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A Simulation Study for Effect of Wettability on Oil Recovery by Waterflooding

A graduation project is submitted to the Petroleum Engineering Department in partial fulfillment of the requirements for the degree of Bachelor of Science in

Petroleum Engineering

BY

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سُورَةُ الفَاتِحَةِ

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إِيَّاكَ نَعۡبُدُ وَإِيَّاكَ نَسۡتَعِينُ ٥ ٱهۡدِنَا

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وَلَا ٱلضَّآلِّينَ ٧

SUPERVISOR CERTIFICATION

I certify that the preparation of this project entitled

A Simulation Study for Effect of Wettability on Oil Recovery by Waterflooding ,

Prepared by

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Was made under my supervision at General Petroleum Engineering Branch of Petroleum Engineering Department in partial fulfillment of the Requirements for the Degree of Bachelor of Science in Petroleum Engineering.

Signature:

Name: Dr. Mohammed Idrees Ali Al-Mossawy (Supervisor)

Date:

DEDICATION

To my parents and to our family who made this accomplishment possible, to the righteous martyrs of Iraq.

The prophit Mohammed - may God’s prayers and peace be upon him - said: "He who does not thank people does not thank God." I thank the honorable Dr. Mohammed Idrees Al-Mossawy for his precious advices and valuable guidance which helped us in our research and illuminated the darkness that stood in our way.

I would also like to thank all the professors who were a candle that lights our paths with science and knowledge. Praise be to Allah before and after.

Abstract

Most of the large petroleum discoveries have already been made, but the demand for energy is still increasing. To meet the demands, some methods for getting the existing resources from the subsurface up to the surface have to be applied.

One of these methods includes Secondary Oil Recovery, Especially waterflooding, this provides two majors objectives, one to displacement hydrocarbons, other maintain reservoir pressure. And this method is coming after natural drive mechanism, may produce up to 50% of the remaining oil in place, but this not a fixed ratio, can be less, and this oil recovery ratio depends on the properties of the reservoir and fluids, one of these properties is wettability, which is mean fluid stacking on rock than others. The purpose of this project was to investigate the possible options of effect wettability on oil recovery by waterflooding in ECLIPSE 100 through simulations of virtual and real models.

So in a virtual case, modeling nine reservoirs that have different permeability and wettability then investigate it with different patterns, to get the pattern that gives the highest possible oil recovery, in the real case, use real data to modeling the reservoir then investigate it with different patterns and times to water flooding, and selecting the best case which gives the highest oil recovery.

The results show in virtual reservoir model The highest pattern is direct line (W-wet, homogeneous permeability) the best one in recovery. while in the real reservoir model the results show the best recovery at Start of water flooding project.

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CHAPTER ONE: INTRODUCTION

1. 1 Introduction

The world is facing growing challenges in oil and gas supply in order to sustain growth in energy demand and the economy. Growth in global population and industrialization in developing countries will result into an increase in global energy consumption and hence further pressure on the available oil resources. Oil-producing companies are encountering increasing difficulties and challenges in accessing new conventional reserves, and are therefore turning to more complex developments like the deep and ultra-deep offshore to deliver growth and boost production to meet the increasing energy demand. However, even the huge oil and gas reservoirs discovered in deep and ultra-deep offshore will only yield about 30 - 40% recovery by primary reservoir energy but the problem of recovery of a greater percentage of what is left behind will persist.

Waterflooding is by far the most widely applied method of improved oil recovery over the years with good results in conventional and unconventional (tight oil) reservoirs, Due to its accessibility and low costs. It is so well developed and understood that every field at all favorable to the technique will sooner or later be water flooded. The economics of water flooding is usually more attractive than any alternative technique, which increases its preferred position. Where water flooding is carefully designed and controlled, the ultimate recovery at the end of the secondary operation may be equivalent to a well-managed and efficient primary water drive.

Water flooding increases the recovery of crude oil by maintaining the reservoir pressure and by driving the pore saturation of crude oil down to a value characteristic of the lithology of the reservoir and the physico-chemical interaction of the crude and the displacing water. Unfortunately, the residual oil saturation to water flooding may vary from 5 to 40 percent, and, in addition, the injected water may sweep only a part of the reservoir when the mobility of the water is significantly greater than that of the oil or when the permeability distribution in the reservoir varies greatly.

An understanding of the properties of the oil-bearing rock and the reservoir fluids, interactions between the rock and the fluids, and in particular, multiphase flow, is very essential in the choice, design, installation and management of projects for enhanced oil recovery. Multiphase flow processes in natural porous media or synthetic porous materials is a common phenomenon in many diverse fields of science and engineering. Such fields include agricultural, aeronautical, Biomedical, ceramic, chemical, and petroleum engineering, food and soil sciences, as well as in porous metallurgy. Typical examples of great practical interest and economic importance are production of oil and gas from reservoir rocks, underground water flow and transport of inorganic pollutants in unconsolidated soil formations and their removal through remediation process, water flooding, and/or gas injection in oil reservoirs.

One of the most important properties in multiphase flow is wettability, Because wettability plays an important role as that determines the interactions between the solid (rock) and the liquids in the reservoirs (crude oil, brine). Wettability has been recognized as one of the key parameters controlling the remaining oil-in-place. The ultimate recovery of oil and other non-aqueous phase liquids (NAPLs) depends on the residual saturations and relative permeabilities of each of the phases. In a two-phase flow, one phase will wet the porous medium more than the other phase. This wetting phase occupies the smaller pores, crevices, and corners while the non-wetting phase occupies the larger pores with the exact mix determined by the capillary pressure. No matter the pair of fluids used (gas/water, oil/water, gas/oil) the positioning of the fluids will be somewhat identical at identical saturations. On the other hand, for three-phase flow there will be an intermediate wetting phase which will be positioned uniquely in the porous medium, leading to a whole new regime of flow paths (DiCarlo, 2000). These variations in pore-scale positioning of each fluid directly affect the important macroscopic properties of relative permeability, residual saturation and oil recovery.

1. 2 Problem statement

All reservoir engineers seek to get a great oil recovery this can be achieved by water flooding with choosing the best pattern.

In reality, choosing pattern and time Affected by many parameters such as permeability, wettability, number of well, flow rate and geometry of reservoir. Oil recovery It can also be affected if there are free gas in a reservoir or not and salinity of water.

All these parameters should study in waterflood project, because choosing a wrong pattern is mean less oil recovery 'Less Profits'.

Can solve this problem by test patterns with different wettability and different permeabilities distributions.

1. 3 Objectives

The objectives that will be studied in project:

1. To investigate effect of wettability in cases permeability variations.
2. To investigate effect of wettability on the patterns selected on waterflooding.
3. Optimize waterflooding for a real field case.

1. 4 Scope of work

The scope of the project for two reservoirs (virtual model , real field case) :

1- Wettability: type a-water wet, b- oil wet, intermediate-wet.

2- Permeability variation:

a- All layer have same: perm(X), perm(Y), perm(Z).

b- Decreasing with depth for all: perm(X), perm(Y), perm(Z).

c- Increasing with depth for all: perm(X), perm(Y), perm(Z).

3- Patterns: using a- Peripheral Injection Patterns. b- Five spot

d- Seven spot d- Direct line drive.

4- Optimum time: flooding at a- at starting of production.

b- at bubble point.

CHAPTER TWO: LITERATURE REVIEW

2. 1 Introduction

The terms primary oil recovery, secondary oil recovery, and tertiary (enhanced) oil recovery are traditionally used to describe hydrocarbons recovered according to the method of production or the time at which they are obtained. Primary oil recovery describes the production of hydrocarbons under the natural driving mechanisms present in the reservoir without supplementary help from injected fluids such as gas or water. In most cases, the natural driving mechanism is a relatively inefficient process and results in a low overall oil recovery. The lack of sufficient natural drive in most reservoirs has led to the practice of supplementing the natural reservoir energy by introducing some form of artificial drive. Secondary oil recovery refers to the additional recovery that results from the conventional methods of water injection and immiscible gas injection. Usually, the selected secondary recovery process follows the primary recovery but it can also be conducted concurrently with the primary recovery. Waterflooding is perhaps the most common method of secondary recovery. However, before undertaking a secondary recovery project, it should be clearly proven that the natural recovery processes are insufficient; otherwise there is a risk that the substantial capital investment required for a secondary recovery project may be wasted. Tertiary (enhanced) oil recovery is that additional recovery over and above what could be recovered by primary and secondary recovery methods. Various methods of enhanced oil recovery (EOR) are essentially designed to recover oil, commonly described as residual oil, left in the reservoir after both primary and secondary recovery methods have been exploited to their respective economic limits. In this section of project We review principle of waterflooding and wettability.

2. 2 Factors to considered in waterflooding

in determining the suitability of a candidate reservoir for waterflooding, the following reservoir characteristics must be considered [1]:

a- Reservoir geometry : The areal geometry of the reservoir will influence the location of wells and, if offshore, will influence the location and number of platforms required. The reservoir's geometry will essentially dictate the methods by which a reservoir can be produced through water-injection practices.

b- Fluid properties : The physical properties of the reservoir fluids have pronounced effects on the suitability of a given reservoir for further development by water-flooding. The viscosity of the crude oil is considered the most important fluid property that affects the degree of success of a waterflooding project. The oil viscosity has the important effect of determining the mobility ratio that, in turn, controls the sweep efficiency.

c- Reservoir depth : Maximum injection pressure will increase with depth. these mean lifting oil from very deep wells lead to limit the maximum economic (w-o) ratios that can be tolerated, and This is the opposite a shallow reservoir because this must be less than fracture pressure. in waterflood operations, there is a critical pressure (approximately 1 psi/ft of depth) that, if exceeded, permits the injecting water to expand openings along fractures or to create fractures. This results in the channeling of the injected water or the bypassing of large portions of the reservoir matrix. Consequently, an operational pressure gradient of 0.75 psi/ft of depth normally is allowed to provide a sufficient margin of safety to prevent pressure parting.

d- Lithology and rock properties : Reservoir lithology and rock properties that affect flood ability and success include: Porosity , Permeability , Clay content ,Net thickness . In some complex reservoir systems, only a small portion of the total porosity, such as fracture porosity, will have sufficient permeability to be effective in water-injection operations.also if there is a lot of shall or claystone in the oil zone, the waterflooding will fill the pores and this means swelup and thus loss of permeability.

e- Fluid saturations : oil saturation that provides a sufficient supply of recoverable oil is the primary criterion for successful flooding operations.

f- Reservoir uniformity and pay continuity

- Reservoir uniformity is important in the success of secondary oil recovery.
- Thief zones may substantially reduce the efficiency and presence of heterogeneity can make a reservoir poor candidate for waterflooding.
- Continuity of the pay zone is also another important factor. A discontinuous pay zone may cause depletion of the reservoir in another a layer when injection is made through a singlewell.

g- Primary reservoir driving mechanisms : primary recovery. The term refers to the production of hydrocarbons from a reservoir without the use of any process, These types of reservoirs are identified by initial reservoir pressures that are greater than that of the bubble point pressure. There are six driving mechanisms:

- Rock and liquid expansion
- Solution gas drive
- Gas cap drive
- Water drive
- Gravity drainage drive
- Combination drive

2. 3 Optimum time to waterflooding

The most common procedure for determining the optimum time to start waterflooding is to calculate : Anticipated oil recovery , Fluid production rates, Anticipated financial 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 injectors .[1] Cole (1969) lists the following factors as being important when determining the reservoir pressure (or time) to initiate a secondary recovery project:

1) 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 .
2) Free gas saturation : The impact of the free must be considered when planning field development by water of gas injection:

- In water injection projects. It is desirable to have an initial gas saturation, possibly as much as 10%. This suggests that there might be benefits of initiating the waterflood process at a pressure that is below the bubble point pressure
- In gas injection projects. Zero gas saturation in the oil zone is desired. This occurs while reservoir pressure exists at or above bubble-point pressure.

3) Cost of injection equipment. This is related to reservoir pressure which indicates that at higher pressures, the cost of injection equipment increases.
4) Productivity of producing wells. A high reservoir pressure is desirable to:
   - Increase the productivity of producing wells
   - Extend the flowing period of the wells
   - Decrease lifting costs
   - Shorten the overall life of the project
5) Effect of delaying investment on the time value of money Overall life of the reservoir

2. 4 Waterflooding 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 [1]. this selection can be achieved by:

- converting existing production wells into injectors.
- drilling infill injection wells.

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 infectivity.

in general, essentially four types of well arrangements are used in fluid injection projects:

1- Irregular Injection Patterns : Willhite (1986) points out that surface or subsurface topology and/or the use of slant-hole drilling techniques may result in production or injection wells that are not uniformly located. Some small reservoirs are developed for primary production with a limited number of wells and when the economics are marginal, perhaps only few production wells are converted into injectors in a nonuniform pattern. Faulting and localized variations in porosity or permeability may also lead to irregular patterns.

2- Peripheral Injection Patterns: In peripheral flooding, the injection wells are located at the external boundary of the reservoir and the oil is displaced toward the interior of the reservoir, as shown in Figure 2-1. Based on Craig (1971).

3- Regular Injection Patterns : fields are developed in a very regular pattern. The most common patterns, as shown in Figure 2-2. are the following:
   - Direct line drive : The lines of injection and production are directly opposed to each other. a = distance between wells of the same type, and d =distance between lines of injectors and producers.

- Staggered line drive : The wells are in lines as in the direct line, but the injectors and producers are no longer directly opposed but laterally displaced by a distance of (a/2).
- Five spot: This is a special case of the staggered line drive in which the distance between all like wells is constant, i.e., a = 2d. Any four injection wells thus form a square with production well at the center.
- Seven spot. The injection wells are located at the corner of a hexagon with production well at its center.
- Nine spot. This pattern is similar to that of the five spot but with an extra injection well drilled at the middle of each side of the square. The pattern essentially contains eight injectors surrounding one producer.

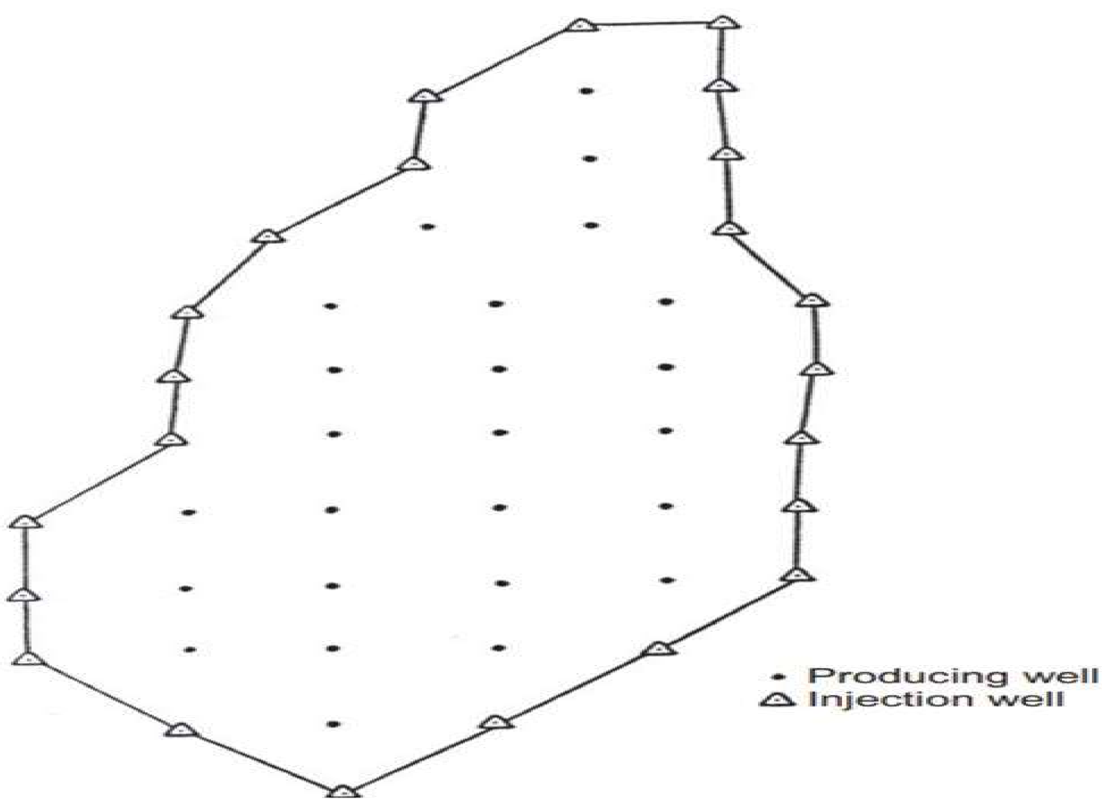


Figure 2. 1 : Typical peripheral waterflood. (After Cole, F, 1969). [1]

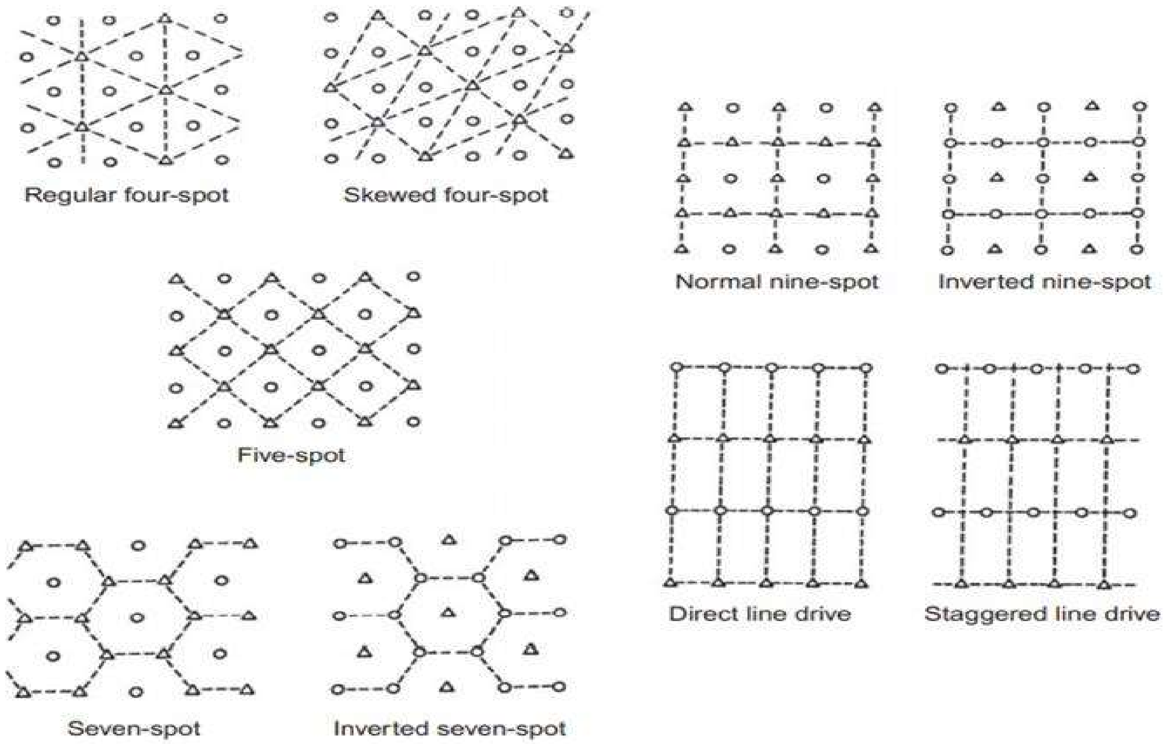


Figure 2. 2 : Flood patterns. (Permission to publish by the Society of Petroleum Engineers). [1]

4. Crestal and Basal Injection Patterns : In crestal injection, as the name implies, the injection is through wells located at the top of the structure. Gas injection projects typically use a crestal injection pattern. In basal injection, the fluid is injected at the bottom of the structure. (Figure 2-3).

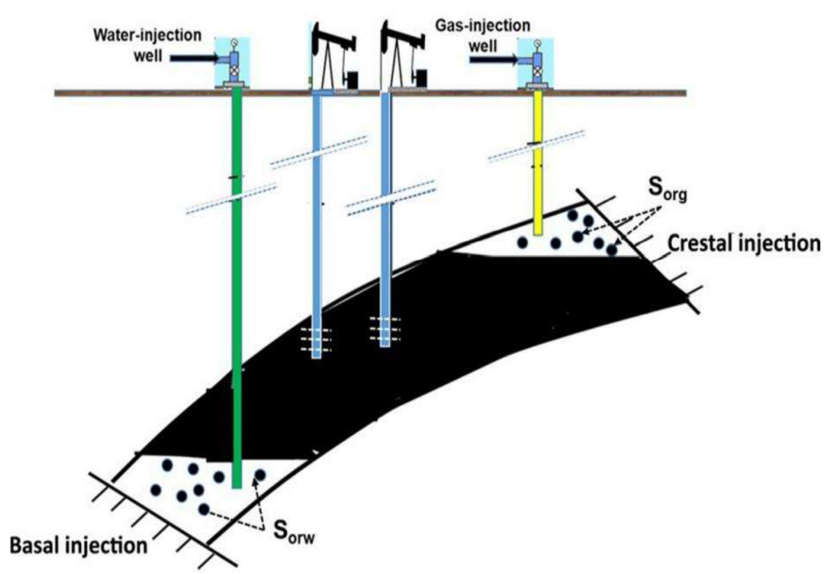


Figure 2. 3: Well managements for dipping reservoirs.[1]

2. 5 Overall recovery efficiency

The overall recovery factor (efficiency) RF can calculate by : **RF = ED EA EV** and this will explain in next sections.

2. 6 Displacement efficiency (ED)

is defined as the fraction of movable oil that has been displaced from the swept zone at any given time or pore volume injected. Because an immiscible gas injection or waterflood will always leave behind some residual oil, ED will always be less than (1.0), Mathematically, the displacement efficiency is expressed as:

$$ED = \frac{\text{Volume of oil at start of flood} - \text{Remaining oil volume}}{\text{Volume of oil at start of flood}} \quad (2.1)$$

Buckley and Leverett (1942) developed a well-established theory, called the frontal displacement theory, which provides the basis for establishing such a relationship. This classic theory consists of two equations: A- Fractional flow equation B- Frontal advance equation.

2. 6.1 Fractional Flow Equation

The development of the fractional flow equation is attributed to Buckley and Leverett (1942). Eq. fractional flow, displacement by water :

$$f_w = \frac{1 - \left(\frac{0.001127(kk_{ro})A}{\mu_o i_w}\right)[0.433(\rho_w - \rho_o)\sin(\alpha)]}{1 + \frac{k_{ro}\,\mu_w}{k_{rw}\,\mu_o}} \quad (2.2)$$

Eq. fractional flow, displacement by gas:

$$f_g = \frac{1 - \left(\frac{0.001127(kk_{rg})A}{\mu_o i_g}\right)[0.433(\rho_g - \rho_o)\sin(\alpha)]}{1 + \frac{k_{ro}\mu_g}{k_{rg}\mu_o}} \quad (2.3)$$

$f = fractional\ flow$

$\rho = density.\frac{g}{cc}$

$k =$ absolute permeability. md

kr = relative permeability. for oil . gas . water

i = injection rate $.\frac{bbl}{day}$

μ = gas viscosity. cp

A = cross − sectional area. ft2

our objective is to get best waterflooding, This can be achieved by decrease (f_W). and there are two impact:

1- Effect of Water and Oil Viscosities :

Figure 2-4 shows the general effect of oil viscosity on the fractional flow curve for both water-wet and oil-wet rock systems. a higher oil viscosity results in an upward shift (an increase) in the fractional flow curve. Higher injected water viscosities will result in reduction in fw (can see this in equation Previous).

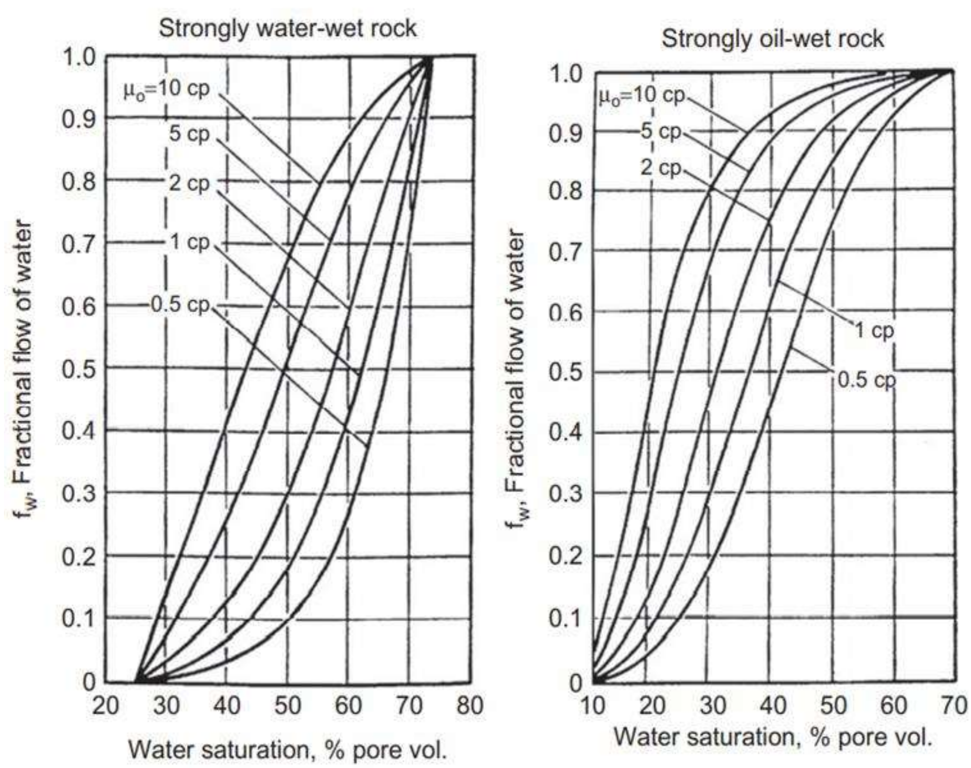


Figure 2. 4 : Effect of oil viscosity on (f_w). [1

2- Effect of Dip Angle and Injection Rate :

Case 1: Injection Well is Located Down-dip. a more efficient performance is obtained. This improvement is due to the fact that the term "$(\frac{0.001127(kk_{ro})A}{\mu_o i_w})[0.433(\rho_w - \rho_o)\sin(\alpha)]$" will always remain positive, which leads to a decrease (downward shift) in the fw curve.

Case 2: Injection Well is Located Up-dip. which causes an increase (upward shift) in the fw curve. It is beneficial, therefore, when injection wells are located at the top of the structure to inject the water at a higher injection rate to improve the displacement efficiency.

2. 6.2 Frontal Advance Equation

Equations used to determine the water saturation at particular point.

2. 7 Areal sweep efficiency (E_A)

- defined as the fraction of the total flood pattern that is contacted by the displacing fluid.
- It increases steadily with injection from zero at the start of the flood until breakthrough occurs.
- The areal sweep efficiency depends basically on the following three main factors:

1. Flood Patterns.

Keep in mind how many wells are there to be injected and how many wells to produce so Flood patterns include these:

1) Direct line drive 2) Staggered line drive 3) five, seven or nine spots. The most common is five spots <u>one in middle to producer and four in corners to as injector</u> or <u>one in middle as injector and four as producer.</u>

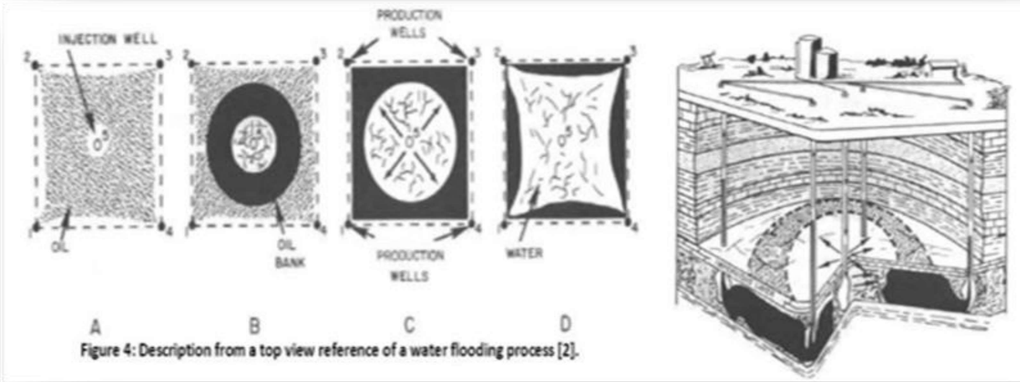


Figure 4: Description from a top view reference of a water flooding process [2].

Figure 2. 5 : description from top view reference of a water flooding process.[10]

2. Mobility Ratio

- It is important factor in fluid movement within rocks.
- Defined the mobility of any fluid in reservoir rock is effective permeability (Kr) divided by viscosity (μ).
- But in your mind these equations. which faster if I injection water what I need? Is need to make oil move very fast or water move faster? Answer **no** I want the oil move fast and water slowly so the velocity equal mobility ratio.
  - ❖ one fluid used to displace another fluid.
  - ❖ Five spot producer in mid and four injector wells in corners
  - ❖ Mobility ratio (M): 0.4 and 1.43
  - ❖ Result when (M) greater than one the displacing fluid perhaps water or gas moves faster than oil and will likely bypass some of it resulting in a low sweep efficiency. when (M) less than one, the oil is capable of moving faster than the displacing fluid and we have good sweep efficiency.

Since we cannot easily alter the reservoir permeability, we have only to choices forreducing (M) and thus improving recovery we may reduce the viscosity of oil or increase the viscosity of displacing fluid, so we can reduce oil viscosity by heating or increase viscosity displacing water by adding some polymer.

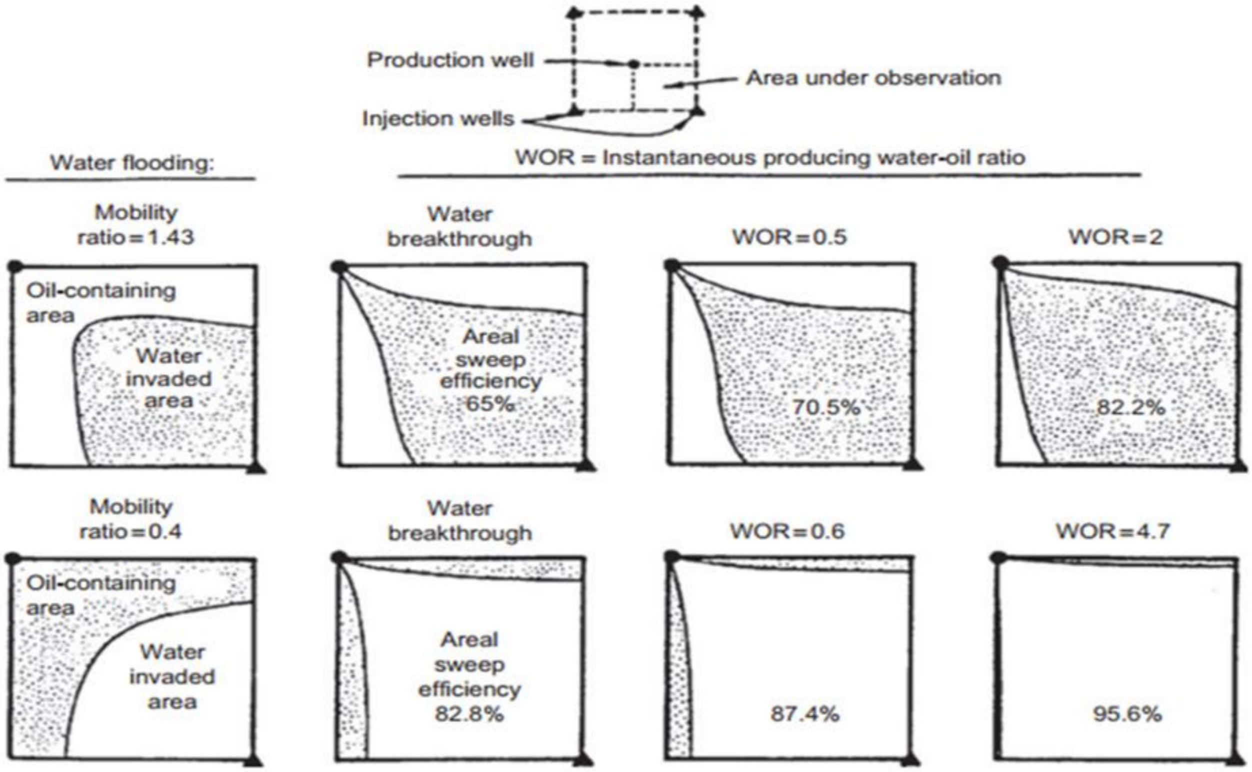


Figure 2. 6: X-ray shadowgraphs of flood progress. (Permission to publish by the Society of Petroleum Engineers). [1]

3. permeability.

The type of permeability and direction and amount of permeability where in water injection the vertical permeability is better to make water go up, and in waterflooding the horizontal permeability is better to sweeping the oil.

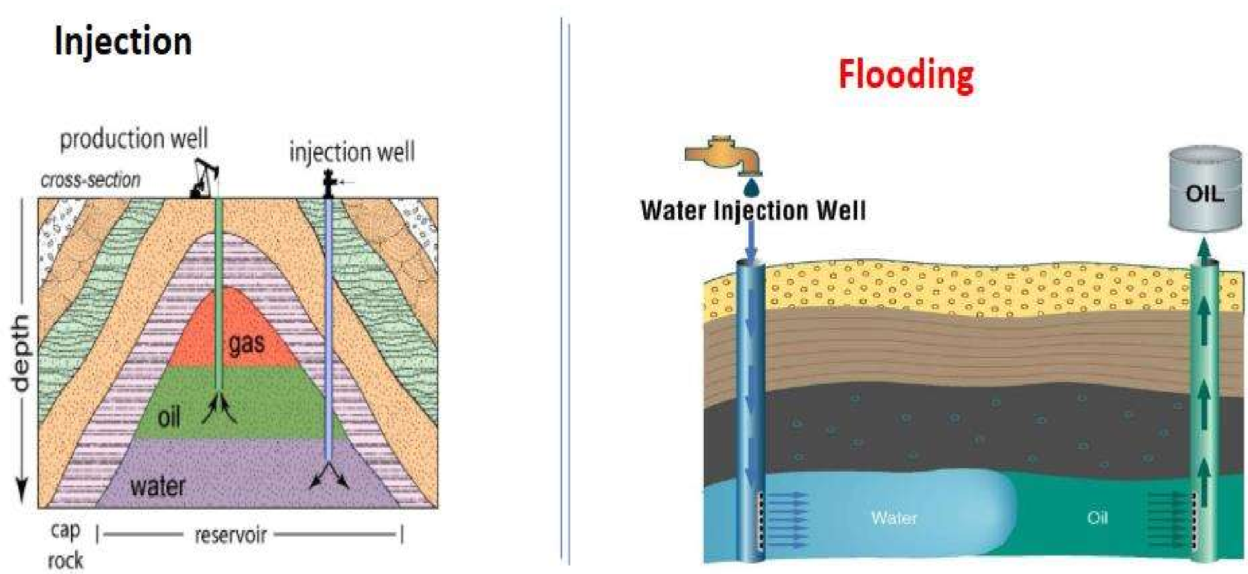


Figure 2. 7: injection vs flooding[10]

4. Cumulative Water Injected.

- Continued injection after breakthrough can result in substantial increases in recovery, especially in the case of an adverse mobility ratio. so shown that significant quantities of oil may be swept by water after breakthrough. It should be pointed out that the higher the mobility ratio, the more important is the "after-breakthrough" production
- how much water i can inject inside reservoir? how many barrels of water have been injected at given time in one year, two years? because you'd need to overflow or overflood.

$$w_{ii} = \frac{\pi h \phi s_{gi} r_{ei}^2}{5.616} \qquad (2.4)$$

where:
w_{ii} = cumulative water injected to interference. bbl
s_{gi} = intial gas saturation
ϕ = porosity
r_{ei} = half the distacne between adjancent intectors. ft

$$i_w = \frac{0.00707 h \Delta p}{\left(\frac{\mu_w}{k_{rw}} \ln\frac{r}{r_w} + \frac{\mu_o}{\mu_{ro}} \ln\frac{r_o}{r}\right)} \qquad (2.5)$$

where:
i_w = water injection. bbl/day
Δp = pressuer difference between injector and producor. psi
k = absolute permeability. md
k_{ro} = relative permeability of oil at swi
k_{rw} = relative permeability of water at s_{wBT}
r_o = outer radius of the oil bank. ft
r = outer radius of the water bank. ft
r_w = wellboer radius. ft

2. 7.1 Areal sweep efficiency (EA) method

Methods of predicting the areal sweep efficiency are essentially divided into the following three phases of the flood:

- Before breakthrough

$$E_A = \frac{w_{inj}}{(vp)(s_{wBT} - swi)} \qquad (2.6)$$

w_{inj} = cumulative water injected . bbl
w_{inj} = flood pattern pore volume . bbl

- At breakthrough

$$E_{ABT} = 0.54602036 + \frac{0.0317081}{M} + \frac{0.30222997}{e^M} + 0.00509693M \qquad (2.7)$$

E_{ABT} = areal sweep efficiency *at* breakthrough
$M = Mobilityratio$

- After breakthrough

$$E_A = E_{ABT} + 0.2749ln\left(\frac{w_{inj}}{w_{iBT}}\right) \qquad (2.8)$$

E_A = areal sweep efficiency *after* breakthrough
W_{inj} = *cumulative water injected . bbl*
W_{iBT} = *umulative water injected at* breakthrough

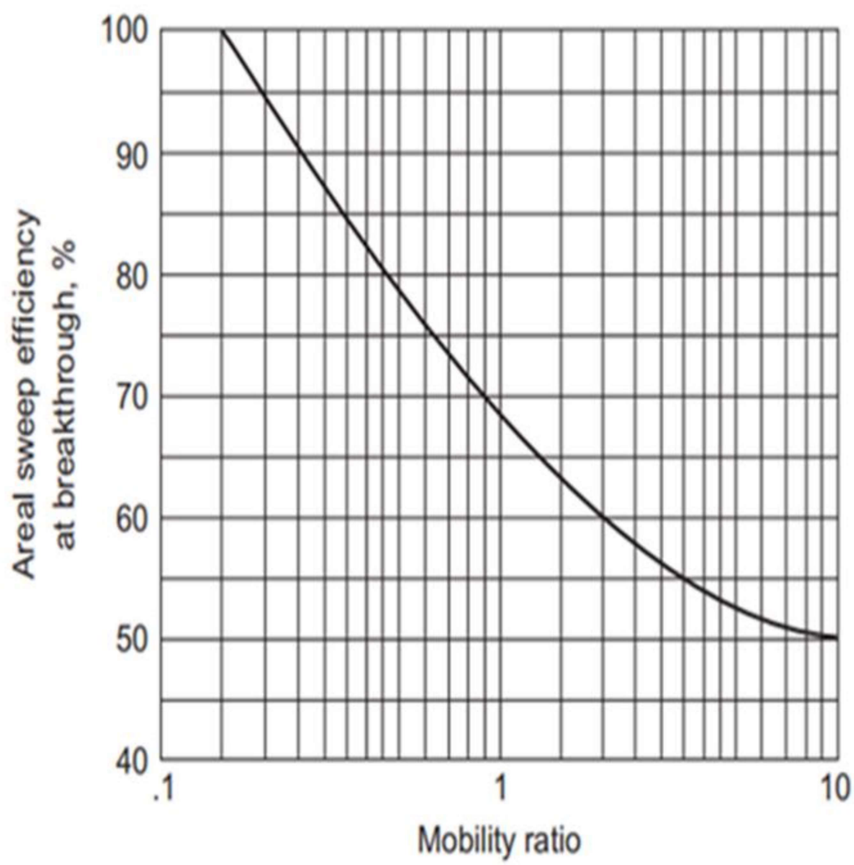


Figure 2. 8 :Areal sweep efficiency at breakthrough. (Permission to publish by the Society of Petroleum Engineers). [1]

2. 7.2 Fluid Infectivity

- Injection rate is a key economic variable that must be considered when evaluating a waterflooding project.
- empirical methods for estimating water injectivity for regular pattern floods have been proposed by Muskat (1948) and Deppe (1961). The authors derived their correlations based on the following assumptions:
  - I. Steady-state conditions.
  - II. No initial gas saturation.
  - III. Mobility ratio of unity.

Water injectivity is defined as the ratio of the water injection to the pressure difference between the injector and producer, or:

$$I = \frac{i_w}{\Delta p} \qquad (2.9)$$

where:
$I =$ injectivity . bbI/day/psi
$i_w =$ injection rate. bbI/day
$\Delta p =$ difference between injection pressuer and producting well bottom hole flowing pressuer.

When the injection fluid has the same mobility as the reservoir oil (mobility ratio M=1), the initial injectivity at the start of the flood is referred to as Ibase, or

$$I_{base} = \frac{i_{base}}{\Delta p_{base}} \qquad (2.10)$$

$where$:
$I_{base} = inital (base) water\ injection\ rate. bbI/day$
$\Delta p_{base} = intial\ (base) pressuer\ difference\ between\ injector\ and\ producor.$

- For a five-spot pattern that is completely filled with oil, i.e., Sgi = 0, Muskat(1948) proposed the following injectivity equation:
- Several studies have been conducted to determine the fluid injectivity at mobility ratios other than unity. All of the studies concluded the following:
  - ❖ At favorable mobility ratios, i.e., M < 1, the fluid injectivity declines as the areal sweep efficiency increases.
  - ❖ At unfavorable mobility ratios, i.e., M > 1, the fluid injectivity increases with increasing areal sweep efficiency.

- Caudle and Witte (1959) used the results of their investigation to develop a mathematical expression that correlates the fluid injectivity with the mobility ratio and areal sweep efficiency for five-spot patterns. which is defined as the ratio of the fluid injectivity at any stage of the flood to the initial (base) injectivity.

$$I_{base} = \frac{0.003541\ \mathrm{h\ k\ k_{ro}} \Delta \mathrm{P_{base}}}{\mu o \left[\ln \frac{d}{rw} - 0{:}619\right]} \tag{2.11}$$

$$\left(\frac{i}{\Delta p}\right)_{base} = \frac{0.003541\ \mathrm{h\ k\ k_{ro}}}{\mu o \left[\ln \frac{d}{rw} - 0{:}619\right]} \tag{2.12}$$

where:
i_{base} = base (initial)water injection rate. bbl/day
h = net thickness. ft
k = absolute permeability. md
k_{ro} = oil relative permeability as evaluated at Swi
Δp_{base} = base (initial)pressure difference. psi
d = distance between injector and producer. ft
r_w = wellbore radius. ft

$$\gamma = \frac{\text{Fluid injectivity at any stage of the flood}}{\text{Base initial ð Þ fluid injectivity}} \tag{2.13}$$

$$\gamma = \frac{\left(\frac{i_w}{\Delta p}\right)}{\left(\frac{i}{\Delta p}\right)} \tag{2.14}$$

- The two possible scenarios for the practical use of Equation follow:
- Scenario 1: Constant Injection Pressure and Variable Injection Rate.
- Scenario 2: Constant Injection Rate and Variable Injection Pressure.

2. 7.3 Effect of Initial Gas Saturation

In solution-gas-drive reservoir. The gas saturation is usually present in the reservoir, when the waterflooding, it is necessary to inject water equal to the volume of the pores occupied with free gas before oil production and the volume of this water is called (fill-up volume).

During waterflooding, a portion of the free gas usually will be displaced by (the leading edge of the oil bank), cause (mobility ratio) between the displacing oil and the displaced gas, and this occurs if the initial saturation of the gas has reached critical saturation.

The increase in oil saturation in (oil bank) equals the decrease in the initial saturation of the gas, and oil saturation in (oil bank) is a result of the water displacing oil from (water zone). The increase in oil saturation in (oil zone) will not be called (oil re-saturation effect). operation of displace called (gas fill up).

With continued water injection, the leading edge of the oil bank reaches the producing well.

Craig, Geffen, and Morse (1955) developed a methodology that is based on dividing the flood performance into four stages. The method, known as the CGM method after the authors.

1. Start—interference

2. Interference—fill-up

3. Fill-up—water breakthrough

4. Water breakthrough—end of the project

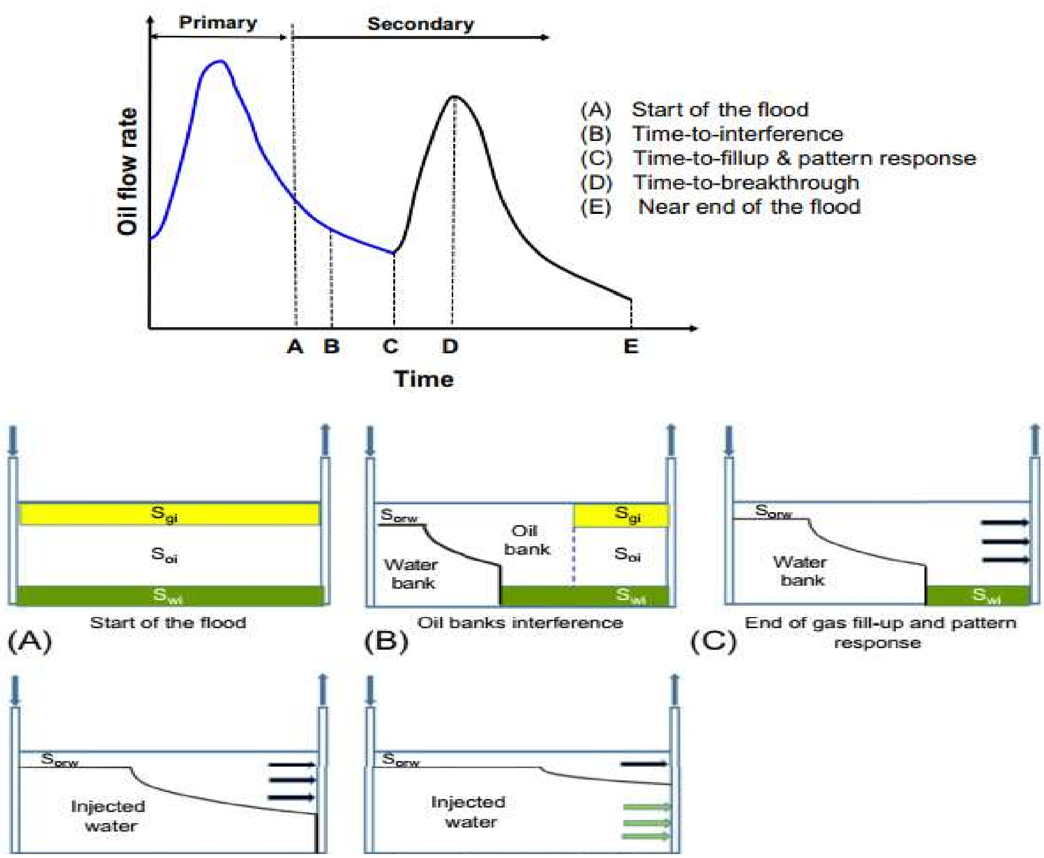


Figure 2. 9 Time-sequence of primary and secondary development stages.[1]

2. 7.4 Impact of Water Fingering and Tonguing

In thick, dipping formations containing heavy viscous oil, water tends to advance as a “tongue” at the bottom of the pay zone. with gas will overrun the oil due to gravity differences unless stopped by a shale barrier within the formation or by a low overall effective vertical permeability. In linear laboratory experiments, it was observed that the fluid interface remains horizontal and independent of fluid velocity when the viscosities of the two phases are equal. If the oil and water have different viscosities, the original horizontal interface will become tilted. Dake (1978) developed a gravity segregation model that allows the calculation of the critical water injection rate icrit that is required to propagate a stable displacement.. Dake introduced the two parameters, the Dimensionless Gravity Number “G” and the End-point Mobility Ratio M*, that can be used to define the stability of displacement.

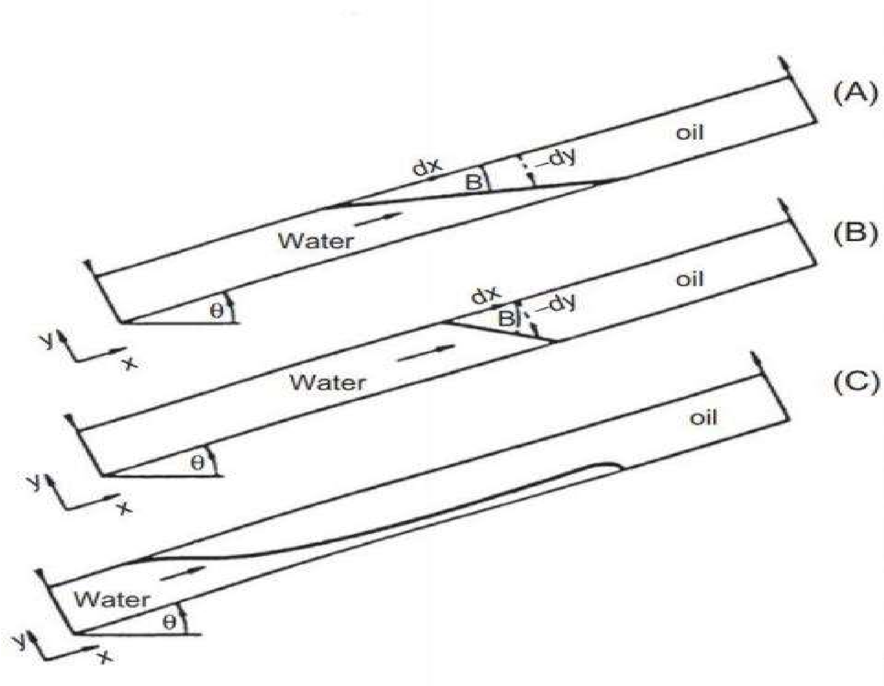


Figure 2. 10: Stable and unstable displacement1- M* > 1 * G > (M* – 1) stable * G < (M* – 1) unstable 2-M* = 1 This is a very favorable condition 3- M* < 1 unconditionally stable.[1]

- Dimensionless gravity number:

$$G = \frac{7.853\times10^{-6} k k_{rw} A(\rho_w - \rho_o)\sin(\theta)}{i_w \mu_w} \quad (2.15)$$

- End-point mobility ratio:

$$M^* = \frac{(krw)_{@Sorw}}{(krw)_{@Swi}} \frac{\mu o}{\mu w} \quad (2.16)$$

the critical flow rate:

$$i_{crit} = \frac{7.853\times10^{-6} k k_{rw} A(\rho_w - \rho_o)\sin(\theta)}{\mu_w (M^* - 1)} \quad (2.17)$$

where:
k = absolute permeability, md
krw = relative permeability to water as evaluated at Sorw
A = cross-sectional area
ρw = water density, lb/ft3
icrit = critical water injection rate, bbl/day
krw = relative permeability to water @ Sor
μw = water viscosity, cp
k = absolute permeability, md
θ = dip angle in radians, i.e., (π θ/180)

2. 8 Vertical sweep efficiency

The vertical sweep efficiency, EV, is defined as the fraction of the vertical section of the pay zone that is the injection fluid. This particular sweep efficiency depends primarily on:

(1) the mobility ratio .

(2) total volume injected.

because of nonuniform vertical layers permeability, any injected fluid will tend to move through the reservoir with an irregular front. In the more high permeability layers of reservoir , the injected water will travel more rapidly than in the less permeable zone. The degree of permeability variation is considered by far the most significant parameter influencing the vertical sweep efficiency.

2. 8.1 problems and solutions

To calculate the vertical sweep efficiency, the following three issues must be addressed:

1. How to properly describe and define the vertical permeability variations in mathematical terms

2. How to determine the minimum number of layers that are sufficient to model the injected water displacement performance and the recovery of the crude oil

3. How to assign the proper average rock properties for each layer after layering upscaling (called the zonation problem)

solutions :

1- Reservoir Vertical Heterogeneity :
Reservoir Heterogeneity is then defined as a variation in reservoir properties , Particularly permeability . Dykstra and Parsons (1950) introduced the concept of the permeability variation V, which is designed to describe the degree of heterogeneity within the reservoir. The value of this uniformity coefficient ranges between zero for a completely homogeneous system and one for a completely heterogeneous system

2- Minimum Number of Layers :
Based on a computer study, Craig (1971) outlined some guidelines for selecting the minimum number of layers needed to predict the performance of a reservoir under waterflooding operation.

3- The Zonation Problem :
In waterflooding calculations, usually to divide the reservoir into a number of layers that have equal thickness but different permeabilities and porosities. Traditionally, two methods are used in the industry to assign the proper average permeability for each layer:

a- the positional method :

The positional method describes layers according to their relative location within the vertical rock column. This method assumes that the injected fluid remains in the same elevation (layer) as it moves from the injector to the producer. average permeability in a selected layer (elevation) should be calculated by applying the geometric-average permeability as given by Equation:

$$k_{avg} = exp\left[\frac{\sum_{i=1}^{n} hi \ln(ki)}{\sum_{i=1}^{n} hi}\right] \quad (2.18)$$

If all thickness is equal

$$k_{avg} = (k_1 k_2 k_3 \ldots k_n)^{1/n} \quad (2.19)$$

a- the permeability ordering method :

The permeability ordering method is essentially based on the Dykstra and Parsons (1950) permeability sequencing technique. The core analysis permeabilities are arranged in a decreasing permeability order and a plot. The probability scale is divided into equalpercent increments with each increment representing a layer. The permeability for each layer is assigned to the permeability value that corresponds to the midpoint of each interval.

2. 8.2 Calculation of Vertical Sweep Efficiency

Two methods :

I. Stiles' method
II. the Dykstra–Parsons method.

These two methods assume that the reservoir is composed of an idealized layered system, as shown schematically in Figure 2.12 . The layered system is selected based on the permeability ordering approach with layers arranged in order of descending permeability. The common assumptions of both methods are:

1- No cross-flow between layers
2- Immiscible displacement
3- Linear flow
4- The distance water has traveled through each layer is proportional to the permeability of the layer
5- Piston-like displacement

The basic idea used in Stiles' method and the Dykstra-Parsons method is to determine the frontal position in each layer at the time water breakthrough occurs in successive layers.If the flow capacity of each layer is defined by the product of permeability and thickness, i.e., kh, then the water and oil flow rates from all layers can be calculated to yield the producing water–oil ratio.

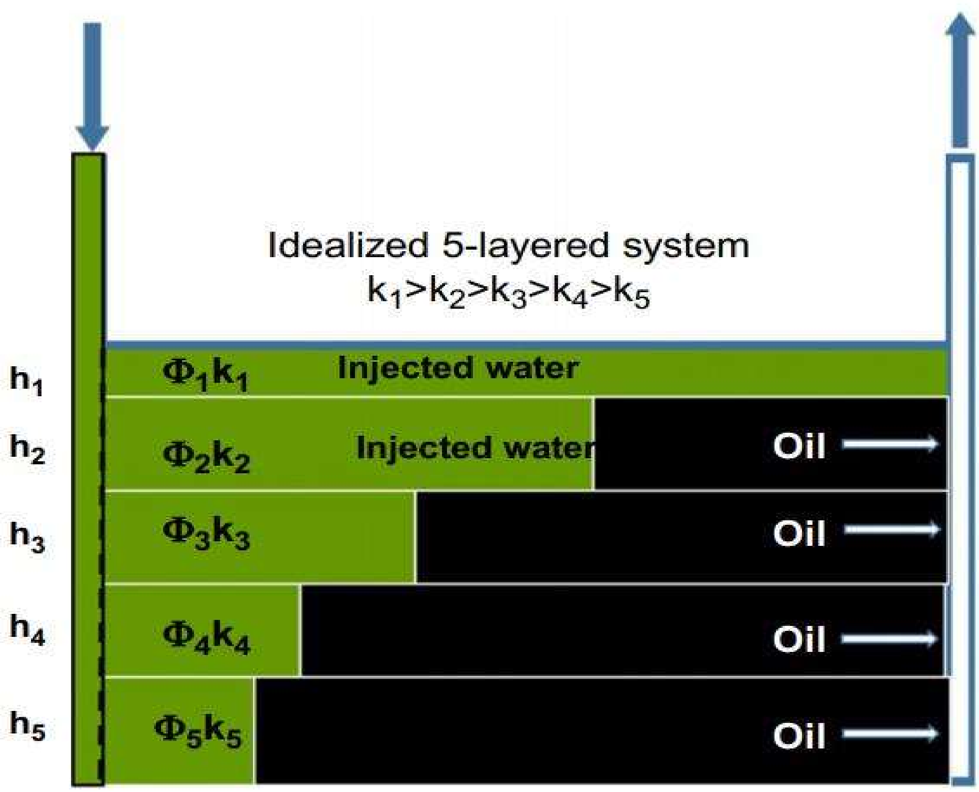


Figure 2. 11: Idealized pattern layered system.[1]

I. Stiles' Method :

Stiles assumes that in a layered system, the water breakthrough occurs in a sequence that starts in the layer with the highest permeability. Stiles suggested that the vertical sweep efficiency can be calculated from the following expression.

$$Ev = \frac{ki\sum_{j=1}^{i} hj + \sum_{j=i+1}^{n} (kh)j}{kiht} \tag{2.20}$$

If the values of the porosity vary between layers:

$$Ev = \frac{\left(\frac{k}{\emptyset}\right)i\sum_{j=1}^{i} (\emptyset h)j + \sum_{j=i+1}^{n} (kh)j}{\left(\frac{k}{\emptyset}\right)i\sum_{j=1}^{n} (\emptyset h)j} \tag{2.21}$$

where

i = breakthrough layer, i.e., $i = 1,2,3, \ldots n$
n = total number of layers
E_V = vertical sweep efficiency
h_t = total thickness, ft
h_i = layer thickness, ft

Stiles also developed the following expression for determining the surface water–oil ratio as breakthrough occurs subsequently on layer-by-layer:

$$WOR_S = A\left[\frac{\sum_{j=1}^{i} (kh)j}{\sum_{j=i+1}^{n} (kh)j}\right] \tag{2.22}$$

With

$$A = \frac{Krw}{Kro}\frac{\mu o}{\mu w}\frac{Bo}{Bw} \tag{2.23}$$

where

WOR_s = surface water-oil ratio, STB/STB
k_{rw} = relative permeability to water at S_{or}
k_{ro} = relative permeability to oil at S_{wi}

II. The Dykstra–Parsons Method :

de Souza and Brigham (1981) grouped the vertical sweep efficiency curves for **(0 ≤M ≤ 10 and 0.3. ≤ V ≤0.8)** into one curve ‘in Figure 2-13 ’ The authors used a combination of WOR, V, and M to define the correlation parameter Y :

$$Y = \frac{(WOR+0.4)(18.948-2.499V)}{(M-0.8094V+1.137)10^{x}} \quad (2.24)$$

With

$$x = 1.6453V^{2} + 0.935V - 0.6891 \quad (2.25)$$

Fassihi (1986) proposed the following non-linear function, which can be solved iteratively for the vertical sweep efficiency EV:

$$a_1 E_V^{a2}(1 - Ev)^{a3} - Y = 0 \quad (2.26)$$

Where:

$a_1 = 3.334088568$
$a_2 = 0.7737348199$
$a_3 = 1.225859406$

The Newton–Raphson method is perhaps the appropriate technique for solving Equation . To avoid the iterative process, the following expression could be used to estimate the vertical sweep efficiency using the correlating parameter Y:

$$Ev = a1 + a2\ln(Y) + a3\,[\ln(Y)]^{2} + a4[\ln(Y)]^{3} + \frac{a5}{\ln(Y)} + a6Y \quad (2.27)$$

With the coefficients a_1 through a_6 as given by:

$a_1 = 0.19862608$ $a_2 = 0.18147754$
$a_3 = 0.01609715$ $a_6 = 2.7688363 \times 10^{-4}$
$a_5 = -4.2968246 \times 10^{-4}$ $a_4 = -4.6226385 \times 10^{-3}$

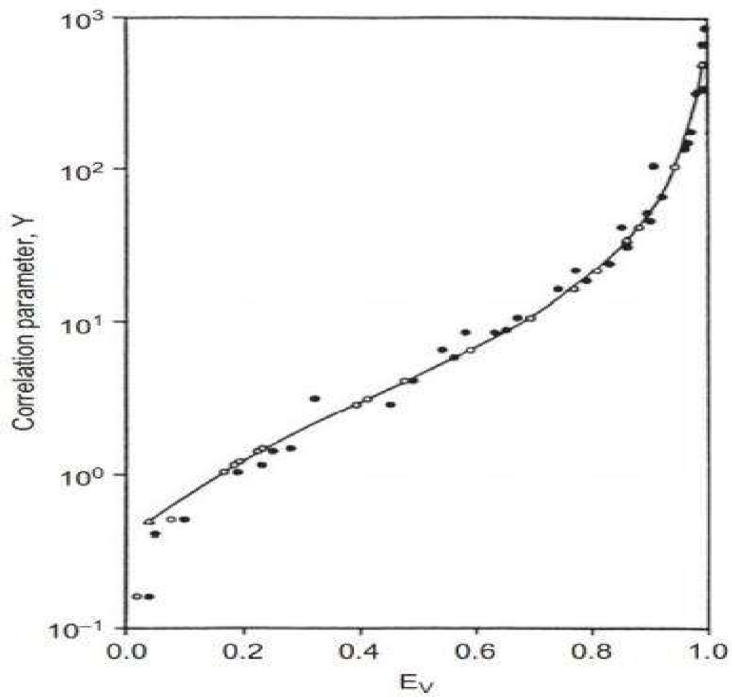


Figure 2. 12: EV versus the correlating parameter Y.[1]

2. 9 Methods of predicting recovery performance for layered reservoir

including:

Simplified Dykstra-Parsons Method :Dykstra and Parsons (1950) proposed a correlation for predicting waterflood oil recovery that uses the mobility ratio, permeability variation, and producing water–oil ratio as correlating parameters. Johnson (1956) developed a simplified graphical approach for the Dykstra and Parsons method that is based on predicting the overall oil recovery “R” at water–oil ratios of 1, 5, 25, and 100 bbl/bbl in in Figure 2.13

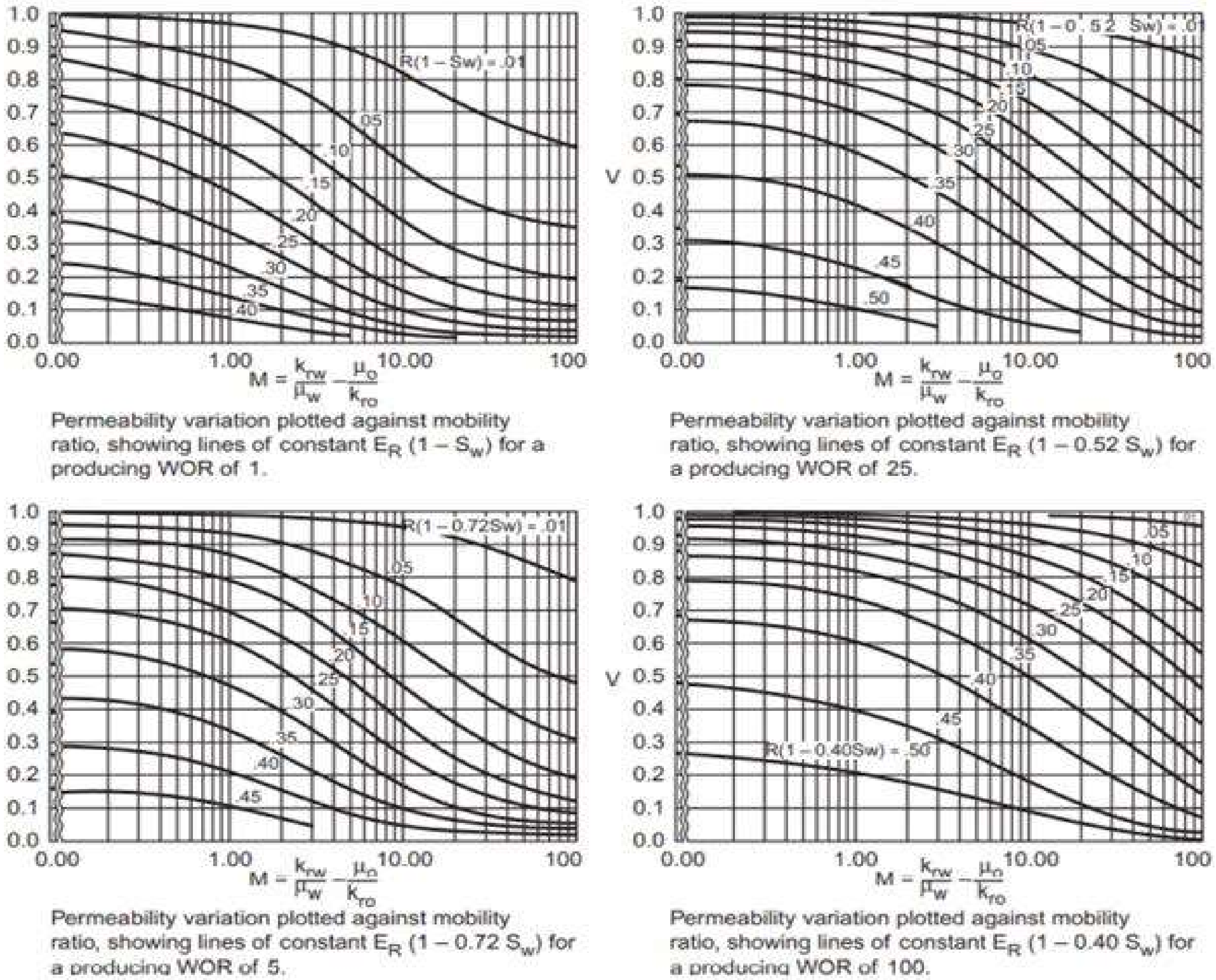


Figure 2. 13: Simplified Dykstra and Parsons curves.[1]

1- Modified Dykstra-Parsons Method : Felsenthal, Cobb, and Heuer (1962) extend the work of Dykstra and Parsons to account for the presence of initial gas saturation at the start of flood. Assuming a constant water injection rate iw, the method is summarized in the steps in reference .

2- Craig-Geffen-Morse Method :

With the obvious difficulty of incorporating the vertical sweep efficiency in oil recovery calculations, Craig et al. (1955) proposed performing the calculations for only one selected layer in the multilayered system. The selected layer, identified as the base layer, is considered to have a 100% vertical sweep efficiency. The performance of each of the remaining layers can be obtained by “sliding the timescale” , the method is summarized in the steps in reference .

In addition to methods of predicting water flood performance, there are empirical prediction methods that provide estimates of ultimate waterflood recovery factors. Based on 73 sandstone reservoirs, Guthrie and Greenberger (1963) developed an empirical expression that correlates the recovery factor with Permeability (k) md , Porosity (ϕ) , Oil viscosity (μo) cp , Connate water saturation Swc , Reservoir thickness (h) ft :

$$RF = 0.2719\log(k) + 0.2556\,S_{WC} - 0.1355\log(\mu o) - 1.538\emptyset - 0.0008488h + 0.11403 \qquad (2.28)$$

Arps (1967) statistically correlated the recovery factor as a function of the initial pressure pi and pressure at depletion pa by the following relationship:

$$RF = 54.898\left[\frac{\emptyset(1-Swi)}{Boi}\right]^{0.0422}\left[\frac{\mu wi\ k}{\mu oi}\right]^{0.077}(Sw)^{-0.1903}\left(\frac{P1}{Pa}\right)^{-0.2159} \qquad (2.29)$$

2.10 Wettability:

To understand the fundamental concept behind wettability, we first introduce its definitions. Wettability has been variously defined in the literature but can be essentially summarized as : • The relative ability of a fluid to spread on a solid surface in the presence of another fluid, for example, water spreading more than the oil or vice versa • The tendency of surfaces to be preferentially wet by one fluid phase, for example, water or oil preferentially wetting • The tendency of one fluid of a fluid pair (oil-water) to coat the the surface of a solid spontaneously. Considering all these definitions, it is clear that whichever way wettability is addressed, it basically means that in a multiphase situation, one of the fluid phases (oil or water) has a greater degree of affinity toward the solid surface of the reservoir rock. [2]

2.10.1 Measurement of reservoir rock wettability

Reservoir wettability can be evaluated by two different groups of methods: qualitative and quantitative. In qualitative methods, wettability is indirectly inferred from other measurements,such as capillary pressure curves or relative permeability curves. However, relative permeability curve methods are suitable only for discriminating between strongly water-wet and strongly oil-wet cores. while quantitative methods are direct measurement methods, where the wettability is measured on actual rock samples using reservoir fluid samples and wettability is reported in terms of a certain wettability index, signifying the degree of water, oil wetness, or intermediate wetness. These direct quantitative methods include contact angle measurement, the Amott test, and the U.S. Bureau of Mines (USBM) wettability method. in this project will explain only contact angle.

2.10.1.1 Contact angle measurement

the contact angle, θ, measured through the denser fluid, defines which fluid wets the solid surface.Young in 1807, showed that the droplet of a liquid will take a certain shape due to the interfacial tensions acting on it.

$$\sigma_{S1} + \sigma_{12}\, cos\theta = \sigma_{S2} \qquad (2.30)$$

$$or\ \theta = \cos^{-1}(\frac{\sigma_{S2} - \sigma_{S1}}{\sigma_{12}}) \qquad (2.31)$$

σs1= the tension force between Fluid 1 and the solid surface.

σs2= the tension force between Fluid 2 and the solid surface.

σ12= the tension force between Fluid 1 and Fluid 2. (as Figure 2-23)

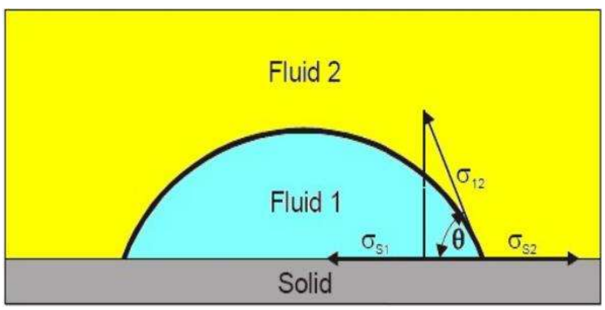


Figure 2. 14: contact angle with two fluids and solid.

when σs1 > σs2, cosθ = negative, θ > 90º, fluid 2 is the wetting phase.

When σs2 > σs1, cosθ = positive, θ < 90º, fluid 1 is the wetting phase.

When σs2 = σs1, cosθ = 0, θ = 90º, the surface is neutral wet.

for example fluid 1 = water ,fluid 2 = oil (as Figure 2-24)

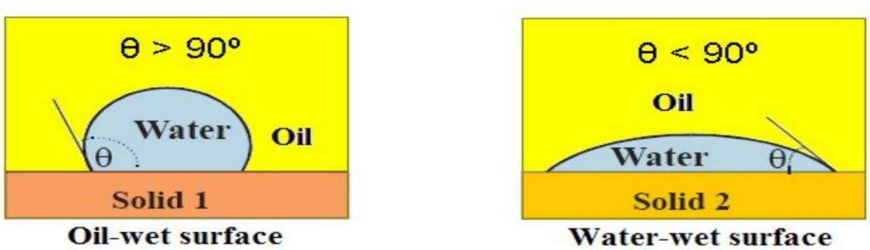


Figure 2. 15: oil wet vs water wet

2.10.2 Classification/types of wettability

A variety of wettability states exist for petroleum reservoirs, primarily depending on both reservoir fluid and rock characteristics . On a pore level, wettability in porous media has been classified as either homogeneous or heterogeneous. By definition, homogeneous means the entire rock surface has uniform wetting tendencies, whereas heterogeneous indicates distinct rock surface regions that exhibit different wetting tendencies.Radke et al. have stated that strongly water wet, strongly oil wet, and intermediate wet systems fall under the category of homogeneous, whereas fractional and mixed-wet systems fall under the category of heterogeneous.

2.10.2.1 Water Wet

In this wettability state, all pore surfaces of the rock have preference for the water phase rather than the hydrocarbon phase, and as a result of this condition, the gas and oil are contained in the centers of the pores.

2.10.2.2 Oil Wet

This wettability state is exactly the opposite of the water-wet state, that is, the relative positions of the hydrocarbons and water are reversed. It is believed that surface active asphaltenic components of the oil phase cause this wetting state.

2.10.2.3 Intermediate Wet

The definition of intermediate wettability state from a pore level standpoint is somewhat vague in that there is some tendency for both phases (oil and water) to have preference for the rock surface; however, if that tendency is equal, then this may be termed as neutral-wetting state or considered as a special category of intermediate wettability.

2.10.2.4 Fractional Wettability

Fractional wettability has been variously characterized as Dalmatian, speckled, or spotted because some of the pores are water wet, while others are oil wet, or, in other words, a portion of the rock is strongly water wet, while the rest is strongly oil wet. Jerauld and Rathmell state that Dalmatian wettability is where there are oil-wet and water-wet regions in the same pore.

2.10.2.5 Mixed Wettability

Mixed wettability was proposed by Salathiel in 1973, referring to a special type of fractional wettability in which the oil-wet surfaces form continuous paths through the larger pores. Salathiel, however, states that mixed wettability he introduced should be distinguished from the fractional wettability. Jerauld and Rathmell in their paper have introduced Prudhoe Bay oil field in Alaska as a large and prolific mixed-wet reservoir. However, they conclude that the wettability of Prudhoe Bay differs from the mixed wettability proposed by Salathiel because aspects of the wettability they studied are closer to Dalmatian wettability. [2]

2.10.3 Effect wettability on relative permeability

The wetting phase occupies the smaller pore openings and will affect the nonwetting phase permeability only to a limited extent. The nonwetting phase occupies the central or larger pore openings that a small nonwetting phase saturation will drastically reduce the wetting phase permeability .

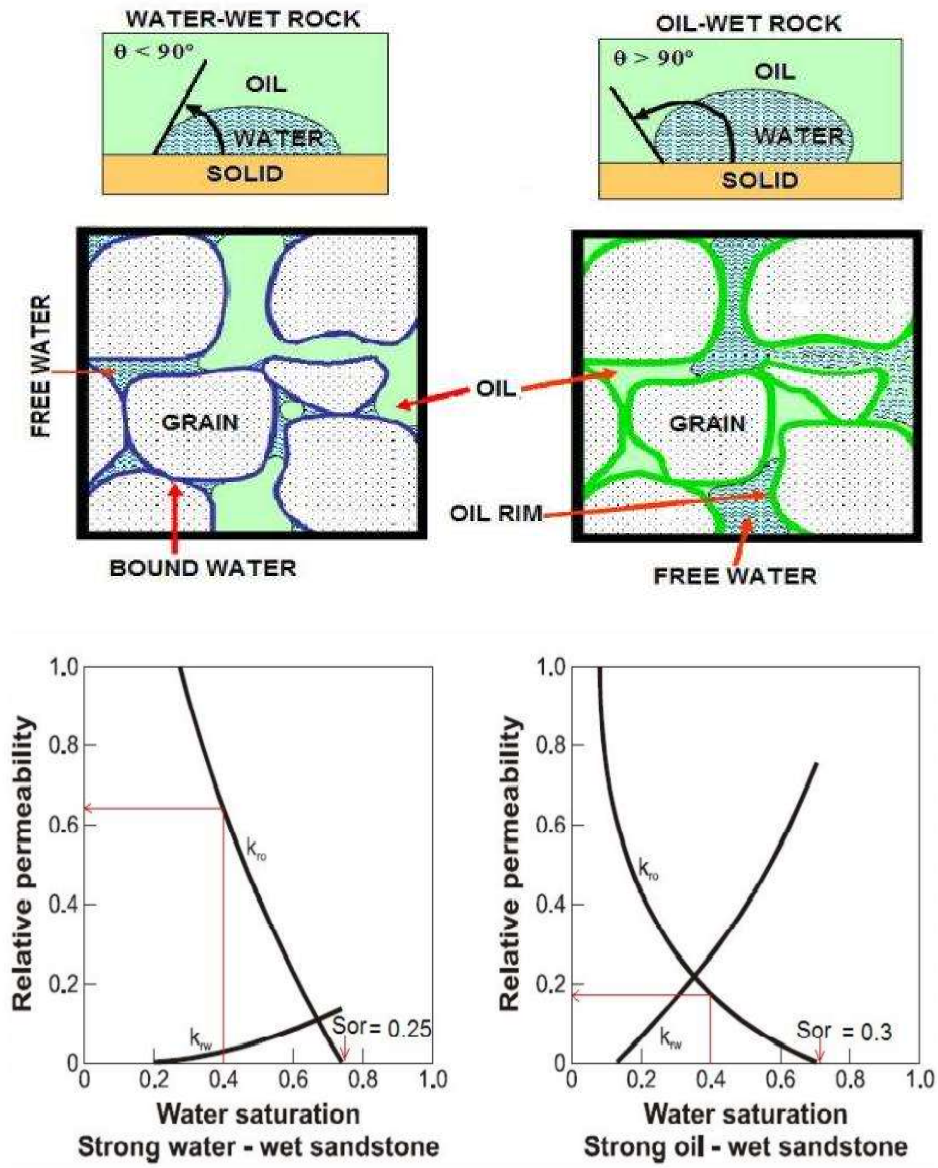


Figure 2. 16: Relationship between relative permeability and wettability [11]

CHAPTER THREE: METHODOLOGY

3. 1 Introduction

This chapter will display what we do to study, and we depend on two reservoirs, first it Synthetic Reservoir, this reservoir modeling will depending on correlations and on information approximated from the real reservoirs.

Another reservoir is A real case, is one of the most important oil fields border in southern Iraq. Adjacent to the Fauqi and Abu Ghirab oil fields common with Iran.
The 3D seismic data showed the structural and stratigraphic of the A real case field, where the results showed that the structure is an anticline fold with two structural domes, the northern culmination is shallower and less deformation.

A real case oil field is one of the most important field in southern of Iraq. The first exploration well BU-1 was drilled in June 1969 with total depth of 4298 m. real case field was discovered after the drilling of BU-1 well which proved the availability of commercial oil in Mishrif Formation, A real case Oilfield was brought into production in 1976.

To achieve study we do : data (acquisition, processing), modeling (static ,dynamic ,physics-rock) ,strategy and simulating (run cases) as shown Figure 3.1.so fig 3.1 show flow work Where there are four phases from the start of data collection through the creation of a reservoir modeling and then the development of the plan then simulation to reach the results.

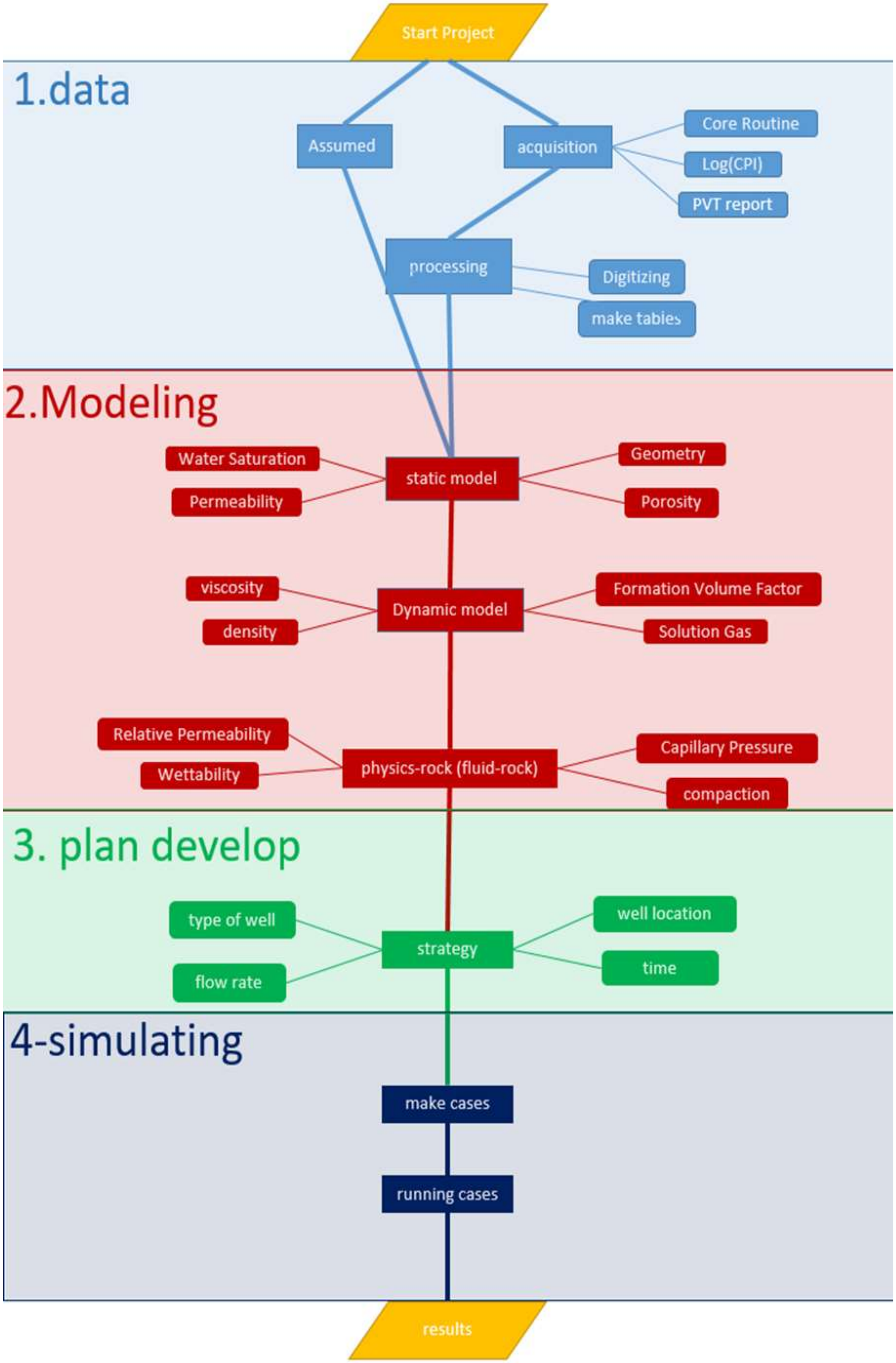


Figure 3. 1: flow chart for work

3. 2 Data used

We can divide two part one of them Synthetic Reservoir Model and other for buzurgan field.

3. 2.1 Virtual Reservoir Model

It's assumed reservoir , top of it at depth 12000 ft, has the following properties:

1- geometry and thickness : It's a regular shape, square at top and base have dimensions $(1000ft \times 1000\ ft \times 200ft)$ in (I, J and K) .

2- porosity = 0.2

3- permeability : the absolute permeability assumed as shown in table 3-1

layers	homogeneous permeability(md)	heterogeneous permeability 1 (md)	heterogeneous permeability 2 (md)
1	x=100 y =100 z=10	x=100 y =100 z=10	x=20 y =20 z=2
2	x=100 y =100 z=10	x=80 y =80 z=8	x=40 y =40 z=4
3	x=100 y =100 z=10	x=60 y =60 z=6	x=60 y =60 z=6
4	x=100 y =100 z=10	x=40 y =40 z=4	x=80 y =80 z=8
5	x=100 y =100 z=10	x=20 y =20 z=2	x=100 y =100 z=10

Table 3. 1: assumed permeability in Synthetic Reservoir Model

4- PVT and reservoir condition: the reservoir type is heavy oil (no-gas phase) with API = 20, Maximum pressure = 6000 psi, bubble pressure =1160.3 psi, temperature = 170 deg F, datum level = -12230ft, water salinity =8000 ppm .

5- Wettability and relative permeability: oil-wet, water-wet, intermediate-wet, to modeling wettability, need the information of relative permeability as shown in table 3-2. [3]

	Water-wet	intermediate-wet	Oil-wet
Swi	0.2	0.2	0.2
Sor	0.1	0.2	0.3
Ew=Krw(Sor)	0.6	0.8	0.8
Eo=Kro(Swi)	0.8	0.8	0.5
Nw	3	2	3
No	2	2	3

Table 3. 2: information about the relative permeability needed to model wettability

6- development strategies: includes: completion operation : automated design, constant number of well = 36 with 3 types of regular pattern : seven-spot , direct line , five-spot, maximum production flow rate is 10000 STB/day for each well (theoretical) with bottom hole pressure is 2000 psi and maximum injection flow rate 11000 STB/day with bottom hole pressure is 8000 psi .

3. 2.2 A real field

the top of layer which is contain oil : 3780 m and base is 4184 m, and has the following properties:

1- geometry : the real case Field have two dome, south dome and north dome and have seven layers , the oil in layer mb21, and we can see a contour map for this layer in figure 3-2, also there are depth Penetration of wells to each layer, in Appendix A

1- The Range of Porosity: the porosity of a real case Field we got it from logs (CPI) can see it in Appendix A, but can take min. and max as shown in table 3-3.

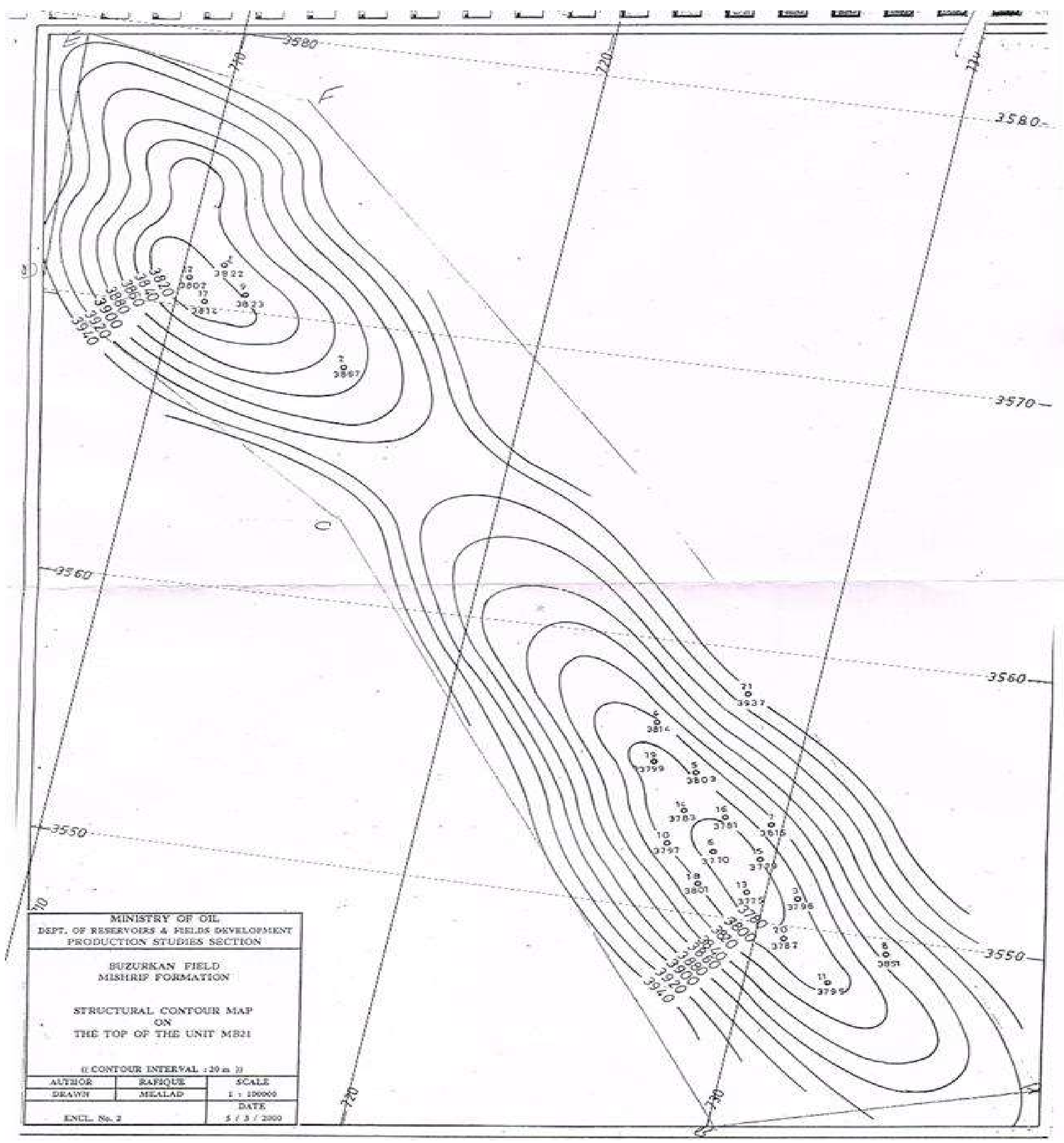


Figure 3. 2: contour map for layer mb21 in a real case Field.

2- The Range of Porosity: the porosity of a real case Field we got it from logs (CPI) can see it in Appendix B, but can take min. and max as shown in table 3-3.

	Mb21-mc1	Mc1-Mc2	Mc2- RUMAILA
min	0.06	0.03	0.09
max	0.2	0.12	0.14

Table 3. 3: Range of Porosity for Buzurgan Field

3- Range of Permeability : the permeability of Buzurgan Field we got it from a relationship porosity-permeability it from can see it in Appendix A, but can take min. and max as shown in table 3-4.

	Mb21−mc1	Mc1−Mc2	Mc2− RUMAILA
Min.	2.7 md	0.76 md	2.6 md
Max.	58.6 md	14.5 md	40.1 md

Table 3. 4: Range of Permeability for Buzurgan Field

4- PVT and reservoir condition: the API = 23.5 and depending on the PVT of several wells and temperature = 233.6 F , we can shown some properties in Figure 3-3.

5- Wettability: assumed depending on production data, type: water-wet.

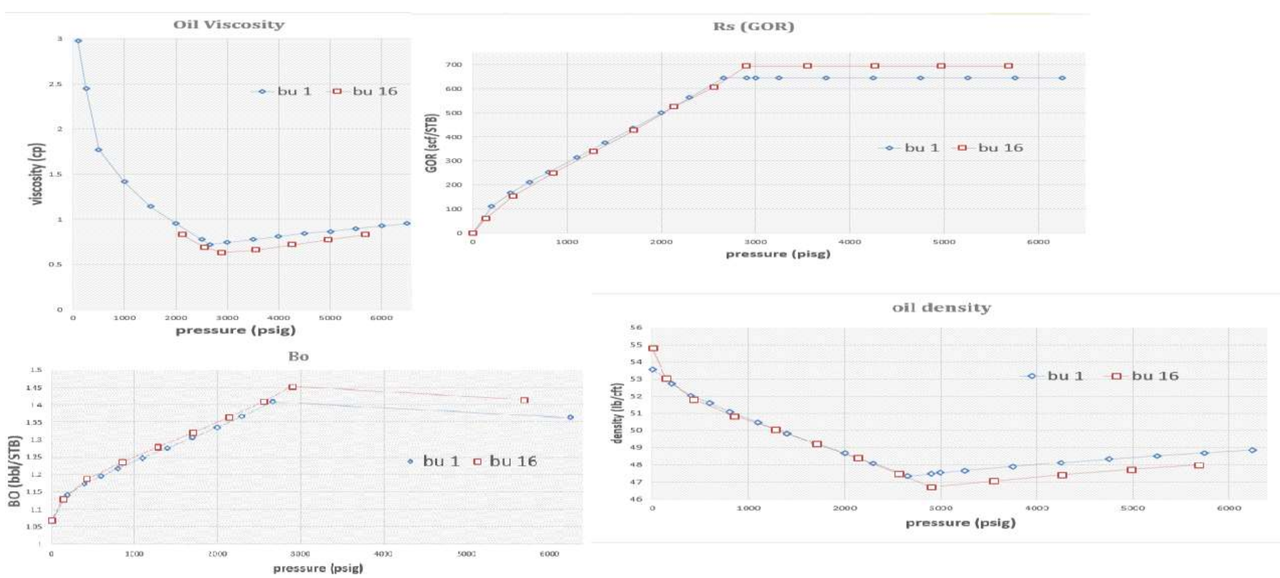


Figure 3. 3: properties for Bu-16 and Bu-1 in Buzurgan Field

6- Development strategies: includes: completion operation: perforation at layer m21 from 10- 50 m, number of well = 21, with production data in Appendix A.

3. 3 Software used

The software used in this project includes the following programs:

1- Didger: is the most advanced digitising software program available, with numerous sophisticated features and an easy-to-use and intuitive user interface ,you can use Didger to precisely convert paper maps, graphs, aerial photographs, or any other plotted information into a versatile digital format that you can use with other software.

2- PVTP: is a tool for the production or reservoir engineer to use to predict the effect of process conditions on the composition of hydrocarbon mixtures with accuracy and speed. The compositional behaviour of complex mixtures including gas mixtures, gas condensates, retrograde condensates, volatile oils and black oils can be interpreted and predicted with confidence. The PVT package can be used as a stand-alone analytical tool, or can be used to generate tables of fluid properties, reduced compositions or matched parameters (Tc, P, ω Volume Shift Parameters and Binary Interaction Coefficients) for other applications such as reservoir simulators, well analysis packages, up to production process simulator. As the industry integrates their reservoir, production wells, surface gathering network and process models together having consistent PVT characterizations that can be used at all levels in the system is fundamental. A reservoir engineer will typically have a characterization with up to five pseudos, while the process engineer wants to model each component. PVTP enables a representative characterization to be developed for both engineering needs. the ability to manipulate and predict compositional changes using two distinct methodologies, 1) The Black Oil Model 2) The Equation of State Model - EoS.

3- Petrel: is a software platform used in the exploration and production sector of the petroleum industry. It allows the user to interpret seismic data, perform well correlation, build reservoir models, visualize reservoir simulation results, calculate volumes, produce maps and design development strategies to maximize reservoir exploitation. Risk and uncertainty can be assessed throughout the life of the reservoir. Petrel is developed and built by Schlumberger. Petrel software includes black oil model and other models.The black oil model deals with oil,gas and water as mass components and only the gas allowed to dissolve in oil and water. There are many reservoir processes that can be modelled using the black oil model include primary depletion, waterflooding and immiscible gas injection.Schlumberger Limited is an oilfield services company.Schlumberger employees represent more than 140 nationalities working in more than 120 countries.Schlumberger has four principal executive offices located in Paris, Houston, London, and The Hague.Schlumberger is incorporated in Willemstad, Curaçao as Schlumberger N.V.and trades on the New York Stock Exchange, Euronext Paris, the London Stock Exchange and SIX Swiss Exchange.Schlumberger is a Fortune Global 500 company, ranked 287 in 2016,and also listed in Forbes Global 2000, ranked 176 in 2016.

4- ECLIPSE: is Schlumberger reservoir simulation software.The ECLIPSE doesn't have one interface, instead of this, there are solvers and software for preprocess and postprocess. They can be launched with ECLIPSE launcher or ECLIPSE OFFICE. ECLIPSE also integrated with Petrel and can be run from Petrel interface.ECLIPSE simulator suite consists of two separate solvers: ECLIPSE 100 for black oil modeling with gas condensate options; ECLIPSE 300 for compositional and thermal modeling.There are auxiliary software packages for data preparation and postprocessing of the simulation results:CLIPSE OFFICE (preparation and analysis of model data),FrontSim (streamlines modeling),VFPI (software for the account of the loss of friction in the wellbore),PSEUDO (generator of three-dimensional pseudofunction of relative permeabilities and capillary pressure)SCAL (core data analysis),SCHEDULE (setting up the production history),PVTi (generating PVT data from the laboratory analysis of oil and gas samples),FLOVIZ (an interactive 3D visualization).

3. 4 Mythology used

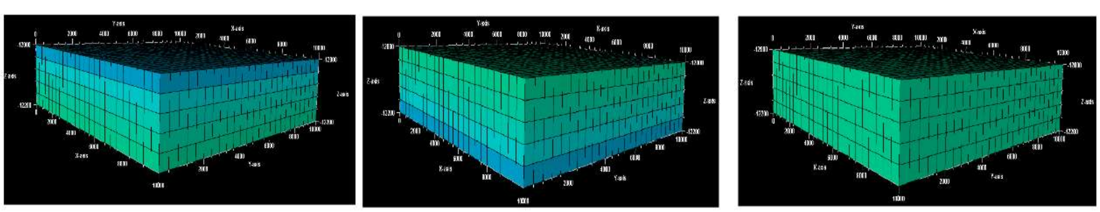
To simulated reservoir, need to make:

- Static model: is modeling rock properties such as porosity, permeability…etc which does not change with time.
- Fluids modeling (Dynamic model): is modeling reservoir fluids properties such as formation volume factor, viscosity, density, solution gas...etc and all these properties change with pressure which is change with time
- Rock-Fluid properties "Rock Physics": uses in reservoir engineering and simulation to describe multiphase flow in the reservoir. There are three rock-fluid properties, wettability, capillary pressure, and relative permeability.

  Development strategies: it's Set plans, includes the number of wells, location of wells, type of drive (primary, secondary, tertiary), and determine the type of well (injector or producer), flow rate to wells.

3. 4.1 Virtual Reservoir Model

1- Static model: convert reservoir to grid blocks, (25 * 25 * 5) blocks in (i,j,k) as shown in figure 3-4, then distribution porosity and permeability on blocks , the permeability will distribution on blocks as shown in Table 3-١ ,this means there are three assumed types that will study in this project to test effect change of permeability on wettability.



heterogeneous permeability increase with depth | heterogeneous permeability decrease with depth | homogeneous permeability

Figure 3. 4: Permeability Distribution for Virtual Reservoir Model

2- Fluid modeling (Dynamic model): depending on section "3.2.1 Data of Synthetic Reservoir Model /4- PVT and reservoir condition" and correlation, can modeling $Bo.\ Rs\ .\mu o.\rho o$.as shown in figure 3.5.

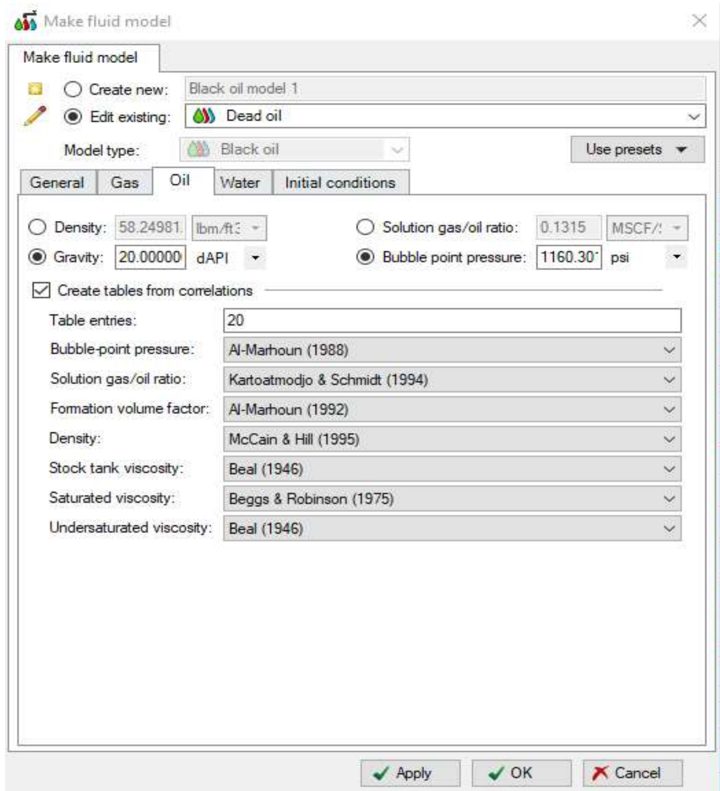


Figure 3. 5: choosing correlations for modeling

3- Rock-Fluid properties "Rock Physics": wettability is one of the properties that affect on relative permeability so we will depend on table 3-2 to modeling relative permeability as shown in Figure 3-6.

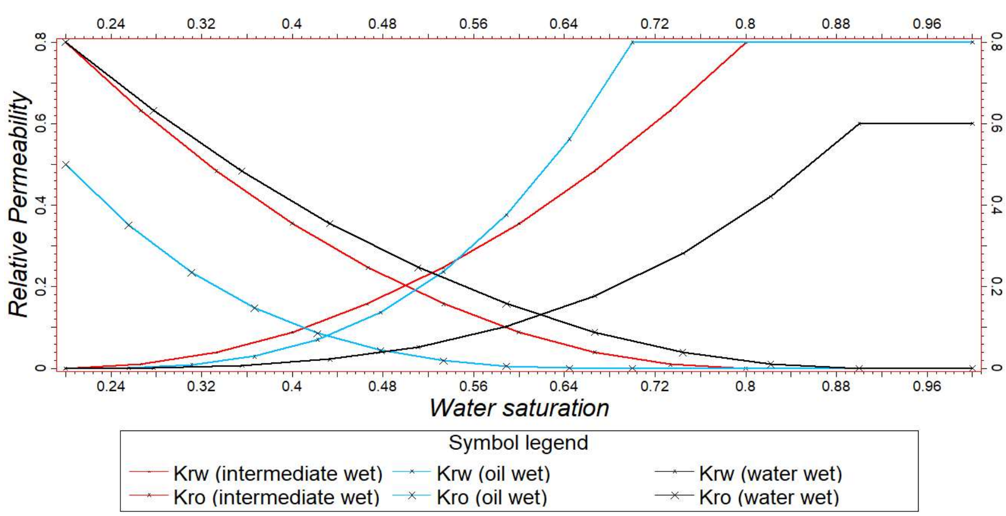


Figure 3. 6: curves of relative permeability affected by different wets

4- Development strategies: the strategy is waterflooding with three types of patterns: direct line, five-spot, seven-spot, show in Figure 3-7.with a constant number of wells and a constant flow rate.

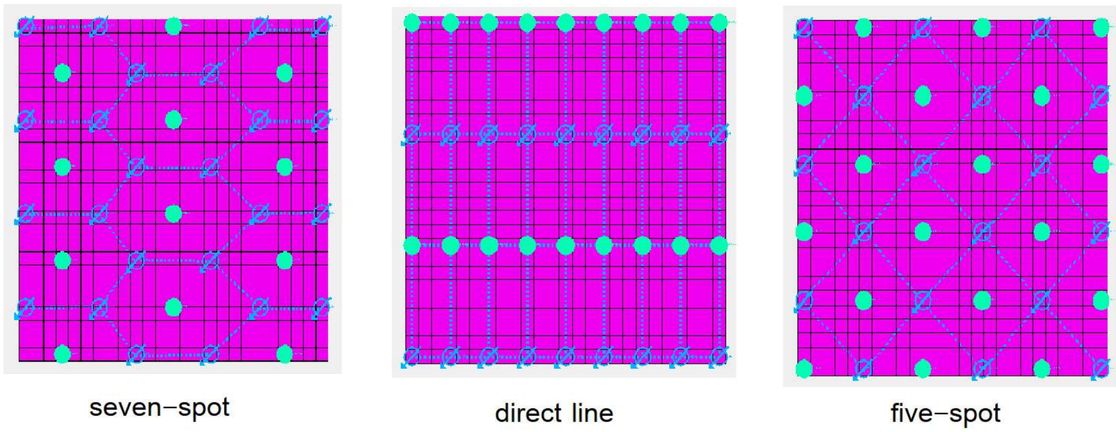


Figure 3. 7: patterns for Virtual Reservoir Model

3. 4.2 A real model

Before modeling real case field, need to analyzing, correcting and Preparing data, and this can achievable by:

a- Digitizing: convert shape (contour map, logs) to numbers, for contour map numbers represent (x,y,z),while logs numbers represent (value of property, depth) and this achievable by Didger and Surfer 12.

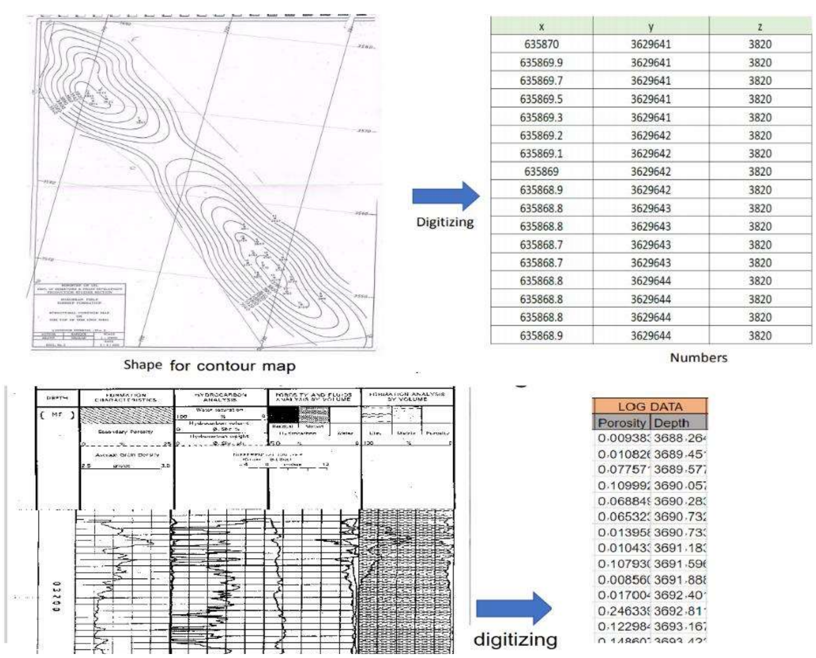


Figure 3. 8: digitizing for contour map and log (CPI)

b- find relationship porosity-permeability : to modeling permeability, we need to input it in petrel as a correlation with porosity and can find this relationship by plotting porosity vs permeability then find the equation of best fitline by excel , shown Appendix A.

c- Correcting: use PVT data for the real case field with use correlations for Generation of PVT tables for use in simulation in petrel, and this can achievable by PVTP software.

d- Preparing: to preparing data we put it as tables or in form (text, vol.) or convert equation as expression to can import it in petrel. after processing data, we do :

1- Static model: first, convert the field to grids blocks by using a contour map and depth of the top of each layer, then input data of porosity which is getting it from logs (CPI), and permeability from relationships, then use upscaling to find the averaged value of property to 3D grid cells that the wells penetrate, then the values for each cell along the well trajectory can be interpolated between the wells in the 3D grid. The result is a grid with Property values for each cell.

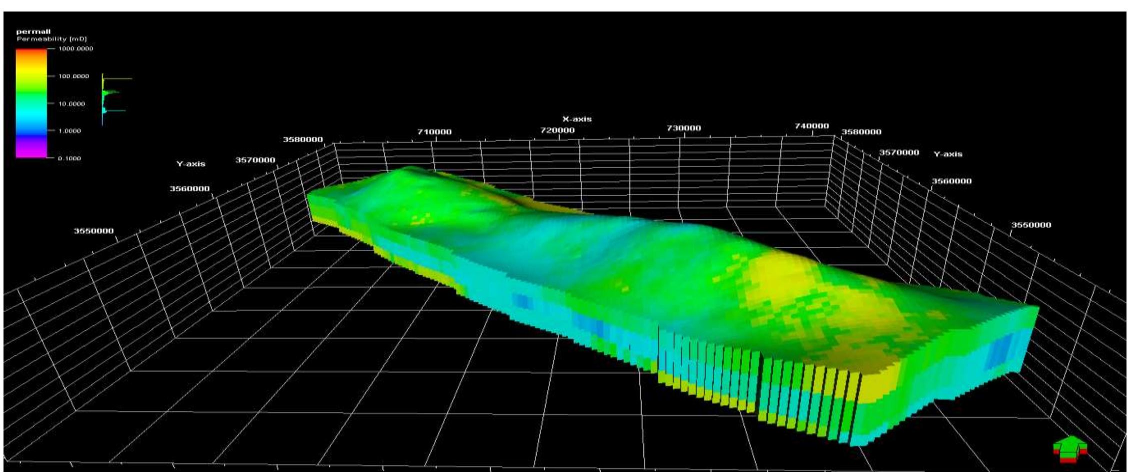


Figure 3. 9: Permeability Distribution to a real case field.

2- Fluid modeling (Dynamic model): it's just needed to add tables after processing by pvtp software directly, in figure 3-10, and use correlation for missing data.

3- Rock-Fluid properties "Rock Physics": assumed data depending on history match, and correlations.

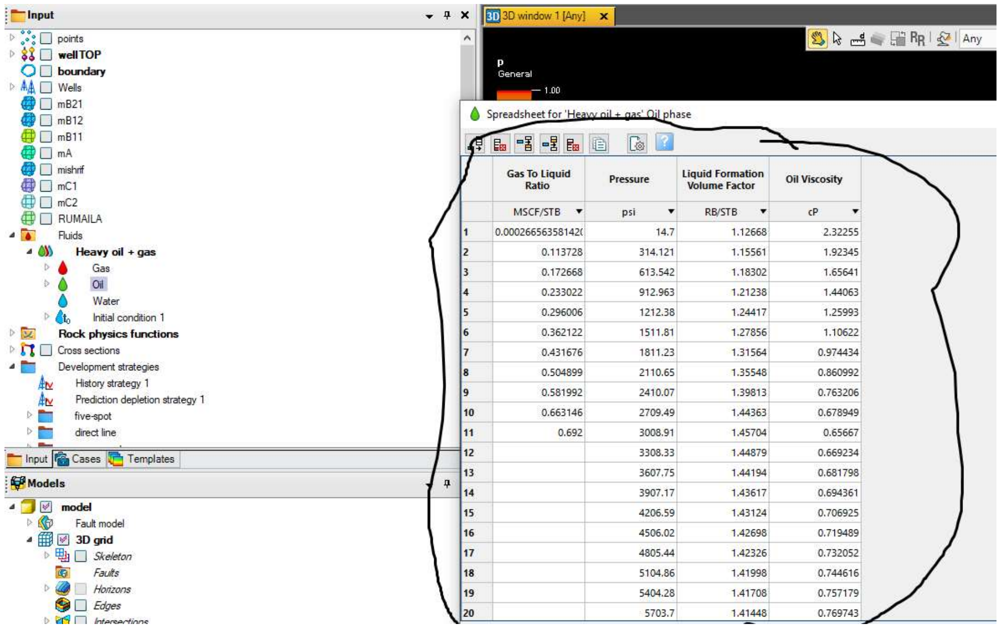


Figure 3. 10: add tables of PVT in petrel

4- Development strategies: the strategy is history match, depletion, waterflooding with four types of patterns: peripheral, direct line, five-spot, seven-spot.different times to waterflooding, with a constant number of wells and a constant flow rate.

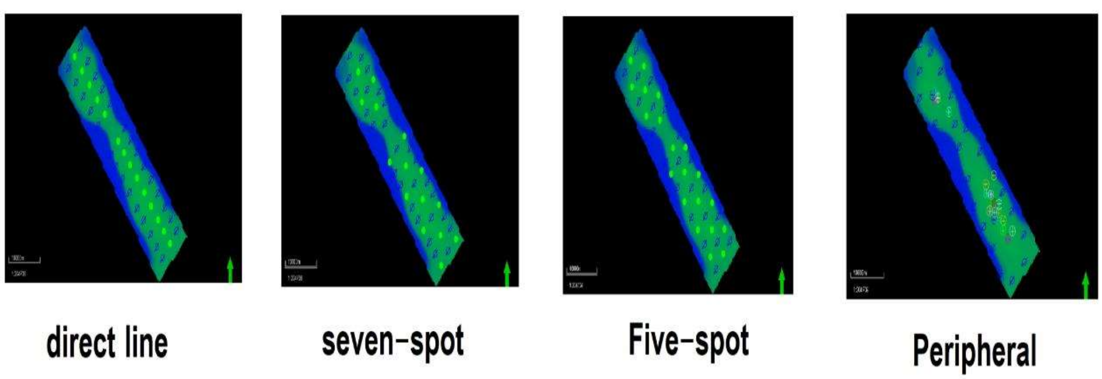


Figure 3. 11: Patterns for A real case

3. 5 Cases investigate

simulation case: it consists of specifying the input properties, then selecting predefined initial conditions and fluids models, rock physics functions, and strategies, together to simulating, As shown in figure 3-11.

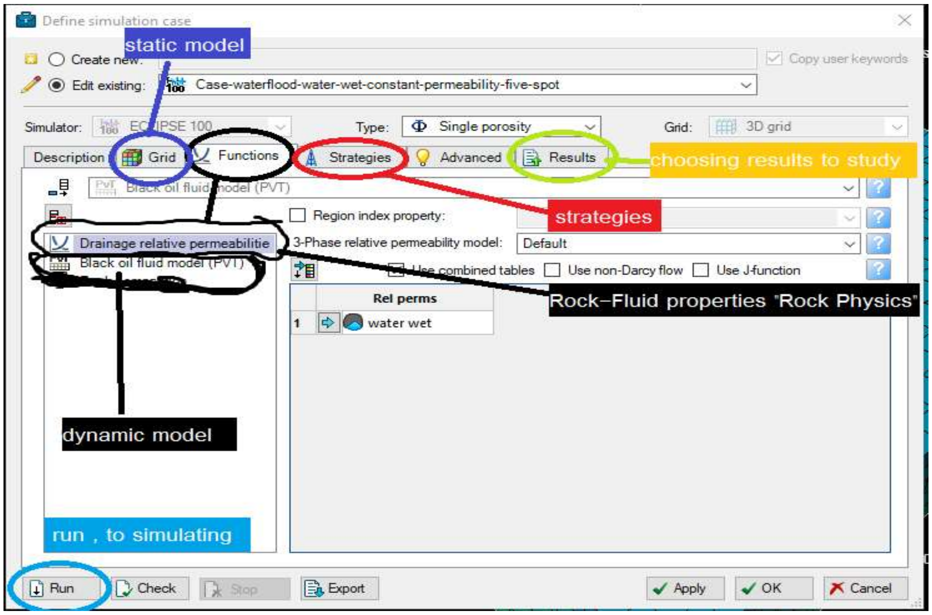


Figure 3. 12: case window, to define the case

3. 5.1 Virtual Reservoir Model

This reservoir has three types of permeability, three wets, three patterns, and other properties are fixed. Which means need to create 27 cases as:

No.cases	Type Of cases	wettability	patterns	permeability
1st 2nd 3rd	Waterflooding	Water-wet	Five spot Direct line Seven spot	Homogeneous (constant Permeability)
4th 5th 6th	Waterflooding	Water-wet	Five spot Direct line Seven spot	Heterogeneous increase with elevation (decrease with depth)
7th 8th 9th	Waterflooding	Water-wet	Five spot Direct line Seven spot	Heterogeneous decrease with elevation (increase with depth)

10th 11th 12th	Waterflooding	Oil-wet	Five spot Direct line Seven spot	Homogeneous (constant Permeability)
13th 14th 15th	Waterflooding	Oil-wet	Five spot Direct line Seven spot	Heterogeneous increase with elevation (decrease with depth)
16th 17th 18th	Waterflooding	Oil-wet	Five spot Direct line Seven spot	Heterogeneous decrease with elevation (increase with depth)
19th 20th 21th	Waterflooding	Intermediate -wet	Five spot Direct line Seven spot	Homogeneous (constant Permeability)
22th 23th 24th	Waterflooding	Intermediate -wet	Five spot Direct line Seven spot	Heterogeneous increase with elevation (decrease with depth)
25th 26th 27th	Waterflooding	Intermediate -wet	Five spot Direct line Seven spot	Heterogeneous decrease with elevation (increase with depth)

Table 3. 5 :Cases of Virtual Reservoir Model

3. 5.2 A real model case

The Buzurgan Field has one history matching strategy and depletions, four types of pattern and two time to waterflood , this mean there are 10 cases as :

No.cases	Strategy	wettability	pattern	Time of waterflooding
1st	history matching(1977-2003)	water-wet	non	non
2nd	depletion (1977-2060)	water-wet	non	non
3rd	waterflood (1977-2060)	water-wet	peripheral	at start
4th	waterflood(1977 -2060)	water-wet	five spot	at start
5th	waterflood(1977 -2060)	water-wet	direct line	at start
6th	waterflood(1977 -2060)	water-wet	seven spot	at start
7th	depletion (1977-1980) waterflood (1980-2060)	water-wet	peripheral	at bubble point
8th	depletion (1977-1996) waterflood (1996-2060)	water-wet	five spot	at bubble point
9th	depletion (1977-2000) waterflood (2000-2060)	water-wet	direct line	at bubble point

10th	depletion (1977-1985) waterflood (1985-2060)	water-wet	seven spot	at bubble point

Table 3. 6: Cases of Real Reservoir Model

3. 6 Gantt Chart

This Gantt chart illustrates a project schedule,It shows each stage and the time period specified for it within the specified date and the percentage of completion in each part.

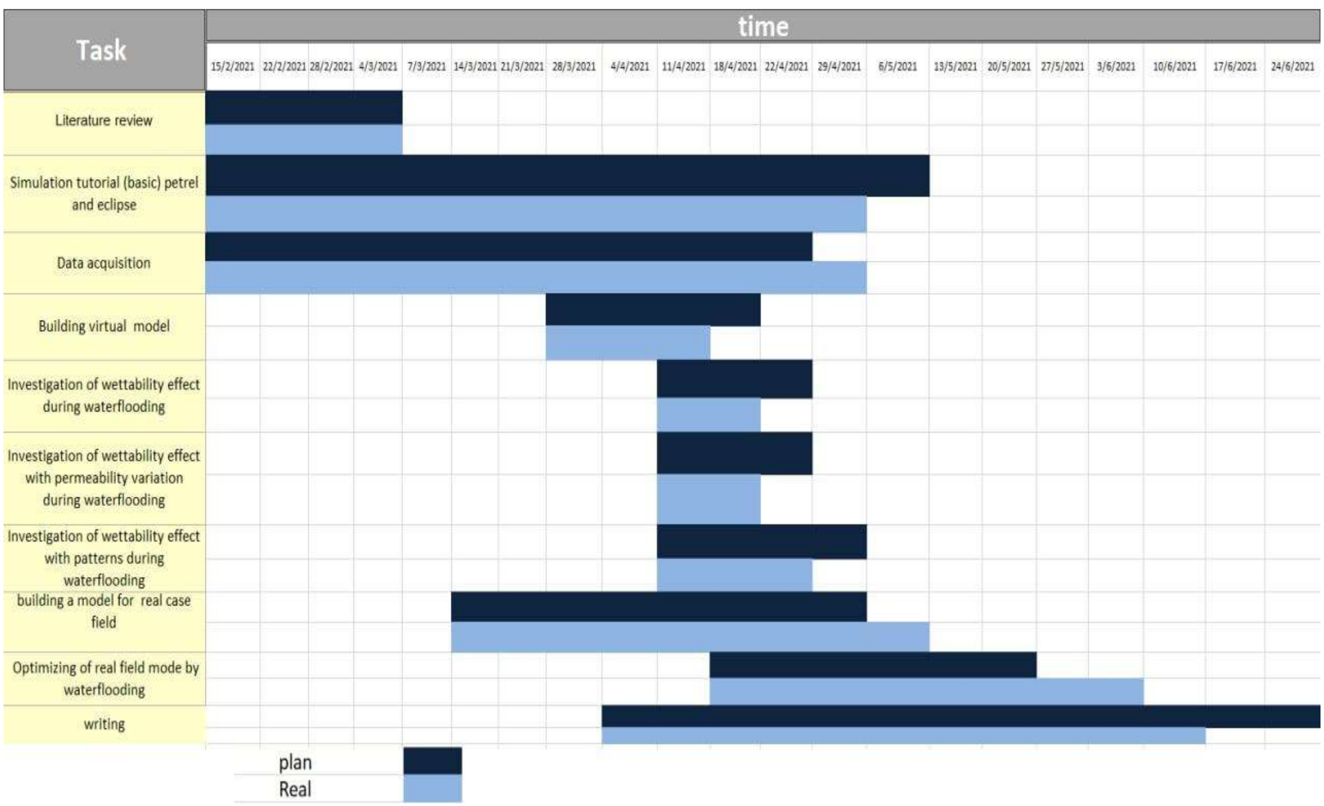


Figure 3. 13: Gantt chart

CHAPTER FOUR: RESULTS AND DISCUSSIONS

This chapter will display the results of the study for two cases(real and Virtual) with a discussion it

4. 1 Virtual Reservoir Model :

4.1.1 Water-wet :

4.1.1.1 homogeneous Permeability:

Figure 4-1 shows the result for homogeneous permeability in water-wet case with 3 types of patterns includes: five-spot, direct-line, seven-spot.

Figure 4. 1: Result 1 for virtual reservoir

the first period of time can observe the five-spot always is higher than the direct-line, this is due to two reasons, one, have four direction of flooding in five-spot, while there two direction in direct-line as show in figure 4-2,

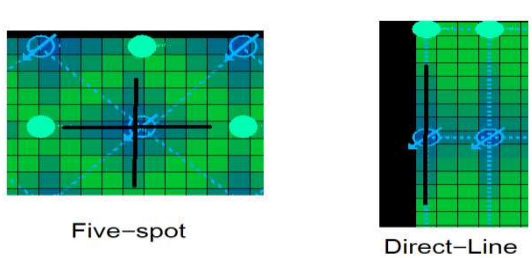


Figure 4-2: the direction of waterflooding in patterns

other, the injection wells of five-spot spreads all over the reservoir. But with time can observe in direct-line can sweep area biggest the five-spot at homogeneous cases and this because of Wells convergence in it as show in fugure 4-3.

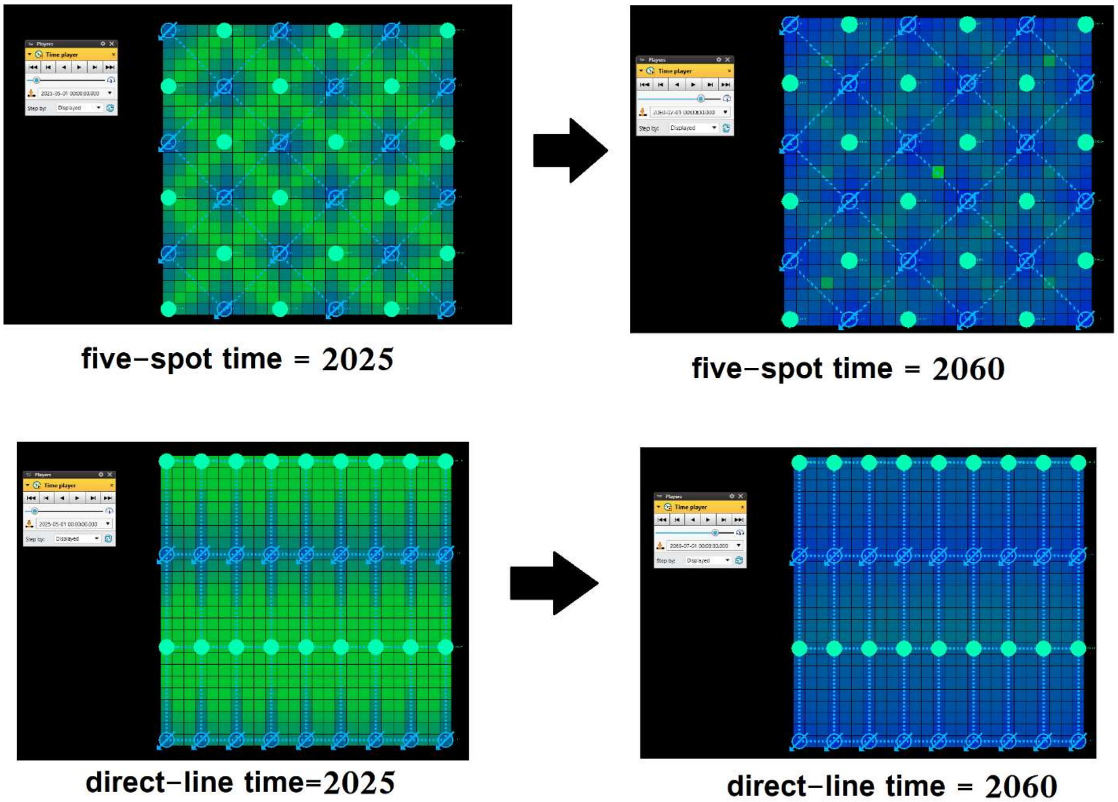


Figure 4. 2: Waterflooding with different times and patterns.

4.1.1.2 Heterogeneous Permeability (decrease with depth) :

Noted in figure 4-4 which show the Permeability decrease with depth in the water-wet case with three types of the patterns (seven spot, five spot, direct line), the heterogeneous permeability in vertical this meaning is the effect on vertical sweep efficiency, read section “2.8 Vertical sweep efficiency /2.8.1 problems and solutions”, As a consequence of the non-uniform vertical layers permeability, any injected fluid will tend to move through the reservoir with an irregular front. In the more permeable portions of the reservoir or high permeability layers, the injected water will travel more rapidly than in the less permeable zone, and layer with a high permeability called a channel and the increase permeability variation (more Heterogeneity) will cause reduce in vertical sweep efficiency and therefore recovery oil factor decreases, read section “2.5 Overeal recovery efficiency the five spot is higher oil recovery , in direct-line, the distance between production wells and injection wells is largest the five-spot and this means longer channel which left left more residual oil

Figure 4. 3: Result 2 for virtual reservoir

4.1.1.3 Heterogeneous Permeability (increase with depth) :

in result 3 Permeability increase with depth in the water-wet case with three types of patterns (seven-spot, five-spot, direct line) as shown in Figure 4-5 .

Figure 4. 4: Result 3 for virtual reservoir

It's not different from result 2 (section 4.1.1.2 Permeability heterogeneous (decrease with depth)) but have oil recovery less and the difference between (heterogeneous permeability 1 and heterogeneous permeability 2) , as shown in the Figure 4-6,

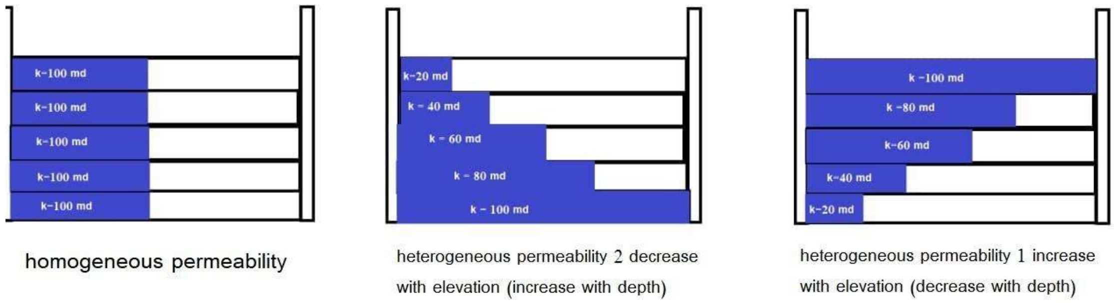


Figure 4. 5: Waterflooding with different permeabilities.

because of gravitation and flowing between layers, in the section "2.8.2 Calculation of Vertical Sweep Efficiency", is assumed there is no flow between layers and in this situation the curves will match (there is no difference between heterogeneous permeability 1 and heterogeneous permeability 2) as shown in the Figure 4-7.

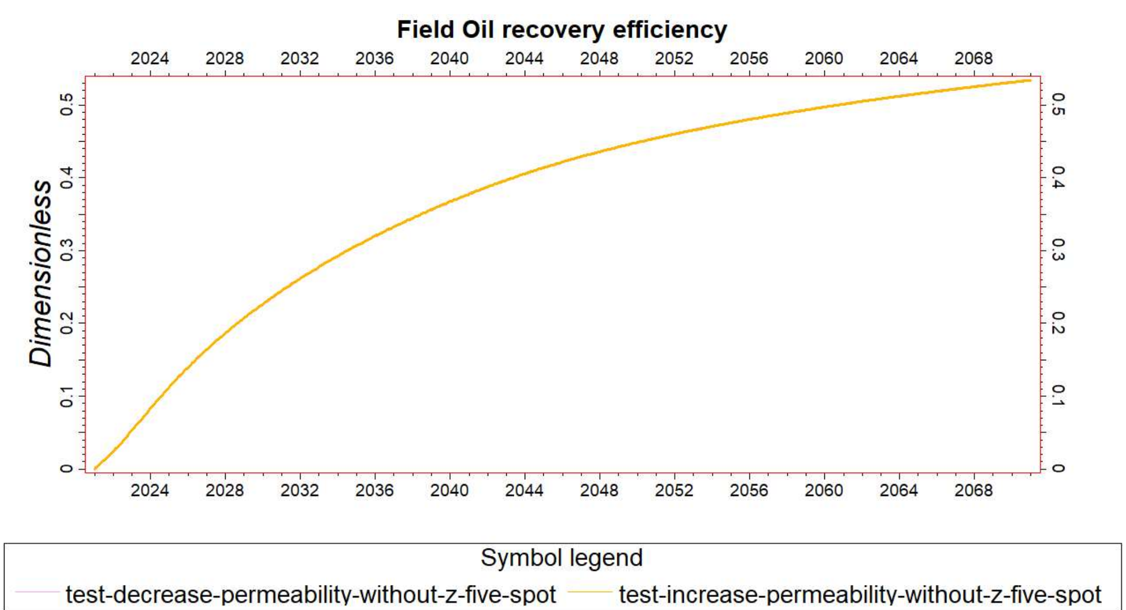


Figure 4. 6: Test case without Z- direction

4.1.2 Oil-wet :

4.1.2.1 Homogeneous Permeability:

the figure 4-8 shows the result for homogeneous permeability in oil-wet case with 3 types of patterns includes: five-spot, direct-line, seven-spot. the direct line has the highest oil recovery same result 1 (section 4.1.1.1 homogeneous Permeability) only is less oil recovery

.

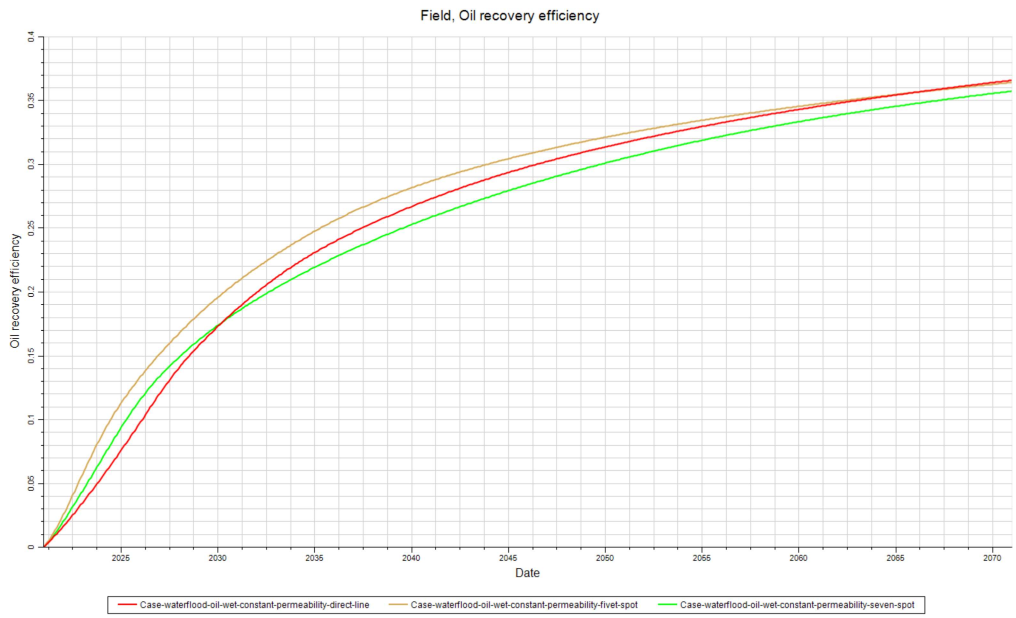


Figure 4. 7: Result 4 for virtual reservoir

4.1.2.2 Permeability heterogeneous (decrease with depth) :

in result 5 Permeability decrease with depth in the oil-wet case with three types of patterns (seven-spot, five-spot, direct line) as shown in Figure 4-5 . and which has highest oil recovery in five-spot same (section 4.1.1.2 heterogeneous Permeability (increase with depth))

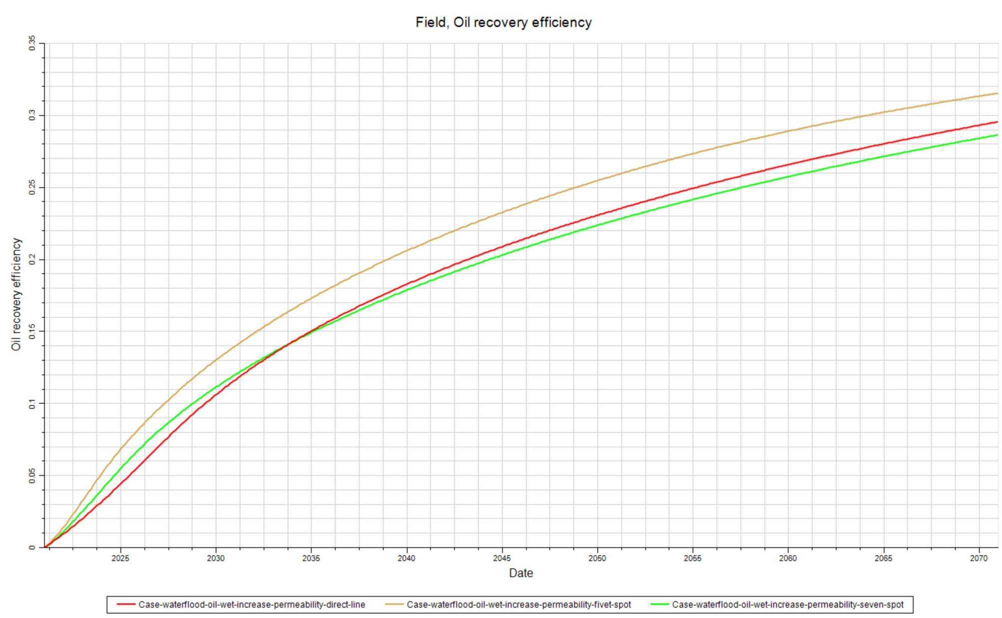


Figure 4. 8: Result 5 for virtual reservoir

4.1.2.3 Permeability heterogeneous (increase with depth) :

Noted in figure 4-10 which show the Permeability increase with depth in the oil-wet case with three types of the patterns (seven spot, five spot, direct line), and which has highest oil recovery in five-spot same (section 4.1.1.3 heterogeneous Permeability (increase with depth))

Figure 4. 9: Result 6 for virtual reservoir

4.1.3 intermediate-wet :

4.1.3.1 homogeneous Permeability:

in result ٨ homogeneous Permeability with depth in the intermediate-wet case with three types of patterns (seven-spot, five-spot, direct line) as shown in Figure 4-١١. and which has highest oil recovery in direct-line same (section 4.1.1.1 heterogeneous Permeability (increase with depth))

Figure 4. 10: Result 7 for virtual reservoir

4.1.3.2 Permeability heterogeneous (decrease with depth) :

the figure 4-12 shows the result for permeability decrease with depth in intermediate-wet case with 3 types of patterns includes: five-spot, direct-line, seven-spot. the five spot has the highest oil recovery same result 2 (section 4.1.1.2 homogeneous Permeability) only is less oil recovery .

Figure 4. 11: Result 8 for virtual reservoir

4.1.3.3 Permeability heterogeneous (increase with depth)

the figure 4-12 and it's last reservoir (result) shows the result for permeability increase with depth in intermediate-wet case with 3 types of patterns includes: five-spot, direct-line, seven-spot. the five spot has the highest oil recovery same result 3 (section 4.1.1.2 homogeneous Permeability).

Figure 4. 12: Result 9 for virtual reservoir

we noted water-wet has higher oil recovery than intermediate-wet which has higher oil recovery than oil-wet, and this is because The wetting phase will stick on the rocks, while The non-wetting phase occupies the central or larger pore openings.

4.2 Real case model

4.2.1 history matching

the figures (4-14, 4-15) show comparing between real data (available) and simulation

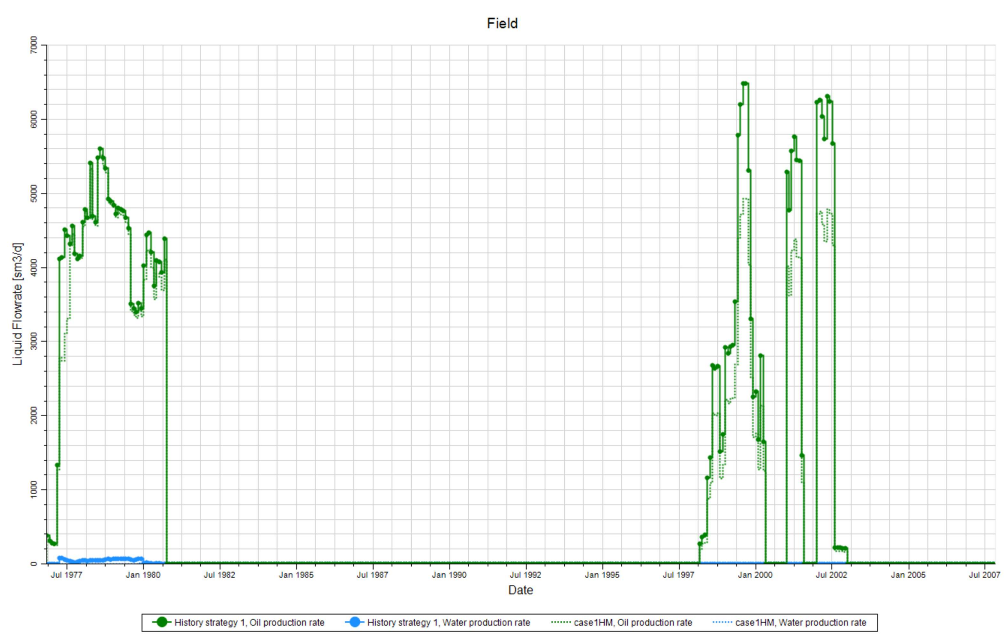


Figure 4. 13: Result 1-a for real case

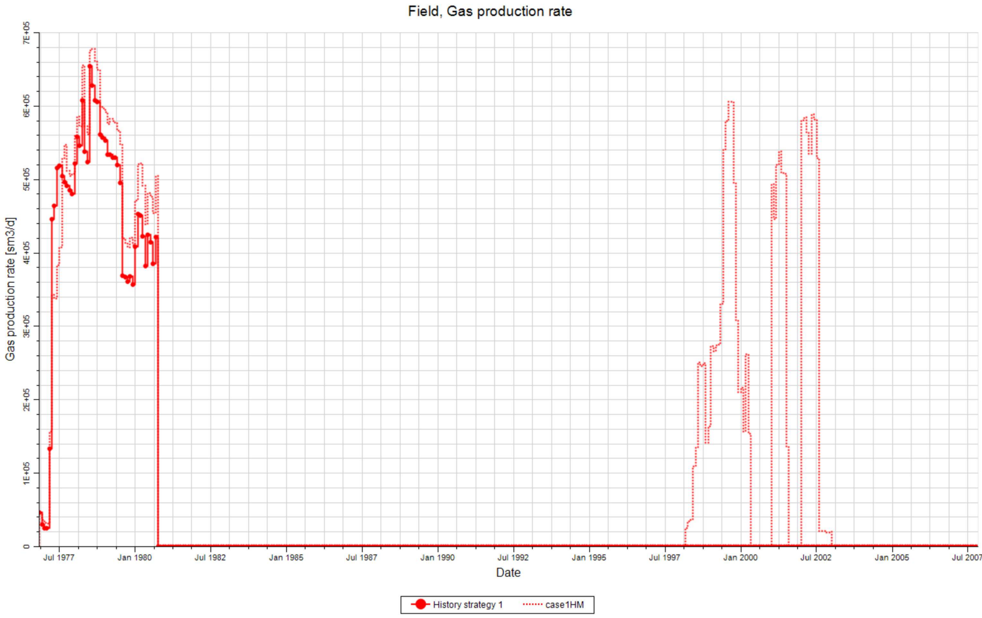


Figure 4. 14: Result 1-b for real case

History matching use to find true relative permeability as show in Figure 4-16

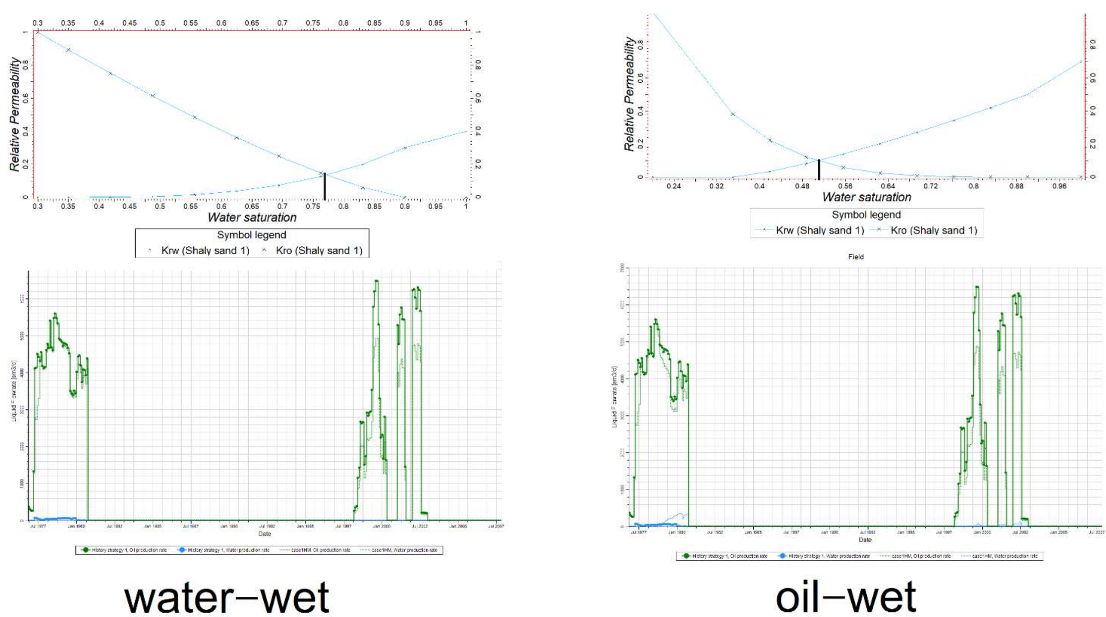


Figure 4. 15 :Choosing best history matching

4.2.2 Optimum time :

4.2.2.1 Peripheral

Figure 4-17 show waterflooding in pattern of Peripheral type with two times at start and at bubble point , is look close but the time at the start is highest .

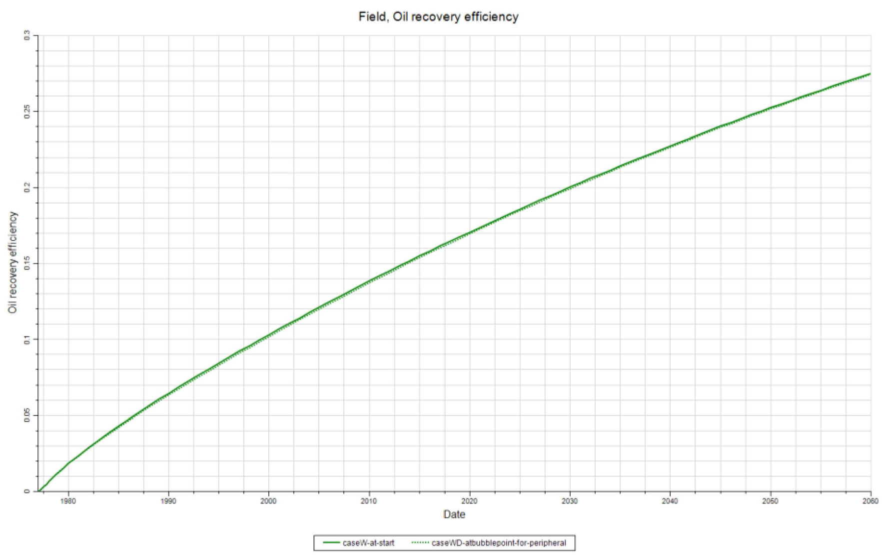


Figure 4. 16: Result 2 for real case

4.2.2.2 Five spot

Figure 4-18 show waterflooding in pattern of five spot type with two times at start and at bubble point, the time at the start is highest.

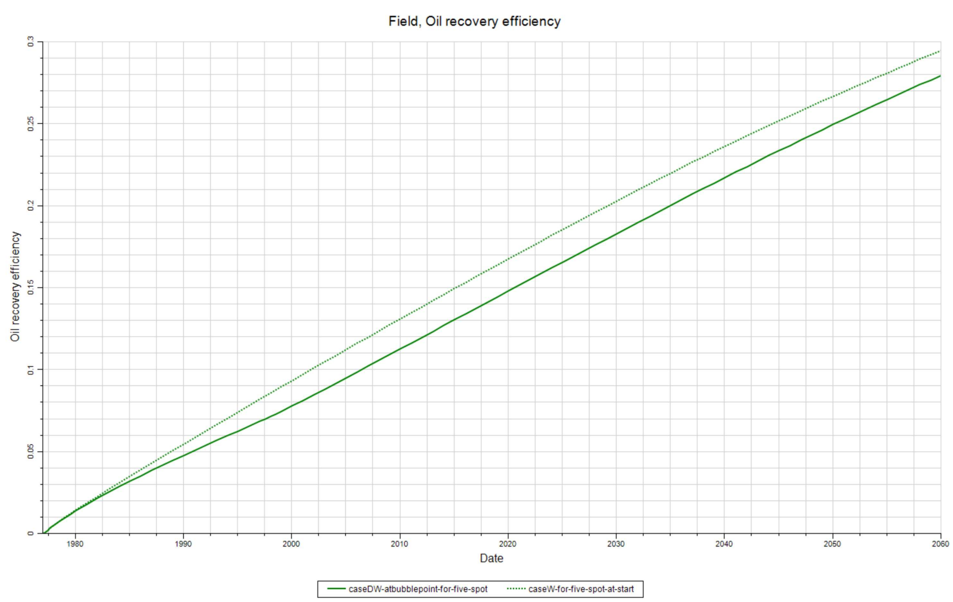


Figure 4. 17: Result 3 for real case

4.2.2.3 Direct-line :

Figure 4-19 show waterflooding in pattern of direct line type with two times at start and at bubble point, the time at the start is highest.

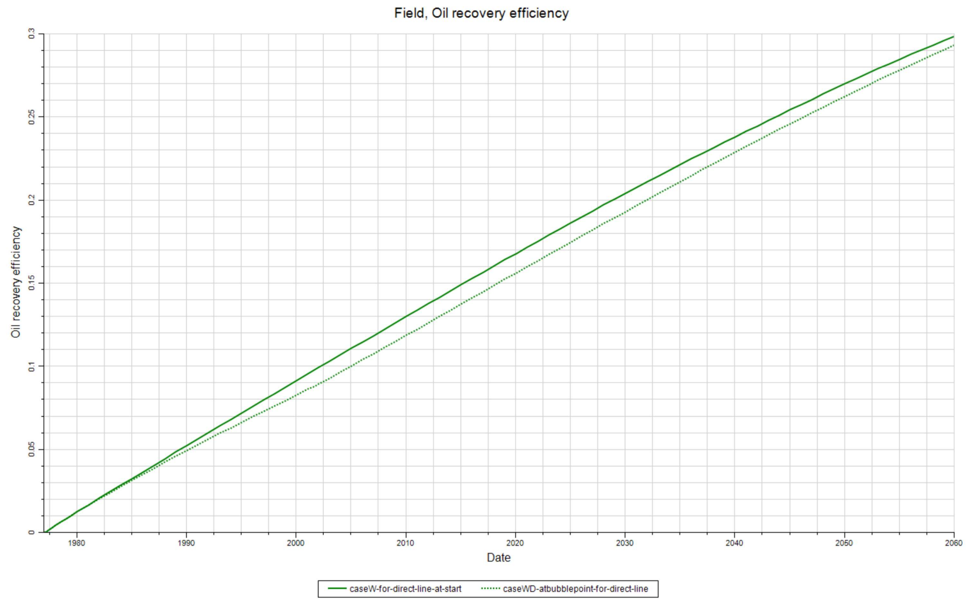


Figure 4. 18: Result 4 for real case

4.2.2.4 Seven spot :

Figure 4-20 show waterflooding in pattern of seven spot type with two times at start and at bubble point, the time at the start is highest.

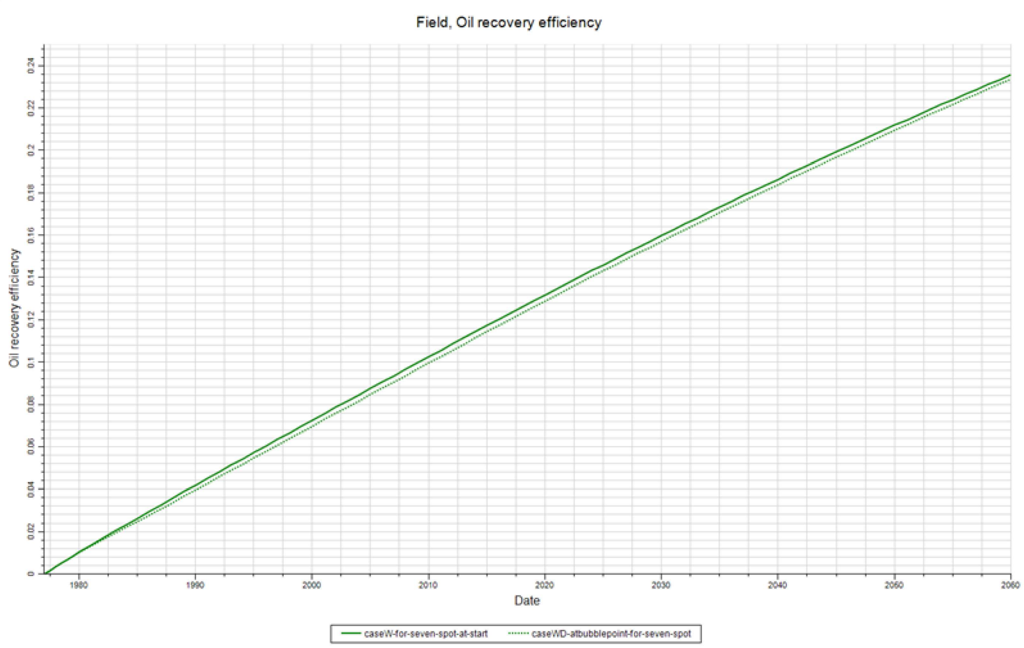


Figure 4. 19: Result 5 for real case

from previous results Always oil recovery flooding at start case higher than flooding at bubble point, and this because at start case pressure drop gradual slow.

4.2.3 Patterns

Figure 4-21 show waterflooding with different pattern (Peripheral ,five spot ,direct line ,seven spot) at start time.

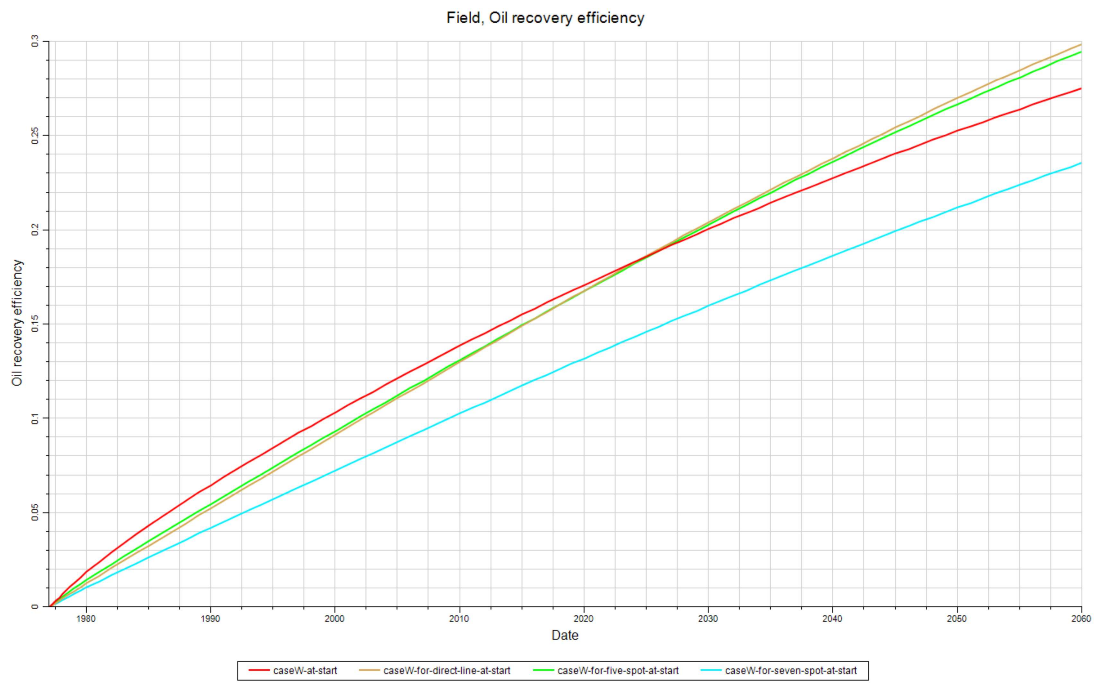


Figure 4. 20: Result 6 for real case

And The direct-line has higher oil recovery and because of well locations

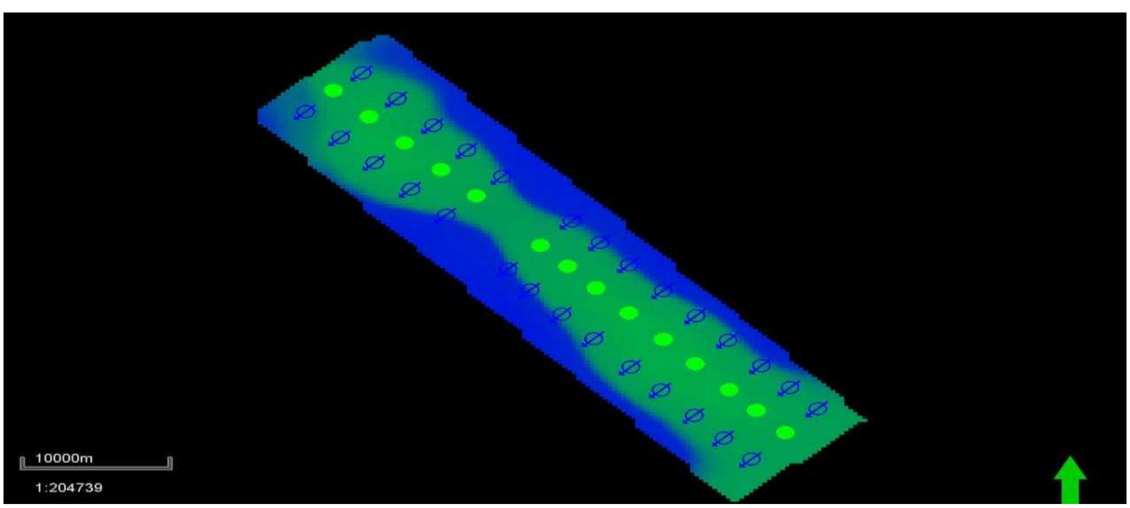


Figure 4. 21: locations of wells for direct line in real case

CHAPTER FIVE:

CONCLUSIONS AND RECOMMENDATIONS

This chapter present the conclusions of the mean objectives of the project for both models and a recommendations for future work as shown below:

5. 1 Conclusions

5. 1.1 Virtual Reservoir Model

A- Water-Wet (different permeability, direct-line, five spot, seven spot)

- In water-wet case the direct-line give the higher oil recovery in homogeneous permeability than the other patterns.

B- Oil-Wet (different permeability, direct-line, five spot, seven spot)

- In Oil-wet case the direct-line give the higher oil recovery in homogeneous permeability than the other patterns.

C- Intermediate-Wet (different permeability, direct-line, five spot, seven spot)

- In Intermediate-Wet case the direct-line give the higher oil recovery in homogeneous permeability than the other patterns.

5. 1.2 A Real Reservoir Model :

A- The optimum time to waterflooding (at start of production, at Pb)

- waterflooding at start of production identical waterflooding at Pb .

B- Waterflooding at start of production (direct-line, five spot, seven spot)

- In waterflooding at start of production case the direct-line give the higher oil recovery than the other patterns .

5. 2 Recommendations

1 . Investigate the effect of the free gas on waterflooding .
2 . Calculate the economic cost of the waterflooding project for all cases.
3 . Investigate with irregular pattern.[4]
4 . Investigate with fractures and seals.
5 . Investigate with areal heterogeneous permeability (x,y).
6 . Investigate with dip angle effect

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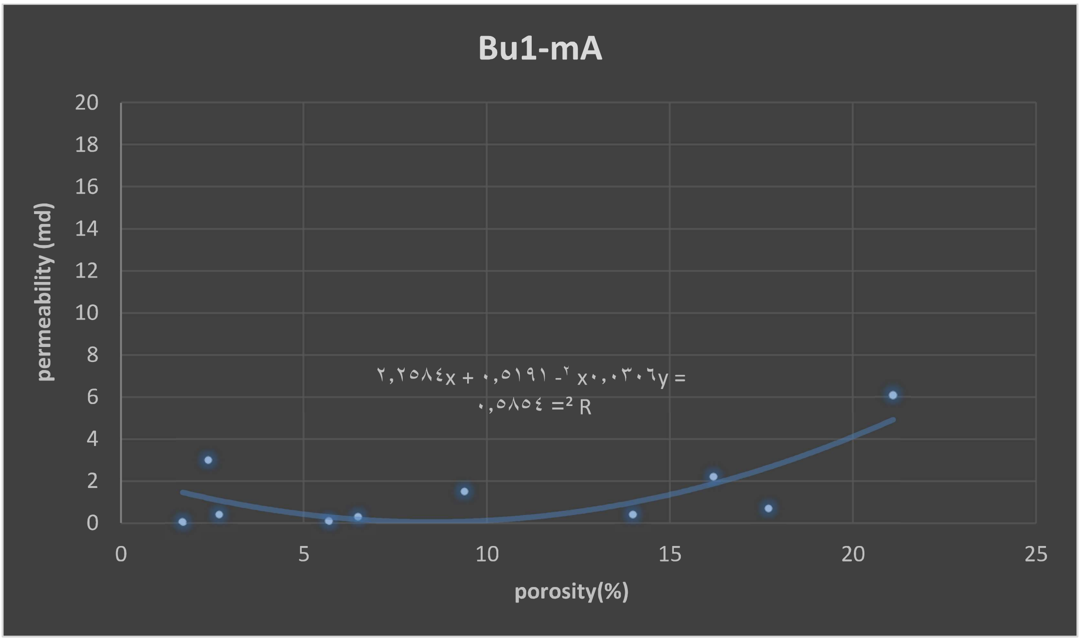
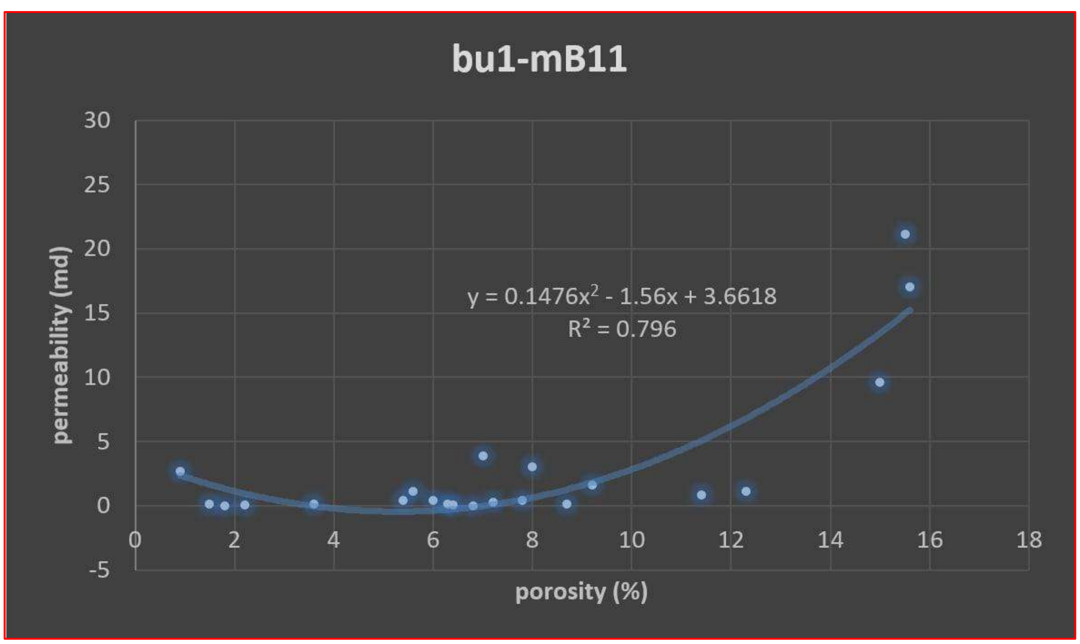
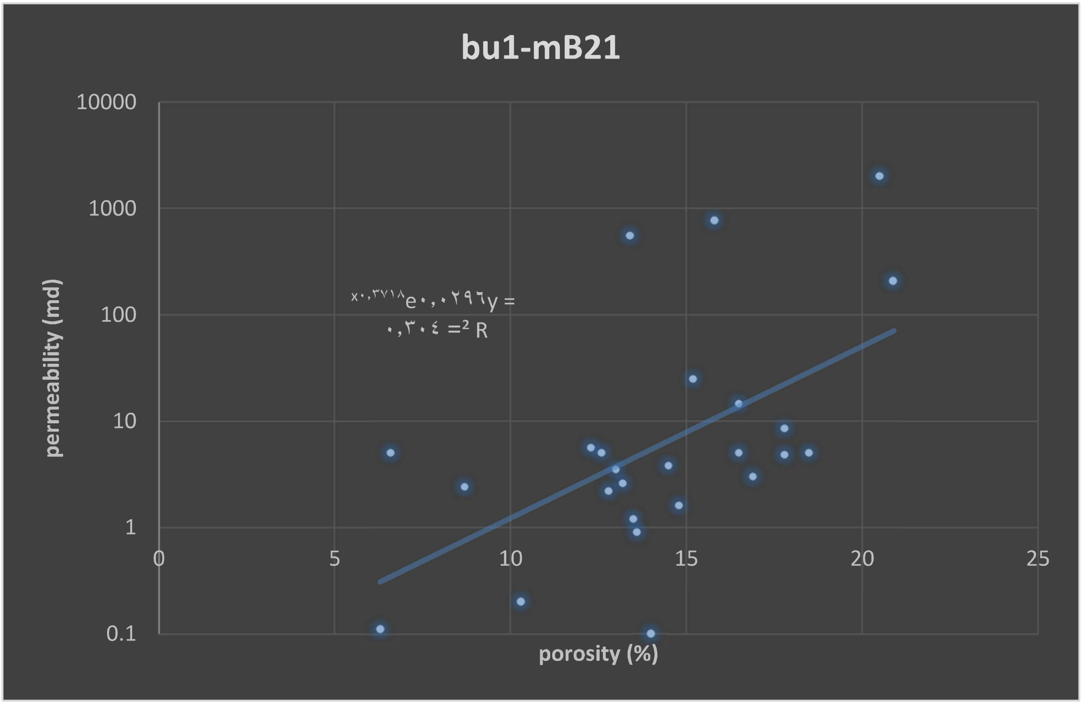
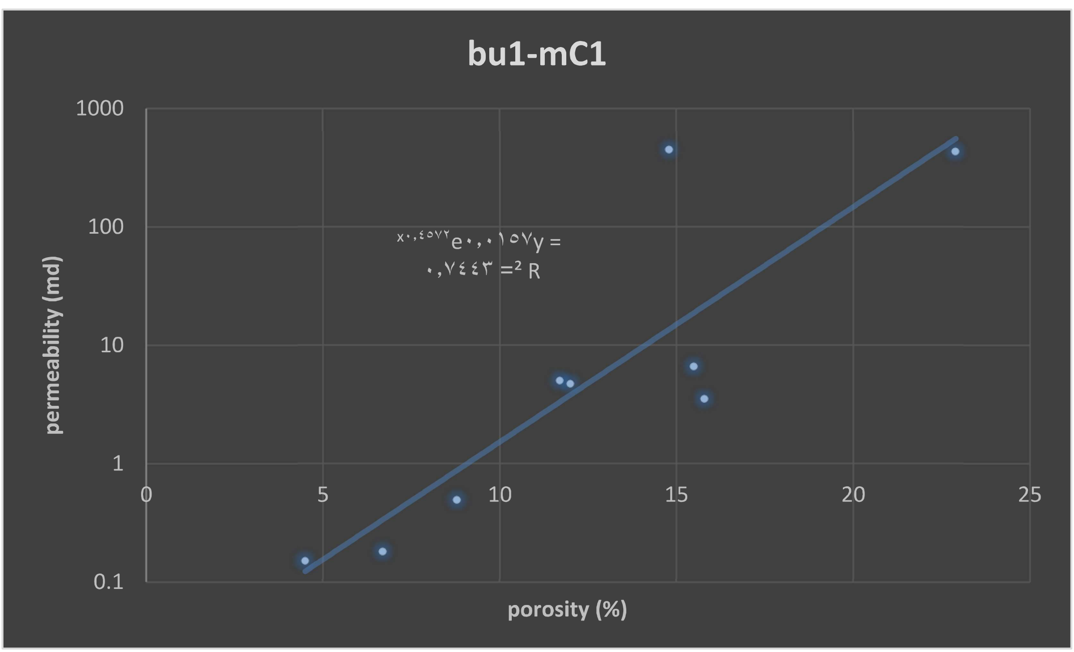
Appendix A:

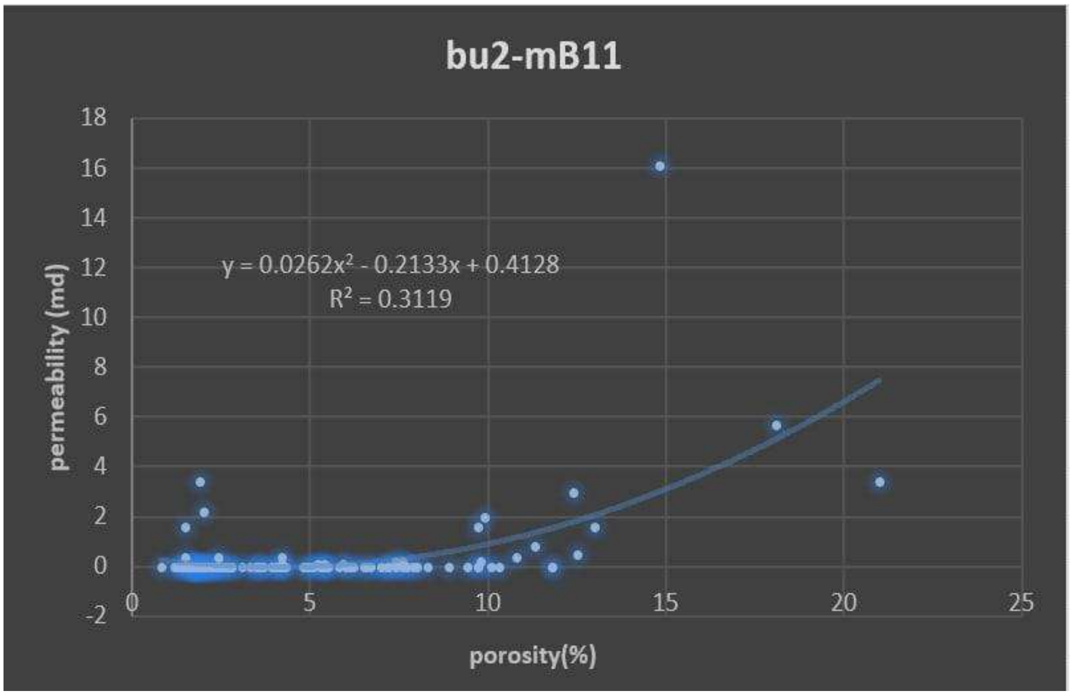
Relationship porosity-permeability :

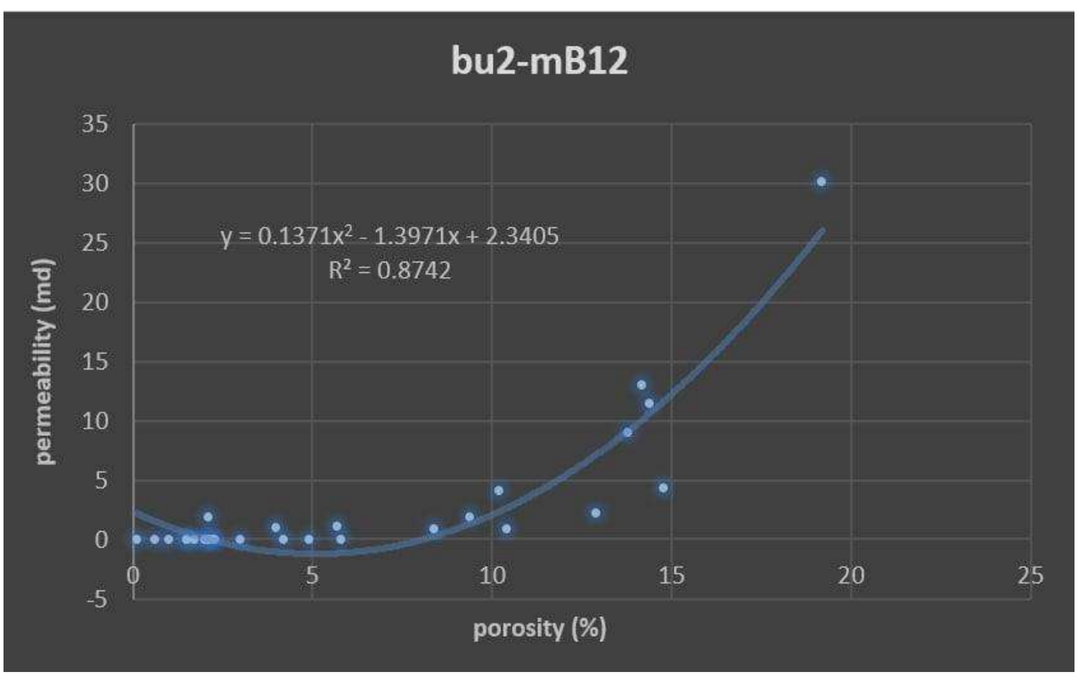


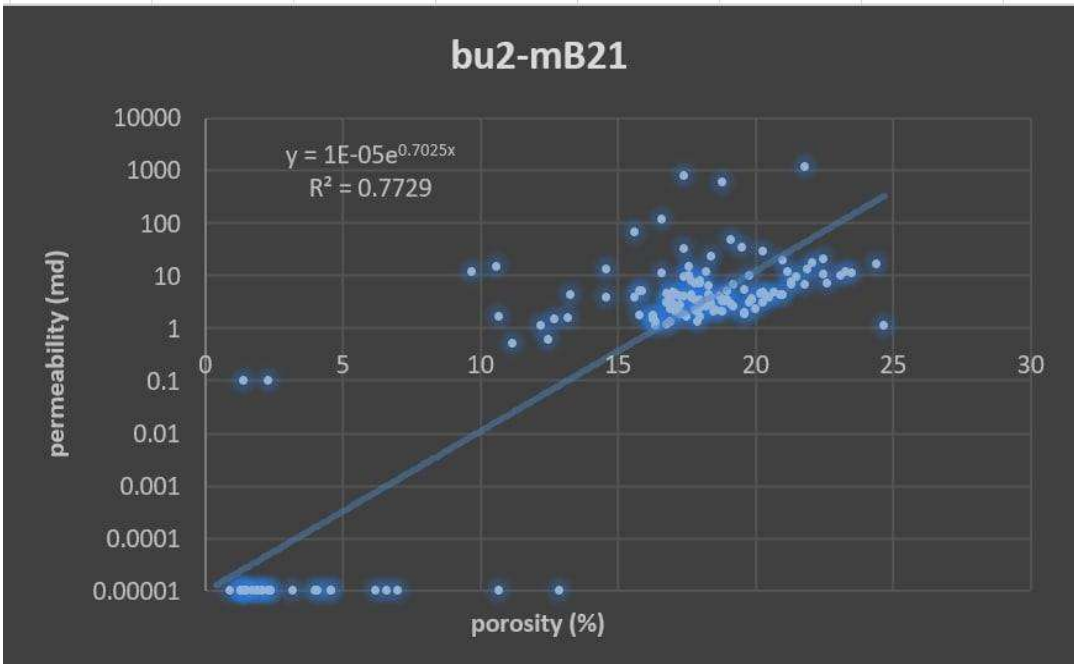


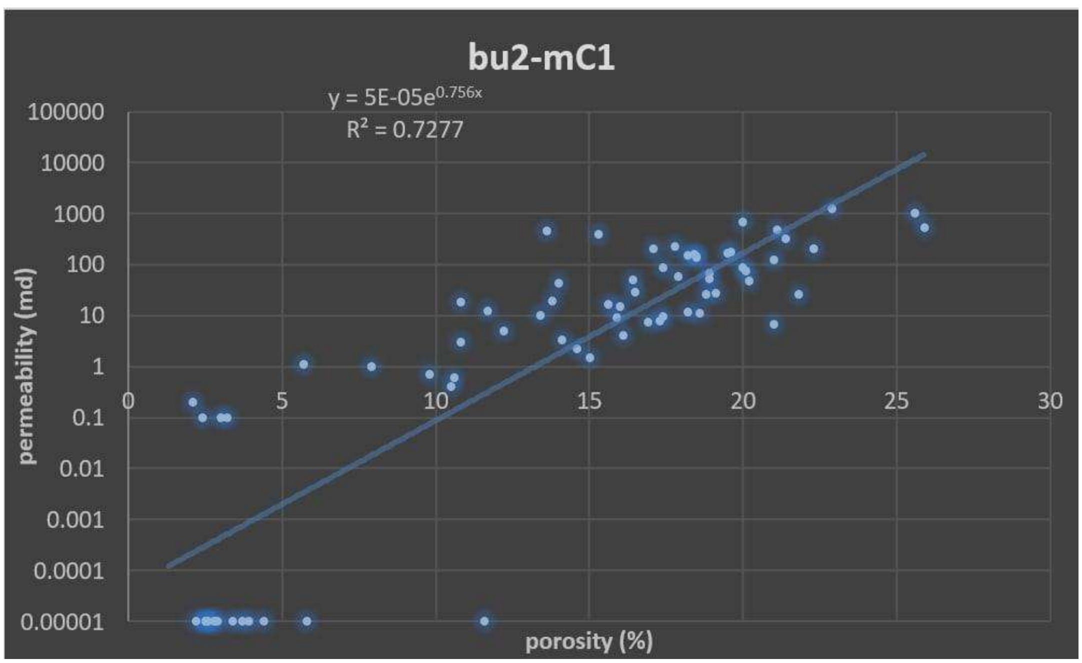

bu1-mB21
y = ٠,٠٢٩٦e^(٠.٣٧١٨x)
R^2 = ٠,٣٠٤
permeability (md)
10000
1000
100
10
1
0.1
0
5
10
15
20
25
porosity (%)


bu1-mC1
y = ٠,٠١٥٧e^(٠.٤٥٧٢x)
R^2 = ٠,٧٤٤٣
permeability (md)
1000
100
10
1
0.1
0
5
10
15
20
25
porosity (%)


bu2-mB11
y = 0.0262x² - 0.2133x + 0.4128
R² = 0.3119
permeability (md)
porosity(%)
18
16
14
12
10
8
6
4
2
0
-2
0
5
10
15
20
25


bu2-mB12
y = 0.1371x² - 1.3971x + 2.3405
R² = 0.8742
permeability (md)
porosity (%)
35
30
25
20
15
10
5
0
-5
0
5
10
15
20
25


bu2-mB21
y = 1E-05e0.7025x
R² = 0.7729
permeability (md)
porosity (%)
10000
1000
100
10
1
0.1
0.01
0.001
0.0001
0.00001
0
5
10
15
20
25
30


bu2-mC1
y = 5E-05e0.756x
R² = 0.7277
permeability (md)
porosity (%)
100000
10000
1000
100
10
1
0.1
0.01
0.001
0.0001
0.00001
0
5
10
15
20
25
30

Appendix B:

Depth and thickness:

TABLE No. : 1

BUZURKAN FIELD
MISHRIF FORMATION SUBDIVIDISIONS

SUB-DIVIDISIONS \ WELL No.		BU-1 K.B. : 55 m DEPTH m	BU-1 THICK. m	BU-1 PHI %	BU-2 K.B. : 36.7 m DEPTH m	BU-2 THICK. m	BU-2 PHI %	BU-3 K.B. : 30.7 m DEPTH m	BU-3 THICK. m	BU-3 PHI %
MISHRIF	TOP	3732.6	342.2		3759.4	347.2		3689	363.6	
mA	TOP	3749	22.7		3778	20.4		3697	21	
	BOTTOM	3771.6			3798.4			3718		
mB11	TOP	3804.5	37.2		3832	37		3751	40	
	BOTTOM	3841.7			3869			3791		
mB12	TOP	3855.7	8.3		3882	9		3804	9	
	BOTTOM	3864			3891			3813		
mB21	TOP	3877.3	77	14.7	3904	79.8	17.6	3826.5	84	13.3
	BOTTOM	3954.3			3983.8			3910.5		
mC1	TOP	3954.3	61.2	17.3	3983.8	65.2	17.5	3910.5	92.1	16.3
	BOTTOM	4015.5			4049			4002.6		
mC2	TOP	4015.5	45.5	11	4049	43		4002.6	34.4	12.5
	BOTTOM	4061			4092			4037		
RUMAILA	TOP	4074.8			4106.6			4052.6		

ALL DEPTHS ARE MEASURED FROM K.B..

TABLE No. :2

BUZURKAN FIELD
MISHRIF FORMATION SUBDIVIDISIONS

SUB-DIVIDISIONS \ WELL No.		BU-4 K.B. : 33.7 m DEPTH m	BU-4 THICK. m	BU-4 PHI %	BU-5 K.B. : 22.4m DEPTH m	BU-5 THICK. m	BU-5 PHI %	BU-6 K.B. : 25.6 m DEPTH m	BU-6 THICK. m	BU-6 PHI %
MISHRIF	TOP	3712.7			3691.5	353		3660.5	351.5	
mA	TOP	3718.5	28		3698.5	20		3666.5	21.5	
	BOTTOM	3746.5			3718.5			3688		
mB11	TOP	3768.5	48.5		3752	46		3730	35	
	BOTTOM	3817			3798			3765		
mB12	TOP	3832	4		3804.5	8.5		3775	10.5	
	BOTTOM	3836			3813			3785.5		
mB21	TOP	3848	88		3825	87	15.5	3795.5	83	16
	BOTTOM	3936			3912			3878.5		
mC1	TOP	3936	81.8		3912	78	14	3878.5	81.5	15.8
	BOTTOM	4017.8			3990			3960		
mC2	TOP	4017.8	36.2		3990	38	14.7	3960	35	15.4
	BOTTOM	4054			4028			3995		
RUMAILA	TOP				4044.5			4012		

ALL DEPTHS ARE MEASURED FROM K.B..

TABLE No. :6

BUZURKAN FIELD
MISHRIF FORMATION SUBDIVIDISIONS

SUB-DIVIDISIONS \ WELL No.		BU-16 K.B. : 24.5m DEPTH m	BU-16 THICK. m	BU-16 PHI %	BU-17 K.B. : 34.4 m DEPTH m	BU-17 THICK. m	BU-17 PHI %	BU-18 K.B. : 25 m DEPTH m	BU-18 THICK. m	BU-18 PHI %
MISHRIF	TOP	3676.5	348		3702	339		3687	352	
mA	TOP	3680.5	20.5		3723	19		3693	31	
	BOTTOM	3701			3742			3724		
mB11	TOP	3738	34.5		3773.5	31.5		3756.5	34	
	BOTTOM	3772.5			3805			3790.5		
mB12	TOP	3785	12.5		3826	6.5		3802	9	
	BOTTOM	3797.5			3832.5			3811		
mB21	TOP	3806	83.5	16.5	3848.5	72.5		3826	77	
	BOTTOM	3889.5			3921			3903		
mC1	TOP	3889.5	85.5	17.5	3921	63		3903	74	
	BOTTOM	3975			3984			3977		
mC2	TOP	3975	34.5	15.8	3984	45		3977	45.5	
	BOTTOM	4009.5			4029			4022.5		
RUMAILA	TOP	4024.5			4041			4039		

ALL DEPTHS ARE MEASURED FROM K.B..

TABLE No. :6

BUZURKAN FIELD
MISHRIF FORMATION SUBDIVIDISIONS

SUB-DIVIDISIONS \ WELL No.		BU-16 K.B. : 24.5m			BU-17 K.B. : 34.4 m			BU-18 K.B. : 25 m		
		DEPTH m	THICK. m	PHI %	DEPTH m	THICK. m	PHI %	DEPTH m	THICK. m	PHI %
MISHRIF	TOP	3676.5	348		3702	339		3687	352	
mA	TOP	3680.5	• 20.5		3723	19		3693	31	
	BOTTOM	3701			3742			3724		
mB11	TOP	3738	34.5		3773.5	31.5		3756.5	34	
	BOTTOM	3772.5			3805			3790.5		
mB12	TOP	3785	12.5		3826	6.5		3802	9	
	BOTTOM	3797.5			3832.5			3811		
mB21	TOP	3806	83.5	16.5	3848.5	72.5		3826	77	
	BOTTOM	3889.5			3921			3903		
mC1	TOP	3889.5	85.5	17.5	3921	63		3903	74	
	BOTTOM	3975			3984			3977		
mC2	TOP	3975	34.5	15.8	3984	45		3977	45.5	
	BOTTOM	4009.5			4029			4022.5		
RUMAILA	TOP	4024.5			4041			4039		

ALL DEPTHS ARE MEASURED FROM K.B. .

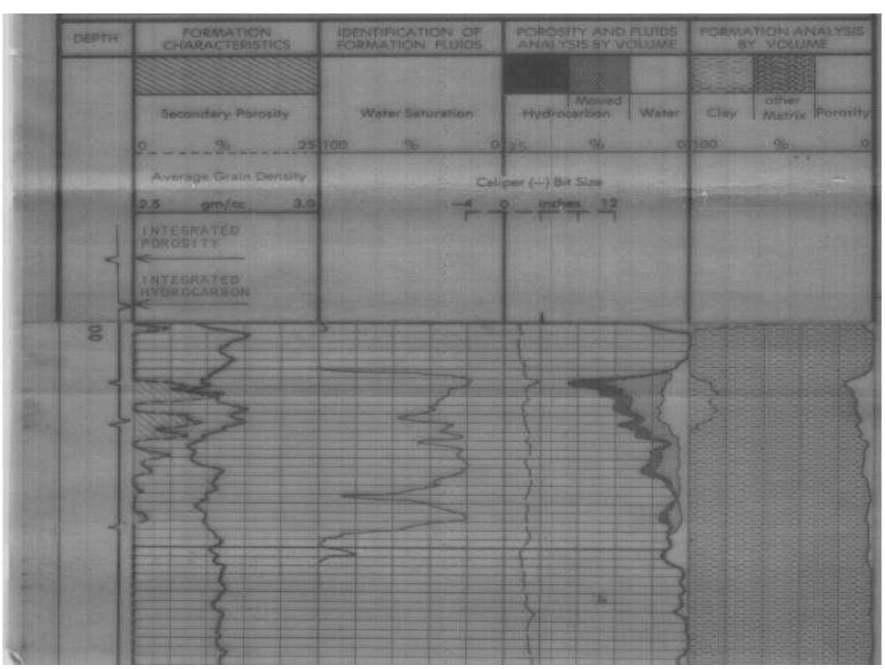
TABLE No. : 7

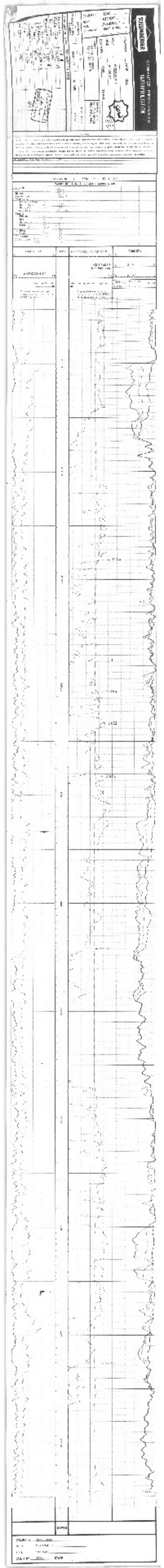
BUZURKAN FIELD
MISHRIF FORMATION SUBDIVIDISIONS

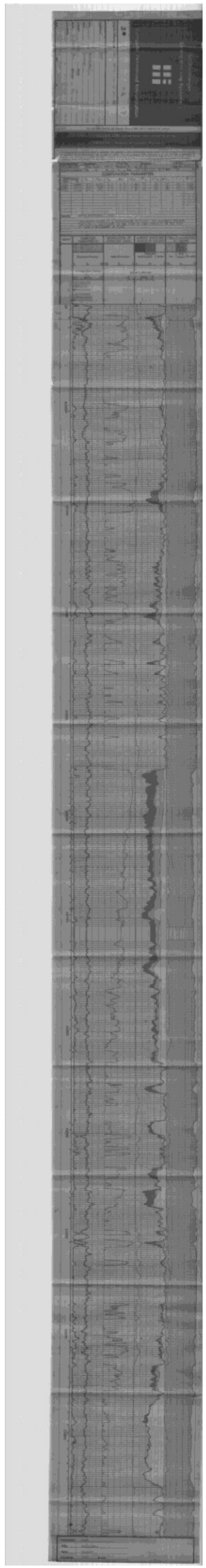
SUB-DIVIDISIONS \ WELL No.		BU-19 K.B. :23.5 m			BU-20 K.B. : 28 m			BU-21 K.B. :24.7 m		
		DEPTH m	THICK. m	PHI %	DEPTH m	THICK. m	PHI* %	DEPTH m	THICK. m	PHI %
MISHRIF	TOP	3688	350		3675	373		3829	355	
mA	TOP	3694.5	23							
	BOTTOM	3717.5								
mB11	TOP	3755	46							
	BOTTOM	3801								
mB12	TOP	3807	10.5							
	BOTTOM	3817.5								
mB21	TOP	3822.5	79.5		3810	89.5	15	3961.5	83.5	
	BOTTOM	3902			3899.5			4045		
mC1	TOP	3902	73		3899.5	96	13	4045	90	
	BOTTOM	3953.5			3995.5			4135		
mC2	TOP	3902	45		3995.5	24.5	13.3	4135	35	
	BOTTOM	4020			4020			4170		
RUMAILA	TOP	4038			4048			4184		

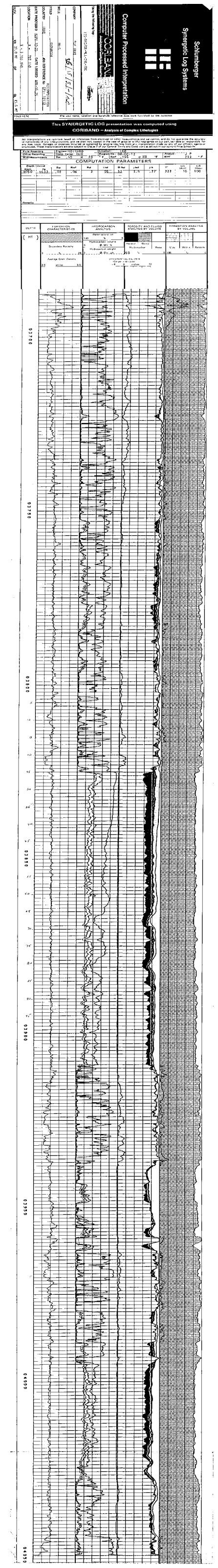
ALL DEPTHS ARE MEASURED FROM K.B. .

API (logs):









Routine Core :

Carottes Cores	Récupération Recovery	Niveau géologique geological horizon	Profondeur Depth	Nature du Plug Horizontal H Vertical V Plug direction	Porosité en % Porosity in %	Perméabilité Permeability en millidarcys	Poids spécifique vrai de la roche g/cm3 Specific weight	Observations Observations ①
N° 2			9308,0	H	16,0	1,03	2,86	
				V				
			9371,0	H	7,2	0,107	2,85	
				V	9,4	0,58	2,84	
			9375,50	H	4,7	0,08	2,86	
				V				
			9378,0	H	17,5	0,57	2,84	
				V				
			9379,0	H	9,40	0	2,86	
				V				
			9383,50	H	13,1	0,45	2,85	
				V				
			9386,5	H	17,4	1,25	2,88	
				V	18,3	1,27	2,85	
			9388,0	H				
				V	16,0	0,40	2,85	
			9392,0	H	12,9	0,07	2,84	
				V				
			9401,00	H	10,7	0,08	2,85	
				V				
			9402,0	H				
				V	3,7	0	2,85	
			9407,0	H	5,2	0,071	2,84	
				V				
			9415,0	H	4,3	0	2,85	
				V				
			9418,50	H	4,0	0	2,82	
				V	4,3	0,048	2,82	
N° 3			9420,0	H	3,8	0,056	2,83	
				V				
			9425,0	H	6,6	0	2,82	

POROSITY AND PERMEABILITY RESULTS

Well No. : Bu 18
Formation : Mishrif

Table 3

Sample No.	Core No.	Depth (m)	Nature	Porosity %	Permeability Air (md)	Slip Corrected Air Permeability (md)
24 V	3	3803.30	L.S. light col. vuggy	17.6	7.7	5.9
25 H	4	3909.10	L.S. grey col.	2.8	0.23	0.14
25 V		3909.10	L.S. grey col.	3.8	<0.2	<0.2
26 H		3909.85	L.S. light col.	12.8	1.4	1.0
26 V		3909.85	L.S. light grey col.	12.6	0.41	0.26
27 H		3910.27	L.S. light col.	11.4	1.6	1.1
27 V		3910.27	L.S. light grey col.	9.5	0.44	0.28
28 H		3910.96	L.S. light col.	9.9	0.39	0.25
28 V		3910.96	L.S. light grey col.	7.7	<0.2	<0.2
29 H		3911.06	L.S. light grey col.	---	<0.2	<0.2
29 V		3911.06	L.S. light col.	9.2	0.22	0.13
30 H		3911.92	L.S. light grey col.	6.3	0.43	0.28
30 V		3911.92	L.S. light grey col.	5.5	0.50	0.32
31 H		3912.30	L.S. grey col.	8.5	<0.2	<0.2
31 V		3912.30	L.S. grey col.	5.2	<0.2	<0.2
32 H		3912.97	L.S. grey col.	7.7	0.84	0.56
33 H		3913.32	---	---	---	---
33 V		3913.32	L.S. grey col.	8.3	0.125	0.07

RESULTATS DES PØRØSITES ET DES PERMEABILITES

PUITS BUZURGAN 2

CØTES		PØRØ	PERM.MD	DENSITE	ØBSERVATIØNS
12660.00	H	3.5	.0	2.71	
12660.00	V	2.9	.0	2.72	
12661.00	H	4.2	.0	2.71	
12661.00	V	4.3	.0	2.71	
12662.00	H	6.6	.0	2.72	
12662.00	V	7.5	.0	2.73	
12663.00	H	4.5	CASSE	2.72	
12663.00	V	4.1	.0	2.72	
12664.00	H	6.1	.0	2.74	
12664.00	V	5.2	.0	2.74	
12665.00	H	8.0	.0	2.73	
12665.00	V	5.2	.0	2.72	
12666.00	H	5.2	.1	2.70	
12666.00	V	4.9	.0	2.70	
12667.00	H	2.3	.0	2.73	
12667.00	V	2.4	.0	2.74	
12668.00	H	4.1	.0	2.73	
12668.00	V	4.6	.0	2.73	
12669.00	H	5.1	.0	2.72	
12669.00	V	6.7	.0	2.72	
12670.00	H	7.9	.0	2.73	
12670.00	V	4.5	.2	2.71	
12671.00	H	7.4	.0	2.73	
12671.00	V	6.9	.0	2.72	
12672.00	H	2.2	.0	2.72	
12672.00	V	2.0	.0	2.73	
12673.00	H	2.2	.0	2.74	
12673.00	V	3.3	.0	2.75	
12674.00	H	3.9	.0	2.77	
12674.00	V	4.1	.0	2.73	
12675.00	H	7.4	.0	2.72	
12675.00	V	7.6	.0	2.79	

CØRE ANALYSIS

WELL BUZURGAN 3

DEPTH	PLUG DIRECTION	PORØSITY	PERMEABILITY IN MILLIDARCYS	SPECIFIC WEIGHT G/CM3	OBSERVATIONS
12371.00	H	10.4	BRØKEN	2.72	
12371.00	V				LACKING
12372.00	H	12.1	.0	2.70	
12372.00	V				LACKING
12373.00	H	8.5	BRØKEN	2.71	
12373.00	V				LACKING
12374.00	H	4.5	BRØKEN	2.69	
12374.00	V	1.8	BRØKEN	2.68	
12375.00	H	5.5	FISSURED	2.73	
12375.00	V	8.7	.0	2.76	
12376.00	H				LACKING
12376.00	V	4.8	.9	2.72	
12377.00	H	10.1	BRØKEN	2.70	
12377.00	V	7.0	.9	2.75	
12378.00	H	17.2	1.9	2.74	
12378.00	V	12.9	1.8	2.71	
12379.00	H	4.9	.0	2.72	
12379.00	V				LACKING
12380.00	H	2.9	2.4	2.71	
12380.00	V	3.4	2.8	2.74	
12381.00	H	10.5	.5	2.73	
12381.00	V	10.3	.5	2.74	
12382.00	H	11.7	2.1	2.74	
12382.00	V	13.0	1.3	2.72	
12383.00	H	7.7	1.6	2.71	
12383.00	V	6.4	2.1	2.71	
12385.00	H	15.5	BRØKEN	2.69	
12385.00	V	11.4	BRØKEN	2.70	
12386.00	H	15.4	FISSURED	2.70	
12386.00	V	8.7	.3	2.70	
12387.00	H	15.5	BRØKEN	2.71	
12387.00	V	19.3	1.5	2.71	

DRTEN. BØUSSENS SCE.CALCUL PRØGRAMME(PØRØSITY) 15/2/1971

K 10

Plug No		Depth m	Gas Permeability md	Porosity %	Grain density g/cc	Note
1H		4015.05	6.28	16.3	2.82	
1V		=	10.99	13.9	2.85	
2H		4016.05	39.34	20.2	2.77	
2V		=	9.60	17.1	2.75	
3H		4017.70	4.20	9.9	2.72	
3V		=	2.34	9.9	2.67	
4H		4012.10	0.0	6.9	2.95	
4V		=	3.05	10.7	2.91	
5H		4018.60	0.0	1.3	2.72	
5V		=	0.0	9.9	2.80	
6H		4019.05	0,0	3.7	2.85	
6V		=	0.0	3.7	2.69	
7H		4020.30	0.0	3.7	2.72	
7V		=	0.0	3.9	2.54	
8H		4027.05	0.33	8.8	2.63	
8V		=	0.17	6.7	2.67	
9H	مفرد	4025.40	0.23	7.0	2.78	
10H	مفرد	4030.35	0.0	7.6	[illegible]	

Well - Bu - 12

Plug-No	gas Permeability md	P rosity %	grain density g/cc		Note
52H	0.64	10.9	2.768		
52V	6.06	18.6	2.763		
53H	0.71	16.5	2.735		
53V	2.46	14.4	2.769		
54H	75.71	16.5	2.768	~~broken~~	~~broken~~
54V	0.67	10.9	2.825		
55H	4.97	19.32	2.788		
55V	2.00	19.64	2.816		
56H	9.77	18.5	2.813		
56V	4.59	20.9	2.787		
57H	3.55	21.5	2.787		
57V	4.77	20.8	2.798		
58H	6.57	18.64	2.818		
58V	5.56	21.65	2.827		
59H	9.36	14.78	2.789		
59V	2.64	9.44	2.745		
60H	484.22	23.6	2.735		
60V	542.14	22	2.806		
61H	16.76	16.69	2.759		
61V	1.42	16.95	2.759		