Sudan University of Science and Technology
College of Petroleum and Mining Engineering
Department of Petroleum Engineering

Evaluation of recovery efficiency and injection rate of waterflooding 'five-spot' pattern for a sudanese oil field.

تقييم كفاءة الاستخلاص و معدل الحقن للغمر المائي لشبكة خماسية لحقل نفط سوداني

Submitted to Collage of Petroleum Englineering & Technology for a partial fulfilment of the requirement for B.Tech Degree

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الاستهلال

قال تعالى:

[أَنْزَلَ مِنَ السَّمَاءِ مَاءً فَسَالَتْ أَوْدِيَةٌ بِقَدَرِهَا فَاحْتَمَلَ السَّيْلُ زَبَدًا رَابِيًا وَمِمَّا يُوقِدُونَ عَلَيْهِ فِي النَّارِ ابْتِغَاءَ حِلْيَةٍ أَوْ مَتَاعٍ زَبَدٌ مِثْلُهُ كَذَلِكَ يَضْرِبُ اللَّهُ الْحَقَّ وَالْبَاطِلَ فَأَمَّا الزَّبَدُ فَيَذْهَبُ جُفَاءً وَأَمَّا مَا يَنْفَعُ النَّاسَ فَيَمْكُثُ فِي الْأَرْضِ كَذَلِكَ يَضْرِبُ اللَّهُ الْأَمْثَالَ] [الرعد :17]

{صدق الله العظيم}

Dedication

To our Parents fathers and mothers who lighting the Path for us to move forward, advising, and motivating us by their wide wisdom to reach this level of life without them we would not become the person who we are today.

For Petroleum Student who will share and upgrade the oil industry Revolution in our great country Sudan. We are humble to offer this modest work and we hope that assisting to guide and understand some principle of an oil industry process. Thanks all for supporting and encouraging.

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His dynamism,vision,sincerty and motivation have deeply inspired us.He has taught us the methodology to carry out the research and to present the research works as clearly as possible.It was a great privilege and honor to work and study under his guidance.

Abstract

Water Flood Is A Mean Of Maintaining The Reservoir Pressure. It Improves The Sweep Efficiency For Oil And Accordingly Increases The Recovery Factor.

Water flooding is very important in the oil field, therefore this research is designed to evaluate the water flooding for Heglig field in order to monitor the impact of water flooding on reservoir performance.

In this research selction of suitable pilot area and designing for water flooding using the CMG.Therefore, several scenarios has been done to select the optimum method to increas the oil recovery of Heglig field.

The results shows that water injection as inverted 5-spot (4 producer , 1 injector) with injection rate of 1200 bbl in Heglig field sector model can increase the cumulative oil production from this area up to 1.5 million barrels.

المستخلص

تعتبر عملية الغمر المائي وسيلة للحفاظ علي ضغط المكمن حيث تعمل علي تحسين كفاءة الاكتساح للنفط وبالتالي زيادة معامل الاستخلاص.

يعتبر الغمر المائي مهما جدا في مجال النفط ، لذلك تم تصميم هذا البحث لتقييم الغمر المائي لمكمن نفط بحقل هجليج من اجل مراقبة تأثير الغمر المائي على اداء المكمن.

في هذا البحث تم اختيار منطقة مناسبة و تصميم للغمر المائي باستخدام برنامج CMG و ذلك بعدة محاولات(scenarios) من أجل اختيار أمثل طريقة لزيادة انتاجية النفط في حقل هجليج.

و تظهر النتائج أن حقن الماء بشبكة خماسية (عكسية) inverted 5 spot pattern بمعدل حقن 1200 bbl يمكن أن يزيد من انتاج النفط التراكمي (cumulative production) لهذه المنطقة الى 1.5 مليون برميل.

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Nomenclature

A	Cross-sectional area available for flow, ft^2
Φ	Porosity, fraction
ρ_o	Oil density, lbm/ft^3 or g/cm^3
ρ_w	Water density, lbm/ft^3 or g/cm^3
μ_w	Water viscosity, cp
μ_o	Oil viscosity, cp
u_{wx}	Water Darcy velocity in the x direction, ft/day
S_w	Water saturation, fraction P.V.
S_{orw}	Residual oil saturation to waterflooding, fraction
S_{oi}	Initial oil saturation or $(1 - S_{wc})$, fraction
S_o	Oil saturation, fraction PV
q_w	Water-production rate, B/D
q_t	Total production rate, B/D
P_c	Capillary pressure, psia
P	The required injection pressure,psia.
k_o	Permeability to oil, darcies
Iw	Desired daily injection rate
f_{wf}	Fractional flow of water at flood frontro
f_w	Fractional flow of water
F_{pvg}	Fraction of displaceable pore volume that is gas saturated
σ_{ws}	The IFT between the water and solid phases
σ_{ow}	The IFT between the oil and water phases
σ_{os}	The IFT between the oil and solid phases
IFT	Interfecial Tension

μ_w	Viscosity of water, cp
μ_o	Viscosity of oil, cp
μ_i	Viscosity of fluid phase *i*
λ_i	Mobility of fluid phase *i*
k_{rwe}	Relative permeability to water at the endpoint
k_{rw}	Relative permeability to water
k_{roe}	Relative permeability to oil at the endpoint
k_{ro}	Relative permeability to oil
k_i	Relative permeability of fluid phase *i*

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Chapter One

Introduction

1.1 Introduction:

The conventional crude oil recovery mechanism globally is divided into primary, secondary and tertiary (Figure 1.1). The primary recovery method start the life of any recovery from a dug oil reservoir in which through the natural energy and high pressure embedded in the ground the oil is pushed to the surface. Continuous process of recovery eventually lead to a depletion in the pressure and energy in the oil bearing formation which make secondary recovery important in recovering more of the Original Oil In Place (OOIP) of a given reservoir. Tertiary oil recovery reduces the oil's viscosity to increase oil production. Tertiary recovery is started when secondary oil recovery techniques are no longer enough to sustain production or when there is heavy crude oil component.

The most popular type of secondary recovery is the waterflooding process (Figure 1.2). Waterflooding is dominant among fluid injection methods and is without question responsible for the current high level of production rate and reserves. It popularity is accounted for by:

1. the general availability of water,
2. the relative ease with which water is injected, owing to the hydraulic head it possesses in the injection well,
3. the ability with which water spreads through an oil-bearing formation,
4. and water efficiency in displacing oil.

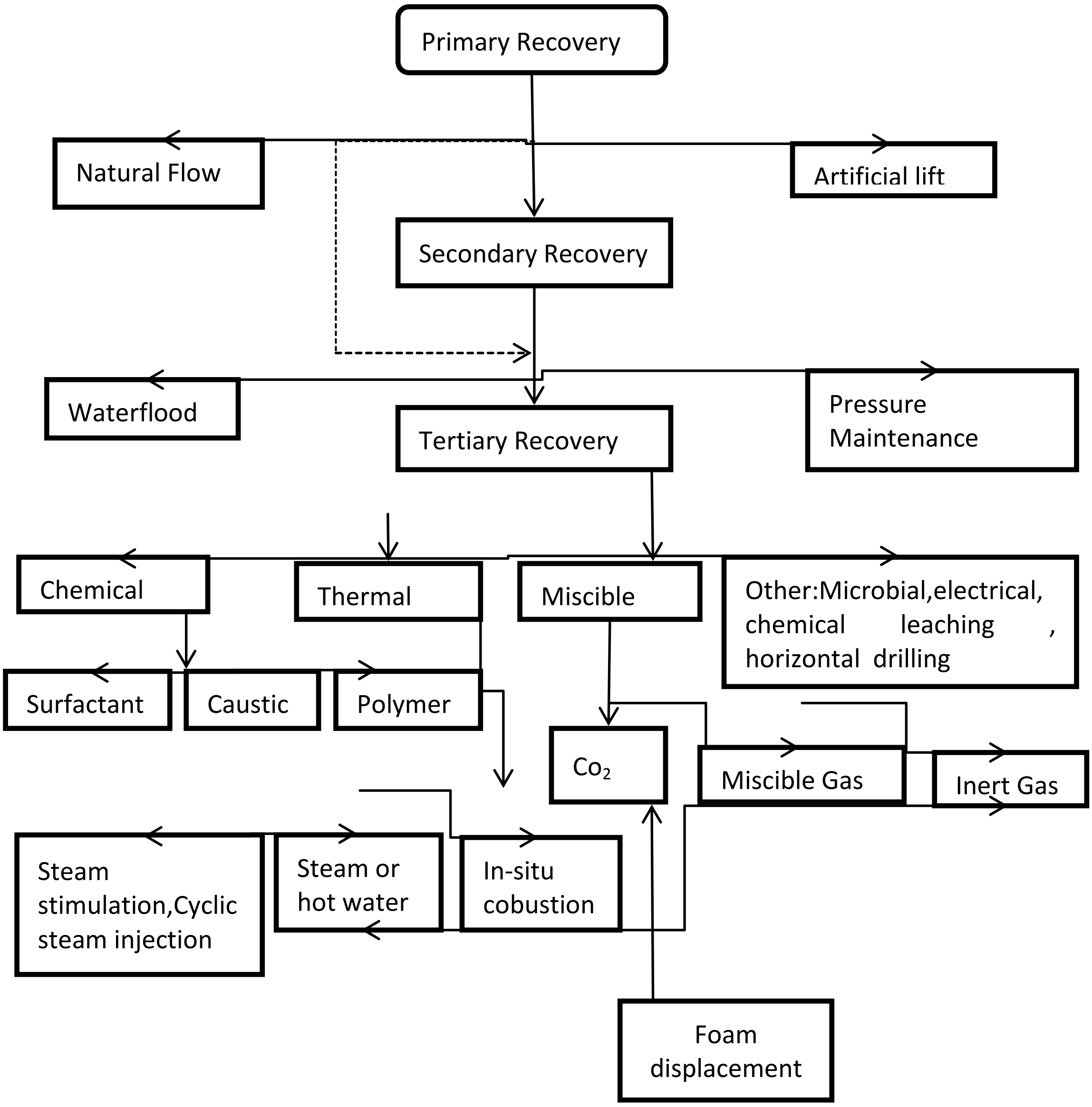


Fig. 1-1. Conventional oil recovery mechanism

.(Willhite, G.P. 1986.)

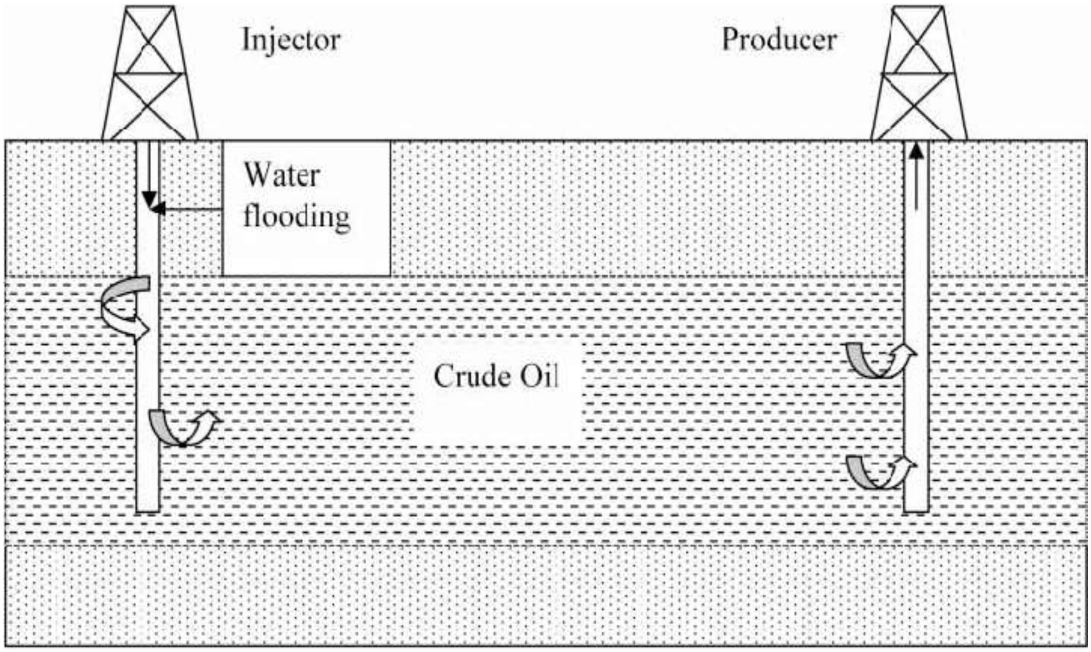


Fig. 1-2. Waterflooding process showing injector and producer wells. .(Willhite, G.P. 1986.)

1.2 Problem statement:

For many reasons, a reservoir may approach the end of its primary life having recovered only a small fraction of the oil in place. Occurrence of this makes secondary recovery operations feasible and economically attractive through waterflooding. Sudan’s current average crude oil production is estimated at 60,000 barrels per day and it’s reserve at 6 billion barrels. Most reservoirs in Sudan have been developed by natural depletion since put into production, and the development is characterized by sparse wells of high production, big pressure differential, delayed infill drilling , and rapid investment recovery. Waterflooding is used to solve these problems. Waterflooding is dominant among fluid injection methods and is responsible for the current high level of production rate of crude oil.

1.3 Research hypothesis:

1. The same rate is given to all injectors. The reason to do so is so that there is no breakthrough from a producer caused by a high injector rate long before the breakthrough occurs from the other injectors. This will reduce excess of water well spacing between input wells and between output and input wells were kept constant (constant well spacing ratio). Well cost is the most expensive in a water flood project, thus an optimal pattern and number of wells is required.
2. Increasing injection rate indefinitely is impossible as pumping facilities are limited in capacity and high injection rate might fracture formation. High injection rate may also induce high water-cut in a short time before the project pay-back time is attained.
3. Decreasing the injection rate is neither preferable as it might slows down the recovery which may be against the project economy.
4. The evaluation for three phase reservoir model
5. The flowing bottom hole pressure for well(s) is 200 psi
6. The injection pressure is constant for all well(s)

1.4 Objectives:

The main goal is to maximize oil recovery and minimize water production with the least amount and number of water flood variable.

The clear-cut objectives:

1. Determine the optimum injection rate.
2. Calculate the cumulative water injection.
3. Evaluate the overall performance.

Chapter Two

Theoretical Background and Literature Review

2.1 Introduction:

It is generally acknowledged that the first waterflood occurred as a result of accidental
water injection in the Pithole City area of Pennsylvania in 1865. In 1880, Carll concluded that water, finding its way into a wellbore from shallow sands, would move through oil sands and be beneficial in increasing oil recovery. Many of the early waterfloods occurred accidentally by leaks from shallow water sands or by surface water accumulations entering drilled holes. At that time it was felt that the main function of water injection was to maintain reservoir pressure, allowing wells to have a longer productive life than pressure depletion.

2.2 Literature Review:

Over the years, waterflooding has been most widely used secondary oil recovery method after the exhaustion of the primary depletion energy of the reservoir (Craft and Hawkins, 1991). Waterflooding basically involves pumping water through an injection well into the reservoir. The water then forces itself through the pore spaces and sweeps the oil toward another set of wells known as producers. As a result, there is an increment in the total oil production from the reservoir. However, the percentage of water in the produced fluids steadily increases. On the average, this process can lead to the recovery of about one-third of the original oil in place (OOIP), leaving behind about twothirds (Meshioye et al., 2010).
According to Craig (1971), the popularity of water injection is mainly due to its availability, mobility, displacement efficiency and ease of injection. At some point during waterflooding operations, it becomes uneconomical to continue these operations because the cost of removing and disposing of water exceeds the net income generated from the oil production (Lake et al., 1992). Due to the ever-increasing necessity of producing oil reservoirs optimally by improving oil recovery,

minimizing water production and better maintenance of reservoir pressure, engineers are plagued with challenges such as optimal completions zones for injectors and producers, optimal flood pattern to adopt and number/type of producers and injectors to use in oil field waterflood development. These problems are commonly encountered in waterflood operations.

Some waterflood optimization problems are undertaken by some researchers. (Meshioye et al., 2010) presented a methodology in which waterflooding is been controlled by smart injector well technology to help optimize or increase the net present value of the field. The optimization procedure was carried out on three different case studies of commingled reservoir having different layer characteristics. A setup optimization procedure was applied, where rate allocation method was used at each zone of the smart injector well. The major drawback of their work was that the layers were not discretized to incorporate the effect of vertical communication and gravity within the layers.

Other researches such as those conducted by (Spath, McCants, 1997), (Alhuthali et al. 2006, Ogali 2011) aimed at predicting and optimization of waterflood performance by employing a combination of geostatistical and dynamic reservoir simulation techniques.

(Spath, McCants, 1997) studied waterflood optimization using a combined geostatistical 3D streamline approach. They used a combination of stochastic reservoir description techniques and streamline simulation to optimize volumetric sweep efficiency in a mature West Texas waterflood and used an IMPES, finite-difference scheme to validate the results obtained.

(Alhuthali et al., 2006) carried out a robust optimization which aimed at maximizing the sweep efficiency of the reservoir using multiple geological scenarios based on equalizing the breakthrough time of the waterfront at all producers. They validated the approach using 2D synthetic and 3D field models. Their results showed that the approach was computationally and practically efficient in optimizing the injection/production rates in a waterflooding project. However, their approach did not consider a stochastic approach to waterflood optimization on multiple realizations and quantification of uncertainty associated with the optimization results.

(Ogali, 2011) conducted a research which focused on the optimization of waterflood using streamline simulation.

The streamline-based simulation workflow used for computing well allocation factors (WAFs) and injection efficiencies was proposed by Thiele and Batycky (2006). These efficiencies were used to optimize oil recovery by effectively reallocating water available for injection. The proposed methodology was validated with a case study which showed that reallocating available injection water to more efficient injection wells in a five-spot pattern waterflood leads to optimization of oil production. The results showed that kV/kH ratio, heterogeneity and zones of injection all play a significant role in the performance of waterflooding. However, his study involved analysis of the impact of several factors on waterflooding and waterflood optimization in the five-spot pattern only and other waterflood patterns were not considered. Optimization analysis would be more appropriate if the results from the five-spot pattern were compared with other waterflood patterns.

(Denis, 2012), a very successful, well documented and characterized field trial was conducted since 1960. The Bartlesville reservoir in northeastern Oklahoma has been one of the most prolific oil producing formations in the United states.

Vittoratos, Boccardo and Clifford (2015). Increasingly the remaining conventional oil resources to be developed are offshore and heavy. The North Sea leads this transition, with several projects planned for development with an API of less than 15. Implicitly the industry assumes that waterflood practices & paradigms developed for onshore light oils can be applied largely unmodified for offshore heavy oils. This paper presents experimental data that question one of the key assumptions: the optimal voidage replacement ratio (VRR) equals one. The experiments were motivated by the accumulation of field empirical observations suggesting that water injected to displace heavy oils forms in the reservoir channel-like communication paths from the injectors to the producers. Once formed – typically early in the waterflood - the channels can degrade further economic recovery of the heavy oil as the water to oil ratio increases significantly. The large offshore spacings will likely exacerbate this effect for most depositional environments.

Ogbeiwi, Yetunde Aladeitan and Dickson Udebhulu (2018). The aim of this study was to optimize waterflooding from a case study model using reservoir simulation techniques. A simple optimization methodology involving the analysis of the effects of zones of production and injection, pattern of waterflood selected and number/type of producers and injectors on cumulative recovery from a waterflooded reservoir was used.Results revealed that (1) pressure maintenance/increment is more effective when there is water injection into more zones of the reservoir, (2) for waterflood operations involving the use of vertical injectors, higher water production was observed because water is expected to flow more conveniently in the upward direction due to gravity rather than laterally and (3) with horizontal injectors, higher cumulative production was achieved especially for cases where water is injected into the same zones from which oil is produced.

At this research we will study the effect of two scenarios of five-spot pattern and the injection rate on the production of oil in the Sudan oil field and evaluate the overall performance.

2.3 Theoretical Background:

2.3.1 Factors to Consider in waterflooding:

Thomas, Mahoney, and winter (1989) pointed out that in determining the suitability of a candidate reservoir for waterflooding, the following reservoir characteristics must be considered:

- Reservoir geometry
- Fluid properties
- Reservoir depth
- Lithology and rock properties
- Fluid saturations
- Reservoir uniformity and pay continuity
- Primary reservoir driving mechanisms

2.3.2 Factors Controlling Waterflood Recovery:

Oil recovery due to waterflooding can be determined at any time in the life of a waterflood project if the following four factors are known:

- Oil-in-Place at the Start of Waterflooding: The oil-in-place at the time of initial water injection is a function of the floodable pore volume and the oil saturation. Floodable pore volume is highly dependent on the selection and application of net pay discriminators such as permeability (and porosity) cutoffs. A successful flood requires that sufficient oil be present to form an oil bank as water moves through the formation. An accurate prediction of waterflood performance or the interpretation of historical waterflood behavior can only be made if a reliable estimate of oil-in-place at the start of waterflooding is available.
- Areal Sweep Efficiency: This is the fraction of reservoir area that the water will contact. It depends primarily upon the relative flow properties of oil and water, the injection- production well pattern used to flood the reservoir, pressure distribution between the injection and production wells and directional permeability.
- Vertical Sweep Efficiency: Vertical sweep refers to the fraction of a formation in the vertical plane which water will contact. This will depend primarily upon the degree of vertical stratification existing in the reservoir.
- Displacement Sweep Efficiency: This represents the fraction of oil which water will displace in that portion of the reservoir invaded by water.

Waterflood recovery is dependent on a number of variables. The variables which usually have the greatest impact on waterflood behavior are listed below:

- Oil saturation at the start of waterflooding. So
- Residual oil saturation to waterflooding, Sor (Sorw)

- Connate water saturation, Swc
- Free gas saturation at the start of water injection, Sg
- Water floodable pore volume, Vp, bbls (This takes into account the permeability orporosity net pay discriminator)
- Oil and water viscosity, µo and µw
- Effective permeability to oil measured at the immobile connate water saturation, (ko) swir
- Relative permeability to water and oil, krw and kro
- Reservoir stratification, (Dykstra-Parsons coefficient, V)
- Waterflood pattern (symmetrical or irregular)
- Pressure distribution between injector and producer
- Injection rate, BWPD
- Oil formation volume factor, Bo

2.3.3 Waterflooding versus Pressure Maintenance:

Maximum combined primary and secondary oil recovery occurs when water flooding is initiated at or near the initial bubble point pressure. When water injection commences at a time in the life of a reservoir when the reservoir pressure is at a high level, the injection is frequently referred to as a pressure maintenance project. On the other hand, if water injection commences ata time when reservoir pressure has declined to a low level due to primary depletion, the injection process is usually referred to as a waterflood. In both instances, the injected water displaces oil and is a dynamic displacement process. Nevertheless, there are important differences in the displacement process when water displaces oil at high reservoir pressures compared to the displacement process which occurs in depleted low pressure reservoirs. (James 1990).

2.3.4 Optimum Time To Start Waterflood:

The most common procedure for determining the optimum time to start waterflooding is to calculate:

- Anticipated oil recovery.

- Fluid production rates.
- Monetary investment.
- Availability and quality of the water supply.
- Costs of water treatment and pumping equipment.
- Costs of maintenance and operation of the water installation facilities.
- Costs of drilling new injection wells or converting existing production wells into injectorsThese calculations should be performed for several assumed times and the net income for each case determined. The scenario that maximizes the profit and perhaps meets the operator's desirable goal is selected.

Cole (1969) lists the following factors as being important when determining the reservoir pressure (or time) to initiate a secondary recovery project:

- Reservoir oil viscosity. Water injection should be initiated when the reservoir pressure reaches its bubble-point pressure since the oil viscosity reaches its minimum value at this pressure. The mobility of the oil will increase with decreasing oil viscosity, which in turns improves the sweeping efficiency.
- Free gas saturation. (1) In water injection projects. It is desirable to have initial gassaturation, possibly as much as 10%. This will occur at a pressure that is below the bubble point pressure. (2) In gas injection projects. Zero gas saturation in the oil zone is desired. This occurs while reservoir pressure is at or above bubble-point pressure.
- Cost of injection equipment. This is related to reservoir pressure, and at higher pressures, the cost of injection equipment increases. Therefore, a low reservoir pressure at initiation of injection is desirable.
- Productivity of producing wells. A high reservoir pressure is desirable to increase the productivity of producing wells, which prolongs the flowing period of the wells, decreases lifting costs, and may shorten the overall life of the project. Effect of delaying investment on the time value of money. A delayed investment in injection facilities

is desirable from this standpoint.

- Overall life of the reservoir. Because operating expenses are an important part of total costs, the fluid injection process should be started as early as possible.

Some of these six factors act in opposition to others. Thus the actual pressure at which a fluid injection project should be initiated will require optimization of the various factors in order to develop the most favorable overall economics.

The principal requirement for a successful fluid injection project is that sufficient oil must remain in the reservoir after primary operations have ceased to render economic the secondary recovery operations. This high residual oil saturation after primary recovery is essential not only because there must be a sufficient volume of oil left in the reservoir, but also because of relative permeability considerations. A high oil relative permeability, i.e., high oil saturation, means more oil recovery with less production of the displacing fluid. On the other hand, low oil saturation means a low oil relative permeability with more production of the displacing fluid at a given time.

2.3.5 Selection of Flooding Patterns:

One of the first steps in designing a waterflooding project is flood pattern selection. The objective is to select the proper pattern that will provide the injection fluid with the maximum possible contact with the crude oil system. This selection can be achieved by (1) converting existing production wells into injectors or (2) drilling infill injection wells. When making the selection, the following factors must be considered:

- Reservoir heterogeneity and directional permeability.
- Direction of formation fractures.
- Availability of the injection fluid (gas or water).
- Desired and anticipated flood life.
- Maximum oil recovery.
- Well spacing, productivity and injectivity

In general, the selection of a suitable flooding pattern for the reservoir depends on the number and location of existing wells. In some cases, producing wells can be converted to injection wellswhile in other cases it may be necessary or desirable to drill new injection wells. Essentially four types of well arrangements are used in fluid injection projects:

- ✓ Irregular injection patterns.
- ✓ Peripheral injection patterns.
- ✓ Regular injection patterns.

Injection / producer pattern layouts

Fig. 2.1 shows a variety of injector/producer pattern layouts that can be considered. In reality, the existing wellbore locations might limit the pattern layout to a nonsymmetrical arrangement like that shown in **Fig. 2.2**. Also, as shown in **Fig. 2.3**, the orientation of the rows of producers and injectors must take into account any permeability anisotropy and natural-fracture orientation. At offshore locations, the number of well slots on the drilling platforms limits the number of producers and injectors and their layout.

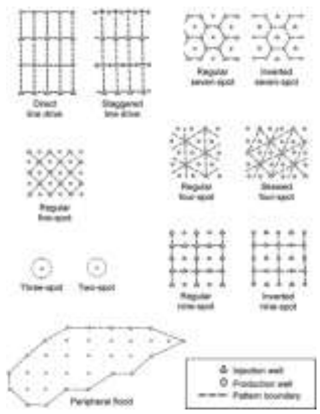


Fig.2.1 – Common waterflood-pattern configurations. (Petroleum engineering Handbook , Larry W. Lake)

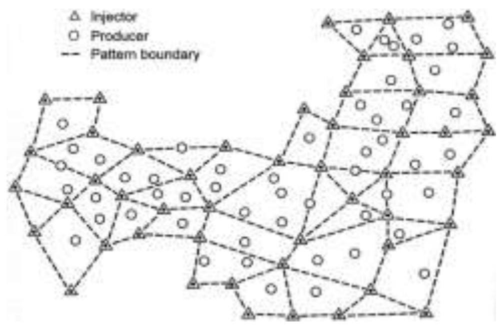


Fig.2.2 – Irregular five-spot pattern layout (Petroleum engineering Handbook , Larry W. Lake)

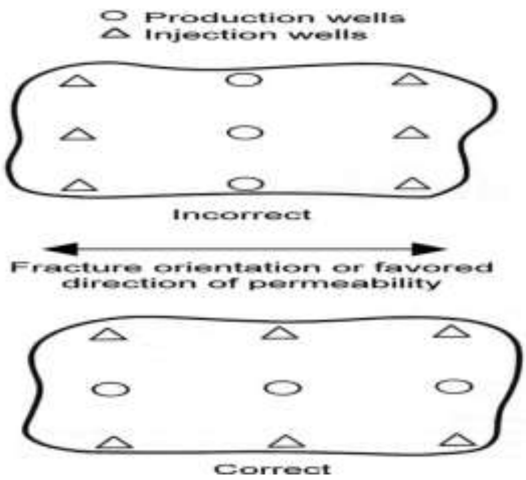


Fig. 2.3 – Correct and incorrect pattern alignment with antisotropic permeability, or an oriented fracture system. (Petroleum engineering Handbook , Larry W. Lake)

2.4 Microscopic efficiency of immiscible displacement:

At the pore level (i.e., where the water and oil phases interact immiscibly when moving from one set of pores to the next), wettability and pore geometry are the two key considerations. The interplay between wettability and pore geometry in a reservoir rock is what is represented by the laboratory-determined capillary pressure curves and water/oil relative permeability curves that engineers use when making original oil in place (OOIP) and fluid-flow calculations. This article discusses these basic concepts and their implications for initial water- and oil-saturation distribution, relative permeability, and how initial gas saturation will affect water/oil flow behavior.**Fig (2-4)** (Craig Jr., F.F. 1971.) is a schematic diagram of the water/oil displacement process.

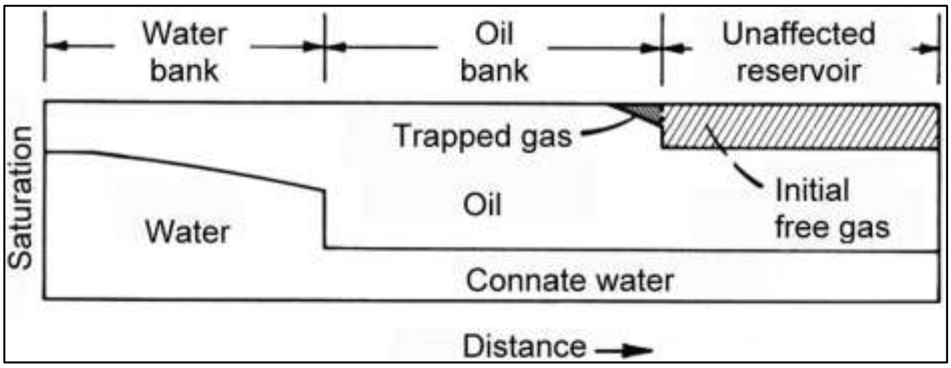


Fig.(2-4) Saturation profile during a waterflood. **.(Willhite, G.P. 1986.)**

2.5 Fundamental principles governing fluid and rock interactions:

2.5.1 interfacial tension(IFT)

The interfacial tension between two fluids represents the amount of work required to create a new unit of surface area at the interface. The IFT is a fundamental thermodynamic property of an interface.It is defined as the energy required to increase the area of the interface by one unit. (willihite paul).

The interfacial tension can also be thought of a measure of the immiscibility of two fluids. Typical values of oil-brine interfacial tensions are on the order of 20 to 30 dynes/cm.

2.5.2 Wettability

Wettability is defined in terms of the interaction of two immiscible phases, such as oil and water, and a solid surface, such as that of the pores of a reservoir rock. For understanding wettability concepts and for simple laboratory determinations, the solid surface is taken as a smooth flat surface. Fig.(2-5) illustrates two styles of wettability: water-wet and oil-wet.(Willhite, G.P. 1986.). Eq. 2.2 describes the force relationship that is in balance for the drop of water that is on the solid surface and is surrounded by oil. The interfacial tension (IFT) between the oil and water phases varies depending on the compositions of the phases but generally is relatively high, in the 10 to 30 dyne/cm range. The contact angle θ is used to define which fluid phase is more wetting—for low contact angles, the water phase is more wetting, whereas for high contact angles, the oil phase is more wetting.

$$\boldsymbol{\sigma_{os} - \sigma_{ws} = \sigma_{ow} \cos\theta} \text{............Eq.2.2}$$

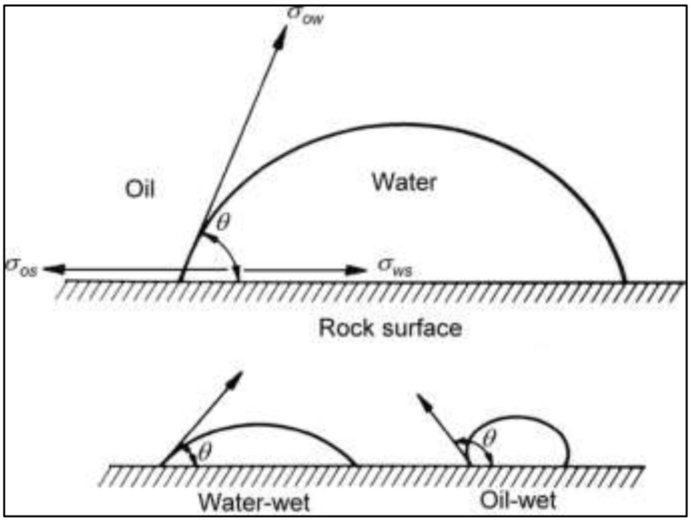


Fig. (2-5) .Wettability of oil/water/solid system.(Willhite, G.P. 1986.)

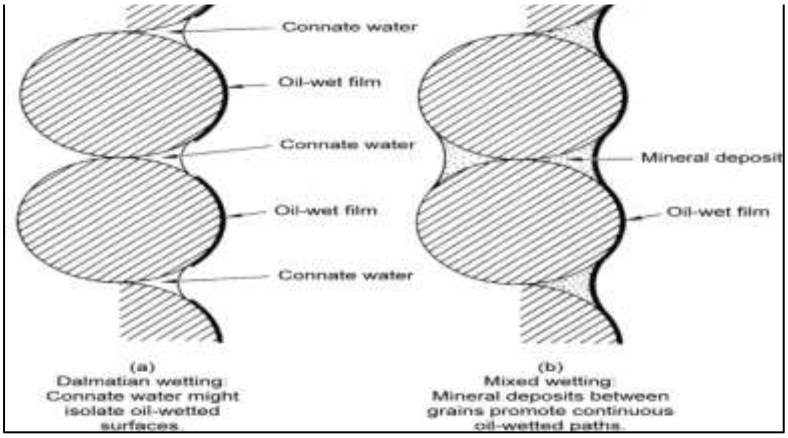
The particular contact angle depends on many variables, including the composition of the crude oil and the amount of gas in solution; the salinity and pH of the connate brine; the mineralogy of the rock surfaces; and the salinity and pH of the injected water that is used for waterflooding. The concentration of surface-active components (e.g., asphaltenes) that are in the crude oil and that can adsorb on the rock surfaces affects wettability.

Reservoir rocks typically are described as being water-wet, oil-wet, or intermediate-wet. A water-wet rock surface is one that has a strong preference to be coated, or "wetted," by the water phase, so that there will be a continuous water phase on the rock surfaces. Oil-wet rocks prefer to be coated with oil instead of water. Strongly oil-wet rocks have been created for laboratory studies but, as discussed below, are unlikely to exist in real reservoirs. Intermediate-wet reservoir rocks have been found in several oil reservoirs. The term "dalmatian wetting" describes reservoir rocks that have both oil-wet and water-wet surfaces. Fig. 2-5 illustrates two styles of intermediate-wetting.

Two types of laboratory measurements commonly are used to estimate wettability. First, the crude-oil/brine IFT values can be measured on smooth rock surfaces of various mineralogies. Second, Amott tests can be run on the reservoir rock to determine the extents to which it imbibes oil and brine. When running the Amott tests, it is critical to initialize the core plugs as close to original reservoir conditions as possible either by using well-preserved core samples or by aging the core plugs in the presence of reservoir crude oil. High-quality water/oil capillary-pressure (P_c) and water/oil relative permeability (k_{rwo}) data, both of which are strongly affected by rock wettability, are needed as input to waterflood calculations, whether using simple engineering methods or complex numerical reservoir simulators.

2.5.3 Pore geometry:

The pore geometry for any reservoir rock is the result of its depositional and diagenetic history. The depositional environment determines a rock's grain size and sorting. Post-depositional diagenetic changes caused by various types of cementation, leaching, and clay alteration will impact a rock's pore characteristics whether the rock is primarily silica or carbonate.



Fig(2-6) Relationship of mineralogy to wetting conditions: . (Willhite, G.P. 1986.)
(a) dalmation wetting and (b) mixed wetting. (Willhite, G.P. 1986.)

Fig (2-6)and (2-7). show photomicrographs and k_{rwo} curves for a sandstone with large, well-connected pores and for one with small, well-connected pores, respectively. These illustrate just one of many possible differences in pore geometry. Pore distributions in carbonate rocks often are more complicated because of vug networks and fractures. Also, there are many scales of pore-geometry heterogeneities;

a core plug has one scale of pore-size variation, but other important variations are found at each higher scale.

2.5.4 Capillary Pressure:

The characteristics of and differences between the drainage and imbibition capillary pressure/water-saturation **(P_c/S_w)** curves are considered. Capillary pressure affects waterflood performance and engineering calculations because the extent to which the water/oil flood front is vertically and horizontally "smeared out" during the waterflood is controlled by the P_c/S_w imbibition curve.

Reservoir rocks are considered to be water-wet initially because all reservoir rocks were deposited in water-filled environments or were immersed in water soon after deposition, when their overlying sediments were deposited. The drainage P_c/S_w curve describes the drainage process, or the P_c/S_w relationship while the nonwetting-fluid phase (oil) displaces the wetting-fluid phase (brine) from various parts of the pore system, thus decreasing the wetting-phase saturation. If during the displacement process the process is reversed and the wetting-phase saturation increases, it is known as imbibition (the imbibing of the wetting phase).

Fig (2-8). shows the drainage and imbibition P_c/S_w characteristics of a strongly water-wet rock. The minimum wetting or water saturation from the drainage process is termed the connate (or irreducible) water saturation. The maximum water saturation from the imbibition process defines the minimum nonwetting-phase saturation, or (for waterflooding considerations) the residual oil saturation to waterflooding S_{orw}. Fig (2-9) and (2-10) show the drainage and imbibition P_c/S_w curves from the laboratory tests of an oil-wet rock and a rock with intermediate wettability, respectively. Fig.2-10 includes both the spontaneous (number 2 on curve) and the forced (number 3 on curve) portions of the imbibition curve. Spontaneous imbibition occurs without any pressure being applied to the test apparatus, whereas obtaining the forced imbibition portion of the curve requires an external pressure to be applied. Note that $P_c = 0$ does not define the S_{orw}.

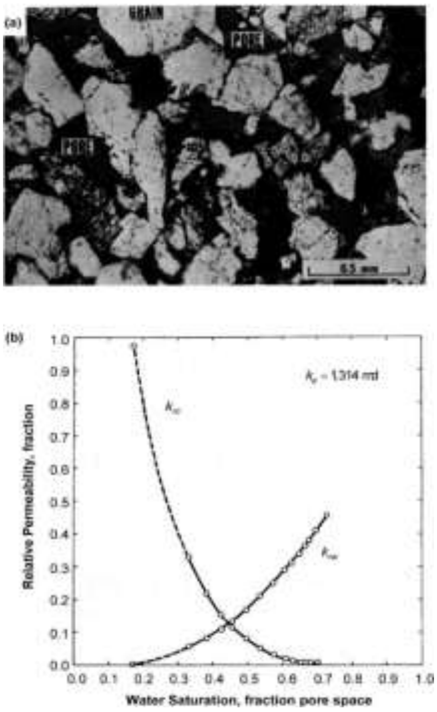


Fig. 2-7

Photomicrograph (a) and water/oil relative permeability curve (b) for a sandstone with large,
well-connected pores. k_a =air permeability.(Willhite, G.P. 1986).

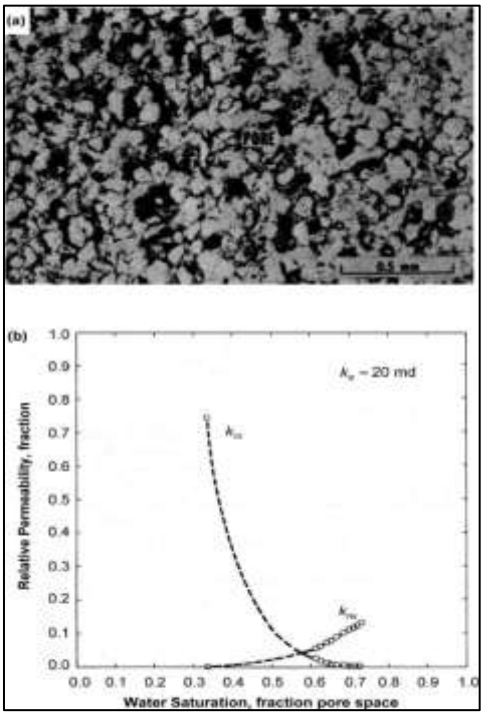


Fig. 2-8

Photomicrograph (a) and water/oil relative permeability curve (b) for a sandstone with small, well-connected pores.(Willhite, G.P. 1986).)

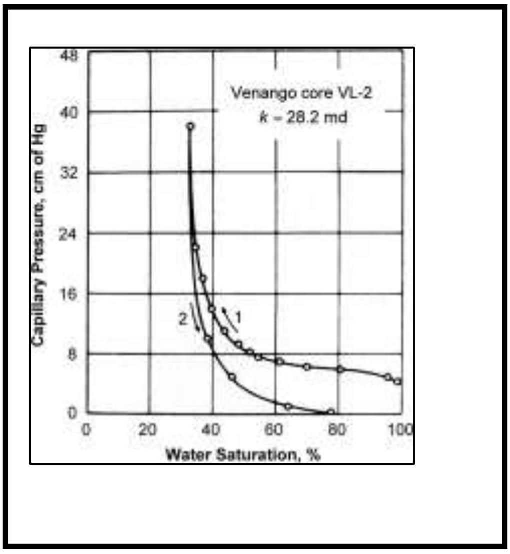


Fig (2-9). Capillary pressure characteristics for a strongly water-wet rock. Curve 1 represents drainage, and Curve 2 represents imbibition. (Willhite, G.P. 1986).

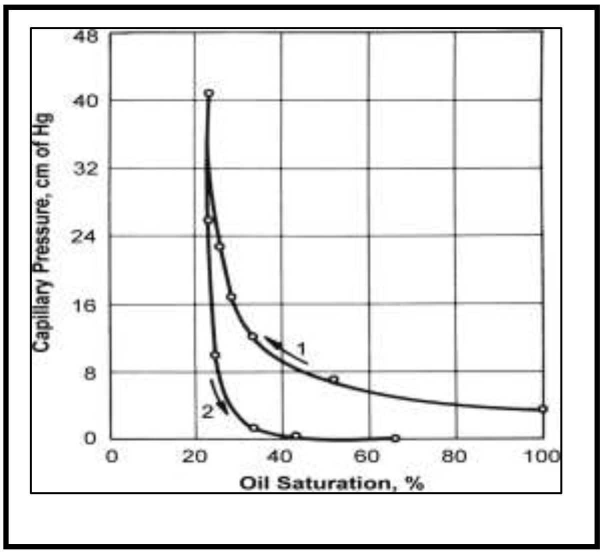


Fig (2-10). Water/oil capillary pressure characteristics for Tensleep Sandstone oil-wet rock. Curve 1 represents drainage, and Curve 2 represents imbibition.(Willhite, G.P. 1986)

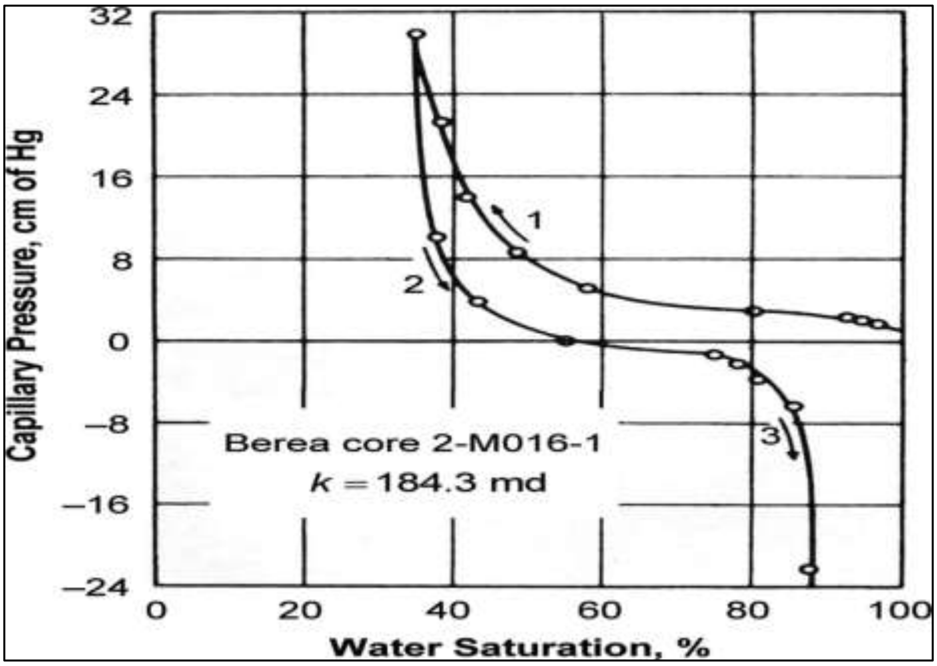


Fig. (2-11). Water/oil capillary-pressure characteristics for intermediate wettability. Curve 1 represents drainage, Curve 2 represents spontaneous imbibition, and Curve 3 represents forced imbibition. (Willhite, G.P. 1986).

2.6 Initial Water-Oil-Saturation Distribution:

An oil field's initial water-/oil-saturation distribution depends on its hydrocarbon history and has a significant effect on its waterflooding potential. The pore system in a reservoir rock contains a very large number of pore bodies whose filling by oil is controlled by the diameters of the pore throats that link them.

During the oil-filling process, the oil first enters through the largest pore_throats, and all other parts of the pore system remain filled with connate brine. As more oil enters the reservoir trap, the oil column lengthens downward. Just above the oil/water contact, only the pores that are accessible from the largest pore throats fill with oil. At the top of the oil column, where the capillary pressure is greatest, not only the largest pores are oil-filled, but also some that have smaller pore throats. The very fine pore spaces remain filled with connate brine.

This process continues until the oil column reaches its maximum length. This whole process is the drainage cycle of the P_c/S_w curves. At this point in the process, oil is filling the largest pores and water is filling the smallest pores; however, the P_c/S_w drainage curve governs the percentage of each. Connate brine will remain as films on the surfaces of the largest pores, but surface-active components of the crude oil might adsorb on some of the pore surfaces, rendering them oil-wet. Hence, the overall system can have mixed-wet characteristics.

There are oil fields that, although initially filled through a drainage process, when discovered were on the imbibition cycle because of a complicated hydrocarbon or structural history. Portions of several west Texas San Andres carbonate reservoirs and the Prudhoe Bay field of Alaska are examples of such oil fields.

This original water-/oil-saturation distribution is important to understand for waterflooding because it controls the efficiency of the waterflood in portions of the reservoir. It also relates directly to the residual oil saturation that can be achieved at the end of a waterflood.

2.7 Relative permeability:

Relative permeability (k_r)is an important aspect due to the characteristics of imbibition oil/water k_r curves. These govern the nature and efficiency of the waterflood displacement and how much of the OOIP will be recovered before the waterflood economic limit is reached.

The shapes of the imbibition water/oil k_r curves depend on pore geometry and wettability. As noted earlier, Figs. 6 and 7 show the differences between these curves for a sandstone with large, well-connected pores and one with small, well-connected pores. The k_{rw} is greatly reduced for the sandstone with small pores at all saturation levels. Fig (2-8). shows the effect of wettability, as measured by the U.S. Bureau of Mines (USBM) Amott wettability index, on the water/oil k_r curves. As is expected for a change from water-wet to oil-wet in such laboratory tests, the water k_r curve rises with increasing oil-wetness and the oil k_r curve decreases.

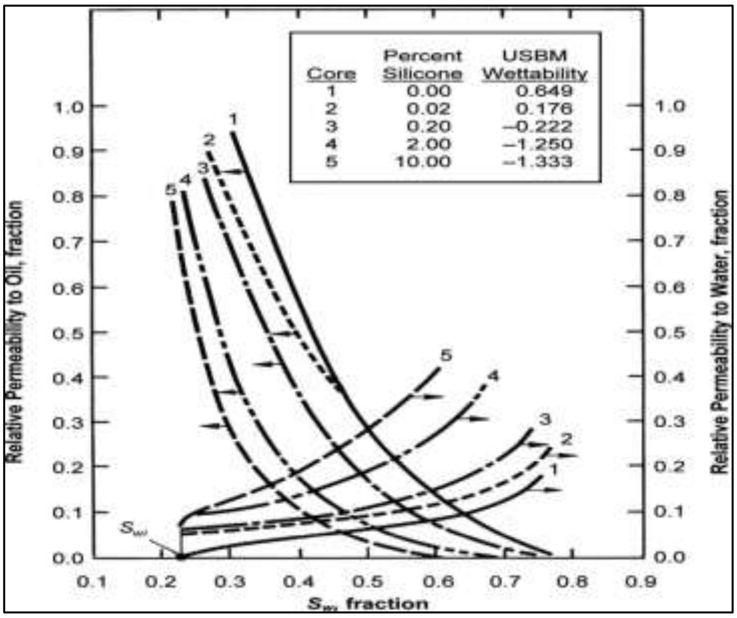


Fig (2-12). Oil and water relative permeability for Squirrel-sandstone cores for water-wet and oil-wet conditions.(Willhite, G.P. 1986).

Most importantly, laboratory-determined water/oil k_r data should be obtained at the best approximation of reservoir conditions. Salathiel describes the importance of this to actual field oil/water displacement.(Salathiel, R.A. 1973). Fig (2-12). shows the results of Salathiel's laboratory experiments that relate to the East Texas oil field. These curves show that the oil relative permeability for water-wet conditions is significantly different than for mixed-wet conditions. In water-wet conditions, the oil phase becomes discontinuous and loses its mobility quickly. In mixed-wet conditions, the oil maintains phase continuity by means of the oil-wetted rock surfaces and slowly drains to significantly lower oil saturations. The comparison of the laboratory results to the actual field production data and the residual-oil-saturation-pressure core data showed that the reservoir had mixed-wettability, yielding S_{orw} values of < 10% PV in many portions of the reservoir.

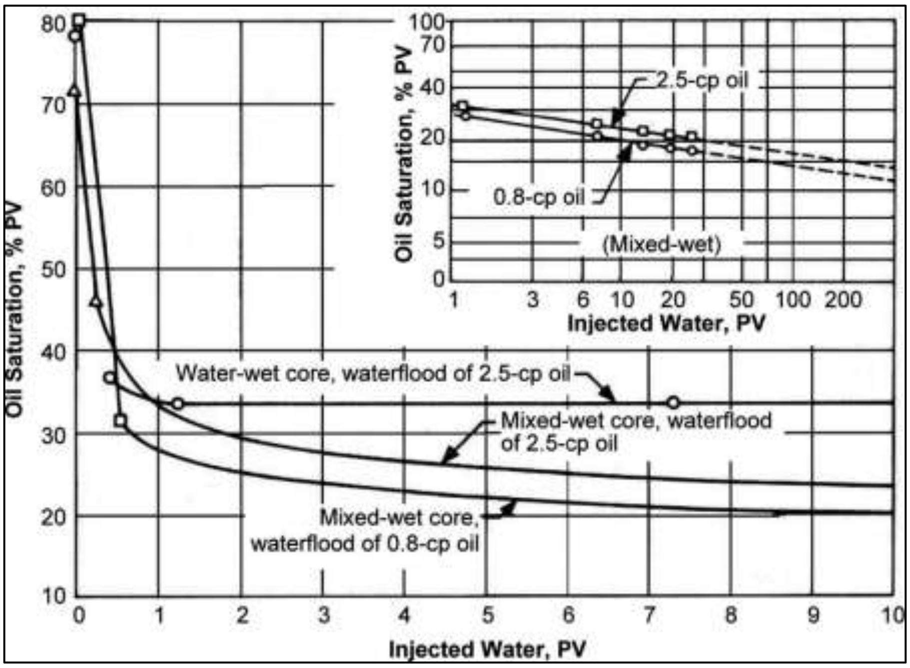


Fig (2-13). Comparison of waterflood behavior for mixed-wet and water-wet cores. Insert shows extension of mixed-wet-core flooding data. .(Willhite, G.P. 1986).

2.8 Residual oil saturation:

For waterflooding, the two most important numbers for a reservoir rock are the connate-water saturation S_{wc} and the S_{orw}. The S wc determines how much oil initially is in each unit volume of rock when the reservoir is discovered. The $\mathbf{S_{orw}}$ is how much of the OOIP will remain in rock that will be well swept by injected-water volumes. Assuming that the oil-formation-volume factor is the same at the beginning and the end of the waterflood, the equation for the unit-displacement efficiency is Eq(2.3):

$$\mathbf{E_D = 1 - \frac{S_{orw}}{S_{oi}}} \text{....................}\mathbf{Eq.(2.3)}$$

The $\mathbf{S_{orw}}$ is the endpoint of the water/oil imbibition k_{ro} curve, which was discussed above; however, for simple waterflood calculations this value is the most critical one. Table 1 compares Salathiel's S_{orw} results for the water-wet conditions to those for the mixed-wet conditions.(Salathiel, R.A. 1973).The $\mathbf{S_{orw}}$ for the mixed-wet samples generally was 10% PV lower than for the water-wet samples. In the water-wet conditions, more of the oil phase gets "snapped off" and therefore trapped and immobilized as isolated oil globules by the increasing water saturation. Jerauld and

Rathmell(Jerauld, G.R. and Rathmell, J.J. 1997.)found similar results for the Prudhoe Bay field.

Rock Sample	Permeability, md	Porosity, % BV	S_w at Time of "Contact," % PV	S_o After 25 PV of Waterflooding	
				Water-Wet	Mixed-Wet
Boise (sandstone)	1,094	29.3	13.5	33.5	20.5
Upper Austin (sandstone)	596	28.0	20.0	30.0	22.9
Woodbine Outcrop (sandstone)	690	33.0	17.0	27.3	30.7
Upper Noodle (limestone)	620	21.2	18.9	40.5	28.1
Lissie (sandstone)	536	21.9	7.2	42.5	29.1

Tabel 2--2 - Residual oil saturation after 25 PV of waterflooding(Salathiel, R.A. 1973.)

S_{orw} can be measured several ways. It can be determined as part of all relative permeability laboratory studies. Historically, short core-plug "floodpot" tests have been run in the laboratory, and only the rock sample's porosity, absolute air permeability, S_{wc}, S_{orw}, and permeability at the two endpoint saturations have been reported. It is important to ensure that these laboratory tests are conducted long enough for the displacement to be taken to its true endpoint. They can be performed either as displacement tests or by using a centrifuge to measure these data. Displacement tests historically have been used, but because of improvements in centrifuge technology, the centrifuge approach is becoming more common. Usually, floodpot-test times are inadequate to reach a true S_{orw}. Imbibition capillary pressure measurements obtain more-reliable values for water-wet porous media.

Generally, $\mathbf{S_{orw}}$ is inversely related to S_{wi}. This can be understood in terms of the pore spaces that become filled with water and oil. While the S_{wi} decreases (or the S_{oi} increases), the oil phase occupies more of the pores and fills more of the smaller pore spaces. When water displaces the oil, the advancing waterfront traps more of the oil, especially if the rock is water-wet.

The performance of a waterflood depends on the impact of viscous and capillary forces on $\boldsymbol{S_{orw}}$ and $\boldsymbol{k_r}$. At reservoir flow rates, the viscous forces do not vary enough to make a significant difference in k_r and S_{orw}; however, under laboratory conditions, viscous and capillary forces are major considerations because short core-plug displacement tests actually measure pressure drops and fluid-production volumes as a function of time that include large capillary end effects. These data must be entered into interpretative calculations to derive the water/oil P_c/S_w and k_r curves that are used later in field waterflood calculations. The laboratory personnel must choose what length of core plugs to test, what flow rates and pressure drops to apply, whether to make the measurements at steady-state or unsteady-state conditions, and how to interpret these data.

2.9 Initial Gas Saturation:

In many oil reservoirs, a free-gas saturation formed during the early production period because the waterflood was not initiated before the reservoir pressure had dropped through the oil bubblepoint pressure. For many years, the effect of this gas saturation on S_{orw} has been a subject of considerable technical interest. Fig (2-13). summarizes the experimental results of several investigators and shows the impact of initial gas saturation (S_{gt}) on S_{orw} for water-wet rocks. The S_{orw} decreased as S_{gt} increased. Because gas is the most nonwetting of the fluid phases, the residual gas phase occupies the center of the pore bodies and hence can reduce the volume of oil that is trapped.

2.10 Other considerations:

Historically, most laboratory tests have been run at surface temperature and pressure conditions using dead crude oils and constant brine salinity when measuring water/oil P_c/S_w and k_r data. More recently, researchers at the U. of Wyoming and the U. of Texas have published papers concerning studies of the effect of temperature, salinity, and oil composition on wettability and waterflood oil recovery.[Sharma, M.M. and Filoco, P.R. 2000.][Zhou, X., Morrow, N.R., and Ma, S. 1996.] Those studies show that oil recovery increases with higher temperature, and generally also with variation in salinity.

2.10.1 Mobility ratio:

The mobility of a phase (Eq. 2.4) is defined as its relative permeability divided by its viscosity. Hence, mobility combines a rock property (relative permeability) with a fluid property (fluid viscosity). The water/oil relative permeability is assumed to depend only on the saturations of the two fluid phases.

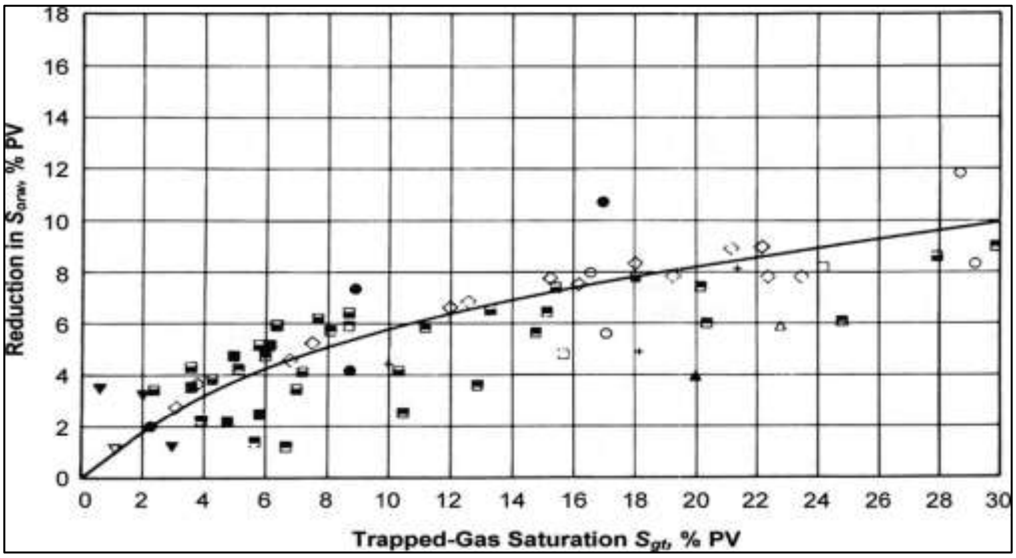


Fig (2-14)Effect of trapped-gas saturation on waterflood oil recovery for preferentially water-wet rocks.(Willhite, G.P. 1986).

$$\lambda_i = \left(\frac{k_i}{\mu_i}\right) \text{ , ...Eq.(2.4)}$$

Mobility relates to the amount of resistance to flow through a reservoir rock that a fluid has at a given saturation of that fluid. Because viscosity is in the denominator of this equation, low-viscosity fluids generally have high mobility and high-viscosity fluids generally have low mobility.

The mobility ratio **M** generally is defined as the mobility of the displacing phase (for waterflooding, water) divided by the mobility of the displaced phase (oil). Eq.(2-5) present the mobility-ratio equation:

$$M = \frac{k_{rw}}{\mu_w}\frac{\mu_o}{k_{ro}} \text{....................Eq.(2.5)}$$

where μ_w = viscosity of water, cp; μ_o = viscosity of oil, cp; k_{rw} = relative permeability to water; and k_{ro} = relative permeability to oil.

Mobility ratios are considered to be either "favorable" or "unfavorable." A favorable mobility ratio is a low value (≤ 1); this means that the displaced phase (oil) has a higher mobility than does the displacing phase (water). An unfavorable mobility ratio (> 1) is the other way around. In practical terms, a favorable mobility ratio means that the displaced oil phase can move more quickly through the reservoir rock than can the displacing water phase.

For simple waterflooding calculations, the mobility ratio is calculated at the endpoint relative permeability values for the two phases. Hence, the equation to be used for the waterflood mobility ratio is Eq.(2.6) :

$$M = \frac{k_{rwe}}{k_{roe}} \frac{\mu_o}{\mu_w} \text{....................Eq(2.6)}$$

This mobility ratio assumes a plug-like displacement between the oil phase at connate-water saturation before the flood front and the water phase at residual oil saturation behind the flood front.

In most reservoir situations, water's viscosity is lower than oil's, making the viscosity ratio unfavorable for water to displace oil efficiently; however the relative permeability of water at residual oil saturation is lower by a factor of two to eight than that of oil at connate-water saturation. Hence, for many reservoirs, the mobility ratio is close to unity (favorable) if the oil viscosity is greater than the water viscosity at reservoir conditions only by a factor of five.

2.10.2 The effect of viscous and capillary forces on residual oil saturation:

In the early and mid-1950's< the effect of rate oil recovery by waterflooding was investigated intensively. There were debates on how results from short laboratory cores could be scaled to reservoir conditions. One part of the problem involved the relative importance of viscous forces to capillary forces on the residual oil saturation.

2.10.3 Correlation of residual oil saturation with capillary and viscous forces:

The dependence of residual oil saturation on the capillary and ciscous forces present at the time of trapping was demonstrated by Moore and Slobod and verified by the extensive experiments of Abrams for water-wet porous media. Using concepts of dimensional analysis and scaling, Moore and Slobod prposed that the residual oil saturation should be a function of a dimensonless group representing the ratio of viscous forces to capillary forces.

2.10.4 The Effect of Trapped Gas on Residual Oil Saturation:

Waterfloods in solution gas-drive reservoirs usually begin after reservoir pressure has declined and GOR's have become excessive. At this point, there is an appreciable free-gas saturation in the pore space. When water is injected into a porous medium containing oil, water, and gas, residual saturations of both oil and gas may remain. The injection of water into a solution gas-drive reservoir usually occurs at rates that cause repressurization of the reservoir. If pressures are high enough, the gas that has been trapped by the displacement process will dissolve in the oil with no effect on subsequent residual oil saturations. The presence of a trapped gas saturation at the time residual oil is trapped by water has a substantial effect on the residual oil saturation in preferentially water-wet rock.

2.10.5 Capillary number:

There have been several investigations of the effect of viscous forces and interfacial tension forces on the trapping and mobilization of residual oil.
From these studies, correlations between a dimensionless parameter called the capillary number, N_{vc}.

The capillary number is the ratio of viscous force to interfacial tension force.

$$\mathbf{N_{vc} = (constant)\frac{v\mu_w}{\sigma_{ow}} = (constant)\frac{k_o\Delta p}{\emptyset\sigma_{ow}L}}$$

The capillary number increases as the viscous force increases or as the interfacial tension force decreases. The EOR methods that have been developed and applied to reservoir situations are designed either associated with the injected fluid or to decrease the interfacial tension force between the injected fluid and the reservoir oil. The next three sections discuss increase the viscous force .

2.10.6 Mobilization of residual Oil:

Residual oil is confined in porous media by interfacial forces that exist between the oil and water acting in the pores. conceptually ,one would expect to be able to displace ganglion by increasing the viscous forces that tend to push the ganglion out or by decreasing the interfacial forces that hold the ganglion in place . several studies experimental verification of this expectation **.**

The effect of viscous force (pressure gradient) on residual oil saturation the Berea core was saturated with water and flooded to an interstitial water saturation of 29% by injection of oil .then,it was flooded with brine until no oil is produced .

A corresponding relationship between oil recovery and IFT was devolped in the mid to late 1960's .Wagner and Leach demonstrated that the residual nonwetting oil phase could be displaced by a nonwetting hydrocarbon vapor phase at reservoir pressure gradients when the IFT was less than 0.7 dynes/cm[0.7 mN/m] (Taber and Taber et al) conducted a systematic investigation of the effect of viscous forces (Δp/L) and capillary forces (σ_w) on Berea sandstone cores to determine the onset of residual oil mobilizatioa as well as the relationship between residual oil saturation and (MIL).

2.10.7 Injection –Water –Sensitivity studies :

The factors to which injection-water-sensitivity studies relate are water-source and –volume options, source-water/connate-water compatibility, and source-water/reservoir-rock interactions. After the preliminary reservoir evaluation indicates that waterflooding is likely to be economically justified and that it will increase significantly the volume of oil recovered, the next consideration is to find an acceptable source from which to obtain enough water for the proposed waterflood project. **Fig. 2.14** schematically shows the variety of natural sources for such water. Onshore locations typically obtain injection water from subsurface aquifer intervals or nearby streams or rivers. Nearshore and offshore waterflood projects typically use seawater.

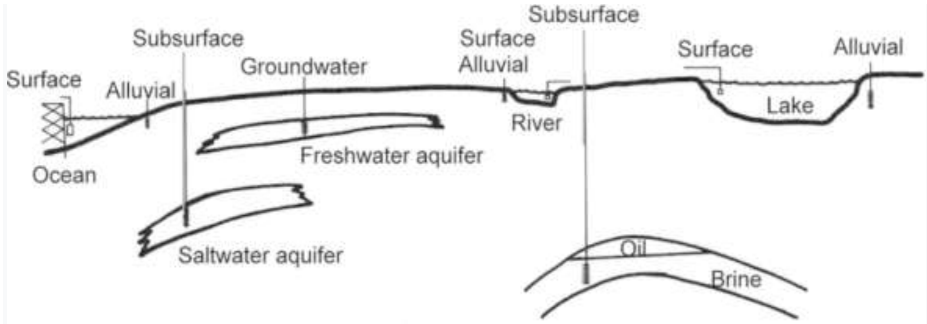


Fig. 2.15– Possible injection-water sources (Petroleum engineering Handbook , Larry W. Lake)

Source-water/connate-water compatibility mainly concerns whether mixing the two waters causes any precipitation of insoluble carbonate or sulfate compounds that might impair reservoir permeability. Although permeability impairment typically is not a major consideration, precipitation and scale buildup in pumps and other surface water-handling equipment can cause costly downtime and repairs.

Potential sensitivity of the reservoir pay intervals to the injection water is a major consideration. For sandstone reservoirs that contain various types of clay, the key consideration is whether there exists clay sensitivity to the difference between the connate-water salinity and the injection-water salinity, particularly for freshwater injection-water sources. Such sensitivity can occur either as clay swelling or as mobilization of clay fines, both of which can reduce reservoir permeability significantly. For high-porosity chalk reservoirs, the injection-water/reservoir-rock interaction might weaken the rock framework and cause pore collapse and surface subsidence.

Another aspect of injection-water sensitivity is the amount and size of suspended particulate being carried by the injection water. This is a concern mainly when using surface water sources for the injection water. An example of where this is a significant consideration is the Kuparuk oil field on the North Slope of Alaska, U.S.A., where nearshore ocean water is the waterflood injection water. There, the spring runoff down the rivers from the Brooks Mountains can cause the nearshore ocean water to contain unacceptable amounts of solid particulate for several weeks of the year. Similar problems occur in the Gulf of Mexico in fields near the mouth of the Mississippi River. Also in the Gulf of Mexico, water that is drawn from too near the surface often contains organic matter that can reduce injectivity.

2.10.8 Limitation of Waterflooding technology

Waterflooding can increase the volume of oil recovered from a reservoir; however, it is not always the best technology to use and it can have complicating factors. When evaluating how best to produce a particular oil reservoir, a petroleum engineer should include waterflooding in the options that are analyzed, both technically and economically. Those evaluations should include such potentially complicating factors as:

- Compatibility of the planned injected water with the reservoir’s connate water
- Interaction of the injected water with the reservoir rock (clay sensitivities, rock dissolution, or generally weakening the rock framework)
- Injection-water treatment to remove oxygen, bacteria, and undesirable chemicals
- The challenges involved in separating and handling the produced water that has trace oil content, naturally occurring radioactive materials (NORMs), and various scale-forming minerals.

2.11 Overview of reservoir simulation and modeling:

According to Assadollahi (2012), Reservoir simulations play a very important role in the modern reservoir management process. They are used to develop a reservoir management plan and to monitor and evaluate reservoir performance. Fluid flow through the porous media is modeled using a mass conservation equation in combination with Darcy’s equation

The mass conservation law for a component in a representative elementary volume (REV) of porous media is:

$$\textit{Fluid Accumulation} = \textit{Fluid Flux} + \textit{Sink/Source}\ (\textit{Production/Injection})$$

Before simulation certain assumptions are made (e.g. three components: oil, water and gas, immiscibility of oil/gas with water, isothermal system). Approximations and discretization techniques are needed to obtain a numerical reservoir model to be solved by a computer program; known as a reservoir simulator.

The reservoir is divided into many small grids/cells/grid-blocks to take into account the reservoir heterogeneity. The physical rock and fluid properties are attributed to each grid block and the initial and boundary conditions are provided to the model to solve the flow equations numerically. Computations are carried out for oil, gas and water phases at discrete time steps to determine the pressure and saturation fields for each phase in every single grid-block.

In general, due to the diversity and large amount of work and data interpretations, different commercial software are used to build the final numerical reservoir model. Thereafter a reservoir simulator is used to predict the future production from a reservoir.

The real numerical reservoir models contain several thousand up to several millions of 6 grid blocks.The simulation process consists of describing the reservoir (i.e. model construction), matching historical performance, and predicting the future performance of the reservoir under a variety of scenarios.

Chapter Three

Methodology

3.1 Introduction:

In this chpter the procedure followed to get the results will be discussed , the main stages of the project can be stated as the following :

- collecting all data required.
- Building the model.
- Running the process (5 spot and inversed 5 spot).
- Displaying the result in forms of graphs and curves.
- Discussing the results and forming the conclusions.

3.2 Data required for CMG:

- ➢ Reservoir rock properties Data
  - Porosity, %.
  - Permeability, md.
  - Water saturation, %.
- ➢ Reservoir condition Data.
  - Original Reservoir temperature, ˚F.
  - Original Reservoir pressure, psia.
  - Reservoir pressure before implementing waterflooding, psia.
  - Current Reservoir pressure, psia.
- ➢ Reservoir fluid characteristics Data.
  - Oil gravity.
  - Bubble point pressure, psia.
- ➢ Production & injection Data.
  - Injectors number.
  - Producer number.
  - Mobility ratio.

3.3 CMG content:

Several elements which are:

- I/O control.
- Reservoir.
- Component.
- Rock & Fluid prosperities.
- Initial condition.
- Numerical.
- Geo-mechanic.
- Well & Recurrent

3.4 Oil displaced:

Until water arrives and the end of a system, oil will be produced at the same rate as water is injected for an incompressible system where the interstitial water was assumed to be immobile. When water breakthrough occurs , a water saturation gradient exists from the inlet to the end of the system. The volume of water in the system. the volume of water in the system between $x = x_1 and\ x = x_2$ can be obtained by integrating the equation:

$$V_w = \int_{x_1}^{x_2} S_w A\emptyset dx \quad \text{.......(3.1)}$$

Where V_w the volume of water in porous rock between $x_1 and\ x_2$

The volume of oil displaced from the region is

$$V_o = V_w - A\emptyset(x_2 - x_1)S_{wi} \text{.......(3.2)}$$

Where $V_o$is the volume of oil displaced from the interval:

$$x_1 \leq x \leq x_2$$

Welge and Cragi developed solution to Eq 3.1.the following development parallels their solutions

Let $\overline{S_w}$ represent the volumetric average water saturation for the region

$$x_1 \leq x \leq x_2$$

Then

$$\overline{S_w} = \frac{\int_{x_1}^{x_2} S_w A \emptyset dx}{\int_{x_1}^{x_2} A \emptyset dx} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(3.3)$$

For constant values of $\emptyset$ and A , Eq 3.3 can be reduces to

$$\overline{S_w} = \frac{\int_{x_1}^{x_2} S_w dx}{x_2 - x_1} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(3.4)$$

The integrand in Eq . 3.4 can be evaluated by use of the Eq

$$x_{s_w} = \frac{q_t t}{A\emptyset}\left(\frac{\partial f_w}{\partial s_w}\right)_{s_w} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(3.5)$$

The derivative of the product $x_{s_w}$is expressed in Eq .3.5

$$\mathrm{d}(\mathrm{x}_{\mathrm{s_w}}) = \mathrm{S_w dx} + \mathrm{xdS_w} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(3.6)$$

The integrand of

$$S_w dx = d(x_{s_w}) \sim x dS_w \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(3.7)$$

Substitution into Eq .3.1 with corresponding changes of integration limits yields Eq.3.6

$$\overline{\mathrm{S_w}} = \frac{1}{\mathrm{x_2 - x_1}} \int_1^2 [\mathrm{d(xS_w) - xdS_w}] \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(3.8)$$

$$\overline{\mathrm{S_w}} = \frac{1}{\mathrm{x_2 - x_1}} \int_{\mathrm{x_1 S_{w1}}}^{\mathrm{x_2 S_{w2}}} \mathrm{d(xS_w)} - \frac{1}{\mathrm{x_2 - x_1}} \int_1^2 \mathrm{xdS_w} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(3.9)$$

And

$$\overline{\mathrm{S_w}} = \frac{\mathrm{x_2 S_{w2} - x_1 S_{w1}}}{\mathrm{x_2 - x_1}} - \frac{1}{\mathrm{x_2 - x_1}} \int_1^2 \mathrm{xdS_w} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(3.10)$$

Now consider the remaining integral Eq.3.8 from Eq.3.7

$$\int_1^2 \mathrm{xdS_w} = \int_1^2 \frac{\mathrm{q_t t}}{\mathrm{A\emptyset}} \left(\frac{\partial \mathrm{f_w}}{\partial \mathrm{s_w}}\right)_{\mathrm{s_w}} \mathrm{dS_w} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(3.11)$$

$$\int_1^2 \mathrm{xdS_w} = \frac{\mathrm{q_t t}}{\mathrm{A\emptyset}} \int_1^2 \left(\frac{\partial \mathrm{f_w}}{\partial \mathrm{s_w}}\right)_{\mathrm{s_w}} \mathrm{dS_w} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(3.12)$$

And

$$\int_1^2 \mathrm{xdS_w} = \frac{\mathrm{q_t t}}{\mathrm{A\emptyset}} \int_1^2 \mathrm{df_w} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(3.13)$$

Therefore

$$\int_1^2 \mathrm{xdS_w} = \frac{\mathrm{q_t t}}{\mathrm{A\emptyset}} (\mathrm{f_{w2}} - \mathrm{f_{w1}}) \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(3.14)$$

Thus the expression for the average water saturation for the interval

$$x_1 \leq x \leq x_2$$

Is given by Eq.3.13

$\overline{S_w} = \frac{x_2 S_{w2} - x_1 S_{w1}}{x_2 - x_1} - (\frac{q_t t}{A\emptyset})\frac{(f_{w2} - f_{w1})}{x_2 - x_1}$..(3.15)

When $x_1 = 0$ and sufficient time has passed for water arrived at the end of the core $(x_2 = L)$, the average water saturation in the core is

$\overline{S_w} = S_{w2} - \frac{q_t t}{A\emptyset L}(f_{w2} - f_{w1})$..(3.16)

Usually, $f_{w1} = 1.0\ at\ x = 0$ ans Eq.3.14 becomes

$\overline{S_w} = S_{w2} - \frac{q_t t}{A\emptyset L}(1 - f_{w1})$..(3.17)

We note that q,t represent the total volume of water injected (W_i) ,while $A\emptyset L$ is the PV of the porous rock , V_p . we define Q_i by Eq.3.6 as the number of PV's of water injected

$Q_i = \frac{W_i}{A\emptyset L}$.. (3.18)

For constant injection rate,

$Q_i = \frac{q_t t}{A\emptyset L}$..(3.19)

And Eq.3.15 becomes

$\overline{S_w} = S_{w2} - Q_i(1 - f_{w1})$..(3.20)

Because the displaced hydrocarbon saturation is $\overline{S_w} - S_{wi}$,the cumulative oil displaced, N_p,is given by Eq.3.21

$N_p = V_p(\overline{S_w} - S_{wi})$..(3.21)

Where the FVF was assumed to be 1.0

One further simplification is possible .at the end of the system ($x = L$) the water saturation is S_{w2} after water arrives .from the equation :

$$x_{sw} = \frac{q_t t}{A\emptyset}(\frac{\partial f_w}{\partial s_w})_{s_w}$$

$$x_{sw2} = L = \frac{q_t t}{A\emptyset}\left(\frac{\partial f_w}{\partial s_w}\right)_{s_w}$$

Or

$$Q_i = \frac{1}{\left(\frac{\partial f_w}{\partial s_w}\right)_{s_w}} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(3.22)$$

So that

$$\overline{S_w} = S_{w2} - \frac{(1 - f_{w1})}{f'_{sw2}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(3.23)$$

Where

$$f'_{sw2} = \frac{1}{\left(\frac{\partial f_w}{\partial s_w}\right)_{s_w}} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(3.24)$$

a tangent drawn at to the frictional flow curve at a saturation $S_{w2} \geq S_{wf}$ .the tangent intersects the $f_w = 1.0$ line at S.we now show that the S_e is $\overline{S_{w2}}$

$$\left(\frac{\partial f_w}{\partial s_w}\right)_{s_w} = \frac{1 - f_{w2}}{S_e - S_{w2}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(3.25)$$

From Eq.3.25

$$\left(\frac{\partial f_w}{\partial s_w}\right)_{s_{w2}} = \frac{1 - f_{w2}}{\overline{S_w} - S_{w2}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(3.26)$$

Comparison of Eqs.3.25 and 3.26 shows that $S_e = \overline{S_w}$ as the average saturation after breakthrough can be obtained by finding the intersection of the tangent to the $f_w - S_w$ curve with $f_w = 1.0$.

Production rates:

The fractional flow of water is determined from the frontal advance solution for every value of S_{w2} . thus

$$q_{w2} = \frac{f_{w2} q_t}{B_w} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(3.27)$$

$$q_{o2} = \frac{f_{o2} q_t}{B_o} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(3.28)$$

And

$$q_{o2} = \frac{(1 - f_{w2}) q_t}{B_o} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(3.29)$$

The WOR is a measure of the efficiency of the displacement at a point in the process. In production operations its represent the volume of water that must be handled to produce a unit volume of oil . Eq.3.30 defines the WOR for a linear system.

$$WOR = \left(\frac{f_{w2}}{f_{o2}}\right)\left(\frac{B_o}{B_w}\right) \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(3.30)$$

3.5 Steps of building the Water Injection Modeling CMG:

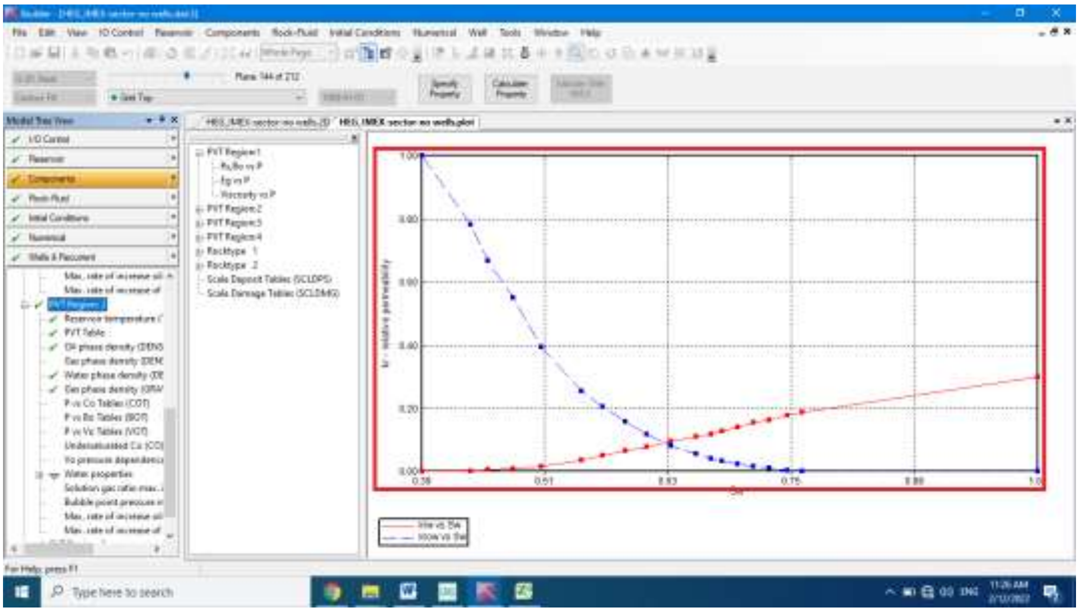


Figure (3.1): describe the insert of the component & phase properties – definition

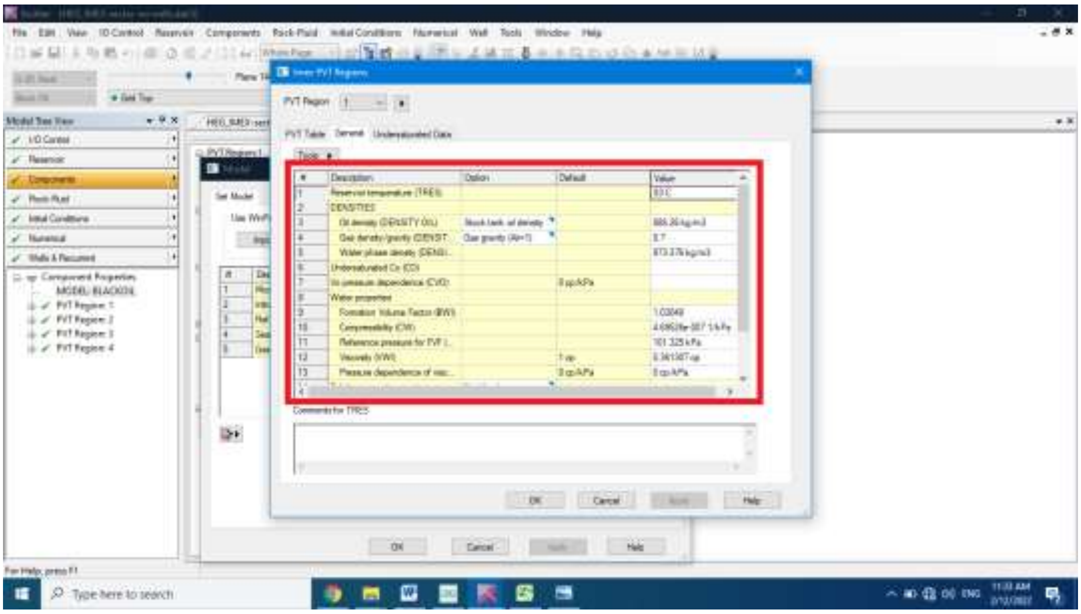


Figure (3.2): describe the insert of the component & phase properties – general

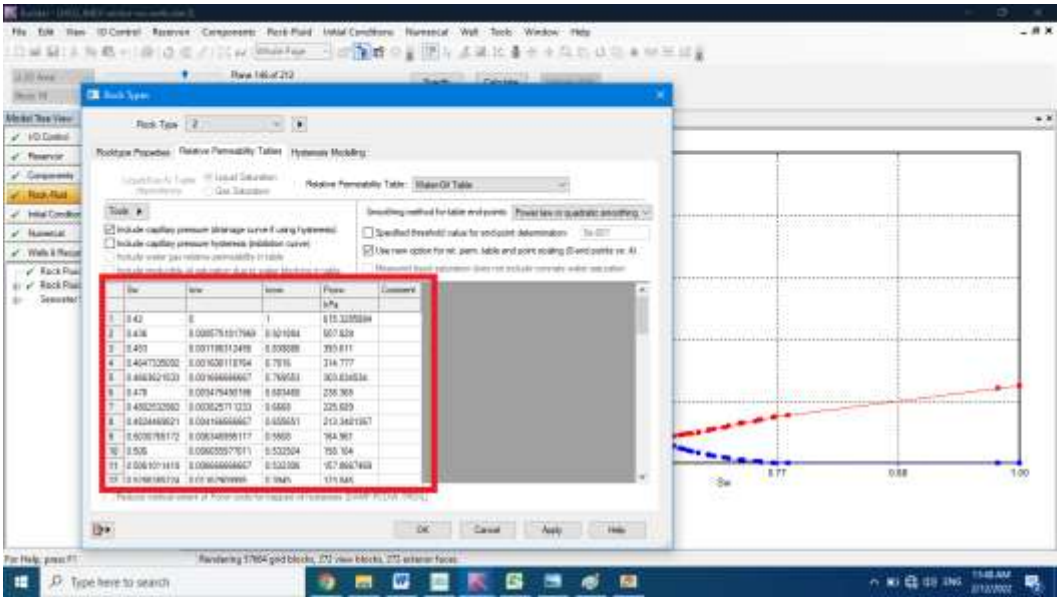


Figure (3.3): rock & fluid properties – showing the relative permeability table of rock type 2

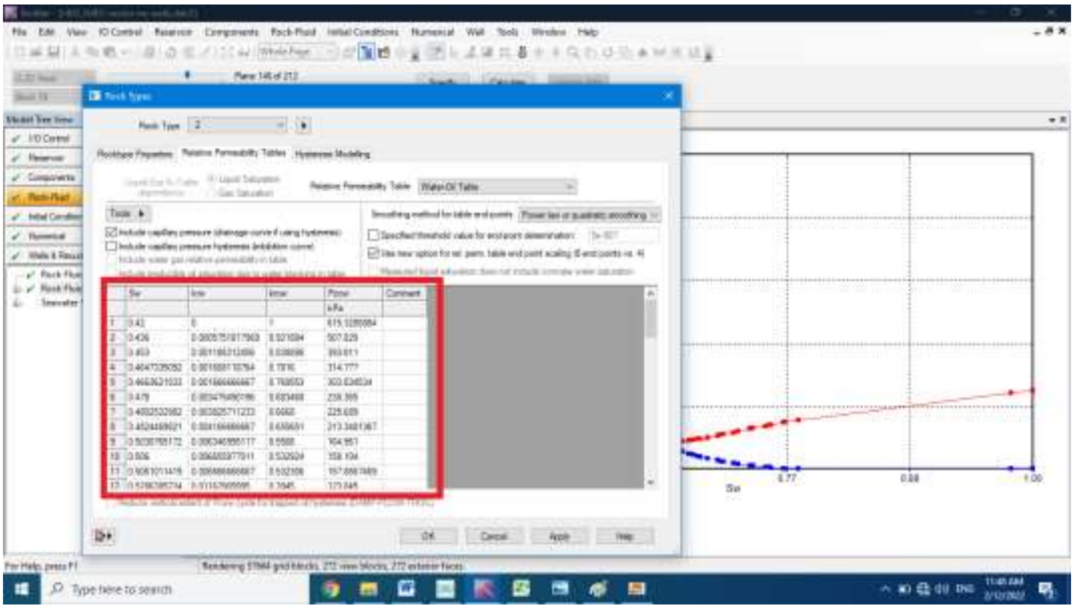


Figure (3.3): rock & fluid properties – showing the relative permeability table of rock type 2

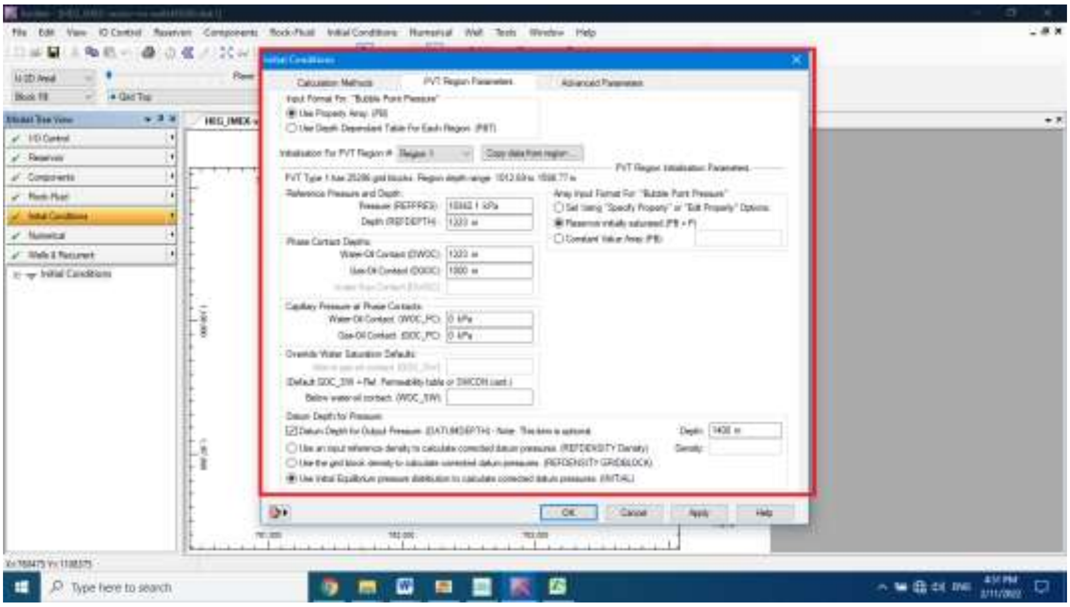


Figure (3.4): describing how to insert the initial condition

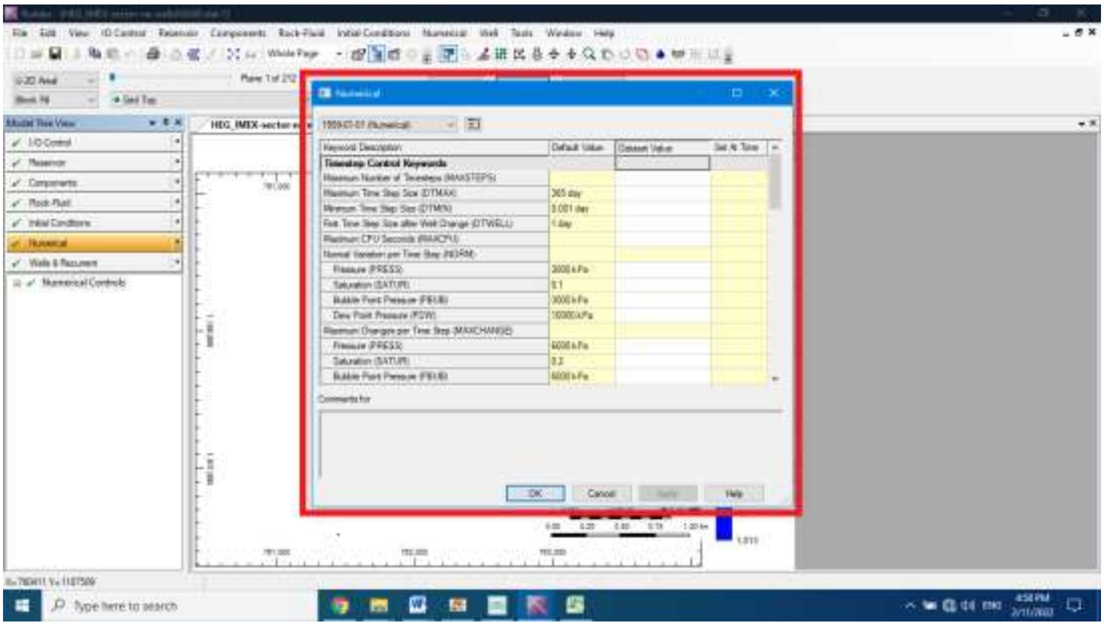


Figure (3.5): view the numerical – general option

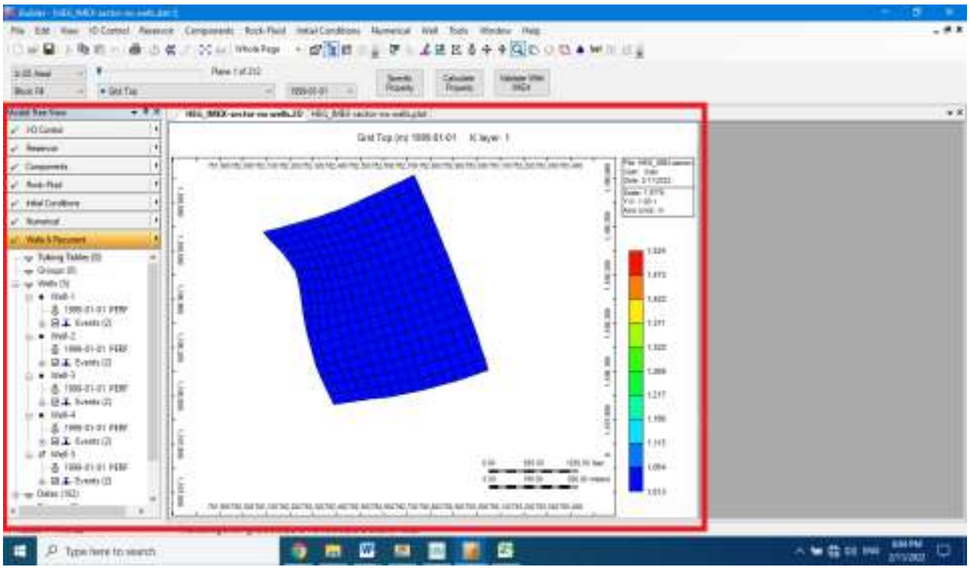


Figure (3.6): wells & recurrent – grid top of base case 2D

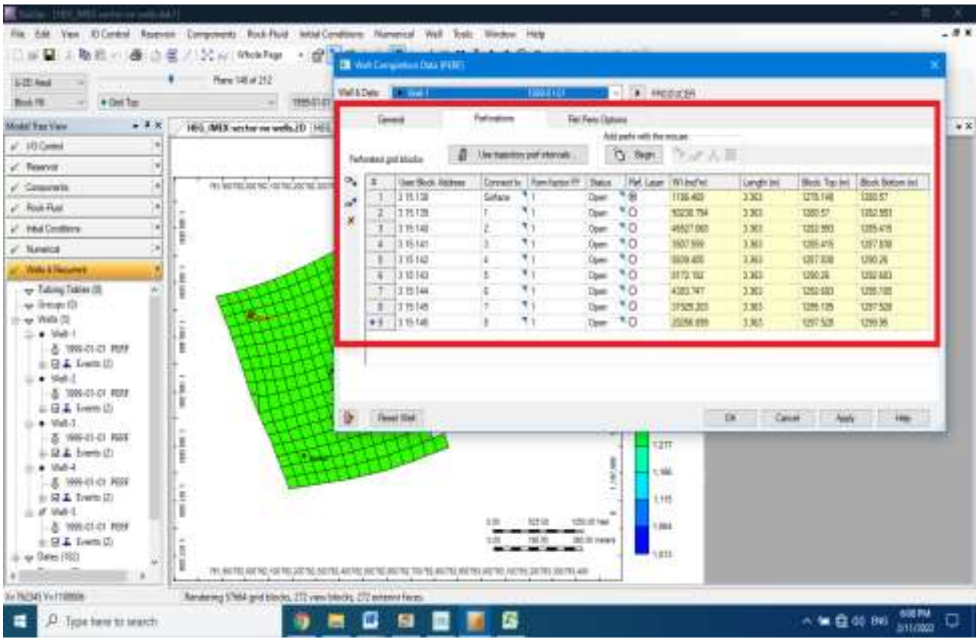


Figure (3.7): wells & recurrent – change the perforation depth for (well 1)

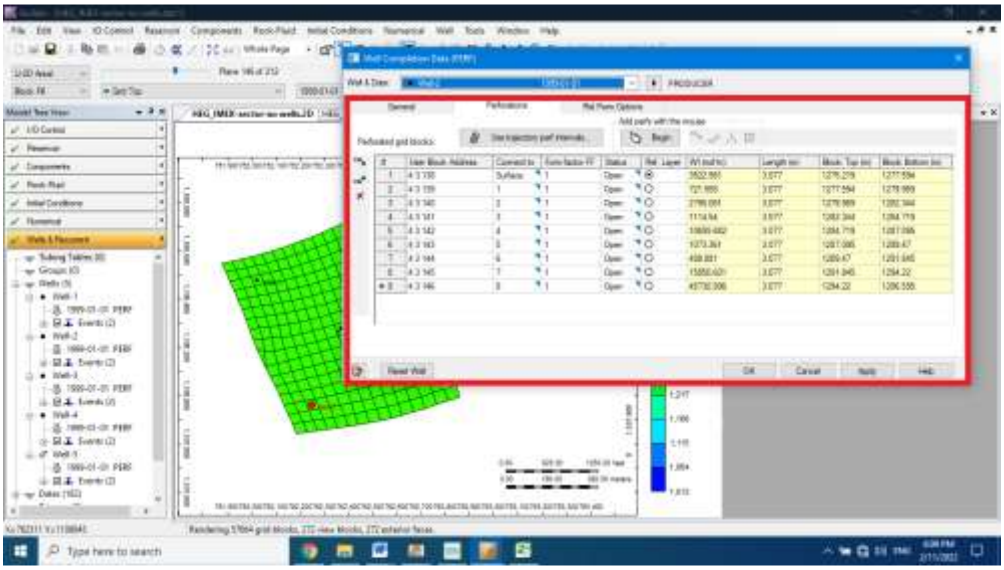


Figure (3.8): wells & recurrent – change the perforation depth for (well 2)

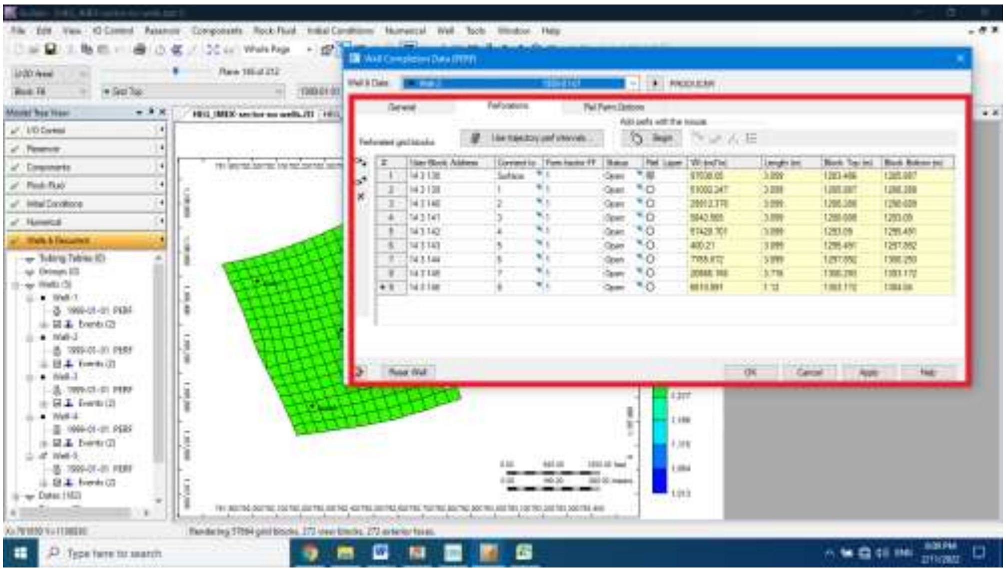


Figure (3.9): wells & recurrent – change the perforation depth for (well 3)

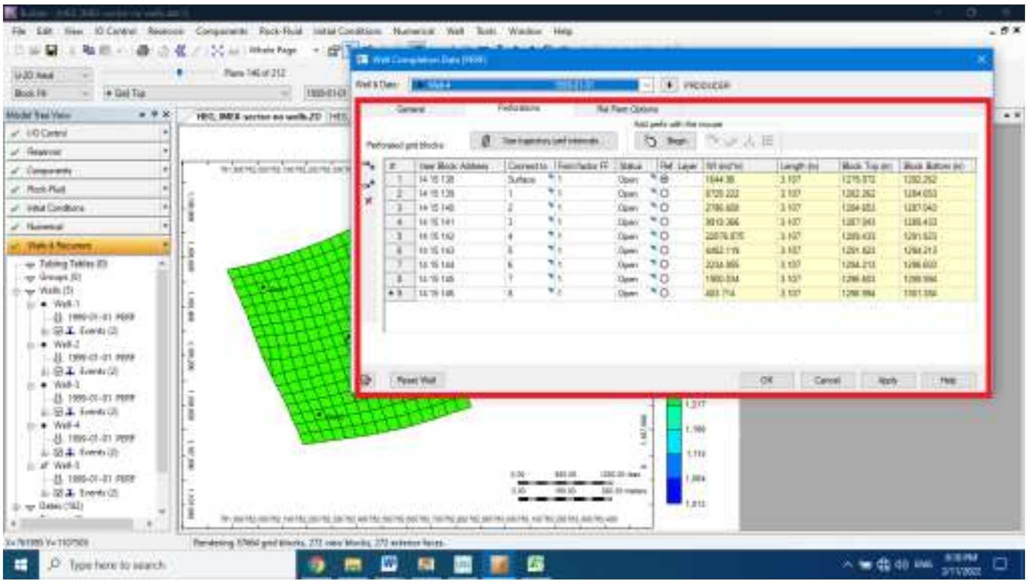


Figure (3.10): wells & recurrent – change the perforation depth for (well 4)

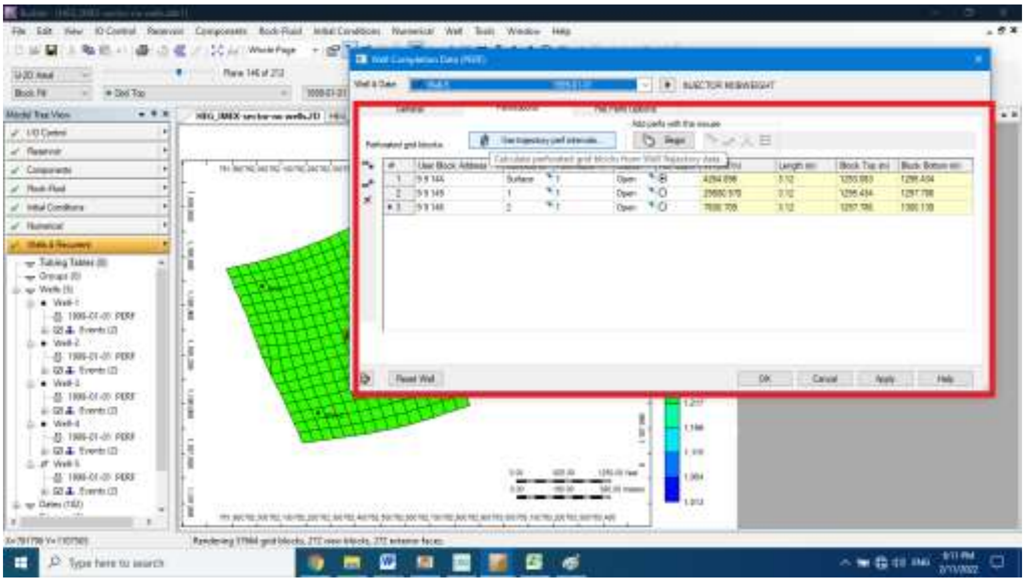


Figure (3.11): wells & recurrent – change the perforation depth for (well 5)

Chapter Four

Results and Discussion

4.1 Introduction:

The waterflooding has been implemented in Heglieg field since 1999 and performance was good but faced the problem of high water cut from producer and water oil ratio (WOR) need to be optimized.

4.2 Basic Information of Heglig Field Location:

Heglig contains a large oilfield central to Sudan’s economy, which was already reeling from the loss of oil revenues after the south spoilt off.

The field was first developed in 1996 by Arkis Energy .Today is operated by Greater Nile Petroleum Operating Company.

Heglig is located on latitude 29° 23' 73" East;and longitude 10° 00' 48"North.

The field consist of two main oil field , Heglig and Unity.

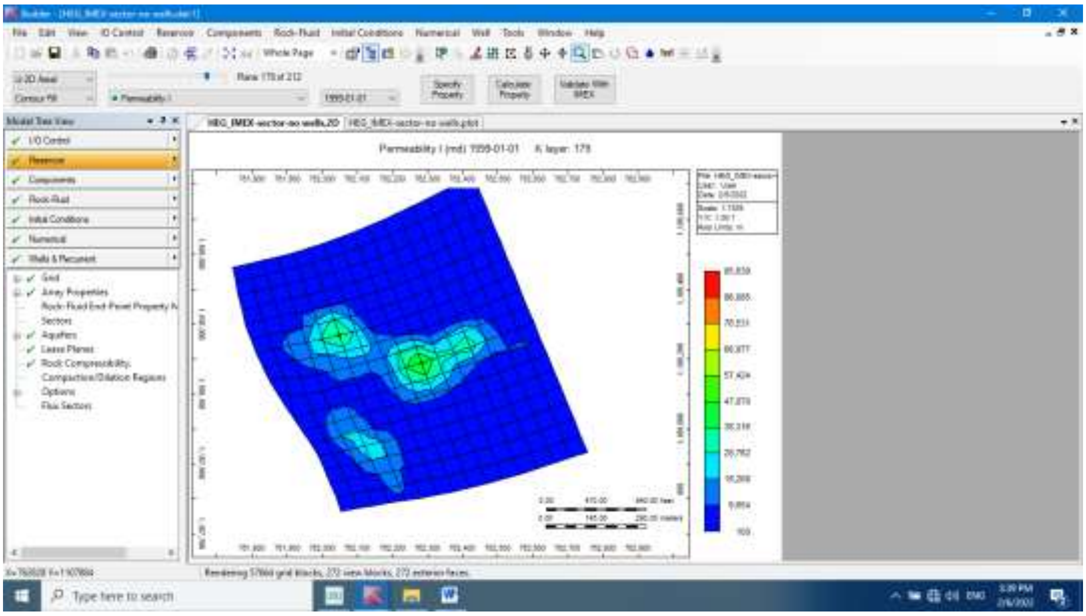


Figure (4.1): Formation permeability

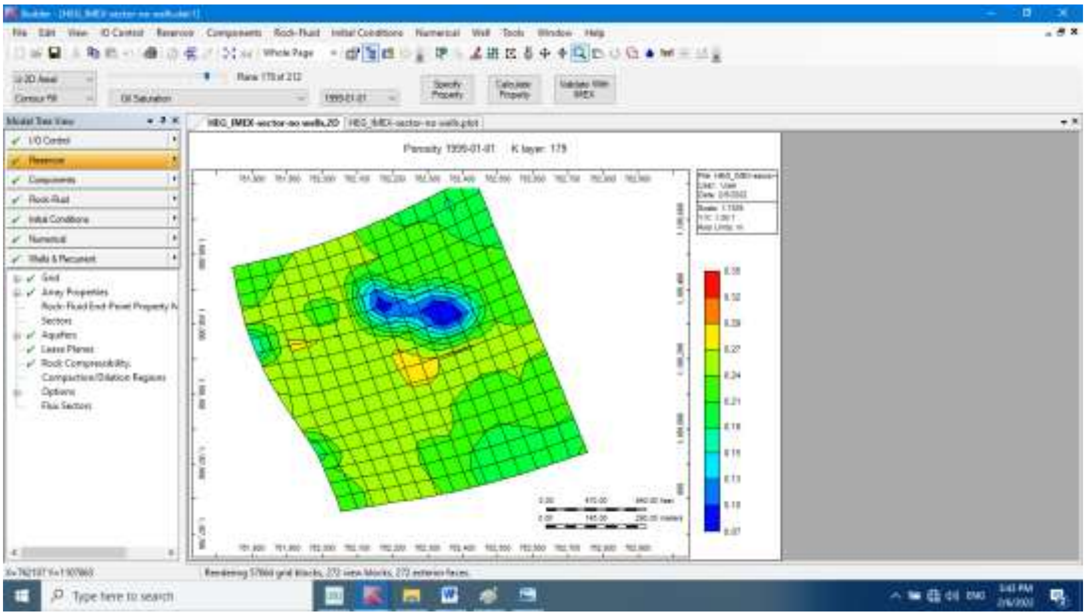


Figure (4.2) Formation porosity

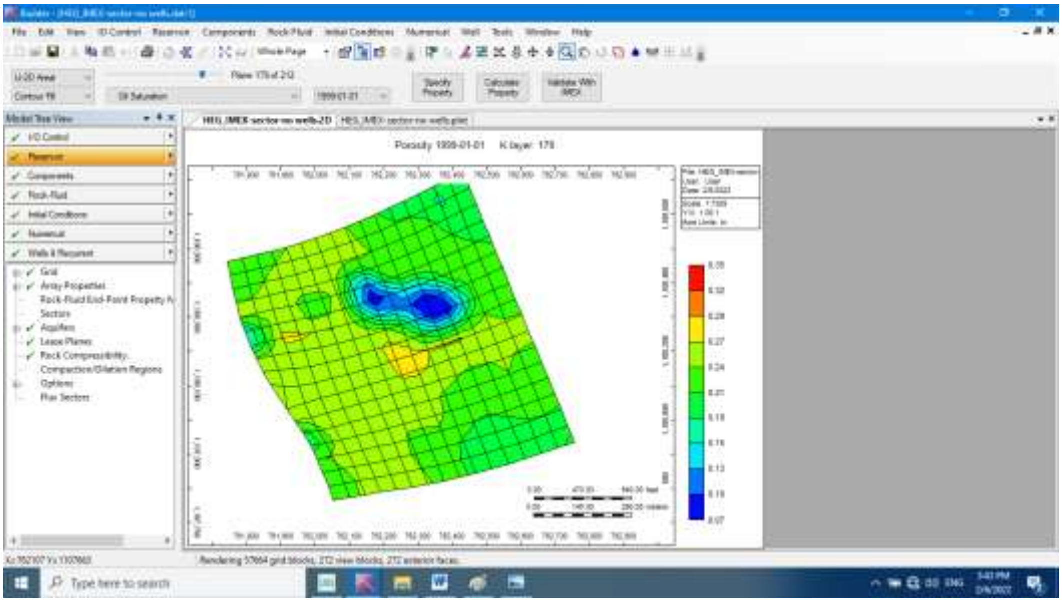


Figure (4.3) Formation Oil Saturation

4.3 Case study:

Two cases has been studied in this research in order to come up with more suitable scenarios for Heglig field and these cases as follow:

4.3.1 Case one:

In this case five wells have been drilled to perform five spot pattern .Figure 4.4 & 4.5 shows the location of the wells and time line view for this case

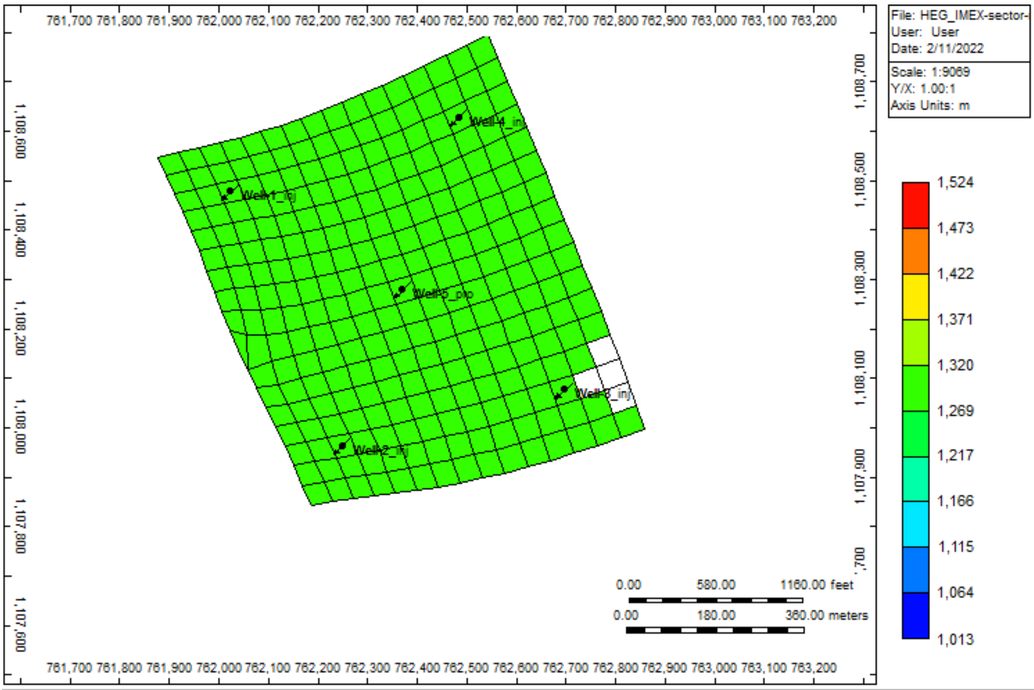


Figure (4.4): Normal five spot

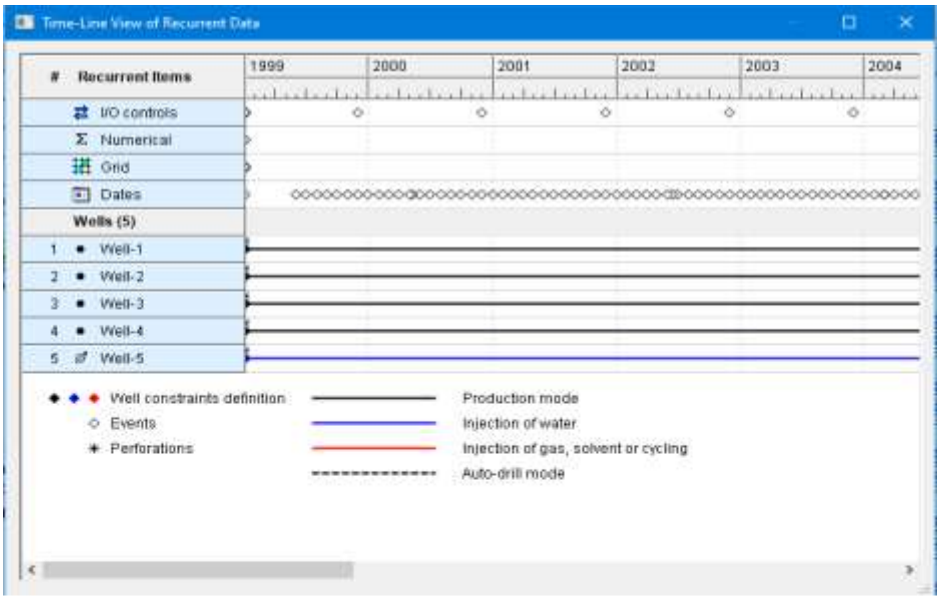
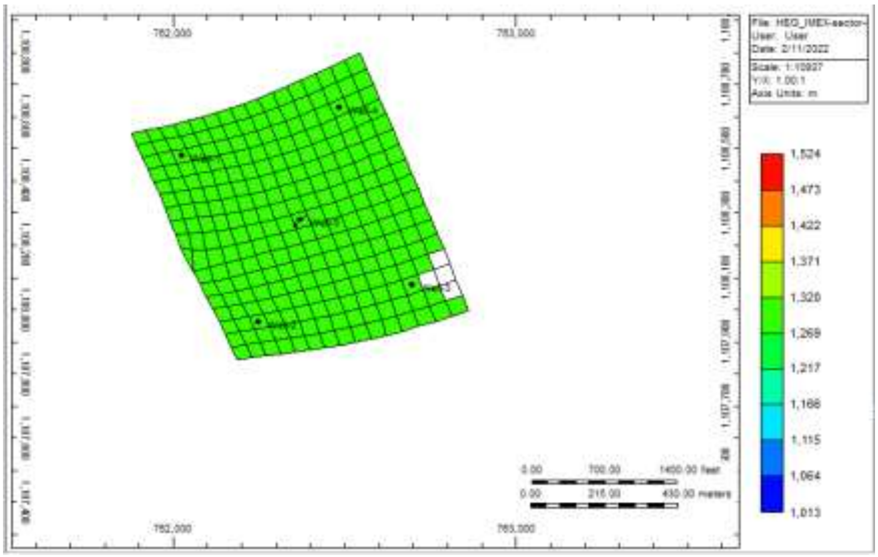


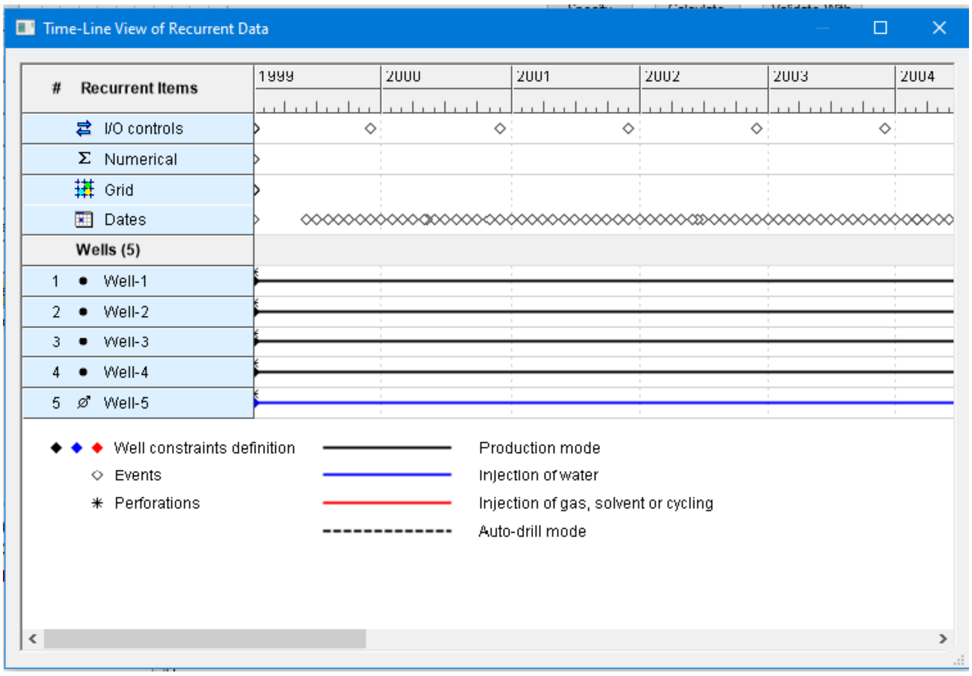
Figure (4.5): Time line view – 5-wells producer

4.3.2 Case two: (Inverted Five Spot)

In this case injection wells and produce from the current four wells as 5 spot patterns .Figure(4.6) and (4.7) shows the location for the wells in 2D and time line view for this case.



Figure(4.6) Inverted Five Spot



Figure(4.7) Time Line View for 4-wells producer & 1-well injector

After running the simulation model it has been found that case one gave high cumulative oil and it has been selected for more sensitive analysis and optimization for water injection rate.

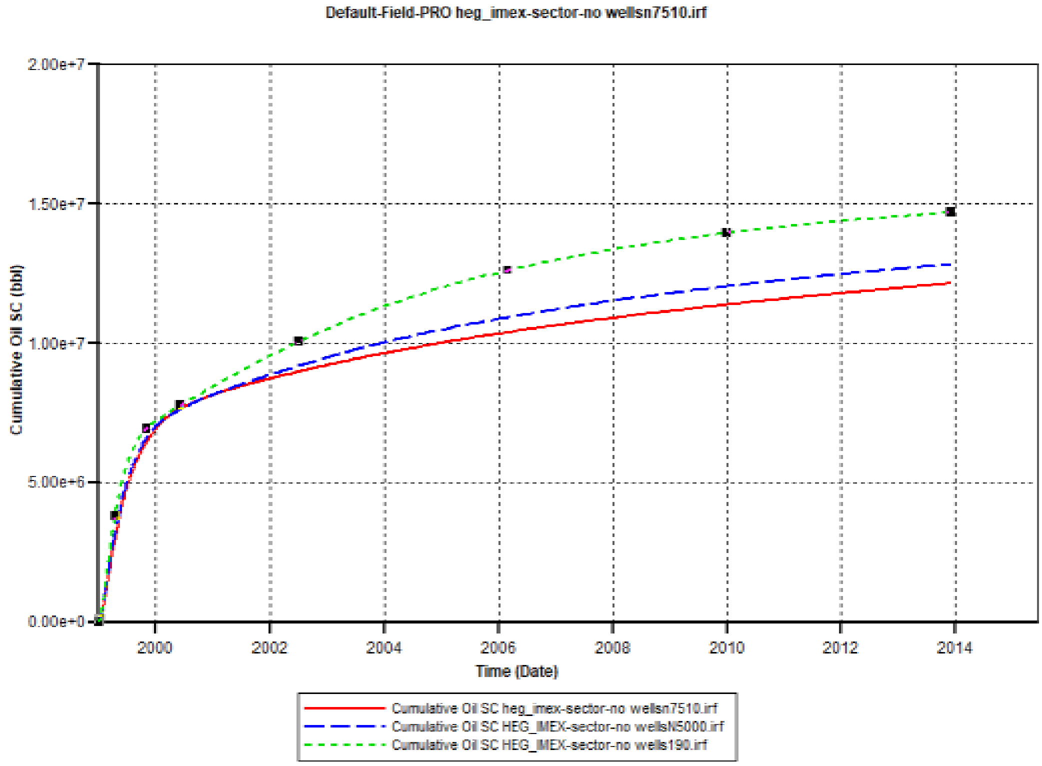


Figure (4.8): Cumulative Oil VS Time for normal 5 spot

Injecting with a constant injection rate to measure the cumulative production, when injecting with injection rate of 190 m^3/day, it's obvious that the cumulative production rate is much higher than injecting with injection rate of 5000 m^3/day. And that represents the optimum cumulative production.

When injecting with injection rate of 7510 m^3/day, the cumulative production is much lower than the other two previous cumulative productions.

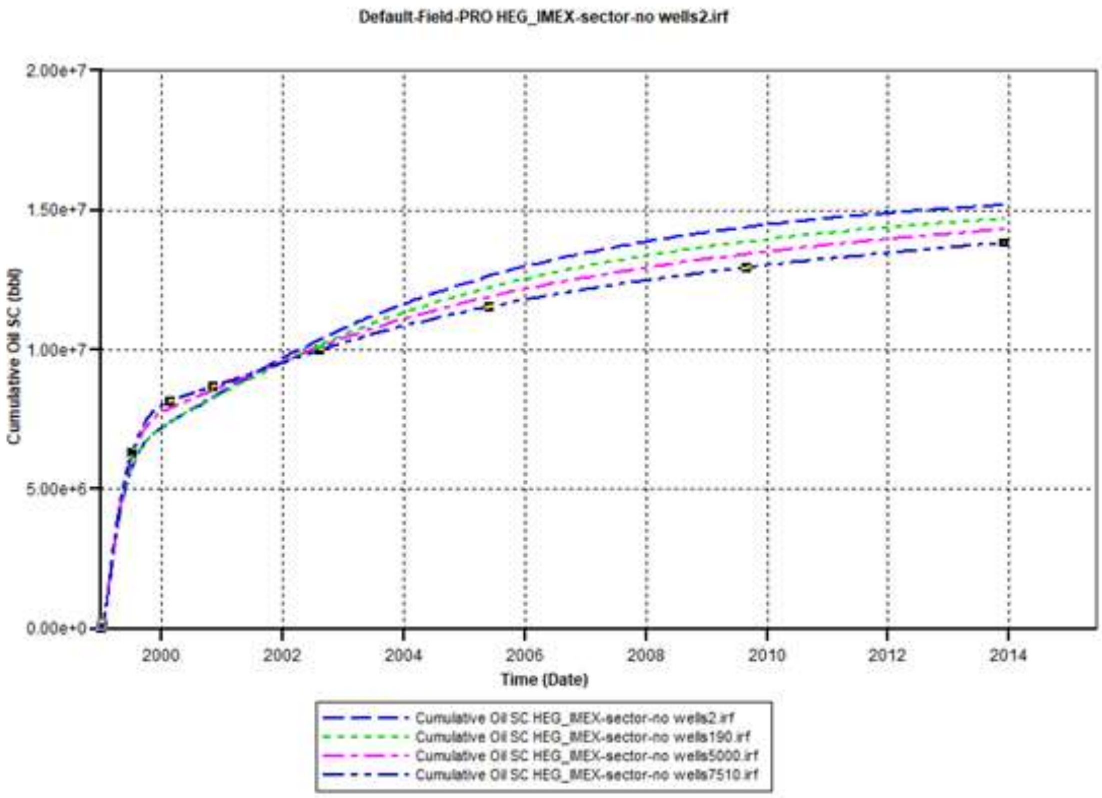


Figure (4.9): Cumulative Oil for inversed 5 spot

The figure show that when injecting with rate of 190 m^3/day it represent the optimum injection rate than when injecting with rate of 5000m^3/day.

When injecting with injection rate of 7510 m^3/day, the cumulative production is much lower than the other two previous cumulative productions.

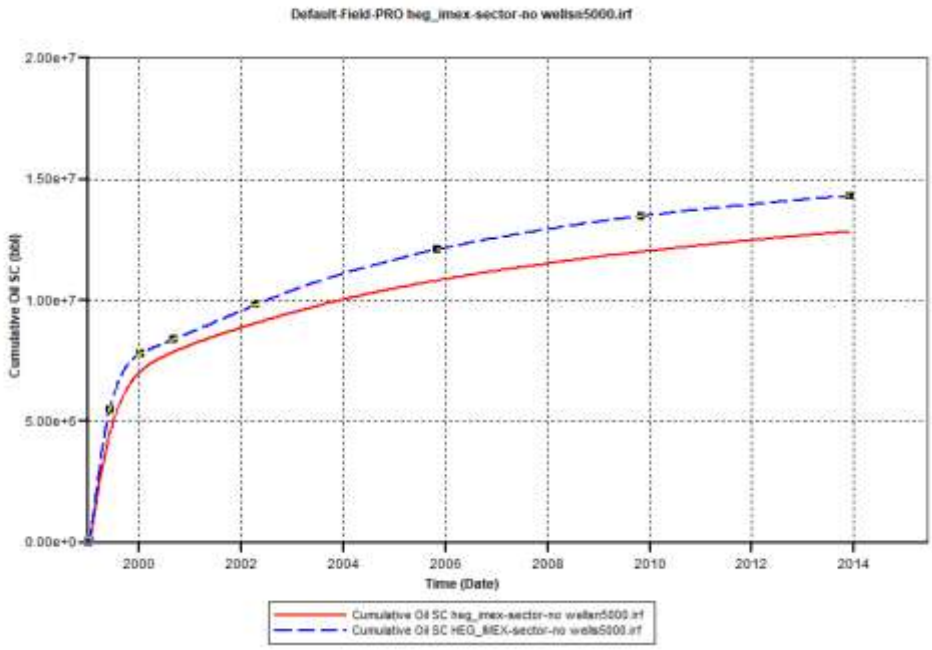


Figure (4.10): compare between (Inverse 5 spot) and (5 spot)

This figure shows the differences between the normal and inverted 5 spots pattern, clearly the inverted 5 spot pattern is the best pattern for the production.

Table 4-1: The cumulative oil for injection rate of 800 bbl for normal 5 spot

injection rate bbl/day	Cumulative oil bbl	Time
	0	1/1/1999
	4.19*10^6	22/4/1999
800	6.97*10^6	10/11/1999
	7.84*10^6	24/6/2000
	1.02*10^7	1/7/2002
	1.30*10^7	1/3/2006
	1.44*10^7	1/1/2010
	1.51*10^6	1/12/1013

injection rate bbl/day	Cumulative oil bbl	Time
	0	1/1/1999
	3.80*10^6	16/4/1999
	1.00*10^7	7-Jan-02
1200	6.79*10^6	10/10/1999
	7.77*10^6	7/6/2000
	1.25*10^7	1/3/2006
	1.39*10^7	1/1/2010
	1.47*10^7	1/12/2013

Table 4-2: cumulative oil for injection rate of 1200 bbl for normal 5 spot

Table 4-3: cumulative oil for injection rate of 5000 bbl for normal 5 spot

injection rate bbl/day	Cumulative oil bbl	Time
	0	1/2/1999
	5.51*10^6	1/7/1999
	8.00*10^6	1/2/2000
5000	8.36*10^6	25/8/2001
	9.9*10^6	1/6/2000
	1.21*10^7	1/12/2005
	1.34*10^7	1/12/2009
	1.43*10^7	1/13/2013

Table 4-4: cumulative oil for injection rate of 7510 bbl for normal 5 spot

injection rate bbl/day	Cumulative oil bbl	Time
	0	1/2/1999
	6.3*10^6	7/7/1999
7510	8.15*10^6	25/2/2000
	8.66*10^6	1/11/2000
	1.15*10^6	1/6/2005
	1.29*10^7	1/9/2009
	1.38*10^7	1/12/2013

Table 4-5: cumulative oil for injection rate of 7510 bbl for inversed 5 spot

injection rate bbl/day	Cumulative oil bbl	Time
	0	1/1/1999
	917311	1/9/1999
7510	1.23*10^6	27/7/2000
	1.34*10^6	13/6/2001
	1.44*10^6	15/9/2002
	1.58*10^6	1/12/2004
	1.78*10^6	1/4/2009
	1.93*10^6	1/12/2013

Table 4-6: cumulative oil for injection rate of 1200 bbl for inversed 5 spot.

injection rate bbl/day	Cumulative oil bbl	Time
	0	1/1/1999
	618080	19/4/1999
1200	1.10*10^6	1/11/1999
	1.23*10^6	1/6/2000
	1.60*10^6	15/6/2002
	2.00*10^6	1/3/2006
	2.22*10^6	1/1/2010
	2.33*10^6	1/12/2013

Table 4-7: cumulative oil for injection rate of 5000 bbl for inversed 5 spot.

injection rate bbl/day	Cumulative oil bbl	Time
	0	1/1/1999
5000	674700	23/4/1999
	1.08*10^6	17/10/1999
	1.62*10^6	1/8/2002
	2.06*10^6	1/2/2006
	2.30*10^6	1/1/2010
	2.43*10^6	1/12/2013

Chapter Five

Conclusion and Recommendation

5.1 Conclusion:

The area has been selected with good permeability, good porosity, good sand thickness, optimum well spacing and location for regular 5 spot well patterns.

For two scenarios have been suggested which are 4 well producer and one injector , 4 well injector and one producer.

It has been found that the best scenario is (4 well producer and one injector).

In this scenario of normal 5 spots well pattern several rates between (500-7510) bbl/day injection rate has been tested. The rate 1100 bbl/day – injection has been found the best rate.

5.2 Recommendation:

Reservoir pressure must be supported by using water flooding to avoid formation fracture.

The amount of water injected must be provided at suitable rates.

The researchers recommend that for implementing this project, should give high production at less cost.

The facilities for handling produced fluids for a waterflood must be designed with considerable flexibility.

Depending on the source of the injected water, the water might need a treatment to remove oxygen, prevent scale and corrosion.

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