http://journal.uir.ac.id/index.php/JGEET

E-ISSN : 2541-5794
P-ISSN : 2503-216X

Journal of Geoscience,
Engineering, Environment, and Technology
Vol 10 No 04-2/2025

RESEARCH ARTICLE

Sensitivity Test Analysis Using Reservoir Simulation on Surfactant-Polymer Injection with Core Modeling

Ludovika Jannoke [1,*], Muhammad Rizal Syaifullah[1]
[1] Universitas Pertamina, Department of Petroleum Engineering, Jakarta, 12220, Indonesia

* Corresponding author : ludovika.jannoke@universitaspertamina.ac.id
Tel.:+62 87-876-700-341

Received: Aug 4, 2025; Accepted: Jan 6, 2025.
DOI: 10.25299/jgeet.2025.10.1.1.24407

Abstract

This research aims to determine the results in increasing the effective recovery factor carried out by doing core modeling to be carried out for application to the field. Prior to the research, EOR screening was conducted to maximize the results, and from the EOR screening results, the EOR method that can be used is surfactant-polymer injection. This research was conducted using laboratory data from open source to do data modeling such as core data and surfactant-polymer data. After obtaining laboratory data, perform core modeling using laboratory data that is matched against laboratory test data. After the coreflooding simulation results are obtained by matching and after optimization, the next step is to up-scale the data to the field to carry out the scenario. There are three initial scenarios, namely basecase, waterflooding, and surfactant-polymer injection. After that, sensitivity tests were carried out on the total PV injection from 0.1 PV to 0.2 PV. And the maximum result was obtained in the surfactant-polymer injection scenario with 0.18 PV injected. The recovery factor was 51.21% with a total cumulative oil production of 190.3 MMBBL. Determination of the best scenario is determined through an increase in recovery factor, besides that the time carried out in all scenarios is carried out for 40 years.

Keywords: Enhanced Oil Recovery, Surfactant-polymer injection, Core Modelling, Recovery Factor

---

1. Introduction

The age of a production field is very influential in the productivity of the field, because as the production period increases, the productivity will decrease. This is influenced by the amount of hydrocarbons produced more and more from the reservoir and has an influence on the decline in natural energy in producing hydrocarbons from the reservoir. In order to produce the available hydrocarbons, an enhanced oil recovery method is required. Enhance Oil Recovery or EOR is a method used in increasing the production of oil that remains in the reservoir and can still be produced. In EOR there are 4 (four) different methods, namely chemical flooding, thermal flooding, microbial flooding, and miscible flooding. The EOR method with chemical flooding has 3 (three) methods with different chemicals, namely polymer injection, alkali injection, and surfactant injection (Terry, 2001). In addition to age, reservoir type also greatly affects the production of a field. In reservoirs with This research uses some data obtained through open-source type reservoirs have high permeability but due to the fractures created are not well-connected causing limited fluid flow and causing the reservoir to lose pressure without producing the reservoir (Nelson, 2001).

In this study, the reservoir type is naturally fractured reservoir with poorly connected compartments that cause a pressure drop during production but has a small hydrocarbon fluid production. In natural flow production in the field that will be carried out enhanced oil recovery has a total cumulative oil recovery of 22.87 MMBBL with a recovery factor of 6.14% of total recovery so that it is not possible to produce in natural flow. The recovery is quite small due to several factors, namely the wettability of the reservoir and the type of reservoir it has, because at the beginning of the field being produced it has an initial pressure value of 3000 psi, but at the time of production the field has a pressure drop with an average pressure of 750 psia up to 1000 psia but has a low recovery factor value.

To overcome these problems, this research will use chemical flooding or chemical injection methods to increase production in fields with age or reservoir formations that are difficult to produce (Taber et al., 1997). Chemical injections are advanced EOR method by adding chemicals such as alkaline, surfactant, and polymer into the slug and injected into the reservoir. This method has been proven to increase the production of hydrocarbons that are still trapped in porous media and can reduce the saturation of oil. Along with the development of technology, there are chemical injection methods using surfactant-polymer materials that are applied. This surfactant-polymer flooding method aims to reduce the value of IFT/interfacial tension (tension between surfaces) because if a reservoir has a large interfacial tension (IFT) value, the mobility of the oil contained in the reservoir will be more difficult to move, therefore surfactants are used in this method. And the purpose of using polymer in this study is also to increase the value of sweep efficiency by increasing the viscosity value of the pushing fluid in order to push the hydrocarbon fluid with a lower viscosity than the viscosity value of the pushing fluid.

In this research, we analyzed the results of laboratory coreflooding tests using a predetermined surfactant polymer, which will be applied to field data. This research will use CMG software which consists of several software. Some of the software that will be used include CMG Builder with the STARS type, CMG CMOST-Ai, and CMG results. The use of software aims to implement the results of laboratory testing and sensitivity tests will be carried out to obtain the best strategy results with the best recovery factor increase. This research aims to determine the concept and working principle of chemical flooding activities, knowing the parameters that need to be considered in conducting EOR, especially the chemical flooding method, knowing the parameters that affect the optimization model of the core, knowing the value of the success rate of a well in production after the chemical flooding process in terms of increasing oil production, knowing the value of the surfactant-polymer concentration to be used in the surfactant-polymer flooding method.

2. Methods

This research uses some data obtained through open source developed by Hakiki et al. (2015) and Gutierrez et al. (2022). The data obtained are core data, surfactant data, and polymer data. In addition, researchers also prepare field data and several scenarios that will be implemented. This research was carried out using simulation/experimental methods carried out in CMG software to determine the surfactant-polymer flooding method that is effective in field use. This research was conducted in the R field with the reservoir model in **Figure 1** having dimensions of 5 x 34 x 36 so that a total of 6120 grid blocks with a total of 36 layers and only contained in one zone. In **Table 1**, **Table 2**, and **Table 3** are the characteristics of the reservoir that will be surfactant-polymer flooding.

It can be seen from **Figure 2** that in the reservoir to be researched there are three faults that are not connected or not connecting reservoirs. From this it can be known that the reservoir is a natural fractures reservoir. Natural fracture reservoir is a reservoir with planar discontinuities created in the reservoir. macroscopic scale caused by physical deformation or diagenesis (Nelson, 2001). Reservoirs with this type have high permeability values, but fractures that are not well connected will cause a decrease in pressure but cannot produce large amounts of

Table 1. Reservoir Model Description

Parameter	Value	Unit
Grid Dimension	5 x 34 x 36	-
Grid Type	Orthogonal	-
Porosity Dist.	0.05 - 0.25	-
Permeability I	0 - 2149	mD
Permeability J	0 - 2149	mD
Permeability K	0 - 300	mD
Depth	5741.71	FT
Thickness	115-1147	FT

Table 2. Reservoir Properties

Reservoir Properties	Value	Unit
Water Density	62.7967	lb/ft^3
Rock Comprehensibility	3.45E-06	psi^{-1}
Oil Viscosity	1	cp
Water Viscosity	0.96	cp
Reservoir Depth	5741.71	ft
Reservoir Temperature	149	deg-F
Reservoir Pressure	3000	psia
SG Oil	0.72	-
°API	65.03	-

Table 3. Total Reserve in Reservoir

Parameter	Value	Unit
Gross formation vol.	53200	MMcuft
Formation pore vol.	6260	MMcuft
Aqueous phase vol.	4190	MMcuft
Oil phase vol.	2074	MMcuft
Gaseous phase vol.	0	cuft
Solid phase vol.	0	cuft

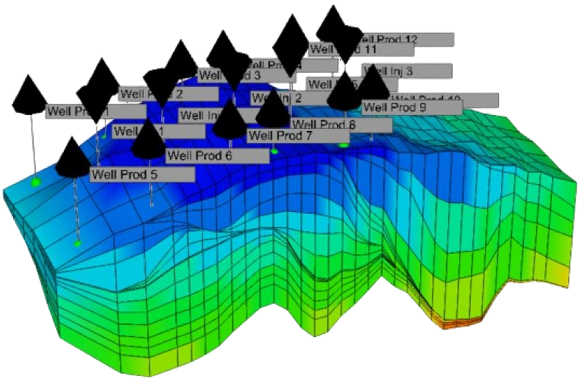

Fig 1. Reservoir Illustration

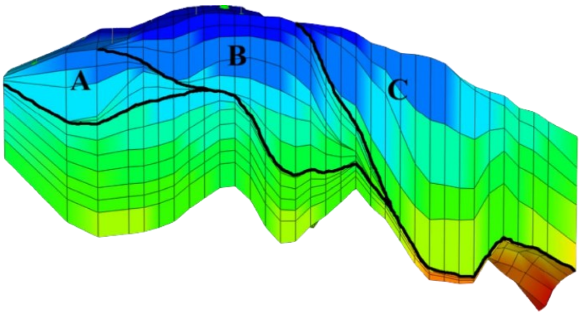

Fig 2. Reservoir Compartment

hydrocarbons to the production well. In each reservoir there are three compartments that have been given a letter symbol. Each compartment consists of a different number of wells. Compartment A consists of two production wells and one injection well, compartment B has six production wells and three injection wells, and compartment C has four production wells and one injection well.

In this research, first modeling of core data (**Table 4** and **Table 5**) obtained for simulation is carried out, namely from the results of testing from previous study which was carried out laboratory tests (Kristanto et al., 2019). The core data that was modeled was obtained from the results of laboratory tests on a production field in Indonesia, precisely in Limau, Riau. The core data used has the following characteristics:

The value of the core flooding test results with a total recovery factor of 65.7% of the total recovery factor as shown on **Figure 3**. These results were obtained by conducting laboratory testing with core samples from one of the oil fields in Indonesia. The core sample from modelling is shown at **Figure 4**.

In addition to modeling core data, there are also modeling results from the chemicals to be used, namely surfactants and polymers. Surfactant obtained with type SS-B8020 and polymer HYBOMAX 4785. Modeling performed on surfactant and polymer types includes several measurements including IFT measurements of surfactant solutions at several concentrations, and polymer rheology measurements. In the measurement of interfacial tension on surfactants, it was carried out at several concentrations in order to find out the results of the lowest IFT measurement at a temperature of 104.4°C, as shown at **Table 6**. The purpose of conducting the test at a temperature of 104.4°C was to see the effectiveness of reducing IFT at high temperatures, in addition, the test was also carried out to find out the surfactant which will be used at high temperatures and will not cause the surfactant to be damaged.

Results of IFT surfactant measurements show that surfactant with concentration 0.1% shows the smallest IFT value because the smaller the IFT produced, the better it will be to increase oil recovery. The selection of surfactant type with SS-B8020 or super surfactant type is based on several advantages, namely low concentration, salt tolerance, and several problems found in formations such as emulsion, scale, and corrosion can be avoided because the use of surfactant is used with low concentration.

From **Table 7**, the results obtained from the test were on the polymer with a concentration of 1100 ppm, which produced the largest recovery factor among the other two polymer concentrations. At a water viscosity of 0.96 cP, it is known to be lighter than the oil viscosity of 1 cP, this can affect the movement of water in the reservoir. Where if the water viscosity value is smaller than the viscosity value of the hydrocarbon, it will cause a water fingering or channeling phenomenon because water will tend to follow

Table 4. Core Characterization

Core Properties	**Value**	**Unit**
Long	7.385	cm
Diameter	3.828	cm
Bulk Volume	85.027	cc
Pore Volume	21.427	cc
Porosity	25.2	%
Permeability	1653	mD
Thickness	0.111302	ft
Oil Saturation	0.542972	ft
Pressure	100	psi
OOIP	11.63	cc

Table 5. Reserve Unit at Core

Parameters	**Value**	**Unit**
Gross formation volume	0.003	ft3
Formation pore volume	0.00076	ft3
Aqueous phase volume	0.00035	ft3
Oil phase volume	0.00041	ft3
Gaseous phase volume	0	ft3
Solid phase volume	0	ft3

Table 6. Result of IFT surfactant measurements

Concentration (%)	**IFT (dynes/cm)**
0	8
0.1	0.001247
0.15	0.00164367
0.2	0.00280933
0.3	0.00250467

Table 7. Rheology of Polymer

RPM	**Shear Rate, (1/day)**	**Viscosity (cP) at Concentration**		
		1000 ppm	**1100 ppm**	**1200 ppm**
6	7.92	15.78	14.05	15.27
12	15.8	9.09	11.24	13.03
30	39.6	7.06	8.69	10.54
60	79.2	4.85	4.74	6.82
100	132	4.1	4.1	5.62
120	158	3.58	2.6	5

the oil when the production process is carried out (Ahmed et al., 2023).

Therefore, a polymer with a concentration of 1100 ppm is calculated to be able to increase the viscosity of formation water or displacement fluid higher than the viscosity of hydrocarbons. In addition, rheological testing on polymer with a concentration of 1100 ppm produced a viscosity of 2.6 cP because the viscosity of the oil was 1 cP to increase the effectiveness of the sweep efficiency with an effective range of the displacing fluid to be effective, namely 1 cP-5 cP (Al-Shammari et al., 2011). Furthermore, in determining the concentration of surfactant-polymer that will be used in the application in the field to carry out EOR, namely with 0.1% surfactant and 1100 ppm polymer because the results of laboratory testing and testing using software have the best results compared to several other concentrations.

This research method is explained with flowchart at **Figure 5** below, flow chart of the procedure for implementing this final project. Starting by conducting a literature study to determine the methods and processes that will be carried out in the final project. Next, find laboratory data consisting of core flooding data and chemical flooding data. Next, modeling the core until inputting chemical data and matching the laboratory data. After completion of determining the data to be used after performing history matching, up scaling the field that has been modeled to carry out scenarios to increase oil recovery. After running all scenarios and analyzing the selection of the best scenario determined from several determinations.

Before analyzing the results of the selected coreflooding samples, it is necessary to match the data that has been tested in the laboratory and with the data inputted into the simulation software. The matching process is carried out on the simulation results with the lab test results by performing sensitivity on the relative permeability data from three interpolations. The first interpolation describes the results when pre-flush is performed, the second interpolation describes the results when surfactant-polymer injection is performed, and the third interpolation

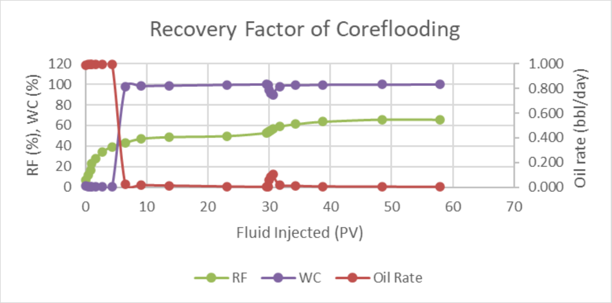

Fig 3. Coreflooding Graph

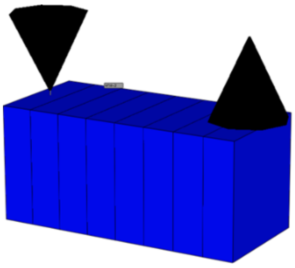

Fig 4. Core Sample

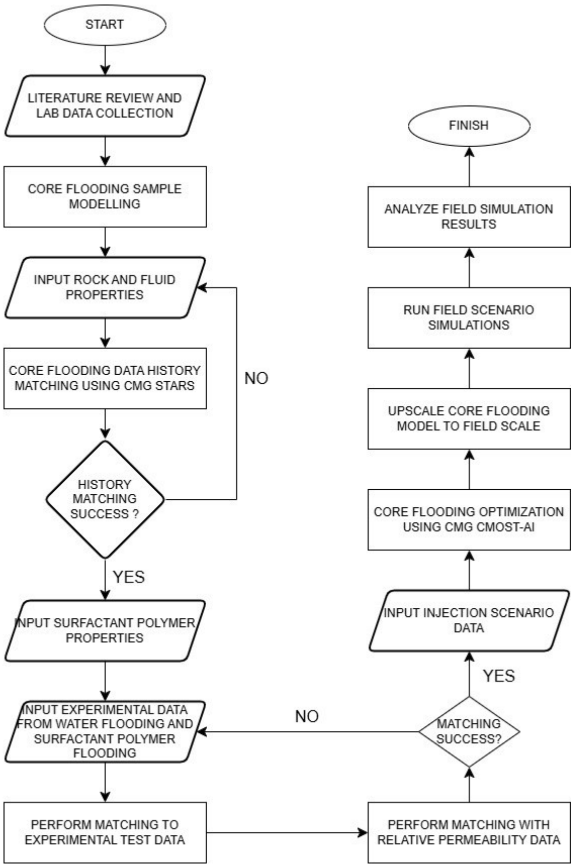

Fig 5. Research Workflow

describes the results when post-flush. The three interpolations are performed sensitivity to obtain the results of matching from the software to continue performing sensitivity with the CMG CMOST-Ai software.

After obtaining the sensitivity results from the relative permeability data, optimization is carried out to obtain the most optimal sensitivity results. Optimization is carried out with a focus on increasing the cumulative oil in the core sample, which has carried out as many as 500 experiments. The results of the 500 experiments are based on parameters that have an effect on the size of the cumulative oil produced. Each parameter will be given a range between the limits specified in **Table 8**.

In the field development scenario by using core data that has been subjected to sensitivity tests using CMG CMOST-Ai. The scenario that is focused on is the sensitivity of the total pore volume of the field. So, there will be development of the total injection volume. The total injection volume will be seen from the total pore volume saturated by oil.

From **Figure 6** it can be seen that the field that will be injected is not all of the pore volume saturated by oil. This study only injected 40% of the total pore volume that contained oil saturation. The selection was based on the size and duration of the injection to be carried out. Of the 40%, the injection scenario will only be carried out at 0.1 PV - 0.2 PV.

The scenario that the researcher will use is listed in **Table 9** by performing sensitivity to the total injection volume. The selection of the total PV injection is based on the length of time and effectiveness of the injection. In the scenario above, there is the value of the chemical injection that will be injected into the reservoir. For the injection value of pre-flush and post-flush are 0.05 PV and 0.15 PV.

Injection scenario is carried out for 40 years with pre-flush and post-flush times in each scenario at the same time. In addition, what distinguishes each scenario is the injection time of chemical injections because chemical injections have a different pore volume injection value. The purpose of determining the pre-flush value with the same value is so that all scenarios have the same start time, in addition, so that the reservoir becomes neutral when chemical injection is carried out, and the large number of pore volume injections in pre-flush is also so that it can reach points that have small porosity values. The post-flush value has the same value because the post-flush itself aims to push the chemical to reach hard-to-reach gaps to maximize the purpose of chemical injection. In addition, post-flush also helps hydrocarbon fluids in mobilizing production wells.

3. Modeling Result

In screening to determine the method used, there are two ways, namely by conducting manual screening and using EORgui software to further ensure the results of the screening method. In the screening results, EOR will input data from oil properties and reservoir characterization. From the result of screening using EORgui can be seen at **Figure 7** and **Figure 8** which shows that the surfactant-polymer flooding method is suitable for this field.

From **Figure 8**, it can be seen that surfactant-polymer is the most recommended method in this field. The parameters used for assessment can be seen in **Figure 7** namely API gravity, oil viscosity, oil saturation, formation type, depth, temperature, and permeability.

Table 8. Interpolation Sets Parameters and Sensitivity Range

Parameter	Sensitivity Range	Set 1	Set 2	Set 3
KROCW	0.1 – 1	0.38	0.2	0.2
KRWIRO	0.1 – 1	0.3	0.6	0.6
NOW	0.1 – 5	0.1	0.25	0.25
NW	0.1 – 5	2.8	5	1.2
SOIRW	0.1 – 1	0.2176	0.2176	0.2176
SORW	0.1 – 1	0.2176	0.2176	0.2176
SWCON	0.1 – 1	0.48795	0.48795	0.48795
SWCRIT	0.1 – 1	0.492	0.48795	0.48795

Table 9. Field Development Scenario

Parameter	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
PV Chemical Injection	0.1	0.12	0.14	0.16	0.18	0.2
Volume Injected (MMBBL)	112	134	156	179	201	223
Pre Flush (day)	1789	1789	1789	1789	1789	1789
Chemical Injection (day)	3578	4294	5009	5725	6441	7156
Post Flush (day)	5583	5583	5583	5583	5583	5583
Day Without Injection (day)	3650	2934	2219	1503	787	72
Duration (year)	40	40	40	40	40	40

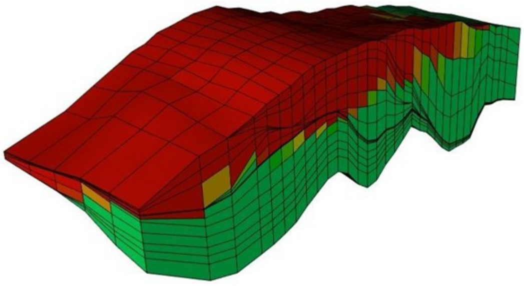

Fig 6. Distribution of Oil Saturation (Initial Condition)

In core modeling, a graph will be obtained to perform mix and match data by performing sensitivity to relative permeability parameters in order to obtain optimal results to be applied or up scaled into the field where optimization related to recovery factors will be carried out. **Figure 8** is the result of history matching carried out to obtain the most optimal results.

The analysis results were obtained with the output of the optimization, namely the maximum cumulative oil with a maximum value of 5.846E-5. Of the several parameters, there are parameters that have a very influential value on the results of the cumulative oil produced, namely residual oil saturation SORW1, critical water saturation SWCRIT1, irreducible oil saturation SOIRW2, connate water saturation SWCON2, exponent to calculate Krw at irreducible oil saturation NW3, and water relative permeability at irreducible oil saturation KRWIRO1 as shown in **Figure 10**.

In the history matching method using 500 experiments with a global error in the base case of 0.554% which is quite small with optimal results, but the desired results with the maximum cumulative oil output are selected from the experimental results with the experiment number_341. **Figure 11** is the result of optimization on the acquisition of cumulative oil production, in the base case data from the data it is known that the value of cumulative oil production in the core is obtained at 4.8E-5 and after optimization the cumulative oil production value is obtained at 5.85E-5 bbl with a total recovery factor of 79%.

It can be seen that the output with the cumulative oil value is in experiment_341 with a global error value of 0.577%, which is different by 0.023% as in **Figure 11**. The difference between the base case and optimal solution results is not far apart and the errors are also not large and can be used as a relative permeability value for each interpolation. These results are obtained through history matching value on the sample.

Before the scenario in increasing oil recovery with the EOR method was carried out, an analysis was first carried out on the base case of the field where the results of the base case produced a recovery factor of 6.14%. In addition, the pressure on the base case experienced a drastic decrease from the initial pressure value of the field in several compartments which caused the recovery factor value to be less than optimal.

The results can be seen during production without using the waterflooding scenario or the surfactant-polymer flooding scenario which produces a very small recovery factor of only 3.22%. This is because the reservoir pressure as a natural driver can be reduced without producing hydrocarbons to the maximum or on a small scale. Bottom hole pressure or BHP also has a big influence because in the

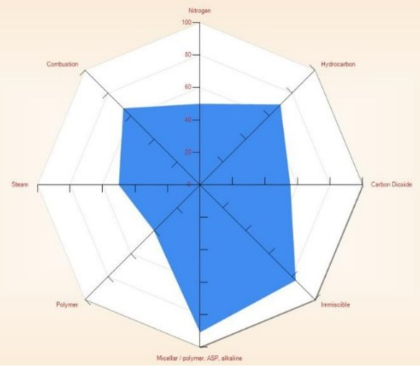

Fig 7. EORgui Software Screening Result

Title TA_101320041

API Gravity 65.03
Oil viscosity [cP] 1.5
Oil Saturation, fraction 0.4
Formation Sandstone
Thickness > 20 ft With Dip
Composition High % C1-C7
Depth [feet] 5741.71
Temperature [deg F] 149
Permeability [mD] 300

Properties	Nitrogen and flue gas	Hydrocarbon	Carbon Dioxide	Immiscible Gases	Miscellar/polymer, ASP, and alkaline flooding	Polymer flooding	Combustion	Steam
Oil API Gravity	> 35 Average 48	> 23 Average 41	> 22 Average 36	> 12	> 20 Average 35	> 15, < 40	> 10 Average 16	> 8 to 13.5 Average 13.5
Oil Viscosity (cp)	< 0.4 Average 0.2	< 3 Average 0.5	< 10 Average 1.5	< 600	< 35 Average 13	>10, <150	< 5,000 Average 1200	< 200,000 Average 4,700
Composition	High % C1-C7	High % C2-C7	High % C5-C12	Not critical	Light, intermediate Some organic acids for alkaline floods	Not critical	Some asphaltic components	Not critical
Oil Saturation (PV fraction)	> 0.40 Average 0.75	> 0.30 Average 0.80	> 0.20 Average 0.55	> 0.35 Average 0.70	> 0.35 Average 0.53	> 0.70 Average 0.80	> 0.50 Average 0.72	> 0.40 Average 0.66
Formation Type	Sandstone or Carbonate	Sandstone or Carbonate	Sandstone or Carbonate	Not critical	Sandstone preferred	Sandstone preferred	High porosity sandstone	High porosity sandstone
Net Thickness (ft)	Thin unless dipping	Thin unless dipping	Wide range	Not critical if dipping	Not critical	Not critical	> 10 feet	> 20 feet
Average Permeability (md)	Not critical	Not critical	Not critical	Not critical	> 10 md Average 450 md	> 10 md Average 800 md	> 50 md	> 200 md
Depth (ft)	> 6000	> 4000	> 2500	> 1800	< 9000 Average 3250	< 9000	< 11500 Average 3500	< 4500
Temperature (deg F)	Not critical	Not critical	Not critical	Not critical	< 200	< 200	> 100	Not critical

Fig 8. Detailed EORgui Software Screening Result

reservoir type with a naturally fractured reservoir, pressure loss can occur without producing on a large scale, as can be seen in **Figure 13** that the pressure drop drastically from 3000 psi experienced a decrease of less than 1000 psi, which results in the hydrocarbons not being able to be pushed towards the production well.

This can be caused by the type of reservoir in flowing hydrocarbon fluids, as well as the mobility of hydrocarbons attached to the reservoir rock which causes it to be unproducible. In addition, the viscosity of the formation water has a smaller value compared to the viscosity of the oil to be produced, this will have an impact on the production process because the formation water will have faster mobility than the mobility of the oil produced, therefore there will be several phenomena such as fingering, low sweep efficiency, increased water production, and uneven production (Putra and Kiono, 2021). Therefore, the selection of EOR methods to be used in order to optimally increase the recovery factor in this field by using the results of EOR screening is surfactant-polymer.

In the results of the running scenario that has been carried out on the sensitivity of the total injection pore volume of all scenarios that have been obtained. At the beginning there is a base case scenario which is a scenario without using an injection well. It can be seen that the results of this base case scenario have a fairly small value when produced with a long time as in the first scenario. Furthermore, the scenario that has been made is carried out as in **Table 10** with constraints that have been determined in each production well and injection well. In addition to the concentration of chemicals that have been known, the total pore volume also has a great influence in increasing the recovery factor. It can be seen that every increase in total pore volume injection can increase the results of recovery factor.

The scenario shown in **Table 10** involves analyzing sensitivity to the total injection volume. The total PV

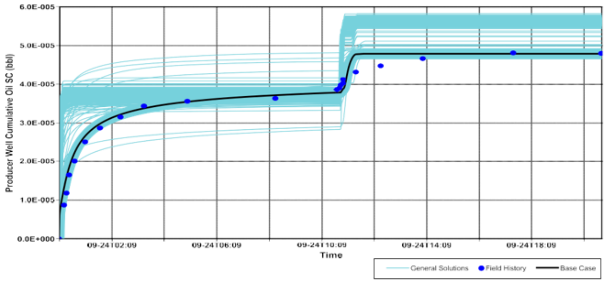

Fig 9. History Matching Result

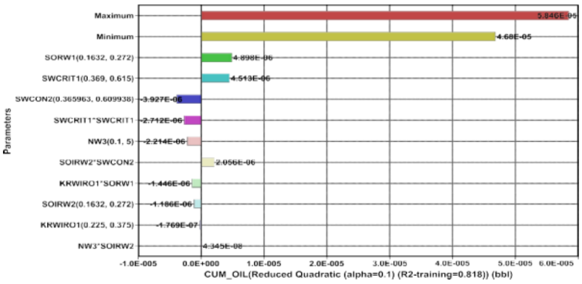

Fig 10. Estimated Effect of History Matching

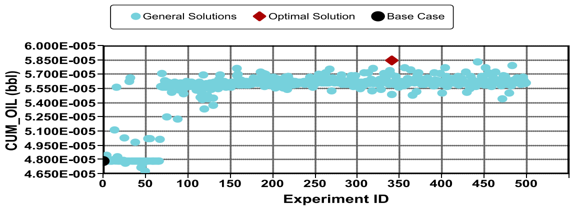

Fig 1. Cummulative Oil Optimization Experiment

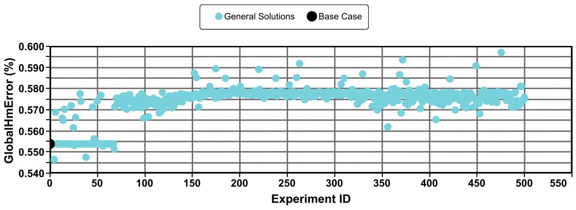

Fig 12. Global Error History Matching Experiment

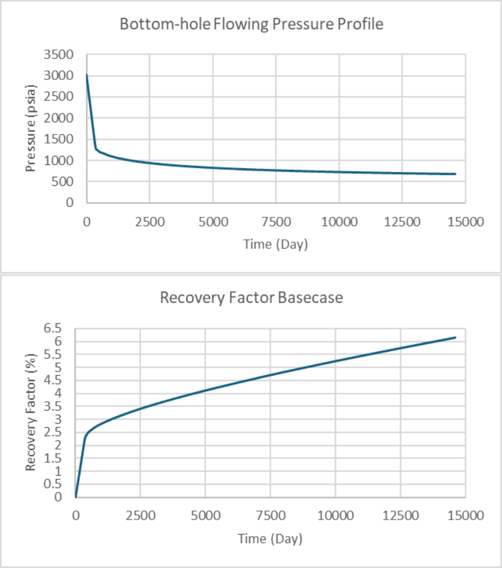

Fig 13. BHP Profile and Recovery Factor at Basecase

Table 10.Simulation Result

Parameter	Base Case	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
PV Chemical Injection	-	0.1	0.12	0.14	0.16	0.18	0.2
Volume Injected (MMBBL)		112	134	156	179	201	223
Pre Flush (day)		1789	1789	1789	1789	1789	1789
Chemical Injection (day)		3578	4294	5009	5725	6441	7156
Post Flush (day)		5583	5583	5583	5583	5583	5583
Day Without Injection (day)		3650	2934	2219	1503	787	72
Duration (year)		40	40	40	40	40	40
Total Cumulative Oil (MBBL)	22.87	183,391	185,860	188,005	189,292	190,298	189,935

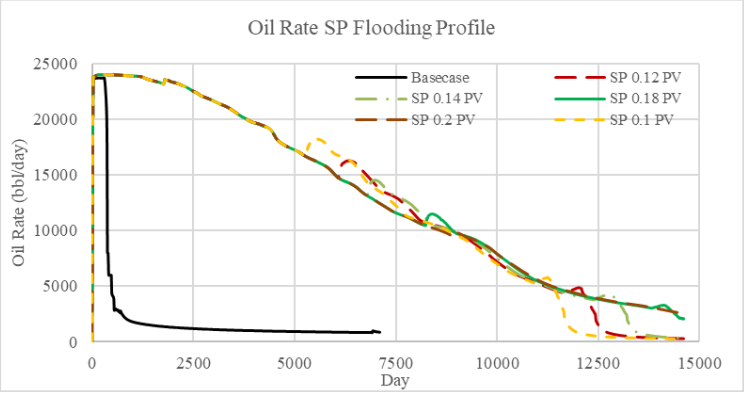

Fig 14. Oil Rate after SP Flooding

injection amount was selected based on both the duration and the effectiveness of the injection process.

The results of the scenario produced several recovery factors with a simulation time of 40 years with differences in the value of the pore volume of chemical injection. From the results obtained from the increase in the recovery factor value, it always increased to the SP point of 0.18 PV with a recovery factor of 51.21%. At an increase in pore volume of 0.2 PV, the recovery factor decreased. In several studies, many things affect this, because several phenomena can occur that can cause a decrease in the recovery factor. This is because the increase in pore volume injection is no longer effective, which causes a phenomenon that causing a decrease in the value of the recovery factor obtained (Zhao et al., 2023). From the results of the sensitivity pore volume, the value of the increase in the recovery factor was obtained which continued to increase along with the increase in the pore volume injection, because the large injection volume greatly influences the increase in the recovery factor, if the larger the injection volume, the larger the recovery factor obtained (Olabode et al., 2024).

Figure 14 is a profile of the oil rate from the field that has undergone surfactant-polymer injection. From the graph produced from the simulation, it can be analyzed that there is an increase in the rate when surfactant-polymer injection is carried out. The graph states that surfactant-polymer flooding has been proven to increase oil recovery from a field as evidenced by the increase in the oil rate after surfactant-polymer flooding was carried out (Zhao et al., 2023).

Shown at **Table 10**, total cumulative oil obtained in each scenario of increasing the total pore volume injection to surfactant-polymer injection. From the results, an increase is seen in each scenario, but in the last scenario it has a lower value compared to the previous cumulative oil results.

So, in the surfactant-polymer flooding test in Field R, swhich can be seen from the test result that the most appropriate EOR method used in the field is surfactant-polymer flooding as obtained by using EORgui software as shown in **Figure 8**. After several history matching and optimizations were carried out on the core samples obtained and up scaled into the field. Furthermore, the scenario that has been determined was carried out on **Table 10** and the results shown as well. From the 5 scenarios of the surfactant-polymer flooding method, the one with the best increase in value was the 0.18 PV scenario with a recovery factor of 51.21% because the increase in pore volume injection of 0.2 PV no longer experienced an increase in recovery factor.

4. Conclusions

Surfactant-polymer flooding has proven to increase the recovery factor of a field with surfactant as a material to reduce interfacial tension and form micelles to increase the mobility of oil left in the reservoir. Polymer as a material to increase the viscosity of the driving fluid to increase sweep efficiency.

The results of EOR screening were obtained manually and using software that is suitable for the field, namely the surfactant-polymer injection method by looking at reservoir characterization and oil properties.

The selection of surfactant-polymer flooding materials is determined from the results of laboratory tests, for surfactants it is determined by the lowest interfacial tension reduction value at a concentration of 0.1%, for polymers it is determined by a stable viscosity reduction and the results of simulation tests, namely at a concentration of 1100 ppm.

The best scenario result is surfactant-polymer flooding with a total PV injection of 0.18 PV with a recovery factor of 51.21% with a total cumulative oil of 190.3 MMBBL.

Some parameters that influence core modeling are residual oil saturation SORW1, critical water saturation SWCRIT1, irreducible oil saturation SOIRW2, connate water saturation SWCON2, exponent to calculate Krw at irreducible oil saturation NW3, and water relative permeability at irreducible oil saturation KRWIRO1.

5. References

Ahmed, M.E., Sultan, A.S., Al-Sofi, A., Al-Hashim, H.S., 2023. Optimization of surfactant-polymer flooding for enhanced oil recovery. Journal of Petroleum Exploration and Production Technology 13, 2109–2123. https://doi.org/10.1007/s13202-023-01651-0.

Al-Shammari, B., Al-Fariss, T., Al-Sewailm, F., Elleithy, R., 2011. The effect of polymer concentration and temperature on the rheological behavior of metallocene linear low-density polyethylene (mLLDPE) solutions. Journal of King Saud University - Engineering Sciences 23, 9–14. https://doi.org/10.1016/j.jksues.2010.07.001.

Gutierrez, M., Benavides, J., Morales, E., Iturralde, S., 2022. Numerical simulation by STARS (CMG) using surfactants for enhanced oil recovery in a reservoir. Journal of Pharmaceutical Negative Results 13, 10–34. https://doi.org/10.47750/pnr.2022.13.s09.002.

Hakiki, F., Maharsi, D.A., Marhaendrajana, T., 2015. Surfactant-polymer coreflood simulation and uncertainty analysis derived from laboratory study. Journal of Engineering and Technological Sciences 47, 706–725. https://doi.org/10.5614/j.eng.technol.sci.2015.47.6.9.

Kristanto, D., Hermawan, Y.D., 2019. Coreflooding test study in the laboratory using surfactant-polymer injection to increase oil field production. In: Proceedings of the National Conference on Earth Science and Technology. UPN "Veteran" Yogyakarta, Yogyakarta, pp. 23–30.

Nelson, R.A., 2001. Geologic Analysis of Naturally Fractured Reservoirs, 2nd ed. Gulf Professional Publishing, Boston.

Olabode, O., Dike, H., Olaniyan, D., Oni, B., Faleye, M., 2024. Experimental investigation of the effect of surfactant–polymer flooding on enhanced oil recovery for medium crude oil. Polymers 16, 1674. https://doi.org/10.3390/polym16121674.

Putra, B.P., Kiono, B.F.T., 2021. Understanding enhanced oil recovery (EOR) as a solution to increase Indonesia's oil production. Journal of New and Renewable Energy 2, 84–100. https://doi.org/10.14710/jebt.2021.11152.

Taber, J.J., Martin, F.D., Seright, R.S., 1997. EOR screening criteria revisited - part 1: introduction to screening criteria and enhanced recovery field projects. SPE Reservoir Engineering 12, 189–198. https://doi.org/10.2118/35385-PA.

Terry, R.E., 2001. Enhanced oil recovery. In: Encyclopedia of Physical Science and Technology, 3rd ed. Academic Press, San Diego, vol. 18, pp. 503–518.

Zhao, L., Li, B., Wei, P., Wang, K., 2023. Experimental study on the evaluation of surfactant/polymer flooding for enhancing oil recovery in Kumkol Oil Field. Journal of Petroleum Exploration and Production Technology 13, 853–864. https://doi.org/10.1007/s13202-022-01564-4.