EVALUATION OF OPTIMAL DESIGNS FOR INFILL WELL DRILLING FOR WATER FLOOD SYSTEMS

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By

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CERTIFICATION

This is to certify that the thesis titled "**EVALUATION OF OPTIMAL DESIGNS FOR INFILL WELL DRILLING FOR WATERFLOOD SYSTEMS**" submitted to the school of postgraduate studies, African University of Science and Technology (AUST), Abuja, Nigeria for the award of the Master's degree is a record of original research carried out by Mohammed Isah in the Department of Petroleum Engineering.

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ABSTRACT

One of the ways of maximizing recovery from a reservoir is by drilling infill wells. Infill well placement is challenging because many well scenarios must be evaluated when undertaking the optimization program and very often, the variables that affect reservoir performance are nonlinearly correlated with some degree of uncertainty. Resultantly, the use of stochastic search algorithms has gained wide acceptance in solving problems associated with well placement.

This research seeks to analyze the efficiency of the flood patterns as published by Crawford and to ascertain the efficiency of the peripheral pattern which is not available in literature. Also employed is an efficient optimization tool to solve the well placement problem by identifying the optimum locations for the infill wells. Particle Swarm Optimization Algorithm (PSA) has proved to be an effective tool in addressing well placement problems, and it was employed in this research as the main optimization algorithm. Flood pattern analysis was conducted to determine the optimum pattern for the development of the reservoir model built for this study. The first was a homogenous model used to determine the recovery efficiencies of the flood patterns, i.e., 5-spot, inverted 5-spot, 9-spot, line drive, peripheral and staged line drive. The efficiencies obtained were 78.63 %, 77.89 %, 76.53 %, 58.89 %, 77.7 % and 59.25 % respectively. These were in agreement with the efficiencies published by Crawford with a 5% error. Investigation into the effect of heterogeneity on pattern selection was studied using cumulative field oil produced, pressure maintenance ability of the patterns, time to breakthrough, optimum pore volume to be injected and the economics of the flood patterns as screening criteria. The peripheral flood pattern was selected as the optimum flood pattern, while the well placement analysis and infill drilling optimization was carried out to maximize recovery from the reservoir.

A sensitivity analysis was conducted to evaluate the impact of permeability anisotropy, injection rate and maximum number of wells to be drilled on the net present value of the reservoir. After the findings, the optimum well locations, the number of wells and the corresponding well spacing was determined.

The major contribution of this work is that a methodology for infill well placement and flood pattern selection has been developed, with the efficiency of peripheral flood pattern added to literature. This is a useful tool to support petroleum engineers in deciding how to maximize the value of their asset - the petroleum reservoir.

KEYWORDS: Reservoir development, optimization, particle swarm algorithm, infill well drilling, waterflood, well placement, sensitivity analysis, peripheral flood pattern, pattern recovery efficiency, permeability anisotropy.

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CHAPTER ONE

INTRODUCTION

1.1 BACKGROUND OF STUDY

The ability of any nation to survive economically depends upon its capacity to produce and manage sufficient supplies of low-cost, safe energy resources like fossil fuels (Isah, 2014). The world's consumption of limited fossil fuel resources currently increases annually by 3 percent, with projections in this trend showing that all known reserves will be exhausted in the next 50years (Isah,2014). Therefore, any sustained attempt to increase the reserves by even as little as 1 percent per annum ensures an effective eternal supply as the world moves slowly towards renewable energy economics. (Callaghan, 1981). So, as the demands on energy industries to increase profitability and reduce environmental pollution continues, many industries are focusing on improving recovery efficiency and means to increase their reserves of resources to provide attractive solutions to the problem of rising energy demands. It is clear how improving reserves benefit profitability by considering the cost of energy.

Conventional and unconventional hydrocarbons are likely to remain the main component of the energy mix needed to meet the growing global energy demand in the next 50 years (Zitha *et al.*, 2010). The worldwide production of crude oil could drop by nearly 40 million B/D by 2020 from existing projects, and an additional 25 million B/D of oil would be needed to keep pace with consumption. Such forecasts according to Adeyinka et. Al., (2017) imply that scientific breakthroughs and technological innovations are needed, not only to secure supply of affordable hydrocarbons but also to minimize the environmental impact of hydrocarbon recovery and utilization.

Crude oil is found in underground porous sandstone or carbonate rock formation, with the first (Primary) stage of oil recovery involving the displacement of oil from the reservoir into the wellbore and up to the surface under its reservoir energy, such as gas drive, water drive, or gravity drainage. In the second stage, an external fluid such as water or gas is injected into the reservoir through injection wells located in the rocks that have fluid communication with producing wells. The purpose of secondary oil recovery is to maintain reservoir pressure and displace hydrocarbon towards the wellbore. The most common secondary recovery technique is water flooding (Ahmad and Baohun, 2010).

Water flooding involves the injection of water into the reservoir to displace the residual oil which could not be produced under the primary recovery towards the producing wells (Willhite, 1986). The injection is carried out by either converting existing producer wells to injectors or drilling infill wells (replacement wells).

It has been known that infill drilling can improve the recovery of hydrocarbon by accelerating the hydrocarbon productions because most reservoirs in the real world are not homogeneous (Guan *et al.,* 2007). Due to this reason of heterogeneity in the reservoirs which leads to water flooding not completely able to sweep the reservoir, the need for proper infill design programs must be carried out. The process involves evaluation of optimum designs of infill wells for the improved oil recovery of water flood systems and evaluation of the flooding pattern implemented.

1.2 STATEMENT OF THE PROBLEM

Developing a field is a challenging job with the main goal being to reach the highest ultimate oil recovery. One of such techniques that could ensure maximum oil recovery is water flooding of a reservoir whose energy is no longer economical to produce. Based on experience of carrying out water flooding in fields all over the world, mostly in the U.S and Canada, various factors have been found to affect flooding operations.

Thomas *et al.,* (1989), pointed out that in determining the sustainability of a candidate reservoir for water flooding, factors such as reservoir geometry, fluid properties, reservoir depth, lithology, fluid saturations, reservoir and pay continuity and primary reservoir drive mechanism need to be understood as they affect the success of the operation. He also noted that due to resource variability in reservoirs, the performance of a flooding operation would also be highly variable leading to some economically unsuccessful operations. Therefore, a prudent way of ensuring economic success must be developed.

Lots of methods are recommended to develop fields, but none of them are compressive enough. To develop a field, the location of a new well should be considered, and then its effect on the ultimate production should be investigated. This approach plays an important role in revitalizing marginal oil and gas fields not just by accelerating recovery but also by adding new reserves, especially in heterogeneous reservoirs. However, designing an infill drilling program is often very tasking, since the design often has to deal with a large number of existing wells and evaluating hundreds or thousands of potential infill alternatives. On the other hand, it is necessary to drill these wells in appropriate points to avoid or minimize the interference in their drainage areas (Sayyafzadeh *et al.,* 2010).

One of the newest methods of developing a field is using streamline simulations. In this approach, there are two main stages: first, to gain the possible advantages from the infill drilling, new producers should be drilled in sections of the reservoir where the oil saturation is high. Secondly, converting mostly dead producers to injectors in order to create a more efficient flooding pattern.

In this work, we use the simulations approach to develop a guideline to drilling new producers, switch some of the old producer wells to injectors in order to increase the oil recovery and also carry out economic evaluation which involves estimating the injection and production rates and making projections of oil recovery for an anticipated life of each flooding pattern. These estimates along with the well layout for the waterflood, provide sufficient technical data to estimate investment requirements, operating costs and income.

For infill drilling to be justified, anticipated revenues from incremental oil drained and rate of its drainage should be sufficient to offset costs on a risk-weighted basis (Singhal, Springer and Turta,2005). Net revenues, besides oil prices, are dependent upon productivity and incremental reserves drained. Incremental reserves, in turn, depend upon heterogeneities/ channeling, etc. causing poor volumetric sweep. The success of infill wells can be measured in terms of their effectiveness in mitigating negative influences due to heterogeneity. Intuitively, in a very heterogeneous system, increasing the number of injection/ production wells should lead to more efficient oil drainage. Such incremental benefit would be relatively less if the target reservoirs were relatively homogeneous.

1.3 RESEARCH AIMS AND OBJECTIVES

This research work aims to carry out Screening of Water floods operations for infill drilling potential, as well as analyze the effect of well pattern on the waterflood performance.

The aim will be actualized through the realization of the following objectives:

i. Reservoir modeling (3D model) under different production mechanism.
ii. Identification of key variables that control the project life and oil recovery.
iii. Simulation of waterflooding operation with different flood pattern arrangements.
iv. Determination of infill well locations using stochastic search algorithm.

1.4 SCOPE OF THE RESEARCH

Studies to be presented in this work shall be based on information available from literature and a synthetic reservoir model built for simulation.

1.5 JUSTIFICATION OF THE RESEARCH

Oil production from mature oil fields accounts for approximately 70% of the worldwide oil production (Qingfeng *et al.,* 2016). In recent years before 2015, due to the increasing energy demand and favorable oil price, increasing fields all over the world were implementing infill drilling (Guan, Du and Wang, 2005). Partly due to that, the world oil supply tends to exceed the demand, plus the structural change of energy consumption towards clean energy and softening global economy. The emerging shale gas and oil production also add to the oversupply, which causes dramatic oil price cuts down to 30 US$/STB for a time. In this fierce oil market, taking a share is crucial for major oil companies, and infill drilling is still a tempting choice, compared to risky and uncertain enhanced oil recovery (EOR) projects.

The strategic statement of the energy sector of Nigeria vision 20:2020 states that it is necessary for the country to embark on energy conservation and energy efficiency initiatives which will require industries to move to energy saving equipment and utilities for a reduction in total power demand (Ndaman, 2012). So, as a result of a shift in Government policy of establishing refineries and petrochemical companies for providing energy and petrochemical at a subsidized rate for its populace to a firm pledge to profit-making companies, energy saving is a pivot to achieving this goal for the existing refineries. Thus, the prime objective of this project is to achieve incremental oil recovery to increase the national oil reserve, which will ensure long lasting income generation for Nigeria, as the country derives 95 % of export earnings and 70 % of government revenue from the oil sector.

It is therefore indispensable to carry out analysis of the screening of infill drilling potential. This will bring about the increase in the oil reserve and accelerate production. These, therefore, justify the need for a project of this nature.

CHAPTER TWO

LITERATURE REVIEW

2.1 INTRODUCTION

In this chapter, well placement in waterflood systems is reviewed. This review includes types and patterns of waterflooding, uncertainty analysis of geological factors that affect waterflooding performance and optimization. Also reviewed in this chapter is the concept of genetic algorithm (GA) as a well placement optimization technique. Finally, the contributions of this research are stated.

Most of the hydrocarbons initially in place are not recovered from primary recovery techniques. As a result, secondary recovery techniques – waterflooding are implemented. These involve maintaining the reservoir pressure as well as fluid displacement to improve recovery of hydrocarbons (Ahmed, 2006).

The most commonly used secondary recovery technique is waterflooding, and for several reasons, waterflooding typically has lower operating costs compared to other fluid injection techniques because water is cheaper and readily available compared to other injection fluids. Also, the mobility ratio – ratio of mobility of displacing fluid to the mobility of displaced fluid – is favorable for efficient fluid displacement. However, waterflooding could have some challenges such as production and surface processing problems due to early water breakthrough, and, wide permeability variations and reservoir heterogeneities affecting fluid transport within the reservoir (Ahmed, 2006).

In waterflooding, several factors should be considered, namely: reservoir geometry, lithology,

porosity and permeability, reservoir depth, continuity of rock properties, fluid saturations and distributions, fluid properties, relative permeabilities, reservoir uniformity and pay continuity, and primary recovery driving mechanisms (Ahmed, 2006). Another important consideration in waterflooding is the optimum time to waterflood, which is based on anticipated oil recovery, reservoir pressure at the start of waterflooding, fluid production rates, monetary investment, availability and quality of the water supply, cost of water treatment and pumping equipment, and so on (Ahmed, 2006).

Although waterflooding is cheaper when compared to other fluid injection techniques, it is still an expensive venture. As a result, if after research and analysis on a petroleum reservoir of interest, it is decided that a waterflood project is necessary, optimization will be essential to maximize the hydrocarbon recovery from the project. Hence, the objective of optimization is to maximize hydrocarbon recovery at the surface per barrel of water injected while minimizing formation damage, maintaining reservoir pressure and with the same or reduced capital and operating costs (Yusuf, 2010).

Well placement and spacing in waterflooding done in either regular patterns or irregular patterns. Waterflooding in older fields was done using irregular patterns; however, recent waterflood projects involve regular patterns. These regular patterns involve a specific arrangement of injectors and producers to maximize recovery from the reservoir. There are several regular patterns used in waterflooding, and so optimization is required to select the best pattern that would efficiently and economically produce the reservoir of interest.

Well spacing is of vital importance in the petroleum industry. The well itself plays a vital role in the development of the petroleum asset to maximize recovery. However, determination of appropriate well spacing for maximum economic oil recovery has been a complicated and controversial issue in oil field development. Various studies have shown a slim relation between well spacing and recovery (John *et al.,* 2010). Nonlinear programming has also been used in literature for optimization of oil reservoirs (John *et al.,* 2010).

Waterflood Optimization – which is in essence pattern balancing – attempts to achieve a balance between injector and producer wells within a pattern, minimize oil migration to adjacent patterns, minimize loss of hydrocarbons into the formation, and maximize the use of available injection water to improve oil recovery. The results of an effective pattern balance are better sweep efficiency with minimal bypassed oil and higher hydrocarbon recovery. It must be noted that although the overall efficiencies of each pattern have been studied and documented over the years, no single pattern is a "one size fits all" (Ogali, 2011).

2.2 WATERFLOODING

Waterflooding is a secondary recovery process in which water compatible with the reservoir of interest is injected into the reservoir to displace residual oil. Waterflooding is more commonly employed than immiscible gas injection – the other secondary recovery process – because water, which is the injectant, is relatively inexpensive compared to gas injectant. Waterflooding has two effects on the reservoir; it reduces the rate of reservoir pressure decline during production, possibly increasing the reservoir pressure with continued injection; and water injected into the reservoir sweeps the oil towards the producers, thus increasing oil production and consequently, cumulative oil production (Rose *et al.*, 1989; Abdel-Kareem *et al.*, 2009).

Although waterflooding is a relatively inexpensive and mature technology, several potential problems may arise during a the process. Some of the problems include inefficient recovery due to varying permeabilities and anisotropy, reservoir heterogeneities affecting fluid transport within the reservoir, early water breakthrough that may cause production and surface processing problems, etc. (Rose *et al.*, 1989).

2.2.1 Types of Waterflooding

In selecting a waterflooding pattern for the reservoir of interest, several factors are considered, such as reservoir heterogeneities – including directional permeability and formation fractures; injection fluid availability; anticipated maximum oil recovery and flood life; and well spacing, productivities, and injectivities. There are two types of waterflooding; patterned waterflooding and non-patterned waterflooding.

In non-patterned waterflooding, there are basically two types; generally irregular well placements and peripheral or flank waterflooding. In patterned waterflooding, where the well placements are done in some repetitive fashion, there are several types namely; regular 4-spot and skewed 4-spot, 5-spot, 7-spot, 9-spot, direct line drive and staggered line drive patterns.

Another type of flooding that can be utilized – depending on reservoir geometry and properties is the crestal and basal pattern. This involves perforating the injector wells up-structure (for gas injection) or down-structure (for water injection) relative to the producer wells, thus utilizing the effect of gravity segregation in the displacement process (Ahmed, 2006).

Based on some assumptions, Crawford in 1960 obtained the efficiencies for several pattern floods. According to him, assuming a unit mobility ratio, steady-state condition, homogeneous and uniform reservoir, and ignoring capillary and gravity effects, the efficiencies were 45% to 90% for 9-spot, 72% for 5-spot, and 56% for direct line drive pattern. The unit mobility ratio used was mobility ratio before water breakthrough.

Older fluid injection projects involved maximizing oil recovery via understanding and utilizing the reservoir heterogeneities. Well placements were irregular in both secondary and tertiary recovery processes. Eventually, it became a norm that well placements be in some repetitive pattern (Ogali, 2011). Several patterns were analyzed to determine the optimum patterns used in secondary and tertiary recovery processes. Recently, reservoir engineers, even after selecting a pattern, do not use the same pattern throughout the reservoir. This is because of two of the criteria considered in pattern selection which are reservoir heterogeneity and overall project economics (Rose *et al.,* 1989). Waterflood recovery is sensitive to heterogeneity. Mobility ratios and well configuration also influence it. During waterflooding, the effect of heterogeneity becomes less severe upon reducing the well spacing as the mobilized oil has to travel a relatively shorter distance to the nearest producing well (Singhal *et al.,* 2005).

The key objective of selecting a flooding pattern is to maximize the contact between the injection fluid and the hydrocarbon system and hence improve oil recovery and the economics of the project. This is a critical step and can be achieved by either drilling infill injector wells or converting existing production wells to injectors.

Figure 2.1 shows various patterns used in waterflooding. In this illustration, there are two types of each pattern; the normal pattern and the inverted pattern types. In the normal pattern type, for a set of injectors and producers, there are several injectors and one producer. In the inverted pattern type, for each set of injectors and producers, there are several producers and one injector.

This means that each of the patterns shown in Figure 2.1 has the normal and the inverted pattern types.

The success of a waterflood flood project can be predicted from proper selection of waterflood patterns. The primary objective is to attain a balance between injection and producer wells within a pattern and minimize oil migration to adjacent patterns and loss into the formation. Balancing patterns essentially means that for every barrel of water injected, a barrel of hydrocarbon is recovered from the production wells surrounding the injector. An unbalanced pattern leads to poor sweep, premature breakthrough, and high-water cycling. An effective pattern balancing leads to better areal sweep and higher oil recovery (Oyebimpe, 2010).

A wide variety of flood patterns (injection-production well arrangement) have been studied with efficiencies for various confined well patterns at breakthrough indicating the effect of the pattern.

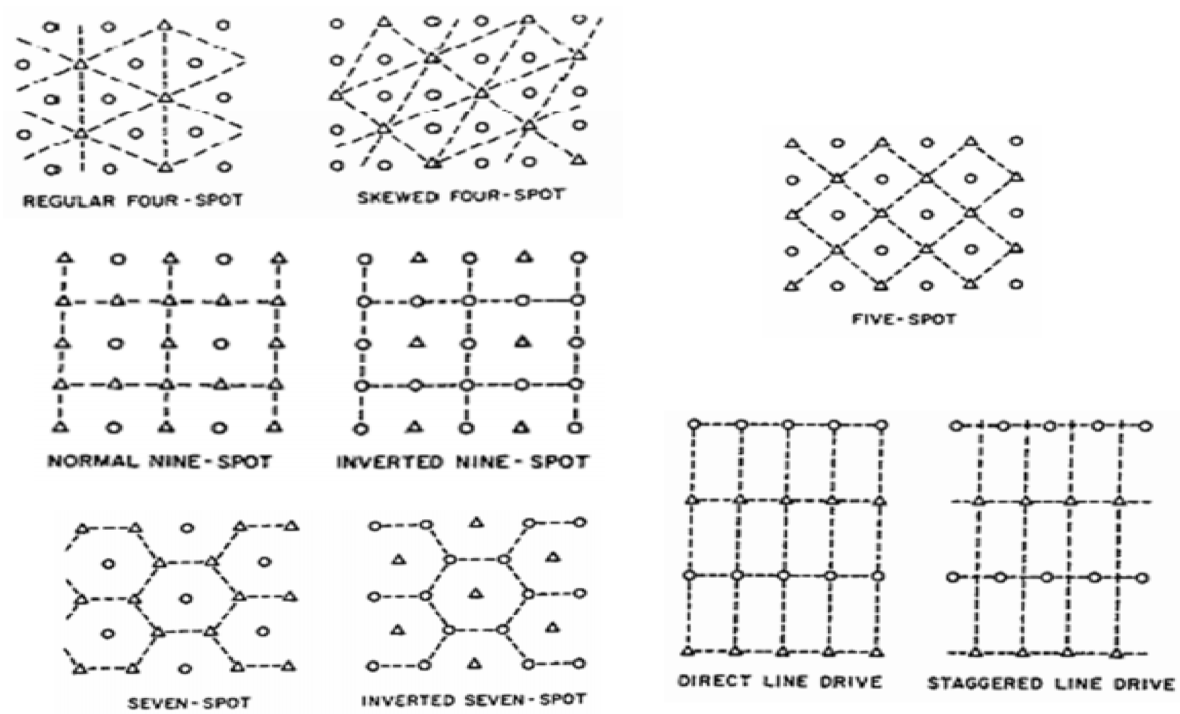

Figure 2.1: *Various patterned flood arrangements – triangles are injectors and circles are producers (Tarek Ahmed, 2006).*

A comparison of the data for the two direct line drive patterns indicate that sweep is a function of spacing ratio, with the greater ratio resulting in higher breakthrough sweep efficiency (Singh and Kiel, 1982). The effect of off-pattern wells was studied by Prats *et al*., *1962* and they found that the oil recovery at breakthrough is always lower with an off-pattern injection well. Sweep out beyond normal pattern was studied by Caudle *et. al.,* 1955.They found that at least 90 percent of the area lying outside the last row of wells and within one well spacing of these wells would ultimately be swept by the injected water.

Landrum and Crawford (1960) studied the effect of directional permeability on sweep efficiency at unit mobility ratio, for a five-spot and direct line drive (square pattern). Their results show that a 45^{o} rotation of patterns could result in approximately 100 percent sweep for the five-spot and approximately zero sweep for a line drive

2.2.2 Factors to Consider in Waterflooding

In determining how suitable a reservoir of interest is for waterflooding, Thomas, Mahoney and Winter (1989) pointed out that several reservoir characteristics must be considered.

i. Reservoir geometry – includes areal geometry influences on well and facility locations, number and location of platforms for offshore operations.

ii. Lithology and rock properties – includes rock types, clay type and content, porosity (single and dual porosity systems), permeability, well spacing, pressure history.

iii. Reservoir depth – involves considering drilling costs especially for new injector wells, dual porosity systems, temperature gradient, fracturing (injection pressure versus depth) and fracture types.

iv. Fluid properties, fluid saturations, and fluid distribution – includes consideration of the saturation and distribution of the phases (oil, water and gas) throughout the reservoir, oil viscosity, oil mobility, and mobility ratio, areal sweep and flood efficiencies.

v. Reservoir uniformity and pay continuity – includes considerations of thief zones, areal continuity of pay zones, faults, fractures, reservoir anisotropy.

vi. Primary reservoir driving mechanisms – includes review of the hydrocarbon recovery that can be achieved via waterflooding, and considering how the primary drive mechanisms will affect the waterflooding process. For instance, solution gas drive reservoirs are the best candidates for waterflooding.

Waterflooding has been employed successfully in many reservoirs. Extensive research and development in this technology have improved the efficiency of this secondary recovery process. Also, waterflooding in most reservoirs is considered a cheaper option for secondary recovery compared to immiscible gas injection. However, waterflooding has several potential problems; for instance, poor fluid transport within the reservoir due to reservoir heterogeneities, production and surface processing problems caused by early water breakthrough. Every reservoir is unique, and so there is no standard "recipe" for waterflooding a reservoir. Also, although considered a cheaper secondary recovery option, a waterflood project is a huge investment.

To maximize oil recovery and economics from a given waterflood project while minimizing injection water volumes and the effects of reservoir heterogeneities, flood management is employed. Extensive research and development of various flood management techniques have been carried out. This research involves employing one of the waterflood management techniques. The optimization objective for a field undergoing water flooding is to maximize expected net present value (NPV) or expected cumulative oil production from the reservoir (Jackson *et al.,* 2017). These objectives are maximized through proper well placement and optimal well control. While well placement and well control are often performed separately, there is increasing interest in performing coupled optimization of both decision variables. This research examined well placement, well control and coupled well placement-well control optimization.

2.2.3 Infill Drilling

Infill drilling is one of the waterflood strategies used to accelerate oil production, increase reserves and achieve better reservoir and operational control (Wu *et al.,* 1989). Infill drilling is a means of improving sweep efficiency by increasing the number of wells in an area, with well spacing reduced to provide access to unswept parts of a field. Modifications to well patterns and the increase in well density are also applied, to change sweep patterns and increase sweep efficiency, particularly in heterogeneous reservoirs. Infill drilling in pattern involves reducing the well spacing between oil producers and water injectors, no evidence of interference has been reported in literature from the reduction of well spacing and increase in well density (Gould and Sam, 1989 and Ghosh *et al.,* 2004). Emmett *et al.* (1971), reported that reducing the well spacing from 40 to 20 acres economically accelerated the production rate and increased ultimate recovery. However, a consistent set of data was not available to correlate waterflooding with well spacing. Thus, there is need to understand the effect of well spacing and pattern on infill well drilling in water flood systems. Wu *et al.*, 1989, reported the results of their study in determining the impact of infill drilling on the waterflood recovery in a West Texas carbonate reservoir in 1989. Their study showed a certain degree of correlation between waterflood recovery and well spacing.

If infill drilling projects are classified by the field environment, the results will be that the onshore fields are the majority (Linhua *et al.,* 2005). It seems that infill drilling is not widely used in the offshore reservoirs as a viable improved hydrocarbon recovery method which might be caused by the unique characteristics of the offshore environments.

Holtz *et al.,*.1991, reported that the Leonardian Restricted Platform Carbonate reservoirs exhibited abnormally low recovery efficiencies. Cumulative production from those mature Permian Basin reservoirs was only 17 percent of the Stock tank original oil in place (STOOIP), less than half the average efficiency of other carbonate reservoirs in the Permian Basin. Later, it was found that this poor recovery efficiency was directly related to high degrees of vertical and lateral facies heterogeneity caused by high-frequency, cyclic sedimentation in low-energy carbonate platform environments. Because of their geologic complexity, the Leonardian Restricted Platform Carbonate reservoirs have the potential of 683 MMSTB for reserve growth. Their study indicated that the ultimate recovery efficiency of the above reservoirs could nearly triple when reservoir development changed from 80-acre primary recovery to 10-acre secondary recovery.

The success of infill drilling as pointed out by Subbey *et al*., (2003) and Bustamante *et al.,* (2005), is directly related to the uncertainties associated with it. Individual reservoir characteristics all add up to give a resultant total uncertainty associated with reservoir performance. Analytical models are characterized by several assumptions and are becoming less efficient in estimation and quantification of various uncertainties due to the increasing complexity of petroleum reservoirs.

Two effects may be observed for infill drilling on an areal sweep. First, oil “held up” in the corners are immediately swept by reversing the streamlines within the pattern; second, patterns that are subject to poor geometry and poor injection/production balance can be improved with denser wells (Qingfeng *et al.,* 2015). Modifications to well patterns and density increase can change sweep patterns and increase sweep efficiency (Alusta and Mackary *et al.,* 2011). One study utilized sector modeling and static properties to optimize well spacing and configuration of infill drilling on 5-spot patterns (Azoug and Patel, 2014). Infill drilling can improve recovery efficiency, but can also be more expensive than a fluid displacement process (Gamal *et al.,* 2011).

Infill drilling in waterflood systems is initiated in the early development projects as in the case of the West Texas Clearfork and San Andres formation (1970). This was so when the current well spacing pattern was perceived not to drain the reservoir effectively. As a result, waterflood infill drilling was used to accelerate the oil output and improve the oil recovery from the regions that might otherwise be bypassed by larger well spacing (Thai *et al.,* 2000). The optimal well spacing is a trade-off between the incremental cost and incremental recovery associated with infill drilling (Mohan, 2011). Thus, our ability to accurately predict the incremental reserves is of importance.

Two main approaches are used in the determination of infill potential. The first one uses empirical techniques to determine infill well numbers and spacing based on a volumetric calculation of oil in place. It ignores the impact of heterogeneity and continuity. The second approach which was used in this study relies on numerical simulation coupled with optimization algorithms.

The current industry practice for the infill well potential determination uses primarily one of these two approaches (Mohan, 2011). The first one is based on decline curve analysis whereby an operator uses the well production history to determine the EUR (economic ultimate recovery). Then, using volumetric calculations, the operator will determine the gas in place. Knowing the approximate recovery expected from a typical gas well, the operator will determine the number of wells needed to deplete the gas reservoir and the well spacing. Such decline curve analysis relies on simplistic assumptions regarding reservoir properties and cannot adequately account for the complex sand continuity and heterogeneity typically present in a reservoir (Mohan, 2011). Also, in most cases, the infill well drilling is conducted using a “blanket drilling” approach without regard for the necessity to drill infill wells in some areas; whereas, developing other parts of the reservoir without infill wells. The second approach relies on a detailed numerical simulation study by generating fine-scale geological descriptions, upscaling of geologic models and history matching of existing wells. The history of matched wells is then used to predict the potential of infill wells. A common source of error here is in the upscaling step which often merges pay and non-pay, thus artificially increasing the sand continuity and reducing the infill benefits. Furthermore, history matching can be cumbersome, time-consuming, and manpower intensive and is rarely used except by large operators. Based on the second approach, this study looked at the remaining mobile oil at the time of infill drilling and located the optimum pattern configurations whose centers have the maximum recovery.

In deciding the infill drilling locations, based on a proper representation of the dynamic continuity of the sand, a screening methodology can be developed to eliminate areas of adequate drainage.

Under the right conditions, infilling of an ongoing pattern waterflood can reduce the project life by at least a factor of two, provides better injection control, improves economic limit and generates a substantial amount of secondary incremental recovery (Gould and Munoz, 1982). If the risks and uncertainties are better understood, the ability to make good development decisions will be greatly enhanced (Awotiku, 2011). These will then help to mitigate uncertainty and shift to the right and narrow the distribution of recovery and net present value. The evaluation and quantification of the effect of key risk factors is sometimes a complex process because of the multiplicity of combinations in development options which are most times represented by running simulations.

It is well established that uncertainty exists in simulated recovery forecasts due to the ambiguity in the measurement and representation of the reservoir and geologic parameters (Friedmann *et al.,* 2001 and Fuller *et al.,* 1992*)*. This is especially true for immature projects, such as deep-water reservoirs, where the high cost of data limits the information that is available to build reservoir models.

Uncertainty in reservoir models is connected to many factors. According to Corre *et al.,* 2000, they are linked to the geological scheme, sedimentary framework, nature of the reservoir rocks, their extent and properties as well as heterogeneities. Due to these myriad sources of uncertainties, a static model is likely the source of the greatest uncertainty in reservoir simulation. Nevertheless, static models have been helpful in supporting future development activities of hydrocarbon reservoirs. A reservoir model is first developed using available data. Except for outcrop and 2-D and 3-D seismic data, most of these data are determined at the reservoir well points. Even for fully developed and matured fields these well points only account for less than 1% of the reservoir volume (Mohaghegh *et al.,* 2006). Thus, parameters used in estimating the hydrocarbon volumes and reserves have uncertainties associated with them.

Ignoring the uncertainties in the reservoir lithology can result in underestimation of the inter wells structural elements and ultimately the connected pore volume. Quantifying uncertainty in volumes of hydrocarbons in place has been a challenge for the oil and gas industry (Akinwumi *et al.,* 2004). The challenge stems from many factors, tangible and intangible, that enters the estimation process. Among the reservoir engineers' tasks is devising strategies to achieve uncertainty assessment of important quantities such as production forecast. The pre and postreservoir performance evaluations are generally not equal. This is due to inability to identify and analyze the key uncertainties in model input parameters.

The uncertainty in geology can be represented by generating multiple, equally probable realizations of the geological model. This results in different performance for the same well configuration evaluated in different realizations of the geological model. Each well configuration must therefore be evaluated for each realization of the geological model, which results in a large number of function evaluations (simulations). For practical applications, a method to reduce the number of simulations for this optimization is required(Onwunalu, 2006).

ED is necessary to minimize the number of simulations to evaluate a large array of parameters. In general, rigorously evaluating N parameters varying at p levels without ED would result in pN simulations. This number can quickly become unmanageable, e.g., for 12 variables varying at 3 levels, we need almost half a million (3^{12}) simulations. ED is used all the way from conception of the geological models through the design of the optimal simulation strategy till the analysis of the results. Recently, some applications of ED technology to reservoir engineering problems have surfaced in the literature (Friedmann *et al.,* 2001, Chewaroungroaj *et al.,* 2000, Corre *et al.,* 2000).

The success of infill drilling as pointed out by Subbey *et al.*, (2003) and Bustamante *et al.,* (2005), is directly related to the uncertainties associated with it. Individual reservoir characteristics all add up to give a resultant total uncertainty associated with reservoir performance. Analytical models are characterized by several assumptions and are becoming less efficient in estimation and quantification of various uncertainties due to increasing complexity of petroleum reservoirs.

According to Ofoh, (1992), infill drilling can improve the recovery of hydrocarbon by accelerating the hydrocarbon productions. However, the determination of infill potential as well as selection of well type and placement has been a challenge (Thakur *et al.,* 1998).

The recommended way to determine infill drilling potential in a reservoir is to conduct a complete reservoir evaluation involving geological, geophysical, and reservoir analyses and interpretations. This approach is prohibitively time-consuming and expensive for some large hydrocarbon fields (Linhua *et al.,* 2005).

The Infill Drilling Predictive Model (IDPM) which requires a minimum amount of reservoir and geologic description has also been used (Fuller *et al.,* 1992). However, IDPM requires knowledge of heterogeneity elements (pay continuity and permeability variation among layers.) which are not easily or often measured in actual fields.

Voneiff and Cipolla, (1996) developed a model-based analysis method, the moving window technique, and applied it to the rapid assessment of infill and recompletion potential in the Ozona field. The method according to the author is quick, but the accuracy decreases with increasing heterogeneity. Empirical correlations (Hudson *et al.,* 2000) are also available to determine infill potential in a complex, low-permeability gas reservoir. These correlations are reservoir specific and therefore have gained limited applications. The use of numerical-based instead of analytical based conceptual models has been reported (Pathak *et al*., 2000), Thus, recommended only are prospects that allow multi-well infill locations, enabling computation of statistically meaningful risk-weighted averages (Singhal *et al.,* 2005). Therefore, quantifying risks and uncertainties help a great deal in decision making. Various methods are currently used in decision making in the oil industry. Some of them are Worst Case/Best Case Scenario, Tornado Plots, Boston Grid, Expected Net Present Value, Decision Trees, Monte Carlo Simulation and Real

Options (Awotiku, 2011). These methods are characterized by different degrees of complexity and specific theoretical assumptions. This work will utilize some of the methods used in decision making to formulate guidelines for understanding and managing risks for successful marginal field development. The proposed workflow enhances the use of experimental design by combining the technique with response surface methods and rational engineering judgment. This approach is recommended for the evaluation of green fields when a new perspective of the economic analysis of project decisions is desired (Carreras *et al.,* 2006).

Yadavalli *et al.,* 1991, evaluated the waterflood infill drilling performance in the study area of the Johnson J.L. “AB” unit in Ector County, West Texas. The economic evaluation for blanket and targeted infill drilling scenarios indicated that the targeted infill drilling scenario resulted in a higher recovery and better economic return than the blanket infill drilling scenario. Moreover, they found that the optimum infill drilling pattern did not need to be a regular pattern.

Xue *et al.,* 1994, compared the waterflood infill drilling and CO_2 flood in the Monahans unit and Johnson J.L. “AB” unit and they found that with waterflood infill drilling at 10-acre spacing, the recovery factor can be as high as 30%. However, the economic analysis indicates that waterflood on a 10-acre well spacing is less profitable when compared to CO_2 flood. Moreover, it is rarely reported that infill drilling practice has been applied to the fields whose current well spacing is less than 10-acre even for the low-permeability hydrocarbon fields.

2.3 WELL PLACEMENT OPTIMIZATION TECHNIQUE

The well placement optimization problem is a high-dimensional, multimodal (for non-trivial problems), constrained optimization problem. The main aim of oil field development is to increase the NPV. One of the methods for increasing NPV is drilling additional oil production wells in the field, which highly depends on the number of wells that would be drilled and the well locations (Beckner, 1995). The proposed infill well locations can be specified according to the contour maps of permeability and oil saturation at the last simulation time step. These contour maps are the best indicator for determining the best and worst locations to drill infill wells (Badru, 2003). These maps are obtained by using a criterion that quantitatively characterizes each grid block for the suitability of the well (Guyaguler, 2002). The high values of the last function (Eq. 2.1) on the map indicate the probable promising locations. The low values indicate locations where infill is not recommended. After determining the possible infill well locations, optimization techniques are adapted to determine the optimal number and locations of infill wells (Quenes, 1994).

$$Target_{Location} ¿ f\left(S_o, x, y, k(x,y)\right) \quad Eq.2.1$$

The optimization algorithms employed for this problem fall into two broad categories: global search, stochastic algorithms and gradient-based algorithms. The stochastic optimization algorithms, such as GAs and simulated annealing, are computational models of natural or physical processes. They do not require the computation of derivatives. In addition, stochastic optimization algorithms possess mechanisms or algorithmic operators to escape from local optima, e.g., the mutation operator in GAs. However, these algorithms tend to require many function evaluations, and their performance depends on the tuning of algorithmic parameters (Onwunalu, 2010).

Well placement optimization problems are a discrete-parameter problem, with the gradient of the objective function (NPV) not defined (Pallav and Wen, 2008), this is the reason why gradient-based algorithms have limited applicability as it falls into a local optimal. Replacement of the discrete parameters (i, j well location) indices was carried out by Pallav and Wen (2008), with the continues counterparts in the spatial domain (x, y well locations) and functional relationship between the objective function and these continues parameters developed. The functional relationship was obtained by replacing the discontinuous Dirac-delta functions in the governing PDE with continues function. Numerical discretization of the modified PDE led to well terms in the mass balance equations that are a continuous function of the continuous well location variables. The efficiency and practical applicability of the gradient-based algorithm was demonstrated using a synthetic model.

Several investigators have applied different algorithms to solve the well deployment problem. Bittencourt and Horne (1997), Guyaguler and Horne (2001) and Guyaguler *et al.* (2002) applied genetic algorithms (GA) to optimize the placement of vertical wells. Optimization under geological uncertainty was considered by Guyaguler and Horne (2001). Yeten (2003), Zyed *et al.,* 2012 and Yeten *et al.* (2003) developed a framework for optimization of nonconventional wells using a genetic algorithm under geological uncertainty. They proposed a procedure can optimize the number, type, and trajectory of a nonconventional well using a generic parameterization of the variables describing the well.

The use of GAs for optimization of well deployment is computationally intensive, requiring many simulations. This is the case because GAs use a generate-and-test paradigm (Cox, 2005) where feasible potential solutions are generated, and each is simulated using the function evaluator (simulator and economic model). In the well placement optimization, the testing of each solution corresponds to performing a simulation for each well configuration over all realizations of the geological model.

Alexander *et al.,* 2009, implemented a genetic algorithm (GA) based tool for the simultaneous optimization of number, location, and trajectory of producer and injector wells. The authors developed software with capabilities to address realistic placement problems having arbitrary well trajectories, complex model grids, and linear and nonlinear constraints. Two strategies were considered to define the initial population of the GA; the first was generated randomly and the second was based on a proposed scenario by the engineer.

Investigators have proposed algorithms using heuristics to reduce the number of simulations required during optimization. Bittencourt and Horne (1997) used a hybrid GA involving GA, tabu search and polytope to reduce the number of simulations required in vertical well placement applications. Pan and Horne (1998) applied the least squares and kriging interpolation techniques as proxies to identify promising well configurations. The proxies were constructed from previously simulated well configurations. Guyaguler *et al.* (2002) also applied a hybrid algorithm using GA, polytope (hill climbing), kriging, and artificial neural networks (ANN) to reduce the number of simulations required. This hybrid algorithm was applied to real field cases, and performance using kriging was found to be superior to that from ANN. Yeten (2003) also used a hybrid algorithm involving GA, polytope, and ANN for optimization of nonconventional well placement. Polytope was used for the local search when the improvement in the best solution was marginal, especially in later generations. The use of ANN as a proxy provided reasonable agreement between the predicted (prior) and observed (posterior) fitness in the application considered by Yeten (2003).

It is in general difficult to assess the performance of proxies applied in well placement optimization. One approach would be to quantify the difference between the optimal solution and the best solution found using the proxy. However, GAs do not guarantee that the globally optimum solution will be found (Cox, 2005; Duda *et al.,* 2001). Hence it is difficult to compare how well a proxy performs during the optimization.

Over the years, lots of research has been done on this problem, most of which using optimization routine coupled to reservoir simulation models. Despite all this research, there is still a lack of robust computer-aided optimization tool to deal with realistic well placement problems (Alexandre *et al.,* 2009).

Watrheq and Mohammed (2014) studied optimization of infill oil well locations with field scale application. This was to determine the optimal well locations, as it is crucial to field development decisions. The reservoir modeling-optimization approach was adopted and applied on sandstone formation of the South Rumaila oil field in Iraq. The authors, first of all, compared the outcomes of different parameters with their measured values through a history matching process to attain the validity of the reservoir flow model. After that, two methods of optimization were adopted to find the optimal number and locations of infill oil wells. The first method was manual optimization via spreadsheet and the second one was automatic optimization through Adaptive Genetic Algorithm (GA). Both methods were done according to the aspects of net present value as an objective function in the wells selection optimization procedures. GA depends on the concept of Darwin's theory of Natural Selection. The genetic program was coupled with the reservoir flow model to re-evaluate the chosen wells at each iteration until the optimal choice was obtained. The genetic algorithm program gave results similar to the results that were obtained by a manual method with much less computation time. Three different future predictions of oil production and NPV cases were studied to determine the optimal future scenario with respect to whether considering water injection or not in the available water injectors (Ofoh, 1992). The first one without water injection, the second and third with 7500 surface bbls/day and 15000 surface bbls/day water injection per well, respectively. According to the relationship between net present value and future production time, the abandonment time was estimated to be at the end of the 8th prediction year for all the above cases. The optimal future scenario was with water injection of 15000 surface bbls/day; however, the current capabilities of surface injection facilities of the oil field could not handle such a rate. Therefore, the optimal future prediction was to continue with water injection of 7500 surface bbl./day/well. The optimal number of infill wells for this case was three wells even though drilling more wells which led to increasing the cumulative oil production. The incremental percent of NPV based on the optimized infill well location scenario improved by 3.4% higher than the base case on no-infill wells.

Adeboye *et al.,* 2017, carried out evaluation of infill drilling in deep waters using an experimental design, with Agbami field as the case study. Two methods were used to determine the reference case; the first was creating a probabilistic model using the uncertainties and secondly, creating a total case and backing out the infill wells from the total case to obtain the reference case. The authors assert that infill drilling is one of the levers through which the Agbami asset team has been able to sustain the plateau production and highlighted the importance of a constant review of an asset for opportunities to increase recovery. Alignment between the asset team and decision makers in the early life of the project, having specific and measurable metrics defined from alignment meetings, and ensuring that all facilities, drilling, and completion constraints built into the forecast workflow are some of the factors responsible for the success of this research study. Adopting two approaches and getting similar results further built confidence in the range of outcomes forecasted from the experimental design work.

Yeten *et al.* (2002) applied a bGA to optimize well type, location, and trajectory for nonconventional wells. Along with that, they developed an optimization tool based on a nonlinear conjugate gradient algorithm to optimize smart well controls. Several helper functions were also implemented including ANN, the Hill Climber (HC). Also, they applied near wellbore upscaling, which approximately accounts for the effects of fine-scale heterogeneity on the flow that occurs in the near-well region by calculating a skin factor for each well segment. The results of this study were presented on fluvial and layered synthetic models, as well as a section model of a Saudi Arabian field. An experimental design methodology was introduced to quantify the effects of uncertainty during optimization. The study also similarly conducted sensitivity analysis to Guyaguler's (2002) study.

Rigot (2003) extended the optimization engine developed by Yeten *et al.* (2002) by implementing an iterative approach to improve the efficiency of multilateral well placement optimization. He divided the original problem into several single well optimizations to speed up the optimization process and improve results. He also applied a proxy to avoid running numerical simulation if the expected productivity of a certain well was within the range of validity of the proxy.

Although previously highlighted studies provided promising optimization results, the used techniques consumed long optimization time. It is commonly unfeasible and computationally very expensive to conduct full optimization in some cases. To accelerate the optimization process, other work concentrated in designing proxies to the reservoir simulator. Pan and Horne (1998) used multivariate interpolation methods such as Least Squares and Kriging as proxies to reservoir simulation. The purpose of the first algorithm is to construct a function that has a simple known form to approximate some objective function. The behavior of this objective function was first observed through a number of simulations. Then, a function was constructed such that it minimized the sum of the squared residual between data and the function values. To begin their study, they selected several well locations for numerical simulation as a sample to train the proxy. Then, the NPV surface maps were generated using the two proxies. These maps were subsequently used to estimate objective function values at new points. They observed that the Kriging method provides a more accurate means to estimate the objective function than the Least Squares interpolation in the tested examples.

Onwunalu (2006), investigated the use of a dynamic proxy model for well placement optimization of an unconventional well. This proxy provided an estimate of the cumulative distribution function (CDF) of the scenario performance, which enabled the quantification of proxy uncertainty. Knowledge of the proxy-based performance estimate in conjunction with the proxy CDF enabled the systematic selection of the most appropriate scenarios for full simulation. The application of the proxy was extended to the optimization of multiple nonconventional wells opened at different times. For the optimization of a single nonconventional well, it was shown that by simulating only 10 or 20 % of the scenarios, optimization results were close to those achieved by simulating all cases. For multiple wells drilled at different times, the dynamic proxy was effective though a relatively high percentage (e.g., 50%) of the cases needed simulation.

Obed, 2016, carried out evaluation of infill well placement optimization using particle swarm algorithm. The research sought to solve the well placement problem by identifying the optimal well locations and evaluation of the effect of number of infill wells and well spacing on the ultimate recovery of a synthetic model used. Uncertainties relating to the reservoir and economic parameters were investigated to monitor their impact on the net present value. Results of the study showed that the optimum well spacing was 40 acres by drilling 4 infill wells in the reservoir.

Guojian *et al.,* 2012, investigated the use of Niche particle swarm optimization (NPSO) algorithm in oil well placement problem. Niche technology was introduced into the particle swarm algorithm to demonstrate its capability to overcome premature convergence and fall into local optimal which is a pitfall of the particle swarm optimization (PSO) algorithm. The authors also highlighted the global optimization ability, fast convergence speed and the ease of operation of NPSO algorithm as what makes it an efficient combinatorial optimization tool.

CHAPTER THREE

METHODOLOGY

This chapter contains a summary of the well placement optimization in waterflood system, workflow used in this research, a summary of the sensitivity analysis, pattern study techniques, and the description of the reservoir modes developed. The assumed rock and fluid properties, as well as optimization algorithms used in the well placement analysis, are also highlighted. The chapter also contains the description of initialization of the model, the criteria used in the analysis and selection of the optimal well pattern optimization workflows used for the selected criteria.

3.1 SCOPE

This research involves the evaluation of several flooding patterns of which efficiencies have been published in the literature except for peripheral flooding pattern by Crawford in 1960. The scope of this research includes creating an actual optimized development and production strategy for the reservoir of interest, using the properties of the formation to carry out a comparative analysis of pattern performance with factors that affect the reservoir production such as heterogeneity, pattern selection, permeability anisotropy among many others.

The study also involved using streamline simulation to analyze waterflood performance on 5-spot, 9-spot, direct line drive, staggered line drive, and peripheral pattern waterflooding. Streamline Simulation is a complementary approach to finite difference simulation that has two primary advantages; the visual representation of the flow between wells in the reservoir as well as the interaction between wells and the reservoir; and injection efficiency of injection wells can be obtained easily along with the allocation factors of the wells. Also considered in this research is the use of search algorithms to determine the optimal location of infill wells to maximize the recovery of bypassed hydrocarbon due to reservoir heterogeneity.

The tools used are Schlumberger Petrel, Schlumberger FrontSim, Schlumberger Eclipse, and Microsoft Excel. Petrel was used to build and populate the reservoir model with petrophysical properties, such as porosity and permeability. Schlumberger FrontSim was used to create the grid for the reservoir model, and streamline simulations and waterflood optimization using pattern recovery efficiency. Microsoft Excel was used for analysis, plotting of graphs and the optimization schedule.

3.2 STREAMLINE SIMULATION WORKFLOW

The reservoir model used in this research was not a history-matched model. However, a hypothetical production scenario was created, and then waterflooding carried out. This was done because as stated earlier, the focus of this research is not to create an actual production strategy that should be implemented in the stated reservoir, but to carry out a comparative analysis of well patterns using the information we have about this reservoir. Using streamline simulation, water injection efficiencies for the injectors are easily obtained, and these are used in reallocating injection water to the injectors. The objective of this is to maximize the use of the injection water and waterflood patterns to maximize oil recovery from the waterflooding process. This research goes even further to not only determine the best pattern to implement, but also determines what parameters affect the flooding process and what search algorithm should be used to determine the infill well locations optimally. This is presented in the analyses of well patterns and algorithm selection.

3.3 MODEL DESCRIPTION

Two reservoir models were constructed using the data obtained from the static model, and pertinent rock and fluid properties, SCAL and well completions data. One included homogeneous properties while the other had heterogeneity introduced. The model was based on a 25x25x15 grid. The grid was in conventional rectangular coordinates without corner point geometry or local grid refinement. The model dimensions in the X-, Y- and Z-direction were 300, 300 and 359 ft. respectively. This amounted to 32,310,000 active cells on a fine-scale equivalent to 24*25*15 grid dimension (9000 3D grid blocks) on a coarse scale. This was able to preserve certain geologic features like thin shale streaks captured in certain layers of the geologic model.

According to the literature, the range of porosity is 8.7 % to 15.7 % with an average of 12.62 % (Killough & Houston, 1996). The porosity in this model is a truncated normal distribution with a mean of 20%, a standard deviation of 7.5%, and a minimum and maximum of 11% and26%. Using this truncated normal distribution, the reservoir model was populated using Petrel.

The interesting feature in the water-oil capillary pressure curve is the discontinuity at about 35 % water saturation. This data was taken from an actual production reservoir study being performed by an oil company. The discontinuity can lead to difficulties in the Newton Raphson convergence for cases in which water saturations are changing significantly. The second feature of the capillary pressure curve is the tail which does not extend to water saturation of 1.0. although unusual, this feature does represent reality in certain reservoirs in which imbibition may have occurred due to tectonic prior to discovery.

The initial reservoir temperature was 100 degrees F with an initial oil phase pressure of 3600 psia at a depth of 9035 feet subsea. The saturation pressure of the oil was 3600 psia. For cells with oil pressures less than this value, the saturation pressure was set equal to the oil phase pressure. At 1000 psi above the saturation pressure the Bo is 0.999 times that of the Bo at Psat. The oil viscosity did not increase with increasing pressure in undersaturated conditions. The density of the stock tank oil was 0.7206 gm/cc, and the molecular weight of the residual oil was 175. The oil pressure gradient was approximately 0.3902 psi/ft. at 3600 psia. The stock tank water density was 1.0095 gm/cc with water formation volume factor (Bw) at 3600 psia of 1.0034 RB/STB yielding a water pressure gradient of approximately 0.436 psi/ft.

The oil-water contact was 9950 feet subsea. The water saturation distribution was calculated based on the oil-water capillary pressure curve. Because of the lack of data above Sw = 0.88149 a small residual oil saturation existed throughout the modeled reservoir. The number of well drilled depends on the pattern of flooding adopted for case scenario.

3.4 FLOOD PATTERN ANALYSIS

The choice of pattern to use in a waterflooding process has always been a tricky task as many factors such geological, engineering and most of all economics must be put into account to efficiently select the pattern to be implemented. In this research, to further understand the effect of pattern selection on recovery performance, two cases are considered; one of a homogeneous model with an average permeability of 500 mD and 50 mD and the other with heterogeneity introduced.

3.4.1 Case 1

In this case, homogeneous reservoir models of average permeability of 50 and 500 mD were built, with all patterns ran to ascertain their effective recovery performance. This case was also divided into two scenarios of which the first was with a cumulative water injection of 20,000 STB/D over a period of 10 years and the second was with an uncontrolled amount of water injection. The first case was to determine the optimum pattern in the face of a limited amount of water for injection as is the case in most offshore operations.

The homogeneous model was built with a 40x40x10 grid. The grid was in conventional rectangular coordinates without corner point geometry or local grid refinement. The model dimensions in the X-, Y- and Z-direction were 2087, 2087 and 100 ft respectively. This amounted to 16000 active cells on a fine-scale grid dimension (D grid blocks) on a coarse scale. This model was modified to suit the requirements by each flood pattern for analysis which involved drilling a different number of injection wells and four producers for all scenario.

3.4.2 Case 2

This case involved the introduction of heterogeneity to mimic the reservoirs in reality as no reservoir in the world is completely homogeneous. Two scenarios as the case 1 was also considered; scenario 1 with moderate heterogeneity and scenario 2 of high heterogeneity. This was to investigate the performance of the patterns in moderately and highly heterogeneous formations, to understand how parameters such has water cut, maximum injection rate, well placements and most of all the patterns affect the recovery performance and to provide insight to the efficiencies of the various flood patterns which are scarce in the literature for cases of moderate and high heterogeneous reservoirs.

Comparison of these pattern efficiencies would then be made to ascertain agreement with literature, with analysis of trends and reasons for agreements or deviation discussed to provide insight into the principles of waterflood operations further. The criteria used for the comparison of the pattern performance was field oil recovery efficiency, water cut, pressure maintenance ability of the pattern and the optimum pore volume to be injected for maximum recovery. The selected pattern was carried forward for the well placement analysis and optimization.

3.5 EFFECT OF AREAL PERMEABILITY VARIATION

With the homogeneous model built of dimensions 40x40x10, the effect of directional permeability variation on the recovery of flood patterns was analyzed with scenarios where the line of injector-producer connections was parallel, and perpendicular investigated. The analysis was with the cumulative water injection of 20,000 STB/D and carried out to understand reservoirs where permeability anisotropy exists. This, of course, was in line with the objective of fostering our understanding of the waterflood principles and how parameters such as these affect reservoir performance because some reservoirs have channels and faults which could affect the developmental strategy of the asset.

3.6 INFILL WELL PLACEMENT DETERMINATION AND OPTIMIZATION

In this section, certain constraints are defined to determine acceptable candidate locations for infill well placement. Several constraints are defined for the determination of infill well locations. Some of these constraints were imposed to make sure the resulting wells are drillable, while others were put in place to avoid creating solutions that are known to perform poorly because the solutions could violate common petroleum engineering practices. Considering that we have control in the initialization process, the constraints could be easily applied to the initial population. The following constraints are defined for infill well placement problem:

1. The oil saturation (S_{oil}) at the proposed location for infill well placement must be greater than or equal to the sum of the residual oil saturation (S_{or}) and 10 percent. This means that any location for infill well placement must have oil saturation higher than the residual oil saturation with at least 10 percent margin. This is done to make sure that the proposed location has a

reasonable amount of oil to be produced from it. All locations that do not meet up to this constraint are eliminated from the search space. The main idea is to avoid placing wells in locations with low oil saturation. Mathematically, this constraint is $S_{oil} \geq (S_{or} + 10\%)$.

2. The average pressure at the proposed location must have a value greater than the threshold reservoir pressure. This constraint is put in place to make sure that the average reservoir pressure of the grid block chosen for infill well placement must have enough pressure to produce the oil, which must be higher than the threshold pressure of the reservoir.

3. Well be placed far away from oil-water contact, aquifer, faults, and boundaries. There are two types of boundaries encountered in this reservoir model, a no-flow boundary or a fault and an aquifer. The direction of flow is always parallel to the no-flow boundary. The well placement constraint for boundary condition is put such that wells are not placed close to faults or no-flow boundaries, and are also not placed close to the aquifer to avoid water coning and high water cut. All candidate locations that are close to faults, aquifer, oil-water contact (OWC) are eliminated from the initial population and removed from the potential locations for infill well placement.

4. *Well will be placed on active blocks*. The reservoir model has 2660 blocks, out of which 1761 blocks are active. All potential infill wells can only be placed and completed in the active blocks of the reservoir model. Also, grid blocks that have wells already placed and producing will be removed from the initial population, as no two wells will be placed in the same grid block, in this work.

In field development projects, the wells are typically drilled in phases. This introduces a time domain into the optimization problem. In other words, the performance of a well will depend on the time it is opened and the oil saturation and pressure in the vicinity of the well when it is put on

production. When the wells are opened at different times, their performance is affected by dynamic properties (e.g., oil/water saturation, pressure) around the wells at the start of production. Dynamic attributes include average saturation around the well, average pressure around the well, average change in saturation around the well, and the average change in pressure around the well. The average saturation and pressure are determined at the start of the simulation while the average change in saturation and average change in pressure are determined by taking the difference between the saturation and pressure at the start of production and at the end of the simulation run time. The average pressure at the proposed well location must be greater than the threshold reservoir pressure to make sure that producing well's pressure will be sufficient energy to sustain production for the given period of time. The threshold reservoir pressure used in this study is 120 barsa. Another constraint that is imposed in the well placement problem is, to avoid locating wells close to the oil-water-contact, aquifers, faults and boundaries. This is done to avoid results that would not maximize the objective function.

Two search algorithms; particles swarm algorithm and genetic algorithms were be employed to determine the infill well locations with the best performing algorithm determined on the basis on Net Present Value of the asset.

CHAPTER FOUR

DISCUSSION OF RESULTS

Results of waterflood pattern analysis using three homogeneous models are presented. The models used had an average permeability of 500 mD, 50 mD, and 10 mD. The effect of pattern selection on the cumulative oil production of each of the model are first discussed with cumulative field oil production and average time to breakthrough used as the basis for comparison. The recovery efficiencies of the patterns are also analyzed in comparison to that published by Crawford in 1960.

The effect of directional permeability on the field production capacity are then discussed for all waterflood patterns on the basis of the three models built and all results summarized.

4.1 Waterflood Pattern Analysis

This study aimed is to establish a theoretical system of injection-production well pattern optimal control, which provides a scientific method and basis for the arrangement and adjustment of a well pattern in waterflooding oilfields. Research into a reasonable well pattern in the oil and gas field development has received significant attention in recent history. In the 1940s, Muskat made a study on the theory of flow mechanism of a simple well pattern. Several authors in literature advanced the discussion and established important theories about the relationship between reservoir sweep and injection models under the condition of unit reservoir heterogeneity and unit mobility ratio. Subsequently, in the 1950s, research in the area was further developed during waterflooding process under the condition of random mobility ratios and the rules governing the reservoir area sweep variation were established. However, in the late 1950s, the method of a "sparse well pattern for large pressure decline" was proposed by other researchers, but their applications failed in practice. Moreover, with the continuous development of oilfield development theory, cognition of the well pattern is also in progress.

Because a well pattern is very important in the production of oil and gas fields, the selection, deployment, and adjustment of a well pattern determinate the production scale, the life of production, and the economic benefits of an oil and gas field. Onshore oil and gas fields are mostly heterogeneous reservoirs. Well pattern optimization is particularly important. Therefore, the establishment of well pattern optimization control theory has an important guiding role in improving the oil field development.

Based on some assumptions, Crawford in 1960 obtained the efficiencies for several pattern floods. According to him, assuming a unit mobility ratio, steady-state condition, homogenous and uniform reservoir and ignoring gravity and capillary effects, the efficiencies were 45 % to 90 % for 9-spot, 72 % for 5-spot, and 56 % for line drive pattern. Little or no attention was given to peripheral or other forms of pattern flooding either due to constraints of economics or time. This is not peculiar to the work of Crawford, but also there is scarce data on the performance of peripheral pattern of flooding in the literature.

To understand the effect of flood patterns on waterflood performance, three homogenous models of average permeability of 500 mD, 50 mD and 10 mD were used, with assumptions similar to that made by Crawford. Two case scenarios are first analyzed, with the first case being waterflood operation with a cumulative water injection of 20,000 STB/D and the second case, without control on the amount of water injected. Figure 4.1 through to Figure 4.3, show the results of various pattern floods performance for the model of 500 mD permeability depicting the performance of various flood patterns with 20,000 STB/D of water injection.

Figure 4.1 shows the field oil production rate of the various flood patterns considered for this analysis. From the plot, the field production rate for line drive and staggered line drive are lower than that of the 5-spot, 9-spot and peripheral patterns. This is as a result of the models used in the estimation of fluid flow in pattern flood. The models rely on the characteristics of the fluid movement near the injection and production wells for a homogenous system.

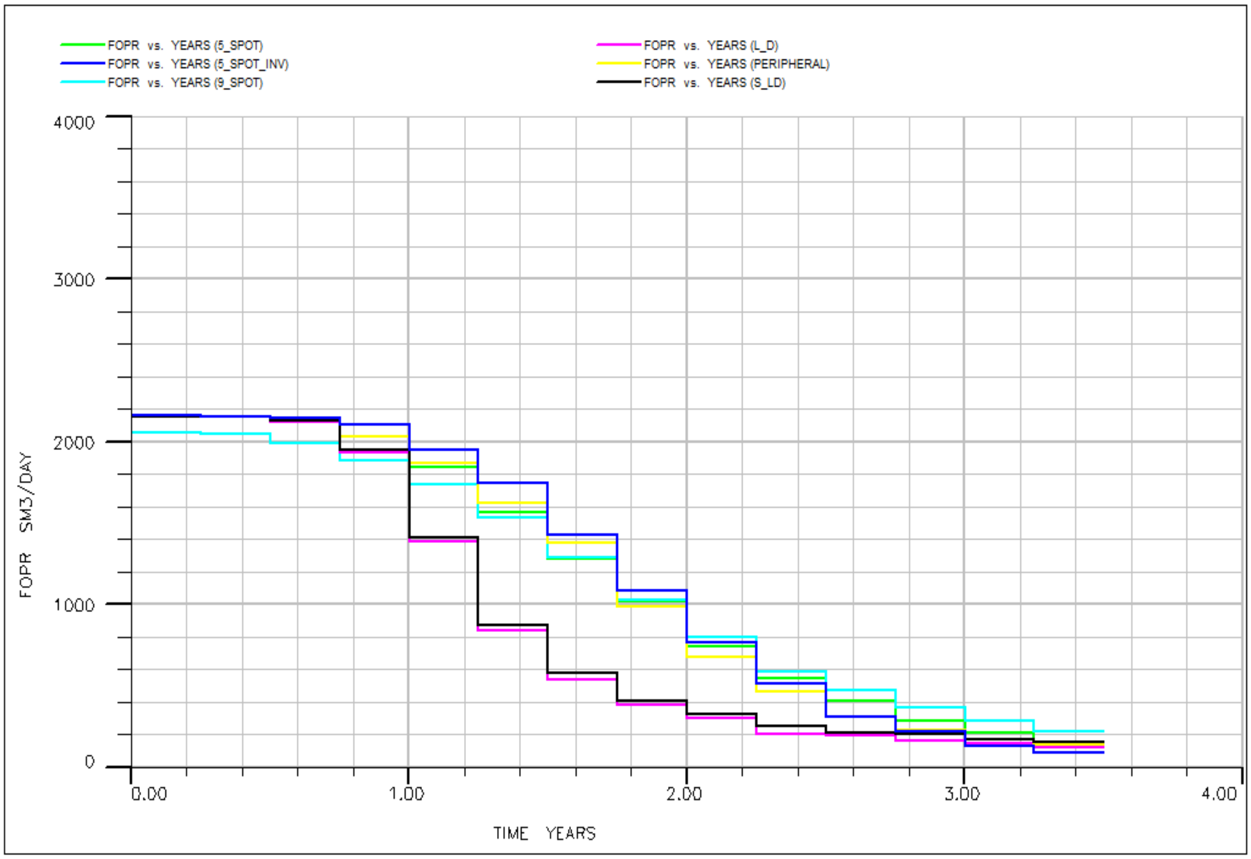

Figure 4.1: *Field Oil Production Rate for 500 mD Permeability Reservoir Model using 20,000 STB/D of water injection.*

For 5-spot, 9-spot, and peripheral, the fluid flow model assumes that the flow is steady, incompressible and radial from the injection well to the outer segment of injection; then fluid flows radially from the outer radius of the production segment to the production well. While for the line drive and staggered line drive, the injection rates are estimated using a combination of radial and linear segments to approximate the pattern area. Fluid flow in the line drive and staggered line drive are approximated with the assumption that radial flow exists around the injection and production wells, with the remainder of the pattern area divided into linear segments. Thus, the pattern area equals the radial flow area around the injection well plus linear flow area between injection and production well plus radial flow area around production wells. These linear segments that exist between the production well and the injection wells lead to a direct line of flow, shortest travel path and largest pressure gradient along a straight-line between the injectors and producers for the line and staggered line drive. Resultantly it leads to an early water breakthrough as shown in Figure 4.3, which limits the production and injection rates that can be achieved using those patterns for flooding.

The rise in the production rate at the latter end of the plot for a line drive and staggered line drive corresponds to the after breakthrough production rate.

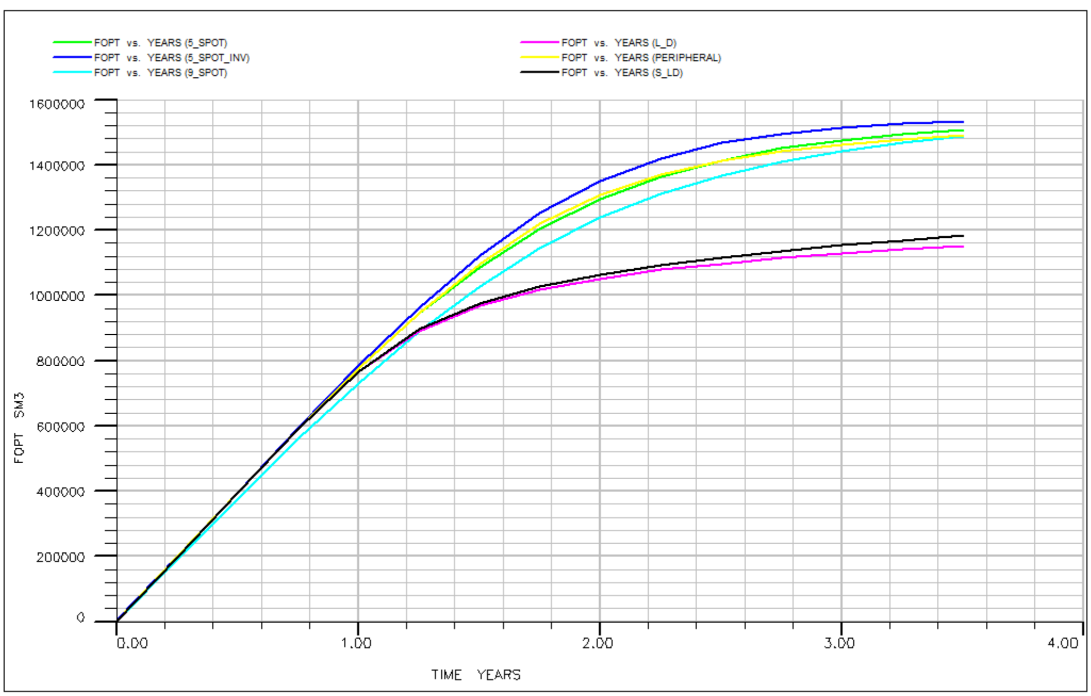

Figure 4.2: *Field Oil Cumulative Production for 500 mD Permeability Reservoir Model using 20,000 STB/D of water injection.*

The flooding pattern formed by injection and production wells is the primary factor in determining the pressure distribution within the reservoir and accordingly, the path through which the injected water will flow. Figure 4.2 shows the results of the field cumulative oil production for the 500 mD model for different flood patterns. In particular, this figure indicates that cumulative production of the line drive and staggered line drive at the early stage of flooding is lower compared to those of 5-spot, 9-spot, and the peripheral patterns. But a high production at the latter end of the flooding process which is after breakthrough. This is because with continued injection beyond breakthrough, the areal sweep efficiency of a line and staggered line drive will continue to increase until it reaches 100 %. However, it may not be economical to operate a flood sufficiently long to attain complete areal coverage.

In contrast to the use of repetitive patterns, a peripheral flood utilizes the edge wells along all or a part of the reservoir boundary as injection wells. This kind of flood pattern requires fewer injection wells per producer compared to other flood patterns thereby requiring a smaller initial investment. Also, this results in less produced water as is shown in Figure 4.3. This is particularly true when operators shut in the production wells which experience water breakthrough and continue to produce only those ahead of the waterfront.

According to Ferrell *et al.* 1960, in their study of end-to-end floods, less injected water is required to recover the oil, and that good areal sweep is achieved, if producing wells are shut-in soon after water breakthrough. But for this procedure to work, it should be obvious that a high permeability is required for the water to move at a desired rate over a long distance from the injector to the producer. As can be seen from Figure 4.2, with a high permeability of 500 mD, the peripheral pattern flood could perform as well as the 5-spot and the 9-spot which are mostly used. And as pertaining to economics, low initial investment also supports its choice as compared to the other pattern floods.

Similar pattern performance trends as of the 500 mD model are shown in Figure 4.4 through to Figure 4.6 for the reservoir model of 50 mD permeability. This is so as permeability is still high enough to allow considerable flow. As shown in Figure 4.5 and Figure 4.6, the performance of peripheral pattern is almost the same with that of a 5-spot and 9-spot. Also, a delayed water breakthrough is shown in Figure 4.6 for peripheral as compared to the 9-spot pattern which makes it a good candidate choice for reservoirs of permeability as 50mD.

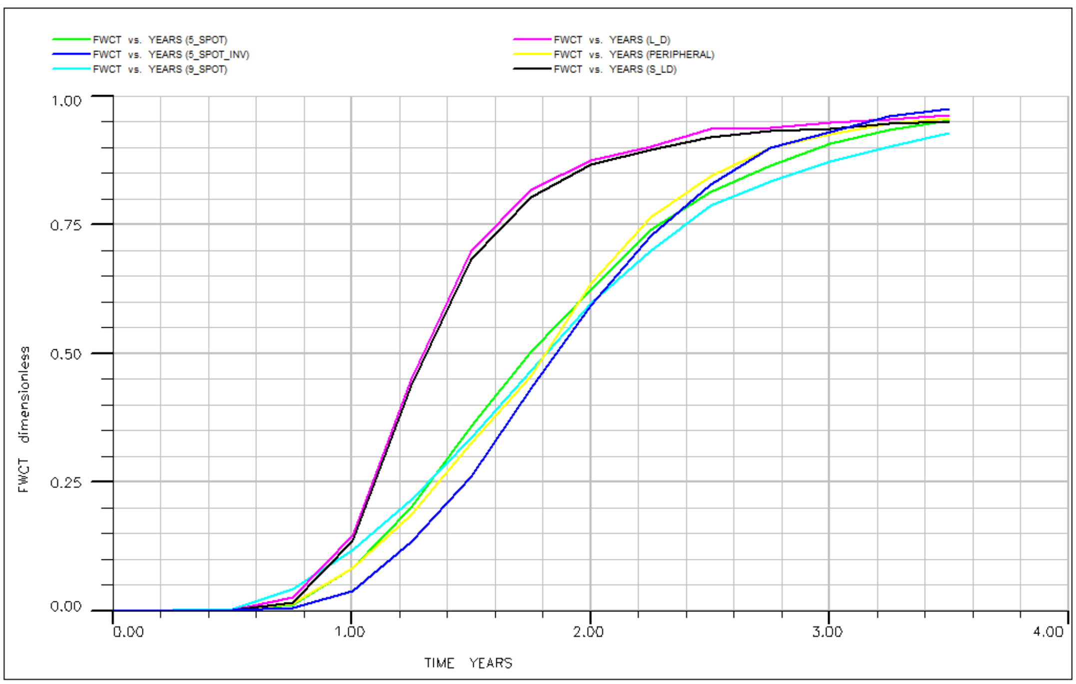

Figure 4.3: *Field Water Cut for 500 mD Permeability Reservoir Model using 20,000 STB/D of water injection.*

This would be appreciably different compared to 500 mD as in the time it will take to reach the ultimate recovery of the reservoir.

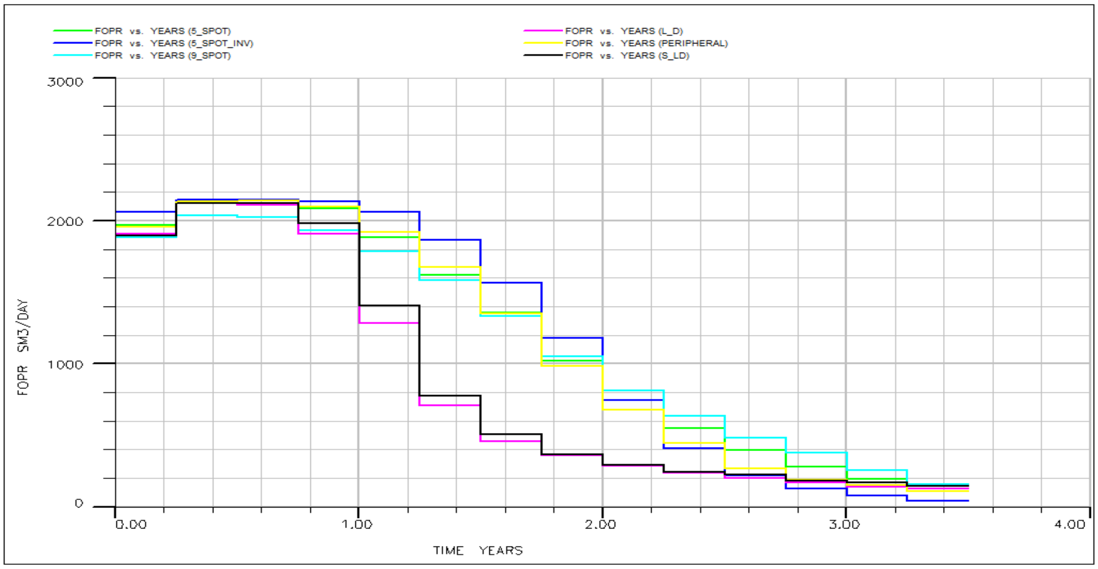

Figure 4.4: *Field Oil Production Rate for 50 mD Permeability Reservoir Model using 20,000 STB/D of water injection.*

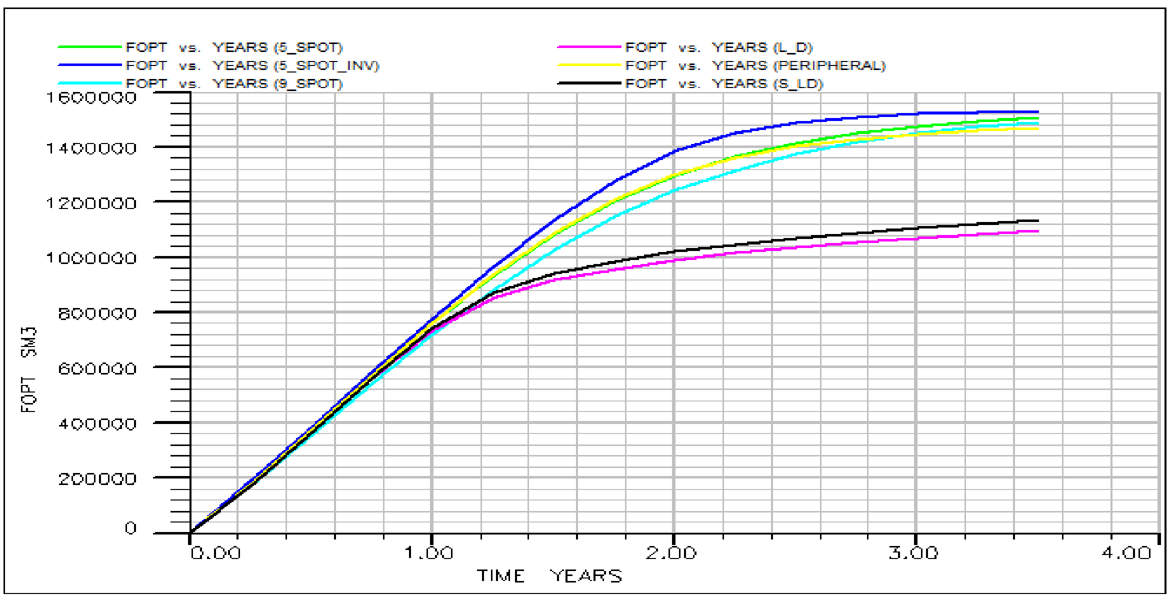

Figure 4.5: *Field Oil Cumulative Production for 50 mD Permeability Reservoir Model using 20,000 STB/D of water injection.*

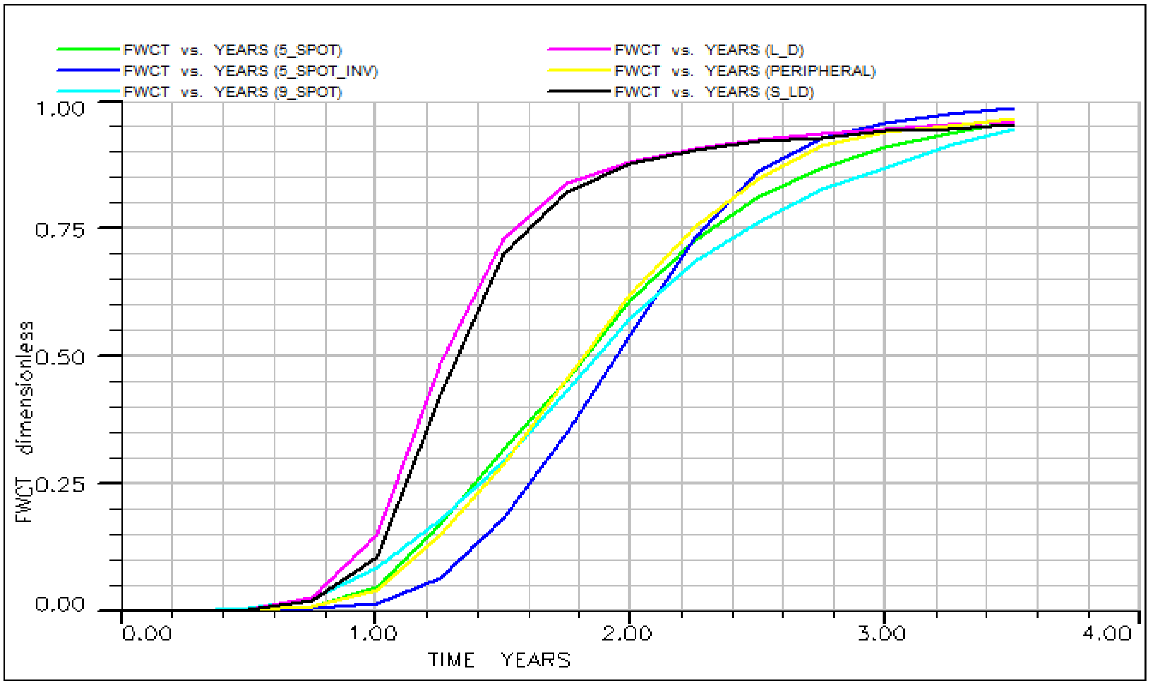

Figure 4.6*: Field Water Cut for 50 mD Permeability Reservoir Model using 20,000 STB/D of water injection.*

Permeability indeed is a governing criterion to flow through porous media. This is depicted by the production trends and rates for the 10 mD permeability reservoir model. Figure 4.7 and Figure 4.8 shows trend of cumulative oil production and field water cut of all the patterns. Particularly of interest are the cumulative oil production trends which as shown take a longer time to reach the ultimate recovery. This is as a result of increased resistance in the flow path which is consequent of a low-permeability value. The cumulative oil production trend for line and staggered line patterns shows that this patterns performance will result in low oil production as these patterns are well suited for formations with medium to high permeability. Thus, not the efficient pattern to be selected for the development of such a model.

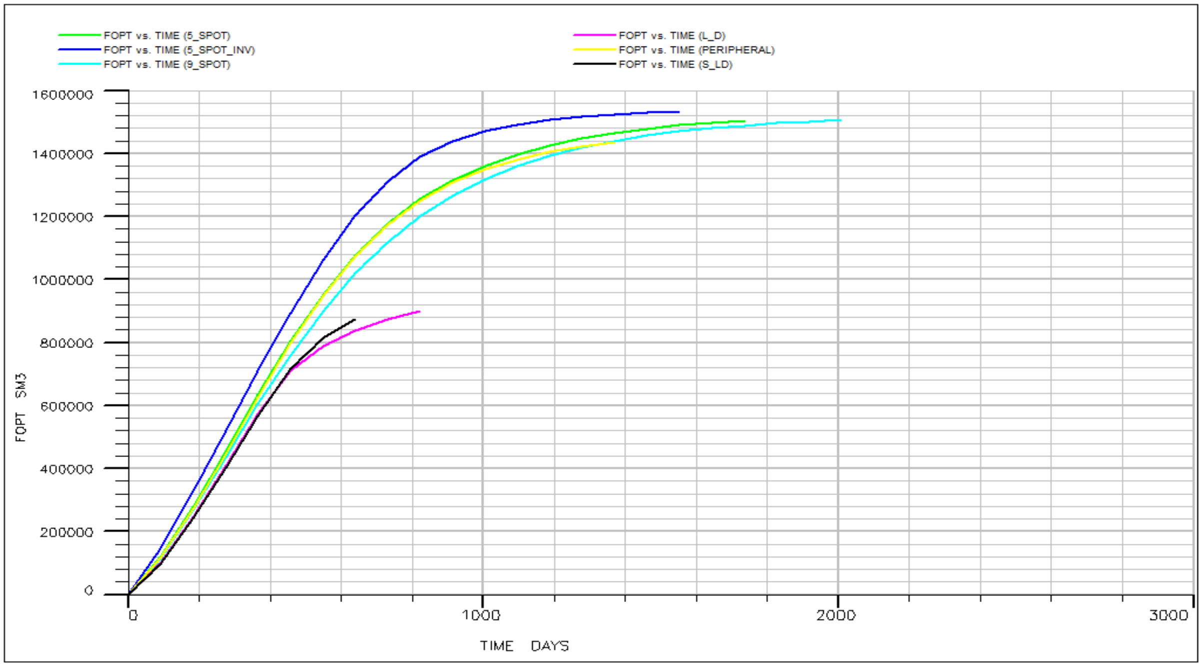

Figure 4.7: *Field Oil Cumulative Production for 10 mD Permeability Reservoir Model using 20,000 STB/D of water injection.*

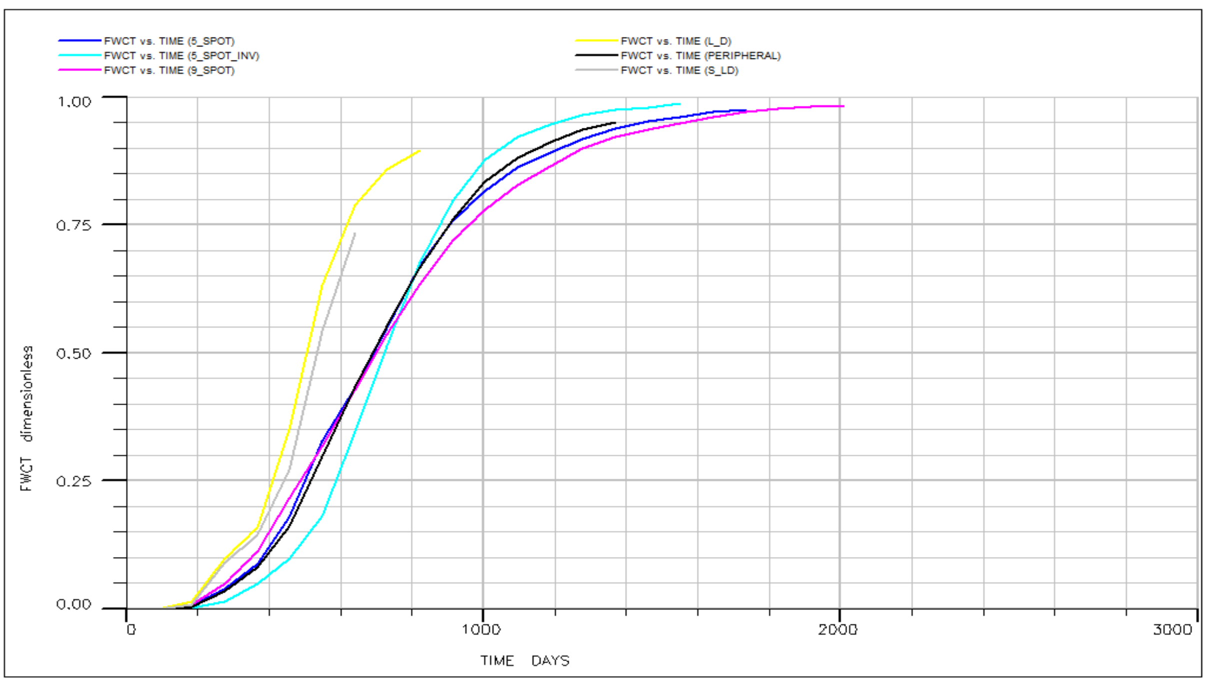

Figure 4.8: *Field Water Cut for 10 mD Permeability Reservoir Model using 20,000 STB/D of water injection.*

The above case scenario was considered given that in an offshore environment, a limited amount of water is available for injection, thus, the need to maximize its usage. The second case scenario is when the amount of water injected is not constrained to 20, 000 STB/D.

Figure 4.9 and 4.10 show the production rate and cumulative oil production of the different well patterns performance. From the figures, the rate and cumulative oil produced by the 9-spot is significantly higher as compared to the 5-spot, and peripheral which had almost similar performance when the amount of water injected was constrained to 20, 000 STB/D. This can be attributed to the fact that of all the patterns, the 9-spot has the most number of wells which leads to a greater amount of water injection as compared to other flood patterns. This, of course, is true because as the amount of water injected increases, the reservoir pressure is much higher as compared to others as shown in Figure 4.11.

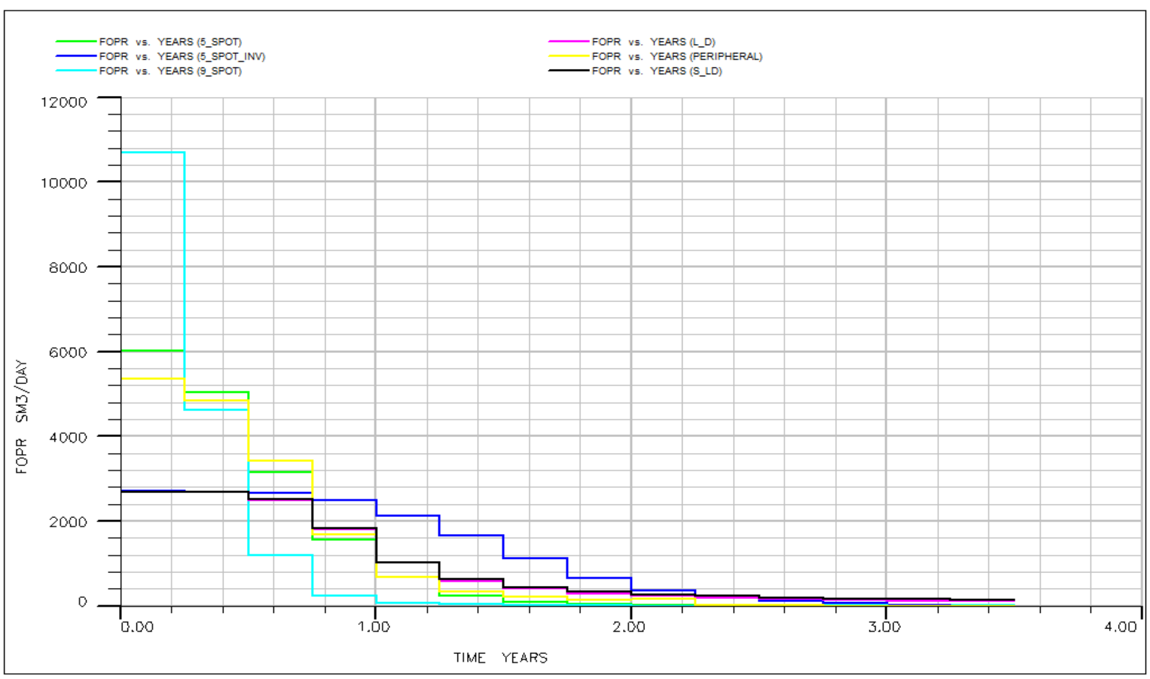

Figure 4.9: *Field Oil Production Rate for 500 mD Permeability Reservoir Model with uncontrolled water injection.*

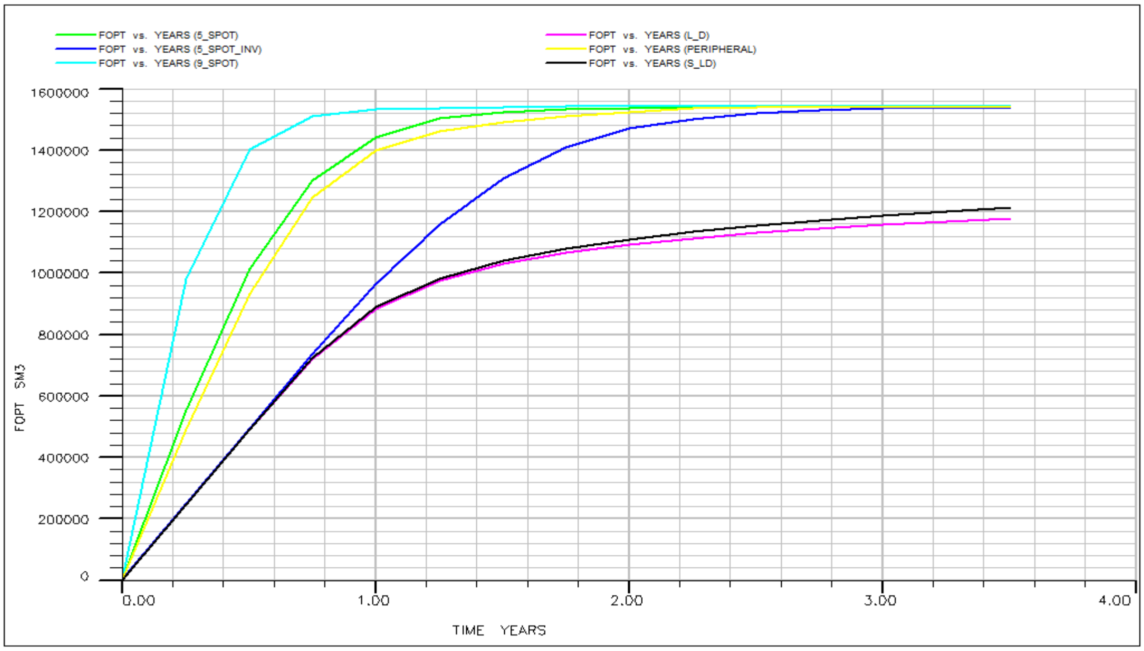

Figure 4.10: *Field Cumulative Oil Production for 500 mD Permeability Reservoir Model with uncontrolled water injection.*

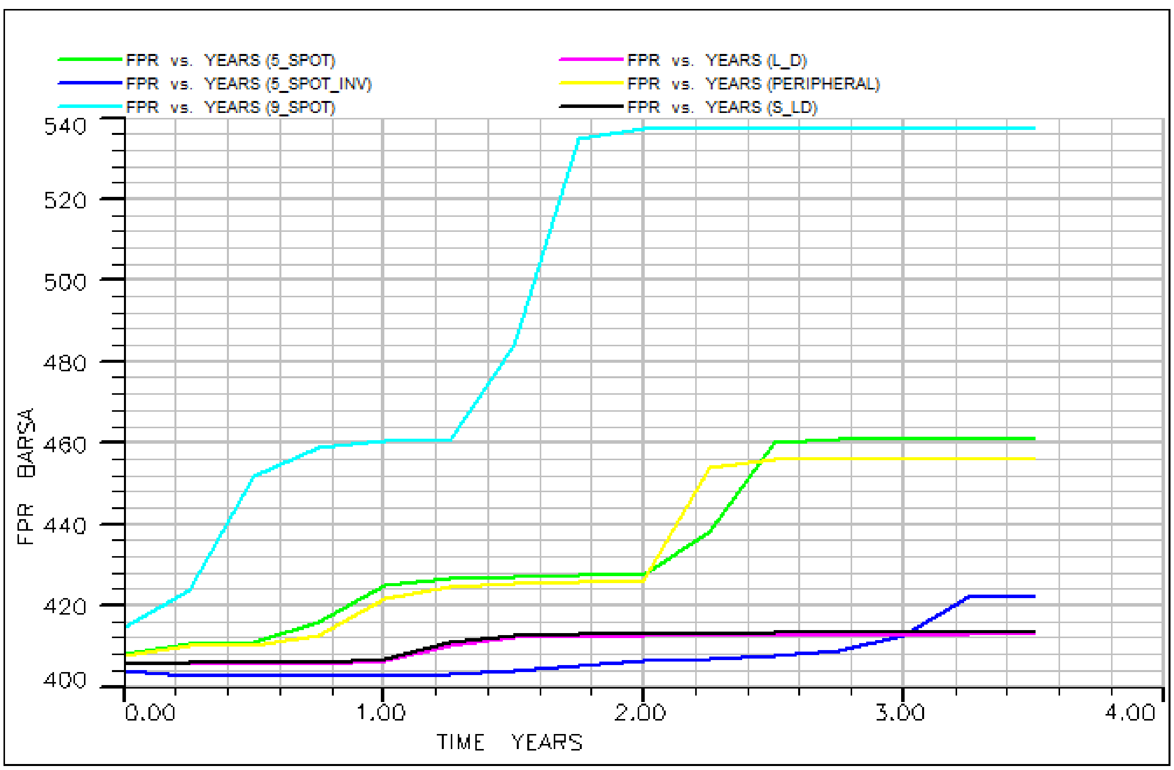

Figure 4.11: *Field Pressure for 500 mD Permeability Reservoir Model with uncontrolled water injection.*

On the other note, having high injectivity is also constrained to formation with high permeability but with a backdrop of early water breakthrough as can be seen from Figure 4. 12. The significant difference in the pressure support provided by the 9-spot is as a result of the fact that the number of wells is about twice the number in 5-spot and peripheral thus, more energy is supplied to the reservoir. This would be a good well pattern for pressure maintenance operation given that the formation is of high permeability and water production is not an issue.

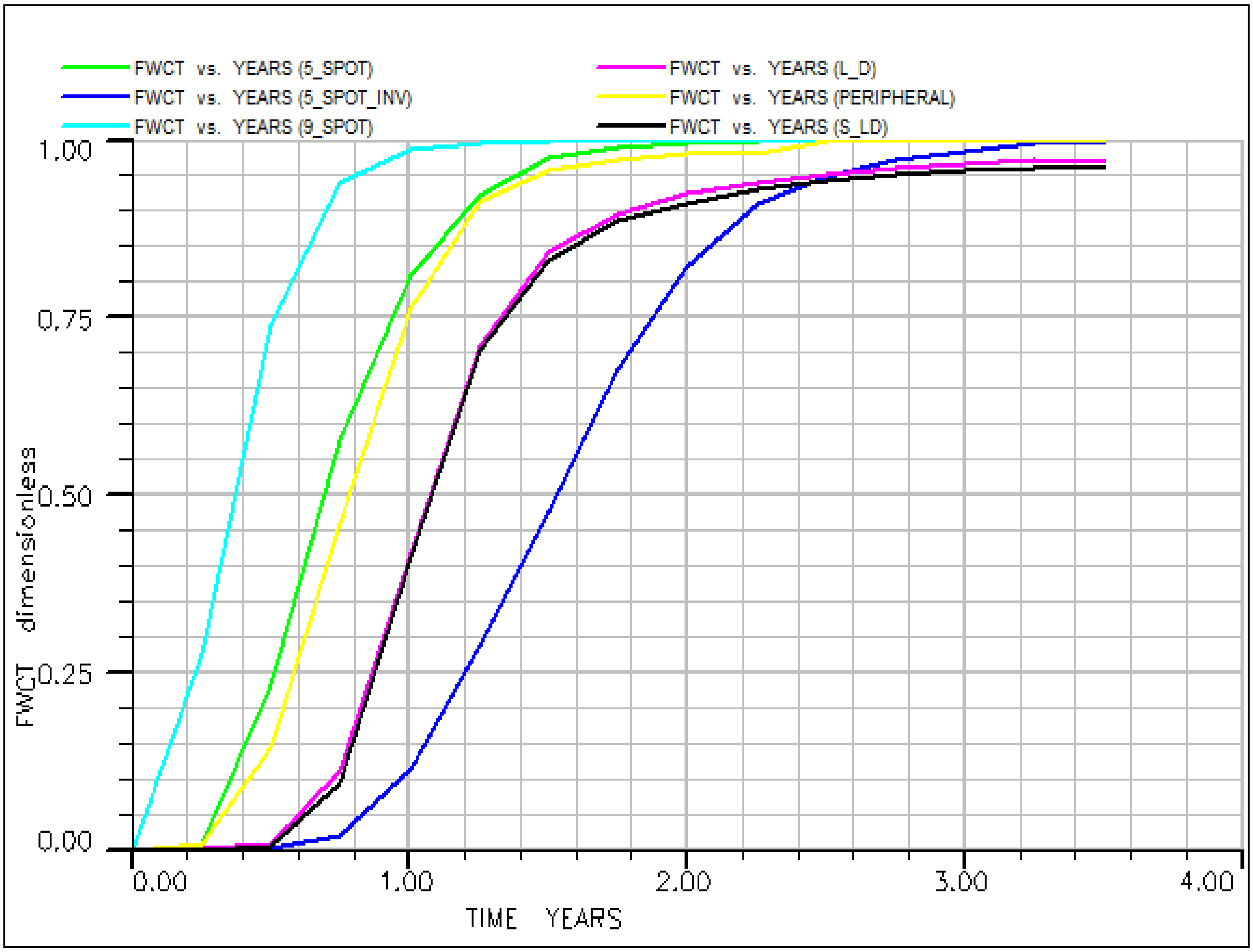

Figure 4.12: *Field Water cut for 500 mD Permeability Reservoir Model with uncontrolled water injection.*

Recovery efficiencies published in 1960 as stated earlier didn't include the peripheral pattern, thus, the need to examine its performance against patterns which have gained acceptance in the industry. Table 4.1 shows a comparison of the efficiencies, and as can be seen from the values, there isn't a considerable difference from what Crawford had published with inclusion into literature the efficiency of the peripheral pattern.

Table 4.1: Recovery efficiency comparison

Pattern	Efficiency by Crawford	Efficiency from Current Research Work
5-Spot	72	78.7
9-Spot	45-90	76.53
Line Drive	56	58.89
Staggered Line Drive	56	59.25
Inverted 5-Spot	73	77.89
Peripheral		**77.7**

4.2 Effect of Directional Permeability on Pattern Production Capacity

Due to the control of geological factors such as deposition, the values of reservoir permeability often show the characteristics of anisotropy. Permeability anisotropy is the basic property of the reservoir, especially fluvial reservoir, which has a negative effect on reservoir exploitation.

When the permeability is much greater in one direction than in other directions, fluid will attempt to flow in the direction of maximum permeability. The effect of directional permeability is the same as the effect of a fracture, although probably not as drastic. Accordingly, the injectors and producers should be arranged along a line perpendicular to the direction of greatest permeability.

Irregularities in the reservoir sand properties long have been a major difficulty to anyone attempting to describe the field characteristics of oil production explicitly. In particular, it is well known that vertical and lateral permeabilities often differ appreciably; however, the existence of large regions with lateral permeability variation is not widely recognized.

Figure 4.13 shows the effect of directional permeability on the sweep efficiency of a 5-spot and line drive as published by Crawford in 1960. The study used theoretical and potentiometric models to investigate the effect of the non-uniform lateral permeability on pattern sweep efficiency and production capacity in waterflood for 5-spot and line drive patterns.

Figure 4.14 shows the effect of directional permeability on several flood pattern on production capacities. Thus, an extension of Crawford's work to understand how this affects production capacity for other flood patterns. The ratio of the pattern production capacity to the production capacity when Kx/Ky equals one is plotted vs. the ratio of Kx/Ky. The data when the pattern covers 40 acres and the distance between the adjacent producers is kept fixed at 660 ft. when the well radii are 0.4 ft.

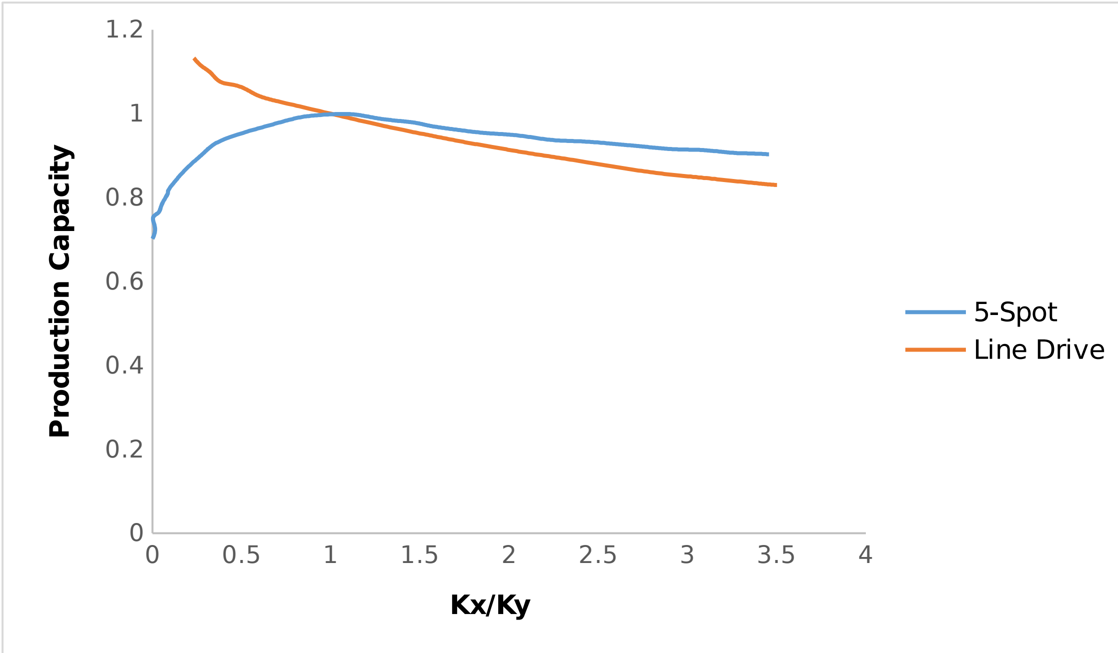

Figure 4.13: *Effect of Directional Permeability on Production Capacity by Crawford*

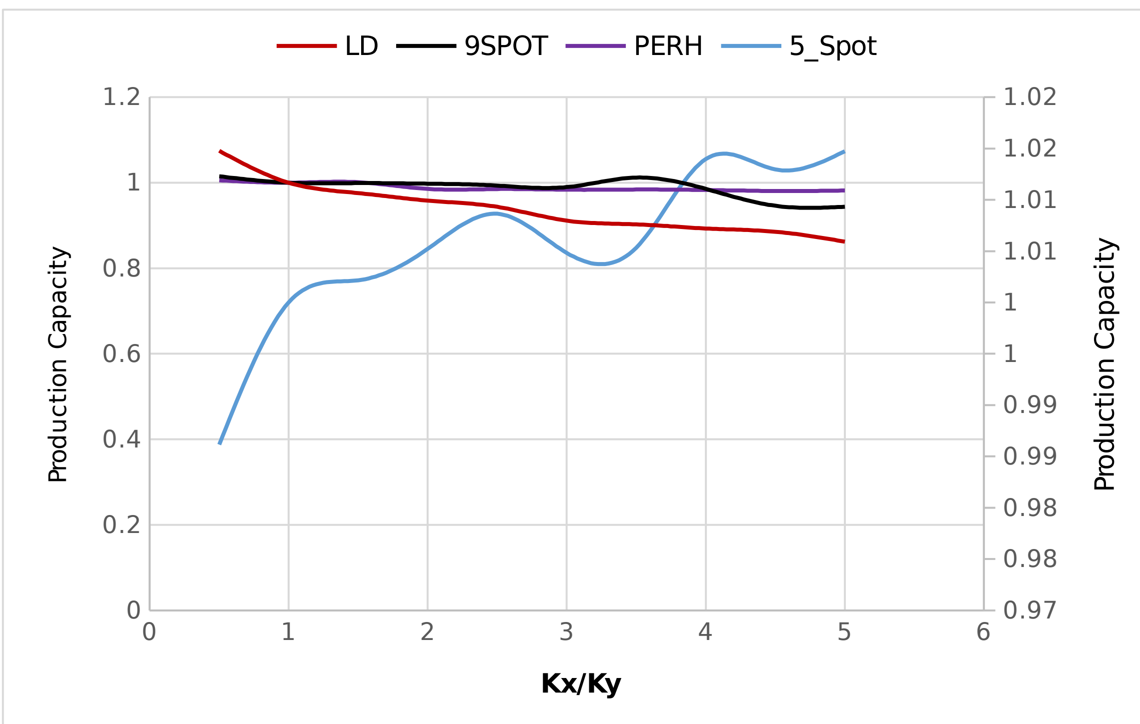

Figure 4.14: *Effect of Directional Permeability on Production Capacity for Flood Patterns*

The curve pertaining to line drive pattern in Figure 4.10 shows that, when Kx/Ky increases, the production capacity decreases. An increasing Kx/Ky is equivalent to a narrowing of the pattern. As shown in the Figure 4.14, the trend for 5-spot compared to that of Crawford in Figure 4.13 shows some unusual effects which may be as a result of the fact that Crawford used a single well with four injectors for his studies, while this model has four production wells and nine injectors. Similar to the trend of the line drive, the trend for peripheral and 9-spot decreases with increasing Kx/Ky. This could be attributed to the fact that the peripheral and 9-spot patterns are more like a line drive in their mechanism of recovery.

The trend for the 5-spot pattern shows a significantly different trend from that proposed by Crawford (1960) for a single well. The trend showed a steady increase at lower values of Kx/Ky ratio and a decrease at a ratio of about 2.5. This decrease in production capacity could be attributed to the point were a good number of the wells has been watered out. The trend repeats itself for ratio values beyond 5.0 which was in accordance with Crawford's findings using a single well.

4.3 Effect of Areal Permeability Variation of Recovery Efficiency

To further improve the research of the effect of areal heterogeneous distribution of reservoir permeability on waterflood recovery, a numerical simulation method was adopted. Under the condition that the factors such as permeability, productivity index and variation in direction parallel and perpendicular to the production well direction were considered. This helped to study the change law of water flooding recovery in reservoirs with different distributions of permeability heterogeneity.

In any reservoir, even if it is considered the most homogeneous reservoir, different plane positions are different in permeability (Liu & Sun, 2017). The difference in areal permeability can be as high as few times, more than a dozen or even dozens of times. In oil field development, this heterogeneity has become the internal condition to cause contradictions on the plane.

Over the decades, much attention has been devoted to the understanding of the effect of permeability variation from layer to layer (Permeability contrast) in the reservoir and how it impairs fluid flow and production. This is so, as permeability represents the flow potential of fluid in the reservoir and how fluid can preferentially move across layers to the production well, thereby leading to early breakthrough due to the non-uniform front. Attention has been given to the understanding of how areal permeability variation across layers (heterogeneity) affect the recovery efficiency assuming the permeability contrast is constant in the reservoir. This is important to production study as it affects the areal sweep efficiency of the reservoir across layers. This investigation was done by aligning the variation of the permeability in a direction parallel and perpendicular to the production wells in two different case scenarios to ascertain its effect on the recovery efficiency.

The reservoir with severe lateral heterogeneity can obtain good recovery if water is injected into high-permeability zones and oil is produced in the low-permeability zones (Ofoh, 1992). The equivalent permeability of the entire reservoir is influenced by the relative distance between the lateral heterogeneity reservoir and the water injection well, because the oil displacement efficiency of the reservoir is related to the value of the equivalent permeability. Therefore, in the case of lateral heterogeneity, the equivalent permeability is low if the mode of water injection in the low-permeability zone and oil producing in the high-permeability zone is adopted.

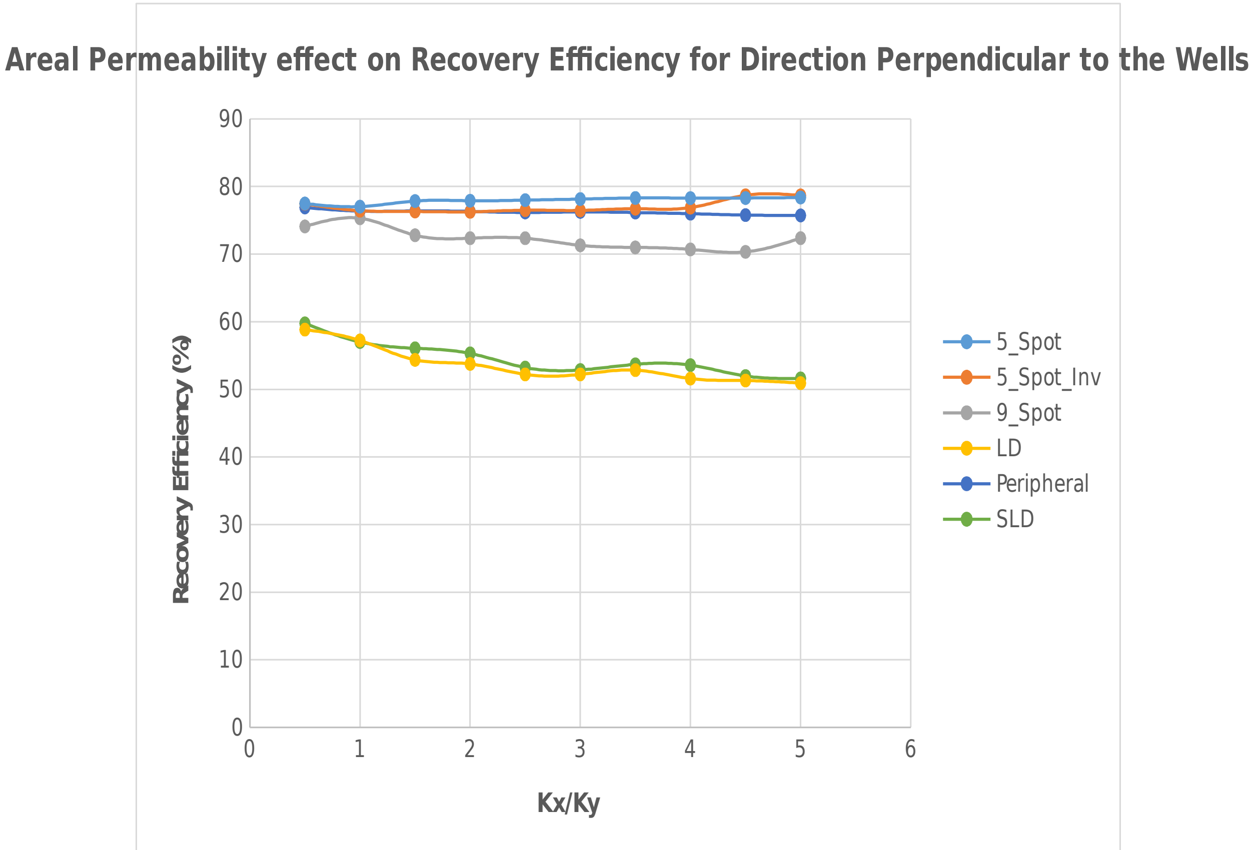

Figure 4.15: *Effect of Areal Permeability Variation Perpendicular to Well Direction on Recovery Efficiency for 500 mD Model*

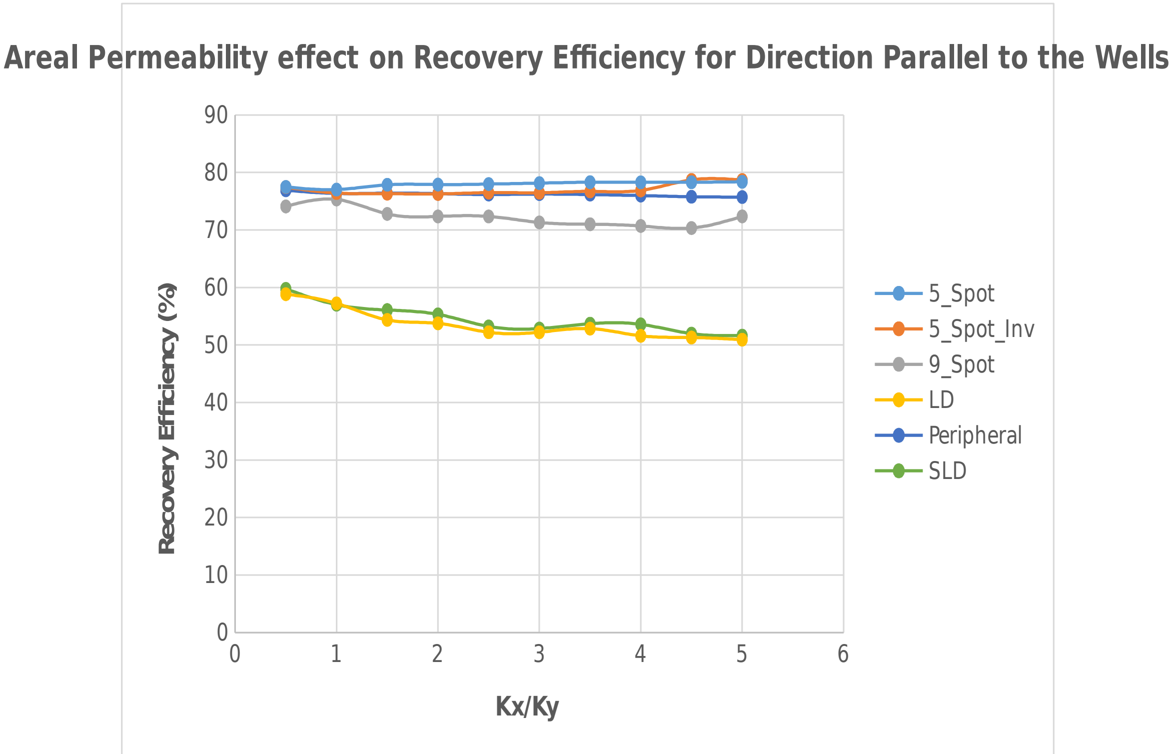

Figure 4.16: *Effect of Areal Permeability Variation Parallel to Well Direction on Recovery Efficiency for 500 mD Model.*

The lower the reservoir permeability variation coefficient is, the more homogeneous the throats are, which means the water breakthrough is relatively weak and the water-free oil recovery is relatively high. Weak water breakthrough phenomenon is bound to make the most of the throats flooded and the oil displacement efficiency of the reservoir improved.

The effect of lateral heterogeneity of permeability on reservoir development can be said to be macroscopic which includes two aspects: quantity and morphology, that is, heterogeneity degree and heterogeneity distribution characteristics, the latter of which can be divided into the form of the plane and vertical (in layer and interlayer) heterogeneity distribution. The influences of intra-strata heterogeneity, including that of thick oil/gas layers of different rhythms and that of thin inter beddings with great variations, on reservoir exploitation, are different in every way.

Similarly, the influences of the degree and the distribution characteristics of areal heterogeneity on oil and gas reservoir development index are different.

Especially for single layer development, multiple layer series (subsection) development, moving-upward-segment-by-segment development, the effect of areal heterogeneity on development efficiency is more prominent than that of vertical heterogeneity. In the case of the same heterogeneity, when the high-permeability zone is parallel to the producing well array or distributed along the long axis of the reservoir as depicted by Figure 4.15 & 16, the recovery rate is minimum. When the high-permeability zone is perpendicular to the long axis of the reservoir, the recovery rate is high; the recovery of the high-permeability zone of dispersive distribution is between the two above.

According to the flow line analysis and calculation results as depicted by Figure 4.11 & 12, if the waterflooding direction is consistent with the direction of the maximum principal permeability in the five-spot pattern, the sweep efficiency is high, and the fluid injection occurs late. For the nine-spot well pattern system, if the well pattern is arranged with an angle of 45° between the line connecting the water injection well and the edge well, and the maximum principal permeability direction in the nine-spot well pattern, the sweep efficiency is high, and the agent injection occurs late.

A comparison of the trend depicted by Figure 4.17 and 4.18 which is for a reservoir model of 50 mD, to Figure 4.15 and 4.16 for 500 mD, shows that the areal heterogeneity effect on waterflood performance of different flooding pattern is same irrespective of the absolute permeability of the reservoir.

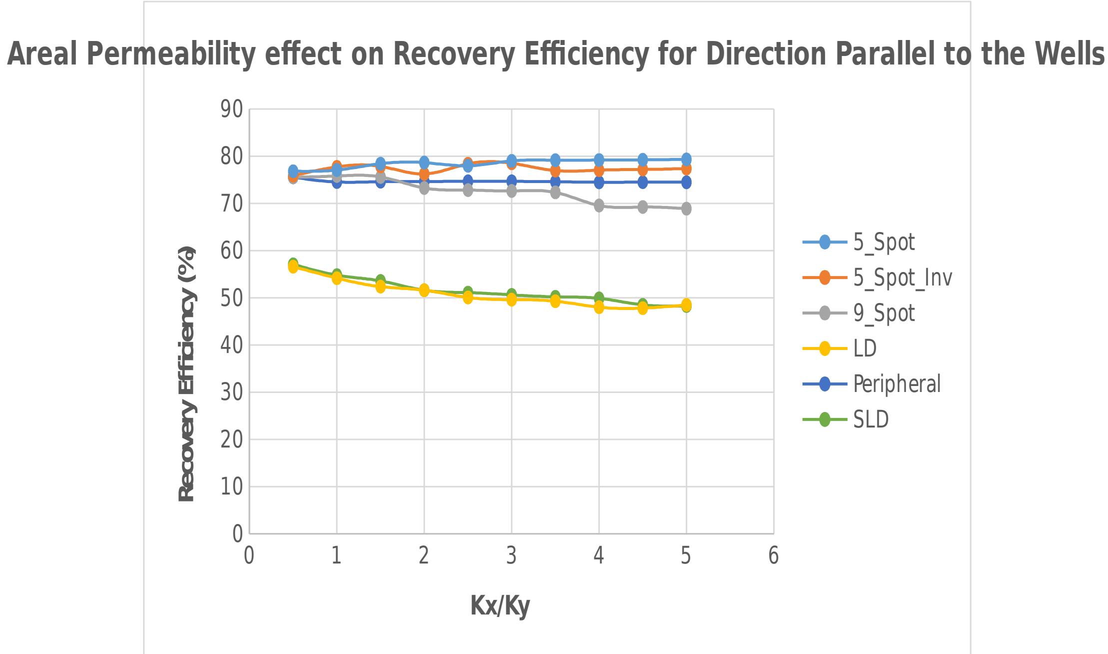

Figure 4.17: *Effect of Areal Permeability Variation Parallel to Well Direction on Recovery Efficiency for 50 mD Model*

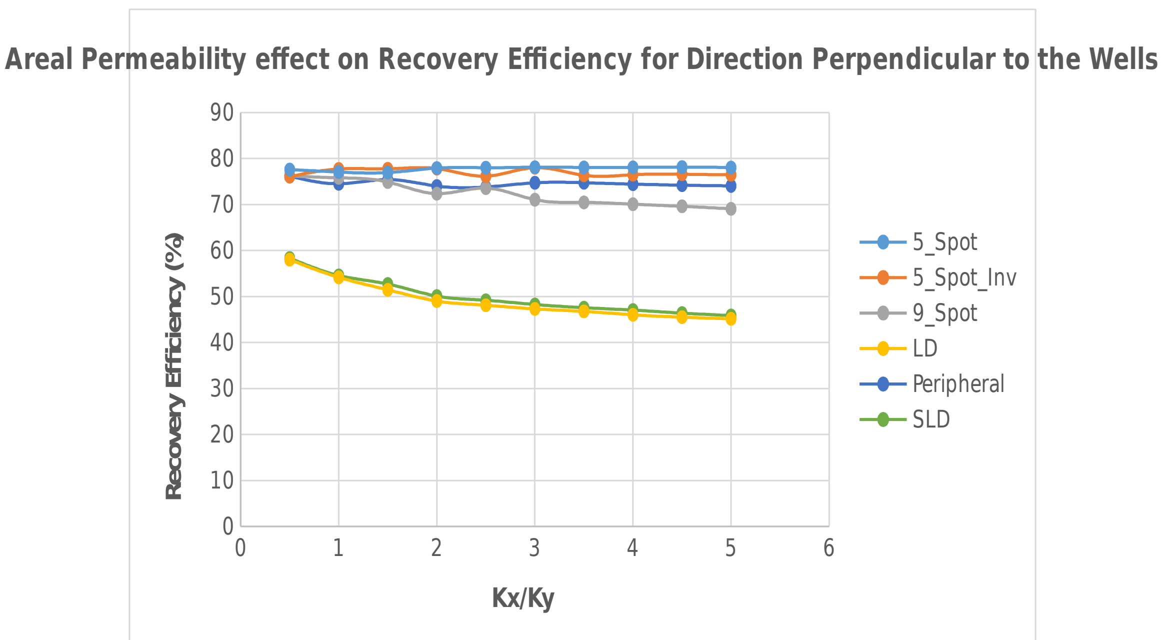

Figure 4.18: *Effect of Areal Permeability Variation Perpendicular to Well Direction on Recovery Efficiency for 50 mD Model*

4.4 Heterogeneity

The magnitude of the permeability of the reservoir rock controls, to a large degree, the rate of water injection that can be sustained in an injection well for a specific pressure at the sandface. Therefore, in determining the suitability of a given reservoir for waterflooding, it is necessary to determine the maximum permissible injection pressure from depth considerations and the rate vs. spacing relationships from the pressure/permeability data. This should indicate roughly the additional drilling that would be required to complete the proposed flood program in a reasonable length of time. So this begs the question of whether waterflooding a heterogenous reservoir is advisable as this would lead to incremental recovery.

Figure 4. 19 shows trends of two scenario cases, one is the base case simulation where the reservoir was produced for 20 years without injection of water, and another where waterflooding was initiated to determine if the reservoir is a good candidate for this operation.

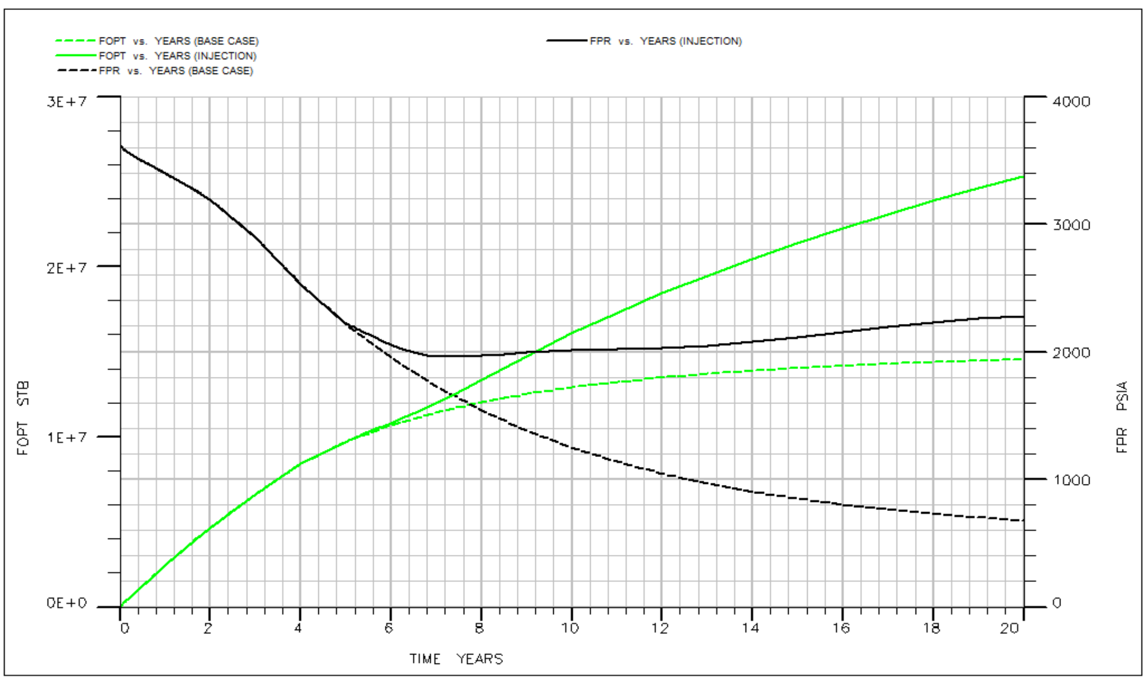

Figure 4.19: *Waterflooding Performance Test for a Heterogenous Reservoir.*

The base case which involves the production of the reservoir on its natural energy shows a decline in the reservoir pressure from a value of 3600 psia to about 700 psia with a cumulative oil production of 13.8 MMSTB. With an injection initiated after four years of production in the second scenario, a rise is seen in the cumulative oil production to a value of about 25.6 MMSTB and a field pressure of about 2300 psia as depicted by the trend in Figure 4.19. This shows clearly that these reservoirs recovery could be increased if waterflooding was carried out, thus, the need to determine the optimum rate of injection which could sustain the reservoir pressure and production without fracturing the formation.

The determination of the optimum injection rate for a waterflood project is important for reasons such as the economics of the injection process, the formation fracturing potential of the injection rate, etc. The result of such sensitivity analysis is as shown in Figure 4.20. This is a plot of reservoir pressure and cumulative oil produced for different injection rates against project life.

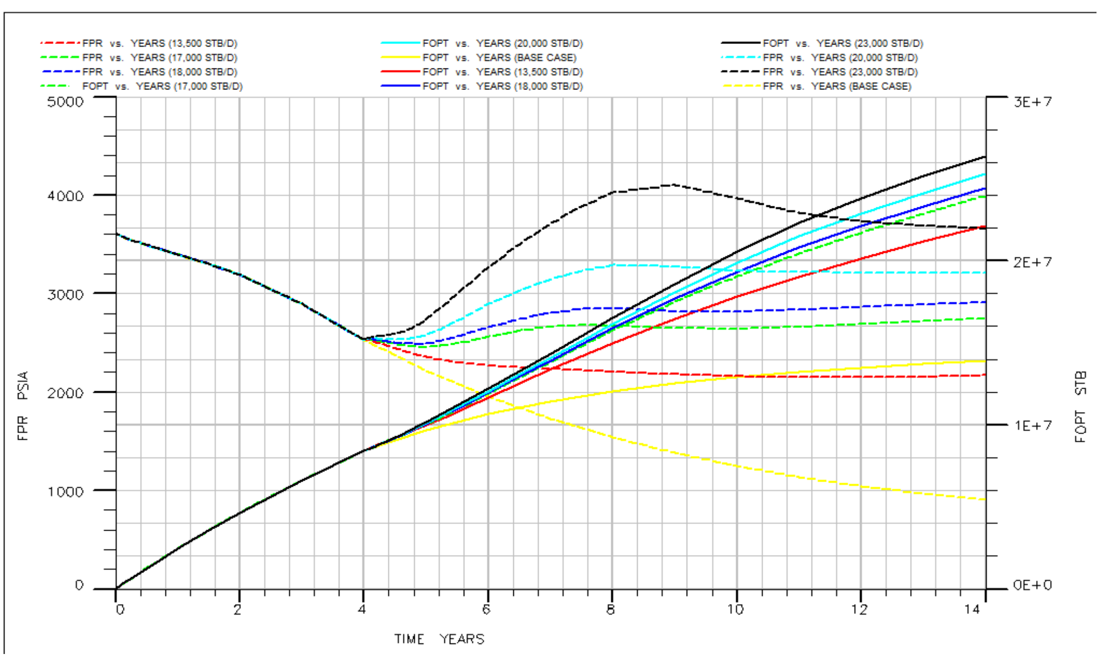

Figure 4.20: *Pressure and Cumulative oil trends for the Injection Rate Sensitivity Analysis for a Heterogenous Reservoir*

The Figure shows results of injection rates of 13,500, 15,000, 17,000, 17,000, 20,000 and 23,000 STB/D injection rates. From the pressures trends, the effect of the injection can be seen at year four, but most evidently is the plateau-like shape of the pressure trends for the 15,000, 17,000, 20,000 and 23,000 STB/D injection rates respectively. For these injection rates, the pressure increased to a plateau and then began to decrease before stabilizing. This is an indication of the formation being fractured as a result of the injection rates. This claim is supported by the trends of watercut and pressure shown in Figure 4.21, which also indicates that the optimum injection rate is 13,500 STB/D. This rate is what shall be used for the flooding operations of the patterns adopted for investigation. Also vivid from Figure 4.20 is the fact that even though the reservoir may be fractured, the cumulative oil produced continued to increase, which suggests that the direction of the fracture might have been perpendicular to the line of producers.

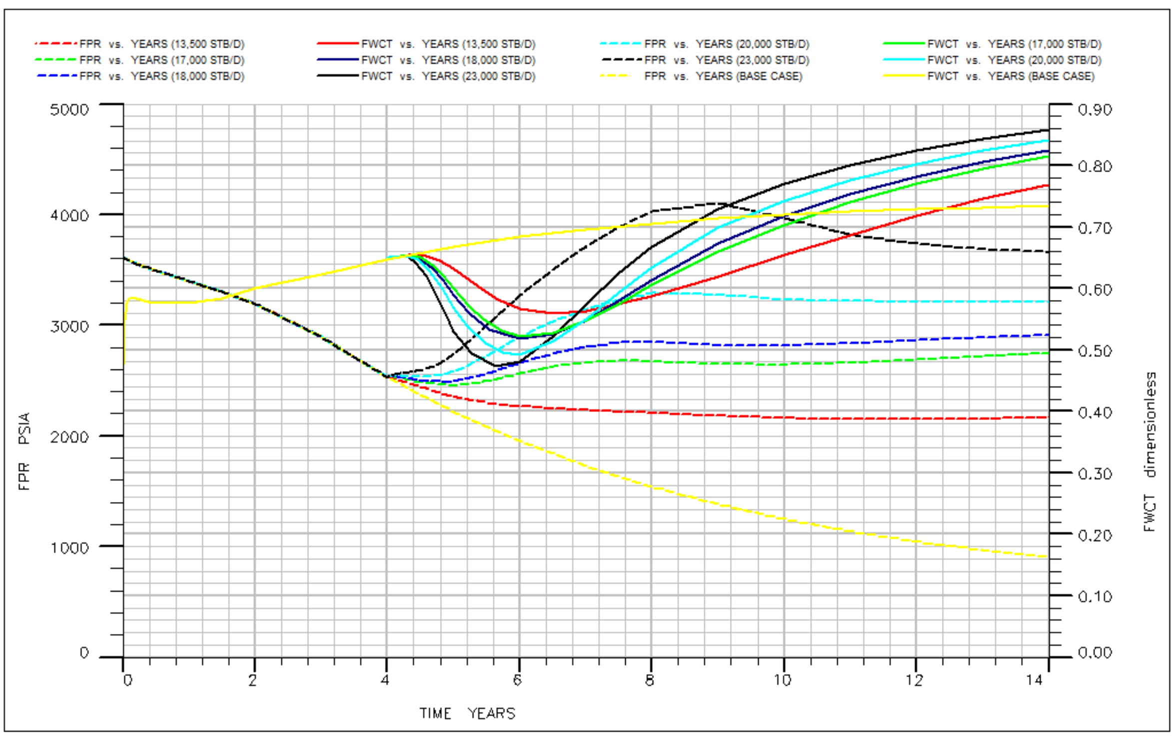

Figure 4.21: *Pressure and Watercut trends for the Injection Rate Sensitivity Analysis for a Heterogenous Reservoir*

Having seen that flooding will improve the reservoir recovery and determined the optimum injection rate, the question now is what will be the performance of these patterns if heterogeneity is moderate or high? Would the level of heterogeneity have an effect on the recovery of the patterns and to what degree?.

Figure 4.22 shows the trends for flow rates of different flood patterns in a moderately heterogeneous reservoir. The low flow rates for the direct line drive and staggered line drive patterns are due to the reduction in the ease of flow of fluid from the injectors to the producers in the direct path to flow in their areal sweep. Remarkably, there is a variation in the trend of the line drive and the staggered line drive which is after breakthrough and preferentially put the staggered line drive over the direct line drive regarding performance. The trends for 5-spot, 9-spot, and peripheral shows similar trends with a very little variation which is similar and shows that for a moderately heterogeneous reservoir, the peripheral pattern does perform as good as the other patterns (5-spot and 9-spot).

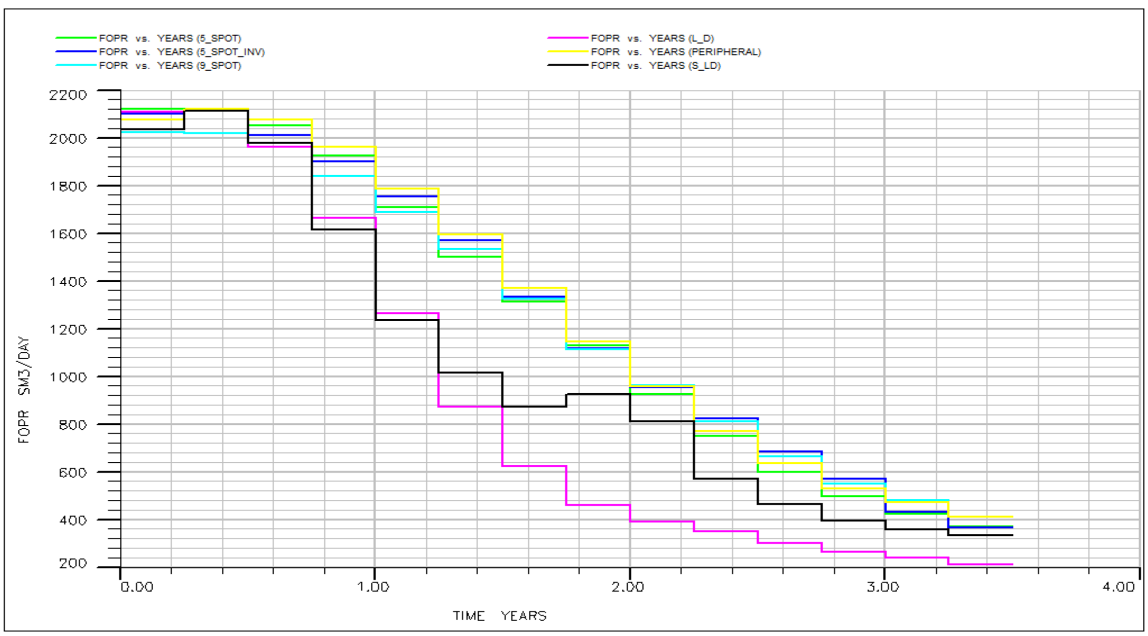

Figure 4.22: *Field Oil Production Rate for moderately heterogeneous reservoir*

A question that may arise to the correlation between heterogeneity and cumulative production is how heterogeneity determined at the microscopic scale in rock samples is related to macroscopic parameters (oil production rate, water cut, etc.) of production performance? It was speculated by Kwen *et al.,* 2011, that the macroscopic heterogeneity of the production formation consisted of rock may be represented to some extent by the microscopic heterogeneity of the rock. So according to Figure 4.23, as compared to the production performance depicted by Figure 4.2 which shows the performance of a homogeneous reservoir model, the reservoir with higher heterogeneity usually has worse production performance compared to a homogeneous reservoir. From the figure, it can be deduced that for a reservoir with moderate heterogeneity, peripheral pattern performs better than the 5-spot and 9-spot. The is so because the reservoir is of generally high absolute permeability.

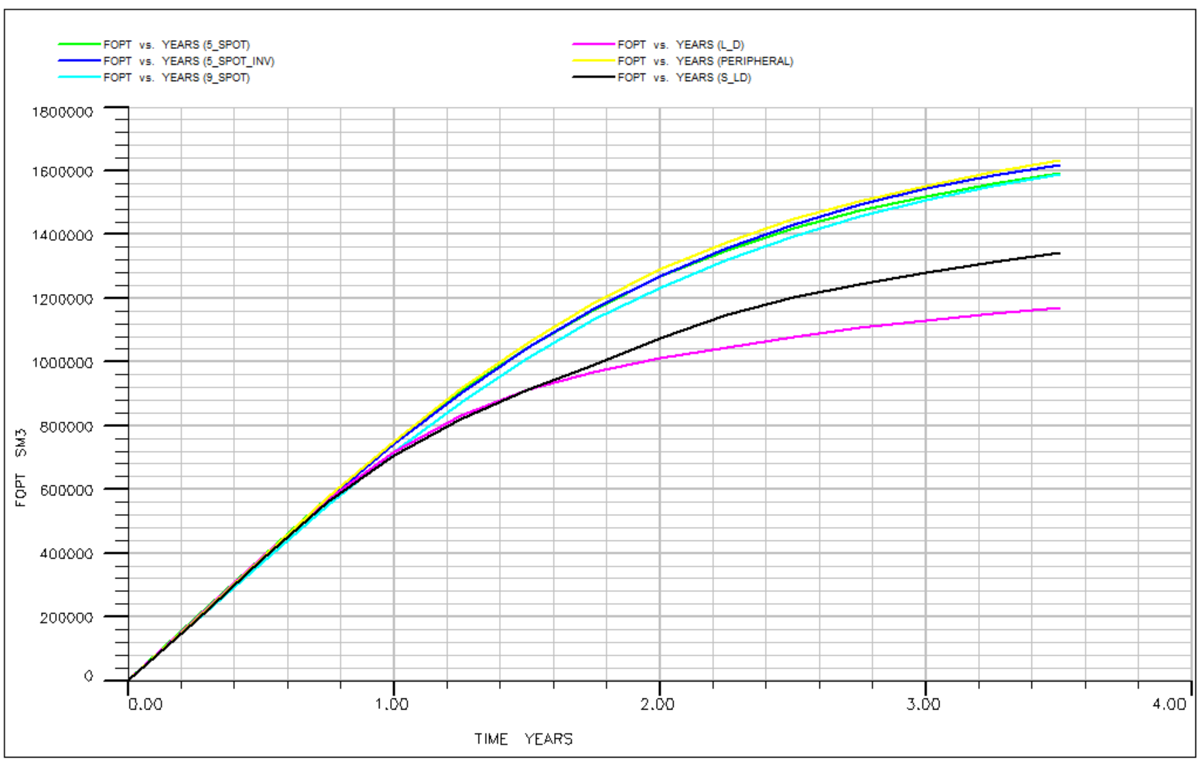

Figure 4.23*: Field Cumulative Oil Production for moderately heterogenous reservoir*

Water injection into the reservoir serves two purposes: pressure maintenance and for fluid displacement. Figure 4.24 shows the field pressure for the various patterns. From this figure, it is clear that staggered line drive and peripheral has higher pressure maintenance trends. This is so because of the high injection rate used for the staggered line drive, and the injection of the peripheral pattern is as though it was done in an aquifer which offers support to the pressure depletion of the reservoir pushing the hydrocarbon towards the crest.

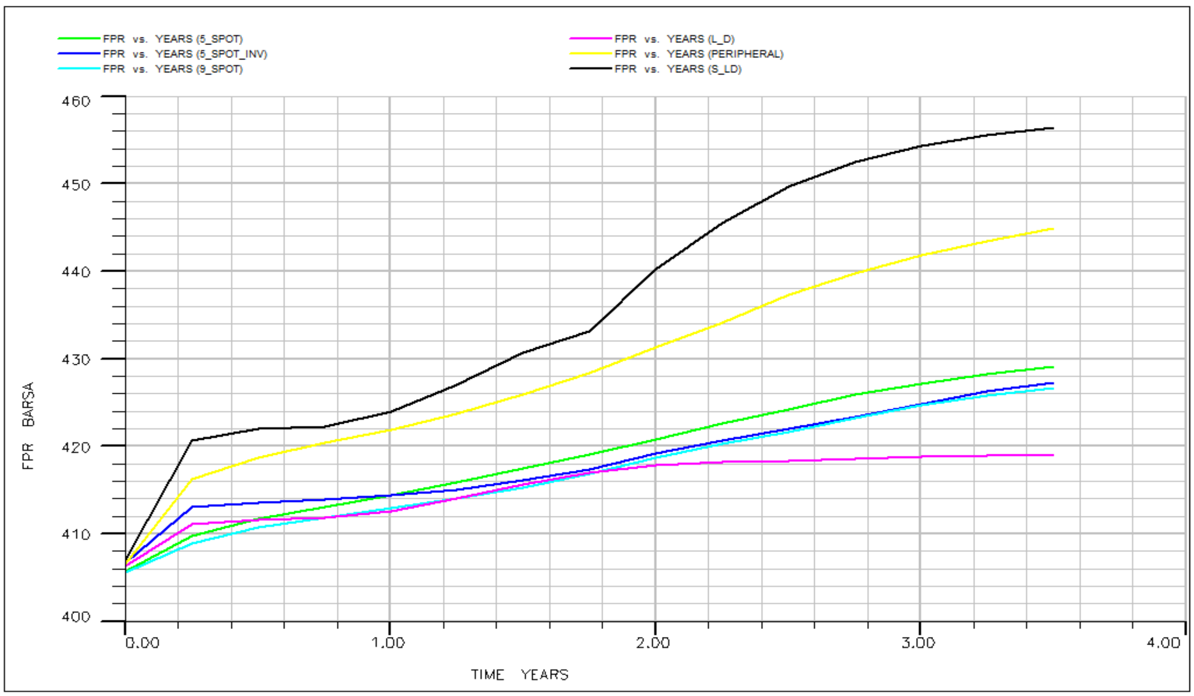

Figure 4.24: *Field Pressure for moderately heterogeneous reservoir*

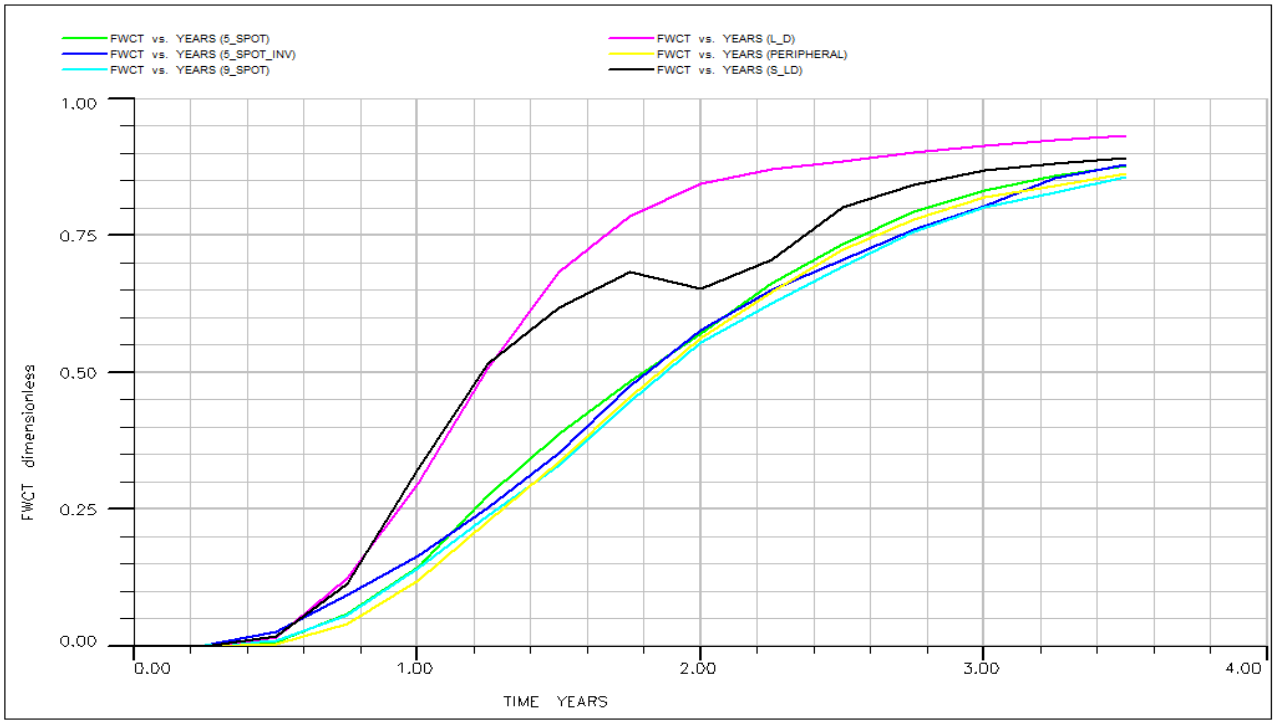

Figure 4.25: *Field Watercut for moderately heterogeneous reservoir*

As expected for the line and staggered line drives, the water cut is high which is as a result of the direct line of flow in the area coverage of both the pattern to injected water and of the other patterns, the peripherals seem to have a delay in water breakthrough compared to the 5-spot and 9-spot. Thus, allowing for water-free oil production.

The above results from Figure 4.23 to Figure 4.25 are for reservoirs with moderate variation in properties (Heterogeneity). So what will be the performance of these patterns for a highly heterogeneous reservoir? This is represented by Figures 4.26 to 4.29. The plot represents the oil production rate, cumulative oil production, field pressure and field watercut of all the patterns.

From Figure 4.26 which shows the production rate for all patterns, it can be seen that the trend for the inverted 5-spot is much high than the other patterns. This very high rate is due to the high injection rate by the injectors which are only possible when high injectivity is possible.

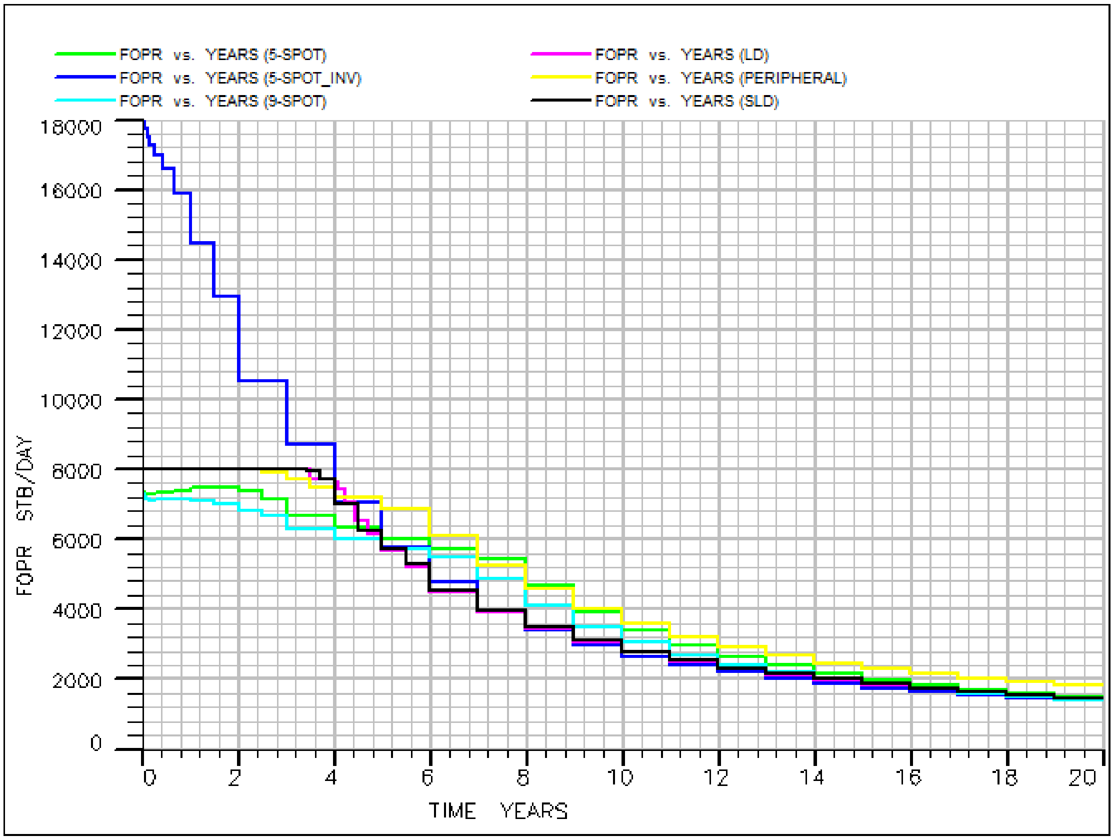

Figure 4.26: *Field Oil Production Rate for highly heterogeneous reservoir*

With an injector of high injection rate of 13500 STB/D and surrounded by four producers, consequently, the rate will be high. Also from this plot, the peripheral pattern can maintain the rate much longer than the other patterns before a decline. The is so because it behaves as the injection is into the aquifer and pushes the hydrocarbon towards the crest. Correspondingly, Figure 4.27 shows a plot of the cumulative oil produced.

Figure 4.28 shows the field pressure trend for the all the patterns. From the trends, it can be seen that for a staggered line drive and the direct line drives, there is attainment of plateau before the decline of the pressure. This shows that at the current injection rate, for these drives, the formation was fractured.

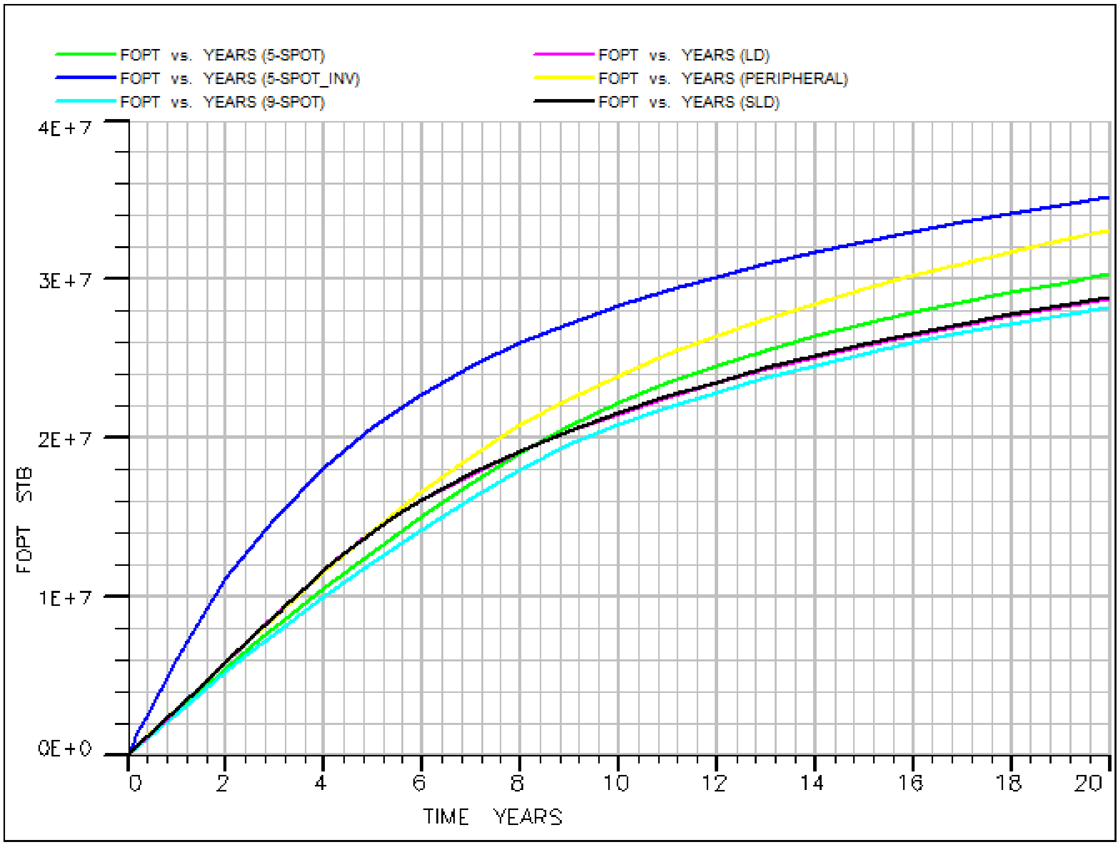

Figure 4.27: *Field Cumulative Oil Production for Highly Heterogenous Reservoir*

The inverted five-spot, followed by the 9-spot and 5-spot has lower field pressure compared to the peripheral which leads to the conclusion that the high cumulative production for the inverted five-spot drive was as a result of the high injection rate which served the purpose of displacement and not pressure support was responsible for such production. But in the case of peripheral, the injected water serves the displacement and pressure support purpose.

Correspondingly, Figure 4.29 which shows the watercut for all patterns depicts a late breakthrough lowest field watercut for the peripheral. Early breakthrough is witnessed by the line and staggered line drives with high watercut for 5-spot and 9-spot patterns.

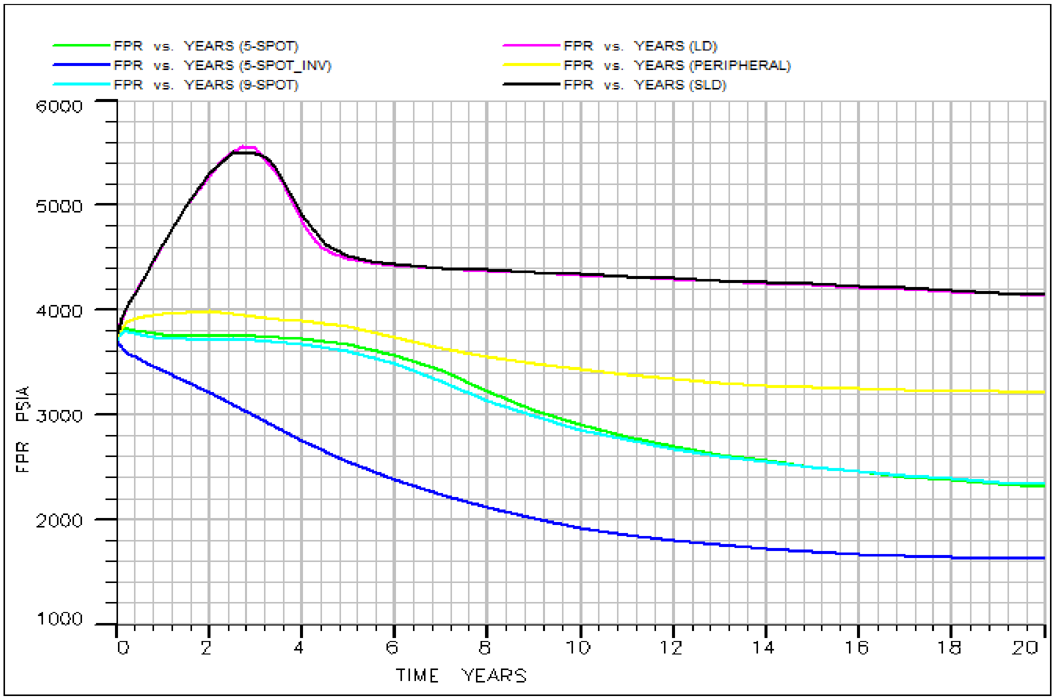

Figure 4.28: *Field Pressure for highly heterogeneous reservoir*

With macroscopic parameters such as production rate, field pressure, watercut and cumulative oil produced used as a screening criteria to determine the best pattern for this reservoir, it will be technically wise to also screen this patterns in terms of the optimal pore volume of water to be injected for each pattern. This analysis is depicted in Figure 4.30, from which the optimum pore volume to be injected for both the line and staggered line drive is 24.2. For comparison of the other patterns in terms of pore volume, a reference pore volume would be selected e.g. 1.25 and the recoveries at this pore volume for 5-spot, 5-spot inverted, line drive, peripheral, staggered line drive, and 9-spot is 25.8,28.4,22.1,26.8, 22.1, 24.8 respectively. This also indicated that the peripheral flooding pattern would be the best developmental strategy considering the macroscopic parameters analyzed and its economics, being that a fewer number of wells are required for peripheral compared to 9-spot and 5-spot which are conventionally used.

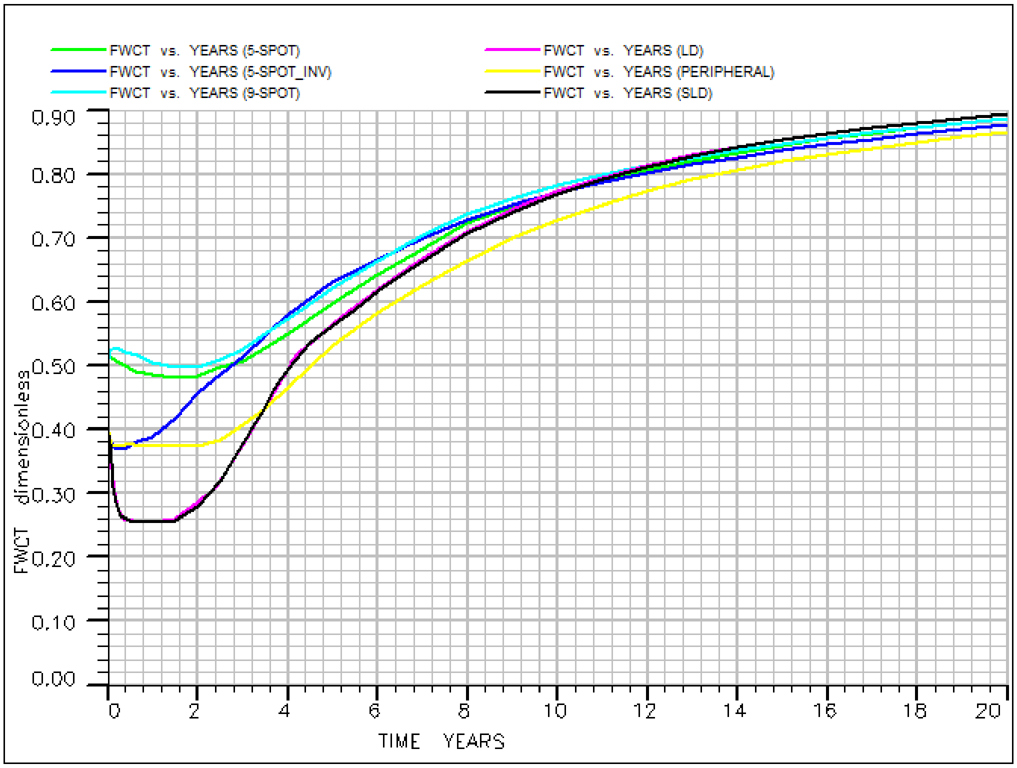

Figure 4.29: *Field Watercut for highly heterogeneous reservoir*

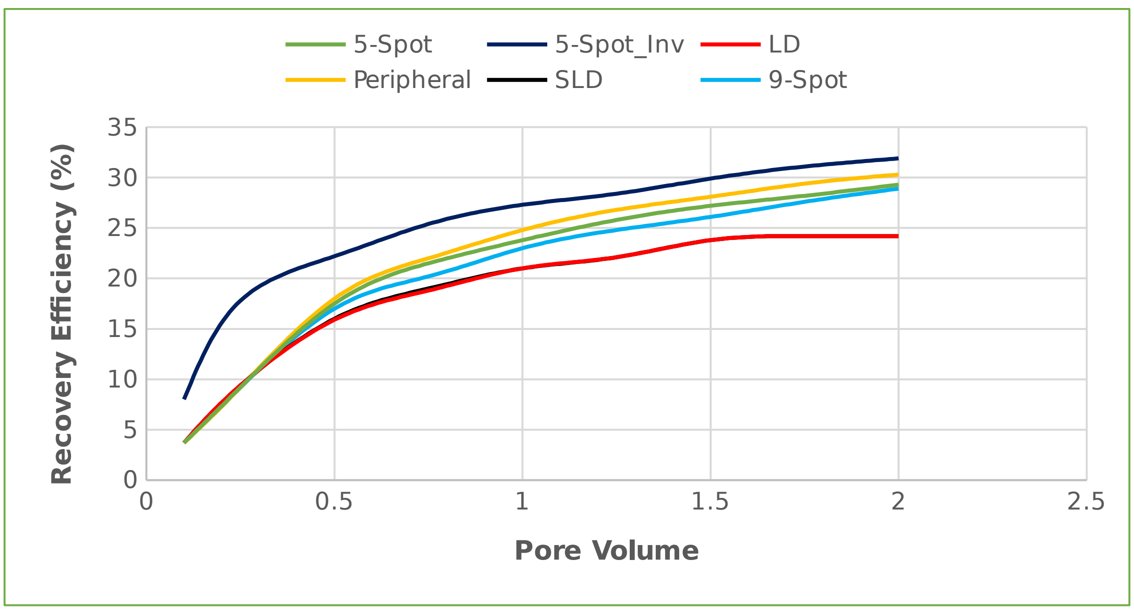

Figure 4.30: *Pore Volume Analysis for Pattern Analysis*

4.5 Production Analysis

One of the most widely used methods of data analysis employed in evaluating a reservoir and prediction of the future production is the decline curve. This is based on the assumption that the past production trend and its controlling factors, will continue in the future and therefore, can be extrapolated and described by a mathematical expression (Tarek Ahmed,2010).

Arps (1945) proposed that the curvature in the production rate vs. time curve can be expressed by a hyperbolic family of mathematical equations. He recognized the exponential, harmonic and hyperbolic as the rate decline types, with each having a different curvature.

He asserted that for an exponential decline, a straight-line relationship will result when a flow rate versus time plot is made on a semi-log scale and also when the flow rate(FOPR) versus cumulative production (FOPT) is plotted on a cartesian scale. For harmonic decline, a rate versus cumulative production trend will result in a straight-line on a semi-log scale, with all other declines having some curvature. But for hyperbolic, none of the above plotting scales, i.e. cartesian, semi-log, will produce a straight-line relationship for a hyperbolic decline.

Figures 4.31 through to 4.35, show trends which depict whether the production decline for the flood patterns is exponential, harmonic or hyperbolic. This trend which clearly shows that the production decline of this reservoir using this flood patterns is hyperbolic has the plot of FOPR vs. Time, FOPR vs. FOPT, etc. did not result to a straight-line relationship.

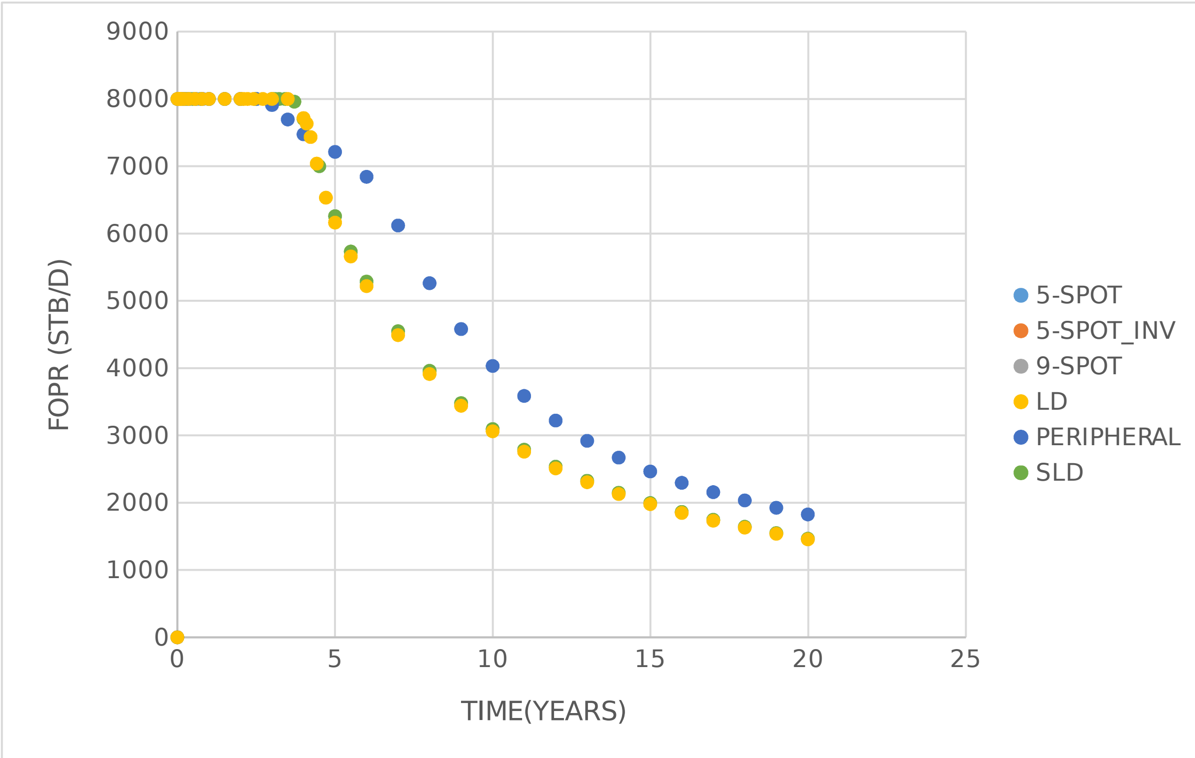

Figure 4.31: *Plot of Field Oil Production Rate Versus Time*

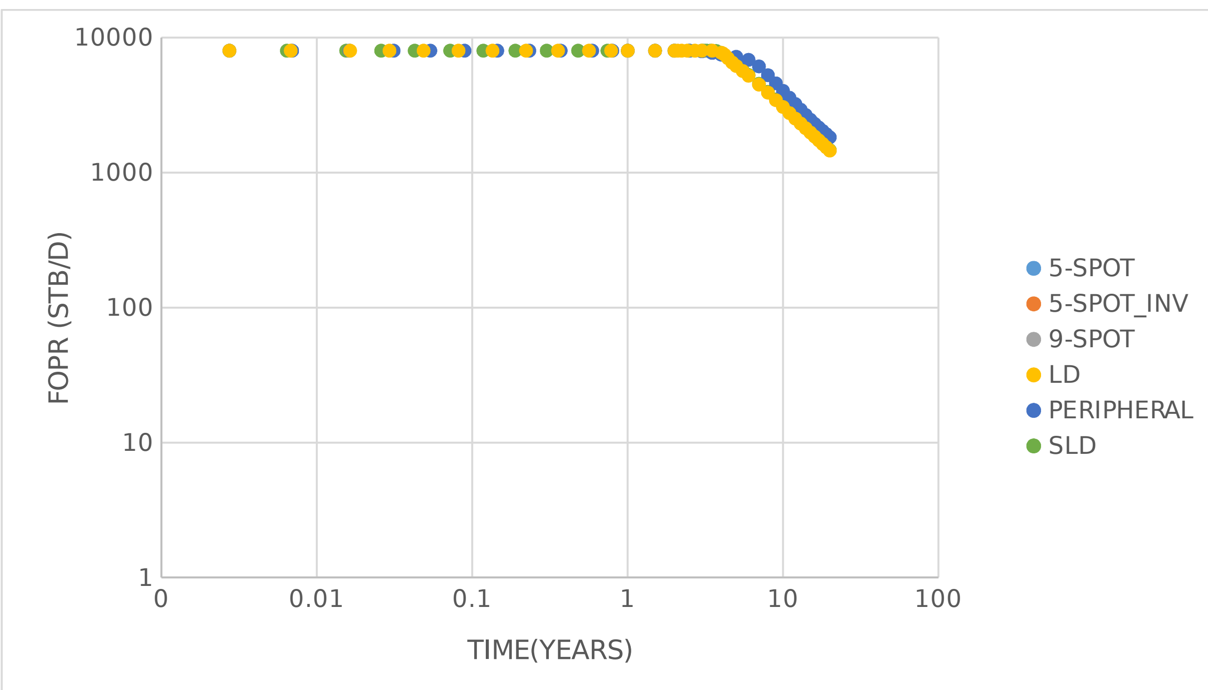

Figure 4.32: *Log Plot of Field Oil Production Rate Versus Time*

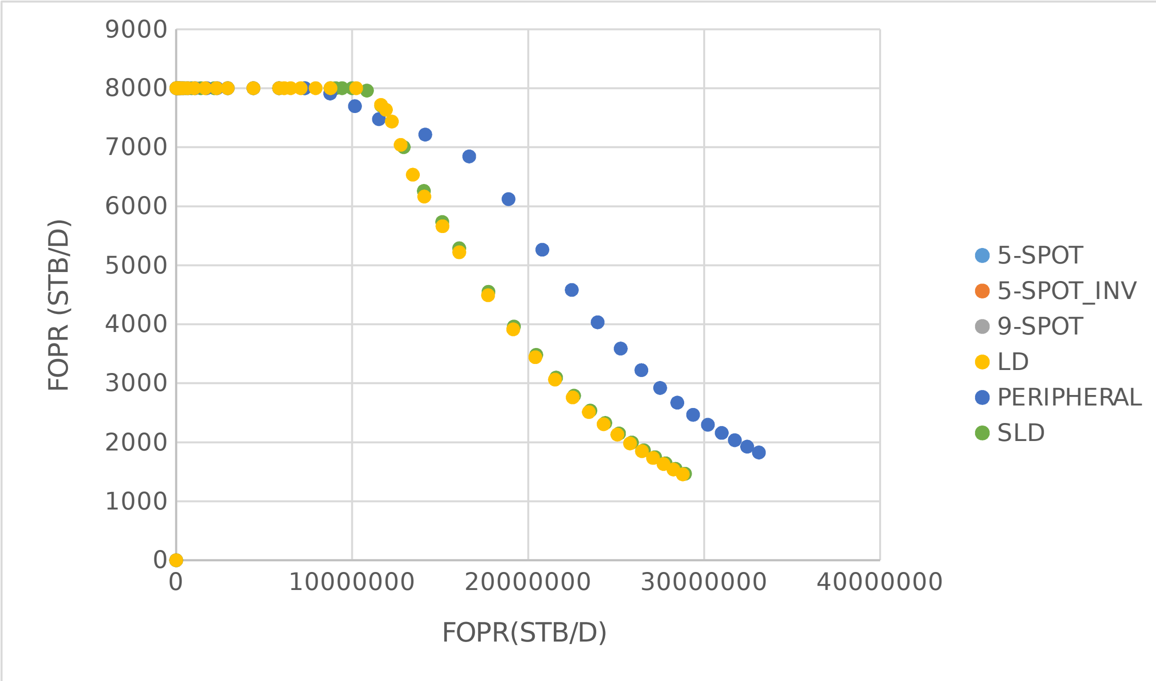

Figure 4.33: *Plot of Field Oil Production Rate Versus Cumulative Oil Production on Cartesian Scale*

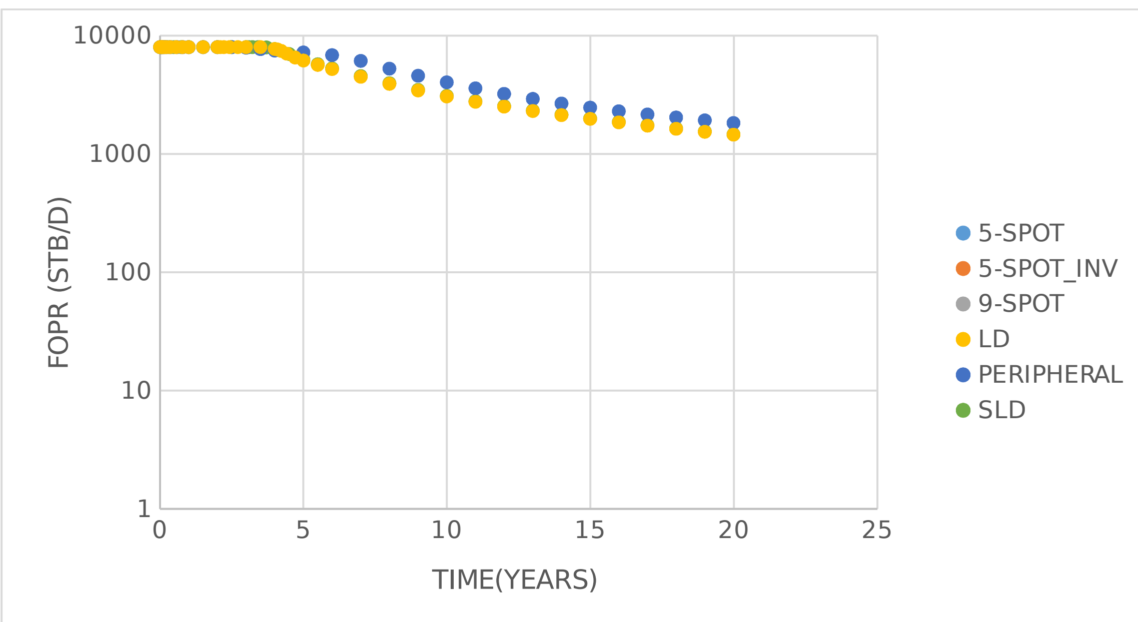

Figure 4.34: *Semi-Log Plot of Field Oil Production Rate Versus Time*

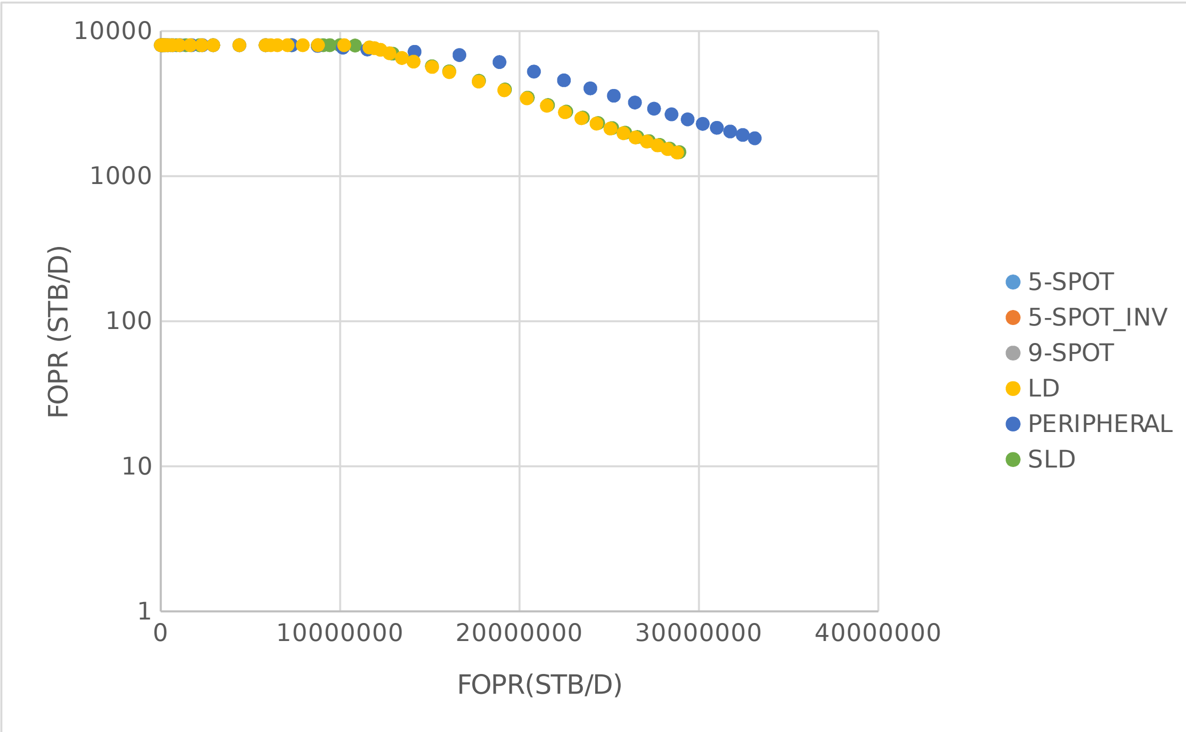

Figure 4.35: *Semi-Log Plot of Field Oil Production Rate Versus Cumulative Oil Production*

4.6 Economic Analysis

The economics of the developmental strategies adopted for a particular reservoir is all that decides whether an asset is worthy of investment or not. So care must be taken to select the right pattern as in the case of scenarios of interest in this research. Having considered production rate, cumulative oil produced, pressure maintenance ability of the patterns and water cut as screening criteria, the almost criteria remains the economics of each of the patterns in question. Table 4.2 shows the capital expenditure (CAPEX), the operating expenditure (OPEX) and the cumulative net cash flow (CNCF) for each of the patterns.

Table 4.2: Developmental Cost of Flooding Patterns

Pattern	CAPEX	OPEX	CNCF
5-Spot	2.1×10^7	3.7×10^8	3.7×10^9
5-Spot Inverted	2.1×10^7	3.7×10^8	7.2×10^9
9-Spot	3.9×10^7	3.7×10^8	3.3×10^9
Line Drive	1.3×10^7	3.7×10^8	4.9×10^9
Staggerd Line Drive	1.3×10^7	3.7×10^8	4.6×10^9
Peripheral	1.9×10^7	3.7×10^8	4.2×10^9

From the Table 4.2, the pattern with the highest net cash flow is the inverted 5-spot, which would be the most economical only if the reservoir can withstand high injectivity and with provision for other means of pressure support, as it provides low-pressure support. Line drive and staggered line drives follow with the next highest net cash flow, but its applicability is constrained due to high water production. The economic analysis thus, supports the claim that for a reservoir with high average permeability, peripheral flooding pattern would be the most economical developmental strategy.

4.7 Infill well Well Location and Optimization

Having selected the peripheral pattern to be the optimum pattern for the development of such a reservoir, the question next to be answered is how many infill wells do we need to drill to recover the bypassed oil? The number of wells to be drilled has to be carefully thought of even though drilling more wells will eventually lead to more production. The bottom line lies in the economics of the process. So to answer this question, a well net present value (NPV) analysis could reveal the maximum number of wells to be drilled to maximize recovery and economically.

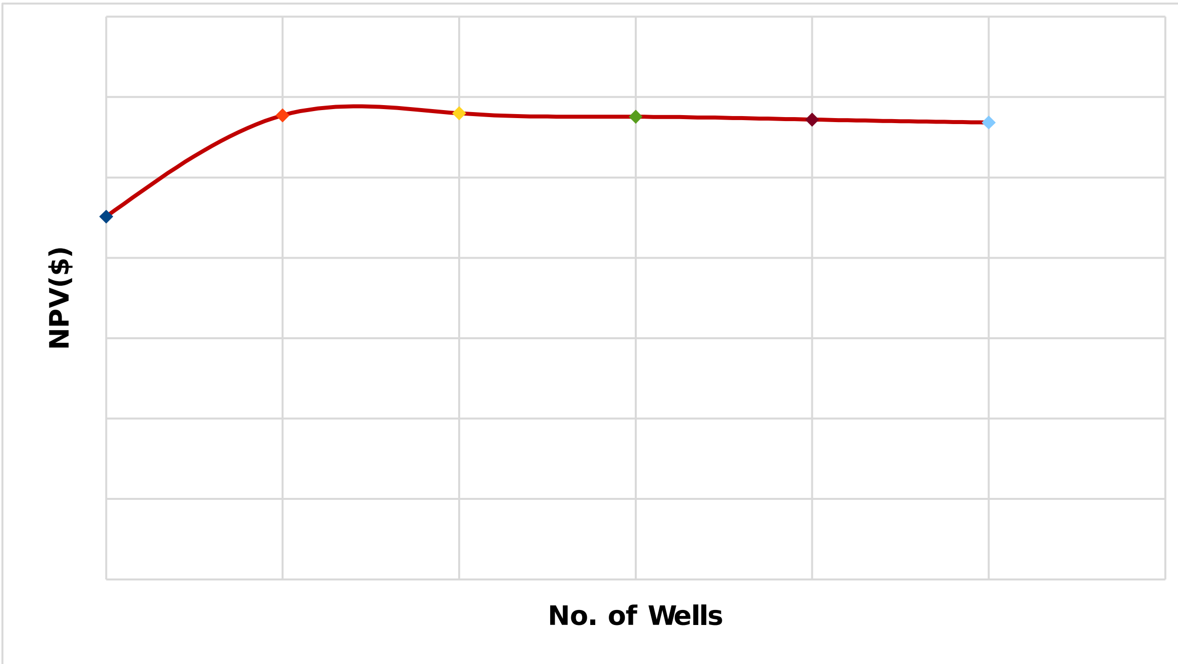

Figure 4.36*: Net Present Value-Well Analysis*

Figure 4.36 shows the result of the NPV-Well analysis, from which it can be seen that the maximum number of infill wells to be drilled. This is represented by the plateau of the trend (the point where NPV began to decrease). The average cost of drilling a well used for this analysis is fifteen million dollars ($15 million). The maximum number of wells to be drilled as depicted by the figure is two. Which are as per this analysis all vertical wells yield a cumulative oil production of 42,423,720 STB and NPV of $2.90E+09.

Figure 4.37 depicts the cumulative oil produced by incremental drilling of infill wells. This shows that the maximum field oil production was in a case where only two wells were drilled. This low production by scenarios of a higher number of infill wells can be explained using the field pressures represented in Figure 4.38. From the trend, the low production of scenarios with infill well number higher than two is because of the low reservoir pressure after two infill wells have been drilled. Thus, the low NPV obtained for such a project.

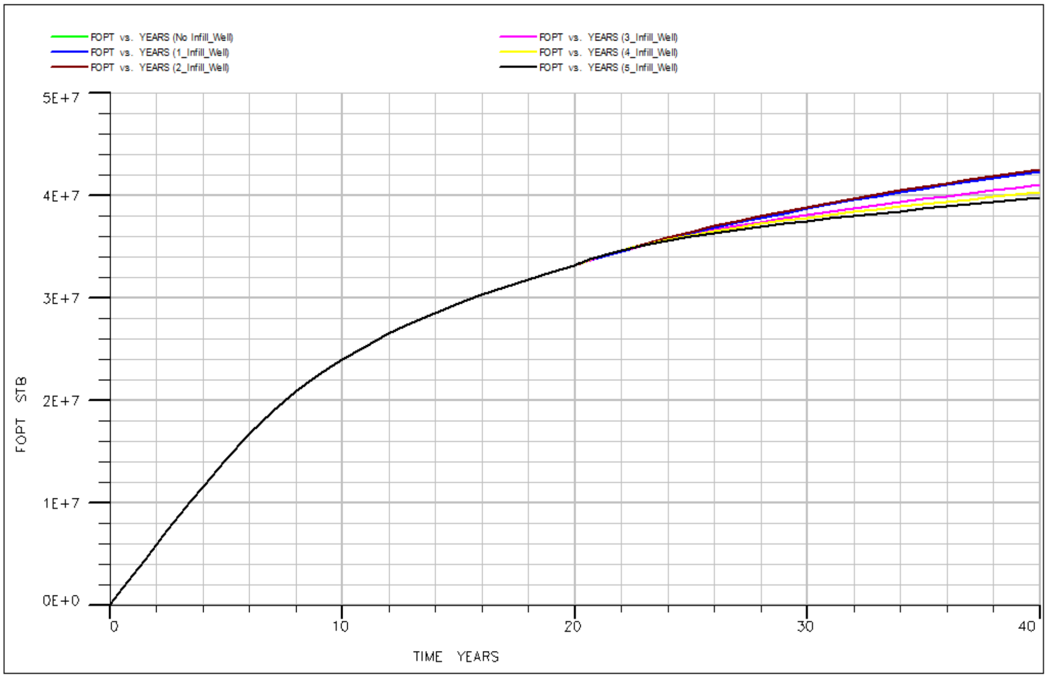

Figure 4.37: Field Oil Cumulative Production of Infill Well Analysis

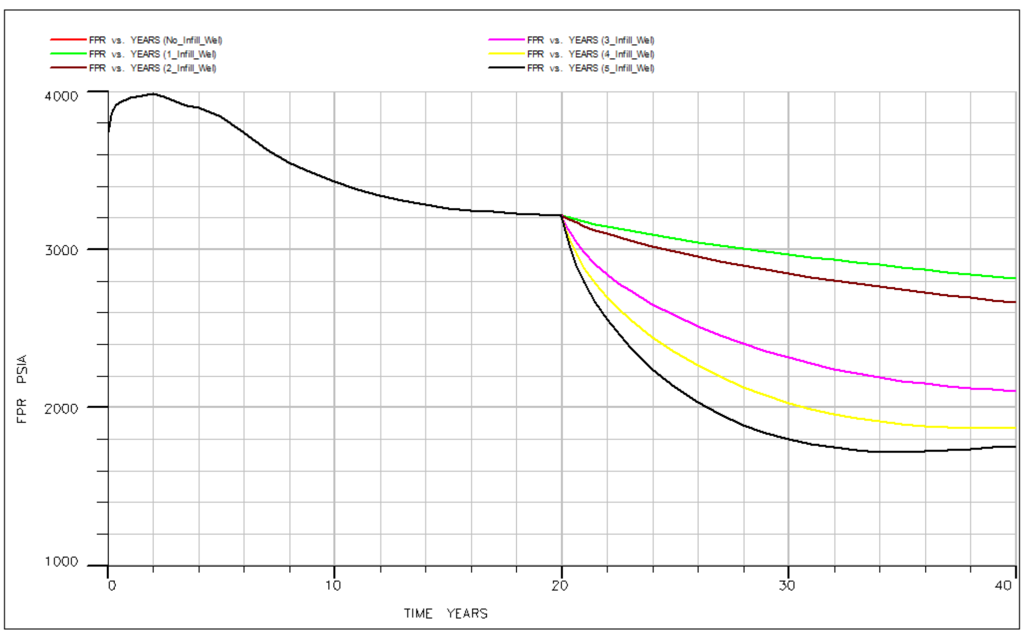

Figure 4.38: Field Pressure of Infill Well Analysis

With the maximum number of wells determined, particle swarm algorithm (PSO) is used to determine the optimum locations of the infill wells with considerations given to the pressure and saturation constraints. The parameters used in the algorithm were adopted from the studies conducted by Obed, 2016. Wells were then placed in these locations to determine the incremental oil recovery. Figure 4.39 and 4.35 show the flood pattern before and after the infill wells have been drilled. Most of the bypassed oil was located in the grids 9 to 20 in the x-direction, 9 to 19 in the y-direction and across the thickness. The color band indicates the degree of oil saturation in every grid. As can be seen, from the two figures, the saturation of oil has reduced from what is depicted in Figure 4.40 which is as a result of the infill drilling program.

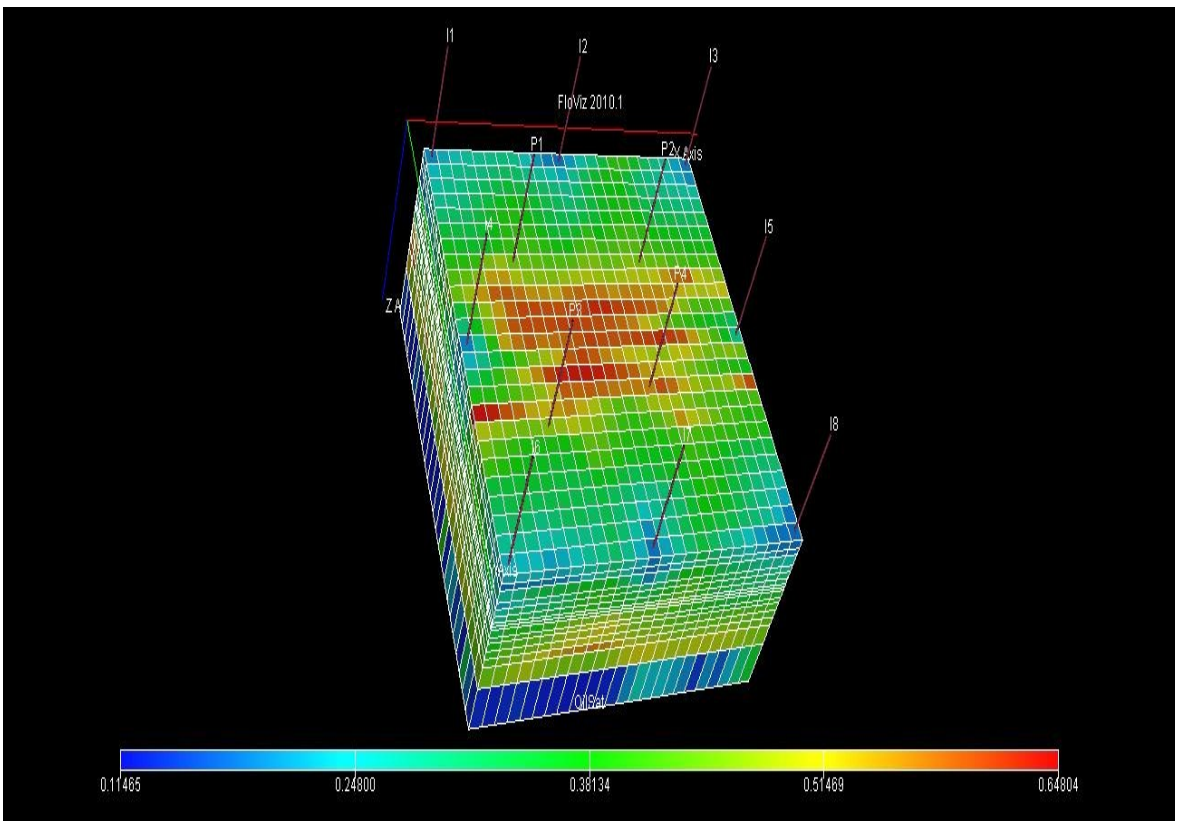

Figure 4.39*: Oil Saturation After Waterflooding Process*

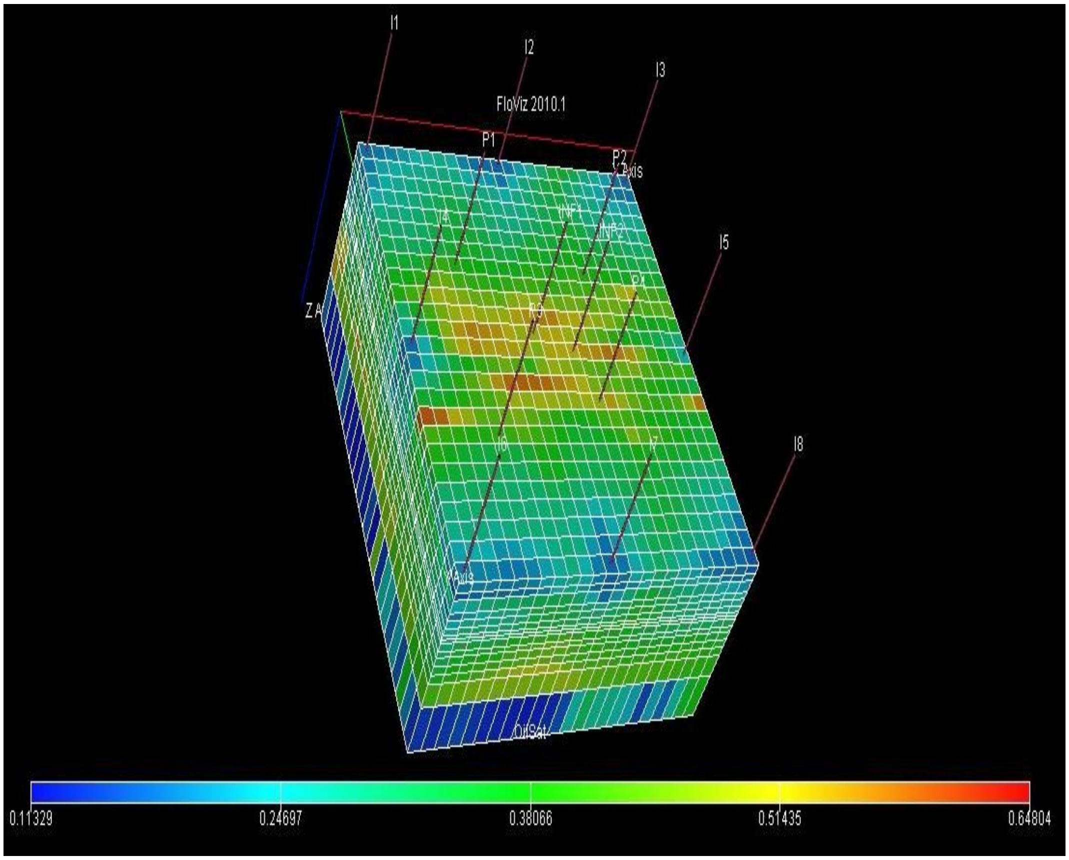

Figure 4.40: *Oil Saturation After Infill Drilling Process*

With this recovery and much more still left underground, a pressure maintenance operation could be adapted to recover more from the reservoir or an enhanced oil recovery technique applied to mobilize the oil.

CHAPTER FIVE

CONCLUSION AND RECOMMENDATIONS

This chapter presents the various conclusions arrived at during the study designed to optimize the performance of a waterflooding process by use of infill wells from a streamline-based workflow. Recommendations shall be given to point out areas of further research to expand the scope of work and to improve the proposed methodology

5.1 CONCLUSIONS

1. Streamline simulation has was used as an efficient and fast tool for obtaining well allocation factors and pattern recovery efficiency which was used to obtain injection efficiency.
2. The effect of pattern selection has a high impact on the recovery from a flooding process and is greatly affected by permeability anisotropy.
3. Peripheral pattern performs much better than the generally accepted 5-spot and 9-spot in a reservoir with a high average permeability and has an efficiency of 77.7 % for and homogeneous reservoir.
4. Particle swarm algorithm is an efficient tool in determining the locations of infill well placement.
5. Screening of wells for shut-in and other reservoir management decisions such as selecting injection well reallocation candidates exhibiting poor injectivity can be easily made with the injection efficiency data derived from the streamline simulation methodology proposed in this study.
6. Infill well drilling leads to incremental recovery in a waterflood system.

5.2 RECOMMENDATIONS

The following recommendations are presented for further studies to improve the methodology and results discussed in this work,

1. Reallocation cycle of the flooding process should be studied to better understand the relationship between reservoir performance (oil production rate and water cut) and the frequency of injection rate reallocation. The advantages of streamline simulation can be better appreciated with the more robust tools.
2. This study considered both the injection and production wells as fully completed, with perforations in 4-15 reservoir layers. Variable layer completions should be considered in a future study to identify the best zones for completion to minimize water production.
3. The time of intervention of an optimization tool in any known reservoir is critical in order to obtain the best results. In this analysis the time to initiate waterflooding was 10 years. It is possible that by starting the optimization earlier, the water cut will be delayed and oil recovery maximized. The determination of the time to start the waterflooding is suggested as a topic for future research.
4. With so much oil still left in place, water alternating gas or gas injection should be considered as a full water flooding process to mobilize the oil by reducing the capillary forces and surface tension.

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NOMENCLATURE

ANN	Artificial Neural Network
bGA	Binary Genetic Algorithm
cGA	Continuous Genetic Algorithm
GA	Genetic Algorithm
HC	Hill Climber
LD	Line Drive
NPV	Net Present Value
PermX	Horizontal Permeability
PermZ	Vertical Permeability
Poro	Porosity
PSA	Particle Swarm Algorithm
SLD	Staggered Line Drive
So	Initial Oil Saturation
Sor	Residual Oil Saturation
TranX	Transmissibility

APPENDICES

APPENDIX A

This section shows the images of the reservoir at initial conditions and the condition of the reservoir after production for all the flood patterns.

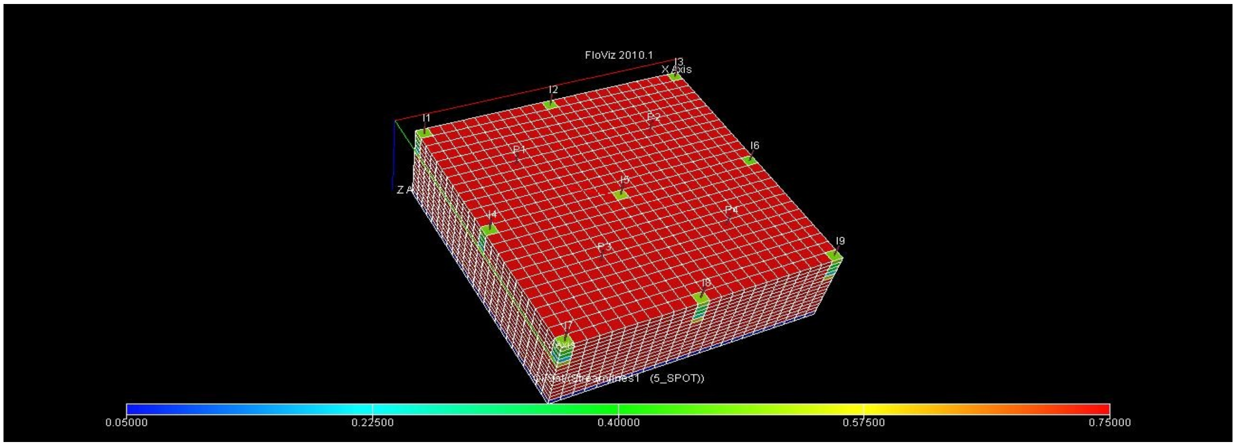

Figure A1: *Reservoir with 5-Spot Pattern at Initial Condition*

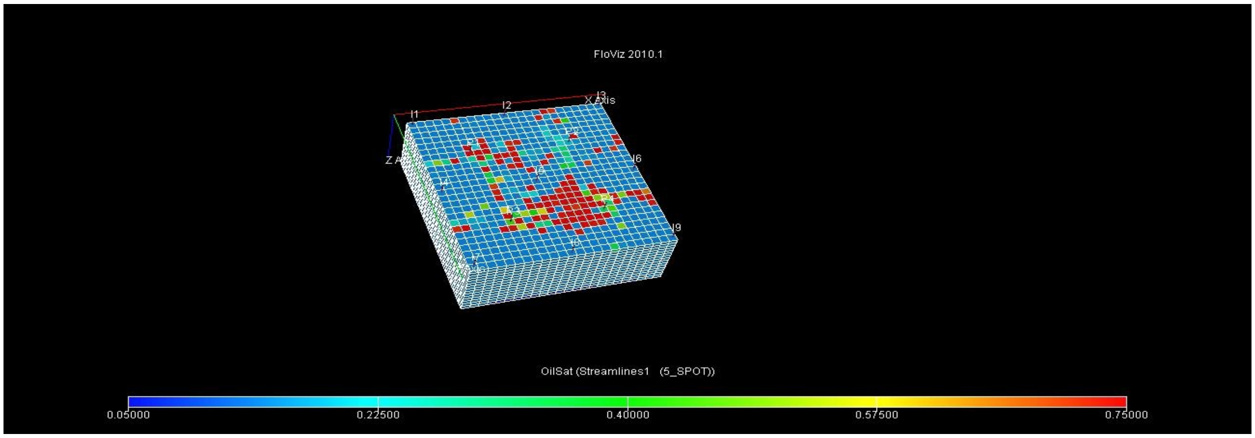

Figure A2: *Reservoir with 5-Spot Pattern after Production*

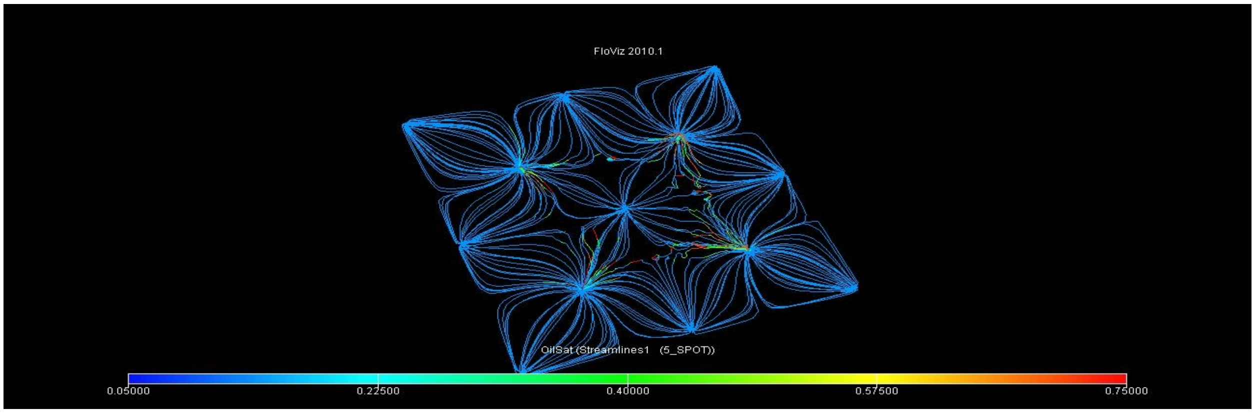

Figure A3: *5-Spot Pattern Streamlines after Production*

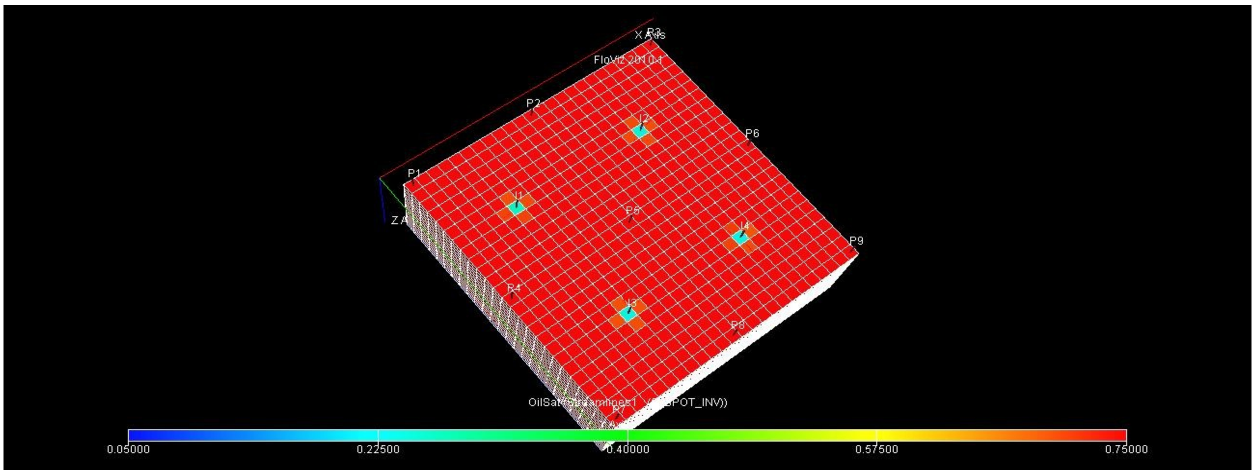

Figure A4: *Reservoir with Inverted 5-Spot Pattern at Initial Condition*

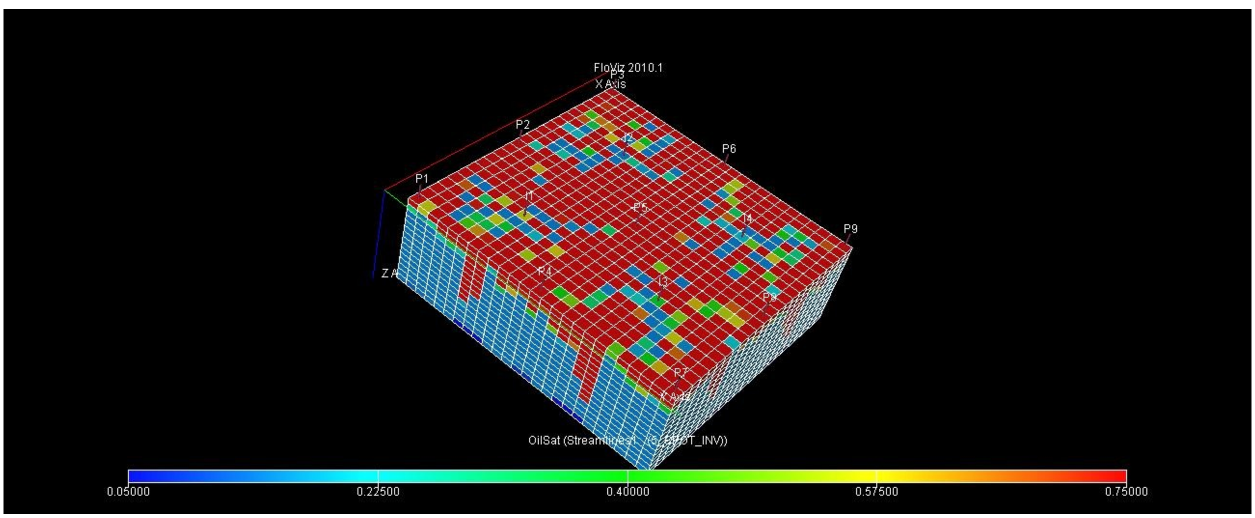

Figure A5: *Reservoir with Inverted 5-Spot Pattern after Production*

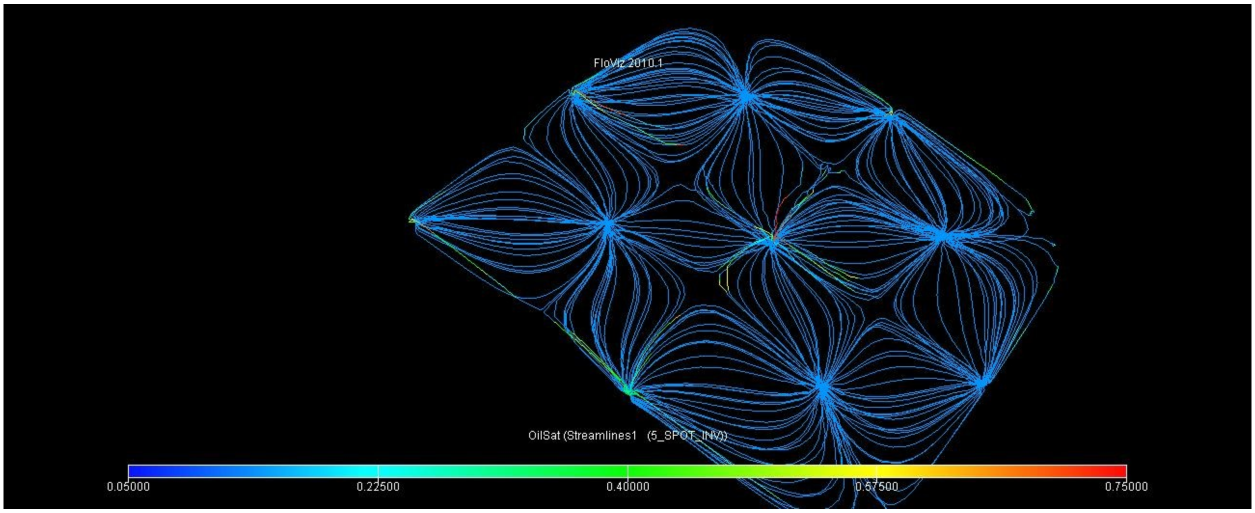

Figure A6: *Inverted 5-Spot Pattern Streamlines after Production*

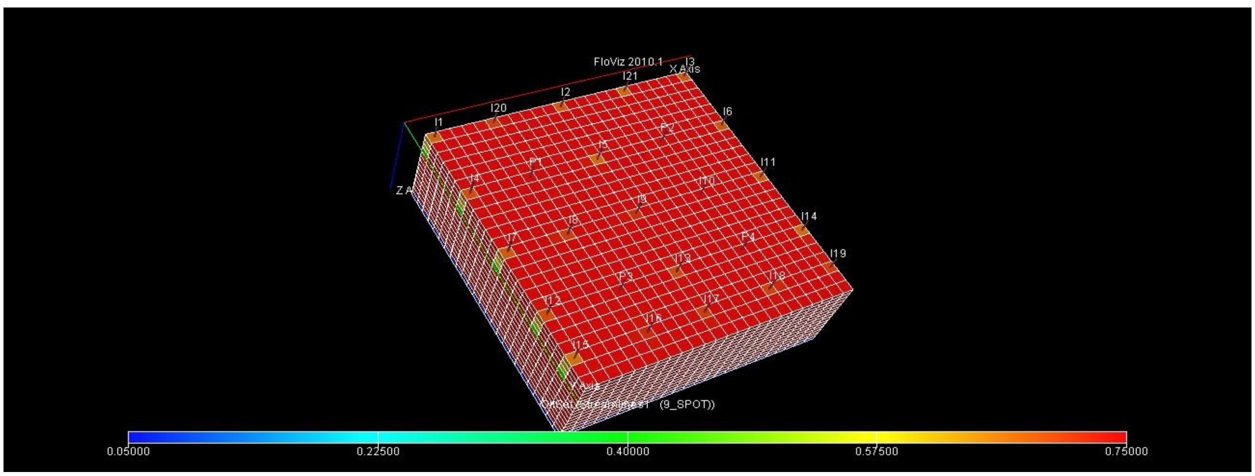

Figure A7: *Reservoir with 9-Spot Pattern at Initial Condition*

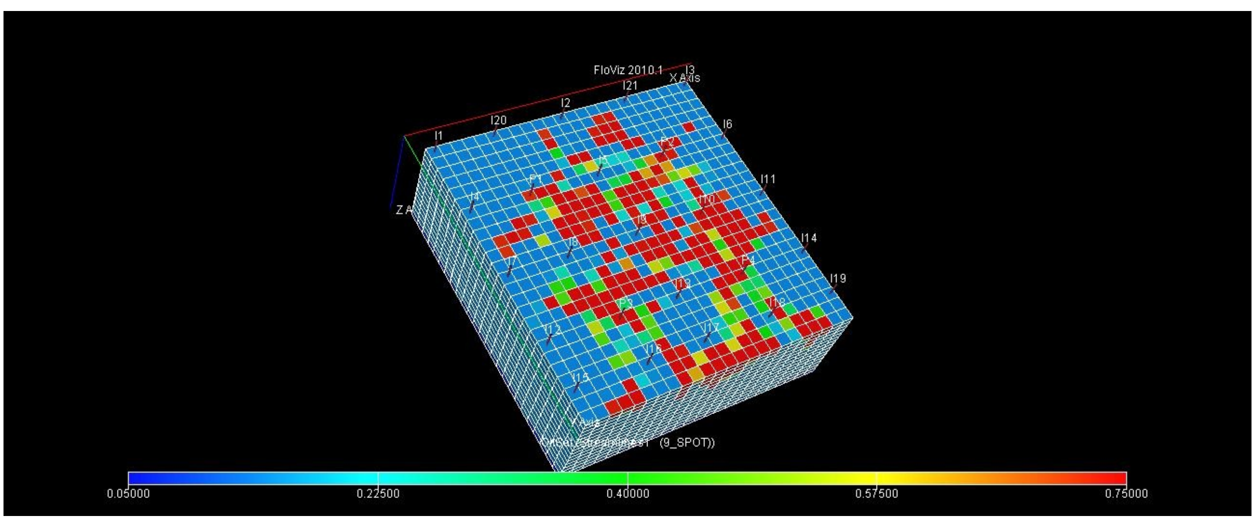

Figure A8: *Reservoir with 9-Spot Pattern after Production*

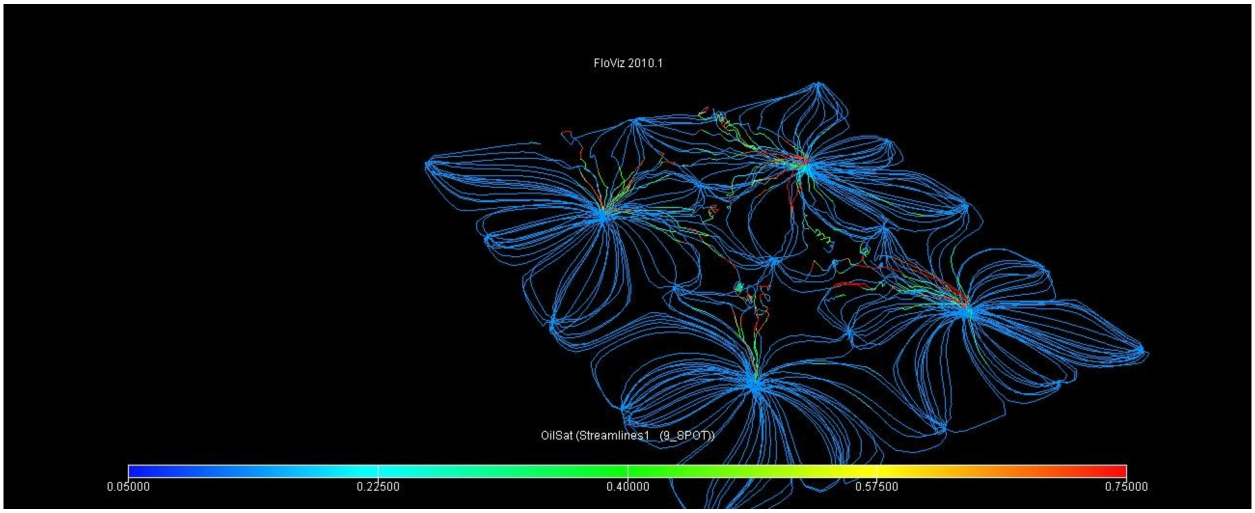

Figure A9: *9-Spot Pattern Streamlines after Production*

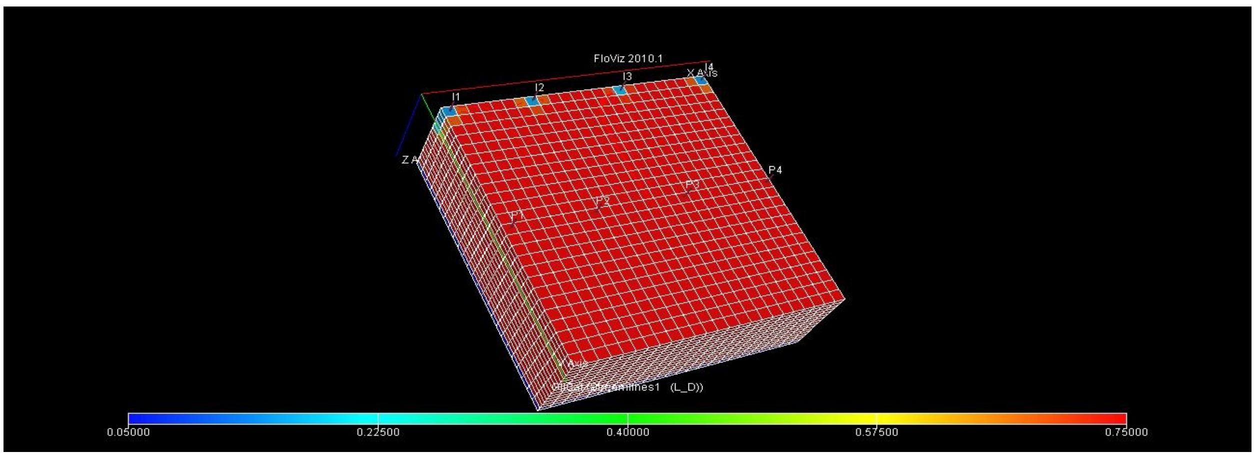

Figure A10: *Reservoir with Line Drive Pattern at Initial Condition*

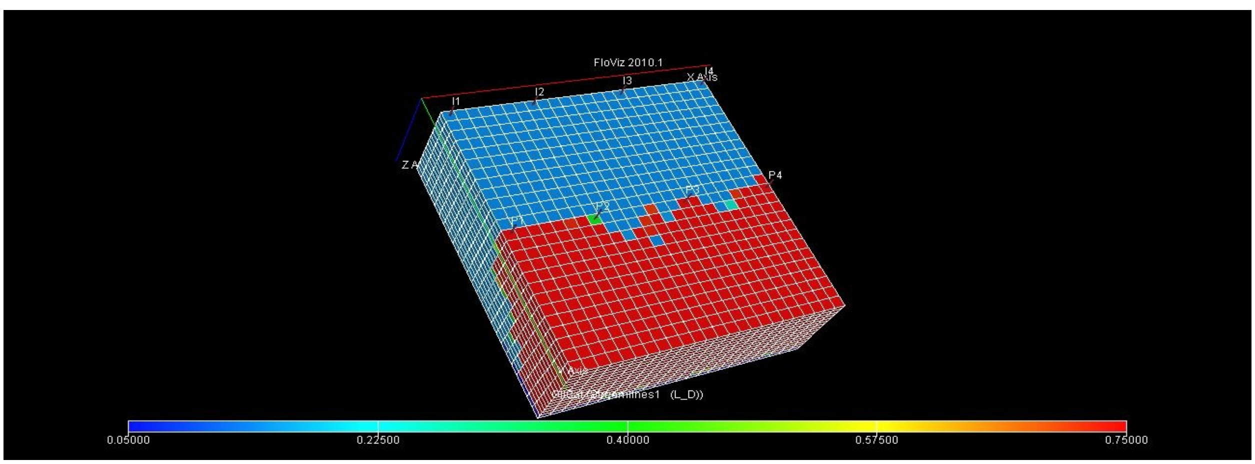

Figure A11: *Reservoir with Line Drive Pattern after Production*

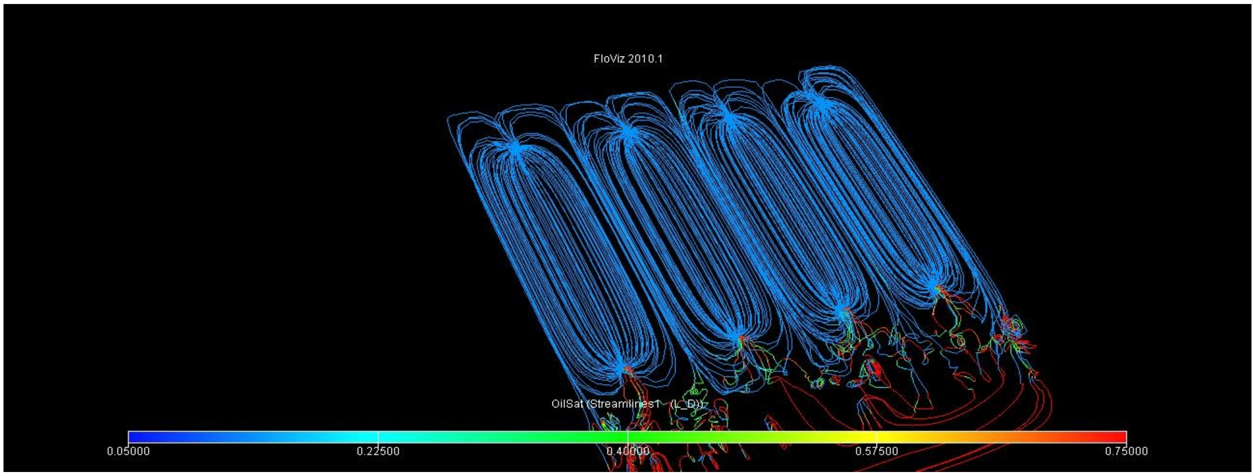

Figure A12: *Line Drive Pattern Streamlines after Production*

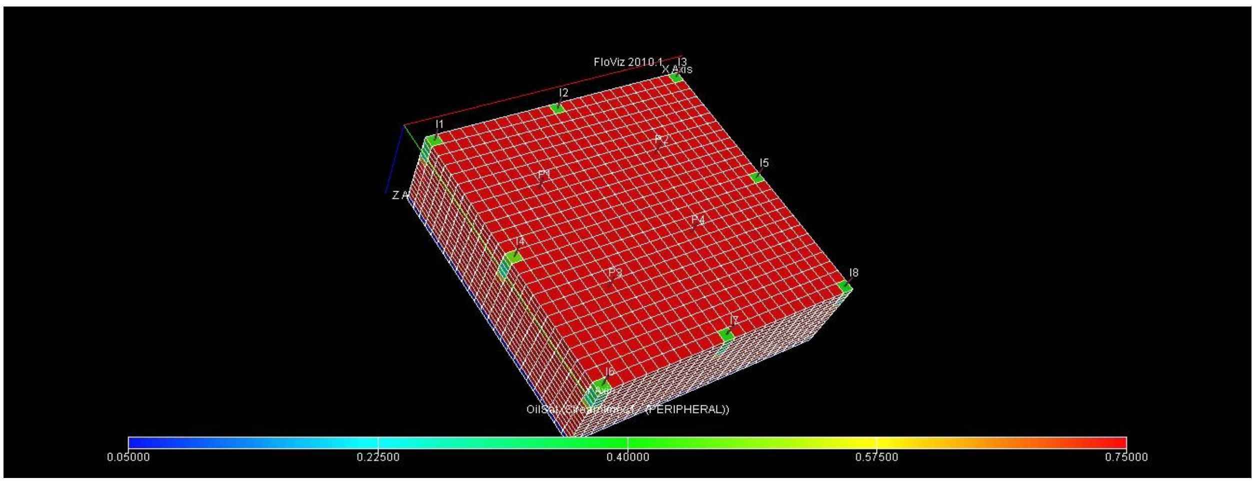

Figure A13: *Reservoir with Peripheral Pattern at Initial Condition*

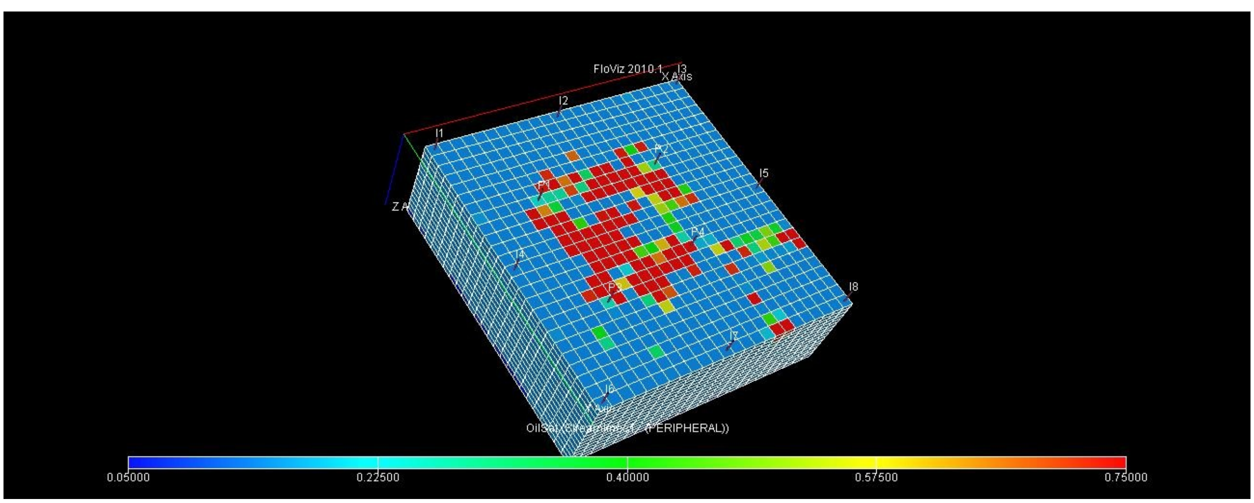

Figure A14: *Reservoir with Peripheral Pattern after Production*

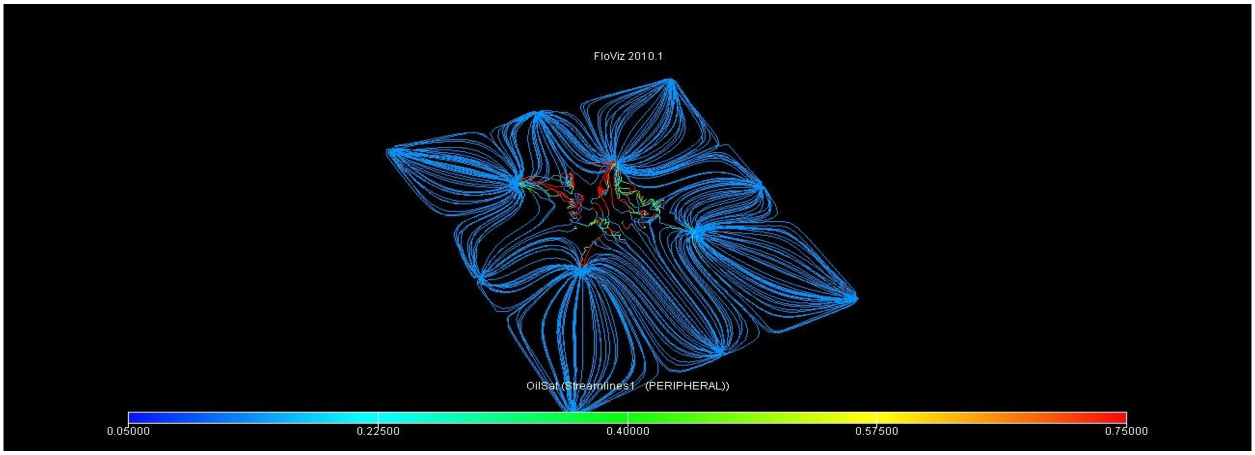

Figure A15: *Peripheral Pattern Streamlines after Production*

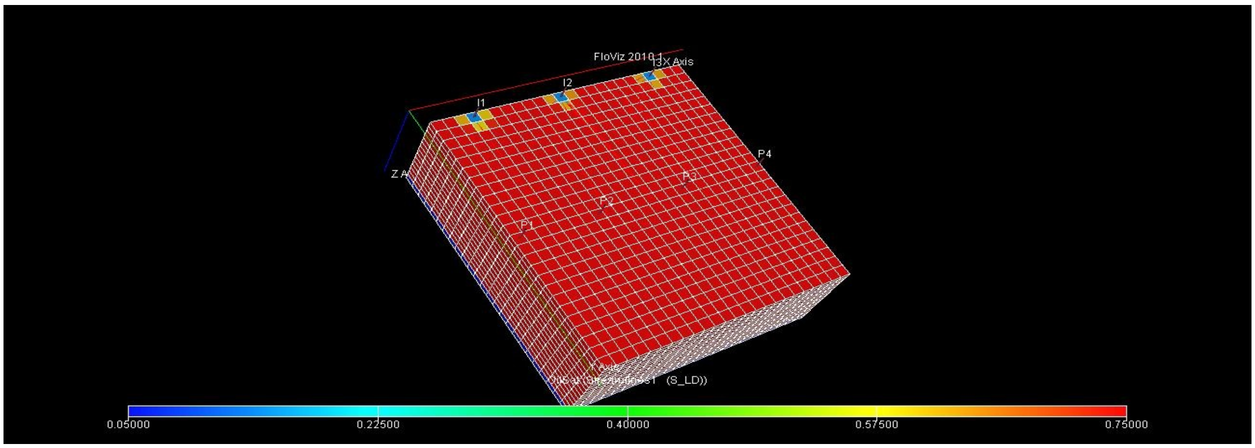

Figure A16: *Reservoir with Staggered Line Drive Pattern at Initial Condition*

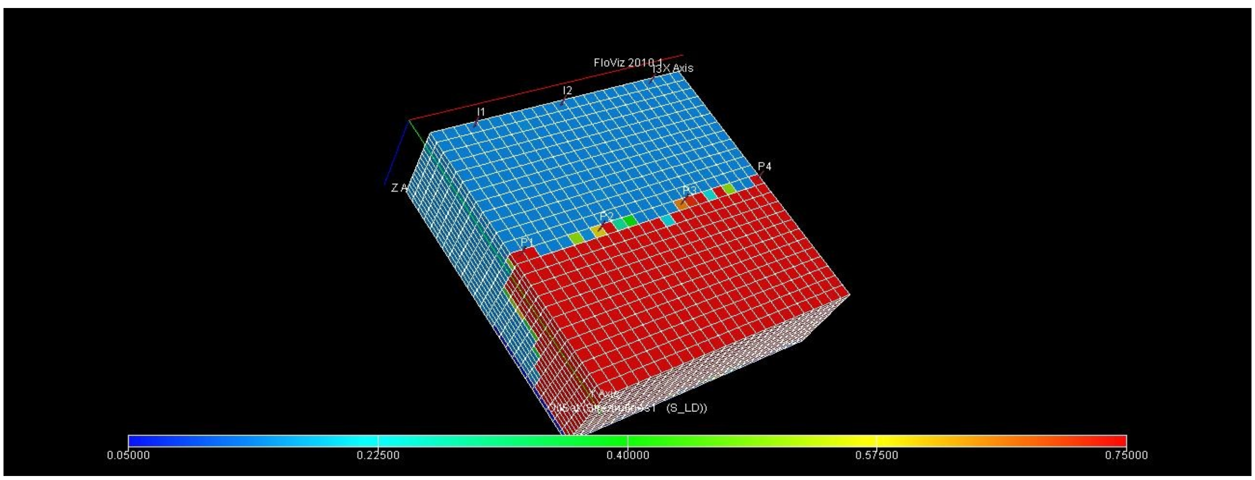

Figure A17: *Reservoir with Staggered Line Drive Pattern after Production*

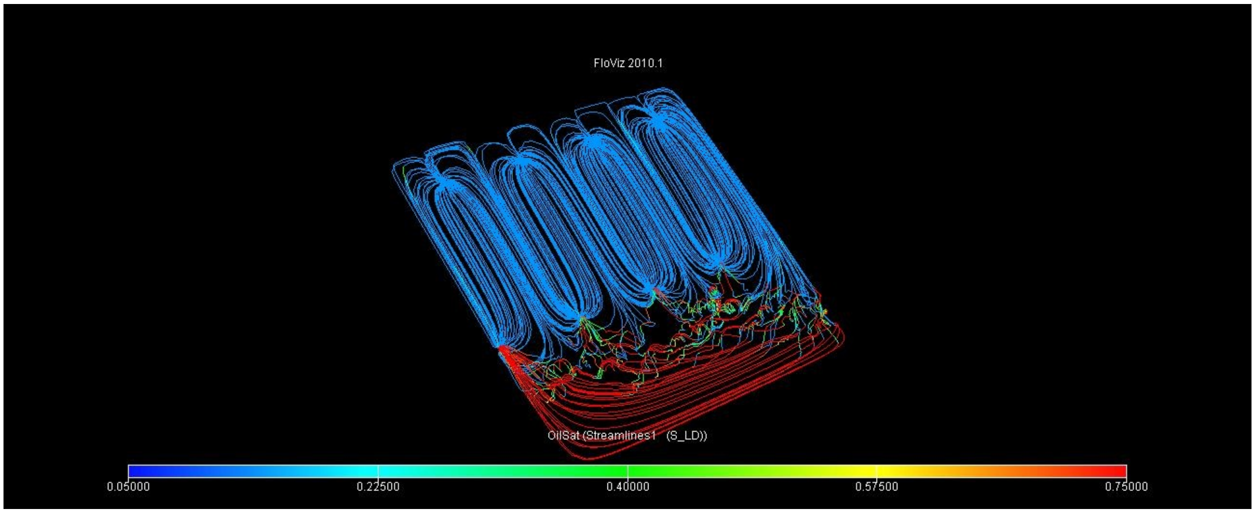

Figure A18: *Staggered Line Drive Pattern Streamlines after Production*

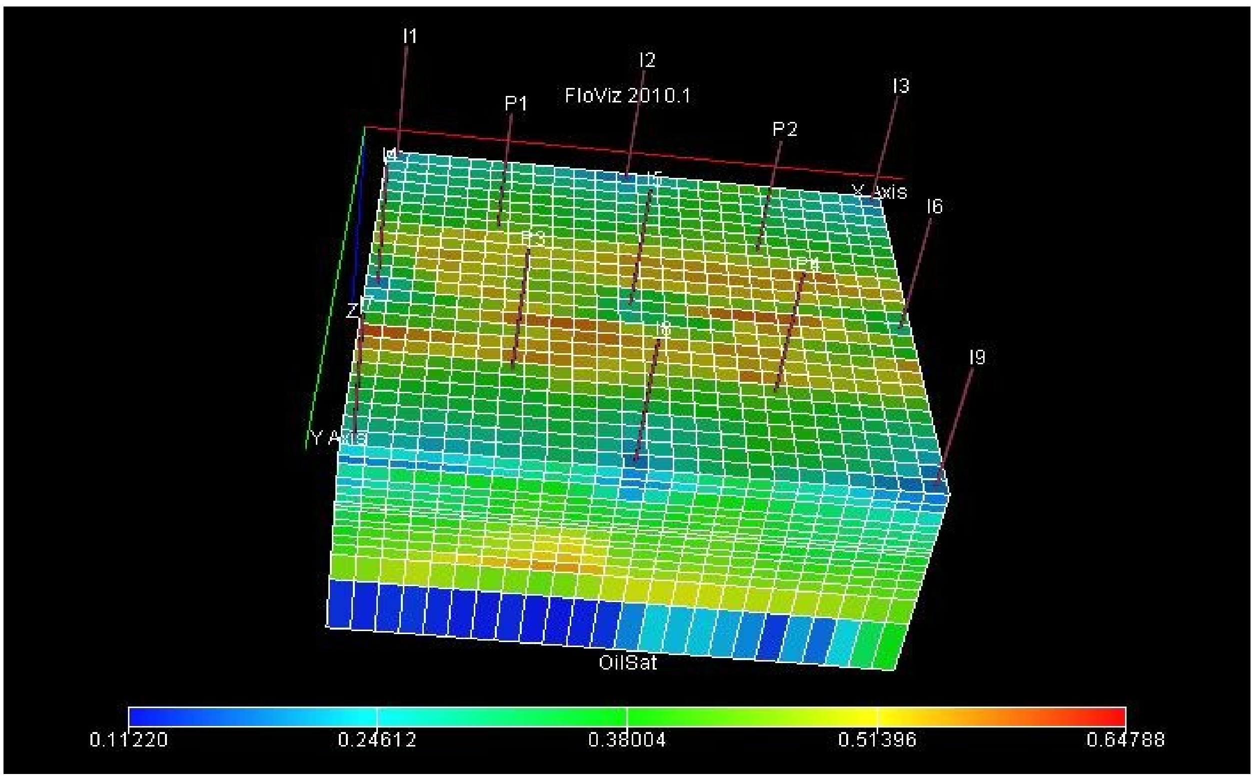

Figure A19: *5-Spot Pattern Streamlines after Production for Heterogeneous Reservoir Model*

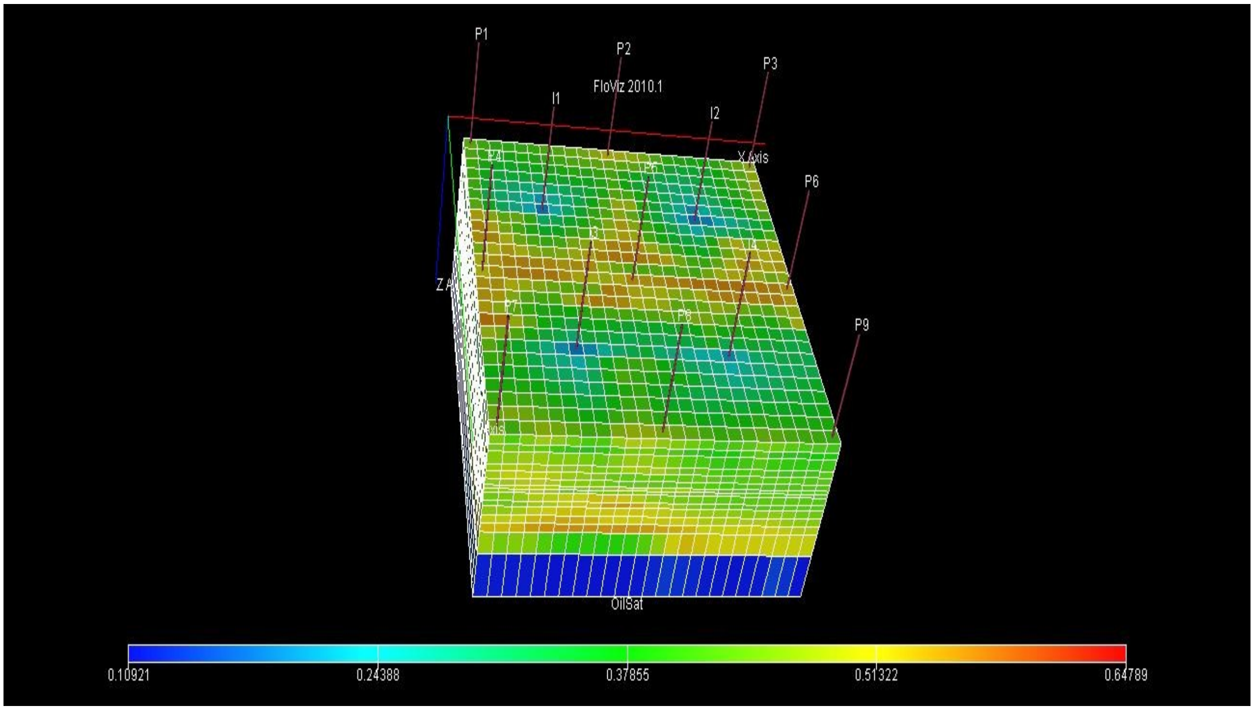

Figure A20: *Inverted 5-Spot Pattern Streamlines after Production for Heterogeneous Reservoir Model*

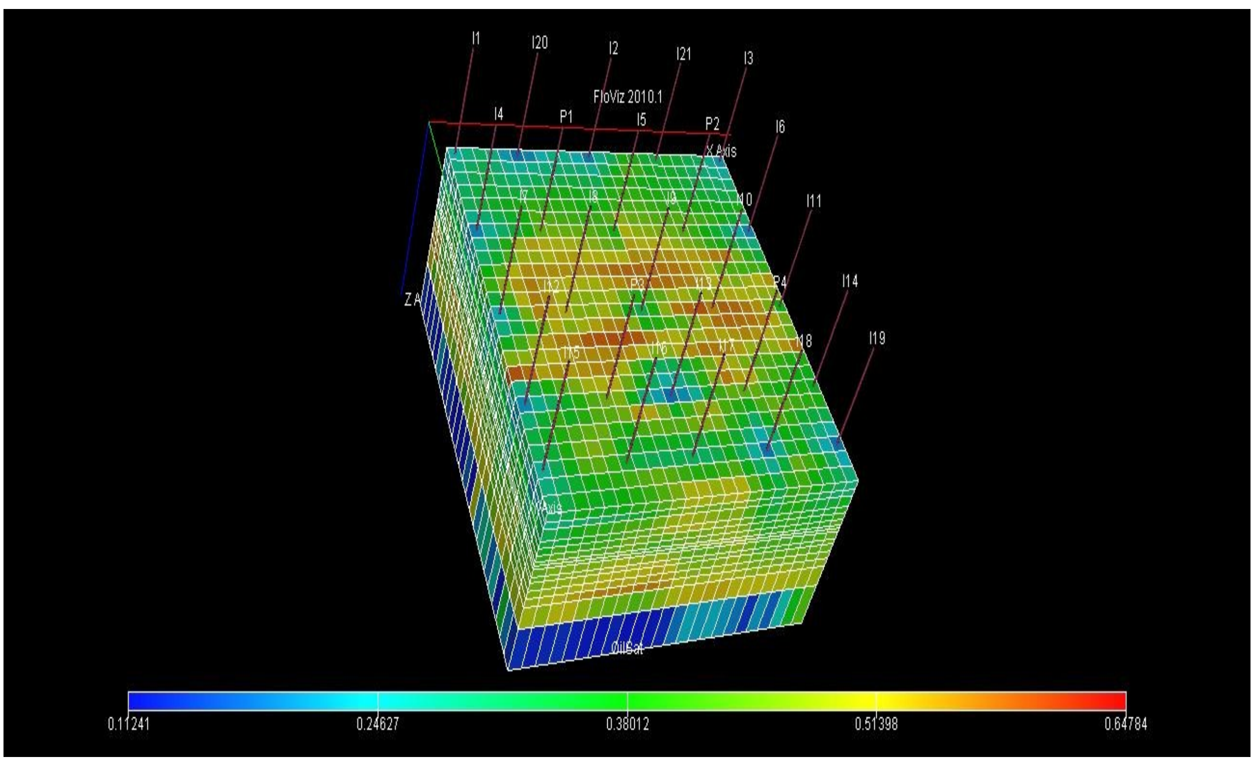

Figure A21: *9-Spot Pattern Streamlines after Production for Heterogeneous Reservoir Model*

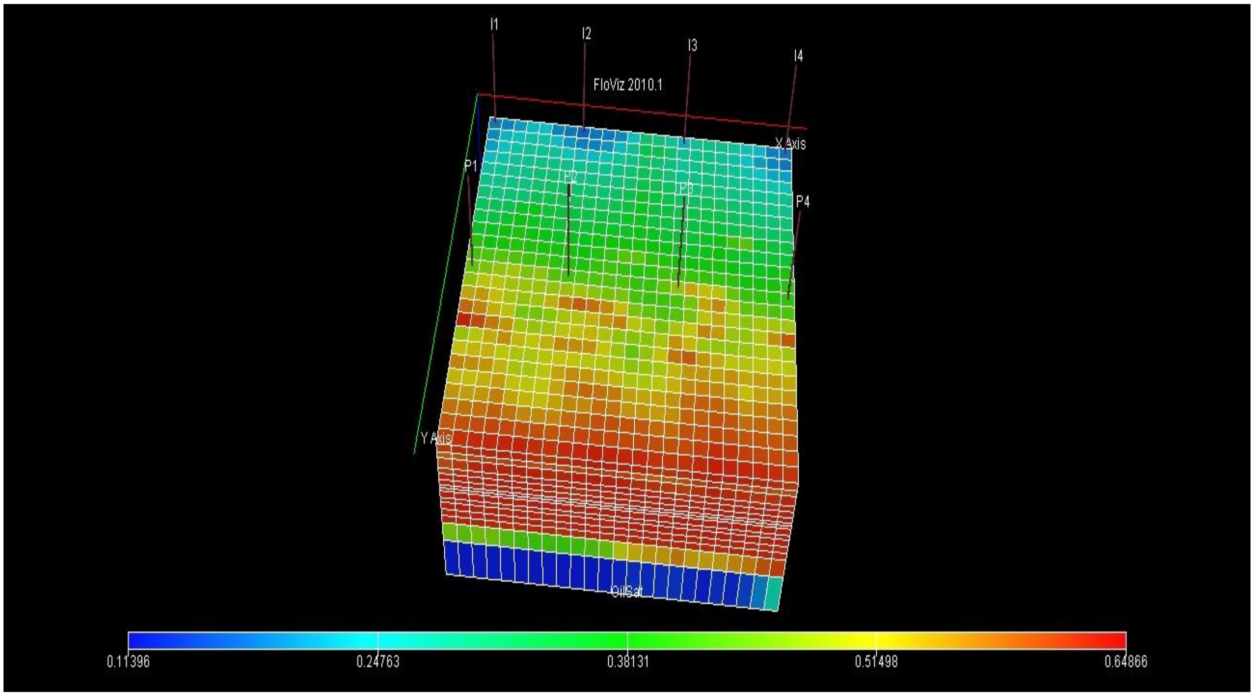

Figure A22*: Line Drive Pattern Streamlines after Production for Heterogeneous Reservoir Model*

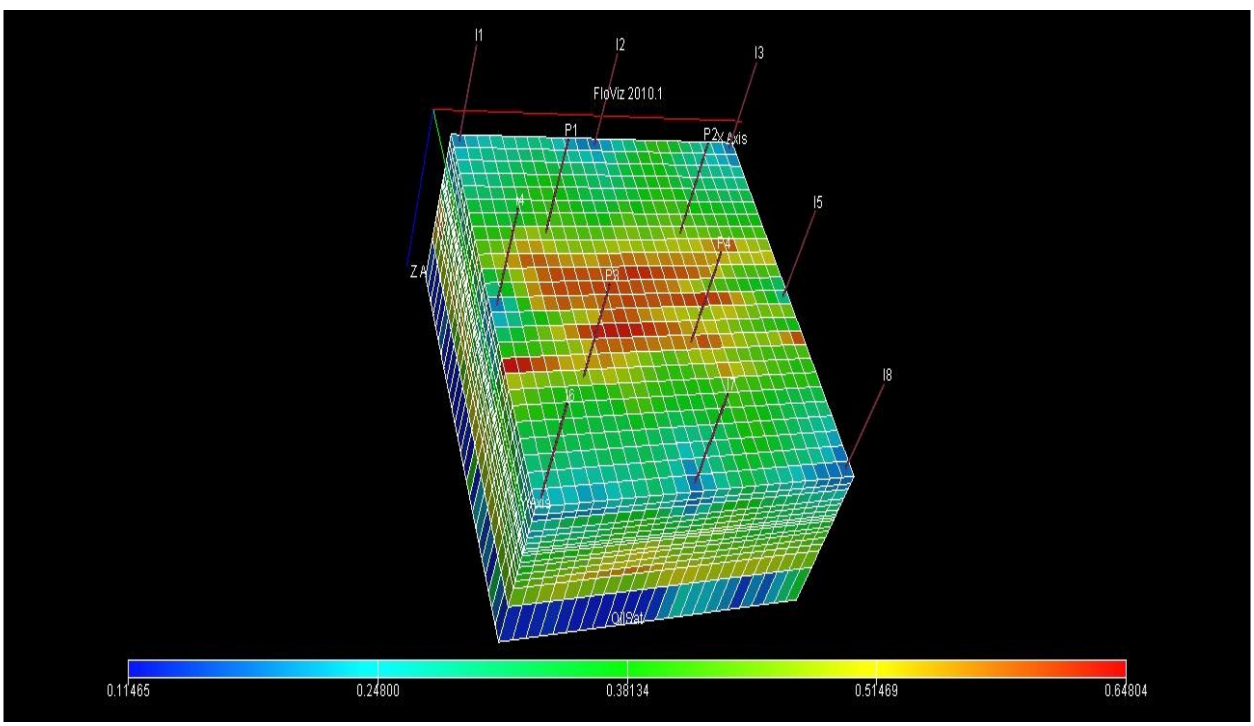

Figure A23*: 5Peripheral Pattern Streamlines after Production for Heterogeneous Reservoir Model*

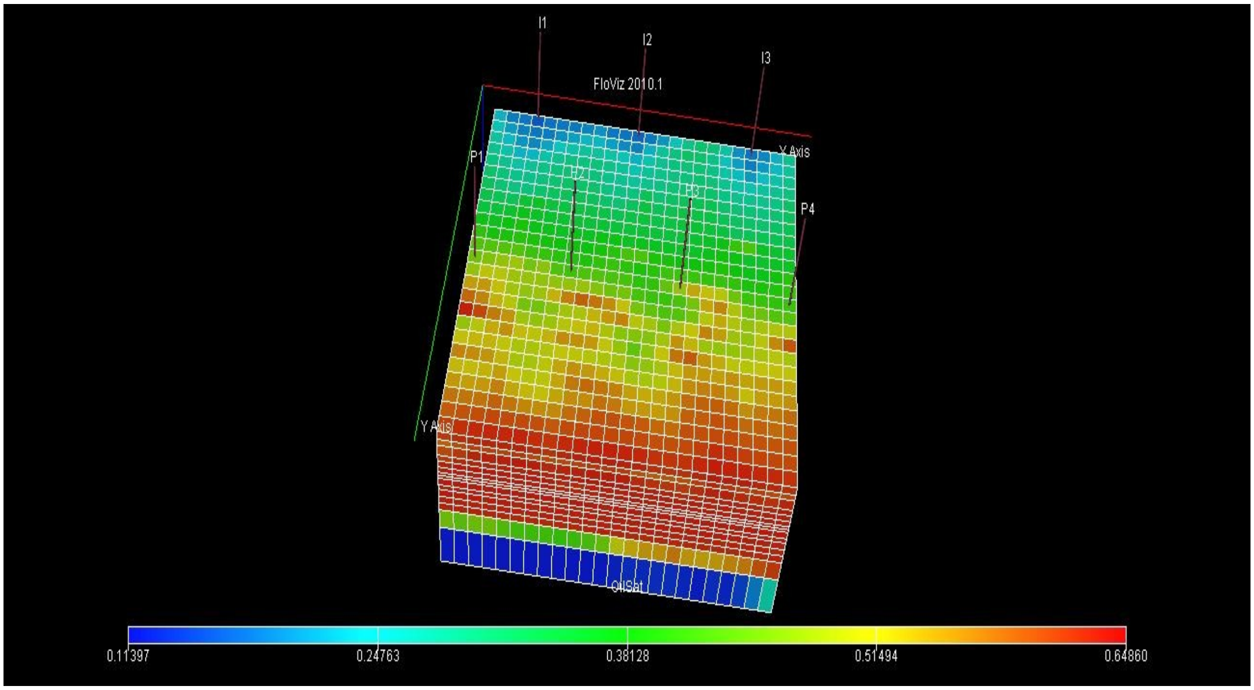

Figure A24*: Staggered Line Drive Pattern Streamlines after Production for Heterogeneous Reservoir Model*