Model Development for Micellar/ Polymer Flooding Process

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Abstract
Flow of hydrocarbon from the reservoir is a function of pressure differential provided by natural reservoir energy at initial stage of production. The pressure declines over time with a corresponding reduction in production rate. To salvage for this, polymer/micellar flooding a chemical method deployed to enhance the recovery of oil from the reservoir. The key point here is to improve overall sweep efficiency. In this work, the reservoir was produced using a polymer injection well and analysis were made using a time step of 1 day over 100 days of production period. Simulation using Eclipse 100 result shows that similar cells in terms of relative permeability reduces with increasing polymer concentration and relative distance from the injector. The field performance in this work was analyzed in terms of production rate, field pressure, and saturation. Peak pressure value of 4470Psia was reached at the day 75 with peak oil production rate of 205STB/Day at day 68 with a continuous decline in oil saturation. Sensitivity study was performed in terms of polymer adsorption/injection rate in relation to time, polymer injection rate/oil production rate against time, fluid oil rate/field pressure against time. The overall result shows that the polymer adsorption weakens the interfacial tension of the in-situ of oil phase.

Keywords— *Model Development, Micellar/Polymer and Flooding Process.*

I. INTRODUCTION

Crude Oil is a major source of energy (world's leading fuel) in the world today utilized in transportation, industries (refining, mining, manufacturing, agriculture, and construction), residential buildings etc. Knowing the vitality of Petroleum Product in the economy, it is highly in demand due to increasing global population. As the world's leading fuel, it accounts for 32.9% of global energy consumption. Global natural gas consumption increases more than 40% between 2018 and 2050, and total consumption reaches nearly 200 quadrillion Btu by 2050 [1] Proceeding along same line, global liquid fuels consumption increases more than 20% between 2018 and 2050, and total consumption reaches more than 240 quadrillion Btu in 2050. Petroleum products are crucial to the global economy today due to increasing energy demand are approximately 1.5% per year [2]. The majority of oil companies today are focusing on maximizing the recovery factor (RF) from their oilfields as well as maintaining an economic oil rate to meet production quota and demand. This is because it is becoming increasingly difficult to discover new oilfields. Most of the sedimentary basins that might contain oil have already been explored and new discoveries tend to be small. The U.S Department of Energy estimates that nearly 377 billion barrels of discovered oil are left behind after conventional primary and secondary production techniques have been employed [3] A typical mature oilfields has an average recovery factor (RF) between 20%-40 % [4].This contrast with a typical RF from gas fields of between 80% and 90%. At current production rates existing proven oil reserves will last 54 years [3]. This is probably as good it has ever been. Improving oil recovery to that typical of gas fields could more than double the time for which oil is available or alternatively allow for increased production rates. This would provide more time for an increasingly energy-hungry world to develop alternative energy sources and technologies. In the typical life of a well, as production continues there is a corresponding decline in pressure. Continuous decline in pressure impedes production rate over time. At first instance, the well produces by natural reservoir energies which accounts for about 15% of OOIP [2]. At decline stage there is need to optimize oil recovery leading to the deployment of secondary and tertiary enhanced recovery techniques which shall be discussed in course of this work.

Water flooding is the most common secondary recovery process worldwide. However, the sweep

Efficiency of conventional water floods can be improved by the injection of polymers. Polymer flooding represents the most mature chemical EOR method as multiple field applications during the past decades exemplify. The main objective of polymer flooding is to improve the mobility ratio (M), defined as the mobility of displacing fluid (water) to the mobility of displaced fluid (oil) ratio. Additionally, polymer injection can accelerate oil production without reducing the residual oil saturation compared to water flooding [5].

Furthermore, Chemical flooding methods are considered as a special branch of EOR processes to produce residual oil after water flooding. These methods are utilized in order to reduce the interfacial tension, to increase brine viscosity for mobility control, and to increase sweep efficiency during tertiary oil recovery [6]. These technologies are deployed in bid to reduce the interfacial tension, to increase brine viscosity for mobility control, and to increase sweep efficiency during tertiary oil recovery. A successful application of this methods is anchored on detail investigation other binding factors such reservoir permeability, and other reservoir rock parameter and composition. It is well known that use of polymer increases the viscosity of the injected water and reduces permeability of the porous media, allowing for an increase in the vertical and areal sweep efficiencies, and consequently, higher oil recovery [7].

Improved oil recovery (IOR) is a term that is sometimes used synonymously with EOR [8] although it also applies to improvements in oil recovery achieved via better engineering and project management, e.g. identifying volumes of oil that have been bypassed during water injection using seismic surveying and then drilling new wells to access those oil pockets [9]. It was first introduced in the late 1980s when the oil price dropped and as a result there was less interest in EOR technologies. At this time there were significant improvements in computer processing speed, computer memory and seismic analysis [10]. Improved computing power enabled engineers to build more complex geological models and thus estimate the effect of reservoir heterogeneity on flow [10] Improved seismic analysis algorithms combined with more powerful computers meant that engineers and geoscientists could use ‘four-dimensional’ seismic surveying, involving the comparison of seismic data taken at different times, in combination with reservoir simulation to identify bypassed volumes of oil on the scale of hundreds of meters horizontally and tens of meters vertically [10]. Using combinations of traditional EOR and IOR technologies it has been possible to achieve RFs of between 50% and 70% [11].

II. LITERATURE REVIEW

A. *Primary Recovery Mechanism*

The recovery of oil by any of the natural drive mechanisms is called “primary recovery.” The term refers to the production of hydrocarbons from a reservoir without the use of any process (such as fluid injection) to supplement the natural energy of the reservoir. The overall performance of oil reservoirs is largely determined by the nature of the energy, i.e., driving mechanism, available for moving the oil to the wellbore. There are basically six driving mechanisms that provide the natural energy necessary for oil recovery;

I. Rock and Liquid expansion drive

II. Depletion drive

III. Gas Cap drive

IV. Water drive

V. Gravity drainage drive

VI. Combination drive

B. Rock and Liquid expansion drive

Rock and fluid expansion occur due to the slightly compressible nature of crude oil, interstitial or connate water. Interstitial or connate water is the initial water saturation in the reservoir at discovery. When an oil reservoir initially exists at a pressure higher than its bubble- point pressure, the reservoir is called an under saturated oil reservoir**.** At pressures above the bubble-point pressure, crude oil, connate water, and rock are the only materials present. As the reservoir pressure declines, the rock and fluids expand due to their individual compressibility.
The reservoir rock compressibility is the result of two factors:

a) Expansion of the individual rock grains

b) Formation compaction

Both of the above two factors are the results of a decrease of fluid pressure within the pore spaces, and both tend to reduce the pore volume through the reduction of the porosity.
As the expansion of the fluids and reduction in the pore volume occur with decreasing reservoir pressure, the crude oil and water will be forced out of the pore space to the wellbore. Because liquids and rocks are only slightly compressible, the reservoir will experience a rapid pressure decline. The oil reservoir under this driving mechanism is characterized by a constant gas-oil ratio that is equal to the gas solubility at the bubble point pressure.
This driving mechanism is considered the least efficient driving force and usually results in the recovery of only a small percentage of the total oil in place [12].

C. Depletion drive

This driving form may also be referred to by the following various terms:

a) Solution gas drive;

b) Dissolved gas drive;

c) Internal gas drive.

In this type of reservoir, the principal source of energy is a result of gas liberation from the crude oil and the subsequent expansion of the solution gas as the reservoir pressure is reduced. As pressure falls below the bubble point pressure, gas bubbles are liberated within the microscopic pore spaces. These bubbles expand and force the crude oil out of the pore space.
[13], suggests that a depletion-drive reservoir can be identified by the following characteristics:

I. **Reservoir pressure:** The reservoir pressure declines rapidly and continuously. This reservoir pressure behavior is attributed to the fact that no extraneous fluids or gas caps are available to provide a replacement of the gas and oil withdrawals.

II. **Water production:** The absence of a water drive means there will be little or no water production with the oil during the entire producing life of the reservoir.

III. **Gas-oil ratio:** A depletion-drive reservoir is characterized by a rapidly increasing gas-oil ratio from all wells, regardless of their structural position. After the reservoir pressure has been reduced below the bubble- point pressure, gas evolves from solution throughout the reservoir. Once the gas saturation exceeds the critical gas saturation, free gas begins to flow toward the wellbore and gas-oil ratio increases. The gas will also begin a vertical movement due to the gravitational forces, which may result in the formation of a secondary gas cap. Vertical permeability is an important factor in the formation of a secondary gas cap.

IV. **Ultimate Oil Recovery:** Oil production by depletion drive is usually the least efficient recovery method. This is a direct result of the formation of gas saturation throughout the reservoir. Ultimate oil recovery from depletion-drive reservoirs may vary from less than 5% to about 30%. The low recovery from this type of reservoirs suggests that large quantities of oil remain in the reservoir and, therefore, depletion-drive reservoirs are considered the best candidates for secondary recovery applications.

D. Water Drive

Some reservoirs have communication with a water zone (aquifer) underneath. When reservoir pressure drops due to production, the compressed water in an aquifer expands into a reservoir and it helps pressure maintenance. This mechanism is called "water drive".

Water drive mechanism will be effective if an aquifer contacting reservoir is very large because water compressibility is very low. For example, an anticline structure with extensive water zone (aquifer) will have the most advantage from the use of a water drive mechanism. Conversely, stratigraphic reservoirs or highly-faulted reservoirs will have limited aquifer volume so water drive is insignificant. Typically, characteristics of reservoirs which are influenced by water drive mechanism are a small pressure decline and a fairly constant producing GOR over a period of time. Small gas production comes from solution gas oil ratio (Rs) and producing gas oil ratio (Rp) gas oil ratio (Rs).

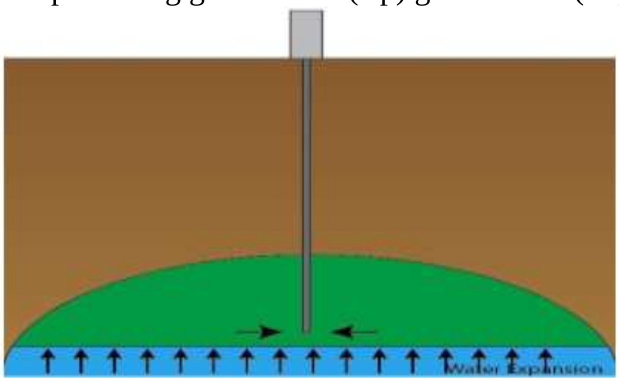


Fig 1: Water drive Mechanism [14]

an aquifer below a reservoir pushes oil towards producing wells and eventually producing wells will have higher water. When the percentage of water production is so high that production becomes not economic, this is called "water out." Wells located at a low structure part will be watered out before wells are at a high structure. Watered-out wells are good candidates to convert to water injection wells for water flood operation.

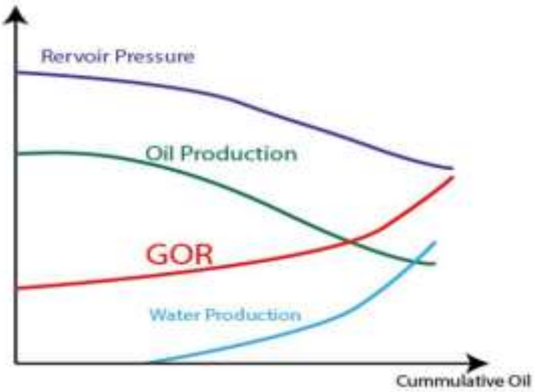


Fig 2 Water drive mechanism profile [14]

E. Gas Cap drive

Some reservoir has a gas cap, which provides energy from gas expansion to help production from a wellbore; therefore, this is called "gas cap drive". When oil is being produced, the gas cap expands and pushes oil downwards to a producing well (Fig 2).

For this type of drive mechanism, it is important to keep gas within a reservoir as long as possible since it is an excellent energy source of the reservoir. Wells which are drilled into a high structure area where the gas cap is located must be closely monitored because this well will have more of a chance to produce gas. When reservoir pressure declines, free gas will come out of a solution. If a well has a good vertical permeability and the production rate is quite low, free gas will migrate and accumulate with an existing gas cap. This is an additional energy source to help production and ultimate recovery will improve. However, if a well produces at a high rate, free gas will be produced with oil and gas and the ultimate recovery will not be as high as it should be. Furthermore, with a high flow rate, gas will flow quickly into oil because it has much lower viscosity than oil. So, this will create a situation called "gas fingering" [16]

For the gas cap drive, declining in production rate and reservoir pressure as slower from this drive is around 20%-40 % [17]

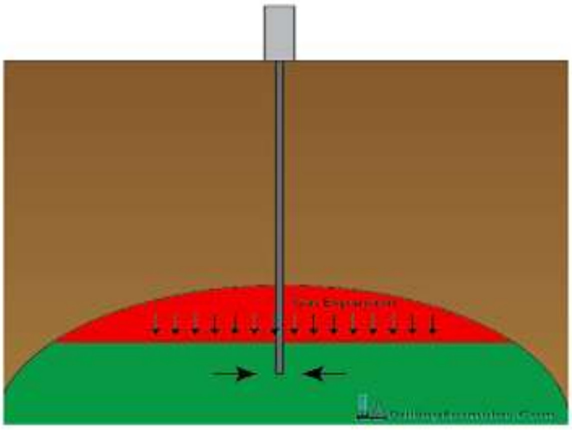


Fig3: Gas-gap drive [14]

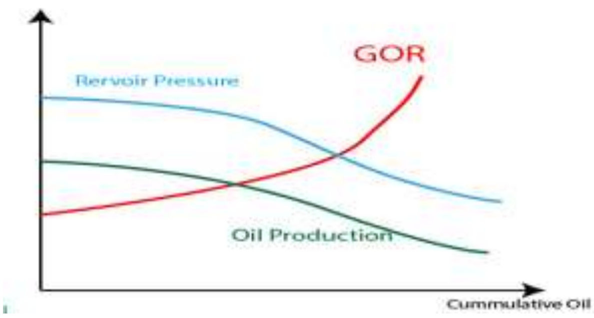


Fig 4: Gas-cap drive profile [14]

F. Gravity drainage drive mechanism.

The fluids in petroleum reservoirs are naturally subjected to gravity forces; hence the density differences between oil, gas and water result in their natural segregation in the reservoir. This process can be used as a drive mechanism but is relatively weak; instead, it is used to make improvements in other mechanisms. The best conditions for gravity drainage are said to be thick oil zones and high vertical permeabilities. As such, in a solution-gas mechanism, the density difference between oil and gas can lead to the formation of a secondary gas cap, which depends upon factors such as reservoir structural geometry, vertical permeability and production rate [18]. This might effectively increase the ultimate recovery factor

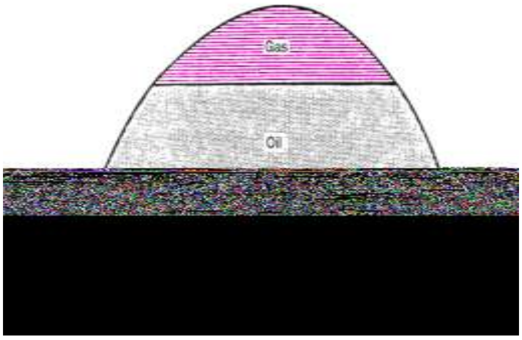


Fig.5: Initial distribution of fluids in a reservoir [18]

G. Combination Drive Mechanism

A reservoir can produce under various mechanisms without any preponderant influence of one mechanism on another. In this sense, production is said to be a result of a combined mechanism in which both water and free gas are available to some degree to displace the oil. From the standpoint of Ahmed, two combinations of driving forces can be present in those reservoirs;

a. Depletion drive and a weak water drive

b. Depletion drive with a small gas cap and a weak water drive.

In both cases, pressure will decrease rapidly given that water encroachment and gas-cap expansion are not enough to maintain reservoir pressure. It is worth mentioning that depletion drive will play an important role in a determined stage of production, given that the reservoir pressure will be reduced below the bubble-point pressure causing the displacement of gas from the solution. Besides, gravity segregation indeed plays an important role in any of the cited drives. The recovery factor for combined mechanisms is greater than recovery for depletion-drive mechanism but less than recovery from water drive and gas-cap drive reservoirs. The ultimate recovery will depend upon the capacity to reduce the strength of recovery by depletion drive. In most cases, it is economically profitable to employ pressure maintenance operations such as gas and/or water injections [12].

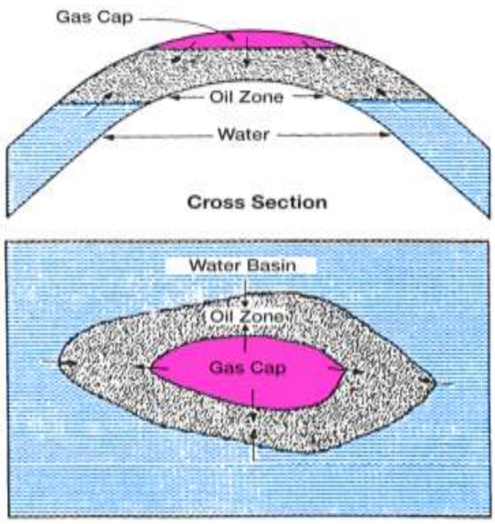


Fig.6: Combination Drive-reservoir [18]

III. RECOVERY FACTOR, RF

Oil companies will want to maximize the value of a field by getting as much of the hydrocarbons out of it as possible. However, it is not feasible to recover the entire hydrocarbon from a reservoir. Only a certain percentage of the total hydrocarbons will be recovered from a field, and this is known as recovery factor [19]. Recovery factor are higher in gas field than in oil fields. Typical recovery factors for gas are about 50-80 % [10]. There is more scope to improve oil recover. Global recovery factors for oil are thought in the range 30-35 % [11].

A. Why is recovery very low?

In furtherance of this review, it's vital to look briefly why recovery is low. Water flooding (which shall be discussed in details later) is currently the preferred recovery technique for most reservoirs because of the higher sustained oil production rates, and the overall higher RFs, that are obtained compared with the case if water were not injected. Oil production without injection is often termed primary recovery. This is because the first wells drilled in a field development are typically production wells to enable oil production and thus the start of income from a field. Where reservoir pressure is well above the bubble point, primary production can be continued for some time before additional pressure support is required to prevent gas coming out of solution in the reservoir.

During depletion, oil flows through the production wells to the surface because the pressure at the base of the well exceeds that exerted by the hydrostatic head of the column of oil in the well. Initially, this occurs naturally but over time the oil rate tends to decrease as the reservoir pressure decreases. In the absence of water injection, pumping may be used to maintain oil rate at economic levels. If reservoir pressure falls below the oil bubble point pressure, gas that was initially dissolved in the oil will come out of solution and, because it has a much lower viscosity, will flow preferentially to the production well. At the same time the viscosity of the remaining oil increases, reducing its mobility further. This will reduce the oil production rate further (although it may increase the total (oil plus gas) production rate through reducing the hydrostatic head in the well). Water (or gas) injection is usually applied before this happens so as to maintain reservoir pressure above the bubble point. For this reason, it is sometimes known as secondary recovery. Water flooding is relatively cheap, especially for offshore fields because of the ready availability of seawater, although care has to be taken to ensure that the injected water does not result in unwanted, adverse reactions in the reservoir. In some cases injected brines may react with the naturally occurring water in the reservoir (termed connate water) to form scale while injecting very pure water rather than brine may result in clay swelling. Both of these may block the rock pores and reduce the rock permeability. The cost of drilling additional wells for injection is more than outweighed by the increased oil rates that result. Re-injection of gas (produced along with the oil) is used when there is no easy, economic way to export it for sale.

The factors affecting RF from water flooding (and gas flooding) can be understood by considering the following approximate relationship [20].

$$RF= E_{PS} \times E_S \times E_D \times E_C \qquad (1)$$

Where;

i. RF is the recovery factor which is defined as the volume of oil recovered over the volume of oil initially in place (OIIP), both measured at surface conditions.

ii. E_{PS} Is the microscopic displacement efficiency. This describes the fraction of oil displaced from the pores by the injected water, in those pores which are contacted by the water.

iii. E_S : Is the macroscopic sweep efficiency—the proportion of the connected reservoir volume that is swept by the injected fluid(s). This is principally affected by heterogeneity in rock permeability and by gravitational segregation of the fluids.

iv. E_D: Is the connected volume factor—the proportion of the total reservoir volume connected to wells This represents the fact that sealing faults or other low-permeability barriers may result in compartments of oil that are not in pressure communication with the rest of the reservoir.

v. E_C : Is the economic efficiency factor, representing the physical and commercial constraints on field life such as facilities life, capacity to deal with produced gas and water, reservoir energy (the reservoir pressure may become so low that fluids cannot be produced).

It can even be seen that if each of the efficiency factors is a very respectable 80% then the overall RF is only 41%. Increasing RF therefore requires each of these factors to be increased to close to 100%. EOR methods are targeted at increasing *EPS* and *ES* while IOR methods also aim to increase *ED* and to some extent *ES*. Improving *EC* is mainly the role of the production and facilities engineers but is also affected by EOR methods if these reduce the amount of water and gas produced alongside the oil, enabling oil to be produced for longer before economic limits are reached.

B. Factors affecting macroscopic sweep efficiency.
The typical microscopic displacement efficiency from a water flood is 70% or less. This is mainly because oil ganglia become trapped in the pore space by capillary [17] but E_{PS} is also affected by the relative permeability characteristics of the rock [21] which control the relative mobility of the oil and water when moving through the pore space. The importance of pore-scale capillary effects on a displacement can be quantified by the capillary number;

$$\mathrm{Ca} = \frac{v\mu}{\gamma} \qquad (2)$$

Where v is the interstitial velocity, μ is the fluid viscosity and γ is the interfacial tension (IFT) between the displaced and displacing fluid. When Ca $<10^{-5}$ flow is dominated by capillary effects and, in particular, capillary trapping is likely to occur. The typical interstitial velocity in an oilfield displacement (distant from the wells) is approximately 10^{-5} ms^{-1}while the viscosity of a typical light oil is similar to that of water (approx. 10^{-3}Pa s). The IFT between brine and oil is approximately 0.1 mNm^{-1} so for a typical water flood the capillary number is approximately 2.5 $\times 10^{-5}$. It is generally not possible to apply a sufficiently large pressure gradient between wells to significantly increase the interstitial velocity or to maintain this velocity while injecting a high-viscosity fluid, thus the only way for a reservoir engineer to increase the capillary number is to reduce the IFT. Based on the above calculations this means that the IFT between the oil and the displacing fluid has to be less than approximately 0.1 mNm^{-1}in order to minimize capillary trapping.
Both capillary and relative permeability effects are also influenced by the wetting behavior of the rock in which the oil is found. As discussed in the previous paragraph, if the rock is water wet then there is a higher residual oil saturation (the proportion of oil which remains permanently trapped by capillary effects at the pore scale). This is caused by the growth in the water film on the rock surface during water injection, which ultimately leads to water bridging at the pore throats [so-called snap-off [9] fig 3] trapping droplets of oil within the pores. As a result, little oil is produced after water breakthrough at the production well unless a higher-pressure drop is applied (which is impractical in most cases). If the rock is oil wet, then the proportion of oil trapped by capillary effects is much lower, as oil continuity is maintained over the rock surfaces and through the

pore throats, but water breakthrough is earlier and there is a long period of time during which oil and water are produced simultaneously. The net result is that overall recovery is generally higher [if the reservoir rocks oil wet but only after a very large throughput of water.

Most oil reservoir rocks are thought to have a heterogeneous wettability, usually termed ‘mixed wettability’, in that larger pores and throats have both water- and oil-wet surfaces but smaller pores remain mainly water wet [18]. It is believed that the reservoir rock changes from an initially water-wet state to this mixed wettability state after the migration of oil into the reservoir [20]. Polar compounds in the oil alter the wettability of the rock by a range of interactions including precipitation of asphaltenes, acid–base interactions and ion binding between charged sites on the pore walls and polar hydrocarbon moieties involving higher valency ions in the water that shares the pore space with the oil [20]. The wettability of reservoir rock thus depends upon its mineralogy, the crude oil composition, the connate water composition and the pore size distribution.

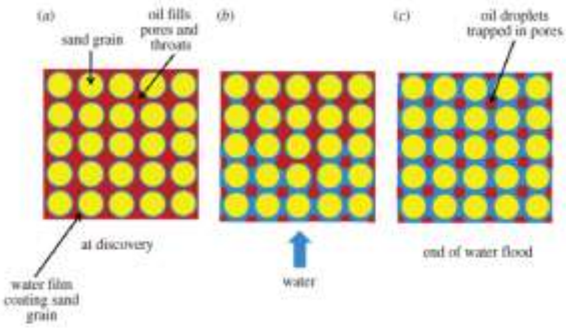


Fig.7: Illustration of oil trapping in a water-wet rock. (*a*) At discovery the sand grains are coated with a thin water film and the pores are filled with oil; (*b*) as water flooding progresses the water films become thicker until (*c*) the water films join and oil continuity is lost [14].

During water flooding in a mixed wettability rock oil and water drain simultaneously through the pore space, snap-off is reduced as most throats have both oil- and water-wet surfaces and thus there is less capillary trapping of oil. This simultaneous drainage of water and oil through the pore space behind the water front combined with the lower residual oil saturation means that more oil is recovered than when the rock is either water or oil wet.

Increasing microscopic displacement efficiency depends upon finding ways to (i) reduce capillary effects, by reducing the oil–water (or gas) IFT, and (ii) modify the rock wettability to the optimum mixed wettability state.

C. *Factors Affecting Macroscopic Sweep Efficiency*

The macroscopic sweep efficiency of a water flood is principally affected by the geological heterogeneity in the reservoir, which controls the spatial distribution of porosity and permeability. Rock permeability is dependent on the number, size and connectivity of the pores in the rock. The permeability of a typical reservoir rock is approximately 10−13m^2. A very good reservoir rock might have permeability as high as 10−11 m^2 while a permeability of 10−15 m2 would be considered very poor. It is controlled by the size of the sediment grains from which the rock was formed, their packing and the subsequent diagenesis (chemical alteration) and cementation (mineral deposition) around those grains. The patterns of grains forming a sedimentary rock depend upon the depositional environment in which the original sediments were formed. These result in permeability heterogeneities with length scales from millimetres to kilometres Fig 7. Higher permeability channels or layers (often described as ‘thief zones’) through the rock is one common, adverse manifestation.

of geological heterogeneity. The injected water flows preferentially through these zones, bypassing volumes of oil contained in the lower permeability portions of the reservoir. This results in early water production along with the oil and a reduce Fig 7. A particular problem is that the distribution of permeability in a reservoir is usually very uncertain. It is possible to infer the general characteristics of the heterogeneity from the depositional environment and sometimes to correlate specific rock layers between wells, but there is virtually no information about the detailed permeability distribution on smaller length scales. This means that statistical approaches, often based on limited numbers of realizations of the possible reservoir heterogeneity, are needed when attempting to predict reservoir performance. The effect of geological heterogeneity is exacerbated if the injected fluid has a much lower viscosity than the oil, as is the case when gas is injected instead of water [15]. This effect is characterized by the mobility ratio *M*, which compares the mobility of the saturating (*S*) and displacing (*D*) phases in the porous medium.

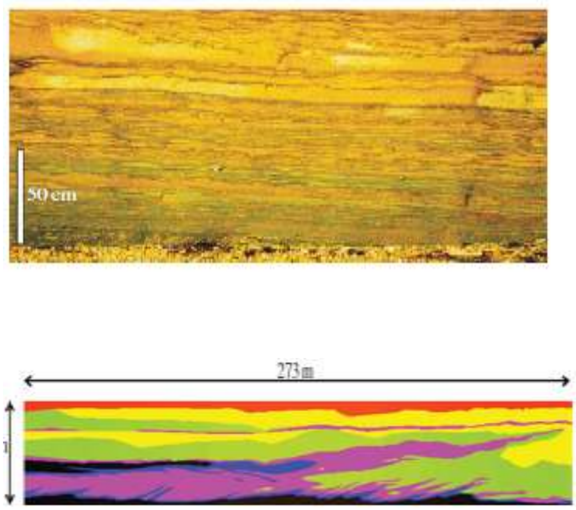


Fig.8: Examples of the types of geological heterogeneities encountered in sandstone oil reservoirs. These examples come from rocks deposited in a deltaic environment. (*a*) Photograph of a heterolithic facies with permeability variations on a centimetre lengthscale vertically and a 10 cm length scale horizontally (after Jackson *et al*.2003). (*b*) Interpreted picture of tidal bar deposits. The length scale of these heterogeneities is approximately 100m [15].

$$M = \frac{\mu_S K_{rD}(S_{or})}{\mu_D K_{rDS}(S_{wc})} \qquad (3)$$

Where $K_{rD}(S_{or})$ is the relative permeability of the porous medium to the displacing phase at the residual oil saturation S_{or} $K_{rDS}(S_{wc})$ is the relative permeability of the oil to the displacing phase at the immovable water saturation S_{wc} and μ is the viscosity of the fluid. This is derived from the Darcy equation. The viscosity component of this equation is usually dominant. Even in a homogeneous reservoir, the macroscopic sweep will be reduced when *M*>1 owing to unstable viscous fingering [16].

Macroscopic sweep may also be affected by gravitational segregation but this is more often observed in gas–oil rather than water–oil displacements because of the higher density contrast between gas and oil [16]. The gas tends to rise above the oil because of its low density and then flow rapidly along the top of the reservoir in an unstable gravity tongue because of its low viscosity. This can result in very early gas breakthrough and poor vertical sweep efficiency. Improving the macroscopic sweep efficiency depends upon finding techniques that minimize the impact of geological heterogeneity. This is usually achieved by a mixture of viscosity modification of the injected fluid and/or flow diversion in which the water is diverted from the higher permeability zones in the reservoir into the lower permeability rock still containing displaceable oil. In gas floods, it is also important to minimize gravitational segregation.

IV. CONVENTIONAL ENHANCED OIL RECOVERY PROCESS

As noted above, the purpose of EOR technologies is to improve the microscopic displacement efficiency and/or the macroscopic sweep efficiency over that obtained from water flooding. Traditionally these involved adding chemicals to the injected water to change its viscosity and/or reduce the IFT with oil, or injecting other fluids into the reservoir (such as carbon dioxide, nitrogen or hydrocarbon gases) that have a very low IFT with the oil (less than 0.1m10^{-1}). Most EOR processes are thus more expensive to implement than a conventional water flood and only become economically attractive for larger oilfields and when the oil price is high.

A. Miscible gas Injection

Miscible gas injection is an EOR process that improves microscopic displacement efficiency by reducing or removing the IFT between the oil and the displacing fluid (the miscible gas). When used after a water flood this has the effect of re-establishing a pathway for the remaining oil to flow through and results in very low residual oil saturation (2%) has been measured in reservoir cores recovered from gas swept zones. The drawback of this process is that the gas is both less viscous and less dense than the oil. As a result, these schemes often have a lower macroscopic sweep efficiency as they are adversely affected by viscous fingering [18] heterogeneity and gravity. The injected gas may be hydrocarbon gas, carbon dioxide or nitrogen depending on what is available and the reservoir conditions. CO_2 *is* Miscible with oil at a relatively low pressure and temperature but obviously requires a source of CO_2. Past applications were in fields near natural sources of CO_2. It can result in problems with corrosion of steel pipe unless care is taken in the design of wells, flowlines and facilities as well as provision for the separation of the CO_2 from the hydrocarbon gas when produced. Nitrogen requires a relatively high reservoir pressure for miscibility and involves the use of additional equipment to separate it from the air.

Hydrocarbon gas is usually readily available from the field itself or adjacent fields and is thus most widely used, especially in fields where there is no ready market for the gas [18]. In most cases, however, the produced gas that was originally associated with the oil has to be artificially enriched with heavier components in order to make it miscible or nearly miscible with the oil. It may also have to be supplemented with gas from other sources or water injection because the volume of produced gas, when re-injected, may not be sufficient to maintain reservoir pressure above the minimum miscibility pressure (MMP).

It is more usual for the injected hydrocarbon gas to be nearly miscible with the oil rather than miscible on first contact. Miscibility then develops between the fluids through the exchange of components, commonly referred to as multi-contact miscibility, resulting in the gas becoming heavier as it passes through the oil and/or the oil becoming lighter [20]. However, even if the gas does not achieve full miscibility with the oil there are likely to be pore-scale displacement benefits compared with a water flood as gas components may dissolve in the oil, causing its volume to increase and its viscosity to reduce. As a result it is possible for an immiscible gas flood to result in a lower residual saturation than a water–oil displacement.

B. Water Alternated Gas

WAG injection is an EOR process that was developed to mitigate the technical and economic disadvantages of gas injection. It is the most widely applied and most successful traditional EOR process [12]. It involves the injection of slugs of water alternately with gas although sometimes the two fluids are injected simultaneously (termed SWAG). Usually, the gas is first contact miscible or multi-contact miscible with the oil but this is not always the case. Injecting water alternately with the gas reduces the volume of gas required to maintain reservoir pressure. It also reduces the tendency for the gas to finger or channel through the oil as the presence of mobile water in the pore space reduces the gas mobility through relative permeability effects. Vertical sweep efficiency is also improved as water, being heavier than oil, tends to slump towards the bottom of the reservoir while the gas, being lighter, rises to the top [15]. Although the majority of WAG applications in the field have been successful, the incremental recovery achieved is generally less than that predicted [21]. Early gas breakthrough and a reduced macroscopic sweep, owing to channeling or gravity over-ride, are common. In addition, there are often operational problems. In particular, injectivity can be lower than expected owing to a reduced total fluid mobility near the well as a result of three-phase relative permeability effects and/or a reduced hydrostatic head in the injection well during gas injection.

C. Chemical Flooding

Chemical flooding is a term that is used to describe the addition of chemicals to the water. Depending on the process, these may change the IFT of water with oil (usually surfactants and alkalis) and/or make the water viscosity match that of the oil (polymers). Chemical flooding has been an option for EOR since the mid-1960s (Standiford, 1964). Early projects using polymer alone were soon supplemented by adding surfactants developed to reduce the water–oil IFT and increase the recovery. Soon afterwards alkalis were added to reduce adsorption of the chemicals by the rock and form added surfactants from charged oil molecules in the reservoir.

D. Polymer Flooding

One means of achieving a more favorable mobility ratio, and thus improve macroscopic sweep, in water flood is to viscosity the water. This has most often been achieved using high molecular weight water-soluble polymers of 2-propenamide (acrylamide) and 2-propenoic acid (acrylic acid) as the partly neutralized sodium salt in a ratio of about 70:30 of polymer to acid by weight [22]. The polymers typically have a molecular weight (or relative molecular mass) of 9–25 million daltons. When dissolved in water, the solutions have a viscosity that depends on the polymer concentration, polymer molecular weight, temperature, water salinity and the concentration of divalent ions. Other polymers, such as xanthan [22]. have been used for the benefit of the improved viscosity yield in more saline water, but these have often been consumed by anaerobic sulfate-reducing bacteria resident in oil reservoirs causing the generation of dissolved hydrogen sulfide (commonly known as known as 'souring'). Polymer flooding can recover a substantial increment of the oil in place, typically 8%, at an additional cost of between US$8 and US$16 per incremental barrel [23], but even after 46 years there are difficulties that limit the use of this technology [22]. Large volumes are needed to make the process work at the field scale. The polymers are most effectively supplied as a dried powder but the equipment needed to dissolve them at suitable rates is bulky and there may not be space for this to be retrofitted on offshore platforms. The resultant solutions are vulnerable to shear damage at high shear rates (over about 1000 s^{-1}) and are particularly damaged by extensional shear. Increasing the viscosity of the injected fluid inevitably makes it more difficult to inject that fluid into the reservoir and, if the polymer solution has not been properly prepared, debris may actually plug the pore space around the well- [21] Once in the reservoir, the polymer molecules are unstable at temperatures above approximately 70°C depending on the water salinity and ionic composition. The mechanisms of thermal degradation are hydrolysis of the amide groups to acid followed by 'salting out' (precipitation, mainly driven by the interaction of the acid groups with calcium ions) of the polymer, or free radical (redox) depolymerization resulting in smaller molecules with a lower viscosity.

E. Alkaline Surfactant Polymer flooding

Alkaline surfactant polymer (ASP) flooding aims to improve microscopic displacement efficiency by reducing the IFT between the water and oil through the addition of a surfactant to the water, while matching the oil and water mobility through the addition of polymer [19]. Alkali is also added to the water to reduce adsorption of the surfactant onto the pore walls and to control the local salinity to ensure minimum IFT. It can also alter the rock wettability. Alkali–surfactant mixtures have also been used to improve macroscopic sweep during WAG. In this process, the gas mobility is further reduced by adding alkali and surfactant to the injected water and thus creating a foam within the pore space [23] Like polymer flooding, ASP flooding can significantly improve RFs with incremental costs quoted to be as low as $2.42 per incremental barrel for an onshore field [21] however, like polymer flooding, there are a number of difficulties which have limited widespread field application, especially offshore. Operational difficulties include the large volumes of chemicals that have to be transported to remote sites and then stored on platforms where space is limited. Additional produced fluid processing is needed as ASP flooding results in the production of emulsions with droplets as small as 10μm in diameter. Finally produced fluids (containing the ASP chemicals) need to be disposed of without impacting the environment. Technical difficulties include the fact that the chemical mix needs to be carefully designed for the fluids to be encountered in the field. ASP flooding works best with relatively low-salinity water (often optimal performance is achieved by the use of a salinity gradient during injection of the different stages), but, offshore, seawater is the only source of injection water so desalination or alternative chemicals may be required.

V. REVIEW OF RELATED WORK

In Furtherance of this work, it is vital to review research done as per the concept in consideration. [22] in their work simulated using slumberger eclipse for recovery by polymer injection where natural depletion of the reservoir was run to 100bars. 5 vertical wells were used and a recovery of 30% was achieved with a production plateau of about 8years. This is preferred to the use of 4 or 6 producing. Polymer injection was simulated by commencing water injection as a secondary recovery mechanism after reservoir depletion to a bottom-hole flowing pressure of above 260 bar followed by a polymer flood. This gave a significant increase in oil recovery from 30% to about 53% with the production plateau sustained for 4.8 years. A total of 11 wells were used, 7 producers and 4 injector wells. Proceeding along similar line, [10], developed a mathematical model for black oil simulation that consist of polymeric solutions in one-dimensional porous media as a function of time and z-coordinate. The mathematical model consisting of heterogeneous, non-linear and simultaneous partial differential equations describes the physical process and consist of various parameters and variables that are involved in lab-scale process to quantify and analyze them. The model-predicted and commercial reservoir (CMG)-simulated oil productions was said to be in good agreement with experimental oil recoveries with a root-mean-square error in the range of 1.5-2.5 at a maximum constant pressure of 3.44MPa as well as temporal variation of the injection between 2.41 and 3.44MPa.

VI. MATERIALS AND METHOD

This chapter extensively discusses the simulation methodology used in this study. The simulation work flow, simulation parameters, mathematical framework and model assumption are presented below;

A. *Mathematical Framework*

1) **Rock Model:** When considering porous media at the macro-scale, the flow is governed by volume averaged equation. Each computational block contains both solid and pore spaces which is filled with fluid, such as gas, oil and water. The percentage of pore space which is called porosity, is defined as

$$\emptyset = \frac{V_{pore}}{V_{bulk}} \quad (4)$$

Where $V_{pore}$the volume of the pore is space and V_{bulk} is the volume of the block. Porosity is a function of pressure (and temperature) and it can be modelled by the following equation;

$$\emptyset(P) = \emptyset_r + c_r(P - P_r) \quad (5)$$

Where, c_r, is the compressibility factor of the reservoir, P is pressure, and $\emptyset_r$ is the reference porosity at the reference pressure P_r.

2) **Fluid Model:** The notion of saturation S_{or} is introduced to define the ration of the volume of phase α to the pore space in a block:

$$S_\alpha = \frac{V_\alpha}{V_{pore}} \quad (6)$$

The saturation of the oil phase (o) and the water phase (w) satisfy the following relationship;

$$S_w + S_0 = 1 \quad (7)$$

Darcy's law is applied to handle the relationship among the flow rate of a phase, reservoir properties fluid properties and pressure in a reservoir, which is described as;

$$Q = -\frac{k_e A \Delta P}{\mu L} \quad (8)$$

Where A is a cross-sectional area in a flow direction, ΔP, is a pressure difference, μ is the viscosity of a fluid, and L is the length of a porous medium in the flow direction, K_e, is the effective permeability for the given phase, which is the product of the absolute permeability k and the relative permeabilityK_r, k is defined as a tensor with respect to all the x, y and z direction; mostly, it is a a diagonal tensor: k= (k_x, k_y, k_z). Darcy's law can also be rewritten, with Darcy's velocity q,

$$q = \frac{Q}{A} = -\frac{K_e}{\mu}\nabla P \quad (9)$$

With gravity, the mass of each of each phase satisfies the following conservation law

$$\frac{\delta}{\delta t}(\emptyset S_\alpha p_\alpha) = \nabla.\left(\frac{KK_{r\alpha}p_\alpha}{\mu_\alpha}(\nabla P_\alpha - \gamma_\alpha \nabla Z)\right) + q_\alpha \qquad (10)$$

Where p_α is the phase density, is the source term that models the mass changes caused by injection or production wells, γ is the gravity, Z is the depth of a block, and $K_{r\alpha}$stands for the relative permeability for the α phase. In addition, when polymer exists in the water phase, the mass conservation law for the water phase becomes;

$$\frac{\delta}{\delta t}(\emptyset S_w p_w) = \nabla.\left(\frac{KK_{rw}p_w}{R_k \mu_{w,e}}(\nabla P_w - \gamma_w \nabla Z)\right) + q_w \qquad (11)$$

Where R_k is, the permeability reduction factor caused by polymer and $\mu_{w,e}$ is the viscosity of a water-polymer solution. The definitions of $R_k$and $\mu_{w,e}$ will be introduced later. The water phase pressure,P_w, and the oil phase pressure,P_o, are related by;

$$P_c(S_w) = P_o - P_w \qquad (12)$$

The pressure difference is called the capillary pressure, which usually depends on the saturations of the phases in porous media and is measured by lab experiments. If saturation and any phase pressure are known, the other phase pressure can be calculated by the above formula.

B. Polymer Model

The flow of polymer is assumed to act as a component dissolved in the water phase, which is modeled by the following equation:

$$\frac{\partial}{\partial t}(\emptyset S_w \rho_w C_p + (1-\emptyset)A_d) = \nabla.\left(\frac{\rho_w C_p KK_{rw}}{R_k \mu_{p,e}}(\nabla P_w - \gamma_w \nabla Z)\right) \qquad (13)$$

Where, C_p,is the concentration of the polymer in the water phase and $A_d$is the polymer adsorbed by the reservoir. When polymer molecules flow through porous media, parts of them are restricted in pores, where only water or brine is allowed to pass by with a reduced mobility. As the polymer solution interacts with the reservoir rock, polymer is adsorbed or desorbed from the rock surface; this mechanism is known as polymer retention. There are two mechanisms during the polymer retention process, which are separated as adsorption of the polymer on rock surfaces and entrapment of polymer molecules in small pore space. Both these mechanisms increase the resistance of flow. These effects are modeled by reducing the permeability of the rock to water.

C. Building Model

The model will be built utilizing Eclipse 300. The following will be computed manually; displacement efficiency, recovery efficiency, Ultimate Recovery, Producers and Injectors number using the following relation;

a. **Recovery Efficiency;**

$$R = E_d \times E_a \times E_v \qquad (14)$$

Where;

$E_a = f(Inverse\ Mobility\ ratio, f_w)$

$E_v = f(\ rock\ properties)$

b. **Cumulative Production by polymer Injection, N_{po}**

$$N_{po} = (\ OOIP - N_p) x\ R(3) \qquad (15)$$

$N_p = Recovery\ during\ primary\ stage$

c. **Displacement Efficiency, E_d**

$$E_d = \frac{S_{wm} - S_{wc}}{1 - S_{wc}} \qquad (16)$$

Where S_{wm},is the water saturation behind the front?

d. **Estimated Ultimate recovery,**

$$EUR = \frac{(N_p + N_{po})}{OOIP} \text{ X } 100 \qquad (17)$$

e. **Numberof producers,**

n_p & $Number\ of\ Injectors, n$

$$n_p = \frac{Q_p}{q_p} \qquad (18)$$

D. Model Assumption

The following assumption was made;

I. The reservoir is considered to be slightly heterogeneous.

II. The aqueous phase's density is considered to be independent of the polymer concentration

III. In the same line, the formation Volume factor is in dependent of the polymer concentration

IV. The polymer solution, reservoir brine and the injected water are represented in the model as miscible components in the aqueous phase, where the degree of mixing is specified through the viscosity terms in the conservation equations.

V. The equation solved by the Eclipse polymer model are a discretized form of differential

Saturation	**Krog**
0.300	0
0.75	1.0

ions.

E. Case Description:
The case history SPE data used in this simulation are presented below;

Table I: Case definition

S/N	Parameter	Description
1	Reservoir Type	Oil reservoir
2	Number of phases	3

Reference Pressure	Krow	PCG
0	1.0	2.0
8000	0.92	2.0

3	Name of phases	Oil, Water, Polymer

F. Grid Description

Table II: The grid properties are shown in the table below;

S/N	Parameter	Description
Grid type	Cartesian (Block Centered)	Ft
Grid Dimension	75x75x37 DX.DY.DZ.	
PERMX	50	Milidarcy
PERMY	50	Milidarcy
PERMZ	50	Milidarcy
Porosity	0.2	

Reservoir depth of total surfaces (TOPs) = 4000ft.

G. Rock and Fluid PVT Properties
The basic rock and fluid parameters used in this study are laboratory data simulated at reservoir conditions. The water, gas and oil saturation functions are shown in the tables below. Other additional critical PVT parameters required for complete Eclipse300 compositional simulation.

Table III: Water Saturation Function (SWFN)

Saturation	Krw	PCow
0.25	0	4.0
0.7	1.0	0

Table IV: Oil Saturation Function (SWFN)

Water PVT Properties (PVTW)
Formation Volume Factor (FVF) = 1.0
Compressibility =3.03E-06

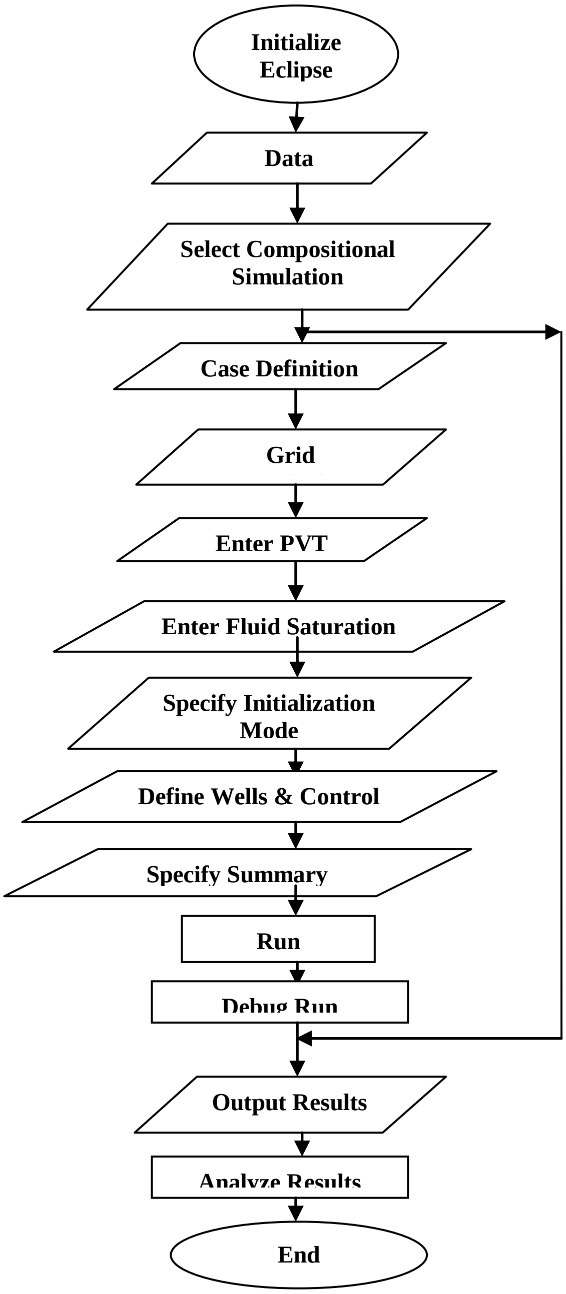
Table V: Dead Oil PVT Properties

Table VI: Fluid Density

Oil	52.000
Water	64.000
Gas	0.04400

F. Simulation of Workflow

In this study, a stepwise algorithm/ simulation flow chart was used to ensure consistent results with model description/ study aim. The diagram in Figure below provides the summary of simulation procedures as employed in this investigation



VII. RESULTS AND DISCUSSION

A. Model Description

The reservoir model considered in this work is shown in Figure (4.1). As illustrated in the figure, the reservoir was produced using a polymer injection well and a production well situated at grid locations, (1, 1,1) and (10, 10, 1) respectively. The analyses were made using a time step of 1 day over 100 days of production period. The critical production constraints are parameters were studied and critically analyzed in terms of field performance and ultimate recovery of the in-situ fluids. A detailed discussion of the simulation results are presented in the preceding figures below.

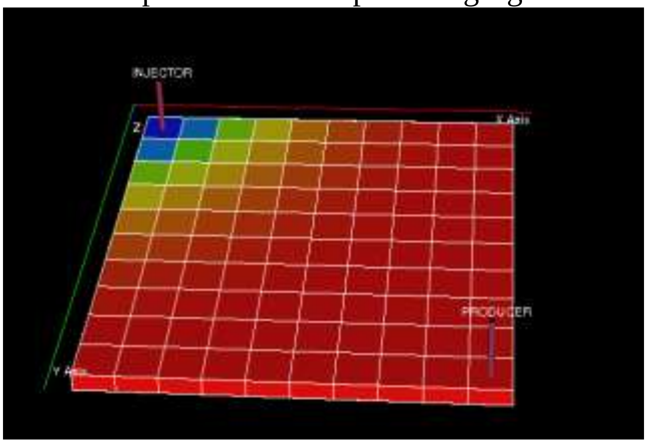


Fig 9: Reservoir Grid Layout showing the Wells Analysis of Polymer Adsorption in the Reservoir Grid Cells

As polymer is introduced into the reservoir rock matrix which discretized using uniform gridding system, the polymer phase which is in aqueous solution with the water phase are continually adsorbed by the formation rock. This process in turn facilitates both the displacement of the in-situ fluids and also a change in fluid mobility caused by relative permeability reduction.

From Fig 10 below, it was shown that rate of adsorption of the polymer is characteristically influenced by the relative concentration of the polymer phase in reservoir cell control volume.

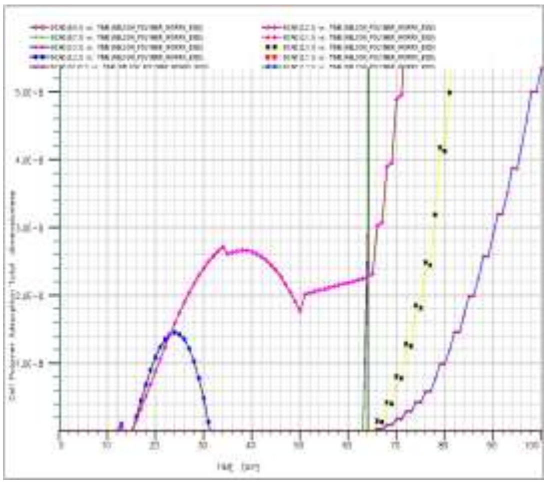


Fig 10: Polymer Adsorption in Selected Reservoir Grid Cells (NB: The cells were chosen diagonally from the injector to the producer – (1, 1, 1), (2, 2, 1), (3, 3, 1), (4, 4, 1), (5, 5, 1), (6, 6, 1), (7, 7, 1), (8, 8, 1), (9, 9, 1) and (10, 10, 1)

Since the concentration of the polymer increases with time, there is corresponding increase in the rate of adsorption. However, it must be noted that there is no uniform trend observed for each cell. This is because of the complex chemical processes associated with the resultant change in the cell control volume relative mobility and interfacial tensions.

Since the concentration of the polymer increases with time, there is corresponding increase in the rate of adsorption. However, it must be noted that there is no uniform trend observed for each cell. This is because of the complex chemical processes associated with the resultant change in the cell control volume relative mobility and interfacial tensions. The change in polymer concentration within the finite reservoir cell was plotted in Fig 10. The selected cells were the 9 cells in injection well vicinity, the median cell located at (6, 7, 1), the producer cell (10, 10, 1) and the cell nearest to the producer, (9, 9, 1).

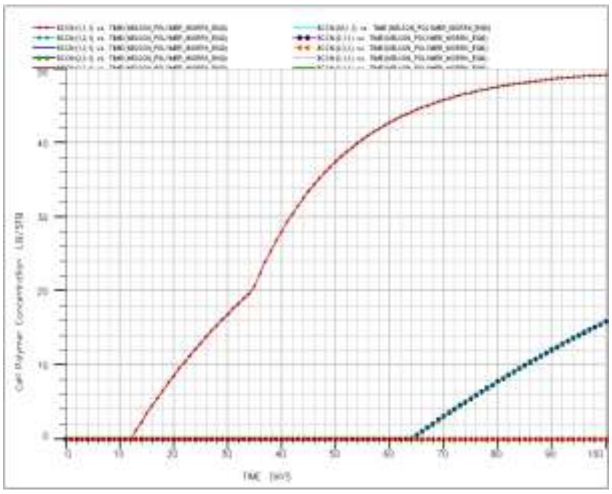


Fig 11: Cell Polymer Concentration of Selected Grid Cells

As shown in the above Fig 11, the polymer cell concentration was highest in the injection well grid block and rapidly decreases towards the producer. The result also showed that within the period analysis, the polymer advancement was still relatively around the injector. In other words, the producer has not been effective affected by the polymer injector.

One of the most important principles underlying oil displacement by polymer flooding is the change in the fluid interfacial tension. This in turn causes a remarkable change in the in-situ fluid capillary pressure as shown in Fig 11. The plots show that the capillary pressure was most remarkable in the injection well vicinity. The median gridblock, (6, 7, 1), and the producer cells do not record any change. This does not mean however, that these cells may not be affect all through the production period. It only shows that within the period of analysis (100 days of production, the effects of interfacial tension reduction of relatively distant cells was not pronounced.

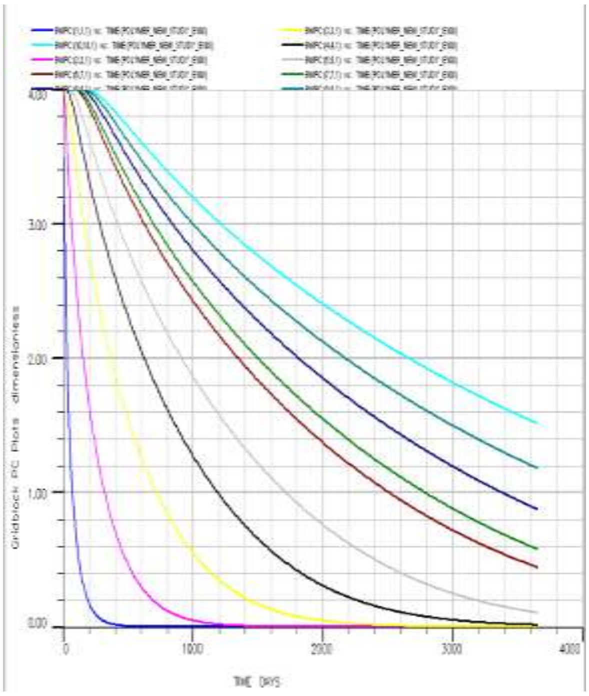


Fig 12: Gridblock Capillary Pressure Plots

From the ongoing analysis, similar selected cells were analyzed in terms of relative permeability change with time as shown in Fig 12. The results clearly illustrates that relative permeability reduces with increasing polymer concentration and relative distance from the injector. Since production was only for a few days, it is not surprising to observe remarkable difference in relative permeability of the injector grid cell and the cells directly next to them as shown by the curve of BKRO (2, 2, 1).

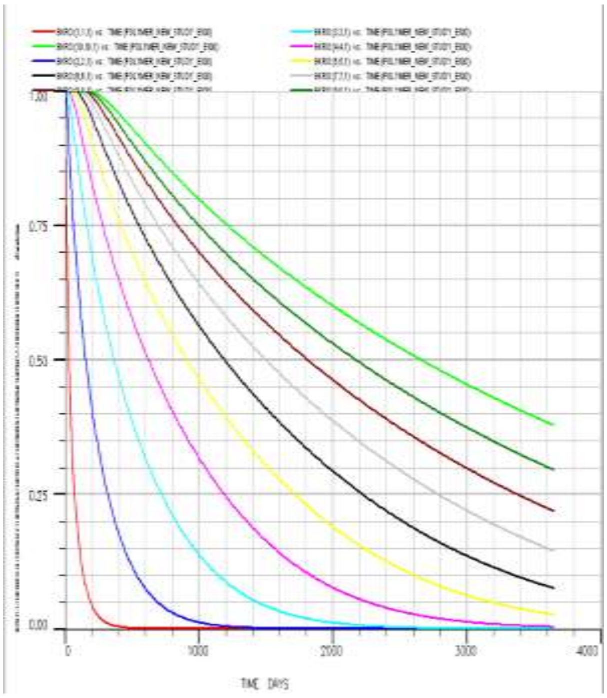


Fig 13: Relative Permeability History of Few Cells

B. Analysis of Field/ Well Production Performance

From general practice, the ultimate aim of any EOR project is to enhance production from the reservoir. In this study, the field production performance was analyzed in terms oil production rate, field pressure and saturation. The Fig 13, 14 and 15 show the field pressure, field oil production rate and field oil saturation history respectively.

The Fig 13 shows that the pressure increases drastically from the onset of production. This is actually caused by the simultaneous polymer injection project implemented from the start of the analysis. After about 75 days, a peak pressure value of 4470psia was reached. However, the corresponding peak oil production rate was already attained at 68 days at a value of approximate 205STB/day. The continuous decline in oil saturation is as a result of production – i.e underground withdrawal/ depletion.

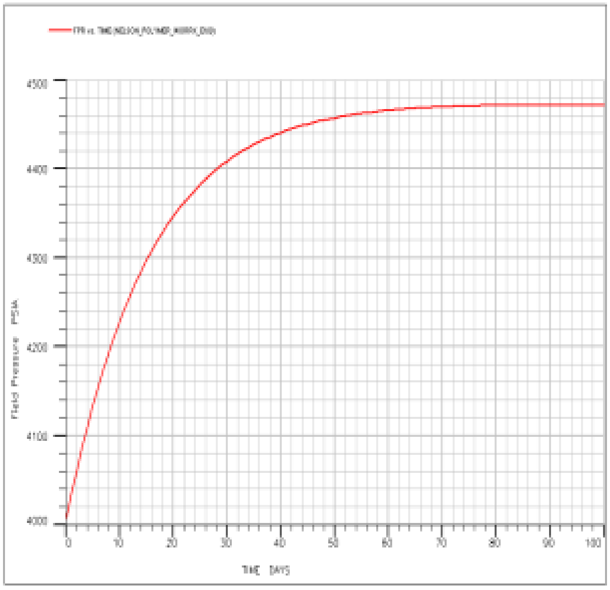


Fig 14: Field Pressure History

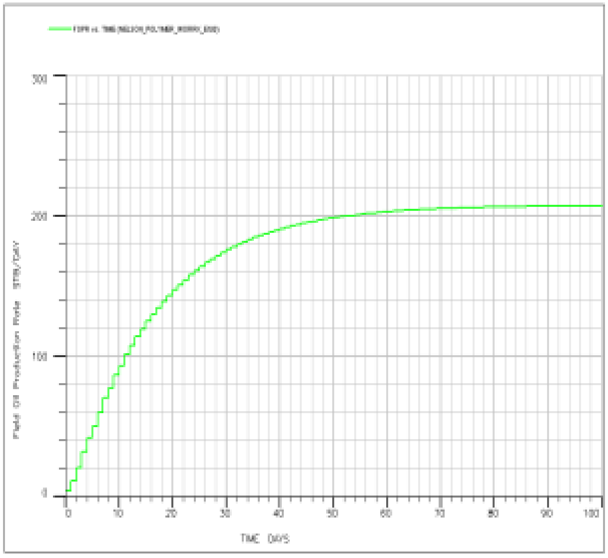


Fig 16: Field Oil Production History

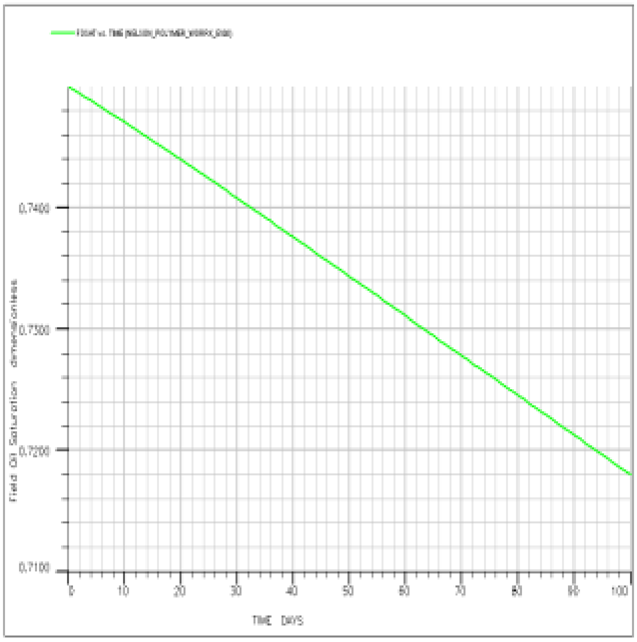


Fig 16: Field Oil Saturation History

C. Sensitivity Studies of Field Performance with Polymer Injection/Adsorption Rate

To fully understand the influence of the polymer injection on the performance of the reservoir considered in this work, a sensitivity study was performed as shown in the Figures (xvi) and (xvii) below.

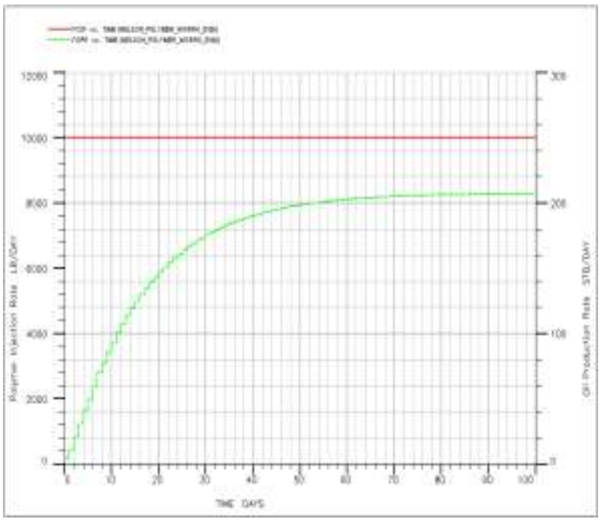


Fig 17: Polymer Injection Rate/ Oil Production Rate versus Time

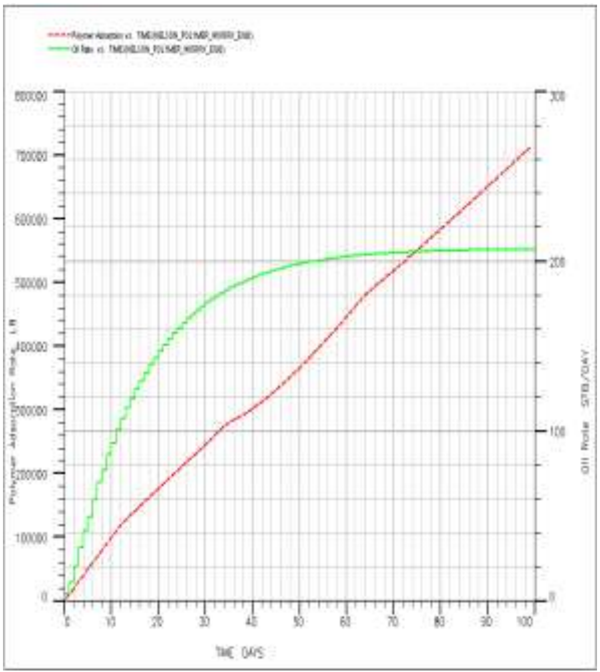


Fig 18: Polymer Adsorption/ Oil Rate versus Time

The result of Fig 17 shows that the polymer was injected at a constant rate of 10000lb/day. The overall effect of this is that there was increase in oil recovery with increasing polymer adsorption as illustrated in Fig 18. This clearly explained the underlying mechanism of EOR project by micellar polymer injection. Therefore, it can be verified that the polymer adsorption weakens the interfacial tension of the in-situ oil phase thereby making it more mobile. This process is simultaneously supported by the in-situ fluid displacement.

The similarity of the trend exhibited by the pressure and rate history confirms the conventional practice of maintaining field pressure as a way of sustaining pressure. This is precisely the ultimate end of typical secondary recovery processes. It could therefore be said that though pressure maintenance is not usually the main target of polymer EOR methods, it nevertheless conforms to the underlying principles of secondary recovery methods in terms of pressure maintenance and in-situ fluid displacement. This extra benefit therefore presents it more viable option where viscous fingering could be a great threat to conventional water flooding project.

IX. Conclusion and Recommendation

A. Conclusion

It is known that in the typical life of a producing well that there is a decline phase accompanied with drop-in production rate due to pressure decline. As an artificial means in the industry polymer injected has been deployed for pressure maintenance. In this work the field performance was analyzed in terms of oil production rate, field pressure and saturation. Results shows that for 75days peak pressure of 4470Psia was reach with a corresponding peak oil production rate reached at 68days(205STB/day). The overall effect of this is that there was increase in oil recovery with increasing polymer adsorption. This clearly explained the underlying mechanism of EOR project by micellar polymer injection. Therefore, it can be verified that the polymer adsorption weakens the interfacial tension of the in-situ oil phase thereby making it more mobile. This process was simultaneously supported by the in-situ fluid displacement.

B. Recommendation

It is worth recommending that to combat pressure decline for ultimate recovery;

1. Polymer/Miscellar flooding is one of the surest ways to maintain pressure haven understood the reservoir properties.

2. In extension, Microbial Enhanced Oil recovery can be deployed alongside polymer recovery.

C. Contribution to Knowledge

Appreciable research has been done within the industry on the application of polymer in enhanced oil recovery. This work is an addendum to already existing work and facts as per the concept. it can be verified that the polymer adsorption weakens the interfacial tension of the in-situ oil phase thereby making it more mobile.

X. APPENDIX

Water Saturation Function (SWFN)

Saturation	Krw	PCow
0.25	0	4.0

0.7	1.0	0

Oil Saturation Function (SWFN)

Saturation	Krog
0.300	0
0.75	1.0

Water PVT Properties (PVTW)
Formation Volume Factor (FVF) = 1.0
Compressibility =3.03E-06.

Dead Oil PVT Properties

Reference Pressure	**Krow**	**PCG**
0	1.0	2.0
8000	0.92	2.0

Fluid Density

Oil	52.000
Water	64.000
Gas	0.04400

SUMMARY Keywords
FWCT
FCPR
FCPT
FCIR
FCIT
FCIP
FCAD
GCPR
'G' /
GCPT
'G' /
GCIR
'G' /
GCIT
'G' /
WCPR
'P' /
WCPT
'P' /
WCIR
'I' /
WCIT
'I' /
CCFR

RPTSCHED (Report Schedule File Output)
'PRES' 'SWAT' 'RESTART=2' 'FIP=2' 'WELLS=2' 'SUMMARY=2' 'CPU=2' 'WELSPECS' 'NEWTON=2' 'PBLK' 'SALT' 'PLYADS' 'RK' 'FIPSALT=2'

WELSPECS (Well Specification for single producer – single injector)

i. **Injection Well**

Well Name = "I"
Group Name = "G"
i-location = 1
j-location = 1
Datum Depth = 4000ft
Shut-in option = NO

ii. **Production Well**

Well Name = "P"
Group Name = "G"
i-location = 10
j-location = 10
Datum Depth = 4000ft
Shut-in option = NO

COMPDAT (Well Completion Data)

i. **Injector**

Well Name = "I"
k-upper = 1
k-lower = 1
Well Open/Shut = OPEN
Wellbore radius = 0.33ft

ii. **Producer**

Well Name = "P"
k-upper = 1
k-lower = 1
Well Open/Shut = OPEN
Wellbore radius = 0.33ft

WCONPROD (Production Well Control and Limits)
Well Name = 'P'
Shut in option = OPEN
Control Mode = BHP
Target BHP = 3999.0psia

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