EVALUATION OF EOR POTENTIAL BY GAS AND WATER FLOODING IN SHALE OIL RESERVOIRS

by

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A Thesis

In

PETROLEUM ENGINEERING

Submitted to the Graduate Faculty
of Texas Tech University in
Fulfillment of
the Requirements for
the Degree of

MASTER OF SCIENCE
IN
PETROLEUM ENGINEERING

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May, 2013

ACKNOWLEDGMENTS

I would like to express my deepest appreciation to my supervisor, Dr. James Sheng for his continuous support and guidance throughout my research. His encouragement, advice, and constructive criticism have driven me to study hard and improve myself persistently during the course of my graduate study. Genuine gratitude is also to the members of the supervisory committee, Dr. Habib Menouar and Dr. Lloyd Heinze. Without their assistance, this work would not have been as fine as it is. I would like to thank Tao Wan for his help in my simulation work.

I would like to direct thanks to the Texas Tech University Petroleum Engineering department for allowing me the opportunity to obtain a degree from a distinguished institution.

I would like to express my love and gratefulness to my beloved family; for their understanding and endless love, through the duration of my studies.

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ABSTRACT

The demand for oil and natural gas will continue to increase for the foreseeable future; unconventional resources such as tight oil, shale gas, shale oil will pose an irreplaceable role in the oil and gas industry to fill the gap between demand and supply. With relatively modest natural gas prices, producing oil from unconventional shale reservoirs, which are less common and less well understood than conventional sandstone and carbonate reservoirs, has attracted more and more interest from oil operators.

Through many tremendous efforts on the development of shale resources, the horizontal well-drilling with multiple transverse fractures has proven to be an effective method for shale gas reservoirs exploitation and it has also been used in extracting oil from shale reservoirs by some operators. However, the oil recovery is very low (5-10%). For the important role of shale resources in the future oil and gas industry, more stimulation and production strategies must be considered and tested to find better methods to improve oil production from shale reservoirs.

Gas flooding and water flooding, relatively simple and cheaper EOR techniques, which have been successfully implemented in conventional and some unconventional tight oil reservoirs for a long time, are considered in our work. A black-oil simulator developed by Computer Modeling Group Ltd was selected in our work. We build a reservoir model of 200ft long, 1000ft wide and 200 ft thick two 1-ft wide ×1000-ft long hydraulic fractures to simulate gas flooding and water flooding in shale oil reservoirs.

We first validate a base model, and discuss the determination of miscibility parameter and injection pressure. Production behavior and oil recovery of different plans are discussed through sensitivity studies. Simulation results of primary production, gas injection and water injection are compared in this thesis. Results show that miscible gas injection has a better effect on improving oil recovery from shale reservoirs than water injection. Solvent injected into the reservoirs above MMP can be fully miscible with oil, reducing oil viscosity greatly, and can lead a better sweep efficiency besides pressure maintenance. Our simulation results indicate that the oil recovery can be increased up to 15.1% by using gas injection in a hydraulically fractured shale reservoir, compared with the original 6.5% recovery from the primary depletion.

This thesis provides a preliminary analysis regarding the EOR potentials by gas and water flooding in shale oil reservoirs. The results show that miscible gas flooding could be a good prospect in the future development of shale oil resources.

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CHAPTER 1

INTRODUCTION

1.1 Research Background

In the face of declining crude oil production, and relatively modest natural gas prices, unconventional reservoirs, which are less common and less well understood than conventional sandstone and carbonate reservoirs, have become an increasingly important resource base. The demand for oil and natural gas will continue to increase for the foreseeable future; unconventional resources such as tight oil, shale gas, shale oil will pose an irreplaceable role in the oil and gas industry to fill the gap between demand and supply.

As the oil and gas industry continues to search for additional unconventional resources to address energy needs, shale resources, a kind of unconventional resource which has ultra-low porosity and ultra-low permeability, has become a focus of exploration and production activity in North America. Oil shale discovered in the Western United States contains an amount of oil that is greater than the proven petroleum reserves in the Middle East. If fully developed, oil shale could supply the current U.S. consumption of oil for a long time. In the past five years, the oil and gas industry made tremendous efforts to develop unconventional shale oil reservoirs with advanced drilling and production techniques, progress in extracting oil from shale deposits has been revolutionizing the energy industry in the United States[1].

Due to the special conditions of unconventional shale reservoirs which have ultra-low porosity, ultra-low permeability and fast pressure depletion, shale reservoirs cannot be produced economically unless applying stimulation techniques. The horizontal well with multiple transverse fractures has proven to be an effective strategy for shale gas reservoir exploitation and it is also used in producing shale oil by some oil companies[2]. However, shale oil is limited to lower recovery efficiency than shale gas because of its higher viscosity and 2-phase flow conditions when the formation pressure drops below the oil bubble point pressure. Even applying multi-stage hydraulic fracturing techniques, the final oil recovery factor could achieve 6% or less[3]. Unlike the development of conventional reservoirs, shale oil reservoirs have a high initial oil rate and reservoir pressure, but well productivity and reservoir pressure drops sharply.

Considering that the development of shale oil reservoirs will be a central point of the oil and gas industry in the future and improving oil recovery in shale oil reservoirs will be a great challenge. We initiate this study to evaluate whether conventional enhanced oil recovery techniques have potential in improving oil production in shale oil reservoirs. Gas flooding and water flooding, relatively simple and cheaper EOR techniques, have been successfully implemented in conventional and some unconventional tight oil reservoirs for a long time. Hence, in our work, we simulate gas flooding and water flooding techniques applied to a shale oil reservoir by CMG simulator to evaluate the potentials of these two techniques in improving oil recovery in shale oil reservoirs.

1.2 Objectives

The primary objective of the study is to evaluate the EOR potential by gas and water flooding in shale oil reservoirs. As different from conventional oil and gas, shale oil has lower recovery efficiency due to its ultra-low porosity, ultra-low permeability and high oil viscosity. Rapidly decreasing of the initial reservoir pressure and initial oil production rate also lead shale oil to have no attractive and economical production. It is time for us to consider applying an EOR strategy in the development of such kind resources. In our work, we will simulate different production plans by gas flooding and water flooding, comparing primary production, to evaluate whether gas flooding and water flooding have a positive effect on shale oil production.

A black-oil simulator developed by Computer Modeling Group Ltd is selected to simulate gas and water flooding in shale oil reservoirs. Different production plans are considered and sensitivity studies investigating the effect of different parameters on production are described in this thesis. Finally we will compare the simulation results of primary production, gas flooding and water flooding to assess whether these two EOR techniques can improve oil recovery from shale oil reservoirs.

1.3 Review of Chapters

This thesis is divided into seven chapters. Chapter 2 presents an extensive literature survey. Research papers concerning unconventional resources, tight oil reservoirs, shale oil, hydraulic fracturing techniques, horizontal well with multiple fracture, and EOR techniques are reviewed.

Chapter 3 briefly describes the Eagle Ford shale formations, including Eagle Ford shale overview, geological setup, reservoir characterization and production summary of Eagle Ford shale formation.

In chapter 4, the procedure of base simulation model setup for a shale oil reservoir is presented. And then we describe the validation analysis of base simulation model and conduct a sensitivity study of base model.

In chapter 5, we talk about the determination of miscibility parameter, injection pressure upper limit, the results of gas injection and water injection simulation, and evaluation of gas flooding potentials in the development of shale oil resources.

Chapter 6 contains the introduction of the base water injection model and presents the water flooding simulation results of different production plan in shale oil reservoir.

Chapter 7 summarizes the research and present conclusions of the research work and recommendation for future work.

CHAPTER 2

LITERATURE REVIEW

The objective of our work is to evaluate the potential of gas flooding and water flooding in the development of shale oil reservoirs. In this chapter, a review of literatures concerning unconventional resources, tight oil reservoirs, shale oil, hydraulic fracturing techniques, horizontal well with multiple fracture, and EOR techniques was presented.

2.1 Unconventional Resources

Unconventional resources do not play a significant role compared with conventional resources in the past because they are lack of economic feasibility to produce. As the demand for oil and natural gas increases rapidly, it has been a big challenge for oil and gas industry to address the word's energy needs. Considering declining crude oil production and relatively high gas prices, the development of unconventional resources will have a significant position in our energy future.

Only a third of worldwide oil and gas reserves are conventional, and the remainders are unconventional resources (Fig 2.1). Unconventional reservoirs are defined as formations that cannot be produced at economic flow rates or that do not produce economic volumes of oil and gas without stimulation treatments or special recovery processes and technologies [4]. Typical unconventional resources cover a broad range of oil and gas deposits which encompass tight oil and gas formations, shale gas, oil shale, coalbed methane, heavy oil and gas hydrate. Unique techniques are required to exploit such types of reservoirs economically because of their extremely low porosity and permeability.

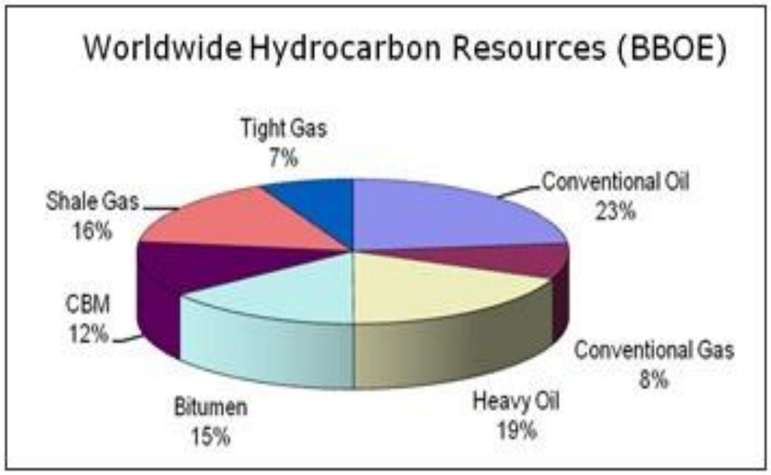


Figure 2.1 Worldwide hydrocarbon resources (CGG)

The concept of resource triangle was proposed by J. Rajnauth, which is a useful way to view the size and nature of the resource base (Fig 2.2). It is obvious that unconventional resources possess the most part of the pyramid. Conventional resources which occupy the top of the triangle are the easiest one to exploit. When moving down the pyramid, unconventional resources such as heavy oil, tight gas, shale gas, coalbed methane and tar sands are in the middle part of the triangle which have larger quantities and have important roles in oil and gas industry recently. At the base of the pyramid are shale oil and gas hydrate which are presently technologically challenging but emerging unconventional resources[5].

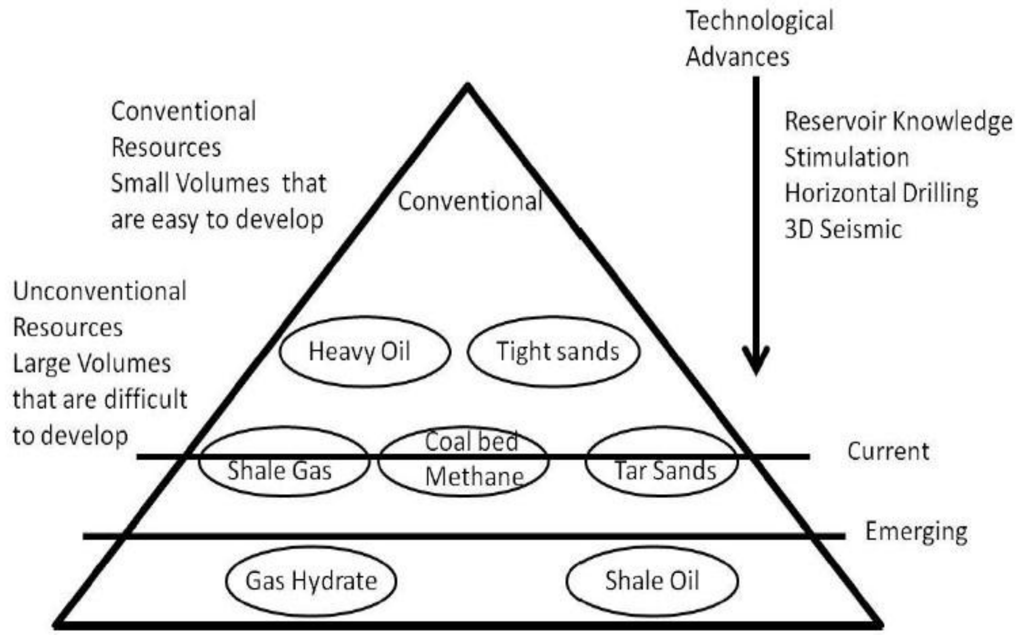


Figure 2.2 Resource Pyramid focusing on Unconventional Resources (Rajnauth 2012)

Thanks to the development of exploration, drilling and completion technologies, unconventional resources have been seen as a viable source of oil and gas production to make up production depletion in conventional reservoirs.

2.2 Tight Oil

Oil and gas typically flow through pore space in the rock. In tight reservoirs, the amount of pore space, the size of the pores, and the extent to which the pores interconnect are significantly less than that in conventional reservoirs which makes it more difficult to produce oil and gas (Fig 2.3 2.4). Generally, “Tight oil” is a term used for oil produced from reservoirs with relatively low porosity and permeability[6].

Unlike conventional reservoir that oil accumulates in the up dip areas above water-bearing rock, tight oil can spread over wide areas and accumulate without down dip water, which is similar to tight gas, shale gas and cold bed methane. The difficulty met recently is just a small part regarding the large opportunity, up to millions of barrels of oil per section for this tight oil resource.

There are two main types of tight oil:

- Oil in original shale source-rock. This kind of source rock typically has the lowest reservoir quality of oil- and gas-bearing rock sand the pore spaces are poorly connected.

- Oil migrated from original shale source rock and accumulated in nearby or distant tight sandstones, siltstones, limestones or dolostones. This kind of tight oil rocks usually have better quality than shales with larger porosity, but still lower quality than conventional reservoir.

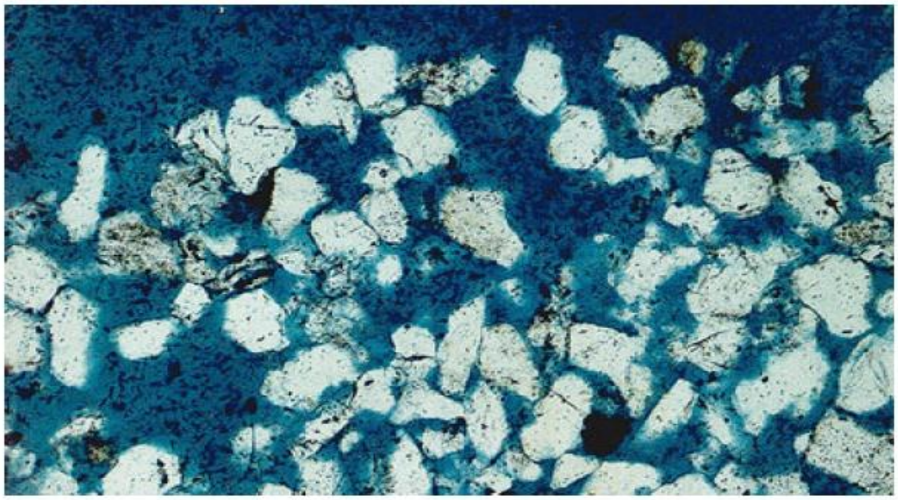


Figure 2.3 Thin section of a conventional sandstone reservoir (Naik 2007)

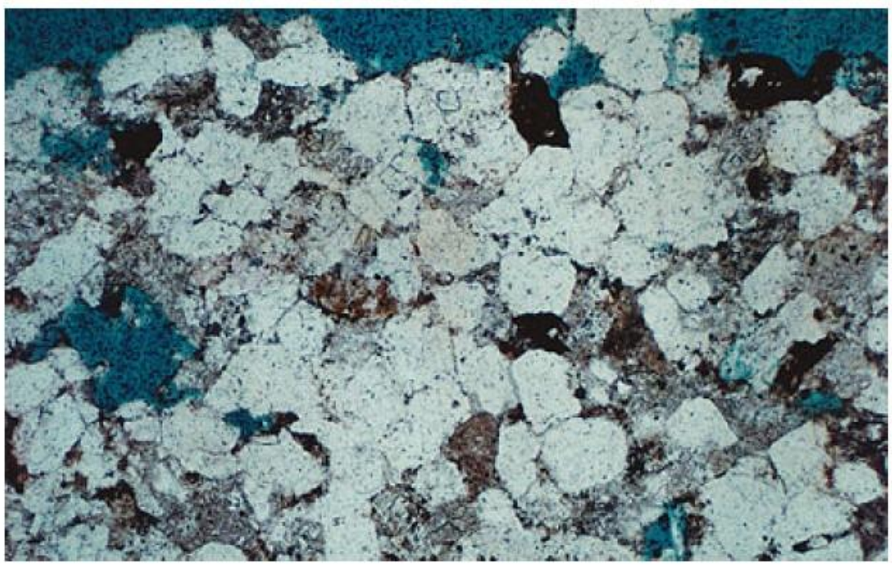


Figure 2.4 Thin section of a tight sandstone reservoir (Naik 2007)

Over the past 20 years, tight oil resources are becoming one of the most attractive explored and produced targets in North America because of the advancements in exploration, well drilling and stimulation technologies combined with increasing demand of oil and gas. Bakken play in the Williston Basin, the Eagle Ford play in Texas, the Cardium play in Alberta, and the Miocene Monterey play of California's San Joaquin Basin are typical tight oil reservoirs in North America. In many of these tight formations, the existence of large quantities of oil has been found for decades and advanced techniques have been implemented to get economical production[7].

Figure 2.5 shows the distribution of tight oil plays in North America which are being produced or prospective reserves. Along the Mid-Continent and Rocky Mountain, many tight oil formations are currently under exploitation, running from central Alberta to southern Texas. Other prospective resources have been identified in the Rocky Mountain region, the Gulf Coast region and northeastern part of United States.

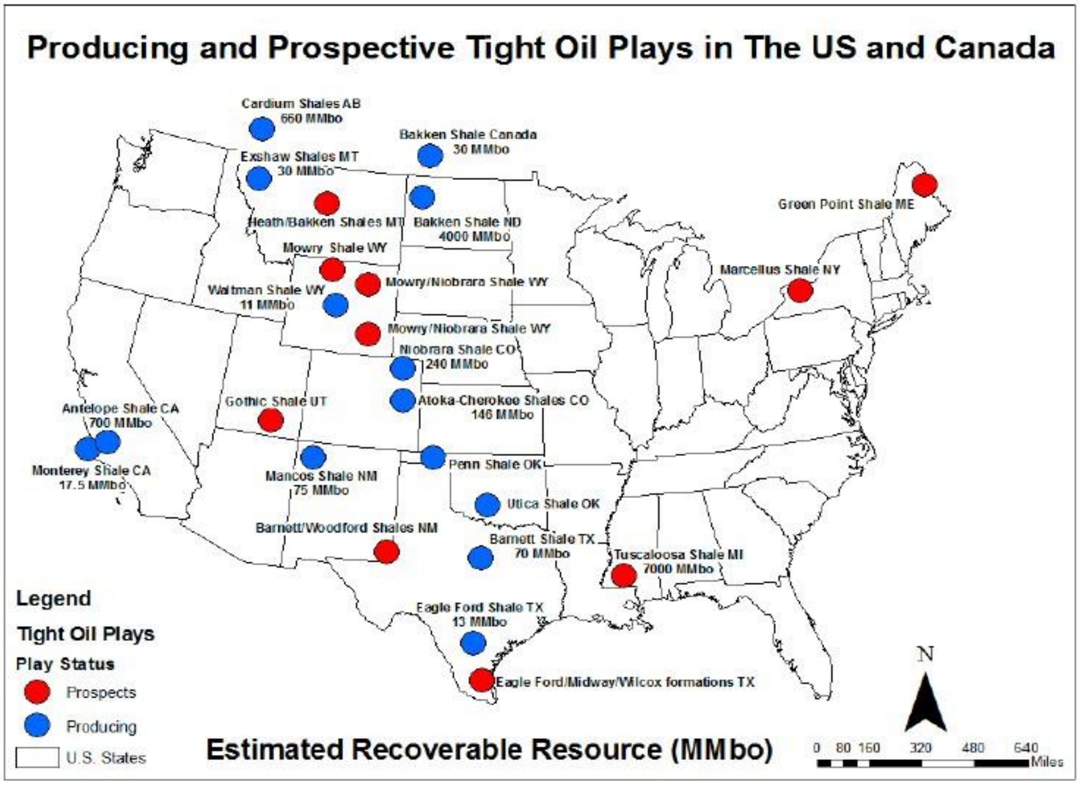


Figure 2.5 Reported Producing and Prospective Tight Oil Resources in North America (EIA 2011)

2.3 Oil Shale and Shale Oil

Shale is a sedimentary rock that contains kerogen that is released as petroleum-like liquids when the rock is heated in the chemical process of pyrolysis. Oil shale was formed millions of years ago by deposition of silt and organic debris on lake beds and sea bottoms. Over long periods of time, heat and pressure transformed the materials into oil shale in a process similar to the process that forms oil; however, the heat and pressure were not as great. Oil shale generally contains enough oil that it will burn without any additional processing, and it is known as "the rock that burns". Oil shale can be mined and processed to generate oil similar to oil pumped from conventional oil wells; however, extracting oil from oil shale is more complex than conventional oil recovery and currently is more expensive. The oil substances in oil shale are solid and cannot be pumped directly out of the ground. The oil shale must first be mined and then heated to a high temperature; the resultant liquid must then be separated and collected. An alternative but currently experimental process referred to as in situ retorting involves heating the oil shale while it is still underground, and then pumping the resulting liquid to the surface[8].

Shale oil, unlike oil shale, does not have to be heated over a period of months to flow into a well. And the oil produced from these plays is premium crude; of better quality on average than West Texas Intermediate (WTI), the US standard crude that is the basis for NYMEX futures. Shale oil plays such as the Bakken, Eagle Ford and the Avalon shale have far more in common with unconventional gas plays such as Appalachia's Marcellus shale and Louisiana's Haynesville shale than they do with Colorado's oil shale. Shale oil is the crude oil that is produced from tight shale formations such as the Niobrara shale of Colorado, the Bakken shale of North Dakota, the Eagle Ford shale of Texas, and the Avalon shale of West Texas and South New Mexico[9].

2.4 Hydraulic Fracturing

Hydraulic fracturing is a well stimulation technique used to extract oil and natural gas trapped underground in low-permeability rock formations by pumping a fracturing fluid under high pressure in order to crack the formations. Permeability represents the ability for fluid flow through a porous material. In order to produce oil and gas from low-permeability reservoirs, tortuous flow path should be built from reservoirs to wellbore surface. Without hydraulic fracturing, primary production rate may be too small to achieve commercial production.

As shown in figure 2.6, top part illustrates the flow pattern in a conventional non-fractured well where the red arrows represent the flow of fluid. However, once an artificial fracture is created, reservoir fluid that is long distance from the well can flow into the fracture and then travel quickly through the fracture to the well. Hydraulic fracturing improves the exposed area of the pay zone and creates a high permeability path which extends significantly from the wellbore to a target production formation. Hence, reservoir fluid can flow more easily from the formation to the wellbore.

During hydraulic fracture, fluids, commonly made up of water and chemical additives, are pumped into the production casing, through the perforations, and into the targeted formation at pressures high enough to cause the rock within the targeted formation to fracture. When the pressure exceeds the rock strength, the fluids open or enlarge fractures that can extend several hundred feet away from the well. After the fractures are created, a propping agent is pumped into the fractures to keep them from closing when the pumping pressure is released. After fracturing is completed, the internal pressure of the geologic formation cause the injected fracturing fluids to rise to the surface where it may be stored in tanks or pits prior to disposal or recycling.

Recovered fracturing fluids are referred to as flow-back. Disposal options for flow-back include discharge into surface water or underground injection. Well fracturing technology can improve the fluid flow in low permeability, heterogeneity, thin reservoir and reservoir with poor connectivity, it can increase the production of single well and the ultimate recovery factor[10].

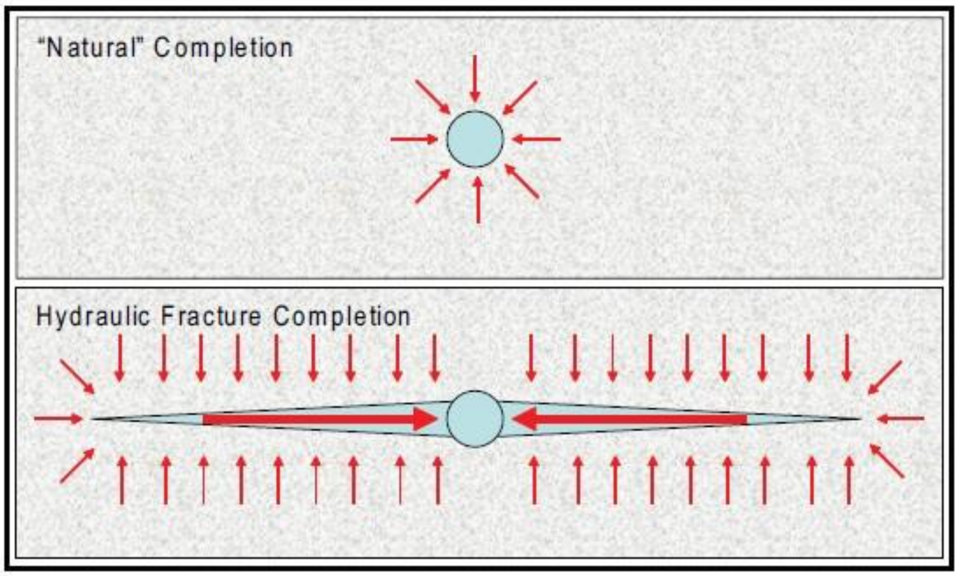


Figure 2.6 Illustration of a fractured and a non-fractured well

2.5 Horizontal Multistage Hydraulic Fracturing

In the last few years, many horizontal wells have been drilled around the word because of booming exploitation in unconventional reservoirs. The major purpose to drill a horizontal well is to improve reservoir contact and enhance well productivity. As an injection well, a long horizontal well provides a large contact area, and therefore enhances well injectivity, which is highly desirable for enhanced oil recovery applications.

As drilling technology continues to exploit more complex and unconventional reservoirs, completion technology is being designed and developed to effectively fracture and stimulate multiple stages along a horizontal wellbore. The growth in multi-stage fracturing has been tremendous over the last four years due to completion technology that can effectively place fractures in specific places in the wellbore. By placing the fracture in specific places in the horizontal wellbore, there is a greater chance to increase the cumulative production in a shorter time frame .Multistage fracturing is a method that injecting fracturing materials to create multiple fractures thereby increasing the reservoir contact area. It is more economical than using mechanical device (such as a bridge plug, packer) to separate each layer to fracture them respectively[11] (Fig 2.7).

Figure 2.7 Horizontal Well with Multi-stage Fracturing (Packers Plus)

The advantages of horizontal multistage fracturing technology is that it can construct precisely, and accurately place fracturing fluid by using ball sealing, the conductivity of fracturing fluid is high, the damage of fracturing fluid is little; and it has reduced the construction period. However multi-stage fracturing is complex, and the technical key is mechanical sitting seal and rubber cylinder and the safety function of sliding sleeve, especially the material requirements of external fracturing pipe's oil sensitive packer and the ball which can open the sliding sleeve are very high. Horizontal multistage fracturing has been widely used in North America, Africa and other more than 10 countries in Middle East. In China, Daqing oil field and southwest gas field are testing at some pilot spot. In recent years, Schlumberger, Baker Hughes, Canada packer energy service companies launched horizontal multistage fracturing technology; they are all advanced model in the world market. Schlumberger's Stage - FRAC horizontal multistage fracturing technology with its advanced fracturing fluid system, can be accurately placed fracturing fluid, what's more fracture conductivity is high, fracturing fluid damage will be small, it can reduce well completion time from several days to a few hours, fracturing level is up to 17 by one construction. Canada packer energy services company's StackFrac technique uses expandable packer, which will deform as borehole change, and perfectly adapted to high temperature and high pressure environment, at present the degree of depth is deepest at 7620 meters in the application of the horizontal well. Baker Hughes's horizontal well naked fracture system not only has naked packer and the ball seat sealing fracturing sliding sleeve, also has the liner top packer and pressure sealing sleeve. It has done 8-lever fracturing in the United States North Dakota beacon Rock[12].

2.6 Enhanced Oil Recovery Techniques

The term enhanced oil recovery (EOR) basically refers to the recovery of oil by any method beyond the primary stage of oil production. It is defined as the production of crude oil from reservoirs through processes taken to increase the primary reservoir drive. These processes may include pressure maintenance, injection of displacing fluids, or other methods such as thermal techniques. EOR techniques include all methods that are used to increase cumulative oil produced as much as possible. The recovery of oil reserves is divided into three main categories as shown in figure 2.8.

In primary recovery process oil is forced out of the reservoir by existing natural pressure of the trapped fluids in the reservoir. The efficiency of oil displacement is primary oil recovery process depends mainly on existing natural pressure in the reservoir. This pressure originated from various forces:

- Expanding force of natural gas
- Gravitational force
- Buoyancy force of encroaching water
- An expulsion force due to the compaction of poorly consolidated reservoir rocks

When the reservoir pressure is reduced to a point where it is no longer effective as a stress causing movement of hydrocarbons to the producing wells, water or gas is injected to augment or increase the existing pressure in the reservoir. Conversion of some of the wells into injection wells and subsequent injection of gas or water for pressure maintenance in the reservoir have been designated as secondary oil recovery. When oil production declines because of hydrocarbon production from the formation, the secondary oil recovery process is employed to increase the pressure required to drive the oil to production wells. The purposes of a secondary recovery technique are:

- Pressure restoration
- Pressure maintenance

The mechanism of secondary oil recovery is similar to that of primary oil recovery except that more than one well bore is involved, and the pressure of the reservoir is augmented or maintained artificially to force oil to the production wells. The process includes the application of a vacuum to a well, the injection of gas or water[13].

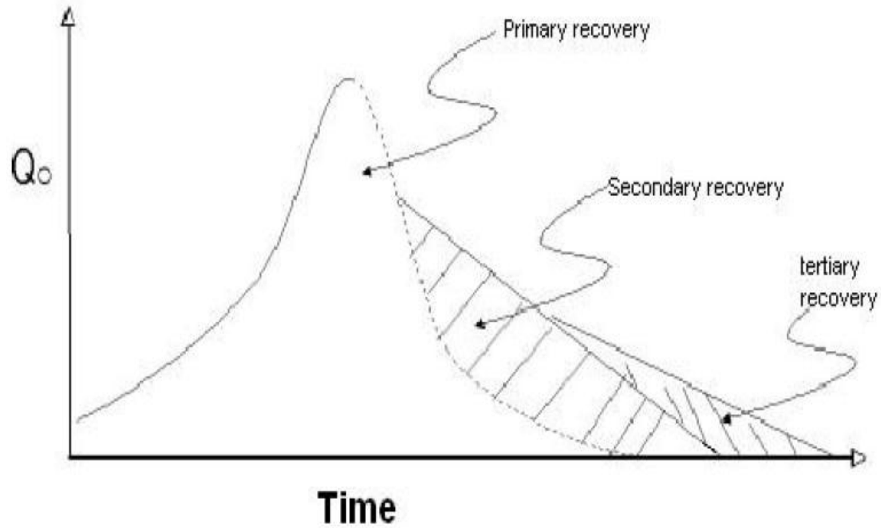


Figure 2.8 Recovery stages of a hydrocarbon reservoir through time (Jelmert et al. 2010)

2.6.1 Water Injection

Water flooding is an improved oil recovery mechanism that is often utilized after the natural drive mechanisms become ineffective. During water flooding projects, water is injected into a reservoir through injection wells to initiate a sweep mechanism that drives the reservoir oil toward the production wells. The injected water creates a bottom water drive on the oil zone pushing the oil upwards. In earlier practices, water injection was done in the later phase of the reservoir life but now it is carried out in the earlier phase so that voidage and gas cap in the reservoir are avoided. Using water injection in earlier phase helps in improving the production as once secondary gas cap is formed the injected water initially tends to compress free gas cap and later on pushes the oil thus the amount of injection water required is much more. The water injection is generally carried out when solution gas drive is present or water drive is weak. Therefore for better economy the water injection is carried out when the reservoir pressure is higher than the saturation pressure.

Water is injected for two reasons:

- For pressure support of the reservoir.
- To sweep or displace the oil from the reservoir, and push it towards an oil production well.

The selection of injection water method depends upon the mobility rate between the displacing fluid (water) and the displaced fluid (oil). The water injection however, has some disadvantages, some of these disadvantages are:

- Reaction of injected water with the formation water can cause formation damage.
- Corrosion of surface and sub-surface equipment.

2.6.2 Gas Injection

There are two major types of gas injection, miscible gas injection and immiscible gas injection. In miscible gas injection, the gas is injected at or above minimum miscibility pressure (MMP) which causes the gas to be miscible in the oil. On the other hand in immiscible gas injection, flooding by the gas is conducted below MMP. This low pressure injection of gas is used to maintain reservoir pressure to prevent production cut-off and thereby increase the rate of production. The miscible gas injection displacement is defined as the processes where the effectiveness of the displacement results primarily from miscibility between the oil in place and the injected fluid. Displacement fluids, such as hydrocarbon solvents, CO2, flue gas, and nitrogen, are considered. Miscibility plays a role in surfactant processes, but is not primary recovery mechanism for these processes. In an immiscible displacement process, such as a water flooding, the microscopic displacement efficiency, ED, is generally much less than unity. Part of the crude oil in the places contacted by the displacing fluid is trapped as isolated drops, stringers, or pendular rings, depending on the wettability. When this condition is reached, relative permeability to oil is reduced essentially to zero and continued simply flows around the trapped oil. This limitation to oil recovery may be overcome by the application of miscible displacement processes in which the displacing fluid is miscible with the displaced fluid at the conditions existing at the displacing-fluid/displaced-fluid interface. Interfacial tension (IFT) is eliminated. If the two fluids do not mix in all proportions to form a single phase, the process is called immiscible. In practice, solvents that are miscible with crude oil are more expensive than water or dry gas, and thus an injected solvent slug must be relatively small for economic reasons. For this situation, the primary (solvent) slug may be followed by a larger volume of a less expensive fluid, such as water or a lean gas. Various gases and liquids are suitable for use as miscible displacement agents in either FCM or MCM processes. These include low-molecular-weight hydrocarbons, mixtures of hydrocarbons, CO2, nitrogen, or mixtures of these. The particular application will depend on the reservoir pressure, temperature, and compositions of the crude oil and the injected fluid[14].

Tertiary recovery refers to processes in the porous medium that recover oil not produced by the conventional primary and secondary production methods. By EOR is meant to improve the sweep efficiency in the reservoir by use of injectants that can reduce the remaining oil saturation below the level achieved by conventional injection methods. Included in remaining oil defined here are both the oil trapped in the flooded areas by capillary forces, and the oil in areas not flooded by the injected fluid. Examples of injectants are CO2 or chemicals added to the injected water. In summary, EOR is to reduce the residual oil saturation and to improve the sweep efficiency in all directions.

CHAPTER 3

EAGLE FORD SHALE PLAY

As oil and gas industry continues to search for additional resources to address the world's energy needs, the Eagle Ford Shale in Texas has become a focus of exploration and production activity in North America. The Eagle Ford Shale formation is considered by many to be the most significant new opportunity for unconventional hydrocarbons, both oil and natural gas, in the United States. This chapter briefly introduces the Eagle Ford Shale, describes the geological setup of Eagle Ford shale formation, its characteristics and production history.

3.1 Eagle Ford Shale Overview

The Eagle Ford Shale play is located in South Texas and produces from various depths between 4,000 and 14,000 feet. The Eagle Ford Shale takes its name from the town of Eagle Ford Texas where the shale outcrops at the surface in clay form. The Eagle Ford is the most active shale play in the world with more than 250 rigs running and operators are indicating the play will be developed for decades to come. According to the Texas Railroad Commission, 2010 production in the Eagle Ford Shale exceeded 3.5 million barrels of oil and will increase over the next few years. Those potential resources are classified as "unconventional" because the hydrocarbons are trapped in formations of shale, a fine-grained, sedimentary rock and require innovative technologies to extract. Advancements in two of those technologies, horizontal drilling and hydraulic fracturing have made production of hydrocarbons from these unconventional resources commercially viable in some areas and greatly increased U.S. energy supplies. The Eagle Ford Shale has been identified as a premier play in North America and is expected to provide energy resources for decades to come. Geologic studies in the Eagle Ford, which spans over 400 miles in south Texas, have revealed the potential for large quantities of hydrocarbons; and energy companies have obtained the rights to explore for and produce hydrocarbons on significant amounts of acreage stretching across the area. The full extent of the Eagle Ford Shale's possible role as a major hydrocarbon resource is not yet known, and full-scale production could be several years away. Many challenges remain, including environmental concerns and the lack of infrastructure to support production. However, the successful development of the Eagle Ford, and other shale plays across the U.S., will present many benefits[15].

Benefits from high volumes of liquid-rich hydrocarbons, the Eagle Ford formation will be a central point in oil and gas industry of North America. The types of hydrocarbons produced from the Eagle Ford shale vary from dry gas to gas condensate to oil, making it a liquid-rich play. The direction of phase change from liquid to gas in the Eagle Ford shale is from north to south and from shallow to deep, where oil is mainly present in the shallowest northern section. Figure 3.1 shows the oil (green), condensate (orange) and dry gas (red) producing windows.

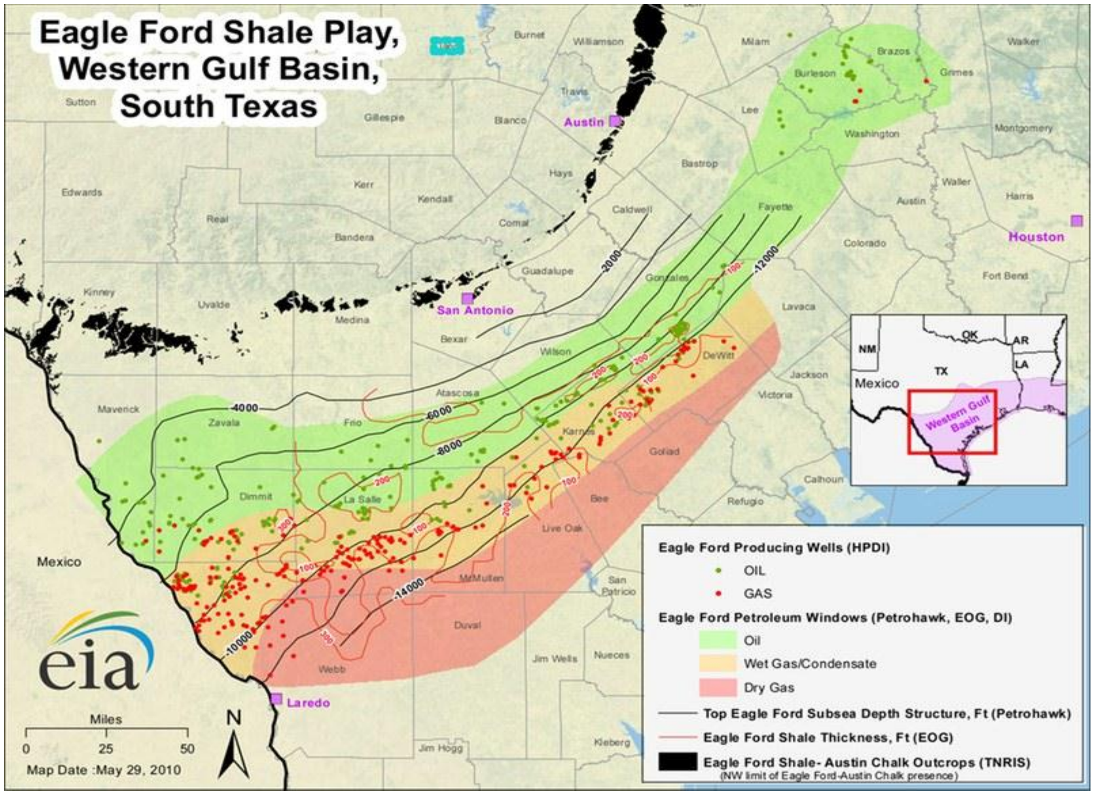


Figure 3.1 Eagle Ford Shale map (Energy Information Administration, 2011)

3.2 Geology

The Eagle Ford shale is one of the most recent developments in unconventional exploration that trends across Texas from the Mexican Border in the South into East Texas, roughly 50 miles wide and 400 miles long. It is located in several counties stretching Giddings field in Brazos and Grimes counties down into the Maverick Basin in Maverick County (Fig 3.2). Outcrops of Eagle Ford shale formation can be seen in a line roughly following the Ouachita Uplift that runs through Austin, Waco, and Fort Worth. The formation is the source rock for the Austin Chalk oil and gas formation. In south Texas, where it has hydrocarbon potential within the fairway, the Eagle Ford formation is found between 5,000 ft and 16,000 ft below the surface.

The Eagle Ford Shale is a Cretaceous sediment, directly beneath the Austin Chalk Shale, that is traditionally known as a source rock in South and East Texas. Producers also drilled through the play for many years targeting the Edwards Limestone formation along the Edwards Reef Trend. Although it is widely known as shale, the formation is composed of organic-rich calcareous mudstones and marls that were deposited during two transgressive sequences, the upper and lower Eagle Ford. According to Bazan's work, due to a more oxygenated environment as depth decreases, the lower Eagle Ford is organically richer and produces more hydrocarbons than the upper Eagle Ford.

The Eagle Ford Shale producing interval is found at depths between 4,000 and 14,00 feet. The shale is up to 400 feet thick in some area, but averages 250 ft across the play. Generally, natural fracturing is not prominent. To date, the most prolific area for production occurs along the Edwards Reef Trend and where it converges with the Sligo Reef Trend. Both geologic distinctions are also referred as the Edwards Margin and Sligo Shelf Margin[16].

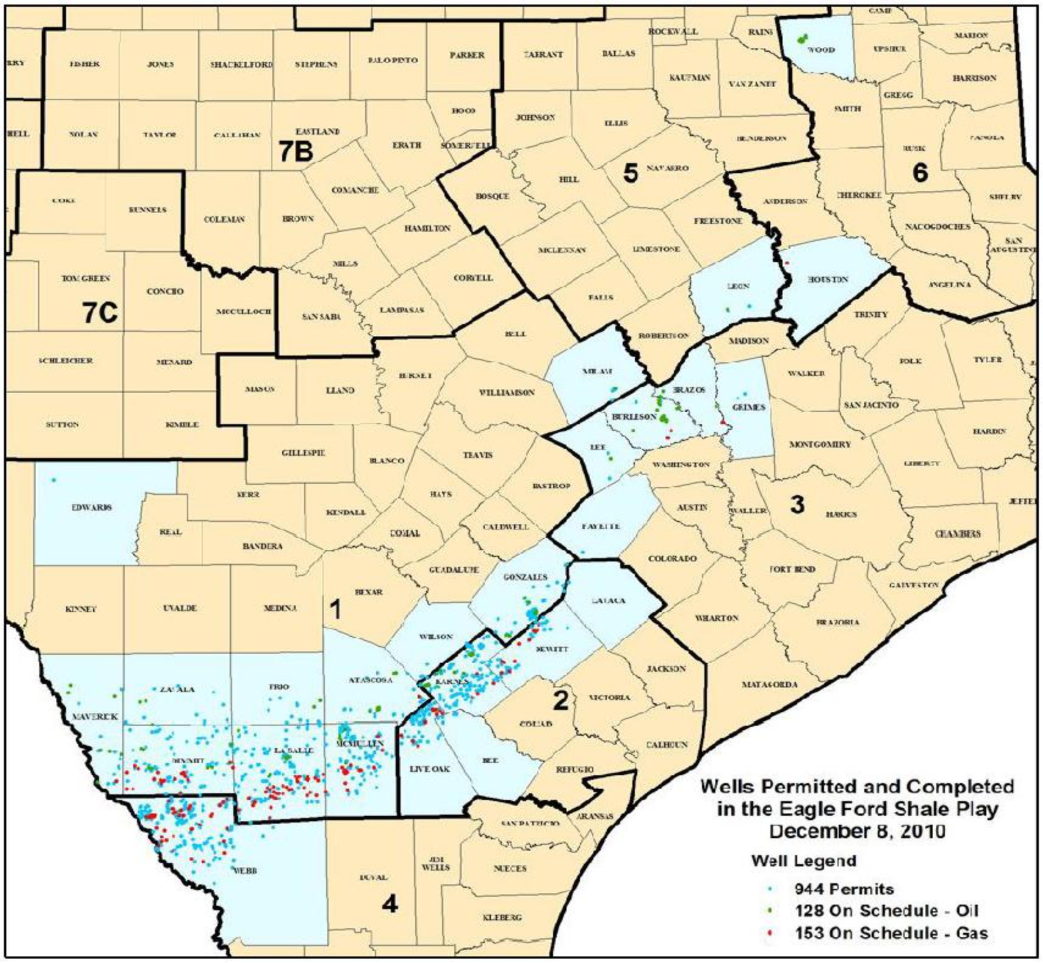


Figure 3.2 Eagle Ford Shale location on map of Texas (Railroad Commission of Texas)

Fig 3.3 shows the variation of the stratigraphic column across the play. Eagle Ford shale formation was deposited during late Cretaceous period, approximately 145 to 65million years ago and records Cenomanian to Tutonian transgression (Jiang 1989). The Eagle Ford formation overlies Woodbine group which includes the Woodbine sands of East Texas and southwest Louisiana, the Tuscaloosa sands of Central Louisiana and the Buda limestone of Texas and it is overlain by the Austin Chalk. Condon and Dyman (2006) described the geology, structural features, and environment of the Eagle Ford. Some basic structure features of Eagle Ford Shale vary significantly. The Eagle Ford Shale producing interval is found at depths between 4,000 and 14,00 feet, the gross height varies from 100 to 300 ft thick, pressure gradient has a range of 0.55 to 0.85 psi/ft and the bottom-hole temperature changes from 150 ^{0}F to 350 ^{0}F[17].

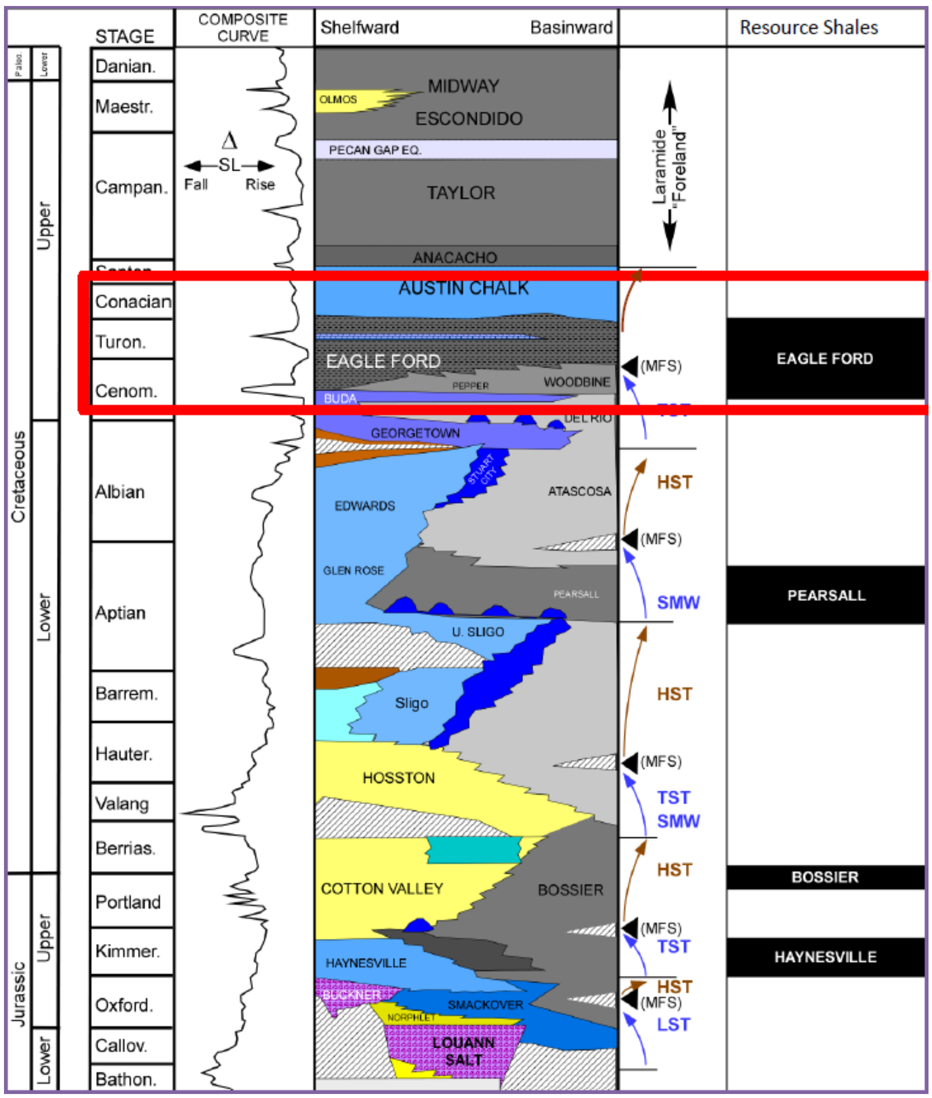


Figure 3.3 Stratigraphic column (Chesapeake Energy)

3.3 Characterization of Eagle Ford Shale

The characteristics of the Eagle Ford Shale play change substantially across the southwest to northeast strike of the play. Shale thickness ranges from 45 feet in the Austin area to more than 500 feet in the dark shales that outcrop in Dallas County, and true vertical depths range from 2,500 to 13,000 feet. Pressure gradients, total organic content and mineralogy also vary significantly.

The Eagle Ford Shale contains 38–88% clay minerals, and about 50% of the clay minerals are smectites (TETC, 1990a). The Eagle Ford Shale can be classified as clay shale based on the classification by Underwood (1967). Swell potential, compressibility, and creep deformation are expected to be high in Eagle Ford Shale due to high percentage of smectite. The average carbonate content for Eagle Ford shale is 10%, ranging from 2% to 39% with a high coefficient of variation (Fig3.4). Most of the rock samples from Eagle Ford shale had carbonate content less than 10%. Some of the higher carbonate contents, greater than 20%, may be due to the presence of fossil shale fragments. The Eagle Ford Shale has an average water content of 16%, ranging between 4% and 25%. A histogram and fitted normal distribution curve, based on the calculated average and standard deviation, are plotted in Fig 3.5 for water content data[16].

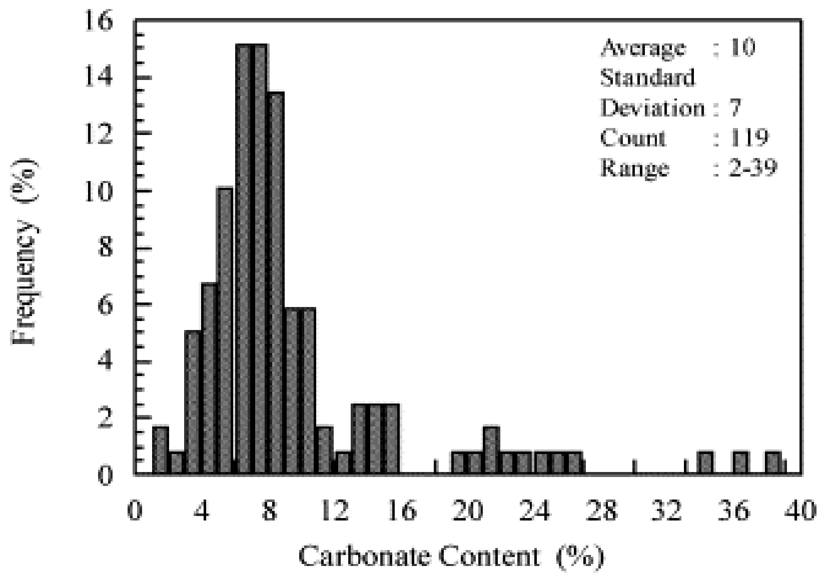


Figure 3.4 Histogram for carbonate content for Eagle Ford Shale (Hsu and Nelson 2002)

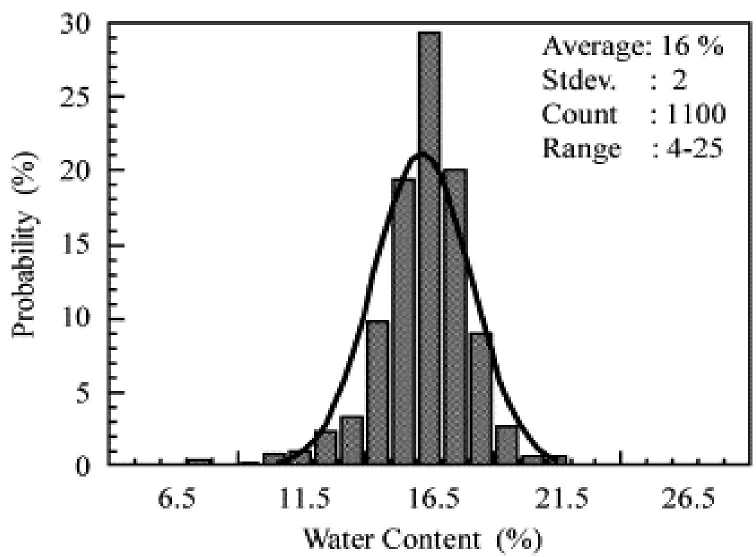


Figure 3.5 Histogram for water content for Eagle Ford Shale (Hsu and Nelson 2002)

Eagle Ford development began as hale gas play in LaSalle County (in the southwest part of the play) in late 2008. Not surprisingly, the first stimulation designs were slick-water fractures patterned after what had been done in the Barnett. However, the reservoir properties of the Eagle Ford are substantially different. While the Barnett is a very brittle gas bearing siltstone with a high Young's modulus (7E6 psi), the Eagle Ford produces both gas and high-gravity oil, and is mainly a clay-rich limestone with very low quartz content. This tends to make it less brittle (more ductile), with a low Young's modulus (2E6 psi). Because the rock is relatively soft (low Young's modulus), it is prone to proppant embedment. While the Barnett Shale has about 0.20 grain diameters of embedment at 5,000 psi closure stress, the Eagle Ford can have an entire grain diameter of embedment at 10,000-psi closure stress[18].

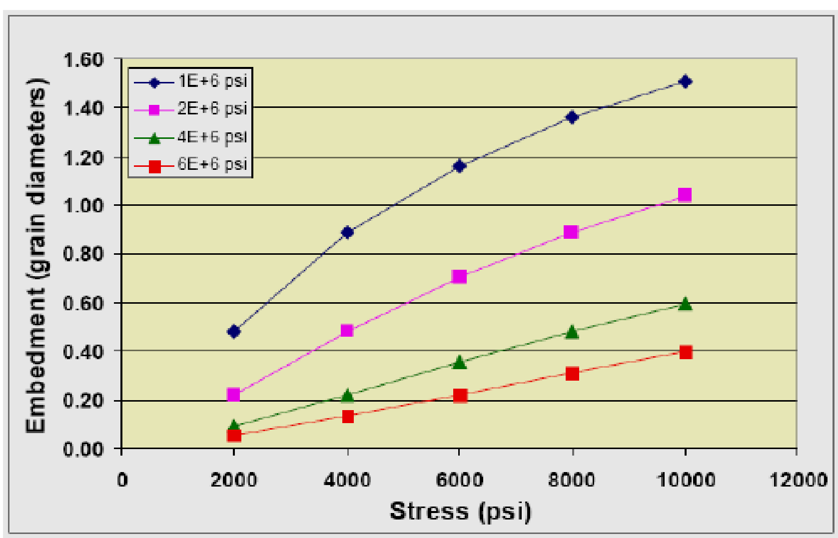


Figure 3.6 Proppant-embedment simulation for various YM vs closure stress

(Cipolla et al. 2008)

3.4 Production Summary

The Eagle Ford shale has long been known as a shale resource rock, but only recently has it been recognized as a viable shale play formation. The Eagle Ford Shale is a hydrocarbon producing formation that is a source rock for Austin Chalk which is approximately 4,000 to 14,000 feet below the surface. The first few exploration wells in the Eagle Ford shale were drilled in the late 2008 in LaSalle County. The core focus of this drilling activity is between 10,000 and 12,000 feet below surface. The formation is discovered containing both natural gas and oil deposits.

There were 1262 producing oil leases on schedule in 2012; 368 producing oil leases on schedule in 2011; 72 producing oil leases in 2010; and 40 producing oil leases in 2009. There were 875 producing gas well on schedule in 2012; 550 producing gas wells in 2011; 158 producing gas wells in 2010; and 67 producing gas wells in 2009.Production of oil, gas and condensate has increased dramatically from 2010 to 2011.Oil production increased by more than six times from 2010 to 2011, with 2011 production at 28,315,540 bbls. Gas production was more than doubled from 2010 to 2011, with 2011 production at 271,831,688 mcf. Condensate production was tripled from 2010 to 2011, with 2011 production at 21,089,214 bbls. The Eagle Ford Shale has expanded at an unprecedented rate, it will quite possibly be the largest single development in the history of the state of Texas and ranks as the single largest oil & gas development in the world[19].

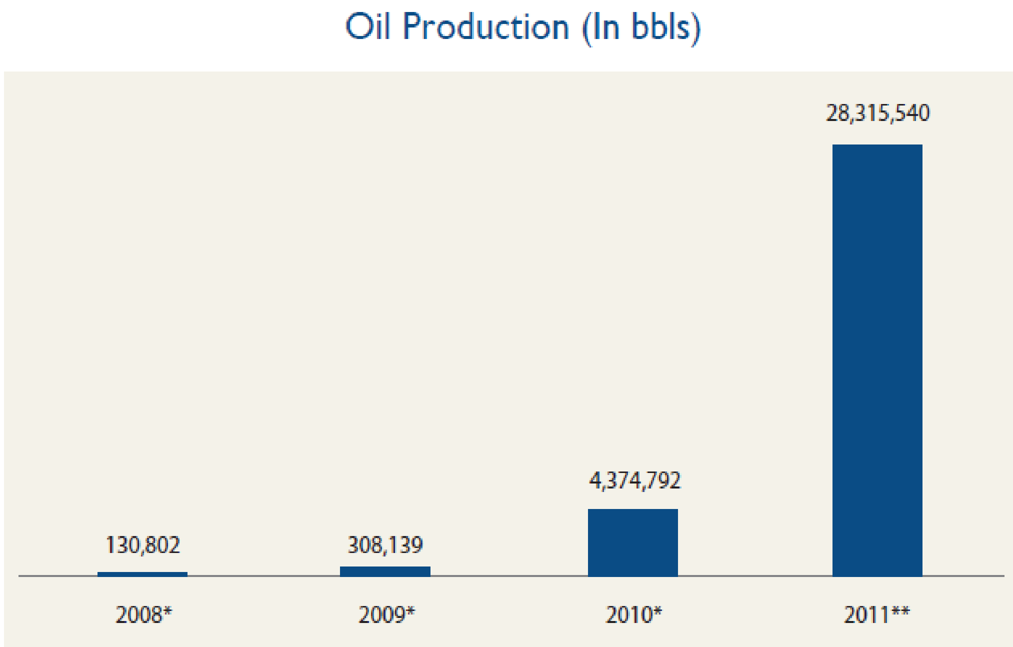


Figure 3.7 Oil production form Eagle Ford shale play
(The Railroad Commission of Texas Estimates)

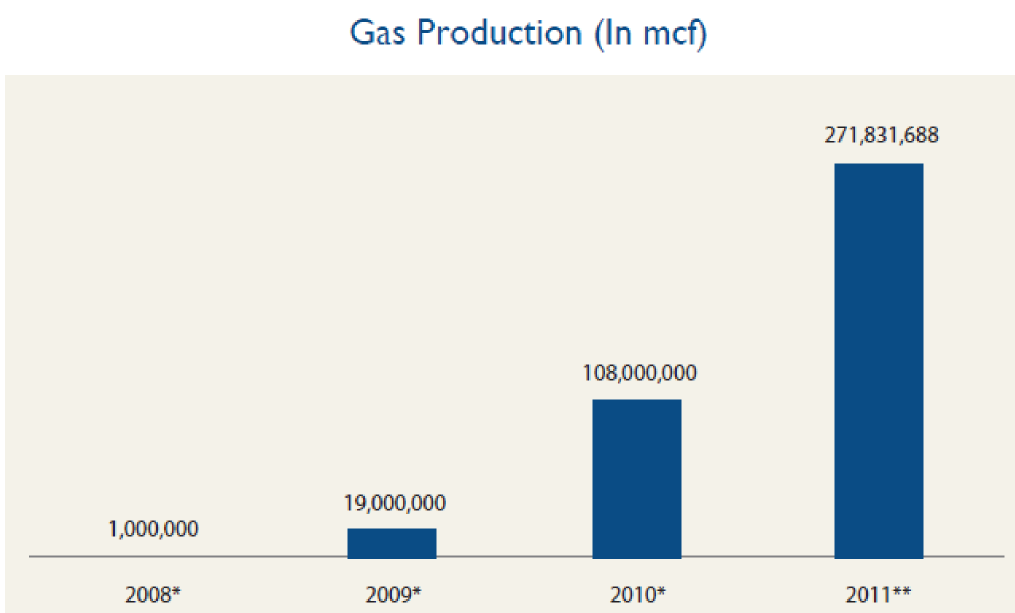


Figure 3.8 Gas production form Eagle Ford shale play
(The Railroad Commission of Texas Estimates)

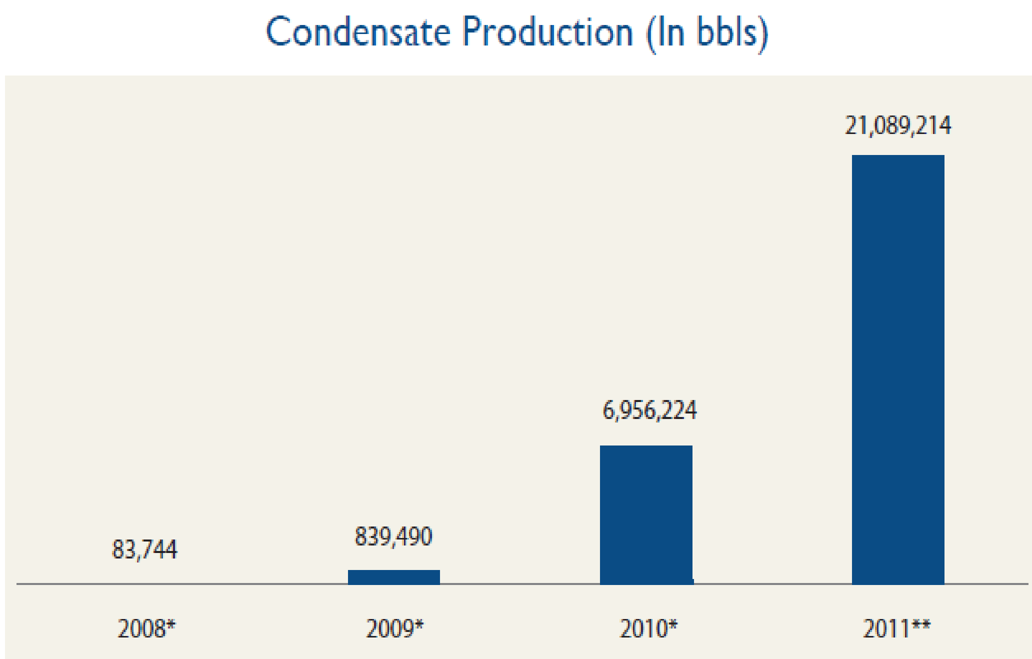


Figure 3.9 Condensate production form Eagle Ford shale play

(The Railroad Commission of Texas Estimates)

CHAPTER 4

BASE CASE RESERVOIR SIMULATION

Based on the rock, fluid and other geological parameters described in Chapter 3, this chapter shows the procedure of base simulation model setup for a shale oil reservoir. We introduce the base reservoir model, the results of model validation, and then describe the sensitivity analysis results.

4.1 Description of the Simulator

To conduct a simulation study, it was necessary to choose a simulator and to create a geologic model. For this study, a simulation software owned by Computer Modeling Group Ltd is used. IMEX is a black oil simulator in CMG. It models three phases fluid in gas, gas-water, oil-water reservoir in one, two, or three dimensions. IMEX models multiple PVT and equilibrium regions, as well as multiple rock types, and it has flexible relative permeability choices.

4.2 Base Model Description

Unconventional reservoirs, which are less common and less well understood than conventional sandstone and carbonate reservoirs, have become an increasingly important resource base. Because of their low-porosity, low-permeability, fast pressure depletion, unconventional reservoirs cannot be produced economically unless applying stimulation techniques. Unconventional tight sand and shale oil reservoirs need stimulated reservoir volume (SRV) created by hydraulic fracturing to let oil or gas flow from matrix to the created fractured network and horizontal well to improve the contact area with the formation. Thus tight sand and shale oil reservoir which have ultra-low permeability needs horizontal wells drilling with transverse hydraulic fractures to achieve commercially production.

According to Rubin's (2010) work, an extremely fine grid reference solution (5-14 million cells in 2-D) which was capable of modeling fracture flow was created. Using cells which are no longer than the width of actual fractures (assumed as 0.001 ft.), and flow into the fracture from the matrix using cells small enough to properly capture the very large pressure gradient involved. He showed that it is possible to accurately model flow from a fractured shale reservoir using logarithmically spaced, locally refined grids with fracture cells represented using approximately 2.0 ft. wide cells and maintaining the same conductivity as the original 0.001 ft wide fracture. Compared to conventional simulation model of multi-stage hydraulic fractured reservoirs, Rubin's model provides a very good example which shows an excellent correlation between 2-ft-fracture coarse model and 0.001 ft wide fracture model. This fine grid model simplifies the conventional model which prevents many computation error, offering us more time to focus on the research of production performance near the fracture[20].

In Wan's work (Evaluation of the EOR Potential in Shale Oil Reservoirs by Cyclic Gas Injection, MS thesis 2013), a 2000 ft long×1000ft wide×200 ft thick shale oil reservoir model with a horizontal well and 10 transverse fractures was built (Fig

4.1). Similar to Rubin's work, 2-ft wide grid cells with 83.3 md-ft conductivity (k= 41.65 md, w_f= 2 ft) were used to simulate the physical fracture flow and each fracture was placed 200ft apart. The reservoir properties data Wan used in this model is from published data in Eagle Ford shale (Table 4.1) (Bazan, Larkin, et al. 2010). The initial reservoir pressure for this field is 6,425 psi. The permeability for this shale reservoir is ultra-tight about 100 nano-Darcy. Assuming the Eagle Ford field is homogeneous and isotropic which has the same 100 nano-Darcy permeability and 0.06 porosity in each point and in every direction.

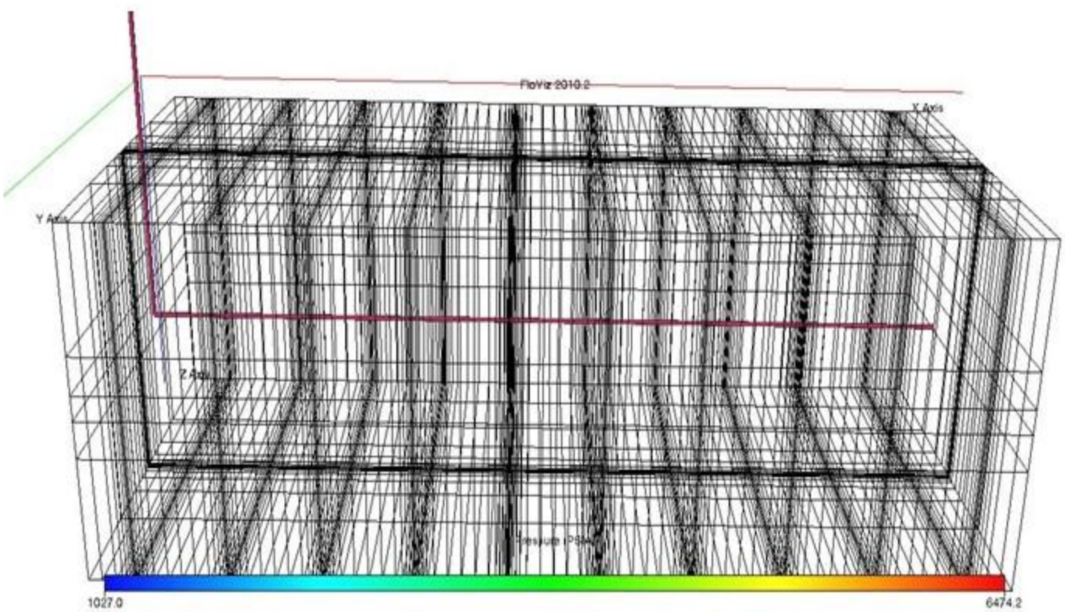


Figure 4.1 Horizontal well with 10 hydraulic fractures model (Wan, 2013)

Table 4.1Reservoir properties for Eagle Ford shale

Initial Reservoir Pressure	6,425 psi
Porosity of Shale matrix	0.06
Initial Water Saturation	0.3
Compressibility of Shale	$5*10^{-6}$ psi^{-1}
Shale Matrix Permeability	0.0001 md
Oil API	42
Reservoir temperature	255 ^0F
Gas Specific Gravity	0.8
Reservoir Thickness	200 ft
Bubble Point for Oil	2398 psi

Table 4.2 Designed Hydraulic Fractures Properties

Fracture Stages	10
Fracture Spacing	200 ft
Fracture Conductivity	83.3 md-ft
Fracture Half-length	500 ft
Fracture Cell Width	2 ft

Table 4.3 Relative permeability end points for fracture and matrix

	Matrix	Fracture
N_0	5	1.5
N_g	2	1
S_{wi}	0.3	0.05
S_{org}	0.3	0.1
S_{gc}	0.05	0
K_{rg} at S_{org}	1	1

To simplify the computation and work efficiently, a 200 ft long×1000ft wide×200 ft thick model with single hydraulic fracture was selected as base simulation model in Tao's work. Fig 4.2 shows the schematic of simulation the whole reservoir with 10 hydraulic fractures and simulation of single hydraulic fracture stimulated reservoir volume and the correction of these two models have already been proved in his work. During the primary production process, the well is controlled by bottom-hole pressure (BHP) which is set up as 2500 psi.

The Goal of our work is to evaluate the potential of conventional EOR techniques such as gas and water injection for improving oil production from tight sand and shale oil. Modeling the whole Eagle ford reservoir may contain tremendous number of grid blocks, and it is of course time-consuming to model these complex fracture networks. Thus, we built a small shale oil reservoir model which is 200ft long×1000ft wide×200 ft thick based on Wan's model. We develop this small part of shale oil reservoir with two vertical wells with single fracture respectively. The reservoir properties data used in this model is also from published data in Eagle Ford shale (Bazan, Larkin, et al. 2010). As shown in Fig 4.3, 8470 (22*55*7) grid-cells are used to simulate this part of reservoir. In this model we use 1-ft wide cells with 41.65 md-ft conductivity which were located at the boundary of reservoir model to simulate the physical flow between two hydraulic fractures.

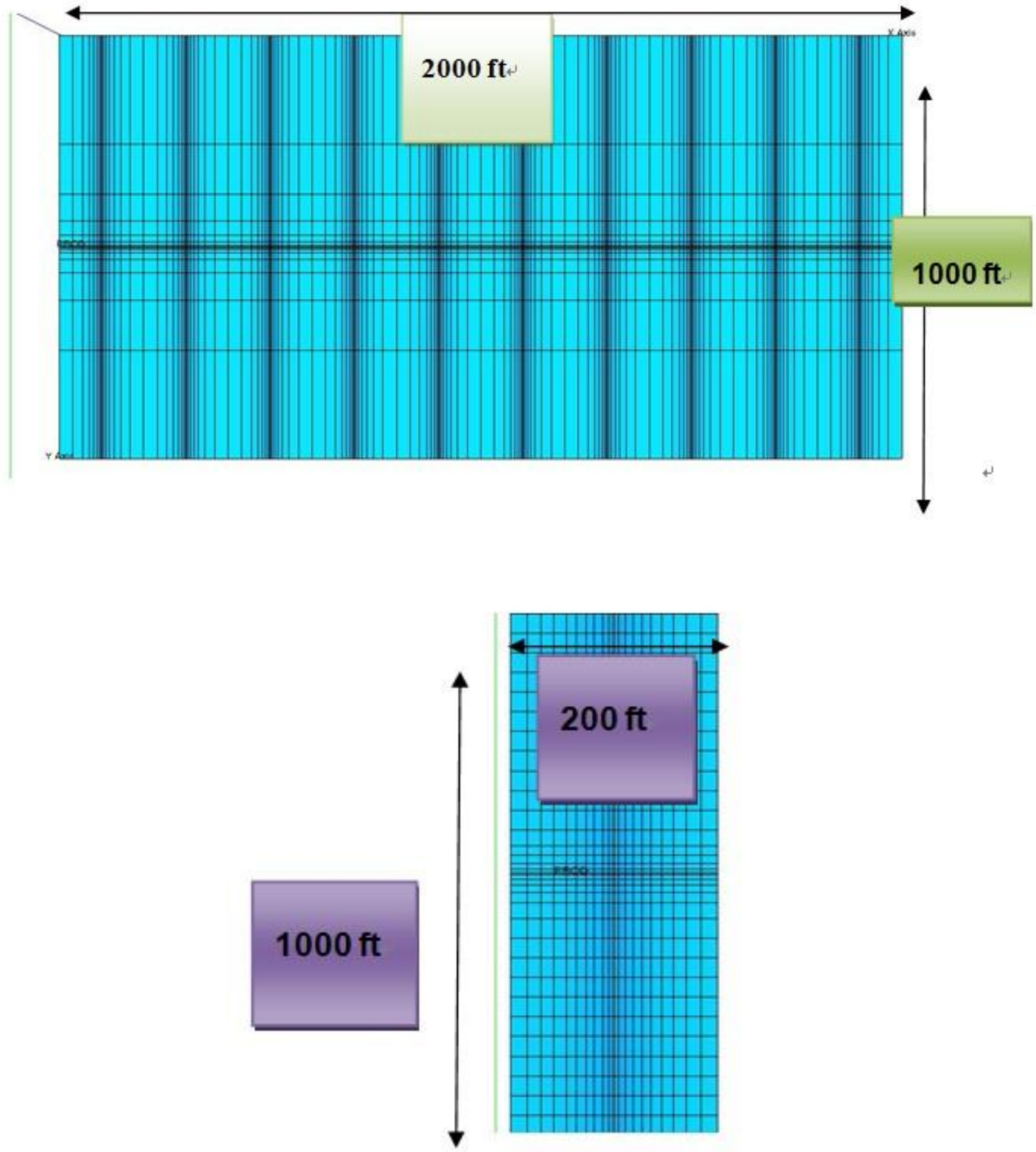


Figure 4.2 10 Hydraulic fractures SRV vs. single hydraulic fracture SRV (Wan, 2013)

According to Wan's work, a 200ft long×1000ft wide×200 ft thick reservoir model with a 2-ft wide ×1000-ft long hydraulic fracture was selected to simulate cyclic gas injection in shale oil reservoir. This 2-ft wide fracture was used for both injection and production. In our case, we want to focus on the gas and water injection performance between two fractures. So we separate this 2-ft wide fracture into two 1-ft wide fractures in our model and locate them at the edge of the model. One fracture was used to inject gas or water and the other one was used for production.

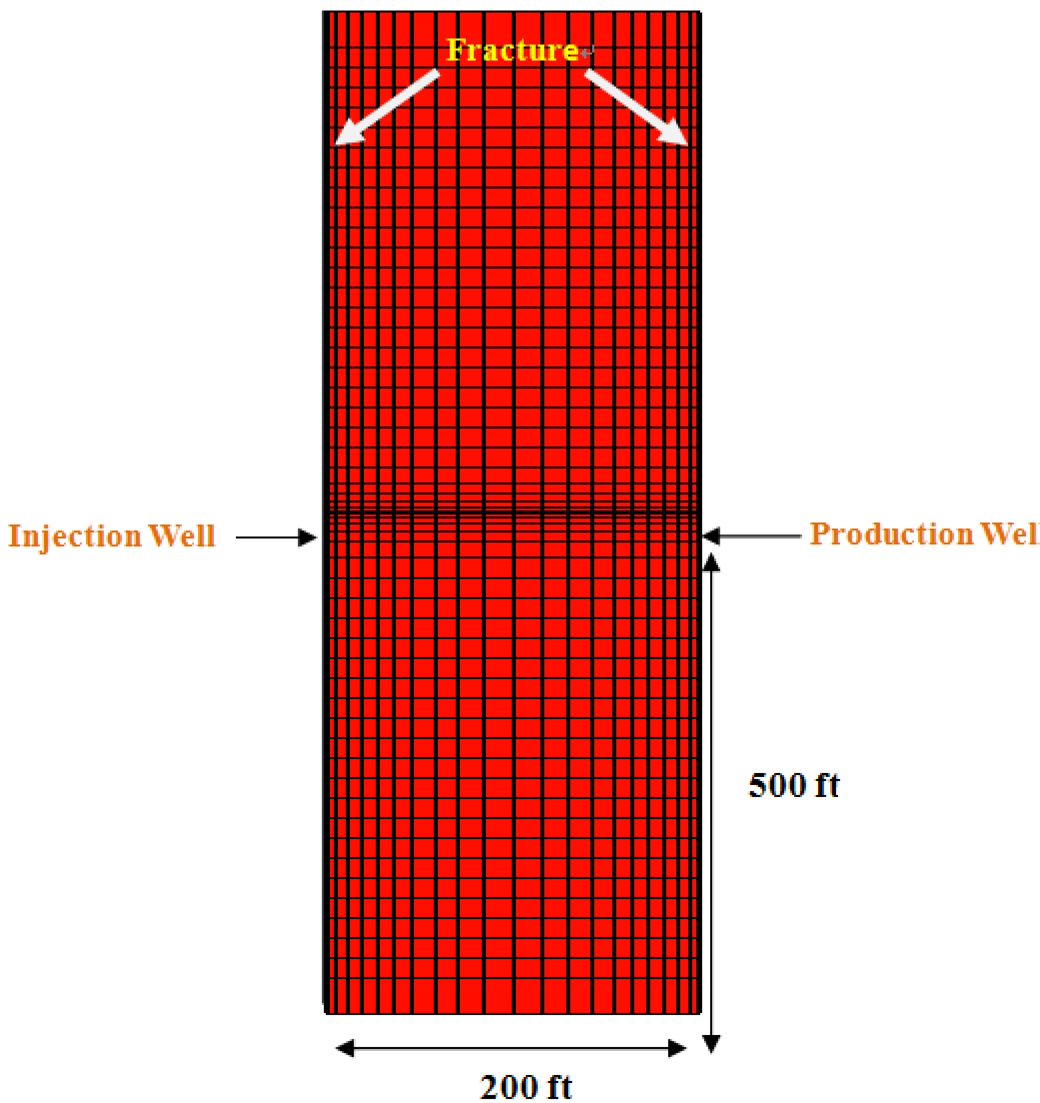


Figure 4.3 Two vertical wells with single hydraulic fractures

4.3 Base Reservoir Model Validation

Before applying gas or water injection simulation on our basic model, we should implement same production scenario on two models to test the results from the model with a 2-ft hydraulic fracture and the model which has two 1-ft hydraulic fractures. We need to make sure the validity of our basic model before continuing simulation work.

Scenario 1

Case 1: 7200 days of Primary production (200ft long×1000ft wide×200 ft thick, one 2-ft wide fracture)

Case 2: 7200 days of Primary production (200ft long×1000ft wide×200 ft thick, two 1-ft wide fractures)

In Tao Wan's model, there are 8085 (21×55×7) cells with single 2-ft wide hydraulic fracture（Case 1）. In our case, 8470 cells were used, simulating two 1-ft wide hydraulic fractures. For scenario 1, a 7200-day primary production scenario has been implemented on two models and the wells were controlled by bottom-hole pressure (BHP) which was set up as 2500 psi. Keeping well controlled by BHP that is above the bubble point pressure can prevent solution gas liberating from the oil, thus we can avoid the complex situation.

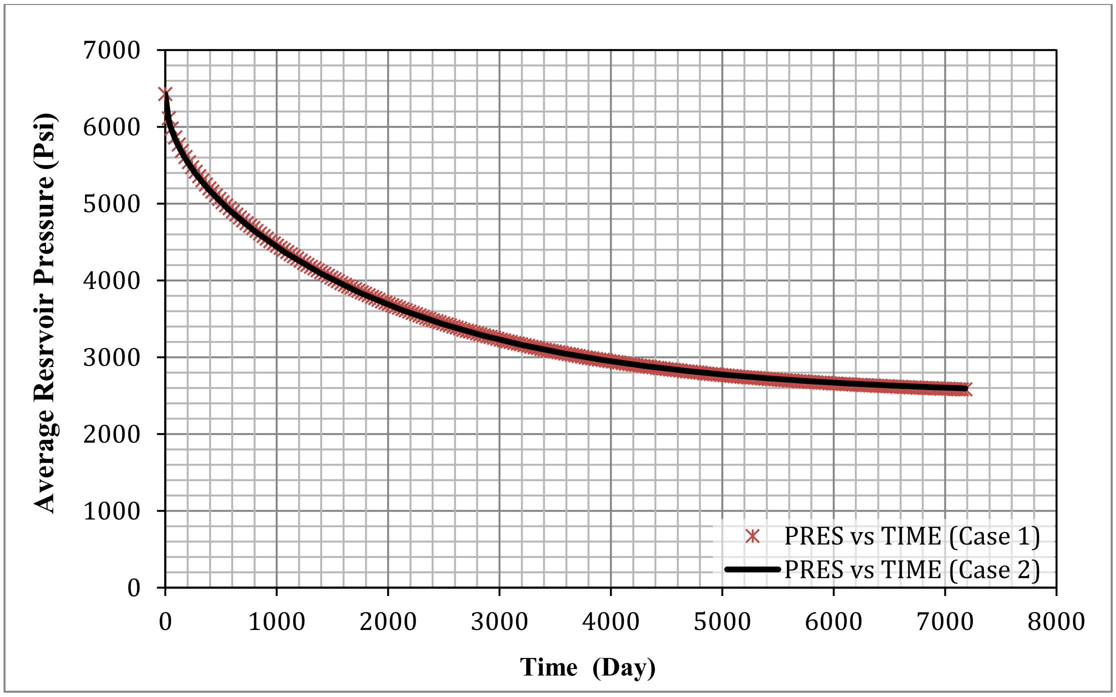


Figure 4.4 Reservoir Average Pressure vs Time

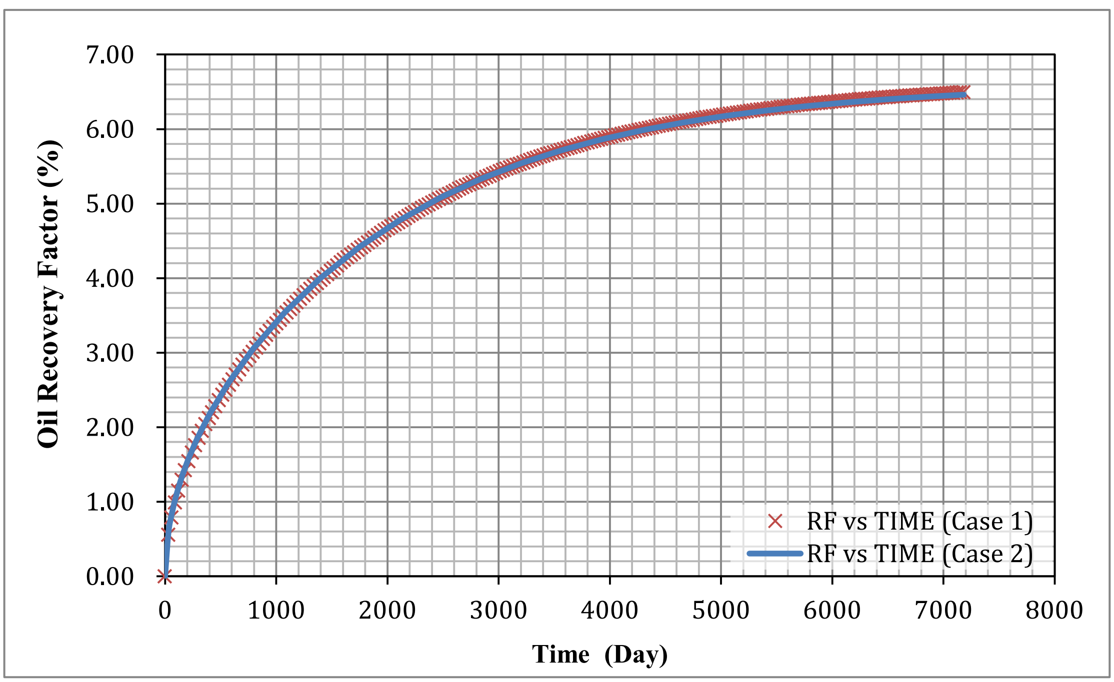


Figure 4.5 Field Oil Recovery Factor vs Time

As shown in Fig 4.3 and Fig 4.4, the average reservoir pressure depletion curve and oil recovery factor curve for two models matches perfectly for every time step. The cumulative oil production for case 1 is 16.293 MSTB and it is 16.598 MSTB in case 2 (Table 4.4).

Table 4.4 Field cumulative oil production and OOIP recovery

	Case 1	**Case 2**
Cumulative Oil Production (MSTB)	16.293	16.598
Current Fluids In Place (MSTB)	234.52	234.20
Overall Recovery (%)	6.50	6.62

Scenario 2

Case 3: 7200 days of Primary production+30 cycles of gas injection, each cycle includes: 200 days injection and 200 days production (200ft long×1000ft wide×200 ft thick, one 2-ft wide fracture)

Case 4: 7200 days of Primary production+30 cycles of gas injection, each cycle includes: 200 days injection and 200 days production (200ft long×1000ft wide×200 ft thick, two 1-ft wide fractures)

For scenario 2, we select a production scenario which has 7200-day primary production followed with 30 cycles of miscible gas injection, each cycle includes 200days injection and 200 days production and the well is also controlled by bottom hole pressure (BHP) which is set up as 2500 psi.

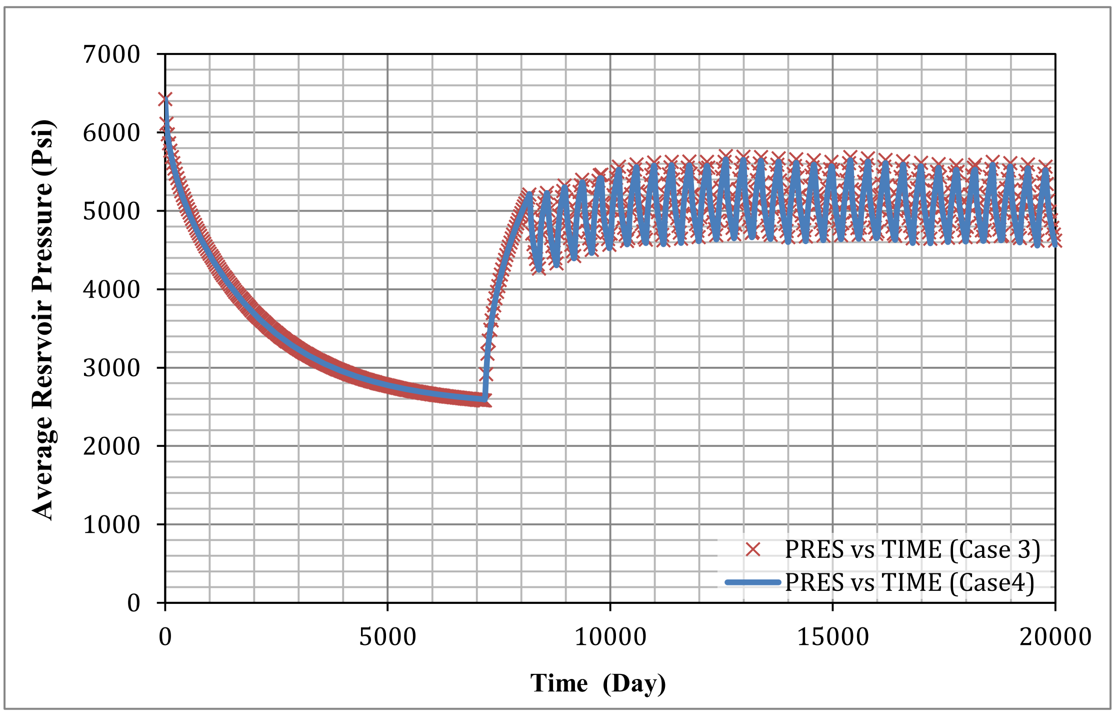


Figure 4.6 Reservoir Average Pressure vs Time

Fig 4.5 shows that the average reservoir pressure change of two models are consistent with each other, after 7200 days of primary production, a 1000-day gas injection was implemented to increase the reservoir pressure from 2450 psi to 5000psi and then 30 cycles of gas injection were applied. In cyclic injection period, the average reservoir pressure variations almost follow the same magnitude of fluctuation for each cycle.

Table 4.5 Field cumulative oil production and OOIP recovery for two models

	Case 3	**Case 4**
Cumulative Oil Production (MSTB)	63.979	62.316
Current Fluids In Place (MSTB)	186.84	188.50
Overall Recovery (%)	25.5	24.85

From Fig 4.6 we can figure out that these two models have the same tendency of enhancing oil recovery effect. In the first 7200-day primary production period, the oil recovery factor is about 6.5% and then from the beginning of the cyclic gas injection, cumulative oil production has been increasing, finally, about 25 % oil recovery factor is achieved. The cumulative oil production for case 3 is 63.979 MSTB while it is 62.316 MSTB in case 4 (Table 4.5). After applying two production scenarios on two models, simulation results from our basic model are almost the same with Tao Wan's model. Thus, it's accurate to use our basic model to evaluate the potential of gas and water injection in shale oil reservoir.

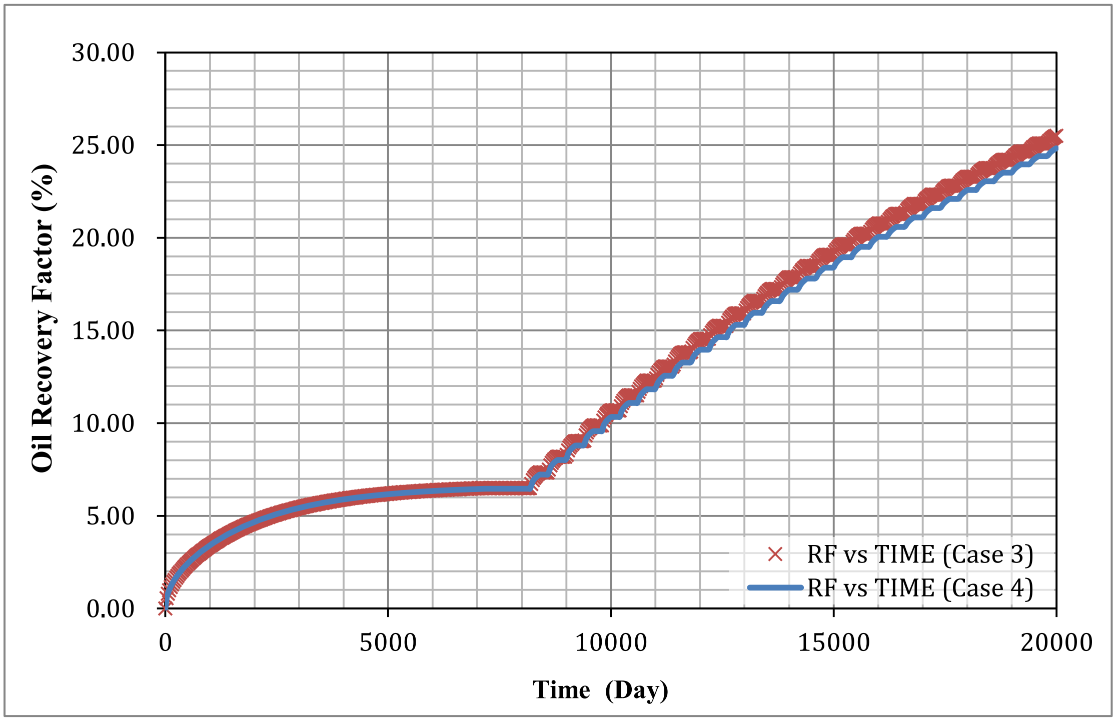


Figure 4.7 Field Oil Recovery Factor vs Time

4.4 Base Model Sensitivity Studies

The production behavior and recovery of oil from the low permeability shale formation is a function of the rock, fluid and the fracturing operations. Sensitivity analysis is a quantitative method of determining the important parameters which affect shale oil production performance. The parameters considered in this thesis include fracture half-length, flowing bottom-hole pressure, rock compressibility and matrix permeability. Sensitivity studies are necessarily for designing better simulation model and understanding the fundamental behavior of shale oil production system.

4.4.1 Fracture Half-length

The fracture half-length used in the base model is 500 ft. Three another fracture half-lengths of 365 ft, 245 ft, 125 ft are selected to compare the effect of fracture length on shale oil production.

Figure 4.7, 4.8 and 4.9 show the results of the different fracture half-length on the average reservoir pressure, cumulative oil production, oil rate, and recovery factor. The graph of average reservoir pressure for different fracture half-length shows that, the reservoir pressure decreases faster in case of longer fracture half-length. The average reservoir pressure at the end of 20 years for 500 ft fracture half-length is close to the bottom hole pressure limit of 2500 psi. The reservoir average pressure stays higher with shorter fracture half-length, leading lower ultimate oil recovery factor.

Longer fracture length means higher drainage volume of reservoir and hence the well can achieve higher initial production rate which will lead a higher cumulative oil production and higher ultimate recovery factor.

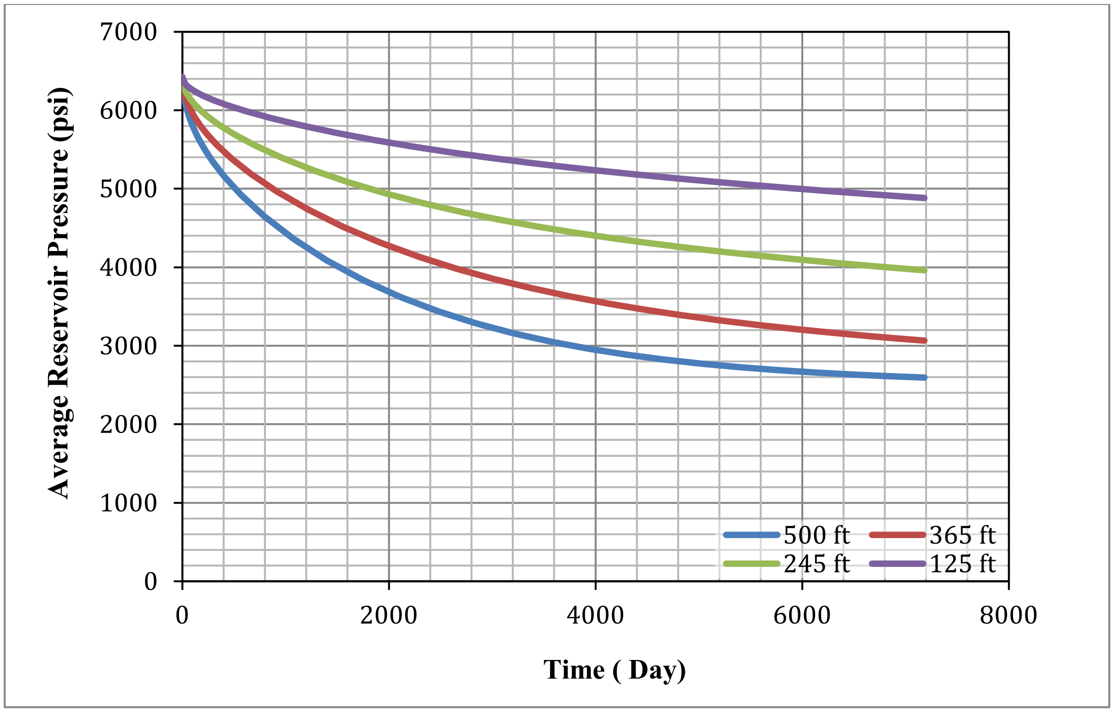


Figure 4.8 Reservoir Average Pressure vs Time (Fracture Half-length Sensitivity)

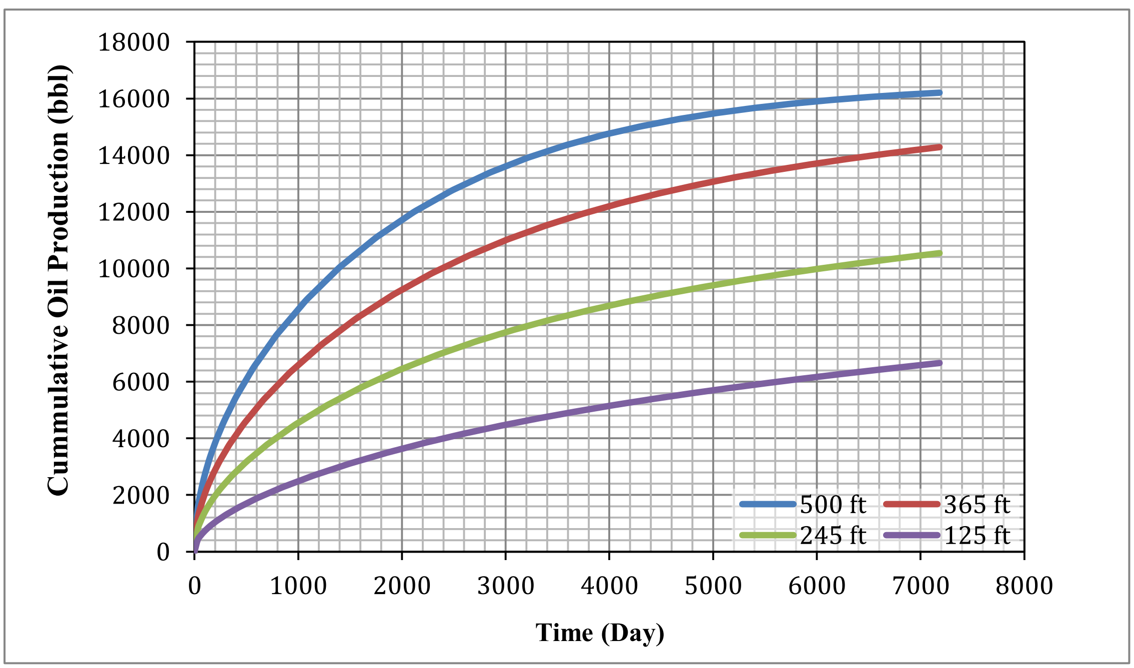


Figure 4.9 Cumulative Oil Production vs Time (Fracture Half-length Sensitivity)

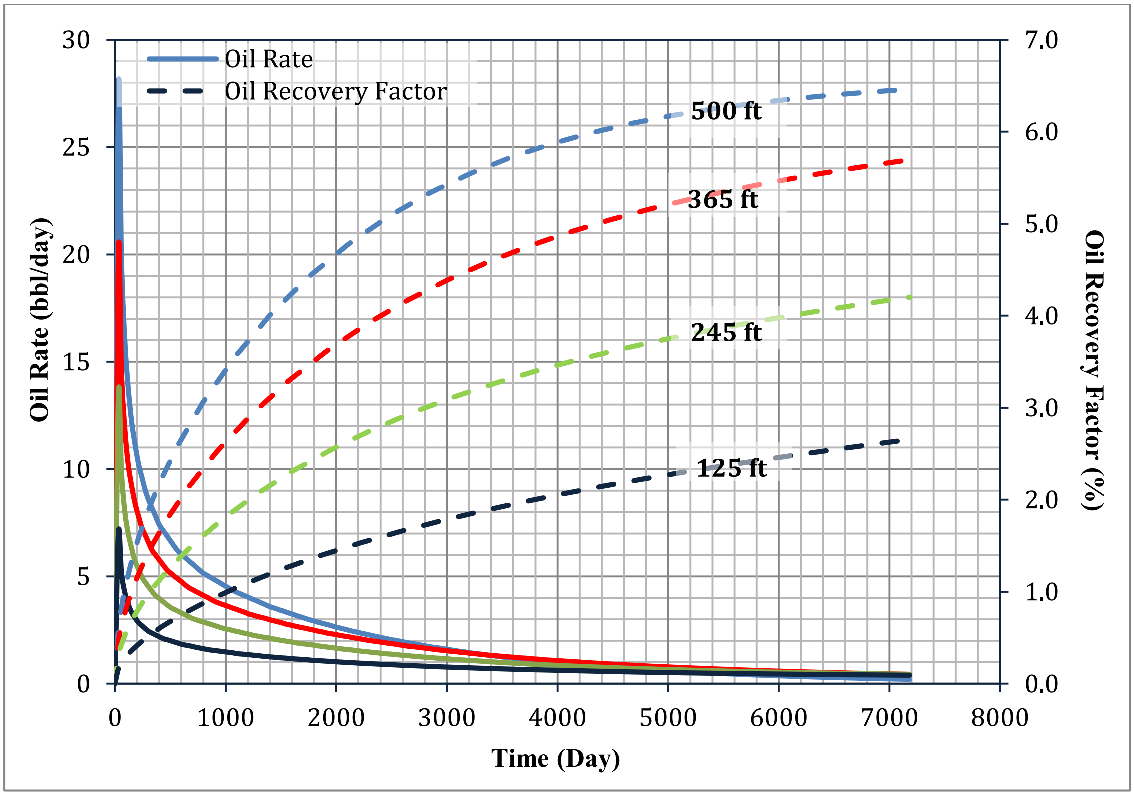


Figure 4.10 Oil rate and oil recovery factor vs. time (Fracture Half-length Sensitivity)

4.4.2 Flowing Bottom-Hole Pressure

The Eagle Ford reservoir is over-pressured and the reservoir is expected to be exploited primarily by depletion only, thus a lower flowing bottom-hole pressure (FBHP) can contribute to extra recovery from the reservoir. But in this thesis, we want to evaluate the potential of gas and water injection in shale reservoir, in order to avoid complex situation, the model was controlled by flowing bottom-hole pressure which was set up to 2500psi. The flowing bottom-hole pressure we select to test model sensitivity is 1500 psi, 1000 psi and 500 psi.

Fig 4.10 – 4.12 shows the results for the effect of different flowing bottom-hole pressure values on the cumulative oil production, recovery factor, average reservoir pressure and oil rate. With higher flowing bottom-hole pressure, lower initial oil rate can be acquired when start production. The oil recovery factor for the oil produced above the bubble-point (2500 psi case) is only 6.5%. With the bottom-hole pressure decreasing to 1500 psi, 1000 psi and 500 psi, the oil recovery factor augment to 11.78%, 12.51%, and 12.99%. As expected, with lower flowing bottom-hole pressure, higher cumulative oil production can be achieved.

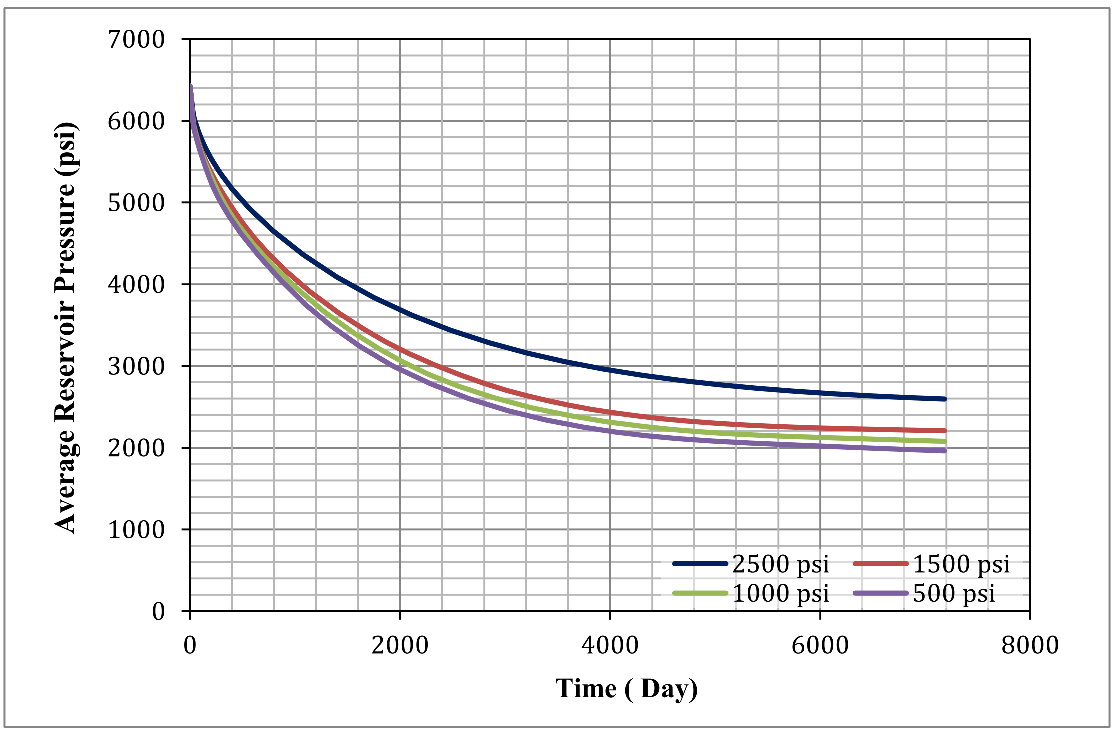


Figure 4.11 Reservoir Average Pressure vs Time (Flowing Bottom-hole Pressure Sensitivity)

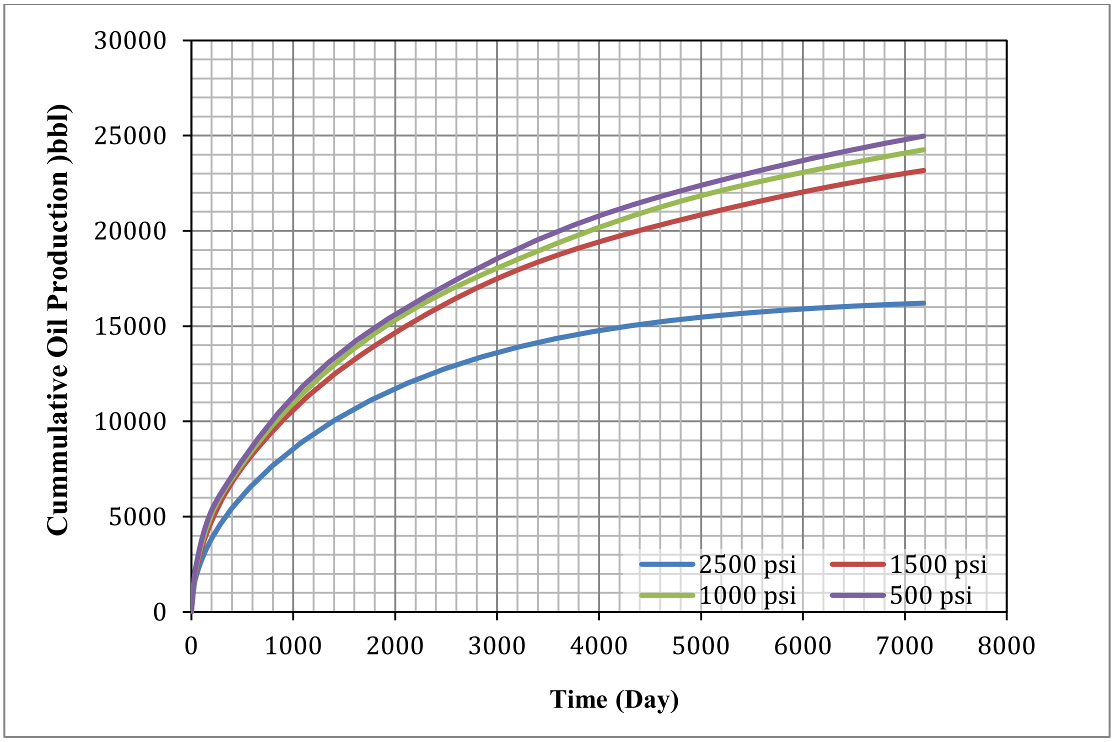


Figure 4.12 Cumulative Oil Production vs Time (Flowing Bottom-hole Pressure Sensitivity)

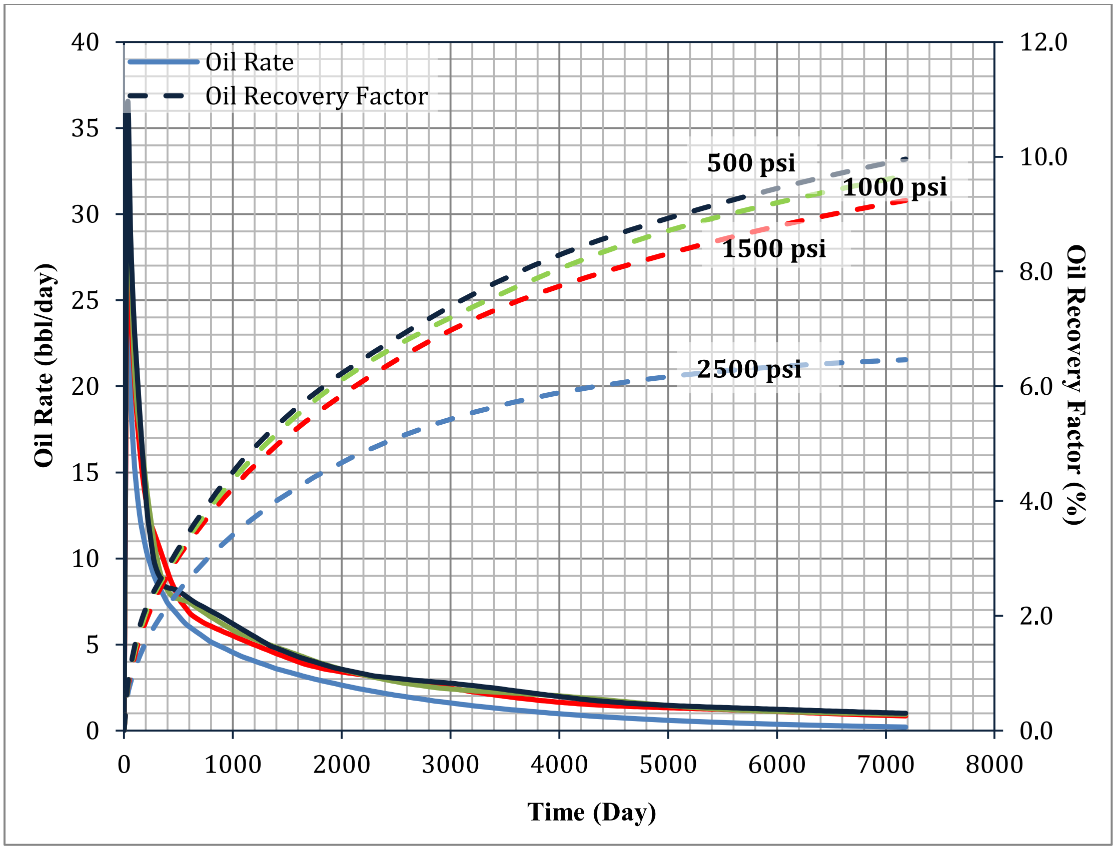


Figure 4.13 Oil Rate and Oil Recovery Factor vs Time (Flowing Bottom-hole Pressure Sensitivity)

4.4.3 Rock Compressibility

Though the general rock compressibility curves for sandstone and limestone reservoirs were provided by Hall's (Hall, 1953), shale rock compressibility values and particularly for the Eagle Ford shale could not be found in the published literature. According to Hsu and Nelson's work (2002), they expected the compressibility of the Eagle Ford shale to be on higher side because of the high amount of smectite (50%) in the clay minerals (38-88%).

Figure 4.13-4.15 shows the effect of different rock compressibility values on the cumulative oil production, recovery factor, average reservoir pressure and oil rate. The rock compressibility value used in the base case simulation is $5*10^{-6}$ psi^{-1}. And then we selected three another compressibility values of $15*10^{-6}$ psi^{-1}, $30*10^{-6}$ psi^{-1}, and $1*10^{-6}$ psi^{-1}.

From the graph below, we can figure out that the reservoir pressure decrease more rapidly when the reservoir is found to be more compressible. So a reservoir which is more compressible may have a higher cumulative oil production and higher final oil recovery factor.

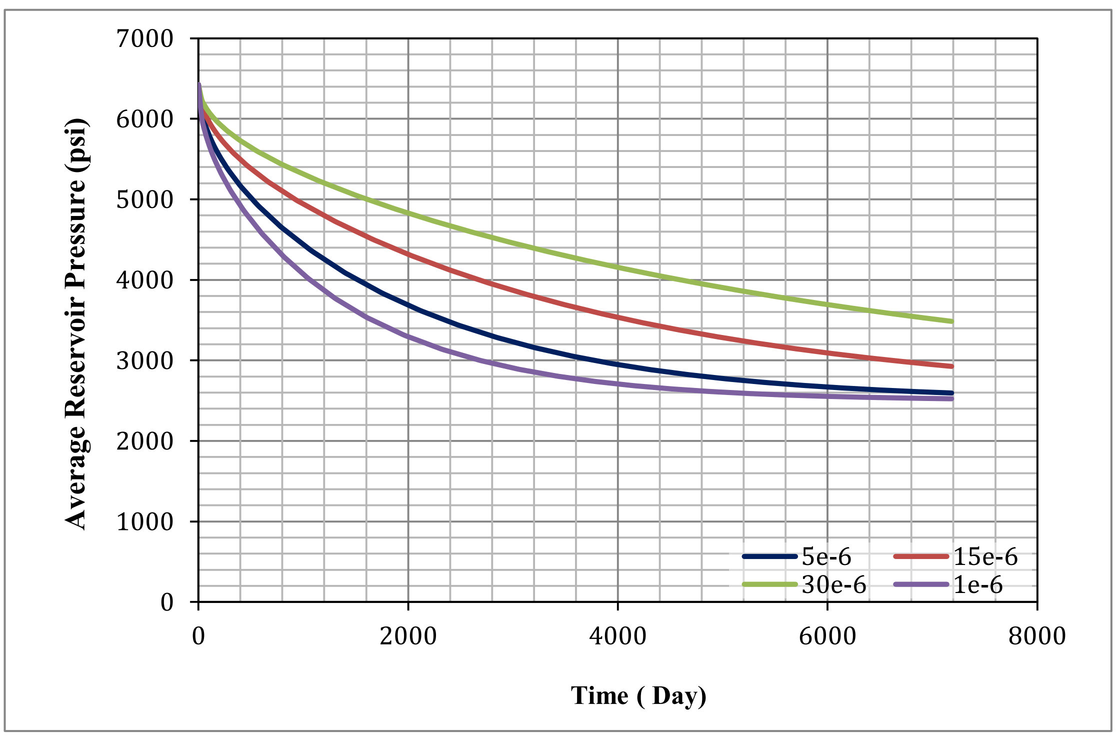


Figure 4.14 Reservoir Average Pressure vs Time (Rock Compressibility Sensitivity)

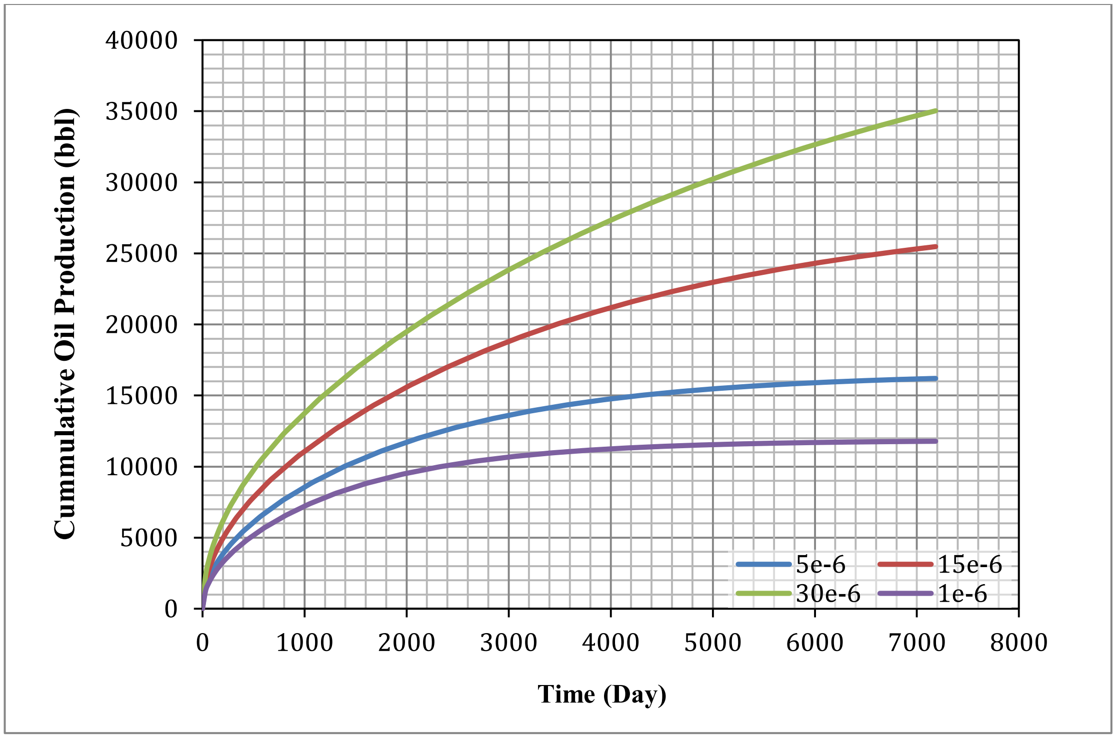


Figure 4.15 Cumulative Oil Production vs Time (Rock Compressibility Sensitivity)

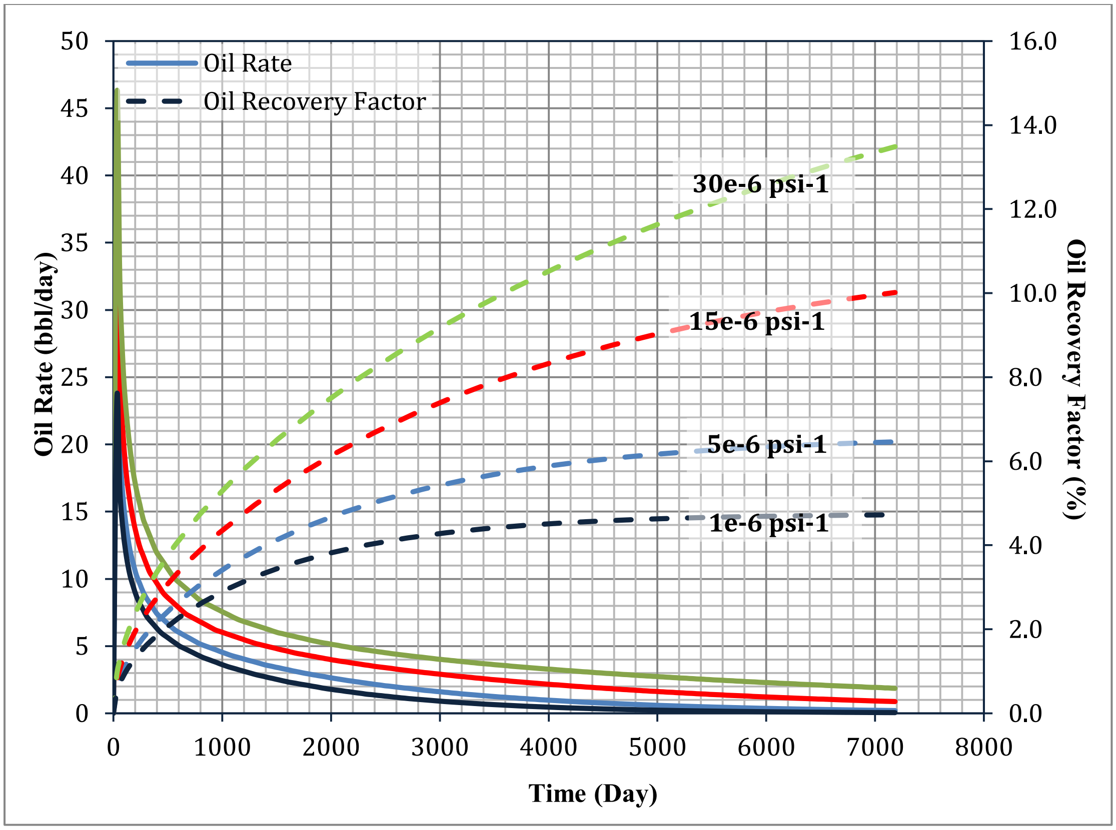


Figure 4.16 Oil Rate and Oil Recovery Factor vs Time (Rock Compressibility Sensitivity)

4.4.4 Matrix Permeability

Figs 4.16-4.18 show the results for different matrix permeability, k, values on the cumulative oil production, recovery factor, average reservoir pressure, and oil rate. The permeability value used in the base model is $1*10^{-4}$ md (100 nano-darcy). Another three permeability values of 1.10^{-3} md, 5.10^{-4} md and 5.10^{-5} md are selected in matrix permeability sensitivity analysis.

Because base model is controlled by bottom hole pressure which is set up to 2500 psi, so the average reservoir pressure for these four cases cannot be lower than

2500psi. Although the reservoir pressure is controlled to 2500 psi and the final oil recovery factor stays close for all cases, the advantage of higher matrix permeability can be pointed out easily. In case of $5*10^{-5}$ md, after 20 years production, the average pressure was not lowered much. But with higher matrix permeability, the reservoir pressure can decline rapidly to the 2500 psi limit set for the flowing bottom-hole pressure as showed in $1*10^{-3}$ md and $5*10^{-4}$ md case.

The cumulative oil production and oil recovery factor results show that at the end of 20 years production, 6.5% and 5.7% oil recovery can be obtained from $1*10^{-4}$ md and $5*10^{-5}$ md cases respectively. But for higher matrix permeability cases such as $1*10^{-3}$ md and $5*10^{-4}$ md, to get the same oil recovery, only two and four years are needed. Higher matrix permeability means better hydraulic conductivity, leading higher initial oil rate and higher cumulative oil production.

The matrix permeability is an important parameter and must be determined accurately. The recovery from the formation with various permeability can be distinctly different. Shale permeability can be quite difficult to quantify. Core measurements are typically orders of magnitude lower than the effective shale permeability, but a conventional formation test or buildup test is not possible with such low permeability. Mohamed, et al (2011) showed that analysis of fracture calibration tests may provide shale permeability, particularly if the test uses a very low injected volume.

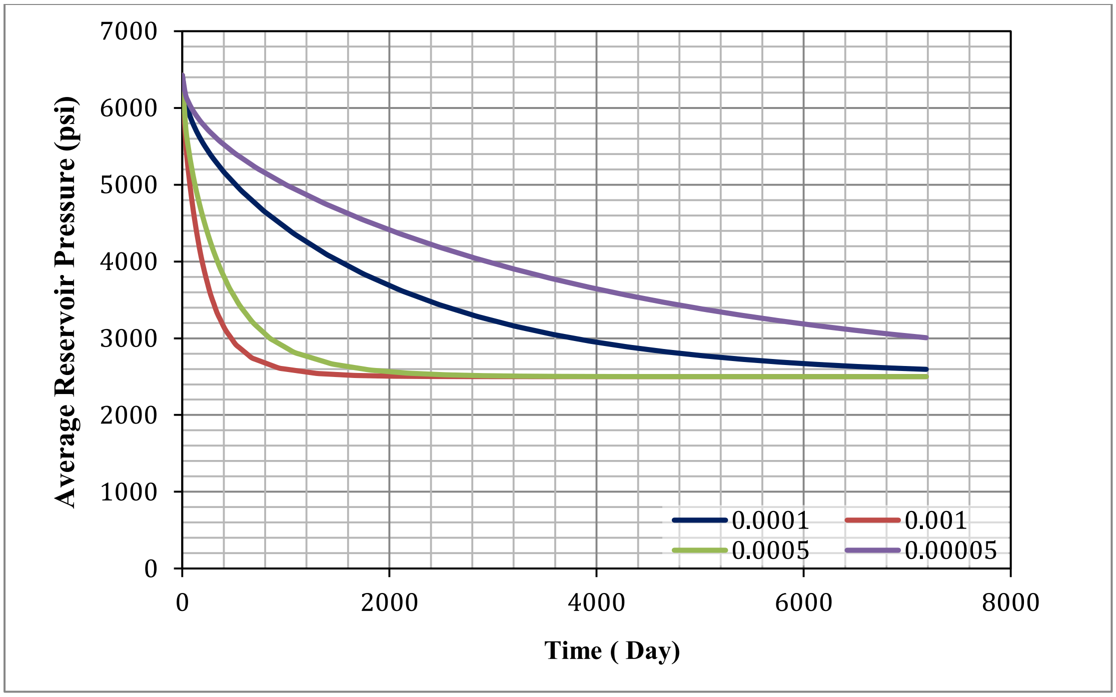


Figure 4.17 Reservoir Average Pressure vs Time (Matrix Permeability Sensitivity)

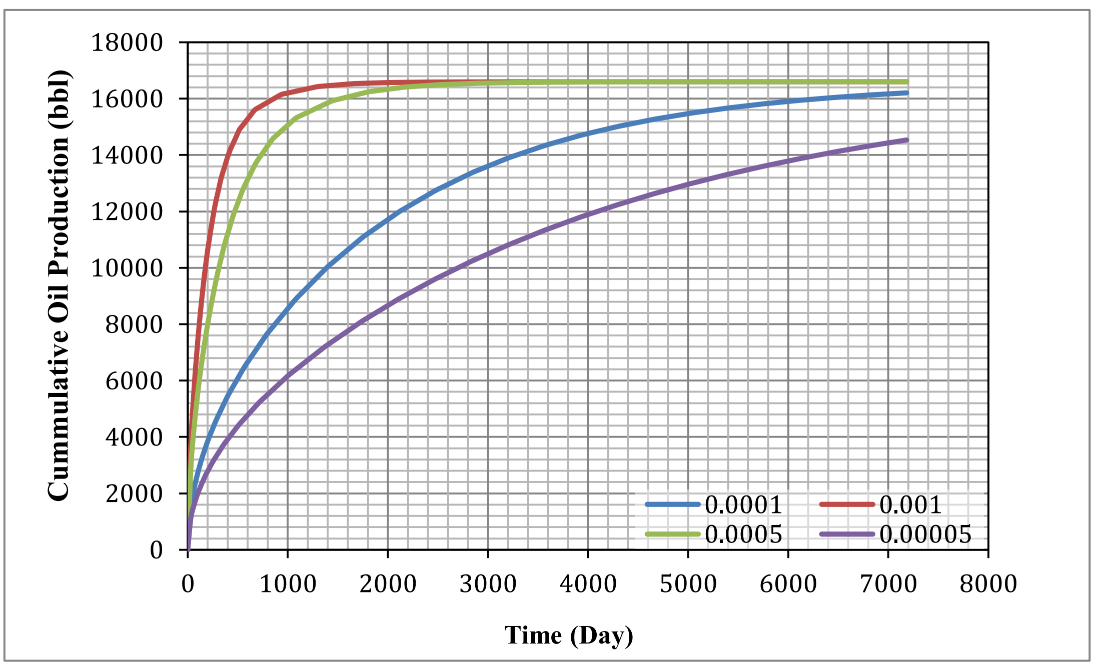


Figure 4.18 Cumulative Oil Production vs Time (Matrix Permeability Sensitivity)

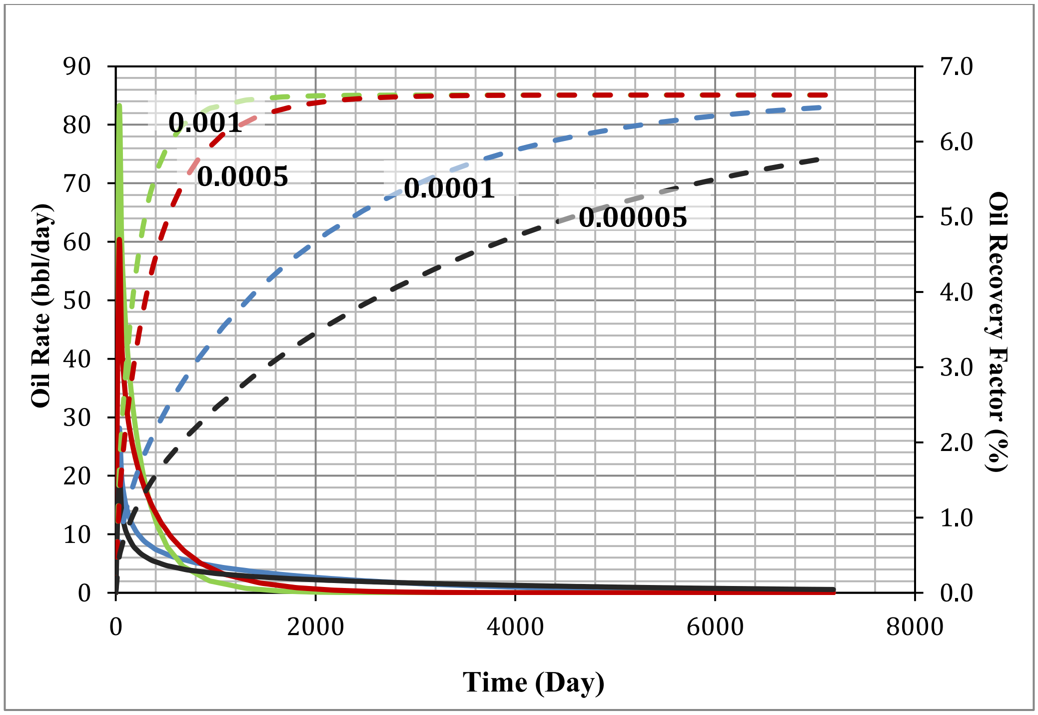


Figure 4.19 Oil Rate and Oil Recovery Factor vs Time (Matrix Permeability Sensitivity)

This chapter introduces our base simulation model, describes the validation results, and illustrates sensitivity to key parameters affecting the production of the shale oil from the stimulated reservoir volume including fracture half-length, rock compressibility, flowing bottom-hole pressure, and matrix permeability.

CHAPTER 5

MISCIBLE GAS FLOODING SIMULATION

Oilfield development is usually divided into primary, secondary and tertiary production stages. Enhanced oil recovery belonging to secondary and tertiary production stages is any process that injecting water, gas, chemicals or heat energy into an oil reservoir, to increase the amount of crude oil that can be extracted from an oil field. Enhanced oil recovery techniques will be implemented after several years' primary production when reservoir energy is depleted, the reservoir pressure declines and consequently the oil production rate decreases. Typically, in conventional oil reservoir, the amount of oil that can be extracted with primary drive mechanisms is about 20-30% and by secondary and tertiary recovery can go up more than 50% of the original oil in place (OOIP). This thesis focuses on the potential of using conventional EOR techniques to improve oil recovery from shale oil reservoirs which have ultra-low permeability. In this chapter we will talk about the determination of miscibility parameter, injection pressure upper limit, the results of gas injection and water injection simulation, and evaluation of gas flooding and water flooding potentials in the development of shale oil resources.

5.1 Miscibility Parameter Determination

The objective of miscible displacement is to reduce the residual oil saturation through the complete elimination of the interfacial tension (IFT) between oil and the displacing fluid (solvent). This is achieved if oil and the displacing fluid are miscible;

they mix together in all proportions to form one single-phase. Miscibility can be obtained on first contactor through multiple contact. Todd and Longstaff (1972) proposed a method of simulating miscible displacement performance without considering detailed compositions. Their method involves modifying the physical properties and the flowing characteristic of the miscible fluids in a three-phase black-oil simulator. They introduced a mixing parameter ω, which determines the amount of mixing between the miscible fluids within a grid block. A value of zero corresponds to the immiscible displacement, whereas a value of one corresponds to complete mixing. The mixing of solvent and oil is controlled by a pressure-dependent mixing parameter, ω_o (Omegaos). When the block pressure is so much lower than the minimum miscibility pressure (MMP) that ω_o= 0.0, solvent is displacing oil immiscibility. As the block pressure increases, this mixing parameter reaches its maximum value ω_{omax} at the MMP. The maximum value ω_{omax}, however, cannot be estimated adequately. There is only a limited amount of published material to aid in this estimation. When no better data is available, the CMG manual suggests a value in the range of 0.5 to 0.8 as a first approximation. ω_o is considered to be a function of pressure and is entered as such a function on the PVTS keyword[21].

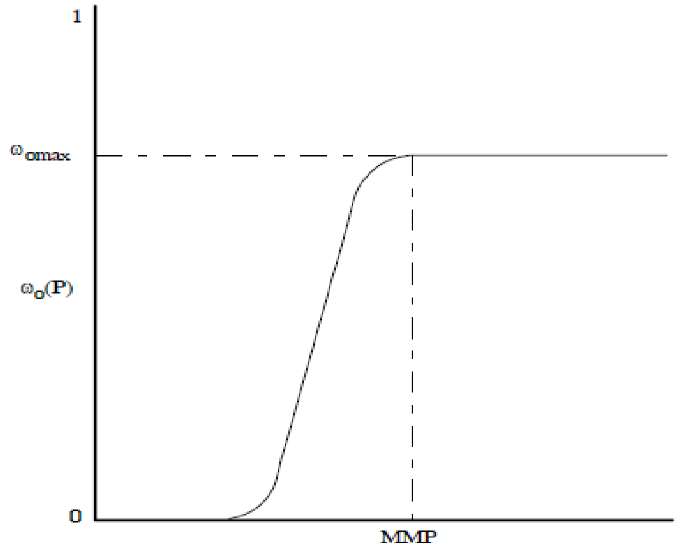


Figure 5.1 ω versus P

5.2 Breakdown Pressure Determination

In our work, gas and water injection are applied in unconventional reservoir which has ultra-low permeability, thus higher injection pressure may be needed for an efficient injection. To safely and efficiently inject fluids into reservoir, an accurate prediction of the fracture initiation pressure is a necessary requirement.

The commonly used model for fracture initiation pressure determination makes use of the ratio of the horizontal effective stress and the vertical stress as a function of the Poisson's ratio. In-situ stresses are the stresses within the formation, which act as a compressive on the formation. Vertical stress which is also called overburden stress is simply the sum of all the pressures induced by all the different rock layers. Therefore, if there has been no external influences- such as tectonics and the rocks are behaving elastically, the vertical stress σ_v , at any given depth H, is given by :

$$\sigma_v = \sum_{0}^{H} \rho_n g h_n \tag{5.1}$$

Where ρ_n is the density of rock layer n, g is the acceleration due to gravity and h_n is the vertical height of zone n, such $h_1+h_2+\ldots+h_n=H$. This is often expressed more simply in terms of an overburden gradient, g_{ob}:

$$\sigma_v = g_{ob} H \quad (5\text{-}2)$$

The stress at any point near the wellbore can be resolved into three principal stresses: vertical, radial and tangential stresses. From Deily and Owens (1969) we can get expressions for the radial and tangential stresses induced by a pressure in the wellbore p_w, at a radius R, from the center of the well (wellbore radius r_w):

$$\sigma_r = -\left[p_w - \alpha(p_r + p_w - p_R)\right]\left(\frac{{r_w}^2}{R^2}\right) + \left(1 + \frac{{r_w}^2}{R^2}\right)\sigma_v \tag{5.3}$$

And

$$\sigma_t = \left(p_w - p_r\right)\left(\frac{{r_w}^2}{R^2}\right) + \left(\frac{v}{1-v}\right)\left(1 - \frac{{r_w}^2}{R^2}\right)\left(p_{ob} - p_r\right) \tag{5.4}$$

Where p_R is the pressure at a radius R from the center of the well, α is Biot's poroelastic constant, p_r is the reservoir pressure and p_{ob} is the overburden pressure. At the wellbore face, the stresses due to wellbore pressure will be at a maximum. Also, this is by definition the point at which the fracture initiates. At the wellbore R→r_w and p_r→$p_w$so that:

$$\sigma_t = \left(\frac{2v}{1-v}\right)\left(g_{ob}H - \alpha p_r\right) - \left(p_w - \alpha p_r\right) \text{(5-4)and} \ \sigma_r = p_w - p_r \tag{5.5}$$

Furthermore, Barree (1996) went on to show that provided the rock does not have any significant tensile strength or plastic deformation, failure of the rock occurs when the tangential stress is reduced to zero. Therefore, from equation 5-4 with σ_t =0 and p_w equal to the breakdown pressure p_{if}, rearranging gives:

$$p_{if} = (\frac{2v}{1-v})(g_{ob}H - \alpha p_r) + \alpha p_r \tag{5.6}$$

In our case, vertical depth of reservoir is 9984 ft, reservoir pressure is 6425 psi, the overburden pressure gradient g_{ob} can be set from 1 to 1.1 psi/ft and Biot's poroelastic α is constant, which is measure of how effectively the fluid transmits the pore pressure to the rock gains. It depends upon variables such as the uniformity and sphericity of the rock, usually assumed to be 0.7 and 1 for petroleum reservoirs. Poisson's ratio "v" is defined as an elastic constant that is a measure of the compressibility of material perpendicular to the applied stress, or the ratio of latitudinal to longitudinal strain. From Eaton's published paper Poisson's ration typically has a range from 0.25-0.4 which will vary with burial depth. We select 0.35 as Poisson's ratio to estimate breakdown pressure in our case. Thus, based on the data mentioned above, initiation fracture pressure can be developed by equation 5-6. In our situation, P_{if} has a range from 10257 psi to 11481 psi, which means our injection pressure must be lower than this value to achieve a safe and efficient injection process.

5.3 Gas flooding Simulation

5.3.1 Base gas flooding model description

A 200ft long×1000ft wide×200 ft thick reservoir model which has two vertical well with two single fractures (described in Chapter 4) is selected to apply miscible

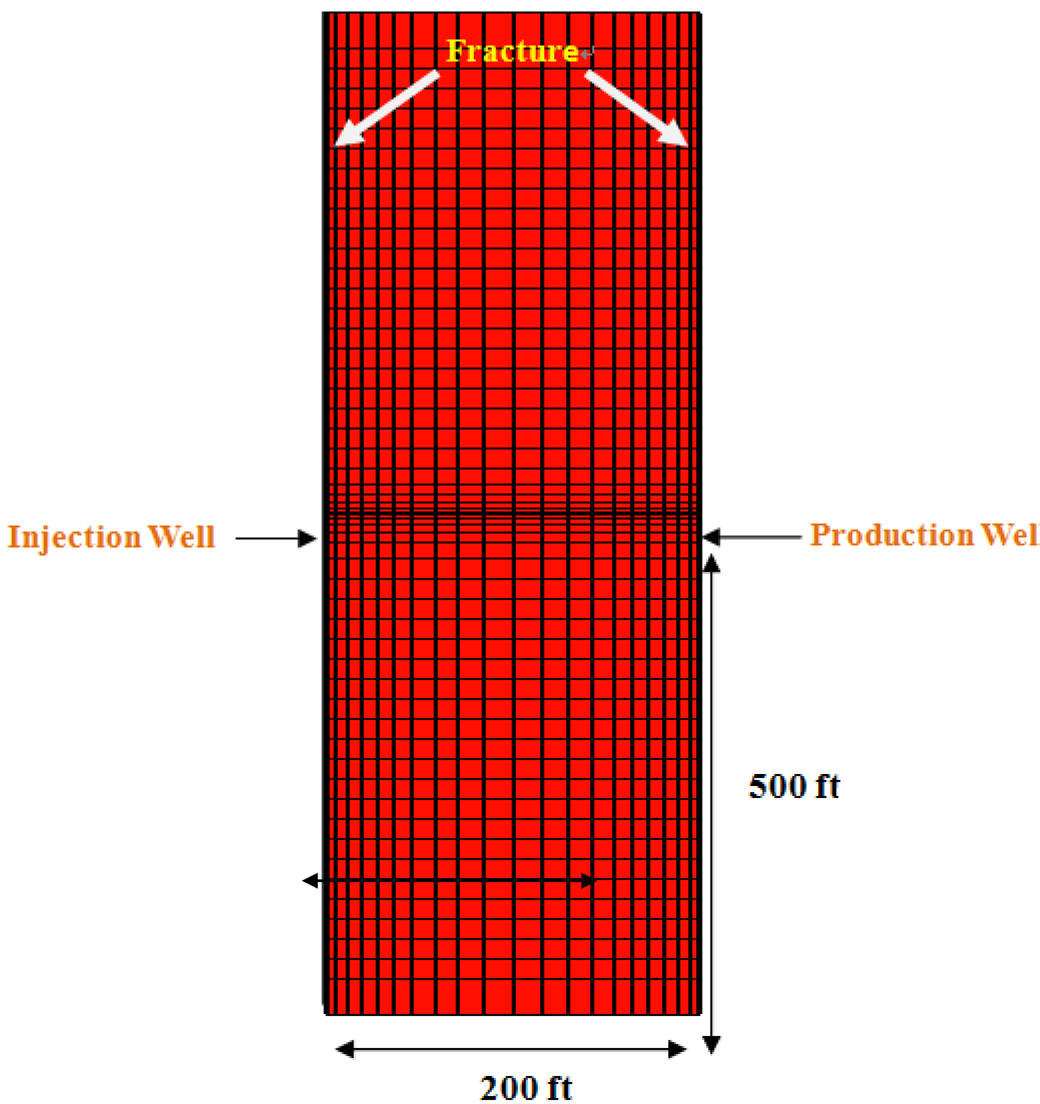


Figure 5.2 Base gas flooding model

gas injection simulation (Fig 5.2). The model uses a 4-component system which consisting of water, oil, dissolved gas and solvent. We assume that the model has constant hydrocarbon fluid composition in all simulation works, and all fluid properties are determined by oil pressure and bubble point pressure. The reservoir fluid, rock and geological parameters used in this model are from Eagle Ford Shale reservoirs. The gravity of original gas is 0.8, oil compressibility is $1*10^{-5} psi^{-1}$, rock compressibility is $5*10^{-6}$ psi^{-1}. The injected fluid is composed of 77% C1, 20% C2 and 3% C6. The mixing of solvent and free gas is governed by ω_g (OMEGASG), which is assumed pressure independent. ω_g is bounded by zero and one. Since solvent/gas has a lower mobility ratio than oil/solvent, ω_g is usually greater than ω_{omax}. In our case OMEGASG is set as 1.0, assuming solvent and free gas have a complete mixing. In this base simulation model, the maximum solvent injection rate is 400 Mscf/day and maximum injection pressure is set as 7000 psi. For the production well, the flowing bottom-hole pressure is 2500 psi. The injection well is controlled by maximum injection pressure; the well will automatically change the injection rate to keep a constant bottom-hole pressure.

Gas flooding process starts after 7200 days of primary production and a 30-year injection period is selected. As we want to evaluate the potential of gas injection in shale oil reservoir, the basic gas injection model is used to test whether applying gas injection technique in shale oil reservoir has a positive result, it is a trial process and then several other production scenarios will be measured for making the best decision.

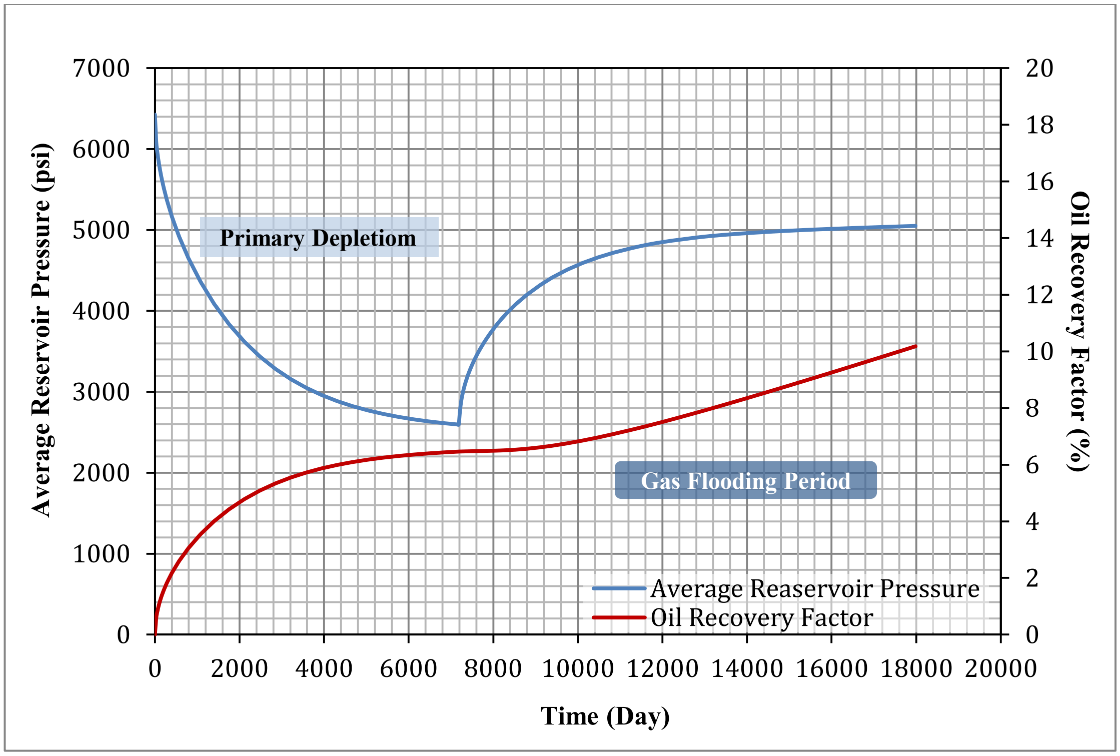


Figure 5.3 Average reservoir pressure and oil recovery factor vs time

Fig 5.3 shows the result of 7200 days primary production followed by a 30-year gas injection. In the primary production period, reservoir pressure declines from 6425 psi to 2500 psi, only 6.5% of original oil in place can be exploited out of the reservoir. When implement gas injection after primary production, reservoir pressure has an obviously increasing from 2500 psi to 5000 psi and finally 10.2% of overall recovery can be acquired.

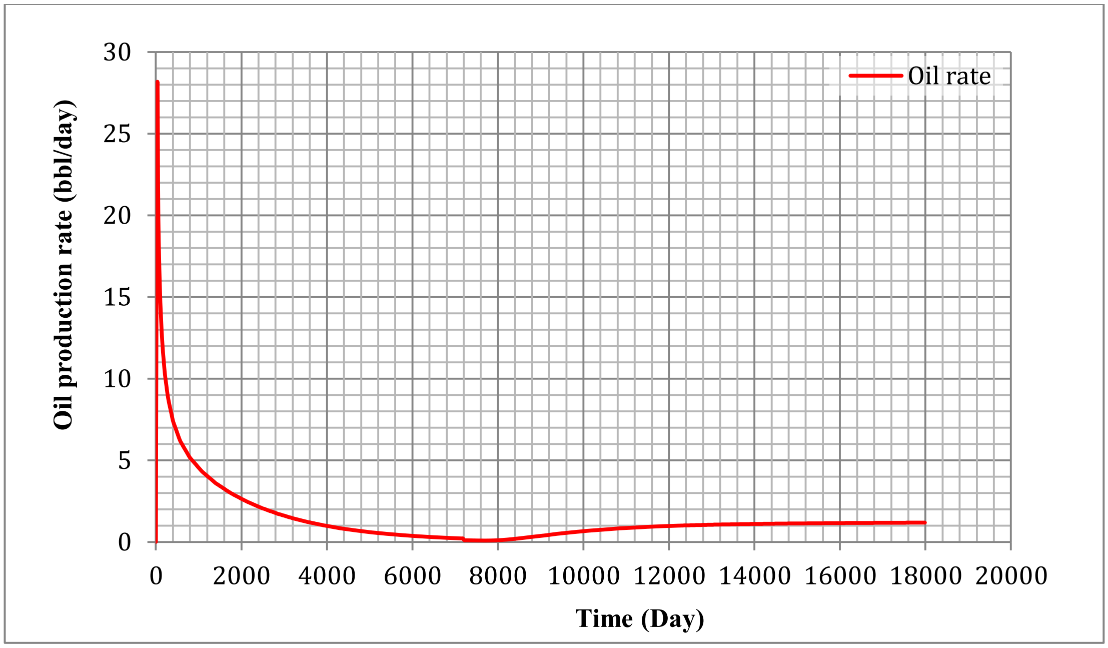


Figure 5.4 Oil production rate vs time

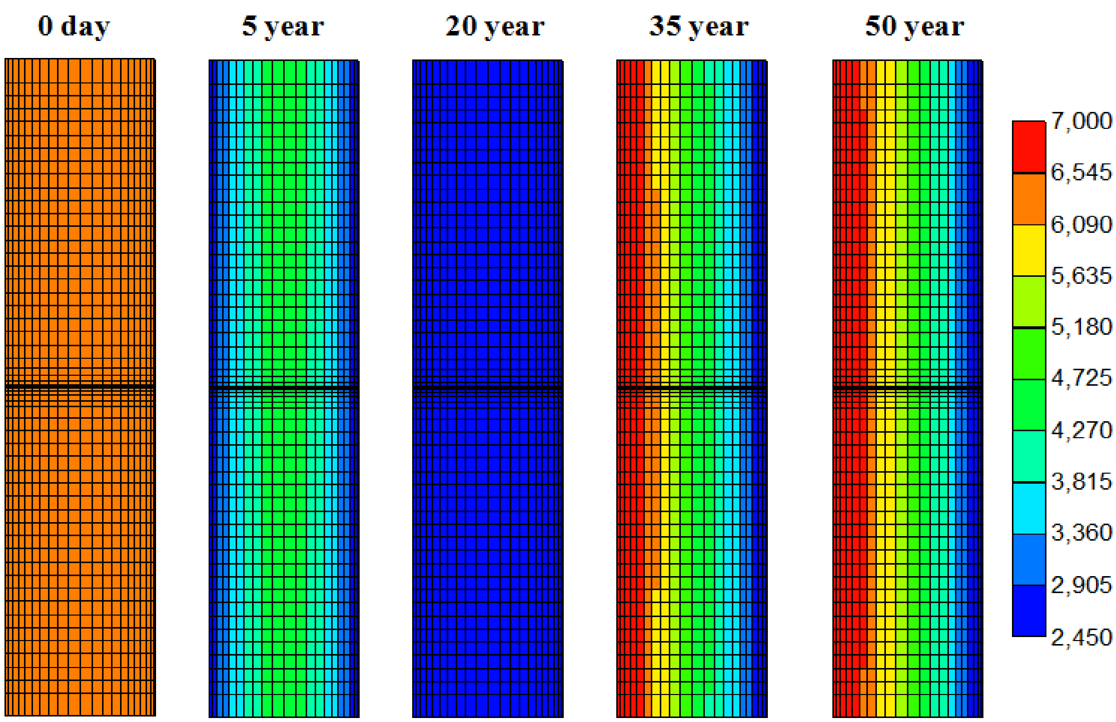


Figure 5.5 Reservoir pressure distribution as a function of time

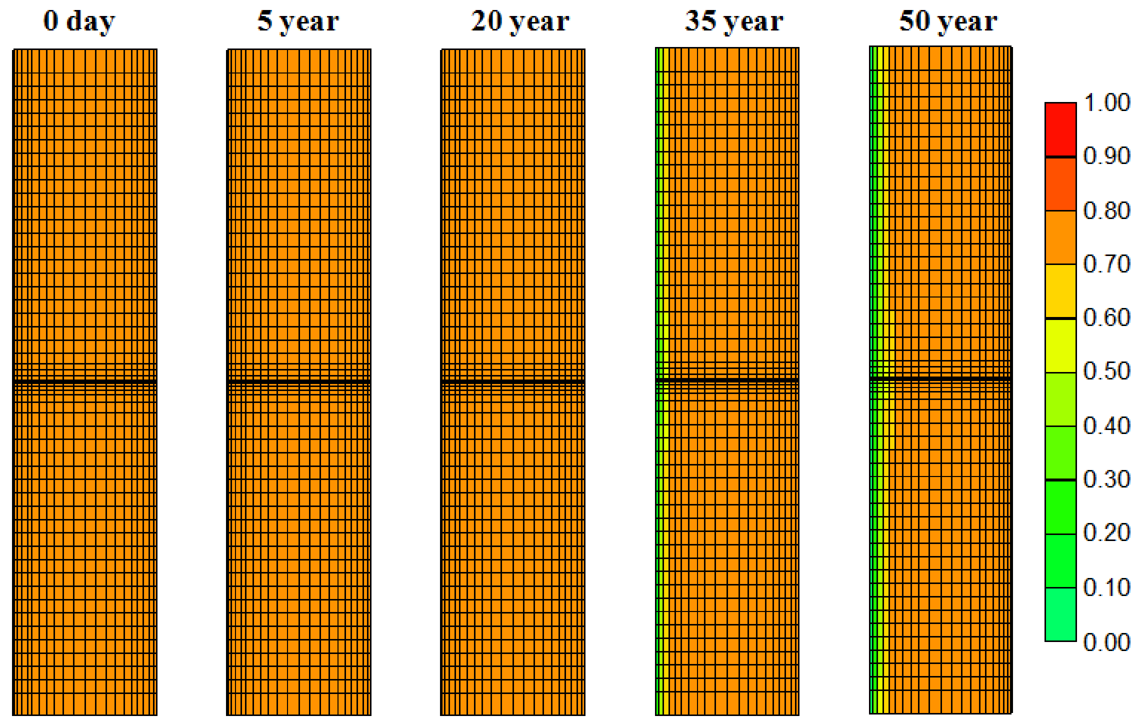


Figure 5.6 Oil saturation distribution as a function of time

Fig 5.4 shows the base gas injection case result for oil rate. In primary production period, oil rate decreases rapidly from the initial rate 27.47 bbl/day to 10.26 bbl/day after 200 days of production and to 2.72 within 5 year. The oil production rate at the end of 20 years is 0.21 bbl/day. The cumulative oil recovery after 20 years of primary production is 16.209 MSTB (Table 5.1) which corresponds to a recovery factor of 6.46.

Fig 5.5, 5.6 show the pressure variation and oil saturation distribution during the production period. When start gas injection process, the solvent will be injected into reservoir through injection well and mix with reservoir fluids, leading oil viscosity decrease. Oil is pushed away from injection well and in the meantime the reservoir pressure build up for the same time periods as shown in fig 5.5.

Table 5.1 Oil production result of base injection case

	Primary Production	GasInjection
Cumulative Oil Production (MSTB)	16.209	25.570
Overall Recovery (%)	6.46	10.19
Incremental Oil (MSTB)	NA	9.361
Incremental Recovery	NA	3.73

5.3.2 Gas flooding plan

Generally, horizontal well with multi-stage hydraulic fractures is the main technique to exploit shale resources. In this thesis, we want to evaluate whether EOR techniques which are implemented in conventional reservoirs successfully have future in shale oil reservoir. Simulation results from base gas injection model offer us positive potential of applying EOR techniques in shale oil reservoir. Because of the ultra-low permeability of shale reservoir, it is more difficult for injected materials to push reservoir fluids from injection well to production well. Thus, in our production model we extend the production time from 50 years in base model to 70 years, and we expect to find a production plan which injects less solvent for recovering more oil in the same production period.

Plan 1:3600 days of primary production & 60 years of gas flooding production

In production plan 1, gas injection start after 3600 days (10 years) of primary production. Fig 5.7, 5.8 show the results for oil recovery factor, average pressure and oil rate versus time. The reservoir pressure decreases fast from initial reservoir pressure to 3000 psi as the reservoir in mainly by depletion drive in first 10 years' primary production. Once applying gas injection, the reservoir pressure increases from 3000 psi to more than 5000 psi gradually, leading a directly augment of oil production.

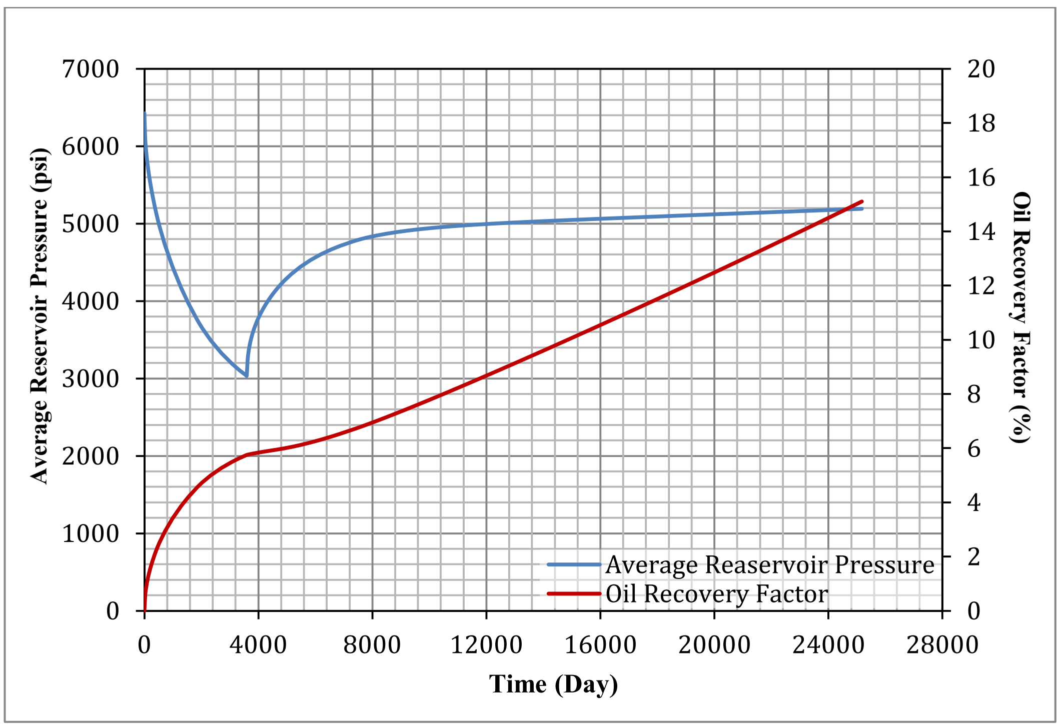


Figure 5.7 Average reservoir pressure and oil recovery factor vs time

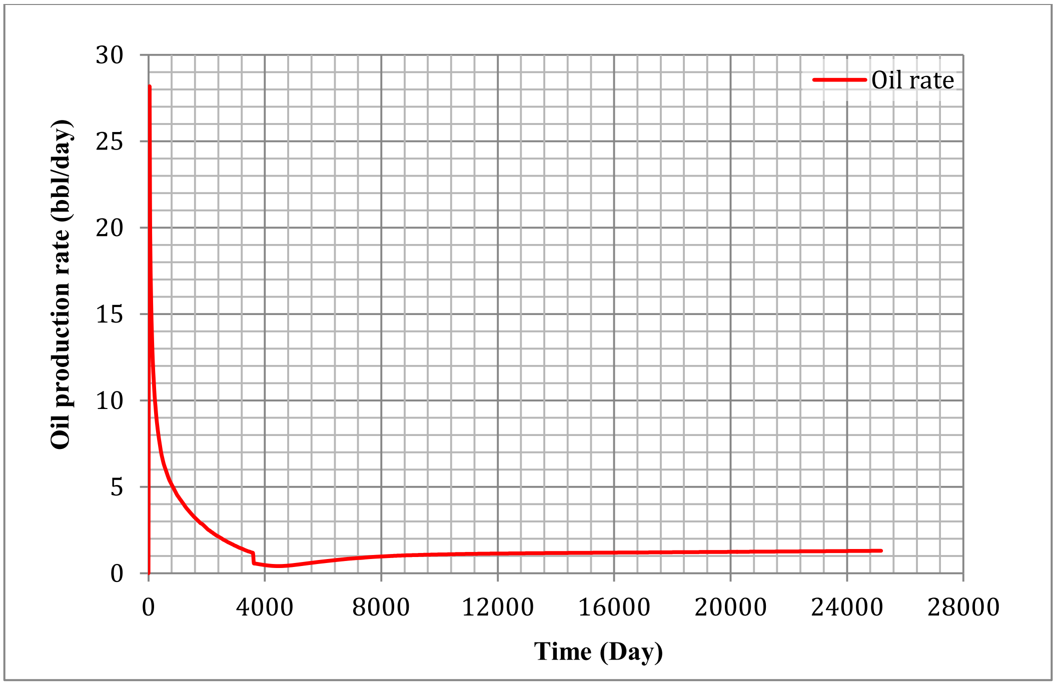


Figure 5.8 Oil production rate vs time

From oil production rate graph, the oil rate decreases from the initial rate 27.47 bbl/day to 10.26 bbl/day after 200 days of production and to 2.72 within 5 year. At the end of primary production period, the oil rate is 0.57 bbl/day. When start the gas injection process, oil rate has a small increasing trend. Finally oil rate can achieve 1.3 bbl/day. 37.912 MSTB of oil can be obtained finally, leading an oil recovery factor of 15.12% (Table 5.2).

Fig 5.9, 5.10 show the pressure variation and oil saturation distribution during the production period. When start gas injection process, the solvent will be injected into reservoir through injection well and mix with reservoir fluids, leading oil viscosity decrease. Oil is pushed away from injection well and in the meantime the reservoir pressure build up for the same time periods as shown in Fig 5.9. Due to ultra-low permeability of shale reservoir, fluids transmission in such kind of reservoirs is much more difficult than that in conventional reservoirs. This also results in small increasing of oil rate after applying gas injection.

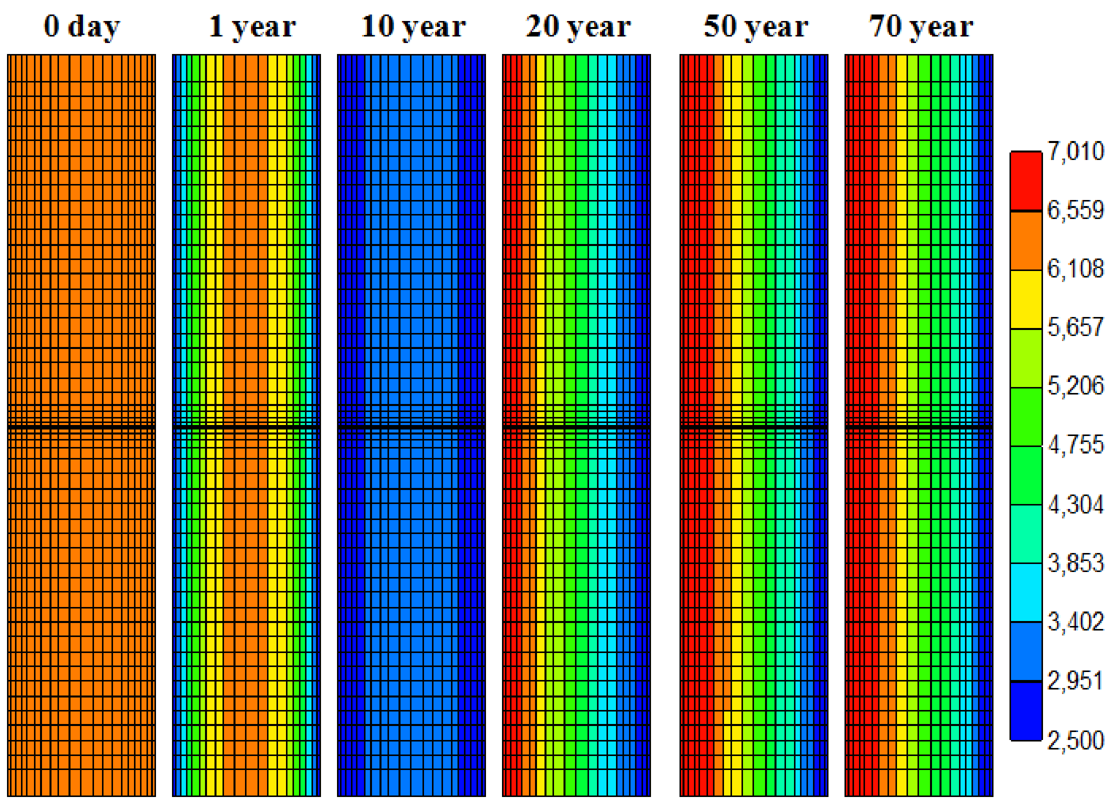


Figure 5.9 Reservoir pressure distribution as a function of time

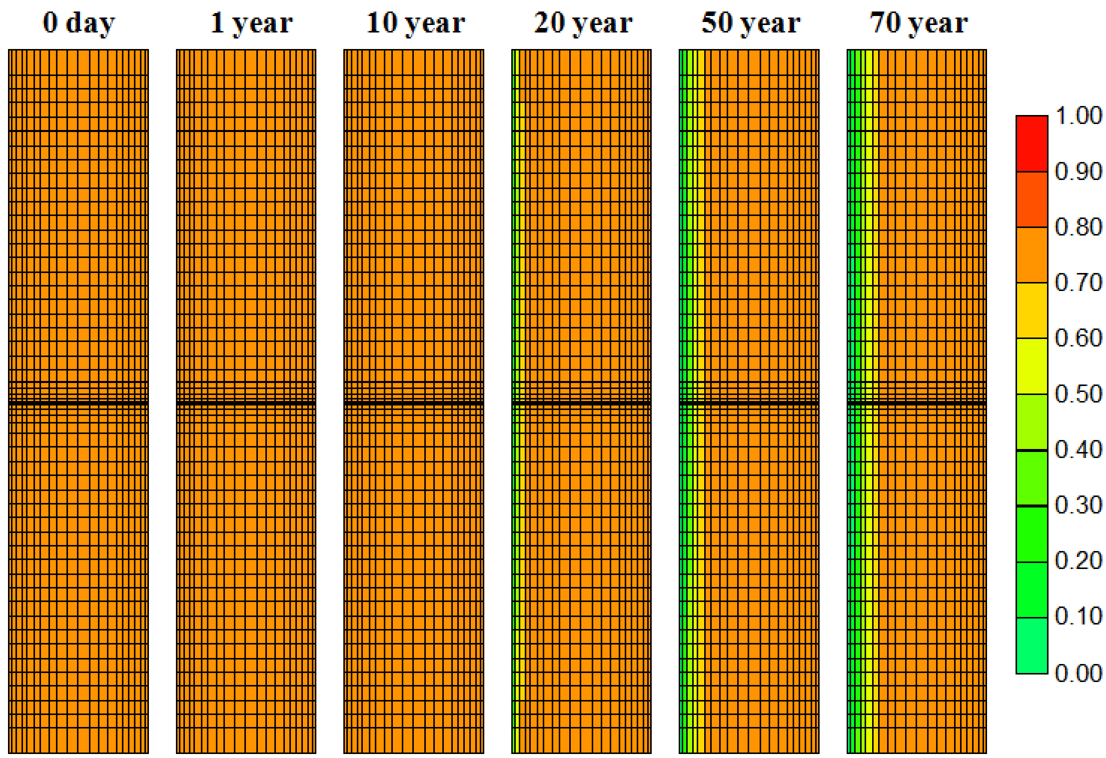


Figure 5.10 Oil saturation distribution as a function of time

Table 5.2 Cumulative oil production and solvent injection (Plan 1)

	Oil	**Solvent**
Cumulative Production	37.912 MSTB	NA
Cumulative Injection	NA	74.245 MMSCF
Overall Recovery	15.12 %	NA
Incremental Oil	21.703 MSTB	NA
Incremental Recovery	8.66 %	NA

Plan 2: 3600 days of primary production & 60 years of gas flooding production

For production plan 2, we still start gas injection after 3600 days (10 years) of primary production. In this plan, we change the injection schedule from constant injection to cyclic injection. Each injection cycle has 5 years' injection and 5 years' shut in period. Fig 5.11, shows the results for oil recovery factor, average pressure versus time. The reservoir pressure decreases from initial reservoir pressure to 3000 psi in primary production period and then begins to increase with the implementing of gas injection. We shut in injection well every 5 years, thus fluctuation growth occurs in average reservoir pressure curve. The overall recovery factor at the end of 70 years is 14.42%.

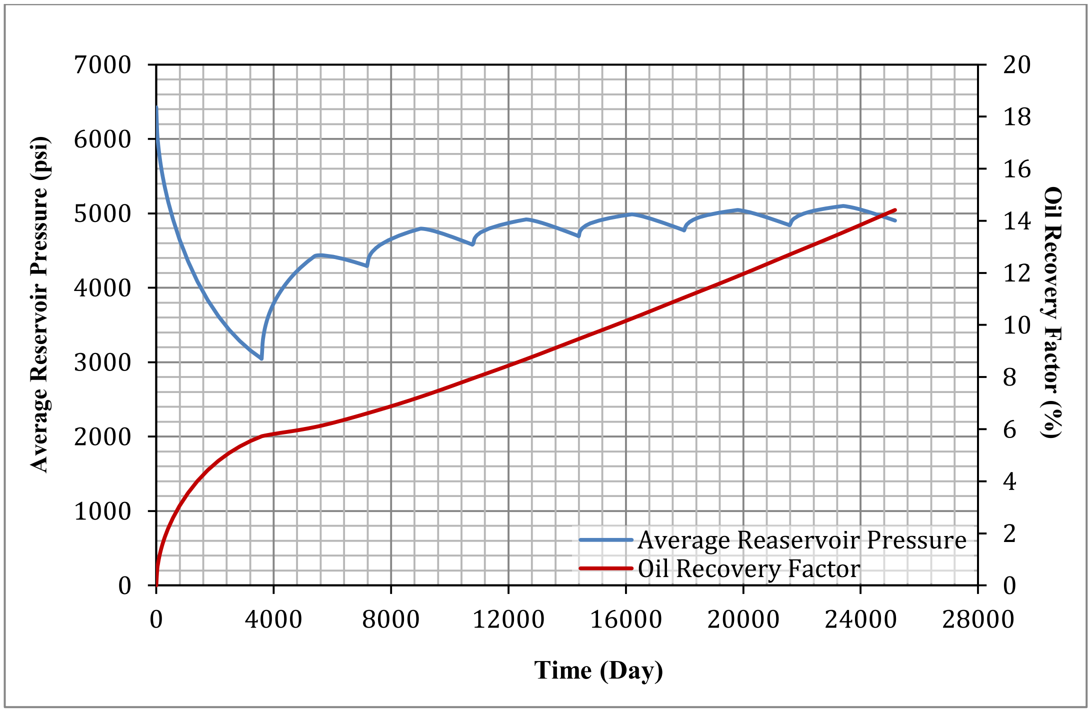


Figure 5.11 Average reservoir pressure and oil recovery factor vs time

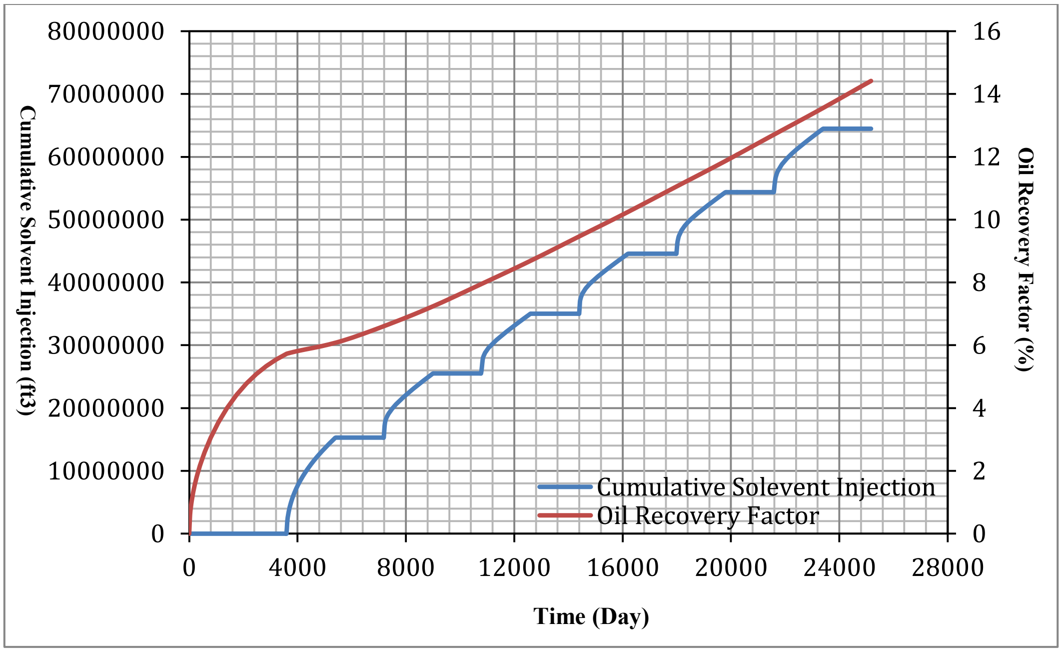


Figure 5.12 Cumulative solvent injection and oil recovery vs time

Table 5.3 Cumulative oil production and solvent injection (Plan 2)

	Oil	Solvent
Cumulative Production	36.189 MSTB	NA
Cumulative Injection	NA	64.473 MMSCF
Overall Recovery	14.42 %	NA
Incremental Oil	19.98 MSTB	NA
Incremental Recovery	7.96 %	NA

Plan 3: 70 years of gas flooding production

In production plan 3, we implement gas injection at the beginning of the development. Keep gas injection and oil production simultaneously for 70 years. Figure 5.12, 5.13 show the results for oil recovery factor, average pressure and oil rate versus time. Because we apply gas injection simultaneously with production, and reservoir pressure is very high as 6425 psi, so the initial injection rate and production rate are lower than previous plans, reservoir pressure decreases slowly from initial reservoir pressure to 5000 psi, this in turn cause a lower oil recovery factor than that of plan 1 and plan2.

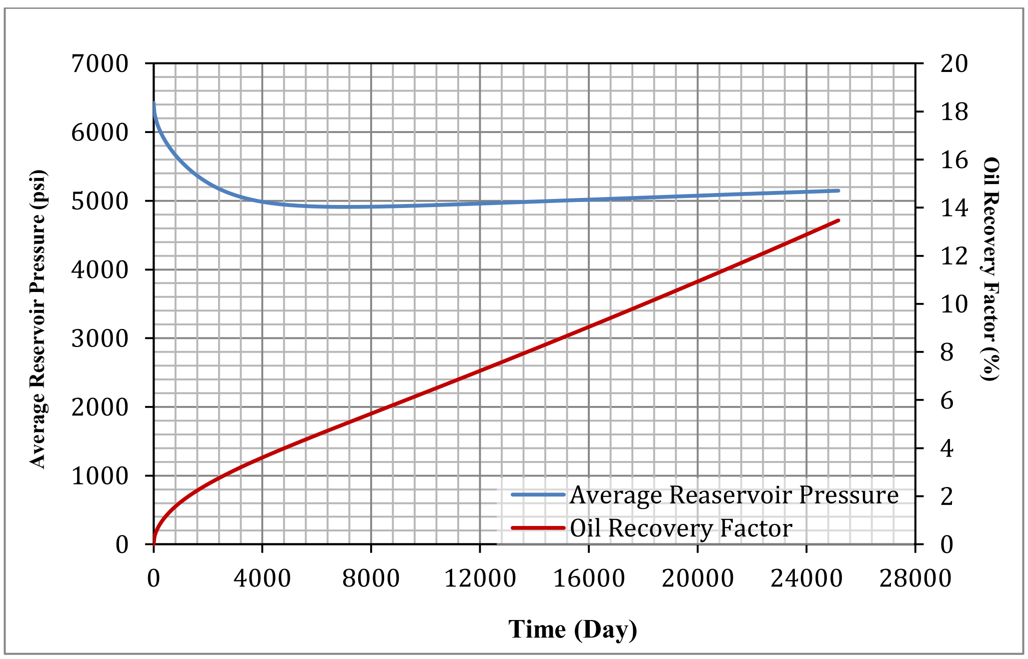


Figure 5.13 Average reservoir pressure and oil recovery factor vs time

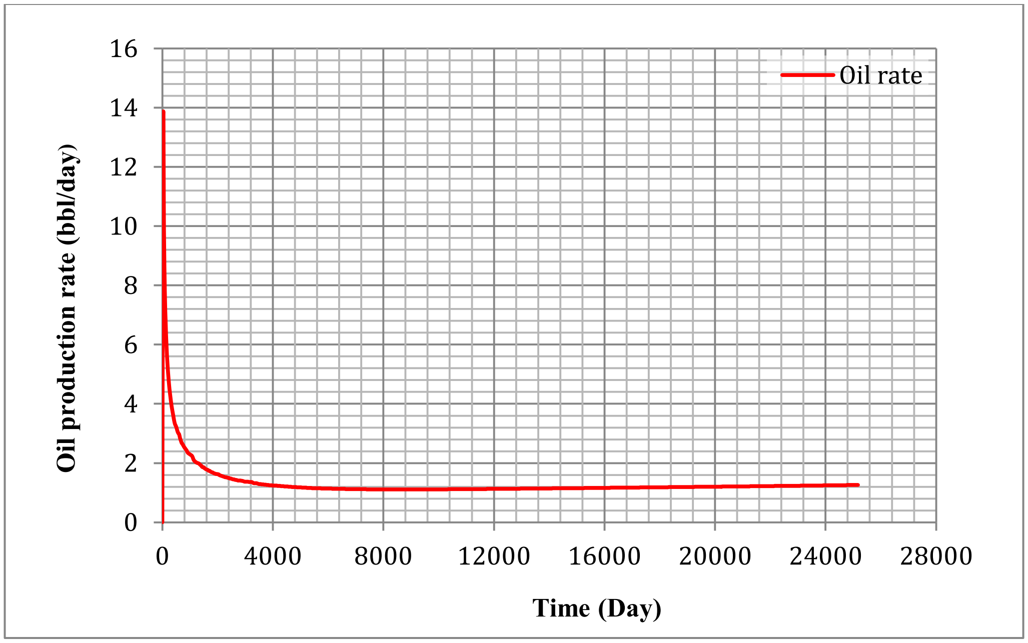


Fig 5.13 Oil production rate vs. time

Table 5.4 Cumulative oil production and solvent injection (Plan 3)

	Oil	Solvent
Cumulative Production	33.828 MSTB	NA
Cumulative Injection	NA	64.327 MMSCF
Overall Recovery	13.48 %	NA
Incremental Oil	17.619 MSTB	NA
Incremental Recovery	7.02 %	NA

We considered three production plans in this thesis, in the first plan gas is injected after 10years's primary production and then continue gas injection for 60 years, 74.245 MMSCF of gas was injected into the reservoir, producing 37.912 MSTB of oil corresponding a oil recovery factor of 15.12%. In the second plan, gas is also injected after 10 years' primary production and then applies cyclic gas injection; each injection process has 5 years' injection and 5 years' shut in period. In this process, 64.473 MMSCF of gas was used to produce about 14.42% of original oil in place. For the plan 3, gas injection is implemented at the beginning of the development. We can easily figure out that plan 3 has a lower oil production in first 10 years because only one production well is used instead of two production wells in the other two plans which directly influences the finale oil recovery. So it's not necessary to apply gas injection at the beginning of the development, implementing gas flooding after several years' natural pressure depletion will have a better stimulation result. The results of three simulation plan show that the ultimate recovery is not quite different for these three different injection plans, but less solvent is injected in plan 2 and ultimate oil recovery obtained from plan 2 is close to plan 1. Therefore, cyclic gas injection after 10 years' primary production may be an optimum decision. Generally speaking, because of the ultra-low permeability of shale reservoir, it's more difficult for injection materials transmit and displace oil than that in conventional reservoirs or tight oil reservoirs which have better condition than shale reservoirs. But through our work, positive potential of gas flooding in such kind of reservoirs is obtained, and we will continue research on more production scenario to find an optimum EOR method in shale oil reservoirs.

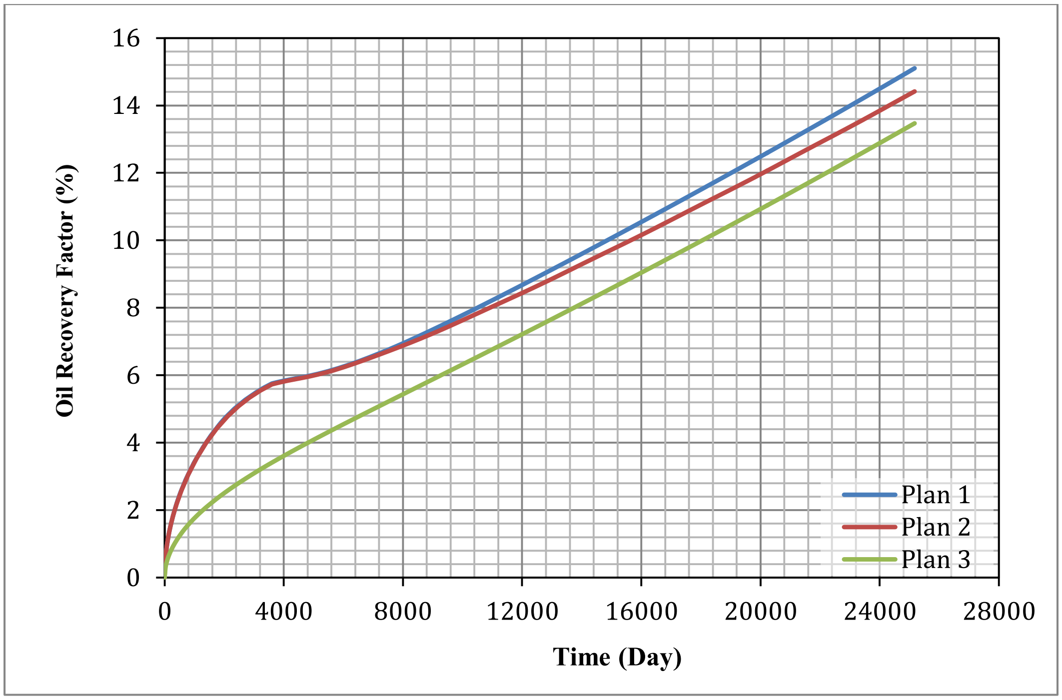


Figure 5.14 Oil recovery factor vs time

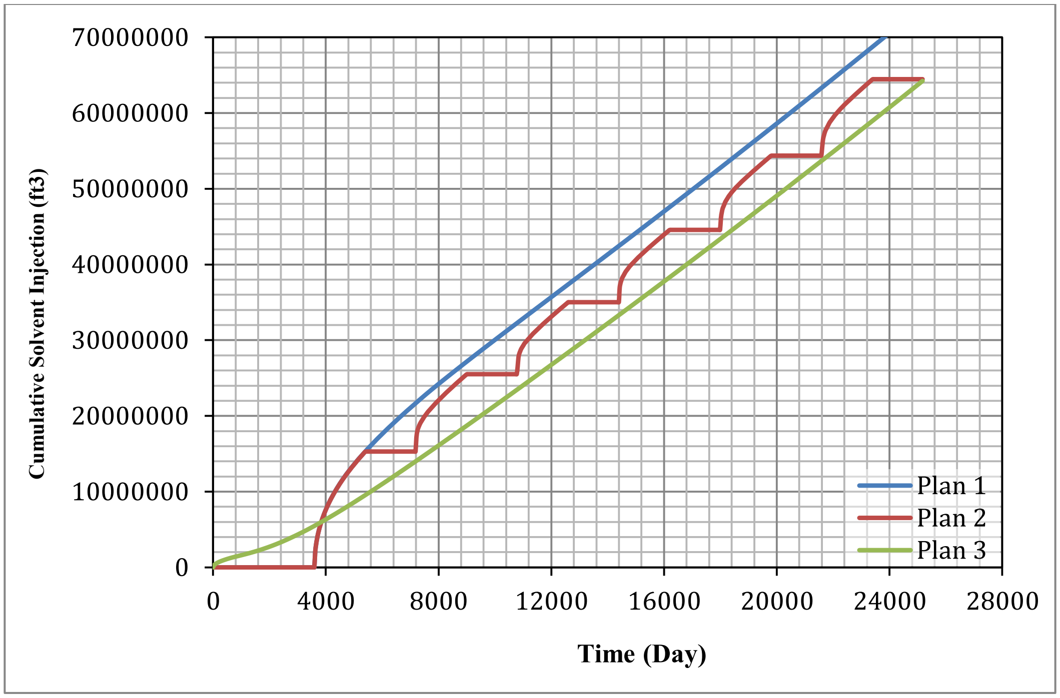


Figure 5.15 Cumulative solvent injection vs time

Table 5.5 Gas flooding simulation results

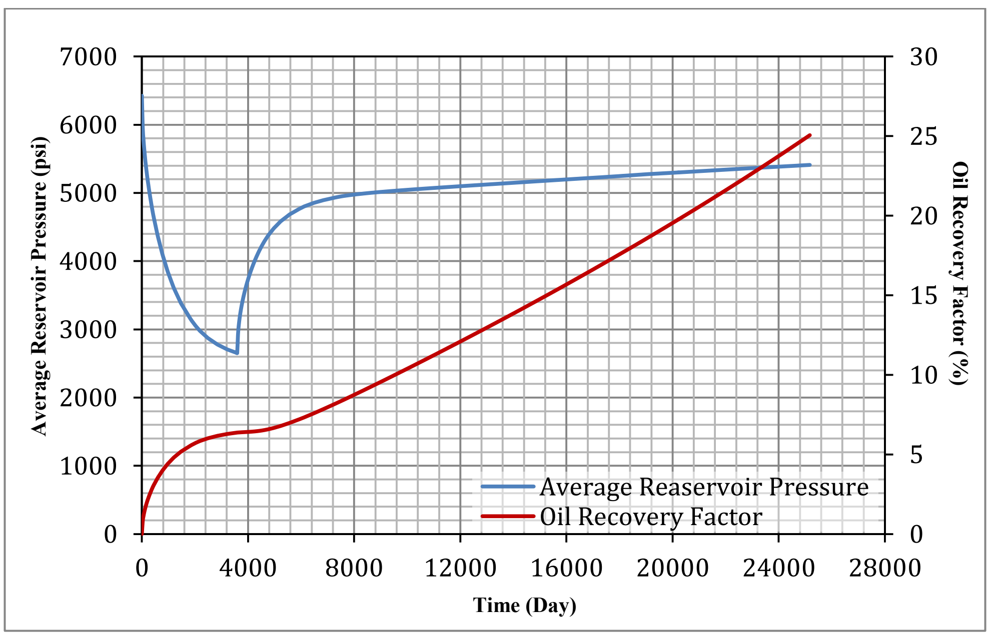
	Plan 1	**Plan 2**	**Plan 3**
Cumulative Oil Production	37.912 MSTB	36.189 MSTB	33.828 MSTB
Cumulative Gas Injection	74.245 MMSCF	64.473 MMSCF	64.327 MMSCF
Overall Oil Recovery (10 years)	5.75%	5.75%	3.4%
Overall Oil Recovery (30 years)	8.14%	7.95%	6.68%
Overall Oil Recovery (50 years)	11.49%	11.05%	9.97%
Overall Oil Recovery (70 years)	15.12%	14.42 %	13.48 %

- Plan 1: 10-year primary production & 60 years of gas flooding
- Plan 2: 10-year primary production & 60 years of cyclic gas flooding
- Plan 3: 70 years of gas flooding production

5.3.3 Other production plan test

Based on the previous simulation results of gas injection, gas flooding has a positive effect on improving oil recovery in shale oil reservoir. Typically, unconventional resources are often developed by horizontal well with multi-stage of fractures. So gas may be injected into reservoir by horizontal wells. A key question needs to be answered when complete the well is fracture spacing. So in this section we will describe two simulation cases which have different fracture spacing, offering more information for gas injection by horizontal well with multi-stage fractures.

Case 1 Fracture distance is 150 ft



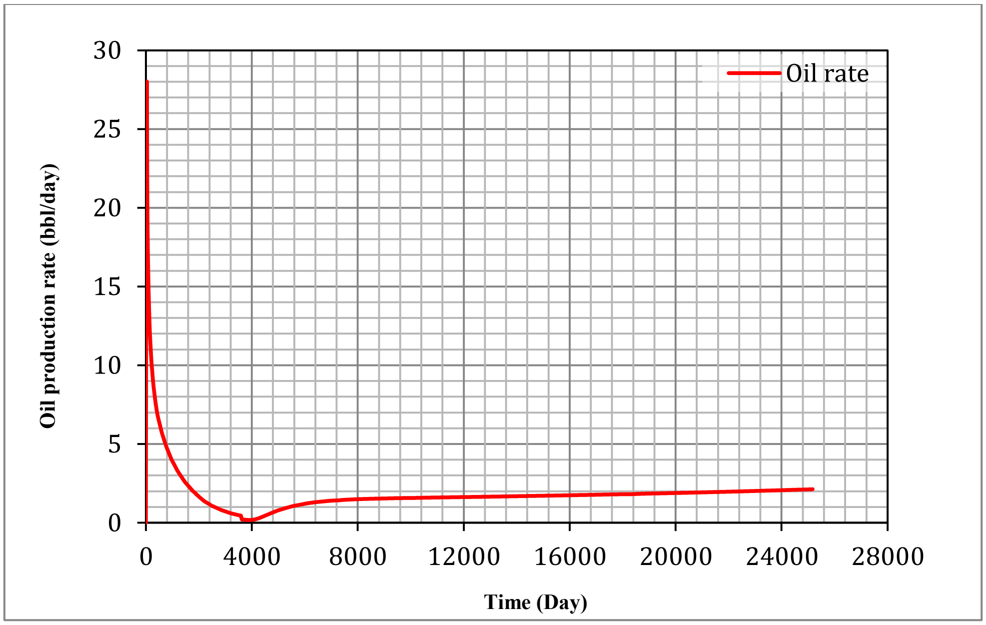
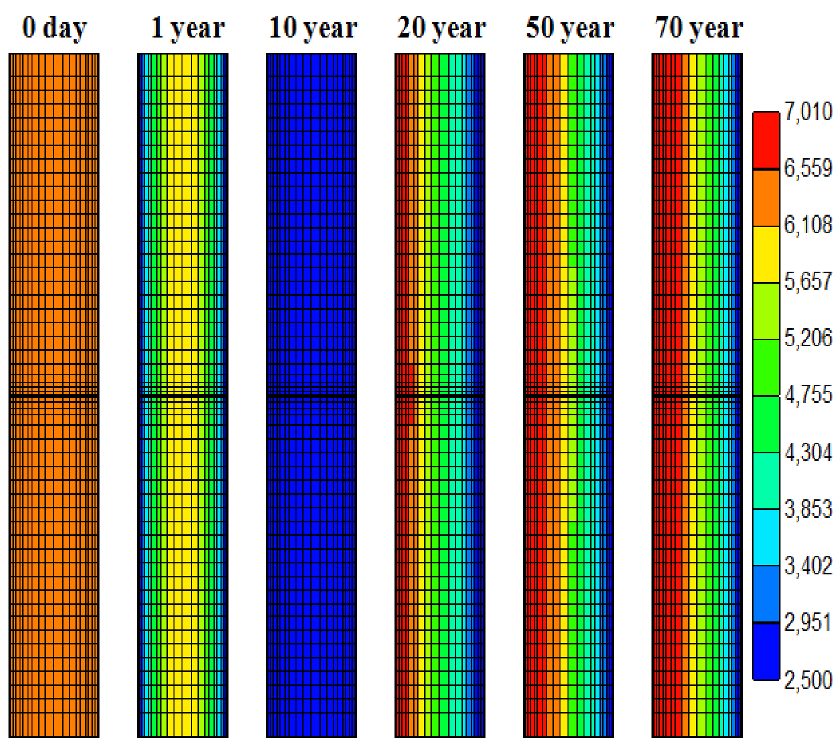


Figure 5.16 Average reservoir pressure, oil recovery factor and oil rate vs time



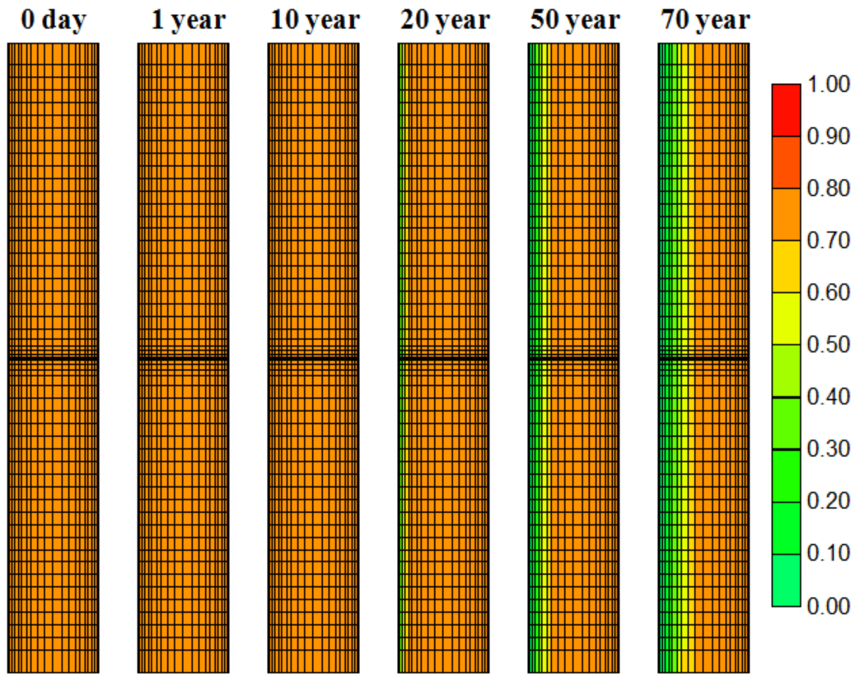


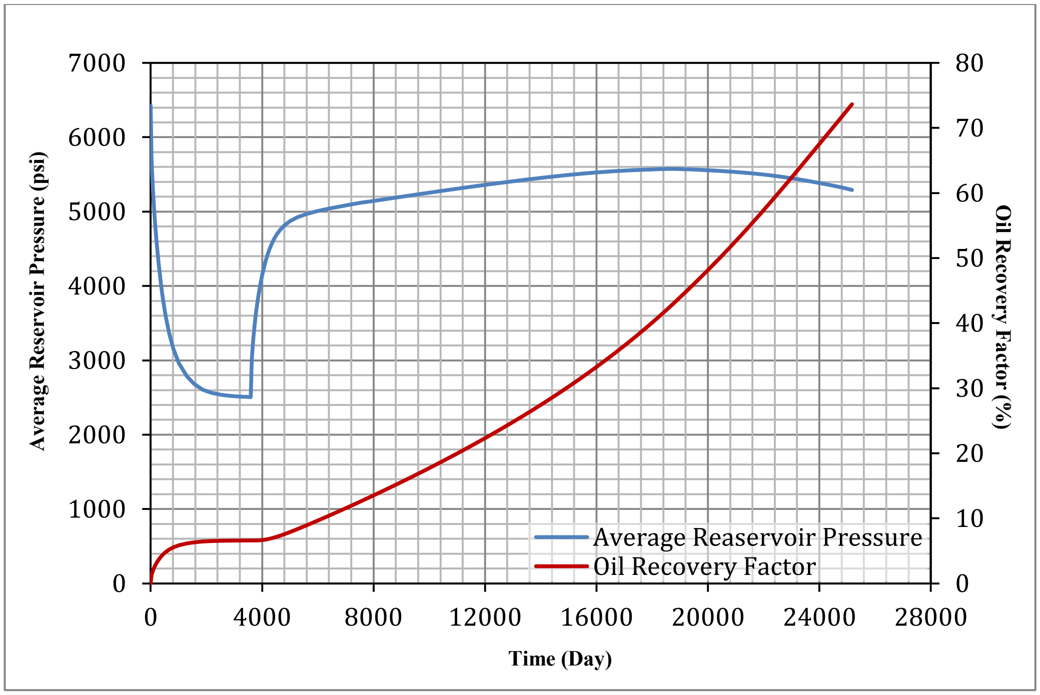
Figure 5.17 Reservoir pressure& oil saturation distribution a function of time

In case 1, a fracture spacing of 150 ft is selected. Figure 5.16 shows the average pressure, recovery factor and oil rate as a function of time. The reservoir pressure decreases from initial reservoir pressure to lower than 3000 psi in first 10 years' primary production. And then the reservoir pressure increases to more than 5000 psi after applying gas injection. The oil rate decreases from the initial rate 27.32 bbl/day to 10.21 bbl/day after 200 days of production and to1.98 within 5 year. At the end of primary production period, the oil rate is 0.44 bbl/day. When start the gas injection process, oil rate has a small increasing trend. Finally oil rate can achieve 2.13 bbl/day. 47.166 MSTB of oil can be obtained finally, corresponding a oil recovery factor of 25.06%.

Fig 5.17 shows the pressure variation and oil saturation distribution during the production period. Oil is pushed away from injection well and in the meantime the reservoir pressure build up for the same time periods. Compared to the model with fracture spacing of 200 ft, pressure transmission and sweep efficient in this case is better because of the closer fracture spacing, leading a higher oil recovery factor.

Case 2 Fracture distance is 100 ft

In case 2, we change fracture spacing to100 ft. Figure 18 shows the average pressure, recovery factor and oil rate as a function of time. Fig 5.19, shows the pressure variation and oil saturation distribution during the production period. Distinguish difference can be pointed out in these results. The reservoir pressure can be lowered to 2500 psi in first 10 years' primary production. And then the reservoir pressure increases to around 5600 psi after applying gas injection. The oil rate can be increased from 0.30 bbl/day to 6.6 bbl/day after primary production period. Pressure transmission and sweep efficient in this case is much better than any other case, corresponding to a high recovery factor which is 73.65%. Closer fracture spacing leads to not only higher cumulative oil production but also higher oil production rate and higher ultimately oil recovery factor which means better drainage between fractures.



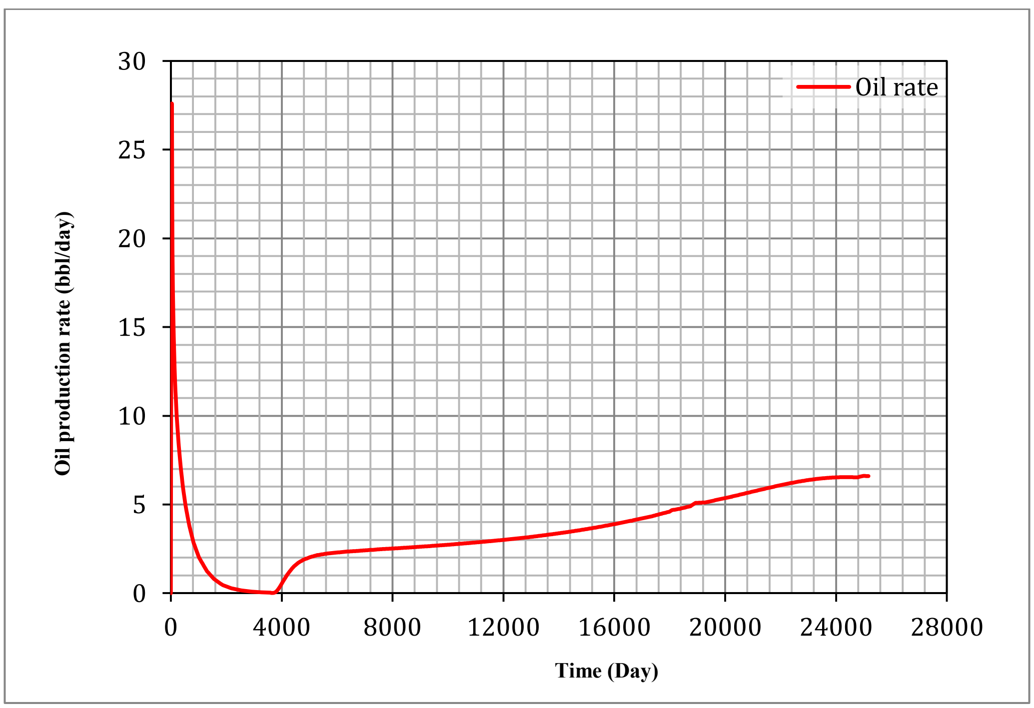


Figure 5.18 Average reservoir pressure, oil recovery factor and oil rate vs time

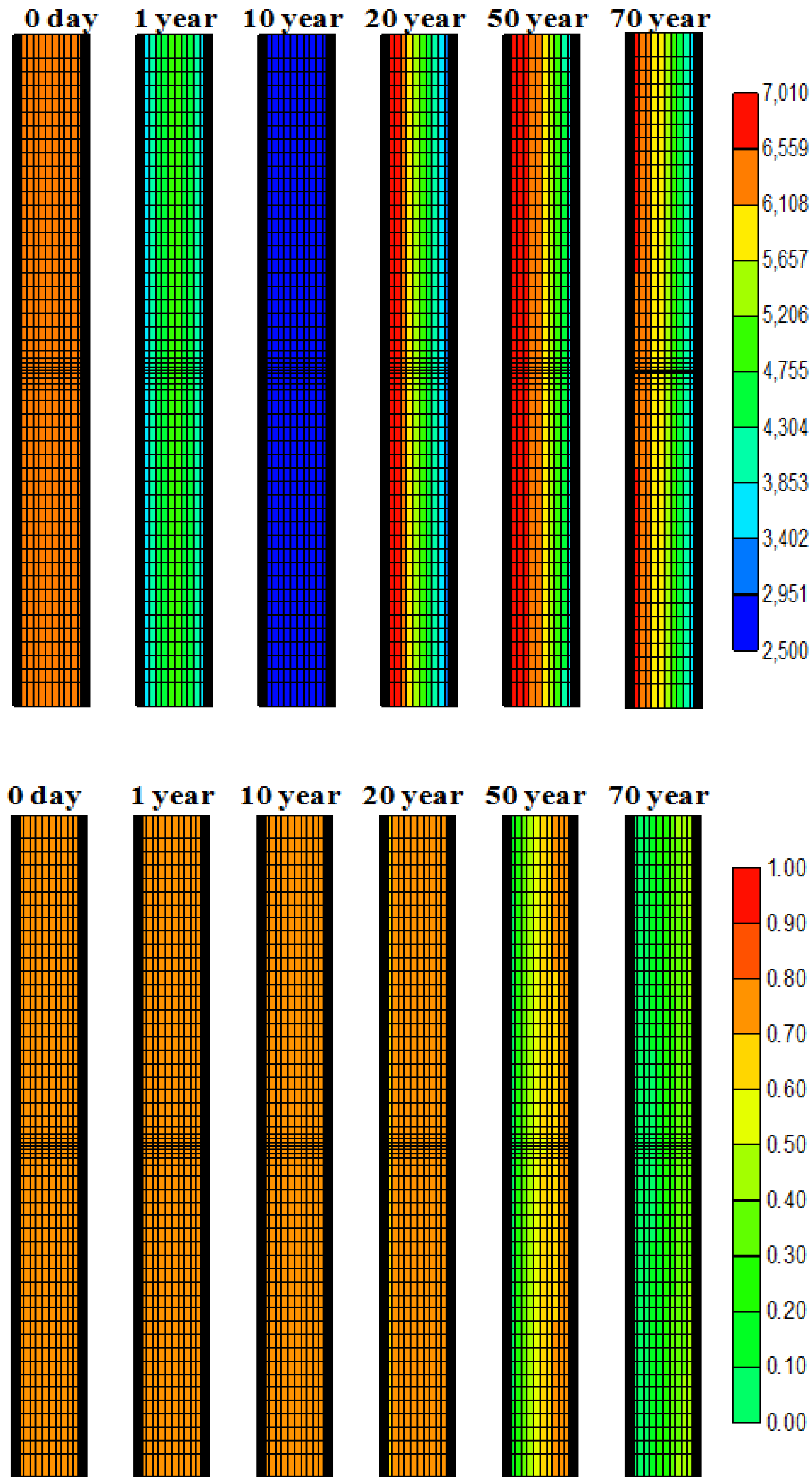


Figure 5.19 Reservoir pressure& oil saturation distribution a function of time

The objective of testing these production plans with different fracture spacing is to obtain information for gas injection in horizontal well with multi-stages fractures. Horizontal well with multi-stage of fractures is mainly utilized in the development of shale resources, so EOR techniques such as gas flooding, water flooding will be applied by horizontal wells. Fracture spacing is one of the key questions when completing a horizontal well. Through our test, closer fracture spacing means better drainage and better contact between injection well and production well. Though closer fracture spacing will need more fracture stages and increase the cost per well, it will have a much better production performance which will have better sweep efficiency higher oil production rate, corresponding a higher ultimately oil recovery factor. From the results of this test, we can see bright future of gas flooding in shale reservoirs by the utilization of horizontal well with multi-stage of fractures.

5.4 Sensitivity Analysis of Gas Flooding Simulation Model

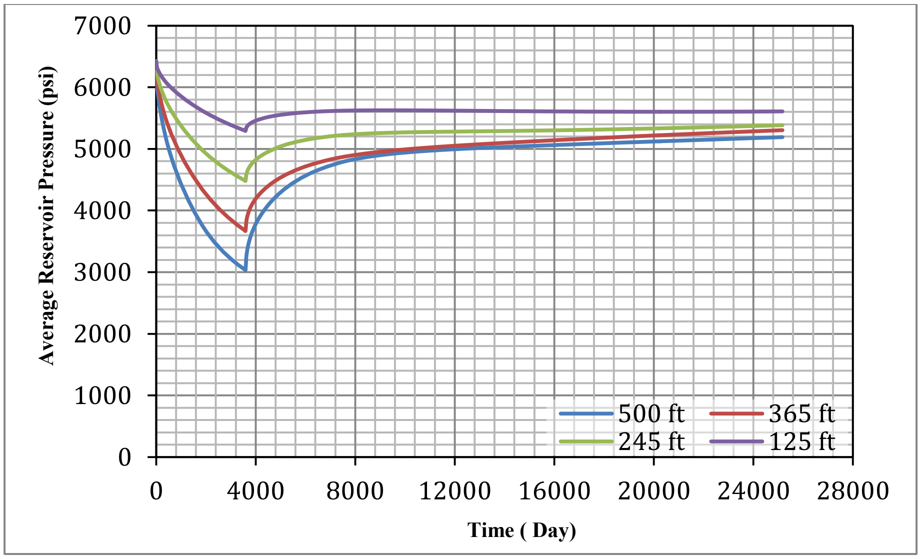
The production behavior and recovery of oil from the low permeability shale formation is a function of the rock, fluid and the fracturing operations. Sensitivity analysis is a quantitative method of determining the important parameters which affect shale oil production performance. The parameters considered in this thesis include fracture half-length, flowing bottom-hole pressure, rock compressibility and matrix permeability. Sensitivity studies are necessarily for designing better simulation model and understanding the fundamental behavior of shale oil production system.

5.4.1 Fracture Half-length

The fracture half-length used in the base model is 500 ft. Three another fracture half-lengths of 365 ft, 245 ft, 125ft are selected to compare the effect of fracture length on gas flooding production.

Figures5.20 shows the results of the different fracture half-length on the average reservoir pressure, cumulative oil production, injection rate, oil rate, and recovery factor as a function of time. The graph of average reservoir pressure for different fracture half-length shows that, the reservoir pressure decreases faster in case of longer fracture half-length in primary production period. The average reservoir pressure at the end of 10 years stays higher with shorter fracture half-length, leading a lower recovery of primary production and a lower initial injection rate for gas injection.

Longer fracture length means higher drainage volume of reservoir which will create proportionately higher production rates and gas injection process can have a better effect in maintaining reservoir pressure which will lead a higher cumulative oil production and higher ultimate recovery factor.



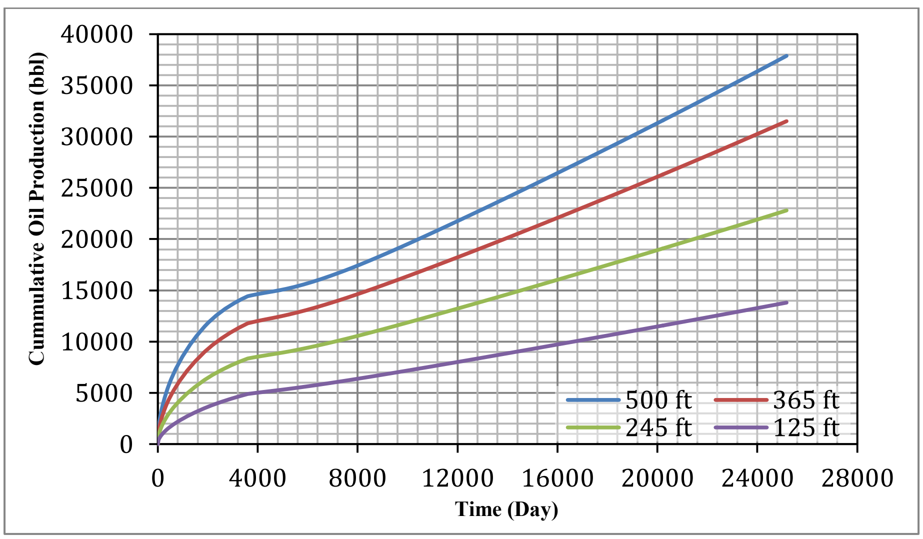
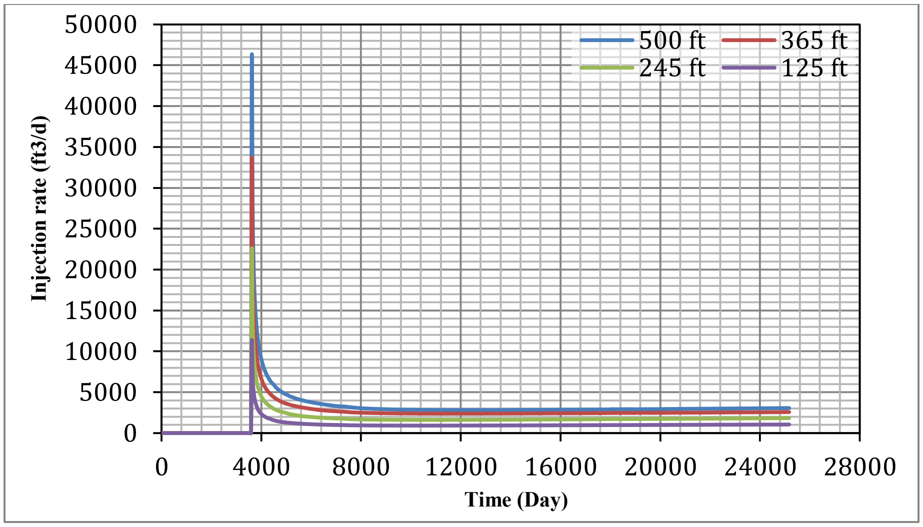


Figure 5.20 Fracture half-length sensitivity. Average reservoir pressure, cumulative oil production, oil rate, oil recovery factor and injection rate vs. time.



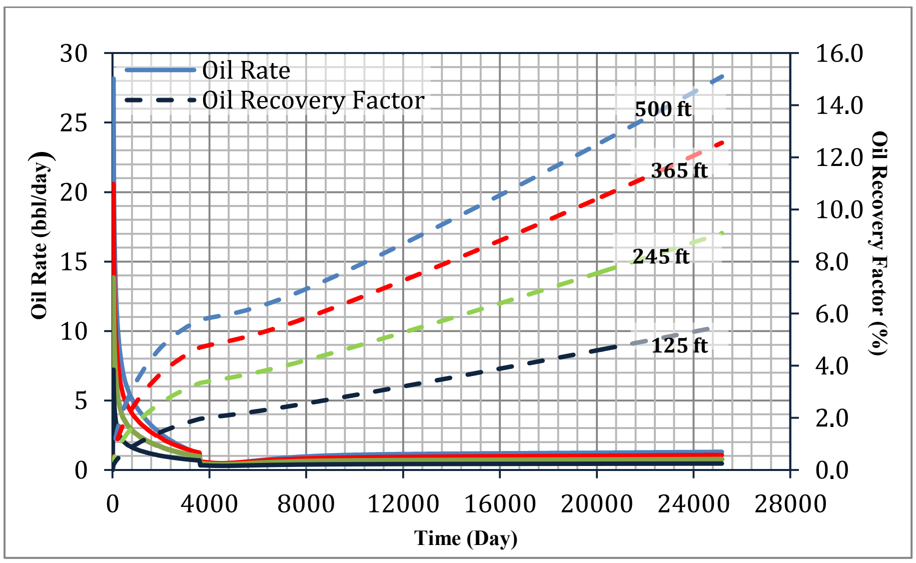
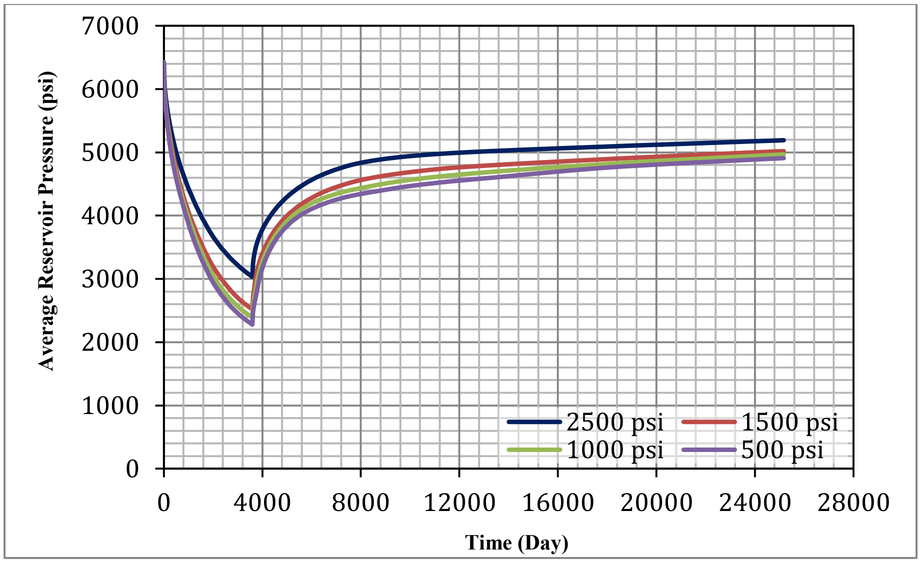


Figure 5.20 Continued

5.4.2 Flowing Bottom-Hole Pressure

The Eagle Ford reservoir is over-pressured and the reservoir is expected to be exploited primarily by depletion only, thus a lower flowing bottom-hole pressure (FBHP) can contribute to extra recovery from the reservoir. But in this thesis, we want to evaluate the potential of gas and water injection in shale reservoir, in order to avoid complex situation, we consider a system where the pressure is maintained high enough to guarantee the entire reservoir remains single phase throughout the gas flooding process, so the base injection model is controlled by flowing bottom hole pressure which was set up to 2500psi. The flowing bottom-hole pressure we select to test model sensitivity is 1500 psi, 1000 psi and 500 psi.

Fig 5.21 shows the results for the effect of different flowing bottom-hole pressure values on the cumulative oil production, recovery factor, injection rate, average reservoir pressure and oil rate. In primary production period, with lower flowing bottom-hole pressure, higher initial oil rate can be acquired, leading a faster decreasing of average reservoir pressure. At the end of 10 years, the average reservoir pressure can be lowered down to 2279 psi and 2392 psi for flowing bottom-hole pressure of 500 psi and 1000 psi. As expected, with lower flowing bottom-hole pressure, higher cumulative oil production can be achieved in primary production period. However, the oil rate slightly declines with production BHP reduction in the early period from 4000 days to 8000 days. The reason for oil rate reduction might be the reservoir pressure decreases below the bubble point pressure, which indicates that miscible flow turns back into two-phase flow. This will greatly decrease the efficiency of gas flooding. But, due to a period of lower oil production rate, reservoir pressure rises up and goes back to higher that bubble point pressure. Then, miscible flow appears again in the later production time. Thus, even though BHP increases, the oil rate still declines in early period and goes back normal in the end.



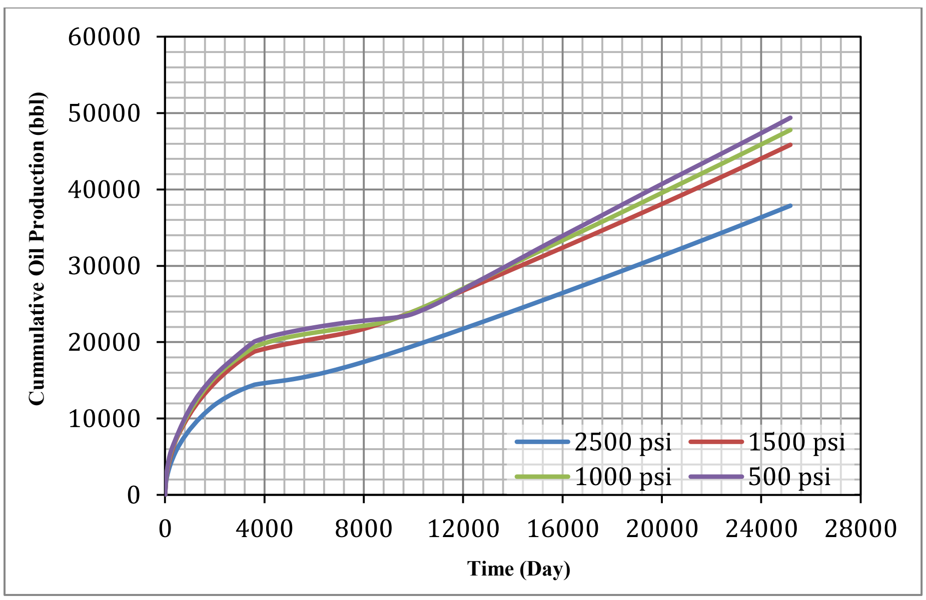
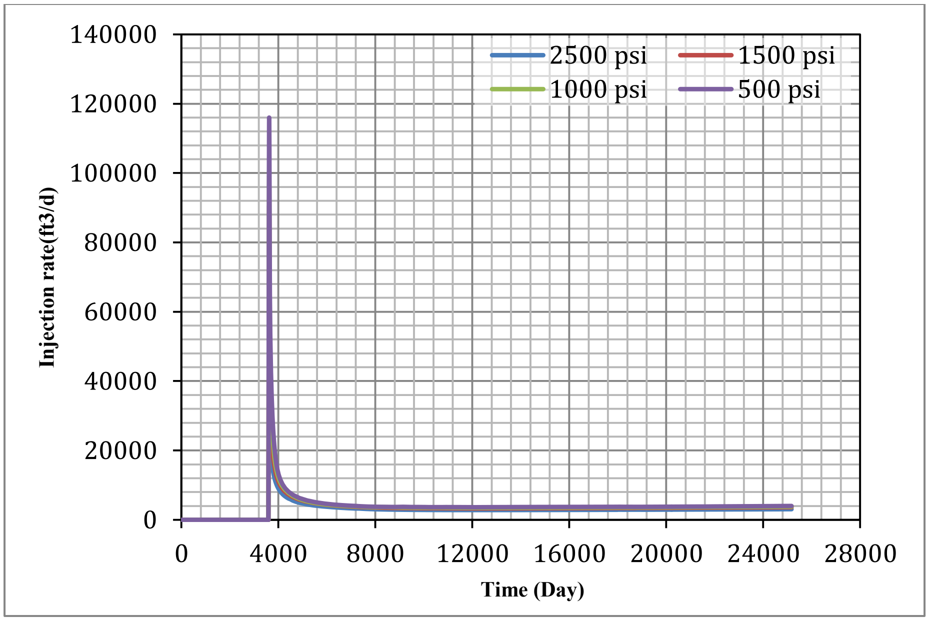


Figure 5.21 Flowing bottom-hole pressure sensitivity. Average reservoir pressure, cumulative oil production, oil rate, oil recovery factor and injection rate vs. time.



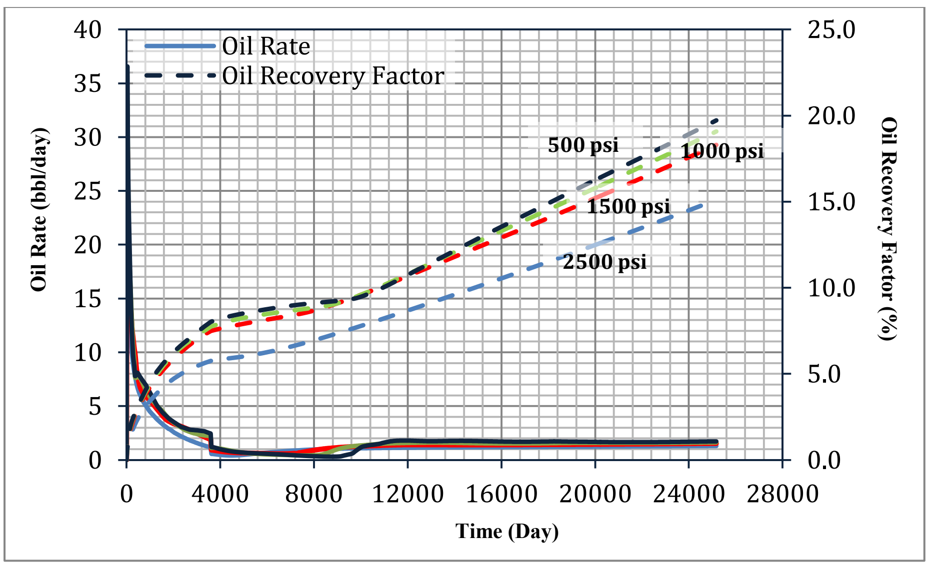
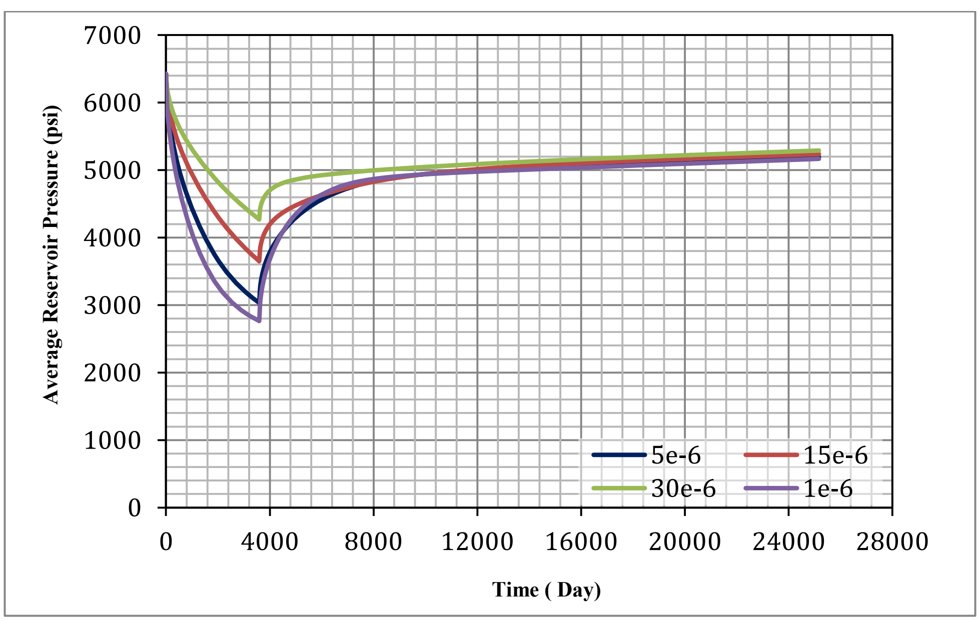


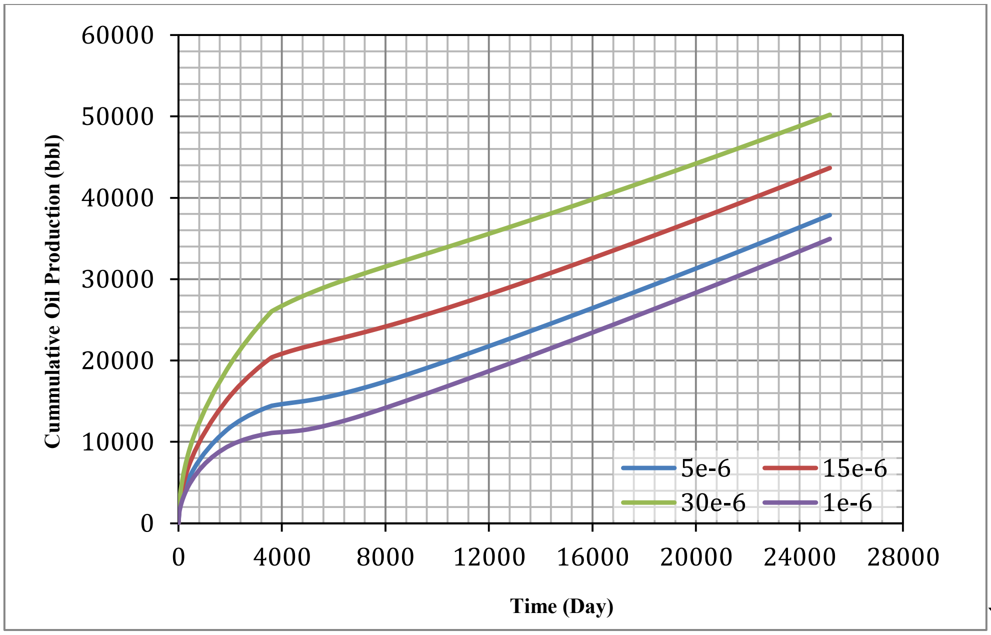
Figure 5.21 Continued

5.4.3 Rock Compressibility

Though the general rock compressibility curves for sandstone and limestone reservoirs were provided by Hall's (Hall, 1953), shale rock compressibility values and particularly for the Eagle Ford shale could not be found in the published literature. According to Hsu and Nelson's work (2002), they expected the compressibility of the Eagle Ford shale to be on higher side because of the high amount of smectite (50%) in the clay minerals (38-88%).

Figure 5.22shows the effect of different rock compressibility values on the cumulative oil production, recovery factor, average reservoir pressure and oil rate. The rock compressibility value used in the base case simulation is $5*10^{-6}$ psi^{-1}. And then we selected three another compressibility values of $15*10^{-6}$ psi^{-1}, $30*10^{-6}$ psi^{-1}, and $1*10^{-6}$ psi^{-1}. From the graph below, we can figure out that different values of rock compressibility mainly influence the primary production which is driven by natural pressure depletion. The results show that the reservoir with higher rock compressibility value will have a higher initial production rate and a higher oil production in primary period and then will lead a higher final oil recovery factor.





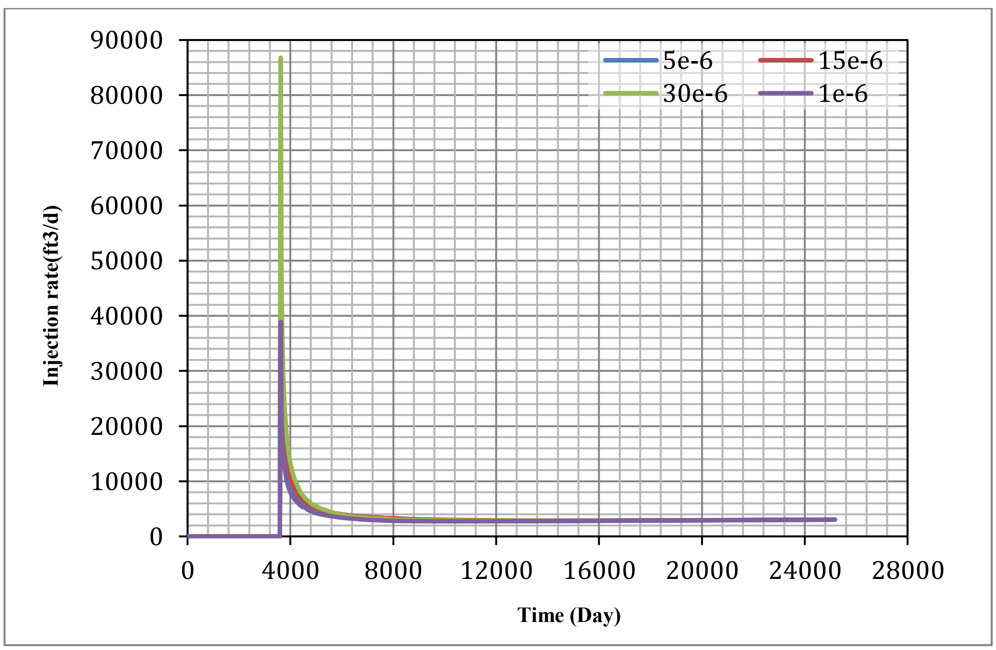


Figure 5.22 Rock compressibility sensitivity. Average reservoir pressure, cumulative oil production, oil rate, oil recovery factor and injection rate vs. time.

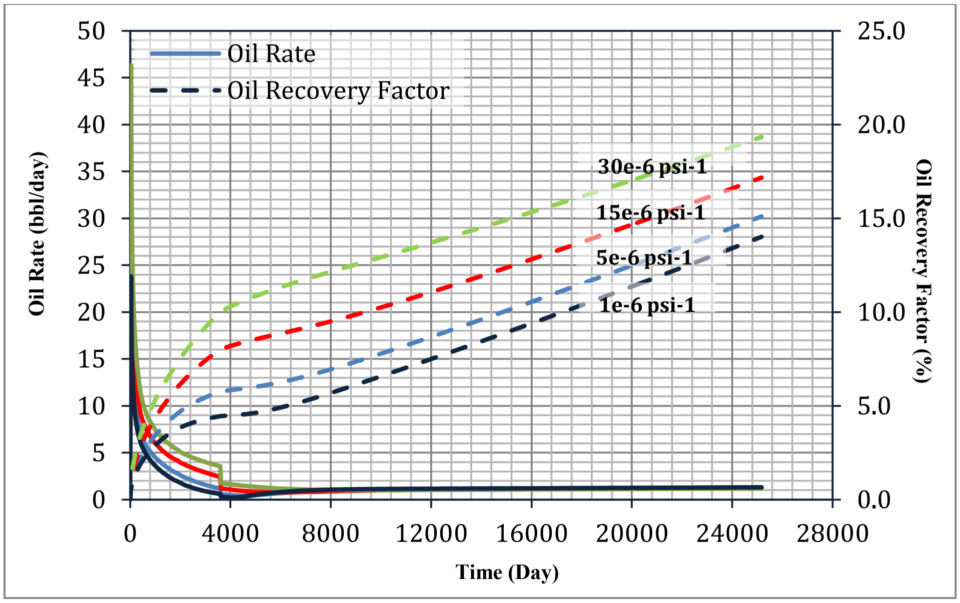


Figure 5.22 Continued

5.4.4 Matrix Permeability

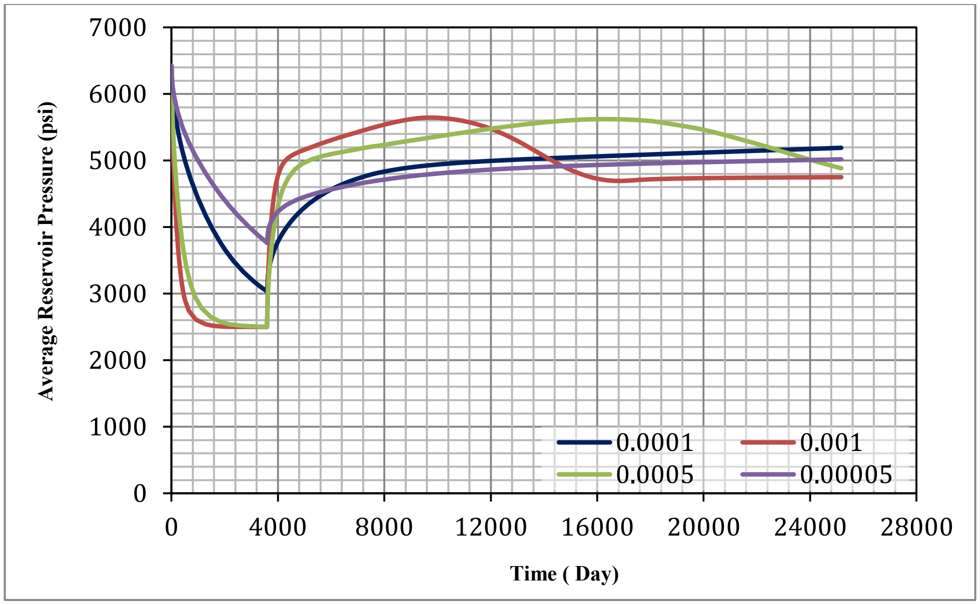
Fig 5.23shows the results for different matrix permeability values, k, on the average reservoir pressure, cumulative oil production and oil recovery factor. The permeability value used in the base model is $1*10^{-4}$ md (100 nano-darcy). Another three permeability values of $1*10^{-3}$ md, $5*10^{-4}$ md and $5*10^{-5}$md are selected in matrix permeability sensitivity analysis.

Because base model is controlled by bottom hole pressure which is set up to 2500 psi, so the average reservoir pressure for these four cases cannot be lower than 2500psi. From the results below, the average reservoir pressure can be lowered down to the 2500 psi pressure limit set after 5 years and 8 years' primary production for the

$1*10^{-3}$md case and $5*10^{-4}$md case while the average reservoir pressure cannot be lowered down in case of $5*10^{-5}$md.

The cumulative oil production and oil recovery factor results show that when start gas injection after 10 years' primary production, the oil production increase rapidly in case of $1*10^{-3}$md and $5*10^{-4}$md. After injecting gas for 20 years, for the $1*10^{-3}$md case 51% OOIP oil can be produced and 23.4% oil recovery factor can be obtained in case of $5*10^{-5}$md. At meanwhile, only 8.14% and 5.93% OOIP oil can be exploited from the case of $1*10^{-4}$ md$5*10^{-5}$md.Higher matrix permeability means better hydraulic conductivity, better reaction between injection well and production well, better sweep efficiency, which correspond a higher initial oil rate and higher cumulative oil production.

The matrix permeability is an important parameter and must be determined accurately. The recovery from the formation with various permeability can be distinctly different. Shale permeability can be quite difficult to quantify. Core measurements are typically orders of magnitude lower than the effective shale permeability, but a conventional formation test or buildup test is not possible with such low permeability. Mohamed, et al (2011) showed that analysis of fracture calibration tests may provide shale permeability, particularly if the test uses a very low injected volume.



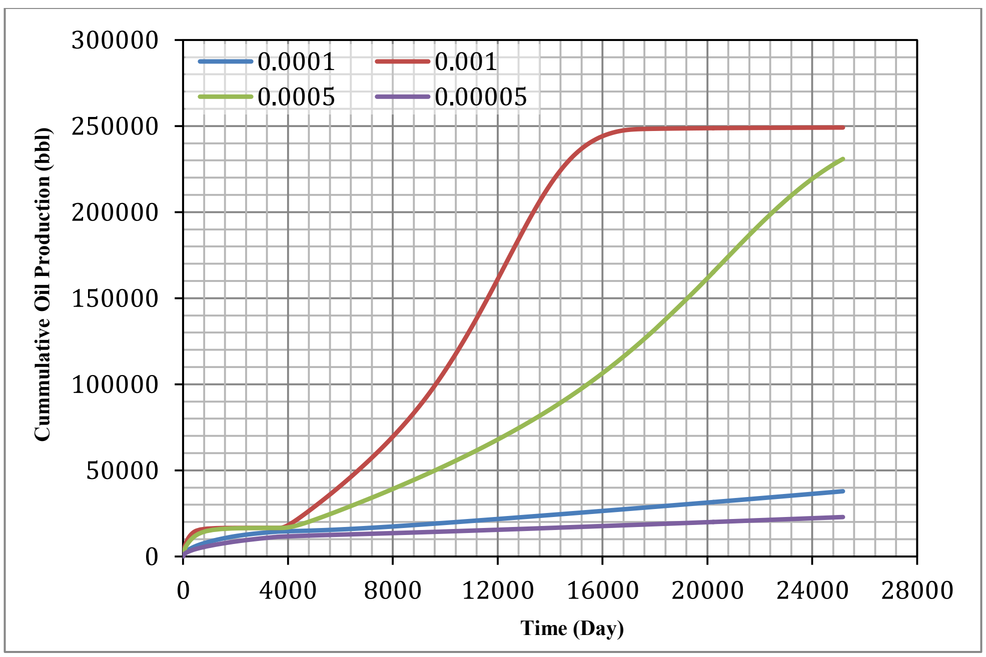


Figure 5.23 Rock compressibility sensitivity. Average reservoir pressure, cumulative oil production, oil rate and oil recovery factor vs. time.

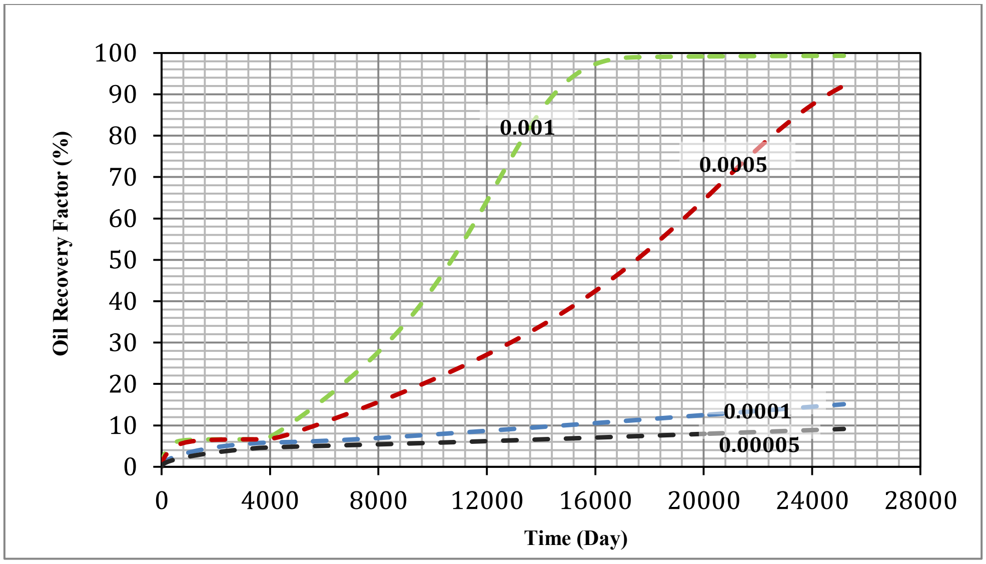


Figure 5.23 Continued

This chapter introduces the determination of miscibility parameter and breakdown pressure, describes base gas injection simulation model, provides results of different production plans and illustrates sensitivity to key parameters affecting the gas flooding production of the shale oil from the stimulated reservoir volume including fracture half-length, rock compressibility, flowing bottom-hole pressure, and matrix permeability. All the results described in this chapter can be used to design better development scenarios for shale oil reservoirs and offering useful information for other research projects.

CHAPTER 6

WATER FLOODING SIMULATION

Unconventional reservoirs contain a large volume of oil and gas resources around the word. Recent high oil and gas prices stimulated interest in developing unconventional reservoirs especially in shale gas and oil resources. Advanced horizontal drilling and hydraulic facture techniques have been applied in the exploitation of shale reservoir, but there maintains a lack of understanding of how conventional EOR techniques such as gas flooding and water flooding should perform in these reservoirs. Water flooding is widely used because water injection is relatively inexpensive, and may be economic despite the low ultimate recoveries obtained. An additional value of water flooding is that, water flooding is a low-risk option that can be used to recover some additional oil while more advanced lab and pilot studies are being designed. Thus, improving oil recovery by water flooding in such reservoirs is an attractive goal. This chapter describes the base water injection model and simulation results of water flooding in shale oil reservoir.

6.1 Description of Water Flooding Simulation Model

A 200ft long×1000ft wide×200 ft thick reservoir model which has two half-vertical well with two half fractures (same model with gas injection) is selected to simulate water flooding in shale oil reservoir. In this water injection simulation model, the maximum water injection rate is 3500 STB/day and maximum injection pressure is also set as 7000 psi. For production well, the flowing bottom-hole pressure is 2500 psi.

The injection well is controlled by maximum injection pressure, the well will automatically change the injection rate to keep a constant bottom-hole pressure.

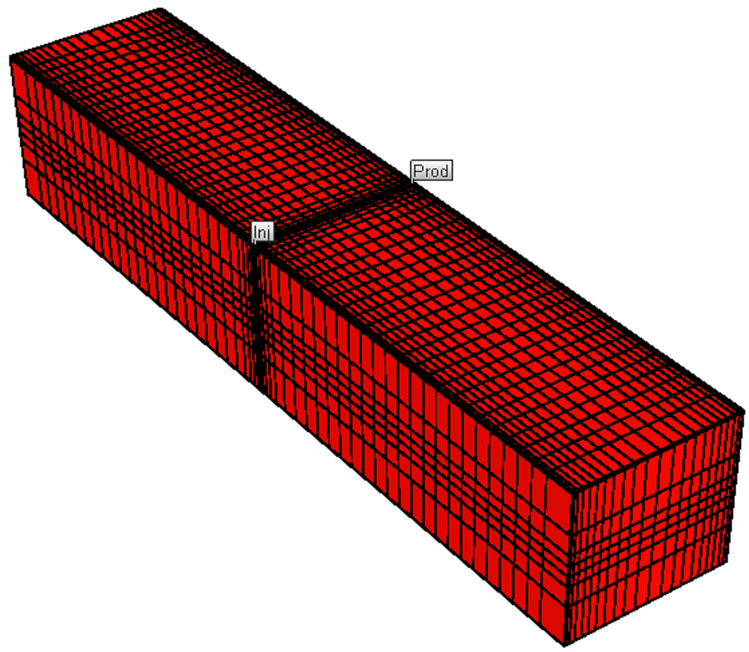


Figure 0.1 Base water injection model

6.2 Water Flooding Plan

Plan 1: 3600 days of primary production & 60 years of water flooding production

In production plan 1, we start inject water into reservoir after 3600 days (10 years) of primary production. The production is driven by natural pressure depletion in first 10 years. The reservoir pressure decreases from 6425 psi to 3000 psi in primary production period and then gradually increases to more than 4000 psi after applying water injection (Fig 6.1). The initial oil rate is 27.47 bbl/day, after 200 days of primary production it decreases to 10.26 bbl/day. At the end of primary production, the oil rate is 0.57 bbl/d. When start water injection, no big differences of production rate can be figured out from the graph. Because shale reservoir has a ultra-low permeability, the injection fluid is difficult to transmit from injection well to producer, the response of production well to water flooding is poor, this also leads a low injection rate, during water flooding process the oil rate just can be 0.8 bbl/ day, corresponding an oil recovery factor of 11.9%.

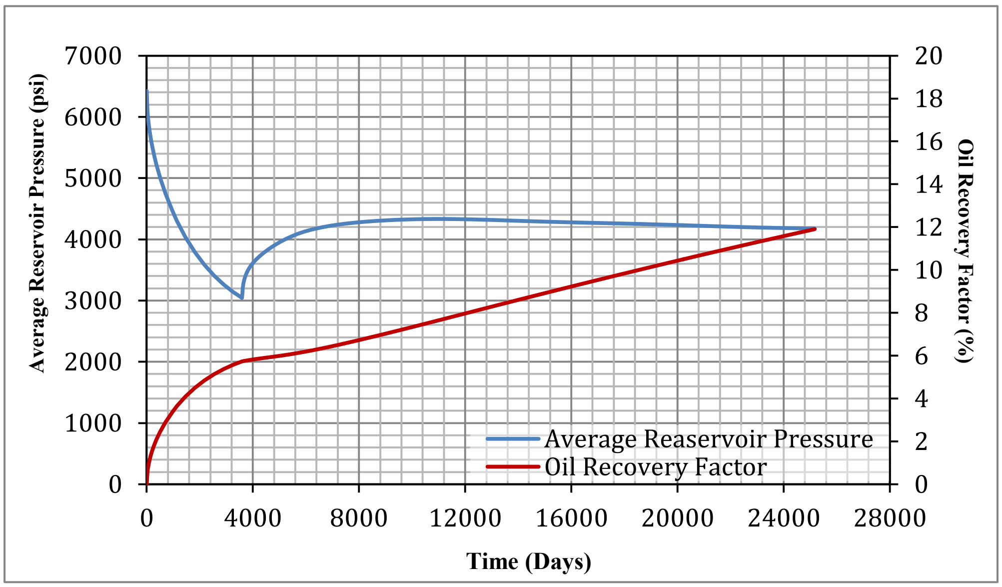


Figure 6.2 Average reservoir pressure and oil recovery factor vs time

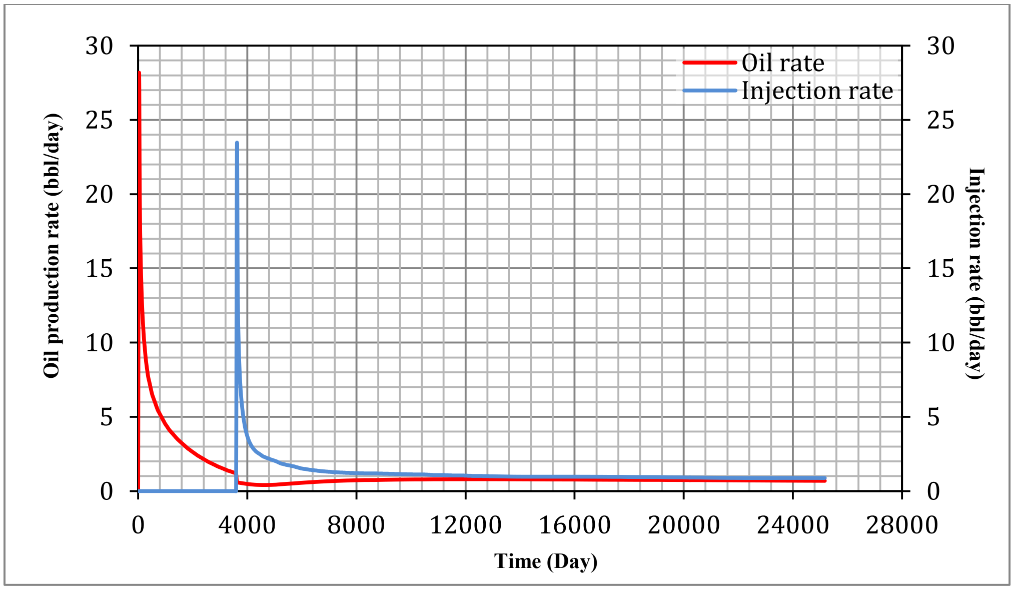


Figure 6.3 Oil production rate and injection rate vs time

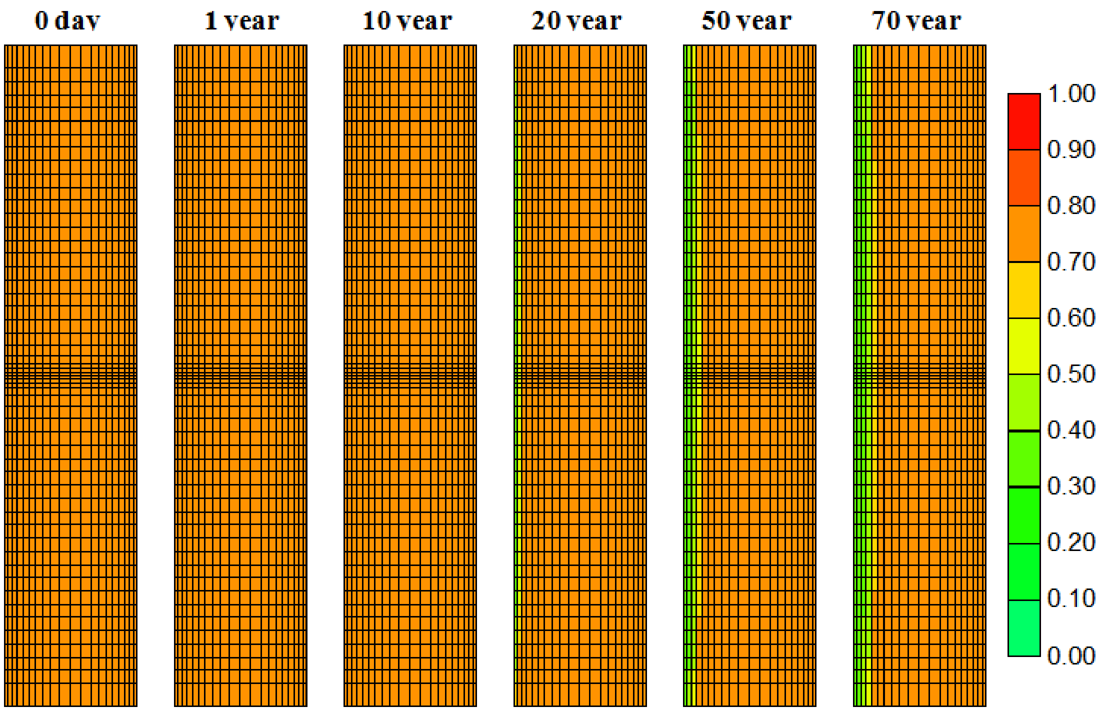


Figure 6.4 Oil saturation map of plan 1

Plan 2: 3600 days of primary production & 60 years of water flooding production

For production plan 2, we still start water injection after 3600 days (10 years) of primary production. In this plan, we change the injection schedule from constant injection to cyclic injection. Each injection cycle has 5 years' injection and 5 years' shut in period. Fig 6.4, shows the results for oil recovery factor, average pressure versus time. The reservoir pressure decreases from initial reservoir pressure to 3000 psi in primary production period and then begins to increase with the implementing of water injection. We shut in injection well every 5 years, thus fluctuation growth occurs in average reservoir pressure curve. The initial oil rate is 27.47 bbl/day, the oil rate declines fast to 5 bbl/d within 3 years. At the end of primary production, the oil rate is 0.57 bbl/d. When start water injection, the initial water injection rate is 23.15 bbl/d and quickly decreases to 2 bbl/d in 3 years. Because of cyclic injection, fluctuation occurs in injection rate curve. Because shale reservoir has a ultra-low permeability, the injection fluid is difficult to transmit from injection well to producer, the response of production well to water flooding is poor, thus oil rate does not have obvious change when start water injection, during water flooding process the oil rate just can be 0.69 bbl/ day, corresponding an oil recovery factor of 11.03%.

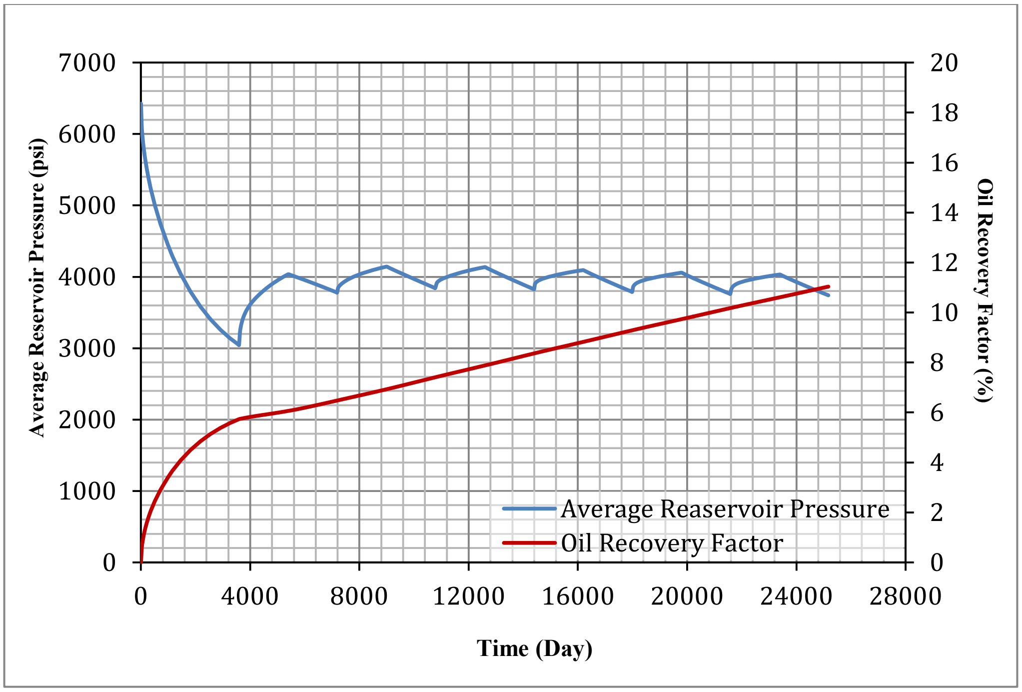


Figure 6.5 Oil production rate and injection rate vs time

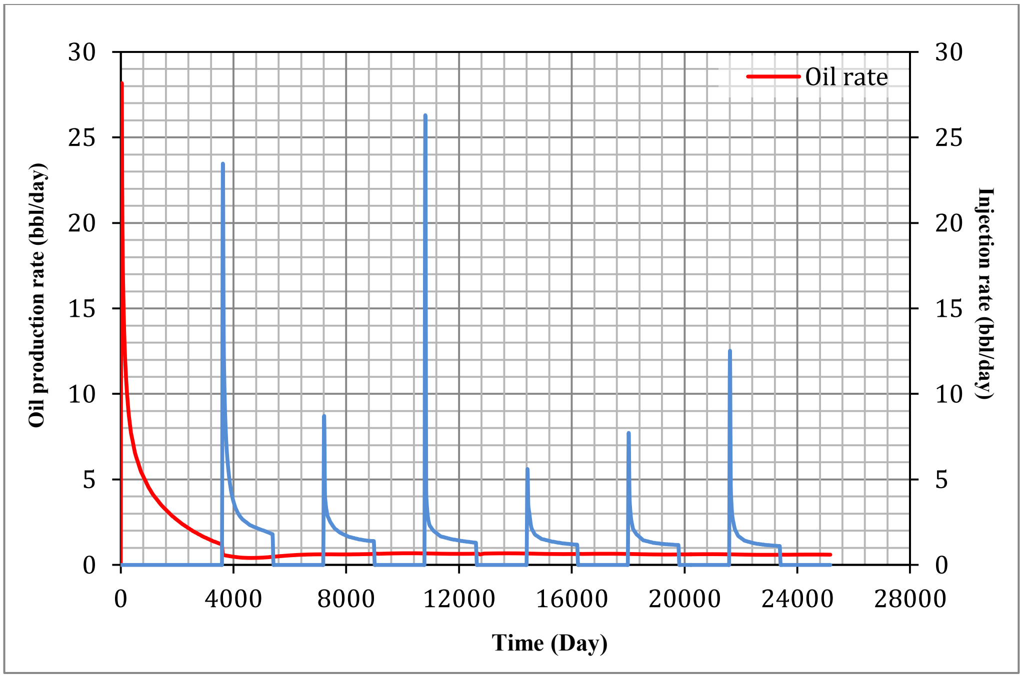


Figure 6.6 Oil production rate and injection rate vs time

Plan 3: 70 years of water flooding production

For production plan 3, we implement water injection at the beginning of the development. Keep water injection and oil production simultaneously for 70 years. Fig 6.6, 6.7 show the results for oil recovery factor, average pressure and oil rate versus time. Because we apply water injection simultaneously with production, and reservoir pressure is very high as 6425 psi, so the initial injection rate and production rate are lower than previous plans. The initial water injection rate is only 2.67 bbl/d which is much lower than that in plan 1 (23.15 bbl/d), the reservoir pressure decreases slowly from initial reservoir pressure to 4000 psi, this in turn cause a lower oil recovery factor than that of plan 1. The ultimate oil recovery factor is 11%.

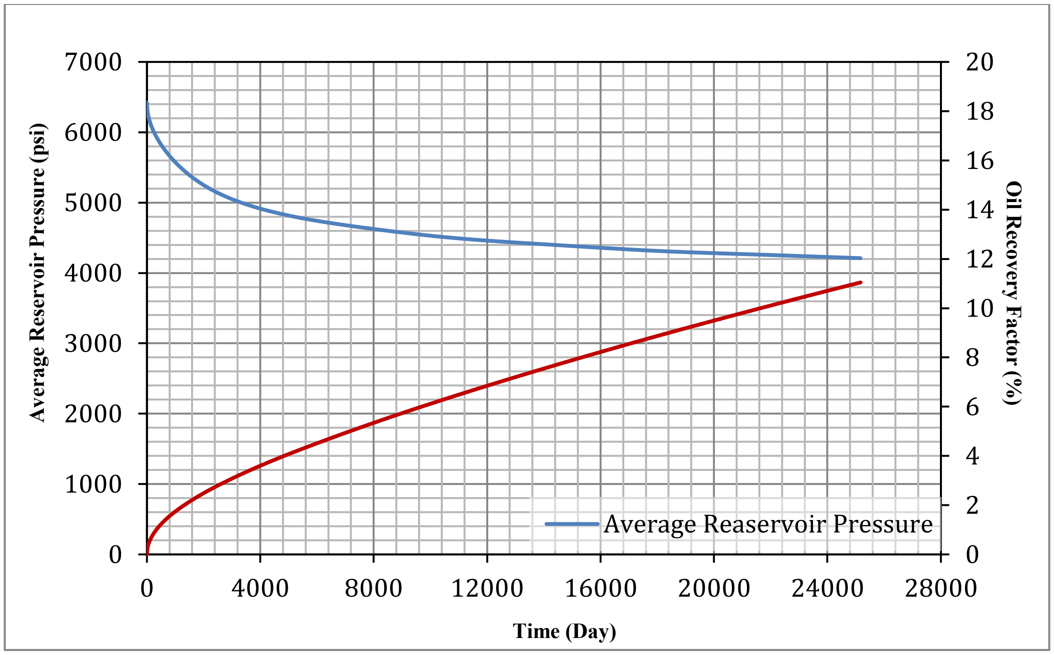


Figure 6.7 Oil production rate and injection rate vs time

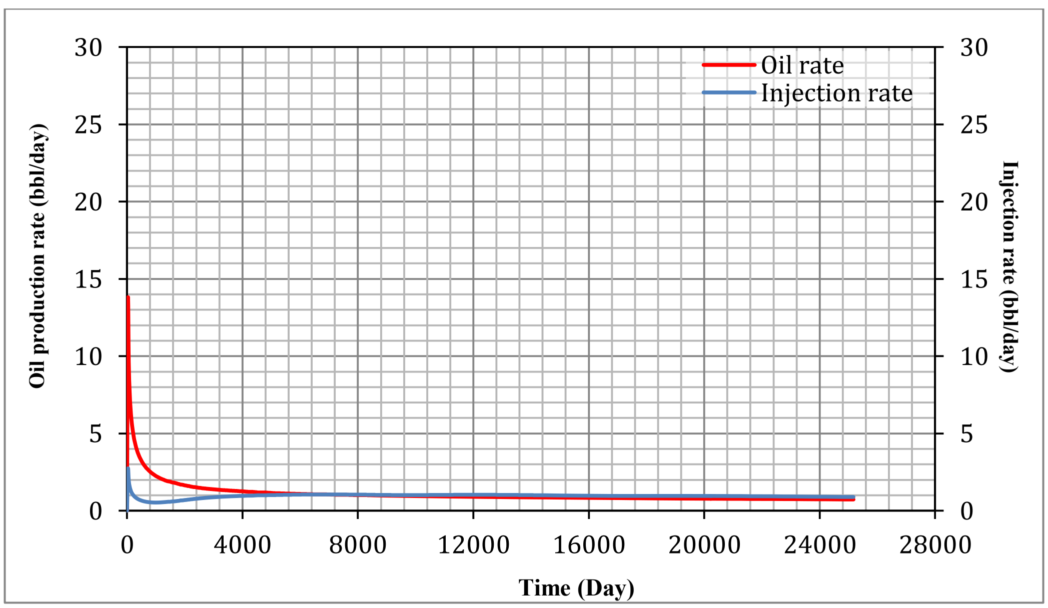


Figure 6.8 Oil production rate and injection rate vs time

In water flooding simulation work, three production plans were considered; in the first plan water was injected after 10 years' primary production and then continues water flooding for 60 years, 27.020 MSTB of water was injected into the reservoir, producing 29.872 MSTB of oil corresponding a oil recovery factor of 11.9%. In the second plan, water was also injected after 10 years' primary production and then apply cyclic water injection, each injection process has 5 years' injection and 5 years' shut in period. In this process, 21.883 MSTB of water was injected to produce about 11.03% of original oil in place. For the plan 3, water injection was implemented at the beginning of the development. We can easily figure out that plan 3 has a lower oil production in first 10 years because only one half-production well is used instead of two half-production wells in the other two plans which directly influences the finale oil recovery. So it's not necessary to apply water injection at the beginning of the development, especially in such kind reservoir which has high reservoir pressure and ultra-low permeability. It is widely accepted that implementing EOR techniques after several years' natural pressure depletion will have a better production performance. The results of three simulation plan show that the ultimate recovery is not quite different for these three different injection plans. Shale reservoirs have ultra-low porosity and permeability; it's difficult for injected fluids flow from injection well to production well, leading a low productivity and low injectivity. The response of whole reservoir to water injection is poor.

- Plan 1: 10-year primary production & 60 years of water flooding
- Plan 2: 10-year primary production & 60 years of cyclic water flooding

- Plan 3: 70 years of water flooding production

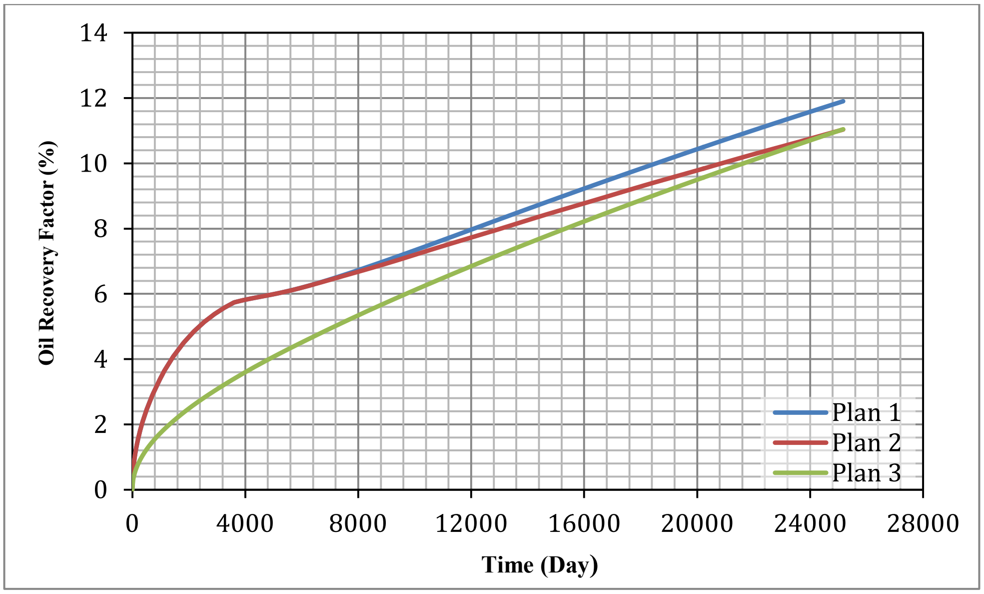


Figure 6.9 Oil recovery factor vs time

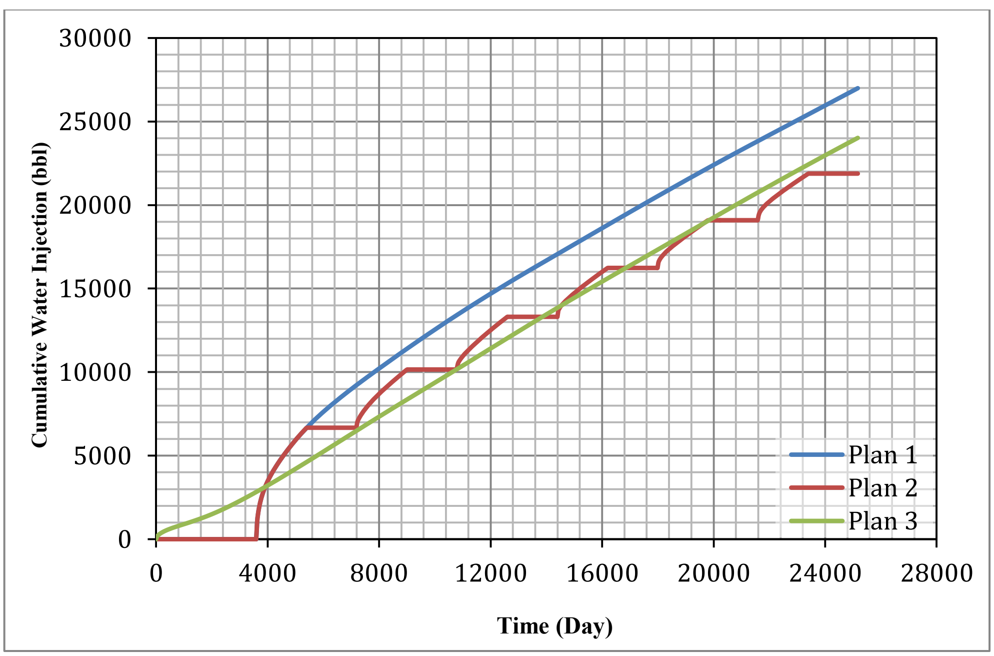


Figure 6.10 Cumulative water injection vs time

Table 6.1 Water flooding simulation results

	Plan 1	Plan 2	Plan 3
Cumulative Oil Production	29.872 MSTB	27.693 MSTB	27.732 MSTB
Cumulative Water Injection	27.020 MSTB	21.883 MSTB	24.046 MSTB
Overall Oil Recovery (10 years)	5.73%	5.73%	3.39%
Overall Oil Recovery (30 years)	7.59%	7.21%	6.41%
Overall Oil Recovery (50 years)	9.8%	9.30%	8.87%
Overall Oil Recovery (70 years)	11.9%	11.03%	11.05%

Water flooding is a kind of EOR technique that has been successfully applied in the development of conventional reservoirs or some tight oil reservoirs. Water flooding, the process of injecting water into an oil reservoir to displace the crude, is perhaps the most economical of any improved oil recovery process due to the general availability of water, ease of injection and limited development costs. This chapter introduces the base water injection simulation model, provides results of different production plans. Chapter 7 puts a summary of the complete thesis and draws out important conclusions from the work. Also, it recommends possible future work in continuation of the work done in this thesis.

CHAPTER 7

CONCLUSIONS AND RECOMMENDATIONS

This thesis is a preliminary analysis to evaluate the EOR potential by gas and water flooding in shale oil reservoirs. The main objective was to assess the viability of gas and water flooding in improving oil recovery from shale formation. This chapter contains a summary of this study. And then we suggest ideas for future work based on the work done in this thesis.

7.1 Summary and Conclusions

As shale resources become a focus of exploration and production activity in North America, oil and gas industry made tremendous efforts to research on stimulating the oil and gas production from shale reservoirs. The horizontal well with multiple transverse fractures has proven to be an effective strategy for shale gas reservoir exploitation and it is also used in producing shale oil by some oil companies. However, due to complex conditions of shale oil, the production performance is still not attractive. Improving oil recovery will be a great challenge in the development of shale oil reservoirs. Thus, we initiate our work, considering conventional EOR techniques, gas and water injection, which have been successfully implemented in conventional and some unconventional tight oil reservoirs for a long time, to assess the potential of improving shale oil recovery by EOR techniques.

The cases chosen for this study are not comprehensive, but may represent somewhat typical situations. A black-oil simulator owned by Computer Modeling

Group Ltd was used in this study to simulate a number of production plans for gas flooding and water flooding. 8470 (22*55*7) grid-cells are used to build a 200ft long×1000ft wide×200ft thick reservoir model. In this model we use 1-ft wide cells with 41.65 md-ft conductivity which were located at the boundary of the model to simulate the physical flow between two hydraulic fractures. Three typical production plans for gas and water injection were presented in this thesis respectively. In spite of the limited work of this study, it is still possible to reach some conclusions.

1. Because of the ultra-low permeability of shale reservoirs, in a 200 ft wide shale oil reservoir model, it’s more difficult for injection materials transmit and displace oil than that in conventional reservoirs or tight oil reservoirs which have better condition than shale reservoirs. Although in miscible condition, oil viscosity just can be reduced around the fracture, the main effect of gas injection is pressure maintenance.

2. According to sensitivity analysis, matrix permeability is the main parameter causing low oil recovery from shale reservoirs. Designing a closer fracture spacing will have an obviously positive influence on shale oil production. It, not only leads a higher initial production rate but also a much better sweep efficiency for miscible gas flooding, resulting an attractive ultimate oil recovery factor.

3. Water flooding is the process of injecting water into an oil reservoir to displace the crude. In an ultra-low porosity, ultra-low permeability and high oil viscosity shale oil reservoir, injecting water through high conductivity fracture has less

effect on improving oil recovery than gas injection. Unlike miscible gas which can reduce oil viscosity injected water just act as pressure maintenance for the reservoir. Ultra-low permeability cause a worse sweep efficiency, leading a low productivity and low injectivity. The response of whole reservoir to water injection is poor.

4. Compare the simulation results of gas flooding and water flooding, miscible gas injection has a better effect on improving oil recovery in shale reservoirs. Injected solvent can be miscible with oil, reducing oil viscosity, and lead a better sweep efficiency than water, besides pressure maintenance. Gas injection a better production plan and completion plan will have a good prospect in improving oil production from shale oil reservoirs.

7.2 Recommendations

1. We simulate two half-vertical well with two 1-ft wide fractures to represent two half-fractures in our work. Miscible gas injection simulation results show us positive effect on improving shale oil recovery. Next step we should test the gas flooding in two horizontal wells with multiple transverse hydraulic fracture. If we have a good completion plan, the final recovery factor may be very good.

2. In our work, although water injection in shale oil reservoir did not have a result as well as gas injection, we cannot conclude that water injection has no potential in the development of shale oil reservoirs absolutely, because we have not optimize the injection process and may factors have not been included in our simulation model.

3. Economic analysis should be done in the future work for the determination of the optimum injection, production and completion plan. Hope our work can offer information for further research on the development of shale oil reservoirs.

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APPENDIX

BASE CASE SIMULATION CMG INPUT FILE

```
**
*********************************************************************
**************
** MODEL:  22x55x7       Miscible gas injection  MODEL
*********************************************************************
**
** This Model mainly investigates the effects of Miscible gas injection on the**
**oil recovery for shale oil reservoirs, techniques implemented with two-half**
** vertical well and in the presence of two 1-ft wide hydraulic fractures     **
*********************************************************************
**
RESULTS SIMULATOR IMEX 201110
INUNIT FIELD
WSRF WELL 1
WSRF GRID TNEXT
WSRF SECTOR TNEXT
OUTSRF WELL
```

OUTSRF RES ALL

OUTSRF GRID BPP KRG KRO KRW PRES SG SO SSPRES SW VISG VISO

*OUTPRN *GRID *SO *PRES

WPRN GRID TIME

WPRN WELL TIME

**$ Distance units: ft

RESULTS XOFFSET 0.0000

RESULTS YOFFSET 0.0000

RESULTS ROTATION 0.0000 **$ (DEGREES)

RESULTS AXES-DIRECTIONS 1.0 -1.0 1.0

****

***

** Reservoir Description Section

****

***

GRID VARI 22 55 7

KDIR DOWN

DI IVAR

1	4	6	8	8	9	10	12	12	14	16
16	14	12	12	10	9	8	8	6	4	1

DJ JVAR

35 21*20 16 10 8 6 4 2 4 6 8 10 16 21*20 35

DK ALL

1210*52.8 1210*26.4 1210*14.2 1210*13.2 1210*14.2 1210*26.4 1210*52.8

DTOP

1210*9884

**$ Property: Permeability I (md) Max: 0.0001 Min: 0.0001

**$ Property: Permeability I (md) Max: 41.65 Min: 0.0001

*PERMI *IJK

1:1 1:55 1:7 41.65

2:21 1:551:7 0.0001

22:22 1:55 1:741.65

NULL CON 1

POR CON 0.06

PERMJ EQUALSI

PERMK EQUALSI * 0.1

**$ 0 = pinched block, 1 = active block

PINCHOUTARRAY CON   1

PRPOR 5000

CPOR 5e-6

*MODEL *MISNCG   ** Use the pseudomiscible option with

 ** no chase gas.

****

*** ** Component Property section

****

***

TRES 255

PVT EG 1

**$ p RsBoEgvisovisg

14.696 4.68138 1.09917 4.101590.9026440.0136014

173.583 32.19231.11173 49.12250.803844 0.0137243

332.47 65.2796 1.12711 95.36760.719427 0.0139054

491.357 101.6211.1443 142.801 0.651788 0.0141273

650.244 140.361.16295 191.364 0.59727 0.014385

809.131 181.027 1.18287 240.971 0.552597 0.0146766

968.018 223.32 1.20393 291.506 0.515357 0.0150009

1126.9 267.027 1.22604342.8240.483819 0.0153574

1285.79 311.989 1.24913 394.75 0.45674 0.0157453

1444.68 358.084 1.27314 447.084 0.433209 0.0161637

1603.57 405.212 1.29803 499.604 0.412545 0.0166117

1762.45 453.293 1.32376 552.077 0.394234 0.0170877

1921.34 502.257 1.3503 604.264 0.377877 0.0175899

2080.23 552.048 1.3776 655.935 0.363163 0.0181162

2239.11 602.616 1.40566 706.874 0.349843 0.0186643

2398 653.915 1.43443 756.888 0.337718 0.0192317

3218.4 929.142 1.59372 995.3790.288941 0.0223706

4038.8 1219.15 1.76935 1195.74 0.255067 0.0256431

4859.2 1521.47 1.95964 1360.490.229917 0.0288538

5679.6 1834.432.16332 1496.290.21036 0.0319135

6500 2193.142554 2.379391609.67 0.19463 0.0347948

*PVTS ** PVT table for solvent

***p rss es viss omg_s

14.696 0 4.10159 0.0136014 0

173.5830 49.1225 0.0137243 0

332.47 0 95.3676 0.0139054 0

491.3570 142.801 0.0141273 0

650.2440 191.364 0.014385 0

809.1310 240.971 0.0146766 0

968.0180 291.506 0.0150009 0

1126.9 0 342.824 0.0153574 0

1285.790 394.75 0.0157453 0

1444.680 447.084 0.0161637 0

1603.570 499.604 0.0166117 0

1762.450 552.077 0.0170877 0

1921.340 604.264 0.0175899 0

2080.230 655.935 0.0181162 0

2239.110 706.874 0.0186643 0

23980 756.888 0.0192317 0.74

3218.4 0 995.379 0.0223706 0.74

4038.8 0 1195.74 0.0256431 0.74

4859.2 0 1360.49 0.0288538 0.74

5679.6 0 1496.29 0.0319135 0.74

6500 0 1609.67 0.0347948 0.74

GRAVITY GAS 0.8

REFPW 14.696

DENSITY WATER 62.4

DENSITY SOLVENT 0.06248

BWI 1.06212

CW 3.72431e-006

VWI 0.23268

CVW 0.0

**$ Property: PVT Type Max: 1 Min: 1

PTYPE CON 1

DENSITY OIL 50.863

CO 1e-5

OMEGASG 1.0   ** Gas and solvent mixing parameter

MINSS   0.2   ** Minimum solvent saturation

ROCKFLUID

****

***

```
** Rock-Fluid Properties

*************************************************************************
***

RPT 1

**$ Swkrwkrow

SWT

0.2     0       1       5

0.25    0.00040.6027  4

0.3     0.0024 0.449   3

0.31    0.0033 0.4165 2.8

0.35    0.0075 0.3242 2.5

0.4     0.01670.2253  2

0.45    0.031   0.1492 1.8

0.5     0.0515 0.0927 1.6

0.6     0.1146 0.0265 1.4

0.7     0.2133 0.0031 1.2
```

0.8 0.3542 0 1

0.9 0.54380 0.5

1 0.7885 0 0

**$ SlkrgkrogPcog

SLT

0.3 0.6345 0 1.92

0.4 0.5036 0.00002 1.15

0.5 0.3815 0.00096 0.77

0.6 0.2695 0.00844 0.5

0.7 0.1692 0.03939 0.32

0.8 0.0835 0.1301 0.22

0.85 0.0477 0.2167 0.18

0.9 0.01830.3454 0.15

0.95 0 0.5302 0.12

1 0 1 0.1

RPT 2

**$ Swkrwkrow

SWT

0	0	1
0.05	0.05	0.95
0.25	0.25	0.75
0.5	0.5	0.5
0.75	0.75	0.25
0.95	0.95	0.05
1	1	0

**$ Slkrgkrog

SLT

0.00	1.00	0.00
0.05	0.95	0.05

```
0.25  0.75   0.25

0.50  0.50   0.50

0.75  0.25   0.75

0.95  0.05   0.95

1.00  0.00   1.00

*RTYPE *IJK

1:1 1:55 1:7 2

2:21 1:55 1:7 1

22:22 1:55 1:7 2

  *INITIAL

**********************************************************************

***

   ** Initial Conditions Section

**********************************************************************

***

VERTICAL DEPTH_AVE WATER_OIL EQUIL
```

REFDEPTH 9984

REFPRES 6425

DWOC 15000

PB CON 2398

PBS CON 2398

*NUMERICAL

****

***

** Numerical Methods Control Section

****

***

DTMIN 1e-9

NORTH 40

ITERMAX 100

RUN

DATE 2010 1 1

```
DTWELL 1e-008

**$

WELL  'Inj2'

**$ wdepthwlengthrel_roughwhtempbhtempwradius

INJECTOR MOBWEIGHT 'Inj2'

IWELLBORE  MODEL

**$ wdepthwlengthrel_roughwhtempbhtempwradius

   9987.  200.  0.0001  60.  255.  0.25

INCOMP  SOLVENT  GLOBAL  0.77  0.  0.2  0.  0.  0.  0.  0.03  0.

OPERATE  MAX  BHP  7000.  CONT

OPERATE  MAX  STS  400000.  CONT

**$          rad  geofacwfrac  skin

GEOMETRY  K  0.25  0.37  0.5  0.

PERF  GEOA  'Inj2'

**$ UBA      ff  Status  Connection

22 28 4   1.  OPEN    FLOW-FROM  'SURFACE'
```

```
**$

**$

WELL  'Prod2'

PRODUCER 'Prod2'

OPERATE  MIN  BHP  2500.  CONT

**$ UBA ff Status Connection

**$ rad geofacwfrac skin

**$ UBA ff Status Connection

**$ UBA              ff  Status  Connection

**$          rad  geofacwfrac  skin

GEOMETRY  K  0.25  0.37  0.5  0.

PERF  GEOA  'Prod2'

**$ UBA      ff  Status  Connection

22 28 4   1.  OPEN    FLOW-TO  'SURFACE'



WELL  'Inj1'
```

```
**$ wdepthwlengthrel_roughwhtempbhtempwradius

INJECTOR MOBWEIGHT 'Inj1'

IWELLBORE  MODEL

**$ wdepthwlengthrel_roughwhtempbhtempwradius

   9987.  200.  0.0001  60.  255.  0.25

INCOMP  SOLVENT  GLOBAL  0.77  0.  0.2  0.  0.  0.  0.  0.03  0.

OPERATE  MAX  BHP  7000.  CONT

OPERATE  MAX  STS  400000.  CONT

**$         rad  geofacwfrac  skin

GEOMETRY  K  0.25  0.37  0.5  0.

PERF  GEOA  'Inj1'

**$ UBA      ff  Status  Connection

1 28 4   1.  OPEN   FLOW-FROM  'SURFACE'



WELL  'Prod1'

PRODUCER 'Prod1'
```

```
OPERATE  MIN  BHP  2500.  CONT

**$ UBA ff Status Connection

**$ rad geofacwfrac skin

**$ UBA ff Status Connection

**$ UBA              ff  Status  Connection

**$          rad  geofacwfrac  skin

GEOMETRY  K  0.25  0.37  0.5  0.

PERF  GEOA  'Prod1'

**$ UBA      ff  Status  Connection

1 28 4   1.  OPEN    FLOW-TO  'SURFACE'



OPEN 'Prod1'

OPEN 'Prod2'

SHUTIN 'Inj1'

SHUTIN 'Inj2'

 *AIMSET *CON 0
```

```
*AIMWELL *WELLN

WSRF GRID TNEXT



TIME 360

OPEN 'Prod1'

OPEN 'Prod2'

SHUTIN 'Inj1'

SHUTIN 'Inj2'

*AIMSET *CON 0

AIMWELL WELLN

WSRF GRID TNEXT



TIME 1800

OPEN 'Prod1'

OPEN 'Prod2'

SHUTIN 'Inj1'
```

```
SHUTIN 'Inj2'

*AIMSET *CON 0

AIMWELL WELLN

WSRF GRID TNEXT



TIME 3600

SHUTIN 'Prod1'

OPEN 'Prod2'

OPEN 'Inj1'

SHUTIN 'Inj2'

*AIMSET *CON 0

AIMWELL WELLN

WSRF GRID TNEXT



TIME 7200

SHUTIN 'Prod1'
```

```
OPEN 'Prod2'

OPEN 'Inj1'

SHUTIN 'Inj2'

*AIMSET *CON 0

AIMWELL WELLN

WSRF GRID TNEXT



TIME 18000

SHUTIN 'Prod1'

OPEN 'Prod2'

OPEN 'Inj1'

SHUTIN 'Inj2'

*AIMSET *CON 0

AIMWELL WELLN

WSRF GRID TNEXT
```

TIME 25200

SHUTIN 'Prod1'

OPEN 'Prod2'

OPEN 'Inj1'

SHUTIN 'Inj2'

*AIMSET *CON 0

AIMWELL WELLN

WSRF GRID TNEXT

****

STOP

RESULTS SPEC 'Permeability J'

RESULTS SPEC SPECNOTCALCVAL -99999

RESULTS SPEC REGION 'All Layers (Whole Grid)'

RESULTS SPEC REGIONTYPE 'REGION_WHOLEGRID'

RESULTS SPEC LAYERNUMB 0

RESULTS SPEC PORTYPE 1

RESULTS SPEC EQUALSI 0 1

RESULTS SPEC SPECKEEPMOD 'YES'

RESULTS SPEC STOP

RESULTS SPEC 'Permeability K'

RESULTS SPEC SPECNOTCALCVAL -99999

RESULTS SPEC REGION 'All Layers (Whole Grid)'

RESULTS SPEC REGIONTYPE 'REGION_WHOLEGRID'

RESULTS SPEC LAYERNUMB 0

RESULTS SPEC PORTYPE 1

RESULTS SPEC EQUALSI 1 0.1

RESULTS SPEC SPECKEEPMOD 'YES'

RESULTS SPEC STOP

VITA

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