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Heterogeneity Effect on Polymer Injection: a Study of Sumatra Light Oil

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ABSTRACT - The production of oil and gas is heavily dependent on the heterogeneity of the reservoir. Optimizing the production plan and maximizing recovery from the reservoir depends on an understanding of how heterogeneity affects fluid flow and recovery. Techniques such as water flooding and polymer flooding were used to increase oil production from reservoirs while evaluating the impact of reservoir heterogeneity. Numerical simulations in homogeneous and heterogeneous models were performed in this research to identify the optimal operational parameters that will optimize oil recovery and assess the effect of heterogeneity in the reservoir on the recovery factor of the reservoir. The result showed that the homogeneous model obtained 59.86% of the oil recovery factor, while the heterogeneous reservoirs for Lk = 0.2, 0.4, and 0.6 resulted from 45.83%, 69.27%, and 80.46% of oil recovery after twenty years of production, respectively. The heterogeneous reservoir with Lk = 0.6 indicated the highest sweep efficiency compared to other scenarios, while the reservoir with Lk = 0.2 showed the lowest sweep efficiency.

Keywords: Reservoir Heterogeneity, Polymer Flooding, Chemical Flooding, EOR, Reservoir Simulation

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INTRODUCTION

After water flooding has been implemented in an oil reservoir, polymer flooding is frequently considered as a follow-up of secondary approach (Al-Shakry et al., 2018)but accelerated production due to polymer flooding may be limited by reduced injectivity. The objective of this paper is to give guidelines for optimizing polymer injectivity as key parameter for polymer flooding design. Analysis of polymer injection data from field tests, and different analytical and simulation approaches from academic or commercial simulators will be discussed. Field realistic laboratory flooding in porous medium has been performed. Presented experiments study the influence of pre-injection treatment like pre-shearing or other methods on rheological properties in porous medium. Injectivity is discussed in relation to polymer molecular weight, polymer concentration, pre-treatment, and presence of oil. Field scale injectivity is reviewed from available literature data. Impact of fracturing has been analyzed in order to isolate the matrix impact on injectivity and compare to laboratory data. Investigations show that injection pressure build up in the near wellbore region, which is also referred to as polymer shear thickening behavior, limits the injectivity of polymer solutions. The effect is more significant when high molecular weight polymer is injected compared to high polymer concentration. Hence, pre-shearing the polymer solution prior injection weakens the elastic properties of polymer while maintaining its viscous properties. Also, better polymer injectivity observed when oil is present (two phase flow. Because of its simplicity and low cost, water flooding is often the major enhanced oil recovery (EOR) technology utilized to improve oil recovery (Shi et al., 2020). Water is injected into the reservoir to displace oil toward producing wells (Wang et al., 2020). Water flooding, on the other hand, may not completely sweep the reservoir or adequately retrieve the residual oil (Akbari et al., 2019)the reduction of mobility ratio and improvement of conformance in heterogeneous reservoirs with a high coefficient of permeability variation (V. In such instances, polymer flooding can be used to boost oil recovery even more (Rita et al., 2019).

Polymer Flooding

Over the past few decades, polymer flooding has been consistently used to improve oil recovery following flooding (Al-Shakry et al., 2018)but accelerated production due to polymer flooding may be limited by reduced injectivity. The objective of this paper is to give guidelines for optimizing polymer injectivity as key parameter for polymer flooding design. Analysis of polymer injection data from field tests, and different analytical and simulation approaches from academic or commercial simulators will be discussed. Field realistic laboratory flooding in porous medium has been performed. Presented experiments study the influence of pre-injection treatment like pre-shearing or other methods on rheological properties in porous medium. Injectivity is discussed in relation to polymer molecular weight, polymer concentration, pre-treatment, and presence of oil. Field scale injectivity is reviewed from available literature data. Impact of fracturing has been analyzed in order to isolate the matrix impact on injectivity and compare to laboratory data. Investigations show that injection pressure build up in the near wellbore region, which is also referred to as polymer shear thickening behavior, limits the injectivity of polymer solutions. The effect is more significant when high molecular weight polymer is injected compared to high polymer concentration. Hence, pre-shearing the polymer solution prior injection weakens the elastic properties of polymer while maintaining its viscous properties. Also, better polymer injectivity observed when oil is present (two phase flow. In order to improve the sweep efficiency, the viscosity of the injected water must be increased using water-soluble polymers (Temizel et al., 2017).

Utilizing polymer flooding also aims to lessen the displacing fluid's mobility so that it is less mobile than the fluid being displaced. Polymer flooding is one of the most widely utilized Enhanced Oil Recovery (EOR) processes in the oil industry (Erfando et al., 2019)there will be decreasing of production rates of a field along with decreasing pressure. This led to the necessity for further efforts to increase oil production. Therefore, pressure support is required to improve the recovery factor. Supportable pressure that can be used can be either water flooding and polymer flooding. This study aims to compare recovery factor to scenarios carried out, such as polymer flooding with different concentrations modeled in the same reservoir model to see the most favorable scenario. The method used in this research is reservoir simulation method with Computer Modeling Group (CMG. Polymer flooding is the process of introducing polymer solutions into oil reservoirs to enhance oil displacement and sweep efficiency, hence increasing oil recovery (Ramadhan et al., 2021). Additionally, to seal off areas with high permeability and thief zones (Dano et al., 2019).

The following equation can be used to calculate mobility ratio:

$$M = \frac{\lambda_w}{\lambda_o} = \frac{k_{rw}/\mu_w}{k_{ro}/\mu_0} \tag{4}$$

Where, M = Mobility ratio
λ_w = Mobility of water
λ_o = Mobility of oil
k_{rw} = Relative permeability to water
k_{ro} = Relative permeability to oil
μ_w = Viscosity of water
μ_o = Viscosity of oil

The mobility ratio indicates the relative velocities of two fluids. Oil travels faster than water in favorable conditions (M<1) but water moves faster than oil in adverse conditions (M>1) and tends to breakthrough first. One advantage of polymer over water is that it produces more viscous fluid as opposed to just water (Tobing, 2018). As a result, the reservoir receives an injection of a polymer solution (Farajzadeh et al., 2021). Thus, frontal stability issues caused by waterflooding are improved by the EOR method of polymer flooding (Akbari et al., 2019).

The type and concentration of the polymer, the temperature and pressure of the reservoir, and the type of oil being produced are all variables that affect how well polymer flooding works (Arab et al., 2018). Additionally, the polymer solution may aid in lowering water mobility, which may aid in preventing the development of fingering and channeling routes (Kalbani et al., 2019). High-viscosity fluid injection, however, can potentially raise the chance of reservoir damage and lower oil production effectiveness (Gavrielatos et al., 2018).

Polymer flooding is a considered trying cEOR technique for recovering residual oil, particularly in heavy oil when waterflooding is ineffective because of viscous fingering (Ezeh et al., 2021). The two most common types of polymers are synthetic polymers like hydrolyzed polyacrylamide (HPAM) (Alli, 2019) and its derivatives and biologically generated biopolymers like xanthan gum (XG) (Freire & Moreno, 2020). For the majority of the field polymer floods, HPAM has been used. This is because it is less expensive than XG and is easily accessible. When exposed to high temperatures, divalent cations are known to cause HPAM polymers to become unstable. Even at pH 7, the acrylamide groups in the HPAM polymer undergo hydrolysis to generate acrylate groups at temperatures higher than 60ºC. (Seright et al., 2021).

Biopolymers like xanthan gum have only been applied in a few numbers of fields due to their high cost and tendency to plug (Ezeh et al., 2021).

The effectiveness of oil recovery can be increased by combining polymer flooding with other EOR techniques, such as surfactant flooding (Uzoho et al., 2019). By lowering IFT and causing the pressure differential across the oil droplets to exceed the maintaining capillary force, the addition of the surfactant aids in the mobilization of oil. The capillary number is the ratio of viscous to capillary forces:

$$N_{ca} = \frac{\mu v}{\sigma \emptyset} \qquad (3)$$

Where, N_{ca} = Capillary number
μ = Displacing fluid viscosity
v = Darcy velocity
σ = Oil-water IFT
∅ = Reservoir porosity

Polymer flooding is a method for increasing oil recovery by introducing a polymer solution into the reservoir (Akbari et al., 2019). The polymer concentration is critical to the efficacy of polymer flooding (Scott et al., 2020). To obtain the appropriate viscosity and mobility control effects, the concentration must be adjusted (Kalbani et al., 2019).

The typical concentration of polymers applied to polymer flooding in parts per million (ppm) can vary based on a number of factors, including the individual polymer employed, reservoir conditions, and project objectives (Ramadhan & Maneeintr, 2022). Polymer concentrations in oil reservoirs, on the other hand, often vary from 100 to 3,000 ppm (Erfando et al., 2019).

Concentrations outside of this range may be applied in some situations, depending on the reservoir's unique needs and the intended viscosity and mobility control effects (Al-Shakry et al., 2018). When greater sweep efficiency and oil recovery are the primary aims, higher concentrations may be used (Ibrahim et al., 2019). However, leveraging extremely high polymer concentrations may result in increased viscosity, which might impair injectivity and cause pressure loss in the reservoir (Arab et al., 2018).

Al-Shakry et al., 2018 and Manichand & Seright, 2014 reported in their experiments, they used the polymer concentration of 500, 1000, 1500, 2000, 2500, and 3000 ppm.

Heterogeneity of Reservoir

Reservoir heterogeneity is a basic feature that influences the behavior and performance of oil and gas reservoirs (Izgec et al., 2006). It refers to the variances and contrasts in rock and fluid characteristics that occur within subterranean formations (Srochviksit & Maneeintr, 2016). The geographical variations and variances in rock and fluid characteristics inside an oil or gas reservoir are referred to as reservoir heterogeneity (Tuncharoen & Srisuriyachai, 2018). It depicts the non-uniform distribution of geological properties that influence fluid flow and reservoir storage (Vo-Thanh et al., 2022). Reservoir heterogeneity can occur at many different sizes, from small-scale changes within individual rock strata to larger-scale variances over the whole reservoir (Lüftenegger & Clemens, 2017).

Reservoir heterogeneity is an important factor to consider in reservoir characterization and modeling (Ding et al., 2019). Accurate heterogeneity characterization by techniques like as core analysis, well logging, and seismic imaging aids in understanding the distribution of rock and fluid characteristics (Raza et al., 2019). This data is subsequently fed into reservoir simulation models, which are used to properly anticipate fluid flow behavior, improve well location, and build successful enhanced oil recovery systems (Fancy, 2010). Overall, a thorough understanding of reservoir heterogeneity is required for effective reservoir management and maximum hydrocarbon recovery (Tiab & Donaldson, 2016).

One of the ways to determine the heterogeneity or the reservoir is using the Dykstra-Parsons permeability correlation (Fancy, 2010). It is a method for estimating the length or size of reservoir variability in terms of permeability (Al-Shakry et al., 2018). It is founded on an examination of the spatial correlation of permeability values at various distances inside a reservoir (Novriansyah et al., 2020).

Another way to estimate the reservoir heterogeneity is with the Lorenz coefficient (Tiab & Donaldson, 2016). It is also known as the Gini coefficient or Gini index (Fancy, 2010). the Lorenz coefficient (Lk), which determines the number of reservoir characteristics, is utilized to check the permeability distribution (Temizel et al., 2017).

The heterogeneity plays a key role in oil production in the reservoir. A better understanding of the effect of reservoir heterogeneity on oil production can be the consideration of which method to be used in producing oil in the reservoir. This study helps to gain more understanding of the heterogeneity effect in polymer flooding which could be considered in modelling polymer injection in South Sumatera Basin.

METHODOLOGY

The Computer Modeling Group supports the reservoir modeling approach employed in this study (CMG). On the CMG STARS simulator, a 3D numerical model is used in this investigation. Due to the design and evaluation of all chemical additive based chemical EOR processes, the selected simulator was utilized. The only simulator that considers the intricate phenomena necessary to precisely represent processes like foam flooding, low salinity water injection, and Alkaline-Surfactant-Polymer (ASP) flooding.

CMG-STARS is a flexible and resilient reservoir simulator that can handle complicated reservoir characteristics like as fractures, faults, and heterogeneities. CMG-STARS is particularly good at modeling thermal processes including steam flooding, steam-assisted gravity drainage (SAGD), and in situ combustion. It is appropriate for simulating complicated multiphase flow behavior, such as oil, water, gas, and vapor phases. Since the chemical injection is temperature dependent, the use of CMG-STARS is the most suitable to model the case.

Reservoir Simulation

In assessing the potential output and profitability of complex processes like polymer flooding, simulation models play an important role. Accurate laboratory data and trustworthy representations of its physical events are required for a precise simulation.

Table 1 presents the reservoir simulation model which is generated using 30 × 30 × 11 Cartesian grid model, representing 500 × 500 ft and 66 ft of reservoir size and thickness, respectively. The reservoir properties are collected from (Yuliandari et al., 2019), (Haris, 2020) & (Abdurrahman et al., 2015) that works on Air Benakat formation in Jambi Province, South Sumatera Basin, Indonesia. The targeted reservoir for this simulation is the sandstone formation (Irmaya et al., 2022) in Air Benakat in South Sumatera Basin.

Yuliandari et al., (2019) and Haris, (2020) worked to determine geological, geophysical and reservoir characterization of the Air Benakat formation, then concluded the formation has average porosity and average permeability are 0.247 and 132 mD, respectively.

Table 1
Reservoir Properties

Parameter	Value	Unit
Top Depth	4593	ft
Reservoir Size	500 × 500	ft
Thickness	66	ft
Porosity	0.247	-
Permeability	132	mD

Reservoir Pressure	2035	psi
Reservoir Temperature	150	ºF
API Gravity	41.38	API
Oil viscosity	22	cp
OOIP	4.6×10^5	bbl

The oil reservoir in Air Benakat formation has API gravity 41.38 with the formation temperature 150 ºF. The pressure in the formation is 2035 is calculated based on the pressure gradient of the formation. With the reservoir properties above, the simulation then run, and it shows the OOIP of the formation is 4.6×10^5 bbl.

Table 2
Chemical Properties

Parameter	Polymer
MW (lb/lb mole)	100,000
Viscosity (cp)	70

Table 3
Production Constrains for Simulation

Parameter	Value	Unit
Fracture Pressure	3360	Psi
Max. BHP at Injector	3300	Psi
Max. Production Rate	250	bopd

Fracture pressure of the reservoir is forecasted with Hubbert-Willis's equation at 3360 psi. Thus, maximum injection bottom hole pressure (BHP) is set at 3300 psi to prevent the formation to break down due to the fracture. Also, maximum production rate is set at 250 bopd as explained in Table 3.

Reservoir Heterogeneity

Two essential characteristics of a reservoir that influence its capacity to produce oil and gas are porosity and permeability (Zhang, 2019). The percentage of the rock's volume that is made up of voids is known as porosity, whereas the rate at which fluids can pass through the rock is known as permeability (Satter & Iqbal, 2016). These qualities can be distributed throughout a reservoir in a complicated and highly changeable manner, with variations occurring at various scales (Ahmed, 2019).

The porosity and permeability distribution in the reservoir can be generated in a variety of realizations using simulation approaches like sequential Gaussian simulation or stochastic simulation (Aadnøy & Looyeh, 2019). This gives a variety of fluid flow behavior scenarios that can be used to analyze the degree of uncertainty in hydrocarbon reserves and improve production methods (Fanchi, 2018).

Reservoir term "heterogeneity" refers to the variety in rock qualities throughout the reservoir (Temizel et al., 2017). Permeability is one of the important characteristics of rocks that has an impact on heterogeneity (Fanchi, 2018). Parallel Layer and Serial Layer are two categories for the permeability combination (Ramadhan & Maneeintr, 2022).

The heterogeneity of the reservoir can also be measured using a variety of techniques (Ibrahima et al., 2017). One of the most popular techniques is the Lorenz Coefficient (Lk), which can be obtained from Figure. 1 by dividing area 1 by area 2, which is one of the approaches. Lk is regarded as having a uniform permeability distribution if it is close to zero (Ahmed, 2019).

The Lorenz coefficient (Lk), which specifies how many reservoir features there are, is used to confirm the permeability distribution in order to create a heterogeneous model (Fancy, 2010). Geostatistically, determining the geographical distribution of porosity and permeability is also done using a sequential Gaussian simulation (Tiab & Donaldson, 2016). The normal range of values for the Lorenz coefficient is $0.2 < Lk < 0.6$. The obtained Lk value for this investigation is 0.2, 0.4, and 0.6 as presented in Figure 1.

In this study, porosity and permeability are correlated using linear regression with combination of Ms. Excel, MatLab, and CMG to distribute the heterogeneity of porosity and permeability as presented in Figure 2 and Figure 3. The porosity and permeability range from 0.20 – 0.30 and 50 – 350 mD for Lk = 0.2, 25 – 800 mD for Lk = 0.4, and 5 – 1750 mD for Lk = 0.6 respectively.

$$\log(k) = a \times \emptyset^{q} \times b \tag{5}$$

Where, k is permeability.
$\emptyset$ is porosity.
a, b, and q are regression parameters.

The porosity and permeability in this study as presented in Figure 2 and Figure 3 are distributed using Gaussian (normal) distribution in MatLab.

Then, the distribution of both value is added to CMG-STARS as the reservoir simulator. The model of the reservoir in this study is generated with one production and one injection well, with a quarter five-spot well pattern. Injector-producer inter-well distance of 707 ft since both wells are located diagonally.

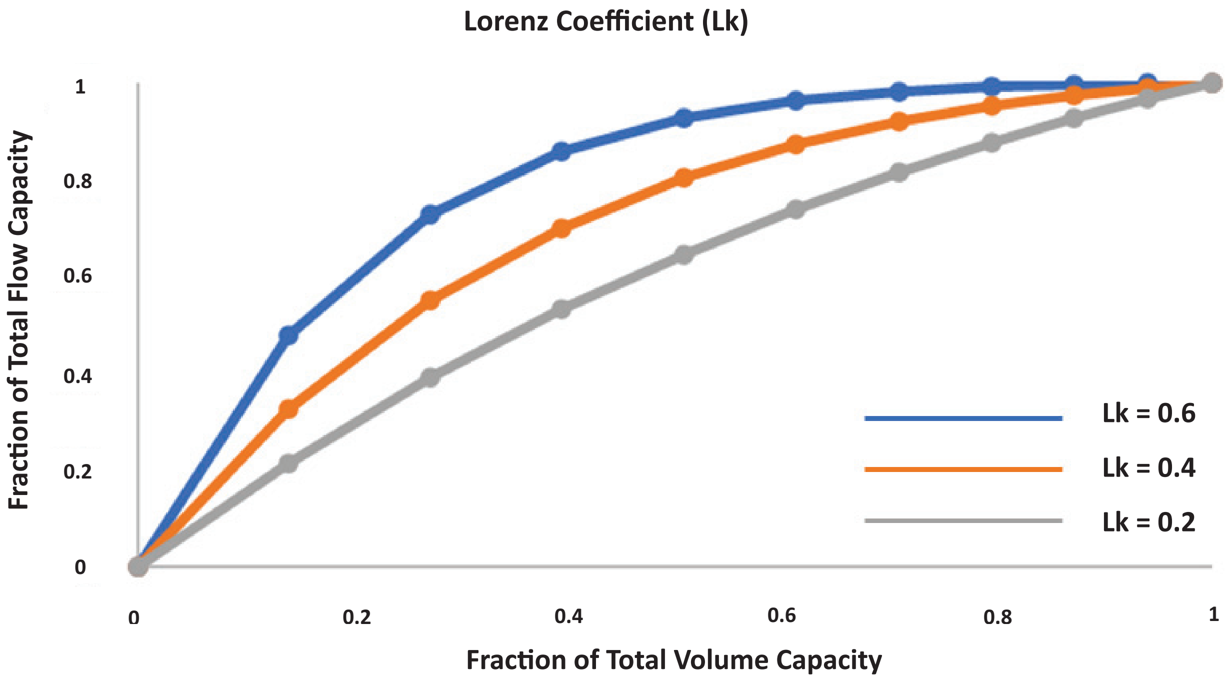

Figure 1
Lorenz Coefficient (Lk) of the reservoir

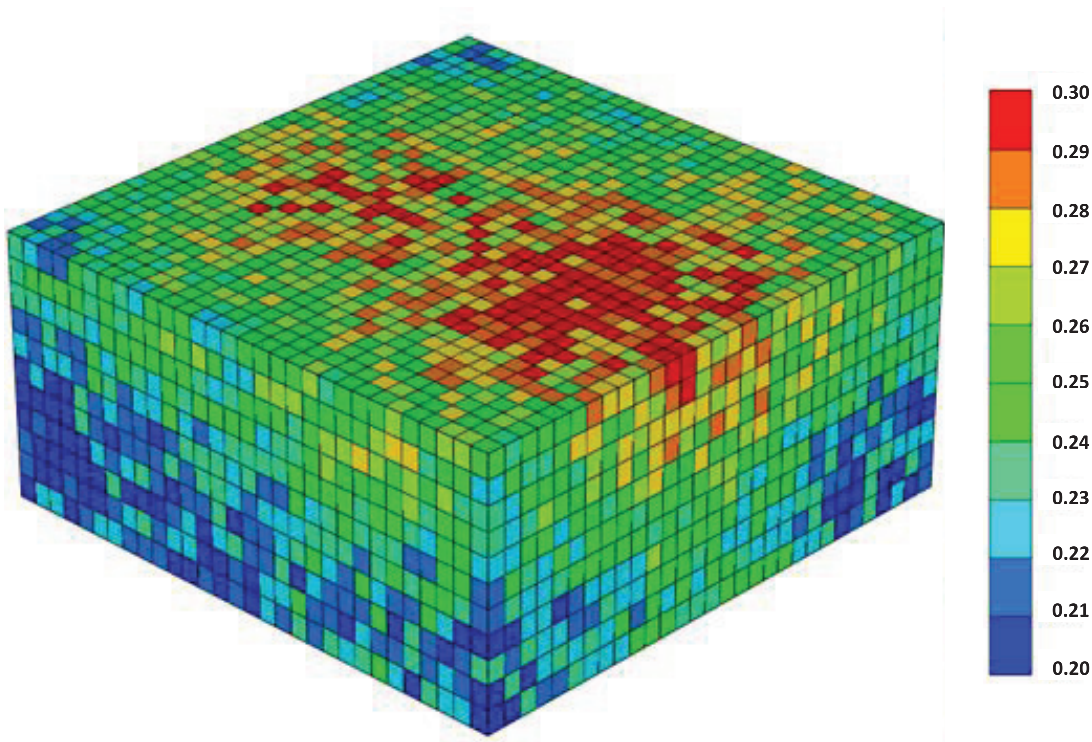

Figure 2
Porosity distribution of the reservoir

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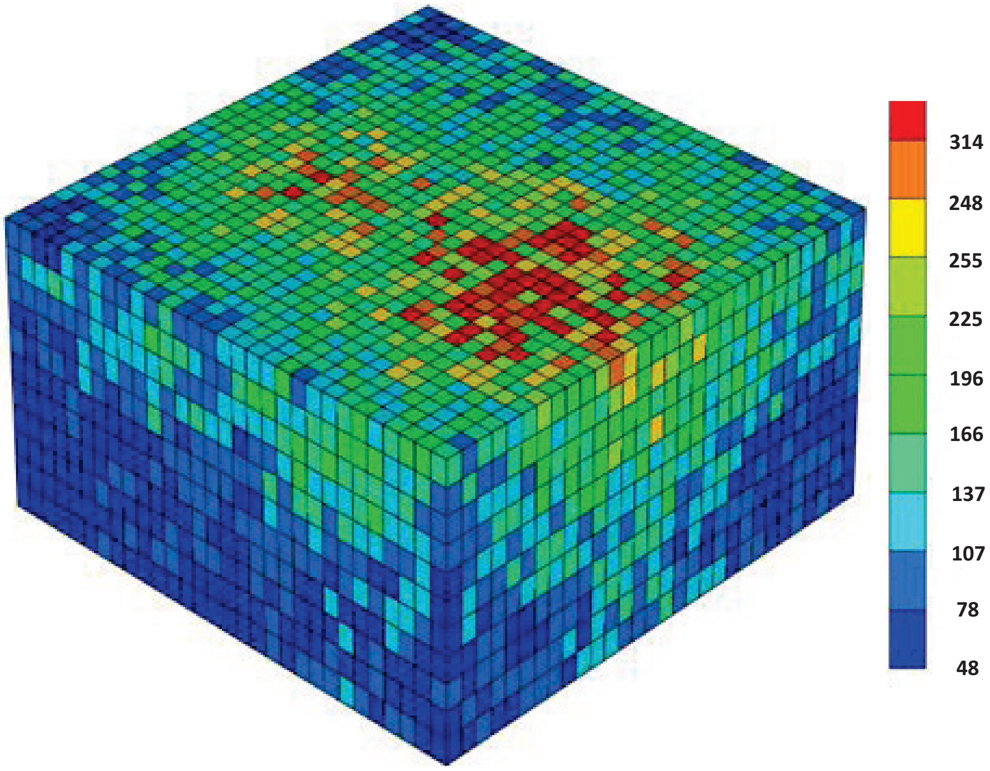

Figure 3
Permeability distribution of the reservoir

Through the simulation run, a single polymer with a consistent concentration is injected using the traditional technique known as "single polymer injection." This method's objective was to assess and compare the efficiency of the novel approach to more traditional water flooding techniques. The efficiency of water flooding can be impacted by reservoir heterogeneity, such as changes in permeability and geological characteristics. Polymer flooding is especially beneficial in reservoirs with large permeability differences, where water tends to flow via high-permeability zones. Polymer viscosity increases assist keep injected fluids into low-permeability zones, enhancing sweep efficiency.

Polymer flooding for this study starts after 3-year of water flooding at 1 PV injection. Because polymer flooding can increase the effectiveness of water flooding, it is frequently chosen as an enhanced oil recovery (EOR) technique. During water flooding, the water is injected into the reservoir and sweeps through it, pushing the oil into the production well. The high-permeability zones, however, tend to be bypassed by the water as it flows through the reservoir, leaving behind pockets of oil that are challenging to retrieve.

RESULT AND DISCUSSION

The model is run with water flooding since the beginning of the production. Waterflood is chosen as the pressure maintenance for the reservoir due to the fact that its effectiveness to maintain the pressure and increase the oil production (Sidiq et al., 2019).

In this study, some water flooding scenarios are run to obtain the base case scenario to deplete the reservoir (Lamas et al., 2021). The typical PV (Pore Volume) injected in waterflooding might vary based on reservoir features, fluid properties, and project objectives (Erfando et al., 2019). However, a reasonable rule of thumb for the PV injected in waterflooding is 0.5 to 2.5 times the reservoir's pore capacity. Therefore, the injection of 1.0 of water flooding into formation is run to see the effect of each scenario in oil production.

Furthermore, the effect of heterogeneity of the reservoir is compared to the homogeneous reservoir. Accordingly, the scenario for each water injection is run for both models, homogeneous and heterogeneous reservoirs.

Polymer Flooding

To improve the sweep efficiency of water flooding, 1500 ppm of polymer is chosen to be injected into the reservoir. For polymer flooding projects, a concentration of 1500 ppm is frequently chosen since research has shown that it strikes a fair compromise between increasing sweep efficiency and lowering the cost of the polymer injection (Al-Shakry et al., 2018) & (R S Seright, 2016).

- Effect on Cumulative Oil Production

The cumulative oil production of water and polymer floods is shown in Figure 8. The presence of polymer greatly raises water viscosity, which in turn causes a decrease in the oil-polymer viscosity ratio and an increase in the macroscopic sweep efficiency. Figure 4. and Table. 4 indicate the oil production cumulative of the reservoir after 3-year of water flooding and 17-year polymer flooding compared in homogeneous model with and in heterogeneous model with Lk = 0.2, 0.4, and 0.6.

Water flooding in the heterogeneous reservoir shows the higher oil production cumulative compared to all heterogeneous scenarios. However, for the heterogeneous reservoir, the results indicate that the more heterogeneous reservoir, the more oil produced.

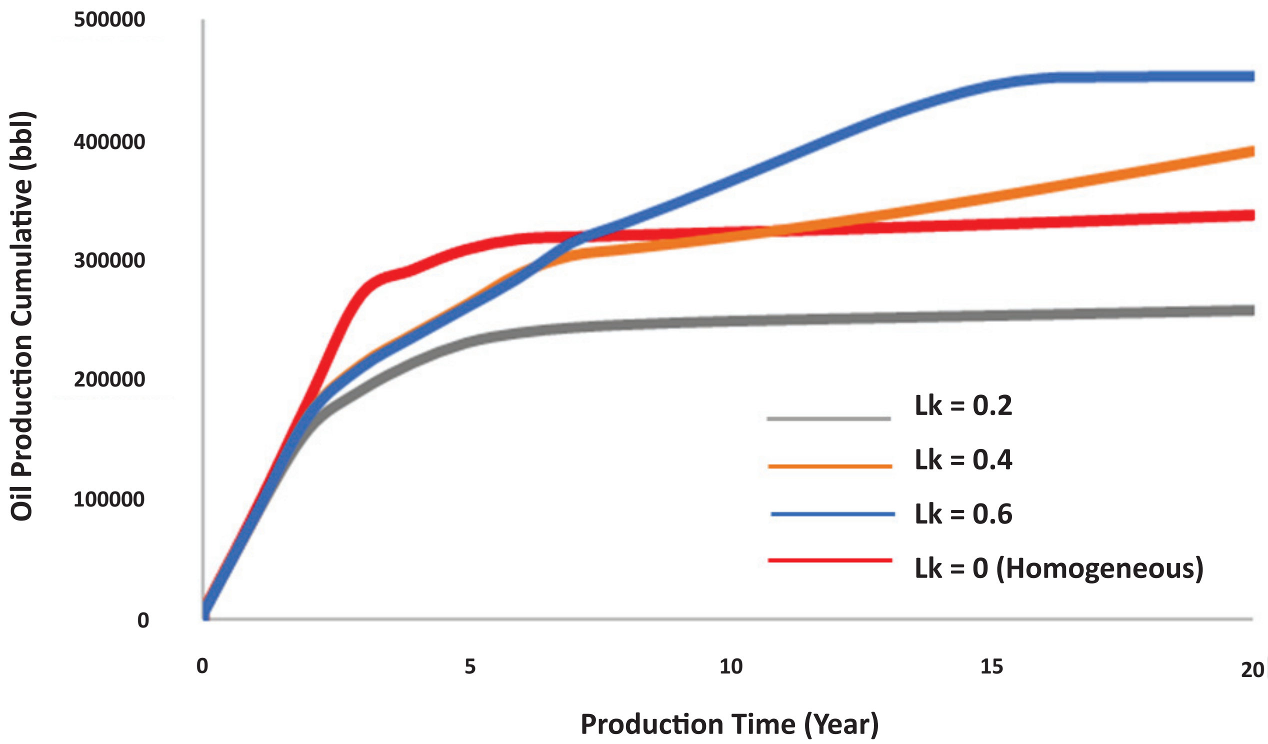

Figure 4
Oil production cumulative after polymer flooding

Table 4
Summary of oil production cumulative after polymer flooding

Oil Production Cumulative (1×10^5 bbl)		
	Water Flooding	Polymer Flooding
Lk = 0.0	2.70	3.37
Lk = 0.2	1.91	2.58
Lk = 0.4	2.09	3.90
Lk = 0.6	2.10	4.53

In polymer flooding scenarios, homogeneous reservoir produces less oil compared to heterogeneous reservoirs with Lk = 0.4 and Lk = 0.6. This occurs due to the water breakthrough in the homogeneous reservoir occurs later in the reservoir. However, once it happens, the reservoir starts to produce more water compared to heterogeneous reservoir, which explains the next part.

Heterogeneous reservoir with Lk = 0.2 has lesser oil production compared to other heterogeneous reservoir models. The permeability and porosity of a less heterogeneous reservoir tend to be uniform, resulting in fewer variations in flow pathways for the injected fluid to reach and sweep over the oil-bearing zones. This reduces the connection between the injected fluid and the oil, decreasing the capacity to efficiently displace and generate the oil. Furthermore, in a less heterogeneous reservoir, the lack of major fluctuations in permeability and porosity leads to low sweep efficiency, leaving significant volumes of unrecovered oil behind.

In summary, reservoir heterogeneity provides variations in permeability, porosity, and flow pathways, all of which are required for successful fluid displacement and increased oil recovery. When compared to a less heterogeneous reservoir with more uniform characteristics and restricted connection between the fluids, a more heterogeneous reservoir provides more opportunities for the injected fluid to interact and displace the oil, resulting in higher oil output.

Effect on Water Cut

As discussed in the previous section, the water cut plays crucial impact on the oil production after polymer flooding. To observe hot the polymer flooding affects the oil production, the water cut is presented in Figure 5.

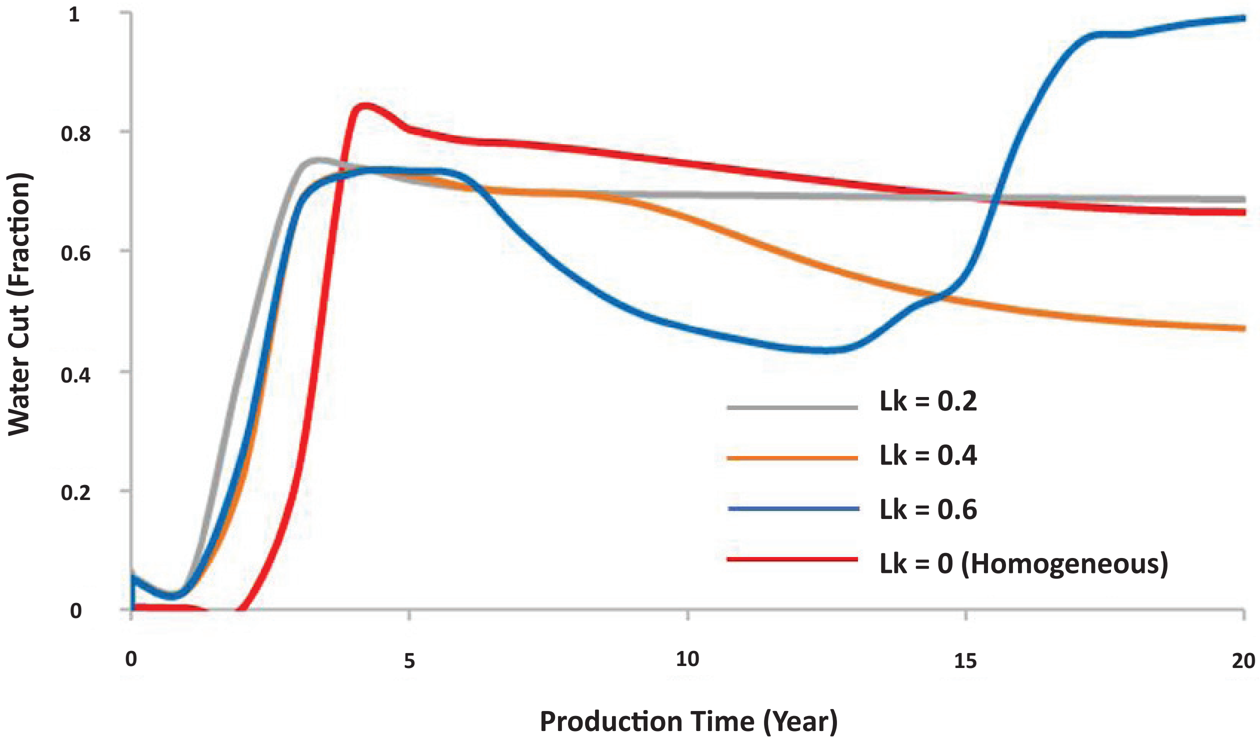

Figure 5
Water cut of the reservoir after polymer flooding

As portrays in Figure 5. The water cut does not occur in homogeneous reservoir until the first three-year of production, this happens because the injection water does not reach the production well. However, after the water breakthrough happens and it reaches the production well, the water cut increases quickly. In the fourth year, the water cut is at 83% of total production.

For heterogeneous reservoir, the water cut occurs faster than homogeneous reservoir. This happens due to the water fingering is more likely to occur in the heterogeneous reservoir. As indicated in Figure 5. the heterogeneous reservoir with Lk = 0.2, 0.4, and 0.6, the field starts to produce the water earlier than homogeneous reservoir. However, after the polymer injected in the third year, the water cut does not increase as much as in homogeneous reservoir until the end twenty year of production time.

For homogeneous reservoir with Lk = 0.6 after 6 years of production time, the water cut decreases until fifteen year of production before it starts to increase the water production. This indicates that polymer injection helps the heterogeneous reservoir to produce more oil in the pore throat of the reservoir by increasing the water viscosity in reservoir (Jouenne et al., 2018).

Effect on Oil Recovery Factor

To properly increase oil recovery and evaluate the flooding process are the two most crucial issues in polymer flooding. Although polymer cannot alter the residual oil saturations on its own, over time both water and polymer flooding will result in the production of movable oil. Polymer flood is intended to advance the production profile.

Table 5. represents the increase in recovery factor for water flooding and polymer flooding of homogeneous and heterogeneous reservoir models.

In homogeneous reservoir, the recovery factor of polymer flooding is 59.86%. While in heterogeneous reservoir, the recovery factor is 45.83%, 69.27%, and 80.46% for Lk = 0.2, 0.4, and 0.6, respectively.

Because of the greater sweep efficiency and oil displacement, the recovery factor after polymer flooding is often larger than after primary or waterflooding. However, providing a precise or average recovery factor following polymer flooding is difficult since it varies greatly depending on the unique reservoir conditions and the efficiency of the polymer flood.

Effect on Sweep Efficiency

Reservoir heterogeneity has a significant impact on sweep efficiency during fluid displacement processes such as polymer flooding.

Because of reservoir heterogeneity, preferred flow routes within the reservoir might result in flow channeling and bypassing of the injected fluid. High-permeability zones can operate as conduits, enabling injected fluid to take the route of least resistance, whereas low-permeability zones can act as barriers, inhibiting fluid flow. Because the injected fluid skips major areas of the reservoir, leaving untapped oil behind, this non-uniform flow distribution can diminish sweep efficiency. The stability of the sweep front, which is the leading edge of the displacing fluid that pushes oil ahead of it, can be affected by reservoir heterogeneity. Because of changes in permeability and porosity, the sweep front in heterogeneous reservoirs can become unstable. Because of this instability, the injected fluid fingers into high-permeability zones, leaving isolated pockets of unswept oil behind. Because the displacing fluid cannot reach and displace the confined oil pockets, sweep efficiency suffers.

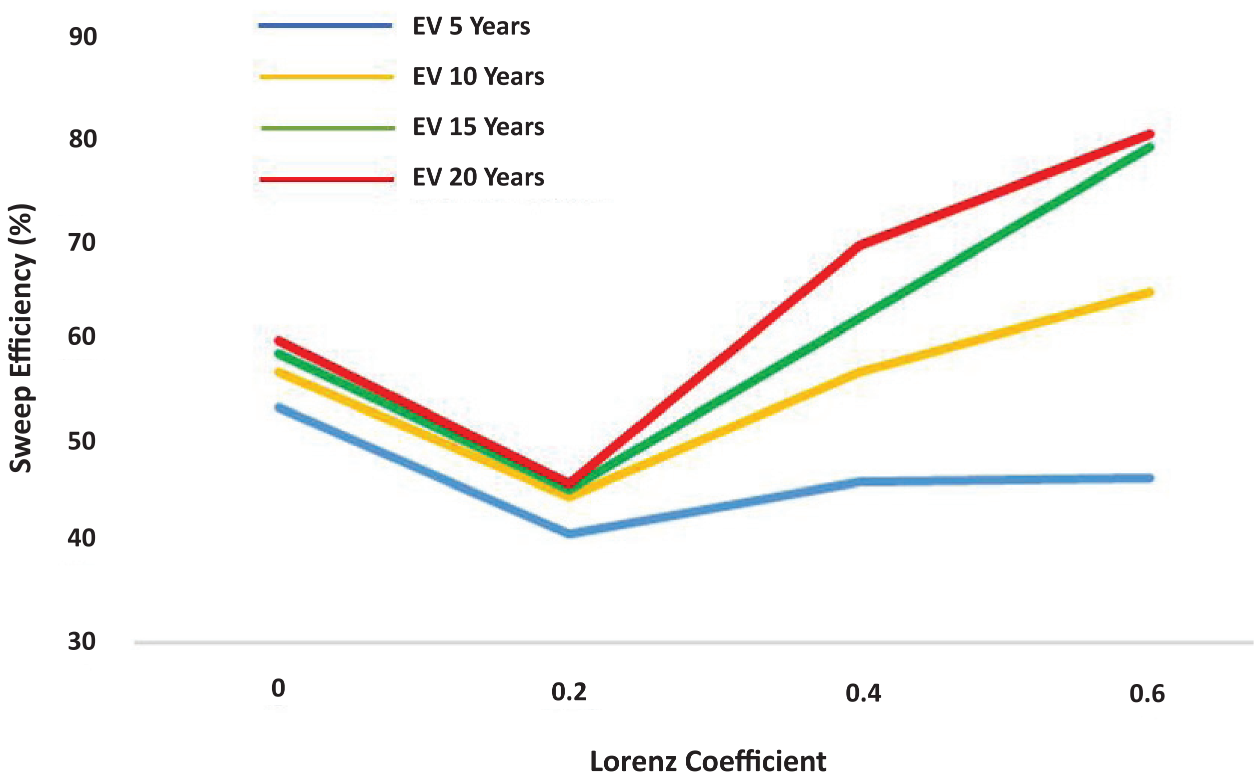

Figure 6
Effect of lorenz coefficient on sweep efficiency

Figure 6. represents the correlation of reservoir heterogeneity with sweep efficiency. Homogeneous reservoir (Lk = 0) shows that sweep efficiency (EV) slightly increases over time from 5, 10, 15, and 20 years of production time. For heterogeneous reservoir with Lk = 0.2, the sweep efficiency portrays marginally increases EV over time. However, the EV is lower than homogeneous reservoir.

Reservoir with Lk = 0.4 represents the constant increase in EV over 5, 10, 15, and 20 years. The same trend can be observed from reservoir with Lk = 0.4 with higher increasement for EV overtime. The difference between EV trends of reservoir with Lk = 0.4 and reservoir with Lk = 0.6 is at the end of 20 years of injection, EV's increasement of reservoir with Lk = 0.6 is not so different from 15 year. This occurs due to the reservoir has more than 90% of water cut, as presented in previous section.

CONCLUSIONS

Reservoir simulation is successfully conducted to evaluate the effect of heterogeneity in Air Benakat formation in South Sumatera Basin, Indonesia. From the results obtained, homogeneous reservoir shows the higher sweep efficiency (EV) compared to heterogeneous reservoir for the first five-years. However, the heterogeneous models show better incremental of EV in ten, fifteen, and twenty years of injection. Moreover, heterogeneous reservoirs have higher cumulative oil production for twenty years of production for Lk = 0.4 and Lk = 0.6, which have 69.27 and 80.46% of oil recovery factor after twenty years. Nevertheless, the heterogeneous reservoir is one setting where waterflood and polymer flood performance may be severely impacted by several factors. Hence, to ascertain the characteristics related to the polymer flow through porous media, rheology studies as well as single-phase and two-phase core flooding tests are required. Adsorption, inaccessible pore volume, residual resistance factor, fluid viscosity, and relative permeabilities are among the qualities that are crucial.

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GLOSSARY OF TERMS

Symbol	Definition	Unit
API	American Petroleum Institute	
ASP	Alkaline-Surfactant-Polymer	
BHP	Bottom Hole Pressure	psi
cEOR	Chemical Enhanced Oil Recovery	
CMG	Computer Modelling Group	
EOR	Enhanced Oil Recovery	
EV	Sweep efficiency	%
HPAM	Hydrolyzed Polyacrylamide	
IFT	Interfacial Tension	
IOR	Improved Oil Recovery	
Lk	Lorenz Coefficient	
M	Mobility Ratio	
Mw	Molecular Weight	lb/lbmole
pH	Potential Hydrogen	
ppm	Part per million	
OOIP	Original Oil in Place	bbl
PV	Pore Volume	%
XG	Xanthan Gum	

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