THE TUNING OF THE TODD AND LONGSTAFF MIXING PARAMETER IN LIMITED COMPOSITIONAL SIMULATION TO OPTIMIZE RECOVERY FROM A GAS CONDENSATE RESERVOIR

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By

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CERTIFICATION

This is to certify that the thesis titled "**THE TUNING OF THE TODD AND LONGSTAFF MIXING PARAMETER IN LIMITED COMPOSITIONAL SIMULATION TO OPTIMIZE RECOVERY FROM A GAS CONDENSATE RESERVOIR**" submitted to the school of postgraduate studies, African University of Science and Technology (AUST), Abuja, Nigeria for the award of the Master's degree is a record of original research carried out by Abdulsalam, Awal Adava in the Department of Petroleum Engineering.

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By

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ABSTRACT

A gas condensate reservoir is a type of gas reservoir that exists when the reservoir temperature is between the critical temperature and the cricondentherm. Compositional simulators are used to simulate these types of reservoirs but they require a lot of input data and high CPU processing time. Black oil simulators have been employed to simulate these types of reservoirs by introducing a mixing parameter to determine the degree of mixing between the injected fluid and the fluid in place.

This research focuses on the tuning of the Todd and Longstaff mixing parameter in limited compositional simulation to optimize recovery from a gas condensate reservoir. This research was achieved by studying the production performance of a condensate reservoir using a limited compositional simulator. Three different production schemes were analyzed in the case study namely, natural depletion, gas injection, and water alternating gas (WAG) injection. Comparative analysis was carried out for all production schemes in the case study to determine similarities and differences between the results from the fully compositional and limited compositional simulation. Both simulators were used to track the saturations and pressures at the layers in the model where the production well was completed. The tracked saturations and pressures were used to determine the impact of condensate banking on reservoir performance.

A set of well configurations and injection patterns was used to evaluate the impact of varying the Todd and Longstaff mixing parameter on the gas condensate recovery and also to determine the optimal mixing parameter for gas injection and WAG injection in gas condensate reservoirs. Sensitivity analysis was employed to determine the effect of Todd and Longstaff mixing parameter, initial water saturation, and permeability anisotropy on the cumulative recovery.

The results obtained from this study shows that; for a lean gas condensate reservoir, the results from the fully compositional and limited compositional simulation are not similar if the Todd and Longstaff mixing parameter is not optimized, natural depletion of gas condensate reservoirs is not very effective because of the condensate banking and low condensate recovery, gas injection and WAG process are the recommended methods to produce gas condensate reservoirs. It is concluded that for optimal recovery from a lean gas condensate reservoir the mixing parameter should be between 0.990 and 0.996, and permeability anisotropy has a significant effect on condensate recovery.

KEYWORDS: Gas Condensate reservoir, miscible gas injection, limited compositional simulation, water alternating gas (WAG) injection, Todd and Longstaff mixing parameter, condensate banking.

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CHAPTER ONE

1.0 Introduction

This chapter gives a brief introduction to gas condensate reservoirs and the use of Todd and Longstaff mixing parameter in a limited compositional simulator. It also outlined the aims and objectives, research question, motivation, scope, and limitations of the study.

1.1 Gas Condensate Reservoirs

A gas condensate reservoir is a type of gas reservoir that exists when the reservoir temperature is between the critical temperature and cricondentherm (McCain, 2017). This type of reservoir has been found in the Niger Delta region (Adewusi, 1998). Under certain conditions of temperature and pressure, the fluid from this type of reservoir separates into two phases, a gas and a liquid called a retrograde condensate which is the fluid of interest (Fan et al., 2005). Sometimes, the quantity of retrograde condensate produced from this type of reservoir might be small thereby treated as a wet gas reservoir (McCain, 2017). The liquid produced from this type of reservoir is usually light-coloured or colourless at the stock tank with gravities above 45 °API and gas-oil ratios (GOR) between 5000-100000 SCF/STB (Craft et al., 2012).

Miscible gas injection is used to improve the recovery from gas condensate reservoirs. This is achieved by injecting gas into the reservoir thereby reducing the interfacial tension between the injected fluid and the fluid in place, making the fluid displace each other more freely (Stalkup, 1983). This process is also used to mitigate condensate blockage around the reservoir wellbore (Nasiri-Ghiri et al., 2015). Availability of gas is often an issue when dealing with miscible gas injection. This process is faced with a more challenging issue which is the high mobility ratio between the injected gas and the fluid in place (Koval, 1963, Hassan et al., 2019). The high mobility ratio experienced in the reservoir later results in early gas breakthrough and poor sweep efficiency (Al-Haboobi, 2019, Koval, 1963). This phenomenon is termed Saffman-Taylor instability or viscous fingering (Todd & Longstaff, 1972). Water alternating gas (WAG) injection is another recovery process that involves the alternating injection of gas and water. This process has been employed to solve this issue of viscous fingering in miscible gas injection, thereby increasing sweep efficiency in gas condensate reservoirs. It does this by reducing the mobility ratio at the displacement front thereby reducing the effect of viscous fingering (Al-Haboobi, 2019).

Reservoir simulation is a tool often used in the oil and gas industry to determine the performance of a reservoir. Compositional simulators are used for the simulation of gas condensate reservoirs, but they require a lot of input data and high processing time (Bolling, 1987). Todd and Longstaff (1972) developed a model for predicting miscible flood performance in a numerical simulator. They came up with a mixing parameter (ω) which is adjusted to measure the degree of mixing between the oil and gas phase between a grid block. This adjustable mixing parameter made a black oil simulator an efficient tool for simulating gas condensate reservoirs especially when the input data is sparse. Todd and Longstaff (1972) explained that when the mixing parameter (ω) is zero (0), it can be said that there is no mixing between the injected fluid and the fluid in place, but when the mixing parameter (ω) is one (1), there is a complete mixing between the injected fluid and the fluid in place. They further explained that a mixing parameter (ω) between zero (0) and one (1) signifies partial mixing within the grid block. They finally recommended that a mixing parameter (ω) of 0.667 should be used for simulation of laboratory studies, and a value of 0.333 for field projects.

This research focuses on the tuning of the Todd and Longstaff mixing parameter (ω) in limited compositional simulation to optimize recovery from a gas condensate reservoir. Simulations of natural depletion of the reservoir, miscible gas injection, and WAG injection were studied using a limited compositional simulator. Optimum recovery was determined by analyzing different injection patterns, well configuration, and tuning of mixing parameter (ω) in the limited compositional simulations.

1.2 The motivation of the Study

The focus of oil and gas explorations in the past few decades has been on gas condensate reservoirs. Compositional simulators are constantly used by reservoir engineers to accurately predict and optimize recovery from gas condensate reservoirs (Coats, 1985). But this approach is limited by major constraints of excessive input data requirement and high processing time. In 1972, Todd and Longstaff developed a model for the prediction of miscible flooding performance using a limited compositional simulator. They came up with a mixing parameter (ω) for predicting the degree of mixing between the fluid injected and the fluid in place. In their case study, they recommended a mixing parameter of 0.333 for the field project. This mixing parameter was generalized for all types of reservoirs but limited to five-spot injection patterns. Several studies have recommended various mixing parameters for the simulation of various injection processes. Therefore, there is a need to determine an accurate mixing parameter irrespective of the injection pattern, that can be used to predict the optimal recovery from gas condensate reservoirs with a range of fluid compositions. This study attempts to study the optimal mixing parameter for simulating the performance of a lean gas condensate reservoir located in the Niger Delta.

1.3 Research Questions Posed in this Study

This study is designed to answer the following research questions:

- Can the results from a fully compositional simulation of reservoir performance be comparable to the results from a limited compositional simulation in a gas condensate reservoir?
- And if so, at what mixing parameter will the recovery from both simulations be about the same?
- How does tuning the Todd and Longstaff mixing parameter affect the recovery from a gas condensate reservoir using different injection patterns and well configurations?
- What is the correct mixing parameter for simulating recovery performance during miscible gas injection and water-alternating-gas (WAG) injection in a gas condensate reservoir?
- What is the effect of the mixing parameter and permeability anisotropy (kv/kh) on the cumulative oil produced from a gas condensate reservoir?
- What is the impact of condensate banking on the cumulative oil recovery from a gas condensate reservoir?

1.4 Aims of the Study

Numerical simulators are known to be good predictive tools for the estimation and optimization of oil and gas recovery from reservoirs. This study aims at the tuning of the Todd and Longstaff mixing parameter (ω) in limited compositional simulation to optimize recovery from a gas condensate reservoir using a case study derived from the Niger Delta.

1.5 Objectives of the Study

The objectives of this study include:

- To compare the results obtained from fully compositional simulation (benchmark) of the oil produced from a gas condensate reservoir to those from limited compositional simulation by varying Todd and Longstaff mixing parameter (ω).
- To determine the impact of condensate banking on the cumulative oil recovery from a gas condensate reservoir.
- To evaluate the impact of varying the Todd and Longstaff mixing parameter (ω) on the gas condensate recovery using horizontal well, five-spot injection pattern, and staggered line drive.
- To determine the impact of permeability anisotropy varying the Todd and Longstaff mixing parameter (ω) on the cumulative oil produced from a gas condensate reservoir.

1.6 Scope and Limitation of the Study

In this study, the recovery performance of a gas condensate reservoir by natural depletion was first explored. Then, two regular injection patterns (i.e., five-spot injection pattern and staggered line drive) were used to analyze the recovery from the application of miscible gas injection and WAG process to the condensate reservoir. The fully compositional simulation was used only as a benchmark to compare the recoveries from the condensate reservoir to those obtained from the limited compositional simulations.

1.7 Organization of the Thesis

The thesis is presented in five Chapters. The introduction and aims and objectives of this study are presented in Chapter 1. Chapter 2 contains a literature review to provide an understanding of the background and previous studies related to condensate reservoirs and limited compositional simulation. In Chapter 3, the study methodology is presented. The results obtained from the simulations are presented and discussed in Chapter 4. In Chapter 5, a summary of this study and a set of conclusions are presented, and then recommendations are proposed for further research to improve the results of this study.

CHAPTER TWO

2.0 Literature Review

A review of the literature on gas condensate reservoirs is presented in this chapter. This chapter contains an overview of gas condensate reservoirs where the development of gas condensate systems and condensate banking in the reservoir were discussed and reviewed. Miscible gas injection was also reviewed and Todd and Longstaff (1972) work was compared with other preceding works.

2.1 Gas condensate reservoirs overview.

Gas condensate reservoirs consist mainly of methane (C1), short-chain hydrocarbons, and long-chain hydrocarbon called heavy ends. Under certain conditions of temperature and pressure, the fluid from this type of reservoir separates into two phases, a gas and a liquid called a retrograde condensate which is the fluid of interest (Fan et al., 2005). The liquid produced from this type of reservoir is usually light-coloured or colourless at the stock tank with gravities above 45 °API, and gas-oil ratios (GOR) between 5000 and 100000 SCF/STB (Craft et al., 2012). As this reservoir is produced the reservoir temperature tends to remain constant while reservoir pressure declines until it gets to its dew point as shown in figure 2.1. At this point, the liquid phase rich in heavy ends drops out of the solution (Fan et al., 2005). According to Fan et al. (2005), further decline in the reservoir pressure below the dew point will result in two main negative effects which are; decrease in condensate and gas production as a result of near-wellbore blockage, and reduction in the heavy ends produced due to gas droplet during production.

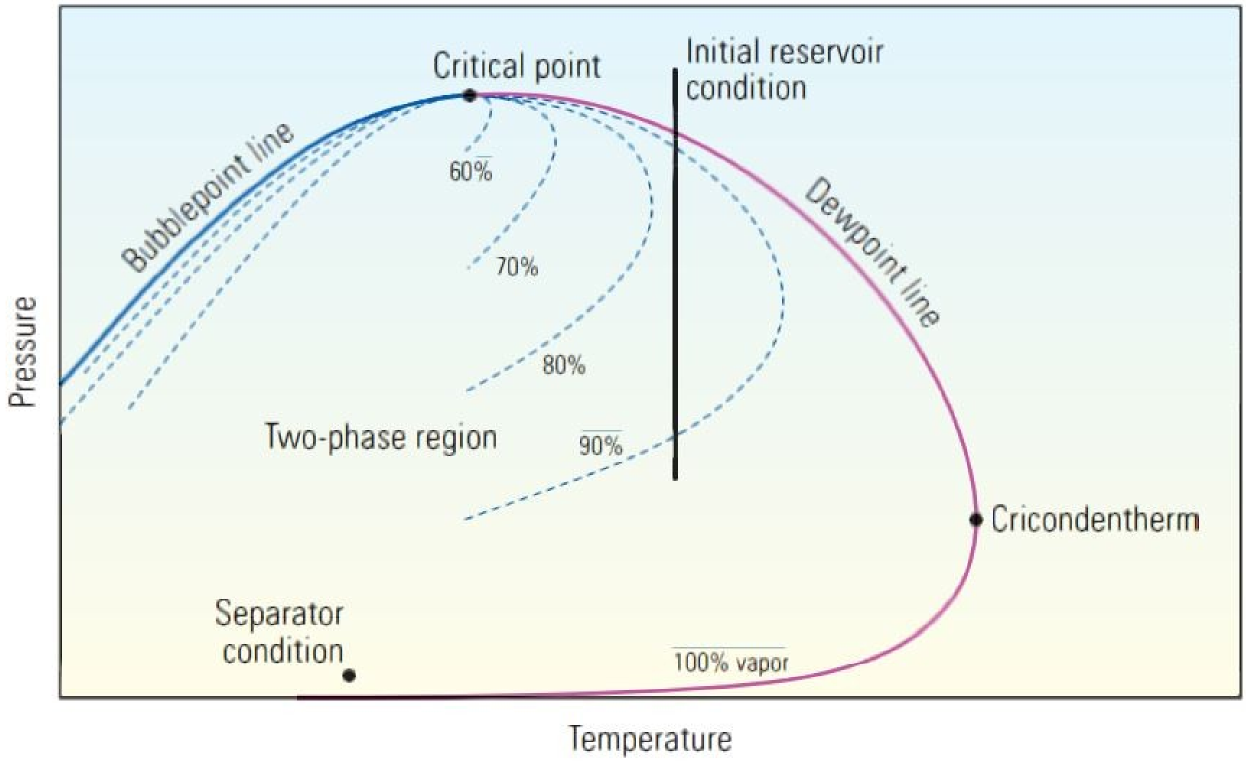


Figure 2.1: Phase Diagram of a Gas Condensate System (Fan et al., 2005).

The behavior of gas condensate reservoirs during production can be described using three concentric flow regions from the wellbore to the reservoir boundary. The regions are Region I--near the wellbore, Region II--condensate build-up, and Region III and IV--single gas-phase flow (Adel et al., 2006). The schematic in Figure 2.2 shows these different regions.

Region I

This region is close to the near-wellbore region with high condensate saturation. In this region, simultaneous flow of gas and condensate occurs. For this region to exist bottom-hole flowing pressure has to be less than the critical pressure, i.e., the pressure at which condensate saturation is equal to the critical saturation (Adel et al., 2006). This region is also called condensate banking region because of the accumulation of condensate around the wellbore, which results in a decrease in the gas effective permeability, thereby leading to low gas production (Hassan et al., 2019, Rahimzadeh et al., 2016).

Region II

In Region II, the reservoir pressure is less than the dew point pressure, which leads to condensate dropping from the gas phase. The dropped condensate in this region is immobile because its saturation is less than the critical saturation required for the condensate to flow (Adel et al., 2006).

Region III and IV

Only the gas phase exists in Region IV and this is as a result of the reservoir pressure being above the dew point pressure. As the reservoir pressure declines due to production and approaches the dew point pressure, a transition region is formed which is known as Region III. This region represents the transition between Region II and Region IV (Adel et al., 2006).

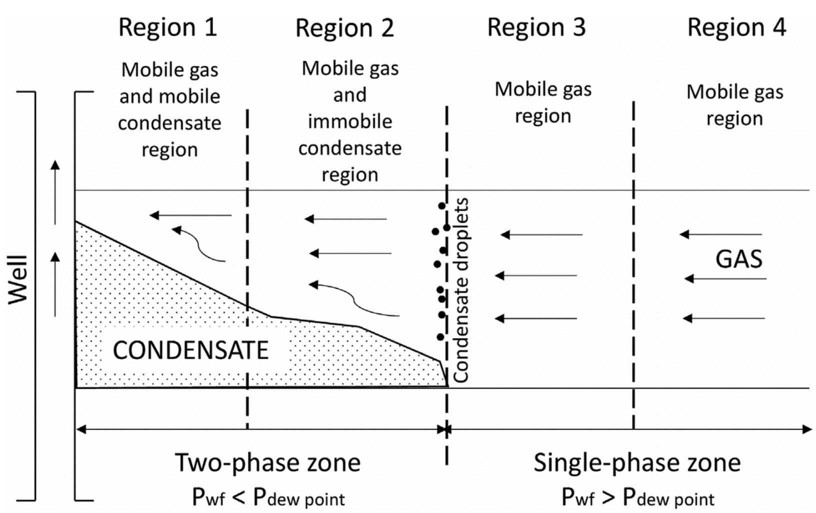


Figure 2.2: Saturation Regions in a Gas Condensate Reservoir (Adapted from Ganie et al., 2019).

Adel et al. (2006) reported that the literature documents many wells that have been lost due to near-wellbore condensate blockage. With the increase in interest in the production of high-temperature, high-pressure wells, the problem of near-wellbore condensate blockage is a disturbing challenge to the oil and gas industry (Barnum et al., 1995). In 1994 Afidick et al. reported that the Arun field in Indonesia showed a 50% productivity loss approximately 10 years after it was put on production due to near-wellbore condensate blockage (Afidick et al., 1994). The Petroleum Development Oman and Shell have also reported productivity loss of 67% of wells in two fields due to the same problem (Rahimzadeh et al., 2016). Other gas-condensate reservoirs reported to be affected by condensate blockage are Cupiagua field in Colombia, Karachaganak field in Kazakhstan, North field in Qatar, and Shtokmanovskoye field in the Russian Barents Sea (Ganie et al., 2019).

The ways to mitigate the problems of condensate blockage have been reported by Hassan et al. (2019). These methods can be classified into short-term solutions (temporary methods) and long-term solutions (permanent methods). The temporary methods for mitigating near-wellbore condensate blockage include acid treatment, solvent injection, gas injection, and water alternating gas (WAG) injection; while the permanent methods are wettability-altering chemicals, drilling horizontal wells, and hydraulic fracturing. But Ganie et al. (2019) did a review of the wettability alteration mechanism in condensate banking and they reported that hydraulic fracturing and horizontal wells could fall in the temporary methods of mitigating against gas condensate because they only delay the problem and reduce the impacts on the well's productivity. The gas injection is the most practical, but not the most economical of all the condensate blockage mitigation techniques mentioned. This is because gas injection maintains the reservoir pressure above the dew point which solves the condensate blockage problem, thereby increasing the productivity of the reservoir (Hassan et al., 2019, Nasiri Ghiri et al., 2015, Craft et al., 2012). Solvent injection could have been an effective method, but it is faced with a major challenge of a short life span (Ganie et al., 2019). This was evident from Al-Anazi et al.'s (2005) investigation when they used methanol in the removal of condensate banking in the Hatter's Pond field in Alabama. They observed a significant increase in productivity after four (4) months of methanol application and later a productivity decline. Ganie et al. (2019) also reported that the safety issue associated with handling low flashpoints in solvents is another drawback in the application of solvent injection. Table 2.1 summarizes the different methods used for mitigating condensate blockage reported by Hassan et al. (2019.

Table 2.1: Methods of solving and mitigating against condensate blockage, situation, mechanism, and limitation (Source: Adapted from Hassan et al., 2019**).**

Methods	Suitable situation	Mechanism	Limitation
Acid treatments	Damaged or low permeability around the wellbore.	Remove condensate blockage around the wellbore.	Causes damage due to precipitation of acid–mineral reaction products.
Solvents Injection	High IFT between condensate and gas.	Increases gas relative permeability.	The solvent used has to be compatible with both reservoir brine and the formation fines.
Gas injection/ recycling	Significant pressure reduction.	Maintain $P_{res} > P_{dew\text{-}point.}$	A large amount of gas is needed. Natural gas

			is often used, but it has its own market.
Water alternating gas	Vertical heterogeneous reservoir.	Maintain P_{res} > $P_{dew\text{-}point.}$	Very expensive.
Wettability alteration	Liquid-wet reservoirs	Surfactant is used to change the grain surface wettability near-wellbore from liquid-wet to gas-wet.	Only reduces surface free energy without surface roughness.
Horizontal wells	Thin reservoir formation.	Increase well contact area, minimize pressure drawdown.	Expensive compared to a vertical well.
Hydraulic Fracturing	Tight reservoirs.	Increase well contact area, minimize pressure drawdown.	Delay time of reaching a P_{dew} -point.

The following section is a discussion of the theory of miscible gas injection and how to overcome the associated issues of viscous fingering with the use of Todd and Longstaff mixing parameter (ω) are discussed.

2.2 Miscible Gas Injection.

Gas injection and gas cycling are regular practices used in gas condensate reservoirs to tackle condensate blockage around the wellbore and to increase productivity (Nasiri-Ghiri et al., 2015). Flue gas, H_2S, CO_2, and N_2 gas are injected into the reservoirs for these purposes, but CO_2 and

N_2 gas are often used (Hassan et al., 2019). These gases undergo a miscible displacement process when injected into the reservoir by forming a single phase with the oil. The benefits of using these gases include tackling issues associated with condensate blockage as well as improving the microscopic sweep efficiency in the reservoir (Green & Willhite, 2018). This improved sweep efficiency is achieved due to the reduction of interfacial tension between the injected gas and the crude oil, thereby making the fluids displace each other more freely within the reservoir (Stalkup, 1983). The driving force for this miscible displacement process to occur is diffusion and dispersion (Al-Haboobi, 2019).

Based on how miscibility is developed in the reservoir, the miscible gas injection can be classified as first contact miscible (FCM) and multiple contact miscible (MCM) processes (Green & Willhite, 2018). Let us review these two miscible processes.

2.2.1 First Contact Miscible (FCM) Process.

According to Green and Willhite (2018), the first contact miscible process commences by the injection of a relatively small primary slug that is miscible with the crude oil. A larger less expensive secondary slug is later injected into the reservoir. It is expected that the primary and secondary slugs injected become miscible with each other, but if miscibility fails to occur, then a residual saturation of the primary slug material will be trapped in the displacement process (Green & Willhite, 2018). Figure 2.3 shows the FCM process where a higher molecular-weight hydrocarbon such as propane which exists as a gas at atmospheric condition and oil which exists as a liquid becomes miscible. This can only be achieved at an increased reservoir temperature and pressure condition, where propane exists as liquid alongside the crude oil. At this point, these two liquids will mix and become miscible (Green & Willhite, 2018). The minimum miscibility pressure can be gotten by calculating the saturation pressure of the mixture of the gas condensate and the injection gases.

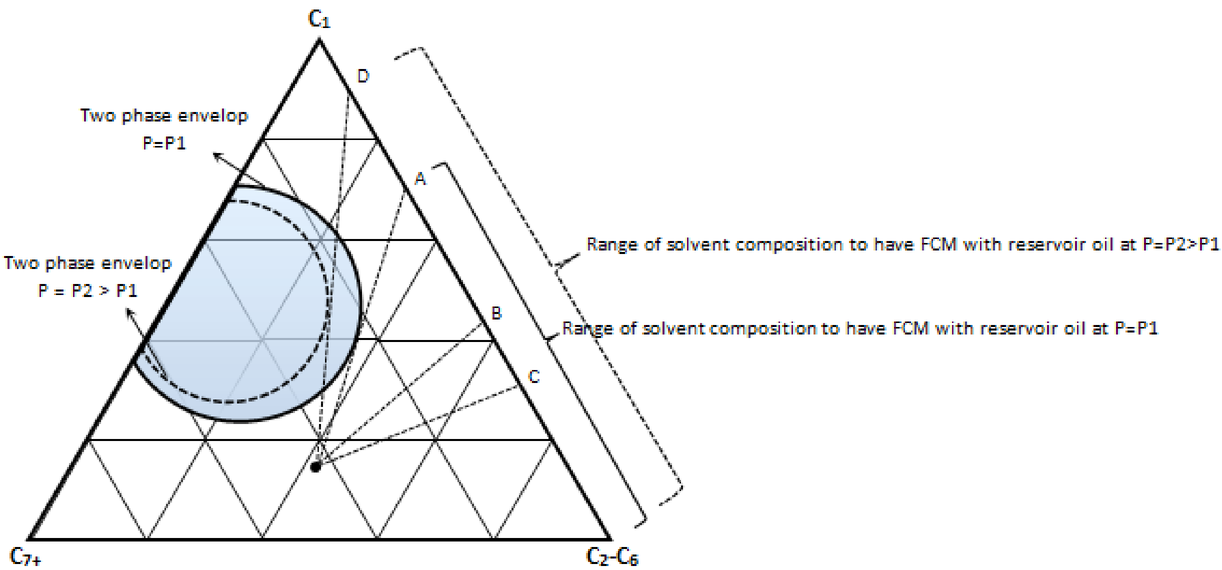


Figure 2.3: Schematic of First Contact Miscible (Source: perminc.com/resources**).**

2.2.2 Multiple Contact Miscible (MCM) Process.

For the multiple contact miscible process, the miscibility is developed through in-situ composition changes resulting from multiple contacts and mass transfer between the injected fluid and reservoir oil. This process is classified as vaporizing-gas (lean-gas) drive and condensing-gas (enriched-gas) drive (Sanger, 1998). This classification was first proposed by Zick (1986) where he conducted a multiple contact experiment on reservoir fluid. The pilot-scale experiment was conducted by loading a sample of reservoir fluid and introducing a sample of injectant. The cell was allowed to equilibrate at the desired pressure where phase volume was measure and the equilibrium gas phase was removed and analyzed. After he repeated the experiment several times and observed seven contacts during each experiment, he then concluded that a combined condensing and vaporizing gas drive mechanism rather than the conventional condensing mechanism may be responsible for the displacement of reservoir oil by enriched gases.

2.2.2.1 Vaporizing-gas drive.

The injected gas in this vaporizing-gas drive is lean (i.e., methane and other low molecular weight hydrocarbon or sometimes inert gases, such as nitrogen). According to Green and Willhite (2018), the composition of the lean gas is modified as it moves through the reservoir so that it becomes miscible with the original reservoir oil. That is, the injected fluid is enriched in composition through multiple contacts with the oil, during which intermediate components in the oil are vaporized into the injected gas. Under proper conditions, this enrichment can be such that the injected fluid of modified composition will become miscible with the oil at some point in the reservoir. From that point on, under idealized conditions, a miscible displacement process will occur in the reservoir (Green & Willhite, 2018). Figure 2.4 shows a schematic of the vaporizing-gas drive process where the injected gas ‘S’ after contacting the oil ‘O’ forms a mixture ‘M1’ that is split into two equilibrated phases of liquid ‘L1’ and gas ‘V1’, determined by the equilibrium tie line. Gas ‘V1’ has much higher mobility than liquid ‘L1’ thereby moving faster and making further contact with fresh oil to form mixture ‘M2’. This process continues till the gas phase no longer forms two-phase when contact with fresh oil. At this point, it can be said that the gas phase becomes miscible with the oil phase and this is indicated with point ‘C’.

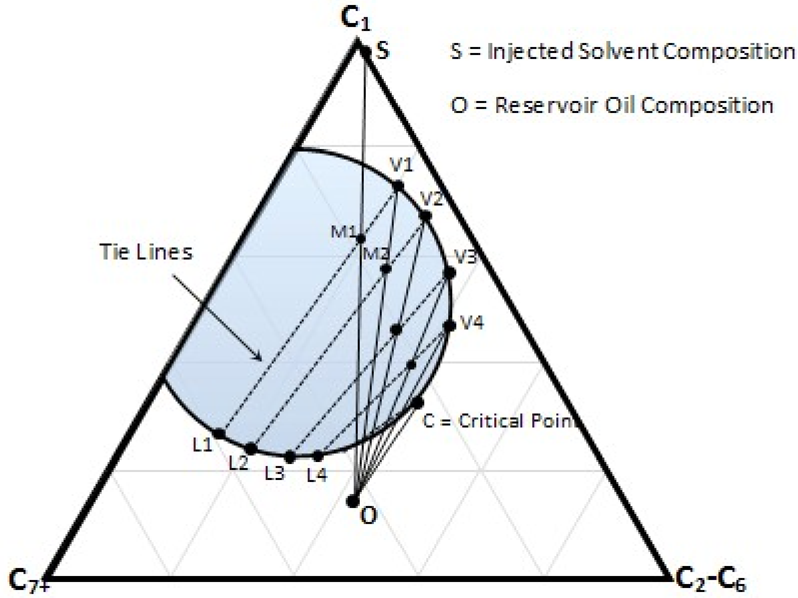


Figure 2.4: Schematic of Vaporizing Gas Drive Process (Source: perminc.com/resources**).**

2.2.2.2 Condensing-gas drive.

For the condensing gas process, the injected fluid which is the enriched gas is composed of intermediate molecular weight hydrocarbons and is more expensive. Green and Willhite (2018) described the mechanisms of the condensing gas drive as a two-stage process. First, the reservoir oil near the injection well is enriched in composition by contact with the injected fluid first put into the reservoir. Second, the hydrocarbon components are condensed from the injected fluid into the oil and thus the process is called a condensing process. Green and Willhite (2018) reported that under proper conditions, the oil will be sufficiently modified in composition as it comes in contact with the injected fluid to become miscible with additional injected fluid and a miscible displacement will occur in the reservoir. The enriched gas process typically can be operated at a lower pressure than the vaporizing gas process (Green & Willhite, 2018). Figure 2.5 which illustrates the behavior of a condensing gas drive depicts that, the injected fluid 'S' after contacting the oil ‘O’ forms a mixture ‘M1’ splits into liquid and gas phase ‘L1’ and ‘V1’ respectively. ‘V1’ has a much higher mobility ratio than ‘L1’ moves faster and makes a fresh contact with the fresh injected fluid to form a mixture ‘M2’. This process continues until the composition of the liquid phase is altered progressively in a similar manner along the bubble point curve until it reaches a critical point. At this point, it can be said that the gas phase becomes miscible with the oil phase.

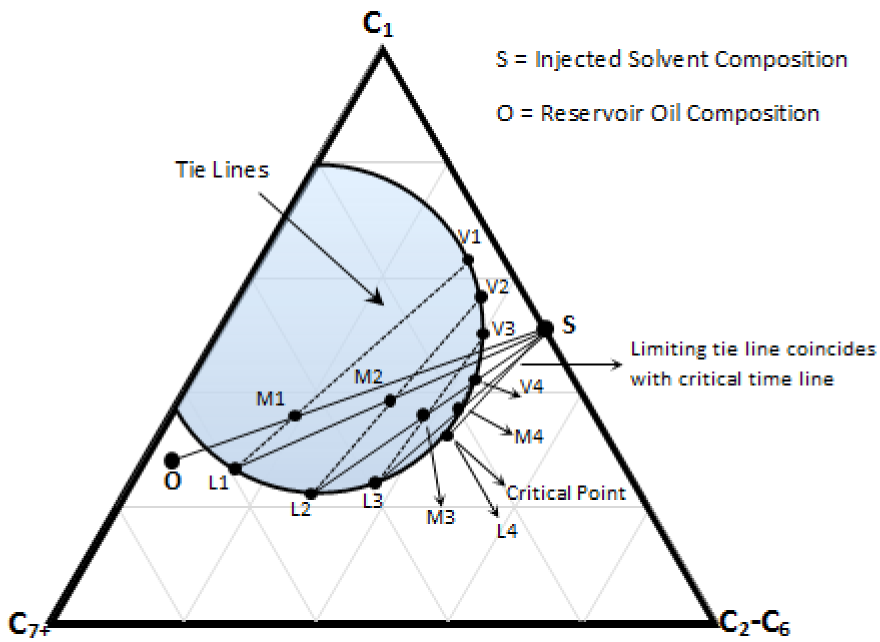


Figure 2.5: Schematic of Condensing Gas Drive (Source: perminc.com/resources**).**

2.2.3 Miscible gas injection challenges.

The availability of injection gas is one of the challenges faced by the miscible gas injection process. In 1963, Koval reported that another major challenge is the high mobility ratio between the injected gas and the crude oil. This high mobility ratio causes gas fingering which later results in early gas breakthrough and poor areal sweep (Al-Haboobi, 2019, Koval, 1963). This phenomenon is termed Saffman-Taylor instability or viscous fingering (Todd & Longstaff). A schematic of viscous fingering in a reservoir is shown in Figure 2.6.

Figure 2.6: Schematic of Viscous Fingering (Source: perminc.com/resources**).**

To solve the problem of viscous fingering, Koval (1963) developed an empirical model for predicting the performance of unstable miscible displacement in heterogeneous media. This model helps to predict oil recovery and solvent cut as a function of the pore volumes of solvent injected. The Koval model is developed based on the Buckley-Leverett equation where he replaced the function of the fractional flow in Buckley-Leverett's equation with a Koval factor (K-factor). In developing the K- factor, he assumes that a single parameter can be used to characterize viscosity effects which are called the effective viscosity ratio. Koval (1963) noted that viscous fingering is a result of longitudinal dispersion, channeling, viscosity difference, gravity difference, and other factors such as diffusion and flooding rates. He, therefore, suggested a value termed K-value to represent viscous fingering which is as follows:

$$K = \left[0.78 + 0.22 \left(\frac{\mu_o}{\mu_s} \right)^{1/4} \right]^4 \tag{2.1}$$

Where μ_o and μ_s are the viscosities of the oil phase and the injected solvent.

2.2.4 Todd & Longstaff Model.

In 1972 Todd & Longstaff developed a model for predicting miscible flood performance in a numerical simulator using a five-spot injection pattern. The model was designed for a two-component miscible flow in a three-component reservoir simulator. A comparison of the Todd-Longstaff model to the Koval's (1963) model shows that it has a parameter (ω) that is adjustable to measure the degree of mixing between the oil and gas phases within a grid block. The degree of mixing is dependent on the fluid properties (i.e., density and viscosity) in the mixing zone between the injected fluid and the oil. The Todd-Longstaff mixing parameter (ω) also describes the amount of viscous fingering within the grid block in a black oil reservoir simulator. A mixing parameter (ω) of one (1) indicates complete mixing between the injected fluid and the oil within the grid block while a mixing parameter (ω) of zero (0) means immiscible displacement or no mixing between the injected fluid and the oil within the grid block. If the Todd-Longstaff mixing parameter is between 0 and 1, it can be referred to as partial mixing within the grid block. For a complete mixing, the density of the mixture is defined as follows:

$$\rho_m = \rho_o \frac{S_o}{S_n} + \rho_s \frac{S_s}{S_n} \tag{2.2}$$

$$S_n = S_o + S_g \tag{2.3}$$

Where

ρ_m, ρ_o, and ρ_s are the densities of the mixture, oil and injected solvent respectively and,

S_o, S_n, and S_s are the saturation of the oil, non-wetting phase, and injected solvent respectively.

For partial mixing, the effective densities are:

$$\rho_{oe} = (1 - \omega)\rho_o + \omega\rho_m \tag{2.4}$$

And

$$\rho_{se} = (1 - \omega)\rho_s + \omega\rho_m \tag{2.5}$$

Where

ρ_{oe} and ρ_{se} are the effective density of oil and injected solvent and,

ω is the mixing parameter.

Todd and Longstaff (1972) recommended a mixing parameter (ω) of $2/3$ for laboratory studies and $1/3$ for field projects and secondary miscible displacements with relatively low injection rate. They also recommended a formula to determine the relative permeability of the miscible injected fluid and oil relative permeabilities. This formula is stated as follows:

$$k_{ro} = \frac{S_o}{S_n} k_{rn} \tag{2.6}$$

And

$$k_{rg} = \frac{S_g}{S_n} k_{rn} \tag{2.7}$$

$$k_{rn} = k_{rn}(S_w) \tag{2.8}$$

Where

k_{ro} and k_{rg} are the relative permeability of oil and gas and,

k_{rn} is the imbibition relative permeability of the non-wetting phase.

Blunt and Christie (1993) extended Todd and Longstaff's (1972) work by developing an analytical model to determine the mixing parameter (ω) for a water alternating gas (WAG) process. They were able to successfully adjust the mixing parameter (ω) for simultaneous water alternating gas (SWAG) process. Blunt and Christie (1993) reported that the value of the mixing parameter (ω) depends on the fractional flow of injected water for both secondary and tertiary displacement. But unfortunately, they could not vary the mixing parameter ω for a periodic WAG process due to the difficulties in performing analytical solutions.

2.3 Chapter Summary

This chapter has discussed and reviewed gas condensate reservoirs, challenges associated with gas condensate reservoirs, miscible gas injection, and Todd & Longstaff's (1972) work. At the end of the review, it can be deduced that condensate banking is a major challenge faced in gas condensate reservoirs, and also Todd and Longstaff’s (1972) work was limited to a five-spot injection pattern with no specific type of reservoir stated. Therefore there is a need to examine;

- The effectiveness of gas injection and WAG process in mitigating against condensate banking
- The effect of different well configurations and injection patterns when tuning the Todd and Longstaff mixing parameter.

The next chapter presents a concise procedure on how the above points will be achieved.

CHAPTER THREE

3.1 Methodology

This chapter covers the methodology of this study. It presents the procedures used to achieve the study's aim and objectives. The assumptions and rationale behind adopting the chosen procedures are also discussed and reviewed in detail.

3.2 Introduction

Gas condensate data from the Niger Delta region was used as the basic data for this study. Commercial software was the main tool used for simulations conducted in this study. This software comprises two main simulators. A limited compositional model (black oil simulator) was the main focus of this study while the compositional simulator was used as a benchmark for comparative analysis of results. The Pressure-Volume and Temperature (PVT) tables, SCAL tables, and reservoir models were generated and simulated using this software. The three different condensate production cases investigated included natural depletion, gas injection, and water-alternating-gas (WAG) process. Sensitivity analysis was carried out by varying the Todd and Longstaff mixing parameter, initial water saturation, and permeability anisotropy (kv/kh) ratio for the different cases investigated to determine their effects on condensate recovery. Figure 3.1 shows a schematic of the methodology workflow.

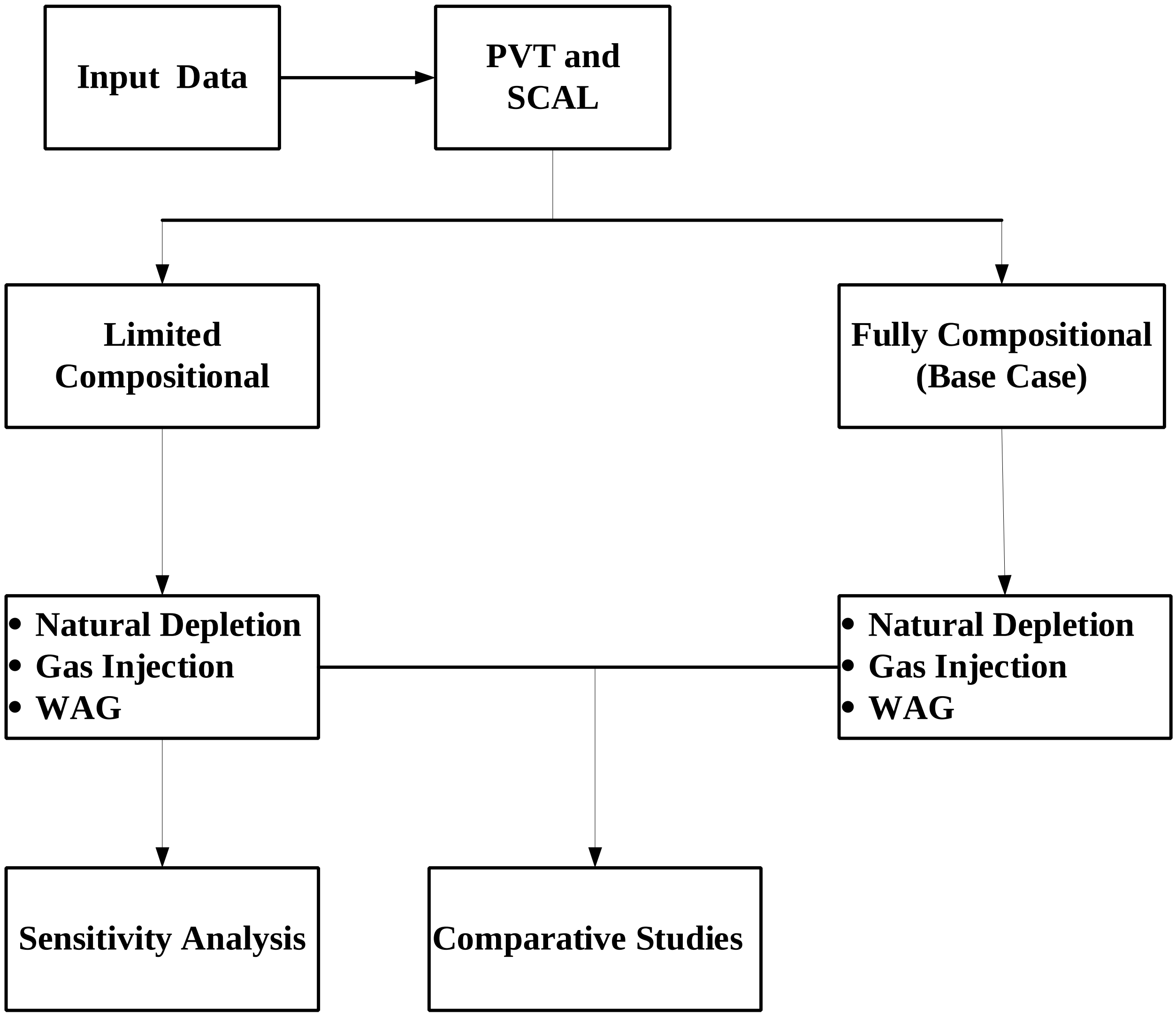


Figure 3.1: Methodology Workflow

3.3 PVT and SCAL Input data

PVT studies are necessary for characterizing reservoir fluid and evaluating their volumetric performance at various pressure levels (Tarek, 2001). Several laboratory experiments such as constant compositional expansion (CCE), differential liberation, separator tests, and constant-volume depletion (CVD) are conducted in characterizing the reservoir fluid. Whitson and Brule (2000) have mentioned that CCE and CVD laboratory tests are standard laboratory tests for gas condensate wells. Therefore, the reservoir fluid composition in Table 3.1 obtained from Akpabio et al. (2015) was used as input data for these tests. The three-parameter Peng-Robinson Equation of State (EOS) was chosen to simulate the laboratory tests. Peng-Robinson was chosen due to its high application in petroleum engineering and its superior capability to predict liquid densities (Whitson and Brule, 2000). Using Whitson and Torp's (1983) method, the results of the CVD laboratory test were then exported as the PVT tables for the limited compositional model. The omega values, critical values of temperature and pressure, Binary Interaction Coefficient (BIC), and other characteristic properties of the fluid were estimated at dew point and temperature of 4191 psia and 176.6 $^{\circ}F$ and were exported as the PVT tables for the fully compositional model.

Relative permeability data for the gas-oil system were obtained from Wobo et al. (2017) while the saturation data for the water-oil curve were estimated using Corey's (1957) correlation. These data were used to generate the SCAL tables for the limited and fully compositional models.

Table 3.1: Well-stream Composition (Source: Akpabio et al., 2015)

No.	Component	Reservoir fluid mol % (Zi)

1	N_2	0.14
2	CO_2	0.18
3	H_2S	0
4	C_1	87.26
5	C_2	5.25
6	C_3	2.61
7	i-C_4	0.67
8	n-C_4	0.9
9	i-C_5	0.41
10	n-C_5	0.31
11	C_6	0.57
12	C7+	1.5
	TOTAL	100

3.4 Reservoir Model Description

A three-dimensional reservoir with cartesian grids was adopted in building the limited and fully compositional models. The reservoir was modeled as a homogeneous reservoir with grid block dimensions of $20 \times 20 \times 10$ in the x-, y- and z-directions, constant porosity, and constant areal permeability in all directions. The vertical permeability was varied to model permeability anisotropy. The reservoir model and fluid properties are given in Tables 3.2 and 3.3. A schematic of the reservoir model used in the simulation runs is shown in Figure 3.2.

Table 3.2: Average Reservoir Properties.

Properties	Value	Unit
Grid Block Dimension	$20 \times 20 \times 10$	

Grid Block Size $D_x \times D_y \times D_z$	250 $\times$ 250 $\times$ 10	ft
Porosity, ϕ	0.22	
Permeability, $k_x = k_y$	910	mD
Vertical Permeability, k_z	91	mD
Initial Reservoir Pressure, p_i	4191	psia
Formation Water Compressibility, C_w	2.91e-6	psia^{-1}
	0.22	
Reservoir Temperature	176.6	$^{\circ}F$
Reference Depth	8400	ft
Reservoir Tops	8325	ft
Gas-Water Contact (GWC)	8490	ft
Gas-Oil Contact (GOC)	8335	ft
Gas Production Rate	7000	Mscf/day
Reservoir Bottom Hole Pressure	1000	psia
Wellbore Radius	0.5	ft
Minimum Oil Production Rate	20	bbl/day
Minimum Gas Production Rate	10	Mscf/day
Minimum Water Cut	0.95	

Table 3.3: Initial Fluid Properties

Properties	Value	Unit
Formation Volume Factor of Water, B_w	1.0001	rb/stb
Gas Gravity	0.73	
Saturation Pressure, p_d	4191	psia
Gravity Rock Compressibility, c_f	4e-6	psia^{-1}

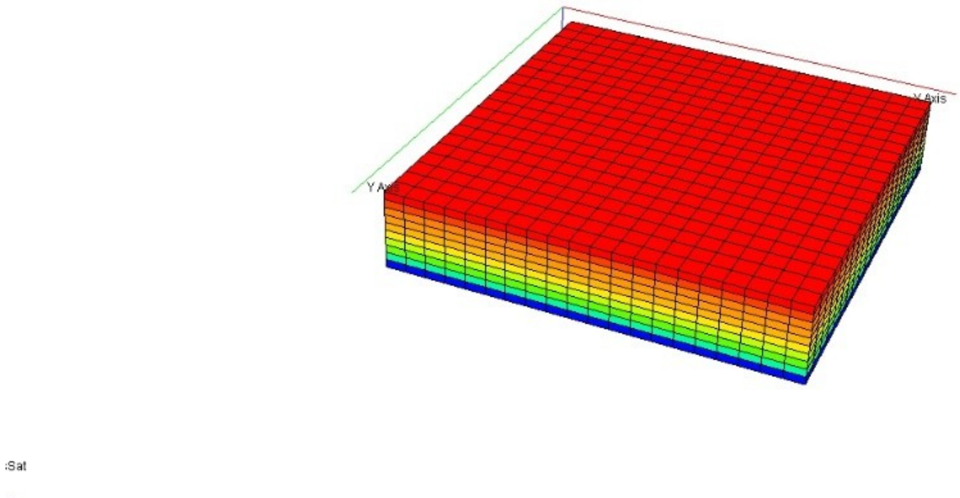


Figure 3.2: Reservoir simulation model.

3.5 Model Simulation

The reservoir was simulated using both black oil and compositional simulators. Three production schemes investigated in the case study are natural depletion, gas injection, and WAG process. Natural depletion was first studied to determine how long and at what rate the reservoir could produce with its natural energy. Gas injection and WAG process were also studied because these two processes are proven methods of enhanced oil recovery for condensate reservoirs and known as methods for mitigating condensate blockage (Hassan et al., 2019).

3.5.1 Natural Depletion

The natural depletion process involves producing the reservoir using the natural reservoir pressure which serves as the driving force for the flow of hydrocarbons to the surface. As the hydrocarbons are being produced the reservoir pressure declines which gives room for water influx into the reservoir from adjacent aquifers. The process was simulated by producing the reservoir for 20 years at a bottom hole pressure (BHP) of 1000 psia. Different gas rates varying from 2000 to 20000 Mscf/day were used in the study to determine the best rate to produce the reservoir during natural depletion. The rate determined from natural depletion was then used as first the gas production rate during gas injection and WAG process.

3.5.2 Gas Injection

Gas injection is a regular production method used to maintain the reservoir pressure in gas condensate reservoirs to increase condensate recovery and minimize condensate blockage (Nasiri-Ghiri et al., 2015). Although natural depletion can produce the reservoir to a certain level, Hagoort (1988) stated that condensate recovery is always poor due to retrograde condensation at pressures below the dew point. So, there is a need to study gas injection to analyze the volumes of condensate that can be produced from the reservoir.

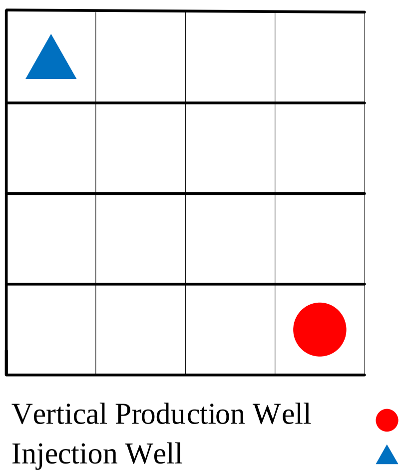
In this study, gas injection was conducted by injecting gas to displace the fluid in place in the reservoir. The injected gas undergoes a miscible displacement process when it is in contact with the in-situ fluid in the reservoir by forming a single phase with the fluid in place. Thus, there is a need to determine the minimum miscibility pressure (MMP) before gas injection. The MMP is the minimum pressure at which miscibility occurs between the displacing and the displaced fluid. It was determined using commercial PVT software. Apart from running experiments, there are two major ways of determining the MMP, i.e., either through empirical correlations or phase-behavior calculations using an equation of state (EOS). The use of the EOS-based phase-behavior calculation was chosen because of its high level of accuracy and precision (Green and Willhite, 2018). The hydrocarbon gas produced from the reservoir, which comprises mostly methane was used as the injection gas for the minimum miscibility test. After the MMP was determined, a gas injection was then carried out at a pressure higher than the MMP. This was done to ensure that there was total miscibility between the injected gas and the fluid in place. The injection was conducted in such a way that about 80% of the produced gas was reinjected into the reservoir.

3.5.3 Water-Alternating-Gas (WAG) Injection

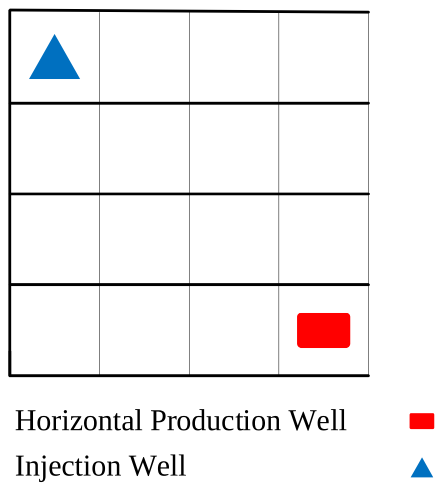
It is known that the recovery efficiency of a gas injection process is limited by the high mobility ratio which develops between the injected gas and in-place fluids resulting in viscous fingering and a reduction in volumetric sweep efficiency. This high mobility ratio is caused by the low viscosity of the gas. Therefore, there is a need to study another injection process that results in a lower mobility ratio. The water-alternating-gas (WAG) process can overcome the limitations of pure gas injection by alternate injection of gas followed by water into the reservoir. The injected water helps to improve the macroscopic sweep efficiency while the injected gas improves the microscopic sweep efficiency, thus reducing the adverse mobility ratio. In this study, a WAG process was simulated using a WAG ratio of 1:1 by alternating the injection of gas and water every three months.

3.6 Injection Patterns

Injection pattern is very crucial in any secondary or tertiary enhanced oil recovery process. This is because the sweep efficiency is dependent on the injection pattern. The four injection patterns were studied in this work, including (1) use of one vertical producer and one vertical injection well drilled diagonal to each other, (2) a pair of diagonal wells—a vertical injector and horizontal producer, (3) the staggered line drive, and (4) a five-spot pattern. The objective was to study the recovery efficiency using the various patterns of wells to produce the condensate reservoir. Figure 3.3 shows the schematic of the well orientations for the two regular patterns used in the study.



(a) Two Vertical Wells



(b) Horizontal Producer and Vertical Injector

Figure 3.3: Well Orientation for regular patterns used in the study.

3.6.1 Staggered Line Drive

Figure 3.4 shows the orientation of the wells used in the staggered line drive. To simulate the staggered line drive, a five-well pattern shown in Figure 3.4 was used. Four injection wells were drilled at each corner of the reservoir model with a producer well drilled at the center. The four injection wells were drilled in such a way that the distance between the producer well and the injection wells was laterally displaced by a distance of a/2. In the model, the injection wells were drilled in grid cells (1,6), (1,15), (20,6), and (20,15) with a producer well drilled in grid cell (10,10).

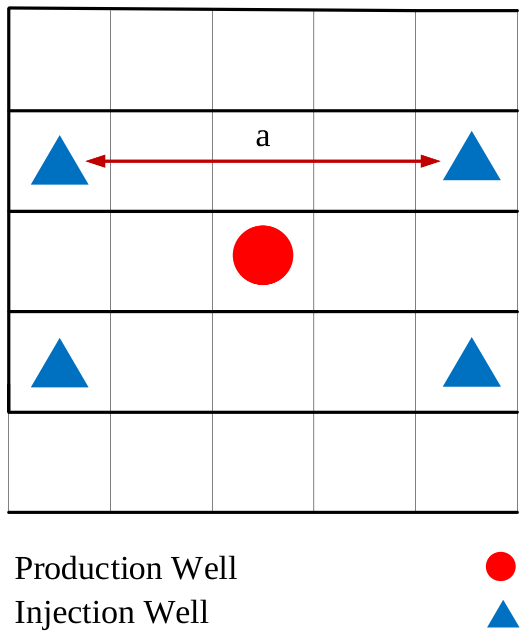


Figure 3.4: Well Orientation for Staggered Line Drive.

3.6.2 Five-Spot Pattern

The performance of a five-spot injection pattern which is one of the most commonly used patterns to analyze sweep efficiency in large reservoirs was analyzed in this study. Figure 3.5 shows the orientation of the wells used in the five-spot model. Four injection wells were drill at each corner of the reservoir model with a producer well placed at the center. These wells were drilled in such a way that the distances between the four injection wells were the same as the distances between the production wells at the center. The injection wells were drilled in grid cells (1,1), (1,20), (20,1), and (20,20) with a producer well drilled in grid cell (10,10) in the simulation model.

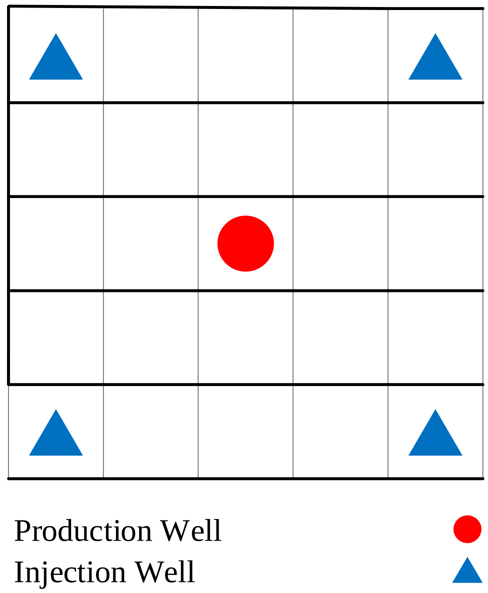


Figure 3.5: Well Orientation for Five Spot Injection Pattern.

3.7 Study of Todd and Longstaff Mixing Parameter (ω)

Todd and Longstaff (1972) studied the effect of viscous fingering in miscible gas injection and introduced a mixing parameter (ω) that can be used to measure the degree of mixing between the oil and gas phase within a grid block. They observed that a mixing parameter (ω) equal to $\frac{2}{3}$ is appropriate for laboratory studies and $\frac{1}{3}$ is for a field project. In this study, the Todd-Longstaff mixing parameter (ω) was varied from 0 to 1 for all the simulation runs with the limited compositional simulator. The cumulative recoveries from the limited compositional simulator were then compared to the cumulative recoveries from the fully compositional simulator.

3.8 Analysis of Condensate Banking

Condensate banking has been described in several publications as a major problem that affects condensate recovery in gas condensate reservoirs. Ganie et al. (2019) reported that most of these condensates are usually banked around the wellbore rather than being produced to the surface. This occurrence around the wellbore is a result of the average reservoir pressure being less than the critical pressure, i.e., the pressure at which condensate saturation is equal to the critical saturation (Adel et al., 2006). In this study, to analyze condensate banking, the simulator tracked the saturations and pressures at the layers in the model where the production well was completed. The production well was completed from layer 5 to layer 8 in the model but the focus will be paid to layer 8 because it is believed that is the closest layer to the wellbore. The pressure and saturation distributions were tracked for all periods in the simulations.

3.9 Sensitivity Analysis

To get an optimum recovery from the production of the gas condensate reservoir, a sensitivity analysis was carried out. This analysis is one of the core objectives of this study. Sensitivity analysis was used to better understand the effect of each parameter on the objective function. For this study, the objective function was the cumulative recovery. In a sensitivity analysis, several variables can be analyzed if the variable is dependent on the chosen objective function. In this study, the parameters considered are the Todd and Longstaff mixing parameter (ω), the initial water saturation, and permeability anisotropy (kv/kh). These parameters were analyzed to see their effect on the cumulative oil produced. And using a response surface methodology (RSM) an equation was developed to estimate the cumulative oil produced considering the parameters evaluated in the sensitivity analysis as the independent variables.

The methodology presented in this chapter was used in a case study to evaluate the productivity of a gas condensate reservoir in the Niger Delta. The results and discussion of the case study are presented in the next Chapter.

CHAPTER FOUR

4.0 Results and Discussion

This chapter presents the results obtained from the execution of the study methodology. The results from the PVT experiments are first presented where the matched experimental and calculated results are shown. The results for all simulations were then presented emphasizing the cumulative oil and gas recoveries, pressure drop, and water cut for the natural depletion case, gas injection, and WAG process. The cumulative oil recoveries from the fully compositional simulations were compared to those obtained from the limited compositional simulations. This was done to validate the accuracy of the limited compositional simulation models and to analyze the impacts of varying the Todd-Longstaff mixing parameter on condensate recovery using the limited compositional models. Condensate banking was analyzed for the different cases studied in this work. Finally, results from sensitivity analysis were presented and discussed in this Chapter.

4.1 Pressure-Volume and Temperature (PVT) Analysis

The reservoir phase diagram obtained from the case study is shown in Figure 4.1. From this diagram, the reservoir temperature is between the critical temperature and the cricondentherm. This signifies that the reservoir is a gas condensate reservoir. It can also be observed from the phase diagram that the reservoir temperature is closer to the cricondentherm than the critical temperature. As a result of this observation, this type of gas condensate reservoir can be termed a lean gas condensate reservoir. This is evident from the ternary plot shown in Figure 4.2 where the two-phase region comprises more lean gas, i.e., closer to the C1 apex.

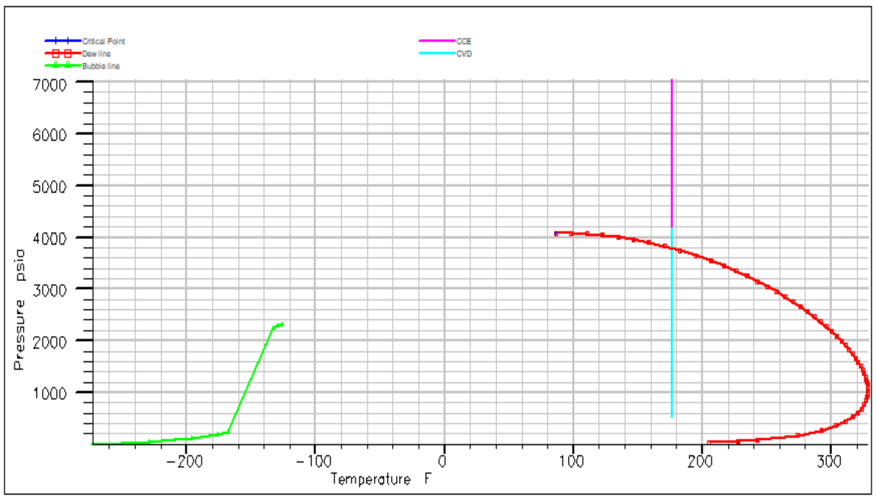


Figure 4.1: Reservoir Phase Diagram.

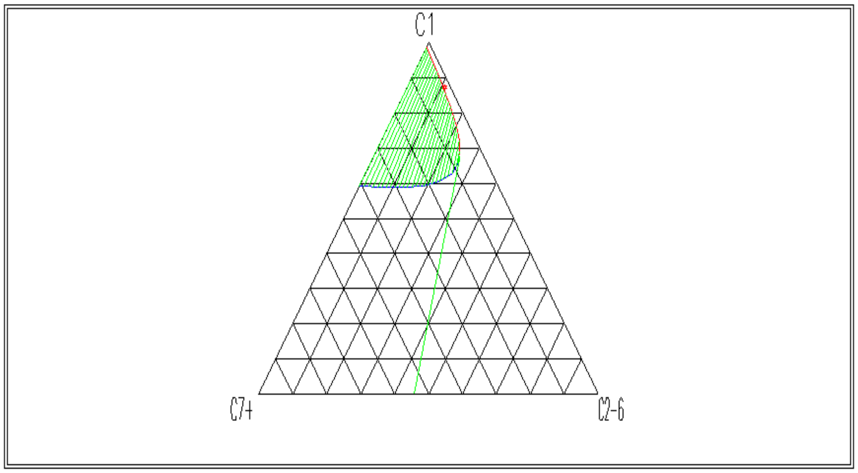


Figure 4.2: Reservoir Ternary Plot.

Figures 4.3 through 4.5 show the plots of the PVT analysis comparing the experimental values and the calculated values obtained from application of the Peng Robinson EOS method. The results indicated that there was a good match between the experimental and calculated results obtained for all the plots by tuning the EOS parameters.

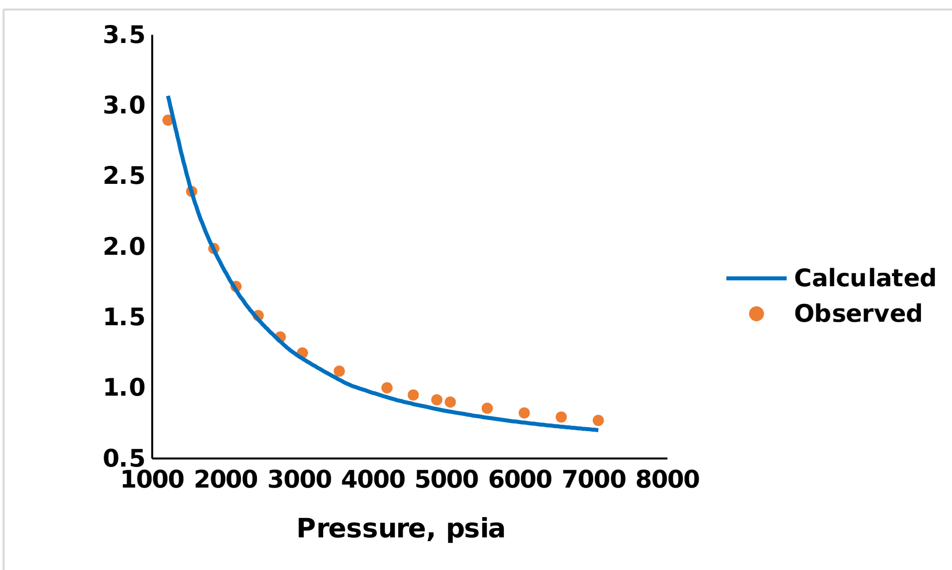


Figure 4.3: CCE Experiment (Relative Volume).

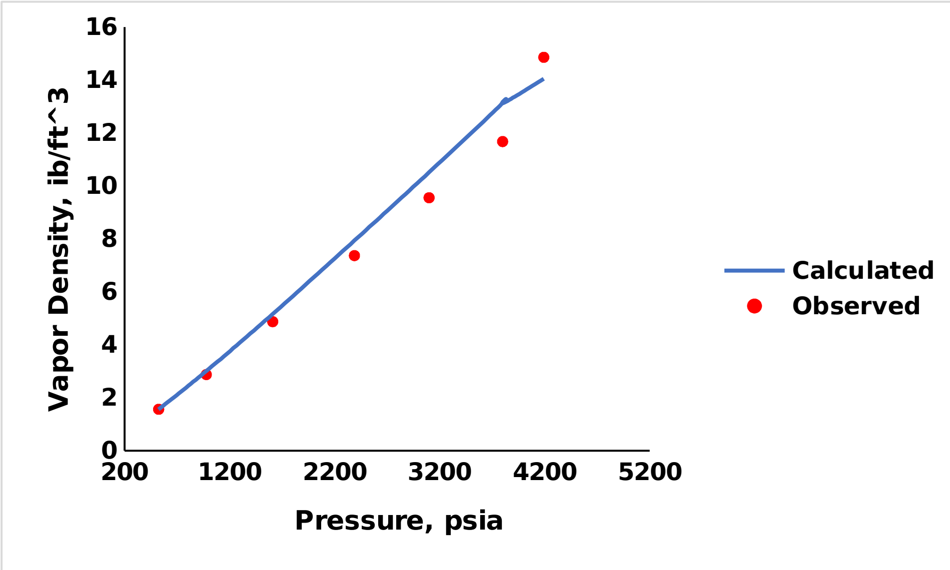


Figure 4.4: CVD Experiment (Vapor Density).

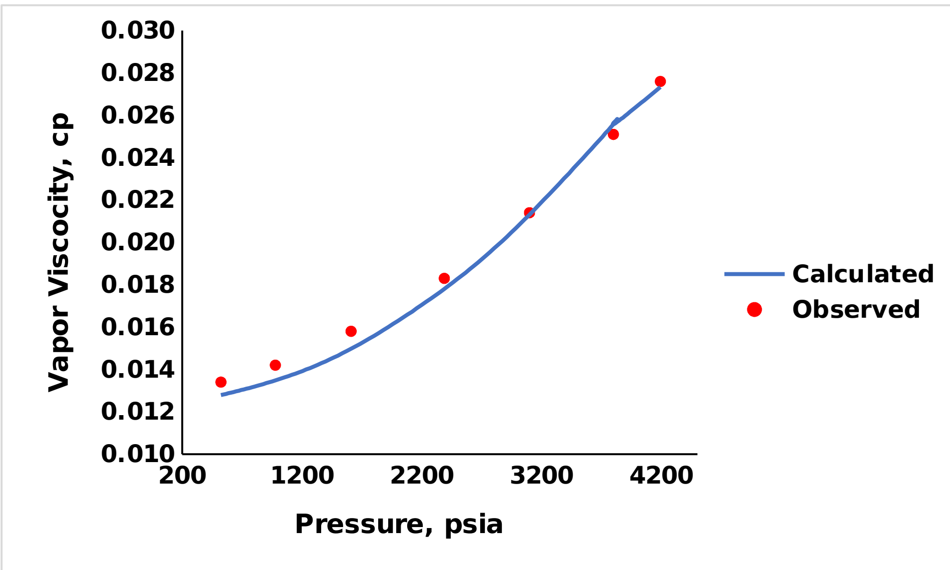


Figure 4.5: CVD Experiment (Vapor Viscosity).

Matching the vapor density and viscosity is of great importance in the limited compositional model because the fluid displacement instabilities are dependent on the vapor density and viscosity. Therefore, Figures 4.4 and 4.5 show a good match between the calculated vapor density and vapor viscosity versus the observed data from the CVD experiments.

4.2 Simulation Results

The fully compositional and limited compositional simulation results obtained for the three cases analyzed are discussed in this section.

4.2.1 Initial Hydrocarbon in Place

The volumes of oil (STOOIP) and gas initially in place (GIIP) were first determined for both the fully compositional and limited compositional models without drilling neither a producer nor an injector well. The results of the gas and oil originally in place are shown in Figures 4.6 and 4.7. It is observed from the results that the STOOIP from the limited compositional model is about 13 times greater than that of the fully compositional model, while the initial gas in place from the fully compositional model is about 4 times greater than the GIIP from the limited compositional model. It is expected that the results from the fully compositional model are more accurate because the compositional simulator is better suited to capture the phase behavior (PVT characteristics) of a gas condensate reservoir. In this case study, the differences between the STOOIP and GIIP from the full compositional vs. limited compositional models are quite high. This difference is attributed to the type of reservoir being simulated, i.e., a lean gas condensate reservoir. As pointed out by Bolling (1987) it is quite impossible to get corresponding volumes of hydrocarbon in place for a fully compositional and limited compositional model when dealing with a lean gas condensate reservoir. He also noted that in this type of reservoir the simulated results do not always match field production data. In our case, the initial oil in place which was of more interest was estimated to be 1.9 MMbbl from the fully compositional and 27 MMbbl from the limited compositional model.

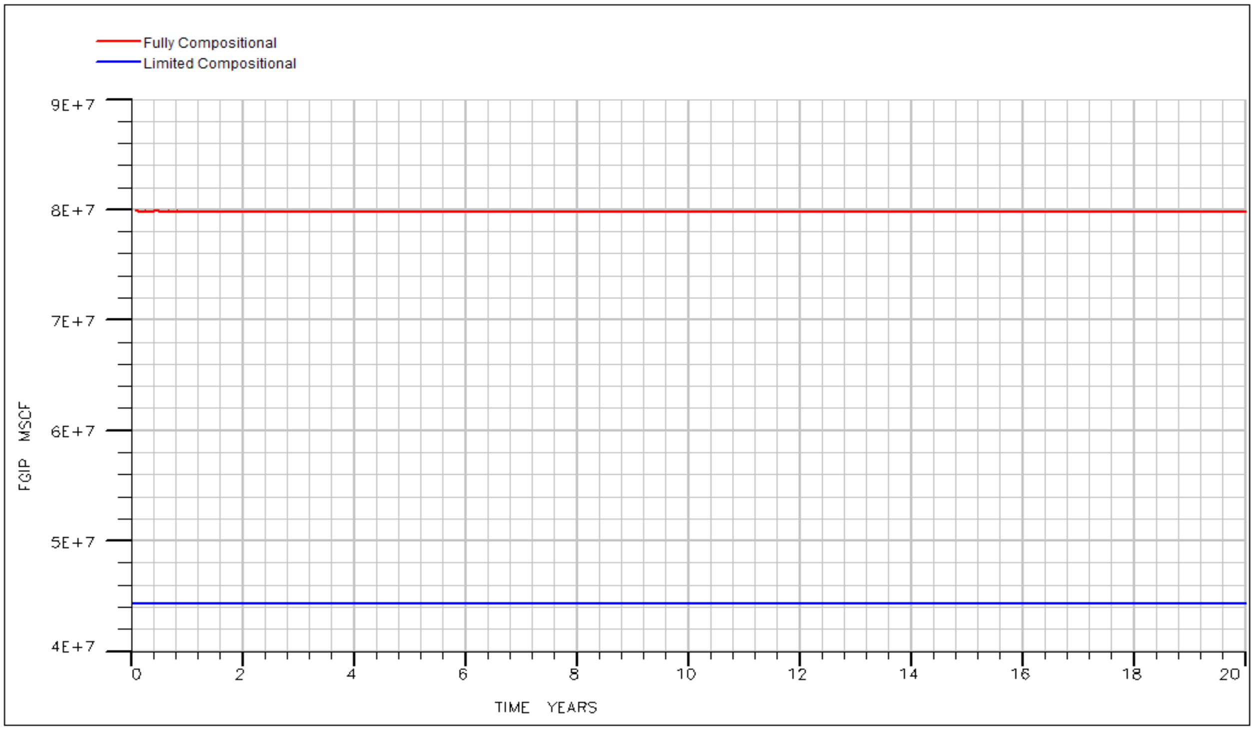


Figure 4.6: Comparison of Gas Initially in Place (GIIP) from Fully Compositional vs. Limited Compositional Models.

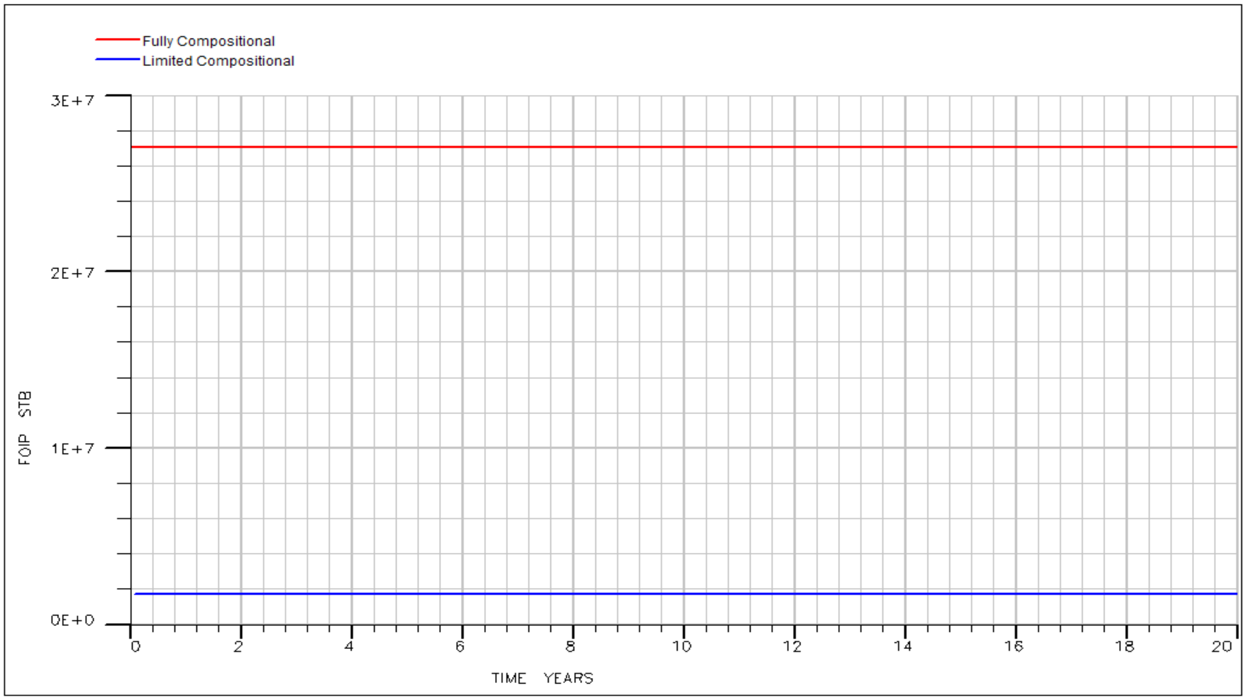


Figure 4.7: Comparison of Stock Oil Originally in Place (STOOIP) from Fully Compositional vs. Limited Compositional Models.

After estimating the STOOIP and the GIIP, a production well was drilled in the model to study natural depletion of the gas condensate reservoir. The results of this analysis are presented in the following section.

4.2.2 Natural Depletion

The natural depletion case was studied to determine the cumulative volume of oil to be recovered from the condensate reservoir during a 20-year production with its natural energy. The first step was to run only the fully compositional model to determine a minimum production rate to sustain natural depletion of the reservoir for 20 years. After simulating natural depletion of the condensate reservoir considering a range of gas production rates from 2000 to 20000 MSCF/d, the production rate of 7000 Mscf or (7 million scf) was adopted as the optimal rate for further studies. Figure 4.8 shows the reservoir pressure profile.

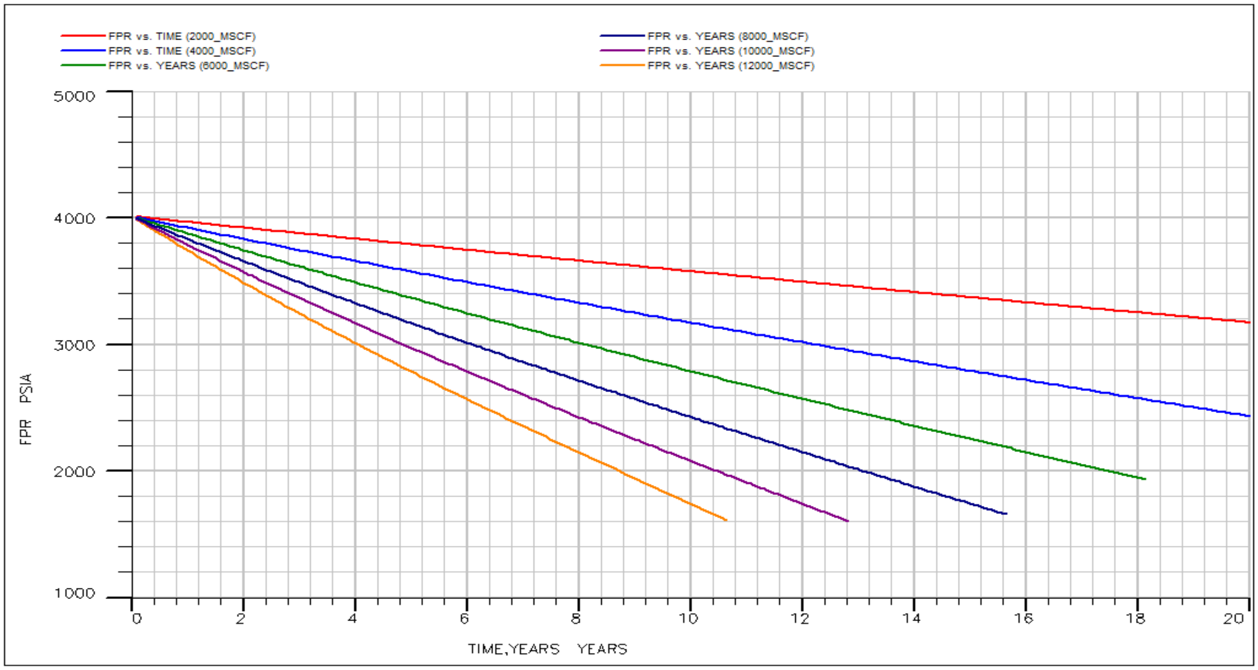


Figure 4.8: Pressure Profile for Fully Compositional Simulation of Natural Depletion of Condensate reservoir.

At this rate, the gas condensate reservoir can be produced for about 17 years by natural depletion before the well is shut in because of a high water cut. This rate of 7000 Mscf/d was chosen because it is postulated that gas condensate production during gas and water-alternate-gas (WAG) injection can be sustained at this rate for 20 years target. It was observed that the reservoir will produce the reservoir for more than 20 years using rates lower than the 7000 Mscf/d but with minimal natural pressure depletion. Producing the reservoir at higher rates (greater than 7000 Mscf/d) will lead to premature shut-in before 17 years due to high water cut. The obtained rate of 7000 Mscf was adopted to simulate the fully compositional and limited compositional model. About 378 Mbbl and 3.6 MMbbl cumulative oil was recovered for the fully compositional and limited compositional simulation, respectively. The volume of condensate recovered which is about 20% of the STOOIP for the fully compositional simulation can be considered an appreciable amount. According to Lopez (2000) for a typical gas condensate reservoir without aquifer support, the amount of condensate recovery should be between 20-30%. This was not the case for the limited compositional simulation, as the cumulative oil recovered was about 13%. This may probably because the compositional phenomena active during the depletion was not adequately represented (Coats, 1985).

Figure 4.9 shows the cumulative gas production for this case. The reservoir pressure and water cut profiles are shown in Figures 4.10 and 4.11.

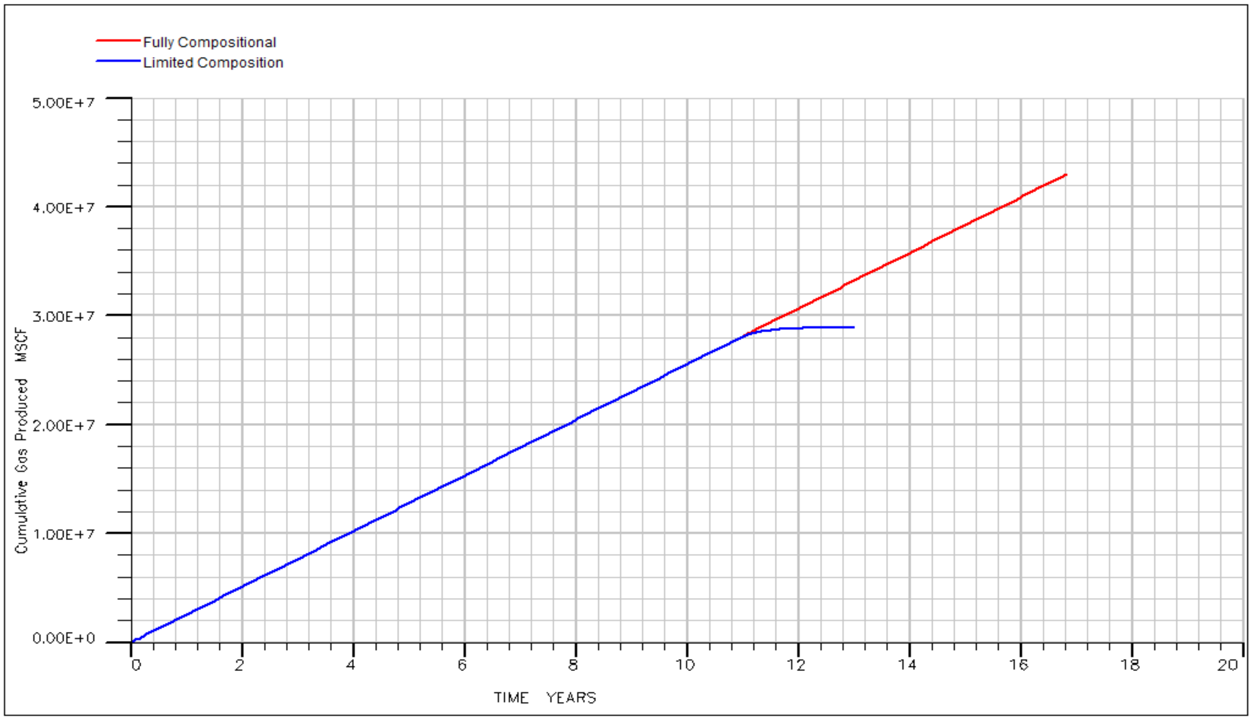


Figure 4.9: Comparison of Cumulative Gas Produced for Fully and Limited Compositional Simulations of Natural Depletion into a Condensate reservoir.

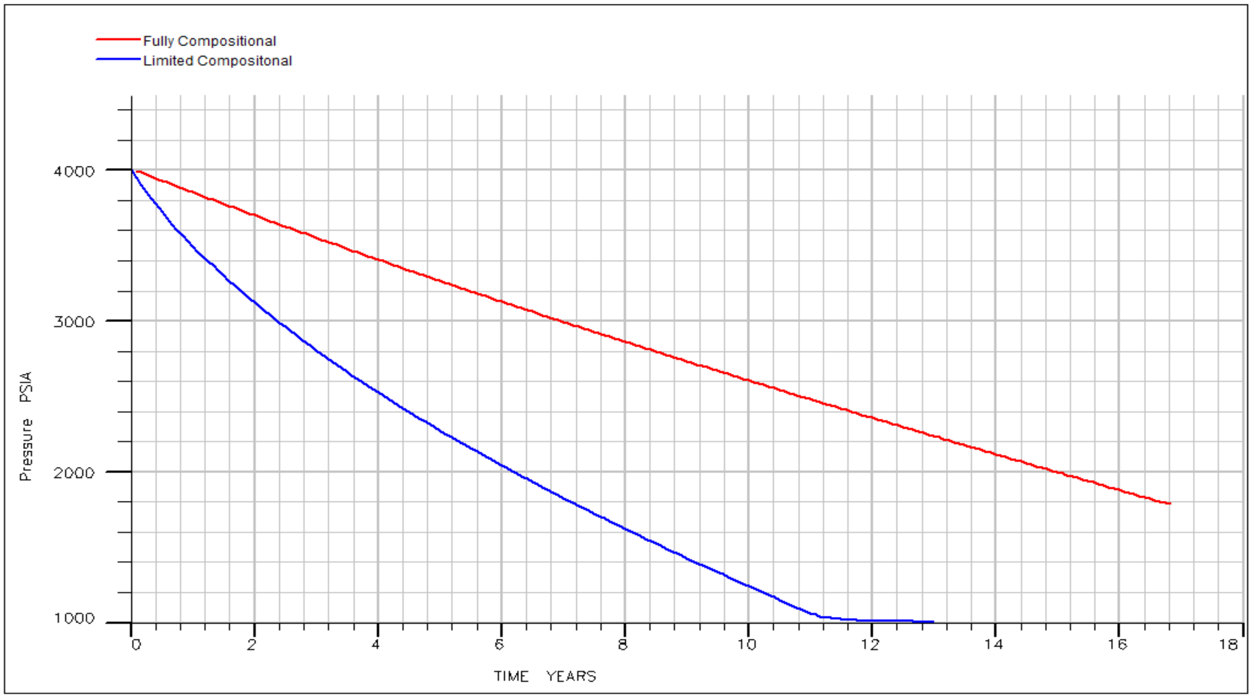


Figure 4.10: Comparison of Reservoir Pressure for Fully and Limited Compositional Simulations of Natural Depletion into a Condensate reservoir.

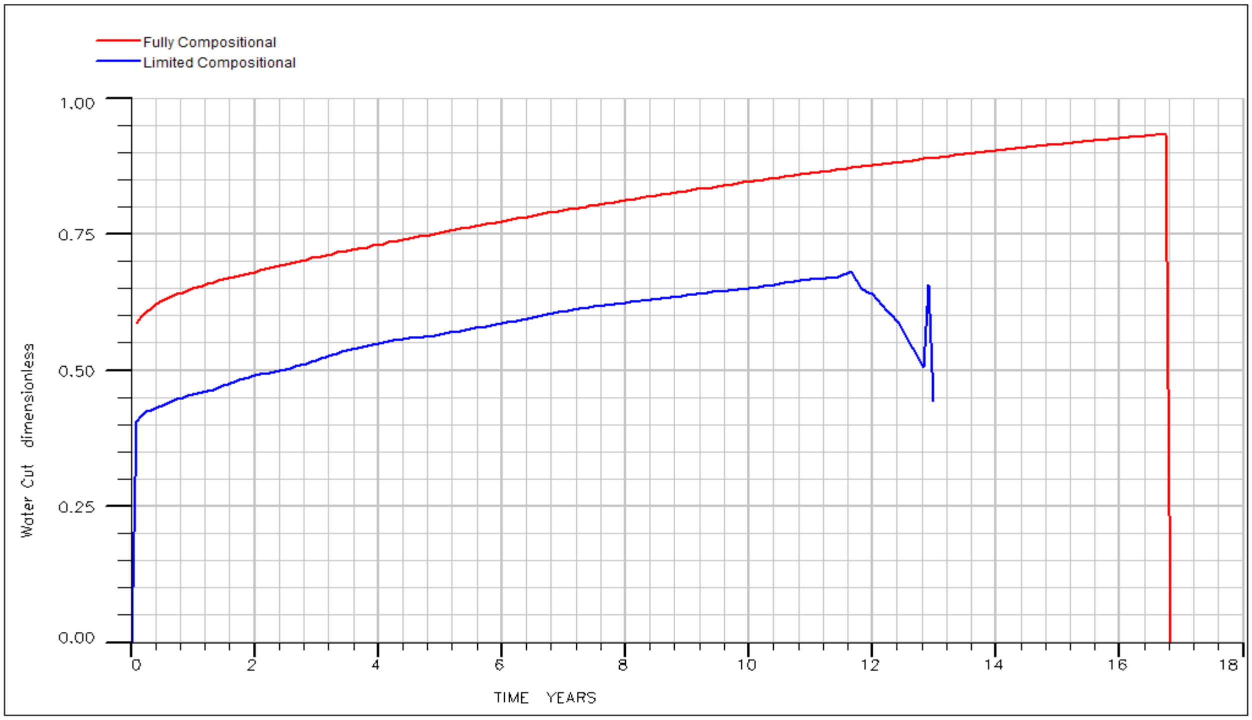


Figure 4.11: Comparison of Water cut for Fully and Limited Compositional Simulations of Natural Depletion into a Condensate reservoir.

The comparison of results of the cumulative gas produced for the fully compositional and limited compositional simulation indicated that both have a steady and simultaneous increase from the beginning of production to the 11th year. In the 11th year, constant gas production was observed for the limited compositional simulation which lasted for barely one year before the well shut-in while gas production for the fully compositional simulation maintained its steady gas production increase till the 17th year. This change in gas production trend is a result of the difference in the estimated gas in place. The difference in the estimated gas in place also leads to the different reservoir pressure shown in Figure 4.10. As shown in Figure 4.11, the water cut for the limited compositional simulation rose from zero to 40% as production commenced and remained almost constant till the well shut-in at the 11th year, while the water cut for the fully compositional simulation was 50% at the start of production and rose to 95% till the well shut-in at the 17th year. It can be said that the well shut-in for the fully compositional was due to the production constraint kept in place.

Figure 4.12 tells more about the condensate recovery, as it shows a plot of the Field Oil Efficiency (FOE) vs. time for both the fully and limited compositional simulation. It can be observed that a high efficiency was seen for the fully compositional simulation compared to the limited compositional simulation, although more condensate was recovered for the limited compositional simulation. This is because oil efficiency calculation uses initial oil in place as the basis for estimation. Therefore, the oil produced for the fully compositional compared to the oil in place is higher than that of the limited compositional simulation.

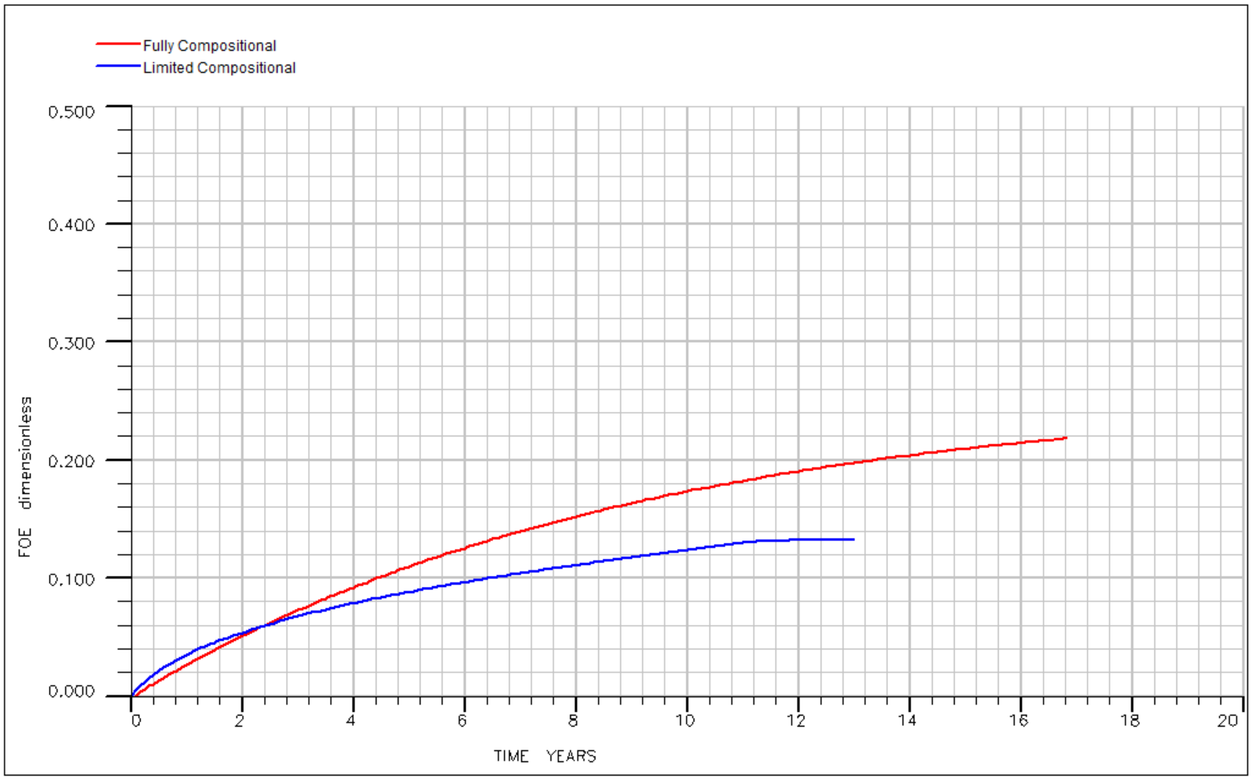


Figure 4.12: Comparison of Field Oil Efficiency for Fully and Limited Compositional Simulations of Natural Depletion into a Condensate reservoir.

4.2.3 Gas Injection

Before gas injection, a minimum miscibility pressure (MMP) of 5420 psia was calculated using the injection gas composition. The MMP is the pressure at which miscibility will occur between the injected gas and the fluid in place. It is known that the gas can be injected into this reservoir at MMP or above the MMP. After MMP was determined gas injection into the condensate reservoir commenced. The gas produced from the reservoir was reinjected into the reservoir to minimize the problem of injection gas availability. Since the reservoir is a lean gas condensate reservoir, most of the gas produced from this type of reservoir is also lean gas.

Gas was injected at a reinjection rate of 5600 Mscf/d and pressure of 5450 psia. Miscibility can be said to develop immediately as the lean gas was reinjected into the reservoir. This is because the lean gas was reinjected at a pressure higher than the MMP which is sufficient enough to immediately achieve miscibility between the reinjected lean gas and the reservoir fluid. This type of displacement can be termed first contact miscibility (FCM) process. Figures 4.13 through 4.16 show the saturation distributions of gas and oil before and during the simulation of gas injection using the fully compositional and limited compositional simulators. These plots represent a 2-d pictorial view of the reservoir with the injection well located at (1,1) layer 1-4 and the production well located at (20, 20) layer 4-8.

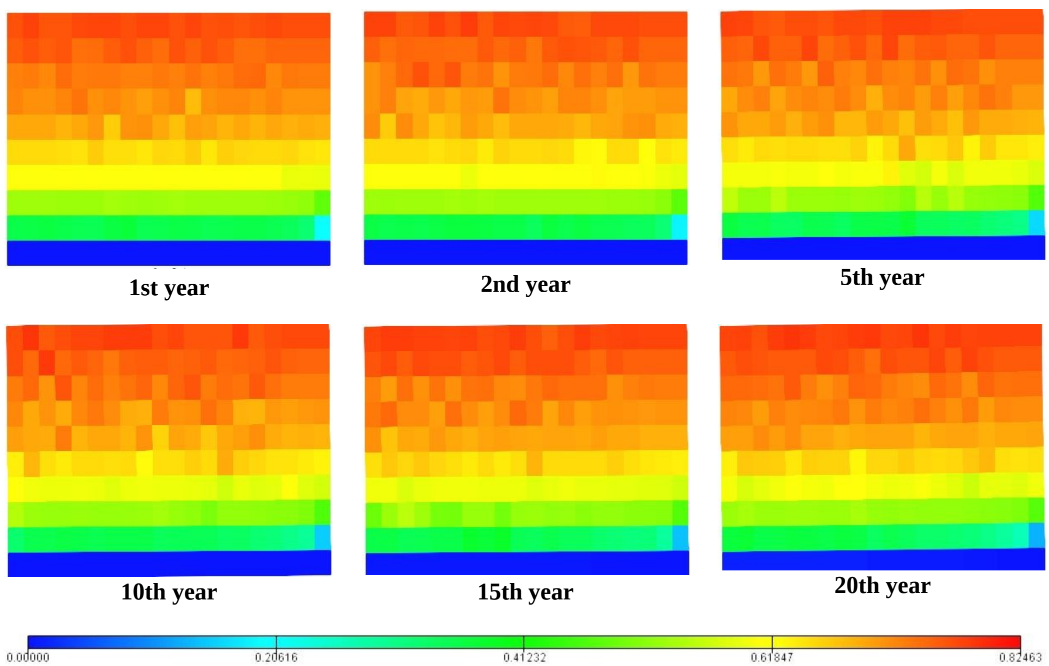


Figure 4.13: Gas saturation distribution for Fully Compositional Simulation of gas injection into a Condensate reservoir.

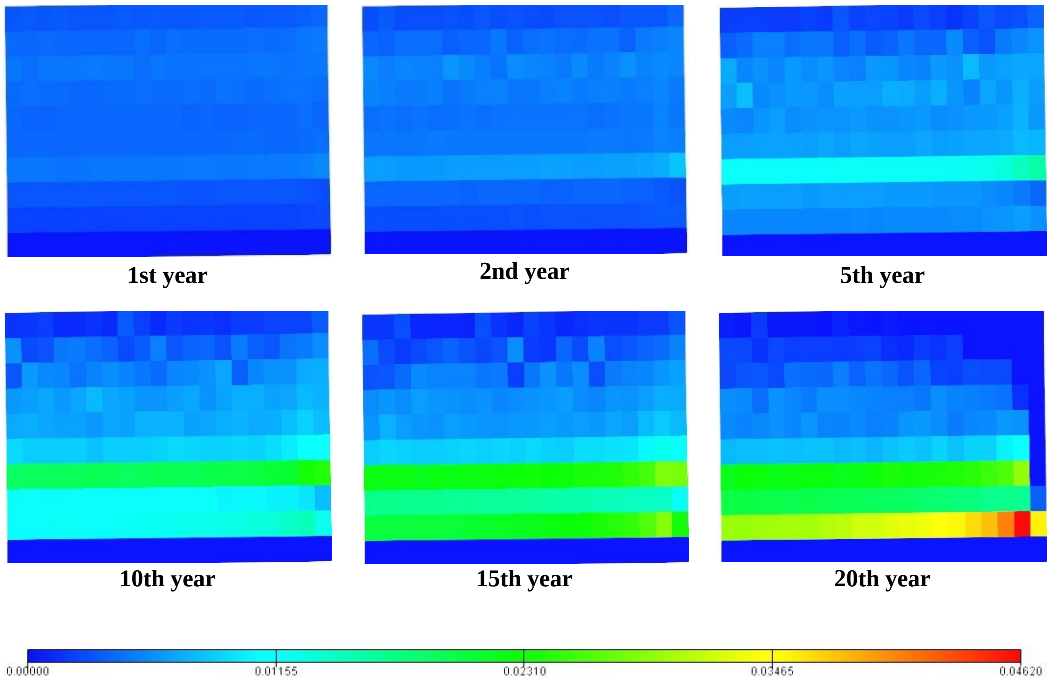


Figure 4.14: Oil saturation distribution for Fully Compositional Simulation of gas injection into a Condensate reservoir.

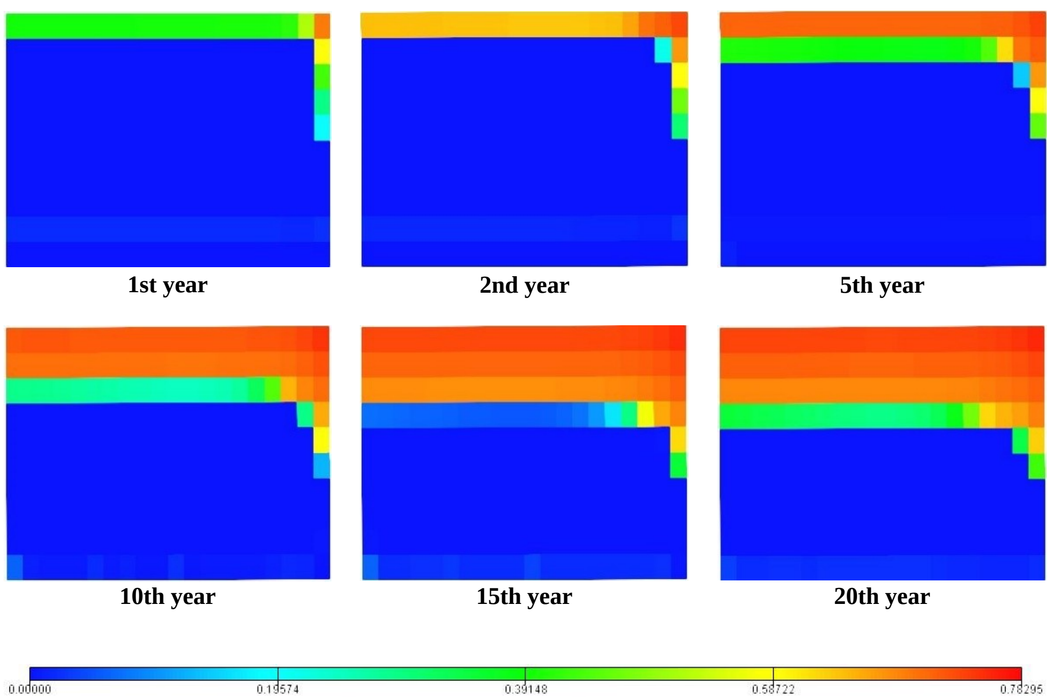


Figure 4.15: Gas saturation distribution for Limited Compositional Simulation of gas injection into a Condensate reservoir.

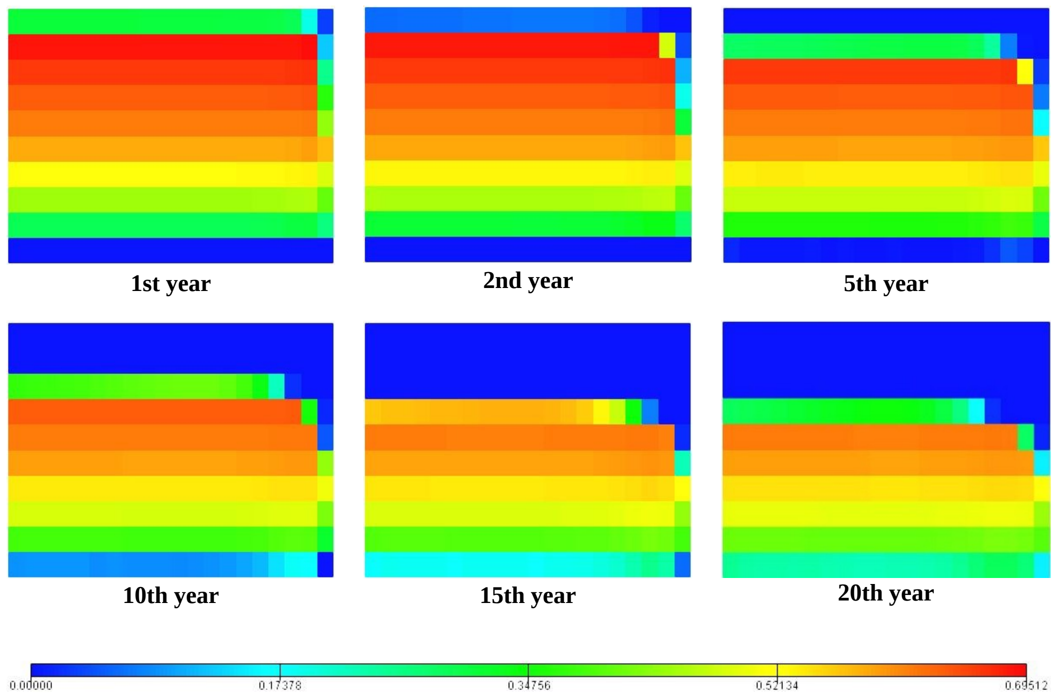


Figure 4.16: Oil saturation distribution for Limited Compositional Simulation of gas injection into a Condensate reservoir.

The gas saturation as represented in Figure 4.13 for the fully compositional simulation was observed to be almost the same along the production years. This was probably because 80% of the produced gas was reinjected into the reservoir. In Figure 4.14 the oil saturation increased alongside the production year. This is because a typical gas condensate reservoir is a single-phase fluid at the initial reservoir condition. As production commenced, the reservoir temperature remains constant while reservoir pressure decreases. Decrease in reservoir pressure continues till the dew point called the saturation pressure. At this saturation pressure, oil saturation starts to increase as the liquid phase is formed (Li Fan, 2005). Using a mixing parameter of 0.333 for the limited compositional simulation as proposed by Todd and Longstaff (1972), the gas saturation in Figure 4.15 increased while the oil saturation in Figure 4.16 decreased along the production year. This is probably because black oil simulators are used in simulating fluids comprising of a single phase. At the commencement of production gas-rich condensate is produced from the reservoir as a result of a change of phase due to temperature and pressure thereby causing the reservoir to have a high oil saturation. As production continues, the saturation of the gas increases as a result of condensate blockage in the reservoir. At this point, high gas saturation and a low oil saturation are observed.

Figures 4.17, 4.18, 4.19, and 4.20 present a comparison of the cumulative gas production, field oil efficiency, field water cut, and field pressure for the fully compositional and limited compositional simulations.

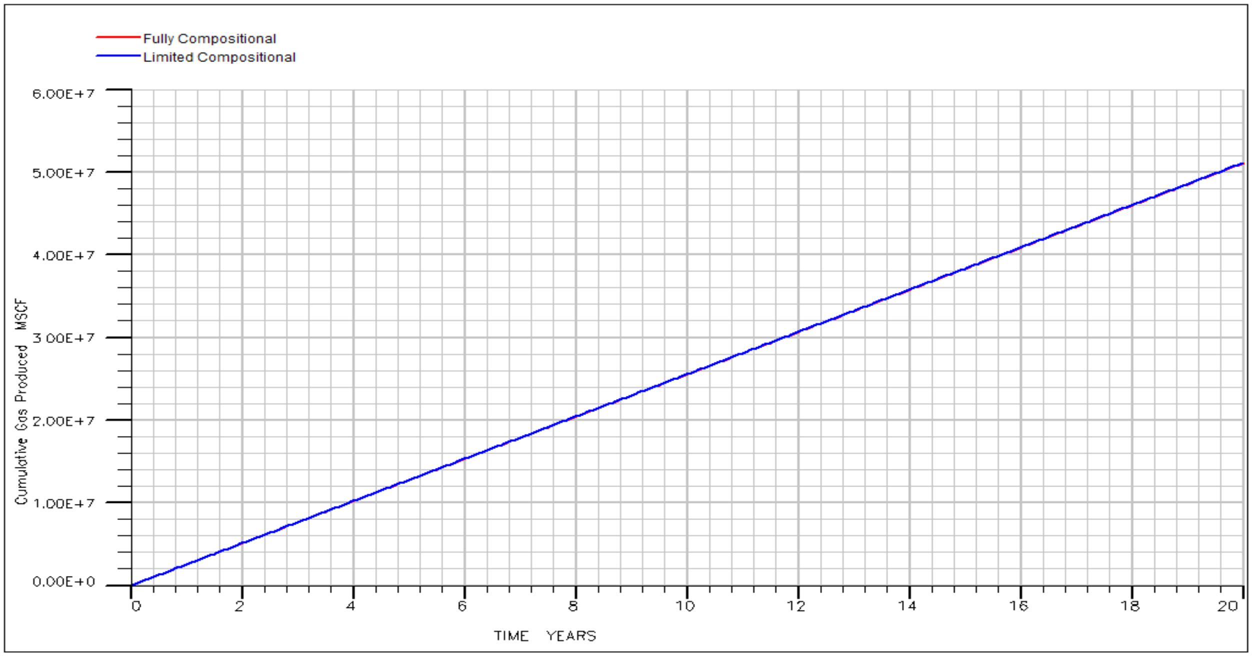


Figure 4.17: Comparison of Cumulative Gas Produced by gas Injection from Fully and Limited Compositional Simulations.

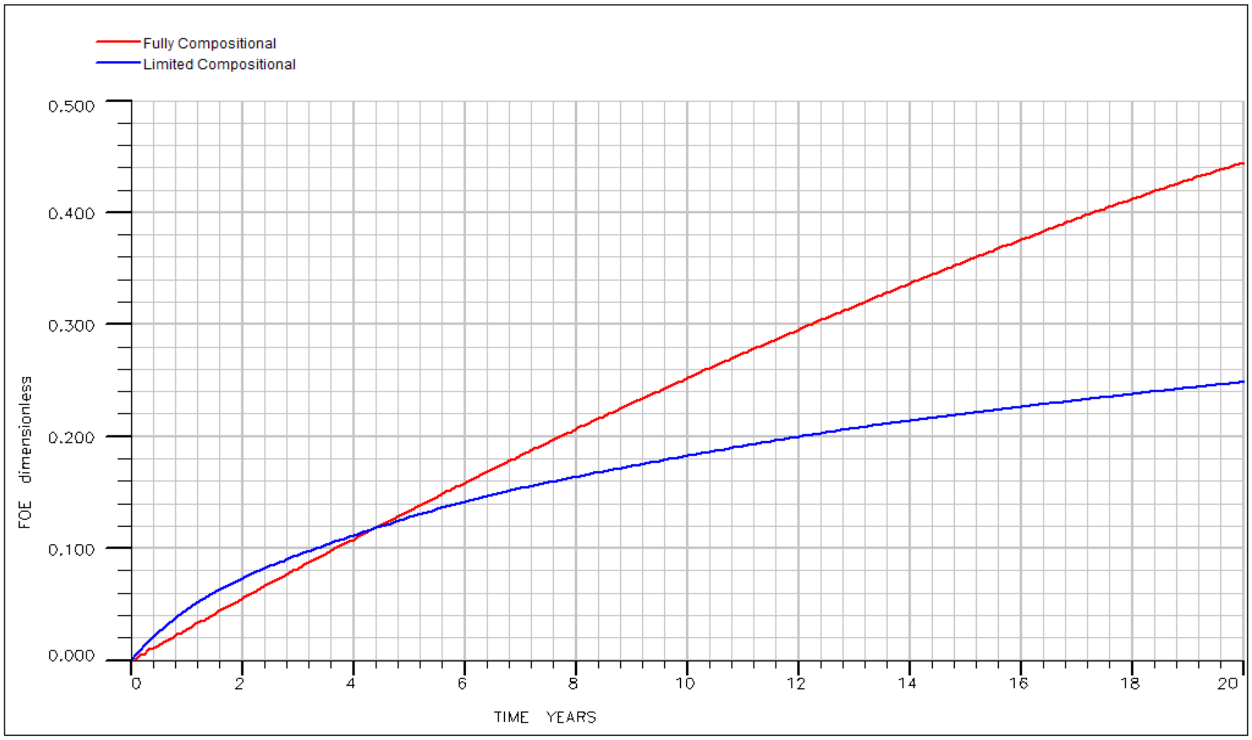


Figure 4.18: Comparison of Field Oil Efficiency from Fully and Limited Compositional Simulations.

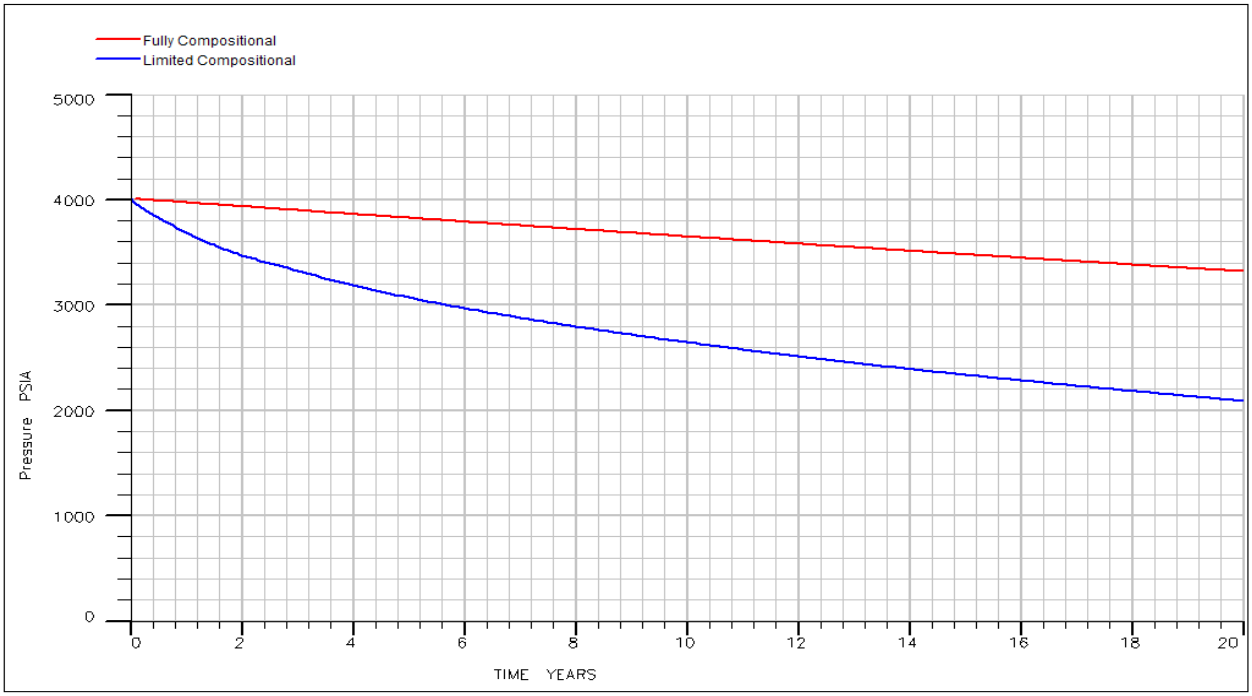


Figure 4.19: Comparison of Field Pressure for Fully and Limited Compositional Simulations of gas injection into a Condensate reservoir.

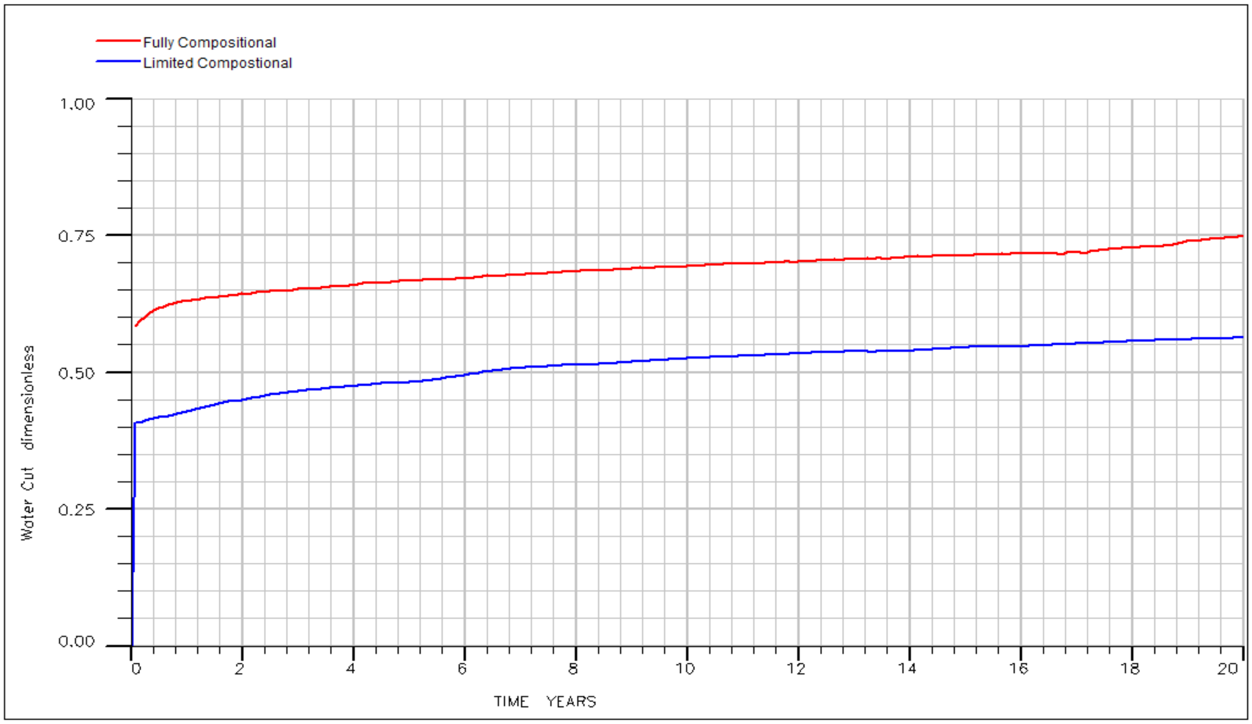


Figure 4.20: Comparison of Water cut for Fully and Limited Compositional Simulations of gas injection into a Condensate reservoir.

After simulating the reservoir for 20 years with gas injection, cumulative gas produced was the same for both the fully compositional and limited compositional simulation. These same values might probably be because of the constant reinjection of 80% of the produced lean gas.

A cumulative oil recovery of 800 Mbbl for the fully composition simulation and 6.7 MMbbl for the limited compositional simulation was obtained after the simulation. These oil volumes can be estimated to be 43% and 24%, respectively. Although, the field oil efficiency plot shows that the fully compositional has a better oil efficiency than the limited compositional simulation. These different results was due to the type of reservoir been studied which is lean gas condensate (Bolling, 1978).

Taking the results for water-cut in Figure 4.20 into consideration, it was expected that the limited compositional simulation should have better pressure maintenance. But this was not the case here, this discrepancy can be attributed to the type of reservoir been studied which is a lean gas condensate. While Coats (1985) has stated that almost the same results can be obtained if the reservoir is a near-critical or rich gas condensate.

4.2.4 WAG Injection

Even though gas injection increases the hydrocarbon recovery, its efficiency can be limited by the adverse mobility ratio between the displaced hydrocarbon and the injected gas. This mobility ratio is greatly influenced by the low viscosity of the injected gas. Water-alternating-gas (WAG) injection has been reported to counteract the limitations of pure gas injection. The WAG process was initiated in the case study by injecting water into the reservoir for 3 months before alternating to gas injection. The WAG cycle was 3-month water followed by gas injection. Water injection was done to improve the microscopic sweep efficiency while the gas injection was to improve the macroscopic sweep efficiency (Stalkup, 1983). Water injection is designed to reduce the cumulative amount of gas injected and the mobility ratio. Figures 4.21 and 4.22 show the saturation distributions of gas and oil before and during the simulation of WAG for fully compositional simulation.

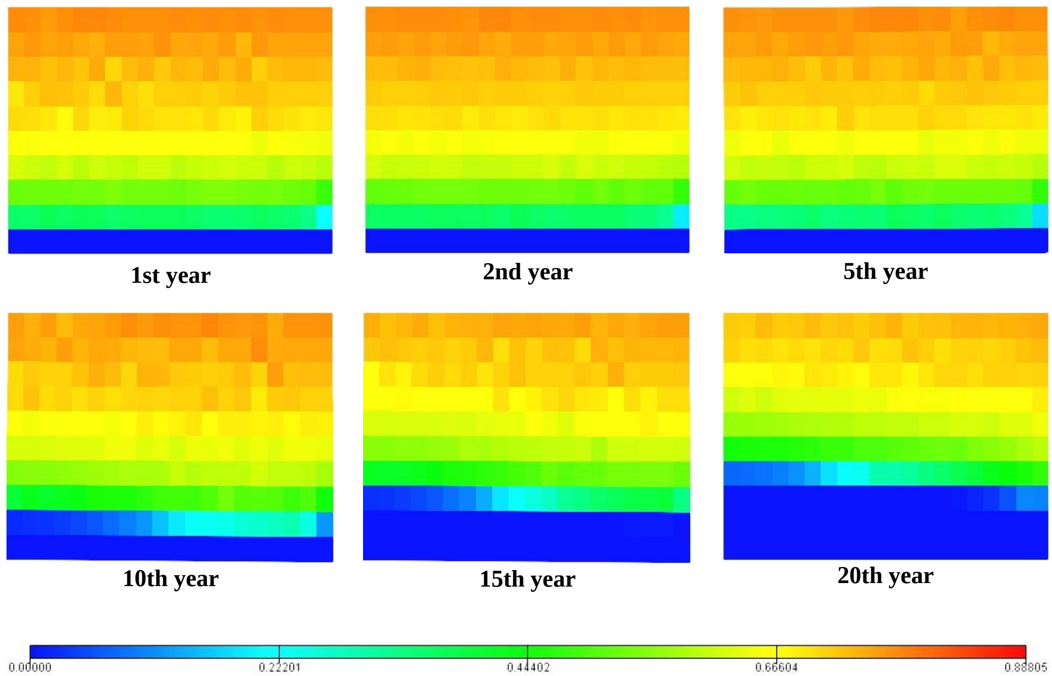


Figure 4.21: Gas saturation distribution for Fully Compositional Simulation of WAG into a Condensate reservoir.

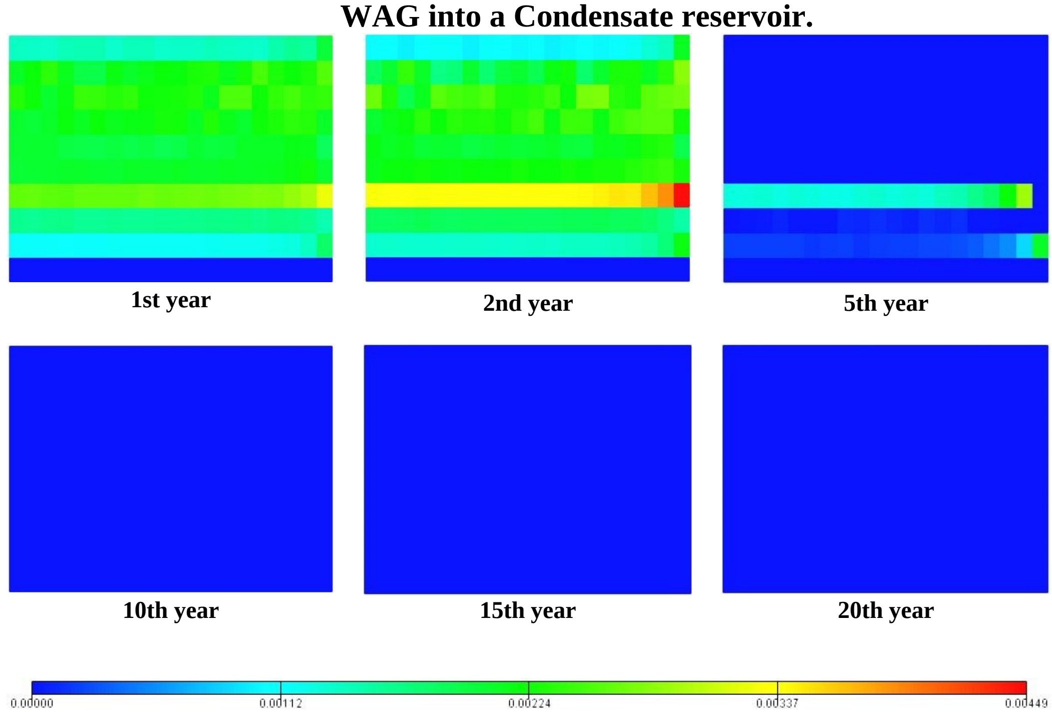


Figure 4.22: Oil saturation distribution for Fully Compositional Simulation of WAG into a Condensate reservoir.

Gas saturation decreased gradually while oil saturation decreased rapidly along the production years. The gradual reduction in gas saturation is a result of the water introduced as an injection fluid, unlike in the gas injection for the fully compositional simulation where only gas was utilized as an injection fluid. Both macroscopic and microscopic sweep efficiencies were improved as oil saturation decreased to zero during this displacement process. This rapid decrease in the oil saturation can also be said to be a result of WAG process been a mitigation option for condensate banking. The pixel plots are presented in Figures 4.23 and 4.24 for the gas and oil saturation distributions obtained from the limited compositional simulation.

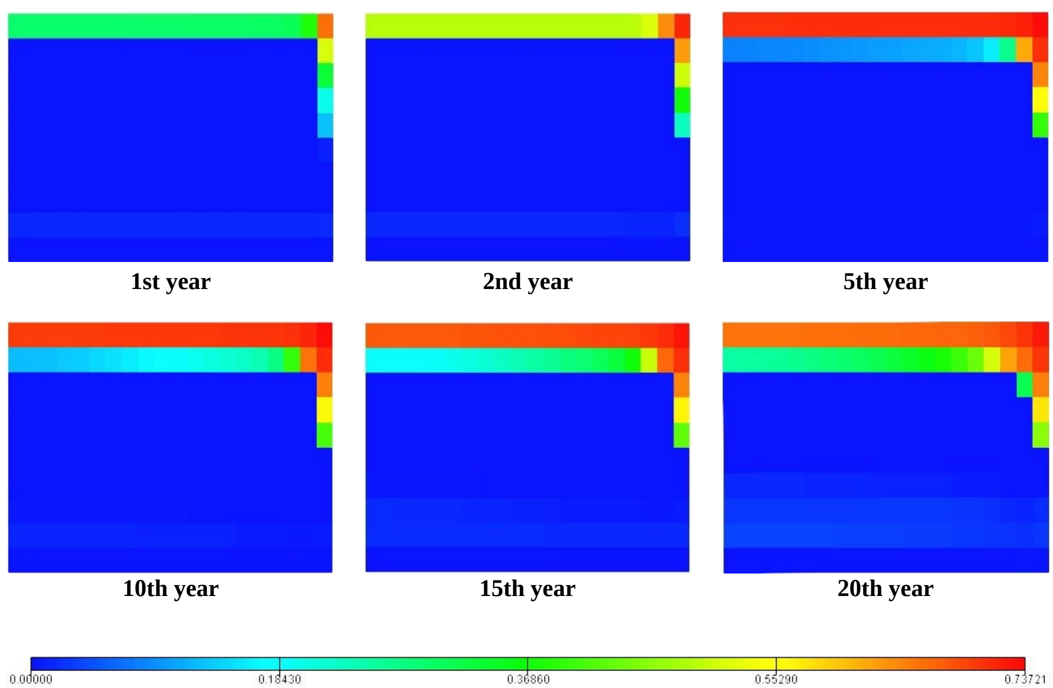


Figure 4.23: Gas saturation distribution for Limited Compositional Simulation of WAG into a Condensate reservoir.

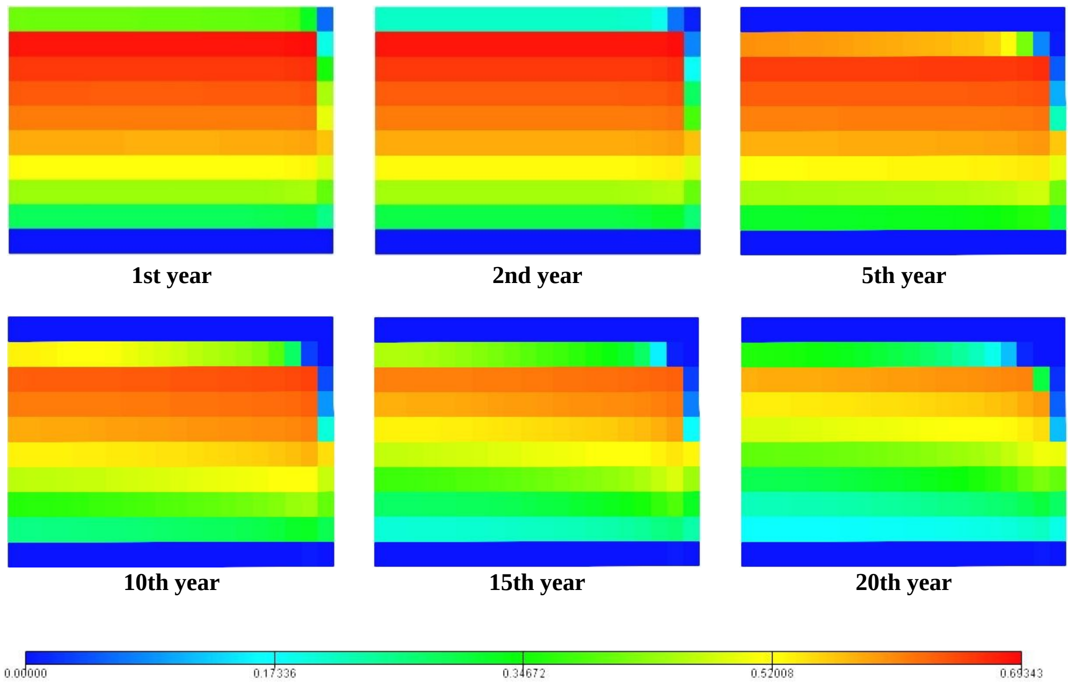


Figure 4.24: Oil saturation distribution for Limited Compositional Simulation of WAG into a Condensate reservoir.

As discussed for the limited compositional simulation of gas injection into a condensate reservoir, the same trend was observed for the WAG process. But in this scenario, the increase in gas saturation and decrease in oil saturation was gradual. This could be because of water introduced as an injection fluid. As the injected water helps in improving the microscopic sweep efficiency (Afzali et al., 2018).

Figures 4.25 and 4.26 compares the cumulative gas produced and field oil efficiency from the WAG injection based on the fully compositional and limited compositional simulations. The cumulative oil recovered after the simulation was 950 Mbbl and 10.9 MMbbl for fully and limited compositional simulation, respectively. These oil recoveries were calculated to be about 59% and 41% of the oil in place for the fully and limited compositional simulation, respectively. From the results of the simulation, it can be said that there was about an 18% increment in condensate recovery compared to the recovery from pure gas injection for both the fully and limited compositional models. The results agree with the findings by Belazreg and Mahmood (2019) where they concluded that 5 to 10% increment in oil recovery is expected for a WAG pilot process over pure gas injection, while for a field study up to 20% oil increment is expected from WAG compared to gas injection. The field oil efficiency for the fully and limited compositional simulation which are shown in Figure 4.26 indicates that the fully compositional has a higher oil efficiency than the limited compositional. This is because the oil produced as compared to the oil initially in place for the fully compositional was higher than the limited compositional simulation.

The comparisons of the water cut and reservoir pressure profiles for the WAG process from both fully compositional and limited compositional simulations are shown in Figures 4.27 and 4.28, respectively. The water cut profile obtained from WAG injection using the fully compositional and limited compositional simulations was the same as that obtained for gas injection. The reservoir pressure for the fully compositional simulation increases slightly above the dew point pressure of 4191 psia as the well was produced for 20 years. This slight increase above the dew point pressure can be said to be good pressure maintenance for the reservoir as it was facilitated by the improved microscopic sweep efficiency. The reservoir pressure for the limited compositional simulation was observed to be far below the dew point pressure as it was thought to be. This might probably be because of the lean gas condensate reservoir been examined in this case study.

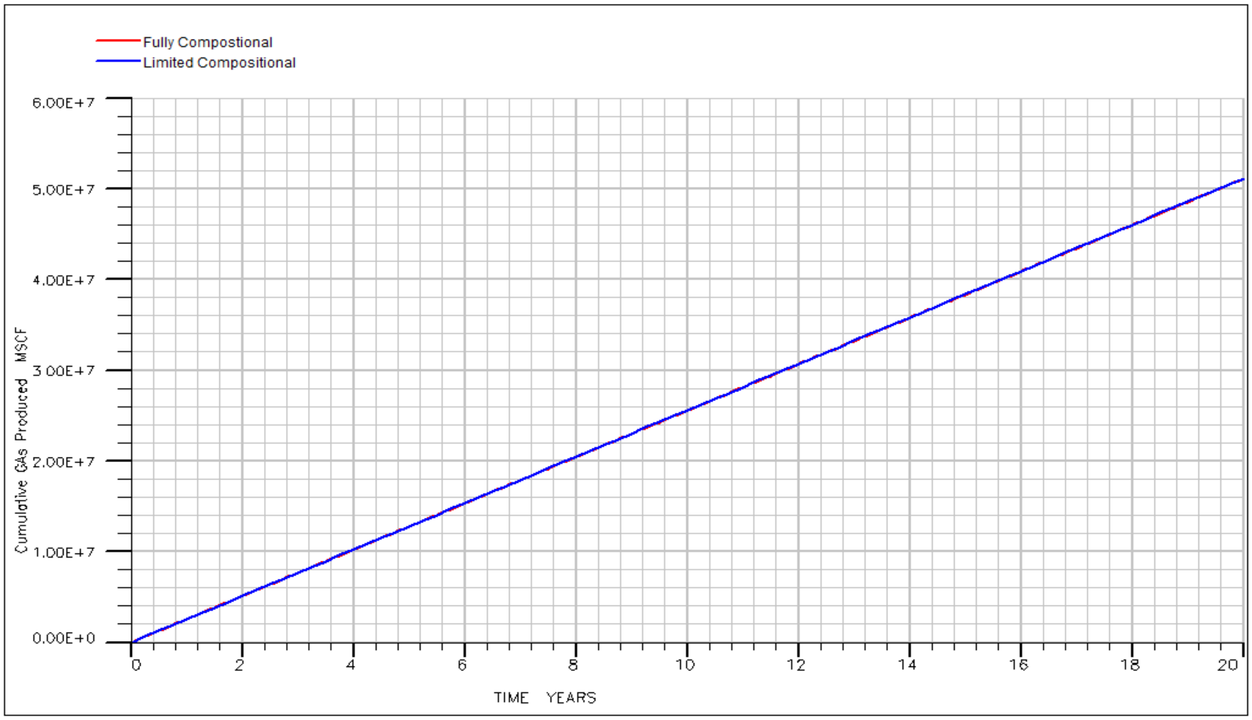


Figure 4.25: Comparison of Cumulative Gas Produced for Fully and Limited Compositional Simulations of WAG injection into a Condensate reservoir.

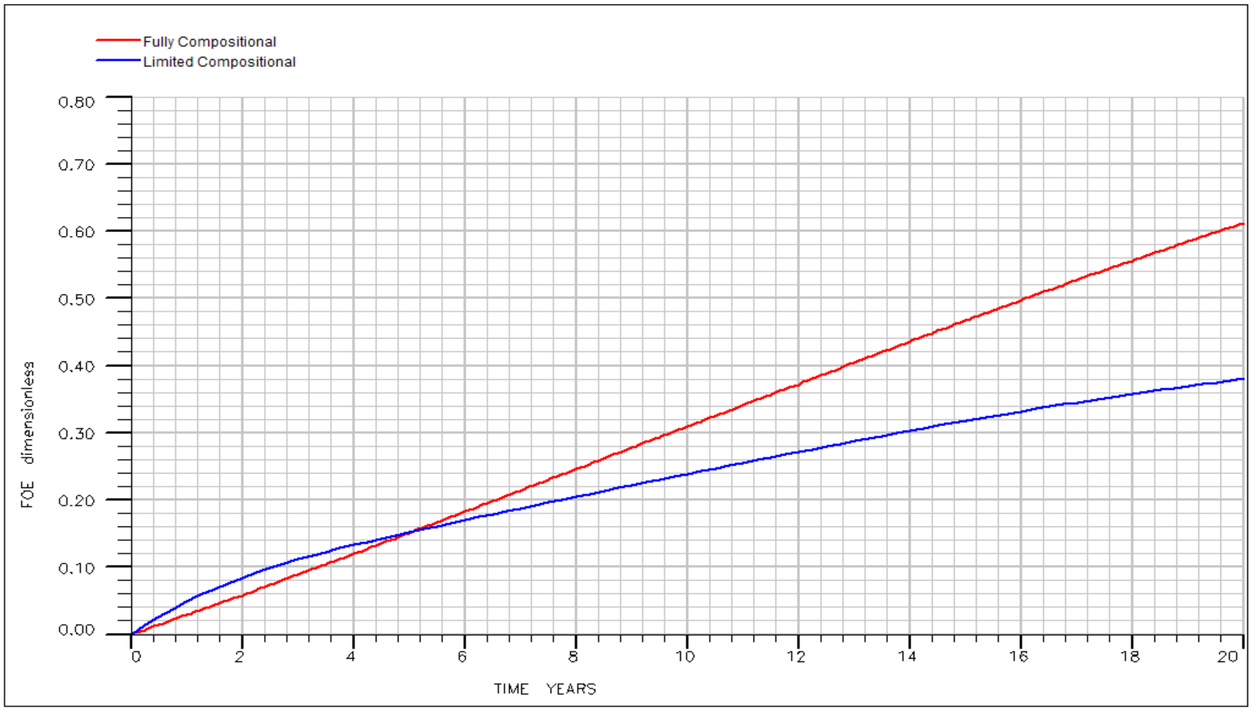


Figure 4.26: Comparison of Field Oil Efficiency for Fully and Limited Compositional Simulations of WAG injection into a Condensate reservoir.

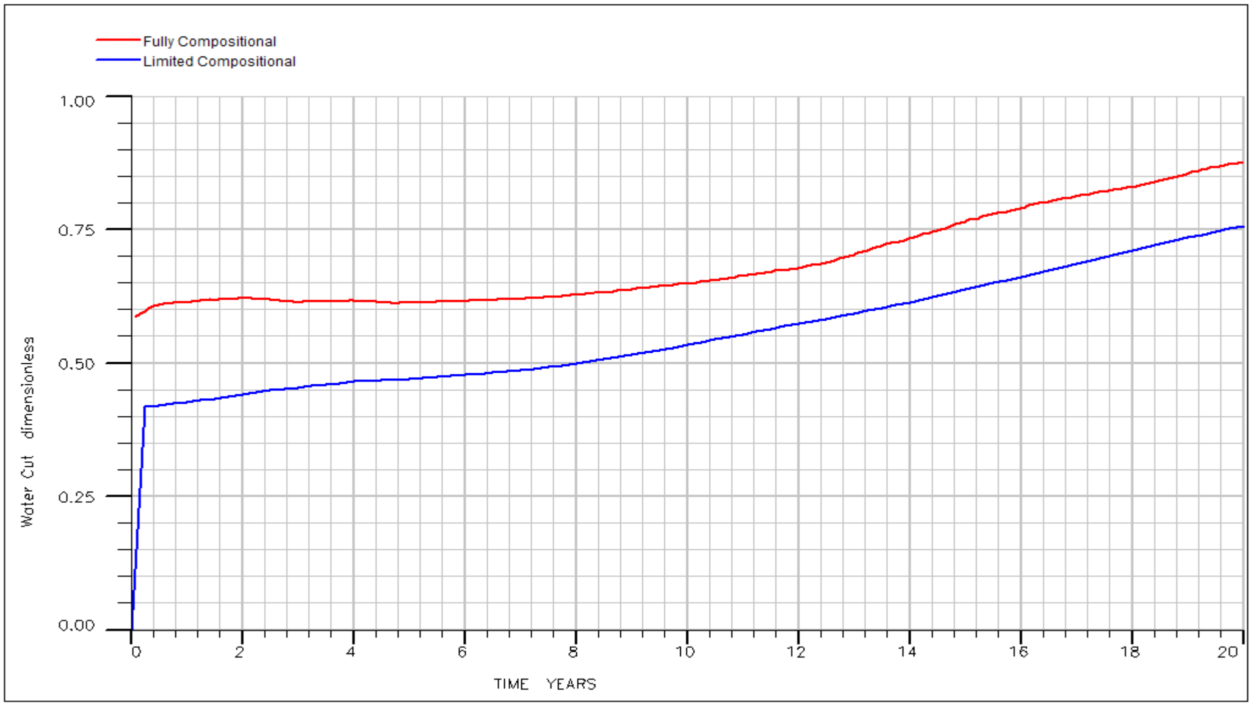


Figure 4.27: Comparison of water cut profiles for Fully and Limited Compositional Simulations of WAG injection into a Condensate reservoir.

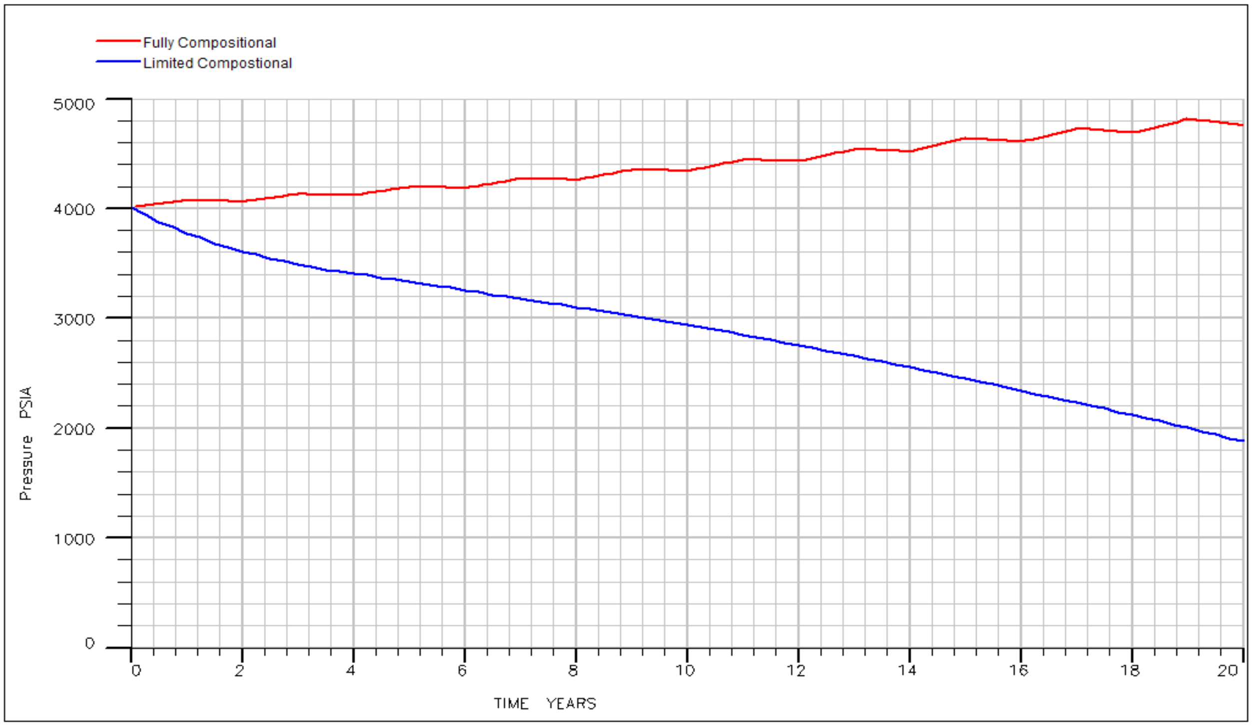


Figure 4.28: Comparison of Field Pressures for Fully and Limited Compositional Simulations of WAG injection into a Condensate reservoir.

4.3 Effect of Todd-Longstaff Mixing Parameter and Well Configuration and Injection Pattern on condensate Recovery.

Results obtained for the condensate recovery when the Todd-Longstaff mixing parameter (ω) was varied for different well configurations and injection patterns using the limited compositional simulator are presented and discussed in this section.

The values used in tuning the Todd-Longstaff mixing parameter are listed in Table 4.1. The mixing parameter was tuned for the simulation of gas injection and WAG process using the two well configurations (i.e., two vertical wells; vertical injector-horizontal producer pair) and the staggered line drive, and five-spot injection patterns.

Table 4.1: Mixing Parameters used in Limited Compositional Simulation of Gas injection and WAG injection in Condensate reservoir.

Run	Mixing Parameter (ω)
1	0
2	0.167
3	0.333
4	0.500
5	0.667
6	0.833
7	0.990
8	0.992
9	0.994
10	0.996
11	0.998
12	1.000

4.3.1 Effect of Well Configuration on Condensate Recovery.

This section is divided into two, gas injection and WAG injection. It discusses the results obtained when the mixing parameter was tuned using the different well configurations in the limited compositional simulation.

4.3.1.1 Effect of Well Configuration on Condensate Recovery for Gas Injection.

Figures 4.29 and 4.30 show the volume of condensate recovered for well configuration when mixing parameter was tuned in the limited compositional simulation. As mixing parameter was increased (i.e., **ω** = 0, 0.167, 0.333, 0.5, and 0.8333), a slight increase in condensate recovery was observed. The slight increase in condensate volume signifies that the impact of viscous fingering has been reduced gradually as the mixing parameter increases, indicating an increase in miscibility between the injected fluid and the in-situ fluid. Viscous fingering exists because of the high mobility ratio of the displacing fluid. A relatively higher increment in condensate volume was observed when the mixing parameter was set between 0.990 and 0.998. At this point, the mobility ratio tends to decrease as the impact of viscous fingering decreases correspondingly. An abrupt increase in condensate recovery was observed when the mixing parameter was set to 1. This abrupt increase in condensate production was probably due to complete mixing with little or no viscous fingering as defined in the Todd and Longstaff model (1972).

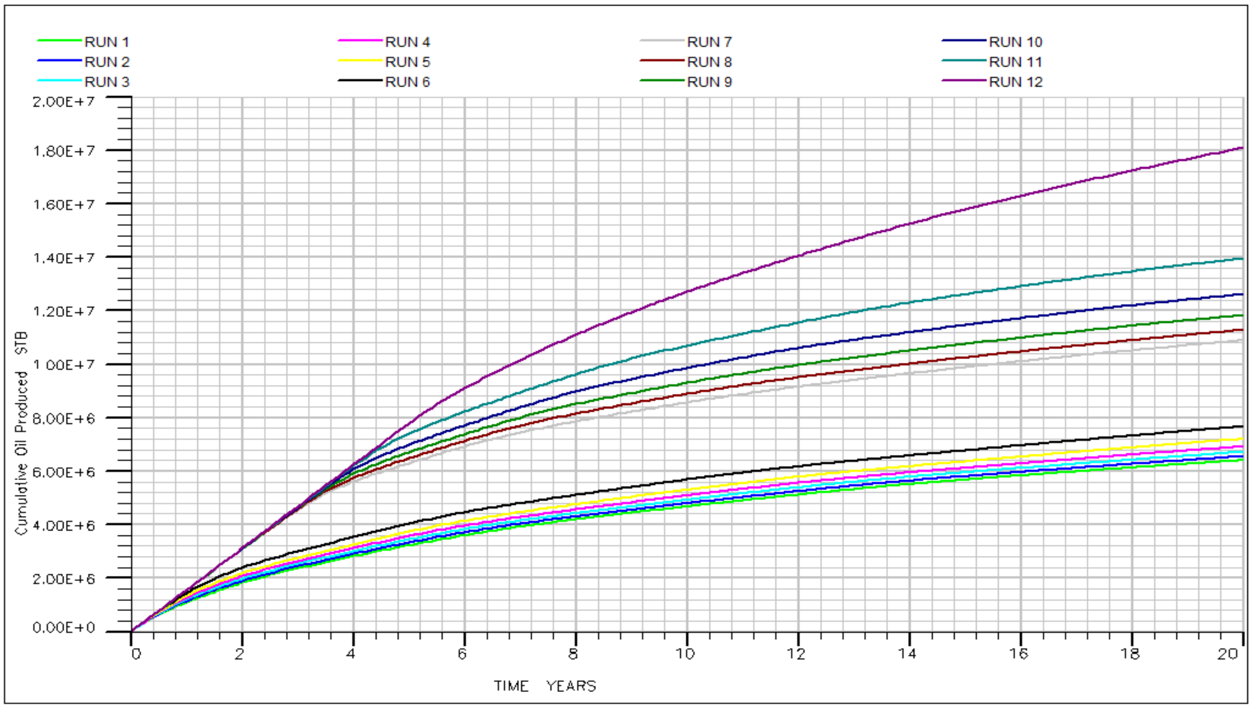


Figure 4.29: Condensate Produced after Tuning Mixing Parameter for Vertical Injector-Vertical Producer Pair using Limited Compositional Simulations of Gas injection. See Table 4.1 for the definition of ω used in the simulations.

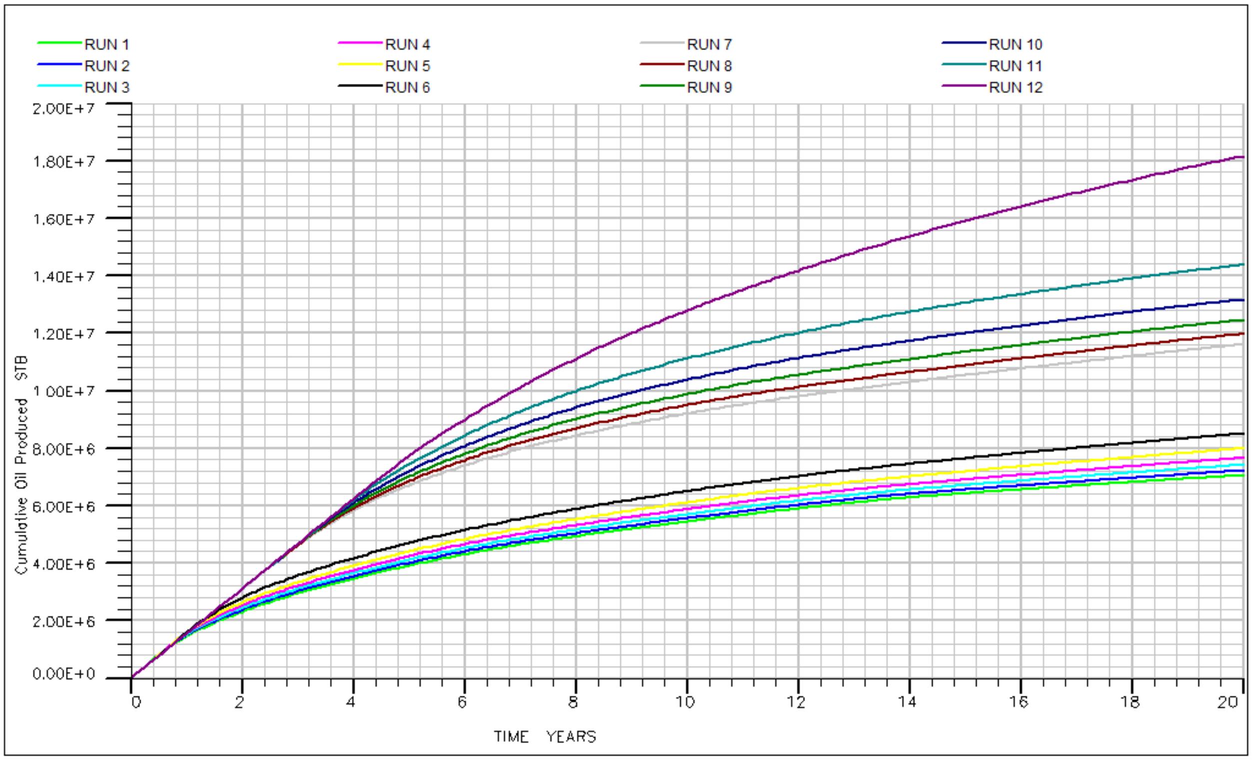


Figure 4.30: Condensate Produced after Tuning Mixing Parameter for Vertical Injector-Horizontal Producer Pair using Limited Compositional Simulations of Gas injection. See Table 4.1 for the definition of ω used in the simulations.

The comparison of the results of the percentage condensate recovery obtained from the two well configurations (i.e., vertical injector-vertical producer vs. vertical injector-horizontal producer) by gas injection is shown in Table 4.2.

Table 4.2: Percentage Condensate Recovery from Gas Injection after Tuning Mixing Parameter in Limited Compositional Simulation for Two Well Configurations.

Run	Mixing Parameter (ω)	Condensate Recovery, %	
		Vertical Injector-Vertical Producer	Vertical Injector-Horizontal Producer
1	0	23.5	26.3
2	0.167	24.6	27.0
3	0.333	25.0	27.8
4	0.500	26.0	28..6
5	0.667	26.7	29.8
6	0.833	28.7	31.8
7	0.990	40.9	43.3
8	0.992	42.6	44.6
9	0.994	44.3	46.4
10	0.996	47.0	49.0
11	0.998	51.9	53.5
12	1.000	67.5	67.8

Using the two well configurations, the percentage condensate recovery of 43% was obtained from the fully compositional simulation. When the values in Table 4.2 were compared with the 43% condensate recovery from the fully compositional model, it is observed that the 42.6% condensate recovery from the vertical injector and vertical producer pair in the limited compositional model is a close match. In this case, the mixing parameter was set equal to 0.992 in the limited compositional model. Using the vertical injector and horizontal producer pair in the limited compositional simulator yielded a 43.3% condensate recovery by gas injection. Again, this result closely matched the 43% recovery obtained from the fully compositional model for the same well configuration. The corresponding mixing parameter (ω) is 0.99 for the vertical injector and horizontal producer pair used in simulating gas injection in the limited compositional model. This comparison was to help to determine the optimum condensate recovery using gas injection by varying the Todd-Longstaff mixing parameter (ω) in the limited compositional simulation.

Figures 4.31 and 4.32 shows a pixel plot for condensate saturation at the 1st, 2nd, 5th, 10th, 15th, and 20th year using the optimum mixing parameters for the two well configurations. The pixel plot shows a 2-d view of the reservoir with the injection well at (1,1) layer 1-4 and producer well (20,20) layer 4-7.

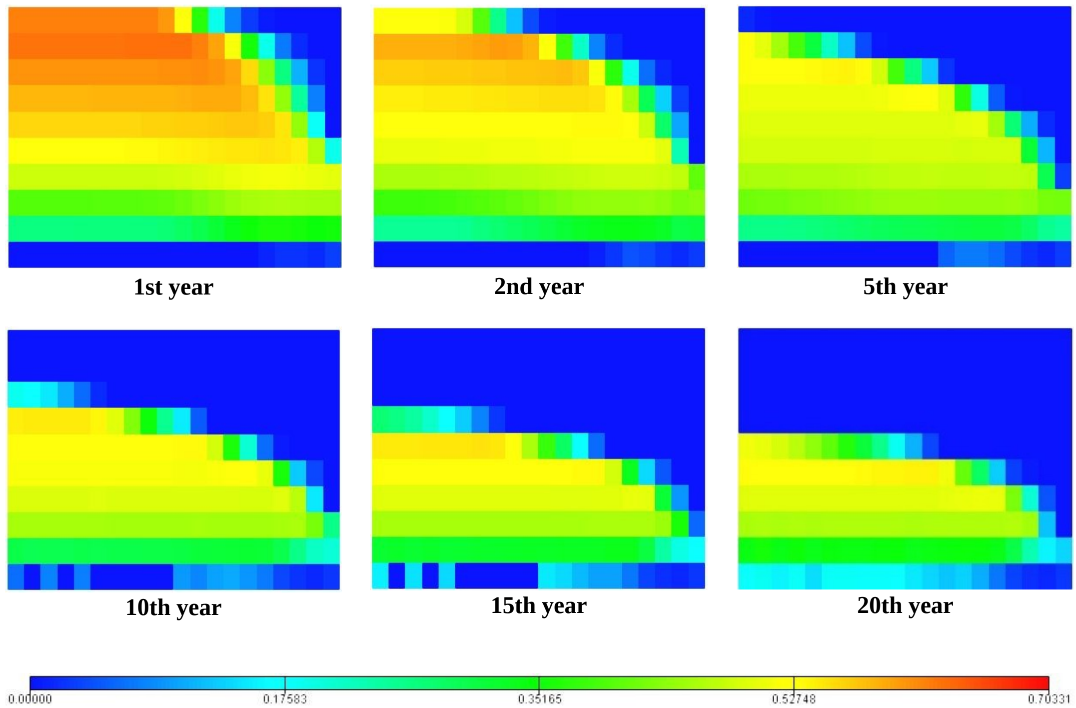


Figure 4.31: Condensate Saturation Distribution for Optimum mixing parameter using Vertical Injector and Vertical Producer Pair in Gas injection.

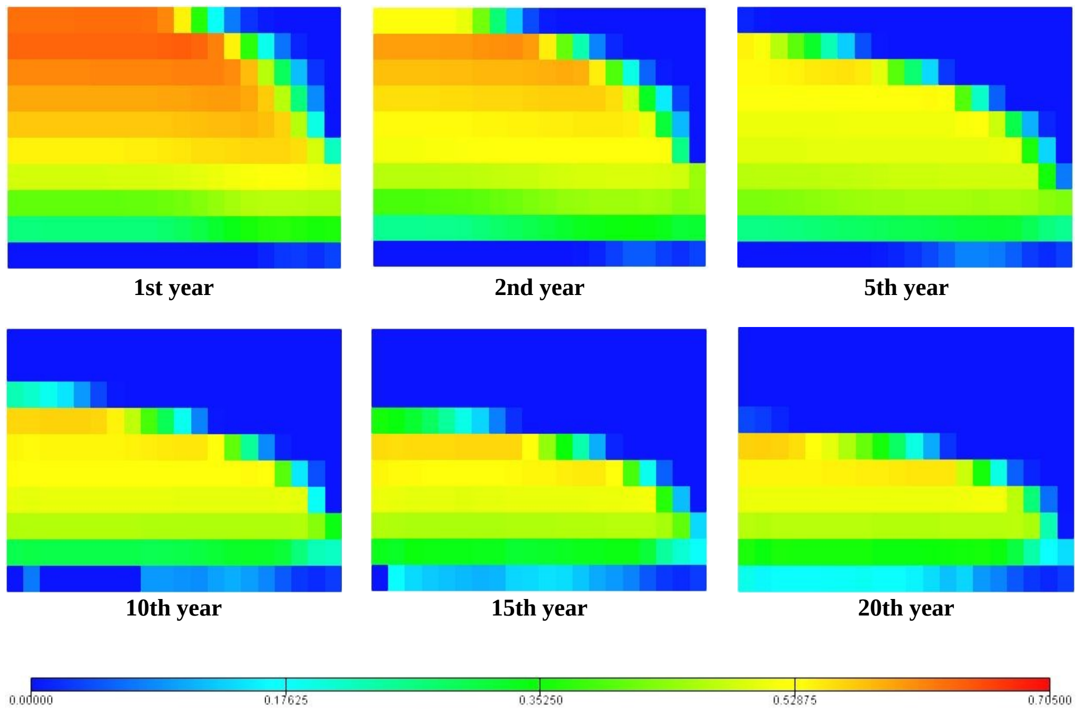


Figure 4.32: Condensate Saturation Distribution for Optimum mixing parameter using Vertical Injector and Horizontal Producer Pair in Gas injection.

A comparative analysis of the results obtained using the optimum mixing parameter and the two well configurations in the limited compositional simulation versus those from the fully compositional simulation is presented below. Figures 4.33 through 4.36 show the cumulative gas produced, cumulative oil produced, water cut and reservoir pressure profiles from these simulations.

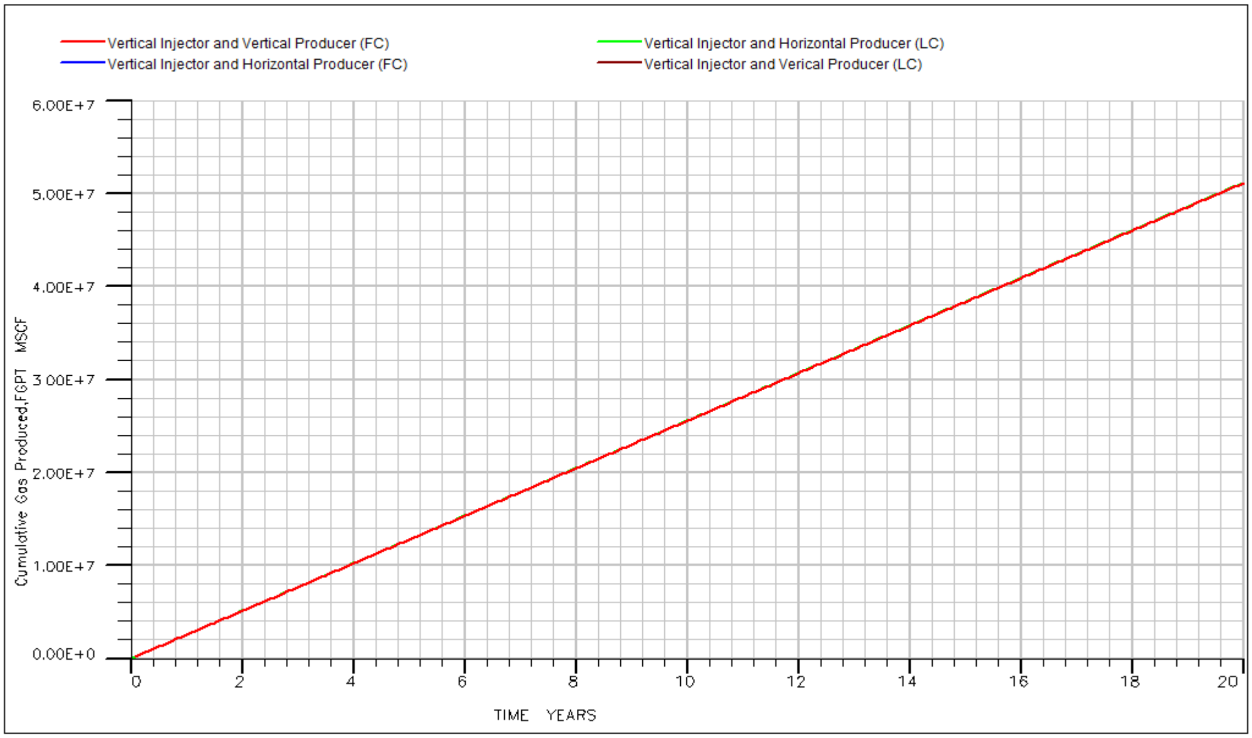


Figure 4.33: Effect of Well Configuration on the Cumulative Gas Produced by Gas injection for Fully and Limited Compositional Simulations with optimum mixing parameter.

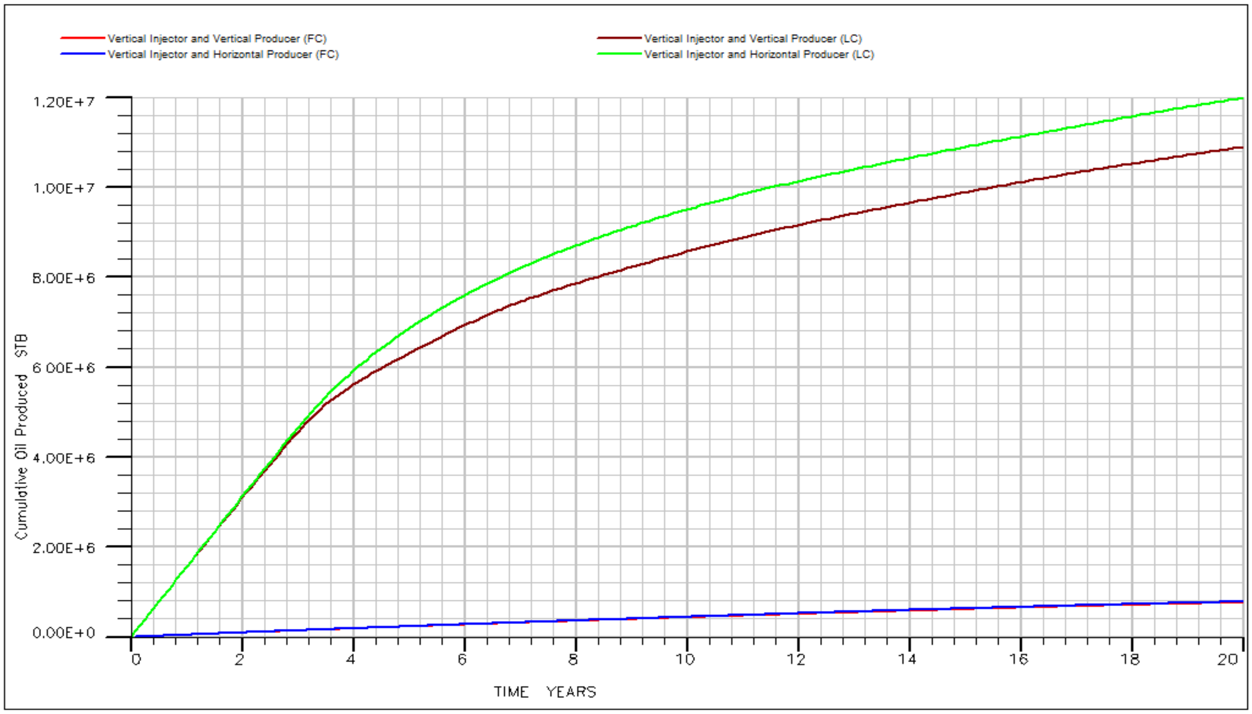


Figure 4.34: Effect of Well Configuration on the Cumulative Oil Produced by Gas injection for Fully and Limited Compositional Simulations with optimum mixing parameter.

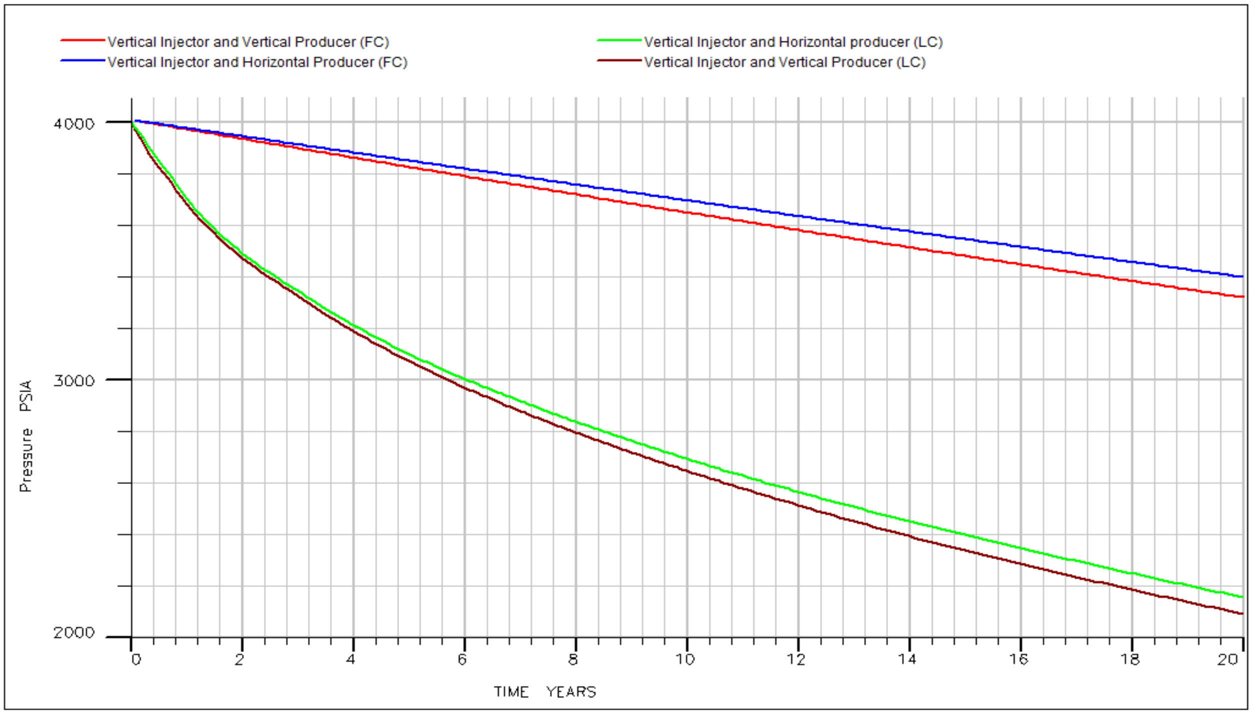


Figure 4.35: Effect of Well Configuration on the Reservoir Pressure by Gas injection for Fully and Limited Compositional Simulations with optimum mixing parameter.

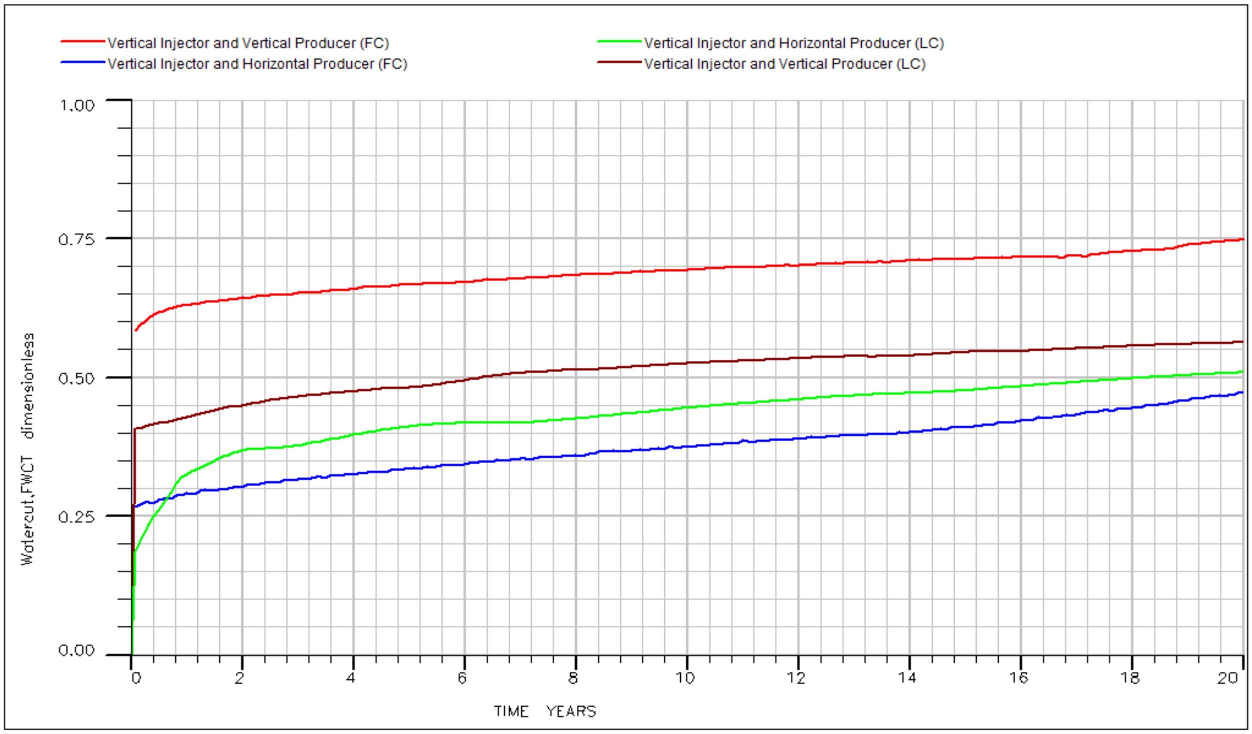


Figure 4.36: Effect of Well Configuration on the Water cut Profile by Gas injection for Fully and Limited Compositional Simulations with optimum mixing parameter.

The results shown in Figures 4.33 through 4.36 indicate that the performance of the vertical injector and horizontal producer is better than those of the vertical injector and vertical producer. The vertical injector-horizontal producer well configuration gave a higher cumulative oil produced, lower water cut, and more effective reservoir pressure maintenance than vertical injector-vertical producer pair for both the fully compositional and limited compositional simulation. This result is expected because the horizontal producer has more contact with the reservoir and yields higher recovery. Notwithstanding, horizontal wells change the radial flow drainage pattern in vertical wells into a combination of radial, linear and elliptical flows (Economides et al., 2013). The low water cut profile in the horizontal producer signifies a reduction in water coning in the reservoir. Note that the cumulative gas produced was the same for the fully and limited compositional simulations.

4.3.1.2 Effect of Well Configuration on Condensate Recovery for WAG Injection

The same trend observed when the mixing parameter was tuned for gas injection was also observed for WAG injection. An increment of 10-15% of condensate recovery from WAG injection versus gas injection was observed after tuning the mixing parameter in the limited compositional simulation. This increment in WAG condensate recovery is because WAG injection helps in improving the microscopic sweep efficiency in gas injection processes (Afzali et al., 2018). Figures 4.37 and 4.38 shows the result obtained from the two well configurations using the limited compositional simulation of WAG injection. The simulations were conducted using the optimum Todd-Longstaff mixing parameter.

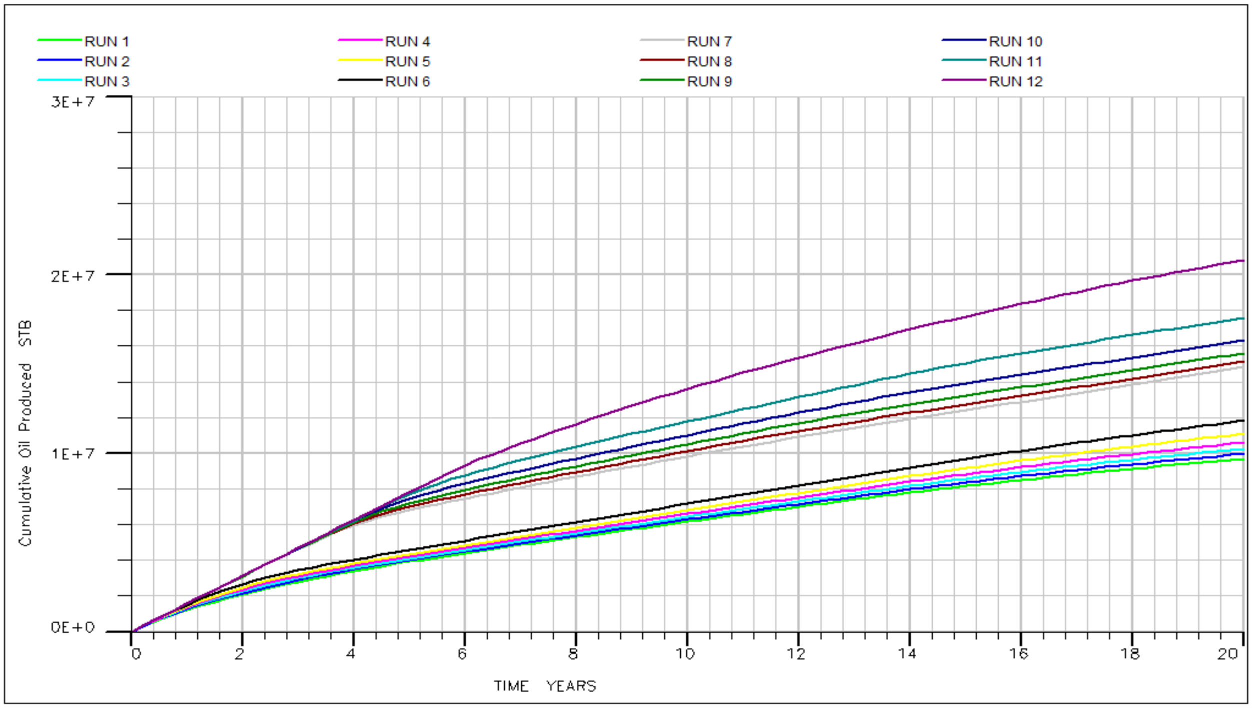


Figure 4.37: Condensate Produced from Vertical Injector-Vertical Producer Pair by WAG injection for Fully and Limited Compositional Simulations with optimum mixing parameter. See Table 4.1 for the definition of ω used in the simulations.

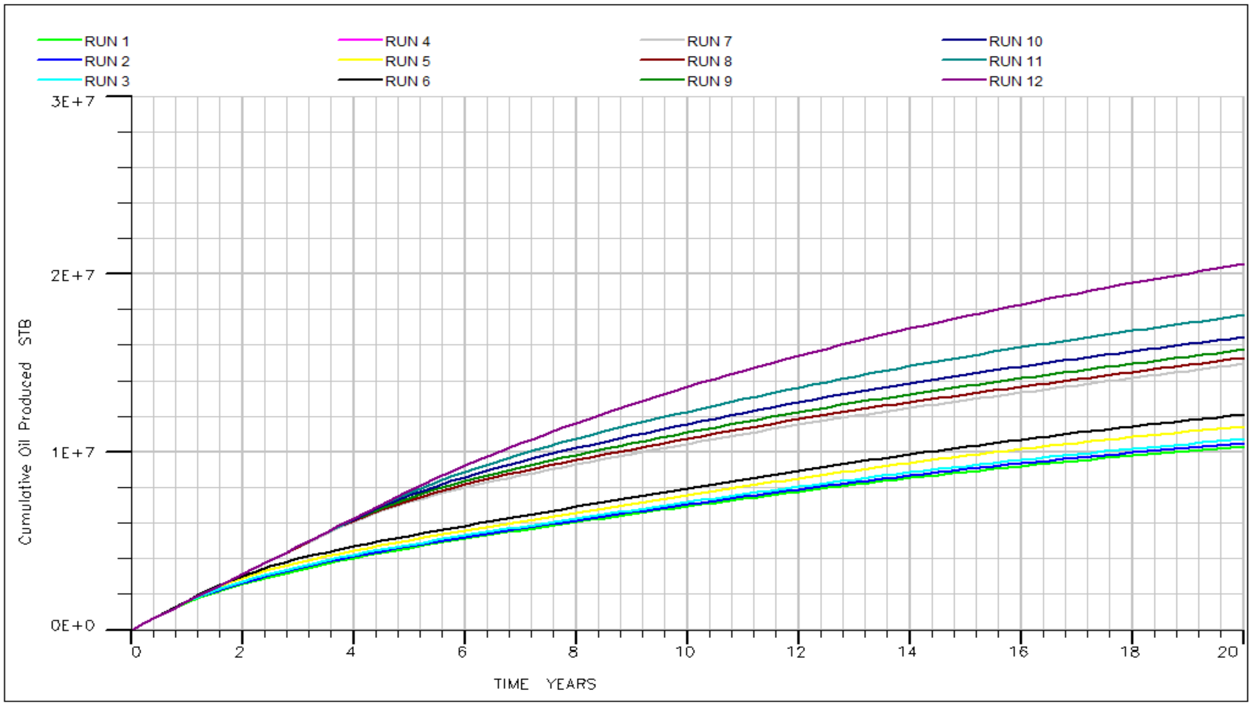


Figure 4.38: Condensate Produced from Vertical Injector-Horizontal Producer Pair by WAG injection for Fully and Limited Compositional Simulations with optimum mixing parameter. See Table 4.1 for the definition of ω used in the simulations.

Table 4.3 is a comparison of the results of the percentage condensate recovery obtained from the two well configurations (i.e., vertical injector-vertical producer vs. vertical injector-horizontal producer) by WAG injection.

Table 4.3: Percentage Condensate Recovery by WAG Injection after Tuning Mixing Parameter in Limited Compositional Simulation for Different Well Configurations.

Run	Mixing Parameter	Condensate Recovery, %	
		Vertical Injector-Vertical Producer	Vertical Injector-Horizontal Producer
1	0	36.0	38.3
2	0.167	37.3	39.2
3	0.333	38.5	40.3
4	0.500	39.9	41.0
5	0.667	41.0	42.4
6	0.833	44.3	45.2
7	0.990	55.3	56.2
8	0.992	56.5	57.1
9	0.994	57.2	57.9
10	0.996	58.8	59.7
11	0.998	65.7	67.0
12	1.000	77.4	77.9

The results of the WAG injection were analyzed similarly as was done for the gas injection. Using the two well configurations, the percentage condensate recovery of 59% was obtained from the fully compositional simulation of the WAG injection. Comparing the values in Table 4.3 with the 59% condensate recovery from the fully compositional model, it was observed that the 58.8% condensate recovery from the vertical injector and vertical producer pair in the limited compositional model was a close match. The WAG injection yielded a 59.7% condensate recovery using the vertical injector and horizontal producer pair in the limited compositional simulator; this result closely matched the 59% recovery obtained from the fully compositional model for the same well configuration. The corresponding mixing parameter (ω) is 0.996 for the two well configurations used in simulating WAG injection in the limited compositional model.

This comparison was to determine the optimum condensate recovery using WAG injection by varying the Todd-Longstaff mixing parameter (ω) in the limited compositional simulation.

Figures 4.39 and 4.40 illustrate the condensate saturation distributions in the reservoir at the 1st, 2nd, 5th, 10th, 15th, and 20th year of WAG injection. The results are for the optimum Todd-Longstaff mixing parameter (ω) in the limited compositional simulation using the two well configurations.

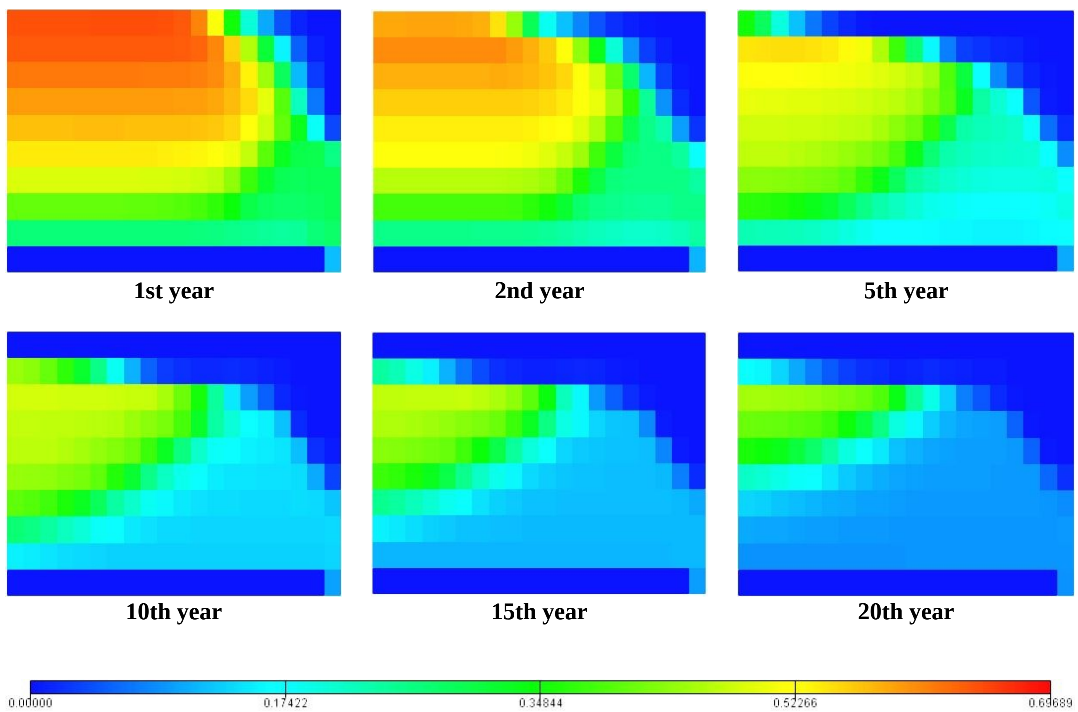


Figure 4.39: Condensate Saturation Distribution for Optimum mixing parameter using Vertical Injector and Vertical Producer Pair in WAG injection.

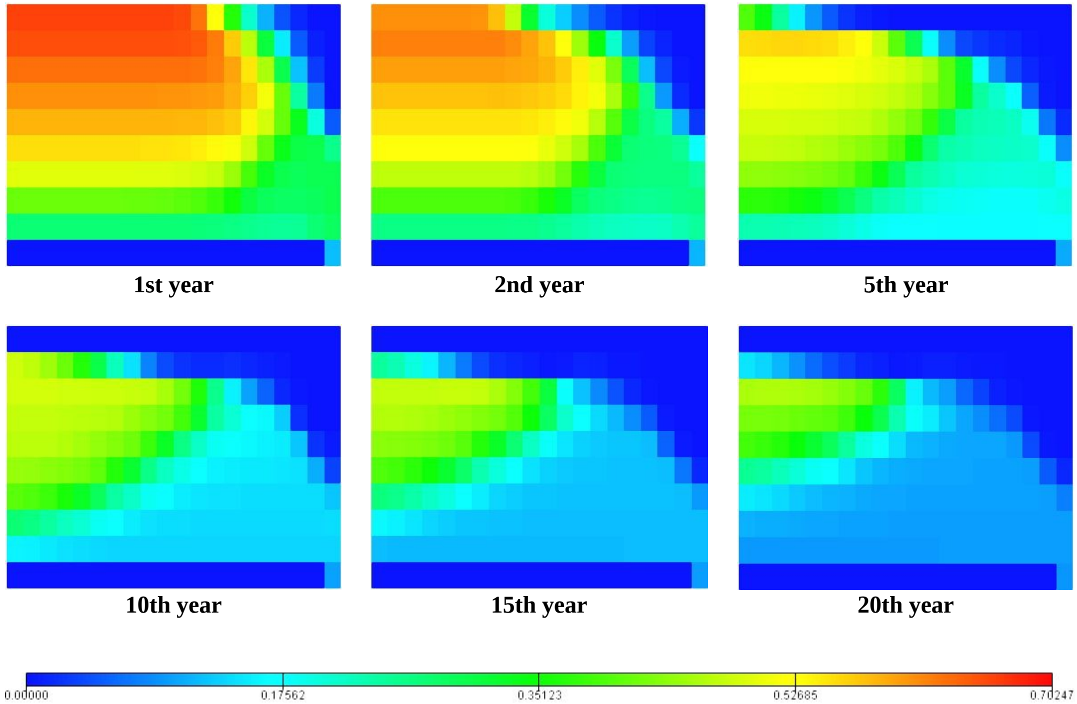


Figure 4.40: Condensate Saturation Distribution for Optimum mixing parameter using Vertical Injector and Horizontal Producer Pair in WAG injection.

The results from WAG injection using the optimum mixing parameter and the two well configurations in the limited compositional simulation are compared to those obtained from the fully compositional simulation. Figures 4.41 through 4.44 show the plots of the cumulative gas produced, cumulative oil produced, water cut and reservoir pressure profiles from these simulations.

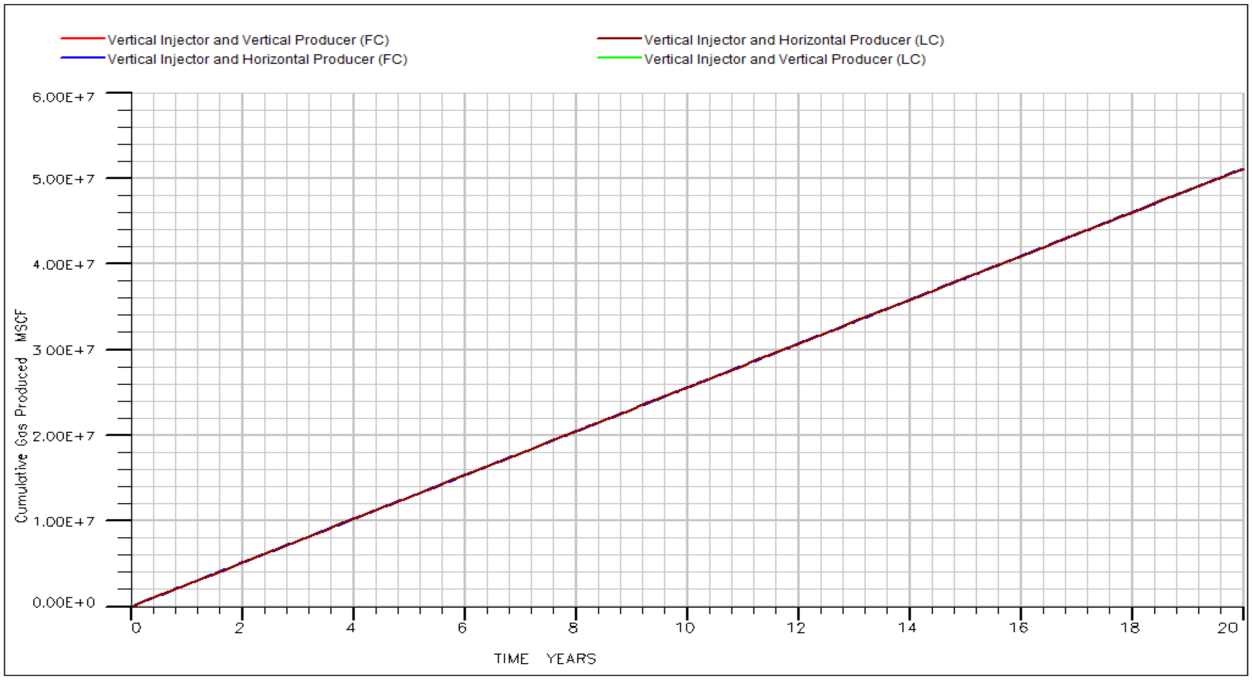


Figure 4.41: Effect of Well Configuration on the Cumulative Gas Produced by WAG injection for Fully and Limited Compositional Simulations with optimum mixing parameter.

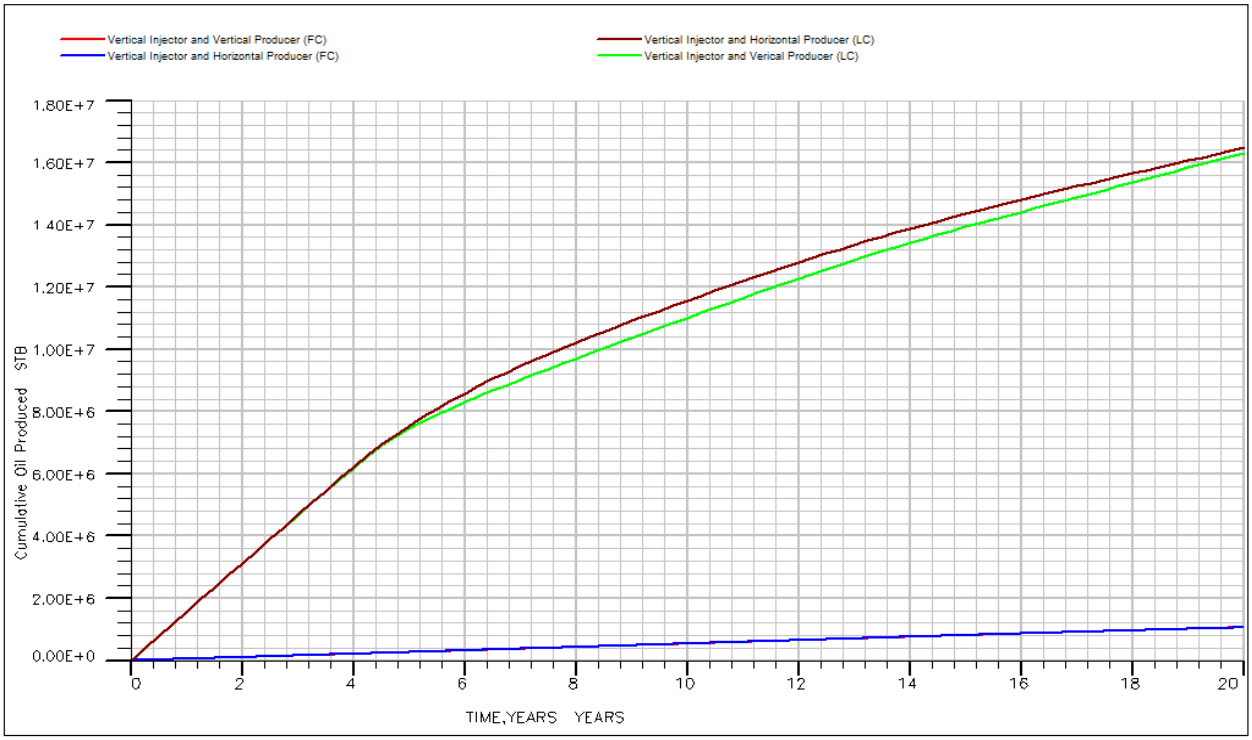


Figure 4.42: Effect of Well Configuration on the Cumulative Oil Produced by WAG injection for Fully and Limited Compositional Simulations with optimum mixing parameter.

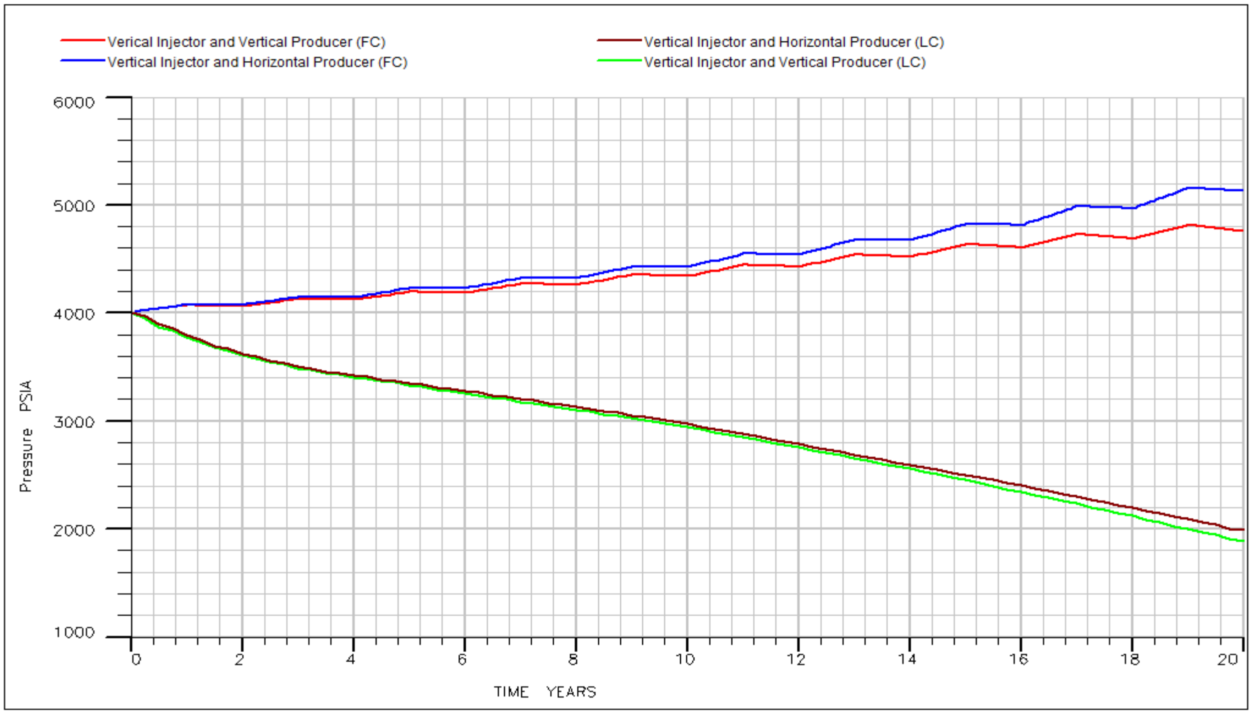


Figure 4.43: Effect of Well Configuration on Reservoir Pressure by WAG injection for Fully and Limited Compositional Simulations with optimum mixing parameter.

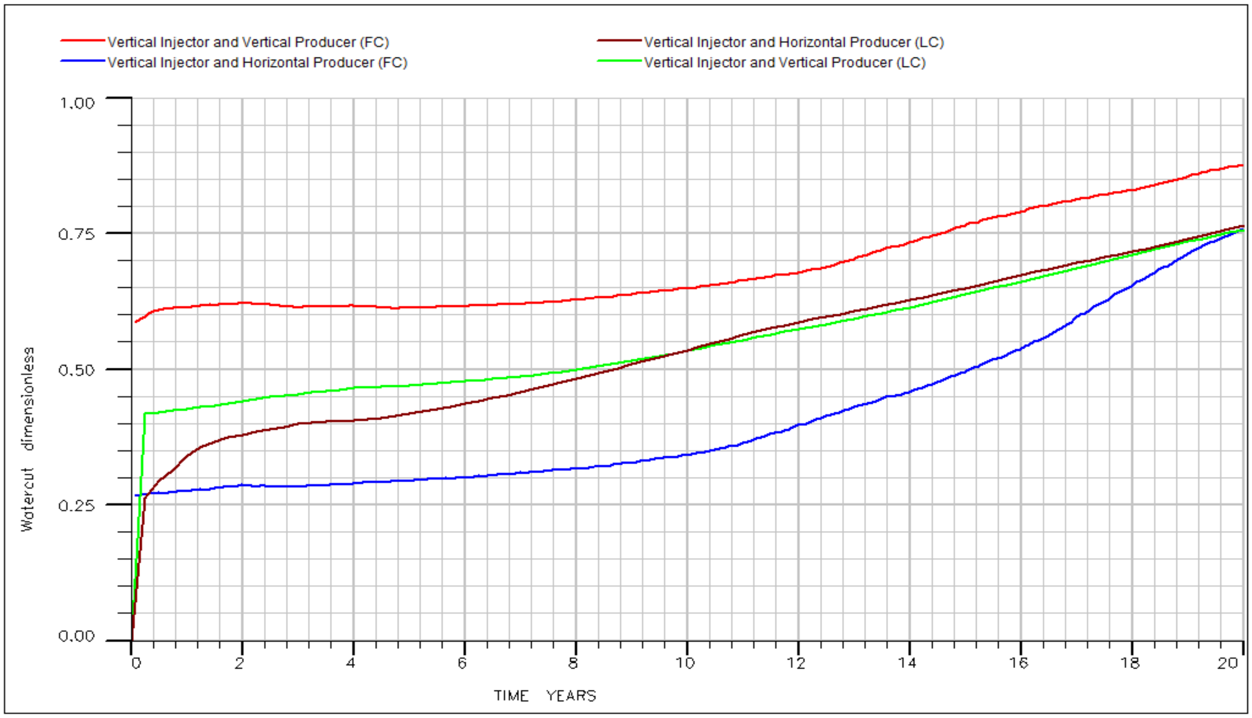


Figure 4.44: Effect of Well Configuration on Water cut by WAG injection for Fully and Limited Compositional Simulations with optimum mixing parameter.

The same trend was observed from the results of WAG injection for the two well configurations compared to the results of gas injection. For the WAG injection process, the vertical injector and horizontal producer yielded a better condensate recovery performance than the vertical injector-vertical producer pair in terms of the cumulative oil produced, water cut, and reservoir pressure maintenance.

4.3.2 Effect of Injection Pattern on Condensate Recovery.

The effect of injection patterns on condensate recovery is discussed in this section. First, the results from gas injection are presented, followed by the discussion of the results from WAG injection using different injection patterns in fully and limited compositional simulation.

4.3.2.1 Effect of Injection Pattern on Condensate Recovery by Gas Injection.

Figures 4.45 and 4.46 show the cumulative volume of condensate recovered by gas injection using limited compositional simulation. The results are for five-spot (Figure 4.45) and staggered line drive patterns (Figure 4.46) using the set of the Todd and Longstaff mixing parameters shown in Table 4.4.

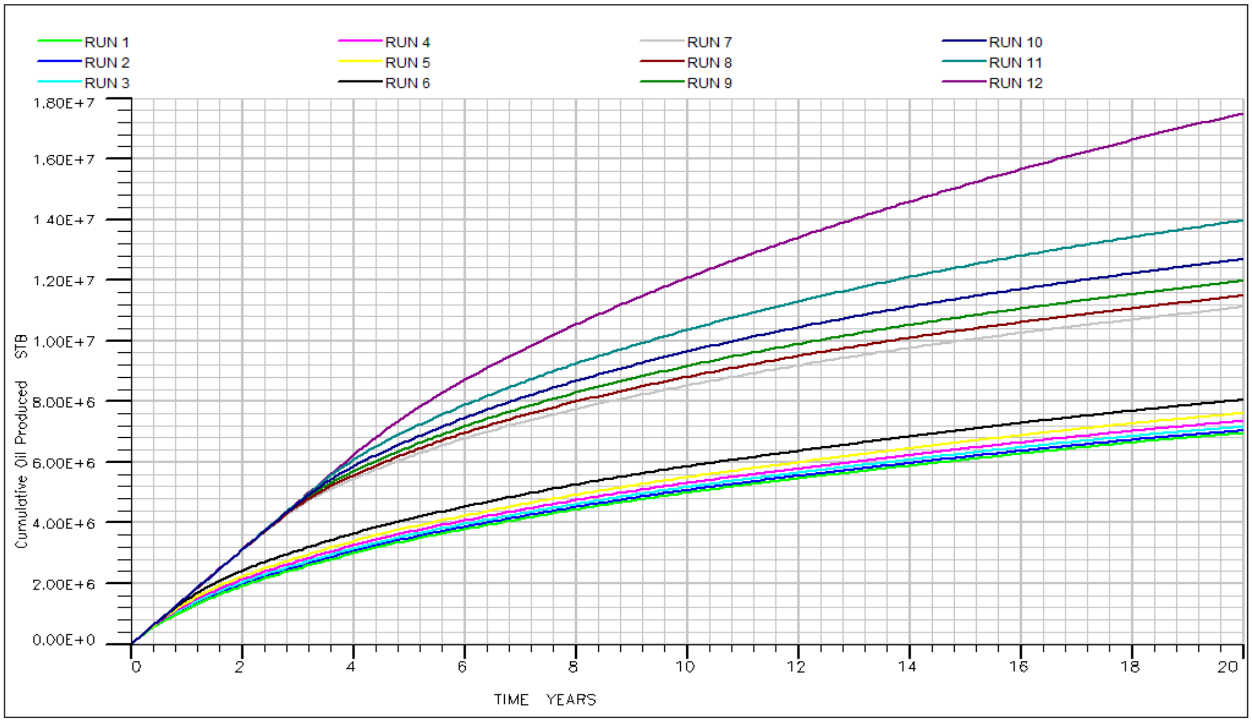


Figure 4.45: Condensate Produced after Tuning Mixing Parameter for Five-spot Injection Pattern using Limited Compositional Simulations of Gas injection. See Table 4.4 for the definition of ω used in the simulations.

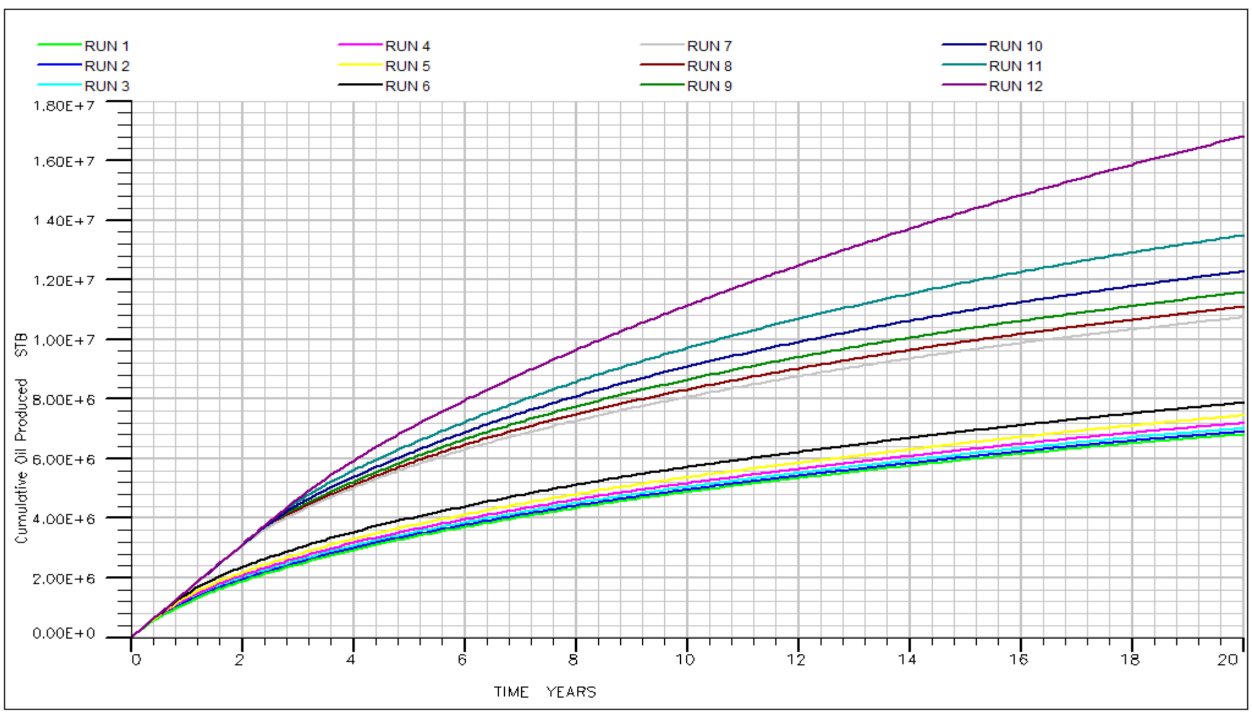


Figure 4.46: Condensate Produced after Tuning Mixing Parameter for Staggered-Line Drive using Limited Compositional Simulations of Gas injection. See Table 4.4 for the definition of ω used in the simulations.

The cumulative oil produced when mixing parameter was zero in the limited compositional simulation for the five-spot injection pattern was 6.94 MMstb, while that of staggered line drive was 6.87 MMstb. This cumulative oil produced for both injection patterns was the lowest from the results of the simulations because there is no mixing between the injected fluid and the fluid in place. Therefore, the interfacial tension between the fluid is high thereby causing viscous fingering in the reservoir (Todd and Longstaff, 1972). A slight increase in the cumulative oil produced for both injection patterns was observed for mixing parameters set equal to 0.167, 0.333, 0.5, 0.667, and 0.833. This slight increase in the cumulative oil produced was probably due to viscous fingering reducing gradually with the increase of in mixing parameter. At Todd-Longstaff mixing parameters between 0.99 and 0.998, a high volume of cumulative oil was produced for both injection patterns studied. This is because these mixing parameters are close to 1 where complete mixing between the injected fluid and fluid in place is expected. At this point of complete mixing, Todd and Longstaff concluded that viscous fingering does not exist.

Table 4.4 shows the percentage condensate recovered by gas injection in the two patterns simulated after tuning the Todd-Longstaff mixing parameter in the limited compositional simulator.

Table 4.4: Percentage Condensate Recovery by Gas Injection after Tuning Mixing Parameter in Limited Compositional Simulation for Different Injection Patterns.

Run	Mixing Parameter	Condensate Recovery, %	
		Staggered-Line Drive	Five-Spot Injection Pattern
1	0	25.5	26.0
2	0.167	25.9	26.3
3	0.333	26.1	26.8
4	0.500	26.9	27.5
5	0.667	28.0	28.5
6	0.833	29.3	30.1
7	0.990	40.1	41.5
8	0.992	41.7	42.9
9	0.994	43.2	44.7
10	0.996	45.9	47.4
11	0.998	49.9	52.4
12	1.000	62.6	65.0

Using the two well patterns, the percentage condensate recovery of 42% was obtained from the fully compositional simulation. When the values in Table 4.4 were compared with the 42% condensate recovery from the fully compositional model, it is observed that the 41.7% recovery factor for staggered-line drive in the limited compositional model is a close match. In this case, the mixing parameter was set equal to 0.992 in the limited compositional model. Using the five-spot pattern in the limited compositional simulator yielded a 41.5% condensate recovery by gas injection. Again, this result closely matched the 42% recovery obtained from the fully compositional model for the same well patterns. The corresponding mixing parameter (ω) is 0.99 for five-spot pattern used in simulating gas injection in the limited compositional model. This comparison was carried out to determine the optimum condensate recovery by gas injection using the two well patterns and varying the Todd-Longstaff mixing parameter (ω) in the limited compositional simulation.

The distribution of condensate saturation at the 1st, 2nd, 5th, 10th, 15th, and 20th year of gas injection using the optimum Todd-Longstaff mixing parameter (ω) for staggered-line drive pattern is shown in Figure 4.47. Figure 4.58 shows the saturation distributions for the five-spot injection pattern. The results of the flooding pattern for condensate saturations for the 1st, 2nd, 5th, 10th, 15th, and 20th year are shown in Figures 4.49 and 4.50 for the staggered-line drive and five-spot injection patterns, respectively.

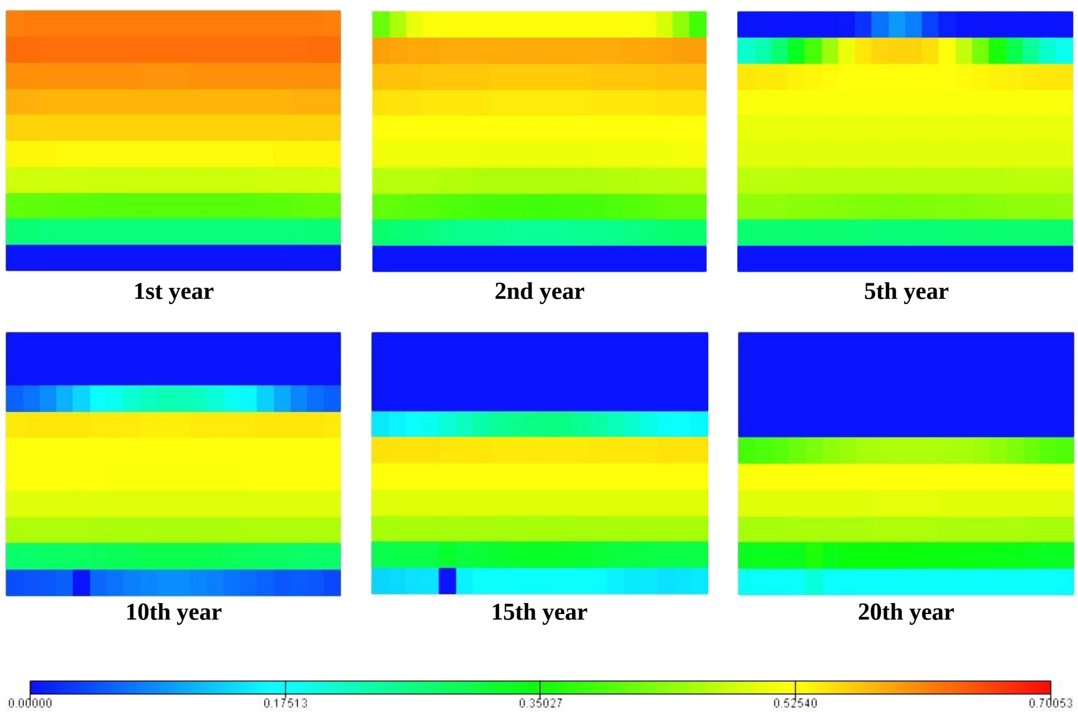


Figure 4.47: Condensate Saturation Distribution for Staggered-Line Drive for Gas Injection in Limited Compositional Simulation.

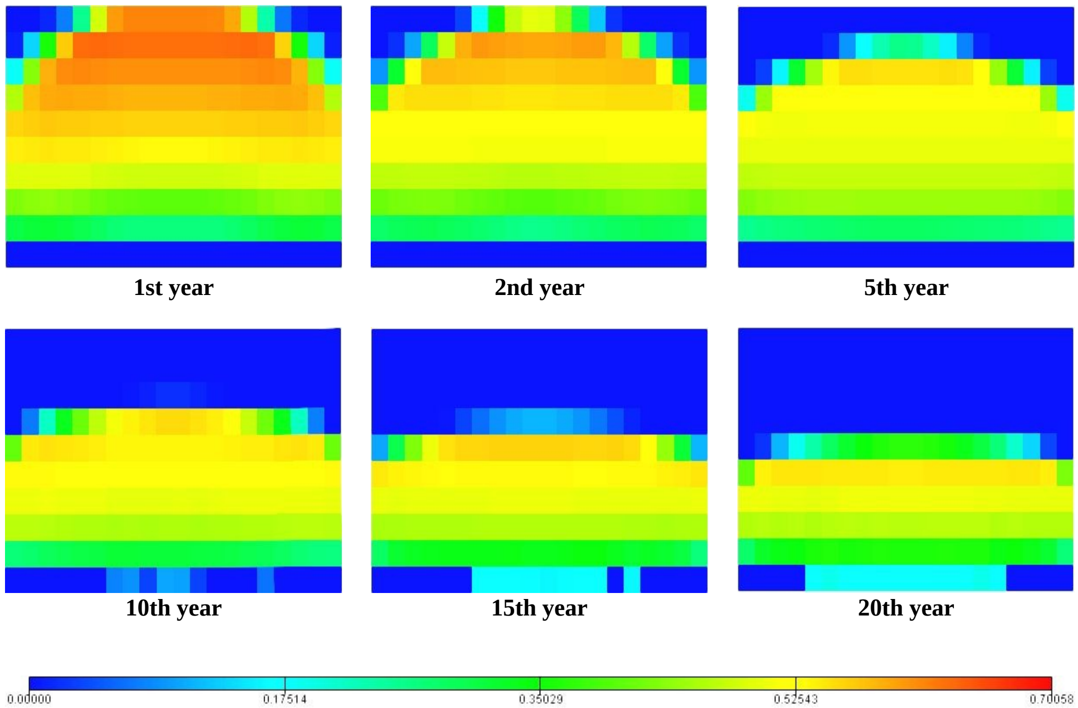


Figure 4.48: Condensate Saturation Distribution for Five-Spot Injection for Gas Injection in Limited Compositional Simulation.

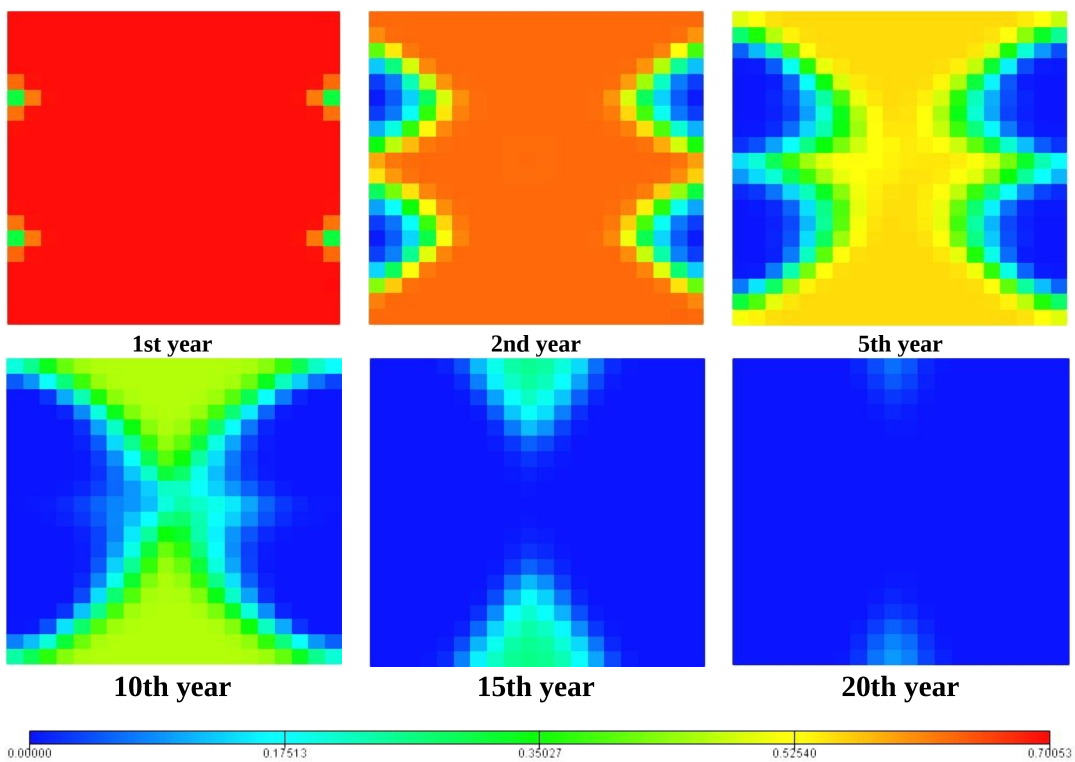


Figure 4.49: Flooding Pattern showing Condensate Saturation for Staggered-Line Drive for Gas Injection in Limited Compositional Simulation.

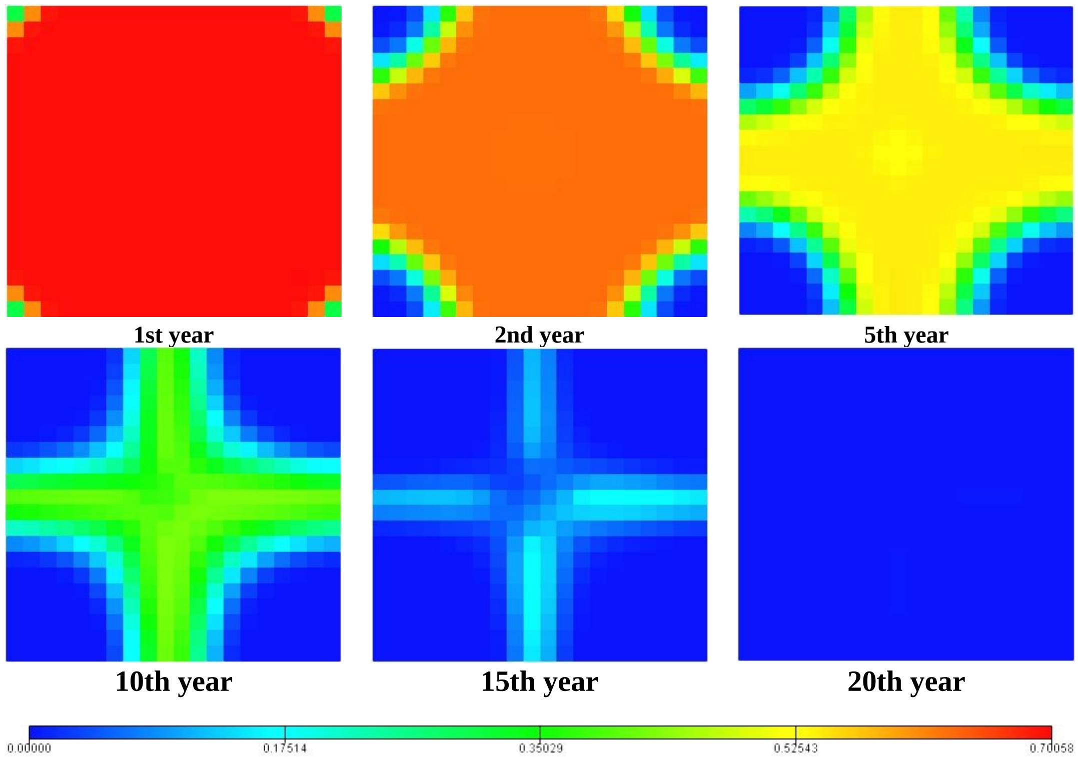


Figure 4.50: Flooding Pattern showing Condensate Saturation for Five-Spot Injection for Gas Injection in Limited Compositional Simulation.

A comparative analysis of the results of gas injection obtained using the two well patterns and the optimum Todd-Longstaff mixing parameters in the limited compositional simulation versus those from the fully compositional simulation is presented below. Figures 4.51 through 4.54 show the plots of the cumulative gas produced, cumulative oil produced, water cut and reservoir pressure profiles from these simulations.

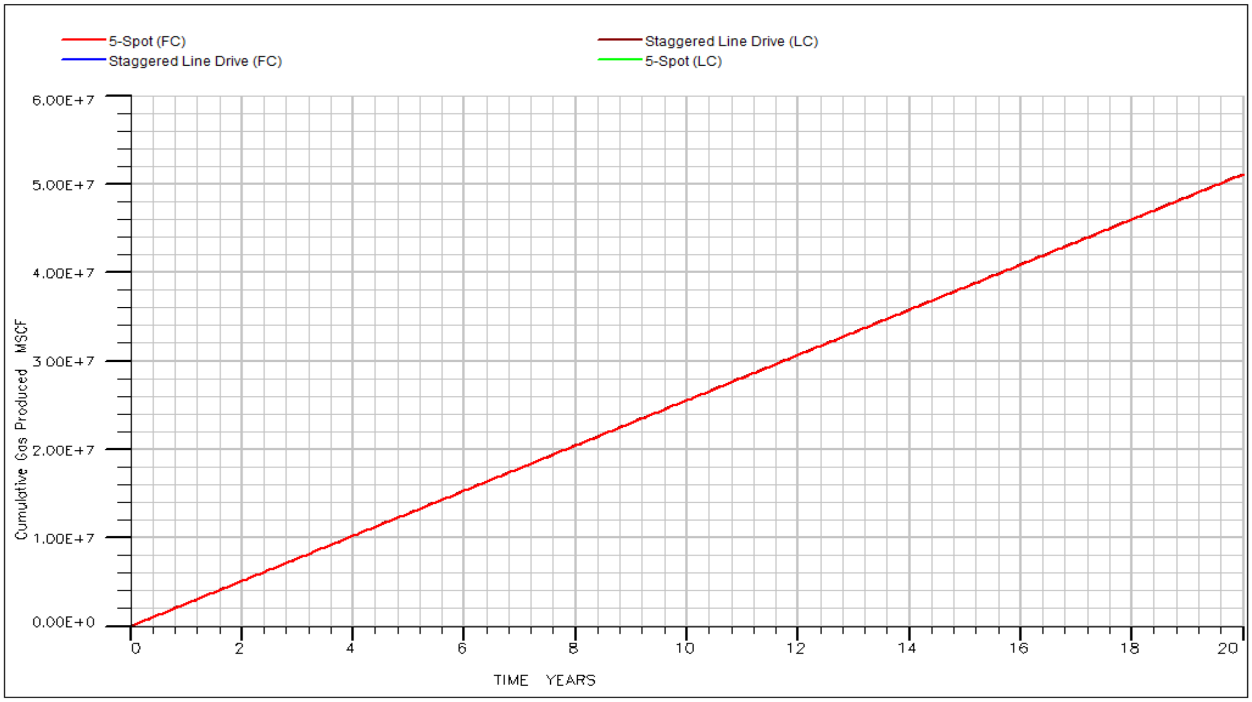


Figure 4.51: Effect of Injection Well Pattern on Cumulative Gas Produced by Gas Injection using Fully and Limited Compositional Simulations of Gas injection into a Condensate reservoir with the optimum mixing parameter.

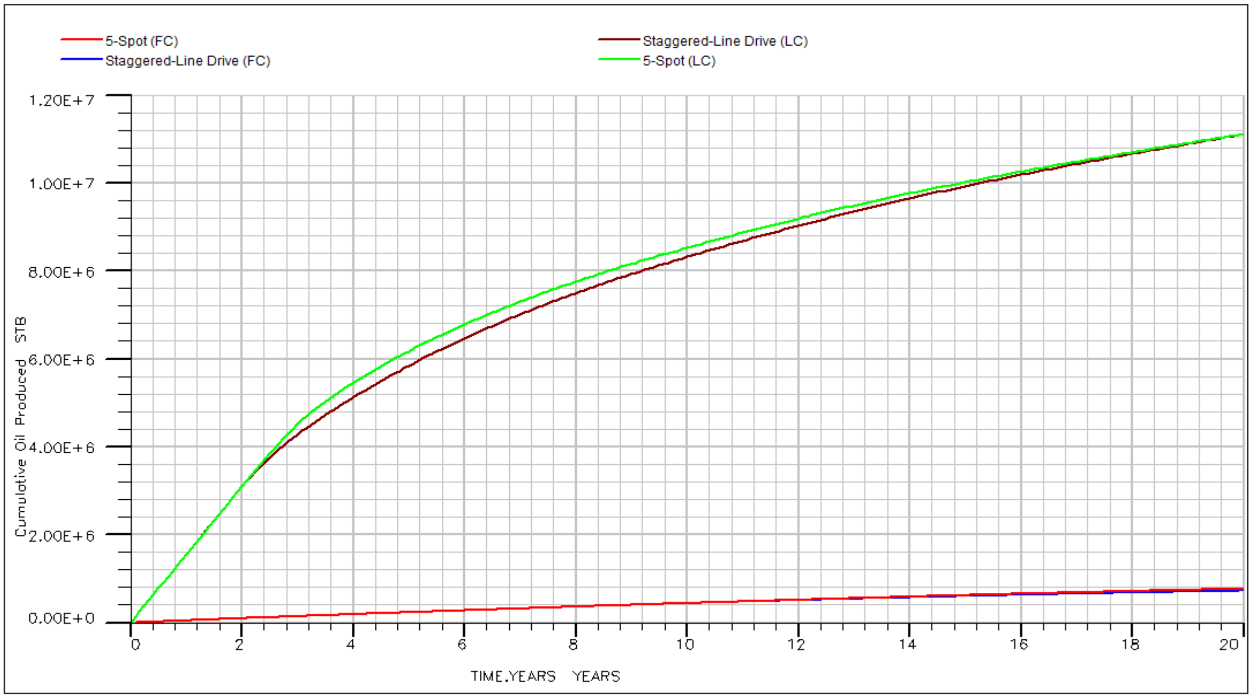


Figure 4.52: Effect of Injection Well Pattern on Cumulative Oil Produced by Gas Injection using Fully and Limited Compositional Simulations with the optimum mixing parameter.

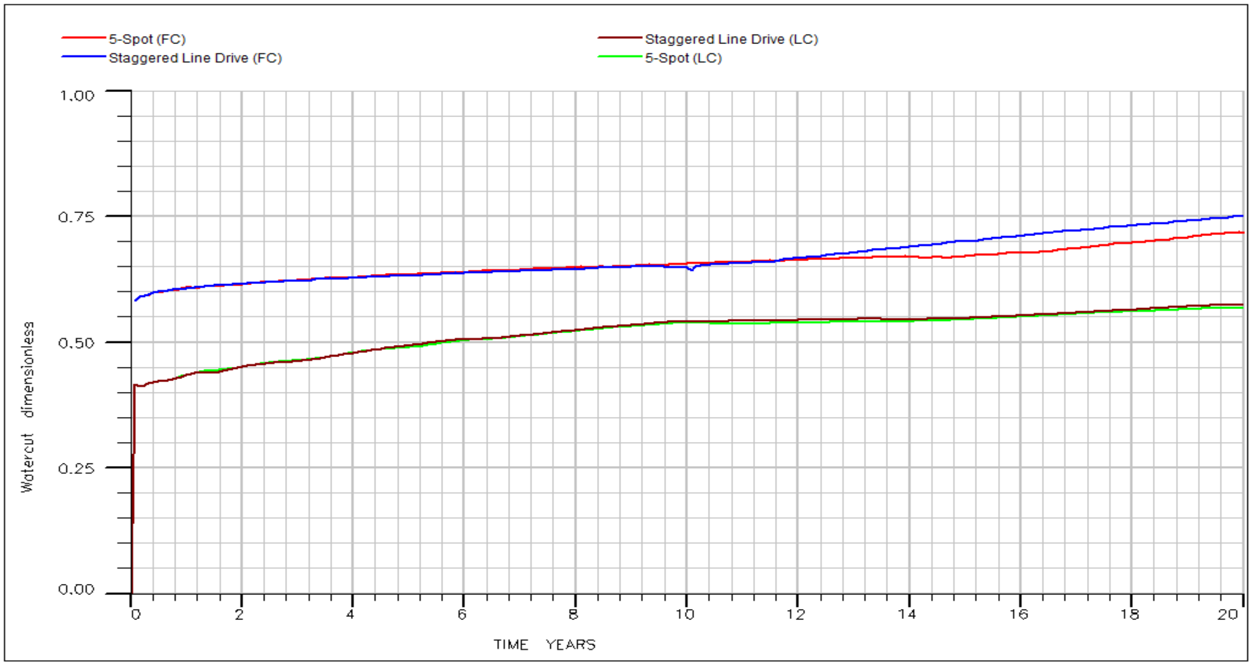


Figure 4.53: Effect of Injection Well Pattern on Water-cut for Gas Injection using Fully and Limited Compositional Simulations with the optimum mixing parameter.

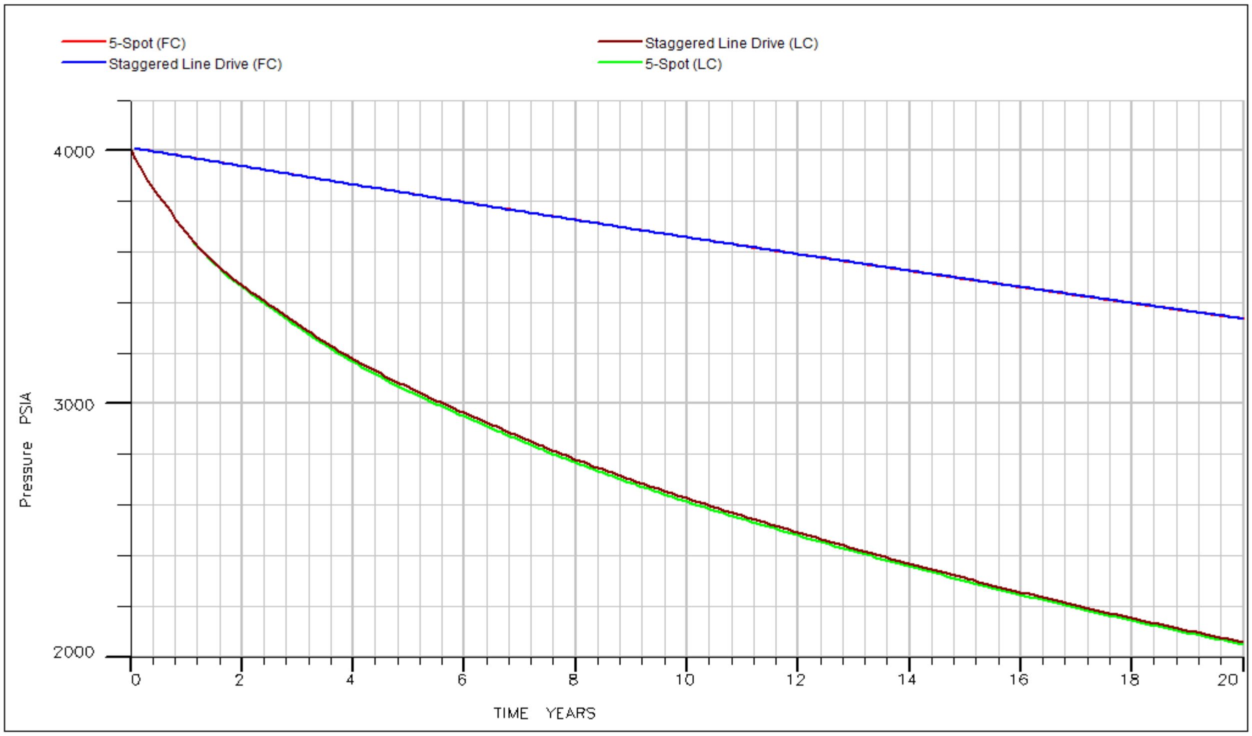


Figure 4.54: Effect of Injection Well Pattern on Reservoir Pressure for Gas Injection using Fully and Limited Compositional Simulations with the optimum mixing parameter.

The results obtained from the gas injection indicated that the five-spot injection pattern gave a higher cumulative oil recovery from both the fully compositional and limited compositional simulation with the optimum mixing parameter. This improved recovery from the five-spot pattern might be attributed to the constant spacing between the producer and four injection wells in a five-spot pattern. Note that the cumulative gas produced, water cut and reservoir pressure maintenance from the two injection patterns were about the same for both the fully compositional and limited compositional simulation with optimum mixing parameters.

4.3.2.2 Effect of Injection Pattern on Condensate Recovery by WAG Injection

The same trend observed when the mixing parameter was tuned for gas injection was also observed for WAG injection. Comparison of gas injection and WAG injection indicated an increment of 8-16% of condensate recovery after tuning the mixing parameter for WAG injection. This increment in condensate recovery has been noted because of the enhanced microscopic sweep efficiency by WAG injection. Figures 4.55 and 4.56 show the plot of cumulative oil recovery from the Staggered-line drive and five-spot WAG injection patterns using various mixing parameters in the limited compositional simulation. Table 4.5 also shows the cumulative oil recovery obtained by varying the Todd-Longstaff mixing parameters for the two well injection patterns.

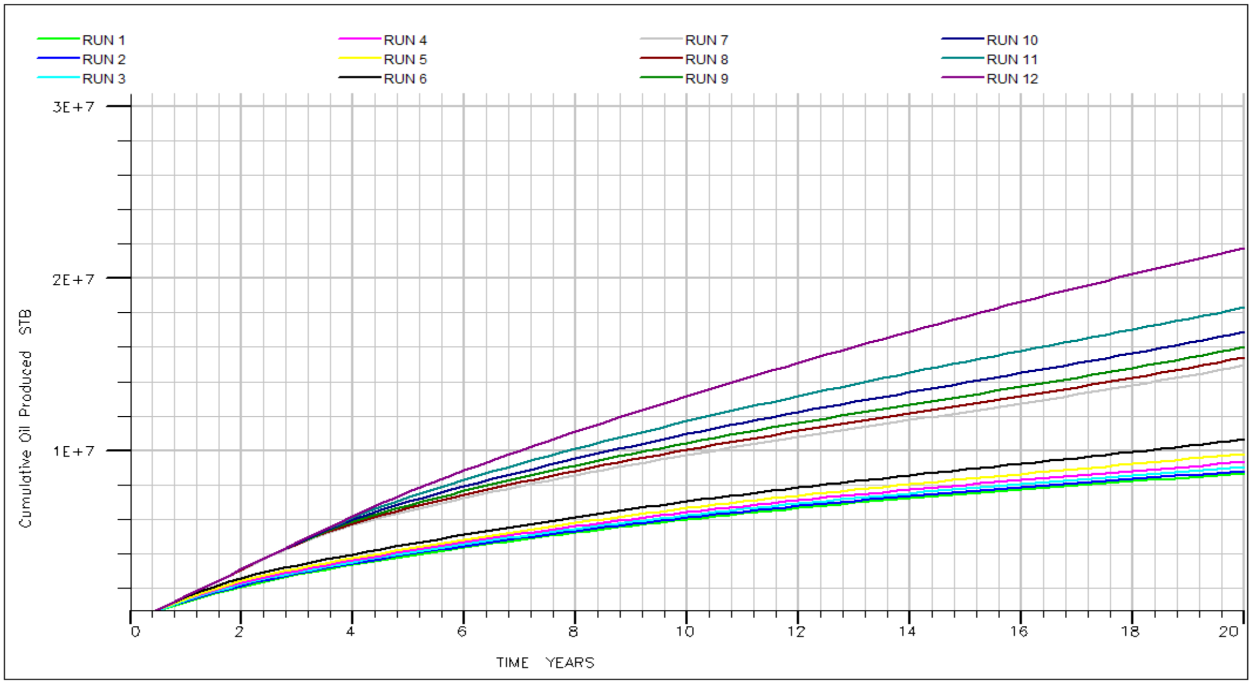


Figure 4.55: Condensate Produced after Tuning Mixing Parameter for Staggered-Line Drive using Limited Compositional Simulations of WAG injection. See Table 4.5 for the definition of ω used in the simulations.

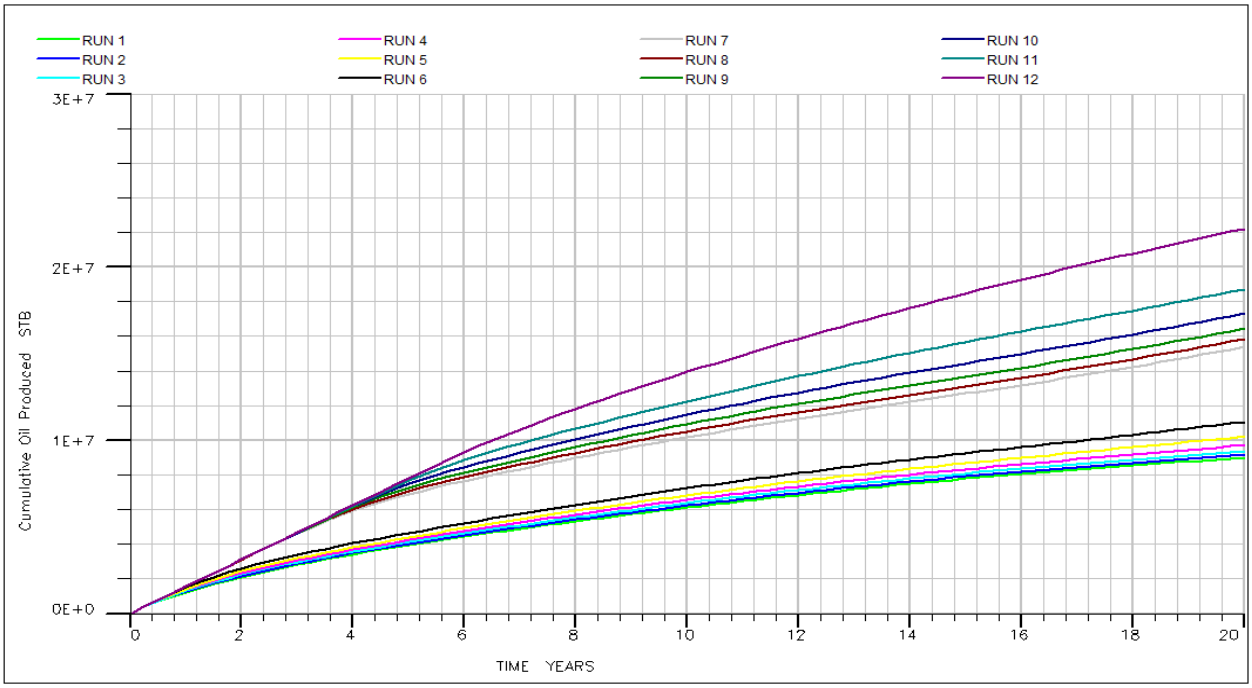


Figure 4.56: Condensate Produced after Tuning Mixing Parameter for Five-Spot using Limited Compositional Simulations of WAG injection. See Table 4.5 for the definition of ω used in the simulations.

The percentage condensate recovery obtained from the limited compositional simulation of WAG injection using the two well injection patterns was compared to that from the fully compositional simulations. The comparison indicated optimum values of the mixing parameters to be used in a limited compositional simulation to match the results of WAG injection from a fully compositional simulation.

Table 4.5: Percentage Condensate Recovery by WAG Injection after Tuning Mixing Parameter in Limited Compositional Simulation for Different Injection Patterns.

Run	Mixing Parameter	Condensate Recovery, %	
		Staggered-Line Drive	Five-Spot Injection Pattern
1	0	32.0	33.7
2	0.167	32.7	34.6
3	0.333	33.7	35.0
4	0.500	34.8	36.4
5	0.667	36.7	38.0
6	0.833	40.1	40.8
7	0.990	56.0	57.4
8	0.992	57.6	59.0
9	0.994	59.7	61.3
10	0.996	62.9	64.1
11	0.998	68.1	69.4
12	1.000	80.7	82.5

The percentage condensate recovered for fully compositional simulation of WAG injection was 59% of the initial oil in place. Using the values listed in Table 4.5, it can be deduced that condensate recovery of 59.7% (of oil originally in place) from staggered-line drive WAG process and the limited compositional simulation, matches the results from the fully compositional simulation. The optimum mixing parameter of 0.994 was used to simulate WAG for this case. For the five-spot pattern, 59% condensate recovery which matched the results of the fully compositional simulations was obtained using an optimum mixing parameter of 0.992 in a limited compositional simulation. Figures 4.57 and 4.58 illustrate the condensate saturation distribution in the limited compositional models after the 1st, 2nd, 5th, 10th, 15th, and 20th year of WAG injection into the two patterns The flooding patterns showing condensate saturation for 1st, 2nd, 5th, 10th, 15th, and 20th year obtained during the simulation are shown in Figure 4.59 and 4.60.

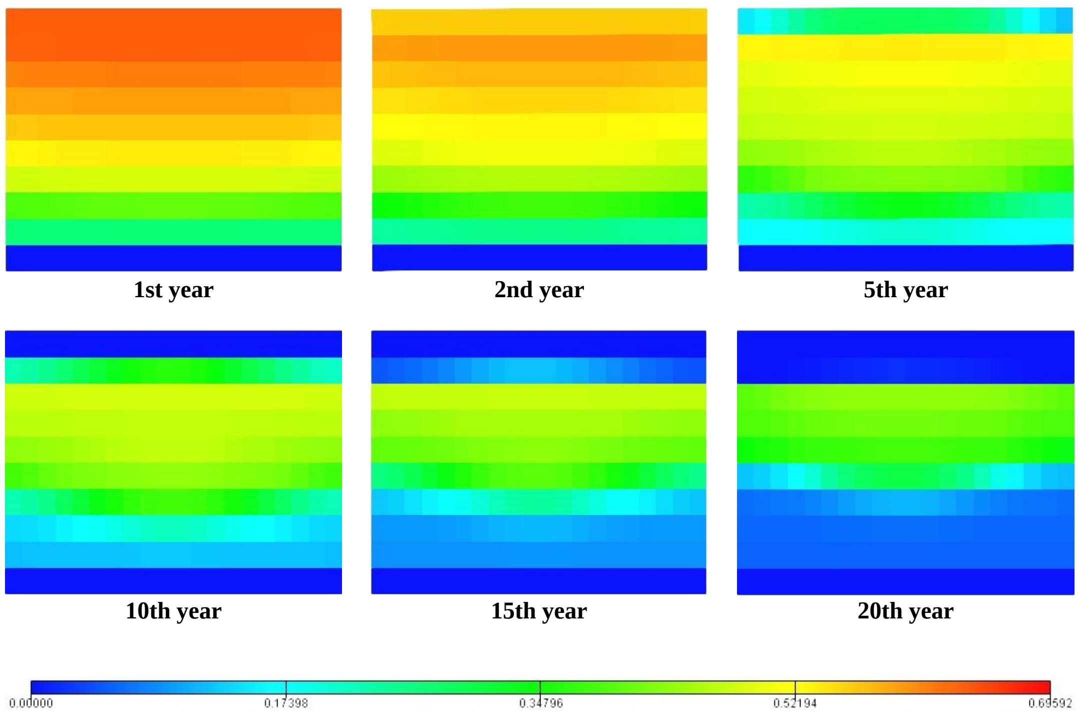
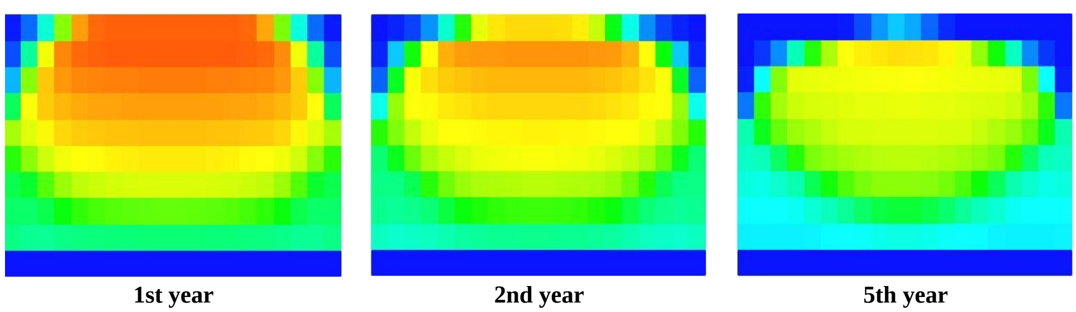


Figure 4.57: Condensate Saturation Distribution for Staggered-Line Drive WAG Injection in Limited Compositional Simulation.



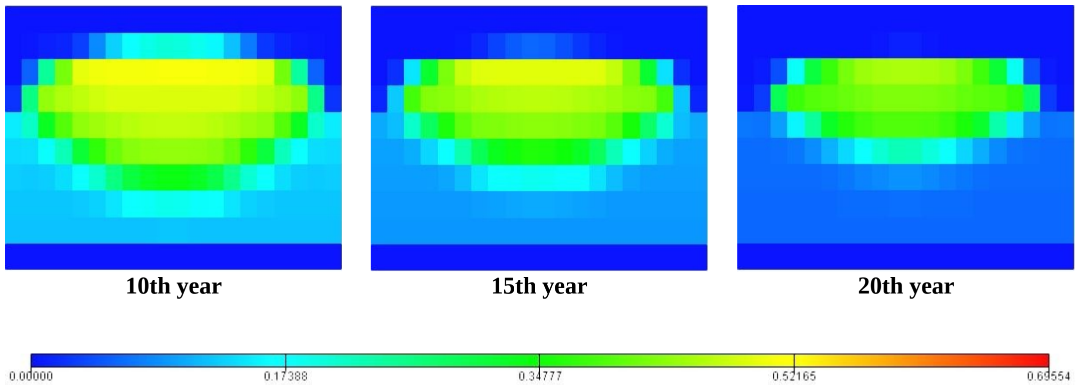


Figure 4.58: Condensate Saturation Distribution for Five-Spot WAG Injection in Limited Compositional Simulation.

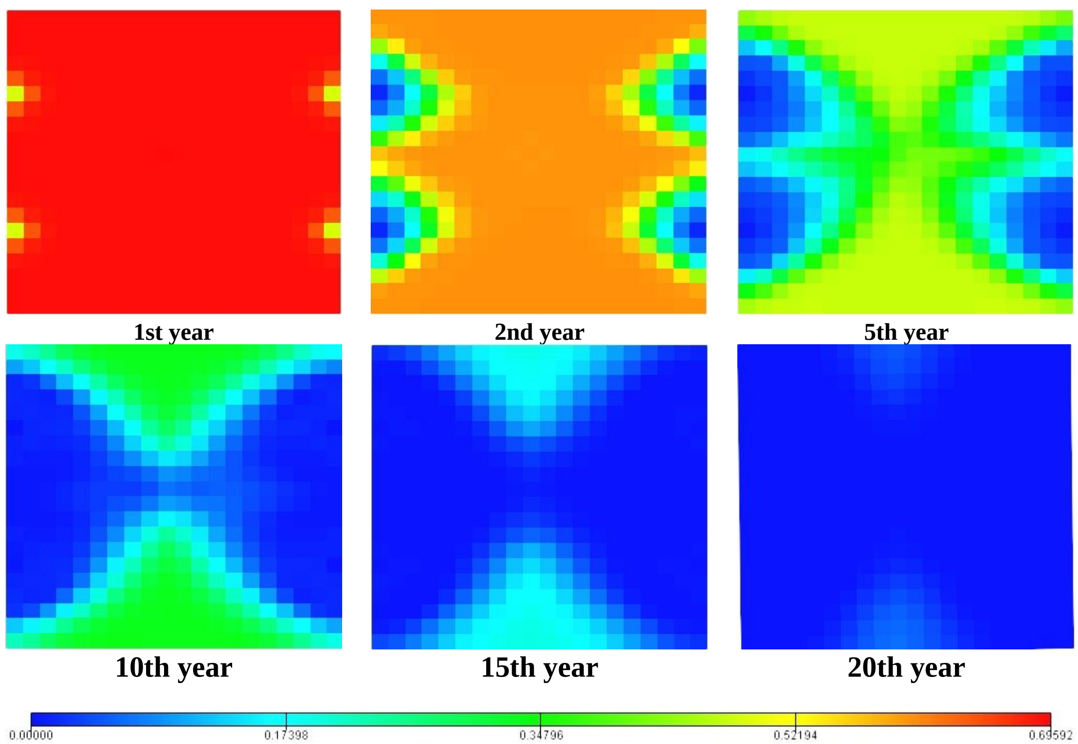


Figure 4.59: Flooding Pattern showing Condensate Saturation for Staggered-Line Drive for WAG Injection in Limited Compositional Simulation.

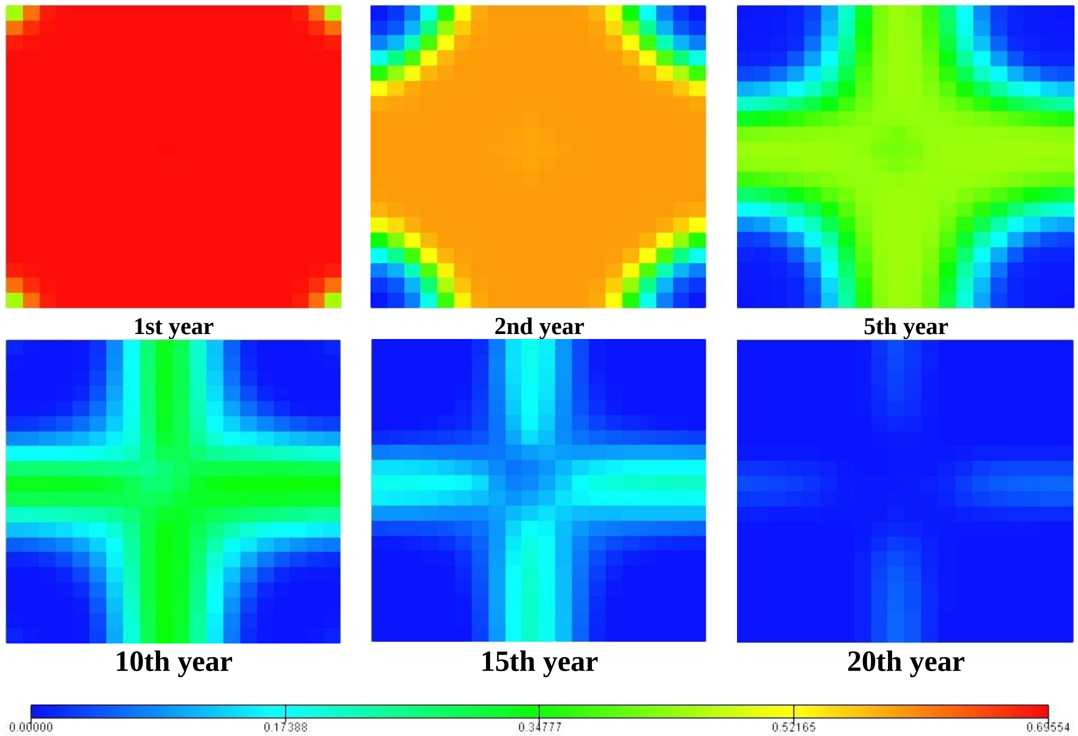


Figure 4.60: Flooding Pattern showing Condensate Saturation for Five-Spot Injection for WAG Injection in Limited Compositional Simulation.

Figures 4.61 through 4.64 show a comparison of the reservoir performance obtained from the fully compositional simulations of WAG injection versus the results from the limited compositional simulations using the optimum mixing parameters. The results plotted in these figures include the cumulative oil produced, cumulative gas produced, water cut, and reservoir pressure profiles.

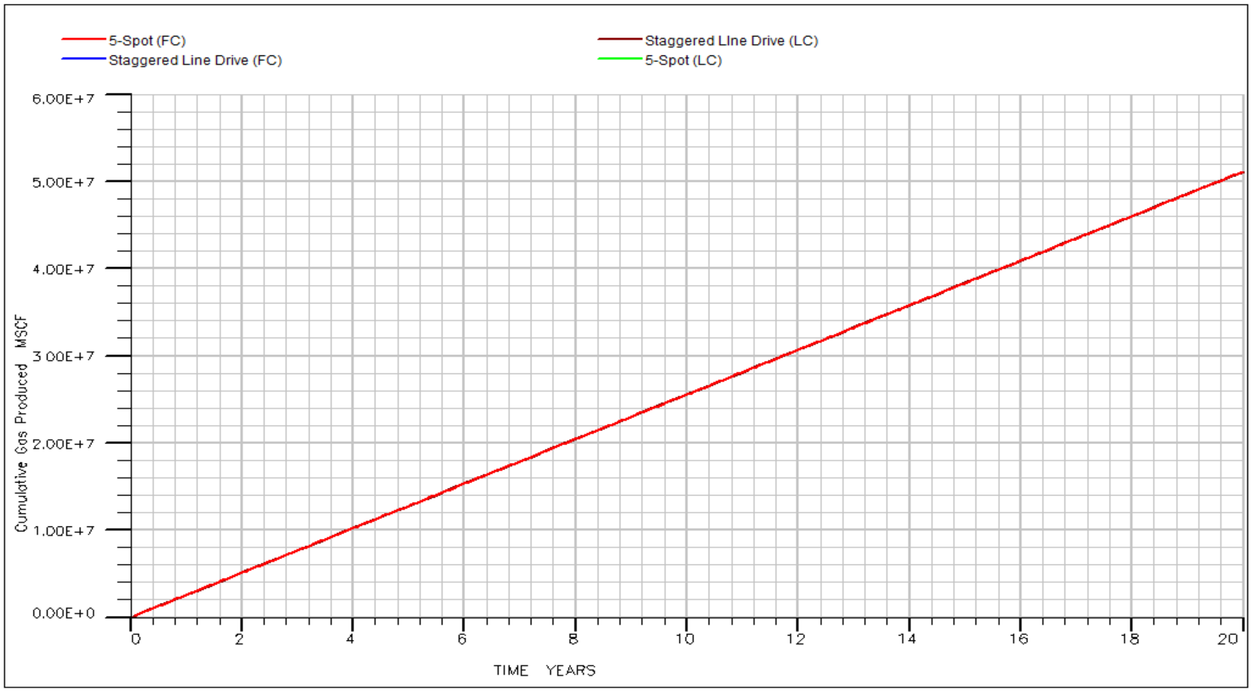


Figure 4.61: Effect of Injection Pattern on Cumulative Gas Produced for WAG Injection Using Fully and Limited Compositional Simulations with the optimum mixing parameters.

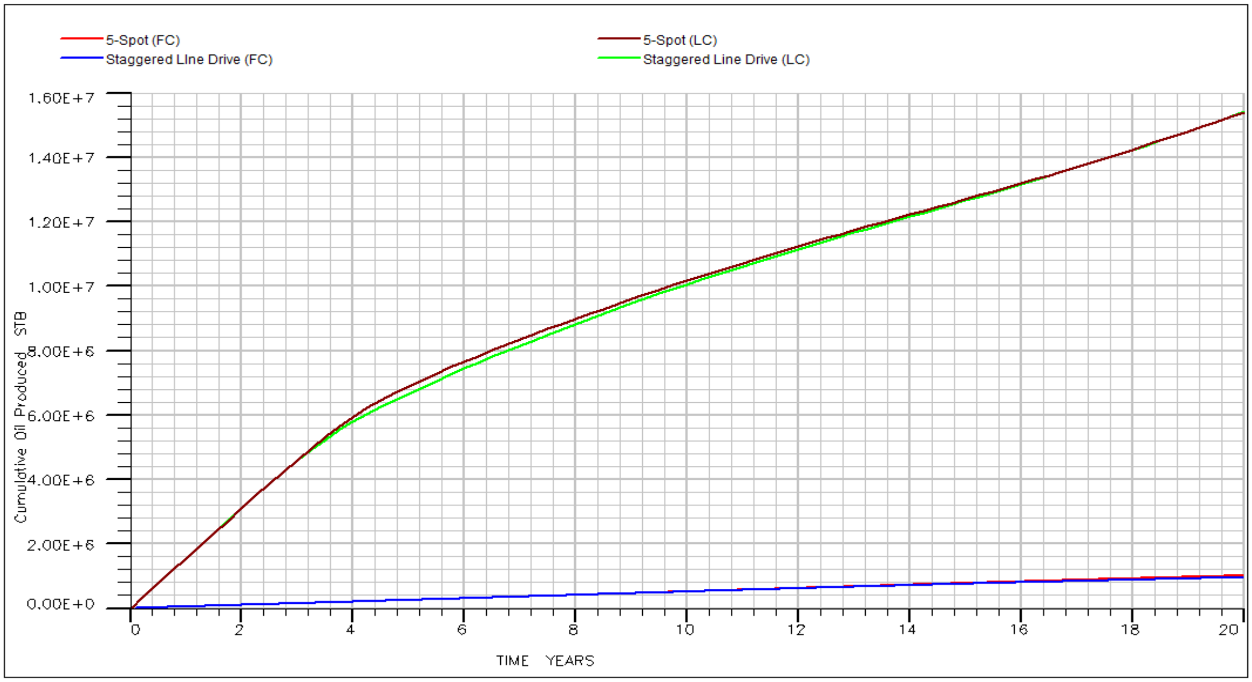


Figure 4.62: Effect of Injection Pattern on Cumulative Oil Produced for WAG Injection Using Fully and Limited Compositional Simulations with the optimum mixing parameters.

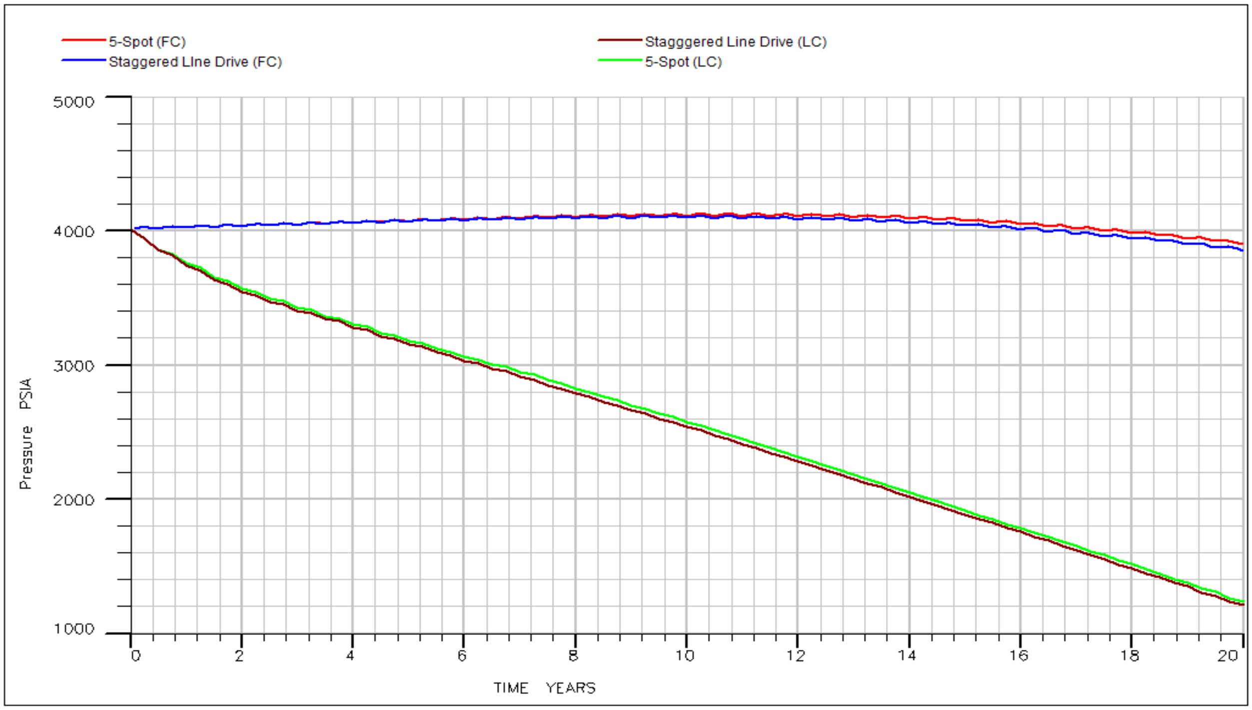


Figure 4.63: Effect of Injection Pattern on Reservoir Pressure for WAG Injection Using Fully and Limited Compositional Simulations with the optimum mixing parameters.

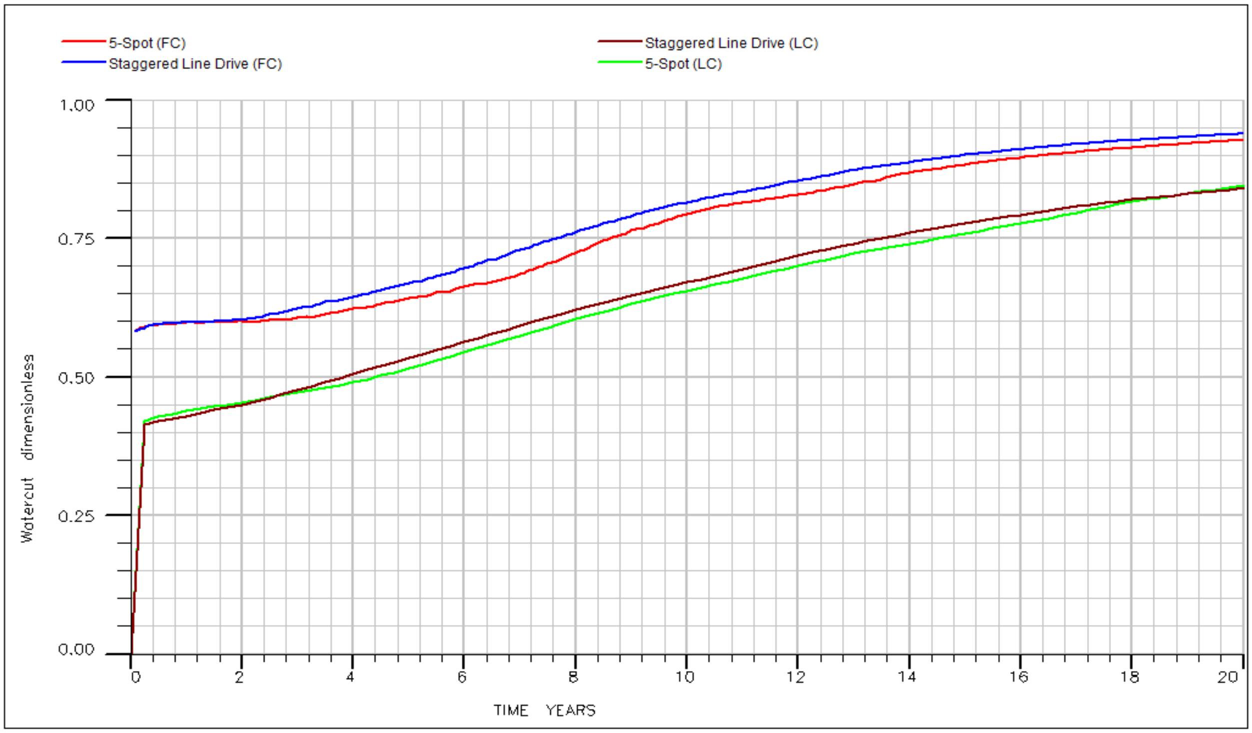


Figure 4.64: Effect of Injection Pattern on Water cut for WAG Injection Using Fully and Limited Compositional Simulations with the optimum mixing parameters.

As was observed from the gas injection, the WAG injection in the five-spot pattern also gave a higher condensate recovery compared to the staggered-line drive. The results hold for both the fully compositional and limited compositional simulations. Table 4.6 is a summary of the results obtained from tuning the Todd-Longstaff mixing parameter in this study. Using these mixing parameters, both the fully compositional and limited compositional models yield comparable condensate recovery factors.

Table 4.6: Optimum Todd-Longstaff Mixing Parameters in this Study

Well Type & Configuration		**Optimum T-L Mixing Parameter**	
		Gas Injection	**WAG Injection**
Well Configuration	Vertical Inj - Vertical Prod	0.992	0.996
	Vertical Inj -Horizontal Prod	0.990	0.996
Well Pattern	Staggered-Line drive	0.992	0.994
	Five-Spot	0.990	0.992

4.4 Condensate Banking

Condensate banking in the reservoir and around the wellbore was determined by plotting the saturation in the production layer against time. The saturation plots are shown in the production layer because it is the layer where most of the condensates are being banked around the wellbore. Figures 4.65 and 4.66 show the plots of condensate saturation at the end of the simulation as a function of distance for the three cases studied, namely, natural depletion, gas injection, and WAG using the fully compositional and limited compositional simulation.

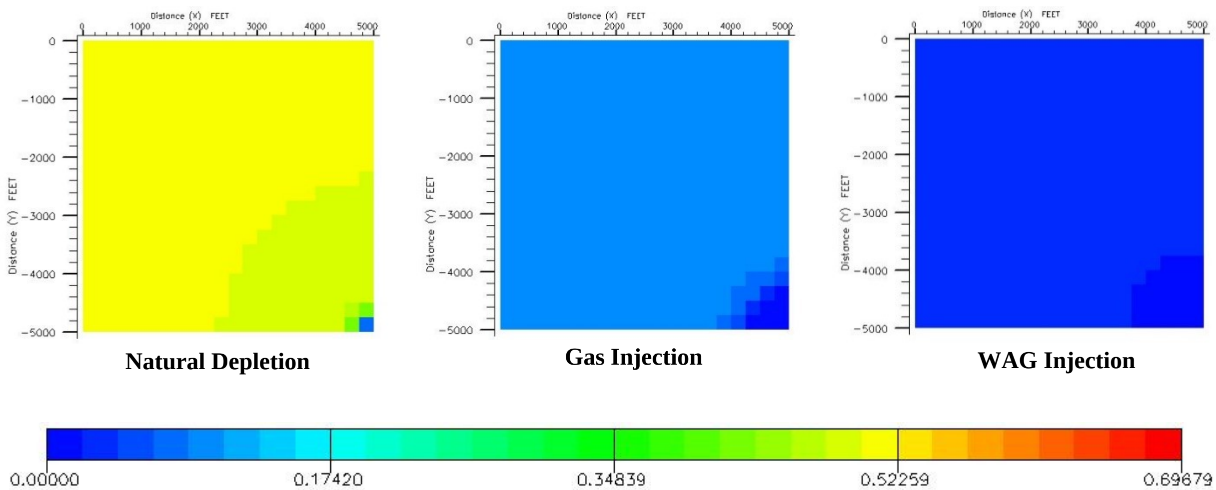


Figure 4.65: Saturation Distributions (after 20 years) to show Condensate Banking for Fully Compositional Simulations of Natural Depletion, Gas Injection, and WAG Injection.

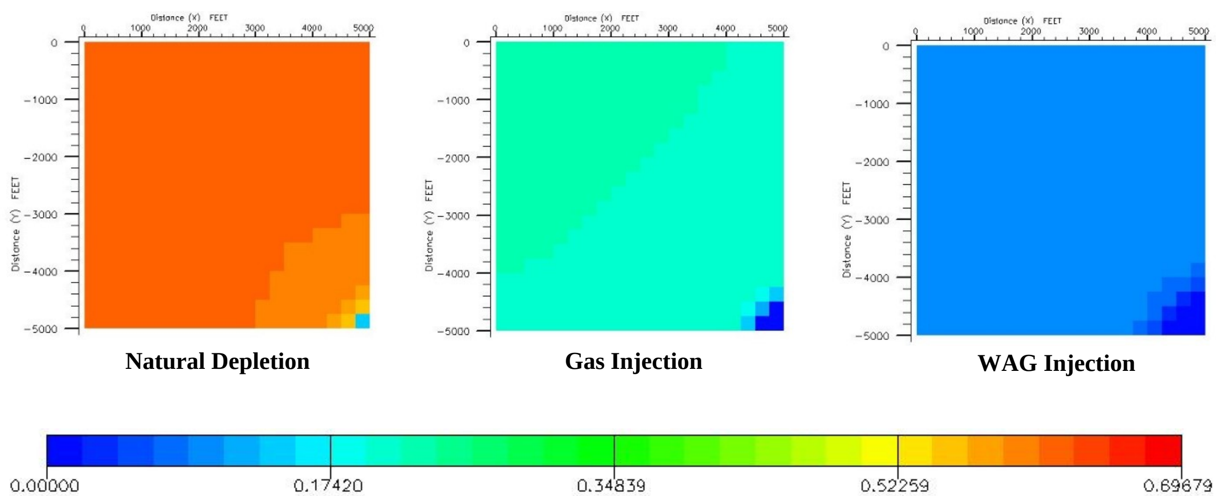


Figure 4.66: Saturation Distributions (after 20 years) to show Condensate Banking for Limited Compositional Simulations of Natural Depletion, Gas Injection, and WAG Injection.

It is observed from the plots that the saturation around the production layer during natural depletion was high compared to the results of the gas injection and WAG process for both fully compositional and limited compositional simulation. This is because there is no mitigation plan for condensate banking in the case of natural depletion. This relatively high condensate banking leads to a decrease in effective permeability to gas, thereby resulting in low production. In contrast, gas injection and WAG process have been reported by Hassan et al. (2019) to be methods of mitigating gas condensate banking. The efficiency of gas injection and WAG as methods to improve condensate production is evident from the plots indicating the low residual oil saturation. The reduced oil saturation observed from gas injection and WAG process occurred because the reservoir pressure was maintained around the dew point pressure. Also, it is possible that the gas injected helped in increasing the gas relative permeability within the reservoir and around the wellbore.

4.5 Sensitivity Analysis

Sensitivity analysis was carried out to determine the impacts of initial water saturation (Swi), permeability anisotropy (kv/kh), and the Todd-Longstaff mixing parameter on the cumulative oil produced (Np). For this analysis, gas injection was studied using vertical injection and vertical producer wells in a limited compositional simulation. Table 4.7 shows the different values of Swi, kv/kh, mixing parameter, and the cumulative oil produced from the simulations. This table was generated using Response Surface Methodology and a commercial design of experiment software.

Table 4.7: Input Data and Cumulative oil Recovery Generated from Design of Experiment for Sensitivity Analysis

Run	Swi	kv/kh	Mixing Parameter	Np, *10^6 bbl
1	0.2	0.0100	0.333	7.00
2	0.2	0.0100	0.500	7.24
3	0.2	0.0100	0.500	7.24
4	0.3	0.8000	0.000	6.90
5	0.2	0.0100	0.500	7.24
6	0.2	0.1000	0.500	7.30
7	0.3	0.0001	1.000	4.30
8	0.1	0.0001	0.000	0.60
9	0.2	0.0100	0.500	7.24
10	0.2	0.0100	0.500	7.24
11	0.2	0.0100	0.500	7.24
12	0.1	0.8000	1.000	18.30
13	0.2	0.0100	0.667	7.49
14	0.2	0.0100	0.500	7.24
15	0.2	0.0010	0.500	6.92

The results of the sensitivity analysis are shown in Figures 4.67 through 4.69.

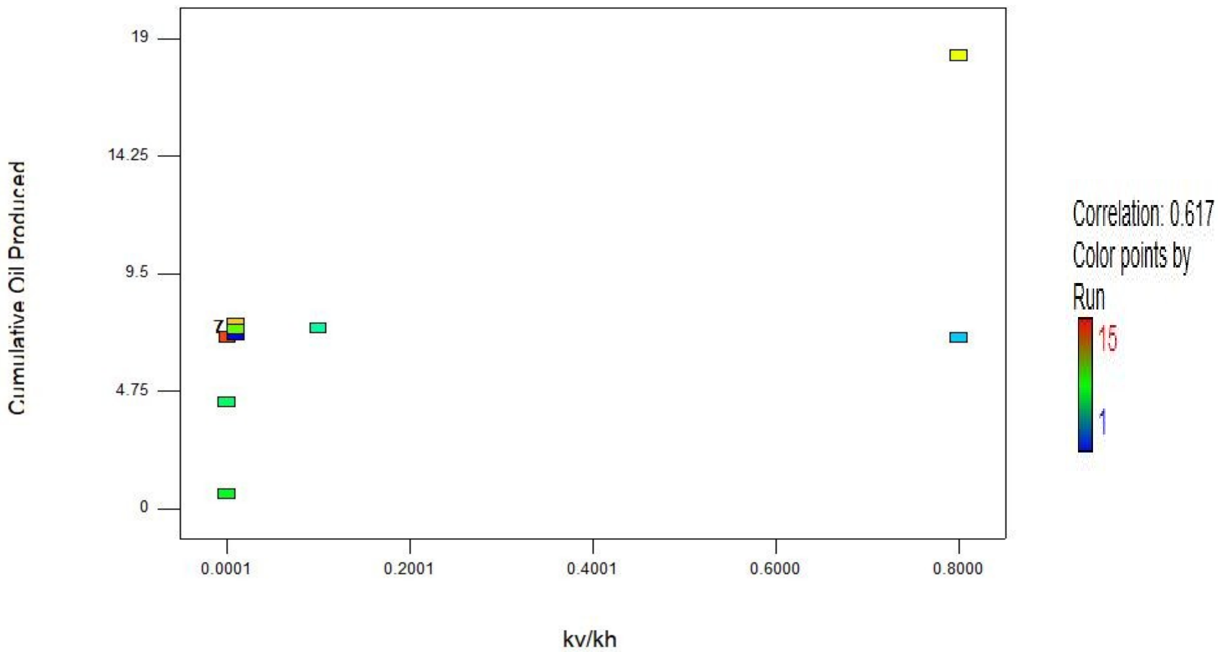


Figure 4.67: Plot of Cumulative oil Produced vs. kv/kh for Sensitivity Analysis using Response Surface Methodology.

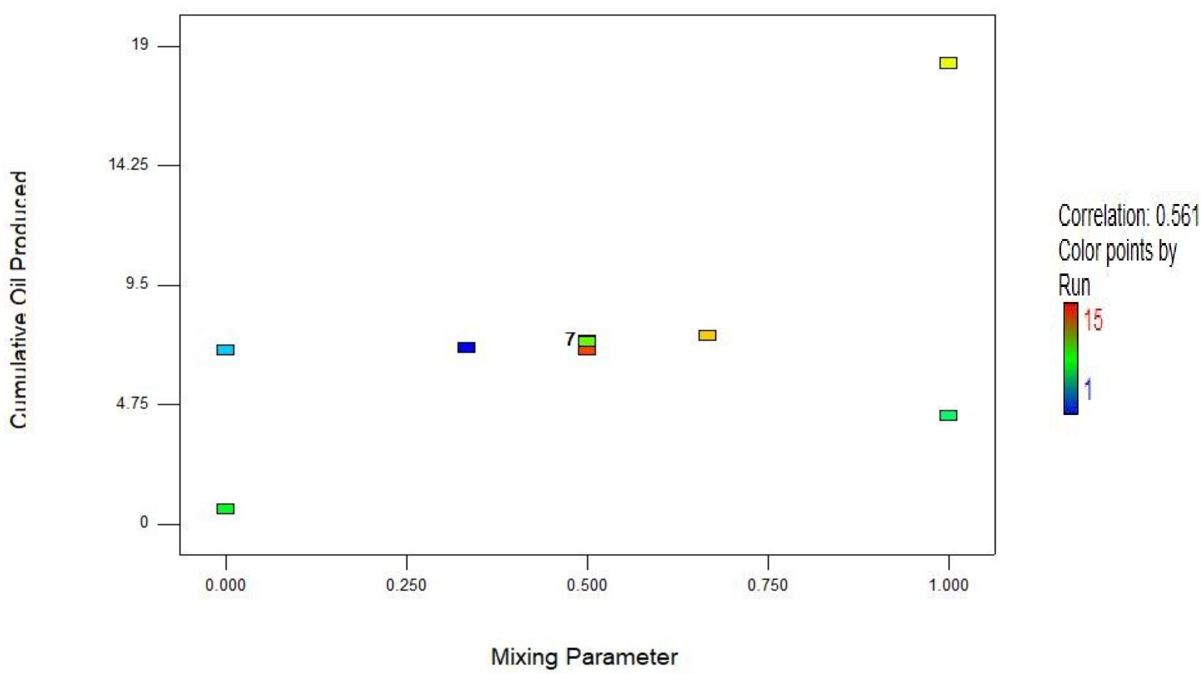


Figure 4.68: Plot of Cumulative oil Produced vs. Todd-Longstaff Mixing Parameter for Sensitivity Analysis using Response Surface Methodology.

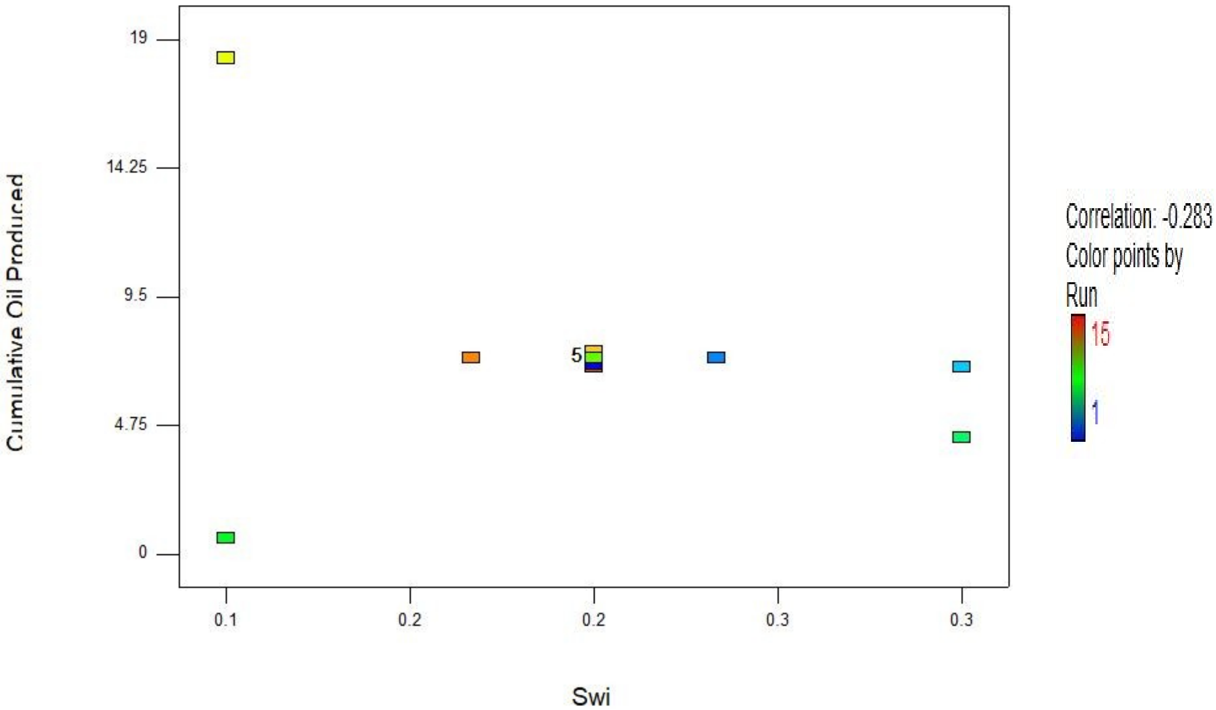


Figure 4.69: Plot of Cumulative oil Produced vs. Swi for Sensitivity Analysis using Response Surface Methodology.

Correlation coefficients obtained from the plots of cumulative oil produced vs. kv/kh, mixing parameter, and Swi are 0.617, 0.561, and -0.283, respectively. These correlation coefficients indicate that kv/kh has a stronger relationship with the cumulative oil produced, followed by the Todd-Longstaff mixing parameter. The initial saturation, Swi which shows a correlation coefficient of -0.283 has no relationship with the cumulative oil produced. Therefore, one can say that kv/kh is more sensitive to the cumulative oil produced, followed by the mixing parameter and Swi is not sensitive to the cumulative oil produced.

The equation obtained from the response surface modeling during the sensitivity analysis is shown in Equation 4.1 and it is valid for the estimation of the cumulative oil production in this case study.

$$Np = -4.75264 + \left(172.78318 \times {kv}/{kh}\right) + \left(21.533 \times \omega\right) \times \left(53.4389 \times Swi\right) - \left(106.26807 \times {\mathrm{kv}}/{\mathrm{kh}} \times \omega\right)$$
$$- \left(594.17912 \times {kv}/{kh} \times swi\right) - \left(94.99422 \times \omega \times swi\right)$$

…… equation 4.1

where

Np = Cumulative oil produced, MMstb

kv/kh = Permeability Anisotropy

ω = Mixing Parameter

Swi = Initial Oil Saturation

The correlation coefficient, value of R^2 of 0.9995, was obtained from equation 4.1. This high value of the R^2 indicates that equation 4.1 can be used to estimate cumulative oil production given Swi, kv/kh, and ω. Note this equation applies to the case study presented in this work. The adjusted and predicted R^2 are 0.9991 and 0.9842, respectively. These values of coefficients are in reasonable agreement and they validate the accuracy of the proposed correlation. Figure 4.70 shows the predicted vs. actual data using the correlation given in equation 4.1.

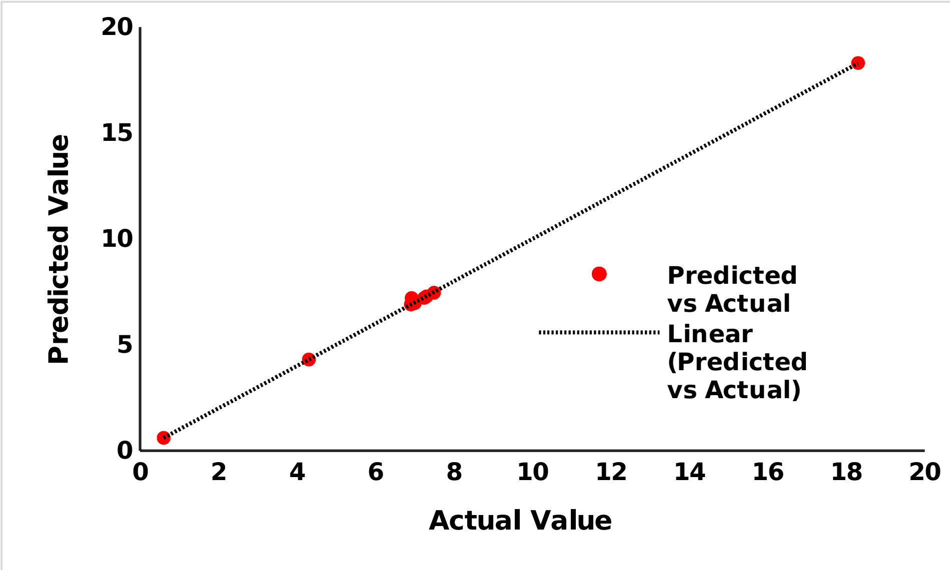


Figure 4.70: Predicted vs Actual Cumulative Oil Production Using Proposed Correlation.

The results shown in Figure 4.70 indicate a good fit, evidence of the accuracy of the proposed correlation of Equation 4.1.

4.6 Pertinent Remarks:

At the end of this chapter, the following observations can be made from the results of this study:

- Results from fully composition simulation were compared with those from limited compositional simulation of a lean gas condensate reservoir.
- The optimum Todd and Longstaff mixing parameters have been determined from the limited compositional simulations for different well configurations and injection patterns. Using the optimum mixing parameters, the results from the limited compositional simulations were comparable to those results from the fully compositional simulations.
- Gas injection and WAG injection seem to provide some mitigation of condensate banking in gas condensate reservoirs. These results agreed with the published literature.

- Sensitivity analysis performed using limited compositional simulation indicated that cumulative oil recovery can be accurately correlated to the Swi, kv/kh, and mixing parameter, ω for the lean gas condensate reservoir studied in this work.

The next chapter outlines the conclusions made from the results of this study and includes a set of recommendations for future research.

CHAPTER FIVE

5.0 Conclusions and Recommendations

This chapter presents the conclusions made after executing the proposed research methodology and analyzing the results. A set of recommendations is proposed for further research to improve the results obtained from this study.

5.1 Summary and Conclusions

Fully compositional and limited compositional simulations have been used to analyze gas condensate reservoirs. Results obtained from the fully compositional simulations were compared to that of limited compositional simulations for all cases studied. Todd and Longstaff mixing parameters were then varied in limited composition simulation for different well configurations and injection patterns after which the optimum mixing parameters were gotten. The impacts of condensate banking and vertical reservoir heterogeneity on condensate recovery were evaluated using the optimum Todd and Longstaff mixing parameters in limited compositional simulation. The following conclusions can be deduced from the results obtained.

- The simulated results of cumulative oil recovery for the gas condensate reservoir obtained from the fully compositional model and the limited compositional model were not similar when the Todd-Longstaff mixing parameter (ω) is not optimized.
- Natural depletion of gas condensate reservoirs is not effective because of the condensate banking and low condensate recovery.
- Gas injection and WAG process are the recommended methods to produce gas condensate reservoirs. Both methods offer the additional benefit of mitigating condensate banking in the reservoir.

- WAG process is more effective than pure gas injection in the production of condensate reservoirs.
- Tuning of the Todd and Longstaff mixing parameter (ω) is required to use a limited compositional simulator to simulate the production performance of a gas condensate reservoir.
- The values of ω between 0.990 and 0.996 are the recommended mixing parameters for simulating condensate recovery by gas injection and WAG processes using limited compositional models. These mixing parameters give comparable recovery factors for both the fully compositional and limited compositional simulations.
- The case study showed that vertical permeability anisotropy has a significant effect on condensate recovery, followed by the Todd and Longstaff mixing parameter.

5.2 Recommendations for Further Studies.

Based on the proposed methodology and results obtained for this study, the following are recommended for further studies:

- PVT tuning should extend to k-values as proposed by Balling (1987) to see if hydrocarbon in place for fully compositional will properly match that of limited compositional simulation in a lean gas condensate reservoir.
- Tuning of Todd and Longstaff mixing parameter should be studied in near-critical gas condensate and rich gas condensate reservoirs for different injection patterns and well configurations.

- Other injection patterns such as peripheral injection pattern should be studied since these patterns are common in the Niger Delta and known for maximum oil recovery and minimum water production.

NOMENCLATURE

API	American Petroleum Institute
BIC	Binary Interaction Coefficient
BHP	Bottom Hole Pressure
C1	Methane
CCE	Constant Composition Expansion
CVD	Constant Volume Depletion
EOS	Equation of State
FCM	First Contact Miscible
GIIP	Gas Initially In Place
GOR	Gas-Oil Ratio
GWC	Gas-Water Contact
IFT	Interfacial Tension
kv/kh	Permeability Anisotropy
k_{ro} and k_{rg}	Relative Permeability of Oil and Gas
k_{rn}	Imbibition Relative Permeability of the Non-wetting Phase.
MCM	Multiple Contact Miscible
MMP	Minimum Miscibility Pressure

Np	Cumulative Oil Produced
$P_{dew-point}$	Dew Point Pressure
P_{res}	Reservoir Pressure
RSM	Response Surface Methodology
S_o, S_n, and S_s	Saturations of Oil, Non-wetting Phase and Injected Solvent
SCF	Standard Cubic Feet
STB	Stock Tank Barrel
STOOIP	Stock Tank Original Oil In Place
Swi	Initial Oil Saturation
WAG	Water Alternating Gas
ρ_m, ρ_o, and ρ_s	Effective Density of Oil and Injected Solvent
ρ_{oe} and ρ_{se}	Effective Density of Oil and Injected Solvent
μ_o and μ_s	Viscosity of Oil Phase and Injected Solvent.
ω	Mixing Parameter

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