 1500 psi. The case that well produced at a constant BHP 1200 psi was the base case. Profiles of bottom-hole pressure of producer were shown in Figure 5.12. It was found the well bottom hole pressures were strictly followed the BHP constrains. Table 5.2 gives the detailed results of cumulative oil production after conducting six huff-n-puff cycles. From the table, even cumulative oil production did increase as the BHP decreased, the increased amount was insignificant. Figure 5.13 exhibits that the water-cuts behave in the same trend at four different bottom-hole pressure. Thus, well produced at condition BHP 1500 psi is suggested. In addition, we conclude BHP is not a crucial factor, and tight control over BHP may not yield benefits both in rising oil production and reducing water production.
Figure 5.12 Profiles of well bottom-hole pressure of producer.

Table 5.2 Cumulative Oil Production under different BHP

<table>
<thead>
<tr>
<th>Well Bottom-hole Pressure (psi)</th>
<th>Cumulative Oil Production (bbl)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1500</td>
<td>3395.76</td>
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<tr>
<td>1200</td>
<td>3440.50</td>
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<tr>
<td>1000</td>
<td>3442.64</td>
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<tr>
<td>800</td>
<td>3481.33</td>
</tr>
</tbody>
</table>

Figure 5.13 Profiles of water cut at different bottom-hole pressure.
5.3 Effect of injection time and economic analysis

In this part, effect of injection time (30 days, 50 days, 100 days, 150 days and 200 days) in each cycle on production was investigated and an economic analysis was conducted. Figure 5.14 to Figure 5.17 illustrate profiles of oil rate at five different injection times, respectively. The highest oil rate reached to 5.3 bbl/d, which occurred at the case injecting 200 days. The lowest oil rate was around 0.5 bbl/d when injecting 30 days. Figure 5.18 gives the cumulative oil production at different injection times. The maximum cumulative oil production was 5,649.1 bbl, which was achieved at condition injecting 150 days. The minimum cumulative oil production was 2,845.3 when injecting 30 days.

![Figure 5.14 Oil rate when injecting 50 days and 30 days.](image)
Figure 5.15 Oil rate when injecting 50 days and 100 days.

Figure 5.16 Oil rate when injecting 150 days and 100 day.
Figure 5.17 Oil rate when injecting 150 days and 200 days.

Figure 5.18 Cumulative oil production at different injection time.
It was observed the cumulative oil production of injecting 150 days was larger than injecting 200 days. Figure 5.17 suggests oil rate of the first cycle when injecting 200 days is larger than injecting 150 days while next five cycles becomes smaller than it. Then, we found more CO₂ was produced from producer when injecting 200 days from Table 5.3. In addition, we concluded that larger amount CO₂ injection has displaced oil into far places in reservoir thus less oil production was achieved when injecting 200 days.

| Table 5.3 Components produced in oil and gas phases between injecting 150 and 200 days |
|---------------------------------|-----------------|-----------------|-----------------|-----------------|
|                                  | 150 Days         |                  | 200 Days         |                  |
|                                  | Produced in Oil (moles) | Produced in Gas (moles) | Total (moles) | Produced in Oil (moles) | Produced in Gas (moles) | Total (moles) |
| CO₂                             | 4.12E+04         | 2.57E+07         | 2.57E+07        | 3.74E+04         | 2.72E+07         | 2.72E+07     |
| CH₄                             | 2.86E+03         | 3.54E+06         | 3.54E+06        | 2.75E+03         | 3.33E+06         | 3.33E+06     |
| N₂-C₂                           | 1.64E+04         | 9.62E+05         | 9.78E+05        | 1.57E+04         | 9.06E+05         | 9.22E+05     |
| C₃                              | 9.42E+04         | 7.12E+05         | 8.06E+05        | 8.91E+04         | 6.71E+05         | 7.60E+05     |
| C₄-6                            | 6.28E+05         | 5.52E+05         | 1.18E+06        | 5.81E+05         | 5.31E+05         | 1.11E+06     |
| C₇-₁₅                           | 2.39E+06         | 2.03E+04         | 2.41E+06        | 2.26E+06         | 2.15E+04         | 2.28E+06     |
| C₁₆-₂₄                          | 5.95E+05         | 5.67E-02         | 5.95E+05        | 5.62E+05         | 6.14E-02         | 5.62E+05     |
| C₂₅+                            | 4.98E+05         | 4.63E-08         | 4.98E+05        | 4.70E+05         | 4.97E-08         | 4.70E+05     |

Figure 5.19 to Figure 5.22 show the profiles of water-cut when injecting different days. All cases showed that water-cut decreased with the number of cycles increasing except the case injecting 30 days. Generally, average water-cut decreased as injection time increasing. However, the case injecting 150 days owned a lowest average water-cut compared with the other four cases. Its water-cut was around 0.6 in the first cycle and stabilized at 0.5 in the following cycles.
Figure 5.19 Water-cut when injecting 50 days and 30 days.

Figure 5.20 Water-cut when injecting 50 days and 100 days.
In this sensitivity analysis, we found soaking time and bottom-hole pressure did not have much influence on cumulative oil production. However, injection time did exert a significant effect on it. It needs to mention that injection time will not be conducted in such a long time in real field operation. For the case injecting 200 days, the bottom hole pressure of injector already exceeded
10,000 psi and reaches breakdown pressure, while we can investigate the sensitivity of injection time in theory.

To compare the profits of different schemes, Net present value (NPV) is taken as our objective function in this economic analysis. NPV is the difference between the present value of cash inflows and cash outflows during a period of time. Oil production is the source of income and gas injection costs. We set monthly discount rate as \( i = 0.008 \), CO\(_2\) price as \$1.5/Mcf and oil price as \$70/bbl. The purchase of CO\(_2\) usually accounts for the largest project cost. The value of CO\(_2\) behaves as a commodity and its price was determined by pressure, pipeline quality and accessibility (National Energy Technology Laboratory, 2010). The oil company has its own pipeline in our case thus the CO\(_2\) is cheaper than common market price. The NPV evaluation is performed for six cycles among five cases, and 2021 Oct 1\(^{st}\) was set as the start of prediction. The NPV variations are summarized in Table 5.4 to Table 5.8.

\[
NPV = \sum_{k=0}^{t} \frac{(NCF)_k}{(1 + i)^k}
\]  

(5.1)

where

\( k \) = month

\( t \) = project life

\((NCF)_k\) = net cash flow for period \( k \)

\( i \) = discount rate (fraction)
Table 5.4 NPV variation when injecting 30 days in each cycle

<table>
<thead>
<tr>
<th>Cycle</th>
<th>Day</th>
<th>Time</th>
<th>Gas Injection Volume (ft³)</th>
<th>Cum. Oil (bbl)</th>
<th>Increment of Cum. Oil (bbl)</th>
<th>Delta NPV ($)</th>
<th>NPV ($)</th>
</tr>
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<td>1800000</td>
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Table 5.5 NPV variation when injecting 50 days in each cycle

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<th>Gas Injection Volume (ft³)</th>
<th>Cum. Oil (bbl)</th>
<th>Increment of Cum. Oil (bbl)</th>
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Table 5.6 NPV variation when injecting 100 days in each cycle

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<th>Time</th>
<th>Gas Injection Volume (ft³)</th>
<th>Cum. Oil (bbl)</th>
<th>Increment of Cum. Oil (bbl)</th>
<th>Delta NPV ($)</th>
<th>NPV ($)</th>
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<td>10/1/21</td>
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Table 5.7 NPV variation when injecting 150 days in each cycle

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<th>Time</th>
<th>Gas Injection Volume (ft³)</th>
<th>Cum. Oil (bbl)</th>
<th>Increment of Cum. Oil (bbl)</th>
<th>Delta NPV ($)</th>
<th>NPV ($)</th>
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Table 5.8 NPV variation when injecting 200 days in each cycle

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<th>Time</th>
<th>Gas Injection Volume (ft³)</th>
<th>Cum. Oil (bbl)</th>
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According to Figure 5.23, NPV was largely improved when the injection time increased. We found injecting 150 days is the optimal scheme among all cases. Thus, NPV can be further improved with the injection time increasing. However, when the injection time was set as 200 days, NPV decreased with the increase of injection time in comparison with injecting 150 days. It was because the benefit of increment oil production cannot make up for the costs due to gas injection in a certain degree. Compared with base case (injecting 50 days), the optimal simulation case has a longer cycle period and NPV will reach to $125,825 on April 22nd, 2029. It did produce more oil, while more gas was injected into the well.
Figure 5.23 Net present value variations under different injection times.
CHAPTER 6
CONCLUSIONS AND FUTURE WORK

6.1 Conclusions

Eight pseudo-components were lumped, and their thermodynamic properties were tuned to match the PVT experiment results using Peng-Robinson EOS. The main tuning parameters during regression process were critical properties of pseudo-components, interaction coefficient and volume shift. A lab-scale simulation model was established first to match the data from core experiment, where relative permeability curves of tight rock and rock compressibility were key uncertainties.

Several influencing factors on water-cut were simulated. Field observed water-cut behavior was qualitatively matched in the simulation by shifting unpropped HF relative permeability curves from matrix-type to fracture-type after CO$_2$ injection.

Our simulation results have shown that initial water saturation, IFT-dependent relative permeability, reactivation of water-bearing layers, and re-opening of unpropped hydraulic fractures may all affect water-cut after gas injection. Among them, re-opening of unpropped hydraulic fractures was the most probable reason behind the high water-cut.

Sensitivity analysis was conducted regarding parameters such as soaking time, injection time, and bottom-hole pressure. Setting injection time as 150 days in each cycle can achieve the highest net present value.
6.2 Future work

Firstly, to model grid’s pressure or saturation variation more accurately in the lab-scale model, grid refinement should be included especially near the interface where permeability or porosity suddenly change.

Secondly, literature suggests asphaltene precipitation may occur in the Wolfcamp basin. Thus, a new PVT model considering asphaltene precipitation should be established to better characterize the reservoir oil. Wettability alteration caused by asphaltene precipitation can be modeled by interpolating several sets of relative permeability and capillary pressure curves, based on the volume fraction of asphaltene deposition. Then, permeability and porosity reduction can be captured as a function of the deposited asphaltene.

Moreover, a coupled geochemical reaction simulator should be employed to explore other possible reasons behind the water-cut rise, including wettability alteration, and chemical reactions between CO₂ and formation minerals.
REFERENCE


