# APPROVAL CERTIFICATE

This senior year project paper entitled

“ Numerical Simulation Study for the Factors Impacting Polymer Flooding in Oil Reservoirs ”

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# Numerical Simulation Study for the Factors Impacting Polymer Flooding in Oil Reservoirs

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*Abstract*— **Nowadays, interest in improved oil recovery methods is driven by high oil prices and the large society's dependence on petroleum derivatives. Thus, oil companies seek to maximize exploration during the concession period. EOR methods are categorized as miscible, thermal and chemical methods. Polymer flooding is a chemical process where a polymer is added to water flooding with the aim of increasing its viscosity, thus reducing the water-to-oil transfer ratio and increasing the vacuuming efficiency. However, it should be noted that before choosing the any EOR method the case must be submitted to the screening criteria. In the case of polymer immersion, the criteria chosen include assessment of the hazardous conditions of the polymer that could lead to its decomposition. Therefore, this project presents an analysis on water flooding as well as polymer flooding oil recovery rate curves compared to the continuous water immersion condition. Simulated cases including different conditions were built and evaluated using CMG simulation software. The differences in terms of porosity, polymer viscosity, and thickness for both polymer immersion and water sinking were made and compared with each other through oil recovery curves to determine there effects on oil recovery.**

***Keywords- Polymer Flooding; EOR Screening;CMG Polymer ; Polymer flooding mechanism***

## I. INTRODUCTION

Generally, oil recovery options are divided into 3 main stages: primary, secondary and tertiary. Historically, the oil and gas industry describes these 3 stages of oil recovery in a chronological sequence. In the initial oil production stage, the primary oil recovery is resulted from displacement energy that occurs naturally in a reservoir. These natural driving mechanisms include depletion drive, gas cap drive, water drive and combination drive. After noticeable reduction in the initial oil production rate, secondary oil recovery takes place. The main purpose of secondary oil recovery is to control the pressure in the reservoir to maintain or increase the oil production rate by introducing external fluid to the reservoir. It is usually done with processes like water flooding or gas injection. Commonly, recovery factor from primary and secondary oil recovery is only around 20 – 40% and is affected by the reservoir rock properties, fluid properties as well as geological heterogeneities (Romero-Zerón, 2012). The third stage of the production, tertiary oil recovery, happens when the cost to production ratio of secondary oil recovery process is no longer economical. The ultimate intention for tertiary oil recovery is to improve the overall oil efficiency. In tertiary oil recovery, the recovery factor is about 30 – 60% (Sino Australia Oil and Gas Ltd, 2013). Also known as enhanced oil recovery, tertiary oil recovery increase hydrocarbon production by altering the formation properties for conducive extraction (Needham and Doe, 1987). The true meaning of enhanced oil recovery is the ultimate oil recovery that can be recovered from a reservoir in a cost-effective manner on top of the oil economically recovered from primary and secondary recovery oil processes. Over the years, research and pilot testing have been conducted to further develop different methods of enhanced oil recovery. These methods include thermal recovery and non-thermal methods, which consist of chemical flooding, miscible flooding, immiscible gas drives and microbial enhanced oil recovery.

Due to the reservoir oil phase-behavior properties, chemical processes often require the injection of chemical formulation in order to displace and mobilize oil effectively by decreasing the interfacial tension between oil and fluid. One of the most promising chemical processes is polymer flooding. Polymer flooding is the evolution of conventional water flooding technique. Instead of using just water to displace oil, polymer is used as an alternative to injection water. The polymer introduced to the injection water affects the viscosity of displaced fluid and hence decreases mobility ratio, improves stratification efficiencies and frontal saturations. The relative flow rates of water and oil are altered by the polymer solution, sweeping larger area of the reservoir and; therefore, more oil is in contact with the polymer solution and displaced to the production well. Implementing polymer flooding earlier at water breakthrough during water flood is more effective and efficient in recovering reservoir oil. Very often, polymers are used in addition to different enhance oil recovery processes. Polymer flooding provides the most efficient results when recovering moderately viscous oil in heterogeneous reservoir after water flood. Reservoirs that underwent water flooding with mobility ratio of less than one is more likely to have higher oil recovery due to better areal sweep efficiency. As vertical sweep efficiency improved, heterogeneous reservoir reacts positively to polymer flooding. Extended usage of polymer flooding can cause permanent damage to reservoir formation, causing a reduction in formation permeability (National Petroleum Council, 1984). Polymer solution is often injected first via the injection well to displaced the oil and followed by the drive water.

And tertiary recovery refers to injection of fluids that are not normally present in the reservoir for two main purposes: boosting the natural energy of the reservoir and creating favorable conditions for residual oil recovery such as: reduction of interfacial tension between displacing and displaced fluid, increasing capillary number, increase water viscosity, reduce oil viscosity, and provide mobility control.
And with that :

- The objective of this research is to provide screening criteria to where and when polymer flooding can be successfully applied.
- This purpose is accomplished by collecting different data from the data and running different Scenarios in software.

## II. OIL RECOVERY METHODS

### A. Primary Recovery

First stage of hydrocarbon production, in which natural reservoir energy, such as gas drive, water drive, or gravity drainage, displaces hydrocarbons from the reservoir, into the wellbore and up to the surface. The primary recovery stage reaches its limit either when the reservoir pressure is so low that the production rates are not economical, or when the proportions of gas or water in the production stream are too high. During primary recovery, only a small percentage of the initial hydrocarbons in place are produced, typically around 10% for oil reservoirs .

Primary Recovery Mechanisms **:** 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:

1. Rock and liquid expansion drive .
2. Depletion drive.
3. Gas cap drive .
4. Water drive .
5. Gravity drainage drive .
6. Combination drive.

### B. Secondary Recovery

Second stage of hydrocarbon production during which an external fluid such as water or gas is injected into the reservoir through injection wells located in rock that has fluid communication with production wells. The purpose of secondary recovery is to maintain reservoir pressure and to displace hydrocarbons toward the wellbore. The most common secondary recovery techniques are gas injection and water flooding. Normally, gas is injected into the gas cap and water is injected into the production zone to sweep oil from the reservoir. A pressure-maintenance program can begin during the primary recovery stage, but it is a form or enhanced recovery. The secondary recovery stage reaches its limit when the injected fluid (water or gas) is produced in considerable amounts from the production wells and the production is no longer economical. The successive use of primary recovery and secondary recovery in an oil reservoir produces about 15% to 40% of the original oil in place.

Secondary Recovery Mechanisms :

- Water injection **:** In a completely developed oil or gas field, the wells may be drilled anywhere from 60 to 600 m (200 to 2000 ft) horizontally from each other, depending on the nature of the reservoir. If water is pumped into alternate wells (i.e., water injection wells) in such a field, the pressure in the reservoir as a whole can be maintained or even increased. In this way, the daily production rate of the crude oil can be increased. In addition the water physically displaces the oil, thus increasing the recovery efficiency. In some reservoirs with a high degree of uniformity and little clay content, water flooding may increase the recovery efficiency to as much as 60 percent or more of the original oil in place. Water flooding was first introducing in Pennsylvania oil fields, somewhat accidently, in the late nineteenth century, and now has been used throughout the world
- Steam injection : Steam injection is used in reservoirs that contain very viscous oils, i.e., those that are thick and flow slowly. The steam not only provides a source of energy to displace the oil, it also causes a marked reduction in viscosity (by raising the temperature of the reservoir), so the crude oil flows faster under any given pressure differential.
- Gas injection : Some oil and gas formations contain large quantities of produced natural gas and carbon dioxide ($CO_2$). This gas is typically produced simultaneously with the liquid hydrocarbon production. The natural gas or $CO_2$ is recovered, recompressed and re-injected into the gaseous portion of the reservoir. The re-injected natural gas or $CO_2$ maintains reservoir pressure and assists with pushing additional liquid hydrocarbons out of the liquid portion of the reservoir.

### C. Enhanced Oil Recovery

Is the process of increasing the amount of oil that can be recovered from an oil reservoir, usually by injecting a substance into an existing oil well to increase pressure and reduce the viscosity of the oil With a conventional oil well, natural pressure in the reservoir pushes the oil to the surface or a pump is used to create the pressure. This usually results in a recovery of about 25% of a well’s oil reserves. Enhanced oil recovery increases the oil recovery by up to 15%. Enhanced oil recovery methods, can be divided into three main categories: Thermal, Gas Injection and Chemical Injection, along with some other methods such as Microbial EOR and Nano-particles

They are mainly applied to extend the production life of an otherwise depleted or uneconomic reservoir by modifying fluid-fluid and fluid-rock properties consequently :

- Thermal EOR: it is the most widely used method and mainly applied for heavy and extra heavy oil as it affects oil viscosity by heating it up.
- Gas Injection: subdivided into miscible and immiscible flooding implies the injection of gases (hydrocarbons, carbon dioxide, nitrogen etc) to reduce oil viscosity, interfacial tension and increase oil swelling.
- Chemical EOR includes the techniques that require injection in the reservoir of a mixture composed of chemical additives and water in order to improve sweep and microscopic efficiency.

EOR methods have presented interest since early 90s while many research and field application have been done in that times with concern to this. In latest times, until the volatility of oil prices hit the industry in 2014, a renew focus and increase of EOR deployment has been observed in many regions of the work, especially in the US and Canada. A forecast of IEA from 2012 depicts that by 2035, EOR production will represent approximately 25% of total world oil production.

The success of an EOR process can be assessed from both technical and economical point of view. Focusing on the technical part, the success is given by the incremental of oil recovered compared to primary or to secondary recovery as the oil production should deviate from the declined rate forecasted before. If on a simulation basis, to assess the gain in oil production is considered to be relatively easy as it can be resumed to the comparison of two cases, on a field application basis thing become more complex.

In this study, we focus on finding new ways to increase the life of field production and evaluating the performance of the existing appropriate method through polymer injection.

## III. OBJECTIVE

- The objective of this report is to provide basic technical information regarding the polymer injection EOR process, which is at the core of the evaluation methodology, for the determination of technically recoverable oil.
- Knowledge of EOR mechanisms using polymer injection
- What are the most suitable and capable reservoirs for injection polymer EOR applications
- Know when and where EOR with polymer injection succeeds or fails.
- Understand software that can simulate the EOR reservoir using polymer injection
- Knowing the effects and negatives of polymer injection on the enhanced recovery reservoir
- See criteria screening for past polymer injections for Enhanced oil recovery

## IV. POLYMER FUNDAMENTALS

### A. *POLYMER*

Already mentioned above, polymer flooding falls under the chemical EOR methods implying a mixture of chemicals and water injected into reservoir in order to decrease the amount of oil trapped inside the porous media. As it is already known, the force balance between viscous and capillary forces is governing the quantity of oil trapped and the capillary number is used as measure to quantify it.

Larson et al. [3] defined the ratio between viscous and capillary forces as capillary number,

Nc:

$$Nc = \frac{\upsilon\mu}{\sigma} \qquad (1)$$

where σ is the interfacial tension, υ and μ refer to the fluid velocity and viscosity, respectively.

### *B. Polymer Type*

Even though on the market there are a lot of potential chemicals suitable for water viscosifying purposes, this paper will focus only on the main once used in the field for polymer flooding: polyacrylamides (HPAM) and polysaccharides (Xanthan gum).

- Polyacrylamides :

The polymers that fall into this category are called synthetic polymers or partially hydrolysis polymers due to their 30-35% degree of hydrolysis. The percentage has been carefully selected in order to optimize certain properties like viscosity, water solubility and retention as well as generating the negatively charged character of the molecules.

The power of HPAM to increase water viscosity is owed to its large molecular weight. The anionic repulsion between polymer molecules and segments causing the elongation of the molecules in solution is an effect that accentuates the mechanism, mainly at higher concentrations.

There are many advantages concerning HPAM usage in polymer flooding, from which permanent permeability reduction, resistance to bacterial attack and lower price are worth to be mentioned. What is more, HPAM is stable under anaerobic conditions but unstable in the presence of iron or under elevated reservoir temperatures. On the other hand, its high sensitivity to water salinity and hardness is hindering it from many field application considerations as shown in Figure 1. [25]

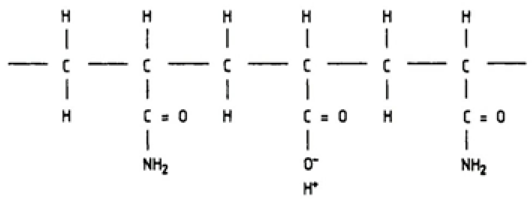

Figure 1 : Molecular structure of HPAM [26]

- Polysaccharides :

These polymers are considered biopolymers as they are produced from polymerization of saccharide molecules through bacterial fermentation process. Polysaccharides mechanism of increasing water viscosity is by snagging and adding a more rigid structure to the solution.

Without any doubt, the biggest advantage of this category of polymers is represented by the insensitivity to salinity and hardness, over countered partly by two side effects: the susceptibility to bacterial attack and no permeability reduction. [25]

All in all, as Manning et al. reported, until 1983, HPAM was used in more than 95% of field floods, statement reinforced by later studies from 2011. Even though its price per unit amount is less compared to biopolymers, total costs get closely when considering mobility reduction, in particularly for high salinity reservoirs. [2]

C. *Polymer flooding mechanism*

Targets to decrease the amount of oil trapped by increasing the viscosity, leading to capillarity suppression by viscous force and mobilization of a higher amount of hydrocarbons. As the increase in capillary number is just one order of magnitude, the effect of polymers in microscopic displacement is rather limited.

However, the feature that stands behind polymer action is macroscopic displacement which primarily target the oil bypassed by water flooding and which can be obtained through a key element: mobility ratio.

Mobility ratio, M, was defined by Ahmed [4] as the ratio of displacing and displaced fluid motilities, as suggested by eq.2. In a polymer flooding case, water (polymer solution) is considered to be the displacing fluid, while oil is the displaced phased.

$$M = \frac{\lambda w}{\lambda o} = \frac{\frac{kw}{\mu w}}{\frac{ko}{\mu o}} = \frac{kw}{\mu w}\frac{\mu o}{ko} \qquad (2)$$

where λ refers to mobility and is defined as permeability k divided by the viscosity μ and the subscript indicating the fluid, where o refers to oil and w refers to water

From literature, for a displacement to be considered favorable, a mobility ratio value less than 1 is expected.

Mobility ratio effects are derived from Buckley Leveret theory of immiscible displacement: low mobility ratios lead to a piston like displacement, a feature extremely wanted in water and polymer flooding applications. In the plot below the water saturation profile from a water flood after 0.2 PV injected displays the differences induced by mobility ratios. Low values exhibit

high shock front which leads to favorable displacements while high mobility ratios lead to a long tailing tendency of two-phase region. Moreover, unfavorable displacement implies an inefficient areal sweep as result of viscous fingering as shown in Figure 2. . [5]

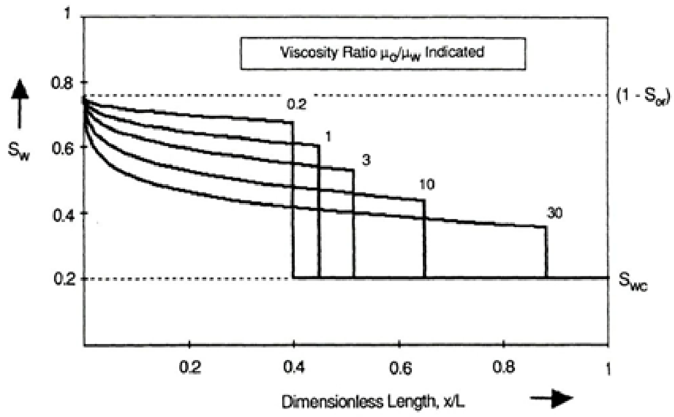


Figure 2: Mobility ratio effect on in-situ saturation profile [6]

Figure 3. depicts the difference between water injection and polymer flooding results in terms of areal sweep. The low-viscosity injection fluid is characterized by viscous fingering and an early breakthrough, whereas the higher-viscosity injection fluid causes a favorable injection front shape due to a lower mobility ratio. This allows for the flood to affect a larger reservoir area, mitigating viscous fingering and increasing areal sweep efficiency and therefore cumulative oil production.

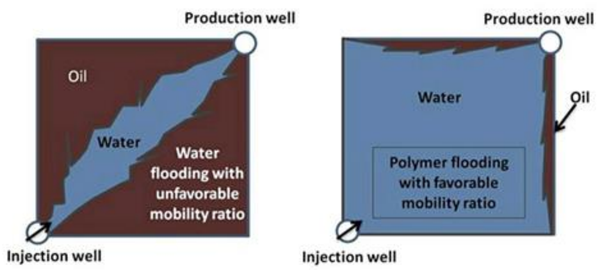


Figure 3: Water and polymer flooding areal sweep [6]

## V. OPERATION PARAMETERS FOR POLYMER FLOODING

Polymer flooding is a very mature method with more than 40 years of applications. it has been shown to be effective in recovering upswept oil by improving the mobility ratio. field practice has shown that polymer flooding can increase recovery of 5-30% of ooip. the total cost of polymer flooding is actually less than for water flooding due to decreased water production and increased oil production. the efficiency of the process is in the range of 0.7 to 1.75 lb. of polymer per bbl. of incremental oil production. [7]

The largest polymer injection aimed at improving the mobility ratio was implemented in 1996 in the daqing oilfield. as of 2004, more than 31 commercial projects were implemented, involving approximately 2427 injection wells and 2916 production wells. polymer injection in the shengli and daqing oilfields yielded incremental oil recoveries ranging from 6 to 12%, contributing to 250,000 barrels per day in 2004. at the end of 2006, water consumption had decreased by 21.8 m3 per cubic meter of oil produced, with a water-cut reduction of one fourth resulting in important savings in regards to produced water treatment and disposal.

Another example of successful polymer injection in the 1990s was in Courtenay, France, where extra oil recoveries from 5 to 30% have been reported after the technology was conducted in a secondary recovery mode as augmented water flooding. [8]

Tables 1, 2, 3 are parameters of previous polymer flooding experiments in fields where this experiment was successful to be taken into account according to the data generated from these fields.

Table 1. K. S. Sorbie, Parameter of polymer flooding [5]

| **Parameter** | **Year 1970s and 1980s** | **After 2000** |
|---|---|---|
| **Oil viscosity** | <200 CP | <10,000 CP |
| **Temperature** | <95°C | <140°C |
| **Permeability** | >20 mD | >10 mD |
| **Salinity** | Low (<3o g/L TDS) | <200 g/L TDS |

Table 2. K. S. Sorbie, Comparison of polymer concentration on oil recovery [5]

| **Polymer concentrations, Ppm** | **Oil production cumulative,BBL** | **Oil recovery factor %** |
|---|---|---|
| 640 | 90,306 | 28.5 |
| 1,500 | 90,723 | 28.6 |
| 3,000 | 91,219 | 28.8 |
| 4,000 | 91,332 | 28.9 |

Table 3. K. S. Sorbie, Polymer Viscosity at various concentration [5]

| **Polymer Concentration** | **Polymer Viscosity** |
|---|---|
| 640 ppm | 0.55 cp |
| 1,500 ppm | 0.59 cP |
| 3,000 ppm | 0 82 cP |
| 4,000 ppm | 0.94 cP |

## VI. EOR SCREENING

The decision-making of considering the implementation of an EOR method to a reservoir starts by assessing the EOR potential of the target reservoir, accomplished in the EOR screening phase. During this phase, the aim is to perform an accurate assessment which provides the answer for the question: " Which is the most suitable EOR technique for the interest reservoir.

All the existing screening methods require deep knowledge regarding field characteristics and behavior, previous EOR experience and the most important, full understanding of the recovery mechanism of each potential EOR technique. As oil and reservoir properties are key elements in the effectiveness of the method, related literature considers that a package of six parameters are most relevant for screening process : porosity, permeability, depth, temperature, oil density and viscosity. [9]

EOR screening methods can be divided into two categories, according to their approach: conventional and advanced screenings.

- Conventional methods are based on the existence of certain ranges for reservoir and oil properties, estimated by experts or previous projects to predict the most favorable EOR techniques. Alvarado and Monique [10] suggested that it should be
- used only to provide a " go/no go" criteria because of their significant limitations.
- Advanced methods are based on identifying analogue fields (in terms of oil and reservoir properties) and the idea that similar fields should show appropriate behavior if the same EOR techniques is applied. This approach predicts the most suitable EOR for the target reservoir conditioned by the successful implementation of this in analogues fields

*Summarizing and discussion on screening range :*

Table 4,5,6,7 provides a summary of polymer flooding screening range for field and total dataset based on the above statistical analysis of the dataset in this study .This summary includes the parameters that contribute to the success of a polymer flooding project, including reservoir properties, polymer properties and evaluations. The minimum and maximum observations mean and median of dataset values are the standard statistics used to describe the screening range.

Table 4. L. W. Lake, Summary of polymer flooding screening range for field dataset [25]

| **Screening range for field dataset** | | | | |
|---|---|---|---|---|
| **Parameters** | Statistics | | | |
| | Mean | Median | Minimum | Maximum |
| **Depth/ft** | 4101 | 4034 | 3215 | 5139 |
| **Net thickness/ft** | 36 | 40.35 | 13.2 | 54.8 |
| **Temperature/°F** | 145.7 | 153.7 | 93.7 | 176.5 |
| **Oil gravity/ ° API** | 36.89 | 40 | 16.2 | 53.2 |
| **Oil viscosity/cP** | 29.31 | 9.7 | 2.6 | 76.96 |
| **Water salinity/ppm** | 8087 | 6326 | 3580 | 28870 |
| **Average permeability/md** | 775.7 | 630 | 192 | 3017 |
| **Dykstra Parsons Coefficient** | 0.7717 | 0.765 | 0.7 | 0.87 |
| **Porosity/%** | 23.47 | 20.3 | 18.2 | 34.8 |
| **Average molecular weight/10^4** | 1896 | 1800 | 1075 | 2750 |
| **Average polymer viscosity/cP** | 87.01 | 66.35 | 17.75 | 220.4 |
| **Average polymer concentration/ppm** | 1250 | 1181 | 650 | 2050 |
| **Injecting pressure/Mpa** | 12.15 | 12.15 | 12 | 12.3 |
| **Injection rate/(PV/a)** | 0.118 | 0.11 | 0.1 | 0.16 |
| **Well spacing/m** | 230.4 | 250 | 150 | 280 |
| **Polymer slug size/PV** | 0.5068 | 0.45 | 0.15 | 0.876 |
| **Water cut before polymer flooding/%** | 93.87 | 94.7 | 86.1 | 96.49 |

Table 5. L. W. Lake, Screening range for other parameters in addition to previous researches[25]

| **Parameters** | **Suggest Range** |
|---|---|
| **Net thickness/ft** | >12 |
| **Dykstra Parsons Coefficient** | <0.87 |
| **Porosity/%** | >8.3 |
| **Average molecular weight/10^4** | 600-2750 |
| **Average polymer viscosity/cp** | <220 |
| **Average polymer concentration/ppm** | 600-2050 |
| **Injecting pressure/Mpa** | 10-20.5 |
| **Injection rate/(PV/a)** | 0.12-0.14 |
| **Well spacing/m** | 200-310 |
| **Polymer slug size/PV** | >0.45 |
| **Water cut before polymer flooding/%** | 93-98 |

Table 6. . L. W. Lake, Summary of polymer flooding screening range for field dataset [25]

| Screening range for field dataset | | | | |
|---|---|---|---|---|
| **Parameters** | Statistics | | | |
| | Mean | Median | Minimum | Maximum |
| **Depth/ft** | 5135 | 5331 | 1558 | 8186 |
| **Net thickness/ft** | 33.46 | 35.1 | 12.1 | 53.8 |
| **Temperature/°F** | 155.9 | 159.5 | 78.89 | 200.7 |
| **Oil gravity/ ° API** | 24.81 | 18.3 | 14.96 | 51.1 |
| **Oil viscosity/cP** | 61.99 | 32.5 | 2.3 | 285.2 |
| **Water salinity/ppm** | 23140 | 18000 | 2127 | 84130 |
| **Average permeability/md** | 601.5 | 519 | 17 | 2330 |
| **Dykstra Parsons Coefficient** | 0.6761 | 0.715 | 0.4 | 0.87 |
| **Porosity/%** | 20.79 | 20 | 8.3 | 32 |
| **Average molecular weight/10^4** | 1436 | 1500 | 600 | 2500 |
| **Average polymer viscosity/cP** | 43.82 | 23 | 15 | 91.1 |
| **Average polymer concentration/ppm** | 1325 | 1350 | 600 | 2000 |
| **Injecting pressure/Mpa** | 13.84 | 12.76 | 10 | 20.5 |
| **Injection rate/(PV/a)** | 0.146 | 0.13 | 0.057 | 0.34 |
| **Well spacing/m** | 191.8 | 193.8 | 100 | 310 |
| **Polymer slug size/PV** | 0.4119 | 0.41 | 0.033 | 0.8 |
| **Water cut** | 92.66 | 95.15 | 78.51 | 98.14 |

Table 7. . L. W. Lake, Summary of polymer flooding screening range for field dataset[25]

| Screening range for combined field dataset | | | | |
|---|---|---|---|---|
| **Parameters** | Statistics | | | |
| | Mean | Median | Minimum | Maximum |
| **Depth/ft** | 4819 | 4593 | 1558 | 8186 |
| **Net thickness/ft** | 34.4 | 39.7 | 12.1 | 54.8 |
| **Temperature/°F** | 151.4 | 153.7 | 78.89 | 200.7 |
| **Oil gravity/ ° API** | 32.06 | 33.6 | 14.96 | 53.2 |
| **Oil viscosity/cP** | 47.61 | 18 | 2.3 | 285.2 |
| **Water salinity/ppm** | 17120 | 7500 | 2127 | 84130 |
| **Average permeability/md** | 669.7 | 575 | 17 | 3017 |
| **Dykstra Parsons Coefficient** | 0.7079 | 0.7350 | 0.4 | 0.87 |
| **Porosity/%** | 21.46 | 20 | 8.3 | 34.8 |
| **Average molecular weight/10^4** | 1574 | 1650 | 600 | 2750 |
| **Average polymer viscosity/cP** | 65.41 | 48.18 | 15 | 220.4 |
| **Average polymer concentration/ppm** | 1296 | 1247 | 600 | 2050 |

## VII. SIMULATION SOFTWARE OF POLYMER FLOODING

### 1- CMG simulation software

Programs used to simulate oil and gas reservoirs, in which development plans can be drawn up for the field and selection of the best well locations, in addition to the ability to design improved extraction processes and evaluate their performance.

CMG Reservoir Simulator is a comprehensive and complete program for simulating types of reservoirs of any degree of structural, geological or fluid complexity. CMG Applications Due to its wide capabilities and abundance compared to other similar simulation software, it can be said that it has become a global standard

CMG FEATURES :

- Simulation of hydrocarbon tanks in the form of composite black oil
- Ability to simulate overheating (thermal simulation)
- Ability to simulate oil tanks in parallel to reduce simulation time
- Ability to simulate chemical harvesting methods such as polymer injection, surfactant and foaming
- Excellent interaction with reservoir fluid properties simulation software such as PVTi, PVTSIM and Win Prop
- Excellent ability to simulate large industrial projects
- Excellent ability to simulate unusual oil and gas reservoirs (unconventional reservoirs)

### 2- PETREL simulation software

From the petroleum engineering programs, which Schlumberger introduced to the world of the oil industry, it entered all fields of exploration, exploitation, reservoir and drilling. In the new version of this software, additional facilities have been provided to facilitate the work.

Also, to speed up work and quick access to data, online work feature is provided in which the user can enter his data into the central server, and other related users check it based on access restriction rating and changes Apply requirements, then save the update.

A program used to model oil and gas reservoirs, and is usually done in building geological models (petro physical properties) and distributing them over the reservoir. In addition, a dynamic model is built that consists of production data (pressures, production, injection), which can be linked to the reservoir simulation, the simulation and the history match.

### 3- UTCHEM Simulator

UTCHEM is a multicomponent, multiphase, three-dimensional chemical compositional reservoir simulation model. The flow and transport equations are as follows :

- A mass conservation equation for each chemical species
- An overall mass conservation equation that yields a pressure equation when combined with a generalized Darcy's law
- An energy conservation equation

Four phases are modeled. The phases are a single component gas phase and up to three liquid phases - aqueous, oleic, and micro emulsion - depending on the relative amounts and effective electrolyte concentration (salinity) of the surfactant/oil/water phase environment. The key to accurate and realistic chemical flooding is to model the complex micro emulsion phase behavior and the various properties associated with these phases (such as interfacial tension, relative permeability, capillary pressure, capillary desaturation and viscosity) and factors that determine the behavior of the species in these phases such as dispersion, adsorption and cat ion exchange.

The resulting flow equations are solved using a block-centered finite-difference scheme. The solution method is implicit in pressure and explicit in concentration (IMPES-like). A third-order spatial discretization is used and in order to increase the stability and robustness of the third-order method, a flux limiter based on the total-variation-diminishing scheme has been added. UTCHEM has been widely used to simulate laboratory and field scale processes such as water flooding, tracers in water, polymer, surfactant/polymer, profile control using gel, and high pH alkaline/surfactant/polymer. The code has also been modified for applications to groundwater contamination and remediation. Some of the applications of UTCHEM are:

- Surfactant flooding
- High pH alkaline/surfactant/polymer flooding
- Polymer flooding
- Conformance control using polymer gels
- Tracer tests
- Formation damage
- Soil remediation
- Microbial enhanced oil recovery
- Surfactant/foam

## VIII. Results and Discussion

### 1. Porosity

Porosity has an explicit effect on the oil recovery rate because it is a key parameter in polymer flooding and water flooding experiments that have been tested as shown in the figures and tables.

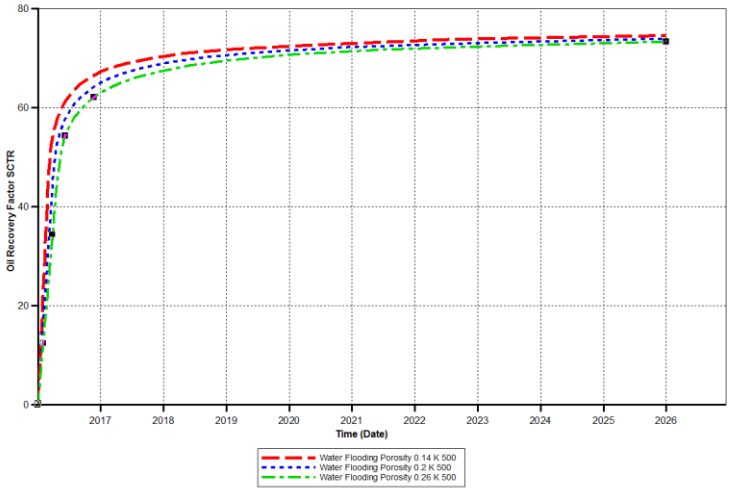


Figure .4 The effect of porosity Water Flooding

Note that the porosity decreases, the higher the oil recovery rate, and a noticeable increase from 2016 to 2019 compared to the porosity changes in the water flooding experiment, as shown in Table 8.

Table .8 The effect of porosity Water Flooding

| Case | Porosity | Permeability | Thickness | Oil Recovery | Figure |
|---|---|---|---|---|---|
| 1 | 0.14 | 500 | 20 | 75% | 4 |
| 2 | 0.2 | 500 | 20 | 73% | |
| 3 | 0.26 | 500 | 20 | 70% | |

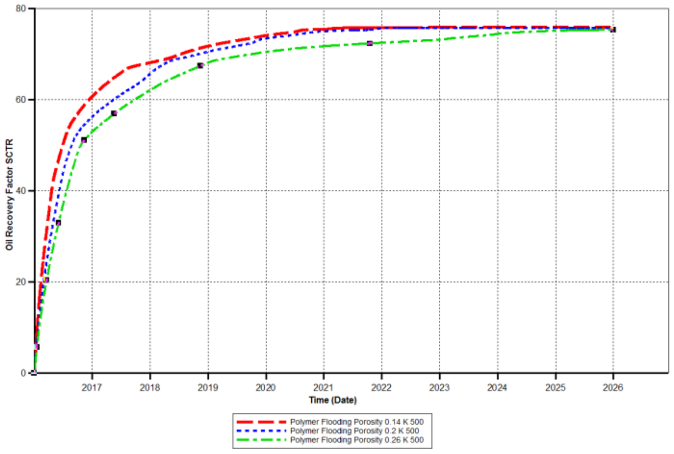


Figure .5 The effect of porosity Polymer Flooding

In figure .5 note that the porosity decreases, the higher the oil recovery rate, and a noticeable increase from 2016 to 2020 compared to the porosity changes in the Polymer flooding experiment, as shown in Table 9.

Table .9 The effect of porosity Polymer Flooding

| Case | Porosity | Permeability | Thickness | Oil Recovery | Figure |
|---|---|---|---|---|---|
| 1 | 0.14 | 500 | 20 | 77% | 5 |
| 2 | 0.2 | 500 | 20 | 74% | |
| 3 | 0.26 | 500 | 20 | 71% | |

*Comparison of water flooding and polymer flooding of porosity :*

Note the difference between the porosity when it is (0.14). In the case of polymer flooding, oil recovery is less than water flooding in 2016 to 2019 and in 2020 it is higher as shown in Figure 6 and Table 10

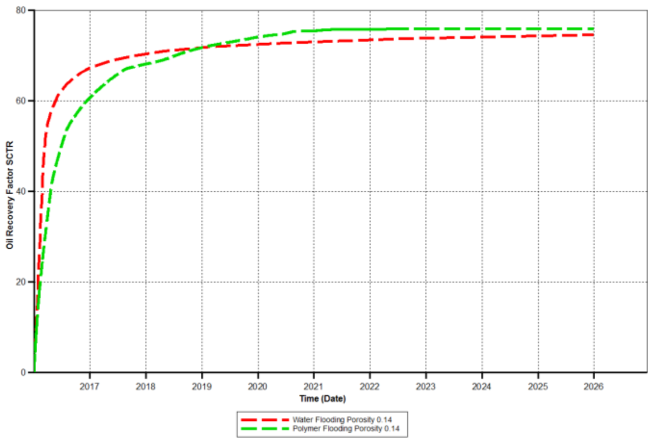


Figure .6 The effect of porosity Water Flooding & Polymer Flooding

Table .10 The effect of porosity Water Flooding & Polymer Flooding

| Case | Porosity | Permeability | Thickness | Oil Recovery | Figure |
|---|---|---|---|---|---|
| Polymer Flooding | 0.14 | 500 | 20 | 78% | 6 |
| Water Flooding | 0.14 | 500 | 20 | 74% | |

Note the difference between the porosity when it is (0.2). In the case of polymer flooding, oil recovery is less than water flooding in 2016 to 2019 and in 2020 it is higher as shown in Figure 7 and Table 11

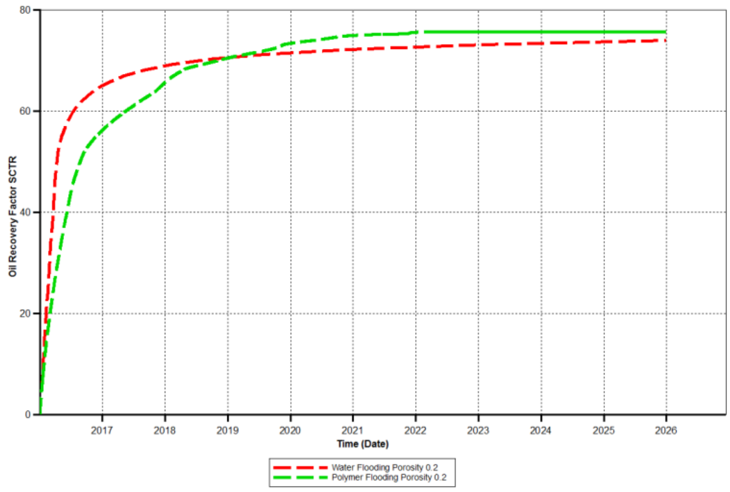


Figure .7 The effect of porosity Water Flooding & Polymer Flooding

Table .11 The effect of porosity Water Flooding & Polymer Flooding

| Case | Porosity | Permeability | Thickness | Oil Recovery | Figure |
|---|---|---|---|---|---|
| Polymer Flooding | 0.2 | 500 | 20 | 75% | 7 |
| Water Flooding | 0.2 | 500 | 20 | 71% | |

Note the difference between the porosity when it is (0.26). In the case of polymer flooding, oil recovery is less than water flooding in 2016 to 2020 and in 2022 it is higher as shown in Figure 8 and Table 12

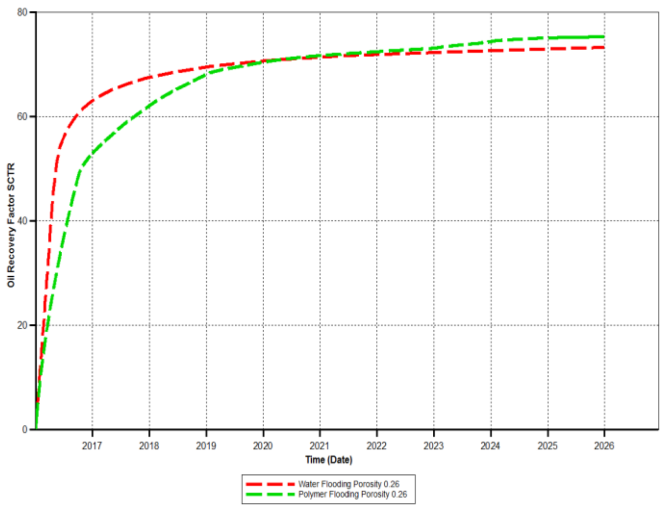


Figure .8 The effect of porosity Water Flooding & Polymer Flooding

Table .12 The effect of porosity Water Flooding & Polymer Flooding

| Case | Porosity | Permeability | Thickness | Oil Recovery | Figure |
|---|---|---|---|---|---|
| **Polymer Flooding** | **0.26** | **500** | **20** | **70%** | **8** |
| **Water Flooding** | **0.26** | **500** | **20** | **66%** | |

2. THICKNESS

Thickness has an effect on the oil recovery rate as it is an influencing factor in the polymer immersion and water immersion experiments tested as shown in the figures and tables.

Note when the thickness decreases, the oil recovery rate increases, and a noticeable increase from 2016 to 2020 compared to the porosity changes in the water flooding experiment, as shown in Figure 9 and Table 13

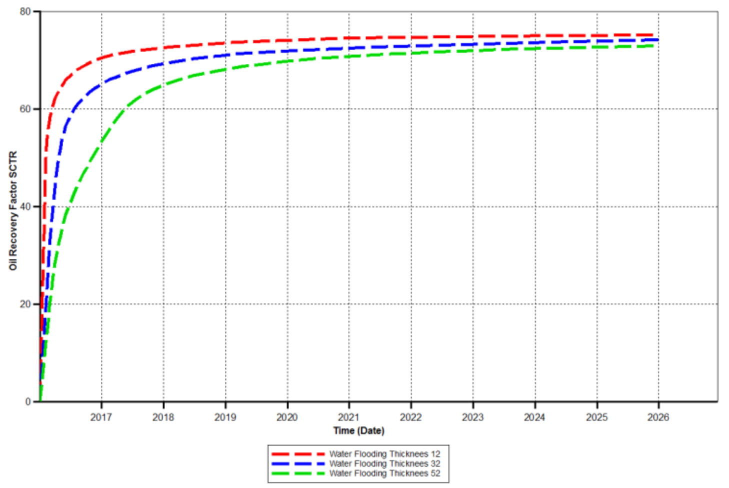


Figure .9 The effect of Thickness Water Flooding

Table .13 The effect of Thickness Water Flooding

| Case | Porosity | Permeability | Thickness | Oil Recovery | Figure |
|---|---|---|---|---|---|
| **1** | **0.2** | **500** | **12** | **76%** | **9** |
| **2** | **0.2** | **500** | **32** | **72%** | |
| **3** | **0.2** | **500** | **52** | **68%** | |

Note when the thickness decreases, the oil recovery rate increases, and a noticeable increase from 2016 to 2018 compared to the porosity changes in the water injection experiment, as shown in Figure 10 and Table 14

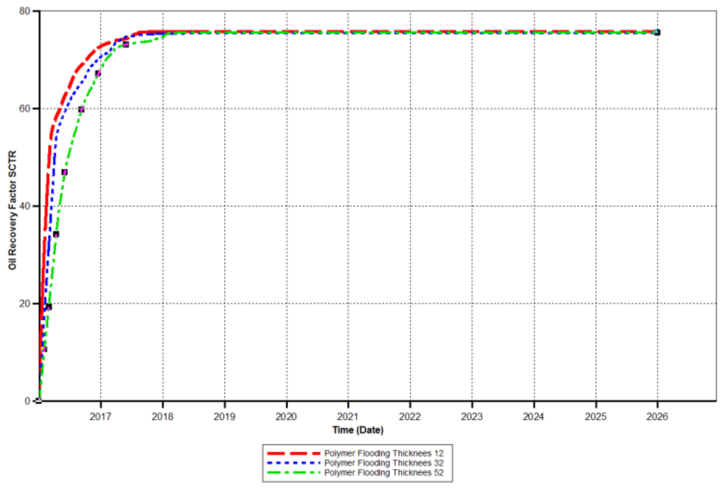


Figure .10 The effect of Thickness Polymer Flooding

Table .14 The effect of Thickness Polymer Flooding

| Case | Porosity | Permeability | Thickness | Oil Recovery | Figure |
|---|---|---|---|---|---|
| 1 | 0.2 | 500 | 12 | 79% | 10 |
| 2 | 0.2 | 500 | 32 | 77% | |
| 3 | 0.2 | 500 | 52 | 75% | |

*Comparison of water flooding and polymer flooding of Thickness :*

Note the difference between the thickness when they are (12). In the case of polymer flooding, the oil extraction is lower than the water flood in 2016/1 to 2016/9, and in 2017 it is higher as shown in Figure 11 and Table 15

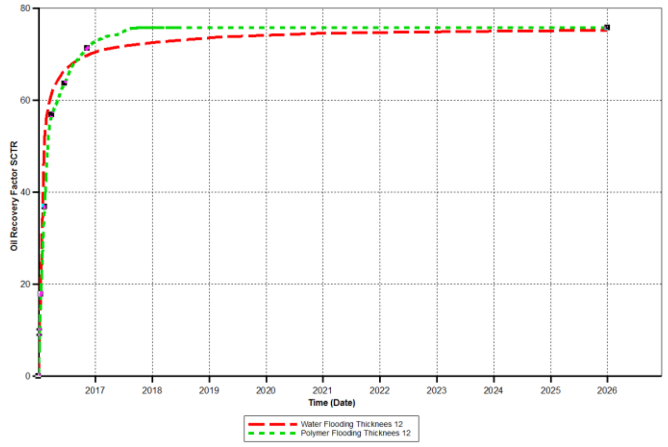


Figure .11 The effect of Thickness Water Flooding & Polymer Flooding

Table .15 The effect of Thickness Water Flooding & Polymer Flooding

| Case | Porosity | Permeability | Thickness | Oil Recovery | Figure |
|---|---|---|---|---|---|
| Polymer Flooding | 0.2 | 500 | 12 | 77% | 11 |
| Water Flooding | 0.2 | 500 | 12 | 75% | |

Note the difference between the thickness when they are (32). In the case of polymer immersion, oil extraction is higher than water overflow as shown in Figure 12 and Table 16

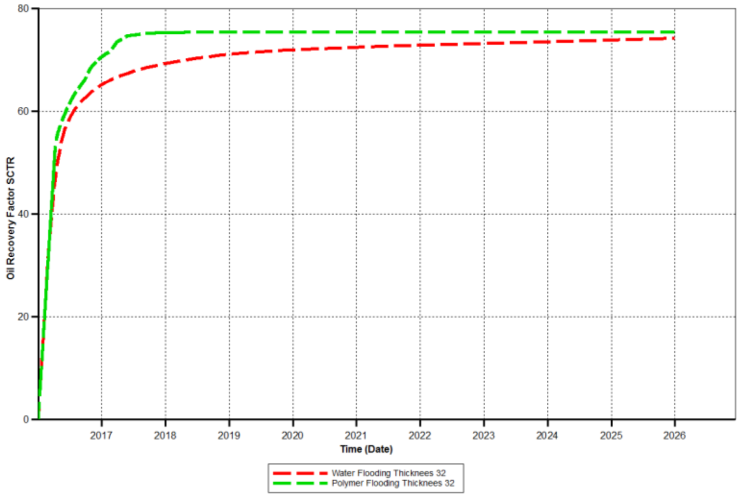


Figure .12 The effect of Thickness Water Flooding & Polymer Flooding

Table .16 The effect of Thickness Water Flooding & Polymer Flooding

| Case | Porosity | Permeability | Thickness | Oil Recovery | Figure |
|---|---|---|---|---|---|
| Polymer Flooding | 0.2 | 500 | 32 | 75% | 12 |
| Water Flooding | 0.2 | 500 | 32 | 71% | |

Note the difference between the thicknesses when they are (52). In the case of polymer immersion, oil extraction is higher than water overflow as shown in Figure 13 and Table 17

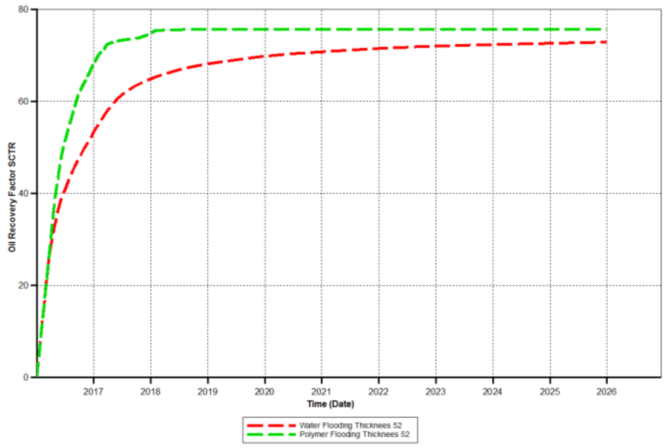


Figure .13 The effect of Thickness Water Flooding & Polymer Flooding

Table .17 The effect of Thickness Water Flooding & Polymer Flooding

| Case | Porosity | Permeability | Thickness | Oil Recovery | Figure |
|---|---|---|---|---|---|
| Polymer Flooding | **0.2** | **500** | **52** | **74%** | **13** |
| Water Flooding | **0.2** | **500** | **52** | **68%** | |

### 3. VISCOSITY POLYMER

The viscosity of the polymer has an obvious effect on the oil recovery rate because it is an important factor in the polymer immersion experiments that were tested

Note that the viscosity of the polymer when it is (10.3) the oil recovery rate is higher and when it is (20.3) the oil recovery rate is lower and when it is (30.3) it is also lower, but with the passage of time and in 2021, the oil recovery rate started to be equal as shown in Figure 14 and Table 18

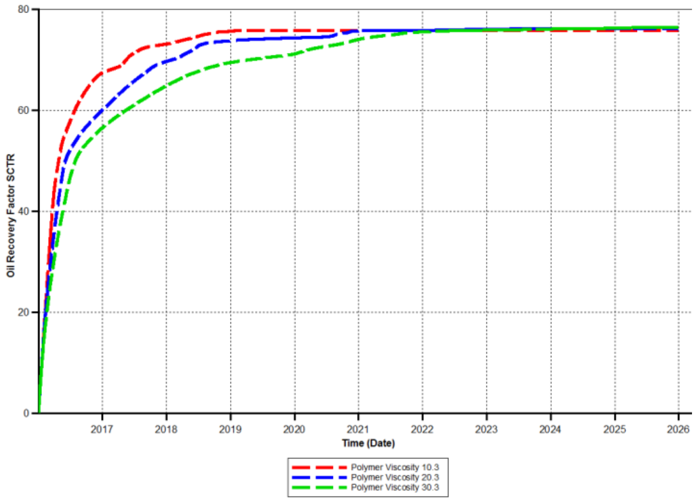


Figure .14 The effect of Viscosity Polymer

Table .18 The effect of Viscosity Polymer

| Case | Porosity | Permeability | Viscosity Polymer | Oil Recovery | Figure |
|---|---|---|---|---|---|
| 1 | **0.2** | **500** | **10.3** | **79%** | **14** |
| 2 | **0.2** | **500** | **30.3** | **77%** | |
| 3 | **0.2** | **500** | **50.3** | **75%** | |

## IX. CONCLUSIONS

- Different scenarios have been simulated by using CMG software to investigate when and where CMG can successfully applied.
- There are some factors which might some effects on polymer flooding performance such as reservoir porosity, permeability, thickness, and viscosity of the injected polymer.
- There is an optimum value for the viscosity of the injected polymer which can achieve the highest oil recovery factor.
- Increasing or decreasing the polymer viscosity above or below the optimum value would have negative impact on polymer flooding performance.
- The optimum value of polymer viscosity might have very strong relationship with viscosity of oil and reservoir permeability.

## X. RECOMMENDATIONS

- Investigate more reservoir characteristics such a temperature or salinity
- The CMG program was used in the polymer flooding experiment, so we recommend using it
- Examine the effect of reservoir heterogeneity on sweep efficiency


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